11 AAC is amended by adding a new chapter to read:

Chapter 25. Royalty Election Under Alaska Gasline Inducement Act.

Section

11 AAC 25.010. Applicability. This chapter applies to the royalty inducements under AS 43.90.300, 43.90.310, and 43.90.330 that are available to

(1) a lessee or other person who is a qualified person under 11 AAC 25.020; and

(2) gas that is qualified under 11 AAC 25.030. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.020. Qualified person. (a) To qualify under AS 43.90.300 for a royalty inducement under AS 43.90.310 for qualified gas, a lessee or other person must

(1) for firm transportation capacity on the Alaska mainline,

(A) enter into a pre-subscription agreement with the licensee before the commencement of the first binding open season of the project;

(B) submit a bid before the close of the first binding open season of the project; however, the person may submit a bid after the close of the first binding open season, but no later than 180 days after the close of the first binding open season, if

(i) the licensee accepts the bid under 18 C.F.R. 157.34(d)(2); and

(ii) the lessee or other person makes, to the satisfaction of the commissioners, a good-faith showing of the circumstances that prevented the lessee or other person from submitting a timely bid, and the commissioners, on the basis of that showing, approve the tender of the bid; or

(C) be the holder of an inducement voucher issued to a person that qualifies under (A) or (B) of this paragraph;

(2) execute, no later than 180 days after the close of the first binding open season of the project, a precedent agreement for firm transportation capacity on the Alaska mainline arising out of an action taken to qualify under (1) of this subsection, or must be the holder of an

inducement voucher issued by the commissioners to a person that executed a precedent agreement as required under this paragraph;

(3) obtain rights under a transportation services agreement

(A) as a party that executes, no later than five years after the close of the first binding open season of the project or two years after the effective date of the certificate of public convenience and necessity issued for the Alaska mainline, whichever date is later, a transportation services agreement arising out of an action taken to qualify under (1) and (2) of this subsection for firm transportation capacity on the Alaska mainline; or

(B) as the holder of an inducement voucher issued to a person qualified under (A) of this paragraph;

(4) file with the commissioners or be the holder of an inducement voucher obtained from a person that filed with the commissioners a complete copy of each of the following no later than 30 days after execution, or, under (E) of this paragraph, no later than 30 days after receipt of a request:

(A) the bid, precedent agreement, and transportation services agreement required to qualify under (1) - (3) of this subsection;

(B) an amendment to or termination of the bid, precedent agreement, or transportation services agreement required to qualify under (1) - (3) of this subsection;

(C) a bid, precedent agreement, or transportation services agreement, if any, arising out of a first binding open season for the Canada mainline;

(D) an amendment to or termination of the bid, precedent agreement, or transportation services agreement filed under (C) of this paragraph;

(E) other documents and information requested by the commissioners to determine qualification for resource inducements under AS 43.90 and this chapter; and

(5) submit, on a form provided by the commissioners, no later than 90 days after the issuance of a certificate of public convenience and necessity for the Alaska mainline, the agreement regarding rolling in expansion costs required by AS 43.90.310(c) or 43.90.330(d), as applicable.

(b) A person eligible for an inducement under AS 43.90.330 must execute the agreement set out in (a)(5) of this section no later than 90 days after issuance of a certificate of public convenience and necessity for the Alaska mainline, unless the person is eligible by reason of an agreement to transfer the inducement voucher, in which case the person must execute the agreement set out in (a)(5) of this section no later than 90 days after issuance of a certificate of public convenience and necessity for the Alaska mainline or the time of filing an application for transfer of the inducement voucher, whichever is later.

(c) The commissioners may extend the deadline set out in (a)(2) of this section if they determine that an extension is in the best interest of the state. However, the commissioners will not extend the deadline later than December 5, 2011.

(d) A person that satisfies the requirements of (a) and (b) of this section and that claims a resource inducement under AS 43.90.310 and this chapter may file an application with the commissioners for a determination that the requirements of (a) and (b) of this section have been met. Upon receipt of the application, the commissioners will make a joint determination whether the applicant meets the requirements for qualification set out in (a) and (b) of this section. A person is not qualified for a resource inducement before application to the commissioners and approval by the commissioners under this section. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 43.90.300 AS 43.90.330

AS 38.05.180 AS 43.90.310 AS 43.90.410

11 AAC 25.030. Qualified gas eligible for royalty inducements. (a) Only qualified gas is eligible for a royalty inducement under AS 43.90.310. Qualified gas is royalty-bearing gas that is produced from a North Slope lease and shipped

(1) on the Alaska mainline in the firm transportation capacity acquired through the bid, precedent agreement, and transportation agreement required to qualify under 11 AAC 25.020(a)(1) - (3);

(2) in an amount no greater than that specified in the bid required to qualify under 11 AAC 25.020(a)(1); and

(3) for a term of years no longer than specified in the bid required to qualify under 11 AAC 25.020(a)(1), excluding any option for extension of the term of years.

(b) In addition to unprocessed gas that is qualified gas under (a) of this section, qualified gas includes

(1) condensate recovered from qualified gas; and

(2) the following, if extracted from qualified gas:

(A) residue gas;

(B) gas plant products;

(C) LNG. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 43.90.300 AS 43.90.330
AS 38.05.180 AS 43.90.310 AS 43.90.410

11 AAC 25.040. Election of royalty inducements. (a) A qualified person that elects under AS 43.90.310(b)(1) and this section to calculate the monthly value of the state's royalty share of qualified gas under the royalty value methodology set out in this chapter, or to amend under AS 43.90.310(b)(2) the terms of an existing lease governing the exercise of the state's right to switch between taking the state's royalty on qualified gas in value or in kind, must submit an application for election on a form provided by the department and other documents and information requested by the department. The qualified person must submit the application and other documents and information

(1) no later than 90 days after issuance of a certificate of public convenience and necessity for the Alaska mainline, if the qualified person acquired firm transportation capacity in the first binding open season of the project; or

(2) no later than 90 days after issuance of a certificate of public convenience and necessity for the Alaska mainline or 30 days after acquisition of the inducement voucher, whichever is later, if a lessee elects the resource inducement as the holder of an inducement voucher received under AS 43.90.330.

(b) Upon receipt of the election form and other documents and information, the commissioner will make a determination on the election and notify the applicant if the election application is approved. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 43.90.300 AS 43.90.330

AS 38.05.180 AS 43.90.310 AS 43.90.410

11 AAC 25.050. Voucher for resource inducements. (a) To request an inducement voucher under AS 43.90.330, a person must apply for an inducement voucher on a form provided by the commissioners. No later than 30 days after notice is received, the applicant must provide other documents and information requested by the commissioners to determine whether the applicant meets the requirements of AS 43.90 and 11 AAC 25.020. Upon receipt of the application and other documents and information, the commissioners will make a joint determination on an application for an inducement voucher, and will issue an inducement voucher if the application is approved.

(b) To transfer an inducement voucher issued under (a) of this section, the holder of the voucher and the proposed transferee must file a joint application on a form provided by the commissioners. The joint application must include a copy of a binding contract between the holder and the proposed transferee for the sale and purchase of North Slope gas produced from a lease. No later than 30 days after notice is received, the applicants must provide other documents and information requested by the commissioners to determine whether to approve the transfer under AS 43.90.330 and 11 AAC 25.020. Upon receipt of the application and other documents and information, the commissioners will make a joint determination on the application, and will issue proof of transfer if the application is approved. A transfer is limited in time and quantity as set out in AS 43.90.330(c). (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 43.90.310 AS 43.90.410

AS 38.05.180 AS 43.90.330

11 AAC 25.060. Monthly value of state's royalty share of qualified gas and reporting. (a) The monthly value of the state's royalty share of qualified gas is the destination value of the qualified gas determined under 11 AAC 25.100 - 11 AAC 25.120, with adjustments to value for differences in location and quality as provided under 11 AAC 25.130 - 11 AAC 25.150, and changes in volume caused by pipeline, plant, and tanker in-kind fuel requirements, gains, and losses as provided under 11 AAC 25.090, less

(1) transportation costs allowed under 11 AAC 25.160 - 11 AAC 25.220;

(2) processing costs allowed under 11 AAC 25.230 - 11 AAC 25.260;

(3) LNG plant costs allowed under 11 AAC 25.270;

(4) deductions allowed by the 1980 Prudhoe Bay Royalty Settlement Agreement for Prudhoe Bay gas covered by that agreement, except that, consistent with the 1995 ANS Royalty Settlement Agreements, a cost or expense of Prudhoe Bay's Central Gas Facility may not be deducted; and

(5) deductions for cleaning and dehydration for qualified gas taken in kind from DL-1 leases not covered by the 1980 Prudhoe Bay Royalty Settlement Agreement, as provided by the superior court in In the Matter of ANS Royalty Litigation, 1JU-77-847 Civil (April 6, 1979); in this paragraph, "DL-1 lease" means an oil and gas lease issued by the state before January 1, 1979 on form DL-1.

(b) A lessee must report the monthly value of qualified gas for each lease and destination. For each lease, a lessee shall report

(1) the quantity of each component of qualified gas produced from that lease during the royalty reporting period;

(2) the quantity and destination value for each component of unprocessed gas delivered to each destination for unprocessed gas;

(3) the quantity and destination value for residue gas at each destination for residue gas;

(4) the quantity and destination value for each gas plant product at each destination for gas plant products;

(5) the quantity and destination value for LNG at each destination for LNG;

(6) the allowance for transportation costs allocated to residue gas, gas plant products, unprocessed gas, and LNG for each destination;

(7) the allowance for unused capacity deductions allocated to residue gas, gas plant products, unprocessed gas, and LNG for each destination;

(8) the allowance for processing costs for gas plant products for each destination;

(9) the allowance for LNG plant costs for each LNG plant and each LNG destination;

(10) each adjustment to gas quantity to meet the in-kind fuel requirements of a pipeline, plant, or tanker, or to account for pipeline gains and losses, plant gains and losses, or tanker gains and losses, if the adjustment is allowed under 11 AAC 25.090;

(11) each quality bank, NGL bank, or similar payment or credit required by 11 AAC 25.150; and

(12) deductions under (a)(4) or (5) of this section allocated to residue gas, gas plant products, unprocessed gas, and LNG for each destination.

(c) For each lease for which a lessee reports under this chapter, the monthly value of the state's royalty share of each of the following may not be less than zero:

(1) residue gas;

(2) gas plant products;

(3) unprocessed gas;

(4) LNG.

(d) For purposes of this chapter, a lessee shall report condensate as a gas plant product, except that a processing allowance may not be taken for condensate.

(e) In calculating the monthly value of the state's royalty share of qualified gas under this chapter, an expense or allowance may not be deducted more than once, and an adjustment, cost, or deduction other than those set out in this section may not be taken.

(f) Unless a provision of this chapter authorizes or requires a different method of allocation, an allocation of costs must be based upon generally accepted accounting principles. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.070. Allocation of gas and costs upstream of the Alaska mainline. (a) Unless otherwise provided in this chapter, a lessee calculating the monthly value of the state's royalty share of qualified gas under this chapter shall allocate gas and costs upstream of the inlet to the Alaska mainline as provided in this section.

(b) Qualified gas must be allocated to each North Slope lease producing royalty-bearing gas that has pipeline transportation access to the Alaska mainline. Qualified gas and non-qualified gas must be allocated among leases held by a lessee on the basis of a percentage for each lease represented by a ratio, the numerator of which is the lessee's quantity of royalty-bearing gas produced from a North Slope lease with pipeline transportation access to the Alaska mainline and the denominator of which is the lessee's quantity of royalty-bearing gas produced from all North Slope leases with pipeline transportation access to the Alaska mainline. For purposes of this subsection, quantities must be measured in MMBtus.

