

AK LEGISLATURE SPECIAL COMMITTEE FILES SCOMM 148 32215

11. *What does allowing two years for claiming capital credits do to the state's revenue projections? How will the added uncertainty introduced into those projections by this provision be accounted for?*

We expect that allowing companies to claim capital credits for two years will actually improve the stability of the state's revenue projections. The effect of the 2 year spreading of costs is that a single high cost year gets spread over two years, muting its negative effect on state revenues. In addition, the state has an opportunity to anticipate and plan on the higher costs that will be experienced in the next ensuing year. Where costs are increasing steadily state the state revenues experience no ill effect from the averaging across two years.

12. *What is a participating area?*

A participating area is a subset of an oil and gas unit that is considered reasonably proven to be capable of producing oil and gas in quantities that would enable the operator to earn a profit. By regulation, an Operator must form a participating area prior to production. The unit boundaries are surface boundaries. The participating area can be visualized as an underground water balloon, but with oil and/or gas as its contents, and the participating area's boundaries are the latex rubber balloon that encapsulates the oil and/or gas reservoir. Traditionally, most participating areas encapsulate the volume of oil and/or gas that is considered to be in communication and sharing the same reservoir pressure and other fluid and reservoir properties. Operators develop oil and gas fields within units on a participating area basis and the owners of leases that overlay any part of the participating area agree upon special Operating Agreement provisions to govern the operator's conduct of development of that Participating Area. The Operator submits and DNR approves a methodology for allocation of production and costs for the unitized leased acreage committed to the participating area.

13. *How much of the government take in the administration's charts is state take? What is included in state take, and how much is each of these segments worth?*

In our attempt to capture the state a fair share of Slope-wide revenues we have focused on the concept of the "share of the incremental dollar" or "marginal tax rate" ("MTR"), rather than "take."

The term "Government Take" refers to the percentage of economic rent going to government. This is the cumulative gross revenues less costs (before tax). It is a life-cycle concept involving all development costs, including a companies cost of capital. We use this concept in analyzing investment on new fields, where all (or most) of the costs will be incurred going forward.

'Take' does not work on legacy fields where most costs were incurred many years ago and have already been recovered. In addition, it does not work for examining a single

year, for if a lot of costs are incurred one year, and you are looking at take the next year, the results can be deceptive.

The Marginal Tax Rate (MTR) is derived by looking at total per barrel government revenues at one price, and then increasing the costs by one dollar. The difference in per barrel government revenues is the marginal tax rate. The MTR is appropriate when costs have been recovered, and it can be looked at for individual years. It is what many economists use to compare government revenues internationally.

Total government revenues include royalties (state, federal, and private), state property tax, state production tax, state corporate income tax, and federal corporate income tax. The relative amounts of these vary depending on price.

Under ACES, with our 2008 cost assumptions, at a \$60/bbl U.S. West Coast ANS price, the marginal tax rate is about 69%. In other words, as the price of oil moves up one dollar, government gets 69 cents of that dollar. About 50 cents of that goes to Alaska, or about \$4.6 billion. This is broken out as follows:

Royalties	\$1.9 B
Production tax (ACES)	\$2.0 B
Property tax	\$0.1 B
State corporate income tax	<u>\$0.6 B</u>
	\$4.6 B

14. *If the government take is a measure of the net value of a barrel of oil, what is that net value? What has been taken out to reach it?*

See question 13

15. *Under what scenario would the gross floor kick in? Specifically, what would have to happen to oil price and/or costs to bring the gross floor into play? Why is the gross floor lower than the ELF take from Prudhoe Bay?*

The floor would kick in when the combination of prices and costs yields net income such that the tax derived under ACES would be less than a tax derived at 10% of the gross revenue at the point of production. Given our assumptions for cost in FY 2008, we estimate the floor would kick in for the combined legacy fields at \$40 West Coast oil price.

