

AK LEGISLATURE FINANCE COMMITTEES FILES 2007-2008 3284

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1 allowed to bill a working interest owner that is not the operator, under unit operating
2 agreements or similar operating agreements that were in effect before December 2,
3 2005, and were subject to negotiation with at least one working interest owner with
4 substantial bargaining power, other than the operator; and

5 (2) the standards adopted by the Department of Natural Resources that
6 determine the costs, other than items listed in (e) of this section, that a lessee is
7 allowed to deduct from revenue in calculating net profits under a lease issued under
8 AS 38.05.180(f)(3)(B), (D), or (E).

9 * Sec. 47. AS 43.55.165(c) is repealed and reenacted to read:

10 (c) Subject to (g) and (h) of this section, if the department finds that the
11 pertinent provisions of a unit operating agreement or similar operating agreement are
12 substantially consistent with the department's determinations and standards under (a)
13 of this section concerning whether costs are lease expenditures and, in addition, finds
14 that at least one working interest owner party to the agreement, other than the
15 operator, with substantial incentive and ability to effectively audit billings under the
16 agreement, in fact is effectively auditing billings under the agreement, the department
17 may authorize or require a producer, subject to conditions prescribed under
18 regulations adopted by the department, to treat as that portion of its lease expenditures
19 for a calendar year applicable to oil and gas produced from a lease or property in the
20 state only

21 (1) the costs, other than items listed in (e) of this section, that are
22 incurred by the operator during the calendar year and that

23 (A) are billed to the producer by the operator under the
24 agreement to which that lease or property is subject and are either not disputed
25 by a working interest owner party to the agreement or are finally determined
26 to be properly billable as a result of dispute resolution; or

27 (B) for a producer that is the operator, would be billable to the
28 producer by the operator in accordance with the terms of the agreement to
29 which that lease or property is subject if the producer were not the operator;
30 and

31 (2) a reasonable percentage, as determined under regulations adopted

1 by the department, of the costs that are billed under (1) of this subsection as an
2 allowance for overhead expenses directly related to exploring for, developing, and
3 producing oil or gas deposits located within the lease or property, to the extent those
4 expenses are not billable under the agreement.

5 * Sec. 48. AS 43.55.165(e) is amended to read:

6 (c) For purposes of this section, lease expenditures do not include

7 (1) depreciation, depletion, or amortization;

8 (2) oil or gas royalty payments, production payments, lease profit
9 shares, or other payments or distributions of a share of oil or gas production, profit, or
10 revenue;

11 (3) taxes based on or measured by net income;

12 (4) interest or other financing charges or costs of raising equity or
13 debt capital;

14 (5) acquisition costs for a lease or property or exploration license;

15 (6) costs arising from fraud, wilful misconduct, [OR] gross
16 negligence, criminal negligence, violation of law, including a violation of 33
17 U.S.C. 1319(e)(1) or 1321(b)(3) (Clean Water Act), or failure to comply with an
18 obligation under a lease, permit, or license issued by the state or federal
19 government;

20 (7) fines or penalties imposed by law;

21 (8) costs of arbitration, litigation, or other dispute resolution activities
22 that involve the state or concern the rights or obligations among owners of interests
23 in, or rights to production from, one or more leases or properties or a unit;

24 (9) costs incurred in organizing a partnership, joint venture, or other
25 business entity or arrangement;

26 (10) amounts paid to indemnify the state; the exclusion provided by
27 this paragraph does not apply to the costs of obtaining insurance or a surety bond
28 from a third-party insurer or surety;

29 (11) surcharges levied under AS 43.55.201 or 43.55.300;

30 (12) for a transaction that is an internal transfer or is otherwise not an
31 arm's length transaction, expenditures incurred that are in excess of fair market value;

1 (13) an expenditure incurred to purchase an interest in any
2 corporation, partnership, limited liability company, business trust, or any other
3 business entity, whether or not the transaction is treated as an asset sale for federal
4 income tax purposes;

5 (14) a tax levied under AS 43.55.011;

6 (15) [THE PORTION OF] costs incurred for dismantlement, removal,
7 surrender, or abandonment of a facility, pipeline, well pad, platform, or other
8 structure, or for the restoration of a lease, field, unit, area, tract of land, body of
9 water, or right-of-way in conjunction with dismantlement, removal, surrender, or
10 abandonment [, THAT IS ATTRIBUTABLE TO PRODUCTION OF OIL OR GAS
11 OCCURRING BEFORE APRIL 1, 2006; THE PORTION IS CALCULATED AS A
12 RATIO OF THE AMOUNT OF OIL AND GAS PRODUCTION, IN BARRELS OF
13 OIL EQUIVALENT, ASSOCIATED WITH THE FACILITY, PIPELINE, WELL
14 PAD, PLATFORM, OTHER STRUCTURE, LEASE, FIELD, UNIT, AREA, BODY
15 OF WATER, OR RIGHT-OF-WAY OCCURRING BEFORE APRIL 1, 2006, TO
16 THE TOTAL AMOUNT OF OIL AND GAS PRODUCTION, IN BARRELS OF
17 OIL EQUIVALENT, ASSOCIATED WITH THAT FACILITY, PIPELINE, WELL
18 PAD, PLATFORM, OTHER STRUCTURE, LEASE, FIELD, UNIT, AREA, BODY
19 OF WATER, OR RIGHT-OF-WAY THROUGH THE END OF THE CALENDAR
20 MONTH BEFORE COMMENCEMENT OF THE DISMANTLEMENT,
21 REMOVAL, SURRENDER, OR ABANDONMENT]; a cost is not excluded under
22 this paragraph if the dismantlement, removal, surrender, or abandonment for which
23 the cost is incurred is undertaken for the purpose of replacing, renovating, or
24 improving the facility, pipeline, well pad, platform, or other structure; [FOR THE
25 PURPOSES OF THIS PARAGRAPH, "BARREL OF OIL EQUIVALENT" MEANS

26 (A) IN THE CASE OF OIL, ONE BARREL;

27 (B) IN THE CASE OF GAS, 6,000 CUBIC FEET;]

28 (16) cost incurred for containment, control, cleanup, or removal in
29 connection with any unpermitted release of oil or a hazardous substance and any
30 liability for damages imposed on the producer or explorer for that unpermitted
31 release; this paragraph does not apply to the cost of developing and maintaining an oil

1 discharge prevention and contingency plan under AS 46.04.030;

2 (17) costs incurred to satisfy a work commitment under an exploration
3 license under AS 38.05.132;

4 (18) that portion of expenditures, that would otherwise be qualified
5 capital expenditures, as defined in AS 43.55.023 [AS 43.55.023(k)], incurred during a
6 calendar year that are less than the product of \$0.30 multiplied by the total taxable
7 production from each lease or property, in BTU equivalent barrels, during that
8 calendar year, except that, when a portion of a calendar year is subject to this
9 provision, the expenditures and volumes shall be prorated within that calendar year;

10 (19) costs incurred to construct, acquire, or operate a refinery or
11 crude oil topping plant, regardless of whether the products of the refinery or
12 topping plant are used in oil or gas exploration, development, or production
13 operations; however, if a producer owns a refinery or crude oil topping plant
14 that is located on or near the premises of the producer's lease or property in the
15 state and that processes the producer's oil produced from that lease or property
16 into a product that the producer uses in the operation of the lease or property in
17 drilling for or producing oil or gas, the producer's lease expenditures include the
18 amount calculated by subtracting from the fair market value of the product used
19 the prevailing value, as determined under AS 43.55.020(f), of the oil that is
20 processed;

21 (20) costs of lobbying, public relations advertising, or policy
22 advocacy.

23 * Sec. 49, AS 43.55.165(h) is amended to read:

24 (h) The department shall adopt regulations that provide for reasonable
25 methods of allocating costs between oil and gas, between gas subject to
26 AS 43.55.011(o) and other gas, and between leases or properties in those
27 circumstances where an allocation of costs is required to determine [THE
28 DETERMINATION OF THE] lease expenditures that are costs of exploring for,
29 developing, or producing oil deposits or costs of exploring for, developing, or
30 producing gas deposits [APPLICABLE TO OIL OR TO GAS], or that are costs of
31 exploring for, developing, or producing oil or gas deposits located within

1 [APPLICABLE TO OIL AND GAS PRODUCED FROM] different leases or
2 properties [, REQUIRES AN ALLOCATION OF COSTS].

3 * Sec. 50. AS 43.55.170(a) is amended to read:

4 (a) Unless the payment or credit has already been subtracted in calculating
5 billable or billed costs under AS 43.55.165(c) [OR (d)], a producer's lease
6 expenditures under AS 43.55.165 must be adjusted by subtracting payments or
7 credits, other than tax credits, received by the producer or by an operator acting for
8 the producer for

9 (1) the use by another person of a production facility in which the
10 producer has an ownership interest or the management by the producer of a
11 production facility under a management agreement providing for the producer to
12 receive a management fee;

13 (2) a reimbursement or similar payment that offsets the producer's
14 lease expenditures, including an insurance recovery from a third-party insurer and a
15 payment from the state or federal government for reimbursement of the producer's
16 upstream costs, including costs for gathering, separating, cleaning, dehydration,
17 compressing, or other field handling associated with the production of oil or gas
18 upstream of the point of production;

19 (3) the sale or other transfer of

20 (A) an asset, including geological, geophysical, or well data or
21 interpretations, acquired by the producer as a result of a lease expenditure or
22 an expenditure that would be a lease expenditure if it were incurred after
23 March 31, 2006; for purposes of this subparagraph,

24 (i) if a producer removes from the state, for use outside
25 the state, an asset described in this subparagraph, the value of the asset
26 at the time it is removed is considered a payment received by the
27 producer for sale or transfer of the asset;

28 (ii) for a transaction that is an internal transfer or is
29 otherwise not an arm's length transaction, if the sale or transfer of the
30 asset is made for less than fair market value, the amount subtracted
31 must be the fair market value; and

1 (B) oil or gas

2 (i) that is not considered produced from a lease or
3 property under AS 43.55.020(e); and

4 (ii) the cost of acquiring which is a lease expenditure
5 incurred by the person that acquires the oil or gas.

6 * Sec. 51. AS 43.55 is amended by adding a new section to article 4 to read:

7 **Sec. 43.55.890. Disclosure of tax information.** Subject to AS 40.25.100 and
8 AS 43.05.230(c), the department may publish the following information under this
9 chapter, if aggregated among three or more producers or explorers, showing by month
10 or calendar year and by lease or property, unit, or area of the state:

11 (1) the amount of oil or gas production;

12 (2) the amount of taxes levied under this chapter or paid under this
13 chapter;

14 (3) the effective tax rates under this chapter;

15 (4) the gross value of oil or gas at the point of production;

16 (5) the transportation costs for oil or gas;

17 (6) qualified capital expenditures under AS 43.55.023(k);

18 (7) exploration expenditures under AS 43.55.025;

19 (8) production tax values of oil or gas under AS 43.55.160;

20 (9) lease expenditures under AS 43.55.165;

21 (10) adjustments to lease expenditures under AS 43.55.170;

22 (11) tax credits applicable or potentially applicable against taxes
23 levied by this chapter.

24 * Sec. 52. AS 43.55.900 is amended by adding new paragraphs to read:

25 (22) "producer" means an owner of an operating right, operating
26 interest, or working interest in a mineral interest in oil or gas;

27 (23) "unit" means a group of tracts of land that is

28 (A) subject to a cooperative or a unit plan of development or
29 operation that has been certified by the commissioner of natural resources
30 under AS 38.05.180(p);

31 (B) subject to a cooperative or a unit plan of development or

1 operation that has been certified by the United States Secretary of the Interior
2 under 30 U.S.C. 226(m);

3 (C) subject to an agreement of the owners of interests in the
4 tracts of land to validly integrate their interests to provide for the unitized
5 management, development, and operation of the tracts of land as a unit, within
6 the meaning of AS 31.05.110(a); or

7 (D) within the unit area of a unit created by order of the
8 Alaska Oil and Gas Conservation Commission under AS 31.05.110(b);

9 (24) "used in the state" means delivered for consumption as fuel in the
10 state, including as fuel consumed to generate electricity.

11 * Sec. 53. AS 43.55.160(c) and 43.55.165(d) are repealed.

12 * Sec. 54. The uncodified law of the State of Alaska is amended by adding a new section to
13 read:

14 APPLICABILITY. (a) Sections 14 - 26, 28 - 32, 34 - 38, 40, 44 - 50, and 53 of this
15 Act apply to oil and gas produced after December 31, 2007.

16 (b) Sections 38 and 40 of this Act apply to statements and reports under
17 AS 43.55.030(a), as amended by sec. 38 of this Act, and AS 43.55.030(e) and (f), as added
18 by sec. 40 of this Act, required to be filed after December 31, 2007.

19 (c) Sections 29 - 32 and 35 of this Act apply to exploration expenditures incurred for
20 work performed after December 31, 2006, that are the basis of tax credits that may be
21 claimed against taxes levied for oil and gas produced after December 31, 2007.

22 (d) AS 43.55.075(a), enacted by sec. 42 of this Act, applies to any tax liability under
23 AS 43.55 with respect to which the period of limitations on assessment under AS 43.05.260
24 had not expired before the effective date of secs. 13 and 42 of this Act.

25 (e) AS 43.55.020(i), enacted by sec. 24 of this Act, applies to any installment
26 payment due after the effective date of sec. 24 of this Act that is not paid timely.

27 (f) The penalty in AS 43.55.030(d), enacted by the amendment to AS 43.55.030(d) in
28 sec. 39 of this Act, applies to any report required to be filed after the effective date of sec. 39
29 of this Act that is not filed timely.

30 (g) The penalty in AS 43.55.040(6), enacted by the amendment to AS 43.55.040 in
31 sec. 41 of this Act, applies to any report, statement, or other document required to be filed

1 after the effective date of sec. 41 of this Act.

