STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
333 West 7th Avenue, Suite 100
Anchorage Alaska 99501

Re: **THE APPLICATION OF BPXA EXPLORATION (ALASKA) INC.** for an order allowing underground injection of fluids for enhanced oil recovery in Aurora Oil Pool, Prudhoe Bay Field, North Slope, Alaska	))))))	Prudhoe Bay Field Aurora Oil Pool Area Injection Order No. 22A April 3, 2003

IT APPEARING THAT:

1. By letter and application dated December 9, 2002, BPXA Exploration (Alaska) Inc. ("BPXA") requested an order from the Alaska Oil and Gas Conservation Commission ("Commission") modifying Area Injection Order No. 22 (corrected version, dated September 17, 2001) authorizing underground injection of miscible injectant ("MI") for enhanced oil recovery in the Aurora Oil Pool ("AOP"), Prudhoe Bay Field, on the North Slope of Alaska.
2. Notice of opportunity for public hearing was published in the Anchorage Daily News on January 28, 2003.
3. The Commission did not receive any protests or comments concerning this application.
4. A hearing concerning BPXA's request was convened in conformance with 20 AAC 25.540 at the Commission's offices, 333 W. 7th Avenue, Suite 100, Anchorage, Alaska 99501 on March 4, 2003.
5. BPXA provided additional information on February 28, 2003 and on March 7, 2003.

FINDINGS:

1. Operators/Surface Owners (20 AAC 25.402(c)(2) and 20 AAC 25.403(c)(3))

   BPXA is the designated operator of the AOP. BPXA, ExxonMobil Production Company, ConocoPhillips Inc., Chevron USA Production, and Forest Oil Corporation are working interest owners. The State of Alaska is the landowner.

2. Project Area Requested for Enhanced Recovery:

The AOP is defined as an accumulation of oil that is common to, and correlates with, the interval between 6765'- 7765' measured depth ("MD") in the Mobil Oil Corporation Mobil-Phillips North Kuparuk State No. 26-12-12 well. The geology of the AOP is described in Conservation Order 457 ("CO 457") and Area Injection Order No. 22 ("AIO 22").

3. Description of Operation (20 AAC 25.402(c)(4))

The AOP is developed from the Prudhoe Bay S-Pad. Tract operations within the pool began in November 2000. The Commission approved water injection with the issuance of AIO 22 on September 7, 2001.

The proposed project involves the cyclical injection of water alternating with enriched hydrocarbon gas into the oil column of the Kuparuk River Formation of the AOP. The injectant will be comprised of hydrocarbon gas, enriched with intermediate hydrocarbons, principally ethane and propane, which is designed to be miscible with the reservoir oil. The proposed source of this enriched gas is offtake from pools within the Prudhoe Bay Unit and processed within the Prudhoe Bay Central Gas Facility.

Requested timing for injection of enriched gas into the AOP is second quarter of 2003 with initial conversion of S-104i. Wells S-101i, S-104i, S-107i, S-112i, and S-114Ai would be converted to allow for future injection of enriched gas.

4. Well Logs (20 AAC 25.402(c)(7))

Well logs for the proposed injection wells are on file with the Commission.

5. Mechanical Integrity (20 AAC 25.402(c)(8))

All newly drilled and converted injection wells have been completed in accordance with 20 AAC 25.412, thus satisfying mechanical integrity requirements. The casing programs for S-l01i, S-104i, S-107i, S-112i, and S-114Ai were permitted and completed in accordance with 20 AAC 25.030. Injection well tubulars have premium threads to prevent tubing leaks and maintain integrity during injection of enriched gas.

Cement bond logs (ultra sonic imaging tool) run in Wells S-104i and S-112i indicate good cement bond across and above the Kuparuk River Formation. The Commission has approved water-flow logs completed in Wells S-l0li, S-107i and S-114Ai to confirm injection containment into the target zone.

