Image Project Order File Cover Page

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This page identifies those items that were not scanned during the initial production scanning phase. They are available in the original file, may be scanned during a special rescan activity or are viewable by direct inspection of the file.

0 064 **Order File Identifier**

Organizing (done) ☑ Two-sided ☐ Rescan Needed

RESCAN

☐ Color Items:

☐ Greyscale Items:

☐ Poor Quality Originals:

☐ Other:

DIGITAL DATA

☐ Diskettes, No.

☐ Other, No/Type:

OVERSIZED (Scannable)

☐ Maps:

☐ Other Items Scannable by a Large Scanner

OVERSIZED (Non-Scannable)

☐ Logs of various kinds:

☐ Other::

NOTES:

BY: Maria Date: 10/20/10 /s/ MP

Project Proofing

BY: Maria Date: 10/20/10 /s/ MP

Scanning Preparation _____ x 30 = _____ + _____ = TOTAL PAGES 869 (Count does **not** include cover sheet)

BY: Maria Date: 10/20/10 /s/ MP

Production Scanning

Stage 1 Page Count from Scanned File: 870 (Count **does** include cover sheet)

Page Count Matches Number in Scanning Preparation: ✓ YES _____ NO

BY: Maria Date: 10/20/10 /s/ MP

Stage 1 If *NO* in stage 1, page(s) discrepancies were found: _____ YES _____ NO

BY: Maria Date: /s/

Scanning is complete at this point unless rescanning is required.

ReScanned

BY: Maria Date: /s/

Comments about this file: Quality Checked

Other Index #064

1. ---------- Various Draft Regulations
2. ---------- Notes
3. ---------- Comments
4. ---------- Transcripts
5. ---------- Final Regulations Package

Other Index #064

#5

FRAN ULMER
LIEUTENANT GOVERNOR
STATE OF ALASKA

RECEIVED
MAY 19 2000
Alaska Oil & Gas Cons. Commission
Anchorage

MEMORANDUM

OFFICE OF THE LIEUTENANT GOVERNOR

DATE: May 12, 2000

TO: ROBERT CHRISTENSON, DEPARTMENT CONTACT, ALASKA OIL AND GAS CONSERVATION COMMISSION

FROM: Carol Collins
Special Assistant, Administrative Code Coordinator

SUBJECT: Permanent Filing of Regulation(s)

AK. OIL AND GAS CONSERVATION COMMISSION: PERMITS TO DRILL AND REGULATORY COST CHARGES
20 AAC 25.005; .605 - .630

Date regulation signed by Lieutenant Governor (or designee)	05/05/2000
Date regulation effective	06/04/2000
Attorney General File No.	993.00.0117
Regulation will be printed in	Register 154, July 2000

ATTACHMENTS

1. Signed Adoption Order/Certification of Compliance	X
2. Designee's Certificate if applicable	N/A

P.O. Box 110015 Juneau, Alaska 99811-0015 Phone (907) 465-3520 Fax (907) 465-5400

ORDER CERTIFYING THE CHANGES TO
REGULATIONS OF THE ALASKA OIL AND GAS CONSERVATION
COMMISSION

The attached eight pages of regulations dealing with regulatory cost charges under AS 31.05.093, and dealing with the drilling of wells under AS 31.05.030 and AS 31.05.090, are hereby certified to be a correct copy of the regulation changes that the Alaska Oil and Gas Conservation Commission adopted at its March 22, 2000 meeting, under the authority of AS 31.05.030, AS 31.05.040, AS 31.05.090 and AS 31.05.093, after compliance with the Administrative Procedure Act (AS 44.62), specifically including notice under AS 44.62.190 and 44.62.200 and opportunity for public comment under AS 44.62.210.

This action is not expected to require an increased appropriation.

On the record, in considering public comments, the Alaska Oil and Gas Conservation Commission paid special attention to the cost to private persons of the regulatory action being taken.

The regulation changes described in this order take effect on the 30th day after they have been filed by the lieutenant governor as provided in AS 44.62.180.

DATE: March 23, 2000
Anchorage, Alaska

Robert N. Christenson, P.E.
Chair

FILING CERTIFICATION

I, Fran Ulmer, Lieutenant Governor for the State of Alaska, certify that on May 5, 2000, at 4:25 p.m., I filed the attached regulations according to the provisions of AS 44.62.040 – 44.62.120.

Lieutenant Governor

Effective June 4, 2000

Register 154, July 2000

RECEIVED
MAY 12 2000
Alaska Oil & Gas Cons. Commission
Anchorage

MEMORANDUM

State of Alaska
Department of Law

TO: Robert N. Christenson, Chair
Alaska Oil & Gas
Conservation Commission

DATE: May 5, 2000

FILE NO.: 993-00-0117

TELEPHONE NO.: 465-3600

FROM: Steven C. Weaver
Assistant Attorney General
Legislation/Regulations Section—Juneau

SUBJECT: Regulations re: permits to drill and regulatory cost charges (20 AAC 25.005; 20 AAC 25.605 – 20 AAC 25.630)

Under AS 44.62.060, we have reviewed the attached adoption and amendment of these regulations by the Alaska Oil and Gas Conservation Commission, and approve the changes for filing by the lieutenant governor. I have reviewed this project under a specific delegation dated April 25, 2000 from the Regulations Attorney. A duplicate original of this memorandum is being furnished to the lieutenant governor, along with the eight pages of regulations and the related documents.

You might wish to contact the lieutenant governor's office to confirm the filing date and effective date of the attached regulation changes.

The February 17, 2000 public notice and the March 23, 2000 certification order both state that this action is not expected to require an increased appropriation. Therefore, a fiscal note under AS 44.62.195 is not required.

In accordance with AS 44.62.125(b)(6), some corrections have been made in the regulations, as shown on the attached copy.

SCW

cc w/enc: Dan Spencer, Director and Regulations Contact
Division of Administrative Services
Department of Administration

Camille Oechsli-Taylor, Commissioner
Alaska Oil & Gas Conservation Commission

Robert E. Mintz
Assistant Attorney General
Oil, Gas, & Mining Section—Anchorage

RECEIVED
MAY 12 2000
Alaska Oil & Gas Cons. Commission
Anchorage

MEMORANDUM

State of Alaska
Department of Law

TO: Robert N. Christenson, Chair
Alaska Oil & Gas
Conservation Commission

DATE: May 5, 2000

FILE NO.: 993-00-0117

TELEPHONE NO.: 465-3600

FROM: Steven C. Weaver
Assistant Attorney General
Legislation/Regulations Section—Juneau

SUBJECT: Regulations re: permits to drill and regulatory cost charges (20 AAC 25.005; 20 AAC 25.605 – 20 AAC 25.630)

Under AS 44.62.060, we have reviewed the attached adoption and amendment of these regulations by the Alaska Oil and Gas Conservation Commission, and approve the changes for filing by the lieutenant governor. I have reviewed this project under a specific delegation dated April 25, 2000 from the Regulations Attorney. A duplicate original of this memorandum is being furnished to the lieutenant governor, along with the eight pages of regulations and the related documents.

You might wish to contact the lieutenant governor's office to confirm the filing date and effective date of the attached regulation changes.

The February 17, 2000 public notice and the March 23, 2000 certification order both state that this action is not expected to require an increased appropriation. Therefore, a fiscal note under AS 44.62.195 is not required.

In accordance with AS 44.62.125(b)(6), some corrections have been made in the regulations, as shown on the attached copy.

SCW

cc w/enc: Dan Spencer, Director and Regulations Contact
Division of Administrative Services
Department of Administration

Camille Oechsli-Taylor, Commissioner
Alaska Oil & Gas Conservation Commission

Robert E. Mintz
Assistant Attorney General
Oil, Gas, & Mining Section—Anchorage

MEMORANDUM

State of Alaska
Department of Law

TO: Hon. Fran Ulmer
Lieutenant Governor

DATE: May 5, 2000

FILE NO.: 993-00-0117

TELEPHONE NO.: 465-3600

FROM: Steven C. Weaver
Assistant Attorney General
Legislation/Regulations Section—Juneau

SUBJECT: Regulations re: permits to drill and regulatory cost charges (20 AAC 25.005; 20 AAC 25.605 – 20 AAC 25.630)

We have reviewed the attached regulations from the Alaska Oil and Gas Conservation Commission. I have reviewed this project under a specific delegation dated April 25, 2000 from the Regulations Attorney. A duplicate of this memorandum is being furnished to Chair Christenson along with a copy of the regulations.

The Department of Law has reviewed the attached regulations against the statutory standards of the Administrative Procedure Act. Based upon our review, we find no legal problems. This memorandum and the attached duplicate memorandum dated May 5, 2000 constitute the written statement of approval under AS 44.62.060(b) and (c) that authorizes your office to file the attached regulations.

The regulation changes were adopted by the Alaska Oil and Gas Conservation Commission after the close of the public comment period. The regulations amend a provision on permits to drill to allow advance oral approvals for certain redrilling activities, and adopt provisions to implement and interpret recently enacted statutory provisions at AS 31.05.093, requiring the commission to calculate and assess regulatory cost charges upon well operators who have obtained permits to drill.

The certification order for the regulations states that this action is not expected to require an increased appropriation. Therefore, a fiscal note under AS 44.62.195 is not required.

We have made a few technical corrections to conform the regulations with the drafting manual under AS 44.62.060 and 44.62.125. The corrections are shown on the attached copy of the regulations.

SCW

cc w/enc: Robert N. Christenson, Chair
Alaska Oil & Gas Conservation Commission

7,06

Notice of Filing and Effective Date of Regulations

New regulations of the Alaska Oil and Gas Conservation Commission, 20 AAC 25.605 – 20 AAC 25.630, address regulatory cost charges under AS 31.05.093. An amendment to an existing regulation, 20 AAC 25.005(a), allows for temporary oral approval of certain drilling operations. These regulation changes were filed by the Lieutenant Governor on May 5, 2000, and became effective on June 4, 2000.

MEMORANDUM **STATE OF ALASKA**

ALASKA OIL AND GAS CONSERVATION COMMISSION

TO: Regulations Attorney
Legislation/Regulations Section
Department of Law

March 30, 2000

FAX No: 276-7542
Telephone No.: 279-1433

SUBJECT: Request for Legal Review of Regulations Project on oil and gas
Your file no: 993-00-0117

FROM: Daniel T. Seamount, Jr.
Commissioner

We are requesting legal review and approval of the attached final regulations on regulatory cost charges and drilling of wells, which were adopted by the Alaska Oil and Gas Conservation Commission.

Enclosed are the following documents:

1. the original and one copy of the final regulations for the Department of Law's use;
2. the original of the signed and dated adoption document;
3. a copy of the public notice;
4. additional regulations notice information form;
5. the original publishers' affidavit of publication;
6. the original of the affidavit of notice;
7. the original of the affidavit of oral hearing;
8. relevant minutes from the March 22, 2000, meeting;
9. staff affidavit for the relevant minutes.

We would appreciate the project being reviewed in time for the regulations to take effect before the end of the current fiscal year, to allow the Commission to timely collect regulatory cost charges. We have worked with Assistant Attorney General Rob Mintz on the project.

Upon completion of your review, please forward the regulations to the lieutenant governor for filing.

STATE OF ALASKA)
) ss.
3RD JUDICIAL DISTRICT)

AFFIDAVIT OF ORAL HEARING

I, Daniel T. Seamount, Jr., Commissioner of the Alaska Oil and Gas Conservation Commission, being sworn, state the following:

On March 21, 2000, at 9:00 AM, in the conference room of the Alaska Oil and Gas Conservation Commission at 3001 Porcupine Drive, Anchorage, Alaska, a public hearing presided over by Robert N. Christenson, P.E., Chair, was held in accordance with AS 44.62.210 for the purpose of taking testimony in connection with the adoption of changes to Title 20, Chapter 25, of the Alaska Administrative Code, dealing with regulatory cost charges and the drilling of wells.

DATE: March 30, 2000
Anchorage, Alaska

Daniel T. Seamount, Jr., Commissioner

SUBSCRIBED AND SWORN TO before me this 30th day of March, 2000.

OFFICIAL SEAL
State of Alaska
DIANA L. FLECK
NOTARY PUBLIC
My Commission Expires: 8-31-03

Diana L. Fleck
Notary Public in and for
the State of Alaska.
My commission expires: August 31, 2003

STATE OF ALASKA)
) ss.
3RD JUDICIAL DISTRICT)

AFFIDAVIT OF NOTICE OF PROPOSED ADOPTION OF REGULATIONS AND FURNISHING OF ADDITIONAL INFORMATION

I, Shelly Hebert, Administrative Clerk I, of Alaska Oil and Gas Conservation Commission, being sworn, state the following:

As required by AS 44.62.190, notice of the proposed adoption of changes to Title 20, Chapter 25, of the Alaska Administrative Code, dealing with regulatory cost charges and the drilling of wells, has been given by

(1) being published in a newspaper or trade publication;
(2) being mailed to interested persons as shown on the attached list;
(3) being mailed or delivered to appropriate state officials;
(4) being furnished to the Department of Law, along with a copy of the proposed regulations;
(5) being furnished to incumbent State of Alaska legislators and the Legislative Affairs Agency;
(6) being furnished to the Resources and Special Oil and Gas Committees of the Alaska House of Representatives and the Resources Committee of the Alaska Senate, along with a copy of the proposed regulations;
(7) being furnished to the staff of the Administrative Regulation Review Committee, along with a copy of the proposed regulations.

As required by AS 44.62.190(d), additional regulations notice information regarding the proposed adoption and amendment of the regulations described above has been furnished to

(1) interested persons as shown on the attached list;
(2) those in (5) - (7) of the list above.

A copy of the notice and the additional information required by AS 44.62.190(d) have also been furnished to the commissioner's office, Department of Administration, for forwarding to the lieutenant governor for publication in the Alaska Administrative Journal as required by AS 44.62.175(a)(1) and 44.62.190(a)(1).

DATE: March 30, 2000
Anchorage, Alaska

Shelly Hebert
Shelly Hebert, Administrative Clerk I

SUBSCRIBED AND SWORN TO me this 30th day of March, 2000.

OFFICIAL SEAL
State of Alaska
DIANA L. FLECK
NOTARY PUBLIC
My Commission Expires: 8-31-03

Diana L. Fleck
Notary Public in and for
the State of Alaska.
My commission expires: August 31, 2003

ALASKA OIL AND GAS CONSERVATION COMMISSION

March 22, 2000
23

Excerpt From Unapproved Minutes

Commissioner Cammy Oechsli Taylor moved and Commissioner Daniel T. Seamount, Jr. seconded the following motion:

"I move that we adopt the regulations as amended on the draft that is dated March 22, 2000 and initialed by the Chair, Bob Christenson, with the addendum insert page."

The motion carried unanimously.

STATE OF ALASKA)
) ss.
3RD JUDICIAL DISTRICT)

AFFIDAVIT OF COMMISSION ACTION

I, Robert N. Christenson, Chair of the Alaska Oil and Gas Conservation Commission, being duly sworn, state the following:

The attached motion dealing with regulatory cost charges under AS 31.05.093, and dealing with the drilling of wells under AS 31.05.030 and AS 31.05.090, was passed by the Alaska Oil and Gas Conservation Commission during its March 22, 2000 meeting.

Date: March 23, 2000

Anchorage, AK

Robert N. Christenson, Chair

SUBSCRIBED AND SWORN TO before me this 23rd day of March, 2000.

OFFICIAL SEAL
State of Alaska
DIANA L. FLECK
NOTARY PUBLIC
My Commission Expires: 8-31-03

Notary Public in and for
The State of Alaska
My commission expires: 8-31-03

ORDER CERTIFYING THE CHANGES TO
REGULATIONS OF THE ALASKA OIL AND GAS CONSERVATION
COMMISSION

The attached eight pages of regulations dealing with regulatory cost charges under AS 31.05.093, and dealing with the drilling of wells under AS 31.05.030 and AS 31.05.090, are hereby certified to be a correct copy of the regulation changes that the Alaska Oil and Gas Conservation Commission adopted at its March 22, 2000 meeting, under the authority of AS 31.05.030, AS 31.05.040, AS 31.05.090 and AS 31.05.093, after compliance with the Administrative Procedure Act (AS 44.62), specifically including notice under AS 44.62.190 and 44.62.200 and opportunity for public comment under AS 44.62.210.

This action is not expected to require an increased appropriation.

On the record, in considering public comments, the Alaska Oil and Gas Conservation Commission paid special attention to the cost to private persons of the regulatory action being taken.

The regulation changes described in this order take effect on the 30th day after they have been filed by the lieutenant governor as provided in AS 44.62.180.

DATE: March 23, 2000
Anchorage, Alaska

Robert N. Christenson, P.E.
Chair

FILING CERTIFICATION

I,_____, Lieutenant Governor for the State of Alaska, certify that on _____, _____, at _____ .m., I filed the attached regulations according to the provisions of AS 44.62.040 – 44.62.120.

_____
Lieutenant Governor

Effective _____

Register _____

MEETING AGENDA **

March 22, 2000

9:00 AM

GENERAL COMMISSION BUSINESS:

1. Proposed regulations.

** Circumstances may cause items to be either added or deleted from the agenda or a meeting cancellation. Please contact Diana Fleck at (907) 793-1221 for confirmation.

SIGN IN SHEET

NAME (PLEASE PRINT)	AFFILIATION
Theresa Rockhill	AGA

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.565. PLANS SUBMITTED UNDER AS 31.05.030(i). (a) A written plan submitted under AS 31.05.030(i) must include an original and three copies of the following material:

(1) the identification of the lessee submitting the plan;

(2) the identification of the field covered by the plan;

(3) a general timetable and description of planned development activities;

(4) a general timetable and description of expected hiring and contracting decisions in connection with the development of the field;

(5) a detailed description of the best efforts that the lessee voluntarily agrees to use to employ residents of the state, consistent with law, and to contract with firms in the state for work in connection with the development of the field, including the fabrication and installation of required facilities, whenever feasible;

(6) the date the plan is submitted; and

(7) the lessee's certification of its voluntary agreement to use its best efforts as set out in the plan, including the name, title, and signature of the individual executing the certification on behalf of the lessee, which person must be authorized to bind the lessee.

(b) Upon receipt of a plan meeting the requirements of (a) of this section, the commission will promptly schedule a public hearing on the plan and give public notice of the hearing in accordance with AS 31.05.050(b). The hearing will be scheduled at least 10 days after the date of the public notice. The provisions of 20 AAC 25.540 do not apply to a hearing

held under this section.

(c) In AS 31.05.030(i) and this section,

(1) "development" means all steps taken in the search for and the exploration, capture, and production of oil or gas;

(2) "firm in the state" means a firm or contractor that

(A) has held an Alaska business license for the preceding six months;

(B) maintains, and has maintained for the preceding six months, a place of business in the state that competently and professionally deals in supplies, services, or construction of the nature required for work in connection with development of an oil or gas field; and

(C) is

(i) a sole proprietorship and the proprietor is an Alaska resident;

(ii) a partnership and more than 50 percent of the partnership interest is held by Alaska residents;

(iii) a limited liability company and more than 50 percent of the membership interest is held by Alaska residents;

(iv) a corporation that has been incorporated in the state or is authorized to do business in the state; or

(v) a joint venture and a majority of the venturers qualify as firms in the state under this paragraph. (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.040 AS 31.05.060

20 AAC 25.005(a) is amended to read:

20 AAC 25.005. PERMIT TO DRILL. (a) Before drilling or redrilling a well or re-entering an abandoned well, a person shall submit and obtain the commission's approval of an application for a Permit to Drill (Form 10-401). If, after drilling a well, a person wishes immediately to redrill below the structural or conductor casing to a new bottom-hole location not requiring a spacing exception under 20 AAC 25.055, the person may request oral approval from the commission to avoid interruption of operations. If oral approval is obtained, the name of the representative of the commission who provided oral approval and the date of the approval must be included on the application for a Permit to Drill, which must be submitted by the commission's next working day for final approval by the commission.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am / / , Register)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.605. CALCULATION OF REGULATORY COST CHARGES. (a) The formula for determining a person's regulatory cost charge under AS 31.05.093 is

$$RCC = \frac{V_{OP}}{V_{TOT}} * (A - F - L)$$

where

RCC = the regulatory cost charge;

V_{OP} = the total volume of oil and gas produced from, and oil, gas, water, and other fluids injected into, during the most recently concluded calendar year, wells for which a permit to drill has been issued under AS 31.05.090, of which the person is the operator on the first day of the fiscal year, and ~~which~~ that have not before that day been plugged and abandoned and reported as abandoned in accordance with ~~regulations of the commission~~ this chapter;

V_{TOT} = the total volume of oil and gas produced from, and oil, gas, water, and other fluids injected into, during the most recently concluded calendar year, all wells for which a permit to drill has been issued under AS 31.05.090 and ~~which~~ that have not before the first day of the fiscal year been plugged and abandoned and reported as abandoned in accordance with ~~regulations of the commission~~ this chapter;

A = the appropriation, other than from federal receipts, made for the operating costs of the commission for the fiscal year;

F = the commission's reasonable estimate of the total fees to be collected under AS 31.05.090 during the fiscal year;

L = the lapsed amount of a previous appropriation that is appropriated ~~from the general fund~~ for the fiscal year under AS 31.05.093(d).

(b) For purposes of calculating regulatory cost charges, volumes of fluids produced from or injected into wells ~~will be~~ consist of the applicable volumes reported to the commission under 20 AAC 25.230(b) and 20 AAC 25.432, except that

(1) if an operator has failed to report a volume as required, if two or more reported volumes are inconsistent, or if the commission determines that a reported volume is otherwise unreliable, the commission will, in its discretion, calculate or estimate volumes as it considers appropriate;

(2) the commission will, in its discretion, add the volume of a substantial spill or other release of oil or gas that is not included in a report under 20 AAC 25.230(b) or 20 AAC 25.432.

(c) For purposes of AS 31.05.093(a) and this chapter, a well is considered plugged and abandoned and reported as abandoned in accordance with this chapter if ~~regulations of the commission when~~ the well has been abandoned in accordance with 20 AAC 25.105 and 20 AAC 25.112 and a complete well record for the well, including a description of plugging operations, on a Well Completion or Recompletion Report and Log (Form 10-407) as required by 20 AAC 25.070(3) has been filed with the commission after abandonment. (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.093

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.610. ESTIMATED REGULATORY COST CHARGES. (a) Before determining regulatory cost charges for a fiscal year under 20 AAC 25.615, the commission will, in its discretion, establish estimated regulatory cost charges to be paid during the first quarter of the fiscal year. The amount of an estimated regulatory cost charge is ~~will be~~ one-fourth of the

commission's reasonable estimate, based on information then available, of what the person's regulatory cost charge will be for that fiscal year.

(b) The commission will provide a person subject to an estimated regulatory cost charge with written notice of the amount of the charge and the payment date. The commission ~~which~~ will set a payment date to be at least 20 days after the date of the notice. The person shall pay the estimated regulatory cost charge by the payment date. (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.093

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.615. COMMISSION'S DETERMINATION OF REGULATORY COST CHARGES. (a) After the later of the beginning of a fiscal year or the date of enactment of an appropriation for the operating costs of the commission for that fiscal year, the commission will provide to persons subject to a regulatory cost charge under AS 31.05.093 written notice of the proposed regulatory cost charges to be imposed on persons subject to regulatory cost charges for that fiscal year and the basis for the charges, in accordance with 20 AAC 25.605.

(b) Within 30 days after notice is issued under (a) of this section, a person subject to a regulatory cost charge may submit comments on, or request a revision to, the regulatory cost charges proposed by the commission. A request for a revision must be accompanied by an explanation of the basis for the requested revision. Before a hearing is held under (c) of this section, the commission will provide all persons subject to a regulatory cost charge with copies

of comments and requests for revision received by the commission or with notice of the persons' right to inspect those comments and requests for revision.

(c) Within 60 days after notice is issued under (a) of this section, the commission will hold a public hearing (in accordance with 20 AAC 25.540) on the proposed regulatory cost charges.

(d) Within 90 days after notice is issued under (a) of this section, the commission will issue an order determining the regulatory cost charges to be paid and the ~~date or~~ dates by which the charges must be paid. The commission will provide written notice to each person subject to a regulatory cost charge of the person's regulatory cost charge and payment dates.

(e) The commission will not determine or adjust previously determined regulatory cost charges based on ~~late-filed or amended~~ fluid volume reports that are filed (or amended), or on other fluid volume corrections that are made, after the deadline under (b) of this section for responding to the commission's notice of proposed regulatory cost charges, except if the commission finds that

(1) a person has grossly under-reported the person's V_{OP}, as defined in 20 AAC 25.605(a);

(2) under-reporting as described in (1) of this subsection has caused or will cause others' regulatory cost charges to be materially excessive; and

(3) correcting the excessive regulatory cost charges is in the public interest. (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.040 AS 31.05.093

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.620. PAYMENT DATES FOR REGULATORY COST CHARGES. (a) If the commission ~~has ordered~~ orders payment of estimated regulatory cost charges under 20 AAC 25.610, the commission will establish payment dates for regulatory cost charges during the second, third, and fourth quarters of the fiscal year. No later than each payment date, a person subject to a regulatory cost charge shall pay one-third of the difference between the person's regulatory cost charge and any estimated regulatory cost charge previously paid for the fiscal year, except that a regulatory cost charge may be prepaid, in part or in whole, at any time.

(b) If the commission ~~has~~ does not order~~ed~~ payment of estimated regulatory cost charges under 20 AAC 25.610, the commission will establish payment dates for regulatory cost charges during each quarter or each third of the fiscal year. No later than each payment date, a person subject to a regulatory cost charge shall pay one-fourth, if four payment dates are established, or one-third, if three payment dates are established, of the person's regulatory cost charge, except that a regulatory cost charge may be prepaid, in part or in whole, at any time.

(c) The commission will set the first payment date in a fiscal year to be at least 20 days after the date the commission provides notice under 20 AAC 25.615(d). (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.093

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.625. SUPPLEMENTAL APPROPRIATIONS. In the case of regulatory cost charges based on a supplemental appropriation for a fiscal year,

(1) the commission will determine regulatory cost charges using the commission's determinations of fluid volumes and well operatorship previously made in connection with the regular appropriation for the fiscal year;

(2) in applying the formula set out in 20 AAC 25.605(a), the commission will set the variables "F" and "L" equal to zero;

the commission will use the procedures set out in 20 AAC 25.615, except that

(3) the period for submitting comments or requesting a revision under 20 AAC 25.615(b) is 10 days instead of 30 days;

(A)

(B)

~~(4) the period~~ within which a public hearing will be held under 20 AAC 25.615(c) is 20 days instead of 60 days; the commission will provide notice of that hearing at least 10 days before the date of that hearing; the 30-day notice requirement under 20 AAC 25.540 does not apply to a hearing held under this paragraph; and

(C)

~~(5) the period~~ within which the commission will issue an order determining regulatory cost charges under 20 AAC 25.615(d) is 30 days instead of 90 days;

(4)

~~(6)~~ 20 AAC 25.620 does not apply; and

(5)

~~(7)~~ the commission will set the payment date for regulatory cost charges to be at least 10 days after the date the commission provides notice under 20 AAC 25.615(d). (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.040 AS 31.05.093

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.630. VIOLATIONS. In addition to any other available remedy for nonpayment, a person's failure timely to pay a regulatory cost charge or estimated regulatory cost charge of which the person has been provided written notice by the commission subjects the person to enforcement action under 20 AAC 25.535. (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.093 AS 31.05.150

20 AAC 25.005(a) is amended to read:

and for which an application for a Permit to Drill has not previously been submitted

20 AAC 25.005. PERMIT TO DRILL. (a) Before drilling or redrilling a well or re-entering an abandoned well, a person shall submit and obtain the commission's approval of an application for a Permit to Drill (Form 10-401). If, after drilling a well, a person wishes immediately to redrill below the structural or conductor casing to a new bottom-hole location not requiring a spacing exception under 20 AAC 25.055, the person may request oral approval from the commission to avoid interruption of operations. If oral approval is obtained, the name of the representative of the commission who provided oral approval and the date of the approval must be included on the application for a Permit to Drill, which must be submitted by the commission's next working day for final approval by the commission.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 11/7/99, Register 152; am / / , Register)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.605. CALCULATION OF REGULATORY COST CHARGES. (a) The formula for determining a person's regulatory cost charge under AS 31.05.093 is

$$RCC = \frac{V_{OP}}{V_{TOT}} * (A - F - L + C)$$

where

3-22-00

RCC = the regulatory cost charge;

V_{OP} = the total volume of oil and gas produced from, and oil, gas, water, and other fluids injected into, during the most recently concluded calendar year, wells for which a permit to drill has been issued under AS 31.05.090, of which the person is the operator on the first day of the fiscal year, and which have not before that day been plugged and abandoned and reported as abandoned in accordance with regulations of the commission;

V_{TOT} = the total volume of oil and gas produced from, and oil, gas, water, and other fluids injected into, during the most recently concluded calendar year, all wells for which a permit to drill has been issued under AS 31.05.090 and which have not before the first day of the fiscal year been plugged and abandoned and reported as abandoned in accordance with regulations of the commission;

A = the appropriation, other than ~~of~~ from federal receipts, made for the operating costs of the commission for the fiscal year;

F = the commission's reasonable estimate of the total fees to be collected under AS 31.05.090 during the fiscal year;

L = the lapsed amount of a previous appropriation that is appropriated from the general fund for the fiscal year under AS 31.05.093(d)~~;~~

~~C = an allowance reasonably estimated by the commission to cover regulatory cost charges that the commission is unable to collect~~.

(b) For purposes of calculating regulatory cost charges, volumes of fluids produced from or injected into wells will be the applicable volumes reported to the commission under 20 AAC 25.230(b) and 20 AAC 25.432, except that

(1) if an operator has failed to report a volume as required, if two or more reported volumes are inconsistent, or if the commission determines that a reported volume is otherwise unreliable, the commission will, in its discretion, calculate or estimate volumes as it considers appropriate;

(2) the commission will, in its discretion, add the volume of a substantial spill or other release of oil or gas that is not included in a report under 20 AAC 25.230(b) or 20 AAC 25.432.

(c) For purposes of AS 31.05.093(a) and this chapter, a well is considered "plugged and abandoned and reported as abandoned in accordance with regulations of the commission" when the well has been abandoned in accordance with 20 AAC 25.105 and 20 AAC 25.112 and a complete well record for the well, including a description of plugging operations, on a Well Completion or Recompletion Report and Log (Form 10-407) as required by 20 AAC 25.070(3) has been filed with the commission after abandonment. (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.093

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.610. ESTIMATED REGULATORY COST CHARGES. (a) Before determining regulatory cost charges for a fiscal year under 20 AAC 25.615, the

commission ~~may~~ will, in its discretion, establish estimated regulatory cost charges to be paid during the first quarter of the fiscal year. The amount of an estimated regulatory cost charge will be one fourth of the commission's reasonable estimate, based on information then available, of what the person's regulatory cost charge will be for that fiscal year.

(b) The commission will provide a person subject to an estimated regulatory cost charge with written notice of the amount of the charge and the payment date, which will be at least 20 days after the date of the notice. The person shall pay the estimated regulatory cost charge by the payment date. (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.093

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.615. COMMISSION'S DETERMINATION OF REGULATORY COST CHARGES. (a) After the later of the beginning of a fiscal year or the date of enactment of an appropriation for the operating costs of the commission for that fiscal year, the commission will provide to persons subject to a regulatory cost charge under AS 31.05.093 written notice of the proposed regulatory cost charges to be imposed on persons subject to regulatory cost charges for that fiscal year and the basis for the charges, in accordance with 20 AAC 25.605.

(b) Within 30 days after notice is issued under (a) of this section, a person subject to a regulatory cost charge may submit comments on, or request a revision to, the regulatory cost charges proposed by the commission. A request for a revision must be accompanied by an explanation of the basis for the requested revision. Before a hearing

is held under (c) of this section, the commission will provide all persons subject to a regulatory cost charge with copies of comments and requests for revision received by the commission or with notice of the persons' right to inspect those comments and requests for revision.

(c) Within 60 days after notice is issued under (a) of this section, the commission will hold a public hearing ~~to receive comments~~ on the proposed regulatory cost charges.

(d) Within 90 days after notice is issued under (a) of this section, the commission will issue an order determining the regulatory cost charges to be paid and the date or dates by which the charges must be paid. The commission will provide written notice to each person subject to a regulatory cost charge of the person's regulatory cost charge and payment dates.

Replace with insert

(e) Except in its discretion under extraordinary circumstances, the commission will not adjust previously determined regulatory cost charges based on late-filed or amended fluid volume reports that are filed after the deadline for responding to the commission's notice of proposed regulatory cost charges. (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.040 AS 31.05.093

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.620. PAYMENT DATES FOR REGULATORY COST CHARGES. (a) If the commission has ordered payment of estimated regulatory cost charges under 20 AAC 25.610, the commission will establish payment dates for regulatory cost charges during the second, third, and fourth quarters of the fiscal year. No later than each

payment date, a person subject to a regulatory cost charge shall pay one third of the difference between the person's regulatory cost charge and any estimated regulatory cost charge previously paid for the fiscal year, except that a regulatory cost charge may be prepaid, in part or in whole, at any time.

(b) If the commission has not ordered payment of estimated regulatory cost charges under 20 AAC 25.610, the commission will establish payment dates for regulatory cost charges during each quarter or each third of the fiscal year. No later than each payment date, a person subject to a regulatory cost charge shall pay one fourth (if four payment dates are established) or one third (if three payment dates are established) of the person's regulatory cost charge, except that a regulatory cost charge may be prepaid, in part or in whole, at any time.

(c) The commission will set the first payment date in a fiscal year to be at least 10 days after the date the commission provides notice under 20 AAC 25.615(d). (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.093

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.625. SUPPLEMENTAL APPROPRIATIONS. In the case of regulatory cost charges based on a supplemental appropriation for a fiscal year,

(1) the commission will determine regulatory cost charges using the commission's determinations of fluid volumes and well operatorship previously made in connection with the regular appropriation for the fiscal year;

(2) in applying the formula set out in 20 AAC 25.605, the commission will set the variables "F" and "L" equal to zero;

(3) the period for submitting comments or requesting a revision under 20 AAC 25.615(b) is 10 days instead of 30 days;

(4) the period within which a public hearing will be held under 20 AAC 25.615(c) is 20 days instead of 60 days; the commission will provide notice of that hearing at least 10 days before the date of that hearing; the 30 day notice requirement under 20 AAC 25.540 does not apply to a hearing held under this paragraph.

(5) the period within which the commission will issue an order determining regulatory cost charges under 20 AAC 25.615(d) is 30 days instead of 90 days;

(6) 20 AAC 25.620 does not apply;

(7) the commission will set the payment date for regulatory cost charges to be at least 10 days after the date the commission provides notice under 20 AAC 25.615(d). (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.040 AS 31.05.093

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.630. VIOLATIONS. In addition to any other available remedy for nonpayment, a person's failure timely to pay a regulatory cost charge or estimated regulatory cost charge of which the person has been provided written notice by the commission subjects the person to enforcement action under 20 AAC 25.535. (Eff. / / , Register)

Authority: AS 31.05.030 AS 31.05.093 AS 31.05.150

Insert

20 AAC 25.615

(e) The commission will not determine or adjust previously determined regulatory cost charges based on late-filed or amended fluid volume reports that are filed, or on other fluid volume corrections that are made, after the deadline under (b) of this section for responding to the commission's notice of proposed regulatory cost charges, except ~~when~~ if the commission finds that

(1) a person has grossly under-reported the person's V_{OP}, as defined in 20 AAC 25.605(a); as described in (1) of this subsection

(2) ~~that~~ under-reporting has caused or will cause others' regulatory cost charges to be materially excessive; and

(3) ~~the importance of~~ correcting the excessive regulatory cost charges ~~outweighs the benefits of finality~~ is in the public interest.

3-22-00

ALASKA OIL AND GAS CONSERVATION COMMISSION

PUBLIC HEARING

In Re:

PROPOSED REGULATION CHANGES REGARDING REGULATORY COST CHARGE, and APPLICATIONS FOR PERMIT TO DRILL.

TRANSCRIPT OF PROCEEDINGS

Anchorage, Alaska
March 21, 2000
9:10 o'clock a.m.

APPEARANCES:

Commissioners: MR. ROBERT N. CHRISTENSON, CHAIRMAN
MS. CAMILLE OECHSLI TAYLOR
MR. DAN SEAMOUNT

Attorney General's Office: MR. ROBERT E. MINTZ

* * * * * *

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ORIGINAL

1 **P R O C E E D I N G S**

2 (On record - 9:10 a.m.)

3 CHAIRMAN CHRISTENSON: This hearing is called

4 to order in the matter -- let's see, it's March.....

5 COMMISSIONER OECHSLI TAYLOR: 21st.

6 CHAIRMAN CHRISTENSON: .....21st. And this is

7 the Alaska Oil and Gas Conservation Commission at 3000 (sic)

8 Porcupine Road in Anchorage. It's about 10 after 9:00 o'clock

9 in the morning. And the object of this hearing is to hear

10 testimony on some changes to the regulations, proposed changes

11 to the regulations, dealing with the regulatory cost charge,

12 and with some existing applications on the permit to drill

13 section.

14 We're open for testimony but we have no one to testify.

15 COMMISSIONER OECHSLI TAYLOR: As I understand,

16 Ms. Blackhill may have.....

17 CHAIRMAN CHRISTENSON: You're going to testify?

18 Okay. Sorry.

19 MS. BLACKHILL: That's okay. I didn't sign in

20 as testifying. I was waiting to see if anybody else was going

21 to show up.

22 CHAIRMAN CHRISTENSON: So if you would, please,

23 state your name and the organization you represent.

24 MS. ROCKHILL: Theresa Rockhill, Alaska Oil and

25 Gas Association.

The task group -- the AOGCC Regulation Review Task Group did look through the proposed changes to the permit to drill section, and found that that was acceptable. Didn't have any proposed comments on that particular section.

And looking -- should I just go ahead and go through all of them at this point?

CHAIRMAN CHRISTENSON: Sure.

MS. ROCKHILL: In looking through the proposed chan- -- or the regulatory cost charge language, we did want to bring up some issues but not provide the Commission with any specific language.

So under 20 AAC 25.605, in the second sentence, we wanted to clarify the term, persons, refers to operators.

CHAIRMAN CHRISTENSON: Where are we -- okay, 605. You're on page two?

MS. ROCKHILL: On page -- right, under second sentence and 605, calculation of regulatory cost charge. I'm working off a copy that I downloaded off the Web so I may not be on the same page as you.

CHAIRMAN CHRISTENSON: 605. And you're in the definitions, right?

MS. ROCKHILL: No, sir, under calculation of regulatory cost charge,.....

CHAIRMAN CHRISTENSON: Yeah.

MS. ROCKHILL: .....A, the formula for

determining a person's regulatory cost charge.

COMMISSIONER OECHSLI TAYLOR: The former -- okay.

MS. ROCKHILL: We just wanted -- yeah. We just wanted to confirm that persons refers to operators.

CHAIRMAN CHRISTENSON: Okay. This first persons here?

MS. ROCKHILL: Right. And then under the formula, F, referring to total fees, we wanted to check and see if that includes both the permit fees and any federal funds the Commission receives. Is that all-inclusive of those two sources of fees?

CHAIRMAN CHRISTENSON: Okay. Does it include all fees is what you're asking?

MS. ROCKHILL: Yes, sir. And then in C of the formula, task group members did not feel that this would be acceptable since it would result in operators having to pick up the cost charges of delinquent operators.

And then down in 25.615(e),.....

CHAIRMAN CHRISTENSON: 21.61-.....

COMMISSIONER OECHSLI TAYLOR: 615?

MS. ROCKHILL: Yes. 25.615(e), wanted to inquire whether this ensures that any adjustments the Commission determines to make will be made for all operators. If there's an adjustment that needs to be made, it obviously

would have to be made for all operators. They just wanted to ensure that that was, in fact, the intent.

And the final comment that we had was under 620(c). And we don't feel that 10 days is adequate time. We think we probably need a little more time than the 10 days that's provided. That's 620(c).

CHAIRMAN CHRISTENSON: 620(c).

MS. ROCKHILL: And those are the extent of the comments that I have to submit.

CHAIRMAN CHRISTENSON: Okay. So you don't have a suggestion. You just want more than 10 days?

MS. ROCKHILL: The task group thought that 20 days as provided previously earlier in the proposed language would be adequate. Ten days can be a little troublesome I think to push paperwork through sometimes.

CHAIRMAN CHRISTENSON: Okay. Any others?

MS. ROCKHILL: That's it.

CHAIRMAN CHRISTENSON: Okay. Thank you very much.

MS. ROCKHILL: Thank you.

CHAIRMAN CHRISTENSON: I guess I would be -- better find out is there anybody else that wants to testify?

COMMISSIONER OECHSLI TAYLOR: Doesn't look like it.

CHAIRMAN CHRISTENSON: So I guess at this time,

1 we have all our comments?
2 COMMISSIONER OECHSLI TAYLOR: I think so. I
3 checked with Diana before we started the hearing, and she has
4 not received anything in writing from any party.
5 CHAIRMAN CHRISTENSON: Do we have to cover
6 anything on this or is this just a information notice?
7 COMMISSIONER OECHSLI TAYLOR: I think it went
8 right to Juneau.
9 CHAIRMAN CHRISTENSON: Maybe this -- we've
10 already covered that, right?
11 COMMISSIONER OECHSLI TAYLOR: I think so.
12 CHAIRMAN CHRISTENSON: So do we have any other
13 business on this matter?
14 COMMISSIONER OECHSLI TAYLOR: I just -- I
15 wanted to just address two of those issues real quickly with
16 Rob.
17 The question about -- well, the comment about 615.(e),
18 the adjustments, as I understand it, the way this 615 is set
19 out having the opportunity for comment by an operator with
20 respect to the Commission's calculations, the way this is
21 intended to be set up is to provide everybody with the
22 opportunity to end up with overall adjusted figures. So if
23 you're adjusting any figure, it affects -- it impacts
24 everybody.
25 MR. MINTZ: That's right. That's why the

1 process is set up that way so that the -- to provide a way for
2 the Commission to make sure it hears from everybody at the same
3 time so that -- because everyone's going to be affected by any
4 change.
5 COMMISSIONER OECHSLI TAYLOR: And then with
6 respect to -- under 605, the provision and the formula for C,
7 an allowance for an estimated regulatory cost charge that the
8 Commission is unable to collect. I'm not sure that I am clear
9 about where that came from. Is that the portion of the formula
10 that came from the model that the Public Utilities Commission
11 had in their formula?
12 MR. MINTZ: Right. Right.
13 COMMISSIONER OECHSLI TAYLOR: And with respect
14 to F, as I understand it, that is only the fees for the
15 estimate for drilling permit fees of $100 each.
16 MR. MINTZ: Right.
17 COMMISSIONER OECHSLI TAYLOR: But as I
18 understand it, the question about the federal funding, when the
19 legislature appropriates our funds for the year, that $100,000
20 is already subtracted out of what we can collect from program
21 receipts.
22 MR. MINTZ: Is it? I mean.....
23 COMMISSIONER OECHSLI TAYLOR: I'll double-check
24 that.
25 MR. MINTZ: I mean I don't.....

CHAIRMAN CHRISTENSON: It is on all our budgets.

MR. MINTZ: The federal funds are not -- really were not reflected in this at all in these regs.

COMMISSIONER OECHSLI TAYLOR: In the formula.

MR. MINTZ: Yeah. But -- okay. So if -- you're saying like a grant, the UIC grant is -- I assume that does have to be appropriated.

COMMISSIONER OECHSLI TAYLOR: It is appropriated but as I understand looking at the budget documents, they allocate which funding source that money comes from. But I'll double-check to be sure. It was my understanding that the amount that is appropriated that we can collect through designated program receipts does not include the 100,000 for federal funding, but we'll double-check that.

MR. MINTZ: Yeah. That might be something that we need to clarify in the regs here.

COMMISSIONER OECHSLI TAYLOR: Right.

MR. MINTZ: On the first point that Ms. Rockwell mentioned -- Rockhill mentioned, the person -- whether the person is an operator, not always -- I mean the reason this says, person, and not, operator, is because under the regulatory cost charge statute, the person liable for the regulatory cost charge is a person that operates the wells in question on the first day of the fiscal year. So on July 1st,

1 the only people who are liable for regulatory cost charges are
2 operators. However, the operator might be replaced on
3 July 10th by someone else, and it's still the person who is
4 operator on July 1st that's liable for the regulatory cost
5 charges. So that's why that terminology is drafted the way it
6 is.
7 Just like if with property taxes, generally speaking,
8 it's the ownership on, say, January 1st of the year. If I own
9 a property on January 1st, I'm liable for paying the property
10 taxes even if I sell it to someone else on January 10th.
11 CHAIRMAN CHRISTENSON: Yeah, but I don't --
12 that wasn't the question, was it? The question was this person
13 mean the operator, not what time of year the charge is due.
14 COMMISSIONER SEAMOUNT: It means operator on
15 July 1st.
16 MR. MINTZ: But at the time that the Commission
17 determines by order regulatory cost charges that different
18 people have to pay, that person may or may not still be an
19 operator.
20 COMMISSIONER OECHSLI TAYLOR: So it envisions
21 the actual calculation and bill going to the person who is the
22 operator on July 1st. And if it's somebody subsequently
23 different, that's to be worked out between the two parties.
24 MR. MINTZ: Right. I mean there has to be a
25 cut off date, and the statute makes that cut off date the first

1 day of the fiscal year.

2 CHAIRMAN CHRISTENSON: Yeah. I understand that

3 part. But does person mean operator? I think that's the

4 question.

5 MR. MINTZ: Not necessarily.

6 COMMISSIONER OECHSLI TAYLOR: By the time you

7 send the bill, the person could no longer be the operator, but

8 that person was the operator on July 1.

9 COMMISSIONER SEAMOUNT: Well, could you insert

10 the operator on July 1st for person then?

11 MR. MINTZ: Well,.....

12 COMMISSIONER SEAMOUNT: I guess you need to

13 define what -- who the person is.

14 MR. MINTZ: Well, the thing is that the regs

15 have to be -- the regs are only part of the package that are

16 being implemented, the statute and the regs. The regs don't

17 repeat everything that's in the statute. The statute makes

18 clear that it's the person who's the operator on July 1st. And

19 the practice in Alaska regs is not to repeat what's already in

20 the statute.

21 COMMISSIONER SEAMOUNT: So it's already been

22 defined then.

23 COMMISSIONER OECHSLI TAYLOR: Right. It's

24 actually the first line of .093, says every person that on the

25 first day of a state fiscal year is the operator of a well.

1 CHAIRMAN CHRISTENSON: Do we need to discuss
2 any of the other ones? We've got to check on the fee thing.
3 COMMISSIONER OECHSLI TAYLOR: Yeah. I'll check
4 on that to make sure that we have provided for not double
5 billing.
6 CHAIRMAN CHRISTENSON: Adjustment is for all
7 operators. And the addition of time in the back to be beyond
8 10 days. I mean the way it is is at least 10 days. So they're
9 requesting that we make that more.
10 Is this -- Rob, is this just for the first year or is
11 this for all subsequent years as well?
12 MR. MINTZ: For -- it's for all years.
13 CHAIRMAN CHRISTENSON: Okay.
14 MR. MINTZ: I mean I think the rationale for
15 reducing it to 10 days was that that notice that gives the
16 person 10 days is at the end of a somewhat lengthy process,
17 that there would already be the proposed regulatory cost charge
18 that would be sent out, and then there would be an opportunity
19 for comment, a hearing, and then the final one would be set,
20 and then there would be at least 10 days. However, I take it,
21 this is something maybe Ms. Rockhill would want to address,
22 that what she's really talking about is just the internal
23 procedures for generating checks and so forth might -- 10 days
24 might just be a little bit compressed.
25 CHAIRMAN CHRISTENSON: Yeah. What we're

1 saying, though, under 615 is we've got 30 days notice and then
2 we've got 60 days after that, and then 90 days after that with
3 all this backing and forthing, right, on the numbers.
4 MR. MINTZ: Uh-hum.
5 CHAIRMAN CHRISTENSON: So then once we tell
6 them what it is, then they've got 10 days, at least 10 days.
7 yeah. I think we could.....
8 COMMISSIONER OECHSLI TAYLOR: So for the.....
9 CHAIRMAN CHRISTENSON: This doesn't co- -- did
10 we -- we need to figure out this calendar right. Did we figure
11 out this calendar relative to the end of the fiscal year?
12 MR. MINTZ: How do you mean?
13 CHAIRMAN CHRISTENSON: Well, with regard to
14 when is that 10 days going to fall? What month?
15 MR. MINTZ: Well, it depends on how quickly the
16 process works because most of these are -- these time limits
17 are maximum time limits.
18 CHAIRMAN CHRISTENSON: Yeah.
19 MR. MINTZ: So the only one that isn't is the
20 first 30 days I think. Let's see.
21 CHAIRMAN CHRISTENSON: Because we have an issue
22 with how long before we collect in that first quarter, right?
23 COMMISSIONER OECHSLI TAYLOR: Right. And I
24 think that's why it was done that way. We had 30, 60, and 90
25 days.

1 MR. MINTZ: But there's also the estimated --
2 is the option to collect estimated regulatory cost charges.
3 COMMISSIONER OECHSLI TAYLOR: Right. So if we
4 need money, we can estimate -- send out a first estimate,
5 though, and then take that time to calculate -- take the whole
6 first quarter to calculate.....
7 CHAIRMAN CHRISTENSON: Yeah.
8 COMMISSIONER OECHSLI TAYLOR: .....what you
9 need.
10 CHAIRMAN CHRISTENSON: Okay. Well, we can look
11 at that, what the calendar looks like, and make sure we've got
12 that figured out.
13 COMMISSIONER OECHSLI TAYLOR: Okay.
14 CHAIRMAN CHRISTENSON: Okay. Any more
15 business?
16 COMMISSIONER OECHSLI TAYLOR: I don't know if
17 we have one more person who wants to testify or comment.
18 CHAIRMAN CHRISTENSON: Any more -- are there
19 any more people who would like to testify? Going, going, gone.
20 Okay. Hearing none, we're adjourned.
21 (Off record 9:27 a.m.)
22 **END OF PROCEEDINGS**
23
24
25

C E R T I F I C A T E

UNITED STATES OF AMERICA)
)ss.
STATE OF ALASKA)

I, Laura Ferro, Notary Public in and for the State of Alaska, and Reporter for Metro Court Reporting, Inc., do hereby certify:

That the foregoing Alaska Oil & Gas Conservation Commission Public Hearing, was taken before myself on the 21st day of March 2000, commencing at the hour of 9:10 o'clock a.m., at the offices of Alaska Oil & Gas Conservation Commission, 3001 Porcupine Street, Anchorage, Alaska;

That the hearing was transcribed by myself to the best of my knowledge and ability.

IN WITNESS WHEREOF, I have hereto set my hand and affixed my seal this 30th day of March 2000.

Laura Ferro

Notary Public in and for Alaska
My commission expires: 05/03/01

ALASKA OIL AND GAS CONSERVATION COMMISSION

March 21, 2000
9:00 AM

PUBLIC HEARING

NAME – AFFILIATION (PLEASE PRINT)	TELEPHONE	Do you plan to comment? Yes	No
THERESA Rockhill	272-1481		
Jack Hartz	793-1232		No
Chris Phillips / BP			no

ALASKA OIL AND GAS CONSERVATION COMMISSION

March 21, 2000
9:00 AM

PUBLIC HEARING

NAME – AFFILIATION (PLEASE PRINT)	TELEPHONE	Do you plan to comment? Yes	No
Kristen Nelson/Pet News AK	248-3622		NO

MEMORANDUM

State of Alaska
Department of Law

TO: Robert Christenson, Chair
Alaska Oil & Gas Conservation Commission
Dept. of Administration

DATE: February 25, 2000

FILE NO.: 993-00-0117

TELEPHONE NO.: 465-3600

FROM: Deborah E. Behr
Assistant Attorney General
and Regulations Attorney
Legislation and Regulations Section

SUBJECT: Regulations File Opening Re: AOGCC: Regulatory Cost Charges and Drilling of Wells (20 AAC 25)

We have received Commissioner Camille Oechsli Taylor's memorandum of February 16, 2000, regarding this project, along with a copy of the proposed regulations. The project has been assigned to Assistant Attorney General Rob Mintz, phone number 269-5100.

Our department's file number for this project is 993-00-0117. This file number should be used on any further correspondence pertaining to this project.

DEB:jn

cc: Dan Spencer, Regulations Contact
Dept. of Administration

Camille Oechsli Taylor, Commissioner
Alaska Oil & Gas Conservation Commission
Dept. of Administration

Carol Collins, AAC Coordinator
Lt. Governor's Office

Rob Mintz
Assistant Attorney General
Anchorage

RECEIVED
FEB 28 2000
Alaska Oil & Gas Cons. Commission
Anchorage

MEMORANDUM STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

TO: Deborah E. Behr
Regulations Attorney
Legislation/Regulations Section

DATE: February 16, 2000

SUBJECT: File-opening request for Amendments to 20 AAC 25

FROM: Camillé Oechsli Taylor
Commissioner

We are requesting that you open a new file for a regulations project regarding changes in Title 20, Chapter 25, of the Alaska Administrative Code, dealing with regulatory cost charges, to implement and interpret AS 31.05.093, and dealing with the drilling of wells, to implement and interpret AS 31.05.030 and AS 31.05.090. Enclosed is a copy of the Public Hearing Notice, Additional Regulations Notice Information and a draft of the regulations.

We hope to have the regulations in effect as soon as possible.

Please assign an assistant attorney general to this project. We have worked with Assistant Attorney General Rob Mintz on his topic.

Our contact person for the project is Robert Christenson at 279-1433 ext. 221.

Suggested changes to January 2000 supplement as follow:

pages 126 and 129
20 AAC 25.015. "CHANGES TO AN APPROVED DRILLING PROGRAM"
title should be changed to "CHANGES TO A PROGRAM IN A PERMIT TO DRILL"

page 132
20 AAC 25.030(c)(1) line 3, change "hold" to "hole"

page 138
20 AAC 25.035(e)(1)(A)(ii) line 2, change "blinds/shear" to "blind/shear"
20 AAC 25.035(e)(1)(B)(i) line 3, change "BHA" to "BHAs"

page 142
20 AAC 25.035(e)(10)(B) line 3 (first line on page), change "approve" to "approved"

page 145
20 AAC 25.036(c)(5) line 2, change "be" to "have" also, is – in the work bi-directional necessary?

Page 146
20 AAC 25.036(c)(10)(A) line 2, change "commissioner" to "commission"
20 AAC 25.036(d)(1) line 5, delete the word "to" at the end of the line

page 148
20 AAC 25.040(c) line 3, delete the word

page 149
20 AAC 25.050(c)(3) line 4, change "with

Post-it® Fax Note 7671	Date [redacted] # of pages ▶ 5
To JONIE FLEETWOOD	From [redacted]
Co./Dept. DOL	Co. AOGCC
Phone # 269-5223	Phone # 793-1236
Fax # 279-8644	Fax #

page 150
20 AAC 25.050(g) line 1, change "required" to "require"

page 151
20 AAC 25.055(a)(4) line 3, change "or" to "on"

page 155
20 AAC 25.070(3) line 8 (second line on page), change "hold" to "hole"

page 156
20 AAC 25.072(a) line 3, delete "," between drill and rigs

page 160
20 AAC 25.080(i) line 2, delete"." between "31.05.090" and "other"

page 168
20 AAC 25.120(e) second line, add "of" between "time" and "the"

page 169
20 AAC 25.170(c) second line, delete ":"

page 173
20 AAC 25.225 third line, change "alternate" to "alternative"

page 174
20 AAC 25.228(f) first line, insert "not" between "may" and "be"
20 AAC 25.228(i)(2) first line, insert "and" between "handling," and "analysis"

page 175
20 AAC 25.235(a) seventh line, change "mouth" to "month"

page 180
20 AAC 25.265(b) third line, change "presentative" to "representative"

page 184
20 AAC 25.285(c)(10)(C) line 4, insert "stack" between "BOP" and "equal"

page 186
20 AAC 25.286(b) line 1, change "hold" to "hole"
20 AAC 25.286(c) line 3, change "at" to "it"

page 187
20 AAC 25.286(d)(4)(A) line 3, insert "a minimum" between "maintaining" and "pressure"

page 188
20 AAC 25.287 WELL CONTROL REQUIREMENTS FOR WIRELINE OPERATIONS
change title to WELL CONTROL "EQUIPMENT" FOR WIRELINE OPERATIONS?

page 190
20 AAC 25.320(a) second line, change "forms" to "a form"

page 196
20 AAC 24.460(c) first line, insert "in" between "will," and "its"

2/15/2000 additional errors
Suggested changes to January 2000 supplement as follow:

page 131
20 AAC 25.030(b)(1) line 3, change "of" to "or"

page 133
20 AAC 25.030(f) line 6, change "no" to "not"

page 137
20 AAC 25.035(c)(2)(B) line 4, change . to ; at sentence end

page 140
20 AAC 25.035(e)(F)(iii) line 1, insert "a" between "be" and "remotely"

page 153
20 AAC 25.066(a)(6) line 2, change "alram" between "visual" and "must" to "alarm"

page 155
20 AAC 25.071(a) line 3, change "radio-activity" to "radioactivity"

page 156
20 AAC 25.071(c)(2) line 4, change "place" to "placed"

page 159
20 AAC 25.080(e)(2) line 3, change "high" to "higher"

page 162
20 AAC 25.107(b) line 4, delete "the" between "within" and "three"

page 168
20 AAC 25.120(c)(1) change "lest" between "at" and "10" to "least"

page 179
20 AAC 25.252(h)(2) fourth line, insert "," after "plugged"

page 180
20 AAC 25.265(a)(2) first line, insert "-" between "surface" and "controlled"
20 AAC 25.265(c) second line, first word, change "and" to "an"

page 182
20 AAC 25.285(c)(3) insert "," after "operations"

page 187
20 AAC 25.287(e)(2) line 6, sentence end, change "." to ";"

page 190
20 AAC 25.300 eighth line, insert"," after "sources"
20 AAC 25.320(a) seventh line, change "had" to "has"

page 191
20 AAC 25.402(b) eighth line, insert "," after "freshwater"

page 193
20 AAC 25.412 title, insert "," after "DISPOSAL"

page 198
20 AAC 25.510
picture is of old seal, new seal has partial image of moose.

page 206
20 AAC 25.540(c)(10) sixth line, change "conditiong" to "conditioning"
20 AAC 25.540(c)(10)(B) second line, change ";" to "."

Other –

page 169
20 AAC 25.170(b) first line, "this" between "of" and "section" not contained in regulation changes

page 183
20 AAC 25.285(c)(3)(B)(iv) third line, "be" between "not" and "sized" not contained in regulation changes

page 204
20 AAC 25.537(e)(2) first and fourth lines, "United States" is spelled out, whereas previous version of regulations contain "U.S."

Subject: additional error
Date: Wed, 16 Feb 2000 15:06:36 -0900
From: Wendy Mahan <Wendy_Mahan@admin.state.ak.us>
Organization: doa-aogcc
To: Robert E Mintz <robert_mintz@law.state.ak.us>,
Steve Weaver <Steve_Weaver@law.state.ak.us>,
Camille Oechsli <cammy_oechsli@admin.state.ak.us>

Additional error found in published supplement

page 127
20 AAC 25.005(c)(9) first line, change "tablulation" to "tabulation"

Thanks,
Wendy

Feb. 17 2000

STATE OF ALASKA
NOTICE OF PROPOSED CHANGES IN THE REGULATIONS OF THE ALASKA OIL AND GAS CONSERVATION COMMISSION AND NOTICE OF PUBLIC HEARING

Notice is given that the Alaska Oil and Gas Conservation Commission ("AOGCC"), under the authority of AS 31.05.030 and AS 31.05.040, proposes to adopt regulation changes in Title 20, Chapter 25, of the Alaska Administrative Code, dealing with regulatory cost charges, to implement and interpret AS 31.05.093, and dealing with the drilling of wells, to implement and interpret AS 31.05.030 and AS 31.05.090, including:

1. New sections are proposed to be added establishing a formula for calculating regulatory cost charges, addressing the determination of fluid volumes and wells reported as abandoned, providing for the payment of estimated regulatory cost charges, prescribing the process for AOGCC's determination of persons' regulatory cost charges, addressing payment dates, addressing regulatory cost charges based on a supplemental appropriation, and addressing enforcement in the event of nonpayment of charges;

2. Existing regulations concerning applications for a permit to drill are proposed to be amended to allow for temporary oral approval of certain drilling operations involving a new bottom-hole location.

Notice is also given that any person interested may present written comments relevant to the proposed action, including the potential costs to private persons of complying with the proposed action, by writing to AOGCC, 3001 Porcupine Drive, Anchorage, AK 99501-3192, so that they are received no later than March 21, 2000. Additionally, any interested person may present oral or written comments relevant to the proposed action, including the potential costs to private persons of complying with the proposed action, at a hearing to be held at 3001 Porcupine Drive, Anchorage, Alaska, on March 21, 2000. The hearing will be held from 9:00 a.m. to 11:00 a.m. and might be extended if necessary to accommodate those present before 10:00 a.m. who do not have an opportunity to testify.

If you are a person with a disability who may need a special accommodation, auxiliary aid or service, or alternative communication format in order to participate in the process on the proposed regulations, please contact Diana Fleck at 793-1221 by 4:00 PM, March 14, 2000, to ensure that any necessary accommodations can be provided.

This action is not expected to require an increased appropriation.

Copies of the proposed regulations may be obtained at the AOGCC office, 3001 Porcupine Drive, Anchorage, Alaska 99501-3192, or on the AOGCC website at:

http://www.state.ak.us/local/akpages/ADMIN/ogc/homeogc.htm.

After the close of the public comment period and hearing, the AOGCC will either adopt these or other proposals dealing with the same subjects, without further notice, or decide to take no action on it. The language of the final regulations may vary from that of the proposed regulations. You should comment during the time allowed if your interest could be affected.

Date: February 16, 2000

Camillé Oechsli Taylor
Commissioner

Published February 17, 2000
ADN AO# 02014026

ADDITIONAL REGULATIONS NOTICE INFORMATION
(AS 44.62.190(d))

1. Adopting agency: Alaska Oil and Gas Conservation Commission.

2. General subject of regulations: regulatory cost charges and drilling of wells.

3. Citation of regulations: 20 AAC 25.005; 20 AAC 25.605 – 25.630.

4. Reason for the proposed action: compliance with new state statute and procedural clarification of recent comprehensive revisions to agency regulations.

5. Program category and BRU affected: Alaska Oil and Gas Conservation Commission.

6. Cost of implementation to the state agency: zero.

7. The name of the contact person for the regulations: Robert N. Christenson, Chairman, Alaska Oil and Gas Conservation Commission, 3001 Porcupine Drive, Anchorage, AK 99501-3192, (907) 279-1433.

8. The origin of the proposed action: members of state agency.

9. Date: February 16, 2000

10. Prepared by: Camillé Oechsli Taylor
Camillé Oechsli Taylor
Commissioner
Alaska Oil and Gas Conservation Commission
(907) 279-1433

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That said newspaper has been approved by the Third Judicial Court, Anchorage, Alaska, and it now and has been published in the English language continually as a daily newspaper in Anchorage, Alaska, and it is now and during all said time was printed in an office maintained at the aforesaid place of publication of said newspaper. That the annexed is a copy of an advertisement as it was published in regular issues (and not in supplemental form) of said newspaper on the above dates and that such newspaper was regularly distributed to its subscribers during all of said period. That the full amount of the fee charged for the foregoing publication is not in excess of the rate charged private individuals.

Legal Clerk Eva Alexie

Eva Alexie

Subscribed and sworn to me before this date:

Feb 23, 2000

Notary Public in and for the State of Alaska.
Third Division. Anchorage, Alaska

MY COMMISSION EXPIRES: Feb 8, 2004

P. Bullock

PENNY BULLOCK
NOTARY
PUBLIC
STATE OF ALASKA

STATE OF ALASKA
NOTICE OF PROPOSED CHANGES IN THE REGULATIONS OF THE ALASKA OIL AND GAS CONSERVATION COMMISSION AND NOTICE OF PUBLIC HEARING

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If you are a person with a disability who may need a special modification, auxiliary aid or service, or alternative communication format in order to participate in the process on the proposed regulations, please contact [illegible] at [illegible] March 14, [illegible] that any [illegible] modations [illegible]

This action [illegible] to [illegible] appropriation.

Copies of the [illegible] regulations may be [illegible] the AOGCC [illegible] Porcupine Drive, Anchorage, Alaska 99501-3192, or on the AOGCC website at: http://www.state.ak.us/local/akpages/ADMIN/aoc/homeaoc.htm

After the close of the public comment period and hearing, the AOGCC will either adopt these or other proposals dealing with the same subject, without further notice or decide to take no action on it. The language of the final regulations may vary from that of proposed regulations. You should comment during the time allowed if your interest could be affected.

Date: February 14, 2000
/s/Camille Oechsli Taylor
Commissioner

Pub.: Feb. 17, 2000

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Division of Oil & Gas
3601 C Ste 1380
Anchorage, AK 99503-5948

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Department of Natural Resources
Office of the Commissioner
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Governmental Coordination
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Juneau, AK 99811-0030

X BOB POE, Commissioner
SOA Department of Administration
Office of the Commissioner
P O Box 110200 Mail Stop 0200
Juneau, AK 99811-0200

X Wilson Condon, Commissioner
SOA Department of Revenue
P O Box 110400
Juneau, AK 99811-0400

X John Pilkinton, Director
SOA Department of Revenue
Oil & Gas Audit Division
550 W 7th Ave, Ste 570
Anchorage, AK 99501-3557

X Robert Mintz, Asst Atty General
SOA Dept. of Law, Civil Division
Oil, Gas & Mining Section
1031 W 4th Ave Ste 200
Anchorage, AK 99501-1994

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ALASKA STATE LEGISLATURE- HOUSE
CO-CHAIR - RESOURCES COMMITTEE
STATE CAPITOL, RM 108
JUNEAU, AK 99801-1182

✓ THE HONORABLE RICK HALFORD
ALASKA STATE LEGISLATURE- SENATE
CHAIR - RESOURCES COMMITTEE
STATE CAPITOL, RM 121
JUNEAU, AK 99801-1182

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STATE CAPITOL, RM 128
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✓ THE HONORABLE JIM WHITAKER
ALASKA STATE LEGISLATURE- HOUSE
CHAIR-SPECIAL COMMITTEE ON O&G
STATE CAPITOL, RM 13
JUNEAU, AK 99801-1182

✓ THE HONORABLE JEANNETTE JAMES
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CHAIR - STATE AFFAIRS COMMITTEE
STATE CAPITOL, RM 102
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✓ THE HONORABLE JERRY WARD
ALASKA STATE LEGISLATURE- SENATE
CHAIR - STATE AFFAIRS COMMITTEE
STATE CAPITOL, RM 423
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— DEBORAH E BEHR
LEGISLATION/REGULATIONS SECTION
DEPARTMENT OF LAW
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✓ AOGA
Judy Brady
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Anchorage AK 99503-2035

Key:

☑ notice + Regs (Second pg)

☒ notice + (Second pg. only)

☐ Diana will handle

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GCA ENERGY ADV
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OIL & GAS JOURNAL
BOB WILLIAMS
1700 W LOOP SOUTH STE 1000
HOUSTON TX 77027

PETRAL CONSULTING CO
DANIEL L LIPPE
9800 RICHMOND STE 505
HOUSTON TX 77042

MOBIL OIL
N H SMITH
12450 GREENSPOINT DR
HOUSTON TX 77060-1991

MARK ALEXANDER
7502 ALCOMITA
HOUSTON TX 77083

MARATHON OIL CO
GEORGE ROTHSCHILD JR RM 2537
P O BOX 4813
HOUSTON TX 77210

UNOCAL
REVENUE ACCOUNTING
P O BOX 4531
HOUSTON TX 77210-4531

EXXON EXPLOR CO
LAND/REGULATORY AFFAIRS RM 301
P O BOX 4778
HOUSTON TX 77210-4778

EXXON EXPLORATION CO.
T E ALFORD
P O BOX 4778
HOUSTON TX 77210-4778

CHEVRON USA INC.
ALASKA DIVISION
ATTN: CORRY WOOLINGTON
P O BOX 1635
HOUSTON TX 77251

PETR INFO
DAVID PHILLIPS
P O BOX 1702
HOUSTON TX 77251-1702

PHILLIPS PETR CO
ALASKA LAND MGR
P O BOX 1967
HOUSTON TX 77251-1967

PHILLIPS PETROLEUM COMPANY
W ALLEN HUCKABAY
PO BOX 1967
HOUSTON TX 77251-1967

WORLD OIL
MARK TEEL ENGR ED
P O BOX 2608
HOUSTON TX 77252

EXXON CO USA
RESERVES COORD RM 1967
P O BOX 2180
HOUSTON TX 77252-2180

EXXON CO USA
J W KIKER ROOM 2086
P O BOX 2180
HOUSTON TX 77252-2180

EXXON CO USA
GARY M ROBERTS RM 3039
P O BOX 2180
HOUSTON TX 77252-2180

EXXON CO USA
M W ALBERS RM 1943
P O BOX 2180
HOUSTON TX 77252-2180

PENNZOIL E&P
WILL D MCCROCKLIN
P O BOX 2967
HOUSTON TX 77252-2967

CHEVRON CHEM CO
LIBRARY & INFO CTR
P O BOX 2100
HOUSTON TX 77252-9987

MARATHON
MS. NORMA L. CALVERT
P O BOX 3128, STE 3915
HOUSTON TX 77253-3128

ACE PETROLEUM COMPANY
ANDREW C CLIFFORD
PO BOX 79593
HOUSTON TX 77279-9593

PHILLIPS PETR CO
ERICH R. RAMP
6330 W LOOP SOUTH
BELLAIRE TX 77401

PHILLIPS PETR CO
JOE VOELKER
6330 W LP S RM 492
BELLAIRE TX 77401

PHILLIPS PETR CO
PARTNERSHIP OPRNS
JIM JOHNSON
6330 W LOOP S RM 1132
BELLAIRE TX 77401

TEXACO INC
R EWING CLEMONS
P O BOX 430
BELLAIRE TX 77402-0430

WATTY STRICKLAND
2803 SANCTUARY CV
KATY TX 77450-8510

TESORO PETR CORP
LOIS DOWNS
8700 TESORO DR
SAN ANTONIO TX 78217

INTL OIL SCOUTS
MASON MAP SERV INC
P O BOX 338
AUSTIN TX 78767

ROBERT G GRAVELY
7681 S KIT CARSON DR
LITTLETON CO 80122

DIANE SUCHOMEL
10507D W MAPLEWOOD DR
LITTLETON CO 80127

GEORGE G VAUGHT JR
P O BOX 13557
DENVER CO 80201

AMOCO PROD CO
LIBRARY RM 1770
JILL MALLY
1670 BROADWAY
DENVER CO 80202

C & R INDUSTRIES, INC.
KURT SALTSGAVER
1801 BROADWAY STE 1205
DENVER CO 80202

JERRY HODGDEN GEOL
408 18TH ST
GOLDEN CO 80401

NRG ASSOC
RICHARD NEHRING
P O BOX 1655
COLORADO SPRINGS CO 80901-1655

RUBICON PETROLEUM, LLC
BRUCE I CLARDY
SIX PINE ROAD
COLORADO SPRINGS CO 80906

JOHN A LEVORSEN
200 N 3RD ST #1202
BOISE ID 83702

RUI ANALYTICAL
JERRY BERGOSH
P O BOX 58861
SALT LAKE CITY UT 84158-0861

TAHOMA RESOURCES
GARY PLAYER
1671 WEST 546 S
CEDER CITY UT 84720

MUNGER OIL INFOR SERV INC
P O BOX 45738
LOS ANGELES CA 90045-0738

LA PUBLIC LIBRARY
SERIALS DIV
630 W 5TH ST
LOS ANGELES CA 90071

US OIL & REFINERY CO
TOM TREICHEL
2121 ROSECRANS AVE #2360
ES SEGUNCO CA 90245-4709

BABSON & SHEPPARD
JOHN F BERGQUIST
P O BOX 8279 VIKING STN
LONG BEACH CA 90808-0279

ANTONIO MADRID
P O BOX 94625
PASADENA CA 91109

ORO NEGRO, INC.
9321 MELVIN AVE
NORTHRIDGE CA 91324-2410

PACIFIC WEST OIL DATA
ROBERT E COLEBERD
15314 DEVONSHIRE ST STE D
MISSION HILLS CA 91345-2746

76 PRODUCTS COMPANY
CHARLES BURRUSS RM 11-767
555 ANTON
COSTA MESA CA 92626

SANTA FE ENERGY RESOURCES INC
EXPLOR DEPT
5201 TRUXTUN AV STE 100
BAKERSFIELD CA 93309

TEXACO INC
PORTFOLIO TEAM MANAGER
R W HILL
P O BOX 5197X
BAKERSFIELD CA 93388

US GEOL SURV
KEN BIRD
345 MIDDLEFIELD RD MS 999
MENLO PARK CA 94025

SHIELDS LIBRARY
GOVT DOCS DEPT
UNIV OF CALIF
DAVIS CA 95616

H L WANGENHEIM
5430 SAWMILL RD SP 11
PARADISE CA 95969-5969

ECONOMIC INSIGHT INC
SAM VAN VACTOR
P O BOX 683
PORTLAND OR 97207

US EPA REGION 10
LAURIE MANN OW-130
1200 SIXTH AVE
SEATTLE WA 98101

MARPLES BUSINESS NEWSLETTER
MICHAEL J PARKS
117 W MERCER ST STE 200
SEATTLE WA 98119-3960

DUSTY RHODES
229 WHITNEY RD
ANCHORAGE AK 99501

DEPT OF REVENUE
BEVERLY MARQUART
550 W 7TH AV STE 570
ANCHORAGE AK 99501

DEPT OF REVENUE
OIL & GAS AUDIT
DENISE HAWES
550 W 7TH AV STE 570
ANCHORAGE AK 99501

FAIRWEATHER E&P SERV INC
JESSE MOHRBACHER
715 L ST #4
ANCHORAGE AK 99501

GUESS & RUDD
GEORGE LYLE
510 L ST, STE 700
ANCHORAGE AK 99501

STATE PIPELINE OFFICE
LIBRARY
KATE MUNSON
411 W 4TH AVE, STE 2
ANCHORAGE AK 99501

TRUSTEES FOR ALASKA
725 CHRISTENSEN DR STE 4
ANCHORAGE AK 99501

FORCENERGY INC.
JIM ARLINGTON
310 K STREET STE 700
ANCHORAGE AK 99501

YUKON PACIFIC CORP
JOHN HORN VICE CHM
1049 W 5TH AV
ANCHORAGE AK 99501-1930

PRESTON GATES ELLIS LLP
LIBRARY
420 L ST STE 400
ANCHORAGE AK 99501-1937

ALASKA DEPT OF LAW
ROBERT E MINTZ ASST ATTY GEN
1031 W 4TH AV STE 200
ANCHORAGE AK 99501-1994

GAFO
GREENPEACE
PAMELA MILLER
125 CHRISTENSEN DR. #2
ANCHORAGE AK 99501-2101

DEPT OF NATURAL RESOURCES
DIV OF OIL & GAS
TIM RYHERD
550 W 7TH AVE STE 800
ANCHORAGE AK 99501-3510

DEPT OF REVENUE
OIL & GAS AUDIT
FRANK PARR
550 W 7TH AVE STE 570
ANCHORAGE AK 99501-3540

BAKER OIL TOOLS
ALASKA AREA MGR
4710 BUS PK BLVD STE 36
ANCHORAGE AK 99503

HDR ALASKA INC
MARK DALTON
2525 C ST STE 305
ANCHORAGE AK 99503

N-I TUBULARS INC
3301 C STREET STE 209
ANCHORAGE AK 99503

ANADARKO
MARK HANLEY
3201 C STREET STE 603
ANCHORAGE AK 99503

~~ALASKA OIL & GAS ASSOC~~
~~JUDY BRADY~~
~~121 W FIREWEED LN STE 207~~
~~ANCHORAGE AK 99503-2035~~

ANADRILL-SCHLUMBERGER
3940 ARCTIC BLVD #300
ANCHORAGE AK 99503-5711

AK JOURNAL OF COMMERCE
OIL & INDUSTRY NEWS
ROSE RAGSDALE
4220 B STREET STE #210
ANCHORAGE AK 99503-5911

DEPT OF NATURAL RESOURCES
DIV OF OIL & GAS
BRUCE WEBB
3601 C ST STE 1380
ANCHORAGE AK 99503-5948

DEPT OF NATURAL RESOURCES
DIV OIL & GAS
WILLIAM VAN DYKE
3601 C ST STE 1380
ANCHORAGE AK 99503-5948

DEPT OF NATURAL RESOURCES
DIV OF OIL & GAS
JULIE HOULE
3601 C ST STE 1380
ANCHORAGE AK 99503-5948

DEPT OF NATURAL RESOURCES
DIV OF OIL & GAS
JAMES B HAYNES NATURAL RESRCE MGR
3601 C ST STE 1380
ANCHORAGE AK 99503-5948

DEPT OF NATURAL RESOURCES
PUBLIC INFORMATION CTR
3601 C STREET STE 200
ANCHORAGE AK 99503-5948

DEPT OF NATURAL RESOURCES
DIV OF OIL & GAS
JIM STOUFFER
3601 C STREET STE 1380
ANCHORAGE AK 99503-5948

FINK ENVIRONMENTAL CONSULTING, INC.
THOMAS FINK, PHD
6359 COLGATE DR.
ANCHORAGE AK 99504-3305

ARLEN EHM GEOL CONSLTNT
2420 FOXHALL DR
ANCHORAGE AK 99504-3342

JAMES E EASON
8611 LEEPER CIRCLE
ANCHORAGE AK 99504-4209

RUSSELL DOUGLASS
6750 TESHLAR DR
ANCHORAGE AK 99507

STU HIRSH
9630 BASHER DR.
ANCHORAGE AK 99507

US BUREAU OF LAND MNGMNT
ANCHORAGE DIST OFC
DICK FOLAND
6881 ABBOTT LOOP RD
ANCHORAGE AK 99507

US BUREAU OF LAND MNGMNT
ANCHORAGE DIST OFC
PETER J DITTON
6881 ABBOTT LOOP ROAD
ANCHORAGE AK 99507

US BLM AK DIST OFC
RESOURCE EVAL GRP
ART BONET
6881 ABBOTT LOOP RD
ANCHORAGE AK 99507-2899

THOMAS R MARSHALL JR
1569 BIRCHWOOD ST
ANCHORAGE AK 99508

CASS ARIEY
3108 WENTWORTH ST
ANCHORAGE AK 99508

UNIVERSITY OF ALASKA ANCHORAGE
INST OF SOCIAL & ECON RESEARCH
TERESA HULL
3211 PROVIDENCE DR
ANCHORAGE AK 99508

TRADING BAY ENERGY CORP
PAUL CRAIG
5432 NORTHERN LIGHTS BLVD
ANCHORAGE AK 99508

US MIN MGMT SERV
RICHARD PRENTKI
949 E 36TH AV
ANCHORAGE AK 99508-4302

US MIN MGMT SERV
AK OCS REGIONAL DIR
949 E 36TH AV RM 110
ANCHORAGE AK 99508-4302

US MIN MGMT SERV
RESOURCE STUDIES AK OCS REGN
KIRK W SHERWOOD
949 E 36TH AV RM 603
ANCHORAGE AK 99508-4302

REGIONAL SUPRVISOR, FIELD OPERATNS
MINERALS MANAGEMENT SERVICE
ALASKA OCS REGION
949 E 36TH AV STE 308
ANCHORAGE AK 99508-4363

US MIN MGMT SERV
LIBRARY
949 E 36TH AV RM 603
ANCHORAGE AK 99508-4363

US MIN MGMT SERV
RESOURCE EVAL
JIM SCHERR
949 E 36TH AV RM 603
ANCHORAGE AK 99508-4363

US MIN MGMT SERV
FRANK MILLER
949 E 36TH AV STE 603
ANCHORAGE AK 99508-4363

JOHN MILLER
3445 FORDHAM DR
ANCHORAGE AK 99508-4555

USGS - ALASKA SECTION
LIBRARY
4200 UNIVERSITY DR
ANCHORAGE AK 99508-4667

CIRI
LAND DEPT
P O BOX 93330
ANCHORAGE AK 99509-3330

ANCHORAGE TIMES
BERT TARRANT
P O BOX 100040
ANCHORAGE AK 99510-0040

ARCO ALASKA INC
JOANN GRUBER ATO 712
P O BOX 100360
ANCHORAGE AK 99510-0360

ARCO ALASKA INC
LEGAL DEPT
MARK P WORCESTER
P O BOX 100360
ANCHORAGE AK 99510-0360

ARCO ALASKA INC
STEVE BENZLER ATO 1404
P O BOX 100360
ANCHORAGE AK 99510-0360

ARCO ALASKA INC
LIBRARY
P O BOX 100360
ANCHORAGE AK 99510-0360

ARCO ALASKA INC
MARK MAJOR ATO 1968
P O BOX 100360
ANCHORAGE AK 99510-0360

ARCO ALASKA INC
LAND DEPT
JAMES WINEGARNER
P O BOX 10036
ANCHORAGE AK 99510-0360

ARCO ALASKA INC
SAM DENNIS ATO 1388
P O BOX 100360
ANCHORAGE AK 99510-0360

ARCO ALASKA INC
SHELIA ANDREWS ATO 1130
PO BOX 100360
ANCHORAGE AK 99510-0360

PETROLEUM INFO CORP
KRISTEN NELSON
P O BOX 102278
ANCHORAGE AK 99510-2278

ARCO ALASKA INC
KUP CENTRAL WELLS ST TSTNG
WELL ENG TECH NSK 69
P O BOX 196105
ANCHORAGE AK 99510-6105

ALYESKA PIPELINE SERV CO
PERRY A MARKLEY
1835 S BRAGAW - MS 575
ANCHORAGE AK 99512

ALYESKA PIPELINE SERV CO
CHUCK O'DONNELL
1835 S BRAGAW - MS 530B
ANCHORAGE AK 99512

ALYESKA PIPELINE SERV CO
LEGAL DEPT
1835 S BRAGAW
ANCHORAGE AK 99512-0099

US BUREAU OF LAND MGMT
OIL & GAS OPRNS (984)
J A DYGAS
222 W 7TH AV #13
ANCHORAGE AK 99513-7599

ANCHORAGE DAILY NEWS
EDITORIAL PG EDTR
MICHAEL CAREY
P O BOX 149001
ANCHORAGE AK 99514

DAVID W. JOHNSTON
320 MARINER DR.
ANCHORAGE AK 99515

JWL ENGINEERING
JEFF LIPSCOMB
9921 MAIN TREE DR.
ANCHORAGE AK 99516-6510

NORTHERN CONSULTING GROUP
ROBERT BRITCH, P.E.
2454 TELEQUANA DR.
ANCHORAGE AK 99517

GERALD GANOPOLE CONSULT GEOL
2536 ARLINGTON
ANCHORAGE AK 99517-1303

BRISTOL ENVIR SERVICES
JIM MUNTER
201 E 56TH AVE STE 301
ANCHORAGE AK 99518

DAVID CUSATO
600 W 76TH AV #508
ANCHORAGE AK 99518

ASRC
CONRAD BAGNE
301 ARCTIC SLOPE AV STE 300
ANCHORAGE AK 99518

ARMAND SPIELMAN
651 HILANDER CIRCLE
ANCHORAGE AK 99518

HALLIBURTON ENERGY SERV
MARK WEDMAN
6900 ARCTIC BLVD
ANCHORAGE AK 99518-2146

OPSTAD & ASSOC
ERIK A OPSTAD PROF GEOL
P O BOX 190754
ANCHORAGE AK 99519

JACK O HAKKILA
P O BOX 190083
ANCHORAGE AK 99519-0083

ENSTAR NATURAL GAS CO
RICHARD F BARNES PRES
P O BOX 190288
ANCHORAGE AK 99519-0288

MARATHON OIL CO
OPERATIONS SUPT
P O BOX 196168
ANCHORAGE AK 99519-6168

MARATHON OIL CO
BRAD PENN
P O BOX 196168
ANCHORAGE AK 99519-6168

UNOCAL
P O BOX 196247
ANCHORAGE AK 99519-6247

UNOCAL
KEVIN TABLER
P O BOX 196247
ANCHORAGE AK 99519-6247

EXXON COMPANY USA
MARK P EVANS
PO BOX 196601
ANCHORAGE AK 99519-6601

BP EXPLORATION (ALASKA) INC
MR. DAVIS, ESQ
P O BOX 196612 MB 13-5
ANCHORAGE AK 99519-6612

BP EXPLORATION (ALASKA) INC
BOB WILKS MB 5-3
P O BOX 196612
ANCHORAGE AK 99519-6612

BP EXPLORATION (ALASKA) INC
INFO RESOURCE CTR MB 3-2
P O BOX 196612
ANCHORAGE AK 99519-6612

BP EXPLORATION (ALASKA) INC
PETE ZSELECZKY LAND MGR
P O BOX 196612
ANCHORAGE AK 99519-6612

BP EXPLORATION (ALASKA) INC
SUE MILLER
P O BOX 196612 M/S LR2-3
ANCHORAGE AK 99519-6612

BP EXPLORATION (ALASKA), INC.
MARK BERLINGER MB 8-1
PO BOX 196612
ANCHORAGE AK 99519-6612

AMERICA/CANADIAN STRATIGRPH CO
RON BROCKWAY
P O BOX 242781
ANCHORAGE AK 99524-2781

AMSI/VALLEE CO INC
WILLIAM O VALLEE PRES
PO BOX 243086
ANCHORAGE AK 99524-3086

L G POST O&G LAND MGMT CONSULT
10510 CONSTITUTION CIRCLE
EAGLE RIVER AK 99577

DIANA FLECK
18112 MEADOW CRK DR
EAGLE RIVER AK 99577

D A PLATT & ASSOC
9852 LITTLE DIOMEDE CIR
EAGLE RIVER AK 99577

PINNACLE
STEVE TYLER
20231 REVERE CIRCLE
EAGLE RIVER AK 99577

DEPT OF NATURAL RESOURCES
DGGS
JOHN REEDER
P O BOX 772805
EAGLE RIVER AK 99577-2805

COOK INLET VIGIL
JAMES RODERICK
P O BOX 916
HOMER AK 99603

COOK INLET KEEPER
BOB SHAVELSON
PO BOX 3269
HOMER AK 99603

RON DOLCHOK
P O BOX 83
KENAI AK 99611

PHILLIPS PETR
ALASKA OPERATIONS MANAGER
J W KONST
P O DRAWER 66
KENAI AK 99611

DOCUMENT SERVICE CO
JOHN PARKER
P O BOX 1468
KENAI AK 99611-1468

KENAI PENINSULA BOROUGH
ECONOMIC DEVEL DISTR
STAN STEADMAN
P O BOX 3029
KENAI AK 99611-3029

NANCY LORD
PO BOX 558
HOMER AK 99623

PENNY VADLA
P O BOX 467
NINILCHIK AK 99639

BELOWICH COAL CONSULTING
MICHAEL A BELOWICH
HC31 BOX 5157
WASILLA AK 99654

JAMES GIBBS
P O BOX 1597
SOLDOTNA AK 99669

PACE
SHEILA DICKSON
P O BOX 2018
SOLDOTNA AK 99669

KENAI NATL WILDLIFE REFUGE
REFUGE MGR
P O BOX 2139
SOLDOTNA AK 99669-2139

ALYESKA PIPELINE SERVICE CO
VALDEZ CORP AFFAIRS
SANDY MCCLINTOCK
P O BOX 300 MS/701
VALDEZ AK 99686

VALDEZ PIONEER
P O BOX 367
VALDEZ AK 99686

VALDEZ VANGUARD
EDITOR
P O BOX 98
VALDEZ AK 99686-0098

UNIV OF ALASKA FAIRBANKS
PETR DEVEL LAB
DR V A KAMATH
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FAIRBANKS AK 99701

NICK STEPOVICH
543 2ND AVE
FAIRBANKS AK 99701

RICK WAGNER
P O BOX 60868
FAIRBANKS AK 99706

JACK HAKKILA
P O BOX 61604
FAIRBANKS AK 99706-1604

C BURGLIN
P O BOX 131
FAIRBANKS AK 99707

FAIRBANKS DAILY NEWS-MINER
KATE RIPLEY
P O BOX 70710
FAIRBANKS AK 99707

FRED PRATT
P O BOX 72981
FAIRBANKS AK 99707-2981

DEPT OF NATURAL RESOURCES
DIV OF LAND
REG MGR NORTHERN REGION
3700 AIRPORT WAY
FAIRBANKS AK 99709-4699

K&K RECYCL INC
P O BOX 58055
FAIRBANKS AK 99711

ASRC
BILL THOMAS
P O BOX 129
BARROW AK 99723

RICHARD FINEBERG
P O BOX 416
ESTER AK 99725

UNIV OF ALASKA FBX
PETR DEVEL LAB
SHIRISH PATIL
437 DICKERING
FAIRBANKS AK 99775

UNIVERSITY OF ALASKA FBKS
PETR DEVEL LAB
DR AKANNI LAWAL
P O BOX 755880
FAIRBANKS AK 99775-5880

SENATOR LOREN LEMAN
STATE CAPITOL RM 113
JUNEAU AK 99801-1182

DEPT OF ENVIRON CONSERV SPAR
CHRIS PACE
410 WILLOUGHBY AV STE 105
JUNEAU AK 99801-1795

SNEA(P)
DISTR FRANCE/EUROPE DU SUD/AMERIQUE
TOUR ELF
CEDEX 45
992078 PARIS LA DEFE FRANCE

4

CD

1 ALASKA OIL AND GAS CONSERVATION COMMISSION
2 MEETING
3
In Re:)
4)
CHAPTER 25, ALASKA OIL AND GAS)
5 CONSERVATION COMMISSION REGULATION)
CHANGES.)
6)
7
TRANSCRIPT OF PROCEEDINGS
8
Anchorage, Alaska
9 September 29, 1999
9:06 o'clock a.m.
10
APPEARANCES:
11
Commissioners: MR. ROBERT N. CHRISTENSON, CHAIRMAN
12 MS. CAMILLE OECHSLI
MR. DAVID W. JOHNSTON
13
Attorney General's Office: MR. ROBERT E. MINTZ
14
* * * * * *
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17
18
19
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21
22
23
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25

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Alaska Oil & Gas Cons. Commission
Anchorage

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1 PROCEEDINGS
2 (On record - 9:06 a.m.)
3 CHAIRMAN CHRISTENSON: I would like to call
4 this meeting to order. The purpose of this meeting this
5 morning is for the Commission to consider the changes made by
6 the AG's office, and we'll be going over their -- Rob Mintz
7 will be going over their -- those one at a time. Procedurally,
8 the way this works is that at the end of the session we'll be
9 voting on the adoption of these regulations. We're not
10 intending to take detailed questions with regard to specifics
11 in regulations from the audience today. However, if you do
12 have general process questions on the way things will proceed
13 from here, we'll be happy to answer those. It's our
14 anticipation that once they're adopted, they'll go from the
15 AG's office to the Lieutenant Governor, and from that point on
16 after they are approved from 30 days after that point they'll
17 be in effect. So that's kind of roughly the time table. We
18 don't really know how long it will take to get through the
19 Lieutenant Governor's office.
20 So are there any questions at this point, general
21 questions on the process?
22 MR. WORCESTER: If I could make a few brief comments
23 I'd appreciate it.
24 CHAIRMAN CHRISTENSON: Process, Mark. Process.
25 MR. WORCESTER: Well (indiscernible - simultaneous

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1 talking) the process, yes.
2 CHAIRMAN CHRISTENSON: Not the regulations.
3 MR. WORCESTER: Okay. My name is Mark Worcester. I'm
4 with ARCO Alaska, Inc. Unfortunately, due to the amount of
5 notice, I have not been able to -- it's been impossible for
6 AOGA to meet and be able to make any comments on process or
7 substantively. We have not received copies of the latest
8 edition until yesterday afternoon, and that's basically is my
9 process concern is that this regulation project is more than
10 five years old at this point. The Commission has adopted
11 regulations two times, and there's been substantial work by --
12 done by AOGA and its members as well as the Commission and the
13 Department of Law on these regulations. The Department of Law
14 has been actively involved through that whole process through
15 both adoptions. In a quick review of this -- the latest
16 changes being recommended by the Department of Law show
17 extensive changes. A quick perusal will show that easily.
18 Many of these are substantive in my view and overly restrict
19 the discretion of and the way of doing business that the
20 Commission has very successfully used over the years. It's
21 impossible as I say with the timing for us to prepare and I'm
22 not sure we're even invited to make comments on what we view is
23 significant substantive changes that may deserve more
24 consideration.
25 And so I on behalf of ARCO only request that the

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1 Commission not act today. I know we're all eager to get this
2 process done and over with and this regulation process finally
3 put to bed but after all this work I believe it would be
4 inappropriate not to consider the comments after an adequate
5 time for review for the changes, and with an understanding of
6 why the Department of Law is recommending these changes.
7 I understand the Department of Law's role is to --
8 limited to matters of form and opinions as to legality, not to
9 substitute its judgment for the appropriateness of the acts of
10 discretion of the Commission.
11 And so with that I'm very interested in listening to
12 the -- Mr. Mintz's comments about why these changes are here
13 and hope that the Commission will entertain the comments of the
14 regulated community and other members of the public. Thank
15 you.
16 CHAIRMAN CHRISTENSON: Okay. Duly noted. Rob, would
17 you proceed to go through the changes? I think you're going to
18 go through it page by page so that we all know what's going on.
19 MR. MINTZ: Yes. Let me first say that of course
20 Mr. Worcester is absolutely right. There are a number of
21 substantive changes reflected in this new version. In no case
22 was any substantive change unilaterally made by the Department
23 of Law but these basically were the result of raising issues
24 and then consultation with one or more commissioners and often
25 through the commissioners' staff as to the appropriate

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1 response. But of course it's totally within the Commission's
2 judgment today as to whether the Commission as a whole agrees
3 with these proposed changes and whether it wants to adopt them.
4 Basically everything in here is a result of a process
5 that occurred through review of the regs by the Regulation
6 Section of the Department of Law. And I guess I would say
7 there are three categories of changes. Probably the most
8 common one is what I call formal changes. Changes in style,
9 convention, which actually would not require readoption by the
10 Commission but since there are other changes that do require
11 readoption, they're all part of the package.
12 The second type of change basically resulted from the
13 Department of Law Regulation Section determination that there
14 was a legal problem with an aspect of the regs, and then the
15 change reflects the solution to the problem as I say through
16 consultation with one or more commissioners.
17 And then the third category would be instances where
18 the Regulation Section review found an ambiguity or lack of
19 clarity in what the earlier version of the regulation was
20 trying to accomplish, and the change reflects an attempt to
21 clarify that. And in some cases actually just through the back
22 and forth during this process either individual commissioners
23 or staff members came up with other improvements that they
24 thought should be considered. And so I guess that adds up to
25 four categories of changes.

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1 So I'll go through these page by page and basically
2 give any commissioner a chance to ask questions or raise
3 issues. And in some cases I'll try and explain what the
4 changes are about.
5 The first page is just formal changes. And I'll
6 just -- just to save time I'll just kind of roll ahead and ask
7 that any commissioner interrupt me with any questions on any
8 page.
9 CHAIRMAN CHRISTENSON: Good.
10 MR. MINTZ: The second page is basically formal changes
11 or clarifications except for an additional requirement which I
12 believe originated in with a staff suggestion, and that is that
13 in addition to governmental section line coordinates for
14 identifying a well location that the surface location also be
15 identified with reference to the state plane coordinate system.
16 Turning to page three, there -- I don't think there are
17 any substantive changes here, just clarifying our formal
18 changes.
19 Same on page four.
20 Same on page five.
21 Same on page six.
22 Now, at the top of page seven, there are two changes.
23 And this change is reflected throughout the regs in similar
24 situation. One is -- this has to do with oral approval of an
25 application and followed by submission of the written

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1 application. And it was the thought of either one or more
2 commissioners that -- or the staff or both that if the
3 Commission has to be responding that quickly, that the operator
4 should also be responding very expeditiously, and that the
5 written submission should be within three days as opposed to
6 three working days.
7 The other change was something that Regulation Section
8 said is necessary to conform with the law, and that is the
9 requirement of -- that the written application be made for
10 final approval by the Commission because essentially a
11 commission -- multi-member commission can't really delegate its
12 ultimate authority to anyone else as a staff -- such as a staff
13 member.
14 The oth- -- the rest of the changes on page seven are
15 clarifying or technical/formal.
16 On page eight, the substantive change is at the bottom,
17 subsection (b). The bond in general is supposed to make sure
18 that among other things, a well is abandoned and the location
19 is cleared properly. As previously written, when the
20 Commission would allow an amount less than $100,000 for single
21 well, it -- the criteria in there was that the cost of well
22 abandonment would be less than 100,000, but since the bond is
23 supposed to also cover location clearance, the proposed change
24 would clarify that the total cost of abandonment and location
25 clearance would have to be less than $100,000.

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1 On page nine is clarifying or technical changes.
2 On page 10, at the bottom, paragraph (3) and (4), these
3 are the first of many situations where the Regulation Section
4 determined that there needed to be a standard set out in the
5 reg to apply to the Commission's decision. Generally speaking,
6 what's going on in the regs in these situations is there's a
7 requirement or a -- basically a requirement set out but with an
8 escape valve that with -- on Commission approval or sometimes
9 it says in the Commission's discretion the requirement could be
10 changed or waived. And the Regulation Section points out that
11 if there's no standard, then there's a strong possibility that
12 the regulation would be found arbitrary or to put it another
13 way, the regulation would be found to be an attempt to allow
14 the Commission to act arbitrarily. And to make sure that
15 doesn't happen, it's important to specify what grounds the
16 Commission would use to grant the waiver or the variance. And
17 essentially the -- I mean conceptually it's a very simple fix
18 because you just look at the goal that you're trying to
19 accomplish through the requirement, and you're essentially
20 saying here's the requirement to accomplish that goal but if
21 the operator can show there's another way to accomplish that
22 same goal, then the Commission will allow that other way.
23 Now moving on to page 11, here's another example of
24 adding such a standard. In subsection (c) paragraph (2)(B).
25 Paragraph -- I'm sorry, page 12 at the bottom of the

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1 page, there's another standard added there.
2 (Whispered side conversation)
3 MR. MINTZ: Subsection (a) of the section actually sets
4 out the goals of the casing and cementing program. And this
5 standard says basically if you need -- that if you need
6 remedial action to meet those requirements, then that would be
7 required.
8 On page 13, paragraph (5), I think this was on the
9 advice of staff through one or more commissioners that two of
10 the examples on line five are inapplicable and so they were
11 deleted, that is cement channeling and mechanical failure of
12 equipment.
13 On page 14, 25.033.(a), the phrase, in its discretion,
14 is deleted for a similar reason to what I just described in
15 connection with the addition of standards. If the Commission
16 determines that a drilling fluid system is not necessary, then
17 I -- the question is is there any why the Commission would not
18 allow drilling operation to go forward without the drilling
19 fluid system. And in the absence of anyone coming up with that
20 reason, it would reduce arbitrariness and increase
21 predictability to simply provide for the -- provide for that
22 blanket rule that you have to be equipped with a drilling fluid
23 system unless the Commission determines it's not necessary.
24 Page 15 just reflects clarification of terminology.
25 On page 16 the deletion in (d) and (f) of the phrase

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1 drill- -- well, basically referenced to rotary drilling rig
2 operation, that reflects a suggestion by staff or one or more
3 commissioners or both that these requirements should apply
4 whether or not it's a rotary operation.
5 On page 17, paragraph (2) at the top, there's the
6 addition of a standard of the sort I previously described. And
7 deletion of the phrase, in its discretion. On paragraph (2)
8 and (3), well control data, the term, control, has been deleted
9 simply to clarify or to avoid confusion. Most everywhere else
10 in the regs well control refers to basically avoiding blowouts
11 and physical problems like that. And here it's a di- -- it's
12 used in a different sense and by deleting the word, control,
13 well data is -- the context makes clear what you are talking
14 about.
15 Page 18 a standard has been added.
16 Page 19 it has clarifying technical corrections.
17 Page 20 -- oh, pa- -- at the bottom of page 19 and 20,
18 there's a deletion of, in its discretion, for the same reason I
19 described earlier. And then paragraph two on page 20, this is
20 just re-writing the standard to clarify what you're trying to
21 accomplish.
22 On page 21, it's the first of a number of updates in
23 the terminology at the bottom. API 5M apparently is now
24 referred to as 5K.
25 The changes on page 22 are just clarifying language.

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1 And on page 23 there are clarifying language and the
2 addition of a standard. Paragraph (iii) at the end of first
3 sentence where there's a possibility that the Commission will
4 require a higher rate of working pressure, and the standard is
5 as the Commission considers necessary to maintain well control.
6 On page 24, there are terminology changes. And then at
7 the bottom of the page, (F)(i), this was a suggestion by staff
8 or one or more commissioners or both to change the BOP
9 requirement.
10 And same comments on page 25, some changes in the BOP
11 requirements.
12 On page 26, again, a suggestion from staff or one or
13 more commissioners that the reference to rigid pipe in
14 paragraph (6) include the term, steel. And then standards were
15 added in (6)(A) and (6)(F) to govern variances.
16 On page 27, these are basically clarifying technical
17 corrections.
18 Same on page 28.
19 On page 29, same, but there's also -- no, these are
20 just clarifying and technical corrections.
21 On page 30, there's a change in the BOP requirement in
22 paragraph (2)(A) at the top. No, it's not a change, just
23 clarifying language. Sorry.
24 On page 31, there is a -- the same standard for a
25 variance to the working pressure requirement as we described

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1 earlier. That is in paragraph (3) at the top, considers
2 necessary to maintain well control.
3 Page 32 clarifying and technical changes.
4 Same on page 33.
5 On page 34, paragraph (10), again the addition of steel
6 and rigid steel pipe, and the addition of a standard for
7 approval of a -- other conduit.
8 Page 35 are clarifying and language changes to conform
9 to the language elsewhere in the regs.
10 Page 36, Section 37, there's a standard added for the
11 Commission to approve alternate well control procedures.
12 37, basically it's updating the requirements and what
13 has to be on the identifying sign. I think the substantive
14 change may be in par- -- in subsection (c) where -- which
15 concerns signs at platforms or multiple well drill sites. Some
16 information may be posted on one sign rather than on a sign in
17 front of each well.
18 Page 38 only has technical, clarifying, or formal
19 changes.
20 And I think that's true on page 39 as well.
21 And that is also true on page 40.
22 On page.....
23 COMMISSIONER OECHSLI: I think at the bottom of page 40
24 it looks like the coordinates -- oh, never mind. You're right.
25 MR. MINTZ: Yeah. The top of page 41 there's a

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1 substantive addition suggested by staff or a commissioner, and
2 that is requiring reference to the state plane coordinate
3 system for the surface location.
4 Page 42 is simply formal language changes.
5 Page 43, there's been a change suggested in subsection
6 (e) in the standard for granting a variance from the notice
7 requirements in connection with spacing exceptions. And it
8 basically provides a more -- well, a different standard which
9 is feasibility of complying -- or lack of feasibility with
10 complying with the regular notice requirement because I think
11 on reconsideration it appeared that it's not very likely that
12 there's going to be a more effective means of providing notice
13 than individual certified mail but it's really a question of
14 feasibility.
15 I don't see anything substantive on page 44 or 45.
16 And on 46, there's an addition of a standard in (a)(3)
17 where the Commission will require additional sensors as the
18 Commission considers is necessary for safety.
19 Nothing substantive on 47 or 48 or 49.
20 By the way I should get -- I should emphasize
21 regardless of whether I express an opinion that there's nothing
22 substantive, the Commission is free of course to have a
23 different view and to take exception and to either reject or
24 accept or modify any of those changes.
25 CHAIRMAN CHRISTENSON: Okay.

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1 MR. MINTZ: On page 50, this has to do with the well
2 data that are required to be filed under statute within 30 days
3 after well is completed, suspended, or abandoned. Now,
4 apparently there are some sorts of data that in at least some
5 cases cannot feasibly be available in 30 days. And so this
6 change -- the change basically requires that the operator
7 submit a proposed date for when they can be submitted as
8 opposed to just leaving it up to the operator to file them as
9 soon as available.
10 On page 51, language is added to clarify that the
11 concept of shutdown is a temporary shutdown.
12 And on page 52, subsection (d), continuing with the
13 shutdown concept, basically this adds a standard for
14 determining whether there should be a grant of an additional
15 period allowing well shutdown. The standard is if the operator
16 shows that operational circumstances beyond the operator's
17 control prevent resumption within a 12 month period.
18 Paragraph (sic) 53, I think that's just -- wait. Oh,
19 there is. Sorry.
20 Back on page 52, this is just a legal problem here.
21 The existing Section 75 provides -- well, this has to do with
22 the Commission's authority to regulate non oil and gas well
23 drilling in certain areas of the case where -- certain areas of
24 the state where there are particular hazards that the
25 Commission identifies. The problem is that the statute

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1 requires that the Commiss- -- if the Commission is going to
2 define such an area and regulate drilling, it has to do that by
3 regulation. And the existing regulation said the Commission
4 would do that by order. And basically that's inconsistent with
5 the statute. So the Department of Law actually recommends that
6 Section 75 be repealed. However, it probably requires a
7 separate regulation project with separate notice to appeal
8 that. So for the time being, we are just recommending that the
9 amendments be withdrawn. And that's what this cross out does.
10 I don't see anything further substantive on page 53 or
11 on 54.
12 Page 55, subsection (c), the phrase, in its discretion,
13 has been deleted following the principle that if the standards
14 have been met for getting an authorization, an authorization
15 should be granted.
16 And then on page -- the top of page 56, there's a
17 standard added that would govern the Commission's decision to
18 impose additional conditions on an authorization. Namely, the
19 standard is that the things you are trying to achieve in this
20 section which are set out in subsection (c) are -- require the
21 additional conditions to be imposed. And otherwise, there are
22 formal or technical changes only.
23 Similarly on page 57.
24 Similarly on page 58. I would just explain a number of
25 cases. For example, in subsection (b) where it refers to

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1 removal of the drill rig from location, the phrase, from
2 location, has been deleted to clarify something. Some places
3 in the regs, location is used in the context of location
4 clearance, and it has a more general or broader meaning than
5 the actual well. And we wanted to be clear that in this case
6 abandonment is triggered by removal of the drill rig from the
7 well and not just from the general location.
8 On page 59, basically subsection (e) reflects the
9 change I earlier described requiring final approval by the
10 Commission in the case of an earlier oral approval. And in
11 this case the 10 days for filing the written application has
12 been reduced to three days to make it consistent with the
13 general rule throughout the regs.
14 And that same change has been made on page 60.
15 Page 61, subsection (a) deletes the phrase, in its
16 discretion, for the reasons I earlier described. Then there is
17 a significant substantive change that was suggested by a staff
18 or one or more commissioners, and that is that as revised, a
19 well can be suspended even if it has been completed in the
20 certain circumstances that are set out in paragraph two. And
21 then subsection -- oh. The existing reg and indeed I think the
22 current reg before these were adopted uses the -- uses a
23 standard paying quantities, produced in paying quantities in
24 (a)(1), and the Regulation Section advised that it's necessary
25 to define this. And the definition set out here is basically

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1 one of two standard definitions in the oil industry. And it's
2 the one that seemed most applicable to this situation because
3 it would -- it only requires that enough oil or gas be produced
4 to pay for the cost of operating the well as opposed to also
5 paying back the investment cost.
6 Subsection (b) includes the changes to three days and
7 requiring final approval of the Commission.
8 On page 62, paragraph two -- par- -- I'm sorry,
9 subsection (c) is changed. This has to do with the fact that
10 in general, information, and this usually concerns well data,
11 that is not required to be submitted to the Commission but is
12 voluntarily submitted has to be kept confidential if the
13 operator so requests. And basically as previously written,
14 subsection (c) more or less repeated that provision. However,
15 the information that is required to demonstrate that a well
16 should be suspended is not information that's voluntarily
17 submitted. So it doesn't really fall within that protection.
18 Yet in consulting with one or more commissioners we understood
19 that it is important to assure in this reg that whatever
20 confidentiality may be afforded by law will be afforded by law,
21 and that's what the re-writing attempts to do, basically to the
22 extent that the information submitted here is required to be
23 submitted under the statute, it will be maintained confidential
24 for as long as the statute requires, and if it's not required
25 to be submitted, it will be maintained confidential if it's a

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1 trade secret. And a trade secret is defined in the -- Uniform
2 Trade Secrets Act quite broadly. Basically if there is value
3 to the owner of that information by keeping it secret, then --
4 I'm kind of oversimplifying but it's a broad definition.
5 On page 62, subsection (d) paragraph (2), a standard
6 has been added for waiving the requirements for plugging here.
7 And page 63, at the top it basically just specifies
8 what standard is going to apply to location clearance. And 63,
9 a standard is added for the Commission's approval for plugging
10 from the top of fill instead of plugged back total depth.
11 64 is just clarifying changes.
12 And 65 para- -- subparagraph (c) in the middle, a
13 standard has been added. It's basically the same one that is
14 on the bottom of page 63, having to do with plugging, variants
15 on plugging.
16 There's nothing substantive on 66.
17 On page 67, subsection (g) and paragraph (1), this is
18 clarifying the surface plugging requirements based on
19 consultation with staff and one or more commissioners. I'm
20 probably not the best person to explain it but if there are any
21 questions, I think Commissioner Johnston could probably explain
22 it.
23 COMMISSIONER JOHNSTON: Yeah. I think all this does is
24 make it clear that testing of the cement retainer can occur
25 before you place the cement so it gives a broader latitude in

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1 terms of testing the cement plugs and mechanical plugs.
2 MR. MINTZ: 68 is clarify and formal changes.
3 On page 69, subsection (a) at the top, a standard has
4 been added for allowing a marker post rather than a marker
5 plate. And subsection (d) I think that's just one addition,
6 paragraph (3) there, the well name has been added to the
7 requirement -- to the information that has to be on the marker.
8 That was a suggestion from staff or a commissioner.
9 On page 70, Section 140, the standards for allowing --
10 approving conversion to a water well have been somewhat
11 clarified and revised. Basically it requir- -- that would not
12 require that the proposed use as a freshwater well is bona
13 fide.
14 And then Section 170(a) at the bottom, the language for
15 triggering location clearance has been clarified so that it's
16 not necessarily after the well has been abandoned but it could
17 be and presumably will often be at the time the well is
18 abandoned. It could be at or after.
19 Page 71, the Regulation Section recommended that there
20 be more clear and certain provisions showing that where a lease
21 is basically controlled or properties controlled by either DNR
22 in the case of a state lease or the United States Department of
23 Interior in case of federal lease that the surface location
24 requir- -- clearance requirements of those agencies would be
25 deferred to.

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1 And in addition, (2)(C) on page 71, a standard has been
2 added to govern the Commission's approval of closing pits in a
3 different manner than filling and grading them.
4 Page 72 reflects similar changes in offshore location
5 clearance to what I described in Onshore.
6 And so does 73.
7 74, you might want to frame. There are no changes.
8 75, (d) at the top, there's a standard added for
9 variance from the tubing and packer requirement. Otherwise,
10 there are clarifying or formal corrections.
11 On page 76, Section 210, the in its discretion language
12 has been deleted because there didn't seem to be any occasions
13 on which the general would not be suitable.
14 And then on page 77, Section 225, there's a standard
15 added for the Commission to approve alternative test methods to
16 the multi-point -- rather to a multi-point back-pressure
17 method. And since there apparently is more than one type of
18 multi-point back-pressure method, the word, the, has been
19 changed to, a, at the beginning of the sentence.
20 Page 78, subsection (b), at the suggestion of staff or
21 a commissioner, the phrase, and gas meters runs, has been
22 deleted because that's considered part of the hydrocarbon
23 measurement equipment.
24 And at page 79 at the top, subsection (g), a standard
25 has been added to govern the schedule approved by the

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1 Commission.
2 Similarly on page 80, Section 230, a standard has been
3 added to govern the Commission's determination of what are
4 acceptable equipment and techniques, and then in the first line
5 of subsection (a), the phrase, or allocated, has been deleted
6 because again based on an analysis by staff or one or more
7 commissioners, it's clear that the Commission actually wants to
8 require a measurement in every case. And actually it's the
9 second sentence of this subsection which provides an exception
10 for allocation. And what it basically says is -- well, I mean
11 the first sentence is you have to measure production from each
12 well. The second sentence says, well, you could measure it
13 from a group of wells if it's accurately allocated to each
14 well. And those are really the only two alternatives that the
15 Commission wants to allow as I understand it.
16 Section (sic) 81 is just technical or formal changes.
17 Okay. And the same in 82.
18 On page 83, the first line at the top of the page has
19 been deleted but it's been replaced by a similar provision on
20 page 86 which we'll get to when we get to page 86.
21 And then similar -- still in subsection (a), basically
22 we've reworded the description of the types of waste that will
23 be permitted. And it basically broadens it somewhat so that
24 whatever the Commission determines are suitable for disposal in
25 a Class II well or waste that the Commission may authorize for

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1 underground disposal.
2 And then subsection (c)(1) at the bottom, this change
3 is necessary to conform with EPA regulations on the UIC
4 programs that basically the plat in question has to show all
5 wells that are within the quarter mile zone whether or not they
6 penetrate the injection zone.
7 Page 84, these are just clarifying or formal changes.
8 On page 85, the suggestion of a commissioner,
9 subsection (d), would require mechanical integrity testing at
10 least once every four years.
11 And in subsection (e), the triggers for notifying the
12 Commission and possibly taking corrective action in the case of
13 indications of pressure communication or leakage have been
14 somewhat limited. And now it's the -- and the hoop stress
15 criteria has been deleted. And a previous -- on a previously
16 required Commission approved corrective action, again, at the
17 suggestion of one or more commissioners, this has been changed
18 to not always require corrective action but in some cases give
19 it the option of increased surveillance. And the standard has
20 been added for -- of requir- -- of ensuring protection of fresh
21 water.
22 Subsection (f), in its discretion, has been deleted
23 because if the standard is met, then there doesn't seem to be
24 any reason not to follow the general rule.
25 Subsection (sic) 86, this -- all this cross out and

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1 additional language is simply rewriting to make it clear and
2 conform to approved syntax.
3 And then new subsection (l) does the same thing that
4 the introductory sentence of subsection (a) used to do, and
5 that is to make clear that if underground disposal is regulated
6 by the EPA, and this would be basically in practice non-Class
7 II wells, then the Commission's program does not apply.
8 Subsection (sic) 87 are clarifying the language
9 changes.
10 Same as -- same with page 88.
11 Same with page 89.
12 Same with page 90. Basically at the top of the page,
13 (c) and (d), it used to say well workover and repair, but since
14 subsection (a) defines workover as including repair, the repair
15 has been deleted as superfluous.
16 Subsection -- on page 91 are technical clarifying
17 changes.
18 And same on page 92.
19 On page 93, (9)(A) near the bottom, there's been a
20 change in the BOP requirements suggested by staff or one or
21 more commissioners. From API 2M to 5K, and from greater than
22 to equal to or greater than.
23 Similar change on page 94, (10)(A) and (10)(C) and
24 (10)(D).
25 COMMISSIONER OECHSLI: I don't think (10)(A) is a

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1 change. I think it's just a rewording.
2 MR. MINTZ: You're right. Sorry.
3 COMMISSIONER OECHSLI: Okay.
4 MR. MINTZ: Page 95, these changes are equivalent to
5 what were done earlier in the regs: adding steel to rigid
6 pipe, adding a standard for approving other conduit, and adding
7 a standard for approving other types of joints.
8 Page 96, the change here is in -- aside from the
9 technical changes, subsection (g) previously referred to
10 geological hazard information acquired in connection with the
11 Application for Sundry Approvals but one or more of the
12 commissioners pointed out that there generally is not
13 geological hazard information obtained in connection with the
14 Application for Sundry Approvals, and the geological infor- --
15 hazard information would have been obtained while drilling the
16 well and so that change is reflected in subsection (g).
17 Subsection (sic) 97 is just clarifying or formal
18 changes.
19 And similarly on 98 and on 99 and on 100 and on 101.
20 On page 102, subsection (e) at the top, the same change
21 I just described on geologic hazard information, and then
22 Section 288, there is a standard added for approve an alternate
23 well control procedures and equipment. And deletion of, in its
24 discretion.
25 Page 103 is just a technical change.

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1 Same on 104.
2 Same on 105.
3 On 106, Section 402(a), a standard has been added and
4 the reference to discretion deleted with regard to authorizing
5 enhanced recovery fluid injection. And the rest of the changes
6 are more or less clarifying language.
7 Same on 107.
8 And 108, subsection (f), this reflects the same changes
9 were made earlier on waste disposal injection wells deleting
10 the reference to hoop stress and add- -- basically broadening
11 the options for dealing with the situation to include increased
12 surveillance.
13 And adding a standard in subsection (g) for additional
14 mechanical integrity tests.
15 In subsection -- in 412(b) at the bottom of the page,
16 standards are added for approving different equipment or
17 different placement of a packer.
18 Page 110, these are clarifying changes.
19 So -- I mean page 111, subsection (c) at the bottom has
20 been updated to refer to the federal regulation where EPA's act
21 for exemptions are actually set out.
22 And then in -- on page 112, Section 450(a), the in its
23 discretion language has been deleted so that basically if the
24 applicant demonstrates that the applicable requirements are
25 met, then the -- I'm sorry, if the change in requirements will

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1 not result in increased risk of movement of fluids into fresh
2 water, then the Commission will allow the changes.
3 113 are technical or formal changes.
4 114 is another page with no changes.
5 CHAIRMAN CHRISTENSON: That makes two, right?
6 MR. MINTZ: Yeah. Actually, it may interest you to
7 know that the Regulation Section said for a regulations project
8 of this size, it was in uncommonly good shape and required
9 unusually few changes.
10 CHAIRMAN CHRISTENSON: We will duly note that.
11 COMMISSIONER JOHNSTON: Is it possible to make a change
12 on 114 just to -- in the spirit of things here?
13 MR. MINTZ: On page 115, this is just clarifying
14 language.
15 Page 116 at the top, a standard is added to explain the
16 basis for the Commission conditioning its approval.
17 And then (b), the final approval by the Commission and
18 the three days as opposed to three working days has been added.
19 On page 117, the shading of the moose has been slightly
20 changed. That was just a joke.
21 Nothing on page 118. That makes three.
22 COMMISSIONER OECHSLI: We're up to three or four, the
23 moose.
24 MR. MINTZ: Well, four. Yeah.
25 On page 119, subsection (b) at the bottom -- oh,

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1 actually there are no substantive changes on this page or on
2 page 120 or on page 121.
3 At the top of page 122, second line, there was an error
4 in the citation of the federal regulation which has been
5 corrected.
6 COMMISSIONER JOHNSTON: So what does that citation now
7 read, Rob?
8 MR. MINTZ: 30 C.F.R. 250.1500.
9 COMMISSIONER JOHNSTON: 1500.
10 MR. MINTZ: Yeah.
11 COMMISSIONER JOHNSTON: Okay.
12 MR. MINTZ: I don't see any substantive changes on 123.
13 On 535, this is the Enforcement provision. This has
14 been significantly rewritten although mostly it's just
15 clarifying. Well, subsection (b) adds the requirement that
16 written notification to a person subject to the action be by
17 personal service or certified mail.
18 Then there is a -- in subsection (c) on time limits,
19 there's more of a standard on that. First that the time can be
20 extended for good cause shown which is basically kind of a
21 legal term of art that has been defined in case law. And
22 subsection (c), the standard length for response has been
23 increased from 10 to 15. Otherwise they're just clarifying
24 language changes.
25 Nothing substantive on 125.

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1 On page 126, subsection (b), the regulation section
2 advised that the last phrase which has been deleted is
3 superfluous.
4 Page 127, which deals with Emergency Action, subsection
5 (a), the Regulation Section advised that the conditions for
6 emergency order be limited to those where there's immediate
7 harm to public health or safety. They were concerned that if
8 it was broader that it would be subject to legal challenge.
9 And then on -- looking further at the first sentence, and
10 particularly in relationship to the other sections on hearings
11 and orders, I raised the question of -- it became clear to me
12 that emergency actions really should not be a necessarily
13 limited to those resulting from a violation because there might
14 be a situation where the Commission has authorized something,
15 for example, in an order, and then circumstances change so that
16 what's authorized is now presenting a threat to public health
17 or safety and there might have to be a temporary emergency
18 modification of that order, for example. So I recommend that
19 the last ph- -- well, the last part of the sentence be deleted
20 so that there's no limit on the use of emergency orders to
21 situation where there's a violation.
22 Subsection (c)(3) has been changed so that if a hearing
23 lasts longer than 14 days, for example, or if there's some
24 other need to extend the period of the emergency order to
25 protect against immediate harm to public health, that that's an

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1 option. Health or safety.
2 And then subsection (d) clarifies the procedural
3 relationship between this section and other sections. And
4 basically provides among other things that in general there
5 will be a hearing -- a hearing will be governed by the regular
6 hearing provisions of Section 540 except that it will only have
7 to be 10 days notice rather than 30 days. And there's no
8 requirement that a person request a public hearing. And
9 subsection (d) also clarifies that in the case of an
10 enforcement action, the ordinary enforcement action has kind of
11 a process of a possibility of informal conference or review
12 followed later by a hearing. Well, when there's an emergency
13 order that needs an immediate hearing, those procedures will
14 not be followed because you'll go right to a hearing unless the
15 operator wants to extend the process in which you could have an
16 extension. And that's set out in subsection (d).
17 Page 128, subsection (a) -- say, I'm getting a little
18 bit horse. I wonder if we could have a brief recess so I could
19 get some water.
20 CHAIRMAN CHRISTENSON: I'm sure we can do that.
21 COMMISSIONER OECHSLI: I think this might be a good
22 time for a break.
23 CHAIRMAN CHRISTENSON: Go off record.
24 (Off record)
25 (On record)

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1 CHAIRMAN CHRISTENSON: Let's go back on record, please.
2 Mr. Mintz, have you recovered your voice?
3 MR. MINTZ: Temporarily. Thanks.
4 CHAIRMAN CHRISTENSON: Temporarily, okay.
5 MR. MINTZ: Okay. We're on.....
6 CHAIRMAN CHRISTENSON: Would you continue, please?
7 MR. MINTZ: We're on page 128, Hearings, subsection
8 (a). There have been some changes here to -- basically to
9 conform to the statutory requirements. The statute requires a
10 hearing in many cases. And the regulation has a attempted to
11 reconcile that requirement with the fact that some -- in many
12 cases there actually is -- there's no dispute and no need for a
13 hearing and so therefore basically provides that the notice
14 will tentatively set a hearing, and then a hearing would be
15 held if there is a request for a hearing.
16 Now, the existing reg requires that -- well, actually I
17 don't remember off hand what the existing reg requires but the
18 reg as previously adopted required a requester to identify an
19 interest and the reasons for a hearing. And the regulation
20 section advised that there really can't be any limitation on a
21 person's right to request a hearing and obtain the hearing
22 under the statute, and therefore that provision has been
23 deleted in the revision. And also there's a -- now it provides
24 that the Commission will provide a telephone number in the
25 notice that the public may call to find out if the tentative

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1 hearing will, in fact, be held.
2 Other than that, the changes are basically technical or
3 clarifying.
4 On page 129, paragraph (10) at the bottom, there has
5 been some additional language suggested to clarify the
6 procedures that the Commission would use when it's dealing with
7 confidential information. And that is essentially when due
8 process requires that all the parties in a hearing have access
9 to whatever evidence the Commission will consider whether or
10 not that's confidential, there must be safeguards to reconcile
11 that need with the need to protect confidentiality. And this
12 specifies that the Commission will as necessary review
13 confidential information in camera, that is to say, in secret;
14 and to redact, which is to say, edit, Commission decisions if
15 necessary to protect confidential information.
16 And on page 130, paragraph (11) at the top, this is a
17 proposed change so that currently as written, the reg would
18 require a written transcript of a hearing to be prepared in
19 every case. But upon reflection and consideration of the
20 practice of other agencies, it's clear that the Commission
21 should have the option of not always having a transcript, and
22 therefore the proposal is to re-write the regs so that it
23 requires that a hearing be recorded and the recording included
24 in the public record. And if necessary at a later point. a
25 transcript could be made. Otherwise, there are clarifying or

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1 technical changes.
2 Same on page 131.
3 Same on page 132.
4 Then we go to Definitions. The changes on 133 are just
5 clarifying or adding definition of a term used in the regs.
6 COMMISSIONER JOHNSTON: Excuse me, Rob.
7 MR. MINTZ: Yeah.
8 COMMISSIONER JOHNSTON: Definition number (4), I do not
9 believe we need anymore with the changes that we.....
10 MR. MINTZ: Oh.
11 COMMISSIONER JOHNSTON: .....made in the previous
12 sections.
13 MR. MINTZ: There's no more reference to API 2K?
14 COMMISSIONER JOHNSTON: I do not believe with the
15 changes that we have made that there will be any more
16 references to the 2M or the 2K BOP. The only references that
17 I'm aware relative to the 2K had to do with the size of the
18 outlet, and that has now been changed to a reference to equal
19 to or greater than 5K. So.....
20 MR. MINTZ: All right. When we get to the point of a
21 motion to adopt, I'll -- I need to think about how to deal with
22 that.
23 COMMISSIONER JOHNSTON: Okay.
24 MR. MINTZ: Okay. On page 134, just chan- --
25 clarifying changes.

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1 Also 135.
2 And 136, and there are a couple of new definitions of
3 words that are already used in the regs.
4 137, nothing substantive.
5 138. I think the only significant change there is
6 addition of the definition of the term, public water system.
7 And the Regulation Section recommended adopting the same
8 definition that DEC has because that is also under the Safe
9 Drinking Water Act. And it's advisable that the state use the
10 same definition of the term which appears in the same act.
11 By the way, that -- what that definition is is as
12 follows. Public water system means any source of water, intake
13 works, collection system, treatment works, storage facility, or
14 distribution system, including a vehicle or vessel used to
15 distribute water from which water is available for pu- -- for
16 human consumption. Public water system includes a system
17 providing water to more than one residential dwelling unit,
18 including a duplex or to a factory, office building,
19 restaurant, school, or similar facility, but does not include a
20 system serving only one single family residence.
21 And the regulation section advises that this definition
22 is consistent with the EPA definition under the Safe Drinking
23 Water Act.
24 On page 139, there's a new definition of tour, which I
25 understand is an industry term of art.

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1 And on page 140, a definition of working day, there are
2 still a few places in the regs that refer to working day, and
3 that's generally in the context of the next working day.
4 And that looks like it. If the commissioners have any
5 questions, I'll try and answer them.
6 CHAIRMAN CHRISTENSON: David, do you have any
7 questions?
8 COMMISSIONER JOHNSTON: I don't believe so although I
9 think we may want to take a look at the language on page 86.
10 The paragraph that says, this section does not apply to
11 underground disposal that is regulated under the federal
12 register there, what happens in a situation -- I mean would
13 that -- would this remove authority from us if, say, a federal
14 well, a Class I well, was injecting and it was determined to be
15 contaminating fresh water, would this preclude the Commission
16 from taking any action to step in and remedy that solution or
17 that problem?
18 MR. MINTZ: Well, this -- it would preclude the
19 Commission from acting under that section. If there is some
20 other authority that the Commission has, it wouldn't affect
21 that. I mean there is some question of federal preemption in
22 the area of underground injection. And the citation there in
23 subsection (l) is actually the description of the underground
24 injection program in Alaska.
25 COMMISSIONER JOHNSTON: Right.

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1 MR. MINTZ: And, of course, the Class II program is
2 administered by the Commission and all the others are
3 administered by EPA. Now -- so leaving aside whatever federal
4 preemption issues there might be, that if there is some other
5 source of authority for the Commission to take enforcement
6 action or to take some response to underground contamination
7 from an unregulated well, then that wouldn't affect that
8 authority. It does say that anything in this section,
9 Section 252, doesn't apply. But I mean this section basically
10 has to do with authorizations and how you go about authorizing
11 injection. And so that really wouldn't be applicable anyway.
12 COMMISSIONER OECHSLI: I think there's some subsections
13 that do deal with monitoring and reporting requirements.
14 MR. MINTZ: Right, but that's for Class II wells.
15 COMMISSIONER OECHSLI: When that first sentence that
16 was deleted was inserted, the situation that we were trying to
17 avoid was in a case where -- maybe this is going to affect us
18 while we're in transition with respect to wells that are
19 permitted both as Class I and Class II. But what was happening
20 was an operator was questioned about whether or not under their
21 Class I permit, they needed to also file an application under
22 this because this doesn't say any place on its face that it has
23 to do with Class II, it just says if you want to dispose under
24 ground, you've got to get permission from us. So what we were
25 trying to avoid was a situation where an operator would be

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1 perceived as violating some state requirement that they have to
2 get an application from us. But as I understand it, the
3 reporting obligations are going both ways, both to the state
4 and the federal government with respect to mechanical
5 integrity. In fact, I believe it's the state that's doing
6 those mechanical integrity tests, the witnessing of those
7 tests.
8 MR. MINTZ: Well, I mean if that's true, I assume that
9 must be by agreement between EPA and the Commission. But I
10 mean the Commission is not regulating Class I wells. I
11 mean.....
12 COMMISSIONER OECHSLI: So then to the extent that any
13 of these reporting requirements the state would want to keep
14 enforced, it would be done through that agreement with the
15 federal government?
16 MR. MINTZ: Correct.
17 COMMISSIONER OECHSLI: Okay. Does that answer your
18 questions?
19 COMMISSIONER JOHNSTON: The citation 40 C.F.R. 147.101,
20 that is the Alaska program.
21 MR. MINTZ: Yes. And the Alaska program basically has
22 two parts. One is Class II.....
23 COMMISSIONER JOHNSTON: That we regulate.
24 MR. MINTZ: Right.
25 COMMISSIONER JOHNSTON: So that's the distinction

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1 then.....
2 MR. MINTZ: Yes.
3 COMMISSIONER JOHNSTON: .....is that really this is
4 kind of pointing to paragraph (B) then of that -- when you
5 say.....
6 MR. MINTZ: Well, the operator.....
7 COMMISSIONER JOHNSTON: .....regulated by the
8 environmental.....
9 MR. MINTZ: Yeah.
10 COMMISSIONER JOHNSTON: .....that really says paragraph
11 (B), not paragraph (A).
12 MR. MINTZ: Right.
13 COMMISSIONER JOHNSTON: Okay.
14 COMMISSIONER OECHSLI: I think that was the only
15 question I had.
16 COMMISSIONER JOHNSTON: Yeah.
17 MR. MINTZ: On the observation that the definition of
18 AP 2 -- API 2K might not be needed, I think it might be most
19 efficient if I took a short break and checked with the
20 Regulation Section to see what to do on this because we can't
21 be 100 percent sure that there's no reference to 2K left
22 without going through it. And I think the solution is going to
23 be to adopt the regs as is, and then the Regulation Section has
24 the authority to delete that definition if it's no longer
25 needed.

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1 COMMISSIONER JOHNSTON: It's no longer needed.
2 MR. MINTZ: But I want to check on that.
3 COMMISSIONER JOHNSTON: Okay.
4 MR. MINTZ: So, Mr. Chairman, would it be okay to take
5 a short break again?
6 CHAIRMAN CHRISTENSON: All right. We can go off
7 record.
8 (Off record)
9 (On record)
10 CHAIRMAN CHRISTENSON: Any further comments from Dave
11 and Cammi?
12 COMMISSIONER OECHSLI: I have one more.....
13 CHAIRMAN CHRISTENSON: Questions?
14 COMMISSIONER OECHSLI: .....question for Rob. In a
15 number of places for what appears to be for consistency, the
16 regulations attorney changed the wording on documents or
17 reports that get filed to us, and they changed the wording
18 from, filed with, to, submitted to. Do you know why that
19 change was made, and was there any intent to change how it's
20 being handled currently?
21 MR. MINTZ: Well, it's not intended to change anything
22 substantively. I think it was made -- I think that previously
23 there was basically some inconsistency that sometimes it said
24 file, sometimes it said submitted, and now it says submitted
25 all the time basically.

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1 CHAIRMAN CHRISTENSON: Rob, did you have an opportunity
2 to get the answer to the question?
3 MR. MINTZ: Yes. I'm advised that if the Commission
4 adopts the regulations with the current definitions including
5 the definition of API 2K and then it turns out that that
6 definition is superfluous, that the Regulation Section can
7 delete the definition without further Commission action. So I
8 would recommend doing that.
9 CHAIRMAN CHRISTENSON: Okay. Thank you. Any further
10 comment, David, Cammi?
11 COMMISSIONER OECHSLI: Not from me.
12 COMMISSIONER JOHNSTON: No.
13 CHAIRMAN CHRISTENSON: Call for a motion.
14 COMMISSIONER JOHNSTON: Then, Mr. Chairman, I would
15 like to move that we adopt the proposed regulations with the
16 changes as reflected in the review by our fine attorney, Mr.
17 Mintz, this morning.
18 CHAIRMAN CHRISTENSON: Okay. Call for a vote.
19 COMMISSIONER JOHNSTON: I vote yes.
20 CHAIRMAN CHRISTENSON: Cammi?
21 COMMISSIONER OECHSLI: Yes.
22 CHAIRMAN CHRISTENSON: Yes? I vote yes. That's three
23 affirmative votes for adopting the regulations as presented by
24 Mr. Mintz this morning. So we'll set the wheels in motion to
25 get that done.

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1 With regard to comments from Mr. Worcester, I would
2 like to just mention that there's been a great deal of work
3 done by Mr. Mintz who we appreciate, and the reg attorney down
4 there in Juneau, as well as the commissioners, and certainly
5 recognition to Dave Johnston who has had this project going for
6 a long time and has done a whole lot of work. So I believe
7 that we've through the course of the year -- the many years
8 that we've had industry comment. We've had a lot of time to
9 find out what the views of industry are. We believe we've
10 protected those. So with all due respect, we thank the
11 industry and for all their work, and Mr. Johnston for his
12 outstanding work, as well as Attorney General Rob.
13 So with that, we are concluded.
14 (Off record 10:48 a.m.)
15 END OF PROCEEDINGS
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1 CERTIFICATE
2 UNITED STATES OF AMERICA)
)ss.
3 STATE OF ALASKA)
4 I, Laura Ferro, Notary Public in and for the State of
5 Alaska, and Reporter for Metro Court Reporting, do hereby
6 certify:
7 That the foregoing Alaska Oil & Gas Conservation
8 Commission Meeting was taken before myself on the 29th day of
9 September 1999, commencing at the hour of 9:06 o'clock a.m., at
10 the offices of Alaska Oil & Gas Conservation Commission, 3001
11 Porcupine Street, Anchorage, Alaska;
12 That the meeting was transcribed by myself to the best
13 of my knowledge and ability.
14 IN WITNESS WHEREOF, I have hereto set my hand and
15 affixed my seal this 4th day of October 1999.
16
17 Notary Public in and for Alaska
My commission expires: 05/03/01
18
19
20
21
22
23
24
25

signed and notarized on original

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To: Dan Williamson
Fx 263-7894
From Blair Wondzell
279-1433
9/23/97

Blair Wondzell's Comments

MMS Study of 7 Days vs 14 Days Between BOP Tests. (file:14d-bops) 9/19/97)

Reliability of Blowout Preventers Tested Under Fourteen and Seven Days Time Interval, by Tetrahedron, Inc., December 20, 1996.

The study collected considerable data and massaged it. Some of the problems I have are in the definitions of initial vs subsequent test and in what constitutes a BOPE failure. Systems included in the BOPE study are: "blowout preventers, choke and kill lines, choke manifold, and auxiliary equipment."

The definitions are at 7.2.1 and start on page 10. Apparently valves that don't hold pressure but can be greased until they do, are not considered a failure. A test was considered to have failed only if "critical equipment" failed, which is defined as equipment required to hold pressure in a well control situation and that does not have backup - this could exclude choke and kill line valves and pipe rams if there are two of them leaving only the annular and blind rams as "critical", but are they a backup for each other?

Table 8.5(a) DATA SUMMARY on page 19 tabulates data for 0-7 day tests (40 tests with 10 failures) and 8-14 day tests (71 tests with 27 failures). Adjusting the 0-7 day tests: 71/40 x 10 = 18 failures. It appears the 14 day tests had 50% higher failure rates than the 7 day tests.

The study conclusions are on page 28, no. 1 and 3 are interesting.

> "1. No statistically significant difference exists in failure rates for all BOPs (surface and subsea included) tested between 0 to 7 days interval and between 8 to 14 days interval.
>
> 2. Component failures are not affected by the BOP test interval in general.
>
> 3. There is not a significant correlation between failure rate and BOP test interval.
>
> 4. Subsea BOPs have smaller failure rate than surface BOPs."

Conclusion 3 states "there is not a significant correlation" , we noted a 50% higher rate, I wonder what it takes to be "significant"?

DRAFT

11/30/98 submitted by AOGA

WELL CONTROL DRILLS AND BOP PRESSURE TESTS

AOGA requests the AOGCC revise its BOP test frequency requirement from 7-days to a 14-day frequency and substitute provisions for mandatory well control drills in regulations. Reducing frequency of BOP testing to 14-days will not compromise equipment integrity and may improve safety. Implementing the proposal for well control drills will increase the regulatory emphasis on preparation for well control and thereby improve the Commission's control over safety and protection of the environment.

BOP PRESSURE INTEGRITY

After installation and successful pressure-testing of a BOP, there is no added safety benefit resulting from retest of the BOP within either 7 days (current regulations) or 14 days. Consequently, after studying this issue from 1992 to 1997, the U.S. Department of Interior, Minerals Management Service (MMS) amended federal regulations governing the testing requirements for BOP systems (30 CFR Part 250) used in drilling and completion operations on the Outer Continental Shelf (OCS). MMS discussed revision to the BOP test regulations as follows:

> "... The rule allows a lessee up to 14 days between BOP pressure tests. MMS based this rule on a study of BOP performance which concluded that no statistical difference exists in failure rates for BOP's tested between 0 and 7 day intervals and between 8 and 14 intervals." [1]

In studies supporting the MMS conclusion, Tetrahedron[2] concluded:

- Seven day testing hampers flow of drilling activity and leads to inefficiency.
- Too much testing can cause component failure due to exposure to high pressures and abrasive materials.
- Testing within fourteen days will provide at least same level of protection as the seven day test interval.

Note that in pressure testing well control equipment, rig crews follow different procedures than those used for responding to fluid influx into a well. Testing BOPs does not directly improve crew competence in maintaining well control and does not test crews response to an influx.

RISK REDUCTION

Reducing the frequency of BOP testing to 14-days (after equipment is installed and successfully pressure tested) can improve safety by eliminating some activities that have inherent risk:

- pulling pipe out of the hole to conduct BOP tests increases risk of incurring hole problems and may increase the likelihood of fluid influx (swabbing) into the hole;
- testing surface equipment at high pressure exposes personnel to risk in the event of equipment failure;

WELL CONTROL DRILLS AND BOP PRESSURE TESTS

WELL CONTROL DRILLS

As an offset to reducing pressure testing of BOPs to 14-days, AOGA proposes the Commission incorporate weekly Well Control Drills into regulation to ensure crews are familiar with techniques to be implemented in the event of a kick. Unlike BOP testing, drills require crews to demonstrate competency in operating the BOP and choke manifold to prevent escalation of a well kick into a well control incident.

One of the major factors that influences the wellbore pressures after a kick is taken is the volume of the influx. The smaller the influx, the less severe will be the pressures during the well kill operation. In this respect, it is important that the crew react quickly to any sign than an influx may have occurred and promptly execute the prescribed control procedure to minimize kick volume. Drills should be designed to reduce the time that the crew take to implement these procedures and carried out in the most realistic manner. [3]

SUMMARY

AOGA members recommend the Commission reduce the frequency of mandatory BOP testing to a 14-day frequency and emphasize quality drills (in regulations) to enhance well control preparedness. We request the Commission accept the decision reached by the MMS BOP testing and allow Operators 14-days between tests in exchange for regulations requiring drills. AOGA believes this proposal will strengthen the Commission's regulatory focus on activities that have a meaningful impact in improving well control.

[1] U.S. Department of Interior, Minerals Management Service, 29604 FR Volume 63, Number. 104, June 1, 1998

[2] Reliability of Blowout Preventers Tested Under Fourteen and Seven Days Time Interval, Study Report, Submitted to MMS, Tetrahedron, December 20, 1996.

[3] "Drills and Slow Circulating Rates", BPX Well Control Manual, March, 1996

WELL CONTROL DRILLS AND BOP PRESSURE TESTS

PROPOSED REGULATIONS

AOGA proposes supplementing proposed BOP language (in each relevant section) with paragraphs (D), (E), (F) and (G).

11) the BOPE must be function pressure-tested as follows:

(A) when the BOPE is installed or changed, and at least once every 14 days~~2 weeks~~ thereafter, BOPE pipe rams, blind rams, kelly valves, emergency valves, and choke manifolds must be function pressure-tested (individually closed and differentially pressure-tested) to the maximum estimated wellhead pressure to which it may be exposed, or to the pressure as reported in the Permit to Drill, using a non-compressible fluid;

(B) BOP stack ram equipment that has been used, repaired, or changed, and other BOPE that has been repaired or changed, must be function pressure-tested to the maximum estimated wellhead pressure to which it may be exposed, or to the pressure as reported in the Permit to Drill, using a non-compressible fluid, before next wellbore entry;

(C) annular preventers must be tested to not less than 50 percent of the required working pressure;

(D) well control drills will be conducted at least once per week and will include any combination of raising or lowering the pit level indicator, advancing or retarding the flow rate indicator, or actuating the gas detectors. The purpose of BOP drills is to familiarize drillcrews with techniques that will be implemented in the event of a kick. Drills should be designed to reduce the time that the crew takes to implement these procedures.

(E~~D~~) BOP test results and the results of well control drills (response time) must be recorded as part of the daily record required by 20 AAC 25.xxx(x);

(F~~E~~) a minimum of 24 hours notice of each function pressure test must be provided so that a representative of the commission can witness the test;

(G~~e~~) The commission will, in its discretion, require, in consultation with the drilling foreman, drills simulating well control problems in accordance with paragraph (D) of this section. ~~. Drills will, in the commission's discretion, include any combination of raising or lowering the pit level indicator, advancing or retarding the flow rate indicator, or actuating the gas detectors.~~

[NOTE: The "base text" (above) was drafted by Curtis Blount (AAI). The text in paragraph "G" above was proposed by the Commission. The underlined and strike-out text would represent a change to the current language.]

MEMORANDUM

ALASKA OIL AND GAS CONSERVATION COMMISSION

State of Alaska

(PI Manual; divregs.doc)
November 25, 1998

To: Commissioners

Blair 11/25/98
Fm: Blair Wondzell

Subject: Information to Support Staff Recommendation that Minimum Diverter Sizes should be 16 inch Diameter.

Purpose: Submittal to the Hearing Record, AOGCC Regulation in Title 20, Chapter 25.

OVERVIEW

One third of the drilling-well blowouts in Alaska have been thru diverters (2/3 thru BOPs). Two of the Cook Inlet blowouts that experienced diverter failure cost $190 million – an average of $ 95 million each (damage cost figures are not available for the other blowout wells). Adequate diverter systems are important to the Alaska oil industry, therefore they are important to the State of Alaska. The major problems with diverting gas (and associated sand) are the buildup of pressure at the base of the conductor and vent line erosion due to high the velocities.

The most recent "diverter" blowout in Alaska was the Cirque #1 well which had 2 - 10" vent lines; erosion rates were extreme, demonstrating that there were too many ells and the vents were too small. Arco recommended, and we agreed that "bigger is better" and that "For onshore applications such as the North Slope of Alaska, a single 16 or a pair of 12" vent lines should be used ". Researchers have shown that a single, straight, large diameter vent is superior to a pair of smaller, non-straight vent lines.

On the Steelhead blowout, the 10" diameter vent line plugged with chunks of coal. The men running for the escape modules were still on the platform when it exploded. When Marathon came back to the well, they installed a 20" diverter vent line.

Of the 13 diverter-systems on the slope, 3 have 10" vent lines, 1 has a 12" vent line, and 9 have 16" vent lines. Based on the above information and information presented below, the Staff recommends a minimum 16" diameter vent line.

DIVERTER SYSTEMS

When drilling below a conductor pipe where the presence of shallow gas is possible, a diverter system is installed on the conductor casing. The systems is composed of an annular preventer to close off the vertical flow path below the pitcher nipple and a vent line teed in below the preventer to vent the formation fluids away from the rig – commonly 75' to 100'. The purpose of the diverter system is to enable the drilling crew to abandon the rig; it is not designed to regain control of the well (a BOP does that).

Conductors are normally set about 80 feet (2-joints) below ground level. The diverter system (annular preventer and vent line valve) are installed on the conductor; the well is then drilled to the surface casing depth – commonly 1500 feet or deeper (a BOP will be installed on the surface casing). When a kick occurs, the preventer is closed and the vent-line valve is opened – this should cause the formation gas to be vented a safe distance from the rig. Various studies disclose that diverters fail about half the time, resulting in loss of the rig or heavy damage to it.

If the well is shut-in on a gas flow, the formation pressure buildup at the shoe of the conductor will cause the gas to flow up the outside of the conductor and exit under the rig where it can be ignited. Diverting the flow only buys a little time because under the best of conditions, the vent lines are expected to last only minutes before they wash out. If the vent line is small, it will restrict the gas flow, accelerating the erosion of the vent line and will allow pressure to buildup under the conductor which could result in flow up the outside of the conductor to under the rig where it would catch fire.

Various studies show that the best way to slow down the erosion of the vent line is to reduce the velocity of the sand particles. The only way to reduce the velocity of the sand particles is to install a larger vent line and choke the end. A larger vent line not only reduces the erosion rate it also reduces the pressure on the shoe of the conductor.

AOGCC DIVERTER REQUIREMENTS and AOGA'S PROPOSAL

Current AOGCC regulations require a 10-inch diameter diverter vent line that is bifurcated; the commission has allowed a single 16-inch instead and in some cases a single 14". The draft regulations at 20 AAC 25.035. (b)(1) specifies

> "a 16-inch minimum diameter diverter vent line, assembled as follows:"

Chris Phillips, representing AOGA has argued that a 12-inch diameter vent line is adequate. Their Nov. 2, 1998 submittal revised their previous "12-in. diameter vent line proposal" and is as follows:

> "the diverter vent line must be a minimum of 10 inches in diameter and, if less than 16 inches in diameter, must bifurcate in directions that ensure safe downwind venting, assembled as follows:"

AOGA presented no data to support their position.

THE ECONOMIC IMPORTANCE OF DIVERTERS

Blowouts are expensive, both in dollars and in public attitude. OCS REPORT MMS 84-0029 analyzed all GOM drilling encounters with shallow gas since 1958. The study analyzed the 27 occurrences and estimated there was $400 million in damages and 28 lives lost.

"Control of Shallow Gas Kicks: a Case History" In this IADC paper presented at the ASIA PACIFIC WELL CONTROL CONFERENCE at Jakarta, Indonesia on November 29, 1995 by Black and Laurie, these comments were made:

> During the early 1980's, Unocal experienced five shallow gas events as either operator or partner. Four of these events resulted in blowouts which cost Unocal and its partners $225+MM. (See Table 1.) In four of these events, the gas flow was diverted. In all four cases, the diverter failed, resulting in catastrophic events. The fifth event, which occurred on Platform Gilda, was controlled by shutting in the well with the BOP's.

The four wells placed on diverters cost $ 225 million – approximately $ 55 million each; the well controlled by the BOP cost $ 0.1 million.

I've analyzed several Alaska blowouts, approximately 57% had BOPs and 29% diverters. Based on the above information, diverter design, construction, and operation is highly important to the Alaska oil industry.

LITERATURE REVIEW

Following are listed the salient points of several published reports and articles.

Single vent-line design selected for diverter system
Reliability calculations indicated that the failure rate for a single 12" diverter was 2%. "For the dual vent system (2-10"), the failure rate was estimated to be 5% due to a combination of human and control system reliability. However, this increased to over 50% when erosion effects were taken into account. The single vent system is therefore more reliable and easier to operate as well as being lighter than the dual vent system". Crawley,F.K. O&GJ, Sept14,1987.

Subsea diverting is new option for shallow gas. This paper presents some options for subsea diverting of gas. Roche,J.R., O&GJ REPORT, May 5, 1986.

Larger diverters would prevent cratering. This report concludes that diverter vent lines should be larger. They conclude that for a 12 1/4" hole, a 12 diverter is appropriate. Griffin,C., O&GJ REPORT, Feb 10, 1986.

SHALLOW GAS KICKS, SAFETY ASPECTS RELATED TO DIVERTER SYSTEM
They make these points:

- Diverter systems fail in about 50% of the cases where they are used to handle shallow gas.
- From WOAD, 33% of all blowouts are shallow gas, and in 54% of the blowouts the consequence was total loss or severe-damage to the drilling rig.
- Erosion rates in 1986 North Sea diverter systems is 1-2 mm/min (or more).
- A smaller wellbore will reduce erosion rates in the diverter system, but it will still fail in a short time.
- The best single means of increasing the lifetime of the diverter system seems to be to increase the diameter of the diverter lines combined with a reduction in the diameter at the outlet. This will decrease the erosion rate significantly. By combining this action with a simultaneous reduction in wellbore diameter, an erosion rate reduction by a factor of several hundred is possible.

A.S.VERITAS RESEARCH, Nokleberg,L., Schuller,R.B., and Sontvedt,T. NIF-COURSE 7137, June 1986.

ARCO Kuparuk Development Drilling Diverter Design Arco conducted their Wind plume test using a 16" diverter line. For 10/27/94 meeting at AOGCC.

ECD plots aid in dynamic kill of shallow gas They reported results of tests and presented guidelines to aid in the selection of diverter sizes. They reported: "As a general rule of thumb, the minimum size (internal diameter) of diverting lines should be 1.5 times larger than the hole size drilled. For example, from Fig.2, an 8 ½-in hole should have a diverter of at least 12-in. diameter." Balraj, D.N. & Chandra, A., Oil & Natural Corp. Ltd., Dehradun, India, O&GJ Dec. 12, 1994.

A Shallow Gas Research Program On October 6, 1985 a shallow gas blowout occurred on the semi-submersible "West Vanguard"; the diverter system and riser failed as a result of the extremely large flow of gas and solids. Gas came into the drilling platform where it ignited; the explosion and fire resulted in one life lost and several hundred million Norwegian kroner in damages. Holes were worn in the diverter bends in a period of less than 20 minutes. An experimental investigation was performed. Summary results are;

- Particle velocity is the most significant factor on erosive wear. (Can be controlled by mounting a choke at the ends of the diverter lines).
- Particle size has very little influence on the value of specific erosion.
- Increase of bending diameter reduces the value of specific erosion. (Reducing bend angle to 60 deg. from 90 deg. extended life 80%; a bend diameter of 0.83m had almost a 50% improved lifespan over the 0.26m bend radius).
- Hardfacing extends the lifetime of bends. (Up to 3.5 x greater than mild steel).

- Efforts should be made to design diverter systems as straight as possible, avoiding bends.

Further discussion included drilling a pilot hole thru areas of possible shallow gas. IADC/SPE 17256, Ginrod,M., Haaland,O., & Ellingsen,B. Statoil A/S.

Experimental Study of Erosion in Diverter Systems Due to Sand Production A summary of the observations, results, and conclusions are as follows:

- In the GOM, shallow gas blowouts account for 25% of all blowouts in the area (in Alaska its 29%).
- "Wear rates of 8-in./hr were measured for short radius "Ells."
- Common modes of diverter failure have been:
  (1) a failure of the vent line valve to open,
  (2) formation fracture at the conductor shoe due to insufficient vent line size, and
  (3) erosion of the vent line, particularly at ells.
- Typical locations of erosion type failures tend to occur:
  (1) at bends in the diverter line.
  (2) at flexible hoses connecting the diverter to the wellhead.
  (3) at valves or just downstream from valves.
  (4) In the wellhead and diverter spool.
- Data was collected on 31 cases; time for flow to stop was not known for 3 cases.
  (1) two blowouts were dynamically killed,
  (2) in one case, two relief wells were used to effect control, and
  (3) in 25 cases (90%), the wells plugged due to borehole collapse.
  In 14 cases (50%) flow stopped within one day; in 22 cases (79%) flow stopped within one week.
- Various design criteria are presented. For an example using a 10-in. vent line, 0.375 in. wall, a gas rate of 100 MMSCF/D and sand production; the last Ell in the vent line had an estimated life of 6.7 min.
- RECOMMENTATIONS: Bends in diverter lines should be avoided when possible; if required a plugged Tee or Vortice Ell should be used. The use of a sand probe at the vent line exit is recommended as a warning device.

SPE/IADC 18716 by Bourgoyne,A.T. Jr., Louisiana State U.

CONCLUSIONS AND RECOMMENDATIONS

Blowout preventers are used to control flow from a well. Diverters are used to divert flow away from the well so that the drilling crew can abandon the rig.

When casing strings are set shallow, the formation at the shoe may not be able to contain the gas pressure from lower zones being drilled, in which case the gas frequently flows up the outside of the conductor. When this happens, it exits under the rig floor where it generally ignites and can destroy the rig.

Sand grains in shallow gas formations are generally, poorly cemented. The overburden pressure is insufficient to mechanically lock the particles and being gas saturated, the fluid does not "glue" the sand grains together. Therefore, when gas starts flowing out of the formation, it generally carries sand with it.

Gas is very compressible. The volume is directly proportional to the pressure: as the pressure is decreased by a factor of two, the volume increases by a factor of two. For a specific size conduit, as the volume increases, the velocity must also increase. For example, consider a gas sand at 1500' TVD, the pressure would be about 650 psia. As the gas nears the surface, it expands because the pressure drops from the 650 psia to near atmospheric – 15 psia; this causes the velocity to become very large. The sand being transported by the gas erodes the vent line. The Veritas paper said that sand erodes vent-lines at the rate of 1 to 2 mm/min. or more. The SPE/IADC 18716 experiments measured metal erosion rates of 8 in./hr.; about equal to one inch in 7.5 minutes. Most vent lines are less than one in. thick.

Regarding vent line size, most people who study diverter failures, conclude "bigger is better" – from the stand point of erosion as well as plugging. The 10" diverter on the Steelhead plugged before the people could exit the platform and was subsequently replaced by a 20" system. One of the papers summarized above concludes the vent line should be at least as large as the hole being drilled, another paper concludes the vent line should be 1.5 times the diameter of the hole being drilled.

There are 13 wells on the slope that use diverters. There are 9 rigs which have 16" vent lines, 1 that has a 12", and 3 that have 10" vent lines.

Recommendations: The diverter regulations are modified as indicated below.

- Staring with the last sentence in (b) ;

The following provisions apply to a diverter system:

(1) the diverter system must consist of a remotely operated annular pack-off device, a full-opening vent line valve, and a diverter vent line that is a minimum of 16 inches in diameter unless a smaller size is specifically approved by the commission to account for smaller hole size and or geologic conditions.

- Inserted somewhere in the diverter regulations;

"If the hole that is to be drilled thru a diverter is larger than the vent line, a pilot hole not larger than the vent line shall be drilled first, then the hole opened."

References: all references cited in this document are available at the commission office, 3001 Porcupine Drive, Anchorage – contact Blair Wondzell.

FORMATION INTEGRITY TEST

fit-defin.doc

Formation Integrity Test (FIT) is a test conducted in accordance with a procedure approved by the commission to determine the competency of the drilled formation to hold hydraulic pressure and/or to determine the integrity of the cement surrounding a casing shoe. The test may be conducted to leak off (LOT), to fracture pressure (FFP), or with commission approval to equivalent mud weight (EMW).

BEW - problem?

poorly conducted testing

wants AOGA to agree on procedure

not described in any API RP

- there is room for variation

.030

(f) requires integrity of casing shoe to contain wellbore pressure → doesn't get reported until 070 requires (complete, abandon, suspend)

→ what other demonstration is needed?

