

02/07/13  
SB 21 -  
Proposed  
Amendments  
and Letter  
of Intent

<TARGET><BILL>SB 21</BILL><SUBJECT>02-07-13 SB 21 -  
Proposed Amendments and Letter of  
Intent</SUBJECT><COMM>STTP28</COMM></TARGET>

AMENDMENT #1

OFFERED IN THE SENATE

BY SENATOR GARDNER

TO: SB 21

- 1 Page 9, line 30, through page 11, line 3:
- 2 Delete all material.
- 3
- 4 Renumber the following bill sections accordingly.
- 5
- 6 Page 11, line 29, through page 12, line 17:
- 7 Delete all material.
- 8
- 9 Renumber the following bill sections accordingly.
- 10
- 11 Page 13, line 15, through page 16, line 25:
- 12 Delete all material.
- 13
- 14 Renumber the following bill sections accordingly.
- 15
- 16 Page 18, line 14, through page 19, line 4:
- 17 Delete all material.
- 18
- 19 Renumber the following bill sections accordingly.
- 20
- 21 Page 23, line 15:
- 22 Delete "Sections 2, 5, 6, 22 - 24, and 26"
- 23 Insert "Sections 2, 5, 6, 16 - 18, and 20"

1 F 14 4n (Gardner)  
2 F 14 4n (Gardner)  
3 F 14 4n (Gardner)  
4 F 14 4n (Gardner)  
5 - not offered

1

2 Page 23, line 17:

3 Delete "Sections 3 and 21"

4 Insert "Sections 3 and 15 of this Act"

5

6 Page 23, line 18:

7 Delete "Sections 7, 11, 13, 14, and 25"

8 Insert "Section 7 - 10 and 19"

9

10 Page 23, lines 20 - 21:

11 Delete all material.

12

13 Page 23, line 24:

14 Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"

15 Insert "Sections 3, 7 - 10, 12, 15, and 19"

16

17 Page 23, line 31:

18 Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26"

19 Insert "Sections 1, 2, 5, 6, 16 - 18, and 20"

20

21 Page 24, line 2:

22 Delete "sec. 30"

23 Insert "sec. 24"

AMENDMENT #2

OFFERED IN THE SENATE  
TO: SB 21

BY SENATOR GARDNER

- 1 Page 23, line 3, following "section,":
- 2       Insert "for the first seven years immediately following the commencement of
- 3 production subject to tax under AS 43.55.011(e),"

AMENDMENT #3

OFFERED IN THE SENATE  
TO: SB 21

BY SENATOR GARDNER

1 Page 10, line 19, through page 11, line 3:

2 Delete all material.

3

4 Renumber the following bill sections accordingly.

5

6 Page 11, line 29:

7 Delete "sec. 11"

8 Insert "sec. 9"

9

10 Page 13, line 15, through page 16, line 25:

11 Delete all material.

12

13 Renumber the following bill sections accordingly.

14

15 Page 18, line 14, through page 19, line 4:

16 Delete all material.

17

18 Renumber the following bill sections accordingly.

19

20 Page 23, line 15:

21 Delete "Sections 2, 5, 6, 22 - 24, and 26"

22 Insert "Sections 2, 5, 6, 18 - 20, and 22"

23

1 Page 23, line 17:

2 Delete "Sections 3 and 21"

3 Insert "Sections 3 and 17 of this Act"

4

5 Page 23, line 18:

6 Delete "Sections 7, 11, 13, 14, and 25"

7 Insert "Sections 7, 9, 11, 12, and 21"

8

9 Page 23, line 20:

10 Delete "Sections 9, 10, 12, 15, and 20 of this Act apply"

11 Insert "Section 10 of this Act applies"

12

13 Page 23, line 24:

14 Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"

15 Insert "Sections 3, 7, 9, 11, 12, 14, 17, and 21"

16

17 Page 23, line 31:

18 Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26"

19 Insert "Sections 1, 2, 5, 6, 10, 18 - 20, and 22"

20

21 Page 24, line 2:

22 Delete "sec. 30"

23 Insert "sec. 26"

AMENDMENT #4

OFFERED IN THE SENATE

BY SENATOR GARDNER

TO: SB 21

1 Page 1, line 2, following "rate;":

2 Insert "**relating to the minimum tax on oil and gas production;**"

3

4 Page 2, following line 18:

5 Insert a new bill section to read:

6 **\*\* Sec. 3.** AS 43.55.011(f) is repealed and reenacted to read:

7 (f) Except for oil and gas subject to (i) of this section and gas subject to (o) of  
8 this section, the provisions of this subsection apply to oil and gas produced from each  
9 lease or property within a unit or nonunitized reservoir that has cumulatively produced  
10 1,000,000,000 BTU equivalent barrels of oil or gas by the close of the most recent  
11 calendar year and from which the average daily oil and gas production from the unit or  
12 nonunitized reservoir during the most recent calendar year exceeded 100,000 BTU  
13 equivalent barrels. Notwithstanding any contrary provision of law, a producer may not  
14 apply tax credits to reduce its total tax liability under (e) of this section for oil and gas  
15 produced from all leases or properties within the unit or nonunitized reservoir below  
16 10 percent of the total gross value at the point of production of that oil and gas. If the  
17 amount of tax calculated by multiplying the tax rate in (e) of this section by the total  
18 production tax value of the oil and gas taxable under (e) of this section produced from  
19 all of the producer's leases or properties within the unit or nonunitized reservoir is less  
20 than 10 percent of the total gross value at the point of production of that oil and gas,  
21 the tax levied by (e) of this section for that oil and gas is equal to 10 percent of the  
22 total gross value at the point of production of that oil and gas. In this subsection, "total  
23 gross value at the point of production" means the gross value at the point of

1 production as adjusted by AS 43.55.160(f), if applicable."  
2

3 Renumber the following bill sections accordingly.  
4

5 Page 5, line 27:

6 Delete "sec. 4"

7 Insert "sec. 5"  
8

9 Page 6, line 19, through page 7, line 5:

10 Delete all material and insert:

11 "(B) for oil and gas produced from leases or properties subject  
12 to AS 43.55.011(f), **10 percent of the gross value at the point of production**  
13 **of that oil and gas** [THE GREATEST OF

14 (i) ZERO;

15 (ii) ZERO PERCENT, ONE PERCENT, TWO  
16 PERCENT, THREE PERCENT, OR FOUR PERCENT, AS  
17 APPLICABLE, OF THE GROSS VALUE AT THE POINT OF  
18 PRODUCTION OF THE OIL AND GAS PRODUCED FROM THE  
19 LEASES OR PROPERTIES DURING THE MONTH FOR WHICH  
20 THE INSTALLMENT PAYMENT IS CALCULATED; OR

