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

Re: THE APPLICATION OF Hilcorp Alaska, LLC for modification of Disposal Injection Order 34A to allow commercial waste disposal injection in the Sterling Formation in the Kenai Unit Well 12-17 (PTD No. 208-089), Section 17, T4N, R11W, S.M.	**Disposal Injection Order No. 34B** **Docket No. DIO-16-001** **Sterling Formation** **Kenai Unit Well 12-17** **October 19, 2016**

IT APPEARING THAT:

1. On November 20, 2008, the Alaska Oil and Gas Conservation Commission (AOGCC) issued Disposal Injection Order 34 (DIO 34) for the Kenai Unit 12-17 well (KU 12-17), operated by Marathon Oil Company (Marathon).

2. The AOGCC issued administrative approval DIO 34.001 on December 17, 2008 clarifying the fluids eligible for Class II waste disposal in KU 12-17.

3. The AOGCC issued Disposal Injection Order 34A (DIO 34A) on May 27, 2009 to expand the approved underground waste disposal injection interval.

4. Effective February 1, 2013, Hilcorp Alaska, LLC (Hilcorp) acquired ownership of the Kenai Unit from Marathon Oil Company and became the operator.

5. By application dated July 25, 2016, Hilcorp requested the AOGCC amend DIO 34A to allow commercial waste disposal injection in KU 12-17. Letters supporting the Hilcorp application were included from Glacier Oil and Gas Corporation, BlueCrest Alaska Operating LLC., and AIX Energy, LLC.

6. Pursuant to 20 AAC 25.540, the AOGCC scheduled a public hearing for September 15, 2016. On July 28, 2016, the AOGCC published notice of the opportunity for that hearing on the State of Alaska's Online Public Notice website and on the AOGCC's website and electronically transmitted the notice to all persons on the AOGCC's email distribution list. On July 29, 2016, the notice was published in the ALASKA DISPATCH NEWS.

7. The AOGCC received a request to hold the public hearing.

8. At the September 15, 2016 hearing Hilcorp provided testimony and presented evidence in support of its Application. Ms. Gretchen Stoddard, a public person, also presented testimony. The record was closed at the end of the hearing.

9. The information submitted by Hilcorp, hearing testimony, the findings, conclusions and administrative record for DIO 34 and DIO 34A, and public well history records are the basis for this amended order.

FINDINGS:

1. <u>Location of Adjacent Wells (20 AAC 25.252(c)(1)) (Source: - Revised this Order)</u>

   KU 12-17 was directionally drilled in June-July 2008 to a total depth of 6585 feet measured depth (MD), which is equivalent to 5786 feet true vertical depth (TVD). The bottom-hole location for KU 12-17 is in Section 17, Township 4N, Range 11W, Seward Meridian (2823 feet from north line, 163 feet from east line). The surface location is on the Hilcorp-operated Drill Site 41-18 within the Kenai Gas Field in Section 18, Township 4N, Range 11W (848 feet from north line, 742 feet from east line). The plat included with Hilcorp's application shows the location of all wells within a ¼-mile radius of KU 12-17.

2. <u>Notification of Operators/Surface Owners (20 AAC 25.252(c)(2) and 20 AAC 25.252(c)(3)) (Source: - Revised this Order)</u>

   Hilcorp is the only operator within a ¼-mile radius of the proposed disposal well. Surface owners within a ¼-mile radius of KU 12-17 are Salamatof Native Corporation and Cook Inlet Regional Corporation. All surface owners were originally notified by letter regarding the initial proposed injection using KU 12-17 according to the "Affidavit of Notice to Surface Owners and Operators" provided by Marathon in support of DIO 34.

3. <u>Geological Information on Disposal and Confining Zones (20 AAC 25.252(c)(4)) (Source: revised this Order)</u>

   The Sterling Formation (Sterling) consists of thick, sandy, meandering stream bar deposits alternating with coals and shales. Sterling B1 and B2 intervals, as shown on Figures 5 and 5A of Marathon's original application for DIO 34, are the intended injection zone, from 4002 feet to 4147 feet TVD. Porosity and permeability in the disposal interval range up to 28 percent and 1000 millidarcies, respectively. The disposal injection zone is within the aquifer exemption area defined by EPA in 40 CFR 147.102(b)(1)(iii). Marathon perforated the Sterling B2 interval in KU 12-17 from 4110 feet to 4140 feet TVD for primary waste disposal injection. No additional perforations have been added. A coal layer from 3919 feet to 3926 feet TVD was identified by Marathon and is confirmed by Hilcorp as providing upper confinement for injected fluids. Interpreted cross sections indicate the upper confining layer is laterally continuous across the Kenai Gas Field.