Under ELF, the gross tax rate would have been 15% X the field-specific ELF. The 10% gross floor would kick in for Prudhoe at an ELF of 0.67. Our forecast would be for this to trigger in 2017. Prior to that, the ELF for Prudhoe Bay would still be above the 10% floor.

16. *Why does the gross floor provision require a less aggressive upside tax?*

There is the potential for significant new investment in both the Prudhoe Bay and Kuparuk River Units. A significant volume of known viscous and heavy oil is located within these two units, and its development will be costly. In addition, investments which slow the pace of decline by 1 or 2 percentage points can mean significant volumes of production at lower costs and thus result in significant revenue to the state. In balancing the lower costs associated with expanding existing developments in legacy fields with the importance of more costly new reservoir developments in these legacy fields, the administration struck a balance that more aggressively protected the state in a low oil price-high cost environment, and in return the administration left producers with a greater upside in the event of higher oil prices and lower costs. It is unreasonable to expect that the producers would proceed with high cost developments within legacy fields, having no protection on the downside, if there were not greater rewards received for taking the risks associated with costs and oil prices. Further, where enhancements to existing production in legacy fields have relatively lower costs compared to similar production volumes coming from new developments, this lower cost benefit is captured in the net tax structure, by lower costs being netted against gross revenues.

17. *The administration's world average figures use the mean "to kick out extreme numbers." If the extreme numbers are real, why would we kick them out?*

The purpose of looking at international "government take" numbers is to provide some guidance as to the fairness of the tax scheme, where "fairness" is measured against international norms. (Note that the notion of "government take" actually says very little about comparative investment attractiveness – which is also importantly a function of the size of the resource prize, and costs of exploration, development, and production.) The calculation of an "average" is indeed highly sensitive to data that falls in the extreme ends of the spectrum ("outliers") that is, an extreme value can significantly move the "average". However, an extreme value tells one little about "norms". The "median" statistic is not affected by outliers; accordingly, as a guide to fairness norms, the "median" provides more robust information.

18. *If, as we are told, North Slope oil production is declining by 6 percent a year, then next year we will be producing about 75,000 barrels a day less. If the administration's less aggressive upside tax leaves \$1 a barrel on the table, what return in terms of exploration and development would make foregoing that \$27,375,000 worthwhile?*

A: The administration's upside tax is not less aggressive than the current PPT structure. It proposes an increase in the net tax rate on legacy fields of 25% instead of the current 22.5%. In addition, ACES changes progressivity by having it begin at \$30/bbl instead of PPT's current \$40/bbl net income. While the rate of increase is slightly less aggressive (0.2% under ACES vs. 0.25% under PPT), the significance of the ACES' earlier start-up

is that PPT progressivity would not provide greater revenue to the state than that provided by ACES until oil prices were over \$120/bbl.

Sincerely,

Pat Galvin, *Commissioner*
Department of Revenue

Title: Capital Spending on Alaska's North Slope Wells, Field Facilities and Exploration

Prepared: Chuck Logsdon, Greg Bidwell, and Charlie Nienhuis, Economists, Department of Revenue

Date: Updated 10/3/07

Purpose: Provide information to legislature on capital spending on the North Slope

Data Source: See sources on "Capex" sheet

Key Assumptions: None

History: Spreadsheet has been maintained and updated since the early 1990s.

Disclaimer: The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

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Capital Spending on Alaska's North Slope Wells, Field Facilities and Exploration

Millions of nominal Dollars (Dollars of the day)