(c) Unless prohibited under (d) of this section or 11 AAC 25.160 - 11 AAC 25.220, a lessee may deduct costs of pipeline transportation allowed under this chapter for a pipeline upstream of the inlet to the Alaska mainline. The deduction will be allowed for pipeline transportation from the boundary of the unit of production to a gas treatment plant located outside the unit of production, or, if the lease of production is not within a unit, the lessee may deduct the costs of pipeline transportation from the boundary of the lease of production to a gas treatment plant located off the lease of production.

(d) If carbon dioxide exceeding the percentage of carbon dioxide allowed into the Alaska mainline is transported in a pipeline upstream of the Alaska mainline, the lessee shall allocate transportation costs between the excess carbon dioxide and all other gas based on their relative volumes. A deduction may not be taken in calculating the monthly value of the state's royalty share of qualified gas for costs allocated to excess carbon dioxide under this subsection.

(e) Except for a cost that may be deducted under 11 AAC 25.060(a)(4) or (5), a lessee in calculating royalty on qualified gas under this chapter may not deduct a cost of the lease or unit of production, a cost to meet the specifications for acceptance into the Alaska mainline, or a cost of putting gas and associated substances in marketable condition, including the cost of a gas treatment plant upstream of the inlet to the Alaska mainline. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.080. Allocation of gas and costs downstream of inlet to the Alaska mainline. (a) Unless otherwise provided in this chapter, a lessee calculating the monthly value of the state's royalty share of qualified gas under this chapter shall allocate gas and costs at and downstream of the inlet to the Alaska mainline as provided in this section.

(b) Based on its characteristics at destination, as destination is determined under this section and 11 AAC 25.100(b), qualified gas shall be characterized as one of the following:

(1) unprocessed gas;

(2) residue gas;

(3) one of the following gas plant products:

(A) NGL mix;

(B) fractionated gas plant products.

(c) If the lessee or its affiliate delivers into the Alaska mainline or a pipeline downstream of the inlet to the Alaska mainline both qualified gas from a lease and non-qualified gas from the same lease or from another source, the lessee shall allocate unprocessed gas, residue gas, and gas plant products between the qualified gas from the lease and the non-qualified gas as follows:

(1) the lessee shall account for unprocessed gas delivered from a pipeline downstream of the inlet of the Alaska mainline on the basis of the quantity of each component of unprocessed gas delivered from the pipeline; the lessee shall allocate, on a component-by-component basis, unprocessed gas between the qualified gas from the lease and non-qualified gas; the allocation to a lease must be based on a percentage for the lease representing a ratio, the

numerator of which is the quantity of the component of qualified gas from the lease that the lessee or its affiliate delivered into the pipeline during the royalty reporting period and the denominator of which is the total quantity of the same component that the lessee or its affiliate delivered into the pipeline from other sources during the royalty reporting period;

(2) residue gas resulting from processing by the lessee or its affiliate in any processing plant serviced by a pipeline downstream of the inlet to the Alaska mainline must be allocated between the qualified gas from the lease and non-qualified gas on the basis of MMBtus; the allocation to a lease must be based on the percentage for the lease representing a ratio, the numerator of which is the quantity of a 100 percent share of the methane plus the quantity of a fractional share of the ethane in the qualified gas from the lease that the lessee or its affiliate delivered into the pipeline during the royalty reporting period, and the denominator of which is the quantity of all the methane plus the quantity of a fractional share of all the ethane that the lessee or its affiliate delivered into the pipeline from other sources during the royalty reporting period; the fractional share of ethane to be used for purposes of allocation under this paragraph is the weighted average extraction plant recovery rate for ethane in residue gas for all processing plants serviced by the pipeline and used by the lessee or its affiliate in the royalty reporting period;

(3) the NGL mix resulting from processing by the lessee or its affiliate in any processing plant serviced by a pipeline downstream of the inlet to the Alaska mainline shall be allocated by the lessee between qualified and non-qualified gas from the lease; an allocation must be made for each component in the NGL mix; the allocation to a lease must be based on the percentage for the lease representing a ratio, the numerator of which is the quantity of the

component in the qualified gas from the lease that the lessee or its affiliate delivered into the pipeline during the royalty reporting period, and the denominator of which is the quantity of the component the lessee or its affiliate delivered into the pipeline from other sources during the royalty reporting period;

(4) the lessee shall allocate between qualified gas from a lease and non-qualified gas a fractionated gas plant product resulting from processing by the lessee or its affiliate in a processing plant serviced by a pipeline downstream of the inlet to the Alaska mainline; the allocation to a lease must be based on the percentage for the lease representing a ratio, the numerator of which is the quantity of a component in the qualified gas from the lease that the lessee or its affiliate delivered into the pipeline during the royalty reporting period, and the denominator of which is the quantity of the same component that the lessee or its affiliate delivered into the pipeline from other sources during the royalty reporting period; the component to be used for purposes of allocation under this paragraph is the component that corresponds with the fractionated gas plant product.

(d) If a lessee or its affiliate transports both qualified and non-qualified gas from a lease or from another source between the same receipt and delivery points for a pipeline under more than one agreement with the pipeline, and if the agreements contain different charges for the same service, the lessee shall allocate the qualified and non-qualified gas from the lease or from another source between the agreements based on MMBtus. However, qualified gas transported on the Alaska mainline or Canada mainline shall be allocated only to firm transportation capacity acquired through a commitment made in the first binding open season for the mainline.

(e) The actual and reasonable costs allowed for transportation under 11 AAC 25.060 -

11 AAC 25.090 and 11 AAC 25.160 - 11 AAC 25.210 must be allocated between unprocessed gas, residue gas, gas plant products, and LNG by destination according to the methodology set out in the applicable transportation services agreement. If the transportation services agreement does not set out a methodology, allocation must be based on MMBtus and mileage of haul.

(f) If a lessee or its affiliate processes both qualified and non-qualified gas from a lease or from another source at a processing plant downstream of the inlet to the Alaska mainline under more than one agreement with that plant for processing, and if the agreements contain different charges for the same service, the qualified gas from the lease and non-qualified gas must be allocated proportionately between the agreements.

(g) In allocating under this section the value of unprocessed gas, residue gas, gas plant products, and LNG between qualified and non-qualified gas from a lease or to another source, a lessee may either adjust volume for a pipeline, plant, and tanker in-kind fuel requirement, for gain, and for loss for all gas from any source using the method set out in 11 AAC 25.090 or not make an adjustment for gas from any source for that purpose under this subsection. After a lessee chooses whether to adjust volumes for the purpose of this subsection, it cannot change its choice without the commissioner's approval. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.090. Adjustments to royalty volumes for pipeline, plant, and tanker in-kind fuel requirements, gains, and losses. (a) A lessee calculating the monthly value of the state's royalty share of qualified gas under this chapter may adjust its royalty volumes only to the extent allowed by this section.

(b) If the costs of a pipeline, plant, or tanker are deductible under this chapter, and the pipeline, plant, or tanker has an in-kind fuel requirement rather than a monetary charge for fuel use directly attributable to transporting, processing, liquefying, or regasifying qualified gas, the lessee may reduce the quantity of qualified gas on which it pays royalty in value by the quantity of the in-kind fuel requirement assessed against that qualified gas, except as provided in this section, 11 AAC 25.080(g), or 11 AAC 25.200.

(c) If a lessee or its affiliate transports, processes, liquefies, or regasifies qualified gas under an arm's length contract and the charge under that contract for those purposes is deductible under this chapter, losses experienced under the contract of no more than two percent of the total volume of gas delivered under the contract that are assessed against the qualified gas under the terms of the contract may be used to reduce the quantity of qualified gas on which the lessee pays royalty to the state. However, a reduction in quantity is allowed under this subsection only if the lessee also reports increases in the quantity of qualified gas on which it pays royalties to the state if gains in volume of qualified gas are realized under the terms of the arm's length contract.

(d) If a lessee or its affiliate transports, processes, liquefies, or regasifies qualified gas under a contract or agreement other than an arm's length contract, a loss in volume is not allowed in calculating the monthly value of the state's share of royalty gas under this chapter.

(e) Each in-kind fuel requirement, loss, and gain allowed or required under this section must be reported separately by lease and destination and must be allocated between unprocessed gas, residue gas, gas plant products, and LNG. Allocation must be according to the method set out in the applicable transportation services agreement or processing agreement. If the transportation services agreement or processing agreement does not set out an allocation method, allocation must be based on

(1) MMBtus, for a processing agreement; and

(2) MMBtus and mileage of haul, for a transportation agreement.

(f) If the cost of transporting carbon dioxide is not allowed under 11 AAC 25.070(d), an in-kind fuel deduction is not allowed for transporting carbon dioxide. For purposes of this section, in-kind fuel requirements must be allocated between the excess carbon dioxide and all other gas based on their relative volumes.

(g) Notwithstanding the terms of an existing lease or unit agreement, a lessee may reduce royalty volumes for an in-kind fuel requirement for qualified gas treated in a gas treatment plant located on the North Slope even if the plant is not on the lease of production or within the unit of production. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.100. Destination and destination value. (a) The destination value for qualified gas is the fair market value at destination as determined under this section.

(b) For purposes of this chapter, the destination for a lessee's unprocessed gas, residue gas, gas plant products, or LNG is the point at which the gas exits a pipeline, without then entering an interconnecting pipeline, processing plant, liquefaction facility, LNG tanker, or regasification facility, except that

(1) the destination for qualified gas that enters a first destination market must be within that first destination market and may not be downstream of that first destination market; if

qualified gas enters an interconnecting pipeline for transportation downstream of a first destination market, its destination for purposes of this chapter is the point of interconnection;

(2) qualified gas that has been processed to extract residue gas or a fractionated gas plant product is at its destination; and

(3) the destination for qualified gas may not be downstream of the point of an arm's length sale of the qualified gas.

(c) The commissioner will designate first destination markets. In designating first destination markets, the commissioner will consider whether

(1) North Slope gas is physically transported, bought, sold, processed, or, in the case of LNG, regasified in the market;

(2) on average each day, more than 100,000 MMBtus of residue gas are sold in arm's length transactions in the market;

(3) a reliable and widely available industry trade publication publishes a reliable price each month for residue gas in the market, and the published price is based on at least 10 unrelated arm's length sales in that market for the month;

(4) another first destination market is upstream of the market being evaluated for designation under this section as a first destination market; and

(5) any other relevant factor is material to the designation of a first destination market.

(d) The commissioner will designate at least one first destination market to apply to royalty reporting periods beginning after the commencement of commercial operation of the project. Notice of the first destination markets designated by the commissioner will be posted on the department's website. The commissioner may designate other first destination markets by posting notice of the designation on the department's website no later than 15 days before the first day of a royalty reporting period affected by the designation.

(e) If the destination for qualified gas is a first destination market designated by the commissioner, the destination value is the published price for that destination from a source designated by the commissioner, except that

(1) for residue gas and the methane component of unprocessed gas, if the published price designated by the commissioner is less than 95 percent of the value calculated under 11 AAC 25.110 for that royalty reporting period, the destination value for that royalty reporting period is the value calculated under 11 AAC 25.110; and

(2) for any gas plant product or any component other than methane in unprocessed gas, if a published price is not available for that first destination market or if the published price is not a reliable price for that gas plant product or component in that market, the commissioner may designate and require the use of a published price from a different market, as adjusted for location differences under 11 AAC 25.130.

(f) The commissioner may add to, replace, or remove entries on the list of designated published prices by posting a revised list of published prices on the department's website at least 15 days before the first day of a royalty reporting period affected by the revised list if the commissioner determines that

(1) a new market has developed for North Slope gas or any component of or right to North Slope gas, a new gas pipeline is built that transports North Slope gas, or a change in the first destination markets has occurred;

(2) a designated published price is not reliable;

(3) a designated published price is published in a publication that is not reliable;

(4) a new publication is started, an existing publication adds a new price, or a previously unreliable publication becomes reliable;

(5) a person subject to this chapter or the affiliate of that person attempts to influence the publication of prices used under this chapter in a manner adverse to the interests of the state; or

(6) other factors relevant to the designation of first destination markets under (c) of this section or to the reliability of published prices support the addition, replacement, or removal of entries on the list of designated published prices.