2 * Sec. 55. The uncodified law of the State of Alaska is amended by adding a new section to
3 read:

4 TRANSITION: ASSIGNMENT OF OIL AND GAS AUDITORS IN THE
5 DEPARTMENT OF REVENUE AND DEPARTMENT OF NATURAL RESOURCES.
6 Notwithstanding any contrary provision of law, employees employed as oil and gas auditors
7 performing production tax audits or as their immediate supervisors in the Department of
8 Revenue and employees employed as oil and gas auditors performing royalty audits,
9 including net profit share audits, or as their immediate supervisors in the Department of
10 Natural Resources are assigned to the exempt service in accordance with AS 39.25.110(42),
11 added by sec. 10 of this Act, and may not be included in the general government or
12 supervisory collective bargaining units of state employees except as provided in this section.
13 All oil and gas auditors performing production tax audits or royalty audits and their
14 immediate supervisors hired before the effective date of sec. 10 of this Act have the option of
15 (1) continuing in the general government or supervisory collective bargaining units and being
16 subject to their respective collective bargaining agreements; or (2) being removed from those
17 bargaining units. Those employees have 90 days from the effective date of sec. 10 of this Act
18 to exercise the option to continue in the collective bargaining units. The option taken under
19 this section by the employee is irrevocable. The employees choosing to be removed from
20 those bargaining units are removed after any notice period required by a collective
21 bargaining agreement.

22 * Sec. 56. The uncodified law of the State of Alaska is amended by adding a new section to
23 read:

24 TRANSITION: REGULATIONS. The Department of Natural Resources and the
25 Department of Revenue may proceed to adopt regulations to implement this Act. The
26 regulations take effect under AS 44.62 (Administrative Procedure Act), but not before the
27 effective date of the law implemented by the regulation.

28 * Sec. 57. The uncodified law of the State of Alaska is amended by adding a new section to
29 read:

30 RETROACTIVITY OF CERTAIN PROVISIONS OF THIS ACT. Sections 27 and
31 33 of this Act are retroactive to July 1, 2003.

- 1 * Sec. 58. Sections 14 - 26, 28 - 32, 34 - 38, 40, 44 - 50, and 53 of this Act take effect
2 January 1, 2008.
- 3 * Sec. 59. Except as provided in sec. 58 of this Act, this Act takes effect immediately under
4 AS 01.10.070(c).

STAKEHOLDERS

Estimated Financial Impacts of Various Approaches to Current (PPT) Provisions

November 8, 2007

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Base Tax Rate

Average FY2008-2014 Amount Above / (Below) PPT (\$M)

<u>WC ANS Price</u>	<u>Average FY2008-2014 Amount Above / (Below) PPT (\$M)</u>		
	<u>HB 2001</u>	<u>House Oil & Gas</u>	<u>House Resources</u>
	25%	22.5%	25%
\$40	\$101	\$0	\$101
\$60	\$231	\$0	\$231
\$80	\$351	\$0	\$351
\$100	\$470	\$0	\$470
\$120	\$589	\$0	\$589

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

Progressivity

Average FY2008-2014 Amount Above / (Below) PPT (\$M)

WC ANS Price	Average FY2008-2014 Amount Above / (Below) PPT (\$M)		
	HB 2001	House Oil & Gas	House Resources
	\$30 Net Trigger 0.2% Rate Apply to Net	\$50 Gross Trigger 0.225% Rate Apply to Gross	\$30, \$40, \$50, \$60 Net 0.2%, 0.3%, 0.4%, 0.5% Apply to Gross
\$40	\$0	\$0	\$0
\$60	\$135	\$227	\$248
\$80	\$132	\$596	\$1,038
\$100	(\$16)	\$932	\$2,619
\$120	(\$261)	\$1,285	\$4,766

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

TAPS Tariff

Average FY2008-2014 Amount Above / (Below) PPT (\$M)

<u>WC ANS Price</u>	<u>Average FY2008-2014 Amount Above / (Below) PPT (\$M)</u>		
	<u>HB 2001</u>	<u>House Oil & Gas</u>	<u>House Resources</u>
	FERC	FERC	Reasonable
\$40	\$0	\$0	\$53
\$60	\$0	\$0	\$53
\$80	\$0	\$0	\$53
\$100	\$0	\$0	\$53
\$120	\$0	\$0	\$53

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).



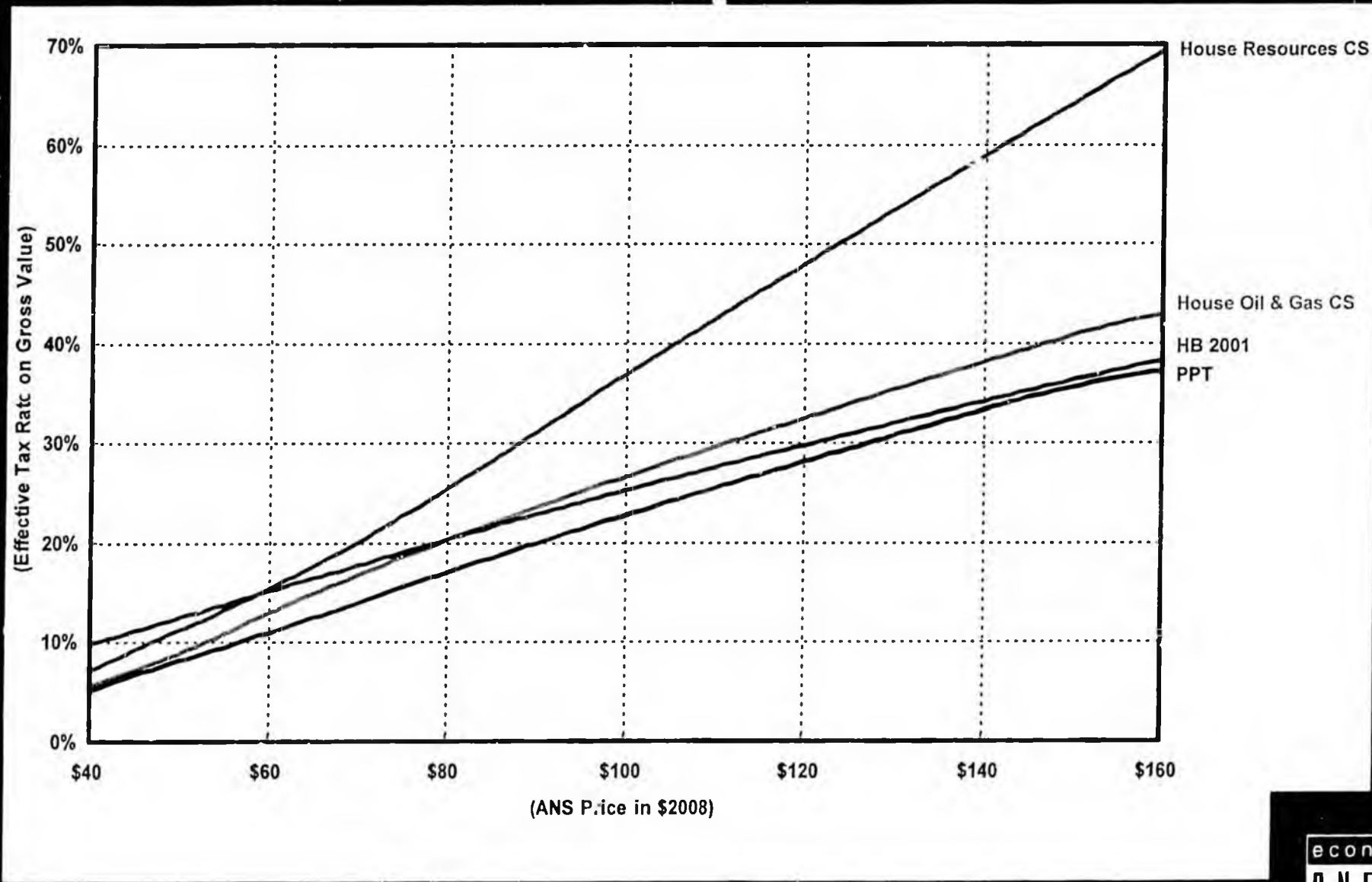
TIE Credits

Average FY2008-2014 Amount Above / (Below) PPT (\$M)

<u>WC ANS Price</u>	<u>Average FY2008-2014 Amount Above / (Below) PPT (\$M)</u>		
	<u>HB 2001</u>	<u>House Oil & Gas</u>	<u>House Resources</u>
	None	3 Years	3 Years
\$40	\$176	\$47	\$47
\$60	\$176	\$47	\$47
\$80	\$176	\$47	\$47
\$100	\$176	\$47	\$47
\$120	\$176	\$47	\$47

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

Estimated Average Effective Tax Rate on Gross Taxable Value at Various West Coast ANS Price Levels (FY 2008-2014)



Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).



Estimated Average Effective Tax Rate, Government Shares and Revenue Impacts at Various West Coast ANS Price Levels (FY 2008-2014)

Average ANS West Coast Price in Real 2008 Dollars:	\$40.00	\$60.00	\$80.00	\$100.00	\$120.00	\$140.00	\$160.00
Effective Tax Rate on Gross Taxable Value (Percent)							
PPT	5.1%	10.9%	17.0%	22.7%	28.1%	33.2%	37.2%
HB 2001	9.9%	15.1%	20.3%	25.2%	29.7%	34.1%	38.2%
House Oil & Gas	5.6%	13.0%	20.3%	26.7%	32.5%	38.1%	43.0%
House Resources	7.2%	15.4%	25.4%	36.9%	48.0%	58.9%	69.6%
Total Government Share of Net Cash (Percent)							
PPT	60.5%	60.6%	62.7%	65.3%	67.8%	70.4%	72.2%
HB 2001	64.5%	63.5%	64.9%	66.8%	68.8%	70.9%	72.9%
House Oil & Gas	60.9%	62.0%	64.9%	67.7%	70.5%	73.3%	75.7%
House Resources	61.9%	63.5%	68.2%	74.1%	79.9%	85.7%	91.4%
Marginal Government Share of Net Cash (Percent)							
PPT	58.9%	63.7%	70.7%	75.9%	81.0%	86.2%	78.9%
HB 2001	59.7%	65.4%	70.7%	75.1%	79.3%	83.5%	84.9%
House Oil & Gas	83.5%	68.5%	74.1%	79.5%	84.8%	90.2%	85.1%
House Resources	61.5%	71.1%	86.6%	99.1%	110.2%	121.3%	132.4%
Annual Average Tax Difference Above/(Below) PPT (Nominal \$M)							
HB 2001	\$423	\$587	\$635	\$608	\$493	\$287	\$423
House Oil & Gas	\$42	\$288	\$638	\$965	\$1,313	\$1,680	\$2,301
House Resources	\$201	\$666	\$1,668	\$3,516	\$5,964	\$8,965	\$12,983

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

Summary Comparison between Various House Approaches to Production Tax

<u>Issue</u>	<u>Current Law</u>	<u>HB 2001 (ACES)</u>	<u>House O&G</u>	<u>House Resources</u>	<u>House Finance</u>
Base Rate	<i>AS 43.55.011 (e) & (g)</i>	<i>Bill Sections 15 & 17</i>			
Base Tax Rate		25%		25%	

Progressivity	<i>AS 43.55.011(g) & (h)</i>	<i>Bill Sections 17,18</i>		
\$/bbl Starting point	\$40 net	\$30 net	\$50 gross	\$30,40,50,60 net
Tax/\$ of Price Index	0.25%	0.20%	0.25%	.2,.3,.4,.5%
Average Value over	month	year	month	month
Applied to	net	net	gross	gross
Cap		25% of net	25% of gross	none

Gross Value Floor	<i>AS 43.55.011(f)</i>	<i>Bill Section 15, 16, 31-36, & 41-42</i>	
Base		Prudhoe; Kuparuk	
Rate		10%	
Credits further reduce floor tax?		No	

Investment Credits	<i>AS 43.55.023</i>	<i>Bill Section 26-28, 38-44 & 63</i>		
Investment Credits	Taken in year of investment	1/2 in each of two years	Taken in year of investment	Taken in year of investment
Loss Carry Forward Credits		25%		rate in (e) (25%)
Transitional Investment Credits	Yes	No	3 years of investment instead of 5	3 years of investment instead of 5

Summary Comparison between Various House Approaches to Production Tax

Issue	Current Law	HB 2001 (ACES)	House O&G	House Resources	House Finance
Exploration Credits	AS 43.55.025	Bill Section 36 - 44			
Rates		20; 40%		30;40%	
G&A Costs		bad acts I		bad acts I	
DNR approval required?		Always		Always	
Confidentiality of well data		2 years		2 years	
Pre-existing well		Two consecutive drilling seasons		Two consecutive drilling seasons	
"DNR TIE" Credits for pre 2003 seismic work?		5%		5%	

State Purchase of Credits	AS 43.55.023(f) & (g)	Bill Section 45 (AS 43.55.028)
Paid from:	"appropriations made by law"	oil and gas credit fund, funded from production taxes
Annual dollar cap per taxpayer?	\$25 million	none
ARM Board Purchases?	n/a	n/a

Allowable Lease Expenditures	AS 43.55.165	Bill Sections 52-64
Use producer audits of operators?	Explicit	Explicit repealed; Implicit
Disallow bad acts II?	yes	add violation of law, lease or license
Dispute resolution	except with state	except with state
DR&R Allowed?	Allocated	No
"Corrosion" Issue		\$0.30 + unscheduled events disallowed
Field Topping Plants allowed?	Yes	No
Off Lease allowed	yes; other tests	yes; other tests

Summary Comparison between Various House Approaches to Production Tax

<u>Issue</u>	<u>Current Law</u> <i>AS 43.05.230 and royalty statutes</i>	<u>HB 2001 (ACES)</u> <i>Bill Sections 2-9,11-13, 49 & 61</i>	<u>House O&G</u>	<u>House Resources</u>	<u>House Finance</u>
Information					
forward looking information required	none	information "necessary to forecast ... revenues under AS 43.55". Penalty up to \$1000 a day.	information "necessary to forecast ... revenues under AS 43.55".	information "necessary to forecast ... revenues under AS 43.55". Penalty up to \$1000 a day.	
Disclosure of tax information	if aggregated to "prevent the identification of particular returns."	if aggregated other producers	if aggregated w/2 other producers	if aggregated w/2 other producers	
DNR sharing royalty information w/ DOR	limited ability	expanded ability	expanded ability	expanded ability	
DOR sharing tax information with DNR	limited ability	expanded ability	expanded ability	expanded ability	