Cammy

FINAL DRAFT 11/14/96
A VALID LEAK-OFF TEST
WHAT IS REQUIRED

PRE TEST PREPARATION Knowledge of the type formation csg shoe set in, how the casing running and cement job went, and what is expected of a PIT and why.
A valid casing pressure integrity test plotted on a graph - pressure vs volume.
A high pressure pump capable of pumping smoothly at 0.25 bpm.
An accurate pressure gauge - 25 psi increments preferable.
Accurate volume measurement equipment - a tank calibrated in 0.25 bbl increments and/or pump strokes.
Leak free surface equipment and a balanced mud system.

TEST PROCEDURES

Casing PIT. After cleaning out to the top of the float collar or to between the float collar and the float shoe, conduct a casing **pressure integrity test** (**PIT**) to at least 50% of the required BOP working pressure; plot pressure versus volume in 0.25 bbl increments or equivalent pump stokes. Hold the final pressure for at least 10 minutes and continue to plot points.

Formation PIT. Drill out the float collar (if not previously done so), the cement, the shoe, the rat hole, and drill at least 20 feet of new formation, note the type of formation drilled. Circulate bottoms up and check the weight of mud in versus weight of mud out - they should be within 0.1 ppg; if not, circulate until the system balances to within 0.1 ppg.

Pull up inside the casing shoe, do not pump a slug. Close a blowout preventer and pump down the drill pipe at the slowest rate required to over-come filtration losses, normally 0.25 bbl per minute. Record the pressure at 0.25 bbl increments (or equivalent strokes) on the plot with the casing PIT.

The first few points may be erratic, but after that the points should establish a straight line a little to the right of the casing PIT . Continue to pump until the plot starts to deviate to the right from a straight line, this is the leak-off point used to calculate equivalent mud weight. Depending on company policy, either stop the test at this point by shutting down the pump and closing the shut-in valve or continue to pump until the pressure does not increase with incremental fluid pumped because the fracture pressure has been reached - the plot becomes horizontal. Evaluate the data.

UNOCAL's policy: (Leak Off Test Procedure, Baker Platform August 30, 1993) "Continue to pump until the pressure does not increase with incremental fluid pumped (the graph becomes a horizontal line). In practice it is acceptable to pump 3 - 5 bbls additional after initiation of the fracture. Shut off the pumps and record the pressures versus time for approximately 10 minutes."

BPX's policy: (Well Control Manual, XWH Edition) "Stop the pump when any deviation from linearity is notice between pump pressure and volume pumped. Record the final pump pressure and calculate LO EMW." Where LO is leak off and EMW is equivalent mud weight.

Exxon's policy: (Pressure Integrity Tests, data thru March 1986) "Continue pumping until leak-off is evident on plotted data (plot curves to the right). Pump a small volume (1 or 2 additional data points) after leak-off is noted to confirm it. When leak-off is confirmed, stop pumping and close shut-in valve. Record 10-second shut-in pressure. Record shut-in pressure decline at 1 min intervals until pressure levels off (5 - 15 min)."

ARCO's policy: (Practical Well Control, PETEX, Third Edition, 1991). "On a graph, plot the fluid pumped in 1/4 - bbl increments versus drill pipe pressure until the formation at the shoe starts to take fluid; at this point, the pressure will continue to rise, but at a slower rate (fig 14). Repeat the test to verify the point at which the formation just starts to take fluid; this point is leak-off pressure."

After stopping the pump and closing the shut-in valve, record and plot the initial (10 second) shut-in pressure and the pressure each minute for approximately 10 minutes; if the pressure has not stabilized, continue to record and plot the pressure versus time for 5 add'l min. Check the system for leaks. Evaluate the test.

Valid LOT. If the initial shut-in pressure is approximately equal to the leak-off pressure, and the shut-in pressure after 10 min has essentially stabilized, bleed the pressure down to a calibrated tank and record the volume of fluid recovered. Calculate the EMW = MW + P/(0.052 x D) where "P" is the leak-off pressure. If this value is approximately as expected, a valid LOT has probably been obtained. If in doubt, retest and evaluate as in the Channel Confirmation Test.

Cement Channel. If one or more of the following conditions exist, plan to retest as in the original test; if they all exist, suspect a cement channel: 1) the leak -off pressure is substantially below the expected value; 2) the initial shut-in pressure is below the leak-off pressure: and 3) during the 10 min shut-in period the pressure drops significantly and does not readily stabilize.

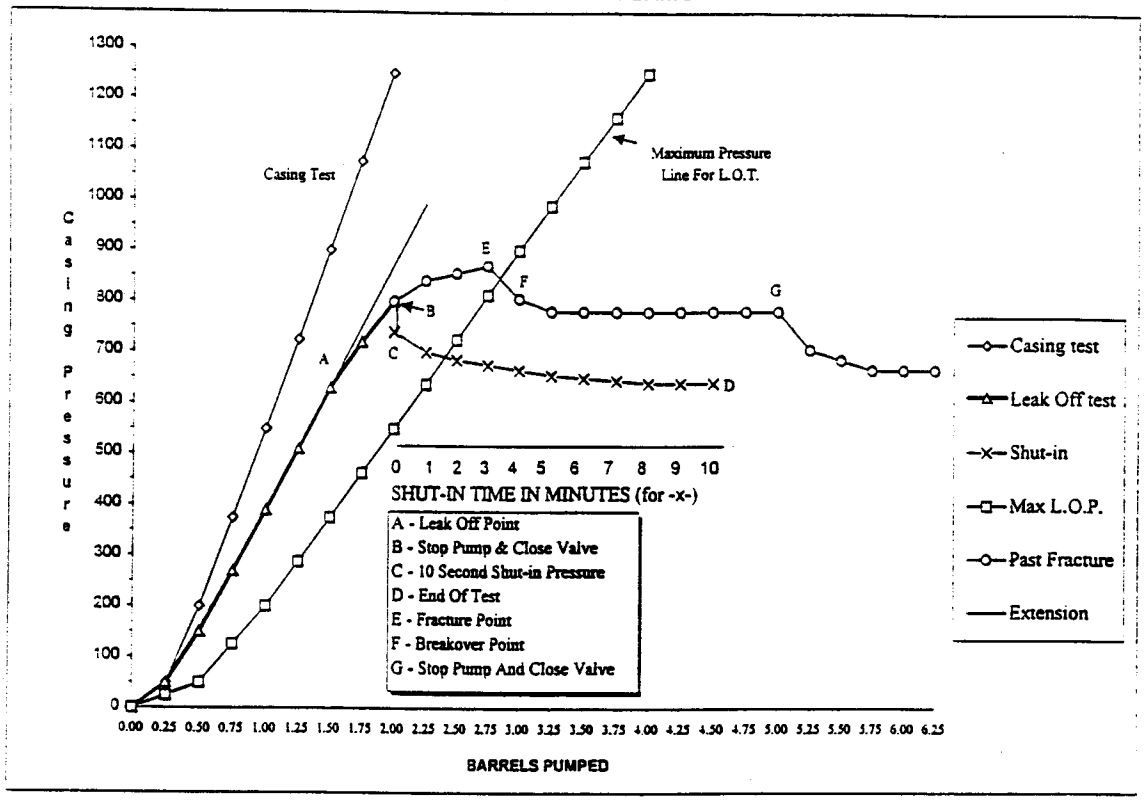
Channel Confirmation Test (CCT). The second test is very important, so conduct the test carefully, accurately recording and plotting the pressure versus volume pumped. Check the system for leaks. Conduct the test at the same rate as the first test. Continue the test to beyond leak-off as before and shut-in, recording the initial shut-in pressure and the pressure at one minute intervals. Record and plot the data as long as the pressure continues to decrease, but not less than 10 min. Compare the data to the first test, especially the leak-off pressure.

Channel Confirmation. If an equivalent or lower leak-off pressure is obtained and the shut-in pressure declined to below about 3/4 of the "leak-off" (above CCT) pressure, a cement channel may exist. Could further confirm by going to leak-off and stopping the pump, note and record shut-in pressures for 5 min; repeat to leak-off with shut-in - do this three time total. Evaluate the repeat leak-off pressures - if increasing, probably a good test; however, if leak-off pressures are decreasing, probably a cement channel exists. Squeeze or evaluate further as warranted.

Please provide comments to Blair Wondzell, Ph 279-1433 or Fax 276-7542.

TYPICAL LEAK-OFF TEST PLOT

TO ILLUSTRATE TERMS



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UNOCAL 76

Sept. 20, 1994

Alaska Region

Mr. David W. Johnston, Chairman
Alaska Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, Alaska 99501

Dear Mr. Johnston:

I would again like to thank you and the Commission for the opportunity to meet with you on Sept. 14, 1994 in the public meeting. Several issues were brought out that need to be addressed, one of Unocal's major concerns is regulations concerning the abandonment of offshore platforms.

During the meeting Mr. Mike Craig of Unocal made a presentation on the abandonment of offshore platforms and pipelines. The key departures from the current code are shallower cut offs for the platform legs, leaving pieces of the structure on bottom and abandonment of the pipelines in place. We believe this to be an environmentally practical approach to a very difficult issue. There is major interest in the abandonment issue from many parties both here in Alaska and nationally. Unocal would like to work with yourselves and any other interested parties to address any items pertaining platform abandonment regulations.

In the written copy of the brief that was presented to Commissioners on Sept. 14, 1994 there was a list of references. These references included conversations with people involved in the marine and fishing industries both here in Alaska and outside. As per our Sept. 20, 1994 telephone conversation, the phone numbers of these people are included in case you would like to call them. If there are any other queries concerning the presentation, please feel free to call me at 263-7677.

Sincerely Yours

Dan Williamson

Dan Williamson
Drilling Supt.

cc G.R. Schmidt
R. Crouch

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References and Telephone Numbers

1. Meeting between Mr. R.C. Visser and Mr. Russell Douglas, Commissioner of the Alaska Oil and Gas Conservation Commission, on July 18, 1994 at the AOGCC offices in Anchorage.
   (Robert Visser (310) 316-5934 or (808) 669-3033)

2. "Abandonment and Removal of Offshore Oil and Gas Facilities: Education and Information Transfer," Summary of MMS/SLC Workshop Proceedings, Santa Barbara, CA, March 1994.

3. State Lands Commission: "Removal of Offshore Platforms Heidi, Hilda, Hope, and Hazel," Negative Declaration Document, May 9, 1994.

4. Personal communication, R. Visser with Mr. Jim Dore, Committee Chairman of the Association of Diving Contractors, Lafayette, Louisiana, September 7, 1994.
   (Jim Dore (318) 989-0000)

5. Reggio, Jr. V.C.: "Rigs-to-Reefs, The Use of Obsolete Petroleum Structures As Artificial Reefs," Minerals Management Service OCS Report, MMS 87-0015, 1987.

6. National Research Council: "Disposal of Offshore Platforms," National Academy Press, Washington, DC, 1985.

7. Corps of Engineers: "The Cook Inlet Environment, A Background Study of Available Knowledge," Anchorage, AK, August 1972.

8. Personal Communication, R. Visser with Mr. Jeff Fox, Alaska Department of Fish and Game, Soldotna, Alaska, September 9,1994.
   (Jeff Fox 283-2276)

9. Meeting, R. Visser with Mr. Ken Castner in the Cook Inlet RCAC offices in Kenai, Alaska on July 21, 1994.
   (Ken Castner 235-8252)

10. Personal communication, R. Visser with Petty Officer Gudgeon of the U.S. Coast Guard in Anchorage, Alaska, September 9, 1994.
    (Officer Gudgeon 271-6700)

11. Personal communication, R. Visser with Mr. Tony Joslyn, Pilot with the Southwest Alaska Pilot Association based in Homer, Alaska, September 9, 1994.
    (Tony Joslyn 235-8783)

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COOK INLET FACILITIES - ABANDONMENT BRIEF

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COOK INLET FACILITIES - ABANDONMENT BRIEF

Summary

It is recommended that the current regulation for total removal of the Cook Inlet platforms to fifteen feet below the Inlet floor be modified to (1) a requirement for piling and well string removal to a minimum of at least minus one foot below the Inlet floor, and, (2) a requirement that structural remains may be left on the Inlet bottom provided at least 50 feet of draft is left between these remains and mean low low water. It is further recommended that offshore pipelines be abandoned in place after being, flushed clean, filled with seawater, cut and capped at each end.

Further, regulations should allow no more than 10 years to elapse after platform utility has ceased for platform decommissioning operations begin, to allow for 'batch' platform removals. Pipelines, however, should be abandoned in place within 1 year of cessation of further utility.

These modifications are proposed in the interests of diver safety,. environmental protection and economy. The rationale for these changes is that the safety of removal operations will be enhanced, and that the structural remains will pose no interference with shipping or fishing in Upper Cook Inlet.

1. Purpose

The purpose of this brief is summarize background information concerning Cook Inlet offshore regulatory abandonment requirements, and outline what the industry believes to be safe and pragmatic changes to the present Alaska Oil and Gas Conservation Commission regulations. Justifications for these changes as outlined.

2. Regulatory Background

2.1 Alaska Regulations

Three state agencies have primary responsibility for the regulation of oil and gas upstream activities in Alaska. These agencies are:

Alaska Oil and Gas Conservation Commission (AOGCC)
Alaska Department of Natural Resources (DNR)
Alaska Department of Environmental Conservation (DEC)

The AOGCC regulates drilling, abandonment, plugging, production practices and recovery methods. The DNR issues mineral leases and operating permits on state-owned land. The DEC is Alaska's primary pollution control agency.

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Current regulations from the Alaska Oil and Gas Conservation Commission (20 AAC 25.172) state that, for offshore platform locations, all casing, wellhead equipment, piling, structures, and other obstructions must be removed to a depth of at least 15 feet below the Inlet seafloor. The Commission has the option of approving a different cutoff depth after review of sea bottom conditions.

There appears to be a question of interpretation regarding the application of AOGCC regulations and jurisdiction over abandonment of platform structures and piling.[1]

Neither the Department of Natural Resources nor the Department of Environmental Conservation, however, appear to have any regulations that deal with platform abandonment. It is possible, however, that in some cases the original lease documents from the DNR contain platform removal requirements.

A federal permit for platform abandonment will be required from the Army Corps of Engineers. This may require an Environmental Assessment or possibly even an Environmental Impact Statement (EIS), in coordination with the DEC.

2.2 Other States

The California State Lands Commission regulations require well and platform piling removal to minus five feet.[2] These requirements are modified in the event of special bottom or platform design conditions. For instance, the removal plan for Chevron's platform Hazel in the Santa Barbara channel allows removal to minus one foot below the ocean bottom. Its large caisson legs are somewhat similar to those of the Cook Inlet platforms.[3]

2.3 Minerals Management Service

The Minerals Management Service regulations require removal to minus fifteen feet. Operators, however, may justify a different depth in their abandonment application. A joint committee of California SLC and the MMS is currently attempting to resolve the differences between the state and federal regulations. In the Gulf of Mexico, the Association of Diving Contractors has formally made a request to the MMS to change the fifteen feet requirement to five feet. The request was made on the basis of diver safety.[4]

At the request of the Department of Interior, in 1984, the National Research Council created the Committee on Disposition of Offshore Platforms to investigate alternative dispositions of offshore platforms. The recommendations from this committee led to the implementation of the so-called Rigs-to-Reef program by the MMS and the Gulf Coast states. In this program, platforms may be abandoned in-place by toppling to create an artificial reef, or they may be moved to a designated artificial reef area and dumped. This program has proven to be beneficial and cost effective to both the offshore oil industry and the fishing industry.[5,6]

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3. Discussion

3.1 The Problem

The AOGCC requirement that, upon platform abandonment, all piling and structures be removed to fifteen feet below the Inlet bottom will be difficult and dangerous to accomplish, and would be very expensive. With the pile subs embedded fifteen feet in the stiff Inlet soils, it will not be possible to lift the platform structure without external jetting. Divers will have to remove the soil around the piling by jetting to free the platform structure. This would be a time consuming operation, and would expose the divers to considerable dangers as the central Cook Inlet has extreme tidal conditions, low visibility and cold temperatures. In fact, because of the continuously shifting Inlet bottom due to tidal action, it may not be possible to uncover enough of the piling to free the platform structure. Further, removal of pile-supporting soil resulting in unsupported pile lengths of 15 feet or more would increase the potential of pile buckling under the vertical leg loads, which would further endanger the divers.

Only a few preliminary studies have been performed to investigate abandonment methods and costs of Cook Inlet platforms. These studies assumed total platform removal down to minus 15 feet, and the transportation of the remains to salvage yards in the lower forty-eight. Estimated abandonment costs are several million dollars per platform[6].

There is, however, no compelling need to remove well casing and piling to a depth of minus fifteen feet, nor is there an environmental benefit to remove the platform structures in their entirety. In fact, their removal may negatively impact the environment, by eliminating the limited fishery habitats created by the platforms.

3.2 Upper Cook Inlet Fishing

The only commercial fishing that is permitted north of the Forelands in Upper Cook Inlet is salmon fishing using set nets. There are currently about 140 set netter license holders on both sides of Upper Cook Inlet. Although nets are allowed to be set as much as one mile from shore, in practice, the set nets do not extend more than about 100 to 200 yards from shore. There is no other fishing in the waters of the Upper Cook Inlet, i.e., there is no on-bottom trawling, there is no crab and shrimp fishing, and there is limited sport fishing.[7,8]

In a discussion with Mr. Ken Castner, a Cook Inlet set netter, and also Chairman of the Prevention, Response, Operations and Safety (PROPS) Committee of the Cook Inlet Citizens Advisory Committee, it was his opinion that the fishing industry would have no problems with leaving platform remains on the Inlet bottom.[9] It was pointed out by Mr. Castner that there are many boulders on the Inlet bottom that make bottom trawling impossible, and any platform remains would not create more of an obstruction than the boulders.

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3.3 Shipping Interference

The only other commercial use of Upper Cook Inlet is by commercial and military vessels to and from the Port of Anchorage. The Port maintains a water depth of 37 feet below low low water through dredging to accommodate the maximum draft of 37 feet of the vessels that use the port. There are no identified marine traffic lanes through Upper Cook Inlet, although vessels usually follow the same route.[10] Minimum underkeel water depth while traversing the Inlet is 10 feet. In other words, vessels will not traverse shoal areas, or areas where there are known obstructions, unless there is at least 47 feet of water.[11]

A regulatory requirement, therefore, that any platform remains be at least 50 feet below low low water should present no problems to the shipping industry.

4. Platform Abandonment Operation - Scenario Outline

Below are listed the general steps that might be involved in the abandonment of a typical 4-leg tower platform:

1. Decommission facilities and wells.
2. Remove deck sections.
3. Sever horizontal and diagonal tower bracing by surface cable cutting.
4. Sever piling from each freestanding tower leg, by internal blasting just below the leg.
5. Topple each tower leg parallel to the current.
6. Verify cutoff and draft requirements are met.

FIGURES 1 through 4, attached, illustrate the complement of oil and gas facilities in the Inlet (offshore platforms and pipelines), the water depths at each platform location, the primary components comprising a typical tower-type Inlet platform, and the proposed disposition of those components after abandonment.

5. Conclusions

There are no compelling reasons to require the removal of well casing and piling down to a depth of fifteen feet below the Inlet bottom. Regulations that require (1) removal of the well casing and piling to one foot below the Inlet bottom, and, (2) permit abandonment of platform structural remains if located at least 50 feet below low low water should pose no interference with either the fishing industry or with the shipping industry. Without cathodic protection the structural remains will corrode away rather rapidly and most will probably disappear in about twenty to thirty years.

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6. References

1. Meeting between Mr. R.C. Visser and Mr. Russell Douglas, Commissioner of the Alaska Oil and Gas Conservation Commission, on July 18, 1994 at the AOGCC offices in Anchorage.

2. "Abandonment and Removal of Offshore Oil and Gas Facilities: Education and Information Transfer," Summary of MMS/SLC Workshop Proceedings, Santa Barbara, CA, March 1994.

3. State Lands Commission: "Removal of Offshore Platforms Heidi, Hilda, Hope, and Hazel," Negative Declaration Document, May 9, 1994.

4. Personal communication, R. Visser with Mr. Jim DorÉ, Committee Chairman of the Association of Diving Contractors, Lafayette, Louisiana, September 7, 1994.

5. Reggio, Jr. V.C.: "Rigs-to-Reefs, The Use of Obsolete Petroleum Structures As Artificial Reefs," Minerals Management Service OCS Report, MMS 87-0015, 1987.

6. National Research Council: "Disposal of Offshore Platforms," National Academy Press, Washington, DC, 1985.

7. Corps of Engineers: "The Cook Inlet Environment, A Background Study of Available Knowledge," Anchorage, AK, August 1972.

8. Personal Communication, R. Visser with Mr. Jeff Cox, Alaska Department of Fish and Game, Soldotna, Alaska, September 9,1 994.

9. Meeting, R. Visser with Mr. Ken Castner in the Cook Inlet RCAC offices in Kenai, Alaska on July 21, 1994.

10. Personal communication, R. Visser with Petty Officer Gudgeon of the U.S. Coast Guard in Anchorage, Alaska, September 9, 1994.

11. Personal communication, R. Visser with Mr. Tony Joslyn, Pilot with the Southwest Alaska Pilot Association based in Homer, Alaska, September 9, 1994.

FIGURES

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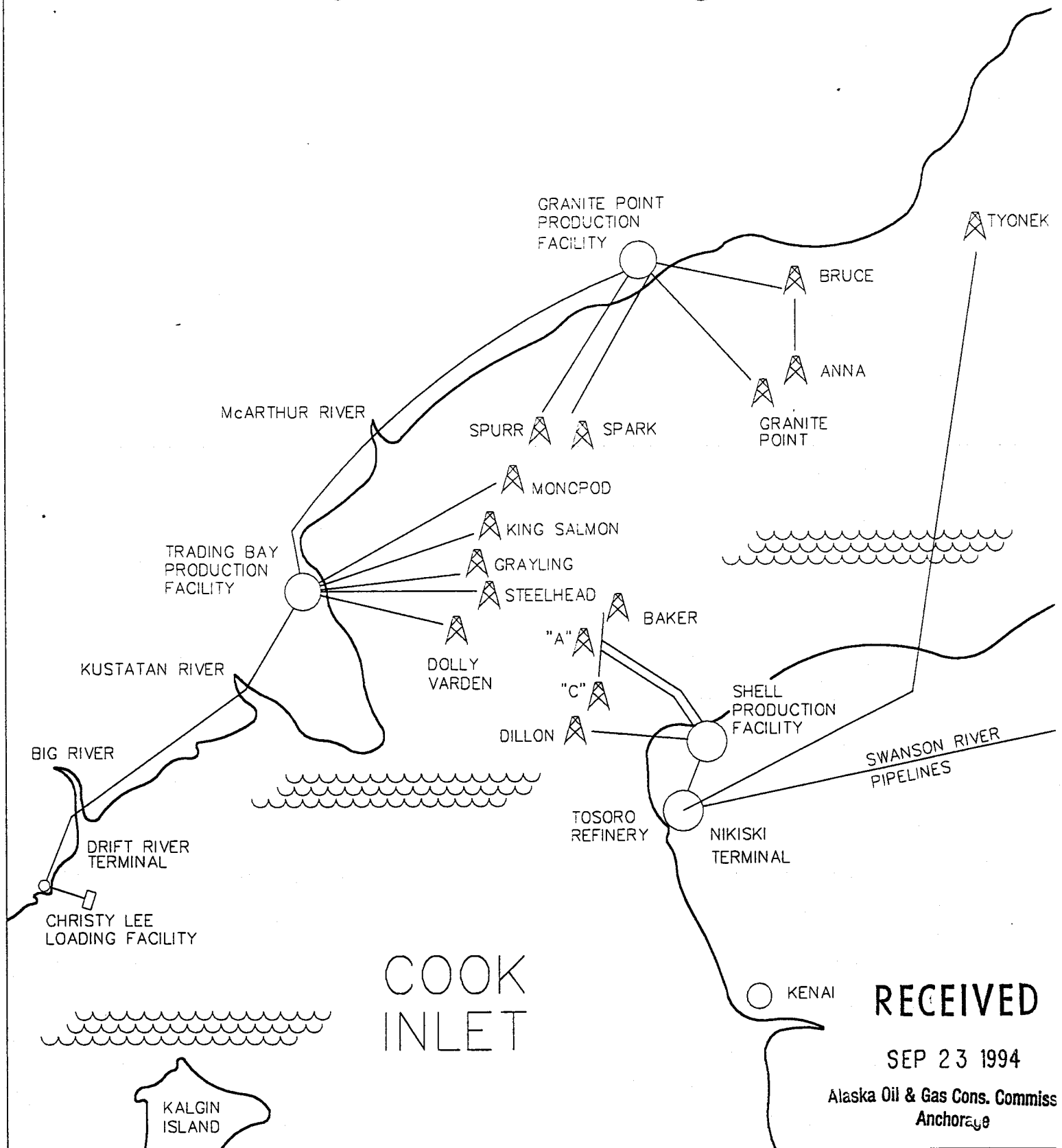

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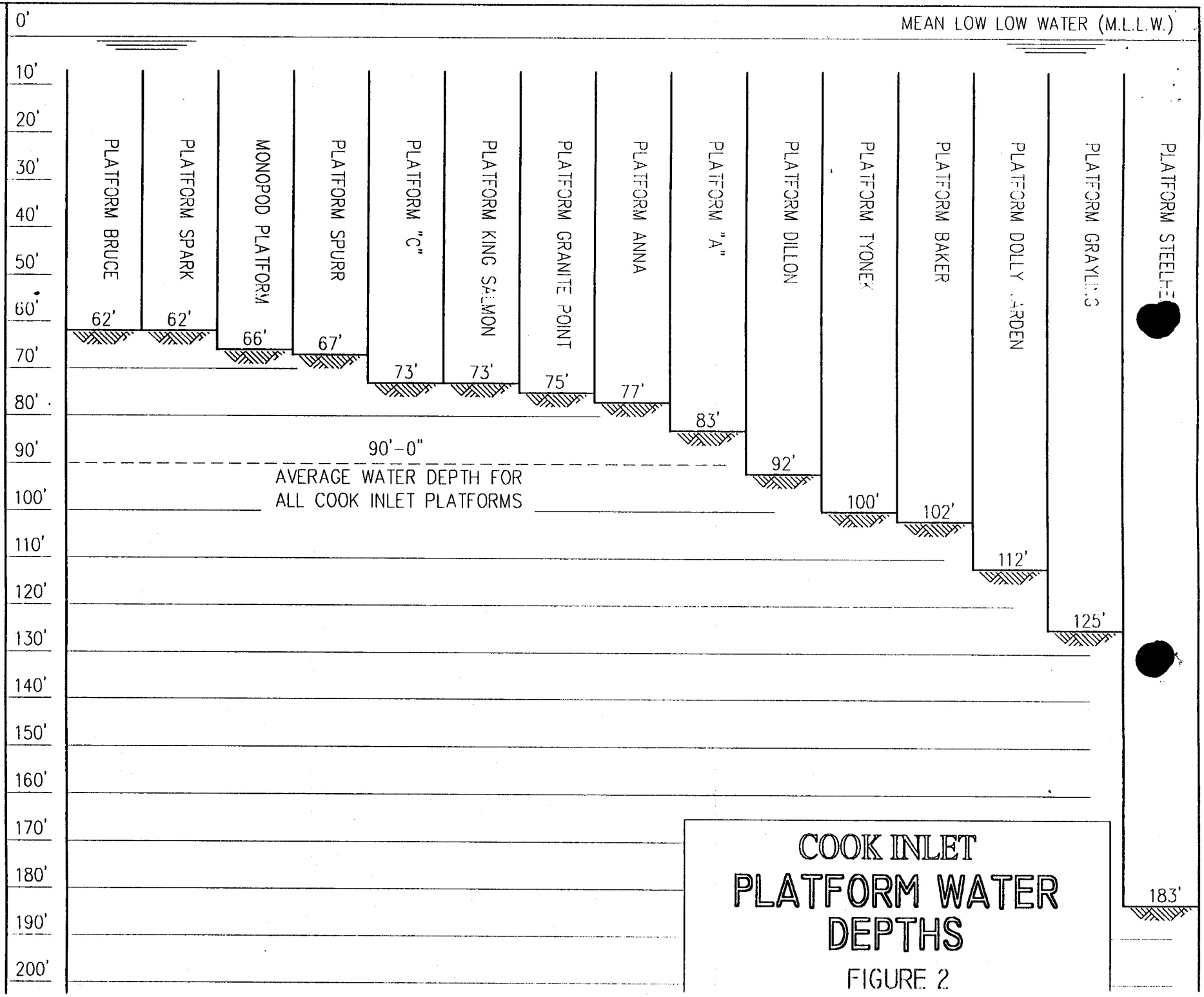
COOK INLET OFFSHORE OIL & GAS FACILITIES

FIGURE I



COOK INLET
PLATFORM WATER DEPTHS
FIGURE 2

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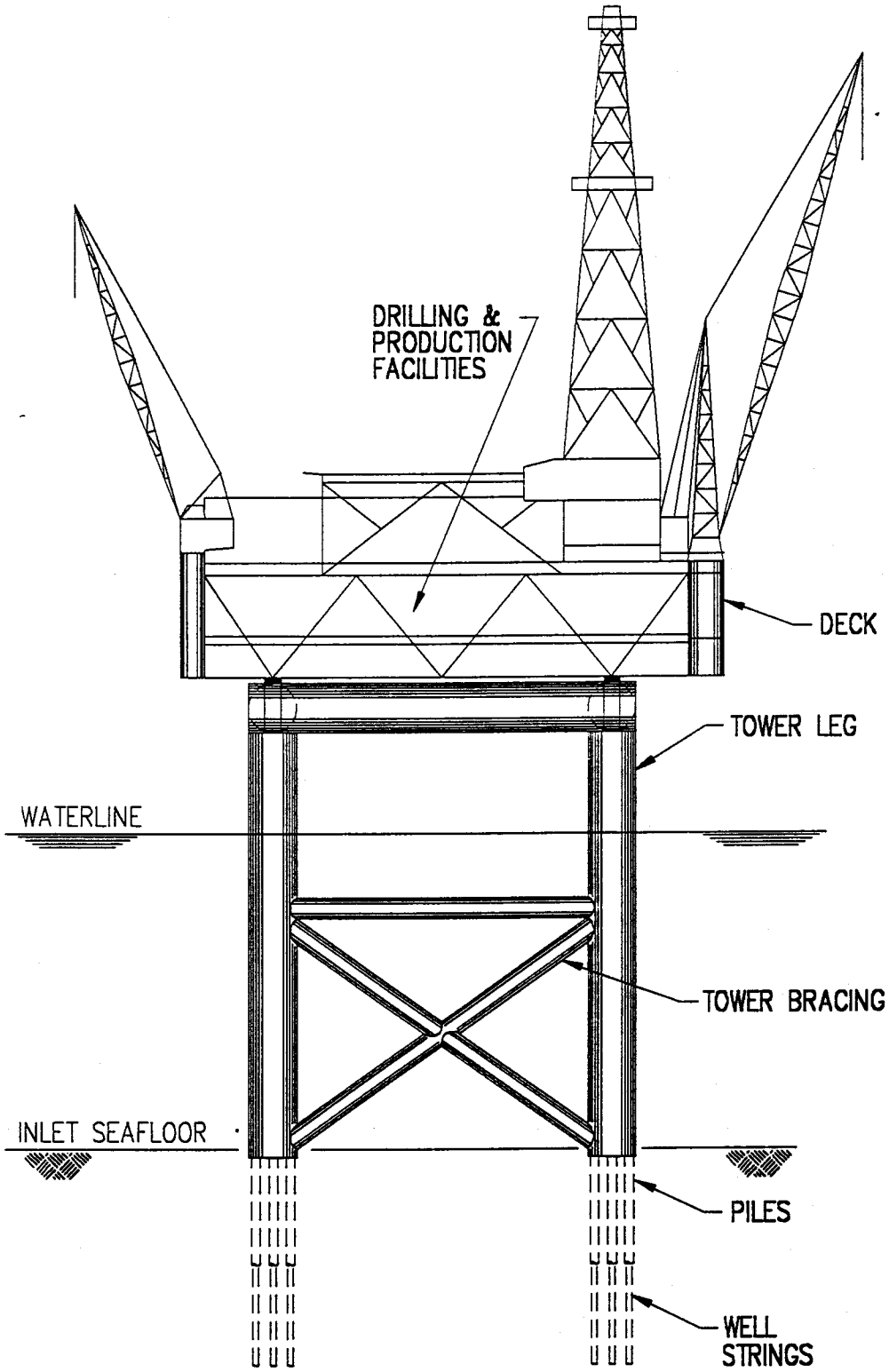

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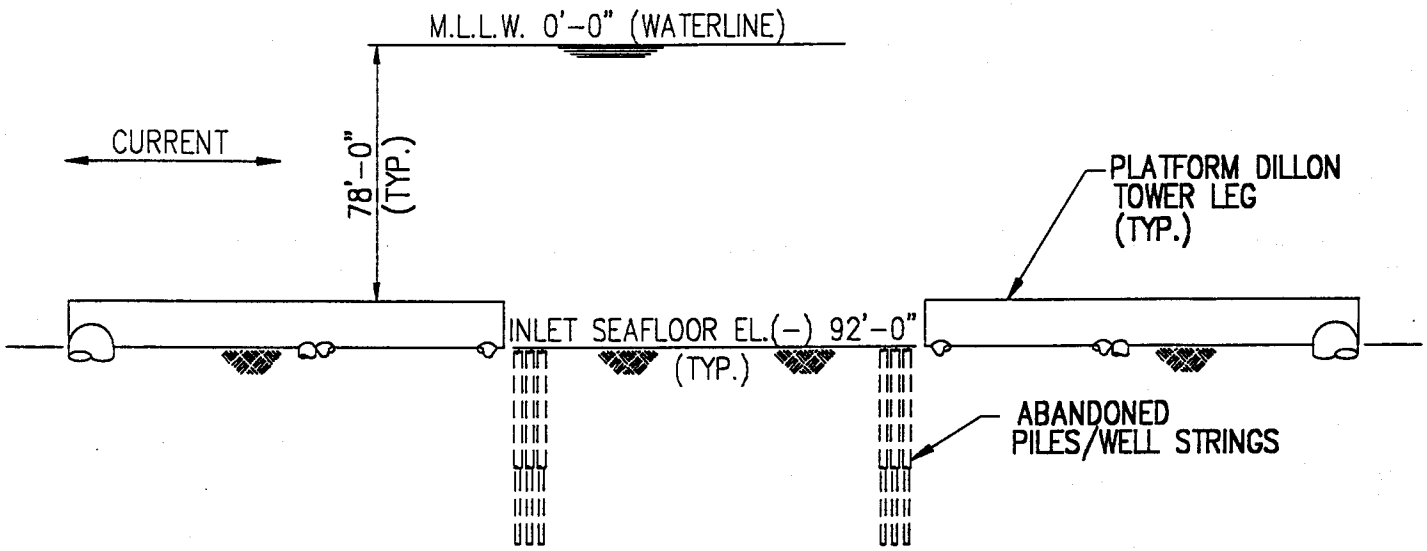
Anchorage

COOK INLET PLATFORM COMPONENTS

FIGURE 3

PLATFORM	INLET SEAFLOOR EL. (FT.)	LEG DIA. (FT.)	DIST. M.L.L.W. TO LEG (FT.)
BRUCE	62	14	48 *
SPARK	62	13	49 *
MONOPOD	66	28.5	37.5*
SPURR	67	13	54
"C"	73	15.5	57.5
KING SALMON	73	15.5	57.5
GRANITE POINT	75	17	58
ANNA	77	14	63
"A"	83	18.5	64.5
DILLON	92	14	78
TYONEK	100	14	86
BAKER	102	14	88
DOLLY VARDER	112	17	95
GRAYLING	125	17	108
STEELHEAD	183	18	165

* – MOVE LEGS TO DEEPER WATER WITH AT LEAST 50' DRAFT.
– CONSIDER REFLOATING MONOPOD



NOTE: DRILLING & PRODUCTION FACILITIES AND DECK STRUCTURE REMOVED TO SHORE.

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Anchorage

COOK INLET
PLATFORM REMNANTS DISPOSITION
FIGURE 4

EXAMPLE RE-WORDING

20 AAC 25.172 OFFSHORE LOCATION CLEARANCE

(a) After all offshore wells are abandoned from a fixed platform and no further utility exists for the platform, the site must be cleared of obstructions such that any remnants will not interfere with either fishing or shipping interests. Well strings and platform pilings will be removed to at least one foot below the seafloor. The platform's tower may be abandoned in place, provided sufficient draft is left between tower components and mean low low water such that the platform remnants will not interfere with marine navigation or fishing rights that exist at the time of abandonment.

Offshore pipelines may be abandoned in place, provided they are flushed clean, filled with seawater, cut and sealed with a cap at both ends.

The operator must verify, to the satisfaction of the commission, that the prescribed cutoff elevation and draft requirements are met.

The period elapsed between cessation of platform utility and platform removal may not exceed ten years. Pipelines must be flushed and abandoned within one year of cessation of utility.

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SEP 23 1994

Alaska Oil & Gas Cons. Commission
Anchorage

Unocal Oil & Gas Division
Unocal Corporation
909 West 9th Avenue, P.O. Box 196247
Anchorage, Alaska 99519
Telephone (907) 276-7600

UNOCAL 76

September 13, 1994

Alaska Oil And Gas Conservation Commission
3001 Porcupine Drive
Anchorage, Alaska 99501-3192

Subject: UNOCAL's Comments
AOGCC's Draft Reg. 20 AAC 25.235, August 31, 1994

Dear Commissioners;

Thank you for the opportunity to respond to the Commission's draft regulations.

We are deeply concerned by your change to the draft regulations regarding incident gas under one hour in duration. We believe this change will be detrimental to industry and to ultimate oil recovery in the State of Alaska. We therefore urge the commission to return to its original draft language designating this gas as "needed for safety".

You stated early in this process, "Statistics demonstrate that operators in the state of Alaska have conserved gas while producing oil. Less than 1 percent of all gas produced is flared and less than 8 percent is considered lease uses." Since the current system of flare gas reporting and oversight has worked well for many years, we believe the Commission should be careful not to "through the baby out with the bath water."

Under One Hour Gas is "Needed for Safety"

We believe that the small volume of gas in the under one hour category can only be disposed of safely by means of flaring and therefore should be classified as "needed for safety".

Historically, the Commission has always considered this gas as "needed for safety". It is only at this late hour that that determination has been brought into question. It is inconceivable that the Commission, when it setup the current gas flare allowable system, did not know or understand that flaring included more than pilot and purge. I am sure that they asked the same question that this Commission has asked industry, "Why are the you asking for different allowables for their facilities?" I am sure they received similar responses and explanations. After weighing the facts, they made the determination that these small quantities of gas were "needed for safety".

Under the original proposal the AOGCC maintained the authority to question gas flaring under one hour in duration. The AOGCC has both the authority and responsibility to ask an operator to gather and supply additional information if it suspects there is improper flaring of gas.

As we stated in the initial hearings on this issue Unocal's has a similar interest to the State on the issue of conserving gas. We sell it. Gas has a real value to us. As reasonable people, which we are, we are not going to burn more gas than is needed or than can be justified.

AOGCC Jurisdiction

Your wording change appears to give the Department of Revenue (DOR) final say in the categorization of some gas flaring. As a result, it also adds a large degree of uncertainty as to the reporting of flare events.

We believe the commission has both the authority and responsibility to determine what gas flaring is "needed for safety", and what constitutes "waste"; not the Department of Revenue. I imagine the legislature did this because 1) you are the agency with the technical expertise to make that determination and 2) you bring an unbiased perspective to the issue. The legislature did not allow the industry to determine this point. If it had, it is likely all flaring would be defined as "needed for safety". Likewise, the legislature did not allow DOR to determine this point. If it had, it is likely that nothing would be defined as "needed for safety" and that all flaring would be defined as "waste".

We further believe that the commission should not delegate these determinations to the DOR because the DOR has a strong bias (I will not speculate on the reasons for this bias). Mr. John Pilkinton's (DOR), August 16, 1994, letter to you illustrates this point of bias. In his letter, he characterizes the "large number of these shorter incidences" as "not talking about a great deal of money for taxation." Yet he considers no reporting requirement too unreasonable, burdensome or expensive for industry. He also appears willing to spend a lot of tax payer's dollars to review these reports and try to get "not ... a great deal of money." This is not a reasonable approach and does not appear to be cost effective for the citizens of Alaska.

Department of Revenue Requirements

The DOR has stated it's intention to require companies to log all flaring events. This was most recently expressed by the DOR representative at the, August 31, 1994, meeting and in a conversation with him following the hearing. From DOR's perspective the costs to the industry and/or the cost to the tax payers of the State of Alaska do not matter. The cost of additional government and industry employee will be much greater than any potential tax revenue. This extra operating expense will reduce the life of these properties and thus reduce oil reserves.

As we have stated before, our facilities are old and not fully automated. We **do not** have meters on every line connected to some central computer, so as to pin point the cause of every flaring event. Since most of these short duration events last only several minutes it is likely that the exact cause of many events would not be able to be determined. None-the-less we would be required to have someone ready to record the event and then try to determine its cause.

Since our employees work 12 hours per day on a "seven days on and seven days off" schedule, it requires four employees to cover any one position. Thus adding one position to a facility staff requires 4 people. Assuming an average cost of $90,000 per year for wages and benefits, adding one position per facility will cost $360,000 per year per facility (This is approximately 10% of our yearly expenses at several of our facilities). There are 15 platforms and approximately 14 land based facilities that would be effect. If each facility added one position, the cost of these new reporting requirements would be $10,440,000 per year. This is a great deal of money to spend inorder to collect "not .... a great deal of money for taxation."

Subject: UNOCAL's Comments
AOGCC's "Report on Flared Gas, January 19, 1994"
Date: September 13, 1994

Again we therefore urge the commission to return to its original draft language designating this gas as "needed for safety". We thank you for the opportunity to respond to the Commission's draft regulation. If you have any questions, please let me know.

Very truly yours,

Paul W. Lokke
Senior Production Engineer
UNOCAL

CC: File
Martin Morell

1 ALASKA OIL AND GAS CONSERVATION COMMISSION
2 PUBLIC HEARING
3
In Re:)
4)
REGULATIONS MEETING - HB 380.)
5)
6
TRANSCRIPT OF PROCEEDINGS
7
Anchorage, Alaska
8 September 15, 1999
9:07 o'clock a.m.
9
APPEARANCES:
10
Commissioners: MR. ROBERT CHRISTENSON, CHAIRMAN
11 MS. CAMILLE OECHSLI
MR. DAVE JOHNSTON
12
13 Attorney General's Office: MR. ROBERT E. MINTZ
14 * * * * * *
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1 PROCEEDINGS
2 (On record - 9:07 a.m.)
3 CHAIRMAN CHRISTENSEN: I would like to call this
4 hearing to order. Subject to the hearing is as it is and
5 notice that we published on 8/10/99 in regard to the 380 bill,
6 House Bill 380. All persons wishing to testify need to be
7 sworn in. Did we get the list out this morning? Thanks.
8 The way we're going to run this morning is that we're
9 going to have a hearing initially to hear any testimony, and
10 then we will adjourn the hearing and call our business meeting
11 to order where we will discuss and adopt or whatever we decide
12 to do subsequent to that. So we'll start out with a hearing,
13 and anybody who wishes to testify -- Gary Carlson, you wish to
14 testify this morning?
15 MR. CARLSON: Yes.
16 CHAIRMAN CHRISTENSEN: Okay. Would you like to come
17 up?
18 MR. CARLSON: You understand the deal about the
19 swearing in with regard to -- you wish to be sworn in as sworn
20 testimony? We do accept other testimony. We do accept other
21 testimony but it will not be given as much weight as sworn
22 testimony. Do you wish to be sworn in?
23 MR. MINTZ: Excuse me. Sorry to interrupt,
24 Mr. Chairman. But my understanding of the swearing versus non-
25 sworn statement is adjudicatory type hearing and not a

1 regulatory type hearing under the Administrative Procedure Act.
2 I would advise just asking for unsworn statements because I
3 don't think -- we don't want to be in a position of possibly
4 deterring anyone from testifying here.
5 CHAIRMAN CHRISTENSEN: Okay.
6 MR. MINTZ: Thank you.
7 CHAIRMAN CHRISTENSEN: So you're going to have an
8 unsworn statement.
9 MR. CARLSON: Okay. I was going to ask what does that
10 mean to me.
11 CHAIRMAN CHRISTENSEN: Would you state your name and
12 your company, please?
13 MR. CARLSON: Sure. My name is Gary Carlson. I'm Vice
14 President of Forcenergy in Alaska for Alaska.
15 CHAIRMAN CHRISTENSEN: Okay.
16 MR. CARLSON: Forcenergy submitted written testimony
17 and I do not intend to read that. It -- I think it is -- is
18 clear and doesn't need to be repeated. I do want to say,
19 however, though that -- that our company appreciates AOGCC's
20 open thinking and attitude to improve this process. It's
21 evidenced in the fact that I -- that I believe this is the
22 third hearing.
23 Our major concern -- Forcenergy's major concern is that
24 in the proposed regulation AOGCC's approach could
25 unintentionally destroy the incentive to develop these new

1 resources, that the intent of the legislation was to -- to
2 cause action on the -- on the part of industry to go out and --
3 and to try to do something with these 30 year old previously
4 discovered oil fields. And so we are very concerned about
5 the -- the constitutionality of any of the regulations, and --
6 and I think that's fully covered in our written -- in our
7 written testimony. We think this would be counter to the -- to
8 the charter of the AOGCC.
9 And -- and I would like to add from Forcenergy's
10 standpoint, we have and we will, you know, meet the intent of
11 this legislation not just on these properties but on all our
12 properties. We think it's just good business and -- and
13 especially for a new company in -- in Alaska, and that we
14 appreciate being involved with the process and hope that --
15 that following this hearing that we can prepare our first plan
16 and have it to you before the end of the month. That would
17 be -- that is our goal and we can do that. And we are pleased
18 to understand that -- that this could consummate the -- the
19 public input so we -- we don't continue to put off supplying
20 our plan because we're going about our business and we're doing
21 the right thing but it won't be a plan if we've done it. You
22 know, so we are anxious for -- for us to do our part, and I'd
23 be glad to answer any questions or -- or deal with any
24 comments.
25 CHAIRMAN CHRISTENSEN: Okay. Any comments, questions?

1 COMMISSIONER OECHSLI: I don't have any questions.
2 CHAIRMAN CHRISTENSEN: Dave?
3 COMMISSIONER JOHNSTON: Yeah, I have one question for
4 you, Mr. Carlson. In your letter dated September 14, 1999,
5 you've indicated that -- and I think in the second paragraph
6 that you want to re-emphasize your position that AS
7 31.05.030(i) does not require any implementing regulations.
8 MR. CARLSON: Uh-hum.
9 COMMISSIONER JOHNSTON: Could you expand a little bit
10 more about your thinking on that?
11 MR. CARLSON: Yeah. Our -- as I understood the -- the
12 legislative process when we went -- went through this that --
13 and talking to the people that were involved in -- in putting
14 the final wording in the -- in the legislation, what they
15 intended us to do or the industry to do is to basically expose
16 ourself to public scrutiny, and that the -- the intent of the
17 legislation as we would -- we would deal with Alaskan hire on a
18 professional -- you know, from a professional standpoint, and
19 that we would be required to make a -- a plan and -- and defend
20 it, and that the agency that was going to manage the hearing
21 would -- would approve it. Simple as that, that there wouldn't
22 be a non-improved plan. The only -- the only way that we could
23 not -- cannot manage our part of that plan is to not have
24 submitted it.
25 COMMISSIONER JOHNSTON: Do you see any benefit at all

1 in adopting regulations to articulate the statutory
2 requirements?
3 MR. CARLSON: Maybe a framework so the -- and I'm
4 thinking about more from a -- from a regulatory standpoint,
5 maybe a framework so that all of the companies that have to
6 come before you with plans if that -- the attention of other
7 companies, that they cover the same concepts but beyond that, I
8 can see no advantage, and I would even question that advantage
9 in that one of the -- you know, for instance, we're involved
10 with two -- two fields that are covered by this legislation,
11 one is West Foreland the other is Redoubt Shoal. The West
12 Foreland Field is one well. And a plan for West Foreland would
13 be extremely simply I think -- should be -- where you're
14 talking about major construction and you're talking about
15 hiring new people on your own payroll your procedures would
16 be -- would be different. So it's hard for me to put on your
17 hat and try to decide how, you know, you want to look at the
18 process. I guess I'll stand by my first comment that we didn't
19 think regulations were necessary, that we would be able to be
20 thorough enough in our plan presentation that would -- you
21 know, we would be able to answer both the questions from the
22 commission and the public.
23 COMMISSIONER JOHNSTON: Thank you. I appreciate that
24 because I've been trying to struggle as to what hat I wish to
25 wear in this particular case. And one of the benefits that I

1 thought I saw in establishing regulations is to help guard the
2 companies as to how that plan would come together and what some
3 of those elements are, but what I'm hearing is that at least
4 from your perspective that a free flowing presentation might be
5 more suitable and more consistent with the statutory elements.
6 MR. CARLSON: Yeah. With the intent of the law, I
7 would -- or the legislation. I will if I could I would make a
8 comment to follow up yours, Mr. Johnston, and that is that
9 process worked very well. Those countries in the Netherlands
10 is a -- is a good example that the way they have managed
11 business and -- and government relations is they have turned to
12 the industry and asked them what is your plan whether it be
13 environmental performance. What is your plan, you would
14 develop your plan, and then hold yourselves accountable to
15 those plans rather than write new regulations. So it is --
16 it's unusual for the United States I will say that but it's not
17 unusual on a world-wide scale.
18 COMMISSIONER JOHNSTON: I guess one of the aspects that
19 I'm a little bit troubled by in terms of, you know, this idea
20 of establishing a frame work or not is how would you advise the
21 Commission in terms of making a -- you know, in terms of what
22 our role would be in the approval of these things. How would
23 we distinguish between a plan that, say, Forcenergy would
24 present that was very detailed and fully flushed out, et
25 cetera, versus one that just says, you know, I promise to do my

1 best and nothing more than that. Do you think we give those
2 equal value and equal weight? And how would we come down on
3 that kind of issue? What would you advise the Commission to --
4 how would we deal with that?
5 MR. CARLSON: Well, I -- and I think I would say --
6 we're coming back to that second paragraph then that -- that --
7 that holding the companies accountable for supplying a plan
8 is -- is the key part, and I would look to the agency as a
9 vehicle by which you would provide a place and notice, public
10 notice, and -- and put the seriousness -- of the -- these
11 plans on the right pers- -- in the right perspective, and --
12 and implement a -- you know, in an orderly fashion if we get
13 the plan in -- in -- within 20 days, we would be subject to a
14 hearing, and that you would distribute the plan or make it
15 available. That's what I envisioned the Commission's role
16 originally, and -- and I refer back to some verbal testimony
17 that Representative Hodgins made and -- in whenever it was, a
18 month or so ago. And he was key in --in drafting the
19 legislation, that he felt strongly that public scrutiny was
20 going to be what was going to be required, and that -- and that
21 was his intent and -- and that's how I understood it
22 originally, too.
23 COMMISSIONER JOHNSTON: So you would ne- -- if under
24 your understanding of the statute, you would not necess- -- you
25 would see the role of the Commission as being passive in the

1 approval of these plans and not active. We wouldn't
2 necessarily be saying this doesn't quite measure up. We would
3 just be merely the vehicle under which the public presentation
4 would be made, and then once that public presentation was made,
5 regardless of how detailed it may or may not be, we would go
6 ahead and approve that. Is that.....
7 MR. CARLSON: That's correct.
8 COMMISSIONER JOHNSTON: .....conceptually.....
9 MR. CARLSON: Right.
10 COMMISSIONER JOHNSTON: And then the -- I guess the
11 public pressure would be the thing that would really be kind of
12 the driving behind this as to whether you really measured up or
13 didn't.
14 MR. CARLSON: That's.....
15 COMMISSIONER JOHNSTON: Is that the concept that
16 we.....
17 MR. CARLSON: That's right, yeah. And the people that
18 were interested we would assume would be at the hearing, or the
19 press, or, you know, this is the type of pressure that we -- we
20 would be subjecting ourself to, which is pretty strong.
21 COMMISSIONER JOHNSTON: So if Forcenergy came up with
22 just a sham of a plan and presented it, you would expect the
23 press to pick that up and say.....
24 MR. CARLSON: Uh-hum.
25 COMMISSIONER JOHNSTON: .....dah, dah, dah.

1 MR. CARLSON: Exactly.
2 COMMISSIONER JOHNSTON: All right. Okay.
3 MR. CARLSON: I don't have any further comments, and if
4 there's some questions.....
5 CHAIRMAN CHRISTENSEN: More questions?
6 COMMISSIONER JOHNSTON: No, no further questions.
7 Thank you.
8 CHAIRMAN CHRISTENSEN: Okay, thanks. Is there anybody
9 else that would like to make a statement or comment in this
10 hearing? Anybody in the room? I guess we have no telephone
11 calls later, right?
12 COMMISSIONER OECHSLI: Not that I'm aware of.
13 CHAIRMAN CHRISTENSEN: Okay.
14 COMMISSIONER JOHNSTON: I did note that we only have
15 two people signing our sign-in sheet. It would be nice if we
16 could get a record of all people attending. So if we could
17 circulate this again and if we could get all people signing it,
18 we would certainly appreciate that.
19 CHAIRMAN CHRISTENSEN: So do we have any further
20 business for the hearing?
21 COMMISSIONER JOHNSTON: Well, there doesn't appear to
22 be any further requests for comments so I guess we can close
23 the hearing at this point.
24 CHAIRMAN CHRISTENSEN: Cami, do you have anything else
25 for the hearing?

1 COMMISSIONER OECHSLI: No.
2 CHAIRMAN CHRISTENSEN: Okay. We'll close the hearing.
3 (Off record - 9:21 a.m.)
4 END OF PROCEEDINGS
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1 CERTIFICATE
2 UNITED STATES OF AMERICA)
)ss.
3 STATE OF ALASKA)
4 I, Laura Ferro, Notary Public in and for the State of
5 Alaska, and Reporter for Metro Court Reporting, Inc., do hereby
6 certify:
7 That the foregoing Alaska Oil & Gas Conservation
8 Commission Hearing, was taken before myself on the 15th day of
9 September 1999, commencing at the hour of 9:07 o'clock a.m., at
10 the offices of Alaska Oil & Gas Conservation Commission, 3001
11 Porcupine Street, Anchorage, Alaska;
12 That the hearing was transcribed by myself to the best
13 of my knowledge and ability.
14 IN WITNESS WHEREOF, I have hereto set my hand and
15 affixed my seal this 16th day of September 1999.
16
17 _____
Notary Public in and for Alaska
My commission expires: 05/03/01
18
19
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21
22
23
24
25

1 ALASKA OIL AND GAS CONSERVATION COMMISSION
2 MEETING
3
In Re:)
4)
CHAPTER 25, ALASKA OIL AND GAS)
5 CONSERVATION COMMISSION REGULATION)
CHANGES.)
6)
7
TRANSCRIPT OF PROCEEDINGS
8
Anchorage, Alaska
9 September 29, 1999
9:06 o'clock a.m.
10
APPEARANCES:
11
Commissioners: MR. ROBERT N. CHRISTENSON, CHAIRMAN
12 MS. CAMILLE OECHSLI
MR. DAVID W. JOHNSTON
13
Attorney General's Office: MR. ROBERT E. MINTZ
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* * * * * *
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Page 2

1 PROCEEDINGS
2 (On record - 9:06 a.m.)
3 CHAIRMAN CHRISTENSON: I would like to call
4 this meeting to order. The purpose of this meeting this
5 morning is for the Commission to consider the changes made by
6 the AG's office, and we'll be going over their – Rob Mintz
7 will be going over their – those one at a time. Procedurally,
8 the way this works is that at the end of the session we'll be
9 voting on the adoption of these regulations. We're not
10 intending to take detailed questions with regard to specifics
11 in regulations from the audience today. However, if you do
12 have general process questions on the way things will proceed
13 from here, we'll be happy to answer those. It's our
14 anticipation that once they're adopted, they'll go from the
15 AG's office to the Lieutenant Governor, and from that point on
16 after they are approved from 30 days after that point they'll
17 be in effect. So that's kind of roughly the time table. We
18 don't really know how long it will take to get through the
19 Lieutenant Governor's office.
20 So are there any questions at this point, general
21 questions on the process?
22 MR. WORCESTER: If I could make a few brief comments
23 I'd appreciate it.
24 CHAIRMAN CHRISTENSON: Process, Mark. Process.
25 MR. WORCESTER: Well (indiscernible - simultaneous

Page 3

1 talking) the process, yes.
2 CHAIRMAN CHRISTENSON: Not the regulations.
3 MR. WORCESTER: Okay. My name is Mark Worcester. I'm
4 with ARCO Alaska, Inc. Unfortunately, due to the amount of
5 notice, I have not been able to – it's been impossible for
6 AOGA to meet and be able to make any comments on process or
7 substantively. We have not received copies of the latest
8 edition until yesterday afternoon, and that's basically is my
9 process concern is that this regulation project is more than
10 five years old at this point. The Commission has adopted
11 regulations two times, and there's been substantial work by –
12 done by AOGA and its members as well as the Commission and the
13 Department of Law on these regulations. The Department of Law
14 has been actively involved through that whole process through
15 both adoptions. In a quick review of this – the latest
16 changes being recommended by the Department of Law show
17 extensive changes. A quick perusal will show that easily.
18 Many of these are substantive in my view and overly restrict
19 the discretion of and the way of doing business that the
20 Commission has very successfully used over the years. It's
21 impossible as I say with the timing for us to prepare and I'm
22 not sure we're even invited to make comments on what we view is
23 significant substantive changes that may deserve more
24 consideration.
25 And so I on behalf of ARCO only request that the

Page 4

1 Commission not act today. I know we're all eager to get this
2 process done and over with and this regulation process finally
3 put to bed but after all this work I believe it would be
4 inappropriate not to consider the comments after an adequate
5 time for review for the changes, and with an understanding of
6 why the Department of Law is recommending these changes.
7 I understand the Department of Law's role is to –
8 limited to matters of form and opinions as to legality, not to
9 substitute its judgment for the appropriateness of the acts of
10 discretion of the Commission.
11 And so with that I'm very interested in listening to
12 the – Mr. Mintz's comments about why these changes are here
13 and hope that the Commission will entertain the comments of the
14 regulated community and other members of the public. Thank
15 you.
16 CHAIRMAN CHRISTENSON: Okay. Duly noted. Rob, would
17 you proceed to go through the changes? I think you're going to
18 go through it page by page so that we all know what's going on.
19 MR. MINTZ: Yes. Let me first say that of course
20 Mr. Worcester is absolutely right. There are a number of
21 substantive changes reflected in this new version. In no case
22 was any substantive change unilaterally made by the Department
23 of Law but these basically were the result of raising issues
24 and then consultation with one or more commissioners and often
25 through the commissioners' staff as to the appropriate

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1 response. But of course it's totally within the Commission's
2 judgment today as to whether the Commission as a whole agrees
3 with these proposed changes and whether it wants to adopt them.
4 Basically everything in here is a result of a process
5 that occurred through review of the regs by the Regulation
6 Section of the Department of Law. And I guess I would say
7 there are three categories of changes. Probably the most
8 common one is what I call formal changes. Changes in style,
9 convention, which actually would not require readoption by the
10 Commission but since there are other changes that do require
11 readoption, they're all part of the package.
12 The second type of change basically resulted from the
13 Department of Law Regulation Section determination that there
14 was a legal problem with an aspect of the regs, and then the
15 change reflects the solution to the problem as I say through
16 consultation with one or more commissioners.
17 And then the third category would be instances where
18 the Regulation Section review found an ambiguity or lack of
19 clarity in what the earlier version of the regulation was
20 trying to accomplish, and the change reflects an attempt to
21 clarify that. And in some cases actually just through the back
22 and forth during this process either individual commissioners
23 or staff members came up with other improvements that they
24 thought should be considered. And so I guess that adds up to
25 four categories of changes.

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1 So I'll go through these page by page and basically
2 give any commissioner a chance to ask questions or raise
3 issues. And in some cases I'll try and explain what the
4 changes are about.
5 The first page is just formal changes. And I'll
6 just – just to save time I'll just kind of roll ahead and ask
7 that any commissioner interrupt me with any questions on any
8 page.
9 CHAIRMAN CHRISTENSON: Good.
10 MR. MINTZ: The second page is basically formal changes
11 or clarifications except for an additional requirement which I
12 believe originated in with a staff suggestion, and that is that
13 in addition to governmental section line coordinates for
14 identifying a well location that the surface location also be
15 identified with reference to the state plane coordinate system.
16 Turning to page three, there – I don't think there are
17 any substantive changes here, just clarifying our formal
18 changes.
19 Same on page four.
20 Same on page five.
21 Same on page six.
22 Now, at the top of page seven, there are two changes.
23 And this change is reflected throughout the regs in similar
24 situation. One is – this has to do with oral approval of an
25 application and followed by submission of the written

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1 application. And it was the thought of either one or more
2 commissioners that – or the staff or both that if the
3 Commission has to be responding that quickly, that the operator
4 should also be responding very expeditiously, and that the
5 written submission should be within three days as opposed to
6 three working days.
7 The other change was something that Regulation Section
8 said is necessary to conform with the law, and that is the
9 requirement of – that the written application be made for
10 final approval by the Commission because essentially a
11 commission – multi-member commission can't really delegate its
12 ultimate authority to anyone else as a staff – such as a staff
13 member.
14 The oth- – the rest of the changes on page seven are
15 clarifying or technical/formal.
16 On page eight, the substantive change is at the bottom,
17 subsection (b). The bond in general is supposed to make sure
18 that among other things, a well is abandoned and the location
19 is cleared properly. As previously written, when the
20 Commission would allow an amount less than $100,000 for single
21 well, it – the criteria in there was that the cost of well
22 abandonment would be less than 100,000, but since the bond is
23 supposed to also cover location clearance, the proposed change
24 would clarify that the total cost of abandonment and location
25 clearance would have to be less than $100,000.

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1 On page nine is clarifying or technical changes.
2 On page 10, at the bottom, paragraph (3) and (4), these
3 are the first of many situations where the Regulation Section
4 determined that there needed to be a standard set out in the
5 reg to apply to the Commission's decision. Generally speaking,
6 what's going on in the regs in these situations is there's a
7 requirement or a -- basically a requirement set out but with an
8 escape valve that with -- on Commission approval or sometimes
9 it says in the Commission's discretion the requirement could be
10 changed or waived. And the Regulation Section points out that
11 if there's no standard, then there's a strong possibility that
12 the regulation would be found arbitrary or to put it another
13 way, the regulation would be found to be an attempt to allow
14 the Commission to act arbitrarily. And to make sure that
15 doesn't happen, it's important to specify what grounds the
16 Commission would use to grant the waiver or the variance. And
17 essentially the -- I mean conceptually it's a very simple fix
18 because you just look at the goal that you're trying to
19 accomplish through the requirement, and you're essentially
20 saying here's the requirement to accomplish that goal but if
21 the operator can show there's another way to accomplish that
22 same goal, then the Commission will allow that other way.
23 Now moving on to page 11, here's another example of
24 adding such a standard. In subsection (c) paragraph (2)(B).
25 Paragraph -- I'm sorry, page 12 at the bottom of the

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1 page, there's another standard added there.
2 (Whispered side conversation)
3 MR. MINTZ: Subsection (a) of the section actually sets
4 out the goals of the casing and cementing program. And this
5 standard says basically if you need -- that if you need
6 remedial action to meet those requirements, then that would be
7 required.
8 On page 13, paragraph (5), I think this was on the
9 advice of staff through one or more commissioners that two of
10 the examples on line five are inapplicable and so they were
11 deleted, that is cement channeling and mechanical failure of
12 equipment.
13 On page 14, 25.033.(a), the phrase, in its discretion,
14 is deleted for a similar reason to what I just described in
15 connection with the addition of standards. If the Commission
16 determines that a drilling fluid system is not necessary, then
17 I -- the question is is there any why the Commission would not
18 allow drilling operation to go forward without the drilling
19 fluid system. And in the absence of anyone coming up with that
20 reason, it would reduce arbitrariness and increase
21 predictability to simply provide for the -- provide for that
22 blanket rule that you have to be equipped with a drilling fluid
23 system unless the Commission determines it's not necessary.
24 Page 15 just reflects clarification of terminology.
25 On page 16 the deletion in (d) and (f) of the phrase

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1 drill- -- well, basically referenced to rotary drilling rig
2 operation, that reflects a suggestion by staff or one or more
3 commissioners or both that these requirements should apply
4 whether or not it's a rotary operation.
5 On page 17, paragraph (2) at the top, there's the
6 addition of a standard of the sort I previously described. And
7 deletion of the phrase, in its discretion. On paragraph (2)
8 and (3), well control data, the term, control, has been deleted
9 simply to clarify or to avoid confusion. Most everywhere else
10 in the regs well control refers to basically avoiding blowouts
11 and physical problems like that. And here it's a di- -- it's
12 used in a different sense and by deleting the word, control,
13 well data is -- the context makes clear what you are talking
14 about.
15 Page 18 a standard has been added.
16 Page 19 it has clarifying technical corrections.
17 Page 20 -- oh, pa- -- at the bottom of page 19 and 20,
18 there's a deletion of, in its discretion, for the same reason I
19 described earlier. And then paragraph two on page 20, this is
20 just re-writing the standard to clarify what you're trying to
21 accomplish.
22 On page 21, it's the first of a number of updates in
23 the terminology at the bottom. API 5M apparently is now
24 referred to as 5K.
25 The changes on page 22 are just clarifying language.

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1 And on page 23 there are clarifying language and the
2 addition of a standard. Paragraph (iii) at the end of first
3 sentence where there's a possibility that the Commission will
4 require a higher rate of working pressure, and the standard is
5 as the Commission considers necessary to maintain well control.
6 On page 24, there are terminology changes. And then at
7 the bottom of the page, (F)(i), this was a suggestion by staff
8 or one or more commissioners or both to change the BOP
9 requirement.
10 And same comments on page 25, some changes in the BOP
11 requirements.
12 On page 26, again, a suggestion from staff or one or
13 more commissioners that the reference to rigid pipe in
14 paragraph (6) include the term, steel. And then standards were
15 added in (6)(A) and (6)(F) to govern variances.
16 On page 27, these are basically clarifying technical
17 corrections.
18 Same on page 28.
19 On page 29, same, but there's also -- no, these are
20 just clarifying and technical corrections.
21 On page 30, there's a change in the BOP requirement in
22 paragraph (2)(A) at the top. No, it's not a change, just
23 clarifying language. Sorry.
24 On page 31, there is a -- the same standard for a
25 variance to the working pressure requirement as we described

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1 earlier. That is in paragraph (3) at the top, considers
2 necessary to maintain well control.
3 Page 32 clarifying and technical changes.
4 Same on page 33.
5 On page 34, paragraph (10), again the addition of steel
6 and rigid steel pipe, and the addition of a standard for
7 approval of a -- other conduit.
8 Page 35 are clarifying and language changes to conform
9 to the language elsewhere in the regs.
10 Page 36, Section 37, there's a standard added for the
11 Commission to approve alternate well control procedures.
12 37, basically it's updating the requirements and what
13 has to be on the identifying sign. I think the substantive
14 change may be in par- -- in subsection (c) where -- which
15 concerns signs at platforms or multiple well drill sites. Some
16 information may be posted on one sign rather than on a sign in
17 front of each well.
18 Page 38 only has technical, clarifying, or formal
19 changes.
20 And I think that's true on page 39 as well.
21 And that is also true on page 40.
22 On page.....
23 COMMISSIONER OECHSLI: I think at the bottom of page 40
24 it looks like the coordinates -- oh, never mind. You're right.
25 MR. MINTZ: Yeah. The top of page 41 there's a

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1 substantive addition suggested by staff or a commissioner, and
2 that is requiring reference to the state plane coordinate
3 system for the surface location.
4 Page 42 is simply formal language changes.
5 Page 43, there's been a change suggested in subsection
6 (e) in the standard for granting a variance from the notice
7 requirements in connection with spacing exceptions. And it
8 basically provides a more -- well, a different standard which
9 is feasibility of complying -- or lack of feasibility with
10 complying with the regular notice requirement because I think
11 on reconsideration it appeared that it's not very likely that
12 there's going to be a more effective means of providing notice
13 than individual certified mail but it's really a question of
14 feasibility.
15 I don't see anything substantive on page 44 or 45.
16 And on 46, there's an addition of a standard in (a)(3)
17 where the Commission will require additional sensors as the
18 Commission considers is necessary for safety.
19 Nothing substantive on 47 or 48 or 49.
20 By the way I should get -- I should emphasize
21 regardless of whether I express an opinion that there's nothing
22 substantive, the Commission is free of course to have a
23 different view and to take exception and to either reject or
24 accept or modify any of those changes.
25 CHAIRMAN CHRISTENSON: Okay.

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1 MR. MINTZ: On page 50, this has to do with the well
2 data that are required to be filed under statute within 30 days
3 after well is completed, suspended, or abandoned. Now,
4 apparently there are some sorts of data that in at least some
5 cases cannot feasibly be available in 30 days. And so this
6 change -- the change basically requires that the operator
7 submit a proposed date for when they can be submitted as
8 opposed to just leaving it up to the operator to file them as
9 soon as available.
10 On page 51, language is added to clarify that the
11 concept of shutdown is a temporary shutdown.
12 And on page 52, subsection (d), continuing with the
13 shutdown concept, basically this adds a standard for
14 determining whether there should be a grant of an additional
15 period allowing well shutdown. The standard is if the operator
16 shows that operational circumstances beyond the operator's
17 control prevent resumption within a 12 month period.
18 Paragraph (sic) 53, I think that's just -- wait. Oh,
19 there is. Sorry.
20 Back on page 52, this is just a legal problem here.
21 The existing Section 75 provides -- well, this has to do with
22 the Commission's authority to regulate non oil and gas well
23 drilling in certain areas of the case where -- certain areas of
24 the state where there are particular hazards that the
25 Commission identifies. The problem is that the statute

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1 requires that the Commiss- -- if the Commission is going to
2 define such an area and regulate drilling, it has to do that by
3 regulation. And the existing regulation said the Commission
4 would do that by order. And basically that's inconsistent with
5 the statute. So the Department of Law actually recommends that
6 Section 75 be repealed. However, it probably requires a
7 separate regulation project with separate notice to appeal
8 that. So for the time being, we are just recommending that the
9 amendments be withdrawn. And that's what this cross out does.
10 I don't see anything further substantive on page 53 or
11 on 54.
12 Page 55, subsection (c), the phrase, in its discretion,
13 has been deleted following the principle that if the standards
14 have been met for getting an authorization, an authorization
15 should be granted.
16 And then on page -- the top of page 56, there's a
17 standard added that would govern the Commission's decision to
18 impose additional conditions on an authorization. Namely, the
19 standard is that the things you are trying to achieve in this
20 section which are set out in subsection (c) are -- require the
21 additional conditions to be imposed. And otherwise, there are
22 formal or technical changes only.
23 Similarly on page 57.
24 Similarly on page 58. I would just explain a number of
25 cases. For example, in subsection (b) where it refers to

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1 removal of the drill rig from location, the phrase, from
2 location, has been deleted to clarify something. Some places
3 in the regs, location is used in the context of location
4 clearance, and it has a more general or broader meaning than
5 the actual well. And we wanted to be clear that in this case
6 abandonment is triggered by removal of the drill rig from the
7 well and not just from the general location.
8 On page 59, basically subsection (e) reflects the
9 change I earlier described requiring final approval by the
10 Commission in the case of an earlier oral approval. And in
11 this case the 10 days for filing the written application has
12 been reduced to three days to make it consistent with the
13 general rule throughout the regs.
14 And that same change has been made on page 60.
15 Page 61, subsection (a) deletes the phrase, in its
16 discretion, for the reasons I earlier described. Then there is
17 a significant substantive change that was suggested by a staff
18 or one or more commissioners, and that is that as revised, a
19 well can be suspended even if it has been completed in the
20 certain circumstances that are set out in paragraph two. And
21 then subsection -- oh. The existing reg and indeed I think the
22 current reg before these were adopted uses the -- uses a
23 standard paying quantities, produced in paying quantities in
24 (a)(1), and the Regulation Section advised that it's necessary
25 to define this. And the definition set out here is basically

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1 one of two standard definitions in the oil industry. And it's
2 the one that seemed most applicable to this situation because
3 it would -- it only requires that enough oil or gas be produced
4 to pay for the cost of operating the well as opposed to also
5 paying back the investment cost.
6 Subsection (b) includes the changes to three days and
7 requiring final approval of the Commission.
8 On page 62, paragraph two -- par- -- I'm sorry,
9 subsection (c) is changed. This has to do with the fact that
10 in general, information, and this usually concerns well data,
11 that is not required to be submitted to the Commission but is
12 voluntarily submitted has to be kept confidential if the
13 operator so requests. And basically as previously written,
14 subsection (c) more or less repeated that provision. However,
15 the information that is required to demonstrate that a well
16 should be suspended is not information that's voluntarily
17 submitted. So it doesn't really fall within that protection.
18 Yet in consulting with one or more commissioners we understood
19 that it is important to assure in this reg that whatever
20 confidentiality may be afforded by law will be afforded by law,
21 and that's what the re-writing attempts to do, basically to the
22 extent that the information submitted here is required to be
23 submitted under the statute, it will be maintained confidential
24 for as long as the statute requires, and if it's not required
25 to be submitted, it will be maintained confidential if it's a

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1 trade secret. And a trade secret is defined in the -- Uniform
2 Trade Secrets Act quite broadly. Basically if there is value
3 to the owner of that information by keeping it secret, then --
4 I'm kind of oversimplifying but it's a broad definition.
5 On page 62, subsection (d) paragraph (2), a standard
6 has been added for waiving the requirements for plugging here.
7 And page 63, at the top it basically just specifies
8 what standard is going to apply to location clearance. And 63,
9 a standard is added for the Commission's approval for plugging
10 from the top of fill instead of plugged back total depth.
11 64 is just clarifying changes.
12 And 65 para- -- subparagraph (c) in the middle, a
13 standard has been added. It's basically the same one that is
14 on the bottom of page 63, having to do with plugging, variants
15 on plugging.
16 There's nothing substantive on 66.
17 On page 67, subsection (g) and paragraph (1), this is
18 clarifying the surface plugging requirements based on
19 consultation with staff and one or more commissioners. I'm
20 probably not the best person to explain it but if there are any
21 questions, I think Commissioner Johnston could probably explain
22 it.
23 COMMISSIONER JOHNSTON: Yeah. I think all this does is
24 make it clear that testing of the cement retainer can occur
25 before you place the cement so it gives a broader latitude in

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1 terms of testing the cement plugs and mechanical plugs.
2 MR. MINTZ: 68 is clarify and formal changes.
3 On page 69, subsection (a) at the top, a standard has
4 been added for allowing a marker post rather than a marker
5 plate. And subsection (d) I think that's just one addition,
6 paragraph (3) there, the well name has been added to the
7 requirement -- to the information that has to be on the marker.
8 That was a suggestion from staff or a commissioner.
9 On page 70, Section 140, the standards for allowing --
10 approving conversion to a water well have been somewhat
11 clarified and revised. Basically it requir- -- that would not
12 require that the proposed use as a freshwater well is bona
13 fide.
14 And then Section 170(a) at the bottom, the language for
15 triggering location clearance has been clarified so that it's
16 not necessarily after the well has been abandoned but it could
17 be and presumably will often be at the time the well is
18 abandoned. It could be at or after.
19 Page 71, the Regulation Section recommended that there
20 be more clear and certain provisions showing that where a lease
21 is basically controlled or properties controlled by either DNR
22 in the case of a state lease or the United States Department of
23 Interior in case of federal lease that the surface location
24 requir- -- clearance requirements of those agencies would be
25 deferred to.

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1 And in addition, (2)(C) on page 71, a standard has been
2 added to govern the Commission's approval of closing pits in a
3 different manner than filling and grading them.
4 Page 72 reflects similar changes in offshore location
5 clearance to what I described in Onshore.
6 And so does 73.
7 74, you might want to frame. There are no changes.
8 75, (d) at the top, there's a standard added for
9 variance from the tubing and packer requirement. Otherwise,
10 there are clarifying or formal corrections.
11 On page 76, Section 210, the in its discretion language
12 has been deleted because there didn't seem to be any occasions
13 on which the general would not be suitable.
14 And then on page 77, Section 225, there's a standard
15 added for the Commission to approve alternative test methods to
16 the multi-point -- rather to a multi-point back-pressure
17 method. And since there apparently is more than one type of
18 multi-point back-pressure method, the word, the, has been
19 changed to, a, at the beginning of the sentence.
20 Page 78, subsection (b), at the suggestion of staff or
21 a commissioner, the phrase, and gas meters runs, has been
22 deleted because that's considered part of the hydrocarbon
23 measurement equipment.
24 And at page 79 at the top, subsection (g), a standard
25 has been added to govern the schedule approved by the

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1 Commission.
2 Similarly on page 80, Section 230, a standard has been
3 added to govern the Commission's determination of what are
4 acceptable equipment and techniques, and then in the first line
5 of subsection (a), the phrase, or allocated, has been deleted
6 because again based on an analysis by staff or one or more
7 commissioners, it's clear that the Commission actually wants to
8 require a measurement in every case. And actually it's the
9 second sentence of this subsection which provides an exception
10 for allocation. And what it basically says is -- well, I mean
11 the first sentence is you have to measure production from each
12 well. The second sentence says, well, you could measure it
13 from a group of wells if it's accurately allocated to each
14 well. And those are really the only two alternatives that the
15 Commission wants to allow as I understand it.
16 Section (sic) 81 is just technical or formal changes.
17 Okay. And the same in 82.
18 On page 83, the first line at the top of the page has
19 been deleted but it's been replaced by a similar provision on
20 page 86 which we'll get to when we get to page 86.
21 And then similar -- still in subsection (a), basically
22 we've reworded the description of the types of waste that will
23 be permitted. And it basically broadens it somewhat so that
24 whatever the Commission determines are suitable for disposal in
25 a Class II well or waste that the Commission may authorize for

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1 underground disposal.
2 And then subsection (c)(1) at the bottom, this change
3 is necessary to conform with EPA regulations on the UIC
4 programs that basically the plat in question has to show all
5 wells that are within the quarter mile zone whether or not they
6 penetrate the injection zone.
7 Page 84, these are just clarifying or formal changes.
8 On page 85, the suggestion of a commissioner,
9 subsection (d), would require mechanical integrity testing at
10 least once every four years.
11 And in subsection (e), the triggers for notifying the
12 Commission and possibly taking corrective action in the case of
13 indications of pressure communication or leakage have been
14 somewhat limited. And now it's the -- and the hoop stress
15 criteria has been deleted. And a previous -- on a previously
16 required Commission approved corrective action, again, at the
17 suggestion of one or more commissioners, this has been changed
18 to not always require corrective action but in some cases give
19 it the option of increased surveillance. And the standard has
20 been added for -- of requir- -- of ensuring protection of fresh
21 water.
22 Subsection (f), in its discretion, has been deleted
23 because if the standard is met, then there doesn't seem to be
24 any reason not to follow the general rule.
25 Subsection (sic) 86, this -- all this cross out and

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1 additional language is simply rewriting to make it clear and
2 conform to approved syntax.
3 And then new subsection (l) does the same thing that
4 the introductory sentence of subsection (a) used to do, and
5 that is to make clear that if underground disposal is regulated
6 by the EPA, and this would be basically in practice non-Class
7 II wells, then the Commission's program does not apply.
8 Subsection (sic) 87 are clarifying the language
9 changes.
10 Same as -- same with page 88.
11 Same with page 89.
12 Same with page 90. Basically at the top of the page,
13 (c) and (d), it used to say well workover and repair, but since
14 subsection (a) defines workover as including repair, the repair
15 has been deleted as superfluous.
16 Subsection -- on page 91 are technical clarifying
17 changes.
18 And same on page 92.
19 On page 93, (9)(A) near the bottom, there's been a
20 change in the BOP requirements suggested by staff or one or
21 more commissioners. From API 2M to 5K, and from greater than
22 to equal to or greater than.
23 Similar change on page 94, (10)(A) and (10)(C) and
24 (10)(D).
25 COMMISSIONER OECHSLI: I don't think (10)(A) is a

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1 change. I think it's just a rewording.
2 MR. MINTZ: You're right. Sorry.
3 COMMISSIONER OECHSLI: Okay.
4 MR. MINTZ: Page 95, these changes are equivalent to
5 what were done earlier in the regs: adding steel to rigid
6 pipe, adding a standard for approving other conduit, and adding
7 a standard for approving other types of joints.
8 Page 96, the change here is in -- aside from the
9 technical changes, subsection (g) previously referred to
10 geological hazard information acquired in connection with the
11 Application for Sundry Approvals but one or more of the
12 commissioners pointed out that there generally is not
13 geological hazard information obtained in connection with the
14 Application for Sundry Approvals, and the geological infor- --
15 hazard information would have been obtained while drilling the
16 well and so that change is reflected in subsection (g).
17 Subsection (sic) 97 is just clarifying or formal
18 changes.
19 And similarly on 98 and on 99 and on 100 and on 101.
20 On page 102, subsection (e) at the top, the same change
21 I just described on geologic hazard information, and then
22 Section 288, there is a standard added for approve an alternate
23 well control procedures and equipment. And deletion of, in its
24 discretion.
25 Page 103 is just a technical change.

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1 Same on 104.
2 Same on 105.
3 On 106, Section 402(a), a standard has been added and
4 the reference to discretion deleted with regard to authorizing
5 enhanced recovery fluid injection. And the rest of the changes
6 are more or less clarifying language.
7 Same on 107.
8 And 108, subsection (f), this reflects the same changes
9 were made earlier on waste disposal injection wells deleting
10 the reference to hoop stress and add- -- basically broadening
11 the options for dealing with the situation to include increased
12 surveillance.
13 And adding a standard in subsection (g) for additional
14 mechanical integrity tests.
15 In subsection -- in 412(b) at the bottom of the page,
16 standards are added for approving different equipment or
17 different placement of a packer.
18 Page 110, these are clarifying changes.
19 So -- I mean page 111, subsection (c) at the bottom has
20 been updated to refer to the federal regulation where EPA's act
21 for exemptions are actually set out.
22 And then in -- on page 112, Section 450(a), the in its
23 discretion language has been deleted so that basically if the
24 applicant demonstrates that the applicable requirements are
25 met, then the -- I'm sorry, if the change in requirements will

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not result in increased risk of movement of fluids into fresh water, then the Commission will allow the changes.
113 are technical or formal changes.
114 is another page with no changes.
CHAIRMAN CHRISTENSON: That makes two, right?
MR. MINTZ: Yeah. Actually, it may interest you to know that the Regulation Section said for a regulations project of this size, it was in uncommonly good shape and required unusually few changes.
CHAIRMAN CHRISTENSON: We will duly note that.
COMMISSIONER JOHNSTON: Is it possible to make a change on 114 just to -- in the spirit of things here?
MR. MINTZ: On page 115, this is just clarifying language.
Page 116 at the top, a standard is added to explain the basis for the Commission conditioning its approval.
And then (b), the final approval by the Commission and the three days as opposed to three working days has been added.
On page 117, the shading of the moose has been slightly changed. That was just a joke.
Nothing on page 118. That makes three.
COMMISSIONER OECHSLI: We're up to three or four, the moose.
MR. MINTZ: Well, four. Yeah.
On page 119, subsection (b) at the bottom -- oh,

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actually there are no substantive changes on this page or on page 120 or on page 121.
At the top of page 122, second line, there was an error in the citation of the federal regulation which has been corrected.
COMMISSIONER JOHNSTON: So what does that citation now read, Rob?
MR. MINTZ: 30 C.F.R. 250.1500.
COMMISSIONER JOHNSTON: 1500.
MR. MINTZ: Yeah.
COMMISSIONER JOHNSTON: Okay.
MR. MINTZ: I don't see any substantive changes on 123.
On 535, this is the Enforcement provision. This has been significantly rewritten although mostly it's just clarifying. Well, subsection (b) adds the requirement that written notification to a person subject to the action be by personal service or certified mail.
Then there is a -- in subsection (c) on time limits, there's more of a standard on that. First that the time can be extended for good cause shown which is basically kind of a legal term of art that has been defined in case law. And subsection (c), the standard length for response has been increased from 10 to 15. Otherwise they're just clarifying language changes.
Nothing substantive on 125.

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On page 126, subsection (b), the regulation section advised that the last phrase which has been deleted is superfluous.
Page 127, which deals with Emergency Action, subsection (a), the Regulation Section advised that the conditions for emergency order be limited to those where there's immediate harm to public health or safety. They were concerned that if it was broader that it would be subject to legal challenge. And then on -- looking further at the first sentence, and particularly in relationship to the other sections on hearings and orders, I raised the question of -- it became clear to me that emergency actions really should not be a necessarily limited to those resulting from a violation because there might be a situation where the Commission has authorized something, for example, in an order, and then circumstances change so that what's authorized is now presenting a threat to public health or safety and there might have to be a temporary emergency modification of that order, for example. So I recommend that the last ph- -- well, the last part of the sentence be deleted so that there's no limit on the use of emergency orders to situation where there's a violation.
Subsection (c)(3) has been changed so that if a hearing lasts longer than 14 days, for example, or if there's some other need to extend the period of the emergency order to protect against immediate harm to public health, that that's an

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option. Health or safety.
And then subsection (d) clarifies the procedural relationship between this section and other sections. And basically provides among other things that in general there will be a hearing -- a hearing will be governed by the regular hearing provisions of Section 540 except that it will only have to be 10 days notice rather than 30 days. And there's no requirement that a person request a public hearing. And subsection (d) also clarifies that in the case of an enforcement action, the ordinary enforcement action has kind of a process of a possibility of informal conference or review followed later by a hearing. Well, when there's an emergency order that needs an immediate hearing, those procedures will not be followed because you'll go right to a hearing unless the operator wants to extend the process in which you could have an extension. And that's set out in subsection (d).
Page 128, subsection (a) -- say, I'm getting a little bit horse. I wonder if we could have a brief recess so I could get some water.
CHAIRMAN CHRISTENSON: I'm sure we can do that.
COMMISSIONER OECHSLI: I think this might be a good time for a break.
CHAIRMAN CHRISTENSON: Go off record.
(Off record)
(On record)

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CHAIRMAN CHRISTENSON: Let's go back on record, please. Mr. Mintz, have you recovered your voice?
MR. MINTZ: Temporarily. Thanks.
CHAIRMAN CHRISTENSON: Temporarily, okay.
MR. MINTZ: Okay. We're on.....
CHAIRMAN CHRISTENSON: Would you continue, please?
MR. MINTZ: We're on page 128, Hearings, subsection (a). There have been some changes here to -- basically to conform to the statutory requirements. The statute requires a hearing in many cases. And the regulation has a attempted to reconcile that requirement with the fact that some -- in many cases there actually is -- there's no dispute and no need for a hearing and so therefore basically provides that the notice will tentatively set a hearing, and then a hearing would be held if there is a request for a hearing.
Now, the existing reg requires that -- well, actually I don't remember off hand what the existing reg requires but the reg as previously adopted required a requester to identify an interest and the reasons for a hearing. And the regulation section advised that there really can't be any limitation on a person's right to request a hearing and obtain the hearing under the statute, and therefore that provision has been deleted in the revision. And also there's a -- now it provides that the Commission will provide a telephone number in the notice that the public may call to find out if the tentative

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hearing will, in fact, be held.
Other than that, the changes are basically technical or clarifying.
On page 129, paragraph (10) at the bottom, there has been some additional language suggested to clarify the procedures that the Commission would use when it's dealing with confidential information. And that is essentially when due process requires that all the parties in a hearing have access to whatever evidence the Commission will consider whether or not that's confidential, there must be safeguards to reconcile that need with the need to protect confidentiality. And this specifies that the Commission will as necessary review confidential information in camera, that is to say, in secret; and to redact, which is to say, edit, Commission decisions if necessary to protect confidential information.
And on page 130, paragraph (11) at the top, this is a proposed change so that currently as written, the reg would require a written transcript of a hearing to be prepared in every case. But upon reflection and consideration of the practice of other agencies, it's clear that the Commission should have the option of not always having a transcript, and therefore the proposal is to re-write the regs so that it requires that a hearing be recorded and the recording included in the public record. And if necessary at a later point. a transcript could be made. Otherwise, there are clarifying or

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1 technical changes.
2 Same on page 131.
3 Same on page 132.
4 Then we go to Definitions. The changes on 133 are just
5 clarifying or adding definition of a term used in the regs.
6 COMMISSIONER JOHNSTON: Excuse me, Rob.
7 MR. MINTZ: Yeah.
8 COMMISSIONER JOHNSTON: Definition number (4), I do not
9 believe we need anymore with the changes that we.....
10 MR. MINTZ: Oh.
11 COMMISSIONER JOHNSTON: .....made in the previous
12 sections.
13 MR. MINTZ: There's no more reference to API 2K?
14 COMMISSIONER JOHNSTON: I do not believe with the
15 changes that we have made that there will be any more
16 references to the 2M or the 2K BOP. The only references that
17 I'm aware relative to the 2K had to do with the size of the
18 outlet, and that has now been changed to a reference to equal
19 to or greater than 5K. So.....
20 MR. MINTZ: All right. When we get to the point of a
21 motion to adopt, I'll -- I need to think about how to deal with
22 that.
23 COMMISSIONER JOHNSTON: Okay.
24 MR. MINTZ: Okay. On page 134, just chan- --
25 clarifying changes.

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1 Also 135.
2 And 136, and there are a couple of new definitions of
3 words that are already used in the regs.
4 137, nothing substantive.
5 138. I think the only significant change there is
6 addition of the definition of the term, public water system.
7 And the Regulation Section recommended adopting the same
8 definition that DEC has because that is also under the Safe
9 Drinking Water Act. And it's advisable that the state use the
10 same definition of the term which appears in the same act.
11 By the way, that -- what that definition is is as
12 follows. Public water system means any source of water, intake
13 works, collection system, treatment works, storage facility, or
14 distribution system, including a vehicle or vessel used to
15 distribute water from which water is available for pu- -- for
16 human consumption. Public water system includes a system
17 providing water to more than one residential dwelling unit,
18 including a duplex or to a factory, office building,
19 restaurant, school, or similar facility, but does not include a
20 system serving only one single family residence.
21 And the regulation section advises that this definition
22 is consistent with the EPA definition under the Safe Drinking
23 Water Act.
24 On page 139, there's a new definition of tour, which I
25 understand is an industry term of art.

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1 And on page 140, a definition of working day, there are
2 still a few places in the regs that refer to working day, and
3 that's generally in the context of the next working day.
4 And that looks like it. If the commissioners have any
5 questions, I'll try and answer them.
6 CHAIRMAN CHRISTENSON: David, do you have any
7 questions?
8 COMMISSIONER JOHNSTON: I don't believe so although I
9 think we may want to take a look at the language on page 86.
10 The paragraph that says, this section does not apply to
11 underground disposal that is regulated under the federal
12 register there, what happens in a situation -- I mean would
13 that -- would this remove authority from us if, say, a federal
14 well, a Class I well, was injecting and it was determined to be
15 contaminating fresh water, would this preclude the Commission
16 from taking any action to step in and remedy that solution or
17 that problem?
18 MR. MINTZ: Well, this -- it would preclude the
19 Commission from acting under that section. If there is some
20 other authority that the Commission has, it wouldn't affect
21 that. I mean there is some question of federal preemption in
22 the area of underground injection. And the citation there in
23 subsection (l) is actually the description of the underground
24 injection program in Alaska.
25 COMMISSIONER JOHNSTON: Right.

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1 MR. MINTZ: And, of course, the Class II program is
2 administered by the Commission and all the others are
3 administered by EPA. Now -- so leaving aside whatever federal
4 preemption issues there might be, that if there is some other
5 source of authority for the Commission to take enforcement
6 action or to take some response to underground contamination
7 from an unregulated well, then that wouldn't affect that
8 authority. It does say that anything in this section,
9 Section 252, doesn't apply. But I mean this section basically
10 has to do with authorizations and how you go about authorizing
11 injection. And so that really wouldn't be applicable anyway.
12 COMMISSIONER OECHSLI: I think there's some subsections
13 that do deal with monitoring and reporting requirements.
14 MR. MINTZ: Right, but that's for Class II wells.
15 COMMISSIONER OECHSLI: When that first sentence that
16 was deleted was inserted, the situation that we were trying to
17 avoid was in a case where -- maybe this is going to affect us
18 while we're in transition with respect to wells that are
19 permitted both as Class I and Class II. But what was happening
20 was an operator was questioned about whether or not under their
21 Class I permit, they needed to also file an application under
22 this because this doesn't say any place on its face that it has
23 to do with Class II, it just says if you want to dispose under
24 ground, you've got to get permission from us. So what we were
25 trying to avoid was a situation where an operator would be

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1 perceived as violating some state requirement that they have to
2 get an application from us. But as I understand it, the
3 reporting obligations are going both ways, both to the state
4 and the federal government with respect to mechanical
5 integrity. In fact, I believe it's the state that's doing
6 those mechanical integrity tests, the witnessing of those
7 tests.
8 MR. MINTZ: Well, I mean if that's true, I assume that
9 must be by agreement between EPA and the Commission. But I
10 mean the Commission is not regulating Class I wells. I
11 mean.....
12 COMMISSIONER OECHSLI: So then to the extent that any
13 of these reporting requirements the state would want to keep
14 enforced, it would be done through that agreement with the
15 federal government?
16 MR. MINTZ: Correct.
17 COMMISSIONER OECHSLI: Okay. Does that answer your
18 questions?
19 COMMISSIONER JOHNSTON: The citation 40 C.F.R. 147.101,
20 that is the Alaska program.
21 MR. MINTZ: Yes. And the Alaska program basically has
22 two parts. One is Class II.....
23 COMMISSIONER JOHNSTON: That we regulate.
24 MR. MINTZ: Right.
25 COMMISSIONER JOHNSTON: So that's the distinction

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1 then.....
2 MR. MINTZ: Yes.
3 COMMISSIONER JOHNSTON: .....is that really this is
4 kind of pointing to paragraph (B) then of that -- when you
5 say.....
6 MR. MINTZ: Well, the operator.....
7 COMMISSIONER JOHNSTON: .....regulated by the
8 environmental.....
9 MR. MINTZ: Yeah.
10 COMMISSIONER JOHNSTON: .....that really says paragraph
11 (B), not paragraph (A).
12 MR. MINTZ: Right.
13 COMMISSIONER JOHNSTON: Okay.
14 COMMISSIONER OECHSLI: I think that was the only
15 question I had.
16 COMMISSIONER JOHNSTON: Yeah.
17 MR. MINTZ: On the observation that the definition of
18 AP 2 -- API 2K might not be needed, I think it might be most
19 efficient if I took a short break and checked with the
20 Regulation Section to see what to do on this because we can't
21 be 100 percent sure that there's no reference to 2K left
22 without going through it. And I think the solution is going to
23 be to adopt the regs as is, and then the Regulation Section has
24 the authority to delete that definition if it's no longer
25 needed.

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1 COMMISSIONER JOHNSTON: It's no longer needed.
2 MR. MINTZ: But I want to check on that.
3 COMMISSIONER JOHNSTON: Okay.
4 MR. MINTZ: So, Mr. Chairman, would it be okay to take
5 a short break again?
6 CHAIRMAN CHRISTENSON: All right. We can go off
7 record.
8 (Off record)
9 (On record)
10 CHAIRMAN CHRISTENSON: Any further comments from Dave
11 and Cammi?
12 COMMISSIONER OECHSLI: I have one more.....
13 CHAIRMAN CHRISTENSON: Questions?
14 COMMISSIONER OECHSLI: .....question for Rob. In a
15 number of places for what appears to be for consistency, the
16 regulations attorney changed the wording on documents or
17 reports that get filed to us, and they changed the wording
18 from, filed with, to, submitted to. Do you know why that
19 change was made, and was there any intent to change how it's
20 being handled currently?
21 MR. MINTZ: Well, it's not intended to change anything
22 substantively. I think it was made -- I think that previously
23 there was basically some inconsistency that sometimes it said
24 file, sometimes it said submitted, and now it says submitted
25 all the time basically.

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1 CHAIRMAN CHRISTENSON: Rob, did you have an opportunity
2 to get the answer to the question?
3 MR. MINTZ: Yes. I'm advised that if the Commission
4 adopts the regulations with the current definitions including
5 the definition of API 2K and then it turns out that that
6 definition is superfluous, that the Regulation Section can
7 delete the definition without further Commission action. So I
8 would recommend doing that.
9 CHAIRMAN CHRISTENSON: Okay. Thank you. Any further
10 comment, David, Cammi?
11 COMMISSIONER OECHSLI: Not from me.
12 COMMISSIONER JOHNSTON: No.
13 CHAIRMAN CHRISTENSON: Call for a motion.
14 COMMISSIONER JOHNSTON: Then, Mr. Chairman, I would
15 like to move that we adopt the proposed regulations with the
16 changes as reflected in the review by our fine attorney, Mr.
17 Mintz, this morning.
18 CHAIRMAN CHRISTENSON: Okay. Call for a vote.
19 COMMISSIONER JOHNSTON: I vote yes.
20 CHAIRMAN CHRISTENSON: Cammi?
21 COMMISSIONER OECHSLI: Yes.
22 CHAIRMAN CHRISTENSON: Yes? I vote yes. That's three
23 affirmative votes for adopting the regulations as presented by
24 Mr. Mintz this morning. So we'll set the wheels in motion to
25 get that done.

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1 With regard to comments from Mr. Worcester, I would
2 like to just mention that there's been a great deal of work
3 done by Mr. Mintz who we appreciate, and the reg attorney down
4 there in Juneau, as well as the commissioners, and certainly
5 recognition to Dave Johnston who has had this project going for
6 a long time and has done a whole lot of work. So I believe
7 that we've through the course of the year -- the many years
8 that we've had industry comment. We've had a lot of time to
9 find out what the views of industry are. We believe we've
10 protected those. So with all due respect, we thank the
11 industry and for all their work, and Mr. Johnston for his
12 outstanding work, as well as Attorney General Rob.
13 So with that, we are concluded.
14 (Off record 10:48 a.m.)
15 END OF PROCEEDINGS
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1 CERTIFICATE
2 UNITED STATES OF AMERICA)
)ss.
3 STATE OF ALASKA)
4 I, Laura Ferro, Notary Public in and for the State of
5 Alaska, and Reporter for Metro Court Reporting, do hereby
6 certify:
7 That the foregoing Alaska Oil & Gas Conservation
8 Commission Meeting was taken before myself on the 29th day of
9 September 1999, commencing at the hour of 9:06 o'clock a.m., at
10 the offices of Alaska Oil & Gas Conservation Commission, 3001
11 Porcupine Street, Anchorage, Alaska;
12 That the meeting was transcribed by myself to the best
13 of my knowledge and ability.
14 IN WITNESS WHEREOF, I have hereto set my hand and
15 affixed my seal this 4th day of October 1999.
16
17 _____
Notary Public in and for Alaska
My commission expires: 05/03/01
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1 ALASKA OIL AND GAS CONSERVATION COMMISSION
2 MEETING
3
In Re:)
4)
CHAPTER 25, ALASKA OIL AND GAS)
5 CONSERVATION COMMISSION REGULATION)
CHANGES AND REVISIONS.)
6)
7
TRANSCRIPT OF PROCEEDINGS
8
Anchorage, Alaska
9 April 6, 1999
9:00 o'clock a.m.
10
APPEARANCES:
11
Commissioners: MR. DAVID W. JOHNSTON, CHAIRMAN
12 MS. CAMILLE OECHSLI
MR. ROBERT CHRISTENSON
13
Attorney General's Office: MR. ROBERT E. MINTZ
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1 PROCEEDINGS
2 (On record - 9:05 a.m.)
3 CHAIRMAN JOHNSTON: I would like to call this meeting
4 to order. I would like to begin by noting that the date is
5 April the 6th, 1999. The time is approximately five after 9:00
6 o'clock. We are located in the offices of the Oil and Gas
7 Conservation Commission, and the head table consists of
8 Commissioners Johnston, Christenson, and Oechsli.
9 We are here today to consider some minor revisions to
10 our proposed regulations. Specifically, those changes have to
11 primarily deal with how we reference the Manual of Petroleum
12 Measurement Standards, and also how we are referencing the
13 various recommended practices put out by the API.
14 To begin with, the changes as I said are rather minor.
15 What we are doing with regard to the recommended practices is
16 to specifically reference the addition that we are referencing.
17 For example, the first change would be on page 44, and that is
18 with regard to paragraph B. We are referencing the API
19 recommended practice number 49, Recommended Practices for Safe
20 Drilling of Wells Containing Hydrogen Sulfide, and we are
21 referencing the second edition. And that is dated April 15th,
22 1987. Again, not a substantive change at all but more of a --
23 more specificity for the people reading these regulations.
24 The second change along those lines or slightly
25 different lines is the changes that are occurring on page 78.

1 This has to do with regard to the API Manual of Petroleum
2 Measurement Standards. What we'll be doing there is
3 referencing ent- -- instead of the entire document, the -- we
4 are referencing only relevant portions of that document. And
5 so on page 78, you will be seeing the words relevant portions
6 of the API Manual of Petroleum Measurement Standards.
7 MR. MINTZ: Excuse me. I think it says relevant parts.
8 CHAIRMAN JOHNSTON: Relevant parts. I'm sorry. Again,
9 that similar change would be appearing on page 79 in paragraph
10 (g) and (h). And then on page 80 paragraph (k), we defined
11 what those relevant parts are. And the relevant parts of the
12 Manual of Petroleum Measurement Standards would exclude Chapter
13 19 in its entirety as well as Chapter 11, except for the
14 following chapters, and that is Chapter 11.1 Volume 1; 11.1
15 Volume X; 11.2.1; 11.2.2; the Addendum to Section 2.2; and
16 finally Chapter 11.2.3.
17 Moving on then, on page 83, we are -- the change there
18 has to do with the code of federal registers. And
19 specifically, that change is to adopt that standard by
20 reference. On page 103, we will be referring to -- under 290,
21 we will be referring to the second addition of API RP 55
22 Recommended Practices for Oil and Gas Producing and Gas
23 Processing Plant Operations Involving Hydrogen Sulfide. So
24 again, insert the word second addition.
25 And then finally on page 121, you'll see a list of

1 recommended practices, and, again, throughout that list, we
2 will be referencing the specific addition. So no real change
3 because earlier we had referenced the date but we are now going
4 to reference the addition as well as the date. So beginning
5 with the first item there, API RP 5C7, Recommended Practices
6 for Coiled Tubing Operations and Oil and Gas Well Services,
7 insert first addition.
8 Number two, API RP 13B-1, Recommended Practice Standard
9 Procedure for Field Testing Water-Based Drilling Fluids, insert
10 second addition.
11 Number three, RP -- API RP 13 B-2, Recommended Practice
12 Standard Procedure for Field Testing Oil-Based Drilling Fluids,
13 insert third addition.
14 MR. MINTZ: This one, 13 B-2, actually does represent a
15 substantive change because the commission previously adopted
16 the second addition which was a 1991 document, and then it's
17 been discovered that just last year, February 1998, the third
18 addition came out.
19 CHAIRMAN JOHNSTON: Right. In reviewing those two
20 documents, they look almost identical though so I don't think
21 there is a serious change at all. Let's see. We were on,
22 what, item number three?
23 Number four, API RP 49, Recommended Practices for Safe
24 Drilling of Wells Containing Hydrogen Sulfide, insert second
25 addition.

1 Number five, API RP 53, Recommended Practices for
2 Blowout Prevention Equipment Systems for Drilling Wells, insert
3 third addition.
4 Number six, API RP 57, Recommended Practices for
5 Offshore Well Completion, Servicing, Workover, and Plug and
6 Abandonment Operations, insert first addition.
7 Number seven, API RP 64, Recommended Practices for
8 Diverter Systems Equipment and Operations, insert first
9 addition.
10 Number eight, API RP 68, Recommended Practice for Oil
11 and Gas Well Servicing and Workover Operations Involving
12 Hydrogen Sulfide, insert first addition.
13 And I believe with that, that pretty well takes care of
14 the changes that we have to consider this morning.
15 MR. MINTZ: There is one more set of changes at
16 subsection D of the same section, reference to the 30 CFR,
17 it -- of course it's implied that these are adopted by
18 reference but.....
19 CHAIRMAN JOHNSTON: Right.
20 MR. MINTZ: .....this is made specific now.
21 CHAIRMAN JOHNSTON: So insert again which are adopted
22 by reference.
23 Well, then I would like to then move that the
24 commission consider these and adopt these changes for
25 incorporation into our proposed regulations. Is there a

1 second?
2 COMMISSIONER OECHSLI: I have a question first. Back
3 to page 83. What was the change there again?
4 CHAIRMAN JOHNSTON: Where in paragraph (a), you notice
5 the third line from the bottom of the paragraph, we were
6 referring to the 40 CFR 144.6, we are inserting the words which
7 is adopted by reference.
8 Any further discussion?
9 COMMISSIONER CHRISTENSON: Do we want to recognize any
10 of those letters we got in or correspondence regarding these
11 things into the record?
12 CHAIRMAN JOHNSTON: I think at this time, the public
13 comment has officially ended and I don't think we can
14 officially recognize any more comments.
15 MR. MINTZ: That would be my advice, yeah, that the
16 commission could and should consider them in terms of possible
17 future recommended changes.
18 COMMISSIONER CHRISTENSON: Okay.
19 CHAIRMAN JOHNSTON: Any further discussion? Do we have
20 a second?
21 COMMISSIONER CHRISTENSON: Second.
22 CHAIRMAN JOHNSTON: Okay. Then I assume no objections
23 to incorporating these? If not, then I guess the commission
24 will then accept these proposed changes as articulated this
25 morning. So is there any other matters we need to discuss this

1 morning?
2 COMMISSIONER OECHSLI: I think I want to confirm that
3 we've just adopted all the changes as of this April 6th
4 copy.....
5 CHAIRMAN JOHNSTON: Right.
6 COMMISSIONER OECHSLI: .....draft of the regulations.
7 CHAIRMAN JOHNSTON: Okay, thank you. With that, then I
8 would like to adjourn this meeting. Thank you.
9 (Off record - 9:15 a.m.)
10 END OF PROCEEDINGS
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1 CERTIFICATE
2 UNITED STATES OF AMERICA)
)ss.
3 STATE OF ALASKA)
4 I, Cary Wells, Notary Public in and for the State of
5 Alaska, and Reporter for Metro Court Reporting, do hereby
6 certify:
7 That the foregoing Alaska Oil & Gas Conservation
8 Commission Hearing, was taken before Laura Ferro on the 6th day
9 of April 1999, commencing at the hour of 9:05 o'clock a.m., at
10 the offices of Alaska Oil & Gas Conservation Commission, 3001
11 Porcupine Street, Anchorage, Alaska;
12 That the hearing was transcribed by Laura Ferro to the
13 best of her knowledge and ability.
14 IN WITNESS WHEREOF, I have hereto set my hand and
15 affixed my seal this 8th day of April 1999.
16
17 _____
Notary Public in and for Alaska
My commission expires:
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1 ALASKA OIL AND GAS CONSERVATION COMMISSION
2 PUBLIC HEARING
3
In Re:)
4)
CHAPTER 25, ALASKA OIL AND GAS)
5 CONSERVATION COMMISSION REGULATION)
CHANGES AND REVISIONS.)
6)
7
TRANSCRIPT OF PROCEEDINGS
8
Anchorage, Alaska
9 December 30, 1998
9:00 o'clock a.m.
10
APPEARANCES:
11
Commissioners: MR. DAVID W. JOHNSTON, CHAIRMAN
12 MS. CAMILLE OECHSLI
MR. ROBERT CHRISTENSON
13
Attorney General's Office: MR. ROBERT E. MINTZ
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24 Alaska Oil & Gas Cons. Commission
25 Anchorage

1 P R O C E E D I N G S
2 (On record - 9:10 a.m.)
3 CHAIRMAN JOHNSTON: Good morning. I'd like to call
4 this meeting to session. I'd note the time is approximately
5 ten minutes after nine o'clock. The date is December 30th,
6 1998, and we are located in the offices of the Oil & Gas
7 Conservation Commission, located at 3001 Porcupine Drive,
8 Anchorage, Alaska. The head table consists of Commissioners
9 Johnston, Oechsli and Christenson. And before we proceed any
10 further, I would like to introduce our new chair, who happens
11 to be Bob Christenson, that was announced here this last week.
12 So it's my pleasure to inform the public here that we now have
13 a new chair. My term expired on the 28th of November, and so
14 Bob will be taking over from me.
15 The purpose of these proceedings this morning is to
16 allow the commission, the three of us, to deliberate to
17 consider adopting proposed regulations. There will be only
18 deliberations of the commission this morning. We will not be
19 taking testimony and testimony is not sought in this meeting.
20 We will be making a transcript of these proceedings today, so
21 if you wish to have a copy of that transcript, we'd ask that
22 you contact the court reporter directly to do so.
23 So with that brief introduction, I guess I'd like to
24 turn the table over to Mr. Mintz, who has a series of
25 proposed -- or revisions to the document that we ended up with

1 on, I guess it was, the -- December the 17th or 18th -- was
2 that the Wednesday?
3 MR. MINTZ: I guess it would've been the 16th.
4 CHAIRMAN JOHNSTON: I think the 16th, you're probably
5 right. So we ended up with a document on the 16th. I think
6 that document was distributed to members of the public, and we
7 have since had the opportunity to review that document. I know
8 I had several changes that I detected in the body of that
9 document that I relayed to Mr. Mintz. Mr. Mintz has
10 incorporated that in a new draft version. The version that we
11 are considering today will be dated December 30, 1998.
12 So, Mr. Mintz, if you would could kind of bring us up
13 to date between the version that was -- that we issued
14 following the meeting on December 16th with this newer version
15 that is dated December 30th, I'd appreciate that.
16 MR. MINTZ: Sure. Well, of course there are a number
17 of very technical changes, typo corrections and so forth,
18 indent corrections that I'm not going to take up your time
19 going over, and there are a few spelling -- misspellings that
20 had to be corrected. But let me just -- and there are some
21 internal cross-references that had to be corrected, and unless
22 you want me to detail those, I'll just pass those by.
23 In a number of cases in the regs the phrase "nominal
24 inside diameter" was used in reference to choke outlets, and
25 after discussions with you, you suggested that that be changed

1 to "nominal diameter."
2 CHAIRMAN JOHNSTON: Removing the word "inside."
3 MR. MINTZ: Right. So that's been done. There were --
4 at one of the previous meetings there was some repetition found
5 in the provisions for -- oh, remote controls of BOP equipment.
6 Sometimes there were three paragraphs that repeated what was in
7 two, and those changes were implemented. I think you
8 detected.....
9 CHAIRMAN JOHNSTON: Yes, and.....
10 MR. MINTZ: .....more examples.
11 CHAIRMAN JOHNSTON: .....maybe we can touch
12 specifically on those changes later on. I have a few last
13 minute changes I came up with in my review earlier this week.
14 MR. WONDZELL: David, I also have some, in most cases,
15 minor changes, but in particular on the coil tubing BOP
16 controls,.....
17 CHAIRMAN JOHNSTON: Okay. Why don't we.....
18 MR. WONDZELL: .....there's some things that came to my
19 attention.
20 CHAIRMAN JOHNSTON: Why don't we put those off to the
21 back burner right now and we'll get Rob to bring us up to date
22 with the draft of the -- we did the 30th.
23 MR. MINTZ: Well, in 033 H there's a reference to
24 formation competency, and I think there are different places in
25 the regs to competence and competence review, so I changed that

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1 to competence so it would be consistent. The dictionary shows
2 they mean the same thing. Okay, here's a substantive one. On
3 page 19, subsection (e) at the top of the page, we had
4 discussed this, it used to say -- it used to refer to open hole
5 drilling operations begin below the first casing, and you've
6 raised the question about whether that should be surface
7 casing, and I don't know whether you've had a chance to talk to
8 Blair about that, but I wanted to bring that up as a possible
9 issue.
10 CHAIRMAN JOHNSTON: There was a couple of proposals
11 that I thought could be useful. There's one suggestion that we
12 say "the first casing anchored in competent strata," my problem
13 with that though is that earlier we reference the conductor
14 casing supposedly being anchored in competent strata, and so
15 I'm not sure that that's what we want to say, that first casing
16 anchored in competent strata, if in fact the criteria of the
17 conductor casing is that it's not anchored in competent strata.
18 So I think, you know, looking at both sides of it, it seems
19 like the surface casing, if you look at our definition of
20 surface casing we say that that is the first string of casing
21 which the BOP needs to be hung off. The conductor casing is
22 optional. You can or -- you may or may not, depending on your
23 own proposal, you know, that you advance to the commission, put
24 the BOP on the conductor casing. But in all cases we want it
25 on the surface casing.

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1 MR. WONDZELL: Conductor casing is virtually never
2 anchored in competent formation, it is set normally at two
3 joints below ground level and into the gravel so that fluids
4 can circulate back to the surface while you're drilling for
5 your surface casing. So.....
6 CHAIRMAN JOHNSTON: Well, for example, Blair,.....
7 MR. WONDZELL: .....the first casing anchored in
8 competent formation is correct.
9 CHAIRMAN JOHNSTON: For example, in -- if you look just
10 immediately above this paragraph E, in paragraph D we say "if
11 formation competence at the structural casing setting depth is
12 not adequate..." you know, so we refer to the fact that
13 structural and conductor needs to be set in competent casing --
14 or strata. And that theme kind of appears under conductor
15 casing as well. So -- but again if you look at the definition
16 of surface casing, it says that that is the string that you
17 must have BOPs on.
18 MR. WONDZELL: That's correct. And in the case of
19 McArthur River there's a casing string above it that's required
20 that must also have BOPs put in it.
21 CHAIRMAN JOHNSTON: But that was not in my conservation
22 order, I'd suspect then.
23 MR. WONDZELL: Uh-huh.
24 CHAIRMAN JOHNSTON: Okay.
25 MR. WONDZELL: But it was a competent -- competent

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1 string.....
2 CHAIRMAN JOHNSTON: Yeah, I understand.....
3 MR. WONDZELL: .....conductor casing's are not normally
4 intended to be competent;.....
5 CHAIRMAN JOHNSTON: But my.....
6 MR. WONDZELL: .....they can be driven, they can be
7 drilled, they can be jetted, they can be cemented, they can be
8 foamed. And.....
9 CHAIRMAN JOHNSTON: Okay. Well, my point is that it
10 seemed to me to remove any confusion as to when the BOP is
11 needed to be put on, and that is when you dropped below the
12 surface casing, you have to have your BOPs. Above that, it's
13 kind of discretionary, and it may -- and in fact in some cases
14 we may elect to require the BOP earlier, but we'd probably do
15 that by conservation order. So, I was just trying to remove
16 confusion there.
17 MR. MINTZ: Okay. On page 22, the very top line, it
18 used to say, "the outermost valve..." I thought it probably is
19 sufficient to say the "outer valve."
20 MR. WONDZELL: That's better.
21 MR. MINTZ: And then (iv), small 4 -- (H) (iv), a
22 bypass line, Dave suggested adding at least the diameter of the
23 choke line. Is that.....
24 MR. WONDZELL: Uh-huh.
25 MR. MINTZ: Okay. Then on page 28, new subparagraph

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1 (C) is added, a fire wall. I guess that was in 035, but was
2 not previously in 036.
3 CHAIRMAN JOHNSTON: Right.
4 MR. MINTZ: And subparagraph (F) has been reworded to
5 make it more consistent with the wording in 035. Actually I
6 can't remember. Maybe you can explain that.
7 CHAIRMAN JOHNSTON: Yeah. What we had here in the
8 earlier version, we had two paragraphs devoted to the choke and
9 kill line as to where it is connected, and in looking at that
10 we determined that in fact the only difference between those
11 two paragraphs were in paragraph one, you talked about
12 connecting to a drilling spool or BOP body, in paragraph two
13 you talked about connecting to the tree. The rest of the
14 specific criteria under both of those paragraphs were in fact
15 the same. So it appeared to me for -- you know, for the sake
16 of saving words, that to come up with a -- to combine the two
17 proposed -- or the two paragraphs as one and just say
18 "connected to flange outlets on a drilling spool the BOP body
19 or the tree," depending on what you have, is the criteria that
20 we want to indicate. So to streamline that provision we just
21 -- from two paragraphs to one, basically.
22 MR. MINTZ: At the bottom of the page, (H), Roman
23 Numeral (i), the phrase, "if the required BOPE stack is 5000
24 psig or greater" is added. Again, I don't remember, but I
25 think that's to make it consistent with the requirement in 035.

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1 CHAIRMAN CHRISTENSON: That's right. Yeah, that
2 provision was in 035, it appeared that it should be -- it
3 should apply to 036 as well.
4 MR. MINTZ: Then on the next page 29, I think you
5 noticed that what used to be subparagraph (H) kind of repeated
6 what was already in some other provision. Paragraph (H) which
7 is no longer -- well, it used -- it would be paragraph (I) now,
8 said "if pressure deployment of tools, tubing liner and casing
9 as planned in underbounds drilling operation, a riser or
10 lubricator the size of the BHA..." etcetera. Where was that --
11 oh yeah, that was back in the earlier provisions.
12 CHAIRMAN JOHNSTON: Essentially we had two paragraphs
13 that said the same thing in that section, so we just struck the
14 second paragraph there,.....
15 MR. MINTZ: Right.
16 CHAIRMAN JOHNSTON: .....but it was almost
17 word-for-word.
18 MR. MINTZ: Then still on page 29, paragraph (8), we
19 clarified the language, it used to say, "at least one positive
20 seal manual valve or hydraulic valve," and you said what we're
21 really trying to say is: "...at least one positive seal manual
22 or hydraulic valve."
23 CHAIRMAN JOHNSTON: And that change needs to be done
24 elsewhere on this document too. We need to go back and do kind
25 of a global search on it. What it used to say is: one

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1 positive seal manual valve, comma, hydraulic valve or BOP
2 ramps, and it appears to me that the adjective that we wanted
3 to modify both valves with was the one positive seal. So now
4 we've changed to one positive seal manual or hydraulic valve
5 BOP ramps, etcetera.
6 MR. MINTZ: Do you know where the other instances are?
7 CHAIRMAN JOHNSTON: I have it marked in the older
8 versions of the document, I don't know what pages it would be
9 on this particular one, but we can get close.
10 MR. MINTZ: If you have it marked on the 12-28 version
11 it's almost identical.
12 CHAIRMAN JOHNSTON: I do have it marked on that.
13 MR. MINTZ: So you'll bring that up when we get to
14 that?
15 CHAIRMAN JOHNSTON: Right. As soon as you get done, I
16 can jump in and do a couple of changes as well.
17 MR. MINTZ: Well, back on 033 -- or not.....
18 CHAIRMAN JOHNSTON: The page number?
19 MR. MINTZ: Well, actually -- I'm sorry, I'll find
20 that. Before we get to that I was told by the Juneau office
21 that any time there's an abbreviation basically we need to
22 define it. So if you turn to the definitions in the back, I
23 wanted to point out the new abbreviations, make sure that
24 they're correct. The first one is number (4) on page 116, API
25 2M, followed by API 5M, number (5).

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1 CHAIRMAN JOHNSTON: Okay.
2 MR. MINTZ: Does that look right? It will work. Okay.
3 And number (8), barrel, the definition used to say barrel
4 included stock tank barrel, and then goes on to say what it
5 means, and I have a separate definition for stock tank barrel
6 later. So we don't need that other phrase in there.
7 I think the next new one.....
8 MR. WONDZELL: Well, under (8) I have.....
9 CHAIRMAN JOHNSTON: Under what please, (8)?
10 MR. WONDZELL: If you're going to define stock tank
11 barrel at standard conditions then you don't need the standard
12 conditions in the barrel under (8).
13 MR. MINTZ: Well, actually, if you look at page 121,
14 (62), I just defined stock tank barrel as barrel for purposes
15 of these regulations, which I think is correct.
16 MR. WONDZELL: Yeah, but you defined barrel up here as
17 a standard barrel.
18 MR. MINTZ: Yeah. Isn't that how it's used in the
19 regs?
20 MR. WONDZELL: Frankly, I'd have to do a search on
21 that. I'm not too sure of that.
22 MR. MINTZ: Okay.
23 MR. WONDZELL: But barrel means -- it has lots of
24 different definitions, and also reservoir barrels.
25 MR. MINTZ: I mean I didn't change that. That -- the

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1 only thing I did was.....
2 MR. WONDZELL: My best suggestion would be to just
3 leave barrel at 42 US gallons, which is what it is, and then
4 move the standard condition back to the stock tank barrel.
5 MR. MINTZ: I see.
6 MR. WONDZELL: That would be more accurate and more
7 consistent with what most of us do.
8 MR. MINTZ: Uh-huh, okay.
9 MR. WONDZELL: A barrel is just 42 gallons, period.
10 MR. MINTZ: Okay. So we just -- 42 US gallons. And
11 then back on number (62), stock tank barrel means -- and then
12 take what's currently the definition of barrel?
13 MR. WONDZELL: Yeah.
14 MR. MINTZ: 42.....
15 MR. WONDZELL: Is what you've defined there really as a
16 stock tank barrel.
17 MR. MINTZ: Okay, good.
18 CHAIRMAN JOHNSTON: So stock tank barrel would be --
19 means barrel at -- measured at 60 Fahrenheit, then 14.65 psia?
20 MR. WONDZELL: That's correct.
21 CHAIRMAN JOHNSTON: Is that what you were going to say?
22 MR. MINTZ: Yes. Okay.
23 CHAIRMAN JOHNSTON: I assume that we -- I mean how far
24 do you take this -- these abbreviations? Do we have to
25 abbreviate F.....

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1 MR. MINTZ: No.
2 COMMISSIONER JOHNSTON: .....or define F?
3 MR. MINTZ: No.
4 CHAIRMAN JOHNSTON: Okay. And psia?
5 MR. MINTZ: Yes.
6 CHAIRMAN JOHNSTON: We do, okay.
7 MR. MINTZ: So and then the next, I think, is (38) on
8 page 119, mg/l means milligrams per liter. mscf means thousand
9 standard cubic feet. At the top of page 120, ppm means parts
10 per million. Then down in the middle, psi means pounds per
11 square inch; psia means pounds per square inch absolute; psig
12 means pounds per square inch gauge, which I originally typed as
13 guage (ph). Number (56), scf means standard cubic feet. Then
14 on page 121, standard cubic foot has the meaning given to cubic
15 foot in AS 31.05.170 which basically uses the standard
16 conditions. stb means stock tank barrel, and then stock tank
17 barrel, as we just described that.
18 CHAIRMAN JOHNSTON: Right. So does that take care of
19 everything you wanted to cover?
20 MR. MINTZ: No, not quite.
21 CHAIRMAN JOHNSTON: Okay. Because I think there's a
22 couple of earlier changes that we need to cover too.
23 MR. MINTZ: Okay, on page 13 there's a suggestion to
24 change the word, this is (c)(1) to change the word
25 "audio-warning devices" to "audible warning devices." And on

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1 page 29, (iii) and (iv) used to say -- it used to refer to
2 requiring a BOP stack of up to API 5M, and I guess there is an
3 ambiguity about whether that is up to and including, up to and
4 not including. But -- so I changed it to the language that's
5 used basically everywhere else, the same type of phrase, API 5M
6 BOP stack or less, and then greater than an API 5M BOP stack,
7 and then the same in number (4).
8 CHAIRMAN JOHNSTON: Anything else?
9 MR. MINTZ: Yeah. Page 79, at the top, this is
10 referring to the filing requirements at the completion of a
11 workover or a repair operation. And in the second line where I
12 changed the phrase to "as described" in 20 AAC 25.070(3), it
13 used to say "in accordance with..." But since 25.070 really
14 talks about filing requirements that apply after abandonment or
15 completion, it was ambiguous as to whether this was really
16 doing anything, so now it just says that the summary of daily
17 well operations as described in 070(3) is what's required to be
18 filed.
19 Okay. I think that covers the changes that are in
20 there. There are a few other issues that have been raised that
21 I haven't reflected any changes.
22 CHAIRMAN JOHNSTON: We talked about a couple of other
23 changes that you did not present this morning, and I dial
24 everybody in on those right now. But if we look at page 15,
25 paragraph (g), we reworded paragraph (g). We haven't really

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1 changed the meaning of it at all, but we've done a rewording on
2 it, and I think it used to say "a drilling fluid return sample
3 must be taken and tested to determine density just before
4 tripping the drill pipe when drilling an exploratory or
5 stratigraphic well. We've moved the ...when drilling an
6 exploratory or stratigraphic test well... -- or when drilling a
7 development or service well when known hydrocarbon-bearing
8 strata are exposed to open hole the operator shall take a
9 drilling fluid return sample. So we just kind of rearranged
10 the paragraph to make sure that the sample was taken for both
11 of those cases. It was not clear in the earlier version.
12 And then briefly just a small change, I think it's
13 probably back on -- let's see if I can find it here, be on
14 probably about page 6, and that's at the top of the page,
15 paragraph (2), the last line -- or the second to the last line
16 on paragraph (2), we've inserted "...which must be submitted
17 within the commission's next three working days." The earlier
18 version said "...and submitted within the commission's next
19 three working days." So it was not clear as to whether the
20 signature or the name of the representative needed to be
21 submitted or was the sundry application by adding which "must
22 be submitted" modifies then the term "sundry application."
23 MR. WONDZELL: Is oral supposed to be better than
24 verbal?
25 CHAIRMAN JOHNSTON: Yes. Believe it or not.

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1 MR. WONDZELL: Difficult to believe.
2 CHAIRMAN JOHNSTON: Okay. Now there's a few changes
3 that I came across, and basically back in the workover sections
4 on the BOP requirements -- and they are very similar to some of
5 the earlier changes, but the first one I have was probably on
6 or near page 79. All right. And it's paragraph (c)(1) on 79,
7 and again it's that at least one positive seal manual valve,
8 hydraulic valve, what we need to do is scratch the first
9 "valve" and insert "or". So it should be one positive seal
10 manual or hydraulic valve or BOP bind ramp, etcetera.
11 Okay. Then on page 81, I believe it will be, paragraph
12 (8) on page 81 needs to be stricken. If you'd look up there
13 you will see that that is a repetition of paragraph (6). And
14 we had earlier debated that, I think, last Wednesday or
15 Wednesday two weeks ago, and we had deleted that repetitive
16 paragraph in earlier language having to do with the drilling
17 BOP requirements, and so we need to delete it here as well.
18 You know, I think the next change will be on the next
19 page, it would be -- let me see here, okay it was actually on
20 page 83, and I think I'll probably want to ask Blair about
21 this. But if you look at paragraph (D)(8), right at the top of
22 the page, Blair,.....
23 MR. WONDZELL: Okay.
24 CHAIRMAN JOHNSTON: .....we see a bypass line, and we
25 don't indicate the minimum size, and I was going to suggest

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1 that we insert the language "...at least two inches in nominal
2 diameter" which seems to -- made up with the reference that we
3 provide in earlier BOP descriptions having to do with coil
4 tubing work.
5 MR. WONDZELL: Yes. And that would work.
6 MR. MINTZ: Okay. So bypass line.....
7 CHAIRMAN JOHNSTON: Comma, at least two inches in
8 nominal diameter.
9 MR. MINTZ: Do the other ones say -- have a comma in
10 them?
11 CHAIRMAN JOHNSTON: Yes. So at least two inches in
12 nominal diameter. Okay, the next.....
13 MR. MINTZ: Well, wait, just before we leave that,
14 where it says BOP stack APF 5M or less, I think other places it
15 says -- it would say BOP -- no, it would say API 5M BOP stack
16 or less. Just to make that consistent.
17 CHAIRMAN JOHNSTON: Run that by us again?
18 MR. MINTZ: Other places it would say requiring.....
19 CHAIRMAN JOHNSTON: On paragraph (d)?
20 MR. MINTZ: Yes.
21 CHAIRMAN JOHNSTON: Okay.
22 MR. MINTZ: .....requiring an API 5M BOP stack or less.
23 CHAIRMAN JOHNSTON: Okay. So it should be API 5M.....
24 MR. MINTZ: BOP stack or less. And then it would say
25 at the end of the sentence, requiring greater -- or actually

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1 greater than an API 5M BOP stack.
2 CHAIRMAN JOHNSTON: Okay. And the next change I would
3 have is on page 85, and it would be paragraph (d)(1), and
4 again, scratch the first valve there and insert "or" so it's a
5 positive seal manual or hydraulic valve.
6 MR. MINTZ: So word that again? 85.....
7 CHAIRMAN JOHNSTON: Page 85,.....
8 MR. MINTZ: .....near the top under (d)(1)?
9 CHAIRMAN JOHNSTON: .....paragraph (d)(1). At least
10 one positive seal manual or hydraulic valve.
11 Okay. Then on page 86, and this would be a question
12 again for Blair, if you look on paragraph (4)(A) we talk about
13 the accumulator capacity, we say necessary to close all BOPs by
14 maintaining a minimum pressure. Elsewhere, Blair, when we read
15 that paragraph in our earlier BOP discussions, 036 and 035,
16 we -- after BOPs we have, "...except for blind rams."
17 MR. WONDZELL: That needs to be put in there.
18 MR. MINTZ: Were there commas in there earlier?
19 CHAIRMAN JOHNSTON: Yes.
20 MR. MINTZ: So it's necessary to close all BOPs, comma,
21 except for blind rams?
22 CHAIRMAN JOHNSTON: Right.
23 MR. MINTZ: Not just except, but except for?
24 CHAIRMAN JOHNSTON: "Except for blind rams." Okay.
25 Then on the next page 87, paragraph (e)(2), another question

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1 for you, Blair. If you look -- we're talking, after each
2 installation of BOPE or other well control equipment, the
3 equipment must be pressure-tested, should we insert the word
4 "function" before "pressure-tested" there?
5 MR. WONDZELL: I think -- let me see what section --
6 let me check and see what section we're in. What is being
7 tested here is a body test of the O-rings, and this happened to
8 be one of the ones that I wanted to refer to in a couple of
9 places which is after each installation, and this might be
10 multi-times in a day, so what you're really checking is the
11 seating of that O-ring to see that it holds pressure, and so
12 after each installation of BOP or other well control equipment
13 and before wellbore entry the equipment must be pressure-
14 tested, not to the required pressure but to the expected
15 wellbore pressure.
16 CHAIRMAN JOHNSTON: Okay. So in this particular
17 paragraph the idea of a function pressure-test would not be
18 appropriate?
19 MR. WONDZELL: That would not be appropriate. Let me
20 see what I have back here.
21 CHAIRMAN JOHNSTON: Okay. I just wanted to make
22 certain about that. And then I have that same question on the
23 next page, and it would be on (d)(2), and I suspect again that
24 you would be just doing the pressure-test, not a function
25 pressure-test.

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1 MR. WONDZELL: Well, on this one though, we wanted to
2 change this to the maximum expected wellhead pressure.....
3 CHAIRMAN JOHNSTON: Now backup, on which one?
4 MR. WONDZELL: Where you had it on 87.
5 CHAIRMAN JOHNSTON: So you're saying what?
6 MR. WONDZELL: where it says maximum potential surface
7 pressure, change that to maximum expected wellhead pressure.
8 Potential pressure would be assuming almost a blowout
9 condition; expected wellhead pressure would be that pressure
10 which would actually expect the equipment to seat, not that at
11 what it might see in a near blowout condition.
12 CHAIRMAN CHRISTENSON: Are you in paragraph (2), Blair?
13 MR. WONDZELL: I'm in paragraph (2) where it says,
14 potential -- to the maximum potential surface pressure to which
15 it may be subjected, should be changed to the maximum expected
16 wellhead pressure.
17 CHAIRMAN JOHNSTON: Before we make that change, let me
18 understand, because we had in earlier discussions debated the
19 use of the term "potential" when we talk about the pressure. I
20 mean we made a big deal of saying at one time we were talking
21 the anticipated pressure. I think we'd -- they were seeing
22 cases that there may have been some expected pressure in there
23 as well. But we had decided.....
24 MR. WONDZELL: Estimated too.
25 CHAIRMAN JOHNSTON: And estimated, right. But we

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1 decided to standardize throughout this document on potential
2 surface pressure.
3 MR. WONDZELL: Well, there are two different concepts
4 here. When you're testing putting in your BOP equipment, you
5 want to put the BOP equipment and do your initial test to the
6 maximum pressure that it may be exposed. That would be
7 assuming a blowout condition. In this case you've got tested
8 -- done a full test on your BOP equipment, you've broken one
9 connection, put your tools inside the lubricator, you make that
10 one connection up. What you're going to test it to, and the
11 easy thing to test it to and it's most often done is they
12 simply test it to the pressure that's in the well at that point
13 at that time. Unless, of course, they think that after they
14 perforated the pressure is going to be higher. So in the one
15 case you size your BOPs and you do your basic test to the
16 maximum potential pressure.....
17 CHAIRMAN JOHNSTON: Okay, so that.....
18 MR. WONDZELL: .....that you might get at the surface
19 -- so there are two different concepts here.
20 CHAIRMAN JOHNSTON: And that would be the concept that
21 you would be doing in paragraph (e)(1)?
22 MR. WONDZELL: That is correct.
23 CHAIRMAN JOHNSTON: Right, you would test to the
24 maximum potential pressure.
25 MR. WONDZELL: Exactly.

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1 CHAIRMAN JOHNSTON: In paragraph (e)(2) what you want
2 to do is test to the pressure that you currently have.
3 MR. WONDZELL: You would expect it to be on it during
4 that use, and they are two different concepts.
5 COMMISSIONER OECHSLI: So on the older version I think
6 we'd written to the maximum anticipated wellhead pressure.
7 That's -- what was your suggestion, Blair, expected?
8 MR. WONDZELL: Expected.
9 CHAIRMAN JOHNSTON: Expected. Now.....
10 MR. WONDZELL: And what the concept there is is what
11 you actually expect that connection to see during -- until you
12 re-break it again, really.
13 CHAIRMAN JOHNSTON: Okay, but now let's look earlier in
14 this paragraph we say must be pressure-tested to the required
15 working pressure showing in the approved Application for Sundry
16 Approvals, or in its absence to the maximum -- now we're in
17 certain expected.
18 MR. WONDZELL: Not in (2), are we?
19 CHAIRMAN JOHNSTON: In (e)(2).
20 MR. WONDZELL: Oh, we want to take out a chunk in here.
21 I'm sorry. Tested to the -- I did this incompletely. I want
22 to take out the reference to the Application for Sundry
23 Approval, tested to the maximum expected wellhead pressure.
24 CHAIRMAN JOHNSTON: So we should scratch in paragraph
25 (e)(2) the phrase, to the required working pressure shown in an

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1 approved Application for Sundry Approvals or in its absence?
2 MR. WONDZELL: That is correct.
3 CHAIRMAN JOHNSTON: Now the paragraph will then read:
4 Must be pressure-tested to the maximum expected surface
5 pressure to which it may be subjected.
6 CHAIRMAN CHRISTENSON: Actually, Blair said wellhead
7 pressure was --.....
8 MR. WONDZELL: Wellhead pressure would -- yeah,
9 probably wellhead pressure would get the meaning across.
10 CHAIRMAN JOHNSTON: Maximum expected.....
11 MR. WONDZELL: .....and a little more convenient.
12 CHAIRMAN JOHNSTON: .....wellhead. Okay. Now with
13 that in mind, turn the page and look at (d)(2). And I assume
14 that in (d)(2) you want to make the same change.
15 MR. WONDZELL: The page numbers are different between
16 this one, so I'm having to take just a little bit longer to
17 match up here.
18 CHAIRMAN JOHNSTON: Now we're under 287, well control
19 equipment for wireline operations. It's paragraph (d)(2).
20 MR. WONDZELL: I'm sorry, I'm back looking at it. The
21 figures are not matching very well -- yes, very definitely.
22 CHAIRMAN JOHNSTON: So paragraph (d)(2) then would
23 read, after each installation of the wellhead control equipment
24 it must be pressure-tested before wellbore entry, and scratch
25 to the required working pressure showing on the approved

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1 Application for Sundry Approvals or in its absence, and then to
2 the maximum expected wellhead pressure. Right?
3 MR. WONDZELL: Yes.
4 MR. MINTZ: Well,.....
5 CHAIRMAN JOHNSTON: To which it may be subjected.
6 MR. MINTZ: Yeah, I -- just some suggestion that we
7 make a slight change in the language on (e)(2) on the previous
8 page just to make it parallel. Where it says, "...and before
9 wellbore entry...", to put that "after pressure-tested," just
10 let -- just as it's in there.
11 MR. WONDZELL: Yes, uh-huh.
12 MR. MINTZ: Pressure-tested, comma, before wellbore
13 entry.
14 MR. WONDZELL: Sure, and after wellbore entry or before
15 wellbore entry.
16 CHAIRMAN JOHNSTON: So that after each installation of
17 BOPE or other well control equipment,.....
18 MR. MINTZ: Comma.
19 CHAIRMAN JOHNSTON: .....comma, the equipment must be
20 pressure-tested before wellbore entry.
21 MR. WONDZELL: Uh-huh.
22 CHAIRMAN JOHNSTON: Okay. Now given those changes do
23 we need to go back and look at 025 and 036 then?
24 MR. WONDZELL: Well, those have to do with a different
25 type of operation, and I didn't specifically check them, but I

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1 don't think they automatically have to be changed as well.
2 Certainly not in 035.
3 CHAIRMAN JOHNSTON: You might look on page 30, for
4 example. This is on 036. Probably near 30, anyway. Yeah.
5 This is on 036, the coil tubing stuff, I believe. For example,
6 (d)(2). Take a look at (d)(2) on page 30.
7 MR. WONDZELL: Okay.
8 CHAIRMAN JOHNSTON: Are you working on the 12-30 draft?
9 MR. WONDZELL: I have that here, but I have a different
10 draft version.
11 CHAIRMAN JOHNSTON: Yeah. I have three versions so I
12 appreciate the confusion. Okay, (d)(2), other well control
13 equipment must be pressure-tested to the required working
14 pressure specified in the approved permit to the drill after
15 each -- is that what we want to say there? I think there's a
16 clear distinction between, you know, these wire line and
17 service operations versus drilling. It appears to me that the
18 pressure-test here ought to be to the higher pressure, I would
19 think.
20 MR. WONDZELL: Let me catch up here. Yes, we thought
21 the same change -- we think the same change needs to be made
22 there.
23 CHAIRMAN JOHNSTON: So under (d)(2).....
24 MR. WONDZELL: I would add Rob's words, before wellbore
25 entry. Again, this is where you're just trying to test the one

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1 break that you've made in the system to get your bottomhole
2 assembly up inside to lubricate it.
3 CHAIRMAN JOHNSTON: Okay. What change did you think
4 needs to be made?
5 MR. WONDZELL: Oh, under (2), other well control
6 equipment must be pressure-tested to the maximum expected
7 wellhead pressure after each installation and before wellbore
8 entry. That's down below, isn't it -- you can sort that out
9 like the other ones, but taking out the words "required working
10 pressure specified in the approved permit to drill after each
11 installation" and substituting "the maximum expected wellhead
12 pressure after each installation."
13 MR. MINTZ: Blair, just so I can understand this
14 better, why wouldn't you want to pressure-test it to the
15 required working pressure?
16 MR. WONDZELL: The reason that you -- when you put on
17 your BOPs and you test them you make sure that everything works
18 well, but during the day when you're using a lubricator, you
19 break one connection and you insert tools and then you make
20 that connection back up, all you're checking to see, you're
21 doing a body test now, you're checking to see if that
22 connection holds pressure, see that the -- frankly, if somebody
23 put the O-ring in it, if it's not cross-threaded or the O-ring
24 is not crossed. And what you end up doing in most cases is
25 testing it to the wellbore pressure that exists in the tree

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1 under most operations. Very easy to do.
2 MR. MINTZ: And it's harder to test it to the required
3 working pressure?
4 MR. WONDZELL: Absolutely. And it is much less apt to
5 get tested that way.
6 MR. MINTZ: Okay. Pressure-test it to the maximum
7 expected wellhead pressure?
8 MR. WONDZELL: Right. And in most cases what's done in
9 practice is they simply open the master valve and let the
10 pressure up to whatever pressure happens to be on the tree.
11 CHAIRMAN JOHNSTON: So then you want to keep the --
12 after each installation of the wellhead -- well control
13 equipment though, right?
14 MR. WONDZELL: Yes.
15 CHAIRMAN JOHNSTON: Okay. So the only thing we're
16 doing is deleting "to the required working pressure specified
17 in the approved permit to drill" and substituting "to the
18 maximum expected wellhead pressure"?
19 MR. WONDZELL: That's correct.
20 CHAIRMAN JOHNSTON: And you don't see any need to
21 change anything in the -- in 035?
22 MR. WONDZELL: No.
23 CHAIRMAN JOHNSTON: Okay. Making this change here and
24 elsewhere appears to make then the pressure-testing consistent
25 throughout, that if you're engaged in pressure-testing, what

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1 you have described as a body test, you're only testing to the
2 maximum expected wellhead pressure, and that theme is carried
3 throughout in each section regardless of whether it's in
4 drilling here or in workover.
5 MR. WONDZELL: Right. The coil tubing or -- the coil
6 tubing or wireline operations we're using a lubricator where it
7 comes into play.
8 CHAIRMAN JOHNSTON: Right. That takes care of the
9 changes that I had come across earlier this week in reviewing
10 this document. Blair, you said you had some additional points
11 that you wanted to bring up?
12 MR. WONDZELL: Sure do. Unfortunately, the draft I
13 worked on is quite a few pages.....
14 CHAIRMAN JOHNSTON: What?
15 MR. WONDZELL: Unfortunately, the draft I worked on is
16 quite a few pages.....
17 CHAIRMAN JOHNSTON: Yeah, I know.
18 MR. WONDZELL: .....and it's a little bit of trouble
19 matching them.
20 CHAIRMAN JOHNSTON: It's going to be -- you're working
21 on that version that we distributed.....
22 MR. WONDZELL: E-mail.....
23 COMMISSIONER JOHNSTON: .....two weeks ago?
24 MR. WONDZELL: Yes.
25 CHAIRMAN JOHNSTON: Right. What section are you first

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1 talking about?
2 MR. WONDZELL: Let's see, page 14 on the 30 draft.
3 CHAIRMAN JOHNSTON: Page 14 on the earlier draft?
4 MR. WONDZELL: Yes -- no, on the 30 draft, the 12-30-98
5 draft.
6 CHAIRMAN JOHNSTON: Okay.
7 MR. WONDZELL: I do have a few page numbers for
8 cross-correlation, but not many.
9 MR. MINTZ: 14?
10 MR. WONDZELL: Page 14. Up near the top, under
11 equipment.
12 CHAIRMAN JOHNSTON: What paragraph?
13 MR. WONDZELL: On the top of page 14, and it's number
14 (4) up there. It says, equipment to keep the drilling mud
15 condition as appropriate for drilling operations being
16 conducted, and the thought here is that you may not be able to
17 do it exactly, so you want to put in some words to come as
18 close as practical. For example, if you're bringing -- if
19 you're getting water in out of the formation or something like
20 this, you can't exactly keep them in compliance with designated
21 fluid requirements, so some words like this would work:
22 Equipment to, comma, as practical as possible, comma, keep the
23 drilling mud condition as appropriate for the drilling
24 operation being conducted. Just acknowledging that you can't
25 get there all the time.

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1 CHAIRMAN CHRISTENSON: So we're talking about being as
2 close to an ideal here as possible?
3 CHAIRMAN JOHNSTON: Right.
4 CHAIRMAN CHRISTENSEN: But not being on the ideal?
5 MR. WONDZELL: As practical as possible, yeah.
6 MR. MINTZ: But isn't that implied and appropriate?
7 MR. WONDZELL: I don't know the answer to that. Well,
8 it's appropriate for the drilling operations. I think "as
9 practical as possible" certainly gives the impression that it's
10 recognizing that you can't do that absolutely.
11 CHAIRMAN JOHNSTON: So, Rob, what about language?
12 MR. MINTZ: Well, maybe when we have a break I.....
13 COMMISSIONER OECHSLI: I have a question.
14 MR. MINTZ: .....could work on some language there.
15 CHAIRMAN JOHNSTON: Okay.
16 COMMISSIONER OECHSLI: Well, I guess I have a question
17 though about what we're trying to capture. Are we trying to
18 capture what equipment is necessary when you plan, when you
19 begin the operation or something that happens subsequent to
20 your starting the operation and conditions change? In other
21 words, if you go in expecting certain conditions are you
22 expected to have the equipment that's appropriate for those
23 conditions or are you saying that it's okay at the beginning to
24 have equipment that's not quite exactly right but close?
25 MR. WONDZELL: What we're saying is that you can't

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1 necessarily get the equipment to keep the mud exactly where you
2 want it.
3 CHAIRMAN JOHNSTON: Well, but I think, Cammie, you
4 bring up a good point. This paragraph merely is describing the
5 nature of the equipment that you bring onsite before you drill
6 that well, and so you need to have equipment to keep the
7 drilling mud conditions as appropriate. Now whether you
8 actually get there or not is a different matter, but you need
9 the equipment. I think you're more concerned about when you're
10 actually drilling whether you acquire that. That's a different
11 thing.
12 MR. MINTZ: That's correct.
13 CHAIRMAN JOHNSTON: This is before the operation. This
14 is before drilling. And you're saying the nature of the
15 equipment that you bring to the site needs to do these things,
16 and one of the things that we need to do is to make sure that
17 you are conditioning your drilling mud as appropriate for the
18 program being conducted. So I think it works here. Now, in
19 implementing it, I agree with you, Blair, that we can only
20 implement it in terms of what is practical.
21 MR. WONDZELL: Okay, next suggestion. What page are we
22 on here. Well, it's page 24 of the edition that we worked on.
23 CHAIRMAN JOHNSTON: Page 24 of the earlier edition you
24 say?
25 MR. WONDZELL: Yes, uh-huh.

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1 CHAIRMAN JOHNSTON: That might be on page 21 of the new
2 edition.
3 MR. WONDZELL: Yes, it is. Okay. What I've since
4 found out, and I wasn't there when I had some hand in doing
5 this before, is that a lot of coil tubing units do not have
6 controls at the accumulator. The only controls that they have
7 are the remote controls. So better language would be, instead
8 of (D) and (E), take (D) and (E) out, would be "one complete
9 set of operable remote BOP controls on or near the driller or
10 operator's console and, if not in close proximity, the drilling
11 platform. I could make a copy of this as you read this.
12 CHAIRMAN JOHNSTON: Blair, why don't we go ahead and
13 just discuss it right now. What we'll probably do is take a
14 break and work on specific language.
15 MR. WONDZELL: Okay.
16 CHAIRMAN JOHNSTON: Because at the end of the day we've
17 got to have actual specific language that we want to endorse.
18 MR. WONDZELL: Okay. Well, the concept here is that we
19 don't have controls at the accumulator on most coil tubing
20 rigs. So the only controls that you can have are the remote
21 set, and if those need to be at or near the driller or
22 operator's console -- and it's just a re-write of (D) and (E).
23 Would you want me to read that again?
24 CHAIRMAN JOHNSTON: Yeah, go ahead and run it by us
25 again.

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1 MR. WONDZELL: Okay. One complete set of operable
2 remote BOPE controls on or near the driller's or operator's
3 console and, little (i), if not in close proximity to the
4 drilling platform floor for coil tubing drilling operations, a
5 second annular type preventor closing control located on the
6 drilling floor on the platform floor. Little (ii). For rotary
7 rig operations, in addition to the controls from the
8 accumulator system, at least one remote -- at least one
9 operable remote BOP control on the drilling floor.
10 CHAIRMAN JOHNSTON: I suspect we'll want to spend a
11 little bit of time on that -- on redrafting that.
12 MR. WONDZELL: Yeah, I think so.
13 COMMISSIONER JOHNSTON: But.....
14 MR. MINTZ: Sorry. If I understand the concept, in
15 rotary drilling you have controls on the accumulator system and
16 you want another remote controls on or near the driller's or
17 operator's console?
18 MR. WONDZELL: That's correct.
19 MR. MINTZ: And in coil tubing you want one set of
20 remote controls plus a second annular type preventor closing
21 control if the remote controls are not in close proximity to
22 the drilling platform; if that is correct?
23 MR. WONDZELL: That's correct.
24 CHAIRMAN JOHNSTON: You know -- do you remember a
25 couple weeks ago we had three paragraphs in here and we elected

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1 to scratch the third one rather than the first one? It appears
2 that had we scratched the first one and kept the third one that
3 that would've addressed the concerns. So we might want to, in
4 all cases, just say insert -- in paragraph (D), for example, in
5 rotary drilling one complete set of operable remote controls,
6 and then paragraph (E), in coil tubing operations. Would that
7 take care of the concerns most easily?
8 MR. MINTZ: Well, I think we have to repeat the
9 complete set from (D). But.....
10 CHAIRMAN JOHNSTON: Oh, yeah.
11 MR. MINTZ: But anyway,.....
12 MR. WONDZELL: You can do it that way as well, sure.
13 MR. MINTZ: Would this apply throughout? 036 and.....
14 CHAIRMAN JOHNSTON: It would apply throughout.
15 MR. WONDZELL: It would apply throughout for the coil
16 tubing stuff.
17 MR. MINTZ: And that would be in the workover sections
18 too?
19 MR. WONDZELL: Uh-huh. Because it's rig specific.
20 CHAIRMAN JOHNSTON: So why don't we work up some
21 language. We'll take a break and work up some language on
22 that. But before we break anyway, is there any other things
23 that we need to talk about this morning, Blair?
24 MR. WONDZELL: Yeah, I have some more items on there.
25 This shows up in a couple of different places. On the next

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1 page under G where it says: a fill-up line above the uppermost
2 BOP, that should be specific for rotary rig operations because
3 you don't have that condition in coil tubing operations. The
4 fill-up line above the uppermost BOP for rotary rig operations.
5 MR. MINTZ: Okay. Just for consistency with other
6 language, I'd suggest starting the phrase with: In rotary
7 drilling rig operations, comma.
8 MR. WONDZELL: Yes, I don't have a problem with that.
9 CHAIRMAN JOHNSTON: Now, again, in rotary rig.....
10 MR. MINTZ: In rotary drilling rig operations.....
11 CHAIRMAN JOHNSTON: In rotary.....
12 MR. MINTZ: Comma, a fill-up line above the uppermost
13 BOP.....
14 CHAIRMAN JOHNSTON: Okay, and that change would appear
15 elsewhere as well. And at the break we'll have to determine
16 what those elsewhere's are.
17 MR. MINTZ: Yeah, I'm not sure how many elsewhere's
18 there are.
19 CHAIRMAN JOHNSTON: The computer can do that often
20 easier than we can.
21 MR. WONDZELL: Yeah, that's one good thing about the
22 computer.
23 MR. MINTZ: That's right.
24 MR. WONDZELL: On the next page under -- I know it's
25 right here, under (iii), you've already picked up those on the

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1 stack, greater than and so on, didn't you? No, you didn't.
2 Immediately upstream beats choke at least one full opening
3 valve for an operation requiring a BOP stack -- where on here
4 -- up to and including 5000 pounds -- or 5M, backup to and
5 including.
6 CHAIRMAN JOHNSTON: This is not drilling, is it?
7 MR. MINTZ: This is 035.
8 COMMISSIONER JOHNSTON: Yeah, this is drilling, this is
9 035.
10 MR. WONDZELL: Is this 035 or.....
11 MR. MINTZ: Yeah, this is primary drilling.
12 MR. WONDZELL: Okay. I'm wrong -- I'm wrong there.
13 That doesn't belong in there.
14 CHAIRMAN JOHNSTON: I will note though, in this
15 paragraph -- this iii paragraph, that we might want to re-write
16 it in terms of requiring an API 5M BOP stack similar to the
17 change that we made earlier, just for consistency and language.
18 That's also in paragraph (iv).
19 MR. WONDZELL: Uh-huh.
20 MR. MINTZ: Yeah, I'll have to look at how it's used
21 throughout.
22 MR. WONDZELL: On page 26, that's number -- in coil
23 tubing -- drilling operation -- under (ii), about halfway down
24 the page, in coil tubing unit operations, I'd like to have the
25 word "drilling" put in there, coil tubing unit drilling

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1 operations, because we do require quite a bit more -- there's
2 quite a bit more requirements for drilling operations in (ii),
3 workovers, cleanouts and so on.
4 MR. MINTZ: This 036 applies to drilling and completion
5 operations, so you don't want to exclude completion operation
6 from it, do you?
7 MR. WONDZELL: The numbers have all been changed.
8 Well, you keep -- you refer to rotary drilling rig operations,
9 yeah, to be consistent you should be talking about coil tubing
10 unit drilling operations.
11 MR. MINTZ: Okay, but the thing is it's rotary drilling
12 rig operations, not rotary rig drilling operations. Could you
13 say -- I'm not familiar with the terminology in coil tubing,
14 could you say coil tubing drilling rig operations -- isn't that
15 when you call it a rig?
16 MR. WONDZELL: No, you refer to it as a coil tubing
17 unit.
18 MR. MINTZ: Because I think your concerns adequately --
19 because see,.....
20 MR. WONDZELL: I think that's not a significant.....
21 CHAIRMAN JOHNSTON: There's no change there?
22 MR. WONDZELL: No.
23 MR. MINTZ: I'd just point out that the introductory
24 subsection says it applies to drilling and completion
25 operations, so.....

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1 CHAIRMAN JOHNSTON: Right.
2 MR. MINTZ: Okay.
3 MR. WONDZELL: The next one is the same one that we
4 talked about on the remote controls. It was down here under
5 page 28 -- and on page 30 is, maximum expected wellhead
6 pressure.
7 CHAIRMAN JOHNSTON: And we've already talked about that
8 change, right?
9 MR. WONDZELL: Yeah, we've talked about change, but I
10 don't think on that page.
11 MR. MINTZ: I have it anyway.
12 MR. WONDZELL: Okay, then I misnoted that one. Then
13 the next one is back in the range of 90, page 90.
14 CHAIRMAN JOHNSTON: Page 90 on the older version?
15 MR. WONDZELL: Page 91 on the older version, yes.
16 CHAIRMAN JOHNSTON: Right. So you're back in the
17 workover operations, 280?
18 MR. WONDZELL: Yes, on -- actually b-4 -- small (b)(4)
19 B as in boy, (4).
20 CHAIRMAN JOHNSTON: On BOP equipment?
21 MR. WONDZELL: It's in workover operations. I'll find
22 it here. There's a lot of page difference there. Okay, it's
23 on page 78.
24 COMMISSIONER JOHNSTON: 78.
25 MR. WONDZELL: And it's on (4). I want to change that

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1 from workover fluid to wellbore fluid, in that the workover
2 fluid implies that you're going to specifically put a -- pull
3 it in there, circulate out whatever is in the wellbore, and
4 circulate in the workover fluid, and that's not the case. In a
5 lot of situations you simply use -- do your work in whatever
6 fluid is in there, so it's actually the "wellbore fluid" would
7 be a better term.
8 Okay, and then the next one is on page 81, but it's the
9 controls again that we talked about.
10 CHAIRMAN JOHNSTON: All right.
11 MR. WONDZELL: The next one is near page 87, and again
12 that has the remote control stuff up there, but also in (8) at
13 the top of page 87.....
14 MR. MINTZ: The new 87? I'm sorry.
15 MR. WONDZELL: The new -- yeah, your new 87, at the top
16 of the page on 8, where it says a kill line with flange should
17 be provisions for a kill line. Coil tubing operations, you
18 probably wouldn't have them -- you wouldn't normally hook them
19 up.
20 CHAIRMAN JOHNSTON: Okay, run that change by us again.
21 MR. WONDZELL: Okay, this is in coil tubing work string
22 operations, and on page -- where it says a kill line with
23 flange or hub connections, those are not normally hooked up, so
24 if you added the words "provisions for" at the start of that,
25 which would mean that you would have a flanged opening on the

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1 tree or on a cross or something like that where you could hook
2 it up if you need to, but you wouldn't -- you don't normally
3 hook them up. So provisions for a kill line rather than
4 requiring a kill line.
5 MR. MINTZ: Okay. Let me just ask you about that
6 because this is all a list of equipment, and just to me the
7 word "provisions" doesn't sound like a kind of equipment, so
8 could we specify that more? Are you really talking about a
9 connection for a kill line?
10 MR. WONDZELL: Uh-huh.
11 CHAIRMAN JOHNSTON: So, in other words, you would have
12 the kill line on location?
13 MR. WONDZELL: You would have a kill line, you'd have
14 the connections for it, you just wouldn't necessarily hook it
15 up. So you would provide for it but you wouldn't hook it;
16 everything would be there on location. Provisions for it would
17 seem to be the best.....
18 CHAIRMAN JOHNSTON: So you could actually say a kill
19 line with provisions for flanged or hubbed connections to the
20 BOP body? So you have the kill line.....
21 MR. WONDZELL: Unless you want to say unhooked, but
22 I.....
23 MR. MINTZ: Can I -- maybe I can work on this in the
24 break and come back and talk about that.
25 MR. WONDZELL: Unless you can work on it in the break.