6. Injection Fluid and Rates (20 AAC 25.402(c)(9))

a. Source Water and Produced Water: The Aurora waterflood project uses produced water from GC-2. The composition of GC-2 produced water and compatibility issues were addressed in the original AIO 22 application. With increased surface pressures, maximum water injection capacity at AOP is estimated at 40,000 BPD.

b. Miscible Hydrocarbon Gas: The proposed project requests approval for injection of enriched gas from the Prudhoe Bay Central Gas Facility. The enriched gas is hydrocarbon with similar composition to reservoir fluids in the AOP and therefore no compatibility issues are anticipated in the formation or confining zones. Planned maximum enriched gas injection at AOP are estimated at 20 million SCF per day.

7. Injection Pressures (20 AAC 25.402(c)(10))

Enriched gas and water injection operations at the AOP are expected to be above the Kuparuk River Formation parting pressure to enhance injectivity and improve recovery of oil. Maximum proposed surface injection pressure is 2800 psi for water and 3800 psi for gas.

8. Fracture Information (20 AAC 25.402(c)(11))

With a maximum surface water injection pressure of 2800 psi, the injection gradient will be 0.85 psi/ft, assuming no friction losses, which will not propagate fractures through the confining layers. The overlying Kalubik and HRZ shales, which have a combined thickness of approximately 110 feet, have a fracture gradient 0.8 to 0.9 psi/ft. The underlying Miluveach/Kingak shale sequence has a fracture gradient of approximately 0.85 psi/ft.

9. Water Analysis (20 AAC 25.402(c)(12))

The compositions of injection water and AOP connate water were provided in Exhibit IV-4 of the original AIO application.

10. Aquifer Exemption (20 AAC 25.402(c)(13))

On July 11, 1986, the Commission approved Aquifer Exemption Order 1 ("AEO 1") for Class II injection activities within the Western Operating Area of the Prudhoe Bay Unit. The AOP is entirely within the area covered by AEO-1.

11. Hydrocarbon Recovery and Reservoir Impact (20 AAC 25.402(c)(14))

On September 7, 2001, BPXA testified the in place oil was 110-146 million barrels, and free gas was 15 to 75 billion standard cubic feet. BPXA projected primary and waterflood recovery to be 30-40 million STB (roughly 27% with an upside potential of approximately 34%). A recovery percentage of 12% was projected for primary only. Additional reserves of 3-5% were projected with miscible gas injection, suggesting about 4 million barrels recovery if applicable to the entire AOP. These recovery percentages are consistent with those reported for other Kuparuk River Formation pools. The projected enhanced recovery reserves from waterflood plus miscible gas is roughly 12 to 26 million barrels, more than double that expected from primary production (13-18 million barrels).

BPXA testified that the reservoir pressure at which the enriched gas is miscible with the reservoir oil is about 2700 psi. BPXA testified that the reservoir pressures are about 2000 to 2500 psi within the West block, and 3000 and 3100 psi within the

North of Crest Block, and South-East of Crest Block, respectively. However, Commission records of well reservoir pressure measurements for 2002 show some wells (S-105 and S-108) within the North of Crest Blocks and South-East of Crest Blocks to be below 2700 psi. These pressures may not be representative due to factors such as insufficient shut-in time or inaccurate method of gathering. Figures 1, 2, and 3 illustrate pressures by well and block as compared to minimum miscibility pressure.

Table 1 and Figure 4 show the AOP production history compiled from the Commission's production database. Net voidage calculations were performed using the fluid volume factors supplied by BPXA. Through January 31, 2003, cumulative production was 4.6 million stock tank barrels ("STB") of oil, 1.1 million barrels of water, and 26.7 billion standard cubic feet ("SCF") of gas. Produced water injection from Gathering Center 2 ("GC-2") was 3.9 million barrels. Cumulative net voidage is approximately 22 million reservoir barrels, excluding gas cap expansion and aquifer influx. Aurora produced gas is currently used within the Prudhoe Bay Unit facilities as fuel or injected into the Sadlerochit gas cap.