All Companies

<u>Year</u>	<u>Exploration</u>	<u>Development</u>	<u>Total</u>
1975			3,827
1976			1,166
1977			890
1978	274	400	674
1979	174	1,282	1,456
1980	176	1,604	1,780
1981	419	3,104	3,523
1982	647	3,839	4,486
1983	818	1,100	1,918
1984	258	1,193	1,451
1985	514	1,547	2,061
1986	288	771	1,059
1987	288	1,020	1,308
1988	36	765	801
1989	132	748	880
1990	96	1,061	1,157
1991	120	1,178	1,298
1992	216	991	1,207
1993	192	1,148	1,220
1994	72	808	892
1995	84	748	856
1996	108	826	922
1997	96	1,070	1,142
1998	72	1,560	1,608
1999	48	1,179	1,239
2000	60	1,545	1,697
2001	152	1,636	1,788
2002	126	1,054	1,180
2003	90	970	1,060
2004	67	980	1,047
2005	30	1,268	1,301
2006	123	1,591	1,714
2007	194	1,787	1,981
Sources: 1975-1989: Data from the "International Oil Tax Comparison Study", April 1990.			
Study did not provide a breakdown by company and no detail for the years 1975-1977.			
1990-2000: BP and Arco annual reports; Communications with BP, Arco Alaska.			
Various published sources. A breakdown by company provided, but no breakout of			
exploration cost and development costs. Exploratory costs assumed to follow			
\$12 million dollar per well rule of thumb.			
2001-2004: Communication with BP, ConocoPhillips 2002 & 2003 Annual Reports,			
publications/extrapolations for others. Breakout of capex by company & type Capex spending.			
2005-2007: Unaudited taxpayer submitted EIC and PPT credit information as of 10/3/07.			
Exploration and development spending breakdown may contain inaccuracies, due to limited			
information and to the fact that costs that do not qualify for exploration credits may qualify under			
the PPT as development capital credits.			



Alaska State Legislature

Mike Doogan

Representative
District 25, Anchorage

September 18, 2007

Commissioner Patrick Galvin
Alaska Department of Revenue
550 West 7th Avenue, Suite 1820
Anchorage, AK 99501

Dear Commissioner Galvin:

As I indicated, your briefing this morning on the administration's oil production tax proposal raised a variety of questions for me. I apologize if these questions seem scattershot. I am asking them in the order they occurred to me as the briefing progressed, not in any order of importance. Here goes.

1. Deputy Commissioner Marcia Davis said at the outset that the administration wanted to fashion a tax plan that encouraged industry investment and enhanced state revenue. Are these goals listed in priority order; that is, in instances that inevitable trade-offs arose between the two goals, were they decided in favor of investment over revenue?
2. Was the failure to predict income from the existing PPT all attributable to higher costs being claimed by the industry? If not, what other factors led to the spectacular chasm between what had been predicted for PPT and what was paid?
3. Since there has been no auditing of costs claimed by the industry under PPT, what confidence can we have that the administration's projections based on that data are accurate?
4. Insofar as the administration's plan is based on confidential information, how will the legislature be able to satisfy itself that such data is accurate and is being interpreted properly?
5. In what ways is the administration's tax plan "intended to drive new production?" What sort of research was performed to estimate the effect of the state's production tax policy on the industry's decisions to explore or develop? What other factors are involved? Where do state taxes rank in the hierarchy of industry decision-making?

State Capitol
Juneau, AK 99801
907-465-4998 or 800-689-4998
Fax 907-465-4419

716 West 4th Avenue
Anchorage, AK 99501
907-269-0216
Fax 907-269-0218

Rep.Mike.Doogan@legis.state.ak.us

6. What is the history of industry investment in exploration and development in Alaska, in terms of dollars spent? Has Alaska's percentage of worldwide annual spending for exploration changed during the past 10 years?
7. What happened to the "challenges of writing regulations for PPT" mentioned in the department's analysis of Aug. 3?
8. Is the administration considering contracting for auditors needed for any net profits tax?
9. The original PPT was written as a method of getting a gas pipeline. Since that approach has failed, what will the administration be proposing for provisions that allowed producers to write gas line costs off against their oil taxes?
10. What are the proposed credits for oil exploration and development credited against?
11. What does allowing two years for claiming capital credits do to the state's revenue projections? How will the added uncertainty introduced into those projections by this provision be accounted for?
12. What is a participating area?
13. How much of the government take in the administration's charts is state take? What is included in state take, and how much is each of these segments worth?
14. If the government take is a measure of the net value of a barrel of oil, what is that net value? What has been taken out to reach it?
15. Under what scenario would the gross floor kick in? Specifically, what would have to happen to oil price and/or costs to bring the gross floor into play? Why is the gross floor lower than the ELF take from Prudhoe Bay?
16. Why does the gross floor provision require a less aggressive upside tax?
17. The administration's world average figures use the mean "to kick out extreme numbers." If the extreme numbers are real, why would we kick them out?
18. If, as we are told, North Slope oil production is declining by 6 percent a year, then next year we will be producing about 75,000 barrels a day less. If the administration's less aggressive upside tax leaves \$1 a barrel on the table, what return in terms of exploration and development would make foregoing that \$27,375,000 worthwhile?

