

HJR

33

ALASKA STATE LEGISLATURE

REPRESENTATIVE KURT OLSON

- Chair, Labor and Commerce
- Member: Rules, Resources, Military and Veterans Affairs

Session: January - April
State Capitol
Juneau, AK 99801-1182
Phone: 907-465-2693
Fax: 907-465-3835



Interim: May - December
145 Main Street Loop, Ste 221
Kenai, AK 99611
Phone: 907-283-2690
Fax: 907-283-2763

Official Business

Summary of Changes CSHJR 33

Page 1:

Lines 5-6

Delete "on March 22, 2009"

Insert "in September 2008"

Page 2:

Line 19

Following "Mt. Redoubt"

Insert "in a safe and responsible manner"

Pg 1 Line 3 (Title)



26-LS0896AS
Bullock
4/14/09

CS FOR HOUSE JOINT RESOLUTION NO. 33()
IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTY-SIXTH LEGISLATURE - FIRST SESSION

BY

Offered:
Referred:

Sponsor(s): REPRESENTATIVES OLSON, Chenault, Johnson, Gatto, Ramras, Neuman, Thomas, Hawker, Coghill, Muñoz, Wilson, Fairclough, Lynn, Millett

A RESOLUTION

1 **Urging immediate action by the governor, the Alaska Congressional delegation, and**
2 **state and federal agencies to assist in the restart of oil production in Cook Inlet that was**
3 **affected by the eruption of Mt. Redoubt in a safe and responsible manner.**

4 **BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

5 **WHEREAS** a period of increased volcanic activity began at Mt. Redoubt in
6 September 2008; and

7 **WHEREAS** the proximity of Mt. Redoubt to state population centers, airports, and oil
8 production facilities makes the recent volcanic eruptions particularly threatening to Alaskans;
9 and

10 **WHEREAS** the eruption cycle that began on March 22, 2009, resulted in massive
11 snow and glacial melt in the Drift River Valley, leading to the flooding of the Drift River; and

12 **WHEREAS** the Drift River oil storage and transfer facility is located in the floodplain
13 of the river and in the path of flooding caused by lahars; and

14 **WHEREAS**, in an effort to avert a potential oil discharge into Cook Inlet, the Drift
15 River terminal was shut down, and the oil in its storage tanks was drawn down; and

1 **WHEREAS**, because of the complexity of crude oil production in Cook Inlet, the
2 length of time production wells are shut down adversely affects the ability to return to normal
3 production levels; and

4 **WHEREAS** the Drift River terminal, as a crucial waypoint in the delivery of oil
5 produced from Cook Inlet platforms, is integral to the operation of the Trading Bay and
6 Granite Point facilities, the Tesoro refinery in Nikiski, and future oil and gas development and
7 production in the Cook Inlet; and

8 **WHEREAS** the shutdown of the Drift River facility disrupts oil production on Cook
9 Inlet platforms and adversely affects the operation of oil and gas facilities throughout the
10 Cook Inlet basin; and

11 **WHEREAS** the oil services industries on which these platforms and facilities depend
12 have been forced to curtail production and lay off workers as a result of the closure of the
13 Drift River terminal; and

14 **WHEREAS** a prolonged closure of the terminal threatens to cripple the regional
15 economy, with a decline in oil and gas production, potential price increases, and layoffs in the
16 oil and gas sector and the industries that support it;

17 **BE IT RESOLVED** that the Alaska State Legislature urges immediate action by the
18 governor, the Alaska Congressional delegation, and state and federal agencies to assist in the
19 restart of oil production in Cook Inlet that was affected by the eruption of Mt. Redoubt in a
20 safe and responsible manner.

21 **COPIES** of this resolution shall be sent to the Honorable Barack Obama, President of
22 the United States; the Honorable Joseph R. Biden, Jr., Vice-President of the United States and
23 President of the U.S. Senate; the Honorable Ken Salazar, United States Secretary of the
24 Interior; the Honorable Lisa P. Jackson, Administrator of the U.S. Environmental Protection
25 Agency; Admiral Arthur E. Brooks, Commander, Seventeenth Coast Guard District; the
26 Honorable Tom Irwin, Commissioner, Department of Natural Resources; the Honorable Larry
27 Hartig, Commissioner, Department of Environmental Conservation; and the Honorable Lisa
28 Murkowski and the Honorable Mark Begich, U.S. Senators, and the Honorable Don Young,
29 U.S. Representative, members of the Alaska delegation in Congress.

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MEMORANDUM

TO: Representative Craig Johnson, Co-Chair
Representative Mark Neuman, Co-Chair
House Resources Committee

FROM: Rep. Kurt Olson

DATE: April 11, 2009

RE: House Joint Resolution 26-LS0896\R Hearing Request
HJR 33

Pending introduction and referral, I respectfully request a hearing on House Joint Resolution 26-LS0896\R at your earliest possible convenience.

The resolution urges immediate action by the governor, the Alaska Congressional delegation, and state and federal agencies to assist in the restart of oil production in Cook Inlet that was affected by the eruption of Mt. Redoubt.

The shut down of the Drift River oil storage and transfer facility after the eruption of Mt. Redoubt has adversely affected oil and gas production and development in the Cook Inlet basin. The closure threatens to cripple the regional economy with a decline in oil and gas production, potential price increases, and layoffs in the oil and gas sector and the industries that support it.

The economic welfare of the region depends on resumed production in the Cook Inlet, and I urge the appropriate parties to assist in the restart of production in the region.

Please contact my staff, Konrad Jackson, at 465-4954 with any questions regarding this legislation.

Email: Representative Kurt Olson@legis.state.ak.us

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Sponsor Statement

HJR 26-LS0896\R (HJR 33)

Alaska's economy is largely dependent on oil and gas production in the Cook Inlet basin. Much of this production has been stopped, however, due to the recent volcanic activity at Mt. Redoubt. The production stoppage threatens to cripple the state economy with a decline in oil and gas production, potential price increases, and substantial layoffs.

The shutdown of the Drift River oil storage and transfer facility is a substantial blow to production and development in the region. The facility is a crucial waypoint in the delivery of oil produced from Cook Inlet platforms and is integral to the operation of the Trading Bay and Granite Point facilities, the Tesoro refinery in Nikiski, and future oil and gas development and production in the Inlet. Its closure not only affects platforms and facilities in the Cook Inlet basin, but the support industries on which they depend.

Because the economic implications of reduced production in the Cook Inlet have the potential to affect the state economy in such a profound way, I respectfully urge the appropriate parties to assist in the restart of production in the region.

I kindly ask for your favorable consideration of this legislation. If you have any questions or concerns, please do not hesitate to contact me or my staff.

Email: Representative_Kurt_Olson@legis.state.ak.us

FISCAL NOTE

STATE OF ALASKA
2009 LEGISLATIVE SESSION

Fiscal Note Number: _____
 Bill Version: HJR 33
 () Publish Date: _____

Identifier (file name): _____ Dept. Affected: _____
 Title RESTART COOK INLET PRODUCTION RDU _____
 Component _____
 Sponsor OLSON, Chenault, Johnson, Gatto, Ramras, Neuman...
 Requester _____ Component Number _____

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2010	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
OPERATING EXPENDITURES								
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	0.0	0.0

CAPITAL EXPENDITURES								
CHANGE IN REVENUES ()								

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts								
1003 GF Match								
1004 GF								
1005 GF/Program Receipts								
1037 GF/Mental Health								
Other Interagency Receipts								
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2009) cost: _____

POSITIONS

Full-time								
Part-time								
Temporary								

ANALYSIS: (Attach a separate page if necessary)

Prepared by: House Resources Committee
 Division: _____
 Approved by: Representative Mark Neuman, Co-Chair
House Resources Committee

Phone 465-3715
 Date/Time 4/13/09 12:00 AM
 Date 4/13/2009

SB

243

DOUSE COMMITTEE REPORT

(9)

Date Referred to Committee: April 6, 2010

FURTHER REFERRALS: Labor and Commerce
Finance

Date of Committee Action: 9 Apr 2010

The RESOURCES Committee considered:

CS FOR SENATE BILL NO. 243(FIN)

"An Act relating to geothermal resources; relating to the royalty obligation for geothermal resources; transferring from the Department of Natural Resources to the Alaska Oil and Gas Conservation Commission authority over permitting and inspection of geothermal wells; providing for a regulatory cost charge for geothermal wells; and providing for an effective date."

SB 243-GEOTHERMAL RESOURCE:ROYALTY/PERMIT/FEE

Recommends it be replaced with HCS or CS for KSSB 243 (Res)
For Senate Bills with new title: Technical Title New Title: HCR Same Title New Title

- attach amendments
- add new referral to _____ Committee
- Letter of Intent _____ Committee

List of Abbrev for Depts.:
ADM
CED
COR
CRT
EED
DEC
DFG
GOV
DHS
LWF
LAW
LEG
MVA
DNR
DPS
REV
DOT
UA

<u>NEW FISCAL NOTES</u> *Assigned by Chief Clerk's Office				
List by Dept(s):	*FN#	Fiscal	Indet.	Zero

<u>PREVIOUS FISCAL NOTES</u>				
List by Dept(s):	FN#	Fiscal	Indet.	Zero
ADM	4			✓
DNR	3			✓
REV	2			✓

<u>Signing with recommendations</u>	Printed Last Name	DP	DNP	NR	AM
	Edgman	X			
	Olson	X			
	Johnson				
	Neuman				
Chair:	Carey				
Chair:	Neuman				

ALASKA STATE LEGISLATURE

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Chair
Senate Special Committee on Energy
Senate Committee on World Trade,
Technology and Innovations

Co-Chair
Senate Resources Committee

Member
Senate Judiciary Committee

SENATOR LESIL MCGUIRE

Sectional Analysis of Senate Bill 243: 26-LS 1346~~PS~~

Please note that a sectional analysis is not an authoritative interpretation of a bill. The bill itself is the best statement of its contents.

- Section 1** amends AS 31.05.030 clarifying that the Alaska Oil and Gas Conservation Commission (AOGCC) has jurisdiction over the exploration and development of geothermal resources; except for the management of leases and units.
- Section 2** amends the royalty rate for geothermal resources in AS 38.05.181(g) to reflect federal royalty rates; 1.75% of gross income during the first 10 years and 3.5% of gross income thereafter.
- Section 3** adds a new section to AS 41.06 delineating jurisdiction over geothermal resources between the AOGCC and Department of Natural Resources (DNR).
- Section 4** amends AS 41.06.010 to allow the AOGCC to investigate the waste of geothermal resources.
- Section 5** repeals and reenacts AS 41.06.020 to set out the jurisdiction of the AOGCC over all land in the state and to allow for the suspension of the application of chapter 06 on federal land if similarly regulated by Federal government and clarifies the application of the chapter.
- Section 6** amends AS 41.06.030(a) to clarify that a plan of development and operation for a geothermal resource must be filed with the AOGCC.
- Section 7** amends AS 41.06.030(b) to clarify that unitization by DNR of a geothermal resource system under AS 41.06.030 when the geothermal resource system includes state land.
- Section 8** amends AS 41.06.030(c) to conform to the changes made in section 7.
- Section 9** amends AS 41.06.030 by inserting a new subsection (e) that allows the commissioner of DNR to adopt regulations necessary to implement the purposes and intent of chapter 6.

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Section 10 amends AS 41.06 by adding a new section 41.06.035 allowing the AOGCC to issue orders and impose requirements to prevent waste and protect correlative rights on any geothermal operation. This section also allows the AOGCC to adopt regulations regulate the management of a geothermal resource.

Section 11 repeals and reenacts AS 41.06.040(a) governing the authority of the AOGCC to adopt regulations governing the safe development~~management~~ of a geothermal resource.

Section 12 amends AS 41.06.040 (b) by replacing the commissioner of DNR's authority governing the filing of a surety bond with the AOGCC to allow the AOGCC to require a geothermal operator to file a surety bond.

Section 13 amends AS 41.06.040(c) to require notification of the AOGCC rather than the DNR is geothermal exploration encounters hydrocarbons and other fissionable materials.

Section 14 amends AS 41.06.040(d) to replace the commissioner of DNR with the AOGCC for the purposes of authorizing inspection of a geothermal operation.

Section 15 repeals and reenacts AS 41.06.050 governing the AOGCC permitting process for geothermal exploration and development drilling.

Section 16 amends AS 41.06 by adding a new section 41.06.055 authorizing a regulatory cost charge for geothermal wells.

Section 17 repeals and reenacts AS 41.06.060 providing definitions for AS 41.06

Section 18 repeals AS 41.06.030(d) governing lease operations under an approved plan of development and AS 41.06.040(e) the exemption from AOGCC authority of geothermal resources.

Section 19 adds a new section to the uncodified law of the State of Alaska that applies the royalty rates established by section 2 to leases entered into or renewed after the effective date of the act and directs the commissioner of DNR to offer the royalty rates established by section 2 to an existing lessee.

Section 20 adds a new section to the uncodified law of the State of Alaska that governs the transition of authorities over geothermal resources established in this act.

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SENATOR LESIL MCGUIRE

Section 21 adds a new section to the uncodified law of the State of Alaska that gives direction to the revisor of statutes.

Section 22 immediate effective date for section 20

Section 23 effective date of July 1, 2010

Prepared By: Michael Pawlowski, Aide to Senator McGuire

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number: 3
 Bill Version: CSSB 243(FIN)
 (S) Publish Date: 4/2/10

Identifier (file name): CSSB243(FIN)-DNR-DOG-03-31-10 Dept. Affected: Natural Resources
 Title: No Royalty on Geothermal Resources RDU: Resource Development
 Component: Oil and Gas Development
 Sponsor: Sen McGuire
 Requester: SFIN Component Number: 439

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2011	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
OPERATING EXPENDITURES								
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	0.0

CAPITAL EXPENDITURES								
CHANGE IN REVENUES ()								

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts								
1003 GF Match								
1004 GF								
1005 GF/Program Receipts								
1037 GF/Mental Health								
Other Interagency Receipts								
TOTAL		0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2010) cost: _____

POSITIONS

Full-time								
Part-time								
Temporary								

ANALYSIS: (Attach a separate page if necessary)

Under AS 38.05.181(g) SB 243 reduces royalty on gross revenues from 10% under current lease conditions to 1.75% of the gross revenues derived from geothermal leases during the first 10 years of income generating production on state leased lands, with a 3.5% royalty rate thereafter. These royalty rates apply to a geothermal lease or the renewal of a geothermal lease entered into on or after the effective date of the Act.

Given the immature state of the geothermal industry in Alaska, the impact to royalty revenue is indeterminate. Although a reduced royalty rate will lead to less royalty collected for a given geothermal project, this reduced royalty rate may make geothermal projects on state lands more competitive. This bill will also transfer certain drilling inspection functions and other authorities to AOGCC. There will be no budget impact to DNR as a consequence of this transfer. Without SB 243 DNR must either hire or contract drilling engineers and inspectors to meet the potential demand of geothermal leasing.

Sec. 17 (d) defines those waters where the Division of Mining, Land and Water will continue to manage water rights in the state when the water is not a "geothermal resource."

Prepared by: Kevin Banks
 Division: Oil and Gas
 Approved by: Tom Irwin
Natural Resources

Phone 269-8800
 Date/Time 3/31/10 1:00 PM
 Date 3/31/10 5:15pm

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number: 4
 Bill Version: CSSB 243(FIN)
 (S) Publish Date: 4/2/10

Identifier (file name): SB243CS -DOA-AOGCC-03-31-10 Dept. Affected: Admin
 Title: "An Act relating to the royalty obligation for geothermal resources." RDU: AOGCC
 Component: AOGCC
 Sponsor: Senator Lesil McGuire
 Requester: (S) FIN Component Number: 2010

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2011	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
OPERATING EXPENDITURES								
Personal Services	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Travel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Contractual	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Supplies	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Land & Structures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grants & Claims	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES								
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CHANGE IN REVENUES ()								
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FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1003 GF Match	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1004 GF	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1005 GF/Program Receipts	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1037 GF/Mental Health	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Interagency Receipts		0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2010) cost: 0.0

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: (Attach a separate page if necessary)

Additional work for the Alaska Oil and Gas Conservation Commission (AOGCC) resulting from this bill could be managed by existing staff. The agency would need to provide training for Commissioners and staff on geothermal drilling and production practices, but the costs would be absorbed by the agency. Therefore, AOGCC submits a zero fiscal note.

Prepared by: Jody J. Colombie, Special Assistant I
 Division: Alaska Oil and Gas Conservation Commission
 Approved by: Rachael Petro, Deputy Commissioner
Department of Administration

Phone (907) 793-1221
 Date/Time 3/31/10 10:00 AM
 Date 3/31/2010

Geothermal State Leasing

(Taken from www.geothermal.org)

Alaska

Legislative Reference: Alaska Administrative Code 41.06.40 – 41.06.60; Alaska Statutes - Alaska Public Lands Act, Section 38.910, Section 38.05.181 – 38.05.182

Agency Responsible for Leasing: Department of Natural Resources Division of Lands

Leasing: Leasing is by competitive bid in areas designated by the Commissioner of the Department of Natural Resources. On state land that has not been declared a competitive geothermal area or withdrawn from geothermal prospecting, the commissioner may issue a prospecting permit to the first qualified bidder. Upon discovery of geothermal resources in commercial quantities the permit maybe converted to a noncompetitive lease.

Lease Terms:

Primary: 10 years

Renewal: 5 years if engaged in drilling and thereafter for duration of commercial production

Rentals: \$3.00 per acre per year

Royalties: 10 – 15 % of gross revenue derived for products, sale, or use of geothermal resources under the lease. Royalties may be taken in kind if in the best interest of the state.

Arizona

Legislative Reference: Legislative Reference Title 12 Natural Resources Article 22 Geothermal Resource R12-5-2201 to R12-5-2217

Agency Responsible for Leasing: State Land Department

Leasing: Leasing is by competitive bid

Lease Terms:

Primary: 10 years

Renewal: As long as production is maintained

Rentals: \$1.00 per acre per year

Royalties: Not less than 12.5 % of the market value

California

Legislative Reference: California Public Resource Code 6901-6925.2

Agency Responsible for Leasing: State Lands Commission

Leasing: Leasing is by competitive bid in areas selected for lease by the commission. Prospecting permits are available and may be convertible to a lease upon discovery with such terms as specified in 6913.

Lease Terms:

Primary: 10 years

Renewal: Yes, for so long as geothermal resources are being or capable of being produced or utilized in commercial quantities

Rentals: \$1.00 per acre per year escalating, or prospecting permit

Royalties: Not less than 10 % of gross revenue

Not less than 20 % of gross revenue of mineral products

The Commissioner may provide for a royalty of less than 10 % for direct heat applications.

Colorado

Legislative Reference: Colorado Statutes Title 36 Natural Resources 36-1-115
Development of oil, gas, or geothermal resources areas.
36-1-147 Geothermal Leases.

Agency Responsible for Leasing: State Board of Land Commissioners

Leasing: Leases issued by the State Board of Land Commissioners may be awarded as the result of negotiation or competitive bidding. 36-1-113 (2)

Lease Terms:

Primary: Set in lease

Renewal: For as long as production continues

Rentals: Set in lease

Royalties: Set in lease

Hawaii

Legislative Reference: Hawaii Administrative Rules Title 13 Department of Land and Natural Resources Subtitle 7 Water and Land Development Chapter 183 Rules on Leasing and Drilling Geothermal Resources

Agency Responsible for Leasing: Department of Land and Natural Resources

Leasing: Leases on state land shall be granted only on a competitive bid basis. Leasing on reserved land may be granted on a competitive bid basis by public auction or without auction to the occupier or to his assignee upon a vote of two-thirds of the Board members. Exploration permits are also available on any state or reserved land.

Lease Terms:

Primary: 10 years

Renewal: For up to a maximum of 65 years

Rentals: Set by Board

Royalties: Determined by the Board

Royalties on by-products not less than 5 %

Idaho

Legislative Reference: Idaho Statutes Title 47 Mines and Mining Chapter 16 Geothermal Resources 47-1601 to 47-1611 Administrative Code 20.03.15 to 20.03.120

Agency Responsible for Leasing: State Board of Land Commissioners

Leasing: Leasing is by competitive bid in areas designated by the Director of the Department of Lands as being in a Known Geothermal Resource Area (KGRA) or where there is competitive interest, i.e. two or more applications are received on the same day for the same site. Other areas are available on a noncompetitive basis.

Lease Terms:

Primary: 10 years

Renewal: The primary term can be extended if lessee is actively engaged in drilling once geothermal resources are proved or utilized in paying quantities. The lease shall be extended but in no event for more than 40 years. After the end of the primary term, the lessee has preferential right to renewal for a second 40 years.

Rentals: \$1.00 per acre per year – first five years

\$2.00 per acre per year – second five years

\$3.00 per acre per year – thereafter

Royalties: 10 % of the amount of value of geothermal resource, 5 % of the associated byproducts.

Kansas

No leasing regulations for geothermal.

Montana

Legislative Reference: Montana Code Annotated 2001 77-4-101 to 77-4-109, 77-4-121 to 77-4-129; Administrative Rule of Montana 36.25.103 and 104; Subchapter 4 Geothermal Rules and Regulations 36.25.401 to 36.25.413

Agency Responsible for Leasing: Board of Land Commissioners

Leasing: All leasing is by competitive bid. If at the lease sale, no bid is made on the tract for which an application was made, the applicant may negotiate with the Board.

Lease Terms:

Primary: 10 years

Renewal: The lease will continue in effect beyond the primary ten years if the lessee is engaged in drilling for geothermal resources. The lease shall continue in force so long as geothermal resources in paying quantities are produced.

Rentals: \$1.00 per acre per year

Royalty: 10 % of the gross revenue; minimum \$2.00 per acre per year

Nebraska

Legislative Reference: Nebraska State Statutes Section 66-1101 to 66-1106

Nebraska has not developed any provisions for leasing of state lands for geothermal exploration and development. However, for minerals as well and oil and gas, leasing competition is by competitive auction.

Nevada

Legislative Reference: Nevada Revised Statutes 534A.010; 534A.050

No leasing regulations for geothermal development.
For leasing, see Lands, Contract Department.

New Mexico

Legislative Reference: New Mexico Annotated Code Title 19 Chapter 14-1; Title 19 Chapter 2-7; Title 19 Chapter 13-7 to 13-12

Agency Responsible for Leasing: New Mexico State Lands Office

Leasing: Leases are available on a non-competitive basis. However, the Commissioner of Public Lands may at his discretion reject any application and offer the tract or tracts at public auction. Lands classified as "known geothermal fields" are leased through public auction through either sealed or oral bidding procedure.

Lease Terms:

Primary: 5 years

Renewal: Primary term can be renewed for additional 5 years and thereafter so long as geothermal resources are being produced or utilized or are capable of being produced or utilized in commercial quantities.

Rentals: \$1.00 per acre or fraction thereof per year. Escalates to \$5.00 per acre per year after primary lease term.

Royalties: 10 % of the gross revenue from the sale or use of steam, brines or hot water, associated gases or other forms of heat or energy derived from production with a minimum of \$2.00 per acre or fraction thereof per year. A royalty of not less than 2 % nor more than 5 % of the gross revenue received for the sale of mineral products or chemical compounds recovered from geothermal fluids.

A royalty of 8 % of the net revenue for the operation of an energy producing plant on the leased land.

A royalty of not less than 2 % nor more than 10 % of the gross revenue received from the operation of the geothermal resource for recreational, space heating, or health purposes.

North Dakota

Legislative Reference: North Dakota Century Code Chapter 38-19

Agency Responsible for Leasing: The State Industrial Commissioner – Office of the State Geologist

Leasing: Leases are negotiated.

Oklahoma

Legislative Reference: Oklahoma Statutes Title 64 Public Lands

Agency Responsible for Leasing: The Land Office

Leasing: The Commissioners of the Land Office have not adopted specific rules and regulations relating to the leasing of school or other public lands for the purpose of geothermal exploration and development.

Oregon

Legislative Reference: Oregon Revised Statutes (ORS) Chapters 522 and 273, Oregon Administrative Rules 141-075

Agency Responsible for Leasing: The Division of State Lands

Leasing: Leases are available on both competitive and non-competitive bases. Geothermal exploration permits are also available, but allow only for nonexclusive access to land for geothermal exploration.

Lease Terms:

Primary: 10 years

Renewal: 5 years extension if resource discovery has been made or is imminent.

No lease shall exceed 50 years; lessee has right of first refusal in the event the Division decides to continue leasing.

Rentals: Years 1 – 3: \$1.00 per acre

Year 4: \$3.00 per acre

Years 5 – 10: \$5.00 per acre

Renewal geothermal lease: \$5.00 per acre

Royalties: A royalty of at least 10 % upon the production value of the geothermal resources produced under the lease and sold or utilized by the lessee. The production value shall be determined by the gross sale price paid by the plant or other purchaser for value.

Royalties on By-Products: 1 % of the gross sale price of de-mineralized water sold, exchanged or otherwise disposed of.

South Dakota

Legislative Reference: South Dakota Codified Laws Chapter 5-1-2, 5-1-7, 5-7-19 to 25

Agency Responsible for Leasing: Department of Schools and Public Lands

Leasing: Leasing is on a competitive basis by public auction; the commissioner retains the right to reject any or all bids.

Lease Terms:

Primary: 10 years

Renewal: So long as resources are produced from the leased lands

Rental: Not less than \$1.00 per acre per year.

Royalty: Not less than 10 % of the gross value received from the sale of steam brines at the point of delivery to the purchaser.

A 5 % royalty of the gross revenue from sale of mineral products or chemical compounds recovered from geothermal fluid or chemical compounds.

Texas

Legislative Reference: Texas Natural Resources Code (TNRC) – Title 5 Chapter 141 and Chapter 51.192

Agency Responsible for Leasing: Railroad Commission, Commissioner of the General Land Office

Leasing: All leasing is by competitive bid.

Lease Terms:

Primary: Generally 3-5 years

Renewable: As long as actively pursuing development. Thereafter so long as productive.

Rentals: Established at the time of bid or negotiated thereafter.

Royalties: Established at the time of bid or negotiated thereafter.

Utah

Legislative Reference: Utah Code Section 73-22-1 to 73-22-9, and 59-12-02

Agency Responsible for Leasing: Utah School and Institutional Trust Lands Administration

Leasing: In known geothermal areas lands have been withdrawn and are available for sealed bid competitive leasing upon nomination by a potential lessee. Non-withdrawn lands are available from over-the-counter leasing.

Lease Terms:

Primary: 10 years

Renewable: Primary term extendable if spudding or drilling wells. The lease is extendable indefinitely so long as in production.

Rentals: \$1.00 per acre per year escalates to \$4.00 per acre per year after expiration of primary lease term.

Royalties: 10% on production or minimum of \$4.00 per acre per year.

Washington

Legislative Reference: Revised Code of Washington Chapter 79.76, 79.12, 79.13, 79.01, 79.02, Washington Annotated Code 332-22

Agency Responsible for Leasing: Department of Natural Resources, Division of Lands

Leasing: Leasing may be by competitive bid or negotiation.

Lease Terms:

Primary: 10 years

Renewal: Up to 55 years subject to approval every 5 years upon approval of plan of Development.

Rentals: Years 1 to 5, not less than \$1.25 per acre per year or \$250, whichever is greater; years 6 to 10, not less than \$2.00 per acre per year or \$500, whichever is greater.

Royalties: 10 % of the gross proceeds received from the sale of such geothermal resources which are derived, generated or manufactured from the premises sufficient for commercial sales, and 10 % of the fair market value thereof of products utilized but not sold, and 10 % of the gross proceeds for all byproducts derived from the leasehold estate.

Wyoming

Wyoming has never adopted rules and regulations for geothermal leasing. General leasing provisions are found in Wyoming Statutes Title 36 Chapter 5 (36-5-101) Qualification of lessees; lease terms; rental.

ALASKA STATE LEGISLATURE

Session
State Capitol Building, Room 125
Juneau, Alaska 99801-1182
Phone (907) 465-2995
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Chair
Senate Special Committee on Energy
Senate Committee on World Trade,
Technology and Innovations

Co-Chair
Senate Resources Committee

Member
Senate Judiciary Committee

SENATOR LESIL MCGUIRE

Annual Royalty Due Under the SB 243 for the Proposed Mt. Spur Geothermal Project

The following was prepared based on the numbers provided by ORMAT, Inc. to the Senate Resources Committee.

Assumptions:

1. 50 Megawatt Geothermal Project
2. 95% Capacity factor
3. \$130 per Megawatt/Hour

At the 1.75% rate for the first 10 years:

- $50 \text{ MW} \times 8760 \text{ hrs/yr} \times 95\% \text{ CF} \times \$130 \text{ MW/hr} \times 1.75\% = \$946,627.50$ annually

At the 3.5% rate (effective in perpetuity after the first 10 years):

- $50 \text{ MW} \times 8760 \text{ hrs/yr} \times 95\% \text{ CF} \times \$130 \text{ MW/hr} \times 3.5\% = \$1,893,255$ annually

*It is important to note that if the Mt. Spur project is developed by a private entity as proposed, the corporation would also be subject to Alaska's corporate income tax.

Prepared by: Michael Pawlowski, Aide to Senator McGuire

Debra Higgins

From: Foerster, Catherine P (DOA) [cathy.foerster@alaska.gov]
Sent: Tuesday, April 06, 2010 3:43 PM
To: Rep. Craig Johnson
Cc: Seamount, Dan T (DOA); Norman, John K (DOA)
Subject: SB243

Good afternoon Representative Johnson,

SB243 is floating around in the House right now. There is a portion on royalty rates and a portion transferring some authorities from DNR to AOGCC.

The AOGCC has no opinion on the royalty piece, but here are our thoughts on the portion of SB243 relating to transferring authority from DNR to AOGCC:

The bill transfers some, but not all authorities for regulating geothermal operations from the DNR to the AOGCC. The authorities transferred are the authority to regulate drilling and production operations, the authority to protect correlative rights, and the authority to prevent physical waste of the resource. The DNR retains all of its authorities as a landowner.

The authorities being transferred to AOGCC are consistent with regulatory authorities already held by the AOGCC for oil and gas operations.

The AOGCC already has in place the expertise to allow us to take on these authorities. Most importantly, we have experienced drilling engineers who know what to look for when approving a drilling or well work permit to ensure safety and good operational practices. And we have experienced field inspectors who know what safety equipment is needed and how to test that equipment to demonstrate that it operates properly.

Since we already have the appropriate staff in place, there will be no fiscal impact by making this transfer of authority. However, if this bill does not pass, it will likely cost the State money for the DNR to hire or contract the needed expertise I described above.

Also, this change in authority is consistent with the way geothermal operations are regulated in other states. The only states that have an agency other than their oil and gas regulatory agency overseeing geothermal are Idaho and Utah – which are not oil producing states.

One last comment: The AOGCC's costs are paid by the industry we regulate, through a regulatory cost charge. This bill recognizes that fact, and establishes that geothermal producers will participate in that cost charge, similarly to the way that oil and gas producers do. I.e., during exploration there is no charge; only once production commences are charges billed.

If you have any questions, please do not hesitate to send them my way.

Thanks.

ALASKA STATE LEGISLATURE

Senate Resources Committee

**Senator Bill Wielechowski,
Co-Chair Senate Resources**

State Capitol Building, Room 115

Juneau, Alaska 99801-1182

Phone (907) 465-2435

Fax (907) 465-6615

sen.bill.wielechowski@legis.state.ak.us



**Senator Lesil McGuire, Co-Chair
Senate Resources**

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sen.lesil.mcguire@legis.state.ak.us

TO: Representative Johnson, House Resources, Co-Chairman

Representative Neuman

FR: Senator Lesil McGuire

RE: Request to Schedule

Dear Representatives Johnson and Neuman,

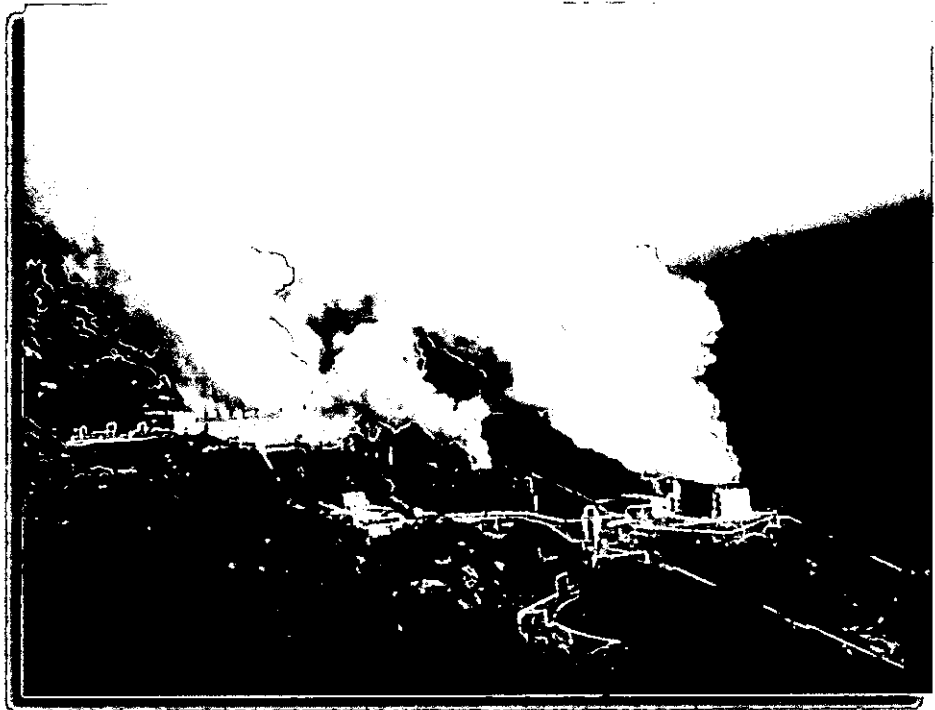
Please schedule Senate Bill 243: *No Royalty on Geothermal Resource* for a hearing in the Senate Finance Committee at your earliest convenience.

Attached you will find:

1. Sponsor Statement
2. The most current version of the bill: CS SB 243 (FIN) [version 26-LS1346\P]
3. Fiscal Notes
 - a. Revenue 4/2/10
 - b. DNR 4/2/10
4. Sectional Analysis for CS SB 243 (FIN)
5. The original version of the bill: 26-LS134\A
6. Backup Documents
 - a. Royalty Sheet for Senate Finance
 - b. Letter of Support from Akutan
 - c. Ormat Presentation to Senate Resources
 - d. Geothermal Royalty Rates
 - e. USGS Geothermal Paper

Assessment of Moderate- and High-Temperature Geothermal Resources of the United States

Scientists with the U.S. Geological Survey (USGS) recently completed an assessment of our Nation's geothermal resources. Geothermal power plants are currently operating in six states: Alaska, California, Hawaii, Idaho, Nevada, and Utah. The assessment indicates that the electric power generation potential from identified geothermal systems is 9,057 Megawatts electric (MWe), distributed over 13 states. The mean estimated power production potential from undiscovered geothermal resources is 30,033 MWe. Additionally, another estimated 517,800 MWe could be generated through implementation of technology for creating geothermal reservoirs in regions characterized by high temperature, but low permeability, rock formations.



Geothermal power plants at The Geysers in northern California. Currently, the United States has an installed and utilized power production capacity of more than 2,500 Megawatts-electric (MWe) from geothermal plants located in Alaska, California, Hawaii, Idaho, Nevada, and Utah. (USGS photograph by Julie Donnelly-Nolan.)

Introduction

The U.S. Geological Survey (USGS) has recently assessed the electric power generation potential of conventional geothermal resources in the United States. These resources are concentrated in the States of Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming, which contain all 241 identified moderate-temperature (90 to 150°C; 194 to 302°F) and high-temperature (greater than 150°C) geothermal systems located on private or accessible public lands.

(Geothermal systems located on closed public lands, such as national parks, were not included in the assessment.) Electric-power potential was also determined for seven low-temperature (less than 90°C) systems in Alaska for which local conditions make electric power generation feasible. In addition, the assessment also includes a provisional estimate of the power generation potential from the application of unconventional, Enhanced Geothermal Systems (EGS) technology in Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. This assessment benefited from cooperation and coordination with the Department of Energy (DOE); Bureau of Land Management (BLM); the University of Nevada, Reno; the University of Utah; Idaho National Laboratory; Lawrence Berkeley

National Laboratory; state and local agencies; and the geothermal industry.

Identified Geothermal Systems

Currently, the United States has an installed and utilized power production capacity of more than 2,500 Megawatts-electric (MWe) from geothermal plants located in Alaska, California, Hawaii, Idaho, Nevada, and Utah. The nearly 15,000 Gigawatt-hours (GWh) of geothermal power generated in 2005 constituted 25% of domestic nonhydroelectric renewable electrical power generation. (Power generation of 1 MWe provides 8.77 GWh of electricity in 1 year.) The results of the new assessment for the power generation potential from identified geothermal systems yield a mean total of 9,057 MWe

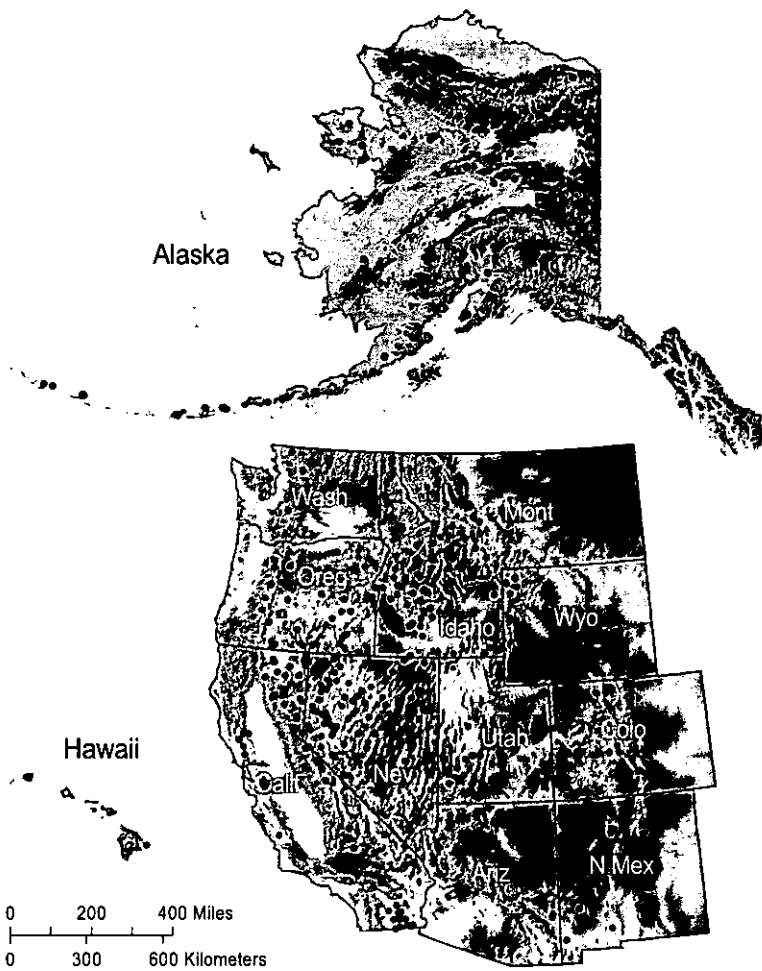


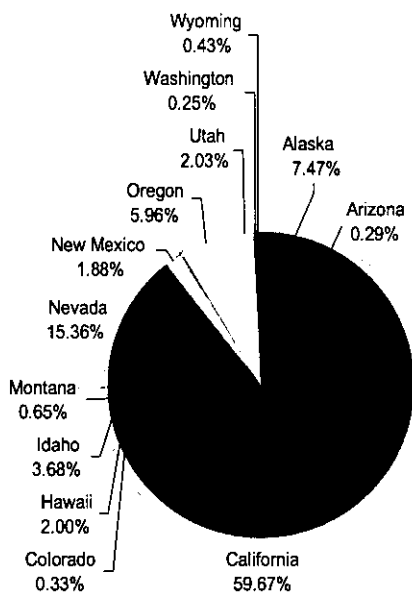
Figure 1. Map showing the location of identified moderate-temperature and high-temperature geothermal systems in the United States. Each system is represented by a black dot.

with a 95% probability of 3,675 MWe and a 5% probability of 16,457 MWe (table 1). The distribution of the individual systems across the study area is shown in figure 1. State totals were derived from summations of volumetric models for the thermal energy and electric generation potential of each individual geothermal system (Muffler, 1979; Williams and others, 2008). The results of the assessment indicate that full development of identified systems alone could expand geothermal power production by approximately 6,500 MWe and to seven additional states. The distribution of identified geothermal resources among the 13 states with identified geothermal resources is shown graphically in figure 2A. California, with large producing geothermal fields at The Geysers, the Salton Sea, and Coso, has 59.7% of the total resource, followed by Nevada with 15.4% and Alaska with 7.5%.

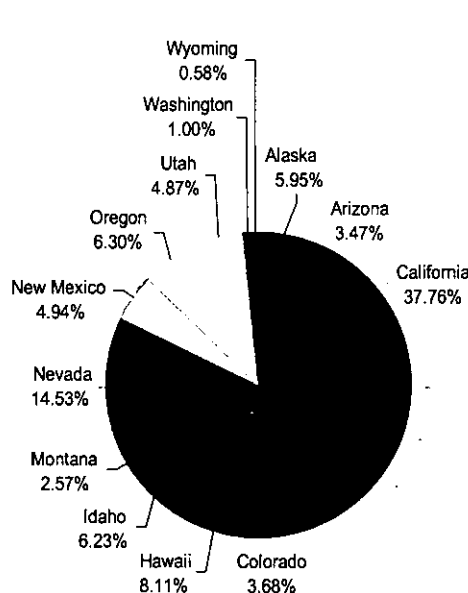
Undiscovered Geothermal Resources

Undiscovered geothermal resources were assessed for the same states in which the identified moderate- and high-temperature geothermal systems are located, based on a series of Geographic Information Systems (GIS) statistical models for the spatial correlation of

A. Identified Geothermal Resources



B. Undiscovered Resources



C. Enhanced Geothermal Systems

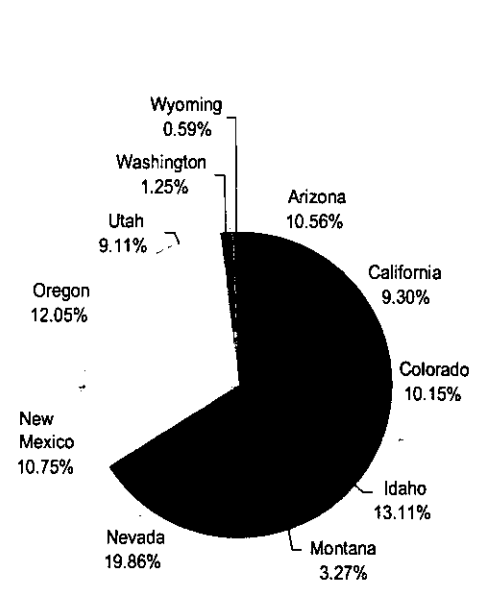


Figure 2. Pie charts illustrating the distribution of (A) identified, (B) undiscovered and (C) Enhanced Geothermal Systems (EGS) resources (mean estimates) among the western states. Alaska and Hawaii were not included in the assessment of EGS resources because of a lack of information in those states.

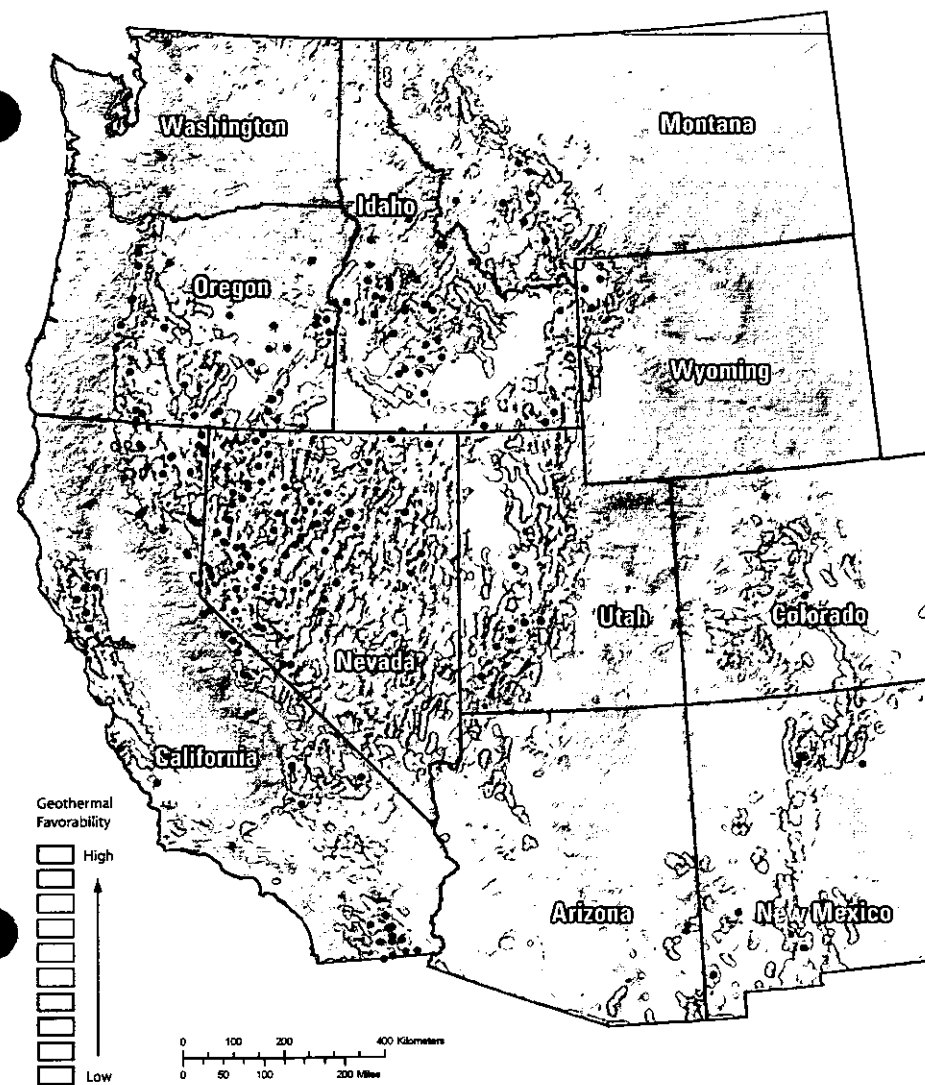


Figure 3. Example map from one of a series of 28 spatial models showing the relative favorability of occurrence for geothermal resources in the western contiguous United States. The other models differ in details but show generally similar favorability patterns. Warmer colors equate with higher favorability. Identified geothermal systems are represented by black dots.

geological factors that facilitate the formation of geothermal systems. The mean estimated power production potential from undiscovered resources located on private and accessible public lands is 30,033 MWe, with a 95% probability of 7,917 MWe and a 5% probability of 73,286 MWe. As illustrated in figure 2B, compared to the identified resources, a larger fraction of the undiscovered geothermal resources are located outside California. This reflects both the limited degree of exploration and development in States other than California and Nevada and the uniqueness of the vapor-dominated geothermal reservoir at The Geysers in northern California, which contributes

approximately 1,000 MWe to the identified geothermal resource for the State but is unlikely to be matched by any equivalent occurrences on private or accessible public lands elsewhere in the United States. The undiscovered resources results indicate that additional exploration could add substantially to the total of identified geothermal resources and further expand geothermal power production. As indicated by the geothermal favorability map shown in figure 3, regions with significant geothermal potential but few identified geothermal systems include northeastern Nevada, western Utah, southern Idaho, eastern Oregon, and parts of New Mexico and Colorado.

Enhanced Geothermal Systems

Conventional geothermal resources depend on hydrothermal fluid circulation that arises only with the convergence of high temperatures—due either to magmatism or other tectonic processes that elevate temperature gradients in the Earth's crust—and permeability, typically fracture permeability produced as a result of active faulting (Duffield and Sass, 2003). Enhanced Geothermal Systems (EGS) are geothermal resources that require some form of engineering to develop the permeability necessary for the circulation of hot water or steam and the recovery of heat for electrical power generation. Because exploitation of EGS resources incorporates the augmentation or creation of permeability in place, the presence of elevated temperatures at drillable depths is the dominant factor controlling the quality of the resource.

Under the assumption of continued successful implementation of EGS technology, models for the extension of geothermal energy recovery techniques into regions of hot but low permeability crust yield an estimated mean electric power resource on private and accessible public land of 517,800 MWe (table 1), with a 95% probability of 345,100 MWe and a 5% probability of 727,900 MWe. This is approximately half of the current installed electric power generating capacity in the United States and an order of magnitude larger than the conventional geothermal resource. This estimate does not include Alaska and Hawaii, because there is not enough information to accurately estimate crustal temperatures in those States on a regional basis. With EGS technology at an early stage of development (DOE, 2008), the assessment results should be considered provisional.

The high crustal heat flow favorable for EGS development is more uniformly distributed across the western United States, and this is reflected in the distribution of the resource among the states, as shown in figure 2C. The EGS resource distribution, although large in total magnitude, is also relatively diffuse. In contrast to power production from conventional geothermal reservoirs, which is often concentrated at 10 to 20 MWe per km² of field area, the EGS resource outside of the high-temperature margins of

Table 1. Electric power generation potential in Megawatts-electric (MWe) from identified and undiscovered geothermal resources and Enhanced Geothermal Systems in the western United States.

[All electric power generation figures are calculated on a basis of 30 years of production. F95 represents a 95% chance of at least the amount tabulated; other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. N is the number of identified geothermal systems included in the estimate].

State	N	Identified Resources (MWe)				Undiscovered Resources (MWe)				Enhanced Geothermal Systems (MWe)			
		F95	F50	Mean	F5	F95	F50	Mean	F5	F95	F50	Mean	F5
Alaska	53	236	606	677	1,359	537	1,428	1,788	4,256	NA	NA	NA	NA
Arizona	2	4	20	26	70	238	775	1,043	2,751	33,000	52,900	54,700	82,200
California	45	2,422	5,140	5,404	9,282	3,256	9,532	11,340	25,439	32,300	47,100	48,100	67,600
Colorado	4	8	11	30	67	252	821	1,105	2,913	34,100	51,300	52,600	75,300
Hawaii	1	84	169	181	320	822	2,027	2,435	5,438	NA	NA	NA	NA
Idaho	36	81	283	333	760	427	1,391	1,872	4,937	47,500	66,700	67,900	92,300
Montana	7	15	51	59	130	176	573	771	2,033	9,000	16,100	16,900	27,500
Nevada	56	515	1,216	1,391	2,551	996	3,243	4,364	11,507	71,800	101,300	102,800	139,500
New Mexico	7	53	153	170	343	339	1,103	1,484	3,913	35,600	54,400	55,700	80,100
Oregon	29	163	485	540	1,107	432	1,406	1,893	4,991	43,600	61,500	62,400	84,500
Utah	6	82	171	184	321	334	1,088	1,464	3,860	32,600	46,500	47,200	64,300
Washington	1	7	20	23	47	68	223	300	790	3,900	6,300	6,500	9,800
Wyoming	1	5	31	39	100	40	129	174	458	1,700	2,900	3,000	4,800
Total	248	3,675	8,356	9,057	16,457	7,917	23,739	30,033	73,286	345,100	507,000	517,800	727,900

identified geothermal systems averages approximately 0.5 MWe per km². However, continued advances in EGS technology, particularly with respect to creation of reservoirs at great depth and improved thermal energy recovery, could add substantially to the resource estimates (DOE, 2008).

EGS are not the only type of unconventional geothermal resource. Previous assessments (see for example, Muffler, 1979) indicated significant unconventional geothermal resource potential associated with fluids in deep sedimentary basins of the United States. These unconventional geothermal resources will be assessed in a future study.

Geothermal resources have the potential to play a much more significant role in our Nation's energy mix. This assessment of geothermal resources in the United States is only part of the

USGS effort to help ensure our Nation's energy future.

References

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Duffield, W.A., and Sass, J.H., 2003, Geothermal energy—clean power from the Earth's Heat: U.S. Geological Survey Circular 1249, 36 p. [<http://pubs.usgs.gov/circ/2004/c1249/>]

Muffler, L.P.J., 1979, Assessment of geothermal resources of the United States—1978, U.S. Geological Survey Circular 790, 163 p.

Williams, C.F., Reed, M.J., and Mariner, R.H., 2008, A review of methods applied by the U.S. Geological Survey in the assessment of identified geothermal resources: U.S. Geological Survey Open-File Report 2008-1296 [<http://pubs.usgs.gov/of/2008/1296/>]

USGS Geothermal Resources Assessment Team—Colin F. Williams, Marshall J. Reed, Robert H. Mariner, Jacob DeAngelo, S. Peter Galanis, Jr.

Edited by James W. Hendley II
Graphic design by Jeanne DiLeo

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Menlo Park, CA 94025

This Fact Sheet and any updates to it are available online at <http://pubs.usgs.gov/fs/2008/3082/>

Impact of SB243 on Geothermal Development in Alaska

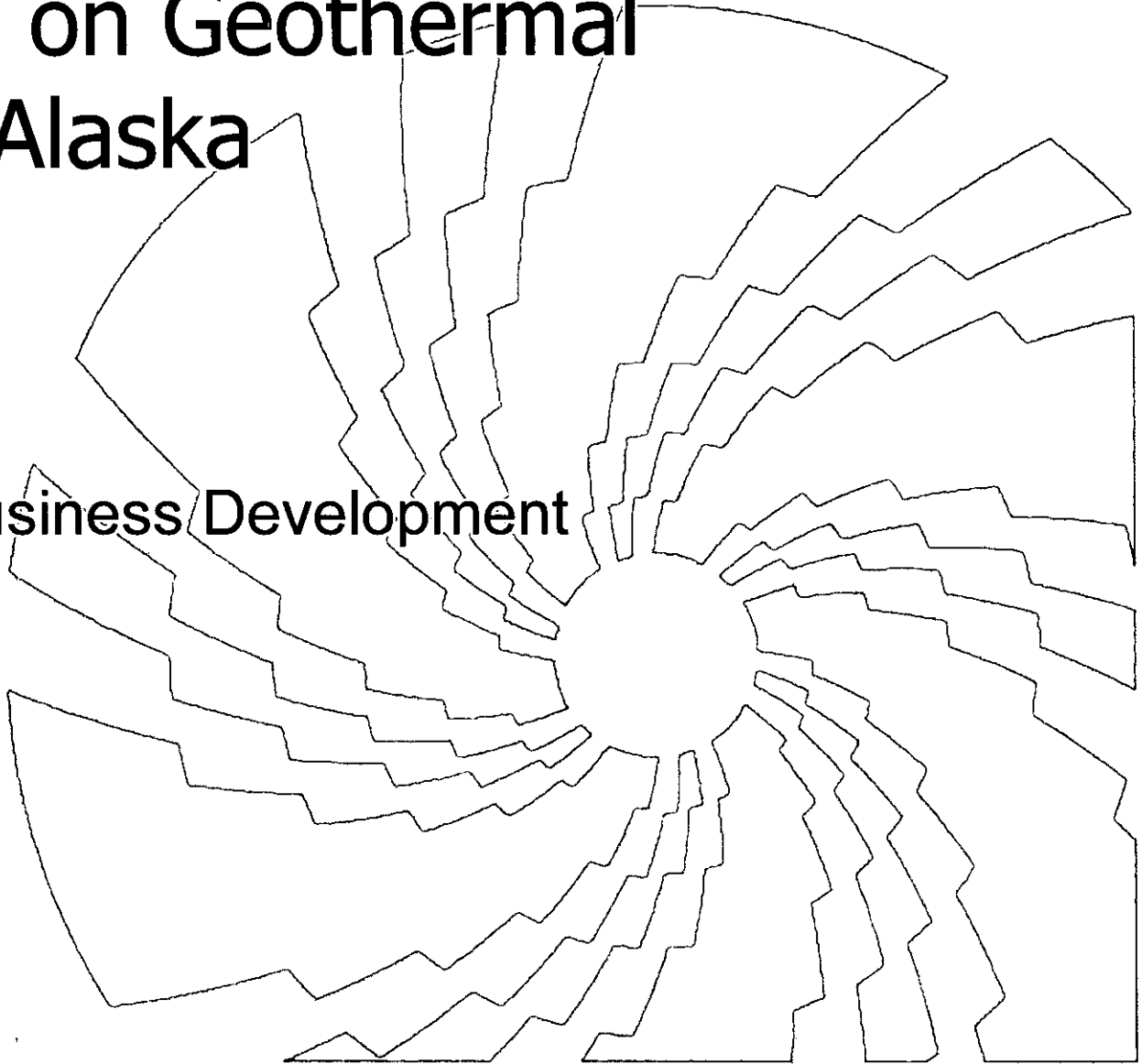
Paul Thomsen

Director of Policy and Business Development

Ormat Technologies, Inc

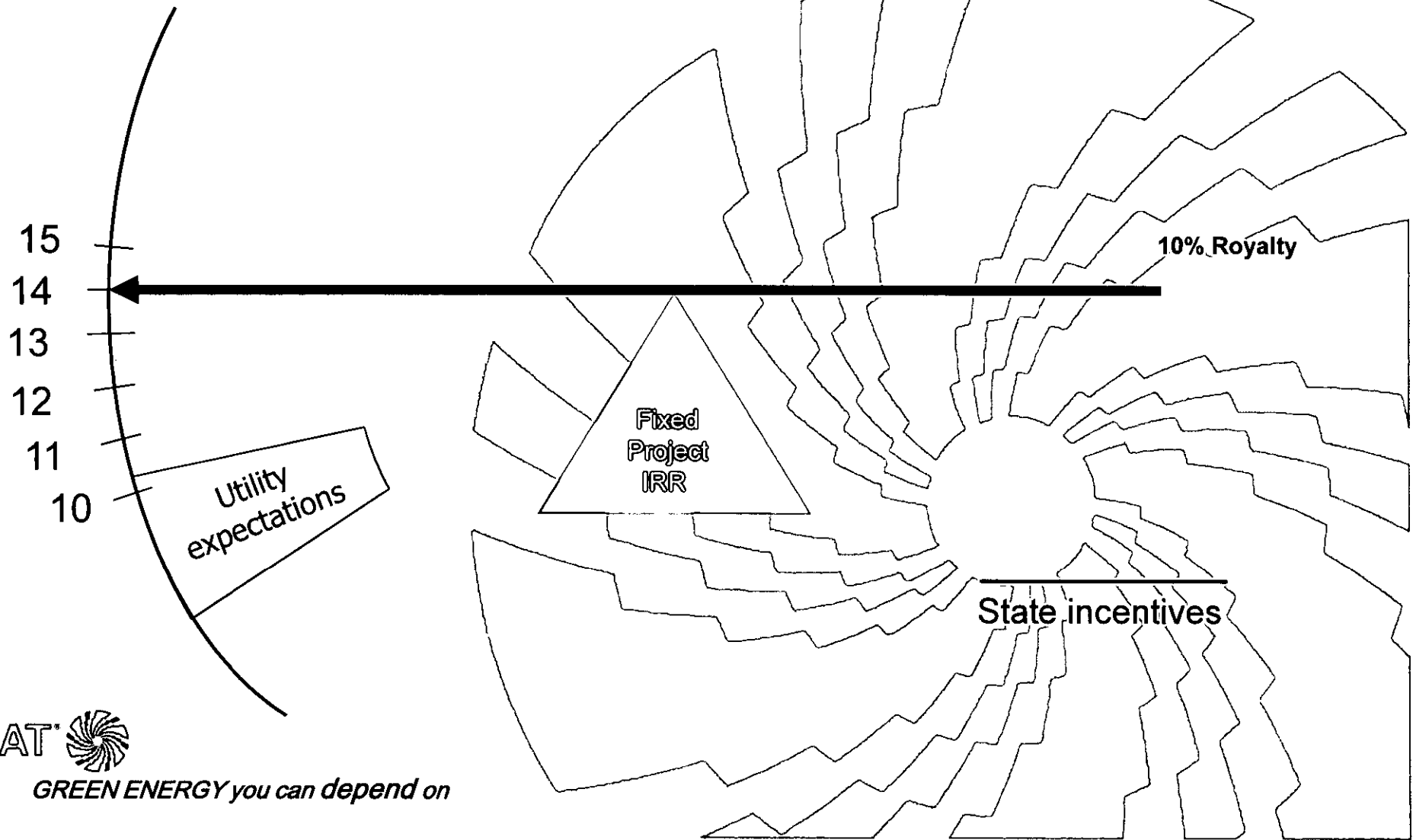


GREEN ENERGY you can depend on



Estimated Power Price, Current Conditions

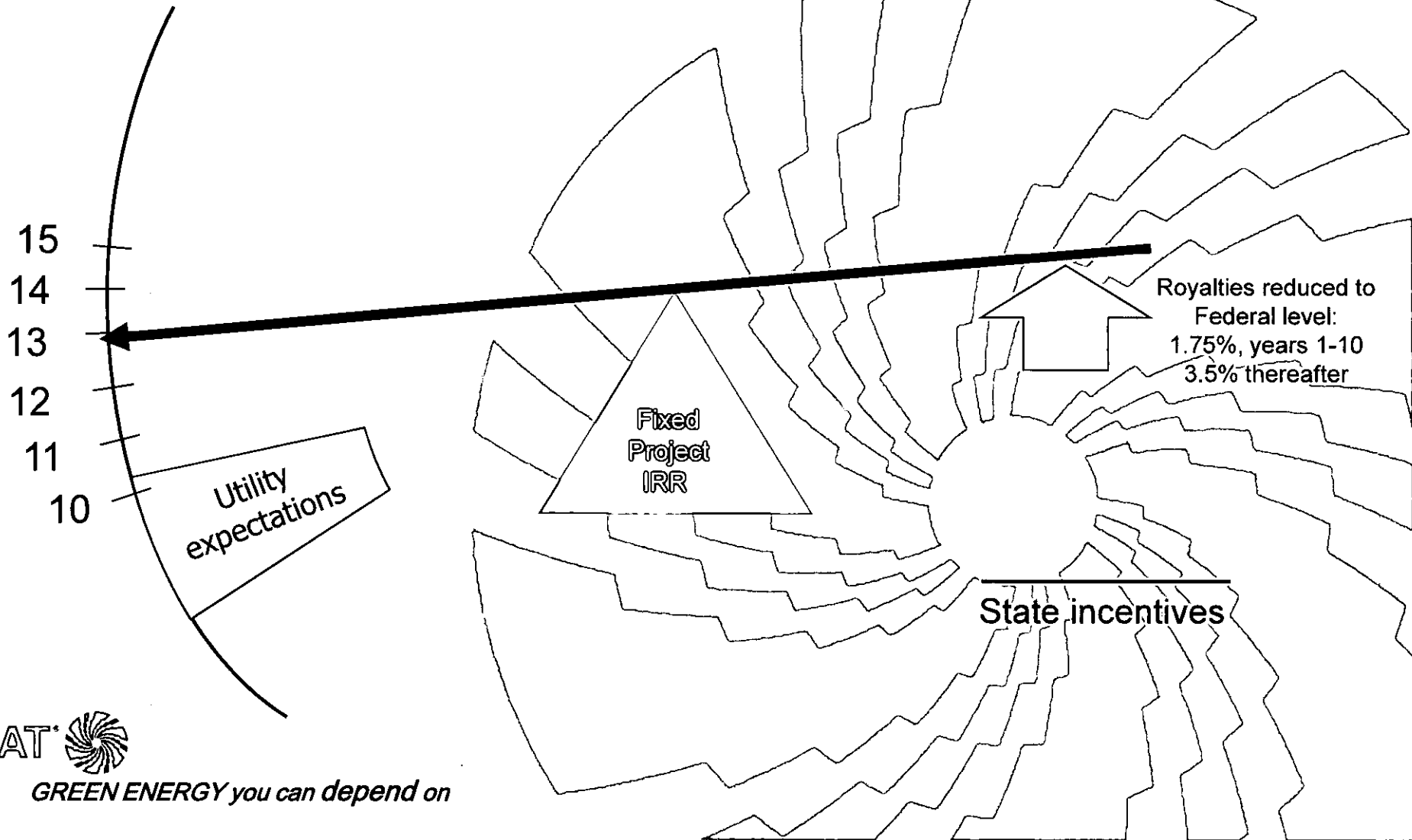
Power price to Railbelt utilities [c/kWh]



GREEN ENERGY you can depend on

Impact of SB243 on Mt Spurr Power Price

Estimated power price to Railbelt utilities [c/kWh]

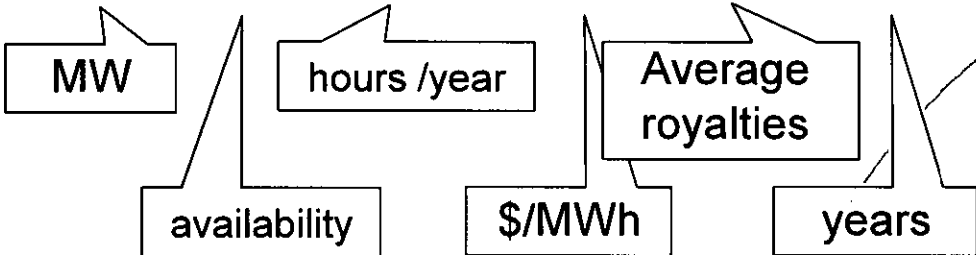


Economic Benefits to the State of Alaska

- Estimated royalty payment in 25 years¹:

$$50 * 0.95 * 8760 * 130 * 2.8\% * 25 =$$

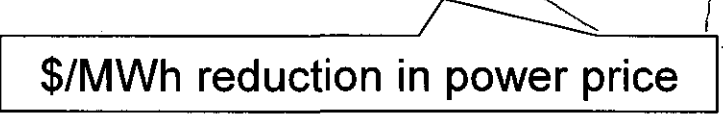
\$38 million



- Saving to railbelt ratepayers¹:

$$50 * 0.95 * 8760 * 10 * 25 =$$

\$104 million



- Total economic benefit:

>\$140 million

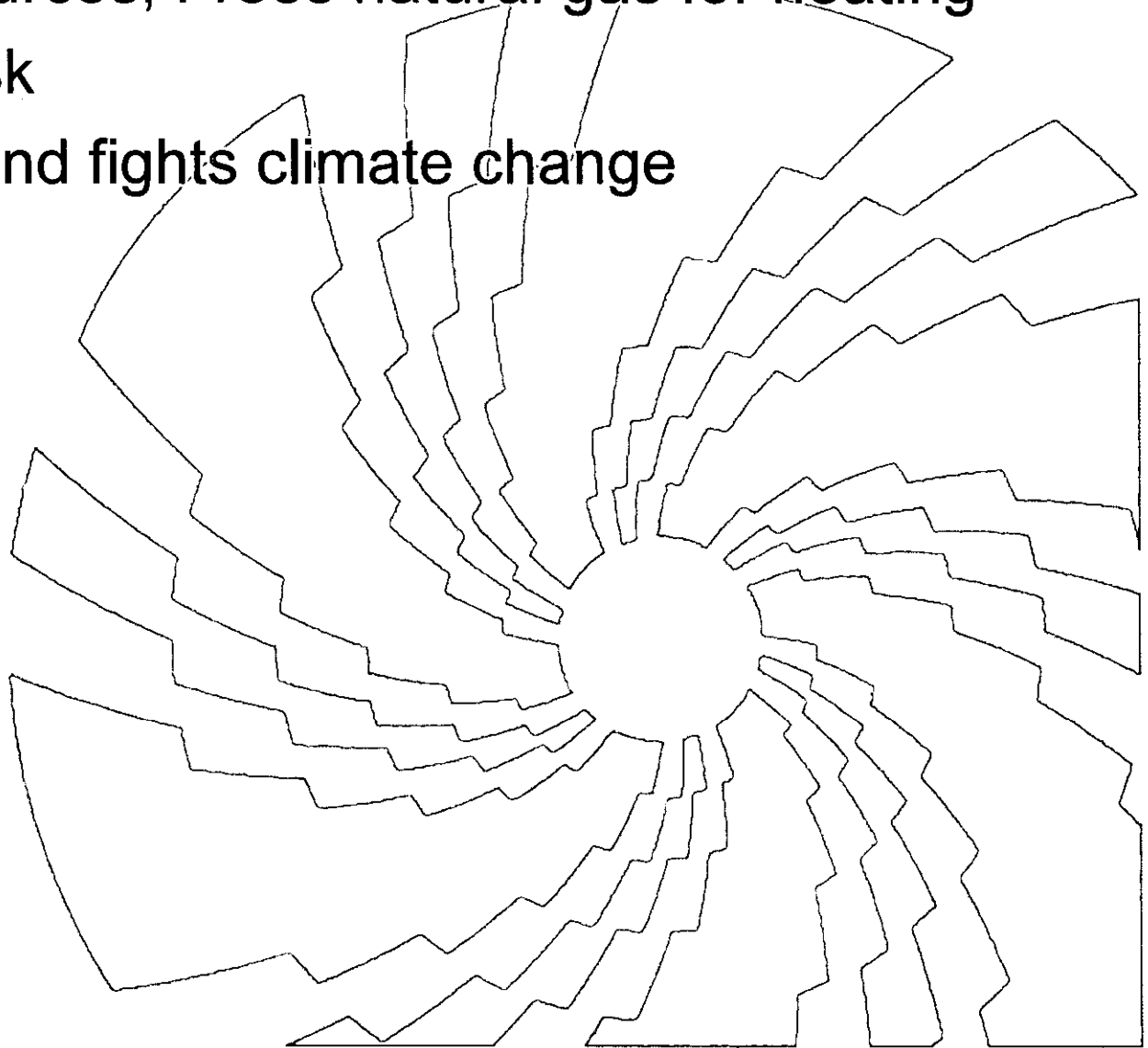
¹ This is a simplified calculation, not accounting for inflation and other factors that will affect actual payment / saving



GREEN ENERGY you can depend on

Other Benefits to the State of Alaska

- Diversifies energy sources; Frees natural gas for heating
- Removes fuel cost risk
- Reduces emissions and fights climate change
- Creates green jobs



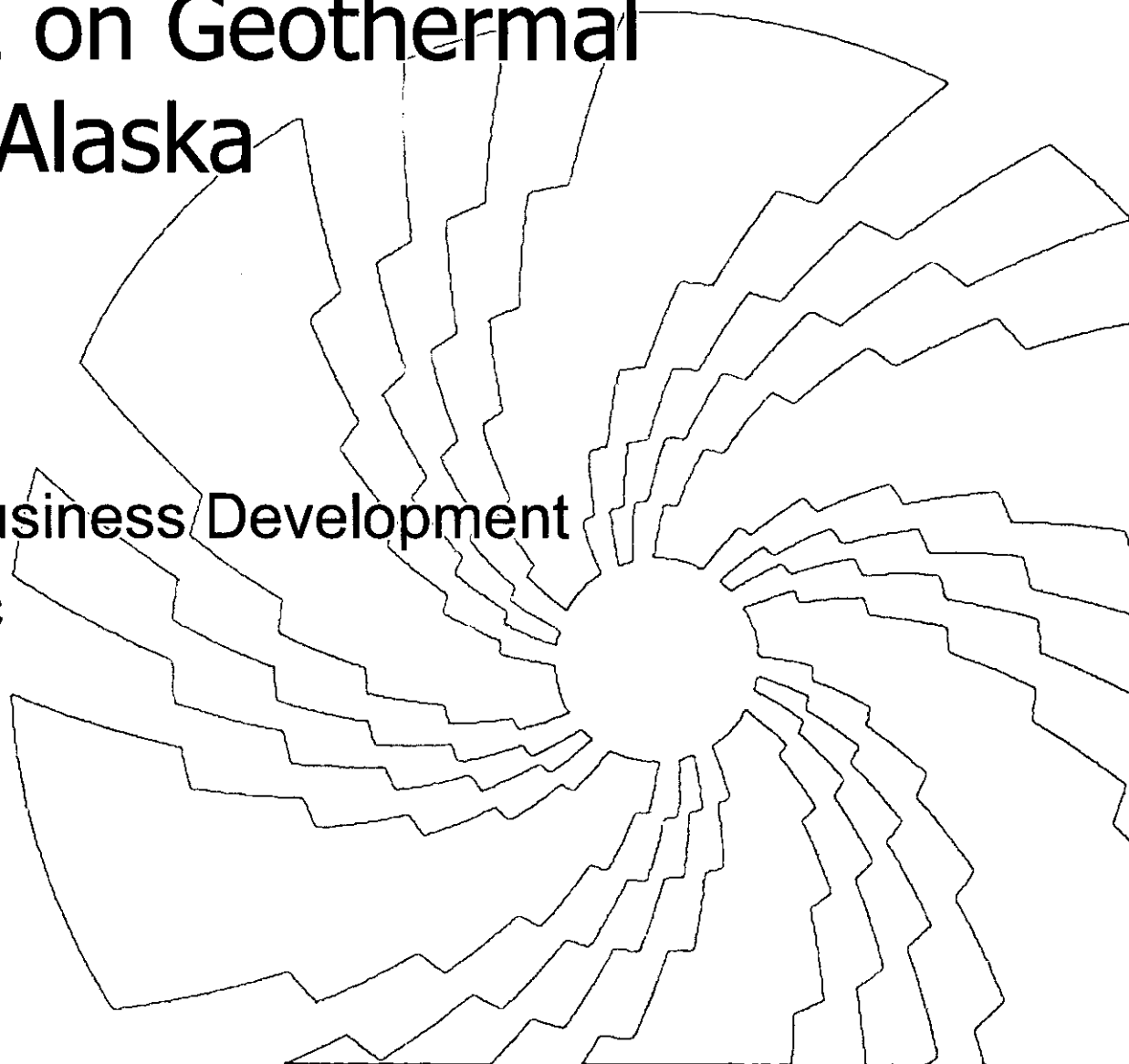
GREEN ENERGY you can depend on

Impact of SB242 on Geothermal Development in Alaska

Paul Thomsen

Director of Policy and Business Development

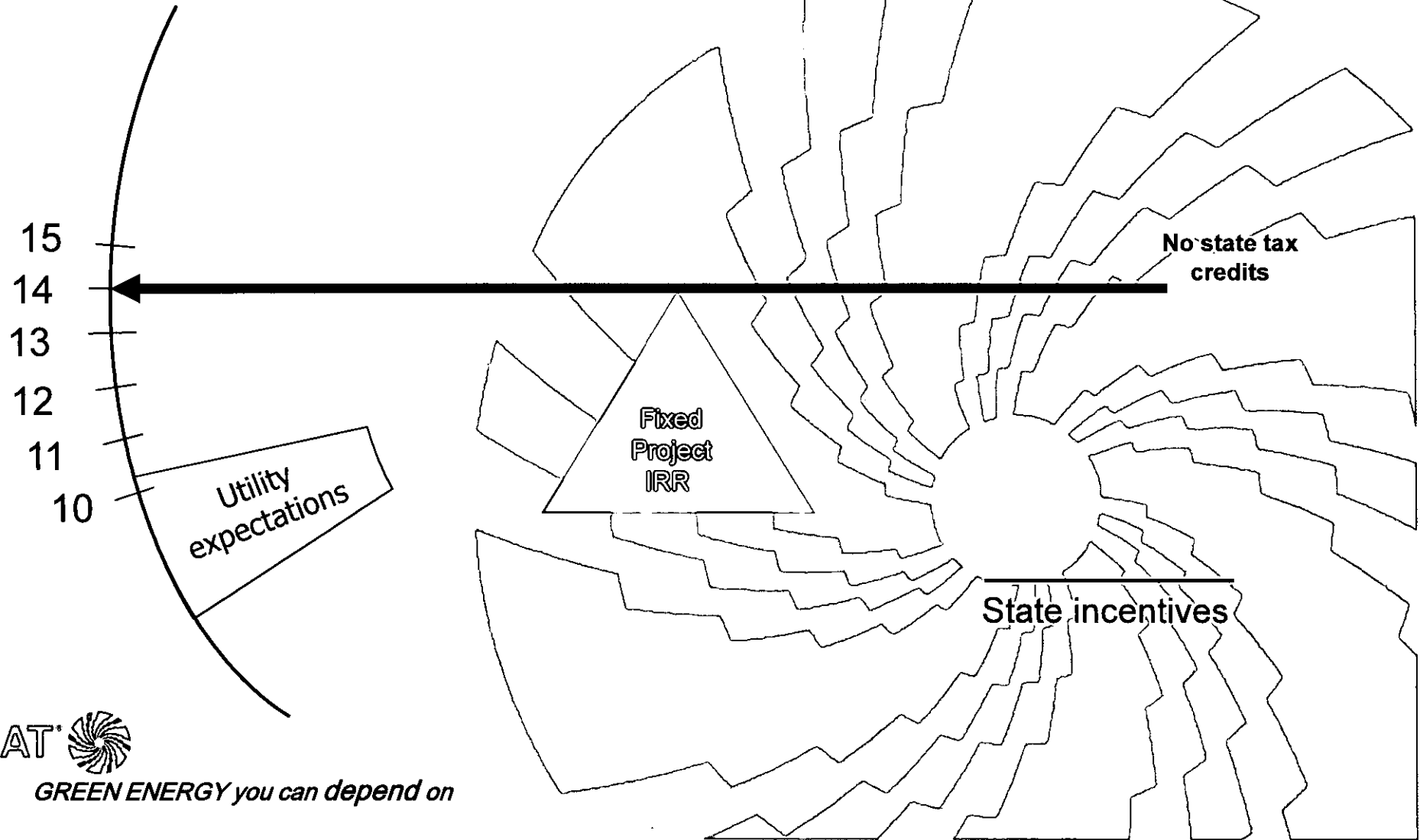
Ormat Technologies, Inc



GREEN ENERGY you can depend on

Estimated Power Price, Current Conditions

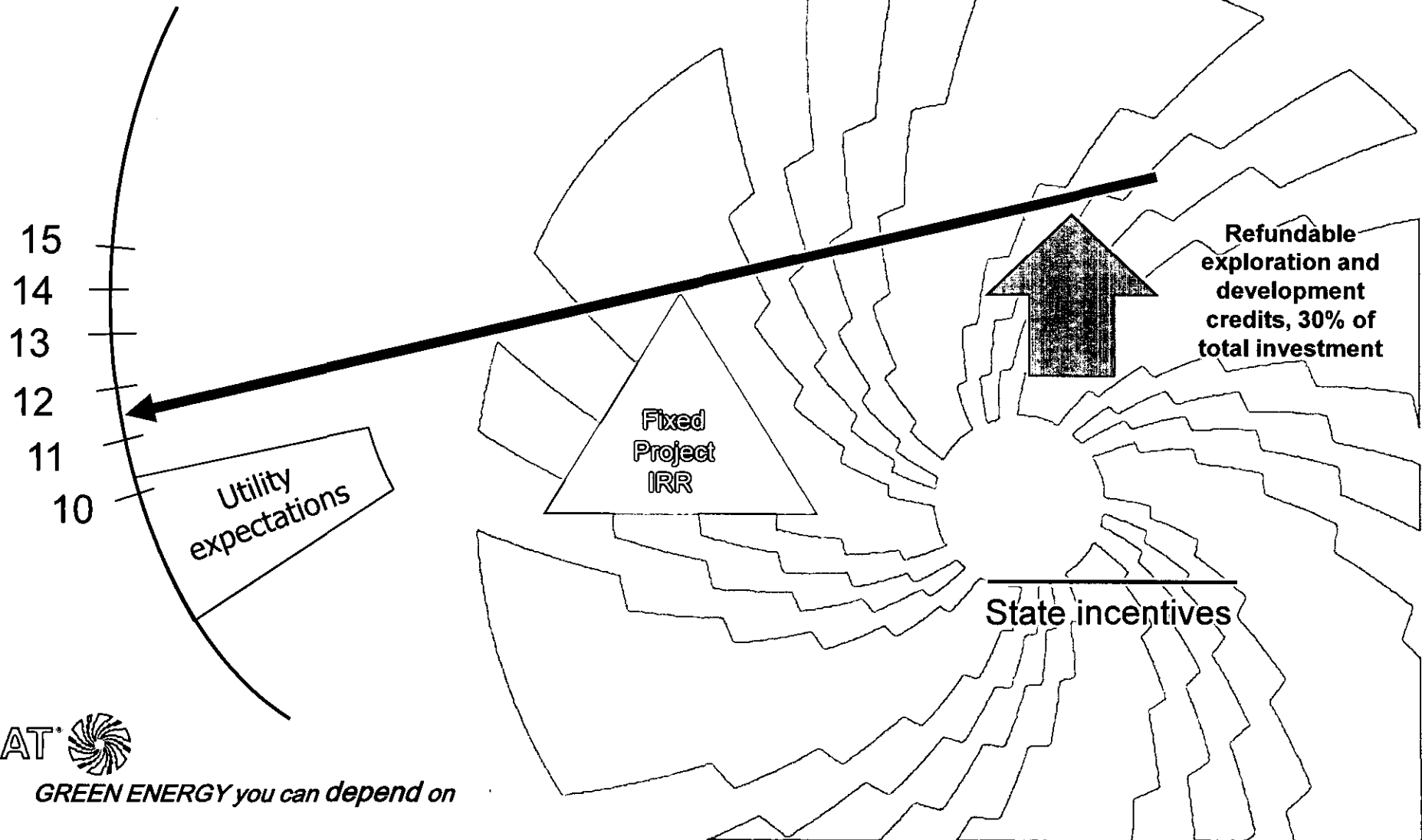
Estimated power price to
Railbelt utilities [c/kWh]



GREEN ENERGY you can depend on

Impact of SB243 on Mt Spurr Power Price

Estimated power price to Railbelt utilities [c/kWh]



GREEN ENERGY you can depend on

Cost and Economic Benefits to the State of AK

- Estimated cost of tax credits:

$$30\% * 275 =$$

Estimated cost of exploration
and development [\$m]

(\$82.5 million)

- Estimated saving to railbelt ratepayers¹:

$$50 * 0.95 * 8760 * 25 * 25 =$$

MW

hours /year

years

availability

\$/MWh saving

\$260 million

- Total economic benefit:

>\$175 million

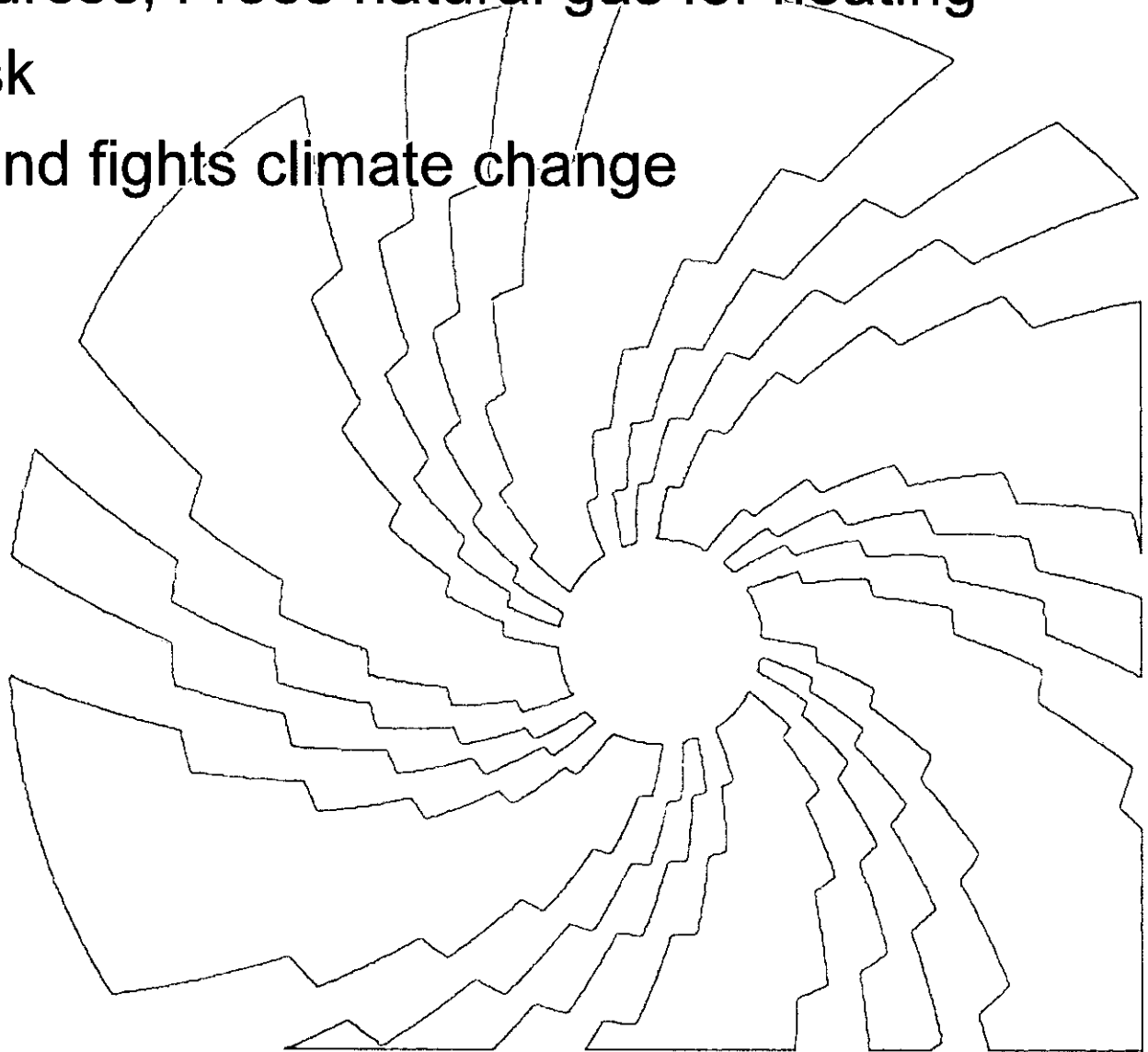
¹ This is a simplified calculation, not accounting for inflation and other factors that will affect actual saving



GREEN ENERGY you can depend on

Other Benefits to the State of Alaska

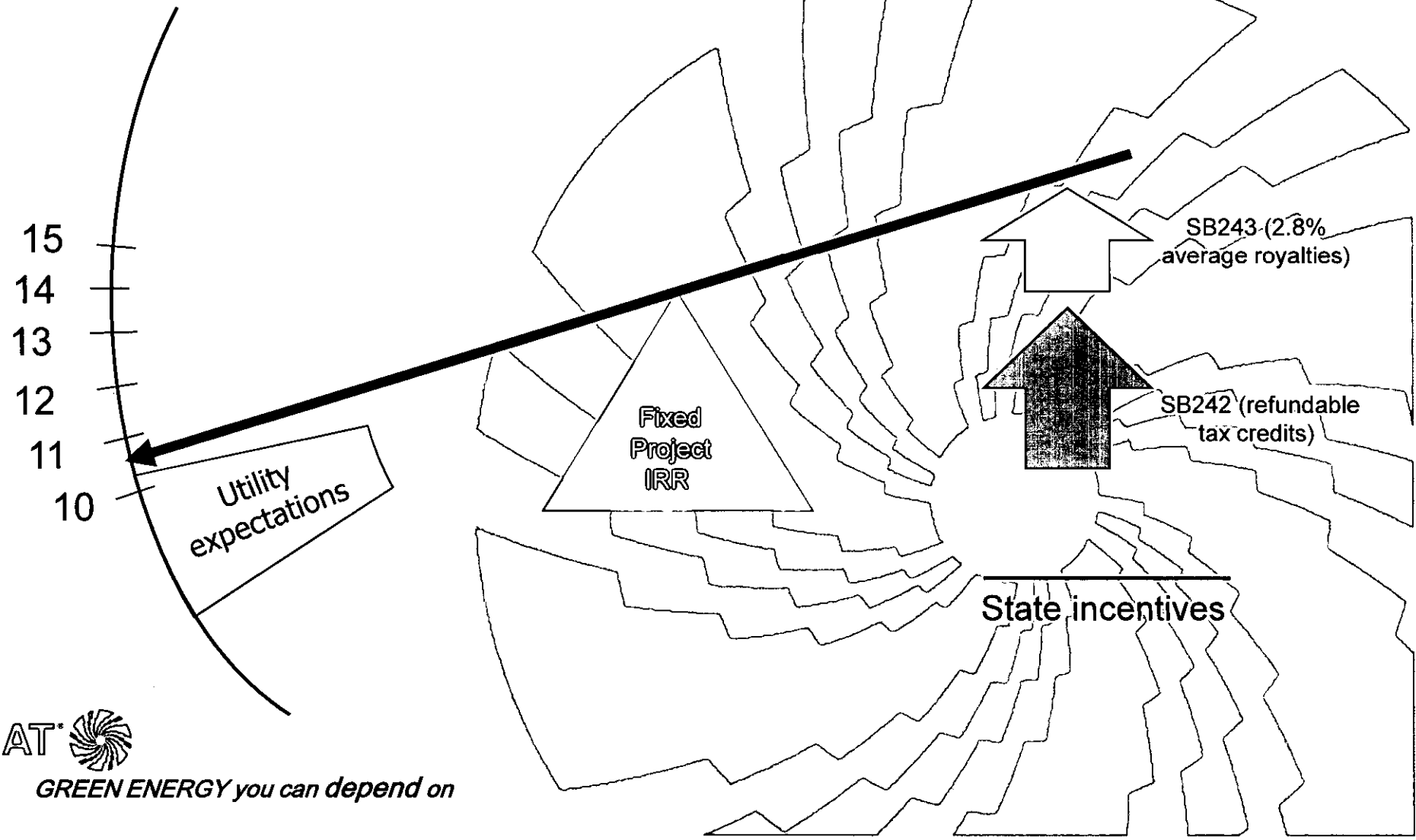
- Diversifies energy sources; Frees natural gas for heating
- Removes fuel cost risk
- Reduces emissions and fights climate change
- Creates green jobs



GREEN ENERGY you can depend on

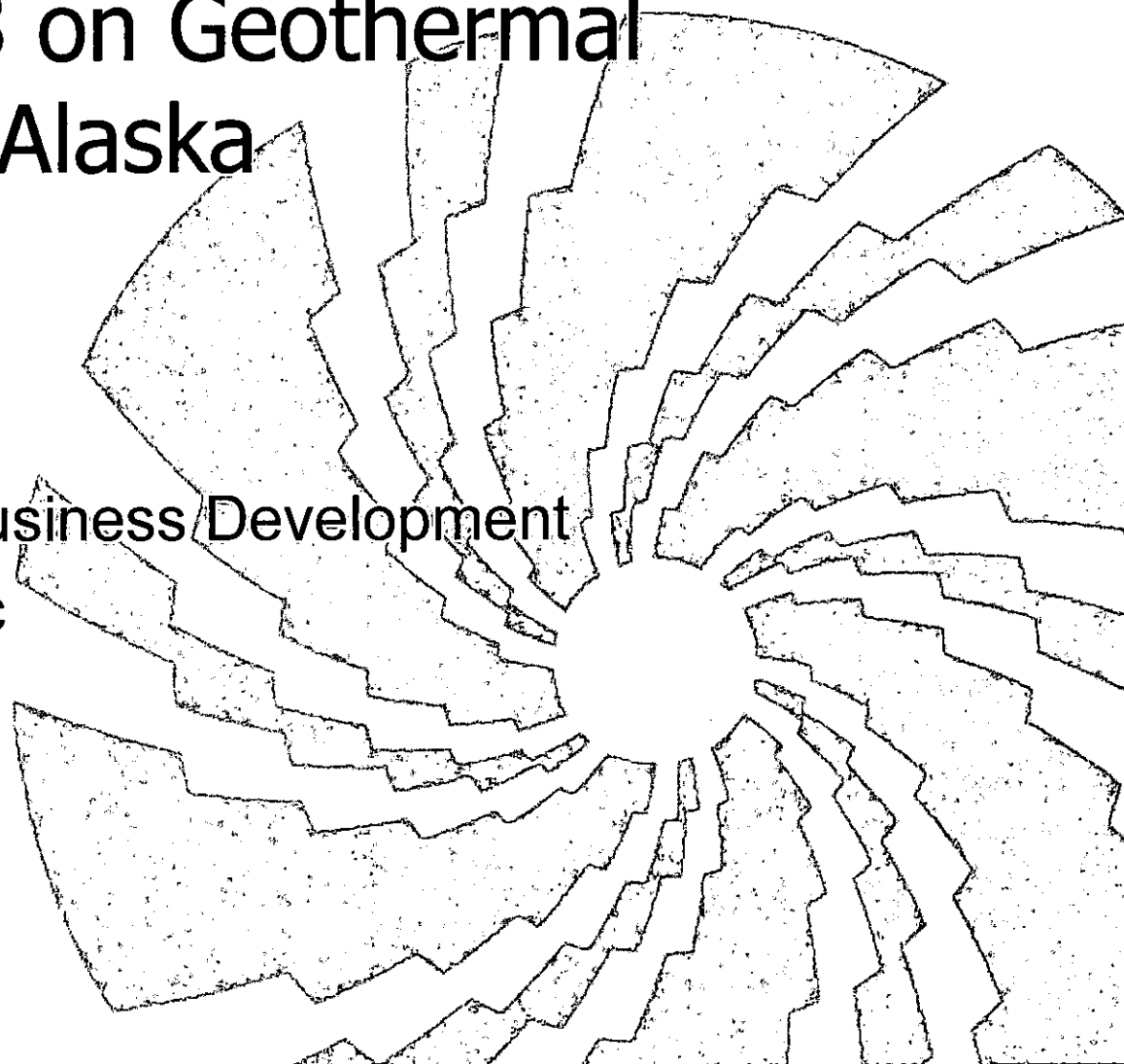
Impact of SB242 + SB243 on Power Price

Estimated power price to Railbelt utilities [c/kWh]



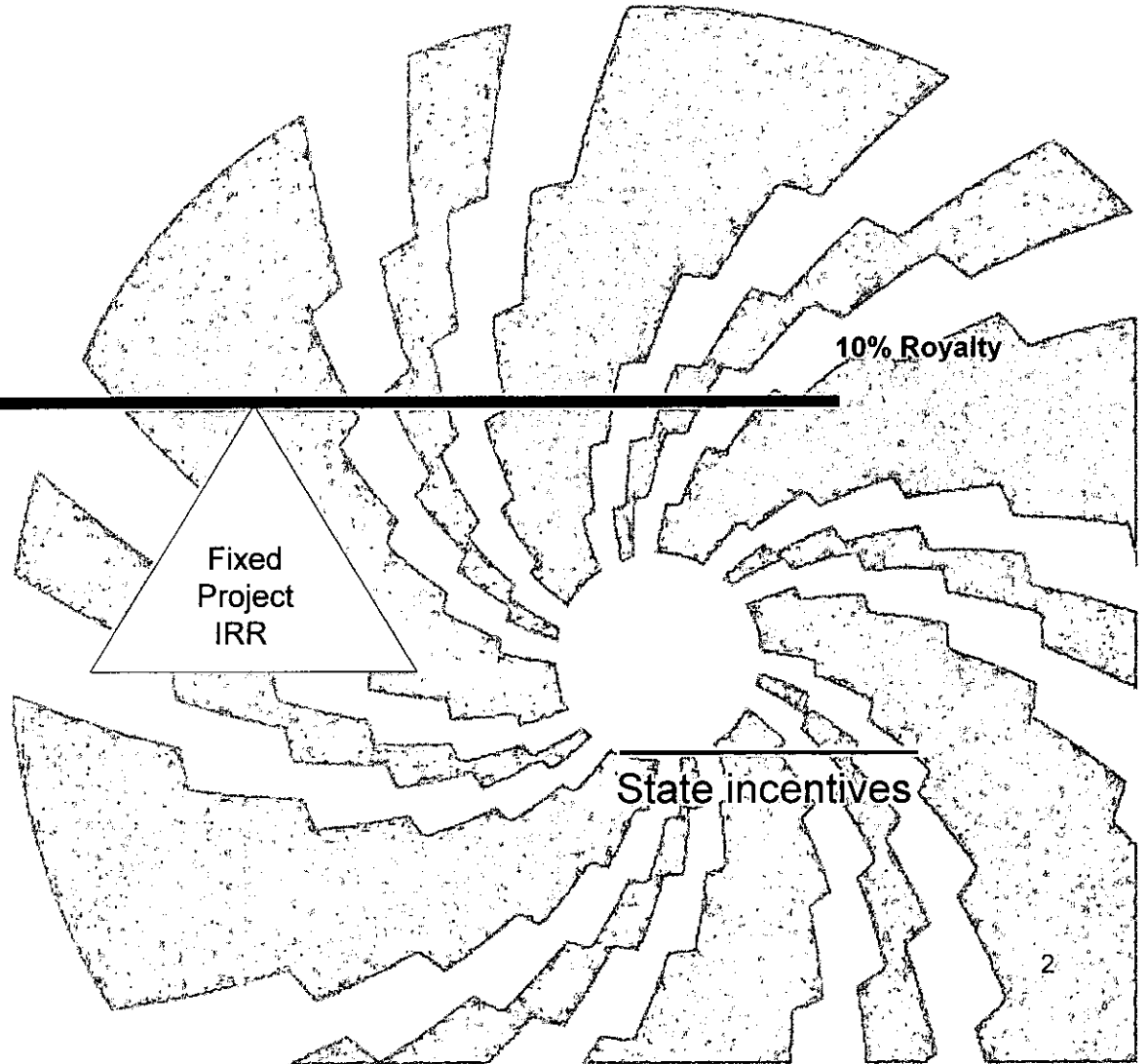
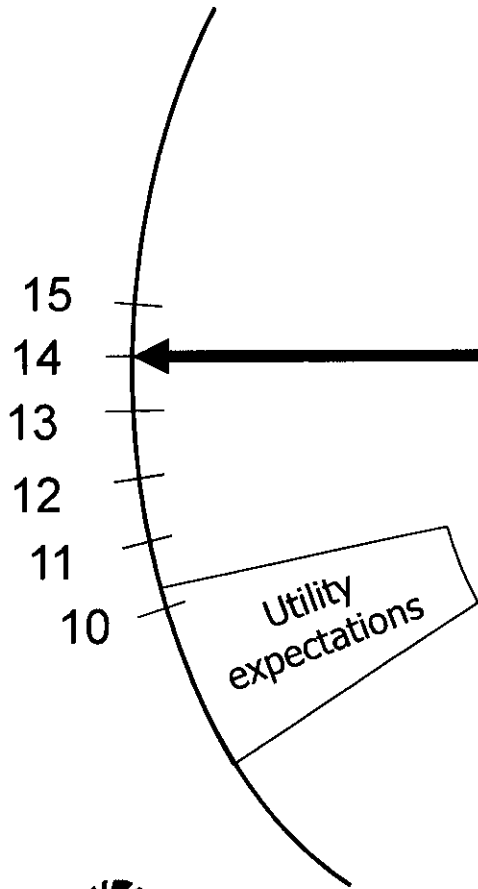
Impact of SB243 on Geothermal Development in Alaska

Paul Thomsen
Director of Policy and Business Development
Ormat Technologies, Inc



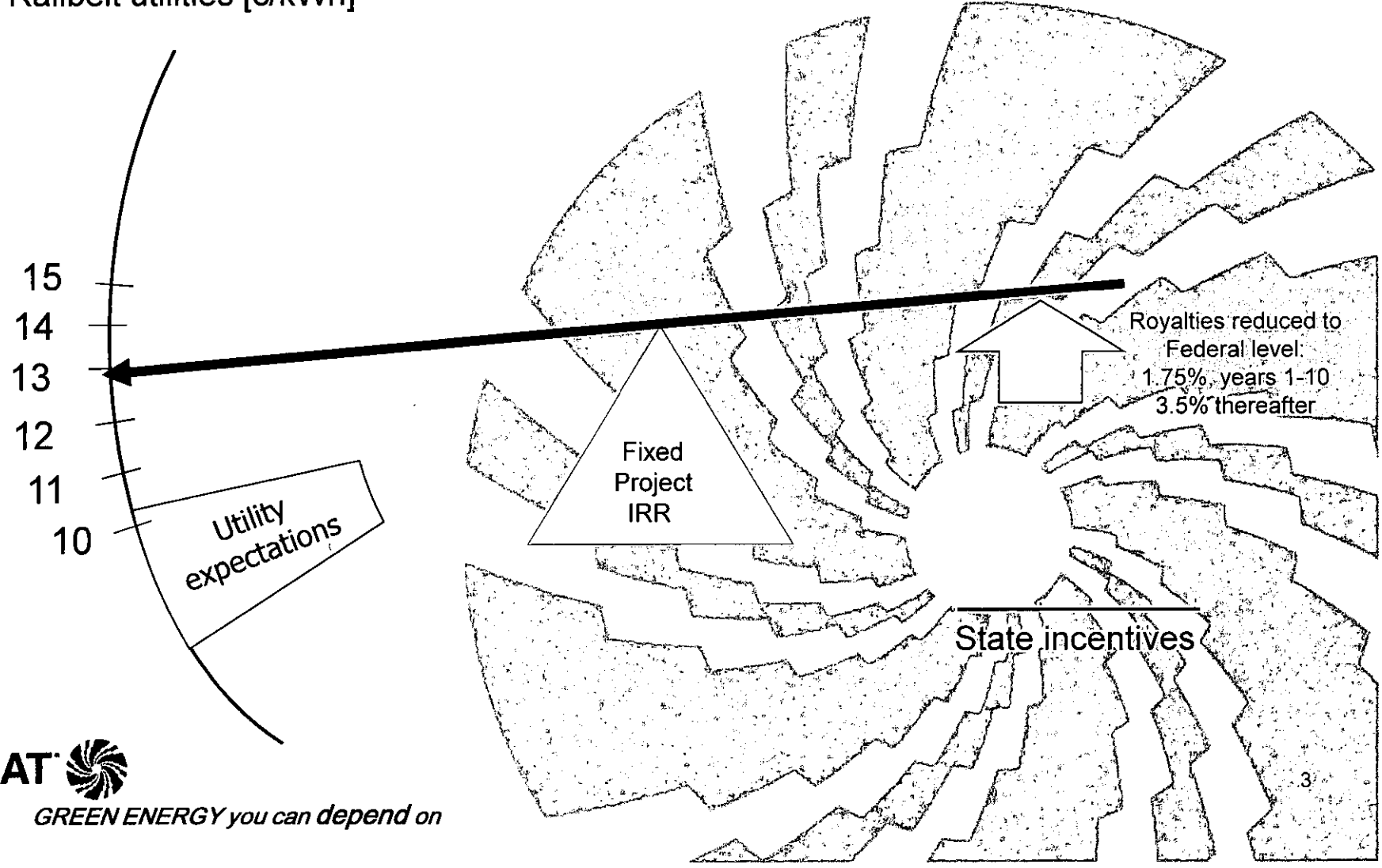
Estimated Power Price, Current Conditions

Power price to Railbelt utilities [c/kWh]



Impact of SB243 on Mt Spurr Power Price

Estimated power price to Railbelt utilities [c/kWh]

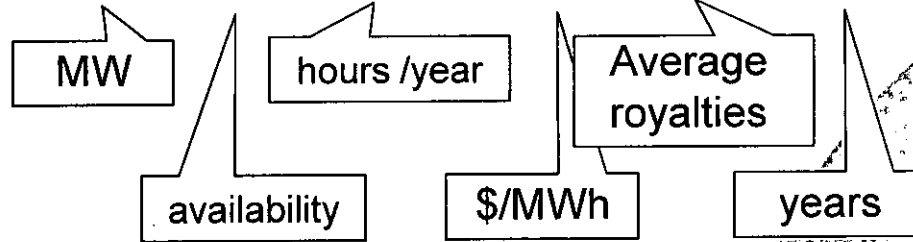


Economic Benefits to the State of Alaska

■ Estimated royalty payment in 25 years¹:

$$50 * 0.95 * 8760 * 130 * 2.8\% * 25 =$$

\$38 million



■ Saving to railbelt ratepayers¹:

$$50 * 0.95 * 8760 * 10 * 25 =$$

\$104 million

\$/MWh reduction in power price

■ Total economic benefit:

>\$140 million

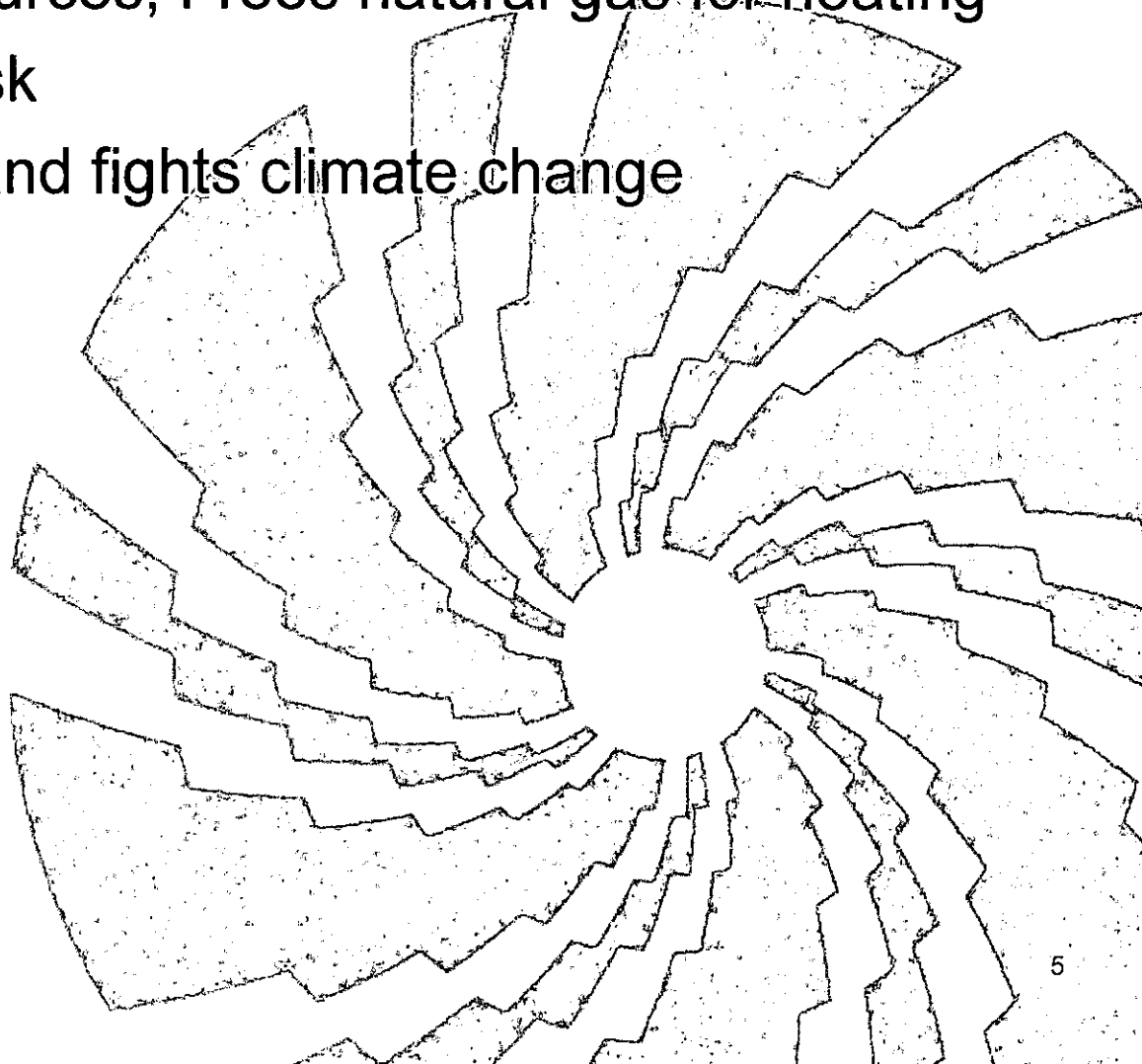
¹ This is a simplified calculation, not accounting for inflation and other factors that will affect actual payment / saving



GREEN ENERGY you can depend on

Other Benefits to the State of Alaska

- Diversifies energy sources; Frees natural gas for heating
- Removes fuel cost risk
- Reduces emissions and fights climate change
- Creates green jobs



ORMAT 

GREEN ENERGY you can depend on

SB

274



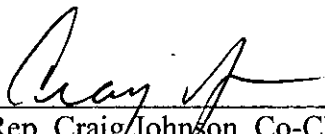
SENATOR FRED DYSON

March 23, 2010

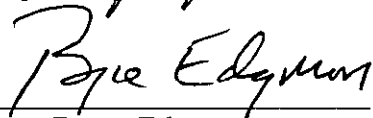
To: Members of House Resources

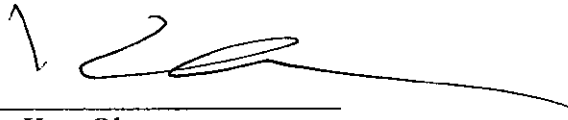
From: Senator Fred Dyson


I am respectfully requesting to waive SB274, "An Act naming the state fish hatchery on the Elmendorf Air Force Base the William Jack Hernandez Sport Fish Hatchery" out of House Resources Committee.

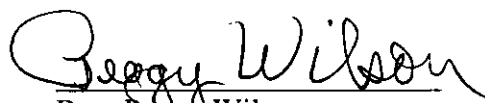

Rep. Craig Johnson, Co-Chair

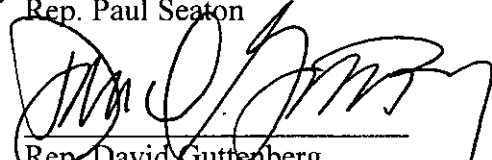

Rep. Mark Neuman, Co-Chair

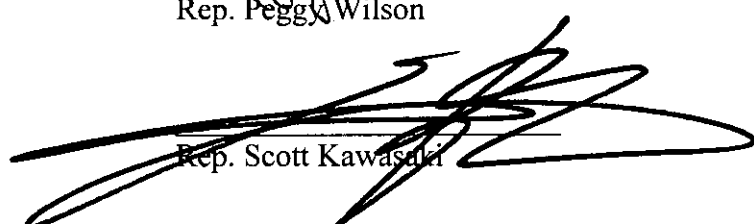

Rep. Bryce Edgmon

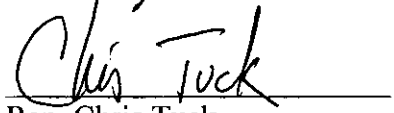

Rep. Kurt Olson


Rep. Paul Seaton


Rep. Peggy Wilson


Rep. David Guttenberg


Rep. Scott Kawasaki


Rep. Chris Tuck



SENATOR FRED DYSON

SPONSOR STATEMENT

SB 274 – William Jack Hernandez Sport Fish Hatchery

The purpose of this bill is to name the new state fish hatchery on Elmendorf Air Force Base, the William Jack Hernandez Sport Fish Hatchery. Hernandez pioneered the fish rearing and fish hatchery program at Ft. Richardson.

William Jack "Bill" Hernandez served his country valiantly during WWII, serving as a civilian contractor on Wake Island in the South Pacific, building fortifications for USMC personnel. Wake Island was attacked by the Japanese on Dec. 7, 1941, the same day as the Pearl Harbor attack, and a violent 16 day struggle ensued between the Marine regiment and an overwhelming enemy force. On December 23, 1941, Wake Island was captured and Mr. Hernandez was taken as a prisoner of war. He was a POW for three years before being released following surrender of the Japanese forces in 1945.

In 1947 Mr. Hernandez enlisted in the US Army, and in 1956 his unit was transferred to Fort Richardson where he became a Fish and Wildlife Conservation NCO. His orders were to rehabilitate the lakes and streams on post. As a result of Mr. Hernandez efforts, in 1957 the Secretary of the Army approved a cooperative agreement between the Army, the Alaska Territorial Department of Fish and Game, and the Fort Richardson power plant, allowing the plant's cooling pond to be used for rearing fish. Mr. Hernandez ran the fish rearing project, and annual production reached 12,000 rainbow trout, 100,000 Chinook salmon smolt, and 200,000 Coho salmon smolt.

In 1968 Mr. Hernandez retired from the US Army and received an Army Commendation Medal for his efforts. Shortly after retirement, Hernandez was hired by the Alaska Department of Fish and Game as a Fish Culturist at the Fire Lake Hatchery. In a few years he returned to Fort Richardson to manage the large scale fish hatchery constructed at the cooling pond. He also worked at the nearby Elmendorf fish hatchery. In 1983, after 26 years of dedicated service raising salmon and trout, Hernandez retired.

Sadly, Hernandez died of cancer in 2003. The Veterans of Foreign Wars Post 7665 honored him with a 21-gun salute. He was the epitome of Tom Brokaw's "Greatest Generation." Without his drive and dedication, the fish rearing project at Fort Richardson would have never gotten off the ground. His life's work made an enormous contribution to the sport and commercial fishing industry of the Cook Inlet region. Please honor William Jack "Bill" Hernandez by supporting this legislation.

Contact: Chuck Kopp, Staff to Senator Dyson (907)465-6580

AMENDMENT

OFFERED IN THE SENATE
TO: SB 274

BY SENATOR DYSON

- 1 Page 1, line 1, following the first occurrence of "the":
- 2 Insert "new"
- 3
- 4 Page 1, line 5, following "Sec. 35.40.225.":
- 5 Insert "**William Jack Hernandez Sport Fish Hatchery.**"
- 6
- 7 Page 1, line 5:
- 8 Delete "located"
- 9 Insert "under construction"
- 10
- 11 Page 1, line 6, following "Anchorage":
- 12 Insert "scheduled to be completed in May 2011"

SB 274 Notes

1. Director Charlie Swanton, ADF&G, Division of Sport Fish, states that he takes no official position with respect to naming a public facility. Swanton also states he has no objection to the proposed name (William Jack Hernandez) for the fish hatchery.
2. Director Swanton states the Division of Sport Fish has not received any additional recommendations for naming the fish hatchery, other than recommendations for naming it after William Jack Hernandez, and several former staff members have also recommended naming the new hatchery after Hernandez.
3. The new state fish hatchery will be completed May 2011.
4. Citizens (including current and former ADF&G employees) who strongly support this legislation and wish to testify via teleconference:

Tom Namtvedt, 5640 Portage Drive, Wasilla, AK 99654 – (907)355-7403

Larry Engel, 16341 E Vera Way, Palmer, AK 99645-8641 – (907)745-4132

Darrell Keifer, 3709 Carleton Ave, Anchorage, AK 99517-1542 – (907)279-3187

Fred Williams, PO Box 88, Copper Center, AK 99573 – (907)822-3922

Gary A. Wall, PO Box 101007, Anchorage, AK 99510-1007 – (907)223-4640 cell/333-5901 hm

Sidney Logan, PO Box 2589, Soldotna, AK 99669-2589 – (907)262-4048

David A Watsjold, 2811 Cutwater Ct, Anchorage, AK 99516-3473 – (907)345-5166

Robert (Bugs) McCartney, PO Box 91, Palmer, AK 99645 – (907)376-3551

Louis S Bandirola (retired Deputy Director, Division of Sport Fish, ADF&G), 2616 Douglas Hwy, Apt 106, Juneau, AK 99801-2047 – (907) 780-4207

Larry J Heckart (retired Regional Research Supervisor, Division of Sport Fish, ADF&G), PO Box 11046, Anchorage, AK 99511-0446 – (907) 349-3361

Contact: Chuck Kopp, Staff to Senator Dyson (907)465-6580

5640 Portage Drive
Wasilla, AK 99654
aktn@gci.net
December 24, 2009

Representative Wes Keller
600 E. Railroad Avenue
Wasilla AK, 99654

Dear Representative Keller:

I am a retired ADF&G fisheries biologist, commercial fisherman and one of your constituents. I and various active and retired ADF&G biologists are requesting your assistance with legislation to name the new Elmendorf fish hatchery after the man who pioneered the fish rearing and hatchery program at the Ft Richardson: William Jack (Bill) Hernandez (biography, photos, news clippings and draft bill attached). The Elmendorf hatchery is under construction and is scheduled to be completed in May of 2011. I have written Representative Dahlstrom and Senator Dyson, who represent Elmendorf AFB, to sponsor legislation to name the hatchery after Mr. Hernandez.

Mr. Hernandez was a remarkable man who was a Wake Island civilian POW during WWII, enlisted in the U.S. Army after liberation, and, in 1957, while a sergeant in the Army, started the fish rearing program at Ft. Richardson. He ran the fish rearing facility for 11 years, with annual production reaching 12,000 catchable-size rainbow trout, 100,000 Chinook smolt and 200,000 coho smolt. Bill retired from the Army in 1968, and I was appointed to be his successor at Ft Richardson. Bill left huge "shoes" to fill. There was no hatchery at the site then but rather the pond was segregated into three areas for rearing fish. Two old Quonset huts served as living quarters, warehouse, office and lab. Trout were stocked in lakes on military land as well as Anchorage area lakes. Salmon smolt were released into Ship Creek, and returning adult salmon contributed to the commercial and sport fishery. Bill often worked seven days a week, with limited assistance from ADF&G or Army personnel. Bill was not immune from other duties regularly assigned to NCOs, and he spent one night a week as duty NCO at HQ Co. Bill was a busy guy! After Army retirement, Bill worked another 15 years as a fish culturist for ADF&G at the Fire Lake Hatchery and the new hatcheries on Ft. Richardson and Elmendorf AFB.

Sadly, Bill died of cancer in 2003. Without his drive and dedication, the fish rearing project at Ft. Richardson would have never gotten off the ground and the hatchery there probably would have never been constructed. He made an enormous contribution to Anchorage sport fishermen and Cook Inlet commercial fishermen. Please honor William Jack (Bill) Hernandez by helping with this legislation.

Respectfully,



Tom Namtvedt



Representative Wes Keller

January 25, 2010

Mr. Tom Namtvedt
5640 Portage Drive
Wasilla, Alaska 99654

Dear Mr. Namtvedt:

Thank you for your letter regarding a recommendation to name the Fort Richardson Fish Hatchery after Mr. Hernandez. Based on the historical account, the concept of fish hatcheries in Southcentral Alaska must truly be attributed to his efforts.

I am joining you in suggesting to Representative Dahlstrom that she sponsor legislation to name the soon to be completed Elemendorf fish hatchery after William Jack (Bill) Hernandez. I will join her as a co-sponsor of that bill. I am asking her, as she serves as the Representative for Elemendorf Air Force Base.

Again, I would like to thank you for bring this information to my attention. It is important to honor those who throughout our history have done the work that makes Alaska what it is today. Obviously, Mr. Hernandez is one of those pioneers who should not be forgotten.

Sincerely:

A handwritten signature in black ink that reads "Wes Keller".

Wes Keller
Representative
District 14

Cc: Representative Nancy Dahlstrom

William Jack Hernandez

William Jack (Bill) Hernandez was born in Los Angeles, California on April 30, 1920 and died Aug. 31, 2003 in Wasilla. At the age of 21, Bill was employed by Morrison-Knudson Construction Co. building fortifications on Wake Island. After the attack on Pearl Harbor, he and other civilian contractor personnel were assigned to assist the Marine detachment defending the Wake Island. On Dec. 23, 1941, Wake Island was captured, and Bill was imprisoned in various POW camps in China. He survived an escape attempt, breaking his ankle while jumping from a train. He was subsequently recaptured, and this is described in several books on the battle of Wake Island, perhaps most notably "Jim's Journey: A Wake Island Civilian POW's Story" as well as a History Channel documentary: "Wake Island: Alamo of the Pacific."

After the war, Bill returned to California enlisting in the Army in 1947. He initially served as a foreign language interpreter, and his early military career took him to Korea and Europe. Bill honed his chess skills and became a Chess Master. At one point, Bill defeated Japan's top chess player. In 1956, his unit was transferred to Fort Richardson, where he became a Fish and Wildlife Conservation NCO. His orders were to rehabilitate the lakes and streams on post. In 1957, after several months of negotiating with the military and others, Bill received a letter from the Secretary of the Army approving a cooperative agreement between the Army, the Alaska Territorial Department of Fish and Game and the Fort Richardson power plant which allowed the plant's cooling pond to be utilized for rearing fish. Bill ran the fish rearing project, and annual production reached as high as 12,000 catchable-size rainbow trout, 100,000 Chinook smolt and 200,000 coho smolt. Bill retired from the Army in 1968 and received an Army Commendation Medal for his efforts: *"Through his perseverance, ingenuity, and scholarly research, he conceived and pioneered a process of rearing rainbow trout, silver salmon and king salmon from the fingerling stage to the migratory smolt, and in addition, accelerated the restocking of post and community lakes and streams. By virtue of Sergeant Hernandez' diligent efforts coupled with his high sense of responsibility, the military conservation program in Alaska received successive official and recorded recognition by the State Legislature of Alaska and by the United States Senate. His invaluable service to the military and civilian communities of Alaska earned him the worthy respect and admiration of all with whom he came in contact."*

Shortly after his Army retirement, Bill was hired by the Alaska Department of Fish and Game as a Fish Culturist at the Fire Lake Hatchery. He returned to Ft Richardson a few years later to manage the large scale hatchery constructed at the cooling pond. Bill also worked at the Elmendorf hatchery. In 1983, after 26 years of dedicated service raising salmon and trout, Bill retired again.

Bill then purchased a boat and fished commercially for seven seasons in Bristol Bay. When not fishing, Bill spent his time at his cabin on Lake Susitna and groomed snowmobile trails in the area. He was a member of the Wake Island Civilian Survivors Association, a Mason, and a Cooperative Weather Observer for NOAA. Though Bill never married, his many friends and dog Peggy were his Alaskan family. He was loved and respected by everyone who knew him.

Bill was buried in his native California, close to his twin sister Jewel with whom he shared a special bond. The Veterans of Foreign Wars Post 7665 honored him with a 21-gun salute. **Bill Hernandez was the epitome of Tom Brokaw's "Greatest Generation".**

**THE
FOLLOWING
DOCUMENT(S)
ARE
POOR
ORIGINAL
COPIES**

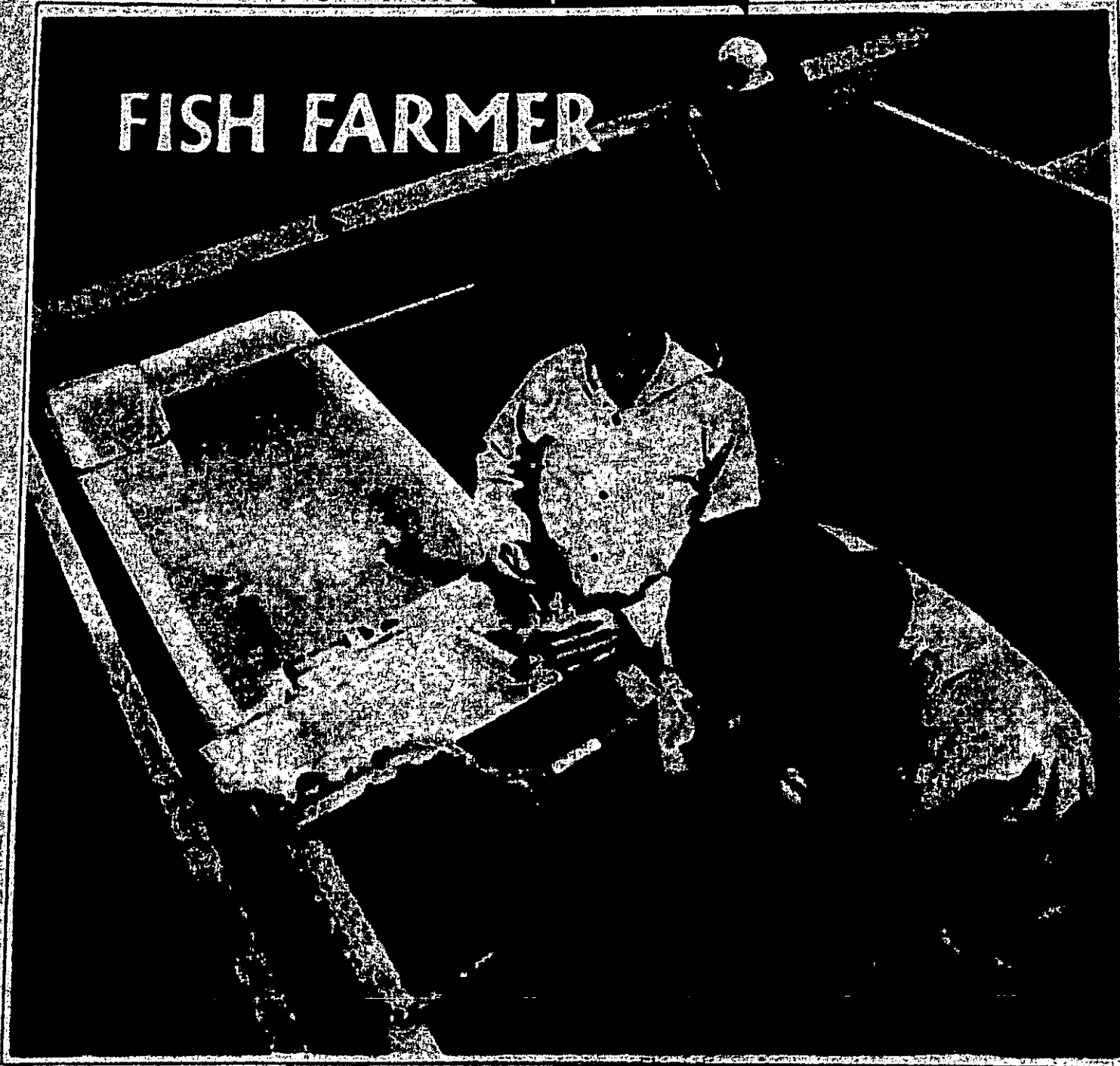
We Alaskans

The Anchorage Daily News Magazine

April 17, 1983

- **Satch:** Ah, graft and corruption!
- **Ski to Sea Relay:** Fast, frantic fun
- **General Delivery:** Preparing for spring

FISH FARMER



Harvest days at the hatchery

Story by Andrew Feriala / photos by Paul Brown

Brown is the color of the hatchery. The walls are painted a dark, rich brown, and the floor is a lighter shade of the same color. The air is thick with the scent of fish and the sound of water splashing. The hatchery is a busy place, with workers in white coats and aprons moving about, their hands busy with the fish. The fish are kept in large, rectangular tanks, each with its own filtration system. The tanks are arranged in rows, and the workers are constantly checking on them, adjusting the water levels and the temperature. The hatchery is a place of precision and care, where every detail matters. The workers are trained to handle the fish with the utmost gentleness, and they know that the health of the fish is their top priority. The hatchery is a place where life is nurtured, and where the future of the fishery is being prepared.



hatchery

Continued from page 9

scooping up a few fish at a time in long-handled nets.

The nets are emptied into the tubs with a wild splashing that is stilled as the tranquilizer, called MC-222, takes effect. The drug tranquilizes voluntary muscle action without affecting the involuntary muscles, so a fish can breathe through its gills but cannot lift a fin to save its life.

Each fish is picked up by two hands. A gentle squeeze to the middle of the gut confirms the fish's status. Eggs will protrude from the underside of a ripe female. Males will squirt clear liquid or white milt.

Females with eggs are passed into a tub next to the doorway of a tent covering a length of the raceway. Males are transferred to a penned-off area at the far end of the raceway. Inside the Quonset-shaped tent two handlers work steadily.

One holds the fish upside down while the other picks up a metallic device shaped like a common garden hose nozzle. A brown hose trails off into the water and is attached to a large green cylinder of the same oxygen hospitals use. There is a trigger on the nozzle device and, at the end, a short, thick needle that looks as though it could fill a basketball. The needle is sharp, though, and a quick jab into the fish's body cavity just behind the dorsal fin produces no blood.

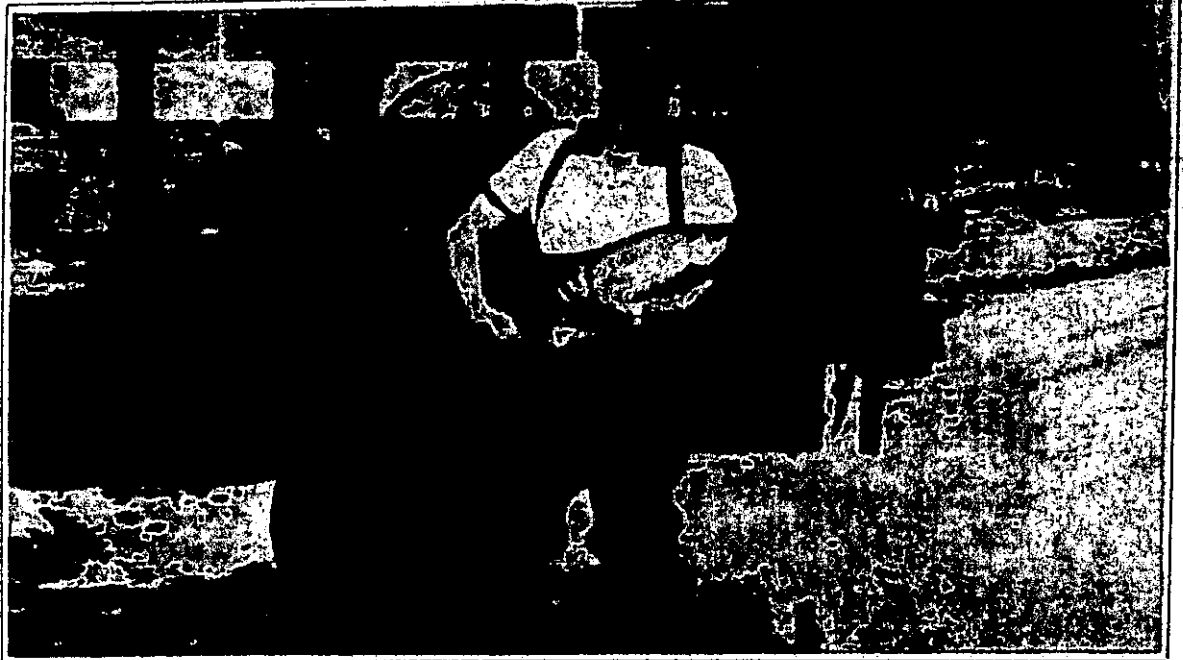
With a pull of the trigger, oxygen at low pressure flows into the fish, gently forcing out the bright orange eggs in a steady stream that spills into a round plastic tray. The eggs are checked to see if the color is normal and if there are any genetic mutations. Occasionally, bad eggs will be dark or green.

At one time eggs were harvested by squeezing the sides of the fish, a process that damaged the eggs and hurt the fish.