   Commercial gas accumulations occur in the Sterling in other parts of the KU. In the section of the Sterling penetrated by KU 12-17, all intervals but the deepest—*i.e.*, Sterling Pool 6—are water wet. Gas storage in Sterling Pool 6 is isolated from the shallower Sterling B1 and B2 disposal injection intervals by laterally continuous coal, silt, and shale layers.

Gas storage injection in the Kenai Gas Field occurs into Sterling Pool 6. KU 12-17 penetrated the Sterling Pool 6 at a depth of 4706 feet TVD. The gas storage injection zone is isolated from the Sterling B1 and B2 intervals by laterally continuous coal, silt, and shale layers and by well construction (casing and cement). Marathon identified, and Hilcorp confirms, the specific lower confinement for the Sterling B1 and B2 as being the interval from 4150 feet to 4203 feet TVD. Structure maps reviewed by Hilcorp indicate there are no transmissive faults in the vicinity of Drill Site 41-18 at depths that correlate to the injection zone and confining layers.

DIO 34A expanded the approved waste disposal injection interval to be from 3600 feet to 4200 feet TVD in response to Marathon's modeling of the fracture extension assuming no confining layers. Marathon reported that this extreme case model (with no confining layers) could result in fracture extension within the interval 3600 feet to 4150 feet TVD.

4. Evaluation of Confining Zones (20 AAC 25.252(c)(9)) (Source: - Revised this Order)

Marathon's application for DIO 34 relied on fracture model updates for waste disposal injection wells KU 11-17 and KU 24-07RD (which are also located on the Drill Site 41-18 and dispose into the Sterling). The KU 11-17 and KU 24-07RD model updates evaluated a range of factors to determine the sensitivity of those factors to fracture dimensions. Historical performance data (*i.e.*, rate, pressure, and fluid composition data) for KU 11-17 and KU 24-07RD were also used in the model updates to estimate fracture geometry for an injected volume of up to 2 million barrels. Marathon reported that similar rock and fluid properties allow these fracture model updates to predict fracture behavior for KU 12-17. The KU fracture model updates are in the AOGCC's files.

For DIO 34, Marathon predicted a fracture height of 200 feet, growing into the Sterling B1 interval, and a half-length of 4,000 feet as the most likely case based on the fracture model updates and nearby waste injection performance in the Sterling. The modeling predictions indicate neither the upper nor lower confining layers would be penetrated because of the planned injection operations in KU 12-17. Additional evidence that the confining layers would be effective barriers includes the historic injection into the Sterling within the KU 11-17, KU 14-4, KU 24-07, and KU 24-07RD wells.

More rigorous fracture simulations specific to KU 12-17 were performed at Marathon's initiative using actual well and formation data gathered during drilling and completion activities, including well log and step-rate test results. Simulations evaluated fracture geometry using stress profiles representing different confining layers. A worst case scenario involving no confining layers was also evaluated to determine the maximum possible fracture growth.

In 2011, Marathon contracted a third-party (Advantek International, Inc. (Advantek)) to provide additional monitoring and analysis of KU 12-17 injection. The results of Advantek's fracture geometry assessment, which utilizes pressure falloff test data and several modeling software approaches based on historical injection data, indicate there was no evidence of out of zone fracture growth. Advantek's analysis of fracture propagation and geometry with a 3D model, based on the 2011 pressure falloff test, indicated fracture height of 165 feet and half-length of 410 feet, further indicating fracture containment within the ¼ mile radius around KU 12-17.

5. Standard Laboratory Water Analysis of the Formation (20 AAC 25.252(c)(10)); Aquifer Exemption (20 AAC 25.252(c)(11)) (Source: DIO 34A)

   By regulation (*i.e.*, 40 CFR 147.102(b)(1)(iii)), EPA has exempted those portions of aquifers below 1300 feet TVD in the Kenai Gas Field. As additional confirmation that the water below 1300 feet TVD is not fresh water, Marathon provided the water analysis for a Sterling water sample taken from KU 14-6 indicating total dissolved solids greater than 10,000 mg/l.