Current net voidage rates reported within the West, North of Crest and South-East of Crest Blocks are 25,000, 6,000 and 5,000 reservoir barrels per day, respectively. Cumulative net voidage within these blocks is 17 million barrels, 3.7 million barrels, and 1.7 million barrels, respectively.

BPXA plans to begin water injection within S-114Ai of the West Block soon, at an expected injection rate of 10,000-15,000 barrels per day. Additionally, wells S-112 and S-110 are planned for injection. Facilities projects are currently being "considered" to increase the water source volume for injection and to increase water injection pressure. With these "considered" additions, BPXA projects that AOP water injection rates will increase to 40,000 barrels per day from the current injection rate of 10,000 barrels per day.

While BPXA testified that reservoir simulation shows reservoir pressure within the West Block will be restored to above minimum miscibility by the end of 2003, it is not apparent how this will be accomplished without curtailment of production.

AOP production and waterflood operations are not being conducted in a manner consistent with testimony provided in support of Conservation Order 457. BPXA on behalf of the Aurora Working Interest Owners, testified that their "reservoir management strategy is, once water injection commences, we will inject at a VRR of greater than 1.0 to restore reservoir pressure." BPXA further committed to inject at a balanced VRR to maintain reservoir pressure.

Enhanced recovery reserves from miscible injection and from waterflood may be jeopardized if reservoir pressure is not restored. Additional reservoir pressure information appears needed to set an appropriate path forward for the depletion of the reservoir. The following wells are recommended for shut-in bottom hole pressure measurements to insure the reservoir is not overdepleted. If the wells shut-in reservoir pressure are below the reported minimum miscibility pressure, further production curtailment should be considered. Wells in order of priority and concern are as follows:

- S-106 West Block. Low measured reservoir pressures (2254 psi (2/9/02)), high GORs indicating possible over depletion.
- S-102 West Block. Low measured reservoir pressures (2199 psi (4/10/02)), high GORs (10,000 scf/STB in December). This well is currently being curtailed. Pressure measurement would not impact production.
- S-105 NOC block. This is the initial block planned for miscible injection. Reservoir pressure measurement suggests this well to be near or below 2700 psi.
- S-100 West Block. Extremely high voidage cumulative and overall rates (12 MMRVB).
- S-108 High GOR. Low recorded reservoir pressure. May not be in communication with remaining wells in block.

*The above evaluation is based upon information supplied to the Commission as of March 7, 2003.

12. <u>Mechanical Condition of Adjacent Wells (20 AAC 25.402(c)(15))</u>

Mechanical integrity has been established for the wells within ¼ mile radius of proposed injectors. Mechanical integrity is based upon calculated cement tops being at an adequate height above the injection zone to prevent fluid that is injected into the AOP from flowing into other zones or to the surface.

CONCLUSIONS:

1. BPXA's application and testimony fulfills the general requirements of 20 AAC.25.402, except that the proposed injection of fluids has not been shown to function primarily to enhance recovery of oil and gas under current reservoir conditions.
2. The project has been represented as a miscible injection project and, as such, it is implied that the reservoir pressure is above minimum miscibility pressure. Measurements suggest reservoir pressures are below minimum miscibility in the West Block and possibly within portions of the Southeast of Crest Block and North of Crest Block.
3. AOP production and waterflood operations are not being conducted in a manner consistent with testimony provided in support of Conservation Order 457
4. Cumulative net reservoir voidage is 22.4 million barrels, and is increasing by

approximately 26,000 barrels each day.

5. BPXA's current reservoir management strategy is unclear. A comprehensive reservoir management plan is required which addresses water injection and repressurization of the reservoir in preparation for miscible gas injection to ensure greater ultimate recovery of the oil in the AOP.

6. Enhanced oil recovery operations may be jeopardized unless reservoir voidage is replenished and reservoir pressure is increased.