(g) If the destination for qualified gas has not been designated by the commissioner as a first destination market, destination value for the qualified gas is the published price designated by the commissioner in the nearest first destination market, with an adjustment for location differences under 11 AAC 25.130 and an adjustment for quality to the extent allowed under 11 AAC 25.140, except that if the destination and first destination market are not physically connected by pipeline, the destination value will be determined under 11 AAC 25.120.

(h) If the commissioner adds to, revises, or removes adjustments for location differences under 11 AAC 25.130, the commissioner will post a change in location differentials on the department’s website at least 15 days before the first day of a royalty reporting period affected by the change.

(i) To be arm's length for a royalty reporting period, a contract or agreement must be considered arm's length

(1) when the contract was executed or the agreement was made; and

(2) during the entire time of the royalty reporting period.

(j) If a published price from a source designated by the commissioner under this section is not available for a royalty reporting period, the destination value is

(1) for residue gas, as determined by the commissioner based on all other available published prices designated for use under 11 AAC 25.110, with a location differential, if any, determined by the commissioner; and

(2) for unprocessed gas, gas plant products, and LNG, destination value as determined under 11 AAC 25.120.

(k) For purposes of this chapter, the commissioner will determine whether a price or publication is reliable. In determining whether a price is reliable, the commissioner will consider whether the price is indicative of market transactions in the relevant market and whether the price relies on a volume-weighted average of reported transactions. In determining that a publication is reliable, the commissioner may consider

(1) whether buyers and sellers regularly and customarily use the publication;

(2) whether the publication is regularly and customarily referenced in purchase or sales contracts;

(3) whether the publication uses adequate survey techniques, including the gathering of information from a substantial number of sales;

(4) whether the publication publishes the range of reported prices it uses to calculate its index price;

(5) whether the publication is independent from lessees and their affiliates; and

(6) other factors relevant to whether a publication publishes prices that are accurate and representative for gas purchases and sales. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.110. Alternative destination value for residue gas and methane in unprocessed gas. (a) If, for a royalty reporting period, the published price designated by the commissioner for residue gas and methane in unprocessed gas reaching destination after entry into a first destination market serviced by the Canada mainline is less than 95 percent of the alternative value calculated under this section, the destination value for that royalty reporting period is the alternative value calculated under this section.

(b) The alternative destination value calculated under this section is based on a market basket of published prices for residue gas. The market basket includes published prices designated by the commissioner for each market center designated by the commissioner.

(c) For purposes of calculating alternative destination value under this section, the commissioner will designate market centers where

(1) the published price identified under (j)(1)(B) of this section is reported for the same date or period as the published price for other market centers to be used in the market basket; and

(2) the market center is either

(A) a first destination market; or

(B) a first market center under (i) of this section.

(d) The published price for each market center designated under (c) of this section is netted back from the location of the delivery point most directly associated with the published price for the market center to the point a pipeline supplying the market center interconnects with the Canada mainline. Netting back is based on the weighted average of the pipeline tariffs between the point of interconnection to the Canada mainline and the location of the delivery point most directly associated with the published price for the market center. A tariff used for purposes of this subsection is the simple average recourse rate

(1) for firm transportation services for the calendar year immediately preceding the year of the royalty reporting period; and

(2) calculated based on a 100 percent load factor.

(e) The published price for each market center designated under (c) of this section, after netting back to the point of interconnection to the Canada mainline under (d) of this section, will be weighted. Weighting under this subsection is on the basis of MMBtus shipped or delivered in the preceding calendar year as follows:

(1) for the market center of a first destination market that is not in a region that produces and exports more gas than it consumes, the quantity to be used to determine the weighted published price is the quantity of gas delivered into a pipeline directly servicing both the project and the market center in the preceding calendar year;

(2) for the market center of a first destination market that is in a region that produces and exports more gas than it consumes, the quantity to be used to determine a weighted published price is the quantity of gas consumed in that market in the preceding calendar year;

(3) for a market center that is a first market center downstream of a first destination market in a region that produces and exports more gas than it consumes, the quantity

to be used to determine a weighted published price is the quantity of gas received into the pipeline most directly connecting the first destination market and that first market center and nearest to the market center.

(f) After the published price for each market center designated under (c) of this section is netted back to the point of interconnection to the Canada mainline under (d) of this section and weighted under (e) of this section, the weighted price is netted forward from the point of interconnection to the Canada mainline to a lessee's destination for qualified gas entering a first destination market. The lessee's costs of transportation allowed by this chapter between the point of interconnection to the Canada mainline and destination is used to net the weighted price forward.

(g) The department will make the calculations described in (d) and (e) of this section and post them to the department's website at least 15 days before an affected royalty report is due. If a market center does not meet the criteria set out in (c) of this section for a royalty reporting period, that market center will not be used for that royalty reporting period in making the calculations described in (d) and (e) of this section.

(h) Market centers and published prices designated by the commissioner will be posted by the commissioner on the department's website. Based on the criteria set out in (c) of this section, the commissioner may add to, replace, or remove entries on the list of designated market centers and published prices by posting a revised list on the department's website at least 15 days before the first day of a royalty reporting period that is affected by the revision, if the commissioner determines that

(1) market centers meeting the requirements of (c) of this section have changed;

(2) a designated published price is not reliable;

(3) a designated published price is published in a publication that is not reliable;

(4) a new publication is started, an existing publication adds a new price, or a previously unreliable publication becomes reliable;

(5) a person or an affiliate of the person subject to this chapter attempts to influence the publication of prices used under this section in a manner adverse to the interests of the state; or

(6) other factors relevant to the designation of market centers under (c) of this section or to the reliability of published prices support the addition, replacement, or removal of entries on the list of designated market centers and published prices.

(i) For purposes of this section, a market center is a first market center if

(1) it is directly connected to and downstream of a first destination market;

(2) the first destination market identified under (1) of this subsection is in a region that produces and exports more gas than it consumes;

(3) there is not another market center between the first destination market identified under (1) of this subsection and the market center; and

(4) more than 250,000 MMBtus of residue gas are shipped on average each day from the first destination market identified under (1) of this subsection to the market center.

(j) In this section,

(1) "market center" means a location or area

(A) where more than 25,000 MMBtus of residue gas are sold in arm's length transactions on average each day; and

(B) for which a reliable and widely available industry trade publication publishes a reliable price for the market center based on at least five unrelated arm's length sales of residue gas at that market center in the royalty reporting period and in at least nine of the preceding 12 calendar months;

(2) "netting back" means to calculate the price or value of gas at an upstream location based on the price or value of gas at a downstream location, minus the costs of transportation between the upstream and downstream locations;

(3) "netting forward" means to calculate the price or value of gas at a downstream location based on the price or value of gas at an upstream location, plus the costs of transportation between the upstream and downstream locations. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.120. Destination value in absence of reliable published prices. (a) If the destination for qualified gas is not a first destination market, and the commissioner has not designated an applicable location differential for that destination under 11 AAC 25.130 for purposes of adjusting a published price from a first destination market to the destination, destination value is determined under (b) or (c) of this section, as applicable.

(b) The destination value of qualified gas sold by a lessee or an affiliate under an arm's length contract is the gross proceeds accruing to the lessee or affiliate, except as provided in this subsection. To claim the benefit of this section, the lessee shall demonstrate that its contract is arm's length. The commissioner may require a lessee to certify in writing that its arm's length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly. If an arm's length contract does not set out the consideration actually transferred either directly or indirectly from the buyer to the seller, the commissioner may require that the qualified gas sold under that contract be valued at destination under (c) of this section. If the commissioner determines that the gross proceeds accruing under an arm's length contract to the lessee or an affiliate of the lessee do not represent the reasonable value of the qualified gas because of misconduct by the contracting parties, or because the lessee breached its duty to the state to market the qualified gas for the mutual benefit of the lessee and the state, the commissioner may require the lessee to value the qualified gas under (c) of this section.

(c) If qualified gas is not sold under an arm's length contract, or if the lessee is required under (b) of this section to determine destination value under this subsection, the destination value of qualified gas is the fair market value for the qualified gas as determined by the commissioner based on prices received in arm's length spot sales, other reliable sources of price or market information, and comparable arm's length contracts for purchases, sales, or other dispositions of like-quality gas. In evaluating the comparability of an arm's length contract for purposes of this subsection, the commissioner will consider

(1) price;

(2) the time of execution;

(3) the contract's duration;

(4) each market served;

(5) the contract's terms;

(6) the quality and volume of the gas; and

(7) other factors appropriate to reflect the value of the qualified gas.

(d) In this section,

(1) "gross proceeds" means the money and other consideration accruing to an oil and gas lessee or its affiliate for the disposition of qualified gas; "gross proceeds" include

(A) payments to the lessee or its affiliate for dehydration, measurement, gathering, or other services, to the extent that the lessee is obligated to perform those services at no cost to the state as lessor or otherwise;

(B) tax reimbursements accruing to a lessee or its affiliate even though the state's royalty interest may be exempt from taxation; and

(C) money and other consideration, including the forms of consideration identified in this paragraph, to which a lessee or its affiliate is contractually or legally entitled but that the lessee or affiliate does not seek to collect through reasonable efforts;

(2) "spot sale" means a contract for the sale of gas that

(A) requires a seller to sell to a buyer a specified amount of unprocessed gas, residue gas, or a gas plant product at a specified price over a fixed period, usually of short duration;

(B) does not normally require a cancellation notice to terminate; and

(C) does not contain an obligation to, or imply an intent to, continue in later periods. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.130. Location differentials. (a) The commissioner will establish location differentials to

(1) calculate the destination value of qualified gas at a destination upstream of a first destination market; or

(2) calculate the destination value of a gas plant product or component other than methane in a first destination market if a published price for that gas plant product or component is not available or is not reliable.

(b) To establish a location differential, the commissioner will consider

(1) the difference between a reliable published price for residue gas or a gas plant product in a market with a reliable published price and the price paid for residue gas, a gas plant product, or unprocessed gas in the market without a reliable published price;

(2) the cost of transportation between the market with a reliable published price and the market without a reliable published price;

(3) other factors relevant to differences in value that result from the market location.

(c) The commissioner will give notice of location differentials established under this section by posting a list on the department's website. The commissioner may add to, replace, or remove entries on the list of location differentials by posting a revised list of location differentials on the department's website at least 15 days before the first day of a royalty reporting period affected by the action. A location differential posted by the commissioner to the department's website under this section is not subject to retroactive change.

(d) If the commissioner is notified in writing at least three months before a first shipment that a lessee or its affiliate will transport qualified gas to a destination upstream of a first destination market, the commissioner will post a location differential for that destination on the department's website at least 15 days before the first day of a royalty reporting period affected by the posting.

(e) If the commissioner is not notified in writing at least three months before a first shipment that a lessee or its affiliate will transport qualified gas to a destination, and the commissioner has not posted a location differential for the destination on the department's website, the destination value and location differential for that destination may be adjusted by the commissioner based on the criteria for destination value set out in this chapter and the criteria for location differentials set out in this section. An adjustment under this subsection is retroactive to the date of first shipment. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.140. Quality differentials for unprocessed gas. (a) The commissioner will establish a quality differential to be used in valuing unprocessed gas.

(b) The commissioner will establish a quality differential to allow a lessee that elects not to take a processing allowance for qualified gas to deduct a quality differential that is representative of processing costs.

