Alaska Department of Natural Resources
Summary of Public Comments Received on Proposed Regulations
Being Adopted Under the Alaska Gasline Inducement Act
and DNR's Action on Those Comments

I. INTRODUCTION

In 2007 the Alaska state legislature passed the Alaska Gasline Inducement Act ("AGIA" or "the Act") and the governor signed the Act into law as AS 43.90.010-AS 43.90.900. The Act offers certain royalty and tax inducements to a person that commits to acquire firm transportation capacity in the first binding open season for an Alaska natural gas pipeline project licensed under the Act.

In late 2007, TransCanada Alaska Company LLC ("TransCanada") applied for a license under the Act. On December 5, 2008, TransCanada was granted a license under the Act. In 2009, TransCanada announced its intent to conduct a first binding open season for a project licensed under the Act. On January 29, 2010, TransCanada filed its plan for conducting a first binding open season with the Federal Energy Regulatory Commission ("FERC"). According to TransCanada, the first binding open season for the project will start on or about April 30, 2010 and close three months later, on or about July 30, 2010.

The Act's offer of royalty inducements is not self-executing. Rather, the Act requires that, prior to the start of the first binding open season for a project licensed under the Act, the commissioner of the department of natural resources ("DNR") adopt regulations pertaining to royalty gas shipped under a commitment made in the first binding open season for the project. For that gas, the Act requires that the regulations establish: (1) a method to determine the monthly value of the state's royalty share of gas, and (2) terms under which the state will exercise its right to switch between taking its royalty share of gas in value or in kind ("RIV or RIK"). The Act further states that the regulatory methods for valuing the royalty share of gas and for RIV/RIK switching are not mandatory unless elected by a North Slope oil and gas lessee. A qualified lessee may elect one, both, or neither of the two royalty inducements.

DNR developed proposed regulations under the Act. The proposed regulations were made available for public comment on February 19, 2010. The period for public comment closed March 22, 2010. Prior to the close of the public comment period, DNR received written comments on the proposed regulations from Representative Keller, BP Exploration (Alaska) Inc. ("BP"), ConocoPhillips Alaska, Inc. ("ConocoPhillips"), and ExxonMobil Production Company ("ExxonMobil").

In this document DNR summarizes the public comments received and its responses to or action on them. Comments, responses, and action are organized by broad subject area. The document also addresses some of the changes to its proposed AGIA regulations between the start of the public comment period on February 19, 2010 and final adoption of regulations.

II. QUALIFIED GAS

The proposed regulations described the gas qualifying for royalty inducements under the Act as gas that is

> (1) royalty-bearing,
> (2) produced from a state oil and gas lease located on the North Slope,
> (3) transported on the Alaska mainline in firm transportation capacity acquired under the bid, precedent agreement, and transportation services agreement submitted during and arising out of the first binding open season for the project,
> (4) in a volume no greater than specified in the bid, and
> (5) for a term of years no longer than specified in the bid.

In its public comments, BP argues that only one of the two royalty inducements identified in the Act is limited to gas shipped in firm transportation capacity acquired in the first binding open season. BP asserts that DNR has the authority to extend its new royalty valuation methodology to all North Slope gas. BP parses the language of AS 43.90.310, construing that section of the Act to limit only one of the two inducements—RIV/RIK switching—to gas shipped in firm transportation capacity acquired in the first binding open season.

BP's argument for one of two possible constructions of AS 43.90.310 is at odds with other provisions of the Act. AS 43.90.310 is the second of four sections of the Act specifically addressing the royalty and tax (or "resource") inducements offered by the Act. AS 43.90.310 follows the introductory section—AS 43.90.300—which states in subsection (a):

> Notwithstanding any contrary provision of law, a lessee or other person that demonstrates to the satisfaction of the commissioners that the person has committed to acquire firm transportation capacity in the first binding open season of the project is qualified to receive the resource inducement set out in AS 43.90.310 and 43.90.320 for gas produced on the North Slope and shipped in firm transportation capacity acquired in the first binding open season of the project.

While the English language may allow for two possible constructions of AS 43.90.310—including the one argued for by BP—AS 43.90.300 does not. Both the royalty valuation and RIV/RIK switching terms are limited to gas shipped in firm transportation capacity acquired in the first binding open season of the project.

Representative Keller, chairman of the administrative regulation review committee ("ARRC") of the Alaska state legislature expressed concern that the proposed regulations are overinclusive because they extend royalty inducements when the commitment to pipeline capacity comes within 180 days <u>after</u> the close of the first binding open season, rather than <u>before</u> the close of the first binding open season. The following proposed language generated Representative Keller's concern:

> (a) A person claiming a resource inducement provided in this chapter must qualify under this section.
> (b) To qualify, a person must … 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; [or]
> (C) <u>submit a bid tendered after the close of the first binding open season, but not later than 180 days after expiration of the first binding open season of the project</u>, that is
> > (i) accepted by the licensee, and
> > (ii) accepted at the discretion of the commissioners after the bidder makes <u>a good faith showing of the circumstances that prevented the person from submitting a timely bid</u> ….

(Emphasis added). While DNR does not believe it has the expansive authority BP suggests to extend inducements on royalty valuation regardless of when, if ever, a person commits to firm transportation capacity, and regardless of the quantity limitations contained in such a commitment, the proposed regulations do allow for the possibility of extending royalty inducements to gas which is the subject of a minimally-tardy commitment, but only where a timely commitment was prevented for justifiable reasons, and only because the Act itself defines "open season" in such a way as to suggest that result. "Open season," for the purpose of Act, means the "process that complies with 18 C.F.R. Part 157, Subpart B (Open Seasons for the Alaska Natural Gas Transportation Projects) or a similar process for soliciting commitment for pipeline capacity under the regulations ….of the Regulatory Commission of Alaska ["RCA"]." AS 43.90.900(17). The applicable federal regulations, 18 C.F.R § 157.33 and 18 C.F.R. § 157.34, require that the licensee for the project consider bids tendered after the open season. Those bids must contain a statement explaining why the bidder did not submit a timely bid.[1] Since the AGIA licensee, TransCanada, will be required to comply with the federal regulations in accepting a late bid under certain circumstances, DNR's decision to also consider such bids is a reasonable interpretation of the authorizing statute. Therefore, the proposed 11 AAC 25.020 allows a person to tender a bid within 180 days after the close of open season, but requires the bidder to show why it was unable to make a timely bid.

While DNR appreciates the comments made by both BP and Representative Keller, for the reasons explained above, DNR has not changed the substance of its proposed AGIA regulations on this subject. The final regulations being adopted today reflect the same requirements as the proposed regulations.

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[1] 18 C.F.R. §157.34(d)(2) states: "A prospective applicant must consider any bids tendered after the expiration of the open season by qualifying bidders and may reject them only if they cannot be accommodated due to economic, engineering, design, capacity or operational constraints, or accommodating the request would otherwise adversely impact the timely development of the project, and a detailed explanation must accompany the rejection. Any bids tendered after the expiration of the open season must contain a good faith showing, including a statement of the circumstances which prevented the late bidder from tendering a timely bid and how those circumstances have changed. If a prospective applicant determines at any time that, based on the criteria stated above, no further late bids for capacity can be accommodated, it may request Commission approval to summarily reject any further requests."

III. DESTINATION VALUE

The proposed regulations establish a method for determining the monthly value of the state's royalty gas shipped in firm transportation capacity acquired in conjunction with the first binding open season for the project. The method is a "netback method," which requires an oil and gas lessee to report the quantity, attributes, and fair market value of qualified gas at destination, and account for certain costs incurred in treating, processing, and transporting the gas between the lease and destination. The royalty value for the gas is its destination value, minus allowable costs.

Generally speaking, under the proposed regulations, destination value is fair market value as measured by a reliable published price designated by DNR, with adjustments for location and quality where necessary. Only in the absence of a reliable published priceis destination value its fair market value as measured by sales price or other relevant factors, depending on the circumstances. DNR's decision to use reliable published prices as the primary determinant of destination value is premised on the Act. AS 43.90.310(a) states that "[t]he regulations must … provide a method for establishing a fair market value for each component of the state's royalty gas that is based on pricing data from reliable and widely available industry trade publications …."