7. Additional reservoir pressure measurements are required to determine if enriched gas should be injected, and the course of action to take for repressurization if measurements show the blocks to be below minimum miscibility pressure. Reservoir pressure measurements within the following wells are needed.
   - West Block: S-106, S-100, S-102
   - SE of Crest Block: S-108
   - North of Crest Block: S-105

NOW, THEREFORE, IT IS ORDERED THAT:

BPXA's application for injection of enriched gas in Aurora Oil Pool is denied without prejudice to BPXA's right to renew its application at a later date.

DONE at Anchorage, Alaska and dated April 3, 2003.

____
Sarah Palin, Chair
Alaska Oil and Gas Conservation Commission

____
Randy Ruedrich, Commissioner
Alaska Oil and Gas Conservation Commission

____
Daniel T. Seamount, Jr., Commissioner
Alaska Oil and Gas Conservation Commission

AS 31.05.080 provides that within 20 days after receipt of written notice of the entry of an order, a person affected by it may file with the Commission an application for rehearing. A request for rehearing must be received by 4:30 PM on the 23rd day following the date of the order, or next working day if a holiday or weekend, to be timely filed. The Commission shall grant or refuse the application in whole or in part within 10 days. The Commission can refuse an application by not acting on it within the 10-day period. An affected person has 30 days from the date the Commission refuses the application or mails (or otherwise distributes) an order upon rehearing, both being the final order of the Commission, to appeal the decision to Superior Court. Where a request for rehearing is denied by nonaction of the Commission, the 30 day period for appeal to Superior Court runs from the date on which the request is deemed denied (i.e., 10th day after the application for rehearing was filed).

TABLE 1
Production Aurora Wells - January 2003 *

Well	Oil, STBD	Water, BPD	Gas, MSCFD	WI, BD	Cum Oil, MSTB	Cum Water, MB	Cum Gas Prod, MSCF	Cum WI, MBBL	** Cum Net Voidage, Million Barrels
S-103	2,179	1,555	2,748	0	959	589	1,029	0	**2.2**
S-105	510	63	3,096	0	331	418	828	0	**1.4**
S-104	0	0	0	3,238	75	5	64	554	**-0.5**
Total NOC	**2,689**	**1,618**	**5,844**	**3,238**	**1,365**	**1,012**	**1,921**	**554**	**3.1**
S-108	389	23	5,465	0	164	9	1,427	0	**1.3**
S-110	0	0	0	0	131	9	267	0	**0.3**
S-112	272	10	285	0	43	0	35	0	**0.1**
S-109	0	0	0	0	0	0	0	0	**0.0**
SE	**661**	**33**	**5,750**	**0**	**339**	**18**	**1,729**	**0**	**1.7**
S-100	2,638	120	10,248		1,641	11	12,979	0	**12.2**
S-106	1,478	323	9,501		789	53	5,579	0	**5.3**
S-102***					324	9	2,869	0	**2.7**
S-113B	1,083	0	3,465		110	0	275	0	**0.3**
S-114A					0	0	1	0	**0.0**
S-101				1,348	61	1	1,316	2,186	**-2.2**
S-107				5,066	4	13	7	1,150	**-1.2**
Total West	**5,199**	**443**	**23,214**	**6,414**	**2,929**	**87**	**23,026**	**3,336**	**17.1**
Total Aurora	**8,549**	**2,094**	**34,808**	**9,652**	**4,632**	**1,117**	**26,675**	**3,890**	**21.9**

* January 2003 production numbers in Commission database.
Further validation is required.
** Commission Staff computation using V-200 PVT Data Exhibit II-3 of Aurora Pool Rules submittal of July 23, 2001
Compares with BP Submittal Voidage Calculations of 3.7 Million RVB,
1.7 Million RVB and 17 Million RVB at NOC, SEC and West Fault Blocks
These voidage volumes do not account for effects of Aquifer Influx or gas-cap expansion