Statute of Limitations *AS 43.05.260* *Bill Sections 1,14,50 new AS 43.55.075*

State assessment must be issued within	3 yrs	6 yrs	6 yrs	6 yrs
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DOR Auditors *As 39.25.100* *Bill Sections 10, 65, 67*

DOR & DNR auditors exempt employees?	no	yes	yes	yes
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Effective Date *Bill Section 64*

Generally	n/a	Jan 1 2008	Jan 1 2008	Jan 1 2007
Retroactive to April 1 2006	n/a	deferred maintenance issues	deferred maintenance issues	Loss carryforward, TIE limitations, most cost redefinitions

Summary Comparison between Various House Approaches to Production Tax

Issue Current Law HB 2001 (ACES) House O&G House Resources House Finance

Downstream Costs *As 43.55.150*

Reasonable v actual	3 criteria linked by "and"	3 criteria linked by "and"	3 criteria linked by "and"	3 criteria linked by "or"
<i>Prima facie</i> reasonable Taps Tariff	Filed TAPS tariff	Filed TAPS tariff	Filed TAPS tariff	FMV (TSM not adjudicated just and reasonable)

TAPS - interest rates set at

Gas Ceilings thru 2022 *As 43.55.011*

Where	CI	CI	non North Slope	CI + gas used in the state
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Additional Penalties *new As 43.55.020*

Penalty for under estimated payments	IRS Penalties (i.e. interest)	IRS Penalties (i.e. interest)	IRS Penalties (i.e. interest)	5% in addition to IRS Penalties (i.e. interest)
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Intent Language

overall intent of legislation	n/a	no	no	included
long standing interpretation of SOL	n/a	included	no	included
Half the money from certain retroactive applications to PERS and public education fund	n/a	no	no	included
tax savings from gas ceilings outside CI passed on to ultimate consumers	n/a	no	no	included

Alaska Oil and Gas Association



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TESTIMONY OF THE
ALASKA OIL AND GAS ASSOCIATION
TO THE HOUSE FINANCE COMMITTEE
REGARDING CSHB 2001(RES)

November 8, 2007

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"). AOGA is the trade association for the oil and gas industry in Alaska. Our 17 members account for the majority of oil and gas exploration, development, production, transportation, refining and marketing activities in the state. Our membership includes Agrium, Alyeska Pipeline Service Co., and Alaska's instate refiners. It includes companies new to this state, hoping for the opportunity to explore. It includes companies that are active today and do not yet have production (but hope to in the future). And it includes companies that are producing today and have been producing here for years.

As one of its important functions, AOGA provides a forum for its members to consider regulatory and legislative proposals, and to reach agreement about industry positions on those proposals. Normally, to establish an AOGA position, a 5/6 vote is required. This ensures that, when AOGA voices a position, regulators and legislators can be assured that that position is the position of the overwhelming majority of Alaska's oil and gas industry.

But on tax issues, AOGA takes this approval process to the highest level. We take positions about taxes only if there is complete consensus in our Tax Committee about what is to be said. Every member receives a copy of each proposed statement on taxes while it is still only in draft form, and if any of them objects to something in a proposed statement, either that portion of the statement is rewritten to satisfy the objection, or else it is deleted. My testimony today has been developed and approved under this principle, with no dissent.

Throughout this special legislative session, individual companies have presented their views based on their operations and the impact of the proposed legislation to their individual companies. The role for AOGA is obviously different, and we have focused our testimony on two key areas.

First, we've strived to put into perspective the critical importance of continued and future industry investment needed to address the most significant issue facing Alaska's future—declining production to the State of Alaska.

Second, through AOGA's Tax Committee, we've provided very specific comments on the numerous technical components of the versions of the legislation before each committee. We've relied heavily on the expertise and experience of our Tax Committee members who have years of experience operating within the state's tax structure. Given the release of the House Resources Committee version of HB2001 just 1½ days ago, there simply hasn't been time for us to develop the quantitative assessment of the technical components in time for this morning's hearing. We are continuing our work in this area and will submit that analysis into the record as quickly as we can for your consideration.

We've heard it said repeatedly that our industry will "game the system" to take unfair advantage of the State — even to the point, some have asserted, of improperly claiming costs for lobbying, advertising or donations to Alaskan charities, despite assurances by the Administration that those costs are not allowed under the present law and will not be tolerated on audit. Accusations of "gaming the system" implies the companies will cheat on their taxes and cheat on the way they do business, if they think they can get away with it. Not only is that against the law, it is an insult to the integrity of the thousands of honest Alaskans who work in our industry.

Second, we all probably know, or know of, individuals who "game the system" a little bit when they report and pay their own income taxes to the IRS. They might pad a deduction, or fail to include cash income they got, or fudge their tax a little in some other way. To the extent someone might do this, it is because he or she feels the odds of being audited and caught by the IRS are small enough to make it worth taking that chance. But do you know anyone who would "game the system" if the chances of being audited by the IRS were 100 percent? Of course not. Well, oil companies are audited twice. First, by each other to ensure no unnecessary or inflated costs are charged to one another when they jointly operate a field. And these audits are every bit as aggressive as the IRS in making sure no costs are improperly included in the bills they have to pay. Second, oil company returns are audited for every state tax they report and pay to the State, for every tax period. The State's present oil and gas tax auditors are smart, experienced and professionally qualified, and we expect the new ones to be hired will be equally good.

Most recently, we hear it being said that the Gaffney Kline economic model shows Alaska can safely raise the production tax far beyond PPT's current levels without jeopardizing investments for the North Slope. I'm no expert, so I left their Capex Multiplier, Opex Multiplier and Production Multiplier at 100% so I wouldn't exaggerate the model's outputs. Then, when I plugged zero in as the value of the oil, the model came up with the totally unexpected result that the producer's internal rate of return is 156 percent. This was so incredible when I saw it, let me repeat it: the model shows an internal rate of return of 156% for the producer when you set oil prices at zero. Try it yourself. And, just as amazing, it shows the State's net present value to be \$1 billion at a price of zero. So this made me wonder what the model shows if I plugged zero in as the volume of oil being produced, instead of plugging it in as the price. The model still

calculated the same wonderful internal rate of return of 156% for the producer, and the State's net present value had actually increased to \$1.3 billion. If all activity on the North Slope were so spectacularly profitable even with no production or with oil prices of zero, then the whole world would be beating a path to Alaska's door to get a piece of that action. But the whole world is not on its way here, and this plain fact proves there must be something wrong.

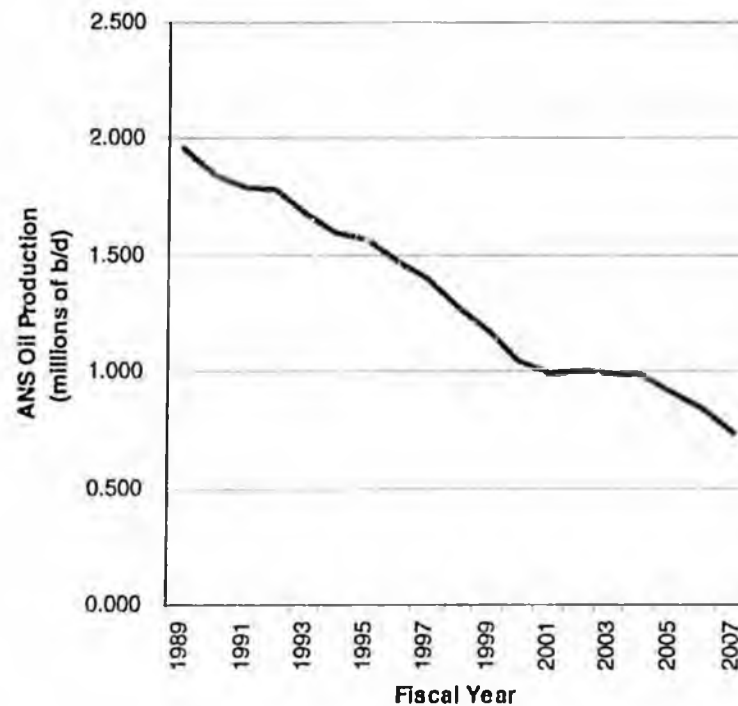
I'm not saying these surprising results prove the model is wrong. Instead, I'm saying that, if it is correct, then these results show there must be some very significant limitations as to the proper use of the model and the meaningfulness of its results. In the time since it was first demonstrated, we have repeatedly heard legislators and members of the public alike citing the model as proof that Alaska could raise its production tax rate to 50% or more of the "net value" without affecting investment. Such statements are not correct, and they reflect a serious misimpression about how the model can properly be used and about what it actually shows. In addition, the model appears to have inflated production volumes and has conveniently left out future operating and capital expenditures necessary to keep the well flowing, facility tie-in and operating costs from the rest of the infrastructure, future abandonment costs, etc. We find it very troubling that a model that is so narrow in its focus, and that considers only one type of investment opportunity in Alaska, is perpetuated to represent the total investment suite of opportunities available in Alaska.

If Alaska oil and gas opportunities are so profitable, according to the Gaffney Kline model, then why is production less than one third of its peak, and why have we only produced less than one quarter of the oil potential in Alaska? Even Pioneer and ENI have recently requested royalty relief for their developments. Doesn't that send a message on the challenges facing new explorers and future development of Alaska's resources? We believe that the focus needs to be on how to encourage the increasing investment needed to develop Alaska's resource potential. Increasing taxes will not help.

The realities that confront Alaska are these: First, nearly 90% of the discretionary money that the State is spending this fiscal year is coming from oil production, and the Department of Revenue ("DOR") predicts that oil revenues will account for over 80% of the State's unrestricted discretionary revenues through Fiscal Year 2013, and 70% or more of those revenues from FY 2014 to the end of its forecast period, FY 2017.¹ These percentages are before factoring in state revenues from a natural gas pipeline and from its associated natural gas production. Oil production has been, is today, and promises to remain the cornerstone of the finances of state government.

Second, production decline is eroding this cornerstone. On the next page is a graph showing how the average daily production rate for North Slope oil has become less and less since FY 1989. It is a historical fact that, on average from FY 1997 to FY 2007, North Slope production each year has been 6.2% less than the year before, while Cook Inlet oil production declined at an average of 8.0% a year.²

Third, it is going to cost billions and billions of dollars to slow this decline down. The North Slope's historical decline of 6% a year has occurred despite industry's investment of over

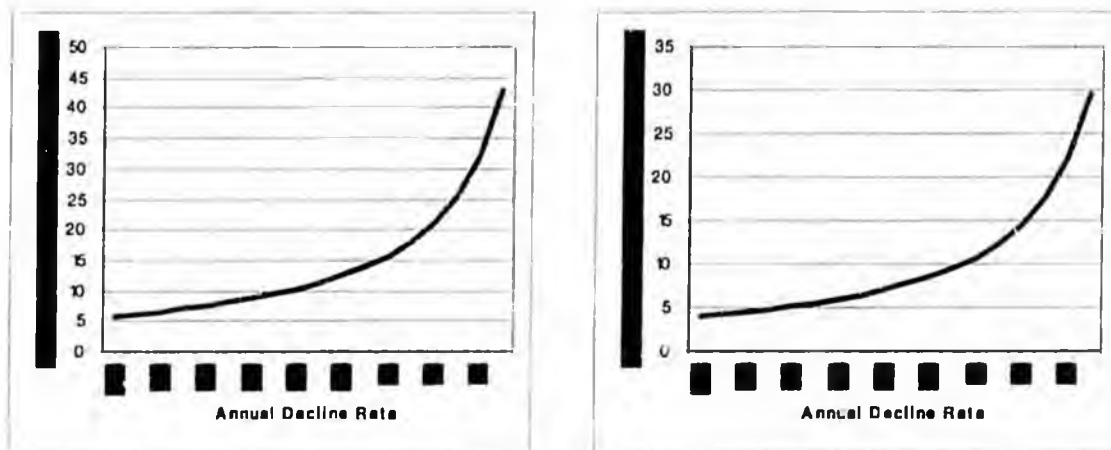


two billion dollars a year to produce more oil. Slowing the rate of decline below 6% will require each year massive increases beyond industry's already substantial, historic level of investment. We believe the investment level needs to increase to be over \$3 to \$4 billion to mitigate production decline. That is almost double the current level of investment being undertaken. Even the DOR's production forecast shows what increasing level of investment is needed. How do you attract the significant increase in investment needed? We don't believe increasing taxes will attract more investment, we believe it will slow down the investment levels needed. Increasing taxes will reduce the attractiveness of new projects and opportunities.

The difference between an ongoing decline of 6% a year and, for instance, 3% may not sound like much, but the difference for Alaska's future is profound. At present it seems the ultimate limit for North Slope oil production may be determined by the minimum capacity of TAPS to pump oil through the pipeline. The new pumps that Alyeska Pipeline Service Company is installing along the pipeline have a rated minimum capacity of 200,000 barrels a day, according to testimony cited during the House Resources Committee's hearings last week on HB 2001. However, the president of Alyeska earlier this year said publicly that the pipeline's minimum capacity with the new pumps will be about 300,000 barrels a day.*

* Whatever the mechanical threshold may actually prove to be for the new pumps being installed, it is generally expected that some new way will be found to operate TAPS at throughputs below that threshold.