(c) In establishing a quality differential, the commissioner will consider

(1) the cost of gas processing;

(2) standard deductions allowed or used by other governments or royalty owners to reflect quality differences or processing costs, including the fractionation allowance allowed by the Alberta government for fractionating propane, butane, and pentane plus;

(3) the composition of a lessee's gas or gas from a North Slope lease, unit, participating area, or reservoir; and

(4) other factors relevant to whether a quality differential is representative of processing costs.

(d) The commissioner will post quality differentials on the department's website at least 15 days before a royalty report affected by the quality differential is due. The commissioner may add to, replace, or remove entries on the list of quality differentials by posting a revised list of quality differentials on the department's website at least 15 days before a royalty report is due. A location differential posted by the commissioner on the department's website under this section is not subject to retroactive change. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.150. Quality bank. If a quality bank, NGL bank, or other mechanism is established to compensate or charge persons transporting gas on a pipeline for differences in the relative quality of gas tendered or received, a lessee shall adjust royalty volume or royalty payments to the state based on the same principles used by the quality bank, NGL bank, or other mechanism to compensate or charge a person transporting gas for differences in the relative quality of gas tendered or received. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.160. Transportation costs. (a) In calculating the monthly value of the state's royalty share of qualified gas, a lessee may deduct transportation costs as provided in

11 AAC 25.060 - 11 AAC 25.090 and 11 AAC 25.160 - 11 AAC 25.220. Only actual and reasonable transportation costs are allowed under this section that are incurred and paid by the lessee or its affiliate and not refunded to the lessee or its affiliate for transporting qualified gas between the boundary of the unit of production and destination, or, if the lease of production is not within a unit, between the lease of production and destination.

(b) If a lessee, its marketing affiliate, or any affiliate other than a transportation affiliate transports qualified gas on a transportation affiliate, transportation costs for the lessee must be reported on the basis of the actual and reasonable costs of the transportation affiliate, unless the lessee, its marketing affiliate, or affiliate other than the transportation affiliate pays the transportation affiliate a lower amount or has an agreement or contract with the transportation affiliate for a lower amount, in which case the lower amount must be used.

(c) For purposes of 11 AAC 25.060 - 11 AAC 25.090 and 11 AAC 25.160 - 11 AAC 25.220, a marketing entity, pipeline entity, LNG transportation entity, or other entity is an affiliate of the lessee if the lessee and the other entity are affiliated during the royalty reporting period, or were affiliated when the contract for sale, marketing, transportation, or other service was executed or an agreement for sale, marketing, transportation, or other service was made.

(d) If a lessee or an affiliate receives a payment or credit from a transportation entity, the lessee shall reduce the cost or deduction claimed in reporting and paying royalties on qualified gas by the amount of the payment or credit attributable to that gas. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.170. Transportation contracts at arm's length. (a) If a lessee or an affiliate transports qualified gas under an arm's length contract, the transportation allowance used to determine the monthly value of the lessee's qualified gas must be the actual and reasonable costs incurred and paid by the lessee or an affiliate and not refunded to the lessee or the affiliate for transportation, less any costs disallowed under 11 AAC 25.060 - 11 AAC 25.090 or 11 AAC 25.160 - 11 AAC 25.220. To claim a transportation allowance under this section, the lessee shall demonstrate that the contract is arm's length.

(b) If the commissioner determines that the consideration set out in an arm's length contract exceeds the consideration actually transferred either directly or indirectly from the lessee or an affiliate to the transportation entity for the transportation, the commissioner may require that the transportation allowance be reduced or redetermined under 11 AAC 25.180 - 11 AAC 25.200.

(c) If the commissioner determines that the consideration paid under an arm's length transportation contract exceeds the reasonable value of the transportation because of misconduct by the contracting parties, or because the lessee breached a duty to the state to market the production for the mutual benefit of the lessee and the state, the commissioner may require that the transportation allowance be reduced or redetermined under 11 AAC 25.180 - 11 AAC 25.200. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.180. Transportation contracts not at arm's length - Alaska mainline and Canada mainline. (a) If a lessee, its marketing affiliate, or any affiliate other than a transportation affiliate transports qualified gas on the Alaska mainline or Canada mainline and that pipeline is a transportation affiliate, the cost of transportation must be the allowable actual and reasonable cost, as determined under (b) - (m) of this section, 11 AAC 25.160, and 11 AAC 25.210, of transportation provided by the pipeline that is the transportation affiliate. However, if the circumstances described in (n) of this section occur, the amount determined under that subsection must be used as the cost of transportation.

(b) If calculating allowable actual and reasonable cost in accordance with (b) - (m) of this section, the lessee, without regard to whether a pipeline is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC), and except as provided in (c) - (m) of this section, shall calculate that cost in accordance with the FERC *Cost-of-Service Rates Manual*, dated June 1999, the FERC Order Issuing Clarification and Granting Rehearing in Southern Natural Gas Co., 130 FERC ¶ 61,193 (Docket nos. CP09-36-002, CP09-40-001, and AD10-3-000, March 18, 2010), and the FERC Order Granting Rehearing in Florida Gas Transmission Co., 130 FERC ¶ 61,194 (Docket nos. CP09-17-001, AC08-161-002, and AD10-3-000, March 18, 2010). The FERC documents listed in this subsection are adopted by reference for purposes of this section, except as provided in (c) - (m) of this section.

(c) The cost of transportation under (b) - (m) of this section is determined by first identifying the term of years and profile for capital recovery in the transportation services agreement under which qualified gas is shipped. If those terms match the terms offered in the plan for conducting an open season for the Alaska mainline, the negotiated rate generated by those terms under the plan for conducting an open season for the Alaska mainline, as modified under (b) and (d) - (m) of this section, is the cost of transportation used to calculate the transportation allowance, unless the negotiated rate generated under the plan for conducting an open season for the Alaska mainline, as modified under (b) and (d) - (m) of this section, is greater than the amount determined under (n) of this section, in which case the amount determined under (n) of this section is the cost of transportation.

(d) If the transportation services agreement under which the qualified gas is shipped does not set out a profile for capital recovery, or sets out a term of years and profile for capital recovery other than one offered in the plan for conducting an open season for the Alaska mainline, depreciation must be calculated to recover capital investment over the economic life of the pipeline, and must be calculated using annual composite depreciation percentages that result in levelized rates over the life of the transportation services agreement and that recover that part of total capital investment that is the greater of 4/5 or the percentage that equals the ratio of the original term of years in the transportation services agreement to the economic life of the pipeline. In this calculation, the economic life must be the estimated useful life used to calculate the initial recourse rate for the pipeline.

(e) In the absence of long-term debt actually issued for the Alaska mainline or Canada mainline, as applicable, a lessee shall compute the return on the part of the capital investment treated as financed with long-term debt using the weighted average of the cost of long-term debt for the proxy group designated by the department under 11 AAC 25.190(j). After the commencement of commercial operations of the Alaska mainline or Canada mainline, as applicable, at least 75 percent of the capital investment must be treated as financed with long-term debt, unless the applicable transportation services agreement provides for a higher percentage debt, in which case the higher percentage must be used.

(f) Capital investment must be the properly allocable part of the lower of capital investment

(1) that would be properly reportable on FERC Form 2 if the pipeline were subject to FERC jurisdiction;

(2) that is prudently incurred, as determined by the regulatory agency with jurisdiction over the pipeline; or

(3) allowed under the applicable transportation services agreement.

(g) A change in ownership of an asset does not alter the original cost valuation of capital investment.

(h) An allowance for funds used during construction (AFUDC) must be calculated consistent with the FERC *Cost-of-Service Rates Manual* adopted by reference in (b) of this section, except to the extent modified by this section. AFUDC begins to accrue no earlier than the time certificate pre-filing commences under 18 C.F.R. 157.21(e). AFUDC must be compounded annually, and not more frequently. For purposes of determining AFUDC, 70 percent of the capital investment must be treated as financed with long-term debt for the period before the commencement of commercial operations of the Alaska mainline or Canada mainline, as applicable, unless the applicable transportation services agreement provides for a higher percentage debt, in which case the higher percentage must be used.

(i) An allowance for the cost to dismantle and remove the pipeline and for restoration after removal of the pipeline may be taken only if specifically identified and approved by the regulatory agency with jurisdiction over the pipeline in an applicable tariff for the pipeline.

(j) Tax depreciation used to calculate accumulated deferred income taxes for the Alaska mainline is seven years for all depreciable property, consistent with 26 U.S.C. 168. Tax depreciation used to calculate accumulated deferred income taxes for the Canada mainline is the terms of years set out in the federal income tax laws of Canada for depreciation of pipeline property.

(k) Operating and maintenance expenses may not include ad valorem taxes or any other cost otherwise recoverable under (b) and (d) - (m) of this section. Operating and maintenance expenses must be the properly allocable part of the lower of operating and maintenance expenses

(1) that would be properly reportable on FERC Form 2 if the pipeline were subject to FERC jurisdiction;

(2) that are prudently incurred, as determined by the regulatory agency with jurisdiction over the pipeline; or

(3) allowed under the applicable transportation services agreement.

(*l*) Except for refunds and surcharges permitted by the regulatory agency with jurisdiction over the pipeline, an adjustment may not be made for recoveries in the prior period that exceed or are less than the transportation affiliate's allowable actual and reasonable cost as determined under (c) - (i) of this section.

(m) Per-unit transportation costs for transportation of qualified gas by a transportation affiliate must be based on a 100 percent load factor of certificated capacity even if the capacity is not used at a 100 percent load factor.

(n) If the cost of transportation calculated under (b) - (m) of this section is greater than the amount the lessee or its affiliate actually pays for transportation, the amount actually paid and not the cost of transportation calculated under (b) - (m) of this section shall be used by the lessee in calculating the monthly value of the state's royalty share of qualified gas.

(o) In this section, "plan for conducting an open season for the Alaska mainline" means the original plan as filed by TransCanada Alaska Company, LLC with FERC in Docket No. PF09-11-001 on January 29, 2010. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.190. Transportation contracts not at arm's length - pipelines other than the Alaska mainline and Canada mainline. (a) If a lessee, its marketing affiliate, or any affiliate other than a transportation affiliate transports qualified gas on a pipeline other than the Alaska mainline or Canada mainline and that pipeline is a transportation affiliate, the cost of transportation must be the allowable actual and reasonable cost, as determined under (b) - (n) of this section, 11 AAC 25.160, and 11 AAC 25.210, of transportation provided by the pipeline that is the transportation affiliate. However, if the circumstances described in (o) of this section occur, the amount determined under that subsection must be used as the cost of transportation.

(b) If calculating allowable actual and reasonable cost in accordance with (b) - (n) of this section, the lessee, without regard to whether a pipeline is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC), and except as provided in (c) - (n) of this section, shall calculate that cost in accordance with the FERC *Cost-of-Service Rates Manual*, dated June 1999, the FERC Order Issuing Clarification and Granting Rehearing in Southern Natural Gas Co., 130 FERC ¶ 61,193 (Docket nos. CP09-36-002, CP09-40-001, and AD10-3-000, March 18, 2010), and the FERC Order Granting Rehearing in Florida Gas Transmission Co., 130 FERC ¶ 61,194 (Docket nos. CP09-17-001, AC08-161-002, and

AD10-3-000, March 18, 2010). The FERC documents listed in this subsection are adopted by reference for purposes of this section, except as provided in (c) - (n) of this section.

(c) The applicable costs of transportation are determined for a calendar year by calculating the total amount for the year for the following items and allocating that total, as provided under this section, to the qualified gas:

(1) an allowance for operating and maintenance expenses of the pipeline;

(2) annual depreciation on capital investment in the pipeline at original cost;

(3) annual amortization of allowance for funds used during construction (AFUDC);

(4) an after-tax return on the sum of capital investment in the pipeline at original cost net of depreciation accumulated before the year of calculation, and AFUDC net of cumulative AFUDC amortized before the year of calculation, with the undepreciated capital investment and unamortized AFUDC balances adjusted to account for accumulated deferred income taxes and retirements; a return may not be earned on cash working capital;

(5) income tax on the equity part of the return on capital investment under (4) of this subsection;

(6) ad valorem taxes on the pipeline;

(7) if specifically identified and approved in an applicable tariff for a regulated pipeline, an allowance for the cost to dismantle and remove the pipeline and for restoration after removal of the pipeline.