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1 MR. MINTZ: Yeah. Maybe it will be a long break.
2 MR. WONDZELL: Provisions for it would be adequate.
3 Okay, I think I have just one more. The other one, that's
4 fine. That's all I have.
5 CHAIRMAN JOHNSTON: That's it, huh?
6 MR. WONDZELL: Yeah.
7 CHAIRMAN JOHNSTON: I have just a general question for
8 you, Blair, and maybe Rob may want to comment on this. When we
9 talk about coil tubing operations, I sometimes read coil tubing
10 unit operations, and other times I read coil tubing operations.
11 Do we want to standardize on the term?
12 MR. MINTZ: Well, frankly, I think that's just the way
13 it was in AOGA's draft, and I didn't know whether the
14 difference was significant or not. Do you know, Blair?
15 MR. WONDZELL: Well, I'm trying to -- chasing around to
16 see if I think there is any difference between it, coil tubing
17 operations and coil tubing unit operations.
18 CHAIRMAN JOHNSTON: It seems to me that the term "unit"
19 is not really necessary.
20 MR. WONDZELL: Unless you're talking about the physical
21 surface equipment. If you're talking about I'm going to do
22 this with coil tubing, you're talking about a coil tubing
23 cleanout, you're not talking necessarily about coil tubing unit
24 cleanout. The unit is the whole works and particularly the
25 stuff at the surface. You could say I'm talking about a drill

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1 pipe cleanout without saying I'm talking about a rotary
2 drilling rig cleanout.
3 MR. MINTZ: Maybe we can go into this at the break.
4 MR. WONDZELL: Yeah.
5 CHAIRMAN JOHNSTON: I have it noted.
6 MR. MINTZ: But before we do, I wanted to ask Blair,
7 yesterday I think you raised a question of whether the workover
8 section should contain a requirement along the lines of what's
9 in the drilling sections for -- oh, yeah, posting drilling
10 hazards and relevant parts of the sundry approval.
11 MR. WONDZELL: Absolutely. All coil tubing and
12 drilling rig operations, whether they're doing workovers or
13 actual drilling operations ought to have a set of standing
14 orders and a hazard section, if it's appropriate, and on the
15 location should be the approved 401 or 403, if those are
16 applicable for being conducted under those operations, they
17 should be on location.
18 MR. MINTZ: Okay, let's talk about the details of that
19 because we have to get the language. Now if it's a 403 there
20 wouldn't be a drilling hazard section, would there, or would
21 there?
22 MR. WONDZELL: Not necessarily. Not necessarily, but
23 there could be.
24 MR. MINTZ: And would there also be the standing
25 orders?

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1 MR. WONDZELL: Always standing orders.
2 MR. MINTZ: And would that apply to, for example,
3 wireline operations?
4 MR. WONDZELL: Probably not to wireline operations.
5 MR. MINTZ: Okay, so it wouldn't be in 287, but it
6 would be in, let's see.....
7 MR. WONDZELL: Let me reconsider that. I think it
8 wouldn't hurt to leave it in there. The (indiscernible) line
9 operation could be a one person deal but rated line or
10 conductor line we do have more than one, so you should have
11 some -- yeah, I think so.
12 MR. MINTZ: So then maybe we could have a general
13 provision in 527 applied to both drilling and workover?
14 MR. WONDZELL: Well, wherever we had that other 8 guy
15 (ph) stuff is where we -- in the general provisions where we
16 thought that ought to go in there.
17 CHAIRMAN JOHNSTON: That would be the easiest way to
18 insert it.
19 MR. WONDZELL: That would be where most people are apt
20 to see it too.
21 CHAIRMAN JOHNSTON: Right. So we could.....
22 COMMISSIONER OECHSLI: In the general.....
23 CHAIRMAN JOHNSTON: Yeah, we could almost -- that's the
24 paragraph (g) on page 24, and insert it as paragraph (g) on
25 page 106.

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1 MR. MINTZ: We'd have to make some modification to.....
2 CHAIRMAN JOHNSTON: With modifications, right.
3 MR. WONDZELL: Uh-huh.
4 COMMISSIONER JOHNSTON: Although I'm not sure how much
5 modifications we'd have to do really.
6 MR. MINTZ: Well, there's not a permit to drill in the
7 workover section.
8 CHAIRMAN JOHNSTON: That's true.
9 COMMISSIONER OECHSLI: Are you suggesting in moving the
10 language out of page 24 and page 31 and just putting it in 527?
11 MR. WONDZELL: Well, I'd rather see the -- that's more
12 specific in page 24 than what we were proposing to capture in
13 that back section, so everybody would be aware of the
14 requirements. We certainly want to see them in that drilling
15 section because that's where they most apply and they're most
16 necessary.
17 MR. MINTZ: Okay then. Maybe we should put separate
18 provisions back in the workover sections.
19 MR. WONDZELL: I thought we had worked out some
20 yesterday that seemed to be pretty abbreviated to go back in
21 there to remind people that these are requirements for all of
22 these operations.
23 CHAIRMAN JOHNSTON: Do we have specific language to
24 look at then?
25 MR. WONDZELL: Yes.

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1 COMMISSIONER OECHSLI: I think -- yeah, this is -- Rob
2 and I talked about it a little bit yesterday, but a hazard
3 section if required and a copy of the standing orders must be
4 posted on the rig floor, copy of the approved permit to drill
5 or sundry notice must be on location. We needed to work on
6 that language.
7 MR. MINTZ: I don't think we could repeat the same
8 thing in each substantive (ph) section and also in the general
9 section. We have to decide where it should be, whether on the
10 general or the spe-.....
11 CHAIRMAN JOHNSTON: Well, if we're going to list it as
12 a specific cri- -- or requirement under each one of these
13 sections, you don't need it in the general section.
14 MR. WONDZELL: Why don't you take in the general
15 section and make a reference such as we have and refer back to
16 the details in this section because this section is a lot more
17 detailed.
18 COMMISSIONER OECHSLI: If I understand your earlier
19 suggest though was to add something to the workover section so
20 that there would be in three different places.
21 MR. MINTZ: Well, you can do it either way. I mean I
22 thought part of the rationale for AOGA's re-write of the well
23 control sections was that an operator could look, find out what
24 kind of operation he's doing and look in that one section.
25 CHAIRMAN JOHNSTON: Which applies to all operations.

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1 MR. MINTZ: Yeah -- no, no. Look in the particular
2 section, whether it's in primary drilling or work string, you
3 know, well servicing, and find basically everything he needed
4 to do. And that's why there's a lot of repetition between
5 them. But on the other hand, AOGA still did have a general
6 section, so I don't know what the rationale is for what goes in
7 what or, you know, what. All I'm saying is I don't think we
8 can really -- you know, really want to repeat the same
9 provisions in the specific sections under the general section.
10 We need to decide where.....
11 MR. WONDZELL: Well, because back in E in the general
12 section you were about to start into the standing orders
13 anyway, and they're repeating stuff again in F. When you talk
14 about that person having the authority and responsibility to
15 shut it in, what he's actually doing is following the standing
16 orders. And what I'm saying is that this is the general
17 section, general requirements were very specific in our piece
18 of the pie, the whole set of regulations, let's give them an
19 abbreviated account of what we expect there as far as documents
20 and these are ones that are now required on our BOP test sheets
21 when the inspectors come on the drilling operations. If you
22 want to refer to the more detailed sections elsewhere, that's
23 fine. But -- okay, are we ready for a break now?
24 CHAIRMAN JOHNSTON: Yes. So what we're going to do is
25 look at specific language for this hazard section and make a

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1 determination as to where we want to put it. Why don't we then
2 take a break. This break will probably be longer than 10 or 15
3 minutes, so why don't we try and get back here by at least
4 11:00. Would that be enough time?
5 MR. MINTZ: Well, why don't we take a half-hour.
6 CHAIRMAN JOHNSTON: A half-hour break, okay.
7 (Off record - 10:40 a.m.)
8 (On record - 11:25 a.m.)
9 CHAIRMAN JOHNSTON: We're ready to reconvene. Back on
10 record. We had taken a half-hour break that actually was a bit
11 longer than that, I guess, to consider some actual language in
12 those areas that we had talked about. Before we do that I'd
13 like to point out one change, also in paragraph 070 -- did you
14 have the page number there?
15 COMMISSIONER OECHSLI: 42.
16 CHAIRMAN JOHNSTON: 42 -- it's on page 42. And that we
17 have added a new paragraph (4) that states: Upon request of
18 the commission after completion, abandonment or suspension of
19 the well or completion or plugging of a well branch, file with
20 the commission a copy of the daily record required by one of
21 this section. The reason for that change is that I had come
22 across that provision being required as part of a workover
23 operation. And in turning back to the requirement of drilling,
24 I did not see a similar provision. And I think part of the
25 reason was we had modified the paragraph (3) to indicate a

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1 summary of the well report, and prior to that it was really the
2 well report that we received was the detailed one or that was
3 what was implied. So what paragraph (4) does then is gives
4 equal weight to the possibility that a -- the detailed record
5 may be required for -- to be submitted to the commission for
6 both drilling operations and well workover. So this makes it
7 consistent with the well workover provision.
8 So, Rob, you have some language then for us to take a
9 look at?
10 MR. MINTZ: Right. Okay. I noted down four instances
11 where I was to try and come up with language. The first one is
12 on page 21, having to do with the remote controls, (D) and (E).
13 I don't have -- I don't have my language in legible enough form
14 to distribute so I'll just do it orally for now. But I wanted
15 to point out here that there -- the question of using the term
16 driller's console or operator's console, and I think you had
17 done a search to see how that's used throughout the regs, but
18 what I wanted to find out is whether it's appropriate to use
19 driller's console for rotary operations, and operator's console
20 for coil tubing, or whether we need to keep both of them as
21 options.
22 CHAIRMAN JOHNSTON: I think that was -- that had been
23 my understanding throughout this discussion that when we talk
24 about rotary drilling we really were talking about a driller's
25 console, and when we were talking about coil tubing operations

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1 we were talking about the operator's console. Is that a fair
2 assessment?
3 MR. WONDZELL: You're talking about the operator's
4 console in coil tubing drilling, but you're really talking
5 about the driller's station in rotary drilling because he
6 really doesn't have a console in the same sense that a coil
7 tubing operator does.
8 CHAIRMAN JOHNSTON: So are you suggesting that we
9 change driller's console to driller's station?
10 MR. WONDZELL: Driller's station would be a better
11 word, yes.
12 MR. MINTZ: What are the other places in the regs for
13 this?
14 CHAIRMAN JOHNSTON: Okay. We have a number of examples
15 throughout the document, Blair, where we have a criteria for
16 something to be next to or in close proximity to the driller's
17 console. Now of course we would be changing that to driller's
18 station, but I'm wondering if we should also apply those same
19 standards to the operator's console. And I think before we
20 say, we need to look at the specific examples. For example, on
21 page 13 -- at least it should be close to 13, I did the search
22 on -- yes, for example, page 13, (c)(1) where we talk about the
23 drilling fluid system intended to maintain the wellbore in an
24 overbalanced condition, it says (1) a recording pit fluid level
25 indicator with both visual and audible warning devices located

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1 in the immediate area of the driller's console. Should that
2 also be the driller's station and operator's console?
3 MR. WONDZELL: Yes, but in reflection, maybe that's --
4 what's the dictionary definition of console? I don't think it
5 makes a whole lot of difference.
6 CHAIRMAN JOHNSTON: I think you're probably right. I
7 think we can live with console or station. I think it's more
8 like.....
9 MR. WONDZELL: I think we can too.
10 CHAIRMAN JOHNSTON: But in this particular case should
11 we insert the words, in the immediate area of the driller's or
12 operator's console? Would this not apply equally well to both
13 coil and rotary?
14 MR. WONDZELL: It's more to the driller's, rotary.
15 You're asking if the coil tubing operator needs to know what
16 the pit level is. I mean is that your specific question?
17 CHAIRMAN JOHNSTON: Well, my question is more simply in
18 some cases we'd make a distinction between the operator's
19 console and the driller's console. Now in certain instances,
20 and this is one, we have a criteria that is specific only to
21 the driller's console.
22 MR. WONDZELL: Because.....
23 CHAIRMAN JOHNSTON: I think it's just a matter of going
24 down through this and saying, yes, we only want to make this to
25 the driller's console and not the operator's console.

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1 MR. WONDZELL: I think you just want this one for
2 rotary drilling, so that's.....
3 CHAIRMAN JOHNSTON: Okay, so driller's console is good
4 here. On the top of page 14.....
5 MR. MINTZ: But wait, before we leave that. So do we
6 know that the term "driller" is not appropriate in coil tubing
7 operations?
8 MR. WONDZELL: It's -- you talk about the operator in
9 coil tubing, you don't talk about the driller.
10 MR. MINTZ: Okay. But if you want this recording
11 drilling fluid pit level indicator requirement to only apply to
12 rotary then I think we should say that right there.
13 MR. WONDZELL: Well, don't you -- you're saying that by
14 using the driller's console. You don't talk about a driller in
15 coil tubing.
16 MR. MINTZ: Well, if you think that's clear enough.
17 MR. WONDZELL: Sure.
18 COMMISSIONER OECHSLI: With the change, otherwise we're
19 on B, like you did on 22, which we prefaced that line by saying
20 "in rotary drilling rig operations"?
21 CHAIRMAN JOHNSTON: Okay. Another example of this is
22 on the next page, page 14 at the top of the page, number
23 (3) a drilling fluid flow sensor with a readout convenient to
24 the driller's console. Again, is that just for rotary or is it
25 for a coil as well?

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1 MR. WONDZELL: It's just -- this is primarily drilling.
2 This is primarily rotary drilling.
3 CHAIRMAN JOHNSTON: Okay.
4 MR. WONDZELL: Running large mud systems. Really I
5 would like to leave those words just as they are. During the
6 -- and the reason I say that, during the time of the
7 effectiveness of these regulations if coil tubing operations
8 became -- coil tubing drilling became more of a stand-alone
9 drilling operation it is conceivable that you could have mud
10 systems and you could start having this stuff, but under
11 current operations of coil tubing drilling in the state you
12 just don't have it.
13 CHAIRMAN JOHNSTON: Okay.
14 MR. WONDZELL: I'd really like to leave it the way it
15 is.
16 CHAIRMAN JOHNSTON: Let's look at another example here
17 on page 22, paragraph (H)(i).
18 MR. WONDZELL: Okay.
19 CHAIRMAN JOHNSTON: It says: two or more adjustable
20 chokes, one of which must be hydraulic and remotely controlled
21 from near the driller's console.
22 MR. WONDZELL: That again is rotary drilling.
23 CHAIRMAN JOHNSTON: Rotary drilling, okay. The next
24 one I have listed would be on or around page 40, and it looks
25 like it would be actually on page 41 at the top of the page.

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1 COMMISSIONER OECHSLI: On page 42?
2 CHAIRMAN JOHNSTON: Oh, is there one on page 42, okay.
3 COMMISSIONER OECHSLI: One.
4 CHAIRMAN JOHNSTON: Oh, you're right. Actually, yes,
5 there's about three references on page 40 to 41. So you have
6 one in (a)(1) above the rig floor near the driller's console.
7 I think, again, that would be rotary we're talking about there,
8 right?
9 MR. WONDZELL: Well, these were written for rotary but
10 they should also apply for coil tubing drilling.
11 COMMISSIONER OECHSLI: Okay.
12 MR. WONDZELL: We could say near the driller's console
13 upon the rig floor, but these certainly are intended to apply
14 to coil tubing drilling as well as rotary drilling even though
15 the specific language was written with rotary drilling in mind.
16 CHAIRMAN JOHNSTON: So can't we just say, or operator's
17 console there, at the end there, one above the drill rig floor
18 near the driller's console or operator's console?
19 MR. WONDZELL: Why don't you just say near the
20 driller's console if present, because if you're talking -- if
21 you're doing coil tubing drilling you don't have a driller's
22 console on the rig floor -- you don't have the driller's
23 station.
24 MR. MINTZ: But you'd still want the system above the
25 drill rig floor?

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1 MR. WONDZELL: Uh-huh, one at the drill rig floor.
2 CHAIRMAN JOHNSTON: So one above the drill rig floor
3 near the driller's console, right?
4 MR. WONDZELL: Uh-huh, if it's rotary.
5 CHAIRMAN JOHNSTON: If it's rotary, or.....
6 MR. WONDZELL: Just on the drill rig or on the
7 platform, really, if it's coil tubing.
8 MR. MINTZ: So how would you phrase it in coil tubing;
9 one above the drilling -- one on the drilling platform?
10 MR. WONDZELL: Yeah, or one above the drilling
11 platform, that would work.
12 CHAIRMAN JOHNSTON: So do we have some language to
13 propose?
14 MR. MINTZ: Well, I'm working on it here. Okay, here's
15 what I propose: Take the last phrase, one over the shale
16 shaker and put it as the second in the list. So it says, one
17 under the substructure near the cellar, comma, one over the
18 shale shaker, comma, and one above the drilling platform in a
19 coil tubing operation or above the drill rig floor near the
20 driller's console in a rotary drilling rig operation.
21 MR. WONDZELL: Or actually you could reduce some of
22 those words by saying one above the drilling platform or the
23 drill rig floor near the driller's console, and you leave out
24 the direct references to coil tubing and rotary drilling.
25 CHAIRMAN JOHNSTON: Do you want to read that back to us

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1 one more time, Rob?
2 MR. MINTZ: Okay. The last phrase would then be one
3 above the drilling platform or above the drill rig floor near
4 the driller's console.
5 CHAIRMAN JOHNSTON: All right. And then that same
6 change needs to be done in paragraph (3), okay. And then if
7 you turn to page 41, each alarm must be -- at the top of the
8 page, item number (9), each alarm must be automatic and must be
9 visible and audible from the driller's console. I would think
10 there we should say audible from the driller's or operator's
11 console.
12 MR. MINTZ: Okay.
13 COMMISSIONER JOHNSTON: Okay, the next reference would
14 be on or about page 82.
15 COMMISSIONER OECHSLI: 81.
16 CHAIRMAN JOHNSTON: Is it on 81?
17 COMMISSIONER OECHSLI: Uh-huh, 6 and 7.
18 CHAIRMAN JOHNSTON: No, 6 and 7, there's one below
19 that, I believe.
20 MR. MINTZ: Yeah, on 82, two or more adjustable chokes.
21 CHAIRMAN JOHNSTON: Yes. And again that would be just
22 the driller's console, right, on (11)(A)?
23 MR. WONDZELL: Yes.
24 CHAIRMAN JOHNSTON: Okay. Well, that takes care of all
25 the references to the driller's console.

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1 MR. MINTZ: Okay. So then my first language change is
2 on page 21, (D) and (E). So for (D), I propose the following:
3 In rotary drilling rig operations, comma, one complete set of
4 operable remote BOPE controls on or near the driller's console,
5 comma, in addition to controls on the accumulator system.
6 MR. WONDZELL: Okay.
7 MR. MINTZ: And then in (E) it would say in coil tubing
8 operations one complete set of operable remote BOPE controls on
9 or near the operator's console and, comma, if these controls
10 are not in close proximity to the drilling platform floor,
11 comma, a second annular type preventor closing control located
12 on the drilling platform floor.
13 MR. WONDZELL: That sounds workable.
14 COMMISSIONER OECHSLI: So in (D), the only thing you
15 changed is "added in the rotary drilling rig operations"?
16 MR. MINTZ: And deleted, or operators, or operators.
17 COMMISSIONER OECHSLI: And what did you do for (E)
18 again?
19 MR. MINTZ: In coil tubing operations, comma, one
20 complete set of operable remote BOP controls on or near the
21 operator's console. In other words, the same language as in
22 (D), but operator's instead of driller's. And, comma, if these
23 controls are not in close proximity to the drilling platform
24 floor, comma, a second annular type preventor closing control
25 located on the drilling platform floor.

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1 MR. WONDZELL: That sounds fine.
2 MR. MINTZ: I'm trying to maintain kind of a master
3 copy that's reflecting all these changes.
4 CHAIRMAN JOHNSTON: Yeah, we're just trying to get us
5 -- okay, and that change will also then appear on page 28, 81
6 and 86.
7 MR. MINTZ: That's correct. Okay. The next change is
8 on page 87 -- no, that's not true -- oh, yeah, the next page is
9 on 84, actually. And what I'm doing here is adapting the
10 language from the drilling sections on posting information in
11 the vicinity. So what I propose is to change what's now
12 subsection (g) to subsection (h), and insert a new subsection
13 (g).
14 CHAIRMAN JOHNSTON: And that would have to do with the
15 posting of the hazard?
16 MR. MINTZ: Right. And here's the proposed language I
17 have: In a rotary drilling rig operation the operator shall
18 have on location a copy of the approved Application for Sundry
19 Approvals, if applicable, and shall post on the drilling rig
20 floor any geologic hazard information required in connection
21 with the Application for Sundry Approvals, and a copy of the
22 standing order specifying well control procedures.
23 MR. WONDZELL: That will work.
24 MR. MINTZ: In a coil tubing operation the operator
25 shall post in the operator's cab a copy -- actually should cab

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1 be console; is that the same thing?
2 MR. WONDZELL: Cab and console are the same thing.
3 CHAIRMAN JOHNSTON: Well, I think the difference
4 is.....
5 MR. MINTZ: Oh, yeah.
6 COMMISSIONER JOHNSTON: .....that the console is inside
7 the cab.
8 MR. MINTZ: I understand. Right. Okay. So post to
9 the operator's cab a copy of the Application for Sundry
10 Approvals if applicable. Any geologic hazard information
11 required in connection with the Application for Sundry
12 Approvals and a copy of the standing orders specifying well
13 control procedures. And then the same last sentence: When an
14 additional or separate substructure is used in a coil tubing
15 operation the operator shall post a second set of standing
16 orders on the drilling platform floor.
17 MR. WONDZELL: That will work.
18 MR. MINTZ: And then there's a similar one on page 87,
19 and actually that's -- it's the same actually. But that would
20 be.....
21 CHAIRMAN JOHNSTON: So that's inserted as a new
22 paragraph (F)?
23 MR. MINTZ: Exactly. This is the same actually.
24 CHAIRMAN JOHNSTON: So insert it as a new
25 paragraph (F)?

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1 MR. MINTZ: Exactly.
2 CHAIRMAN JOHNSTON: Okay, and change (F) to (G).
3 MR. MINTZ: Because this section that goes into also
4 has either rotary or coil tubing operations.
5 CHAIRMAN JOHNSTON: Right.
6 MR. MINTZ: Now while we're on page 87, at the top
7 there, paragraph (8), here's what I came up with. Insert the
8 phrase, capable of being attached so that it says: A kill line
9 capable of being attached with flange or hub connections to the
10 BOP body, drilling spool tree, wellhead or other well control
11 equipment. That doesn't do it?
12 MR. WONDZELL: We can make it work, that's fine.
13 MR. MINTZ: And then finally on page 88 at the bottom
14 again, insert a new subsection (e) and change the current
15 subsection (e) to (f):
16 CHAIRMAN CHRISTENSON: What page are you on?
17 MR. MINTZ: 88. And the new subsection (e) would read
18 as follows: The operator shall post in the operator's cab a
19 copy of the approved Application for Sundry Approvals, if
20 applicable. Any geologic hazard information required in
21 connection with the application for sundry approval and a copy
22 of the standing orders specifying well control procedures.
23 MR. WONDZELL: Okay.
24 MR. MINTZ: And that's the end of the language I came
25 up with. I didn't have a chance to go through all the

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1 references to API 5M BOP stacks, and so forth. But if the
2 commission so directs, the Department of Law can just make that
3 language consistent as part of our review.
4 CHAIRMAN JOHNSTON: I think that would be appreciated
5 if you could standardize that language so that we are referring
6 to the stacks in the same manner throughout so it would be, I
7 guess, API 2M BOP stacks -- 5M stacks.
8 MR. MINTZ: Now did I leave out anything?
9 CHAIRMAN CHRISTENSON: Can we make that more general to
10 cover other inconsistencies as well or consistencies
11 (indiscernible) BOP stacks?
12 MR. MINTZ: Well, I mean if it's something within the
13 Department of Law's authority to correct, then we can just do
14 it. If it isn't then I think you'd have to specify what you
15 want to do, so there's probably nothing more we can do along
16 those lines.
17 COMMISSIONER OECHSLI: Is your list done?
18 CHAIRMAN JOHNSTON: I've covered everything that I had
19 listed. So I'm pleased. We've covered everything that I
20 wanted to talk about today.
21 COMMISSIONER OECHSLI: Everything's covered on my list.
22 Do you have anything?
23 CHAIRMAN JOHNSTON: Everything taken care of?
24 COMMISSIONER OECHSLI: Do you have anything?
25 CHAIRMAN CHRISTENSEN: Yes.

1 CHAIRMAN JOHNSTON: So at this point.....
2 COMMISSIONER OECHSLI: We're done before noon?
3 CHAIRMAN JOHNSTON: .....then we ought to entertain a
4 motion.
5 COMMISSIONER OECHSLI: I'll move to adopt the changes
6 to 20 AAC.25 as written in the draft 12-30-98 regulations with
7 the changes that we've made with -- together with Rob today.
8 CHAIRMAN CHRISTENSEN: I'll second it.
9 CHAIRMAN JOHNSTON: And since it's seconded, I will
10 vote in favor, and I guess we have a unanimous vote on the
11 adoption of these regulations.
12 COMMISSIONER OECHSLI: what happens now time-wise, Rob?
13 MR. MINTZ: Well, since there are some changes that
14 were adopted today that are not reflected in the file, you
15 know, on the hard drive, I'll have to get those implemented.
16 And we have to have some -- we have to have some documents
17 filled out, a certification order signed by the chairperson and
18 some affidavits of hearings and so forth we have to collect
19 together. We have to get a transcript of this meeting and then
20 those documents together with the regulations and other
21 documents that have been collected along the way, such as
22 public notices, will be sent to the Department of Law for
23 Department of Law review. First I have to do a review and then
24 send a memo along with that to the regulations attorney in
25 Juneau, and then they conduct a review. And assuming they

1 approve the regs then they would send them onto the Lieutenant
2 Governor's Office for filing. And they would become effective
3 30 days after the Lieutenant Governor files it.
4 CHAIRMAN CHRISTENSEN: So that's 30 days after January
5 15th (ph) then?
6 MR. MINTZ: One can always hope.
7 COMMISSIONER OECHSLI: Well, thank you very much, Rob.
8 You've done a good job. And thanks to everybody else because a
9 lot of people put a lot of time into this document.
10 CHAIRMAN JOHNSTON: I certainly want to raise my voice
11 in that direction as well. I'd like to thank our industry
12 representatives, those that are currently present here and
13 those that are not that have worked on these. They're deeply
14 appreciated, and I know there's been a lot of work on these
15 things over the last few years. Again, your work is very
16 definitely appreciated. I'd also like to recognize Blair
17 Wondzell for the amount of time and effort that he has spent on
18 it, I deeply appreciate that, Blair. And I know there's other
19 people on the staff that we need to acknowledge as well, but we
20 really do need to acknowledge you since you are one of the main
21 people guiding us on these regs. And, Rob, again I thanked you
22 last week, but again I think your role here has been
23 understated and it's been very helpful for us, and thank you
24 for all the guidance that you have had to offer us, and maybe
25 you'll continue to offer us again. Again, thank you.

1 CHAIRMAN CHRISTENSEN: One of the things, David, that
2 came up as a question a long time back, I think we should
3 acknowledge that we did this with regard to the platform
4 removal discussion and language, we were requested by the
5 industry to take note of the studies and so forth that's been
6 done, and in our deliberations with DNR we've passed that
7 information on to DNR, and they have the report that was
8 written and assured us that they have been and will continue to
9 use that as a guide, so that the work that they did was not for
10 naught.
11 CHAIRMAN JOHNSTON: And I think along those lines I
12 would certainly like to extend the invitation or express a
13 willingness to DNR, at least our DNR representative here, that
14 to the extent that you find it beneficial to consult with us on
15 platform removal and that sort of thing, we'd be more than
16 happy to work with you to give you our thoughts on that on
17 platform removal to the extent that you may be establishing
18 your own criteria. We'd be more than pleased to work
19 cooperatively with the folks over at DNR.
20 So with that is there anything else that we need -- any
21 loose ends? Okay, I guess then I'd like to adjourn this public
22 meeting and, once again, thank you all for your attendance.
23 (Off record - 11:55 a.m.)
24 END OF PROCEEDINGS
25

1 CERTIFICATE
2 UNITED STATES OF AMERICA)
3 STATE OF ALASKA) ss.
4 I, Cary Wells, Notary Public in and for the State of
5 Alaska, and Reporter for Metro Court Reporting, do hereby
6 certify:
7 That the foregoing Alaska Oil & Gas Conservation
8 Commission Hearing, was taken before Laura Fero on the 30th day
9 of December 1998, commencing at the hour of 9:00 o'clock a.m.,
10 at the offices of Alaska Oil & Gas Conservation Commission,
11 3001 Porcupine Street, Anchorage, Alaska;
12 That the hearing was transcribed by Laurel L. Earl to
13 the best of her knowledge and ability.
14 IN WITNESS WHEREOF, I have hereto set my hand and
15 affixed my seal this 6th day of December 1998.
16 Notary Public in and for Alaska
17 My commission expires: _____
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1 ALASKA OIL AND GAS CONSERVATION COMMISSION
2 PUBLIC HEARING
3
4 In Re:)
5 PROPOSED CHANGES IN THE REGULATIONS OF)
THE ALASKA OIL AND GAS CONSERVATION)
6 COMMISSION AND SUPPLEMENTAL NOTICE OF)
PUBLIC HEARING.)
7)
8
9 TRANSCRIPT OF PROCEEDINGS
10 Anchorage, Alaska
October 15, 1998
9:00 o'clock a.m.
11
APPEARANCES:
12
Commissioners: MR. DAVID W. JOHNSTON, CHAIRMAN
13 MS. CAMILLE OECHSLI
MR. ROBERT N. CHRISTENSON
14
Alaska Oil & Gas Assn: MR. CHRIS PHILLIPS (BP)
15 MR. MARK WORCESTER (ARCO)
16 Shared Services Drilling Group: MR. CHUCK MALLORY (ARCO)
MR. MIKE ZANGHI (ARCO)
17 MR. FRITZ GUNKEL
MR. MARK BERLINGER (BP)
18
Unocal: MR. DAN WILLIAMSON
19
20 * * * * * RECEIVED
21
22 OCT 29 1998
23
24 Alaska Oil & Gas Cons. Commission
25 Anchorage

1 P R O C E E D I N G S
2 (On record - 9:10 a.m.)
3 CHAIRMAN JOHNSTON: I'd like to call this hearing to
4 order. I'd note the time is approximately 10 minutes after the
5 9:00 o'clock hour. The date is October the 15th, 1998. We are
6 located in the commission's offices at 3001 Porcupine Drive,
7 Anchorage, Alaska. To begin, my name is David Johnston. I'm
8 joined today with Commissioners Camie Oechsli and
9 Bob Christenson. Laurel Far- -- Laura Farley, excuse me, of
10 Metro Court Reporting will be making the transcript of the
11 proceedings today (sic). If you wish to obtain a copy of the
12 transcript, we'd ask that you contact Metro Court Reporting
13 directly to do so.
14 The purpose of these proceedings are to consider
15 testimony concerning the commission's proposed revisions to
16 regulations. That's Title 20, Chapter 25, governing oil and
17 gas drilling and production in the state of Alaska. The
18 commission provided public notice of these proceedings in the
19 Anchorage Daily News on August 21st, 1998, and in the Alaska
20 Administrative Journal on August 31st, 1998. In addition, we
21 mailed out copies of the notice to people on our mailing list.
22 So with that introduction, I would like to begin with
23 testimony. We have a list of people indicating a desire to
24 appear before the commission. Now from our prior hearings on
25 these regulations there seemed to -- it seemed to make sense to

1 ask if there was a particular order that would make sense from
2 the participants out there. Is that the case today or shall we
3 just go down the list and take them by order of the sign-in
4 sheet?
5 MR. PHILLIPS: Mr. Chairman, if I could propose, AOGA
6 has some testimony to provide that represents a large group of
7 companies, and perhaps that might be appropriate to be first.
8 CHAIRMAN JOHNSTON: Is there any objections to allowing
9 the AOGA representative to present testimony first? And I
10 believe that may frame the follow-up discussions for everybody
11 else. Okay, there being none, then I'd like to recognize
12 Chris Phillips, representing AOGA today, I guess.
13 MR. PHILLIPS: That's correct.
14 CHAIRMAN JOHNSTON: And as you appear before the
15 commission we'd ask that you identify yourself for the record
16 and indicate who you are representing.
17 MR. PHILLIPS: For the record, my name is
18 Chris Phillips. I'm with BP, but today I'm representing AOGA
19 as I give testimony.
20 Mr. Chairman, Commissioners, thank you very much for
21 the opportunity to give testimony today. Since -- over the
22 last two months we have been reviewing the regulations that
23 were put out in public as AOGA, and we submitted to you on
24 September 30th some comments that we had, and we also said at
25 that time that we proposed to give some testimony today to

1 provide you further comments.
2 I don't propose to go over the comments that we made in
3 the letter about a month ago. I think they stand for
4 themselves. But today we'd like to provide you with testimony
5 in four specific areas, and we have representatives of the AOGA
6 companies here today to address those.
7 The first area is surface cementing. This is an issue
8 where we provided testimony to you two years ago. We would
9 like to again provide testimony to you, particularly to give
10 the two more recent commissioners an opportunity to hear the
11 AOGA position on that.
12 The second area where we'd like to provide testimony is
13 with regard to the BOP testing frequency.
14 The third area we'd like to provide a minimum of
15 testimony and suggest, perhaps, the formation of a work group
16 to further work on these regulations, and that's in the area of
17 the requirements for BOP equipment. And in brief let me
18 explain that. In looking at the regulations we find that they
19 don't properly address some of the new technology and some of
20 the different technologies, and as a work group within AOGA we
21 have put some draft language together, very much at a working
22 copy level, and we would give that to you today. But it's
23 quite clear that it is something that will benefit from a work
24 group type environment where members of the commission could
25 also work together to develop appropriate language. What we've

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1 done, in essence in that area, is divided the BOP equipment
2 requirements into specific areas that address very particular
3 parts of our operations. For example, drilling, work-overs,
4 cold tubing, re-entry, and wireline operations. And trying to
5 keep the language consistent throughout those. And we'd
6 appreciate you giving some consideration to formation of a work
7 group there.
8 The last area where we'd propose to give some testimony
9 is with regard to the change of ownership language in the draft
10 regulations that the commission sent out.
11 And with the commission's approval, we would like to
12 start by giving testimony in the surface cement area, and we
13 have Chuck Mallory with us today from Shared Surface Drilling,
14 who is prepared to give a presentation on overheads, and at the
15 end of the presentation he will be able to leave you a copy of
16 those overheads and a copy of his speaker notes which should
17 accurately reflect what he says today.
18 CHAIRMAN JOHNSTON: Before we move into subsequent
19 testimony, perhaps you could elaborate a little bit more fully
20 on your comments in your letter dated September 30th to us
21 concerning the use of the API recommended practices?
22 MR. PHILLIPS: In the absence of anyone else from the
23 audience commenting, we had some concern in general that there
24 were a lot of references to API recommended practices and
25 concern that the regulations would be subject to modification

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1 by API recommended practices, unless those recommended
2 practices were dated or it was apparent that those -- that the
3 reference was to recommended practices in effect in the date of
4 the regulations.
5 CHAIRMAN JOHNSTON: I think the commission can easily
6 handle providing a date, and I think in most cases we have
7 indicated a date of the recommended practice. I believe the
8 only one that we had difficulty establishing a date for was the
9 measurement standards, and what we may elect to do there is --
10 and backing up just a little bit, the problem with giving a
11 date for the measurement standards is a multi-volume document
12 that has numerous dates associated with it. So what we thought
13 we would do is indicate the manual in effect on a particular
14 date. And that date is in the foreseeable future. As we move
15 a little bit forward on adopting this, probably the effect of
16 the -- having the effective date when we adopt the regulations,
17 I guess, indicate the manual that was in effect was as of that
18 date. Would that alleviate some of those concerns?
19 MR. PHILLIPS: I guess I believe it would.
20 CHAIRMAN JOHNSTON: Right. You further went on to
21 indicate that some of the recommended practices were just that,
22 recommended practices, and that they should not necessarily be
23 requirements as -- to be imposed by the commission?
24 MR. PHILLIPS: That's correct.
25 CHAIRMAN JOHNSTON: What is your concern with having

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1 the commission impose recommended practices.....
2 MR. PHILLIPS: May.....
3 CHAIRMAN JOHNSTON: .....as opposed to using them as
4 guidelines?
5 MR. PHILLIPS: Is there any comment from the audience,
6 perhaps?
7 MR. WORCESTER: I guess.....
8 CHAIRMAN JOHNSTON: If we could ask you to come up and
9 use the microphone, please?
10 MR. WORCESTER: I'm Mark Worcester. I'm with ARCO, but
11 I am also in this context speaking on behalf of AOGA. I think
12 the -- and I'm not the engineer and I'm not familiar with
13 working with recommended practices, so it's just the concepts
14 in the language that I can speak to. But my understanding is
15 that the -- of the nature of recommended practices is that they
16 do not establish requirements, that they essentially give --
17 they will suggest considerations in the engineering -- an
18 engineer will take into account in good engineering practices,
19 just such as the regulations that -- and the statute that the
20 commission is used to operating under. It will have a more
21 general reference to good oilfield engineering practices or
22 something like that. Well, the -- as I understand it, the
23 recommended practices of the API are engineers getting together
24 and essentially identifying things that a good engineer would
25 take into consideration when they are faced with a particular

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1 application. So they don't attempt to try to tell people this
2 is what you have to do, but these are things that you might
3 want to consider when you have a particular problem you're
4 addressing. So I think that it puts an engineer a little bit
5 at risk when they read this and they say we just -- we must
6 meet the minimum requirements. When minimum requirements
7 aren't stated it will create an ambiguity as far as someone --
8 what it means to comply with that regulatory requirement.
9 Perhaps an engineer who is more familiar with specifics could
10 give some example, but that's what I understand to be the
11 dilemma that would be -- by essentially acting as if these were
12 creating minimum standards when -- and requirements and
13 imposing them as minimum requirements when they are not worded
14 or intended to be used that way.
15 CHAIRMAN JOHNSTON: Thank you. In your September 30th
16 submittal you also indicated your concern or suggested that
17 there may be a concern relative to 20 AAC 25.030(c)(6), having
18 to do with -- indicating that slotted liners, perforated liners
19 and screens installed to blow the production packer are
20 considered as production and equipment and not as casing. Is
21 there a problem that you see there in considering that? I know
22 you asked a question there, and I don't think we're prepared to
23 answer questions at this point. But I'd like to explore to see
24 if there's a concern there that AOGA is seeing that maybe the
25 commission did not recognize.

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1 MR. PHILLIPS: Again, I'd like to turn perhaps to an
2 engineer in the audience who might want to address that. Is
3 there anyone who might volunteer?
4 MR. MALLORY: Could you rephrase the question or repeat
5 it?
6 CHAIRMAN JOHNSTON: One of the comments made by AOGA in
7 its September 30th, 1998 submittal was -- at least it indicated
8 to me that there might be some concern relative to a particular
9 section under our casing and cementing requirements,
10 specifically that was 20 AAC 25.030(c)(6). That says slotted
11 liners, pre-perforated liners and screens installed below the
12 production packer are considered as production equipment and
13 not as casing. AOGA then goes on to ask us a question which,
14 as I indicated, I'm not prepared to answer today, but because
15 AOGA asked the question that they did, it raised a -- it caused
16 me to wonder if there was some concern that AOGA sees with this
17 requirement that the commission didn't necessarily recognize.
18 And if you would care to address that, we'd appreciate that.
19 But if you would step up to the microphone, please?
20 MR. MALLORY: Certainly. For the record, my name is
21 Chuck Mallory. I'm a senior drilling engineer employed by ARCO
22 Alaska in the Shared Services Drilling Group.
23 CHAIRMAN JOHNSTON: Thank you.
24 MR. MALLORY: To answer your question, I believe that
25 the question that's posed here is a very minor point relating

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1 to where and what should be described on the APD, the
2 Application for Permit to Drill. I believe it's the 10-401,
3 because normally we will list a slotted liner or pre-perforated
4 liner in the same block of information as the conductor, the
5 surface pipe and any intermediate casing. And I think that
6 this question is just seeking clarification on where we would
7 specify that a slotted liner is going to be part of the well
8 design. I don't believe it raises any technical issues
9 regarding classifications as stipulated here in your proposed
10 language.
11 CHAIRMAN JOHNSTON: My concern when I saw that, and
12 I've not fully explored this yet myself, but I thought I'd take
13 advantage of this opportunity to do that a little bit more, I
14 was wondering if AOGA was possibly seeing a conflict between
15 this and actually submitting requirements that are spelled out
16 for casing. In other words, are we getting ourselves into a
17 bit of a trap here where we spell out cementing requirements
18 for production casing, and if we don't articulate this as not
19 being considered casing, then do we then cause you to have to
20 cement this -- these liners and perforated -- pre-perforated
21 liners, would that cause you to cement those in place if we
22 don't make a distinction of this nature?
23 MR. MALLORY: Mr. Chairman, as you, I haven't studied
24 this issue in detail, but I believe that we are not concerned
25 with -- in any way with the production casing cementing as it

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1 pertains to these slotted liners. This was more of a
2 procedural question on where you would like this part of the
3 well design to be noted in the Application for Permit to Drill.
4 CHAIRMAN JOHNSTON: Thank you very much.
5 MR. MALLORY: You're welcome.
6 CHAIRMAN JOHNSTON: I don't believe I have any further
7 questions for you, Mr. Phillips, concerning the September 30th
8 submittal.
9 Any questions from my fellow commissioners?
10 MS. OECHSLI: I have none.
11 (Pause - commissioners confer in whispered tones)
12 CHAIRMAN JOHNSTON: Perhaps you could elaborate for us,
13 Mr. Phillips, on page 3 of your submittal, relative to the
14 reference to 20 AAC 25.080(e)(2), it's about a third of the way
15 from the bottom. You're indicating that the recommendation
16 from AOGA is to delete subsection (e)(2) because the
17 requirements of (1) and (3) should provide sufficient
18 protection. Could you elaborate on that a little bit more
19 fully?
20 MR. PHILLIPS: Again, I mean I think it's appropriate
21 to have an engineering representative address that since this
22 is an issue that's current within the drilling departments of
23 the companies. So I'll ask someone else to come forward and
24 address that specific concern.
25 CHAIRMAN JOHNSTON: Is there an engineer in the

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1 audience that might address the AOGA concerns relative to 080,
2 annular disposal?
3 (Pause - commissioners confer in whispered tones)
4 CHAIRMAN JOHNSTON: I guess we -- one of the points is
5 a point of clarification. When AOGA says "the requirements of
6 (1) and (3) should provide sufficient protection" what do you
7 mean when you say the requirements of (1) and (3) should
8 provide sufficient protection? Are you referring to (1) and
9 (3) in the subsection (e)(2) or are you referring to (1) and
10 (2) in a previous subsection?
11 MR. PHILLIPS: I believe we're referring to
12 requirements (1) and (3) in that subsection.
13 MS. OECHSLI: Okay. That answers my question.
14 MR. PHILLIPS: Is that clear?
15 MS. OECHSLI: Yes, that answers my question.
16 Thank you.
17 CHAIRMAN JOHNSTON: Okay. I guess at this point then
18 we will proceed down the list of people indicating that they
19 wish to testify, unless you have any further comments?
20 MR. PHILLIPS: As part of our testimony we had two or
21 three people who would.....
22 CHAIRMAN JOHNSTON: I see. Okay, right.
23 MR. PHILLIPS: .....like to give specific testimony in
24 those four areas we discussed.
25 CHAIRMAN JOHNSTON: Right. I'm sorry. I just.....

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1 MR. PHILLIPS: And I think.....
2 CHAIRMAN JOHNSTON: .....jumped ahead, I guess.
3 MR. PHILLIPS: .....those are probably the people who
4 have indicated they wish to speak, although some of them may be
5 speaking on behalf of their own companies as opposed to on
6 behalf of AOGA.
7 CHAIRMAN JOHNSTON: Okay. Why don't we go ahead and
8 proceed with the supporting testimony for AOGA then.
9 MR. PHILLIPS: Okay. The first area is in the area of
10 surface cementing. As I indicated to you, Chuck Mallory is
11 going to address that. And this is something that we discussed
12 at length two years ago, and we made a large presentation to
13 you and we submitted a significant amount of technical
14 testimony both in terms of a report and oral testimony at the
15 hearing. I think today we'd just like to give a very broad
16 overview of where the companies are and give you our view of
17 the best way to proceed in regulation for the future.
18 CHAIRMAN JOHNSTON: Right. Thank you. At this time if
19 Mr. Mallory can approach us again?
20 MR. PHILLIPS: Hopefully we need to set up this
21 view-graph machine.
22 (Off record)
23 (On record - 9:32 a.m.)
24 MR. MALLORY: Good morning. For the record my name is
25 Chuck Mallory. I'm employed by ARCO Alaska as a senior

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1 drilling engineer in the Shared Services Drilling Group. As I
2 give this testimony this morning I'm going to be speaking from
3 overheads of which I have speaker's notes, and at the
4 conclusion of this testimony we have copies of these overheads
5 and speaker's notes for the commission.
6 The purpose of this testimony is to propose language
7 describing the acceptance and criteria for surface casing
8 cementing. Briefly, the topics that I plan to cover during
9 this presentation include the following: A review of the basis
10 of design for casing in cement; a discussion of surface casing
11 and cement integrity specifically in the areas of sealing
12 integrity and structural integrity; a discussion of the
13 proposed language, the proposed language as proposed by the
14 AOGCC, and also as proposed by AOGA. As I stand here before
15 you, I represent AOGA and its companies.
16 What you see here is the first paragraph of the
17 proposed regulations under Casing and Cementing. It gives a
18 concise and comprehensive basis of design for a well's casing
19 and cementing program. AOGA is in agreement with the
20 commission that these eight points form the basis of design for
21 casing in cement.
22 As you know, wells are typically constructed with two
23 or more strings of casing. Examples include conductor,
24 surface, intermediate, and production strings. Each of these
25 casing strings perform different functions. And these

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1 differences are reflected in the load cases and design factors
2 of the casing program and the slurry in pumping program for the
3 cement. The challenge for the design engineer is to find a
4 cost effective solution which meets this basis of design.
5 Let's take a closer look at surface casing and basis of
6 design in permafrost regions.
7 As applied to surface casing, the eight points which
8 make up the basis of design establish a requirement for sealing
9 and structural integrity. Sealing integrity means sealing from
10 within and from without. We need the surface casing and its
11 cement to confine drilling fluids to the cased interval and the
12 open hole below it. We must prevent the movement, migration,
13 and contamination of fluids and strata which are behind the
14 surface casing.
15 Structural integrity ensures that the well can
16 withstand the varying pressures, temperatures, and loads
17 imposed not only during drilling but throughout the life of the
18 well. Loads unique to permafrost regions include thaw
19 subsidence and freeze-back. So how do modern well designs in
20 permafrost regions ensure the sealing and structural integrity
21 of surface casing?
22 Let's discuss sealing integrity first. A competent
23 casing shoe is one of the most important factors in insuring
24 the sealing integrity of surface casing. The integrity of the
25 shoe insures that the surface casing does not allow the

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1 migration of fluids up the outside of the casing string. It is
2 verified with the formation integrity tests and must meet a
3 design value before drilling progresses in subsequent hole
4 sections.
5 The casing itself must provide sealing integrity to
6 internal and external pressures. Casing size, weight, grade,
7 and connections are carefully designed to ensure sealing
8 integrity throughout the life of the well. In addition to the
9 shoe strength and structural integrity of the surface casing,
10 benefit is also gained from bringing cement as close to the
11 surface as is practical. This can be difficult due to the weak
12 nature of permafrost. However, a failure to return cement to
13 surface does not in itself condemn the sealing integrity of the
14 surface casing.
15 Next we'll address the structural integrity of surface
16 casing. As we have already seen, the sealing and structural
17 integrity of surface casing are closely related. Oil well
18 casings must withstand varying loads as pressures,
19 temperatures, and external stresses change over time. It is
20 critical that the design engineer approach the problem of
21 casing design with a clear understanding of what can and cannot
22 be safely assumed. From the standpoint of surface casing and
23 permafrost regions, it is not safe to assume that the casing is
24 supported by cement through the permafrost. This approach is
25 tacet in the design loads for surface casing and is reflected

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1 in the size, weight, and grade of the tubulars and the
2 connections employed on them.
3 We see then that with prudent design principles cement
4 across the permafrost is not required to ensure the structural
5 integrity of surface casing. Summarizing then, we believe that
6 what is required to ensure that surface casing and cement
7 fulfills its basis of design is a competent shoe, verified with
8 the formation integrity test, a casing design based on worst
9 case design cases. We do not believe that circulating cement
10 to surface should be a requirement of surface casing integrity.
11 I will now read for the record the AOGCC proposed
12 language dealing with surface casing and cement. Surface
13 casing must be cemented by filling the annular space with
14 cement from the shoe to the surface, however, if cement does
15 not circulate to the surface, if an excessive quantity of
16 cement circulates to surface or if the formation integrity test
17 shows an inadequate cement job, A., the operator shall notify
18 the commission before drilling ahead, and B., the commission
19 will, in its discretion, require 1., a cement quality log or
20 other approved method to evaluate the adequacy of the cement to
21 contain potential wellbore pressures and fluids, and 2.,
22 remedial action before drilling ahead. This is the AOGCC
23 proposed language.
24 I will now read for the record and the commission the
25 AOGA proposed language for surface casing and cement. Surface

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1 casing shall be cemented by pumping a volume calculated to fill
2 the annular space with cement from the shoe to the surface. If
3 cement does not circulate to the surface the commission shall
4 be notified. The operator shall perform a formation integrity
5 test, FIT, and if the evaluation of the FIT shows an inadequate
6 cement job, the commission shall be notified and the commission
7 may require a cement quality log or other approved method to
8 evaluate the adequacy of the cement to contain potential
9 wellbore pressures and fluids, and if necessary may require
10 remedial action to ensure a competent casing shoe before
11 drilling ahead.
12 We believe this language addresses the basis of design
13 as it applies to surface casing and cement. Furthermore, it
14 provides prudent regulatory oversight in the unique case of
15 permafrost cementing. Reiterating. We believe this language
16 addresses the basis of design as it applies to surface casing
17 and cement. Furthermore, it provides prudent regulatory
18 oversight in the unique case of permafrost cementing. We
19 believe this language will not reduce mechanical well
20 integrity. It does not put people, the environment or natural
21 resources at risk. We believe this language will enable us to
22 reduce our waste streams. Finally, we believe this language
23 will help us to continue to develop Alaska's natural resources
24 in a cost effective manner. Thank you.
25 CHAIRMAN JOHNSTON: In terms of your last statement

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1 there, relative to the cost effectiveness or the -- of drilling
2 wells, can you indicate for us what you feel is the impact of
3 the more rigid requirement in terms of requiring cement to
4 surface, how that has impacted on the cost of the wells?
5 MR. MALLORY: Yes. Our figures show that since we have
6 been trying with extreme measures to cement surface casing to
7 the surface, it has cost us approximately $40,000 per well.
8 CHAIRMAN JOHNSTON: That's $40,000 total cost or
9 incremental cost above what you used to spend?
10 MR. MALLORY: That's an incremental cost above what we
11 used to spend.
12 CHAIRMAN JOHNSTON: And what do you attribute that
13 incremental cost to; what is actually causing you to absorb
14 those costs?
15 MR. MALLORY: To answer that question I'm going to have
16 to get into a brief review of the practices that we currently
17 follow. Is that acceptable?
18 CHAIRMAN JOHNSTON: Yes, that would be fine.
19 MR. MALLORY: Currently we're doing two-stage cement
20 jobs on most surface casing strings with what's called a DV
21 tool. The incremental costs that I just quoted for you is
22 primarily due to the cost for the DV tool, the rig time to
23 perform the second stage and the extra time to drill out the DV
24 tool and the cement below it.
25 CHAIRMAN JOHNSTON: So the incremental would be -- the

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1 incremental cost is really -- what I'm hearing is almost
2 unavoidable cost then if you go to the requirement to have
3 cement all the way to the surface. And what I'm hearing, I
4 guess, is that in analyzing how best this is done, industry has
5 elected to use the DV collars as the most cost effective way of
6 achieving this requirement. And there's really no other way to
7 lower the cost beyond going to DV collars and doing the cement
8 job in two stages. Is that correct?
9 MR. MALLORY: As I understand the question, that is
10 correct.
11 CHAIRMAN JOHNSTON: And if you attempted to do it in a
12 single stage that may end up actually costing you more money to
13 attempt to get cement to the surface in a single stage, or is
14 there just greater uncertainty.....
15 MR. MALLORY: Greater uncertainty on the ability to
16 observe cement to surface with the single stage cemented from
17 the shoe.
18 CHAIRMAN JOHNSTON: And for the benefit of our new
19 commissioners here, what are some of the problems that you've
20 seen in getting cement to the surface? I mean what are the
21 causes of some of those problems?
22 MR. MALLORY: Problems specific to a single stage pump
23 from the shoe or.....
24 CHAIRMAN JOHNSTON: Right.
25 MR. MALLORY: .....for all cement jobs?

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1 CHAIRMAN JOHNSTON: Let's take it one at a time and at
2 least at this point just investigate the difficulties that you
3 experienced in getting cement on the single stage job from the
4 shoe to the surface.
5 MR. MALLORY: There -- I will ask if it's okay with the
6 commissioners -- there are other people representing AOGA in
7 the audience that can address the historical record of
8 cementing from the shoe a lot more accurately than I can.
9 CHAIRMAN JOHNSTON: If there are other individuals in
10 the audience that would be better prepared to answer that
11 question, if they'd indicate with a show of their hands?
12 MR. ZANGHI: (Indiscernible - away from microphone)
13 CHAIRMAN JOHNSTON: Please.
14 MR. ZANGHI: For the record my name is Mike Zanghi.
15 I'm with ARCO Alaska. And just let me rephrase the question
16 you asked regarding difficulties that we've had in the past
17 achieving cement to surface with single stage jobs. They vary
18 throughout the -- throughout the North Slope. One potential
19 cause of not achieving cement to surface is lost circulation.
20 An attempt to try to get the full column of cement from the
21 bottom of the surface casing to the top of the surface, that
22 hydrostatic head has been too much for weak zones that may
23 occur in the permafrost region. Other potential causes of not
24 achieving cement to surface each and every time is insufficient
25 removal of potential cuttings in the well that may cause a

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1 bridging. And then third is uncertain hole size behind the
2 casing, the amount of volume that is required to fill the
3 annular space, especially in the permafrost region. As Chuck's
4 slide showed the hole enlargement that occurs in the permafrost
5 region is not entirely predictable. Below the permafrost
6 region the size of the hole is predictable. In the permafrost
7 region it's -- the hole gets enlarged quite a bit and it's not
8 always predictable. So the volume of cement that is required
9 is not always known for each and every well.
10 CHAIRMAN JOHNSTON: In the -- I guess it's been what,
11 two years since we have looked at this issue. In that time has
12 there been any work done on developing better cement that might
13 allow you to get this stuff to the surface easier, has there
14 been any work done on controlling hole size in the permafrost?
15 MR. ZANGHI: I can't speak to controlling hole size in
16 the permafrost. There have been some, what we hoped to be,
17 advancements in cement type that is of a lower density that
18 still retains its strength that could potentially be pumped to
19 the surface. We're certainly in early stages of trying to
20 understand if that -- if those methods can work.
21 CHAIRMAN JOHNSTON: Any questions?
22 MR. CHRISTENSON: No, I have no further questions.
23 MS. OECHSLI: I have none.
24 CHAIRMAN JOHNSTON: Thank you.
25 MR. GUNKEL: If I can make a comment directed to your

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1 question. I'm Fritz Gunkel, I'm the drilling manager for
2 Shared Services Drilling. David, on your question regarding
3 hole size and cement design, we're constantly seeking to
4 improve the predictability of the hole size, not just for
5 cementing but also for minimizing the amount of drill cuttings
6 we create, reduce the waste that we create during drilling.
7 And we have recently made some steps that look promising,
8 aren't conclusive. We've drilled some small wellbores at
9 Melanie Point where we drilled a wellbore that was very nearly
10 gauge, the same as bit size, through the entire permafrost
11 section, and we're evaluating the reasons why we think it's
12 more complex than just the right drilling fluid. It's a
13 combination of mechanics and chemistry.
14 Also we're working steadily with the cement suppliers,
15 looking at methods to lighten the column. Speaking of Mike's
16 point about the potential for lost circulation, we've recently
17 done a couple of jobs where we've actually added nitrogen to
18 the cement. We call them foam cement jobs, to lighten the
19 column in an effort to make the single stage cement job more
20 predictable, bring that cement to surface. But to go with
21 that, we'd like to make the point that still bringing cement to
22 surface is something that we're frequently able to do, even
23 with conventional technologies. The problem is that we can't
24 guarantee ourselves that we'll accomplish it each and every
25 time. And under the current regulations the risks that we

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1 incur if we don't bring cement to surface are that without this
2 DV tool that we discussed earlier, we would have to do
3 something to gain access to the wellbore that would compromise
4 the structural integrity of the casing. We'd have to perforate
5 it or alternatively we can do something referred to as a top
6 job, run pipe down the side. In managing that risk, we've
7 routinely installed this DV tool that Chuck referred to which
8 causes us to every time incur that additional cost and also
9 frequently circulate large amounts of cement to surface because
10 we don't want to be in the position where we have not brought
11 cement to surface. Not because of our belief about the
12 structural value, but because of the, you know, risk of not
13 meeting regulation and then the subsequent actions we'd have to
14 take to meet regulation.
15 CHAIRMAN JOHNSTON: Before you go, Fritz, one of the
16 concerns a couple years ago was just using DV collars, I think
17 there was -- at least I walked away from some of those
18 discussions with some concern that if we were to go down this
19 route and oppose this requirement and actually see you using DV
20 collars, that we might regret that decision because of
21 integrity problems with the casing. Have you experienced any
22 problem using DV collars to date with preserving integrity of
23 casing?
24 MR. GUNKEL: We have experienced problems. Of the
25 wells that we drilled in the last year, we've had three wells

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1 where the DV collar failed to pressure test at the end of the
2 job. We obtained the cement job but at the end, you know, the
3 last test, as Chuck referred to as we have to be sure that we
4 have structural integrity not only in the -- or sealing
5 integrity not only in the annulus, but in the casing itself,
6 and when the mechanics of that tool failed we did not have that
7 sealing integrity. So in those cases what we had to do is
8 suspend those wells and work out a method to repair them, which
9 we did. We spent additional monies and went in and installed a
10 device called a casing patch across that zone. Now
11 statistically it's a relatively small percentage of wells.
12 This would be less than 5% of our wells have failed, but the
13 implications of those failures are quite expensive. If the
14 casing patch doesn't give you adequate cement -- adequate
15 sealing integrity, it can mean that you have a wellbore you
16 cannot use and you have to abandon it according to regulations
17 to surface and start over. Up to this point in using DV
18 collars we haven't had to do that, but we actually have one
19 remaining well of these three that we're planning on going out
20 and repairing. So the risk is there. We certainly have worked
21 hard and our suppliers have done a fine job of providing us a
22 reliable tool, but it's a risk that we don't believe is
23 merited, you know, based on the assurance we're putting in with
24 the stage collar. So that's why we're recommending another
25 approach.

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1 CHAIRMAN JOHNSTON: So how expensive is it to run a
2 patch if your DV collar fails?
3 MR. GUNKEL: At that point now you're really talking
4 about a major expense. If you're prepared -- and we are now
5 prepared as we've seen these worked out a scheme to approach
6 this, to repair this immediately when we encounter it, you're
7 probably entering a two-day operation plus the investment and
8 the additional tools. So you're talking about something that's
9 going to cost incrementally roughly 150 to $200,000 to your
10 operation.
11 CHAIRMAN JOHNSTON: How successful do you think you've
12 been in bringing cement to the surface using a two-stage
13 cementing technique? Have you been able to achieve cement in
14 all cases to surface or are you still experiencing some
15 problems?
16 MR. GUNKEL: Still I'm not able to give you the exact
17 statistics. We're quite successful with the stage collar in
18 bringing cement to surface. We design our process to be quite
19 successful because what we're managing is really a -- the risk
20 of the implications from a regulatory perspective if we don't
21 bring cement to surface. And so as a result what we do is we
22 pump large volumes of cement to assure that we, you know,
23 offset any potential to be inaccurate in the whole volumes.
24 And I would estimate that our success in that is 90%
25 successful. Now -- but that's by design, and as a result we

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1 deal with much larger waste streams of excess cement, and then
2 the investment we've already talked about.
3 CHAIRMAN JOHNSTON: And how have you been dealing with
4 your excess cement at the surface?
5 MR. GUNKEL: We follow the regulations on disposal for
6 material that has been circulated downhole.
7 CHAIRMAN JOHNSTON: So in most cases that goes down a
8 Class II UIC well or.....
9 MR. GUNKEL: That's correct.
10 CHAIRMAN JOHNSTON: .....down the annulus of an
11 adjacent well?
12 MR. GUNKEL: That's correct.
13 CHAIRMAN JOHNSTON: Both scenarios you.....
14 MR. GUNKEL: It depends on the area and it depends on
15 whether we have an injection point that's acceptable for a
16 Class II injection as an annulus. In a large part of the field
17 we have dedicated a Class II injection well where a majority of
18 this material, if it's been circulated in the wellbore, is
19 injected.
20 CHAIRMAN JOHNSTON: So under the AOGA proposal in order
21 for the commission to determine if the well has been adequately
22 cemented you would rely primarily then on the formation
23 integrity test?
24 MR. GUNKEL: That's correct. Now it's -- that's not
25 the sole criteria that we use. As in most of our business we

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1 look at a variety of indicators, things as qualitative as
2 cement lift, just the indication that pressures are increasing
3 as we're lifting cement up the annulus. There's quite a bit of
4 diagnostics we can do to give ourselves the assurance that we
5 lifted cement adequately. Just the timing of the occurrence of
6 lost circulation with respect to this can give us fairly clear
7 indications of where we have lost circulation. But the most
8 definitive indication is a FIT test.
9 CHAIRMAN JOHNSTON: Fritz, currently, you know, with
10 our requirement of cement to surface we use -- we don't just
11 rely on the formation integrity test ourselves; there's -- as
12 you say, there are many indicators that we rely on. Of course
13 one of those is to seek good cement returns to the surface, and
14 I guess my concern is, you know, what we would be doing as a
15 substitute measure, what -- how would the commission have
16 clarity that in fact we do have a good cement job. As you
17 remember, we got into this area because we were seeing too many
18 broaches to the surface with our annular disposal program.
19 Once we all focused on the problem and changes were made in
20 cementing practices, we have -- to my knowledge anyway, have
21 not had any examples of a broach to the surface since we
22 adopted the more rigid standards. So on one hand, you know, I
23 recognize the importance of keeping drilling costs to a
24 minimum. On the other hand though, we need to make sure that
25 the operations are done in such a manner that we do not lead to

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1 problems associated with waste disposal as well as well
2 control.
3 And I guess my question is how confident do you feel
4 that the formation integrity test is going to be kind of a more
5 important indicator than these other -- basically what you're
6 offering us, as a commission, is to rely on the formation
7 integrity test as basically almost the sole means available to
8 the commission, and if I understand your language, that
9 formation integrity test would only be provided to us if there
10 was a problem, or you would indicate that there was a problem
11 after you yourself looking at the formation integrity test and
12 in fact the commission would not necessarily see that. Is that
13 what I'm understanding?
14 MR. GUNKEL: Well, to go back to sort of the beginning
15 of your question, first in the objectives, our objectives are
16 clearly to obtain cement integrity, to obtain a casing string
17 that is installed with the integrity where all fluids that are
18 in place or injected or used for drilling fluids are isolated
19 to the intended zones. We are proposing this with the full
20 confidence that what we're proposing will assure that. At the
21 same time with your observation about the absence of broaching
22 incidents since this regulation occurred, there's also been,
23 you know, a number of other steps taken to assure that we're
24 injecting to meet all criteria to assure that we prevent
25 further broaching based on what we've learned. So we don't

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1 couple the sealing integrity gain in the top section of the
2 wellbore by getting cement to surface to the assurance that
3 broaching will be prevented. We do, with complete confidence,
4 feel that the -- a quality FIT test that indicates we have zone
5 isolation to shoe is the best assurance. It's -- indicates the
6 quality of cement in the most competent formation and in the
7 area that we feel is the best and has been proven to be the
8 best area of sealing.
9 My understanding of the -- you know, to the point of
10 your question, I don't believe it's AOGA's intent to withhold a
11 FIT test on any well. I anticipate we would provide the
12 results of FIT tests, as we do today. But what we're saying is
13 that the two levels of assurance that AOGCC has is, one, a
14 successful, adequate FIT test, and, two, that we are seeking to
15 bring cement to surface by pumping what we calculate to be the
16 volume of cement to surface. We still intend to attempt to
17 achieve that, but we feel that the added assurance of the
18 absolute requirement of having cement to surface is unnecessary
19 to meet the requirements that we're both concerned about.
20 CHAIRMAN JOHNSTON: And, again, just to kind of capture
21 the proper background here, how would you determine the
22 calculated volume? What -- I mean clearly we understand that
23 the hole that you drill, especially through the permafrost, is
24 not a gauge hole, that you'll have wash-outs, etcetera,
25 etcetera. How would you then determine what is the calculated

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1 volume?
2 MR. GUNKEL: At this point I'd like to ask for some
3 help from, you know, a design engineer here, so maybe I could
4 ask Chuck or Mike to give me a hand here. If that would be all
5 right with you?
6 CHAIRMAN JOHNSTON: That's perfectly fine.
7 MR. ZANGHI: I can speak specifically to those
8 practices relating to the -- what I'm most familiar with which
9 is the greater Kuparuk area, and the -- what we'll do is we'll
10 -- an initial well in a given area, we'll estimate what we
11 think the hole enlargement is based on previous history that
12 we've had, and then we will calculate that volume of cement to
13 fill that annular space. Following the results of that job we
14 will either increase or decrease the amount of cement for the
15 next job. And our practice has been that that method has been
16 successful in the areas -- certainly in the areas that I'm
17 familiar with.
18 I'm not sure if that addresses your question
19 specifically.
20 CHAIRMAN JOHNSTON: Well, yeah, again I just wanted to
21 provide some background in anticipating additional questions
22 that we may have as we kind of chew on this request that AOGA
23 is making. But as I understand it, the calculated volume would
24 be based upon a statistical average volume of holes that you've
25 drilled over the past couple years, I guess.

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1 MR. ZANGHI: It would be -- I would say that it would
2 be a little bit more specific in the regard that each drill
3 site, each pad has -- at least we've experienced different
4 levels of wash-out, and so we wouldn't necessarily take a
5 statistical average of an entire field, it would be on a more
6 regional pad-by-pad basis, and in some cases it's been a
7 cluster of wells on a pad. The design engineer will look at
8 the history and see what it has taken to get cement to surface
9 in previous wells and go with that.
10 CHAIRMAN JOHNSTON: So I guess given, for the last two
11 years anyway, we've -- you've undertaken cement to surface
12 doing a two-stage cement job and that sort of thing, you would
13 use that, I assume, as at least a partial basis for determining
14 on a future well the calculated volume. You'd look at the
15 volumes that you actually were required to do in prior wells
16 and anticipate moving that volume out to the pad?
17 MR. ZANGHI: Certainly given our success at achieving
18 cement to surface on these two-stage jobs, that's getting us a
19 better handle on the size of the hole behind that pipe, so that
20 what we've done here the past two years with two-stage jobs has
21 certainly added to our knowledge base of what the hole size
22 required. We feel like we had a fairly adequate knowledge base
23 to begin with and we would certainly take into consideration
24 these last sets of wells.
25 COMMISSIONER CHRISTENSON: What's been your experience

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1 over the last couple of years in failing to bring cement to the
2 surface?
3 MR. ZANGHI: We have -- again I don't have the specific
4 numbers, but I think Fritz suggested a number of 90% success on
5 these two-stage jobs which, I think, is probably accurate on a
6 broad basis. We still have a number of wells that even via the
7 means we're currently using, some sort of remedial action has
8 had to -- has been undertaken. And the 40 -- I just might want
9 to add, the $40,000 number that per well, I think was thrown
10 out, was an incremental for a two-stage job over a one-stage
11 job, and I don't believe reflects the cost of -- the additional
12 cost of remediation or failure which has been quite substantial
13 in the past couple of years.
14 COMMISSION OECHSLI: Does it include disposal costs?
15 MR. ZANGHI: I believe it does. If I could just
16 respectively (sic) add one more thing about annular injection
17 and just kind of confirm what Fritz said is -- our position is
18 that that top portion of the well in which is the permafrost,
19 our experience has been, is not fully cemented permafrost
20 region is not necessary to achieve isolation of annular
21 injection of fluids. We continue to annular inject in the
22 regions that we operate and have experienced no change in
23 failure rate in annular injection. In fact we had none that I
24 know of in my time here, prior to the new regulations, and we
25 continue to have no annular injection broaching issues. We

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1 feel it's that bottom portion of the well that's the -- is a
2 critical part of containing the annular injection, along with
3 proper containment; proper confining zone and proper injection
4 zone.
5 COMMISSIONER OECHSLI: Do I understand correctly that
6 if under the AOGA proposal you would no longer do a two-stage
7 cement job?
8 MR. ZANGHI: We would no longer perform two-stage
9 cement jobs on each and every well, that is correct.
10 COMMISSIONER OECHSLI: Do you have some idea as to what
11 your success rate then would be for getting cement all the way
12 to the surface?
13 MR. ZANGHI: I can only speak to historical -- what we
14 saw before, and again I'm going to -- at this point I only have
15 to speak for the fields that I'm familiar with. And if I
16 recall from previous discussions that we've had, our success
17 rate was in the 50 to 60% range of getting cement to surface.
18 Via new technologies and lighter weight cement, via more
19 information on annular volumes, we would hope that that
20 percentage would increase. To achieve 100% on a single safe
21 job and on every job is not something I can sit here and tell
22 you that that will happen. But as described in our proposal,
23 that would be the -- that would certainly be the goal of each
24 cement job.
25 CHAIRMAN JOHNSTON: I suppose -- I mean part of the

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1 problem with bringing cement to the surface is just the sheer
2 length of the pipe that you're running for surface casing; is
3 that not correct? I mean we're seeing some just tremendous
4 strings of surface casing, and to cement that all the way to
5 the surface is a very difficult task, is it not?
6 MR. ZANGHI: The length of the casing string can make
7 fully cementing pipe more problematic. In the case where it's
8 lost circulation not necessarily because the true vertical
9 depth of the well is the same whether it's at zero degrees or
10 at 60 degrees, and so we're still dealing with the same amount
11 of hydrostatic head pressure. So in areas -- in cases where
12 it's related to failure of the wellbore to support a full
13 column of cement it would have -- it would have no bearing.
14 CHAIRMAN JOHNSTON: Are all your well circulation zones
15 in the permafrost; is that where you experience the problem or
16 do you see problems below the permafrost as well?
17 MR. ZANGHI: Again, speaking for the areas I'm familiar
18 with, I would not -- I would not portray 100% of lost
19 circulation in the permafrost. I would -- certainly don't have
20 the information in front of me, but in the region immediately
21 below the permafrost there may be. But I don't have that
22 information at this time.
23 CHAIRMAN JOHNSTON: So under the AOGA proposal if you
24 had identified an area that had lost circulation in a layer of
25 rock below the permafrost, that might be a place where you

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1 would be a candidate for a two-stage cement job? What I heard
2 you to say earlier is that you would not -- I think your
3 preference would be -- under the AOGA proposal would be to only
4 do single cement jobs, but I'm also hearing, in at least your
5 choice of words, that you wouldn't necessarily rule out dual
6 stage jobs, that there would still be an appropriate
7 application of that procedure.
8 MR. ZANGHI: The use of two-stage cementing is -- has
9 always been available to the design engineer, and if we
10 encounter a series of wells in which we don't feel we can meet
11 the objectives, the eight objectives of a surface casing
12 cementing, DV tools, as well as other non-conventional cement
13 means, may be employed, again with the specific goal of trying
14 to meet the stated requirements of the surface casing cementing
15 and not necessarily to achieve full cement to surface but
16 achieve what we feel is the design criteria of casing and
17 cementing in the surface hole.
18 CHAIRMAN JOHNSTON: Okay. Thank you. Any other
19 questions?
20 COMMISSIONER OECHSLI: I don't have anything else.
21 COMMISSIONER CHRISTENSON: I understand -- I'm not sure
22 about who made the statement but it was with regard to the fact
23 that since we've been requiring this cement to surface, the way
24 the regulation is now and proposed, that that had not been the
25 sole cause or solution for not having broaching to surface any

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1 more, that there had been other advancements that had been done
2 that had contributed to that no broaching phenomenon. Whoever
3 said that, could you give us an idea what that was, what the
4 new techniques are that.....
5 MR. GUNKEL: Fritz Gunkel, Shared Services Drilling.
6 To answer your question, Mr. Christenson, we've severely
7 curtailed annular injection in many parts of our field. In
8 large parts of the field there is no annular injection because
9 we've set such stringent criteria for wells that would allow
10 annular injection that we've not, because of proximity of other
11 wells, allowed annular injection to occur. So in my area of
12 operation currently, all injection of this type goes to
13 dedicated injection wells.
14 COMMISSIONER CHRISTENSON: Okay. So it's nothing that
15 you have in the well design or anything like that, it's just
16 the fact that you've changed your disposal methods?
17 MR. GUNKEL: That is correct.
18 COMMISSIONER CHRISTENSON: Okay. Thank you.
19 MR. ZANGHI: If I could just add, and for the record I
20 think I described an area that I'm responsible for. We have
21 continued to annular inject in the fields that we operate, and
22 have not taken any significant change in our -- in the way we
23 inject or the way we design wells prior to the new regulations.
24 So our annular injection has continued. We now have a --
25 probably a decade now of successful annular injection in the

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1 greater Kuparuk area. And -- and eight years of pre-new
2 cementing regulations and two years of post.
3 COMMISSIONER CHRISTENSON: Okay, so you see no change
4 then?
5 MR. ZANGHI: No, no change. Or certainly our -- we've
6 had no broaching incidents with no change in the success rate
7 of our annular injection. It's made no demonstrable effect on
8 our annular injection.
9 COMMISSIONER CHRISTENSON: Thanks.
10 CHAIRMAN JOHNSTON: Okay, I think we're -- we've pretty
11 well exhausted ourselves on surface casing cementing.
12 Mr. Phillips, I guess you had broken it down into your AOGA
13 testimony and to various sections. How long do you feel the
14 next section may take us; is it something that is easily
15 handled or would this be a good time to take a break?
16 MR. PHILLIPS: I believe the testimony that remains is
17 very limited in terms of what we were going to provide, and we
18 could probably get it over quite quickly indeed.
19 CHAIRMAN JOHNSTON: Okay. Why don't we go ahead and
20 proceed then, at least to section II of your comments, and then
21 we will take a break at 10:30 or so.
22 MR. PHILLIPS: Okay. That sounds good. The second
23 issue we wanted to address was around BOP testing frequency,
24 and Mark Berlinger of Shared Service Drilling has some comment
25 on that, and we also want to provide you some supporting

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1 information for your consideration. Perhaps if Mark could -- I
2 understand will come forward, that will be all ready.
3 MR. BERLINGER: And for the record, I'm Mark Berlinger.
4 I work for BP and Shared Services Drilling, and I'm making
5 comments here on behalf of AOGA. We request an amendment of
6 the BOP pressure test requirements on 20 AAC 25.036 to be
7 consistent with the US Department of Interior Minerals
8 Management Service regulations. In June -- June 1st of this
9 year the Federal Register will enter as testimony today the
10 Minerals Management Service amended their regulations governing
11 the testing requirements for BOP systems used in drilling and
12 completion in the Outer Continental Shelf, allowing lessees up
13 to 14 days between BOP tests. The MMS based their rule on a
14 study of BOP performance which concluded that no statistical
15 difference exists in failure rates for BOPs tested between zero
16 and seven days, and eight and 14 day intervals. And so we
17 provide this as -- as a record of this testimony. In addition,
18 the supporting study that MMS used in making that determination
19 was a study entitled "The Reliability of Blow-out Preventers
20 Tested Under 14 and 7 Day Time Intervals," prepared by
21 Tetrahedron, on December 20th, 1996, and entered this report
22 and to the record as testimony.
23 The summary request to change current regulations in
24 the Tetrahedron report recommended the change of revising the
25 test frequency to -- because they said they felt that -- or

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1 reported that the seven day test hampers the flow of drilling
2 activities leading to inefficiency, too much testing can cause
3 component failure due to exposures of high pressure and
4 abrasive materials, and the testing within the 14 days provides
5 at least the same level of protection as the seven day
6 interval. Those are pieces of information that are contained
7 in this report.
8 CHAIRMAN JOHNSTON: You indicated that the MMS just
9 revised the regulations. Did I get the date right, in June
10 1998?
11 MR. BERLINGER: June 1st, 1998, yes.
12 CHAIRMAN JOHNSTON: And.....
13 MR. BERLINGER: Federal Register, yeah.
14 CHAIRMAN JOHNSTON: .....what were their requirements
15 prior to this amended regs?
16 MR. BERLINGER: Is there someone that worked on the OCS
17 that can give details?
18 MR. GUNKEL: Fritz Gunkel, Shared Services Drilling.
19 The requirement was weekly BOP testing.
20 COMMISSIONER CHRISTENSON: I haven't read that report
21 yet but how much of that information in that MMS report comes
22 from Alaska drilling?
23 MR. BERLINGER: I don't know that any has come from
24 Alaska drilling. The study came from an industry work group
25 with MMS, and I believe most of the information came actually

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1 out of the Gulf of Mexico.
2 COMMISSIONER CHRISTENSON: Thanks.
3 CHAIRMAN JOHNSTON: I think one of my concerns with
4 going to a two-week cycle is I understand, and correct me if
5 I'm wrong, but many of the crews working the drilling rigs work
6 a two-week on, two-week off schedule; is that right?
7 MR. BERLINGER: Yes.
8 CHAIRMAN JOHNSTON: Then how do you ensure under a
9 two-week BOP testing schedule that that second crew is going to
10 be conducting BOP tests?
11 MR. BERLINGER: Okay, well we test BOPs at a number of
12 occasions through the well, and in addition to the requirements
13 around the regulations. The crew changeover in terms of -- I'm
14 just thinking about how -- in terms of the crew changeover, I
15 haven't considered that a factor. We've -- get reported BOP
16 test frequency of BOP test results in our morning reports every
17 day, and it's something we look at on a daily basis, and at
18 least the drilling operation that I'm part of, and I expect --
19 I would expect the other drilling operations, that's something
20 that we look at on a daily basis, seven days a week, 365 days a
21 year of reporting.
22 MR. MALLORY: May I offer some testimony to give
23 clarity to that answer?
24 MR. BERLINGER: Yeah, sure.
25 CHAIRMAN JOHNSTON: Yes.

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1 MR. MALLORY: Chuck Mallory, Shared Services Drilling.
2 Mr. Commissioner, as I understand it, your question was if the
3 commission was to approve a two-week testing frequency you are
4 somewhat concerned that due to the timing of tests some of the
5 crews might not in fact be testing the BOPs beyond tower when
6 the BOPs are tested. I'd just like to clarify something. The
7 BOP test is a functional test of equipment; it is not in any
8 way a test of personnel and their reactions. The test or the
9 training and the drills that we do to test people's reactions
10 and knowledge of policies is completely separate from BOP
11 testing.
12 Did that answer your question?
13 CHAIRMAN JOHNSTON: It certainly helps. I guess when
14 does that training go on?
15 MR. MALLORY: There are specific requirements. I can't
16 cite policy, but there are specific requirements by operators
17 and also by drilling contractors on the frequency of trip
18 drills and those are the types of drills that we're talking
19 about, testing reactions of people, and I would -- I could get
20 back to you on that, but I would say that it's done at least
21 daily. Maybe someone else here in the room could add clarity
22 to that point.
23 MR. GUNKEL: Fritz Gunkel, Shared Services Drilling.
24 On the point of training, we exceed in our drilling contractors
25 -- exceed regulation, you know, from the standpoint that we

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1 have MMS, you know, level well control training that's offered
2 deep into the drilling organizations of our contractors, and
3 that has to be updated every two years. But on a daily basis,
4 and the thing that impacts all personnel, is that we hold daily
5 drills, you know, of the execution of the well control
6 functions that include the BOP, and these are frequently every
7 tower during the day.
8 But to get to the point, I believe, of your question is
9 what assurance does the commission have that the BOPs will be
10 tested in a timely manner on a 14-day cycle. I guess I'd like
11 to make the point that first of all, we consider the BOP or
12 well control equipment are absolutely a critical piece of
13 safety equipment. So, you know, regardless of the test
14 frequencies required in regulation, we're going to take the
15 steps to assure competence of the well control equipment. We
16 consider it, you know, a key safety device in our operations.
17 Also, our operations by their nature have to be
18 designed that through the hand-off of rig personnel and laborer
19 and supervisors that we've retained continuity, we retain the
20 knowledge of when we did something last and when we would do it
21 again, and given the high priority of this item, you know, we
22 will certainly retain continuity. In fact on a weekly BOP test
23 interval, frequently the weekly test will cross the shift
24 change of key personnel, and the key personnel supervising a
25 rig site are the operator's company representative and the

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1 contractor's tool pusher, and those are the people who are key
2 in assuring that all of our health, safety, environment and
3 business requirements are met. And today under the weekly
4 interval, we deal with personnel change in the interval. We
5 have no problem meeting the requirement. The same set of
6 issues exist in the MMS areas where crews work weekly or
7 bi-weekly. So I'm confident in making this proposal that there
8 be no threat to the continuity and frequency of BOP testing.
9 And actually in the practice of our operations frequently we,
10 because our aim is to drill wells quite efficiently, would end
11 up testing more frequently than that just by the nature of our
12 operations. We would move from well to well more frequently
13 than every two weeks in some cases.
14 I hope that helps.
15 CHAIRMAN JOHNSTON: Yes, it certainly does.
16 MR. WILLIAMSON: Good morning. My name is
17 Dan Williamson, with Unocal Alaska. We -- your question was
18 about crew change on a two-week basis which is done on the
19 Slope now. We -- for years we've been doing a week and a week,
20 and so it's -- we've had no problem with ensuring that there is
21 a proper hand-over in that. So it is -- you know, we've proven
22 it's very doable. And along with my colleagues the BOPs in
23 well control is our primary and fundamental safety issue out
24 there, and we take it very seriously. So I think, you know,
25 going to a two-week test, as far as it slipping through the

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1 crack, I don't think that's a real issue for us.
2 MR. CHRISTENSON: Given the interest that we've had in
3 getting the various environmental groups to make their
4 decisions and so forth in stuff that's pending such as broken
5 ice, I notice that the North Star -- oh, I'm not talking into
6 the mic -- wouldn't -- wouldn't this be relaxing this
7 requirement to 14 days now in a period when we're trying to
8 convince everybody that we're doing the safest thing we can
9 possibly do on the Slope be a -- have a negative impact on
10 those agencies?
11 MR. GUNKEL: Fritz Gunkel, Shared Service Drilling.
12 Mr. Christenson, we don't think this is something that should
13 cause anybody concern that we're relaxing our safety
14 requirements. The report that we've submitted actually points
15 out some of the disadvantages of exercising this equipment on
16 the frequency that a weekly well control test requires. And to
17 the point we would not take steps that would compromise our
18 capability to control the well. So I think the report we're
19 submitting supports that, and I'd certainly like to be sure
20 that the record, you know, asserts that AOGA is proposing
21 something that they feel only retains or actually improves, you
22 know, the integrity of our operations.
23 COMMISSIONER CHRISTENSON: Okay, so you don't think
24 there's any compromise in the safety aspect?
25 MR. GUNKEL: No, we don't.

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1 COMMISSIONER CHRISTENSON: Okay, thanks.
2 CHAIRMAN JOHNSTON: Any further questions?
3 COMMISSIONER CHRISTENSON: I have none.
4 CHAIRMAN JOHNSTON: Okay. Then why don't we take a
5 short recess and try and pick this up in about 10 more minutes.
6 (Off record - 10:37 a.m.)
7 (On record - 10:55 a.m.)
8 CHAIRMAN JOHNSTON: I'd like to go back on record.
9 Mr. Phillips, we're ready to move into your third category.
10 MR. PHILLIPS: Thank you, Mr. Chairman. Again, my name
11 is Chris Phillips, for the record. I just -- before I address
12 the other two categories, I would like to go back to the
13 question that Commissioner Oechsli asked, I believe. And that
14 was regarding 25.080(e)(2), and your question was about AOGA's
15 recommendation that this subsection be deleted. And the
16 subsection reads: The downhole disposal pressure may not
17 exceed the downhole pressure obtained during the formation
18 integrity test conducted below the outer casing shoe. And I
19 just wanted to give a little bit of clarity to our
20 recommendation. And essentially it is that it is almost
21 impossible to inject fluids without exceeding the pressure
22 obtained from the formation integrity test, and it is our view
23 that subsection (e)(1) and subsection (e)(3) actually provide
24 you with the integrity requirements of this whole section. So
25 I hope that provides the clarity that you were looking for.

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1 CHAIRMAN JOHNSTON: It does. Thank you.
2 MR. PHILLIPS: If I could come onto the third item, I
3 think I've probably said all that we need to say. What I have
4 is a letter that I have written to you on behalf of AOGA,
5 attaching a working copy of some language which I would like to
6 propose is a starting point from which we can move forward with
7 this issue of blowout prevention equipment. The issue came
8 about by the way the regulations have changed and the
9 consolidation that had happened and our view that there was not
10 sufficient clarity between the different types of activity on
11 the North Slope. For example, coil tubing drilling has, you
12 know, different requirements to -- through tubing drilling,
13 drilling itself, work-overs, re-entry, through tubing
14 perforating, and wireline operations. Amongst AOGA we have
15 worked over the last six weeks to try and get some language in
16 those categories that would adequately address your concerns
17 and our concerns, and we think we've got quite a long way, we'd
18 say about 90% of the way there, but it is lacking, you know,
19 some discussion which we think is important to have with staff
20 of the commission. And what we would propose is if there is a
21 way that that can be arranged that perhaps a work group could
22 be convened to very quickly, we believe, bring this recommended
23 language from a working copy to something that could be
24 potentially inserted in regulation and make its way through the
25 Department of Law.

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1 CHAIRMAN JOHNSTON: I think we can certainly make
2 members of our staff available to answer questions that the
3 work group may have. I guess my question for you is given
4 that, how long would it take for the work group to come back
5 and present their recommendation to us?
6 MR. PHILLIPS: I would say that within two weeks from
7 today we can have a very clear recommendation. I mean I think
8 what you see in the letter that we've written to you is some
9 very clear direction, but since it's such a broad issue and
10 covers not only folks operating in Anchorage but the folks on
11 the North Slope, there is a lot of input from a lot of
12 different people. So I think within two weeks we could
13 certainly have something that your staff could look at and we
14 would be available to provide dialogue at that time.
15 CHAIRMAN JOHNSTON: What our plan, moving forward from
16 this hearing, is to hold a series of meetings/hearings
17 beginning, I believe in the first week of November we'll be
18 putting a notice in the paper concerning these
19 meetings/hearings. The purpose of that is to allow the
20 commission to deliberate among itself to determine which
21 recommendations, changes we want to embrace, and it is also to
22 allow us the opportunity to take additional testimony. I guess
23 what I would request then is that the recommendation of this
24 work group be made available on that first Monday.
25 MR. PHILLIPS: Okay.

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1 CHAIRMAN JOHNSTON: That should give you the two
2 weeks.....
3 MR. PHILLIPS: And then some.
4 CHAIRMAN JOHNSTON: .....and then some in order to do
5 that.
6 MR. PHILLIPS: Absolutely.
7 CHAIRMAN JOHNSTON: So if we can go with that as a
8 commitment then I think advancing with the work group is
9 appropriate and we can also make staff available for
10 consultation to answer questions, etcetera.
11 MR. PHILLIPS: In the interim period?
12 CHAIRMAN JOHNSTON: Right.
13 MR. PHILLIPS: Okay. Then we can make a commitment to
14 that and also we can have available to you people, you know,
15 who can give very specific testimony or can answer the
16 commissioners' questions if we can just make some arrangements
17 about which of the dates would be appropriate to do that.
18 CHAIRMAN JOHNSTON: Right. And those -- the follow-up
19 with the commission would occur during our public setting.
20 MR. PHILLIPS: Right.
21 CHAIRMAN JOHNSTON: And I think we can map out that
22 strategy certainly on that first Monday.
23 MR. PHILLIPS: Good.
24 CHAIRMAN JOHNSTON: And I believe I don't recall what
25 the date is, but I think it's like the first. Anyway, it's the

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1 first or the third is the first meeting -- the 3rd of November.
2 We will be putting that notice in the paper very shortly.
3 Anyway, it's the first Monday in November, whatever that is,
4 and we will be meeting Monday, Wednesday -- Monday, Tuesday,
5 Wednesday each week basically, and hopefully wrap this up
6 without too much additional time other than the time that we
7 have earmarked in our notice.
8 MR. PHILLIPS: And AOGA will certainly make ourselves
9 available and we will bring -- given a schedule we will bring
10 the appropriate people who have knowledge in the areas to the
11 meetings.
12 CHAIRMAN JOHNSTON: I guess the one caveat I'd like to
13 put on this, and I'm sure you're thinking along the same lines,
14 is that I would insist that the recommendations be -- have the
15 similar look and feel, that you don't present us a list of
16 recommendations that appears to be written by several different
17 work groups. I want to see a theme throughout the thing and
18 changes where appropriate, obviously, but there should be
19 consistency as well.
20 MR. PHILLIPS: Absolutely. And that's certainly been
21 our intent in embarking upon this, that we get thematically
22 throughout the various sections, they have, as you say, the
23 same look and feel,.....
24 CHAIRMAN JOHNSTON: Right.
25 MR. PHILLIPS: .....and would be -- we hope it would

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1 make things easier for folks to understand and would certainly
2 acknowledge new technology that's happening out in the field.
3 CHAIRMAN JOHNSTON: And do you vision then presenting a
4 product to us that would track this, the working categories as
5 you see it?
6 MR. PHILLIPS: Absolutely. And I think that the
7 language you'd also find in each of the working categories
8 would track each other and you'd readily be able to move
9 between one and the next. I would acknowledge as well some
10 very real problems and differences in the field. Wireline
11 re-entry is very much different from, you know, a work-over
12 operation, and, you know, trying to impose one set of
13 requirements on both of those is probably inappropriate. And
14 trying to write one section that covers all is almost
15 impossible.
16 CHAIRMAN JOHNSTON: Indeed it is. Now this looks like
17 a very -- a good way to proceed on this. And in looking at the
18 working categories, I'm intrigued by them and I think certainly
19 the breakdown has merit, and I would encourage the work group
20 to go ahead and flush the standards out under each one of
21 these.
22 MR. PHILLIPS: Okay. And as we committed, we will have
23 a finished product for you available the first Monday in
24 November.
25 CHAIRMAN JOHNSTON: Very good.

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1 MR. PHILLIPS: That was the third issue that AOGA had.
2 The final issue was a very minor issue, but I asked
3 Mark Worcester to address it. It's about the change of
4 ownership section of the regulations.
5 MR. WORCESTER: Thank you, Mr. Chairman and
6 Commissioners. Mark Worcester again. I am with ARCO, speaking
7 on behalf of AOGA here. Actually we had two miscellaneous
8 items that we just failed to get into our written comments that
9 we submitted, so we are taking the opportunity that you
10 provided to make them orally here.
11 The first one was with regard to 20 AAC 25.022 which in
12 its existing form requires a change of ownership to be reported
13 by operator. And the proposed regulation would have the owner
14 acquiring the information do this report or file that form. In
15 looking at this we were struck by the perhaps more fundamental
16 question of what the need or purpose of the commission, perhaps
17 trying to duplicate land ownership, record information that is
18 already kept by DNR or other land owners, and so I -- what we
19 would suggest, instead of amending this regulation, is that we
20 would suggest that the commission considering just repealing
21 that. Quite frankly, I have not studied this and I don't think
22 anyone here focused too much on this, but we're not -- we're
23 not sure what role this serves currently in as far as the
24 commission's operations. And so that is our suggestion, that
25 you consider repealing this regulation.

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1 The other comment is with regard to 20 AAC 25.520, and
2 it's entitled, "Field and Pool Regulation." And the thing that
3 -- even though it talks about field and pool regulation and
4 classification, when it gets down to actually describing the
5 kind of order that can be issued by the commission, it only
6 mentions pool orders, and not field orders. And both the words
7 "field" and "pool" are defined, and AOGA believes it would be
8 appropriate that the commission retain the flexibility to issue
9 orders under 520 that would apply to field as well as just to
10 pools. I can give you an example where you've effectively done
11 this already at Pt. McIntyre, a participating area. The pool
12 rules apply both to the Stump Island pool, as well as to the
13 Pt. McIntyre pool. I think there are other times where it may
14 be appropriate to have rules that would apply to several pools
15 with special subsets of rules that would apply to individual
16 pools. If you make this change, you would also need to make
17 corresponding changes to references to pool rules in various
18 other places in the regulations, and that would be -- and I'll
19 give you these in written form too: .030(a), .055(a), .280(c),
20 and .432(b). If I caught all the places where there are
21 references to issues of pool rules my word search worked
22 correctly that is.
23 Those are my only additional comments.
24 CHAIRMAN JOHNSTON: Okay. Before you go, and
25 concerning your change -- or your recommendation to the change

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1 of ownership, I guess as I understand you, we shouldn't be
2 really concerned about this information because that
3 information is more appropriately kept by other entities in the
4 state?
5 MR. WORCESTER: That is -- essentially that. And
6 actually I would add that as far as I'm aware, there's no
7 requirement that the initial ownership be reported or retained
8 by the commission, so it would be sort of odd if change of
9 ownership needs to be somehow submitted to the -- filed with
10 the commission when initial ownership is not required. As far
11 as I am aware that the focus of the commission's regulation has
12 been on the operator rather than with regard to owners. And we
13 believe that that is, you know, sufficient and appropriate.
14 CHAIRMAN JOHNSTON: What about the situation where
15 we're dealing with fee land; not state land, not federal
16 government land but privately held, should that information be
17 reported to us in that case?
18 MR. WORCESTER: The change of ownership?
19 CHAIRMAN JOHNSTON: Yes.
20 MR. WORCESTER: Maybe just what this is focused on -- I
21 haven't really given -- and AOGA certainly has not, I think,
22 given thought to at what point and how -- to what extent the
23 commission should get itself involved in and concerning
24 people's right, how they've proven their rights to be doing
25 what they're doing on the land.

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1 CHAIRMAN JOHNSTON: Yeah, I think the original intent,
2 and maybe we've kind of lost it here as we've made these
3 various changes, is I think you have to read this in
4 conjunction with 020, and I think in hindsight now 020 has
5 implied that the owner was in fact the operator. And if the
6 owner changes then the commission needs to know that from the
7 standpoint of that being an indication that there is now a new
8 operator.
9 MR. WORCESTER: I think that -- that would be my guess
10 too,.....
11 CHAIRMAN JOHNSTON: Right.
12 MR. WORCESTER: .....because I think that -- and you
13 can take it, a narrow definition of what owner is and actually
14 make it the operator.
15 CHAIRMAN JOHNSTON: Yeah.
16 MR. WORCESTER: You could construe the definition in
17 the -- as the person has the -- I think it's the person who has
18 the right to drill, and usually the person that has the right
19 to drill is not necessarily every working interest owner, but
20 would be the operator. And if you think of it in that context
21 the operator comes to you, gives the bond and so forth, and
22 then if the operator changes you'd want to know that. And I
23 think requiring a Notice of a Change of Operator on a well
24 would be something that the commission would be appropriately
25 interested in.

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1 CHAIRMAN JOHNSTON: Right. Thank you.
2 MR. PHILLIPS: Chris Phillips again, for the record.
3 That does conclude testimony, Mr. Chairman, that AOGA proposed
4 to give today. Just perhaps if we could ask one question,
5 getting just a little more clarity about the meetings that you
6 propose to have, just so that we can think about staff that we
7 need to bring from the various member companies. Do you
8 propose to lay out an agenda in the first meeting, for example,
9 that you propose to have over the course of the next few weeks
10 so that we can seek those people in or have you given that any
11 thought?
12 CHAIRMAN JOHNSTON: I think that was -- that is
13 probably something that we could consider on that first Monday
14 is to map out a tentative schedule for review. As you know,
15 from our prior contact with adopting proposed regs, we often
16 get sidetracked and agendas don't necessarily -- are not
17 necessarily followed. But I think it is certainly my intent to
18 try and move through these as quickly as we possibly can to get
19 these things out. We've been working on them for a good number
20 of years now and so it almost seems like a career, but, you
21 know, I think maybe the best way to proceed is to see if we can
22 hammer out an agenda and commit to that and move forward on it
23 and just make a concerted effort to get our work done in the
24 time frame that we have allotted. I understand the dilemma
25 that industry would feel or other people in the public that may

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1 have some concerns about a particular section that if they
2 don't have a sense of where we are in our deliberations that
3 they'll miss that opportunity. And yet it would create a
4 burden for the public to sit here every morning for the next
5 four weeks as we deliberate in November.
6 MR. PHILLIPS: Certainly.
7 CHAIRMAN JOHNSTON: So.....
8 MR. PHILLIPS: I appreciate your clarification.
9 CHAIRMAN JOHNSTON: Right. So maybe that can be one of
10 our first topics that we take up on that subsequent Monday, to
11 try and map out some sort of strategy for moving forward and
12 getting a sense, maybe article by article, that we'll devote so
13 much time per article.
14 MR. PHILLIPS: Good.
15 CHAIRMAN JOHNSTON: Thank you.
16 MR. PHILLIPS: Thank you very much.
17 CHAIRMAN JOHNSTON: I guess at this time I would -- I'm
18 looking down at the list here and I have -- those people that
19 have indicated -- that indicated that they desired to testify
20 have, in fact in one way or the other, appeared before us this
21 morning. But I'd like to, again, extend the opportunity. Is
22 there anybody in the audience that wishes to appear before the
23 commission? Mr. Williamson, you indicated your desire.
24 MR. WILLIAMSON: My name is Dan Williamson, with
25 Unocal. One of the -- let me state the topic I'll be talking

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1 about, in 20 AAC 25.030, Casing and Cementing, Section (d)
2 specific Well Cementing Practices in number (7). This recently
3 came to my attention, I hadn't had an opportunity to present it
4 in the AOGA forum, so I'm here as Unocal presenting, and if I
5 could read it to you and then get some clarification.
6 It says: For intermediate or production casing in a
7 service well used for injection a cement quality bond or other
8 valuation log approved by the commission must be run to
9 demonstrate isolation of injected fluids to the approved
10 interval. A minimum of 24 hours' notice of the logging
11 operation must be provided so a representative of the
12 commission may witness it.
13 The issue I'd like to bring up is the last part, about
14 the 24 notice -- 24 hours' notice of logging operation so that
15 a representative of the commission may witness it. The log in
16 itself is a -- if the commission is wanting to see that a log
17 is done, the log itself done by a third party -- qualified
18 third party is printed out and delivered as part of the final
19 well report that -- and in the sundries that comes to the
20 commission. It's also noted on the IADC reports that end --
21 any morning reports that a log has been done. I don't know as
22 far as having one of the commission's representatives there,
23 not to detract any of their qualifications, but I don't know
24 that they would be able to -- and qualified to run the log, if
25 you understand what I mean. I guess the intent is if the

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1 commission wants to make sure the log is done, it is receiving
2 proof from a third party that it's being done. And as far as
3 bringing one of the inspectors out, it's just another
4 logistical complication for the operators and not really
5 knowing if it's accomplishing what the commission had in mind
6 when putting this in here. I guess that's my comment on it.
7 CHAIRMAN JOHNSTON: Okay. Thank you, Mr. Williamson.
8 Do you have anything in writing for us that you could.....
9 MR. WILLIAMSON: I can deliver something to you. I
10 just -- like I say, I just picked up on this. I'll do that.
11 CHAIRMAN JOHNSTON: Right. Even if you wanted to leave
12 us a paper today, just kind of expressing that, you know, this
13 is an area of concern, that will allow us to then spring off of
14 that to have a dialogue between ourselves and our public
15 meetings that we'll hold in November.
16 MR. WILLIAMSON: Okay.
17 CHAIRMAN JOHNSTON: So it would be helpful if you'd
18 leave something with us in writing, and it doesn't have to be
19 fancy, you know. If you want to scribble something down, this
20 is your concern, circle the section and briefly indicate, you
21 know, that you have concern from a logistics standpoint and
22 some concern relative to even the necessity of having an
23 inspector out there while you run these logs.
24 MR. WILLIAMSON: Okay. Thank you.
25 (Pause - commissioners confer in whispered tones)

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1 CHAIRMAN JOHNSTON: Is there any other individual in
2 the audience wishing to testify on the proposed regulations
3 this morning? Okay, I do not see any. At this point then I'd
4 like to go off record for just a few minutes. I'd like to
5 consult with our attorney, and then we'll come back.
6 (Off record - 11:20 a.m.)
7 (On record - 11:22 a.m.)
8 CHAIRMAN JOHNSTON: We're back on record. We've just
9 determined that there is no other individual wishing to
10 testify. I would like to turn to my other commissioners and
11 ask if they have any further questions of anybody?
12 COMMISSIONER OECHSLI: I don't.
13 COMMISSIONER CHRISTENSON: No further questions.
14 CHAIRMAN JOHNSTON: Okay. The commission has no
15 further questions so at this point I see no need to continue
16 the hearing and so we'd adjourn as of, oh, approximately 20
17 minutes after 11:00 o'clock. Thank you very much.
18 (Off record - 11:22 a.m.)
19 END OF PROCEEDINGS
20
21
22
23
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25

1 CERTIFICATE
2 UNITED STATES OF AMERICA)
)ss.
3 STATE OF ALASKA)
4 I, Laurel L. Earl, Notary Public in and for the State
5 of Alaska, and Reporter for Elite Court Reporting, do hereby
6 certify:
7 That the foregoing Alaska Oil & Gas Conservation
8 Commission Hearing was taken before Laura Farley of Metro Court
9 Reporting, on the 15th day of October 1998, commencing at the
10 hour of 9:00 o'clock a.m., at the offices of Alaska Oil & Gas
11 Conservation Commission, 3001 Porcupine Street, Anchorage,
12 Alaska;
13 That the hearing was transcribed by myself to the best
14 of my knowledge and ability.
15 IN WITNESS WHEREOF, I have hereto set my hand and
16 affixed my seal this 25th day of October 1998.
17
18 Notary Public in and for Alaska
19
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#3

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To: Commissioner Cammie Oechsli 276-7542
AOGCC

Pages: 5

From: Judy Brady, Executive Director Date: July 19, 1999

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July 19, 1999

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AOGA Comments on Proposed Regulations (20 AAC 25.565) Implementing AS 31.05.030(i)

Dear Commissioners:

The Alaska Oil and Gas Association (AOGA) appreciates the opportunity to provide comments to the Alaska Oil and Gas Conservation Commission (AOGCC) on proposed regulations (20 AAC 25.565) implementing AS 31.05.030(i).

As you are aware, the Alaska Oil and Gas Association is a private, non-profit trade association. Its 18 member companies represent the majority of oil and gas exploration, production, transportation, refining and marketing activities in Alaska.

AOGA did not take a position on House Bill 380, passed by the Legislature in 1998 to encourage investment in certain undeveloped or shut in Cook Inlet fields, and therefore did not participate in the hearings that preceded its passage. Our interest at this time, relating to the AOGCC proposed regulations, is in maintaining the good working relationship on local hire that has developed between members of the oil and gas industry and the State of Alaska in recent years.

The members of Alaska's oil and gas industry made a renewed commitment to voluntary measures for local hire efforts through the cooperative work of Governor Knowles' Oil and Gas Policy Council. Over the last few years, individual companies have worked with the legislature and the administration to develop voluntary local hire legislation and/or agreements that meet the spirit of local hire goals as well as the legal parameters.

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The AOGA member companies are proud of this local hire record and recognize the cooperative efforts that have resulted in legislation and regulations for voluntary local hire processes that have not been challenged on constitutional grounds. (For reference purposes, we have attached a brief summary of previous legal decisions in this area).

It is in this context that AOGA has reviewed the proposed regulation addressing requirements for "a voluntary agreement by the lessee to use its best efforts to employ residents of this state, consistent with law and to contract with firms in this state for work in connection with the development of the field, including the fabrication and installation of required facilities, whenever feasible."

AOGA has several concerns with the proposed regulation. First, given the language of the statute and the efforts that have occurred in the past, AOGA would question the need to adopt regulations to implement AS 31.05.030(i). The language of the statute clearly states the intent of the legislature, therefore to propose regulations "to make specific and interpret" the language of the statute seems unnecessary.

The primary area of concern is that portions of the proposed regulation would be subject to constitutional challenge, particularly the paragraph addressing "a lessee's best efforts " in 20 AAC 25.565 (7) (b). The proposed regulation requires application of "a quantitative decision matrix to justify any decision to employ a person other than a resident of the state or to contract with a firm other than a firm in this state". This requirement goes well beyond "best efforts" and is contrary to practices developed in statute and regulation over the past few years. We recommend that you delete this provision.

The second provision that raises constitutional concerns is language in paragraph (d), which proposes to give AOGCC the ability to decide whether or not the plan, including local hire provisions, "is complete at the time it is submitted". This language raises the issue of voluntary versus mandatory actions, which has been the trigger for court challenges in the past. Under the language of the enabling statute, it appears that AOGCC's role is to hold a public hearing on the plan, with no intention that the Commission have the authority to modify or reject the plan based upon the completeness or details of the lessees "best efforts". In fact, had the statute contained such authority, the statute itself would be subject to challenge. We recommend that you modify or delete this section.

Finally, we note that the draft regulation proposed to define "firm in this state" and "resident". Definitions for "Alaska business" and "Alaska resident" are both defined in statute. We recommend that these sections be deleted as unnecessary and potentially problematic as the definitions are not consistent.

We will be attending the AOGCC hearing on July 21. Development of local hire language in regulation or statute that meets both the spirit and intent, as well as the letter of the law will always be a challenge, but it can be done as we have witnessed in other instances over the last few years.

Thank you for the opportunity to present these concerns.

Sincerely,

Judith Brady

JUDITH BRADY
Executive Director

JB:ts

Summary of Local Hire Decisions

Note: The members of Alaska's oil and gas industry are proud of our voluntary local hire record in Alaska. Companies have worked with the legislature and the administration in developing voluntary local hire legislation and/or agreements that meet the spirit of local hire goals as well as the legal parameters. This summary documents the legal history of local hire attempts that were not successful because they failed the test of constitutional law.

There are several examples in Alaska's history of unlawful attempts to *require* that work be performed by Alaska residents. Unfortunately, each of these experiences generated ill-feeling and deterioration of working relationships throughout the time they were being argued. These cases provide an opportunity to learn from and move forward on voluntary local hire efforts that achieve the intended goals and meet the constitutional tests articulated in these rulings.

Prior to the discovery of oil on the Kenai Peninsula in 1956, the main resource industry in Alaska was commercial fishing. Local fishermen constantly chaffed against the fishermen and processors of Washington State, who largely controlled the industry. In 1949, the Territorial Legislature enacted a law requiring nonresident fishermen to pay a commercial license fee of $50, while residents had to pay only $5. The preference was struck down by the United States Supreme Court in Mullaney v. Anderson, 342 U.S. 415, 72 S.Ct. 428, 96 L.Ed. 458 (1952).

With the discovery of Prudhoe Bay, and the impending construction of the Trans Alaska Pipeline, oil and gas development became the major resource industry of the state. In 1972, the State Legislature adopted an act entitled "Local Hire Under State Leases," AS 38.04.010-090 (1977). The key provision of the Act was the requirement that "all oil and gas leases, easements or right-of-way permits for oil or gas pipeline purposes, unitization agreements, or any renegotiation of any of the preceding to which the state is a party" contain a provision "requiring the employment of qualified Alaska residents" in preference to nonresidents. Although the Alaska Supreme Court upheld the act, the United States Supreme Court unanimously struck it down as a violation of the privileges and immunities clause in Hicklin v. Orbeck, 437 U.S. 518, 98 S.Ct. 2482 (1978).

Another source of contention was construction projects funded by state or municipal monies. The state legislature adopted a local hire law requiring that 95% or more of construction crews working on public construction projects must be Alaska residents. AS 36.10.010 et seq. (repealed). In Robison v. Francis, 713 P.2d 259 (Alaska 1986), the Alaska Supreme Court, having received guidance from the U. S. Supreme Court in Hicklin, held the local hire law unconstitutional under the privileges and immunities clause. The court held that the reach of the law was broad (about 60 to 70% of all construction is public facilities construction), and, of greatest note, that the justification – preference of residents over nonresidents – is impermissible:

Restricting entry by non-residents into a job market will make more positions available to residents. It is not difficult to make a case to a sympathetic legislature, whose members are accountable only to residents, that residents are deserving of protection because some of them are unemployed. But the universality of this condition is itself a reason why it is impermissible as a justification in privileges and immunities analysis. If every state could exclude or severely limit non-resident workers because some of its residents were unemployed our country would be "little more than a league of states" rather than "the Union which now exists." Paul v. Virginia, 75 U.S. (8 Wall) 168, 180, 19 L.Ed. 357, 360 (1869). Such a result would run strongly counter to the policy of national economic unity on which the privileges and immunities clause is based. The result would not be much better if the power to exclude non-resident workers were limited to those states with above average unemployment. Many states fit that category and many of the others, no doubt, have particular industries in which a case for protection can be made.

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713 P.2d at 267-68.

In 1986, the Alaska Legislature adopted legislation to frame a preference for certain workers in "underemployment zones" and "economically distressed zones" within the state. AS 36.10.005-.990 (1986). If the Department of Labor designated a certain zone as either economically distressed or a zone of underemployment, a contractor on a public construction project would be required to hire residents of the zone for at least half of its work force. AS 36.10.160. The Alaska Supreme Court struck down the preference as violative of the Alaska Constitution equal protection provision. State v. Enserch Alaska Const., Inc., 787 P.2d 624 (Alaska 1989): "We conclude that the disparate treatment of unemployed workers in one region in order to confer an economic benefit on similarly-situated workers in another region is not a legitimate legislative goal." 787 P.2d at 634. In so holding, the court relied heavily on the privileges and immunities analysis in the Robison case.

Other attempts to mandate preference for Alaskan residents have likewise been struck down by the Alaska Supreme Court and the United States Supreme Court. See, e.g., Lynden Transport, Inc. v. State, 532 P.2d 700 (Alaska 1975) (grandfather rights to resident trucking companies but not nonresident trucking companies); Sheley v. Alaska Bar Association, 620 P.2d 640 (1980) (residency requirement for bar admission applicants); Zobel v. Williams, 457 U.S. 55,102 S.Ct. 2309, 72 L.Ed.2d 672 (1982) (permanent fund dividend program preference for long-term residents over recent residents); Gilman v. Martin, 662 P.2d 120 (Alaska 1983) (borough ordinance granting preference to borough residents). Cf. Irby-Northface v. Commonwealth Electric, 664 P.2d 557, 562 (Alaska 1983) (concurring judges would have struck down as unconstitutional a provision granting a preference in state construction projects to resident bidders).

Forcenergy Inc

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July 15, 1999

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Original in Rey File

Commissioner Robert N. Christenson, P.E.
Chairman, Alaska Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, Alaska 99501-3192

Dear Commissioner Christenson:

On behalf of Forcenergy Inc (Forcenergy), I appreciate this opportunity to submit comments on the Alaska Oil and Gas Conservation Commission's (AOGCC's) proposal to adopt new regulations, 20 AAC 25.565, implementing AS 31.05.030(i). As a preliminary matter, it is not clear that any regulations are necessary to further interpret or implement the clear, concise legislative policy reflected in AS 31.05.030(i). However, as a company which was intimately involved in the deliberations leading to passage of the Cook Inlet royalty reduction legislation, Forcenergy is obviously interested in assuring that any regulations intended to implement the statutory provision accurately reflect the intent of the underlying legislation, avoid expanding the scope of the legislation and are legally defensible. Unfortunately, we believe AOGCC's current proposal fails on all three fronts.

As we have discussed with you previously, the legislative history behind the amendment of AS 31.05.030 to add subsection (i) reflects a conscious decision by the involved legislators to provide language that is instructive, not permissive. In its usage of the word "shall" instead of "may", the legislature intentionally limited AOGCC's role in facilitating public review of plans. The intent was to assure that the AOGCC's role was limited to accepting plans, should lessees elect to submit them, noticing those plans for public hearing, holding public hearings on the plans and, following those hearings, approving the plans within the prescribed time. The language of the statute is clear and unambiguous in this regard.

The record reflects that previous drafts which implied that approval of submitted plans was discretionary and which provided more detailed standards for defining criteria for agency consideration were abandoned in favor of the final language. There is nothing in the record to suggest that the legislature intended that the AOGCC substitute its judgment for that of the lessee in determining what constitutes best efforts toward employing Alaska residents or determining the feasibility of the lessee's contracting with firms in the state for work in connection with development of affected fields. In fact, the statute simply provides that in order to be approved, a plan must contain a voluntary agreement by the lessee "to use its best efforts to employ residents of this state, consistent with law, and to contract with firms in this state for work in connection with the development of the field, including the fabrication and installation of required facilities, whenever feasible."

Similarly, there is no support for the proposition that the legislature intended that the agency require lessees to use a quantitative matrix to justify their hiring or contracting decisions, as would be required under 20 AAC 25.565(b), that the agency prescribe the detailed and limiting qualifications for "firms in the state" or "residents", as would be the case under 20 AAC 25.565(e)(1) and (e)(3), respectively, or that it define "development" to include each and every activity outlined in 20 AAC 25.565(2)(A) - (L).

AS 31.05.030(i) was carefully crafted to reflect the intent that a lessee's agreement to use its best efforts to hire and contract within Alaska be voluntary and unconstrained. In fact, the language was purposely chosen to provide what was believed to be the strongest local hire and contracting language likely to withstand legal challenge, while at the same time providing for an assured public review process. That review was intended to expose a lessee's plans and commitments to broad review by the public, including the legislature, where deficiencies could be identified and addressed. To reinforce the likelihood of its policy being successfully implemented, the legislature chose not only to direct the AOGCC to approve plans which contain such voluntary agreements, but also provided that its approvals could not subsequently be appealed.

In contrast, the language of 20 AAC 25.565(b), 20 AAC 25.565(d) and 20 AAC 25.565(e) collectively implies little if any discretion on the lessee's part in defining the scope of field "development" or in establishing the criteria for hiring and contracting decisions, thus begging the question of whether a plan constrained by these provisions would be truly voluntary. As the legislature has clearly demonstrated in recent years—both in its passage of HB 393, the Alaska North Slope Stranded Gas Act and its passage of the Northstar legislation, it is capable of defining Alaska residency standards and reporting requirements for itself when it chooses to do so. Its failure to do so in this instance in no way implies that it intended to delegate those responsibilities to the AOGCC.

Finally, we oppose the adoption of any new regulations to implement AS 31.05.030(i). However, recognizing that the AOGCC may conclude otherwise, we recommend that only those regulations which are reasonably necessary to list the elements of voluntary plans and to clarify the timing for scheduling of hearings on those plans be adopted. We believe that this can be accomplished by amending the AOGCC's proposed regulations as reflected in the attached mark-up. Suggested additions appear in bold and underlined type, while suggested deletions are capitalized and enclosed in brackets. We believe that adoption of these suggested changes will assure that legislative policy is implemented and that the agency's regulations will be defensible as within the scope of its authority.

Thank you again for this opportunity to express our concerns and to provide our recommendations. If you or your colleagues have any questions, please feel free to call.

Sincerely,

Gary. E. Carlson
Vice President

Enclosure

cc Senator Drue Pearce
Commissioner David W. Johnston
Commissioner Camille Oechsli
Alaska Oil and Gas Association

Forcenergy Inc's Suggested Revisions to AOGCC's Proposed New Regulations

—20 AAC 25.565—

20 AAC 25.565 PLANS SUBMITTED UNDER AS 31.05.030(i) (a) A written plan submitted under AS 31.05.030(i) must include

(1) identification of the lessee or lessees participating in the plan;
(2) identification of the field covered by the plan;
(3) a general timetable and description of planned development activities;
(4) a general timetable and description of expected hiring and contracting decisions in connection with development of the field;
(5) a**n** [DETAILED] explanation of how the lessee will **voluntarily** use its best efforts [, IN ACCORDANCE WITH (b) OF THIS SECTION,] to employ residents of th[E]**is** state, consistent with law, and to contract with firms in this state for work in connection with the development of the field, **including the fabrication and installation of required facilities, whenever feasible;**
(6) the date the plan is submitted; and
(7) the lessee's certification of its voluntary agreement to use its best efforts as set out in the plan, including the name, title, and signature of the individual executing the certification on behalf of the lessee, which person must be authorized to bind the lessee.

[(b) A LESSEE'S BEST EFFORTS UNDER (a)(5) OF THIS SECTION MUST INCLUDE APPLICATION OF A QUANTITATIVE DECISION MATRIX TO JUSTIFY ANY DECISIONS TO EMPLOY ANY PERSON OTHER THAN A RESIDENT OF THE STATE OR TO CONTRACT WITH A FIRM OTHER THAN A FIRM IN THIS STATE FOR WORK IN CONNECTION WITH THE DEVELOPMENT OF THE FIELD. THE MATRIX MUST ADDRESS:

(1) QUALIFICATIONS OF EMPLOYMENT APPLICANTS AND FIRMS;
(2) COSTS;
(3) AVAILABILITY OF RESIDENTS AND FIRMS IN THE STATE;
(4) EXPERIENCE OF EMPLOYMENT APPLICANTS AND FIRMS;
(5) PRODUCTIVITY ISSUES; AND
(6) MANAGEMENT ISSUES.]

[(c)]**(b)** Upon receipt of a plan, the commission will immediately schedule a public hearing on the plan under 20 AAC 25.540, except that the hearing will be scheduled for no more than 20 days following public notice of the hearing.

[(d) A WRITTEN PLAN WILL NOT BE CONSIDERED TO HAVE BEEN RECEIVED BY THE COMMISSION UNLESS THE PLAN IS COMPLETE AT THE TIME IT IS SUBMITTED. IF THE COMMISSION REJECTS A PLAN AS INCOMPLETE, IT WILL INFORM THE LESSEE AS TO THE RESPECT(S) IN WHICH THE

PLAN IS INCOMPLETE, AND THE LESSEE MAY SUBMIT ANOTHER PLAN FOR THE FIELD. UNDER THIS SUBSECTION, A PLAN IS "COMPLETE" IF IT CONTAINS ALL OF THE PROVISIONS REQUIRED UNDER (a) OF THIS SECTION AND ADDRESSES ALL PHASES OF DEVELOPMENT CONTEMPLATED UNDER (e)(2) OF THIS SECTION.]

[(e) IN AS 31.05.030(i) AND THIS SECTION,

(1) "FIRM IN THIS STATE" MEANS A PERSON THAT

(A) HOLDS A CURRENT ALASKA BUSINESS LICENSE;
(B) PROVIDES GOODS OR SERVICES UNDER THE NAME AS APPEARING ON THE PERSON'S CURRENT ALASKA BUSINESS LICENSE;
(C) HAS MAINTAINED A PLACE OF BUSINESS WITHIN THE STATE STAFFED BY THE PERSON'S EMPLOYEE FOR A PERIOD OF SIX MONTHS IMMEDIATELY PRECEDING THE DATE OF THE PLAN;
(D) IS INCORPORATED OR QUALIFIED TO DO BUSINESS UNDER THE LAWS OF THE STATE , IS A SOLE PROPRIETORSHIP AND THE PROPRIETOR IS A RESIDENT OF THE STATE, OR IS A PARTNERSHIP AND ALL PARTNERS ARE RESIDENTS OF THE STATE; AND
(E) IF A JOINT VENTURE, IS COMPOSED ENTIRELY OF VENTURES THAT QUALIFY UNDER (A) - (D) OF THIS PARAGRAPH;

(2) "IN CONNECTION WITH THE DEVELOPMENT OF THE FIELD" MEANS ANY AND ALL STEPS TAKEN IN THE SEARCH FOR, EXPLORATION, CAPTURE, AND PRODUCTION OF OIL AND GAS AND THE TRANSPORTATION OF OIL AND GAS OFF THE PROPERTY, INCLUDING

(A) RESERVOIR EVALUATION AND DEPLETION ANALYSIS;
(B) ENGINEERING AND DESIGN;
(C) FABRICATION OF PRODUCTION AND SUPPORT FACILITIES;
(D) CONSTRUCTION OF PRODUCTION AND SUPPORT FACILITIES;
(E) INSTALLATION OF PRODUCTION AND SUPPORT FACILITIES;
(F) OPERATION AND MAINTENANCE OF PRODUCTION AND SUPPORT FACILITIES;
(G) DRILLING AND WORKOVER OF WELLS;
(H) SERVICE AND SUPPORT:
(I) PRODUCTION OPERATIONS;
(J) METERING OPERATIONS;
(K) TRANSPORTATION OF OIL AND GAS OFF THE PROPERTY, AND
(L) ABANDONMENT AND SITE CLEARANCE;

(3) "RESIDENT" HAS THE SAME MEANING AS IN AS 43.23.095.]

Alaska State Legislature

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Senator Drue Pearce

July 13, 1999

Commissioner Robert N. Christenson, P.E.
Chairman, Alaska Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, Alaska 99501-3192

Dear ~~Commissioner Christenson~~: Bob

As provided by your notice dated June 16, 1999, I am submitting the following comments regarding the Alaska Oil and Gas Conservation Commission's (AOGCC's) proposed new regulations (20 AAC 25.565) implementing AS 31.05.030(i), the recently enacted Cook Inlet royalty reduction legislation. Your notice describes the proposed action as intended "... to implement, make specific and interpret AS 31.05.030(i)." While it may be debatable whether new regulations of any sort are necessary to implement this statute, it is my opinion that regulations "to make specific and interpret" the very explicit language of the statute are both unnecessary, and potentially harmful to the underlying legislative intent expressed by the statute.

You may recall that I originally introduced SB 256, the language of which was subsequently incorporated in a companion House Bill, HB 380. During review of the proposed legislation in the House, the focus was on the underlying policy of whether it was appropriate to provide an incentive to encourage the development of previously discovered, but undeveloped Cook Inlet oil and gas fields, and, if so, how to protect and advance the State's interests. The legislative record reflects considerable discussion of how to protect the State's upside potential, leading ultimately to amendments to identify the six specific fields potentially eligible for royalty reduction and to establish caps in the quantities of both oil and gas eligible for royalty reduction. While the bill was under consideration by the House, no amendments to address local hire or in-state contracting concerns were proposed. CSHB 380(FIN) passed the House on April 7, 1998, and was referred to the Senate for consideration.

Following first reading in the Senate on April 8th, CSHB 380(FIN) was referred to the Senate Resources and Finance Committees. The bill was reported out of the Resources Committee without amendment on April 16, 1998, and out of the Finance Committee on the following day. Following passage of the bill on April 17th, Senator Halford served notice of reconsideration, and the bill was held on reconsideration until April 20th. During that period, members of my staff and I met on several occasions with Senator Halford, his staff and representatives of Forcenergy to negotiate the final language of a proposed amendment, which ultimately became the language of AS 31.05.030(i).

Senator_Drue_Pearce@legis.state.ak.us

Senator Halford had prepared a proposed amendment to CSHB 380(FIN)(title am) which was the starting point for those discussions. That amendment would have provided that:

> "a lessee that has not been granted approval of a production plan by the Alaska Royalty Oil and Gas Development Advisory Board under AS 38.06.040(a)(5) before the date production for sale commences from the field described by the plan is ineligible for the royalty reduction described in this paragraph on oil or gas produced from the field; subject to approval of the plan by the board under AS 38.06.040.(a)(5),"

In addition, Senator Halford's proposal would have amended the existing language of AS 38.06.040(a) by adding a new paragraph (5) directing that the Royalty Oil and Gas Development Advisory Board (Royalty Board) shall:

> "(5) grant approval within 45 days after receipt of a production plan for the production for sale of oil or gas from a field described in AS 38.05.180(f)(5) if the plan includes provisions for the lessee to use all reasonable efforts to obtain from a manufacturer in this state the reasonably necessary materials for the construction of facilities used to produce oil or gas from that field; in determining whether a lessee has used all reasonable efforts in this paragraph, the board shall consider
>
> (A) the relative costs of materials in proportion to the benefits to manufacturers in this state; and
>
> (B) the health, safety, and environmental conditions and requirements to ensure maintenance of the lessee's operational standards."

During lengthy discussions of the proposed amendments, several problems were identified. These included concerns regarding the potential for increased risk of third-party challenges as a result of the Royalty Board's, or for that matter, any state agency's exercise of discretion to grant or deny approval of a plan, and concerns that prescribing specific local hire or contracting standards would invite constitutionality challenges.

Based upon those discussions, Senator Halford agreed to the language now appearing in AS 31.05.030(i). This language vested responsibility for accepting and approving written plans with the AOGCC, instead of with the Royalty Board. On April 20th, the Senate returned to second reading for the purpose of considering amendments, and unanimously adopted the proposed amendment. The bill then passed the Senate on reconsideration without further amendment by a vote of 14-4, and was transmitted to the House where that body subsequently concurred with the Senate amendments.

Unlike Senator Halford's original proposal, the language of AS 31.05.030(i), as adopted, makes explicit that the AOGCC has no discretion in approving a plan, provided a lessee chooses to submit one, <u>and</u> it "contains a voluntary agreement by the lessee to use its best efforts to employ residents of this state, consistent with law, and to contract with firms in this state for work in connection with the development of the field, including the fabrication and

installation of required facilities, whenever feasible." The legislature could have chosen to further define "best efforts", "feasible" and "development", or it could have chosen to explicitly delegate that responsibility to the AOGCC. However, in recognition that to withstand constitution challenges, a lessee's agreement to use its best efforts must truly be voluntary, it chose to do neither.

Thus, based upon my personal involvement throughout the legislature's review and passage of this legislation—from the drafting and introduction of SB 256, through the final negotiations leading to the adoption of the amendment dealing with local hire and contracting, to final passage of the bill—there is no evidence in the record to suggest that the legislature intended to leave to the AOGCC's discretion the determination of what constitutes a lessee's "best efforts", what is or is not "feasible" or what constitutes "development", as those terms are used in AS 31.05.030.

To the contrary, I believe the record clearly reflects that the legislature intended to provide certainty, and to minimize the risk of successful challenges to the legislation on constitutional or other bases. Quite simply, AS 31.05.030(i) was intended to provide a predictable process and a defined timeline during which your agency shall act affirmatively to hold a hearing and approve plans submitted under its authority, provided those plans meet the sole requirement set forth in the statute.

That requirement is both simple and explicit—the plan must contain "a voluntary agreement by the lessee to use its best efforts to employ residents of this state, consistent with law, and to contract with firms in this state for work in connection with the development of the field, including the fabrication and installation of required facilities, whenever feasible." While you may want to read additional authorities into the statute, there is nothing in the record to support your doing so.

In my opinion, you go well beyond both legislative intent and your agency's authority in attempting to legislate through regulation such requirements as those under 20 AAC 25.565(b) that a lessee's best efforts "must include application of a quantitative decision matrix to justify any decision to employ a person other than a resident of the state or to contract with a firm other than a firm in this state for work in connection with the development of the field". Similarly, the provisions of 20 AAC 25.565(e)(1) and (2) appear to go well beyond what is required to provide informed public notice, hold public hearings and approve plans submitted under AS 31.05.030(i).

To the extent that you feel that any new regulations are necessary, I urge you to limit those regulations to the requirements now set forth in 20 AAC 25.565(a), without reference to the proposed paragraph (b), and 20 AAC 25.565(c). The provisions of these sections are reasonable, straight-forward and understandable. They also provide the relevant information necessary to assure effective public notice and to provide consistency in the format of submitted plans by specifying what is required for a written plan to be complete for the purposes of holding a hearing. However, unlike the provisions of 20 AAC 25.565(b), (d) and (e), these proposed regulations leave the responsibility for defining the scope of each proposed field development and explaining how a lessee intends to voluntary use its best efforts to promote increased hiring and contracting within the state precisely where the legislature intended—with affected lessees.

While all of us support increased local hiring and contracting with Alaska businesses and individuals for personal services and the fabrication of needed facilities, we must assure that our efforts to that end are practical and defensible as a matter of law. For the reasons discussed above, I am concerned that the provisions of proposed 20 AAC 25.565(b), (d) and (e), while well-intentioned, will not meet those standards.

Sincerely,

Drue Pearce

Drue Pearce
Senate President

cc: David W. Johnston, Commissioner
Camille Oechsli, Commissioner

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JUL 14 1999
Alaska Oil & Gas Cons. Commission
Anchorage

Alaska State Legislature

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Official Business

December 18, 1998

Mr. David W. Johnston, Chairman
Alaska Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, AK 99501-3192

Dear Mr. Johnston,

During the consideration of HB 380 and the corresponding senate bill, the legislature added specific language to ensure that any company seeking a royalty reduction be required to maximize Alaska hire, construction, fabrication and contracting.

The Alaska Oil and Gas Conservation Commission is the entity which must review and approve planned efforts to employ Alaskans and use Alaskan contractors and fabricators. Have you received any royalty reduction plans or developed regulations for their review? Have you developed a system to require those seeking royalty reduction to prove that specific component construction in Alaska is unfeasible?

House Bill 380 provides a unique incentive for Cook Inlet development. I hope the Commission is working to ensure that instate benefits in jobs, fabrication, construction and contracting are commensurate with the royalty savings allowed.

Thank you for your efforts. We will be following this process in the Senate Resources Committee during the next session.

Sincerely,

Rick Halford

RICK HALFORD

cc: Robert N. Christenson, Commissioner, AOGCC
Cammy Oechsli, Commissioner, AOGCC

fax rec'd 11/9

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DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

November 9, 1998

Dave Johnston, Chair
Alaska Oil and Gas Conservation
Commission
3001 Porcupine Drive
Anchorage, AK 99501

Dear Mr. Johnston:

The Department of Natural Resources, Division of Oil and Gas ("DNR") reviewed the proposed revisions to the AOGCC's regulations and offers the following comments.

Historically there has been confusion about the overlapping jurisdiction of the AOGCC and DNR. DNR suggests that the AOGCC should use this revision of its regulations as an opportunity to clarify the respective roles of DNR and the AOGCC in regulating the oil and gas industry. Where both agencies require the same information to fulfill their regulatory responsibilities, they should coordinate to develop common filing requirements to minimize the burden on industry (See AS 31.05.026(c)).

During this review of revisions to its regulations, DNR urges the AOGCC to consider the areas of concurrent jurisdictions, and evaluate how the petroleum industry can be most efficiently regulated. The following list of regulations where DNR and the AOGCC's jurisdiction overlap and there is the opportunity for coordinated efforts is not complete. To the extent that members of industry might be confused about which agencies' regulations should apply, they should assume that they must comply with both agencies' directives, unless they have a specific, contrary direction from both agencies.

20 AAC 25.005. PERMIT TO DRILL

Comment: The location of a well, at the surface and in the subsurface, is one of the most basic and critical pieces of well information DNR looks for. With recent improvements in computer technology, government and the industry do almost all of their mapping using geographic infomation systems (GIS) rather than by manual cartographic techniques. GIS mapping requires location data in grid or spherical coordinates or latitude and longitude. Most operators will already have this information available to them and by having them provide this information to the commission there will be a single authoritative source for well location information.

Proposed Revision:
20 AAC 25.005. PERMIT TO DRILL.
(c) An application for a Permit to Drill must be accompanied by the following unless already on file with the commission and identified in the application:
(1) a fee of $100 payable to the State of Alaska, Department of Revenue;
(2) a plat identifying the property and showing
(A) the coordinates of the proposed location of the well at the surface, at the top of each objective formation, and at total depth, referenced to governmental section lines, NAD27 Alaska State Plane, and latitude and longitude;

20 AAC 25.022. CHANGE OF OWNERSHIP
Comment: A change of ownership on a state lease is not effective until approved by DNR. 11 AAC 82.605.

Proposed Revision:
20 AAC 25.022. CHANGE OF OWNERSHIP. Whenever a person becomes an owner of a property on which operations subject to this chapter are proposed to the commission or are being conducted, the person shall file a Notice of Change of Ownership (Form 10-417) within 15 days after conveyance or approval of assignment under 11 AAC 82.605 if on a state lease. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)
Authority: AS 31.05.030

20 AAC 25.050. WELLBORE SURVEYS.
Comment: As stated above much of the mapping and analysis that industry and government does is now computer based and in some cases requires a higher level of accuracy than may have been available in the past. DNR would like for the commission to obtain directional survey data in digital format to facilitate mapping and well log analysis on computers. We are also want to ensure a complete record for directional wellbore surveys in the case of multiple branch wellbores. We would prefer to have all well branches include surveys integrating survey data from the well branch and the main borehole up to the surface.

Proposed Revision:
20 AAC 050
(d) Within 30 days after the completion, abandonment, or suspension of a well, a complete paper and digital copy of each inclination and directional survey must be filed with the commission on a media type acceptable to the commission. A composite survey may also be filed if the operator believes this would better represent the well course. If a composite survey is filed, the operator shall specify the portion of each survey used in the composite.

Proposed Revision:
20 AAC 050(f)
(8) a plat showing the coordinates, referenced to governmental section lines, NAD27 Alaska State Plane, and latitude and longitude, of the surface location and at total depth, the plotted well course, and any well(s) within 500 feet of any portion of the wellbore.

20 AAC 25.070. RECORDS AND REPORTS
Comment: The records and reports for some wells lack completeness. This may, in part, be because specific required details of the daily record or drilling history are not itemized. By providing at least a partial list will improve the record of well activity for future reference.

The daily record should contain clear language with fewer abbreviations to avoid confusion for future use. The historic need for brevity in these daily records is no longer valid. This practice should be changed for future clarity.

Proposed Revision:

20 AAC 25.070. RECORDS AND REPORTS. The operator of a well shall

(1) keep a detailed accurate daily record of the actual drilling, maintenance, completion, suspension, and abandonment operations[,]. The daily record should include drilling depths and brief description of principal items of work done such as running casing, drill-stem tests, coring, sidewall sampling, and logging, and the tests required by this chapter[,] as well as identification of zones of abnormal pressure, lost circulation, and other hole difficulties encountered. [which]The daily record should be written in clear language with no abbreviated words and must be available for inspection at reasonable times by the commission

(A) at the well; and

(B) in the state for five years after the date of well abandonment;

(2) file with the commission before well completion or, if the well is not completed, before well abandonment a survey plat certified by a registered land surveyor showing the precise surface location of the well; however, only the first well drilled from a fixed platform or a multiple-well site must have a certified survey;

(3) file with the commission, within 30 days after completion, abandonment, or suspension of the well, a complete well record on the Well Completion or Recompletion Report and Log (Form 10-407), including locations referenced to governmental section lines, NAD27 Alaska State Plane, and latitude and longitude a copy of the daily reports of well operations and the tests required by this chapter.

20 AAC 25.071. GEOLOGIC DATA AND LOGS.

Comments: The DNR would like to see several changes to the commission's data submission requirements. Delays in well completion or temporary suspension of operations sometimes result in months going by between data collection and submission to the commission.

All testing should be summarized to avoid the need to sift through huge volumes of documentation on lengthy test procedures to find out that a well failed to flow oil or gas. Also the summary should include information on repeat formation test (RFT) and modular formation dynamics test (MDT) tests and on any fluids recovered in those tests. Current language does not specifically require critical information of this type and it is almost always lacking from the commission's records.

Proposed Revision:

20 AAC 25.071. GEOLOGIC DATA AND LOGS.

(b) [WITHIN 30 DAYS AFTER COMPLETION, SUSPENSION, OR ABANDONMENT OF A WELL, WHICHEVER HAPPENS FIRST]As soon as available, the operator shall file with the commission

(1) a sepia and a reproduced copy of a complete mud log or a lithology log consisting of a detailed record and description of the sequence of strata encountered, including kind and character of the rock and all shows of hydrocarbons;

(2) a complete set of washed and dried, legibly identified samples of all drill cuttings, as caught by the operator in accordance with good geological practices, consisting of a minimum of one-quarter cup in volume or three ounces in weight of cuttings for each sample interval;

(3) a lithologic description and, if available, photographs of all conventional and sidewall cores; conventional core descriptions must include all apparent textural, fluid, and lithological variations, including rock type, porosity, fractures, bedding plane attitudes, sedimentary structure, grain size, and presence of hydrocarbons;

(4) a chip or chips from each foot of recovered conventional core, except that chips need not be submitted until 30 days after the conventional core is analyzed; the chips must be representative of the one-foot interval, and must be approximately either one cubic inch in volume, or two ounces in weight;
(5) a list of the geologic markers encountered in the well and the measured and true vertical depths of each marker;
(6) a sepia and a reproduced copy of all logs run in the well (including common derivative formats such as tadpole plots of dipmeter data and borehole images produced from sonic or resistivity data. and composite log formats), except [velocity surveys] and experimental logs;
(7) if available, a tape, diskette, or other electronic media acceptable to the commission and a verification listing of the digital data for all logs run in the well, except [velocity surveys and]experimental logs, and a written description of the logical and physical format of the digital data; and
(8) a copy of all drill stem test and production test data and charts, include a briefing summary of testing, including production tests (IP), drill stem tests (DST), repeat formation tests (RFT), or modular formation dynamics tests (MDT), and other production and formation testing data; the summary should include test date, time, depth, formation name, method of operation, recovered fluid type(s), fluid amount, and fluid rate, GOR, oil gravity, pressure, and choke size, when available; conventional and sidewall core analysis determinations of porosity, permeability and fluid saturation; geochemical and formation [water]fluid analyses obtained by the operator; [these data must be filed as soon as available if the 30-day filing period cannot be met].

(c) The commission will, in its discretion, waive or modify the requirements of [(a), (b)(1), AND (b)(2)] this section for a well if they would not significantly add to the geologic knowledge of the area in light of the information that is available from other wells in the area [FOR DEVELOPMENT WELLS].

(d) In this section
(1) "experimental logs" means logs that are not commercially available from a logging contractor [SO NEWLY DEVELOPED OR SO LIMITED OR SPECIALIZED IN APPLICATION THAT THEY ARE NOT COMMONLY RUN ON PETROLEUM EXPLORATION OR DEVELOPMENT WELLS]; and

(2) "velocity survey" means a survey, the primary purpose of which is to determine velocity of seismic waves through formations penetrated by a well by measuring travel times of seismic pulses from or near the surface to geophones placed at [A SEISMOMETER LOWERED TO] various depths in the well.

(Eff. 4/2/86, Register 97; am ___/___/___, Register __)
Authority: AS 31.05.030 AS 31.05.035

20 AAC 25.072. SHUTDOWN OF DRILLING OR COMPLETION [WELL] OPERATIONS.
Comment: Operators should be aware that they must also obtain approval from DNR for a suspension of operations on a state lease (11 AAC 82.670).

20 AAC 25.110 (e) SUSPENDED WELLS
Comment: The regulation should specify the information required in the well status report or the form number if applicable.

20 AAC 25.170. ONSHORE LOCATION CLEARANCE.

20 AAC 25.172. OFFSHORE LOCATION CLEARANCE.

Comment: The AOGCC has authority to manage and regulate the safety, waste and conservation issues relating to wells on public and private land in the state (AS 31.05.030). The AOGCC's jurisdiction is over wells, and does not extend to management of the surface impacts of drilling. The surface landowners; the state and federal governments, Native corporations and villages and private landowners all, have the authority to determine how the surface will be rehabilitated and restored after a well is completed. 20 AAC 25.170 and .172 give the AOGCC authority to regulate surface restoration and rehabilitation beyond the scope of its statutory authority.

Recently proposed modifications to 20 AAC 25.170 and .172 address this problem by limiting the AOGCC's jurisdiction when the surface owner has exercised jurisdiction. These changes lessen the most problematic issue created by the proposed regulation. However, those changes do not resolve the fundamental issue that the AOGCC lacks statutory authority to regulate the restoration and rehabilitation of onshore and offshore drilling sites beyond the well. All regulatory requirements that purport to extend the AOGCC's jurisdiction beyond their statutory responsibility for plugging and abandoning wells and removing the wellhead casing and drilling equipment should be deleted from these regulations . The AOGCC cannot determine if a road, pipeline or platform constructed in connection with a well should be removed or abandoned in place. It is the surface land owners' right and responsibility to determine how the surface of the drill site will be restored and rehabilitated.

20 AAC 25.215. COMMINGLING OF PRODUCTION. (a)

Comment: DNR approves the methodology for allocation of production and costs for royalty purposes under 11 AAC 83.371. Does the commission intend to approve a different production allocation methodology for its purposes?

20 AAC 25.225. POTENTIAL OF GAS WELLS

Comment: What is the definition of *regular production*? This term is also used in 20 AAC 25.055, .270, .517, and .560.

20 AAC 25.235. GAS DISPOSITION. (a)

If PA's + pools are not the same, how do you submit single form → is DNR willing to accept AOGCC form?

Comment: DNR requires a gas disposition report when production comes from multiple participating areas. Since AOGCC's pools are not the same as DNR's participating areas, adoption of this regulation will result in an additional reporting burden on operators. AOGCC and DNR should reduce duplication by allowing operators to submit a single gas disposition report that fulfills the needs of both agencies.

20 AAC 25.517. PLAN OF DEVELOPMENT AND OPERATION.

Comment: AS 31.05.030(d)(9) states that the commission may require the filing and approval of a plan of development and operation for a field or pool to prevent waste, maximize recovery and protect correlative rights. The DNR requires that Plans of Development be submitted for approval for state lands committed to a unit. 11 AAC 83.343(a) lists the requirements for a DNR Plan of Development . DNR requires long and short term development and exploration plans to insure that the state's resources are being adequately developed. Requiring an applicant to submit substantially the same information for approval to both agencies for state lands creates a duplicative administrative burden.

The DNR recommends that the commission not amend 20 AAC 25.517. Moreover, the DNR does not believe that the AOGCC has authority to overrule unit plans on state lands that have been approved by the DNR commissioner. See generally, AOGCC/DNR Unitization Jurisdiction, 1996 Op. Atty' Gen (Alaska, June 3, 1996). The current 20 AAC 25.517 avoids the duplicative administrative burden for state lands committed to a unit or PA.

Finally, proposed 20 AAC 25.518 is basically 20 AAC 25.517(c). Is this housekeeping or is the proposed change designed to accomplish something?

20 AAC 25.537 (a) PUBLIC AND CONFIDENTIAL WELL INFORMATION.

Comment: Operators sometimes manage to work within the established regulations to postpone filing public and confidential well information or are non-compliant in filing within the 30-day period as required by 20 AAC 25.070 and 20 AAC 25.537. This information is of interest to DNR and the public. We believe that the release of additional milestone information and dates will improve operator timeliness and will provide stakeholders and the public a better understanding of ongoing activity.

Proposed Revision to existing regulation:

20 AAC 25.537 (a) PUBLIC AND CONFIDENTIAL WELL INFORMATION.

(a) The commission will routinely make available to the public, by means of records or reports, in its offices or elsewhere, or by means of regular publication, the following information:

(1) surface and proposed bottom-hole location of each well, after approval of the Permit to Drill (Form 10-401);

are they needed by AOGCC?

(2) surface and proposed bottom-hole location, and commencement of drilling date after commencement of drilling of the well;

(3) surface and proposed bottom-hole location, and rig release date after a drill rig is removed from the well site

(4) [2] total depth, bottom-hole location and well status after the Well Completion or Recompletion Report and Log (Form 10-407) is filed;

(5) [3] regular production data and regular production reports, as required to be filed by the operator each month;

(6) [4] injection data and injection reports, as required to be filed by the operator each month; and

(7) [5] all data filed on a well as required by this chapter upon expiration of the confidential period described in (d) of this section.

Sincerely,

John Shively
Commissioner

Alaska Oil and Gas Association

121 West Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907) 272-1481 Fax: (907) 279-8114

October 15, 1998

David Johnston, Chairman
Alaska Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, Alaska 99501

Additional AOGA Comments to Proposed
Changes to the AOGCC Regulations

Dear Commissioner Johnston:

Subsequent to our letter of September 30, the members of the AOGCC Regulations Review Task Group have continued our review of several sections of the Proposed Changes in the Regulations of the AOGCC, dated August 21, 1998. Attached please find a working copy of our suggestions for three sections of the proposed regulations: "20 AAC 25.036. Well control for Coiled Tubing Drilling: Blowout Prevention Equipment and Drilling Fluid Program Requirements", "20 AAC 25.280. Workover Operations" and "20 AAC 25.285. Blowout Prevention Equipment for Workover Operations".

For section 20 AAC 25.036, we suggest that the scope of the section be generalized to include all through-tubing re-entry drilling and completion operations utilizing coiled tubing units, snubbing units and other types of equipment. To reflect this change, the suggested title of the section is: "20 AAC 25.036. Well Control for Through Tubing Re-entry Drilling and Completion Operations: Blow Out Prevention Equipment and Drilling Fluid Program Requirements".

For section 20 AAC 25.280, we suggest that segments concerning the Application for Sundry Approvals and BOPE test results currently contained in section 25.285 of the AOGCC proposed regulations be moved and incorporated into appropriate locations in section 25.280.

For section 20 AAC 25.285, we suggest that the section be restructured to separate the well control equipment requirements of the various work categories considered "workover operations". The specific work categories we suggest for workovers are: tubing or drill pipe workover operations, workstring conveyed perforating operations, workstring service operations wireline operations and other workover operations. Attached is a listing of potential work categories with their specific activities. Also attached are examples of the type of language we believe is appropriate for these work categories. In this attachment, for reference only, we have arbitrarily renumbered the sections dealing with the workover operations.

We would welcome further discussion with the Commission and /or staff regarding these suggestions and specific language.

Sincerely,

Chris T. Phillips

Chris Phillips, Chairman
AOGCC Regulations Review Task Group

Attachment

AOGA suggests the various sections which concern well control equipment for drilling and workover operations be organized under "work categories", rather than based on the type of equipment used to perform the work. The following are suggested work categories covering drilling and workover operations:

1) Primary Drilling and Completion
   - Drilling from Surface Casing on Down after setting surface casing or after the primary BOPE has been installed
   - Drilling below top set completion into oil/gas and/or water bearing formations capable of sustained flow at the time of the operation after setting protective/production casing prior to penetrating the target horizon.
   - Drilling below top set completion into oil/gas and/or water bearing formations capable of sustained flow at the time of the operation.
   - Running Casing and/or Production Tubing
   - Re-Entry work where Production Tubing and Packer are Removed
   - Include Provisions for Underbalanced Operations

2) Through Tubing Re-Entry Drilling and Completion Operations
   - Drilling and Completion Operations Performed through Existing Production Tubing and Packer
   - Includes Provisions for Underbalanced Operations

3) Tubing or Drill Pipe Workover Operations
   - Pulling Production Tubing and Milling Production Packer
   - Running Production Tubing and Packer

4) Workstring Conveyed Perforation Operations (CT, Snubbing Unit, Rotary Drilling Unit & etc.)
   - Perforation Operations performed on Cased Wells without Production Tubing
   - Re-Entry type operations using Jointed or Continuous pipe where the casing is perforated into gas, oil, or water bearing formations capable of sustained flow at the time of the operation.

5) Workstring Service Work
   - All other Workstring Operations

6) Wireline (Slickline and Conductor Line/E-Line) Operations
   - All categories of work performed using Slickline or Conductor Line

7) Other Workover Operations

Through Tubing Re-Entry Drilling and Completion Operations

- Drilling and Completion Operations Performed through Existing Production Tubing and Packer
- Includes Provisions for Underbalanced Operations

20 AAC 25.036. WELL CONTROL FOR THROUGH TUBING RE-ENTRY DRILLING AND COMPLETION OPERATIONS; BLOWOUT PREVENTION EQUIPMENT AND DRILLING FLUID PROGRAM REQUIREMENTS.

(a) An application for a Permit to Drill (Form 10-401) relating to coiled tubing or other through-tubing drilling operations must include the following information or refer to that information if on file with the commission:

(1) a diagram of each blowout preventer (BOP) stack and related well control equipment to be used; and

(2) a list of the blowout prevention equipment (BOPE) with specifications.

(b) A Through Tubing Re-Entry well drilled or completed must be equipped with BOPE meeting the requirements of this subsection from the time that drilling penetrates out casing or liner until the drilled portion has been completed, suspended, or abandoned. The following provisions apply to BOPE:

(1) The required working pressure of the BOPE must exceed the anticipated surface pressure to which it may be subjected;

(2) Well control equipment must include at least one positive seal manual valve, hydraulic valve, or blind ram flanged to the well head; and hydraulic rams providing, at a minimum, ~~for~~ blind, and pipe ram capabilities;

(A) Coiled tubing BOPE's rams must at a minimum provide for pipe,

be a remotely controlled hydraulic valve; or

(ii) two full-opening flanged or hubbed wing valves or companion valves on the tree (or wellhead), which valves must be at least two inches in nominal diameter and must meet the required working pressure specified in the Permit to Drill, and the outer of which valves on the choke side must be a remotely controlled hydraulic valve;

(E) an annular preventer, stripper, rotating head, RBOP (Rotating Blow Out Preventer), or pack-off for open hole deployment, unless using a lubricator of sufficient length to enclose the entire bottom hole assembly (BHA) below a high pressure pack-off , stripper, rotating head, RBOP, or annular preventer;

(F) for Underbalanced Drilling Operations, well control equipment must also include:

(i) slip capabilities;

(ii) a riser or lubricator sized to the BHA providing for pressure deployment from the BOPE rams to the high pressure pack-off, stripper, annular preventer, or rotating head;

(G) a choke manifold equipped with

(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's console;

(ii) a line at least two inches in nominal diameter downstream of

that are flanged to the wellhead or tree;

(7) the BOP and related well control equipment must be installed, used, maintained, and tested in a manner that ensures well control and, at a minimum, conforms with API RP 53, *Recommended Practices for Blowout Prevention Systems* (March 1997), or API RP 5C7, Recommended Practices for Coiled Tubing Operations in Oil and Gas Well Services (December 1996), which are adopted by reference. ;

AOGA Note: RP 5C7 specifically excludes CTD, may not be appropriate reference

(c) BOPE must be tested as follows:

(1) the BOP stack, valves, and related equipment must be pressure-tested to the maximum expected wellhead pressure, before initial wellbore entry, each time the BOP stack is modified, at least once every two weeks thereafter;

(2) the BOPs must be function-tested after any action that disconnects the hydraulic system lines from the BOPs and at least once each day except when the workstring is continuously in the well or the BHA does not clear the BOP, in which case function-testing must be performed as soon as possible thereafter;

(3) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(4) a minimum of 24 hours notice of each BOPE pressure test must be provided so that a representative of the commission can witness the test.

(d) A through-tubing drilling operation must be equipped with a drilling fluid system, unless the Commission determines, in its discretion, that a drilling fluid system is not necessary for primary well control. A drilling fluid system used for primary well control must

(1) have a volumetric capacity for drilling fluid reserves appropriate for the volume of the wellbore; and

(2) include equipment that is necessary to keep the drilling mud conditioned as specified in the Permit to Drill and that is appropriate for the drilling operations being conducted.

(e) All equipment must be in good operating condition at all times and must be protected to ensure reliable operation under the range of weather conditions that may be encountered at the well site.

(f) The operator shall post in the operator's cab a copy of the approved Permit to Drill, including the drilling hazard section required by 20 AAC 25.005(c)(4), and a copy of the standing orders specifying well control procedures. When an additional or separate sub-structure is used, the operator shall post a second set of standing orders on the drilling platform floor.

(g) Upon request of the operator, the commission will, in its discretion, approve a variance from the BOPE requirements of this section.

20 AAC 25.280. WORKOVER OPERATIONS. (a) An application for well workover operations must be submitted by filing an Application for Sundry Approvals (Form 10-403). The application must be approved by the commission before entering well to conduct the following operations:

(1) perforate or reperforate casing;

(2) stimulate;

(3) pull tubing;

(4) alter casing;

(5) repair well.

(b) The Application for Sundry Approvals (Form 10-403) relating to well workover operations must include the following information or refer to that information if on file with the commission:

(1) the current condition of the well;

(2) a copy of the proposed program for well work;

(3) a diagram of the blowout preventer (BOP) stack and related equipment; and a list of the blowout prevention equipment (BOPE) with specifications; and

(4) a description of the workover fluid to be used for primary well control; and

(5) the estimated current bottom-hole pressure, or the actual pressure if available.

(c) The operator shall keep records and reports of well workover and repair operations, including BOPE test results, in conformance with the requirements of 20 AAC 25.070 (1) or, in the case of wireline work, in the daily work log;

(d) The operator shall file with the commission, within 30 days after completion of workover or repair operations, a complete well record on a Report of Sundry Well Operations (Form 10-404), including a copy of the daily reports of well operations and the tests as required by 20 AAC 25.070.

(e) Upon application, the commission will, in its discretion, waive the requirements of this section for wells in a pool for which pool rules have been prescribed under 20 AAC 25.520.

Workstring Conveyed Perforation Operations (CT, Snubbing Unit, Rotary Drilling Unit & etc.)

- Perforation Operations performed on Cased Wells without Production Tubing
- Re-Entry type operations using Jointed or Continuous pipe where the casing is perforated into gas, oil, or water bearing formations capable of sustained flow at the time of the operation.

20 AAC 25.286. BLOWOUT PREVENTION EQUIPMENT FOR WORKSTRING CONVEYED PERFORATION OPERATIONS

(a) A BOP and related well control equipment must be installed, used, maintained, and tested in a manner that ensures well control during well work operations.

(b) The required working pressure of the BOPE and other Well Control Equipment must exceed the anticipated surface pressure to which it may be subjected during well work operations.

(c) A full lubricator system or open hole deployment type system must be used;

BOP Equipment Requirements Include;

(1) A high pressure seal such as a Pack-Off, Stripper, Annular or Rotating head

(2) BOPE provisions for as a minimum of pipe, and blinding operation on the nominal workstring diameter

(A) Coiled tubing BOPE's rams shall at a minimum provide for pipe, slip, cutting, and blinding operations on the nominal CT in service.

(3) In operations where the perforation guns can not be fully contained within the lubricator system, provisions must be made to isolate

wellbore pressure by maintaining kill weight fluid in the well or other means if a full pressure deployment and removal system is not utilized.

(4) an annular preventer, stripper, rotating head, RBOP (Rotating Blow Out Preventer), or pack-off for open hole deployment, unless using a lubricator of sufficient length to enclose the entire bottom hole assembly (BHA) below a high pressure pack-off , stripper, rotating head, or annular preventer;

(5) an hydraulic actuating system with:

(A) a hydraulic actuating system with sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled hydraulic valve while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off;

(B) an accumulator powered by at least two independent sources of power and an accumulator backup system supplied by an independent nitrogen source having sufficient capacity to close all BOPs and to hold them closed;

(6) locking devices on the ram-type preventers;

(7) one complete set of operable remote BOPE controls on or near the operator's console and, if not in close proximity to the operator's

console, a second complete set of BOPE controls located on or near the work platform floor when a secondary work structure is used;

(8) Provisions for a kill line with flanged or hubbed connections, hammer unions, or internally clamped (swivel or chicksan) joints on hardline or fire-resistant rotary hose upstream of its connection to the BOP body, drilling spool, or wellhead are required on all Workstring Conveyed Perforating Operations;

(d) A BOPE assembly required under this section must be tested as follows:

(1) BOPE pipe and blind rams must be individually closed and differentially pressure-tested to the maximum estimated wellhead pressure to which it may be exposed, using a non-compressible fluid, at least once every two weeks;

(2) BOPE and other well control equipment bodies (Lubricator, pack-off, stripper, and etc.) must also be pressure-tested to the maximum estimated wellhead pressure, at least once each day unless continuously in the hole, and after each installation of the BOPE before wellbore entry; and

(3) the BOPE rams must be closed and pressure-tested to the maximum estimated wellhead pressure to which it may be exposed, using a non-compressible fluid, and after each installation of the BOPE before wellbore entry if the RAMS have been used, repaired or changed out;

(4) the BOPE hydraulic connections to the rams must be verified to be operational after each installation of the BOPE before wellbore entry;

(e) Upon request, the commission will, in its discretion, approve a variance from the requirements of this section.