Destination value under the proposed regulations differs from destination value under preexisting lease terms. While the language used in the state's oil and gas lease form has changed over the decades, generally preexisting leases require payment of royalties based on the highest of several measures of destination value, including: (1) the sales price a lessee receives for the gas; (2) the sales price other North Slope lessees receive for like-quality gas; and (3) the market value of the gas. The Act does not require the state to forego royalty payments on the highest of multiple measures of destination value, and can be read as simply stating that the market value measure of destination value must be determined with reference to reliable published prices if available. Nonetheless, DNR drafted its proposed regulations to create a few select inducements for participation in the first binding open season for the project. One inducement included in the proposed regulations is a reduction in the number of measures of value a lessee must pay the highest of. Generally, the proposed regulations require use of a single measure of value (though they do include a second measure of value for residue gas, and methane in unprocessed gas, where the two measures of market value diverge by 5% or more). In most instances, the single measure of value is a reliable published price designated by DNR.

A. Destination Value is not Higher of Sales Price or Prevailing Value

In commenting on the proposed regulations, BP states that under the new royalty regulations royalties will fall due on the higher of sales price or prevailing value. BP's comment is misdirected. BP's comment mentions taxes three times and appears to be a product of submitting comments to the department of revenue on proposed tax regulations within a week of when it submitted comments to DNR on proposed royalty regulations. The department of revenue taxes on the higher of sales price or prevailing value; DNR does not tax, does not use the term "prevailing value" in its proposed regulations, and does not require payments on the higher of sales price and any second measure of value under its proposed regulations. Thus, DNR did not change its proposed regulations based on this comment from BP.

B. Act Requires Use of Published Prices in Calculating Destination Value, Where Available and Reliable

In its comments ExxonMobil requests that destination value be based on the sales prices it receives for its qualified gas. While DNR could leave sales price in place as one of multiple measures of value, and assess royalties on the higher of sales price or market value, DNR does not read ExxonMobil's comment as a request to pay on the higher of multiple measures of value. DNR reads ExxonMobil's comment as a request pay on the basis of sales price only, and not on the basis of published prices. DNR lacks authority to adopt regulations consistent with ExxonMobil's request, since the Act dictates, "[t]he regulations must … provide a method for establishing a fair market value for each component of the state's royalty gas <u>that is based on pricing data from reliable and widely available industry trade publications</u> …." (Emphasis added). A sales price may or may not reflect fair market value and is not "pricing data from reliable and widely available industry trade publications." Only in those instances where it is impossible to carry out the complete statutory directive because reliable published prices do not exist can DNR attempt to meet the remaining dictates of the statutory language by looking to sales price as a potential measure of fair market value. Even then, sales price may not represent fair market value, especially if the "buyer" and "seller" are affiliates without opposing economic interests. Consequently, DNR did not change its proposed regulations based on this comment from ExxonMobil.

C. Other Public Comments on Destination Value, Generally

Industry comments that "destination value" and "alternative destination value" may not reflect sales price or value at the actual destination for the gas (BP, ExxonMobil), or value reasonably achievable (ConocoPhillips), especially where a lessee transports gas downstream of a "first destination market" or sells gas on the basis of its BTU content (BP). ConocoPhillips and ExxonMobil comment that the regulations give DNR broad authority to change published prices, location differentials, and quality differentials used in calculating royalties simply by posting the changes on DNR's website. ConocoPhillips comments that the prospect of changes posted to DNR's website leaves lessees uncertain about the future. Industry did not suggest a solution to these perceived problems, other than to assess royalties on sales price—which has already been discussed—and to drop "alternative destination value" as a potential measure of value for qualified gas.

In developing the proposed regulations, DNR was constrained by the need to use reliable published prices in measuring fair market value. Published prices are not available for all potential destinations for North Slope gas, and even where published prices are available, they are not always reliable. Further, the first gas to be subject to valuation under the regulations being adopted today will be produced with the commencement of commercial operations of the project, approximately ten years hence, and the last gas to be subject to valuation under the regulations being adopted today may be produced thirty-five to forty-five years hence (though amendment of the regulations could considerably shorten these periods). Markets, publications, and appropriate differentials will all change over these prolonged periods in ways that are currently unknown. These facts influenced many of the decisions made in developing the regulations, as discussed below.

1. DNR to designate publications, prices, location differentials, quality differentials, first destination markets, and first market centers

DNR was unable to "hard-wire" into its regulations specific publications and specific price measures within those publications while keeping true to the legislative dictate to capture fair market value over the decades (AS 43.90.310(a) and (d)). DNR cannot know now the ultimate destinations for qualified gas,[2] cannot know whether current publications will continue to exist, cannot know what new publications may come into being, and cannot know if certain price measures within publications may become unreliable. Further, DNR does not know now how the price in one market may change relative to the price in another market, or how the price of one component of North Slope gas may change relative to the price of other components or of unprocessed gas, and so cannot now specify location and quality differentials certain to assure fair market value over time. For these reasons, DNR determined that the regulations need to include an ability to identify over time the markets that actually develop for North Slope gas, and to change with time the publications, prices within publications, location differentials, and quality differentials used in determining destination value for royalty gas. The proposed regulations included the necessary flexibility on each of these counts, but also set out criteria DNR must follow as it identifies or changes "first destination markets," "first market centers," publications, prices within publications, location differentials, and quality differentials over time.

While DNR has not substantially changed its use of and approach to designations between the time of public notice and final adoption of the regulations, in response to industry comment DNR has clarified the criteria for designations in the final regulations. For example, DNR has refined the criteria for identification of "first market centers" and for determination of whether a publication or price within a publication is reliable. DNR has also revised the criteria it is to consider each time it makes or changes a designation.

2. Published prices for "first destination markets" are reasonably achievable

The regulations in most instances base destination value on published prices in or adjusted to or from a "first destination market." Generally speaking, a first destination market is a market where, among other things,

(1) North Slope gas is physically transported, bought, sold, processed, or, in the case of LNG, regasified in the market;
(2) more than 100,000 MMBtu of residue gas is sold in arm's-length transactions on average each day in the market;
(3) a reliable and widely available industry trade publication publishes a reliable price each month for residue gas in the market which is based on at least ten unrelated arm's-length sales in that market for the month; and
(4) there is not another first destination market upstream of the market.

[2] The plan for open season filed with FERC by the licensee under the Act allows for two separate projects to two different destinations. One project would include a pipeline to Canada, where gas would either be sold as unprocessed gas or processed for sale as residue gas and gas plant products. An alternative project would include a pipeline to Valdez, where gas would be liquefied for shipment by tanker as LNG to unspecified destinations, which may include the western coast of the United States or Asian markets.

In developing these criteria for a "first destination market," DNR effectively targets markets where a lessee bringing North Slope gas into the market would have a reasonable opportunity to sell that gas at or near reliable published prices, with appropriate planning, prudence, and regard for both the interests of the lessee and the state as lessor. DNR cannot require a lessee to sell its gas entering a first destination market in that first destination market. However, if the lessee chooses not to do so, and instead transports the gas further downstream, value is nonetheless "reasonably achievable" in the first destination market, and hence royalty valuation based on reliable publish prices in or adjusted to that market is consistent with the statutory dictate to use reliable published prices where available, and also is fair to both the lessee and the state as lessor. Similarly, if the lessee chooses to market gas upstream of a first destination market when its gas, with appropriate planning and prudence, can reach a first destination market, then value based on such downstream market is also "reasonably achievable".