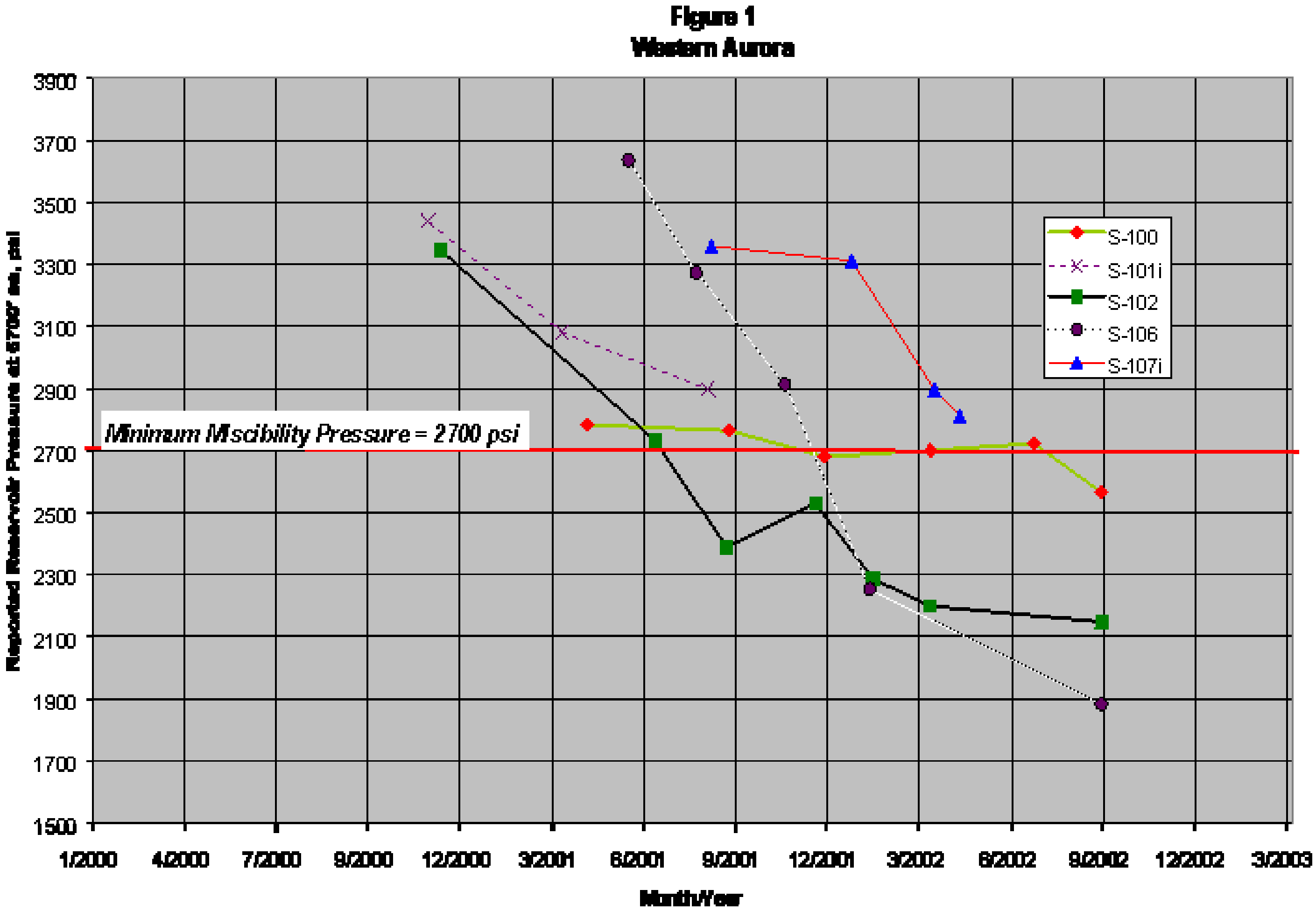
Figure 1
Western Aurora
3900
3700
3500
3300
3100
2900
2700
2500
2300
2100
1900
1700
1500
Reported Reservoir Pressure at 6700' ss, psi
Minimum Miscibility Pressure = 2700 psi
S-100
S-101i
S-102
S-106
S-107i
1/2000
4/2000
7/2000
9/2000
12/2000
3/2001
6/2001
9/2001
12/2001
3/2002
6/2002
9/2002
12/2002
3/2003
Month/Year