That's what I've got right now. As a general matter, I'm concerned that the administration is trying to outguess the oil companies and influence those

companies' future decisions with a single tool – production taxes – that either (a) will not work or (b) will pay too much, in terms of foregone revenue, for the exploration and development it buys.

I look forward to your answers, and to further discussion of the administration's proposal.

Sincerely,

[Sent by e-mail]

Rep. Mike Doogan
House District 25

CC: Rep. Beth Kerttula, House Minority Leader
Rep. Kurt Olson, Chair, House Special Committee on Oil & Gas

State of Alaska

Department of Revenue
Commissioner's Office



SARAH PALIN, GOVERNOR

333 Willoughby Avenue, 11th Floor

P.O. Box 110400

Juneau, Alaska 99811-0405

Phone: (907) 465-2300

Fax: (907) 465-2394

Sectional Analysis ACES

- Section 1:** Expresses legislative intent regarding application of the statute of limitations.
- Section 2:** Provides for the Department of Natural Resources to share with the Department of Revenue confidential information for use in administering the production tax or forecasting tax revenue, and maintains confidentiality.
- Sections 3-9:** No substantive change. Amends references to altered statutes.
- Section 10:** Provides for an exempt class of oil and gas auditors and supervisors.
- Section 11:** See sections 3-9.
- Section 12:** Makes conforming amendment regarding disclosure of certain taxpayer information.
[See Sec. 61]
- Section 13:** Provides for the Department of Revenue to share production tax information with the Department of Natural Resources, and maintains taxpayer confidentiality.
- Section 14:** Makes conforming amendments regarding statute of limitations for production tax.
[See Sec. 50]
- Section 15:** Repeals tax levy under PPT and establishes new oil and gas tax as calculated in following sections.
- Section 16:** Replaces current North Slope tax floor with new 10% gross tax floor on certain very large fields.
- Section 17:** Establishes net tax rate of 25% plus a progressivity factor of 0.2%.
- Section 18:** Lowers progressivity trigger from \$40 per barrel to \$30 per barrel (net) and provides for annual calculation instead of monthly.
- Sections 19-20:** Conforming amendments.
- Section 21:** Makes conforming change consistent with section 55, to the existing provision preventing Cook Inlet producers from utilizing Cook Inlet tax ceiling to export tax credits to other areas of the state.
- Section 22:** Changes the monthly installment tax calculations to conform to changes made by sections 15-18 and to take account of the existing Cook Inlet tax ceilings.
- Sections 23-25:** Conforming amendments.
- Section 26:** Limits to 50% the amount of a capital credit that may be claimed for a single calendar year; conforms data submission requirements for exploration capital credits to the data submission requirements for AS 43.55.025 exploration credits

[See Sec. 39]; Limits use of capital credits generated in fields subject to the 10% gross tax floor to taxes on oil and gas from those fields.

Section 27: Conforms the tax credit rate for carried-forward annual loss to the new basic net tax rate enacted by section 17, and provides that fields subject to the 10% gross tax floor may not carry forward losses.

Section 28: Conforming amendments for transferable tax credit certificates, increases from 60 to 120 days a time limit for Department of Revenue approval of certificates, and applies the 50% annual limitation in section 26 to certificates.

Sections 29-30: Conforming amendments..

Section 31: Clarifies that tax-exempt entities may not apply for transferable credit certificates.