21 (iii) THE SUM OF 25 PERCENT AND THE TAX  
22 RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g)  
23 MULTIPLIED BY THE REMAINDER OBTAINED BY  
24 SUBTRACTING 1/12 OF THE PRODUCER'S ADJUSTED LEASE  
25 EXPENDITURES FOR THE CALENDAR YEAR OF PRODUCTION  
26 UNDER AS 43.55.165 AND 43.55.170 THAT ARE DEDUCTIBLE  
27 FOR THE OIL AND GAS UNDER AS 43.55.160 FROM THE  
28 GROSS VALUE AT THE POINT OF PRODUCTION OF THE OIL  
29 AND GAS PRODUCED FROM THOSE LEASES OR PROPERTIES  
30 DURING THE MONTH FOR WHICH THE INSTALLMENT  
31 PAYMENT IS CALCULATED];"

- 1
- 2 Page 9, line 30:
- 3 Delete "sec. 7"
- 4 Insert "sec. 8"
- 5
- 6 Page 11, line 29:
- 7 Delete "sec. 11"
- 8 Insert "sec. 12"
- 9
- 10 Page 23, line 15:
- 11 Delete "Sections 2, 5, 6, 22 - 24, and 26"
- 12 Insert "Sections 2, 3, 6, 7, 23 - 25, and 27"
- 13
- 14 Page 23, line 17:
- 15 Delete "Sections 3 and 21"
- 16 Insert "Sections 4 and 22 of this Act"
- 17
- 18 Page 23, line 18:
- 19 Delete "Sections 7, 11, 13, 14, and 25"
- 20 Insert "Sections 8, 12, 14, 15, and 26"
- 21
- 22 Page 23, line 20:
- 23 Delete "Sections 9, 10, 12, 15, and 20"
- 24 Insert "Sections 10, 11, 13, 16, and 21"
- 25
- 26 Page 23, line 24:
- 27 Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"
- 28 Insert "Sections 4, 8, 12, 14, 15, 18, 22, and 26"
- 29
- 30 Page 23, line 31:
- 31 Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26"

1           Insert "Sections 1, 2, 3, 6, 7, 10, 11, 13, 16, 21, 23 - 25, and 27"

2

3   Page 24, line 2:

4           Delete "sec. 30"

5           Insert "sec. 31"

AMENDMENT #5

OFFERED IN THE SENATE

BY SENATOR GARDNER

TO: SB 21

1 Page 1, lines 1 - 2:

2 Delete "relating to appropriations from taxes paid under the Alaska Net Income  
3 Tax Act;"

4

5 Page 1, line 12, through page 2, line 18:

6 Delete all material and insert:

7 **\*\* Section 1.** AS 43.55.011(g) is amended to read:

8 (g) For each month of the calendar year for which the producer's average  
9 monthly production tax value under AS 43.55.160(a)(2) of a [PER] BTU equivalent  
10 barrel of the taxable oil and gas is more than \$30, the amount of tax for purposes of  
11 (e)(2) of this section is determined by multiplying the monthly production tax value of  
12 the taxable oil and gas produced during the month by the tax rate calculated as  
13 follows:

14 (1) if the producer's average monthly production tax value of a [PER]  
15 BTU equivalent barrel of the taxable oil and gas for the month is not more than \$62.50  
16 [\$92.50], the tax rate is 0.4 percent multiplied by the number that represents the  
17 difference between that average monthly production tax value of a [PER] BTU  
18 equivalent barrel and \$30; [OR]

19 (2) if the producer's average monthly production tax value of a [PER]  
20 BTU equivalent barrel of the taxable oil and gas for the month is more than \$62.50  
21 but not more than \$92.50, the tax rate is the sum of 13 [25] percent and the product  
22 of 0.3 [0.1] percent multiplied by the number that represents the difference between  
23 the average monthly production tax value of a [PER] BTU equivalent barrel and

1           **\$62.50; or**  
2                           **(3) if the producer's average monthly production tax value of a**  
3           **BTU equivalent barrel of the taxable oil and gas for the month is more than**  
4           **\$92.50, the tax rate is the sum of 22 percent and the product of 0.1 percent**  
5           **multiplied by the number that represents the difference between the average**  
6           **monthly production tax value of a BTU equivalent barrel and \$92.50, except that**  
7           the sum determined under this paragraph may not exceed **35** [50] percent."

8  
9    Renumber the following bill sections accordingly.

10  
11   Page 5, line 27:

12       Delete "sec. 4"

13       Insert "sec. 3"

14

15   Page 6, lines 11 - 13:

16       Delete "[THE SUM OF] 25 percent **of** [AND THE TAX RATE CALCULATED FOR  
17   THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY]"

18       Insert "the sum of 25 percent and the tax rate calculated for the month under  
19   AS 43.55.011(g) multiplied by"

20

21   Page 6, lines 26 - 28:

22       Delete "[THE SUM OF] 25 percent **of** [AND THE TAX RATE CALCULATED FOR  
23   THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY]"

24       Insert "the sum of 25 percent and the tax rate calculated for the month under  
25   AS 43.55.011(g) multiplied by"

26

27   Page 7, lines 9 - 11:

28       Delete "[THE SUM OF] 25 percent **of** [AND THE TAX RATE CALCULATED FOR  
29   THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY]"

30       Insert "the sum of 25 percent and the tax rate calculated for the month under  
31   AS 43.55.011(g) multiplied by"

1

2 Page 7, lines 19 - 21:

3 Delete "[THE SUM OF] 25 percent of [AND THE TAX RATE CALCULATED FOR  
4 THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY]"5 Insert "the sum of 25 percent and the tax rate calculated for the month under  
6 AS 43.55.011(g) multiplied by"

7

8 Page 8, line 25, through page 9, line 11:

9 Delete all material.

10

11 Renumber the following bill sections accordingly.

12

13 Page 9, line 30:

14 Delete "sec. 7"

15 Insert "sec. 5"

16

17 Page 11, line 29:

18 Delete "sec. 11"

19 Insert "sec. 9"

20

21 Page 21, line 10, though page 22, line 31:

22 Delete all material and insert:

23 **"\* Sec. 20.** AS 43.55.160(a), as amended by sec. 19 of this Act, is amended to read:24 (a) Except as provided in (b) **and (f)** of this section, for the purposes of25 (1) AS 43.55.011(e), the annual production tax value of the taxable oil,  
26 gas, or oil and gas subject to this paragraph produced during a calendar year is the  
27 gross value at the point of production of the oil, gas, or oil and gas taxable under  
28 AS 43.55.011(e), less the producer's lease expenditures under AS 43.55.165 for the  
29 calendar year applicable to the oil, gas, or oil and gas, as applicable, produced by the  
30 producer from leases or properties, as adjusted under AS 43.55.170; this paragraph  
31 applies to

1 (A) oil and gas produced from leases or properties in the state  
2 that include land north of 68 degrees North latitude, other than gas produced  
3 before 2022 and used in the state;