Workstring Service Work

- All other Workstring Operations.

20 AAC 25.287. BLOWOUT PREVENTION EQUIPMENT FOR WORKSTRING SERVICE OPERATIONS.

(a) A BOP and related well control equipment must be installed, used, maintained, and tested in a manner that ensures well control during workstring service operations.

(b) The required working pressure of the BOPE must exceed the anticipated surface pressure to which it may be subjected during workover operations.

(c) For through-tubing operations with coiled tubing, small diameter drill pipe, or small diameter tubing,

(1) A full lubricator system or open hole deployment type system must be used;

(2) Well control equipment requirements include:

(A) A high pressure seal such as a Pack-Off, Stripper, Annular preventer, rotating head, or RBOP (Rotating Blow Out Preventer);

(B) BOP equipment should at a minimum provide for pipe sealing on the nominal workstring diameter, and blinding operation.

(i) Coiled tubing BOPE's rams should at a minimum provide for pipe, slip, cutting, and blinding operations on the nominal CT in service.

(C) an hydraulic actuating system with:

(i) a hydraulic actuating system with sufficient accumulator capacity

to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled hydraulic valve while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off;

(ii) an accumulator powered by at least two independent sources of power and an accumulator backup system supplied by an independent nitrogen source having sufficient capacity to close all BOPs and to hold them closed;

(D) locking devices on the ram-type preventers;

(E) one complete set of operable remote BOPE controls on or near the operator's console and, if not in close proximity to the operator's console, a second complete set of BOPE controls a second annular preventer closing control located on or near the work platform floor when a secondary work structure is used;

(3) Provisions for a kill line with flanged or hubbed connections to the BOP body, drilling spool, tree, or wellhead;

(d) A BOPE assembly required under this section must be tested as follows:

(1) BOPE pipe and blind rams must be individually closed and differentially pressure-tested to the maximum estimated wellhead pressure to which it may be exposed, using a non-compressible fluid, at least once every two weeks;

(2) BOPE and other well control equipment bodies (Lubricator, pack-off,

stripper, and etc.) must also be pressure-tested to the maximum estimated wellhead pressure, at least once each day unless continuously in the hole, and after each installation of the BOPE before wellbore entry; and

(3) the BOPE rams must be closed and pressure-tested to the maximum estimated wellhead pressure to which it may be exposed, using a non-compressible fluid, and after each installation of the BOPE before wellbore entry if the RAMS have been used, repaired or changed out;

(4) the BOPE hydraulic connections to the rams must be verified to be operational after each installation of the BOPE before wellbore entry;

(e) Upon request, the commission will, in its discretion, approve a variance from the requirements of this section.

Wireline (Slickline and Conductor Line/E-Line) Operations

- All categories of work performed using Slickline or Conductor Line

20 AAC 25.288. WELL CONTROL EQUIPMENT FOR WIRELINE OPERATIONS.——

(a) Wireline workover operations must be equipped with:

(1) a set of wireline rams suitable or sized for each diameter of wire passing through the Wireline Valve;

(2) a lubricator or pressure deployment system; and

(3) a high pressure pack-off, stripper, or greasehead (GIT) with linewiper, stripper, or packoff.

(b) For downhole wireline operations, the commission will, in its discretion, approve alternate well control equipment installations.

(c) Well control equipment required under this section for wireline well work operations must be tested as follows:

(1) well control equipment (Lubricator, wireline valve, pack-off, stripper, stuffing box etc.) must be pressure-tested to the maximum estimated wellhead pressure to which it may be exposed, using a non-compressible fluid, at least once every two weeks;

(2) the well control equipment bodies must also be pressure-tested to the maximum estimated wellhead pressure, at least once each day and after each installation of the well control equipment before wellbore entry; and

(3) the wireline valve rams must be function-tested at least once every

two weeks and after each installation of the wireline valve before wellbore entry if the RAMS have been used, repaired or changed out;

(4) test results will be documented on the daily work log, and the test results will be available to the AOGCC on request;

(d) Upon request, the commission will, in its discretion, approve a variance from the requirements of this section.

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in this section may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

AOGA PRESENTATION TO AOGCC
Surface Casing and Cement
October 15, 1998

Purpose:

Propose language describing acceptance criteria for surface casing cementing.

TESTIMONY TO AOGCC
Surface Casing and Cement
Outline

1. Review basis of design for casing and cement
2. Discuss surface casing and cement integrity
   - Sealing integrity
   - Structural integrity
3. Proposed language
4. Impact of proposed language

General Basis of Design for Casing and Cement
20 AAC 25.030 (a)

...a well casing and cementing program must be designed to:

1. provide suitable and safe operating conditions for the total measured depth proposed
2. confine fluids to the wellbore
3. prevent migration of fluids from one stratum to another
4. ensure control of well pressures encountered
5. protect against thaw subsidence and freezeback effects within permafrost
6. prevent contamination of freshwater
7. protect significant hydrocarbon zones
8. provide well control until the next casing is set

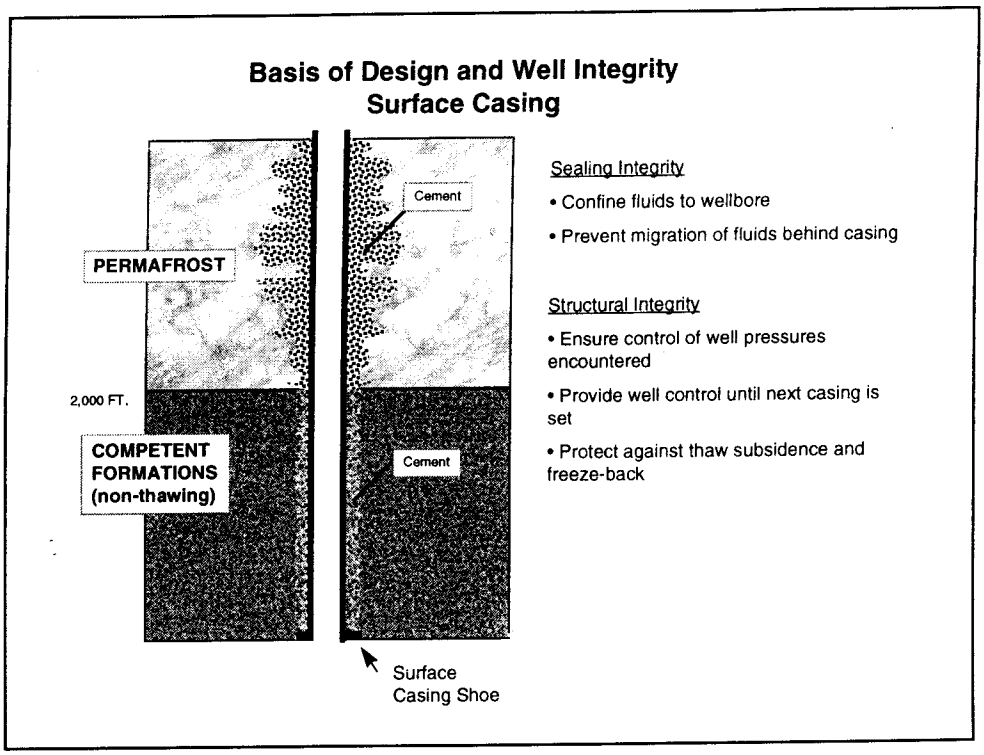
What you see here is the first paragraph of the proposed regulations under Casing and Cementing.

It gives a concise and comprehensive Basis of Design for a well's Casing and Cementing program. AOGA is in agreement with the Commission that these eight points form the Basis of Design for Casing and Cement.

As you know, wells are typically constructed with two or more strings of casing. Examples include Conductor, Surface, Intermediate and Production strings.

Each of these casing strings perform different functions, and these differences are reflected in the load cases and design factors of the casing program and the slurry and pumping program for the cement. The challenge for the design engineer is to find a cost effective solution which meets this Basis of Design.

Let's take a closer at Surface Casing and Basis of Design in permafrost regions.

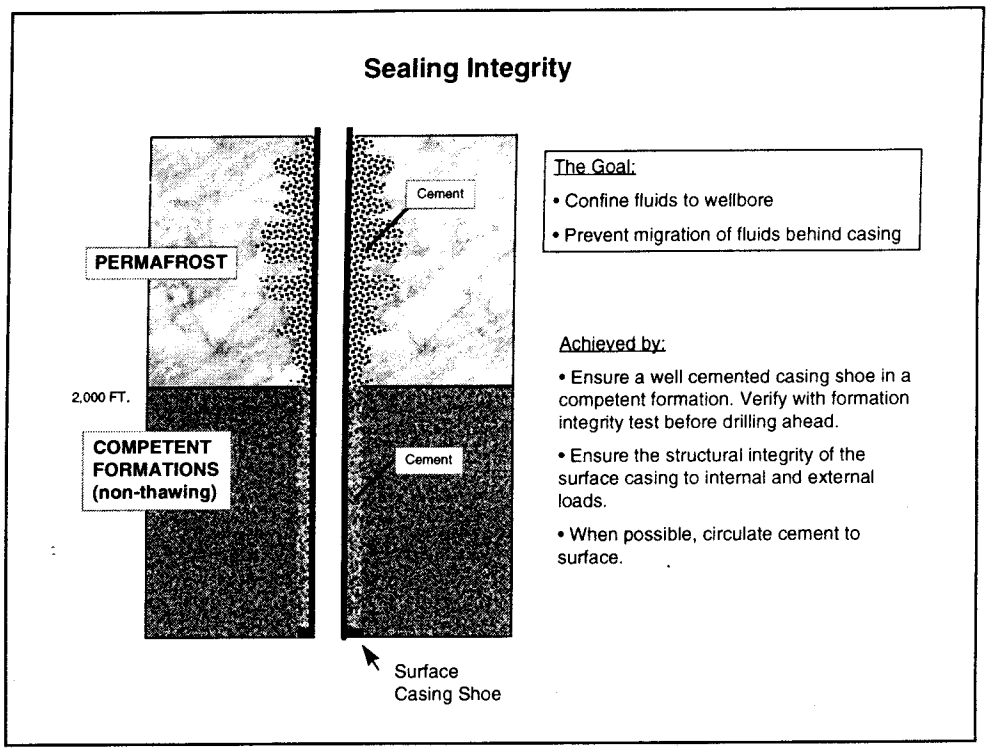


As applied to surface casing, the eight points which make up the Basis of Design establish a requirement for sealing and structural integrity.

Sealing integrity means sealing from within and from without. We need the surface casing and its' cement to confine drilling fluids to the cased interval and the open hole below it. We must prevent the movement, migration and contamination of fluids and strata which are behind the surface casing.

Structural integrity ensures that the well can withstand the varying pressures, temperatures and loads imposed not only during drilling, but throughout the life of the well. Loads unique to permafrost regions include thaw subsidence and freeze-back.

So how do modern well designs in permafrost regions ensure the sealing and structural integrity of surface casing?

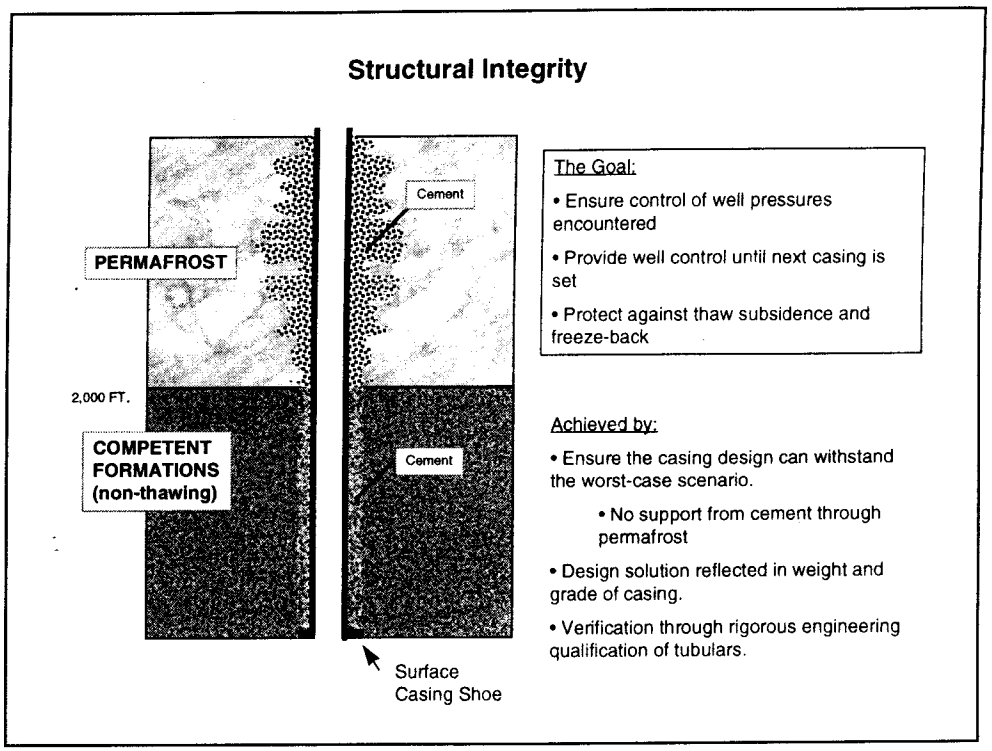


A competent casing shoe is one of the most important factors in ensuring the sealing integrity of surface casing. The integrity of the shoe ensures that the surface casing does not allow the migration of fluids up the outside of the casing string. It is verified with a formation integrity test and must meet a design value before drilling progresses in subsequent hole sections.

The casing itself must provide sealing integrity to internal and external pressures. Casing size, weight, grade and connections are carefully designed to ensure sealing integrity thoughout the life of the well.

In addition to the shoe strength and structural integrity of the surface casing, benefit is also gained from bringing cement as close to surface as is practical. This can be difficult due to the weak nature of the permafrost. However, a failure to return cement to surface does not in itself condemn the sealing integrity of the surface casing.

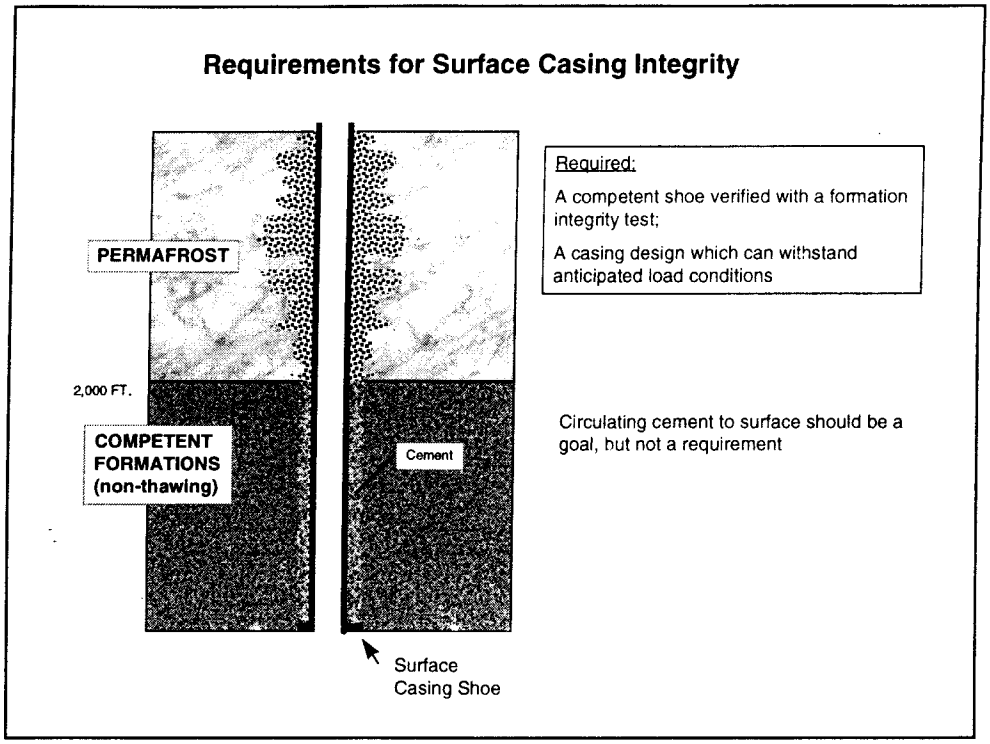
Next we'll address the structural integrity of surface casing.



As we have already seen, the sealing and structural integrity of surface casing are closely related. Oil well casings must withstand varying loads as pressures, temperatures and external stresses change over time. It is critical that the design engineer approach the problem of casing design with a clear understanding of what can and cannot be safely assumed.

From the standpoint of surface casing in permafrost regions, it is not safe to assume that the casing is supported by cement through the permafrost. This approach is tacit in the design loads for surface casing and is reflected in the size, weight and grade of the tubulars and the connections employed on them.

We see then that with prudent design principles, cement across the permafrost is not required to ensure the structural integrity of surface casing.



Summarizing, then, we believe that what is required to ensure that surface casing and cement fullfills its' Basis of Design is

- A competent shoe verified with a formation integrity test
- A casing design based on worst case design cases.

We do not believe that circulating cement to surface should be a requirement of surface casing integrity.

AOGCC Proposed Language
Surface Casing and Cement

Surface casing must be cemented by filling the annular space with cement from the shoe to the surface; however, if cement does not circulate to the surface, if an excessive quantity of cement circulates to the surface, or if the formation integrity test shows an inadequate cement job,

(A) the operator shall notify the commission before drilling ahead; and

(B) the commission will, in its discretion, require

(i) a cement quality log or other approved method to evaluate the adequacy of the cement to contain potential wellbore pressures and fluids; and

(ii) remedial action before drilling ahead;

AOGA Proposed Language
Surface Casing and Cement

Surface casing shall be cemented by pumping a volume calculated to fill the annular space with cement from the shoe to the surface.

If cement does not circulate to the surface, the commission shall be notified. The operator shall perform a Formation Integrity Test (FIT), and if the evaluation of the FIT shows an inadequate cement job, the commission shall be notified, and the commission may require a cement quality log or other approved method to evaluate the adequacy of the cement to contain potential wellbore pressures and fluids and, if necessary, may require remedial action to ensure a competent casing shoe before drilling ahead.

We believe this language addresses the Basis of Design as it applies to Surface Casing and Cement. Furthermore, it provides prudent regulatory oversight in the unique case of permafrost cementing.

Impact of AOGA Proposed Language

- Does not jeopardize well integrity
- Will help to reduce waste
- Will result in more cost effective wells

We believe this language addresses the Basis of Design as it applies to Surface Casing and Cement. Furthermore, it provides prudent regulatory oversight in the unique case of permafrost cementing.

We believe this language will not reduce mechanical well integrity. It does not put people, the environment or natural resources at risk.

We believe this language will enable us to reduce our waste streams.

Finally, we believe this language will help us to continue to develop Alaska's natural resources in a cost effective manner.

Thank you.

BOP PREVENTER - TEST FREQUENCY

AOGA members request amendment of BOP pressure test requirements (20 AAC 25.036(d)(11)) to be consistent with federal regulations.

US DOI MMS regulations allow 14 days between BOP tests for drilling and completion operations on the Outer Continental Shelf (June 1, 1998).

MMS based decision on the report "Reliability of Blowout Preventers Tested Under Fourteen and Seven Days Time Intervals", December, 1996

(2) The principal purpose for which the Department intends to use the information;

(3) The routine uses the Department may make of the information; and

(4) The effects on the individuals, if any, of not providing the information;

(d) Ensure that the component maintains no system of records without public notice and that it notifies appropriate Department officials of the existence or development of any system of records that is not the subject of a current or planned public notice;

(e) Maintain all records that are used by the Department in making any determination about an individual with such accuracy, relevance, timeliness, and completeness as is reasonably necessary to ensure fairness to the individual in the determination;

(f) Except as to disclosures made to an agency or made under the FOIA, make reasonable efforts, prior to disseminating any record about an individual, to ensure that the record is accurate, relevant, timely, and complete;

(g) Maintain no record describing how an individual exercises his or her First Amendment rights, unless it is expressly authorized by statute or by the individual about whom the record is maintained, or is pertinent to and within the scope of an authorized law enforcement activity;

(h) When required by the Act, maintain an accounting in the specified form of all disclosures of records by the Department to persons, organizations, or agencies;

(i) Maintain and use records with care to prevent the unauthorized or inadvertent disclosure of a record to anyone; and

(j) Notify the appropriate Department official of any record that contains information that the Privacy Act does not permit the Department to maintain.

§ 16.55 Other rights and services.

Nothing in this subpart shall be construed to entitle any person, as of right, to any service or to the disclosure of any record to which such person is not entitled under the Privacy Act.

4. Appendix I of part 16 is revised to read as follows:

Appendix I to Part 16—Components of the Department of Justice

Unless a separate address is listed below, the address for each component is: (component name), U.S. Department of Justice, 950 Pennsylvania Avenue, NW., Washington, DC 20530–0001. For all components marked by an asterisk, FOIA and Privacy Act requests should be sent to the Office of Information and Privacy, U.S. Department of Justice, Flag Bldg., Suite 570, Washington, DC 2053–0001. The components are:

A

Office of the Attorney General *
Office of the Deputy Attorney General *
Office of the Associate Attorney General *
Office of the Solicitor General

B

Office of Information and Privacy *
Office of the Inspector General
Office of the Intelligence Policy and Review
Office of Intergovernmental Affairs *
Office of Investigative Agency Policies
Office of Legal Counsel
Office of Legislative Affairs *
Office of Policy Development *
Office of Professional Responsibility
Office of Public Affairs *

C

Antitrust Division, U.S. Department of Justice, LPB Bldg., Suite 200, Washington, DC 20530–0001
Civil Division, U.S. Department of Justice, 901E Bldg., Room 808, Washington, DC 20530–0001
Civil Rights Division, U.S. Department of Justice, NYAV Bldg., Room 8000B, Washington, DC 20530–0001
Criminal Division, U.S. Department of Justice, WCTR Bldg., Suite 1075, Washington, DC 20503–0001
Environment and Natural Resources Division, U.S. Department of Justice, Post Office Box 4390, Washington, DC 20044–4390
Justice Management Division
Tax Division, U.S. Department of Justice, JCB Bldg., Room 6823, Washington, DC 20503–0001
Bureau of Prisons, U.S. Department of Justice, HOLC Bldg., Room 738, 320 First Street, NW., Washington, DC 20534–0001
Community Relations Service, U.S. Department of Justice, BICN Bldg., Suite 2000, Washington, DC 20530–0001
Drug Enforcement Administration, U.S. Department of Justice, Washington, DC 20537–0001
Executive Office for Immigration Review, U.S. Department of Justice, Suite 2400, 5107 Leesburg Pike, Falls Church, VA 22041–0001
Executive Office for United States Attorneys, U.S. Department of Justice, BICN Bldg., Room 7100, Washington, DC 20530–0001
Executive Office for United States Trustees, U.S. Department of Justice, 901E Bldg., Room 780, Washington, DC 20530–0001
Federal Bureau of Investigation, U.S. Department of Justice, 935 Pennsylvania Avenue, NW., Washington, DC 20535–0001 (for field offices, consult your telephone book)
Foreign Claims Settlement Commission, U.S. Department of Justice, BICN Bldg., Room 6002, 600 E Street, NW., Washington, DC 20579–0001
Immigration and Naturalization Service, U.S. Department of Justice, CAB Bldg., 425 Eye Street, NW., Washington, DC 20536–0001 (for field offices, consult your telephone book)
INTERPOL-U.S. National Central Bureau, U.S. Department of Justice, Washington, DC 20530–0001
National Drug Intelligence Center, U.S. Department of Justice, Fifth Floor, 319 Washington Street, Johnstown, PA 15901–1622
Office of Community Oriented Policing Services, U.S. Department of Justice, VT1 Bldg., Twelfth Floor, Washington, DC 20530–0001
Office of Justice Programs, U.S. Department of Justice, Room 5337, 810 Seventh Street, NW., Washington, DC 20531–0001
Pardon Attorney, U.S. Department of Justice, FRST Bldg., Fourth Floor, Washington, DC 20530–0001
United States Marshals Service, U.S. Department of Justice, Lincoln Place, Room 1250, CSQ3, 600 Army Navy Drive, Arlington, VA 22202–4210

PART 50—STATEMENTS OF POLICY

5. The authority citation for part 50 continues to read as follows:

Authority: 5 U.S.C. 301; 28 U.S.C. 509, 510; and 42 U.S.C. 1921 et seq., 1973c.

§ 50.8 [Removed and Reserved]

6. Section 50.8 of part 50 is removed and reserved.

Dated: May 22, 1998.

Janet Reno,

Attorney General.

[FR Doc. 98–14341 Filed 5–29–98; 8:45 am]

BILLING CODE 4410–BE–M

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 250

RIN 1010–AC37

Blowout Preventer (BOP) Testing Requirements for Drilling and Completion Operations

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: This rule amends the regulations governing the testing requirements for BOP systems used in drilling and completion operations on the Outer Continental Shelf (OCS). The rule allows a lessee up to 14 days between BOP pressure tests. MMS based this rule on a study of BOP performance which concluded that no statistical difference exists in failure rates for BOP's tested between 0- and 7-day intervals and between 8- and 14-day intervals. MMS estimates that the 14-day testing requirement could save industry $35 to $46 million a year without compromising safety.

EFFECTIVE DATE: The rule is effective on June 30, 1998.

FOR FURTHER INFORMATION CONTACT: Bill Hauser, Engineering and Research Branch, at (703) 787–1613.

SUPPLEMENTARY INFORMATION: MMS proposed revising the regulations for BOP testing in a notice of proposed rulemaking published in the **Federal Register** (62 FR 37819) on July 15, 1997. We received five sets of comments during the 60-day comment period, which closed on September 15, 1997. This final rule amends the regulations found at 30 CFR 250.407 and 250.516 and becomes effective on June 30, 1998. On that date, MMS will rescind Notice to Lessees and Operators (NTL) 97-1N because the new rule will be in effect. MMS issued NTL 97-1N on January 31, 1997, to inform lessees that they could begin testing BOP systems on intervals up to 14 days.

Comments on the Rule

The five commenters consisted of four large oil companies and a drilling contractor. All five commenters supported the proposed revision to allow lessees up to 14 days between BOP pressures tests. In addition, they commented on the following parts of the proposed rule: testing frequency for workovers; testing of blind-shear rams; test duration; and use of maximum anticipated surface pressure (MASP) for determining BOP test pressures. Those comments and MMS" responses are discussed below.

BOP Testing Frequency During Workovers

Comment—One company stated that many workovers include completion or re-completion operations and asked if the amended regulations apply to the completion phase of a workover.

Response—The revised BOP testing requirements do not apply to the completion phase of workover operations. According to the definition in § 250.601, workover operations mean the work conducted on wells after the initial completion for the purpose of maintaining or restoring the productivity of the well. After the initial completion, you must test your BOP equipment according to the requirements of subpart F, Oil and Gas Well-Workover Operations.

Comment—Another commenter asked MMS to consider similar changes in testing frequency for workover operations after gathering necessary data.

Response—MMS will consider similar changes to the regulations after the completion of an appropriate study.

Testing of the Blind or Blind-Shear Ram

Comment—One commenter recommended that the requirement to test the blind or blind-shear ram at least once every 30 days (§ 250.407(d)(4)) should include an exclusion if the ram was tested during a routine test.

Response—The intent of this requirement is to ensure that the blind or blind-shear ram is tested at least once every 30 days. We revised the second sentence in this paragraph to now read as follows: "Additionally, the interval between any blind or blind-shear ram tests may not exceed 30 days." The 30-day interval begins with any test.

Testing of a Casing Safety Valve

Comment—One commenter asked MMS to define what was meant by a "casing safety valve." The commenter interpreted "casing safety valve" as a valve installed on a casing swage to facilitate circulation while running casing.

Response—We removed the term "casing safety valve" and have revised the wording of the final rule to be closer to the current rule. The new wording is "You must actuate safety valves assembled with proper casing connections prior to running casing."

Weekly Crew Drills

Comment—One company commented that the new regulations required weekly drills to familiarize personnel engaged in completion operations but there was not a similar requirement for drilling personnel.

Response—MMS continues to require well-controls drills for each drilling crew. The requirements for well-control drills during drilling are found in § 250.408. That section requires the lessee to conduct a well-control drill for each drilling crew.

Test Duration

Comment—One company thought that MMS should require a 5-minute test for large blowout preventers because of the larger fluid volumes needed for testing and leak detection.

Response—MMS requires a 5-minute test for subsea BOP equipment because of the larger volume of fluid in the system. MMS believes that a 3-minute test is appropriate for surface blowout preventer equipment provided the lessee measures the test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder.

Use of MASP in Determining Test Pressures

Comment—Three companies commented on the use of MASP for determining test pressures for BOP equipment. One recommended using MASP because it was more consistent with current industry practices and would reduce undue stress, wear, and tear on BOP components. The company recommended using a conservative method of determining MASP. Another company recommended that MMS not use MASP for determining the required BOP test pressure due to the variety of methods used by operators to calculate MASP. The third company did not feel that changing the test pressures to MASP will improve the reliability of BOP equipment if the common definition of MASP is used. However that company said that testing to the rated working pressure can be excessive and that test pressures should be related to the design of the well.

Response—MMS believes that these comments show industry's interest in using MASP in determining BOP test pressures. They also show that MMS and industry must reach a common methodology for determining MASP. Therefore, MMS has decided not to require the use of MASP for establishing BOP test pressures in this rule. The rule continues to require the lessee to test BOP components at their rated working pressures (70 percent for an annular preventer) or as otherwise approved by the District Supervisor.

As discussed in the preamble of the proposed rule, District Supervisors base the approval of alternate test pressures on a comparison of the anticipated surface pressure calculations submitted with the application for permit to drill (APD) to MASP calculations made by MMS drilling engineers. If the two calculations compare favorably, the District Supervisor approves the requested test pressures. If the calculations for anticipated surface pressure are less than those calculated by MMS, the District Supervisor advises the lessee of any necessary revisions to the APD.

We are currently rewriting the regulations for Subpart D, Oil and Gas Drilling Operations, so we will continue to examine the use of MASP in determining BOP test pressures. We plan to publish the Notice of Proposed Rulemaking for subpart D by the end of the summer.

Testing at Casing and Liner Points

MMS acknowledged in the preamble to the proposed rule that there was at least one situation where it may not be necessary to test the BOP system. MMS has added two sentences to § 250.407(a)(3) that explain when a lessee will be allowed to omit a test of the BOP system at some casing and liner points. This addition is intended to clearly describe in the regulatory text the circumstance when MMS will allow a lessee to not test the BOP system. That circumstance occurs when a lessee doesn't remove the BOP stack to run

casing or a liner, and the required BOP-test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test. The lessee must clearly indicate in its APD which casing strings and liners meet these criteria.

Recently, MMS published a final rule redesignating 30 CFR part 250. The new numbering is used here as follows: § 250.406 replaces § 250.56; § 250.407 replaces § 250.57; § 250.408 replaces § 250.58; § 250.516 replaces § 250.86; and § 250.601 replaces § 250.91.

Procedural Matters

Executive Order (E.O.) 12866

MMS estimates that this final rule will save the oil and gas industry $34.5 to $46 million per year. These savings result from having to conduct fewer BOP tests and increased drilling efficiency. Direct economic effects are reduced drilling costs for each well drilled on the OCS. The rule does not add any new costs to industry, and it will not reduce the level of safety to personnel or the environment. Since the rule will have an annual effect on the economy of less than $100 million, the rule is not a significant regulatory action.

The rule will not affect the level of drilling activity on the OCS. It will reduce the number of BOP tests conducted, which should result in reduced drilling time for each well. Once the lessee completes a well, the rig will move on to the next well. This will not have any adverse effects on employment, investment, productivity, innovation, or on the ability of U.S.-based enterprises to compete with foreign-based enterprises in other markets because the economic effects are minor. The rule will have no effect on competition. Therefore, in accordance with E. O. 12866, a review by the Office of Management and Budget (OMB) is not necessary.

Regulatory Flexibility Act

This final rule will not have any significant effects on a substantial number of small entities. This rule affects only two groups that operate on the OCS: (1) lessees that contract drilling operations and (2) drilling contractors.

A lessee that qualifies as a small entity could see a minor, positive economic benefit due to the cost savings from conducting fewer BOP tests. However, any savings would probably be offset by increased costs to contract a drilling rig. Day rates for offshore drilling rigs are increasing due to high rig utilization.

In general, entities that engage in offshore activities are not small due to technical and financial resources and experience needed to safely conduct these operations. Small entities are more likely to operate onshore or in State waters—areas not covered by this rule. When small entities do work in the OCS, they are likely to be service contractors and not owner/operators of OCS platforms or drilling rigs.

Your comments are important. The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small business about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions of MMS, call toll-free (888) 734-3247.

Paperwork Reduction Act (PRA) of 1995

As part of the Notice of Proposed Rulemaking process, OMB approved the proposed information collection requirements in 30 CFR Part 250, Subpart D, Oil and Gas Drilling Operations (OMB Control Number 1010-0053) and Subpart E, Oil and Gas Well-Completion Operations (OMB Control Number 1010-0067), as required by the PRA of 1995 (44 U.S.C. 3501 *et seq.*). MMS did not receive any comments on the information collection aspects in the notice of proposed rulemaking. The final rule did not change any of the information collection requirements. PRA provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

The collections of information in these subparts consist of reporting and recordkeeping requirements on the conditions of a drilling site and well-completion operations in the OCS. MMS uses the information to determine if lessees are properly providing for safe operations and protection of human life or health and the environment. MMS estimated the total annual burden for subpart D to be 108,581 hours. This reflects a decrease of 12,499 recordkeeping hours as a result of the rule. The estimated total annual burden for subpart E is 4,841 hours. MMS estimates that the rule reduced the annual burden for subpart E by 2,563 recordkeeping hours.

Takings Implication Assessment

The Department of the Interior (DOI) certifies that this final rule does not represent a governmental action capable of interference with constitutionally protected property rights. Thus, MMS did not need to prepare a Takings Implication Assessment pursuant to E.O. 12630, Governmental Action and Interference with Constitutionally Protected Property Rights.

Unfunded Mandates Reform Act of 1995

DOI has determined and certifies according to the Unfunded Mandates Reform Act, 2 U.S.C. 1502 *et seq.*, that this rule will not impose a cost of $100 million or more in any given year on State, local, and tribal governments, or the private sector.

E.O. 12988

DOI has certified to OMB that this rule meets the applicable civil justice reform standards provided in sections 3(a) and 3(b)(2) of E.O. 12988.

National Environmental Policy Act

DOI has determined that this action does not constitute a major Federal action significantly affecting the quality of the human environment. Therefore, preparation of an Environmental Impact Statement is not required.

List of Subjects in 30 CFR Part 250

Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Investigations, Mineral royalties, Oil and gas development and production, Oil and gas exploration, Oil and gas reserves, Penalties, Pipelines, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements, Sulphur development and production, Sulphur exploration, Surety bonds.

Dated: May 15, 1998.

Sylvia V. Baca,

Deputy Assistant Secretary, Land and Minerals Management.

For the reasons stated in the preamble, the Minerals Management Service (MMS) amends 30 CFR part 250 as follows:

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

1. The authority citation for part 250 continues to read as follows:

Authority: U.S.C. 1334.

2. In § 250.406, the fourth sentence in paragraph (d)(10)(i) is revised to read as follows:

§ 250.406 Blowout preventer systems and system components.

* * * * *

(d) * * *

(10) * * *

(i) * * * All required manual and remotely controlled valves of a kelly cock or comparable type in a top-drive system must be essentially full-opening and tested according to the test pressure and test frequency as stated in § 250.407 of this part. * * *

3. Section 250.407 is revised to read as follows:

§ 250.407 Blowout preventer (BOP) system tests, inspections, and maintenance.

(a) *BOP pressure testing timeframes.* You must pressure test your BOP system:

(1) When installed;

(2) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before 12 a.m. (midnight) on the 14th day following the conclusion of the previous test. However, the District Supervisor may require testing every 7 days if conditions or BOP performance warrant; and

(3) Before drilling out each string of casing or a liner. The District Supervisor may allow you to omit this test if you did not remove the BOP stack to run the casing string or liner and the required BOP-test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test. You must indicate in your APD which casing strings and liners meet these criteria.

(b) *BOP test pressures.* When you test the BOP system, you must conduct a low pressure and a high pressure test for each BOP component. Each individual pressure test must hold pressure long enough to demonstrate that the tested component(s) holds the required pressure. Required test pressures are as follows:

(1) All low pressure tests must be between 200 and 300 psi. Any initial pressure above 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test. You must conduct the low pressure test before the high pressure test.

(2) For ram-type BOP's, choke manifold, and other BOP equipment, the high pressure test must equal the rated working pressure of the equipment or the pressure otherwise approved by the District Supervisor; and

(3) For annular-type BOP's, the high pressure test must equal 70 percent of the rated working pressure of the equipment or the pressure otherwise approved by the District Supervisor.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes.

(1) For surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder.

(2) If the equipment does not hold the required pressure during a test, you must remedy the problem and retest the affected component(s).

(d) *Additional BOP testing requirements.* You must:

(1) Use water to test a surface BOP system;

(2) Stump test a subsurface BOP system before installation. You must use water to stump test a subsea BOP system. You may use drilling fluids to conduct subsequent tests of a subsea BOP system;

(3) Alternate tests between control stations and pods. If a control station or pod is not functional, you must suspend further drilling operations until that station or pod is operable;

(4) Pressure test the blind or blind-shear ram during a stump test and at all casing points. Additionally, the interval between any blind or blind-shear ram tests may not exceed 30 days;

(5) Function test annulars and rams every 7 days between pressure tests;

(6) Pressure-test variable bore-pipe rams against all sizes of pipe in use, excluding drill collars and bottom-hole tools;

(7) Test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly;

(8) Actuate safety valves assembled with proper casing connections prior to running casing, and

(9) If you install casing rams, you must test the ram bonnet before running casing.

(e) *Postponing BOP tests.* You may postpone a BOP test if you have well-control problems such as lost circulation, formation fluid influx, or stuck drill pipe. If this occurs, you must conduct the required BOP test on the first trip out of the hole. You must record the reason for postponing any test in the driller's report.

(f) *Visual inspections.* You must visually inspect your surface and subsea BOP systems and marine riser at least once each day if weather and sea conditions permit. You may use television cameras to inspect subsea equipment. The District Supervisor may approve alternate methods and frequencies to inspect a marine riser. Casing risers on fixed structures and jackup rigs are not subject to the daily underwater inspections.

(g) *BOP maintenance.* You must maintain your BOP system to ensure that the equipment functions properly.

(h) *BOP test records.* You must record the time, date, and results of all pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the driller's report. In addition, you must:

(1) Record BOP test pressures on pressure charts;

(2) Have your onsite representative certify (sign and date) BOP test charts and reports as correct;

(3) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. You may reference a BOP test plan if it is available at the facility;

(4) Identify the control station or pod used during the test;

(5) Identify any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities;

(6) Retain all records, including pressure charts, driller's report, and referenced documents, pertaining to BOP tests, actuations, and inspections at the facility for the duration of drilling; and

(7) After drilling is completed, you must retain all the records listed in paragraph (h)(6) of this section for a period of 2 years at the facility, at the lessee's field office nearest the Outer Continental Shelf (OCS) facility, or at another location conveniently available to the District Supervisor.

(i) *Alternate methods.* The District Supervisor may require, or approve, more frequent testing, as well as different test pressures and inspection methods, or other practices.

4. Section 250.516 is revised to read as follows:

§ 250.516 Blowout preventer system tests, inspections, and maintenance.

(a) *BOP pressure testing timeframes.* You must pressure test your BOP system:

(1) When installed; and

(2) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before 12 a.m. (midnight) on the 14th day following the conclusion of the previous test. However, the District Supervisor may require testing every 7 days if conditions or BOP performance warrant.

(b) *BOP test pressures.* When you test the BOP system, you must conduct a low pressure and a high pressure test for each BOP component. Each individual pressure test must hold pressure long enough to demonstrate that the tested component(s) holds the required pressure. The District Supervisor may approve or require other test pressures or practices. Required test pressures are as follows:

(1) All low pressure tests must be between 200 and 300 psi. Any initial pressure above 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test. You must conduct the low pressure test before the high pressure test.

(2) For ram-type BOP's, choke manifold, and other BOP equipment, the high pressure test must equal the rated working pressure of the equipment.

(3) For annular-type BOP's, the high pressure test must equal 70 percent of the rated working pressure of the equipment.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes.

(1) For surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder.

(2) If the equipment does not hold the required pressure during a test, you must remedy the problem and retest the affected component(s).

(d) *Additional BOP testing requirements.* You must:

(1) Use water to test the surface BOP system;

(2) Stump test a subsurface BOP system before installation. You must use water to stump test a subsea BOP system. You may use drilling or completion fluids to conduct subsequent tests of a subsea BOP system;

(3) Alternate tests between control stations and pods. If a control station or pod is not functional, you must suspend further completion operations until that station or pod is operable;

(4) Pressure test the blind or blind-shear ram at least every 30 days;

(5) Function test annulars and rams every 7 days;

(6) Pressure-test variable bore-pipe rams against all sizes of pipe in use, excluding drill collars and bottom-hole tools; and

(7) Test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly;

(e) *Postponing BOP tests.* You may postpone a BOP test if you have well-control problems. You must conduct the required BOP test as soon as possible (i.e., first trip out of the hole) after the problem has been remedied. You must record the reason for postponing any test in the driller's report.

(f) *Weekly crew drills.* You must conduct a weekly drill to familiarize all personnel engaged in well-completion operations with appropriate safety measures.

(g) *BOP inspections.* You must visually inspect your BOP system and marine riser at least once each day if weather and sea conditions permit. You may use television cameras to inspect this equipment. The District Supervisor may approve alternate methods and frequencies to inspect a marine riser.

(h) *BOP maintenance.* You must maintain your BOP system to ensure that the equipment functions properly.

(i) *BOP test records.* You must record the time, date, and results of all pressure tests, actuations, crew drills, and inspections of the BOP system, system components, and marine riser in the driller's report. In addition, you must:

(1) Record BOP test pressures on pressure charts;

(2) Have your onsite representative certify (sign and date) BOP test charts and reports as correct;

(3) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. You may reference a BOP test plan if it is available at the facility;

(4) Identify the control station or pod used during the test;

(5) Identify any problems or irregularities observed during BOP system and equipment testing and record actions taken to remedy the problems or irregularities;

(6) Retain all records including pressure charts, driller's report, and referenced documents pertaining to BOP tests, actuations, and inspections at the facility for the duration of the completion activity; and

(7) After completion of the well, you must retain all the records listed in paragraph (i)(6) of this section for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

(j) *Alternate methods.* The District Supervisor may require, or approve, more frequent testing, as well as different test pressures and inspection methods, or other practices.

[FR Doc. 98-14294 Filed 5-29-98; 8:45 am]

BILLING CODE 4310-MR-P

DEPARTMENT OF THE TREASURY

Office of Foreign Assets Control

31 CFR Chapter V

Blocked Persons, Specially Designated Nationals, Specially Designated Terrorists, Specially Designated Narcotics Traffickers, and Blocked Vessels: Addition of Sudanese Government Designations, Removal of Two Individuals, and Unblocking of a Vessel

AGENCY: Office of Foreign Assets Control, Treasury.

ACTION: Amendment of final rule.

SUMMARY: The Treasury Department is adding to appendices A and B to 31 CFR chapter V the names of 62 entities which have been determined to act for or on behalf of, or to be owned or controlled by the Government of Sudan. In addition, the entries for two individuals previously designated as specially designated narcotics traffickers are being removed from appendices A and B. The entry for a vessel is also being removed from appendix C, as it is no longer considered to be property in which the Government of Cuba has an interest. Technical changes are also made to the notes to the appendices.

EFFECTIVE DATE: May 26, 1998.

FOR FURTHER INFORMATION CONTACT: Office of Foreign Assets Control, Department of the Treasury, Washington, DC 20220; tel.: 202/622-2520.

SUPPLEMENTARY INFORMATION:

Electronic Availability

This document is available as an electronic file on *The Federal Bulletin Board* the day of publication in the **Federal Register**. By modem, dial 202/512-1387 and type "/GO FAC," or call 202/512-1530 for disk or paper copies. This file is available for downloading without charge in WordPerfect 5.1, ASCII, and Adobe Acrobat[R] readable (*.PDF) formats. For Internet access, the address for use with the World Wide Web (Home Page), Telnet, or FTP protocol is: fedbbs.access.gpo.gov. The document is also accessible for downloading in ASCII format without charge from Treasury's Electronic Library ("TEL") in the "Business, Trade and Labor Mall" of the FedWorld bulletin board. By modem, dial 703/321-3339, and select the appropriate self-expanding file in TEL. For Internet access, use one of the following protocols: Telnet = fedworld.gov (192.239.93.3); World Wide Web (Home Page) = http://www.fedworld.gov; FTP

RELIABILITY OF BLOWOUT PREVENTERS TESTED UNDER FOURTEEN AND SEVEN DAYS TIME INTERVAL

STUDY REPORT

SUBMITTED TO

MINERALS MANAGEMENT SERVICES
OF
THE U.S. DEPARTMENT OF INTERIOR

SUBMITTED BY

TETRAHEDRON, INC.

December 20, 1996

Results presented in this report are based on the data received from the industry.

1.0 SUMMARY

BOP reliability study has been completed. Statistical analyses were done on data collected from the oil industry using a 99% confidence level. Results of the analyses indicated that:

- BOP failure rate when tested at interval between 8 to 14 days can not be claimed to be different than when tested between 0 to 7 days.
- Failure rate of most components were also not significantly different when tested between 0-7 and 8-14 days time interval.
- Failure rate of initial tests were greater than subsequent tests.
- Results obtained from this analysis are valid only for the interval ranges studied. They do not show significant correlation between failure rate and interval between test. This result should not be extrapolated to draw conclusions on other time interval failure rates.

2.0 PROBLEM STATEMENT

2.1 Blowout Preventers

Blowout prevention Systems (referred to as Blowout Preventer, BOP, in this study) are used in oil and gas fields during drilling operations to prevent uncontrolled release of reservoir fluids. BOPs considered in this study are composed of all systems required to operate the blowout preventers under varying rig and well conditions. These systems are: blowout preventers, choke and kill lines, choke manifold, and auxiliary equipment. It does not include marine riser. Appendix A provides figures of typical BOP systems.

2.2 Current Regulation

In accordance with Federal Regulations as published in 30 CFR section 250.57 surface and subsea blowout preventers must be tested:

(a) when installed;

(b) before drilling out each string of casing or before continuing operations in cases where the cement is not drilled out;

(c) at least once each week, but not exceeding 7 days between pressure tests, alternating between control stations. A period of more than 7 days between BOP tests is allowed when there is a stuck drill pipe or there are pressure control operations, and remedial efforts are being performed, provided that the pressure tests are conducted as soon as possible and before normal operation resumes.

2.3 Request to Change Current Regulation

Each test requires substantial time and effort and causes delay in drilling operations. The oil industry feels that testing within seven days (as discussed in section 2.2(c) above) is not necessary because:

(i) Seven day testing hampers flow of drilling activity and leads to inefficiency.
(ii) Too much testing can cause component failure due to exposure to high pressures and abrasive materials.
(iii) Testing within fourteen days will provide at least same level of protection as the seven day test interval.

In 1992, the oil industry requested Minerals Management Services (MMS) of the U.S. Department of Interior to evaluate the required current seven day test frequency and to see if this could be extended to fourteen day interval. MMS in reviewing this request decided to do a study to see if *within* fourteen day test interval will provide the same amount of safety as *within* seven day test interval.

3.0 PREVIOUS STUDIES

3.1 Study Performed by MMS

In 1993, MMS began a review of the BOP testing and maintenance requirements. This included:

- Evaluating two SINTEF studies sponsored by Norwegian Petroleum Directorate (NPD).
- Gathering BOP test data from drilling operations.
- Holding workshop and gathering industry input.
- Conducting study of BOP test charts. Study included:
  - Building a database.
  - Analysis of data.

The MMS study indicated that failures rates were substantially greater than recorded by SINTEF. In addition, it was also determined that percentage of good tests varied with duration of test intervals as shown below:

1 to 7 days	= 57%
8 to 12 days	= 48%
13 to 15 days	= 38%

This data showed a trend that BOP performance decreased as the test interval increased. Based on these results and discussions with industry, MMS decided that a second study was necessary to assess BOP performance on the Outer Continental Shelf.

3.2 Study Performed by SINTEF

This study was performed to ascertain the reliability of both surface and subsea BOPs in the Norwegian sector of the North Sea. The study indicated that:

- Surface BOPs fail more often than subsea BOPs due to less redundancy in safety mechanism.
- High failure rate is associated with inadequate preventive maintenance.

4.0 SCOPE OF CURRENT STUDY

MMS and the U.S. petroleum industry considered it essential to perform a more thorough study that can lead to conclusions on whether 14 day test interval will provide safe operating conditions at a drilling site. MMS and industry worked together in setting the parameters for the study. The following industry groups participated in selecting the contractor for the study:

American Petroleum Institute
Independent Petroleum Association of America
International Association of Drilling Contractors
National Ocean Industries Association
Offshore Operators Committee

MMS and these industry groups hired Tetrahedron, Inc. on February 13, 1996, to assess BOP performance. Tasks to be performed under this study included:

(i) Meeting with MMS and the industry for developing a study method that will be acceptable to all parties involved.

(ii) Review of existing data/information collected by MMS.

(iii) Developing methodologies including data acquisition forms/techniques, data evaluation and quality control and data analyses methods.

(iv) Data analyses and reporting.

(v) Development of data base.

(vi) Presentation of the results at a workshop.

5.0 MEETING WITH THE STAKE HOLDERS

5.1 First Meeting

A kick-off meeting was held in Houston on February 27, 1996. Participants in the meeting were representatives from MMS, Tetrahedron, Inc., American Petroleum Institute, Independent Petroleum Association of America, International Association of Drilling Contractors, National Ocean Industries Association, and Offshore Operators Committee.

Purpose of this meeting was to develop a plan for the acquisition of data that will be acceptable to both the industry and regulatory agency. Highlights of the outcome of this meeting are given below:

1. The study will include only BOP systems. Diverter systems are not included in the scope of this study.

2. BOP test reports will be submitted by contractors in a preferred format for consistency and for the purpose of capturing all relevant information. The preferred format will be developed by Tetrahedron, Inc. and provided to the contractors by MMS.

3. A "condition of approval" will be developed and mailed to the industry under which they may perform BOP testing within 14 days instead of 7 days and submit test results for analyses.

4. Each test result submitted by the contractor/operator should be supported by test report, charts and diagrams maintaining consistent equipment identification numbering.

5. Terminologies used in the study were defined for maintaining consistency.

5.2 Second Meeting

Second meeting was held on August 28, 1996 at the MMS office in New Orleans with the stake holders. Highlights of the meeting are given below:

- Phase I report was presented by Tetrahedron, which indicated that based on the data, there was not enough evidence to claim that BOP failure rates when tested between 1-7 days and 8-14 days are different.

- Following decisions were taken:

(i) More data was to be gathered to see if there is difference in the failure rates of surface and

subsea BOPs.

(ii) Analysis of BOP component failures was to be included in the study.

(iii) Analysis of failure rates for each day (between 0 to 14 days) and its relationship to "test interval" was to be developed as part of the study.

(iv) Database was to be developed in Excel.

6.0 REVIEW OF EXISTING DATA

Data collected by MMS was reviewed to see the randomness of distribution. It was noticed that the data concentrated around 7 day and 14 day test period. Raw data indicated that failure rate increased as time interval between tests increased. No statistical analysis was done to validate this result.

7.0 METHODOLOGY

7.1 Data Acquisition

Data was acquired for analyses through the office of MMS from the drilling contractors/operators. "BOP and Choke Manifold Test Report" forms were provided to them which in most cases were filled out and sent along with pressure charts and relevant diagrams. In some cases companies used their own forms to provide the data for this study. A sample of "BOP and Choke Manifold Test Report" is provided in Appendix B. This form was prepared in accordance with the agreement reached in the "kick-off meeting" and was accepted by MMS and the industry before being sent out.

7.1.1 Data Transfer and Recording

Figure 7.1 is a flow diagram showing how the data was transferred, recorded and analyzed. All data were sent to MMS by the industry. MMS forwarded this data to Tetrahedron. Tetrahedron recorded the data and assigned numbers as they were received in a database for tracking purposes. Data was then forwarded to Tetrahedron's blowout prevention expert for review, validation and comments. The BOP expert filled out a performance evaluation form for each failed BOP. Data along with the performance evaluation form was sent back to the data recorder for recording in the main database that captured information on each BOP test including *operator, leasewell, contractor, rigname, date, location of BOP, test duration, success/failure, test type, test fluid, time pressure held, and components failed.* The data entered into the database was analyzed using statistical techniques as described in section 7.3.

7.2 Data Validation

All data received from the oil field was validated by reviewing the reports and the charts to see if all information provided was accurate. Validation was done by the BOP expert who also ensured that there was consistency between reports. This was important because reports came from many different sources which had to be standardized for analysis.

For each failure, the BOP expert filled out a *performance evaluation form* that indicated the component that failed, type of BOP (surface or subsea), test duration, and BOP expert's comments (if any) on the report.

Figure 7.1 Flow diagram of data transfer, recording and analysis.

7.2.1 Definitions

In this study BOP failure has been defined as given below:

BOP Failure: For both subsequent and initial test, a test was considered to have failed if any piece of equipment had to be physically repaired or sent to shop for repairs even if it had back-up.

A subsequent test was considered to have failed if any critical equipment failed during a pressure test. A critical equipment is defined as any equipment which would be required to hold well bore pressure in a well control situation and did not have a backup.

BOP Non-Failure: Failure to obtain test data resulting from test equipment failures, air in line, bump in chart, realigned chart or other errors not associated with actual testing of BOP was not considered a BOP failure.

For non-critical equipment (equipment that have backup), a subsequent test was not considered failed if it could be functioned or operated without repair and would obtain good test within three test runs.

In case of initial test, if any piece of equipment could be functioned or operated without repair showing good test, it was not considered a failure irrespective of the number of test runs required to reach the successful test.

Initial Test: Initial test is defined as any test that is conducted when a blowout preventer is installed at the well. Many reports received from the industry designated tests as initial test with "test interval" greater than zero, indicating that other test(s) have been conducted on the BOP before. It was considered legitimate designation based on following rationale:

(i) If an initial test fails and components of the BOP have to be repaired, then subsequent test after repair is also considered initial test.

(ii) If after conducting an initial test no activity is performed that will expose the BOP to pressure environment, then subsequent test is considered initial test.

In this study we have included all tests that were designated "initial test" in the reports as such.

Connection Failure: Connection failures that were considered as BOP failures in this study included:

(i) Ring gasket connections on flanges of rams, annulars, inside choke valves, inside kill line valves, bonnet seal connections.

(ii) Well head connections.

(iii) Any connections on BOP equipment that did not have backup.

Connection failures that were not considered as BOP failures included:

(i) Test equipment and related test equipment connections (i.e. chiksan line connections).

(ii) Drilling rig equipment (i.e. mud pump body connections, valve cap gaskets, liner gaskets, union leaks on mud line and stand pipe.)

(iii) Ring gasket connection down stream of choke.

7.3 Statistical Techniques Used in the Study

It is essential to use statistical methods when inference about a population is to be made based on data from a sample. Variations between samples within a population resulting from natural distribution should be considered. Two samples from same population can have different "mean values". These mean values may be large depending upon the variance in the population. Therefore, before we infer that two samples that are different come from two separate populations, we must compare there mean values in light of the variance that exist in the data. In this study we selected a significance level of 99%, meaning that we would not consider that samples came from two different populations unless we were 99% certain. In other words, we want to be 99% sure that we do not erroneously reject our hypothesis that failure rates in 0-7 days time interval and 8-14 days time interval represent the same population. Rejection of the hypothesis would indicate that time interval between tests has an effect on the failure rates.

Note: Population in this study refers to all the BOP systems that will be used under similar conditions.

Statistical techniques used in this study assume normal distribution of the data as the sample size (n) is large (>30).

7.3.1 Sampling

Random sampling technique was used for collecting data from the industry. Data were received from the industry in random fashion without any geographical, drilling contractor, operator bias. Data were received at the MMS office and forwarded to Tetrahedron where they were numbered in the order they were received for tracking purposes. It was then separated into three categories by *time interval between tests*. The purpose of this separation was to see if each time interval represented a separate population. The time intervals used were:

0 to 7 days between tests

8 to 14 days between tests
Initial tests

7.3.2 Hypothesis Testing

Hypothesis testing is usually used when finding differences between two population means or proportions. Such a test was considered appropriate for this study since the objective is to see if the proportion of failures under various time intervals between tests are different.

For this study we have used a probability of error in our inference to be 1% (significance level, alpha = 0.01). This means that 99% of the time when our hypothesis (null hypothesis) about the population is correct we will not reject it based on our sample outcome. In other words we can be 99% confident that we do not erroneously reject our null hypothesis.

Eight hypotheses were tested as given in Table 7-1.

TABLE 7-1

Hypothesis 1: Proportion of failures in BOPs when tested between 0 to 7 days "$\mathbf{P_1}$" and between 8 to 14 days "$\mathbf{P_2}$" are equal.
Hypothesis 2: Proportion of failures in BOPs when tested between 0 to 7 days "$\mathbf{P_1}$" and initial tests "$\mathbf{P_2}$" are equal.
Hypothesis 3: Proportion of failures in BOPs when tested between 8 to 14 days "$\mathbf{P_1}$" and initial tests "$\mathbf{P_2}$" are equal.
Hypothesis 4: Proportion of failures when tested between 0 to 7 days for surface BOPs "$\mathbf{P_1}$" and subsea BOPs "$\mathbf{P_2}$" are equal.
Hypothesis 5: Proportion of failures when tested between 8 to 14 days for surface BOPs "$\mathbf{P_1}$" and subsea BOPs "$\mathbf{P_2}$" are equal.
Hypothesis 6: Proportion of failures in *surface BOPs* when tested between 0 to 7 days "P_1" and between 8 to 14 days "$\mathbf{P_2}$" are equal.
Hypothesis 7: Proportion of failures in *subsea BOPs* when tested between 0 to 7 days "$\mathbf{P_1}$" and between 8 to 14 days "$\mathbf{P_2}$" are equal.
Hypothesis 8: Proportion of failures in *subsea BOPs (total)* "$\mathbf{P_1}$" and *surface BOPs (total)* "$\mathbf{P_2}$" are equal.

In addition, for component failure additional 22 hypotheses were tested as shown in Table 7-2.

TABLE 7-2

Hypothesis 1: Proportion of failures in "Annular" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal. Hypothesis 2: Proportion of failures in "Pipe Ram" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal. Hypothesis 3: Proportion of failures in "Blind Ram" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal.
Hypothesis 4: Proportion of failures in "Kill Manual" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal. Hypothesis 5: Proportion of failures in "Kill Remote" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal. Hypothesis 6: Proportion of failures in "Manifold Manual" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal.
Hypothesis 7: Proportion of failures in "Manifold Remote" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal. Hypothesis 8: Proportion of failures in "Choke Manual" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal. Hypothesis 9: Proportion of failures in "Choke Remote" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal.
Hypothesis 10: Proportion of failures in "Drill String Valve" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal. Hypothesis 11: Proportion of failures in "Inside BOP" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal. Hypothesis 12: Proportion of failures in "Connections" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal.
Hypothesis 13: Proportion of failures in "Test equipment" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal.

Hypothesis 14: Proportion of failures in "Other Failed Parts" when tested between 0-7 days "P_1" and between 8 to 14 days "P_2" are equal.
Hypothesis 15: Proportion of failures in "Annular" when tested between 0-7 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal. Hypothesis 16: Proportion of failures in "Ram (pipe and blind ram combined)" when tested between 0-7 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal. Hypothesis 17: Proportion of failures in "Manifold Valve (manual and remote combined)" when tested between 0-7 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal. Hypothesis 18: Proportion of failures in "Inside BOP and Drill String Valve combined" when tested between 0-7 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal.
Hypothesis 19: Proportion of failures in "Annular" when tested between 8-14 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal. Hypothesis 20: Proportion of failures in "Ram (pipe and blind ram combined)" when tested between 8-14 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal. Hypothesis 21: Proportion of failures in "Manifold Valve (manual and remote combined)" when tested between 8-14 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal. Hypothesis 22: Proportion of failures in "Inside BOP and Drill String Valve combined" when tested between 8-14 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal.

Following test procedure was used for all tests:

Null Hypothesis H_o: P_1 is equal to P_2

Alternate Hypothesis H_A: P_1 is not equal to P_2

and the test statistics used is:

$$Z = (p_1 - p_2)/(p_1(1-p_1)/n_1 + p_2(1-p_2)/n_2)^{1/2}$$

Reject H_o if absolute value of $Z > Z_{0.005}$

or Reject H_o if absolute value of $Z > 2.575$

Note: "P" refers to population and "p" refers to sample.

7.3.3 Regression Analysis

Regression analysis helps to create mathematical models that show a relationship between two or more variables. Purpose of these models are to develop methods for predicting a value of a dependent variable. For this study, "failure rate" was selected as the dependent variable, and "time interval between tests" was used as the independent variables. Multiple regression, which can incorporate more than one independent variable, was considered appropriate for this study. Stepwise selection procedure for variables was used to eliminate effects of multicollinearity.

7.3.4 Model Definition

A model was tested to see if there was significant correlation between dependent (failure) and independent variables (time). Analysis of Variance (ANOVA) was conducted on the data to achieve this objective.

Model Description

A fourth order polynomial was selected to model failure rate as a function of time interval between tests as shown below:

$$F = b_0 + c_1 t + c_2 t^2 + c_3 t^3 + c_4 t^4$$

where:

F = Failure rate
b and c = constants
t = time interval between tests

Hypothesis for the Test

Null hypothesis $H_0 = c_1 = c_2 = c_3 = c_4 = 0$
Alternate hypothesis H_A = at least one of the "c" is not equal to zero.

8.0 RESULTS

8.1 Data Summary

A total of 155 test reports were analyzed for this study. Summary of data acquired is presented in Table 8.1

TABLE 8.1 DATA SUMMARY

Test Outcome	0-7 Day Interval	8-14 Day Interval	Initial Test	Total
Success	27	48	17	92
Failure	13	23	27	63
Total	40	71	44	155

8.2 Test Outcome by Type of BOP

Test data were also separated by BOP type (surface or subsea). A summary of data by BOP type is presented in Table 8.2. Five test reports that are part of Table 8.1 did not indicate type of BOP (surface or subsea), therefore, were not included in Table 8.2.

TABLE 8.2 TEST OUTCOME BY TYPE OF BOP

Test Outcome	Surface (0-7 days)	Surface (8-14 days)	Subsea (0-7 days)	Subsea (8-14 days)
Success	13	15	13	31
Failures	7	15	5	7
Total	20	30	18	38

8.3 Hypotheses Test Results

Hypotheses tests were conducted as discussed in section 7.3.2. Results of the tests are summarized in Table 8.3

TABLE 8.3 Hypotheses Test Results

Test #	Hypothesis	p_1	p_2	Test Statistics	$Z_{0.005}$	Comments
1.	Proportion of failures in BOPs when tested between 0 to 7 days "**P_1**" and between 8 to 14 days "**P_2**" are equal.	.325	.324	.01	2.575	Based on data, we cannot say that it is different.
2.	Proportion of failures in BOPs when tested between 0 to 7 days "**P_1**" and initial "**P_2**" are equal.	.325	.614	-2.67	2.575	Based on data, we can say that it is different.
3.	Proportion of failures in BOPs when tested between 8 to 14 days "**P_1**" and initial test "**P_2**" are equal.	.324	.614	-3.15	2.575	Based on data, we can say that it is different.
4.	Proportion of failures when tested between 0 to 7 days for surface BOPs "**P_1**" and subsea BOPs "**P_2**" are equal.	.350	.278	.48	2.575	Based on data, we cannot say that it is different.
5.	Proportion of failures when tested between 8 to 14 days for surface BOPs "**P_1**" and subsea BOPs "**P_2**" are equal.	.50	.180	2.90	2.575	Based on data, we can say that it is different.
6.	Proportion of failures in *surface BOPs* when tested between 0 to 7 days "P_1" and between 8 to 14 days "**P_2**" are equal.	.35	.50	-1.07	2.575	Based on data, we cannot say that it is different.
7.	Proportion of failures in *subsea BOPs* when tested between 0 to 7 days "P_1" and between 8 to 14 days "**P_2**" are equal.	.278	.180	.80	2.575	Based on data, we cannot say that it is different.
8.	Proportion of failures in *subsea BOPs (total)* "**P_1**" and *surface BOPs (total)* "**P_2**" are equal.	.21	.42	2.37	2.575	Based on data, we cannot say that it is different.

8.4 Relationship Between Failure Rate and Test Interval

Failure rate for each time interval was calculated from the data and is presented in Table 8.4 (Failure Rate Summary) below. Initial tests were included in this analysis.

Table 8.4 Failure Rate Summary

No.	Interval Between Tests (days)	Sample Size	Failure Rate
1	0	32	.469
2	1	4	.75
3	2	3	.33
4	3	5	1.00
5	4	6	1.00
6	5	13	.31
7	6	8	.56
8	7	8	.38
9	8	11	.55
10	9	2	0
11	10	9	.44
12	11	8	.25
13	12	10	.40
14	13	17	.31
15	14	19	.26

As discussed in section 7.3.3 and 7.3.4, regression analysis was conducted to determine correlation between failure rate and time interval between tests. The ANOVA for the data as obtained from SAS (Statistical Analysis System) computer output is provided below:

Variable t^2 entered R-square =0.29743161

	DF	Sum of Squares	Mean Square	F	Prob.F
Regression	1	0.07049873	0.07049873	4.23	0.0667
Error	10	0.16652627	0.01665263		

Variable	Parameter Estimate	Stand. Error	Sum of Squares	F	Prob>F
Intercept	0.50575813	0.05681276	1.31970463	79.25	0.0001
t^2	-0.00116512	0.00056627	0.07049873	4.23	0.0667

No other variable met the 0.1500 significance level for entry into the model

According to this analysis, failure rate (F) may be represented by the following equation:

$$F = 0.506 - 0.00117t^2$$

Where "t" is the time in days between tests.

The ANOVA shows that none of the constants in the equation $F = b_0 + c_1t + c_2t^2 + c_3t^3 + c_4t^4$, except b_0 (0.5058) and c_2 (-0.001), could be considered significant. The R-square value (0.2974) even with these two constants is very low and indicates that there is no significant correlation between failure rate and time interval between tests.

8.5 Component Failure

The final factors to be analyzed were the individual components that were found to have failed during testing. These components included:

1. Annular
2. Piperam
3. Blindram
4. Kill manual valve
5. Kill remote valve
6. Manifold manual valve
7. Manifold remote valve
8. Choke manual valve
9. Choke remote valve
10. Drill string valve
11. Inside BOP
12. Connections
13. Test equipment
14. Other failed parts (pod, hammer union, choke swaco, hose etc.)

A summary of component failure distribution is presented in Tables 8.5 (a) & (b). Graphical presentation of this data is provided in Figures 8-1 through 8-3. Please note that the number of tests analyzed for 0-7 days, 8-14 days, and initial test intervals were 40, 71, and 44 respectively.

TABLE 8.5(a) DATA SUMMARY

Component	Failure (0-7 days) (Total 40 tests)	Failure (8-14 days) (Total 71 tests)	Initial Test (Total 44 tests)	Total
Annular	2	4	2	8
Piperam	1	4	0	5
Blindram	1	1	1	3
Kill Manual Valve	0	0	2	2
Kill Remote Valve	0	1	2	3
Manifold Manual V.	2	9	9	20
Manifold Remote V.	0	1	2	3
Choke Manual Valve	0	0	0	0
Choke Remote Valve	0	0	0	0
Drill String Valve	0	2	5	7
Inside BOP	3	2	4	9
Connection	0	0	3	3
Test Equipment	1	2	4	7
Other Failed Parts	0	1	3	4
Total	10	27	37	74

8.5.1 Hypotheses Test Results

Hypotheses tests were conducted as discussed in section 7.3.2. Results of the tests are summarized in Table 8.5.1.

Table 8.5(b) Component Failure by Category of Test and BOP Type

Component	Surface BOP (0-7 days)	Subsea BOP (0-7 days)	Surface BOP (8-14 days)	Subsea BOP (8-14 days)	Surface BOP (Initial Test)	Subsea BOP (Initial Test)
Annular	1	1	4	0	2	0
Pipe Ram	0	1	3	1	0	0
Blind Ram	0	1	1	0	1	0
Kill Manual V.	0	0	0	0	2	0
Kill Remote V.	0	0	1	0	1	1
Manifold Manual V.	0	2	5	4	5	4
Manifold Remote V.	0	0	1	0	2	0
Choke Manual V.	0	0	0	0	0	0
Choke Remote V.	0	0	0	0	0	0
Drill String V.	0	0	2	0	3	2
Inside BOP	1	2	2	0	2	2
Connection	0	0	0	0	3	0
Test Equipment	1	0	0	2	2	2
Other Parts	0	0	0	1	3	0

Figure 8-1 (Pie Chart)

Figure 8-2 (Pie Chart)

Figure 8-3 (Pie Chart)

Figure 8-4

TABLE 8.5.1 Hypotheses Test Results for Component Failures

Test #	Hypothesis	p1	p2	Test Statistics	$Z_{0.005}$	Comments
1.	Proportion of failures in "Annular" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	.05	.056	-.14	2.575	Based on data, we cannot say that it is different.
2.	Proportion of failures in "Pipe Ram" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	.025	.056	-.84	2.575	Based on data, we cannot say that it is different.
3.	Proportion of failures in "Blind Ram" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	.025	.014	.39	2.575	Based on data, we cannot say that it is different,
4.	Proportion of failures in "Kill Manual Valve" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	0.0	0.0	0.0	2.575	Based on data we cannot say that it is different
5.	Proportion of failures in "Kill Remote Valve" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	0.0	.014	-1.00	2.575	Based on data, we cannot say that it is different.
6.	Proportion of failures in "Manifold Manual Valve" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	.05	.127	-1.47	2.575	Based on data, we cannot say that it is different.
7.	Proportion of failures in "Manifold Remote Valve" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	0.0	.014	-1.00	2.575	Based on data, we cannot say that it is different.
8.	Proportion of failures in "Choke Manual Valve" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	0.0	0.0	0.0	2.575	Based on data we cannot say that it is different.
9.	Proportion of failures in "Choke Remote Valve" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	0.0	0.0	0.0	2.575	Based on data we cannot say that it is different.

10.	Proportion of failure in "Drill String Valve" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	0.0	.028	-1.43	2.575	Based on data, we cannot say that it is different.
11.	Proportion of failures in "Inside BOP" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	.075	.028	1.02	2.575	Based on data, we cannot say that it is different.
12.	Proportion of failures in "Connections" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	0.0	0.0	0.0	2.575	Based on data we cannot say that it is different.
13.	Proportion of failures in "Test Equipment" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	.025	.028	-.10	2.575	Based on data, we cannot say it is different.
14.	Proportion of failures in "Other Failed Parts" when tested between 0 to 7 days "p1" and between 8 to 14 days "p2" are equal.	0.0	0.14	-.51	2.575	Based on data, we cannot say that it is different.
15.	Proportion of failures in "Annular" when tested between 0-7 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal.	0.05	.056	-.08	2.575	Based on data, we cannot say that it is different.
16.	Proportion of failures in "Ram (pipe and blind ram combined)" when tested between 0-7 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal.	0.0	.11	-1.49	2.575	Based on data, we cannot say that it is different.
17.	Proportion of failures in "Manifold Valve (manual and remote combined)" when tested between 0-7 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal.	0.0	.11	-1.49	2.575	Based on data, we cannot say that it is different.
18.	Proportion of failures in "Inside BOP and Drill String Valve combined" when tested between 0-7 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal.	.05	.11	-.93	2.575	Based on data, we cannot say that it is different.
19.	Proportion of failures in "Annular" when tested between 8-14 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal.	.13	0	2.12	2.575	Based on data, we cannot say that it is different.
20.	Proportion of failures in "Ram (pipe and blind ram combined)" when tested	.13	.026	1.56	2.575	Based on data, we

	between 8-14 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal.					cannot say that it is different.
21.	Proportion of failures in "Manifold Valve (manual and remote combined)" when tested between 8-14 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal.	.20	.11	1.01	2.575	Based on data, we cannot say that it is different.
22.	Proportion of failures in "Inside BOP and Drill String Valve combined" when tested between 8-14 days for surface BOPs "P_1" and subsea BOPs "P_2" are equal.	0.13	0.0	2.15	2.575	Based on data, we cannot say it is different.

9.0 CONCLUSIONS

Following conclusions can be drawn from this BOP reliability study:

1. No statistically significant difference exists in failure rates for all BOPs (surface and subsea included) tested between 0 to 7 days interval and between 8 to 14 days interval.

2. Component failures are not affected by the BOP test interval in general.

3. There is not a significant correlation between failure rate and BOP test interval.

4. Subsea BOPs have smaller failure rate than surface BOPs.

10.0 FUTURE STUDY

Enough data has been collected to conduct future study in BOP reliability. This study could include:

- Analysis of type of fluid used for BOP testing and its correlation with failure.
- Regression analyses of component failure to determine which components have a greater impact on BOP failure.

APPENDIX A

TYPICAL BOP SYSTEMS

APPENDIX B

BOP and Choke Manifold Test Report Form

CO

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Alaska Oil & Gas Cons. Commission
Anchorage

Comments concerning
20 AAC 25.030 (d)(7)

The commission requires 24 hrs notice for inspector to be on location to witness a cement quality log be run on an injection well.

Comments:

a) The log is run by a qualified third party

b) The log is presented to AOGCC in the Sundry at the end of the well

c) The running of the log is noted in the daily report.

d) The actual interpertation of the log needs to be done by a qualified logging engineer and the operators own engineering staff.

(1) If the AOGCC wants this included to make sure the log gets done present practices insure this

(2) If the AOGCC want this included to have their individual look at the log, he may well not have the expertise.

(3) This provides an additional logistical burden on the operator

(4) Additional demands on AOGCC inspectors.

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Anchorage

Submitted By

Dan W. Williamson

Dan McCarty

Unocal

Alaska Oil and Gas Association

AOGA

121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907)272-1481 Fax: (907)279-8114

September 30, 1998

David Johnston, Chairman
Alaska Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, Alaska 99501

ORIGINAL

Additional AOGA Comments to
Proposed Changes to AOGCC Regulations

Dear Commissioner Johnston:

In response to the Supplemental Notice of Proposed Changes in the Regulations of the Alaska Oil and Gas Conservation Commission, dated August 21, 1998, the members of the Alaska Oil and Gas Association (AOGA) AOGCC Regulations Review Task Group have met over the past several weeks to review these changes.

Please find attached our preliminary comments and recommended changes to the regulations. We will continue to review these regulations and will make additional comments at the October 15, 1998, public hearing.

If you have any questions or require additional information in this regard, please do not hesitate to call either myself at 564-4757 or Mike Bill, ARCO, at 263-4254.

Sincerely,

Chris J. Phillips

Chris Phillips, Chairman
AOGCC Regulations Review Task Group

Attachment

RECEIVED
SEP 30 1998
Alaska Oil & Gas Cons. Commission
Anchorage

ALASKA OIL AND GAS ASSOCIATION
COMMENTS ON
PROPOSED CHANGES IN THE REGULATIONS OF THE
ALASKA OIL AND GAS CONSERVATION COMMISSION

September 30, 1998

25.005(h): "A permit to drill is not valid at a location where the applicant does not have the right to drill for, produce and remove oil and gas."

Strike the words, "produce and remove". Although an applicant may not have the right to produce and remove oil and gas, the applicant may have the right to drill for oil and gas, as in the case of a COST well. ok

25.030(c)(3): "...surface casing must be set below the base of all water-bearing strata known or reasonably expected to contain freshwater..."

AOGA recommends reverting back to the language adopted by the Commission in 1996, as follows: "...surface casing must be set below the base of all water-bearing strata known or reasonably expected to serve as a source of freshwater and at a depth sufficient to provide a competent anchor for blowout prevention equipment;" ok

25.030(c)(6): "...slotted liners, pre-perforated liners, and screens installed below the production packer are considered as production equipment and not as casing."

Does this mean that we no longer list slotted liners, etc., as casing on the Permit to Drill and the Completion Report?

25.030(d)(4): "...surface casing must be cemented by filling the annular space with cement from the shoe to the surface; however, if cement does not circulate to the surface, if an excessive quantity of cement circulates to surface, or if the formation integrity test shows an inadequate cement job..."

Current regulations detail the functional requirements of surface casing, but measure the effectiveness of surface casing cement by requiring observation of cement at surface and completion of an acceptable formation integrity test.

In recent years, operators have increased the volume of pumped cement and implemented technologies intended to ensure observation of cement at surface. These measures ensure that cement is observed at surface the majority of the time. However, because of uncertainties in estimating hole size (due to washout through the permafrost interval), the increased cement volumes have resulted in additional returned cement waste (and increased trucking and disposal) and have occasionally still resulted in lack of cement at surface.

AOGA expects to review this issue at the October 15, 1998, public hearing and to propose revised language at that time.

25.030(f): "A formation integrity test must be performed if blowout prevention equipment is installed ~~on a casing.~~" ok

In the case of through tubing drilling or re-entry, the blowout preventer is not installed on the casing. Is it the intent of the proposed language that a formation integrity test is not required in this situation?

25.033(a)(2): "...a drilling fluid with as low a gel strength as practicable to minimize the potential of a hydrostatic pressure surge when the drilling assembly is run into the wellbore;"
25.033(a)(3): "...a drilling fluid with as low a viscosity as practicable to enhance the drop-out of solids and escape of any entrained gas;"

The wording, "as low a gel strength as practicable" and "as low a viscosity as practicable" reflect old technology and should be replaced by "rheological properties designed to...". wow
prevent swabbing

25,033(c): "...Tests must be conducted in conformance with API RP 13B-1, *Recommended Practice for Standard Procedure for Field Testing Water-Based Drilling Fluids* (September 1997)..."

The incorporation of a number of API Recommended Practices is problematic. As the name of the publications suggest, the referenced API documents establish recommendations, not rules or minimum requirements. They are not drafted as regulations, and do not serve to provide minimum standards. Thus, considerable ambiguity is created by language in the draft rules, which would require that certain actions "meet the minimum requirements of" (20 AAC 25.065) or "must be conducted in conformance with" (20 AAC 25.033(c)) a certain recommended practice. picky could say "as determined by the Com."

25.035(b)(1): "...a 16 inch minimum diameter diverter vent line..."
25.035(b)(3): "...the diverter vent line must be a minimum of 10 inches in diameter and, if less than 16 inches in diameter, must bifurcate in directions that ensure safe downwind venting..."

In 1996, the AOGCC proposed a 16 inch minimum diverter line. Following testimony during a public hearing on November 20, 1996, the Commissioners agreed to revise the regulations to require a 12 inch minimum diverter. In addition, the Commissioners advised their intent to add waiver requirements to grandfather existing Alaska rigs. Language agreed by the Commissioners in 1996 follows: the staff has always supported a 16" diverter as has Com practice

> ***20 AAC 25.035(b) ~~26.035(b)(1)~~ before drilling below the structural or conductor casing, unless such casing is equipped with BOPE conforming with (c) of this section, a high capacity flow diverter system must be installed to provide safety for personnel and equipment. The diverter system will consist of a remotely operated annular pack-off device, a full opening vent line valve, and a 12 inch minimum diameter diverter vent line. The vent line must be assembled...***

AOGA still supports this language.

25.035(d)(11): "...the BOPE must be pressure-tested as follows: (A) when the BOPE is installed or changed, and at least once each week thereafter..."

The Alaska Oil and Gas Association members request that the AOGCC amend BOP pressure test requirements (20 AAC 25.036(d)(11)) to be consistent with federal regulations. On June 1, 1998, the U.S. Department of Interior, Minerals Management Service (MMS) amended 30 CFR Part 250, "Blowout Preventer (BOP) Testing Requirements for Drilling and Completion Operations" (63 Federal Register 29604-29608, June 1, 1998) to allow 14 days between BOP tests for drilling and completion operations on the Outer Continental Shelf.

No way

25.035(g): "The toolpushers, drillers, and person(s)-in-charge on a drill rig floor must be trained in accordance with the training standards contained in 30 C.F.R. 250.210-250.215 (revised as of July 1, 1996)."

The reference is incorrect. It should read, "30 C.F.R. 250, Subpart O".

ok

25.036: WELL CONTROL FOR COILED TUBING DRILLING: BLOWOUT PREVENTION EQUIPMENT AND DRILLING FLUID PROGRAM REQUIREMENTS

AOGA is still reviewing this section and plans to supply detailed comments and suggested changes prior to or at the October 15, 1998 hearing.

25.065(b): "...each operator shall meet the requirements of API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide (April 1987)...".

This Recommended Practice is not currently listed in the API catalog.

25.080(b)(12): "...the duration of the disposal operation, not to exceed 90 days;"

AOGA understands the maximum 90 day period refers to a disposal operation from an individual well and disposal operations from other wells may take place within the 1 year maximum permit period (25.080(d)(2)).

25.080(e)(2): "...the downhole disposal pressure may not exceed the downhole pressure obtained during the formation integrity test conducted below the outer casing shoe;"

AOGA recommends subsection (e)(2) be deleted . The requirements of (1) and (3) should provide sufficient protection.

No!

25.105(h)(1)(A): "...by the displacement method, a cement plug must be placed from 100 feet below the base to 50 feet above the base of the perforated interval..."

Insert the word "feet" between the words "50" and "above".

ok

25.115(a): "An operator that shuts in a completed development or service well for more than 90 days shall file a report with the commission no later than 120 days after shutting in the well. The report must provide..."

25.115(b): "An operator of a shut-in well shall file with the commission an annual update of the report required under (a) of this section."

AOGA believes the time requirements in these sections will result in an unreasonable reporting burden on both the operators and the commission. For example, in the Prudhoe EOA, approximately 50 wells have been shut in for over 90 days for various reasons at any particular time. These reasons range from wells temporarily not economically competitive due to facility capacity constraints or changes in productivity, to wells with mechanical problems awaiting repair. In response to continuous efforts to maximize field production, those wells temporarily shut-in may be brought back on at any time as well conditions or facility capacity changes, and other wells may be shut-in. We suggest the time frames be changed to require reporting of each well shut in over 2 years with follow-up reporting at 5 year intervals.

25.205(a): "...or any uncontrolled release that results in an interruption of operations at a production facility."

This requirement could require reporting of very minor interruptions (i.e., to tighten a fitting, etc.). We suggest the wording adopted by the commission in 1996: "...or an uncontrolled release that results in a shutdown of a production facility."

25.228(b): "Hydrocarbon measuring equipment must be fabricated and installed in accordance with the API Manual of Petroleum Measurement Standards, as revised from time to time, which is adopted by reference.
25.228(l): "The Commission will, in its discretion, require a minimum of 24 hours notice before the following operations so that its representative can confirm compliance with the API Manual of Petroleum Measurement Standards, as revised from time to time, which is adopted by reference:..."

25.228(b) requires actions "in accordance with the API Manual of Petroleum Measurement Standards, as revised from time to time." The draft regulations properly restrict references to API Recommended Practices to particular documents that are in existence. The reference to the Manual of Petroleum Measurement Standards must also be to a specific document. It would be inappropriate to delegate to API the ability to effectively re-write the regulations without the opportunity for AOGCC review and decision and the public comment required by the Administrative Procedures Act.

Insert the word "New" at the beginning of the sentence in 25.228(b), so it reads "New hydrocarbon measuring equipment....". Replace the words "as revised from time to time" in both references with the following: "in effect at the time these regulations are adopted". yes NO

25.228(d): "...show the raw or factored pulses, average temperature, pressure, relative density, or gravity, meter factors,..."

Strike the comma following "relative density" so it reads, "...relative density or gravity,...".

25.285: BLOWOUT PREVENTION EQUIPMENT FOR WORKOVER OPERATIONS

AOGA is still reviewing this section and plans to supply detailed comments and suggested changes prior to or at the October 15, 1998 hearing.

25.412(b): "...The packer must be placed within 200 feet of the top of the perforation."

Sufficient interval should be allowed to perforate to the top of the potential injection interval or objective formation without requiring a workover to change the packer location.

AOGA recommends the Commission include the following language at the end of this section allowing for a variance:

> ***"(f) Upon request of the operator, the commission will, in its discretion, approve variances from the requirements of (b) - (d) of this section to allow for special or unusual conditions as long as the design requirements of (a) of this section are not diminished."***

25.560(b)(1): "...completed on the date it is first perforated for regular production, or if not perforated, on the date it is abandoned or suspended."

Definition 12 states "complete" means to equip and condition a well as an oil, gas or service well so that it is capable of producing oil or gas or of injecting fluids. The proposed language in 25.560(b)(1) seems inconsistent with this definition since some wells are perforated prior to running tubing and other wells may be completed with slotted liners.

~~good~~ good Point

25.990: DEFINITIONS

Some terms in the proposed regulations are not defined. We assume that the commission is relying on the API RP definitions. However, these definitions in the various RPs can be different. For example, following are the definitions of "function testing" as defined in two different RPs:

API RP53 - Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells:

> ***"3.1.40 function test: Closing and opening (cycling) equipment to verify operability."***

API RP5C7 - Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services:

> ***"function pressure test: The pressure test which requires the well control component or flow control device to undergo actuation to demonstrate its ability to effect a seal.***

#2

3/21/00 Reg hearing

Teresa Rockhill - AOGA

Regs task group

- no comment re/ permit to drill

.605 person = operator

? F - does it include federal funds

PUC → C - task force objects to b/c they pkw costs of delinquent operators

yes .615 (e) - adjustment for <u>all</u> operators

.620(c) - 10 days too short (task force prefers 20 days)

→ ck w/ Duncan finance

.005 PTD

what is a redrill?

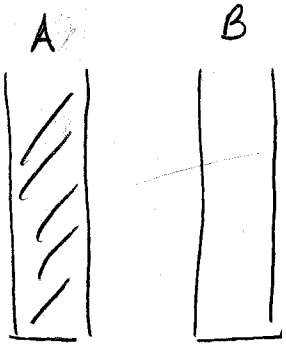
how is it different than well branch?

(e) no $100 for well branch

- on 7/1/00 (A) identify all wells which are not P+A
  (B) calculate the volume of fluids (produced + injected) for <u>all the wells in A</u> for 1999 = V_{TOT}
  (C) calculate by operator = V_{OP}
  breakdown by pool/field

- what if operator changes sometime after 7/1

(1)

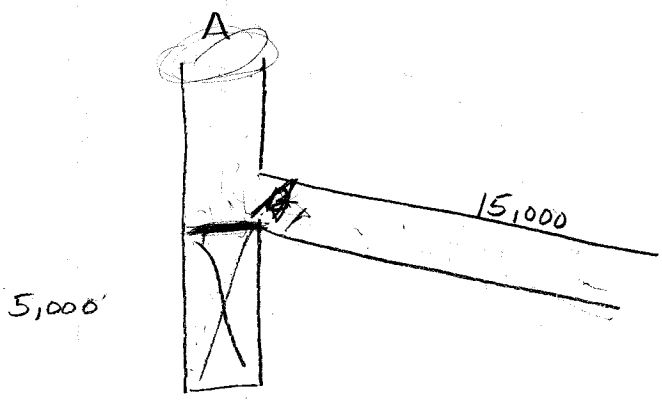


A - drilled 1/99 - produces 10,000 Bbl
P+A 12/99 -
B - drilled 1/2000 -

on 7/1/2000 A doesn't count (well or volume)
B no volume for '99

- how many re-drills/year?

(2)



A - drilled 1/99 - produces 5,000 bbl
P+A - 5/99
B - drilled 6/99 - produces 15,000 bbl
still producing in 2000

on 7/1/00 A doesn't count?
B does - what volume?

(3) Same as above

A - drilled 1/99 - produces 20,000 bbl
P+A 1/2000
B - drilled 2/2000 - still producing

on 7/1/00 - A doesn't count
B doesn't count

- how many wells are plugged between January + June?

24, 31 §527

→ p42 (4) ✓
meter factor

12/30/98 Regs adoption mtg

~~is "barrel" used~~

max potential – what it might be

max anticipated/expected potential – less than potential (more closely related to actuals

p21 – re-work p28, p81, p86
p22 – additional change

move language from p24/31 to §527 ?
separate provisions for §527

General section or 3 separate §'s

Tim Rylands Digital Directional Survey Request.

96-14	Uno Cal	Granite Pt	53	Paper	
96-45	Uno Cal	Granite Pt	52	Paper	
96-56	Uno Cal	MGS St 17195	32	Paper	
97-16	ARCO	W. Gold Hill	2E20	Paper	
97-85	ARCO	West Hay #1	Digital and Paper		OK
97-145	Uno Cal	Granite Pt	55	Paper	
97-234	Forcenergy	W. McArthur R #4		Paper	
98-24	BPX	DIU MPI	2-56/EID	Paper	
98-47	Forcenergy	W. McArthur R.	#5	Paper	
98-142	Marathon	Wolthake	#2	Recompletion. Dir Survey Not required.	

All the operators have been contacted by phone or e-mail requesting digital Data.

Looks like four operators of the five on the list did not send digital copies of directional Surveys.

12/16/98 Reg mtg
Clean copy of regs handed out

MMS is going away from certified well control program + moving towards performance based
- 6mos to 1yr

<u>not complete</u>
- table of contents
- history / authority for new sections
- not proof-read

→ schedule another mtg

.033 - .037
.280 - .288
.527

p27.
→ used → for well-control
what else?

BEW p16-17
✓ p20 (2)(B)
p23 wants anticipated changed to potential
✓ p24
✓ p26

change anticipated to potential

→ mtg 10 days from notice

	policy	wording
1.	Cement to surface .030	
2.	FIT - .030 + .080 ↳ insert procedure w/ PTD	.030
3.	.035 16" diverter BOP tests 7/14 days	BOP
4.	~~.080 - annular~~ ~~↳ Rob - hearing re/ "freshwater"~~	- casing shoe pressure
5.	mtg w/ DNR re/ site clearance	P+A / Site Clearance
6.		.215 ~~commingling~~
7.		.228 ~~Measurement Equip~~
✓8.	.432 Report of Underground Injection ck w/ jack	
✓ 9.	.440 new subsection	
10.		.517 ~~POD~~
✓ 11.	.520 ~~Field~~ + Pool	
✓12.	~~.560 Time~~	
13.	definitions : abandon complete shut down	

→ API references

T/C from Jim Haynes

12/14 .170 (pk) to the extent ← duplicate

having jurisd ← DNR questions whether AOGCC has jurisd

(b) will, in discretion, grant extension ← DNR wants it crossed out as to the

(a)(2) → AOGCC has no authority

(c) incomplete sentence

.172 (c) ≡ 1yr conflicts w/ agreements

(1) –(D) AOGCC doesn't have authority

12/10 t/c w/ Patrick + Jim (DNR)
re/ .170 + .172 fax 562-3852

what does Shell/Cross Timbers DR+R agreement look like?
does it just collect $ to guarantee
or does it set aside to satisfy obligation

Statute triggers
reporting abandonment
that causes dilemma

170 "location" – what does it mean
was an issue in Exxon tax case
state argued obligation not fixed – current tax deduction
only if fixed liability

lease uses the same words
170(a)(1) mimicks DL1 lease form
DNR reads lease form to be discretionary

Exxon argued 'location' means all of PB

DNR doesn't want AOGCC too make it mandatory to remove
"structures"

"within 1yr" is language in DL1 lease
now unit agreement is "2" yrs
(AOGCC was part of DNR then
PBUA says 3 yrs

Unit Equip = well equipment
under unit agreement

Abandonment Cost Estimates
for Shell C1 Platform
May 1995
Belmar Engineering + Mgmt Services

12/2/98 reqs mtg
Keith Lynch re/ annular disp. requirement

~~[illegible]~~

~~or~~ (e)(2)
~~or a higher pr~~

✓ diverter
BOP test
Cement

pulling pipe out of hole

Mark Berlinger
impose weekly drills
+ change BOP test to 14 days

MMS - 14 days for testing cycle + no waiver
actual pressure test
BLM - state doesn't require operator to pull
bit out of hole

12/2/98 Regs mtg

BOP testing

correlation between test cycle + maintenance - article

BOP tests - equip integrity

- crew competence

? BOP failures — does state count H_2S failures as a BOP failure?

Cement to surface

BEW has problem w/ AOGA proposal

1. Industry can't agree on how to do FIT
2. " reluctant to do FIT to breakdown pressure to demonstrate shoe integrity

problem for industry

1) lesser cement at surface
2) use of stage tool; occassionally creates weak spot

* primary motivation is to stop using stage collars
proposal returns practice to pre-'96

what's the innuendo that there is ~~weak~~ cement integrity?

- once well is plugged is there any safety issue?

10/24 11/1 waiver
BOP test response to Eider well

12/7/98 Reg mtg
Article 2
.172 offshore well site clearance
any off shore is on state lease

table →
* .172(a) table – ck w/ Dan Williamson

[to a depth determined by the Commission in cooperation
w/ the DNR plan of DR+R for the platform

pipeline –
→ ck w/ JPO
gathering lines / custody transfer

Phillips –
AOGCC wider jurisdiction
– pipeline waste / contamination

Corps
DEC
DNR
DO+G / Lands / JPO

* API RP 49
did we order API RP's + Measurement binders?

Jim Haynes } DNR
Bill Butt } JPO

12/8/98 Reg mtg

Dan Williamson - Unocal

Corps of engineers

* Viser report

ck w/ table → DNR ref Shell/Cross Timbers

agreements/process for making determinations

→ from technical standpoint

→ where do we get $?

reg requires ① commission to determine that no further utility exists for platform

② inspect

③ monthly reports

④ approve plan of removal

⑤ oversee abandonment

"site" the well on the "location"

cement at outer casing shoe + ~~[illegible]~~ through the confining zone

that fluid won't go

increased pressure will not result in fluids broaching to surface or propagating fractures thru confining zone

12/9/98 Reg continued

* abandon / plugging

BOP

"Annular type preventer" define (see p 29 BOP)

p12 — drilled portion has been plugged
or the well is completed, except when hydraulic
communication to the operable section has been isolated

p18 - variance / waiver

* site / location

drill site

location — area
site - pt in the area

12/1/98 Reg Mtg

.440(d) captures current practice + fed reg

? .105 mudline = bottom of mud ← Mud

sea floor =
↳ needs defining

* mudline needs to be defined

[X] verification requirements in .172

FIT presentation ; Keith Lynch Arco

want good cement at shoe – don't want breakdown of cement

BEW If you remove pressure limitation
substitute vol. limitation
3 bbl/minute ;

Arco – now 2-5 bbl/minute

for friction to drop off → 1 bbl/minute or less

establish rate + that sets pressure
usually 3 bbl/min.
try to stay above 3

how do these rates + volumes compare?
2-5 vs 20-30 bbl/minute (high side of disposal wells)
large tubing

* check other annular disposal regs →

surface pressure 1500 lbs
2-5 bbls/minute

surface pressure limitations would be difficult to implement

what about volume limitations

11/30/98 Reg mtg

AOGA comments re/ annular disposal —
Keith Lynch - Arco
FIT test results vary

Mike Zoghi -

if pressure effects FRAC, what factors do they use to insure confinement?
- injection pressures monitored continuously
- casing/annular pressure monitored on neighboring wells

→ data from Arco re/

BOP Stuff:
.035(b)(3)

→ Article 2 re-write
105 dealt w/ 2 issues

beyond plugging, other work that needed to be done to walk away well scattered

→ new rig in Cook Inlet
→ ck w/ BEW for clearance requirements

11/30/98 .228(b) re-deployment of equip?

re/ API references
standardize

→ "in conformance with"
does that cover all situations?

* → 432(b) needs to reflect content

.517 plan of reservoir development + depletion

WELL	PLUGGING	REMOVE CASING	MARKER
onshore		later (.120) 3ft	yes
fixed offshore platform		later (.172) 15ft	no
mobile bottom-founded		before removing rig (.172)	no
jack-up rig		before removing rig (.172)	no
floating drilling vessel		before removing rig (.172)	no
artificial island		later (.172)	no
shifting natural island		later (.172)	no
beach		(new) later	no

.120 well - abandonment marker

- doesn't apply to "fixed" platform, mobile bottom-founded structure, jack-up rig, floating drilling vessel, artificial gravel island, shifting natural island, or beach location

- if the marker is not installed can well still be "abandoned"?

.172(d) offshore clearance

before rig moves off } abandon from mobile-founded structure, jack-up rig, or floating drilling vessel

(e) artificial gravel island, shifting natural island or beach location

---

plug + abandon

	plug	cut-off (same time or later)	marker	
when is it abandoned? BEW - after pipe is cut off -	- onshore	later (.120 + marker)	Yes	3ft below original ground
	- fixed off-shore platform	later	No	1ft below sea floor
	- offshore - mobile bottom-founded	same time (before rig moves)	No	5ft below mudline
	- jack up rig	same time "	No	
	- floating drilling vessel	same time "	No	
	- beach	later	No	5ft below mudline
	- artificial island	later	No	
	- shifting natural island	later	No	

11/16/98 Reg mtg

AOGA response to DNR comments

- NA027 → not universal
  would give us voluntarily - not needed in regulation

- ownership → don't need; or at least apply only to non-state land

- wellbore surveys
  both paper + digital - hard to get w/in 30 days

- .071 - object to trade names
  liked AOGCC language

- .537 - oppose subsection additions (2) + (3) burdensome

- .070 - databases are designed to use industry accepted abbreviations
  - BEW - different co's use different abbreviations
  - Jim Ryland - industry standard changes - if you look at historical record 20 yrs later

BEW - AOGA should propose standard terms

Unocal - Kevin Jabler

re/ .072 - Concerned w/ platform removal reg
lots of work done on these - public comment
wants them implemented at either dept

11/16/98 (Cont Regs mtg)
AOGA - BOP

define clearly:
Completion — primary drilling
work over - tree off + service - tree on
function pressure test
open/close loop

other terms - stripper etc = common industry terms

service - not removing tubing + workover distinction
CT - cleanout
stimulation
patcher

.280 reporting requirements for workover/service
.285

"workover" needs to be defined

on .280 - don't need 403 for "reperforate" or "stimulate"
.285 - bring in AOGA proposal

Mark Berlinger re: BOP testing - support 14 day testing
1992-1997 several studies by MMS
test upon installation / change
** which rig had BOP installed upside down?
initial failure rate for SS is about 1/4; ongoing about 1/10th

- well control → 14 day tests

SS → 8% initial test failure rates

? 7 day tests – increases wear on equip
what does Canada do?

which operations are less prone to blow-out?

"prudent operator manages risk" . . .

↳ 1. Do other operators share a similar 8% failure rate?
2. what factors, in your opinion, contribute to differing failure results?
1. doesn't know
2. " "

*** Do we have data re/ BOP test failure rate?

11/17/98 Reg mtg

Unocal comments – Mitch

BEW – re/ BOP tests + failures
our database – 1209
810 passing
399 at least 1 failure
33% failure rate

Mark Belinger – SS
1400 8% failure rate
initial / on-going / change out of rams

→ FIT = BEW wants definition

11/18/98 Regs

AOGA letter re/ DNR comments

* ck list of what is triggered by "abandon" or "suspend" status

* where does FIT get referred to in Regs?

what is a valid formation integrity test?
if there is such a large grey area, why do we rely on the info?

data is used for different purposes
1) to drill ahead
2) cement channeling
? 3) annular disposal

* SS 5/96
procedure for drilling/annular

* what does fed reg say about mg/l?
* what do other states say re/ disposal pressure for annular?

7-8,000 bbl for dev. well ; 20-25,000 bbls for exploratory
→ 3 bbl/min

11/2/98

Table

To come:

BOP regs by AOGA

DNR regs comments
- location clearance

.022
.025

.030 (c)(3) see .080 language

cement to surface - Canada
- broaching went away; b/c no other annular disp. or other well construction?
- cement bond logs not accurate; are there any other tools?

~~p13 - (d)(7)~~
~~should it be in (a)? compare w/ current reg~~ pg 7

~~(e) then what is standard?~~
~~Dan Williamson says that is current standard?~~

- API reference

- 16" diverter vent line - Blair - materials
mms requires 12"
floaters that come up to cook inlet

- .080

Costs

11/3/98 Reg Mtg

.105 beginning

* (h)(1)(D)

.105 → cut off casing before moving rig

* wellhead removal

add to .105 - plugging for ~~well bands~~ production control

fix "abandon" by adding "removal + cutting of wellhead"

RP's - Mark Worcester
no problem w/ use of "conform"

* .110(b) - if oral approval is given, why submit 403 - why not just submit 404 or 407?

1 out of 10 →

11/4/98 table
draft .105/.110

DNR considers AOGCC out of the picture after well abandonment marks

.170 + .172

.285

.432

.440 — 2 issues

Jim Ryherd - MGS #32
public disclosure on rig move
needs to know when data is available

→ completed — perforating

Steve — completion reports

560(a) keep
(b) table

11/9/98 – Reg mtg

AOGA proposal for BOPE Reg
written by category of drilling activity

* are these 10 sections the substitute for .033 - .036 ?
? .280 - .285

57% of blowouts caused by swabbing –
w/ conventional drilling rig

diverter size

floating rig 12" MMS
what does it cost to retrofit to 16" ?

max 16" → or lg enough for hole size
sound basis in engineering + safety

.035(i) waiver provision should
elaborate criteria for basing waiver decisions

what are floaters equipped w/ ? 12" or other

what is right size for hole you are drilling ?

AOGA to work on proposed language

---

next monday

Table : complete

11/10/98 Reg Mtg:
DNR comments submitted in writing

AOGA would like time to respond - 11/16 next mtg

Permit to Drill - NA027 -
cartographic technique
may be a problem for small operator / contractor surveyor

.170/.172
① land subject to state leases
② offshore subject to state + federal leases
③ private on-shore land

"drilling + plugging of wells"
prevent contamination of water → reserve pits

off-shore drilling structure → may be too far removed from C's duties
- platform abandonment agreements
Patrick Coughlin

10/15/98 Reg hearing

Chris Phillips – BP – on behalf of AOGA
4 specific areas
1 – surface cementing
2 – BOP testing frequency
3 – work group to work on BOP equipment
– don't properly address new technology + different technology
– would benefit from work group
4 – change of ownership language

Suggests Chuck Mallary provide testimony re/ cementing

– re/ API references
want date — for measurement standards only
ok to fix by reference to date of edition when reg adopted

Mark Worcester – Arco – on behalf of AOGA
re/ API recommended Practice ≠ minimum practice or requirement

– slotted liners considered production equip not casing
Chuck Mallary – ARCO / shared services

Chris Phillips – 080 – delete (e)(2) b/c (e)(1)+(3)

(1) Surface Cementing Chuck Mallary
.030(a) 1–8 – AOGA agrees
most wells – 2 casings
Surface casing design in permafrost regions
Seating integrity
structural integrity can be accomplished w/o cement across permafrost
∴ cement to surface should not be requirement for surface casing integrity
AOGA proposed surface casing cement reg as agreed
– reduce waste stream; cost effective

w/ costs – what is impact?
$40,000/well → incremental cost
Currently do 2-stage cement job w/ DV tool + rig time for 2nd stage + rig time to drill out DV tool

difficulty w/ getting cement from shoe to surface in single stage

Mike Zenghi – ARCO
they vary throughout NS
- lost circulation
weak zones in permafrost region
- insufficient removal of cuttings → causing bridging
- uncertain hole size – especially in permafrost (tends to get enlarged)

Fritz Gunkel – Shared Service
w/ hole size + cement types
working to reduce hole size
working w/ cement suppliers
mostly get cement to surface, but b/c of requirement the risk of not getting cement to surface leads them to use DV tool

DV collars + casing integrity; failure of casing integrity in some cases b/c of DV collar – less than 5%
expensive result if it can't be repaired
90% success rate w/ 2 stage cement job in getting cement to surface

absence of branching
other factors contributed to that
goal would be to achieve cement to surface

Mike Zanghi
length of surface casing does impact getting cement to surface
what other factors contributed to no breaks?
Fritz Gunkel
Changed disposal method

Mike Zanghi –
Greater Kuparuk area – no problem
No changes in mean rate of annular injection

② BOP testing frequency
Mark Bolinger – SSD – on behalf of AOGA
proposes change to conform to MMS — 14 days between tests
revise test frequency
Fritz Gunkel MMS requirement had been weekly

Mark Bolinger – Gulf of Mexico drilling – not AK drilling
how to test + ensure that it touches all crews;

Chuck Mallary – timing of tests; function test of equip
not people; training of people to respond
is separate – testing of crew reaction is different
than BOP

Fritz Gunkel – daily drills of operation of well control equip

Dan Williamson – NWOCC
shift change is link; won't slip through cracks

→ given broken ice issues (Northstar) does relaxing this BOP test
impact those decisions?
Fritz Gunkel – report suggests problems w/ testing equip too often
no compromise in safety

Chris Phillips

re/ .080 (e)(2)

? almost impossible to dispose at lower pressure than FIT

③ re/ BOP equip

proposes work group mtg

2 wks from today can have completed recommendation

④ Change of ownership

Mark Worcester

.022 – proposes repealing it

– not sure what purpose it serves

.520 – should apply to "pools" as well as "fields"

if change is adopted

.030(a)

.055(a)

.280(e)

.432(b)

w/ respect to .022

nothing requires owner to file to begin w/

* – how do you verify right to drill?

* on what occasions does AOGCC need to know who owners are?

Dan Williamson - Unocal

.030(d)(7)

24hr notice for representative to witness

why do we want inspector to witness cement quality log or other evaluation log

10/15/98 hearing notes

✓ how would you do cement on surface casing under AOGA proposed reg

- Currently do 2 stage-cement w/ DV tool - 90% success

what is success rate w/o of aogcc proposal - Mike Z - historical 50-60% - would expect greater advances in cement -

- does $40,000 incremental cost include disposal costs - yes

what other factors contributed to no breaches

9/29/99 Regs mtg -

Mark Worcester - Arco

- AOGA, because of lack of time, have been unable to review

- quick review show many changes, Many are significant on behalf of Arco, ask for additional comment period will listen to DOL + hope for opportunity to comment

Rob Mintz

there are a number of substantive changes

reviewed by regulations section; changes

- style + convention changes
- legal problems identified; solution
- ambiguity → clarity
- staff changes

.075 should be repealed

p85 - working day

p86 → ? State regs don't apply? or no need to get application

Adopted

need definition

science chemistry

- PSI : pounds per square inch
- PSIA : pounds per square inch absolute. Psia is equal to the gauge pressure plus the pressure of the atmosphere at that point.
- PSIG : pounds per square inch gauge

oil industry

- STB stock tank barrel - barrel of liquid at standard condition
- SCF standard cubic foot - cubic foot at standard condition - su statute
- MSCF thousand standard cubic feet

oil industry

5M stack — configuration, as well as a pressure rating
5000 psi — is this the same? pressure rating only

PPM -

define

- API 5M
- API 2M

American Petroleum Institute
Blowout Preventer ~~Arrangement~~ Configuration ~~for~~ at a working pressure of 5,000 psi

means - an API defined BOP (or BOPE) configuration w/ a working pressure of 5000 psi

psia
psig

To ck w/ AOGCC

plp → ck w/ Bob, Jack, Blair – "drilling program"

* + where should we stick "no 401 necessary solely to straighten the original hole, sidetrack junk, or correct mechanical difficulties"

BEW

(a) to change a program approved in a permit to drill

Bob C. p17 (2) are we requiring this info to be submitted w/ PTD "review"

(3)

BEW p27 35 96 100 (c) delete + ~~or~~ and

p40 Alaska State Base Plane ~~projection~~ – Cartesian coordinate system used throughout US

la state

46/47 Colors to lights + horns – Rob discourages substantive changes

51 specific is preferable; basis for setting up tickler system

67 * need to rewrite

p83-86 .252 UIC

AOGCC comments on Draft Northstar Class I Permit and Fact Sheet

Fact Sheet:

Second page, Regulatory Framework section: "The AOGCC regulates Class II injection wells, which are defined as those wells used 1) to dispose of waste fluids brought to the surface from oil and gas production operations, 2) for enhanced recovery of oil and gas, or 3) for storage of hydrocarbons which are liquid at standard temperature and pressure (see 40 CFR 144.6)."

Please change the word "defined" to "classified"

Fourth page, Rock cuttings, 140,000 barrels. Is this a raw volume or after grinding? Volume appears low, even prior to grinding.

Other comment – two years for drilling phase – Is this a reasonable estimate? And what affect will the drilling schedule and any delays have on the two-phase approach to fluid injection?

Page 4 and 5. Limiting disposal to the lowest interval may unnecessarily limit operation of the well, especially since EPA has determined there are no USDW's.

Draft Permit:

Page 12
A. Construction
1. Casing and Cementing. Are you requiring cementing the intermediate into the surface casing? It is unclear from your description.
2. Tubing and Packer Specifications

Requiring the packer to initially be set 150' from the lowermost injection zone is unnecessary and will require a well workover and recompletion to access the upper injection zone at a later date. We suggest that you give the operator flexibility to install the packer above the upper injection zone and only limit the initial operating parameters to injection in the lowermost zone.

Setting the packer close to the lower zone will also eliminate the possibility of surveillance between the two disposal intervals. The restriction on injection to the lowest interval seems unnecessary because it eliminates any contingency in case the lower zone completely plugs off or has some other problem.

Page 13
3. Mechanical Integrity
b. (2) A static temperature baseline from the injection zone(s) to the base of the permafrost prior to well operation is valuable data for subsequent diagnostic surveillance. Wells must be shut-in at least 3 days to obtain a static temperature survey and therefore a routine survey should be conducted when timing is appropriate for the operator (i.e. during annual maintenance shutdowns, etc.).

Page 14 (first paragraph)
b. (2) Is running the tracer tests in slurry injection mode a normal occurrence?

PNL (pulse neutron log) with borax logs for channel identification should be considered an acceptable alternative to RA tracer logs. The PNL has been used in areas of the North Slope to trace water movement outside casing with considerable success.

5. Injection Pressure Limitation
In the second paragraph, the conditions for exceeding the 3000-psi limit seem arbitrary, especially without any direct disposal experience in this area. These conditions may be justifiably revised when more operational experience is acquired.

The nature of waste/solids disposal is damaging to any well where it is conducted. The rock in the injection zone is reasonably porous and permeable, however, damage by solids will require near well stimulation. The near well area needs to be stimulated periodically to maintain the flow path and continually expose fresh rock for fluid leakoff and creation of more storage space for solids. The ability to create significant fractures is severely limited because the waste fluids are either clear or non-engineered for the purpose of rock fracturing. It takes a very large amount of hydraulic horsepower to create a fracture with slurry and extensions would require even higher levels. It is unlikely that significant fractures can be created and extended any significant length with a single disposal pump.
////
Limiting disposal to the lowest interval may be unnecessarily limit operation of the well, especially since EPA has determined there are no USDW's.

Also, drilling may take more than two years and that should be allowed in the permit, i.e., ... two years or while development drilling is ongoing.

General Comment

Does the EPA have the ability to modify the permit conditions administratively if early time well performance shows some adverse or even opportunistic conditions? We find it invaluable because oftentimes our orders are issued prior to having complete information for a project and conditions often are considerably different than those considered prior to project startup. It is appropriate to recognize that aspect of development projects and make allowances for altering permit conditions based in sound engineering and geologic principles that will not harm the environment and maintain safe conditions. It may be advisable to allow such changes upon application and demonstration without having to repeat the entire public process, or at least foreshorten it.

Typographical errors:

Draft Permit	page 13 II(C)(1)(b) change "mechanica" to "mechanical" Page 13 II(C)(3)(b)(1) change "stabilzing" to "stabilizing"
Fact Sheet	second page, second paragraph, second line, delete "has" between "and" and "therefore" seventh page, Compatibility of Formation and Intestate change "Intestate" to "injectate" in title and at sentence end.

9/28/98 t/c from Jim White

would like copies of revised regs .055, .520 + .225 to be faxed to him

would like complete set mailed to:

Jim White
12225 Stoney Crossing
San Antonio
78247

fax (210) 490-2524

9/28/98 t/c from Bree Britt – JPO / State

expressed concern about potential conflict between our reg .172 that would regulate subsea pipeline + DNR lands or their Right of Way Leases.

explained we were working on language to acknowledge we weren't trying to ~~[illegible]~~ exert authority that would cause conflict.

Will fax language
We'll have Mike Barnhill talk w/ Bob Minty

Subject: Proposed AOGCC Regulations
Date: Fri, 25 Sep 1998 12:23:20 -0800
From: "Bill Britt" <BBRITT@jpo.doi.gov>
To: pattyb@dnr.state.ak.us
CC: cammy_oechsli@admin.state.ak.us

Patty - Carol C. says you're the ADNR reg queen. As such, I refer you to:

http://www.state.ak.us/local/akpages/ADMIN/ogc/regsann.htm

If you look at 20 AAC 25.172(b), you'll see that AOGCC is thinking of regs for abandonment of subsea pipelines. Aside from the fact that AOGCC probably doesn't have any authorities in this area, their specific requirements may conflict with DR&R plans/efforts that we (or Lands, for Crosstown) intend to pursue.

How do we handle these things? The comment deadline is 10/1. AOGCC is aware of the issue - Cammy brought it to my attention in the first place.

9/22 Nan T

→ DNR does not let transferor off the hook
- as condition of approving assignment, State will have to acknowledge

Forcenergy bond is w/ shaky co. - poor rating
bonding standard - should state adopt policy?
MMS

She'll ck to see if DNR considers platform a facility

Subject: reg notice
Date: Fri, 11 Jun 1999 15:24:55 -0800
From: "Rob Mintz" <Robert_Mintz@law.state.ak.us>
To: <Cammy_Oechsli@admin.state.ak.us>

Attached is a revised public notice and additional regulations notice information document for the HB 380 regs. Please note that the entire notice process must be done from scratch: i.e., not just the newspaper publication (which as we discussed should be in more than one paper, and Juneau recommends three) but also the Alaska Admin. Journal, the mailings to your mailing list, the mailings to legislators (the non-session addresses should be used now), committees, etc. And as you know some of the distribution must include a copy of the regulations as well.

Please run a final version by me before issuing the notice and additional not. inf. form. Thanks.

PHNOTICE-380.doc	**Name:** PHNOTICE-380.doc **Type:** Winword File (application/msword) **Encoding:** x-uuencode

Subject: Fwd: Re: AOGCC regs
Date: Fri, 11 Jun 1999 15:16:39 -0800
From: "Rob Mintz" <Robert_Mintz@law.state.ak.us>
To: <Cammy_Oechsli@admin.state.ak.us>

Date: Fri, 11 Jun 1999 15:03:32 -0800
From: "Steve Weaver" <Steve_Weaver@law.state.ak.us>
To: "Rob Mintz" <Robert_Mintz@law.state.ak.us>
Subject: Re: AOGCC regs

A good question. I finished a first read and started working through your e-mails in early to mid-May, and then got sidetracked on a number of rush projects. One project still lies in wait for me, but is back with the client agency for the moment, so now I can re-immerse myself in the AOGCC regulations.

Would you be able to reserve a block of time early next week (Tuesday or Wednesday would be best), to resolve substantive questions over the phone? Once we've talked, I'll have a better sense of how much time I'll need to get a markup to you and the commissioners. I'd like to wrap up most of my work on the AOGCC regulations by the end of the month at the latest, since I expect 352 pages of drinking water regulations in early July. Next weekend, I'll be out of town, on annual leave from Friday the 18th through Monday the 21st, and possibly Tuesday the 22nd. Let me know how your schedule looks.

Rob

- JW White bonding problem
- can we raise bonding requirements ?
- w/ AOGA written comments
- API — shall conduct operations in conformance with...

"well + well branch" .071

shall "utilize" RP

- abandon definition

* pool/field for tax purposes

Alberta regs

? surface casing depth - G8
casing cementing G9

- notify w/in 24hrs of drilling start-up
- can't move rig w/o approval unless
  completed
  suspended or abandoned in accordance w/ Bd approval

- driller has certificate - 1st Line Supervisor
- BOP drills performed prior to drilling out surface casing shoe
- " " " by each drilling crew every 7 days
  - both recorded in drilling log book

- diverter size ?

Rob - Natural Gas Policy Act Determination

#1

Changes in the Regulations of the
Alaska Oil and Gas Conservation Commission
Effective November 7, 1999

IMPORTANT NOTICE

The attached regulation changes take effect on November 7, 1999. In addition to the attached regulation changes, readers are reminded that certain provisions of the Commission's regulations that were in effect before November 7, 1999, have not been changed and will continue in effect, and that those provisions are not set out in the attached regulation changes. Readers should continue to refer to the regulations in effect before November 7, 1999, for those provisions, which include:

20 AAC 25.075, 25.260, 25.420, 25.505, 25.528, 25.545, and 25.550 in their entirety; and

portions of 20 AAC 25.071, 25.072, 25.080, 25.200, 25.235, 25.252, 25.440, 25.450, 25.460, and 25.537.

CHAPTER 25.
ALASKA OIL AND GAS CONSERVATION COMMISSION.

Article

1. Drilling
   (20 AAC 25.005-20 AAC 25.080)
2. Abandonment and Plugging
   (20 AAC 25.105-20 AAC 25.172)
3. Production Practices
   (20 AAC 25.200-20 AAC 25.290[85])
4. Reports
   (20 AAC 25.300-20 AAC 25.320)
5. Enhanced Recovery
   (20 AAC 25.400-20 AAC 25.460)
6. General Provisions
   (20 AAC 25.505-20 AAC 25.570)
7. Definitions
   (20 AAC 25.990)

Pub Letter: Article headings should be on same line as article numbers, and centered, as in existing text.

ARTICLE 1.
DRILLING.

Section

05. Permit to drill
10. Re-entry of a suspended well
15. Changes to an approved drilling program [PERMIT]
20. Designation of operator
22. Change of ownership
25. Bonding
26. Claims
30. Casing and cementing
33. Primary well control for drilling: drilling fluid program and drilling fluid [SURFACE] system
35. Secondary well control for primary drilling and completion: blowout prevention equipment [(BOPE)] and diverter requirements
36. Secondary well control for through-tubing drilling and completion: blowout prevention equipment requirements
37. Well control requirements for other drilling and completion operations
40. Well identification
45. (Repealed)
47. Reserve pits and tankage
50. Wellbore surveys [DEVIATION]

Temporary shutdown

55. Drilling units and well spacing
61. Well site surveys
65. Hydrogen sulfide
66. Gas detection
70. Records and reports
71. Geologic data and logs
72. Shutdown of drilling or completion [WELL] operations
75. Other wells in designated areas
80. Annular disposal of drilling waste

20 AAC 25.005 is repealed and readopted to read:

20 AAC 25.005. PERMIT TO DRILL. (a) Before drilling or redrilling a well or re-entering an abandoned well, a person shall submit and obtain the commission's approval of an application for a Permit to Drill (Form 10-401).

(b) The commission will classify a well as~~:~~

(1) exploratory;

(2) development, either oil or gas;

(3) service; or

(4) stratigraphic test.

(c) An application for a Permit to Drill must be accompanied by each of the following items, except for an item ~~unless~~ already on file with the commission and identified in the application:

(1) a fee of $100 payable to the State of Alaska/AOGCC ~~Department of Revenue~~;

(2) a plat identifying the property and the property's owners ~~its owner(s)~~ and showing

(A) the coordinates of the proposed location of the well at the surface, at the top of each objective formation, and at total depth, referenced to governmental section lines;

(B) the coordinates of the proposed location of the well at the surface, referenced to the state plane coordinate system for this state as maintained by the National Geodetic Survey in the National Oceanic and Atmospheric Administration;

(C) ~~(B)~~ the proposed depth of the well at the top of each objective formation and at total depth; and

(D) ~~(C)~~ other information required by 20 AAC 25.050(b);

(3) a diagram and description of the blowout prevention equipment (BOPE) as required by 20 AAC 25.035, 20 AAC 25.036, or 20 AAC 25.037, as applicable;

(4) information on drilling hazards, including

(A) the maximum downhole pressure that may be encountered, criteria used to determine it, and maximum potential surface pressure based on a methane gradient;

(B) data on potential gas zones; and

(C) data concerning potential causes of hole problems such as ~~over-pressured zones~~ abnormally geo-pressured strata, lost circulation zones, and zones that have a propensity for differential sticking;

(5) a description of the procedure for conducting formation integrity tests, as required under 20 AAC 25.030(f);

(6) a complete proposed casing and cementing program as required by 20 AAC 25.030, and a description of any slotted liner, pre-perforated liner, or screen to be installed;

(7) a diagram and description of the diverter system as required by 20 AAC 25.035, unless this requirement is waived by the commission under 20 AAC 25.035(h)(2);

(8) a drilling fluid program, including a diagram and description of the drilling fluid system, as required by 20 AAC 25.033;

(9) for an exploratory or stratigraphic test well, a tabulation setting out the depths of predicted abnormally geo-pressured strata as required by 20 AAC 25.033(f);

(10) for an exploratory or stratigraphic test well, a seismic refraction or reflection analysis as required by 20 AAC 25.061(a);

(11) for a well drilled from an offshore platform, mobile bottom-founded structure, jack-up rig, or floating drilling vessel, an analysis of seabed conditions as required by 20 AAC 25.061(b);

(12) evidence showing that the requirements of 20 AAC 25.025 have been met;

(13) a copy of the proposed drilling program; ~~and~~

(14) a general description of how the operator plans to dispose of drilling mud and cuttings and a statement of whether the operator intends to request authorization under 20 AAC 25.080 for an annular disposal operation in the well.

(d) For a well that is to be intentionally deviated, the requirements of 20 AAC 25.050(b) must be met.

(e) If ~~A~~ well ~~may have~~ has multiple well branches, ~~and unless drilled solely to conduct sidetrack operations,~~ each branch requires a separate Permit to Drill. If ~~When~~ multiple well branches are proposed from a single conductor, surface, or production casing, the applicant shall designate one branch as the primary wellbore and include all information required under (c) of this section with the ~~its corresponding~~ application for a Permit to Drill for that branch. For each subsequent well branch, the application for a Permit to Drill need only include information under (c) of this section that is unique to that branch and need not include the $100 fee.

(f) Each well must be identified by a unique name designated by the operator and a unique API number assigned by the commission under 20 AAC 25.040(b). For a well with multiple well branches, each branch must similarly be identified by a unique name and API number by adding a suffix to the name designated for the well by the operator and to the number assigned to the well by the commission.

(g) If drilling operations are not commenced within 24 months after the commission approves an application for a Permit to Drill, the Permit to Drill expires.

(h) A Permit to Drill is not valid at a location where the applicant does not have a right to drill for oil and gas. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25.010 is amended to read:

20 AAC 25.010. RE-ENTRY OF A SUSPENDED WELL. (a) Before re-entering [IF] a suspended well [IS TO BE RE-ENTERED] to conduct completion operations, the operator shall submit and obtain the commission's approval of an [THE FORM ENTITLED] Application for Sundry Approvals (Form 10-403) [FOR COMMISSION APPROVAL]. The Application for Sundry Approvals [FORM 10-403 FILING] must set out the current condition of the well and the proposed program for completion operations.

(b) Before re-entering [IF] a suspended well ~~to conduct~~ [IS TO BE RE-ENTERED] TO ~~CONDUCT~~ [ACTUAL] drilling operations, the operator shall submit and obtain the commission's approval of an application for a [THE FORM ENTITLED] Permit to Drill (Form 10-401) [FOR COMMISSION APPROVAL] in conformance with 20 AAC 25.005.

(c) The operator shall file with the commission within 30 days after completion, abandonment, or suspension of the well a Well Completion or Recompletion Report and Log (Form 10-407) and all information required by 20 AAC 25.070(3) [20 AAC 25.070] and 20 AAC 25.071. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25.015 is repealed and readopted to read:

20 AAC 25.015. CHANGES TO ~~AN APPROVED DRILLING~~ A PROGRAM IN A PERMIT TO DRILL. (a) To change an ~~approved~~ program approved in a Permit to Drill (Form 10-401) before drilling operations ~~have started~~ start, the operator shall

(1) submit and obtain the commission's approval of a new application for a Permit to Drill ~~(Form 10-401)~~ if the surface location is changed, if the bottom-hole location or the location of an objective formation is changed by more than 500 feet laterally or vertically, or if the change requires a spacing exception under 20 AAC 25.055; however, no additional fee is required; or

(2) otherwise notify the commission and obtain its approval of the change if the change is not covered by (1) of this subsection.

(b) To change an ~~approved drilling~~ program approved in a Permit to Drill or to change information under 20 AAC 25.005(c) after drilling operations ~~have started~~ start, the operator shall

(1) submit and obtain the commission's approval of a new application for a Permit to Drill, accompanied by a fee of $100, if the bottom-hole location or the location of an objective formation is changed by more than 500 feet laterally or vertically, or if the change requires a spacing exception under 20 AAC 25.055; or

(2) submit and obtain the commission's approval of an Application for Sundry Approvals (Form 10-403) if the change is not covered by (1) of this subsection; the Application for Sundry Approvals must set out the approved program, the current condition of the well, and the proposed changes; in cases where prompt approval is needed, oral approval may be requested from the commission; if oral approval is obtained, the name of the representative of the commission who provided oral approval and the date of the approval must be included on the Application for Sundry Approvals,

which must be submitted within ~~the commission's next~~ three ~~Working~~ days for final approval by the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

(c) By signing the Designation of Operator form, the newly designated operator agrees to accept the obligations of an operator. The newly designated operator shall

20 AAC 25.020 is amended to read:

20 AAC 25.020. DESIGNATION OF OPERATOR. If an owner of a property wishes to [RELINQUISH THE ROLE OF OPERATOR, OR] designate a new operator for the property, the owner shall submit to the commission for approval a Designation of Operator (Form 10-411). The commission will not approve the designation of a new operator without the signature of the [The] newly designated operator ~~shall~~ [MUST] signify acceptance of the obligations as operator on the same Designation of Operator form [FORM 10-411] and ~~shall~~ [MUST] furnish a bond and, if required, security as provided for in 20 AAC 25.025. The commission's acceptance of the designated operator's bond constitutes the release of the [OWNER'S OR] former operator's bonding obligation for the property indicated on the Designation of Operator form [Form 10-41]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register__)

Authority: AS 31.05.030

20 AAC 25.022 is amended to read:

20 AAC 25.022. NOTICE [CHANGE] OF OWNERSHIP. ~~When a person~~ Within 15 days after a [A] person becomes an owner [~~A PERSON~~ WHO IS THE OPERATOR] of a property on which operations subject to this chapter are [HAVE BEEN] proposed to the commission or are being conducted, the person shall file a Notice of [CHANGE OF] Ownership (Form 10-417) [within 15 days] AFTER CONVEYANCE, EACH TIME THAT AN OWNER OR LANDOWNER, AS DEFINED BY AS 31.05.170, CONVEYS ALL OR A

PARTIAL INTEREST IN THE PROPERTY TO ANOTHER PERSON]. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.025 is repealed and readopted to read:

20 AAC 25.025. BONDING. (a) An operator proposing to drill a well for which a permit is required under 20 AAC 25.005 shall file a bond and, if required under (2) of this subsection, security to ensure that each well is drilled, operated, maintained, repaired, and abandoned and each location is cleared in accordance with this chapter. The bond must be

(1) a surety bond issued on Form 10-402A in favor of the Alaska Oil and Gas Conservation Commission by an authorized insurer under AS ~~29~~ 21.09 whose certificate of authority is in good standing; or

(2) a personal bond of the operator on Form 10-402B accompanied ~~by and whose performance is guaranteed~~ guaranteeing the operator's performance; security must be by security in the form of a certificate of deposit or irrevocable letter of credit issued in the sole favor of the Alaska Oil and Gas Conservation Commission by a bank authorized to do business in the state, or ~~in the commission's discretion,~~ must be in another form ~~of security~~ that the commission determines to be adequate to ensure payment.

(b) A bond and, if required, security must be in the amount of not less than $100,000 to cover a single well or not less than $200,000 for a blanket bond covering all of the operator's wells in the state, except that the commission will ~~in its discretion~~ allow an amount less than $100,000 to cover a single well if the operator demonstrates to the commission's satisfaction in the application for a Permit to Drill (Form 10-401) that the cost of well abandonment and location clearance will be less than $100,000.

(c) A bond and, if required, security must remain in effect until the abandonment of all wells covered by them and until the commission approves final clearance of the locations ~~are approved by the commission~~. The commission will then release the bond and security upon written request of the operator.

(d) Payment under a surety bond or security does not relieve an operator from the requirements ~~any obligations~~ of AS 31.05 and ~~under~~ this chapter except to the extent that a default is actually cured, or from any liability under AS 31.05.150. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.150

20 AAC 25.026 is amended to read:

20 AAC 25.026. CLAIMS. Commission approval of the abandonment of a well and the release of the bond[,] required by 20 AAC 25.025 [SEC. 25 OF THIS CHAPTER,] constitutes a presumption of proper abandonment, but does not relieve an operator of further claim by the commission after the abandonment. (Eff. 4/13/80, Register 74; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.030 is repealed and readopted to read:

20 AAC 25.030. CASING AND CEMENTING. (a) A complete proposed well casing and cementing program must be submitted with an application for a Permit to Drill (Form 10-401). Unless modified or altered by ~~special~~ pool rules established under 20 AAC 25.520, a well casing and cementing program must be designed to

(1) provide suitable and safe operating conditions for the total measured depth proposed;

(2) confine fluids to the wellbore;

(3) prevent migration of fluids from one stratum to another;

(4) ensure control of well pressures encountered;

(5) protect against thaw subsidence and freezeback effects within permafrost;

(6) prevent contamination of freshwater;

(7) protect significant hydrocarbon zones; and

(8) provide well control until the next casing is set, considering all factors relevant to well control including formation fracture gradients, formation pressures, casing setting depths, and proposed total depth.

(b) General well casing and cementing provisions are as follows:

(1) casing design and setting depth must be based on engineering and geologic factors relevant to the immediate vicinity, including the presence or absence of hydrocarbons, potential drilling hazards, and permafrost;

(2) for all casing strings on which blowout prevention equipment (BOPE) will be installed, cement may not be drilled out until sufficient compressive strength has been reached to obtain a valid formation integrity test;

(3) within permafrost intervals, fluids that have a freezing point above the minimum permafrost temperature may not be left in casing-by-casing annuli or inside the casing upon completion, suspension, or shutdown of well operations, without commission approval of an alternate method that the commission determines will prevent damage to the casing;

(4) ~~when~~ if casing is subjected to prolonged drilling operations, the commission will, ~~in its discretion~~ as necessary to verify casing integrity, require the casing to be pressure-tested, calipered, or otherwise evaluated by a method approved by the commission;

(5) ~~where~~ if zonal coverage is required under (a) of this section, and the commission believes zonal isolation might not have been established, the commission will ~~in its discretion~~, require a cement quality log or other method to demonstrate isolation of the zone.

(c) Specific well casing provisions are as follows:

(1) structural casing must be set by driving, jetting, or drilling to a minimum depth of 70 feet in ~~all~~ offshore wells to support unconsolidated shallow strata, to provide hole stability for initial drilling operations, and to provide a competent anchor for a diverter system;

(2) for onshore wells, conductor casing must be set by driving, jetting, or drilling to a depth sufficient to provide anchorage for a diverter system, and for offshore wells, conductor casing must be set no less than 300 feet and no more than 1,000 feet below the mudline datum; ~~except that~~ however, the commission will ~~in its discretion~~

(A) approve a different casing setting depth ~~when~~ if necessary to permit the casing shoe to be set in a competent formation or below formations that should be isolated; or

(B) authorize an operator to drill without setting conductor casing based upon information from wells drilled in the immediate vicinity and other available data, if the commission determines that the absence of conductor casing will not jeopardize well control

(3) surface casing must be set below the base of all strata known or reasonably expected to serve as a source of drinking water for human consumption and at a depth sufficient to provide a competent anchor for ~~blowout prevention equipment~~ BOPE;

(4) one or more intermediate casing strings must be set ~~when~~ if required for protection of oil or gas or for protection against abnormally geo-pressured strata and lost circulation zones, or ~~when~~ if otherwise required by well conditions;

(5) production casing must be set and cemented through, into, or just above the production interval;

(6) slotted liners, pre-perforated liners, and screens installed below a production packer are considered ~~as~~ production equipment and not ~~as~~ casing.

(d) Specific well casing cementing provisions are as follows:

(1) if structural casing is set by drilling or jetting, the structural casing must be cemented with ~~a quantity of~~ cement sufficient to fill the annular space from the shoe to the surface;

(2) if conductor casing is set by drilling or jetting, the conductor casing must be cemented by filling the annular space with cement from the shoe to the surface; if ~~blowout prevention equipment~~ BOPE is to be installed on the conductor casing, the adequacy of the cement to contain potential wellbore pressures and fluids must be demonstrated by a formation integrity test;

(3) ~~upon approval of the commission,~~ conductor casing cement may be washed out to a depth not exceeding the depth of the structural casing shoe, if installed;

(4) surface casing must be cemented by filling the annular space with cement from the shoe to the surface; however, if cement does not circulate to the surface, if an excessive quantity of cement circulates to the surface, or if the formation integrity test shows an inadequate cement job,

(A) the operator shall notify the commission before drilling ahead; and

(B) the commission will ~~in its discretion,~~ require

(i) a cement quality log or other approved method to evaluate the adequacy of the cement to contain potential wellbore pressures and fluids; and

(ii) remedial action as necessary to meet the requirements of (a) of this section before drilling ahead;

(5) intermediate and production casing must be cemented with sufficient cement to fill the annular space from the casing shoe to a minimum of 500 feet above all significant hydrocarbon zones and abnormally geo-pressured strata or, ~~where~~ if zonal coverage is not required under (a) of this section from the casing shoe to a minimum of 500 feet above the casing shoe; if ~~there are~~ indications of improper cementing exist such as lost returns, ~~cement channeling, or mechanical failure of equipment~~ or if the formation integrity test shows an inadequate cement job, remedial action must be taken;

(6) ~~in cases where~~ if the intermediate or production string is a liner, a minimum of 100 feet overlap between the outer and inner strings is required; the interval of overlap must be made pressure competent and must be pressure-tested in accordance with (e) of this section;

(7) for intermediate or production casing in a service well used for injection, a cement quality log or other evaluation log approved by the commission must be run to demonstrate isolation of the injected fluids to the approved interval.

(e) A casing pressure test must be performed if ~~blowout prevention equipment will~~ BOPE is to be installed on a casing. The casing must be tested to hold a surface pressure equal to 50 percent of the required working pressure of the ~~blowout prevention equipment~~ BOPE as specified in the Permit to Drill under 20 AAC 25.035(e)(3) or 20 AAC 25.036(c)(3). The results of this test and any subsequent tests of the casing must be recorded as required by 20 AAC 25.070(1).

(f) Except for through-tubing drilling, a formation integrity test must be performed if ~~blowout prevention equipment~~ BOPE is installed on a casing. The test must be performed to a predetermined equivalent mud weight, leak-off, or fracture pressure as specified in the ~~well plan~~ application for the Permit to Drill. The test must be conducted after drilling out of the casing shoe into at least 20 feet but not more than 50 feet of new formation. The test results must demonstrate that the integrity of the casing shoe is sufficient to contain anticipated

application for the Permit to Drill

wellbore pressures identified in the ~~well plan~~. The test procedure followed and the data from the test and any subsequent tests of the formation must be recorded as required by 20 AAC 25.070(1).

(g) Upon request of the operator, the commission will, in its discretion, approve variances from the requirements of (b) - (f) of this section to allow for special or unusual conditions ~~as long as~~ if the design requirements of (a) of this section are ~~not diminished~~ satisfied. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.033 is repealed and readopted to read:

20 AAC 25.033. PRIMARY WELL CONTROL FOR DRILLING: DRILLING FLUID PROGRAM AND DRILLING FLUID SYSTEM. (a) A drilling operation must be equipped with a drilling fluid system meeting the requirements of this section, unless the commission determines ~~, in its discretion,~~ that a drilling fluid system is not necessary for primary well control. The operator shall submit with an application for a Permit to Drill (Form 10-401) a proposed drilling fluid program and a diagram with a list of equipment for a drilling fluid system designed to prevent the loss of primary well control. The drilling fluid system must be designed to maintain the wellbore in overbalanced condition except as otherwise provided under (i) of this section. A drilling operation is also subject to the requirements of 20 AAC 25.527.

(b) A drilling fluid program and drilling fluid system intended to maintain the wellbore in overbalanced condition must be designed to provide and maintain

(1) a drilling fluid

(A) of sufficient density to overbalance the pressure of uncased formations penetrated; and

(B) with rheological properties designed to

(i) minimize the potential of a hydrostatic pressure surge or swab when the drilling assembly is run into or pulled out of the wellbore; and

(ii) enhance the drop-out of solids and the escape of ~~any~~ entrained gas; and

(2) a volumetric capacity for drilling fluid reserves adequate for the volume of the wellbore, based on known or anticipated drilling conditions to be encountered, rig storage capacity, weather conditions, and estimated time for delivery.

(c) A drilling fluid system intended to maintain the wellbore in overbalanced condition must include

(1) a recording drilling fluid pit level indicator with both visual and audible warning devices located in the immediate area of the driller's ~~console~~ station;

(2) a drilling fluid measuring system or trip tank for accurately determining drilling fluid volumes required to fill the wellbore on trips;

(3) a drilling fluid flow sensor with a readout convenient to the driller's ~~console~~ station to enable the operator to determine whether drilling fluid returns equal drilling fluid pump discharge rates;

(4) equipment to keep the drilling mud conditioned as appropriate for the drilling operation being conducted; and

(5) methane and hydrogen sulfide detection equipment as required by 20 AAC 25.066.

(d) ~~For rotary drilling rig operations,~~ drilling fluid testing equipment must be on the drill site at all times. Tests to determine drilling fluid density and viscosity must be performed once each tour, or more frequently ~~when~~ if conditions warrant.

(e) To ensure that primary well control is effectively maintained, the following practices must be employed in rotary drilling rig operations when tripping the drilling assembly out of the wellbore:

(1) the drilling fluid within the wellbore must be in balance and conditioned to maintain drilling fluid properties within close tolerance to the properties necessary for well control;

(2) the flow nipple or trip tank must be visually observed to ensure that there is no indication of formation fluid influx;

(3) the wellbore must be kept full of drilling fluid at all times;

(4) the annulus must be filled with fluid

(A) each time that five stands of drill pipe have been removed from the wellbore; and

(B) more frequently than required in (A) of this paragraph, if necessary to prevent the hydrostatic pressure from dropping by 75 psi or more;

(5) the volume of drilling fluid required to keep the wellbore full while tripping the drilling assembly out of the wellbore must be measured and recorded on the daily drilling report or trip sheet.

(f) Additional requirements that apply to exploratory and stratigraphic test wells ~~drilled by a rotary drilling rig~~ are as follows:

(1) the operator shall include with an application for a Permit to Drill a tabulation that sets out the depths of predicted abnormally geo-pressured strata;

as the commission considers necessary to evaluate the potential for a well control problem,

the operator shall include with an application for a Permit to Drill

(2) if the operator has geophysical data from the area, a seismic velocity analysis constrained by germane well ~~control~~ data ~~must be performed~~ to predict the potential of encountering abnormally geo-pressured strata, with the analysis displayed by plotting interval transit time versus depth; the commission will, ~~in its discretion,~~ require a ~~confidential~~ review from the operator of the velocity analysis and of the plot of interval transit time versus depth;

the operator shall include with an application for a Permit to Drill

(3) if the operator does not have geophysical data from the area, an analysis of germane well ~~control~~ data ~~must be performed~~ to predict the potential of encountering abnormally geo-pressured strata;

(4) a drilling fluid monitoring unit must be used and continuously observed during ~~rotary~~ drilling rig operations, including tripping, to monitor and record

(A) gas entrained in the drilling fluid;

(B) drilling fluid density;

(C) drilling fluid salinity;

(D) the rate of penetration; and

(E) hydrogen sulfide, as required by 20 AAC 25.065;

(5) means for communication between the drilling fluid monitoring unit and the ~~rotary~~ drill rig floor must be installed and maintained in working condition while open hole operations are taking place, and drill rig floor personnel must be notified immediately ~~when~~ if excursions from normal trends occur for any of the parameters set out in (4) of this subsection.

(g) ~~When~~ If drilling an exploratory or stratigraphic test well, or ~~when~~ if drilling a development or service well while known hydrocarbon-bearing strata are exposed to open hole, the operator shall take a drilling fluid return sample and test the sample to determine density just before tripping the drill pipe.

Density test results must be recorded as required by 20 AAC 25.070(1). If the density is less than that of the drilling fluid being pumped down the drilling assembly, the drilling fluid must be circulated and conditioned until a close tolerance of the properties of the return drilling fluid with the input drilling fluid is achieved.

(h) If formation competence at the structural casing setting depth is not adequate to permit circulation of drilling fluids while drilling the conductor hole, a program that provides for safety in that drilling operation must be described and submitted to the commission for approval. This program must be supported by pertinent information including seismic and geologic data, water depth, drilling fluid hydrostatic pressure, and a contingency plan for moving off location.

(i) The commission will ~~in its discretion,~~ approve underbalanced drilling operations and if the commission determines that underbalanced drilling operations can be performed without loss of well control associated equipment changes. A request for underbalanced drilling must include a description of all equipment and procedures to ensure proper containment of formation and return fluids.

(j) Upon request by the operator, the commission will, in its discretion, approve a waiver of the requirements of (c) - (g) of this section if the alternative drilling fluid program and drilling fluid system meet the design criteria of (b) of this section and the corresponding equipment and procedures are at least equally effective in preventing the loss of primary well control. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.035 is repealed and readopted to read:

20 AAC 25.035. SECONDARY WELL CONTROL FOR PRIMARY DRILLING AND COMPLETION: BLOWOUT PREVENTION EQUIPMENT AND DIVERTER REQUIREMENTS. (a) This section applies to drilling and completion operations other than those covered by 20 AAC 25.036 or 20 AAC 25.037. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall submit the following information with the application for a Permit to Drill (Form 10-401) or refer in the application to that information if that information is already on file with the commission:

(1) a diagram of the blowout preventer (BOP) stack or diverter and related equipment for each proposed casing installation; ~~and~~

(2) a list of the blowout prevention equipment (BOPE) and if applicable, diverter equipment with specifications.

(c) Except as provided in (d) and (h) of this section, a high capacity flow diverter system must be installed to provide safety for personnel and equipment before rotary rig drilling is performed below a well's structural or conductor casing, unless the casing is equipped with BOPE conforming with (e) of this section. The following provisions apply to a diverter system:

(1) the diverter system must consist of a remotely operated annular pack-off device, a full-opening vent line valve, and a diverter vent line ~~whose~~ with a diameter ~~is~~

(A) of at least 16 inches, unless a smaller diameter is approved by the commission to account for smaller hole size, geological conditions, rig layout, or surface facility constraints; and

(B) at least as large as the diameter of the hole to be drilled, unless a pilot hole with a diameter no larger than that of the vent line is drilled first; the commission will ~~in its~~

~~discretion~~ waive the requirement of this paragraph if the operator demonstrates, based on drilling experience in the near vicinity, that drilling a pilot hole would not be necessary for safety;

(2) the diverter system must be assembled as follows:

(A) the diverter vent line outlet must be located below the annular pack-off, either as an integral part of the annular pack-off device or as a vent-line outlet spool immediately below it;

(B) the actuating mechanism for the vent line valve must be integrated with the actuating mechanism for the annular pack-off device in a fail-safe manner so that the vent line valve ~~will~~ automatically opens before ~~prior to~~ full closure of the annular pack-off;

(C) the vent line must extend to a point at least 75 feet (i) away ~~removed~~ from a potential source of ignition; and (ii) ~~at least 75 feet~~ beyond the drill rig substructure; or to a point within the ~~the~~ reserve pit, ~~but in~~ and at least ~~no case fewer than~~ 50 feet beyond ~~from~~ the drill rig substructure;

(D) the vent line must be as straight as possible, secured to prevent movement, and designed to avoid freeze-up;

(E) the vent line may be secured to the rig and with portable cradle supports, but may not be attached to flowlines, cable trays, or other processing equipment;

(F) all turns with a bend radius less than 20 times the inside diameter of the vent line must be targeted;

(G) all valves must be full-opening;

(3) a clearly marked "warning zone" must be established on each side and ahead of the vent line tip, and the following restrictions must be in effect within the warning zone, beginning with the

function test of the diverter system immediately before drilling operations begin and ending with diverter system rig-down:

(A) ~~no~~ a prohibition on vehicle parking;

(B) ~~no~~ a prohibition on ignition sources or running equipment;

(C) ~~no~~ a prohibition on staged equipment or materials;

(D) the restriction of traffic to essential foot or vehicle traffic only;

(4) the commission will, in its discretion, inspect the diverter system ~~will, in the commission's discretion, be inspected by the Commission~~ for compliance with the requirements of this subsection and require the operator to test the system ~~tested~~ to ensure proper operation.

(d) If the formation competence at the structural casing setting depth is not adequate to permit use of a diverter system while drilling the conductor hole, a program that provides for safety in that drilling operation must be described and submitted to the commission for approval. This program must be supported by pertinent information including seismic and geologic data, water depth, drilling fluid hydrostatic pressure, and a contingency plan for moving off location.

(e) A well must be equipped with BOPE meeting the requirements of this subsection from the time that open hole drilling operations begin below the surface casing until the drilled portion has been plugged or the well is completed, except ~~when~~ if hydraulic communication to the open hole section is isolated. The following provisions apply to BOPE and other well control equipment:

(1) in rotary drilling rig operations,

(A) for an operation requiring a BOP stack less than API 5~~M~~K, BOPE must have at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except that pipe rams need not be sized to ~~for~~ bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(B) for an operation requiring a BOP stack equal to or greater than API 5M ~~or greater~~ K, BOPE must have at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except that pipe rams need not be sized to BHAs ~~for bottom-hole assemblies~~ and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(2) in coiled tubing unit operations, the well control equipment must include

(A) for an operation requiring a BOP stack equal to or less than API 5M K ~~or less~~,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer; ~~and~~

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(iv) at least one preventer equipped with pipe rams that fit the size of tubing, liner, or casing being used, except that pipe rams need not be sized to BHAs ~~for bottom-hole assemblies~~ and drill collars; and

(B) for an operation requiring a BOP stack greater than API 5~~M~~K,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers; ~~and~~

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; (iv) and at least two preventers equipped with pipe rams that fit the size of tubing, liner, or casing being used, except that pipe rams need not be sized to BHAs ~~except for bottom-hole assemblies~~ and drill collars;

(3) the rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected ~~and~~ as the commission will ~~be specified~~ specify in the approved Permit to Drill; the working pressure that the equipment must be rated to meet or exceed; however, ~~except that~~ the rated working pressure of the annular type preventer need not exceed 5,000 psi, unless the commission requires a higher rated working pressure ~~is required by~~ as the commission considers necessary to maintain well control; if the maximum potential surface pressure exceeds the rated working pressure of the annular type preventer, the operator shall submit with the application for a Permit to Drill a well-control procedure that indicates how the annular type preventer will be used and what pressure limitations will be applied during each mode of pressure control;

(4) a BOPE assembly must include

(A) a hydraulic actuating system with

(i) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled

hydraulic valve while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off; and

(ii) an accumulator pump system consisting of two or more pumps with independent power sources (primary and secondary) and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(B) locking devices on the ram-type preventers;

(C) a fire wall to shield accumulators and primary controls;

(D) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's ~~console~~ station, in addition to controls on the accumulator system;

(E) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's ~~console~~ station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor;

(F) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool or on the BOP body with two full-opening valves on each outlet, conforming to the following specifications:

(i) the outlets must be at least two inches in nominal diameter, except that for rotary drilling rig operations, if the required BOP is rated equal to or greater than API ~~2M~~ 5K, the nominal diameter of the choke outlets must be at least three inches;

(ii) each valve must be sized at least equal to the required size of the outlet to which it is attached;

(iii) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(iv) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid;

(G) in rotary drilling rig operations, a fill-up line above the uppermost BOP; and

(H) a choke manifold equipped with

(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's ~~console~~ station if the operation requires a BOP stack equal to or greater than API 5M ~~or greater~~;

(ii) a line at least two inches in nominal diameter downstream of each choke;

(iii) immediately upstream of each choke, at least one full-opening valve for an operation requiring a BOP stack less than API 5M, or at least two full-opening valves for an operation requiring a BOP stack equal to or greater than API 5M ~~or greater~~; and

(iv) a bypass line, at least the diameter of the choke line, with at least one full-opening valve for an operation requiring a BOP stack less than API 5M, or at least two full-opening valves for an operation requiring a BOP stack equal to or greater than API 5M ~~or greater~~;

(5) the rated working pressure of the wellhead assembly and of all valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must equal or exceed the required working pressure ~~of the BOPE~~ specified for the BOPE in the approved Permit to Drill, except that the rated working pressure of lines downstream of the choke need not exceed ~~may be rated to~~ 50 percent of the required working pressure of the BOPE;

(6) kill and choke lines must

(A) be constructed of rigid steel pipe, fire-resistant rotary hose, or other ~~suitable~~ conduit that has been approved by the commission as capable of withstanding the temperature and pressure of an ignited uncontrolled release;

(B) be as straight as practical;

(C) if constructed of rigid steel pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(D) be secured to prevent excessive whip or vibration;

(E) be sized to prevent excessive erosion or fluid friction; and

(F) be assembled without hammer unions or internally clamped swivel joints, unless ~~such joints are specifically approved by~~ the commission determines that those joints do not compromise maintenance of well control;

(7) for lubricated drilling operations or operations below a normally closed annular type preventer, the choke line may be used for drilling returns;

(8) connections attached directly to the wellhead, tree, or BOPE must be flanged or hubbed;

(9) for rotary drilling rig operations, auxiliary well control equipment must include

(A) a kelly cock valve installed below the swivel and, at the bottom of the kelly, a full-opening lower kelly valve of a design that allows it to be run through the BOP stack, with a properly sized wrench for each valve stored in a conspicuous location readily accessible to the drilling crew; and

(B) an inside BOP and a full-opening drilling assembly safety valve in the open position on the drill rig floor to fit all connections that are in the drilling assembly;

(10) the BOPE must be tested as follows:

(A) when installed, repaired, or changed, and at least once a week thereafter, BOPE, including kelly valves, emergency valves, and choke manifolds, must be function pressure-tested to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(B) ~~when~~ if BOP sealing ram type equipment has been used, it must be function pressure-tested, before the next wellbore entry, to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(C) non-sealing equipment must be function-tested weekly ~~and~~ after a repair or change, and after an ~~or any~~ action that disconnects the hydraulic system lines from the BOPE, except that ~~when~~ if the workstring is continuously in the well ~~or the BHA does not clear the BOP~~, function-testing must be performed as soon as possible ~~thereafter~~ after the workstring is pulled out of the well and the BHA clears the BOP;

(D) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(E) ~~a minimum of~~ at least 24 hours notice of each function pressure test must be provided so that a representative of the commission can witness the test.

(f) In consultation with the drilling ~~foreman~~ rig supervisor, the commission will, in its discretion, require drills simulating well control problems. ~~Drills will, in the commission's discretion,~~ The commission will, in its discretion, include in the drills any combination of raising or lowering the pit level indicator, advancing or retarding the flow rate indicator, or actuating the gas detectors.

(g) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Permit to Drill and shall post on the drilling rig floor the drilling hazard information required by 20 AAC 25.005(c)(4) and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Permit to Drill, the drilling hazard information required by 20 AAC 25.005(c)(4), and a copy of the standing orders specifying well control procedures. ~~When~~ If an additional or separate substructure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(h) Upon request of the operator, the commission will, in its discretion, approve a variance

(1) from the BOPE requirements in (e) of this section if the variance provides at least an equally effective means of well control; and

(2) from the diverter system requirements in (c) of this section if the variance provides at least equally effective means of diverting flow away from the drill rig or if drilling experience in the near vicinity indicates that a diverter system is not necessary. (Eff. 4/13/80, Register 74; am 2/22/81, Register 77; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.036. SECONDARY WELL CONTROL FOR THROUGH-TUBING DRILLING AND COMPLETION: BLOWOUT PREVENTION EQUIPMENT REQUIREMENTS. (a) This section applies to drilling and completion operations performed through existing production tubing. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall submit the following information with the application for a Permit to Drill (Form 10-401) or refer in the application to that information if that information is already on file with the commission:

(1) a diagram of each blowout preventer (BOP) stack and related well control equipment to be used; ~~and~~

(2) a list of the blowout prevention equipment (BOPE) with specifications.

(c) A well must be equipped with BOPE meeting the requirements of this subsection from the time that drilling penetrates beyond casing or liner until the drilled portion has been plugged or the well is completed, except ~~when~~ if hydraulic communication to the open hole section has been isolated. The following provisions apply to BOPE and other well control equipment:

(1) in rotary drilling rig operations,

(A) for an operation requiring a BOP stack equal to or less than API 5~~M~~K ~~or less~~, BOPE must have at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except that pipe rams need not be sized to ~~for~~ bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(B) for an operation requiring a BOP stack greater than API 5~~M~~K, BOPE must have at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except that pipe rams need not be sized to BHAs ~~for bottom-hole assemblies~~ and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(2) in coiled tubing unit operations, the well control equipment must include

(A) for an operation requiring a BOP stack equal to or less than API 5M ~~or less~~,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer; ~~and~~

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and (iv) at least one preventer equipped with pipe rams that fit the size of the tubing, liner, or casing being used, that pipe rams need not be sized to BHAs, except ~~for bottom-hole assemblies~~ and drill collars; and

(B) for an operation requiring a BOP stack greater than API 5M,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers; ~~and~~

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and (iv) at least two

preventers equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except ~~for bottom-hole assemblies~~ that pipe rams need not be sized to BHAs and drill collars;

(3) the rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected ~~and~~ ; if the commission will ~~be specified~~ specify in the approved Permit to Drill ~~except that~~ ; however, the rated working pressure of an annular type preventer need not exceed 5,000 psi, unless the commission requires a higher rated working pressure ~~is required by~~ as the commission considers necessary to maintain well control; if the maximum potential surface pressure exceeds the rated working pressure of the annular type preventer, the operator shall submit with the application for a Permit to Drill a well control procedure that indicates how the annular type preventer will be used and the pressure limitation that will be applied during each mode of pressure control;

(4) a BOPE assembly must include

(A) a hydraulic actuating system with

(i) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled hydraulic valve while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off; and

(ii) an accumulator pump system consisting of one or more pumps with independent power sources (primary and secondary), and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(B) locking devices on the ram-type preventers;

(C) a fire wall to shield accumulators and primary controls;

(D) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's ~~console~~ station, in addition to controls on the accumulator system;

(E) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's ~~console~~ station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor;

(F) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool, the BOP body, or the tree, with two full-opening valves on each outlet, conforming to the following specifications:

(i) the outlets and valves must be at least two inches in nominal diameter;

(ii) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(iii) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid;

(G) for open hole deployment, an annular type preventer, unless a lubricator of sufficient length to enclose the entire ~~bottom hole assembly~~ (BHA) below a high pressure sealing element is used; and

(H) for conventional open loop fluid process drilling operations, a choke manifold equipped with

(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's or operator's ~~console~~ station if the operation requires a BOP stack equal to or greater than API 5M ~~or greater~~;

(ii) a line at least two inches in nominal diameter downstream of each choke;

(iii) immediately upstream of each choke, at least one full-opening valve for an operation requiring a BOP stack equal to or less than API 5M ~~or less~~, or at least two full-opening valves for an operation requiring a BOP stack greater than API 5M; and

(iv) a bypass line at least two inches in nominal diameter with at least one full-opening valve immediately upstream of each choke for an operation requiring a BOP stack equal to or less than API 5M ~~or less~~, or with at least two full-opening valves immediately upstream of each choke for an operation requiring a BOP stack greater than API 5M;

(5) in an underbalanced drilling operation, well control equipment must have bi-directional slip capabilities;

(6) the rated working pressure of the wellhead assembly and of all valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must equal or exceed the required working pressure ~~of the BOPE~~ specified for the BOPE in the approved Permit to Drill, except that the rated working pressure of lines downstream of the choke need not exceed ~~may be rated to~~ 50 percent of the required working pressure of the BOPE;

(7) for lubricated drilling operations or operations below a normally closed annular type preventer, the choke line may be used for drilling returns;

(8) at least one positive seal manual or hydraulic valve or BOPE blind ram, one set of BOPE pipe rams, and, if used, the drilling spool must be flanged to the wellhead or tree;

(9) connections directly to the BOPE, other than connections described in (8) of this subsection, must be flanged or hubbed, except that suitably pressure-rated quick connects may be used if a positive seal manual valve, hydraulic valve, or BOPE blind ram and an annular type preventer or sealing ram are flanged to the wellhead or tree below the quick connection;

(10) kill and choke lines must

(A) be constructed of rigid steel pipe, fire-resistant rotary hose, or other ~~suitable~~ conduit that has been approved by the commission as capable of withstanding the temperature and pressure of an ignited uncontrolled release;

(B) be as straight as practical;

(C) if constructed of rigid steel pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(D) be secured to prevent excessive whip or vibration;

(E) be sized to prevent excessive erosion or fluid friction; and

(F) be assembled without hammer unions or internally clamped swivel joints, except that hammer unions and internally clamped swivel joints may be used on the kill line upstream of the valves that are flanged to the wellhead or tree.