Whether the new pumps' operating threshold is 200- or 300,000 barrels a day, the point is the same: There is a big difference between a 6% decline and 3% in terms of how long it would take to get to either threshold from this fiscal year's projected level of 740,000 barrels a day.³ Below are two graphs that show how big this difference is. I should emphasize that these charts are not predictions. They show only the purely mathematical results that flow from the decline rate one chooses.⁴



The chart of the left shows the time to decline from 740,000 barrels a day in FY 2007 to a 200,000-barrel-a-day threshold, the one on the right shows the time to get to 300,000 barrels a day. At a 6% rate of decline the 200,000-barrel threshold is hit in 21 years, but at a 3% decline it would take 43. If the threshold is 300,000 barrels a day, it would be hit after 15 years at 6% and 30 years at 3 percent. For either threshold, the difference between 3% decline and 6% decline gives enough additional time for almost an entire new generation of Alaskans to grow up. When AOGA says the choices facing this Legislature can affect the next generation, we mean it literally.

Fortunately for Alaska, the opportunities exist that should allow the rate of decline to be slowed below 6 percent. These opportunities are in oil and gas exploration, in the development of the huge resources of heavy and viscous oil that are already known to exist, and in the renewal and continued development of the existing fields. In our testimony before the committees previously considering this legislation, we have explained how all three kinds of investment in production will be needed if Alaska is to meet the challenge of production decline. The pattern and timing of the cash flows are different between one kind of investment and another, as is the amount of risk that each entails. But one thing is certain, they are all needed to maximize the resource recovery for Alaska.

One point that bears repeating is that the heavy and viscous oil resource lies within the areas of the so-called "legacy fields," as does the preponderance of the remaining opportunities for squeezing more "conventional" oil out of currently producing fields. The renewal of the existing fields will become increasingly important, as the existing production facilities need to be adapted, retrofitted or perhaps even replaced in order to be fit for service for the coming decades.

At the same time, in-fill drilling to drain the spaces between the existing wells, or develop new oil, offers the best promise of slowing decline in the short term. The pattern and timing of the cash flows are very different between in-fill drilling and renewal of major production facilities on the surface. So even within a classic "legacy field" without considering its resource of heavy and viscous oil, there is significant variation among the investments to be made, the economics for those investments, and the incentives for them. It would be a serious mistake to treat the "legacy fields" as economic monoliths, impervious to how they are taxed and unaffected by the incentives that may be granted them or withheld.

The last point I would like to make today is about destabilizing the investment climate here. In 2005 Governor Murkowski disregarded procedures established by regulation (15 AAC 55.027) and ordered DOR to aggregate certain fields within the Prudhoe Bay Unit, including fields with heavy oil in the West Sak formation, with the main field for ELF purposes. The result was an administratively created change in the tax law of over \$120 million a year. Last year the Legislature enacted the PPT, further increasing the production tax by over \$800 million during the last nine months of 2006 alone. And it did this retroactively back to April first of last year.

Now the Resources CS before you proposes to increase the production tax yet again, and even more massively — on the order of \$1.5 billion over even the PPT each year at \$80 real oil prices, according to DOR's fiscal note for the Resources CS. And, once again, it being proposed to make this change retroactive, this time to the first of this year.

As I have explained, you have been allowed to have serious misimpressions about what the Gaffney Kline model really shows and about how limited its proper use actually is. These misimpressions have, in turn, led to a serious underestimating of the effects of this newest change on future investment decisions about exploration, heavy and viscous oil development, and the renewal and ongoing development of existing "conventional" fields. The laws of economics say there will be adverse impacts on investment decisions here if the House CS becomes law.

It is unfortunate that so many in the public, and even in the halls here, do not believe the warnings being given by the explorers and producers here. Perhaps even this AOGA testimony will change no one's mind. But I have to hope it will. The future of Alaska is at stake, and we urge this Legislature to pull back to safer ground.

Thank you for giving AOGA this opportunity to testify.

ENDNOTES

¹ DOR, *Revenue Sources Book Spring 2007*, p. 17, Figure 2-13 ("Total Unrestricted General Purpose Revenue, FY 2006 and Forecasted FY 2007-2017"), column captioned "Percent From Oil".

² When production declines at $X\%$ a year, this means the production rate after one year (P_1) is $(1 - X\%)$ of the initial production rate (P_0), or $P_1 = P_0 \times (1 - X\%)$. After the second year the production rate (P_2) is $(1 - X\%)$ of the rate after one year of production, or $P_2 = P_1 \times (1 - X\%) = [P_0 \times (1 - X\%)] \times (1 - X\%)$, which can be simplified as $P_2 = P_0 \times (1 - X\%)^2$. After 10 years of decline, the rate P_{10} is $P_0 \times (1 - X\%)^{10}$. North Slope production was 1.404 million barrels a day in FY 1997 and 740 thousand barrels a day in FY 2007, while Cook Inlet produced 37 thousand barrels a day in '97 and 16 thousand barrels a day in '07. See DOR, *Revenue Sources Book Spring 2007*, pp. 97-98. So for the last 10 years of North Slope production decline,

$$1,404,000 \times (1 - X\%)^{10} = 740,000.$$

Dividing both sides of this equation by 1,404,000 gives:

$$(1 - X\%)^{10} = 740,000/1,404,000 = 0.5271.$$

One can solve for $(1 - X\%)$ by taking the 10th root of both sides of this latter equation:

$$\sqrt[10]{(1 - X\%)^{10}} = \sqrt[10]{0.5271}, \text{ or}$$

$$(1 - X\%) = 0.9380.$$

Since $(1 - X\%)$ is the same as $1 - X\%$, one can subtract 1 from each side of the equation to get:

$$-X\% = -0.0620,$$

and then dividing both sides by -1 yields:

$$X\% = 6.20.$$

In other words, the rate of decline averaged 6.20% a year for the North Slope. The same calculations for Cook Inlet, using beginning and ending production of 37,000 and 16,000 barrels a day respectively instead of 1,404,000 and 740,000, yields an average annual decline rate of 8.0 percent.

³ DOR, *Revenue Sources Book Spring 2007*, p.

⁴ Here is the math for the 300,000-barrel-a-day threshold shown in the right-hand graph: From the analysis in Endnote 1 above, we know that for a given decline rate R , the volume of production after N years of decline is $P \times (1 - R)^N$. So for each decline rate in the table, you use that as the value of R in the formula, and then you solve for X as the value of N that gives 300,000 barrels a day as the rate. The equation for this is:

$$740,000 \times (1 - R)^X = 300,000.$$

When you take the logarithm of both sides of this equation, you get the following equation:

$$\log[740,000 \times (1 - R)^X] = \log[300,000].$$

The reason for using logarithms is that they have the property that the logarithm of two numbers being multiplied together equals the sum of the logarithms for each of them, while the logarithm of a number raised to an exponent X equals X times the logarithm of that number. Using this gives the following restatement of the prior equation:

$$\log[740,000] + X \times \log[1 - R] = \log[300,000].$$

Subtracting $\log[740,000]$ from both sides of the last equation yields the following:

[continued on next page]

$$X \times \log[(1 - R)] = \log[300,000] - \log[740,000].$$

Now you can solve for X by dividing both sides of the last equation by $\log[(1 - R)]$, which yields:

$$X = \frac{\log[300,000] - \log[740,000]}{\log[(1 - R)]}.$$

By plugging the decline rate of your choice into this last equation as the value of R , the value of X can be calculated by simple arithmetic and a set of logarithm tables, or with a calculator or computer that can compute logarithms. This straightforward calculation has been done for each of the decline rates shown in the right-hand graph. The equations and arithmetic are the same for the left-hand graph, except that 200,000 replaces 300,000 in the equations.

Comments On ACES Petroleum Tax Proposal, October, 2007
By Ken Thompson, Managing Director, AVCG/Brooks Range Petroleum

Personal Background

For the record, my name is Ken Thompson. I reside at 12031 Lilac Drive, Anchorage, Alaska. I am the Managing Director for Alaska Venture Capital Group, or AVCG LLC, an independent oil exploration company formed with a sole focus on the North Slope of Alaska. AVCG is a privately held member LLC comprised of private equity investors made up of 15 independent oil and gas companies and individuals from Kansas and me as an owner/member partner from Alaska. AVCG has a technical and operational services' subsidiary company called Brooks Range Petroleum, with offices and staff in Anchorage. In Alaska and on the North Slope, we operate under the name Brooks Range Petroleum.

AVCG has lease holdings and explores currently only in Alaska...and nowhere else. AVCG/Brooks Range Petroleum likes to think of our company as "Alaska's *Independent Oil and Gas Company.*"

AVCG LLC has been very active in the past seven North Slope areawide lease sales and active in acquiring acreage held by other companies where we see potential. We and our partners currently hold over 300,000 acres of exploration leases in five exploration prospect areas on the Slope. Our exploration strategy is to explore in the central part of the North Slope for fields in the 10-100+ million barrels range, fields that may be too small for the giant producers but satisfy as niche fields that can be "company makers" for a small independent. We believe there are hundreds of millions if not billions of barrels of oil left on the central North Slope in smaller fields of this size for small independents like ours that want to take this type of exploration risk.

Last year, AVCG LLC announced joint venture agreements with two Canadian independents, TG World Energy and Bow Valley Energy, and with a private exploration company from Houston, Ramshorn Exploration. Together, as working interest co-owners we are exploring the central part of the North Slope.

In the winter of 2006, AVCG participated with an ownership interest in the Cronus exploration well about 10 miles southwest of the Kuparuk Field, operated by Pioneer Natural Resources. Unfortunately, that well was a dry hole.

This past winter for the first time, our operations subsidiary, Brooks Range Petroleum operated the drilling of two exploration wells for our working interest partners in the Gwydyr Bay area of the North Slope, just northwest of Prudhoe Bay. One well, the Sak River #1, was a dry hole, but we were excited to announce earlier this year that our Northshore #1 well northwest of the Prudhoe Bay Field did strike oil. We plan to complete and test this well this winter. In addition, we ran a 130-square mile 3D

seismic survey over our acreage and surrounding area in the Gwydyr Bay area on the North Slope. In total this past drilling season, our JV Group invested over \$44 million on land, seismic and drilling activities.

This winter our Joint Venture Group will be among the most active of explorers as we plan to shoot over 200 square miles of new seismic data on the extreme western and eastern sides of the Central North Slope and to drill up to four exploration wells. We plan to test the Northshore #1 well and also drill one or two other exploration wells nearby to see if we can discover a sufficient volume of oil to warrant a commercial development at Gywdyr Bay. We will drill our Tofkat #1 well south of the Alpine Field and also drill a fourth exploration well on a prospect to be named. In total, our group will spend over \$40 million in seismic and exploratory drilling in winter 2008. If our Northshore oil completion test is as suspected and one of the wells strikes oil close by, we may proceed with Northshore development with more substantial capital investment in the second half of 2008.

My comments today represent the perspectives of a small, independent exploration company that is actively exploring on the North Slope with a good level of activity, generally on prospects that because of smaller size no longer interests the major companies. At the end of next drilling season, AVCG since 1999 and our partners since last year will have jointly invested over \$100 million in Alaska even though none in our group have generated any revenues yet from Alaska oil, so we sincerely appreciate being listened to. We think in the long run we can bring substantial, incremental value to the State of Alaska. Please wish us good luck.

Many of you also know me as the past President of ARCO Alaska, Inc. from 1994-1998. I also served as Executive Vice-President for ARCO and head of global oil and gas exploration for ARCO. I do have exploration and production experience in 10 U.S. states and in over 20 countries throughout the world, so I'll also share my perspective in how I see the ACES bill in the context of competitiveness in the United States and in the world.

General Comments On ACES Legislation

At this point, I would like to address various key points in the ACES legislation.

First, our company prefers that the PPT be allowed to run its course in the next few years, and that ACES not be approved with its current provisions. I agree with Dr. Pedro van Meurs that in the light of declining oil production in the state of Alaska and prospectivity trending to smaller field sizes, the State should not once again increase its taxes after having done so last year. I will tell you that when recruiting companies to join in our Alaska ventures in 2005 and 2006, many were concerned about the threat of tax increases in Alaska. PPT proved tax increases were not a threat but a reality. Adding yet another tax increase via the ACES bill this year shows instability

in Alaska's tax policy which results in uncertainty and risk when making investment decisions.

I heard that consultant Daniel Johnston differed strongly from Dr. van Meurs and urged the oil industry to understand the "cloud of corruption" over the existing Petroleum Profits Tax, or PPT, and that this alone provides a good reason to change PPT. I challenge Daniel Johnston that the bushel should not be thrown out because of a few bad apples.

In fact, last year during the PPT debates, I recall those who are guilty of paying bribes and some who are accused of taking bribes actually supported a 20% base tax rate, not the 22.5% base rate that was finally adopted. In fact, I'd like to think that the almost all in the Legislature and in Industry were honest, that they could be trusted in their deliberations last year, and that the final answer of PPT was a good answer and an honorable answer.

It is also very important to keep in mind that the progressivity tax was added at high oil prices to drive the real tax rate to even higher levels than 22.5%, with a range exceeding 30% now possible at certain prices. And let's not forget to tack on the royalty, the corporate tax, the ad valorem property tax, and environmental and permitting fees. It appeared to me that the checks and balances in the system worked in the Legislature last year, and I applaud the honesty of the legislators who in the end made a positive difference.

But I sit here feeling as if the honest and trustworthy investors in this industry are being punished alongside the guilty. I personally think this will have negative consequences for Alaska in the long haul in relationships and even in sustainable increased value.

But I am politically astute enough to know that the ACES train is moving fast down the track, so I can stand out of the way or jump on board and try to make the ACES bill better before we reach derailment in the long-term relationships between this industry I love and this State I love.

So, I have some suggestions of things not to change and things to change in the ACES proposal.

Five Things *Not* To Change In ACES

- 1) **Keep the exploration and development investment tax credits.** For a small explorer startup company like AVCG LLC, the exploration economics with the exploration tax credits ranging from 20-40% as provided by PPT and with ACES are more favorable with an improvement in the investor's rate of return as compared with Alaska's old severance tax system. Near-term cash flow because of the investment tax credits is higher which improves the return

on investment. Plus refund of cash to companies like AVCG and our working interest partners via the credits mean that we can apply that cash to our capital budget the next year to run adequate seismic and do additional drilling that increases the chance of more oil production and reserves for us and for the State.