4 (B) oil and gas produced from leases or properties in the state  
5 outside the Cook Inlet sedimentary basin, no part of which is north of 68  
6 degrees North latitude; this subparagraph does not apply to

7 (i) gas produced before 2022 and used in the state; or

8 (ii) oil and gas subject to AS 43.55.011(p);

9 (C) oil produced before 2022 from each lease or property in the  
10 Cook Inlet sedimentary basin;

11 (D) gas produced before 2022 from each lease or property in  
12 the Cook Inlet sedimentary basin;

13 (E) gas produced before 2022 from each lease or property in  
14 the state outside the Cook Inlet sedimentary basin and used in the state, other  
15 than gas subject to AS 43.55.011(p);

16 (F) oil and gas subject to AS 43.55.011(p) produced from  
17 leases or properties in the state;

18 (G) oil and gas produced from leases or properties in the state  
19 no part of which is north of 68 degrees North latitude, other than oil or gas  
20 described in (B), (C), (D), (E), or (F) of this paragraph;

21 (2) AS 43.55.011(g), the monthly production tax value of the taxable

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

30 (B) oil and gas produced during a month from leases or  
31 properties in the state outside the Cook Inlet sedimentary basin, no part of

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

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

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

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

27  
28 Renumber the following bill sections accordingly.

29  
30 Page 23, line 1:

31 Delete "a new subsection"

1 Insert "new subsections"

2  
3 Page 23, following line 10:

4 Insert a new subsection to read:

5 "(g) A separate annual production tax value must be calculated under (a)(1) of  
6 this section for

7 (1) oil and gas produced from leases or properties in the state that  
8 include land north of 68 degrees North latitude, other than gas produced before 2022  
9 and used in the state;

10 (2) oil and gas produced from leases or properties in the state outside  
11 the Cook Inlet sedimentary basin, no part of which is north of 68 degrees North  
12 latitude, during a calendar year before or during the last calendar year under  
13 AS 43.55.024(b) for which the producer could take a tax credit under  
14 AS 43.55.024(a); this paragraph does not apply to

15 (A) gas produced before 2022 and used in the state; or

16 (B) oil and gas subject to AS 43.55.011(p);

17 (3) oil produced before 2022 from each lease or property in the Cook  
18 Inlet sedimentary basin;

19 (4) gas produced before 2022 from each lease or property in the Cook  
20 Inlet sedimentary basin;

21 (5) gas produced before 2022 from each lease or property in the state  
22 outside the Cook Inlet sedimentary basin and used in the state, other than gas subject  
23 to AS 43.55.011(p);

24 (6) oil and gas subject to AS 43.55.011(p) produced from leases or  
25 properties in the state;

26 (7) oil and gas produced from leases or properties in the state no part  
27 of which is north of 68 degrees North latitude, other than oil or gas described in (2),  
28 (3), (4), (5), or (6) of this subsection."

29  
30 Page 23, line 12:

31 Delete "AS 43.55.011(g), 43.55.023(i), and 43.55.160(c) are"

- 1           Insert "AS 43.55.023(i) is"
- 2
- 3   Page 23, line 15:
- 4           Delete "Sections 2, 5, 6, 22 - 24, and 26"
- 5           Insert "Sections 1, 4, 20, 21, and 23"
- 6
- 7   Page 23, line 17:
- 8           Delete "Sections 3 and 21"
- 9           Insert "Sections 2 and 19 of this Act"
- 10
- 11   Page 23, line 18:
- 12           Delete "Sections 7, 11, 13, 14, and 25"
- 13           Insert "Sections 5, 9, 11, 12, and 22"
- 14
- 15   Page 23, line 20:
- 16           Delete "Sections 9, 10, 12, 15, and 20"
- 17           Insert "Sections 7, 8, 10, 13, and 18"
- 18
- 19   Page 23, line 24:
- 20           Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"
- 21           Insert "Sections 2, 5, 9, 11, 12, 15, 19, and 22"
- 22
- 23   Page 23, line 31:
- 24           Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26"
- 25           Insert "Sections 1, 4, 7, 8, 10, 13, 18, 20, 21, and 23"
- 26
- 27   Page 24, line 2:
- 28           Delete "sec. 30"
- 29           Insert "sec. 27"

ALASKA STATE LEGISLATURE  
Trans Alaska Pipeline Throughput Committee

**Sen. Peter Micciche, Co-Chair**

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*Shows Sen.  
Gardner's  
amendments*

**LETTER OF INTENT**

The Senate Special Committee on Trans Alaska Pipeline System (TAPS) Throughput was formed specifically to evaluate solutions designed to reverse or significantly reduce the historical decline in the quantity of oil produced from leases or properties north of 68 degrees North latitude and shipped through the Trans Alaska Pipeline System. The Committee recognizes that oil revenue is extremely important to the State of Alaska and currently funding over 90% of Alaska's essential services and critical infrastructure including education, public safety, health and social services and transportation. The Committee is also aware that projected declines in the Trans Alaska Pipeline System throughput may compound the operational and cost issues that could jeopardize the viability and safe operation of the Trans Alaska Pipeline System.

The Committee was the first to consider SENATE BILL 21 "An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; relating to the determination of annual oil and gas production tax values including adjustments based on a percentage of gross value at the point of production from certain leases or properties; making conforming amendments; and providing for an effective date."

The Committee held six meetings with the intent of framing the discussion around SB 21 through a lens of evaluating direct impacts to the TAPS production decline. The Committee process was designed for fairness and equal participation by majority and minority members. The Committee included expert consultant, agency, the Alaskan public and industry testimony in the process through many productive hours and publicly-available meetings evaluating the potential positive and negative effects on production through revised Alaska oil tax policy. Most importantly, the Committee provided over five hours of Committee time for public testimony from every LIO in the state, as well as telephonically from any location. Every Alaskan that chose to address the Committee was warmly welcomed and given the opportunity to share their support and/or concerns.

The Committee has arrived at several key findings after completing the process of evaluating SB 21 and the effects of oil tax on production. They include:

- Regarding oil revenue that funds the vast majority of governmental functions for the people of Alaska, there are many factors in which the State has little control, including the price of North Slope oil. Total government take through oil taxation is the only lever under the control of the people of Alaska.
- The ACES tax structure has likely contributed to advancing the decline of oil production and throughput in TAPS, primarily due to a lack of competitiveness with other OECD producing regions.
- When evaluating with increased production as a primary objective, ACES credits should have been more specifically directed toward projects resulting in production and less toward general spending.
- Specific incentives and a competitive oil tax regime in Alaska will likely result in additional production-related spending.
- There has been a direct correlation in other OECD producing regions between production-related spending and increased production.
- Current fiscal spending policies appear to have an adverse effect on the business climate and willingness to invest in the State of Alaska. Policies must deliver the clear message to the business community that Alaska will not continue taxing to fund unsustainable levels of government spending.
- Although SB 21 is an adequate platform from which a respectful dialogue can begin, in the current form the bill may not adequately provide production credit incentives and opportunities; a level revenue proportion for Alaskans; and protections for Alaska hire and re-investment.