Sections 32-36: Conforming amendments.

Section 37: Updates provisions for exploration credits, provides that a suspended well does not qualify for credits until completed or abandoned, and excludes costs arising from gross negligence or environmental or health and safety violations.

Section 38: Modifies eligibility provisions for exploration wells credits to better define and enforce the requirement to test a previously unexplored prospect while allowing for several exploration wells within a limited period of time.

Section 39: Clarifies the data submission requirements for exploration credits, reduces the confidentiality period for certain data, applies the 50 percent annual limitation in section 26 to exploration credits, and provides for public disclosure of basic information relating to credits.

Section 40: Clarifies that tax-exempt entities may not transfer exploration tax credits.

Sections 41-42: Conforming and clarifying amendments.

Section 43: Changes the definition of "preexisting well" for purposes of exploration credits to exclude wells drilled within 540 days rather than 150 days.

Section 44: Establishes 5% credit which may be claimed against seismic exploration expenses incurred before July 1, 2003, in exchange for seismic data, the acquisition of which is determined by the Commissioner of DNR to be in the best interest of the state.

Section 45: Creates Oil and Gas Tax Credit Fund for the purposes of purchasing certain tax credits from explorers and producers; Establishes procedure and standards for appropriation into and management of fund. (Replaces existing credit buy-back provisions [See Sec. 63])

Section 46: Requires producers to file annual report with the Department of Revenue annually, even if no tax is due that year, and expands examples of required information.

Section 47: Assesses penalty for late filing of reports required under sections 46 and 48.

Section 48: Requires producers and explorers to report certain expenditures and adjustments annually to the Department of Revenue and allows the Department of Revenue to require monthly reporting of information considered necessary for administering of taxes.

Section 49: Authorizes the Department of Revenue to require reporting of information needed for revenue forecasting purposes and to assess penalties for failure to timely file reports.

- Section 50:** Extends statute of limitations for production tax to six years, subject to extension due to changes in federal income tax, and provides for tax effects of retroactive changes in items that affect a producer's tax.
- Section 51:** Allows the Department of Revenue to establish and require electronic filing and payment.
- Section 52:** Clarifies how production tax values (i.e., taxable values) of oil and gas are calculated, consistent with changes enacted by sections 15-18.
- Section 53:** Makes conforming amendments required under section 52.
- Sections 54-55:** Further implements the changes enacted by section 52, providing for allocation of lease expenditures among leases or properties, and specifies an "anti double-dipping" provision with respect to Cook Inlet tax ceilings.
- Section 56:** Amends the description of deductible lease expenditures, provides that only expenditures allowed by regulation may be deducted, and makes terminology for overhead expenses consistent with ordinary usage.
- Section 57:** Conforms with section 56; existing language is moved to a different subsection.
- Section 58:** Makes non-deductible all expenditures for dismantlement, removal, or restoration; for repair, replacement, or repair associated with interruption of or reduction in oil or gas production or releases of oil, gas, or other substances; and for refineries or topping plants; allows for deduction of added value of refinery or topping plant products used in lease operations.
- Section 59:** Clarifies language of existing provision on cost allocation.
- Section 60:** Conforming change regarding repeal of certain provisions (see section 63).
- Section 61:** Authorizes Department of Revenue to publish production tax information if aggregated among at least three producers or explorers.
- Section 62:** Adds definitions needed for other provisions of Act.
- Section 63:** Repeals transitional investment expenditure (TIE) tax credit; repeals provisions for using unit operating agreements to determine deductible lease expenditures; Repeals existing provisions for state refund of certain tax credit certificates and makes conforming repeals.
- Section 64:** Applicability provisions: most substantive tax changes apply starting January 1, 2008; several apply back to April 1, 2006.
- Sections 65-68:** Transition provisions.
- Section 69:** Makes certain provisions of the act retroactive consistent with section 64; Makes section 40 retroactive to beginning of exploration tax credit program (July 1, 2003).
- Section 70:** Provides for January 1, 2008, effective date for most substantive changes to production tax.
- Section 71:** Establishes immediate effective date for Act other than as provided by section 70.