(d) A BOPE assembly must be tested as follows:

(1) when installed, repaired, or changed, and at least once a week thereafter, the BOPE, including emergency valves and choke manifolds, must be function pressure-tested to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(2) other well control equipment must be pressure-tested to the maximum ~~expected~~ potential wellhead pressure after each installation of the well control equipment and before wellbore entry, except that ~~when~~ if testing against the annular type preventer, pressure testing need not exceed 50 percent of the rated working pressure of the annular type preventer;

(3) ~~when~~ if BOP sealing ram type equipment has been used, it must be function pressure-tested, before the next wellbore entry, to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(4) non-sealing equipment must be function-tested weekly ~~and~~, after a repair or change, ~~or~~ and after an ~~any~~ action that disconnects the hydraulic system lines from the BOPE, except that ~~when~~ if the workstring is continuously in the well ~~or the BHA does not clear the BOP~~, function-testing must be performed as soon as possible after the workstring is pulled out of the well and the BHA clears the BOP ~~thereafter~~;

(5) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(6) ~~a minimum of~~ at least 24 hours notice of each function pressure test must be provided so that a representative of the commission can witness the test.

(e) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Permit to Drill and shall post on the drilling rig floor the drilling hazard information required by 20 AAC 25.005(c)(4) and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Permit to Drill, the drilling hazard information required by 20 AAC 25.005(c)(4), and a copy of the standing orders specifying well

control procedures. ~~When~~ If an additional or separate sub-structure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(f) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.037. WELL CONTROL REQUIREMENTS FOR OTHER DRILLING AND COMPLETION OPERATIONS. For ~~unconventional~~ drilling and completion operations for which the provisions of 20 AAC 25.033, 20 AAC 25.035, or 20 AAC 25.036 would not be practical or appropriate, the commission will ~~in its discretion,~~ approve alternate well control procedures and equipment if the procedures and equipment are adequate to maintain well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.040 ~~(a) and (b) are~~ is amended to read:

(a) Every well must be identified by a sign posted in a conspicuous place. During the period of time from <u>commencement of drilling operations</u> [SPUD] to well completion, suspension, or abandonment, the sign must be on or near the <u>drill rig</u> [DERRICK], but not more than 100 feet from the well. <u>After well completion or suspension</u> [FOR SUSPENDED OR PRODUCIBLE WELLS], the well sign must be at the wellhead or on the wellhead building. The sign must be of durable construction, large

enough to be legible under normal conditions at a distance of 50 feet, and maintained in legible condition. Each sign must show the

(1) name designated by the operator under 20 AAC 25.005(f) for [OF] the well drilled from the surface location;

(2) name of the owner;

(3) name of the operator if different from the owner;

(4) API [WELL] number that the commission has, under (b) of this section, assigned to the well;

(5) well surface location by governmental quarter section, section, township and range; and

(6) Permit to Drill [DRILLING PERMIT] number ~~or numbers~~ that the commission has assigned under (b) of this section during the period of time from ~~commencement of drilling operations~~ [SPUD] to well completion, suspension, or abandonment.

(b) The commission will assign a Permit to Drill number and an API number [EACH WELL WILL BE ASSIGNED AN API WELL NUMBER BY THE COMMISSION] when a Permit to Drill (Form 10-401) [THE DRILLING PERMIT] is approved.

(c) For platforms or multiple-well drill sites, the information required in (a)(2) - (a)(5) [(a)(1) - (a)(3) AND (a)(5)] of this section may be posted on one sign on the platform or at the entrance to the drill site.

~~Note to publisher: subsection (c) is unchanged.~~

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.047 is amended to read:

20 AAC 25.047. RESERVE PITS AND TANKAGE. (a) Before a person commences drilling [SPUDDING] a well [PERMITTED UNDER 20 AAC 25.005], a [PROPER AND APPROPRIATE] reserve pit must be constructed[,] or [APPROPRIATE] tankage installed for the reception and

confinement of drilling fluids and cuttings, to facilitate the safety of the drilling operation, and to prevent contamination of freshwater [GROUND WATER] and damage to the surface environment. The ~~confining surfaces of the reserve pit must be impervious~~ [SPECIAL PRECAUTIONS MUST BE TAKEN TO RENDER IMPERVIOUS THE ~~CONFINING SURFACE OF A RESERVE PIT.~~] confining surface of a reserve pit must be impervious. If practical, confinement diking in construction of a reserve pit must be avoided. If confinement dikes are necessary, they must be kept to a minimum. Dikes must be constructed and maintained to ensure [INSURE] their confinement integrity.

(b) Upon [TERMINATION OF] completion, suspension, or abandonment of the well [OPERATIONS], the operator shall proceed with diligence to [DISPOSE OF OR SOLIDIFY IN PLACE ALL PUMPABLE FLUIDS, AND SHALL] leave the reserve pit in a condition that does not constitute a hazard to freshwater [GROUND WATER]. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.050 is repealed and readopted to read:

20 AAC 25.050. WELLBORE SURVEYS. (a) A well that is not intentionally deviated must be

(1) drilled as close to vertical as is possible using conventional drilling techniques, except that deviation is permitted for short intervals to straighten the hole, sidetrack junk, or correct mechanical difficulties;

(2) surveyed to determine the inclination from vertical with surveys starting at 500 feet and no more than 500 feet apart to total depth; and

(3) surveyed by a complete continuous directional survey if ~~any~~ a portion of the well path is less than 500 feet from a property line where the ownership by owner or landowner is not identical on

both sides of the line, or if ~~any~~ a portion of the well path is less than 200 feet from any other vertical or deviated well; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface.

(b) If a well is to be intentionally deviated, the application for a Permit to Drill (Form 10-401) must

(1) include a plat, drawn to a suitable scale, showing the path of the proposed wellbore, including all adjacent wellbores within 200 feet of any portion of the proposed well; and

(2) ~~list the names of~~ For all ~~operators of~~ wells within 200 feet of the proposed wellbore, (A) list the names of the operators of those wells, to the extent that those names are known or discoverable in public records, and show that each named operator has been furnished a copy of the application by certified mail; or (B) state that the applicant is the only affected owner.

(c) A well that is intentionally deviated must be

(1) directionally surveyed at intervals not more than 500 feet apart on straight or tangent sections of the well during the normal course of drilling, and at intervals not exceeding 100 feet in all portions of the hole where intentional angle changes are performed;

(2) surveyed by a continuous directional survey if ~~any~~ a portion of the well path is less than 500 feet from a property line where the ownership by owner or landowner is not identical on both sides of the line; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface; and

(3) surveyed by a continuous directional survey if ~~any~~ a deviated portion of the wellbore is less than 200 feet from any other vertical or deviated well; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface.

(d) Within 30 days after the completion, abandonment, or suspension of a well, and within 30 days after completion or plugging of a well branch, a complete digital copy of each inclination and directional survey not previously filed must be filed with the commission in a format acceptable to the commission. A composite survey may ~~also~~ additionally be filed if the operator believes this would better represent the well course. If a composite survey is filed, the operator shall specify the portion of each survey used in the composite.

(e) If the final location of the producing interval of a well is not in compliance with 20 AAC 25.055 or ~~other rules of the commission applicable to the reservoir~~ with pool rules established under 20 AAC 25.520, the operator shall apply for an exception. The commission will review the application ~~Will be handled~~ in accordance with 20 AAC 25.540. The well may not be produced until the exception is granted.

(f) A wellbore survey report required by (a) or (c) of this section must contain

(1) the name of the surveying company;

(2) the name, title, and signature of the person who actually performed the survey;

(3) the date on which the survey was performed;

(4) the type of survey conducted;

(5) the method used in calculating the survey;

(6) a complete identification of the well ~~showing~~ or, in the case of a well with more than one bottom-hole location, a complete identification of the well branch; the identification must show the name of the well designated by the operator under 20 AAC 25.005(f), the name of the operator, the property name or lease number, the Permit to Drill number assigned under 20 AAC 25.040(b), the API number, and the field name;

(7) the depth interval over which the survey was conducted; and

(8) a plat showing the coordinates ~~, referenced to governmental section lines,~~ of the surface location, the plotted well course, and ~~any well(s)~~ wells within 500 feet of any portion of the wellbore; these coordinates must be referenced to governmental section lines; and

(B) of the surface location, referenced to the state plane coordinate system for this state as maintained by the National Geodetic Survey in the National Oceanic and Atmospheric Administratio

(g) The commission will, in its discretion, require submittal of the original film, time sheets, charts, graphs, discs, and other data used to compile the survey required by (a) or (c) of this section.

(h) Upon application, the commission will, in its discretion, waive all or part of the directional survey requirements of this section or approve alternate means for determining the location of a wellbore if the variance at least equally ensures accurate surveying of the wellbore to prevent well intersection, to comply with spacing requirements, and to ensure protection of correlative rights. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.055 is repealed and readopted to read:

20 AAC 25.055. DRILLING UNITS AND WELL SPACING. (a) The commission will, in its discretion, establish drilling units to govern well spacing and prescribe a spacing pattern by ~~special~~ pool rules adopted in accordance with 20 AAC 25.520. In the absence of an order by the commission establishing drilling units or prescribing a spacing pattern for a pool, the following statewide spacing requirements apply:

(1) for a well drilling for oil, a wellbore may be open to test or regular production within 500 feet of a property line only ~~where~~ if the owner is the same and the landowner is the same on both sides of the line;

(2) for a well drilling for gas, a wellbore may be open to test or regular production within 1,500 feet of a property line only ~~where~~ if the owner is the same and the landowner is the same on both sides of the line;

(3) ~~where~~ if oil has been discovered, the drilling unit for the pool is a governmental quarter section; not more than one well may be drilled to and completed in that pool on any governmental quarter section~~, not may~~; a well ~~be drilled~~ may not be drilled or completed closer than 1,000 feet to any well drilling to or capable of producing from the same pool;

(4) ~~where~~ if gas has been discovered, the drilling unit for the pool is a governmental section; not more than one well may be drilled to and completed in that pool on any governmental section~~, not may~~; a well ~~be drilled~~ may not be drilled or completed closer than 3,000 feet to any well drilling to or capable of producing from the same pool.

(b) A well may not begin regular production of oil from a property that is smaller than the governmental quarter section upon which the well is located or begin regular production of gas from a property that is smaller than the governmental section upon which the well is located, unless the interests of the persons owning the drilling rights in and the right to share in the production from the quarter section or section, respectively, have been pooled under AS 31.05.100.

(c) A pooling agreement under AS 31.05.100 must be filed with the commission before regular production from the affected property begins.

(d) ~~An~~ The commission will review an application for an exception to the provisions of this section ~~will be handled~~ in accordance with 20 AAC 25.540. The applicant for an exception shall send notice of the application by certified mail to the owners, landowners, and operators described ~~below~~ in (1) of this subsection and shall furnish the commission with a copy of the notice, the date of mailing, and the addresses to which the notice was sent. The application must include

(1) the names of all owners, landowners, and operators of all properties within 1,000 feet of a well drilling for oil or within 3,000 feet of a well drilling for gas for which an exception is ~~required~~ sought;

(2) a plat drawn to a scale of one inch equaling 2,640 feet or larger, showing the location of the well for which the exception is sought, all other completed and drilling wells on the property, and all adjoining properties and wells; and

(3) ~~a statement~~ an affidavit by a person acquainted with the facts, verifying that all facts are true and that the plat correctly portrays pertinent and required data.

(e) Upon application by the operator, the commission will ~~in its discretion,~~ establish notice requirements different from those of (d) of this section if the operator demonstrates to the commission's satisfaction that compliance with the notice requirements in (d) of this section is not feasible because of the complexity of ownership within the notice area~~, a more effective means of providing notice is available~~. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.100

20 AAC 25.061 is amended to read:

20 AAC 25.061. WELL SITE SURVEYS. (a) For an exploratory or stratigraphic test well, near [NEAR] surface strata to a depth of ~~[200]~~ 2,000 feet in the vicinity of the well [SITE AREA FOR ALL EXPLORATORY AND STRATIGRAPHIC TEST WELLS] must be evaluated seismically by common depth point refraction or reflection profile analysis, or by another method approved by the commission, to identify anomalous velocity variations indicative of potential shallow gas sources. Analysis results must be included with the application for the Permit to Drill (Form 10-401).

(b) For a well drilled offshore from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel, the ~~[THE]~~ vicinity of the well [SITE AREA] must be evaluated by sidescan sonar and other pertinent surveys to determine whether potential seabed hazards to drilling operations are present [FOR EACH TYPE OF WELL LISTED IN 20 AAC 25.005 TO BE DRILLED OFFSHORE FROM A

MOBILE BOTTOM-FOUNDED, JACK-UP OR FLOATING UNIT]. Survey results must be included with the application for Permit to Drill [(FORM 10-401)].

(c) Upon request by the operator, the commission will, in its discretion, [WILL] waive the requirements of this section if the operator can identify, by other equally effective means, the likelihood of encountering potential shallow gas or seabed hazards or if the commission already has information that substantiates the presence or absence of shallow gas or seabed hazards. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.065(a) and (b) are amended, (c) is repealed and readopted, and (d) is repealed, to read:

20 AAC 25.065. HYDROGEN SULFIDE. (a) If [When] hydrogen sulfide gas is encountered in excess of 20 ppm, the operator shall notify the commission within 24 hours after the encounter.

(b) If a well is to be drilled in an area where a formation to be penetrated is known to contain hydrogen sulfide gas, or if hydrogen sulfide gas is encountered while drilling, the [EACH] operator shall conform with [MEET THE REQUIREMENTS OF] API RP 49, *Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide*, 2d edition, April 15, 1987, which is adopted by reference.

(c) If the ~~there is an insufficient~~ history of drilling in an area is insufficient to know whether hydrogen sulfide gas exists, the commission will specify on the Permit to Drill (Form 10-401) that the operator shall comply with minimum requirements for detection monitoring, contingency and control, and training, as follows:

(1) in addition to the automatic hydrogen sulfide detection system required in

20 AAC 25.066, at least three manual detectors with an adequate supply of extra detector tubes must be available on the location;

(2) hydrogen sulfide treating material for the drilling mud must be available on or near the location, in good condition and in sufficient quantity to adequately treat the mud system should hydrogen sulfide be encountered;

(3) detailed emergency operating procedures must be defined and posted to ensure the safety of all personnel should hydrogen sulfide be encountered;

(4) detailed step-by-step remedial procedures must be developed and posted to cover emergencies while drilling or tripping;

(5) personnel protective equipment must be available on the location;

(6) all persons engaged in drilling operations must be trained for emergency procedures in the presence of hydrogen sulfide gas and in the use of personal protective equipment, alarm systems, and emergency exit procedures.

(d) Repealed ___/___/___. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Att'n AAC Coordinator: Please insert effective date of repealer

Authority: AS 31.05.030

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in ~~this section~~ 20 AAC 25.065 may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070, or if not available from the American Petroleum Institute, may be obtained from Global Engineering Documents, 15 Inverness Way East, Englewood, CO 80150.

Note to publisher: italics should be added to title of publication cited in subsection (b).

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.066. GAS DETECTION. (a) ~~All~~ drilling and workover rigs must meet the following minimum requirements for methane and hydrogen sulfide gas detection:

(1) the methane detection system must have a minimum of three sensing points; one sensing point must be under the substructure near the cellar, one must be over the shale shaker, and one must be above the drill rig floor near the driller's ~~console~~ station or above the drilling platform; if the mud pits are remote from the shale shaker and enclosed, a fourth sensor must be located over the mud pits;

(2) methane sensors must be placed to detect a "lighter-than-air" gas;

(3) the hydrogen sulfide detection system must have a minimum of three sensing points; sensing point must be one under the substructure near the cellar, one must be near the shale shaker, and one must be above the drill rig floor near the driller's ~~console~~ station or above the drilling platform; the commission will ~~in its discretion,~~ require additional sensors as the commission considers necessary for safety, such as at the entrance to living quarters if they are adjacent to the drill rig, or over the mud pits if they are remote from the shaker and enclosed;

(4) hydrogen sulfide sensors must be placed to detect a "heavier-than-air" gas;

(5) sensors must be automatic, acting independently ~~(i.e.,~~ and in parallel, and with one-minute minimum sampling intervals;

(6) each detection system must include separate and distinct visual and audible alarms; the visual alarm must signal the low level gas alarm and the audible alarm the high level gas alarm; an audible alarm may have an "acknowledge" button;

(7) the methane low level gas alarm must be set at not over 20 percent LEL ~~(lower explosive limit)~~; the high level alarm must be set at not over 40 percent LEL;

(8) the hydrogen sulfide low level gas alarm must be set at 10 ppm; the high level alarm must be set at not over 20 ppm;

(9) each alarm must be automatic and must be visible and audible from the driller's or operator's ~~console~~ station; the hydrogen sulfide alarm must be audible throughout the drilling location, including the camp buildings.

(b) A gas detection system that continuously performs self-checking or diagnostics must be function-tested when a BOP stack is initially installed after a drill rig is set up, when a commission-witnessed BOP test occurs, and no less frequently than once every six months. Other gas detection systems must be calibrated and tested when a BOP stack is initially installed after a drill rig is set up, when a commission-witnessed BOP test occurs, and no less frequently than once every 30 days. The operator shall maintain at the drill rig an accessible record of gas detection system tests and calibrations.

(c) A failure in a gas detection system must be reported to the commission within 24 hours after the failure. The commission will, in its discretion, require well operations to be discontinued if a gas detection system fails. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.070 is repealed and readopted to read:

20 AAC 25.070. RECORDS AND REPORTS. The operator of a well shall

(1) keep a detailed accurate daily record of the actual drilling, completion, workover, repair, and plugging operations, and of the tests required by this chapter; the daily record ~~which~~ must be available for inspection at reasonable times by the commission

(A) at the well; and

(B) in the state for five years after the date of well abandonment;

(2) file with the commission before well completion or, if the well is not completed, before well abandonment a survey plat certified by a registered land surveyor showing the precise surface location of the well; however, only the first well drilled from a fixed platform or a multiple-well location must have a certified survey;

(3) file with the commission, within 30 days after completion, abandonment, or suspension of the well and within 30 days after completion or plugging of a well branch, if occurring at a different time, a complete well record on the Well Completion or Recompletion Report and Log (Form 10-407), including the tests required by this chapter and a summary of daily well operations reporting drilling depths, ~~zones of abnormal pressure~~ abnormally geo-pressured strata, lost circulation and other hole difficulties encountered, simulated kick drills, mud weight, and a brief description of principal items of work done, such as running and cementing casing, drill stem tests, BOP tests, coring, sidewall sampling, and logging; in the case of a well with multiple well branches, information pertaining to and filed under this paragraph with respect to a portion of a well need not be re-filed unless changed; and

(4) upon request of the commission after completion, abandonment, or suspension of the well or completion or plugging of a well branch, file with the commission a copy of the daily record required by (1) of this section. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.071(b) is repealed and readopted, and (c) and (d) are amended, to read:

(b) Within 30 days after completion, suspension, or abandonment of a well, whichever occurs first, and within 30 days after completion or plugging of a well branch, if occurring at a different time, the operator shall file with the commission, unless previously filed,

(1) a sepia and a reproduced copy of a complete mud log or a lithology log consisting of a detailed record and description of the sequence of strata encountered, including the kind and character of the rock and all shows of hydrocarbons; an electronic image file in a format acceptable to the commission may be substituted for the sepia;

(2) a complete set of washed and dried, legibly identified samples of all drill cuttings, as caught by the operator in accordance with good geological practices, consisting of a minimum of one-quarter cup in volume or three ounces in weight of cuttings for each sample interval;

(3) a lithologic description and, if available, photographs of ~~all~~ each conventional and sidewall core~~s~~; conventional core descriptions must include ~~all~~ apparent textural, fluid, and lithologic variations, including rock type, porosity, fractures, bedding plane attitudes, sedimentary structure, grain size, and presence of hydrocarbons;

(4) ~~a chip or~~ chips from each foot of recovered conventional core, except that chips need not be submitted until 30 days after the conventional core is analyzed; the chips must be representative of the one-foot interval, and must be approximately either one cubic inch in volume, or two ounces in weight;

(5) a list of the geologic markers encountered and the measured and true vertical depths of each marker;

(6) a sepia and a reproduced copy of all logs run, including common derivative formats such as tadpole plots of dipmeter data and borehole images produced from sonic or resistivity data, and including composite log formats; ~~except~~ C; however, copies of velocity surveys and experimental logs need not be included; an electronic image file in a format acceptable to the commission may be substituted for the sepia;

(7) a tape, diskette, or other electronic ~~media~~ medium acceptable to the commission and a verification listing of the digital data for all logs run, except velocity surveys and experimental logs; the verification listing must include ~~and~~ a written description of the logical and physical format of the digital data; ~~and~~ stet

(8) a copy of all drill stem test and production test data and charts; ¶(B) a brief summary of production tests, drill stem tests, wireline formation tests, and other formation tests performed, including test date, time, depth, duration, method of operation, recovered fluid ~~type(s)~~ types, fluid ~~amount(s)~~ amounts, gas-oil ratio, oil gravity, pressure, and choke size; ~~any~~ ¶(C) conventional and sidewall core analysis determinations, if any, of porosity, permeability, and fluid saturation; ~~and any~~ ¶(D) geochemical and formation fluid analyses obtained, if any. ~~the data described in this paragraph must be filed as soon as available if the 30-day filing period cannot be met.~~

(c) The commission will, in its discretion, waive or modify the requirements of [(a), (b)(1), AND (b)(2) OF] this section for a well if ~~they~~ those requirements would not significantly add to the geologic knowledge of the area in light of the information that is available from other wells in the area [~~FOR~~ DEVELOPMENT WELLS].

Del. underline beneath "For"

(d) In this section

(1) "experimental logs" means logs that are not commercially available from a well logging contractor [SO NEWLY DEVELOPED OR SO LIMITED OR SPECIALIZED IN APPLICATION

the following items, or a written request proposing a date for submitting those items, subject to commission approval of that date for timeliness, if those items are unavailable within the 30-day filing period set out in this subsection:
¶(A)

THAT THEY ARE NOT COMMONLY RUN ON PETROLEUM EXPLORATION OR DEVELOPMENT WELLS]; and

(2) "velocity survey" means a survey, the primary purpose of which is to determine velocity of seismic waves through formations penetrated by a well by measuring travel times of seismic pulses from or near the surface to geophones placed at [A SEISMOMETER LOWERED TO] various depths in the well. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.035

20 AAC 25.072(a), (b), and (d) are amended to read:

TEMPORARY

20 AAC 25.072. [SHUTDOWN OF DRILLING OR COMPLETION [WELL] OPERATIONS.

(a) If [CLIMATE, OPERATIONAL OR ENVIRONMENTAL CONCERNS, PRUDENCY, OR OTHER] circumstances prevent the continuation of the program approved on a Permit to Drill (Form 10-401) [THE DRILLING PERMIT], or if an operator wishes to change drill rigs [FOR RIG SUBSTITUTION], the operator shall apply to the commission for approval to shut down drilling or completion [WELL] operations. ~~The~~ decide whether to commission will [in its discretion] approve the temporary shutdown of drilling or completion [WELL] operations. The request for operation shutdown must be submitted on [THE LETTER OF APPLICATION MUST SET OUT A FULL JUSTIFICATION FOR THE SHUT DOWN AND BE ACCOMPANIED BY] an Application for Sundry Approvals (Form 10-403), providing a full justification for the shutdown, a description of [WHICH SETS OUT] the proposed condition of the wellbore [WELL BORE] upon shutdown of drilling or completion [WELL] operations, the approximate date when drilling or completion [WELL] operations will resume, and a proposed program for securing

temporarily. Based on the information received under this subsection, the [THE]

the well during the period of shutdown. An Application for Sundry Approvals is not required for planned shutdowns of well operations ~~that are stated~~ (, if those shutdowns are described) in the approved Permit to Drill.

(b) The operator shall file with the commission, within 30 days after ~~well~~ (operation) shutdown, a complete well record on a Report of Sundry Well Operations (Form 10-404), including a summary [COPY] of [THE] daily [REPORTS OF] well operations as described in [REQUIRED BY] 20 AAC 25.070(3) [20 AAC 25.070(a)(1)] and a copy of all logs run in the well as required by 20 AAC 25.071(b)(6) [20 AAC 25.071(b)(5)]. The commission will, in its discretion, waive the requirements of this subsection if drilling or completion [WELL] operations are to be resumed within 60 days (after operation shutdown).

. . .

Note to publisher: subsection (c) is unchanged.

(d) If well operations are not resumed within 12 months, ~~unless the commission grants an extension upon application of the operator,~~ the operator shall immediately proceed to abandon or suspend the well. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Upon application of the operator, the commission will extend the 12-month period, if the operator shows that operational circumstances beyond the operator's control prevent resumption within the 12-month period.

~~20 AAC 25.075 is amended to read:~~

~~20 AAC 25.075. OTHER WELLS IN DESIGNATED AREAS. There are areas in the state~~ where drilling [OPERATIONS] could unexpectedly encounter oil, gas, or hazardous substances at shallow depths. When the commission obtains sufficient evidence ~~to~~ define a specific area and the approximate depth range of the substances, it ~~will~~ issue an order that defines the area and stipulates [WILL PRESENT THE EVIDENCE, DEFINE THE AREA, AND STIPULATE] a drilling depth. After the issuance of such an order, any drilling [WELL DRILLED] in the defined area, for any purpose, that ~~exceeds the stipulated depth will require a Permit to Drill (Form 10-401) [DRILLING PERMIT] and~~

Publisher: Existing 20 AAC 25.075 is unchanged.

~~may be subject to the other requirements of this chapter. (Eff. 4/13/80, Register 74; am / / ,~~

Register __)

~~Authority: AS 31.05.030~~

20 AAC 25.080(a) - (e) and (h)(1) are amended, and (f) is repealed and readopted, to read:

(a) A person may not dispose of drilling waste through the annular space of a well unless authorized by the commission under this section. The [AN] operator of a well permitted under AS 31.05.090 may request authorization for the [SUCH A] disposal of drilling waste through the well's annular space by filing with the commission [IN AN APPLICATION FOR A PERMIT TO DRILL (FORM 10-401) OR] an Application for Sundry Approvals (Form 10-403) supplemented with ~~any~~ additional information as required under this section.

(b) A request for authorization under this section must include the following information or refer to that information if that information is already on file with the commission:

(1) the annulus to be used for disposal [A DESIGNATION OF THE WELL THAT WILL RECEIVE DRILLING WASTE];

. . .

(3) a stratigraphic description of the interval exposed to the open annulus and other information sufficient to support a commission finding that the waste will be confined and will not come to the surface or, except to the extent allowed under (e)(1) of this section, contaminate freshwater [THE DEPTH AND THICKNESS OF THE RECEIVING ZONE AND THE CONFINING ZONE, AND SUFFICIENT INFORMATION TO DEMONSTRATE CONFINEMENT];

. . .

(5) the ~~type(s)~~ types and [AN ESTIMATE OF THE] maximum volume of waste to be disposed of and the estimated density of the waste slurry [TO BE DISPOSED];

. . .

(8) details that show that the shoe of the outer casing is set below the base of permafrost, if present, and any freshwater aquifer, other than freshwater excepted under (e)(1) of this section, [AND PERMAFROST, IF PRESENT,] and is adequately cemented [WITH SUFFICIENT CEMENT] to provide zone isolation; the information relied upon and submitted must include (A) cementing records and (B) a cement quality log or formation integrity test records;

(9) details that show that the inner and outer casing strings have sufficient strength in collapse and burst to withstand the anticipated pressure of disposal operations; [AND]

(10) the downhole pressure obtained during a formation integrity test conducted below the outer casing shoe;

(11) identification of ~~any~~ the hydrocarbon zones, if any, above the depth to which the inner casing is cemented;

(12) the duration of the disposal operation, not to exceed 90 days;

(13) whether ~~any~~ drilling waste has previously been disposed of in the annular space of the well and, if so, a summary of the ~~date(s)~~ dates of the disposal ~~operation(s);~~ operations, the ~~volume(s)~~ volumes of waste disposed of and the ~~well(s)~~ wells where the drilling waste was generated;

(14) the well where the drilling waste to be disposed of was or will be generated;

(15) if the operator proposes not to comply with a limitation established in (d) of this section, an explanation of why compliance would be imprudent; ~~and~~

(16) any additional data required by the commission to confirm containment of drilling waste.

(c) The commission will [in its discretion,] authorize an annular disposal operation [OF DRILLING WASTE THROUGH THE ANNULAR SPACE OF A WELL PERMITTED UNDER AS 31.05.090] described in the Application for Sundry Approvals, as that application has been ~~(as~~ supplemented under this section), and subject to any modifications prescribed by the commission, if the commission [it] determines that the

(1) waste will be adequately confined [CONTAINED IN A SUITABLE RECEIVING ZONE];

(2) disposal will not

(A) contaminate freshwater, except to the extent allowed under (e)(1) of this section;

. . .

(C) impair the mechanical integrity of any [THE] well [USED FOR DISPOSAL]; or

. . .

(d) Unless the operator demonstrates[, BY WRITTEN APPLICATION,] that compliance [it] is imprudent to comply [with a limitation established in (1) - (4) of this subsection is imprudent], the commission will not authorize disposal of drilling waste

. . .

(3) into a hydrocarbon-bearing stratum; or

. . .

On a case-by-case basis, and as the commission considers necessary to ensure that the standards in (c) of this section are met, the commission will impose conditions upon an authorization to dispose of drilling waste under this section.

(e) In addition to any other conditions that the commission in its discretion imposes on a case-by-case basis, an authorization to dispose of drilling waste under this section is subject to the following conditions:

(1) drilling waste may not be disposed of into freshwater, unless the #(A) ~~except~~ freshwater is identified in the Application for Sundry Approvals; and #(B) ~~request for authorization that the~~ commission finds that the freshwater has a total dissolved solids content of more than 3,000 mg/l and is not reasonably expected to supply a public water system; the commission will, in its discretion, provide 15 days notice and the opportunity for a public hearing in accordance with 20 AAC 25.540 before making that finding;

(2) the downhole disposal pressure may not exceed the downhole pressure obtained during the formation integrity test conducted below the outer casing shoe, or a higher pressure specified in the authorization upon the commission's finding that the higher pressure will not cause drilling waste to migrate above the confining zone;

(3) if drilling waste appears above the confining zone, the operator shall immediately cease disposal, notify the commission, and take appropriate remedial action; [and]

(4) [(2)] ~~(4[2])~~ if the commission notifies the operator that disposal operations pose a threat to well integrity, safety, oil or gas recovery, or freshwater, except to the extent allowed under (1) of this subsection, the operator shall immediately cease disposal and take appropriate remedial action as approved or required by the commission.

(f) For each annular disposal operation authorized under this section, the operator shall report the following information to the commission on a Report of Annular Disposal (Form 10-423) not later than 30 days after the end of the period authorized for the disposal operation:

(1) the dates when disposal began and ended; ~~and~~

(2) the volume of drilling waste disposed of in each of the following categories:

(A) the aggregate of drilling wastes described in (h)(1) of this section;

(B) the aggregate of drilling wastes described in (h)(2) of this section; and

(C) each substance determined to be a drilling waste under (h)(3) of this section.

. . .

Note to publisher: subsection (g) is unchanged.

(h) In this section, "drilling waste" means the following substances, unless identified as a hazardous waste in 40 C.F.R. [Part] 261:

(1) drilling mud, drilling cuttings, reserve pit fluids, cement-contaminated drilling mud, completion fluids, [AND] formation fluids associated with the act of drilling a well permitted under 20 AAC 25.005, and any added water needed to facilitate pumping of drilling mud~~s~~ or drilling cuttings;

. . .

Note to publisher: subsection (i) is unchanged.

(Eff. 9/22/96, Register 139; am ___/___/___, Register ___)

Authority: AS 31.05.030

Delete underline beneath period

ARTICLE 2.
ABANDONMENT AND PLUGGING.

Keep as is published, on same line as "ARTICLE 2", and centered.

Section
105. [PLUGGING, SUSPENSION, AND] Abandonment of wells
107. Plugging well branches
110. Suspended wells
112. Well plugging requirements
115. Shut-in wells
120. Well abandonment marker
140. Water wells
170. Onshore location clearance
172. Offshore location clearance

20 AAC 25.105 is repealed and readopted to read:

20 AAC 25.105. ABANDONMENT OF WELLS. (a) All wells that have been permitted on a property under 20 AAC 25.005 must be abandoned before expiration of the owner's rights in that property or if, after notice and hearing, the commission orders abandonment for safety reasons or because the operator has effectively abandoned operations prior to the expiration of the lease. If the owner is the landowner, all wells that have been permitted on a property by 20 AAC 25.005 must be abandoned within one year following permanent cessation of the operator's oil and gas activity within the field where the wells are located or according to an abandonment schedule approved by the commission, unless the wells are earlier abandoned for safety reasons.

(b) A well drilled onshore or from a fixed offshore platform must be abandoned before removal of the drill rig ~~from location~~ unless the well is completed as an oil, gas, or service well or is suspended, or unless well operations are shut down in accordance with 20 AAC 25.072. ~~All~~ Each well drilled from a fixed offshore platform must be abandoned before the platform is removed or dismantled.

(c) A well drilled offshore from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel must be abandoned before removal of the drill rig ~~from location~~ unless

(1) the well is completed as an oil, gas, or service well; or

(2) subsea equipment for well re-entry is properly installed ~~in a manner approved by the commission~~ and either the well is suspended or well operations are shut down in accordance with 20 AAC 25.072.

(d) A well drilled from a beach, artificial island, or shifting natural island must be abandoned before removal of the drill rig ~~from location~~ unless the well is completed as an oil, gas, or service well or is suspended, or unless well operations are shut down in accordance with 20 AAC 25.072 and plans for maintaining the integrity of the location are approved by the commission.

(e) An Application for Sundry Approvals (Form 10-403) must be ~~filed with~~ submitted to and approved by the commission before work is begun to abandon a well, except that oral approval may be obtained from the commission if it is followed within ~~10~~ three days by the ~~filing~~ submission of an Application for Sundry Approvals for final approval by the commission. The commission will attach conditions to its Approval ~~will be conditioned~~ as necessary to protect freshwater and hydrocarbon resources. ~~An~~ The Application for Sundry Approvals must include

(1) the reason for abandoning the well; and

(2) a statement of proposed work, including

(A) information on abnormally geo-pressured strata;

(B) the manner of placement, kind, size, and location, by measured depth, of existing and proposed plugs;

(C) plans for cementing, shooting, testing, and removing casing;

(D) if the Application for Sundry Approvals is ~~filed~~ submitted after beginning work, the name of the representative of the commission who provided oral approval, and the date of the approval; and

(E) ~~all~~ other information pertinent to abandonment of the well ~~information~~. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.107. PLUGGING WELL BRANCHES. (a) An operator may plug a well branch before abandoning or suspending the well. If a well branch has not been completed, the operator shall plug the well branch before removal of the drill rig ~~from location~~, unless well operations are shut down in accordance with 20 AAC 25.072.

(b) An Application for Sundry Approvals (Form 10-403) must be ~~filed with~~ submitted to and approved by the commission before work is begun to plug a well branch, except that oral approval may be obtained from the commission if it is followed within three days by the submission of an Application for Sundry Approvals for final approval by the commission. The provisions of 20 AAC 25.105(e) apply to the application, except that instead of including the reason for abandoning the well, the application must include the reason for plugging the well branch and the reason for not immediately abandoning or suspending the well.

(c) The provisions of 20 AAC 25.112(a) - (c) and (e) - (i) apply to plugging a well branch.

(d) This section does not apply to the temporary plugging of a well branch for production control purposes. (Eff. __/__/__, Register ____)

Authority: AS 31.05.030

20 AAC 25.110 is repealed and readopted to read:

20 AAC 25.110. SUSPENDED WELLS. (a) ~~Where~~ IF allowed under 20 AAC 25.105, the commission will, ~~in its discretion,~~ upon application by the operator under (b) of this section, approve the suspension of a well ~~that has not been completed~~ if

(1) the well

(A) encounters hydrocarbons of sufficient quality and quantity to indicate that the well is capable of producing in paying quantities, as reasonably demonstrated by well tests or interpretive formation evaluation data; for purposes of this paragraph, "paying quantities" means quantities sufficient to yield a return in excess of operating costs;

(B) is a candidate for redrilling;

(C) has potential value as a service well; or

(D) is located on a pad or platform with active producing or service wells; and

(2) the operator justifies to the commission's satisfaction why the well should not be ~~completed or~~ abandoned; and, if the well is not completed, why the well should not be completed; sufficient reasons include the

(A) unavailability of surface production or transportation facilities;

(B) imprudency of security maintenance of a completed well in a shut-in status;

(C) need for pool delineation and evaluation to determine the prudency of pool development.

(b) An Application for Sundry Approvals (Form 10-403) must be ~~filed with~~ submitted to and approved by the commission before plugging operations are begun in a well for which suspension is proposed, except that oral approval may be obtained from the commission if it is followed within ~~10~~ three days by the ~~filing~~ submission of an Application for Sundry Approvals for final approval by the commission. Approval will be conditioned as necessary to protect freshwater and hydrocarbon resources. An Application for Sundry Approvals must include

(1) the reason for suspending the well and information showing that the applicable criteria for suspension under (a) of this section have been met; and

(2) a statement of proposed work, including

(A) information on abnormally geo-pressured strata;

(B) the manner of placement, kind, size, and location, by measured depth, of existing and proposed plugs;

(C) plans for cementing, shooting, testing, and removing casing;

(D) if the Application for Sundry Approvals is ~~filed~~ submitted after beginning work, the name of the representative of the commission who provided oral approval, and the date of the approval; and

(E) ~~all~~ other information pertinent ~~information~~ to suspension of the well.

(1) for the period specified under AS 31.05.035(c), if the information is described in 20 AAC 25.071(b); or

(2) ~~for the time that the~~ information has value as a trade secret, if the information is not described in 20 AAC 25.071(b) but is determined by the commission to constitute a trade secret under AS 45.50.940.

(c) At the operator's request accompanying the submission, information ~~voluntarily~~ submitted to show that the applicable criteria for well suspension under (a) of this section have been met will be kept confidential ~~in accordance with 20 AAC 25.537~~.

(d) A well approved for suspension must be plugged in accordance with the requirements of 20 AAC 25.112, except that the requirements of 20 AAC 25.112(d) do not apply if

(1) a wellhead is installed or the well is capped with a mechanical device to seal the opening; and

(2) a bridge plug capped with 50 feet of cement or a continuous cement plug extending 200 feet within the interior casing string is placed at or above 300 feet below the surface; the commission will ~~in its discretion~~, waive the requirement of this paragraph for a development well drilled from a pad or platform, if the commission determines that the level of activity on the pad or platform assures adequate surveillance of that development well

(e) Until a suspended well has been abandoned or re-entered, the operator shall maintain the integrity of the location, provide the commission with a well status report every five years, and clear the location in accordance with 20 AAC 25.170(a)(2) or (b) or with 20 AAC 25.172(c)(2) or (d), as applicable ~~a manner approved by the commission~~. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.112. WELL PLUGGING REQUIREMENTS. (a) Plugging of the uncased portion of a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface. The minimum requirements for plugging the uncased portion of a wellbore are as follows:

(1) by the displacement method, a cement plug must be placed

(A) from 100 feet below the base to 100 feet above the top of all hydrocarbon-bearing strata;

(B) from the well's total depth to 100 feet above the top of all hydrocarbon-bearing strata;

(C) from the well's plugged back total depth to 100 feet above the top of all hydrocarbon-bearing strata, if all hydrocarbon-bearing, abnormally geo-pressured, and freshwater strata below are isolated; however, ~~except that~~ the commission will ~~in its discretion~~, if the commission determines that the objectives of this subsection will be met, approve plugging from the top of fill or the top of junk instead of from the plugged back total depth; or

(D) from 100 feet below the base to 50 feet above the base of each significant hydrocarbon-bearing stratum and from 50 feet below the top to 100 feet above the top of each significant hydrocarbon-bearing stratum;

(2) by the displacement method, a cement plug must be placed from 100 feet below the base to 50 feet above the base of each abnormally geo-pressured strat~~a~~ and from 50 feet below the top to 100 feet above the top of each ~~the~~ abnormally geo-pressured strat~~a~~; ~~and~~

(3) by the displacement method, a cement plug must be placed from 150 feet below the base to 50 feet above the base of the deepest freshwater stratum.

(b) Plugging of a well must include effectively segregating uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. The minimum requirement for plugging to segregate uncased and cased portions of a wellbore is one of the following ~~as follows~~:

(1) by the displacement method, a continuous cement plug must be placed from 100 feet below to 100 feet above the casing shoe;

(2) by the downsqueeze method using a retainer set no less than 50 feet but no more than 100 feet above the casing shoe, a volume of cement sufficient to fill the wellbore from the retainer to 100 feet below the casing shoe must be pumped through the retainer, and cement must be pumped above the retainer to cap it with a 50 foot cement plug; ~~or~~

(3) by the downsqueeze method using a production packer set no less than 50 feet but no more than 500 feet above the casing shoe, a volume of cement sufficient to fill the wellbore from 100 feet below the casing shoe to the packer must be pumped through the packer, and cement must be pumped above the packer to cap it with a 50 foot cement plug.

(c) Plugging of cased portions of a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface. The minimum requirements for plugging cased portions of a wellbore are as follows:

(1) perforated intervals must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the base to 50 feet above the base of the perforated interval and from 50 feet below the top to 100 feet above the top of the perforated interval;

(B) by the displacement method, a cement plug placed from the well's total depth to 100 feet above the top of the perforated interval;

(C) by the displacement method, a cement plug placed from the well's plugged-back total depth to 100 feet above the top of the perforated interval, if all hydrocarbon-bearing, abnormally geo-pressured, and freshwater strata below are isolated; ~~except that~~ however, the commission will ~~, in its discretion,~~ approve plugging from the top of fill or the top of junk instead of from the plugged-back total depth, if the commission determines that the objectives of this subsection will be met

(D) by the downsqueeze method using a cement retainer or production packer set no less than 50 feet but no more than 500 feet above the perforated interval, a volume of cement pumped through the retainer or packer sufficient to fill the wellbore from 100 feet below the base of the perforated interval to the retainer or packer; ~~or~~

(E) if the perforations are isolated from open hole below, a mechanical bridge plug set no more than 50 feet above the top of the perforated interval, and either a minimum of

75 feet of cement placed on top of the plug by the displacement method or a minimum of 25 feet of cement placed on top of the plug with a dump bailer;

(2) casing stubs within outer casing must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the stub to 100 feet above the stub;

(B) by the downsqueeze method using a retainer set 50 feet above the stub, a volume of cement pumped below the retainer sufficient to fill the casing stub with 150 feet of cement, and cement pumped above the retainer to cap it with a 50 foot cement plug; ~~or~~

(C) if the casing stub annulus is cemented, a mechanical bridge plug set no more than 25 feet above the casing stub, and either a minimum of 75 feet of cement placed on top of the plug by the displacement method or a minimum of 25 feet of cement placed on top of the plug with a dump bailer;

(3) ~~where~~ If freshwater is present, the smallest diameter casing string extending to the surface must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the depth of the surface casing shoe to 100 feet above the depth of the shoe; ~~or~~

(B) a mechanical bridge plug set 100 feet below the depth of the surface casing shoe and at least 200 feet of cement placed on top of the plug.

(d) Plugging of the surface of a well must meet the following requirements:

(1) by the displacement method, a cement plug at least 150 feet in length, with the top of the cement no more than ~~5~~ Five feet below original ground level onshore, or between 10 and 30 feet below the mudline datum offshore, must be placed within the smallest diameter casing string; ~~and~~ (2) either

~~(2)~~ (A) all annular space open at the surface onshore, or in communication with open hole and extending to the mudline datum offshore, must be plugged with cement to seal the annular space in a manner satisfactory to the commission; or

~~(3)~~ (B) all casing interior to the surface casing must be recovered to a depth of 100 feet or more below the original ground level onshore or the mudline datum offshore and the casing stubs plugged with cement as provided in (c)(2)(A) of this section; if the cement plug is extended to within the distance from the surface specified in (1) of this subsection, the requirement of (1) of this subsection ~~will~~ need not be ~~deemed~~ met.

(e) Cement used for plugging within zones of permafrost must be designed to set before freezing and have a low heat of hydration.

(f) Each of the respective intervals of a wellbore between the various plugs must be filled with fluid of sufficient density to exert a hydrostatic pressure exceeding the greatest formation pressure of permeable formations in the intervals between the plugs at the time of abandonment.

(g) Except for surface plugs, the operator shall record the actual location and integrity of cement plugs, cement retainers, or bridge plugs required by this section ~~by~~ using one of the following methods, which in the case of a cement retainer or bridge plug may be performed before cement is placed on top of the plug:

(1) placing sufficient weight on the plug to confirm its location and to confirm that the ~~cement or mechanical~~ plug has set and a competent plug is in place~~, in which event testing of the cement placed above the bridge plug or retainer is not required~~; ~~or~~

(2) testing the plug to hold a surface pressure of 1,500 psig or 0.25 psi/ft multiplied by the true vertical depth of the casing shoe, whichever is greater, and tagging the plug to confirm location; however, surface pressure ~~must~~ may not subject the casing to a hoop stress that will exceed 70 percent of the minimum yield strength of the casing.

(h) ~~A minimum of~~ At least 24 hours notice of plugging operations must be given to the commission so that a representative of the commission can witness the operations.

(i) The commission will, in its discretion, approve a variance from the requirements of this section if the variance provides for at least equally effective plugging of the well and prevention of fluid movement into sources of hydrocarbons or freshwater. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.115. SHUT-IN WELLS. (a) No later than March 31 of each year, an operator shall file with the commission a report on ~~all~~ completed development or service wells that have been shut in for 365 days or longer as of January 1 of that year. The report must provide

(1) the current known mechanical condition of the well, including the condition of ~~all~~ installed tubing and casing strings;

(2) the date the well was shut in and the circumstances surrounding the decision to shut in the well; and

(3) an analysis of the future utility of the well.

(b) The commission will ~~in its discretion,~~ require an operator of a shut-in well to file additional information as the commission considers necessary to ensure that freshwater and hydrocarbon sources are protected. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.120 is repealed and readopted to read:

20 AAC 25.120. WELL ABANDONMENT MARKER. (a) The exact surface location of an abandoned well must be shown by a steel well abandonment marker. The marker must be a marker plate meeting the requirements of (b) of this section. However, upon the request of ~~except that if a marker post is requested by~~ the surface owner, and if ~~approved by~~ the commission determines that a marker post does not create a hazard or obstacle, the commission will approve ~~the marker must be~~ a marker post meeting the requirements of (c) of this section.

(b) A marker plate must be

(1) at least 1/4 inch thick;

(2) at least 18 ~~eighteen~~ inches square or in diameter; and

(3) welded to and must cover ~~covering~~ the outermost casing string.

(c) A marker post must

(1) be at least four inches in diameter and at least 10 feet long;

(2) be set in cement inside well casing or firmly welded with supporting fillets to the top of a steel plate secured to the casinghead or casing stub;

(3) extend from four to six feet above final ground level; and

(4) be closed at the top with a screw cap, welded plate, or cement plug.

(d) The following information ~~name of the operator, Permit to Drill number(s), and API number(s)~~ must be bead-welded directly to the marker:

(e) The commission will, in its discretion, inspect the marker to verify proper installation and well information at the time of the location clearance required under 20 AAC 25.170.

¶ (1) the name of the operator;
¶ (2) the number that the commission has, under 20 AAC 25.040(b), assigned to the Permit to Drill for the well;
¶ (3) the name designated for the well by the operator under 20 AAC 25.005(f);
¶ (4) the API number for the well, with any suffix appended to the number under 20 AAC 25.005(f).

(f) This section does not apply to abandoned wells drilled offshore. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

and is subject to commission approval, based upon the commission's determination that the proposed use as a freshwater well is bona fide

20 AAC 25.140 is amended to read:

20 AAC 25.140. WATER WELLS. If a well drilled onshore for oil or gas is to be plugged and abandoned, but is safe for use who wishes to use the well as a freshwater well must obtain [,] may safely be used as a freshwater well, and such a use is desired by a person, written authorization to do so authority for this action must be obtained from the landowner and the owner of the surface rights. The authorization must provide for the authorized person's assumption of full responsibility for the final plugging of the water well. This authorization must be filed with and approved by the commission. After Following the commission's approval of the plugging of the well to protect the freshwater bearing strata to a depth after the commission's approval of approved by the commission for conversion to a water well, and for compliance with 20 AAC 25.170(a)(2) or 20 AAC 25.172(c) or (c) the location clearance, the operator is relieved of further obligation under the operator's bond. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.170 is repealed and readopted to read:

20 AAC 25.170. ONSHORE LOCATION CLEARANCE. (a) At or the time that After a well drilled onshore ~~has been~~ is abandoned and before the earlier of one year after well abandonment or the expiration of the owner's rights in the property,

(1) the operator shall remove the wellhead equipment and casing to a depth at least three feet below original ground level and install a well abandonment marker in accordance with 20 AAC 25.120; and

(2) ~~except to the extent that~~ unless the operator demonstrates to the commission that the surface owner has authorized a different disposition ~~has been approved by another government agency having jurisdiction or authorized by the surface owner~~ to facilitate a genuine beneficial use, the operator shall

(A) remove all materials, supplies, structures, and installations from the location;

(B) remove all loose debris from the location;

(C) fill and grade all pits or close them in another manner approved by the commission as adequate to protect public health and safety; and

(D) leave the location in a clean and graded condition.

(c) ~~(b)~~ The commission will modify the time period set out in (a) of this section as follows ~~, in its discretion, grant an extension of time beyond one year after well abandonment~~:

(1) if a longer period is approved by the Department of Natural Resources, as to a state lease, or by the United States Department of the Interior, as to a federal lease; ~~or~~

(2) ~~upon receipt of~~ an Application for Sundry Approvals (Form 10-403) stating

(A) a request for a specific extension not to exceed one year;

(B) the reason an extension is necessary;

(C) a description of location clearance progress; and

(D) the expiration date of the owner's rights to enter the location.

~~(c)~~ (d) After the work required under (a) of this section has been completed at a location, the commission will, in its discretion, conduct an on-site inspection to verify the location condition at the time of inspection, including the presence of a proper well marker if above ground, as required under 20

approves a time period beyond one year after well abandonment for location clearance, the commission will set an identical time period for compliance with (a) of this section

the commission will grant an extension of time beyond one year after well abandonment, if the commission determines that the extension does not threaten public health or safety or the surface owner's interests, and that the operator does not seek an extension for purposes of delay; to seek an extension under this paragraph, the operator must submit

Publisher: Keep AAC title number together with the rest of the citation, on next page.

¶(b) If a well described in (a) of section is located on state or federal land, and if the agency acting on behalf of the state or federal government as lessor approves a disposition different from that required under (a)(2) of this section, the commission will accept that disposition instead of requiring the operator to comply with (a)(2) of this section.

AAC 25.120, and will provide the operator a report of the inspection. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.172 is repealed and readopted to read:

20 AAC 25.172. OFFSHORE LOCATION CLEARANCE. (a) ~~After~~ No later than the time that all wells drilled from a fixed offshore platform ~~have been~~ are abandoned and ~~when~~ the platform is removed or dismantled, the operator shall remove all well casing to a depth at least one foot below the mudline. The operator shall provide the commission with verification, using appropriate means approved by the commission, that the casing has been removed as required. If ~~another government agency having jurisdiction~~ an agency acting on behalf of the state or federal government as lessor approves leaving the platform in place after well abandonment, the commission will accept that approval and waive requirements of this subsection ~~will be waived~~.

(b) When a well ~~has been~~ is abandoned from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel, the operator shall remove the wellhead equipment, casing, piling, and other obstructions to a depth at least five feet below the mudline before removing the drill rig ~~from location~~, unless otherwise approved by the commission as adequate to protect public health and safety. The operator shall provide the commission with verification, using appropriate means approved by the commission, that the requirements of this subsection have been met.

(c) ~~After~~ At or after the time that a well drilled from a location on a beach, artificial island, or shifting natural island ~~location has been~~ is abandoned, and before the earliest of one year after well abandonment, the time that the operator stops activities necessary to ensure the integrity of the location, or the expiration of the owner's rights in the property,

(1) the operator shall remove the wellhead equipment and casing to a depth at least five feet below the mudline datum; and

(2) ~~except to the extent that~~ unless the operator demonstrates to the commission that the surface owner has authorized a different disposition ~~has been approved by another government agency having jurisdiction or authorized by the surface owner~~ to facilitate a genuine beneficial use, the operator shall

(A) remove all materials, supplies, structures, and installations from the location;

(B) remove all loose debris from the location;

(C) fill and grade all pits or close them in another manner approved by the commission as adequate to protect public health and safety; and

(D) leave the location in a clean and graded condition.

(e) ~~(d)~~ ~~The commission will, in its discretion, grant an extension of time beyond one year after well abandonment to comply with (c) of this section if a longer period is approved by~~ If the Department of Natural Resources, as to a state lease, or by the United States Department of the Interior, as to a federal lease, approves a time period beyond one year after well abandonment for location clearance, the commission will set an identical time period for compliance with (c) of this section.

(f) ~~(e)~~ After the work required under (c) of this section has been completed at a location, the commission will, in its discretion, conduct an on-site inspection to verify the location condition at the time of inspection ~~and~~ If the commission conducts an inspection, the commission will provide the operator a report of the inspection. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

(d) If a well described in (c) of this section is located on state or federal land, and if the agency acting on behalf of the state or federal government as lessor approves a disposition different from that required under (c)(2) of this section, the commission will accept that disposition instead of requiring the operator to comply with (c)(2) of this section

ARTICLE 3.
PRODUCTION PRACTICES.

Section
200. Production equipment
205. Notification of uncontrolled release [ACCIDENTAL LOSS] of oil or gas
210. Multiple completions [COMPLETION] of wells
215. Commingling of production
225. Potential of gas wells
228. Production measurement equipment for custody transfer
230. Measurement, allocation, and reporting of well production [PRODUCTION MEASUREMENT]
235. Gas disposition
240. Gas-oil ratio [RATIOS] limitations
245. Common production facilities
250. (Repealed)
252. Underground disposal of [WATER AND OTHER] oil field wastes [WASTE FLUIDS] and underground storage of [LIQUID] hydrocarbons
255. (Repealed)
260. Illegal production
265. Automatic shut-in equipment
270. Initial reservoir properties [PRESSURE]
275. (Repealed) [RESERVOIR FLUID PROPERTIES]
280. Workover operations
285. Secondary well control for tubing workover operations: blowout [BLOWOUT] prevention equipment requirements [FOR WORKOVER OPERATIONS]
286. Well control requirements for workstring service operations
287. Well control requirements for wireline operations
288. Well control requirements for other service operations
290. Operations producing hydrogen sulfide

20 AAC 25.200 (a) and (d) are amended to read:

(a) Surface production equipment must be installed to control, separate, clean, [AND] gather, and carry to the point of custody transfer or other disposition in a safe manner all produced oil, gas, and water. All equipment must be installed, operated, and maintained in accordance with good oil field engineering practices [ESTABLISHED INDUSTRY PRACTICE].

. . .

Note to publisher: subsections (b) and (c) are unchanged.

(d) All producing wells capable of unassisted flow must be completed with downhole production equipment consisting of suitable tubing and a packer [which] effectively [isolates] the tubing-casing annulus from fluids being produced, unless [otherwise specifically approved by] the commission.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.205 is amended to read:

20 AAC 25.205. NOTIFICATION OF UNCONTROLLED RELEASE [ACCIDENTAL LOSS] OF OIL OR GAS. (a) [The] commission [must be immediately notified by the operator] of any uncontrolled release exceeding 10 barrels of oil or 1000 mscf of [ACCIDENTAL LOSS OF CRUDE OIL OR NATURAL] gas [or both] from a well or production handling operation or any uncontrolled release that results in a shut-down of operations at a production facility.

(b) Within five days after the release [ACCIDENTAL LOSS], the operator shall submit a preliminary written report to the commission, followed by a final written report within 30 days, detailing the following facts:

(1) [time of] incident;

(2) [location where] incident took place;

(3) [volumes of ~~oil and gas released and recovered~~ [CRUDE OIL AND OF NATURAL GAS LOST];

(4) [cause of the release [LOSS];

(5) ~~responsive actions taken to prevent further release~~ responsive actions taken [AND PLANNED] to prevent additional releases [~~ACTIONS TAKEN AND PLANNED TO PREVENT~~ FURTHER LOSS]; and

(6) ~~any~~ plans, actions, equipment, or procedural changes to prevent or minimize the risk of future releases [EQUIPMENT OR PROCEDURAL CHANGES, IF APPLICABLE, TO PREVENT THE LOSS FROM RECURRING]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.210 is amended to read:

20 AAC 25.210. MULTIPLE COMPLETIONS [COMPLETION] OF WELLS. A well may not be completed in more than one pool without approval of the commission. The commission will ~~in its discretion~~, require evidence of complete separation of flowstreams from separate pools, as ascertained by a pressure test or other acceptable test [TESTS] conducted at the time the packers are set. Subsequently, if packer leakage is suspected, the commission will require [in its discretion, request] the operator to provide proof of complete separation of the pools involved in the completions or make a packer leakage test. ~~A minimum of~~ At least 24 hours notice [NOTIFICATION] must be given so that the packer leakage test may be witnessed by a representative of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.215 is amended to read:

20 AAC 25.215. COMMINGLING OF PRODUCTION. (a) On the surface, the production from one pool may not be commingled with that from another pool except if [when] the quantities from each pool are determined by [AT LEAST] monthly well tests or by another method of determining pool production approved by the commission.

(b) Commingling of production within the same wellbore [WELL BORE] from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission (1) finds that waste will not occur, and that production from separate pools can be properly allocated; [,] (2) and [the commission] issues an order providing for commingling for [ALL] wells completed from these pools within the field. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.225 is amended to read:

20 AAC 25.225. POTENTIAL OF GAS WELLS. (a) All gas wells must be tested by [the] multi-point back-pressure method before regular [SIGNIFICANT] production. The commission will ~~in its discretion~~ approve alternative test methods if the commission determines that they provide substantially the same information as the multi-point back-pressure method. The test results and calculations must be reported to the commission on the [FORM ENTITLED] Gas Well Open Flow Potential Test Report (Form 10-421) within 30 days after the test. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.228 is repealed and readopted to read:

20 AAC 25.228. PRODUCTION MEASUREMENT EQUIPMENT FOR CUSTODY TRANSFER. (a) ~~All~~ Each hydrocarbon production must be measured in accordance with this section before severance from the property or unit where produced. Crude oil sample collection, handling, and analysis in connection with production measurement must be performed in conformance with relevant parts of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998.

(b) Hydrocarbon measurement equipment ~~and gas meter runs~~ must be fabricated, installed, and maintained in conformance with relevant parts of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998.

(c) If a totalizer system is microprocessor-based, it must be equipped with

(1) a back-up battery or uninterruptible power supply that provides for operation during times of system power failures; or

(2) a backup pulse accumulator or other approved equivalent that counts and preserves meter pulses in the event of a power or computer failure.

(d) If a microprocessor totalizing system is used, the reports of net measured volumes for the custody transfer intervals must, at a minimum, show the raw or factored pulses, average temperature, pressure, relative density or gravity, meter factors, correction factors, and ~~the~~ gross standard volumes.

(e) Fluid samplers must be ~~either~~ a probe or a slipstream type. The sampler location must be located in conformance with Chapter 8 of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998.

(f) Functional bypasses may not be connected around custody transfer or sales measurement equipment such as tanks, meters, gauges, sample containers, or gas meter runs.

(g) Oil meters must be periodically proved and gas meters must be periodically calibrated in conformance with relevant parts of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998, and on a schedule approved by the commission according to the volumes being metered and the need to quickly detect inaccuracies. In metering operations, the actual throughput or gross standard volume must be determined by multiplying the indicated volume, corrected for temperature and pressure, by the meter factor obtained during proving. If a meter factor differs by more than 0.0025 from the previously obtained meter factor, from the applicable value on the meter curve, or from a baseline factor in the absence of a meter curve, the meter must be taken out of service or corrective action performed to bring the meter factor within the required tolerance.

(h) Provers used for certification of custody transfer meters must be calibrated by the waterdraw method, master meter method, or other commission-approved equivalent, in conformance with relevant parts of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998.

(i) The commission will, in its discretion, require ~~a minimum of~~ at least 24 hours notice before the following operations so that a representative of the commission can witness the operation:

(1) calibration of provers used for certification of custody transfer meters;

(2) crude oil sample collection, handling, and analysis in connection with production measurement;

(3) oil meter proving and volume calculations;

(4) gas meter calibration and volume calculations.

(j) Upon request, the commission will, in its discretion, approve a variance from the requirements of this section if the variance will result in equal or improved accuracy in measuring hydrocarbons severed from the property or unit.

(k) In this section, "relevant parts of the API *Manual of Petroleum Measurement Standards*" means the API *Manual of Petroleum Measurement Standards* excluding Chapter 19 in its entirety and excluding those portions of Chapter 11 other than Chapter 11.1, Volume 1; Chapter 11.1, Volume X; Chapter 11.2.1; Chapter 11.2.2; Addendum to Section 2.2; and Chapter 11.2.3. The relevant parts of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998, are adopted by reference. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the relevant parts of the API *Manual of Petroleum Measurement Standards* may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

20 AAC 25.230 is repealed and readopted to read:

20 AAC 25.230. MEASUREMENT, ALLOCATION, AND REPORTING OF WELL PRODUCTION. (a) Production from each well must be measured ~~or allocated~~ to determine the quantities of oil, gas, and water, using equipment and techniques acceptable to the commission as accurate and reliable. Production from a group of wells, property, or unit may be measured as a whole, if individual well test facilities and allocation methods acceptable to the commission are employed to test and allocate production to each well at least monthly.

(b) The volumes of produced gas, oil, and water must be reported monthly for each well on the Monthly Production Report (Form 10-405) or by an alternate format, including electronic means, acceptable to the commission. A well must be identified by its API number and the name designated by the operator under 20 AAC 25.005(f). Production from a well with multiple well branches must be

aggregated and reported under the API number and well name of the primary wellbore. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.235 (a) is ~~amended~~ repealed and readopted to read:

(a) For each production facility the operator shall compile and report monthly gas disposition and acquisition on the Facility Report of Produced Gas Disposition (Form 10-422). The operator shall report gas acquisition or disposition ~~as~~ by category, as follows: (1) gas sold; (2) gas reinjected; (3) gas flared or vented; (4) gas used for lease operations other than ~~flared or vented~~ flaring or venting; [OR] (5) natural gas liquids (NGLs) produced; (6) gas purchased; (7) gas transferred; ~~or~~ (8) other. If a facility's production comes from multiple pools, the operator shall allocate production between each producing pool as a percentage of the total volume of gas that the facility handled for the month.

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Publisher: The rest of 20 AAC 25.235 is unchanged.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 1/1/95, Register 132; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095 AS 31.05.170

20 AAC 25.240 is repealed and readopted to read:

20 AAC 25.240. GAS-OIL RATIO LIMITATIONS. (a) An oil well may not be produced if the gas-oil ratio of the well exceeds the original solution gas-oil ratio of the crude within the producing pool by more than 100 percent.

(b) Upon written application by an operator, the commission will, in its discretion, waive the limitation in (a) of this section if

(1) an enhanced recovery project ~~is operating~~ operates in the pool from which the well is producing;

(2) produced gas is being returned to the same pool; or

(3) acquisition of pool performance data is necessary to determine an optimum reservoir management program.

(c) ~~E~~xceptions to the limitation in (a) of this section for conditions other than those specified in (b) of this section ~~will, in the commission's discretion, be granted~~ in accordance with 20 AAC 25.540 only after application, notice, and an opportunity for public hearing.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.245 is amended to read:

20 AAC 25.245. COMMON PRODUCTION FACILITIES. Common facilities may be used to receive the production from any number of wells or pools if appropriate tankage or other measuring equipment is installed so that production from each well can be [ACCURATELY] determined by means approved by the commission in accordance with 20 AAC 25.228 [AT LEAST ONCE EACH MONTH].

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.252 (a) - (c), ~~(e)~~ and (f), ~~and (h)~~ (e), and (h) are amended, (d) ~~is~~ subsections repealed and readopted, and ~~a~~ new (k) ~~is~~ and (l) are added, to read:

20 AAC 25.252. UNDERGROUND DISPOSAL OF [WATER AND OTHER] OIL FIELD WASTES [WASTE FLUIDS] AND UNDERGROUND STORAGE OF [LIQUID] HYDROCARBONS.

(a) ~~Unless authorized by the United States Environmental Protection Agency under federal law, the~~ [THE] underground disposal of [FRESHWATER OR SALT WATER, BRACKISH WATER, OR OTHER] oil field wastes [WASTE FLUIDS] and the underground storage of [LIQUID] hydrocarbons[,] are prohibited except as ordered by the commission under this section. In [IN] response to a letter of application for injection filed by an operator, ~~[FOR UNDERGROUND DISPOSAL OR STORAGE]~~ the commission will issue an order authorizing ~~in its discretion, authorize~~ [FOR] the underground disposal of oil field wastes that the commission determines are suitable for disposal ~~consisting of~~ fluids ~~described~~ in 40 C.F.R. 144.6(b)~~(1)~~ as revised as of July 1, 1998, which is adopted by reference, or in a Class II well, as defined the underground storage of hydrocarbons. An order authorizing disposal or [OF] storage wells remains valid unless revoked by the commission.

Del. underline beneath "underground disposal"

Del. underline beneath "or"

Del. underline beneath "storage"

(b) The operator has the burden of demonstrating that the proposed disposal or storage operation will not allow the movement of oil field wastes or hydrocarbons [FLUID] into sources of freshwater. Disposal or storage wells must be cased and the casing cemented in a manner that will isolate the disposal or storage zone and protect oil, gas, and freshwater sources.

(c) An application for underground disposal or storage [INJECTION] must include

(1) a plat showing the location of all proposed disposal and storage wells, [INCLUDING] abandoned or other unused wells, production wells, dry holes, and any other wells that penetrate the ~~disposal or storage~~ [INJECTION] zone within one-quarter mile of each proposed disposal or storage well;

. . .

Note to publisher: paragraphs (2) and (3) are unchanged.

(4) the name, description, depth, and thickness of the formation into which fluids are to be disposed or stored [INJECTED] and appropriate geological data on the disposal or storage [INJECTION] zone and confining zones ~~zone(s) [ZONES]~~, including lithologic descriptions [description] and geologic names [name];

...

Note to publisher: paragraph (5) is unchanged.

(6) a description of [the casing of the disposal or storage wells, or the proposed casing program and] the proposed method for demonstrating the mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that not fluids will [move behind casing beyond the approved [TESTING CASING BEFORE USE OF THE] disposal or storage zone ~~[WELLS]~~;

(A) the casing of the disposal or storage wells, if the wells are existing; or

(B) the proposed casing program, if the disposal or storage wells are new

(7) a statement as to the type of oil field wastes to be disposed or hydrocarbons stored [FLUID TO BE INJECTED], their [ITS] composition, their [ITS] source, [AND] the estimated maximum amounts to be disposed or stored [INJECTED] daily, and the compatibility of fluids to be disposed or stored with the disposal or storage zone;

~~(8) the estimated average and maximum disposal or storage [INJECTION] pressure;~~

Publisher: Paragraph (8) is unchanged

(9) evidence [and data] to support a commission finding that the proposed disposal or storage operation [well] will not initiate or propagate fractures through the confining zones that [WHICH] ~~zone(s) [ZONES] which~~ might enable the oil field wastes or stored hydrocarbons [INJECTION FLUID OR FORMATION FLUID] to enter [any] freshwater strata;

(10) a [AN] standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which disposal or storage [FLUID INJECTION] is proposed[, BY A STANDARD LABORATORY WATER

ANALYSIS DETERMINATION, OR BY AN ANALYTICAL METHOD ACCEPTABLE TO THE COMMISSION]; [AND]

(11) a reference to any applicable freshwater exemption issued in accordance with 20 AAC 25.440; [;] and

(12) a report on the mechanical condition of ~~all wells~~ each well that ~~have~~ has penetrated the disposal or storage zone within a one-quarter mile radius of a disposal or storage well. Del underline in beneath period

(d) The mechanical integrity of a disposal or storage well must be demonstrated under 20 AAC 25.412 before disposal or storage operations are begun, ~~and~~ after a well workover affecting mechanical integrity is conducted, and at least once every four years. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual disposal or storage operations. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(e) ~~If the casing-tubing annulus pressure subjects the casing to a hoop stress that exceeds 70 percent of the minimum yield strength of the casing, or if a disposal rate increase, operating pressure observation, or pressure test indicates pressure communication or leakage of any casing, tubing, or packer [THERE IS MORE THAN A 200 PSI CHANGE IN PRESSURE BETWEEN CONSECUTIVE PRESSURE READINGS], the operator shall notify the commission [MUST BE IMMEDIATELY NOTIFIED] by the next working day and implement commission-approved corrective action [TAKEN].~~ If an injection rate, operating pressure observation, or pressure test indicates pressure communication or leakage in any casing, tubing, or packer, the operator shall notify the commission by the next working day and shall implement corrective action or increased surveillance as the commission requires to ensure protection of freshwater.

(f) The commission will [in its discretion,] require additional mechanical integrity tests ~~if~~ the commission considers them prudent for conservation purposes or protection of freshwater.

. . .

Note to publisher: subsection (g) is unchanged.

If wells, including freshwater wells or other borings, are located within a one-quarter mile radius of the disposal or storage well, are a possible means for oil field wastes or hydrocarbons to move into sources of freshwater, and are under the control of the operator, the operator shall ensure that the wells are properly repaired, plugged, or otherwise modified to prevent the movement of oil field wastes or hydrocarbons into sources of freshwater; or

(h) ~~[THE OPERATOR SHALL PROVIDE A REPORT ON THE MECHANICAL CONDITIONS OF ALL WELLS THAT HAVE PENETRATED THE INJECTION ZONE WITHIN A ONE-QUARTER MILE RADIUS OF A PROPOSED DISPOSAL OR STORAGE WELL.] It is the operator's responsibility to ensure [ASSURE] that all [ANY OF THE] wells, including water wells and other borings, under the operator's control within a one-quarter mile radius of the disposal or storage well [THE RADIUS OF INVESTIGATION] which may allow the movement of oil field wastes or hydrocarbons [FLUIDS] into sources of freshwater are properly repaired, plugged, or otherwise modified. If wells exist that are not under the operator's control, the commission will not approve the application until the person [OPERATOR] responsible for those~~ wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of oil field wastes or hydrocarbons ~~[FLUIDS]~~ into sources of freshwater.

(1) the operator, the operator shall ensure that the wells are properly repaired, plugged, or otherwise modified to prevent the movement of oil field wastes or hydrocarbons into sources of freshwater; or

(2) a person other than the operator, the commission will not issue an order under (a) of this section to the operator until the operator presents evidence to the commission's satisfaction that the person who controls the wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of oil field wastes or hydrocarbons into sources of freshwater.

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(1) This section does not apply to underground disposal that is regulated under 40 C.F.R. 147.101 by the United States Environmental Protection Agency.

Note to publisher: subsections (i) and (j) are unchanged.

(k) The annular disposal of drilling wastes approved under 20 AAC 25.080 is an operation incidental to drilling a well and is not a disposal operation subject to this section. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.265 is repealed and readopted to read:

20 AAC 25.265. AUTOMATIC SHUT-IN EQUIPMENT. (a) A completed well with an offshore surface location ~~which~~ and that is capable of unassisted flow of hydrocarbons to the surface, must be equipped with a commission-approved

(1) fail-safe automatic surface safety valve (SSV) system capable of preventing an uncontrolled flow; and

(2) fail-safe automatic surface-controlled subsurface safety valve (SSSV) system capable of preventing an uncontrolled flow, unless another type of subsurface valve with that capability is approved by the commission; this valve must be in the tubing string and located below the mudline datum or, if permafrost is present, below the permafrost.

(b) An operator may demonstrate by a no-flow test that a well is incapable of unassisted flow of hydrocarbons to the surface. ~~A minimum of~~ At least 24 hours notice must be given so that a representative of the commission can witness the test.

(c) The commission will, in its discretion, ~~also~~ require an # SSV~~s~~ #system, an # SSSV~~s~~ #system, or both on a well~~s~~ with an onshore surface location~~s~~, after notice and an opportunity for hearing in accordance with 20 AAC 25.540.

(d) A representative of the commission ~~will~~ shall witness operation and performance tests at intervals and times as prescribed by the commission to confirm that the SSV #system, SSSV #system, and ~~all~~ associated equipment are in proper working condition. If an SSV #system, SSSV #system, or associated equipment fails the performance test, ~~it~~ the system or associated equipment must be repaired within the time frame specified by the commission or the well must be shut in. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.270 is amended, and new subsections are added to read:

20 AAC 25.270. INITIAL RESERVOIR PROPERTIES [PRESSURE]. (a) The operator shall determine the initial reservoir pressure in each ~~any~~ new pool before regular [SIGNIFICANT] production. The

results must be reported to the commission on a the form entitled Reservoir Pressure Report (Form 10-412).

(b) The operator shall obtain fluid samples from each new pool at the time of discovery or ~~prior~~ before ~~to~~ regular production and determine

(1) the crude oil composition assay;

(2) pressure, volume, and temperature ~~(PVT)~~ properties of the crude oil; and

(3) the solution or non-associated gas composition assay.

Publisher: Delete underline beneath new subsections (b)-(d).

(c) Sampling and analysis must be conducted and reported in accordance with good oil field engineering practices. Reports must be submitted to the commission within 45 days following the completion of the determinations required in (b) of this section.

(d) The operator shall determine within three months after discovery of each new oil pool the original solution gas-oil ratio by a well test conducted in a manner approved by the commission. The operator shall report the results on the Well Status Report and Gas-Oil Ratio Tests (Form 10-409) within 45 days after the test. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Att'y. AAC Coordinator: Please insert effective date into editor's note

20 AAC 25.275 is repealed:

20 AAC 25.275. RESERVOIR FLUID PROPERTIES. Repealed. (Eff. 4/2/86, Register 97; repealed ___/___/___, Register __)

Editor's note: Effective __/__/99, Register ___, the substance of 20 AAC 25.275 was relocated to 20 AAC 25.270.

20 AAC 25.280(a) is repealed and readopted, subsections (b)-(d) ~~20 AAC 25.280(a) - (d)~~ are amended, and a new subsection (e) is added, to read:

20 AAC 25.280. WORKOVER OPERATIONS. (a) An ~~application for well workover operations must be submitted by filing an [THE FORM ENTITLED]~~ Application for Sundry Approvals (Form 10-403) ~~The application~~ must be submitted to and approved by the commission in order to enter a well and ~~before entering a [PRODUCIBLE OR INJECTION] well to~~ one or more of conduct the following types of well workover operations:

(1) ~~perforate or reperforate casing; [,]~~ the perforation or reperforation of casing;

(2) ~~stimulate; [,]~~ stimulation;

(3) ~~pull tubing; [,]~~ the pulling of tubing;

(4) ~~alter casing; [,]~~ alteration of the casing;

(5) ~~repair well.~~ repairs to the well.

(b) The Application for Sundry Approvals [FORM 10-403 FILING] must set out [THE FOLLOWING:]

(1) the current condition of the well;

(2) a copy of the proposed program for well work;

(3) unless already on file with the commission, a diagram and description of the well control [BOP] equipment to be used, including if applicable a list of the blowout prevention equipment (BOPE) with specifications [REQUIRED BY 20 AAC 25.285(a) AND THE STATIC BOTTOM-HOLE PRESSURE];

(4) a description of any wellbore [THE WORKOVER] fluid to be used for primary well control; ~~[.]~~ and

(5) the ~~estimated~~ current bottom-hole pressure, or, if data setting out the actual pressure ~~if~~ are not available, an estimate of the current bottom-hole pressure

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(c) The operator shall keep records and reports of well workover [and repair] operations, including BOPE test results, in conformance with the requirements of 20 AAC 25.070(1) [20 AAC 25.070(a)].

(d) The operator shall file with the commission, within 30 days after completion of workover [AND repair] operations, [a complete well record] on a Report of Sundry Well Operations (Form 10-404), a complete record of the work performed and the tests conducted, and a summary of [INCLUDING A COPY OF THE] daily [REPORTS OF] well operations as described in [AND THE TESTS AS REQUIRED BY] 20 AAC 25.070(3) [20 AAC 25.070(a)(1)]. Upon request, the operator shall file with the commission a copy of the daily record required by 20 AAC 25.070(1).

(e) Upon application, the commission will, in its discretion, waive the requirements of this section for wells in a pool for which pool rules have been prescribed under 20 AAC 25.520. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.285 is repealed and readopted to read:

20 AAC 25.285. SECONDARY WELL CONTROL FOR TUBING WORKOVER OPERATIONS: BLOWOUT PREVENTION EQUIPMENT REQUIREMENTS. (a) This section applies to workover operations performed with the tree removed. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected ~~and may not be less than the rating~~

~~shown in~~ If an approved Application for Sundry Approvals (Form 10-403) ~~except that the~~ is required under 20 AAC 25.280, the commission will specify in that approved application the working pressure that the equipment must be rated to meet or exceed. However, the rated working pressure of the annular type preventer need not exceed 5,000 psi.

(c) Well control equipment must include

(1) at least one positive seal manual or hydraulic valve or BOPE blind ram and one set of BOPE pipe rams flanged to the well head;

(2) in rotary drilling rig operations,

(A) for an operation requiring a BOP stack less than API 5~~M~~K, at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, that pipe rams need not be sized to ~~except for~~ bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(B) for an operation requiring a BOP stack equal to or greater than API 5~~M~~K ~~or greater~~, at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, that pipe rams need not be sized to BHAs ~~except for bottom-hole assemblies~~ and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(3) in coiled tubing unit operations,

(A) for an operation requiring a BOP stack equal to or less than API 5~~M~~K ~~or less~~,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer;

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(iv) at least one preventer equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except that pipe rams need not be sized to BHAs ~~for bottom-hole assemblies~~ and drill collars; and

(B) for an operation requiring a BOP stack greater than API 5~~M~~K,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers;

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(iv) at least two preventers equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except that pipe rams need not sized to BHAs ~~for bottom-hole assemblies~~ and drill collars;

(4) if a tapered string is used, either an additional set of rams for each size of pipe being run or a variable ram, except ~~when~~ if small diameter tubulars are used to perform a clean-out operation through a production packer or to clean out a liner where the casing has been top set;

(5) locking devices on the ram-type preventers;

(6) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's ~~console~~ station, in addition to controls on the accumulator system;

(7) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's ~~console~~ station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor;

(8) a hydraulic actuating system with

(A) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed, and all power sources are shut off; and

(B) an accumulator pump system consisting of two or more pumps with independent power sources (primary and secondary) and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(9) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool or on the BOP body with two full-opening valves on each outlet, conforming to the following specifications:

(A) the outlets must be at least two inches in nominal diameter, except that for rotary drilling rig operations, if the required BOP is rated equal to or greater than API ~~2M~~ 5K, the nominal diameter of the choke outlets must be at least three inches;

(B) each valve must be sized at least equal to the required size of the outlet to which it is attached;

(C) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(D) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid; and

(10) a choke manifold equipped with

(A) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's ~~console~~ station if the operation requires a BOP stack equal to or greater than API 5~~M~~K ~~or greater~~;

(B) a line at least two inches in nominal diameter downstream of each choke;

(C) immediately upstream of each choke, at least one full-opening valve for an operation requiring a BOP stack less than API 5~~M~~K ~~or less~~, or at least two full-opening valves for an operation requiring a BOP stack equal to or greater than API 5~~M~~K; and

(D) a bypass line, at least two inches in nominal diameter, with at least one full-opening valve for an operation requiring a BOP stack less than API 5~~M~~K ~~or less~~, or at least two full-opening valves for an operation requiring a BOP stack equal to or greater than API 5~~M~~K.

(d) The rated working pressure of valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must exceed the maximum potential surface pressure to which they may be subjected and may not be less than the ~~rating~~ required working pressure specified for the BOPE ~~shown~~ if any, under 20 AAC 25.230, in an approved Application for Sundry Approvals, except that the rated working pressure of lines downstream of the choke ~~may be rated to~~ need not exceed 50 percent of the required working pressure of the BOPE.

(e) Kill and choke lines must

(1) be constructed of rigid steel pipe, fire-resistant rotary hose, or other ~~suitable~~ conduit that has been approved by the commission as capable of withstanding the temperature and pressure of an ignited uncontrolled release;

(2) be as straight as practical;

(3) if constructed of rigid steel pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(4) be secured to prevent excessive whip or vibration;

(5) be sized to prevent excessive erosion or fluid friction; and

(6) be assembled without hammer unions or internally clamped swivel joints, unless ~~such joints are specifically approved by~~ the commission determines that those joints do not compromise the maintenance of well control

(f) The BOPE must be tested as follows:

(1) when installed, repaired, or changed, and at least once a week thereafter, BOPE, including emergency valves and choke manifolds, must be function pressure-tested, using a non-compressible fluid, to the required working pressure ~~shown~~ specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, ~~in its absence~~ if that application is not required, to the maximum potential surface pressure to which ~~it~~ the BOPE may be subjected, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(2) ~~when~~ if BOP sealing ram type equipment has been used, it must be function pressure-tested before the next wellbore entry, using a non-compressible fluid, to the required working pressure ~~shown~~ specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, ~~in its absence~~ if that application is not required, to the maximum potential surface pressure to which ~~it~~ that equipment may be subjected, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(3) non-sealing equipment must be function-tested weekly ~~and~~ after a repair or change, ~~or~~ ~~any~~ after an action that disconnects the hydraulic system lines from the BOPE, except that ~~when~~ if the workstring is continuously in the well ~~or the BHA does not clear the BOP~~, function-testing must be performed as soon as possible after the workstring is pulled out of the well and the BHA clears the BOP ~~thereafter~~;

(4) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(5) ~~a minimum of~~ at least 24 hours notice of each function pressure test must be provided so that a representative of the commission can witness the test.

(g) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Application for Sundry Approvals, if ~~applicable~~ that application is required under 20 AAC 25.280, and shall post on the drilling rig floor any geologic hazard information obtained while drilling the well ~~required in connection with the Application for Sundry Approvals~~ and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Application for Sundry Approvals, if ~~applicable~~ that application is required under 20 AAC 25.280, any geologic hazard information obtained while drilling the well ~~required in connection with the Application for Sundry Approvals~~, and a copy of the operator's standing orders specifying well control procedures. ~~When~~ If an additional or separate ~~sub~~ substructure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(h) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of ensuring well control. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.286. WELL CONTROL REQUIREMENTS FOR WORKSTRING SERVICE OPERATIONS. (a) This section applies to through-tubing operations that are not ~~covered by~~ subject to the requirements of 20 AAC 25.036 or 20 AAC 25.285, and that are performed with coiled tubing, small diameter drill pipe, or small diameter tubing. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall use a full lubricator system or open hole deployment type system.

(c) The rated working pressure of the blowout prevention equipment (BOPE) and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected ~~and may not be less than the rating~~ ~~shown in~~ If is required under 20 AAC 25.230, the commission will specify in that approved application the working pressure that the equipment must be rated to meet or exceed. However, an approved Application for Sundry Approvals (Form 10-403) ~~except that the~~ working pressure of the annular type preventer need not exceed 5,000 psi.

(d) Well control equipment must include

(1) at least one positive seal manual or hydraulic valve or blind ram flanged to the ~~well~~ wellhead or tree;

(2) in rotary drilling rig operations,

(A) for an operation requiring a BOP stack equal to or less than API 5M~~I or less~~K, at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except that pipe rams need not be sized to ~~for~~ bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(B) for an operation requiring a BOP stack greater than API 5~~M~~K, at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except ~~for bottom-hole assemblies~~ (that pipe rams need not be sized to BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(3) in coiled tubing unit operations,

(A) for an operation requiring a BOP stack equal to or less than API 5~~M~~K ~~or less~~,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer; and

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(B) for an operation requiring a BOP stack greater than API 5~~M~~K,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers; and

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer;

(4) a hydraulic actuating system with

(A) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed, and all power sources are shut off; and

(B) an accumulator pump system;

(5) locking devices on the ram-type preventers;

(6) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's ~~console~~ station, in addition to controls on the accumulator system;

(7) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's ~~console~~ station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor; and

(8) a kill line capable of being attached with flanged or hubbed connections to the BOP body, drilling spool, tree, wellhead, or other well control equipment.

(e) The operator shall test the BOPE assembly as follows:

(1) at least once a week, and after each use, repair, or change, BOPE pipe and blind rams must be function pressure-tested, using a non-compressible fluid, to the required working pressure ~~shown~~ specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, ~~in its absence~~ if that application is not required, to the maximum potential surface

pressure to which they may be subjected, except that the annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(2) after each installation of BOPE or other well control equipment, the equipment must be pressure-tested, before wellbore entry, to the maximum ~~expected~~ potential wellhead pressure to which it may be subjected, except that when testing against the annular type preventer, pressure testing need not exceed 50 percent of the rated working pressure of the annular type preventer;

(3) non-sealing equipment must be function-tested weekly ~~and~~ a after repair or change, ~~or~~ and ~~any~~ after an action that disconnects the hydraulic system lines from the BOPE, except that ~~when~~ if the workstring is continuously in the well ~~or the BHA does not clear the BOP~~, function-testing must be performed as soon as possible ~~thereafter~~ after the workstring is pulled out of the well and the BHA clears the BOP;

(4) after each well installation of the BOPE, the BOPE hydraulic connections to the rams must be visually verified before wellbore entry.

(f) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Application for Sundry Approvals, if ~~applicable~~ that application is required under 20 AAC 25.280, and shall post on the drilling rig floor any geologic hazard information ~~required in connection with the Application for Sundry Approvals~~ obtained while drilling the well and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Application for Sundry Approvals, if ~~applicable~~ that application is required under 20 AAC 25.280, any geologic hazard information ~~required in connection with the Application for Sundry Approvals~~ obtained while drilling the well, and a copy of the operator's standing orders specifying well control procedures. ~~When~~ If an additional or separate ~~sub-~~ sub structure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(g) Upon request of the operator, the commission will, in its discretion, approve a variance from

the requirements of this section if the variance provides at least an equally effective means of well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.287. WELL CONTROL EQUIPMENT FOR WIRELINE OPERATIONS. (a) This section applies to workover or service operations performed with slickline or conductor line with the tree in place. These operations are also subject to the requirements of 20 AAC 25.527.

(b) Well control equipment must include

(1) a set of wireline rams suitable or sized for each diameter of wire passing through the wireline valve;

(2) a lubricator or pressure deployment system; and

(3) a high pressure pack-off, stripper, or greasehead with linewiper, stripper, or pack-off.

(c) The rated working pressure of the well control equipment must exceed the maximum potential surface pressure to which it may be subjected ~~and may not be less than the rating shown in~~ If an approved Application for Sundry Approvals (Form 10-403) is required under 20 AAC 25.280, the commission will specify in that approved application the working pressure that the equipment must be rated to meet or exceed. However ~~except that the~~ working pressure of an annular type preventer need not exceed 5,000 psi.

(d) The operator shall test the well control equipment as follows:

(1) at least once a week, equipment must be function pressure-tested, using a non-compressible fluid, to the required working pressure ~~shown~~ specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, if that application is not required ~~in its absence~~, to the maximum potential surface pressure to which ~~it~~ that equipment may be subjected;

(2) after each installation of the well control equipment, ~~it~~ that equipment must be pressure-tested, before wellbore entry, to the maximum ~~expected~~ potential wellhead pressure to which ~~it~~ that equipment may be subjected;

(3) if the wireline valve rams have been used, repaired or changed, the wireline rams must be closed and function pressure-tested before wellbore entry, using a non-compressible fluid, to the required working pressure ~~shown~~ specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, ~~in its absence~~ if that application is not required, to the maximum potential surface pressure to which they may be subjected.

(e) The operator shall post in the operator's cab a copy of the approved Application for Sundry Approvals, if ~~applicable~~ that application is required under 20 AAC 25.280, any geologic hazard information ~~required in connection with the Application for Sundry Approvals~~ obtained while drilling the well, and a copy of the operator's standing orders specifying well control procedures.

(f) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.288. WELL CONTROL REQUIREMENTS FOR OTHER SERVICE OPERATIONS. For downhole service operations not covered by 20 AAC 25.285 - 20 AAC 25.287, the commission will ~~in its discretion,~~ approve alternate well control procedures and equipment, if the commission determines that the alternate procedures and equipment are adequate to ensure well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.290 OPERATIONS PRODUCING HYDROGEN SULFIDE. An operator of a well or pool that produces hydrogen sulfide gas shall install, operate, and maintain surface production equipment in conformance with API RP 55, *Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide*, 2d edition, February 15, 1995, which is adopted by reference. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in ~~this section~~ 20 AAC 25.290 may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070, or if not available from the American Petroleum Institute, may be obtained from Global Engineering Documents, 15 Inverness Way East, Englewood, CO 80150.

ARTICLE 4.
REPORTS.

Section
300. Request for additional information
310. Books and records
320. Filing of forms

20 AAC 25.300 is amended to read:

20 AAC 25.300. REQUEST FOR ADDITIONAL INFORMATION. This chapter does not limit or restrict the authority of the commission to require the furnishing of those [such] additional reports, data, or other information relative to drilling, production, transportation, storage, or handling of [CRUDE] oil or [NATURAL] gas and relative to injection operations on oil and gas properties and units in the state [ALASKA], as the commission considers [may appear to it] to be necessary or desirable, either generally or specifically, for the prevention of waste, the protection of correlative rights, the prevention of fluid movement [~~MOVEMENT~~ OF FLUIDS] into freshwater sources, and the conservation of [THE] natural resources. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

a Dal underline beneath "movement"

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.310 is amended to read:

20 AAC 25.310. BOOKS AND RECORDS. Operators of [ALL OPERATORS, PRODUCERS ~~All operators[,] of [PRODUCERS~~ TRANSPORTERS, STORERS, AND HANDLERS OF CRUDE OIL AND NATURAL GAS ON] oil and gas properties and units within the state [ALASKA] shall make and maintain [(1) AND KEEP IN ALASKA] for a period of not less than five years, ~~books and records necessary~~ [APPROPRIATE] books and records necessary ~~BOOKS AND RECORDS~~ [COVERING THEIR OPERATION IN ALASKA. THE DATA FROM

THESE BOOKS AND RECORDS MUST BE USED] to make and substantiate the reports required by this chapter. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.320(a) is repealed and readopted, and (b) is amended, to read:

20 AAC 25.320. FILING OF FORMS. (a) ~~Where~~ If this chapter requires a form to be filed or submitted, one originally signed, ~~commission-approved~~ commission-furnished form must be submitted to the commission with the required number of copies indicated on each form. A computer-generated form may be submitted in place of the form furnished by the commission if ~~it~~ the computer-generated form contains the same required information and has been approved for format by the commission.

(b) Forms required by this chapter will be furnished by the commission upon request and will be revised at the discretion of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

and upon the commission's determination that the requirements of this section and 20 AAC 25.412 are met,

ARTICLE 5.
ENHANCED RECOVERY.

Section
400. (Repealed)
402. Enhanced recovery operations
410. (Repealed)
412. Casing, cementing, and tubing of injection wells for enhanced recovery, disposal, and storage
420. Notice of commencement and discontinuance of injection operations
430. Enhanced recovery records
432. Report of underground injection
440. Freshwater aquifer exemption
450. Underground injection control variances
460. Area injection orders

20 AAC 25.402 is repealed and readopted to read:

20 AAC 25.402. ENHANCED RECOVERY OPERATIONS. (a) Enhanced recovery operations involving the introduction of extraneous forms of energy into a pool by injection are prohibited, except as ordered by the commission under this section. In response to an application for injection filed by an operator, the commission will issue an order authorizing ~~in its discretion, authorize~~ the injection of fluids that function primarily to enhance recovery of oil and gas and that are appropriate for enhanced recovery. Except as provided in (i) of this section, an order authorizing injection for an enhanced recovery project remains valid unless revoked by the commission.

(b) The operator has the burden of demonstrating that the proposed operation will not allow the movement of fluid into sources of freshwater. Injection wells must be cased, the casing cemented, and the wells operated in a manner that will isolate the injection zone and protect oil, gas, and freshwater. ~~It is the operator's responsibility to ensure that all~~ If wells, including fresh water wells and other borings, ~~under the operator's control~~ are located within a one-quarter mile radius of an injection well, ~~which may allow the movement of~~ are a possible means for fluids to move into sources of freshwater, and are under the control of ¶ (1) the operator, the operator shall ensure that the wells are properly repaired, plugged, or otherwise modified. ~~If wells exist that are not under the operator's control,~~ the commission will not issue an order under (a) of this section until ~~approve the application until the person~~ to prevent the movement of fluids into sources of freshwater; or ¶ (2) a person other than the operator,

the operator presents evidence to the commission's satisfaction that the person who controls the ~~responsible for these~~ wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of fluids into sources of freshwater.

(c) An application for injection must include

(1) a plat showing the location of ~~all~~ each proposed injection well~~s~~, abandoned or other unused well~~s~~, production well~~s~~, dry hole~~s~~, and ~~any~~ other well~~s~~ ~~that penetrate the injection zone~~ within one-quarter mile of each proposed injection well;

(2) a list of all operators and surface owners within a one-quarter mile radius of each proposed injection well;

(3) an affidavit showing that the operators and surface owners within a one-quarter mile radius have been provided a copy of the application for injection;

(4) a full description of the particular operation for which approval is requested;

(5) the names, descriptions, and depths of the pools to be affected;

(6) the name, description, depth, and thickness of the formation into which fluids are to be injected, and appropriate geological data on the injection zone and confining ~~zone(s)~~ zone, including lithologic descriptions and geologic names;

(7) logs of the injection wells if not already on file with the commission;

(8) a description of ~~the casing of the injection wells, or the proposed casing program,~~ ~~and~~ the proposed method for demonstrating mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that no fluids will move behind casing beyond the approved injection zone;

(9) a statement of the type of fluid to be injected, ~~its~~ the fluid's composition, ~~its~~ the fluid's source, the estimated maximum amounts to be injected daily, and ~~its~~ the fluid's compatibility with the injection zone;

; and a description of
¶ (A) the casing of the injection wells if the wells are existing; or
¶ (B) the proposed casing program, if the injection wells are new

(10) the estimated average and maximum injection pressure;

(11) evidence to support a commission finding that each proposed injection well will not initiate or propagate fractures through the ~~overlying strata or~~ confining ~~zone(s)~~ zones that might enable the injection fluid or formation fluid to enter ~~any~~ freshwater strata;

(12) a standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which fluid injection is proposed;

(13) a reference to any applicable freshwater exemption issued under 20 AAC 25.440;

(14) the expected incremental increase in ultimate hydrocarbon recovery; and

(15) a report on the mechanical condition of ~~all wells~~ each well that ~~have~~ has penetrated the injection zone within a one-quarter mile radius of ~~each~~ a proposed injection well.

(d) The commission will publish notice of the enhanced recovery application and provide the opportunity for a hearing in accordance with 20 AAC 25.540.

(e) The mechanical integrity of an injection well must be demonstrated under 20 AAC 25.412 before injection is begun and after a well workover affecting mechanical integrity is conducted. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual injection. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(f) If ~~the casing-tubing annulus pressure subjects the casing to a hoop stress that exceeds 70 percent of the minimum yield strength of the casing, or if~~ an injection rate, operating pressure observation, or pressure test indicates pressure communication or leakage in any casing, tubing, or

packer, the operator shall notify the commission by the next working day and shall implement ~~commission-approved~~ corrective action or increased surveillance as the commission requires to ensure protection of freshwater.

(g) The commission will ~~in its discretion,~~ require additional mechanical integrity tests, if the commission considers them prudent for conservation purposes or protection of freshwater.

(h) The commission will, in its discretion, approve a modification to an existing or pending injection operation under 20 AAC 25.507, ~~when~~ if the applicant proves to the commission, upon application containing sufficient detail for the commission to evaluate the proposed modification, that the modification will not allow the movement of fluids into sources of freshwater.

(i) If injection operations are not begun within 24 months after the ~~approval~~ date of the order authorizing enhanced recovery ~~approval~~ expires unless a letter of application for extension is approved by the commission.

(Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.412 is repealed and readopted to read:

20 AAC 25.412. CASING, CEMENTING, AND TUBING OF INJECTION WELLS FOR ENHANCED RECOVERY, DISPOSAL, AND STORAGE. (a) A well used for injection must be cased and cemented in accordance with 20 AAC 25.030 to prevent leakage into oil, gas, or freshwater sources.

(b) A well used for injection must be equipped with tubing and a packer, or with other equipment that isolates pressure to the injection interval, ~~unless otherwise specifically approved by the commission~~ unless the commission approves the operator's use of alternate means to ensure that injection of fluid is limited to the injection zone. The minimum burst pressure of the tubing must exceed the maximum surface injection pressure by at least 25 percent. The packer must be placed within 200 feet measured depth above the top of the perforations, unless ~~otherwise approved by~~ the commission approves a different placement depth as the commission considers appropriate given the thickness and depth of the confining zone.

(c) Before injection begins, a well must be pressure-tested to demonstrate the mechanical integrity of the tubing and packer and of the casing immediately surrounding the injection tubing string. The casing must be tested at a surface pressure of 1,500 psig or at a surface pressure of 0.25 psi/ft multiplied by the true vertical depth of the casing shoe, whichever is greater, but the casing may not be subjected to a hoop stress that will exceed 70 percent of the minimum yield strength of the casing. The test pressure must show stabilizing pressure and may not decline more than 10 percent within 30 minutes.

(d) The operator shall provide a cement quality log or other well data approved by the commission to demonstrate isolation of the injected fluids to the approved interval.

(e) ~~A minimum of~~ At least 24 hours notice of a pressure test required by (c) of this section must be given so that a representative of the commission can witness the test. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.430 is amended to read:

20 AAC 25.430. ENHANCED RECOVERY RECORDS. Each operator shall keep accurate records showing volumes of fluids produced, injected volumes, reservoir pressures, and injection pressures, by well and pool. Each operator shall retain these records for five years. The commission will, in its discretion, specify retention of these records for a longer time period. Upon reasonable notice, the commission [OR ITS AUTHORIZED REPRESENTATIVE] must be given full access during normal business hours to all records. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.432 is repealed and readopted, to read:

20 AAC 25.432. REPORT OF UNDERGROUND INJECTION. An operator that injects fluids into subsurface strata through a service well for any purpose, other than fracturing, acidizing, or other similar treatment, shall file with the commission

(1) monthly reports that show all injected volumes and other data, by well and pool, as required by the commission on the Monthly Injection Report (Form 10-406) and, if applicable, the Facility Report of Produced Gas Disposition (Form 10-422); and

(2) an annual report that shows annual and total cumulative volumes injected and produced and other data, for each pool or injection project area within the pool, as required by the commission on the Annual Report of Injection Projects (Form 10-413); the annual report must be submitted by April 1 ~~each year unless it is required by~~ unless pool rules established under 20 AAC 25.520 require the report to be included with a pool specific annual surveillance report. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.440(c) is amended, and a new subsection (d) is added, to read:

(c) Freshwater aquifers within ~~the~~ state [ALASKA] that ~~were [ARE]~~ C, as of June 19, 1986, are designated as exempt aquifers by the United States Environmental Protection Agency [AT THE TIME THE COMMISSION IS GRANTED PRIMARY ENFORCEMENT RESPONSIBILITY] under 40 C.F.R. 147.102 are 42 U.S.C. 300h-4 ~~are~~ [WILL BE] accepted as exempt aquifers by the commission [WITHOUT FURTHER ACTION].

(d) A commission order designating a freshwater aquifer or a portion of it as an exempt freshwater aquifer is not effective with respect to underground disposal or storage operations subject to

20 AAC 25.252 or injection operations subject to 20 AAC 25.402 until the United States Environmental Protection Agency has been provided the opportunity to review the order under 40 C.F.R. 144.7(b)(3) and has

(1) approved the order, if it was issued under (a)(1) of this section; or

(2) has allowed the applicable time period within which to disapprove the order to expire without acting on it, if ~~it~~ the order was issued under (a)(2) of this section. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.450 (a) is amended to read:

(a) If injection does not occur into, through, or above [A] freshwater [SOURCE OR NON-EXEMPT FRESHWATER AQUIFER], the commission will, [in its discretion,] authorize [less stringent] requirements that are less stringent for a well or project established under 20 AAC 25.252(h) or 20 AAC 25.402(b) than [otherwise required by] the requirements in this chapter, [,] for the radius of investigation, casing and cementing, the tubing and packer, mechanical integrity, operation, monitoring, and reporting, to the extent that the commission determines that the reduction in requirements will not result in an increased risk of movement of fluids into [A] freshwater [SOURCE].

(Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC ~~25.460 is~~ 25.460(a)(4), (b)(2), (c)(1), and (d) are amended to read:

20 AAC 25.460. AREA INJECTION ORDERS. (a) Upon application under this section and subject to the provisions of 20 AAC 25.252 or 20 AAC 25.402, as applicable, the commission will, in its discretion, after [LEGAL] notice and opportunity for public hearing in accordance with 20 AAC 25.540,

issue an order permitting the underground injection of fluids on an area basis, rather than for each well individually, if the wells are

. . .

Note to publisher: ~~**paragraph (1) is unchanged.**~~ paragraphs (1)-(3) are unchanged

AOC Coordinate Please insert effective date into repealer.

~~(2) within the same field, facility site, reservoir, project, or similar area; and~~

~~(3) operated by a single operator. [; AND]~~

(4) repealed / / [USED TO INJECT OTHER THAN HAZARDOUS WASTE].

(b) In the [The] area injection order to the commission will specify

. . .

Note to publisher: paragraph (1) is unchanged.

(2) the requirements for drilling, completing, operating, monitoring, reporting, and abandoning all wells authorized by the order.

(c) In the [The] area injection order to the commission will, in its [the commission's] discretion, authorize the operator to drill, complete, and operate, to convert, or to plug and abandon wells within the area if

(1) the operator files with the commission an application for a Permit to Drill (Form 10-401) or an Application for Sundry Approvals (Form 10-403), as appropriate, for commission approval before the operator starts work; and

. . .

Note to publisher: paragraph (2) is unchanged.

(d) If the commission determines that a [any] well drilled and operated under an area injection order or an order issued under this section does not satisfy all of the requirements [REQUIRE-MENTS] of this section, the commission will take enforcement action to ensure compliance. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Register _____, _____ ~~1997~~ 2000 MISCELLANEOUS BOARDS

Authority: AS 31.05.030

ARTICLE 6.
GENERAL PROVISIONS.

Section
505. Scope of regulations
507. Change of an approved program
510. Commission [OFFICE, HOURS, AND] seal
515. United States government land [LEASES]
517. Plan of reservoir [FOR POOL] development and operation[, AND INTEGRATION OF INTERESTS]
518. Agreements integrating interests ~~under AS 31.05.110(a)~~
520. Field and pool regulation and classification
525. (Repealed)
526. Conduct of operations [AND FIRE HAZARD]
528. Open pit storage of oil
530. Cooperative [COOPERATION] agreements with other parties
534. Tests, surveys, and inspections [REMEDIAL MEASURES]
535. Enforcement
536. (Repealed)
537. Public and confidential [WELL] information
538. (Repealed)
539. Emergency action
540. Hearings
545. Public mailing lists
550. Oaths
555. (Repealed)
556. Orders
557. Subpoenas
560. Time
570. (Repealed) [DEFINITIONS]

20 AAC 25.507 is repealed and readopted to read:

20 AAC 25.507. CHANGE OF AN APPROVED PROGRAM. (a) Except as otherwise provided by 20 AAC 25.015, if an operator desires to make a substantive change in ~~an approved~~ a program or activity for which commission approval is required and has been obtained under AS 31.05 or this chapter, complete details of the well's current condition and the proposed change must be submitted to the commission with ~~the~~ an Application for Sundry Approvals (Form 10-403). A change ~~of~~ to an approved program or activity may not

be undertaken without commission approval. The commission will condition its approval as the commission considers necessary or appropriate to ensure compliance with the standards on which the original approval was based.

(b) ~~Where~~ If operational necessity requires prompt action, oral approval of a change may be obtained from the commission. The required Application for Sundry Approvals must be submitted for final approval by the commission. That application must set within ~~the commission's next~~ three ~~working~~ days ~~setting~~ out the name of the person who provided approval and the date of the oral approval. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.510 (a) and (b) are repealed, and (c) is amended, to read:

20 AAC 25.510. COMMISSION [OFFICE, HOURS, AND] SEAL. (a) Repealed ___/___/___.

(b) Repealed ___/___/___.

(c) The official seal of the commission is reproduced below.

Att'n AAC Coordinator: Please insert effective date for repealers.

Note to publisher: Commission seal shown on the next page to be inserted here

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.017 AS 31.05.030

ALASKA OIL AND GAS CONSERVATION COMMISSION

SINCE 1955

20 AAC 25.515 is amended to read:

20 AAC 25.515. UNITED STATES GOVERNMENT LAND [LEASES]. A person, including a federal agency, drilling for or producing oil or [NATURAL] gas or conducting underground injection activities related to the recovery and production of oil or gas on federal land subject to the state's police powers shall comply with all applicable regulations and orders of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.027 AS 31.05.030

20 AAC 25.517 is repealed and readopted to read:

20 AAC 25.517. PLAN OF RESERVOIR DEVELOPMENT AND OPERATION. (a) Before commencement of regular production from an oil or gas pool, the operator shall submit to the commission a plan of reservoir development and operation for the pool or the portion of the pool for which development is contemplated by the operator.

(b) Unless otherwise ordered by the commission, the operator shall submit to the commission annual progress reports under the plan of reservoir development and operation. Any amendments and updates to the plan also must be submitted at least annually.

(c) The plan of reservoir development and operation must provide for

(1) the prevention of waste;

(2) the protection of correlative rights; and

(3) a greater ultimate recovery of oil and gas. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 [AS 31.05.110]

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.518. AGREEMENTS INTEGRATING INTERESTS ~~UNDER AS 31.05.110(a)~~. A voluntary agreement for the purpose of integrating interests under AS 31.05.110(a) must be filed with the commission no later than 30 days after ~~it~~ that agreement is executed. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.110

20 AAC 25.520 is amended to read:

20 AAC 25.520. FIELD AND POOL REGULATION AND CLASSIFICATION. (a) Upon the motion of the commission, or the request of an affected owner or [PROPERTY] operator [OR OWNER] at any time after the discovery of oil or gas in a field or pool, the commission will hold a hearing [will be held] in accordance with 20 AAC 25.540, and the commission will issue an order, based upon the evidence presented, classifying the pool as an oil or gas pool in a field and prescribing rules to govern the proposed [FOR THE] development and operation of the pool. In the [A] pool order, the commission [so issued] will establish requirements that the commission considers necessary to

(1) prevent waste, protect freshwater, [AND] protect correlative rights, and ensure a greater ultimate recovery of oil and gas; and

(2) [be] based on the operating and technical data presented.

(b) The commission will, in its discretion, [RECLASSIFY FIELDS AND POOLS, OR] amend pool orders in accordance with the procedures set forth in 20 AAC 25.540 ~~[RECLASSIFY FIELDS AND POOLS, OR AMEND POOL ORDERS]~~ [UPON THE PRESENTATION OF ADDITIONAL DATA AT A SUBSEQUENT HEARING]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Del. underline beneath "amend pool orders"

Authority: AS 31.05.030 AS 31.05.050 AS 31.05.060 AS 31.05.095 AS 31.05.100

20 AAC 25.526 is amended to read:

20 AAC 25.526. CONDUCT OF OPERATIONS [AND FIRE HAZARD]. An operator shall carry on all operations and maintain the property at all times in a safe and skillful manner in accordance with good oil field engineering [INDUSTRY] practices[,] and having due regard for the preservation and conservation of the property and protection of freshwater. [EACH WELL LOCATION AND PROPERTY MUST BE MAINTAINED IN A MANNER TO PREVENT FIRES. ALL RUBBISH, DEBRIS, WASTE MATERIAL, SPILLED OIL, AND ANY OTHER SUBSTANCE THAT CONSTITUTES A FIRE HAZARD MUST BE DISPOSED OF IN AN ENVIRONMENTALLY SAFE MANNER.] (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.527. GENERAL WELL CONTROL REQUIREMENTS FOR DRILLING, COMPLETION, WORKOVER, AND SERVICE OPERATIONS. (a) This section applies to all well drilling, completion, workover, and service operations. The requirements of this section are in addition to the applicable requirements of 20 AAC 25.033 - 20 AAC 25.037 and 20 AAC 25.285 - 20 AAC 25.288.

(b) ~~All~~ Equipment must be in good operating condition at all times and must be protected to ensure reliable operation under the range of weather conditions that may be encountered at the well site.

(c) ~~All~~ Well control equipment and fluids must be installed, used, maintained, and tested in a manner that ensures well control and, except as otherwise provided in this chapter, that conforms with the applicable provisions of the following documents, which are adopted by reference:

(1) API RP 5C7, *Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services*, 1st edition, December 1996;

(2) API RP 13B-1, *Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids*, 2d edition, September 1997;

(3) API RP 13B-2, *Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids*, 3d edition, February 1998;

(4) API RP 49, *Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide*, 2d edition, April 15, 1987;

(5) API RP 53, *Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells*, 3d edition, March 1997;

(6) API RP 57, *Recommended Practices for Offshore Well Completion, Servicing, Workover, and Plug and Abandonment Operations*, 1st edition, January 15, 1986;

(7) API RP 64, *Recommended Practices for Diverter Systems Equipment and Operations*, 1st edition, July 1, 1991;

(8) API RP 68, *Recommended Practice for Oil and Gas Well Servicing and Workover Operations Involving Hydrogen Sulfide*, 1st edition, January 1998.

(d) The toolpushers, drillers, and ~~person(s) in charge~~ persons-in-charge on a rotary drilling or workover rig floor must be trained in accordance with the drilling well control training standards contained in 30 C.F.R. 250.1500 - 250.1524 ~~(Subpart O)~~ as revised as of July 1, 1998, which are adopted by reference. The

toolpushers, drillers, and ~~person(s) in charge~~ persons-in-charge on a coiled tubing drilling rig must be trained in accordance with the well servicing well control training standards contained in 30 C.F.R. ~~250.155~~ 250.1503 - 250.1524 ~~(Subpart O)~~ as revised as of July 1, 1998, which are adopted by reference.

(e) The ~~person(s) in charge~~ persons-in-charge on a drill rig floor must have the authority and responsibility to shut in the well if it starts to flow.

(f) The operator shall keep records and reports of well drilling, workover, and repair operations, including BOPE test results, in accordance with 20 AAC 25.070(1) or, in the case of wireline work or other service operations, in the daily work log, which ~~will~~ must be made available to the commission upon request. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: Copies of the American Petroleum Institute recommended practices referred to in ~~this section~~ 20 AAC 25.527 may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070, or if not available from the American Petroleum Institute, may be obtained from Global Engineering Documents, 15 Inverness Way East, Englewood, CO 80150.

20 AAC 25.530 is amended to read:

20 AAC 25.530. COOPERATIVE [COOPERATION] AGREEMENTS WITH OTHER PARTIES. The commission will, in its discretion, from time to time enter into agreements [ARRANGEMENTS] with state and federal agencies, industry committees, or individuals, with respect to special projects, services, and studies relating to underground fluid injection and the conservation of oil and gas. If an agreement [ARRANGEMENT] requires the commission to use procedures ~~or apply~~

~~rules~~ not covered in this chapter, the procedures necessary to carry out the intent of the agreement [ARRANGEMENT] will be formulated and made available at the office of the commission after public notice and opportunity for public comment, ~~pursuant to 15~~ in accordance with 20 AAC 25.540. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: [AS 31.05.023] AS 31.05.030

20 AAC 25.534 is amended to read:

(a) As the commission considers

20 AAC 25.534. TESTS, SURVEYS, AND INSPECTIONS [REMEDIAL MEASURES]. [When considered] necessary or advisable to carry out the purposes of AS 31.05 [THE] (Alaska Oil and Gas Conservation Act) and this chapter, the commission will require that tests or surveys be made to determine the (1) quality of oil and gas produced; (2) [the] formation, casing, tubing, or other pressures; (3) [the] existence of any waste of [CRUDE] oil, gas, or reservoir energy; (4) or [the] risk of fluid movement into freshwater [SOURCES]. (b) [The commission will, in its discretion, exercise its statutory power to enter and conduct on-site investigations and inspections at reasonable times of facilities, equipment, practices, records, or operations for the purpose of ensuring compliance with the requirements of this chapter. [IF IT IS DETERMINED THAT THE REQUIREMENTS OF THIS CHAPTER ARE NOT BEING MET, THE COMMISSION WILL ORDER REMEDIAL WORK OR TAKE OTHER ACTION IT CONSIDERS NECESSARY.] (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.535. ENFORCEMENT. (a) ~~When~~ If the commission ~~has reason to believe~~, as the result of an investigation or otherwise, considers that a person ~~has~~ may have violated or failed to comply with a provision of AS 31.05, this chapter, or a commission order, permit, or other approval, the commission will, in its discretion, take enforcement action under this section against ~~give written notification to~~ the person.

If the commission proposes to take enforcement action under this section against a person, the commission will send the person written notification by personal service or by certified mail, return receipt requested.

(b) The commission's written notification to the person will

(1) state the nature of the apparent violation or noncompliance;

(2) summarize the ~~basis of the commission's~~ reasons why the commission considers reason ~~to believe that~~ a violation or noncompliance ~~has~~ to have occurred;

(3) state the action that the commission proposes to take under (e) of this section; and

(4) inform the person of the person's rights and liabilities under (c) - (e) of this section.

The commission will, in its discretion, extend the 15-day response period for good cause shown.

(c) Within ~~10~~ 15 days after ~~issuance~~ receipt of a notification under (b) of this section, ~~or within such longer period as the commission may specify~~, a person may file with the commission a written response ~~(1) acquiescing~~ that concurs in whole or in part ~~in~~ with a proposed commission action, ~~(2) requesting~~ requests informal review, or ~~(3) requesting~~ requests a hearing under 20 AAC 25.540. If a person fails to file a timely written response, the ~~person~~ commission will ~~be deemed~~ consider the person to have ~~acquiesced in~~ accepted the proposed commission action by default. If a person requests a hearing, the commission will schedule a hearing under 20 AAC 25.540.

(d) If a person requests informal review under (c) of this section, the commission will provide an opportunity for the person to submit documentary material and make a written or oral statement. The commission will then issue a ~~tentative~~ proposed decision or order. A proposed decision or order ~~which~~ becomes final 11 days after it is issued unless within 10 days after it is issued the person files a written request for a hearing, in which case the ~~tentative~~ proposed decision or order is of no effect. If the person requests a hearing, the commission will schedule a hearing under 20 AAC 25.540.

(e) ~~After~~ If a person ~~acquiesces~~ concurs in a proposed action under (c) of this section, or after an informal review or a hearing under (c) or (d) of this section, and ~~when~~ if the commission finds that a person has violated or failed to comply with a provision of AS 31.05, this chapter, or a commission order, permit, or other approval, the commission will, in its discretion, order one or more of the following, as it determines to be applicable:

(1) corrective action or remedial work;

(2) revocation or suspension of a permit or other approval;

(3) payment under the bond required by 20 AAC 25.025; ~~and~~

(4) imposition of penalties under AS 31.05.150.

(f) The commission's action under (e) of this section after an informal review or a hearing is not limited to what ~~was~~ the commission proposed under (b)(3) of this section, ~~as long as~~ if the person ~~had~~ has reasonable notice and opportunity to be heard as to the commission's action.

(g) An action by the commission under this section is in addition to any action the commission may take under AS 31.05.160.

(h) ~~When~~ If an apparent violation or noncompliance described in a notification under (b)(1) of this section relates to the underground disposal of oil field wastes or the underground storage of liquid hydrocarbons requiring commission authorization under 20 AAC 25.252 or relates to the injection of fluids requiring commission authorization under 20 AAC 25.402 or 20 AAC 25.460, ~~any~~ a person ~~having~~ with an interest that is or may be adversely affected may intervene in proceedings under this section. (Eff. ___/___/___, Register __)

Authority:			
	AS 31.05.030	AS 31.05.050	AS 31.05.095
	AS 31.05.040	AS 31.05.060	AS 31.05.150

20 AAC 25.537 (a)(1), (b), and (c) are amended to read:

20 AAC 25.537. PUBLIC AND CONFIDENTIAL [WELL] INFORMATION. (a) The commission will routinely make available to the public, by means of records or reports, in its offices or elsewhere, or by means of regular publication, the following information:

(1) surface and proposed bottom-hole locations [LOCATION] of each well[,] after approval of the Permit to Drill (Form 10-401);

. . .

Note to publisher: the remainder of subsection (a) is unchanged.

(b) Engineering, geologic, geophysical, and other commercial information [INFORMATION] not required by this chapter, but voluntarily filed with the commission will be kept confidential if the person filing the information so requests. This subsection does not apply to information submitted in a public hearing under 20 AAC 25.540~~, the confidentiality of which will be governed by other applicable law~~.

(c) In this section, "well status" means the classification of a well as oil, gas, service, suspended, shut-in, or abandoned.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: [AS 31.05.026] AS 31.05.035 [AS 31.05.170]
AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.539. EMERGENCY ACTION. (a) The commission will, in its discretion, issue a temporary emergency order without a hearing if necessary to protect against immediate harm to public health or safety ~~imminent waste, irreparable harm to correlative rights, contamination of freshwater, or a safety hazard resulting from a violation of a provision of AS 31.05, this chapter, or a commission order~~. Before issuing a temporary emergency order, the commission will attempt to communicate with the operator about the circumstances and need for a temporary order.

(b) In support of ~~A~~ temporary emergency order, the commission will ~~be supported by~~ issue a written decision describing the factual and legal basis for the action, including the necessity for acting on an emergency basis. The commission will provide ~~The~~ decision ~~will be provided~~ to the operator within 24 hours of the issuance of the order.

(c) A temporary emergency order expires after 14 days unless

(1) an earlier expiration date is established in that ~~the~~ order;

(2) the operator agrees to an extension; or

(3) within that time period the commission begins under (d) of this section a hearing ~~has actually commenced~~, in which case that ~~the temporary emergency~~ order remains ~~will remain~~ in effect for an additional period not to exceed the shorter of 14 days after the date ~~day~~ the hearing begins ~~commences~~ or three working days after the date ~~day~~ the hearing ends; the commission will extend that period if necessary to protect against immediate harm to public health or safety. ~~closes, whichever period is shorter. For the purposes of a notice of hearing under this subsection, the notice period is 10 days, and the 30 day notice period established in 20 AAC 25.540 does not apply~~. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.050 AS 31.05.095

AS 31.05.040 AS 31.05.060 AS 31.05.150

(d) The commission will, in its discretion, make the temporary emergency order permanent or modify or extend that order after a public hearing. If the temporary emergency order constitutes an enforcement action under 20 AAC 25.535(e)(1) or (2), the procedures under 20 AAC 25.535(b)(4), (c), and (d) do not apply to a commission action under this subsection unless the operator agrees to an extension sufficient to implement those procedures. If the operator does not agree to an extension, the commission's written decision under (b) of this section satisfies the requirements of 20 AAC 25.535(a) and (b)(1)-(3). The provisions of 20 AAC 25.540 apply to a public hearing under this subsection, except that

(1) the commission will provide notice of that hearing at least 10 days before the date of that hearing; and

(2) the requirement in 20 AAC 25.540 that a person request a public hearing does not apply.

20 AAC 25.540 is repealed and readopted to read:

20 AAC 25.540. HEARINGS. (a) On its own motion or if a written request is received to issue an order affecting a single well or a single field, the commission will publish notice in an appropriate newspaper as provided in AS 31.05.050(b). ~~The~~ In the notice, the commission will set out the essential details of the requested order, ~~and~~ provide an opportunity for public comment, and provide a telephone number that the public may use to learn if the commission will hold the tentative hearing. ~~The notice will~~ tentatively specify the place, time, and date for ~~the~~ a public hearing ~~that will be scheduled no fewer than~~ The commission will tentatively set a hearing date that is at least 30 days after the date of publication of the notice. ~~Any~~ A person may submit a written protest or written comments during that 30-day period. In addition, ~~any~~ a person may request that the tentatively scheduled hearing be held by filing a written request with the commission ~~at its office in Anchorage, Alaska~~ within 15 days after the publication date of the notice. ~~The request for hearing must identify the requester's interest in the proposed action and provide the reasons for desiring a public hearing.~~ If the commission ~~determines that a significant issue is raised in~~ receives a timely request for hearing, or if the commission desires to hold a hearing, the commission will hold a hearing ~~will be held~~ on the date and time specified in the notice. If ~~no~~ a request for ~~a~~ hearing is not timely filed, the commission will, in its discretion, issue an order without a hearing.

(b) On its own motion or if a written request for a public hearing is received concerning a matter within the jurisdiction of the commission under this chapter, the commission will publish notice in an appropriate newspaper as provided in AS 31.05.050(b). ~~The~~ In the notice, the commission will provide the essential details of the matter and set out the place for the public hearing, the date, and the time for the public hearing. The commission will set a date that is at least ~~The~~ hearing ~~will be scheduled no fewer than~~ 30 days after the date of publication.

(c) Except as otherwise provided in (e) of this section, the following procedures apply to public hearings conducted under (a) or (b) of this section:

(1) the hearing will be called to order and the subject of the hearing, along with the date and place of public notice given for the hearing, will be read into the record;

(2) the commission will receive both sworn testimony and unsworn statements; it will give greater weight in its deliberations to sworn testimony;

(3) all persons wishing to testify will be sworn;

(4) each witness shall state the witness's name and whom the witness represents;

(5) each witness who wishes to give expert testimony shall state the witness's qualifications, and the commission will rule on whether the witness qualifies as an expert;

(6) the applicant will be asked to present testimony first; all others wishing to present testimony will be heard next; upon request, the commission will, in its discretion, allow cross-examination of witnesses;

(7) a person wishing to make an oral statement will be allowed to do so after the conclusion of all testimony;

(8) the commission will, in its discretion, ask questions of a witness;

(9) except as may be allowed under (6) of this subsection, ~~no one will be permitted to~~ a person may not ask questions of witnesses directly; to have a question directed to a witness, a person ~~shall~~ must provide the question in writing, along with the person's name and that of the witness, to a designated commission representative; before the end of the hearing, the commission will review these questions and ask those that it believes will be helpful in eliciting needed information; all questions will be included in the public record;

(10) ~~when~~ if disclosure of otherwise confidential information is required, ~~such~~ the commission will limit and condition disclosure ~~will be limited and conditioned~~ to the extent necessary to comport with applicable constitutional, statutory ~~(including trade secret provisions, such as AS 45.50.940(3))~~, and common law doctrines that protect trade secrets within the meaning of AS 45.50.940 and other commercially sensitive, confidential, and proprietary information; in limiting or conditioning disclosure under this paragraph, the commission will, as necessary

(A) review confidential information in-camera; and
(B) redact commission decisions to protect confidential information.

(11) ~~a written transcript of~~ the hearing will be ~~prepared and~~ recorded and the recording included in the public record of the hearing;

(12) the commission will, in its discretion, allow pre-filed written testimony in place of or in addition to oral testimony.

(d) The commission will hold hearings on matters of statewide or general application ~~will be held~~ under the applicable provisions of AS 44.62.

(e) In a hearing under 20 AAC 25.535, a party may be represented by counsel, call and examine witnesses, present relevant evidence unless unduly cumulative or repetitious, cross-examine witnesses, impeach witnesses, and rebut adverse evidence. The commission will establish a reasonable date before the hearing by which the commission will and each party must provide: ¶ (1) the names and addresses of persons known to have knowledge of relevant facts and, unless privileged, ¶ (A) ~~their~~ written or recorded statements by those persons; ¶ (B) or summaries of statements by those persons; ¶ (2) the name, address, and qualifications of each expert who will testify at the hearing, and a written description of the substance of the expert's proposed testimony, the expert's opinion, and the underlying basis of that opinion; and ¶ (3) a copy of all documents and a description of all other tangible things intended to be used in the hearing. The commission will base its decision with respect to contested issues of fact only on evidence presented during the hearing.

(f) By means of ~~Pursuant to~~ a pre-hearing conference or otherwise, the commission will, in its discretion, establish additional procedures for a specific hearing consistent with the procedures in (c) or (e) of this section, as applicable, or as otherwise necessary to provide due process to a party. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.050 AS 31.05.070
AS 31.05.040 AS 31.05.060

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.556. ORDERS. ~~All~~ Any orders of the commission require approval of at least two commissioners. (Eff. ___/___/___, Register __)

Authority: AS 31.05.011 AS 31.05.030 AS 31.05.040

20 AAC 25.557 is amended to read:

20 AAC 25.557. SUBPOENAS. (a) The commission will, in its discretion, issue subpoenas [AND SUBPOENAS DUCES TECUM]. Upon a written request, the commission will, in the commission's discretion, issue

(b) ~~A~~ a subpoena [SUBPOENAS DUCES TECUM] for the production of books, records, papers, or other documents of any sort [will, in the commission's discretion, be issued by the commission upon a written request]. The applicant must establish [THAT HE OR SHE HAS] a proper relation to the matter, and must show the relevance of the evidence sought and the facts expected to be proved by that evidence [them]. Upon a written request, the commission will, in the commission's discretion, issue a

(c) ~~A [THE ISSUANCE OF A]~~ subpoena requiring the attendance of a witness for the purpose of taking oral testimony before the commission [will, in the commission's discretion, be issued by the commission upon a written request]. The applicant must establish a [THAT HE OR SHE HAS] proper relation to the matter and give the name and address of the desired witness. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.040 AS 31.05.070

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.560. TIME. ~~Where~~ If AS 31.05 or this chapter requires or permits a person to file or submit a document with the commission, the document is considered filed or submitted when it is received in the commission's office. (Eff. ___/___/___, Register ___)

Authority: AS 31.05.030 AS 31.05.035 AS 31.05.040

20 AAC 25.570 is repealed:

20 AAC 25.570. DEFINITIONS. Repealed. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 1/1/95, Register 132; repealed ___/___/___, Register ___)

Editor's note: As of ___/___/___, Register ___ (~~_____ 19___~~), the substance of 20 AAC 25.570 was moved to 20 AAC 25.990.

Att'n AAC Coordinator

Enter effective date & register number where indicated, in editor's note.

ARTICLE 7.
DEFINITIONS.

Section
990. Definitions

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.990. DEFINITIONS. In this chapter, unless the context requires otherwise,

(1) "abandon" means to plug a well in accordance with 20 AAC 25.112 and without the commission's approval of well suspension under 20 AAC 25.110;

(2) "abnormally geo-pressured strata" means subsurface zones where the pore pressure exceeds a gradient of 0.50 psi/ft;

(3) "API" means the American Petroleum Institute;

~~(4) "API 2M" means an API-defined BOP configuration with a working pressure of 2,000 psi~~.

(4) ~~(5)~~ "API 5~~M~~K" means an API-defined BOP configuration with a rated ~~working~~ pressure of 5,000 psi and as described in API RP 53, adopted by reference at 20 AAC 25.527(c) under 20 AAC 25.040(b);

(5) ~~(6)~~ "API number" means the number assigned by the commission for a well or well branch consistent with the API well numbering convention;

(6) ~~(7)~~ "API RP" means API recommended practices;

(7) ~~(8)~~ "barrel" means 42 U.S. gallons;

(8) "BHA" means bottom-hole assembly;

(9) "BOP" means blowout preventer, which is a casinghead assembly equipped with special gates or rams or other pack-offs that can be closed around the drill pipe, tubing, casing, or tools, and that completely closes the top of the casing to control well pressure;

(10) "BOPE" means blowout prevention equipment;

(11) "bottom-hole location" means the subsurface point at the greatest measured ~~depth~~ penetration of a well or a well branch;

(12) "casing stub" means the remnant of a casing string when the upper portion of the casing has been cut and recovered;

(13) "commission" means the Alaska Oil and Gas Conservation Commission;

(14) "complete" means to equip and condition a well as an oil, gas, or service well so that it is capable of producing or injecting fluids; in the case of a well branch in a previously completed well, "complete" means to equip and condition a well branch so that it is capable of contributing to the well's production or injection of fluids;

(15) "completion operation" means work performed in a well after the casing and cementing of the wellbore, ~~and~~ "completion operation" includes plugging, perforating, stimulating, testing, and equipping the well to produce or inject fluids;

(16) "conductor casing" means a casing string set before surface casing; depending on well configuration, ~~it~~ "conductor casing" can be either the first or second string of casing set in a well and usually supports a diverter system;

(17) "day" means a calendar day;

(18) "development well" means a well drilled to a known productive pool;

(19) "displacement method" means pumping a cement slurry or other material into a well through a drillpipe or other tubular string and recovering displaced fluids on the surface;

(20) "diverter system" means an assembly of nipples, valves, and piping attached to a well's structural or conductor casing for venting a gas kick away from the drill rig;

(21) "downsqueeze method" means pumping a cement slurry or other material into a well through a drillpipe or other tubular string and forcing displaced fluids into a downhole formation;

(22) "drilling fluid" means any fluid used for the purpose of drilling a well;

(23) "drilling operations" means the penetration of ground below the setting depth of structural or conductor casing, ~~if set~~, using a drilling rig capable of performing the permitted well work, and for purposes other than setting structural or conductor casings; "drilling operations" ~~and~~ includes the running of casing, cementing, and other downhole work performed ancillary to formation evaluation, and ~~all~~ operations necessary to complete and equip the well so that formation fluids can be safely brought to the surface;

(24) "drilling unit" means an area of a pool, ¶(A) established by the commission under AS 31.05.100, either by order or by regulation, ¶(B) to which no more than one oil or gas well may be drilled, and ¶(C) from which no more than one oil or gas well may produce;

(25) "exploratory well" means a well drilled to discover or to delineate a pool;

(26) "fluid" means any material or substance that flows or moves, whether in a semi-solid, liquid, sludge, gaseous, or other form or state;

(27) "freshwater" means water ~~having~~ that ¶(A) has a total dissolved solids concentration of less than 10,000 mg/l ~~that~~ and occurs in a stratum not exempted under 20 AAC 25.440, or ¶(B) ~~water that~~ occurs in a stratum that serves as a source of drinking water for human consumption;

(28) "function pressure-test" means to actuate a component and demonstrate its ability to effect a pressure seal;

(29) "function-test" means to actuate a component to demonstrate its proper functioning without subjecting it to pressure;

(30) "gas well" means a well that produces predominantly gas at a gas-oil ratio over 100,000 scf/stb, unless on a pool-by-pool basis the commission establishes another ratio;

(31) "gas-oil ratio" means the cubic feet of gas, determined at 60° F and 14.65 psia, that are produced per stock tank barrel of oil produced;

(32) "injection" means the subsurface emplacement of fluid for enhanced recovery of oil or gas, disposal of oil field wastes, or underground storage of hydrocarbons;

(33) "intermediate casing" means a casing string run between the surface casing and the production casing or production liner and cemented in place to isolate abnormally geo-pressured strata, lost circulation zones, salt sections, or unstable shale sections;

(36) "LEL" means lower explosive limit;

(35) ~~(34)~~ "landowner" has the meaning given in AS 31.05.170;

(37) ~~(35)~~ "liner" means a string of casing that does not extend to surface but is hung inside the previous casing string or ~~may be~~ set and cemented in place within the previous casing string;

(38) ~~(36)~~ "meter curve" means a graph of the meter factor plotted against the flow rate, or of the pulse-per-unit-volume factor plotted against the flow rate, over the operating range of a meter;

(39) ~~(37)~~ "meter factor" means the number obtained by dividing the gross standard volume of liquid passed through a meter as measured by a prover during proving by the corresponding meter indicated volume at standard conditions;

(40) ~~(38)~~ "mg/l" means milligrams per liter;

(41) ~~(39)~~ "mscf" means thousand standard cubic feet;

(42) ~~(40)~~ "mudline datum" means

(A) for a beach location, the plane of mean low water depth extended beneath the well site;

(34) "junk" means debris lost in a hole; "junk" includes a lost bit, pieces of a bit, milled pieces of pipe, wrenches, or a relatively small object that impedes drilling;

(B) for a location on a shifting natural island, the depth at which a horizontal plane through the toe of the island intersects the wellbore;

(C) for a location on an artificial island, the depth of the mudline as it existed before construction of the island; or

(D) for other offshore locations, the mudline;

(43) ~~(41)~~ "multiple completion" means the completion of a well so as to permit production from more than one pool, with the production from each pool completely segregated;

(44) ~~(42)~~ "offshore" means, in addition to its ordinary meaning, beach, artificial island, and shifting natural island locations;

(45) ~~(43)~~ "oil well" means a well that produces predominantly oil at a gas-oil ratio of 100,000 scf/stb or lower, unless on a pool-by-pool basis the commission establishes another ratio;

(46) ~~(44)~~ "operator" means an owner or a person authorized by an owner who is responsible for drilling, development, production, injection, disposal, storage, abandonment, and location clearance;

(47) ~~(45)~~ "owner" has the meaning given in AS 31.05.170;

(48) ~~(46)~~ "pilot gas" means gas routed to a safety flare system to maintain an ignition source;

(49) ~~(47)~~ "ppm" means parts per million;

(50) ~~(48)~~ "pressure-test" means to demonstrate the pressure integrity of a system without actuating its components;

(51) ~~(49)~~ "production casing" means the casing installed from the wellhead to the top of or through the completion interval and cemented in place to seal off production or injection zones and water-bearing formations;

(52) ~~(50)~~ "property" means a legally described tract of land, submerged or otherwise, to which a person has the right to drill, extract, remove, clean, process, and dispose of oil, gas, and associated substances;

(53) ~~(51)~~ "psi" means pounds per square inch;

(54) ~~(52)~~ "psia" means pounds per square inch absolute;

(56) ~~(53)~~ "psig" means pounds per square inch gauge;

(55) "psi/ft" means pounds per square inch per foot, as a measure of pressure change with depth;

(57) "public water system" has the meaning given in 18 AAC 80.1990, as amended as of October 1, 1999, and as amended from time to time; 18 AAC 80.1990 is adopted by reference;

~~(54)~~ "purge gas" means gas used to maintain forward flow and positive pressure in a safety flare system;

(59) ~~(55)~~ "reservoir" means the same as "pool" in AS 31.05.170;

(60) ~~(56)~~ "scf" means standard cubic feet;

(61) ~~(57)~~ "service well" means a well used for injecting water, gas, or other fluids into a reservoir or producing formation in pressure maintenance, enhanced recovery, or storage operations, for disposing of oil field wastes, or for conducting other operations in support of oil or gas production;

(62) ~~(58)~~ "shut in" means to close a well's surface, wellhead, or subsurface valves to halt flow from or into the well, with the completion interval remaining open to the tubing below the closed valves;

(63) ~~(59)~~ "sidetrack operation" means a drilling operation conducted for the purpose of straightening the original hole, bypassing junk, or correcting mechanical difficulties in the original hole;

(64) ~~(60)~~ "standard cubic foot" has the meaning given to "cubic foot" in AS 31.05.170;

(65) ~~(61)~~ "stb" means stock tank barrel;

(66) ~~(62)~~ "stock tank barrel" means 42 U.S. gallons, measured at 60° F and 14.65 psia;

(67) ~~(63)~~ "stratigraphic test" means a hole drilled for the sole purpose of gaining structural or stratigraphic information to aid in exploring for oil and gas;

(68) ~~(64)~~ "structural casing" means a short string of large diameter pipe ~~which may be~~ that is set by driving, jetting, or drilling to support unconsolidated shallow sediments, provide hole stability for initial drilling operations, and provide anchorage for a diverter system;

(69) ~~(65)~~ "surface casing" means a string of casing set and cemented in a well to prevent lost circulation while drilling deeper and to protect strata known or reasonably expected to serve as a source of drinking water for human consumption; usually ~~it~~ "surface casing" is the first string of casing upon which ~~blowout prevention equipment~~ BOPE is set;

(70) ~~(66)~~ "suspend" means to plug a well in accordance with 20 AAC 25.110 and ~~with the operator's reserving~~ to reserve the option later to re-enter and (A) redrill the well or (B) complete the well as an oil, gas, or service well;

(71) "tour" means a work shift in the drilling of a well;

(72) ~~(67)~~ "underbalanced drilling" means drilling under conditions where the hydrostatic head of the drilling fluid column is intentionally designed to be lower than the pressure of the formation being drilled;

(73) ~~(68)~~ "well" (A) means a hole penetrating the earth, usually cased with steel pipe, and (i) from which oil or gas, or both, is obtained or obtainable; or (ii) that ~~which~~ is made for the purpose of finding or obtaining oil or gas or of supporting oil or gas production; and (B) includes a well ~~may have~~ with multiple well branches drilled to different bottom-hole locations;

(74) ~~(69)~~ "well branch" means that portion of a well drilled below the structural or conductor casing to access a separate objective in a well with more than one bottom-hole location; (Eff. ___/___/___, Register ___)

Authority: AS 31.05.030

Editor's note: Before ___/___/___, Register ___ ~~(_____ 19__)~~, the substance of 20 AAC 25.990 was contained in 20 AAC 25.570. The history note for 20 AAC 25.990 does not reflect the history of 20 AAC 25.570.

(75) "working day" means a calendar day other than Saturday, Sunday, or a state holiday.

Att'n AAC Coordinator
Insert effective date & register number in editor's note.

MEMORANDUM

State of Alaska
Department of Law

TO: Robert N. Christenson, Chair
Alaska Oil & Gas Conservation Commission

DATE: October 8, 1999

FILE NO.: 993-94-0171

TELEPHONE NO.: 465-3600

FROM: Steven C. Weaver
Assistant Attorney General
Legislation/Regulations Section—Juneau

SUBJECT: Regulations re: procedures of the Alaska Oil and Gas Conservation Commission (20 AAC 25)

Under AS 44.62.060, we have reviewed the attached adoption, amendment, and repeal of these regulations by the Alaska Oil and Gas Conservation Commission (AOGCC), and approve the changes for filing by the lieutenant governor. I have reviewed this project under a specific delegation dated August 27, 1999 from the Regulations Attorney. A duplicate original of this memorandum is being furnished to the lieutenant governor, along with the 140 pages of regulations and the related documents. We note that the AOGCC adopted the regulations with handwritten edits by the Department of Law.

You might wish to contact the lieutenant governor's office to confirm the filing date and effective date of the attached regulation changes.

The supplemental public notices of August 24, 1998, October 22, 1998, and November 21, 1998, and the October 5, 1999 certification order all state that this action is not expected to require an increased appropriation. Therefore, a fiscal note under AS 44.62.195 is not required.

In accordance with AS 44.62.125(b)(6), some corrections have been made in the regulations, as shown on the attached copy.

SCW

cc w/enc: Dan Spencer, Director & Regulations Contact
Division of Administrative Services
Department of Administration

Cammy Oechsli, Commissioner
Alaska Oil & Gas Conservation Commission

Rob Mintz
Assistant Attorney General
Oil, Gas & Mining Section--Anchorage

RECEIVED

OCT 19 1999

Alaska Oil & Gas Cons. Commission
Anchorage

CHAPTER 25.
ALASKA OIL AND GAS CONSERVATION COMMISSION.

Article

1. Drilling
   (20 AAC 25.005-20 AAC 25.080)
2. Abandonment and Plugging
   (20 AAC 25.105-20 AAC 25.172)
3. Production Practices
   (20 AAC 25.200-20 AAC 25.290[85])
4. Reports
   (20 AAC 25.300-20 AAC 25.320)
5. Enhanced Recovery
   (20 AAC 25.400-20 AAC 25.460)
6. General Provisions
   (20 AAC 25.505-20 AAC 25.570)
7. Definitions
   (20 AAC 25.990)

Publisher: Article headings should be on same line as article numbers, and centered, as in existing text.

ARTICLE 1.
DRILLING.

Section

05. Permit to drill
10. Re-entry of a suspended well
15. Changes to an approved drilling program [PERMIT]
20. Designation of operator
22. Change of ownership
25. Bonding
26. Claims
30. Casing and cementing
33. Primary well control for drilling: drilling fluid program and drilling fluid [SURFACE] system
35. Secondary well control for primary drilling and completion: blowout prevention equipment [(BOPE)] and diverter requirements
36. Secondary well control for through-tubing drilling and completion: blowout prevention equipment requirements
37. Well control requirements for other drilling and completion operations
40. Well identification
45. (Repealed)
47. Reserve pits and tankage
50. Wellbore surveys [DEVIATION]

Temporary shutdown

55. Drilling units and well spacing
61. Well site surveys
65. Hydrogen sulfide
66. Gas detection
70. Records and reports
71. Geologic data and logs
72. [Shutdown] of drilling or completion [WELL] operations
75. Other wells in designated areas
80. Annular disposal of drilling waste

20 AAC 25.005 is repealed and readopted to read:

20 AAC 25.005. PERMIT TO DRILL. (a) Before drilling or redrilling a well or re-entering an abandoned well, a person shall submit and obtain the commission's approval of an application for a Permit to Drill (Form 10-401).

(b) The commission will classify a well as:

(1) exploratory;

(2) development, either oil or gas;

(3) service; or

(4) stratigraphic test.

items, except for an item

each of

(c) An application for a Permit to Drill must be accompanied by the following ~~unless~~ already on file with the commission and identified in the application:

(1) a fee of $100 payable to the State of Alaska/AOGCC ~~Department of Revenue~~;

(2) a plat identifying the property and the property's owners ~~its owner(s)~~ and showing

(A) the coordinates of the proposed location of the well at the surface, at the top of each objective formation, and at total depth, referenced to governmental section lines;

(B) the coordinates of the proposed location of the well at the surface, referenced to the state plane coordinate system for this state as maintained by the National Geodetic Survey in the National Oceanic and Atmospheric Administration;

(C) ~~(B)~~ the proposed depth of the well at the top of each objective formation and at total depth; and

(D) ~~(C)~~ other information required by 20 AAC 25.050(b);

(3) a diagram and description of the blowout prevention equipment (BOPE) as required by 20 AAC 25.035, 20 AAC 25.036, or 20 AAC 25.037, as applicable;

(4) information on drilling hazards, including

(A) the maximum downhole pressure that may be encountered, criteria used to determine it, and maximum potential surface pressure based on a methane gradient;

(B) data on potential gas zones; and

(C) data concerning potential causes of hole problems such as ~~over-pressured zones~~ abnormally geo-pressured strata, lost circulation zones, and zones that have a propensity for differential sticking;

(5) a description of the procedure for conducting formation integrity tests, as required under 20 AAC 25.030(f);

(6) a complete proposed casing and cementing program as required by 20 AAC 25.030, and a description of any slotted liner, pre-perforated liner, or screen to be installed;

(7) a diagram and description of the diverter system as required by 20 AAC 25.035, unless this requirement is waived by the commission under 20 AAC 25.035(h)(2);

(8) a drilling fluid program, including a diagram and description of the drilling fluid system, as required by 20 AAC 25.033;

(9) for an exploratory or stratigraphic test well, a tabulation setting out the depths of predicted abnormally geo-pressured strata as required by 20 AAC 25.033(f);

(10) for an exploratory or stratigraphic test well, a seismic refraction or reflection analysis as required by 20 AAC 25.061(a);

(11) for a well drilled from an offshore platform, mobile bottom-founded structure, jack-up rig, or floating drilling vessel, an analysis of seabed conditions as required by 20 AAC 25.061(b);

(12) evidence showing that the requirements of 20 AAC 25.025 have been met;

(13) a copy of the proposed drilling program; ~~and~~

(14) a general description of how the operator plans to dispose of drilling mud and cuttings and a statement of whether the operator intends to request authorization under 20 AAC 25.080 for an annular disposal operation in the well.

(d) For a well that is to be intentionally deviated, the requirements of 20 AAC 25.050(b) must be met.

(e) ~~A~~ If well ~~may have~~ has multiple well branches, ~~and unless drilled solely to conduct sidetrack operations,~~ each branch requires a separate Permit to Drill. ~~When~~ If multiple well branches are proposed from a single conductor, surface, or production casing, the applicant shall designate one branch as the primary wellbore and include all information required under (c) of this section with ~~its corresponding~~ the application for a Permit to Drill for that branch. For each subsequent well branch, the application for a Permit to Drill need only include information under (c) of this section that is unique to that branch and need not include the $100 fee.

(f) Each well must be identified by a unique name designated by the operator and a unique API number assigned by the commission under 20 AAC 25.040(b). For a well with multiple well branches, each branch must similarly be identified by a unique name and API number by adding a suffix to the name designated for the well by the operator and to the number assigned to the well by the commission.

(g) If drilling operations are not commenced within 24 months after the commission approves an application for a Permit to Drill, the Permit to Drill expires.

(h) A Permit to Drill is not valid at a location where the applicant does not have a right to drill for oil and gas. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25.010 is amended to read:

20 AAC 25.010. RE-ENTRY OF A SUSPENDED WELL. (a) Before re-entering [IF] a suspended well [IS TO BE RE-ENTERED] to conduct completion operations, the operator shall submit and obtain the commission's approval of an [THE FORM ENTITLED] Application for Sundry Approvals (Form 10-403) [FOR COMMISSION APPROVAL]. The Application for Sundry Approvals [FORM 10-403 FILING] must set out the current condition of the well and the proposed program for completion operations.

(b) Before re-entering [IF] a suspended well ~~to conduct~~ [IS TO BE RE-ENTERED] TO keep lowercase keep lowercase ~~CONDUCT~~ [ACTUAL] drilling operations, the operator shall submit and obtain the commission's approval of an application for a [THE FORM ENTITLED] Permit to Drill (Form 10-401) [FOR COMMISSION APPROVAL] in conformance with 20 AAC 25.005.

(c) The operator shall file with the commission within 30 days after completion, abandonment, or suspension of the well a Well Completion or Recompletion Report and Log (Form 10-407) and all information required by 20 AAC 25.070(3) [20 AAC 25.070] and 20 AAC 25.071. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25.015 is repealed and readopted to read:

20 AAC 25.015. CHANGES TO ~~AN APPROVED DRILLING~~ A PROGRAM IN A PERMIT TO DRILL. (a) To change an ~~approved~~ approved in a Permit to Drill (Form 10-401) program before drilling operations ~~have started~~ start, the operator shall

(1) submit and obtain the commission's approval of a new application for a Permit to Drill ~~(Form 10-401)~~ if the surface location is changed, if the bottom-hole location or the location of an objective formation is changed by more than 500 feet laterally or vertically, or if the change requires a spacing exception under 20 AAC 25.055; however, no additional fee is required; or

(2) otherwise notify the commission and obtain its approval of the change if the change is not covered by (1) of this subsection.

(b) To change an ~~approved drilling~~ approved in a Permit to Drill program or to change information under 20 AAC 25.005(c) after drilling operations ~~have started~~ start, the operator shall

(1) submit and obtain the commission's approval of a new application for a Permit to Drill, accompanied by a fee of $100, if the bottom-hole location or the location of an objective formation is changed by more than 500 feet laterally or vertically, or if the change requires a spacing exception under 20 AAC 25.055; or

(2) submit and obtain the commission's approval of an Application for Sundry Approvals (Form 10-403) if the change is not covered by (1) of this subsection; the Application for Sundry Approvals must set out the approved program, the current condition of the well, and the proposed changes; in cases where prompt approval is needed, oral approval may be requested from the commission; if oral approval is obtained, the name of the representative of the commission who provided oral approval and the date of the approval must be included on the Application for Sundry Approvals,

which must be submitted within ~~the commission's next~~ three ~~Working~~ days for final approval by the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

(2) By signing the Designation of Operator form, the newly designated operator agrees to accept the obligations of an operator. The newly designated operator shall

20 AAC 25.020 is amended to read:

20 AAC 25.020. DESIGNATION OF OPERATOR. If an owner of a property wishes to [RELINQUISH THE ROLE OF OPERATOR, OR] designate a new operator for the property, the owner shall submit to the commission for approval a Designation of Operator (Form 10-411). The commission will not approve the designation of a new operator without the signature of the [The] newly designated operator ~~shall~~ [MUST] signify acceptance of the obligations as operator on the same Designation of Operator form [FORM 10-411] and ~~shall~~ [MUST] furnish a bond and, if required, security as provided for in 20 AAC 25.025. The commission's acceptance of the designated operator's bond constitutes the release of the [OWNER'S OR] former operator's bonding obligation for the property indicated on the Designation of Operator form [Form 10-41]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register__)

Authority: AS 31.05.030

20 AAC 25.022 is amended to read:

20 AAC 25.022. NOTICE [CHANGE] OF OWNERSHIP. ~~When a person~~ Within 15 days after a [A] person becomes an owner [~~A PERSON~~ WHO IS THE OPERATOR] of a property on which operations subject to this chapter are [HAVE BEEN] proposed to the commission or are being conducted, the person shall file a Notice of [CHANGE OF] Ownership (Form 10-417) [within 15 days] [AFTER CONVEYANCE, EACH TIME THAT AN OWNER OR LANDOWNER, AS DEFINED BY AS 31.05.170, CONVEYS ALL OR A

PARTIAL INTEREST IN THE PROPERTY TO ANOTHER PERSON]. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.025 is repealed and readopted to read:

20 AAC 25.025. BONDING. (a) An operator proposing to drill a well for which a permit is required under 20 AAC 25.005 shall file a bond and, if required under (2) of this subsection, security to ensure that each well is drilled, operated, maintained, repaired, and abandoned and each location is cleared in accordance with this chapter. The bond must be

(1) a surety bond issued on Form 10-402A in favor of the Alaska Oil and Gas Conservation Commission by an authorized insurer under AS ~~29~~ 21.09 whose certificate of authority is in good standing; or

(2) a personal bond of the operator on Form 10-402B accompanied ~~by and whose performance is guaranteed~~ guaranteeing the operator's performance; security must be by security in the form of a certificate of deposit or irrevocable letter of credit issued in the sole favor of the Alaska Oil and Gas Conservation Commission by a bank authorized to do business in the state, or ~~in the commission's discretion,~~ must be in another form ~~of security~~ that the commission determines to be adequate to ensure payment.

(b) A bond and, if required, security must be in the amount of not less than $100,000 to cover a single well or not less than $200,000 for a blanket bond covering all of the operator's wells in the state, except that the commission will ~~in its discretion,~~ allow an amount less than $100,000 to cover a single well if the operator demonstrates to the commission's satisfaction in the application for a Permit to Drill (Form 10-401) that the cost of well abandonment and location clearance will be less than $100,000.

(c) A bond and, if required, security must remain in effect until the abandonment of all wells covered by them and until the commission approves final clearance of the locations ~~are approved by the commission~~. The commission will then release the bond and security upon written request of the operator.

(d) Payment under a surety bond or security does not relieve an operator from the requirements ~~any obligations~~ of AS 31.05 and ~~under~~ this chapter except to the extent that a default is actually cured, or from any liability under AS 31.05.150. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.150

20 AAC 25.026 is amended to read:

20 AAC 25.026. CLAIMS. Commission approval of the abandonment of a well and the release of the bond[,] required by 20 AAC 25.025 [SEC. 25 OF THIS CHAPTER,] constitutes a presumption of proper abandonment, but does not relieve an operator of further claim by the commission after the abandonment. (Eff. 4/13/80, Register 74; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.030 is repealed and readopted to read:

20 AAC 25.030. CASING AND CEMENTING. (a) A complete proposed well casing and cementing program must be submitted with an application for a Permit to Drill (Form 10-401). Unless modified or altered by ~~special~~ pool rules established under 20 AAC 25.520, a well casing and cementing program must be designed to

(1) provide suitable and safe operating conditions for the total measured depth proposed;

(2) confine fluids to the wellbore;

(3) prevent migration of fluids from one stratum to another;

(4) ensure control of well pressures encountered;

(5) protect against thaw subsidence and freezeback effects within permafrost;

(6) prevent contamination of freshwater;

(7) protect significant hydrocarbon zones; and

(8) provide well control until the next casing is set, considering all factors relevant to well control including formation fracture gradients, formation pressures, casing setting depths, and proposed total depth.

(b) General well casing and cementing provisions are as follows:

(1) casing design and setting depth must be based on engineering and geologic factors relevant to the immediate vicinity, including the presence or absence of hydrocarbons, potential drilling hazards, and permafrost;

(2) for all casing strings on which blowout prevention equipment (BOPE) will be installed, cement may not be drilled out until sufficient compressive strength has been reached to obtain a valid formation integrity test;

(3) within permafrost intervals, fluids that have a freezing point above the minimum permafrost temperature may not be left in casing-by-casing annuli or inside the casing upon completion, suspension, or shutdown of well operations, without commission approval of an alternate method that the commission determines will prevent damage to the casing;

(4) ~~when~~ IF casing is subjected to prolonged drilling operations, the commission will, ~~in its discretion~~ as necessary to verify casing integrity, require the casing to be pressure-tested, calipered, or otherwise evaluated by a method approved by the commission;

(5) ~~where~~ if zonal coverage is required under (a) of this section, and the commission believes zonal isolation might not have been established, the commission will ~~in its discretion~~, require a cement quality log or other method to demonstrate isolation of the zone.

(c) Specific well casing provisions are as follows:

(1) structural casing must be set by driving, jetting, or drilling to a minimum depth of 70 feet in ~~all~~ offshore wells to support unconsolidated shallow strata, to provide hole stability for initial drilling operations, and to provide a competent anchor for a diverter system;

(2) for onshore wells, conductor casing must be set by driving, jetting, or drilling to a depth sufficient to provide anchorage for a diverter system, and for offshore wells, conductor casing must be set no less than 300 feet and no more than 1,000 feet below the mudline datum; ~~except that~~ however, the commission will ~~in its discretion~~

(A) approve a different casing setting depth ~~when~~ if necessary to permit the casing shoe to be set in a competent formation or below formations that should be isolated; or

(B) authorize an operator to drill without setting conductor casing based upon information from wells drilled in the immediate vicinity and other available data, if the commission determines that the absence of conductor casing will not jeopardize well control

(3) surface casing must be set below the base of all strata known or reasonably expected to serve as a source of drinking water for human consumption and at a depth sufficient to provide a competent anchor for ~~blowout prevention equipment~~ BOPE;

(4) one or more intermediate casing strings must be set ~~when~~ if required for protection of oil or gas or for protection against abnormally geo-pressured strata and lost circulation zones, or ~~when~~ if otherwise required by well conditions;

(5) production casing must be set and cemented through, into, or just above the production interval;

(6) slotted liners, pre-perforated liners, and screens installed below a production packer are considered ~~as~~ production equipment and not ~~as~~ casing.