The Committee's intent to pass the bill to the Senate Resources Committee in the original form for further processing is in no way an expression of support by Committee members for SB 21 in current form. In fact, most members have expressed concern for key concepts that would require revision prior to supporting the bill as it moves through the legislative process.

Key concerns being passed through this letter with an expectation of consideration moving forward will be communicated in two sections. The first section below includes throughput-related Committee recommendations:

- Evaluate providing a guarantee of investment in Alaska and a further incentive for stemming production decline from leases or properties north of 68 degrees North latitude by fixing the amount of production used in determining the reasonable transportation costs to determine transportation deduction costs for pipelines and gas treatment plants under the Oil and Gas Production Tax and Oil Surcharge, AS 43.55, so that producers receive a benefit for increased oil production and throughput in the Trans Alaska Pipeline System but incur a corresponding limitation on deductions due to throughput declines after December 31, 2015.
- Evaluate expanding the application of the Gross Revenue Exclusion in units formed before 2003 (Legacy Areas). The Senate Resources Committee should specifically inquire about expansions of existing Participating Areas, increasing recovery factors in

existing Participating Areas, and Participating Areas that contain oil with an API gravity of 20 degrees or less.

- Evaluate specific production-related credits allowed under ACES for inclusion in SB 21 as a direct incentive for costs that deliver production. Require that credits are charged against actual production to eliminate currently-existing negative revenue liability to the State.

The Committee is united in several philosophies that are also recommendations to be considered in SB 21, not related to throughput, including:

- Firm incentives for Alaska Hire and Alaska Purchase,
- Evaluating significant and specific incentives for unconventional and heavy oil,
- Evaluating a production credit system for producers willing to provide propane fuels for the people of rural Alaska in areas unlikely to receive natural gas distribution if/when a natural gas pipeline is constructed, and
- Evaluating employing progressivity as a tool to level the proportion of take for Alaskans across the various oil price environments.

Although not supported unanimously by the Committee, yet in the spirit of fairness for all Committee members, the Minority Committee member has requested the following considerations to be passed onto the Senate Resource Committee:

- Evaluate a time limit into the future for the 20% Gross Revenue Exclusion.
- Evaluate removing the Net Operating Loss provision in SB 21.
- Evaluate adding a 10% minimum gross tax at the gross value at the point of production.
- Consider [bracketing] progressivity [at varying rates] as the price of oil varies.

The Senate Special Committee on Trans Alaska Pipeline System (TAPS) Throughput will continue to convene to identify and evaluate additional mitigation solutions for operational and regulatory TAPS production-related obstacles in the future. The Committee looks forward to the constructive dialogue and additional processing that will occur within the Legislature related to SB 21 the remainder of this session.

Respectfully submitted to the Senate Resource Committee on February 7, 2013,

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Sen. Peter A. Micciche, Co-Chair

---

Sen. Mike Dunleavy, Co-Chair

**ALASKA STATE LEGISLATURE**  
**Trans Alaska Pipeline Throughput Committee**

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**LETTER OF INTENT**

The Senate Special Committee on Trans Alaska Pipeline System (TAPS) Throughput was formed specifically to evaluate solutions designed to reverse or significantly reduce the historical decline in the quantity of oil produced from leases or properties north of 68 degrees North latitude and shipped through the Trans Alaska Pipeline System. The Committee recognizes that oil revenue is extremely important to the State of Alaska and currently funding over 90% of Alaska's essential services and critical infrastructure including education, public safety, health and social services and transportation. The Committee is also aware that projected declines in the Trans Alaska Pipeline System throughput may compound the operational and cost issues that could jeopardize the viability and safe operation of the Trans Alaska Pipeline System.

The Committee was the first to consider SENATE BILL 21 "An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; relating to the determination of annual oil and gas production tax values including adjustments based on a percentage of gross value at the point of production from certain leases or properties; making conforming amendments; and providing for an effective date."

The Committee held six meetings with the intent of framing the discussion around SB 21 through a lens of evaluating direct impacts to the TAPS production decline. The Committee process was designed for fairness and equal participation by majority and minority members. The Committee included expert consultant, agency, the Alaskan public and industry testimony in the process through many productive hours and publicly-available meetings evaluating the potential positive and negative effects on production through revised Alaska oil tax policy. Most importantly, the Committee provided over five hours of Committee time for public testimony from every LIO in the state, as well as telephonically from any location. Every Alaskan that chose to address the Committee was warmly welcomed and given the opportunity to share their support and/or concerns.

The Committee has arrived at several key findings after completing the process of evaluating SB 21 and the effects of oil tax on production. They include:

- Regarding oil revenue that funds the vast majority of governmental functions for the people of Alaska, there are many factors in which the State has little control, including the price of North Slope oil. Total government take through oil taxation is the only lever under the control of the people of Alaska.
- The ACES tax structure has likely contributed to advancing the decline of oil production and throughput in TAPS, primarily due to a lack of competitiveness with other OEDC producing regions.
- When evaluating with increased production as a primary objective, ACES credits should have been more specifically directed toward projects resulting in production and less toward general spending.
- Specific incentives and a competitive oil tax regime in Alaska will likely result in additional production-related spending.
- There has been a direct correlation in other OEDC producing regions between production-related spending and increased production.
- Current fiscal spending policies appear to have an adverse effect on the business climate and willingness to invest in the State of Alaska. Policies must deliver the clear message to the business community that Alaska will not continue taxing to fund unsustainable levels of government spending.
- Although SB 21 is an adequate platform from which a respectful dialogue can begin, in the current form the bill may not adequately provide production credit incentives and opportunities; a level revenue proportion for Alaskans; and protections for Alaska hire and re-investment.

The Committee's intent to pass the bill to the Senate Resources Committee in the original form for further processing is in no way an expression of support by Committee members for SB 21 in current form. In fact, most members have expressed concern for key concepts that would require revision prior to supporting the bill as it moves through the legislative process.

Key concerns being passed through this letter with an expectation of consideration moving forward will be communicated in two sections. The first section below includes throughput-related Committee recommendations:

- Evaluate providing a guarantee of investment in Alaska and a further incentive for stemming production decline from leases or properties north of 68 degrees North latitude by fixing the amount of production used in determining the reasonable transportation costs to determine transportation deduction costs for pipelines and gas treatment plants under the Oil and Gas Production Tax and Oil Surcharge, AS 43.55, so that producers receive a benefit for increased oil production and throughput in the Trans Alaska Pipeline System but incur a corresponding limitation on deductions due to throughput declines after December 31, 2015.
- Evaluate expanding the application of the Gross Revenue Exclusion in units formed before 2003 (Legacy Areas). The Senate Resources Committee should specifically inquire about expansions of existing Participating Areas, increasing recovery factors in

existing Participating Areas, and Participating Areas that contain oil with an API gravity of 20 degrees or less.