Likewise, the credits for losses for a startup company like ours while we establish production and also the development investment credit can take substantial risk out of development of smaller fields that our company is focusing on. May of these smaller fields can add up over time and provide significant incremental revenue to the State.

- 2) **Keep the "standard tax deduction/exemption" for smaller companies.** The "Small Producer Tax Credit" that exempts up to the first \$12,000,000 in production taxes for smaller companies can allow us to return a larger share of our annual cash flow for exploration and investment while we build the company to a critical mass of reserves and production necessary to expand staffing and have a routine level of major capital spending each year.
- 3) **Keep the new ACES tax credit allowance for qualified delineation wells.** A new proposal in the ACES bill that was not in the PPT law is the possible tax credit allowance for the investment in up to two delineation wells following a discovery. This would be very helpful to small explorers as well as for large companies on the North Slope where often one well is not enough to determine if field size is large enough to warrant development.

A real case in point is that should we have a discovery this coming winter at our Tokkat exploration well on the western side of the Slope, we will have to drill one or two delineation wells to confirm if field size is sufficient to develop the resource at this remote location. Often, due to the nature of these complex stratigraphic traps where sands unpredictably come and go, the delineation wells can be almost as risky as the initial exploration well. Having a credit where the State, in a real sense, is sharing in the risk will – I think – expedite delineation of new fields and advance development for revenues.

- 4) **Keep the revised progressivity tax rate at 0.2% per dollar increase in oil price.** The PPT tax law had an incremental tax rate of 0.25% per each dollar increase in oil price above a trigger price while the new ACES reduces this incremental tax rate to 0.2% per dollar increase in oil price at a trigger price. While we can debate all day long the competitiveness of Alaska's tax rate with other countries' fiscal systems, giving some reduction in this surcharge keeps the government take at more reasonable levels. However, as I'll outline below, I would change the ACES trigger price back to \$40 per barrel net and not the proposed \$30 per barrel net if Alaska wants to better balance revenues with industry capital investment at low prices as I'll more fully discuss.

- 5) Do establish the Oil and Gas Tax Credit Fund for the purposes of purchasing certain tax credits from explorers and producers. This ACES provision would establish a procedure and standard for appropriation into this fund and management of this fund. Having a clear and transparent way for small explorers to receive their credits at full value is extremely important for AVCG to then be able to plow those credits back into seismic and exploration on the North Slope.

Four Things To Change In ACES

- 1) Change the recovery of tax credits from two years as proposed in ACES back to the recovery of credits in one year currently provided for in the PPT law. In the PPT law, a company could file for the various credits, and if approved, would receive those full capital credits not to exceed credits of \$25 million per company. In the new ACES law, while the cap has been removed which is very positive, the credits are refunded over two years instead of over one year, e.g., 50% of qualified credits can be applied for in the first year once a well is completed or abandoned and 50% in the following year.

For a small company like ours, this will definitely affect our capital spending in a given winter as we plow all the credit refunds back into seismic or exploration drilling. As a very real example, AVCG and our working interest owners are projecting to spend \$41 million in seismic and exploration drilling this coming winter and likely around the same in 2009. We calculate that we could receive \$16 million cash in qualified credits in mid-year 2008. So essentially, our working interest owners are planning to provide cash out of pocket of \$25 million for the 2009 drilling season; this is a fixed number based on cash availability in these small companies to spend toward the Alaska portfolio. If the State refunds only one-half of this credit in the first year, or only \$8 million instead of \$16 million, AVCG and our partners will still provide \$25 million out of our pockets as now planned and budgeted...meaning our overall spending in 2009 will be \$33 million, not \$41 million, i.e. \$25 million from our available funds and only \$8MM from the State. This would mean one less well that will be drilled by our group in 2009. And one less chance for another discovery that eventually could provide revenues to us all. With small companies, this is just the way our cash flow situation works. And for some of our AVCG investors like me, when I say "out of pocket," I mean "out of pocket."

So, we hope the full credit can be applied for and refunded in a given year. We hope this happens for all of industry. As an innovative compromise, however, the Legislature may consider a "Small Company Refund" provision that allows for companies that meet the no production or low production measures in the "Small Company Tax Credit" provision of the PPT law - that remains in ACES - to receive tax credit refunds that are fully refunded in the

first year for qualified costs. Once a company grows in production beyond this "small company" measure with more substantial cash flow, perhaps refunds of 50% each year would apply as outlined in ACES.

- 2) **Change the base tax rate in ACES from 25% back to the PPT tax rate of 22.5%, and re-review again in 2011 after some time has passed as allowed for in current law.** As I mentioned in my introduction, I felt the 22.5% base tax rate was reasonable. And the real tax rate is much higher with the tax progressivity factor. But what is fair, and how exactly is "fair" determined?

I saw a copy of a presentation entitled "Guiding Principles For A New Production Tax System" by the Department of Revenue urging the changes in ACES, arguing that the average government take in various international countries averaged 67% for all types of fiscal regimes internationally, averaged 74% for production sharing agreements, but only 55% for tax and royalty regimes internationally. Somehow, the Department of Revenue representatives concluded an average of 68% as provided for in ACES would be close to the average of 67% for all types of regimes internationally.

First, the average recommended to Alaska is the average of all regimes, i.e. the averaging of government take from tax and royalty regimes with the government take from production sharing agreement (PSA) regimes. In some countries that I worked in that had production sharing regimes, the risk profile for capital development was often much different than in regimes that use a tax and royalty regime such as Alaska. In PSA countries, it was not unusual for a producer on capital projects to have a very low initial tax burden until the capital investment was fully recovered plus a negotiated rate-of-return was achieved. Then and only then was the government take increased substantially...thus giving the average take for such countries as 74%. But the risk profile was often much better than Alaska, i.e. there was up front recovery of capital and a preferred investor rate-of-return. That is not the risk profile of Alaska when a company first has production...the ACES high tax rate and the added progressivity tax will start immediately along with royalties, corporate taxes, property tax and other charges rather than allowing for recovery of capital and a contractual rate-of-return.

As another distinction, most of the individual people and company investors specifically in AVCG, LLC, do not consider international regimes as areas to consider as competition for our investment dollars with Alaska. Rather, the main competition for most AVCG Owners' cash is in other states in the U.S. I found it astounding and concerning that the average of 67% for all international regimes did not consider weight-averaging in the major American producing states. As examples, the current government takes in the Gulf of Mexico offshore – one of the main competing areas for Alaska investment

dollars – averages 45%. This is under consideration by the U.S. government for increase, but it is highly doubtful with the boom going on in deep water exploration and development that the U.S. government would increase the government take from 45% to 68%.

In other producing states that compete for investment by our AVCG investors, the state and federal combined government takes in 2006 were as follows and averaged 45-57%:

U.S. Gulf of Mexico	45%
Colorado	51%
Wyoming	52%
Kansas	53%
Texas	53%
New Mexico	53%
Oklahoma	53%
California	53%
Louisiana	57%

To my knowledge, these states do not have the added progressivity surcharge tax which further separates Alaska in government take from these competing states. I would argue that Alaska should have a government take of 55% if we were to maintain long-term competitiveness with these other states for investment dollars. Having said that, some of these states do not have the prospectivity of Alaska, so Alaska could command some premium in take, but certainly not as high as being proposed in ACES.

If Alaska set a government take at 60% to the government and 40% to the investor, the ACES legislation should be amended to allow for a base tax rate of 22.5% not 25%, should be amended to allow for a trigger price of \$40 per barrel and not \$30 per barrel, and the incremental progressivity tax rate increase should be 0.2% per dollar.

- 3) Change the trigger price to \$40 per barrel net and not \$30 per barrel.** If the government take is to be the fair and equitable 60% and not the unfair 68%, the trigger price should stay the same as in the PPT law, i.e. \$40 per barrel net. If Alaska is to share in high prices with the progressivity surcharge tax, then Alaska should share in the pain of low prices. To amend the trigger price lower when and if prices collapse will be a false economy measure for the State of Alaska. When prices fall and a company's cash flow is sharply reduced, capital spending will fall. A "double whammy" to be taxed more with a progressivity tax at lower prices further reduces the amount of capital for re-investment.

- 4) Consider some type of "Transitional Investment Expenditure (TIE)" tax credit. This provision allowed for in PPT was repealed in ACES. While this provision does not greatly benefit our company, AVCG, because we did not have large seismic or exploration drilling costs between March 31, 2001, and April 1, 2006, it is important to other major investors in Alaska

As an example, the largest explorer and developer in Alaska, ConocoPhillips, now with the ARCO heritage assets was hardest hit in tax exposure with the change from the old severance tax law to the PPT and now to ACES. I simply think allowing a good steward who is the largest explorer in Alaska some transition allowance to ease the pain of greatly increased taxes is the right thing to do and can only build better, more trusting relationships.

Again, this provision does not greatly benefit our company, however.

Concluding Remarks

This concludes my remarks. I tried to share the perspective of an independent exploration company that only invests in Alaska. My ultimate wish would be for the State to leave PPT alone and re-review it under the law as planned in 2011 or perhaps even in 2010. But if the ACES train has left the station and cannot be stopped, I urge you to at least consider the five things our company would not change in this bill and the four things we would change.

The above comments are offered with a hope that there can be an eventual win-win solution to this complex subject of the State realizing more revenues at higher prices while attracting exploration and development investors who can also realize upside at higher prices for the substantial risk they have taken in the remote and harsh environment of the North Slope. In the end, I hope both sides get a fair and equitable share at all price levels.

And my comments are offered with the highest sincerity that the State and Industry can someday restore a mutual trust at all levels.

I sincerely thank you for the opportunity to present my comments, and I would be happy to take any questions.

Respectfully submitted,

Ken Thompson

TESTIMONY OF CRAIG HAYMES

ON PROPOSED CS HB 2001 (RES)

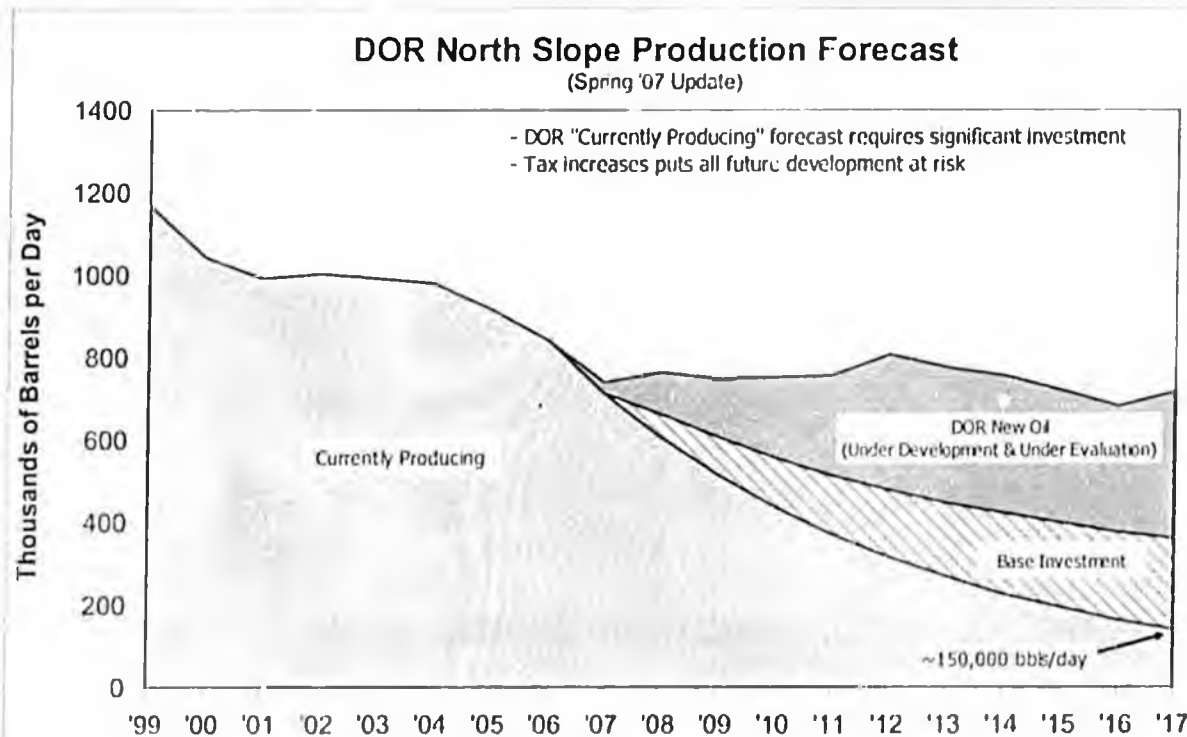
TO THE ALASKA HOUSE FINANCE COMMITTEE

NOVEMBER 8, 2007

EXECUTIVE SUMMARY

Alaska's Future

- **Alaska has significant resource potential**
 - Produced 17 billion barrels of oil, world class result, production today 1/3 of peak
 - Undiscovered technically recoverable resources – 53 BB oil; 259 TCF gas
 - Alaska's world ranking of proved reserves is declining - 14th in 1977, 30th today
 - Prudhoe Bay/Kuparuk > 70% of North Slope production – hubs for future opportunities
- **Alaska's high cost environment challenges pace of exploration & development**
 - Severe arctic conditions, remote, sensitive environment, exploration restrictions
 - Effective application of technology critical
- **Alaska & industry collaboratively need to create a resource development policy**



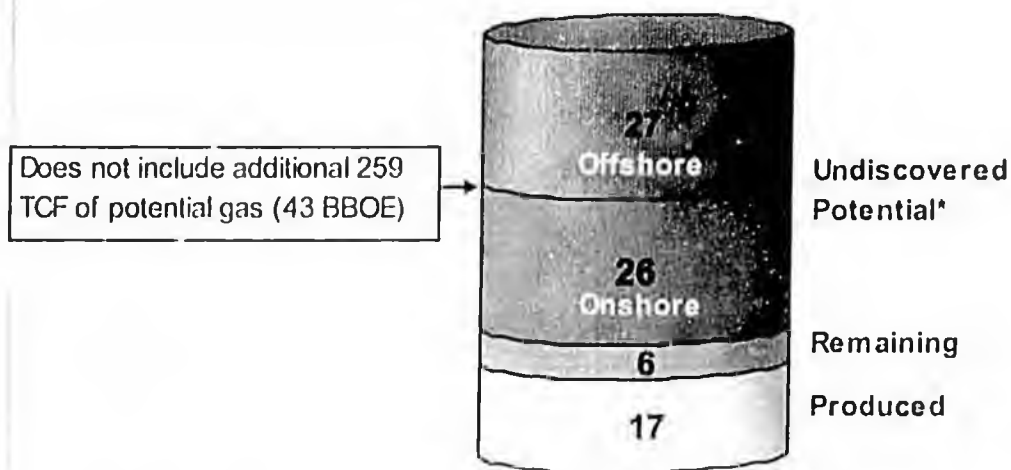
In 10 years, 75% of oil production will come from new investments. Such production will need > \$30-40 Billion of new investments

ExxonMobil

Alaska Needs a Long-Term Resource Development Policy

- We propose a collaborative approach to develop a sustainable long-term resource policy:
 - Characterization of state-wide resource potential
 - Identification of key issues challenging exploration and development
 - Determination of key factors that impact resource value
 - Establishment of goals and measurement of progress
 - A fiscal policy that will encourage development of remaining resources
 - Regular meetings with industry and agency representatives

Alaska Resource Assessment
76 Billion Barrels of Oil



How do we commercialize Alaska's full resource potential?