6. Well Logs (20 AAC 25.252(c)(5)) (Source: DIO 34)

   Log data from KU 12-17 are on file with the AOGCC.

7. Demonstration of Mechanical Integrity and Disposal Zone Isolation (20 AAC 25.252(c)(6)) (Source: - Revised this Order)

   KU 12-17 was drilled to be a Class II waste disposal injector. The well was directionally drilled south to a depth of 5786 feet TVD (6585 feet MD); constructed with 20-inch conductor casing set at 189 feet TVD, 10-3/4-inch surface casing set at 1492 feet TVD, and 7-5/8-inch production casing set at 5786 feet TVD; and plugged back to 5682 feet TVD. The injection completion consists of 4-1/2-inch injection tubing run to 3896 feet TVD and a permanent packer installed at 3865 feet TVD, thereby establishing the Sterling as the intended zone for underground injection control (UIC) Class II disposal.

   The surface casing is cemented from shoe depth to the surface. The production casing is constructed with sufficient cement to cover from total depth to 2517 feet TVD.

   A cement bond log was run in KU 12-17 to evaluate cement placement and bond integrity of the casing string isolating the planned injection zone. Marathon evaluated the 7-5/8-inch casing interval with a cement bond log from 5680 feet to 2373 feet TVD. An estimated cement top of 2586 feet TVD with good to excellent cement bond is interpreted from the log data. Cement bond appears to be excellent throughout, both above and below the proposed Sterling B1 and B2 injection intervals. The interpreted top of the cement is approximately 360 feet above the top of the upper confining zone. Hilcorp has reviewed the cement bond log and confirmed the cement top as 2585 feet TVD.

   A required mechanical integrity test (MIT) was performed on December 16, 2008, prior to commencing injection. An AOGCC witnessed MIT was performed after injection commenced for the first time in August 2009, and an AOGCC-witnessed MIT has been completed every two years with the last test being April 21, 2015.

   A temperature log was run on KU 12-17 prior to the start of injection on December 16, 2008 establishing a baseline. After stable injection was established, an additional temperature log was run and the log data indicates that fluids were exiting the perforations into the intended zone.

Marathon and subsequently Hilcorp have continuously monitored wellhead pressures using a supervisory-controlled automated data acquisition system and daily visual inspections and pressure recordings. Annual due diligence reviews will be performed for all active slurry injections on Drill Site 41-18. Reviews will evaluate pressure trend data and fracture modeling update results and be submitted to the AOGCC.

8. <u>Disposal Fluid Type, Composition, Source, Volume, and Compatibility with Disposal Zone (20 AAC 25.252(c)(7)) (Source: - Revised this Order)</u>

KU 12-17 will be the third active waste disposal well on the KU 41-18 drill site injecting into the Sterling; there are another three active waste disposal wells within the Kenai Gas Field (two Kenai Gas Field waste disposal wells are plugged and abandoned). Hilcorp is using KU 12-17 to dispose of drilling, production, completion, workover and other Class II wastes originating from exploration and development well activities on the Kenai Peninsula.

Marathon projected the injection volume into KU 12-17 could exceed 1,000,000 barrels of Class II wastes over the expected life of the field. Marathon expected the injection rate to average 1000 barrels per day (with a maximum injection rate of 7200 barrels per day), with rates of up to 5 barrels per minute. The expected performance was less than the injection performance used in fracture modeling for this project.

Hilcorp does not foresee the KU 12-17 yearly injection volumes of 250,000 to 500,000 barrel/year to change substantially over the next several years. The KU 12-17 has injected over 1.6 million barrels of class II waste to date. Hilcorp expects to continue an average injection rate of 1500 barrels per day with a maximum injection rate of 7200 barrels per day and spot rates up to 5 barrels per minute.

No compatibility concerns relating to injected fluids and in-situ formation fluids have been identified by either Marathon or Hilcorp although more than 11.7 million barrels of Class II wastes have been injected into the KU disposal wells.

9. <u>Estimated Injection Pressures (20 AAC 25.252(c)(8)) (Source: Revised this Order)</u>

The maximum surface injection pressure is limited by the 3000 psig working pressure of the injection pump, which is currently calibrated with a 2250 psi pressure safety relief system.