Figure 2
North of Crest

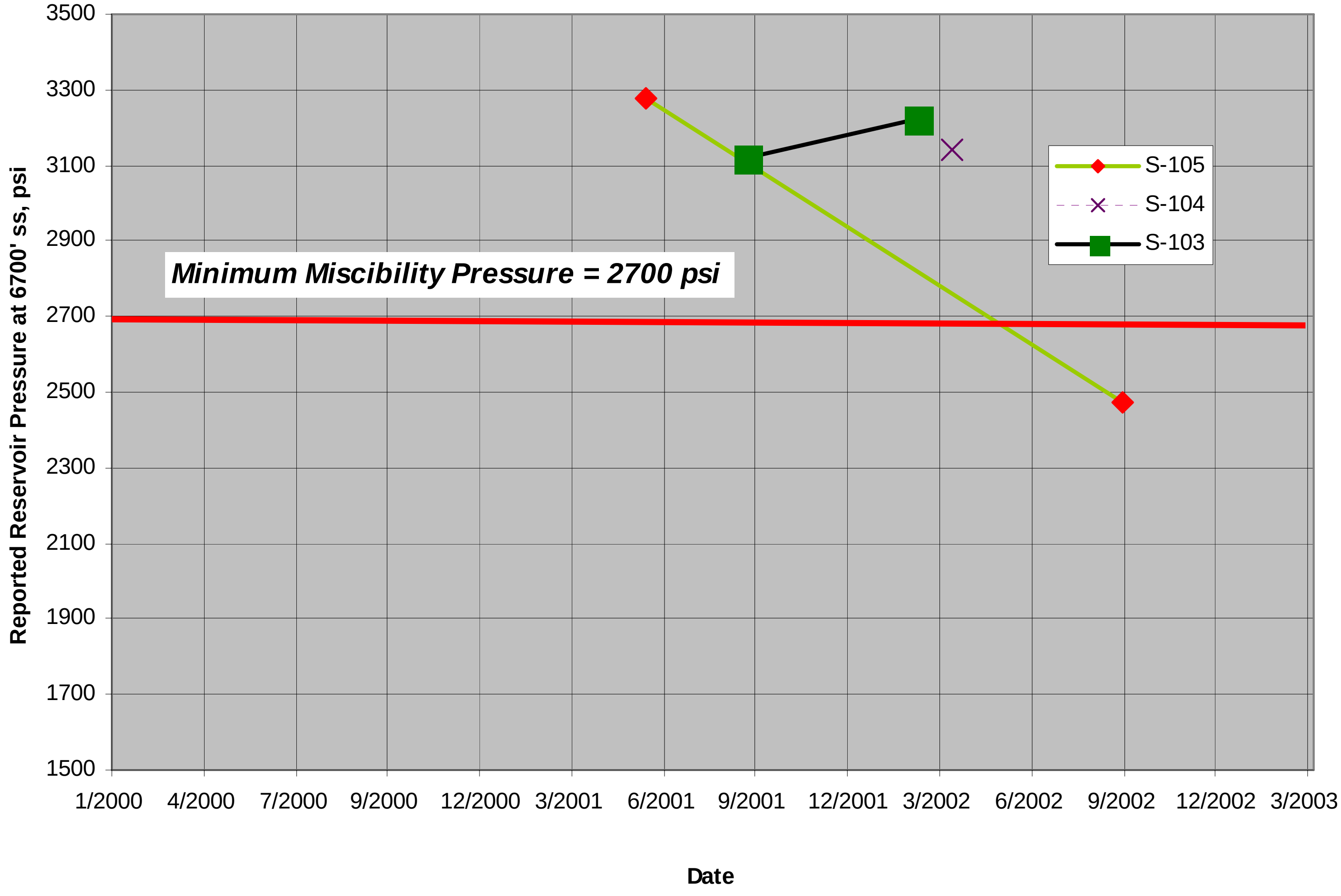

Figure 3
South East Of Crest Crest