SOURCE: USGS, MMS, DNR

* mean undiscovered technically recoverable resource

Fiscal Predictability Is Important

- **Industry needs a predictable fiscal environment**
 - Investments are capital intensive and typically evaluated over decades
- **Changing fiscal environment for capital projects reduces attractiveness of investments**
 - For every well or project not progressed, production and State revenues are forgone
- **Support the concept of a net based tax**
- **PPT has only been in existence for slightly more than one year**
 - Department of Revenue has not completed regulations or started an audit
 - Willing to work with DOR and its auditors to improve understanding of joint interest billings

**Policies established today will
impact attractiveness of
potential future projects**

Proposed Tax Increase More Complicated

- **Proposed CS HB 2001 creates greater uncertainty**
 - Additional reporting requirements for exploration tax credits - credit qualification linked to release of proprietary information
 - Exploration confidentiality protection diminished
 - Additional information requests ambiguous – “other records and information the department considers necessary....”
 - Actual transportation costs versus “reasonableness” standard
 - Qualified lease expenditures restricted to those incurred on the lease producing oil or gas
 - Disallowance/Limitation of costs associated with refineries/crude oil topping plants

Proposed changes increase complexity and costs

Proposed Tax Increase Significant

- **Proposed CS HB 2001 increases administrative burden for Department and Industry**
 - Increasing statute of limitations from 3 to 6 years
 - Elimination of requirement for JI Billings as starting point for audits
- **Proposed CS HB 2001 unreasonably excessive**
 - Reduction of transitional tax credits
 - Excessive late filing and document submission penalties
 - Publication of proprietary tax information

At today's prices

- **ACES would increase production taxes by 350% since 2005**
- **CS HB 2001 would increase production taxes by 470% since 2005**

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TESTIMONY OF CRAIG HAYMES
ON PROPOSED CS HB 2001(RES)
TO THE ALASKA HOUSE FINANCE COMMITTEE
NOVEMBER 8, 2007

INTRODUCTION

Mr. Chairman, members of the committee:

Good morning. For the record, my name is Craig Haymes. I am the Alaska Production Manager for ExxonMobil, a position I commenced in January of this year. I reside in Anchorage with my family. I want to thank the committee for the opportunity to express ExxonMobil's views regarding the Administration's proposed tax increase.

I would like to state at the outset that ExxonMobil believes the current PPT tax rate and the increase proposed by the Administration will not result in the additional investment needed to maximize the development of Alaska's resources. When you consider Alaska's resource potential and the current production decline we do not support the tax increase proposed by the Administration.

ExxonMobil has had a presence in Alaska for over 50 years and has been a key player in Alaska's oil industry development, spending and investing over \$20 billion dollars. We are currently active with our co-owners at Prudhoe Bay, Kuparuk, Duck Island, Granite Point and Point Thomson. Our current working interest share of oil production in the State is approximately 150,000 barrels per day and we are the largest owner of

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discovered Alaska gas resources. We look forward to working with Alaska for many years to come.

Alaska has significant undiscovered resource potential in both oil and gas; but oil production is declining - today it is one third of the peak of over 2 million barrels per day in 1988. Increasing investment in Alaska is needed to mitigate oil production decline - Government and industry have a common goal - to maximize economic resource development, both oil and gas. Challenging this significant resource potential, and the pace of exploration and development, is Alaska's high cost environment. For any investor, higher costs reduce attractiveness of opportunities.

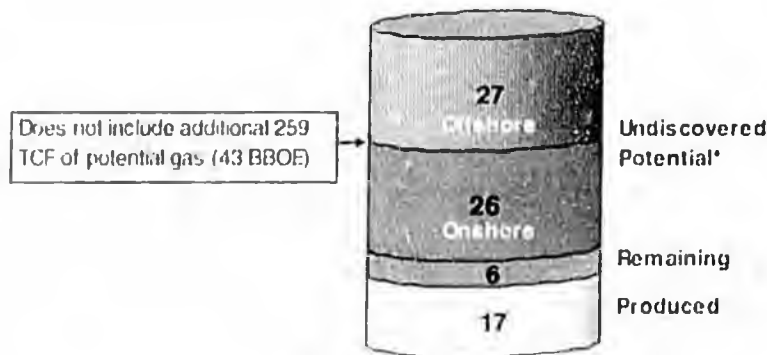
ExxonMobil believes technology is the lifeblood of the industry and the key to unlocking Alaska's future resources. Historically, the effective application of technology by ExxonMobil and other companies has proven to be successful in reducing costs for the exploration and development of Alaska's resources. Significant long term research and development of technology will be required to realize Alaska's resource potential.

The full development of Alaska's resource potential will require Government, the industry, and the people of Alaska to work together to enhance the development of Alaska's resources. We believe that Alaska needs to create a long-term resource development policy, a policy that will encourage increasing investment needed to mitigate production decline, a policy that recognizes Alaska's high cost and challenging environment, a policy that will encourage the full development of Alaska's oil and gas resources.

ALASKA RESOURCE POTENTIAL IS SIGNIFICANT

According to the US Geological Survey and the US Minerals Management Service, Alaska still has undiscovered technically recoverable resources of over 53 billion barrels of oil. This is in addition to the Department of Natural Resources estimate for known remaining oil resources of 6 billion barrels. When you consider this resource potential, Alaska has only produced one quarter of its oil potential. Alaska still has the potential to produce another 59 billion barrels of oil. Expanding the resource assessment to include gas almost doubles this undiscovered potential on an oil equivalent basis. Alaska has significant oil and gas resources.

**Alaska Resource Assessment
76 Billion Barrels of Oil**



SOURCE: USGS, MMS, DNR

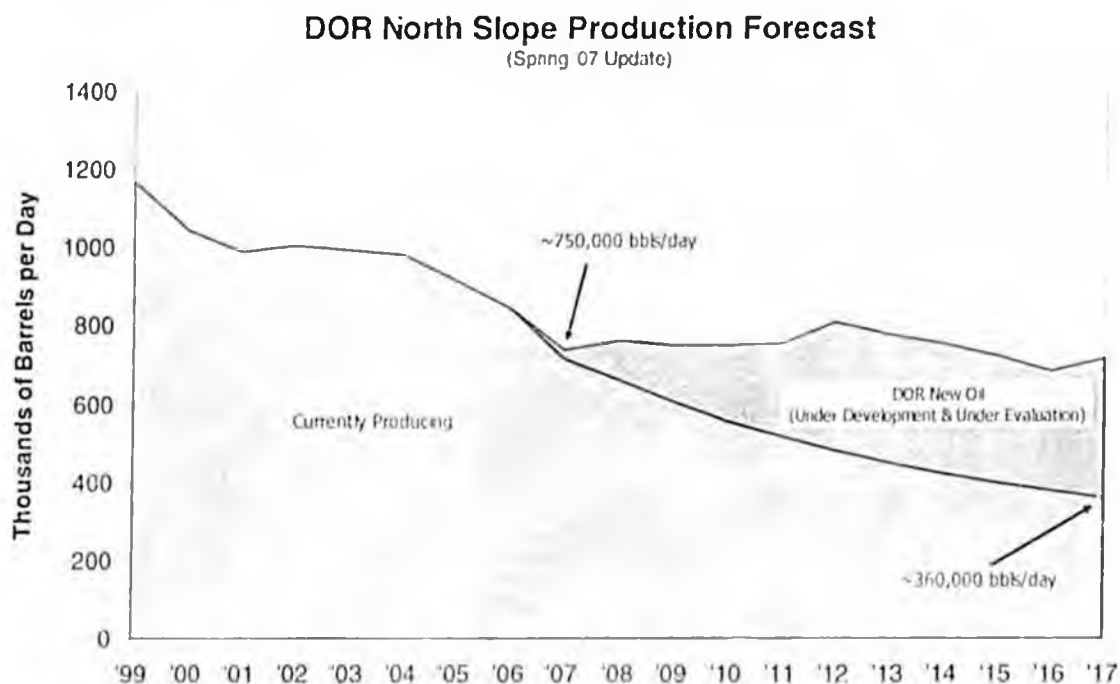
* means undiscovered technically recoverable resource

Whilst Alaska's resource potential is high, the Oil and Gas Journal and Energy Information Administration report that its world ranking of proved reserves has declined from 14th in 1977 to a position closer to 30th today. How can Alaska increase proved reserves: how can we commercialize Alaska's resource potential?

ALASKA'S FUTURE OIL PRODUCTION

Alaska is currently producing approximately 750,000 barrels of oil per day from the North Slope, one third of its peak production. The Department of Revenue released a production forecast in their Spring Revenue Sources Book. The forecast consists of two main components, as shown in the chart below.

- Current base production (shown as green)
- Future "Under Development and Under Evaluation" production (shown as blue)



As the Department's forecast shows, the current base production is estimated to decline at 9% annually to approximately 360,000 barrels per day by 2017 with continued investment. That is a production level of less than half of today's. The Department's forecast also shows that this production decline will be partially mitigated by the "Under Development and Under Evaluation" production – which includes future investments in areas such as development drilling in non core areas, satellite developments, and enhanced oil recovery from existing fields. Based on this forecast, 50% of future oil

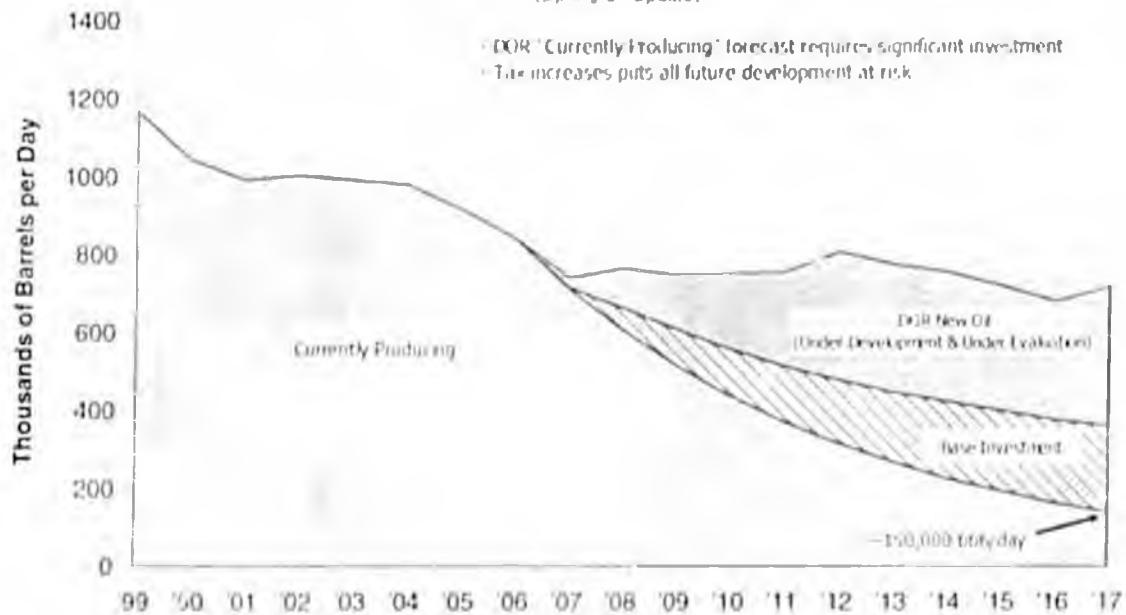
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production in 10 years is not even developed or producing today. Considering that most North Slope projects take at least 5-7 years to bring discovered resources to production, near term investment for these activities will be critical to underpin the future of Alaska's oil production.

As I mentioned earlier, the Department of Revenue's forecast is based on a 9% annual decline in Alaska's current base production. However, this decline includes current production enhancement investments at the core Prudhoe Bay, Kuparuk and Alpine areas. The Department's forecast does not highlight that this activity requires investment decisions that are no different from the "Under Development and Under Evaluation" categories. As such, a more accurate representation of the future investment levels required to achieve the Department's forecast is show in the chart below.

DOR North Slope Production Forecast

(Spring 07 Update)



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As this chart shows, Alaska's oil production from the North Slope could be as low as 150,000 barrels per day within 10 years without ongoing and increasing investment (assuming 15% decline, which is typical for large oil fields such as Prudhoe Bay). Based on this forecast, within 10 years, 75% of production will come from new investments.

Conservatively, we estimate that at least \$30-40 billion of new investment is required within the next 10 years to achieve the Department of Revenue forecast. This does not include the billions of dollars of additional operating expenditures that would be required to support the developments once they are producing. This is a significant level of future investment and spending.