(d) For purposes of determining the allowance described in (c)(1) of this section, the proper allocation of operating and maintenance expenses must be determined with reference to whether the applicable transportation services agreement requires rolled-in or incremental rate treatment. Operating and maintenance expenses may not include ad valorem taxes or any other cost otherwise recoverable under (c)(2) - (7) of this section. Operating and maintenance expenses must be the properly allocable portion of the lower of operating and maintenance expenses

(1) that would be properly reportable on FERC Form 2 if the pipeline were subject to FERC jurisdiction;

(2) that are prudently incurred, as determined by the regulatory agency with jurisdiction over the pipeline; or

(3) allowed under the applicable transportation services agreement.

(e) For purposes of (c)(2), (4), and (5) and (h) of this section,

(1) capital investment must be the properly allocable part of the lower of capital investment

(A) that would be properly reportable on FERC Form 2 if the pipeline were subject to FERC jurisdiction;

(B) that is prudently incurred, as determined by the regulatory agency with jurisdiction over the pipeline; or

(C) allowed under the applicable transportation services agreement;

(2) the proper allocation of capital investment must be determined with reference to whether the applicable transportation services agreement requires rolled-in or incremental rate treatment; and

(3) a change in ownership of an asset does not alter the original cost valuation of

capital investment.

(f) AFUDC used to determine the items described in (c)(3) and (4) of this section must be calculated consistent with the FERC *Cost-of-Service Rates Manual,* adopted by reference in (b) of this section,

(1) with AFUDC being accrued beginning at the time that certificate pre-filing, if required under 18 C.F.R. 157.21, commences under 18 C.F.R. 157.21(e), or if pre-filing is not required, at the time that filing of an application for a FERC certificate of public convenience and necessity is accepted under 18 C.F.R. 157.8; and

(2) using the weighted average cost of capital determined in accordance with (i) and (j) of this section, and annual compounding.

(g) For purposes of determining annual depreciation and annual amortization of AFUDC under (c)(2) and (3) of this section, depreciation and amortization must be calculated using the same term of years and same profile for capital recovery used in the transportation services agreement under which qualified gas is shipped. However, if the transportation services agreement does not set out a profile for capital recovery, or establishes a depreciation schedule that recovers total capital before the conclusion of the pipeline's economic life as determined in the initial proceeding for a FERC certificate of public convenience and necessity, depreciation must be calculated to recover capital investment over the economic life of the pipeline, and must be calculated using annual composite depreciation percentages that recover an equal percentage of original plant investment each year. In this calculation the economic life must be the estimated useful life used to calculate the initial recourse rate for the pipeline, or the pipeline's initial generally prevailing rate if a recourse rate is not offered. A change in ownership of an asset does not alter the depreciation schedule, or the accumulated deferred income taxes, established by the original owner of the pipeline when annual depreciation and annual amortization of AFUDC is determined under (c)(2) and (3) of this section. A capital investment may be depreciated only once, and may not be depreciated below a reasonable salvage value. If specifically identified and provided for in an applicable tariff for a regulated pipeline, the salvage value may be negative, unless the calculation of costs under (c) of this section includes an allowance under (c)(7) of this section for dismantlement and removal of the pipeline and restoration after removal of the pipeline.

(h) For pipelines that are regulated either by FERC or the Regulatory Commission of Alaska, accumulated deferred income taxes will be calculated consistent with the FERC *Cost-of-Service Rates Manual*, adopted by reference in (b) of this section, using the tax depreciation schedule established by the relevant taxing authority for pipeline assets and the book depreciation schedule established under (g) of this section.

(i) For purposes of determining the return on capital investment for a gas pipeline under (c)(4) of this section, the percentage of the capital investment treated as financed with long-term debt is the percentage actually used by the pipeline owner to finance the pipeline or 70 percent, whichever amount is greater. The remainder is treated as financed with equity. The return on the portion of the capital investment treated as financed with long-term debt is the actual cost, if any, of the debt or, in the absence of actual cost, the return computed by the department using the weighted average of the cost of long-term debt for the proxy group designated by the department under (j) of this section.

(j) For purposes of (c)(4) of this section, an after-tax rate of return on the percentage of the capital investment treated as financed with equity will be determined by the department for a calendar year. The department will use a two-stage discounted cash flow model to determine the return on capital investment in a pipeline. In implementing that model, the department will give substantial weight to the FERC Policy Statement in *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, Docket No. PL07-2-000, dated April 17, 2008 and adopted by reference for that purpose, subject to the following:

(1) the department will designate the group of proxy companies from companies that meet the following criteria:

(A) the company is publicly traded;

(B) the company is a natural gas pipeline company;

(C) the company and its shares are recognized and tracked by Value Line or a similar investment information service;

(D) pipeline operations constitute a high proportion of the company's business;

(E) the company or its predecessor in interest has been in operation for at least three years;

(F) there are estimates by Institutional Brokers Estimate System (I/B/E/S) established by Thomson Reuters, or similar widely available, reliable estimates, of five-year earnings growth for the company;

(G) the company has a history of paying dividends or distributions and is currently paying a dividend or distribution;

(H) the company has not eliminated or announced an intention to eliminate its dividend or distribution;

(2) in determining whether a company meeting the criteria under (1) of this subsection should be included in the group of proxy companies, the department may consider the following factors:

(A) the size of the company's market capitalization;

(B) the company's credit rating;

(C) whether four or more companies have already been selected for inclusion in the proxy group of companies;

(3) the department will calculate the rate of return for a calendar year based on information about the group of proxy companies for a recent 12-month period selected by the department.

(k) For purposes of (c)(5) of this section, the

(1) combined federal and state income tax rate for the year of calculation must be used for a pipeline located within the United States;

(2) applicable combined foreign income tax rate for the year of calculation must be used for a pipeline located in another country.

(*l*) The amounts described in (c)(1) and (5) - (7) of this section must be calculated for every calendar year on the same basis, which may be either

(1) the amounts incurred during, or applicable to, the calendar year of calculation; or

(2) if the pipeline was

(A) in operation for at least nine months during the calendar year immediately preceding the calendar year of calculation, the amounts incurred during, or applicable to, that immediately preceding calendar year; the amounts are annualized or prorated if necessary to account, respectively, for the pipeline's being in operation for less than that entire immediately preceding calendar year or less than the entire calendar year of calculation; or

(B) not in operation for at least nine months during the calendar year immediately preceding the calendar year of calculation, good-faith estimates of the amounts that will be incurred during, or will be applicable to, the calendar year of calculation; an overestimate or underestimate is deducted from or added to, respectively, the amounts used for the next calendar year.

(m) To allocate the total amount for the items set out in (c) of this section to a specific quantity of qualified gas,

(1) per-unit transportation cost is based on contracted capacity or throughput during the royalty reporting period for the pipeline as a whole, whichever amount is greater, unless the pipeline commences commercial operations after issuance of a certificate of public convenience and necessity for the Alaska mainline, in which case per-unit transportation cost is based on a 100 percent load factor of certificated capacity;

(2) the costs of different categories of pipeline transportation services bear the same relationship to one another as under the recourse rates in the applicable tariff, unless the department determines that the relationship under the applicable tariff is unreasonable, in which case the department will allocate costs among different categories of pipeline transportation services;

(3) the costs of pipeline transportation between different pairs of receipt and delivery points bear the same relationship to one another as under the recourse rates in the applicable tariff, unless the department determines that the relationship under the applicable tariff is unreasonable, in which case the department will allocate costs to pipeline transportation between different pairs of receipt and delivery points.

(n) A management fee is not an allowable cost of transportation for the purpose of calculating a transportation affiliate's allowable actual and reasonable costs of transportation under this section.

(o) If the cost of transportation as calculated under (b) - (n) of this section is greater than the negotiated rate for transportation available to a lessee or its affiliate, the negotiated rate and not the cost of transportation as calculated under (b) - (n) of this section must be used in calculating the monthly value of the state's royalty share of qualified gas. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

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11 AAC 25.200. Transportation contracts not at arm's length - LNG transportation.

(a) If a lessee, its marketing affiliate, or any affiliate other than a transportation affiliate transports qualified gas using an LNG transportation affiliate, transportation costs must be the LNG transportation affiliate's allowable actual and reasonable costs incurred between the outlet of a liquefaction plant and the inlet of a regasification plant, as those costs are determined under (b) - (*l*) of this section, 11 AAC 25.160, and 11 AAC 25.210. However, if 11 AAC 25.160(b) applies, the amount determined under 11 AAC 25.160(b) must be used for transportation costs.

(b) For purposes of (a) of this section, the applicable costs of transportation are

(1) an allowance for operating and maintenance expense;

(2) annual depreciation on capital investment;

(3) a return on capital investment; and

(4) positioning costs, amortized over 36 months.

(c) For purposes of (b)(1) of this section, the allowance for operating and maintenance expense is the amount of expense actually incurred that is the direct cost of operation and maintenance attributable to a lessee's qualified gas.

(d) For purposes of (b)(2) and (3) of this section, a cost of capital allowance that consists of depreciation and a return on invested capital will be allowed.

(e) For purposes of (b)(2) and (3) of this section, depreciation and a return on capital investment must be calculated using the methodology set out in the Department of Revenue publication *Computation of a Cost-of-Capital Allowance under 15 AAC 55.196, Incorporating Depreciation and Return on Invested Capital for Marine Vessels and Improvements*, Second Edition, dated September 19, 2003; that publication is adopted by reference except as follows:

(1) the methodology is applied as if the term "vessel" read "LNG pipeline or tanker";

(2) the useful life for purposes of the methodology is 30 years;

(3) the weighted average cost of capital is 0.2 percentage point greater than that

otherwise calculated under the methodology.

(f) A cost of capital allowance under this section for a vessel will be allowed only for days when the vessel is in allowable service, in allowable lay up, or in allowable dry dock as provided in (g) of this section.

(g) For purposes of this section,

(1) a vessel is in allowable service if the vessel is

(A) in service within the meaning given in 15 AAC 55.900, unless the vessel is in dry dock; or

(B) idle for a period of fewer than 90 consecutive days immediately before operation in allowable service under (A) of this paragraph; for purposes of this subparagraph, a vessel is not idle if it is in dry dock;

(2) a vessel is laid up if it is idle for a period of 90 or more consecutive days; for purposes of this paragraph, a vessel is not idle if it is in dry dock;

(3) a vessel is in allowable lay up if the vessel is laid up during a calendar year, but only to the extent that the total number of days it is or has been laid up while owned or effectively owned by the lessee or its affiliate through the end of that calendar year does not exceed the total number of days it is or has been in allowable service while owned or effectively owned by the lessee or its affiliate through the end of that calendar year;

(4) a vessel is in allowable dry dock if the vessel is in dry dock during a calendar year, but only for that fraction of the total days in dry dock that equals the sum of the number of days during the year that the vessel is in allowable service and the number of days during the year that the vessel is in allowable lay up, divided by the sum of the number of days during the

year that the vessel is in allowable service, the number of days during the year that the vessel is laid up, and the number of days during the year that the vessel is in alternative service;

(5) a vessel is in alternative service if it is not in lay up, dry dock, or allowable service; and

(6) if necessary to determine a vessel's status during a month, the vessel's status at later times will be considered.