3. Valuation as if all gas is liquids-poor residue gas denies state incremental value of natural gas liquids

The regulations are specifically designed to capture the incremental value attributable to the liquids-rich nature of North Slope gas. They therefore require accounting for the actual molecular composition of gas from each North Slope lease, and the NGL mix, propane, butane, and pentanes plus, as well as a fractional share of the ethane, that are or could be extracted from North Slope gas. The regulations also allow a deduction for the actual, reasonable costs of extracting and fractionating these liquids for a lessee that chooses to do so, or a quality differential for a lessee that chooses not to do so. While BP suggests that the state in certain circumstances accept the lower, BTU-equivalent value normally realized for liquids-poor or residue gas, commercial powerhouses, such as the North Slope lessees, are unlikely to forego the "liquids uplift" from liquids-rich North Slope gas and should not expect the state to do so. Further, because a market cannot be a "first destination market" absent a high volume of residue gas sales, and the availability of processing is a necessary prerequisite to the sale of residue gas derived from liquids-rich gas, the very criteria used to identify a market as a "first destination market" assure that lessees will have a reasonable opportunity to extract and fractionate liquids in or before the first destination market. Consequently they are likely capable of realizing the destination values to be used for royalty purposes, including liquids uplift, assuming appropriate planning, prudence, and regard for both the interests of the lessee and the state as lessor.

4. "Alternative destination value" is an inducement relative to "highest of" terms contained in existing leases

While the regulations largely eliminate calculation of destination value based on the highest of multiple measures of royalty value, they do include an "alternative destination value" for residue gas and methane in unprocessed gas. A lessee, with appropriate planning, prudence, and regard for the interests of both the lessee and the state as lessor, is well-positioned to realize at least the alternative destination value for its gas by choosing where to ship and sell its gas. This "alterative destination value" comes into play in a month where there is a 5% or greater spread between the designated published price for residue gas in a first destination market and alternative destination value; existing lease terms require the use of the highest measure of destination value each and every month, regardless of how small or big the spread. Additionally, with alternative destination value there is at most two measures of destination value applicable to specific gas in a given month, not three measures of destination value, as is frequently the case under existing lease terms. Most importantly, the "alternative destination value" for a royalty reporting month will be known before the royalty report is due for the month; in contrast, the state's original lease terms do not permit a lessee to known final destination value until audits of other lessees in the field have been conducted – a process that can take a number of years.

Alternative destination value is designed to provide the state with some protection from matters frequently within the control of lessees or their affiliates but outside the state's sphere of influence. If a lessee neglects to plan or act with prudence, alternative destination value protects the state's interests without requiring the state to prove that the lessee failed to plan or was reckless. Similarly, if a lessee or its affiliate chooses to ship or sell so as to maximize a global portfolio at the expense of value it could realize on North Slope gas, alternative destination value safeguards the state's interests without requiring the state to prove that the lessee engaged in self-dealing. For example, assume a lessee, when planning for Canadian gas, makes a multi-decade commitment to pay for Canadian pipeline capacity, but then finds itself without sufficient Canadian gas to fill the capacity. If the lessee chooses to fill that capacity with North Slope gas to defray its losses occasioned by its Canadian interests, even though it knows of a better alternative for maximizing the value of its North Slope gas, the lessee may be required to pay the state royalties based on alternative destination value. This is an intended effect of the regulations. It allows the lessee to pursue its global interests, but not at the state's expense, and without litigation over whether there was self-dealing or imprudence. Despite industry comment, DNR chooses not to eliminate this feature in the final regulations being adopted today.

D. Destination Value for LNG

BP comments that the regulations include an unintended bias against LNG because LNG is more apt to be sold under a long-term contract, which allows for the possibility that the sales price under the long-term contract and destination value as measured under the regulations may diverge over time. Of course, if in diverging sales price exceeds destination value, BP will reap the benefit of the difference. Only if sales price consistently underperforms destination value will BP be required to pay royalties on an amount in excess of its realizations.

The structure of the regulations has nothing to do with a bias for or against LNG, but rather reflect the existing and evolving nature of the LNG market and statutory dictates. Historically, LNG was sold under long-term contracts, and those long-term contracts sometimes contained fixed price terms. However, industry practice has changed and will continue to evolve. "Long-term" contracts are becoming shorter. New "long-term" contracts typically tie sales price to market indices—including spot market prices—thus allowing sales price to equal or more closely approximate fair market value. And new "long-term" contracts often include "reopeners" or "market-outs" to allow renegotiation of price or termination of a contract if the sales price, formula, or index set out in the contract becomes problematic.

Further, published prices do not exist for all markets for LNG, and may not be reliable where they do exist. While DNR expects published prices to become more common and more reliable for LNG, if there is not a reliable published price appropriate for use in valuing North Slope

LNG, the regulations specify that the sales price for LNG becomes its destination value.[3] In that instance, sales price is destination value, eliminating any risk of divergence in sales price and destination value.

BP also comments that even if a contract for sale of LNG is indexed, it may be indexed to a published price for a different month than the month used in determining destination value under the regulations. BP has several protections against this scenario. First, presumably it has yet to enter a long-term contract to sell LNG manufactured from North Slope gas. At such time as it negotiates a long-term contract to sell LNG manufactured from North Slope gas, it can insist on contract terms that avoid a mismatch in months. Second, nothing in the regulations dictate the month DNR must choose in designating a published price in a first destination market for LNG. Thus, if BP enters a long-term contract for the sale of LNG manufactured from North Slope gas, and fails to include language in the contract to prevent a mismatch in months, BP can advise DNR of its contract terms and advocate that DNR's designation of a published price for LNG delivered into the first destination market being serviced by BP include a designation of month that matches up with the month used in the price term of BP's long-term contract for sale of LNG.

While DNR has made changes to the regulations governing destination value between public notice and final adoption, those changes are largely intended to clarify the regulations, rather than dramatically shift the substance of the regulations. However, DNR is eliminating the section on alternative destination value for LNG from the final regulations. The deletion of that section is not due to public comments received, but because of the current lack of information on probable destinations for LNG manufactured from North Slope gas, as well as the less-evolved indices currently available for valuing LNG.

IV. DEDUCTIONS FROM DESTINATION VALUE FOR ACTUAL AND REASONABLE COSTS

As mentioned in Part III above, the proposed regulations establish a method for determining the monthly value of the state's royalty gas shipped in firm transportation capacity acquired in the first binding open season for an Alaska natural gas pipeline project licensed under the Act. The method requires an oil and gas lessee to report the value of qualified gas at destination, and allows the lessee to deduct certain costs incurred in treating, processing, and transporting the gas between the lease and destination. In this section DNR addresses public comments made on cost deductions.

A. Regulated Pipeline Tariffs

In its comments, BP identifies six subjects the proposed regulations address "in a reasonable and helpful way." One of those six is the "use of FERC-approved tariffs paid with respect to RIV gas." While the regulations do allow deduction of FERC-approved tariffs paid by a shipper to an unrelated pipeline in an arm's-length transaction, they do not allow deduction of the tariff a shipper "pays" an affiliated pipeline (except in limited circumstances). In their comments, ExxonMobil and ConocoPhillips argue that the regulations should allow deduction of

[3] Except in certain circumstances where the sales price is suspect or the "buyer" at destination is an affiliate.

payments made for FERC, RCA, and NEB-regulated facilities,[4] including pipelines, even when the shipper and pipeline are affiliated. ConocoPhillips urges that for the project to be built, it will likely need to be owned in whole or part by affiliates of the lessees, yet the regulations "discriminate" against ownership by affiliates by not, in all instances, allowing deduction of the tariff a shipper "pays" its affiliate. ExxonMobil states that a lessee-shipper cannot selectively exclude costs from rate base, and that it should not have to determine what costs DNR will deem allowable.

DNR appreciates the simplicity of allowing a deduction for the contract price for pipeline transportation. And when the contract is between unrelated parties with opposing economic interests, DNR expects the shipper's interest in paying the lowest possible charge for pipeline transportation will work to the state's benefit. However, the higher a charge a shipper pays for pipeline transportation, the greater a lessee's deduction in calculating not only royalties but also taxes due the state, and the lower the lessee's royalty and tax payments to the state. Where the "contract" for pipeline transportation is agreed to by two affiliates, the charge for pipeline transportation will be transferred from one affiliate to another affiliate. Within the family of related entities the payment and receipt will cancel out, and the affiliates may be indifferent to whether the charge is high or low, except that if the charge is high, royalty and tax deductions will be high and royalty and tax payments low. Thus, where the "contract" for pipeline transportation is agreed to by two affiliates, the contract "charge" is suspect. Moreover, because FERC tends not to scrutinize whether a negotiated rate for transportation best reflects the reasonable costs of transportation, regulatory "blessing" of such rates provides the state with little effective protection.