While one worker pours the eggs into a larger bucket, another tosses the rainbow into a penned-off section of the raceway inside the tent. The fish slips into the water like a limp torpedo and lies still for a minute or two, gills working in gulps. The constantly flowing water soon washes away the paralyzing drug. With little flicks of the tail and a few turns of the head, the fish rights itself and surges off into the distance.

Forty fish contribute 1,200 to 2,000 eggs apiece. The eggs are disinfected to kill germs from human contact and given to another worker for fertilization.

The process is quick. With the male fish held firmly in one hand, the handler squeezes a white stream of milt into the bucket. Unlike females, most males die after contributing to the genetic pool. It is



Bill Hernandez cradles the last fish he will handle at Fort Richardson. Now he plans to catch fish for himself.



This year the Elmendorf hatchery will produce 5 million rainbow trout eggs.

the same in the wild. There is no natural reason for male fish to live another winter. Although winter water temperatures dip to as low as 34 degrees, virtually stopping all feeding and movement, the low oxygen content in the lakes would not support larger fish populations.

Elmendorf is able to function year-round as a hatchery because it receives from an Air Force generating plant a constant supply of 83-degree waste water that is piped half a mile to the hatchery. There it is mixed with Ship Creek water and brought to a stable temperature.

The temperatures are constantly monitored and alarm sound if there is a variance of more than a few degrees. Rainbows cannot live in water above 63 degrees without suffering from a killing form of stress. For salmon, the

disaster brink is several degrees lower. Rainbows live in 42-degree water in the winter and 46-degree water in the spring when spawning.

Of the 19 fish hatcheries and rearing facilities in Alaska, Elmendorf is the only one that handles brood stock rainbow, the fish from which we get more fish. Other hatcheries trap wild salmon in streams and collect the eggs for rearing.

There are approximately 18,000 of the dark, fat trout in three raceways at Elmendorf, ranging in age from 1 to 4 years.

Watching thousands of them rolling in the water can arouse even the most casual fisherman, but catching these hand-fed beauties would be quite a trick.

An eight-foot-high chain-link fence surrounds the property. Inside, eight large white

plastic dishes create invisible barriers just inside the fence. Cross their line of fire and a shrieking alarm goes off outside the office and inside the newly constructed manager's house just a hundred yards away.

Casting a long line over the fence wouldn't work, either. A 20-foot moat of land separates the fence from the tanks. Reaching the ponds would be simple enough, but dragging a fighting trout overboard and flipping it over the fence would be all but impossible.

There is more science than meets the eye inside the hatchery. Besides the electronically controlled warm water system, there is food that would captivate the most jaded readers of *Jack and Wagon*.

Back in the 1950s, the early

days of fisheries science, fish at hatcheries outside were fed chopped cattle guts. Seemed like a good idea at the time. It was a waste product, the fish ate it voraciously, and it appealed to people who thought all that came from cattle was good.

But the diet soon caused epidemic disease and many early hatcheries were closed.

Today, fish food is a science itself. Bagged in 50-pound sacks like dog food, the Oregon mash used at Elmendorf contains 23 ingredients ranging from fish meal to vitamins. An abundance of herring oil makes the pellets soft. Mature fish are fed at least once a day and consume, Hernandez says, about 1 percent of their total body weight daily. Young fish are fed more often, up to seven times a day. The Elmendorf hatchery uses 700 pounds of fish food daily in the peak spring season.

Although he had the opportunity to advance in the Department of Fish and Game hierarchy and the later bureaucracies that came to control the hatcheries in Alaska, Hernandez never pursued those career avenues. This summer, after working more than 21 years for others in the handling of fish, Hernandez will harvest fish on his own. With his 20-foot boat, the Hernandez, he will head out into Bristol Bay to catch his salmon.

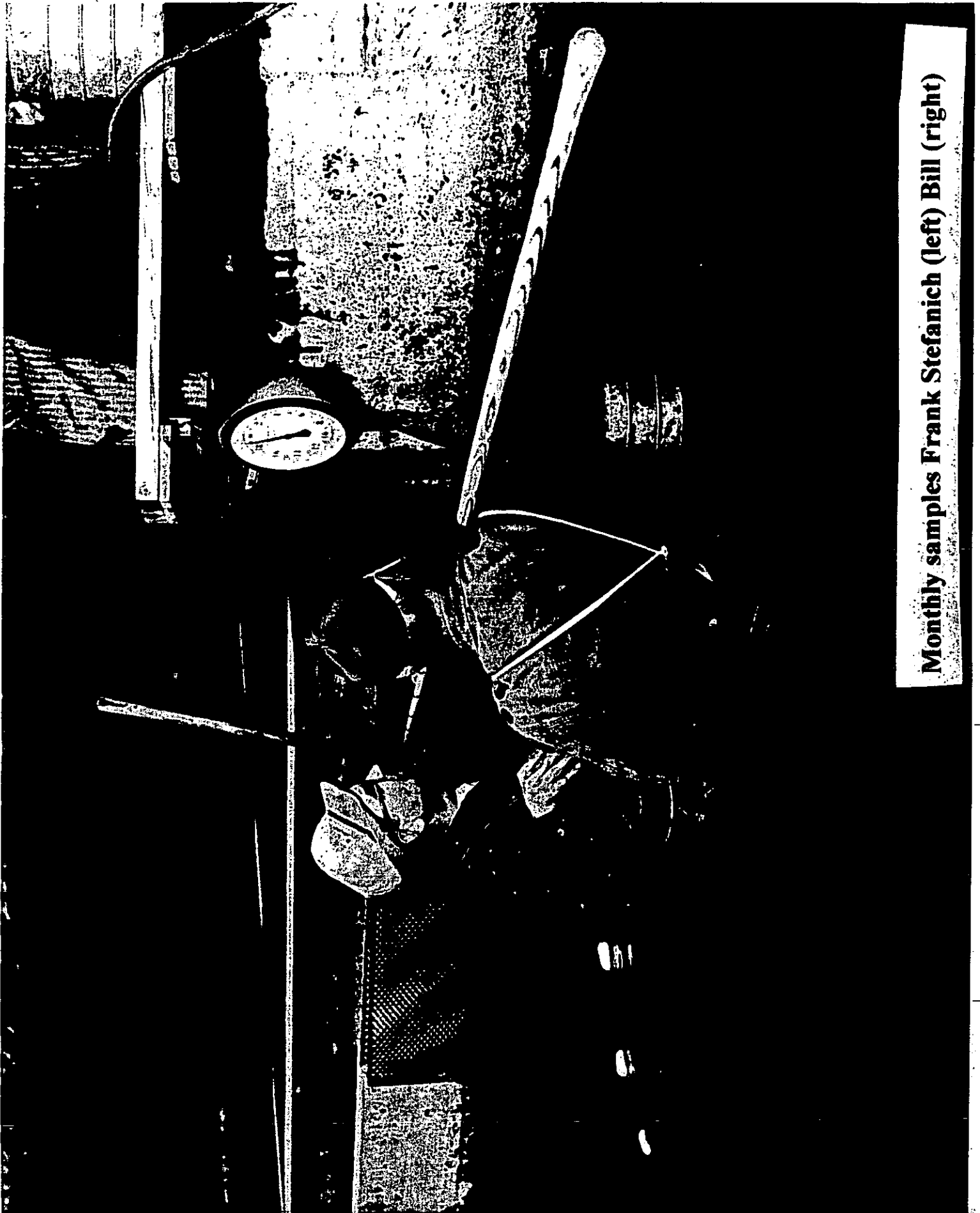
A home computer will help him keep track of catch rates, fish behavior and feeding patterns. But out on the rolling bay, Hernandez will use his own instincts, gleaned from years of experience, to catch fish.

© Andrew Sarna is a reporter for The Daily News.





Who needs a tagging trailer (Bill 2nd from left)



Monthly samples Frank Stefanich (left) Bill (right)

SB

301

HOUSE COMMITTEE REPORT

(9)

Date Referred to Committee: April 9, 2010

FURTHER REFERRALS: Finance

Date of Committee Action: 4-12-10

The **RESOURCES** Committee considered:

SENATE BILL NO. 301

"An Act relating to the power project fund; authorizing the Alaska Energy Authority to charge and collect fees relating to the power project fund; authorizing the Alaska Energy Authority to sell and authorizing the Alaska Industrial Development and Export Authority to purchase loans of the power project fund; providing legislative approval for the sale and purchase of loans of the power project fund under the memorandum of understanding dated February 17, 2010; and providing for an effective date."

SB 301-POWER PROJECT FUND

Recommends it be replaced with HCS or CS for _____ ()
 For Senate Bills with new title: Technical Title New Title: HCR _____ Same Title New Title

- attach amendments
- add new referral to _____ Committee
- Letter of Intent _____ Committee

List of Abbrev for Depts:
 ADM
 CED
 COR
 CRT
 EED
 DEC
 DFG
 GOV
 DHS
 LWF
 LAW
 LEG
 MVA
 DNR
 DPS
 REV
 DOT
 UA

NEW FISCAL NOTES				
*Assigned by Chief Clerk's Office				
List by Dept(s):	*FN#	Fiscal	Indet.	Zero

PREVIOUS FISCAL NOTES				
List by Dept(s):	FN#	Fiscal	Indet.	Zero
DOT	1			✓
REV	2			✓
CED	3			✓
CED	4			✓

<u>Signing with recommendations</u>	Printed Last Name	DP	DNP	NR	AM
	OLSON			X	
Olga Edgmon	Edgmon	X			
	SEATON			X	
Paul Seaton	WILSON	X			
	SEATON	Y			
	SEATON			X	
Chair:	Johnson				
Chair:	Johnson	X			



March 18, 2010

The Honorable Lyman Hoffman
The Honorable Bert Stedman
Co-Chairs, Senate Finance Committee
Alaska State Legislature
State Capitol Room 516
Juneau, Alaska 99801-1182

RE: SB 301, "An Act relating to the Power Project Fund"

Dear Senators Hoffman and Stedman:

On March 17, 2010, SB 301 (Companion Bill HB 411) passed the Senate Resources Committee and was referred to Senate Finance. This legislation is intended to allow the Alaska Energy Authority (AEA) to charge and collect fees relating to the Power Project Fund (PPF) and authorize AEA to sell and authorize the Alaska Industrial Development and Export Authority (AIDEA) to purchase loans of the PPF.

SB 301 allows AEA to charge and collect fees in administering the PPF, similar to the authority AEA has to charge and collect fees in administering the Bulk Fuel Revolving Loan Fund (BFRLF.) AEA charges an application fee and an origination fee for a loan of the BFRLF; AEA proposes to charge similar fees for a PPF loan application and loan.

SB 301 also authorizes AEA to sell and AIDEA to purchase certain loans from the PPF. The proposed sale of existing loans will recapitalize the PPF with approximately \$20.6 million. To maximize the price paid to AEA for the sale of the loans, the bill includes provisions for AEA to repurchase from AIDEA loans which later default. This repurchase provision substantially reduces financial risk to AIDEA and allows AIDEA to purchase the loans without significant discount.

We respectfully request you to schedule SB 301 for hearing in Senate Finance, and we urge favorable action on this bill. A copy of the Memorandum of Understanding between AIDEA and AEA, fiscal notes and sectional analysis are attached. We will be happy to meet with you and other members of the committee to provide any other information you may require. Thank you for considering our request.

Sincerely,

ALASKA ENERGY AUTHORITY

Steve Haagenson
Executive Director

Attachments (4)

cc: Ted Leonard, AIDEA Executive Director

HB 411 and SB 301

An Act relating to the power project fund

Sectional Analysis

Section	Analysis
1	AS 42.45.010(a) is amended to allow proceeds from the sale of power project loans to be deposited into the power project fund (PPF).
2	AS 42.45.010(d) repeals and reenacts AEA authority to adopt regulations relating to the loan program by specifically allowing AEA to establish fees for applications and loan originations.
3	AS 42.45.010 is amended by adding new subsections – (k) to provide that fees collected will be deposited into the general fund. (l) provides authority to AEA to sell loans of the PPF with legislative approval, allows AEA to repurchase loans sold under this subsection which default, allows proceeds received to be deposited into the fund.
4	AS 44.88.080 is amended by adding new subsection (30) allowing AIDEA to purchase from AEA, as an investment of the revolving fund, PPF loans.
5	Uncodified law is amended by adding a new section providing for legislative approval for AEA to sell and AIDEA to purchase certain power project fund loans. This section references the 2/17/10 MOU between AIDEA and AEA that memorializes the proposed terms of the sale and purchase.
6	Provides for an immediate effective date

Prepared by AEA

Exhibit A

Alaska Energy Authority
Power Project Loans
as of 2/9/10

Payment Period	Loan #	Loan Name	Outstanding Commitment	Current Balance	Next Due Date	Interest Rate	Payment Amount	Maturity Date
Annually								
	40901044	QINARMIUT CORP	\$0.00	\$84,841.03	10/1/10	0.00	\$12,266.17	10/1/16
	40901045	CORDOVA ELEC CO OP	\$0.00	\$742,857.13	6/11/10	0.00	\$28,571.43	6/11/35
	40901047	ST PAUL, CITY OF	\$0.00	\$97,306.42	10/1/10	3.00	\$8,614.18	10/1/23
	40901048	WRANGELL, CITY OF	\$0.00	\$78,553.50	7/1/10	2.00	\$27,238.92	7/1/12
	40901050	PELICAN UTILITY DISTRICT	\$0.00	\$15,161.70	7/1/10	5.61	\$2,191.43	7/1/19
	40901057	ST PAUL, CITY OF	\$0.00	\$1,260,000.00	10/1/10	0.00	\$90,000.00	10/1/23
Total for Annually				\$2,278,719.78			\$168,882.13	
SemiAnnually								
	40901009	SITKA, CITY OF	\$0.00	\$9,178,074.93	7/1/10	4.00	\$307,037.96	1/1/33
	40901049	GWITCHYAA ZHEE UTILITY	\$0.00	\$145,384.29	7/1/10	6.16	\$9,844.52	1/1/20
	40901051	AP&T TOK DOT LAKE	\$0.00	\$232,837.77	7/1/10	0.00	\$12,254.63	7/1/19
	40901052	AP&T (TETLIN)	\$0.00	\$172,614.56	7/1/10	4.20	\$11,121.71	7/1/19
	40901059	AP&T (PRINCE OF WALES PROJECT)	\$0.00	\$893,333.30	7/1/10	0.00	\$20,000.00	1/1/37
	40901060	ELFIN COVE, COMMUNITY OF	\$0.00	\$550,325.15	7/1/10	0.00	\$13,102.98	1/1/31
	40901061	SOUTHERN ENERGY	\$0.00	\$517,673.38	7/1/10	5.60	\$21,480.18	7/1/30
	40901062	YAKUTAT, CITY & BOROUGH OF	\$0.00	\$125,792.95	7/1/10	3.00	\$7,325.59	1/1/20
	40901065	AVEC NIGHTMUTE	\$0.00	\$205,283.22	7/1/10	0.00	\$10,804.38	7/1/19
	40901068	AP&T (SKAGWAY)DYE LINE EXTENSION	\$0.00	\$114,153.48	7/1/10	2.00	\$6,052.95	7/1/20
	40901071	TUNTUTULIAK COMMUNITY SERVICES A	\$0.00	\$129,509.64	7/1/10	0.00	\$5,396.23	1/1/22
	40901072	GUSTAVUS ELECTRIC COMPANY	\$0.00	\$118,626.84	7/1/10	5.40	\$10,288.01	1/1/17
	40901076	NAPASKIAK ELEC UTILITY	\$0.00	\$6,304.97	7/1/10	5.80	\$1,669.45	1/1/12
	40901079	TDX SAND POINT GENERATING INC	\$0.00	\$203,984.12	7/1/10	4.00	\$10,109.49	1/1/23
	40901080	AK POWER CO-POW SWITHGEAR PROJ.	\$0.00	\$167,889.70	7/1/10	5.45	\$7,639.46	1/1/27
	40901081	AK POWER CO-SKAGWAY LINE EXT	\$0.00	\$187,093.47	7/1/10	5.45	\$6,660.67	1/1/37
	40901084	AK POWER CO-SOUTH FORK HYDRO	\$0.00	\$1,576,590.23	7/1/10	5.45	\$57,000.66	1/1/36
	40901085	ADAK, CITY OF (DOWNSIZE GEN)	\$0.00	\$85,577.88	7/1/10	5.39	\$6,648.22	1/1/18
	40901086	TDX NORTH SLOPE GENERATING INC	\$0.00	\$796,539.85	7/1/10	3.00	\$34,972.27	1/1/24
	40901090	TDX NORTH SLOPE GENERATING INC	\$0.00	\$746,334.45	7/1/10	5.15	\$35,901.66	1/1/25
	40901091	TDX SAND POINT GENERATING INC	\$0.00	\$120,251.45	7/1/10	5.11	\$5,454.25	7/1/26
	40901092	AK POWER CO	\$0.00	\$63,010.57	7/1/10	5.11	\$2,912.94	1/1/26
	40901093	PORT HEIDEN, CITY OF	\$0.00	\$38,730.34	7/1/10	5.09	\$2,403.24	7/1/20
	40901094	YAKUTAT, CITY & BOROUGH OF	\$0.00	\$224,977.15	7/1/10	4.92	\$17,225.39	1/1/18
	40901095	TDX NORTH SLOPEGENERATING, INC	\$0.00	\$1,193,582.30	7/1/10	4.92	\$53,356.61	7/1/26
	40901096	CHENA POWER LLC	\$0.00	\$530,138.84	7/1/10	5.02	\$23,729.86	7/1/26
	40901097	CRAIG, CITY OF	\$0.00	\$482,653.23	7/1/10	5.05	\$19,908.31	1/1/29
	40901100	GUSTAVUS ELECTRIC, INC	\$0.00	\$928,029.76	7/1/10	4.69	\$29,659.32	7/1/38
	40901102	CHIGNIK LAGOON POWER UTILITY	\$0.00	\$30,920.85	7/1/10	4.62	\$5,599.19	1/1/13
	40901104	ALASKA WIND POWER, LLC	\$0.00	\$143,502.81	7/1/10	4.88	\$7,176.84	1/1/14
	40901106	NUSHAGAK ELECTRIC & TELEPHONE COI	\$0.00	\$12,010.97	7/1/10	4.99	\$4,820.30	1/1/15
	40901107	TDX NORTH SLOPE GENERATING, INC.	\$0.00	\$2,500,000.00	7/1/10	5.46	\$104,892.75	1/1/30
Total for SemiAnnually				\$22,421,732.45			\$872,450.02	
Grand Total				\$24,700,452.23				

Prepared by AEA

Memorandum of Understanding

This Memorandum of Understanding ("MOU") is entered into this 17th day of February, 2010, between the Alaska Energy Authority ("AEA") and the Alaska Industrial Development and Export Authority ("AIDEA").

Recitals

- A. The power project fund ("PPF") is established as a separate fund of AEA under AS 42.45.010(a).
- B. AEA may make PPF loans for financing various activities related to the development of energy generation and transmission projects, bulk fuel storage facilities, waste energy, energy conservation, or alternative energy facilities, or may make loans to the bulk fuel revolving loan fund for the purposes described in AS 42.45.250(l).
- C. The Renewable Energy Grant Fund was established under AS 42.45.045 to finance certain energy projects in Alaska, with an emphasis on feasible energy projects that provide a cost benefit to Alaska ratepayers, and projects that will serve areas in which the average cost of energy exceeds the average cost of energy in other areas of the state.
- D. AEA makes PPF loans available to assist project developers meet their matching fund obligations under the Renewable Energy Fund Grant Recommendation Program. By doing so, AEA is able to leverage the funding available from each program to better promote the development of cost efficient, renewable energy projects for the benefit of Alaska ratepayers.
- E. The PPF currently has less than \$5,000,000 available for serving the purposes of the fund.
- F. AEA desires to sell, and AIDEA desires to purchase, the outstanding PPF loans identified in the attached Exhibit A.
- G. In this MOU, in order to maximize the amount AIDEA would be willing to pay for the PPF loans identified in Exhibit A and minimize financial risk to AIDEA from purchasing the PPF loans, AEA agrees to repurchase from AIDEA any outstanding loan if the borrower has a payment default after the sale.
- H. The outstanding PPF loans identified in Exhibit A have a combined current balance as of February 9, 2010, of \$24,700,452.23, and earn interest at annual rates that range from 0% to 6.16%.

- I. AEA and AIDEA agree that the outstanding loans identified in Exhibit A have a projected present value as of the closing date (expected to be in July 2010) of approximately \$20.6 million. This present value is the value of projected loan payments over the life of the outstanding loans, discounted at 6.02%, which was AIDEA's return on investments for the three year period ended September 30, 2009.
- J. AEA and AIDEA agree that the sale and purchase of the outstanding PPF loans identified in Exhibit A at the present value of the loans will both adequately capitalize the Power Project Fund and provide a reasonable investment for the revolving fund of AIDEA.
- K. The sale and purchase of the outstanding PPF loans identified in Exhibit A will require, among other things, the enactment of legislation approving the sale and purchase.
- L. This MOU is intended to set forth the principal terms and conditions under which AEA would sell, and AIDEA would purchase, the outstanding PPF loans identified in Exhibit A. The parties intend that this MOU be incorporated into legislation to be submitted to the Alaska State Legislature authorizing the sale and purchase of the loans.

NOW, THEREFORE, in exchange for the mutual promises contained herein and for other consideration the receipt and adequacy of which is hereby acknowledged, the parties agree as follows:

- 1. AEA agrees to sell, and AIDEA agrees to purchase, the outstanding PPF loans identified in Exhibit A on the closing date, expected to be in July 2010, for a purchase price equal to the present value as of the closing date of all PPF loans identified in Exhibit A.
- 2. In this MOU, the "present value" of a PPF loan means the present value of all scheduled loan payments on the PPF loan over the entire remaining life of the PPF loan, using a discount rate of 6.02%.
- 3. Based upon the definition of "present value," AIDEA and AEA estimate that the purchase price of all PPF loans identified in Exhibit A on the closing date will be approximately \$20.6 million.
- 4. AEA shall repurchase from AIDEA any outstanding PPF loan if the borrower defaults on payment after the sale. The repurchase price shall equal the present value of the loan determined on the date of the payment default by the borrower, less any payments received by AIDEA after the payment default date. AIDEA may exercise the right to have AEA repurchase a PPF loan by sending notice to AEA of the payment default.

AEA shall pay AIDEA within 30 days of the notice of payment default from unencumbered and uncommitted funds in the Power Project Fund. If the PPF has an inadequate amount of unencumbered and uncommitted funds to repurchase the PPF loan from AIDEA within 30 days of the notice of default, AEA shall make payments to AIDEA with unencumbered and uncommitted funds as they become available in the Power Project Fund (through repayments from other PPF loans or otherwise), with interest on the unpaid balance at the annual rate of four percent (4%) from the date 30 days after the notice of default. Nothing in this paragraph precludes AIDEA from rescinding a notice of default.

WHEREFORE the parties have executed this Agreement as of the date first written above.

Alaska Energy Authority


by: Steve Haagenson
Executive Director

Alaska Industrial Development and Export Authority


by: Ted Leonard
Executive Director

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number: 1
Bill Version: SB 301
(S) Publish Date: 2/26/10

Identifier (file name): 0974-DOT-CO-01-04-10 Dept. Affected: DOT&P
Title: Power Project Fund RDU: Administration and Support Services
Component: Commissioner's Office
Sponsor: _____ Component Number: 530
Requester: _____

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2011	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
OPERATING EXPENDITURES								
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	0.0	0.0

CAPITAL EXPENDITURES								
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CHANGE IN REVENUES ()								
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FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts								
1003 GF Match								
1004 GF								
1005 GF/Program Receipts								
1037 GF/Mental Health								
Other Interagency Receipts								
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2010) cost: _____

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: (Attach a separate page if necessary)

This bill has no fiscal impact on the Department of Transportation and Public Facilities

Prepared by: Mary Siroky, Legislative Liaison Phone 465-4772
Division: DOT&PF, Commissioner's Office Date/Time: 1/4/10 5:25 PM
Approved by: Frank Richards Date: 1/4/2010
Deputy Commissioner, DOT&PF

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number: 2
Bill Version: SB 301
(S) Publish Date: 2/26/10

Identifier (file name): 0974-REV-TRS-1-6-10
Title: AIDEA Power Project Fund
Sponsor: Rules
Requester: Request of Governor
Dept. Affected: Revenue
RDU: Taxation and Treasury
Component: Treasury
Component Number: 121

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2011	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
OPERATING EXPENDITURES								
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	0.0	0.0

CAPITAL EXPENDITURES								
-----------------------------	--	--	--	--	--	--	--	--

CHANGE IN REVENUES ()								
-------------------------------	--	--	--	--	--	--	--	--

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts								
1003 GF Match								
1004 GF								
1005 GF/Program Receipts								
1037 GF/Mental Health								
Other Interagency Receipts								
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2010) cost: _____

POSITIONS

Full-time								
Part-time								
Temporary								

ANALYSIS: (Attach a separate page if necessary)

The Department of Revenue anticipates no fiscal impact as a result of this legislation.

Prepared by: Ginger Blaisdell for Jerry Burnett, Deputy Commissioner Phone 465-3669
Division: Treasury Division Date/Time 1/5/10; 9:48am
Approved by: Ginger Blaisdell, Director Date 1/6/10; 1:49pm
Administrative Services Division

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number: 3 **CORRECTED**
 Bill Version: SB 301
 (S) Publish Date: 3/8/10

Identifier (file name): SB301-CED-AIDEA-3-2-10 Dept. Affected: DCCED
 Title: Power Project Fund Loan Portfolio Sale RDU: 125
 Component: AIDEA Operations
 Sponsor: Rules by Request of the Governor
 Requester: Senate Resources Committee Component Number: 1234

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2011	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
OPERATING EXPENDITURES								
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	0.0	0.0

CAPITAL EXPENDITURES								
-----------------------------	--	--	--	--	--	--	--	--

CHANGE IN REVENUES ()								
-------------------------------	--	--	--	--	--	--	--	--

FUND SOURCE (Thousands of Dollars)

	FY 2011	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2010) cost: _____

POSITIONS

	FY 2011	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
Full-time							
Part-time							
Temporary							

ANALYSIS: (Attach a separate page if necessary)

This bill authorizes the Alaska Energy Authority (AEA) to charge and collect fees relating to the power project fund (PPF.) See AEA's fiscal note for details.

In addition to authorizing the collection of fees, this bill allows AEA to sell and the Alaska Industrial Development and Export Authority to make a one-time purchase of substantially all loans from the PPF loan portfolio.

Prepared by: Sara Fisher-Goad, Deputy Director-Operations
 Division: Alaska Industrial Development and Export Authority
 Approved by: Emil Notti, Commissioner
Department of Commerce, Community and Economic Development

Phone 907-771-3012
 Date/Time 2/17/10 12:00 AM
 Date 3/2/2010

FISCAL NOTE 3 ****CORRECTED****

STATE OF ALASKA
2010 LEGISLATIVE SESSION

BILL NO. SB 301

ANALYSIS CONTINUATION

AEA and AIDEA have developed a memorandum of understanding outlining the terms of the sale. AIDEA will purchase outstanding loans at a discount rate equivalent to 6.02%, its return on investments for the 3-year period ended September 30, 2009. To maximize the price paid, AEA agrees to repurchase from AIDEA loans which later default. Estimated sale proceeds are approximately \$20.6 million. The closing date of the sale is anticipated to be in July 2010.

No additional operating costs are anticipated with this legislation.

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number: 4 **CORRECTED**
Bill Version: SB 301
(S) Publish Date: 3/8/10

Identifier (file name): SB301-CED-AEA-3-2-10 Dept. Affected: DCCED
Title: Power Project Fund Loan Portfolio Sale RDU: 453
Sponsor: Rules by Request of the Governor Component: Statewide Project Development
Requester: Senate Resources Committee Component Number: 2888

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2011	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
OPERATING EXPENDITURES								
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	0.0
CAPITAL EXPENDITURES								
CHANGE IN REVENUES ()		**						

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts								
1003 GF Match								
1004 GF								
1005 GF/Program Receipts								
1037 GF/Mental Health								
Other Interagency Receipts								
TOTAL		0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2010) cost: _____

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: (Attach a separate page if necessary)

This bill authorizes the Alaska Energy Authority (AEA) to charge and collect fees relating to the power project fund (PPF.) Currently, AEA only collects funds from applicants relating to the direct cost of analyzing the feasibility of a project. All fees would be deposited into the general fund; however, AEA will request an annual appropriation to have collected fees be deposited into the PPF. A similar annual appropriation is requested for fees collected from bulk fuel loans. ** Estimated fees are indeterminate until regulations are adopted; however, as a reference, AEA charges a \$25 application fee and a .5% origination fee for loans from the Bulk Fuel Revolving Loan Fund.

In addition to authorizing the collection of fees, this bill allows AEA to sell and the Alaska Industrial Development (continued on page 2)

Prepared by: Sara Fisher-Goad, Deputy Director-Operations
Division: Alaska Energy Authority
Approved by: Emil Notli, Commissioner
Department of Commerce, Community and Economic Development

Phone 907-771-3012
Date/Time 2/17/10 12:00 AM
Date 3/2/2010

FISCAL NOTE 4 **CORRECTED**

STATE OF ALASKA
2010 LEGISLATIVE SESSION

BILL NO. SB 301

ANALYSIS CONTINUATION

and Export Authority to make a one-time purchase of substantially all loans from the PPF loan portfolio. AEA and AIDEA have developed a memorandum of understanding outlining the terms of the sale. AIDEA will purchase outstanding loans at a discount rate equivalent to 6.02%, its return on investments for the 3-year period ended September 30, 2009. To maximize the price paid, AEA agrees to repurchase from AIDEA loans which later default. Estimated sale proceeds are approximately \$20.6 million. The closing date of the sale is anticipated to be in July 2010.

No additional operating costs are anticipated with this legislation.

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ALASKA STATE LEGISLATURE

SENATE FINANCE COMMITTEE

Senator Bert Stedman, Co-Chair
State Capitol, Room 516
Juneau, AK 99801-1182
(907) 465- 3873 - Phone
(907) 465-3922 - Fax
Senator_Bert_Stedman@legis.state.ak.us



Official Business

Senator Lyman Hoffman, Co-Chair
State Capitol, Room 518
Juneau, AK 99801-1182
Phone - (907) 465- 4453
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Senator_Lyman_Hoffman@legis.state.ak.us

SPONSOR STATEMENT CSSB 305(FIN) (title am)

SB 305 separates oil and natural gas for purposes of calculating the progressivity portion of the production tax under AS 43.55. Under this bill the progressivity surcharges for oil and Cook Inlet and in-state gas would be calculated together, but distinctly from export gas, instead of the current practice on all oil and gas combined. The progressivity structure itself would be unchanged, based on 0.4% of the production value that exceeds \$30 per barrel for oil, and \$30 per BTU barrel of oil equivalent for gas. The base tax rate is unchanged at 25% of production tax value.

Under current law the tax rate is based on the combined BTU value of oil and gas. However, oil and gas can have vastly different values on a BTU basis. Currently a BTU of oil is worth much more than a BTU of gas. Accordingly, once a major gas sale starts, overlaying the existing oil production, the BTU value of the combined oil and gas would be much lower than it was for oil alone. This has been referred to as the dilution effect and could cause a significant reduction in oil taxes as a result of a major gas sale. The existing tax structure, in conjunction with the inherent uncertainty of future oil and gas prices, exposes the state to significant financial risk were a major gas sale to occur. The structure also creates economic instability for entities looking to participate in the development and financing of a natural gas pipeline project in Alaska. SB 305 removes the dilution effect by having progressivity calculated distinctly for oil and gas. This will result in no reduction in oil taxes from a major gas sale.

As in current law, the bill gives the Department of Revenue the authority to adopt regulations to allocate costs between oil and gas, with the added instruction that a method based on relative BTU barrel of oil equivalents should be considered. That method was the one adopted by the department under the same authority for implementation of the current law.

Some producers currently produce Cook Inlet gas or other in-state gas along with North Slope oil. If all gas were separated from oil these producers would see an immediate tax increase. The bill is not intended to increase taxes on current activity. Having the progressivity for Cook Inlet gas and other in-state gas calculated together replicates the current situation, so these producers will see no tax increases. Only progressivity on export gas, like the gas from a major gas sale, would be calculated distinctly. This will prevent a major gas sale from diluting progressivity on oil.

Under the tax inducement provisions of the Alaska Gasline Inducement Act (AGIA), the tax structure in place at the time of the first binding open season (May 1, 2010), may be locked in for the first ten years of gas commercialization. Consequently, to the extent there is interest in decoupling our tax structure, it needs to be done before April 30, 2010.

LEGAL SERVICES

COPY

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM

March 30, 2010

SUBJECT: Sectional summary of CSSB 305(RIN), Draft Version "T" with comparison to Draft Version "P" (Work Order No. 26-LS1577\T and 26-LS1577\P)

TO: Senate Finance Committee

FROM: Donald M. Bullock Jr.
Legislative Counsel

Section 1. Amends AS 29.60.850(b) to reference the new separate progressive tax on gas as a source of money that may be appropriated to the community revenue sharing fund. The "community revenue sharing fund" was established in AS 29.60.850(a), "for the purpose of making community revenue sharing payments to municipalities, reserves, and communities for any public purpose." *There is no amendment to AS 29.60.850(b) in CSSB 305(FIN), Draft Version "P" because the progressive tax on oil in AS 43.55.011(g) continued and would continue to be a source for appropriation.*

Section 2. Amends AS 43.55.011(e) to make separate references to the monthly progressive taxes on oil and gas. The progressive tax on oil, gas produced in Cook Inlet, and gas produced elsewhere and used in the state is in AS 43.55.011(g). The progressive tax on other gas is in AS 43.55.011(p). *Section 1 of CSSB 305(FIN), Draft Version "P" amended AS 43.55.011(e)(2) to refer only to the progressive tax on oil.*

Section 3. Amends AS 43.55.011(g) to have the tax rate determined using the production tax values of oil and the production tax values on a BTU equivalent basis of gas produced in Cook Inlet and gas produced elsewhere and used in the state. Applies the tax rate only to that oil and gas production. Makes no change in the tax rates or the range of production tax values within which the two tax rates apply. *Section 2 in CSSB 305(FIN), Draft Version "P" determined the progressive rate only on the production tax value of oil and applied that rate only to oil.*

Section 4. Adds a new subsections, (p), to AS 43.55.011. Provides for a progressive tax applicable to gas production that is not included in AS 43.55.011(g) as amended in sec. 3 of the bill. Provides that the tax rate is applied to the production tax value of a BTU equivalent of gas. Uses the same tax rates and ranges of production tax values as AS 43.55.011(g) under current law. *The progressive tax on gas in new subsection AS 43.55.011(p) has no counterpart in CSSB 305(FIN), Draft Version "P."*

Section 5. Amends AS 43.55.020(a) to describe the determination of the amount of a monthly installment payment for production taxes when the progressive tax on oil, Cook Inlet gas, and other gas used in the state, and the progressive tax applicable to other gas are determined separately. *Section 6 of CSSB 305(FIN), Draft Version "P" amended AS 43.55.020(a)(1) by excluding gas from the determination of that part of the installment payment that was based on the progressive tax applicable only to oil.*

Section 6. Amends AS 43.55.020(d), relating to a settlement with the royalty owner, by adding references to the progressive tax on the gas to which AS 43.55.011(p) is applicable. *There is no similar provision in CSSB 305(FIN), Draft Version "P" because the reference to AS 43.55.011(g) was still applicable.*

Section 7. Amends AS 43.55.160(a), relating to the determination of the production tax value of oil and gas, by providing the means for determining the production tax value of oil and the production tax value of gas separately. Reorders the subparagraphs so that the subparagraphs related to the production tax value of gas produced outside of Cook Inlet and other gas not used in the state are at the end. *Section 7 in CSSB 305(FIN), Draft Version "P" also amended AS 43.55.160(a), but amended the subsection by removing references to gas when determining the production tax value of oil for purposes of the progressive tax on oil.*

Section 8. Amends AS 43.55.165(h), relating to the requirement that the Department of Revenue adopt regulations for allocating lease expenditures, by requiring that the Department of Revenue consider allocating lease expenditures in proportion to the BTU equivalent barrels of oil produced and gas produced from each lease or property. *Section 9 in CSSB 305(FIN), Draft Version "P" also amended AS 43.55.165(h) in the same manner.*

Section 9. Adds a new subsection, AS 43.55.170(d), which is similar to the amendment to AS 43.55.165(h) in sec. 8, but is applicable to allocating adjustments to lease expenditures. Directs the Department of Revenue to consider allocating adjustments based on the proportion of the BTU equivalents of oil and gas produced. *Section 10 in CSSB 305(FIN), Draft Version "P" also amended AS 43.55.170 by adding a new subsection in the same manner.*

Section 10. Requires a producer that underpays an installment payment after December 31, 2009 and before the effective date because of the retroactive application of the new progressive tax section to pay the amount of the underpayment on the date the first installment payment is due after the effective date of the Act. *There is no similar section in CSSB 305(FIN), Draft Version "P" because the changes in that version were applicable after the effective date of the Act.*

Section 11. Makes the progressive tax provisions of the bill - secs. 2 - 4 and 7 - retroactive to January 1, 2010. *There is no similar section in CSSB 305(FIN), Draft Version "P" because the changes in that version were applicable after the effective date of the Act.*

Section 12. Makes the Act take effect immediately. *The immediate effective date is the same as the immediate effective date in sec. 11 of CSSB 305(FIN), Draft Version "P."*

Bill sections in CSSB 305(FIN), Draft Version "P" that have no counterpart in
CSSB 305(FIN), Draft Version "T"

Sec. 3 in CSSB 305(FIN), Draft Version "P", that amends AS 43.55.011(j) by adding a reference to AS 43.55.011(e)(1), rather and AS 43.55.011(e) because of the exclusion of the progressive tax on gas in that bill, has no counterpart in CSSB 305(FIN), Draft Version "T", which has a progressive tax on gas.

Sec. 4 in CSSB 305(FIN), Draft Version "P" that amends AS 43.55.011(o) by adding a reference to AS 43.55.011(e)(1), rather and AS 43.55.011(e) because of the exclusion of the progressive tax on gas in that bill, has no counterpart in CSSB 305(FIN), Draft Version "T", which has a progressive tax on gas.

Sec. 8 in CSSB 305(FIN), Draft Version "P" that amends AS 43.55.160(c) by removing a reference to gas for the purpose of determining the progressive tax rate on gas has no counterpart in CSSB 305(FIN), Draft Version "T", which has a progressive tax on gas.

Sec. 11 in CSSB 305(FIN), Draft Version "P" made the Act applicable after the effective date of the Act; CSSB 305(FIN), Draft Version "T" has no similar provision because of the retroactive effect of provisions in the bill.

DMB:med
10-022.lmb

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number: 1
 Bill Version: CSSB 305(FIN)
 (S) Publish Date: 3/31/2010

Identifier (file name): 2010 03 31 FN CSSB305 SFIN Dept. Affected: Revenue
 Title: _____ RDU: Taxation and Treasury
 Component: Tax Division
 Sponsor: Senate Finance Committee
 Requester: Senate Finance Committee Component Number: 2476

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2011	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
OPERATING EXPENDITURES								
Personal Services								
Travel								
Contractual	0.0							
Supplies								
Equipment								
Land & Structures								
Grants & Claims								
Miscellaneous								
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES								
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CHANGE IN REVENUES ()	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts								
1003 GF Match								
1004 GF	0.0							
1005 GF/Program Receipts								
1037 GF/Mental Health								
Other Interagency Receipts								
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2010) cost: 0.0

POSITIONS

Full-time	0.0							
Part-time								
Temporary								

ANALYSIS: (Attach a separate page if necessary)

This bill separates oil and natural gas for purposes of calculating the progressivity portion of the production tax under AS 43.55. Under this bill the progressivity surcharges for oil and Cook Inlet and in-state gas would be calculated together, but distinctly from export gas, instead of the current practice on all oil and gas combined. The progressivity structure itself would be unchanged, based on 0.4% of the production that value that exceeds \$30 per barrel for oil, and \$30 per BTU barrel of oil equivalent for gas. The base tax rate is unchanged at 25% of production tax value.

Prepared by: Miles Baker, Finance Aide
 Division: Senate Finance Committee
 Approved by: Senator Stedman, Co-Chair
Senate Finance Committee

Phone: (907) 465-3873
 Date/Time: 3/30/2010 7:00pm
 Date: 3/31/2010 8:00am

FISCAL NOTE # 1

STATE OF ALASKA
2010 LEGISLATIVE SESSION

BILL NO. CSSB 305(FIN)

ANALYSIS CONTINUATION

Under current law the tax rate is based on the combined BTU value of oil and gas. However, oil and gas can have vastly different values on a BTU basis. Currently a BTU of oil is worth much more than a BTU of gas. Accordingly, once a major gas sale would start up, overlaying the existing oil production, the BTU value of the combined oil and gas would be much lower than it was for oil alone. This could cause a significant reduction in oil taxes as a result of a major gas sale.

This structure, in conjunction with the inherent uncertainty of future oil and gas prices, exposes the state to significant financial risk were a major gas sale to occur. The structure also creates economic instability for entities looking to participate in the development and financing of a natural gas pipeline project in Alaska.

Under the tax inducement provisions of the Alaska Gasline Inducement Act (AGIA), the tax structure in place at the time of the first binding open season (May 1, 2010), may be locked in for the first ten years of gas commercialization. Consequently, to the extent there is interest in decoupling our tax structure, it needs to be done before April 30, 2010.

The bill removes the dilution effect by having progressivity calculated distinctly for oil and gas. This will result in no reduction in oil taxes from a major gas sale.

As in current law, the bill gives the Department of Revenue the authority to adopt regulations to allocate costs between oil and gas, with the added instruction that a method based on relative BTU barrel of oil equivalents should be considered. That method was the one adopted by the department under the same authority for implementation of the current law, for the same purposes as would be for the proposed law.

Some producers currently produce Cook Inlet gas or other in-state gas along with North Slope oil. If all gas were separated from oil these producers would see an immediate tax increase. The bill is not intended to increase taxes on current activity. Having the progressivity for Cook Inlet gas and other in-state gas calculated together replicates the current situation, so these producers will see no tax increases. Only progressivity on export gas, like the gas from a major gas sale, would be calculated distinctly. This will prevent a major gas sale from diluting progressivity on oil.

Expenditures

The Tax Division is in the process of developing a new, single, comprehensive, integrated tax management system for all tax types. The new system will incorporate tax programs and recent tax changes as necessary to improve the efficiency and accuracy of the Division's revenue collection efforts. There is a \$300,000 request in the Governor's FY2011 Capital Budget to complete the agency's IT plan for submission and review by the Enterprise Investment Board. It is assumed that the tax structure changes contained in this bill will be addressed by this systemwide review and eventual restructuring project.

To: Senate Finance Committee

Attn: Senator Bert Stedman, Co-Chairman

From: David Wood

Date: 2 March, 2010

Re: Answer to Question & Request Raised by Senator Thomas during My Testimony (25 February 2010) – Fiscal Years 2008 and 2009

The very pertinent and perceptive question asked earlier today by Senator Thomas sought information with respect to how might the gas dilution / cross subsidy effect identified in Alaska's current production tax rules have impacted the production taxes actually paid in recent periods had a gas line been in operation at the time?

In order to provide an indicative answer to this question I have taken the data for price, volume and costs (excluding Cook Inlet Gas) for fiscal years 2008 and 2009 (i.e. July 2007 to June 2008 and July 2008 to June 2009), which are available from the Alaska Department of Revenue (DOR), Fall 2008 and 2009 Revenues Sources Books (RSB), (Dec 2008 and Dec 2009). These two periods encompass the wide range of oil prices that prevailed since the ACES rules were in place. The six tables attached (three for each fiscal period) to this document provide the necessary data and calculations to establish the impact of the cross subsidy effect.

Note that in this calculation the annual figures for production volumes and costs are distributed pro rata according to days / month across each month of the year. This assumption was necessary as DOR do not publish a monthly breakdown of the production tax calculation. This approximation is responsible for the small difference between the actual production tax paid and that calculated in the tables that follow. For fiscal year 2008 the calculated production tax shown in Table 1 is 2.7% higher than the actual production tax paid (\$6867.3 million). For fiscal year 2009 the calculated production tax shown in Table 1 is 4.5% higher than the actual production tax paid (\$3112.0 million). These slight differences are not considered significant in the context of the purpose of this analysis.

Fiscal Year 2008

Table 1 calculates the production tax for oil based on actual data showing the components of that calculation. As no gas is exported the calculations are based upon oil barrels only. This results in total production tax of **\$ 7.462 billion** which is reduced by investment credits of \$411.5 million to \$ 7.050 billion. The calculation shown essentially reproduces the figures from the RSB (2.7% difference attributed to monthly pro rata production and cost allocations).

Table 2 assumes a 4.5 bcf/day gas line and calculates production tax for this hypothetical gas stream on a stand-alone basis (i.e. not combined with oil). The calculation uses the U.S. wellhead natural gas prices from the EIA's records for the months in question. There would be some small differentials between these prices and AECO prices in Alberta, but I believe they are close enough for the purpose. I have also assumed gas transportation costs of \$4.5/mcf (\$27/boe) and field costs (capital costs plus operating costs) of \$400 million (\$1.46/ boe) which are those used by Commissioner Galvin in the examples he provided from the DOR in his testimony of 24 February 2010. This data computes a total production tax of **\$ 1.140 billion** to which no investment credits are applied.

By adding the computed production taxes in tables 1 and 2 the stand-alone oil and gas production tax for this FY 2008 (assuming 4.5 bcf /day) would be **\$8.599 billion** (reduced to \$8.187 billion by the deduction of \$411.5 million investment credits).

Table 3 calculates the production tax by combining the revenue cost and volume streams from tables 1 and 2 to provide a combined oil and gas production tax calculation of **\$6.776 billion** (reduced to \$6.365 billion by the deduction of \$411.5 million investment credits).

For this period the loss to the State in production tax revenue caused by the cross subsidy effect of combining oil and gas in the production tax calculation would have amounted to:

$$\text{\$6.776 billion less \$8.599 billion} = \text{-\$1.822 billion.}$$

This calculation is in line with the figures of potential loss in fiscal revenue discussed during the testimonies.

Fiscal Year 2009

Table 4 calculates the production tax for oil based on actual data showing the components of that calculation. As no gas is exported the calculations are based upon oil barrels only. This results in total production tax of **\$ 3.601 billion** which is reduced by investment credits of \$350 million to \$ 3.251 billion. The calculation shown essentially reproduces the figures from the RSB (4.5% difference attributed to monthly pro rata production and cost allocations).

Table 5 assumes a 4.5 bcf/day gas line and calculates production tax for this hypothetical gas stream on a stand-alone basis (i.e. not combined with oil). The calculation uses the U.S. wellhead natural gas prices from the EIA's records for the months in question. There would be some small differentials between these prices and AECO prices in Alberta, but I believe they are close enough for the purpose. I have also assumed gas transportation costs of \$4.5/mcf (\$27/boe) and field costs (capital costs plus operating costs) of \$400 million (\$1.46/ boe) which are those used by Commissioner Galvin in the examples he provided from the DOR in his testimony of 24 February 2010. This data computes a total production tax of **\$ 0.583 billion** to which no investment credits are applied.

By adding the computed production taxes in tables 1 and 2 the stand-alone oil and gas production tax for this FY 2009 (assuming 4.5 bcf /day) would be **\$4.185 billion** (reduced to \$3.835 billion by the deduction of \$350 million investment credits).

Table 6 calculates the production tax by combining the revenue cost and volume streams from tables 4 and 5 to provide a combined oil and gas production tax calculation of **\$3.381 billion** (reduced to \$3.031 billion by the deduction of \$350 million investment credits).

For this period the loss to the State in production tax revenue caused by the cross subsidy effect of combining oil and gas in the production tax calculation would have amounted to:

\$3.381 billion less \$4.185 billion = -\$0.804 billion.

This calculation indicates a lower potential loss in fiscal revenue for fiscal year 2009 compared to fiscal year 2008. This is due to the lower prices and value of oil and gas revenue streams in fiscal year 2009. However, \$0.8 billion remains a substantial potential loss in a relative low price / value environment.

Sincerely,

David Wood

dw@dwasolutions.com

2 March 2010

Table 1. Oil Stand-alone Production Tax Calculation (July 2007 to June 2008)

FY 2008 Production Tax Revenues: Actual Versus Potential Under Alternative Mechanisms (Analysis Based on Actual US West Coast Prices and Cost Data)																	
Month	US West Coast Oil Price	Per Barrel Total Costs	Per Barrel Production Tax Value	Progressivity Threshold	PTV less Progressivity Threshold	PTV Rate per Dollar of Adjusted PTV	Incremental Rate	Volume (Millions barrels)	Combined Progressivity Tax (CPT)	Base Production Tax (BPT) Rate	Base Production Tax (BPT) Value	CPT + BPT Value	CPT + BPT less Investment Credits				
	\$/barrel	\$/barrel	PTV \$/barrel	\$/barrel	\$/barrel	%	%	millions barrels	\$ millions	%	\$ millions	\$ millions	\$ millions				
A	B	C	D= {B + C}	E	F= (D + E) >= 0	G	H= (F * G)	I	J= (D * H * I)	K	L= (D * I * K)	M= (J + L)	N= (M - P)				
Monthly Analysis, \$30 PTV \$/boe threshold and 0.004% progressivity parameter under Current Law as enacted in 2007																	
Jul	75.93	-22.88	53.05	-30	23.05	0.40%	9.22%	19.4	95.0	25.00%	257.5	352.5					
Aug	73.83	-22.88	50.95	-30	20.95	0.40%	8.38%	19.4	82.9	25.00%	247.4	330.3					
Sep	79.92	-22.88	57.04	-30	27.04	0.40%	10.81%	18.8	115.9	25.00%	268.0	383.9					
Oct	84.77	-22.88	61.89	-30	31.89	0.40%	12.75%	19.4	153.3	25.00%	300.5	453.8					
Nov	92.98	-22.88	70.10	-30	40.10	0.40%	16.04%	18.8	211.3	25.00%	329.3	540.6					
Dec	88.64	-22.88	65.76	-30	35.76	0.40%	14.30%	19.4	182.7	25.00%	319.3	501.9					
Jan	91.16	-22.88	68.28	-30	38.28	0.40%	15.31%	19.4	203.0	25.00%	331.5	534.5					
Feb	94.42	-22.88	71.54	-30	41.54	0.40%	16.61%	18.2	215.9	25.00%	324.9	540.8					
Mar	105.06	-22.88	82.18	-30	52.18	0.40%	20.87%	19.4	333.1	25.00%	399.0	732.1					
Apr	112.37	-22.88	89.49	-30	59.49	0.40%	23.79%	18.8	400.2	25.00%	420.4	820.6					
May	125.41	-22.88	102.53	-30	72.53	0.40%	29.01%	19.4	577.6	25.00%	497.8	1075.4					
Jun	133.78	-22.88	110.90	-30	80.90	0.40%	32.36%	18.8	674.4	25.00%	521.0	1195.5					
Totals:								229.3	8245.3	25.00%	4216.6	7461.9	7050.4				
Data Source: Alaska Department of Revenue (DOR), Fall 2008 Revenues Sources Book (RSB), (Dec 2008)																	
FY2008 Taxable North Slope barrels /day: 626,456										229.3 millions barrels in FY2008		Lease Expenditures (\$/bb): 16.78		TT&T (\$/bb): 6.10		Capex Credits (\$ millions): 411.5	

2 March 2010

Table 2. Gas Stand-alone Production Tax Calculation (July 2007 to June 2008) [Assuming Gas Line Operational]

FY 2008 Production Tax Revenues: 4.5 bcf /day Hypothetical Gas Sales (Standalone Production Tax Calculation)
(US Gas Price Data from EIA)

Month	EIA U.S.	Per Barrel Production Tax Value	PTV less Progressivity Threshold \$/boe	PTV less Progressivity Threshold \$/boe	PTV Rate per Dollar of Adjusted PTV %	Incremental Progressivity Rate %	Volume (Millions boe) millions boe	Progressivity Tax (Gas Tax (Gas Separately) \$/ millions	Base Production Tax (BPT) Rate	Base Production Tax (BPT) Value \$/ millions	Total Production Tax (BPT + CPT + BPT less Investment Credits \$/ millions				
	Wellhead Price \$/mcf										Per BOE Total Costs for Gas \$/boe	Progressivity Threshold \$/boe	Progressivity Threshold \$/boe	Progressivity Threshold \$/boe	Progressivity Threshold \$/boe
A	B	C	D=	E	F=	G	H=	I	J=	K	L=	M=	N=		
2007/2008			(B + C)		(D + E) >= 0		(F * G)		(D * H * I)		(D * I * K)	(J + L)	(M - P)		
Monthly Analysis, \$30 PTV \$/boe threshold and 0.004% progressivity parameter under Current Law as enacted in 2007															
Jul	6.32	-28.46	9.46	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	55.0	55.0			
Aug	5.87	-28.46	6.76	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	39.3	39.3			
Sep	5.42	-28.46	4.06	-30	0.00	0.40%	0.00%	22.5	0.0	25.00%	22.9	22.9			
Oct	5.90	-28.46	6.94	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	40.4	40.4			
Nov	6.58	-28.46	11.02	-30	0.00	0.40%	0.00%	22.5	0.0	25.00%	62.0	62.0			
Dec	6.97	-28.46	13.36	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	77.7	77.7			
Jan	6.99	-28.46	13.48	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	78.4	78.4			
Feb	7.55	-28.46	16.84	-30	0.00	0.40%	0.00%	21.8	0.0	25.00%	91.6	91.6			
Mar	8.29	-28.46	21.28	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	123.7	123.7			
Apr	8.94	-28.46	25.18	-30	0.00	0.40%	0.00%	22.5	0.0	25.00%	141.7	141.7			
May	9.81	-28.46	30.40	-30	0.40	0.40%	0.16%	23.3	1.1	25.00%	176.7	177.9			
Jun	10.82	-28.46	36.46	-30	6.46	0.40%	2.59%	22.5	21.2	25.00%	205.1	226.3			
Totals:								274.5	22.8	25.00%	1114.8	1186.7	1186.7		
Data Source: EIA for gas price										TT&T (\$/mcf):		4.5			
Hypothetical gas production (bcf/day):			4.5		274.5 millions boe in FY2008		Lease Expenditures (\$/boe)		1.46		TT&T (\$/boe):		27.00		
										Capex Credits (\$ millions):		0.0			
Combined Production Tax Calculated on an oil + gas stand-alone calculation:												8998.5		8187.0	

2 March 2010

Table 3. Oil & Gas Combined Production Tax Calculation (July 2007 to June 2008)

FY 2008 Production Tax Revenues: Oil plus Gas Combined														
(Analysis Assumes Actual Oil Plus Hypothetical Gas)														
Month	Oil + Gas		Per Barrel Production Tax Value	PTV less Progressivity Threshold	PTV less Progressivity Threshold	PTV Rate per Dollar of Adjusted PTV	Incremental Progressivity Rate	Oil + Gas Volume (Millions boe)	Combined Progressivity Tax (CPT)	Base				
	Effective BOE Price	Effective Per BOE Total Costs								Base Production Tax (BPT) Rate	Base Production Tax (BPT) Value	CPT + BPT Value	CPT + BPT less \$400 in credits	
A	B	C	D= (B + C)	E	F= (D + E) >= 0	G	H= (F * G)	I	J= (D * H * I)	K	L= (D * I * K)	M= (J + L)	N= (M - P)	
Monthly Analysis, \$30 PTV \$/boe threshold and 0.004% progressivity parameter under Current Law as enacted in 2007														
Jul	55.22	-25.92	29.30	-30	0.00	0.40%	0.00%	42.7	0.0	25.00%	312.5	312.5		
Aug	52.79	-25.92	26.87	-30	0.00	0.40%	0.00%	42.7	0.0	25.00%	286.7	286.7		
Sep	54.09	-25.92	28.17	-30	0.00	0.40%	0.00%	41.3	0.0	25.00%	290.8	290.8		
Oct	57.87	-25.92	31.95	-30	1.95	0.40%	0.78%	42.7	10.6	25.00%	340.8	351.4		
Nov	63.83	-25.92	37.91	-30	7.91	0.40%	3.16%	41.3	49.5	25.00%	391.3	440.9		
Dec	63.13	-25.92	37.21	-30	7.21	0.40%	2.88%	42.7	45.8	25.00%	396.9	442.7		
Jan	64.34	-25.92	38.42	-30	8.42	0.40%	3.37%	42.7	55.2	25.00%	409.9	465.1		
Feb	67.66	-25.92	41.74	-30	11.74	0.40%	4.69%	39.9	78.2	25.00%	416.5	494.7		
Mar	74.92	-25.92	49.00	-30	19.00	0.40%	7.60%	42.7	158.9	25.00%	522.7	681.6		
Apr	80.37	-25.92	54.45	-30	24.45	0.40%	9.78%	41.3	219.9	25.00%	562.1	782.0		
May	89.15	-25.92	63.23	-30	33.23	0.40%	13.29%	42.7	358.6	25.00%	674.5	1033.1		
Jun	96.26	-25.92	70.34	-30	40.34	0.40%	16.14%	41.3	468.7	25.00%	726.1	1194.8		
Totals:								503.8	1445.4	25.00%	5320.9	6776.3	6364.8	
Difference Between Production Tax Calculated on a combined Oil & Gas Basis Minus Standalone Oil and Gas Basis:											-1822.3	-1822.3	P	
											Capex Credits (\$ millions):		411.5	

2 March 2010

Table 4. Oil Stand-alone Production Tax Calculation (July 2008 to June 2009)

FY 2009 Production Tax Revenues: Actual Versus Potential Under Alternative Mechanisms (Analysis Based on Actual US West Coast Prices and Cost Data)														
	US West Coast Oil Price	Per Barrel Total Costs	Per Barrel Production Tax Value	PTV less Progressivity Threshold	PTV less Progressivity Threshold	PTV Rate per Dollar of Adjusted PTV	Incremental Progressivity Rate	Volume (Millions barrels)	Combined Progressivity Tax (CPT)	Base Production Tax (BPT) Rate	Base Production Tax (BPT) Value	CPT + BPT Value	CPT + BPT less Investment Credits	
Month	\$/barrel	\$/barrel	PTV \$/barrel	\$/barrel	\$/barrel	%	%	millions barrels	\$ millions	%	\$ millions	\$ millions	\$ millions	
A	B	C	D=	E	F=	G	H=	I	J=	K	L=	M=	N=	
			(B + C)	(D + E) >= 0	(F * G)	(D * H * I)	(D * H * I)			(D * I * K)	(J + L)	(M - P)		
Monthly Analysis, \$30 PTV \$/boe threshold and 0.004% progressivity parameter under Current Law as enacted in 2007														
Jul	132.87	-26.15	106.72	-30	76.72	0.40%	30.69%	18.6	607.6	25.00%	495.0	1102.5		
Aug	115.98	-26.15	89.83	-30	59.83	0.40%	23.93%	18.6	398.8	25.00%	416.6	815.5		
Sep	101.86	-26.15	75.71	-30	45.71	0.40%	18.28%	18.0	248.5	25.00%	339.8	588.3		
Oct	73.65	-26.15	47.50	-30	17.50	0.40%	7.00%	18.6	61.7	25.00%	220.3	282.0		
Nov	53.94	-26.15	27.79	-30	-2.21	0.40%	-0.88%	18.0	-4.4	25.00%	124.7	120.3		
Dec	37.70	-26.15	11.55	-30	-18.45	0.40%	-7.38%	18.6	-15.8	25.00%	53.6	37.8		
Jan	39.01	-26.15	12.86	-30	-17.14	0.40%	-6.86%	18.6	-16.4	25.00%	59.6	43.3		
Feb	42.78	-26.15	16.63	-30	-13.37	0.40%	-5.35%	16.8	-14.9	25.00%	69.7	54.8		
Mar	47.75	-26.15	21.60	-30	-8.40	0.40%	-3.36%	18.6	-13.5	25.00%	100.2	86.7		
Apr	46.56	-26.15	20.41	-30	-9.59	0.40%	-3.84%	18.0	-14.1	25.00%	91.6	77.5		
May	58.23	-26.15	32.08	-30	2.08	0.40%	0.83%	18.6	4.9	25.00%	148.8	153.7		
Jun	69.80	-26.15	43.65	-30	13.65	0.40%	5.46%	18.0	42.8	25.00%	195.9	238.7		
								Totals:	218.4	1285.3	25.00%	2315.8	9601.1	3251.1
Data Source: Alaska Department of Revenue (DOR), Fall 2009 Revenues Sources Book (RSB), (Dec 2009)														
FY2009 Taxable North Slope barrels /day: 598,463				218.4 millions barrels in FY2009				Lease Expenditures (\$/bbl): 19.67		TT&T (\$/bbl): 6.48		Capex Credits (\$ millions):		P 350.0

Table 5. Gas Stand-alone Production Tax Calculation (July 2008 to June 2009) [Assuming Gas Line Operational]

FY 2009 Production Tax Revenues: 4.5 bcf /day Hypothetical Gas Sales (Standalone Production Tax Calculation) (US Gas Price Data from EIA)															
Month	EIA U.S. Wellhead Price		Per Barrel Production Tax Value		PTV less Progressivity Threshold		PTV Rate per Dollar of Progressivity		Incremental Progressivity Rate	Volume (Millions boe)	Progressivity Tax (Gas Calculated Separately)	Base Production Tax (BPT) Rate	Total Production Tax (BPT + CPT + BPT less Investment Credits)		
	\$/mcf	\$/boe	\$/boe	\$/boe	\$/boe	\$/boe	%	%					%	%	\$ millions
A	B	C	D=	E	F=	G	H=	I	J=	K	L=	M=	N=		
2007/2008			(B + C)	(D + E) >= 0	(F * G)	(H * I)	(D * H * I)	(J + L)	(M - P)						
Monthly Analysis, \$30 PTV \$/boe threshold and 0.004% progressivity parameter under Current Law as enacted in 2007															
Jul	10.62	-28.46	35.26	-30	5.26	0.40%	2.10%	23.3	17.2	25.00%	204.9	222.2			
Aug	8.32	-28.46	21.46	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	124.7	124.7			
Sep	7.27	-28.46	15.16	-30	0.00	0.40%	0.00%	22.5	0.0	25.00%	85.3	85.3			
Oct	6.36	-28.46	9.70	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	56.4	56.4			
Nov	5.97	-28.46	7.36	-30	0.00	0.40%	0.00%	22.5	0.0	25.00%	41.4	41.4			
Dec	5.87	-28.46	6.76	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	39.3	39.3			
Jan	5.15	-28.46	2.44	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	14.2	14.2			
Feb	4.19	-28.46	-3.32	-30	0.00	0.40%	0.00%	21.0	0.0	25.00%	0.0	0.0			
Mar	3.72	-28.46	-6.14	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	0.0	0.0			
Apr	3.43	-28.46	-7.88	-30	0.00	0.40%	0.00%	22.5	0.0	25.00%	0.0	0.0			
May	3.45	-28.46	-7.76	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	0.0	0.0			
Jun	3.45	-28.46	-7.76	-30	0.00	0.40%	0.00%	22.5	0.0	25.00%	0.0	0.0			
Totals:								273.8	17.2	25.00%	566.2	583.4	583.4		
Data Source: EIA for gas price										TT&T (\$/mcf):		4.5			
Hypothetical gas production (bcf/day):			4.5		273.8 millions boe in FY2009		Lease Expenditures (\$/boe)		1.46		TT&T (\$/boe):		27.00		
										Capex Credits (\$ millions):		0.0			
Combined Production Tax Calculated on an oil + gas stand-alone calculation:												4184.5		8834.5	

Table 6. Oil & Gas Combined Production Tax Calculation (July 2008 to June 2009)

FY 2009 Production Tax Revenues: Oil plus Gas Combined														
(Analysis Assumes Actual Oil Plus Hypothetical Gas)														
Month	Oil + Gas Effective BOE Price		Oil + Gas Effective Per BOE Total Production Tax Value		PTV less Progressivity Threshold		PTV Rate per Dollar of Adjusted PTV		Incremental Oil + Gas Volume Progressivity Rate		Base Production Tax (BPT) Rate		Base Production Tax (BPT) Value	
	A	B	C	D=	E	F=	G	H=	I	J=	K	L=	M=	N=
	\$/boe	\$/boe	PTV \$/boe	\$/boe	\$/boe	%	%	millions boe	\$ millions	%	\$ millions	\$ millions	\$ millions	\$ millions
			(B + C)		(D + E) >= 0	(F * G)	(D * H * I)			(D * I * K)	(J + L)	(M - P)		
Monthly Analysis, \$30 PTV \$/boe threshold and 0.004% progressivity parameter under Current Law as enacted in 2007														
Jul	94.41	-27.44	66.97	-30	36.97	0.40%	14.79%	41.8	414.1	25.00%	699.9	1114.0		
Aug	79.24	-27.44	51.80	-30	21.80	0.40%	8.72%	41.8	188.8	25.00%	541.4	730.2		
Sep	69.47	-27.44	42.03	-30	12.03	0.40%	4.81%	40.5	81.8	25.00%	425.1	506.9		
Oct	53.91	-27.44	26.47	-30	0.00	0.40%	0.00%	41.8	0.0	25.00%	276.7	276.7		
Nov	43.86	-27.44	16.43	-30	0.00	0.40%	0.00%	40.5	0.0	25.00%	166.1	166.1		
Dec	36.32	-27.44	8.88	-30	0.00	0.40%	0.00%	41.8	0.0	25.00%	92.8	92.8		
Jan	34.50	-27.44	7.06	-30	0.00	0.40%	0.00%	41.8	0.0	25.00%	73.8	73.8		
Feb	32.97	-27.44	5.53	-30	0.00	0.40%	0.00%	37.8	0.0	25.00%	52.2	52.2		
Mar	33.61	-27.44	6.17	-30	0.00	0.40%	0.00%	41.8	0.0	25.00%	64.5	64.5		
Apr	32.11	-27.44	4.67	-30	0.00	0.40%	0.00%	40.5	0.0	25.00%	47.3	47.3		
May	37.36	-27.44	9.92	-30	0.00	0.40%	0.00%	41.8	0.0	25.00%	103.7	103.7		
Jun	42.49	-27.44	15.06	-30	0.00	0.40%	0.00%	40.5	0.0	25.00%	152.3	152.3		
Totals:									492.2	684.7	25.00%	2695.7	3380.5	3030.5
Difference Between Production Tax Calculated on a combined Oil & Gas Basis Minus Standalone Oil and Gas Basis:												-604.1	-604.1	P
												Capex Credits (\$ millions):		350.0



Senator Joe Paskvan

Alaska State Senate • District E • Fairbanks • Ft Wainwright

March 26, 2010

Representative Mark Neuman
State Capitol, Room 432
Juneau, AK 99801-1182

Mark
Dear Representative Neuman,

You are likely aware of the discussions taking place in both chambers of the Alaska Legislature concerning decoupling and the legal implication that the first day of the open season has on Alaska's tax regime. Many have studied this topic and contributed much to the discussions. This letter is my attempt to respectfully convey my rationale for reaching the conclusion that decoupling is needed – and needed before May 1, the first day of the open season. I recognize that I am one legislator among sixty, but I feel that I would be remiss in my responsibilities if I did not share what I believe to be absolutely critical to our state's future. After reading, I invite you to contact me with any questions, comments or concerns regarding this important issue.