- Evaluate specific production-related credits allowed under ACES for inclusion in SB 21 as a direct incentive for costs that deliver production. Require that credits are charged against actual production to eliminate currently-existing negative revenue liability to the State.

The Committee is united in several philosophies that are also recommendations to be considered in SB 21, not related to throughput, including:

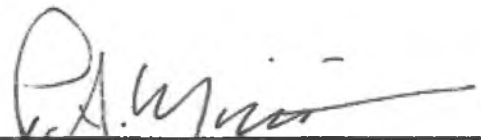
- Firm incentives for Alaska Hire and Alaska Purchase,
- Evaluating significant and specific incentives for unconventional and heavy oil,
- Evaluating a production credit system for producers willing to provide propane fuels for the people of rural Alaska in areas unlikely to receive natural gas distribution if/when a natural gas pipeline is constructed, and
- Evaluating employing progressivity as a tool to level the proportion of take for Alaskans across the various oil price environments.


Although not supported unanimously by the Committee, yet in the spirit of fairness for all Committee members, the Minority Committee member has requested the following considerations to be passed onto the Senate Resources Committee:

- Evaluate a time limit into the future for the 20% Gross Revenue Exclusion.
- Evaluate removing the Net Operating Loss provision in SB 21.
- Evaluate adding a 10% minimum gross tax at the gross value at the point of production.
- Consider progressivity as the price of oil varies.

The Senate Special Committee on Trans Alaska Pipeline System (TAPS) Throughput will continue to convene to identify and evaluate additional mitigation solutions for operational and regulatory TAPS production-related obstacles in the future. The Committee looks forward to the constructive dialogue and additional processing that will occur within the Legislature related to SB 21 the remainder of this session.

Respectfully submitted to the Senate Resources Committee on February 7, 2013,

  
Sen. Peter A. Micciche, Co-Chair

  
Sen. Mike Dunleavy, Co-Chair

**SENATE COMMITTEE REPORT  
First Committee of Referral**

DATE: 1/16/13

FURTHER: Resources  
Finance

Date of 5-Day Notice: 1/17/13  
(in accordance with Uniform Rule 23)

DATE TURNED  
IN TO OFFICE: 2/8/13

Senate Special Committee on Trans Alaska Pipeline System Throughput considered SENATE BILL NO. 21

**SB 21-OIL AND GAS PRODUCTION TAX**

"An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; relating to the determination of annual oil and gas production tax values including adjustments based on a percentage of gross value at the point of production from certain leases or properties; making conforming amendments; and providing for an effective date."

and recommends:

- be replaced with CS \_\_\_\_\_ (\_\_\_\_\_)  Same Title  New Title
- adopt previous CS \_\_\_\_\_ (\_\_\_\_\_)  Same Title  New Title
- attached amendment(s)
- adopt TTP Letter of Intent
- further referral to \_\_\_\_\_ Committee

Dept Abbr.	
ADM	LWF
CED	LAW
COR	LEG
CRT	MVA
EED	DNR
DEC	DPS
DFG	REV
GOV	DOT
DHS	UA

Previous FISCAL NOTE(S)				
Dept.	Fiscal	Indet.	Zero	FN #
'REV'		✓		1
DNR		✓		2

PREVIOUS FISCAL NOTE(S)				
Dept.	Fiscal	Indet.	Zero	FN #

APPROPRIATION - no fiscal note

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	DO PASS	DO NOT PASS	NO REC	AMEND
<i>Berta Gardner</i>	GARDNER				✓
<i>Ganna J. Fairclough</i>	FAIRCLOUGH				✓
<i>Neil McCune</i>	McCune				✓
CO-CHAIR: <i>Michael Sato</i>	DUNLEAVY			✓	
CO-CHAIR: <i>RA Micicche</i>	MICICCHE				✓



THE STATE  
of **ALASKA**  
GOVERNOR SEAN PARNELL

## Department of Revenue

COMMISSIONER'S OFFICE  
Bryan Butcher, Commissioner

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February 7, 2013

The Honorable Berta Gardner  
Alaska State Senator  
State Capitol, Room 417  
Juneau, AK 99801-1182

Dear Senator Gardner:

I am writing in response to your February 1, 2013 letter with questions that arose during the Econ One Research presentation. I have worked with Mr. Pulliam and our economic research staff to answer your questions below. Please see questions in italics and our responses immediately below the questions.

1. *In recent years in Alaska there has been discussion about the majors being in "harvest mode." Is there any reason to believe that this characterization is incorrect?*

Alaska's majors (defined here as CP, EM and BP) continue to develop their properties, which have billions of additional recoverable barrels in reserves. In addition, they are expanding (in the case of Conoco at CD-5 and Exxon and BP at Pt. Thompson) and have attempted to develop new fields (e.g., Liberty for BP) but have met with technical challenges. In addition, they have invested in recent years in updating older facilities in aging fields, facilities that will enable these fields to produce for many years to come. These activities are not consistent with companies that are in "harvest mode."

2. *Slide 26: Producer spending (in red) between 2007 and 2012 is roughly level while "all other" spending (in green) is doubled over the same period. We don't really know if producers were doing new work or maintenance work, but does the green portion indicate that ACES was successful in bringing new participants to Alaska?*

Capital spending by large producers (red) grew by approximately \$250 million between 2007 and 2012. At the same time, capital spending by all others (green) grew by approximately \$320 million. The growth in "all others" over this period overlaps with the development of Oooguruk and Nikaitchuq by Pioneer Natural Resources and ENI, though the (green) spending in Chart 26 encompasses additional companies.

Pioneer Natural Resources is the operator at Oooguruk and has a 70% working interest, which it acquired in 2002 during the ELF period. ENI holds the remaining 30%, which it acquired through the purchase of the Alaskan assets of Armstrong Oil & Gas in August 2005, also during the ELF period. The project was sanctioned in January 2006.

ENI is the operator of Nikaitchuq. ENI acquired a 30% interest in Nikaitchuq with the purchase of the Alaskan assets of Armstrong Oil & Gas in August 2005. ENI acquired the remaining 70% interest in

the Unit from Anadarko in March 2007. Anadarko in turn acquired its interest from Kerr-McGee.

KMG/Armstrong, ENI's predecessor in interest at Nikaitchuq, began drilling exploration and appraisal wells in the 2003-2004 season and drilled six wells prior to 2006. ENI sanctioned development of Nikaitchuq in February 2008 after receiving royalty relief approval from DNR in the second half of 2007.

ENI also owned interests in the North Tarn field (Mustang), which it acquired from Armstrong in August 2005. ENI farmed out its interests in these properties in 2010 to Brooks Range and a group of independents. Brooks Range and its partners are actively trying to advance Mustang and other projects as well.