The state has a long history of questioning the appropriateness of pipeline charges set by agreement among affiliates, and tribunals have found affiliated charges to exceed just and reasonable rates by billions of dollars. Further, while rate disputes are common among third-party shippers and pipelines, rarely in the history of the state has an affiliated shipper challenged the rate charged by an affiliated pipeline. Without a rate dispute, FERC, RCA, and NEB will not take the same hard-look at a tariff as they would in contested rate proceedings. Fair market value for royalty should not hinge on the delay and uncertainties associated with regulatory proceedings when the parties to the contract are affiliated.

For the above reasons, DNR has not changed its regulations to allow a lessee to in every instance deduct the full amount an affiliate pipeline charges, even if the charges are "approved" by FERC, RCA, or NEB.

B. Exclusion of Certain Costs

BP, ConocoPhillips, and ExxonMobil submitted comments questioning the exclusion of certain costs.

1. Gas lost by an affiliated pipeline, plant, or tanker

BP states that just as a deduction is allowed when gas is lost under an arm'-length contract for transportation or processing, a deduction should also be allowed for gas lost by an

[4] "NEB" is Canada's National Energy Board. It regulates Canadian pipelines.

affiliated pipeline, tanker, or plant. DNR does not adopt BP's suggestion for the following reasons.

The regulations allow a deduction for losses under an arm's-length contract, as long as gains are reported as well. The opposing economic interests of those involved in the arm's-length contract assure that these losses are real, and that any dispute about the losses is apt to be resolved between the parties to the contract without intervention or cost to the state. When gas is "lost," that gas may show up as a "gain" in another reporting period or in another pipeline.

However, when parties are affiliated, they lack the same incentive as unrelated parties to track down and properly account for off-setting gains. Were the state to allow affiliate "losses," it would not have a ready mechanism to verify those "losses" or locate and require payments on "gains" recognized in another reporting period or another pipeline.

The regulations being adopted today prohibit a deduction for gas lost by an affiliated pipeline, tanker, or plant. The prohibition contained in the regulations is similar to a prohibition contained in regulations adopted the Minerals Management Service ("MMS"), which manages certain federal oil and gas leases. 30 C.F.R. §206.154(d) and §206.157(f)(7).

BP's comments also suggest that BP might view LNG "boil off" as "losses" it cannot take if LNG tankers are owned by an affiliate. However, BP states in a footnote that, "For most if not all LNG tankers, this boiled-off gas is burned as fuel to power the ship instead of being wasted by venting it unburned into the air." Qualified gas used as fuel to transport qualified gas by LNG tanker is not lost gas, but fuel gas. The regulations allow a deduction or adjustment to volumes for gas used as fuel, regardless of whether the lessee or shipper and LNG tanker are affiliated.

BP suggests that the exclusion for gas lost by an affiliate is particularly burdensome for LNG, where affiliated plants and tankers are more likely. Given the clarification that fuel gas is not "lost", DNR sees no particular burden for LNG. As with LNG tankers, the regulations allow a deduction or adjustment to volumes for gas a liquefaction or regasification plant uses as fuel, regardless of whether the lessee and LNG plant are affiliated.

2. Intra-hub transfer, marketer, broker, and storage fees

ExxonMobil comments that intra-hub transfer, marketer, broker, and storage fees are reasonable costs that should be allowed as deductions in calculating royalties due the state. The regulations disallow:

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

- 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;

- a fee paid to a broker, including a fee paid to a person who arranges marketing or transportation;

- a cost or fee incurred for storage, except that a lessee may deduct: (a) a charge by a pipeline for storage for up to 30 days when the storage is required under the applicable transportation services agreement and is necessary for pipeline operations, and (b) a cost or fee for the storage as part of LNG transportation.

These four exclusions are patterned after MMS exclusions. 30 C.F.R. §206.157(f)(8), (g)(1), (g)(2), (g)(4), (g)(5), 30 C.F.R. §206.158 (d)(1).

The four exclusions are consistent with a lessee's duty to market royalty gas at no expense to the state as lessor. The first three exclusions obviously relate to marketing qualified gas. The fourth exclusion also relates to marketing, though not as obviously. A lessee storing gas for more than 30 days is likely storing gas to sell it in a season that commands higher prices. Since the regulations do not require a lessee to share the higher price with the state, the state should not share in storage fees incurred while a lessee waits for the higher price.

While ExxonMobil may be correct that the expenses are reasonable expenses incurred by ExxonMobil, all reasonable expenses incurred by ExxonMobil are not deductible when calculating royalties due the state. The four exclusions ExxonMobil commented on remain in the final regulations being adopted today.

3. Costs to meet pipeline specifications, including costs of the GTP

BP and ConocoPhillips comment that the regulations should allow costs incurred in treating gas to meet the specifications for acceptance into the Alaska mainline, including the cost of a new gas treatment plant (GTP) to be built as part of the project. BP comments that the cost of the GTP is substantial, and any disallowance of its costs would provide a disincentive for proceeding with the project. ConocoPhillips asserts that it is inappropriate to deny these costs on the basis of a 1979 court decision that was superseded and contradicted by an order approving a 1980 settlement agreement. BP adds that the regulations allow deductions for the cost of LNG and NGL plants downstream of the Alaska mainline, and it is not clear to BP what basis exists for different treatment of upstream and downstream plants.

A response to these comments requires a discussion of the state's oil and gas lease forms, court decisions issued in 1979 and 1994, settlement agreements entered in 1980 and 1995, and legislative action in 1978 and 2007.

Most, if not all, North Slope leases issued in or before 1978 are on the "DL-1" lease form. The DL-1 lease form has been the subject of protracted litigation. Some of the claims raised in that litigation were addressed in 1979 and 1994 court decisions. A 1979 court decision concluded that any cost incurred by a lessee upstream of the meter for receipt of oil into the TransAlaska Pipeline is a cost to be borne by the lessee only and is not deductible in calculating royalties, save only the cost of cleaning and dehydration of hydrocarbons taken as royalty-in-kind. *In the Matter of ANS Royalty Litigation*, 1JU-77-847, Civil (April 6, 1979). Similarly, a 1994 court decision concluded that, except for the cost of an extraction plant, the cost of placing oil and gas in marketable condition is the lessee's and is not deductible from royalty. *In the Matter of ANS Royalty Litigation*, 1JU-77-847, Civil (December 15, 1994).

The legislature has spoken to the same issue. In late 1977, lessees first asserted that the DL-1 lease form required the state as lessor to share in costs incurred upstream of the meter for receipt of hydrocarbons into a pipeline for transportation off the North Slope. When the legislature convened in 1978, it amended the state's oil and gas leasing statute to forever squelch such arguments as to any lease issued in the future. AS 38.05.180(f) was amended to read:

> (f) [T]he commissioner may issue oil and gas leases or leases for gas only on state land to the highest responsible qualified bidder as follows:
>
> (1) …;
>
> (2) whenever, under any of the leasing methods listed in this subsection, <u>a royalty share</u> is reserved to the state, it <u>shall be delivered in pipeline quality and free of all lease or unit expenses, including but not limited to separation, cleaning, dehydration, gathering, salt water disposal, and preparation for transportation off the lease or unit area</u>;

(Emphasis added). Despite the 1978 legislative action and 1979 court decision, the state found itself in a predicament in 1980. It wanted the ability to take a portion of its royalty oil in-kind from DL-1 leases in Prudhoe Bay on terms no less favorable than taking its royalty oil in-value. However, the 1979 court decision obligated the state to pay the costs of cleaning and dehydration for hydrocarbons taken in-kind, but not hydrocarbons taken in-value. To resolve this predicament, the state entered a settlement agreement, which covers most but not all leases in the Prudhoe Bay Unit. The state agreed to pay a fixed amount, which would escalate with the producer price index over time, for costs incurred upstream of a pipeline leaving the North Slope; the amount was the same for both royalty-in-value and royalty-in-kind. At the time, the state believed the amount agreed to would be less than if it took all hydrocarbons in-kind and had to pay the full costs of cleaning, dehydration, and an extraction plant, but more than if it took all hydrocarbons in-value, with an obligation to pay only the costs of an extraction plant. The 1980 settlement was approved by the court. *In the Matter of ANS Royalty Litigation*, 1JU-77-847, Civil (August 13, 1980). Later, the same court would rule that the state was not estopped by the 1980 settlement agreement from challenging a lessee's claim for upstream costs for leases <u>not</u> covered by the 1980 Prudhoe Bay settlement agreement; the court also reaffirmed a lessee's obligation to produce oil and gas free of upstream costs to the state, with the exceptions noted above. *In the Matter of ANS Royalty Litigation*, 1JU-77-847, Civil (December 15, 1994).