Following research into this matter, it is clear to me that the State of Alaska needs to separate its oil tax and its gas tax structures. This is necessary as the British thermal unit (BTU) equivalency benchmark currently in place is not relevant to the real world pricing of oil and gas. The 6:1 BTU benchmark was marginally acceptable when it applied to no gas production. Now that the ratio may actually apply to and be locked in under AGIA, Alaska needs to separate oil and gas taxation; to not do so would be dangerous to the State of Alaska's financial future.

Chart 1 (attached) depicts, from a historical view, the pricing deviation and the magnitude of the fluctuations from the BTU benchmark. The chart essentially shows the frequency of high oil pricing relative to gas pricing. If one looks at the chart while thinking about risk to the state under the currently linked tax structures, the chart shows that risk to the state exists about 95% of the time historically. The deviation from the benchmark means that the lower value gas is diluting the higher value oil under a combined tax structure. About 95% of the time, the risk is great for Alaska.

Recently, the ratio has been between 15:1 and 20:1, with occasional spikes even higher, such as August 2009, when a ratio greater than 20:1 existed. Today, too, the ratio is 20:1.

In Juneau:

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The best and only evidence available to the State Legislature indicates that for the immediate and long term (i.e., 20 years) that the deviation from the BTU benchmark will not only continue, but that the magnitude of the deviation will also continue. US Department of Energy (DOE) oil and gas pricing forecasts for 2020 to 2030 show oil at \$115 to \$130 per barrel; natural gas pricing is shown in the range of \$5.25 to \$7.50 per mcf. See Chart 2 (attached, two pages).

If one were to try to place this forecasted ratio on the Department of Revenue's chart, a 15:1 to 18:1 ratio would be, literally, off the chart. That should indicate to the Legislature that the potential risk to Alaska is also off the chart. Also, the risk to the state is for 100% of the forecasted period of time.

Using a Department of Revenue (DOR) presentation, the magnitude to the risk is shown in dollars — actually in billions of dollars. See Chart 3 (attached). Using mid-range oil pricing (i.e., \$120) and high gas pricing (i.e., \$8), the loss of revenues to the state is about \$2 billion per year. This risk is one that the state cannot afford to take. When one looks to the first two charts, the risk and magnitude of it is clear and Alaska is endangered.

To better understand the risk, and magnitude of that risk, a straightforward analysis of what \$2 billion means is helpful. Cumulatively, the \$2 billion represents 100% of the production tax (i.e., \$1.1B) plus 100% of the state's royalty (i.e., \$.7B) plus another \$.2B cash from savings. This is also shown in a slightly different DOR slide which shows the \$2B loss of revenues because of the linkage between oil and gas taxes producing negative combined revenues. See Chart 4 (attached). In other words, Alaska would get less revenue under the combined tax than if Alaska only collected oil revenues. This is an important reason why the linkage between oil and gas tax must be decoupled.

It is troubling to see DOR portraying the best information on 2020 – 2030 pricing (i.e., from the US DOE) as non-meaningful or, at best, as only a guess. In evaluating risk, the validity of information should only be questioned if more reliable or more credible information exists. Monetary figures are presented by DOR as if they are based upon a report or study or some other credible source. Possibly this omission of a source is done to argue that the risk portrayed in the non-fact-based slide is equal to the real risk based upon the reliable and credible information known. If so, this raises serious questions as to what standards, if any, are used by DOR in its presentations. If decisions are not based upon the best and only evidence, what is the standard which DOR does rely upon?

The reasons for the lack of logic may never be understood. Objectively, DOR can be viewed as rejecting the best and only evidence of pricing and relying upon the conjectural and speculative. This is apparently done to obstruct the decoupling of oil and gas tax structures.

Decoupling is the objectively reasonable method to avoid the risk to Alaska of losing, from both its royalty share and production tax, billions of dollars per year. It is objectively reasonable as it is based upon the best and only evidence from forecasted oil and gas pricing.

This letter addresses the financial risk to our state; it is, however, also appropriate to speak to the legal risk which has been mentioned by some. There are a number of legal opinions, including but not limited to the recent opinion of Attorney General Sullivan, which have touched upon the legal risk of acting now as compared to later. The only way that a definitive answer would be received, as to a later decoupling after May 1st, would be in the context of litigation against the State with the Alaska Supreme Court publishing a decision on a matter of first impression. We do not know, and cannot know, at this time the definitive answer as to what the Court's legal conclusion might be regarding a later decoupling. Therefore, it is prudent and wise in this context to act now when prompt action can be taken to avoid any legal risk in remedying the obvious financial risk to our state. Let me be clear, there is no legal risk by decoupling now.

I am not willing to bet the future of Alaska and risk losing billions per year based upon DOR's speculation, conjecture and non-fact based figures. The proper path to follow is to immediately decouple oil and gas taxation. This decoupling removes the risk to Alaska as it puts an end to the most perverse potential of Alaska giving away billions while our resource is exported. Decoupling secures Alaska's royalty share. Decoupling secures Alaska's receipt of production taxes.

Please do not hesitate to contact me directly if you have comments or questions.

Sincerely,

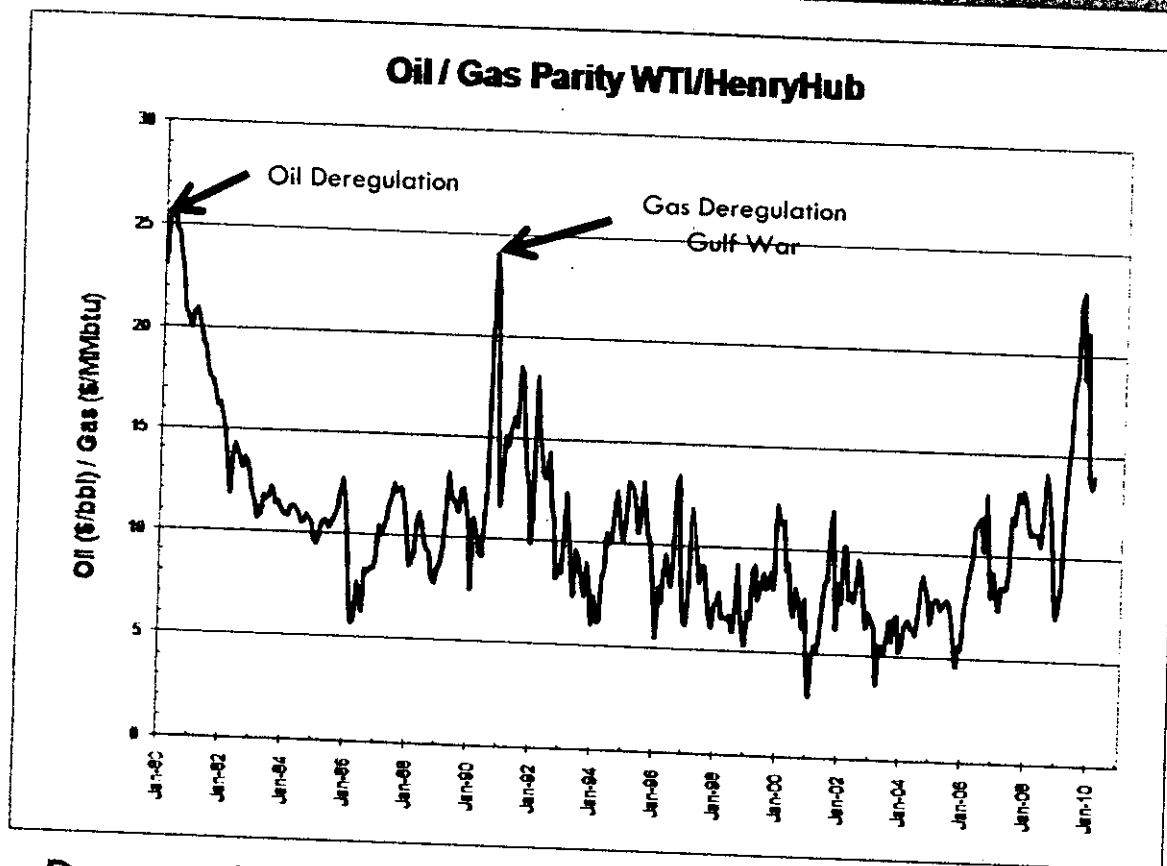


Senator Joe Paskvan

March 26, 2010

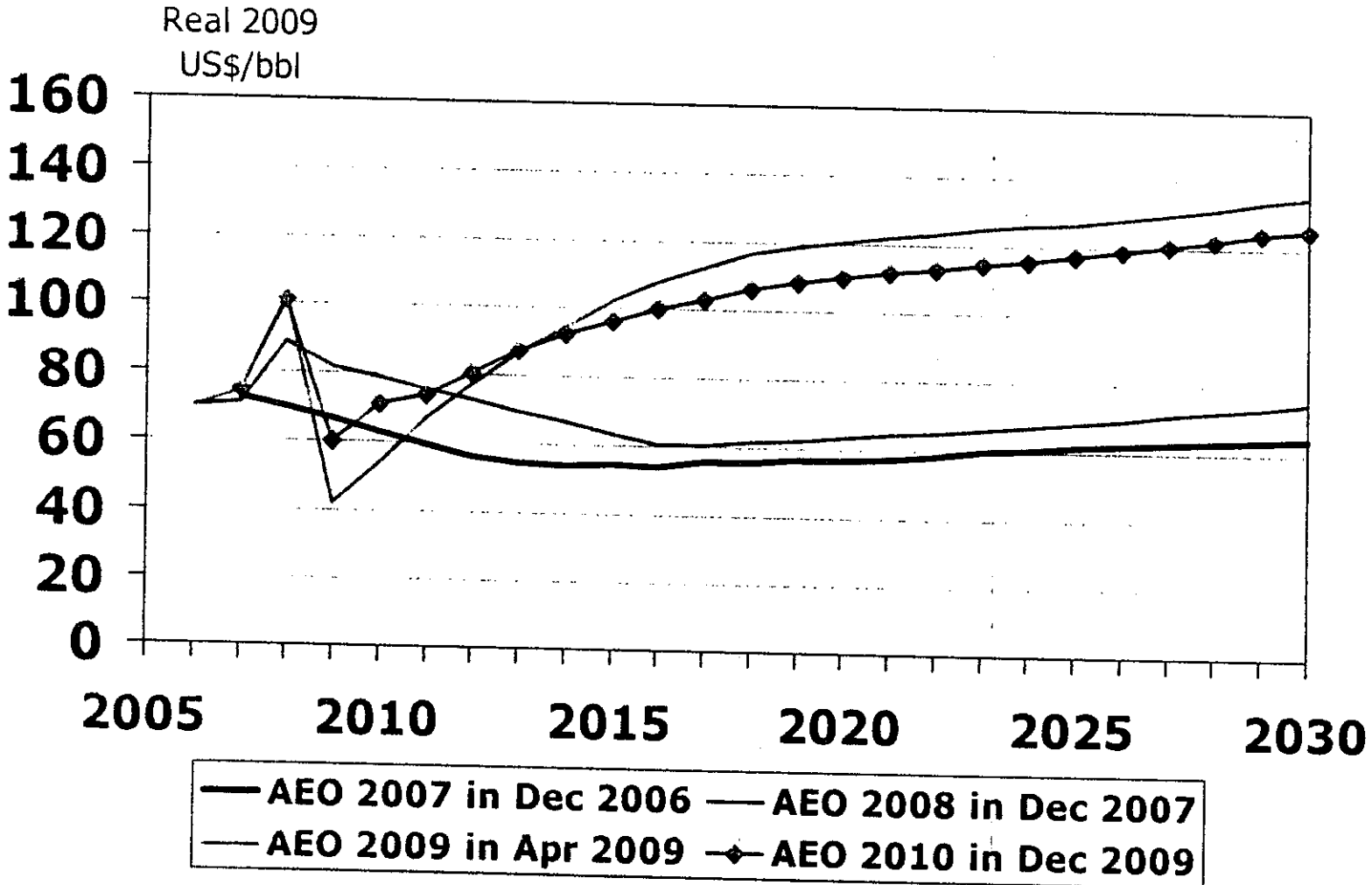
Page 3

The Oil/Gas Price Parity....



....Has Been Higher than Expected....

Comparison of Recent US DOE Annual Energy Outlooks for Light Sweet Imported Oil Prices



Comparison of Recent US DOE Annual Energy Outlooks for Alberta Hub Natural Gas Prices

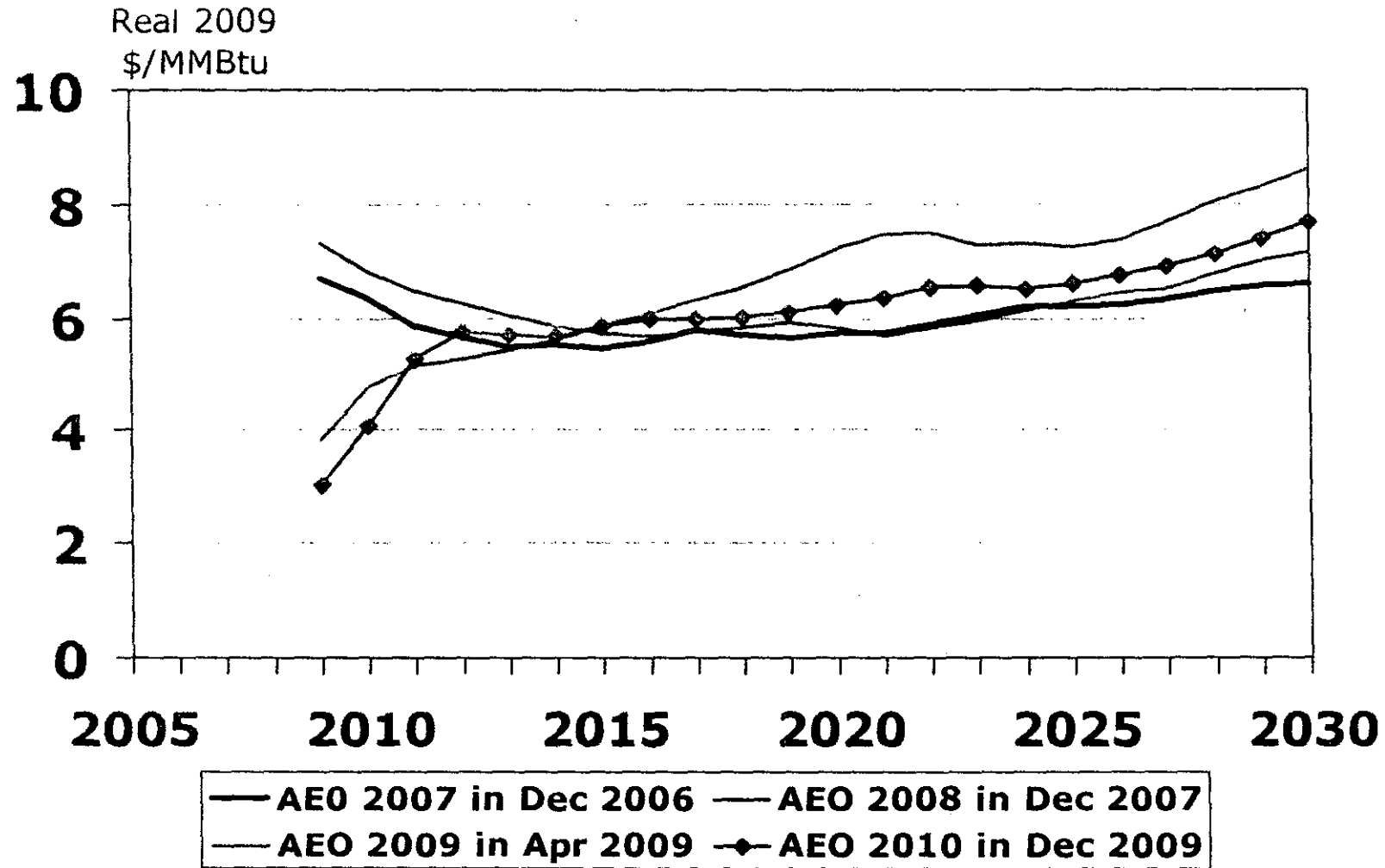
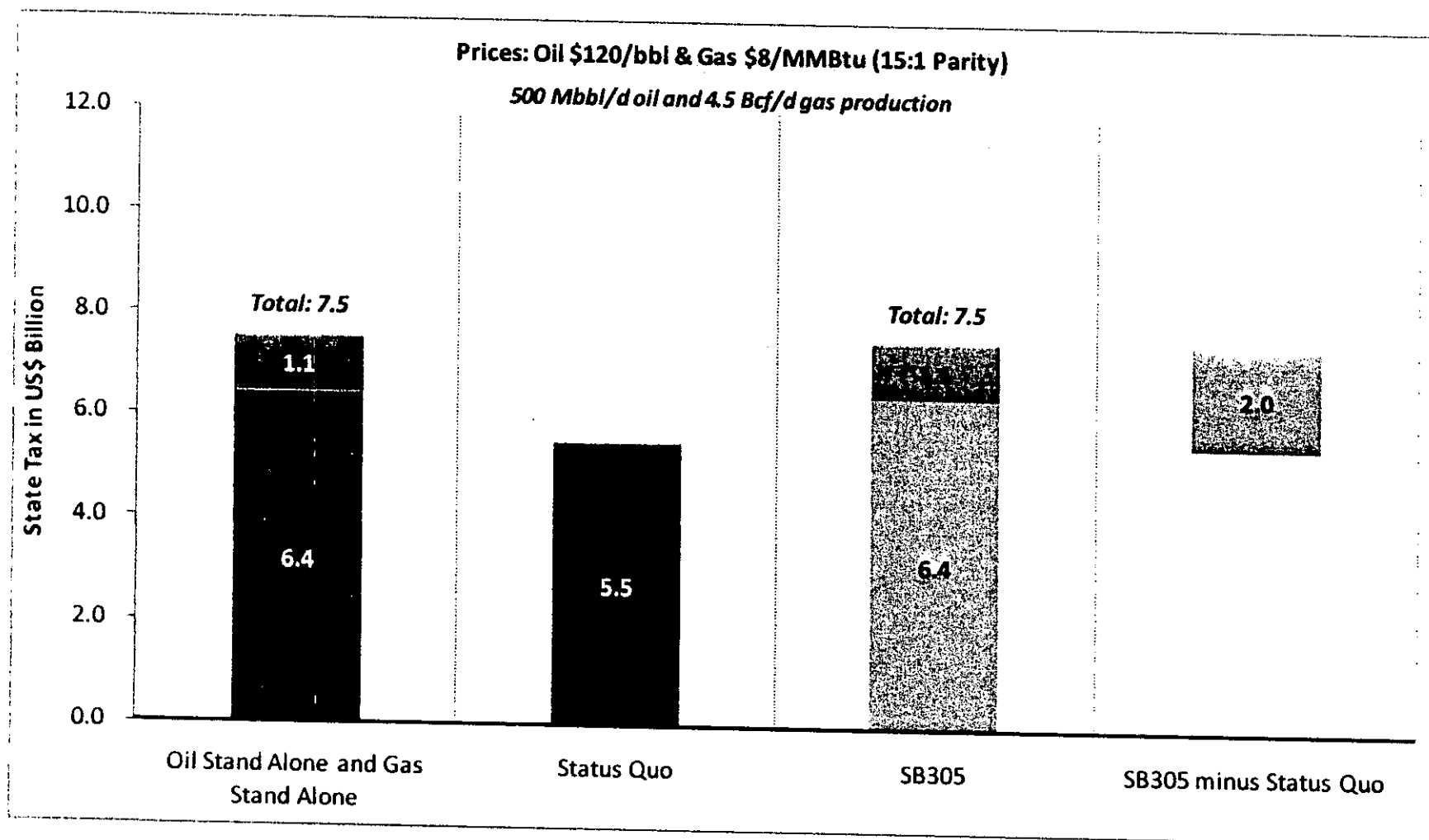


CHART 3

5342

	Oil	Gas	Combined
ANS Price	\$120.00\$/bbl	\$8.00\$/mmbtu	
Daily Production	500,000Bbl/d	4.5Bdf/d	
Annual Production	182,500,000 bbl	1,643Bcf/year	
Total Annual Gross Sales Value	\$21,900,000,000	\$13,140,000,000	\$35,040,000,000
Marine and TAPS Tariff on Oil	(\$6.50) \$/bbl		
Gas Pipeline and Gas Treatment Plant		(\$4.50) \$/mmbtu	
Transportation Costs	(\$1,186,250,000.00)	(\$7,391,250,000)	(\$8,577,500,000)
Value at Point Of Production	\$20,713,750,000	\$5,748,750,000	\$26,462,500,000
Royalty and Federal	(\$2,589,218,750.00)	(\$718,593,750.00)	(\$3,307,812,500)
Taxable Point of Production Value	\$18,124,531,250	\$5,030,156,250.00	\$23,154,687,500
<u>Lease Expenditures</u>			
Opex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
Capex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
Total Lease Expenditures	(\$4,000,000,000)	(\$400,000,000)	(\$4,400,000,000)
Production Tax Value (PTV)	\$14,124,531,250	\$4,630,156,250	\$18,754,687,500
PTV on BOE basis	\$88.45	\$19.33	\$47
Base Tax (25%*PTV)	\$3,531,132,813	\$1,157,539,063	\$4,688,671,875
Progressive Tax Rate	23.38%	0.00%	6.79%
Progressive Tax	\$3,302,376,216	\$0	\$1,273,703,865
Total Tax Due before credits	\$6,833,509,029	\$1,157,539,063	\$5,962,375,740
Credits Applied Against Taxes	(\$400,000,000)	(\$40,000,000)	(\$440,000,000)
Total Tax after credits	\$6,433,509,029	\$1,117,539,063	\$5,522,375,740

At high parity, SB305 > Status Quo



To: Rep. Craig Johnson
Rep. Mark Neuman
Co-Chairs, House Resources Committee

From: Roger Marks, Logsdon & Associates

Date: 4/2/10

Re: HB 414 - Oil/Gas Crossover Price for Production Tax Dilution Effect

On Wednesday March 31 we made a presentation on HB 414, the bill that would separate oil and gas for calculating the production tax. Oil and gas are combined under current law. Currently oil is valued much higher than gas. If that relationship endured to that time of a major gas sale, the addition of gas onto oil activity could dilute oil value, which could reduce oil taxes by a significant amount.

We presented Department of Revenue figures from February 24, 2010 that displayed the magnitude of the annual tax losses. They were as follows:

\$8/mmbtu gas / \$75/bbl oil (market prices): \$0.3 billion
\$8/mmbtu gas/ \$100/bbl oil (market prices): \$1.1 billion
\$8/mmbtu gas / \$120/bbl oil (market prices):\$2.0 billion

The question arose in the committee as to what the crossover points might be, the prices where the dilution effect would be zero. The other question was whether dilution would only occur when the market price of oil was more than 6 times the price of gas, the ratio of BTUs in a barrel of oil to an mmbtu (million BTUs) of gas.

First, the crossover would be determined by three other factors in addition to the market prices. First, it would depend on the relative volumes of oil and gas. Second, it would depend on the difference in transportation costs between oil and gas. Finally, it would also depend on the relative upstream capital and operating costs for oil and gas.

Using the Department of Revenue assumptions we calculated the crossover points. The assumptions were as follows:

Oil

Production of 500,000 bbls/day
Transportation cost deduction of \$6.50/bbl
Upstream capital costs of \$2 billion
Upstream operating costs of \$2 billion

Gas

Production of 4.5 bcf/day
Transportation cost deduction of \$4.50/mmbtu
Upstream capital costs of \$200 million
Upstream operating costs of \$200 million

We computed crossover points for the three oil prices and one gas price used in the above illustration:

Crossover Point where Dilution Effect is Zero

At \$75/bbl oil market price	Gas crossover point = \$11/mmbtu gas market price
At \$100/bbl oil market price	Gas crossover point = \$15/mmbtu gas market price
At \$120/bbl oil market price	Gas crossover point = \$18/mmbtu gas market price
At \$8/mmbtu gas market price	Oil crossover point = \$60/bbl oil market price

Monthly Oil and Natural Gas Price Analysis

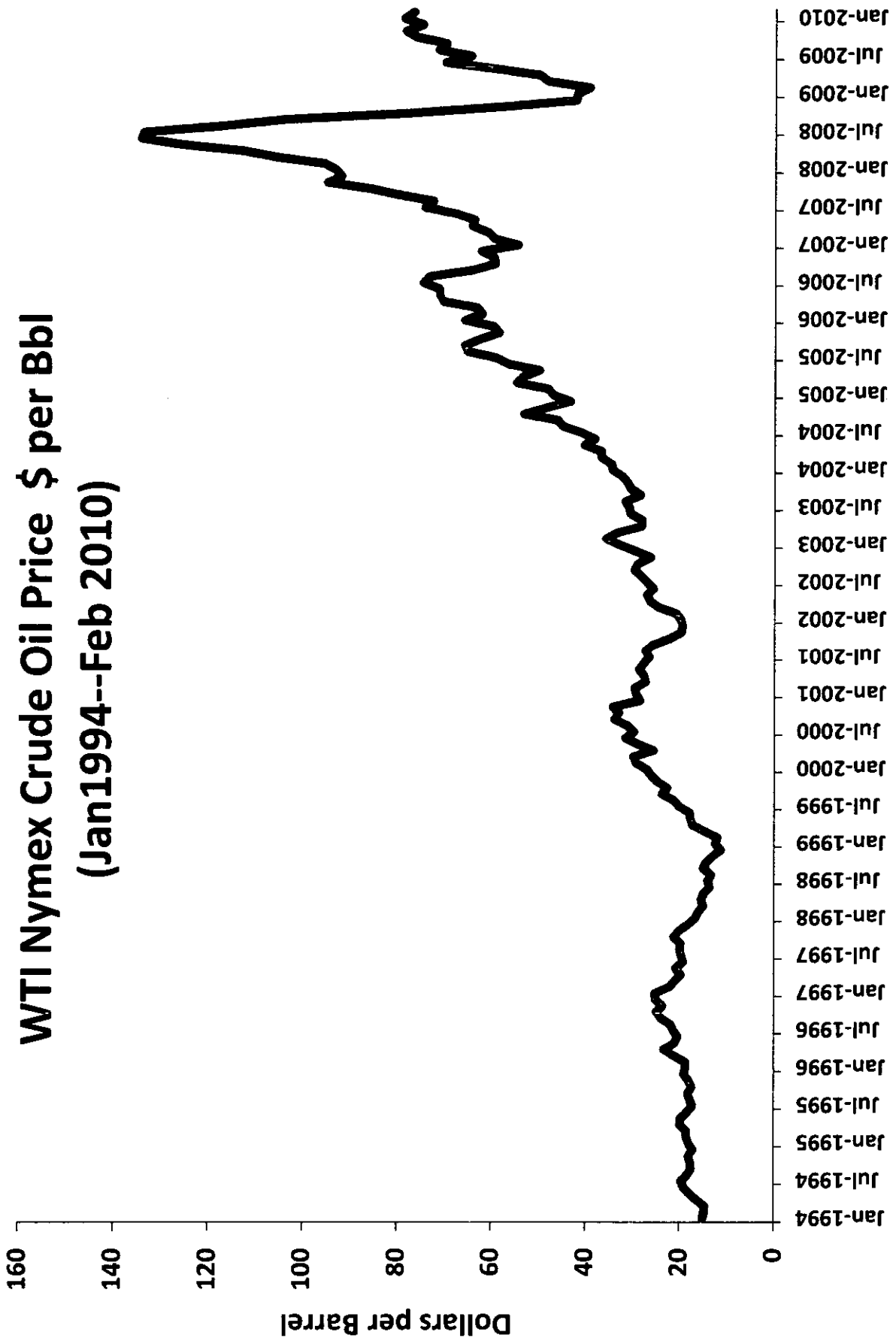
Logsdon and Associates

April 2, 2010

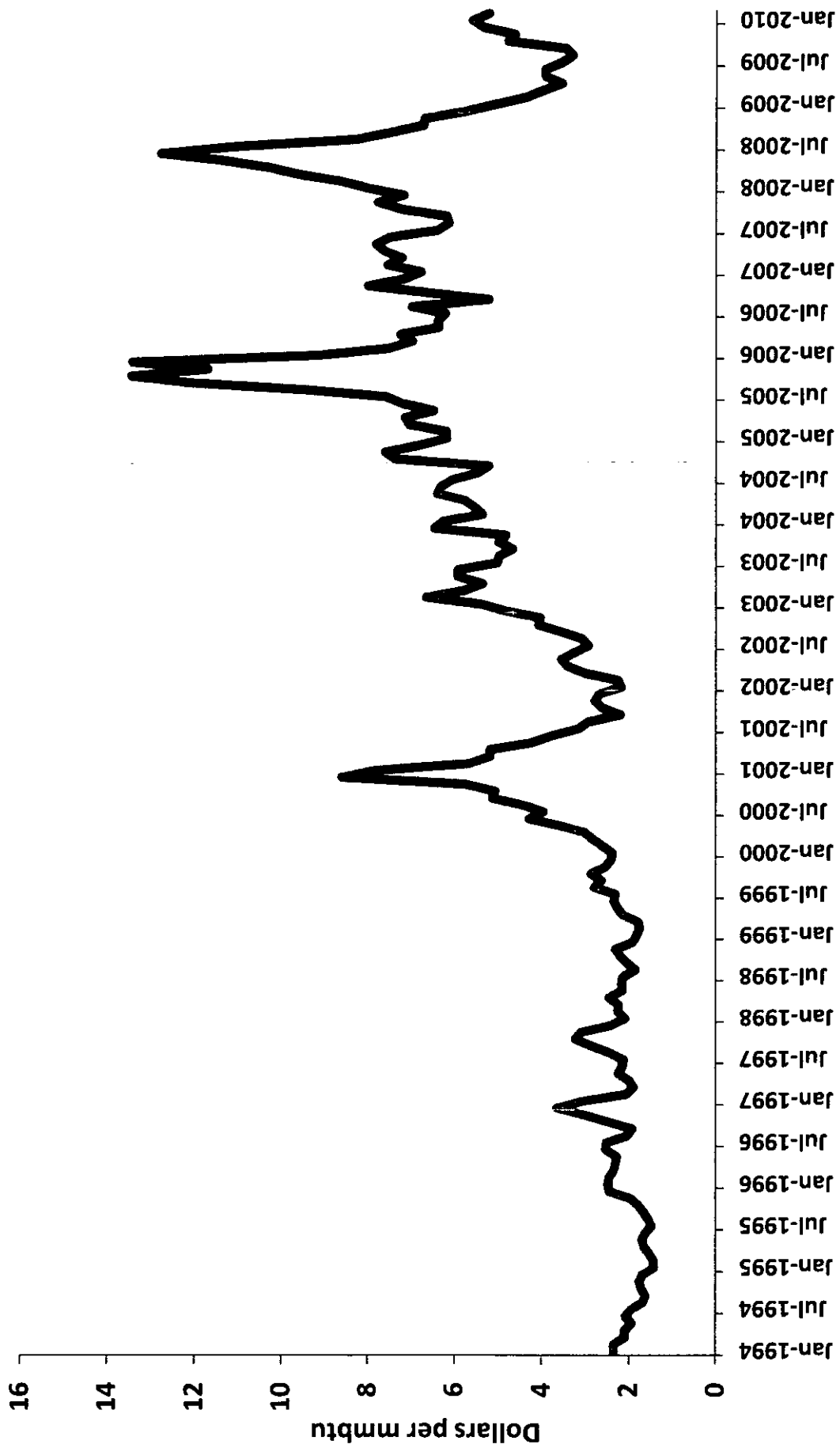
Average Monthly Closing Prices for U.S. Crude Oil and Natural Gas as Reported on the New York Mercantile Exchange (NYMEX)

- West Texas Intermediate (WTI) oil and Henry Hub Gas prices are quoted daily on the NYMEX. The near month contract tracks very closely with the spot price since the delivery of physical barrels of WTI oil and Henry Hub gas underwrite the futures contract.
- The spot price is assessed by survey of buyers and sellers of physical cargos or lots or tranches. The near month NYMEX contract is determined in a regulated transparent market.
- The following charts illustrate both volatility and trend of oil and natural gas prices over the last 16 years.
- The charts start in 1994 because that is the first year that the natural gas contract was offered on the NYMEX.
- The price of oil is stated in dollars per barrel. The price of gas is stated in millions of British thermal units (btu), a measure of energy content.

WTI Nymex Crude Oil Price \$ per Bbl (Jan 1994--Feb 2010)



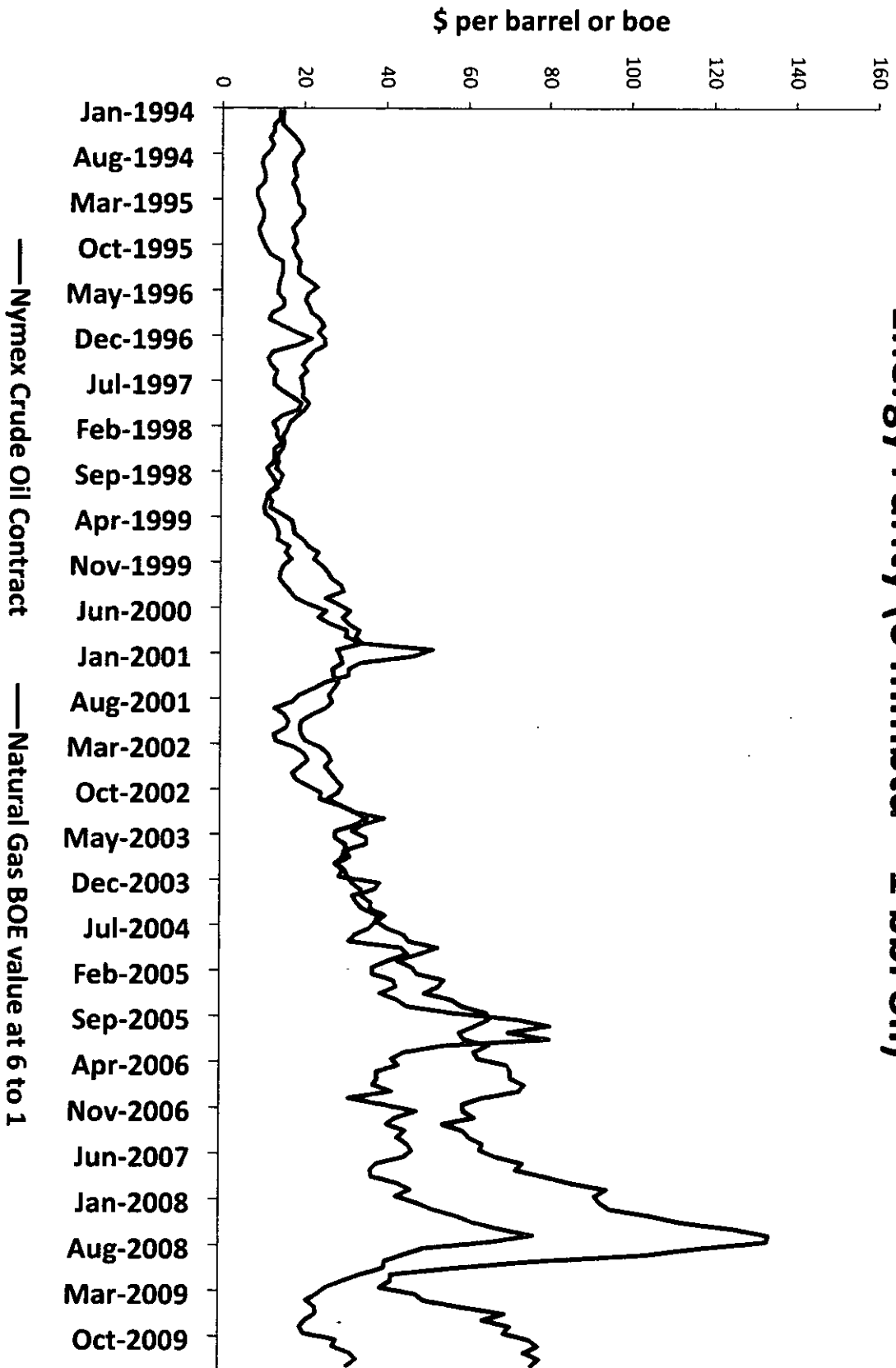
Henry Hub Nymex Natural Gas Futures Jan 1994—Feb 2010 (\$ per Million BTU)



Comparison of Oil and Gas on an Apples to Apples Basis

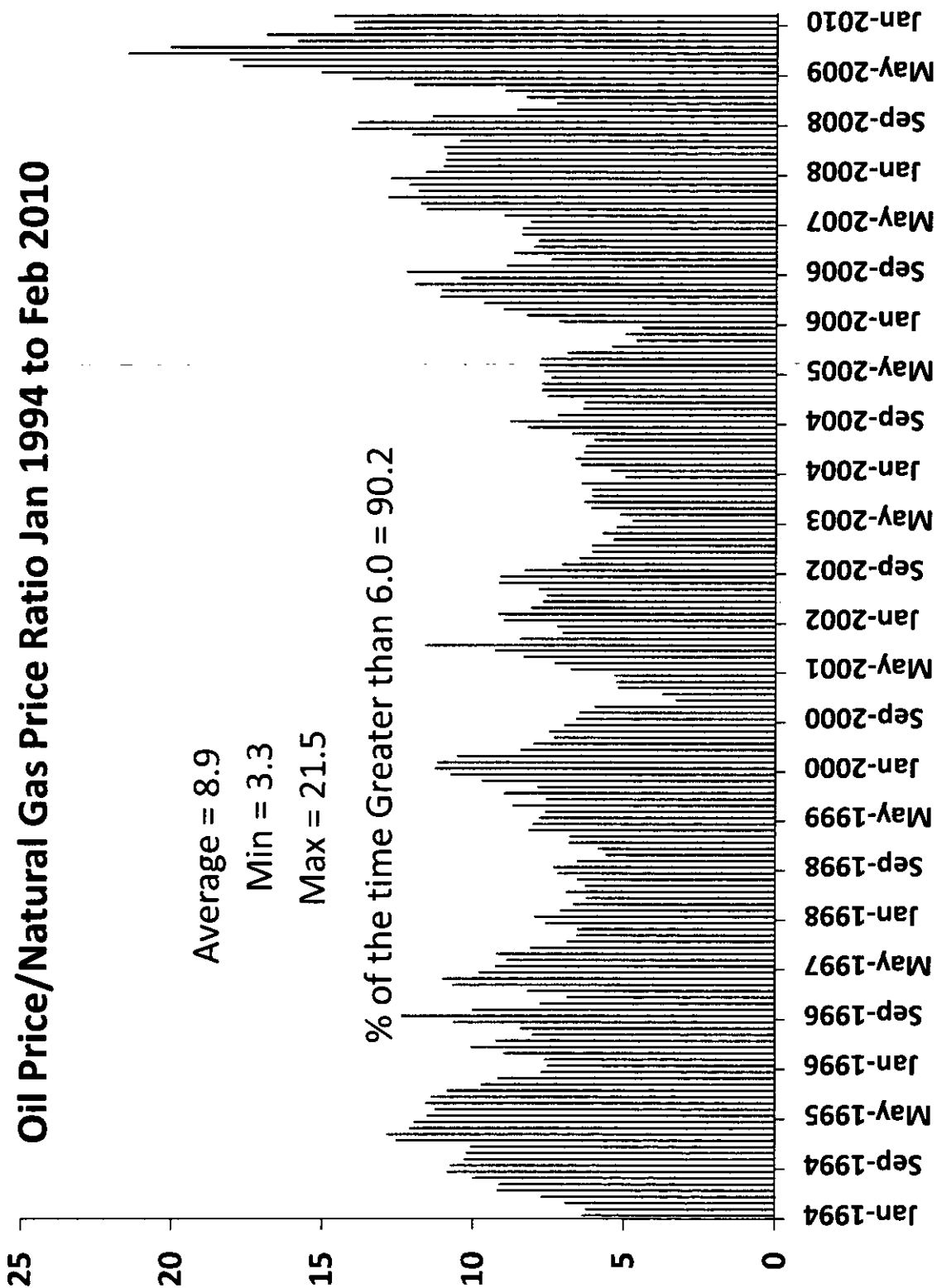
- The following chart makes an apples to apples comparison between the price of the two substances by converting the gas price to a barrel equivalent price based on the physical energy properties of the two substances. There are six million btu's in a barrel of oil and gas prices are quoted per one million btu.
- What you see is that gas tends to be less valuable on a per btu basis.

Nymex Oil vs. Nymex Natural Gas if Gas Sold at Energy Parity (6 mmbtu = 1 bbl oil)



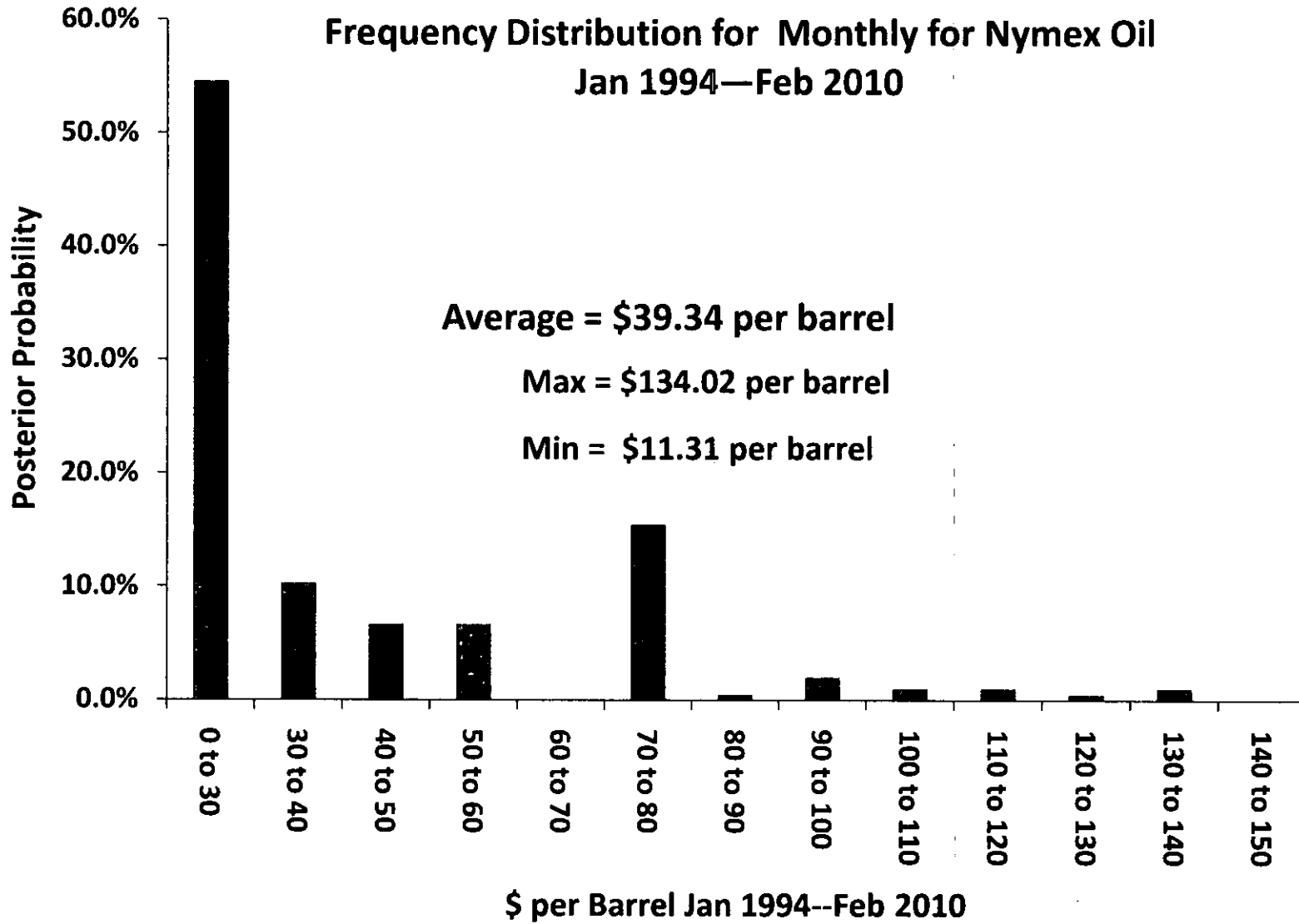
What is the historic number of btu's of gas needed to have the same value as a barrel of oil?

- The following chart makes this comparison.
- Clearly there have been some points in time when gas has sold at energy parity (6 to 1) or better with oil. This has not happened very often.
- The other thing to notice is that although there appears to be a partial correlation over time, the relationship between oil and gas prices is highly unstable from month to month.

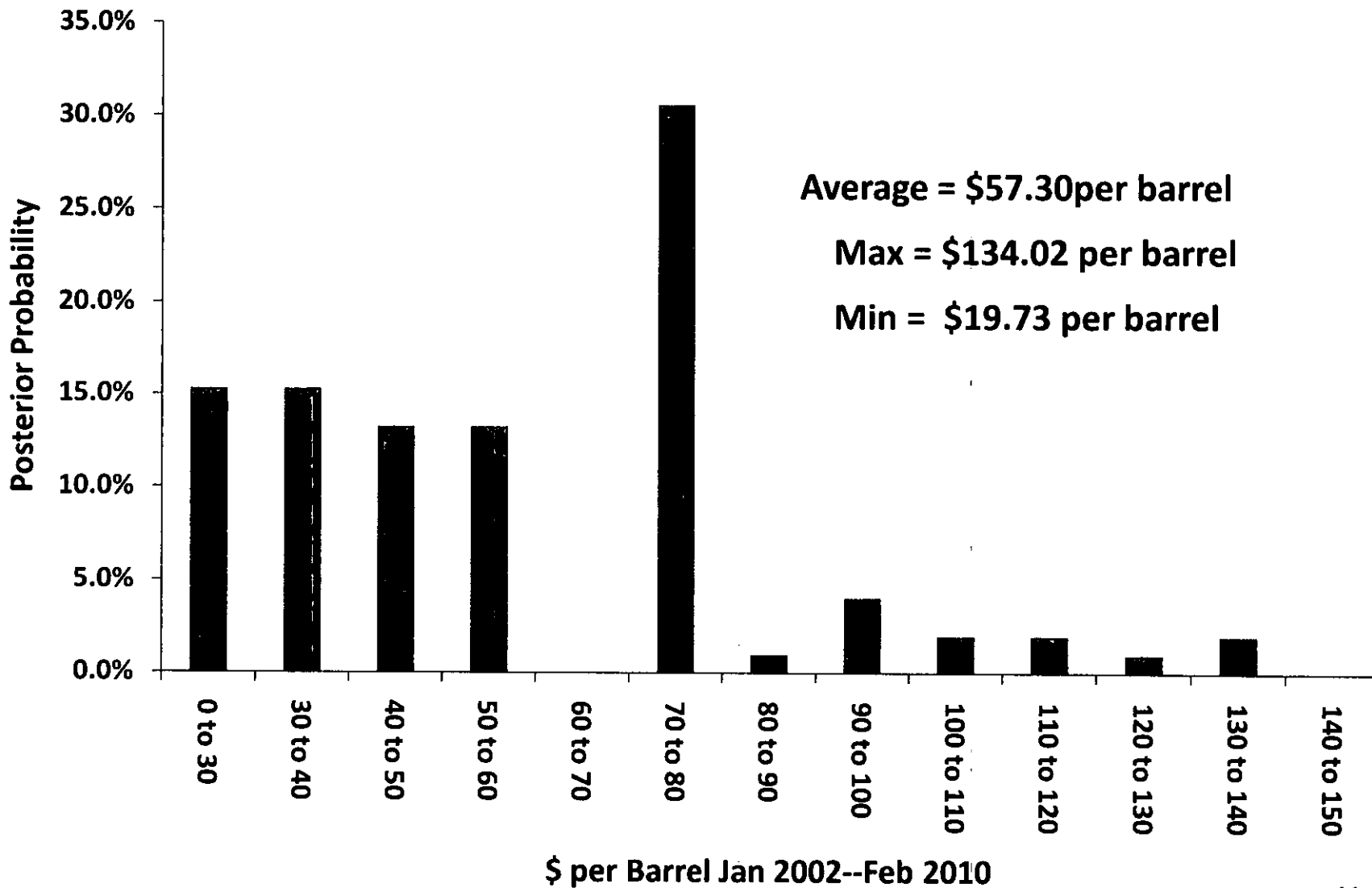


Looking at oil and gas prices using frequency distributions

- The following charts are based on the percent of time that oil or gas prices fell within certain intervals.
- This is essentially a historical probability view.
- Three time periods are examined, long term medium term and shortterm. Jan 1994—Feb 2010, Jan 2002—Feb 2010. and Jan 2004—Feb 2010.
- Look for spikes and bunching, what statisticians call modes and central tendencies.
- The charts on the next two pages clearly show that we are in an evolving oil pricing world. The oil price frequency distribution shown between Jan 1994 and Feb 2010 on on the next page, shows that between 1994 and 2010, 55% of the time the price of oil was \$30/bbl or less. In the next chart, covering 2002 through 2010, oil prices were \$30/bbl or less only 15% of the time.



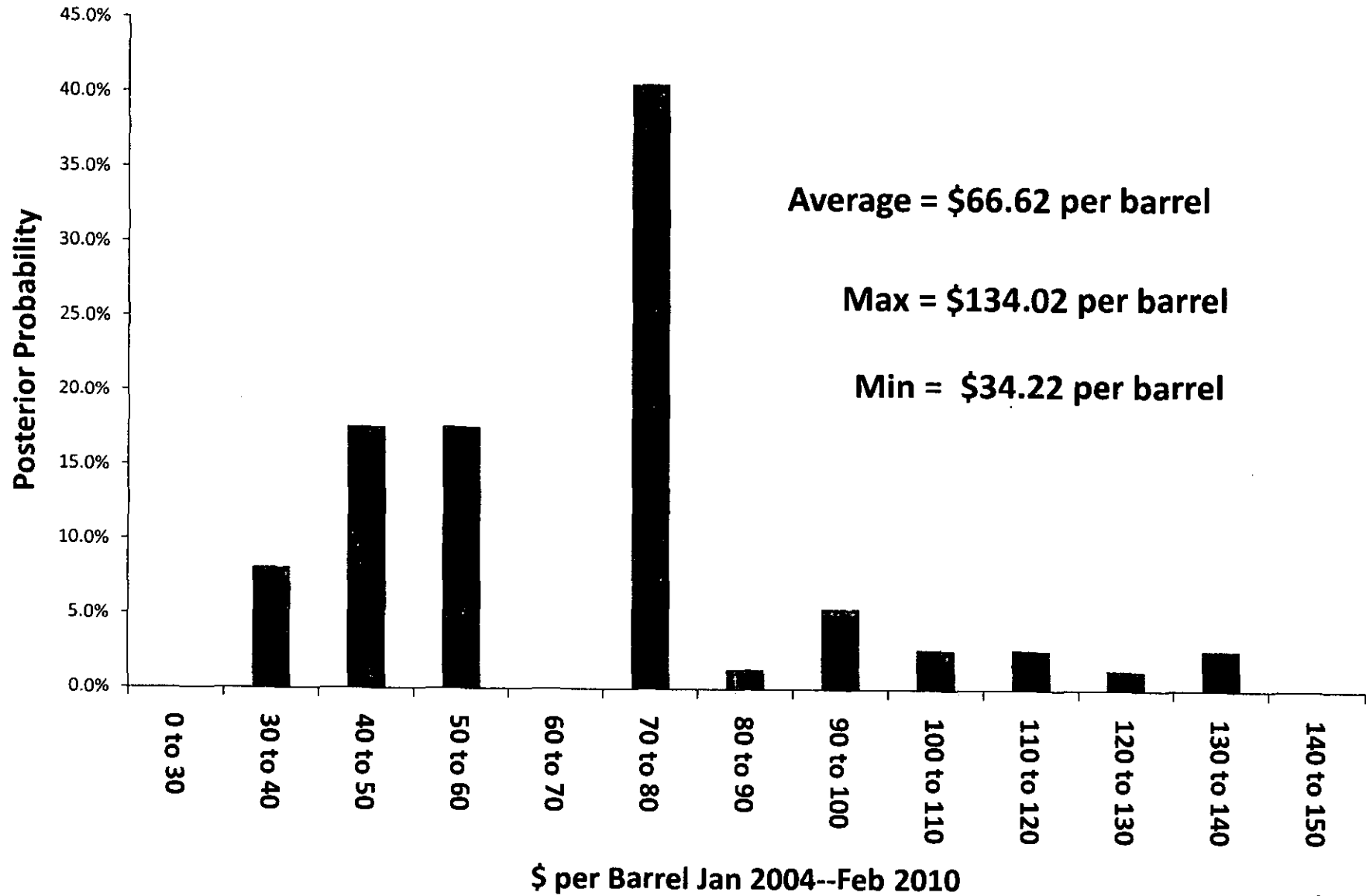
Frequency Distribution for Monthly for Nymex Oil Jan 2002—Feb 2010



A much more recent shorter term view

- The following chart shows the frequency distribution for oil prices from January 2004 through February 2010.
- Notice that for this most recent 6 year period that oil prices have traded in a pretty tight range between \$70 and \$80, 40% of the time.
- Connecting the spikes gives you a somewhat symmetric shape. This suggests that at we are in a market that trends to a price in the \$70 to \$80 range.

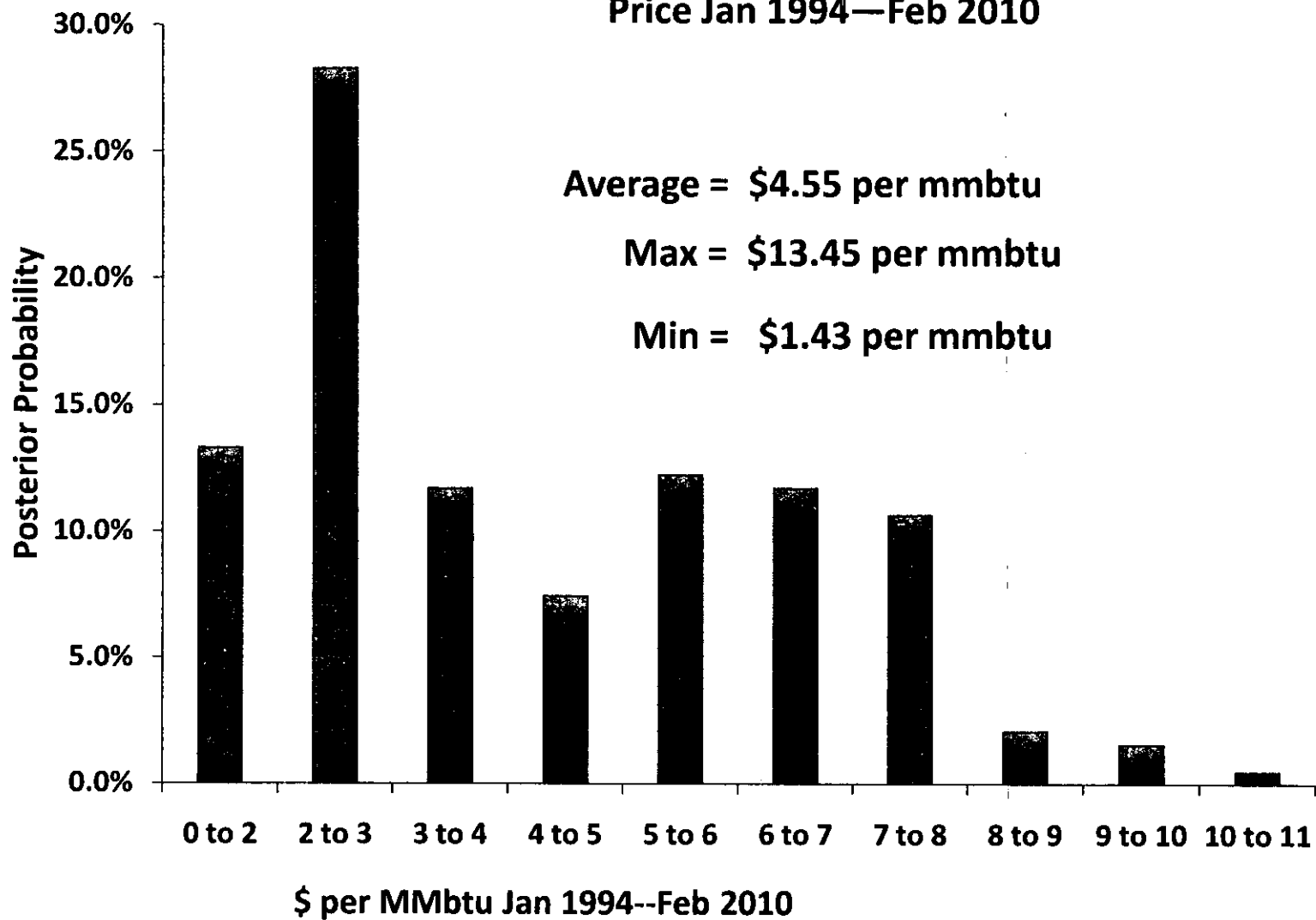
Frequency Distribution for Monthly for Nymex Oil Jan 2004—Feb 2010



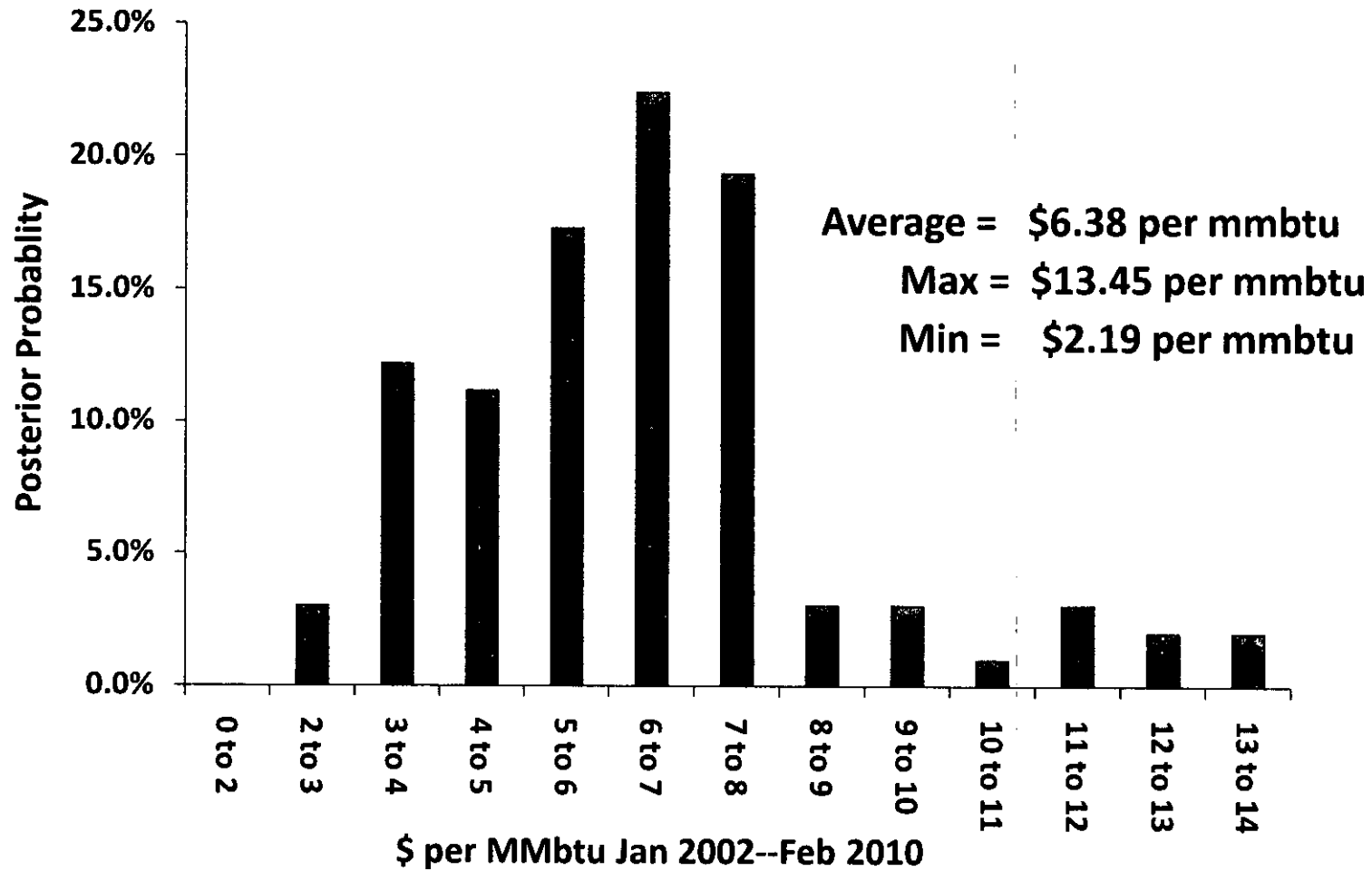
Gas Price Frequency Distributions

- Comparing the following three charts it can be seen that gas prices viewed over the longer time period of Jan 1994—Feb 2010 were most frequently in the \$2-\$3 range but relatively evenly distributed all the way up to \$8 per mmbtu.
- Going to the distribution from Jan 2002 to Feb 2010 shows that dropping the earlier 8 years moves the distribution up to center around the \$5 to \$8 range.
- The final chart shows that distribution of gas prices from Jan 2004 to Feb 2010 where gas prices become more bunched in the region of \$6 to \$8 per mmbtu.
- The today's situation in the gas market with gas around \$4 is consistent with the 16 year average (\$4.55) rather than either the last 8 or 6 year averages of \$6.38 and \$7.01 respectively.