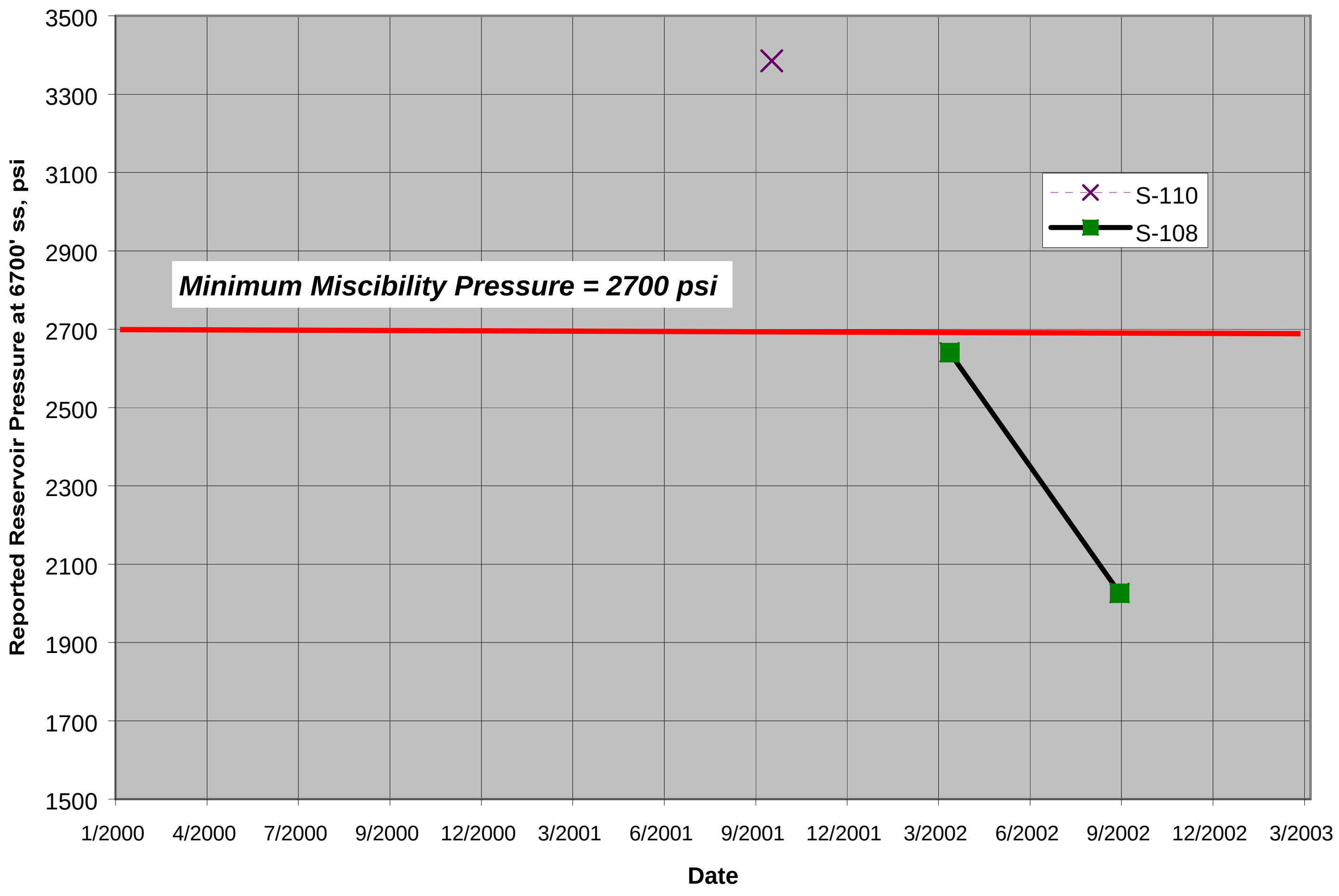

Figure 4
Aurora Production and Injection