(d) Specific well casing cementing provisions are as follows:

(1) if structural casing is set by drilling or jetting, the structural casing must be cemented with ~~a quantity of~~ cement sufficient to fill the annular space from the shoe to the surface;

(2) if conductor casing is set by drilling or jetting, the conductor casing must be cemented by filling the annular space with cement from the shoe to the surface; if BOPE ~~blowout prevention equipment~~ is to be installed on the conductor casing, the adequacy of the cement to contain potential wellbore pressures and fluids must be demonstrated by a formation integrity test;

(3) ~~upon approval of the commission,~~ conductor casing cement may be washed out to a depth not exceeding the depth of the structural casing shoe, if installed;

(4) surface casing must be cemented by filling the annular space with cement from the shoe to the surface; however, if cement does not circulate to the surface, if an excessive quantity of cement circulates to the surface, or if the formation integrity test shows an inadequate cement job,

(A) the operator shall notify the commission before drilling ahead; and

(B) the commission will ~~in its discretion,~~ require

(i) a cement quality log or other approved method to evaluate the adequacy of the cement to contain potential wellbore pressures and fluids; and

(ii) remedial action as necessary to meet the requirements of (a) of this section before drilling ahead;

(5) intermediate and production casing must be cemented with sufficient cement to fill the annular space from the casing shoe to a minimum of 500 feet above all significant hydrocarbon zones and abnormally geo-pressured strata or, ~~where~~ if zonal coverage is not required under (a) of this section from the casing shoe to a minimum of 500 feet above the casing shoe; if ~~there are~~ exist indications of improper cementing, such as lost returns, ~~cement channeling, or mechanical failure of equipment~~ or if the formation integrity test shows an inadequate cement job, remedial action must be taken;

(6) ~~In cases where~~ if the intermediate or production string is a liner, a minimum of 100 feet overlap between the outer and inner strings is required; the interval of overlap must be made pressure competent and must be pressure-tested in accordance with (e) of this section;

(7) for intermediate or production casing in a service well used for injection, a cement quality log or other evaluation log approved by the commission must be run to demonstrate isolation of the injected fluids to the approved interval.

(e) A casing pressure test must be performed if ~~blowout prevention equipment will~~ BOPE is to be installed on a casing. The casing must be tested to hold a surface pressure equal to 50 percent of the required working pressure of the ~~blowout prevention equipment~~ BOPE as specified in the Permit to Drill under 20 AAC 25.035(e)(3) or 20 AAC 25.036(c)(3). The results of this test and any subsequent tests of the casing must be recorded as required by 20 AAC 25.070(1).

(f) Except for through-tubing drilling, a formation integrity test must be performed if ~~blowout prevention equipment~~ BOPE is installed on a casing. The test must be performed to a predetermined equivalent mud weight, leak-off, or fracture pressure as specified in the ~~well plan~~ application for the Permit to Drill. The test must be conducted after drilling out of the casing shoe into at least 20 feet but not more than 50 feet of new formation. The test results must demonstrate that the integrity of the casing shoe is sufficient to contain anticipated

wellbore pressures identified in the ~~well plan~~ application for the Permit to Drill. The test procedure followed and the data from the test and any subsequent tests of the formation must be recorded as required by 20 AAC 25.070(1).

(g) Upon request of the operator, the commission will, in its discretion, approve variances from the requirements of (b) - (f) of this section to allow for special or unusual conditions ~~as long as~~ if the design requirements of (a) of this section are ~~not diminished~~ satisfied. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.033 is repealed and readopted to read:

20 AAC 25.033. PRIMARY WELL CONTROL FOR DRILLING: DRILLING FLUID PROGRAM AND DRILLING FLUID SYSTEM. (a) A drilling operation must be equipped with a drilling fluid system meeting the requirements of this section, unless the commission determines ~~, in its discretion,~~ that a drilling fluid system is not necessary for primary well control. The operator shall submit with an application for a Permit to Drill (Form 10-401) a proposed drilling fluid program and a diagram with a list of equipment for a drilling fluid system designed to prevent the loss of primary well control. The drilling fluid system must be designed to maintain the wellbore in overbalanced condition except as otherwise provided under (i) of this section. A drilling operation is also subject to the requirements of 20 AAC 25.527.

(b) A drilling fluid program and drilling fluid system intended to maintain the wellbore in overbalanced condition must be designed to provide and maintain

(1) a drilling fluid

(A) of sufficient density to overbalance the pressure of uncased formations penetrated; and

(B) with rheological properties designed to

(i) minimize the potential of a hydrostatic pressure surge or swab when the drilling assembly is run into or pulled out of the wellbore; and

(ii) enhance the drop-out of solids and the escape of ~~any~~ entrained gas; and

(2) a volumetric capacity for drilling fluid reserves adequate for the volume of the wellbore, based on known or anticipated drilling conditions to be encountered, rig storage capacity, weather conditions, and estimated time for delivery.

(c) A drilling fluid system intended to maintain the wellbore in overbalanced condition must include

(1) a recording drilling fluid pit level indicator with both visual and audible warning devices located in the immediate area of the driller's ~~console~~ station;

(2) a drilling fluid measuring system or trip tank for accurately determining drilling fluid volumes required to fill the wellbore on trips;

(3) a drilling fluid flow sensor with a readout convenient to the driller's ~~console~~ station to enable the operator to determine whether drilling fluid returns equal drilling fluid pump discharge rates;

(4) equipment to keep the drilling mud conditioned as appropriate for the drilling operation being conducted; and

(5) methane and hydrogen sulfide detection equipment as required by 20 AAC 25.066.

(d) ~~For rotary drilling rig operations,~~ drilling fluid testing equipment must be on the drill site at all times. Tests to determine drilling fluid density and viscosity must be performed once each tour, or more frequently ~~when~~ if conditions warrant.

(e) To ensure that primary well control is effectively maintained, the following practices must be employed in rotary drilling rig operations when tripping the drilling assembly out of the wellbore:

(1) the drilling fluid within the wellbore must be in balance and conditioned to maintain drilling fluid properties within close tolerance to the properties necessary for well control;

(2) the flow nipple or trip tank must be visually observed to ensure that there is no indication of formation fluid influx;

(3) the wellbore must be kept full of drilling fluid at all times;

(4) the annulus must be filled with fluid

(A) each time that five stands of drill pipe have been removed from the wellbore; and

(B) more frequently than required in (A) of this paragraph, if necessary to prevent the hydrostatic pressure from dropping by 75 psi or more;

(5) the volume of drilling fluid required to keep the wellbore full while tripping the drilling assembly out of the wellbore must be measured and recorded on the daily drilling report or trip sheet.

(f) Additional requirements that apply to exploratory and stratigraphic test wells ~~drilled by a rotary drilling rig~~ are as follows:

(1) the operator shall include with an application for a Permit to Drill a tabulation that sets out the depths of predicted abnormally geo-pressured strata;

as the commission considers necessary to evaluate the potential for a well control problem, (2) if the operator has geophysical data from the area, the operator shall include with an application for a Permit to Drill a seismic velocity analysis constrained by germane well ~~control~~ data ~~must be performed~~ to predict the potential of encountering abnormally geo-pressured strata, with the analysis displayed by plotting interval transit time versus depth; the commission will ~~in its discretion~~, require a ~~confidential~~ review from the operator of the velocity analysis and of the plot of interval transit time versus depth;

(3) if the operator does not have geophysical data from the area, the operator shall include with an application for a Permit to Drill an analysis of germane well ~~control~~ data ~~must be performed~~ to predict the potential of encountering abnormally geo-pressured strata;

(4) a drilling fluid monitoring unit must be used and continuously observed during ~~rotary~~ drilling rig operations, including tripping, to monitor and record

(A) gas entrained in the drilling fluid;

(B) drilling fluid density;

(C) drilling fluid salinity;

(D) the rate of penetration; and

(E) hydrogen sulfide, as required by 20 AAC 25.065;

(5) means for communication between the drilling fluid monitoring unit and the ~~rotary~~ drill rig floor must be installed and maintained in working condition while open hole operations are taking place, and drill rig floor personnel must be notified immediately ~~when~~ if excursions from normal trends occur for any of the parameters set out in (4) of this subsection.

(g) ~~When~~ If drilling an exploratory or stratigraphic test well, or ~~when~~ if drilling a development or service well while known hydrocarbon-bearing strata are exposed to open hole, the operator shall take a drilling fluid return sample and test the sample to determine density just before tripping the drill pipe.

Density test results must be recorded as required by 20 AAC 25.070(1). If the density is less than that of the drilling fluid being pumped down the drilling assembly, the drilling fluid must be circulated and conditioned until a close tolerance of the properties of the return drilling fluid with the input drilling fluid is achieved.

(h) If formation competence at the structural casing setting depth is not adequate to permit circulation of drilling fluids while drilling the conductor hole, a program that provides for safety in that drilling operation must be described and submitted to the commission for approval. This program must be supported by pertinent information including seismic and geologic data, water depth, drilling fluid hydrostatic pressure, and a contingency plan for moving off location.

(i) The commission will ~~in its discretion,~~ approve underbalanced drilling operations and if the commission determines that underbalanced drilling operations can be performed without loss of well control associated equipment changes. A request for underbalanced drilling must include a description of all equipment and procedures to ensure proper containment of formation and return fluids.

(j) Upon request by the operator, the commission will, in its discretion, approve a waiver of the requirements of (c) - (g) of this section if the alternative drilling fluid program and drilling fluid system meet the design criteria of (b) of this section and the corresponding equipment and procedures are at least equally effective in preventing the loss of primary well control. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.035 is repealed and readopted to read:

20 AAC 25.035. SECONDARY WELL CONTROL FOR PRIMARY DRILLING AND COMPLETION: BLOWOUT PREVENTION EQUIPMENT AND DIVERTER REQUIREMENTS. (a) This section applies to drilling and completion operations other than those covered by 20 AAC 25.036 or 20 AAC 25.037. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall submit the following information with the application for a Permit to Drill (Form 10-401) or refer in the application to that information if that information is already on file with the commission:

(1) a diagram of the blowout preventer (BOP) stack or diverter and related equipment for each proposed casing installation; ~~and~~

(2) a list of the blowout prevention equipment (BOPE) and if applicable, diverter equipment with specifications.

(c) Except as provided in (d) and (h) of this section, a high capacity flow diverter system must be installed to provide safety for personnel and equipment before rotary rig drilling is performed below a well's structural or conductor casing, unless the casing is equipped with BOPE conforming with (e) of this section. The following provisions apply to a diverter system:

(1) the diverter system must consist of a remotely operated annular pack-off device, a full-opening vent line valve, and a diverter vent line with a ~~whose~~ diameter ~~is~~

(A) of at least 16 inches, unless a smaller diameter is approved by the commission to account for smaller hole size, geological conditions, rig layout, or surface facility constraints; and

(B) at least as large as the diameter of the hole to be drilled, unless a pilot hole with a diameter no larger than that of the vent line is drilled first; the commission will ~~in its~~

~~discretion~~ waive the requirement of this paragraph if the operator demonstrates, based on drilling experience in the near vicinity, that drilling a pilot hole would not be necessary for safety;

(2) the diverter system must be assembled as follows:

(A) the diverter vent line outlet must be located below the annular pack-off, either as an integral part of the annular pack-off device or as a vent-line outlet spool immediately below it;

(B) the actuating mechanism for the vent line valve must be integrated with the actuating mechanism for the annular pack-off device in a fail-safe manner so that the vent line valve ~~will~~ automatically opens before ~~prior to~~ full closure of the annular pack-off;

(C) the vent line must extend to a point at least 75 feet ~~removed~~ (i) away from a potential source of ignition, and ~~at least 75 feet~~ (ii) beyond the drill rig substructure, or to a point within the ~~the~~ reserve pit, ~~but in~~ and at least ~~no case fewer than~~ 50 feet ~~from~~ beyond the drill rig substructure;

(D) the vent line must be as straight as possible, secured to prevent movement, and designed to avoid freeze-up;

(E) the vent line may be secured to the rig and with portable cradle supports, but may not be attached to flowlines, cable trays, or other processing equipment;

(F) all turns with a bend radius less than 20 times the inside diameter of the vent line must be targeted;

(G) all valves must be full-opening;

(3) a clearly marked "warning zone" must be established on each side and ahead of the vent line tip, and the following restrictions must be in effect within the warning zone, beginning with the

function test of the diverter system immediately before drilling operations begin and ending with diverter system rig-down:

(A) ~~no~~ a prohibition on vehicle parking;

(B) ~~no~~ a prohibition on ignition sources or running equipment;

(C) ~~no~~ a prohibition on staged equipment or materials;

(D) the restriction of traffic to essential foot or vehicle traffic only;

(4) the commission will, in its discretion, inspect the diverter system ~~will, in the commission's discretion, be inspected by the Commission~~ for compliance with the requirements of this subsection and require the operator to test the system ~~tested~~ to ensure proper operation.

(d) If the formation competence at the structural casing setting depth is not adequate to permit use of a diverter system while drilling the conductor hole, a program that provides for safety in that drilling operation must be described and submitted to the commission for approval. This program must be supported by pertinent information including seismic and geologic data, water depth, drilling fluid hydrostatic pressure, and a contingency plan for moving off location.

(e) A well must be equipped with BOPE meeting the requirements of this subsection from the time that open hole drilling operations begin below the surface casing until the drilled portion has been plugged or the well is completed, except ~~when~~ if hydraulic communication to the open hole section is isolated. The following provisions apply to BOPE and other well control equipment:

(1) in rotary drilling rig operations,

(A) for an operation requiring a BOP stack less than API 5~~M~~K, BOPE must have at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except that pipe rams need not be sized to ~~for~~ bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(B) for an operation requiring a BOP stack equal to or greater than API 5M ~~or greater~~, BOPE must have at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except that pipe rams need not be sized to BHAs ~~for bottom-hole assemblies~~ and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(2) in coiled tubing unit operations, the well control equipment must include

(A) for an operation requiring a BOP stack equal to or less than API 5M ~~or less~~,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer; ~~and~~

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and (iv) at least one preventer equipped with pipe rams that fit the size of tubing, liner, or casing being used, except that pipe rams need not be sized to BHAs ~~for bottom-hole assemblies~~ and drill collars; and

(B) for an operation requiring a BOP stack greater than API 5~~M~~K,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers;

~~and~~

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and (iv) at least two preventers equipped with pipe rams that fit the size of tubing, liner, or casing being used, except that pipe rams need not be sized to BHAs ~~except for bottom-hole assemblies~~ and drill collars;

(3) the rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected ~~and~~ as the commission will ~~be specified~~ specify in the approved Permit to Drill; the working pressure that the equipment must be rated to meet or exceed; however, ~~except that~~ the rated working pressure of the annular type preventer need not exceed 5,000 psi, unless the commission requires a higher rated working pressure ~~is required by~~ as the commission considers necessary to maintain well control; if the maximum potential surface pressure exceeds the rated working pressure of the annular type preventer, the operator shall submit with the application for a Permit to Drill a well-control procedure that indicates how the annular type preventer will be used and what pressure limitations will be applied during each mode of pressure control;

(4) a BOPE assembly must include

(A) a hydraulic actuating system with

(i) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled

hydraulic valve while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off; and

(ii) an accumulator pump system consisting of two or more pumps with independent power sources (primary and secondary) and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(B) locking devices on the ram-type preventers;

(C) a fire wall to shield accumulators and primary controls;

(D) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's ~~console~~ station, in addition to controls on the accumulator system;

(E) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's ~~console~~ station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor;

(F) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool or on the BOP body with two full-opening valves on each outlet, conforming to the following specifications:

(i) the outlets must be at least two inches in nominal diameter, except that for rotary drilling rig operations, if the required BOP is rated equal to or greater than API ~~2M~~ 5K, the nominal diameter of the choke outlets must be at least three inches;

(ii) each valve must be sized at least equal to the required size of the outlet to which it is attached;

(iii) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(iv) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid;

(G) in rotary drilling rig operations, a fill-up line above the uppermost BOP; and

(H) a choke manifold equipped with

(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's ~~console~~ station if the operation requires a BOP stack equal to or greater than API 5~~M~~K ~~or greater~~;

(ii) a line at least two inches in nominal diameter downstream of each choke;

(iii) immediately upstream of each choke, at least one full-opening valve for an operation requiring a BOP stack less than API 5~~M~~K, or at least two full-opening valves for an operation requiring a BOP stack equal to or greater than API 5~~M~~K ~~or greater~~; and

(iv) a bypass line, at least the diameter of the choke line, with at least one full-opening valve for an operation requiring a BOP stack less than API 5~~M~~K, or at least two full-opening valves for an operation requiring a BOP stack equal to or greater than API 5~~M~~K ~~or greater~~;

(5) the rated working pressure of the wellhead assembly and of all valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must equal or exceed the required working pressure ~~of the BOPE~~ for the BOPE specified in the approved Permit to Drill, except that the rated working pressure of lines downstream of the choke ~~may be rated to~~ need not exceed 50 percent of the required working pressure of the BOPE;

(6) kill and choke lines must

(A) be constructed of rigid steel pipe, fire-resistant rotary hose, or other ~~suitable~~ conduit that has been approved by the commission as capable of withstanding the temperature and pressure of an ignited uncontrolled release;

(B) be as straight as practical;

(C) if constructed of rigid steel pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(D) be secured to prevent excessive whip or vibration;

(E) be sized to prevent excessive erosion or fluid friction; and

(F) be assembled without hammer unions or internally clamped swivel joints, unless ~~such joints are specifically approved by~~ the commission determines that those joints do not compromise maintenance of well control;

(7) for lubricated drilling operations or operations below a normally closed annular type preventer, the choke line may be used for drilling returns;

(8) connections attached directly to the wellhead, tree, or BOPE must be flanged or hubbed;

(9) for rotary drilling rig operations, auxiliary well control equipment must include

(A) a kelly cock valve installed below the swivel and, at the bottom of the kelly, a full-opening lower kelly valve of a design that allows it to be run through the BOP stack, with a properly sized wrench for each valve stored in a conspicuous location readily accessible to the drilling crew; and

(B) an inside BOP and a full-opening drilling assembly safety valve in the open position on the drill rig floor to fit all connections that are in the drilling assembly;

(10) the BOPE must be tested as follows:

(A) when installed, repaired, or changed, and at least once a week thereafter, BOPE, including kelly valves, emergency valves, and choke manifolds, must be function pressure-tested to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(B) ~~when~~ if BOP sealing ram type equipment has been used, it must be function pressure-tested, before the next wellbore entry, to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(C) non-sealing equipment must be function-tested weekly, ~~and~~ after a repair, or change, and after an ~~or any~~ action that disconnects the hydraulic system lines from the BOPE, except that ~~when~~ if the workstring is continuously in the well ~~or the BHA does not clear the BOP~~, function-testing must be performed as soon as possible ~~thereafter~~; after the workstring is pulled out of the well and the BHA clears the BOP

(D) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(E) ~~a minimum of~~ at least 24 hours notice of each function pressure test must be provided so that a representative of the commission can witness the test.

(f) In consultation with the drilling ~~foreman~~ rig supervisor, the commission will, in its discretion, require drills simulating well control problems. ~~Drills will, in the commission's discretion,~~ The commission will, in its discretion, include in the drills any combination of raising or lowering the pit level indicator, advancing or retarding the flow rate indicator, or actuating the gas detectors.

(g) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Permit to Drill and shall post on the drilling rig floor the drilling hazard information required by 20 AAC 25.005(c)(4) and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Permit to Drill, the drilling hazard information required by 20 AAC 25.005(c)(4), and a copy of the standing orders specifying well control procedures. ~~When~~ If an additional or separate substructure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(h) Upon request of the operator, the commission will, in its discretion, approve a variance

(1) from the BOPE requirements in (e) of this section if the variance provides at least an equally effective means of well control; and

(2) from the diverter system requirements in (c) of this section if the variance provides at least equally effective means of diverting flow away from the drill rig or if drilling experience in the near vicinity indicates that a diverter system is not necessary. (Eff. 4/13/80, Register 74; am 2/22/81, Register 77; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.036. SECONDARY WELL CONTROL FOR THROUGH-TUBING DRILLING AND COMPLETION: BLOWOUT PREVENTION EQUIPMENT REQUIREMENTS. (a) This section applies to drilling and completion operations performed through existing production tubing. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall submit the following information with the application for a Permit to Drill (Form 10-401) or refer in the application to that information if that information is already on file with the commission:

(1) a diagram of each blowout preventer (BOP) stack and related well control equipment to be used; ~~and~~

(2) a list of the blowout prevention equipment (BOPE) with specifications.

(c) A well must be equipped with BOPE meeting the requirements of this subsection from the time that drilling penetrates beyond casing or liner until the drilled portion has been plugged or the well is completed, except ~~when~~ if hydraulic communication to the open hole section has been isolated. The following provisions apply to BOPE and other well control equipment:

(1) in rotary drilling rig operations,

(A) for an operation requiring a BOP stack equal to or less than API 5K ~~or less~~, BOPE must have at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except that pipe rams need not be sized to ~~for~~ bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(B) for an operation requiring a BOP stack greater than API 5K, BOPE must have at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except that pipe rams need not be sized to BHAs ~~for bottom-hole assemblies~~ and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(2) in coiled tubing unit operations, the well control equipment must include

(A) for an operation requiring a BOP stack equal to or less than API 5M ~~or less~~,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer; ~~and~~

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and (iv) at least one preventer equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except that pipe rams need not be sized to BHAs ~~for bottom-hole assemblies~~ and drill collars; and

(B) for an operation requiring a BOP stack greater than API 5M,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers; ~~and~~

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and (iv) at least two

preventers equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except ~~for bottom hole assemblies~~ that pipe rams need not be sized to BHAs and drill collars;

(3) the rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected ~~and~~ ; the commission will ~~be specified~~ specify in the approved Permit to Drill. ~~except that~~ the rated working pressure of an annular type preventer need not exceed 5,000 psi, unless the commission requires a higher rated working pressure ~~is required by~~ as the commission considers necessary to maintain well control; if the maximum potential surface pressure exceeds the rated working pressure of the annular type preventer, the operator shall submit with the application for a Permit to Drill a well control procedure that indicates how the annular type preventer will be used and the pressure limitation that will be applied during each mode of pressure control; the working pressure that the equipment must be rated to meet or exceed; however,

(4) a BOPE assembly must include

(A) a hydraulic actuating system with

(i) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled hydraulic valve while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off; and

(ii) an accumulator pump system consisting of one or more pumps with independent power sources (primary and secondary), and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(B) locking devices on the ram-type preventers;

(C) a fire wall to shield accumulators and primary controls;

(D) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's ~~console~~ station, in addition to controls on the accumulator system;

(E) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's ~~console~~ station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor;

(F) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool, the BOP body, or the tree, with two full-opening valves on each outlet, conforming to the following specifications:

(i) the outlets and valves must be at least two inches in nominal diameter;

(ii) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(iii) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid;

(G) for open hole deployment, an annular type preventer, unless a lubricator of sufficient length to enclose the entire ~~bottom hole assembly~~ (BHA) below a high pressure sealing element is used; and

(H) for conventional open loop fluid process drilling operations, a choke manifold equipped with

(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's or operator's ~~console~~ station if the operation requires a BOP stack equal to or greater than API 5M ~~or greater~~;

(ii) a line at least two inches in nominal diameter downstream of each choke;

(iii) immediately upstream of each choke, at least one full-opening valve for an operation requiring a BOP stack equal to or less than API 5M ~~or less~~, or at least two full-opening valves for an operation requiring a BOP stack greater than API 5M; and

(iv) a bypass line at least two inches in nominal diameter with at least one full-opening valve immediately upstream of each choke for an operation requiring a BOP stack equal to or less than API 5M ~~or less~~, or with at least two full-opening valves immediately upstream of each choke for an operation requiring a BOP stack greater than API 5M;

(5) in an underbalanced drilling operation, well control equipment must have bi-directional slip capabilities;

(6) the rated working pressure of the wellhead assembly and of all valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must equal or exceed the required working pressure ~~of the BOPE~~ specified for the BOPE in the approved Permit to Drill, except that the rated working pressure of lines downstream of the choke need not exceed ~~may be rated to~~ 50 percent of the required working pressure of the BOPE;

(7) for lubricated drilling operations or operations below a normally closed annular type preventer, the choke line may be used for drilling returns;

(8) at least one positive seal manual or hydraulic valve or BOPE blind ram, one set of BOPE pipe rams, and, if used, the drilling spool must be flanged to the wellhead or tree;

(9) connections directly to the BOPE, other than connections described in (8) of this subsection, must be flanged or hubbed, except that suitably pressure-rated quick connects may be used if a positive seal manual valve, hydraulic valve, or BOPE blind ram and an annular type preventer or sealing ram are flanged to the wellhead or tree below the quick connection;

(10) kill and choke lines must

(A) be constructed of rigid steel pipe, fire-resistant rotary hose, or other ~~suitable~~ conduit that has been approved by the commission as capable of withstanding the temperature and pressure of an ignited uncontrolled release;

(B) be as straight as practical;

(C) if constructed of rigid steel pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(D) be secured to prevent excessive whip or vibration;

(E) be sized to prevent excessive erosion or fluid friction; and

(F) be assembled without hammer unions or internally clamped swivel joints, except that hammer unions and internally clamped swivel joints may be used on the kill line upstream of the valves that are flanged to the wellhead or tree.

(d) A BOPE assembly must be tested as follows:

(1) when installed, repaired, or changed, and at least once a week thereafter, the BOPE, including emergency valves and choke manifolds, must be function pressure-tested to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(2) other well control equipment must be pressure-tested to the maximum ~~expected~~ potential wellhead pressure after each installation of the well control equipment and before wellbore entry, except that ~~when~~ if testing against the annular type preventer, pressure testing need not exceed 50 percent of the rated working pressure of the annular type preventer;

(3) ~~when~~ if BOP sealing ram type equipment has been used, it must be function pressure-tested, before the next wellbore entry, to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(4) non-sealing equipment must be function-tested weekly ~~and~~, after a repair or change, ~~or~~ and after any ~~any~~ action that disconnects the hydraulic system lines from the BOPE, except that ~~when~~ if the workstring is continuously in the well ~~or the BHA does not clear the BOP~~, function-testing must be performed as soon as possible after the workstring is pulled out of the well and the BHA clears the BOP ~~thereafter~~;

(5) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(6) ~~a minimum of~~ at least 24 hours notice of each function pressure test must be provided so that a representative of the commission can witness the test.

(e) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Permit to Drill and shall post on the drilling rig floor the drilling hazard information required by 20 AAC 25.005(c)(4) and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Permit to Drill, the drilling hazard information required by 20 AAC 25.005(c)(4), and a copy of the standing orders specifying well

control procedures. ~~When~~ If an additional or separate sub-structure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(f) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.037. WELL CONTROL REQUIREMENTS FOR OTHER DRILLING AND COMPLETION OPERATIONS. For ~~unconventional~~ drilling and completion operations for which the provisions of 20 AAC 25.033, 20 AAC 25.035, or 20 AAC 25.036 would not be practical or appropriate, the commission will ~~in its discretion,~~ approve alternate well control procedures and equipment if the procedures and equipment are adequate to maintain well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.040 ~~(a) and (b) are~~ is amended to read:

(a) Every well must be identified by a sign posted in a conspicuous place. During the period of time from commencement of drilling operations [SPUD] to well completion, suspension, or abandonment, the sign must be on or near the drill rig [DERRICK], but not more than 100 feet from the well. After well completion or suspension [FOR SUSPENDED OR PRODUCIBLE WELLS], the well sign must be at the wellhead or on the wellhead building. The sign must be of durable construction, large

enough to be legible under normal conditions at a distance of 50 feet, and maintained in legible condition. Each sign must show the

(1) name designated by the operator under 20 AAC 25.005(f) for [OF] the well drilled from the surface location;

(2) name of the owner;

(3) name of the operator if different from the owner;

(4) API [WELL] number that the commission has, under (b) of this section, assigned to the well;

(5) well surface location by governmental quarter section, section, township, and range; and

(6) Permit to Drill [DRILLING PERMIT] number ~~or numbers~~ that the commission has assigned under (b) of this section [during the period of time from ~~commencement of drilling operations~~ [SPUD] to well completion, suspension, or abandonment].

(b) The commission will assign a Permit to Drill number and an API number [EACH WELL WILL BE ASSIGNED AN API WELL NUMBER BY THE COMMISSION] when a Permit to Drill (Form 10-401) [THE DRILLING PERMIT] is approved.

(c) For platforms or multiple-well drill sites, the information required in (a)(2) - (a)(5) [(a)(1) - (a)(3) AND (a)(5)] of this section may be posted on one sign on the platform or at the entrance to the drill site.

~~Note to publisher: subsection (c) is unchanged.~~

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.047 is amended to read:

20 AAC 25.047. RESERVE PITS AND TANKAGE. (a) Before a person commences drilling [SPUDDING] a well [PERMITTED UNDER 20 AAC 25.005], a [PROPER AND APPROPRIATE] reserve pit must be constructed[,] or [APPROPRIATE] tankage installed for the reception and

confinement of drilling fluids and cuttings, to facilitate the safety of the drilling operation, and to prevent contamination of freshwater [GROUND WATER] and damage to the surface environment. The ~~confining surfaces of the reserve pit must be impervious~~ [SPECIAL PRECAUTIONS MUST BE TAKEN TO RENDER IMPERVIOUS THE ~~CONFINING SURFACE OF A RESERVE PIT.~~] confining surface of a reserve pit must be impervious. If practical, confinement diking in construction of a reserve pit must be avoided. If confinement dikes are necessary, they must be kept to a minimum. Dikes must be constructed and maintained to ensure [INSURE] their confinement integrity.

(b) Upon [TERMINATION OF] completion, suspension, or abandonment of the well [OPERATIONS], the operator shall proceed with diligence to [DISPOSE OF OR SOLIDIFY IN PLACE ALL PUMPABLE FLUIDS, AND SHALL] leave the reserve pit in a condition that does not constitute a hazard to freshwater [GROUND WATER]. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.050 is repealed and readopted to read:

20 AAC 25.050. WELLBORE SURVEYS. (a) A well that is not intentionally deviated must be

(1) drilled as close to vertical as is possible using conventional drilling techniques, except that deviation is permitted for short intervals to straighten the hole, sidetrack junk, or correct mechanical difficulties;

(2) surveyed to determine the inclination from vertical with surveys starting at 500 feet and no more than 500 feet apart to total depth; and

(3) surveyed by a complete continuous directional survey if ~~any~~ a portion of the well path is less than 500 feet from a property line where the ownership by owner or landowner is not identical on

both sides of the line, or if ~~any~~ a portion of the well path is less than 200 feet from any other vertical or deviated well; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface.

(b) If a well is to be intentionally deviated, the application for a Permit to Drill (Form 10-401) must

(1) include a plat, drawn to a suitable scale, showing the path of the proposed wellbore, including all adjacent wellbores within 200 feet of any portion of the proposed well; and

(2) ~~list the names of~~ For all ~~operators of~~ wells within 200 feet of the proposed wellbore (A) list the names of the operators of those wells, to the extent that those names are known or discoverable in public records, and show that each named operator has been furnished a copy of the application by certified mail; or (B) state that the applicant is the only affected owner.

(c) A well that is intentionally deviated must be

(1) directionally surveyed at intervals not more than 500 feet apart on straight or tangent sections of the well during the normal course of drilling, and at intervals not exceeding 100 feet in all portions of the hole where intentional angle changes are performed;

(2) surveyed by a continuous directional survey if ~~any~~ a portion of the well path is less than 500 feet from a property line where the ownership by owner or landowner is not identical on both sides of the line; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface; and

(3) surveyed by a continuous directional survey if ~~any~~ a deviated portion of the wellbore is less than 200 feet from any other vertical or deviated well; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface.

(d) Within 30 days after the completion, abandonment, or suspension of a well, and within 30 days after completion or plugging of a well branch, a complete digital copy of each inclination and directional survey not previously filed must be filed with the commission in a format acceptable to the commission. A composite survey may ~~also~~ additionally be filed if the operator believes this would better represent the well course. If a composite survey is filed, the operator shall specify the portion of each survey used in the composite.

(e) If the final location of the producing interval of a well is not in compliance with 20 AAC 25.055 or ~~other rules of the commission applicable to the reservoir~~ with pool rules established under 20 AAC 25.520, the operator shall apply for an exception. The commission will review the application ~~will be handled~~ in accordance with 20 AAC 25.540. The well may not be produced until the exception is granted.

(f) A wellbore survey report required by (a) or (c) of this section must contain

(1) the name of the surveying company;

(2) the name, title, and signature of the person who actually performed the survey;

(3) the date on which the survey was performed;

(4) the type of survey conducted;

(5) the method used in calculating the survey;

(6) a complete identification of the well ~~showing~~ or, in the case of a well with more than one bottom-hole location, a complete identification of the well branch; the identification must show the name of the well designated by the operator under 20 AAC 25.005(f), the name of the operator, the property name or lease number, the Permit to Drill number assigned under 20 AAC 25.040(b), the API number, and the field name;

(7) the depth interval over which the survey was conducted; and

(8) a plat showing the coordinates ~~, referenced to governmental section lines~~ (A) of the surface location, the plotted well course, and ~~any well(s)~~ wells within 500 feet of any portion of the wellbore; (B) these coordinates must be referenced to governmental section lines; and

(B) of the surface location, referenced to the state plane coordinate system for this state as maintained by the National Geodetic Survey in the National Oceanic and Atmospheric Administration.

(g) The commission will, in its discretion, require submittal of the original film, time sheets, charts, graphs, discs, and other data used to compile the survey required by (a) or (c) of this section.

(h) Upon application, the commission will, in its discretion, waive all or part of the directional survey requirements of this section or approve alternate means for determining the location of a wellbore if the variance at least equally ensures accurate surveying of the wellbore to prevent well intersection, to comply with spacing requirements, and to ensure protection of correlative rights. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.055 is repealed and readopted to read:

20 AAC 25.055. DRILLING UNITS AND WELL SPACING. (a) The commission will, in its discretion, establish drilling units to govern well spacing and prescribe a spacing pattern by ~~special~~ pool rules adopted in accordance with 20 AAC 25.520. In the absence of an order by the commission establishing drilling units or prescribing a spacing pattern for a pool, the following statewide spacing requirements apply:

(1) for a well drilling for oil, a wellbore may be open to test or regular production within 500 feet of a property line only ~~where~~ if the owner is the same and the landowner is the same on both sides of the line;

(2) for a well drilling for gas, a wellbore may be open to test or regular production within 1,500 feet of a property line only ~~where~~ if the owner is the same and the landowner is the same on both sides of the line;

(3) ~~where~~ if oil has been discovered, the drilling unit for the pool is a governmental quarter section; not more than one well may be drilled to and completed in that pool on any governmental quarter section~~, nor may~~; a well ~~be drilled~~ may not be drilled or completed closer than 1,000 feet to any well drilling to or capable of producing from the same pool;

(4) ~~where~~ if gas has been discovered, the drilling unit for the pool is a governmental section; not more than one well may be drilled to and completed in that pool on any governmental section~~, nor may~~; a well ~~be drilled~~ may not be drilled or completed closer than 3,000 feet to any well drilling to or capable of producing from the same pool.

(b) A well may not begin regular production of oil from a property that is smaller than the governmental quarter section upon which the well is located or begin regular production of gas from a property that is smaller than the governmental section upon which the well is located, unless the interests of the persons owning the drilling rights in and the right to share in the production from the quarter section or section, respectively, have been pooled under AS 31.05.100.

(c) A pooling agreement under AS 31.05.100 must be filed with the commission before regular production from the affected property begins.

(d) The commission will review ~~An~~ application for an exception to the provisions of this section ~~will be handled~~ in accordance with 20 AAC 25.540. The applicant for an exception shall send notice of the application by certified mail to the owners, landowners, and operators described in (1) of this subsection ~~below~~ and shall furnish the commission with a copy of the notice, the date of mailing, and the addresses to which the notice was sent. The application must include

(1) the names of all owners, landowners, and operators of all properties within 1,000 feet of a well drilling for oil or within 3,000 feet of a well drilling for gas for which an exception is sought ~~required~~;

(2) a plat drawn to a scale of one inch equaling 2,640 feet or larger, showing the location of the well for which the exception is sought, all other completed and drilling wells on the property, and all adjoining properties and wells; and

(3) ~~a statement~~ an affidavit by a person acquainted with the facts, verifying that all facts are true and that the plat correctly portrays pertinent and required data.

(e) Upon application by the operator, the commission will ~~in its discretion~~, establish notice requirements different from those of (d) of this section if the operator demonstrates to the commission's satisfaction that compliance with the notice requirements in (d) of this section is not feasible because of the complexity of ownership within the notice area~~, a more effective means of providing notice is available~~. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.100

20 AAC 25.061 is amended to read:

20 AAC 25.061. WELL SITE SURVEYS. (a) For an exploratory or stratigraphic test well, near [NEAR] surface strata to a depth of 2,000 ~~[2000]~~ feet in the vicinity of the well [SITE AREA FOR ALL EXPLORATORY AND STRATIGRAPHIC TEST WELLS] must be evaluated seismically by common depth point refraction or reflection profile analysis, or by another method approved by the commission, to identify anomalous velocity variations indicative of potential shallow gas sources. Analysis results must be included with the application for the Permit to Drill (Form 10-401).

(b) For a well drilled offshore from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel, the vicinity of the [THE] well [SITE AREA] must be evaluated by sidescan sonar and other pertinent surveys to determine whether potential seabed hazards to drilling operations are present [FOR EACH TYPE OF WELL LISTED IN 20 AAC 25.005 TO BE DRILLED OFFSHORE FROM A

MOBILE BOTTOM-FOUNDED, JACK-UP OR FLOATING UNIT]. Survey results must be included with the application for Permit to Drill [(FORM 10-401)].

(c) Upon request by the operator, the commission will, in its discretion, [WILL] waive the requirements of this section if the operator can identify, by other equally effective means, the likelihood of encountering potential shallow gas or seabed hazards or if the commission already has information that substantiates the presence or absence of shallow gas or seabed hazards. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.065(a) and (b) are amended, (c) is repealed and readopted, and (d) is repealed, to read:

20 AAC 25.065. HYDROGEN SULFIDE. (a) If [When] hydrogen sulfide gas is encountered in excess of 20 ppm, the operator shall notify the commission within 24 hours after the encounter.

(b) If a well is to be drilled in an area where a formation to be penetrated is known to contain hydrogen sulfide gas, or if hydrogen sulfide gas is encountered while drilling, the [EACH] operator shall conform with [MEET THE REQUIREMENTS OF] API RP 49, *Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide*, 2d edition, April 15, 1987, which is adopted by reference.

(c) If the ~~there is an insufficient~~ history of drilling in an area is insufficient to know whether hydrogen sulfide gas exists, the commission will specify on the Permit to Drill (Form 10-401) that the operator shall comply with minimum requirements for detection monitoring, contingency and control, and training, as follows:

(1) in addition to the automatic hydrogen sulfide detection system required in

20 AAC 25.066, at least three manual detectors with an adequate supply of extra detector tubes must be available on the location;

(2) hydrogen sulfide treating material for the drilling mud must be available on or near the location, in good condition and in sufficient quantity to adequately treat the mud system should hydrogen sulfide be encountered;

(3) detailed emergency operating procedures must be defined and posted to ensure the safety of all personnel should hydrogen sulfide be encountered;

(4) detailed step-by-step remedial procedures must be developed and posted to cover emergencies while drilling or tripping;

(5) personnel protective equipment must be available on the location;

(6) all persons engaged in drilling operations must be trained for emergency procedures in the presence of hydrogen sulfide gas and in the use of personal protective equipment, alarm systems, and emergency exit procedures.

(d) Repealed ___/___/___. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Att'n AAC Coordinator: Please insert effective date of repealer

Authority: AS 31.05.030

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in ~~this section~~ 20 AAC 25.065 may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070, or if not available from the American Petroleum Institute, may be obtained from Global Engineering Documents, 15 Inverness Way East, Englewood, CO 80150.

Note to publisher: italics should be added to title of publication cited in subsection (b).

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.066. GAS DETECTION. (a) ~~All~~ Each drilling and workover rigs must meet the following minimum requirements for methane and hydrogen sulfide gas detection:

(1) the methane detection system must have a minimum of three sensing points~~)~~; one sensing point must be under the substructure near the cellar, one must be over the shale shaker, and one must be above the drill rig floor near the driller's ~~console~~ station or above the drilling platform; if the mud pits are remote from the shale shaker and enclosed, a fourth sensor must be located over the mud pits;

(2) methane sensors must be placed to detect a "lighter-than-air" gas;

(3) the hydrogen sulfide detection system must have a minimum of three sensing points~~)~~; one sensing point must be under the substructure near the cellar, one must be near the shale shaker, and one must be above the drill rig floor near the driller's ~~console~~ station or above the drilling platform; the commission will ~~in its discretion,~~ require additional sensors as the commission considers necessary for safety, such as at the entrance to living quarters if they are adjacent to the drill rig, or over the mud pits if they are remote from the shaker and enclosed;

(4) hydrogen sulfide sensors must be placed to detect a "heavier-than-air" gas;

(5) sensors must be automatic, acting independently ~~(i.e.,~~ and in parallel~~)~~, and with one-minute minimum sampling intervals;

(6) each detection system must include separate and distinct visual and audible alarms; the visual alarm must signal the low level gas alarm and the audible alarm the high level gas alarm; an audible alarm may have an "acknowledge" button;

(7) the methane low level gas alarm must be set at not over 20 percent LEL ~~(lower explosive limit)~~; the high level alarm must be set at not over 40 percent LEL;

(8) the hydrogen sulfide low level gas alarm must be set at 10 ppm; the high level alarm must be set at not over 20 ppm;

(9) each alarm must be automatic and must be visible and audible from the driller's or operator's ~~console~~ station; the hydrogen sulfide alarm must be audible throughout the drilling location, including the camp buildings.

(b) A gas detection system that continuously performs self-checking or diagnostics must be function-tested when a BOP stack is initially installed after a drill rig is set up, when a commission-witnessed BOP test occurs, and no less frequently than once every six months. Other gas detection systems must be calibrated and tested when a BOP stack is initially installed after a drill rig is set up, when a commission-witnessed BOP test occurs, and no less frequently than once every 30 days. The operator shall maintain at the drill rig an accessible record of gas detection system tests and calibrations.

(c) A failure in a gas detection system must be reported to the commission within 24 hours after the failure. The commission will, in its discretion, require well operations to be discontinued if a gas detection system fails. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.070 is repealed and readopted to read:

20 AAC 25.070. RECORDS AND REPORTS. The operator of a well shall

(1) keep a detailed accurate daily record of the actual drilling, completion, workover, repair, and plugging operations, and of the tests required by this chapter; the daily record ~~which~~ must be available for inspection at reasonable times by the commission

(A) at the well; and

(B) in the state for five years after the date of well abandonment;

(2) file with the commission before well completion or, if the well is not completed, before well abandonment a survey plat certified by a registered land surveyor showing the precise surface location of the well; however, only the first well drilled from a fixed platform or a multiple-well location must have a certified survey;

(3) file with the commission, within 30 days after completion, abandonment, or suspension of the well and within 30 days after completion or plugging of a well branch, if occurring at a different time, a complete well record on the Well Completion or Recompletion Report and Log (Form 10-407), including the tests required by this chapter and a summary of daily well operations reporting drilling depths, ~~zones of abnormal pressure~~ abnormally geo-pressured strata, lost circulation and other hole difficulties encountered, simulated kick drills, mud weight, and a brief description of principal items of work done, such as running and cementing casing, drill stem tests, BOP tests, coring, sidewall sampling, and logging; in the case of a well with multiple well branches, information pertaining to and filed under this paragraph with respect to a portion of a well need not be re-filed unless changed; and

(4) upon request of the commission after completion, abandonment, or suspension of the well or completion or plugging of a well branch, file with the commission a copy of the daily record required by (1) of this section. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.071(b) is repealed and readopted, and (c) and (d) are amended, to read:

(b) Within 30 days after completion, suspension, or abandonment of a well, whichever occurs first, and within 30 days after completion or plugging of a well branch, if occurring at a different time, the operator shall file with the commission, unless previously filed,

(1) a sepia and a reproduced copy of a complete mud log or a lithology log consisting of a detailed record and description of the sequence of strata encountered, including the kind and character of the rock and all shows of hydrocarbons; an electronic image file in a format acceptable to the commission may be substituted for the sepia;

(2) a complete set of washed and dried, legibly identified samples of all drill cuttings, as caught by the operator in accordance with good geological practices, consisting of a minimum of one-quarter cup in volume or three ounces in weight of cuttings for each sample interval;

(3) a lithologic description and, if available, photographs of ~~all~~ each conventional and sidewall core~~s~~; conventional core descriptions must include ~~all~~ apparent textural, fluid, and lithologic variations, including rock type, porosity, fractures, bedding plane attitudes, sedimentary structure, grain size, and presence of hydrocarbons;

(4) ~~a chip or~~ chips from each foot of recovered conventional core, except that chips need not be submitted until 30 days after the conventional core is analyzed; the chips must be representative of the one-foot interval, and must be approximately either one cubic inch in volume, or two ounces in weight;

(5) a list of the geologic markers encountered and the measured and true vertical depths of each marker;

(6) a sepia and a reproduced copy of all logs run, including common derivative formats such as tadpole plots of dipmeter data and borehole images produced from sonic or resistivity data, and including composite log formats; ~~except~~ however, copies of velocity surveys and experimental logs need not be included; an electronic image file in a format acceptable to the commission may be substituted for the sepia;

(7) a tape, diskette, or other electronic ~~media~~ medium acceptable to the commission and a verification listing of the digital data for all logs run, except velocity surveys and experimental logs; ~~and~~ the verification listing must include a written description of the logical and physical format of the digital data; ~~and~~ stet

(8) (B) a copy of all drill stem test and production test data and charts; a brief summary of production tests, drill stem tests, wireline formation tests, and other formation tests performed, including test date, time, depth, duration, method of operation, recovered fluid ~~type(s)~~ types, fluid ~~amount(s)~~ amounts, gas-oil ratio, oil gravity, pressure, and choke size; ~~any~~ (C) conventional and sidewall core analysis determinations, if any, of porosity, permeability, and fluid saturation; ~~and any~~ (D) geochemical and formation fluid analyses obtained, if any.

~~the data described in this paragraph must be filed as soon as available if the 30-day filing period cannot be met.~~

(c) The commission will, in its discretion, waive or modify the requirements of [(a), (b)(1), AND (b)(2) OF] this section for a well if ~~they~~ those requirements would not significantly add to the geologic knowledge of the area in light of the information that is available from other wells in the area [~~FOR~~ "For" DEVELOPMENT WELLS].

Rel. underline beneath

(d) In this section

(1) "experimental logs" means logs that are not commercially available from a well logging contractor [SO NEWLY DEVELOPED OR SO LIMITED OR SPECIALIZED IN APPLICATION

the following items, or a written request proposing a date for submitting those items, subject to commission approval of that date for timeliness, if those items are unavailable within the 30-day filing period set out in this subsection:
(A)

THAT THEY ARE NOT COMMONLY RUN ON PETROLEUM EXPLORATION OR DEVELOPMENT WELLS]; and

(2) "velocity survey" means a survey, the primary purpose of which is to determine velocity of seismic waves through formations penetrated by a well by measuring travel times of seismic pulses from or near the surface to geophones placed at [A SEISMOMETER LOWERED TO] various depths in the well. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.035

20 AAC 25.072(a), (b), and (d) are amended to read:

TEMPORARY

20 AAC 25.072. [SHUTDOWN OF DRILLING OR COMPLETION [WELL] OPERATIONS.

(a) If [CLIMATE, OPERATIONAL OR ENVIRONMENTAL CONCERNS, PRUDENCY, OR OTHER] circumstances prevent the continuation of the program approved on a Permit to Drill (Form 10-401) [THE DRILLING PERMIT], or if an operator wishes to change drill rigs [FOR RIG SUBSTITUTION], the operator shall apply to the commission for approval to shut down drilling or completion [WELL] operations. ~~The~~ decide whether to commission will [in its discretion] approve the temporary shutdown of drilling or completion [WELL] operations. The request for operation shutdown must be submitted on [THE LETTER OF APPLICATION MUST SET OUT A FULL JUSTIFICATION FOR THE SHUT DOWN AND BE ACCOMPANIED BY] an Application for Sundry Approvals (Form 10-403), providing a full justification for the shutdown, a description of [WHICH SETS OUT] the proposed condition of the wellbore [WELL BORE] upon shutdown of drilling or completion [WELL] operations, the approximate date when drilling or completion [WELL] operations will resume, and a proposed program for securing

temporarily. Based on the information received under this subsection, the [THE]

the well during the period of shutdown. An Application for Sundry Approvals is not required for planned shutdowns of well operations ~~that are stated~~ , if those shutdowns are described in the approved Permit to Drill.

(b) The operator shall file with the commission, within 30 days after ~~well~~ operation shutdown, a complete well record on a Report of Sundry Well Operations (Form 10-404), including a summary [COPY] of [THE] daily [REPORTS OF] well operations as described in [REQUIRED BY] 20 AAC 25.070(3) [20 AAC 25.070(a)(1)] and a copy of all logs run in the well as required by 20 AAC 25.071(b)(6) [20 AAC 25.071(b)(5)]. The commission will, in its discretion, waive the requirements of this subsection if drilling or completion [WELL] operations are to be resumed within 60 days after operation shutdown.

. . .

Note to publisher: subsection (c) is unchanged.

(d) If well operations are not resumed within 12 months, ~~unless the commission grants an extension upon application of the operator,~~ the operator shall immediately proceed to abandon or suspend the well. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Upon application of the operator, the commission will extend the 12-month period, if the operator shows that operational circumstances beyond the operator's control prevent resumption within the 12-month period.

~~20 AAC 25.075 is amended to read:~~

~~20 AAC 25.075. OTHER WELLS IN DESIGNATED AREAS. There are areas in the state where drilling [OPERATIONS] could unexpectedly encounter oil, gas, or hazardous substances at shallow depths. When the commission obtains sufficient evidence to define a specific area and the approximate depth range of the substances, it will issue an order that defines the area and stipulates [WILL PRESENT THE EVIDENCE, DEFINE THE AREA, AND STIPULATE] a drilling depth. After the issuance of such an order, any drilling [WELL DRILLED] in the defined area, for any purpose, that exceeds the stipulated depth will require a Permit to Drill (Form 10-401) [DRILLING PERMIT] and~~

Publisher: Existing 20 AAC 25.075 is unchanged.

~~may be subject to the other requirements of this chapter. (Eff. 4/13/80, Register 74; am __/__/__,~~

Register __)

~~Authority: AS 31.05.030~~

20 AAC 25.080(a) - (e) and (h)(1) are amended, and (f) is repealed and readopted, to read:

(a) A person may not dispose of drilling waste through the annular space of a well unless authorized by the commission under this section. The [AN] operator of a well permitted under AS 31.05.090 may request authorization for the [SUCH A] disposal of drilling waste through the well's annular space by filing with the commission [IN AN APPLICATION FOR A PERMIT TO DRILL (FORM 10-401) OR] an Application for Sundry Approvals (Form 10-403) supplemented with ~~any~~ additional information as required under this section.

(b) A request for authorization under this section must include the following information or refer to that information if that information is already on file with the commission:

(1) the annulus to be used for disposal [A DESIGNATION OF THE WELL THAT WILL RECEIVE DRILLING WASTE];

. . .

(3) a stratigraphic description of the interval exposed to the open annulus and other information sufficient to support a commission finding that the waste will be confined and will not come to the surface or, except to the extent allowed under (e)(1) of this section, contaminate freshwater [THE DEPTH AND THICKNESS OF THE RECEIVING ZONE AND THE CONFINING ZONE, AND SUFFICIENT INFORMATION TO DEMONSTRATE CONFINEMENT];

. . .

(5) the ~~type(s)~~ types and [AN ESTIMATE OF THE] maximum volume of waste to be disposed of and the estimated density of the waste slurry [TO BE DISPOSED];

. . .

(8) details that show that the shoe of the outer casing is set below the base of permafrost, if present, and any freshwater aquifer, other than freshwater excepted under (e)(1) of this section, [AND PERMAFROST, IF PRESENT,] and is adequately cemented [WITH SUFFICIENT CEMENT] to provide zone isolation; the information relied upon and submitted must include (A) cementing records and (B) a cement quality log or formation integrity test records;

(9) details that show that the inner and outer casing strings have sufficient strength in collapse and burst to withstand the anticipated pressure of disposal operations; [AND]

(10) the downhole pressure obtained during a formation integrity test conducted below the outer casing shoe;

(11) identification of ~~any~~ the hydrocarbon zones, if any, above the depth to which the inner casing is cemented;

(12) the duration of the disposal operation, not to exceed 90 days;

(13) whether ~~any~~ drilling waste has previously been disposed of in the annular space of the well and, if so, a summary of the ~~date(s)~~ dates of the disposal ~~operation(s)~~ operations; the ~~volume(s)~~ volumes of waste disposed of and the ~~well(s)~~ wells where the drilling waste was generated;

(14) the well where the drilling waste to be disposed of was or will be generated;

(15) if the operator proposes not to comply with a limitation established in (d) of this section, an explanation of why compliance would be imprudent; ~~and~~

(16) any additional data required by the commission to confirm containment of drilling waste.

(c) The commission will [in its discretion,] authorize an annular disposal operation [OF DRILLING WASTE THROUGH THE ANNULAR SPACE OF A WELL PERMITTED UNDER AS 31.05.090] described in the Application for Sundry Approvals, as that application has been ~~(as~~ supplemented under this section), and subject to any modifications prescribed by the commission, if [it] the commission determines that the

(1) waste will be adequately confined [CONTAINED IN A SUITABLE RECEIVING ZONE];

(2) disposal will not

(A) contaminate freshwater, except to the extent allowed under (e)(1) of this section;

. . .

(C) impair the mechanical integrity of any [THE] well [USED FOR DISPOSAL]; or

. . .

(d) Unless the operator demonstrates[, BY WRITTEN APPLICATION,] that [it] compliance is imprudent to comply with a limitation established in (1) - (4) of this subsection is imprudent, the commission will not authorize disposal of drilling waste

. . .

(3) into a hydrocarbon-bearing stratum; or

. . .

On a case-by-case basis, and as the commission considers necessary to ensure that the standards in (c) of this section are met, the commission will impose conditions upon an authorization to dispose of drilling waste under this section.

(e) [In addition to any other conditions that the commission in its discretion imposes on a case-by-case basis], an authorization to dispose of drilling waste under this section is subject to the following conditions:

(1) drilling waste may not be disposed of into freshwater, unless the Application for Sundry Approvals; and ~~except~~ freshwater is identified in the ~~request for authorization that the~~ commission finds that the freshwater has a total dissolved solids content of more than 3,000 mg/l and is not reasonably expected to supply a public water system; the commission will, in its discretion, provide 15 days notice and the opportunity for a public hearing in accordance with 20 AAC 25.540 before making that finding;

(2) the downhole disposal pressure may not exceed the downhole pressure obtained during the formation integrity test conducted below the outer casing shoe, or a higher pressure specified in the authorization upon the commission's finding that the higher pressure will not cause drilling waste to migrate above the confining zone;

(3) if drilling waste appears above the confining zone, the operator shall immediately cease disposal, notify the commission, and take appropriate remedial action; [and]

(4) [(2)] ~~(4[2])~~ if the commission notifies the operator that disposal operations pose a threat to well integrity, safety, oil or gas recovery, or freshwater, except to the extent allowed under (1) of this subsection, the operator shall immediately cease disposal and take appropriate remedial action as approved or required by the commission.

(f) For each annular disposal operation authorized under this section, the operator shall report the following information to the commission on a Report of Annular Disposal (Form 10-423) not later than 30 days after the end of the period authorized for the disposal operation:

(1) the dates when disposal began and ended; ~~and~~

(2) the volume of drilling waste disposed of in each of the following categories:

(A) the aggregate of drilling wastes described in (h)(1) of this section;

(B) the aggregate of drilling wastes described in (h)(2) of this section; and

(C) each substance determined to be a drilling waste under (h)(3) of this section.

. . .

Note to publisher: subsection (g) is unchanged.

(h) In this section, "drilling waste" means the following substances, unless identified as a hazardous waste in 40 C.F.R. [Part] 261:

(1) drilling mud, drilling cuttings, reserve pit fluids, cement-contaminated drilling mud, completion fluids, [AND] formation fluids associated with the act of drilling a well permitted under 20 AAC 25.005, and any added water needed to facilitate pumping of drilling mud~~s~~ or drilling cuttings;

. . .

Note to publisher: subsection (i) is unchanged.

(Eff. 9/22/96, Register 139; am ___/___/___, Register ___)

Authority: AS 31.05.030

Delete underline beneath period

ARTICLE 2.
ABANDONMENT AND PLUGGING.

Keep as is published, on same line as "Article 2", and centered.

Section
105. [PLUGGING, SUSPENSION, AND] Abandonment of wells
107. Plugging well branches
110. Suspended wells
112. Well plugging requirements
115. Shut-in wells
120. Well abandonment marker
140. Water wells
170. Onshore location clearance
172. Offshore location clearance

20 AAC 25.105 is repealed and readopted to read:

20 AAC 25.105. ABANDONMENT OF WELLS. (a) All wells that have been permitted on a property under 20 AAC 25.005 must be abandoned before expiration of the owner's rights in that property or if, after notice and hearing, the commission orders abandonment for safety reasons or because the operator has effectively abandoned operations prior to the expiration of the lease. If the owner is the landowner, all wells that have been permitted on a property by 20 AAC 25.005 must be abandoned within one year following permanent cessation of the operator's oil and gas activity within the field where the wells are located or according to an abandonment schedule approved by the commission, unless the wells are earlier abandoned for safety reasons.

(b) A well drilled onshore or from a fixed offshore platform must be abandoned before removal of the drill rig ~~from location~~ unless the well is completed as an oil, gas, or service well or is suspended, or unless well operations are shut down in accordance with 20 AAC 25.072. ~~All~~ Each well drilled from a fixed offshore platform must be abandoned before the platform is removed or dismantled.

(c) A well drilled offshore from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel must be abandoned before removal of the drill rig ~~from location~~ unless

(1) the well is completed as an oil, gas, or service well; or

(2) subsea equipment for well re-entry is properly installed ~~in a manner approved by the commission~~ and either the well is suspended or well operations are shut down in accordance with 20 AAC 25.072.

(d) A well drilled from a beach, artificial island, or shifting natural island must be abandoned before removal of the drill rig ~~from location~~ unless the well is completed as an oil, gas, or service well or is suspended, or unless well operations are shut down in accordance with 20 AAC 25.072 and plans for maintaining the integrity of the location are approved by the commission.

(e) An Application for Sundry Approvals (Form 10-403) must be ~~filed with~~ submitted to and approved by the commission before work is begun to abandon a well, except that oral approval may be obtained from the commission if it is followed within ~~10~~ three days by the ~~filing~~ submission of an Application for Sundry Approvals for final approval by the commission. The commission will attach conditions to its ~~Approval will be conditioned~~ approval as necessary to protect freshwater and hydrocarbon resources. ~~An~~ The Application for Sundry Approvals must include

(1) the reason for abandoning the well; and

(2) a statement of proposed work, including

(A) information on abnormally geo-pressured strata;

(B) the manner of placement, kind, size, and location, by measured depth, of existing and proposed plugs;

(C) plans for cementing, shooting, testing, and removing casing;

(D) if the Application for Sundry Approvals is ~~filed~~ submitted after beginning work, the name of the representative of the commission who provided oral approval, and the date of the approval; ~~and~~ stet

(E) ~~All~~ other information pertinent ~~information~~ to abandonment of the well. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.107. PLUGGING WELL BRANCHES. (a) An operator may plug a well branch before abandoning or suspending the well. If a well branch has not been completed, the operator shall plug the well branch before removal of the drill rig ~~from location~~, unless well operations are shut down in accordance with 20 AAC 25.072.

(b) An Application for Sundry Approvals (Form 10-403) must be ~~filed with~~ submitted to and approved by the commission before work is begun to plug a well branch, except that oral approval may be obtained from the commission if it is followed within three days by the submission of an Application for Sundry Approvals for final approval by the commission. The provisions of 20 AAC 25.105(e) apply to the application, except that instead of including the reason for abandoning the well, the application must include the reason for plugging the well branch and the reason for not immediately abandoning or suspending the well.

(c) The provisions of 20 AAC 25.112(a) - (c) and (e) - (i) apply to plugging a well branch.

(d) This section does not apply to the temporary plugging of a well branch for production control purposes. (Eff. __/__/__, Register ____)

Authority: AS 31.05.030

20 AAC 25.110 is repealed and readopted to read:

20 AAC 25.110. SUSPENDED WELLS. (a) ~~Where~~ IF allowed under 20 AAC 25.105, the commission will, ~~in its discretion,~~ upon application by the operator under (b) of this section, approve the suspension of a well ~~that has not been completed~~ if

(1) the well

(A) encounters hydrocarbons of sufficient quality and quantity to indicate that the well is capable of producing in paying quantities, as reasonably demonstrated by well tests or interpretive formation evaluation data; for purposes of this paragraph, "paying quantities" means quantities sufficient to yield a return in excess of operating costs;

(B) is a candidate for redrilling;

(C) has potential value as a service well; or

(D) is located on a pad or platform with active producing or service wells; and

(2) the operator justifies to the commission's satisfaction why the well should not be ~~completed or~~ abandoned; and, if the well is not completed, why the well should not be completed; sufficient reasons include the

(A) unavailability of surface production or transportation facilities;

(B) imprudence of security maintenance of a completed well in a shut-in status;

(C) need for pool delineation and evaluation to determine the prudence of pool development.

(b) An Application for Sundry Approvals (Form 10-403) must be ~~filed with~~ submitted to and approved by the commission before plugging operations are begun in a well for which suspension is proposed, except that oral approval may be obtained from the commission if it is followed within ~~10~~ three days by the ~~filing~~ submission of an Application for Sundry Approvals for final approval by the commission. Approval will be conditioned as necessary to protect freshwater and hydrocarbon resources. An Application for Sundry Approvals must include

(1) the reason for suspending the well and information showing that the applicable criteria for suspension under (a) of this section have been met; and

(2) a statement of proposed work, including

(A) information on abnormally geo-pressured strata;

(B) the manner of placement, kind, size, and location, by measured depth, of existing and proposed plugs;

(C) plans for cementing, shooting, testing, and removing casing;

(D) if the Application for Sundry Approvals is ~~filed~~ submitted after beginning work, the name of the representative of the commission who provided oral approval, and the date of the approval; and

(E) ~~all~~ other information pertinent ~~information~~ to suspension of the well.

(c) At the operator's request accompanying the submission, information ~~voluntarily~~ submitted to show that the applicable criteria for well suspension under (a) of this section have been met will be kept confidential ~~in accordance with 20 AAC 25.537~~ (1) for the period specified under AS 31.05.035(c), if the information is described in 20 AAC 25.071(b); or (2) ~~for the time that the~~ information has value as a trade secret, if the information is not described in 20 AAC 25.071(b) but is determined by the commission to constitute a trade secret under AS 45.50.940.

(d) A well approved for suspension must be plugged in accordance with the requirements of 20 AAC 25.112, except that the requirements of 20 AAC 25.112(d) do not apply if

(1) a wellhead is installed or the well is capped with a mechanical device to seal the opening; and

(2) a bridge plug capped with 50 feet of cement or a continuous cement plug extending 200 feet within the interior casing string is placed at or above 300 feet below the surface; the commission will ~~in its discretion~~ waive the requirement of this paragraph for a development well drilled from a pad or platform, if the commission determines that the level of activity on the pad or platform assures adequate surveillance of that development well

(e) Until a suspended well has been abandoned or re-entered, the operator shall maintain the integrity of the location, provide the commission with a well status report every five years, and clear the location in accordance with 20 AAC 25.170(a)(2) or (b) or with 20 AAC 25.172(c)(2) or (d), as applicable ~~a manner approved by the commission~~. (Eff. 4/2/86, Register 97; am __/__/__, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.112. WELL PLUGGING REQUIREMENTS. (a) Plugging of the uncased portion of a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface. The minimum requirements for plugging the uncased portion of a wellbore are as follows:

(1) by the displacement method, a cement plug must be placed

(A) from 100 feet below the base to 100 feet above the top of all hydrocarbon-bearing strata;

(B) from the well's total depth to 100 feet above the top of all hydrocarbon-bearing strata;

(C) from the well's plugged back total depth to 100 feet above the top of all hydrocarbon-bearing strata, if all hydrocarbon-bearing, abnormally geo-pressured, and freshwater strata below are isolated; however, ~~except that~~ the commission will, ~~in its discretion~~, if the commission determines that the objectives of this subsection will be met, approve plugging from the top of fill or the top of junk instead of from the plugged back total depth; or

(D) from 100 feet below the base to 50 feet above the base of each significant hydrocarbon-bearing stratum and from 50 feet below the top to 100 feet above the top of each significant hydrocarbon-bearing stratum;

(2) by the displacement method, a cement plug must be placed from 100 feet below the base to 50 feet above the base of each abnormally geo-pressured strat~~a~~ and from 50 feet below the top to 100 feet above the top of each abnormally geo-pressured strat~~a~~; ~~and~~

(3) by the displacement method, a cement plug must be placed from 150 feet below the base to 50 feet above the base of the deepest freshwater stratum.

(b) Plugging of a well must include effectively segregating uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. The minimum requirement for plugging to segregate uncased and cased portions of a wellbore is one of the following: ~~as follows~~:

(1) by the displacement method, a continuous cement plug must be placed from 100 feet below to 100 feet above the casing shoe;

(2) by the downsqueeze method using a retainer set no less than 50 feet but no more than 100 feet above the casing shoe, a volume of cement sufficient to fill the wellbore from the retainer to 100 feet below the casing shoe must be pumped through the retainer, and cement must be pumped above the retainer to cap it with a 50 foot cement plug; ~~or~~

(3) by the downsqueeze method using a production packer set no less than 50 feet but no more than 500 feet above the casing shoe, a volume of cement sufficient to fill the wellbore from 100 feet below the casing shoe to the packer must be pumped through the packer, and cement must be pumped above the packer to cap it with a 50 foot cement plug.

(c) Plugging of cased portions of a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface. The minimum requirements for plugging cased portions of a wellbore are as follows:

(1) perforated intervals must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the base to 50 feet above the base of the perforated interval and from 50 feet below the top to 100 feet above the top of the perforated interval;

(B) by the displacement method, a cement plug placed from the well's total depth to 100 feet above the top of the perforated interval;

(C) by the displacement method, a cement plug placed from the well's plugged-back total depth to 100 feet above the top of the perforated interval, if all hydrocarbon-bearing, abnormally geo-pressured, and freshwater strata below are isolated; ~~except that~~ however, the commission will~~, in its discretion,~~ approve plugging from the top of fill or the top of junk instead of from the plugged-back total depth, if the commission determines that the objectives of this subsection will be met;

(D) by the downsqueeze method using a cement retainer or production packer set no less than 50 feet but no more than 500 feet above the perforated interval, a volume of cement pumped through the retainer or packer sufficient to fill the wellbore from 100 feet below the base of the perforated interval to the retainer or packer; ~~or~~

(E) if the perforations are isolated from open hole below, a mechanical bridge plug set no more than 50 feet above the top of the perforated interval, and either a minimum of

75 feet of cement placed on top of the plug by the displacement method or a minimum of 25 feet of cement placed on top of the plug with a dump bailer;

(2) casing stubs within outer casing must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the stub to 100 feet above the stub;

(B) by the downsqueeze method using a retainer set 50 feet above the stub, a volume of cement pumped below the retainer sufficient to fill the casing stub with 150 feet of cement, and cement pumped above the retainer to cap it with a 50 foot cement plug; ~~or~~

(C) if the casing stub annulus is cemented, a mechanical bridge plug set no more than 25 feet above the casing stub, and either a minimum of 75 feet of cement placed on top of the plug by the displacement method or a minimum of 25 feet of cement placed on top of the plug with a dump bailer;

(3) ~~where~~ if freshwater is present, the smallest diameter casing string extending to the surface must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the depth of the surface casing shoe to 100 feet above the depth of the shoe; ~~or~~

(B) a mechanical bridge plug set 100 feet below the depth of the surface casing shoe and at least 200 feet of cement placed on top of the plug.

(d) Plugging of the surface of a well must meet the following requirements:

(1) by the displacement method, a cement plug at least 150 feet in length, with the top of the cement no more than ~~5~~ Five feet below original ground level onshore, or between 10 and 30 feet below the mudline datum offshore, must be placed within the smallest diameter casing string; ~~and~~ (2) either

~~(2)~~ (A) all annular space open at the surface onshore, or in communication with open hole and extending to the mudline datum offshore, must be plugged with cement to seal the annular space in a manner satisfactory to the commission; or

~~(3)~~ (B) all casing interior to the surface casing must be recovered to a depth of 100 feet or more below the original ground level onshore or the mudline datum offshore and the casing stubs plugged with cement as provided in (c)(2)(A) of this section; if the cement plug is extended to within the distance from the surface specified in (1) of this subsection, the requirement of (1) of this subsection ~~will~~ need not be ~~deemed~~ met.

(e) Cement used for plugging within zones of permafrost must be designed to set before freezing and have a low heat of hydration.

(f) Each of the respective intervals of a wellbore between the various plugs must be filled with fluid of sufficient density to exert a hydrostatic pressure exceeding the greatest formation pressure of permeable formations in the intervals between the plugs at the time of abandonment.

(g) Except for surface plugs, the operator shall record the actual location and integrity of cement plugs, cement retainers, or bridge plugs required by this section ~~by~~, using one of the following methods, which in the case of a cement retainer or bridge plug may be performed before cement is placed on top of the plug:

(1) placing sufficient weight on the plug to confirm its location and to confirm that the ~~cement or mechanical~~ plug has set and a competent plug is in place~~, in which event testing of the cement placed above the bridge plug or retainer is not required~~; ~~or~~

(2) testing the plug to hold a surface pressure of 1,500 psig or 0.25 psi/ft multiplied by the true vertical depth of the casing shoe, whichever is greater, and tagging the plug to confirm location; however, surface pressure ~~must~~ may not subject the casing to a hoop stress that will exceed 70 percent of the minimum yield strength of the casing.

(h) ~~A minimum of~~ At least 24 hours notice of plugging operations must be given to the commission so that a representative of the commission can witness the operations.

(i) The commission will, in its discretion, approve a variance from the requirements of this section if the variance provides for at least equally effective plugging of the well and prevention of fluid movement into sources of hydrocarbons or freshwater. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.115. SHUT-IN WELLS. (a) No later than March 31 of each year, an operator shall file with the commission a report on ~~all~~ completed development or service wells that have been shut in for 365 days or longer as of January 1 of that year. The report must provide

(1) the current known mechanical condition of the well, including the condition of ~~all~~ installed tubing and casing strings;

(2) the date the well was shut in and the circumstances surrounding the decision to shut in the well; and

(3) an analysis of the future utility of the well.

(b) The commission will ~~in its discretion,~~ require an operator of a shut-in well to file additional information as the commission considers necessary to ensure that freshwater and hydrocarbon sources are protected. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.120 is repealed and readopted to read:

20 AAC 25.120. WELL ABANDONMENT MARKER. (a) The exact surface location of an abandoned well must be shown by a steel well abandonment marker. The marker must be a marker plate meeting the requirements of (b) of this section. However, upon the request of ~~except that if a marker post is requested by~~ the surface owner, if ~~approved by~~ the commission determines that a marker post does not create a hazard or obstacle, the commission will approve ~~the marker must be~~ a marker post meeting the requirements of (c) of this section.

(b) A marker plate must be

(1) at least 1/4 inch thick;

(2) at least 18 ~~eighteen~~ inches square or in diameter; and

(3) welded to and must cover ~~covering~~ the outermost casing string.

(c) A marker post must

(1) be at least four inches in diameter and at least 10 feet long;

(2) be set in cement inside well casing or firmly welded with supporting fillets to the top of a steel plate secured to the casinghead or casing stub;

(3) extend from four to six feet above final ground level; and

(4) be closed at the top with a screw cap, welded plate, or cement plug.

(d) The following information ~~name of the operator, Permit to Drill number(s), and API number(s)~~ must be bead-welded directly to the marker:

(e) The commission will, in its discretion, inspect the marker to verify proper installation and well information at the time of the location clearance required under 20 AAC 25.170.

(1) the name of the operator;
(2) the number that the commission has, under 20 AAC 25.040(b), assigned to the Permit to Drill for the well;
(3) the name designated for the well by the operator under 20 AAC 25.005(f);
(4) the API number for the well, with any suffix appended to the number under 20 AAC 25.005(f).

(f) This section does not apply to abandoned wells drilled offshore. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

and is subject to commission approval, based upon the commission's determination that the proposed use as a freshwater well is bona fide

20 AAC 25.140 is amended to read:

20 AAC 25.140. WATER WELLS. If a well drilled onshore for oil or gas is to be [p]lugged and [a]bandoned, is safe for use but [may safely be used] as a freshwater well, [and such a use is desired by] a person who wishes to use the well as a freshwater well must obtain [,] written [a]uthorization to do so [authority for this action must be obtained] from the landowner and the owner of the surface rights. The authorization must provide for the authorized person's assumption of full responsibility for the final plugging of the water well. This authorization must be filed with [and approved by] the commission. After [Following] the commission's approval of the plugging of the well to protect the freshwater bearing strata to a depth approved by the commission for conversion to a water well and after the commission's approval of the location clearance for compliance with 20 AAC 25.170(a)(2) or (b) or 20 AAC 25.172(c)(2) or (d), the operator is relieved of further obligation under the operator's bond. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.170 is repealed and readopted to read:

20 AAC 25.170. ONSHORE LOCATION CLEARANCE. (a) At or the time that ~~After~~ a well drilled onshore ~~has been~~ is abandoned and before the earlier of one year after well abandonment or the expiration of the owner's rights in the property,

(1) the operator shall remove the wellhead equipment and casing to a depth at least three feet below original ground level and install a well abandonment marker in accordance with 20 AAC 25.120; and

(2) ~~except to the extent that~~ unless the operator demonstrates to the commission that the surface owner has authorized a different disposition ~~has been approved by another government agency having jurisdiction or authorized by the surface owner~~ to facilitate a genuine beneficial use, the operator shall

(A) remove all materials, supplies, structures, and installations from the location;

(B) remove all loose debris from the location;

(C) fill and grade all pits or close them in another manner approved by the commission as adequate to protect public health and safety; and

(D) leave the location in a clean and graded condition.

(c) ~~(b)~~ The commission will modify the time period set out in (a) of this section as follows ~~in its discretion, grant an extension of time beyond one year after well abandonment~~

(1) if ~~a longer period is approved by~~ the Department of Natural Resources, as to a state lease, or ~~by~~ the United States Department of the Interior, as to a federal lease; ~~or~~ approves a time period beyond one year after well abandonment for location clearance, the commission will set an identical time period for compliance with (a) of this section

(2) ~~upon receipt of~~ an Application for Sundry Approvals (Form 10-403) stating

(A) a request for a specific extension not to exceed one year;

(B) the reason an extension is necessary;

(C) a description of location clearance progress; and

(D) the expiration date of the owner's rights to enter the location.

the commission will grant an extension of time beyond one year after well abandonment, if the commission determines that the extension does not threaten public health or safety or the surface owner's interests, and that the operator does not seek an extension for purposes of delay; to seek an extension under this paragraph, the operator must submit

Publisher: Keep AAC title number together with the rest of the citation, on next page.

~~(b)~~ (d) After the work required under (a) of this section has been completed at a location, the commission will, in its discretion, conduct an on-site inspection to verify the location condition at the time of inspection, including the presence of a proper well marker if above ground, as required under 20

¶(b) If a well described in (a) of section is located on state or federal land, and if the agency acting on behalf of the state or federal government as lessor approves a disposition different from that required under (a)(2) of this section, the commission will accept that disposition instead of requiring the operator to comply with (a)(2) of this section.

AAC 25.120, and will provide the operator a report of the inspection. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.172 is repealed and readopted to read:

20 AAC 25.172. OFFSHORE LOCATION CLEARANCE. (a) ~~After~~ No later than the time that all wells drilled from a fixed offshore platform ~~have been~~ are abandoned and ~~when~~ the platform is removed or dismantled, the operator shall remove all well casing to a depth at least one foot below the mudline. The operator shall provide the commission with verification, using appropriate means approved by the commission, that the casing has been removed as required. If ~~another government agency having jurisdiction~~ an agency acting on behalf of the state or federal government as lessor approves leaving the platform in place after well abandonment, the commission will accept that approval and waive requirements of this subsection ~~will be waived~~.

(b) When a well ~~has been~~ is abandoned from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel, the operator shall remove the wellhead equipment, casing, piling, and other obstructions to a depth at least five feet below the mudline before removing the drill rig ~~from location~~, unless otherwise approved by the commission as adequate to protect public health and safety. The operator shall provide the commission with verification, using appropriate means approved by the commission, that the requirements of this subsection have been met.

(c) ~~After~~ At or after the time that a well drilled from a location on a beach, artificial island, or shifting natural island ~~location has been~~ is abandoned, and before the earliest of one year after well abandonment, the time that the operator stops activities necessary to ensure the integrity of the location, or the expiration of the owner's rights in the property,

(1) the operator shall remove the wellhead equipment and casing to a depth at least five feet below the mudline datum; and

(2) ~~except to the extent that~~ unless the operator demonstrates to the commission that the surface owner has authorized a different disposition ~~has been approved by another government agency having jurisdiction or authorized by the surface owner~~ to facilitate a genuine beneficial use, the operator shall

(A) remove all materials, supplies, structures, and installations from the location;

(B) remove all loose debris from the location;

(C) fill and grade all pits or close them in another manner approved by the commission as adequate to protect public health and safety; and

(D) leave the location in a clean and graded condition.

(e) ~~(d) The commission will, in its discretion, grant an extension of time beyond one year after well abandonment to comply with (c) of this section if a longer period is approved by~~ If the Department of Natural Resources, as to a state lease, or by the United States Department of the Interior, as to a federal lease, approves a time period beyond one year after well abandonment for location clearance, the commission will set an identical time period for compliance with (c) of this section.

(f) ~~(e)~~ After the work required under (c) of this section has been completed at a location, the commission will, in its discretion, conduct an on-site inspection to verify the location condition at the time of inspection ~~and~~. If the commission conducts an inspection, the commission will provide the operator a report of the inspection. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

(d) If a well described in (c) of this section is located on state or federal land, and if the agency acting on behalf of the state or federal government as lessor approves a disposition different from that required under (c)(2) of this section, the commission will accept that disposition instead of requiring the operator to comply with (c)(2) of this section

Authority: AS 31.05.030

ARTICLE 3.
PRODUCTION PRACTICES.

Section
200. Production equipment
205. Notification of uncontrolled release [ACCIDENTAL LOSS] of oil or gas
210. Multiple completions [COMPLETION] of wells
215. Commingling of production
225. Potential of gas wells
228. Production measurement equipment for custody transfer
230. Measurement, allocation, and reporting of well production [PRODUCTION MEASUREMENT]
235. Gas disposition
240. Gas-oil ratio [RATIOS] limitations
245. Common production facilities
250. (Repealed)
252. Underground disposal of [WATER AND OTHER] oil field wastes [WASTE FLUIDS] and underground storage of [LIQUID] hydrocarbons
255. (Repealed)
260. Illegal production
265. Automatic shut-in equipment
270. Initial reservoir properties [PRESSURE]
275. (Repealed) [RESERVOIR FLUID PROPERTIES]
280. Workover operations
285. Secondary well control for tubing workover operations: blowout [BLOWOUT] prevention equipment requirements [FOR WORKOVER OPERATIONS]
286. Well control requirements for workstring service operations
287. Well control requirements for wireline operations
288. Well control requirements for other service operations
290. Operations producing hydrogen sulfide

20 AAC 25.200 (a) and (d) are amended to read:

(a) Surface production equipment must be installed to control, separate, clean, [AND] gather, and carry to the point of custody transfer or other disposition in a safe manner all produced oil, gas, and water. All equipment must be installed, operated, and maintained in accordance with good oil field engineering practices [ESTABLISHED INDUSTRY PRACTICE].

. . .

Note to publisher: subsections (b) and (c) are unchanged.

(d) All producing wells capable of unassisted flow must be completed with downhole production equipment consisting of suitable tubing and a packer that [which] effectively isolate [isolates] the tubing-casing annulus from fluids being produced, unless [otherwise specifically approved by] the commission specifically approves production through the annulus to increase flow rate without jeopardizing ultimate recovery from the well.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.205 is amended to read:

20 AAC 25.205. NOTIFICATION OF UNCONTROLLED RELEASE [ACCIDENTAL LOSS] OF OIL OR GAS. (a) The operator shall immediately notify the commission [The commission must be immediately notified by the operator] of any uncontrolled release exceeding 10 barrels of oil or 1000 mscf of [ACCIDENTAL LOSS OF CRUDE OIL OR NATURAL] gas [or both] from a well or production handling operation or any uncontrolled release that results in a shutdown of operations at a production facility.

(b) Within five days after the release [ACCIDENTAL LOSS], the operator shall submit a preliminary written report to the commission, followed by a final written report within 30 days, detailing the following facts:

(1) the time of the incident;

(2) the location where the incident took place;

(3) the volumes of ~~oil and gas released and recovered~~ [CRUDE OIL AND OF NATURAL GAS LOST]; [CRUDE] oil and [OF NATURAL] gas released and recovered [LOST];

(4) the cause of the release [LOSS];

(5) ~~responsive actions taken to prevent further release~~ responsive actions taken [AND PLANNED] to prevent additional releases ~~[ACTIONS TAKEN AND PLANNED TO PREVENT~~ [FURTHER LOSS]; ~~[and]~~

(6) ~~any~~ plans, actions, equipment, or procedural changes to prevent or minimize the risk of future releases [EQUIPMENT OR PROCEDURAL CHANGES, IF APPLICABLE, TO PREVENT THE LOSS FROM RECURRING]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.210 is amended to read:

20 AAC 25.210. MULTIPLE COMPLETIONS [COMPLETION] OF WELLS. A well may not be completed in more than one pool without approval of the commission. The commission will ~~in its discretion~~, require evidence of complete separation of flowstreams from separate pools, as ascertained by a pressure test or other acceptable test [TESTS] conducted at the time the packers are set. Subsequently, if packer leakage is suspected, the commission will require ~~in~~ in its discretion, request the operator to provide proof of complete separation of the pools involved in the completions or make a packer leakage test. ~~A~~ At least ~~minimum of~~ 24 hours notice [NOTIFICATION] must be given so that the packer leakage test may be witnessed by a representative of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.215 is amended to read:

20 AAC 25.215. COMMINGLING OF PRODUCTION. (a) On the surface, the production from one pool may not be commingled with that from another pool except [when] if the quantities from each pool are determined by [AT LEAST] monthly well tests or by another method of determining pool production approved by the commission.

(b) Commingling of production within the same wellbore [WELL BORE] from two or more pools is not permitted unless, after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission (1) finds that waste will not occur, and that production from separate pools can be properly allocated; [,] (2) and [the commission] issues an order providing for commingling for [ALL] wells completed from these pools within the field. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.225 is amended to read:

20 AAC 25.225. POTENTIAL OF GAS WELLS. (a) All gas wells must be tested by [the] multi-point back-pressure method before regular [SIGNIFICANT] production. The commission will ~~in its discretion~~ if the commission determines that they provide substantially the same information as the multi-point back-pressure method approve alternative test methods. The test results and calculations must be reported to the commission on the [FORM ENTITLED] Gas Well Open Flow Potential Test Report (Form 10-421) within 30 days after the test. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.228 is repealed and readopted to read:

20 AAC 25.228. PRODUCTION MEASUREMENT EQUIPMENT FOR CUSTODY TRANSFER. (a) ~~All~~ Cap hydrocarbon production must be measured in accordance with this section before severance from the property or unit where produced. Crude oil sample collection, handling, and analysis in connection with production measurement must be performed in conformance with relevant parts of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998.

(b) Hydrocarbon measurement equipment ~~and gas meter runs~~ must be fabricated, installed, and maintained in conformance with relevant parts of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998.

(c) If a totalizer system is microprocessor-based, it must be equipped with

(1) a back-up battery or uninterruptible power supply that provides for operation during times of system power failures; or

(2) a backup pulse accumulator or other approved equivalent that counts and preserves meter pulses in the event of a power or computer failure.

(d) If a microprocessor totalizing system is used, the reports of net measured volumes for the custody transfer intervals must, at a minimum, show the raw or factored pulses, average temperature, pressure, relative density or gravity, meter factors, correction factors, and ~~the~~ gross standard volumes.

(e) Fluid samplers must be ~~either~~ a probe or a slipstream type. The sampler location must be located in conformance with Chapter 8 of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998.

(f) Functional bypasses may not be connected around custody transfer or sales measurement equipment such as tanks, meters, gauges, sample containers, or gas meter runs.

(g) Oil meters must be periodically proved and gas meters must be periodically calibrated in conformance with relevant parts of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998, and on a schedule approved by the commission according to the volumes being metered and the need to quickly detect inaccuracies. In metering operations, the actual throughput or gross standard volume must be determined by multiplying the indicated volume, corrected for temperature and pressure, by the meter factor obtained during proving. If a meter factor differs by more than 0.0025 from the previously obtained meter factor, from the applicable value on the meter curve, or from a baseline factor in the absence of a meter curve, the meter must be taken out of service or corrective action performed to bring the meter factor within the required tolerance.

(h) Provers used for certification of custody transfer meters must be calibrated by the waterdraw method, master meter method, or other commission-approved equivalent, in conformance with relevant parts of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998.

(i) The commission will, in its discretion, require ~~a minimum of~~ at least 24 hours notice before the following operations so that a representative of the commission can witness the operation:

(1) calibration of provers used for certification of custody transfer meters;

(2) crude oil sample collection, handling, and analysis in connection with production measurement;

(3) oil meter proving and volume calculations;

(4) gas meter calibration and volume calculations.

(j) Upon request, the commission will, in its discretion, approve a variance from the requirements of this section if the variance will result in equal or improved accuracy in measuring hydrocarbons severed from the property or unit.

(k) In this section, "relevant parts of the API *Manual of Petroleum Measurement Standards*" means the API *Manual of Petroleum Measurement Standards* excluding Chapter 19 in its entirety and excluding those portions of Chapter 11 other than Chapter 11.1, Volume 1; Chapter 11.1, Volume X; Chapter 11.2.1; Chapter 11.2.2; Addendum to Section 2.2; and Chapter 11.2.3. The relevant parts of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998, are adopted by reference. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the relevant parts of the API *Manual of Petroleum Measurement Standards* may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

20 AAC 25.230 is repealed and readopted to read:

20 AAC 25.230. MEASUREMENT, ALLOCATION, AND REPORTING OF WELL PRODUCTION. (a) Production from each well must be measured ~~or allocated~~ to determine the quantities of oil, gas, and water, using equipment and techniques acceptable to the commission as accurate and reliable. Production from a group of wells, property, or unit may be measured as a whole, if individual well test facilities and allocation methods acceptable to the commission are employed to test and allocate production to each well at least monthly.

(b) The volumes of produced gas, oil, and water must be reported monthly for each well on the Monthly Production Report (Form 10-405) or by an alternate format, including electronic means, acceptable to the commission. A well must be identified by its API number and the name designated by the operator under 20 AAC 25.005(f). Production from a well with multiple well branches must be

aggregated and reported under the API number and well name of the primary wellbore. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.235 (a) is ~~amended~~ repealed and readopted to read:

(a) For each production facility the operator shall compile and report monthly gas disposition and acquisition on the Facility Report of Produced Gas Disposition (Form 10-422). The operator shall report gas acquisition or disposition by category, as follows: ~~as~~ (1) gas sold; (2) gas reinjected; (3) gas flared or vented; (4) gas used for lease operations other than ~~flared or vented~~ flaring or venting; [OR] (5) natural gas liquids (NGLs) produced; (6) gas purchased; (7) gas transferred; ~~or~~ (8) other. If a facility's production comes from multiple pools, the operator shall allocate production between each producing pool as a percentage of the total volume of gas that the facility handled for the month.

Delete underlines

Move

Publisher: the rest of 20 AAC 25.235 is unchanged.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 1/1/95, Register 132; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095 AS 31.05.170

20 AAC 25.240 is repealed and readopted to read:

20 AAC 25.240. GAS-OIL RATIO LIMITATIONS. (a) An oil well may not be produced if the gas-oil ratio of the well exceeds the original solution gas-oil ratio of the crude within the producing pool by more than 100 percent.

(b) Upon written application by an operator, the commission will, in its discretion, waive the limitation in (a) of this section if

(1) an enhanced recovery project ~~is operating~~ operates in the pool from which the well is producing;

(2) produced gas is being returned to the same pool; or

(3) acquisition of pool performance data is necessary to determine an optimum reservoir management program.

(c) Exceptions to the limitation in (a) of this section for conditions other than those specified in (b) of this section ~~will, in the commission's discretion, be granted~~ in accordance with 20 AAC 25.540 only after application, notice, and an opportunity for public hearing. The commission will, in its discretion, grant

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.245 is amended to read:

20 AAC 25.245. COMMON PRODUCTION FACILITIES. Common facilities may be used to receive the production from any number of wells or pools if appropriate tankage or other measuring equipment is installed so that production from each well can be [ACCURATELY] determined by means approved by the commission in accordance with 20 AAC 25.228 [AT LEAST ONCE EACH MONTH].

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.252 (a) - (c), ~~(e)~~ and (f), ~~and (h)~~ (e), and (h) are amended, (d) ~~is~~ subsections repealed and readopted, and ~~a~~ new (k) ~~is~~ and (l) are added, to read:

20 AAC 25.252. UNDERGROUND DISPOSAL OF [WATER AND OTHER] OIL FIELD WASTES [WASTE FLUIDS] AND UNDERGROUND STORAGE OF [LIQUID] HYDROCARBONS.

(a) ~~Unless authorized by the United States Environmental Protection Agency under federal law, the~~ [THE] underground disposal of [FRESHWATER OR SALT WATER, BRACKISH WATER, OR OTHER] oil field wastes [WASTE FLUIDS] and the underground storage of [LIQUID] hydrocarbons[,] are prohibited except as ordered by the commission under this section. In [IN] response to a letter of application for injection filed by an operator, ~~[FOR UNDERGROUND DISPOSAL OR STORAGE]~~ the commission will ~~in its discretion, authorize~~ issue an order authorizing [FOR] the underground disposal of oil field wastes ~~consisting of~~ that the commission determines are suitable for disposal fluids ~~described~~ in 40 C.F.R. 144.6(b)~~(1)~~ as revised as of July 1, 1998, which is adopted by reference, or in a Class II well, as defined the underground storage of hydrocarbons. An order authorizing disposal or [OF] storage wells remains valid unless revoked by the commission.

Del. underline beneath "underground disposal"

Del. underline beneath "or"

Del. underline beneath "storage"

(b) The operator has the burden of demonstrating that the proposed disposal or storage operation will not allow the movement of oil field wastes or hydrocarbons [FLUID] into sources of freshwater. Disposal or storage wells must be cased and the casing cemented in a manner that will isolate the disposal or storage zone and protect oil, gas, and freshwater sources.

(c) An application for underground disposal or storage [INJECTION] must include

(1) a plat showing the location of all proposed disposal and storage wells, [INCLUDING] abandoned or other unused wells, production wells, dry holes, and any other wells [that penetrate the ~~disposal or storage~~ [INJECTION] zone] within one-quarter mile of each proposed disposal or storage well;

. . .

Note to publisher: paragraphs (2) and (3) are unchanged.

(4) the name, description, depth, and thickness of the formation into which fluids are to be disposed or stored [INJECTED] and appropriate geological data on the disposal or storage [INJECTION] zone and confining ~~zone(s) [ZONES]~~ zones, including lithologic ~~description~~ descriptions and geologic ~~name~~ names;

...

Note to publisher: paragraph (5) is unchanged.

(6) a description of [the casing of the disposal or storage wells, or the proposed casing program and] the proposed method for demonstrating the mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that ~~no~~ not fluids will move behind casing beyond the approved [TESTING CASING BEFORE USE OF THE] disposal or storage zone ~~[WELLS]~~;

(6) and a description of
(A) the casing of the disposal or storage wells, if the wells are existing; or
(B) the proposed casing program, if the disposal or storage wells are new

(7) a statement as to the type of oil field wastes to be disposed or hydrocarbons stored [FLUID TO BE INJECTED], their [ITS] composition, their [ITS] source, [AND] the estimated maximum amounts to be disposed or stored [INJECTED] daily, and the compatibility of fluids to be disposed or stored with the disposal or storage zone;

Publisher: Paragraph (8) is unchanged

... ~~(8) the estimated average and maximum disposal or storage [INJECTION] pressure;~~

(9) evidence [and data] to support a commission finding that the proposed disposal or storage operation ~~[well]~~ will not initiate or propagate fractures through the confining ~~zone(s) [ZONES] which~~ zones that [WHICH] might enable the oil field wastes or stored hydrocarbons [INJECTION FLUID OR FORMATION FLUID] to enter [any] freshwater strata;

(10) a ~~[AN]~~ [AN] standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which disposal or storage [FLUID INJECTION] is proposed[, BY A STANDARD LABORATORY WATER

ANALYSIS DETERMINATION, OR BY AN ANALYTICAL METHOD ACCEPTABLE TO THE COMMISSION]; [AND]

(11) a reference to any applicable freshwater exemption issued in accordance with 20 AAC 25.440;~~[.]~~ and

(12) a report on the mechanical condition of ~~all wells~~ each well that ~~have~~ has penetrated the disposal or storage zone within a one-quarter mile radius of a disposal or storage well. Del underline in beneath period

(d) The mechanical integrity of a disposal or storage well must be demonstrated under 20 AAC 25.412 before disposal or storage operations are begun, ~~and~~ after a well workover affecting mechanical integrity is conducted, and at least once every four years. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual disposal or storage operations. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(e) ~~If the casing-tubing annulus pressure subjects the casing to a hoop stress that exceeds 70 percent of the minimum yield strength of the casing, or if a disposal rate increase, operating pressure observation, or pressure test indicates pressure communication or leakage of any casing, tubing, or packer [THERE IS MORE THAN A 200 PSI CHANGE IN PRESSURE BETWEEN CONSECUTIVE PRESSURE READINGS], the operator shall notify the commission [MUST BE IMMEDIATELY NOTIFIED] by the next working day and implement commission-approved corrective action [TAKEN].~~ If an injection rate, operating pressure observation, or pressure test indicates pressure communication or leakage in any casing, tubing, or packer, the operator shall notify the commission by the next working day and shall implement corrective action or increased surveillance as the commission requires to ensure protection of freshwater.

(f) The commission will [in its discretion,] require additional mechanical integrity tests if the commission considers them prudent for conservation purposes or protection of freshwater.

. . .

Note to publisher: subsection (g) is unchanged.

(h) ~~[THE OPERATOR SHALL PROVIDE A REPORT ON THE MECHANICAL CONDITIONS OF ALL WELLS THAT HAVE PENETRATED THE INJECTION ZONE WITHIN A ONE-QUARTER MILE RADIUS OF A PROPOSED DISPOSAL OR STORAGE WELL.] It is the operator's responsibility to ensure [ASSURE] that all [ANY OF THE] wells, including water wells and other borings, under the operator's control within a one-quarter mile radius of the disposal or storage well [THE RADIUS OF INVESTIGATION] which may allow the movement of oil field wastes or hydrocarbons [FLUIDS] into sources of freshwater are properly repaired, plugged, or otherwise modified. If wells exist that are not under the operator's control, the commission will not approve the application until the person [OPERATOR] responsible for those~~ wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of oil field wastes or hydrocarbons ~~[FLUIDS]~~ into sources of freshwater.

IF wells, including freshwater wells or other borings, are located within a one-quarter mile radius of the disposal or storage well, are a possible means for oil field wastes or hydrocarbons to move into sources of freshwater, and are under the control of ¶ (1) the operator, the operator shall ensure that the wells are properly repaired, plugged, or otherwise modified to prevent the movement of oil field wastes or hydrocarbons into sources of freshwater; or ¶ (2) a person other than the operator, the commission will not issue an order under (a) of this section to the operator until the operator presents evidence to the commission's satisfaction that the person who controls the wells has properly repaired, plugged, or

del underline

... ¶ (1) This section does not apply to underground disposal that is regulated under 40 C.F.R. 147.101 by the United States Environmental Protection Agency.

Note to publisher: subsections (i) and (j) are unchanged.

(k) The annular disposal of drilling wastes approved under 20 AAC 25.080 is an operation incidental to drilling a well and is not a disposal operation subject to this section. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.265 is repealed and readopted to read:

20 AAC 25.265. AUTOMATIC SHUT-IN EQUIPMENT. (a) A completed well with an offshore surface location, ~~which~~ and that is capable of unassisted flow of hydrocarbons to the surface, must be equipped with a commission-approved

(1) fail-safe automatic surface safety valve (SSV) system capable of preventing an uncontrolled flow; and

(2) fail-safe automatic surface-controlled subsurface safety valve (SSSV) system capable of preventing an uncontrolled flow, unless another type of subsurface valve with that capability is approved by the commission; this valve must be in the tubing string and located below the mudline datum or, if permafrost is present, below the permafrost.

(b) An operator may demonstrate by a no-flow test that a well is incapable of unassisted flow of hydrocarbons to the surface. ~~A minimum of~~ At least 24 hours notice must be given so that a representative of the commission can witness the test.

(c) The commission will, in its discretion, ~~also~~ require an #C SSV~~s~~ #system, an #C SSSV~~s~~ #system, or both, on a well~~s~~ with an onshore surface location~~s~~, after notice and an opportunity for hearing in accordance with 20 AAC 25.540.

(d) A representative of the commission ~~will~~ shall witness operation and performance tests at intervals and times as prescribed by the commission to confirm that the SSV #system, SSSV #system, and ~~all~~ associated equipment are in proper working condition. If an SSV #system, SSSV #system, or associated equipment fails the performance test, ~~it~~ the system or associated equipment must be repaired within the time frame specified by the commission or the well must be shut in. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.270 is amended, and new subsections are added to read:

20 AAC 25.270. INITIAL RESERVOIR PROPERTIES [PRESSURE]. (a) The operator shall determine the initial reservoir pressure in each ~~any~~ new pool before regular [SIGNIFICANT] production. The

results must be reported to the commission on a the form entitled Reservoir Pressure Report (Form 10-412).

(b) The operator shall obtain fluid samples from each new pool at the time of discovery or ~~prior~~ before ~~to~~ regular production and determine

(1) the crude oil composition assay;

(2) pressure, volume, and temperature ~~(PVT)~~ properties of the crude oil; and

(3) the solution or non-associated gas composition assay.

Publisher: Delete underline beneath new subsections (b)-(d).

(c) Sampling and analysis must be conducted and reported in accordance with good oil field engineering practices. Reports must be submitted to the commission within 45 days following the completion of the determinations required in (b) of this section.

(c) (d) The operator shall determine within three months after discovery of each new oil pool the original solution gas-oil ratio by a well test conducted in a manner approved by the commission. The operator shall report the results on the Well Status Report and Gas-Oil Ratio Tests (Form 10-409) within 45 days after the test. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Att'n. ARC Coordinator: Please insert effective date into editor's note

20 AAC 25.275 is repealed:

20 AAC 25.275. RESERVOIR FLUID PROPERTIES. Repealed. (Eff. 4/2/86, Register 97; repealed ___/___/___, Register __)

Editor's note: Effective ___/___/99, Register ___, the substance of 20 AAC 25.275 was relocated to 20 AAC 25.270.

20 AAC 25.280(a) is repealed and readopted, subsections (b)-(d) ~~20 AAC 25.280(a) - (d)~~ are amended, and a new subsection (e) is added, to read:

20 AAC 25.280. WORKOVER OPERATIONS. (a) An ~~application for well workover operations must be submitted by filing an [THE FORM ENTITLED]~~ Application for Sundry Approvals (Form 10-403) ~~The application~~ must be submitted to and approved by the commission in order to enter a well and ~~before entering a [PRODUCIBLE OR INJECTION] well to~~ conduct one or more of the following types of well workover operations:

(1) ~~perforate or reperforate casing; [;]~~ the perforation or reperforation of casing;

(2) ~~stimulate; [;]~~ stimulation;

(3) ~~pull tubing; [;]~~ the pulling of tubing;

(4) ~~alter casing; [;]~~ alteration of the casing;

(5) ~~repair well.~~ repairs to the well.

(b) The Application for Sundry Approvals [FORM 10-403 FILING] must set out [THE FOLLOWING:]

(1) the current condition of the well;

(2) a copy of the proposed program for well work;

(3) unless already on file with the commission, a diagram and description of the well control [BOP] equipment to be used, including if applicable a list of the blowout prevention equipment (BOPE) with specifications [REQUIRED BY 20 AAC 25.285(a) AND THE STATIC BOTTOM-HOLE PRESSURE];

(4) a description of any wellbore [THE WORKOVER] fluid to be used for primary well control; [;] and

(5) the ~~estimated~~ current bottom-hole pressure, or, if data setting out, the actual pressure ~~if~~ available, are not, an estimate of the current bottom-hole pressure;

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(c) The operator shall keep records and reports of well workover [and repair] operations, including BOPE test results, in conformance with the requirements of 20 AAC 25.070(1) [20 AAC 25.070(a)].

(d) The operator shall file with the commission, within 30 days after completion of workover or [AND] repair] operations, [a complete well record] on a Report of Sundry Well Operations (Form 10-404), a complete record of the work performed and [the tests conducted, and a summary of [INCLUDING A COPY OF THE] daily [REPORTS OF] well operations as described in [AND THE TESTS AS REQUIRED BY] 20 AAC 25.070(3) [20 AAC 25.070(a)(1)]. Upon request, the operator shall file with the commission a copy of the daily record required by 20 AAC 25.070(1).

(e) Upon application, the commission will, in its discretion, waive the requirements of this section for wells in a pool for which pool rules have been prescribed under 20 AAC 25.520. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.285 is repealed and readopted to read:

20 AAC 25.285. SECONDARY WELL CONTROL FOR TUBING WORKOVER OPERATIONS: BLOWOUT PREVENTION EQUIPMENT REQUIREMENTS. (a) This section applies to workover operations performed with the tree removed. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected ~~and may not be less than the rating~~

~~shown in~~ If an approved Application for Sundry Approvals (Form 10-403) is required under 20 AAC 25.280, the commission will specify in that approved application the working pressure that that the equipment must be rated to meet or exceed. However, the rated ~~, except that the~~ working pressure of the annular type preventer need not exceed 5,000 psi.

(c) Well control equipment must include

(1) at least one positive seal manual or hydraulic valve or BOPE blind ram and one set of BOPE pipe rams flanged to the well head;

(2) in rotary drilling rig operations,

(A) for an operation requiring a BOP stack less than API 5M K, at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except ~~for~~ that pipe rams need not be sized to bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(B) for an operation requiring a BOP stack equal to or greater than API 5M K ~~or greater~~, at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except ~~for bottom-hole assemblies~~ that pipe rams need not be sized to BHAs and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(3) in coiled tubing unit operations,

(A) for an operation requiring a BOP stack equal to or less than API 5M K ~~or less~~,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer;

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(iv) at least one preventer equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except ~~for bottom-hole assemblies~~ that pipe rams need not be sized to BHAs and drill collars; and

(B) for an operation requiring a BOP stack greater than API 5~~M~~K,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers;

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(iv) at least two preventers equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except ~~for bottom-hole assemblies~~ that pipe rams need not sized to BHAs and drill collars;

(4) if a tapered string is used, either an additional set of rams for each size of pipe being run or a variable ram, except ~~when~~ if small diameter tubulars are used to perform a clean-out operation through a production packer or to clean out a liner where the casing has been top set;

(5) locking devices on the ram-type preventers;

(6) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's ~~console~~ station, in addition to controls on the accumulator system;

(7) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's ~~console~~ station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor;

(8) a hydraulic actuating system with

(A) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed, and all power sources are shut off; and

(B) an accumulator pump system consisting of two or more pumps with independent power sources (primary and secondary) and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(9) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool or on the BOP body with two full-opening valves on each outlet, conforming to the following specifications:

(A) the outlets must be at least two inches in nominal diameter, except that for rotary drilling rig operations, if the required BOP is rated equal to or greater than API ~~2M~~ 5K, the nominal diameter of the choke outlets must be at least three inches;

(B) each valve must be sized at least equal to the required size of the outlet to which it is attached;

(C) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(D) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid; and

(10) a choke manifold equipped with

(A) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's ~~console~~ station if the operation requires a BOP stack equal to or greater than API 5~~M~~K ~~or greater~~;

(B) a line at least two inches in nominal diameter downstream of each choke;

(C) immediately upstream of each choke, at least one full-opening valve for an operation requiring a BOP stack less than API 5~~M~~K ~~or less~~, or at least two full-opening valves for an operation requiring a BOP stack equal to or greater than API 5~~M~~K; and

(D) a bypass line, at least two inches in nominal diameter, with at least one full-opening valve for an operation requiring a BOP stack less than API 5~~M~~K ~~or less~~, or at least two full-opening valves for an operation requiring a BOP stack equal to or greater than API 5~~M~~K.

(d) The rated working pressure of valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must exceed the maximum potential surface pressure to which they may be subjected and may not be less than the ~~rating~~ required working pressure specified for the BOPE ~~shown~~ in an approved Application for Sundry Approvals, if any, under 20 AAC 25.280, except that the rated working pressure of lines downstream of the choke ~~may be rated to~~ need not exceed 50 percent of the required working pressure of the BOPE.

(e) Kill and choke lines must

(1) be constructed of rigid steel pipe, fire-resistant rotary hose, or other ~~suitable~~ conduit that has been approved by the commission as capable of withstanding the temperature and pressure of an ignited uncontrolled release;

(2) be as straight as practical;

(3) if constructed of rigid steel pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(4) be secured to prevent excessive whip or vibration;

(5) be sized to prevent excessive erosion or fluid friction; and

(6) be assembled without hammer unions or internally clamped swivel joints, unless ~~such joints are specifically approved by~~ the commission determines that those joints do not compromise the maintenance of well control

(f) The BOPE must be tested as follows:

(1) when installed, repaired, or changed, and at least once a week thereafter, BOPE, including emergency valves and choke manifolds, must be function pressure-tested, using a non-compressible fluid, to the required working pressure ~~shown~~ specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, ~~in its absence~~ if that application is not required, to the maximum potential surface pressure to which ~~it~~ the BOPE may be subjected, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(2) ~~when~~ if BOP sealing ram type equipment has been used, it must be function pressure-tested before the next wellbore entry, using a non-compressible fluid, to the required working pressure ~~shown~~ specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, ~~in its absence~~ if that application is not required, to the maximum potential surface pressure to which ~~it~~ that equipment may be subjected, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(3) non-sealing equipment must be function-tested weekly ~~and~~, after a repair or change, ~~or~~ and ~~any~~ after an action that disconnects the hydraulic system lines from the BOPE, except that ~~when~~ if the workstring is continuously in the well ~~or the BHA does not clear the BOP~~, function-testing must be performed as soon as possible after the workstring is pulled out of the well and the BHA clears the BOP ~~thereafter~~;

(4) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(5) ~~a minimum of~~ at least 24 hours notice of each function pressure test must be provided so that a representative of the commission can witness the test.

(g) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Application for Sundry Approvals, if ~~applicable~~ that application is required under 20 AAC 25.280, and shall post on the drilling rig floor any geologic hazard information ~~required in connection with the Application for Sundry Approvals~~ obtained while drilling the well and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Application for Sundry Approvals, if ~~applicable~~ that application is required under 20 AAC 25.280, any geologic hazard information ~~required in connection with the Application for Sundry Approvals~~ obtained while drilling the well, and a copy of the operator's standing orders specifying well control procedures. ~~When~~ If an additional or separate ~~sub~~ sub-structure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(h) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of ensuring well control. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.286. WELL CONTROL REQUIREMENTS FOR WORKSTRING SERVICE OPERATIONS. (a) This section applies to through-tubing operations that are not ~~covered by~~ subject to the requirements of 20 AAC 25.036 or 20 AAC 25.285, and that are performed with coiled tubing, small diameter drill pipe, or small diameter tubing. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall use a full lubricator system or open hole deployment type system.

(c) The rated working pressure of the blowout prevention equipment (BOPE) and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected ~~and may not be less than the rating~~ If ~~shown in~~ is required under 20 AAC 25.280, the commission will specify in an approved Application for Sundry Approvals (Form 10-403) that approved application the working pressure that the equipment must be rated to meet or exceed. However, ~~except that the~~ working pressure of the annular type preventer need not exceed 5,000 psi.

(d) Well control equipment must include

(1) at least one positive seal manual or hydraulic valve or blind ram flanged to the ~~well~~ well head or tree;

(2) in rotary drilling rig operations,

(A) for an operation requiring a BOP stack equal to or less than API 5K ~~5M or less~~, at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, that pipe rams need not be sized to, except ~~for~~ bottom-hole assemblies (BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type; and

(B) for an operation requiring a BOP stack greater than API 5~~M~~K, at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except ~~for bottom-hole assemblies~~ (that pipe rams need not be sized to BHAs) and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(3) in coiled tubing unit operations,

(A) for an operation requiring a BOP stack equal to or less than API 5~~M~~K ~~or less~~,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer; and

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(B) for an operation requiring a BOP stack greater than API 5~~M~~K,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers; and

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA and providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer;

(4) a hydraulic actuating system with

(A) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed, and all power sources are shut off; and

(B) an accumulator pump system;

(5) locking devices on the ram-type preventers;

(6) in rotary drilling rig operations, one complete set of operable remote BOPE controls on or near the driller's ~~console~~ station, in addition to controls on the accumulator system;

(7) in coiled tubing operations, one complete set of operable remote BOPE controls on or near the operator's ~~console~~ station and, if these controls are not in close proximity to the drilling platform floor, a second annular type preventer closing control located on the drilling platform floor; and

(8) a kill line capable of being attached with flanged or hubbed connections to the BOP body, drilling spool, tree, wellhead, or other well control equipment.

(e) The operator shall test the BOPE assembly as follows:

(1) at least once a week, and after each use, repair, or change, BOPE pipe and blind rams must be function pressure-tested, using a non-compressible fluid, to the required working pressure ~~shown~~ specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, ~~in its absence~~ if that application is not required, to the maximum potential surface

pressure to which they may be subjected, except that the annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(2) after each installation of BOPE or other well control equipment, the equipment must be pressure-tested, before wellbore entry, to the maximum ~~expected~~ potential wellhead pressure to which it may be subjected, except that when testing against the annular type preventer, pressure testing need not exceed 50 percent of the rated working pressure of the annular type preventer;

(3) non-sealing equipment must be function-tested weekly ~~and~~ and after a repair or change, ~~or~~ and ~~any~~ after an action that disconnects the hydraulic system lines from the BOPE, except that ~~when~~ if the workstring is continuously in the well ~~or the BHA does not clear the BOP~~, function-testing must be performed as soon as possible ~~thereafter~~ after the workstring is pulled out of the well and the BHA clears the BOP;

(4) after each well installation of the BOPE, the BOPE hydraulic connections to the rams must be visually verified before wellbore entry.

(f) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Application for Sundry Approvals, if ~~applicable~~ that application is required under 20 AAC 25.280, and shall post on the drilling rig floor any geologic hazard information ~~required in connection with the Application for Sundry Approvals~~ obtained while drilling the well and a copy of the operator's standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Application for Sundry Approvals, if ~~applicable~~ that application is required under 20 AAC 25.280, any geologic hazard information ~~required in connection with the Application for Sundry Approvals~~ obtained while drilling the well, and a copy of the operator's standing orders specifying well control procedures. ~~When~~ If an additional or separate ~~sub-~~ sub structure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(g) Upon request of the operator, the commission will, in its discretion, approve a variance from

the requirements of this section if the variance provides at least an equally effective means of well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.287. WELL CONTROL EQUIPMENT FOR WIRELINE OPERATIONS. (a) This section applies to workover or service operations performed with slickline or conductor line with the tree in place. These operations are also subject to the requirements of 20 AAC 25.527.

(b) Well control equipment must include

(1) a set of wireline rams suitable or sized for each diameter of wire passing through the wireline valve;

(2) a lubricator or pressure deployment system; and

(3) a high pressure pack-off, stripper, or greasehead with linewiper, stripper, or pack-off.

(c) The rated working pressure of the well control equipment must exceed the maximum potential surface pressure to which it may be subjected ~~and may not be less than the rating shown in~~ an approved Application for Sundry Approvals (Form 10-403) ~~except that the~~ working pressure of an annular type preventer need not exceed 5,000 psi.

(d) The operator shall test the well control equipment as follows:

(1) at least once a week, equipment must be function pressure-tested, using a non-compressible fluid, to the required working pressure ~~shown~~ in an approved Application for Sundry Approvals or, ~~in its absence~~, to the maximum potential surface pressure to which ~~it~~ may be subjected;

(2) after each installation of the well control equipment, ~~it~~ that equipment must be pressure-tested, before wellbore entry, to the maximum ~~expected~~ potential wellhead pressure to which ~~it~~ that equipment may be subjected;

(3) if the wireline valve rams have been used, repaired or changed, the wireline rams must be closed and function pressure-tested before wellbore entry, using a non-compressible fluid, to the required working pressure ~~shown~~ specified in an approved Application for Sundry Approvals under 20 AAC 25.280 or, ~~in its absence~~ if that application is not required, to the maximum potential surface pressure to which they may be subjected.

(e) The operator shall post in the operator's cab a copy of the approved Application for Sundry Approvals, if ~~applicable~~ that application is required under 20 AAC 25.280, any geologic hazard information ~~required in connection with the Application for Sundry Approvals~~ obtained while drilling the well, and a copy of the operator's standing orders specifying well control procedures.

(f) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.288. WELL CONTROL REQUIREMENTS FOR OTHER SERVICE OPERATIONS. For downhole service operations not covered by 20 AAC 25.285 - 20 AAC 25.287, the commission will ~~in its discretion,~~ approve alternate well control procedures and equipment, if the commission determines that the alternate procedures and equipment are adequate to ensure well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.290 OPERATIONS PRODUCING HYDROGEN SULFIDE. An operator of a well or pool that produces hydrogen sulfide gas shall install, operate, and maintain surface production equipment in conformance with API RP 55, *Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide*, 2d edition, February 15, 1995, which is adopted by reference. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in ~~this section~~ 20 AAC 25.290 may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070, or if not available from the American Petroleum Institute, may be obtained from Global Engineering Documents, 15 Inverness Way East, Englewood, CO 80150.

ARTICLE 4.
REPORTS.

Section
300. Request for additional information
310. Books and records
320. Filing of forms

20 AAC 25.300 is amended to read:

20 AAC 25.300. REQUEST FOR ADDITIONAL INFORMATION. This chapter does not limit or restrict the authority of the commission to require the furnishing of those [such] additional reports, data, or other information relative to drilling, production, transportation, storage, or handling of [CRUDE] oil or [NATURAL] gas and relative to injection operations on oil and gas properties and units in the state [ALASKA], as the commission considers [may appear to it] to be necessary or desirable, either generally or specifically, for the prevention of waste, the protection of correlative rights, the prevention of fluid movement [~~MOVEMENT~~ OF FLUIDS] into freshwater sources, and the conservation of [THE] natural resources. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.310 is amended to read:

20 AAC 25.310. BOOKS AND RECORDS. ~~All operators[,] of [PRODUCERS~~ Operators of [ALL OPERATORS, PRODUCERS, TRANSPORTERS, STORERS, AND HANDLERS OF CRUDE OIL AND NATURAL GAS ON] oil and gas properties and units within the state [ALASKA] shall make and maintain [AND KEEP IN ALASKA] for a period of not less than five years, ~~books and records necessary~~ [APPROPRIATE] ~~BOOKS AND RECORDS~~ books and records necessary [COVERING THEIR OPERATION IN ALASKA. THE DATA FROM

THESE BOOKS AND RECORDS MUST BE USED] to make and substantiate the reports required by this chapter. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.320(a) is repealed and readopted, and (b) is amended, to read:

20 AAC 25.320. FILING OF FORMS. (a) ~~Where~~ If this chapter requires a form to be filed or submitted, one originally signed, ~~commission-approved~~ commission-furnished form must be submitted to the commission with the required number of copies indicated on each form. A computer-generated form may be submitted in place of the form furnished by the commission if ~~it~~ the computer-generated form contains the same required information and has been approved for format by the commission.

(b) Forms required by this chapter will be furnished by the commission upon request and will be revised at the discretion of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

and upon the commission's determination that the requirements of this section and 20 AAC 25.412 are met,

ARTICLE 5.
ENHANCED RECOVERY.

Section
400. (Repealed)
402. Enhanced recovery operations
410. (Repealed)
412. Casing, cementing, and tubing of injection wells for enhanced recovery, disposal, and storage
420. Notice of commencement and discontinuance of injection operations
430. Enhanced recovery records
432. Report of underground injection
440. Freshwater aquifer exemption
450. Underground injection control variances
460. Area injection orders

20 AAC 25.402 is repealed and readopted to read:

20 AAC 25.402. ENHANCED RECOVERY OPERATIONS. (a) Enhanced recovery operations involving the introduction of extraneous forms of energy into a pool by injection are prohibited, except as ordered by the commission under this section. In response to an application for injection filed by an operator, the commission will issue an order authorizing ~~in its discretion, authorize~~ the injection of fluids that function primarily to enhance recovery of oil and gas and that are appropriate for enhanced recovery. Except as provided in (i) of this section, an order authorizing injection for an enhanced recovery project remains valid unless revoked by the commission.

(b) The operator has the burden of demonstrating that the proposed operation will not allow the movement of fluid into sources of freshwater. Injection wells must be cased, the casing cemented, and the wells operated in a manner that will isolate the injection zone and protect oil, gas, and freshwater. ~~It is the operator's responsibility to ensure that all~~ If wells, including fresh water wells and other borings, ~~under the operator's control~~ are located within a one-quarter mile radius of an injection well, ~~which may allow the movement of~~ are a possible means for fluids to move into sources of freshwater, and are under the control of ¶ (1) the operator, the operator shall ensure that the wells are properly repaired, plugged, or otherwise modified. ~~If wells exist that are not under the operator's control,~~ the commission will not ~~approve the application until the person~~ issue an order under (a) of this section until to prevent the movement of fluids into sources of freshwater; or ¶ (2) a person other than the operator,

the operator presents evidence to the commission's satisfaction that the person who controls the ~~responsible for those~~ wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of fluids into sources of freshwater.

(c) An application for injection must include

(1) a plat showing the location of ~~all~~ each proposed injection well~~s~~, abandoned or other unused well~~s~~, production well~~s~~, dry hole~~s~~, and ~~any~~ other well~~s~~ ~~that penetrate the injection zone~~ within one-quarter mile of each proposed injection well;

(2) a list of all operators and surface owners within a one-quarter mile radius of each proposed injection well;

(3) an affidavit showing that the operators and surface owners within a one-quarter mile radius have been provided a copy of the application for injection;

(4) a full description of the particular operation for which approval is requested;

(5) the names, descriptions, and depths of the pools to be affected;

(6) the name, description, depth, and thickness of the formation into which fluids are to be injected, and appropriate geological data on the injection zone and confining ~~zone(s)~~ zone, including lithologic descriptions and geologic names;

(7) logs of the injection wells if not already on file with the commission;

(8) a description of ~~the casing of the injection wells, or the proposed casing program,~~ ~~and~~ the proposed method for demonstrating mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that no fluids will move behind casing beyond the approved injection zone;

(9) a statement of the type of fluid to be injected, ~~its~~ the fluid's composition, ~~its~~ the fluid's source, the estimated maximum amounts to be injected daily, and ~~its~~ the fluid's compatibility with the injection zone;

C, and a description of
¶ (A) the casing of the injection wells if the wells are existing; or
¶ (B) the proposed casing program, if the injection wells are new

(10) the estimated average and maximum injection pressure;

(11) evidence to support a commission finding that each proposed injection well will not initiate or propagate fractures through the ~~overlying strata or~~ confining ~~zone(s)~~ zones that might enable the injection fluid or formation fluid to enter ~~any~~ freshwater strata;

(12) a standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which fluid injection is proposed;

(13) a reference to any applicable freshwater exemption issued under 20 AAC 25.440;

(14) the expected incremental increase in ultimate hydrocarbon recovery; and

(15) a report on the mechanical condition of ~~all wells~~ each well that ~~have~~ has penetrated the injection zone within a one-quarter mile radius of ~~each~~ a proposed injection well.

(d) The commission will publish notice of the enhanced recovery application and provide the opportunity for a hearing in accordance with 20 AAC 25.540.

(e) The mechanical integrity of an injection well must be demonstrated under 20 AAC 25.412 before injection is begun and after a well workover affecting mechanical integrity is conducted. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual injection. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(f) If ~~the casing-tubing annulus pressure subjects the casing to a hoop stress that exceeds 70 percent of the minimum yield strength of the casing, or if~~ an injection rate, operating pressure observation, or pressure test indicates pressure communication or leakage in any casing, tubing, or

packer, the operator shall notify the commission by the next working day and shall implement ~~commission-approved~~ corrective action or increased surveillance as the commission requires to ensure protection of freshwater.

(g) The commission will ~~in its discretion,~~ require additional mechanical integrity tests if the commission considers them prudent for conservation purposes or protection of freshwater.

(h) The commission will, in its discretion, approve a modification to an existing or pending injection operation under 20 AAC 25.507, ~~when~~ if the applicant proves to the commission, upon application containing sufficient detail for the commission to evaluate the proposed modification, that the modification will not allow the movement of fluids into sources of freshwater.

(i) If injection operations are not begun within 24 months after the ~~approval~~ date of the order authorizing enhanced recovery ~~approval~~ expires unless a letter of application for extension is approved by the commission.

(Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.412 is repealed and readopted to read:

20 AAC 25.412. CASING, CEMENTING, AND TUBING OF INJECTION WELLS FOR ENHANCED RECOVERY, DISPOSAL, AND STORAGE. (a) A well used for injection must be cased and cemented in accordance with 20 AAC 25.030 to prevent leakage into oil, gas, or freshwater sources.

(b) A well used for injection must be equipped with tubing and a packer, or with other equipment that isolates pressure to the injection interval, ~~unless otherwise specifically approved by the commission~~ unless the commission approves the operator's use of alternate means to ensure that injection of fluid is limited to the injection zone. The minimum burst pressure of the tubing must exceed the maximum surface injection pressure by at least 25 percent. The packer must be placed within 200 feet measured depth above the top of the perforations, unless ~~otherwise approved by~~ the commission approves a different placement depth as the commission considers appropriate given the thickness and depth of the confining zone.

(c) Before injection begins, a well must be pressure-tested to demonstrate the mechanical integrity of the tubing and packer and of the casing immediately surrounding the injection tubing string. The casing must be tested at a surface pressure of 1,500 psig or at a surface pressure of 0.25 psi/ft multiplied by the true vertical depth of the casing shoe, whichever is greater, but the casing may not be subjected to a hoop stress that will exceed 70 percent of the minimum yield strength of the casing. The test pressure must show stabilizing pressure and may not decline more than 10 percent within 30 minutes.

(d) The operator shall provide a cement quality log or other well data approved by the commission to demonstrate isolation of the injected fluids to the approved interval.

(e) ~~A minimum of~~ At least 24 hours notice of a pressure test required by (c) of this section must be given so that a representative of the commission can witness the test. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.430 is amended to read:

20 AAC 25.430. ENHANCED RECOVERY RECORDS. Each operator shall keep accurate records showing volumes of fluids produced, injected volumes, reservoir pressures, and injection pressures, by well and pool. Each operator shall retain these records for five years. The commission will, in its discretion, specify retention of these records for a longer time period. Upon reasonable notice, the commission [OR ITS AUTHORIZED REPRESENTATIVE] must be given full access during normal business hours to all records. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.432 is repealed and readopted, to read:

20 AAC 25.432. REPORT OF UNDERGROUND INJECTION. An operator that injects fluids into subsurface strata through a service well for any purpose, other than fracturing, acidizing, or other similar treatment, shall file with the commission

(1) monthly reports that show all injected volumes and other data, by well and pool, as required by the commission on the Monthly Injection Report (Form 10-406) and, if applicable, the Facility Report of Produced Gas Disposition (Form 10-422); and

(2) an annual report that shows annual and total cumulative volumes injected and produced and other data, for each pool or injection project area within the pool, as required by the commission on the Annual Report of Injection Projects (Form 10-413); the annual report must be submitted by April 1 ~~each year unless it is required by~~ unless pool rules established under 20 AAC 25.520 require the report to be included with a pool specific annual surveillance report. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.440(c) is amended, and a new subsection (d) is added, to read:

(c) Freshwater aquifers within ~~the~~ state [ALASKA] that ~~were~~ ~~[ARE]~~ C, as of June 19, 1986, are designated as exempt aquifers by the United States Environmental Protection Agency [AT THE TIME THE COMMISSION IS GRANTED PRIMARY ENFORCEMENT RESPONSIBILITY] under 40 C.F.R. 147.102 are 42 U.S.C. 300h-4 ~~are~~ [WILL BE] accepted as exempt aquifers by the commission [WITHOUT FURTHER ACTION].

(d) A commission order designating a freshwater aquifer or a portion of it as an exempt freshwater aquifer is not effective with respect to underground disposal or storage operations subject to

20 AAC 25.252 or injection operations subject to 20 AAC 25.402 until the United States Environmental Protection Agency has been provided the opportunity to review the order under 40 C.F.R. 144.7(b)(3) and has

(1) approved the order, if it was issued under (a)(1) of this section; or

(2) has allowed the applicable time period within which to disapprove the order to expire without acting on it, if ~~it~~ the order was issued under (a)(2) of this section. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.450 (a) is amended to read:

(a) If injection does not occur into, through, or above [A] freshwater [SOURCE OR NON-EXEMPT FRESHWATER AQUIFER], the commission will, [in its discretion,] authorize [less stringent] requirements for a well or project that are less stringent than [otherwise required by] the requirements in this chapter, [,] for the radius of investigation established under 20 AAC 25.252(h) or 20 AAC 25.402(b), the casing and cementing, tubing and packer, mechanical integrity, operation, monitoring, and reporting, to the extent that the commission determines that the reduction in requirements will not result in an increased risk of movement of fluids into [A] freshwater [SOURCE].

(Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC ~~25.460 is~~ 25.460(a)(4), (b)(2), (c)(1), and (d) are amended to read:

20 AAC 25.460. AREA INJECTION ORDERS. (a) Upon application under this section and subject to the provisions of 20 AAC 25.252 or 20 AAC 25.402, as applicable, the commission will, in its discretion, after [LEGAL] notice and opportunity for public hearing in accordance with 20 AAC 25.540,

issue an order permitting the underground injection of fluids on an area basis, rather than for each well individually, if the wells are

paragraphs (1)-(3) are unchanged

...

Note to publisher: ~~paragraph (1) is unchanged.~~

AAC Coordinator: Please insert effective date into repealer.

~~(2) within the same field, facility site, reservoir, project, or similar area; and~~

~~(3) operated by a single operator. [; AND]~~

(4) repealed / / [USED TO INJECT OTHER THAN HAZARDOUS WASTE].

In the (b) [The] area injection order to the commission will specify

...

Note to publisher: paragraph (1) is unchanged.

(2) the requirements for drilling, completing, operating, monitoring, reporting, and abandoning all wells authorized by the order.

In the (c) [The] area injection order to the commission will, in [the commission's] its discretion, authorize the operator to drill, complete, and operate, to convert, or to plug and abandon wells within the area if

(1) the operator files with the commission an application for a Permit to Drill (Form 10-401) or an Application for Sundry Approvals (Form 10-403), as appropriate, for commission approval before the operator starts work; and

...

Note to publisher: paragraph (2) is unchanged.

(d) If the commission determines that [any] a well drilled and operated under an area injection order or an order issued under this section does not satisfy all of the requirements [REQUIRE-MENTS] of this section, the commission will take enforcement action to ensure compliance. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

ARTICLE 6.
GENERAL PROVISIONS.

Section
505. Scope of regulations
507. Change of an approved program
510. Commission [OFFICE, HOURS, AND] seal
515. United States government land [LEASES]
517. Plan of reservoir [FOR POOL] development and operation[, AND INTEGRATION OF INTERESTS]
518. Agreements integrating interests ~~under AS 31.05.110(a)~~
520. Field and pool regulation and classification
525. (Repealed)
526. Conduct of operations [AND FIRE HAZARD]
528. Open pit storage of oil
530. Cooperative [COOPERATION] agreements with other parties
534. Tests, surveys, and inspections [REMEDIAL MEASURES]
535. Enforcement
536. (Repealed)
537. Public and confidential [WELL] information
538. (Repealed)
539. Emergency action
540. Hearings
545. Public mailing lists
550. Oaths
555. (Repealed)
556. Orders
557. Subpoenas
560. Time
570. (Repealed) [DEFINITIONS]

20 AAC 25.507 is repealed and readopted to read:

20 AAC 25.507. CHANGE OF AN APPROVED PROGRAM. (a) Except as otherwise provided by 20 AAC 25.015, if an operator desires to make a substantive change in ~~an approved~~ (a) program or activity for which commission approval is required and has been obtained under AS 31.05 or this chapter, complete details of the (well's) current condition and the proposed change must be submitted to the commission with ~~the~~ (an) Application for Sundry Approvals (Form 10-403). A change ~~of~~ (to) an approved program (or activity) may not

be undertaken without commission approval. The commission will condition its approval as the commission considers necessary or appropriate to ensure compliance with the standards on which the original approval was based.

(b) ~~Where~~ If operational necessity requires prompt action, oral approval of a change may be obtained from the commission. The required Application for Sundry Approvals must be submitted for final approval by the commission. That application must set within ~~the commission's next~~ three ~~working~~ days ~~setting~~ out the name of the person who provided approval and the date of the oral approval. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.510 (a) and (b) are repealed, and (c) is amended, to read:

20 AAC 25.510. COMMISSION [OFFICE, HOURS, AND] SEAL. (a) Repealed ___/___/___.

(b) Repealed ___/___/___.

(c) The official seal of the commission is reproduced below.

Att'n AAC Coordinator: Please insert effective date for repealers.

Note to publisher: Commission seal shown on the next page to be inserted here

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.017 AS 31.05.030

ALASKA OIL AND GAS CONSERVATION COMMISSION

SINCE 1955

20 AAC 25.515 is amended to read:

20 AAC 25.515. UNITED STATES GOVERNMENT LAND [LEASES]. A person, including a federal agency, drilling for or producing oil or [NATURAL] gas or conducting underground injection activities related to the recovery and production of oil or gas on federal land subject to the state's police powers shall comply with all applicable regulations and orders of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.027 AS 31.05.030

20 AAC 25.517 is repealed and readopted to read:

20 AAC 25.517. PLAN OF RESERVOIR DEVELOPMENT AND OPERATION. (a) Before commencement of regular production from an oil or gas pool, the operator shall submit to the commission a plan of reservoir development and operation for the pool or the portion of the pool for which development is contemplated by the operator.

(b) Unless otherwise ordered by the commission, the operator shall submit to the commission annual progress reports under the plan of reservoir development and operation. Any amendments and updates to the plan also must be submitted at least annually.

(c) The plan of reservoir development and operation must provide for

(1) the prevention of waste;

(2) the protection of correlative rights; and

(3) a greater ultimate recovery of oil and gas. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 [AS 31.05.110]

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.518. AGREEMENTS INTEGRATING INTERESTS ~~UNDER AS 31.05.110(a)~~. A voluntary agreement for the purpose of integrating interests under AS 31.05.110(a) must be filed with the commission no later than 30 days after ~~it~~ that agreement is executed. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.110

20 AAC 25.520 is amended to read:

20 AAC 25.520. FIELD AND POOL REGULATION AND CLASSIFICATION. (a) Upon the motion of the commission, or the request of an affected owner or [PROPERTY] operator [OR OWNER] at any time after the discovery of oil or gas in a field or pool, the commission will hold a hearing [will be held] in accordance with 20 AAC 25.540, and the commission will issue an order, based upon the evidence presented, classifying the pool as an oil or gas pool in a field and prescribing rules to govern the proposed [FOR THE] development and operation of the pool. In the [A] pool order [so issued] will, the commission establish requirements that the commission considers necessary to

(1) prevent waste, protect freshwater, [AND] protect correlative rights, and ensure a greater ultimate recovery of oil and gas; and

(2) [be] based on the operating and technical data presented.

(b) The commission will, in its discretion, [RECLASSIFY FIELDS AND POOLS, OR] amend pool orders in accordance with the procedures set forth in 20 AAC 25.540 ~~[RECLASSIFY FIELDS AND POOLS, OR AMEND POOL ORDERS]~~ [UPON THE PRESENTATION OF ADDITIONAL DATA AT A SUBSEQUENT HEARING]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Del. underline beneath "amend pool orders"

Authority: AS 31.05.030 AS 31.05.095 AS 31.05.100
AS 31.05.050 AS 31.05.060

20 AAC 25.526 is amended to read:

20 AAC 25.526. CONDUCT OF OPERATIONS [AND FIRE HAZARD]. An operator shall carry on all operations and maintain the property at all times in a safe and skillful manner in accordance with good oil field engineering [INDUSTRY] practices[,] and having due regard for the preservation and conservation of the property and protection of freshwater. [EACH WELL LOCATION AND PROPERTY MUST BE MAINTAINED IN A MANNER TO PREVENT FIRES. ALL RUBBISH, DEBRIS, WASTE MATERIAL, SPILLED OIL, AND ANY OTHER SUBSTANCE THAT CONSTITUTES A FIRE HAZARD MUST BE DISPOSED OF IN AN ENVIRONMENTALLY SAFE MANNER.] (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.527. GENERAL WELL CONTROL REQUIREMENTS FOR DRILLING, COMPLETION, WORKOVER, AND SERVICE OPERATIONS. (a) This section applies to all well drilling, completion, workover, and service operations. The requirements of this section are in addition to the applicable requirements of 20 AAC 25.033 - 20 AAC 25.037 and 20 AAC 25.285 - 20 AAC 25.288.

(b) ~~All~~ Equipment must be in good operating condition at all times and must be protected to ensure reliable operation under the range of weather conditions that may be encountered at the well site.

(c) ~~All~~ Well control equipment and fluids must be installed, used, maintained, and tested in a manner that ensures well control and, except as otherwise provided in this chapter, that conforms with the applicable provisions of the following documents, which are adopted by reference:

(1) API RP 5C7, *Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services*, 1st edition, December 1996;

(2) API RP 13B-1, *Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids*, 2d edition, September 1997;

(3) API RP 13B-2, *Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids*, 3d edition, February 1998;

(4) API RP 49, *Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide*, 2d edition, April 15, 1987;

(5) API RP 53, *Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells*, 3d edition, March 1997;

(6) API RP 57, *Recommended Practices for Offshore Well Completion, Servicing, Workover, and Plug and Abandonment Operations*, 1st edition, January 15, 1986;

(7) API RP 64, *Recommended Practices for Diverter Systems Equipment and Operations*, 1st edition, July 1, 1991;

(8) API RP 68, *Recommended Practice for Oil and Gas Well Servicing and Workover Operations Involving Hydrogen Sulfide*, 1st edition, January 1998.

(d) The toolpushers, drillers, and ~~person(s)-in-charge~~ persons-in-charge on a rotary drilling or workover rig floor must be trained in accordance with the drilling well control training standards contained in 30 C.F.R. 250.1500 - 250.1524 ~~(Subpart O)~~ as revised as of July 1, 1998, which are adopted by reference. The

toolpushers, drillers, and ~~person(s) in charge~~ persons-in-charge on a coiled tubing drilling rig must be trained in accordance with the well servicing well control training standards contained in 30 C.F.R. ~~250.155~~ 250.1500 - 250.1524 ~~(Subpart O)~~ as revised as of July 1, 1998, which are adopted by reference.

(e) The ~~person(s) in charge~~ persons-in-charge on a drill rig floor must have the authority and responsibility to shut in the well if it starts to flow.

(f) The operator shall keep records and reports of well drilling, workover, and repair operations, including BOPE test results, in accordance with 20 AAC 25.070(1) or, in the case of wireline work or other service operations, in the daily work log, which ~~will~~ must be made available to the commission upon request. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: Copies of the American Petroleum Institute recommended practices referred to in ~~this section~~ 20 AAC 25.527 may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070, or if not available from the American Petroleum Institute, may be obtained from Global Engineering Documents, 15 Inverness Way East, Englewood, CO 80150.

20 AAC 25.530 is amended to read:

20 AAC 25.530. COOPERATIVE [COOPERATION] AGREEMENTS WITH OTHER PARTIES. The commission will, in its discretion, from time to time enter into agreements [ARRANGEMENTS] with state and federal agencies, industry committees, or individuals, with respect to special projects, services, and studies relating to underground fluid injection and the conservation of oil and gas. If an agreement [ARRANGEMENT] requires the commission to use procedures ~~or apply~~

~~rules~~ not covered in this chapter, the procedures necessary to carry out the intent of the agreement [ARRANGEMENT] will be formulated and made available at the office of the commission after public notice and opportunity for public comment, ~~pursuant to 15~~ in accordance with 20 AAC 25.540. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: [AS 31.05.023] AS 31.05.030

20 AAC 25.534 is amended to read:

(a) As the commission considers

20 AAC 25.534. TESTS, SURVEYS, AND INSPECTIONS [REMEDIAL MEASURES]. [When considered] necessary or advisable to carry out the purposes of AS 31.05 [THE] (Alaska Oil and Gas Conservation Act) and this chapter, the commission will require that tests or surveys be made to determine the (1) quality of oil and gas produced; (2) [the] formation, casing, tubing, or other pressures; (3) [the] existence of any waste of [CRUDE] oil, gas, or reservoir energy; (4) or [the] risk of fluid movement into freshwater [SOURCES]. (b) [The] commission will, in its discretion, exercise its statutory power to enter and conduct on-site investigations and inspections at reasonable times of facilities, equipment, practices, records, or operations for the purpose of ensuring compliance with the requirements of this chapter. [IF IT IS DETERMINED THAT THE REQUIREMENTS OF THIS CHAPTER ARE NOT BEING MET, THE COMMISSION WILL ORDER REMEDIAL WORK OR TAKE OTHER ACTION IT CONSIDERS NECESSARY.] (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.535. ENFORCEMENT. (a) ~~When~~ If the commission ~~has reason to believe~~, as the result of an investigation or otherwise, considers that a person ~~has~~ may have violated or failed to comply with a provision of AS 31.05, this chapter, or a commission order, permit, or other approval, the commission will, in its discretion, ~~give written notification to~~ take enforcement action under this section against the person.

If the commission proposes to take enforcement action under this section against a person, the commission will send the person a written notification by personal service or by certified mail, return receipt requested.

(b) The commission's written notification to the person will

(1) state the nature of the apparent violation or noncompliance;

(2) summarize the ~~basis of the commission's~~ reason ~~to believe that~~ as why the commission considers a violation or noncompliance ~~has~~ to have occurred;

(3) state the action that the commission proposes to take under (e) of this section; and

(4) inform the person of the person's rights and liabilities under (c) - (e) of this section.

The commission will, in its discretion, extend the 15-day response period for good cause shown.

(c) Within ~~10~~ 15 days after ~~issuance~~ receipt of a notification under (b) of this section, ~~or within such longer period as the commission may specify~~, a person may file with the commission a written response ~~(1) acquiescing~~ that concurs in whole or in part ~~in~~ with a proposed commission action, ~~(2) requesting~~ requests informal review, or ~~(3) requesting~~ requests a hearing under 20 AAC 25.540. If a person fails to file a timely written response, the ~~person~~ commission will ~~be deemed~~ consider the person to have ~~acquiesced in~~ accepted the proposed commission action by default. If a person requests a hearing, the commission will schedule a hearing under 20 AAC 25.540.

(d) If a person requests informal review under (c) of this section, the commission will provide an opportunity for the person to submit documentary material and make a written or oral statement. The commission will then issue a ~~tentative~~ proposed decision or order. A proposed decision or order ~~which~~ becomes final 11 days after it is issued unless within 10 days after it is issued the person files a written request for a hearing, in which case the ~~tentative~~ proposed decision or order is of no effect. If the person requests a hearing, the commission will schedule a hearing under 20 AAC 25.540.

(e) ~~After~~ If a person ~~acquiesces~~ concurs in a proposed action under (c) of this section, or after an informal review or a hearing under (c) or (d) of this section, and ~~when~~ if the commission finds that a person has violated or failed to comply with a provision of AS 31.05, this chapter, or a commission order, permit, or other approval, the commission will, in its discretion, order one or more of the following, as it determines to be applicable:

(1) corrective action or remedial work;

(2) revocation or suspension of a permit or other approval;

(3) payment under the bond required by 20 AAC 25.025; ~~and~~

(4) imposition of penalties under AS 31.05.150.

(f) The commission's action under (e) of this section after an informal review or a hearing is not limited to what ~~was~~ the commission proposed under (b)(3) of this section, ~~as long as~~ if the person ~~had~~ has reasonable notice and opportunity to be heard as to the commission's action.

(g) An action by the commission under this section is in addition to any action the commission may take under AS 31.05.160.

(h) ~~When~~ If an apparent violation or noncompliance described in a notification under (b)(1) of this section relates to the underground disposal of oil field wastes or the underground storage of liquid hydrocarbons requiring commission authorization under 20 AAC 25.252 or relates to the injection of fluids requiring commission authorization under 20 AAC 25.402 or 20 AAC 25.460, ~~any~~ a person ~~having~~ with an interest that is or may be adversely affected may intervene in proceedings under this section. (Eff. ___/___/___, Register __)

Authority:	AS 31.05.030	AS 31.05.050	AS 31.05.095
	AS 31.05.040	AS 31.05.060	AS 31.05.150

20 AAC 25.537 (a)(1), (b), and (c) are amended to read:

20 AAC 25.537. PUBLIC AND CONFIDENTIAL [WELL] INFORMATION. (a) The commission will routinely make available to the public, by means of records or reports, in its offices or elsewhere, or by means of regular publication, the following information:

(1) surface and proposed bottom-hole locations [LOCATION] of each well[,] after approval of the Permit to Drill (Form 10-401);

. . .

Note to publisher: the remainder of subsection (a) is unchanged.

(b) Engineering, geologic, geophysical, and other commercial information [INFORMATION] not required by this chapter, but voluntarily filed with the commission will be kept confidential if the person filing the information so requests. This subsection does not apply to information submitted in a public hearing under 20 AAC 25.540 ~~the confidentiality of which will be governed by other applicable law~~.

(c) In this section, "well status" means the classification of a well as oil, gas, service, suspended, shut-in, or abandoned.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: [AS 31.05.026] AS 31.05.035 [AS 31.05.170]

AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.539. EMERGENCY ACTION. (a) The commission will, in its discretion, issue a temporary emergency order without a hearing if necessary to protect against ~~imminent waste, irreparable harm to correlative rights, contamination of freshwater, or a safety hazard resulting from a violation of a provision of AS 31.05, this chapter, or a commission order~~ immediate harm to public health or safety. Before issuing a temporary emergency order, the commission will attempt to communicate with the operator about the circumstances and need for a temporary order.

(b) ~~A~~ In support of the temporary emergency order, the commission will ~~be supported by~~ issue a written decision describing the factual and legal basis for the action, including the necessity for acting on an emergency basis. ~~The~~ The commission will provide the decision ~~will be provided~~ to the operator within 24 hours of the issuance of the order.

(c) A temporary emergency order expires after 14 days unless

(1) an earlier expiration date is established in ~~the~~ that order;

(2) the operator agrees to an extension; or

(3) a hearing ~~has actually commenced~~ under (d) of this section, in which case ~~the temporary emergency~~ that order ~~will remain~~ remains in effect for an additional period not to exceed the shorter of 14 days after the ~~day~~ date the hearing ~~commences~~ begins or three working days after the ~~day~~ date the hearing ~~closes, whichever period is shorter~~ ends; the commission will extend that period if necessary to protect against immediate harm to public health or safety. ~~For the purposes of a notice of hearing under this subsection, the notice period is 10 days, and the 30 day notice period established in 20 AAC 25.540 does not apply~~. (Eff. ___/___/___, Register __)

within that time period the commission begins

Authority: AS 31.05.030 AS 31.05.050 AS 31.05.095

AS 31.05.040 AS 31.05.060 AS 31.05.150

(d) The commission will, in its discretion, make the temporary emergency order permanent or modify or extend that order after a public hearing. If the temporary emergency order constitutes an enforcement action under 20 AAC 25.535(e)(1) or (2), the procedures under 20 AAC 25.535(b)(4), (c), and (d) do not apply to a commission action under this subsection unless the operator agrees to an extension sufficient to implement those procedures. If the operator does not agree to an extension, the commission's written decision under (b) of this section satisfies the requirements of 20 AAC 25.535(a) and (b)(1)-(3). The provisions of 20 AAC 25.540 apply to a public hearing under this subsection, except that

(1) the commission will provide notice of that hearing at least 10 days before the date of that hearing; and

(2) the requirement in 20 AAC 25.540 that a person request a public hearing does not apply.

20 AAC 25.540 is repealed and readopted to read:

20 AAC 25.540. HEARINGS. (a) On its own motion or if a written request is received to issue an order affecting a single well or a single field, the commission will publish notice in an appropriate newspaper as provided in AS 31.05.050(b). ~~The~~ In the notice, the commission will set out the essential details of the requested order, ~~and~~ provide an opportunity for public comment, and provide a telephone number that the public may use to learn if the commission will hold the tentative hearing. ~~The notice will~~ tentatively specify the place, time, and date for ~~the~~ a public hearing ~~that will be scheduled no fewer than~~ The commission will tentatively set a hearing date that is at least 30 days after the date of publication of the notice. ~~Any~~ A person may submit a written protest or written comments during that 30-day period. In addition, ~~any~~ a person may request that the tentatively scheduled hearing be held by filing a written request with the commission ~~at its office in Anchorage, Alaska~~ within 15 days after the publication date of the notice. ~~The request for hearing must identify the requester's interest in the proposed action and provide the reasons for desiring a public hearing.~~ If the commission ~~determines that a significant issue is raised in~~ receives a timely request for hearing, or if the commission desires to hold a hearing, the commission will hold a hearing ~~will be held~~ on the date and time specified in the notice. If ~~no~~ a request for ~~a~~ hearing is not timely filed, the commission will, in its discretion, issue an order without a hearing.

(b) On its own motion or if a written request for a public hearing is received concerning a matter within the jurisdiction of the commission under this chapter, the commission will publish notice in an appropriate newspaper as provided in AS 31.05.050(b). ~~The~~ In the notice, the commission will provide the essential details of the matter and set out the place for the public hearing, the date, and the time for the public hearing. The commission will set a date that is at least ~~The~~ hearing ~~will be scheduled no fewer than~~ 30 days after the date of publication.

(c) Except as otherwise provided in (e) of this section, the following procedures apply to public hearings conducted under (a) or (b) of this section:

(1) the hearing will be called to order and the subject of the hearing, along with the date and place of public notice given for the hearing, will be read into the record;

(2) the commission will receive both sworn testimony and unsworn statements; it will give greater weight in its deliberations to sworn testimony;

(3) all persons wishing to testify will be sworn;

(4) each witness shall state the witness's name and whom the witness represents;

(5) each witness who wishes to give expert testimony shall state the witness's qualifications, and the commission will rule on whether the witness qualifies as an expert;

(6) the applicant will be asked to present testimony first; all others wishing to present testimony will be heard next; upon request, the commission will, in its discretion, allow cross-examination of witnesses;

(7) a person wishing to make an oral statement will be allowed to do so after the conclusion of all testimony;

(8) the commission will, in its discretion, ask questions of a witness;

(9) except as may be allowed under (6) of this subsection, ~~no one will be permitted to~~ a person may not ask questions of witnesses directly; to have a question directed to a witness, a person ~~shall~~ must provide the question in writing, along with the person's name and that of the witness, to a designated commission representative; before the end of the hearing, the commission will review these questions and ask those that it believes will be helpful in eliciting needed information; all questions will be included in the public record;

(10) ~~when~~ if disclosure of otherwise confidential information is required, ~~such~~ the commission will limit and condition disclosure ~~will be limited and conditioned~~ to the extent necessary to comport with applicable constitutional, statutory ~~(including trade secret provisions, such as AS 45.50.940(3))~~, and common law doctrines that protect trade secrets within the meaning of AS 45.50.940 and other commercially sensitive, confidential, and proprietary information; in limiting or conditioning disclosure under this paragraph, the commission will, as necessary

(A) review confidential information in-camera; and
(B) redact commission decisions to protect confidential information.

(11) ~~a written transcript of~~ the hearing will be ~~prepared and~~ recorded and the recording included in the public record of the hearing;

(12) the commission will, in its discretion, allow pre-filed written testimony in place of or in addition to oral testimony.

(d) The commission will hold ~~Hearings~~ on matters of statewide or general application ~~will be held~~ under the applicable provisions of AS 44.62.

(e) In a hearing under 20 AAC 25.535, a party may be represented by counsel, call and examine witnesses, present relevant evidence unless unduly cumulative or repetitious, cross-examine witnesses, impeach witnesses, and rebut adverse evidence. The commission will establish a reasonable date before the hearing by which the commission will and each party must provide ¶ (1) the names and addresses of persons known to have knowledge of relevant facts and, unless privileged, ¶ (A) ~~their~~ written or recorded statements by those persons; ¶ (B) or summaries of statements by those persons; ¶ (2) the name, address, and qualifications of each expert who will testify at the hearing, and a written description of the substance of the expert's proposed testimony, the expert's opinion, and the underlying basis of that opinion; and ¶ (3) a copy of all documents and a description of all other tangible things intended to be used in the hearing. The commission will base its decision with respect to contested issues of fact only on evidence presented during the hearing.

(f) By means of ~~Pursuant to~~ a pre-hearing conference or otherwise, the commission will, in its discretion, establish additional procedures for a specific hearing consistent with the procedures in (c) or (e) of this section, as applicable, or as otherwise necessary to provide due process to a party. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.050 AS 31.05.070
AS 31.05.040 AS 31.05.060

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.556. ORDERS. ~~All~~ Orders of the commission require approval of at least two commissioners. (Eff. ___/___/___, Register __)

Authority: AS 31.05.011 AS 31.05.030 AS 31.05.040

20 AAC 25.557 is amended to read:

20 AAC 25.557. SUBPOENAS. (a) The commission will, in its discretion, issue subpoenas [AND SUBPOENAS DUCES TECUM].

Upon a written request, the commission will, in the commission's discretion, issue

(b) ~~A~~ a subpoena [SUBPOENAS DUCES TECUM] for the production of books, records, papers, or other documents of any sort [will, in the commission's discretion, be issued by the commission upon a written request]. The applicant must establish [THAT HE OR SHE HAS] a proper relation to the matter, and must show the relevance of the evidence sought and the facts expected to be proved by that evidence [them].

Upon a written request, the commission will, in the commission's discretion, issue a

(c) ~~A [THE ISSUANCE OF A]~~ subpoena requiring the attendance of a witness for the purpose of taking oral testimony before the commission [will, in the commission's discretion, be issued by the commission upon a written request]. The applicant must establish a [THAT HE OR SHE HAS] proper relation to the matter and give the name and address of the desired witness. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.040 AS 31.05.070

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.560. TIME. ~~Where~~ If AS 31.05 or this chapter requires or permits a person to file or submit a document with the commission, the document is considered filed or submitted when it is received in the commission's office. (Eff. ___/___/___, Register ___)

Authority: AS 31.05.030 AS 31.05.035 AS 31.05.040

20 AAC 25.570 is repealed:

20 AAC 25.570. DEFINITIONS. Repealed. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 1/1/95, Register 132; repealed ___/___/___, Register ___)

Editor's note: As of Register ___ (~~_____ 19___~~ ___/___/___), the substance of 20 AAC 25.570 was moved to 20 AAC 25.990.

Att'n AAC Coordinator: Enter effective date & register number where indicated, in editor's note.

ARTICLE 7.
DEFINITIONS.