With these background facts in mind, I do not believe that the rise in spending by "all others" shown in Slide 26 indicates that ACES (or its provisions) brought new participants to Alaska.

3. *Slide 27: Does this slide show that spending for new units increased 2 ½ times under ACES?*

Slide 27 shows that spending for units not in production as of 2003 (Oooguruk, Nikaitchuq, Pt. Thomson and others) increased from \$426 million in 2007 to \$1,091 million in 2012. 2012 spending was approximately 2.5 times the level of 2007 spending. This represents an increase of approximately 150% during the period in which ACES has been in effect.

4. *Slide 38: This is an area profile for Australia. Can you explain why both employment and capital spending increased dramatically during the period 2002-2011 but Drilling/Development dropped beginning in 2006?*

This slide shows employment and capital spending growing through 2011, while drilling is declining from 2006 forward. I believe these inverse trends are likely the result of two factors. First, the employment data from Australia includes mining operations, not just petroleum operations. We do not have a separate breakout for petroleum employment in Australia. Second, much of the capital spending in Australia has been related to LNG development which will include significant spending on facilities rather than drilling.

5. *Slide 43: Employment is climbing as spending holds steady. Why is this?*

Slide 43 shows a significant growth in Alaska employment beginning in 2006, flattening between 2008 and 2011 and increasing by approximately 5% in 2012 (see also slide 34). The purpose of this slide is to benchmark employment changes in Alaska against other areas. We do not have 2012 comparative data for regions other than the lower-48. The top right panel shows employment growth in the rest of the US rose by a greater amount than the 5% we enjoyed in Alaska in 2012.

Chart 34 shows both Alaska spending (top right) and employment (bottom left) over time. The 5% employment growth between 2011 and 2012 is not matched by a similar increase in capital spending. I do not know the reason for this. I do note that we see the reverse happening between 2007 and 2008, with spending rising by a larger amount than employment. Finally, I'd note that I would not necessarily expect to see a match between capital spending and employment changes. Capital reflects spending on facilities and wells. A component of this will show up in Alaska employment, but some portion will not, as the spending (e.g., engineering, fabrication) may take place outside the state.

6. *Slide 45: Attractiveness of Investments: We talked a bit about the role of various factors such as prospectivity, stability, Internal Rates of Return. What other factors might be considered?*

This slide begins the section on investment analysis. Slide 48 lists the measures or "metrics" we examined in our analysis. I believe these are the significant financial measures that companies consider when making investment decisions. In addition to the measures listed in Slide 48, companies will consider prospectivity, political and fiscal stability, contractual obligations, permitting and access, and environmental and regulatory issues. Companies will also consider whether the project and/or area fits with their overall corporate strategy and operations and their ability of management to adequately focus on the project and/or area. All of these issues matter, though they are not all readily quantifiable. This is why we focused our comparisons on the US, Canada, North Sea and Australia as they share many of the same "non-quantifiable" qualities and are areas in which many of the North Slope producers are active.

7. *Slide 47-52: ACES incumbents have very high IRR. Is it fair to say that this means it is almost impossible to NOT make money under the status quo? If so, why are projects being delayed?*

The higher IRRs for ACES incumbents result entirely from the "buy-down" effect. Additional investment under ACES allows an incumbent to "buy-down" its tax rate on existing production. Under the ACES system a producer can earn those higher IRRs, but only if it reinvests in Alaska to buy down its tax rate. It cannot earn those returns if it chooses to distribute its profits to shareholders, which is vitally important to management, not to mention shareholders. In this sense, the profits (and associated higher IRRs) are somewhat "captive" and may not be viewed as being of same quality (i.e., comparable) to profits earned in other jurisdictions where no such strings are attached.

I believe that this is one reason why projects "are delayed" or not started at all, even though the IRRs are so high. Higher IRRs are a good thing, *ceteris paribus* (meaning all else equal). The challenge here is that all else is not equal, as discussed above.

Another reason is that IRR does not tell the whole story. IRR is just one measure that investors look at. IRR is an investment decision tool, but should not be used to compare mutually exclusive projects, only to decide whether a single project is worth investing in. Moreover, IRRs are not appropriate for comparing projects with different risk characteristics.

It is also important to note that IRR assumes reinvestment of interim cash flows in projects with equal rates of return (the reinvestment can be the same project or a different project). Therefore, IRR overstates the annual equivalent rate of return for a project whose interim cash flows are reinvested at a rate lower than the calculated IRR. This presents a problem, especially for high IRR projects, since there is frequently not another project available in the interim that can earn the same rate of return as the first project.

When the calculated IRR is higher than the true reinvestment rate for interim cash flows, the measure will overestimate, sometimes very significantly, the annual equivalent return from the project. The formula assumes that the company has additional projects, with equally attractive prospects, in which to invest the interim cash flows. This is likely to be the case for the high IRRs indicated for Alaska incumbents.

In short, IRR is one factor, but should not be viewed in isolation. IRR calculations that vary greatly from most other opportunities should probably be taken with "a grain of salt."

8. *Can you show us these IRR slides with a line for SB21 for both incumbent and new participants?*

Charts 62-66 show the same analysis as Charts 49-53 and include SB21.

9. *Slide 47: You indicate development costs of \$16/bbl in Eagle Ford and \$19 in Bakken. We have heard that development costs were significantly higher than that. A recent study using data from the North Dakota Industrial Commission in July 2012 found that the breakeven price for the "average" well in the Bakken formation is \$80-\$90/barrel, with an average decline of 40% in the first year. Can you explain the difference between "development costs" and "break-even price"?*

Breakeven price refers to the price of oil in the market that is necessary for an investor to "breakeven" on its investment. Here breakeven would include recovering costs, including the cost of capital. Development costs (indicated at \$19/bbl in Slide 47) are the investment that one hopes to break even on. So when the ND Commission says the breakeven price is \$80-90/bbl it means that oil prices must be in this range for a producer to plus recover its development costs, including its cost of capital (i.e., a return on capital), operating costs, royalties and taxes.

10. *Slide 49: The cash margins are 2017-2022. This cells looks are cash during the 1<sup>st</sup> 5 years of production (under SB21 tax would be lower). What would it look like during development when both Incumbents and New Producers have lost the ACES credits and deductions?*

The bottom left box shows margins per-barrel of production. It is cash generation divided by production. It's not possible to look at this metric during development as there is no production (i.e., denominator) during that period. Charts 59 and 60 do show producer cash flows under ACES and SB21. The first 5 years shown in these charts are the period of development.