When the legislature passed the Act in 2007, it provided that regulations adopted under the Act include "deductions permitted under the 1980 Royalty Settlement Agreement for Prudhoe Bay gas." The legislature did not authorize DNR to extend those deductions to leases <u>not</u> covered by the 1980 settlement agreement, and DNR believes it lacks authority to do so. However, based on the 1979 and 1994 court decisions discussed above, DNR has authority to extend limited deductions for upstream costs incurred for gas produced from a DL-1 lease. That authority extends only to the cost of cleaning and dehydrating gas taken in kind from leases issued in or before 1978, and to the cost of an extraction plant. The regulations being adopted today allow a deduction for the former, but not the latter.

The regulations <u>do not</u> allow a deduction for costs of an extraction plant upstream of the Alaska mainline for two reasons. First, extraction plants are designed to remove liquids, such as propane, butane, and pentane, from a gaseous stream either to capture the incremental value of the liquids or to bring the gas within pipeline specifications typical for many preexisting pipelines in the Lower 48 states. However, the Alaska mainline is being designed to allow transport of a liquids-rich stream; thus, an extraction plant is not needed to bring gas to pipeline specifications for the Alaska mainline. If lessees choose to extract liquids on the North Slope, they are extracting the liquids there to capture the use or value of the liquids on the North Slope or to transport those liquids with crude in the TransAlaska oil pipeline, and any costs of extraction should be borne by the liquids remaining on the North Slope or transported in TAPS, not the qualified gas transported on a new Alaska natural gas pipeline licensed under the Act.

Second, the Central Gas Facility ("CGF") is an extraction plant at Prudhoe Bay first placed in service in late 1986 or early 1987. Some gas destine for the Alaska mainline may be treated at the CGF. However, lessees have been allowed to recover an amount approximating the royalty share of the costs of the CGF through deductions taken when paying royalties on liquids extracted at the CGF and blended with crude oil for transportation to market via the TransAlaska pipeline, as is evidenced by the additional settlement agreements the state and lessees entered in 1995. The 1995 settlement agreements provide that no cost or expense of the CGF shall be considered in calculating upstream deductions allowed for gas covered by the 1980 settlement agreement.

With this background, it is possible to respond to the public comments. BP and ConocoPhillips comment that the regulations should allow costs incurred in treating gas to meet the specifications for acceptance into the Alaska mainline, including the costs of a new gas treatment plant to be built as part of the project. The regulations do allow such costs to the extent authorized by the legislature or required by court decision or settlement agreement, but DNR is without authority to extend the scope of allowed deductions and does not purport to do so in these regulations.

BP comments that the cost of the GTP is substantial, and any disallowance of its cost would provide a disincentive for proceeding with the project. DNR acknowledges that the cost of the GTP will be substantial. The state will share in its cost to the extent it treats Prudhoe Bay gas covered by the 1980 settlement agreement. The state will not share in its cost for other gas, and does not have the authority to allow the cost, whether substantial or otherwise.

ConocoPhillips asserts that it is inappropriate to deny these upstream costs on the basis of a 1979 court decision that was "superseded" and "contradicted" by an order approving a 1980 settlement agreement. However, the 1980 settlement was, like all settlements, a compromise of a disputed claim, and the court's approval of the settlement did not reflect the court's reconsideration or disavowal of its 1979 decision on the merits. Furthermore, the court's 1994 decision reaffirmed the substance of the 1979 decision, notwithstanding the 1980 settlement agreement.

BP also comments that the regulations allow deductions for the cost of LNG and NGL plants downstream of the Alaska mainline, and it is not clear to BP what basis exists for different treatment of upsteam plants. The basis for the difference in treatment of plants is contained in existing law and the Act. DNR is without authority to further extend upstream deductions, but the Act specifically authorizes deductions for post-production gas processing, such as may occur at an LNG or NGL plant downstream of the Alaska mainline, and Alaska law and lease forms have historically allowed, with limited exceptions, the deduction of costs incurred once North Slope hydrocarbons enter a pipeline for transportation off the North Slope.

C. Limits on Cost Deductions

ConocoPhillips comments, generally, that the regulations systematically overvalue royalty gas through a combination of: 1) "higher of" requirements for destination value; 2) disallowance of certain costs; and 3) where costs deductions are allowed, a requirement that the lessee deduct the "lower of" multiple measures of that cost. Industry concerns about "higher of" requirements for destination value are discussed in Part III, above. The disallowance of specific costs enumerated by industry is discussed in Part IV.B, above. The disallowance of other costs is, in many cases, patterned after federal regulations adopted by MMS to govern royalty valuation of gas produced from federal lands. The state's lease form has its origins in language developed by the federal government for federal oil and gas leasing, and MMS has extensive experience with the valuation of gas for royalty purposes. In recognition of similar leasing laws and MMS experience, DNR has patterned portions of its AGIA regulations after MMS regulations, including MMS regulations on costs that may not be deducted in calculating royalties.

In some instances, the regulations being adopted today require the deduction of the lower of multiple measures of cost. 11 AAC 25.160(b); 11 AAC 25.180(a), (e), (j); 11 AAC 25.190(a), (c), (d); and 11 AAC 25.200(a). Deduction of the lower of multiple measures of cost is required only for affiliate transactions. Most frequently, the lessee is required to deduct the lower of its affiliate's actual, allowable cost or the amount paid to an affiliate under a contract with an affiliate. A lessee should not be allowed to deduct an amount greater than its affiliate actually spends in providing transportation or processing. Nor should a lessee be able to deduct an amount greater than the charge "paid" by an affiliate under a contract between affiliates.

With regard to the Alaska and Canada mainlines, where the lessee and a pipeline are affiliated, the "lower of" comparison includes as one measure of cost the terms offered to shippers in the plan for open season for the Alaska mainline filed by the AGIA licensee, TransCanada, with FERC on January 29, 2010. In calculating royalties due the state, a lessee should not be able to deduct an amount greater than TransCanada's opening offer for transportation services. If a lessee or its affiliate becomes a partial or sole owner of the Alaska or Canada mainline at some time in the future, any increase in the amount it charges an affiliate for transportation services is suspect because of the affiliate relationship and should not be grounds for reducing royalty payments due the state as lessor.

The amount to be used as an affiliate pipeline's actual, allowable cost of capital investment, operating expense, or maintenance expenses is subject to a slightly different "lower of" comparison. A lessee is to deduct the lower of the cost properly reportable to a regulatory agency, prudently incurred, or allowed under an affiliate contract for transportation services. A lessee should not be able to claim a deduction for a cost regulators deny, nor for a cost imprudently incurred, nor for a cost in excess of the amount paid under contract.

Each one of these "lower of" provisions is intended to prevent abuses in cost reporting made possible by two affiliates in roles normally occupied by opposing economic interests. Were

DNR to drop the "lower of" provisions from its regulations as a further inducement for the project, as suggested by ConocoPhillips, the lessees may reap financial gain, but only at the state's expense, and only in ways that cannot be justified.

D. Other Comments on Cost Deductions

ExxonMobil comments, generally, that the starting point for cost deductions should be actual costs. The Act requires that the regulations being adopted today allow deductions for "actual and reasonable" transportation costs and "reasonable and actual" processing costs. Thus, a cost cannot be deducted unless it is both a cost actually incurred and a cost reasonably incurred. The regulations seek to implement the legislative directive to allow only actual and reasonable costs by, generally: 1) disallowing costs outside of the scope of allowable costs, such as the costs of putting gas in marketable or pipeline condition (except where those costs are allowed by settlement); 2) disallowing unreasonable costs, including unverifiable costs, costs imprudently incurred, and costs incurred without due regard for the interests of both lessee and the state as lessor; and 3) for affiliate transactions, looking, in the first instance, to the actual costs incurred by the affiliate, rather than the cost assigned to the transaction in a contract between affiliates.