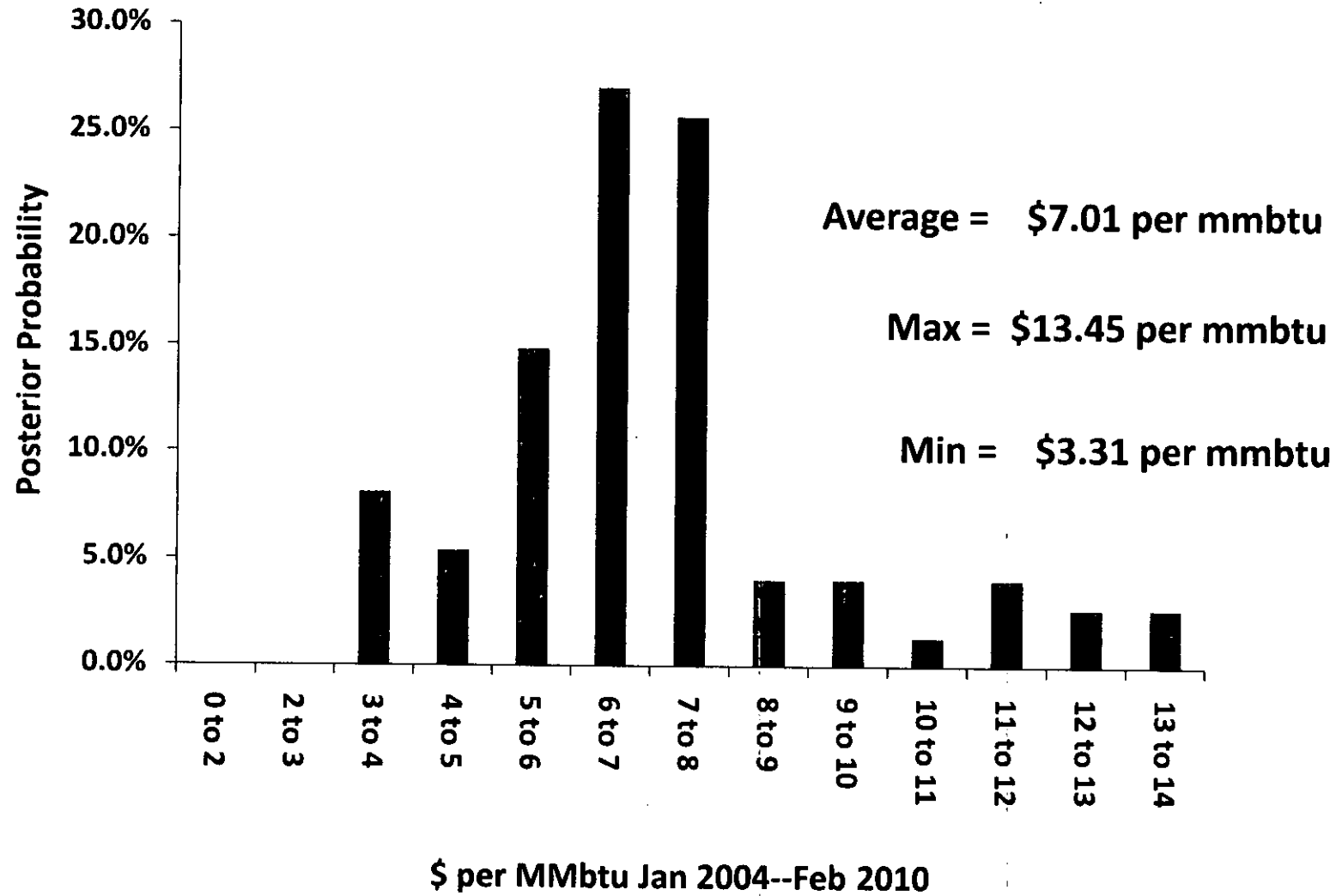
Frequency Distribution for Monthly for NYMEX Natural Gas Price Jan 1994—Feb 2010



Frequency Distribution Monthly for NYMEX Natural Gas Price Near Contract



Frequency Distribution Monthly for NYMEX Natural Gas Price Jan 2004—Feb 2010



SB 305:
The Separation of Oil from Gas
for the Oil & Gas Production Tax

House Resources Committee
Logsdon & Associates
April 7, 2010

Premise of the Bill

- Under current law oil and gas are taxed together
- Oil is worth much more than gas
- The combining mechanism has the potential to materially reduces oil taxes even though oil operations are unaffected

Oil is Different than Gas

- Supply
 - Oil more geographically concentrated (fewer sellers: OPEC)
 - Oil supplies more depleted
 - Lower cost gas is more plentiful
- Demand
 - Oil has fewer substitutes
 - Gas has more substitutes
- Result: Oil is worth more than gas

BTU 9:1

West Coast ANS

- Market Price \$80/bbl
- Less:
 - Shipping \$2.07
 - TAPS \$4.18
- Gross Value \$73.75
- 6 mmbtu's / bbl
- \$12.29 / mmbtu

North Slope Gas

- Market Price \$6/mmbtu
- Less:
 - Tariff AK to AB \$3.54
 - AB Hub \$0.24
 - Tariff AB to L48 \$0.85
- Gross Value \$1.37/mmbtu
- On a straight BTU to BTU basis oil is worth nearly 9 X as much as gas

Some Things that have BTUs

- Oil
- Gas
- Coal
- Wood
- Asphalt
- Shoe Leather
- Rubber
- Coffee grounds
- Citrus rinds
- Corn cobs
- Dung

Mechanics of Current Tax

- 1) Oil gross value (market price less transport cost)
- 2) Gas gross value (market price less transport cost)
- 3) Oil + gas gross value gas = Combined gross value
- 4) Combined gross value – lease capital and operating costs = Combined oil & gas net value
- 5) Combined oil & gas net value / total oil & gas BOEs = p/BOE net value (see Slide # 7)
- 6) Progressivity factor (based on per BOE net value) plus 25% base rate = tax rate
- 7) Single tax rate applied to combined oil & gas net value

Barrel of Oil Equivalents (BOEs): Putting Oil & Gas on an Apples / Apples Basis

- 4.5 billion cubic feet per day (bcf/d) of natural gas
- A cubic foot of North Slope gas will have about 1,100 BTUs
- Natural gas is measured in millions of BTUs (mmbtu)
- 4.5 billion cubic feet per day will have 4.95 million mmbtu's
(4.5 X 1,100)
- A barrel of oil has about 6 mmbtu's
- 4.5 billion cubic feet per day will have the BTU equivalence of
825,000 barrels of oil (BOEs) (4,950,000 / 6)
- If there are 500,000 barrels of oil, total BOEs will total
 $500,000 + 825,000 = 1,325,000$

Progressivity Mechanics

- “Trigger” = \$30 net / BOE value
- “Slope” = 0.4%*
- Progressivity surcharge = (Net per BOE value - \$30) X .004
- Example: if net value = \$50
 - Base tax rate = 25%
 - Progressivity = $(\$50 - \$30) \times .004 = 8\%$
 - Total tax of 33% on net value

* Slope changes to 0.1% after \$92.50 net per BOE value

HOW GAS IMPACTS OIL TAXES

	Oil Alone (p/bbl)
Market Price	\$80.00
Transp cost	\$5.00
Gross Value	\$75.00
Costs	\$20.00
Net (p/barrel or p/mmbtu)	\$55.00
Base rate	25.00%
Progressivity	10.00%
Total tax rate	35.00%

HOW GAS IMPACTS OIL TAXES

	Oil Alone (p/bbl)	Gas (p/mmbtu)
Market Price	\$80.00	\$6.00
Transp cost	\$5.00	\$4.50
Gross Value	\$75.00	\$1.50
Costs	\$20.00	\$0.50
Net (p/barrel or p/mmbtu)	\$55.00	\$1.00
Base rate	25.00%	
Progressivity	10.00%	
Total tax rate	35.00%	
Daily bbls (oil) or mmbtu (gas)	500,000	4,950,000
Daily BOEs	500,000	825,000
Annual million bbls (oil) or million mmbtu (gas)	183	1,807
Annual BOEs (millions)	183	301

HOW GAS IMPACTS OIL TAXES

	Oil Alone (p/bbl)	Gas (p/mmbtu)	:	Combined Oil & Gas
Market Price	\$80.00	\$6.00	:	Oil
Transp cost	\$5.00	\$4.50	:	p/bbl net value
Gross Value	\$75.00	\$1.50	:	Barrels (millions)
			:	Total oil net value (\$mm)
Costs	\$20.00	\$0.50	:	Gas
			:	p/mmbtu net value
Net (p/barrel or p/mmbtu)	\$55.00	\$1.00	:	mmbtu's (millions)
			:	Total gas net value (\$mm)
Base rate	25.00%		:	
Progressivity	10.00%		:	Total oil & gas net value
Total tax rate	35.00%		:	Total BOEs
			:	Net value / BOE
Daily bbls (oil) or mmbtu (gas)	500,000	4,950,000	:	NO PROGRESSIVITY!
Daily BOEs	500,000	825,000	:	
Annual million bbls (oil) or million mmbtu (gas)	183	1,807	:	
Annual BOEs (millions)	183	301	:	

HOW GAS IMPACTS OIL TAXES

	Oil Alone (p/bbl)	Gas (p/mmbtu)	:	Combined Oil & Gas
Market Price	\$80.00	\$6.00	:	Oil
Transp cost	\$5.00	\$4.50	:	p/bbl net value
Gross Value	\$75.00	\$1.50	:	Barrels (millions)
			:	Total oil net value (\$mm)
Costs	\$20.00	\$0.50	:	Gas
			:	p/mmbtu net value
Net (p/barrel or p/mmbtu)	\$55.00	\$1.00	:	mmbtu's (millions)
			:	Total gas net value (\$mm)
Base rate	25.00%		:	Total oil & gas net value
Progressivity	10.00%		:	Total BOEs
Total tax rate	35.00%		:	Net value / BOE
Daily bbls (oil) or mmbtu (gas)	500,000	4,950,000	:	NO PROGRESSIVITY!
Daily BOEs	500,000	825,000	:	
Annual million bbls (oil) or million mmbtu (gas)	183	1,807	:	
Annual BOEs (millions)	183	301	:	

DEPARTMENT OF REVENUE EXAMPLES TO SENATE FINANCE - FEBRUARY 24, 2010

Oil Price	Gas Price	Oil Alone Progressivity Factor	Oil & Gas Combined Progressivity Factor	Reduction in Progressivity Factor	Oil Alone Tax (\$billions)	Gas Alone Tax (\$billions)	Total if Taxed Separately (\$billions)	Combined Tax (\$billions)	Annual Tax Reduction from Combining (\$billions)
\$75	\$8.00	5.38%	0.00%	5.38%	\$1.7	\$1.1	\$2.8	\$2.5	\$0.3
\$100	\$8.00	15.38%	3.59%	11.79%	\$4.0	\$1.1	\$5.1	\$4.0	\$1.1
\$120	\$8.00	23.38%	6.79%	16.59%	\$6.4	\$1.1	\$7.5	\$5.5	\$2.0

* Oil

Production 500,000 bbls/day

Transportation cost deduction \$6.50/bbl

Upstream capital costs \$2 billion

Upstream operating costs \$2 billion

** Gas

Production 4.5 bcf/day

Transportation cost deduction \$4.50/mmbtu

Upstream capital costs \$200 million

Upstream operating costs \$200 million

How can you be so sure about future prices?

- We cannot
- Different price relationships would produce different outcomes
- Since the potential for these outcomes exist, the current tax structure adds another level of risk to an already large amount of uncertainty
- At current price relationships there is a risk of undermining state finances

How SB 305 Works

No change to progressivity formula:

Progressivity on oil and gas:

Progressivity rate =

(production tax value per BOE - \$30) X .004

Total tax rate = 25% base tax rate + progressivity
rate

How Progressivity Operates Now

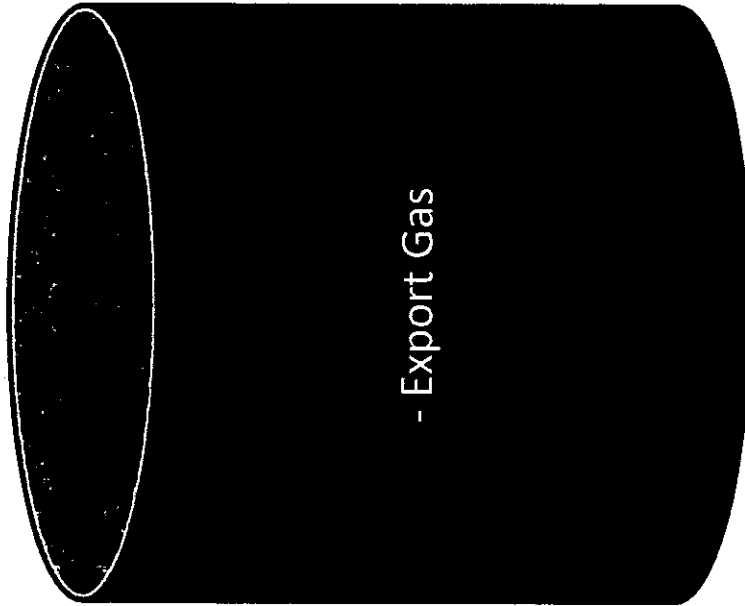
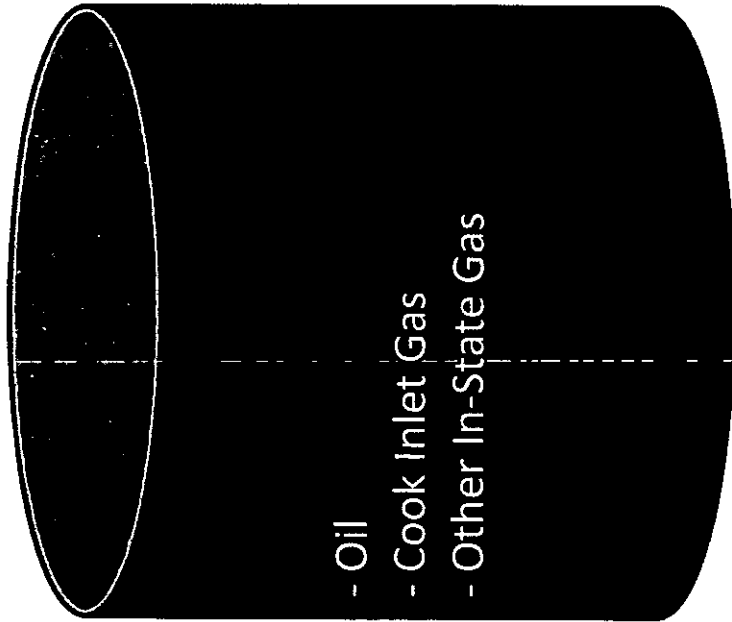
- Each company calculates one statewide progressivity rate based on all activity and the production tax value per BOE
- Company divides operations into 5 segments
 - 1) Cook Inlet oil
 - 2) Cook Inlet gas
 - 3) North Slope oil and gas except gas used in-state
 - 4) Non-North Slope / Non-Cook Inlet oil and gas except gas used in-state
 - 5) Non-Cook Inlet gas used in-state
- For each segment:
 - For each segment calculate tax liability based on total tax rate (base 25% rate plus statewide progressivity rate) and the segment's production tax value
 - For segments 1, 2, and 5 tax liability is lower of ELF or above

SB 305: Instead of One Statewide Progressivity Calculation: Two Progressivity Calculations

- **FIRST: Oil / CI Gas / Other In-State Gas**
 - Progressivity calculated together
 - Same as current activity
 - Same 5 segments treated as now
 - No tax increase on current activity

- **SECOND: Export Gas (Major Gas Sale Gas)**
 - Calculated distinctly: segment unto itself
 - Will not dilute oil progressivity

SB 305: Two Progressivity “Buckets”



Issue: Cost Allocation

- Costs to produce oil and gas are truly joint costs
- Current approach (AS 43.55.165(h)): gives department authority to adopt regulations for allocating costs between oil and gas:
 - As recipients of confidential cost data they are in the best position to evaluate costs
 - A regulatory process allows more time
 - The regulatory process is public
- AS 43.55.165(h) is amended to require the department to consider allocating lease expenditures between oil and gas production in proportion to BTU barrel of oil equivalents (BOE) produced on each substances.

Cost Allocation: BTU Barrel of Oil Equivalent (BOE) Approach

- This is the approach DOR adopted to implement the existing statute for the same cost allocation purposes as this bill
- The same costs that produce oil produce gas
- Since produced together, costs are allocated based on amounts produced
- BOE method: putting oil & gas on apples/apples basis in terms of relative produced volumes

COMMENTS ON
CSSB305 (FIN)

April 7, 2010

Alaska Department of Revenue

Issues Surrounding the Gas Tax Debate At this Time

2

- Entering two open seasons for the gas pipeline
 - Likely to result in Producers continuing to claim changes in the fiscal system are necessary

- Full commitments to ship gas (i.e. project sanction) not expected until 2014

- Stakeholders will continue to discuss:
 - Necessary Producer cash flow from gas development,
 - Relative risks/rewards borne/realized by the Producers and the State,
 - Amount of Fiscal Predictability the Producers need

4/7/2010

Primary State Considerations Today

3

- Are the State's Interests protected going into the uncertainty of the next few years?
 - Achieve a gas pipeline project
 - Secure an appropriate share of revenue from oil and gas production

- Is the State's fiscal system attractive for a gas pipeline project?

- Is the potentially "locked-in" portion of the fiscal system set at an acceptable level for the state?

4/7/2010

4

Modeling CSSB 305(FIN)

Oil Price Range 40 to 200 \$/bbl

Gas Price Parity Range 6 to 26

Oil Production 500 Mbb/d

Gas Production 4.5 Bcf/d

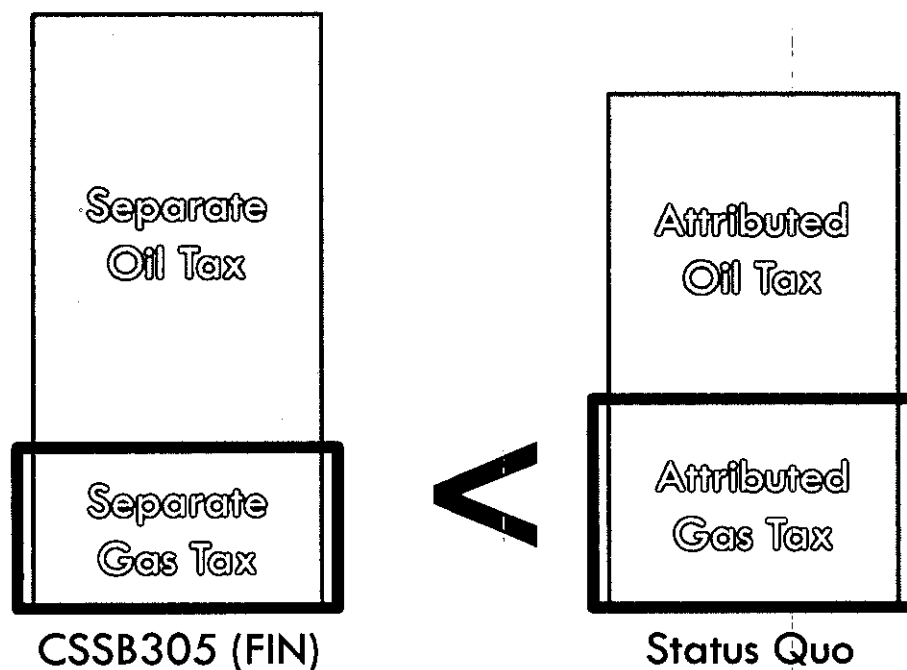
Total OPEX \$ 2.2 Billions

Total CAPEX \$ 2.2 Billions

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In All of the Cases Run: CSSB305 (FIN) Results in a Lower "Locked-in" Gas Tax Obligation

5

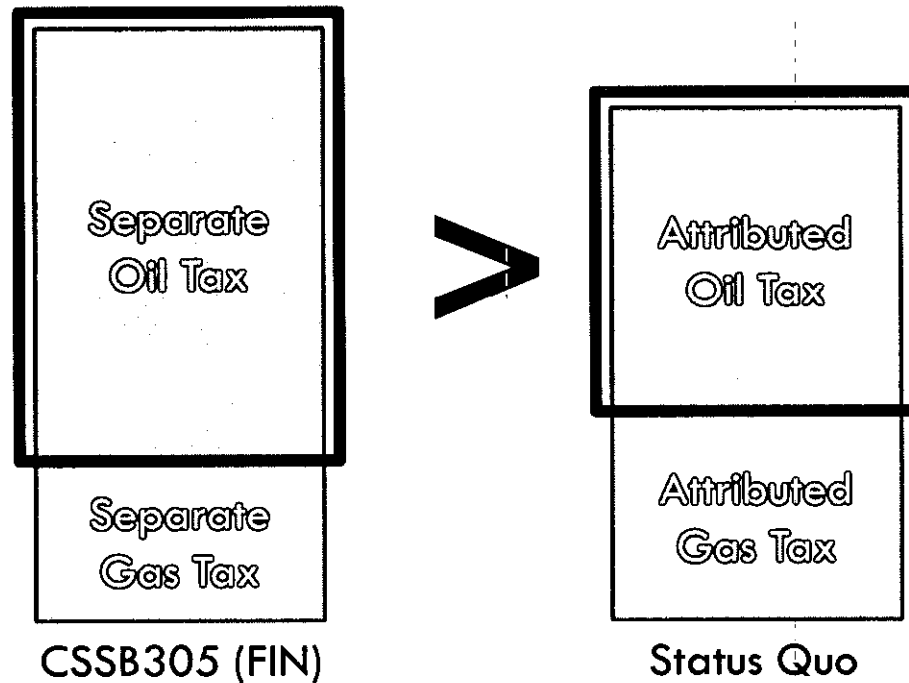


* Cost Allocation assumed to be on either a BTU barrel equivalent (BOE) basis
or on a Point of Production (PoP) basis

*Market price
- Transportation* 4/7/2010

In All of the Cases Run: CSSB305 (FIN) Raises Oil Taxes

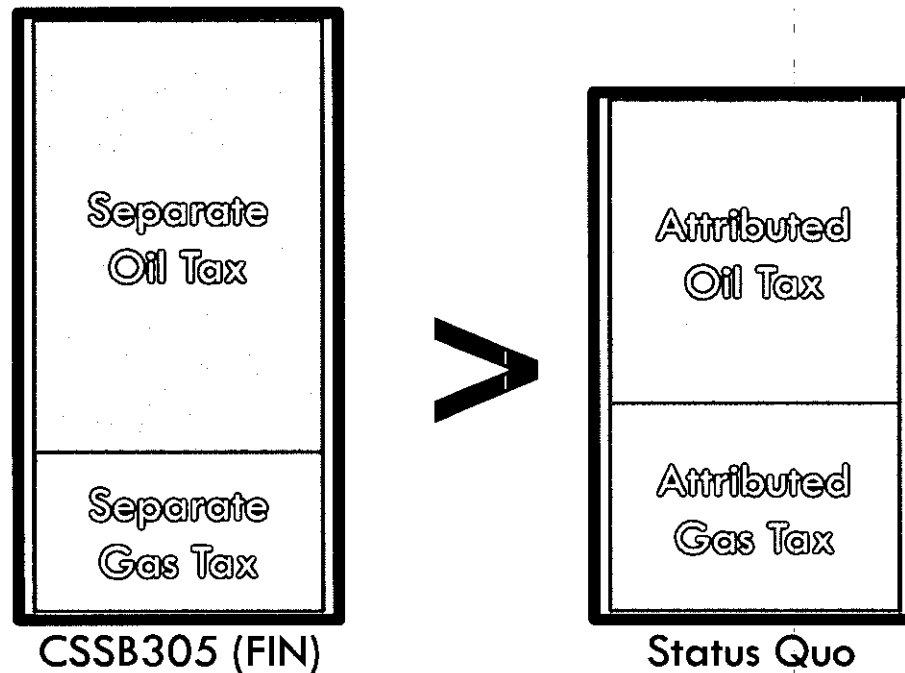
6



* Cost Allocation assumed to be on either a BTU barrel equivalent (BOE) basis
or on a Point of Production (PoP) basis

In over 90% of the Cases Run:
CSSB305 (FIN) Raises Overall Oil and Gas Taxes

7



* Cost Allocation assumed to be on either a BTU barrel equivalent (BOE) basis
or on a Point of Production (PoP) basis

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Example Cases

State Production Tax Revenue

Oil: 500 Mbb/d and Gas: 4.5 Bcf/d

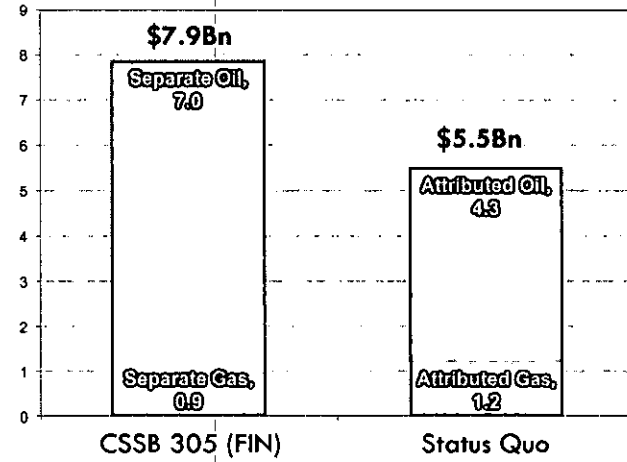
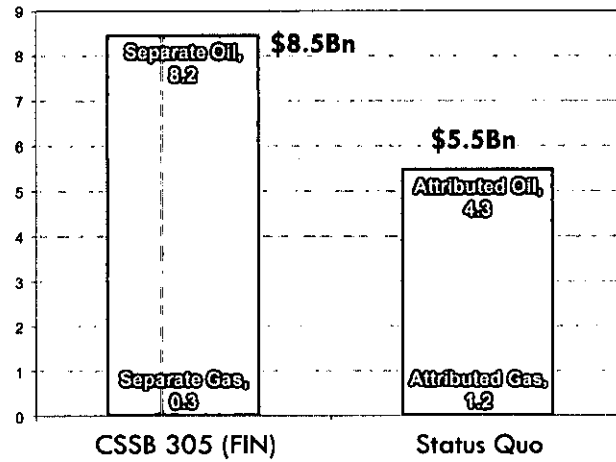
Capex: \$2.2Bn and Opex: \$2.2Bn



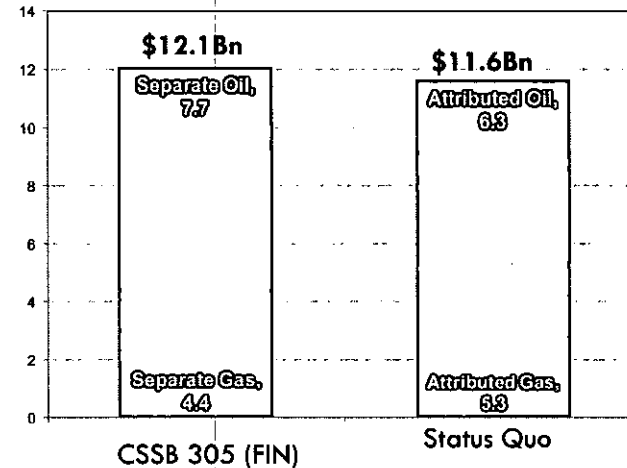
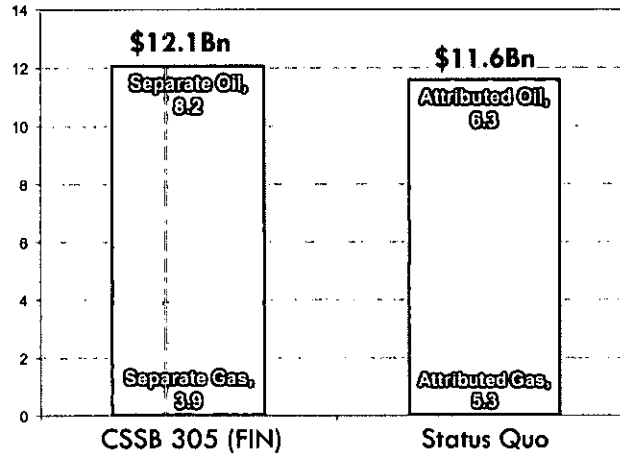
BOE

PoP

\$120/\$8
(15:1)



\$120/\$15
(8:1)



Observations

9

- CSSB305 (FIN) Increases Oil Taxes, and in almost all cases increases total Oil and Gas taxes
 - Provides a higher “starting point” for further discussions with Producers
 - However, it negatively affects projected gas pipeline economics

- CSSB305 (FIN) “Locks-In” a lower Gas Tax Ceiling
 - Enhances the value of the AGIA tax inducement
 - However, it reduces the State’s flexibility in changing gas tax after the open season

- CSSB305 (FIN) could be passed after the open season without conflicting with the AGIA tax inducement

- Lack of a defined cost allocation method creates uncertainty about the actual tax obligation under CSSB305 (FIN)

4/7/2010

CSSB 305 (FIN) MODELING RUNS

4/7/2010

Presentation Back-up Materials

Total Tax Take Comparison

2

□ Model Assumptions:

- One year snapshot
 - 4.5 Bcf/d and 500 Mbbbl/d
 - Total Opex = \$2.2 Bn and Total Capex = \$2.2 Bn
-
- Ran multiple cases varying oil price from 40 to 200 \$/bbl and gas price parity from 6 to 26
 - Ran the above cases for each of BOE, PoP and Fixed cost allocation methodology

4/07/2010

Total Tax CSSB305 (FIN) less Status Quo BOE Cost Allocation

3

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.1	0.3	0.2	0.2	0.2	0.2	0.2	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.5	0.1	0.3	0.8	0.8	0.7	0.8	0.9	0.5	0.0	(0.6)	(0.6)	(0.3)	0.2	0.4	0.4	0.5
10	0.5	0.5	0.5	0.8	1.2	1.4	1.6	1.6	1.3	0.9	0.5	(0.1)	(0.7)	(0.6)	(0.3)	(0.0)	0.3
12	0.5	0.8	0.8	0.9	1.3	1.8	2.1	2.4	2.2	1.8	1.4	1.0	0.5	(0.1)	(0.3)	(0.2)	0.0
14	0.5	0.9	1.1	1.2	1.5	2.0	2.4	2.8	2.8	2.6	2.3	1.9	1.4	0.9	0.4	0.1	0.2
16	0.5	0.9	1.3	1.5	1.8	2.2	2.7	3.1	3.2	3.1	2.9	2.7	2.3	1.9	1.3	0.8	0.6
18	0.5	0.9	1.5	1.7	2.0	2.4	3.0	3.4	3.4	3.5	3.4	3.2	3.0	2.7	2.3	1.8	1.2
20	0.5	0.9	1.6	1.8	2.2	2.6	3.2	3.8	3.8	3.7	3.7	3.7	3.5	3.3	3.0	2.6	2.2
22	0.5	0.9	1.6	2.0	2.3	2.8	3.4	4.1	4.1	4.1	4.0	4.0	3.9	3.8	3.5	3.3	2.9
24	0.5	0.9	1.6	2.1	2.4	2.9	3.6	4.3	4.4	4.4	4.4	4.3	4.2	4.1	4.0	3.8	3.5
26	0.5	0.9	1.6	2.2	2.5	3.1	3.7	4.5	4.6	4.7	4.7	4.6	4.5	4.4	4.3	4.2	4.0

 CSSB305 (FIN) > STATUS QUO

 CSSB305 (FIN) = STATUS QUO

 CSSB305 (FIN) < STATUS QUO

4/07/2010

Total Tax CSSB305 (FIN) less Status Quo PoP Cost Allocation

4

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.0	0.2	0.1	0.1	0.1	0.1	0.1	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.1	0.5	0.5	0.5	0.6	0.6	0.5	(0.6)	(0.6)	(0.6)	(0.2)	0.3	0.3	0.4	0.4
10	0.0	0.0	0.0	0.4	0.8	0.9	1.0	1.1	1.1	0.8	0.4	(0.1)	(0.7)	(0.6)	(0.3)	(0.0)	0.4
12	0.0	0.1	0.0	0.3	0.7	1.1	1.4	1.6	1.7	1.4	1.1	0.7	0.2	(0.3)	(0.5)	(0.3)	(0.1)
14	0.0	0.2	0.1	0.2	0.6	1.2	1.6	1.9	2.2	2.0	1.7	1.4	1.0	0.6	0.0	(0.3)	(0.1)
16	0.0	0.2	0.3	0.2	0.5	1.1	1.6	2.1	2.5	2.4	2.3	2.0	1.6	1.3	0.8	0.3	0.1
18	0.0	0.2	0.5	0.4	0.5	1.0	1.7	2.1	2.6	2.7	2.7	2.5	2.3	1.9	1.5	1.1	0.6
20	0.0	0.2	0.6	0.5	0.7	0.9	1.6	2.2	2.7	2.9	2.9	2.9	2.7	2.5	2.1	1.8	1.3
22	0.0	0.2	0.6	0.7	0.8	1.1	1.5	2.2	2.8	3.1	3.1	3.1	3.0	2.9	2.6	2.3	1.9
24	0.0	0.2	0.6	0.8	0.9	1.2	1.7	2.2	2.8	3.2	3.3	3.3	3.3	3.2	3.0	2.8	2.5
26	0.0	0.2	0.6	0.9	1.1	1.4	1.8	2.3	2.8	3.3	3.4	3.5	3.5	3.4	3.3	3.1	2.9

CSSB305 (FIN) > STATUS QUO

CSSB305 (FIN) = STATUS QUO

CSSB305 (FIN) < STATUS QUO

4/07/2010

Total Tax CSSB305 (FIN) less Status Quo Fixed (90/10) Cost Allocation

5

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.2	0.1	0.2	0.2	0.2	0.3	0.1	(0.4)	(0.4)	0.0	0.2	0.2	0.2	0.2
10	0.0	0.0	0.0	0.2	0.5	0.5	0.5	0.7	0.8	0.6	0.3	(0.2)	(0.8)	(0.6)	(0.3)	0.1	0.5
12	0.0	0.2	0.0	0.2	0.6	0.9	1.0	1.2	1.3	1.2	0.9	0.5	0.1	(0.5)	(0.6)	(0.4)	(0.2)
14	0.0	0.3	0.2	0.2	0.6	1.1	1.4	1.6	1.8	1.8	1.5	1.2	0.8	0.4	(0.1)	(0.4)	(0.3)
16	0.0	0.3	0.4	0.4	0.6	1.1	1.6	1.9	2.2	2.3	2.1	1.8	1.4	1.1	0.6	0.1	(0.1)
18	0.0	0.3	0.6	0.6	0.7	1.1	1.7	2.1	2.5	2.6	2.5	2.3	2.1	1.7	1.3	0.9	0.4
20	0.0	0.3	0.7	0.7	0.9	1.2	1.7	2.2	2.7	2.9	2.9	2.8	2.6	2.3	2.0	1.5	1.1
22	0.0	0.3	0.7	0.9	1.0	1.4	1.8	2.3	2.9	3.1	3.1	3.1	3.0	2.8	2.5	2.2	1.8
24	0.0	0.3	0.7	1.0	1.2	1.5	1.9	2.5	3.0	3.3	3.3	3.3	3.3	3.1	2.9	2.7	2.4
26	0.0	0.3	0.7	1.1	1.3	1.6	2.1	2.7	3.1	3.4	3.5	3.5	3.5	3.4	3.3	3.1	2.8

 CSSB305 (FIN) > STATUS QUO

 CSSB305 (FIN) = STATUS QUO

 CSSB305 (FIN) < STATUS QUO

4/07/2010

MODELING THE OIL TAX INCREASE

4/7/2010

Oil Tax Comparison

7

□ Model Assumptions:

- One year snapshot
 - 4.5 Bcf/d and 500 Mbbl/d
 - Total Opex = \$2.2 Bn and Total Capex = \$2.2 Bn
-
- Ran multiple cases varying oil price from 40 to 200 \$/bbl and gas price parity from 6 to 26
 - Ran the above cases for each of BOE, PoP and Fixed cost allocation methodology

4/07/2010

Oil Tax CSSB305 (FIN) less Status Quo*

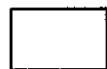
BOE Cost Allocation

8

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.2	0.3	0.5	0.6	0.6	0.7	0.8	0.9	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
8	0.5	0.3	0.7	1.1	1.3	1.5	1.8	2.0	1.8	1.5	1.2	1.1	1.2	1.2	1.3	1.4	1.6
10	0.5	0.6	0.7	1.2	1.7	2.0	2.4	2.8	2.7	2.5	2.3	2.1	1.7	1.8	1.9	2.1	2.3
12	0.5	0.8	0.9	1.2	1.8	2.4	2.8	3.2	3.3	3.2	3.1	2.9	2.7	2.4	2.4	2.6	2.8
14	0.5	0.9	1.1	1.3	1.8	2.4	3.1	3.6	3.7	3.7	3.7	3.6	3.4	3.2	3.0	2.9	3.1
16	0.5	0.9	1.3	1.5	1.9	2.5	3.1	3.8	4.0	4.1	4.1	4.0	4.0	3.8	3.7	3.5	3.4
18	0.5	0.9	1.5	1.7	2.0	2.5	3.3	3.8	4.1	4.4	4.4	4.4	4.4	4.3	4.2	4.0	3.8
20	0.5	0.9	1.6	1.8	2.2	2.6	3.4	4.0	4.2	4.4	4.7	4.7	4.7	4.7	4.6	4.5	4.4
22	0.5	0.9	1.6	2.0	2.3	2.8	3.4	4.2	4.4	4.5	4.6	4.9	5.0	5.0	5.0	4.9	4.8
24	0.5	0.9	1.6	2.1	2.4	2.9	3.6	4.3	4.5	4.7	4.8	4.9	5.1	5.3	5.3	5.2	5.1
26	0.5	0.9	1.6	2.2	2.5	3.1	3.7	4.5	4.6	4.8	5.0	5.1	5.2	5.3	5.5	5.5	5.4



CSSB305 (FIN) > STATUS QUO



CSSB305 (FIN) = STATUS QUO



CSSB305 (FIN) < STATUS QUO

*Oil Tax under the Status Quo equals Total Tax less attributed gas tax

4/07/2010

Oil Tax CSSB305 (FIN) less Status Quo*

PoP Cost Allocation

91

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.0	0.2	0.3	0.4	0.5	0.5	0.6	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
8	0.0	0.0	0.1	0.5	0.7	0.9	1.1	1.4	1.4	1.1	0.8	0.6	0.7	0.8	0.9	1.0	1.1
10	0.0	0.0	0.0	0.4	0.8	1.1	1.4	1.8	2.0	1.8	1.6	1.4	1.0	1.1	1.3	1.4	1.6
12	0.0	0.1	0.0	0.3	0.7	1.2	1.6	2.0	2.3	2.3	2.2	2.0	1.8	1.5	1.5	1.7	1.8
14	0.0	0.2	0.1	0.2	0.6	1.2	1.6	2.1	2.6	2.6	2.6	2.5	2.4	2.2	1.9	1.8	2.0
16	0.0	0.2	0.3	0.2	0.5	1.1	1.7	2.2	2.7	2.8	2.8	2.8	2.7	2.6	2.4	2.2	2.2
18	0.0	0.2	0.5	0.4	0.5	1.0	1.7	2.2	2.7	3.0	3.0	3.1	3.0	3.0	2.8	2.7	2.5
20	0.0	0.2	0.6	0.5	0.7	0.9	1.6	2.2	2.8	3.1	3.2	3.2	3.3	3.2	3.1	3.0	2.9
22	0.0	0.2	0.6	0.7	0.8	1.1	1.5	2.2	2.8	3.2	3.3	3.4	3.4	3.4	3.4	3.3	3.2
24	0.0	0.2	0.6	0.8	0.9	1.2	1.7	2.2	2.8	3.3	3.4	3.5	3.6	3.6	3.6	3.5	3.4
26	0.0	0.2	0.6	0.9	1.1	1.4	1.8	2.3	2.8	3.3	3.5	3.6	3.7	3.8	3.8	3.7	3.7

 CSSB305 (FIN) > STATUS QUO

 CSSB305 (FIN) = STATUS QUO

 CSSB305 (FIN) < STATUS QUO

*Oil Tax under the Status Quo equals Total Tax less attributed gas tax

4/07/2010

Oil Tax CSSB305 (FIN) less Status Quo* Fixed (50/50) Cost Allocation

10

Gas Price Parity Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.2	0.1	0.3	0.3	0.3	0.4	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
8	0.3	0.2	0.5	0.8	1.0	1.2	1.4	1.6	1.5	1.2	0.9	0.7	0.8	0.9	1.0	1.1	1.2
10	0.3	0.4	0.5	1.0	1.4	1.7	2.0	2.3	2.4	2.2	2.0	1.7	1.4	1.5	1.6	1.7	1.9
12	0.3	0.7	0.7	0.9	1.6	2.0	2.4	2.8	2.9	2.9	2.8	2.6	2.4	2.1	2.0	2.2	2.4
14	0.3	0.7	0.9	1.1	1.5	2.2	2.7	3.2	3.4	3.4	3.3	3.2	3.1	2.9	2.6	2.5	2.7
16	0.3	0.7	1.1	1.2	1.6	2.2	2.8	3.5	3.7	3.7	3.7	3.7	3.6	3.5	3.3	3.1	3.0
18	0.3	0.7	1.3	1.4	1.7	2.2	2.9	3.5	3.9	4.0	4.1	4.1	4.0	4.0	3.8	3.7	3.5
20	0.3	0.7	1.4	1.6	1.9	2.3	3.0	3.7	3.9	4.2	4.3	4.4	4.4	4.3	4.3	4.1	4.0
22	0.3	0.7	1.4	1.7	2.0	2.5	3.1	3.8	4.1	4.2	4.5	4.6	4.7	4.7	4.6	4.5	4.4
24	0.3	0.7	1.4	1.8	2.2	2.6	3.2	3.9	4.2	4.4	4.5	4.7	4.9	4.9	4.9	4.9	4.8
26	0.3	0.7	1.4	1.9	2.3	2.7	3.4	4.1	4.4	4.5	4.7	4.8	4.9	5.1	5.2	5.1	5.1

CSSB305 (FIN) > STATUS QUO
 CSSB305 (FIN) = STATUS QUO
 CSSB305 (FIN) < STATUS QUO

*Oil Tax under the Status Quo equals Total Tax less attributed gas tax

Oil Tax CSSB305 (FIN) less Status Quo*

Fixed (75/25) Cost Allocation

00

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	(0.2)	(0.3)	(0.5)	(0.4)	(0.4)	(0.5)	(0.5)	(0.6)	(0.6)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)
8	0.1	(0.3)	(0.1)	0.2	0.2	0.3	0.5	0.6	0.7	0.4	0.0	(0.1)	(0.0)	0.0	0.1	0.1	0.2
10	0.1	0.1	0.1	0.3	0.7	0.8	1.1	1.3	1.6	1.4	1.2	0.9	0.5	0.6	0.7	0.8	0.9
12	0.1	0.4	0.2	0.5	0.8	1.2	1.5	1.8	2.2	2.1	2.0	1.8	1.5	1.2	1.1	1.3	1.4
14	0.1	0.5	0.4	0.5	1.0	1.4	1.8	2.2	2.6	2.6	2.5	2.4	2.2	2.0	1.7	1.6	1.8
16	0.1	0.5	0.6	0.7	1.0	1.5	2.0	2.5	2.9	2.9	2.9	2.9	2.8	2.6	2.4	2.2	2.1
18	0.1	0.5	0.8	0.9	1.1	1.5	2.2	2.7	3.2	3.2	3.3	3.2	3.2	3.1	2.9	2.7	2.5
20	0.1	0.5	0.9	1.0	1.3	1.6	2.2	2.8	3.4	3.5	3.5	3.6	3.5	3.5	3.4	3.2	3.0
22	0.1	0.5	0.9	1.2	1.4	1.8	2.3	2.9	3.5	3.7	3.8	3.8	3.8	3.8	3.7	3.6	3.5
24	0.1	0.5	0.9	1.3	1.5	1.9	2.4	3.0	3.6	3.8	3.9	4.0	4.0	4.0	4.0	3.9	3.8
26	0.1	0.5	0.9	1.4	1.6	2.0	2.5	3.2	3.7	3.9	4.0	4.2	4.2	4.3	4.3	4.2	4.1



CSSB305 (FIN) > STATUS QUO



CSSB305 (FIN) = STATUS QUO



CSSB305 (FIN) < STATUS QUO

*Oil Tax under the Status Quo equals Total Tax less attributed gas tax

4/07/2010

Oil Tax CSSB305 (FIN) less Status Quo* Fixed (90/10) Cost Allocation

12

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	(0.4)	(0.5)	(0.6)	(0.7)	(0.8)	(0.9)	(1.1)	(1.2)	(1.3)	(1.2)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.4)
8	0.0	(0.3)	(0.4)	(0.2)	(0.2)	(0.1)	(0.1)	0.0	0.1	(0.0)	(0.4)	(0.6)	(0.6)	(0.5)	(0.5)	(0.4)	(0.3)
10	0.0	0.0	(0.2)	(0.0)	0.2	0.4	0.5	0.7	1.0	1.0	0.7	0.4	0.0	0.0	0.1	0.3	0.4
12	0.0	0.2	0.0	0.1	0.4	0.7	1.0	1.2	1.6	1.6	1.5	1.3	1.0	0.7	0.6	0.7	0.9
14	0.0	0.3	0.2	0.3	0.5	1.0	1.3	1.6	2.0	2.1	2.0	1.9	1.7	1.5	1.2	1.1	1.2
16	0.0	0.3	0.4	0.4	0.6	1.1	1.5	1.9	2.3	2.5	2.5	2.4	2.3	2.1	1.9	1.6	1.5
18	0.0	0.3	0.6	0.6	0.7	1.2	1.7	2.1	2.6	2.8	2.8	2.8	2.7	2.6	2.4	2.2	2.0
20	0.0	0.3	0.7	0.7	0.9	1.2	1.8	2.3	2.8	3.0	3.1	3.1	3.0	2.9	2.8	2.7	2.5
22	0.0	0.3	0.7	0.9	1.0	1.4	1.8	2.4	2.9	3.2	3.3	3.3	3.3	3.3	3.2	3.1	2.9
24	0.0	0.3	0.7	1.0	1.2	1.5	1.9	2.5	3.1	3.4	3.5	3.5	3.5	3.5	3.5	3.4	3.3
26	0.0	0.3	0.7	1.1	1.3	1.6	2.1	2.7	3.2	3.5	3.6	3.7	3.7	3.7	3.7	3.7	3.6

CSSB305 (FIN) > STATUS QUO

CSSB305 (FIN) = STATUS QUO

CSSB305 (FIN) < STATUS QUO

*Oil Tax under the Status Quo equals Total Tax less attributed gas tax

4/07/2010

Oil Tax Comparison

13

- Model Assumptions:
 - One year snapshot
 - 4.5 Bcf/d and 200 Mbbbl/d
 - Total Opex = \$2.2 Bn and Total Capex = \$2.2 Bn

- Ran multiple cases varying oil price from 40 to 200 \$/bbl and gas price parity from 6 to 26

- Ran the above cases for each of BOE, PoP and Fixed cost allocation methodology

4/07/2010

Oil Tax CSSB305 (FIN) less Status Quo*

BOE Cost Allocation

14

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
8	0.0	0.0	0.3	0.5	0.7	0.8	1.0	1.1	1.1	1.1	1.0	0.9	0.7	0.7	0.8	0.8	0.9
10	0.0	0.0	0.3	0.4	0.9	1.1	1.3	1.5	1.6	1.6	1.6	1.6	1.5	1.4	1.3	1.2	1.3
12	0.0	0.0	0.3	0.6	0.7	1.1	1.5	1.8	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.9
14	0.0	0.0	0.3	0.6	0.9	1.0	1.3	1.9	2.1	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.5
16	0.0	0.0	0.3	0.6	0.9	1.2	1.4	1.7	2.1	2.5	2.6	2.7	2.8	2.8	2.9	2.9	2.9
18	0.0	0.0	0.3	0.6	0.9	1.3	1.5	1.8	2.0	2.3	2.7	2.9	3.0	3.1	3.2	3.2	3.3
20	0.0	0.0	0.3	0.6	0.9	1.3	1.7	1.9	2.1	2.3	2.5	2.9	3.2	3.3	3.4	3.5	3.6
22	0.0	0.0	0.3	0.6	0.9	1.3	1.8	2.1	2.2	2.4	2.6	2.8	3.2	3.4	3.6	3.7	3.8
24	0.0	0.0	0.3	0.6	0.9	1.3	1.8	2.2	2.4	2.5	2.7	2.9	3.1	3.4	3.7	3.9	4.1
26	0.0	0.0	0.3	0.6	0.9	1.3	1.8	2.3	2.5	2.6	2.8	3.0	3.2	3.4	3.6	3.9	4.2



CSSB305 (FIN) > STATUS QUO



CSSB305 (FIN) = STATUS QUO



CSSB305 (FIN) < STATUS QUO

*Oil Tax under the Status Quo equals Total Tax less attributed gas tax

4/07/2010

Oil Tax CSSB305 (FIN) less Status Quo*

PoP Cost Allocation

15

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
8	0.0	0.0	0.0	0.1	0.2	0.4	0.5	0.6	0.7	0.7	0.6	0.5	0.4	0.4	0.4	0.5	0.6
10	0.0	0.0	0.0	0.0	0.1	0.3	0.5	0.7	0.9	1.0	1.0	1.0	0.9	0.9	0.8	0.7	0.7
12	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.7	0.9	1.2	1.2	1.3	1.3	1.3	1.2	1.2	1.1
14	49.0	0.0	0.0	0.0	0.0	0.1	0.3	0.5	0.9	1.2	1.4	1.4	1.5	1.5	1.5	1.5	1.5
16	9.2	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.7	1.1	1.4	1.5	1.6	1.7	1.7	1.8	1.8
18	5.5	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.6	0.9	1.3	1.6	1.7	1.8	1.9	1.9	2.0
20	4.2	318.8	0.0	0.0	0.0	0.0	0.0	0.2	0.5	0.8	1.2	1.6	1.7	1.8	1.9	2.0	2.1
22	3.6	28.2	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.7	1.1	1.5	1.7	1.9	2.0	2.1	2.2
24	3.2	14.4	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.6	0.9	1.4	1.7	1.9	2.0	2.2	2.3
26	2.9	10.1	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.5	0.8	1.2	1.6	1.9	2.0	2.2	2.3

 CSSB305 (FIN) > STATUS QUO

 CSSB305 (FIN) = STATUS QUO

 CSSB305 (FIN) < STATUS QUO

*Oil Tax under the Status Quo equals Total Tax less attributed gas tax

4/07/2010

Oil Tax CSSB305 (FIN) less Status Quo*

Fixed (27/73) Cost Allocation

16

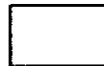
Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.3	0.4	0.5	0.6	0.7	0.9	0.9	0.9	0.8	0.7	0.5	0.5	0.6	0.6	0.6
10	0.0	0.0	0.2	0.3	0.7	0.9	1.1	1.3	1.4	1.4	1.4	1.4	1.3	1.2	1.1	1.0	1.1
12	0.0	0.0	0.2	0.4	0.5	1.0	1.2	1.5	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.7	1.7
14	0.0	0.0	0.2	0.4	0.7	0.9	1.2	1.7	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.3	2.3
16	0.0	0.0	0.2	0.4	0.8	1.0	1.2	1.5	2.0	2.3	2.4	2.5	2.5	2.6	2.7	2.7	2.7
18	0.0	0.0	0.2	0.4	0.8	1.2	1.4	1.6	1.9	2.2	2.6	2.7	2.8	2.9	3.0	3.0	3.1
20	0.0	0.0	0.2	0.4	0.8	1.2	1.5	1.7	2.0	2.1	2.4	2.8	3.0	3.1	3.2	3.3	3.4
22	0.0	0.0	0.2	0.4	0.8	1.2	1.6	1.8	2.1	2.2	2.4	2.7	3.0	3.3	3.4	3.5	3.6
24	0.0	0.0	0.2	0.4	0.8	1.2	1.6	2.0	2.2	2.3	2.5	2.7	3.0	3.3	3.5	3.7	3.8
26	0.0	0.0	0.2	0.4	0.8	1.2	1.6	2.1	2.3	2.4	2.6	2.8	3.0	3.3	3.5	3.8	4.0



CSSB305 (FIN) > STATUS QUO



CSSB305 (FIN) = STATUS QUO



CSSB305 (FIN) < STATUS QUO

*Oil Tax under the Status Quo equals Total Tax less attributed gas tax

4/07/2010

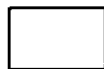
Oil Tax CSSB305 (FIN) less Status Quo* Fixed (50/50) Cost Allocation

07

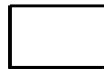
Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	(0.2)	(0.3)	(0.4)	(0.4)	(0.5)	(0.5)	(0.6)	(0.7)	(0.8)	(0.7)	(0.7)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
8	0.0	0.0	(0.1)	(0.2)	(0.1)	(0.1)	(0.3)	(0.0)	0.0	0.1	0.0	(0.1)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)
10	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.6	0.5	0.4	0.3	0.2	0.2
12	0.0	0.0	0.0	0.0	0.2	0.3	0.5	0.7	0.8	1.0	1.1	1.1	1.1	1.0	1.0	0.9	0.8
14	0.0	0.0	0.0	0.0	0.2	0.4	0.6	0.8	1.1	1.3	1.4	1.4	1.5	1.5	1.5	1.4	1.4
16	0.0	0.0	0.0	0.0	0.3	0.4	0.6	0.9	1.2	1.5	1.7	1.7	1.8	1.8	1.8	1.9	1.9
18	0.0	0.0	0.0	0.0	0.3	0.6	0.7	0.9	1.3	1.6	1.8	1.9	2.0	2.1	2.1	2.2	2.2
20	0.0	0.0	0.0	0.0	0.3	0.6	0.8	1.0	1.2	1.7	1.9	2.1	2.2	2.3	2.4	2.5	2.5
22	0.0	0.0	0.0	0.0	0.3	0.6	0.9	1.1	1.3	1.6	1.9	2.2	2.4	2.5	2.6	2.7	2.8
24	0.0	0.0	0.0	0.0	0.3	0.6	0.9	1.2	1.4	1.7	1.9	2.2	2.5	2.7	2.8	2.9	3.0
26	0.0	0.0	0.0	0.0	0.3	0.6	0.9	1.3	1.5	1.8	2.0	2.2	2.4	2.8	2.9	3.0	3.2



CSSB305 (FIN) > STATUS QUO



CSSB305 (FIN) = STATUS QUO



CSSB305 (FIN) < STATUS QUO

*Oil Tax under the Status Quo equals Total Tax less attributed gas tax

4/07/2010

Oil Tax CSSB305 (FIN) less Status Quo*

Fixed (90/10) Cost Allocation

18

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	(0.2)	(0.4)	(0.6)	(0.9)	(1.3)	(1.6)	(1.8)	(2.0)	(2.2)	(2.2)	(2.1)	(2.0)	(2.1)	(2.1)	(2.2)	(2.2)
8	0.0	0.0	(0.2)	(0.4)	(0.6)	(0.9)	(1.1)	(1.2)	(1.3)	(1.4)	(1.4)	(1.5)	(1.5)	(1.6)	(1.6)	(1.6)	(1.6)
10	0.0	0.0	0.0	(0.2)	(0.4)	(0.6)	(0.7)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.9)	(1.0)	(1.2)	(1.2)
12	0.0	0.0	0.0	0.0	(0.2)	(0.5)	(0.6)	(0.5)	(0.5)	(0.4)	(0.4)	(0.3)	(0.2)	(0.3)	(0.4)	(0.5)	(0.6)
14	0.0	0.0	0.0	0.0	(0.1)	(0.3)	(0.4)	(0.4)	(0.3)	(0.2)	(0.1)	0.0	0.2	0.2	0.1	0.1	0.0
16	0.0	0.0	0.0	0.0	0.0	(0.2)	(0.3)	(0.2)	(0.1)	0.0	0.2	0.3	0.5	0.5	0.5	0.5	0.5
18	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.1)	(0.0)	0.1	0.4	0.5	0.7	0.8	0.8	0.8	0.8
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.5	0.7	0.9	1.0	1.1	1.1	1.1
22	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.5	0.8	1.1	1.2	1.3	1.3	1.4
24	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.9	1.2	1.4	1.4	1.5	1.6
26	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.4	0.5	0.7	1.0	1.3	1.5	1.6	1.7	1.7



CSSB305 (FIN) > STATUS QUO



CSSB305 (FIN) = STATUS QUO



CSSB305 (FIN) < STATUS QUO

*Oil Tax under the Status Quo equals Total Tax less attributed gas tax

4/07/2010

MODELING THE GAS TAX LOWERING

4/7/2010

Gas Tax Comparison

20

- Model Assumptions:
 - One year snapshot
 - 4.5 Bcf/d and 500 Mbbl/d
 - Total Opex = \$2.2 Bn and Total Capex = \$2.2 Bn

- Ran multiple cases varying oil price from 40 to 200 \$/bbl and gas price parity from 6 to 26
- Ran the above cases for each of BOE, PoP and Fixed cost allocation methodology

4/07/2010

Gas Tax CSSB305 (FIN) less Status Quo*

BOE Cost Allocation

20

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	(0.2)	(0.2)	(0.2)	(0.4)	(0.5)	(0.6)	(0.6)	(0.7)	(0.8)	(0.3)	(0.3)	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)
8	0.0	(0.2)	(0.4)	(0.3)	(0.5)	(0.8)	(1.0)	(1.1)	(1.3)	(1.5)	(1.8)	(1.7)	(1.4)	(1.1)	(0.9)	(1.0)	(1.1)
10	0.0	(0.0)	(0.2)	(0.5)	(0.5)	(0.6)	(0.8)	(1.1)	(1.4)	(1.6)	(1.8)	(2.1)	(2.4)	(2.4)	(2.3)	(2.1)	(1.9)
12	0.0	0.0	(0.1)	(0.2)	(0.5)	(0.6)	(0.7)	(0.9)	(1.1)	(1.4)	(1.7)	(2.0)	(2.3)	(2.6)	(2.7)	(2.7)	(2.7)
14	0.0	0.0	0.0	(0.1)	(0.2)	(0.4)	(0.7)	(0.8)	(0.9)	(1.1)	(1.4)	(1.7)	(2.0)	(2.3)	(2.6)	(2.8)	(2.9)
16	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.4)	(0.7)	(0.8)	(1.0)	(1.1)	(1.4)	(1.6)	(2.0)	(2.3)	(2.6)	(2.9)
18	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.4)	(0.7)	(0.9)	(1.0)	(1.2)	(1.4)	(1.6)	(1.9)	(2.2)	(2.6)
20	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.3)	(0.4)	(0.7)	(0.9)	(1.1)	(1.2)	(1.4)	(1.6)	(1.9)	(2.2)
22	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.3)	(0.4)	(0.7)	(0.9)	(1.1)	(1.3)	(1.4)	(1.6)	(1.9)
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.3)	(0.5)	(0.7)	(0.9)	(1.2)	(1.3)	(1.5)	(1.7)
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.3)	(0.5)	(0.7)	(0.9)	(1.1)	(1.3)	(1.5)

 CSSB305 (FIN) > STATUS QUO

 CSSB305 (FIN) = STATUS QUO

 CSSB305 (FIN) < STATUS QUO

*Gas Tax under the Status Quo equals Attributed Gas Tax

4/07/2010

Gas Tax CSSB305 (FIN) less Status Quo*

PoP Cost Allocation

22

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.0	(0.0)	(0.2)	(0.3)	(0.4)	(0.4)	(0.5)	(0.6)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)
8	0.0	0.0	0.0	0.0	(0.2)	(0.4)	(0.6)	(0.7)	(0.9)	(1.1)	(1.3)	(1.2)	(0.9)	(0.6)	(0.6)	(0.6)	(0.7)
10	0.0	0.0	0.0	0.0	(0.0)	(0.2)	(0.4)	(0.7)	(0.8)	(1.1)	(1.3)	(1.5)	(1.8)	(1.7)	(1.6)	(1.4)	(1.2)
12	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.2)	(0.4)	(0.6)	(0.9)	(1.1)	(1.3)	(1.6)	(1.9)	(2.0)	(2.0)	(1.9)
14	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.4)	(0.6)	(0.9)	(1.1)	(1.4)	(1.6)	(1.9)	(2.1)	(2.1)
16	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.2)	(0.4)	(0.6)	(0.8)	(1.1)	(1.4)	(1.6)	(1.9)	(2.1)
18	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.1)	(0.2)	(0.4)	(0.6)	(0.8)	(1.0)	(1.3)	(1.6)	(1.9)
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.1)	(0.3)	(0.4)	(0.6)	(0.8)	(1.0)	(1.3)	(1.6)
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.1)	(0.2)	(0.3)	(0.4)	(0.6)	(0.8)	(1.0)	(1.2)
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.1)	(0.2)	(0.3)	(0.4)	(0.6)	(0.8)	(1.0)
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.1)	(0.1)	(0.2)	(0.3)	(0.4)	(0.6)	(0.8)

 CSSB305 (FIN) > STATUS QUO

 CSSB305 (FIN) = STATUS QUO

 CSSB305 (FIN) < STATUS QUO

*Gas Tax under the Status Quo equals Attributed Gas Tax

4/07/2010

Gas Tax CSSB305 (FIN) less Status Quo*

Fixed (49/51) Cost Allocation

28

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	(0.2)	(0.1)	(0.0)	(0.2)	(0.3)	(0.3)	(0.3)	(0.4)	(0.4)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)
8	0.0	(0.2)	(0.3)	(0.2)	(0.4)	(0.6)	(0.8)	(0.9)	(1.1)	(1.3)	(1.5)	(1.4)	(1.1)	(0.7)	(0.7)	(0.7)	(0.8)
10	0.0	(0.0)	(0.2)	(0.4)	(0.3)	(0.5)	(0.7)	(1.0)	(1.2)	(1.4)	(1.6)	(1.9)	(2.1)	(2.1)	(1.9)	(1.8)	(1.6)
12	0.0	0.0	(0.1)	(0.2)	(0.5)	(0.5)	(0.5)	(0.7)	(1.0)	(1.3)	(1.5)	(1.8)	(2.0)	(2.3)	(2.5)	(2.5)	(2.4)
14	0.0	0.0	0.0	(0.1)	(0.2)	(0.4)	(0.5)	(0.6)	(0.8)	(1.0)	(1.2)	(1.5)	(1.8)	(2.1)	(2.4)	(2.6)	(2.7)
16	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.4)	(0.6)	(0.7)	(0.8)	(1.0)	(1.2)	(1.5)	(1.8)	(2.2)	(2.4)	(2.7)
18	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.4)	(0.7)	(0.8)	(0.9)	(1.0)	(1.3)	(1.5)	(1.8)	(2.1)	(2.5)
20	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.3)	(0.4)	(0.7)	(0.8)	(0.9)	(1.1)	(1.3)	(1.5)	(1.8)	(2.0)
22	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.3)	(0.4)	(0.7)	(0.9)	(1.0)	(1.1)	(1.3)	(1.5)	(1.7)
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.3)	(0.5)	(0.7)	(0.9)	(1.0)	(1.2)	(1.3)	(1.5)
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.3)	(0.5)	(0.7)	(0.9)	(1.1)	(1.2)	(1.4)

 CSSB305 (FIN) > STATUS QUO

 CSSB305 (FIN) = STATUS QUO

 CSSB305 (FIN) < STATUS QUO

*Gas Tax under the Status Quo equals Attributed Gas Tax

4/07/2010

Gas Tax CSSB305 (FIN) less Status Quo* Fixed (90/10) Cost Allocation

24

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.4	0.5	0.6	0.7	0.8	1.0	1.1	1.2	1.3	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5
8	0.0	0.3	0.4	0.4	0.3	0.3	0.3	0.2	0.2	0.1	(0.0)	0.2	0.6	0.7	0.6	0.6	0.6
10	0.0	(0.0)	0.2	0.2	0.3	0.2	0.0	(0.1)	(0.2)	(0.3)	(0.4)	(0.6)	(0.8)	(0.7)	(0.4)	(0.2)	0.1
12	0.0	0.0	(0.0)	0.1	0.2	0.2	0.1	(0.1)	(0.3)	(0.4)	(0.6)	(0.7)	(0.9)	(1.1)	(1.2)	(1.1)	(1.0)
14	0.0	0.0	0.0	(0.1)	0.0	0.1	0.1	0.0	(0.1)	(0.3)	(0.6)	(0.7)	(0.9)	(1.1)	(1.3)	(1.5)	(1.5)
16	0.0	0.0	0.0	0.0	(0.1)	0.0	0.0	0.0	(0.1)	(0.2)	(0.4)	(0.6)	(0.8)	(1.0)	(1.2)	(1.5)	(1.6)
18	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.0)	(0.0)	(0.0)	(0.1)	(0.3)	(0.4)	(0.6)	(0.9)	(1.1)	(1.3)	(1.5)
20	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.0)	(0.1)	(0.1)	(0.2)	(0.3)	(0.5)	(0.6)	(0.9)	(1.1)	(1.4)
22	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.3)	(0.5)	(0.7)	(0.9)	(1.1)
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.1)	(0.1)	(0.2)	(0.3)	(0.4)	(0.5)	(0.7)	(0.9)
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)	(0.4)	(0.6)	(0.7)

CSSB305 (FIN) > STATUS QUO

CSSB305 (FIN) = STATUS QUO

CSSB305 (FIN) < STATUS QUO

*Gas Tax under the Status Quo equals Attributed Gas Tax

4/07/2010

Gas Tax Comparison

25

□ Model Assumptions:

- One year snapshot
 - 4.5 Bcf/d and 200 Mbbbl/d
 - Total Opex = \$2.2 Bn and Total Capex = \$2.2 Bn
-
- Ran multiple cases varying oil price from 40 to 200 \$/bbl and gas price parity from 6 to 26
 - Ran the above cases for each of BOE, PoP and Fixed cost allocation methodology

Gas Tax CSSB305 (FIN) less Status Quo*

BOE Cost Allocation

26

Gas Price Parity

Oil Price (\$/bbl)

		40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	(0.2)	(0.1)	(0.2)	(0.3)	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
8	0.0	0.0	(0.2)	(0.3)	(0.2)	(0.4)	(0.5)	(0.6)	(0.7)	(0.8)	(1.0)	(1.1)	(1.2)	(0.9)	(0.6)	(0.6)	(0.6)	(0.6)
10	0.0	0.0	0.0	(0.2)	(0.4)	(0.4)	(0.4)	(0.5)	(0.8)	(0.9)	(1.0)	(1.1)	(1.3)	(1.5)	(1.6)	(1.8)	(1.8)	(1.6)
12	0.0	0.0	0.0	0.0	(0.2)	(0.4)	(0.5)	(0.4)	(0.5)	(0.7)	(0.9)	(1.1)	(1.2)	(1.4)	(1.6)	(1.7)	(1.7)	(1.9)
14	0.0	0.0	0.0	0.0	(0.0)	(0.2)	(0.4)	(0.6)	(0.5)	(0.6)	(0.7)	(0.9)	(1.1)	(1.3)	(1.5)	(1.6)	(1.6)	(1.8)
16	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.2)	(0.3)	(0.5)	(0.6)	(0.6)	(0.7)	(0.9)	(1.0)	(1.2)	(1.5)	(1.5)	(1.6)
18	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.3)	(0.5)	(0.6)	(0.7)	(0.8)	(0.9)	(1.0)	(1.2)	(1.2)	(1.4)
20	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.2)	(0.3)	(0.4)	(0.6)	(0.8)	(0.8)	(0.9)	(1.0)	(1.0)	(1.2)
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.2)	(0.3)	(0.4)	(0.6)	(0.8)	(0.9)	(0.9)	(0.9)	(1.0)
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.1)	(0.2)	(0.3)	(0.4)	(0.5)	(0.7)	(0.9)	(0.9)	(1.0)
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.1)	(0.2)	(0.3)	(0.4)	(0.5)	(0.7)	(0.7)	(0.9)

 CSSB305 (FIN) > STATUS QUO

 CSSB305 (FIN) = STATUS QUO

 CSSB305 (FIN) < STATUS QUO

*Gas Tax under the Status Quo equals Attributed Gas Tax

4/07/2010

Gas Tax CSSB305 (FIN) less Status Quo*

PoP Cost Allocation

27

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.0	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)
8	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.3)	(0.4)	(0.5)	(0.6)	(0.7)	(0.8)	(0.5)	(0.3)	(0.3)	(0.4)
10	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.2)	(0.4)	(0.5)	(0.6)	(0.7)	(0.8)	(1.0)	(1.1)	(1.2)	(1.0)
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.3)	(0.5)	(0.6)	(0.7)	(0.8)	(1.0)	(1.1)	(1.3)
14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.4)	(0.6)	(0.7)	(0.8)	(1.0)	(1.1)
16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.3)	(0.5)	(0.7)	(0.8)	(0.9)
18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.3)	(0.4)	(0.6)	(0.8)
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.1)	(0.3)	(0.4)	(0.6)
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.1)	(0.2)	(0.4)
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.1)	(0.2)
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.2)

 CSSB305 (FIN) > STATUS QUO

 CSSB305 (FIN) = STATUS QUO

 CSSB305 (FIN) < STATUS QUO

*Gas Tax under the Status Quo equals Attributed Gas Tax

4/07/2010

Gas Tax CSSB305 (FIN) less Status Quo*

Fixed (25/75) Cost Allocation

28

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
8	0.0	0.0	(0.2)	(0.2)	(0.2)	(0.3)	(0.4)	(0.5)	(0.6)	(0.7)	(0.8)	(0.9)	(1.0)	(0.7)	(0.4)	(0.4)	(0.5)
10	0.0	0.0	0.0	(0.2)	(0.3)	(0.3)	(0.3)	(0.5)	(0.7)	(0.8)	(0.9)	(1.0)	(1.2)	(1.3)	(1.5)	(1.6)	(1.4)
12	0.0	0.0	0.0	0.0	(0.2)	(0.4)	(0.4)	(0.4)	(0.5)	(0.6)	(0.9)	(1.0)	(1.1)	(1.3)	(1.4)	(1.6)	(1.8)
14	0.0	0.0	0.0	0.0	(0.0)	(0.2)	(0.4)	(0.5)	(0.5)	(0.5)	(0.6)	(0.8)	(1.0)	(1.2)	(1.3)	(1.5)	(1.7)
16	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.2)	(0.3)	(0.5)	(0.5)	(0.6)	(0.7)	(0.8)	(0.9)	(1.2)	(1.4)	(1.5)
18	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.3)	(0.5)	(0.6)	(0.6)	(0.7)	(0.8)	(0.9)	(1.1)	(1.3)
20	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.2)	(0.3)	(0.4)	(0.6)	(0.7)	(0.7)	(0.8)	(0.9)	(1.1)
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.2)	(0.3)	(0.4)	(0.6)	(0.7)	(0.8)	(0.9)	(1.0)
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.1)	(0.2)	(0.3)	(0.4)	(0.5)	(0.7)	(0.8)	(0.9)
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.1)	(0.1)	(0.2)	(0.3)	(0.4)	(0.5)	(0.7)	(0.9)

 CSSB305 (FIN) > STATUS QUO

 CSSB305 (FIN) = STATUS QUO

 CSSB305 (FIN) < STATUS QUO

*Gas Tax under the Status Quo equals Attributed Gas Tax

4/07/2010

Gas Tax CSSB305 (FIN) less Status Quo*

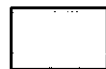
Fixed (90/10) Cost Allocation

29

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.6	0.9	1.0	1.3	1.5	1.7	1.9	2.1	2.3	1.9	2.0	2.1	2.1	2.2	2.2	2.3	2.3
8	0.0	0.5	0.7	0.8	0.8	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.6	1.6
10	0.0	0.0	0.4	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.8	0.8	1.2
12	0.0	0.0	0.0	0.3	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.4	0.3
14	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.5	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.2	0.1
16	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.4	0.4	0.5	0.4	0.3	0.2	0.2	0.2	0.1	0.0
18	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.3	0.4	0.4	0.4	0.3	0.2	0.1	0.0	(0.0)
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.0	(0.1)
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	0.2	0.2	0.3	0.3	0.3	0.2	0.1	0.0
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.1	0.1	0.2	0.2	0.2	0.1



CSSB305 (FIN) > STATUS QUO



CSSB305 (FIN) = STATUS QUO



CSSB305 (FIN) < STATUS QUO

*Gas Tax under the Status Quo equals Attributed Gas Tax

4/07/2010

Alaska Oil and Gas Association



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Marilyn Crockett, Executive Director

**TESTIMONY
OF THE
ALASKA OIL AND GAS ASSOCIATION
REGARDING CSSB 305(FIN) (TITLE AM)**

**PRESENTED TO THE
HOUSE RESOURCES COMMITTEE**

April 7, 2010

Mr. Chairman and Members of the Committee:

My name is Marilyn Crockett and I am the Executive Director of the Alaska Oil and Gas Association (AOGA), the private, nonprofit trade association for the oil and gas industry in Alaska. Our 14 members account for the majority of oil and gas activities in the state. We appreciate the opportunity to share with you our deep concerns about Committee Substitute for Senate Bill 305, Finance, title amended — “SB 305” for short — which has passed the Senate and is now before you for consideration. The written testimony submitted for the record today has been approved by the AOGA Tax Committee, which can only approve testimony or public statements in AOGA’s name about tax matters unless there is no dissent. We recognize, of course, that my oral testimony today will be included in the transcript for today’s hearing.