10. <u>Mechanical Condition of Wells Penetrating the Disposal Zone Within ¼-Mile of KU 12-17 (20 AAC 25.252(c)(12)) (Source: - Revised this Order)</u>

No wells penetrate the Sterling within a ¼-mile radius of KU 12-17. The fracture modeling results provided with the original injection order application led the AOGCC to request a larger area of review (a radius equivalent to the 4000-foot fracture half-length around the proposed disposal well) to evaluate the mechanical condition of wells penetrating the disposal zone.

Eleven wells were identified: eight wells within the Kenai Unit (KU 11-17, KU 14-8, KU 24-7, KU 24-7RD, KU 41-18, KU 41-18X, KU 41-19, and KU 44-18); and three wells within the Kenai Beluga Unit (KBU 13-8, KBU 24-7X, and KBU 33-7). Marathon indicated the cement and casing in each of the wells appear to be adequate to prevent the movement of injected fluids outside of the disposal zone.

Since the original DIO 34 and 34A applications, three additional wells (KBU 32-08, KBU 43-07Y and KBU 31-18) have been drilled within 4000 feet of the KU 12-17 Sterling interval. All of these wells are outside the DIO 34A recommended ¼ mile radius of KU 12-17, and outside of the latest modeling of the fracture half-lengths. Hilcorp indicated the cement and casing in each of the wells is adequate to prevent the movement of injected fluids outside of the disposal zone.

CONCLUSIONS:

1. The requirements and conditions for approval of an underground disposal application in 20 AAC 25.252 are met.

2. DIO 34 and DIO 34A and associated administrative actions should be revoked and replaced with a time-limited disposal injection order tailored to the circumstances of disposal in the KU 12-17 well.

3. Hilcorp’s review of DIO 34A proposes valid updates and modifications to the Findings, Conclusions, and Rules. The proposed ongoing use of the KU 12-17 disposal well including commercial operations does not promote waste or jeopardize correlative rights, is based on sound engineering and geoscience principles, and will not result in an increased risk of fluid movement into freshwater.

4. Commercial disposal operations should be authorized on a well-by-well basis within a DIO to account for specifics within the associated area of review including well integrity and zonal isolation, along with operator contracting and site specific procedures in place to ensure only eligible Class II fluids are disposed.

5. Commercial disposal operations in KU 12-17 should be authorized. Hilcorp has demonstrated that agreements between Hilcorp and third party Oil and Gas Operators (Facility User Agreement (FUA) and Road Use Agreement (RUA)), Hilcorp procedures including the Waste Analysis Plan (WAP) and external manifesting for third party waste, and site employee/contractor waste management training should ensure only eligible Class II fluids are disposed. As operator of the disposal well, Hilcorp bears sole responsibility for the fluids injected.

6. Commercial disposal operations will require additional reporting to AOGCC. A detailed annual report will provide sufficient information for the AOGCC to properly monitor disposal operations. Additional emphasis on Class II fluids eligibility verification, pressure monitoring,

volume accounting, and isolation of the approved fluids to the approved disposal interval is required.

7. AOGCC should update the findings, conclusions, and rules of this DIO periodically.

NOW, THEREFORE, IT IS ORDERED THAT DIO 34 and DIO 34A and all associated administrative approvals are hereby revoked and replaced by this order. All information related to DIO 34 and DIO 34A is hereby incorporated by reference into the record for this order. The following rules, in addition to statewide requirements under 20 AAC 25 (to the extent not superseded by these rules), govern Class II disposal injection operations into the Sterling within KU 12-17:

RULE 1: Injection Strata for Disposal (Source: DIO 34A)
The underground disposal of Class II well oil field waste fluids is permitted into the Sterling within KU 12-17 in the interval from 3600 feet to 4200 feet TVD. The AOGCC may immediately suspend, revoke, or modify this authorization if injected fluids fail to be confined to the approved disposal interval.

RULE 2: Fluids (Source: - Revised this Order)
This authorization is limited to Class II oil field waste fluids generated during drilling, production, workover, or abandonment operations, specifically:

> Drilling fluids; drill cuttings; well workover fluids; stimulation fluids and solids; produced water; rig wash water; formation materials; naturally occurring radioactive materials; scale; tracer materials; glycol dehydration wastes; reserve pit fluids; chemicals used in the well or for production processing at the surface (in direct contact with produced fluids); tank bottoms; precipitation accumulating in drilling and production impoundment areas; pad storm water retention basins; drum rinsate; equipment wash water; and organic materials that are contaminated with crude oil or natural gas liquids.