Section
990. Definitions

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.990. DEFINITIONS. In this chapter, unless the context requires otherwise,

(1) "abandon" means to plug a well in accordance with 20 AAC 25.112 and without the commission's approval of well suspension under 20 AAC 25.110;

(2) "abnormally geo-pressured strata" means subsurface zones where the pore pressure exceeds a gradient of 0.50 psi/ft;

(3) "API" means the American Petroleum Institute;

~~(4) "API 2M" means an API-defined BOP configuration with a working pressure of 2,000 psi~~;

(4) ~~(5)~~ "API 5K ~~5M~~" means an API-defined BOP configuration with a rated ~~working~~ pressure of 5,000 psi and as described in API RP 53, adopted by reference at 20 AAC 25.527(c) under 20 AAC 25.040(b);

(5) ~~(6)~~ "API number" means the number assigned by the commission for a well or well branch consistent with the API well numbering convention;

(6) ~~(7)~~ "API RP" means API recommended practices;

(7) ~~(8)~~ "barrel" means 42 U.S. gallons;

(8) "BHA" means bottom-hole assembly;

(9) "BOP" means blowout preventer, which is a casinghead assembly equipped with special gates or rams or other pack-offs that can be closed around the drill pipe, tubing, casing, or tools, and that completely closes the top of the casing to control well pressure;

(10) "BOPE" means blowout prevention equipment;

(11) "bottom-hole location" means the subsurface point at the greatest measured ~~depth~~ penetration of a well or a well branch;

(12) "casing stub" means the remnant of a casing string when the upper portion of the casing has been cut and recovered;

(13) "commission" means the Alaska Oil and Gas Conservation Commission;

(14) "complete" means to equip and condition a well as an oil, gas, or service well so that it is capable of producing or injecting fluids; in the case of a well branch in a previously completed well, "complete" means to equip and condition a well branch so that it is capable of contributing to the well's production or injection of fluids;

(15) "completion operation" means work performed in a well after the casing and cementing of the wellbore, ~~and~~ "completion operation" includes plugging, perforating, stimulating, testing, and equipping the well to produce or inject fluids;

(16) "conductor casing" means a casing string set before surface casing; depending on well configuration, ~~it~~ "conductor casing" can be either the first or second string of casing set in a well and usually supports a diverter system;

(17) "day" means a calendar day;

(18) "development well" means a well drilled to a known productive pool;

(19) "displacement method" means pumping a cement slurry or other material into a well through a drillpipe or other tubular string and recovering displaced fluids on the surface;

(20) "diverter system" means an assembly of nipples, valves, and piping attached to a well's structural or conductor casing for venting a gas kick away from the drill rig;

(21) "downsqueeze method" means pumping a cement slurry or other material into a well through a drillpipe or other tubular string and forcing displaced fluids into a downhole formation;

(22) "drilling fluid" means any fluid used for the purpose of drilling a well;

(23) "drilling operations" means the penetration of ground below the setting depth of structural or conductor casing, ~~if set~~, and for purposes other than setting structural or conductor casing, using a drilling rig capable of performing the permitted well work; "drilling operations" ~~and~~ includes the running of casing, cementing, and other downhole work performed ancillary to formation evaluation, and ~~all~~ operations necessary to complete and equip the well so that formation fluids can be safely brought to the surface;

(24) "drilling unit" means an area of a pool, ¶(A) established by the commission under AS 31.05.100, either by order or by regulation, ¶(B) to which no more than one oil or gas well may be drilled, and ¶(C) from which no more than one oil or gas well may produce;

(25) "exploratory well" means a well drilled to discover or to delineate a pool;

(26) "fluid" means any material or substance that flows or moves, whether in a semi-solid, liquid, sludge, gaseous, or other form or state;

(27) "freshwater" means water ~~having~~ that ¶(A) has a total dissolved solids concentration of less than 10,000 mg/l ~~that~~ and occurs in a stratum not exempted under 20 AAC 25.440, ¶(B) or ~~water that~~ occurs in a stratum that serves as a source of drinking water for human consumption;

(28) "function pressure-test" means to actuate a component and demonstrate its ability to effect a pressure seal;

(29) "function-test" means to actuate a component to demonstrate its proper functioning without subjecting it to pressure;

(30) "gas well" means a well that produces predominantly gas at a gas-oil ratio over 100,000 scf/stb, unless on a pool by pool basis the commission establishes another ratio;

(31) "gas-oil ratio" means the cubic feet of gas, determined at 60° F and 14.65 psia, that are produced per stock tank barrel of oil produced;

(32) "injection" means the subsurface emplacement of fluid for enhanced recovery of oil or gas, disposal of oil field wastes, or underground storage of hydrocarbons;

(33) "intermediate casing" means a casing string run between the surface casing and the production casing or production liner and cemented in place to isolate abnormally geo-pressured strata, lost circulation zones, salt sections, or unstable shale sections;

(36) "LEL" means lower explosive limit;

(35) ~~(34)~~ "landowner" has the meaning given in AS 31.05.170;

(37) ~~(35)~~ "liner" means a string of casing that does not extend to surface but is (A) hung inside the previous casing string or ~~may be~~ (B) set and cemented in place within the previous casing string;

(38) ~~(36)~~ "meter curve" means a graph of the meter factor plotted against the flow rate, or of the pulse-per-unit-volume factor plotted against the flow rate, over the operating range of a meter;

(39) ~~(37)~~ "meter factor" means the number obtained by dividing the gross standard volume of liquid passed through a meter (as measured by a prover during proving) by the corresponding meter indicated volume at standard conditions;

(40) ~~(38)~~ "mg/l" means milligrams per liter;

(41) ~~(39)~~ "mscf" means thousand standard cubic feet;

(42) ~~(40)~~ "mudline datum" means

(A) for a beach location, the plane of mean low water depth extended beneath the well site;

(34) "junk" means debris lost in a hole; "junk" includes a lost bit, pieces of a bit, milled pieces of pipe, wrenches, or a relatively small object that impedes drilling;

(B) for a location on a shifting natural island, the depth at which a horizontal plane through the toe of the island intersects the wellbore;

(C) for a location on an artificial island, the depth of the mudline as it existed before construction of the island; or

(D) for other offshore locations, the mudline;

(43) ~~(41)~~ "multiple completion" means the completion of a well so as to permit production from more than one pool, with the production from each pool completely segregated;

(44) ~~(42)~~ "offshore" means, in addition to its ordinary meaning, beach, artificial island, and shifting natural island locations;

(45) ~~(43)~~ "oil well" means a well that produces predominantly oil at a gas-oil ratio of 100,000 scf/stb or lower, unless on a pool-by-pool basis the commission establishes another ratio;

(46) ~~(44)~~ "operator" means an owner or a person authorized by an owner who is responsible for drilling, development, production, injection, disposal, storage, abandonment, and location clearance;

(47) ~~(45)~~ "owner" has the meaning given in AS 31.05.170;

(48) ~~(46)~~ "pilot gas" means gas routed to a safety flare system to maintain an ignition source;

(49) ~~(47)~~ "ppm" means parts per million;

(50) ~~(48)~~ "pressure-test" means to demonstrate the pressure integrity of a system without actuating its components;

(51) ~~(49)~~ "production casing" means the casing installed from the wellhead to the top of or through the completion interval and cemented in place to seal off production or injection zones and water-bearing formations;

(52) ~~(50)~~ "property" means a legally described tract of land, submerged or otherwise, to which a person has the right to drill, extract, remove, clean, process, and dispose of oil, gas, and associated substances;

(53) ~~(51)~~ "psi" means pounds per square inch;

(54) ~~(52)~~ "psia" means pounds per square inch absolute;

(55) "psi/ft" means pounds per square inch per foot, as a measure of pressure change with depth;

(56) ~~(53)~~ "psig" means pounds per square inch gauge;

(57) "public water system" has the meaning given in 18 AAC 80.1990, as amended as of October 1, 1999, and as amended from time to time; 18 AAC 80.1990 is adopted by reference;

(58) ~~(54)~~ "purge gas" means gas used to maintain forward flow and positive pressure in a safety flare system;

(59) ~~(55)~~ "reservoir" means the same as "pool" in AS 31.05.170;

(60) ~~(56)~~ "scf" means standard cubic feet;

(61) ~~(57)~~ "service well" means a well used for injecting water, gas, or other fluids into a reservoir or producing formation in pressure maintenance, enhanced recovery, or storage operations, for disposing of oil field wastes, or for conducting other operations in support of oil or gas production;

(62) ~~(58)~~ "shut in" means to close a well's surface, wellhead, or subsurface valves to halt flow from or into the well, with the completion interval remaining open to the tubing below the closed valves;

(63) ~~(59)~~ "sidetrack operation" means a drilling operation conducted for the purpose of straightening the original hole, bypassing junk, or correcting mechanical difficulties in the original hole;

(64) ~~(60)~~ "standard cubic foot" has the meaning given to "cubic foot" in AS 31.05.170;

(65) ~~(61)~~ "stb" means stock tank barrel;

(66) ~~(62)~~ "stock tank barrel" means 42 U.S. gallons, measured at 60° F and 14.65 psia;

(67) ~~(63)~~ "stratigraphic test" means a hole drilled for the sole purpose of gaining structural or stratigraphic information to aid in exploring for oil and gas;

(68) ~~(64)~~ "structural casing" means a short string of large diameter pipe ~~which may be~~ that is set by driving, jetting, or drilling to support unconsolidated shallow sediments, provide hole stability for initial drilling operations, and provide anchorage for a diverter system;

(69) ~~(65)~~ "surface casing" means a string of casing set and cemented in a well to prevent lost circulation while drilling deeper and to protect strata known or reasonably expected to serve as a source of drinking water for human consumption; usually ~~it~~ "surface casing" is the first string of casing upon which ~~blowout prevention equipment~~ BOPE is set;

(70) ~~(66)~~ "suspend" means to plug a well in accordance with 20 AAC 25.110 and ~~with the operator's reserving~~ to reserve the option later to re-enter and (A) redrill the well or (B) complete the well as an oil, gas, or service well;

(71) "tour" means a work shift in the drilling of a well;

(72) ~~(67)~~ "underbalanced drilling" means drilling under conditions where the hydrostatic head of the drilling fluid column is intentionally designed to be lower than the pressure of the formation being drilled;

(73) ~~(68)~~ "well" (A) means a hole penetrating the earth, usually cased with steel pipe, and (i) from which oil or gas, or both, is obtained or obtainable; or (ii) that ~~which~~ is made for the purpose of finding or obtaining oil or gas or of supporting oil or gas production; and (B) includes a well ~~may have~~ with multiple well branches drilled to different bottom-hole locations;

(74) ~~(69)~~ "well branch" means that portion of a well drilled below the structural or conductor casing to access a separate objective in a well with more than one bottom-hole location; (Eff. ___/___/___, Register ___)

Authority: AS 31.05.030

Editor's note: Before ___/___/___, Register ___ ~~(_____ 19___)~~, the substance of 20 AAC 25.990 was contained in 20 AAC 25.570. The history note for 20 AAC 25.990 does not reflect the history of 20 AAC 25.570.

(75) "working day" means a calendar day other than Saturday, Sunday, or a state holiday.

Att'n AAC Coordinator: Insert effective date & register number in editor's note.

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To: Cammy O. **Fax #:**

From: Rob M. **Date:**

Subject: UIC **Pages:** 6, including cover sheet

Message: The map must show all wells within the area. Specific information on wells need only be supplied for wells in the area that penetrate affected zones.

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[Code of Federal Regulations]
[Title 40, Volume 14, Parts 136 to 149]
[Revised as of July 1, 1998]
From the U.S. Government Printing Office via GPO Access
[**CITE: 40CFR146**]

[Page 597-601]

TITLE 40--PROTECTION OF ENVIRONMENT

CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY (CONTINUED)

PART 146--UNDERGROUND INJECTION CONTROL PROGRAM: CRITERIA AND STANDARDS--Table of Co

Subpart C--Criteria and Standards Applicable to Class II Wells

Sec. 146.21 Applicability.

This **subpart** establishes criteria and standards for underground injection control programs to regulate Class II wells.

Sec. 146.22 Construction requirements.

(a) All new Class II wells shall be sited in such a fashion that they inject into a formation which is separated from any USDW by a confining zone that is free of known open faults or fractures within the area of review.

(b)(1) All Class II injection wells shall be cased and cemented to prevent movement of fluids into or between underground sources of drinking water. The casing and cement used in the construction of each newly drilled well

[[Page 598]]

shall be designed for the life expectancy of the well. In determining and specifying casing and cementing requirements, the following factors shall be considered:

(i) Depth to the injection zone;

(ii) Depth to the bottom of all USDWs; and

(iii) Estimated maximum and average injection pressures;

(2) In addition the Director may consider information on:

(i) Nature of formation fluids;

(ii) Lithology of injection and confining zones;

(iii) External pressure, internal pressure, and axial loading;

(iv) Hole size;

(v) Size and grade of all casing strings; and

(vi) Class of cement.

(c) The requirements in paragraph (b) of this section need not apply to existing or newly converted Class II wells located in existing fields if:

(1) Regulatory controls for casing and cementing existed for those wells at the time of drilling and those wells are in compliance with those controls; and

(2) Well injection will not result in the movement of fluids into an underground source of drinking water so as to create a significant risk to the health of persons.

(d) The requirements in paragraph (b) of this section need not apply to newly drilled wells in existing fields if;

(1) They meet the requirements of the State for casing and cementing applicable to that field at the time of submission of the State program to the Administrator; and

(2) Well injection will not result in the movement of fluids into an underground source of drinking water so as to create a significant risk

to the health of persons.

(e) Where a State did not have regulatory controls for casing and cementing prior to the time of the submission of the State program to the Administrator, the Director need not apply the casing and cementing requirements in paragraph (b) of this section if he submits as a part of his application for primacy, an appropriate plan for casing and cementing of existing, newly converted, and newly drilled wells in existing fields, and the Administrator approves the plan.

(f) Appropriate logs and other tests shall be conducted during the drilling and construction of new Class II wells. A descriptive report interpreting the results of that portion of those logs and tests which specifically relate to (1) an USDW and the confining zone adjacent to it, and (2) the injection and adjacent formations shall be prepared by a knowledgeable log analyst and submitted to the director. At a minimum, these logs and tests shall include:

(1) Deviation checks on all holes constructed by first drilling a pilot hole and then enlarging the pilot hole, by reaming or another method. Such checks shall be at sufficiently frequent intervals to assure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling.

(2) Such other logs and tests as may be needed after taking into account the availability of similar data in the area of the drilling site, the construction plan, and the need for additional information that may arise from time to time as the construction of the well progresses. In determining which logs and tests shall be required the following shall be considered by the Director in setting logging and testing requirements:

(i) For surface casing intended to protect underground sources of drinking water in areas where the lithology has not been determined:

(A) Electric and caliper logs before casing is installed; and

(B) A cement bond, temperature, or density log after the casing is set and cemented.

(ii) for intermediate and long strings of casing intended to facilitate injection:

(A) Electric porosity and gamma ray logs before the casing is installed;

(B) Fracture finder logs; and

(C) A cement bond, temperature, or density log after the casing is set and cemented.

(g) At a minimum, the following information concerning the injection formation shall be determined or calculated for new Class II wells or projects:

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(1) Fluid pressure;

(2) Estimated fracture pressure;

(3) Physical and chemical characteristics of the injection zone.

[45 FR 42500, June 24, 1980, as amended at 46 FR 43162, Aug. 27, 1981; 47 FR 5000, Feb. 3, 1982]

Sec. 146.23 Operating, monitoring, and reporting requirements.

(a) Operating requirements. Operating requirements shall, at a minimum, specify that:

(1) Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs. In no case shall injection pressure cause the movement of injection or formation fluids into an underground source of drinking water

(2) Injection between the outermost casing protecting underground sources of drinking water and the well bore shall be prohibited.

(b) Monitoring requirements. Monitoring requirements shall, at a minimum, include:

(1) Monitoring of the nature of injected fluids at time intervals sufficiently frequent to yield data representative of their characteristics;

(2) Observation of injection pressure, flow rate, and cumulative volume at least with the following frequencies:

(i) Weekly for produced fluid disposal operations;

(ii) Monthly for enhanced recovery operations;

(iii) Daily during the injection of liquid hydrocarbons and injection for withdrawal of stored hydrocarbons; and

(iv) Daily during the injection phase of cyclic steam operations

And recording of one observation of injection pressure, flow rate and cumulative volume at reasonable intervals no greater than 30 days.

(3) A demonstration of mechanical integrity pursuant to Sec. 146.8 at least once every five years during the life of the injection well;

(4) Maintenance of the results of all monitoring until the next permit review (see 40 CFR 144.52(a)(5)); and

(5) Hydrocarbon storage and enhanced recovery may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold. Separate monitoring systems for each well are not required provided the owner/operator demonstrates that manifold monitoring is comparable to individual well monitoring.

(c) Reporting requirements. (1) Reporting requirements shall at a minimum include an annual report to the Director summarizing the results of monitoring required under paragraph (b) of this section. Such summary shall include monthly records of injected fluids, and any major changes in characteristics or sources of injected fluid. Previously submitted information may be included by reference.

(2) Owners or operators of hydrocarbon storage and enhanced recovery projects may report on a field or project basis rather than an individual well basis where manifold monitoring is used.

(Clean Water Act, Safe Drinking Water Act, Clean Air Act, Resource Conservation and Recovery Act; 42 U.S.C. 6905, 6912, 6925, 6927, 6974)

[45 FR 42500, June 24, 1980, as amended at 46 FR 43162, Aug. 27, 1981; 47 FR 5000, Feb. 3, 1982; 48 FR 14293, Apr. 1, 1983; 48 FR 31404, July 8, 1983]

Sec. 146.24 Information to be considered by the Director.

This section sets forth the information which must be considered by the Director in authorizing Class II wells. Certain maps, cross-sections, tabulations of wells within the area of review, and other data may be included in the application by reference provided they are current, readily available to the Director (for example, in the permitting agency's files) and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this section is to be submitted to the Administrator.

(a) Prior to the issuance of a permit for an existing Class II well to operate or the construction or conversion of a

[[Page 600]]

new Class II well the Director shall consider the following:

(1) Information required in 40 CFR 144.31 and 144.31(g);

(2) A map showing the injection well or project area for which a permit is sought and the applicable area of review. Within the area of review, the map must show the number or name and location of all existing producing wells, injection wells, abandoned wells, dry holes, and water wells. The map may also show surface bodies of waters, mines (surface and subsurface), quarries and other pertinent surface features including residences and roads, and faults if known or suspended. Only

information of public record and pertinent information known to the applicant is required to be included on this map. This requirement does not apply to existing Class II wells; and

(3) A tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review included on the map required under paragraph (a)(2) of this section which penetrate the proposed injection zone or, in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the area of review which penetrate formations affected by the increase in pressure. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of plugging and complete, and any additional information the Director may require. In cases where the information would be repetitive and the wells are of similar age, type, and construction the Director may elect to only require data on a representative number of wells. This requirement does not apply to existing Class II wells.

(4) Proposed operating data:

(i) Average and maximum daily rate and volume of fluids to be injected.

(ii) Average and maximum injection pressure; and

(iii) Source and an appropriate analysis of the chemical and physical characteristics of the injection fluid.

(5) Appropriate geological data on the injection zone and confining zone including lithologic description, geological name, thickness and depth;

(6) Geologic name and depth to bottom of all underground sources of drinking water which may be affected by the injection;

(7) Schematic or other appropriate drawings of the surface and subsurface construction details of the well;

(8) In the case of new injection wells the corrective action proposed to be taken by the applicant under 40 CFR 122.44;

(9) A certificate that the applicant has assured through a performance bond or other appropriate means, the resources necessary to close plug or abandon the well as required by 40 CFR 122.42(g);

(b) In addition the Director may consider the following:

(1) Proposed formation testing program to obtain the information required by Sec. 146.22(g);

(2) Proposed stimulation program;

(3) Proposed injection procedure;

(4) Proposed contingency plans, if any, to cope with well failures so as to prevent migration of contaminating fluids into an underground source of drinking water;

(5) Plans for meeting the monitoring requirements of Sec. 146.23(b).

(c) Prior to granting approval for the operation of a Class II well the Director shall consider the following information:

(1) All available logging and testing program data on the well;

(2) A demonstration of mechanical integrity pursuant to Sec. 146.8;

(3) The anticipated maximum pressure and flow rate at which the permittee will operate.

(4) The results of the formation testing program;

(5) The actual injection procedure; and

(6) For new wells the status of corrective action on defective wells in the area of review.

(d) Prior to granting approval for the plugging and abandonment of a Class II well the Director shall consider the following information:

(1) The type, and number of plugs to be used;

(2) The placement of each plug including the elevation of top and bottom;

[[Page 601]]

(3) The type, grade, and quantity of cement to be used;

(4) The method of placement of the plugs; and

(5) The procedure to be used to meet the requirements of Sec. 146.10(c).

(Clean Water Act, Safe Drinking Water Act, Clean Air Act, Resource Conservation and Recovery Act: 42 U.S.C. 6905, 6912, 6925, 6927, 6974)

[45 FR 42500, June 24, 1980, as amended at 46 FR 43162, Aug. 27, 1981; 47 FR 5000, Feb. 3, 1982; 48 FR 14293, Apr. 1, 1983]

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To: Dave J. cc: CC RAC **Fax #:**

From: Rob M. **Date:** 8/4/99

Subject: NGP **Pages:** 5, including cover sheet

Message: open language I ran by Steve U. — he said OK

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Change to 20 AAC 25.005(c)(2)

Insert new (B), and re-letter current (B) and (C):

(B) the coordinates of the proposed location of the well at the surface, referenced to the state plane coordinate system for this state as maintained by the National Geodetic Survey in the National Oceanic and Atmospheric Administration;

(C) the proposed depth . . . .

(D) other information required . . . .

Also, change to 20 AAC 25.050(f)(8)

(8) a plat showing the coordinates

(A) of the surface location, the plotted well course, and wells within 500 feet of any portion of the wellbore, referenced to governmental section lines; and

(B) of the surface location, referenced to the state plane coordinate system for this state as maintained by the National Geodetic Survey in the National Oceanic and Atmospheric Administration.

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Amend 20 AAC 25.040(c)

(c) For platforms or multiple-well drill sites, the information required in (a)(2) -- [(a)(1) – (a)(3) AND] (a)(5) of this section may be posted on one sign on the platform or at the main entrance to the drill site.

Proposed new language for 20 AAC 25.110(c):

(c) At the operator's request accompanying the submission, information submitted to show that the applicable criteria for well suspension under (a) of this section have been met will be kept confidential

(1) for the period specified under AS 31.05.035(c), if the information is described in 20 AAC 25.071(b);

(2) as long as the information has value as a trade secret, if the information is not described in 20 AAC 25.071(b) but is determined by the commission to constitute a trade secret under AS 45.50.940.

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Possible revised language for 20 AAC 25.252(a), second sentence:

In [IN] response to a letter of application for injection filed by an operator, the commission will, in its discretion, issue an order authorizing the [FOR] underground disposal of oil field wastes that the commission determines are suitable for disposal in a Class II well, as defined in 40 C.F.R. 144.6(b) as revised as of July 1, 1998, which is adopted by reference, or the underground storage of hydrocarbons.

CHAPTER 25.
ALASKA OIL AND GAS CONSERVATION COMMISSION.

Article

1. Drilling
(20 AAC 25.005-20 AAC 25.080)
2. Abandonment and Plugging
(20 AAC 25.105-20 AAC 25.172)
3. Production Practices
(20 AAC 25.200-20 AAC 25.290[85])
4. Reports
(20 AAC 25.300-20 AAC 25.320)
5. Enhanced Recovery
(20 AAC 25.400-20 AAC 25.460)
6. General Provisions
(20 AAC 25.505-20 AAC 25.570)
7. Definitions
(20 AAC 25.990)

ARTICLE 1.
DRILLING.

Section

05. Permit to drill
10. Re-entry of a suspended well
15. Changes to an approved drilling program [PERMIT]
20. Designation of operator
22. Change of ownership
25. Bonding
26. Claims
30. Casing and cementing
33. Primary well control for drilling: drilling fluid program and drilling fluid [SURFACE] system
35. Secondary well control for primary drilling and completion: blowout prevention equipment [(BOPE)] and diverter requirements
36. Secondary well control for through-tubing drilling and completion: blowout prevention equipment requirements
37. Well control requirements for other drilling and completion operations
40. Well identification
45. (Repealed)
47. Reserve pits and tankage
50. Wellbore surveys [DEVIATION]
55. Drilling units and well spacing
61. Well site surveys
65. Hydrogen sulfide
66. Gas detection
70. Records and reports

71. Geologic data and logs
72. Shutdown of drilling or completion [WELL] operations
75. Other wells in designated areas
80. Annular disposal of drilling waste

20 AAC 25.005 is repealed and readopted to read:

20 AAC 25.005. PERMIT TO DRILL. (a) Before drilling or redrilling a well or re-entering an abandoned well, a person shall submit and obtain the commission's approval of an application for a Permit to Drill (Form 10-401).

(b) The commission will classify a well as:

(1) exploratory;

(2) development, either oil or gas;

(3) service; or

(4) stratigraphic test.

(c) An application for a Permit to Drill must be accompanied by the following unless already on file with the commission and identified in the application:

(1) a fee of $100 payable to the State of Alaska, Department of Revenue;

(2) a plat identifying the property and its owner(s) and showing

(A) the coordinates of the proposed location of the well at the surface, at the top of each objective formation, and at total depth, referenced to governmental section lines;

(B) the proposed depth of the well at the top of each objective formation and at total depth; and

(C) other information required by 20 AAC 25.050.

(3) a diagram and description of the blowout prevention equipment (BOPE) as required by 20 AAC 25.035, 20 AAC 25.036, or 20 AAC 25.037, as applicable;

(4) information on drilling hazards, including

(A) the maximum downhole pressure that may be encountered, criteria used to determine it, and maximum potential surface pressure based on a methane gradient;

(B) data on potential gas zones; and

(C) data concerning hole problems such as over-pressured zones, lost circulation zones, and zones that have a propensity for differential sticking;

(5) a description of the procedure for conducting formation integrity tests, as required under 20 AAC 25.030(f);

(6) a complete proposed casing and cementing program as required by 20 AAC 25.030, and a description of any slotted liner, pre-perforated liner, or screen to be installed;

(7) a diagram and description of the diverter system as required by 20 AAC 25.035, unless this requirement is waived by the commission;

(8) a drilling fluid program, including a diagram and description of the drilling fluid system, as required by 20 AAC 25.033;

(9) for an exploratory or stratigraphic test well, a tabulation setting out the depths of predicted abnormally geo-pressured strata as required by 20 AAC 25.033(f);

(10) for an exploratory or stratigraphic test well, a seismic refraction or reflection analysis as required by 20 AAC 25.061(a);

(11) for a well drilled from an offshore platform, mobile bottom-founded structure, jack-up rig, or floating drilling vessel, an analysis of seabed conditions as required by 20 AAC 25.061(b);

(12) evidence showing that the requirements of 20 AAC 25.025 have been met;

(13) a copy of the proposed drilling program; and

(14) a general description of how the operator plans to dispose of drilling mud and cuttings and a statement of whether the operator intends to request authorization under 20 AAC 25.080 for an annular disposal operation in the well.

(d) For a well that is to be intentionally deviated, the requirements of 20 AAC 25.050(b) must be met.

(e) A well may have multiple well branches, and unless drilled solely to conduct sidetrack operations, each branch requires a separate Permit to Drill. When multiple well branches are proposed from a single conductor, surface, or production casing, the applicant shall designate one branch as the primary wellbore and include all information required under (c) of this section with its corresponding application for a Permit to Drill. For each subsequent well branch, the application for a Permit to Drill need only include information under (c) of this section that is unique to that branch and need not include the $100 fee.

(f) Each well must be identified by a unique name designated by the operator and a unique API number assigned by the commission under 20 AAC 25.040(b). For a well with multiple well branches, each branch must similarly be identified by a unique name and API number by adding a suffix to the name designated for the well by the operator and to the number assigned to the well by the commission.

(g) If drilling operations are not commenced within 24 months after the commission approves an application for a Permit to Drill, the Permit to Drill expires.

(h) A Permit to Drill is not valid at a location where the applicant does not have a right to drill for oil and gas. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25.010 is amended to read:

20 AAC 25.010. RE-ENTRY OF A SUSPENDED WELL. (a) Before re-entering [IF] a suspended well [IS TO BE RE-ENTERED] to conduct completion operations, the operator shall submit and obtain the commission's approval of an [THE FORM ENTITLED] Application for Sundry Approvals (Form 10-403) [FOR COMMISSION APPROVAL]. The Application for Sundry Approvals [FORM 10-

403 FILING] must set out the current condition of the well and the proposed program for completion operations.

(b) Before re-entering [IF] a suspended well to conduct [IS TO BE RE-ENTERED TO CONDUCT ACTUAL] drilling operations, the operator shall submit and obtain the commission's approval of an application for a [THE FORM ENTITLED] Permit to Drill (Form 10-401) [FOR COMMISSION APPROVAL] in conformance with 20 AAC 25.005.

(c) The operator shall file with the commission within 30 days after completion, abandonment, or suspension of the well a Well Completion or Recompletion Report and Log (Form 10-407) and all information required by 20 AAC 25.070(3) [20 AAC 25.070] and 20 AAC 25.071. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25.015 is repealed and readopted to read:

20 AAC 25.015. CHANGES TO AN APPROVED DRILLING PROGRAM. (a) To change an approved program before drilling operations have started, the operator shall

(1) submit and obtain the commission's approval of a new application for a Permit to Drill (Form 10-401) if the surface location is changed, if the bottom-hole location or the location of an objective formation is changed by more than 500 feet laterally or vertically, or if the change requires a spacing exception under 20 AAC 25.055; however, no additional fee is required;

(2) otherwise notify the commission and obtain its approval of the change if the change is not covered by (1) of this subsection.

(b) To change an approved drilling program or to change information under 20 AAC 25.005(c) after drilling operations have started, the operator shall

(1) submit and obtain the commission's approval of a new application for a Permit to Drill (Form 10-401), accompanied by a fee of $100, if the bottom-hole location or the location of an

objective formation is changed by more than 500 feet laterally or vertically, or if the change requires a spacing exception under 20 AAC 25.055;

(2) submit and obtain the commission's approval of an Application for Sundry Approvals (Form 10-403) if the change is not covered by (1) of this subsection; the Application for Sundry Approvals must set out the approved program, the current condition of the well, and the proposed changes; in cases where prompt approval is needed, oral approval may be requested from the commission; if oral approval is obtained, the name of the representative of the commission who provided oral approval and the date of the approval must be included on the Application for Sundry Approvals, which must be submitted within the commission's next three working days. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25.020 is amended to read:

20 AAC 25.020. DESIGNATION OF OPERATOR. If an owner of a property wishes to [RELINQUISH THE ROLE OF OPERATOR, OR] designate a new operator for the property, the owner shall submit to the commission for approval a Designation of Operator (Form 10-411). The newly designated operator shall [MUST] signify acceptance of the obligations as operator on the same Designation of Operator form [FORM 10-411] and shall [MUST] furnish a bond and, if required, security as provided for in 20 AAC 25.025. The commission's acceptance of the designated operator's bond constitutes the release of the [OWNER'S OR] former operator's bonding obligation for the property indicated on the Form 10-411. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register__)

Authority: AS 31.05.030

20 AAC 25.022 is amended to read:

20 AAC 25.022. NOTICE [CHANGE] OF OWNERSHIP. When a person becomes an owner [A PERSON WHO IS THE OPERATOR] of a property on which operations subject to this chapter are [HAVE BEEN] proposed to the commission or are being conducted, the person shall file a Notice of [CHANGE OF] Ownership (Form 10-417) within 15 days [AFTER CONVEYANCE, EACH TIME THAT AN OWNER OR LANDOWNER, AS DEFINED BY AS 31.05.170, CONVEYS ALL OR A PARTIAL INTEREST IN THE PROPERTY TO ANOTHER PERSON]. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.025 is repealed and readopted to read:

20 AAC 25.025. BONDING. (a) An operator proposing to drill a well for which a permit is required under 20 AAC 25.005 shall file a bond and, if required under (2) of this subsection, security to ensure that each well is drilled, operated, maintained, repaired, and abandoned and each location is cleared in accordance with this chapter. The bond must be

(1) a surety bond issued on Form 10-402A in favor of the Alaska Oil and Gas Conservation Commission by an authorized insurer under AS 29 whose certificate of authority is in good standing; or

(2) a personal bond of the operator on Form 10-402B accompanied by and whose performance is guaranteed by security in the form of a certificate of deposit or irrevocable letter of credit issued in the sole favor of the Alaska Oil and Gas Conservation Commission by a bank authorized to do business in the state, or, in the commission's discretion, another form of security that the commission determines to be adequate.

(b) A bond and, if required, security must be in the amount of not less than $100,000 to cover a single well or not less than $200,000 for a blanket bond covering all of the operator's wells in the state, except that the commission will, in its discretion, allow an amount less than $100,000 to cover a single well

if the operator demonstrates in the application for a Permit to Drill (Form 10-401) that the cost of well abandonment will be less than $100,000.

(c) A bond and, if required, security must remain in effect until the abandonment of all wells covered by them and final clearance of the locations are approved by the commission. The commission will then release the bond and security upon written request of the operator.

(d) Payment under a surety bond or security does not relieve an operator from any obligations under this chapter except to the extent that a default is actually cured, or from any liability under AS 31.05.150. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.150

20 AAC 25.026 is amended to read:

20 AAC 25.026. CLAIMS. Commission approval of the abandonment of a well and the release of the bond[,] required by 20 AAC 25.025 [SEC. 25 OF THIS CHAPTER,] constitutes a presumption of proper abandonment, but does not relieve an operator of further claim by the commission after the abandonment. (Eff. 4/13/80, Register 74; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.030 is repealed and readopted to read:

20 AAC 25.030. CASING AND CEMENTING. (a) A complete proposed well casing and cementing program must be submitted with an application for a Permit to Drill (Form 10-401). Unless modified or altered by special pool rules, a well casing and cementing program must be designed to

(1) provide suitable and safe operating conditions for the total measured depth proposed;

(2) confine fluids to the wellbore;

(3) prevent migration of fluids from one stratum to another;

(4) ensure control of well pressures encountered;

(5) protect against thaw subsidence and freezeback effects within permafrost;

(6) prevent contamination of freshwater;

(7) protect significant hydrocarbon zones; and

(8) provide well control until the next casing is set, considering all factors relevant to well control including formation fracture gradients, formation pressures, casing setting depths, and proposed total depth.

(b) General well casing and cementing provisions are as follows:

(1) casing design and setting depth must be based on engineering and geologic factors relevant to the immediate vicinity, including the presence or absence of hydrocarbons, potential drilling hazards, and permafrost;

(2) for all casing strings on which blowout prevention equipment will be installed, cement may not be drilled out until sufficient compressive strength has been reached to obtain a valid formation integrity test;

(3) within permafrost intervals, fluids that have a freezing point above the minimum permafrost temperature may not be left in casing-by-casing annuli or inside the casing upon completion, suspension, or shutdown of well operations, without commission approval;

(4) when casing is subjected to prolonged drilling operations, the commission will, in its discretion, require the casing to be pressure-tested, calipered, or otherwise evaluated by a method approved by the commission;

(5) where zonal coverage is required, and the commission believes zonal isolation might not have been established, the commission will, in its discretion, require a cement quality log or other method to demonstrate isolation of the zone.

(c) Specific well casing provisions are as follows:

(1) structural casing must be set by driving, jetting, or drilling to a minimum depth of 70 feet in all offshore wells to support unconsolidated shallow strata, to provide hole stability for initial drilling operations, and to provide a competent anchor for a diverter system;

(2) for onshore wells, conductor casing must be set by driving, jetting, or drilling to a depth sufficient to provide anchorage for a diverter system, and for offshore wells, conductor casing must be set no less than 300 feet and no more than 1000 feet below the mudline datum; except that the commission will, in its discretion,

(A) approve a different casing setting depth when necessary to permit the casing shoe to be set in a competent formation or below formations that should be isolated; or

(B) authorize an operator to drill without setting conductor casing based upon information from wells drilled in the immediate vicinity and other available data;

(3) surface casing must be set below the base of all strata known or reasonably expected to serve as a source of drinking water for human consumption and at a depth sufficient to provide a competent anchor for blowout prevention equipment;

(4) one or more intermediate casing strings must be set when required for protection of oil or gas, for protection against abnormally geo-pressured strata and lost circulation zones, or when otherwise required by well conditions;.

(5) production casing must be set and cemented through, into, or just above the production interval;

(6) slotted liners, pre-perforated liners, and screens installed below a production packer are considered as production equipment and not as casing.

(d) Specific well casing cementing provisions are as follows:

(1) if structural casing is set by drilling or jetting, the structural casing must be cemented with a quantity of cement sufficient to fill the annular space from the shoe to the surface;

(2) if conductor casing is set by drilling or jetting, the conductor casing must be cemented by filling the annular space with cement from the shoe to the surface; if blowout prevention equipment is to be installed on the conductor casing, the adequacy of the cement to contain potential wellbore pressures and fluids must be demonstrated by a formation integrity test;

(3) upon approval of the commission, conductor casing cement may be washed out to a depth not exceeding the depth of the structural casing shoe, if installed;

(4) surface casing must be cemented by filling the annular space with cement from the shoe to the surface; however, if cement does not circulate to the surface, if an excessive quantity of cement circulates to the surface, or if the formation integrity test shows an inadequate cement job,

(A) the operator shall notify the commission before drilling ahead; and

(B) the commission will, in its discretion, require

(i) a cement quality log or other approved method to evaluate the adequacy of the cement to contain potential wellbore pressures and fluids; and

(ii) remedial action before drilling ahead;

(5) intermediate and production casing must be cemented with sufficient cement to fill the annular space from the casing shoe to a minimum of 500 feet above all significant hydrocarbon zones and abnormally geo-pressured strata or, where zonal coverage is not required, from the casing shoe to a minimum of 500 feet above the casing shoe; if there are indications of improper cementing, such as lost returns, cement channeling, or mechanical failure of equipment, or if the formation integrity test shows an inadequate cement job, remedial action must be taken;

(6) in cases where the intermediate or production string is a liner, a minimum of 100 feet overlap between the outer and inner strings is required; the interval of overlap must be made pressure competent and must be pressure-tested in accordance with (e) of this section;

(7) for intermediate or production casing in a service well used for injection, a cement quality log or other evaluation log approved by the commission must be run to demonstrate isolation of the injected fluids to the approved interval.

(e) A casing pressure test must be performed if blowout prevention equipment will be installed on a casing. The casing must be tested to hold a surface pressure equal to or greater than 50 percent of the required working pressure of the blowout prevention equipment as specified in the Permit to Drill (Form 10-401). The results of this test and any subsequent tests of the casing must be recorded as required by 20 AAC 25.070(1).

(f) Except for through-tubing drilling, a formation integrity test must be performed if blowout prevention equipment is installed on a casing. The test must be performed to a predetermined equivalent mud weight, leak-off, or a fracture pressure as specified in the well plan. The test must be conducted after drilling out of the casing shoe into at least 20 feet but not more than 50 feet of new formation. The test results must demonstrate that the integrity of the casing shoe is sufficient to contain anticipated wellbore pressures identified in the well plan. The test procedure followed and the data from the test and any subsequent tests of the formation must be recorded as required by 20 AAC 25.070(1).

(g) Upon request of the operator, the commission will, in its discretion, approve variances from the requirements of (b) - (f) of this section to allow for special or unusual conditions as long as the design requirements of (a) of this section are not diminished. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.033 is repealed and readopted to read:

20 AAC 25.033. PRIMARY WELL CONTROL FOR DRILLING: DRILLING FLUID PROGRAM AND DRILLING FLUID SYSTEM. (a) A drilling operation must be equipped with a drilling fluid system meeting the requirements of this section, unless the commission determines, in its

discretion, that a drilling fluid system is not necessary for primary well control. The operator shall submit with an application for a Permit to Drill (Form 10-401) a proposed drilling fluid program and a diagram with a list of equipment for a drilling fluid system designed to prevent the loss of primary well control. The drilling fluid system must be designed to maintain the wellbore in overbalanced condition except as otherwise provided under (i) of this section. A drilling operation is also subject to the requirements of 20 AAC 25.527.

(b) A drilling fluid program and drilling fluid system intended to maintain the wellbore in overbalanced condition must be designed to provide and maintain

(1) a drilling fluid

(A) of sufficient density to overbalance the pressure of uncased formations penetrated; and

(B) with rheological properties designed to

(i) minimize the potential of a hydrostatic pressure surge or swab when the drilling assembly is run into or pulled out of the wellbore; and

(ii) enhance the drop-out of solids and the escape of any entrained gas; and

(2) a volumetric capacity for drilling fluid reserves adequate for the volume of the wellbore, based on known or anticipated drilling conditions to be encountered, rig storage capacity, weather conditions, and estimated time for delivery.

(c) A drilling fluid system intended to maintain the wellbore in overbalanced condition must include

audible ?

(1) a recording drilling fluid pit level indicator with both visual ~~and~~ audio warning devices located in the immediate area of the driller's console;

(2) a drilling fluid measuring system or trip tank for accurately determining drilling fluid volumes required to fill the wellbore on trips;

(3) a drilling fluid flow sensor with a readout convenient to the driller's console to enable the operator to determine whether drilling fluid returns equal drilling fluid pump discharge rates;

(4) equipment to keep the drilling mud conditioned as appropriate for the drilling operation being conducted; and

(5) methane and hydrogen sulfide detection equipment as required by 20 AAC 25.066.

(d) For rotary drilling rig operations, drilling fluid testing equipment must be on the drill site at all times. Tests to determine drilling fluid density and viscosity must be performed once each tour, or more frequently when conditions warrant.

(e) To ensure that primary well control is effectively maintained, the following practices must be employed in rotary drilling rig operations when tripping the drilling assembly out of the wellbore:

(1) the drilling fluid within the wellbore must be in balance and conditioned to maintain drilling fluid properties within close tolerance to the properties necessary for well control;

(2) the flow nipple or trip tank must be visually observed to ensure that there is no indication of formation fluid influx;

(3) the wellbore must be kept full of drilling fluid at all times;

(4) the annulus must be filled with fluid

(A) each time that five stands of drill pipe have been removed from the wellbore; and

(B) more frequently if necessary to prevent the hydrostatic pressure from dropping by 75 psi or more;

(5) the volume of drilling fluid required to keep the wellbore full while tripping the drilling assembly out of the wellbore must be measured and recorded on the daily drilling report or trip sheet.

(f) Additional requirements that apply to exploratory and stratigraphic test wells drilled by a rotary drilling rig are as follows:

(1) the operator shall include with an application for a Permit to Drill a tabulation that sets out the depths of predicted abnormally geo-pressured strata;

(2) if the operator has geophysical data from the area, a seismic velocity analysis constrained by germane well control data must be performed to predict the potential of encountering abnormally geo-pressured strata, with the analysis displayed by plotting interval transit time versus depth; the commission will, in its discretion, require a confidential review of the velocity analysis and the plot of interval transit time versus depth;

(3) if the operator does not have geophysical data from the area, an analysis of germane well control data must be performed to predict the potential of encountering abnormally geo-pressured strata;

(4) a drilling fluid monitoring unit must be used and continuously observed during rotary drilling rig operations, including tripping, to monitor and record

(A) gas entrained in the drilling fluid;

(B) drilling fluid density;

(C) drilling fluid salinity;

(D) the rate of penetration; and

(E) hydrogen sulfide, as required by 20 AAC 25.065;

(5) means for communication between the drilling fluid monitoring unit and the rotary drill rig floor must be installed and maintained in working condition while open hole operations are taking place, and drill rig floor personnel must be notified immediately when excursions from normal trends occur for any of the parameters set out in (4) of this subsection.

(g) When drilling an exploratory or stratigraphic test well or when drilling a development or service well while known hydrocarbon-bearing strata are exposed to open hole, the operator shall take a drilling fluid return sample and test the sample to determine density just before tripping the drill pipe. Density test results must be recorded as required by 20 AAC 25.070(1). If the density is less than that of

the drilling fluid being pumped down the drilling assembly, the drilling fluid must be circulated and conditioned until a close tolerance of the properties of the return drilling fluid with the input drilling fluid is achieved.

(h) If formation competence at the structural casing setting depth is not adequate to permit circulation of drilling fluids while drilling the conductor hole, a program that provides for safety in that drilling operation must be described and submitted to the commission for approval. This program must be supported by pertinent information including seismic and geologic data, water depth, drilling fluid hydrostatic pressure, and a contingency plan for moving off location.

(i) The commission will, in its discretion, approve underbalanced drilling operations and associated equipment changes. A request for underbalanced drilling must include a description of all equipment and procedures to ensure proper containment of formation and return fluids.

(j) Upon request by the operator, the commission will, in its discretion, approve a waiver of the requirements of (c) - (g) of this section if the alternative drilling fluid program and drilling fluid system meet the design criteria of (b) of this section and the corresponding equipment and procedures are at least equally effective in preventing the loss of primary well control. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.035 is repealed and readopted to read:

20 AAC 25.035. SECONDARY WELL CONTROL FOR PRIMARY DRILLING AND COMPLETION: BLOWOUT PREVENTION EQUIPMENT AND DIVERTER REQUIREMENTS. (a) This section applies to drilling and completion operations other than those covered by 20 AAC 25.036 or 20 AAC 25.037. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall submit the following information with the application for a Permit to Drill (Form 10-401) or refer in the application to that information if on file with the commission:

(1) a diagram of the blowout preventer (BOP) stack or diverter and related equipment for each proposed casing installation; and

(2) a list of the blowout prevention equipment (BOPE) and if applicable, diverter equipment with specifications.

(c) Except as provided in (d) of this section, a high capacity flow diverter system must be installed to provide safety for personnel and equipment before rotary rig drilling is performed below a well's structural or conductor casing, unless the casing is equipped with BOPE conforming with (e) of this section. The following provisions apply to a diverter system:

(1) the diverter system must consist of a remotely operated annular pack-off device, a full-opening vent line valve, and a diverter vent line whose diameter is

(A) at least 16 inches, unless a smaller diameter is approved by the commission to account for smaller hole size, geological conditions, rig layout, or surface facility constraints; and

(B) at least as large as the diameter of the hole to be drilled, unless a pilot hole with a diameter no larger than that of the vent line is drilled first; the commission will, in its discretion, waive the requirement of this paragraph if the operator demonstrates, based on drilling experience in the near vicinity, that drilling a pilot hole would not be necessary for safety;

(2) the diverter system must be assembled as follows:

(A) the diverter vent line outlet must be located below the annular pack-off, either as an integral part of the annular pack-off device or as a vent-line outlet spool immediately below it;

(B) the actuating mechanism for the vent line valve must be integrated with the actuating mechanism for the annular pack-off device in a fail-safe manner so that the vent line valve will automatically open prior to full closure of the annular pack-off;

(C) the vent line must extend to a point at least 75 feet removed from a potential source of ignition and at least 75 feet beyond the drill rig substructure or to the reserve pit, but in no case fewer than 50 feet from the drill rig substructure;

(D) the vent line must be as straight as possible, secured to prevent movement, and designed to avoid freeze-up;

(E) the vent line may be secured to the rig and with portable cradle supports, but may not be attached to flowlines, cable trays, or other processing equipment;

(F) all turns with a bend radius less than 20 times the inside diameter of the vent line must be targeted;

(G) all valves must be full-opening;

(3) a clearly marked "warning zone" must be established on each side and ahead of the vent line tip, and the following restrictions must be in effect within the warning zone, beginning with the function test of the diverter system immediately before drilling operations begin and ending with diverter system rig-down:

(A) no vehicle parking;

(B) no ignition sources or running equipment;

(C) no staged equipment or materials;

(D) essential foot or vehicle traffic only;

(4) the diverter system will, in the commission's discretion, be inspected by the commission for compliance with the requirements of this subsection and tested to ensure proper operation.

(d) If the formation competence at the structural casing setting depth is not adequate to permit use of a diverter system while drilling the conductor hole, a program that provides for safety in that drilling operation must be described and submitted to the commission for approval. This program must be supported by pertinent information including seismic and geologic data, water depth, drilling fluid hydrostatic pressure, and a contingency plan for moving off location.

(e) A well must be equipped with BOPE meeting the requirements of this subsection from the time that open hole drilling operations begin below the surface casing until the drilled portion has been plugged or the well is completed, except when hydraulic communication to the open hole section is isolated. The following provisions apply to BOPE and other well control equipment:

(1) in rotary drilling rig operations,

(A) for operations requiring less than API 5M BOP stacks, BOPE must have at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except for bottom-hole assemblies and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(B) for operations requiring API 5M or greater BOP stacks; BOPE must have at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except for bottom-hole assemblies and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(2) in coiled tubing unit operations, the well control equipment must include

(A) for operations requiring API 5M BOP stacks or less,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer; and

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer, and at least one preventer equipped with pipe rams that fit the size of tubing, liner, or casing being used, except for bottom-hole assemblies and drill collars;

(B) for operations requiring greater than API 5M BOP stacks,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers; and

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer, and at least two preventers equipped with pipe rams that fit the size of tubing, liner, or casing being used, except for bottom-hole assemblies and drill collars;

(3) the rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected and will be specified in the approved Permit to Drill, except that the rated working pressure of the annular type preventer need not exceed 5,000 psi unless a higher working pressure is required by the commission; if the maximum potential surface pressure exceeds the rated working pressure of the annular type preventer, the operator shall submit with the application for a Permit to Drill a well-control procedure that indicates how the annular type preventer will be used and what pressure limitations will be applied during each mode of pressure control;

(4) a BOPE assembly must include

(A) a hydraulic actuating system with

(i) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled hydraulic valve while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off; and

(ii) an accumulator pump system consisting of two or more pumps with independent power sources (primary and secondary) and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(B) locking devices on the ram-type preventers;

(C) a fire wall to shield accumulators and primary controls;

(D) one complete set of operable remote BOPE controls on or near the driller's or operator's console, in addition to controls on the accumulator system;

(E) in coiled tubing operations, a second annular type preventer closing control located on the drilling platform floor, if the controls required under (D) of this paragraph are not in close proximity to the drilling platform floor;

(F) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool or on the BOP body with two full-opening valves on each outlet, conforming to the following specifications:

(i) the outlets must be at least two inches in nominal diameter, except that for rotary drilling rig operations, if the required BOP is rated greater than API 2M, the nominal diameter of the choke outlets must be at least three inches;

(ii) each valve must be sized at least equal to the required size of the outlet to which it is attached;

(iii) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(iv) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid;

(G) a fill-up line above the uppermost BOP; and

(H) a choke manifold equipped with

(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's console if the required BOPE stack is 5,000 psig or greater;

(ii) a line at least two inches in nominal diameter downstream of each choke;

(iii) immediately upstream of each choke, at least one full-opening valve for an operation requiring a BOP stack less than API 5M, or at least two full-opening valves for an operation requiring a BOP stack API 5M or greater; and

(iv) a bypass line, at least the diameter of the choke line, with at least one full-opening valve for an operation requiring a BOP stack less than API 5M, or at least two full-opening valves for an operation requiring a BOP stack API 5M or greater;

(5) the rated working pressure of the wellhead assembly and of all valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must equal or exceed the required working pressure of the BOPE specified in the approved Permit to Drill, except that lines downstream of the choke may be rated to 50 percent of the required working pressure of the BOPE;

(6) kill and choke lines must

(A) be constructed of rigid pipe, fire-resistant rotary hose, or other suitable conduit that has been approved by the commission;

(B) be as straight as practical;

(C) if constructed of rigid pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(D) be secured to prevent excessive whip or vibration;

(E) be sized to prevent excessive erosion or fluid friction;

(F) be assembled without hammer unions or internally clamped swivel joints, unless such joints are specifically approved by the commission;

(7) for lubricated drilling operations or operations below a normally closed annular type preventer, the choke line may be used for drilling returns;

(8) connections attached directly to the wellhead, tree, or BOPE must be flanged or hubbed;

(9) for rotary drilling rig operations, auxiliary well control equipment must include

(A) a kelly cock valve installed below the swivel and, at the bottom of the kelly, a full-opening lower kelly valve of a design that allows it to be run through the BOP stack, with a properly sized wrench for each valve stored in a conspicuous location readily accessible to the drilling crew; and

(B) an inside BOP and a full-opening drilling assembly safety valve in the open position on the drill rig floor to fit all connections that are in the drilling assembly;

(10) the BOPE must be tested as follows:

(A) when installed , repaired, or changed, and at least once a week thereafter, BOPE, including kelly valves, emergency valves, and choke manifolds, must be function pressure-tested to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50% of its rated working pressure;

(B) when BOP sealing ram type equipment has been used, it must be function pressure-tested, before the next wellbore entry, to the required working pressure specified in the

approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50 percent of its rated working pressure;

(C) non-sealing equipment must be function-tested weekly and after repair, change, or any action that disconnects the hydraulic system lines from the BOPE, except that when the workstring is continuously in the well or the BHA does not clear the BOP, function-testing must be performed as soon as possible thereafter;

(D) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(E) a minimum of 24 hours notice of each function pressure test must be provided so that a representative of the commission can witness the test.

(f) In consultation with the drilling foreman, the commission will, in its discretion, require drills simulating well control problems. Drills will, in the commission's discretion, include any combination of raising or lowering the pit level indicator, advancing or retarding the flow rate indicator, or actuating the gas detectors.

(g) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Permit to Drill and shall post on the drilling rig floor the drilling hazard information required by 20 AAC 25.005(c)(4) and a copy of the standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Permit to Drill, the drilling hazard information required by 20 AAC 25.005(c)(4), and a copy of the standing orders specifying well control procedures. When an additional or separate sub-structure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(h) Upon request of the operator, the commission will, in its discretion, approve a variance

(1) from the BOPE requirements of this section if the variance provides at least an equally effective means of well control; and

(2) from the diverter system requirements of this section if the variance provides at least equally effective means of diverting flow away from the drill rig or if drilling experience in the near vicinity indicates that a diverter system is not necessary. (Eff. 4/13/80, Register 74; am 2/22/81, Register 77; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.036. SECONDARY WELL CONTROL FOR THROUGH-TUBING DRILLING AND COMPLETION: BLOWOUT PREVENTION EQUIPMENT REQUIREMENTS. (a) This section applies to drilling and completion operations performed through existing production tubing. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall submit the following information with the application for a Permit to Drill (Form 10-401) or refer in the application to that information if on file with the commission:

(1) a diagram of each blowout preventer (BOP) stack and related well control equipment to be used; and

(2) a list of the blowout prevention equipment (BOPE) with specifications.

(c) A well must be equipped with BOPE meeting the requirements of this subsection from the time that drilling penetrates beyond casing or liner until the drilled portion has been plugged or the well is completed, except when hydraulic communication to the open hole section has been isolated. The following provisions apply to BOPE and other well control equipment:

(1) in rotary drilling rig operations,

(A) for operations requiring API 5M BOP stacks or less, BOPE must have at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except for bottom-hole assemblies and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(B) for operations requiring greater than API 5M BOP stacks; BOPE must have at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except for bottom-hole assemblies and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(2) in coiled tubing unit operations, the well control equipment must include

(A) for operations requiring API 5M BOP stacks or less,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer; and

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer, and at least one preventer equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except for bottom-hole assemblies and drill collars;

(B) for operations requiring greater than API 5M BOP stacks,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers; and

(iii) if pressure deployment of tools, tubing, liner, or casing is planned, a riser or lubricator sized to the BHA providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer, and at least two preventers equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except for bottom-hole assemblies and drill collars;

(3) the rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected and will be specified in the approved Permit to Drill, except that the rated working pressure of an annular type preventer need not exceed 5,000 psi unless a higher working pressure is required by the commission; if the maximum potential surface pressure exceeds the rated working pressure of the annular type preventer, the operator shall submit with the application for a Permit to Drill a well control procedure that indicates how the annular type preventer will be used and the pressure limitation that will be applied during each mode of pressure control;

(4) a BOPE assembly must include

(A) a hydraulic actuating system with

(i) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled hydraulic valve while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off; and

(ii) an accumulator pump system consisting of one or more pumps with independent power sources (primary and secondary), and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(B) locking devices on the ram-type preventers;

(C) a fire wall to shield accumulators and primary controls; new ?

(D) one complete set of operable remote BOPE controls on or near the driller's or operator's console, in addition to controls on the accumulator system;

(E) in coiled tubing operations, a second annular type preventer closing control located on the drilling platform floor, if the controls required under (D) of this paragraph are not in close proximity to the drilling platform floor;

(F) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool, the BOP body, or the tree, with two full-opening valves on each outlet, conforming to the following specifications:

(i) the outlets and valves must be at least two inches in nominal diameter;

(ii) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(iii) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid;

(G) for open hole deployment, an annular type preventer, unless a lubricator of sufficient length to enclose the entire bottom hole assembly (BHA) below a high pressure sealing element is used; and

(H) for conventional open loop fluid process drilling operations, a choke manifold equipped with

(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's or operator's console if the required BOPE stack is 5,000 psig or greater;

(ii) a line at least two inches in nominal diameter downstream of each choke;

(iii) immediately upstream of each choke, at least one full-opening valve for an operation requiring a BOP stack of up to and including API 5M or at least two full-opening valves for an operation requiring a BOP stack greater than API 5M; and

(iv) a bypass line at least two inches in nominal diameter with at least one full-opening valve immediately upstream of each choke for an operation requiring a BOP stack of up to and including API 5M or with at least two full-opening valves immediately upstream of each choke for an operation requiring a BOP stack greater than API 5M;

(5) in an underbalanced drilling operation, well control equipment must have bi-directional slip capabilities;

(6) the rated working pressure of the wellhead assembly and of all valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must equal or exceed the required working pressure of the BOPE specified in the approved Permit to Drill, except that lines downstream of the choke may be rated to 50 percent of the required working pressure of the BOPE;

(7) for lubricated drilling operations or operations below a normally closed annular type preventer, the choke line may be used for drilling returns;

(8) at least one positive seal manual or hydraulic valve or BOPE blind ram, one set of BOPE pipe rams, and, if used, the drilling spool must be flanged to the wellhead or tree;

(9) connections directly to the BOPE, other than connections described in (8) of this subsection, must be flanged or hubbed, except that suitably pressure-rated quick connects may be used if a positive seal manual valve, hydraulic valve, or BOPE blind ram and an annular type preventer or sealing ram are flanged to the wellhead or tree below the quick connection;

(10) kill and choke lines must

(A) be constructed of rigid pipe, fire-resistant rotary hose, or other suitable conduit that has been approved by the commission;

(B) be as straight as practical;

(C) if constructed of rigid pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(D) be secured to prevent excessive whip or vibration;

(E) be sized to prevent excessive erosion or fluid friction;

(F) be assembled without hammer unions or internally clamped swivel joints, except that hammer unions and internally clamped joints may be used on the kill line upstream of the valves that are flanged to the wellhead or tree.

(d) A BOPE assembly must be tested as follows:

(1) when installed, repaired, or changed, and at least once a week thereafter, BOPE, including emergency valves and choke manifolds, must be function pressure-tested to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50% of its rated working pressure;

(2) other well control equipment must be pressure-tested to the required working pressure specified in the approved Permit to Drill after each installation of the well control equipment and before wellbore entry, except that when testing against the annular type preventer, pressure testing need not exceed 50 percent of the rated working pressure of the annular type preventer;

(3) when BOP sealing ram type equipment has been used, it must be function pressure-tested, before the next wellbore entry, to the required working pressure specified in the approved Permit to Drill, using a non-compressible fluid, except that an annular type preventer need not be tested to more than 50% of its rated working pressure;

(4) non-sealing equipment must be function-tested weekly and after repair, change, or any action that disconnects the hydraulic system lines from the BOPE, except that when the workstring is continuously in the well or the BHA does not clear the BOP, function-testing must be performed as soon as possible thereafter;

(5) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(6) a minimum of 24 hours notice of each function pressure test must be provided so that a representative of the commission can witness the test.

(e) In a rotary drilling rig operation, the operator shall have on location a copy of the approved Permit to Drill and shall post on the drilling rig floor the drilling hazard information required by 20 AAC 25.005(c)(4) and a copy of the standing orders specifying well control procedures. In a coiled tubing operation, the operator shall post in the operator's cab a copy of the approved Permit to Drill, the drilling hazard information required by 20 AAC 25.005(c)(4), and a copy of the standing order specifying well control procedures. When an additional or separate sub-structure is used in a coiled tubing operation, the operator shall post a second set of standing orders on the drilling platform floor.

(f) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.037. WELL CONTROL REQUIREMENTS FOR OTHER DRILLING AND COMPLETION OPERATIONS. For unconventional drilling and completion operations for which the provisions of 20 AAC 25.033, 20 AAC 25.035, or 20 AAC 25.036 would not be practical or appropriate, the commission will, in its discretion, approve alternate well control procedures and equipment. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.040 (a) and (b) are amended to read:

20 AAC 25.040. WELL IDENTIFICATION. (a) Every well must be identified by a sign posted in a conspicuous place. During the period of time from commencement of drilling operations [SPUD] to well completion, suspension, or abandonment, the sign must be on or near the drill rig [DERRICK], but not more than 100 feet from the well. After well completion or suspension [FOR SUSPENDED OR PRODUCIBLE WELLS], the well sign must be at the wellhead or on the wellhead building. The sign must be of durable construction, large enough to be legible under normal conditions at a distance of 50 feet, and maintained in legible condition. Each sign must show the

(1) name designated by the operator under 20 AAC 25.005(f) for [OF] the well drilled from the surface location;

(2) name of the owner;

(3) name of the operator if different from the owner;

(4) API [WELL] number;

(5) well surface location by quarter section, section, township and range; and

(6) Permit to Drill [DRILLING PERMIT] number or numbers during the period of time from commencement of drilling operations [SPUD] to well completion, suspension, or abandonment.

(b) The commission will assign a Permit to Drill number and an API number [EACH WELL WILL BE ASSIGNED AN API WELL NUMBER BY THE COMMISSION] when a Permit to Drill (Form 10-401) [THE DRILLING PERMIT] is approved.

. . .

Note to publisher: subsection (c) is unchanged.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.047 is amended to read:

20 AAC 25.047. RESERVE PITS AND TANKAGE. (a) Before a person commences drilling [SPUDDING] a well [PERMITTED UNDER 20 AAC 25.005], a [PROPER AND APPROPRIATE] reserve pit must be constructed[,] or [APPROPRIATE] tankage installed for the reception and confinement of drilling fluids and cuttings, to facilitate the safety of the drilling operation, and to prevent contamination of freshwater [GROUND WATER] and damage to the surface environment. The confining surfaces of the reserve pit must be impervious. [SPECIAL PRECAUTIONS MUST BE TAKEN TO RENDER IMPERVIOUS THE CONFINING SURFACE OF A RESERVE PIT.] If practical, confinement diking in construction of a reserve pit must be avoided. If confinement dikes are necessary, they must be kept to a minimum. Dikes must be constructed and maintained to ensure [INSURE] their confinement integrity.

(b) Upon [TERMINATION OF] completion, suspension, or abandonment of the well [OPERATIONS], the operator shall proceed with diligence to [DISPOSE OF OR SOLIDIFY IN PLACE ALL PUMPABLE FLUIDS, AND SHALL] leave the reserve pit in a condition that does not constitute a hazard to freshwater [GROUND WATER]. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.050 is repealed and readopted to read:

20 AAC 25.050. WELLBORE DIRECTIONAL SURVEYS. (a) A well that is not intentionally deviated must be

(1) drilled as close to vertical as is possible using conventional drilling techniques, except that deviation is permitted for short intervals to straighten the hole, sidetrack junk, or correct mechanical difficulties;

(2) surveyed to determine the inclination from vertical with surveys starting at 500 feet and no more than 500 feet apart to total depth; and

(3) surveyed by a complete continuous directional survey if any portion of the well path is less than 500 feet from a property line where the ownership by owner or landowner is not identical on both sides of the line, or if any portion of the well path is less than 200 feet from any other vertical or deviated

well; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface.

(b) If a well is to be intentionally deviated, the application for a Permit to Drill (Form 10-401) must

(1) include a plat, drawn to a suitable scale, showing the path of the proposed wellbore, including all adjacent wellbores within 200 feet of any portion of the proposed well; and

(2) list the names of all operators of wells within 200 feet of the proposed wellbore to the extent known or discoverable in public records, and show that each has been furnished a copy of the application by certified mail, or state that the applicant is the only affected owner.

(c) A well that is intentionally deviated must be

(1) directionally surveyed at intervals not more than 500 feet apart on straight or tangent sections of the well during the normal course of drilling, and at intervals not exceeding 100 feet in all portions of the hole where intentional angle changes are performed;

(2) surveyed by a continuous directional survey if any portion of the well path is less than 500 feet from a property line where the ownership by owner or landowner is not identical on both sides of the line; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface; and

(3) surveyed by a continuous directional survey if any deviated portion of the wellbore is less than 200 feet from any other vertical or deviated well; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface.

(d) Within 30 days after the completion, abandonment, or suspension of a well, and within 30 days after completion or plugging of a well branch, a complete copy of each inclination and directional survey not previously filed must be filed with the commission. A composite survey may also be filed if the operator believes this would better represent the well course. If a composite survey is filed, the operator shall specify the portion of each survey used in the composite.

(e) If the final location of the producing interval of a well is not in compliance with 20 AAC 25.055 or other rules of the commission applicable to the reservoir, the operator shall apply for an exception. The application will be handled in accordance with 20 AAC 25.540. The well may not be produced until the exception is granted.

(f) A wellbore survey report required by (a) or (c) of this section must contain

(1) the name of the surveying company;

(2) the name, title, and signature of the person who actually performed the survey;

(3) the date on which the survey was performed;

(4) the type of survey conducted;

(5) the method used in calculating the survey;

(6) a complete identification of the well showing the name of the well designated by the operator under 20 AAC 25.005(f), the name of the operator, the property name or lease number, the Permit to Drill number, the API number, and the field name;

(7) the depth interval over which the survey was conducted; and

(8) a plat showing the coordinates, referenced to governmental section lines, of the surface location, the plotted well course, and any well(s) within 500 feet of any portion of the wellbore.

(g) The commission will, in its discretion, require submittal of the original film, time sheets, charts, graphs, discs, and other data used to compile the survey required by (a) or (c) of this section.

(h) Upon application, the commission will, in its discretion, waive all or part of the directional survey requirements of this section or approve alternate means for determining the location of a wellbore if the variance at least equally ensures accurate surveying of the wellbore to prevent well intersection, to comply with spacing requirements, and to ensure protection of correlative rights. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.055 is repealed and readopted to read:

20 AAC 25.055. DRILLING UNITS AND WELL SPACING. (a) The commission will, in its discretion, establish drilling units to govern well spacing and prescribe a spacing pattern by special pool rules adopted in accordance with 20 AAC 25.520. In the absence of an order by the commission establishing drilling units or prescribing a spacing pattern for a pool, the following statewide spacing requirements apply:

(1) for a well drilling for oil, a wellbore may be open to test or regular production within 500 feet of a property line only where the owner is the same and the landowner is the same on both sides of the line;

(2) for a well drilling for gas, a wellbore may be open to test or regular production within 1500 feet of a property line only where the owner is the same and the landowner is the same on both sides of the line;

(3) where oil has been discovered, the drilling unit for the pool is a governmental quarter section; not more than one well may be drilled to and completed in that pool on any governmental quarter section, nor may a well be drilled or completed closer than 1,000 feet to any well drilling to or capable of producing from the same pool;

(4) where gas has been discovered, the drilling unit for the pool is a governmental section; not more than one well may be drilled to and completed in that pool on any governmental section, nor may a well be drilled or completed closer than 3,000 feet to any well drilling to or capable of producing from the same pool.

(b) A well may not begin regular production of oil from a property that is smaller than the governmental quarter section upon which the well is located or begin regular production of gas from a property that is smaller than the governmental section upon which the well is located, unless the interests of the persons owning the drilling rights in and the right to share in the production from the quarter section or section, respectively, have been pooled under AS 31.05.100.

(c) A pooling agreement under AS 31.05.100 must be filed with the commission before regular production from the affected property begins.

(d) An application for an exception to the provisions of this section will be handled in accordance with 20 AAC 25.540. The applicant for an exception shall send notice of the application by certified mail to the owners and operators described below and shall furnish the commission with a copy of the notice, date of mailing, and the addresses to which the notice was sent. The application must include

(1) the names of all owners and operators of all properties within 1000 feet of a well drilling for oil or within 3000 feet of a well drilling for gas for which an exception is required;

(2) a plat drawn to a scale of one inch equaling 2,640 feet or larger, showing the location of the well for which the exception is sought, all other completed and drilling wells on the property, and all adjoining properties and wells; and

(3) a statement by a person acquainted with the facts, verifying that all facts are true and that the plat correctly portrays pertinent and required data.

(e) Upon application by the operator, the commission will, in its discretion, establish notice requirements different from those of (d) of this section if, because of the complexity of ownership within the notice area, a more effective means of providing notice is available. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.100

20 AAC 25.061 is amended to read:

AAC 25.061. WELL SITE SURVEYS. (a) For an exploratory or stratigraphic test well, near [NEAR] surface strata to a depth of 2000 feet in the vicinity of the well [SITE AREA FOR ALL EXPLORATORY AND STRATIGRAPHIC TEST WELLS] must be evaluated seismically by common depth point refraction or reflection profile analysis, or by another method approved by the commission, to

identify anomalous velocity variations indicative of potential shallow gas sources. Analysis results must be included with the application for the Permit to Drill (Form 10-401).

(b) For a well drilled offshore from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel, the [THE] vicinity of the well [SITE AREA] must be evaluated by sidescan sonar and other pertinent surveys to determine whether potential seabed hazards to drilling operations are present [FOR EACH TYPE OF WELL LISTED IN 20 AAC 25.005 TO BE DRILLED OFFSHORE FROM A MOBILE BOTTOM-FOUNDED, JACK-UP OR FLOATING UNIT]. Survey results must be included with the application for Permit to Drill (Form 10-401).

(c) Upon request by the operator, the commission will, in its discretion, [WILL] waive the requirements of this section if the operator can identify, by other equally effective means, the likelihood of encountering potential shallow gas or seabed hazards or if the commission already has information that substantiates the presence or absence of shallow gas or seabed hazards. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.065(a) and (b) are amended, (c) is repealed and readopted, and (d) is repealed, to read:

20 AAC 25.065. HYDROGEN SULFIDE. (a) When hydrogen sulfide gas is encountered in excess of 20 ppm, the operator shall notify the commission within 24 hours.

(b) If a well is to be drilled in an area where a formation to be penetrated is known to contain hydrogen sulfide gas, or if hydrogen sulfide gas is encountered while drilling, the [EACH] operator shall conform with [MEET THE REQUIREMENTS OF] API RP 49, *Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide* (April 1987), which is adopted by reference.

(c) If there is an insufficient history of drilling in an area to know whether hydrogen sulfide gas exists, the commission will specify on the Permit to Drill (Form 10-401) that the operator shall comply with minimum requirements for detection monitoring, contingency and control, and training, as follows:

(1) in addition to the automatic hydrogen sulfide detection system required in 20 AAC 25.066, at least three manual detectors with an adequate supply of extra detector tubes must be available on the location;

(2) hydrogen sulfide treating material for the drilling mud must be available on or near the location, in good condition and in sufficient quantity to adequately treat the mud system should hydrogen sulfide be encountered;

(3) detailed emergency operating procedures must be defined and posted to ensure the safety of all personnel should hydrogen sulfide be encountered;

(4) detailed step-by-step remedial procedures must be developed and posted to cover emergencies while drilling or tripping;

(5) personnel protective equipment must be available on the location;

(6) all persons engaged in drilling operations must be trained for emergency procedures in the presence of hydrogen sulfide gas and in the use of personal protective equipment, alarm systems, and emergency exit procedures.

(d) Repealed ___/___/___. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in this section may be reviewed during business hours at the commission's office and may be obtained from Global Engineering Documents, 15 Inverness Way East, Englewood, CO 80150.

Note to publisher: italics should be added to title of publication cited in subsection (b).

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.066. GAS DETECTION. (a) All drilling and workover rigs must meet the following minimum requirements for methane and hydrogen sulfide gas detection:

(1) the methane detection system must have a minimum of three sensing points: one under the substructure near the cellar, one above the drill rig floor near the driller's console, and one over the shale shaker; if the mud pits are remote from the shale shaker and enclosed, a fourth sensor must be located over the mud pits;

(2) methane sensors must be placed to detect a "lighter-than-air" gas;

(3) the hydrogen sulfide detection system must have a minimum of three sensing points: one under the substructure near the cellar, one above the drill rig floor near the driller's console, and one near the shale shaker; the commission will, in its discretion, require additional sensors, such as at the entrance to living quarters if they are adjacent to the drill rig, or over the mud pits if they are remote from the shaker and enclosed;

(4) hydrogen sulfide sensors must be placed to detect a "heavier-than-air" gas;

(5) sensors must be automatic, acting independently (i.e., in parallel), and with one-minute minimum sampling intervals;

(6) each detection system must include separate and distinct visual and audible alarms; the visual alarm must signal the low level gas alarm and the audible alarm the high level gas alarm; an audible alarm may have an "acknowledge" button;

(7) the methane low level gas alarm must be set at not over 20% LEL (lower explosive limit); the high level alarm must be set at not over 40% LEL;

(8) the hydrogen sulfide low level gas alarm must be set at 10 ppm (parts per million); the high level alarm must be set at not over 20 ppm;

(9) each alarm must be automatic and must be visible and audible from the driller's console; the hydrogen sulfide alarm must be audible throughout the drilling location, including the camp buildings.

(b) A gas detection system that continuously performs self-checking or diagnostics must be function-tested when a BOP stack is initially installed after a drill rig is set up, when a commission-

witnessed BOP test occurs, and no less frequently than once every six months. Other gas detection systems must be calibrated and tested when a BOP stack is initially installed after a drill rig is set up, when a commission-witnessed BOP test occurs, and no less frequently than once every 30 days. The operator shall maintain at the drill rig an accessible record of gas detection system tests and calibrations.

(c) A failure in a gas detection system must be reported to the commission within 24 hours. The commission will, in its discretion, require well operations to be discontinued if a gas detection system fails.

(Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.070 is repealed and readopted to read:

20 AAC 25.070. RECORDS AND REPORTS. The operator of a well shall

(1) keep a detailed accurate daily record of the actual drilling, completion, workover, repair, and plugging operations, and the tests required by this chapter, which must be available for inspection at reasonable times by the commission

(A) at the well; and

(B) in the state for five years after the date of well abandonment;

(2) file with the commission before well completion or, if the well is not completed, before well abandonment a survey plat certified by a registered land surveyor showing the precise surface location of the well; however, only the first well drilled from a fixed platform or a multiple-well location must have a certified survey;

(3) file with the commission, within 30 days after completion, abandonment, or suspension of the well and within 30 days after completion or plugging of a well branch, if occurring at a different time, a complete well record on the Well Completion or Recompletion Report and Log (Form 10-407), including the tests required by this chapter and a summary of daily well operations reporting drilling depths, zones of abnormal pressure, lost circulation and other hole difficulties encountered, simulated kick

drills, mud weight, and a brief description of principal items of work done, such as running and cementing casing, drill stem tests, BOP tests, coring, sidewall sampling, and logging; in the case of a well with multiple well branches, information pertaining to and filed under this paragraph with respect to a portion of a well need not be re-filed unless changed; and

(4) upon request of the commission after completion, abandonment, or suspension of the well or completion or plugging of a well branch, file with the commission a copy of the daily record required by (1) of this section. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.071(b) is repealed and readopted, and (c) and (d) are amended, to read:

20 AAC 25.071. GEOLOGIC DATA AND LOGS.

. . .

Note to publisher: subsection (a) is unchanged.

(b) Within 30 days after completion, suspension, or abandonment of a well, whichever occurs first, and within 30 days after completion or plugging of a well branch, if occurring at a different time, the operator shall file with the commission, unless previously filed,

(1) a sepia and a reproduced copy of a complete mud log or a lithology log consisting of a detailed record and description of the sequence of strata encountered, including kind and character of the rock and all shows of hydrocarbons; an electronic image file in a format acceptable to the commission may be substituted for the sepia;

(2) a complete set of washed and dried, legibly identified samples of all drill cuttings, as caught by the operator in accordance with good geological practices, consisting of a minimum of one-quarter cup in volume or three ounces in weight of cuttings for each sample interval;

(3) a lithologic description and, if available, photographs of all conventional and sidewall cores; conventional core descriptions must include all apparent textural, fluid, and lithologic variations, including rock type, porosity, fractures, bedding plane attitudes, sedimentary structure, grain size, and presence of hydrocarbons;

(4) a chip or chips from each foot of recovered conventional core, except that chips need not be submitted until 30 days after the conventional core is analyzed; the chips must be representative of the one-foot interval, and must be approximately either one cubic inch in volume, or two ounces in weight;

(5) a list of the geologic markers encountered and the measured and true vertical depths of each marker;

(6) a sepia and a reproduced copy of all logs run (including common derivative formats such as tadpole plots of dipmeter data and borehole images produced from sonic or resistivity data, and composite log formats), except velocity surveys and experimental logs; an electronic image file in a format acceptable to the commission may be substituted for the sepia;

(7) a tape, diskette, or other electronic media acceptable to the commission and a verification listing of the digital data for all logs run, except velocity surveys and experimental logs, and a written description of the logical and physical format of the digital data; and

(8) a copy of all drill stem test and production test data and charts; a brief summary of production tests, drill stem tests, wireline formation tests, and other formation tests performed, including test date, time depth, duration, method of operation, recovered fluid type(s), fluid amount(s), gas-oil ratio, oil gravity, pressure, and choke size; any conventional and sidewall core analysis determinations of porosity, permeability, and fluid saturation; and any geochemical and formation fluid analyses obtained; the data described in this paragraph must be filed as soon as available if the 30-day filing period cannot be met.

(c) The commission will, in its discretion, waive or modify the requirements of [(a), (b)(1), AND (b)(2) OF] this section for a well if they would not significantly add to the geologic knowledge of the area in light of the information that is available from other wells in the area [FOR DEVELOPMENT WELLS].

(d) In this section

(1) "experimental logs" means logs that are not commercially available from a logging contractor [SO NEWLY DEVELOPED OR SO LIMITED OR SPECIALIZED IN APPLICATION THAT THEY ARE NOT COMMONLY RUN ON PETROLEUM EXPLORATION OR DEVELOPMENT WELLS]; and

(2) "velocity survey" means a survey, the primary purpose of which is to determine velocity of seismic waves through formations penetrated by a well by measuring travel times of seismic pulses from or near the surface to geophones placed at [A SEISMOMETER LOWERED TO] various depths in the well. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.035

20 AAC 25.072(a), (b), and (d) are amended to read:

20 AAC 25.072. SHUTDOWN OF DRILLING OR COMPLETION [WELL] OPERATIONS. (a) If [CLIMATE, OPERATIONAL OR ENVIRONMENTAL CONCERNS, PRUDENCY, OR OTHER] circumstances prevent the continuation of the program approved on a Permit to Drill (Form 10-401) [THE DRILLING PERMIT], or if an operator wishes to change drill rigs [FOR RIG SUBSTITUTION], the operator shall apply to the commission for approval to shut down drilling or completion [WELL] operations. The commission will, in its discretion, approve the shutdown of drilling or completion operations. [WELL OPERATIONS. THE LETTER OF APPLICATION MUST SET OUT A FULL JUSTIFICATION FOR THE SHUT DOWN AND BE ACCOMPANIED BY] The request for operation shutdown must be submitted on an Application for Sundry Approvals (Form 10-403), providing a full justification for the shutdown, a description of [WHICH SETS OUT] the proposed condition of the

wellbore [WELL BORE] upon shutdown of drilling or completion [WELL] operations, the approximate date when drilling or completion [WELL] operations will resume, and a proposed program for securing the well during the period of shutdown. An Application for Sundry Approvals is not required for planned shutdowns of well operations that are stated in the approved Permit to Drill.

(b) The operator shall file with the commission, within 30 days after well shutdown, a complete well record on a Report of Sundry Well Operations (Form 10-404), including a summary [COPY] of [THE] daily [REPORTS OF] well operations as described in [REQUIRED BY] 20 AAC 25.070(3) [20 AAC 25.070(a)(1)] and a copy of all logs run in the well as required by 20 AAC 25.071(b)(6) [20 AAC 25.071(b)(5)]. The commission will, in its discretion, waive the requirements of this subsection if drilling or completion [WELL] operations are to be resumed within 60 days.

. . .

Note to publisher: subsection (c) is unchanged.

(d) If well operations are not resumed within 12 months, unless the commission grants an extension upon application of the operator, the operator shall immediately proceed to abandon or suspend the well. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.075 is amended to read:

20 AAC 25.075. OTHER WELLS IN DESIGNATED AREAS. There are areas in the state where drilling [OPERATIONS] could unexpectedly encounter oil, gas, or hazardous substances at shallow depths. When the commission obtains sufficient evidence to define a specific area and the approximate depth range of the substances, it will issue an order that defines the area and stipulates [WILL PRESENT THE EVIDENCE, DEFINE THE AREA, AND STIPULATE] a drilling depth. After the issuance of such an order, any drilling [WELL DRILLED] in the defined area, for any purpose, that exceeds the stipulated

depth will require a Permit to Drill (Form 10-401) [DRILLING PERMIT] and may be subject to the other requirements of this chapter. (Eff. 4/13/80, Register 74; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.080(a) - (e) and (h)(1) are amended, and (f) is repealed and readopted, to read:

20 AAC 25.080. ANNULAR DISPOSAL OF DRILLING WASTE. (a) A person may not dispose of drilling waste through the annular space of a well unless authorized by the commission under this section. The [AN] operator of a well permitted under AS 31.05.090 may request authorization for [SUCH A] disposal of drilling waste through the well's annular space by filing with the commission [IN AN APPLICATION FOR A PERMIT TO DRILL (FORM 10-401) OR] an Application for Sundry Approvals (Form 10-403) supplemented with any additional information required under this section.

(b) A request for authorization under this section must include the following information or refer to that information if on file with the commission:

(1) [A DESIGNATION OF THE WELL THAT WILL RECEIVE DRILLING WASTE] the annulus to be used for disposal;

. . .

(3) a stratigraphic description of the interval exposed to the open annulus and other information sufficient to support a commission finding that the waste will be confined and will not come to the surface or, except to the extent allowed under (e)(1) of this section, contaminate freshwater [THE DEPTH AND THICKNESS OF THE RECEIVING ZONE AND THE CONFINING ZONE, AND SUFFICIENT INFORMATION TO DEMONSTRATE CONFINEMENT];

. . .

(5) the type(s) and [AN ESTIMATE OF THE] maximum volume of waste to be disposed of and the estimated density of the waste slurry [TO BE DISPOSED];

. . .

(8) details that show that the shoe of the outer casing is set below the base of permafrost, if present, and below any freshwater aquifer, other than freshwater excepted under (e)(1) of this section, [AND PERMAFROST, IF PRESENT,] and is adequately cemented [WITH SUFFICIENT CEMENT] to provide zone isolation; the information relied upon and submitted must include (A) cementing records and (B) a cement quality log or formation integrity test records;

(9) details that show that the inner and outer casing strings have sufficient strength in collapse and burst to withstand the anticipated pressure of disposal operations; [AND]

(10) the downhole pressure obtained during a formation integrity test conducted below the outer casing shoe;

(11) identification of any hydrocarbon zones above the depth to which the inner casing is cemented;

(12) the duration of the disposal operation, not to exceed 90 days;

(13) whether any drilling waste has previously been disposed of in the annular space of the well and, if so, a summary of the date(s) of the disposal operation(s); the volume(s) of waste disposed of; and the well(s) where the drilling waste was generated;

(14) the well where the drilling waste to be disposed of was or will be generated;

(15) if the operator proposes not to comply with a limitation established in (d) of this section, an explanation of why compliance would be imprudent; and

(16) any additional data required by the commission to confirm containment of drilling waste.

(c) The commission will, in its discretion, authorize an annular disposal operation [OF DRILLING WASTE THROUGH THE ANNULAR SPACE OF A WELL PERMITTED UNDER AS 31.05.090] described in the Application for Sundry Approvals (as supplemented under this section), subject to any modifications prescribed by the commission, if it determines that the

(1) waste will be adequately confined [CONTAINED IN A SUITABLE RECEIVING ZONE];

(2) disposal will not

(A) contaminate freshwater, except to the extent allowed under (e)(1) of this section;

. . .

(C) impair the mechanical integrity of any well [THE WELL USED FOR DISPOSAL]; or

. . .

(d) Unless the operator demonstrates[, BY WRITTEN APPLICATION,] that it is imprudent to comply with a limitation established in (1) - (4) of this subsection, the commission will not authorize disposal of drilling waste

. . .

(3) into a hydrocarbon-bearing stratum; or

. . .

(e) In addition to any other conditions that the commission in its discretion imposes on a case-by-case basis, an authorization to dispose of drilling waste under this section is subject to the following conditions:

(1) drilling waste may not be disposed of into freshwater, except freshwater identified in the request for authorization that the commission finds has a total dissolved solids content of more than 3,000 mg/l and is not reasonably expected to supply a public water system; the commission will, in its discretion, provide 15 days notice and the opportunity for a public hearing in accordance with 20 AAC 25.540 before making that finding;

(2) the downhole disposal pressure may not exceed the downhole pressure obtained during the formation integrity test conducted below the outer casing shoe, or a higher pressure specified in the

authorization upon the commission's finding that the higher pressure will not cause drilling waste to migrate above the confining zone;

(3) if drilling waste appears above the confining zone, the operator shall immediately cease disposal, notify the commission, and take appropriate remedial action; and

(4[2]) if the commission notifies the operator that disposal operations pose a threat to well integrity, safety, oil or gas recovery, or freshwater, except to the extent allowed under (1) of this subsection, the operator shall immediately cease disposal and take appropriate remedial action as approved or required by the commission.

(f) For each annular disposal operation authorized under this section, the operator shall report the following information to the commission on a Report of Annular Disposal (Form 10-423) not later than 30 days after the end of the period authorized for the disposal operation:

(1) the dates when disposal began and ended; and

(2) the volume of drilling waste disposed of in each of the following categories:

(A) the aggregate of drilling wastes described in (h)(1) of this section;

(B) the aggregate of drilling wastes described in (h)(2) of this section; and

(C) each substance determined to be a drilling waste under (h)(3) of this section.

. . .

Note to publisher: subsection (g) is unchanged.

(h) In this section, "drilling waste" means the following substances, unless identified as a hazardous waste in 40 C.F.R. Part 261:

(1) drilling mud, drilling cuttings, reserve pit fluids, cement-contaminated drilling mud, completion fluids, [AND] formation fluids associated with the act of drilling a well permitted under 20 AAC 25.005, and any added water needed to facilitate pumping of drilling muds or drilling cuttings;

. . .

Note to publisher: subsection (i) is unchanged.

(Eff. 9/22/96, Register 139; am ___/___/___, Register ___)

Authority: AS 31.05.030

ARTICLE 2.
ABANDONMENT AND PLUGGING.

Section
105. [PLUGGING, SUSPENSION, AND] Abandonment of wells
107. Plugging well branches
110. Suspended wells
112. Well plugging requirements
115. Shut-in wells
120. Well abandonment marker
140. Water wells
170. Onshore location clearance
172. Offshore location clearance

20 AAC 25.105 is repealed and readopted to read:

20 AAC 25.105. ABANDONMENT OF WELLS. (a) All wells that have been permitted on a property under 20 AAC 25.005 must be abandoned before expiration of the owner's rights in that property or if, after notice and hearing, the commission orders abandonment for safety reasons or because the operator has effectively abandoned operations prior to the expiration of the lease. If the owner is the landowner, all wells that have been permitted on a property by 20 AAC 25.005 must be abandoned within one year following permanent cessation of the operator's oil and gas activity within the field where the wells are located or according to an abandonment schedule approved by the commission, unless the wells are earlier abandoned for safety reasons.

(b) A well drilled onshore or from a fixed offshore platform must be abandoned before removal of the drill rig from location unless completed as an oil, gas, or service well or suspended, or unless well operations are shut down in accordance with 20 AAC 25.072. All wells drilled from a fixed offshore platform must be abandoned before the platform is removed or dismantled.

(c) A well drilled offshore from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel must be abandoned before removal of the drill rig from location unless

(1) the well is completed as an oil, gas, or service well; or

(2) subsea equipment for well re-entry is installed in a manner approved by the commission and either the well is suspended or well operations are shut down in accordance with 20 AAC 25.072.

(d) A well drilled from a beach, artificial island, or shifting natural island must be abandoned before removal of the drill rig from location unless completed as an oil, gas, or service well or suspended, or unless well operations are shut down in accordance with 20 AAC 25.072 and plans for maintaining the integrity of the location are approved by the commission.

(e) An Application for Sundry Approvals (Form 10-403) must be filed with and approved by the commission before work is begun to abandon a well, except that oral approval may be obtained from the commission if it is followed within 10 days by the filing of an Application for Sundry Approvals. Approval will be conditioned as necessary to protect freshwater and hydrocarbon resources. An Application for Sundry Approvals must include

(1) the reason for abandoning the well; and

(2) a statement of proposed work, including

(A) information on abnormally geo-pressured strata;

(B) the manner of placement, kind, size, and location, by measured depth, of existing and proposed plugs;

(C) plans for cementing, shooting, testing, and removing casing;

(D) if the Application for Sundry Approvals is filed after beginning work, the name of the representative of the commission who provided oral approval, and the date of the approval; and

(E) all other pertinent information. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.107. PLUGGING WELL BRANCHES. (a) An operator may plug a well branch before abandoning or suspending the well. If a well branch has not been completed, the operator shall plug the well branch before removal of the drill rig from location, unless well operations are shut down in accordance with 20 AAC 25.072.

(b) An Application for Sundry Approvals (Form 10-403) must be filed with and approved by the commission before work is begun to plug a well branch. The provisions of 20 AAC 25.105(e) apply to the application, except that instead of including the reason for abandoning the well, the application must include the reason for plugging the well branch and the reason for not immediately abandoning or suspending the well.

(c) The provisions of 20 AAC 25.112(a) - (c) and (e) - (i) apply to plugging a well branch.

(d) This section does not apply to temporary plugging of a well branch for production control purposes. (Eff. __/__/__, Register ____)

Authority: AS 31.05.030

20 AAC 25.110 is repealed and readopted to read:

20 AAC 25.110. SUSPENDED WELLS. (a) Where allowed under 20 AAC 25.105, the commission will, in its discretion, upon application by the operator under (b) of this section, approve the suspension of a well that has not been completed if

(1) the well

(A) encounters hydrocarbons of sufficient quality and quantity to indicate that the well is capable of producing in paying quantities, as reasonably demonstrated by well tests or interpretive formation evaluation data;

(B) is a candidate for redrilling;

(C) has potential value as a service well; or

(D) is located on a pad or platform with active producing or service wells; and

(2) the operator justifies to the commission's satisfaction why the well should not be completed or abandoned; sufficient reasons include

(A) unavailability of surface production or transportation facilities;

(B) imprudency of security maintenance of a completed well in a shut-in status;

(C) need for pool delineation and evaluation to determine prudency of pool development.

(b) An Application for Sundry Approvals (Form 10-403) must be filed with and approved by the commission before plugging operations are begun in a well for which suspension is proposed, except that oral approval may be obtained from the commission if it is followed within 10 days by the filing of an Application for Sundry Approvals. Approval will be conditioned as necessary to protect freshwater and hydrocarbon resources. An Application for Sundry Approvals must include

(1) the reason for suspending the well and information showing that the applicable criteria for suspension under (a) of this section have been met; and

(2) a statement of proposed work, including

(A) information on abnormally geo-pressured strata;

(B) the manner of placement, kind, size, and location, by measured depth, of existing and proposed plugs;

(C) plans for cementing, shooting, testing, and removing casing;

(D) if the Application for Sundry Approvals is filed after beginning work, the name of the representative of the commission who provided oral approval, and the date of the approval; and

(E) all other pertinent information.

(c) Information voluntarily submitted to show that the applicable criteria for well suspension under (a) of this section have been met will be kept confidential in accordance with 20 AAC 25.537.

(d) A well approved for suspension must be plugged in accordance with the requirements of 20 AAC 25.112, except that the requirements of 20 AAC 25.112(d) do not apply if

(1) a wellhead is installed or the well is capped with a mechanical device to seal the opening; and

(2) a bridge plug capped with 50 feet of cement or a continuous cement plug extending 200 feet within the interior casing string is placed at or above 300 feet below the surface; the commission will, in its discretion, waive the requirement of this paragraph for a development well drilled from a pad or platform.

(e) Until a suspended well has been abandoned or re-entered, the operator shall maintain the integrity of the location, provide the commission with a well status report every five years, and clear the location in a manner approved by the commission. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.112. WELL PLUGGING REQUIREMENTS. (a) Plugging of the uncased portion of a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface. The minimum requirements for plugging the uncased portion of a wellbore are as follows:

(1) by the displacement method, a cement plug must be placed

(A) from 100 feet below the base to 100 feet above the top of all hydrocarbon-bearing strata;

(B) from the well's total depth to 100 feet above the top of all hydrocarbon-bearing strata;

(C) from the well's plugged back total depth to 100 feet above the top of all hydrocarbon-bearing strata, if all hydrocarbon-bearing, abnormally geo-pressured, and freshwater strata below are isolated; except that the commission will, in its discretion, approve plugging from the top of fill or the top of junk instead of from the plugged back total depth; or

(D) from 100 feet below the base to 50 feet above the base of each significant hydrocarbon-bearing stratum and from 50 feet below the top to 100 feet above the top of each significant hydrocarbon-bearing stratum;

(2) by the displacement method, a cement plug must be placed from 100 feet below the base to 50 feet above the base of abnormally geo-pressured strata and from 50 feet below the top to 100 feet above the top of the abnormally geo-pressured strata; and

(3) by the displacement method, a cement plug must be placed from 150 feet below the base to 50 feet above the base of the deepest freshwater stratum.

(b) Plugging of a well must include effectively segregating uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. The minimum requirement for plugging to segregate uncased and cased portions of a wellbore is as follows:

(1) by the displacement method, a continuous cement plug must be placed from 100 feet below to 100 feet above the casing shoe;

(2) by the downsqueeze method using a retainer set no less than 50 feet but no more than 100 feet above the casing shoe, a volume of cement sufficient to fill the wellbore from the retainer to 100 feet below the casing shoe must be pumped through the retainer, and cement must be pumped above the retainer to cap it with a 50 foot cement plug; or

(3) by the downsqueeze method using a production packer set no less than 50 feet but no more than 500 feet above the casing shoe, a volume of cement sufficient to fill the wellbore from 100 feet below the casing shoe to the packer must be pumped through the packer, and cement must be pumped above the packer to cap it with a 50 foot cement plug.

(c) Plugging of cased portions of a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface. The minimum requirements for plugging cased portions of a wellbore are as follows:

(1) perforated intervals must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the base to 50 feet above the base of the perforated interval and from 50 feet below the top to 100 feet above the top of the perforated interval;

(B) by the displacement method, a cement plug placed from the well's total depth to 100 feet above the top of the perforated interval;

(C) by the displacement method, a cement plug placed from the well's plugged-back total depth to 100 feet above the top of the perforated interval, if all hydrocarbon-bearing, abnormally geo-pressured, and freshwater strata below are isolated; except that the commission will, in its discretion, approve plugging from the top of fill or the top of junk instead of from the plugged-back total depth;

(D) by the downsqueeze method using a cement retainer or production packer set no less than 50 feet but no more than 500 feet above the perforated interval, a volume of cement pumped through the retainer or packer sufficient to fill the wellbore from 100 feet below the base of the perforated interval to the retainer or packer; or

(E) if the perforations are isolated from open hole below, a mechanical bridge plug set no more than 50 feet above the top of the perforated interval, and either a minimum of 75 feet of cement placed on top of the plug by the displacement method or a minimum of 25 feet of cement placed on top of the plug with a dump bailer;

(2) casing stubs within outer casing must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the stub to 100 feet above the stub;

(B) by the downsqueeze method using a retainer set 50 feet above the stub, a volume of cement pumped below the retainer sufficient to fill the casing stub with 150 feet of cement, and cement pumped above the retainer to cap it with a 50 foot cement plug; or

(C) if the casing stub annulus is cemented, a mechanical bridge plug set no more than 25 feet above the casing stub, and either a minimum of 75 feet of cement placed on top of the plug by the displacement method or a minimum of 25 feet of cement placed on top of the plug with a dump bailer;

(3) where freshwater is present, the smallest diameter casing string extending to the surface must be plugged by one of the following methods:

(A) by the displacement method, a cement plug placed from 100 feet below the depth of the surface casing shoe to 100 feet above the depth of the shoe; or

(B) a mechanical bridge plug set 100 feet below the depth of the surface casing shoe and at least 200 feet of cement placed on top of the plug.

(d) Plugging of the surface of a well must meet the following requirements:

(1) by the displacement method, a cement plug at least 150 feet in length, with the top of the cement no more than 5 feet below original ground level onshore, or between 10 and 30 feet below the mudline datum offshore, must be placed within the smallest diameter casing string; and either

(2) all annular space open at the surface onshore, or in communication with open hole and extending to the mudline datum offshore, must be plugged with cement to seal the annular space in a manner satisfactory to the commission; or

(3) all casing interior to the surface casing must be recovered to a depth of 100 feet or more below the original ground level onshore or the mudline datum offshore and the casing stubs plugged with cement as provided in (c)(2)(A) of this section; if the cement plug is extended to within the distance

from the surface specified in (1) of this subsection, the requirement of (1) of this subsection will be deemed met.

(e) Cement used for plugging within zones of permafrost must be designed to set before freezing and have a low heat of hydration.

(f) Each of the respective intervals of a wellbore between the various plugs must be filled with fluid of sufficient density to exert a hydrostatic pressure exceeding the greatest formation pressure of permeable formations in the intervals between the plugs at the time of abandonment.

(g) Except for surface plugs, the operator shall record the actual location and integrity of cement plugs, cement retainers, or bridge plugs required by this section by

(1) placing sufficient weight on the plug to confirm its location and to confirm that the cement or mechanical plug has set and a competent plug is in place, in which event testing of the cement placed above the bridge plug or retainer is not required; or

(2) testing the plug to hold a surface pressure of 1,500 psig or 0.25 psi/ft multiplied by the true vertical depth of the casing shoe, whichever is greater, and tagging the plug to confirm location; however, surface pressure must not subject the casing to a hoop stress that will exceed 70 percent of the minimum yield strength of the casing.

(h) A minimum of 24 hours notice of plugging operations must be given to the commission so that a representative of the commission can witness the operations.

(i) The commission will, in its discretion, approve a variance from the requirements of this section if the variance provides for at least equally effective plugging of the well and prevention of fluid movement into sources of hydrocarbons or freshwater. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.115. SHUT-IN WELLS. (a) No later than March 31 of each year, an operator shall file with the commission a report on all completed development or service wells that have been shut in for 365 days or longer as of January 1 of that year. The report must provide

(1) the current known mechanical condition of the well, including the condition of all installed tubing and casing strings;

(2) the date the well was shut in and the circumstances surrounding the decision to shut in the well; and

(3) an analysis of the future utility of the well.

(b) The commission will, in its discretion, require an operator of a shut-in well to file additional information to ensure that freshwater and hydrocarbon sources are protected. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.120 is repealed and readopted to read:

20 AAC 25.120. WELL ABANDONMENT MARKER. (a) The exact surface location of an abandoned well must be shown by a steel well abandonment marker. The marker must be a marker plate meeting the requirements of (b) of this section, except that if a marker post is requested by the surface owner and approved by the commission, the marker must be a marker post meeting the requirements of (c) of this section.

(b) A marker plate must be

(1) at least 1/4 inch thick;

(2) at least eighteen inches square or in diameter; and

(3) welded to and covering the outermost casing string.

(c) A marker post must

(1) be at least four inches in diameter and at least 10 feet long;

(2) be set in cement inside well casing or firmly welded with supporting fillets to the top of a steel plate secured to the casinghead or casing stub;

(3) extend from four to six feet above final ground level; and

(4) be closed at the top with a screw cap, welded plate, or cement plug.

(d) The name of the operator, Permit to Drill number(s), and API number(s) must be bead-welded directly to the marker.

(e) The commission will, in its discretion, inspect the marker to verify proper installation and well information at the time of the location clearance required under 20 AAC 25.170.

(f) This section does not apply to abandoned wells drilled offshore. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.140 is amended to read:

20 AAC 25.140. WATER WELLS. If a well drilled for oil or gas is to be plugged and abandoned, but may safely be used as a freshwater well, and such a use is desired by a person, written authority for this action must be obtained from the landowner and owner of the surface rights. The authorization must provide for the authorized person's assumption of full responsibility for the final plugging of the water well. This authorization must be filed with, and approved by, the commission. Following the commission's approval of the plugging of the well to protect the freshwater bearing strata <u>to a depth approved by the commission for conversion to a water well</u> and the location clearance, the operator is relieved of further obligation under the operator's bond. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.170 is repealed and readopted to read:

20 AAC 25.170. ONSHORE LOCATION CLEARANCE. (a) After a well drilled onshore has been abandoned and before the earlier of one year after well abandonment or the expiration of the owner's rights in the property,

(1) the operator shall remove the wellhead equipment and casing to a depth at least three feet below original ground level and install a well abandonment marker in accordance with 20 AAC 25.120; and

(2) except to the extent that the operator demonstrates to the commission that a different disposition has been approved by another government agency having jurisdiction or authorized by the surface owner to facilitate a genuine beneficial use, the operator shall

(A) remove all materials, supplies, structures, and installations from the location;

(B) remove all loose debris from the location;

(C) fill and grade all pits or close them in another manner approved by the commission; and

(D) leave the location in a clean and graded condition.

(b) The commission will, in its discretion, grant an extension of time beyond one year after well abandonment

(1) if a longer period is approved by the Department of Natural Resources, as to a state lease, or by the United States Department of the Interior, as to a federal lease; or

(2) upon receipt of an Application for Sundry Approvals (Form 10-403) stating

(A) a request for a specific extension not to exceed one year;

(B) the reason an extension is necessary;

(C) a description of location clearance progress; and

(D) the expiration date of the owner's rights to enter the location.

(c) After the work required under (a) of this section has been completed at a location, the commission will, in its discretion, conduct an on-site inspection to verify the location condition at the time

of inspection, including the presence of a proper well marker if above ground, as required under 20 AAC 25.120, and will provide the operator a report of the inspection. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.172 is repealed and readopted to read:

20 AAC 25.172. OFFSHORE LOCATION CLEARANCE. (a) After all wells drilled from a fixed offshore platform have been abandoned and when the platform is removed or dismantled, the operator shall remove all well casing to a depth at least ~~one~~ foot below the mudline. The operator shall provide the commission with verification, using appropriate means approved by the commission, that the casing has been removed as required. If another government agency having jurisdiction approves leaving the platform in place after well abandonment, the requirements of this subsection will be waived. transferred on post period.

(b) When a well has been abandoned from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel, the operator shall remove the wellhead equipment, casing, piling, and other obstructions to a depth at least five feet below the mudline before removing the drill rig from location, unless otherwise approved by the commission. The operator shall provide the commission with verification, using appropriate means approved by the commission, that the requirements of this subsection have been met.

(c) After a well drilled from a beach, artificial island, or shifting natural island location has been abandoned and before the earliest of one year after well abandonment, the time that the operator stops activities necessary to ensure the integrity of the location, or the expiration of the owner's rights in the property,

(1) the operator shall remove the wellhead equipment and casing to a depth at least five feet below the mudline datum; and

(2) except to the extent that the operator demonstrates to the commission that a different disposition has been approved by another government agency having jurisdiction or authorized by the surface owner to facilitate a genuine beneficial use, the operator shall

(A) remove all materials, supplies, structures, and installations from the location;

(B) remove all loose debris from the location;

(C) fill and grade all pits or close them in another manner approved by the commission; and

(D) leave the location in a clean and graded condition.

(d) The commission will, in its discretion, grant an extension of time beyond one year after well abandonment to comply with (c) of this section if a longer period is approved by the Department of Natural Resources, as to a state lease, or by the United States Department of the Interior, as to a federal lease.

(e) After the work required under (c) of this section has been completed at a location, the commission will, in its discretion, conduct an on-site inspection to verify the location condition at the time of inspection and will provide the operator a report of the inspection. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

ARTICLE 3.
PRODUCTION PRACTICES.

Section
200. Production equipment
205. Notification of uncontrolled release [ACCIDENTAL LOSS] of oil or gas
210. Multiple completions [COMPLETION] of wells
215. Commingling of production
225. Potential of gas wells
228. Production measurement equipment for custody transfer
230. Measurement, allocation, and reporting of well production [PRODUCTION MEASUREMENT]
235. Gas disposition
240. Gas-oil ratio [RATIOS] limitations
245. Common production facilities
250. (Repealed)
252. Underground disposal of [WATER AND OTHER] oil field wastes [WASTE FLUIDS] and underground storage of [LIQUID] hydrocarbons
255. (Repealed)
260. Illegal production
265. Automatic shut-in equipment
270. Initial reservoir properties [PRESSURE]
275. (Repealed) [RESERVOIR FLUID PROPERTIES]
280. Workover operations
285. Secondary well control for tubing workover operations: blowout [BLOWOUT] prevention equipment requirements [FOR WORKOVER OPERATIONS]
286. Well control requirements for workstring service operations
287. Well control requirements for wireline operations
288. Well control requirements for other service operations
290. Operations producing hydrogen sulfide

20 AAC 25.200 (a) and (d) are amended to read:

20 AAC 25.200. PRODUCTION EQUIPMENT. (a) Surface production equipment must be installed to control, separate, clean, [AND] gather, and carry to the point of custody transfer or other disposition in a safe manner all produced oil, gas, and water. All equipment must be installed, operated and maintained in accordance with good oil field engineering practices. [ESTABLISHED INDUSTRY PRACTICE.]

. . .

Note to publisher: subsections (b) and (c) are unchanged.

(d) All producing wells capable of unassisted flow must be completed with downhole production equipment consisting of suitable tubing and a packer which effectively isolates the tubing-casing annulus from fluids being produced, unless otherwise specifically approved by the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.205 is amended to read:

20 AAC 25.205. NOTIFICATION OF UNCONTROLLED RELEASE [ACCIDENTAL LOSS] OF OIL OR GAS. (a) The commission must be immediately notified by the operator of any uncontrolled release exceeding 10 barrels of oil or 1000 mscf of [ACCIDENTAL LOSS OF CRUDE OIL OR NATURAL] gas, or both, from a well or production handling operation or any uncontrolled release that results in a shut-down of operations at a production facility.

(b) Within five days after the release [ACCIDENTAL LOSS], the operator shall submit a preliminary written report to the commission, followed by a final written report within 30 days, detailing the following facts:

(1) time of incident;

(2) location where incident took place;

(3) volumes of oil and gas released and recovered [CRUDE OIL AND OF NATURAL GAS LOST];

(4) cause of the release; [LOSS;]

(5) responsive actions taken to prevent further release [ACTIONS TAKEN AND PLANNED TO PREVENT FURTHER LOSS]; and

(6) any plans, actions, equipment, or procedural changes to prevent or minimize the risk of future releases [EQUIPMENT OR PROCEDURAL CHANGES, IF APPLICABLE, TO PREVENT

THE LOSS FROM RECURRING]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.210 is amended to read:

20 AAC 25.210. MULTIPLE COMPLETIONS [COMPLETION] OF WELLS. A well may not be completed in more than one pool without approval of the commission. The commission will, in its discretion, require evidence of complete separation of flowstreams from separate pools, as ascertained by a pressure test or other acceptable test [TESTS] conducted at the time the packers are set. Subsequently, if packer leakage is suspected, the commission will, in its discretion, request the operator to provide proof of complete separation of the pools involved in the completions or make a packer leakage test. A minimum of 24 hours notice [NOTIFICATION] must be given so that the packer leakage test may be witnessed by a representative of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.215 is amended to read:

20 AAC 25.215. COMMINGLING OF PRODUCTION. (a) On the surface, the production from one pool may not be commingled with that from another pool except when the quantities from each pool are determined by [AT LEAST] monthly well tests or by another method of determining pool [AN ACCEPTABLE] production [ALLOCATION METHODOLOGY] approved by the commission.

(b) Commingling of production within the same wellbore [WELL BORE] from two or more pools is not permitted unless after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission finds that waste will not occur, production from separate pools can be properly allocated, and the commission issues an order providing for commingling for [ALL] wells

completed from these pools within the field. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.225 is amended to read:

20 AAC 25.225. POTENTIAL OF GAS WELLS. All gas wells must be tested by the multi-point back-pressure method before regular [SIGNIFICANT] production. The commission will, in its discretion, approve alternative test methods. The test results and calculations must be reported to the commission on the [FORM ENTITLED] Gas Well Open Flow Potential Test Report (Form 10-421) within 30 days after the test. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.228 is repealed and readopted to read:

20 AAC 25.228. PRODUCTION MEASUREMENT EQUIPMENT FOR CUSTODY TRANSFER. (a) All hydrocarbon production must be measured in accordance with this section before severance from the property or unit where produced. Crude oil sample collection, handling, and analysis in connection with production measurement must be performed in conformance with the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998, which is adopted by reference.

(b) Hydrocarbon measurement equipment and gas meter runs must be fabricated, installed, and maintained in conformance with the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998, which is adopted by reference.

(c) If a totalizer system is microprocessor-based, it must be equipped with

(1) a back-up battery or uninterruptible power supply that provides for operation during times of system power failures; or

(2) a backup pulse accumulator or other approved equivalent that counts and preserves meter pulses in the event of power or computer failure.

(d) If a microprocessor totalizing system is used, the reports of net measured volumes for the custody transfer intervals must, at a minimum, show the raw or factored pulses, average temperature, pressure, relative density or gravity, meter factors, correction factors, and the gross standard volumes.

(e) Fluid samplers must be either a probe or a slipstream type. The sampler location must be located in conformance with chapter eight of the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998, which is adopted by reference.

(f) Functional bypasses may not be connected around custody transfer or sales measurement equipment such as tanks, meters, gauges, sample containers, or gas meter runs.

(g) Oil meters must be periodically proved and gas meters must be periodically calibrated in conformance with the API *Manual of Petroleum Measurement* Standards, as revised as of November 30, 1998, which is adopted by reference, and on a schedule approved by the commission. In metering operations, the actual throughput or gross standard volume must be determined by multiplying the indicated volume, corrected for temperature and pressure, by the meter factor obtained during proving. If a meter factor differs by more than 0.0025 from the previously obtained meter factor, from the applicable value on the meter curve, or from a baseline factor in the absence of a meter curve, the meter must be taken out of service or corrective action performed to bring the meter factor within the required tolerance.

(h) Provers used for certification of custody transfer meters must be calibrated by the waterdraw method, master meter method, or other commission-approved equivalent, in conformance with the API *Manual of Petroleum Measurement Standards*, as revised as of November 30, 1998, which is adopted by reference.

(i) The commission will, in its discretion, require a minimum of 24 hours notice before the following operations so that a representative of the commission can witness the operation:

(1) calibration of provers used for certification of custody transfer meters;

(2) crude oil sample collection, handling, and analysis in connection with production measurement;

(3) oil meter proving and volume calculations;

(4) gas meter calibration and volume calculations.

(j) Upon request, the commission will, in its discretion, approve a variance from the requirements of this section if the variance will result in equal or improved accuracy in measuring hydrocarbons severed from the property or unit. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the API *Manual of Petroleum Measurement Standards* may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

20 AAC 25.230 is repealed and readopted to read:

20 AAC 25.230. MEASUREMENT, ALLOCATION, AND REPORTING OF WELL PRODUCTION. (a) Production from each well must be measured or allocated to determine the quantities of oil, gas, and water, using equipment and techniques acceptable to the commission. Production from a group of wells, property, or unit may be measured as a whole, if individual well test facilities and allocation methods acceptable to the commission are employed to test and allocate production to each well at least monthly.

(b) The volumes of produced gas, oil, and water must be reported monthly for each well on the Monthly Production Report (Form 10-405) or by an alternate format, including electronic means, acceptable to the commission. A well must be identified by its API number and the name designated by the operator under 20 AAC 25.005(f). Production from a well with multiple well branches must be aggregated and reported under the API number and well name of the primary wellbore. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.235 (a) is amended to read:

20 AAC 25.235. GAS DISPOSITION. (a) For each production facility the operator shall compile and report monthly gas disposition and acquisition on the Facility Report of Produced Gas Disposition (Form 10-422). The operator shall report gas acquisition or disposition as (1) sold; (2) reinjected; (3) flared or vented; (4) used for lease operations other than flared or vented; [OR] (5) natural gas liquids (NGLs) produced; (6) gas purchased; (7) gas transferred; or (8) other. If a facility's production comes from multiple pools, the operator shall allocate production between each producing pool as a percentage of the total volume of gas that the facility handled for the month.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 1/1/95, Register 132; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095
AS 31.05.170

20 AAC 25.240 is repealed and readopted to read:

20 AAC 25.240. GAS-OIL RATIO LIMITATIONS. (a) An oil well may not be produced if the gas-oil ratio of the well exceeds the original solution gas-oil ratio of the crude within the producing pool by more than 100 percent.

(b) Upon written application by an operator, the commission will, in its discretion, waive the limitation in (a) of this section if

(1) an enhanced recovery project is operating in the pool from which the well is producing;

(2) produced gas is being returned to the same pool; or

(3) acquisition of pool performance data is necessary to determine an optimum reservoir management program.

(c) Exceptions for conditions other than those specified in (b) of this section will, in the commission's discretion, be granted only after application, notice, and an opportunity for public hearing.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.245 is amended to read:

20 AAC 25.245. COMMON PRODUCTION FACILITIES. Common facilities may be used to receive the production from any number of wells or pools if appropriate tankage or other measuring equipment is installed so that production from each well can be [ACCURATELY] determined by means approved by the commission in accordance with 20 AAC 25.228 [AT LEAST ONCE EACH MONTH].

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.252 (a) - (c), (e), (f), and (h) are amended, (d) is repealed and readopted, and a new (k) is added, to read:

20 AAC 25.252. UNDERGROUND DISPOSAL OF [WATER AND OTHER] OIL FIELD WASTES [WASTE FLUIDS] AND UNDERGROUND STORAGE OF [LIQUID] HYDROCARBONS.

(a) Unless authorized by the United States Environmental Protection Agency under federal law, the [THE] underground disposal of [FRESHWATER OR SALT WATER, BRACKISH WATER, OR OTHER] oil field wastes [WASTE FLUIDS] and the underground storage of [LIQUID] hydrocarbons are prohibited except as ordered by the commission under this section. In [IN] response to a letter of application for injection filed by an operator, [FOR UNDERGROUND DISPOSAL OR STORAGE] the commission will, in its discretion, authorize the underground disposal of oil field wastes consisting of fluids described in 40

C.F.R. 144.6(b)(1) as revised as of July 1, 1998, or the underground storage of hydrocarbons. An order authorizing disposal or [OF] storage wells remains valid unless revoked by the commission.

(b) The operator has the burden of demonstrating that the proposed disposal or storage operation will not allow the movement of oil field wastes or hydrocarbons [FLUID] into sources of freshwater. Disposal or storage wells must be cased and the casing cemented in a manner that will isolate the disposal or storage zone and protect oil, gas, and freshwater sources.

(c) An application for underground disposal or storage [INJECTION] must include

(1) a plat showing the location of all proposed disposal and storage wells, [INCLUDING] abandoned or other unused wells, production wells, dry holes, and any other wells that penetrate the disposal or storage [INJECTION] zone within one-quarter mile of each proposed disposal or storage well;

. . .

Note to publisher: paragraphs (2) and (3) are unchanged.

(4) the name, description, depth, and thickness of the formation into which fluids are to be disposed or stored [INJECTED] and appropriate geological data on the disposal or storage [INJECTION] zone and confining zone(s) [ZONES], including lithologic description and geologic name;

. . .

Note to publisher: paragraph (5) is unchanged.

(6) a description of the casing of the disposal or storage wells, or the proposed casing program and the proposed method for demonstrating mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that no fluids will move behind casing beyond the approved [TESTING CASING BEFORE USE OF THE] disposal or storage zone; [WELLS;]

(7) a statement as to the type of oil field wastes to be disposed or hydrocarbons stored [FLUID TO BE INJECTED], their [ITS] composition, their [ITS] source, [AND] the estimated maximum amounts to be disposed or stored [INJECTED] daily, and the compatibility of fluids to be disposed or stored with the disposal or storage zone;

(8) the estimated average and maximum disposal or storage [INJECTION] pressure;

(9) evidence and data to support a commission finding that the proposed disposal or storage well will not initiate or propagate fractures through the confining zone(s) [ZONES] which might enable the oil field wastes or stored hydrocarbons [INJECTION FLUID OR FORMATION FLUID] to enter any freshwater strata;

(10) a [AN] standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which disposal or storage [FLUID INJECTION] is proposed[, BY A STANDARD LABORATORY WATER ANALYSIS DETERMINATION, OR BY AN ANALYTICAL METHOD ACCEPTABLE TO THE COMMISSION]; [AND]

(11) a reference to any applicable freshwater exemption issued in accordance with 20 AAC 25.440;[.] and

(12) a report on the mechanical condition of all wells that have penetrated the disposal or storage zone within a one-quarter mile radius of a disposal or storage well.

(d) The mechanical integrity of a disposal or storage well must be demonstrated under 20 AAC 25.412 before disposal or storage operations are begun and after a well workover affecting mechanical integrity is conducted. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual disposal or storage operations. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(e) If the casing-tubing annulus pressure subjects the casing to a hoop stress that exceeds 70 percent of the minimum yield strength of the casing, or if a disposal rate increase, operating pressure observation, or pressure test indicates pressure communication or leakage of any casing, tubing, or packer, [OR IF THERE IS MORE THAN A 200 PSI CHANGE IN PRESSURE BETWEEN CONSECUTIVE PRESSURE READINGS,] the operator shall notify the commission [MUST BE IMMEDIATELY NOTIFIED] by the next working day and implement commission-approved corrective action [TAKEN].

(f) The commission will, in its discretion, require additional mechanical integrity tests if prudent for conservation purposes or protection of freshwater.

. . .

Note to publisher: subsection (g) is unchanged.

(h) [THE OPERATOR SHALL PROVIDE A REPORT ON THE MECHANICAL CONDITIONS OF ALL WELLS THAT HAVE PENETRATED THE INJECTION ZONE WITHIN A ONE-QUARTER MILE RADIUS OF A PROPOSED DISPOSAL OR STORAGE WELL.] It is the operator's responsibility to ensure [ASSURE] that all [ANY OF THE] wells, including water wells and other borings, under the operator's control within a one-quarter mile radius of the disposal or storage well [THE RADIUS OF INVESTIGATION] which may allow the movement of oil field wastes or hydrocarbons [FLUIDS] into sources of freshwater are properly repaired, plugged, or otherwise modified. If wells exist that are not under the operator's control, the commission will not approve the application until the person [OPERATOR] responsible for those wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of oil field wastes or hydrocarbons [FLUIDS] into sources of freshwater.

. . .

Note to publisher: subsections (i) and (j) are unchanged.

(k) The annular disposal of drilling wastes approved under 20 AAC 25.080 is an operation incidental to drilling a well and is not a disposal operation subject to this section. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.265 is repealed and readopted to read:

20 AAC 25.265. AUTOMATIC SHUT-IN EQUIPMENT. (a) A completed well with an offshore surface location, which is capable of unassisted flow of hydrocarbons to the surface, must be equipped with a commission-approved

(1) fail-safe automatic surface safety valve (SSV) system capable of preventing an uncontrolled flow; and

(2) fail-safe automatic surface-controlled subsurface safety valve (SSSV) system capable of preventing an uncontrolled flow, unless another type of subsurface valve is approved by the commission; this valve must be in the tubing string and located below the mudline datum or, if permafrost is present, below the permafrost.

(b) An operator may demonstrate by a no-flow test that a well is incapable of unassisted flow of hydrocarbons to the surface. A minimum of 24 hours notice must be given so that a representative of the commission can witness the test.

(c) The commission will, in its discretion, also require SSVs, SSSVs, or both, on wells with onshore surface locations, after notice and an opportunity for hearing in accordance with 20 AAC 25.540.

(d) A representative of the commission will witness operation and performance tests at intervals and times as prescribed by the commission to confirm that the SSV, SSSV, and all associated equipment are in proper working condition. If an SSV, SSSV, or associated equipment fails the performance test, it must be repaired within the time frame specified by the commission or the well must be shut in. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.270 is amended to read:

20 AAC 25.270. INITIAL RESERVOIR <u>PROPERTIES</u> [PRESSURE]. <u>(a)</u> The operator shall determine the initial reservoir pressure in any new pool before <u>regular</u> [SIGNIFICANT] production. The results must be reported to the commission on the form entitled Reservoir Pressure Report (Form 10-412).

<u>(b) The operator shall obtain fluid samples from each new pool at the time of discovery or prior to regular production and determine</u>

<u>(1) crude oil composition assay;</u>

(2) pressure, volume, temperature (PVT) properties of the crude oil; and

(3) solution or non-associated gas composition assay.

(c) Sampling and analysis must be conducted and reported in accordance with good oil field engineering practices. Reports must be submitted to the commission within 45 days following completion of determinations.

d) The operator shall determine within three months after discovery of each new oil pool the original solution gas-oil ratio by a well test conducted in a manner approved by the commission. The operator shall report the results on the Well Status Report and Gas-Oil Ratio Tests (Form 10-409) within 45 days after the test. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.275. RESERVOIR FLUID PROPERTIES. Repealed. (Eff. 4/2/86, Register 97; repealed ___/___/___, Register __)

20 AAC 25.280(a) - (d) are amended, and a new (e) is added, to read:

20 AAC 25.280. WORKOVER OPERATIONS. (a) An application for well workover operations must be submitted by filing an [THE FORM ENTITLED] Application for Sundry Approvals (Form 10-403). The application must be approved by the commission before entering a [PRODUCIBLE OR INJECTION] well to conduct the following operations:

(1) perforate or reperforate casing; [,]

(2) stimulate; [,]

(3) pull tubing; [,]

(4) alter casing; [,]

(5) repair well.

(b) The Application for Sundry Approvals [FORM 10-403 FILING] must set out [THE FOLLOWING:]

(1) the current condition of the well;

(2) a copy of the proposed program for well work;

(3) unless already on file with the commission, a diagram and description of the well control [BOP] equipment to be used, including if applicable a list of the blowout prevention equipment with specifications [REQUIRED BY 20 AAC 25.285(a) AND THE STATIC BOTTOM-HOLE PRESSURE];

(4) a description of any [THE] workover fluid to be used for primary well control;[.] and

(5) the estimated current bottom-hole pressure, or the actual pressure if available.

(c) The operator shall keep records and reports of well workover and repair operations, including BOPE test results, in conformance with the requirements of 20 AAC 25.070(1) [25.070(a)].

(d) The operator shall file with the commission, within 30 days after completion of workover or [AND] repair operations, a complete well record on a Report of Sundry Well Operations (Form 10-404), the tests conducted, and a summary of [INCLUDING A COPY OF THE] daily [REPORTS OF] well operations as described in ~~accordance with~~ [AND THE TESTS AS REQUIRED BY] 20 AAC 25.070(3) [25.070(a)(1)]. Upon request, the operator shall file with the commission a copy of the daily record required by 20 AAC 25.070(1).

(e) Upon application, the commission will, in its discretion, waive the requirements of this section for wells in a pool for which pool rules have been prescribed under 20 AAC 25.520. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.285 is repealed and readopted to read:

20 AAC 25.285. SECONDARY WELL CONTROL FOR TUBING WORKOVER OPERATIONS: BLOWOUT PREVENTION EQUIPMENT REQUIREMENTS. (a) This section

applies to workover operations performed with the tree removed. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected and may not be less than the rating shown in an approved Application for Sundry Approvals (Form 10-403), except that the working pressure of the annular type preventer need not exceed 5,000 psi.

(c) Well control equipment must include

(1) at least one positive seal manual valve, hydraulic valve, or BOPE blind ram and one set of BOPE pipe rams flanged to the well head;

(2) in rotary drilling rig operations,

(A) for operations requiring less than API 5M BOP stacks, at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except for bottom-hole assemblies and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(B) for operations requiring API 5M or greater BOP stacks; at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except for bottom-hole assemblies and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(3) in coiled tubing unit operations,

(A) for operations requiring API 5M BOP stacks or less,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer;

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(iv) at least one preventer equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except for bottom-hole assemblies and drill collars;

(B) for operations requiring greater than API 5M BOP stacks,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers;

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer; and

(iv) two preventers equipped with pipe rams that fit the size of the tubing, liner, or casing being used, except for bottom-hole assemblies and drill collars;

(4) if a tapered string is used, either an additional set of rams for each size of pipe being run or a variable ram, except when small diameter tubulars are used to perform a clean-out operation through a production packer or to clean out a liner where the casing has been top set;

(5) locking devices on the ram type preventers;

(6) one complete set of operable remote BOPE controls on or near the driller's or operator's console, in addition to controls on the accumulator system;

(7) in coiled tubing operations, a second annular type preventer closing control located on the drilling platform floor, if the controls required under (6) of this subsection are not in close proximity to the drilling platform floor;

(8) in rotary drilling rig operations, at least one operable remote BOP control station on the drilling floor, in addition to controls on the accumulator system;

(9) a hydraulic actuating system with

(A) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs are closed, and all power sources are shut off; and

(B) an accumulator pump system consisting of two or more pumps with independent power sources (primary and secondary) and an accumulator backup system having sufficient capacity to close all BOPs and to hold them closed;

(10) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool or on the BOP body with two full-opening valves on each outlet, conforming to the following specifications:

(A) the outlets must be at least two inches in nominal diameter, except that for rotary drilling rig operations, if the required BOP is rated greater than API 2M, the nominal diameter of the choke outlets must be at least three inches;

(B) each valve must be sized at least equal to the required size of the outlet to which it is attached;

(C) the outermost valve on the choke side must be a remotely controlled hydraulic valve;

(D) the inner valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid; and

(11) a choke manifold equipped with

(A) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's console if the required BOPE stack is 5,000 psig or greater;

(B) a line at least two inches in nominal diameter downstream of each choke;

(C) immediately upstream of each choke, at least one full-opening valve for an operation requiring a BOP stack API 5M or less, or at least two full-opening valves for an operation requiring a BOP stack greater than API 5M; and

(D) a bypass line with at least one full-opening valve for an operation requiring a BOP stack API 5M or less, or at least two full-opening valves for an operation requiring a BOP stack greater than API 5M.

(d) The rated working pressure of valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must exceed the maximum potential surface pressure to which they may be subjected and may not be less than the rating for the BOPE shown in an approved Application for Sundry Approvals, except that lines downstream of the choke may be rated to 50 percent of the required working pressure of the BOPE.

(e) Kill and choke lines must

(1) be constructed of rigid pipe, fire-resistant rotary hose, or other suitable conduit that has been approved by the commission;

(2) be as straight as practical;

(3) if constructed of rigid pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(4) be secured to prevent excessive whip or vibration;

(5) be sized to prevent excessive erosion or fluid friction;

(6) be assembled without hammer unions or internally clamped swivel joints, unless such joints are specifically approved by the commission.

(f) The BOPE must be tested as follows:

(1) when installed, repaired, or changed, and at least once a week thereafter, BOPE, including emergency valves and choke manifolds, must be function pressure-tested, using a non-compressible fluid, to the required working pressure shown in an approved Application for Sundry Approvals or, in its absence, to the maximum potential surface pressure to which it may be subjected, except that an annular type preventer need not be tested to more than 50% of its rated working pressure;

(2) when BOP sealing ram type equipment has been used, it must be function pressure-tested before the next wellbore entry, using a non-compressible fluid, to the required working pressure shown in an approved Application for Sundry Approvals or, in its absence, to the maximum potential surface pressure to which it may be subjected, except that an annular type preventer need not be tested to more than 50% of its rated working pressure;

(3) non-sealing equipment must be function-tested weekly and after repair, change, or any action that disconnects the hydraulic system lines from the BOPE, except that when the workstring is continuously in the well or the BHA does not clear the BOP, function-testing must be performed as soon as possible thereafter;

(4) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(5) a minimum of 24 hours notice of each function pressure test must be provided so that a representative of the commission can witness the test.

(g) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of ensuring well control. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.286. WELL CONTROL REQUIREMENTS FOR WORKSTRING SERVICE OPERATIONS. (a) This section applies to through-tubing operations not covered by 20 AAC 25.036 or 20 AAC 25.285 and performed with coiled tubing, small diameter drill pipe, or small diameter tubing. These operations are also subject to the requirements of 20 AAC 25.527.

(b) The operator shall use a full lubricator system or open hole deployment type system.

(c) The rated working pressure of the BOPE and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected and may not be less than the rating shown in an approved Application for Sundry Approvals (Form 10-403), except that the working pressure of the annular type preventer need not exceed 5,000 psi.

(d) Well control equipment must include

(1) at least one positive seal manual valve, hydraulic valve, or blind ram flanged to the well head or tree;

(2) in rotary drilling rig operations,

(A) for operations requiring API 5M BOP stacks or less, at least three preventers, including

(i) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except for bottom-hole assemblies and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(B) for operations requiring greater than API 5M BOP stacks; at least four preventers, including

(i) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except for bottom-hole assemblies and drill collars;

(ii) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(iii) one annular type;

(3) in coiled tubing unit operations,

(A) for operations requiring API 5M BOP stacks or less,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) a high pressure pack-off, stripper, or annular type preventer; and

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer;

(B) for operations requiring greater than API 5M BOP stacks,

(i) BOPE rams providing for pipe, slip, cutting, and blinding operations on the coiled tubing in service;

(ii) two high pressure pack-offs, strippers, or annular type preventers; and

(iii) if pressure deployment of tools is planned, a riser or lubricator sized to the BHA providing for pressure integrity from the BOPE rams to the high pressure pack-off, stripper, or annular type preventer;

(4) a hydraulic actuating system with

(A) sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs while maintaining a minimum pressure of 200 psi above the required precharge pressure when all BOPs are closed, and all power sources are shut off; and

(B) ~~(ii)~~ an accumulator pump system;

(5) locking devices on the ram type preventers;

(6) one complete set of operable remote BOPE controls on or near the driller's or operator's console, in addition to controls on the accumulator system;

(7) in coiled tubing operations, a second annular type preventer closing control located on the drilling platform floor, if the controls required under (6) of this subsection are not in close proximity to the drilling platform floor; and

(8) a kill line with flanged or hubbed connections to the BOP body, drilling spool, tree, wellhead, or other well control equipment.

(e) The operator shall test the BOPE assembly as follows:

(1) at least once a week, and after use, repair, or change, BOPE pipe and blind rams must be function pressure-tested, using a non-compressible fluid, to the required working pressure shown in an approved Application for Sundry Approvals or, in its absence, to the maximum potential surface pressure to which they may be subjected, except that the annular type preventer need not be tested to more than 50% of its rated working pressure;

(2) after each installation of BOPE or other well control equipment and before wellbore entry, the equipment must be pressure-tested to the required working pressure shown in an approved Application for Sundry Approvals or, in its absence, to the maximum potential surface pressure to which it may be subjected, except that when testing against the annular type preventer, pressure testing need not exceed 50 percent of the rated working pressure of the annular type preventer;

(3) non-sealing equipment must be function-tested weekly and after repair, change, or any action that disconnects the hydraulic system lines from the BOPE, except that when the workstring is continuously in the well or the BHA does not clear the BOP, function-testing must be performed as soon as possible thereafter;

(4) after each well installation of the BOPE, the BOPE hydraulic connections to the rams must be visually verified before wellbore entry.

(f) Upon request of the operator, the commission will, in its discretion, approve a variance from

the requirements of this section if the variance provides at least an equally effective means of well control.

(Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.287. WELL CONTROL EQUIPMENT FOR WIRELINE OPERATIONS. (a) This section applies to workover or service operations performed with slickline or conductor line with the tree in place. These operations are also subject to the requirements of 20 AAC 25.527.

(b) Well control equipment must include

(1) a set of wireline rams suitable or sized for each diameter of wire passing through the wireline valve;

(2) a lubricator or pressure deployment system; and

(3) a high pressure pack-off, stripper, or greasehead with linewiper, stripper, or pack-off.

(c) The rated working pressure of the well control equipment must exceed the maximum potential surface pressure to which it may be subjected and may not be less than the rating shown in an approved Application for Sundry Approvals (Form 10-403), except that the working pressure of an annular type preventer need not exceed 5,000 psi.

(d) The operator shall test the well control equipment as follows:

(1) at least once a week, equipment must be function pressure-tested, using a non-compressible fluid, to the required working pressure shown in an approved Application for Sundry Approvals or, in its absence, to the maximum potential surface pressure to which it may be subjected;

(2) after each installation of the well control equipment, it must be pressure-tested, before wellbore entry, to the required working pressure shown in an approved Application for Sundry Approvals or, in its absence, to the maximum potential surface pressure to which it may be subjected;

(3) if the wireline valve rams have been used, repaired or changed, the wireline rams must be closed and function pressure-tested before wellbore entry, using a non-compressible fluid, to the required working pressure shown in an approved Application for Sundry Approvals or, in its absence, to the maximum potential surface pressure to which they may be subjected.

(e) Upon request of the operator, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of well control.

(Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.288. WELL CONTROL REQUIREMENTS FOR OTHER SERVICE OPERATIONS. For downhole service operations not covered by 20 AAC 25.285 - 20 AAC 25.287, the commission will, in its discretion, approve alternate well control procedures and equipment. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.290 OPERATIONS PRODUCING HYDROGEN SULFIDE. An operator of a well or pool that produces hydrogen sulfide gas shall install, operate, and maintain surface production equipment in conformance with API RP 55, *Recommended Practices for Conducting Oil & Gas Production Operations Involving Hydrogen Sulfide* (February 1995), which is adopted by reference. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in this section may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

ARTICLE 4.
REPORTS.

Section
300. Request for additional information
310. Books and records
320. Filing of forms

20 AAC 25.300 is amended to read:

20 AAC 25.300. REQUEST FOR ADDITIONAL INFORMATION. This chapter does not limit or restrict the authority of the commission to require the furnishing of such additional reports, data, or other information relative to drilling, production, transportation, storage, or handling of [CRUDE] oil or [NATURAL] gas and injection operations on oil and gas properties and units in the state [ALASKA], as may appear to it to be necessary or desirable, either generally or specifically, for the prevention of waste, the protection of correlative rights, the prevention of fluid movement [MOVEMENT OF FLUIDS] into freshwater sources, and the conservation of [THE] natural resources. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.310 is amended to read:

20 AAC 25.310. BOOKS AND RECORDS. All operators[,] of [PRODUCERS, TRANSPORTERS, STORERS, AND HANDLERS OF CRUDE OIL AND NATURAL GAS ON] oil and gas properties and units within the state [ALASKA] shall make and maintain [, AND KEEP IN ALASKA] for a period of not less than five years, books and records necessary [APPROPRIATE BOOKS AND RECORDS COVERING THEIR OPERATION IN ALASKA. THE DATA FROM THESE BOOKS AND RECORDS MUST BE USED] to make and substantiate the reports required by this chapter. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.320(a) is repealed and readopted, and (b) is amended, to read:

20 AAC 25.320. FILING OF FORMS. (a) Where this chapter requires a form to be filed, one originally signed, commission-approved form must be submitted to the commission with the required number of copies indicated on each form. A computer-generated form may be submitted in place of the form furnished by the commission if it contains the same required information and has been approved for format by the commission.

(b) Forms required by this chapter will be furnished by the commission upon request <u>and will be revised at the discretion of the commission</u>. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

ARTICLE 5.
ENHANCED RECOVERY.

Section
400. (Repealed)
402. Enhanced recovery operations
410. (Repealed)
412. Casing, cementing, and tubing of injection wells for enhanced recovery, disposal, and storage
420. Notice of commencement and discontinuance of injection operations
430. Enhanced recovery records
432. Report of underground injection
440. Freshwater aquifer exemption
450. Underground injection control variances
460. Area injection orders

20 AAC 25.402 is repealed and readopted to read:

20 AAC 25.402. ENHANCED RECOVERY OPERATIONS. (a) Enhanced recovery operations involving the introduction of extraneous forms of energy into a pool by injection are prohibited, except as ordered by the commission under this section. In response to an application for injection filed by an operator, the commission will, in its discretion, authorize the injection of fluids that function primarily to enhance recovery of oil and gas and that are appropriate for enhanced recovery. Except as provided in (i) of this section, an order authorizing injection for an enhanced recovery project remains valid unless revoked by the commission.

(b) The operator has the burden of demonstrating that the proposed operation will not allow the movement of fluid into sources of freshwater. Injection wells must be cased, the casing cemented, and the wells operated in a manner that will isolate the injection zone and protect oil, gas, and freshwater. It is the operator's responsibility to ensure that all wells, including water wells and other borings, under the operator's control within a one-quarter mile radius of an injection well, which may allow the movement of fluids into sources of freshwater, are properly repaired, plugged, or otherwise modified. If wells exist that are not under the operator's control, the commission will not approve the application until the person responsible for these wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of fluids into sources of freshwater.

(c) An application for injection must include

(1) a plat showing the location of all proposed injection wells, abandoned or other unused wells, production wells, dry holes, and any other wells that penetrate the injection zone within one-quarter mile of each proposed injection well;

(2) a list of all operators and surface owners within a one-quarter mile radius of each proposed injection well;

(3) an affidavit showing that the operators and surface owners within a one-quarter mile radius have been provided a copy of the application for injection;

(4) a full description of the particular operation for which approval is requested;

(5) the names, descriptions, and depths of the pools to be affected;

(6) the name, description, depth, and thickness of the formation into which fluids are to be injected, and appropriate geological data on the injection zone and confining zone(s), including lithologic descriptions and geologic names;

(7) logs of the injection wells if not already on file;

(8) a description of the casing of the injection wells, or the proposed casing program, and the proposed method for demonstrating mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that no fluids will move behind casing beyond the approved injection zone;

(9) a statement of the type of fluid to be injected, its composition, its source, the estimated maximum amounts to be injected daily, and its compatibility with the injection zone;

(10) the estimated average and maximum injection pressure;

(11) evidence to support a commission finding that each proposed injection well will not initiate or propagate fractures through the overlying strata or confining zone(s) that might enable the injection fluid or formation fluid to enter any freshwater strata;

(12) a standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which fluid injection is proposed;

(13) reference to any applicable freshwater exemption issued under 20 AAC 25.440;

(14) the expected incremental increase in ultimate hydrocarbon recovery; and

(15) a report on the mechanical condition of all wells that have penetrated the injection zone within a one-quarter mile radius of each proposed injection well.

(d) The commission will publish notice of the enhanced recovery application and provide opportunity for a hearing in accordance with 20 AAC 25.540.

(e) The mechanical integrity of an injection well must be demonstrated under 20 AAC 25.412 before injection is begun and after a well workover affecting mechanical integrity is conducted. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual injection. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(f) If the casing-tubing annulus pressure subjects the casing to a hoop stress that exceeds 70 percent of the minimum yield strength of the casing, or if an injection rate, operating pressure observation, or pressure test indicates pressure communication or leakage in any casing, tubing, or packer, the operator shall notify the commission by the next working day and shall implement commission-approved corrective action.

(g) The commission will, in its discretion, require additional mechanical integrity tests.

(h) The commission will, in its discretion, approve a modification to an existing or pending injection operation under 20 AAC 25.507, when the applicant proves to the commission, upon application containing sufficient detail to evaluate the proposed modification, that the modification will not allow the movement of fluids into sources of freshwater.

(i) If injection operations are not begun within 24 months after the approval date, the enhanced recovery approval expires unless a letter of application for extension is approved by the commission. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.412 is repealed and readopted to read:

20 AAC 25.412. CASING, CEMENTING, AND TUBING OF INJECTION WELLS FOR ENHANCED RECOVERY, DISPOSAL, AND STORAGE. (a) A well used for injection must be cased and cemented in accordance with 20 AAC 25.030 to prevent leakage into oil, gas, or freshwater sources.

(b) A well used for injection must be equipped with tubing and packer, or other equipment that isolates pressure to the injection interval, unless otherwise specifically approved by the commission. The minimum burst pressure of the tubing must exceed the maximum surface injection pressure by at least 25 percent. The packer must be placed within 200 feet measured depth above the top of the perforations, unless otherwise approved by the commission.

(c) Before injection begins, a well must be pressure-tested to demonstrate the mechanical integrity of the tubing and packer and the casing immediately surrounding the injection tubing string. The casing must be tested at a surface pressure of 1,500 psig or 0.25 psi/ft multiplied by the true vertical depth of the casing shoe, whichever is greater, but the casing may not be subjected to a hoop stress that will exceed 70 percent of the minimum yield strength of the casing. The test pressure must show stabilizing pressure and may not decline more than 10 percent within 30 minutes.

(d) The operator shall provide a cement quality log or other well data approved by the commission to demonstrate isolation of the injected fluids to the approved interval.

(e) A minimum of 24 hours notice of a pressure test required by (c) of this section must be given so that a representative of the commission can witness the test. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.430 is amended to read:

20 AAC 25.430. ENHANCED RECOVERY RECORDS. Each operator shall keep accurate records showing volumes of fluids produced, injected volumes, reservoir pressures, and injection pressures, by well and pool. Each operator shall retain these records for five years. The commission will, in its discretion, specify retention of these records for a longer time period. Upon reasonable notice, the commission [OR ITS AUTHORIZED REPRESENTATIVE] must be given full access during normal business hours to all records. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.432 is repealed and readopted, to read:

20 AAC 25.432. REPORT OF UNDERGROUND INJECTION. An operator that injects fluids into subsurface strata through a service well for any purpose, other than fracturing, acidizing, or other similar treatment, shall file with the commission

(1) monthly reports that show all injected volumes and other data, by well and pool, as required by the commission on the Monthly Injection Report (Form 10-406) and, if applicable, the Facility Report of Produced Gas Disposition (Form 10-422); and

(2) an annual report that shows annual and total cumulative volumes injected and produced and other data, for each pool or injection project area within the pool, as required by the commission on the Report of Injection Projects (Form 10-413); the annual report must be submitted by April 1 each year unless it is required by pool rules to be included with a pool specific annual surveillance report.

(Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.440(c) is amended, and a new subsection (d) is added, to read:

(c) Freshwater aquifers within the state [ALASKA] that were [ARE] designated as exempt aquifers by the United States Environmental Protection Agency [AT THE TIME THE COMMISSION IS GRANTED PRIMARY ENFORCEMENT RESPONSIBILITY] under 42 U.S.C. 300h-4 are [WILL BE] accepted as exempt aquifers by the commission [WITHOUT FURTHER ACTION].

(d) A commission order designating a freshwater aquifer or a portion of it as an exempt freshwater aquifer is not effective with respect to underground disposal or storage operations subject to 20 AAC 25.252 or injection operations subject to 20 AAC 25.402 until the United States Environmental Protection Agency has been provided the opportunity to review the order and has

(1) approved the order, if it was issued under (a)(1) of this section; or

(2) has allowed the applicable time period within which to disapprove the order to expire without acting on it, if it was issued under (a)(2) of this section. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.450 (a) is amended to read:

20 AAC 25.450. UNDERGROUND INJECTION CONTROL VARIANCES. (a) If injection does not occur into, through, or above [A] freshwater [SOURCE OR NON-EXEMPT FRESHWATER AQUIFER], the commission will, in its discretion, authorize less stringent requirements for a well or project than otherwise required by this chapter, for radius of investigation, casing and cementing, tubing and packer, mechanical integrity, operation, monitoring, and reporting, to the extent that the reduction in requirements will not result in an increased risk of movement of fluids into [A] freshwater [SOURCE]. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.460 is amended to read:

20 AAC 25.460. AREA INJECTION ORDERS. (a) Upon application under this section and subject to the provisions of 20 AAC 25.252 or 25.402, as applicable, the commission will, in its discretion, after [LEGAL] notice and opportunity for public hearing in accordance with 20 AAC 25.540, issue an order permitting the underground injection of fluids on an area basis, rather than for each well individually, if the wells are

. . .

Note to publisher: paragraph (1) is unchanged.

(2) within the same field, facility site, reservoir, project, or similar area; and

(3) operated by a single operator. [; AND]

(4) repealed / / [USED TO INJECT OTHER THAN HAZARDOUS WASTE].

(b) The area injection order will specify

. . .

Note to publisher: paragraph (1) is unchanged.

(2) the requirements for drilling, completing, operating, monitoring, reporting, and abandoning all wells authorized by the order.

(c) The area injection order will, in the commission's discretion, authorize the operator to drill, complete, and operate, to convert, or to plug and abandon wells within the area if

(1) the operator files with the commission a Permit to Drill (Form 10-401) or an Application for Sundry Approvals (Form 10-403), as appropriate, for approval before work; and

. . .

Note to publisher: paragraph (2) is unchanged.

(d) If the commission determines that any well drilled and operated under an area injection order does not satisfy all of the requirements [REQUIRE-MENTS] of this section, the commission will take enforcement action to ensure compliance. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

ARTICLE 6.
GENERAL PROVISIONS.

Section
505. Scope of regulations
507. Change of an approved program
510. Commission [OFFICE, HOURS, AND] seal
515. United States government land [LEASES]
517. Plan of reservoir[FOR POOL] development and operation[, AND INTEGRATION OF INTERESTS]
518. Agreements integrating interests under AS 31.05.110(a)
520. Field and pool regulation and classification
525. (Repealed)
526. Conduct of operations [AND FIRE HAZARD]
528. Open pit storage of oil
530. Cooperative [COOPERATION] agreements with other parties
534. Tests, surveys, and inspections [REMEDIAL MEASURES]
535. Enforcement
536. (Repealed)
537. Public and confidential [WELL] information
538. (Repealed)
539. Emergency action
540. Hearings
545. Public mailing lists
550. Oaths
555. (Repealed)
556. Orders
557. Subpoenas
560. Time
570. (Repealed) [DEFINITIONS]

20 AAC 25.507 is repealed and readopted to read:

20 AAC 25.507. CHANGE OF AN APPROVED PROGRAM. (a) Except as otherwise provided by 20 AAC 25.015, if an operator desires to make a substantive change in an approved program, complete details of the current condition and the proposed change must be submitted to the commission with the Application for Sundry Approvals (Form 10-403). A change of an approved program may not be undertaken without commission approval. The commission will condition its approval as necessary or appropriate.

(b) Where operational necessity requires prompt action, oral approval of a change may be obtained from the commission. The required Application for Sundry Approvals must be submitted within

the commission's next three working days setting out the name of the person who provided approval and the date of the oral approval. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.510 (a) and (b) are repealed, and (c) is amended, to read:

20 AAC 25.510. COMMISSION [OFFICE, HOURS, AND] SEAL. (a) Repealed ___/___/___.

(b) Repealed ___/___/___.

(c) The official seal of the commission is reproduced below.

Note to publisher: Commission seal shown on the next page to be inserted here

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.017 [AS 31.05.030]

20 AAC 25.515 is amended to read:

20 AAC 25.515. UNITED STATES GOVERNMENT LAND [LEASES]. A person, including a federal agency, drilling for or producing oil or [NATURAL] gas or conducting underground injection activities related to the recovery and production of oil or gas on federal land subject to the state's police powers shall comply with all applicable regulations and orders of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.027 AS 31.05.030

20 AAC 25.517 is repealed and readopted to read:

20 AAC 25.517. PLAN OF RESERVOIR DEVELOPMENT AND OPERATION. (a) Before commencement of regular production from an oil or gas pool, the operator shall submit to the commission a plan of reservoir development and operation for the pool or the portion of the pool for which development is contemplated by the operator.

(b) Unless otherwise ordered by the commission, the operator shall submit to the commission annual progress reports under the plan of reservoir development and operation. Any amendments and updates to the plan also must be submitted at least annually.

(c) The plan of reservoir development and operation must provide for

(1) the prevention of waste;

(2) the protection of correlative rights; and

(3) a greater ultimate recovery of oil and gas. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 [AS 31.05.110]

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.518. AGREEMENTS INTEGRATING INTERESTS UNDER AS 31.05.110(a). A voluntary agreement for the purpose of integrating interests under AS 31.05.110(a) must be filed with the commission no later than 30 days after it is executed. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.110

20 AAC 25.520 is amended to read:

20 AAC 25.520. FIELD AND POOL REGULATION AND CLASSIFICATION. (a) Upon the motion of the commission, or the request of an affected owner or [PROPERTY] operator [OR OWNER] at any time after the discovery of oil or gas in a field or pool, a hearing will be held in accordance with 20 AAC 25.540 and the commission will issue an order, based upon the evidence presented, classifying the pool as an oil or gas pool in a field and prescribing rules to govern the proposed [FOR THE] development and operation of the pool. A pool order so issued will

(1) prevent waste, protect freshwater, [AND] protect correlative rights, and ensure a greater ultimate recovery of oil and gas; and

(2) be based on the operating and technical data presented.

(b) The commission will, in its discretion, amend pool orders in accordance with the procedures set forth in 20 AAC 25.540 [RECLASSIFY FIELDS AND POOLS, OR AMEND POOL ORDERS, UPON THE PRESENTATION OF ADDITIONAL DATA AT A SUBSEQUENT HEARING]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.060

AS 31.05.095 AS 31.05.100

20 AAC 25.526 is amended to read:

20 AAC 25.526. CONDUCT OF OPERATIONS [AND FIRE HAZARD]. An operator shall carry on all operations and maintain the property at all times in a safe and skillful manner in accordance with good oil field engineering [INDUSTRY] practices[,] and having due regard for the preservation and conservation of the property and protection of freshwater. [EACH WELL LOCATION AND PROPERTY MUST BE MAINTAINED IN A MANNER TO PREVENT FIRES. ALL RUBBISH, DEBRIS, WASTE MATERIAL, SPILLED OIL, AND ANY OTHER SUBSTANCE THAT CONSTITUTES A FIRE HAZARD MUST BE DISPOSED OF IN AN ENVIRONMENTALLY SAFE MANNER.] (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.527. GENERAL WELL CONTROL REQUIREMENTS FOR DRILLING, COMPLETION, WORKOVER, AND SERVICE OPERATIONS. (a) This section applies to all well drilling, completion, workover, and service operations. The requirements of this section are in addition to the applicable requirements of 20 AAC 25.033 - 20 AAC 25.037 and 20 AAC 25.285 - 20 AAC 25.288.

(b) All equipment must be in good operating condition at all times and must be protected to ensure reliable operation under the range of weather conditions that may be encountered at the well site.

(c) All well control equipment and fluids must be installed, used, maintained, and tested in a manner that ensures well control and, except as otherwise provided in this chapter, that conforms with the applicable provisions of the following documents, which are adopted by reference:

(1) API RP 5C7, *Recommended Practices for Coiled Tubing Operations in Oil and Gas Well Services* (December 1996);

(2) API RP 13B-1, *Recommended Practice for Standard Procedure for Field Testing Water-Based Drilling Fluids* (September 1997);

(3) API RP 13B-2, *Recommended Practice for Standard Procedure for Field Testing Oil-Based Drilling Fluids* (September 1991);

(4) API RP 49, *Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide* (April 1987);

(5) API RP 53, *Recommended Practices for Blowout Prevention Systems* (March 1997);

(6) API RP 57, *Recommended Practices for Offshore Well Completion, Servicing, Workover, and Plug and Abandonment Operations* (January 1986);

(7) API RP 64, Recommended Practices for Diverter Systems Equipment and Operations (July 1991);

(8) API RP 68, *Recommended Practice for Oil and Gas Well Servicing and Workover Operations Involving Hydrogen Sulfide* (January 1998).

(d) The toolpushers, drillers, and person(s)-in-charge on a rotary drilling or workover rig floor must be trained in accordance with the drilling well control training standards contained in 30 C.F.R. 250.1500 - 250.1524 (Subpart O) as revised as of July 1, 1998. The toolpushers, drillers, and person(s)-in-charge on a coiled tubing drilling rig must be trained in accordance with the well servicing well control training standards contained in 30 C.F.R. 250.155 - 250.1524 (Subpart O) as revised as of July 1, 1998.

(e) ~~(f)~~(e) The person(s)-in-charge on a drill rig floor must have the authority and responsibility to shut in the well if it starts to flow.

(f) The operator shall keep records and reports of well drilling, workover, and repair operations, including BOPE test results, in accordance with 20 AAC 25.070(1) or, in the case of wireline work or other service operations, in the daily work log, which will be made available to the commission upon request.

(Eff. ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: Copies of the American Petroleum Institute recommended practices referred to in this section may be reviewed during business hours at the commission's office and may be obtained from

Hazard Section a ~~and~~ (if required) and the
A copy of the Standing Orders must be posted on the rig floor. A copy of the approved Permit to Drill or Sundry Notice must be on location.

the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070, or if not available from the American Petroleum Institute, may be obtained from Global Engineering Documents, 15 Inverness Way East, Englewood, CO 80150.

20 AAC 25.530 is amended to read:

20 AAC 25.530. COOPERATIVE [COOPERATION] AGREEMENTS WITH OTHER PARTIES. The commission will, in its discretion, from time to time enter into agreements [ARRANGEMENTS] with state and federal agencies, industry committees, or individuals, with respect to special projects, services, and studies relating to underground fluid injection and the conservation of oil and gas. If an agreement [ARRANGEMENT] requires the commission to use procedures or apply rules not covered in this chapter, the procedures necessary to carry out the intent of the agreement [ARRANGEMENT] will be formulated and made available at the office of the commission after public notice and opportunity for public comment, pursuant to 11 AAC 25.540. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.023 AS 31.05.030

20 AAC 25.534 is amended to read:

20 AAC 25.534. TESTS, SURVEYS, AND INSPECTIONS [REMEDIAL MEASURES]. When considered necessary or advisable to carry out the purposes of AS 31.05 [THE] (Alaska Oil and Gas Conservation Act) and this chapter, the commission will require that tests or surveys be made to determine the quality of oil and gas produced; the formation, casing, tubing, or other pressures; the existence of any waste of [CRUDE] oil, gas, or reservoir energy; or the risk of fluid movement into freshwater [SOURCES]. The commission will, in its discretion, exercise its statutory power to enter and conduct on-site investigations and inspections at reasonable times of facilities, equipment, practices, records, or

operations for the purpose of ensuring compliance with the requirements of this chapter. [IF IT IS DETERMINED THAT THE REQUIREMENTS OF THIS CHAPTER ARE NOT BEING MET, THE COMMISSION WILL ORDER REMEDIAL WORK OR TAKE OTHER ACTION IT CONSIDERS NECESSARY.] (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.535. ENFORCEMENT. (a) When the commission has reason to believe, as the result of an investigation or otherwise, that a person has violated or failed to comply with a provision of AS 31.05, this chapter, or a commission order, permit, or other approval, the commission will, in its discretion, give written notification to the person.

(b) The commission's written notification to the person will

(1) state the nature of the apparent violation or noncompliance;

(2) summarize the basis of the commission's reason to believe that a violation or noncompliance has occurred;

(3) state the action that the commission proposes to take under (e) of this section; and

(4) inform the person of the person's rights and liabilities under (c) - (e) of this section.

(c) Within 10 days after issuance of a notification, or within such longer period as the commission may specify, a person may file with the commission a written response (1) acquiescing, in whole or in part, in a proposed commission action; (2) requesting informal review; or (3) requesting a hearing under 20 AAC 25.540. If a person fails to file a timely written response, the person will be deemed to have acquiesced in the proposed commission action. If a person requests a hearing, the commission will schedule a hearing under 20 AAC 25.540.

(d) If a person requests informal review, the commission will provide an opportunity for the person to submit documentary material and make a written or oral statement. The commission will then

issue a tentative decision or order, which becomes final 11 days after it is issued unless within 10 days after it is issued the person files a written request for a hearing, in which case the tentative decision or order is of no effect. If the person requests a hearing, the commission will schedule a hearing under 20 AAC 25.540.

(e) After a person acquiesces in a proposed action under (c) of this section, or after an informal review or a hearing under (c) or (d) of this section, and when the commission finds that a person has violated or failed to comply with a provision of AS 31.05, this chapter, or a commission order, permit, or other approval, the commission will, in its discretion, order one or more of the following, as it determines to be applicable:

(1) corrective action or remedial work;

(2) revocation or suspension of a permit or other approval;

(3) payment under the bond required by 20 AAC 25.025; and

(4) imposition of penalties under AS 31.05.150.

(f) The commission's action under (e) of this section after an informal review or a hearing is not limited to what was proposed under (b)(3) of this section, as long as the person had reasonable notice and opportunity to be heard as to the commission's action.

(g) An action by the commission under this section is in addition to any action the commission may take under AS 31.05.160. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.040

AS 31.05.050 AS 31.05.060

AS 31.05.150

20 AAC 25.537 (a)(1), (b), and (c) are amended, and a new (f) is added, to read:

20 AAC 25.537. PUBLIC AND CONFIDENTIAL [WELL] INFORMATION. (a) The commission will routinely make available to the public, by means of records or reports, in its offices or elsewhere, or by means of regular publication, the following information:

(1) surface and proposed bottom-hole locations [LOCATION] of each well[,] after approval of the Permit to Drill (Form 10-401);

. . .

Note to publisher: the remainder of subsection (a) is unchanged.

(b) Engineering, geologic, geophysical, and other commercial information [INFORMATION] not required by this chapter, but voluntarily filed with the commission will be kept confidential if the person filing the information so requests. This subsection does not apply to information submitted for the first time in a public hearing under 20 AAC 25.540, the confidentiality of which will be governed by other applicable law.

(c) In this section, "well status" means the classification of a well as oil, gas, service, suspended, shut-in, or abandoned.

. . .

Note to publisher: subsections (d) and (e) are unchanged.

(f) This section is not intended to limit any constitutional, statutory, or common law rights or obligations of a person or the commission to obtain information or maintain the confidentiality of information filed with the commission, such as may apply to a public hearing under 20 AAC 25.540. Where disclosure of otherwise confidential information is required, such disclosure will be limited and conditioned to the extent necessary to comport with applicable constitutional, statutory (including trade secret provisions, such as AS 45.50.940(3)), and common law doctrines that protect commercially sensitive, confidential, and proprietary information. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: [AS 31.05.026] AS 31.05.030
AS 31.05.035 [AS 31.05.170]

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.539. EMERGENCY ACTION. (a) The commission will, in its discretion, issue a temporary emergency order without a hearing if necessary to protect against imminent waste, irreparable harm to correlative rights, contamination of freshwater, or a safety hazard resulting from a violation of a provision of AS 31.05, this chapter, or a commission order. Before issuing a temporary emergency order, the commission will attempt to communicate with the operator about the circumstances and need for a temporary order.

(b) A temporary emergency order will be supported by a written decision describing the factual and legal basis for the action, including the necessity for acting on an emergency basis. The decision will be provided to the operator within 24 hours of the issuance of the order.

(c) A temporary emergency order expires after 14 days unless

(1) an earlier expiration date is established in the order;

(2) the operator agrees to an extension; or

(3) a hearing has actually commenced, in which case the temporary emergency order will remain in effect for an additional period not to exceed the shorter of 14 days after the day the hearing commences or three working days after the day the hearing closes, whichever period is shorter. For the purposes of a notice of hearing under this subsection, the notice period is 10 days, and the 30 day notice period established in 20 AAC 25.540 does not apply. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.050

AS 31.05.060 AS 31.05.150

20 AAC 25.540 is repealed and readopted to read:

20 AAC 25.540. HEARINGS. (a) On its own motion or if a written request is received to issue an order affecting a single well or a single field, the commission will publish notice in an appropriate newspaper. The notice will set out the essential details of the requested order and provide an opportunity

for public comment. The notice will tentatively specify the place, time, and date for the hearing that will be scheduled no fewer than 30 days after the date of publication. Any person may submit a written protest or written comments during that 30 day period. In addition, any person may request that the tentatively scheduled hearing be held by filing a written request with the commission at its office in Anchorage, Alaska, within 15 days after the publication date. The request for hearing must identify the requester's interest in the proposed action and provide the reasons for desiring a public hearing. If the commission determines that a significant issue is raised in a request for hearing, or if the commission desires to hold a hearing, a hearing will be held on the date and time specified in the notice. If no request for a hearing is timely filed, the commission will, in its discretion, issue an order without a hearing.

(b) On its own motion or if a written request for a public hearing is received concerning a matter within the jurisdiction of the commission under this chapter, the commission will publish notice in an appropriate newspaper. The notice will provide the essential details of the matter and set out the place for the public hearing, the date, and the time for the public hearing. The hearing will be scheduled no fewer than 30 days after the date of publication.