11. *Slide 50: NPV-12 for ACES Incumbent is higher than NPV-12 for Bakken at prices below \$120. Does this mean that using NPV as a measure tells us that under ACES, oil development on the North Slope is more profitable here than in North Dakota?*

Profit is an accounting concept while Net Present Value is an economic concept. A higher Net Present Value for a given project means that at the specified discount rate (in this case 12%) the project creates more value than a project with a lower Net Present Value. Slide 50 shows that the Net Present Value at a 12% discount rate creates more value to the ACES incumbent at prices below \$120. As discussed above for slides 49-53 in the context of IRR, much of the higher NPV associated with the ACES incumbent is due to the tax buy-down on existing production. The ACES New Participant line shows a "break-even" NPV with the Bakken at about \$100/bbl. The difference between these two reflects the impact of the buy-down for the incumbent.

The slide shows that ACES Incumbent has a higher NPV than Bakken until about \$120/bbl, and a similar NPV to Eagle Ford at prices below \$100/bbl. The New Participant has a higher NPV than Bakken until about \$100/bbl, but a lower NPV than Eagle Ford at all price levels.

12. *Slide 52: NPV and IRR for ACES are higher than for Norway but reversed for Cash Margins for 2017-2022. What would this comparison look like if it included the years 2007-2017? And, what is the relative importance of NPV/IRR vs Cash Margins in decision-making?*

The relationships seen in this chart should not change if one looked at 2007-2017 instead, with the potential exception of Canada, where fiscal terms did change during this period. The analysis is based on fiscal terms in place currently, which would apply going forward. NPV, IRR, and Cash Margins are all relevant metrics to producers. Which is more relevant is probably a good question for the producers. I do believe, however, that once a project's IRR is greater than the producer's hurdle rate, differences between IRRs across projects are likely to be viewed as less relevant for the reasons discussed above. I also expect that producers would view NPV as more relevant than IRR for purposes of comparison. Cash margins are important to producers, but they would not likely trump NPV on their own. Put another way, high cash margins, combined with negative NPV's would not lead to investment. PI is also relevant, and would be used to aide management rank projects where budgets or other constraints don't allow them to undertake everything at once, which is common.

13. *Slide 53: Same questions for Canada Oil Sands*

See answer to question #12.

14. *Page 56: The Gross Revenue Exclusion is forever? Was there consideration of doing a 7 year exclusion as we did in the "middle earth" legislation last session?*

Yes, consideration was given to a 7-year GRE as well as the life-of-recovery GRE proposed in SB21. Including the GRE for the life of recovery enhances the investment metrics relative to a 7-year GRE. It also encourages continuing investment and recovery from new fields and removes the potential that oil recovery may be "inefficiently" front loaded in a new project.

15. *Slide 57: Does the phrase "eliminates incentives for gold-plating" also mean "eliminates incentive to reinvest Alaskan profits in Alaska"?*

The term "eliminates incentives for gold plating" refers to the fact that under ACES, the State effectively subsidizes the majority of capital spending for incumbent producers. As prices rise, that subsidy increases and can exceed 100% of the expenditure. This subsidy reduces a producer's incentive to efficiently manage costs. The term "gold plating" is a term of art that describes this situation.

I don't think there is any way to read the phrase as also meaning "eliminates incentives to reinvest in Alaska." In my view SB21 will increase producer's incentives to invest in Alaska. Reducing the government's take on the producer's investment will leave the producer with a greater share of the profits from its investment. That greater share is what will enhance their incentive to reinvest (and continue to earn a greater share of the profits).

Along this line of reasoning, the State should not fear that producers will be encouraged to "take their profits elsewhere." If producers can keep a greater share of what they invest in Alaska, they will be encouraged to reinvest in Alaska, and less tempted to reinvest their profits elsewhere. The structure of SB21 enhances the producer's incentives to invest, and reinvest in Alaska relative to ACES.

*16. Slide 58: May we please see this chart extended to \$200 oil?*

We have attached a revised Slide 58 showing prices up to \$200/bbl as requested. In addition to the price extension, we have shown the figures for the 5-year period FY 2015 - 2019 rather than FY2014-18 as FY 2014 is a transition year.

*17. Slides 59 & 60: Under SB21, the NPV of the governor's proposal is nearly identical for a new producer (\$318m) as an existing producer (\$319). It would seem that these numbers should not be quite so close, since the incumbent gets the value of their spending in years 1 as a 25% tax reduction, whereas the new producer must hold their Net Operating Loss credit for several years. Is it the 15% interest payment that makes up the difference?*

Yes, new producers who don't have a tax liability would not be able to deduct their losses during development under SB21. New producers can carry forward their losses, which are increased by 15% per year, and deduct them against their tax liability once production begins. The 15% increase helps to keep their NPV equivalent to that of the incumbent that has the ability to deduct the loss against current tax liabilities.

*18. How many taxpayers were filing for oil and gas credits on the North Slope for each of the years 2002-2012?*

On the following page is a table that shows the number of companies in each year that either (1) applied for tax credit certificates for credits earned under AS 43.55.023 or AS 43.55.025 on the North Slope, or (2) applied credits earned on the North Slope under AS 43.55.023, .024, or .025 against their tax liabilities in the specified years. This analysis captures the vast majority of companies on the North Slope earning tax credits applicable to the ACES production tax.

With respect to the analysis below, we note that the tax credit under AS 43.55.025 was implemented in 2003. Tax credits under AS 43.55.023 and .024 were implemented with PPT and subsequently expanded with ACES in 2006 and 2007, respectively. The expansion of credits available through PPT and ACES was a large contributing factor to the number of companies earning credits under these programs.

Number of taxpayers filing for oil and gas credits on the North Slope, CY 2002 - 2012	
Calendar Year	Number of Companies
2002	0
2003	0
2004	3
2005	1
2006	13
2007	20
2008	26
2009	33
2010	33
2011	30
2012*	36

\*2012 totals subject to true-up filings due March 31, 2013  
Above data reflects number of companies that either applied for tax credit certificates from activity on the North Slope or applied credits against their tax liability for oil and gas production on the North Slope  
Includes credits under AS 43.55.023, .024, and .025.

19. *The comparisons used in the presentation rely on jurisdictions where much of the development is shale or gas. Can we please see some of the same comparisons using the locations worldwide where British Petroleum, ConocoPhillips and Exxon are producing and making new investments in conventional oil?*

Within OECD countries, these companies are making significant investments in conventional oil production in the North Sea, the U.S. Gulf and Offshore Eastern Canada. The analysis includes North Sea conventional production (both U.K. and Norway). We will look at adding comparisons with the U.S. Gulf and Eastern Canada offshore.

20. *Barry Pulliam testified that Alaska is viewed as unfriendly to business. Do you think that is an accurate view?*

Mr. Pulliam stated that Alaska is viewed as "a high tax, not always friendly place to do business." Mr. Pulliam did not say Alaska is "unfriendly to business." There would seem to be little doubt that Alaska is a "high tax" jurisdiction, particularly at current prices. Mr. Pulliam testified that Alaska has a very challenging physical environment on the North Slope, which is certainly not a "friendly" place to do business. He also mentioned the challenges associated with permitting new projects such as CD-5, a project that filed its first permits more than 5 years before receiving approval. He also stated that permitting practices by the State of Alaska itself were generally viewed positively by business. In addition, he mentioned the challenges associated with offshore development in the aftermath of the Gulf Horizon incident. In addition to these issues, producers are challenged by environmental

lawsuits (e.g., Shell) that seek to delay or discourage development. These are all examples of how Alaska can be viewed as a place that is not always friendly to do business. DOR agrees with Mr. Pulliam's characterization.