We believe proposed legislation to revise a major tax like the production tax should be evaluated to see whether the change would improve the investment climate in Alaska, lead to more investment to help stem the annual oil production decline, simplify and add clarity to Alaska’s complicated tax structure and whether it is something that should be enacted now. AOGA’s 14 member companies agree unanimously that SB 305 fails all of these tests and thus should not be enacted.

We have three main concerns with SB 305:

- 1) It is premature to establish decoupling at this time.
- 2) The justification for decoupling is flawed.
- 3) Determining an appropriate mechanism for cost allocations is complex and further analysis should be done to ensure a proper methodology is established.

SB 305 proposes to alter Alaska's current production tax structure by decoupling oil and gas so that progressivity will apply to them separately and so that revenues and costs will be separately determined, in order to avoid the potential for state revenue "dilution" when major gas sales are commingled with the oil stream. As a consequence of this decoupling, SB 305 proposes to have lease expenditures allocated between oil and gas.

Decoupling is Premature

Our first concern with proposed SB 305 is that it is premature to put decoupling into effect this year. The impetus to pass SB 305 this session appears to be driven by the AGIA provision that purports to provide gas tax fiscal certainty through a lock-in provision on May 1 to any company committing gas during the first open season. And that failure to address the dilution issue prior to that May 1 deadline might prohibit a future correction.

The apparent rush to address this issue will yield a "fix" that is not needed now and one that will result in further complexity to Alaska's already complex production tax system and will lead to adverse unintended tax and administrative consequences, further reducing an already shaky future investment climate—a potential result that neither the State of Alaska nor our industry can afford.

Potential changes to any tax regime need to be carefully considered and designed to ensure the desired objective of resource development is achieved. This is especially true for Alaska. Sufficient time should be given to examine the potential impacts and costs of SB 305 fully.

Flawed Justification for Decoupling

We are also concerned about the very idea of decoupling and the justification that is being offered for it. The \$2 billion figure that is being circulated as the amount of production tax that the State would "lose" each year without decoupling is deeply flawed. Regarding the \$2 billion figure, one must understand that there are three primary drivers that determine how much tax revenue the production tax generates. One is the netback value, the second is the amount of lease expenditures or deductible cost, and the third is the number of BTU equivalent barrels that are being produced. The difference between the first driver and the second is not only the value that is taxed, but when expressed on a BTU equivalent taxable barrel basis, it also determines whether progressivity applies, and if so, what the progressivity rate is.

The analysis for the \$2 billion figure was based on generic deductible-cost data released by the Department of Revenue for the North Slope for 2008, and it also relied on oil production forecasts published by the State. The way these data were used in the analysis yields figures that are not likely to reflect actual circumstances in 2020 when a major gas pipeline is likely to begin operation. In particular, oil production in 2020 is likely to be significantly lower than the state estimate, which reflects an annual decline rate of only 2.7% during the current decade from FY 2010 to FY 2019. Historic annual decline rates for ANS oil have been 5.1% during the past 20 years and 6.6% during the last five.

This difference in decline rate means that, whatever the \$2 billion analysis used as the figure for lease expenditures per barrel, the cost-per-barrel figure using these historic decline rates would be one-third to almost two-thirds higher. This means the analysis significantly overstated the taxable margin per barrel and overstated the tax rate to the extent it shows progressivity as applying. In addition, when

ANS gas production is added to the picture, it means the analysis understated the reduction in costs per BTU equivalent barrel because — with less oil production than the analysis assumed — the change in number of barrels to spread the costs over as a result of having the gas would be proportionally greater.

These distortions are inherent simply from the design of the analysis that produced the \$2 billion figure, and do not depend on the particular numbers which that analysis used as the netback prices of gas and oil, or the deductible costs per barrel. Indeed, as stated in BP's March 12, 2010 letter to the Senate Finance Committee, it is possible in some situations that the State would actually receive more production tax without decoupling than with it. If, however, this Committee believes SB 305 needs to be passed this session, then the effective date of its key provisions, oil and gas decoupling and cost allocations, should be deferred until commercial production of Alaska North Slope gas commences.

Establishing Proper Cost Allocation Methodology is Complex

We are also very troubled over the potential cost allocations that SB 305 would require before major gas development. Under SB 305, taxpayers would be required — either immediately as the Bill now provides, or when commercial ANS gas production begins as we propose — to begin allocating costs between oil and gas. Developing a cost allocation methodology is a complex issue. Determining the proper methodology and understanding its potential impacts on the administration of and compliance with the underlying tax and on current and future investments are matters that should be fully evaluated and studied to ensure the concerns of all potentially affected taxpayers and the State can be adequately addressed.

The enactment of ACES was designed, in part, to incentivize investment and exploration of Alaska's resources. Requiring cost allocations prior to major gas development could undermine that objective. Currently, under AS 43.55.165(h), the Department of Revenue is authorized to develop, when needed, cost allocation methods to determine lease expenditures that are costs of exploring for, developing, or producing oil and gas deposits. If cost allocations are required prior to major gas development, how would costs associated for any lease or property (1) which contains both oil and gas, and (2) currently produces only oil (and possibly trace amounts of gas), be handled when the production of the oil provides information about the reservoir and its potential for major gas development? Would any of the costs be required to be allocated to gas, thereby raising the tax on current oil operations?

On the North Slope, there are producers with current oil production from one field that are also incurring gas related expenditures related to another field without gas production. How would those gas related expenditures be handled? Will the gas related expenditures be allowed for that producer against its oil related production income or only against future gas revenues from future gas production - revenues that producer may not have until many years in the future if at all?

Cost allocations prior to major gas development could also result in unintended consequences for explorers. Currently, an explorer who takes the risk and incurs the cost to explore in Alaska does so with the knowledge its expenses are deductible regardless of whether oil is discovered or gas. SB 305 is not clear and we are concerned that decoupling might be interpreted to mean that exploration expenditures will be deductible only for oil if oil is discovered, and only for gas if gas is discovered.

For an explorer with no production, or for one that only has oil production, discovering gas will mean there is nothing from which its exploration costs can be deducted for that discovery. As a result those costs will become "carried-forward annual loss" converted into a tax credit which can then either be used by that taxpayer in the next tax year or, if certain conditions are met, converted into a transferable tax credit certificate the taxpayer can then possibly sell to other taxpayers or to the state. Given the decoupling of oil and gas proposed by SB 305, the credit for the costs of a gas discovery could be limited so it could only be applied against tax on gas production. Since the tax on nearly all of today's gas production is capped under special rules, explorers who discover gas are likely to find it difficult, if not impossible, to find anyone with gas tax liability under decoupling who could use "carried-forward annual loss" credits from new gas discoveries. This needlessly penalizes explorers who are exploring for gas, as well as those who are exploring for oil but discover gas anyway.

The present tax without decoupling does not penalize explorers in this way, which is another reason why decoupling should be deferred until commercial ANS gas production begins. At that time there would be taxpayers with significant gas tax liability who would be in a position to use "carried-forward annual loss" credits from subsequent gas discoveries.

Entire Production Tax Structure Should Be Re-evaluated

It is important to reiterate AOGA's belief that the overall production tax structure in Alaska needs to re-examined carefully. As we have stated many times before, our primary concern is that the tax rates under the present production tax are already too high and place Alaska at a competitive disadvantage for oil industry investment. Based on the testimony you have heard this session and the Department of Revenue's own forecasts about expected future continuing decline in oil production and in projected industry investment, it is clear that a comprehensive evaluation and revision of the production tax needs to be undertaken if it is to achieve the objective of providing Alaska jobs, increasing Alaska production and maximizing State revenues.

Summary

In summary, then, it is premature to decouple gas from oil at this time. The concern that decoupling seeks to address will not arise until commercial ANS gas production begins. In addition, decoupling now will have unintended adverse consequences for current operations and explorers, particularly if they find gas instead of oil. Further, the case for any decoupling at all has not been adequately proven, and in any event, whatever negative effect there might be on production tax revenues without decoupling seems likely to be substantially less than the \$2 billion a year being claimed.

And finally, the production tax needs to be evaluated as a whole, both to see how well it works internally and how well it fits in with the other elements of Alaska's fiscal regime for oil and gas. We therefore ask this Committee to hold SB 305 in committee and let these matters be evaluated and addressed in a comprehensive fashion, instead of piecemeal as this Bill would do. Enacting SB 305 so it can be in place by May 1st and locked in for AGIA is premature. But if you feel you must enact it, then the effective date of its key provisions, oil and gas decoupling and cost allocations, should be deferred until commercial production of Alaska North Slope gas commences.

Thank you again for the opportunity to provide this testimony.

	decoupled tax rates		implied attributive tax rates	
	oil	gas	oil	gas
price (\$/bbl or \$/mmbtu)	\$120.00	\$8.00	\$120.00	\$8.00
transportation cost (\$/bbl or \$/mmbtu)	\$6.50	\$4.50	\$6.50	\$4.50
gross value (\$/bbl or \$/mmbtu)	\$113.50	\$3.50	\$113.50	\$3.50
volume (bbls/day or mcf/day)	500,000	4,500,000	500,000	4,500,000
BTU barrel of oil equivalents (BOE's)	500,000	750,000	500,000	4,500,000
annual BOE's	182,500,000	273,750,000	182,500,000	273,750,000
total gross value	\$20,713,750,000	\$5,748,750,000	\$20,713,750,000	\$5,748,750,000
non-royalty value	\$18,124,531,250	\$5,030,156,250	\$18,124,531,250	\$5,030,156,250
costs (allocated by BOEs)	\$1,760,000,000	\$2,640,000,000	\$1,760,000,000	\$2,640,000,000
net value	\$16,364,531,250	\$2,390,156,250	\$16,364,531,250	\$2,390,156,250
net value p/boe	\$102.48	\$9.98	\$102.48	\$9.98
gas net value p/mmbtu (boe / 6)		\$1.66		\$1.66
tax rate (base 25% rate plus progressivity)	0.5399	0.25	0.2749	0.6124
tax before credits	\$8,835,437,796	\$597,539,063	\$4,498,687,217	\$1,463,688,523
credits	\$176,000,000	\$264,000,000	\$176,000,000	\$264,000,000
tax	\$8,659,437,796	\$333,539,063	\$4,322,687,217	\$1,199,688,523
TOTAL		\$8,992,976,858		\$5,522,375,740

**SB 350:
Notes on Operation of Tax**

**Logsdon & Associates
House Resources Committee
April 9, 2010**

Example Cases

State Production Tax Revenue

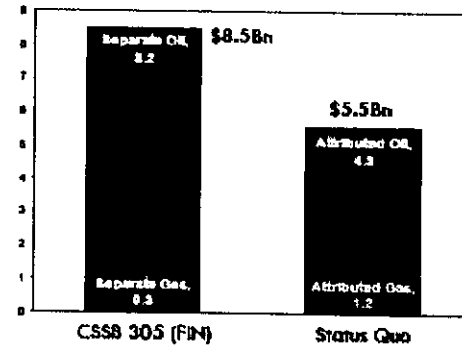
Oil: 500 Mbbl/d and Gas: 4.5 Bcf/d

Capex: \$2.2Bn and Opex: \$2.2Bn

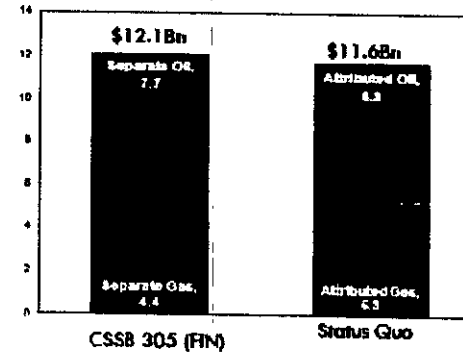
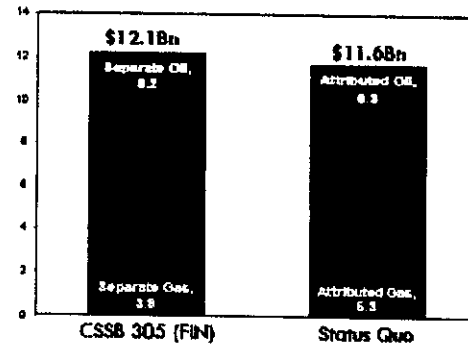
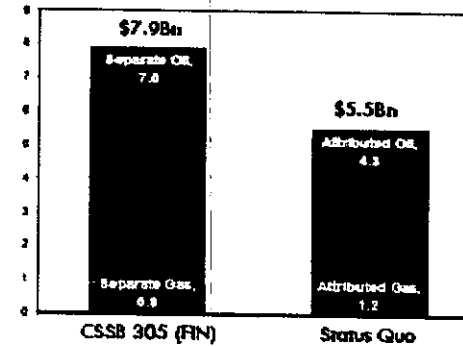
\$120/\$8
(15:1)

\$120/\$15
(8:1)

BOE

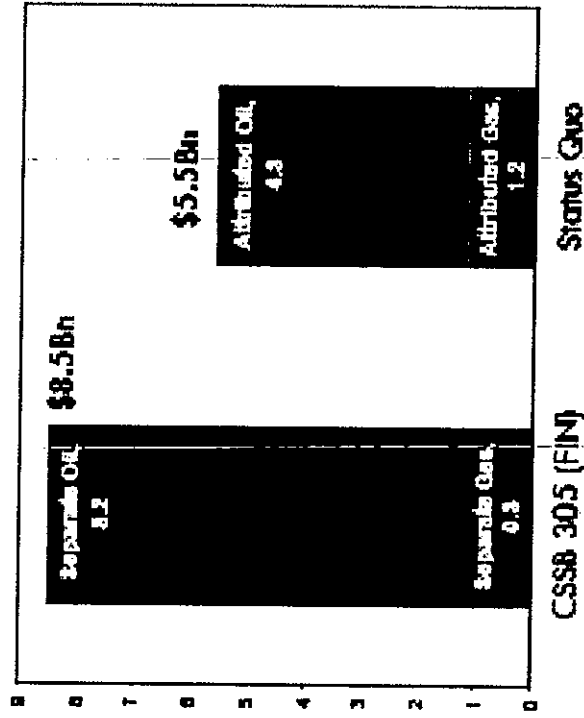


PoP



\$120/\$8
(15:1)

BOE



CSSB 305 (FIN)

Status Quo

OIL AND GAS TAXES COMBINED (STATUS QUO)

	oil	gas	combined
price (\$/bbl or \$/mmbtu)	\$120.00	\$8.00	
transportation cost (\$/bbl or \$/mmbtu)	\$6.50	\$4.50	
gross value (\$/bbl or \$/mmbtu)	\$113.50	\$3.50	
volume (bbls/day pr mcf/day)	500,000	4,500,000	
BTU barrel of oil equivalents (BOE's)	500,000	750,000	
annual BOE's	182,500,000	273,750,000	456,250,000
total gross value	\$20,713,750,000	\$5,748,750,000	\$26,462,500,000
non-royalty gross value			\$23,154,687,500
costs			\$4,400,000,000
net value			\$18,754,687,500
net value p/boe			\$46.98
tax rate (base 25% rate plus progressivity)			0.3179
tax before credits			\$5,962,375,740
credits			\$440,000,000
tax			\$5,522,375,740
DOR GAS TAX ALLOCATION METHODOLOGY (15 AAC 55.220)			
Proportion of Gross Value	0.78	0.22	
Atributed Gas Tax	\$4,322,687,217	\$1,199,688,523	

Attributed Gas Tax per DOR AGIA Regulations (15 AAC 55.220)

- AGIA tax inducement only applied to gas
- Since current tax is combined with oil it was necessary to ascribe that portion which is gas
- Regulation allocates tax based on relative gross value
 - Allocating tax is different than allocating costs
 - Gross value is a very material determinant of the differences in tax value between oil and gas

OIL AND GAS TAXES DECOUPLED

	oil alone	gas alone	total
price (\$/bbl or \$/mmbtu)	\$120.00	\$8.00	
transportation cost (\$/bbl or \$/mmbtu)	\$6.50	\$4.50	
gross value (\$/bbl or \$/mmbtu)	\$113.50	\$3.50	
volume (bbls/day or mcf/day)	500,000	4,500,000	
BTU barrel of oil equivalents (BOE's)	500,000	750,000	
annual BOE's	182,500,000	273,750,000	
total gross value	\$20,713,750,000	\$5,748,750,000	
non-royalty value	\$18,124,531,250	\$5,030,156,250	
costs (allocated by BOEs)	\$1,760,000,000	\$2,640,000,000	
net value	\$16,364,531,250	\$2,390,156,250	
net value p/boe	\$102.48	\$9.98	
tax rate (base 25% rate plus progressivity)	0.5399	0.25	
tax before credits	\$8,835,437,796	\$597,539,063	
credits	\$176,000,000	\$264,000,000	
tax	\$8,659,437,796	\$333,539,063	\$8,992,976,858

Implication

- Alone
 - Gas net value p/boe = \$9.98/boe
 - Gas net value p/mmbtu = \$1.66/mmbtu
- Combined
 - Gas net value p/boe = \$46.98/boe
 - Gas net value p/mmbtu = \$7.83/mmbtu
- Result: under status quo gas with a value of \$1.66 will be taxed as if it had a value of \$7.83

Combining under Current Law

- Combining oil and gas dilutes the oil tax down
- It also “dilutes” the gas tax up
- Fiscal stability is only good if what is being stabilized is good
- Locking in a rate that may be too high negates the value of the AGIA inducement and may not be healthy for the project
- Underscores the problem of combining substances of vastly different values for taxation

Power of Status Quo

- Current dilution effect is clear
- Future discussions
 - Same producers who produce gas produce oil
 - Issue will move beyond gas
 - If the state becomes unhappy with gas taxes - can extract value from producers through oil tax increases
 - Oil taxation will predictably be part of discussion
- Status quo (whatever it is at the time) will inevitably become frame of reference for evaluation

**SB 305:
Flowchart: 26-LS1577\WA.6**

House Resources Committee
Logsdon & Associates
April 10, 2010

Mechanics of Tax (Current & SB 305)

- 1) Oil gross value (market price less transport cost)
- 2) Gas gross value (market price less transport cost)
- 3) Oil + gas gross value gas = total **gross value**
- 4) Total gross value – lease capital and operating costs = **Production tax (net) value**
- 5) Production tax value / total oil & gas BOEs = p/BOE production tax value
- 6) Total tax rate = 25% base rate + progressivity factor (based on p/BOE production tax value)
- 7) Total tax rate applied to production tax value

Progressivity Calculation (Current & SB 305)

- “Trigger” = \$30 p/BOE production tax value
- “Slope” = 0.4%*
- Progressivity surcharge = (P/BOE production tax value - \$30) X .004
- Example: if production tax value = \$50
 - Base tax rate = 25%
 - Progressivity = (\$50 – \$30) X .004 = 8%
 - Total tax of 33% on net value

* Slope changes to 0.1% after \$92.50 net per BOE value

How Progressivity Operates Now

- Each company calculates one statewide progressivity rate based on all combined oil and gas activity
- Company divides operations into segments:
 - 1) Each Cook Inlet oil lease
 - 2) Each Cook Inlet gas lease
 - 3) North Slope oil and gas except gas used in-state
 - 4) Non-North Slope / Non-Cook Inlet oil and gas except gas used in-state
 - 5) Non-Cook Inlet gas used in-state
- For each segment:
 - For each segment calculate tax liability based on total tax rate (base 25% rate plus statewide progressivity rate) X the segment's production tax value
 - For segments 1, 2, and 5 tax liability is lower of ELF or above

Currently: One Progressivity Bucket

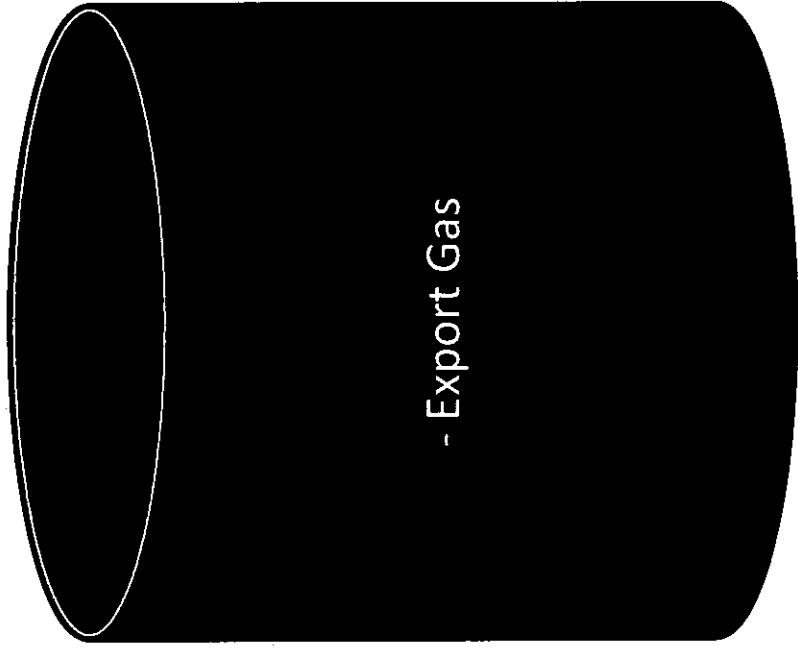
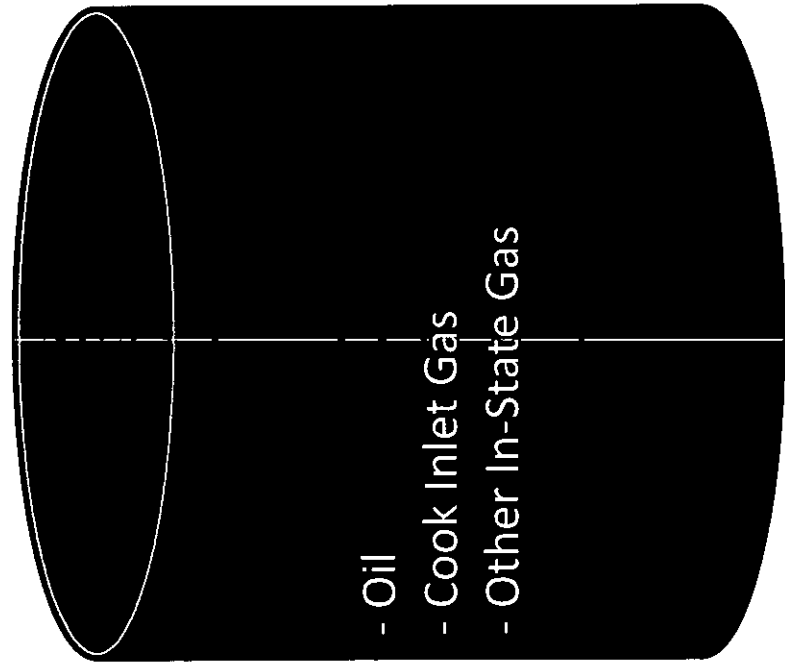


SB 305: Instead of One Statewide Progressivity Calculation: Two Progressivity Calculations

- **FIRST BUCKET: Oil / CI Gas / Other In-State Gas**
 - Progressivity calculated together (no change to formula)
 - Same as current activity
 - Same 5 segments treated as now
 - No tax increase on current activity

- **SECOND BUCKET: Export Gas (Major Gas Sale Gas)**
 - Progressivity calculated distinctly (same formula based on export gas p/BOE production tax value)
 - Segment unto itself: Calculate tax liability based on total tax rate (base 25% rate plus export gas progressivity rate) X export gas production tax value
 - Will not dilute oil progressivity

SB 305: Two Progressivity Buckets





AMENDMENT

OFFERED IN THE HOUSE

BY REPRESENTATIVE JOHNSON

TO: CSSB 305(FIN)(title am)

1 Page 1, lines 1 - 11:

2 Delete "providing that the tax rate applicable to the production of oil as the
3 average production tax value of oil, gas produced in the Cook Inlet sedimentary basin,
4 and gas produced outside of the Cook Inlet sedimentary basin and used in the state
5 increases above \$30 shall be 0.4 percent multiplied by the number that represents the
6 difference between that average monthly production tax value and \$30, or the sum of 25
7 percent and the product of 0.1 percent multiplied by the number that represents the
8 difference between that average monthly production tax value and \$92.50, except that
9 the total rate determined in the calculation may not exceed 50 percent; providing for an
10 increase in the rate of tax on the production of gas as the average production tax value
11 on a BTU equivalent barrel basis of gas produced outside of the Cook Inlet sedimentary
12 basin and not used in the state increases above \$30"

13 Insert "relating to that part of the tax on the production of oil and gas that
14 increases as the average production tax value of the oil and gas increases above \$30"

15

16 Page 2, line 2, following "expenditures;":

17 Insert "relating to the tax on the production of gas in effect at the start of the first
18 binding open season held for the project licensed under the Alaska Gasline Inducement
19 Act;"

20

21 Page 2, following line 12:

22 Insert new bill sections to read:

23 "** Sec. 2. AS 29.60.850(b), as amended by sec. 1 of this Act, is amended to read:

1 (b) Each fiscal year, the legislature may appropriate to the community revenue
 2 sharing fund an amount equal to 20 percent of the money received by the state during
 3 the previous calendar year under AS 43.55.011(g) [AND (p)]. The amount may not
 4 exceed

5 (1) \$60,000,000; or

6 (2) the amount that, when added to the fund balance on June 30 of the
 7 previous fiscal year, equals \$180,000,000.

8 * **Sec. 3.** AS 29.60.850(b), as amended by sec. 2 of this Act, is amended to read:

9 (b) Each fiscal year, the legislature may appropriate to the community revenue
 10 sharing fund an amount equal to 20 percent of the money received by the state during
 11 the previous calendar year under AS 43.55.011(g) and (p). The amount may not
 12 exceed

13 (1) \$60,000,000; or

14 (2) the amount that, when added to the fund balance on June 30 of the
 15 previous fiscal year, equals \$180,000,000."

16
 17 Renumber the following bill sections accordingly.

18
 19 Page 2, following line 24:

20 Insert new bill sections to read:

21 ** **Sec. 5.** AS 43.55.011(e), as amended by sec. 4 of this Act, is amended to read:

22 (e) There is levied on the producer of oil or gas a tax for all oil and gas
 23 produced each calendar year from each lease or property in the state, less any oil and
 24 gas the ownership or right to which is exempt from taxation or constitutes a
 25 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of
 26 this section, the tax is equal to the sum of

27 (1) the annual production tax value of the taxable oil and gas as
 28 calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

29 (2) the sum, over all months of the calendar year, of the tax amounts
 30 determined under

31 [(A) SUBSECTION] (g) of this section [; AND

(B) SUBSECTION (p) OF THIS SECTION].

* Sec. 6. AS 43.55.011(e) as amended to read:

(e) There is levied on the producer of oil or gas a tax for all oil and gas produced each calendar year from each lease or property in the state, less any oil and gas the ownership or right to which is exempt from taxation or constitutes a landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of this section, the tax is equal to the sum of

(1) the annual production tax value of the taxable oil and gas as calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

(2) the sum, over all months of the calendar year, of the tax amounts determined under

(A) subsection (g) of this section; and

(B) subsection (p) of this section."

Renumber the following bill sections accordingly.

Page 3, following line 18:

Insert new bill sections to read:

** Sec. 8. AS 43.55.011(g), as amended by sec. 7 of this Act, is amended to read:

(g) For each month of the calendar year for which the producer's average monthly production tax value under **AS 43.55.160(a)(2)** [AS 43.55.160(a)(2)(A) - (E)] of a BTU equivalent barrel of taxable oil and gas is more than \$30, the amount of tax for purposes of **(e)(2)** [(e)(2)(A)] of this section is determined by multiplying the monthly production tax value of the taxable oil **and gas** produced during the month [, GAS PRODUCED DURING THE MONTH FROM A LEASE OR PROPERTY IN THE COOK INLET SEDIMENTARY BASIN, AND GAS PRODUCED DURING THE MONTH FROM A LEASE OR PROPERTY OUTSIDE THE COOK INLET SEDIMENTARY BASIN AND USED IN THE STATE] by the tax rate calculated as follows:

(1) if the producer's average monthly production tax value [UNDER AS 43.55.160(a)(2)(A) - (E)] of a BTU equivalent barrel of taxable oil and gas for the

1 month is not more than \$92.50, the tax rate is 0.4 percent multiplied by the number
 2 that represents the difference between the producer's average monthly production tax
 3 value [UNDER AS 43.55.160(a)(2)(A) - (E)] of a BTU equivalent barrel of taxable oil
 4 and gas and \$30; or

5 (2) if the producer's average monthly production tax value [UNDER
 6 AS 43.55.160(a)(2)(A) - (E)] of a BTU equivalent barrel of taxable oil and gas for the
 7 month is more than \$92.50, the tax rate is the sum of 25 percent and the product of 0.1
 8 percent multiplied by the number that represents the difference between the producer's
 9 average monthly production tax value [UNDER AS 43.55.160(a)(2)(A) - (E)] of a
 10 BTU equivalent barrel of taxable oil and gas and \$92.50, except that the sum
 11 determined under this paragraph may not exceed 50 percent.

12 * **Sec. 9.** AS 43.55.011(g), as amended by sec. 8 of this Act, is amended to read:

13 (g) For each month of the calendar year for which the producer's average
 14 monthly production tax value under AS 43.55.160(a)(2)(A) - (E) [AS 43.55.160(a)(2)]
 15 of a BTU equivalent barrel of taxable oil and gas is more than \$30, the amount of tax
 16 for purposes of (e)(2)(A) [(e)(2)] of this section is determined by multiplying the
 17 monthly production tax value of the taxable oil [AND GAS] produced during the
 18 month, gas produced during the month from a lease or property in the Cook Inlet
 19 sedimentary basin, and gas produced during the month from a lease or property
 20 outside the Cook Inlet sedimentary basin and used in the state by the tax rate
 21 calculated as follows:

22 (1) if the producer's average monthly production tax value under
 23 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of taxable oil and gas for the
 24 month is not more than \$92.50, the tax rate is 0.4 percent multiplied by the number
 25 that represents the difference between the producer's average monthly production tax
 26 value under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of taxable oil
 27 and gas and \$30; or

28 (2) if the producer's average monthly production tax value under
 29 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of taxable oil and gas for the
 30 month is more than \$92.50, the tax rate is the sum of 25 percent and the product of 0.1
 31 percent multiplied by the number that represents the difference between the producer's

1 average monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a BTU
2 equivalent barrel of taxable oil and gas and \$92.50, except that the sum determined
3 under this paragraph may not exceed 50 percent."
4

5 Renumber the following bill sections accordingly.

6
7 Page 4, following line 9:

8 Insert a new bill section to read:

9 **"* Sec. 11.** AS 43.55.011 is amended by adding a new subsection to read:

10 (p) For each month of the calendar year for which the producer's average
11 monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU
12 equivalent barrel of taxable gas is more than \$30, the amount of tax on the production
13 of gas for purposes of (e)(2)(B) of this section is determined by multiplying the
14 monthly production tax value of the taxable gas produced during the month other than
15 gas produced from a lease or property in the Cook Inlet sedimentary basin or gas
16 produced outside the Cook Inlet sedimentary basin and used in the state by the tax rate
17 calculated as follows:

18 (1) if the producer's average monthly production tax value under
19 AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of taxable gas for the
20 month is not more than \$92.50, the tax rate is 0.4 percent multiplied by the number
21 that represents the difference between the producer's average monthly production tax
22 value under AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of gas and \$30;
23 or

24 (2) if the producer's average monthly production tax value under
25 AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of taxable gas for the
26 month is more than \$92.50, the tax rate is the sum of 25 percent and the product of 0.1
27 percent multiplied by the number that represents the difference between the producer's
28 average monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU
29 equivalent barrel of gas and \$92.50, except that the sum determined under this
30 paragraph may not exceed 50 percent."
31

1 Renumber the following bill sections accordingly.

2

3 Page 6, line 31:

4 Delete "before 2022"

5

6 Page 7, following line 24:

7 Insert new bill sections to read:

8 **"* Sec. 13.** AS 43.55.020(a), as amended by sec. 12 of this Act, is amended to read:

9 (a) For a calendar year, a producer subject to tax under AS 43.55.011(e) - (i)

10 [AND (p)] shall pay the tax as follows:

11 (1) an installment payment of the estimated tax levied by
 12 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
 13 month of the calendar year on the last day of the following month; except as otherwise
 14 provided under (2) of this subsection, the amount of the installment payment is the
 15 sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be
 16 applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount
 17 of the installment payment may not be less than zero:

18 (A) for oil and gas produced from leases or properties in the
 19 state outside the Cook Inlet sedimentary basin but not subject to
 20 AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f), the
 21 greater of

22 (i) zero; or

23 (ii) [AN AMOUNT EQUAL TO] the sum of 25 percent
 24 and the tax rate calculated for the month under AS 43.55.011(g)
 25 multiplied by the remainder obtained by subtracting 1/12 of the
 26 producer's adjusted lease expenditures for the calendar year of
 27 production [APPLICABLE TO THE OIL PRODUCED BY THE
 28 PRODUCER FROM THOSE LEASES AND PROPERTIES] under
 29 AS 43.55.165 and 43.55.170 that are deductible for the leases or
 30 properties under AS 43.55.160 [,] from the gross value at the point of
 31 production of the oil and gas produced from the leases or properties

1 during the month for which the installment payment is calculated
 2 [ADDED TO THE SUM OF 25 PERCENT AND THE TAX RATE
 3 CALCULATED FOR THE MONTH UNDER AS 43.55.011(p)
 4 MULTIPLIED BY THE REMAINDER OBTAINED BY
 5 SUBTRACTING 1/12 OF THE PRODUCER'S ADJUSTED LEASE
 6 EXPENDITURES FOR THE CALENDAR YEAR OF PRODUCTION
 7 APPLICABLE TO THE GAS PRODUCED BY THE PRODUCER
 8 FROM THOSE LEASES AND PROPERTIES UNDER AS 43.55.165
 9 AND 43.55.170 THAT ARE DEDUCTIBLE FOR THE LEASES OR
 10 PROPERTIES UNDER AS 43.55.160 FROM THE GROSS VALUE

11 AT THE POINT OF PRODUCTION OF THE GAS PRODUCED
 12 FROM THE LEASES OR PROPERTIES DURING THE MONTH
 13 FOR WHICH THE INSTALLMENT PAYMENT IS CALCULATED];

14 (B) for oil and gas produced from leases or properties subject
 15 to AS 43.55.011(f), the greatest of

16 (i) zero;

17 (ii) zero percent, one percent, two percent, three
 18 percent, or four percent, as applicable, of the gross value at the point of
 19 production of the oil and gas produced from all leases or properties
 20 during the month for which the installment payment is calculated; or

21 (iii) [AN AMOUNT EQUAL TO] the sum of 25
 22 percent and the tax rate calculated for the month under AS 43.55.011(g)
 23 multiplied by the remainder obtained by subtracting 1/12 of the
 24 producer's adjusted lease expenditures for the calendar year of
 25 production [APPLICABLE TO THE OIL PRODUCED BY THE
 26 PRODUCER FROM THOSE LEASES AND PROPERTIES] under
 27 AS 43.55.165 and 43.55.170 that are deductible for those leases or
 28 properties under AS 43.55.160 [,] from the gross value at the point of
 29 production of the oil and gas produced from those leases or properties
 30 during the month for which the installment payment is calculated
 31 [ADDED TO THE SUM OF 25 PERCENT AND THE TAX RATE

1 CALCULATED FOR THE MONTH UNDER AS 43.55.011(p)
 2 MULTIPLIED BY THE REMAINDER OBTAINED BY
 3 SUBTRACTING 1/12 OF THE PRODUCER'S ADJUSTED LEASE
 4 EXPENDITURES FOR THE CALENDAR YEAR OF PRODUCTION
 5 APPLICABLE TO THE GAS PRODUCED BY THE PRODUCER
 6 FROM THOSE LEASES AND PROPERTIES UNDER AS 43.55.165
 7 AND 43.55.170 THAT ARE DEDUCTIBLE FOR THOSE LEASES
 8 OR PROPERTIES UNDER AS 43.55.160 FROM THE GROSS
 9 VALUE AT THE POINT OF PRODUCTION OF THE GAS
 10 PRODUCED FROM THOSE LEASES OR PROPERTIES DURING
 11 THE MONTH FOR WHICH THE INSTALLMENT PAYMENT IS
 12 CALCULATED];

13 (C) for oil and gas produced from each lease or property
 14 subject to AS 43.55.011(j), (k), or (o), the greater of

15 (i) zero; or

16 (ii) [AN AMOUNT EQUAL TO] the sum of 25 percent
 17 and the tax rate calculated for the month under AS 43.55.011(g)
 18 multiplied by the remainder obtained by subtracting 1/12 of the
 19 producer's adjusted lease expenditures for the calendar year of
 20 production [APPLICABLE TO THE OIL PRODUCED BY THE
 21 PRODUCER FROM THOSE LEASES AND PROPERTIES] under
 22 AS 43.55.165 and 43.55.170 that are deductible under AS 43.55.160
 23 for oil or gas, respectively, produced from the lease or property [,]
 24 from the gross value at the point of production of the oil or gas,
 25 respectively, produced from the lease or property during the month for
 26 which the installment payment is calculated [ADDED TO THE SUM
 27 OF 25 PERCENT AND THE TAX RATE CALCULATED FOR THE
 28 MONTH UNDER AS 43.55.011(g) MULTIPLIED BY THE
 29 REMAINDER OBTAINED BY SUBTRACTING 1/12 OF THE
 30 PRODUCER'S ADJUSTED LEASE EXPENDITURES FOR THE
 31 CALENDAR YEAR OF PRODUCTION APPLICABLE TO THE

1 GAS PRODUCED BY THE PRODUCER FROM THE LEASE OR
2 PROPERTY UNDER AS 43.55.165 AND 43.55.170 THAT ARE
3 DEDUCTIBLE UNDER AS 43.55.160 FOR GAS PRODUCED
4 FROM THE LEASE OR PROPERTY, FROM THE GROSS VALUE
5 AT THE POINT OF PRODUCTION OF THE GAS PRODUCED
6 FROM THE LEASE OR PROPERTY DURING THE MONTH FOR
7 WHICH THE INSTALLMENT PAYMENT IS CALCULATED];

8 (2) an amount calculated under (1)(C) of this subsection for oil or gas
9 produced before 2022 from a lease or property subject to AS 43.55.011(j), (k), or (o)
10 may not exceed the product obtained by carrying out the calculation set out in
11 AS 43.55.011(j)(1) or (2) or 43.55.011(o), as applicable, for gas or set out in
12 AS 43.55.011(k)(1) or (2), as applicable, for oil, but substituting in
13 AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the amount of taxable
14 gas produced during the month for the amount of taxable gas produced during the
15 calendar year and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the
16 amount of taxable oil produced during the month for the amount of taxable oil
17 produced during the calendar year;

18 (3) an installment payment of the estimated tax levied by
19 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
20 on the last day of the following month; the amount of the installment payment is the
21 sum of

22 (A) the applicable tax rate for oil provided under
23 AS 43.55.011(i), multiplied by the gross value at the point of production of the
24 oil taxable under AS 43.55.011(i) and produced from the lease or property
25 during the month; and

26 (B) the applicable tax rate for gas provided under
27 AS 43.55.011(i), multiplied by the gross value at the point of production of the
28 gas taxable under AS 43.55.011(i) and produced from the lease or property
29 during the month;

30 (4) any amount of tax levied by AS 43.55.011(e) or (i), net of any
31 credits applied as allowed by law, that exceeds the total of the amounts due as

1 installment payments of estimated tax is due on March 31 of the year following the
2 calendar year of production.

3 * **Sec. 14.** AS 43.55.020(a), as amended by sec. 13 of this Act, is amended to read:

4 (a) For a calendar year, a producer subject to tax under AS 43.55.011(e) - (i)
5 **and (p)** shall pay the tax as follows:

6 (1) an installment payment of the estimated tax levied by
7 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
8 month of the calendar year on the last day of the following month; except as otherwise
9 provided under (2) of this subsection, the amount of the installment payment is the
10 sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be
11 applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount
12 of the installment payment may not be less than zero:

13 (A) for oil and gas produced from leases or properties in the
14 state outside the Cook Inlet sedimentary basin but not subject to
15 AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f), the
16 greater of

17 (i) zero; or

18 (ii) **an amount equal to** the sum of 25 percent and the
19 tax rate calculated for the month under AS 43.55.011(g) multiplied by
20 the remainder obtained by subtracting 1/12 of the producer's adjusted
21 lease expenditures for the calendar year of production **applicable to**
22 **the oil produced by the producer from those leases and properties**
23 **under AS 43.55.165 and 43.55.170 that are deductible for the leases or**
24 **properties under AS 43.55.160, from the gross value at the point of**
25 **production of the oil [AND GAS] produced from the leases or**
26 **properties during the month for which the installment payment is**
27 **calculated added to the sum of 25 percent and the tax rate**
28 **calculated for the month under AS 43.55.011(p) multiplied by the**
29 **remainder obtained by subtracting 1/12 of the producer's adjusted**
30 **lease expenditures for the calendar year of production applicable**
31 **to the gas produced by the producer from those leases and**

1 properties under AS 43.55.165 and 43.55.170 that are deductible
 2 for the leases or properties under AS 43.55.160 from the gross
 3 value at the point of production of the gas produced from the leases
 4 or properties during the month for which the installment payment
 5 is calculated;

6 (B) for oil and gas produced from leases or properties subject
 7 to AS 43.55.011(f), the greatest of

8 (i) zero;

9 (ii) zero percent, one percent, two percent, three
 10 percent, or four percent, as applicable, of the gross value at the point of
 11 production of the oil and gas produced from all leases or properties
 12 during the month for which the installment payment is calculated; or

13 (iii) an amount equal to the sum of 25 percent and the
 14 tax rate calculated for the month under AS 43.55.011(g) multiplied by
 15 the remainder obtained by subtracting 1/12 of the producer's adjusted
 16 lease expenditures for the calendar year of production applicable to
 17 the oil produced by the producer from those leases and properties
 18 under AS 43.55.165 and 43.55.170 that are deductible for those leases
 19 or properties under AS 43.55.160, from the gross value at the point of
 20 production of the oil [AND GAS] produced from those leases or
 21 properties during the month for which the installment payment is
 22 calculated added to the sum of 25 percent and the tax rate
 23 calculated for the month under AS 43.55.011(p) multiplied by the
 24 remainder obtained by subtracting 1/12 of the producer's adjusted
 25 lease expenditures for the calendar year of production applicable
 26 to the gas produced by the producer from those leases and
 27 properties under AS 43.55.165 and 43.55.170 that are deductible
 28 for those leases or properties under AS 43.55.160 from the gross
 29 value at the point of production of the gas produced from those
 30 leases or properties during the month for which the installment
 31 payment is calculated;

1 (C) for oil and gas produced from each lease or property
2 subject to AS 43.55.011(j), (k), or (o), the greater of

3 (i) zero; or

4 (ii) **an amount equal to** the sum of 25 percent and the
5 tax rate calculated for the month under AS 43.55.011(g) multiplied by
6 the remainder obtained by subtracting 1/12 of the producer's adjusted
7 lease expenditures for the calendar year of production **applicable to**
8 **the oil produced by the producer from those leases and properties**
9 under AS 43.55.165 and 43.55.170 that are deductible under
10 AS 43.55.160 for oil [OR GAS, RESPECTIVELY,] produced from the
11 lease or property, from the gross value at the point of production of the
12 oil [OR GAS, RESPECTIVELY,] produced from the lease or property
13 during the month for which the installment payment is calculated
14 **added to the sum of 25 percent and the tax rate calculated for the**
15 **month under AS 43.55.011(g) multiplied by the remainder obtained**
16 **by subtracting 1/12 of the producer's adjusted lease expenditures**
17 **for the calendar year of production applicable to the gas produced**
18 **by the producer from the lease or property under AS 43.55.165 and**
19 **43.55.170 that are deductible under AS 43.55.160 for gas produced**
20 **from the lease or property, from the gross value at the point of**
21 **production of the gas produced from the lease or property during**
22 **the month for which the installment payment is calculated;**

23 (2) an amount calculated under (1)(C) of this subsection for oil or gas
24 produced before 2022 from a lease or property subject to AS 43.55.011(j), (k), or (o)
25 may not exceed the product obtained by carrying out the calculation set out in
26 AS 43.55.011(j)(1) or (2) or 43.55.011(o), as applicable, for gas or set out in
27 AS 43.55.011(k)(1) or (2), as applicable, for oil, but substituting in
28 AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the amount of taxable
29 gas produced during the month for the amount of taxable gas produced during the
30 calendar year and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the
31 amount of taxable oil produced during the month for the amount of taxable oil

1 produced during the calendar year;

2 (3) an installment payment of the estimated tax levied by
3 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
4 on the last day of the following month; the amount of the installment payment is the
5 sum of

6 (A) the applicable tax rate for oil provided under
7 AS 43.55.011(i), multiplied by the gross value at the point of production of the
8 oil taxable under AS 43.55.011(i) and produced from the lease or property
9 during the month; and

10 (B) the applicable tax rate for gas provided under
11 AS 43.55.011(i), multiplied by the gross value at the point of production of the
12 gas taxable under AS 43.55.011(i) and produced from the lease or property
13 during the month;

14 (4) any amount of tax levied by AS 43.55.011(e) or (i), net of any
15 credits applied as allowed by law, that exceeds the total of the amounts due as
16 installment payments of estimated tax is due on March 31 of the year following the
17 calendar year of production."
18

19 Renumber the following bill sections accordingly.

20
21 Page 8, line 11:

22 Insert new bill sections to read:

23 **** Sec. 16.** AS 43.55.020(d), as amended by sec. 15 of this Act, is amended to read:

24 (d) In making settlement with the royalty owner for oil and gas that is taxable
25 under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable
26 royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the
27 time the tax becomes due to the amount of the tax paid. If the total deductions of
28 installment payments of estimated tax for a calendar year exceed the actual tax for that
29 calendar year, the producer shall, before April 1 of the following year, refund the
30 excess to the royalty owner. Unless otherwise agreed between the producer and the
31 royalty owner, the amount of the tax paid under AS 43.55.011(e) - (g) [AND (p)] on

1 taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or
 2 right to which constitutes a landowner's royalty interest, is considered to be the gross
 3 value at the point of production of the taxable royalty oil and gas produced during the
 4 calendar year multiplied by a figure that is a quotient, in which

5 (1) the numerator is the producer's total tax liability under
 6 AS 43.55.011(e) - (g) [AND (p)] for the calendar year of production; and

7 (2) the denominator is the total gross value at the point of production
 8 of the oil and gas taxable under AS 43.55.011(e) - (g) [AND (p)] produced by the
 9 producer from all leases and properties in the state during the calendar year.

10 * **Sec. 17.** AS 43.55.020(d), as amended by sec. 16 of this Act, is amended to read:

11 (d) In making settlement with the royalty owner for oil and gas that is taxable
 12 under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable
 13 royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the
 14 time the tax becomes due to the amount of the tax paid. If the total deductions of
 15 installment payments of estimated tax for a calendar year exceed the actual tax for that
 16 calendar year, the producer shall, before April 1 of the following year, refund the
 17 excess to the royalty owner. Unless otherwise agreed between the producer and the
 18 royalty owner, the amount of the tax paid under AS 43.55.011(e) - (g) and (p) on
 19 taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or
 20 right to which constitutes a landowner's royalty interest, is considered to be the gross
 21 value at the point of production of the taxable royalty oil and gas produced during the
 22 calendar year multiplied by a figure that is a quotient, in which

23 (1) the numerator is the producer's total tax liability under
 24 AS 43.55.011(e) - (g) and (p) for the calendar year of production; and

25 (2) the denominator is the total gross value at the point of production
 26 of the oil and gas taxable under AS 43.55.011(e) - (g) and (p) produced by the
 27 producer from all leases and properties in the state during the calendar year."

28
 29 Renumber the following bill sections accordingly.

30
 31 Page 11, following line 31:

1 Insert new bill sections to read:

2 ** Sec. 19. AS 43.55.160(a), as amended by sec. 18 of this Act, is amended to read:

3 (a) Except as provided in (b) of this section, for the purposes of

4 (1) AS 43.55.011(e), the annual production tax value of the taxable

5 (A) oil and gas produced during a calendar year from leases or
6 properties in the state that include land north of 68 degrees North latitude is the
7 gross value at the point of production of the oil and gas taxable under
8 AS 43.55.011(e) and produced by the producer from those leases or properties,
9 less the producer's lease expenditures under AS 43.55.165 for the calendar year
10 applicable to the oil and gas produced by the producer from those leases or
11 properties, as adjusted under AS 43.55.170; this subparagraph does not
12 apply to gas subject to AS 43.55.011(o);

13 (B) oil and gas produced during a calendar year from leases or
14 properties in the state outside the Cook Inlet sedimentary basin, no part of
15 which is north of 68 degrees North latitude, is the gross value at the point of
16 production of the oil and gas taxable under AS 43.55.011(e) and produced by
17 the producer from those leases or properties, less the producer's lease
18 expenditures under AS 43.55.165 for the calendar year applicable to the oil
19 and gas produced by the producer from those leases or properties, as adjusted
20 under AS 43.55.170; this subparagraph does not apply to gas subject to
21 AS 43.55.011(o);

22 (C) oil produced during a calendar year from a lease or
23 property in the Cook Inlet sedimentary basin is the gross value at the point of
24 production of the oil taxable under AS 43.55.011(e) and produced by the
25 producer from that lease or property, less the producer's lease expenditures
26 under AS 43.55.165 for the calendar year applicable to the oil produced by the
27 producer from that lease or property, as adjusted under AS 43.55.170;

28 (D) gas produced during a calendar year from a lease or
29 property in the Cook Inlet sedimentary basin is the gross value at the point of
30 production of the gas taxable under AS 43.55.011(e) and produced by the
31 producer from that lease or property, less the producer's lease expenditures

1 under AS 43.55.165 for the calendar year applicable to the gas produced by the
2 producer from that lease or property, as adjusted under AS 43.55.170;

3 (E) gas produced during a calendar year from a lease or
4 property outside the Cook Inlet sedimentary basin and used in the state is the
5 gross value at the point of production of that gas taxable under
6 AS 43.55.011(e) and produced by the producer from that lease or property, less
7 the producer's lease expenditures under AS 43.55.165 for the calendar year
8 applicable to that gas produced by the producer from that lease or property, as
9 adjusted under AS 43.55.170;

10 [(F) GAS PRODUCED DURING A CALENDAR YEAR
11 FROM LEASES OR PROPERTIES IN THE STATE THAT INCLUDE
12 LAND NORTH OF 68 DEGREES NORTH LATITUDE IS THE GROSS
13 VALUE AT THE POINT OF PRODUCTION OF THE GAS TAXABLE
14 UNDER AS 43.55.011(e) AND PRODUCED BY THE PRODUCER FROM
15 THOSE LEASES OR PROPERTIES, LESS THE PRODUCER'S LEASE
16 EXPENDITURES UNDER AS 43.55.165 FOR THE CALENDAR YEAR
17 APPLICABLE TO THE GAS PRODUCED BY THE PRODUCER FROM
18 THOSE LEASES OR PROPERTIES, AS ADJUSTED UNDER AS 43.55.170;
19 THIS SUBPARAGRAPH DOES NOT APPLY TO GAS USED IN THE
20 STATE;

21 (G) GAS PRODUCED DURING A CALENDAR YEAR
22 FROM LEASES OR PROPERTIES IN THE STATE OUTSIDE THE COOK
23 INLET SEDIMENTARY BASIN, NO PART OF WHICH IS NORTH OF 68
24 DEGREES NORTH LATITUDE, IS THE GROSS VALUE AT THE POINT
25 OF PRODUCTION OF THE GAS TAXABLE UNDER AS 43.55.011(e)
26 AND PRODUCED BY THE PRODUCER FROM THOSE LEASES OR
27 PROPERTIES, LESS THE PRODUCER'S LEASE EXPENDITURES
28 UNDER AS 43.55.165 FOR THE CALENDAR YEAR APPLICABLE TO
29 THE GAS PRODUCED BY THE PRODUCER FROM THOSE LEASES OR
30 PROPERTIES, AS ADJUSTED UNDER AS 43.55.170; THIS
31 SUBPARAGRAPH DOES NOT APPLY TO GAS USED IN THE STATE;]

1 (2) AS 43.55.011(g) [AND (p)], the monthly production tax value of
2 the taxable

3 (A) oil and gas produced during a month from leases or
4 properties in the state that include land north of 68 degrees North latitude is the
5 gross value at the point of production of the oil and gas taxable under
6 AS 43.55.011(e) and produced by the producer from those leases or properties,
7 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the
8 calendar year applicable to the oil and gas produced by the producer from
9 those leases or properties, as adjusted under AS 43.55.170; this subparagraph
10 does not apply to gas subject to AS 43.55.011(o);

11 (B) oil and gas produced during a month from leases or
12 properties in the state outside the Cook Inlet sedimentary basin, no part of
13 which is north of 68 degrees North latitude, is the gross value at the point of
14 production of the oil and gas taxable under AS 43.55.011(e) and produced by
15 the producer from those leases or properties, less 1/12 of the producer's lease
16 expenditures under AS 43.55.165 for the calendar year applicable to the oil
17 and gas produced by the producer from those leases or properties, as adjusted
18 under AS 43.55.170; this subparagraph does not apply to gas subject to
19 AS 43.55.011(o);

20 (C) oil produced during a month from a lease or property in the
21 Cook Inlet sedimentary basin is the gross value at the point of production of
22 the oil taxable under AS 43.55.011(e) and produced by the producer from that
23 lease or property, less 1/12 of the producer's lease expenditures under
24 AS 43.55.165 for the calendar year applicable to the oil produced by the
25 producer from that lease or property, as adjusted under AS 43.55.170;

26 (D) gas produced during a month from a lease or property in
27 the Cook Inlet sedimentary basin is the gross value at the point of production
28 of the gas taxable under AS 43.55.011(e) and produced by the producer from
29 that lease or property, less 1/12 of the producer's lease expenditures under
30 AS 43.55.165 for the calendar year applicable to the gas produced by the
31 producer from that lease or property, as adjusted under AS 43.55.170;

1 (E) gas produced during a month from a lease or property
2 outside the Cook Inlet sedimentary basin and used in the state is the gross
3 value at the point of production of that gas taxable under AS 43.55.011(e) and
4 produced by the producer from that lease or property, less 1/12 of the
5 producer's lease expenditures under AS 43.55.165 for the calendar year
6 applicable to that gas produced by the producer from that lease or property, as
7 adjusted under AS 43.55.170 [;

8 (F) GAS PRODUCED DURING A MONTH FROM LEASES
9 OR PROPERTIES IN THE STATE THAT INCLUDE LAND NORTH OF 68
10 DEGREES NORTH LATITUDE IS THE GROSS VALUE AT THE POINT
11 OF PRODUCTION OF THE GAS TAXABLE UNDER AS 43.55.011(e)
12 AND PRODUCED BY THE PRODUCER FROM THOSE LEASES OR
13 PROPERTIES, LESS 1/12 OF THE PRODUCER'S LEASE
14 EXPENDITURES UNDER AS 43.55.165 FOR THE CALENDAR YEAR
15 APPLICABLE TO THE GAS PRODUCED BY THE PRODUCER FROM
16 THOSE LEASES OR PROPERTIES, AS ADJUSTED UNDER AS 43.55.170;
17 THIS SUBPARAGRAPH DOES NOT APPLY TO GAS USED IN THE
18 STATE;

19 (G) GAS PRODUCED DURING A MONTH FROM LEASES
20 OR PROPERTIES IN THE STATE OUTSIDE THE COOK INLET
21 SEDIMENTARY BASIN, NO PART OF WHICH IS NORTH OF 68
22 DEGREES NORTH LATITUDE, IS THE GROSS VALUE AT THE POINT
23 OF PRODUCTION OF THE GAS TAXABLE UNDER AS 43.55.011(e)
24 AND PRODUCED BY THE PRODUCER FROM THOSE LEASES OR
25 PROPERTIES, LESS 1/12 OF THE PRODUCER'S LEASE
26 EXPENDITURES UNDER AS 43.55.165 FOR THE CALENDAR YEAR
27 APPLICABLE TO THE GAS PRODUCED BY THE PRODUCER FROM
28 THOSE LEASES OR PROPERTIES, AS ADJUSTED UNDER AS 43.55.170;
29 THIS SUBPARAGRAPH DOES NOT APPLY TO GAS USED IN THE
30 STATE].

