FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number:	2
Bill Version:	HB 2004
(H) Publish Date:	5/31/06

Revision Date/Time (Note if correction):

Title	Stranded Gas Development Act Amendments	Dept. Affected:	Natural Resources
		RDU	Resource Development
		Component	Oil and Gas Development
Sponsor	Rules by Request of the Governor		
Requester	Governor	Component No.	439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
CAPITAL EXPENDITURES						
CHANGE IN REVENUES ( )				**Indeterminate		

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Estimate of any current year (FY2006) cost: 0.0

Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: *(Attach a separate page if necessary)*

This bill would modify authorization granted to the Commissioner of Revenue to negotiate a contract under AS 43.82. By itself, such modified authorization has zero fiscal impact. Fiscal effects can occur only if a contract is negotiated under the new authorities that changes the status quo fiscal terms or imparts additional costs on the department. This analysis therefore presumes that the draft contract released on May 10, 2006, and discussed in the Commissioner of Revenue's Fiscal Interest Finding is executed. It further assumes that a gasline is constructed as a result of that contract.

** INDETERMINATE. The Fiscal Interest Finding finds that North Slope gas resources would not be developed but for the terms of the proposed contract. It logically follows that long-term (45 years) net fiscal impacts of the bill's authorization, combined with the proposed contract, are very large and positive – on the order of $12 billion in net present value, according to the Fiscal Interest Finding. The rest of this analysis describes DNR's assessment of costs and benefits associated with various contract provisions that would be authorized by this bill as they affect royalties – costs and benefits that have been largely included already in the Fiscal Interest Finding's assessment of overall net State benefits. (Continued)

Prepared by:	William Van Dyke, Acting Director	Phone	269-8800
Division	Oil and Gas	Date/Time	5/19/2006
Approved by:	Michael Menge, Commissioner	Date	5/19/2006
Agency	Natural Resources		

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ANALYSIS CONTINUATION

Sections 2 and 5 of the bill permit a contract negotiated under AS 43.82 to include contract terms that modify provisions of applicable oil and gas leases, unit agreements and other agreements under AS 38. Under the contract (Article 12), the State will agree to take its royalty gas in-kind (RIK) for 35 years. Taking its royalty gas in-kind, with delivery at the first point of accurate metering, entails revenue losses over the life of the contract for the State compared with taking royalty gas in-value (RIV). These revenue losses presume that the gas resources could be developed within a similar timeframe under the existing 2005 fiscal system and include:

- The lost value that the State might receive under its "higher-of" RIV lease valuation provisions. Such value has been estimated at approximately 2 percent of the destination value of the gas. Assuming a $5.50 real gas price, the loss of this 2 percent has an undiscounted real cost of roughly $540 million, or $270 million discounted at 3 percent, over 35 years.
- Costs of putting royalty gas either from non-DL-1 leases or from DL-1 leases outside of Prudhoe Bay Unit into marketable or pipeline quality condition at the Gas Treatment Plant. The State's position has consistently been that it is not responsible for such costs in an RIV framework. Over 35 years the real undiscounted cost to the State of paying these costs will total approximately $460 million, or $220 million discounted at 3 percent.
- Gas marketing. The State will market its RIK gas – a service provided free under RIV lease terms. The State conservatively estimates that this will cost 5 cents per Mcf. This equates to $310 million (undiscounted, real dollars), or $160 million discounted at 3 percent. DNR would also bear costs in assembling a marketing organization.
- The lost option value associated with the ability to switch between receiving gas RIV and RIK. Based in part on a negotiated (but never executed) RIK gas sale contract that exploited this option value, the State estimates that the ability to switch between RIK and RIV is worth roughly 2 cents/Mcf. This comes to an undiscounted real figure of $110 million, or $60 million discounted at 3 percent.
- Costs of impurity disposal. These costs will be the subject of a future negotiation between the owners of a gas treatment plant and a Unit's working interest owners; they will include all full-cycle, direct, indirect, incremental and consequential costs (see Article 8.5) for disposal of water, carbon dioxide and hydrogen sulfide. The State estimates that each 1 cent/Mcf charge for impurity disposal will reduce undiscounted real royalty value by $11.6 million, or $4 million discounted at 3 percent. Full-cycle disposal methods and costs have not been estimated to date nor has any positive value been assigned to the impurity stream.
- Costs associated with potentially increased pipeline transportation charges on existing North Slope pipelines (e.g. the existing Northstar pipelines, the Oliktok pipeline, the Badami pipeline). Taking gas RIK will require the State to pay Federal Energy Regulatory Commission approved tariffs. FERC tariffs will likely be based on an existing pipeline's replacement value, rather than its book value (see Article 8.6). However, original DL-1 leases issued do not specify a FERC transportation deduction for determining RIV value. If the State were to argue for and prevail on some notion of "actual and reasonable" pipeline costs, then the RIV transportation deduction might reflect the book rather than the replacement value of existing pipelines. The State has not quantified these costs.
- Costs associated with long-term storage. For RIV valuation purposes long-term storage is generally considered to be a marketing cost, and therefore is not a cost the State would reimburse. Under RIK, the State will pay gas storage fees to the extent RIK gas is stored. The State has not quantified the extent of such costs.
- Sections 2 and 5 also authorize the State to agree to pay an Upstream Cost Allowance (UCA) (Article 20) on all royalty gas. At 22.4 cents/Mcf, escalating with inflation, the State will receive approximately $590 million (undiscounted, real dollars) or $50 million (discounted at 3 percent) less than under an RIV regime. The 1980 Royalty Settlement obligates the State to pay a UCA for gas produced from the Prudhoe Bay Unit; gas produced from other units is not obligated to pay a UCA.

Section 2 of the bill authorizes the State to acquire an interest in the project. Article 7.2(a) of the draft contract requires the State to own a 20 percent interest in the Gas Treatment Plant, the Alaska to Canadian border pipeline, and the Canadian border to Alberta pipeline. If the cost for these elements holds at 2001 estimates, indexed to inflation, the State will spend roughly $2.7 billion. The Fiscal Interest Finding finds that, for both royalty in-kind and tax in-kind gas, net earnings from the pipeline are roughly $707 million (undiscounted, real) or $577 million (discounted at 3 percent) (Table 12). Roughly two thirds of this benefit can be ascribed to increased royalty value ($471 million undiscounted and $385 million discounted at 3 percent).

Article 7.2(b) requires the State to take an ownership interest, commensurate with its share of expected throughput, in gas transmission lines from all existing units. These costs are unknown as they remain to be negotiated. Depending upon the ultimate purchase price demanded of the State, the net benefits to royalty value may be either positive or negative.

Article 7.2(c) requires the State to take an ownership interest, commensurate with its share of expected throughput, in a gas transmission line from the National Petroleum Reserve Alaska, to a Gas Treatment Plant or the mainline if that transmission line is sanctioned before commencement of commercial operations. Because the State will likely have minimal or no royalty gas in-kind traveling on such a pipeline, the value for royalty will be largely unaffected.

Finally, Sections 2 and 5 of the bill permit modification of unit and other agreements. Article 23.2 of the contract makes use of this authorization. The fiscal effects of this Article, which prohibits the DNR Commissioner from altering or modifying the rate of development at PTU, or from enforcing the Point Thomson Expansion Agreement, are indeterminate.