Governor's Proposed Production Tax Legislation

October 1 2007

Sectional Analysis

Authors: Dan Dickinson & Steve Porter

Section 1 Uncodified Laws (Legislative Intent)

Legislative Intent – refers to changes made in Section 50, page 31. It suggests that the changes are only clarifying a long-standing interpretation of AS 43.05.260 by the Department of Revenue (DOR). Details will be discussed in Section 50.

Section 2 AS 38.05.035(a)

This section allows the DOR access to the Department of Natural Resources (DNR) confidential information for

- 1) its use in forecasting state revenue under AS 43.55 or
- 2) administering AS 43.55, the production tax

In an apparent stylistic change this draft deletes previously repealed portions of AS 38.05.035(a) requiring subsections references to change as indicated in bill sections 3-9 below.

Section 3 AS 38.05.036(b)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 4 AS 38.05.036(f)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

Section 5 AS 38.05.036(g)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 6 AS 38.05.123(f)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 7 AS 38.05.133(e)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 8 AS 38.05.180(j)(6)(B)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 9 AS 38.05.275(c)

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

Section 10 AS 39.25.110(42)

Section 39.25.110 is exempt service. This section adds oil and gas auditors performing production tax auditors and their immediate supervisors to the exempt service. This leaves oil and gas income tax auditors in the classified service.

Section 11 AS 41.09.010(d)

Conforming references in Title 41 required by renumbering in sec. 2 of the proposed legislation.

Section 12 AS 43.05.230(a)

Section 43.05.230 covers disclosure of tax returns and reports. Section 43.05.230(a) (5) adds a reference to AS 43.55.890. The reference to AS 43.55.890 (new section discussed in Section 61) in the proposed legislation would create an exclusion for certain information if aggregated

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

among three or more producers or explorers. This type of information would be allowed under AS 43.05.230(e) if the publication of the statistics was so classified as to prevent the identification of a particular tax payer's return or report. The new section would seem to lower the standard. This proposal would permit information which was "aggregated among three or more producers or explorers" to be divulged to the public even if, for example, a very large taxpayer's information was aggregated with two very small taxpayers so that the large taxpayer's individual taxpayer information could easily be extracted from the information disclosed.

Section 13 AS 43.05.023(h)

The Department of Revenue currently has the authority to share copies of returns, reports, and documents filed under AS 43.65 (Mining License Tax) with DNR. This language broadens the authority of DOR to also share returns, reports and documents filed under AS 43.55 (Oil and Gas Production Tax and Oil Surcharge) with DNR.

Section 14 AS 43.05.260(a)

This section adds AS 43.55.075 (Section 50 of this legislation) to the exceptions to the requirement to have taxes imposed within three years after a return is filed. Details will be discussed in Section 50.

Section 15 AS 43.55.011(e)

The current production tax is calculated on a monthly basis. In the proposal tax would be calculated based on a calendar year. This structure of the law is also changed. Currently AS 43.55.011(e) establishes the base tax rate (22.5%), and progressivity was dealt with elsewhere. However now this section refers to the percentage determined in AS 43.55.011(g) where both the base and progressivity rates would be established. This simplifies the comparison with the floor in AS 43.55.011 (f) - which is compared with a combined base and progressivity tax.

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

Section 16 AS 43.55.011(f)

This section makes changes to the minimum tax.

The current minimum tax is applied is 4% of gross value at the point of production over \$25, 3% of gross over \$20, 2% of gross over \$17.50 and 1% of gross over \$15 and 0% for \$15 and under. The new minimum tax is 10% of gross value at the point of production.

The current minimum tax is applied to all oil and gas produced north of 68 degrees North latitude, i.e. the entire North Slope. The proposed minimum tax would apply only to oil and gas produced from leases or properties within a unit or non-unitized reservoir that have cumulatively produced one billion BTU equivalent barrels of oil or gas and from which the average daily oil and gas production during the most recent calendar year exceed 100,000 BTU equivalent barrels. Based on this limitation, the new minimum tax would only apply to oil and gas produced at Prudhoe Bay and Kuparuk.