ExxonMobil also comments that the regulations allow DNR broad discretion to determine reasonable, allowable transportation and treating costs. ConocoPhillips comments, generally, that the regulations allow DNR broad discretion. ConocoPhillips also requests, generally, greater clarity in the regulations. DNR has revised the proposed regulations in light of these comments, particularly Sections 180 and 190, which govern cost deductions where the lessee and pipeline are affiliates. Among other things, Sections 180 and 190 adopt by reference FERC's *Cost-of-Service Rates Manual* and certain AFUDC cases to the extent not inconsistent with other provisions included in the regulations, thus bringing greater detail to the regulations. Greater detail in these sections provides for more clarity and reduces the opportunity for the exercise of discretion.

V. TERMS FOR TAKING THE STATE'S SHARE OF ROYALTY GAS IN-VALUE (AS MONEY) OR IN-KIND (AS GAS)

The Act requires that DNR adopt regulations allowing a lessee to elect a modification of the terms under which the state will exercise its right to switch between taking its royalty in value or in kind for gas committed for firm transportation in the first binding open season of the project.

ConocoPhillips comments that the regulations differentiate between qualified gas and other gas. ConocoPhillips is correct. The Act authorized DNR to adopt new regulations for royalty-bearing gas produced from a state lease on the North Slope and shipped in firm transportation capacity acquired in the first binding open season for an Alaska natural gas pipeline project licensed under the Act—i.e. "qualified gas." The Act does not authorize DNR to adopt regulations on switching between royalty-in-value and royalty-in-kind ("RIV/RIK switching") for gas that is not qualified gas. Hence, the regulations distinguish between qualified gas and all other gas. The regulations specify the change in terms for RIV/RIK switching available for qualified gas. The regulations are silent as to all other gas. All other gas remains subject to the terms of existing lease, unit, and royalty settlement agreements as they pertain to RIV/RIK switching.

ConocoPhillips also comments that the Prudhoe Bay Unit Agreement requires six months notice for RIV/RIK switching—a period longer than offered as an "inducement" in the regulations being adopted today. ConocoPhillips' statement is outdated. Most of the leases in the Prudhoe Bay Unit were issued in or before 1977 on the DL-1 lease form. Paragraph 13 of the DL-1 lease form did provide for six months notice of RIV/RIK switching. Similarly, the original Prudhoe Bay Unit Agreement, which was approved before oil production commenced in 1977, may have provided for six months notice. However, royalty settlement agreements entered in or about 1991 in the *ANS Royalty Litigation* shortened the notice period to 90 days for all "production"—i.e. both oil and gas—covered by the royalty settlement agreements, including most Prudhoe Bay gas. Further, all older North Slope unit agreements have been amended to limit the required notice to 90 days, and all newer North Slope unit agreements limit the required notice to 90 days. Thus, the notice periods set out in the regulations for volumes in excess of 100 mmcfd are an inducement because they exceed 90 days.

ExxonMobil comments that the regulations do not require any notice of RIV/RIK switching for volumes less than 100 mmcfd. The regulations are silent on the notice requirements for volumes less than 100 mmcfd and are not intended to change preexisting notice requirements for those volumes. Consequently, the notice for volumes less than 100 mmcfd remains at 90 days.

ExxonMobil also comments, generally, that the regulations have removed unspecified preexisting restrictions on how much gas can be switched with each notice. The regulations are silent on how much gas can be switched with each notice. The regulations are not intended to lift any preexisting, applicable restriction on how much gas can be switched with each notice.

Finally, ExxonMobil comments on what is being adopted today as 11 AAC 25.280(d). 11 AAC 25.280(d) reads:

> If a lessee intends to sell more than 80 percent of the lessee's qualified gas under arms-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 on-going 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.

ExxonMobil states that while a lessee can apply for an extension of the notice period, there is no certainty that the notice period will be consistent with a lessee's commercial arrangements for disposition of its gas. DNR acknowledges that there is a burden associated with a lessee's obligation to plan its business in a way that allows the state to switch between taking its royalty share—typically 12.5%—in-value or in-kind on as little as 90 days notice. DNR has worked to minimize that burden in the regulations by: 1) obtaining a limited waiver from FERC so that pipeline capacity can switch between a lessee and the state as royalty gas switches between a lessee and the state, 2) increasing standard notice periods to 120 days for volumes in excess of 100,000 mmcfd and to 180 days for volumes in excess of 200,000 mmcfd, and 3) allowing a lessee to apply for even longer notice where a lessee makes extended commitments to sell an amount equal to or exceeding all or most all of the lessee's share of qualified gas. However, DNR is not willing to altogether forego the right to switch between RIV and RIK, or to further extend the length of required notice without criteria. The right to switch is a valuable right the state reserved to itself at the time of leasing. It provides the state an opportunity to satisfy the in-state market for gas, which is especially important if lessees are unwilling to do so at all or at an appropriate price. It allows the state to leave the gas with a lessee and stay out of the business of marketing gas when the state chooses. And it permits the state to switch to taking gas in-kind if the state doubts a lessee is obtaining, reporting, and paying full fair market value for royalty gas left with a lessee in-value.

Further, the Act does not authorize DNR to forego the right to switch altogether or to extend the notice period without limitation. AS 43.90.310 provides:

> (b) If a lessee or other person qualified for resource inducement under AS 43.90.300 agrees under (c) of this section, the lessee or other person is entitled to elect … to enter into a contract with the state that amends the existing lease terms by providing a mechanism that ensures that, <u>when the state exercises its right to switch</u> between taking its royalty in value or in kind for gas committed for firm transportation in the first binding open season of the project, the lessee or other person does not bear disproportionate transportation costs with respect to the state's royalty gas; and by <u>modifying the required period of notice</u> that the state must provide before exercising the state's right to switch between taking its royalty in value or in kind for gas committed for firm transportation in the first binding open season of the project.

(Emphasis added). Implicit in the language "… when the state exercises its right to switch …" is a directive to maintain the right to switch. Similarly, implicit in the authorization to "modify the required notice period" is that a notice period will be maintained and not extended without limitation.

DNR believes that its regulation on RIV/RIK switching is consistent with the Act and strikes an appropriate balance between protecting the interests of a lessee, public, and state. Other than refining language on RIV/RIK switching to meet general comments seeking greater clarity, DNR has not changed this section of the regulations in response to public comments.

VI. <u>NET PROFIT SHARE LEASES</u>

ConocoPhillips comments that the Act authorizes changes in royalty valuation, not net profit share accounting. DNR agrees with ConocoPhillips. The section on net profit share accounting included in the proposed regulations has been dropped and does not appear in the final regulations.

VII. RESOLUTION OF DISPUTES

BP notes that "most, if not all" existing royalty settlement agreements provide for the arbitration of disputes, and comments that the regulations "appear to compromise this right severely, if not abolish it altogether."

While some existing royalty settlement agreements provide for the arbitration of disputes, none provide for the arbitration of disputes regarding royalty valuation or RIV/RIK switching for gas to be shipped off the North Slope as part of either a project licensed under the Act or what has been referred to as a "Major Gas Sale." Further, DNR questions whether it has authority to mandate arbitration of disputes as part of these regulations, since the Act did not specify arbitration and the regulations are not being adopted to resolve litigation, as were the royalty settlement agreements. Accordingly, the regulations being adopted today do not provided for or permit the arbitration of disputes.

ConocoPhillips comments that the regulations allow DNR to designate first destination markets, market centers, published prices, location differentials, and quality differentials, but do not include provision for public comment on the designations, independent assessment of the designations, or a right to appeal the designations. ConocoPhillips is correct in noting that the regulations being adopted today do not specify all procedures for decision-making and dispute resolution. Absent explicit language in the regulations to the contrary, DNR's intent is to leave in place existing procedures used for decision-making and dispute resolution rather than to create all new procedures applicable only to qualification, royalty valuation, and RIV/RIK switching for gas transported on the Alaska mainline.