The eligibility of other fluids for Class II waste disposal injection will be considered by the AOGCC on a case-by-case basis upon application by the operator.

Commercial Class II oil field waste disposal is approved. Commercial (third party non-Hilcorp generated) Class II oil field waste disposal shall be in compliance with all rules of this DIO and it remains the responsibility of Hilcorp to accurately account for volumes and ensure that all fluids injected meet Class II eligibility requirements.

RULE 3: Injection Rate and Pressure (Source: DIO 34)
Disposal injection is authorized at (a) rates that do not exceed 5 barrels per minute and (b) surface pressures that do not exceed 2400 psig.

RULE 4: Demonstration of Mechanical Integrity (Source: - Revised this Order)
The mechanical integrity of KU 12-17 must be demonstrated before returning the well to service following any workover affecting mechanical integrity. An AOGCC-witnessed mechanical integrity test must be performed at least once every two years after the date of the last AOGCC-

witnessed test. The AOGCC must be notified at least 24 hours in advance of each such test to enable a representative to witness the test. Unless an alternate means is approved by the AOGCC, mechanical integrity tests must be conducted in accordance with AOGCC Industry Guidance Bulletin No. 10-02A, "Mechanical Integrity Testing". The results of all mechanical integrity demonstrations and Hilcorp's interpretation of those results shall be provided to the AOGCC no later than the 5th calendar day of the month following the testing and be readily available for AOGCC inspection.

RULE 5: Well Integrity Failure and Confinement (Source: DIO 34)
Whenever any pressure communication, leakage or lack of injection zone isolation is indicated by the injection rate, an operating pressure observation, a test, a survey, a log, or any other evidence, the operator shall notify the AOGCC by the next business day and submit a plan of corrective action on Form 10-403 for AOGCC approval. The operator shall immediately shut in the well if continued operation would be unsafe or threaten contamination of freshwater, or if so directed by the AOGCC. A monthly report of daily tubing and casing annuli pressures and injection rates must be provided to the AOGCC for KU 12-17 indicating any well integrity failure or lack of injection zone isolation.

RULE 6: Surveillance (Source: - Revised this Order)
Marathon, as operator ran a baseline temperature log December 16, 2008 and a subsequent temperature log was run on August 27, 2009 after injection began to delineate the receiving zone of the injected fluids. Surface pressures and rates must be monitored continuously during injection for any indications of anomalous conditions. Results of daily wellhead pressure observations in KU 12-17 must be documented and available to the AOGCC upon request. The requirement to perform subsequent temperature surveys or other surveillance logging (*e.g.*, water flow; acoustic) will be based on the results of the initial and follow-up temperature surveys and injection performance monitoring data.

No later than July 1 of each year, a report evaluating the performance of the disposal operation must be submitted to the AOGCC. The report shall include data sufficient to characterize the disposal operation, including among other information: injection and annuli pressures (daily average, maximum and minimum); fluid volumes injected (disposal and clean fluid sweeps); injection rates; an assessment of fracture geometry; a description of any anomalous injection results; and a calculated zone of influence for the injection fluids.

Commercial disposal injection details shall also be provided in the annual performance report. The report shall include:

1. an overview of commercial activities for the year;
2. a list, based on manifests, showing waste generating company, identification of well or pad where the waste was generated, type of waste, volume, transport company/driver, signature/name of Hilcorp authority confirming waste as Class II;
3. a list of the operators that Hilcorp has a Facility User Agreement (FUA) with;
4. a list of operators that Hilcorp has a Road Use Agreement (RUA) with;
5. a list of Hilcorp employees having completed the Hilcorp commercial class II training and are authorized to accept waste;
6. a review of the Hilcorp Waste Analysis Plan (WAP) and any changes to the plan;

7. a review of the External Manifest procedures including any changes to the process; and
8. a review of the pre-call and approval policy that is designed to ensure the facility is ready and able to accept and process the commercial waste.