(h) The following requirements apply to the timing of changes in vessel status:

(1) a vessel changing from operation in allowable service to lay up or operation in alterative service begins lay up or operation in alternative service on the day after the last day of cargo discharge in allowable service;

(2) a vessel changing from operation in alternative service to lay up or operation in allowable service begins lay up or operation in allowable service on the day after the last day of cargo discharge in alternative service;

(3) a vessel changing from lay up to operation in allowable service or operation in alternative service begins operation in allowable service or operation in alternative service on the day after the vessel departs from the location where the vessel was laid up;

(4) a vessel going into dry dock begins dry dock status on the day after the last day of cargo discharge or, if going into dry dock from lay up, on the day after the vessel departs from the location where the vessel was laid up;

(5) a vessel finishing dry dock changes from dry dock status to the immediately subsequent status on the day after the vessel departs the dry dock facility;

(6) a vessel begins operation in allowable service on the day that its useful life

begins or, in the case of a used vessel newly acquired by a lessee or its affiliate, on the day that its remaining useful life for that lessee or its affiliate begins, if the vessel proceeds directly to enter operation in allowable service; otherwise, the vessel begins operation in alternative service on the day specified in this paragraph; for purposes of this paragraph, the beginning of a vessel's useful life or remaining useful life is determined in accordance with generally accepted accounting principles.

(i) Allowable voyage and port costs for a vessel are costs actually incurred for the following purposes:

(1) fuel for the vessel while in port and at sea not to exceed the actual cost if purchased from a third party, or if the fuel is not purchased from a third party, the spot market price of comparable fuel as reported in the latest *Platt's Oilgram Price Report* published on or before the date of the fuel purchase for the market nearest the point of refueling, plus related allowable fuel taxes and handling charges;

(2) stores and provisions for the vessel and its captain and crew;

(3) wages and benefits of the vessel's captain and crew;

(4) routine maintenance;

(5) drydocking costs, expensed in the year paid;

(6) port and dock fees;

(7) demurrage;

(8) tug and pilotage fees;

(9) marine agents' fees in port;

(10) lightering;

(11) transshipment charges;

(12) customs fees and duties;

(13) taxes incurred due to the ownership and operation of the vessel, except for income taxes and other taxes (including certain franchise taxes) measured by income;

(14) regular and customary gratuities that are also legal;

(15) insurance premiums actually paid to third-party insurers;

(16) loading and unloading inspection fees;

(17) a reasonable management fee for operating a vessel; this fee is set at six percent of the allowable costs set out in (1) - (3) of this subsection; this set fee covers all general and administrative costs related to vessel operations, including all costs for accounting services, clerical services, administrative services, secretarial services, data processing services, legal services, corporate and operations management, overhead pass-throughs, facility costs and depreciation, corporate planning, risk management, environmental planning and risk evaluation, public affairs, governmental affairs, political affairs, dues and subscriptions, long-range scheduling, and long-range planning; additional deductions will not be allowed for these costs;

(18) other costs directly associated with the operation or maintenance of a vessel, including costs for port services and operations, cargo scheduling and planning, fleet staffing, fleet scheduling, fleet staff training, fleet safety, engineering for repair, engineering for maintenance, engineering for drydocking, quality assurance for vessel operations, communication systems, navigation systems, United States Coast Guard certifications, and utility services; these costs include costs for personnel performing the functions listed and the first level of supervision of these personnel.

(j) For purposes of this section, allowable voyage and port costs for a vessel do not include taxes or fees on the receipt of LNG at a marine terminal from a vessel.

(k) The lessee's actual or reasonable marine transportation cost, as otherwise determined under this section, for a lessee that transports gas produced in the state through a charter, contract of affreightment, sublease, or other arrangement on behalf of a person not affiliated with the lessee, in addition to the cost of transporting the lessee's own gas produced in the state, includes the cost of transporting that non-affiliated person's gas produced in the state and is reduced by the revenue received by the lessee for providing that transportation.

(*l*) In this section, "positioning cost" includes the cost borne by the lessee for placing an LNG tanker into position before the LNG tanker's first voyage in service for that lessee. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

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11 AAC 25.210. Non-allowable transportation costs. (a) A lessee may not include the following costs in calculating an arm's length transportation allowance under 11 AAC 25.170 or a non-arm's length transportation allowance under 11 AAC 25.180 - 11 AAC 25.200:

(1) the cost of transportation of qualified gas downstream of destination;

(2) the cost of transportation of residue gas or gas plant products after processing of qualified gas is complete at destination;

(3) a cost or fee incurred for storage, except that a lessee may deduct

(A) a charge by a pipeline for storage for no more than 30 days if the storage is required under the applicable transportation services agreement and is necessary for pipeline operations;

(B) a cost or fee for the storage as part of LNG transportation, if the fee or cost is allowed under 11 AAC 25.200;

(4) an intra-hub transfer fee paid to a pipeline hub operator for administrative services, including accounting for the sale of qualified gas within a hub and title transfer tracking;

(5) a fee paid to a scheduling service provider;

(6) internal costs to schedule, nominate, and account for the sale or movement of qualified gas, if incurred by a lessee or its affiliate other than a transportation affiliate; those costs include salaries and related costs, rent and space costs, office equipment costs, and legal fees;

(7) an aggregator or marketer fee, including a fee a lessee or its affiliate pays an affiliate or another person to market, purchase, or resell qualified gas, or find or maintain a market for qualified gas;

(8) a fee paid to a broker, including a fee paid to a person that arranges marketing or transportation;

(9) a penalty incurred as a shipper, including

(A) an over-delivery cash-out penalty, including the difference between the price the pipeline pays for over-delivered volumes outside the tolerances and the price received for over-delivered volumes within the tolerances;

(B) a scheduling penalty, including a penalty incurred for differences between daily volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point;

(C) an imbalance penalty, including a penalty incurred for differences between volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point;

(D) an operational penalty, including fees incurred for violation of the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline;

(10) the cost of pipeline transportation within the unit of production, unless

(A) the pipeline is regulated by FERC or the Regulatory Commission of Alaska; or

(B) for Prudhoe Bay gas covered by the 1980 Prudhoe Bay Royalty Settlement Agreement, the cost is allowed under that agreement;

(11) the cost of pipeline transportation within a state unit other than the unit of production where the gas was reinjected into a reservoir, unless

(A) the pipeline is regulated by FERC or the Regulatory Commission of Alaska; or

(B) for Prudhoe Bay gas covered by the 1980 Prudhoe Bay Royalty Settlement Agreement, the cost is allowed under that agreement;

(12) the cost of a gathering pipeline or a pipeline in the state that is not subject to

regulation by FERC or the Regulatory Commission of Alaska;

(13) as provided in 11 AAC 25.070(d), the cost of transporting carbon dioxide in a pipeline upstream of the Alaska mainline in excess of quantities allowed in the specification of conditions for acceptance into the Alaska mainline;

(14) the cost of transporting a gas or associated substance that is not royalty-bearing, except that lessees may include in a transportation allowance the costs of transporting carbon dioxide in quantities not to exceed the quantities allowed in the specification of conditions for acceptance into the Alaska mainline;

(15) other costs a lessee incurs for services it is required to provide at no cost to the state as lessor or otherwise;

(16) costs of arbitration, litigation, or other dispute resolution activity that involves the state or concerns the rights or obligations

(A) among owners of a transportation entity; or

(B) between an owner of a transportation entity and a shipper.

(b) In addition to the costs set out in (a) of this section, a lessee may not include the following costs in determining a non-arm's length transportation allowance under 11 AAC 25.180 - 11 AAC 25.200:

(1) payments, either volumetric or in value, for actual or theoretical losses of qualified gas;

(2) costs of a surety. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.220. Unused capacity deduction. (a) A qualified person that elects under 11 AAC 25.040(b) to calculate royalties under this chapter may deduct a share of its actual and reasonable costs of unused capacity on the Alaska mainline and Canada mainline, if in the royalty reporting period the qualified person's total shipments on a mainline are less than the total of its firm transportation capacity held that month on that mainline. Any deduction for unused capacity may be allowed only as provided in this section.

(b) In calculating unused capacity for purposes of this section, a qualified person shall combine quantities specific to that qualified person and any affiliates. A qualified person shall base calculations under this section on amounts specific to the qualified person and its affiliates, and may not base a calculation on the total amount of

(1) all shippers' firm transportation capacity for a mainline; or

(2) all shippers' production from leases, all shippers' gas from other sources, or all shippers' gas from all sources.

(c) A qualified person's unused capacity for a mainline must be calculated using the same billing determinants used in calculating the applicable recourse rate for the appropriate mainline.

(d) Except as provided in (e) of this section, a qualified person's unused capacity for a month equals AC - AS, where

(1) AC equals allocated capacity; allocated capacity is determined by multiplying FOSFT, as described in (3) of this subsection, by the fraction,

(A) the numerator of which is the shipments of production from leases on the Alaska mainline or Canada mainline, as applicable, on and after the date of commencement of commercial operations and before the month for which the calculation is made; and

(B) the denominator of which is the shipments from all sources on the Alaska mainline or Canada mainline, as applicable, on and after the date of commencement of commercial operations and before the month for which the calculation is made;

(2) AS equals allocated shipments; the figure for allocated shipments is the greater of

(A) shipments of production from leases during the month for which the calculation is made; or

(B) AC multiplied by a fraction, the numerator of which is total shipments from all sources during the month for which the calculation is made, and the denominator of which is TFT, as described in (4) of this subsection;

(3) FOSFT equals firm transportation capacity

(A) held in the royalty reporting period for which the calculation is made; and

(B) acquired through a commitment made in the first binding open season for the Alaska mainline or Canada mainline, as applicable;

(4) TFT equals total firm transportation capacity

(A) held in a royalty reporting period for which the calculation is made; and

(B) acquired through commitments made in the first and subsequent binding open seasons for the Alaska mainline or Canada mainline, as applicable.

(e) Allocated capacity, as calculated under (d) of this section, becomes fixed at the value for the preceding royalty reporting period in the first month beginning after not less than five years of commercial operations of the Alaska mainline if, for that mainline, the qualified person's shipments from all sources for the month for which the calculation is made are less than 95 percent of total firm transportation capacity, as calculated under (d) of this section. The shortfall in shipments must be for reasons other than a temporary reduction in shipments caused by maintenance, pipeline expansion, or force majeure.

(f) In determining a deduction for unused capacity under this section, a qualified person shall make appropriate adjustments to the calculations made under (d) and (e) of this section to account for commitments to firm transportation capacity for some but less than all segments of a mainline and for shipments on some but less than all segments of a mainline.

(g) Actual and reasonable costs of unused capacity under this section do not include the cost of

(1) capacity other than capacity acquired through a commitment to firm transportation capacity made in the first binding open season for the project;

(2) capacity in excess of the volume or duration specified in a commitment to firm transportation capacity specified in a bid submitted under 11 AAC 25.020(a)(1) or its equivalent for the Canada mainline, excluding any option for extension of the term of years;

(3) capacity released to another shipper, except to the extent that the other shipper pays less for that capacity than the lessee or its affiliate is required to pay for that capacity, in which case the quantity released for purposes of this paragraph is calculated as the

total quantity released multiplied by a fraction, the numerator of which is the amount the other shipper pays for the capacity, and the denominator of which is the amount the lessee or its affiliate would be allowed to claim as a transportation deduction under this chapter for the same capacity if it transported qualified gas in that capacity;

(4) capacity acquired from another shipper, except for capacity acquired in connection with the acquisition of substantially all of the releasing shipper's North Slope assets;

(5) unused capacity for which the person is entitled to a deduction in calculating royalties due any royalty owner other than the state;

(6) reservation charges for or attributable to pipeline, measurement, compression, and other permanent and temporary facilities existing before the date of sanction by the licensee for the Alaska mainline; or

(7) expenses other than a reservation charge paid for unused capacity, net of any proceeds, refund, credit, or compensation for the unused capacity.

(h) Amounts deductible under this section for unused capacity are deducted proportionately from destination values calculated under 11 AAC 25.100 - 11 AAC 25.120 by applying the same principles for attributing used capacity to individual leases and to unprocessed gas, residue gas, gas plant products, and LNG.