(c) Except as otherwise provided in (e) of this section, the following procedures apply to public hearings conducted under (a) or (b) of this section:

(1) the hearing will be called to order and the subject of the hearing, along with the date and place of public notice given for the hearing, will be read into the record;

(2) the commission will receive both sworn testimony and unsworn statements; it will give greater weight in its deliberations to sworn testimony;

(3) all persons wishing to testify will be sworn;

(4) each witness shall state the witness's name and whom the witness represents;

(5) each witness who wishes to give expert testimony shall state the witness's qualifications, and the commission will rule on whether the witness qualifies as an expert;

(6) the applicant will be asked to present testimony first; all others wishing to present testimony will be heard next; upon request, the commission will, in its discretion, allow cross-examination of witnesses;

(7) a person wishing to make an oral statement will be allowed to do so after the conclusion of all testimony;

(8) the commission will, in its discretion, ask questions of a witness;

(9) except as may be allowed under (6) of this subsection, no one will be permitted to ask questions of witnesses directly; to have a question directed to a witness, a person shall provide the question in writing, along with the person's name and that of the witness, to a designated commission representative; before the end of the hearing, the commission will review these questions and ask those that it believes will be helpful in eliciting needed information; all questions will be included in the public record;

(10) a written transcript of the hearing will be prepared and included in the public record of the hearing;

(11) the commission will, in its discretion, allow pre-filed written testimony in place of or in addition to oral testimony.

(d) Hearings on matters of statewide or general application will be held under the applicable provisions of AS 44.62.

(e) In a hearing under 20 AAC 25.535, a party may be represented by counsel, call and examine witnesses, present relevant evidence unless unduly cumulative or repetitious, cross-examine witnesses, impeach witnesses, and rebut adverse evidence. The commission will establish a reasonable date before the hearing by which the commission and each party must provide: (1) the names and addresses of persons known to have knowledge of relevant facts and, unless privileged, their written or recorded statement or summaries of statements; (2) the name, address, and qualifications of each expert who will testify at the hearing, and a written description of the substance of the expert's proposed testimony, the expert's opinion, and the underlying basis of that opinion; and (3) a copy of all documents and a description of all other

tangible things intended to be used in the hearing. The commission will base its decision with respect to contested issues of fact only on evidence presented during the hearing.

(f) Pursuant to a pre-hearing conference or otherwise, the commission will, in its discretion, establish additional procedures for a specific hearing consistent with the procedures in (c) or (e) of this section, as applicable, or as otherwise necessary to provide due process to a party. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.040
AS 31.05.050 AS 31.05.060
AS 31.05.070

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.556. ORDERS. All orders of the commission require approval of at least two commissioners. (Eff. ___/___/___, Register __)

Authority: AS 31.05.011 AS 31.05.030

20 AAC 25.557 is amended to read:

20 AAC 25.557. SUBPOENAS. (a) The commission will, in its discretion, issue subpoenas [AND SUBPOENAS DUCES TECUM].

(b) A subpoena [SUBPOENAS DUCES TECUM] for the production of books, records, papers, or other documents of any sort will, in the commission's discretion, be issued by the commission upon a written request. The applicant must establish [THAT HE OR SHE HAS] a proper relation to the matter, and must show the relevance of the evidence sought and the facts expected to be proved by them.

(c) [THE ISSUANCE OF A] A subpoena requiring the attendance of a witness for the purpose of taking oral testimony before the commission will, in the commission's discretion, be issued by the commission upon a written request. The applicant must establish a [THAT HE OR SHE HAS] proper

relation to the matter and give the name and address of the desired witness. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.040

AS 31.05.070

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.560. TIME. Where AS 31.05 or this chapter requires or permits a person to file a document with the commission, the document is considered filed when it is received in the commission's office. (Eff. ___/___/___, Register ___)

Authority: AS 31.05.030 AS 31.05.035

AS 31.05.040

20 AAC 25.570 is repealed:

20 AAC 25.570. DEFINITIONS. Repealed. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 1/1/95, Register 132; repealed ___/___/___, Register ___)

Editor's note: As of Register ___ (_____ 19 ___), the substance of 20 AAC 25.570 was moved to 20 AAC 25.990.

ARTICLE 7.
DEFINITIONS.

Section
990. Definitions

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.990. DEFINITIONS. In this chapter, unless the context requires otherwise,

(1) "abandon" means to plug a well in accordance with 20 AAC 25.112 and without the commission's approval of well suspension under 20 AAC 25.110;

(2) "abnormally geo-pressured strata" means subsurface zones where the pore pressure exceeds a gradient of 0.50 psi/ft;

(3) "API" means the American Petroleum Institute;

(4) "API number" means the number assigned by the commission for a well or well branch consistent with the API well numbering convention;

(5) "API RP" means API recommended practices;

(6) "barrel" includes "stock tank barrel" and means 42 U.S. gallons, measured at 60° F. and 14.65 psia.;

(7) "BOP" means blowout preventer, which is a casinghead assembly equipped with special gates or rams or other pack-offs that can be closed around the drill pipe, tubing, casing, or tools, and that completely closes the top of the casing to control well pressure;

(8) "BOPE" means blowout prevention equipment;

(9) "bottom-hole location" means the subsurface point at the greatest measured depth penetration of a well or a well branch;

(10) "casing stub" means the remnant of a casing string when the upper portion of the casing has been cut and recovered;

(11) "commission" means the Alaska Oil and Gas Conservation Commission;

(12) "complete" means to equip and condition a well as an oil, gas, or service well so that it is capable of producing or injecting fluids; in the case of a well branch in a previously completed well, "complete" means to equip and condition a well branch so that it is capable of contributing to the well's production or injection of fluids;

(13) "completion operation" means work performed in a well after the casing and cementing of the wellbore, and includes plugging, perforating, stimulating, testing, and equipping the well to produce or inject fluids;;

(14) "conductor casing" means a casing string set before surface casing; depending on well configuration, it can be either the first or second string of casing set in a well and usually supports a diverter system;

(15) "day" means a calendar day;

(16) "development well" means a well drilled to a known productive pool;

(17) "displacement method" means pumping a cement slurry or other material into a well through a drillpipe or other tubular string and recovering displaced fluids on the surface;

(18) "diverter system" means an assembly of nipples, valves, and piping attached to a well's structural or conductor casing for venting a gas kick away from the drill rig;

(19) "downsqueeze method" means pumping a cement slurry or other material into a well through a drillpipe or other tubular string and forcing displaced fluids into a downhole formation;

(20) "drilling fluid" means any fluid used for the purpose of drilling a well;

(21) "drilling operations" means the penetration of ground below the setting depth of structural or conductor casing, if set, using a drilling rig capable of performing the permitted well work, and includes the running of casing, cementing, and other downhole work performed ancillary to formation evaluation, and all operations necessary to complete and equip the well so that formation fluids can be safely brought to the surface;

(22) "drilling unit" means an area of a pool established by the commission under AS 31.05.100, either by order or by regulation, to which no more than one oil or gas well may be drilled and from which no more than one oil or gas well may produce;

(23) "exploratory well" means a well drilled to discover or to delineate a pool;

(24) "fluid" means any material or substance that flows or moves, whether in a semi-solid, liquid, sludge, gaseous, or other form or state;

(25) "freshwater" means water having a total dissolved solids concentration of less than 10,000 mg/l that occurs in a stratum not exempted under 20 AAC 25.440, or water that occurs in a stratum that serves as a source of drinking water for human consumption;

(26) "function pressure-test" means to actuate a component and demonstrate its ability to effect a pressure seal;

(27) "function-test" means to actuate a component to demonstrate its proper functioning without subjecting it to pressure;

(28) "gas well" means a well that produces predominantly gas at a gas-oil ratio over 100,000 scf/stb, unless on a pool by pool basis the commission establishes another ratio;

(29) "gas-oil ratio" means the cubic feet of gas, determined at 60° F. and 14.65 psia, that are produced per stock tank barrel of oil produced;

(30) "injection" means the subsurface emplacement of fluid for enhanced recovery of oil or gas, disposal of oil field wastes, or underground storage of hydrocarbons;

(31) "intermediate casing" means a casing string run between the surface casing and the production casing or production liner and cemented in place to isolate abnormally geo-pressured strata, lost circulation zones, salt sections, or unstable shale sections;

(32) "landowner" has the meaning given in AS 31.05.170;

(33) "liner" means a string of casing that does not extend to surface but is hung inside the previous casing string or may be set and cemented in place;

(34) "meter curve" means a graph of the meter factor plotted against the flow rate, or of the pulse-per-unit-volume factor plotted against the flow rate, over the operating range of a meter;

(35) "meter factor" means the number obtained by dividing the gross standard volume of liquid passed through a meter (as measured by a prover during proving) by the corresponding meter indicated volume at standard conditions; ?

(36) "mudline datum" means

(A) for a beach location, the plane of mean low water depth extended beneath the well site;

(B) for a location on a shifting natural island, the depth at which a horizontal plane through the toe of the island intersects the wellbore;

(C) for a location on an artificial island, the depth of the mudline as it existed before construction of the island;

(D) for other offshore locations, the mudline;

(37) "multiple completion" means the completion of a well so as to permit production from more than one pool, with the production from each pool completely segregated;

(38) "offshore" means, in addition to its ordinary meaning, beach, artificial island, and shifting natural island locations;

(39) "oil well" means a well that produces predominantly oil at a gas-oil ratio of 100,000 scf/stb or lower, unless on a pool by pool basis the commission establishes another ratio;

(40) "operator" means an owner or a person authorized by an owner who is responsible for drilling, development, production, injection, disposal, storage, abandonment, and location clearance;

(41) "owner" has the meaning given in AS 31.05.170;

(42) "pilot gas" means gas routed to a safety flare system to maintain an ignition source;

(43) "pressure-test" means to demonstrate the pressure integrity of a system without actuating its components;

(44) "production casing" means the casing installed from the wellhead to the top of or through the completion interval and cemented in place to seal off production or injection zones and water bearing formations;

(45) "property" means a legally described tract of land, submerged or otherwise, to which a person has the right to drill, extract, remove, clean, process, and dispose of oil, gas, and associated substances;

(46) "purge gas" means gas used to maintain forward flow and positive pressure in a safety flare system;

(47) "reservoir" means the same as pool in AS 31.05.170;

(48) "service well" means a well used for injecting water, gas, or other fluids into a reservoir or producing formation in pressure maintenance, enhanced recovery, or storage operations, for disposing of oil field wastes, or for conducting other operations in support of oil or gas production;

(49) "shut in" means to close a well's surface, wellhead, or subsurface valves to halt flow from or into the well, with the completion interval remaining open to the tubing below the closed valves;

(50) "sidetrack operation" means a drilling operation conducted for the purpose of straightening the original hole, bypassing junk, or correcting mechanical difficulties in the original hole;

(51) "stratigraphic test" means a hole drilled for the sole purpose of gaining structural or stratigraphic information to aid in exploring for oil and gas;

(52) "structural casing" means a short string of large diameter pipe which may be set by driving, jetting, or drilling to support unconsolidated shallow sediments, provide hole stability for initial drilling operations, and provide anchorage for a diverter system;

(53) "surface casing" means a string of casing set and cemented in a well to prevent lost circulation while drilling deeper and to protect strata known or reasonably expected to serve as a source of drinking water for human consumption; usually it is the first string of casing upon which blowout prevention equipment is set;

(54) "suspend" means to plug a well in accordance with 20 AAC 25.110 and with the operator's reserving the option later to re-enter and redrill the well or complete the well as an oil, gas, or service well;

(55) "underbalanced drilling" means drilling under conditions where the hydrostatic head of the drilling fluid column is intentionally designed to be lower than the pressure of the formation being drilled;

(56) "well" means a hole penetrating the earth, usually cased with steel pipe, and from which oil or gas, or both, is obtained or obtainable, or which is made for the purpose of finding or obtaining oil or gas or of supporting oil or gas production; a well may have multiple well branches drilled to different bottom-hole locations;

(57) "well branch" means that portion of a well drilled below the structural or conductor casing to access a separate objective in a well with more than one bottom-hole location. (Eff. ___/___/___, Register ___)

Authority: AS 31.05.030

Editor's note: Before Register ___ (_____19___), the substance of 20 AAC 25.990 was contained in 20 AAC 25.570.

Nov. 1 1998 revisions

CHAPTER 25.
ALASKA OIL AND GAS CONSERVATION COMMISSION

Article

1. Drilling
(20 AAC 25.005-20 AAC 25.080)
2. Abandonment and Plugging
(20 AAC 25.105-20 AAC 25.172)
3. Production Practices
(20 AAC 25.200-20 AAC 25.290[85])
4. Reports
(20 AAC 25.300-20 AAC 25.320)
5. Enhanced Recovery
(20 AAC 25.400-20 AAC 25.460)
6. General Provisions
(20 AAC 25.505-20 AAC 25.570)
7. Definitions
(20 AAC 25.990)

ARTICLE 1.
DRILLING

Section

05. Permit to drill
10. Re-entry of a suspended well
15. Changes to an approved drilling program [PERMIT]
20. Designation of operator
22. Change of ownership
25. Bonding
26. Claims
30. Casing and cementing
33. Primary well control for rotary drilling: drilling fluid program and drilling fluid surface system
35. Secondary well control for rotary drilling: blowout prevention equipment [(BOPE)] and diverter requirements
36. Well control for coiled tubing drilling: blowout prevention equipment and drilling fluid program requirements
40. Well identification
45. (Repealed)
47. Reserve pits and tankage
50. Wellbore surveys [DEVIATION]
55. Drilling units and well spacing
61. Well site surveys

65. Hydrogen sulfide
66. Gas detection
70. Records and reports
71. Geologic data and logs
72. Shutdown of drilling or completion [WELL] operations
75. Other wells in designated areas
80. Annular disposal of drilling waste

20 AAC 25.005 is repealed and readopted to read:

20 AAC 25.005. PERMIT TO DRILL. (a) Before drilling or redrilling a well or re-entering an abandoned well, a person shall submit and obtain the commission's approval of an application for a Permit to Drill (Form 10-401).

(b) The commission will classify a well as:

(1) exploratory;

(2) development, either oil or gas;

(3) service; or

(4) stratigraphic test.

(c) An application for a Permit to Drill must be accompanied by the following unless already on file with the commission and identified in the application:

(1) a fee of $100 payable to the State of Alaska, Department of Revenue;

(2) a plat identifying the property and showing

(A) the coordinates of the proposed location of the well at the surface, at the top of each objective formation, and at total depth, referenced to governmental section lines;

(B) the proposed depth of the well at the top of each objective formation and at total depth; and

(C) other information required by 20 AAC 25.050.

(3) a diagram and description of the blowout prevention equipment (BOPE) as required by 20 AAC 25.035 or 20 AAC 25.036, as applicable;

(4) information on drilling hazards, including

(A) the maximum downhole pressure that may be encountered, criteria used to determine it, and maximum potential surface pressure based on a methane gradient;

(B) data on potential gas zones; and

(C) data concerning hole problems such as over-pressured zones, lost circulation zones, and zones that have a propensity for differential sticking;

(5) a complete proposed casing and cementing program as required by 20 AAC 25.030;

(6) a diagram and description of the diverter system as required by 20 AAC 25.035, unless this requirement is waived by the commission;

(7) a drilling fluid program, including a diagram and description of the drilling fluid system, as required by 20 AAC 25.033 or 20 AAC 25.036, as applicable;

(8) for an exploratory or stratigraphic test well, a tabulation setting out the depths of predicted abnormally geo-pressured strata as required by 20 AAC 25.033(e);

(9) for an exploratory or stratigraphic test well, a seismic refraction or reflection analysis as required by 20 AAC 25.061(a);

(10) for a well drilled from an offshore platform, mobile bottom-founded structure, jack-up rig, or floating drilling vessel, an analysis of seabed conditions as required by 20 AAC 25.061(b);

(11) evidence showing that the requirements of 20 AAC 25.025 have been met;

(12) a copy of the proposed drilling program; and

(13) a general description of how the operator plans to dispose of drilling mud and cuttings and a statement of whether the operator intends to request authorization under 20 AAC 25.080 for an annular disposal operation in the well.

(d) For a well that is to be intentionally deviated, the requirements of 20 AAC 25.050(b) must be met.

(e) A well may have multiple well branches ~~active at one time~~, and unless drilled solely to conduct sidetrack operations, each branch requires a separate Permit to Drill. When multiple well branches are proposed from a single conductor, surface, or production casing, the applicant shall designate one branch as the primary wellbore and include all information required under (c) of this section with its corresponding application for a Permit to Drill. For each subsequent well branch, the application for a Permit to Drill need only include information under (c) of this section that is unique to that branch and need not include the $100 fee.

(f) Each well must be identified by a unique name designated by the operator and a unique API number assigned by the commission under 20 AAC 25.040(b). For a well with multiple well branches, each branch must similarly be identified by a unique name and API number by adding a suffix to the name designated for the well by the operator and to the number assigned to the well by the commission.

(g) If drilling operations are not commenced within 24 months after the commission approves an application for a Permit to Drill, the Permit to Drill expires.

(h) A Permit to Drill is not valid at a location where the applicant does not have a right to drill for~~, produce, and remove~~ oil and gas. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25.010 is amended to read:

20 AAC 25.010. RE-ENTRY OF A SUSPENDED WELL. (a) Before re-entering [IF] a suspended well [IS TO BE RE-ENTERED] to conduct completion operations, the operator shall submit and obtain the commission's approval of an [THE FORM ENTITLED] Application for Sundry Approvals (Form 10-403) [FOR COMMISSION APPROVAL]. The Application for Sundry Approvals [FORM 10-403 FILING] must set out the current condition of the well and the proposed program for completion operations.

(b) Before re-entering [IF] a suspended well to conduct [IS TO BE RE-ENTERED TO CONDUCT ACTUAL] drilling operations, the operator shall submit and obtain the commission's approval of an application for a [THE FORM ENTITLED] Permit to Drill (Form 10-401) [FOR COMMISSION APPROVAL] in conformance with 20 AAC 25.005.

(c) The operator shall file with the commission within 30 days after completion, abandonment, or suspension of the well a Well Completion or Recompletion Report and Log (Form 10-407) and all information required by 20 AAC 25.070 (1) and 20 AAC 25.071. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25.015 is repealed and readopted to read:

20 AAC 25.015. CHANGES TO AN APPROVED DRILLING PROGRAM. (a) To change an approved program before drilling operations have started, the operator shall

(1) submit and obtain the commission's approval of a new application for a Permit to Drill (Form 10-401) if the surface location is changed, if the bottom-hole location or the location of an objective formation is changed by more than 500 feet laterally or vertically, or if the change requires a spacing exception under 20 AAC 25.055; however, no additional fee is required;

(2) otherwise notify the commission and obtain its approval of the change if the change is not covered by (1) of this subsection.

(b) To change an approved drilling program or to change information under 20 AAC 25.005(c) after drilling operations have started, the operator shall

(1) submit and obtain the commission's approval of a new application for a Permit to Drill (Form 10-401), accompanied by a fee of $100, if the bottom-hole location or the location of an objective formation is changed by more than 500 feet laterally or vertically, or if the change requires a spacing exception under 20 AAC 25.055;

(2) submit and obtain the commission's approval of an Application for Sundry Approvals (Form 10-403) if the change is not covered by (1) of this subsection; the Application for Sundry Approvals must set out the approved program, the current condition of the well, and the proposed changes; in cases where prompt approval is needed, oral approval may be requested from the commission; if oral approval is obtained, the name of the representative of the commission who provided oral approval and the date of the approval must be included on the Application for Sundry Approvals and submitted within the commission's next three working days. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.090

20 AAC 25.020 is amended to read:

20 AAC 25.020. DESIGNATION OF OPERATOR. If an owner of a property wishes to ~~relinquish the role of operator, or~~[RELINQUISH THE ROLE OF OPERATOR, OR] designate a new operator for the property, the owner shall submit to the commission for approval a Designation of Operator (Form 10-411). The newly designated operator shall [MUST] signify acceptance of the obligations as operator on the same Designation of Operator form [FORM 10-411] and shall [MUST] furnish a bond and, if required, security as provided for in 20 AAC 25.025. The commission's acceptance of the designated operator's bond constitutes the release of the [OWNER'S OR] former operator's bonding obligation for the property indicated on the Form ~~10~~ 10-411. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register__)

Authority: AS 31.05.030

20 AAC 25.022 is amended to read:

20 AAC 25.022. CHANGE OF OWNERSHIP. Whenever a person becomes an owner [A PERSON WHO IS THE OPERATOR] of a property on which operations subject to this chapter are [HAVE BEEN] proposed to the commission or are being conducted, the person shall file a Notice of Change of Ownership (Form 10-417) within 15 days after conveyance[, EACH TIME THAT AN OWNER OR LANDOWNER, AS DEFINED BY AS 31.05.170, CONVEYS ALL OR A PARTIAL INTEREST IN THE PROPERTY TO ANOTHER PERSON]. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.025 is repealed and readopted to read:

20 AAC 25.025. BONDING. (a) An operator proposing to drill a well for which a permit is required under 20 AAC 25.005 shall file a bond and, if required under (2) of this subsection, security to ensure that each well is drilled, operated, maintained, repaired, and abandoned in accordance with this chapter. The bond must be

(1) a surety bond issued on Form 10-402A in favor of the Alaska Oil and Gas Conservation Commission by an authorized insurer under AS 29 whose certificate of authority is in good standing; or

(2) a personal bond of the operator on Form 10-402B accompanied by and whose performance is guaranteed by security in the form of a certificate of deposit or irrevocable letter of credit issued in the sole favor of the Alaska Oil and Gas Conservation Commission by a bank authorized to do business in the state, or, in the commission's discretion, another form of security that the commission determines to be adequate.

(b) A bond and, if required, security must be in the amount of not less than $100,000 to cover a single well or not less than $200,000 for a blanket bond covering all of the operator's wells in the state, except that the commission will, in its discretion, allow an amount less than $100,000 to cover a single well if the operator demonstrates in the application for a Permit to Drill (Form 10-401) that the cost of well abandonment will be less than $100,000.

(c) A bond and, if required, security must remain in effect until the abandonment of all wells covered by them and final clearance of well sites are approved by the commission. The commission will then release the bond and security upon written request of the operator.

(d) Payment under a surety bond or security does not relieve an operator from any obligations under this chapter except to the extent that a default is actually cured, or from any

liability under AS 31.05.150. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.150

20 AAC 25.026 is amended to read:

20 AAC 25.026. CLAIMS. Commission approval of the abandonment of a well and the release of the bond[,] required by 20 AAC 25.025 [SEC. 25 OF THIS CHAPTER,] constitutes a presumption of proper abandonment, but does not relieve an operator of further claim by the commission after the abandonment. (Eff. 4/13/80, Register 74; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.030 is repealed and readopted to read:

20 AAC 25.030. CASING AND CEMENTING. (a) A complete proposed well casing and cementing program must be submitted with an application for a Permit to Drill (Form 10-401). Unless modified or altered by special pool rules, a well casing and cementing program must be designed to

(1) provide suitable and safe operating conditions for the total measured depth proposed;

(2) confine fluids to the wellbore;

(3) prevent migration of fluids from one stratum to another;

(4) ensure control of well pressures encountered;

(5) protect against thaw subsidence and freezeback effects within permafrost;

(6) prevent contamination of freshwater;

(7) protect significant hydrocarbon zones; and

(8) provide well control until the next casing is set, considering all factors relevant to well control including formation fracture gradients, formation pressures, casing setting depths, and proposed total depth.

(b) General well casing and cementing provisions are as follows:

(1) casing design and setting depth must be based on engineering and geologic factors relevant to the immediate vicinity, including the presence or absence of hydrocarbons, potential geohazards, and permafrost;

(2) for all casing strings on which blowout prevention equipment will be installed, cement m~~ust~~ay not be drilled out until sufficient compressive strength has been reached ~~in order~~ to obtain a valid formation integrity test;

(3) within permafrost intervals, fluids that have a freezing point above the minimum permafrost temperature m~~ust~~ay not be left in casing-by-casing annuli or inside the casing upon completion, suspension, or shutdown of well operations, without commission approval;

(4) when casing is subjected to prolonged drilling operations, the commission will, in its discretion, require the casing to be pressure-tested, calipered, or otherwise evaluated by a method approved by the commission;

(5) where zonal coverage is required, and the commission believes zonal isolation m~~ay~~ight not have been established, the commission will, in its discretion, require a cement quality log or other method to demonstrate isolation of the zone.

(c) Specific well casing provisions are as follows:

(1) structural casing must be set by driving, jetting, or drilling to a minimum depth of 70 feet in all offshore wells to support unconsolidated shallow strata, to provide hole stability for initial drilling operations, and to provide a competent anchor for a diverter system;

(2) for onshore wells, conductor casing must be set by driving, jetting, or drilling to a depth sufficient to provide anchorage for a diverter system, and for offshore wells, conductor casing must be set no less than 300 feet and no more than 1000 feet below the mudline datum; except that the commission will, in its discretion,

(A) approve a different casing setting depth when necessary to permit the casing shoe to be set in a competent formation or below formations that should be isolated; or

(B) authorize an operator to drill without setting conductor casing based upon information from wells drilled in the immediate vicinity and other available data;

(3) surface casing must be set below the base of all ~~water bearing~~ strata known or reasonably expected to ~~contain freshwater~~serve as a source of drinking water for human consumption and at a depth sufficient to provide a competent anchor for blowout prevention equipment;

(4) one or more intermediate casing strings must be set when required for protection of oil or gas, for protection against abnormally geo-pressured strata and lost circulation zones, or when otherwise required by well conditions;.

(5) production casing must be set and cemented through, into, or just above the production interval;

(6) slotted liners, pre-perforated liners, and screens installed below a production packer are considered as production equipment and not as casing.

(d) Specific well casing cementing provisions are as follows:

(1) if structural casing is set by drilling or jetting, the structural casing must be cemented with a quantity of cement sufficient to fill the annular space from the shoe to the surface;

(2) if conductor casing is set by drilling or jetting, the conductor casing must be cemented by filling the annular space with cement from the shoe to the surface; ~~however, if cement does not circulate to the surface, if an excessive quantity of cement circulates to the surface, or if the formation integrity test shows an inadequate cement job,~~

~~(A) the operator shall notify the commission before drilling ahead; and~~

~~(B)~~ if blowout prevention equipment is to be installed on the conductor casing, the ~~commission will, in its discretion, require~~

~~(i) a cement quality log or other approved method to evaluate the~~ adequacy of the cement to contain potential wellbore pressures and fluids~~; and~~ must be demonstrated by a ~~(ii) remedial action before drilling ahead~~formation integrity test;

(3) upon approval of the commission, conductor casing cement may be washed out to a depth not exceeding the depth of the structural casing shoe, if installed;

(4) surface casing must be cemented by filling the annular space with cement from the shoe to the surface; however, if cement does not circulate to the surface, if an excessive quantity of cement circulates to the surface, or if the formation integrity test shows an inadequate cement job,

(A) the operator shall notify the commission before drilling ahead; and

(B) the commission will, in its discretion, require

(i) a cement quality log or other approved method to evaluate the adequacy of the cement to contain potential wellbore pressures and fluids; and

(ii) remedial action before drilling ahead;

(5) intermediate and production casing must be cemented with sufficient cement to fill the annular space from the casing shoe to a minimum of 500 feet above all significant hydrocarbon zones and abnormally geo-pressured strata or, where zonal coverage is not required, from the casing shoe to a minimum of 500 feet above the casing shoe; if there are indications of improper cementing, such as lost returns, cement channeling, or mechanical failure of equipment, or if the formation integrity test shows an inadequate cement job, remedial action must be taken;

(6) in cases where the intermediate or production string is a liner, a minimum of 100 feet overlap between the outer and inner strings is required; the interval of overlap must be made pressure competent and must be pressure-tested in accordance with (e) of this section;

(7) for intermediate or production casing in a service well used for injection, a cement quality log or other evaluation log approved by the commission must be run to demonstrate isolation of the injected fluids to the approved interval; a minimum of 24 hours notice of the logging operation must be provided so that a representative of the commission ~~may~~can witness it.

(e) A casing pressure test must be performed if blowout prevention equipment will be installed on a casing. The casing must be tested to a surface pressure equal to 50 percent of the required working pressure of the blowout prevention equipment as specified in the Permit to Drill (Form 10-401). The test pressure must show stabilizing pressure and may not decline more

than 10 percent in 30 minutes. The results of this test and any subsequent tests of the casing must be recorded as required by 20 AAC 25.070(1).

(f) A formation integrity test must be performed if blowout prevention equipment is installed on a casing. The test must be performed to a predetermined equivalent mud weight, leak-off, or a fracture pressure as specified in the well plan. The test must be conducted after drilling out of the casing shoe into at least 20 feet but not more than 50 feet of new formation. The test results must demonstrate that the integrity of the casing shoe is sufficient to contain anticipated wellbore pressures identified in the well plan. The results of this test and any subsequent tests of the formation must be recorded as required by 20 AAC 25.070(1).

(g) Upon request of the operator, the commission will, in its discretion, approve variances from the requirements of (b) - (f) of this section to allow for special or unusual conditions as long as the design requirements of (a) of this section are not diminished. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.033 is repealed and readopted to read:

20 AAC 25.033. PRIMARY WELL CONTROL FOR ROTARY DRILLING: DRILLING FLUID PROGRAM AND DRILLING FLUID SURFACE SYSTEM. (a) For rotary drilling, a proposed drilling fluid program and a diagram with a list of equipment for a drilling fluid system designed to prevent the loss of primary well control must be submitted with an application for a Permit to Drill (Form 10-401). A drilling fluid program and drilling fluid system for rotary drilling must be designed to provide and maintain

(1) a drilling fluid of sufficient density to overbalance the pressure of uncased formations penetrated and compensate for hydrostatic pressure reduction upon withdrawal of the drilling assembly from the wellbore;

(2) a drilling fluid with ~~as low a gel strength as practicable~~rheological properties designed to minimize the potential of a hydrostatic pressure surge when the drilling assembly is run into the wellbore;

(3) a drilling fluid with ~~as low a viscosity as practicable~~rheological properties designed to enhance the drop-out of solids and the escape of any entrained gas;

(4) a drilling fluid system with a volumetric capacity for drilling fluid reserves adequate for the volume of the wellbore.

(b) A drilling fluid system for rotary drilling must be equipped with

(1) an operable degasser to be maintained for use through the drilling and completion of the well;

(2) equipment appropriate for drilling fluid solids control;

(3) a recording drilling fluid pit level indicator with both visual and audio warning devices located in the immediate area of the driller's console;

(4) a drilling fluid measuring system or trip tank for accurately determining drilling fluid volumes required to fill the wellbore on trips;

(5) a drilling fluid flow sensor with a readout convenient to the driller's console to enable the operator to determine whether drilling fluid returns equal drilling fluid pump discharge rates;

(6) drilling fluid agitators of sufficient number and size to ensure that uniform drilling fluid properties are maintained within the system; and

(7) methane and hydrogen sulfide detection equipment as required by 20 AAC 25.066.

(c) Drilling fluid testing equipment for rotary drilling must be on the drill site at all times. Tests to determine drilling fluid density and viscosity must be performed once each tour, or more frequently when conditions warrant. Tests must be conducted in conformance with API RP 13B-1, *Recommended Practice for Standard Procedure for Field Testing Water-Based Drilling Fluids* (September 1997), and API RP 13B-2, *Recommended Practice for Standard Procedure for Field Testing Oil-Based Drilling Fluids* (September 1991), which are adopted by reference, and recorded as required by 20 AAC 25.070(1).

(d) To ensure that primary well control is effectively maintained, the following practices must be employed in rotary drilling before tripping the drilling assembly out of the wellbore:

(1) the drilling fluid within the wellbore must be in balance and conditioned to maintain drilling fluid properties within close tolerance to the properties necessary for well control;

(2) the flow nipple or trip tank must be visually observed to ensure that there is no indication of formation fluid influx;

(3) the wellbore must be kept full of drilling fluid at all times;

(4) the volume of drilling fluid required to keep the wellbore full while tripping the drilling assembly out of the wellbore must be measured and recorded on the daily drilling report or trip sheet.

(e) Additional requirements that apply to exploratory and stratigraphic test wells drilled by rotary drilling are as follows:

(1) the operator shall include with an application for a Permit to Drill (Form 10-401) a tabulation that sets out the depths of predicted abnormally geo-pressured strata;

(2) if the operator has geophysical data from the area, a seismic velocity analysis constrained by germane well control data must be performed to predict the potential of encountering abnormally geo-pressured strata, with the analysis displayed by plotting interval transit time versus depth; the commission will, in its discretion, require a confidential review of the velocity analysis and the plot of interval transit time versus depth;

(3) if the operator does not have geophysical data from the area, an analysis of germane well control data must be performed to predict the potential of encountering abnormally geo-pressured strata;

(4) a drilling fluid monitoring unit must be used and continuously observed during drilling operations, including tripping, to monitor and record

(A) gas entrained in the drilling fluid;

(B) drilling fluid density;

(C) drilling fluid salinity;

(D) the rate of penetration; and

(E) hydrogen sulfide, as required by 20 AAC 25.065;

(5) means for communication between the drilling fluid monitoring unit and the drill rig floor must be installed and maintained in working condition while open hole operations are taking place, and drill rig floor personnel must be notified immediately when excursions from normal trends occur for each of the parameters set out in (4) of this subsection.

(f) A drilling fluid return sample must be taken and tested to determine density just before tripping the drill pipe, when drilling an exploratory or stratigraphic test well by rotary drilling, or

when drilling a development or service well by rotary drilling while known hydrocarbon-bearing strata are exposed to open hole. Density test results must be recorded as required by 20 AAC 25.070(1). If the density is less than that of the drilling fluid being pumped down the drilling assembly, the drilling fluid must be circulated and conditioned until a close tolerance of the properties of the return drilling fluid with the input drilling fluid is achieved.

(g) If formation competency at the structural casing setting depth is not adequate to permit circulation of drilling fluids while drilling the conductor hole, a program that provides for safety in that drilling operation must be described and submitted to the commission for approval. This program must be supported by pertinent information including seismic and geologic data, water depth, drilling fluid hydrostatic pressure, and a contingency plan for moving off location.

(h) The commission will, in its discretion, approve underbalanced drilling operations and associated equipment changes. A request for underbalanced drilling must include a description of all equipment and procedures to ensure proper containment of formation and return fluids.

(i) Upon request by the operator, the commission will, in its discretion, approve a waiver of the requirements of (b) - (f) of this section if the alternative drilling fluid program and drilling fluid system meet the design criteria of (a) of this section and the corresponding equipment and procedures are at least equally effective in preventing the loss of primary well control. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: Copies of the American Petroleum Institute recommended practices referred to in this section may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

20 AAC 25.035 is repealed and readopted to read:

20 AAC 25.035. SECONDARY WELL CONTROL FOR ROTARY DRILLING: BLOWOUT PREVENTION EQUIPMENT AND DIVERTER REQUIREMENTS. (a) An application for a Permit to Drill (Form 10-401) relating to rotary drilling operations must include the following information or refer to that information if on file with the commission:

(1) a diagram of the blowout preventer (BOP) stack or diverter and related equipment for each proposed casing installation; and

(2) a list of the blowout prevention equipment (BOPE) and diverter equipment with specifications.

(b) Except as provided in (c) of this section, a high capacity flow diverter system must be installed to provide safety for personnel and equipment before rotary drilling is performed below a well's structural or conductor casing, unless the casing is equipped with BOPE conforming with (d) of this section. The following provisions apply to a diverter system:

(1) the diverter system must consist of a remotely operated annular pack-off device, a full-opening vent line valve, and, except as provided under (3) of this subsection, a 16-inch minimum diameter diverter vent line, assembled as follows:

(A) the diverter vent line outlet must be located below the annular pack-off, either as an integral part of the annular pack-off device or as a vent-line outlet spool immediately below it;

(B) to prevent closing in the well, the actuating mechanism for the vent line valve must be integrated with the actuating mechanism for the annular pack-off device in

a fail-safe manner so that the vent line valve will automatically open simultaneously with closure of the annular pack-off;

(C) the vent line must extend to a point at least 75 feet removed from a potential source of ignition and at least 75 feet beyond the drill rig substructure or to the reserve pit, but in no case fewer than 50 feet from the drill rig substructure;

(D) the vent line must be as straight as possible, secured to prevent movement, and designed to avoid freezeup;

(E) the vent line may be secured to the rig and with portable cradle supports, but may not be attached to flowlines, cable trays, or other processing equipment;

(F) all turns with a bend radius less than 20 times the inside diameter of the vent line must be targeted;

(G) all valves must be full-opening;

(H) if a bifurcated vent line is used for downwind venting, a fail-safe valve or deflection device must be installed so that one of the bifurcated sections remains open at all times;

(2) a clearly marked "warning zone" must be established on each side and ahead of the vent line tip, and the following restrictions must be in effect within the warning zone, beginning with the function test of the diverter system immediately before drilling operations begin and ending with diverter system rig-down:

(A) no vehicle parking;

(B) no ignition sources or running equipment;

(C) no staged equipment or materials;

(D) essential foot or vehicle traffic only;

(3) when drilling is performed from a drill rig that is active upon the effective date of this paragraph and has not been stacked after the effective date of this paragraph, the diverter line must be a minimum of 10 inches in diameter and, if less than 16 inches in diameter, must bifurcate in directions that ensure safe downwind venting, with each bifurcated section extending to a point at least 75 feet removed from a potential source of ignition;

(4) the diverter system must conform, at a minimum, to API RP 64, *Recommended Practices for Diverter Systems Equipment and Operations* (July 1991), which is adopted by reference;

(5) the diverter system will, in the commission's discretion, be inspected by the commission for compliance with the requirements of this subsection and tested to ensure proper operation.

(c) If the formation competence at the structural casing setting depth is not adequate to permit use of a diverter system while drilling the conductor hole, a program that provides for safety in that drilling operation must be described and submitted to the commission for approval. This program must be supported by pertinent information including seismic and geologic data, water depth, drilling fluid hydrostatic pressure, and a contingency plan for moving off location.

(d) A well drilled or completed with a rotary drilling rig must be equipped with BOPE meeting the requirements of this subsection from the time that drilling is begun below a surface, intermediate, or production casing until the drilled portion has been cased and the casing cemented in place, and from the time a casing is perforated until the well has been completed, suspended, or abandoned. The following provisions apply to BOPE:

(1) API 2M and 3M stacks must have at least three preventers, including

(A) one equipped with pipe rams that fit the size of drill pipe, tubing, or casing being used, except for bottom-hole assemblies and drill collars;

(B) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(C) one annular type;

(2) API 5M, 10M, and 15M stacks must have at least four preventers, including

(A) two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing being used, except for bottom-hole assemblies and drill collars;

(B) one with blind rams, except that a subsea BOPE assembly must have blind/shear rams in place of blind rams; and

(C) one annular type;

(3) the required working pressure of the BOPE must exceed the anticipated surface pressure to which it may be subjected, except that the working pressure of the annular preventer need not exceed 5000 psi unless a higher working pressure is required by the commission; if the anticipated surface pressure exceeds the rated working pressure of the annular preventer, the operator shall submit with the application for a Permit to Drill a well-control procedure that indicates how the annular preventer will be used and what pressure limitations will be applied during each mode of pressure control;

(4) a BOPE assembly must include

(A) a hydraulic actuating system with sufficient accumulator capacity to supply 150 percent of the volume necessary to close all BOPs, except blind rams, and to open the remotely controlled hydraulic valve while maintaining a minimum pressure of

200 psi above the required precharge pressure when all BOPs, except blind rams, are closed and all power sources are shut off;

(B) an accumulator powered by at least two independent sources of power and an accumulator backup system supplied by an independent nitrogen source having sufficient capacity to close all BOPs and to hold them closed;

(C) locking devices on the ram-type preventers;

(D) a fire wall to shield accumulators and primary controls;

(E) one operable remote BOPE control station on the drilling floor;

(F) a kill line and a choke line each connected to a flanged or hubbed outlet on a drilling spool or on the BOP body with two full-opening valves on each outlet, conforming to the following specifications:

(i) the outlets must be at least two inches in nominal inside diameter, except that if the BOP is rated greater than API 2M the nominal inside diameter of the choke outlet must be at least three inches;

(ii) each valve must be sized at least equal to the outlet to which it is attached;

(iii) the outer valve on the choke side must be a remotely controlled hydraulic valve;

(iv) the inner manual valve on both the choke and kill sides may not normally be used for opening or closing on flowing fluid;

(G) a fill-up line above the uppermost BOP; and

(H) a choke manifold equipped with

(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's console if the BOPE is rated 5,000 psig or greater;

(ii) a line at least two inches in nominal inside diameter downstream of each choke;

(iii) two full-opening valves immediately upstream of each choke; and

(iv) a bypass line at least two inches in nominal inside diameter with two full-opening valves;

(5) the working pressure rating of the wellhead assembly and of all valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must equal or exceed the required working pressure of the BOPE specified in the approved Permit to Drill, except that lines downstream of the choke may be rated to 50 percent of the required working pressure of the BOPE;

(6) kill and choke lines must

(A) be constructed of rigid pipe or fire-resistant rotary hose;

(B) be as straight as practical;

(C) if constructed of rigid pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(D) be anchored to prevent excessive whip or vibration;

(E) be sized to prevent excessive erosion or fluid friction;

(F) be assembled without hammer unions or internally clamped (i.e., swivel or chicksan) joints, unless such joints are specifically approved by the commission;

(7) connections to the wellhead, tree, and BOPE must be flanged or hubbed;

(8) auxiliary well control equipment must include

(A) a kelly cock valve installed below the swivel and a full-opening lower kelly valve of a design that allows it to be run through BOPs installed at the bottom of the kelly, with a properly sized wrench for each valve stored in a conspicuous location readily accessible to the drilling crew; and

(B) an inside BOP and a full-opening drilling assembly safety valve in the open position on the drill rig floor to fit all connections that are in the drilling assembly;

(9) all equipment must be in good operating condition at all times and must be protected to ensure reliable operation under the range of weather conditions that may be encountered at the well site;

(10) blind rams must be function-tested each trip but need not be function-tested more than once each day, and all BOPs other than blind rams must be function-tested each day; test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(11) the BOPE must be pressure-tested as follows:

(A) when the BOPE is installed or changed, and at least once each week thereafter, ram-type BOPs, kelly valves, emergency valves, and choke manifolds must be tested to the required working pressure of the BOPE specified in the approved Permit to Drill, and annular preventers must be tested to not less than 50 percent of the required working pressure; test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(B) to ensure that minimum standards are achieved, the operator shall perform the recommended tests for BOP closing units specified in sections 5A and 5B of

API RP 53, *Recommended Practices for Blowout Prevention Systems* (March 1997), which are adopted by reference;

(C) a minimum of 24 hours notice of each pressure test must be provided so that a representative of the commission can witness the test;

(12) the BOP and related well control equipment must be installed, used, maintained, and tested in a manner that ensures well control and, at a minimum, conforms with API RP 53, *Recommended Practices for Blowout Prevention Systems* (March 1997), which is adopted by reference.

(e) The commission will, in its discretion, require, in consultation with the drilling foreman, drills simulating well control problems. Drills will, in the commission's discretion, include any combination of raising or lowering the pit level indicator, advancing or retarding the flow rate indicator, or actuating the gas detectors.

(f) The operator shall post on a drill rig a copy of the approved Permit to Drill, including the drilling hazard section required by 20 AAC 25.005(c)(4), and a copy of the standing orders specifying well control procedures.

(g) The toolpushers, drillers, and person(s)-in-charge on a drill rig floor must be trained in accordance with the training standards contained in 30 C.F.R. 250.~~210 - 250.215 (revised as of July 1, 1996)~~1500 - 250.1524 (Subpart O), revised as of July 1, 1998.

(h) The person(s)-in-charge on a drill rig floor must have the authority and responsibility to shut in the well if it starts to flow.

(i) Upon request of the operator, the commission will, in its discretion, approve a variance

(1) from the BOPE requirements of this section if the variance provides at least equally effective means of well control; and

(2) from the diverter system requirements of this section if the variance provides at least equally effective means of diverting flow away from the drill rig or if drilling experience in the near vicinity indicates that a diverter system is not necessary. (Eff. 4/13/80, Register 74; am 2/22/81, Register 77; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: Copies of the American Petroleum Institute recommended practices referred to in this section may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.036. WELL CONTROL FOR COILED TUBING DRILLING: BLOWOUT PREVENTION EQUIPMENT AND DRILLING FLUID PROGRAM REQUIREMENTS. (a) An application for a Permit to Drill (Form 10-401) relating to coiled tubing drilling operations must include the following information or refer to that information if on file with the commission:

(1) a diagram of each blowout preventer (BOP) stack and related equipment to be used; and

(2) a list of the blowout prevention equipment (BOPE) with specifications.

(b) A well drilled or completed with a coiled tubing drilling rig must be equipped with BOPE meeting the requirements of this subsection from the time that drilling is begun below or through a surface, intermediate, or production casing until the drilled portion has been cased and the casing cemented in place, and from the time a casing is perforated until the well has been

completed, suspended, or abandoned. The following provisions apply to BOPE:

(1) the required working pressure of the BOPE must exceed the anticipated surface pressure to which it may be subjected;

(2) well control equipment must include at least one positive seal manual valve, hydraulic valve, or blind ram flanged to the well head; a high pressure pack-off and lubricator; and hydraulic rams providing blind, shear, slip, and pipe ram capabilities;

(3) a BOPE assembly must include

(A) a hydraulic actuating system with

(i) a single accumulator and a manual hydraulic supply to serve as a backup system; or

(ii) multiple accumulators with a combined capacity greater than 11 gallons and designed so that the failure of a single accumulator does not reduce the total accumulator system capacity by more than 50 percent;

(B) locking devices on the ram-type preventers;

(C) one complete set of operable remote BOPE controls on or near the driller's console and a second annular preventer closing control located on the drilling platform floor;

(D) a kill line and a choke line each connected to

(i) a flanged or hubbed outlet on a drilling spool or on the BOP body with two-full opening valves on each outlet, all of which outlets and valves must be at least two inches in nominal inside diameter and the outer of which valves on the choke side must be a remotely controlled hydraulic valve; or

(ii) two full-opening flanged or hubbed wing valves or companion

valves on the wellhead, which valves must be at least two inches in nominal inside diamter and must meet the required working pressure specified in the Permit to Drill, and the outer of which valves on the choke side must be a remotely controlled hydraulic valve;

(E) an annular preventer for open hole deployment, unless the lubricator is of sufficient length to enclose the entire bottom hole assembly (BHA) below the high pressure pack-off;

(F) a lubricator sized to the BHA for staged pressure deployment; and

(G) a choke manifold equipped with

(i) two or more adjustable chokes, one of which must be hydraulic and remotely controlled from near the driller's console except when drilling is conducted below a production packer in a previously completed zone with a closed pressure drilling system;

(ii) a line at least two inches in nominal inside diameter downstream of each choke;

(iii) two full-opening valves immediately upstream of each choke; and

(iv) a bypass line at least two inches in nominal inside diameter with two full-opening valves;

(4) the working pressure rating of the wellhead assembly and of all valves, pipes, rotary hoses, and other fittings, including all sections of the choke manifold that are subject to full wellhead pressure, must equal or exceed the required working pressure of the BOP specified in the approved Permit to Drill, except that lines downstream of the choke may be rated to 50 percent of the required working pressure of the BOP;

(5) the BOP stack and, if used, the drilling spool must be flanged to the wellhead or tree, and other connections to the BOP must be flanged or hubbed;

(6) kill and choke lines must

(A) be constructed of rigid pipe or fire-resistant rotary hose;

(B) be as straight as practical;

(C) if constructed of rigid pipe, use targeted turns where the bend radius is less than 20 times the inside diameter of the pipe;

(D) be anchored to prevent excessive whip or vibration;

(E) be sized to prevent excessive erosion or fluid friction;

(F) be assembled without hammer unions or internally clamped (i.e., swivel or chicksan) joints, except that hammer unions or internally clamped joints may be used on the kill line upstream of the valves;

(7) the BOP and related well control equipment must be installed, used, maintained, and tested in a manner that ensures well control and, at a minimum, conforms with API RP 5C7, *Recommended Practices for Coiled Tubing Operations in Oil and Gas Well Services* (December 1996), which is adopted by reference.

(c) BOPE must be tested as follows:

(1) the BOP stack, valves, and related equipment must be pressure-tested before initial wellbore entry, each time the BOP stack is modified, and at least weekly;

(2) the BOPs must be function-tested after any action that disconnects the hydraulic system lines from the BOPs and at least once each day except when the coiled tubing is continuously in the well or the BHA does not clear the BOP, in which case function-testing must be performed as soon as possible thereafter;

(3) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(4) a minimum of 24 hours notice of each BOPE pressure test must be provided so that a representative of the commission can witness the test.

(d) A well drilled with a coiled tubing drilling rig must be equipped with a drilling fluid system, unless the Commission determines, in its discretion, that a drilling fluid system is not necessary for primary well control. A drilling fluid system used for primary well control must

(1) have a volumetric capacity for drilling fluid reserves appropriate for the volume of the wellbore; and

(2) include degassers, solids removal equipment, agitators and mixers, mud balance and funnel, and other equipment that is necessary to keep the drilling mud conditioned as specified in the Permit to Drill and that is appropriate for the drilling operations being conducted.

(e) All equipment must be in good operating condition at all times and must be protected to ensure reliable operation under the range of weather conditions that may be encountered at the well site.

(f) The operator shall post in the operator's cab a copy of the approved Permit to Drill, including the drilling hazard section required by 20 AAC 25.005(c)(4), and a copy of the standing orders specifying well control procedures. When a sub-structure is used, the operator shall post a second set of standing orders on the drilling platform floor.

(g) Upon request of the operator, the commission will, in its discretion, approve a variance from the BOPE requirements of this section if the variance provides at least equally effective means of well control. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in this section may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

20 AAC 25.040 (a) and (b) are amended to read:

20 AAC 25.040. WELL IDENTIFICATION. (a) Every well must be identified by a sign posted in a conspicuous place. During the period of time from commencement of drilling operations [SPUD] to well completion, suspension, or abandonment, the sign must be on or near the drill rig [DERRICK], but not more than 100 feet from the well. After well completion or suspension [FOR SUSPENDED OR PRODUCIBLE WELLS], the well sign must be at the wellhead or on the wellhead building. The sign must be of durable construction, large enough to be legible under normal conditions at a distance of 50 feet, and maintained in legible condition. Each sign must show the

(1) name designated by the operator under 20 AAC 25.005(f) for [OF] the well drilled from the surface location;

(2) name of the owner;

(3) name of the operator if different from the owner;

(4) API [WELL] number;

(5) well surface location by quarter section, section, township and range; and

(6) Permit to Drill [DRILLING PERMIT] number or numbers during the period of time from commencement of drilling operations [SPUD] to well completion, suspension, or abandonment.

(b) The commission will assign a Permit to Drill number and an API number [EACH WELL WILL BE ASSIGNED AN API WELL NUMBER BY THE COMMISSION] when a Permit to Drill (Form 10-401) [THE DRILLING PERMIT] is approved.

. . .

Note to publisher: subsection (c) is unchanged.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.047 is amended to read:

20 AAC 25.047. RESERVE PITS AND TANKAGE. (a) Before a person commences drilling [SPUDDING] a well [PERMITTED UNDER 20 AAC 25.005], a [PROPER AND APPROPRIATE] reserve pit must be constructed[,] or [APPROPRIATE] tankage installed for the reception and confinement of drilling fluids and cuttings, to facilitate the safety of the drilling operation, and to prevent contamination of freshwater [GROUND WATER] and damage to the surface environment. The confining surfaces of the reserve pit must be impervious. [SPECIAL PRECAUTIONS MUST BE TAKEN TO RENDER IMPERVIOUS THE CONFINING SURFACE OF A RESERVE PIT.] If practical, confinement diking in construction of a reserve pit must be avoided. If confinement dikes are necessary, they must be kept to a minimum. Dikes must be constructed and maintained to ensure [INSURE] their confinement integrity.

(b) Upon [TERMINATION OF] completion, suspension, or abandonment of the well [OPERATIONS], the operator shall proceed with diligence to [DISPOSE OF OR SOLIDIFY IN PLACE ALL PUMPABLE FLUIDS, AND SHALL] leave the reserve pit in a condition that does

not constitute a hazard to freshwater [GROUND WATER]. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.050 is repealed and readopted to read:

20 AAC 25.050. WELLBORE SURVEYS. (a) A well that is not intentionally deviated must be

(1) drilled as close to vertical as is possible using conventional drilling techniques, except that deviation is permitted for short intervals to straighten the hole, sidetrack junk, or correct mechanical difficulties;

(2) surveyed to determine the inclination from vertical with surveys starting at 500 feet and no more than 500 feet apart to total depth; and

(3) surveyed by a complete continuous directional survey if any portion of the well path is less than 500 feet from a property line where the ownership by owner or landowner is not identical on both sides of the line, or if any portion of the well path is less than 200 feet from any other vertical or deviated well; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface.

(b) If a well is to be intentionally deviated, the application for a Permit to Drill (Form 10-401) must

(1) include a plat, drawn to a suitable scale, showing the path of the proposed wellbore, including all adjacent wellbores within 200 feet of any portion of the proposed well; and

(2) list the names of all operators of wells within 200 feet of the proposed wellbore to the extent known or discoverable in public records, and show that each has been furnished a copy of the application by certified mail, or state that the applicant is the only affected owner.

(c) A well that is intentionally deviated must be

(1) directionally surveyed at intervals not more than 500 feet apart on straight or tangent sections of the well during the normal course of drilling, and at intervals not exceeding 100 feet in all portions of the hole where intentional angle changes are performed;

(2) surveyed by a continuous directional survey if any portion of the well path is less than 500 feet from a property line where the ownership by owner or landowner is not identical on both sides of the line; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface; and

(3) surveyed by a continuous directional survey if any deviated portion of the wellbore is less than 200 feet from any other vertical or deviated well; the survey must be taken at intervals not more than 100 feet apart, beginning within 100 feet of the surface.

(d) Within 30 days after the completion, abandonment, or suspension of a well, and within 30 days after completion or plugging of a well branch, a complete copy of each inclination and directional survey not previously filed must be filed with the commission. A composite survey may also be filed if the operator believes this would better represent the well course. If a composite survey is filed, the operator shall specify the portion of each survey used in the composite.

(e) If the final location of the producing interval of a well is not in compliance with 20 AAC 25.055 or other rules of the commission applicable to the reservoir, the operator shall

apply for an exception. The application will be handled in accordance with 20 AAC 25.540. The well may not be produced until the exception is granted.

(f) A wellbore survey report required by (a) or (c) of this section must contain

(1) the name of the surveying company;

(2) the name, title, and signature of the person who actually performed the survey;

(3) the date on which the survey was performed;

(4) the type of survey conducted;

(5) the method used in calculating the survey;

(6) a complete identification of the well showing the name of the well designated by the operator under 20 AAC 25.005(f), the name of the operator, the property name or lease number, the Permit to Drill number, the API number, and the field name;

(7) the depth interval over which the survey was conducted; and

(8) a plat showing the coordinates, referenced to governmental section lines, of the surface location, the plotted well course, and any well(s) within 500 feet of any portion of the wellbore.

(g) The commission will, in its discretion, require submittal of the original film, time sheets, charts, graphs, discs, and other data used to compile the survey required by (a) or (c) of this section.

(h) Upon application, the commission will, in its discretion, waive all or part of the directional survey requirements of this section or approve alternate means for determining the location of a wellbore if the variance at least equally ensures accurate surveying of the wellbore to prevent well intersection, to comply with spacing requirements, and to ensure protection of

correlative rights. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register ___)

Authority: AS 31.05.030

20 AAC 25.055 is repealed and readopted to read:

20 AAC 25.055. DRILLING UNITS AND WELL SPACING. (a) The commission will, in its discretion, establish drilling units to govern well spacing and prescribe a spacing pattern by special pool rules adopted in accordance with 20 AAC 25.520. In the absence of an order by the commission establishing drilling units or prescribing a spacing pattern for a pool, the following statewide spacing requirements apply:

(1) for a well drilling for oil, ~~no portion of the~~a wellbore may be open to test or regular production within 500 feet of a property line ~~where the ownership by owner or landowner is not identical~~only where the owner is the same and the landowner is the same on both sides of the line;

(2) for a well drilling for gas, ~~no portion of the~~a wellbore may be open to test or regular production within 1500 feet of a property line ~~where the ownership by owner or landowner is not identical~~only where the owner is the same and the landowner is the same on both sides of the line;

(3) where oil has been discovered, the drilling unit for the pool is a governmental quarter section; not more than one well may be drilled to and completed in that pool on any governmental quarter section, nor may a well be drilled or completed closer than 1,000 feet to any well drilling to or capable of producing from the same pool;

(4) where gas has been discovered, the drilling unit for the pool is a governmental section; not more than one well may be drilled to and completed in that pool on any governmental section, nor may a well be drilled or completed closer than 3,000 feet to any well drilling to or capable of producing from the same pool.

(b) A well may not begin regular production of oil from a property that is smaller than the governmental quarter section upon which the well is located or begin regular production of gas from a property that is smaller than the governmental section upon which the well is located, unless the interests of the persons owning the drilling rights in and the right to share in the production from the quarter section or section, respectively, have been pooled under AS 31.05.100.

(c) A pooling agreement under AS 31.05.100 must be filed with the commission before regular production from the affected property begins.

(d) An application for an exception to the provisions of this section will be handled in accordance with 20 AAC 25.540. The applicant for an exception shall send notice of the application by certified mail to the owners and operators described below and shall furnish the commission with a copy of the notice, date of mailing, and the addresses to which the notice was sent. The application must include

(1) the names of all owners and operators of all properties within 1000 feet of a well drilling for oil or within 3000 feet of a well drilling for gas for which an exception is required;

(2) a plat drawn to a scale of one inch equaling 2,640 feet or larger, showing the location of the well for which the exception is sought, all other completed and drilling wells on the property, and all adjoining properties and wells; and

(3) a statement by a person acquainted with the facts, verifying that all facts are true and that the plat correctly portrays pertinent and required data.

(e) Upon application by the operator, the commission will, in its discretion, establish notice requirements different from those of (d) of this section if, because of the complexity of ownership within the notice area, a more effective means of providing notice is available. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.100

20 AAC 25.061 is amended to read:

AAC 25.061. WELL SITE SURVEYS. (a) For an exploratory or stratigraphic test well, near [NEAR] surface strata to a depth of 2000 feet in the well site area [FOR ALL EXPLORATORY AND STRATIGRAPHIC TEST WELLS] must be evaluated seismically by common depth point refraction or reflection profile analysis, or by another method approved by the commission, to identify anomalous velocity variations indicative of potential shallow gas sources. Analysis results must be included with the application for the Permit to Drill (Form 10-401).

(b) For a well drilled offshore from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel, the [THE] well site area must be evaluated by sidescan sonar and other pertinent surveys to determine whether potential seabed hazards to drilling operations are present [FOR EACH TYPE OF WELL LISTED IN 20 AAC 25.005 TO BE DRILLED OFFSHORE FROM A MOBILE BOTTOM-FOUNDED, JACK-UP OR FLOATING UNIT]. Survey results must be included with the application for Permit to Drill (Form 10-401).

(c) Upon request by the operator, the commission will, in its discretion, [WILL] waive the requirements of this section if the operator can identify, by other equally effective means, the likelihood of encountering potential shallow gas or seabed hazards or if the commission already has information that substantiates the presence or absence of shallow gas or seabed hazards.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.065(a) and (b) are amended, (c) is repealed and readopted, and (d) is repealed, to read:

20 AAC 25.065. HYDROGEN SULFIDE. (a) When hydrogen sulfide gas is encountered in excess of 20 ppm, the operator shall notify the commission within 24 hours.

(b) If a well is to be drilled in an area where a formation to be penetrated is known to contain hydrogen sulfide gas, or if hydrogen sulfide gas is encountered while drilling, each operator shall meet the requirements of API RP 49, *Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide* (April 1987), which is adopted by reference.

(c) If there is an insufficient history of drilling in an area to know whether hydrogen sulfide gas exists, the commission will specify on the Permit to Drill (Form 10-401) that the operator shall comply with minimum requirements for detection monitoring, contingency and control, and training, as follows:

(1) in addition to the automatic hydrogen sulfide detection system required in 20 AAC 25.066, at least three manual detectors with an adequate supply of extra detector tubes must be available at the drill site;

(2) hydrogen sulfide treating material for the drilling mud must be available on or near the location, in good condition and in sufficient quantity to adequately treat the mud system should hydrogen sulfide be encountered;

(3) detailed emergency operating procedures must be defined and posted to ensure the safety of all personnel should hydrogen sulfide be encountered;

(4) detailed step-by-step remedial procedures must be developed and posted to cover emergencies while drilling or tripping;

(5) personnel protective equipment must be available at the well site;

(6) all persons engaged in drilling operations must be trained for emergency procedures in the presence of hydrogen sulfide gas and in the use of personal protective equipment, alarm systems, and emergency exit procedures.

(d) Repealed ___/___/___. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in this section may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

Note to publisher: italics should be added to title of publication cited in subsection (b).

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.066. GAS DETECTION. (a) All drilling and workover rigs must meet the following minimum requirements for methane and hydrogen sulfide gas detection:

(1) the methane detection system must have a minimum of three sensing points: one under the substructure near the cellar, one above the drill rig floor near the driller's console, and one over the shale shaker; if the mud pits are remote from the shale shaker and enclosed, a fourth sensor must be located over the mud pits;

(2) methane sensors must be placed to detect a "lighter-than-air" gas;

(3) the hydrogen sulfide detection system must have a minimum of three sensing points: one under the substructure near the cellar, one above the drill rig floor near the driller's console, and one near the shale shaker; the commission will, in its discretion, require additional sensors, such as at the entrance to living quarters if they are adjacent to the drill rig, or over the mud pits if they are remote from the shaker and enclosed;

(4) hydrogen sulfide sensors must be placed to detect a "heavier-than-air" gas;

(5) sensors must be automatic, acting independently (i.e., in parallel), and with one-minute minimum sampling intervals;

(6) each detection system must include separate and distinct visual and audible alarms; the visual alarm must signal the low level gas alarm and the audible alarm the high level gas alarm; an audible alarm may have an "acknowledge" button;

(7) the methane low level gas alarm must be set at not over 20% LEL (lower explosive limit); the high level alarm must be set at not over 40% LEL;

(8) the hydrogen sulfide low level gas alarm must be set at 10 ppm (parts per million); the high level alarm must be set at not over 20 ppm;

(9) each alarm must be automatic and must be visible and audible from the driller's console; the hydrogen sulfide alarm must be audible throughout the drilling location, including the camp buildings.

(b) A gas detection system that continuously performs self-checking or diagnostics must be function-tested when a BOP stack is initially installed after a drill rig is set up, when a commission-witnessed BOP test occurs, and no less frequently than once every six months. Other gas detection systems must be calibrated and tested when a BOP stack is initially installed after a drill rig is set up, when a commission-witnessed BOP test occurs, and no less frequently than once every 30 days. The operator shall maintain at the drill rig an accessible record of gas detection system tests and calibrations.

(c) A failure in a gas detection system must be reported to the commission within 24 hours. The commission will, in its discretion, require well operations to be discontinued if a gas detection system fails. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.070 is repealed and readopted to read:

20 AAC 25.070. RECORDS AND REPORTS. The operator of a well shall

(1) keep a detailed accurate daily record of the actual drilling, maintenance, completion, ~~suspension, and abandonment~~and plugging operations, and the tests required by this chapter, which must be available for inspection at reasonable times by the commission

(A) at the well; and

(B) in the state for five years after the date of well abandonment;

(2) file with the commission before well completion or, if the well is not completed, before well abandonment a survey plat certified by a registered land surveyor showing the precise surface location of the well; however, only the first well drilled from a fixed platform or a multiple-well site must have a certified survey; and

(3) file with the commission, within 30 days after completion, abandonment, or suspension of the well and within 30 days after completion or plugging of a well branch, if occurring at a different time, a complete well record on the Well Completion or Recompletion Report and Log (Form 10-407), including a copy of the daily reports of well operations and the tests required by this chapter; in the case of a well with multiple well branches, information pertaining to and filed under this paragraph with respect to a portion of a well need not be re-filed unless changed.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.071(b) is repealed and readopted, and (c) and (d) are amended, to read:

20 AAC 25.071. GEOLOGIC DATA AND LOGS.

. . .

Note to publisher: subsection (a) is unchanged.

(b) Within 30 days after completion, suspension, or abandonment of a well, whichever ~~happen~~occurs first, and within 30 days after completion or plugging of a well branch, if occurring at a different time, the operator shall file with the commission, unless previously filed,

(1) a sepia and a reproduced copy of a complete mud log or a lithology log consisting of a detailed record and description of the sequence of strata encountered, including kind and character of the rock and all shows of hydrocarbons; an electronic image file in a format acceptable to the commission may be substituted for the sepia;

(2) a complete set of washed and dried, legibly identified samples of all drill cuttings, as caught by the operator in accordance with good geological practices, consisting of a

minimum of one-quarter cup in volume or three ounces in weight of cuttings for each sample interval;

(3) a lithologic description and, if available, photographs of all conventional and sidewall cores; conventional core descriptions must include all apparent textural, fluid, and lithological variations, including rock type, porosity, fractures, bedding plane attitudes, sedimentary structure, grain size, and presence of hydrocarbons;

(4) a chip or chips from each foot of recovered conventional core, except that chips need not be submitted until 30 days after the conventional core is analyzed; the chips must be representative of the one-foot interval, and must be approximately either one cubic inch in volume, or two ounces in weight;

(5) a list of the geologic markers encountered ~~in the well~~ and the measured and true vertical depths of each marker;

(6) a sepia and a reproduced copy of all logs run ~~in the well~~ (including common derivative formats such as tadpole plots of dipmeter data and borehole images produced from sonic or resistivity data, and composite log formats), except velocity surveys and experimental logs; an electronic image file in a format acceptable to the commission may be substituted for the sepia;

(7) ~~if available,~~ a tape, diskette, or other electronic media acceptable to the commission and a verification listing of the digital data for all logs run ~~in the well~~, except velocity surveys and experimental logs, and a written description of the logical and physical format of the digital data; and

(8) a copy of all drill stem test and production test data and charts; conventional and sidewall core analysis determinations of porosity, permeability and fluid saturation; and

formation water analyses obtained by the operator; these data must be filed as soon as available if the 30-day filing period cannot be met.

(c) The commission will, in its discretion, waive or modify the requirements of [(a), (b)(1), AND (b)(2)] this section for a well if they would not significantly add to the geologic knowledge of the area in light of the information that is available from other wells in the area [FOR DEVELOPMENT WELLS].

(d) In this section

(1) "experimental logs" means logs that are not commercially available from a logging contractor [SO NEWLY DEVELOPED OR SO LIMITED OR SPECIALIZED IN APPLICATION THAT THEY ARE NOT COMMONLY RUN ON PETROLEUM EXPLORATION OR DEVELOPMENT WELLS]; and

(2) "velocity survey" means a survey, the primary purpose of which is to determine velocity of seismic waves through formations penetrated by a well by measuring travel times of seismic pulses from or near the surface to geophones placed at [A SEISMOMETER LOWERED TO] various depths in the well. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.035

20 AAC 25.072(a), (b), and (d) are amended to read:

20 AAC 25.072. SHUTDOWN OF DRILLING OR COMPLETION [WELL] OPERATIONS. (a) If [CLIMATE, OPERATIONAL OR ENVIRONMENTAL CONCERNS, PRUDENCY, OR OTHER] circumstances prevent the continuation of the program approved on a Permit to Drill (Form 10-401) [THE DRILLING PERMIT], or if an operator wishes to change drill rigs [FOR RIG SUBSTITUTION], the operator shall apply to the commission for approval

to shut down drilling or completion [WELL] operations. The commission will, in its discretion, approve the shutdown of drilling or completion operations. [WELL OPERATIONS. THE LETTER OF APPLICATION MUST SET OUT A FULL JUSTIFICATION FOR THE SHUT DOWN AND BE ACCOMPANIED BY] The request for operation shutdown must be submitted on an Application for Sundry Approvals (Form 10-403), providing a full justification for the shutdown, a description of [WHICH SETS OUT] the proposed condition of the wellbore [WELL BORE] upon shutdown of drilling or completion [WELL] operations, the approximate date when drilling or completion [WELL] operations will resume, and a proposed program for securing the well during the period of shutdown. An Application for Sundry Approvals is not required for planned shutdowns of well operations that are stated in the approved Permit to Drill (Form 10-401).

(b) The operator shall file with the commission, within 30 days after well shutdown, a complete well record on a Report of Sundry Well Operations (Form 10-404), including a copy of the daily reports of well operations required by 20 AAC 25.070[(a)](1) and a copy of all logs run in the well as required by 20 AAC 25.071(b)(6[5]). The commission will, in its discretion, waive the requirements of this subsection if drilling or completion [WELL] operations are to be resumed within ~~180 [60]~~60 days.

. . .

Note to publisher: subsection (c) is unchanged.

(d) If well operations are not resumed within 12 months, unless the commission grants an extension upon application of the operator, the operator shall immediately proceed to abandon or suspend the well. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.075 is amended to read:

20 AAC 25.075. OTHER WELLS IN DESIGNATED AREAS. There are areas in the state where drilling [OPERATIONS] could unexpectedly encounter oil, gas, or hazardous substances at shallow depths. When the commission obtains sufficient evidence to define a specific area and the approximate depth range of the substances, it will issue an order that defines the area and stipulates [WILL PRESENT THE EVIDENCE, DEFINE THE AREA, AND STIPULATE] a drilling depth. After the issuance of such an order, any drilling [WELL DRILLED] in the defined area, for any purpose, that exceeds the stipulated depth will require a Permit to Drill (Form 10-401) [DRILLING PERMIT] and may be subject to the other requirements of this chapter. (Eff. 4/13/80, Register 74; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.080(a) - (e) and (h)(1) are amended, and (f) is repealed and readopted, to read:

20 AAC 25.080. ANNULAR DISPOSAL OF DRILLING WASTE. (a) A person may not dispose of drilling waste through the annular space of a well unless authorized by the commission under this section. The [AN] operator of a well permitted under AS 31.05.090 may request authorization for [SUCH] disposal of drilling waste through the well's annular space by filing with the commission [IN AN APPLICATION FOR A PERMIT TO DRILL (FORM 10-401) OR] an Application for Sundry Approvals (Form 10-403) supplemented with any additional information required under this section.

(b) A request for authorization under this section must include the following information or refer to that information if on file with the commission:

(1) [A DESIGNATION OF THE WELL THAT WILL RECEIVE DRILLING WASTE] the annulus to be used for disposal;

. . .

(3) a description, including the depth and thickness, of the receiving zone and the confining zone, and sufficient information to demonstrate confinement;

. . .

(5) the type(s) and [AN ESTIMATE OF THE] maximum volume of waste to be disposed of and the estimated density of the waste slurry [TO BE DISPOSED];

. . .

(8) details that show that the shoe of the outer casing is set below the base of any freshwater aquifer and permafrost, if present, and adequately cemented [WITH SUFFICIENT CEMENT] to provide zone isolation; the information relied upon and submitted must include (A) cementing records and (B) a cement quality log or formation integrity test records;

(9) details that show that the inner and outer casing strings have sufficient strength in collapse and burst to withstand the anticipated pressure of disposal operations; [AND]

(10) the downhole pressure obtained during a formation integrity test conducted below the outer casing shoe;

(11) identification of any hydrocarbon zones above the depth to which the inner casing is cemented;

(12) the duration of the disposal operation, not to exceed 90 days;

(13) whether any drilling waste has previously been disposed of in the annular space of the well and, if so, a summary of the date(s) of the disposal operation(s); the volume(s) of waste disposed of; and the well(s) where the drilling waste was generated;

(14) the well where the drilling waste to be disposed of was or will be generated;

(15) if the operator proposes not to comply with a limitation established in (d) of this section, an explanation of why compliance would be imprudent; and

(16) any additional data required by the commission to confirm containment of drilling waste.

(c) The commission will, in its discretion, authorize an annular disposal operation [OF DRILLING WASTE THROUGH THE ANNULAR SPACE OF A WELL PERMITTED UNDER AS 31.05.090] described in the Application for Sundry Approvals (as supplemented under this section), subject to any modifications prescribed by the commission, if it determines that the

...

(2) disposal will not

...

(C) impair the mechanical integrity of any well [THE WELL USED FOR DISPOSAL]; or

...

(d) Unless the operator demonstrates[, BY WRITTEN APPLICATION,] that it is imprudent to comply with a limitation established in (1) - (4) of this subsection, the commission will not authorize disposal of drilling waste

...

(3) into a hydrocarbon-bearing stratum; or

...

(e) In addition to any other conditions that the commission in its discretion imposes on a cases-by-case basis, an authorization to dispose of drilling waste under this section is subject to the following conditions:

(1) drilling waste may not be disposed of into freshwater;

(2) the downhole disposal pressure may not exceed the downhole pressure obtained during the formation integrity test conducted below the outer casing shoe;

(3) if drilling waste appears above the confining zone, the operator shall immediately cease disposal, notify the commission, and take appropriate remedial action; and

(4) [2] if the commission notifies the operator that disposal operations pose a threat to well integrity, safety, oil or gas recovery, or freshwater, the operator shall immediately cease disposal and take appropriate remedial action as approved or required by the commission.

(f) For each annular disposal operation authorized under this section, the operator shall report the following information to the commission on a Report of Annular Disposal (Form 10-423) not later than 30 days after the end of the period authorized for the disposal operation:

(1) the dates when disposal began and ended; and

(3) the volume of drilling waste disposed of in each of the following categories:

(A) the aggregate of drilling wastes described in (h)(1) of this section;

(B) the aggregate of drilling wastes described in (h)(2) of this section; and

(C) each substance determined to be a drilling waste under (h)(3) of this section.

. . .

Note to publisher: subsection (g) is unchanged.

(h) In this section, "drilling waste" means the following substances, unless identified as a hazardous waste in 40 C.F.R. Part 261:

(1) drilling mud, drilling cuttings, reserve pit fluids, cement-contaminated drilling mud, completion fluids, [AND] formation fluids associated with the act of drilling a well permitted under 20 AAC 25.005, and any added water needed to facilitate pumping of drilling muds or drilling cuttings;

. . .

Note to publisher: subsection (i) is unchanged.

(Eff. 9/22/96, Register 139; am ___/___/___, Register ___)

Authority: AS 31.05.030

ARTICLE 2.
ABANDONMENT AND PLUGGING

Section
105. Plugging~~, suspension, and abandonment of well~~[, SUSPENSION, AND ABANDONMENT] of wells
107. Plugging well branches
110. Suspended wells
115. Shut-in wells
120. Well abandonment marker
140. Water wells
170. Onshore location clearance
172. Offshore location clearance

20 AAC 25.105 is repealed and readopted to read:

20 AAC 25.105. PLUGGING~~, SUSPENSION, AND ABANDONMENT~~ OF WELLS. (a) All wells that have been permitted on a property under 20 AAC 25.005 must be ~~abandoned~~plugged in accordance with this section before expiration of the owner's rights in that property or if, after notice and hearing, the commission orders ~~abandonment for safety reasons,~~plugging for safety reasons or because the operator has effectively abandoned operations prior to the expiration of the lease. If the owner is the landowner, all wells that have been permitted on a property by 20 AAC 25.005 must be ~~abandoned~~plugged in accordance with this section within one year following permanent cessation of the operator's oil and gas activity within the field where the wells are located or according to an abandonment schedule approved by the commission, unless earlier ~~abandon~~plugged for safety reasons.

(b) A well drilled onshore or from a fixed offshore platform must be ~~abandoned or suspended~~plugged in accordance with this section before removal of the drill rig from the site unless completed as an oil, gas, or service well or suspended, or unless well operations are shut down in accordance with 20 AAC 25.072.

(c) A well drilled offshore from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel must be ~~abandoned~~plugged in accordance with this section before removal of the drill rig from location unless

(1) the well is completed as an oil, gas, or service well; or

(2) subsea equipment for well re-entry is installed in a manner approved by the commission and either the well is suspended~~ in accordance with 20 AAC 25.110~~ or well operations are shut down in accordance with 20 AAC 25.072.

(d) A well drilled from a beach, artificial island, or shifting natural island must be ~~abandoned or suspended~~plugged in accordance with this section before removal of the drill rig from the site unless completed as an oil, gas, or service well or suspended, or unless well operations are shut down in accordance with 20 AAC 25.072 and plans for maintaining the integrity of the well site are approved by the commission.

(e) ~~A well to be abandoned or suspended must be plugged by the operator in accordance with this section to prevent the movement of fluid either into or between freshwater and hydrocarbon sources and to prevent all other fluid migration within the wellbore.~~ An Application for Sundry Approvals (Form 10-403) must be filed with and approved by the commission before work is begun to ~~abandon or suspend a well~~plug a well under this section, except that oral approval may be obtained from the commission if it is followed within 10 days by the filing of an Application for Sundry Approvals. Approval will be conditioned as necessary to protect freshwater and hydrocarbon resources. An Application for Sundry Approvals must include

(1) the reason for ~~abandonment or suspension~~plugging the well; and

(2) a statement of proposed work, including

(A) information on abnormally geo-pressured strata;

(B) the manner of placement, kind, size, and location, by measured depth, of existing and proposed plugs;

(C) plans for [redacted], cementing, shooting, testing, and removing casing;

(D) if the Application for Sundry Approvals is filed after beginning work, the name of the representative of the commission who provided oral approval, and the date of the approval; and

(E) all other pertinent information.

(f) ~~T~~Plugging of the uncased portion of a wellbore must be ~~plugged with cement~~performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface. The minimum requirements for plugging the uncased portion of a wellbore are as follows:

(1) by the displacement method, a cement plug must be placed

(A) from ~~5~~100 feet below the base to 100 feet above the top of all hydrocarbon-bearing strata;

(B) from the well's total depth to 100 feet above the top of all hydrocarbon-bearing strata;

(C) from the well's plugged back total depth to 100 feet above the top of all hydrocarbon-bearing strata, if all hydrocarbon-bearing, abnormally geo-pressured, and freshwater strata below are isolated; except that the commission will, in its discretion, approve plugging from the top of fill or the top of junk instead of from the plugged back total depth; or

(D) from 100 feet below the base to 50 feet above the base of each significant hydrocarbon-bearing stratum and from 50 feet below the top to 100 feet above the top of each significant hydrocarbon-bearing stratum;

(2) by the displacement method, a cement plug must be placed from 100 feet below the base to 50 feet above the base of abnormally geo-pressured strata and from 50 feet below the top to 100 feet above the top of the abnormally geo-pressured strata; and

(3) by the displacement method, a cement plug must be placed from 150 feet below the base to 50 feet above the base of the deepest freshwater stratum.

(g) ~~U~~Plugging of a well must include effectively segregating uncased and cased portions of the wellbore ~~must be effectively segregated~~ to prevent vertical movement of fluid within the wellbore. The minimum requirement for plugging to segregate uncased and cased portions of a wellbore is as follows:

(1) by the displacement method, a continuous cement plug must be placed from 100 feet below to 100 feet above the casing shoe;

(2) by the downsqueeze method using a retainer set no less than 50 feet but no more than 100 feet above the casing shoe, a volume of cement sufficient to fill the wellbore ~~extend~~ ~~retainer to extend cement~~from the retainer to 100 feet below the casing ~~through a cement retainer or production packer set above retainer to fill the casing stub with 150 feet of 20 AAC 25.105(e), the commission will, in its discretion, produced.~~

~~(h) Hydrocarbon measurement equipment. (f) Gas meter runs must be fabricated, installed, and maintained in accordance with chapter 14 of the API *Manual of Petroleum Measurement Standards*, as revised its representative can confirm compliance with the API *Manual of Petroleum Measurement Standards*, as revised from time to time, which is adopted by~~

~~meter by the waterdraw method, master meter method, or other~~shoe must be pumped through the retainer, ~~from the retainer to 100 feet below the casing shoe,~~ and cement must be pumped above the retainer to cap it with a 50 foot cement plug; or

(3) by the downsqueeze method using a production packer set no less than 50 feet but no more than 500 feet above the casing shoe, ~~cement must be pumped through the packer to extend cement~~a volume of cement sufficient to ~~extend~~ fill the wellbore from 100 feet below the casing shoe to ~~100 feet above the casing shoe or to~~the packer must be pumped through the packer, and cement must be pumped above the packer to cap it with a 50 foot cement plug.

(h) ~~Cased portions of the wellbore must be plugged with cement to ensure~~Plugging of cased portions of a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface. The minimum requirements for plugging cased portions of ~~the~~a wellbore are as follows:

(1) perforated intervals must be plugged by one of the following methods:

(A) by the displacement method, a cement plug must be placed from 100 feet below the base to 50 above the base of the perforated interval and from 50 feet below the top to 100 feet above the top of the perforated interval;

(B) by the displacement method, a cement plug must be placed from the well's total depth to 100 feet above the top of the perforated interval;

(C) by the displacement method, a cement plug must be placed from the well's plugged back total depth to 100 feet above the top of the perforated interval, if all hydrocarbon-bearing, abnormally geo-pressured, and freshwater strata below are isolated;

except that the commission will, in its discretion, approve plugging from the top of fill or the top of junk instead of from the plugged back total depth;

(D) by the downsqueeze method, using a cement retainer or production packer set at the least 50 ft but not more than 500 ft above the perforated interval, ~~the perforated interval, cement must be pumped~~ a volume of cement sufficient to fill the wellbore from 100 feet below the base of the perforated interval to the retainer or production packer; ~~100 feet above the top of the perforated interval~~ must be pumped through a cement retainer ~~or production packer set~~ at least 50 ft but not more than 500 ft above the perforated interval; or

(E) a mechanical bridge plug must be set no more than 50 feet above the top of the perforated interval and at least 75 feet of cement must be placed on top of the bridge plug, if the perforations are isolated from open hole below;

(2) casing stubs within outer casing must be plugged by one of the following methods:

(A) by the displacement method, a cement plug must be placed from 100 feet below the stub to 100 feet above the stub;

(B) by the downsqueeze method, using a retainer set 50 feet above the stub, a volume of cement sufficient to fill the casing stub with 150 feet of cement must be pumped below the retainer, and cement must be pumped ~~cement, and~~ above the retainer to cap it with a 50 foot cement plug; or

(C) a mechanical bridge plug must be set no more than 25 feet above the casing stub and at least 75 feet of cement must be placed on top of the bridge plug;

(3) where freshwater is present, the smallest diameter casing string extending to the surface must be plugged by one of the following methods:

(A) by the displacement method, a cement plug must be placed from 100 feet below the depth of the surface casing shoe to 100 feet above the depth of the shoe; or

(B) a mechanical bridge plug must be set 100 feet below the depth of the surface casing shoe and at least 200 feet of cement must be placed on top of the bridge plug.

(i) ~~Except as provided in 20 AAC 25.110(e), the surface of the well must be plugged as follow~~Plugging of the surface of a well must meet the following requirements:

(1) by the displacement method, a cement plug at least 150 feet in length, with the top of the cement no more than 5 feet below original ground level onshore, or between 10 and 30 feet below the mudline datum offshore, must be placed within the smallest diameter casing string; and either

(2) all annular space open at the surface onshore, or in communication with open hole and extending to the mudline datum offshore, must be plugged with cement to seal the annular space in a manner satisfactory to the commission; or

(3) all casing interior to the surface casing must be recovered to a depth of 100 feet or more below the original ground level onshore or the mudline datum offshore and the casing stubs plugged with cement as provided in (h)(2)(A) of this section; if the cement plug is extended to within the distance from the surface specified in (1) of this subsection, the requirement of (1) of this subsection will be deemed met.

(j) Cement used for plugging within zones of permafrost must be designed to set before freezing and have a low heat of hydration.

(k) Each of the respective intervals of ~~the hol~~a wellbore between the various plugs must be filled with fluid of sufficient density to exert a hydrostatic pressure exceeding the greatest

formation pressure of permeable formations in the intervals between the plugs at the time of abandonment.

(l) Except for surface plugs, the operator shall record the actual location and integrity of cement plugs, cement retainers, or bridge plugs required by this section by

(1) placing sufficient weight on the plug to confirm its location and to confirm that the cement or mechanical plug has set and a competent plug is in place, in which event testing of the cement placed above the bridge plug or retainer is not required; or

(2) testing the plug to hold a surface pressure of 1500 psig or 0.25 psi/ft multiplied by the true vertical depth of the casing shoe, whichever is greater, and tagging the plug to confirm location; however, surface pressure must not subject the casing to a hoop stress that will exceed 70 percent of the minimum yield strength of the casing~~; the test~~.

~~pressure must show stabilizing pressure and in no case may the pressure decline more than 10 percent in 30 minutes.~~

(m) A minimum of 24 hours notice of plugging operations must be given to the commission so that a representative of the commission can witness the operations.

(n) The commission will, in its discretion, approve a variance from the requirements of this section if the variance provides for at least equally effective plugging of the well and prevention of fluid movement into sources of hydrocarbons or freshwater. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.107. PLUGGING WELL BRANCHES. (a) An operator wishing to plug a well branch before abandoning or suspending the well shall file and obtain the commission's approval of an Application for Sundry Approvals (Form 10-403) before beginning work to plug the well branch. The provisions of 20 AAC 25.105(e) apply to the application, except that instead of including the reason for plugging the well the application must include the reason for plugging the well branch and the reason for not immediately abandoning or suspending the well.

(b) A well branch approved for plugging under this section must be plugged in accordance with the requirements of 20 AAC 25.105(f) - (h) and (j) - (n). (Eff. / / , Register)

Authority: AS 31.05.030

20 AAC 25.110 ~~(a), (b), and (c) are amended, (c) is repealed and readopted, and (d) is repealed,~~is repealed and readopted to read:

20 AAC 25.110. SUSPENDED WELLS. (a) ~~Upo~~Where ~~permitted~~ allowed under 20 AAC 25.105, the commission will, in its discretion, upon application by the operator under (b) of this section, approve the suspension of a well that has not been completed if

(1) the well

(~~1~~A) encounters hydrocarbons of sufficient quality and quantity to indicate that the well is capable of producing in paying quantities, as reasonably demonstrated by well tests or interpretive formation evaluation data; ~~[OR]~~

~~(2) is [REASONABLY] demonstrated to have potential [FUTURE] value as a service well; or [.]~~B) is a candidate for redrilling;

(C) has potential value as a service well; or

(3 (D) is located on a pad or platform with active producing or service wells.; and

(b) In addition to the filing requirements set out in 20 AAC 25.105(e), the applicant has the burden of justifying to the commission' (2) the operator justifies to the commission's satisfaction why the well should not be completed or abandoned. Information [THE CONFIDENTIALITY OF INFORMATION] voluntarily submitted in support of well suspension will be kept confidential in ; sufficient reasons include

accordance with 20 AAC 25.537. Justifiable reasons for suspension include

(1) A) unavailability of surface production or transportation [AND RESOURCE MARKETING] facilities are not availablefacilities;

(2) B) imprudency of security maintenance of a completed well in a shut-in status is not prudent;

(3) C) need for pool delineation and evaluation are [IS] necessary to determine prudency of pool development. [AND THE CONSTRUCTION OF PRODUCTION OR ACCESS TO MARKET FACILITIES;]to determine prudency of pool development.

(4) repealed __/__/__(b) An Application for Sundry Approvals (Form 10-403) must be filed with and approved by the commission before plugging operations are begun in a well for which suspension is proposed, except that oral approval may be obtained from the commission if it is followed within 10 days by the filing of an Application for Sundry Approvals. Approval will be conditioned as necessary to protect freshwater and hydrocarbon resources. An Application for Sundry Approvals must include

(1) the reason for suspending the well and information showing that the applicable criteria for suspension under (a) of this section have been met; and

(2) a statement of proposed work, including

(A) information on abnormally geo-pressured strata;

(B) the manner of placement, kind, size, and location, by measured depth, of existing and proposed plugs;

(C) plans for ~~mudding~~, cementing, shooting, testing, and removing casing;

(D) if the Application for Sundry Approvals is filed after beginning work, the name of the representative of the commission who provided oral approval, and the date of the approval; and

(E) all other pertinent information.

(c) Information voluntarily submitted to show that the applicable criteria for well suspension under (a) of this section have been met will be kept confidential in accordance with 20 AAC 25.537.

(~~c~~d) A well approved for suspension must be plugged in accordance with the requirements of 20 AAC 25.105, except that the requirements of 20 AAC 25.105(i) do~~es~~ not apply if

(1) a wellhead is installed or the well is capped with a mechanical device to seal the opening; and

(2) a bridge plug capped with 50 feet of cement or a continuous cement plug extending 200 feet within the interior casing string is placed at or above 300 feet below the surface; the commission will, in its discretion, waive the requirement of this paragraph for a development well drilled from a pad or platform.

~~(d) Repealed ___/___/___.~~

(e) ~~During the period of well suspension,~~Until a suspended well has been abandoned or re-entered, the operator shall maintain the integrity of the well site, provide the commission with a well status report every five years, and clear the location in a manner approved by the commission. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.115. SHUT-IN WELLS. (a) ~~An operator that shuts in a~~No later than March 31 of each year, an operator shall file with the commission a report on all completed development or service well~~ for more than 90 days shall file a report with the commission no later than 120 days after shutting in the well~~s that have been shut in for 365 days or longer as of January 1 of that year. The report must provide

(1) the current known mechanical condition of the well, including the condition of all installed tubing and casing strings;

(2) the date the well was shut in and the circumstances surrounding the decision to shut in the well; and

(3) an analysis of the future utility of the well.

(b) ~~An operator of a shut-in well shall file with the commission an annual update of the report required under (a) of this section.~~

~~(c)~~ The commission will, in its discretion, require an operator of a shut-in well to file additional information to ensure that freshwater and hydrocarbon sources are~~ protected.~~

~~(d) When production testing or injection testing of a shut-in well is performed for not more than one week, cessation of the production testing or injection testing will not trigger a new 120-day filing period under (a) of this section~~protected. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.120 is repealed and readopted to read:

20 AAC 25.120. WELL ABANDONMENT MARKER. (a) The exact surface location of an abandoned well must be shown by a steel well abandonment marker. The marker must be a marker plate meeting the requirements of (b) of this section, except that if a marker post is requested by the surface owner and approved by the commission, the marker must be a marker post meeting the requirements of (c) of this section. The marker may not be installed until wellhead equipment, casing landing heads, and casing are removed to a depth at least three feet below original ground level.

(b) A marker plate must be

(1) at least 1/4 inch thick;

(2) at least eighteen inches square or in diameter; and

(3) welded to and covering the outermost casing string.

(c) A marker post must

(1) be at least four inches in diameter and at least 10 feet long;

(2) be set in cement inside well casing or firmly welded with supporting fillets to the top of a steel plate secured to the casinghead or casing stub;

(3) extend from four to six feet above final ground level; and

(4) be closed at the top with a screw cap, welded plate, or cement plug.

(d) The name of the operator, Permit to Drill number(s), and API number(s) must be bead-welded directly to the marker.

(e) The commission will, in its discretion, inspect the marker to verify proper installation and well information at the time of the location clearance required in 20 AAC 25.170.

(f) This section does not apply to abandoned wells drilled from a fixed platform, mobile bottom-founded structure, jack-up rig, floating drilling vessel, artificial gravel island, shifting natural island, or beach location. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.140 is amended to read:

20 AAC 25.140. WATER WELLS. If a well drilled for oil or gas is to be plugged and abandoned, but may safely be used as a freshwater well, and such a use is desired by a person, written authority for this action must be obtained from the landowner and owner of the surface rights. The authorization must provide for the authorized person's assumption of full responsibility for the final plugging of the water well. This authorization must be filed with, and approved by, the commission. Following the commission's approval of the plugging of the well to protect the freshwater bearing strata to a depth approved by the commission for conversion to a water well and the location clearance, the operator is relieved of further obligation under the operator's bond. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.170(a) ~~is~~and (b) are amended, and (c) is repealed and readopted, to read:

20 AAC 25.170. ONSHORE LOCATION CLEARANCE. (a) The location of an abandoned well onshore [OR UPON A HISTORICALLY STABLE ISLAND,] must be cleared within one year following well abandonment or before expiration of the owner's [OPERATOR'S] rights, whichever occurs first. The operator shall

(1) remove all materials, supplies, structures, and installations from the location~~;~~, except to the extent that the operator demonstrates to the commission that a different disposition has been

(A) ordered by another government agency having jurisdiction; or

(B authorized by the surface owner to facilitate a genuine beneficial use;

(2) remove~~, adequately bury, or incinerate all loose debris occurring on or near~~[, ADEQUATELY BURY, OR INCINERATE] all loose debris from [OCCURRING ON OR NEAR] the location;

(3) fill and grade all pits~~, or close all reserve pits in accordance with a procedure~~ or close them in another manner approved by the commission; and

(4) leave the location in a clean and graded condition.

...

~~Note to publisher: subsection (b) is unchanged~~ (b) The commission will, in its discretion, grant an extension of time beyond one year following well abandonment, upon receipt of an [THE FORM ENTITLED] Application for Sundry Approvals (Form 10-403), on which is stated

...

(4) the expiration date of the owner's [OPERATOR'S] rights to enter the location.

(c) After the work required under (a) of this section has been completed at a location, the commission will, in its discretion, conduct an on-site inspection to verify the location condition

at the time of inspection, including the presence of a proper well marker if above ground, as required under 20 AAC 25.120, and will provide the operator a report of the inspection.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.172 is repealed and readopted to read:

20 AAC 25.172. OFFSHORE LOCATION CLEARANCE. (a) ~~A~~Except as otherwise provided under (b) of this section, after all wells are abandoned from an offshore platform and the commission determines that no further utility exists for the platform, the operator shall

(1) remove all fluids, clean all vessels, and capture entrained and cleaning fluids for proper disposal;

(2) conduct and maintain a written record of monthly inspections of the platform until it has been removed or abandoned under (4) of this subsection;

(3) submit and obtain the commission's approval of a plan to remove or abandon the platform and to clear the site of any obstructions to fishing or navigation; the commission will, in its discretion, impose additional requirements after reviewing this plan;

(4) within 10 years, in accordance with the approved plan,

(A) remove the platform and any other obstructions, severing well strings and platform pilings at least one foot below the sea floor; or

(B) abandon the platform's tower in place, if sufficient draft exists between tower components and mean low water to avoid interfering with fishing or navigation, by

(i) removing from the site all equipment, facilities, and deck sections;

(ii) severing and dropping horizontal and diagonal bracing between leg pairs;

(iii) severing well strings and platform pilings at least one foot below the sea floor; and

(iv) toppling each tower leg-pair parallel to the current; and

(5) provide the commission with verification, using appropriate means approved by the commission, that platform removal or abandonment and site clearance have been completed in accordance with the approved plan and the requirements of this subsection.

(b) Upon written application, the commission will, in its discretion, grant a variance from some or all of the requirements of (a) of this section, other than the requirement to sever well strings, if another government agency having jurisdiction has ordered a disposition of the platform inconsistent with those requirements.

~~S~~ (c) Unless otherwise ordered by another government agency having jurisdiction, subsea pipelines may be abandoned in place if

(1) the pipelines are flushed clean;

(2) the pipelines are cut off below mean low water and the ends sealed with a cap or other means satisfactory to the commission; and

(3) the operator verifies to the satisfaction of the commission that the requirements of (1) and (2) of this subsection have been met.

(~~c~~d) When a well is abandoned from a mobile bottom-founded structure, jack-up rig, or floating drilling vessel, the operator shall

(1) clear the well site before removing the drilling rig from the location by recovering all casing, wellhead equipment, piling, and other obstructions to a depth at least five feet below the mudline, unless otherwise approved by the commission; and

(2) provide the commission with verification, using appropriate means approved by the commission, that the requirements of (1) of this subsection have been met.

(~~d~~e) When a well is abandoned from an artificial gravel island, shifting natural island, or beach location, and before the earliest of one year following abandonment, the time that the operator stops activities necessary to ensure the integrity of the well site, or the expiration of the owner's rights in the property, the operator shall

(1) remove all casing and wellhead equipment to a depth of at least five feet below the mudline datum;

(2) remove all materials, supplies, structures, and installations from the location~~;~~, except to the extent that the operator demonstrates to the commission that a different disposition has been

~~(3) remove from the location, or incinerate, all loose debris~~(A) ordered by another government agency having jurisdiction; or

(B) authorized by the surface owner to facilitate a genuine beneficial use;

(3) remove all loose debris from the location;

(4) fill and grade all pits~~, or close all reserve pits in accordance with procedures~~ or close them in another manner approved by the commission; and

(5) leave the location in a clean and graded condition.

(~~e~~f) After the work required under (~~d~~e) of this section has been completed at a location, the commission will, in its discretion, conduct an onsite inspection to verify the location

condition at the time of inspection and will provide the operator a report of the inspection. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

ARTICLE 3

PRODUCTION PRACTICES

Section

200. Production equipment
205. Notification of uncontrolled release [ACCIDENTAL LOSS] of oil or gas
210. Multiple completions [COMPLETION] of wells
215. Commingling of production
225. Potential of gas wells
228. Production measurement equipment for custody transfer
230. Measurement, allocation, and reporting of well production [PRODUCTION MEASUREMENT]
235. Gas disposition
240. Gas-oil ratio [RATIOS] limitations
245. Common production facilities
250. (Repealed)
252. Underground disposal of [WATER AND OTHER] oil field wastes [WASTE FLUIDS] and underground storage of [LIQUID] hydrocarbons
255. (Repealed)
260. Illegal production
265. Automatic shut-in equipment
270. Initial reservoir properties [PRESSURE]
275. (Repealed) [RESERVOIR FLUID PROPERTIES]
280. Workover operations
285. Blowout prevention equipment for workover operations
290. Operations producing hydrogen sulfide

20 AAC 25.200 (a) and (d) are amended to read:

20 AAC 25.200. PRODUCTION EQUIPMENT. (a) Surface production equipment must be installed to control, separate, clean, [AND] gather, and carry to the point of custody transfer or other disposition in a safe manner all produced oil, gas, and water. All equipment must be installed, operated and maintained in accordance with good oil field engineering practices. [ESTABLISHED INDUSTRY PRACTICE.]

. . .

Note to publisher: subsections (b) and (c) are unchanged.

(d) All producing wells capable of unassisted flow must be completed with downhole production equipment consisting of suitable tubing and a packer which effectively isolates the tubing-casing annulus from fluids being produced, unless otherwise specifically approved by the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.205 is amended to read:

20 AAC 25.205. NOTIFICATION OF UNCONTROLLED RELEASE [ACCIDENTAL LOSS] OF OIL OR GAS. (a) The commission must be immediately notified by the operator of any uncontrolled release exceeding 10 barrels of oil or 1000 mscf of [ACCIDENTAL LOSS OF CRUDE OIL OR NATURAL] gas, or both, from a well or production handling operation or any uncontrolled release that results in an interruption of operations at a production facility.

(b) Within five days after the release [ACCIDENTAL LOSS], the operator shall submit a preliminary written report to the commission, followed by a final written report within 30 days, detailing the following facts:

(1) time of incident;

(2) location where incident took place;

(3) volumes of oil and gas released and recovered [CRUDE OIL AND OF NATURAL GAS LOST];

(4) cause of the release; [LOSS;]

(5) responsive actions taken to prevent further release [ACTIONS TAKEN AND PLANNED TO PREVENT FURTHER LOSS]; and

(6) any plans, actions, equipment, or procedural changes to prevent or minimize the risk of future releases [EQUIPMENT OR PROCEDURAL CHANGES, IF APPLICABLE, TO PREVENT THE LOSS FROM RECURRING]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.210 is amended to read:

20 AAC 25.210. MULTIPLE COMPLETIONS [COMPLETION] OF WELLS. A well may not be completed in more than one pool without approval of the commission. The commission will, in its discretion, require evidence of complete separation of flowstreams from separate pools, as ascertained by a pressure test or other acceptable test[S] conducted at the time the packers are set. Subsequently, if packer leakage is suspected, the commission will, in its discretion, request the operator to provide proof of complete separation of the pools involved in the completions or make a packer leakage test. A minimum of 24 hours notice [NOTIFICATION] must be given so that the packer leakage test may be witnessed by a representative of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.215 is amended to read:

20 AAC 25.215. COMMINGLING OF PRODUCTION. (a) On the surface, the production from one pool may not be commingled with that from another pool except when the

quantities from each pool are determined by [AT LEAST] monthly well tests or by an acceptable production allocation methodology approved by the commission.

(b) Commingling of production within the same wellbore [WELL BORE] from two or more pools is not permitted unless after request, notice, and opportunity for public hearing in conformance with 20 AAC 25.540, the commission finds that waste will not occur, production from separate pools can be properly allocated, and the commission issues an order providing for commingling for [ALL] wells completed from these pools within the field. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.225 is amended to read:

20 AAC 25.225. POTENTIAL OF GAS WELLS. All gas wells must be tested by the multi-point back-pressure method before regular [SIGNIFICANT] production. The commission will, in its discretion, approve alternative test methods. The test results and calculations must be reported to the commission on the [FORM ENTITLED] Gas Well Open Flow Potential Test Report (Form 10-421) within 30 days after the test. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.228 is repealed and readopted to read:

20 AAC 25.228. PRODUCTION MEASUREMENT EQUIPMENT FOR CUSTODY TRANSFER. (a) All hydrocarbon production must be measured in accordance with this section before severance from the property or unit where produced. Crude oil sample collection,

handling, and analysis in connection with production measurement must be ~~must be fabricated and install~~performed in accordance with the API *Manual of Petroleum Measurement Standards*, as revised ~~from time to time~~as of _____, which is adopted by reference.

(b) Hydrocarbon measurement equipment and gas meter runs must be fabricated, installed, and maintained in accordance with the API *Manual of Petroleum Measurement Standards*, as revised as of _____, which is adopted by reference.

(c) If a totalizer system is microprocessor-based, it must be equipped with

(1) a back-up battery or uninterruptible power supply that provides for operation during times of system power failures; or

(2) a backup pulse accumulator or other approved equivalent that counts and preserves meter pulses in the event of power or computer failure.

(d) If a microprocessor totalizing system is used, the reports of net measured volumes for the custody transfer intervals must, at a minimum, show the raw or factored pulses, average temperature, pressure, relative density~~,~~ or gravity, meter factors, correction factors, and the gross standard volumes.

(e) Fluid samplers must be either a probe or a slipstream type. The sampler location must be profiled in accordance with chapter eight of the API *Manual of Petroleum Measurement Standards*, as revised ~~from time to time~~as of _____, which is adopted by reference.

~~(g) B~~(f) Functional bypasses may not be connected around custody transfer or sales measurement equipment such as tanks, meters, gauges, sample containers, or gas meter runs.

(g) Oil meters must be periodically proved and gas meters must be periodically calibrated in accordance with the API *Manual of Petroleum Measurement* Standards, as revised ~~from time to time, which is adopted by reference.~~

~~(h) Meters must be periodically proved in accordance with~~as of _____, which is adopted by reference, and on a schedule approved by the commission. In metering operations, the actual throughput or gross ~~measure~~standard volume must be determined by multiplying the indicated volume, corrected for temperature and pressure, by the meter factor obtained during proving. If a meter factor differs by more than 0.0025 from the previously obtained meter factor, from the applicable value on the meter curve, or from a baseline factor in the absence of a meter curve, the meter must be taken out of service or corrective action performed to bring the meter factor within the required tolerance.

(h) Provers used for certification of custody transfer meters must be calibrated by the waterdraw method, master meter method, or other ~~approved equivalent;~~ commission-approved equivalent, in accordance with the API *Manual of Petroleum Measurement Standards*, revised as of _____, which is adopted by reference~~;~~.

(i) The commission will, in its discretion, require a minimum of 24 hours notice before the following operations so that a representative of the commission can witness the operation:

(1) calibration of provers used for certification of custody transfer meters;

(2) crude oil sample collection, handling, and analysis in connection with production measurement;

(3) oil meter proving and volume calculations;

(j) (4) gas meter calibrations and volume calculations.

(k) Upon request, the commission will, in its discretion, approve a variance from the requirements of this section if the variance will result in equal or improved accuracy in measuring hydrocarbons severed from the property or unit. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the API *Manual of Petroleum Measurement Standards* may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

20 AAC 25.230 is repealed and readopted to read:

20 AAC 25.230. MEASUREMENT, ALLOCATION, AND REPORTING OF WELL PRODUCTION. (a) Production from each well must be measured or allocated to determine the quantities of oil, gas, and water, using equipment and techniques acceptable to the commission. Production from a group of wells, property, or unit may be measured as a whole, if individual well test facilities and allocation methods acceptable to the commission are employed to test and allocate production to each well at least monthly.

(b) The volumes of produced gas, oil, and water must be reported monthly for each well on the Monthly Production Report (Form 10-405) or by an alternate format, including electronic means, acceptable to the commission. A well must be identified by its API number and the name designated by the operator under 20 AAC 25.005(f). Production from a well with multiple well branches must be aggregated and reported under the API number and well name of the primary wellbore. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)
Authority: AS 31.05.030

20 AAC 25.235 (a) is amended to read:

20 AAC 25.235. GAS DISPOSITION. (a) For each production facility the operator shall compile and report monthly gas disposition <u>and acquisition</u> on the Facility Report of Produced

Gas Disposition (Form 10-422). The operator shall report gas acquisition or disposition as (1) sold; (2) reinjected; (3) flared or vented; (4) used for lease operations other than flared or vented; [OR] (5) natural gas liquids (NGLs) produced; (6) gas purchased; (7) gas transferred; or (8) other. If a facility's production comes from multiple pools, the operator shall allocate production between each producing pool as a percentage of the total volume of gas that the facility handled for the month.

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 1/1/95, Register 132; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

AS 31.05.170

20 AAC 25.240 is repealed and readopted to read:

20 AAC 25.240. GAS-OIL RATIO LIMITATIONS. (a) An oil well may not be produced if the gas-oil ratio of the well exceeds the original solution gas-oil ratio of the crude within the producing pool by more than 100 percent.

(b) Upon written application by an operator, the commission will, in its discretion, waive the limitation in (a) of this section if

(1) an enhanced recovery project is operating in the pool from which the well is producing;

(2) produced gas is being returned to the same pool; or

(3) acquisition of pool performance data is necessary to determine an optimum reservoir management program.

(c) Exceptions for conditions other than those specified in (b) of this section will, at the discretion of the commission, be granted only after application, notice, and an opportunity for public hearing. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.245 is amended to read:

20 AAC 25.245. COMMON PRODUCTION FACILITIES. Common facilities may be used to receive the production from any number of wells or pools if appropriate tankage or other measuring equipment is installed so that production from each well can be [ACCURATELY] determined by means approved by the commission in accordance with 20 AAC 25.228 [AT LEAST ONCE EACH MONTH]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.252 (a) - (c), (e), (f), and (h) are amended, (d) is repealed and readopted, and a new (k) is added, to read:

20 AAC 25.252. UNDERGROUND DISPOSAL OF [WATER AND OTHER] OIL FIELD WASTES [WASTE FLUIDS] AND UNDERGROUND STORAGE OF [LIQUID] HYDROCARBONS. (a) Unless authorized by the United States Environmental Protection Agency under 42 U.S.C. 300~~h-1~~f - 300j-9, the [THE] underground disposal of [FRESHWATER OR SALT WATER, BRACKISH WATER, OR OTHER] oil field wastes [WASTE FLUIDS] and the underground storage of ~~liquid~~[LIQUID] hydrocarbons are prohibited except as ordered

by the commission under this section. In [IN] response to a letter of application for injection filed by an operator, [FOR UNDERGROUND DISPOSAL OR STORAGE] the commission will, in its discretion, authorize the underground disposal of oil field wastes consisting of fluids described in 40 C.F.R. 144.6(b)(1) (revised as of July 1, 1997) or the underground storage of hydrocarbons. An order authorizing disposal or [OF] storage wells remains valid unless revoked by the commission.

(b) The operator has the burden of demonstrating that the proposed disposal or storage operation will not allow the movement of oil field wastes or hydrocarbons [FLUID] into sources of freshwater. Disposal or storage wells must be cased and the casing cemented in a manner that will isolate the disposal or storage zone and protect oil, gas, and freshwater sources.

(c) An application for underground disposal or storage [INJECTION] must include

(1) a plat showing the location of all proposed disposal and storage wells, [INCLUDING] abandoned or other unused wells, production wells, dry holes, and any other wells that penetrate the disposal or storage [INJECTION] zone within one-quarter mile of each proposed disposal or storage well;

. . .

Note to publisher: paragraphs (2) and (3) are unchanged.

(4) the name, description, depth, and thickness of the formation into which fluids are to be disposed or stored [INJECTED] and appropriate geological data on the disposal or storage [INJECTION] zone and confining zone(s) [ZONES], including lithologic description and geologic name;

. . .

Note to publisher: paragraph (5) is unchanged.

(6) a description of the casing of the disposal or storage wells, or the proposed casing program and the proposed method for demonstrating mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that no fluids will move behind casing beyond the approved [TESTING CASING BEFORE USE OF THE] disposal or storage zone; [WELLS;]

(7) a statement as to the type of oil field wastes to be disposed or hydrocarbons stored [FLUID TO BE INJECTED], their [ITS] composition, their [ITS] source, [AND] the estimated maximum amounts to be disposed or stored [INJECTED] daily, and the compatibility of fluids to be disposed or stored with the disposal or storage zone;

(8) the estimated average and maximum disposal or storage [INJECTION] pressure;

(9) evidence and data to support a commission finding that the proposed disposal or storage well will not initiate or propagate fractures through the confining zone(s) [ZONES] which might enable the oil field wastes or stored hydrocarbons [INJECTION FLUID OR FORMATION FLUID] to enter any freshwater strata;

(10) ~~an analysis~~a [AN] standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which disposal or storage [FLUID INJECTION] is proposed[, BY A STANDARD LABORATORY WATER ANALYSIS DETERMINATION, OR BY AN ~~proposed, by a standard laboratory water analysis determination[,] or by an analytical method acceptable to the commission~~ANALYTICAL METHOD ACCEPTABLE TO THE COMMISSION]; [AND]

(11) a reference to any applicable freshwater exemption issued in accordance with 20 AAC 25.440;[.] and

(12) a report on the mechanical condition of all wells that have penetrated the disposal or storage zone within a one-quarter mile radius of a disposal or storage well.

(d) The mechanical integrity of a disposal or storage well must be demonstrated under 20 AAC 25.412 before disposal or storage operations are begun and after a well workover affecting mechanical integrity is conducted. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual disposal or storage operations. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(e) If the casing-tubing annulus pressure subjects the casing to a hoop stress that exceeds 70 percent of the minimum yield strength of the casing, ~~or if a rate increase, operating pressure observation,~~ if a disposal rate increase or pressure test indicates pressure communication or leakage of any casing, tubing, or packer, [or if there is more than a 200 psi change in pressure between consecutive pressure readings,] the operator shall notify the commission [MUST BE IMMEDIATELY NOTIFIED] by the next working day and implement commission-approved corrective action [TAKEN].

(f) The commission will, in its discretion, require additional mechanical integrity tests if prudent for conservation purposes or protection of freshwater.

. . .

Note to publisher: subsection (g) is unchanged.

(h) [THE OPERATOR SHALL PROVIDE A REPORT ON THE MECHANICAL CONDITIONS OF ALL WELLS THAT HAVE PENETRATED THE INJECTION ZONE WITHIN A ONE-QUARTER MILE RADIUS OF A PROPOSED DISPOSAL OR STORAGE WELL.] It is the operator's responsibility to ensure [ASSURE] that all [ANY OF THE] wells,

including waterwells and other borings, under the operator's control within a one-quarter mile radius of the disposal or storage well [THE RADIUS OF INVESTIGATION] which may allow the movement of oil field wastes or hydrocarbons [FLUIDS] into sources of freshwater are properly repaired, plugged, or otherwise modified. If wells exist that are not under the operator's control, the commission will not approve the application until the person [OPERATOR] responsible for those wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of oil field wastes or hydrocarbons [FLUIDS] into sources of freshwater.

. . .

Note to publisher: subsections (i) and (j) are unchanged.

(k) The annular disposal of drilling wastes approved under 20 AAC 25.080 is an operation incidental to drilling a well and is not a disposal operation subject to this section. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.265 is repealed and readopted to read:

20 AAC 25.265. AUTOMATIC SHUT-IN EQUIPMENT. (a) A completed well with an offshore surface location, which is capable of unassisted flow of hydrocarbons to the surface, must be equipped with a commission-approved

(1) fail-safe automatic surface safety valve (SSV) system capable of preventing an uncontrolled flow; and

(2) fail-safe automatic surface-controlled subsurface safety valve (SSSV) system capable of preventing an uncontrolled flow, unless another type of subsurface valve is approved

by the commission; this valve must be in the tubing string and located below the mudline datum or, if permafrost is present, below the permafrost.

(b) An operator may demonstrate by a no-flow test that a well is incapable of unassisted flow of hydrocarbons to the surface. A minimum of 24 hours notice must be given so that a representative of the commission can witness the test.

(c) The commission will, in its discretion, also require SSVs, SSSVs, or both, on wells with onshore surface locations, after notice and an opportunity for hearing in accordance with 20 AAC 25.540.

(d) A representative of the commission will witness operation and performance tests at intervals and times as prescribed by the commission to confirm that the SSV, SSSV, and all associated equipment are in proper working condition. If an SSV, SSSV, or associated equipment fails the performance test, it must be repaired within the time frame specified by the commission or the well must be shut in. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.270 is amended to read:

20 AAC 25.270. INITIAL RESERVOIR PROPERTIES [PRESSURE]. (a) The operator shall determine the initial reservoir pressure in any new pool before regular [SIGNIFICANT] production. The results must be reported to the commission on the form entitled Reservoir Pressure Report (Form 10-412).

(b) The operator shall obtain fluid samples from each new pool at the time of discovery or prior to regular production and determine

(1) crude oil composition assay;

(2) pressure, volume, temperature (PVT) properties of the crude oil; and

(3) solution or non-associated gas composition assay.

(c) Sampling and analysis must be conducted and reported in accordance with good oil field engineering practices. Reports must be submitted to the commission within 45 days following completion of determinations.

d) The operator shall determine within three months after discovery of each new oil pool the original solution gas-oil ratio by a well test conducted in a manner approved by the commission. The operator shall report the results on the Well Status Report and Gas-Oil Ratio Tests (Form 10-409) within 45 days after the test. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.275. RESERVOIR FLUID PROPERTIES. Repealed. (Eff. 4/2/86, Register 97; repealed ___/___/___, Register __)

20 AAC 25.280(a) and (b) are amended, and a new (e) is added, to read:

20 AAC 25.280. WORKOVER OPERATIONS. (a) An application for well workover operations must be submitted by filing an [THE FORM ENTITLED] Application for Sundry Approvals (Form 10-403). The application must be approved by the commission before entering a [PRODUCIBLE OR INJECTION] well to conduct the following operations:

(1) perforate or reperforate casing; [,]

(2) stimulate; [,]

(3) pull tubing; [,]

(4) alter casing; [,]

(5) repair well.

(b) The Application for Sundry Approvals [FORM 10-403 FILING] must set out [THE FOLLOWING:]

(1) the current condition of the well;

(2) a copy of the proposed program for well work;

(3) a diagram and description of the BOP equipment required by 20 AAC 25.285[(a)] unless already on file with the commission [AND THE STATIC BOTTOM-HOLE PRESSURE];

(4) a description of the workover fluid to be used for primary well control;[.] and

(5) the estimated current bottom-hole pressure, or the actual pressure if available.

. . .

Note to publisher: subsections (c) and (d) are unchanged.

(e) Upon application, the commission will, in its discretion, waive the requirements of this section for wells in a pool for which pool rules have been prescribed under 20 AAC 25.520.

(Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.285 is repealed and readopted to read:

20 AAC 25.285. BLOWOUT PREVENTION EQUIPMENT FOR WORKOVER OPERATIONS. (a) An Application for Sundry Approvals (Form 10-403) relating to well

workover operations must include the following information or refer to that information if on file with the commission:

(1) a diagram of the blowout preventer (BOP) stack and related equipment; and

(2) a list of the blowout prevention equipment (BOPE) with specifications; and

(b) A BOP and related well control equipment must be installed, used, maintained, and tested in a manner that ensures well control during workover operations.

(c) The required working pressure of the BOPE must exceed the anticipated surface pressure to which it may be subjected during workover operations.

(d) For through-tubing workover operations with coiled tubing, small diameter drill pipe, or small diameter tubing,

(1) a full lubricator system or open hole deployment type system must be used;

(2) other requirements for the BOPE assembly are the same as for coiled tubing drilling under 20 AAC 25.036.

(e) For production tubing or drill pipe workover operations, a BOPE assembly must be installed in accordance with API RP 53, *Recommended Practices for Blowout Prevention Systems* (March 1997), or API RP 5C7, *Recommended Practices for Coiled Tubing Operations in Oil and Gas Well Services* (December 1996), as applicable, which ~~is~~are adopted by reference. At a minimum, the following equipment and components are required:

(1) an annular preventer;

(2) a set of rams with blind and pipe capabilities and, if a tapered string is used, either an additional set of rams for each size of pipe being run or a variable ram;

(3) a hydraulic actuating system with accumulator and backup system;

(4) a kill line with flanged or hubbed connections, hammer unions, or internally

clamped (swivel or chicksan) joints on hardline or fire-resistant rotary hose upstream of its connection to the BOP body, drilling spool, or wellhead;

(5) a choke line with flanged or hubbed connections on hardline or fire-resistant rotary hose;

(6) to connect separately to each of the kill and choke lines,

(i) a flanged or hubbed outlet on a drilling spool or on the BOP body with two-full opening valves on each outlet; or

(ii) two full-opening flanged or hubbed wing valves or companion valves on the wellhead, which valves must meet the required working pressure specified in the Permit to Drill; and

(7) a choke manifold that meets or exceeds the minimum requirements of API RP 53.

(f) Wireline workover operations must be equipped with

(1) a set of wireline rams sized for each diameter of wire passing through the BOPE;

(2) a lubricator system; and

(3) a high pressure pack-off and stripper.

(g) For downhole operations not covered by (d)-(f) of this section, the commission will, in its discretion, approve alternate BOPE installations.

(h) A BOPE assembly required under this section must be tested as follows:

(1) except for wireline operations, BOPE must be tested in accordance with API RP 53, *Recommended Practice for Blowout Prevention Systems* (March 1997), which is adopted by

reference, before wellbore entry and weekly thereafter, and must be function-tested each trip, but need not be function-tested more than once each day;

(2) for wireline operations,

(A) BOPE must be pressure-tested to 1.2 times the estimated wellhead pressure, using a non-compressible fluid, before wellbore entry and weekly thereafter;

(B) the BOP body must also be pressure-tested to 1.2 times the estimated wellhead pressure, using a non-compressible fluid, at least once each day and after each installation of the BOPE before wellbore entry; and

(C) the rams must be function-tested at least once each day and after each installation of the BOPE before wellbore entry if the RAMS have been used, repaired or changed out;

(3) test results must be recorded as part of the daily record required by 20 AAC 25.070(1);

(4) a minimum of 24 hours notice of each pressure test must be provided so that a representative of the commission can witness the test.

(g) Upon request, the commission will, in its discretion, approve a variance from the requirements of this section if the variance provides at least an equally effective means of ensuring well control. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in this section may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.290 OPERATIONS PRODUCING HYDROGEN SULFIDE. An operator of a well or pool that produces hydrogen sulfide gas shall utilize API RP 55, *Recommended Practices for Conducting Oil & Gas Production Operations Involving Hydrogen Sulfide* (February 1995), which is adopted by reference, in installing, operating, and maintaining surface production equipment. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030

Editor's note: A copy of the American Petroleum Institute recommended practices referred to in this section may be reviewed during business hours at the commission's office and may be obtained from the American Petroleum Institute, Order Desk, 1220 L Street, N.W., Washington, D.C. 20005-4070.

ARTICLE 4.
REPORTS

Section
300. Request for additional information
310. Books and records
320. Filing of forms

20 AAC 25.300 is amended to read:

20 AAC 25.300. REQUEST FOR ADDITIONAL INFORMATION. This chapter does not limit or restrict the authority of the commission to require the furnishing of such additional reports, data, or other information relative to drilling, production, transportation, storage, or handling of [CRUDE] oil or [NATURAL] gas and injection operations on oil and gas properties and units in the state [ALASKA], as may appear to it to be necessary or desirable, either generally or specifically, for the prevention of waste, the protection of correlative rights, the prevention of fluid movement [MOVEMENT OF FLUIDS] into freshwater sources, and the conservation of [THE] natural resources. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.310 is amended to read:

20 AAC 25.310. BOOKS AND RECORDS. All operators[,] of [PRODUCERS, TRANSPORTERS, STORERS, AND HANDLERS OF CRUDE OIL AND NATURAL GAS ON] oil and gas properties and units within the state [ALASKA] shall make and maintain [, AND KEEP IN ALASKA] for a period of not less than five years, books and records necessary [APPROPRIATE BOOKS AND RECORDS COVERING THEIR OPERATION IN ALASKA. THE DATA FROM THESE BOOKS AND RECORDS MUST BE USED] to make and

substantiate the reports required by this chapter. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.320(a) is repealed and readopted, and (b) is amended, to read:

20 AAC 25.320. FILING OF FORMS. (a) Where this chapter requires a form to be filed, one originally signed, commission-approved form must be submitted to the commission with the required number of copies indicated on each form. A computer~~iz~~-generated form may be submitted in place of the form furnished by the commission if ~~is~~t contains the same required information and has been approved for format by the commission.

(b) Forms required by this chapter will be furnished by the commission upon request and will be revised at the discretion of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

ARTICLE 5.
ENHANCED RECOVERY

Section

400. (Repealed)
402. Enhanced recovery operations
410. (Repealed)
412. Casing, cementing, and tubing of injection wells for enhanced recovery, disposal, and storage
420. Notice of commencement and discontinuance of injection operations
430. Enhanced recovery records
432. Report of underground injection
440. Freshwater aquifer exemption
450. Underground injection control variances
460. Area injection orders

20 AAC 25.402 is repealed and readopted to read:

20 AAC 25.402. ENHANCED RECOVERY OPERATIONS. (a) Enhanced recovery operations involving the introduction of extraneous forms of energy into a pool by injection are prohibited, except as ordered by the commission under this section. In response to an application for injection filed by an operator, the commission will, in its discretion, authorize the injection of fluids that function primarily to enhance recovery of oil and gas and that are appropriate for enhanced recovery. Except as provided in (i) of this section, an order authorizing injection for an enhanced recovery project remains valid unless revoked by the commission.

(b) The operator has the burden of demonstrating that the proposed operation will not allow the movement of fluid into sources of freshwater. Injection wells must be cased, the casing cemented, and the wells operated in a manner that will isolate the injection zone and protect oil, gas, and freshwater. It is the operator's responsibility to ensure that all wells, including waterwells and other borings, under the operator's control within a one-quarter mile radius of an injection well, which may allow the movement of fluids into sources of freshwater, are properly repaired, plugged, or otherwise modified. If wells exist that are not under the

operator's control, the commission will not approve the application until the person responsible for these wells has properly repaired, plugged, or otherwise modified the wells to prevent the movement of fluids into sources of freshwater.

(c) An application for injection must include

(1) a plat showing the location of all proposed injection wells, abandoned or other unused wells, production wells, dry holes, and any other wells that penetrate the injection zone within one-quarter mile of each proposed injection well;

(2) a list of all operators and surface owners within a one-quarter mile radius of each proposed injection well;

(3) an affidavit showing that the operators and surface owners within a one-quarter mile radius have been provided a copy of the application for injection;

(4) a full description of the particular operation for which approval is requested;

(5) the names, descriptions, and depths of the pools to be affected;

(6) the name, description, depth, and thickness of the formation into which fluids are to be injected, and appropriate geological data on the injection zone and confining zone(s), including lithologic descriptions and geologic names;

(7) logs of the injection wells if not already on file;

(8) a description of the casing of the injection wells, or the proposed casing program, and the proposed method for demonstrating mechanical integrity of the casing and tubing under 20 AAC 25.412 and for demonstrating that no fluids will move behind casing beyond the approved injection zone;

(9) a statement of the type of fluid to be injected, its composition, its source, the estimated maximum amounts to be injected daily, and its compatibility with the injection zone;

(10) the estimated average and maximum injection pressure;

(11) evidence to support a commission finding that each proposed injection well will not initiate or propagate fractures through the overlying strata or confining zone(s) that might enable the injection fluid or formation fluid to enter any freshwater strata;

(12) a standard laboratory water analysis, or the results of another method acceptable to the commission, to determine the quality of the water within the formation into which fluid injection is proposed;

(13) reference to any applicable freshwater exemption issued under 20 AAC 25.440;

(14) the expected incremental increase in ultimate hydrocarbon recovery; and

(15) a report on the mechanical condition of all wells that have penetrated the injection zone within a one-quarter mile radius of each proposed injection well.

(d) The commission will publish notice of the enhanced recovery application and provide opportunity for a hearing in accordance with 20 AAC 25.540.

(e) The mechanical integrity of an injection well must be demonstrated under 20 AAC 25.412 before injection is begun and after a well workover affecting mechanical integrity is conducted. To confirm continued mechanical integrity, the operator shall monitor the injection pressure and rate and the pressure in the casing-tubing annulus during actual injection. The monitored data must be reported monthly on the Monthly Injection Report (Form 10-406).

(f) If the casing-tubing annulus pressure subjects the casing to a hoop stress that exceeds 70 percent of the minimum yield strength of the casing, or if an injection rate, operating pressure observation, or pressure test indicates pressure communication or leakage in any casing, tubing,

or packer, the operator shall notify the commission by the next working day and shall implement commission-approved corrective action.

(g) The commission will, in its discretion, require additional mechanical integrity tests.

(h) The commission will, in its discretion, approve a modification to an existing or pending injection operation under 20 AAC 25.507, when the applicant proves to the commission, upon application containing sufficient detail to evaluate the proposed modification, that the modification will not allow the movement of fluids into sources of freshwater.

(i) If injection operations are not begun within 24 months after the approval date, the enhanced recovery approval expires unless a letter of application for extension is approved by the commission. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.412 is repealed and readopted to read:

20 AAC 25.412. CASING, CEMENTING, AND TUBING OF INJECTION WELLS FOR ENHANCED RECOVERY, DISPOSAL, AND STORAGE. (a) A well used for injection must be cased and cemented in accordance with 20 AAC 25.030 to prevent leakage into oil, gas, or freshwater sources.

(b) A well used for injection must be equipped with tubing and packer, or other equipment that isolates pressure to the injection interval, unless otherwise specifically approved by the commission. The minimum burst pressure of the tubing must exceed the maximum surface injection pressure by at least 25 percent. The packer must be placed within 200 feet ~~of~~measured depth above the top of the perforations, unless otherwise approved by the commission.

(c) Before injection begins, a well must be pressure-tested to demonstrate the mechanical integrity of the tubing and packer and the casing immediately surrounding the injection tubing string. The casing must be tested at a surface pressure of 1,500 psig or 0.25 psi/ft multiplied by the true vertical depth of the casing shoe, whichever is greater, but the casing may not be subjected to a hoop stress that will exceed 70 percent of the minimum yield strength of the casing. The test pressure must show stabilizing pressure and may not decline more than 10 percent within 30 minutes.

(d) The operator shall provide a cement quality log or other well data approved by the commission to demonstrate isolation of the injected fluids to the approved interval.

(e) A minimum of 24 hours notice of a pressure test required by (c) of this section must be given so that a representative of the commission can witness the test. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

~~20 AAC 25.420 (b) is amended to read:~~

~~(b) Within 10 days after permanently discontinuing an injection operation or program, the operator shall notify the commission of the date of discontinuance and the reasons for it. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)~~

~~Authority: AS 31.05.030~~

20 AAC 25.430 is amended to read:

20 AAC 25.430. ENHANCED RECOVERY RECORDS. Each operator shall keep accurate records showing volumes of fluids produced, injected volumes, reservoir pressures, and

injection pressures, by well and pool. Each operator shall retain these records for five years. The commission will, in its discretion, specify retention of these records for a longer time period. Upon reasonable notice, the commission [OR ITS AUTHORIZED REPRESENTATIVE] must be given full access during normal business hours to all records. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.432 is repealed and readopted, to read:

20 AAC 25.432. REPORT OF UNDERGROUND INJECTION. (a) An operator that injects fluids into subsurface strata through a service well for any purpose, other than fracturing, acidizing, or other similar treatment, shall file with the commission each month reports that show all injected volumes and other data, by well and pool, as required by the commission on the Monthly Injection Report (Form 10-406), Report of Injection Projects (Form 10-413), and, if applicable, the Facility Report of Produced Gas Disposition (Form 10-422).

(b) An annual report must be filed that tabulates the monthly information required on the Report of Injection Projects (Form 10-413). The annual report must be submitted by April 1 each year unless it is required by pool rules to be included with a pool specific annual surveillance report.

(Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.440 (c) is amended to read:

(c) Freshwater aquifers within the state [ALASKA] that were [ARE] designated as exempt aquifers by the United States Environmental Protection Agency [AT THE TIME THE COMMISSION IS GRANTED PRIMARY ENFORCEMENT RESPONSIBILITY] under 42 U.S.C. 300h-4 are [WILL BE] accepted as exempt aquifers by the commission [WITHOUT FURTHER ACTION]. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.450 (a) is amended to read:

20 AAC 25.450. UNDERGROUND INJECTION CONTROL VARIANCES. (a) If injection does not occur into, through, or above [A] freshwater [SOURCE OR NON-EXEMPT FRESHWATER AQUIFER], the commission will, in its discretion, authorize less stringent requirements for a well or project than otherwise required by this chapter, for radius of investigation, casing and cementing, tubing and packer, mechanical integrity, operation, monitoring, and reporting, to the extent that the reduction in requirements will not result in an increased risk of movement of fluids into [A] freshwater [SOURCE].

(Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.460 is amended to read:

20 AAC 25.460. AREA INJECTION ORDERS. (a) Upon application under this section and subject to the provisions of 20 AAC 25.252 or 25.402, as applicable, the commission will, in its discretion, after [LEGAL] notice and opportunity for public hearing in accordance with

20 AAC 25.540, issue an order permitting the underground injection of fluids on an area basis, rather than for each well individually, if the wells are

. . .

Note to publisher: paragraph (1) is unchanged.

(2) within the same field, facility site, reservoir, project, or similar area; and

(3) operated by a single operator. [; AND]

(4) repealed / / [USED TO INJECT OTHER THAN HAZARDOUS WASTE].

(b) The area injection order will specify

. . .

Note to publisher: paragraph (1) is unchanged.

(2) the requirements for drilling, completing, operating, monitoring, reporting, and abandoning all wells authorized by the order.

(c) The area injection order will, in the commission's discretion, authorize the operator to drill, complete, and operate, to convert, or to plug and abandon wells within the area if

(1) the operator files with the commission a Permit to Drill (Form 10-401) or an Application for Sundry Approvals (Form 10-403), as appropriate, for approval before work; and

. . .

Note to publisher: paragraph (2) is unchanged.

(d) If the commission determines that any well drilled and operated under an area injection order does not satisfy all of the requirements [REQUIRE-MENTS] of this section, the commission will take enforcement action to ensure compliance. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

ARTICLE 6.
GENERAL PROVISIONS

Section
505. Scope of regulations
507. Change of an approved program
510. Commission [OFFICE, HOURS, AND] seal
515. United States government land [LEASES]
517. Plan of [FOR POOL] development and operation[, AND INTEGRATION OF NTERESTS]
518. Agreements integrating interests under AS 31.05.110(a)
520. Field and pool regulation [AND CLASSIFICATION]
525. (Repealed)
526. Conduct of operations [AND FIRE HAZARD]
528. Open pit storage of oil
530. Cooperative [COOPERATION] agreements with other parties
534. Tests, surveys, and inspections [REMEDIAL MEASURES]
535. Enforcement
536. (Repealed)
537. Public and confidential [WELL] information
538. (Repealed)
539. Emergency action
540. Hearings
545. Public mailing lists
550. Oaths
555. (Repealed)
556. Orders
557. Subpoenas
560. Time
570. (Repealed) [DEFINITIONS]

20 AAC 25.507 is repealed and readopted to read:

20 AAC 25.507. CHANGE OF AN APPROVED PROGRAM. (a) Except as otherwise provided by 20 AAC 25.015, if an operator desires to make a substantive change in an approved program, complete details of the current condition and the proposed change must be submitted to the commission with the Application for Sundry Approvals (Form 10-403). A change of an approved program may not be undertaken without commission approval. The commission will condition its approval as necessary or appropriate.

(b) Where operational necessity requires prompt action, oral approval of a change may be obtained from the commission. The required Application for Sundry Approvals (Form 10-403) must be submitted within the commission's next three working days setting out the name of the person who provided approval and the date of the oral approval. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.095

20 AAC 25.510 (a) and (b) are repealed, and (c) is amended, to read:

20 AAC 25.510. COMMISSION [OFFICE, HOURS, AND] SEAL. (a) Repealed ___/___/___.

(b) Repealed ___/___/___.

(c) The official seal of the commission is reproduced below.

Note to publisher: Commission seal shown on the next page to be inserted here

(Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

20 AAC 25.515 is amended to read:

20 AAC 25.515. UNITED STATES GOVERNMENT LAND [LEASES]. A person, including a federal agency, drilling for or producing oil or [NATURAL] gas or conducting underground injection activities related to the recovery and production of oil or gas on federal land subject to the state's police powers shall comply with all applicable regulations and orders of the commission. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.027 AS 31.05.030

20 AAC 25.517 is repealed and readopted to read:

20 AAC 25.517. PLAN OF DEVELOPMENT AND OPERATION. (a) Before commencement of regular production from an oil or gas pool, the operator shall submit to the commission a plan of development and operation for the pool or the portion of the pool for which development is contemplated by the operator.

(b) Unless otherwise ordered by the commission, the operator shall submit to the commission annual progress reports under the plan of development and operation. Any amendments and updates to the plan also must be submitted ~~to the commission~~ at least annually.

(c) The plan of development and operation must provide for

(1) the prevention of waste;

(2) the protection of correlative rights ~~for the owner of each property in the pool~~; and

(3) a greater ultimate recovery of oil and gas. (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 [AS 31.05.110]

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.518. AGREEMENTS INTEGRATING INTERESTS UNDER AS 31.05.110(a). A voluntary agreement for the purpose of integrating interests under AS 31.05.110(a) must be filed with the commission no later than 30 days after it is executed. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.110

20 AAC 25.520 is amended to read:

20 AAC 25.520. FIELD AND POOL REGULATION [AND CLASSIFICATION]. (a) Upon the motion of the commission, or the request of an affected owner or [PROPERTY] operator [OR OWNER] at any time after the discovery of oil or gas in a field or pool, a hearing will be held in accordance with 20 AAC 25.540 and the commission will issue an order, based upon the evidence presented, [CLASSIFYING THE POOL AS AN OIL OR GAS POOL IN A FIELD AND] prescribing rules to govern the proposed [FOR THE] development and operation of the pool. A pool order so issued will

(1) prevent waste, protect freshwater, [AND] protect correlative rights, and ensure a greater ultimate recovery of oil and gas; and

(2) be based on the operating and technical data presented.

(b) The commission will, in its discretion, amend pool orders in accordance with the procedures set forth in 20 AAC 25.540 [RECLASSIFY FIELDS AND POOLS, OR AMEND

POOL ORDERS, UPON THE PRESENTATION OF ADDITIONAL DATA AT A SUBSEQUENT HEARING]. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.060

AS 31.05.095 AS 31.05.100

20 AAC 25.526 is amended to read:

20 AAC 25.526. CONDUCT OF OPERATIONS [AND FIRE HAZARD]. An operator shall carry on all operations and maintain the property at all times in a safe and skillful manner in accordance with good oil field engineering [INDUSTRY] practices[,] and having due regard for the preservation and conservation of the property and protection of freshwater. [EACH WELL LOCATION AND PROPERTY MUST BE MAINTAINED IN A MANNER TO PREVENT FIRES. ALL RUBBISH, DEBRIS, WASTE MATERIAL, SPILLED OIL, AND ANY OTHER SUBSTANCE THAT CONSTITUTES A FIRE HAZARD MUST BE DISPOSED OF IN AN ENVIRONMENTALLY SAFE MANNER.] Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25.530 is amended to read:

20 AAC 25.530. COOPERATIVE [COOPERATION] AGREEMENTS WITH OTHER PARTIES. The commission will, in its discretion, from time to time enter into agreements [ARRANGEMENTS] with state and federal agencies, industry committees, or individuals, with respect to special projects, services, and studies relating to underground fluid injection and the

conservation of oil and gas. If an agreement [ARRANGEMENT] requires the commission to use procedures or apply rules not covered in this chapter, the procedures necessary to carry out the intent of the agreement [ARRANGEMENT] will be formulated and made available at the office of the commission after public notice and opportunity for public comment, pursuant to 11 AAC 25.540. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.023 AS 31.05.030

20 AAC 25.534 is amended to read:

20 AAC 25.534. TESTS, SURVEYS, AND INSPECTIONS [REMEDIAL MEASURES]. When considered necessary or advisable to carry out the purposes of AS 31.05 (Alaska Oil and Gas Conservation Act) and this chapter, the commission will require that tests or surveys be made to determine the quality of oil and gas produced; the formation, casing, tubing, or other pressures; the existence of any waste of [CRUDE] oil, gas, or reservoir energy; or the risk of fluid movement into freshwater [SOURCES]. The commission will, in its discretion, exercise its statutory power to enter and conduct on-site investigations and inspections at reasonable times of facilities, equipment, practices, records, or operations for the purpose of ensuring compliance with the requirements of this chapter. [IF IT IS DETERMINED THAT THE REQUIREMENTS OF THIS CHAPTER ARE NOT BEING MET, THE COMMISSION WILL ORDER REMEDIAL WORK OR TAKE OTHER ACTION IT CONSIDERS NECESSARY.] (Eff. 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.535. ENFORCEMENT. (a) When the commission has reason to believe, as the result of an investigation or otherwise, that a person has violated or failed to comply with a provision of AS 31.05, this chapter, or a commission order, permit, or other approval, the commission will, in its discretion, give written notification to the person.

(b) The commission's written notification to the person will

(1) state the nature of the apparent violation or noncompliance;

(2) summarize the basis of the commission's reason to believe that a violation or noncompliance has occurred;

(3) state the action that the commission proposes to take under (e) of this section; and

(4) inform the person of the person's rights and liabilities under (c) - (e) of this section.

(c) Within 10 days after issuance of a notification, or within such longer period as the commission may specify, a person may file with the commission a written response (1) acquiescing, in whole or in part, in a proposed commission action; (2) requesting informal review; or (3) requesting a hearing under 20 AAC 25.540. If a person fails to file a timely written response, the person will be deemed to have acquiesced in the proposed commission action. If a person requests a hearing, the commission will schedule a hearing under 20 AAC 25.540.

(d) If a person requests informal review, the commission will provide an opportunity for the person to submit documentary material and make a written or oral statement. The commission will then issue a tentative decision or order, which becomes final 11 days after it is

issued unless within 10 days after it is issued the person files a written request for a hearing, in which case the tentative decision or order is of no effect. If the person requests a hearing, the commission will schedule a hearing under 20 AAC 25.540.

(e) After a person acquiesces in a proposed action under (c) of this section, or after an informal review or a hearing under (c) or (d) of this section, and when the commission finds that a person has violated or failed to comply with a provision of AS 31.05, this chapter, or a commission order, permit, or other approval, the commission will, in its discretion, order one or more of the following, as it determines to be applicable:

(1) corrective action or remedial work;

(2) revocation or suspension of a permit or other approval;

(3) payment under the bond required by 20 AAC 25.025; and

(4) imposition of penalties under AS 31.05.150.

(f) The commission's action under (e) of this section after an informal review or a hearing is not limited to what was proposed under (b)(3) of this section, as long as the person had reasonable notice and opportunity to be heard as to the commission's action.

(g) An action by the commission under this section is in addition to any action the commission may take under AS 31.05.160. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.040

AS 31.05.050 AS 31.05.060

AS 31.05.150

20 AAC 25.537 (a)(1), (b), and (c) are amended, and a new (f) is added, to read:

20 AAC 25.537. PUBLIC AND CONFIDENTIAL [WELL] INFORMATION. (a) The commission will routinely make available to the public, by means of records or reports, in its offices or elsewhere, or by means of regular publication, the following information:

(1) surface and proposed bottom-hole locations [LOCATION] of each well[,] after approval of the Permit to Drill (Form 10-401);

. . .

Note to publisher: the remainder of subsection (a) is unchanged.

(b) Engineering, geologic, geophysical, and other commercial information [INFORMATION] not required by this chapter, but voluntarily filed with the commission will be kept confidential if the person filing the information so requests. This subsection does not apply to information submitted for the first time in a public hearing under 20 AAC 25.540, the confidentiality of which will be governed by other applicable law.

(c) In this section, "well status" means the classification of a well as oil, gas, service, suspended, shut-in, or abandoned.

. . .

Note to publisher: subsections (d) and (e) are unchanged.

(f) This section is not intended to limit any constitutional, statutory, or common law rights or obligations of a person or the commission to obtain information or maintain the confidentiality of information filed with the commission, such as may apply to a public hearing under 20 AAC 25.540. Where disclosure of otherwise confidential information is required, such disclosure will be limited and conditioned to the extent necessary to comport with applicable constitutional, statutory (including trade secret provisions, such as AS 45.50.940(3)), and

common law doctrines that protect commercially sensitive, confidential, and proprietary information. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: [AS 31.05.026] AS 31.05.030

AS 31.05.035 [AS 31.05.170]

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.539. EMERGENCY ACTION. (a) The commission will, in its discretion, issue a temporary emergency order without a hearing if necessary to protect against imminent waste, irreparable harm to correlative rights, contamination of freshwater, or a safety hazard resulting from a violation of a provision of AS 31.05, this chapter, or a commission order. Before issuing a temporary emergency order, the commission will attempt to communicate with the operator about the circumstances and need for a temporary order.

(b) A temporary emergency order will be supported by a written decision~~al document~~ describing the factual and legal basis for the action, including the necessity for acting on an emergency basis. The decision~~al document~~ will be ~~prepared and~~ provided to the operator within 24 hours of the issuance of the order.

(c) A temporary emergency order expires after 14 days unless

(1) an earlier expiration date is established in the order;

(2) the operator agrees to an extension; or

(3) a hearing has actually commenced, in which case the temporary emergency order will remain in effect for an additional period not to exceed the shorter of 14 days after the day the hearing commences or three working days after the day the hearing closes, whichever

period is shorter. For the purposes of a notice of hearing under this subsection, the notice period is 10 days, and the 30 day notice period established in 20 AAC 25.540 does not apply. (Eff. ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.050

AS 31.05.060 AS 31.05.150

20 AAC 25.540 is repealed and readopted to read:

20 AAC 25.540. HEARINGS. (a) On its own motion or if a written request is received to issue an order affecting a single well or a single field, the commission will publish notice in an appropriate newspaper. The notice will set out the essential details of the requested order and provide an opportunity for public comment. The notice will tentatively specify the place, time, and date for the hearing that will be scheduled no fewer than 30 days after the date of publication. Any person may submit a written protest or written comments during that 30 day period. In addition, any person may request that the tentatively scheduled hearing be held by filing a written request with the commission at its office in Anchorage, Alaska, within 15 days after the publication date. The request for hearing must identify the requester's interest in the proposed action and provide the reasons for desiring a public hearing. If the commission determines that a significant issue is raised in a request for hearing, or if the commission desires to hold a hearing, a hearing will be held on the date and time specified in the notice. If no request for a hearing is timely filed, the commission will, in its discretion, issue an order without a hearing.

(b) On its own motion or if a written request for a public hearing is received concerning a matter within the jurisdiction of the commission under this chapter, the commission will publish

notice in an appropriate newspaper. The notice will provide the essential details of the matter and set out the place for the public hearing, the date, and the time for the public hearing. The hearing will be scheduled no fewer than 30 days after the date of publication.

(c) Except as otherwise provided in (e) of this section, the following procedures apply to public hearings conducted under (a) or (b) of this section:

(1) the hearing will be called to order and the subject of the hearing, along with the date and place of public notice given for the hearing, will be read into the record;

(2) the commission will receive both sworn testimony and unsworn statements; it will give greater weight in its deliberations to sworn testimony;

(3) all persons wishing to testify will be sworn;

(4) each witness shall state the witness's name and whom the witness represents;

(5) each witness who wishes to give expert testimony shall state the witness's qualifications, and the commission will rule on whether the witness qualifies as an expert;

(6) the applicant will be asked to present testimony first; all others wishing to present testimony will be heard next; upon request, the commission will, in its discretion, allow cross-examination of witnesses;

(7) a person wishing to make an oral statement will be allowed to do so after the conclusion of all testimony;

(8) the commission will, in its discretion, ask questions of a witness;

(9) except as may be allowed under (6) of this subsection, no one will be permitted to ask questions of witnesses directly; to have a question directed to a witness, a person shall provide the question in writing, along with the person's name and that of the witness, to a designated commission representative; before the end of the hearing, the commission will review

these questions and ask those that it believes will be helpful in eliciting needed information; all questions will be included in the public record;

(10) a written transcript of the hearing will be prepared and included in the public record of the hearing;

(11) the commission will, in its discretion, ~~provide for~~allow pre-filed written testimony in place of or in addition to oral testimony.

(d) Hearings on matters of statewide or general application will be held under the applicable provisions of AS 44.62.

(e) In a hearing under 20 AAC 25.535, a party may be represented by counsel, call and examine witnesses, present relevant evidence unless unduly cumulative or repetitious, cross-examine witnesses, impeach witnesses, and rebut adverse evidence. The commission will establish a reasonable date before the hearing by which the commission and each party must provide: (1) the names and addresses of persons known to have knowledge of relevant facts and, unless privileged, their written or recorded statement or summaries of statements; (2) the name, address, and qualifications of each expert who will testify at the hearing, and a written description of the substance of the expert's proposed testimony, the expert's opinion, and the underlying basis of that opinion; and (3) a copy of all documents and a description of all other tangible things intended to be used in the hearing. The commission will base its decision with respect to contested issues of fact only on evidence presented during the hearing.

(f) Pursuant to a pre-hearing conference or otherwise, the commission will, in its discretion, establish additional procedures for a specific hearing consistent with the procedures in (c) or (e) of this section, as applicable, or as otherwise necessary to provide due process to a party. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.040

AS 31.05.050 AS 31.05.060

AS 31.05.070

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.556. ORDERS. All orders of the commission require approval of at least two commissioners. (Eff. ___/___/___, Register __)

Authority: AS 31.05.011 AS 31.05.030

20 AAC 25.557 is amended to read:

20 AAC 25.557. SUBPOENAS. (a) The commission will, in its discretion, issue subpoenas [AND SUBPOENAS DUCES TECUM].

(b) A subpoena [SUBPOENAS DUCES TECUM] for the production of books, records, papers, or other documents of any sort will, in the commission's discretion, be issued by the commission upon a written request. The applicant must establish [THAT HE OR SHE HAS] a proper relation to the matter, and must show the relevance of the evidence sought and the facts expected to be proved by them.

(c) [THE ISSUANCE OF A] A subpoena requiring the attendance of a witness for the purpose of taking oral testimony before the commission will, in the commission's discretion, be issued by the commission upon a written request. The applicant must establish a [THAT HE OR SHE HAS] proper relation to the matter and give the name and address of the desired witness. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am ___/___/___, Register __)

Authority: AS 31.05.030 AS 31.05.040

AS 31.05.070

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.560. TIME. (a) Where AS 31.05 or this chapter requires or permits a person to file a document with the commission, the document is considered filed when it is received in the commission's office.

(b) For purposes of the applicable time limits established in this chapter, a well is considered

(1) completed on the date ~~it is first perforated for regular production, or if not perforated, on the date it is abandoned or suspend~~the wellhead is installed;

(2) abandoned on the date the surface plug is installed in accordance with 20 AAC 25.105;

(3) suspended on the date the near-surface plug is installed or the well is capped in accordance with 20 AAC 25.105 and 25.110. (Eff. ___/___/___, Register ___)

Authority: AS 31.05.030 AS 31.05.035

AS 31.05.040

20 AAC 25.570 is repealed:

20 AAC 25.570. DEFINITIONS. Repealed. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97; am 1/1/95, Register 132; repealed ___/___/___, Register ___)

Editor's note: As of Register ___ (_____ 19 ___), the substance of 20 AAC 25.570 was moved to 20 AAC 25.990.

ARTICLE 7.

DEFINITIONS

Section
990. Definitions

20 AAC 25 is amended by adding a new section to read:

20 AAC 25.990. DEFINITIONS. In this chapter, unless the context requires otherwise,

(1) "abandon" means to plug a well in accordance with ~~the applicable provisions of 20 AAC 25.105 and, in the case of a well that has not been completed, without the operator's stated intention to determine in the future either to complete the well as an oil, gas, or service well or to abandon the well~~20 AAC 25.105 and without the commission's approval of well suspension under 20 AAC 25.110;

(2) "abnormally geo-pressured strata" means subsurface zones where the pore pressure exceeds a gradient of 0.50 psi/ft;

(3) "API" means the American Petroleum Institute;

(4) "API number" means the number assigned by the commission for a well or wellbore segment consistent with the API well numbering convention;

(5) "API RP" means API recommended practices;

(6) "barrel" includes "stock tank barrel" and means 42 U.S. gallons, measured at 60° F. and 14.65 psia.;

(7) "BOP" means blowout preventer, which is a casinghead assembly equipped with special gates or rams or other packoffs that can be closed around the drill pipe, tubing, casing, or tools, and that completely closes the top of the casing to control well pressure;

(8) "BOPE" means blowout prevention equipment;

(9) "bottom-hole location" means the subsurface point identified by the subsea depth of the greatest measured depth penetration of a well or a welbore segment;

(10) "casing stub" means the remnant of a casing string when the upper portion of the casing has been cut and recovered;

(11) "commission" means the Alaska Oil and Gas Conservation Commission;

(12) "complete" means to equip and condition a well as an oil, gas, or service well so that it is capable of producing oil or gas or of injecting fluids; in the case of a well branch in a previously completed well, "complete" means to equip and condition a well branch so that it is capable of contributing to the well's production of oil or gas or injection of fluids;

(13) "completion operation" means work performed in a well after the casing and cementing of the wellbore, and includes plugging, perforating, stimulating, testing, and equipping the well to produce oil or gas or to inject fluids;;

(14) "conductor casing" means a casing string set before surface casing; depending on well configuration, it can be either the first or second string of casing set in a well and usually supports a diverter system;

(15) "day" means a calendar day;

(16) "development well" means a well drilled to a known productive pool;

(17) "displacement method" means pumping a cement slurry or other material into a well through a drillpipe or other tubular string and recovering displaced fluids on the surface;

(18) "diverter system" means an assembly of nipples, valves, and piping attached to a well's structural or conductor casing for venting a gas kick away from the drill rig;

(19) "downsqueeze method" means pumping a cement slurry or other material into a well through a drillpipe or other tubular string and forcing displaced fluids into a downhole formation;

(20) "drilling fluid" means any fluid used for the purpose of drilling a well;

(21) "drilling operations" means the penetration of ground below the setting depth of structural or conductor casing, if set, using a drilling rig capable of performing the permitted well work, and includes the running of casing, cementing, and other downhole work performed ancillary to formation evaluation, and all operations necessary to complete and equip the well so that formation fluids can be safely brought to the surface;

(22) "drilling unit" means an area of a pool established by the commission under AS 31.05.100, either by order or by regulation, to which no more than one oil or gas well may be drilled and from which no more than one oil or gas well may produce;

(23) "exploratory well" means a well drilled to discover or to delineate a pool;

(24) "fluid" means any material or substance that flows or moves, whether in a semi-solid, liquid, sludge, gaseous, or other form or state;

(25) "freshwater" means water having a total dissolved solids concentration of less than 10,000 milligrams per liter that occurs in ~~strata~~a stratum not exempted under 20 AAC 25.440, or water that occurs in ~~strata that supply~~a stratum that serves as a source of drinking water for human consumption;

(26) "gas well" means a well that produces predominantly gas at a gas-oil ratio over 100,000 scf/stb, unless on a pool by pool basis the commission establishes another ratio;

(27) "gas-oil ratio" means the cubic feet of gas, determined at 60° F. and 14.65 psia, that are produced per stock tank barrel of oil produced;

(28) "injection" means the subsurface emplacement of fluid for enhanced recovery of oil or gas, disposal of oil field wastes, or underground storage of hydrocarbons;

(29) "intermediate casing" means a casing string run between the surface casing and the production casing or production liner and cemented in place to isolate abnormally geo-pressured strata, lost circulation zones, salt sections, or unstable shale sections;

(30) "landowner" has the meaning given in AS 31.05.170;

(31) "liner" means a string of casing that does not extend to surface but is hung from inside the previous casing string or may be set and cemented in place;

(32) "meter curve" means a graph of the meter factor plotted against the flow rate, or of the pulse-per-unit-volume factor plotted against the flow rate, over the operating range of a meter;

(33) "meter factor" means the number obtained by dividing the actual volume of liquid passed through a meter during proving by the volume registered by the meter;

(34) "mudline datum" means

(A) for a beach location, the plane of mean low water depth extended beneath the well site;

(B) for a location on a shifting natural island, the depth at which a horizontal plane through the toe of the island intersects the wellbore;

(C) for a location on an artificial island, the depth of the mudline as it existed before construction of the island;

(D) for other offshore locations, the mudline;

(35) "multiple completion" means the completion of a well so as to permit production from more than one pool, with the production from each pool completely segregated;

(36) "offshore" ~~includes~~means, in addition to its ordinary meaning, beach, artificial island, and shifting natural island locations;

(37) "oil well" means a well that produces predominantly oil at a gas-oil ratio of 100,000 scf/stb or lower, unless on a pool by pool basis the commission establishes another ratio;

(38) "operator" means an owner or a person authorized by an owner who is responsible for drilling, development, production, injection, disposal, storage, abandonment, and location clearance;

(39) "owner" has the meaning given in AS 31.05.170;

(40) "pilot gas" means gas routed to a safety flare system to maintain an ignition source;

(41) "production casing" means the casing installed from the wellhead to the top of or through the completion interval and cemented in place to seal off production or injection zones and water bearing formations;

(42) "property" means a legally described tract of land, submerged or otherwise, to which a person has the right to drill, extract, remove, clean, process, and dispose of oil, gas, and associated substances;

(43) "purge gas" means gas used to maintain forward flow and positive pressure in a safety flare system;

(44) "reservoir" means the same as pool in AS 31.05.170;

(45) "service well" means a well used for injecting water, gas, or other fluids into a reservoir or producing formation in pressure maintenance, enhanced recovery, or storage operations, for disposing of oil field wastes, or for conducting other operations in support of oil or gas production;

(46) "shut down" means to halt temporarily an operation or activity with the intent and obligation to resume the operation or activity at the site in the future;

(47) "shut in" means to shut a well's surface, wellhead, or subsurface valves to halt flow from or into the well, with the completion interval remaining open to the tubing and to the casing;

(48) "sidetrack operation" means a drilling operation conducted for the purpose of straightening the original hole, bypassing junk, or correcting mechanical difficulties in the original hole;

(49) "stratigraphic test" means a hole drilled for the sole purpose of gaining structural or stratigraphic information~~, or both,~~ to aid in exploring for oil and gas;

(50) "structural casing" means a short string of large diameter pipe which may be set by driving, jetting, or drilling to support unconsolidated shallow sediments, provide hole stability for initial drilling operations, and provide anchorage for a diverter system;

(51) "surface casing" means a string of casing set and cemented in a well to protect freshwater and prevent lost circulation while drilling deeper; usually it is the first string of casing upon which blowout prevention equipment is set;

(52) "suspend" means to plug a well in accordance with ~~the applicable provisions of~~ 20 AAC ~~25.105 and~~ 25.110 and with the operator's ~~stated intention to determine in the future either to~~reserving the option later to re-enter and redrill the well or complete the well as an oil, gas, or service ~~well or to abandon the~~ well;

(53) "underbalanced drilling" means drilling under conditions where the hydrostatic head of the drilling fluid column is intentionally designed to be lower than the pressure of the formation being drilled;

(54) "well" means a hole penetrating the earth, usually cased with steel pipe, and from which oil or gas, or both, is obtained or obtainable, or which is made for the purpose of finding or obtaining oil or gas or of supporting oil or gas production; a well may have multiple well branches drilled to different bottom-hole locations;

(55) "well branch" means that portion of a well drilled below the structural or conductor casing to explore or produce a separate objective in a well with more than one bottom-hole location. (Eff. ___/___/___, Register ___)

Authority: AS 31.05.030

Editor's note: Before Register ___ (_____19___), the substance of 20 AAC 25.990 was contained in 20 AAC 25.570.