VIII. EFFECT OF REGULATIONS ON EXISTING ROYALTY SETTLEMENT AGREEMENTS

In its comments, BP asks the affect of the regulations on existing "royalty settlement agreements." BP asks whether acceptance of the offer of royalty inducements for qualified gas would leave the oil royalty provisions of existing royalty settlement agreements intact. Yes, oil royalty provisions of existing royalty settlement agreements would remain intact as to royalty oil and NGLs blended with royalty oil, which are shipped to market in the TransAlaska oil pipeline ("TAPS"). The regulations being adopted today pertain only to gas transported off the North Slope in a new gas pipeline licensed under the Act.

BP asks whether the regulations would supersede the gas royalty provisions of existing royalty settlement agreements. Generally, the gas royalty provisions of existing royalty settlement agreements are specific to the use or sale of particular gas. For example, there are five major categories of gas, each subject to unique treatment because of existing royalty settlement agreements: 1) gas extracted at Prudhoe Bay's Central Gas Facility and blended with crude for shipment on TAPS; 2) "local gas"; 3) "new use gas"; 4) gas shipped off the North Slope as part of a "Major Gas Sale," such as a project licensed under the Act; and 5) gas produced from a lease or participating area not covered by an existing royalty settlement agreement.

The regulations being adopted today are not applicable to the first three categories of gas, and hence have no effect on the gas royalty provisions of existing royalty settlement agreements with regard to those three categories of gas. Only the final two categories of gas may be impacted, and only if both a lessee and its gas are "qualified" under the regulations, meaning, at a minimum, that the gas is royalty-bearing gas produced from a state lease which is transported off the North Slope in firm transportation capacity acquired in the first binding open season for an Alaska natural gas pipeline project licensed under the Act. For this gas, the provisions of existing royalty settlement agreements applicable to the gas remain in effect for gas covered by those agreements, except to the extent superseded by any subsequent agreement, or inconsistent with the terms of the regulations being adopted today.

IX. DEFINITION OF "ALASKA MAINLINE"

Representative Keller commented on the definition of "Alaska mainline" included in the regulations. Representative Keller sought clarity on the range of acceptable destinations for the Alaska segment of a pipeline licensed under the Act. In the final regulations, DNR revised the definition in light of Representative Keller's comment. The definition now reads:

> "Alaska mainline" means
>
> (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 ….

X. REVIEW AND AMENDMENT OF REGULATIONS

The proposed regulations included 11 AAC 25.310, "Review of regulations," 11 AAC 25.330, "Amendment of regulations," and 11 AAC 25.040(e) and (f), pertaining to a lessee's election of one or both royalty inducements following amendment of the regulations. DNR intended to adopt these regulations under the authority of AS 43.90.410, AS 38.05.020(10), and AS 43.90.310(d), (a), and (b), set out in a footnote, below.[5]

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[5] AS 43.90.410: The commissioners [of revenue and natural resources] may jointly adopt or amend regulations for the purpose of implementing the provisions of [the Act]. The commissioner of revenue and the commissioner of natural resources may adopt or amend regulations adopted under authority outside [the Act] as necessary to implement the provisions of [the Act].

AS 38.05.020(10): The commissioner may … exercise the powers and do the acts necessary to carry out the provisions and objectives of AS 43.90 that relate to this chapter.

Generally, these proposed regulations were either explanatory rather than directive or duplicative of requirements already imposed by statute, and thus not appropriate for inclusion in regulations, according to the *Manual on Drafting Administrative Regulations*. Industry objected to these regulations, but for other reasons. The proposed regulations are being dropped from the final regulations being adopted today to comply with the *Manual on Drafting Administrative Regulations*, rather than because of industry comment. DNR nonetheless takes this opportunity to address industry comment, though a discussion of context is needed first.

AS 43.90.310(d): The commissioner of natural resources shall provide for review of the regulations adopted under (a) of this section at least every two years after the commencement of commercial operations to determine whether the regulations continue to meet the requirements of (a) of this section under current conditions, and shall amend the regulations when the requirements are not being met.

AS 43.90.310(a): … The regulations must

(1) minimize retroactive adjustments to the monthly value of the state's royalty share of gas production;
(2) provide a method for establishing a fair market value for each component of the state's royalty gas that is based on pricing data from reliable and widely available industry trade publications and that uses appropriate adjustments to reflect

(A) deductions for actual and reasonable transportation costs for the state's royalty gas, including a reasonable share of the costs associated with unused capacity commitments on gas pipelines from the North Slope to the first destination market with reasonable market liquidity;
(B) location differentials between the destination markets where North Slope gas could be sold;
(C) reasonable and actual costs for gas processing; in this subparagraph, "gas processing" means post-production treatment of gas to extract natural gas liquids; and
(D) deductions permitted under the 1980 Royalty Settlement Agreement for Prudhoe Bay gas; and

(3) establish terms under which the state will exercise its authority to switch between taking its royalty gas in value and in kind to ensure that the state's actions do not unreasonably

(A) cause the lessee or other person to bear disproportionate transportation costs with respect to the state's royalty gas;
(B) interfere with the lessee's or other person's long-term marketing of its production.

AS 43.90.310(b): If a lessee or other person qualified for resource inducement under AS 43.90.300 agrees under (c) of this section, the lessee or other person is entitled to elect

(1) to calculate its gas royalty obligation under the regulations adopted under (a) of this section for natural gas transported on a firm contract executed during the project's first binding open season or under the methodology set out in the existing leases from which the gas is produced, and

(A) upon the request of the lessee, the commissioner of natural resources shall contractually amend the existing lease to effect the election under this paragraph and incorporate as fixed contract terms the relevant regulatory provisions; and
(B) the election under this paragraph remains in effect until new regulations are adopted as a result of a review under (d) of this section, at which time, a lessee or other person qualified under AS 43.90.300 may change its election under this paragraph; upon the request of the lessee, the commissioner of natural resources shall contractually amend the lease to incorporate as fixed contract terms the relevant revised regulatory provisions;

(2) to enter into a contract with the state that amends the existing lease terms by providing a mechanism that ensures that, when the state exercises its right to switch between taking its royalty in value or in kind for gas committed for firm transportation in the first binding open season of the project, the lessee or other person does not bear disproportionate transportation costs with respect to the state's royalty gas; and by modifying the required period of notice that the state must provide before exercising the state's right to switch between taking its royalty in value or in kind for gas committed for firm transportation in the first binding open season of the project.

The Act requires the adoption of regulations to establish a method for royalty valuation and terms for RIV/RIK switching. A North Slope lessee can elect either or both: 1) the new method for royalty valuation, or 2) the new terms for RIV/RIK switching. The election actually or effectively amends existing lease, unit, and/or royalty settlement agreement terms for gas shipped in firm transportation capacity acquired through a commitment made in the first binding open season for a project licensed under the Act. The duration of such an actual or effective amendment of preexisting contractual terms is the subject of this Part X.

An open season for the project licensed under the Act is scheduled for this year, 2010. If successful, the project licensed under the Act is to be permitted and built over the next ten years, with the commencement commercial operations estimated for 2020. Any commitment to pipeline capacity made this year, in 2010, during the first binding open season for the project is expected to obligate a potential shipper to pay for pipeline capacity for twenty to thirty-five years of shipments—from approximately 2020 to 2045 or 2055.

Industry comments question the effect of an amendment of the regulations after a commitment to pipeline capacity is made but before the expiration of the commitment period. Industry's position appears to be that if, prior to the commencement of commercial operation of the project, a lessee elects, say, the method for royalty valuation being adopted today, then produces and ships North Slope gas from the commencement of commercial operations in 2020 until the expiration of its commitment to pipeline capacity in, say, 2055, any intervening amendment of the regulations gives the lessee the opportunity to report royalties under either the original regulations or the amended regulations. On the other hand, under the proposed 11 AAC 25.310, 11 AAC 25.330, and 11 AAC 25.040(e) and (f), the election available to a lessee at the time of amendment of regulations was between the contract terms predating the original regulations and the regulations as amended.