(i) Royalty payments due the state may be reduced only by the royalty-in-value share of the costs of unused capacity calculated under this section.

(j) The lessee shall set out the unused capacity deductions calculated under this section as separate entries on royalty reports filed with the department and may not use these deductions to reduce the royalty value of unprocessed gas, residue gas, gas plant products, or LNG below zero.

(k) In this section,

(1) "sanction" has the meaning given in AS 43.90.900;

(2) "shipments of production from leases" and "total shipments from all sources" on the Alaska mainline or Canada mainline, as applicable, include shipments of production on firm transportation capacity, interruptible capacity, authorized overrun service, or any other type or level of transportation service. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.230. Processing costs. (a) In calculating the monthly value of the state's royalty share of qualified gas, a lessee may deduct processing costs only to the extent authorized by 11 AAC 25.060 - 11 AAC 25.090 and 11 AAC 25.230 - 11 AAC 25.260. Processing costs will be allowed only if they are the actual and reasonable processing costs incurred and paid by the lessee or its affiliate and not refunded to the lessee or its affiliate for processing qualified gas between the inlet to the Alaska mainline and destination.

(b) A processing allowance may not be deducted from the value of unprocessed gas, residue gas, methane, or condensate in calculating the monthly value of the state's royalty share of qualified gas.

(c) If the commissioner establishes a quality differential under 11 AAC 25.140(b) that a lessee may elect to take in lieu of a processing allowance, a lessee may not take both the quality differential and a processing allowance in calculating the monthly value of the state's royalty share of qualified gas.

(d) For purposes of 11 AAC 25.230 - 11 AAC 25.260, a processing plant is an affiliate of a lessee if the lessee and the processing plant are affiliated at any time during the royalty reporting period, or were affiliated when the contract for processing was executed or an agreement for processing was made. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.240. Processing contracts at arm's length. (a) If a lessee or its affiliate processes qualified gas under an arm's length contract, the processing allowance used to determine the monthly value of that lessee's qualified gas must be the actual and reasonable costs incurred and paid by the lessee or its affiliate for processing, less any costs not allowed under 11 AAC 25.060 - 11 AAC 25.090 or 11 AAC 25.230 - 11 AAC 25.260. The lessee shall demonstrate that a contract is arm's length.

(b) If the commissioner determines that the consideration set out in an arm's length contract exceeds the consideration actually transferred either directly or indirectly from the lessee or its affiliate to the processor for the processing, the commissioner may require that the processing allowance be reduced or redetermined under 11 AAC 25.250.

(c) If the commissioner determines that the consideration paid under an arm's length processing contract exceeds the reasonable value of the processing because of misconduct by the contracting parties, or because the lessee has by other means breached a duty to the state to market the production for the mutual benefit of the lessee and the state, the commissioner may require that the processing allowance be reduced or redetermined under 11 AAC 25.250.

(d) An allowance may not be taken for the cost of processing a component for which a royalty share is not reserved to the state. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.250. Processing contracts not at arm's length. (a) If a lessee or its affiliate processes qualified gas in an affiliated gas processing plant, the processing allowance used to determine the monthly value of that lessee's qualified gas must be the plant affiliate's allowable actual and reasonable costs allocated to the royalty reporting period as provided in 11 AAC 25.060 - 11 AAC 25.090 and 11 AAC 25.230 - 11 AAC 25.260.

(b) The processing allowance for a non-arm's length contract or an arrangement without a contract is based upon the plant affiliate's actual and reasonable, directly attributable and allocable processing costs in the form of operating and maintenance expense, overhead, depreciation, and a return on undepreciated capital investment as provided in (d) of this section. Allowable capital costs are the original costs for depreciable fixed assets, including costs of delivery and installation of capital equipment that is an integral part of the processing plant.

(c) To compute depreciation for the purposes of this section, the lessee shall use straight-line depreciation based on the economic life of the processing plant. A change in ownership of a processing plant does not alter the depreciation schedule established by the original processor or lessee for purposes of calculating a processing allowance under this chapter. Notwithstanding a change in ownership, a processing plant may only be depreciated once. Equipment may not be depreciated below a reasonable, positive salvage value.

(d) Each February, the department will determine and publish the prevailing yield during the preceding January on corporate bonds whose relevant characteristics are comparable to those for which Moody's Investor Services, Inc., published its Moody's Seasoned Baa Corporate Bond Yield - All Industries for January 2010. The prevailing yield published by the department is the rate of return for purposes of calculating the return for that calendar year on undepreciated capital investment under (b) of this section.

(e) For new processing plants processing gas involved in a non-arm's length transaction, the lessee shall include in its initial processing allowance estimates of the allocable gas processing costs allowed under (b) of this section for the applicable royalty reporting period. Cost estimates must be based upon the most recently available operations data for the plant; if these data are not available, the lessee shall base cost estimates upon industry data for similar gas processing plants. To the extent that a processing allowance is based on estimates, the lessee shall file royalty reports revising the allowance after actual costs are known.

(f) The billing determinant to be used in calculating a processing allowance under this section is throughput for the processing plant, except that the billing determinant is contract capacity if

(1) the processing plant is constructed after FERC issues a certificate of public convenience and necessity for the Alaska mainline; and

(2) the processing plant solicits and accepts bids for firm processing capacity.

(g) A reasonable share of overhead directly attributable and allocable to the operation and maintenance of a processing plant involved in a non-arm's length transaction is an allowable operating expense for purposes of this section. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

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11 AAC 25.260. Non-allowable processing costs. (a) A lessee may not include the following costs in determining an arm's length processing allowance under 11 AAC 25.240 or a non-arm's length processing allowance under 11 AAC 25.250:

(1) a cost not directly related to processing of qualified gas;

(2) a cost for processing qualified gas downstream of destination;

(3) a cost greater than the consideration transferred, either directly or indirectly, from the lessee or its affiliate to the processor, regardless of the cost or fee identified in a processing contract;

(4) a cost incidental to marketing;

(5) a cost for a processes that normally take place on or near the lease or unit of production, including natural pressure reduction, mechanical separation, heating, cooling, dehydration, compression, and other acts undertaken to put gas in marketable condition.

(b) A lessee may not include the following capital costs in determining a non-arm's length processing allowance under 11 AAC 25.250:

(1) a cost for capital improvement or equipment that is not an integral part of the processing facility;

(2) nondepreciable property, including land and a pipeline right-of-way;

(3) a facility used to store, deliver, or otherwise dispose of residue gas or gas plant products after extraction.

(c) A lessee may not include the following noncapital costs in determining a non-arm's length processing allowance under 11 AAC 25.250:

(1) operating and maintenance cost not directly related to processing;

(2) a cost associated with a capital improvement or equipment if the cost of the capital improvement or equipment is disallowed under (b) of this section;

(3) federal, state, or other income taxes;

(4) production or severance taxes;

(5) royalty payments. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.270. Plant costs for LNG. (a) In calculating the monthly value of the state's royalty share of qualified gas, a lessee may deduct plant costs for liquefaction and regasification using the same rules for the deduction of plant costs for processing set out in 11 AAC 25.060 - 11 AAC 25.090 and 11 AAC 25.230 - 11 AAC 25.260, except as provided in this section. LNG plant costs will be allowed only if they are the actual and reasonable plant costs incurred and paid by the lessee or its affiliate and not refunded to the lessee or its affiliate for liquefaction or regasification of qualified gas between the inlet to the Alaska mainline and destination.

(b) With respect to storage, the prohibition set out in 11 AAC 25.260(b)(3) applies in the case of LNG only after regasification is complete.

(c) For purposes of this section, an LNG plant is an affiliate of a lessee if the lessee and the LNG plant are affiliated at any time during the royalty reporting period, or were affiliated when the contract with the plant was executed or an agreement with the plant was made.

(d) In this section, in addition to having the meaning given in 11 AAC 25.900, "processing" includes liquefaction and regasification. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.280. Lease amendment for switching between royalty-in-value and royalty-in-kind gas. (a) A qualified person that has elected under AS 43.90.310(b)(2) and 11 AAC 25.040 to enter into a contract with the state to amend the existing lease terms that apply to the state's exercise of the state's right to switch between taking the state's royalty share of qualified gas in value or in kind must submit a contract amendment form provided by the department.

(b) While the Federal Energy Regulatory Commission's (FERC) Order on Petition for Waiver, 130 FERC ¶ 61,070 (Docket no. RP10-145-000, January 28, 2010) is in effect, an amended contract under AS 43.90.310(b)(2) and this section will require

(1) the lessee or its affiliate to provide, and the state or the state's royalty-in-kind purchaser to obtain, firm transportation capacity on the Alaska mainline and, if required under (f)

of this section, the Canada mainline by temporary release of capacity from the lessee or its affiliate to the state or the state's royalty-in-kind purchaser when royalty gas that is qualified gas is shipped on the Alaska mainline in kind rather than in value;

(2) the state or the state's royalty-in-kind purchaser to pay the same transportation rate to the same delivery point that the lessee or its affiliate would pay the Alaska mainline and, if required under (f) of this section, the Canada mainline for the firm transportation capacity released, notwithstanding higher or lower recourse rates, and notwithstanding a decision by the state or the state's royalty-in-kind purchaser to ship the royalty-in-kind gas to a delivery point other than the delivery point for the capacity that is to be released; and

(3) the state to increase the notice period for switching between royalty in value and royalty in kind from the period specified in the existing lease to

(A) 120 days if the estimated quantity that is the subject of a notice of switching exceeds 100,000 MMBtus per day but is less than 200,000 MMBtus per day; and

(B) 180 days if the estimated quantity that is the subject of a notice of switching is 200,000 MMBtus per day or greater.

(c) When FERC's Order on Petition for Waiver, 130 FERC ¶ 61,070 (Docket no. RP10-145-000, January 28, 2010) is not in effect, an amended contract under AS 43.90.310(b)(2) and this section will require the state to increase the notice period for switching between royalty in value and royalty in kind from the period specified in the existing lease to 180 days.

(d) If a lessee intends to sell more than 80 percent of the lessee's qualified gas under arm's length sales agreements requiring deliveries over a period exceeding one year, the lessee may apply to the commissioner for an extension of the notice periods set out in (b) and (c) of this section. The commissioner may grant the application if the commissioner determines that the extension

(1) is necessitated by the lessee's arm's length sales agreements requiring deliveries over a period exceeding one year, and is limited to the time period and quantity set out in the sales agreements;

(2) does not interfere with an ongoing royalty-in-kind sale or a proposed royalty-in-kind sale that has been publicly noticed; and

(3) does not compromise the state's ability to sell royalty-in-kind gas for consumption as fuel in the state, including consumption as fuel to generate electricity in the state.

(e) If a lessee or its affiliate that is required to provide firm transportation capacity to the state or the state's royalty-in-kind purchaser under (b) of this section holds firm transportation capacity that extends from more than one receipt point or to more than one delivery point on the Alaska mainline and, if required under (f) of this section, the Canada mainline, the commissioner may determine the receipt and delivery points for the capacity to be temporarily released by determining the receipt and delivery points for the state's royalty gas share as if it were to be taken in value rather than in kind.

(f) If the receipt and delivery points for taking the state's royalty share of qualified gas include receipt and delivery points on both the Alaska mainline and the Canada mainline, and upon the state's switching from royalty in value to royalty in kind, the obligations to provide, accept, and pay for capacity that is temporarily released under (b) of this section extend to both the Alaska mainline and the Canada mainline, even if the state or the state's royalty-in-kind purchaser chooses to transport the royalty-in-kind gas on only the Alaska mainline. However, the obligations to provide, accept, and pay for capacity on the Canada mainline is limited to the state's royalty-in-kind share of capacity acquired in the first binding open season for the Canada mainline. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.290. Request to amend lease, unit agreement, or royalty settlement agreement under AS 43.90.310(b). (a) A qualified person that has elected a royalty inducement under AS 43.90.310 and 11 AAC 25.040 may request, on a request form provided by the commissioner, that the commissioner contractually amend an existing lease. The request form must be signed by a representative of the applicant that is authorized to enter into an agreement to amend the lease.