31 * Sec. 20. AS 43.55.160(a), as amended by sec. 19 of this Act, is amended to read:

1 (a) Except as provided in (b) of this section, for the purposes of

2 (1) AS 43.55.011(e), the annual production tax value of the taxable

3 (A) oil [AND GAS] produced during a calendar year from
4 leases or properties in the state that include land north of 68 degrees North
5 latitude is the gross value at the point of production of the oil [AND GAS]
6 taxable under AS 43.55.011(e) and produced by the producer from those leases
7 or properties, less the producer's lease expenditures under AS 43.55.165 for the
8 calendar year applicable to the oil [AND GAS] produced by the producer from
9 those leases or properties, as adjusted under AS 43.55.170; [THIS
10 SUBPARAGRAPH DOES NOT APPLY TO GAS SUBJECT TO
11 AS 43.55.011(o);]

12 (B) oil [AND GAS] produced during a calendar year from
13 leases or properties in the state outside the Cook Inlet sedimentary basin, no
14 part of which is north of 68 degrees North latitude, is the gross value at the
15 point of production of the oil [AND GAS] taxable under AS 43.55.011(e) and
16 produced by the producer from those leases or properties, less the producer's
17 lease expenditures under AS 43.55.165 for the calendar year applicable to the
18 oil [AND GAS] produced by the producer from those leases or properties, as
19 adjusted under AS 43.55.170; [THIS SUBPARAGRAPH DOES NOT APPLY
20 TO GAS SUBJECT TO AS 43.55.011(o);]

21 (C) oil produced during a calendar year from a lease or
22 property in the Cook Inlet sedimentary basin is the gross value at the point of
23 production of the oil taxable under AS 43.55.011(e) and produced by the
24 producer from that lease or property, less the producer's lease expenditures
25 under AS 43.55.165 for the calendar year applicable to the oil produced by the
26 producer from that lease or property, as adjusted under AS 43.55.170;

27 (D) gas produced during a calendar year from a lease or
28 property in the Cook Inlet sedimentary basin is the gross value at the point of
29 production of the gas taxable under AS 43.55.011(e) and produced by the
30 producer from that lease or property, less the producer's lease expenditures
31 under AS 43.55.165 for the calendar year applicable to the gas produced by the

1 producer from that lease or property, as adjusted under AS 43.55.170;

2 (E) gas produced during a calendar year from a lease or
3 property outside the Cook Inlet sedimentary basin and used in the state is the
4 gross value at the point of production of that gas taxable under
5 AS 43.55.011(e) and produced by the producer from that lease or property, less
6 the producer's lease expenditures under AS 43.55.165 for the calendar year
7 applicable to that gas produced by the producer from that lease or property, as
8 adjusted under AS 43.55.170;

9 (F) gas produced during a calendar year from leases or
10 properties in the state that include land north of 68 degrees North latitude
11 is the gross value at the point of production of the gas taxable under
12 AS 43.55.011(e) and produced by the producer from those leases or
13 properties, less the producer's lease expenditures under AS 43.55.165 for
14 the calendar year applicable to the gas produced by the producer from
15 those leases or properties, as adjusted under AS 43.55.170; this
16 subparagraph does not apply to gas used in the state;

17 (G) gas produced during a calendar year from leases or
18 properties in the state outside the Cook Inlet sedimentary basin, no part of
19 which is north of 68 degrees North latitude, is the gross value at the point
20 of production of the gas taxable under AS 43.55.011(e) and produced by
21 the producer from those leases or properties, less the producer's lease
22 expenditures under AS 43.55.165 for the calendar year applicable to the
23 gas produced by the producer from those leases or properties, as adjusted
24 under AS 43.55.170; this subparagraph does not apply to gas used in the
25 state;

26 (2) AS 43.55.011(g) and (p), the monthly production tax value of the
27 taxable

28 (A) oil [AND GAS] produced during a month from leases or
29 properties in the state that include land north of 68 degrees North latitude is the
30 gross value at the point of production of the oil [AND GAS] taxable under
31 AS 43.55.011(e) and produced by the producer from those leases or properties,

1 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the
2 calendar year applicable to the oil [AND GAS] produced by the producer from
3 those leases or properties, as adjusted under AS 43.55.170; [THIS
4 SUBPARAGRAPH DOES NOT APPLY TO GAS SUBJECT TO
5 AS 43.55.011(o);]

6 (B) oil [AND GAS] produced during a month from leases or
7 properties in the state outside the Cook Inlet sedimentary basin, no part of
8 which is north of 68 degrees North latitude, is the gross value at the point of
9 production of the oil [AND GAS] taxable under AS 43.55.011(e) and produced
10 by the producer from those leases or properties, less 1/12 of the producer's
11 lease expenditures under AS 43.55.165 for the calendar year applicable to the
12 oil [AND GAS] produced by the producer from those leases or properties, as
13 adjusted under AS 43.55.170; [THIS SUBPARAGRAPH DOES NOT APPLY
14 TO GAS SUBJECT TO AS 43.55.011(o);]

15 (C) oil produced during a month from a lease or property in the
16 Cook Inlet sedimentary basin is the gross value at the point of production of
17 the oil taxable under AS 43.55.011(e) and produced by the producer from that
18 lease or property, less 1/12 of the producer's lease expenditures under
19 AS 43.55.165 for the calendar year applicable to the oil produced by the
20 producer from that lease or property, as adjusted under AS 43.55.170;

21 (D) gas produced during a month from a lease or property in
22 the Cook Inlet sedimentary basin is the gross value at the point of production
23 of the gas taxable under AS 43.55.011(e) and produced by the producer from
24 that lease or property, less 1/12 of the producer's lease expenditures under
25 AS 43.55.165 for the calendar year applicable to the gas produced by the
26 producer from that lease or property, as adjusted under AS 43.55.170;

27 (E) gas produced during a month from a lease or property
28 outside the Cook Inlet sedimentary basin and used in the state is the gross
29 value at the point of production of that gas taxable under AS 43.55.011(e) and
30 produced by the producer from that lease or property, less 1/12 of the
31 producer's lease expenditures under AS 43.55.165 for the calendar year

1 applicable to that gas produced by the producer from that lease or property, as
2 adjusted under AS 43.55.170;

3 (F) gas produced during a month from leases or properties
4 in the state that include land north of 68 degrees North latitude is the
5 gross value at the point of production of the gas taxable under
6 AS 43.55.011(e) and produced by the producer from those leases or
7 properties, less 1/12 of the producer's lease expenditures under
8 AS 43.55.165 for the calendar year applicable to the gas produced by the
9 producer from those leases or properties, as adjusted under AS 43.55.170;
10 this subparagraph does not apply to gas used in the state;

11 (G) gas produced during a month from leases or properties
12 in the state outside the Cook Inlet sedimentary basin, no part of which is
13 north of 68 degrees North latitude, is the gross value at the point of
14 production of the gas taxable under AS 43.55.011(e) and produced by the
15 producer from those leases or properties, less 1/12 of the producer's lease
16 expenditures under AS 43.55.165 for the calendar year applicable to the
17 gas produced by the producer from those leases or properties, as adjusted
18 under AS 43.55.170; this subparagraph does not apply to gas used in the
19 state."

20
21 Renumber the following bill sections accordingly.

22
23 Page 12, line 28, through page 13, line 11:

24 Delete all material and insert:

25 **** Sec. 23.** AS 43.55.011(p) is repealed.

26 *** Sec. 24.** The uncodified law of the State of Alaska is amended by adding a new section to
27 read:

28 TRANSITION; REGULATIONS; PAYMENT OF TAX; FILING OF REPORTS. If
29 secs. 1, 4, 7, 10, 12, 15, and 18 of this Act take effect, the Department of Revenue shall adopt
30 regulations providing for the payment of tax and the filing of reports required for the period in
31 which secs. 1, 4, 7, 10, 12, 15, and 18 of this Act are in effect.

1 * **Sec. 25.** The uncodified law of the State of Alaska is amended by adding a new section to
2 read:

3 CONDITIONAL EFFECT OF SECS. 1, 2, 4, 5, 7, 8, 10, 12, 13, 15, 16, 18, 19, AND
4 23 OF THIS ACT; NOTICE. (a) Sections 1, 2, 4, 5, 7, 8, 10, 12, 13, 15, 16, 18, 19, and 23 of
5 this Act take effect only if secs. 21 and 22 of this Act take effect before April 29, 2010.

6 (b) The commissioner of revenue shall notify the revisor of statutes of the date of the
7 start of the first binding open season for the project licensed under AS 43.90 (Alaska Gasline
8 Inducement Act).

9 * **Sec. 26.** The uncodified law of the State of Alaska is amended by adding a new section to
10 read:

11 CONDITIONAL EFFECT OF SECS. 3, 6, 9, 11, 14, 17, AND 20 OF THIS ACT;
12 NOTICE. (a) Sections 3, 6, 9, 11, 14, 17, and 20 of this Act take effect only if more than
13 1,500,000,000 cubic feet of natural gas a day that is produced in the state is tendered for
14 shipment through a natural gas pipeline project in the state to a market in Canada or the 48
15 contiguous states, or to a gas liquefaction facility in the state for shipment in a liquefied state
16 by marine transportation to a market outside of the state.

17 (b) The commissioner of revenue shall notify the revisor of statutes of the date that
18 natural gas was first tendered for shipment under the circumstances described in (a) of this
19 section.

20 * **Sec. 27.** If secs. 1, 4, 7, 10, 12, 15, and 18 of this Act take effect, they take effect
21 April 29, 2010.

22 * **Sec. 28.** If secs. 2, 5, 8, 13, 16, 19, and 23 of this Act take effect, they take effect on the
23 first day immediately following the date on which the open season starts for the project
24 licensed under AS 43.90.

25 * **Sec. 29.** If secs. 3, 6, 9, 11, 14, 17, and 20 take effect, they take effect on the first day of
26 the month immediately following the date on which the condition in sec. 26(a) of this Act is
27 met.

28 * **Sec. 30.** Except as provided in secs. 27 - 29 of this Act, this Act takes effect immediately
29 under AS 01.10.070(c)."

26-LS1577M
Bullock
4/10/10

HOUSE CS FOR CS FOR SENATE BILL NO. 305(RES)
IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTY-SIXTH LEGISLATURE - SECOND SESSION

BY THE HOUSE RESOURCES COMMITTEE

Offered:

Referred:

Sponsor(s): SENATE FINANCE COMMITTEE

A BILL

FOR AN ACT ENTITLED

1 **"An Act relating to that part of the tax on the production of oil and gas that increases as**
2 **the average production tax value of the oil and gas increases above \$30; relating to**
3 **payments of the oil and gas production tax; relating to availability of a portion of the**
4 **money received from the tax on oil and gas production for appropriation to the**
5 **community revenue sharing fund; relating to the allocation of lease expenditures and**
6 **adjustments to lease expenditures; relating to the tax on the production of gas in effect**
7 **at the start of the first binding open season held for the project licensed under the**
8 **Alaska Gasline Inducement Act; and providing for an effective date."**

9 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

10 *** Section 1. AS 29.60.850(b) is amended to read:**

11 (b) Each fiscal year, the legislature may appropriate to the community revenue
12 sharing fund an amount equal to 20 percent of the money received by the state during

1 the previous calendar year under AS 43.55.011(g) and (p). The amount may not
2 exceed

3 (1) \$60,000,000; or

4 (2) the amount that, when added to the fund balance on June 30 of the
5 previous fiscal year, equals \$180,000,000.

6 * Sec. 2. AS 29.60.850(b), as amended by sec. 1 of this Act, is amended to read:

7 (b) Each fiscal year, the legislature may appropriate to the community revenue
8 sharing fund an amount equal to 20 percent of the money received by the state during
9 the previous calendar year under AS 43.55.011(g) [AND (p)]. The amount may not
10 exceed

11 (1) ~~\$60,000,000; or~~

12 (2) the amount that, when added to the fund balance on June 30 of the
13 previous fiscal year, equals \$180,000,000.

14 * Sec. 3. AS 29.60.850(b), as amended by sec. 2 of this Act, is amended to read:

15 (b) Each fiscal year, the legislature may appropriate to the community revenue
16 sharing fund an amount equal to 20 percent of the money received by the state during
17 the previous calendar year under AS 43.55.011(g) and (q). The amount may not
18 exceed

19 (1) \$60,000,000; or

20 (2) the amount that, when added to the fund balance on June 30 of the
21 previous fiscal year, equals \$180,000,000.

22 * Sec. 4. AS 43.55.011(e) is amended to read:

23 (e) There is levied on the producer of oil or gas a tax for all oil and gas
24 produced each calendar year from each lease or property in the state, less any oil and
25 gas the ownership or right to which is exempt from taxation or constitutes a
26 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of
27 this section, the tax is equal to the sum of

28 (1) the annual production tax value of the taxable oil and gas as
29 calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

30 (2) the sum, over all months of the calendar year, of the tax amounts
31 determined under

1 **(A) subsection (g) of this section; and**

2 **(B) subsection (p) of this section.**

3 * **Sec. 5.** AS 43.55.011(e), as amended by sec. 4 of this Act, is amended to read:

4 (e) There is levied on the producer of oil or gas a tax for all oil and gas
5 produced each calendar year from each lease or property in the state, less any oil and
6 gas the ownership or right to which is exempt from taxation or constitutes a
7 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of
8 this section, the tax is equal to the sum of

9 (1) the annual production tax value of the taxable oil and gas as
10 calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

11 (2) the sum, over all months of the calendar year, of the tax amounts
12 determined under

13 [(A) SUBSECTION] (g) of this section [; AND

14 (B) SUBSECTION (p) OF THIS SECTION].

15 * **Sec. 6.** AS 43.55.011(e) as amended by sec. 5 of this Act is amended to read:

16 (e) There is levied on the producer of oil or gas a tax for all oil and gas
17 produced each calendar year from each lease or property in the state, less any oil and
18 gas the ownership or right to which is exempt from taxation or constitutes a
19 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of
20 this section, the tax is equal to the sum of

21 (1) the annual production tax value of the taxable oil and gas as
22 calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

23 (2) the sum, over all months of the calendar year, of the tax amounts
24 determined under

25 **(A) subsection (g) of this section; and**

26 **(B) subsection (q) of this section.**

27 * **Sec. 7.** AS 43.55.011(g) is amended to read:

28 (g) For each month of the calendar year for which the producer's average
29 monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a
30 [AS 43.55.160(a)(2) PER] BTU equivalent barrel of [THE] taxable oil and gas is more
31 than \$30, the amount of tax for purposes of (e)(2)(A) [(e)(2)] of this section is

1 determined by multiplying the monthly production tax value of the taxable oil [AND
2 GAS] produced during the month, gas produced during the month from a lease or
3 property in the Cook Inlet sedimentary basin, and gas produced during the
4 month from a lease or property outside the Cook Inlet sedimentary basin and
5 used in the state by the tax rate calculated as follows:

6 (1) if the producer's average monthly production tax value under
7 AS 43.55.160(a)(2)(A) - (E) of a [PER] BTU equivalent barrel of [THE] taxable oil
8 and gas for the month is not more than \$92.50, the tax rate is 0.4 percent multiplied by
9 the number that represents the difference between the producer's [THAT] average
10 monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a [PER] BTU
11 equivalent barrel of taxable oil and gas and \$30; or

12 (2) if the producer's average monthly production tax value under
13 AS 43.55.160(a)(2)(A) - (E) of a [PER] BTU equivalent barrel of [THE] taxable oil
14 and gas for the month is more than \$92.50, the tax rate is the sum of 25 percent and
15 the product of 0.1 percent multiplied by the number that represents the difference
16 between the producer's average monthly production tax value under
17 AS 43.55.160(a)(2)(A) - (E) of a [PER] BTU equivalent barrel of taxable oil and gas
18 and \$92.50, except that the sum determined under this paragraph may not exceed 50
19 percent.

20 * Sec. 8. AS 43.55.011(g), as amended by sec. 7 of this Act, is amended to read:

21 (g) For each month of the calendar year for which the producer's average
22 monthly production tax value under AS 43.55.160(a)(2) [AS 43.55.160(a)(2)(A) - (E)]
23 of a BTU equivalent barrel of taxable oil and gas is more than \$30, the amount of tax
24 for purposes of (e)(2) [(e)(2)(A)] of this section is determined by multiplying the
25 monthly production tax value of the taxable oil and gas produced during the month [,
26 GAS PRODUCED DURING THE MONTH FROM A LEASE OR PROPERTY IN
27 THE COOK INLET SEDIMENTARY BASIN, AND GAS PRODUCED DURING
28 THE MONTH FROM A LEASE OR PROPERTY OUTSIDE THE COOK INLET
29 SEDIMENTARY BASIN AND USED IN THE STATE] by the tax rate calculated as
30 follows:

31 (1) if the producer's average monthly production tax value [UNDER

1 AS 43.55.160(a)(2)(A) - (E)] of a BTU equivalent barrel of taxable oil and gas for the
2 month is not more than \$92.50, the tax rate is 0.4 percent multiplied by the number
3 that represents the difference between the producer's average monthly production tax
4 value [UNDER AS 43.55.160(a)(2)(A) - (E)] of a BTU equivalent barrel of taxable oil
5 and gas and \$30; or

6 (2) if the producer's average monthly production tax value [UNDER
7 AS 43.55.160(a)(2)(A) - (E)] of a BTU equivalent barrel of taxable oil and gas for the
8 month is more than \$92.50, the tax rate is the sum of 25 percent and the product of 0.1
9 percent multiplied by the number that represents the difference between the producer's
10 average monthly production tax value [UNDER AS 43.55.160(a)(2)(A) - (E)] of a
11 BTU equivalent barrel of taxable oil and gas and \$92.50, except that the sum
12 determined under this paragraph may not exceed 50 percent.

13 * Sec. 9. AS 43.55.011(g), as amended by sec. 8 of this Act, is amended to read:

14 (g) For each month of the calendar year for which the producer's average
15 monthly production tax value under AS 43.55.160(a)(2)(A) - (E) [AS 43.55.160(a)(2)]
16 of a BTU equivalent barrel of taxable oil and gas is more than \$30, the amount of tax
17 for purposes of (e)(2)(A) [(e)(2)] of this section is determined by multiplying the
18 monthly production tax value of the taxable oil [AND GAS] produced during the
19 month, gas produced during the month from a lease or property in the Cook Inlet
20 sedimentary basin, and gas produced during the month from a lease or property
21 outside the Cook Inlet sedimentary basin and used in the state by the tax rate
22 calculated as follows:

23 (1) if the producer's average monthly production tax value under
24 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of taxable oil and gas for the
25 month is not more than \$92.50, the tax rate is 0.4 percent multiplied by the number
26 that represents the difference between the producer's average monthly production tax
27 value under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of taxable oil
28 and gas and \$30; or

29 (2) if the producer's average monthly production tax value under
30 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of taxable oil and gas for the
31 month is more than \$92.50, the tax rate is the sum of 25 percent and the product of 0.1

1 percent multiplied by the number that represents the difference between the producer's
2 average monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a BTU
3 equivalent barrel of taxable oil and gas and \$92.50, except that the sum determined
4 under this paragraph may not exceed 50 percent.

5 * **Sec. 10.** AS 43.55.011 is amended by adding a new subsection to read:

6 (p) For each month of the calendar year for which the producer's average
7 monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU
8 equivalent barrel of taxable gas is more than \$30, the amount of tax on the production
9 of gas for purposes of (e)(2)(B) of this section is determined by multiplying the
10 monthly production tax value of the taxable gas produced during the month other than
11 ~~gas produced from a lease or property in the Cook Inlet sedimentary basin or gas~~
12 ~~produced outside the Cook Inlet sedimentary basin and used in the state by the tax rate~~
13 ~~calculated as follows:~~

14 (1) if the producer's average monthly production tax value under
15 AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of taxable gas for the
16 month is not more than \$92.50, the tax rate is 0.4 percent multiplied by the number
17 that represents the difference between the producer's average monthly production tax
18 value under AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of gas and \$30;
19 or

20 (2) if the producer's average monthly production tax value under
21 AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of taxable gas for the
22 month is more than \$92.50, the tax rate is the sum of 25 percent and the product of 0.1
23 percent multiplied by the number that represents the difference between the producer's
24 average monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU
25 equivalent barrel of gas and \$92.50, except that the sum determined under this
26 paragraph may not exceed 50 percent.

27 * **Sec. 11.** AS 43.55.011 is amended by adding a new subsection to read:

28 (q) For each month of the calendar year for which the producer's average
29 monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU
30 equivalent barrel of taxable gas is more than \$30, the amount of tax on the production
31 of gas for purposes of (e)(2)(B) of this section is determined by multiplying the

1 monthly production tax value of the taxable gas produced during the month other than
2 gas produced from a lease or property in the Cook Inlet sedimentary basin or gas
3 produced outside the Cook Inlet sedimentary basin and used in the state by the tax rate
4 calculated as follows:

5 (1) if the producer's average monthly production tax value under
6 AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of taxable gas for the
7 month is not more than \$92.50, the tax rate is 0.4 percent multiplied by the number
8 that represents the difference between the producer's average monthly production tax
9 value under AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of gas and \$30;
10 or

11 ~~(2) if the producer's average monthly production tax value under~~
12 AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of taxable gas for the
13 month is more than \$92.50, the tax rate is the sum of 25 percent and the product of 0.1
14 percent multiplied by the number that represents the difference between the producer's
15 average monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU
16 equivalent barrel of gas and \$92.50, except that the sum determined under this
17 paragraph may not exceed 50 percent.

18 * Sec. 12. AS 43.55.020(a) is amended to read:

19 (a) For a calendar year, a producer subject to tax under AS 43.55.011(e) - (i)
20 and (p) shall pay the tax as follows:

21 (1) an installment payment of the estimated tax levied by
22 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
23 month of the calendar year on the last day of the following month; except as otherwise
24 provided under (2) of this subsection, the amount of the installment payment is the
25 sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be
26 applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount
27 of the installment payment may not be less than zero:

28 (A) for oil and gas produced from leases or properties in the
29 state outside the Cook Inlet sedimentary basin but not subject to
30 AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f), the
31 greater of

1 (i) zero; or

2 (ii) an amount equal to the sum of 25 percent and the
3 tax rate calculated for the month under AS 43.55.011(g) multiplied by
4 the remainder obtained by subtracting 1/12 of the producer's adjusted
5 lease expenditures for the calendar year of production applicable to
6 the oil produced by the producer from those leases and properties
7 under AS 43.55.165 and 43.55.170 that are deductible for the leases or
8 properties under AS 43.55.160, from the gross value at the point of
9 production of the oil [AND GAS] produced from the leases or
10 properties during the month for which the installment payment is
11 calculated ~~added to the sum of 25 percent and the tax rate~~
12 calculated for the month under AS 43.55.011(p) multiplied by the
13 remainder obtained by subtracting 1/12 of the producer's adjusted
14 lease expenditures for the calendar year of production applicable
15 to the gas produced by the producer from those leases and
16 properties under AS 43.55.165 and 43.55.170 that are deductible
17 for the leases or properties under AS 43.55.160 from the gross
18 value at the point of production of the gas produced from the leases
19 or properties during the month for which the installment payment
20 is calculated;

21 (B) for oil and gas produced from leases or properties subject
22 to AS 43.55.011(f), the greatest of

23 (i) zero;

24 (ii) zero percent, one percent, two percent, three
25 percent, or four percent, as applicable, of the gross value at the point of
26 production of the oil and gas produced from all leases or properties
27 during the month for which the installment payment is calculated; or

28 (iii) an amount equal to the sum of 25 percent and the
29 tax rate calculated for the month under AS 43.55.011(g) multiplied by
30 the remainder obtained by subtracting 1/12 of the producer's adjusted
31 lease expenditures for the calendar year of production applicable to

1 the oil produced by the producer from those leases and properties
2 under AS 43.55.165 and 43.55.170 that are deductible for those leases
3 or properties under AS 43.55.160, from the gross value at the point of
4 production of the oil [AND GAS] produced from those leases or
5 properties during the month for which the installment payment is
6 calculated added to the sum of 25 percent and the tax rate
7 calculated for the month under AS 43.55.011(p) multiplied by the
8 remainder obtained by subtracting 1/12 of the producer's adjusted
9 lease expenditures for the calendar year of production applicable
10 to the gas produced by the producer from those leases and
11 properties under AS 43.55.165 and 43.55.170 that are deductible
12 for those leases or properties under AS 43.55.160 from the gross
13 value at the point of production of the gas produced from those
14 leases or properties during the month for which the installment
15 payment is calculated;

16 (C) for oil and gas produced from each lease or property
17 subject to AS 43.55.011(j), (k), or (o), the greater of

18 (i) zero; or

19 (ii) an amount equal to the sum of 25 percent and the
20 tax rate calculated for the month under AS 43.55.011(g) multiplied by
21 the remainder obtained by subtracting 1/12 of the producer's adjusted
22 lease expenditures for the calendar year of production applicable to
23 the oil produced by the producer from those leases and properties
24 under AS 43.55.165 and 43.55.170 that are deductible under
25 AS 43.55.160 for oil [OR GAS, RESPECTIVELY,] produced from the
26 lease or property, from the gross value at the point of production of the
27 oil [OR GAS, RESPECTIVELY,] produced from the lease or property
28 during the month for which the installment payment is calculated
29 added to the sum of 25 percent and the tax rate calculated for the
30 month under AS 43.55.011(g) multiplied by the remainder obtained
31 by subtracting 1/12 of the producer's adjusted lease expenditures

1 for the calendar year of production applicable to the gas produced
2 by the producer from the lease or property under AS 43.55.165 and
3 43.55.170 that are deductible under AS 43.55.160 for gas produced
4 from the lease or property, from the gross value at the point of
5 production of the gas produced from the lease or property during
6 the month for which the installment payment is calculated;

7 (2) an amount calculated under (1)(C) of this subsection for oil or gas
8 produced from a lease or property subject to AS 43.55.011(j), (k), or (o) may not
9 exceed the product obtained by carrying out the calculation set out in
10 AS 43.55.011(j)(1) or (2) or 43.55.011(o), as applicable, for gas or set out in
11 AS 43.55.011(k)(1) or (2), as applicable, for oil, but substituting in
12 AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the amount of taxable
13 gas produced during the month for the amount of taxable gas produced during the
14 calendar year and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the
15 amount of taxable oil produced during the month for the amount of taxable oil
16 produced during the calendar year;

17 (3) an installment payment of the estimated tax levied by
18 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
19 on the last day of the following month; the amount of the installment payment is the
20 sum of

21 (A) the applicable tax rate for oil provided under
22 AS 43.55.011(i), multiplied by the gross value at the point of production of the
23 oil taxable under AS 43.55.011(i) and produced from the lease or property
24 during the month; and

25 (B) the applicable tax rate for gas provided under
26 AS 43.55.011(i), multiplied by the gross value at the point of production of the
27 gas taxable under AS 43.55.011(i) and produced from the lease or property
28 during the month;

29 (4) any amount of tax levied by AS 43.55.011(e) or (i), net of any
30 credits applied as allowed by law, that exceeds the total of the amounts due as
31 installment payments of estimated tax is due on March 31 of the year following the

1 calendar year of production.

2 * **Sec. 13.** AS 43.55.020(a), as amended by sec. 12 of this Act, is amended to read:

3 (a) For a calendar year, a producer subject to tax under AS 43.55.011(e) - (i)
4 [AND (p)] shall pay the tax as follows:

5 (1) an installment payment of the estimated tax levied by
6 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
7 month of the calendar year on the last day of the following month; except as otherwise
8 provided under (2) of this subsection, the amount of the installment payment is the
9 sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be
10 applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount
11 of the installment payment may not be less than zero:

12 (A) for oil and gas produced from leases or properties in the
13 state outside the Cook Inlet sedimentary basin but not subject to
14 AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f), the
15 greater of

16 (i) zero; or

17 (ii) [AN AMOUNT EQUAL TO] the sum of 25 percent
18 and the tax rate calculated for the month under AS 43.55.011(g)
19 multiplied by the remainder obtained by subtracting 1/12 of the
20 producer's adjusted lease expenditures for the calendar year of
21 production [APPLICABLE TO THE OIL PRODUCED BY THE
22 PRODUCER FROM THOSE LEASES AND PROPERTIES] under
23 AS 43.55.165 and 43.55.170 that are deductible for the leases or
24 properties under AS 43.55.160 [,] from the gross value at the point of
25 production of the oil and gas produced from the leases or properties
26 during the month for which the installment payment is calculated
27 [ADDED TO THE SUM OF 25 PERCENT AND THE TAX RATE
28 CALCULATED FOR THE MONTH UNDER AS 43.55.011(p)
29 MULTIPLIED BY THE REMAINDER OBTAINED BY
30 SUBTRACTING 1/12 OF THE PRODUCER'S ADJUSTED LEASE
31 EXPENDITURES FOR THE CALENDAR YEAR OF PRODUCTION

1 APPLICABLE TO THE GAS PRODUCED BY THE PRODUCER
2 FROM THOSE LEASES AND PROPERTIES UNDER AS 43.55.165
3 AND 43.55.170 THAT ARE DEDUCTIBLE FOR THE LEASES OR
4 PROPERTIES UNDER AS 43.55.160 FROM THE GROSS VALUE
5 AT THE POINT OF PRODUCTION OF THE GAS PRODUCED
6 FROM THE LEASES OR PROPERTIES DURING THE MONTH
7 FOR WHICH THE INSTALLMENT PAYMENT IS CALCULATED];

8 (B) for oil and gas produced from leases or properties subject
9 to AS 43.55.011(f), the greatest of

10 (i) zero;

11 ~~(ii) zero percent, one percent, two percent, three~~
12 ~~percent, or four percent, as applicable, of the gross value at the point of~~
13 ~~production of the oil and gas produced from all leases or properties~~
14 ~~during the month for which the installment payment is calculated; or~~

15 (iii) [AN AMOUNT EQUAL TO] the sum of 25
16 percent and the tax rate calculated for the month under AS 43.55.011(g)
17 multiplied by the remainder obtained by subtracting 1/12 of the
18 producer's adjusted lease expenditures for the calendar year of
19 production [APPLICABLE TO THE OIL PRODUCED BY THE
20 PRODUCER FROM THOSE LEASES AND PROPERTIES] under
21 AS 43.55.165 and 43.55.170 that are deductible for those leases or
22 properties under AS 43.55.160 [,] from the gross value at the point of
23 production of the oil and gas produced from those leases or properties
24 during the month for which the installment payment is calculated
25 [ADDED TO THE SUM OF 25 PERCENT AND THE TAX RATE
26 CALCULATED FOR THE MONTH UNDER AS 43.55.011(p)
27 MULTIPLIED BY THE REMAINDER OBTAINED BY
28 SUBTRACTING 1/12 OF THE PRODUCER'S ADJUSTED LEASE
29 EXPENDITURES FOR THE CALENDAR YEAR OF PRODUCTION
30 APPLICABLE TO THE GAS PRODUCED BY THE PRODUCER
31 FROM THOSE LEASES AND PROPERTIES UNDER AS 43.55.165

1 AND 43.55.170 THAT ARE DEDUCTIBLE FOR THOSE LEASES
2 OR PROPERTIES UNDER AS 43.55.160 FROM THE GROSS
3 VALUE AT THE POINT OF PRODUCTION OF THE GAS
4 PRODUCED FROM THOSE LEASES OR PROPERTIES DURING
5 THE MONTH FOR WHICH THE INSTALLMENT PAYMENT IS
6 CALCULATED];

7 (C) for oil and gas produced from each lease or property
8 subject to AS 43.55.011(j), (k), or (o), the greater of

9 (i) zero; or

10 (ii) [AN AMOUNT EQUAL TO] the sum of 25 percent
11 ~~and the tax rate calculated for the month under AS 43.55.011(g)~~
12 multiplied by the remainder obtained by subtracting 1/12 of the
13 producer's adjusted lease expenditures for the calendar year of
14 production [APPLICABLE TO THE OIL PRODUCED BY THE
15 PRODUCER FROM THOSE LEASES AND PROPERTIES] under
16 AS 43.55.165 and 43.55.170 that are deductible under AS 43.55.160
17 for oil or gas, respectively, produced from the lease or property [,]
18 from the gross value at the point of production of the oil or gas,
19 respectively, produced from the lease or property during the month for
20 which the installment payment is calculated [ADDED TO THE SUM
21 OF 25 PERCENT AND THE TAX RATE CALCULATED FOR THE
22 MONTH UNDER AS 43.55.011(g) MULTIPLIED BY THE
23 REMAINDER OBTAINED BY SUBTRACTING 1/12 OF THE
24 PRODUCER'S ADJUSTED LEASE EXPENDITURES FOR THE
25 CALENDAR YEAR OF PRODUCTION APPLICABLE TO THE
26 GAS PRODUCED BY THE PRODUCER FROM THE LEASE OR
27 PROPERTY UNDER AS 43.55.165 AND 43.55.170 THAT ARE
28 DEDUCTIBLE UNDER AS 43.55.160 FOR GAS PRODUCED
29 FROM THE LEASE OR PROPERTY, FROM THE GROSS VALUE
30 AT THE POINT OF PRODUCTION OF THE GAS PRODUCED
31 FROM THE LEASE OR PROPERTY DURING THE MONTH FOR

1 WHICH THE INSTALLMENT PAYMENT IS CALCULATED];

2 (2) an amount calculated under (1)(C) of this subsection for oil or gas
3 produced before 2022 from a lease or property subject to AS 43.55.011(j), (k), or (o)
4 may not exceed the product obtained by carrying out the calculation set out in
5 AS 43.55.011(j)(1) or (2) or 43.55.011(o), as applicable, for gas or set out in
6 AS 43.55.011(k)(1) or (2), as applicable, for oil, but substituting in
7 AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the amount of taxable
8 gas produced during the month for the amount of taxable gas produced during the
9 calendar year and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the
10 amount of taxable oil produced during the month for the amount of taxable oil
11 produced during the calendar year;

12 (3) an installment payment of the estimated tax levied by
13 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
14 on the last day of the following month; the amount of the installment payment is the
15 sum of

16 (A) the applicable tax rate for oil provided under
17 AS 43.55.011(i), multiplied by the gross value at the point of production of the
18 oil taxable under AS 43.55.011(i) and produced from the lease or property
19 during the month; and

20 (B) the applicable tax rate for gas provided under
21 AS 43.55.011(i), multiplied by the gross value at the point of production of the
22 gas taxable under AS 43.55.011(i) and produced from the lease or property
23 during the month;

24 (4) any amount of tax levied by AS 43.55.011(e) or (i), net of any
25 credits applied as allowed by law, that exceeds the total of the amounts due as
26 installment payments of estimated tax is due on March 31 of the year following the
27 calendar year of production.

28 * Sec. 14. AS 43.55.020(a), as amended by sec. 13 of this Act, is amended to read:

29 (a) For a calendar year, a producer subject to tax under AS 43.55.011(e) - (i)
30 and (q) shall pay the tax as follows:

31 (1) an installment payment of the estimated tax levied by

1 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
2 month of the calendar year on the last day of the following month; except as otherwise
3 provided under (2) of this subsection, the amount of the installment payment is the
4 sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be
5 applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount
6 of the installment payment may not be less than zero:

7 (A) for oil and gas produced from leases or properties in the
8 state outside the Cook Inlet sedimentary basin but not subject to
9 AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f), the
10 greater of

11 ~~(i) zero; or~~

12 (ii) **an amount equal** to the sum of 25 percent and the
13 tax rate calculated for the month under AS 43.55.011(g) multiplied by
14 the remainder obtained by subtracting 1/12 of the producer's adjusted
15 lease expenditures for the calendar year of production **applicable to**
16 **the oil produced by the producer from those leases and properties**
17 under AS 43.55.165 and 43.55.170 that are deductible for the leases or
18 properties under AS 43.55.160, from the gross value at the point of
19 production of the oil [AND GAS] produced from the leases or
20 properties during the month for which the installment payment is
21 calculated **added to the sum of 25 percent and the tax rate**
22 **calculated for the month under AS 43.55.011(q) multiplied by the**
23 **remainder obtained by subtracting 1/12 of the producer's adjusted**
24 **lease expenditures for the calendar year of production applicable**
25 **to the gas produced by the producer from those leases and**
26 **properties under AS 43.55.165 and 43.55.170 that are deductible**
27 **for the leases or properties under AS 43.55.160 from the gross**
28 **value at the point of production of the gas produced from the leases**
29 **or properties during the month for which the installment payment**
30 **is calculated;**

31 (B) for oil and gas produced from leases or properties subject

1 to AS 43.55.011(f), the greatest of

2 (i) zero;

3 (ii) zero percent, one percent, two percent, three
4 percent, or four percent, as applicable, of the gross value at the point of
5 production of the oil and gas produced from all leases or properties
6 during the month for which the installment payment is calculated; or

7 (iii) an amount equal to the sum of 25 percent and the
8 tax rate calculated for the month under AS 43.55.011(g) multiplied by
9 the remainder obtained by subtracting 1/12 of the producer's adjusted
10 lease expenditures for the calendar year of production applicable to
11 the oil produced by the producer from those leases and properties
12 under AS 43.55.165 and 43.55.170 that are deductible for those leases
13 or properties under AS 43.55.160, from the gross value at the point of
14 production of the oil [AND GAS] produced from those leases or
15 properties during the month for which the installment payment is
16 calculated added to the sum of 25 percent and the tax rate
17 calculated for the month under AS 43.55.011(q) multiplied by the
18 remainder obtained by subtracting 1/12 of the producer's adjusted
19 lease expenditures for the calendar year of production applicable
20 to the gas produced by the producer from those leases and
21 properties under AS 43.55.165 and 43.55.170 that are deductible
22 for those leases or properties under AS 43.55.160 from the gross
23 value at the point of production of the gas produced from those
24 leases or properties during the month for which the installment
25 payment is calculated;

26 (C) for oil and gas produced from each lease or property
27 subject to AS 43.55.011(j), (k), or (o), the greater of

28 (i) zero; or

29 (ii) an amount equal to the sum of 25 percent and the
30 tax rate calculated for the month under AS 43.55.011(g) multiplied by
31 the remainder obtained by subtracting 1/12 of the producer's adjusted

1 lease expenditures for the calendar year of production applicable to
2 the oil produced by the producer from those leases and properties
3 under AS 43.55.165 and 43.55.170 that are deductible under
4 AS 43.55.160 for oil [OR GAS, RESPECTIVELY,] produced from the
5 lease or property, from the gross value at the point of production of the
6 oil [OR GAS, RESPECTIVELY,] produced from the lease or property
7 during the month for which the installment payment is calculated
8 added to the sum of 25 percent and the tax rate calculated for the
9 month under AS 43.55.011(g) multiplied by the remainder obtained
10 by subtracting 1/12 of the producer's adjusted lease expenditures
11 for the calendar year of production applicable to the gas produced
12 by the producer from the lease or property under AS 43.55.165 and
13 43.55.170 that are deductible under AS 43.55.160 for gas produced
14 from the lease or property, from the gross value at the point of
15 production of the gas produced from the lease or property during
16 the month for which the installment payment is calculated;

17 (2) an amount calculated under (1)(C) of this subsection for oil or gas
18 produced before 2022 from a lease or property subject to AS 43.55.011(j), (k), or (o)
19 may not exceed the product obtained by carrying out the calculation set out in
20 AS 43.55.011(j)(1) or (2) or 43.55.011(o), as applicable, for gas or set out in
21 AS 43.55.011(k)(1) or (2), as applicable, for oil, but substituting in
22 AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the amount of taxable
23 gas produced during the month for the amount of taxable gas produced during the
24 calendar year and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the
25 amount of taxable oil produced during the month for the amount of taxable oil
26 produced during the calendar year;

27 (3) an installment payment of the estimated tax levied by
28 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
29 on the last day of the following month; the amount of the installment payment is the
30 sum of

31 (A) the applicable tax rate for oil provided under

1 AS 43.55.011(i), multiplied by the gross value at the point of production of the
2 oil taxable under AS 43.55.011(i) and produced from the lease or property
3 during the month; and

4 (B) the applicable tax rate for gas provided under
5 AS 43.55.011(i), multiplied by the gross value at the point of production of the
6 gas taxable under AS 43.55.011(i) and produced from the lease or property
7 during the month;

8 (4) any amount of tax levied by AS 43.55.011(e) or (i), net of any
9 credits applied as allowed by law, that exceeds the total of the amounts due as
10 installment payments of estimated tax is due on March 31 of the year following the
11 calendar year of production.

12 * Sec. 15. AS 43.55.020(d) is amended to read:

13 (d) In making settlement with the royalty owner for oil and gas that is taxable
14 under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable
15 royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the
16 time the tax becomes due to the amount of the tax paid. If the total deductions of
17 installment payments of estimated tax for a calendar year exceed the actual tax for that
18 calendar year, the producer shall, before April 1 of the following year, refund the
19 excess to the royalty owner. Unless otherwise agreed between the producer and the
20 royalty owner, the amount of the tax paid under AS 43.55.011(e) - (g) and (p) on
21 taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or
22 right to which constitutes a landowner's royalty interest, is considered to be the gross
23 value at the point of production of the taxable royalty oil and gas produced during the
24 calendar year multiplied by a figure that is a quotient, in which

25 (1) the numerator is the producer's total tax liability under
26 AS 43.55.011(e) - (g) and (p) for the calendar year of production; and

27 (2) the denominator is the total gross value at the point of production
28 of the oil and gas taxable under AS 43.55.011(e) - (g) and (p) produced by the
29 producer from all leases and properties in the state during the calendar year.

30 * Sec. 16. AS 43.55.020(d), as amended by sec. 15 of this Act, is amended to read:

31 (d) In making settlement with the royalty owner for oil and gas that is taxable

1 under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable
2 royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the
3 time the tax becomes due to the amount of the tax paid. If the total deductions of
4 installment payments of estimated tax for a calendar year exceed the actual tax for that
5 calendar year, the producer shall, before April 1 of the following year, refund the
6 excess to the royalty owner. Unless otherwise agreed between the producer and the
7 royalty owner, the amount of the tax paid under AS 43.55.011(e) - (g) [AND (p)] on
8 taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or
9 right to which constitutes a landowner's royalty interest, is considered to be the gross
10 value at the point of production of the taxable royalty oil and gas produced during the
11 calendar year multiplied by a figure that is a quotient, in which

12 (1) the numerator is the producer's total tax liability under
13 AS 43.55.011(e) - (g) [AND (p)] for the calendar year of production; and

14 (2) the denominator is the total gross value at the point of production
15 of the oil and gas taxable under AS 43.55.011(e) - (g) [AND (p)] produced by the
16 producer from all leases and properties in the state during the calendar year.

17 * Sec. 17. AS 43.55.020(d), as amended by sec. 16 of this Act, is amended to read:

18 (d) In making settlement with the royalty owner for oil and gas that is taxable
19 under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable
20 royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the
21 time the tax becomes due to the amount of the tax paid. If the total deductions of
22 installment payments of estimated tax for a calendar year exceed the actual tax for that
23 calendar year, the producer shall, before April 1 of the following year, refund the
24 excess to the royalty owner. Unless otherwise agreed between the producer and the
25 royalty owner, the amount of the tax paid under AS 43.55.011(e) - (g) and (q) on
26 taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or
27 right to which constitutes a landowner's royalty interest, is considered to be the gross
28 value at the point of production of the taxable royalty oil and gas produced during the
29 calendar year multiplied by a figure that is a quotient, in which

30 (1) the numerator is the producer's total tax liability under
31 AS 43.55.011(e) - (g) and (q) for the calendar year of production; and

1 (2) the denominator is the total gross value at the point of production
2 of the oil and gas taxable under AS 43.55.011(e) - (g) and (g) produced by the
3 producer from all leases and properties in the state during the calendar year.

4 * **Sec. 18.** AS 43.55.160(a) is amended to read:

5 (a) Except as provided in (b) of this section, for the purposes of

6 (1) AS 43.55.011(e), the annual production tax value of the taxable

7 (A) oil [AND GAS] produced during a calendar year from
8 leases or properties in the state that include land north of 68 degrees North
9 latitude is the gross value at the point of production of the oil [AND GAS]
10 taxable under AS 43.55.011(e) and produced by the producer from those leases
11 or properties, less the producer's lease expenditures under AS 43.55.165 for the
12 calendar year applicable to the oil [AND GAS] produced by the producer from
13 those leases or properties, as adjusted under AS 43.55.170; [THIS
14 SUBPARAGRAPH DOES NOT APPLY TO GAS SUBJECT TO
15 AS 43.55.011(o);]

16 (B) oil [AND GAS] produced during a calendar year from
17 leases or properties in the state outside the Cook Inlet sedimentary basin, no
18 part of which is north of 68 degrees North latitude, is the gross value at the
19 point of production of the oil [AND GAS] taxable under AS 43.55.011(e) and
20 produced by the producer from those leases or properties, less the producer's
21 lease expenditures under AS 43.55.165 for the calendar year applicable to the
22 oil [AND GAS] produced by the producer from those leases or properties, as
23 adjusted under AS 43.55.170; [THIS SUBPARAGRAPH DOES NOT APPLY
24 TO GAS SUBJECT TO AS 43.55.011(o);]

25 (C) oil produced during a calendar year from a lease or
26 property in the Cook Inlet sedimentary basin is the gross value at the point of
27 production of the oil taxable under AS 43.55.011(e) and produced by the
28 producer from that lease or property, less the producer's lease expenditures
29 under AS 43.55.165 for the calendar year applicable to the oil produced by the
30 producer from that lease or property, as adjusted under AS 43.55.170;

31 (D) gas produced during a calendar year from a lease or

1 property in the Cook Inlet sedimentary basin is the gross value at the point of
2 production of the gas taxable under AS 43.55.011(e) and produced by the
3 producer from that lease or property, less the producer's lease expenditures
4 under AS 43.55.165 for the calendar year applicable to the gas produced by the
5 producer from that lease or property, as adjusted under AS 43.55.170;

6 (E) gas produced during a calendar year from a lease or
7 property outside the Cook Inlet sedimentary basin and used in the state is the
8 gross value at the point of production of that gas taxable under
9 AS 43.55.011(e) and produced by the producer from that lease or property, less
10 the producer's lease expenditures under AS 43.55.165 for the calendar year
11 applicable to that gas produced by the producer from that lease or property, as
12 adjusted under AS 43.55.170;

13 (F) gas produced during a calendar year from leases or
14 properties in the state that include land north of 68 degrees North latitude
15 is the gross value at the point of production of the gas taxable under
16 AS 43.55.011(e) and produced by the producer from those leases or
17 properties, less the producer's lease expenditures under AS 43.55.165 for
18 the calendar year applicable to the gas produced by the producer from
19 those leases or properties, as adjusted under AS 43.55.170; this
20 subparagraph does not apply to gas used in the state;

21 (G) gas produced during a calendar year from leases or
22 properties in the state outside the Cook Inlet sedimentary basin, no part of
23 which is north of 68 degrees North latitude, is the gross value at the point
24 of production of the gas taxable under AS 43.55.011(e) and produced by
25 the producer from those leases or properties, less the producer's lease
26 expenditures under AS 43.55.165 for the calendar year applicable to the
27 gas produced by the producer from those leases or properties, as adjusted
28 under AS 43.55.170; this subparagraph does not apply to gas used in the
29 state;

30 (2) AS 43.55.011(g) and (p), the monthly production tax value of the
31 taxable

1 (A) oil [AND GAS] produced during a month from leases or
2 properties in the state that include land north of 68 degrees North latitude is the
3 gross value at the point of production of the oil [AND GAS] taxable under
4 AS 43.55.011(e) and produced by the producer from those leases or properties,
5 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the
6 calendar year applicable to the oil [AND GAS] produced by the producer from
7 those leases or properties, as adjusted under AS 43.55.170; [THIS
8 SUBPARAGRAPH DOES NOT APPLY TO GAS SUBJECT TO
9 AS 43.55.011(o);]

10 (B) oil [AND GAS] produced during a month from leases or
11 ~~properties in the state outside the Cook Inlet sedimentary basin, no part of~~
12 which is north of 68 degrees North latitude, is the gross value at the point of
13 production of the oil [AND GAS] taxable under AS 43.55.011(e) and produced
14 by the producer from those leases or properties, less 1/12 of the producer's
15 lease expenditures under AS 43.55.165 for the calendar year applicable to the
16 oil [AND GAS] produced by the producer from those leases or properties, as
17 adjusted under AS 43.55.170; [THIS SUBPARAGRAPH DOES NOT APPLY
18 TO GAS SUBJECT TO AS 43.55.011(o);]

19 (C) oil produced during a month from a lease or property in the
20 Cook Inlet sedimentary basin is the gross value at the point of production of
21 the oil taxable under AS 43.55.011(e) and produced by the producer from that
22 lease or property, less 1/12 of the producer's lease expenditures under
23 AS 43.55.165 for the calendar year applicable to the oil produced by the
24 producer from that lease or property, as adjusted under AS 43.55.170;

25 (D) gas produced during a month from a lease or property in
26 the Cook Inlet sedimentary basin is the gross value at the point of production
27 of the gas taxable under AS 43.55.011(e) and produced by the producer from
28 that lease or property, less 1/12 of the producer's lease expenditures under
29 AS 43.55.165 for the calendar year applicable to the gas produced by the
30 producer from that lease or property, as adjusted under AS 43.55.170;

31 (E) gas produced during a month from a lease or property

1 outside the Cook Inlet sedimentary basin and used in the state is the gross
2 value at the point of production of that gas taxable under AS 43.55.011(e) and
3 produced by the producer from that lease or property, less 1/12 of the
4 producer's lease expenditures under AS 43.55.165 for the calendar year
5 applicable to that gas produced by the producer from that lease or property, as
6 adjusted under AS 43.55.170;

7 (F) gas produced during a month from leases or properties
8 in the state that include land north of 68 degrees North latitude is the
9 gross value at the point of production of the gas taxable under
10 AS 43.55.011(e) and produced by the producer from those leases or
11 properties, less 1/12 of the producer's lease expenditures under
12 AS 43.55.165 for the calendar year applicable to the gas produced by the
13 producer from those leases or properties, as adjusted under AS 43.55.170;
14 this subparagraph does not apply to gas used in the state;

15 (G) gas produced during a month from leases or properties
16 in the state outside the Cook Inlet sedimentary basin, no part of which is
17 north of 68 degrees North latitude, is the gross value at the point of
18 production of the gas taxable under AS 43.55.011(e) and produced by the
19 producer from those leases or properties, less 1/12 of the producer's lease
20 expenditures under AS 43.55.165 for the calendar year applicable to the
21 gas produced by the producer from those leases or properties, as adjusted
22 under AS 43.55.170; this subparagraph does not apply to gas used in the
23 state.

24 * Sec. 19. AS 43.55.160(a), as amended by sec. 18 of this Act, is amended to read:

25 (a) Except as provided in (b) of this section, for the purposes of

26 (1) AS 43.55.011(e), the annual production tax value of the taxable

27 (A) oil and gas produced during a calendar year from leases or
28 properties in the state that include land north of 68 degrees North latitude is the
29 gross value at the point of production of the oil and gas taxable under
30 AS 43.55.011(e) and produced by the producer from those leases or properties,
31 less the producer's lease expenditures under AS 43.55.165 for the calendar year

1 applicable to the oil and gas produced by the producer from those leases or
2 properties, as adjusted under AS 43.55.170; this subparagraph does not
3 apply to gas subject to AS 43.55.011(o);

4 (B) oil and gas produced during a calendar year from leases or
5 properties in the state outside the Cook Inlet sedimentary basin, no part of
6 which is north of 68 degrees North latitude, is the gross value at the point of
7 production of the oil and gas taxable under AS 43.55.011(e) and produced by
8 the producer from those leases or properties, less the producer's lease
9 expenditures under AS 43.55.165 for the calendar year applicable to the oil
10 and gas produced by the producer from those leases or properties, as adjusted
11 under AS 43.55.170; this subparagraph does not apply to gas subject to
12 AS 43.55.011(o);

13 (C) oil produced during a calendar year from a lease or
14 property in the Cook Inlet sedimentary basin is the gross value at the point of
15 production of the oil taxable under AS 43.55.011(e) and produced by the
16 producer from that lease or property, less the producer's lease expenditures
17 under AS 43.55.165 for the calendar year applicable to the oil produced by the
18 producer from that lease or property, as adjusted under AS 43.55.170;

19 (D) gas produced during a calendar year from a lease or
20 property in the Cook Inlet sedimentary basin is the gross value at the point of
21 production of the gas taxable under AS 43.55.011(e) and produced by the
22 producer from that lease or property, less the producer's lease expenditures
23 under AS 43.55.165 for the calendar year applicable to the gas produced by the
24 producer from that lease or property, as adjusted under AS 43.55.170;

25 (E) gas produced during a calendar year from a lease or
26 property outside the Cook Inlet sedimentary basin and used in the state is the
27 gross value at the point of production of that gas taxable under
28 AS 43.55.011(e) and produced by the producer from that lease or property, less
29 the producer's lease expenditures under AS 43.55.165 for the calendar year
30 applicable to that gas produced by the producer from that lease or property, as
31 adjusted under AS 43.55.170;

1 [(F) GAS PRODUCED DURING A CALENDAR YEAR
2 FROM LEASES OR PROPERTIES IN THE STATE THAT INCLUDE
3 LAND NORTH OF 68 DEGREES NORTH LATITUDE IS THE GROSS
4 VALUE AT THE POINT OF PRODUCTION OF THE GAS TAXABLE
5 UNDER AS 43.55.011(e) AND PRODUCED BY THE PRODUCER FROM
6 THOSE LEASES OR PROPERTIES, LESS THE PRODUCER'S LEASE
7 EXPENDITURES UNDER AS 43.55.165 FOR THE CALENDAR YEAR
8 APPLICABLE TO THE GAS PRODUCED BY THE PRODUCER FROM
9 THOSE LEASES OR PROPERTIES, AS ADJUSTED UNDER AS 43.55.170;
10 THIS SUBPARAGRAPH DOES NOT APPLY TO GAS USED IN THE
11 STATE;

12 (G) GAS PRODUCED DURING A CALENDAR YEAR
13 FROM LEASES OR PROPERTIES IN THE STATE OUTSIDE THE COOK
14 INLET SEDIMENTARY BASIN, NO PART OF WHICH IS NORTH OF 68
15 DEGREES NORTH LATITUDE, IS THE GROSS VALUE AT THE POINT
16 OF PRODUCTION OF THE GAS TAXABLE UNDER AS 43.55.011(e)
17 AND PRODUCED BY THE PRODUCER FROM THOSE LEASES OR
18 PROPERTIES, LESS THE PRODUCER'S LEASE EXPENDITURES
19 UNDER AS 43.55.165 FOR THE CALENDAR YEAR APPLICABLE TO
20 THE GAS PRODUCED BY THE PRODUCER FROM THOSE LEASES OR
21 PROPERTIES, AS ADJUSTED UNDER AS 43.55.170; THIS
22 SUBPARAGRAPH DOES NOT APPLY TO GAS USED IN THE STATE;]

23 (2) AS 43.55.011(g) [AND (p)], the monthly production tax value of
24 the taxable

25 (A) oil and gas produced during a month from leases or
26 properties in the state that include land north of 68 degrees North latitude is the
27 gross value at the point of production of the oil and gas taxable under
28 AS 43.55.011(e) and produced by the producer from those leases or properties,
29 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the
30 calendar year applicable to the oil and gas produced by the producer from
31 those leases or properties, as adjusted under AS 43.55.170; this subparagraph

1 does not apply to gas subject to AS 43.55.011(o);

2 (B) oil and gas produced during a month from leases or
3 properties in the state outside the Cook Inlet sedimentary basin, no part of
4 which is north of 68 degrees North latitude, is the gross value at the point of
5 production of the oil and gas taxable under AS 43.55.011(e) and produced by
6 the producer from those leases or properties, less 1/12 of the producer's lease
7 expenditures under AS 43.55.165 for the calendar year applicable to the oil
8 and gas produced by the producer from those leases or properties, as adjusted
9 under AS 43.55.170; this subparagraph does not apply to gas subject to
10 AS 43.55.011(o);

11 (C) oil produced during a month from a lease or property in the
12 Cook Inlet sedimentary basin is the gross value at the point of production of
13 the oil taxable under AS 43.55.011(e) and produced by the producer from that
14 lease or property, less 1/12 of the producer's lease expenditures under
15 AS 43.55.165 for the calendar year applicable to the oil produced by the
16 producer from that lease or property, as adjusted under AS 43.55.170;

17 (D) gas produced during a month from a lease or property in
18 the Cook Inlet sedimentary basin is the gross value at the point of production
19 of the gas taxable under AS 43.55.011(e) and produced by the producer from
20 that lease or property, less 1/12 of the producer's lease expenditures under
21 AS 43.55.165 for the calendar year applicable to the gas produced by the
22 producer from that lease or property, as adjusted under AS 43.55.170;

23 (E) gas produced during a month from a lease or property
24 outside the Cook Inlet sedimentary basin and used in the state is the gross
25 value at the point of production of that gas taxable under AS 43.55.011(e) and
26 produced by the producer from that lease or property, less 1/12 of the
27 producer's lease expenditures under AS 43.55.165 for the calendar year
28 applicable to that gas produced by the producer from that lease or property, as
29 adjusted under AS 43.55.170 [;

30 (F) GAS PRODUCED DURING A MONTH FROM LEASES
31 OR PROPERTIES IN THE STATE THAT INCLUDE LAND NORTH OF 68

1 DEGREES NORTH LATITUDE IS THE GROSS VALUE AT THE POINT
2 OF PRODUCTION OF THE GAS TAXABLE UNDER AS 43.55.011(e)
3 AND PRODUCED BY THE PRODUCER FROM THOSE LEASES OR
4 PROPERTIES, LESS 1/12 OF THE PRODUCER'S LEASE
5 EXPENDITURES UNDER AS 43.55.165 FOR THE CALENDAR YEAR
6 APPLICABLE TO THE GAS PRODUCED BY THE PRODUCER FROM
7 THOSE LEASES OR PROPERTIES, AS ADJUSTED UNDER AS 43.55.170;
8 THIS SUBPARAGRAPH DOES NOT APPLY TO GAS USED IN THE
9 STATE;

10 (G) GAS PRODUCED DURING A MONTH FROM LEASES
11 OR PROPERTIES IN THE STATE OUTSIDE THE COOK INLET
12 SEDIMENTARY BASIN, NO PART OF WHICH IS NORTH OF 68
13 DEGREES NORTH LATITUDE, IS THE GROSS VALUE AT THE POINT
14 OF PRODUCTION OF THE GAS TAXABLE UNDER AS 43.55.011(e)
15 AND PRODUCED BY THE PRODUCER FROM THOSE LEASES OR
16 PROPERTIES, LESS 1/12 OF THE PRODUCER'S LEASE
17 EXPENDITURES UNDER AS 43.55.165 FOR THE CALENDAR YEAR
18 APPLICABLE TO THE GAS PRODUCED BY THE PRODUCER FROM
19 THOSE LEASES OR PROPERTIES, AS ADJUSTED UNDER AS 43.55.170;
20 THIS SUBPARAGRAPH DOES NOT APPLY TO GAS USED IN THE
21 STATE].

22 * Sec. 20. AS 43.55.160(a), as amended by sec. 19 of this Act, is amended to read:

23 (a) Except as provided in (b) of this section, for the purposes of

24 (1) AS 43.55.011(e), the annual production tax value of the taxable

25 (A) oil [AND GAS] produced during a calendar year from
26 leases or properties in the state that include land north of 68 degrees North
27 latitude is the gross value at the point of production of the oil [AND GAS]
28 taxable under AS 43.55.011(e) and produced by the producer from those leases
29 or properties, less the producer's lease expenditures under AS 43.55.165 for the
30 calendar year applicable to the oil [AND GAS] produced by the producer from
31 those leases or properties, as adjusted under AS 43.55.170; [THIS

1 SUBPARAGRAPH DOES NOT APPLY TO GAS SUBJECT TO
2 AS 43.55.011(o);]

3 (B) oil [AND GAS] produced during a calendar year from
4 leases or properties in the state outside the Cook Inlet sedimentary basin, no
5 part of which is north of 68 degrees North latitude, is the gross value at the
6 point of production of the oil [AND GAS] taxable under AS 43.55.011(e) and
7 produced by the producer from those leases or properties, less the producer's
8 lease expenditures under AS 43.55.165 for the calendar year applicable to the
9 oil [AND GAS] produced by the producer from those leases or properties, as
10 adjusted under AS 43.55.170; [THIS SUBPARAGRAPH DOES NOT APPLY
11 TO GAS SUBJECT TO AS 43.55.011(o);]

12 (C) oil produced during a calendar year from a lease or
13 property in the Cook Inlet sedimentary basin is the gross value at the point of
14 production of the oil taxable under AS 43.55.011(e) and produced by the
15 producer from that lease or property, less the producer's lease expenditures
16 under AS 43.55.165 for the calendar year applicable to the oil produced by the
17 producer from that lease or property, as adjusted under AS 43.55.170;

18 (D) gas produced during a calendar year from a lease or
19 property in the Cook Inlet sedimentary basin is the gross value at the point of
20 production of the gas taxable under AS 43.55.011(e) and produced by the
21 producer from that lease or property, less the producer's lease expenditures
22 under AS 43.55.165 for the calendar year applicable to the gas produced by the
23 producer from that lease or property, as adjusted under AS 43.55.170;

24 (E) gas produced during a calendar year from a lease or
25 property outside the Cook Inlet sedimentary basin and used in the state is the
26 gross value at the point of production of that gas taxable under
27 AS 43.55.011(e) and produced by the producer from that lease or property, less
28 the producer's lease expenditures under AS 43.55.165 for the calendar year
29 applicable to that gas produced by the producer from that lease or property, as
30 adjusted under AS 43.55.170;

31 (F) gas produced during a calendar year from leases or

1 properties in the state that include land north of 68 degrees North latitude
2 is the gross value at the point of production of the gas taxable under
3 AS 43.55.011(e) and produced by the producer from those leases or
4 properties, less the producer's lease expenditures under AS 43.55.165 for
5 the calendar year applicable to the gas produced by the producer from
6 those leases or properties, as adjusted under AS 43.55.170; this
7 subparagraph does not apply to gas used in the state;

8 (G) gas produced during a calendar year from leases or
9 properties in the state outside the Cook Inlet sedimentary basin, no part of
10 which is north of 68 degrees North latitude, is the gross value at the point
11 of production of the gas taxable under AS 43.55.011(e) and produced by
12 the producer from those leases or properties, less the producer's lease
13 expenditures under AS 43.55.165 for the calendar year applicable to the
14 gas produced by the producer from those leases or properties, as adjusted
15 under AS 43.55.170; this subparagraph does not apply to gas used in the
16 state;

17 (2) AS 43.55.011(g) and (q), the monthly production tax value of the
18 taxable

19 (A) oil [AND GAS] produced during a month from leases or
20 properties in the state that include land north of 68 degrees North latitude is the
21 gross value at the point of production of the oil [AND GAS] taxable under
22 AS 43.55.011(e) and produced by the producer from those leases or properties,
23 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the
24 calendar year applicable to the oil [AND GAS] produced by the producer from
25 those leases or properties, as adjusted under AS 43.55.170; [THIS
26 SUBPARAGRAPH DOES NOT APPLY TO GAS SUBJECT TO
27 AS 43.55.011(o);]

28 (B) oil [AND GAS] produced during a month from leases or
29 properties in the state outside the Cook Inlet sedimentary basin, no part of
30 which is north of 68 degrees North latitude, is the gross value at the point of
31 production of the oil [AND GAS] taxable under AS 43.55.011(e) and produced

1 by the producer from those leases or properties, less 1/12 of the producer's
2 lease expenditures under AS 43.55.165 for the calendar year applicable to the
3 oil [AND GAS] produced by the producer from those leases or properties, as
4 adjusted under AS 43.55.170; [THIS SUBPARAGRAPH DOES NOT APPLY
5 TO GAS SUBJECT TO AS 43.55.011(o);]

6 (C) oil produced during a month from a lease or property in the
7 Cook Inlet sedimentary basin is the gross value at the point of production of
8 the oil taxable under AS 43.55.011(e) and produced by the producer from that
9 lease or property, less 1/12 of the producer's lease expenditures under
10 AS 43.55.165 for the calendar year applicable to the oil produced by the
11 producer from that lease or property, as adjusted under AS 43.55.170;

12 (D) gas produced during a month from a lease or property in
13 the Cook Inlet sedimentary basin is the gross value at the point of production
14 of the gas taxable under AS 43.55.011(e) and produced by the producer from
15 that lease or property, less 1/12 of the producer's lease expenditures under
16 AS 43.55.165 for the calendar year applicable to the gas produced by the
17 producer from that lease or property, as adjusted under AS 43.55.170;

18 (E) gas produced during a month from a lease or property
19 outside the Cook Inlet sedimentary basin and used in the state is the gross
20 value at the point of production of that gas taxable under AS 43.55.011(e) and
21 produced by the producer from that lease or property, less 1/12 of the
22 producer's lease expenditures under AS 43.55.165 for the calendar year
23 applicable to that gas produced by the producer from that lease or property, as
24 adjusted under AS 43.55.170;

25 **(F) gas produced during a month from leases or properties**
26 **in the state that include land north of 68 degrees North latitude is the**
27 **gross value at the point of production of the gas taxable under**
28 **AS 43.55.011(e) and produced by the producer from those leases or**
29 **properties, less 1/12 of the producer's lease expenditures under**
30 **AS 43.55.165 for the calendar year applicable to the gas produced by the**
31 **producer from those leases or properties, as adjusted under AS 43.55.170;**

1 this subparagraph does not apply to gas used in the state;

2 (G) gas produced during a month from leases or properties
3 in the state outside the Cook Inlet sedimentary basin, no part of which is
4 north of 68 degrees North latitude, is the gross value at the point of
5 production of the gas taxable under AS 43.55.011(e) and produced by the
6 producer from those leases or properties, less 1/12 of the producer's lease
7 expenditures under AS 43.55.165 for the calendar year applicable to the
8 gas produced by the producer from those leases or properties, as adjusted
9 under AS 43.55.170; this subparagraph does not apply to gas used in the
10 state.

11 * Sec. 21. AS 43.55.165(h) is amended to read:

12 (h) The department shall adopt regulations that provide for reasonable
13 methods of allocating costs between oil and gas, between gas subject to
14 AS 43.55.011(o) and other gas, and between leases or properties in those
15 circumstances where an allocation of costs is required to determine lease expenditures
16 that are costs of exploring for, developing, or producing oil deposits or costs of
17 exploring for, developing, or producing gas deposits, or that are costs of exploring for,
18 developing, or producing oil or gas deposits located within different leases or
19 properties. When determining a reasonable method of allocating lease
20 expenditures between the production of oil and the production of gas, the
21 department shall consider allocating lease expenditures in proportion to the BTU
22 equivalent barrels of oil produced and gas produced from each lease or property.

23 * Sec. 22. AS 43.55.170 is amended by adding a new subsection to read:

24 (d) The department shall adopt regulations that provide for reasonable
25 methods of allocating the adjustments to a producer's lease expenditures in (a) of this
26 section and the payments and credits described in (b) of this section between oil and
27 gas, between gas subject to AS 43.55.011(o) and other gas, and between leases or
28 properties in those circumstances where an allocation of costs is required to determine
29 lease expenditures that are costs of exploring for, developing, or producing oil
30 deposits, or costs of exploring for, developing, or producing gas deposits, or that are
31 costs of exploring for, developing, or producing oil or gas deposits located within

1 different leases or properties. When determining a reasonable method of allocating the
2 adjustments to a producer's lease expenditures between the production of oil and the
3 production of gas, the department shall consider allocating the adjustments in
4 proportion to the lease expenditures allocated to the production of oil and the
5 production of gas under regulations adopted by the department under
6 AS 43.55.165(h).

7 * **Sec. 23.** AS 43.55.011(p) is repealed.