ALASKA'S TWO LARGEST OIL FIELDS

The two largest oil fields in Alaska - Prudhoe Bay and Kuparuk account for over 70% of the State's North Slope oil production. With continued investment these fields could remain at this portion of production for the next decade. But like any oil field in the world, in order to keep the oil flowing, additional investments are required; such as the historical significant investments at Prudhoe Bay resulting in the installation of water and gas injection, and gas compression facilities.

Currently, the owners spend over \$2 billion dollars annually to optimize and enhance production from Prudhoe Bay and Kuparuk. These spending levels are in addition to the capital investments pursuing new wells, projects, and enhanced oil recovery opportunities. These operating expenditures are essential to mitigate production decline at these significant fields.

Many of today's exploration and development activities are occurring in and around Prudhoe Bay and Kuparuk. As an example, since the year 2000 there have been multiple Prudhoe Bay satellite fields developed (Aurora, Borealis, Midnight Sun, Polaris, and Orion) which are currently contributing over 40,000 B/D of oil production. By leveraging existing Prudhoe Bay and Kuparuk infrastructure, satellite development costs have been significantly reduced. If the major Prudhoe Bay and Kuparuk developments did not exist these satellite fields would not have been economic to develop. As infrastructure on the North Slope expands the economic viability of future satellite developments increases.

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Development drilling in and around Prudhoe Bay and Kuparuk is another example of their critical contribution to Alaska's oil production. For the past seven years over 900 new wells have been drilled in Prudhoe Bay and Kuparuk. The drilling of these new wells has slowed the overall production decline from 12-15% to an estimated 6-9%. Almost 40% of Prudhoe Bay's production today is from these new wells. For the past two years, development drilling at Prudhoe Bay alone has achieved the equivalent development of resources as the important Oooguruk development.

Prudhoe Bay and Kuparuk have the potential to remain key hubs and enablers for the pursuit of new heavy or viscous oil, light oil and gas projects. Encouraging increasing investment at these key fields is as important as encouraging investment in exploration and development of new fields.

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EXXONMOBIL'S POSITION ON THE ENACTED PPT

I believe it is important that i clarify ExxonMobil's position on the current PPT.

ExxonMobil did not support the PPT that was enacted last year. As we testified last year, we supported the concept of a net based tax but stated that the proposed 20% tax rate, in the original PPT bill, would not encourage the full development of Alaska's resources. We agreed with the 20% tax rate in order to support the progression of a gas pipeline project.

The PPT that was ultimately enacted increased the high 20% base tax rate to 22.5% with progressivity - more than doubling industry's taxation. When combined with the gross royalties and the high cost environment, it reduces the attractiveness of Alaska's resource developments

There has been a lot of discussion recently on PPT revenues and forecasts, which has been used in part to support the Administration's proposal to increase taxes. PPT has only been in existence for slightly more than one year. The Department of Revenue has not completed its PPT regulations or started any PPT audit. ExxonMobil, like a number of the other producers, met with the Department of Revenue several months ago to discuss ways to help the State better forecast its expected PPT revenues and we are willing to continue those efforts. We are also willing to work with Department of Revenue auditors and our partners to improve the understanding of joint interest billings.

EXXONMOBIL'S POSITION ON THE COMMITTEE SUBSTITUTE

I would now like to offer ExxonMobil's view on major provisions of the Committee Substitute for House Bill 2001 (RES). In analyzing the Committee Substitute, we found that virtually all of the provisions are simply tax increases or further increases in complexity. In a number of instances, existing statutory provisions of general applicability are being replaced or supplemented to apply only to the PPT. Our comments are presented in the following section-by-section analysis.

Base Tax Rate & Progressivity:

The first sections I would like to comment on are Sections 15 and 20, commencing on page 11 and 14 respectively. I have combined these two sections together for discussion purposes because they really are the core of the major issues with the proposed Committee Substitute. Section 15 proposes to raise the base PPT tax rate from 22.5% up to 25%. Section 20 proposes to replace the current progressivity surcharge with a higher one based on gross revenues. As I mentioned earlier, ExxonMobil believes the current PPT tax rate will not result in the additional investment needed to maximize the development of Alaska's resources. When you increase the already high base tax rate you reduce the attractiveness of investments. When you then add an additional level of tax as prices increase, the attractiveness of future investments is substantially reduced, which will impact resource recovery and long-term state revenues. This is especially true under a gross tax element which ignores the true economics of a project. We urge this Committee to not adopt either Section 15 or 20 and to reconsider the current base tax and progressivity element.

Penalties:

Section 25, commencing on line 19 of page 18 would establish a 5% penalty for an underpayment of a monthly estimated tax payment. Section 43, commencing on line 13 of page 31 proposes to allow the Department of Revenue to assess a penalty of up to \$1,000 per day for each day a "tax return" is not filed when required. Paragraph (6) of Section 45 commencing on line 26 of page 33, proposes to allow the Department of Revenue to assess a \$1,000 penalty per day for each "report, statement or other document" the Department "considers necessary" to forecast state revenue that a producer, explorer or operator fails to provide when the Department deems necessary. Each of these amendments is unnecessary.

Under current law, there are already significant penalties to ensure taxpayer compliance with filing tax returns, paying the appropriate amount of tax when due and for providing other information to the Department. Such penalties include a 5% penalty per month (25% maximum) for failure to file a tax return and a similar penalty for failure to pay the full amount of tax when due, among others. The Department also has significant powers to compel production of information, including holding investigations, issuing subpoenas and taking depositions. For these reasons, ExxonMobil believes the proposed penalties are excessive and unnecessary.

In addition, the proposed penalties are unreasonably excessive. A \$1,000 per day penalty for each "report, statement or other document" that is not produced "at the time required" by the Department can quickly result in amounts disproportionate to the nature or severity of the offense. For example, a single one page document that a

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taxpayer did not provide six months earlier because the taxpayer reasonably believed it was already addressed in another submission, would subject the taxpayer to a penalty close to \$200,000. Each of these penalties should be removed.

Transition Tax Credits:

Section 29, commencing on line 13 of page 20, proposes to reduce the amount of tax credits for capital expenditures incurred during the five years immediately preceding the enactment of the PPT to those capital expenditures incurred during the prior three years. ExxonMobil believes the current transition provision allowing 100% cost recovery of the prior five years of capital investment is an important feature of the PPT since it recognizes the long time-frame required for a return on an oil and gas investment to occur.

Conversion to the PPT resulted in a 250% tax increase on the entire industry under today's prices. The Legislature recognized this dramatic change to Alaska's production tax regime by including a five-year transition allowance. The transition allowance was put in place to address the impacts on historical investments made under a significantly lower tax rate.

The transition recovery period is also consistent with the State's objective to encourage future capital investment since the producer has to spend \$2 of additional new capital for every \$1 dollar of prior year investment recovered.

We recommend that the Committee reinstate the transition credits originally intended by the Legislature to mitigate the impacts of the conversion to the higher PPT tax and not adopt the proposed changes in Section 29.

Additional reporting requirements for exploration tax credits:

Paragraphs (B) and (C) of Section 34, beginning on line 27 on page 24 would require that in order to qualify for an exploration tax credit an explorer has to agree in writing to release highly proprietary information; such as seismic, well geophysical surveys and core samples.

Providing this type of proprietary information is not the norm throughout North America. Releasing key competitive and high value information would be a concern to any explorer. It often takes decades to progress from exploration to production phase. The release of proprietary and competitive information before an asset is producing is not appropriate so early in the phase of a future development. This would decrease the value of the exploration credit and may discourage an explorer from applying for the credit.

In addition, providing this type of information to the State would increase the amount of investment required of an explorer. Core samples, for example, are very costly.

Providing one-third of the core material to the State would not only add to the costs of exploring, but would be physically challenging and potentially damaging to the integrity of the entire core. The same constraints also apply to other very limited gas, fluid, and solid samples collected by downhole devices like sidewall core guns or formation samplers. Cores can always be made available for state review upon request and analyses of downhole-collected samples are already routinely provided to the state.

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The confidentiality provisions are also of serious concern. The proposal provides confidentiality protection for only ten years for most of the seismic data required to be produced, and for only two years on the rest. Seismic data typically has a shelf life in exploration areas (especially frontier areas) much longer than 10 years. More troubling is that under the proposal, an operator is required to provide a copy of check shot surveys or vertical seismic profiles. These geophysical surveys are expensive and are intended solely for seismic interpretation. They are key pieces of proprietary data. They have an indefinite shelf life and can be used to tie seismic of any vintage, new or old, to wells. Yet under the administration's proposal, such information would be classified as "well data", and afforded only a 2-year period of confidentiality.

These requirements go against the basic principle that if a party is willing to spend money and take risks to collect information critical to the success of a project, that party should be entitled to maintain the confidentiality, value and integrity of that information for the life of the project. Exploration is a long-term effort, requiring the allocation of finite resources across a spectrum of competing opportunities over a number of years to successfully identify those opportunities that will bring financial returns to the explorer. Alaska's exploration tax credits will improve the attractiveness of future programs, but the value of these credits will be undermined by tying them to complying with onerous requirements. ExxonMobil urges this Committee to remove the onerous requirements outlined in Section 34.

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Information Requests:

The Administration is proposing that they require additional information to assist in the administration of the PPT and improve their ability to forecast future revenues for PPT. We recognize conversion to the net based PPT structure has increased the information needs for the Department of Revenue, and ExxonMobil is willing to help the Department meet its needs. We believe that additional information requirements beyond that currently submitted with our tax filings needs to be carefully considered. There must be some limitations and reasonableness standards established.

For example, subsection (f) of Section 44 of the Committee Substitute, commencing on line 4 of page 32, lists items a producer, explorer or an operator would be required to provide the Department on a monthly basis. Items (1)-(7) are clear, however item (8) on line 17 would obligate the producer, explorer or operator to provide any "other records and information the department considers necessary. . ." - every month. This language is ambiguous on what standards would be applied and how a taxpayer would comply. Taxpayers would be required to provide whatever the Department's auditors consider "necessary". We believe item (8) is too open-ended and should be deleted.

Paragraph (5) of Section 45, commencing on line 17 of page 33, would require a producer, explorer or operator to file whatever reports and copies of records the Department considers "necessary" to forecast PPT revenues. We believe this language in paragraph (5) is too vague. While recognizing the Department's need for forward looking data we believe the tax statutes should specify the required information.

Statute Of Limitations

In lines 7-9 on page 34, Section 46 of the Committee Substitute proposes a new six-year statute of limitations for the PPT only. Currently, the statute of limitations for the PPT, as well as all other taxes under Title 43, is three years. The Department has not started a single PPT audit and increasing the statute of limitations can only delay audits and increase administrative costs. We fail to understand why this amendment is needed. Historically, most companies generally extend the audit deadlines as appropriate when requested by the Department of Revenue.

The purpose of a tax statute of limitations is to establish a reasonable time within which an audit must be brought so that the records, documents, and recollections of witnesses are not lost by the time the claims are finally raised. It also provides some limitation on the amount of interest that could accrue on any underpayment claimed in an audit. Extending the statute of limitations to six years could result in audits not being completed for six years, when they may have otherwise been done more quickly, increasing the interest risk to taxpayers.

The present three-year statute of limitations has worked well for all the taxes, including the production tax. We believe lines 7-9 on page 34 should be deleted.

Actual Pipeline/Marine Transportation Costs:

Sections 48 and 49, commencing on line 21 of page 35 and continuing through line 9 on page 36, is proposing that the Department of Revenue can substitute, at anytime, its determination of "reasonable" costs of transportation for the taxpayer's actual pipeline tariffs or marine transportation costs.

Currently, a taxpayer's actual transportation costs are used to determine the taxable value of the taxpayer's oil unless the Department establishes all three conditions set forth in AS 43.55.150(a). The proposed amendment would ease that standard to allow actual costs to be disregarded by an auditor by simply asserting the actual costs do not meet the auditor's view of "reasonableness", despite the existence of valid third party contracts or federally regulated tariffs.

The proposed amendment represents another instance where the Department of Revenue is asking the Legislature to allow it to selectively determine what costs it deems reasonable versus allowing the deduction of valid costs properly incurred. The proposed changes to AS.43.55.150(a) in Section 48 of the Committee Substitute should not be adopted.

In the Committee Substitute, Section 150(b) would be amended, commencing on line 2 of page 36, to provide that only tariff rates that "have been adjudicated as just and reasonable" by the RCA or other regulatory agency are considered prima facia reasonable. This could unduly restrict rates that will be considered as reasonable costs. In certain instances, tariff rates may be properly filed, as currently allowed, and

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not challenged by any party or allowed to go into effect on an interim basis. In such case there may not be a final "adjudication" of the reasonableness of the rates when they go into effect. If challenged, a period of time may pass before the rates are finally determined to be just and reasonable. Any such final determination by the relevant regulatory agency will address any revision in the rate that may be required, including for prior periods. These matters should be left to the determination of the regulatory agencies with responsibility for such matters. There is no need to further condition how these rates will be used to determine allowable transportation costs. Subsection 150(b) should not be revised as proposed.

Location of Lease Expenditures:

Paragraph (2) of Section 52, commencing on line 31 of page 39, and further modified by Paragraph (2) of Section 53, commencing on line 19 of page 40, would limit qualified lease expenditures to only those associated with activities physically located on the premises of the lease or property from which oil or gas is recovered.

Limiting lease expenditures to those incurred physically within the producer's or explorer's lease or property where oil or gas is recovered would reduce the attractiveness of development and exploration activities. Given the extreme arctic conditions and limited construction capabilities on the North Slope, necessary equipment and production modules are often fabricated elsewhere for delivery to the Slope. Drilling rigs, unavailable in Alaska but needed for exploration and well work, are imported from the Lower 48. These are ordinary and necessary costs required for the operation of the North Slope production facilities and exploration activities, both essential for the future development of Alaska's resources.