(b) A request to amend a lease must be submitted at the same time that the qualified person submits the election form for a resource inducement under 11 AAC 25.040. The commissioner will not approve a request to amend a lease until after the commissioner has approved the qualified person's election of resource inducement under 11 AAC 25.040.

(c) An amendment to a lease under AS 43.90.310(b) and this chapter affects only the provisions or parts of a provision of the lease that are amended and shall not be construed as an amendment to any other provision of the lease, unit agreement, or royalty settlement agreement. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.300. Information and audits. (a) The commissioner may require a person that has elected under AS 43.90.310(b)(1) and 11 AAC 25.040 to calculate the monthly value of the state's royalty share of qualified gas under the royalty value methodology set out in 11 AAC 25.060 - 11 AAC 25.270 to submit reports and other information to the state, including information relating to value of the state's royalty share of gas under this chapter and

(1) the lease terms in effect before the lease was amended under AS 43.90.310(a); and

(2) the lessee's royalty obligations for non-qualified royalty gas.

(b) If a lessee's royalty report or royalty payment to the state is based on information that is erroneous, that is inaccurate, that is an estimate before actual data is available, that is later adjusted or disallowed on audit, or that is inconsistent with this chapter or other state or federal law, the lessee shall amend its royalty report and pay the balance of any royalties due as provided under AS 38.05.135(c) - (e).

(c) Nothing in this chapter limits the commissioner's audit rights or right to access information and documents. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.310. No retroactive effect. A retroactive change will not be made to

(1) the designation of a first destination market under 11 AAC 25.100;

(2) the designation of a source of a published price under 11 AAC 25.100 or 11 AAC 25.110;

(3) the designation of a market center under 11 AAC 25.110;

(4) the designation of a location differential under 11 AAC 25.130, other than a retroactive adjustment to destination value and location differentials under 11 AAC 25.130(e); or

(5) the designation of a quality differential under 11 AAC 25.140. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.320. Conversion of foreign currency and units of measurement. (a) If a dollar amount is in Canadian dollars, it must be converted to United States dollars based on the

(1) exchange rate from the Bank of Canada on the date of the transaction, if the transaction pertains only to that date;

(2) relevant month's average exchange rate from the Bank of Canada, if the transaction is not one described in (1) of this subsection.

(b) If a quantity is designated in GigaJoules, the quantity must be converted to MMBtus. (Eff. ___/___/____, Register ____)

Authority: AS 38.05.020 AS 38.05.180 AS 43.90.310

11 AAC 25.900. Definitions. In this chapter, unless the context requires otherwise,

(1) "actual cost" means the full consideration paid;

(2) "affiliate" has the meaning given in AS 43.90.900;

(3) "AFUDC" means allowance for funds used during construction;

(4) "Alaska mainline"

(A) means, with respect to the pipeline system licensed under AS 43.90, the section of the pipeline system that is within this state, that originates at a point in or near Prudhoe Bay, and that terminates at one or more of the following locations:

(i) the Alaska/Yukon border near Beaver Creek;

(ii) Valdez; and

(B) does not include a gas pipeline upstream of the Prudhoe Bay unit, a gas pipeline between Point Thomson and Prudhoe Bay, a gas treatment plant on the North Slope, other facilities used to treat gas to meet pipeline specifications, or an LNG plant or terminal;

(5) "allowance" means a deduction in determining the monthly value of the state's royalty share of qualified gas;

(6) "area" means a geographic region or geologic province, including the Cook Inlet basin or the North Slope of the state;

(7) "arm's length" or "arm's length contract" means a contract or agreement that when executed or made and for each royalty reporting period that it remains in effect is between independent persons who are not affiliates and who have opposing economic interests regarding that contract or agreement;

(8) "Btu" or "British thermal unit" means the quantity of heat required to raise the temperature of one pound of water from 58.5 degrees Fahrenheit to 59.5 degrees Fahrenheit at a constant pressure of one atmosphere;

(9) "Canada mainline" has the meaning given "Yukon - BC Section" in TransCanada Alaska Company LLC’s original, November 30, 2007 application for license under AS 43.90; the definition of "Yukon - BC section" at page 12 of the glossary in that application is

adopted by reference;

(10) "commissioner" means the commissioner of natural resources;

(11) "commissioners" means the commissioner of natural resources and the commissioner of revenue, jointly;

(12) "component" means a constituent part of gas, whether hydrocarbon or nonhydrocarbon; "component" includes

(A) methane;

(B) ethane;

(C) propane;

(D) butane;

(E) isobutane;

(F) normal butane;

(G) pentane;

(H) pentane plus;

(I) condensate recovered downstream of the inlet to the Alaska mainline; and

(J) carbon dioxide and other nonhydrocarbon gases;

(13) "compression" means the process of raising the pressure of gas:

(14) "condensate" means liquid hydrocarbons existing initially in a gaseous phase in an underground reservoir normally exceeding 40 degrees of API gravity, recovered at the surface as a result of condensation without resorting to processing;

(15) "contract" means an oral or written agreement, including amendments or

revisions, between two or more persons with due consideration that creates an obligation enforceable by law;

(16) "control" has the meaning given in AS 43.90.900;

(17) "department" means the Department of Natural Resources;

(18) "destination," when used to refer to the destination of unprocessed gas, residue gas, gas plant products, condensate, or LNG, means destination as determined under 11 AAC 25.080 and 11 AAC 25.100(b);

(19) "downstream" means a point

(A) physically connected by one or more natural gas pipelines; and

(B) generally further from the lease or unit of production, along a path on which gas is flowing from supply receipt points to demand delivery points;

(20) "FERC" means the Federal Energy Regulatory Commission of the United States Department of Energy, or the agency succeeding to its regulatory functions;

(21) "FERC Form 2" means the Federal Energy Regulatory Commission's *FERC Financial Report, FERC Form No. 2: Annual Report of Major Natural Gas Companies*, as revised as of March 26, 2010 and adopted by reference;

(22) "field" means that part of an area underlain by one or more overlapping, contiguous, or superimposed pools, including the Prudhoe Bay field;

(23) "first binding open season" means the project's first open season

(A) in which the licensee requires binding bids for capacity from shippers; and

(B) that concludes no later than December 5, 2011;

(24) "first destination market" means a market that the commissioner has designated a first destination market under 11 AAC 25.100;

(25) "fractionated gas plant product"

(A) means any of the following gas plant products:

(i) ethane;

(ii) propane;

(iii) butane;

(iv) isobutane;

(v) normal butane;

(vi) pentane;

(vii) pentane plus;

(B) does not include NGL mix or condensate;

(26) "gas" means all natural gas and hydrocarbons produced at a well not defined as oil under 11 AAC 88.185;

(27) "gas plant product"

(A) means a separate marketable element, compound, or mixture, whether in liquid, gaseous, or solid form, resulting from processing gas after the inlet to the Alaska mainline;

(B) includes

(i) NGL mix;

(ii) ethane not included in residue gas;

(iii) propane;

(iv) butane;

(v) isobutane;

(vi) normal butane;

(vii) pentane; and

(vii) pentane plus;

(C) does not include residue gas, methane, or condensate;

(28) "gathering" means the movement of lease production to a central accumulation or treatment point, whether that point is on or off the lease or unit of production;

(29) "lease" has the meaning given in AS 43.90.900; "lease" includes a unit agreement or royalty settlement agreement that amends the lease;

(30) "lease of production" means the state oil and gas lease or gas only lease from which gas is produced;

(31) "mainline" means either the Alaska mainline or the Canada mainline, as applicable;

(32) "marketing affiliate" means an affiliate of the lessee whose functions include acquisition of the lessee's production and marketing that production;

(33) "Mcf" or "Mcf of gas" means 1,000 cubic feet of gas measured at 60 degrees Fahrenheit and 14.65 pounds per square inch (absolute);

(34) "MMBtu" means 1,000,000 British thermal units;

(35) "NGL" means one or more natural gas liquids that, singly or in combination, are extracted or recovered from unprocessed or partially processed gas; "NGL" includes

(A) ethane;

(B) propane;

(C) butane;

(D) isobutane;

(E) normal butane;

(F) pentane; and

(G) pentane plus;

(36) "NGL mix" means a mixture of natural gas liquids that

(A) contains two or more of the following components in more than trace quantities:

(i) ethane;

(ii) propane;

(iii) butane;

(iv) pentane; and

(B) is generally the product of extraction at a processing plant but not fractionation;

(37) "North Slope" has the meaning given in AS 43.90.900;

(38) "North Slope gas" means gas produced on the North Slope;

(39) "open season" has the meaning given in AS 43.90.900;

(40) "pentane plus" means pentane and heavier hydrocarbons extracted or fractionated at a gas processing plant;

(41) "processing"

(A) has the meaning given "gas processing" in AS 43.90.310(a)(2)(C);

(B) includes processes designed to remove hydrocarbon or non-hydrocarbon elements or compounds from gas after the gas has entered the Alaska mainline, including absorption, adsorption, or refrigeration;

(42) "processing allowance" means an allowance determined under 11 AAC 25.060 - 11 AAC 25.090 and 11 AAC 25.230 - 11 AAC 25.260 for the actual and reasonable costs of processing gas;

(43) "profile for capital recovery" means the depreciation profile, including levelization if used, and the amount of capital to be recovered over the contract term expressed as a percentage;

(44) "project" has the meaning given in AS 43.90.900;

(45) "qualified gas" means gas that is qualified under 11 AAC 25.030 for royalty inducements;

(46) "qualified person" means a lessee or other person who qualifies under 11 AAC 25.020;

(47) "residue gas" means hydrocarbon gas that, after processing, consists primarily of methane, has a maximum heating value of 1,110 Btus per cubic foot, and is suitable for end-user markets;

(48) "royalty reporting period" means the calendar month in which gas or associated substances are produced and either removed or sold from a lease, or from a unit if the lease is within a unit;

(49) "royalty settlement agreement" means a settlement agreement that

(A) is executed by the state and one or more lessees and approved by a court; and

(B) resolves all or a portion of royalty issues in dispute in litigation;

(50) "transportation allowance" means an allowance for the actual and reasonable cost of moving qualified gas away from the unit of production to destination; "transportation allowance" does not include gathering costs or any other cost incurred with regard to the lease or unit of production;

(51) "transportation affiliate" means an affiliate of the lessee whose principal function is transportation of hydrocarbons by pipeline or tanker, and who transports some or all of the lessee's gas;

(52) "unit of production" means the oil and gas unit, or gas only unit, from which gas is produced;

(53) "unprocessed gas" means gas that is not residue gas, a gas plant product, or LNG;

(54) "upstream" means a point

(A) physically connected by one or more natural gas pipelines; and

(B) generally closer to the lease or unit of production when traveling opposite the path on which gas is flowing from supply receipt points to demand delivery points;

(55) "1980 Prudhoe Bay Royalty Settlement Agreement" means the royalty settlement agreement approved by the superior court in In the Matter of ANS Royalty Litigation, 1JU-77-847 Civil on August 13, 1980;

(56) "1995 ANS Royalty Settlement Agreements" means the royalty settlement

agreements approved by the superior court in In the Matter of ANS Royalty Litigation, 1JU-77-847 Civil on March 15, 1995, April 6, 1995, April 7, 1995, or May 22, 1995. (Eff. ___/___/____, Register ____)

Authority:	AS 38.05.020	AS 43.90.300	AS 43.90.330
	AS 38.05.180	AS 43.90.310	AS 43.90.410