8 * **Sec. 24.** The uncodified law of the State of Alaska is amended by adding a new section to
9 read:

10 TRANSITION; REGULATIONS; PAYMENT OF TAX; FILING OF REPORTS. If
11 secs. 1, 4, 7, 10, 12, 15, and 18 of this Act take effect, the Department of Revenue shall adopt
12 regulations providing for the payment of tax and the filing of reports required for the period in
13 which secs. 1, 4, 7, 10, 12, 15, and 18 of this Act are in effect.

14 * **Sec. 25.** The uncodified law of the State of Alaska is amended by adding a new section to
15 read:

16 CONDITIONAL EFFECT OF SECS. 1, 2, 4, 5, 7, 8, 10, 12, 13, 15, 16, 18, 19, AND
17 23 OF THIS ACT; NOTICE. (a) Sections 1, 2, 4, 5, 7, 8, 10, 12, 13, 15, 16, 18, 19, and 23 of
18 this Act take effect only if secs. 21 and 22 of this Act take effect before April 29, 2010.

19 (b) The commissioner of revenue shall notify the revisor of statutes of the date of the
20 start of the first binding open season for the project licensed under AS 43.90 (Alaska Gasline
21 Inducement Act).

22 * **Sec. 26.** The uncodified law of the State of Alaska is amended by adding a new section to
23 read:

24 CONDITIONAL EFFECT OF SECS. 3, 6, 9, 11, 14, 17, AND 20 OF THIS ACT;
25 NOTICE. (a) Sections 3, 6, 9, 11, 14, 17, and 20 of this Act take effect only if more than
26 1,500,000,000 cubic feet of natural gas a day that is produced in the state is tendered for
27 shipment through a natural gas pipeline project in the state to a market in Canada or the 48
28 contiguous states, or to a gas liquefaction facility in the state for shipment in a liquefied state
29 by marine transportation to a market outside of the state.

30 (b) The commissioner of revenue shall notify the revisor of statutes of the date that
31 natural gas was first tendered for shipment under the circumstances described in (a) of this

1 section.

2 * **Sec. 27.** If secs. 1, 4, 7, 10, 12, 15, and 18 of this Act take effect, they take effect April 29,
3 2010.

4 * **Sec. 28.** If secs. 2, 5, 8, 13, 16, 19, and 23 of this Act take effect, they take effect on the
5 first day immediately following the date on which the open season starts for the project
6 licensed under AS 43.90.

7 * **Sec. 29.** If secs. 3, 6, 9, 11, 14, 17, and 20 take effect, they take effect on the first day of
8 the month immediately following the date on which the condition in sec. 26(a) of this Act is
9 met.

10 * **Sec. 30.** Except as provided in secs. 27 - 29 of this Act, this Act takes effect immediately
11 under AS 01.10.070(c).

Explanation of Amendments to CSSB 305 v. W.A and M

in House Resources

Department of Revenue

April 13, 2010

Current Law:

SALES PROCEEDS

-Transportation costs

= Gross Value of Oil and Gas at Point of Production
(GV at POP) .150

Calculated For Each Segment:

- A. NS oil and gas
- B. Mid Earth oil and gas
- C. CI oil
- D. CI gas
- E. Gas used in state

Annual Production Tax Value
(PTV) .160(a)(1)

$$GV_A \text{ at POP} - LE_A = PTV_A$$

$$GV_B \text{ at POP} - LE_B = PTV_B$$

$$GV_C \text{ at POP} - LE_C = PTV_C$$

$$GV_D \text{ at POP} - LE_D = PTV_D$$

$$GV_E \text{ at POP} - LE_E = PTV_E$$

*Each PTV cannot be < 0

*Excess LEs in each segment get
carried forward as NOL

Monthly Production Tax Value
(PTV) .160(a)(2)

$$GV_A \text{ at POP} - LE_A = PTV_A$$

$$GV_B \text{ at POP} - LE_B = PTV_B$$

$$GV_C \text{ at POP} - LE_C = PTV_C$$

$$GV_D \text{ at POP} - LE_D = PTV_D$$

$$GV_E \text{ at POP} - LE_E = PTV_E$$

* Each PTV cannot be < 0

Current Law:

Calculating the Progressivity Rate .011(g)

Monthly PTV .160(a)(2)

$GV_A \text{ at POP} - LE_A = PTV_A$

$GV_B \text{ at POP} - LE_B = PTV_B$

$GV_C \text{ at POP} - LE_C = PTV_C$

$GV_D \text{ at POP} - LE_D = PTV_D$

$GV_E \text{ at POP} - LE_E = PTV_E$

Add
together



Total BOEs of all Oil
and Gas in Segments
A-E (per regulation)



Average
Monthly
Production Tax
Value

If Average Monthly Production Tax Value is > \$30
then 0.4% progressivity tax rate for each \$1 over
\$30

CSSB305 v. W.A
 CSSB305 v. M

Amendment to (g) and (p): Weighted Average PTV Calculation

Segments

- A. NS oil
- B. Mid Earth oil
- C. CI oil
- D. CI gas
- E. Gas used in state
- F. NS Gas
- G. Mid Earth gas

Annual PTV .160(a)(1)*

$$GV_A \text{ at POP} - LE_A = PTV_A$$

$$GV_B \text{ at POP} - LE_B = PTV_B$$

$$GV_C \text{ at POP} - LE_C = PTV_C$$

$$GV_D \text{ at POP} - LE_D = PTV_D$$

$$GV_E \text{ at POP} - LE_E = PTV_E$$

$$GV_F \text{ at POP} - LE_F = PTV_F$$

$$GV_G \text{ at POP} - LE_G = PTV_G$$

*Each PTV cannot be < 0

* Excess LEs for each segment get carried forward as NOL

Monthly PTV .160(a)(2)*

$$GV_A \text{ at POP} - LE_A = PTV_A$$

$$GV_B \text{ at POP} - LE_B = PTV_B$$

$$GV_C \text{ at POP} - LE_C = PTV_C$$

$$GV_D \text{ at POP} - LE_D = PTV_D$$

$$GV_E \text{ at POP} - LE_E = PTV_E$$

$$GV_F \text{ at POP} - LE_F = PTV_F$$

$$GV_G \text{ at POP} - LE_G = PTV_G$$

* Each PTV cannot be < 0

CSSB305 v. W.A
 CSSB305 v. M

Amendment to (g) and (p) to ensure weighted average calculation

Calculating the Progressivity Rate .011(g)* and .011(p)*

Monthly PTV .160(a)(2)*

$GV_A \text{ at POP} - LE_A = PTV_A$
 $GV_B \text{ at POP} - LE_B = PTV_B$
 $GV_C \text{ at POP} - LE_C = PTV_C$
 $GV_D \text{ at POP} - LE_D = PTV_D$
 $GV_E \text{ at POP} - LE_E = PTV_E$

Add together



Total BOEs of all Oil and Gas in Segments A-E



Average Monthly Production Tax Value .011(g)*

Monthly PTV .160(a)(2)*

$GV_F \text{ at POP} - LE_F = PTV_F$
 $GV_G \text{ at POP} - LE_G = PTV_G$

Add together



Total BOEs of all Oil and Gas in Segments F-G



Average Monthly Production Tax Value .011(p)*

If Average Monthly Production Tax Value is > \$30 then 0.4% progressivity tax rate for each \$1 over \$30 under both (g) and (p)

Why Version M?

Lease Expenditures from NS properties that are not yet producing oil or gas, have very limited opportunity to offset the gross value of other existing NS production, and also can't be used to lower progressivity rate.

Current Law Segments:

- A. NS oil and gas
- B. Mid Earth oil and gas
- C. CI oil
- D. CI gas
- E. Gas used in state



CSSB 305 Segments

- A. NS oil
- B. Mid Earth oil
- C. CI oil
- D. CI gas
- E. Gas used in state
- F. NS Gas
- G. Mid Earth gas

Remember: Lease Expenditures stay inside their Segment. If excess, they become NOLs and .

Version M protects the greater options to offset lease expenditures by moving back and forth between CSSB 305 segments and Current Law segments until big gas fields are developed.

Why Version M?

Lease Expenditures from NS properties that are not yet producing oil or gas, also can't be used to lower progressivity rate.

Monthly PTV .160(a)(2)*

- $GV_A \text{ at POP} - LE_A = PTV_A$
- $GV_B \text{ at POP} - LE_B = PTV_B$
- $GV_C \text{ at POP} - LE_C = PTV_C$
- $GV_D \text{ at POP} - LE_D = PTV_D$
- $GV_E \text{ at POP} - LE_E = PTV_E$

Add together



NS OIL

Total BOEs of all Oil and Gas in Segments A-E



Average Monthly Production Tax Value .011(g)*

Monthly PTV .160(a)(2)*

- $GV_F \text{ at POP} - LE_F = PTV_F$
- $GV_G \text{ at POP} - LE_G = PTV_G$

Add together



NS GAS

Total BOEs of all Oil and Gas in Segments F-G



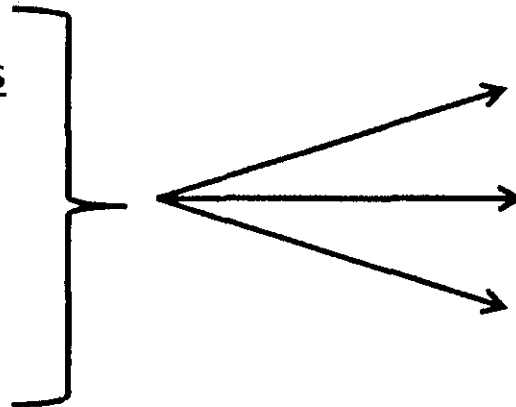
Average Monthly Production Tax Value .011(p)*

CSSB305 v. W.A

SOLUTION: Option 1

Amendment to 165(h) - Gross Value at POP Option
How to allocate Lease Expenditures to Other Production
when no sustained production yet.

Lease Expenditures
w/o production
located
anywhere in state
except
Cook Inlet *



THREE AREAS OF STATE:

- 1) NS
- 2) Mid Earth
- 3) CI

RULE: LEs are allocated to oil and gas produced among three areas of state in proportion to the Gross Value of oil and gas at POP in each Area.

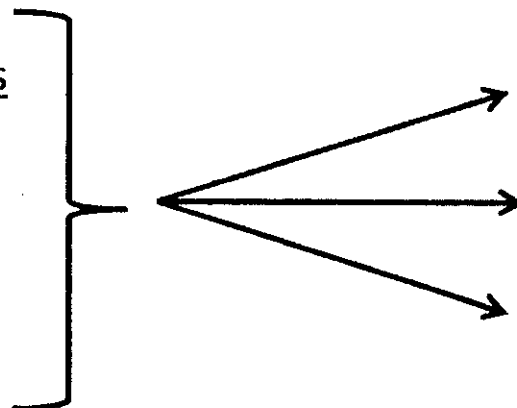
* Lease expenditures for CI allocated on basis of regulations.

CSSB305 v. W.A

**SOLUTION:
Option 2**

Amendment to .165(h) - BOE Option
How to allocate Lease Expenditures to Other Production
when no sustained production yet

Lease Expenditures
w/o production
located
anywhere in state
except
Cook Inlet*

THREE AREAS OF STATE:

- 1) NS
- 2) Mid Earth
- 3) CI

RULE: LEs are allocated to oil and gas produced among three areas of state in proportion to the volume of oil and gas in BOEs in each Area.

* Lease expenditures for CI allocated on basis of regulations.

The End

Response to Request from Rep. Tuck

COMPARISON OF REVENUE FROM
PPT (DE-COUPLED)
VERSUS
STATUS QUO

April 13, 2010

Alaska Department of Revenue

Description of the Analysis

2

- Compared the Overall State tax revenue generated by the status quo combined tax (ACES) versus the PPT tax system as if it had been de-coupled.
- Primary difference between the two:
 - PPT progressivity calculation kicks off at \$40 profit per barrel, and has a slope of .25% per dollar; compared to status quo of a \$30 kick off, and .4% slope;
 - PPT base tax rate was 22.5% compared to 25% status quo.

Example Cases

State Production Tax Revenue

Oil: 500 Mbbbl/d and Gas: 4.5 Bcf/d

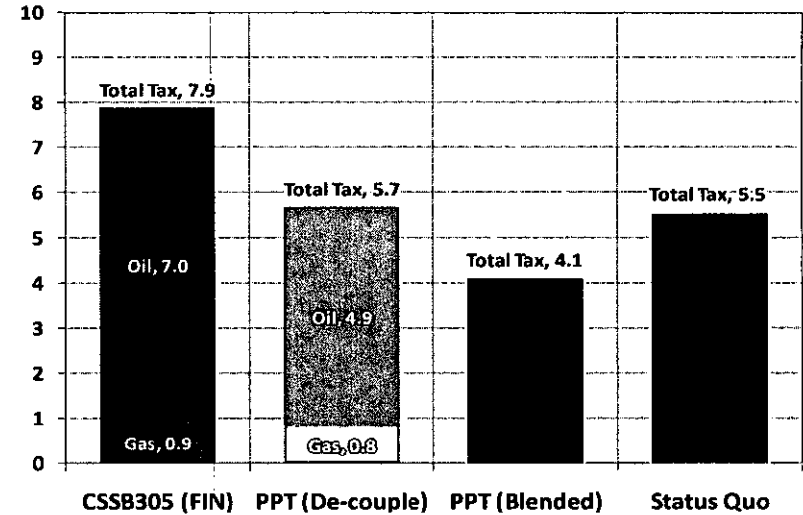
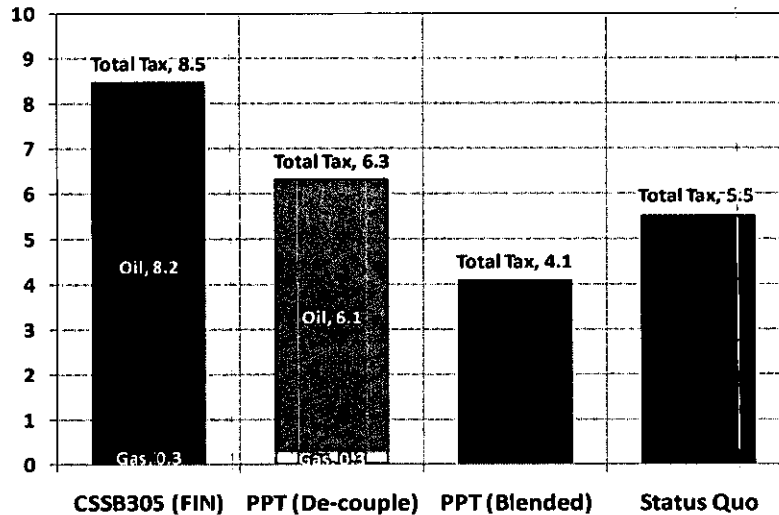
Capex: \$2.2Bn and Opex: \$2.2Bn

3

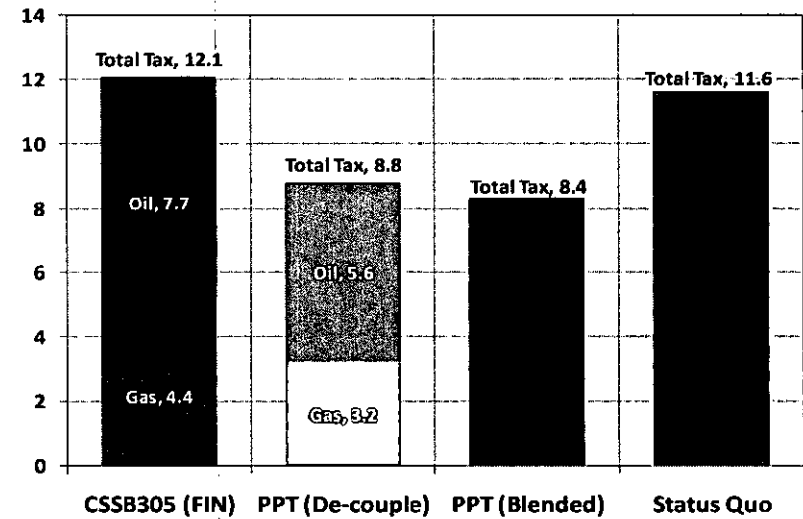
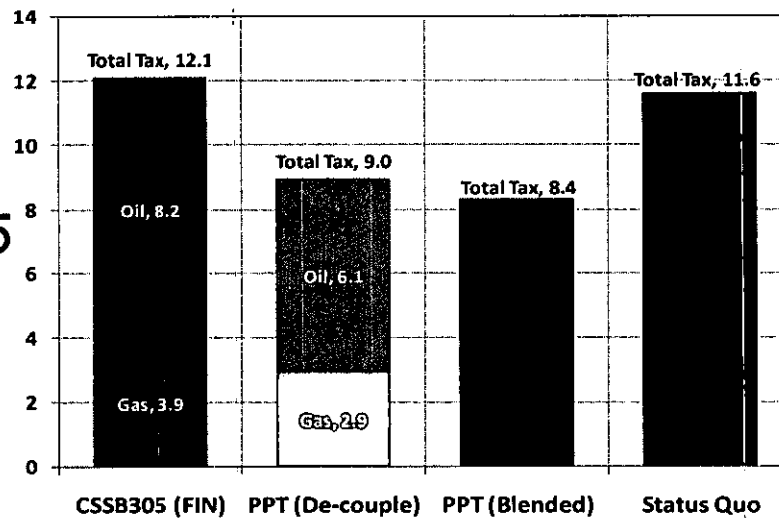
BOE

PoP

\$120/\$8
(15:1)



\$120/\$15
(8:1)



Total Tax Take Comparison

4

- Model Assumptions:
 - One year snapshot
 - 4.5 Bcf/d and either 500 Mbbl/d or 200 Mbbl/d
 - Total Opex = \$2.2 Bn and Total Capex = \$2.2 Bn

- Ran multiple cases varying oil price from 40 to 200 \$/bbl and gas price parity from 6 to 26

- Ran the above cases for each of BOE, PoP and Fixed cost allocation methodology

4/13/2010

Total Tax PPT ("de-coupled") less Status Quo

Cost Allocation: BOE Basis

5

Oil: 500 Mbb/d and Gas: 4.5 Bcf/d
Capex: \$2.2Bn and Opex: \$2.2Bn

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	(0.1)	(0.2)	(0.3)	(0.8)	(1.5)	(2.2)	(3.0)	(3.9)	(4.9)	(5.2)	(5.1)	(4.8)	(4.6)	(4.7)	(5.0)	(5.9)	(7.0)
8	0.4	(0.1)	(0.2)	(0.0)	(0.3)	(0.8)	(1.4)	(2.0)	(2.7)	(3.4)	(4.2)	(4.5)	(4.5)	(4.9)	(5.2)	(5.6)	(5.9)
10	0.4	0.4	(0.0)	0.1	0.2	0.0	(0.3)	(0.6)	(1.1)	(1.7)	(2.3)	(2.9)	(3.7)	(4.2)	(4.6)	(5.1)	(5.5)
12	0.4	0.7	0.4	0.2	0.3	0.4	0.3	0.2	(0.1)	(0.4)	(0.8)	(1.3)	(1.9)	(3.0)	(3.8)	(4.3)	(4.8)
14	0.4	0.7	0.6	0.5	0.5	0.7	0.7	0.7	0.6	0.4	0.2	(0.0)	(0.5)	(1.5)	(2.7)	(3.6)	(4.0)
16	0.4	0.7	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.0	0.9	0.8	0.5	(0.3)	(1.3)	(2.4)	(3.3)
18	0.4	0.7	1.0	1.0	1.0	1.1	1.3	1.3	1.3	1.4	1.4	1.4	1.2	0.5	(0.3)	(1.2)	(2.3)
20	0.4	0.7	1.1	1.1	1.2	1.3	1.5	1.7	1.6	1.7	1.8	1.8	1.7	1.1	0.4	(0.4)	(1.3)
22	0.4	0.7	1.1	1.3	1.3	1.5	1.7	1.9	2.0	2.0	2.0	2.2	2.2	1.6	1.0	0.3	(0.5)
24	0.4	0.7	1.1	1.4	1.5	1.6	1.9	2.2	2.3	2.4	2.4	2.5	2.5	2.0	1.5	0.8	0.1
26	0.4	0.7	1.1	1.5	1.6	1.7	2.0	2.3	2.5	2.6	2.8	2.9	2.8	2.4	1.9	1.2	0.6

 PPT > STATUS QUO

 PPT = STATUS QUO

 PPT < STATUS QUO

4/13/2010

Total Tax PPT ("de-coupled") less Status Quo

Cost Allocation: Point of Production (PoP) Basis

6

Oil: 500 Mbb/d and Gas: 4.5 Bcf/d
Capex: \$2.2Bn and Opex: \$2.2Bn

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	(0.1)	(0.2)	(0.3)	(0.9)	(1.5)	(2.2)	(3.0)	(3.9)	(5.0)	(5.2)	(5.1)	(4.8)	(4.5)	(4.7)	(5.0)	(5.9)	(7.0)
8	0.0	(0.1)	(0.2)	(0.2)	(0.5)	(1.0)	(1.6)	(2.2)	(2.8)	(3.5)	(4.4)	(4.7)	(4.5)	(4.8)	(5.2)	(5.5)	(5.8)
10	0.0	(0.1)	(0.2)	(0.2)	(0.1)	(0.3)	(0.6)	(1.0)	(1.5)	(2.1)	(2.6)	(3.2)	(3.9)	(4.2)	(4.6)	(5.0)	(5.5)
12	0.0	0.1	(0.1)	(0.2)	(0.0)	0.1	(0.1)	(0.3)	(0.6)	(1.0)	(1.4)	(1.9)	(2.3)	(3.1)	(3.9)	(4.4)	(4.8)
14	0.0	0.1	(0.0)	(0.2)	(0.0)	0.2	0.2	0.1	(0.0)	(0.2)	(0.5)	(0.8)	(1.2)	(1.8)	(2.9)	(3.7)	(4.1)
16	0.0	0.1	0.2	(0.1)	(0.1)	0.2	0.4	0.4	0.3	0.2	0.1	(0.1)	(0.3)	(0.7)	(1.7)	(2.7)	(3.6)
18	0.0	0.1	0.4	0.1	(0.1)	0.2	0.5	0.5	0.6	0.5	0.5	0.4	0.3	0.1	(0.7)	(1.6)	(2.7)
20	0.0	0.1	0.5	0.3	0.1	0.1	0.4	0.6	0.7	0.8	0.8	0.8	0.8	0.7	(0.0)	(0.8)	(1.7)
22	0.0	0.1	0.5	0.4	0.3	0.3	0.4	0.7	0.8	0.9	1.0	1.1	1.1	1.1	0.5	(0.2)	(1.0)
24	0.0	0.1	0.5	0.5	0.4	0.4	0.6	0.8	0.9	1.1	1.2	1.3	1.4	1.5	1.0	0.3	(0.4)
26	0.0	0.1	0.5	0.6	0.5	0.6	0.7	0.9	1.0	1.1	1.3	1.5	1.6	1.7	1.3	0.7	0.0

PPT > STATUS QUO

PPT = STATUS QUO

PPT < STATUS QUO

4/13/2010

Total Tax PPT ("de-coupled") less Status Quo

Cost Allocation: BOE Basis

7

Oil: 200 Mbb/d and Gas: 4.5 Bcf/d
Capex: \$2.2Bn and Opex: \$2.2Bn

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	(0.1)	(0.2)	(0.3)	(0.8)	(1.3)	(1.8)	(2.5)	(3.2)	(4.0)	(3.9)	(3.8)	(3.6)	(3.5)	(3.4)	(4.0)	(4.7)
8	0.0	0.0	(0.1)	(0.1)	(0.0)	(0.2)	(0.5)	(1.0)	(1.4)	(1.8)	(2.3)	(2.9)	(3.5)	(3.7)	(3.9)	(4.0)	(4.1)
10	0.0	0.0	0.1	(0.0)	0.0	0.1	0.2	0.0	(0.2)	(0.6)	(0.9)	(1.2)	(1.6)	(2.2)	(2.9)	(3.6)	(3.9)
12	0.0	0.0	0.1	0.3	0.2	0.2	0.3	0.5	0.4	0.3	0.1	(0.1)	(0.4)	(0.9)	(1.4)	(2.0)	(2.6)
14	0.0	0.0	0.1	0.3	0.5	0.4	0.4	0.6	0.7	0.8	0.7	0.7	0.5	0.2	(0.3)	(0.8)	(1.3)
16	0.0	0.0	0.1	0.3	0.6	0.7	0.6	0.6	0.8	1.0	1.1	1.1	1.1	0.9	0.6	0.2	(0.3)
18	0.0	0.0	0.1	0.3	0.6	0.9	0.9	0.8	0.9	1.0	1.3	1.4	1.5	1.3	1.1	0.8	0.5
20	0.0	0.0	0.1	0.3	0.6	0.9	1.1	1.1	1.1	1.2	1.3	1.6	1.8	1.7	1.5	1.3	1.0
22	0.0	0.0	0.1	0.3	0.6	0.9	1.2	1.2	1.3	1.4	1.5	1.7	1.9	1.9	1.8	1.6	1.4
24	0.0	0.0	0.1	0.3	0.6	0.9	1.2	1.4	1.5	1.6	1.7	1.9	2.1	2.1	2.0	1.9	1.7
26	0.0	0.0	0.1	0.3	0.6	0.9	1.2	1.5	1.6	1.7	1.9	2.0	2.2	2.3	2.1	2.1	2.0

PPT > STATUS QUO

PPT = STATUS QUO

PPT < STATUS QUO

4/13/2010

Total Tax PPT ("de-coupled") less Status Quo

Cost Allocation: Point of Production (PoP) Basis

8

Oil: 200 Mbb/d and Gas: 4.5 Bcf/d
Capex: \$2.2Bn and Opex: \$2.2Bn

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	(0.1)	(0.2)	(0.3)	(0.9)	(1.3)	(1.9)	(2.5)	(3.2)	(4.0)	(4.0)	(3.8)	(3.6)	(3.5)	(3.4)	(4.0)	(4.7)
8	0.0	0.0	(0.1)	(0.1)	(0.1)	(0.3)	(0.7)	(1.1)	(1.5)	(1.9)	(2.4)	(3.0)	(3.6)	(3.7)	(3.9)	(4.0)	(4.1)
10	0.0	0.0	0.0	(0.1)	(0.1)	(0.1)	(0.0)	(0.2)	(0.5)	(0.9)	(1.2)	(1.5)	(1.9)	(2.3)	(2.9)	(3.6)	(3.8)
12	0.0	0.0	0.0	0.0	(0.1)	(0.1)	(0.0)	0.1	0.0	(0.1)	(0.4)	(0.6)	(0.9)	(1.1)	(1.5)	(2.0)	(2.7)
14	0.0	0.0	0.0	0.0	(0.1)	(0.1)	(0.0)	0.1	0.2	0.2	0.1	0.0	(0.1)	(0.3)	(0.6)	(1.0)	(1.5)
16	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.1)	0.0	0.2	0.3	0.4	0.4	0.3	0.2	0.1	(0.2)	(0.6)
18	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.0)	0.1	0.3	0.5	0.6	0.6	0.6	0.6	0.4	0.1
20	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.0)	0.1	0.2	0.4	0.6	0.7	0.8	0.8	0.9	0.6
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	0.2	0.4	0.6	0.8	0.9	1.0	1.1	1.0
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.0)	0.1	0.3	0.5	0.8	1.0	1.1	1.2	1.2
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	(0.0)	0.1	0.3	0.5	0.7	1.0	1.2	1.3	1.4

PPT > STATUS QUO

PPT = STATUS QUO

PPT < STATUS QUO

4/13/2010

Observations

9

- In many of the instances, the status quo combined tax would result in more overall tax revenue than PPT decoupled.
- Provides insight into the perception of the “appropriate” state share of oil and gas revenues once a major gas sale occurs.
- Results are an interesting reflection on whether the state is “losing” revenue under a combined tax system.

CSSB305 (FIN) COST ALLOCATION SENSITIVITY

April 13, 2010

Alaska Department of Revenue

Methodology

2

- Model Assumptions:
 - One year snapshot
 - 4.5 Bcf/d and 500 Mbbl/d
 - (additional sensitivity of 4.5 Bcf/d and 200 Mbbl/d)
 - Total Opex = \$2.2 Bn and Total Capex = \$2.2 Bn

- Ran multiple cases varying oil price from 40 to 200 \$/bbl and gas price parity from 6 to 26
- Ran the above cases for each of BOE, PoP and calculated the difference

Total Tax CSSB305 (FIN)

PoP less BOE Cost Allocation

8

Oil: 500 Mbb/d and Gas: 4.5 Bcf/d
Capex: \$2.2Bn and Opex: \$2.2Bn

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
8	(0.5)	(0.1)	(0.2)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.0)	(0.0)	0.0	0.0	0.1	0.1	(0.1)	(0.1)	(0.1)
10	(0.5)	(0.5)	(0.4)	(0.4)	(0.5)	(0.5)	(0.6)	(0.6)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	0.0	0.0
12	(0.5)	(0.7)	(0.8)	(0.7)	(0.6)	(0.7)	(0.7)	(0.8)	(0.5)	(0.4)	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)
14	(0.5)	(0.7)	(1.0)	(1.0)	(0.9)	(0.8)	(0.9)	(1.0)	(0.6)	(0.6)	(0.6)	(0.5)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)
16	(0.5)	(0.7)	(1.0)	(1.3)	(1.2)	(1.1)	(1.0)	(1.1)	(0.7)	(0.6)	(0.7)	(0.7)	(0.7)	(0.6)	(0.5)	(0.5)	(0.5)
18	(0.5)	(0.7)	(1.0)	(1.3)	(1.5)	(1.4)	(1.4)	(1.3)	(0.8)	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)	(0.8)	(0.7)	(0.6)
20	(0.5)	(0.7)	(1.0)	(1.3)	(1.5)	(1.7)	(1.6)	(1.6)	(1.0)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)
22	(0.5)	(0.7)	(1.0)	(1.3)	(1.5)	(1.7)	(1.9)	(1.9)	(1.3)	(1.0)	(0.8)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(1.0)
24	(0.5)	(0.7)	(1.0)	(1.3)	(1.5)	(1.7)	(1.9)	(2.1)	(1.6)	(1.2)	(1.1)	(0.9)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)
26	(0.5)	(0.7)	(1.0)	(1.3)	(1.5)	(1.7)	(1.9)	(2.1)	(1.8)	(1.4)	(1.3)	(1.1)	(1.0)	(1.0)	(1.0)	(1.0)	(1.1)

 PoP > BOE

 PoP = BOE

 PoP < BOE

Total Tax CSSB305 (FIN)

PoP less BOE Cost Allocation

Oil: 200 Mbbl/d and Gas: 4.5 Bcf/d
Capex: \$2.2Bn and Opex: \$2.2Bn

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.0	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
8	0.0	(0.0)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.0)	0.0	0.0	0.0	0.1	(0.0)	(0.0)	(0.0)
10	0.0	(0.0)	(0.3)	(0.2)	(0.3)	(0.4)	(0.4)	(0.5)	(0.3)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	0.0
12	0.0	(0.0)	(0.3)	(0.6)	(0.5)	(0.5)	(0.6)	(0.6)	(0.6)	(0.4)	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.1)
14	0.0	(0.0)	(0.3)	(0.6)	(0.9)	(0.8)	(0.7)	(0.8)	(0.7)	(0.6)	(0.5)	(0.5)	(0.5)	(0.3)	(0.3)	(0.3)	(0.3)
16	0.0	(0.0)	(0.3)	(0.6)	(0.9)	(1.1)	(1.1)	(0.9)	(0.9)	(0.8)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.5)	(0.4)
18	0.0	(0.0)	(0.3)	(0.6)	(0.9)	(1.3)	(1.4)	(1.3)	(1.1)	(0.9)	(0.8)	(0.7)	(0.7)	(0.7)	(0.7)	(0.8)	(0.7)
20	0.0	(0.0)	(0.3)	(0.6)	(0.9)	(1.3)	(1.7)	(1.6)	(1.5)	(1.2)	(0.9)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.9)
22	0.0	(0.0)	(0.3)	(0.6)	(0.9)	(1.3)	(1.8)	(1.9)	(1.8)	(1.5)	(1.2)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
24	0.0	(0.0)	(0.3)	(0.6)	(0.9)	(1.3)	(1.8)	(2.1)	(2.0)	(1.8)	(1.6)	(1.2)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
26	0.0	(0.0)	(0.3)	(0.6)	(0.9)	(1.3)	(1.8)	(2.2)	(2.3)	(2.1)	(1.8)	(1.5)	(1.3)	(1.2)	(1.1)	(1.1)	(1.1)

PoP > BOE

PoP = BOE

PoP < BOE

Gas Tax CSSB305 (FIN)

PoP less BOE Cost Allocation

5

Oil: 500 Mbb/d and Gas: 4.5 Bcf/d
Capex: \$2.2Bn and Opex: \$2.2Bn

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
8	0.0	0.2	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.4
10	0.0	0.0	0.2	0.5	0.5	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7
12	0.0	0.0	0.1	0.2	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8
14	0.0	0.0	0.0	0.1	0.2	0.4	0.6	0.6	0.5	0.5	0.5	0.6	0.7	0.7	0.7	0.8	0.8
16	0.0	0.0	0.0	0.0	0.1	0.2	0.4	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.8	0.8
18	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.7
20	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4	0.5	0.7	0.7	0.7	0.6	0.6	0.6	0.6
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4	0.5	0.6	0.7	0.7	0.7	0.7	0.7
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4	0.5	0.6	0.7	0.7	0.7	0.7
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.5	0.6	0.7	0.7	0.7

 PoP > BOE

 PoP = BOE

 PoP < BOE

Gas Tax CSSB305 (FIN)

PoP less BOE Cost Allocation

6

Oil: 200 Mbb/d and Gas: 4.5 Bcf/d
Capex: \$2.2Bn and Opex: \$2.2Bn

Gas Price Parity

Oil Price (\$/bbl)

	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
6	0.0	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
8	0.0	0.0	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.3	0.3	0.3
10	0.0	0.0	0.0	0.2	0.4	0.4	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6
12	0.0	0.0	0.0	0.0	0.2	0.4	0.5	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6
14	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.7	0.7
16	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.5	0.6	0.6	0.5	0.5	0.5	0.6	0.7	0.7
18	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.7	0.7	0.6	0.6	0.6
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.7	0.7	0.7	0.7
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.7
26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.7

 PoP > BOE

 PoP = BOE

 PoP < BOE

Explanation of Amendment WA.2 to CSSB 305(FIN) (title am)

This amendment repeals the 5% net profit tax cap on gas sold in-state for thirty days following the immediate effective date of the act. After thirty days the 5% in-state tax cap is reenacted.

The reason for the temporary repeal of the in-state cap is that if a producer bids North Slope gas at the initial season and the tax regime is challenged in federal court by buyers once gas flows because their price is higher based on the differential taxation given to Alaska use gas, I believe this would be a violation of the Commerce Clause of the US Constitution. I believe that they would propose the remedy of lowering the export tax rate to the same as the in-state use rate. I think there is a good probability that the federal court would order that proposed remedy instead of allowing the State to repeal the in-state rate at that time as cases are decided on the facts at time of suit not later remedies.

This could mean that the state revenue from the gasline would be almost nothing and would be fixed for the first 10 years of gas flow by the May 1 2010 'contract term' in AGIA if for the gas bid at the start of the first binding open season. Since almost no gas is being sold off the North Slope now, repeal of this provision would not increase anyone's current taxes on gas but would eliminate a huge potential future revenue decrease which is the intent of the bill.

AMENDMENT

OFFERED IN THE HOUSE

BY REPRESENTATIVE SEATON

TO: CSSB 305(FIN)(title am)

1 Page 1, line 2:

2 Delete "oil,"

3 Insert "oil produced in the state and"

4

5 Page 1, lines 2 - 3:

6 Delete ", and gas produced outside of the Cook Inlet sedimentary basin and used
7 in the state"

8

9 Page 1, lines 10 - 11:

10 Delete "and not used in the state"

11

12 Page 2, line 17:

13 Delete "(f), (j), (k), and (o)"

14 Insert "(f), (j), and (k) [(f), (j), (k), AND (o)]

15

16 Page 2, following line 24:

17 Insert a new bill section to read:

18 "** Sec. 3. AS 43.55.011(f) is amended to read:

19 (f) The levy of tax under this section for oil and gas produced north of 68
20 degrees North latitude, other than oil and gas production subject to (i) of this section
21 [AND GAS SUBJECT TO (o) OF THIS SECTION], may not be less than

22 (1) four percent of the gross value at the point of production when the
23 average price per barrel for Alaska North Slope crude oil for sale on the United States

1 West Coast during the calendar year for which the tax is due is more than \$25;

2 (2) three percent of the gross value at the point of production when the
3 average price per barrel for Alaska North Slope crude oil for sale on the United States
4 West Coast during the calendar year for which the tax is due is over \$20 but not over
5 \$25;

6 (3) two percent of the gross value at the point of production when the
7 average price per barrel for Alaska North Slope crude oil for sale on the United States
8 West Coast during the calendar year for which the tax is due is over \$17.50 but not
9 over \$20;

10 (4) one percent of the gross value at the point of production when the
11 average price per barrel for Alaska North Slope crude oil for sale on the United States
12 West Coast during the calendar year for which the tax is due is over \$15 but not over
13 \$17.50; or

14 (5) zero percent of the gross value at the point of production when the
15 average price per barrel for Alaska North Slope crude oil for sale on the United States
16 West Coast during the calendar year for which the tax is due is \$15 or less."

17
18 Renumber the following bill sections accordingly.

19
20 Page 2, line 27:

21 Delete "AS 43.55.160(a)(2)(A) - (E)"

22 Insert "AS 43.55.160(a)(2)(A) - (D)"

23
24 Page 3, line 1:

25 Delete " , "

26 Insert "and"

27
28 Page 3, lines 2 - 4:

29 Delete ", and gas produced during the month from a lease or property outside the
30 Cook Inlet sedimentary basin and used in the state"

1 Page 3, line 6:

2 Delete "AS 43.55.160(a)(2)(A) - (E)"

3 Insert "AS 43.55.160(a)(2)(A) - (D)"

4

5 Page 3, line 9:

6 Delete "AS 43.55.160(a)(2)(A) - (E)"

7 Insert "AS 43.55.160(a)(2)(A) - (D)"

8

9 Page 3, line 12:

10 Delete "AS 43.55.160(a)(2)(A) - (E)"

11 Insert "AS 43.55.160(a)(2)(A) - (D)"

12

13 Page 3, line 16:

14 Delete "AS 43.55.160(a)(2)(A) - (E)"

15 Insert "AS 43.55.160(a)(2)(A) - (D)"

16

17 Page 3, following line 18:

18 Insert a new bill section to read:

19 **** Sec. 5.** AS 43.55.011(m) is amended to read:

20 (m) Notwithstanding any contrary provision of AS 38.05.180(i),
 21 AS 41.09.010, AS 43.55.024, or 43.55.025, the department shall provide by regulation
 22 a method to ensure that, for a calendar year for which a producer's tax liability is
 23 limited by **(j) or (k)** [(j), (k), OR (o)] of this section, tax credits otherwise available
 24 under AS 38.05.180(i), AS 41.09.010, AS 43.55.024, or 43.55.025 and allocated to
 25 gas subject to the limitations in **(j) or (k)** [(j), (k), AND (o)] of this section are
 26 accounted for as though the credits had been applied first against a tax liability
 27 calculated without regard to the limitations under **(j) or (k)** [(j), (k), AND (o)] of this
 28 section so as to reduce the tax liability to the maximum amount provided for under **(j)**
 29 [(j) OR (o)] of this section for the production of gas or (k) of this section for the
 30 production of oil. The regulation must provide for a reasonable method to allocate tax
 31 credits to gas subject to **(j)** [(j) AND (o)] of this section. Only the amount of a tax

1 credit remaining after the accounting provided for under this subsection may be used
2 for a later calendar year, transferred to another person, or applied against a tax levied
3 on the production of oil or gas not subject to (j) or (k) [(j), (k), OR (o)] of this section
4 to the extent otherwise allowed."
5

6 Renumber the following bill sections accordingly.
7

8 Page 3, line 21:

9 Delete "AS 43.55.160(a)(2)(F) and (G)"

10 Insert "AS 43.55.160(a)(2)(E) and (F)"
11

12 Page 3, lines 25 - 26:

13 Delete "or gas produced outside the Cook Inlet sedimentary basin and used in the
14 state"
15

16 Page 3, line 29:

17 Delete "AS 43.55.160(a)(2)(F) and (G)"

18 Insert "AS 43.55.160(a)(2)(E) and (F)"
19

20 Page 4, line 1:

21 Delete "AS 43.55.160(a)(2)(F) and (G)"

22 Insert "AS 43.55.160(a)(2)(E) and (F)"
23

24 Page 4, line 4:

25 Delete "AS 43.55.160(a)(2)(F) and (G)"

26 Insert "AS 43.55.160(a)(2)(E) and (F)"
27

28 Page 4, line 7:

29 Delete "AS 43.55.160(a)(2)(F) and (G)"

30 Insert "AS 43.55.160(a)(2)(E) and (F)"
31

1 Page 4, lines 21 - 22:

2 Delete "but not subject to AS 43.55.011(o)"

3 Insert "[BUT NOT SUBJECT TO AS 43.55.011(o)]"

4

5 Page 6, line 9:

6 Delete "AS 43.55.011(j), (k), or (o)"

7 Insert "AS 43.55.011(j) or (k) [AS 43.55.011(j), (k), OR (o)]"

8

9 Page 6, line 31:

10 Delete "AS 43.55.011(j), (k), or (o)"

11 Insert "AS 43.55.011(j) or (k) [AS 43.55.011(j), (k), OR (o)]"

12

13 Page 7, line 2:

14 Delete "or 43.55.011(o)"

15 Insert "[OR 43.55.011(o)]"

16

17 Page 7, line 4:

18 Delete "or 43.55.011(o)"

19 Insert "[OR 43.55.011(o)]"

20

21 Page 9, lines 14 - 21:

22 Delete "gas produced during a calendar year from a lease or property outside the Cook
23 Inlet sedimentary basin and used in the state is the gross value at the point of production of
24 that gas taxable under AS 43.55.011(e) and produced by the producer from that lease or
25 property, less the producer's lease expenditures under AS 43.55.165 for the calendar year
26 applicable to that gas produced by the producer from that lease or property, as adjusted under
27 AS 43.55.170;

28 (F)"

29

30 Page 9, lines 27 - 28:

31 Delete "this subparagraph does not apply to gas used in the state;"

1

2 Page 9, line 29:

3 Delete "(G)"4 Insert "(F)"

5

6 Page 10, lines 5 - 6:

7 Delete "; this subparagraph does not apply to gas used in the state;"

8 Insert "[GAS PRODUCED DURING A CALENDAR YEAR FROM A LEASE OR
 9 PROPERTY OUTSIDE THE COOK INLET SEDIMENTARY BASIN AND USED IN THE
 10 STATE IS THE GROSS VALUE AT THE POINT OF PRODUCTION OF THAT GAS
 11 TAXABLE UNDER AS 43.55.011(e) AND PRODUCED BY THE PRODUCER FROM
 12 THAT LEASE OR PROPERTY, LESS THE PRODUCER'S LEASE EXPENDITURES
 13 UNDER AS 43.55.165 FOR THE CALENDAR YEAR APPLICABLE TO THAT GAS
 14 PRODUCED BY THE PRODUCER FROM THAT LEASE OR PROPERTY, AS
 15 ADJUSTED UNDER AS 43.55.170];"

16

17 Page 11, lines 8 - 15:

18 Delete "gas produced during a month from a lease or property outside the Cook Inlet
 19 sedimentary basin and used in the state is the gross value at the point of production of that gas
 20 taxable under AS 43.55.011(e) and produced by the producer from that lease or property, less
 21 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar year applicable
 22 to that gas produced by the producer from that lease or property, as adjusted under
 23 AS 43.55.170;

24 (F)"

25

26 Page 11, line 22:

27 Delete all material.

28

29 Page 11, line 23:

30 Delete "(G)"31 Insert "(F)"

1

2 Page 11, lines 30 - 31:

3 Delete "; this subparagraph does not apply to gas used in the state"

4 Insert "[GAS PRODUCED DURING A MONTH FROM A LEASE OR PROPERTY
5 OUTSIDE THE COOK INLET SEDIMENTARY BASIN AND USED IN THE STATE IS
6 THE GROSS VALUE AT THE POINT OF PRODUCTION OF THAT GAS TAXABLE
7 UNDER AS 43.55.011(e) AND PRODUCED BY THE PRODUCER FROM THAT LEASE
8 OR PROPERTY, LESS 1/12 OF THE PRODUCER'S LEASE EXPENDITURES UNDER
9 AS 43.55.165 FOR THE CALENDAR YEAR APPLICABLE TO THAT GAS PRODUCED
10 BY THE PRODUCER FROM THAT LEASE OR PROPERTY, AS ADJUSTED UNDER
11 AS 43.55.170]"

12

13 Page 11, following line 31:

14 Insert a new bill section to read:

15 "* Sec. 10. AS 43.55.160(e) is amended to read:

16 (e) Any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that
17 would otherwise be deductible by a producer in a calendar year but whose deduction
18 would cause an annual production tax value calculated under (a)(1) of this section of
19 taxable oil or gas produced during the calendar year to be less than zero may be used
20 to establish a carried-forward annual loss under AS 43.55.023(b). However, the
21 department shall provide by regulation a method to ensure that, for a period for which
22 a producer's tax liability is limited by AS 43.55.011(j) or (k) [AS 43.55.011(j), (k),
23 OR (o)], any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that
24 would otherwise be deductible by a producer for that period but whose deduction
25 would cause a production tax value calculated under (a)(1)(C) or (D) [(a)(1)(C), (D),
26 OR (E)] of this section to be less than zero are accounted for as though the adjusted
27 lease expenditures had first been used as deductions in calculating the production tax
28 values of oil or gas subject to any of the limitations under AS 43.55.011(j) or (k)
29 [AS 43.55.011(j), (k), OR (o)] that have positive production tax values so as to reduce
30 the tax liability calculated without regard to the limitation to the maximum amount
31 provided for under the applicable provision of AS 43.55.011(j) or (k)

1 [AS 43.55.011(j), (k), OR (o)]. Only the amount of those adjusted lease expenditures
 2 remaining after the accounting provided for under this subsection may be used to
 3 establish a carried-forward annual loss under AS 43.55.023(b). In this subsection,
 4 "producer" includes "explorer.""

5
 6 Renumber the following bill sections accordingly.

7
 8 Page 12, lines 3 - 4:

9 Delete ", between gas subject to AS 43.55.011(o) and other gas,"

10 Insert "[, BETWEEN GAS SUBJECT TO AS 43.55.011(o) AND OTHER GAS,]"

11
 12 Page 12, line 17:

13 Delete ", between gas subject to AS 43.55.011(o) and other gas,"

14
 15 Page 12, following line 27:

16 Insert a new bill section to read: .

17 **"* Sec. 13. AS 43.55.011(o) and AS 43.55.900(24) are repealed."**

18
 19 Renumber the following bill sections accordingly.

20
 21 Page 13, line 2:

22 Delete "secs. 2 - 4 and 7"

23 Insert "secs. 2, 4, 6, and 9"

24
 25 Page 13, line 5:

26 Delete "secs. 2 - 4 and 7"

27 Insert "secs. 2, 4, 6, and 9"

28
 29 Page 13, line 10:

30 Delete "Sections 2 - 4 and 7"

31 Insert "Sections 2, 4, 6, and 9"

CS SB 305 Conceptual Amendment to Amendment 26-LS1577\WA.2

OFFERED IN THE HOUSE

BY REPRESENTATIVE SEATON

TO: Amendment WA.2 to CSSB 305

The tax provisions for in-state sale of gas from the North Slope and other fields are re-enacted 30-days after the effective date of this act

CONCEPTUAL AMENDMENT

OFFERED IN RESOURCES

BY REPRESENTATIVE GUTTENBERG

TO: CSSB 305 W.A

1 Page 3, following line 18

2 Insert new bill section to read:

3 ****Sec. 5.** AS.43.55.011 is amended by adding a new subsection (p) to read:

4

5 (p) The levy of tax under this section for oil and gas produced north of 68 degrees North
6 latitude in a calendar year, other than oil and gas production subject to (i) of this section and gas
7 subject to (o) of this section, may not be less than the tax that would have been levied for the oil
8 or the gas if the calculation of the tax under AS 43.55.011(e) had been made separately for the
9 oil and gas.

CONCEPTUAL AMENDMENT

OFFERED IN THE HOUSE RESOURCES COMMITTEE

TO: CSSB305

1 version W.A: Page 12, lines 9-12; version M: Page 31, lines 19-22

2 Delete

3 **“When determining a reasonable method of allocating lease expenditures between**
4 **the production of oil and the production of gas, the department shall consider**
5 **allocating lease expenditures in proportion to the BTU equivalent barrels of oil**
6 **produced and gas produced from each lease or property.”**

7

8 Insert

9 **“When determining a reasonable method of allocating lease expenditures between**
10 **the production of oil and the production of gas, the department shall to the extent**
11 **possible allocate lease expenditures in proportion to the gross value at the point of**
12 **production for oil produced and gas produced from each lease or property.”**

(4/12/2010)
(pm)

AMENDMENT

OFFERED IN THE HOUSE RESOURCES
COMMITTEE

BY Seaton

TO: CSSB305 v. M

1 Page 31, delete lines 19-22 and replace with:

2 “properties. The department shall allocate lease expenditures between the
3 production of oil and the production of gas in proportion to the gross values at the
4 point of production of the oil and gas produced from each lease or property.”

SB 305 CONCEPTUAL AMENDMENT

We believe the following language addresses the concerns raised by the producers regarding the ability to recognize costs as they are incurred. This can be added to AS 43.55.165(h) in Section 8 of the Current CS (Version W.A):

Costs incurred to explore for, develop or produce oil or gas either

(1) on a lease or property that include land north of 68 degrees North latitude and which did not produce commercial quantities of oil or gas in the calendar year in which the costs were occurred; or

(2) outside of a lease or property, but that include land north of 68 degrees North latitude , will be allocated between

(A) each lease or property producing gas subject to AS 43.55.011(o) that include land north of 68 degrees North latitude and

(B) all other producing leases or properties that include land north of 68 degrees North latitude.

Costs incurred to explore for, develop or produce oil or gas either

(1) on a lease or property outside the Cook Inlet Sedimentary Basin, no part of which is north of 68 degrees North latitude and which did not produce commercial quantities of oil or gas in the calendar year in which the costs were occurred; or

(2) outside of a lease or property, but outside the Cook Inlet Sedimentary Basin, no part of which is north of 68 degrees North latitude, will be allocated between

(A) each lease or property producing gas subject to AS 43.55.011(o) outside the Cook Inlet Sedimentary Basin, no part of which is north of 68 degrees North latitude and

(B) all other producing leases or properties that outside the Cook Inlet Sedimentary Basin, no part of which is north of 68 degrees North latitude.

SJR

3

Alaska State Legislature

SENATOR
GENE THERRIAULT

Mailing Address:
292 Sadler Way, Suite 308
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(907) 488-0857
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Senate

While in session
State Capitol
Juneau, Alaska
99801-1182
(907) 465-4797
Fax: (907) 465-3884
SENATE DISTRICT F

Sponsor Statement

Senate Joint Resolution 3

It is the intent of SJR 3 to show appreciation for the change in National Park policy that now allows park users to carry the firearms they need for personal protection in National Parks.

Alaskans, who have in their state over 75% of the National Park system, understand how important it is to have personal protection when in the wilderness. This bill affirms that progress that has been made in allowing the carrying of firearms under the previous administration and encourages the new Obama administration to continue with the policy and add improvements by allowing open carry in addition as concealed carry.

Whether it is for bear protection, obtaining food in a survival situation, or signaling for assistance when needed, firearms have been on the hips and in the arms of Alaskans since the frontier was first explored. Now the unbroken wilderness and inherent dangers have been exacerbated with the conditioning of animals to lose their natural tendency of avoiding humans. With the Parks Service's steady line of visitors who have no real experience in the true wilderness, the need for protection is more prudent now than ever before.

FISCAL NOTE

STATE OF ALASKA
2009 LEGISLATIVE SESSION

Fiscal Note Number: 1
Bill Version: SJR 3
(S) Publish Date: 2/13/09

Identifier (file name): _____ Dept. Affected: _____
Title SJR 3 FIREARMS IN NATIONAL PARK RDU _____
Sponsor Senator Therriault Component _____
Requester (S) Judiciary Committee Component Number _____

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2010	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
OPERATING EXPENDITURES								
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	0.0

CAPITAL EXPENDITURES								
-----------------------------	--	--	--	--	--	--	--	--

CHANGE IN REVENUES ()								
-------------------------------	--	--	--	--	--	--	--	--

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts								
1003 GF Match								
1004 GF								
1005 GF/Program Receipts								
1037 GF/Mental Health								
Other Interagency Receipts								
TOTAL		0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2009) cost: _____

POSITIONS

Full-time								
Part-time								
Temporary								

ANALYSIS: (Attach a separate page if necessary)

Prepared by: SENATE JUDICIARY COMMITTEE
Division: _____
Approved by: /s/ Senator French, Chair

Phone 465-3892
Date/Time 2/11/09 12:00 AM
Date 2/11/2009



SUPPORTERS CITE SAFETY, CRITICS SEE POLITICAL MOTIVES

Fight Rages Over Guns in Parks

By Dan Testa, 3-05-08

At the end of April, Interior Secretary Dirk Kempthorne will suggest new rules for carrying loaded guns in national parks that will likely relax the restrictions to bring them more in-line with state laws. In Montana, where gun restrictions are relatively few, carrying loaded weapons could be permitted in Glacier and Yellowstone national parks.

Both opponents and supporters of relaxing the ban agree on one thing: Permitting loaded weapons in national parks where they are currently restricted will alter the role these lands play in our national identity. Whether the proposed change is for safety reasons or a political move in an election year, depends on where you stand and whom you ask.

The Argument

At its heart, the question of loaded weapons in national parks comes down to differing conceptions of safety. For gun-rights advocates, relaxing the ban would increase the safety of national parks, allowing visitors to better defend themselves from aggressive people or animals. Guns are currently allowed in Glacier as long as they are unloaded and stored.

Gary Marbut, president of the Montana Shooting Sports Association, believes gun-free zones are inherently dangerous, and cites recent school shootings at Virginia Tech and Northern Illinois University as examples of places where law-abiding citizens could have defended themselves were they allowed to do so.

"Gun-free zones are broken social institutions," Marbut said, "and they need to be fixed anywhere they occur, including in national parks."

Opponents of relaxing the ban disagree that national parks, with respect to gun restrictions, are broken social institutions. And if it isn't broken, they say, don't fix it. Last week the Coalition of National Park Service Retirees protested any plans to reconsider gun regulations.

Pete Hart has worked as a ranger and superintendent in 17 national parks over 38 years, including stints at Glacier, and is now a member of the National Parks Conservation Association. He also carried a weapon in parks for 23 of those years, and echoes many retired park service employees who say national parks are safe, and introducing more weapons into the mix would create problems where none exist.

"The fact that people don't carry firearms in the backcountry is a good thing," Hart said. "I believe in the Second Amendment, but I believe the current regulations are working."

Supporters of changing regulations point out that loaded firearms are restricted on federal parkland, but not U.S. Forest Service or Bureau of Land Management property, representing selective enforcement of gun regulations. Opponents counter that people don't travel from across the country and around the world to visit BLM land like they do for Glacier Park, so the rules should be different considering the diversity of urban and international visitors. Part of national parks' appeal, Hart said, derives from "a certain feeling of tranquility and really firearms don't need to be a part of it."

Poaching could increase if visitors can carry loaded weapons. Whereas park rangers currently have probable cause to investigate a possible poacher if that person is carrying a loaded weapon in the park, that reason no longer holds up if the guns are allowed.

"There's nothing in this ruling that makes poaching legal," counters Andrew Arulanandam, director of public affairs for the National Rifle Association. "That's another baseless argument."

Crime in National Parks: By the Numbers

Gun-rights advocates point to the recent murder of a 24-year-old hiker in the mountains of north Georgia as an example of a victim in the backcountry who might have defended herself with a firearm. But despite such a high-profile example, the National Park Service says the crime statistics across its 390 park units are very low.

Out of 272 million visits, there were 116,588 reported offenses in national parks in 2006. Only 384 of those were violent

crimes – and that includes statistics reported by park police at urban parks like the Lincoln Memorial in Washington, D.C., and the Statue of Liberty in New York. That makes the probability of becoming a victim of a violent crime on national parkland one in 708,333. Out of roughly 1.3 billion visitors to national parks since 2002, two have been killed by animals.

In 2006 the national park system had 11 killings, 35 rapes or attempted rapes, 16 kidnappings, 261 aggravated assaults and 61 robberies. Out of the 11 killings: five were categorized as murders: two people were pushed off cliffs; one was a murder-suicide; one was a drunk driver crash; and two were bodies or remains found where the victim was killed elsewhere.

In Glacier Park, however, crime is virtually nonexistent. There have been 20 cases of poaching since 1997, and none in 2007. In that 10-year span there were 91 general weapons violations, 15 of which occurred last year. Glacier Park had two reports of rape last year, and no kidnappings, robberies or homicides. Glacier also had three reported assaults last year – one with a firearm and two bodily assault cases.

Parks, Guns and Politics

Kemphorne took up the issue of guns in national parks after receiving complaints, organized by Idaho Republican Sen. Mike Crapo, about current regulations from 50 U.S. senators: 41 Republicans and nine Democrats. Montana's Sens. Max Baucus and Jon Tester were among those nine. A prerequisite for holding elected office in most of the Rocky Mountain West, particularly if you're a Democrat, is an immaculate record of pro-gun rights positions, and it is an election year.

All of which has opponents of relaxing gun regulations charging that this is simply a wedge issue, designed by the NRA to get lawmakers on their side in the run-up to a momentous election.

"The NRA inserted a very contentious issue into this election year," said Bryan Faehner, legislative representative for the NPCA. "It's unfortunate that the NRA chose the national parks to flex their muscle."

"It didn't just happen because some senators spoke out," Faehner added. "It was a full-fledged campaign where the NRA covered all the pressure points in Washington, D.C., to make this happen."

But Marbut and Arulanandam say their groups have been pushing for a re-examination of gun regulations in parks for five years now, through two previous elections, and that the issue has finally risen to the top of the stack. The idea that the NRA is creating hoops for lawmakers to jump through, added Arulanandam, wildly overestimates the power of the gun lobby.

"Contrary to popular belief, the NRA does not control congressional schedules, nor do we make the rules of the land as they pertain to firearms," Arulanandam said. "That is just empty rhetoric from those who oppose this measure."

But both Faehner and Arulanandam think that when the Department of Interior releases its new draft regulations for public comment, they are likely to apply state gun laws to national parks.

"It's too premature to speculate," Arulanandam said. "We're cautiously optimistic." **[End of article]**

Comment By garyt, 3-05-08

If people are allowed to have guns in their possession there will be shootouts reminiscence of the OK corral. The gun-control crowd use the same argument every time and it is yet to happen. Why should we have to give up our constitutional rights to satisfy a few people who have no clue of the real world? Are you aware that the areas with the highest crime rates are those that have the strictest gun control laws? New York, Washington DC and San Francisco are some that come to mind. Everytime that you travel from Kalispell to Browning and you don't take apart your gun do you know are breaking the law? The gun-free zones are just inviting these criminals to make headlines.

Comment By Denny, 3-05-08

What is their argument for not allowing guns in the park? I always assumed it was to prevent poaching. I am an honest do-good citizen that contributes positive influence on my community. I have never in my life committed a crime past j-walking, and have never been involved in a firearms accident or offense. I have and hold a concealed carry permit for a pistol. I ask those who oppose the legalization of firearms in the parks this, "On what grounds do you deny my right to carry?" I desire to protect myself and my family. Bear-spray is not always 100% deterrent. I have utilized the modern techniqu of pistol shooting for around 20 years now and can pretty much guarantee that I could effectively eliminate a threat if it were to occur in a national park. Fear, government bureaucracy should not intrude with my right to self defense and the ability to maintain my own species. I'm sure legalizing guns in the park will not cause a spike in crime there, in fact it will if anything deter it, and with wildlife, I guarantee that the only shots that would ever be fired would be in complete self preservation. Thanks.

Comment By Wendy Weinbaum, 3-06-08

As a Jewess in the US, I want to remind everyone that America wasn't won with a registered gun. Nor are criminals stopped by talk, but rather by FIREARMS. That is why all REAL Americans put our 2nd Amendment FIRST!

Comment By Uncle Lar, 3-06-08

In 2006, criminal activity in our national parks included 11 killings, 35 rapes or attempted rapes, 61 robberies, 16 kidnappings and 261 aggravated assaults.

A tiny number, hardly significant, except to all the real people victimized by these crimes. Tell me again why I should surrender my only true means of self defense for your convenience. You want to catch poachers? Arrest them when they shoot.

And please explain if it's so safe why then do your rangers go armed?

Comment By Addicus Daily, 3-06-08

I carry a gun in the parks any way. I have for years. It is concealed and ready for bear or criminal. If you try to take it from me I may confuse you with a criminal.

Comment By Average American, 3-07-08

So let me get this right! The Second Amendment of the Constitution does not apply in National Parks? I did not know the government could abrogate my constitutional rights to effectively defend myself. I understand that Park Rangers may feel more comfortable if they are the only ones armed in the Parks, but they really need to "man up". People have a right to defend themselves. And what is this crap about "agressive people" don't you really mean "depraved criminals". Parks are often far from the police station and a 911 response. Enforcement authorities cannot be everywhere, and the graveyards of full of people who are evidence of that. Get a clue people- government cannot solve all your problems sometimes you have to be self reliant.

Comment By Walt, 3-07-08

As a both a current and retired law enforcement officer, I have authority to carry a concealed weapon under HR-218. I recently took an 11 State trip including going through Yellowstone, Jewel Caverns, Custer State Park and many other State and Federal Parks and properties. Carried my firearm with me to all locations for personal protection. At none of the sites was I asked if I was carrying a firearm. I assumed the philosophy of "don't ask, don't tell".

It would be my bet that many firearms are carried within these areas much like I did, without problems.

Those that are intent in misusing a firearm are those that don't care what the rules are anyway.

Comment By Gery, 3-08-08

I live near the Rocky Mtn. National Park. I am also a U.S. Forest Service volunteer. I carry concealed in both instances. Why? Wolves, grizzly bears, mountain lions and evil humanoids. The aforementioned three have fangs, claws, stealth and speed that I do not have and the fourth is ruthless, cunning and without consience (sp?). To do otherwise would make me stupid and a helpless victim. (Not sure I want to eat at Wendy's or visit an educational campus either.)

Curious that when interacting with outfitters, etc. while with the Forest Service they do not care much for Forest Service Rangers but loathe National Park Rangers. They find them uppity and overbearing like they have their own fiefdom and you the citizen are lucky they let you into their park.

Comment By Did they forget something?, 3-10-08

Glacier National Park had a ranger abducted from the entrance station. She was assaulted and raped before she could escape. We always carry in GNP and don't care about the rangers discovering. The ones you meet in the field are usually very young, still going to school. The rest are bureaucrats, sitting in the office, bitching about something. It's ok for them to carry, but not the public which owns the park?

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Lawsuit Targets New Policy Allowing Guns in Parks

Associated Press
Wednesday, December 31, 2008; A13

The Bush administration was sued yesterday over a new policy that would allow people to carry concealed, loaded guns in most national parks and wildlife refuges.

"The Bush administration's last-minute gift to the gun lobby, allowing concealed semiautomatic weapons in national parks, jeopardizes the safety of park visitors in violation of federal law," said Paul Helmke, president of the Brady Campaign to Prevent Gun Violence. "We should not be making it easier for dangerous people to carry concealed firearms in our parks."

The Brady Campaign sued the Interior Department and its secretary, Dirk Kempthorne, as well as the leaders of the U.S. Fish and Wildlife Service and the National Park Service, in U.S. District Court. The gun-control advocacy group wants a federal judge to issue an immediate injunction stopping the elimination of the 25-year-old federal rule that severely restricts loaded guns in national parks.

An Interior Department spokeswoman would not comment on the lawsuit, saying the department does not discuss pending litigation.

Interior overturned a regulation dating to the Reagan administration that has restricted loaded guns in parks and wildlife refuges. The previous regulation required that firearms be unloaded and placed somewhere that is not easily accessible, such as in a car trunk.

Under a rule to take effect in January, visitors will be able to carry a loaded gun into a park or wildlife refuge -- but only if the person has a permit for a concealed weapon and if the state where the park or refuge is located also allows concealed firearms.

The rules change would take effect before President-elect Barack Obama takes office in January. Overturning the rule would take months or even years if the Obama administration wanted to, since it would require the new administration to restart the lengthy rule-making process.

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Alaska State Legislature

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Senate

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SENATE DISTRICT F

Memorandum

To: Representative Craig Johnson/ C0-Chairman House Resources

From: Senator Gene Therriault

A handwritten signature in black ink, appearing to read "G. Therriault".

Date: April 15, 2009

Re: Senate Joint Resolution 3

.....

I respectfully request a committee hearing on SJR 3 to encourage continuation and improvement on the policy allowing persons to carry firearms in National Parks.

Thank you for honoring this request.