Wellhead pressures shall be monitored daily and maintained for Drill Site 41-18 wells penetrating the disposal zone within an area of review described by a quarter-mile radius around KU 12-17. Pressure records shall be made available for inspection upon AOGCC request. The annual surveillance report shall include for each of these Drill Site 41-18 wells a summary wellhead pressure plot and an assessment of mechanical integrity.

RULE 7: Notification of Improper Class II Injection (Source: - Revised this Order)
Injection of fluids other than those listed in Rule 2 without prior authorization is considered improper Class II injection. Upon discovery of such an event, the operator must immediately notify the AOGCC, provide details of the operation, and propose actions to prevent recurrence. This requirement is in addition to, and does not relieve the operator of any other obligations under the notification requirements of any other State or Federal agency, regulation or law.

If fluids are found to be fracturing through a confining interval or migrating out of the approved injection stratum, the operator must immediately shut in the well. Upon discovery of such an event, the operator must immediately notify the AOGCC, provide details of the operation, and provide a description of the actions it has undertaken to prevent recurrence. Injection may not be restarted until approved by the AOGCC.

RULE 8: Administrative Action (Source: - Revised this Order)
Upon proper application, or its own motion, and unless notice and public hearing are otherwise required, the AOGCC may administratively waive the requirements of any rule stated herein or administratively amend this order as long as the change does not promote waste or jeopardize correlative rights, is based on sound engineering and geoscience principles, and will not result in an increased risk of fluid movement into freshwater.

RULE 9: Compliance (Source: DIO 34A)
All operations must be conducted in accordance with the requirements of this order, AS 31.05, and (unless specifically superseded by AOGCC order) 20 AAC 25. Any noncompliance may result in the suspension, revocation, or modification of this authorization.

RULE 10: Expiration Date (Source: - New this Order)
This order shall expire:

1. two years after injection operations authorized by this order cease;
2. five years from the effective date of this order if injection operations are ongoing; or
3. when the operator changes for a property affected by this order, whichever occurs first.

The commission may reauthorize this order on its own motion or upon proper application from the operator. Applications must be timely filed so that if necessary a hearing under 20 AAC 25.540 can be held and a decision of the commission can be made before the order expires. An application for reauthorization shall include;

1. a review of the existing rules in the order and an analysis whether or not those rules should be retained, amended, or repealed;

2. a review of, and discussion on, whether or not the affected area of the order should be revised; and
3. a discussion of, and justification for, proposed new rules or revisions to existing rules.

DONE at Anchorage, Alaska, and dated October 19, 2016.

//signature on file//	//signature on file//	//signature on file//
Cathy P. Foerster	Daniel T. Seamount, Jr.	Hollis French
Chair, Commissioner	Commissioner	Commissioner

RECONSIDERATION AND APPEAL NOTICE

As provided in AS 31.05.080(a), within **20** days after written notice of the entry of this order or decision, or such further time as the Commission grants for good cause shown, a person affected by it may file with the Commission an application for reconsideration of the matter determined by it. If the notice was mailed, then the period of time shall be **23** days. An application for reconsideration must set out the respect in which the order or decision is believed to be erroneous.

The Commission shall grant or refuse the application for reconsideration in whole or in part within 10 days after it is filed. Failure to act on it within 10 days is a denial of reconsideration. If the Commission denies reconsideration, upon denial, this order or decision and the denial of reconsideration are **FINAL** and may be appealed to superior court. The appeal **MUST** be filed within **33** days after the date on which the Commission mails, **OR 30** days if the Commission otherwise distributes, the order or decision denying reconsideration, **UNLESS** the denial is by inaction, in which case the appeal **MUST** be filed within **40** days after the date on which the application for reconsideration was filed.

If the Commission grants an application for reconsideration, this order or decision does not become final. Rather, the order or decision on reconsideration will be the **FINAL** order or decision of the Commission, and it may be appealed to superior court. That appeal **MUST** be filed within **33** days after the date on which the Commission mails, **OR 30** days if the Commission otherwise distributes, the order or decision on reconsideration. As provided in AS 31.05.080(b), "[t]he questions reviewed on appeal are limited to the questions presented to the Commission by the application for reconsideration."

In computing a period of time above, the date of the event or default after which the designated period begins to run is not included in the period; the last day of the period is included, unless it falls on a weekend or state holiday, in which event the period runs until 5:00 p.m. on the next day that does not fall on a weekend or state holiday.