21. *During his presentation of SB21 to the Legislature, Commissioner Butcher and Chair Micciche had a conversation about fairness being sharing profits of our oil with 1/3 to state, 1/3 to federal government and 1/3 to producers. Do you think a total government take of 2/3 is a reasonable goal?*

The administration is seeking a balance of providing enough profit to entice producers to bring Alaska's resources to market and simultaneously maintaining as much of those benefits as possible for Alaskans in accordance with our constitution. Attempting to capture too great a percentage of those benefits results in leaving resources in the ground as producers seek out better opportunities. With this balance in mind, the administration believes that the total government take should not exceed 2/3 of the profits from oil production. However, given investment alternatives available in other areas, this should be viewed as an upper limit on government take rather than a goal.

22. *What about contractual obligations to develop? We saw with Point Thompson that the duty to develop is enforceable. What do you think about the obligations/duty to develop as a factor in development decision-making?*

Contractual obligations certainly play a role in decision making. The primary lease term is really focused on prudent exploration and delineation. Upon unitization the State has a greater opportunity to leverage operators into development. While over the last decade unitization has been used as a tool to 'extend leases' this paradigm is fundamentally changing and development activities and obligations are becoming standard requirements in new unit approvals. The business decisions for 'explorers' is different than that of 'producers'. Successful exploration doesn't automatically result in development and production. If the economic environment isn't conducive to long term exposure of significant capital funds then developments aren't progressed. This is really a failed opportunity for the industry and the State.

23. *In terms of managing risk, are oil companies more concerned about risk at the low end or about high end?*

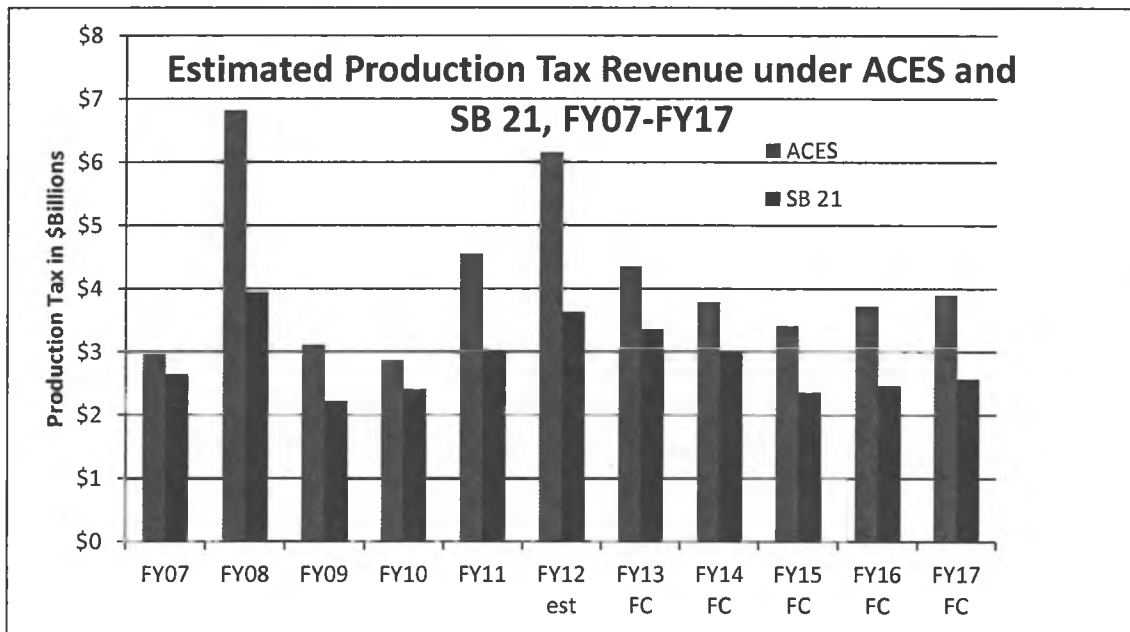
"Risk" is uncertainty. Uncertainty makes projects more "risky." Producers plan around a set of expected prices, but those expected prices may not prove to be correct. They also examine their economics at lower than expected prices (downside risk) and higher than expected prices (upside risk). They are concerned with both. They don't want to be in a situation where downside risk will cause a project will lose money. And, they will be less willing to take on this downside risk if their exposure to upside risk is limited. High progressivity removes much of the upside risk that might otherwise compensate for downside risk.

24. *What do we know about their hurdle rates or reasonable profits?*

We do not know what a specific company's hurdle rate or view of a reasonable profit is. Mr. Pulliam used a 12% discount rate in his analysis, which is widely viewed as reflecting producer's cost of capital in OECD countries. A hurdle rate would not be below the cost of capital. As an economic matter, we would expect producers to view a "reasonable" profit as one that is at least as good as its alternatives. Assuming all factors equal, if a producer can invest all the funds it has available and earn a 20% rate of return for example, it would likely view other opportunities as providing a reasonable profit as long as they also provided this type of return.

25. *In the 1/17/13 presentation "North Slope Oil Production History & Forecast" page 3 shows a forecast for General Fund Unrestricted Revenues for the Years 2012-2017. Can we please see that forecast (and history) for the years 2007-2017 under ACES, HB110 and SB21?*

Below is a chart showing the estimated production tax revenue under ACES and under SB 21, FY 2007 through FY 2017. What is not shown in this chart is the estimated savings from the state's general fund under SB 21 for not having to refund certain credits. From FY 2007 through FY 2012, that amount was approximately \$1.2 billion. From FY 2013 through FY 2017, another savings of approximately \$1.2 billion would be anticipated under SB 21, for a total savings over the 10-year period of about \$2.4 billion.



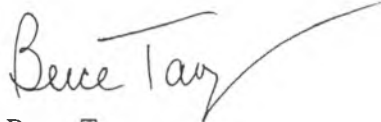
The Honorable Berta Gardner

February 7, 2013

Page 10

I hope that you find this information helpful. I look forward to working together in our continuing efforts through the remainder of this legislative session.

Sincerely,

A handwritten signature in cursive script that reads "Bruce Tangeman". The signature is written in black ink and includes a long, sweeping horizontal line that extends to the right.

Bruce Tangeman  
Deputy Commissioner

Enclosure: revised slide #58

## Key Aspects of Administration's Proposal (cont'd)

- Average Government Take Moves From Progressive to Relatively Neutral Under Proposal