The proposed amendment would also allow an auditor to disallow valid upstream costs if no oil or gas is recovered on the property, regardless if the costs are ordinary and necessary for the prudent and safe operation of the upstream facilities. For example, this proposal would disallow costs associated with a warehouse storing emergency response equipment or a facility housing North Slope workers located on a property that has no production, exploration and development occurring at the time, despite such costs being essential for oil production on the North Slope.

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Disallowing such costs would reduce the attractiveness of future development and exploration projects and diminish the likelihood of those projects being funded. The proposed amendment to Paragraph (2) should not be adopted.

Costs Arising From Noncompliance With Lease/Permit/License Terms:

Paragraph (6) of Section 54, commencing on line 2 of page 41, is proposing to disallow expenditures that result from failure to comply with lease obligations or permit requirements. Such a limitation raises a number of concerns. In certain instances, a lease term is a matter of contract between the lease holder and the state as a contracting party. The contract typically will spell out the means for redress by the parties and the consequence of a "breach" of the contract. This should provide adequate remedies for the state to ensure contract obligations are met. In the case of a federal permit, there likely will be specific provisions that address the consequence of any permit non-compliance and what the permit holder must do to remedy the problem. These provisions are adequate to address any concerns for the state.

There is no recognition in the proposed language of the severity of the non-compliance, or the efforts by the leaseholder or permit holder to comply. This is different from an act of "fraud" or "willful misconduct" contained in the current law. This is complicated by the uncertainty in the proposed language on how such a determination will be made. Particularly if the state is a party to a lease, there should be a separate determination whether there has been non-compliance with the lease term or permit and the remedy should be as spelled out in the contract (or as allowed by existing law). The language "...or failure to comply with an obligation under a lease, permit, or license issued by the state or federal government" is unnecessary.

Disallowance/Limitation Of Costs Associated With Refineries/Crude Oil Topping Plants:

Paragraph (19) starting on line 30 of page 42 proposes to disallow and limit costs associated with refineries and crude oil topping plants, essential components of producing oil from the North Slope.

Currently, the State of Alaska and the federal government require North Slope operators to convert to ultra low sulfur diesel to operate all North Slope motor vehicles and off road equipment. The North Slope producers are considering a modification to the existing Kuparuk crude oil topping plant to produce the required ultra low sulfur diesel. The proposed amendment reduces the economic viability of a potential crude oil topping plant modification. Without a modification to the existing crude oil topping plant, it will be necessary to haul low sulfur diesel up to the slope, requiring up to 50 trucks per day. This could potentially increase environmental impacts, including increased exhaust emissions and potential spill risks from truck accidents. Costs associated with the topping plant should therefore be recoverable just as the costs to truck diesel to the Slope would be.

The Administration's proposed amendment encourages a less optimum solution for the oil industry and the State. Paragraph (19) would increase operating costs while complicating business operations and should not be adopted.

Disclosure Of Tax Information:

Section 57 of the Committee Substitute, commencing on line 24 of page 44, proposes the publication of certain proprietary tax information when such information is aggregated among three or more producers or explorers. We understand the Administration's and Legislature's desire to obtain information necessary for the development of the PPT net tax framework to provide the State of Alaska with a fair return on the development of its energy resources. We also support the Administration's goal of transparency. Aggregation of information from three companies dramatically increases the likelihood that competitors, including competitors whose information is being aggregated, will be able to determine individual company proprietary information.

Such information could be used by competitors to discern information regarding operating costs, investments, contract terms, or other competitive information. This risk of individual company proprietary information being ascertained by competitors could also create conflicts between the proposed amendment and federal protections provided in the Federal Trade Secrets Act and federal Anti Trust laws. The proposed amendment may also violate the Alaska Constitution's right of privacy, equal protection and unlawful takings of commercially sensitive data protections.

The Legislature should ensure taxpayer information remains confidential.

November 8, 2007

Elimination Of Requirement For Joint Interest Billings As Starting Point For Audits:

Section 59 of the Committee Substitute, appearing on line 30 of page 45, proposes to repeal AS 43.55.165(c) and (d). The effect of repealing those sections would be to remove the joint interest billings as the starting point for audits. As a non-operator at Prudhoe Bay, Kuparuk, Duck Island and Granite Point we fail to see how not using this information is to anyone's advantage.

In a field's joint operating agreement the working interest owners have specified what costs an operator can bill to the co-owners. All of a producer's deductible lease expenditures are in accordance with the monthly cost data charged by the field operator to its co-owners. Each year the operator is subjected to very detailed audits by the other owners to ensure compliance with the limitations in those agreements. ExxonMobil currently spends over 100 staff weeks each year auditing operator joint billings to ensure we are not charged any inappropriate costs.

The use of these joint interest billings as the foundation of allowable business expenses would provide greater predictability and eliminate the need for the State to re-audit the same materials. Using joint interest billings will reduce disputes over appropriate deductions as well as the State's and the producers' administrative and audit costs. AS 43.55.165(c) and (d) should not be repealed.

FISCAL PREDICTABILITY IS IMPORTANT

I would now like to address another important element of the business environment for any investor - fiscal predictability. Our investments are capital intensive and typically evaluated over timeframes of decades. A change in the fiscal regime has a direct impact on how we view predictability of the Alaskan fiscal environment. This directly impacts how we evaluate on a risked basis future investment decisions.

The Administration's proposed tax increase would represent the third significant change to Alaska's fiscal terms in the past three years. As a result of these changes, the industry tax burden has increased by approximately 350% at today's prices. With the current Committee Substitute proposal the tax increase would be approximately 470% under today's prices. Changing the fiscal environment for capital intensive projects, that take many years to generate a return, can only reduce the attractiveness of future investments. For every well or project not progressed, additional production and State revenues are forgone. Alaska needs to double its current investment levels in the near term to achieve the Department of Revenues production forecast. Increasing taxes will not encourage the increasing investment needed.

ExxonMobil expects to be involved in Alaska for many years to come. The policies established today, and in the future, will impact the attractiveness of potential projects and the future of Alaska.

November 8, 2007

ALASKA NEEDS A LONG-TERM RESOURCE DEVELOPMENT POLICY

ExxonMobil believes a long-term sustainable resource development policy is required to enable Alaska to maximize its oil and gas resource. We believe there are many factors that need to be considered. I hope that key points addressed in my testimony are considered:

- Alaska has significant resource potential, but it is in a high cost environment
- Oil production is one third of its peak, yet we have only produced one fourth of the oil resource potential. The gas resource potential is equal to oil.
- In 10 years, 75% of Alaska's future oil production needs over \$30-40 billion of new investments - investments that are needed sooner than 10 years.
- Prudhoe Bay and Kuparuk are the "hub" of the North Slope, they
 - Represent 70% of North Slope oil production for the next 10+ years
 - Can provide significant new production in the near term
 - Can be the backbone for future exploration and economic developments, whether it is existing production, future light oil, heavy oil, or gas
 - Need increasing investments to achieve their potential

November 8, 2007

We propose a collaborative approach to develop a sustainable long term resource policy that will encourage the needed increasing investments and build the future of Alaska for many generations to come. We believe that a long term resource policy should consider:

- Characterization of state-wide resource potential
- Identification of key issues challenging exploration and development
- Key factors that impact resource value, such as research and technology, exploration and development costs, regulatory and environmental considerations, land access
- Establishment of goals and measurement of progress
- Fiscal policy that will encourage development of remaining resources
- Regular meetings with industry and agency representatives

ExxonMobil looks forward to working with the Administration, the legislators, industry and the people of Alaska in the future pursuit and development of its oil and gas resources.

Thank you again Mister Chairman for the opportunity to testify today.

Chevron



Testimony on SB2001/ HB2001

**John P. Zager
General Manager, Alaska**

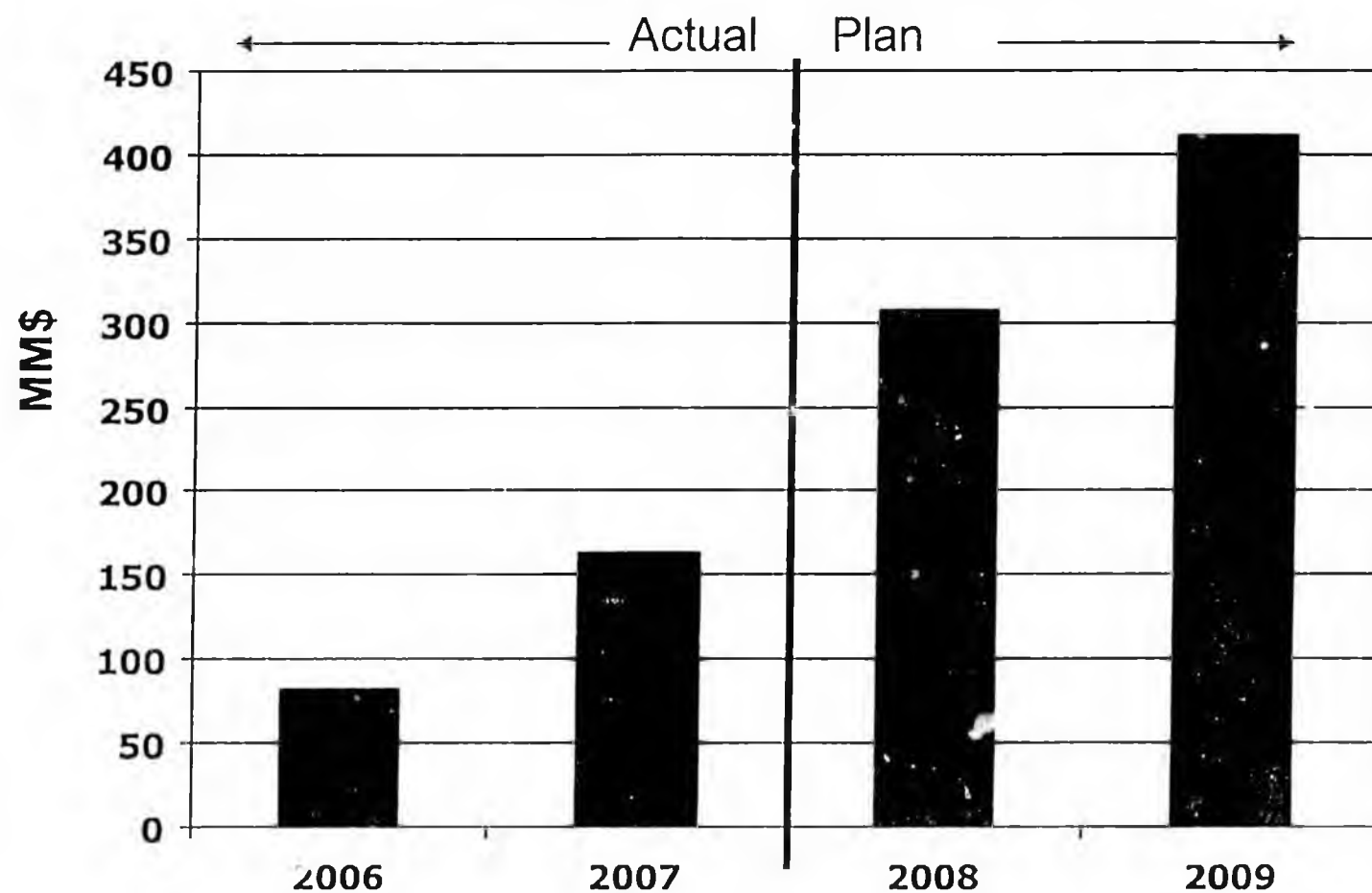


**Juneau, Alaska
November 8, 2007**



Chevron is increasing investment in the Cook Inlet and North Slope exploration under PPT

Capital Investment



Taxing the upside will deter investment

ACES EXAMPLE

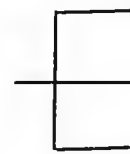
RISKED ECONOMIC ANALYSIS, 4 pt Economic Model

Example A – decision is to drill the well

MEAN EXPECTED VALUE
3.6

DRILL WELL ?
YES

POS
15.0%
Value
20.625



P90
P50
P10

POF
85.0%
Value
-17



FAILURE

NPV

300
100
25

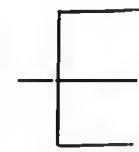
Heavily taxing the upside, can change the investment decision today

Example B – decision is to not drill the well

MEAN EXPECTED VALUE
-0.9

DRILL WELL ?
NO

POS
15.0%
Value
16.125



P90
P50
P10

POF
85.0%
Value
-17



FAILURE

NPV

200
100
25



Look at this bill as it morphs from the original version – is there any balance remaining?

- Base tax rate increase
- Aggressive progressivity
- Transitional Investment Credits reduced or gone
- Retroactive effective date
- Disallowance of certain costs & SB80 language
- Weakening of taxpayer confidentiality
- Multiple layers of penalties for mispayments and errant reporting

Please consider this bill as a whole and find places to restore some balance

Why should we be concerned about costs?



**Cambridge Energy Research Associates
Report issued 4/24/2006**

"RISING CAPITAL COSTS BEAR DOWN ON E&P PROFITABILITY"

"Higher oil and gas prices have encouraged a wave of new investments for discovering and developing resources. However, the soaring costs of exploration and production (E&P) programs and the volatility of energy prices have left many producers uneasy about future profit margins."

"* E&P capital costs are accelerating and have increased approximately 42 percent from 2000 to 2005 (third quarter) compared with a 15 percent rise in the Consumer Price Index."

"* Increasing costs and energy price volatility are having an impact on investments. Oil and gas projects that were profitable at \$22 per barrel in 2002 now require \$35 per barrel to achieve similar returns."

Actual Slides from Testimony to House Finance Committee on April 28, 2006



Parting Questions

- To what degree are you willing to risk future oil and gas investments in Alaska?
- To what degree are you willing to risk the Alaskan economy?
- Is Alaska "open for business"?
- Will Alaska have more or less opportunity for our children after this bill passes?



PIONEER

Pioneer's View of ESG

House Finance Committee
November 8, 2007

NYSE: PXD
www.pxd.com



- **Pioneer Profile**
- **Oooguruk Project Benefits**
- **General Policy Concerns**
- **NPSL “Fair Share”**
- **Exploration Incentives**
- **Conclusion**