Industry, in commenting on the proposed regulations, stated that DNR's interpretation of the election available upon amendment of the Act: 1) means there is no binding contract (BP) and any favorable contract terms could be removed (ConocoPhillips); 2) threatens the effectiveness of the regulations as an inducement (BP and ExxonMobil); 3) creates significant risk and uncertainty (ExxonMobil); 4) lacks standards to prevent abuse (BP); and 5) is contrary to existing contract terms.

However, the Act <u>requires</u> amendment of the regulations in a number of situations, including when the method established for valuing the state's royalty share of gas does not capture "fair market value" or does not allow deduction for the "reasonable" costs of transportation, unused pipeline capacity, and processing. AS 43.90.310(d) and (a)(2). Further, election of the method established for valuing the state's royalty share only "remains in effect until new regulations are adopted." AS 43.90.310(b)(1)(B).

If the election upon amendment of the regulations is as suggested by industry comments, royalties may be paid on less than fair market value and deductions for transportation, unused pipeline capacity, and processing may be unreasonably high. For example, if the regulations as adopted in 2010 set out a method that would capture fair market value in 2010 and allow for reasonable cost deductions in 2010, because of changes that cannot now be anticipated, the regulations may nonetheless capture far less than fair market value and allow unreasonably high cost deductions by, say, 2025. In that instance, DNR will be required by AS 43.90.310(d) to amend the regulations so that they again set out a method for establishing full fair market value and allow only reasonable cost deductions. However, if lessees can elect to keep paying royalties under the original method contained in the 2010 regulations, the 2025 amendment will be to no effect and the state will receive less—possibly far less—than fair market value for its royalty gas for a prolonged period—possibly decades. Industry's argued-for interpretation of the Act would have the Act require payment of fair market value only at a moment in time—2010, when qualified gas has yet to be produced—and not over time—2020-2055, in the example set out above.

On the other hand, if the election at the time of amendment of the regulations is between original lease terms and the regulations as amended, the state always will receive fair market value for its royalty gas, with only reasonable cost deductions. Under lease terms predating the adoption of regulations today, a lessee is required to pay royalties on the highest of multiple measures of value, including fair market value, and is limited to reasonable cost deductions. Under the regulations being adopted today, and as amended over time, a lessee would be required to pay fair market value—no more, no less—and would be limited to reasonable cost deductions. In either case, "fair market value" and "reasonable costs" remain as enduring standards.

Against this backdrop, DNR can now address individual comments made on the proposed regulations. BP comments that the proposed regulations mean there is no binding contract. BP is incorrect. The contract would require, generally, royalty valuation over time using a method consistent with the Act, and, specifically, the method set out in the original regulations for a term ending with amendment of the original regulations. Both the state and a lessee would be bound by that contract.

ConocoPhillips comments that under the proposed regulations an amendment of the regulations could remove favorable contract terms. While amendment could eliminate a chance to pay less than fair market value or take unreasonably high cost deductions, amendment could not obligate a lessee to pay more than a reasonable approximation of fair market value, nor could it prohibit the deduction of actual and reasonable costs.

BP and ExxonMobil comment that amendment threatens the effectiveness of the regulations as an inducement. While the regulations provide numerous inducements, an opportunity to pay less than fair market value or take unreasonably high cost deductions are not intended inducements.

ExxonMobil comments that under the proposed regulations an amendment creates significant risk and uncertainty. However, any amendment would have to comport with the requirements of the Act. ExxonMobil, if it acquires pipeline capacity in the first binding open season and elects to value royalties under the regulations, will have the certainty of paying no more than a reasonable approximation of fair market value, and of an entitlement to actual and reasonable cost deductions.

BP comments that the proposed regulations governing amendment lack standards to prevent abuse. With the regulations being adopted today, the standards for amendment will be as set out by statute, and will require that any regulation adopted under the Act require royalty valuation based on a reasonable approximation of fair market value and an allowance for actual and reasonable costs.

ExxonMobil comments that amendment is contrary to existing contract terms. Existing lease terms require royalty valuation based on the highest of several measures of value (including fair market value) and allow the deduction of actual and reasonable costs. The regulations being adopted today and any amendments thereto also will require royalty valuation based on fair market value and the deduction of actual and reasonable costs, though the obligation to pay on the highest of multiple measures of value is being, in most cases, eliminated, to a lessee's benefit.

In summary, while DNR is dropping the proposed 11 AAC 25.310, 11 AAC 25.330, and 11 AAC 25.040(e) and (f) from the final regulations being adopted today, the deletion of these sections should not be interpreted as a sign of agreement with or responsiveness to industry comment, but rather DNR's efforts to better comply with the *Manual on Drafting Administrative Regulations* by deleting language that is either explanatory rather than directive or duplicative of requirements already imposed by statute, and thus not appropriate for inclusion in regulations.

XI. <u>PUBLIC WORKSHOPS OR HEARINGS</u>

BP's comments include a request for additional public workshops or hearings on the proposed regulations. ConocoPhillips asks for an open dialog among all the gas resource owners before regulations are adopted. ExxonMobil calls for a more collaborative approach that allows for public and industry involvement.

DNR appreciates industry's request for additional opportunities to shape the regulations. However, the Act requires the adoption of regulations prior to the start of the first binding open season for a project licensed under the Act. TransCanada has announced plans to start the first binding open season for a project licensed under the Act on or about April 30, 2010. To comply with the Act, DNR cannot delay adoption of the regulations to allow for additional input from industry.

DNR appreciates the comments that were submitted during the public comment period and has considered them carefully. These comments allowed DNR to make necessary and appropriate changes to the regulations before adoption, and also to refine, clarify, and better state the regulations so as to minimize the likelihood of ambiguity or dispute.

XII. <u>GENERAL COMMENTS NOT SPECIFIC TO ANY ONE ISSUE</u>

ConocoPhillips comments, generally, that the regulations are too complex and lack clarity. DNR sought to reduce the complexity of the regulations and minimize the possibility for conflicting interpretations by adopting by reference certain FERC practices—which are undoubtedly well-known to industry—and by patterning a number of provisions after MMS regulations—also well-known to industry. DNR also has reworked the language of the regulations between public notice and final adoption to further clarify the meaning of regulations and better conform to the standards set out in the *Manual for Drafting Administrative Regulations*.

ConocoPhillips also comments that that the regulations are not an inducement, though BP's comments include a list of "forward steps," presumably considered an inducement. The inducements included in and intended by the regulations are set out in the Conclusion, below.

XIII. CONCLUSION

DNR has considered and acted on each of the comments received during the public comment period. The regulations being adopted today provide North Slope oil and gas lessees with a number of inducements to participate in the first binding open season for an Alaska natural gas pipeline project licensed under the Act. Generally speaking, the regulations:

1. in most instances, allow lessees to pay royalties on a single measure of value—usually fair market value—rather than the highest of multiple measures of value, such as fair market value, the sales price received by a lessee for its gas, and the sales prices received by other North Slope lessees for their gas;

2. require fair market value to be determined with reference to published prices, where available and reliable, rather than leaving open the possibility of dispute over the appropriate method for determining fair market value;

3. eliminate retroactive changes to a destination value used in calculating fair market value, as long as based on a published price, or location or quality differential to a published price;

4. simplify royalty accounting by patterning a number of provisions on MMS regulations governing royalty valuation for federal leases;

5. simplify accounting for affiliate pipeline cost by making use of FERC rules and TransCanada's offer for negotiated rates as set out in its plan for open season, with limited exceptions;

6. require the state to share in the costs of unused pipeline capacity for the Alaska and Canada mainlines;

7. require the state or its royalty-in-kind purchaser to take and pay for certain pipeline capacity vacated with a switch from royalty-in-value to royalty-in-kind; and

8. extend the period of advance notice required when the state switches between taking its royalty in-value or in-kind.

With these regulations, DNR has made every attempt to both safeguard the public interest and provide an inducement for North Slope oil and gas lessees and other persons to proceed with an Alaska natural gas pipeline project licensed under the Act. Questions about the regulations may be directed to Antony Scott, Commercial Analyst, Division of Oil and Gas, Department of Natural Resources, 550 West Seventh Avenue, Anchorage, Alaska 99501, (907) 269-8530.