The current floor compares net values to gross values, and then allows certain credits to be applied against the result – even against the floor. The proposed floor test compares 25% of net plus any progressivity less any credits with 10% of gross. If 10% of gross is higher, that is the tax and a taxpayer may not apply tax credits to reduce its tax liability to below 10 percent of total gross value at the point of production.

Section 17 AS 43.55.011(g)

This section proposes a tax of 25 percent plus 0.2 percent times the progressivity price index, defined in .011(h), however the sum is not to exceed 50 percent. The current law is 22.5 percent

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

plus 0.25 percent times the progressivity price index, however the sum is not to exceed 47.5 percent.

Section 18 AS 43.55.011(h)

This section amends the price index from a monthly calculation to a calendar year calculation.

This section also changes the starting net value of progressivity from \$40 to \$30 a barrel.

Section 19 AS 43.55.011(j)

Conforming changes recognize that both the base and progressivity taxes would be levied in section .011(e) in the proposed legislation.

Section 20 AS 43.55.011(k)

Conforming changes recognize that both the base and progressivity taxes would be levied in section .011(e) in the proposed legislation.

Section 21 AS 43.55.011(m)

This section clarifies what a producer could claim in excess credits from Cook Inlet against taxes on leases or properties elsewhere in the state.

If the amount of excess adjusted lease expenditures multiplied by 25 percent is greater than or equal to the total of the reductions for all leases calculated under the Cook Inlet ceilings in AS 43.55.011(j) or (k) , the total calculated under this paragraph would be zero.

Otherwise the remainder calculated by subtracting the excess adjusted lease expenditures multiplied by 25 percent from the total of the reductions for all leases calculated under AS 43.55.011(j) or (k) would be the total calculated under this paragraph.

This language is currently found in regulation at 15 AAC 55.360 (d)

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

Section 22 AS 43.55.020(a)

This section would reconcile the monthly installment payments of tax to be consistent with other proposed changes, and incorporates some regulatory solutions to some of the ambiguities in the existing legislation concerning Cook Inlet ceilings and credits that could only be applied on an annual basis.

Section 23 AS 43.55.020(d)

Conforming changes recognize that both the base and progressivity taxes would be levied in section .011(e) in the proposed legislation.

Section 24 AS 43.55.020(g)

Reference changes and clarifies annual due date.

Section 25 AS 43.55.020(h)

Reference changes and clarifies annual due date.

Section 26 AS 43.55.023(a)

This section stipulates that no more than half of a capital expenditure tax credit may be applied in a single year.

Section AS 43.55.011(f) states that a tax credit may not be applied to reduce a producer's tax liability below 10 percent of the total gross value at the point of production. This section deals with the excess tax credit left over after a producer reduces their tax to 10% of gross. This section stipulates that the excess tax credit left over may not be used to reduce the producer's taxes outside that unit.

A significant portion of the language -which had originally been copied from section .025 -would now be invoked by referencing AS 43.55.025(f).

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

Section 27 AS 43.55.023(b)

This section changes the amount of carried-forward annual loss that may be taken as a tax credit from 20 percent to 25 percent. (In current law the loss carry-forward at 20% does not equal the base tax rate at 22.5% percent.)

This section also prevents lease expenditures subject to AS 43.55.011(f) i.e., Prudhoe and Kuparuk, from contributing to a carried-forward annual loss.

Section 28 AS 43.55.023(d)

This section would end the ability to transfer or obtain a cash payment for an unused tax credit under AS 43.55.028 (new section) if that unused tax credit is described in the floor sections (i.e. Prudhoe Bay or Kuparuk.)

This section changes the time period that the department has to grant or deny the application from 60 days to 120 days and amends the language that designates the start of the 120 day period.

This section also splits the certificate into two transferrable tax credit certificates, one that is available to use any time and the other that is not available until the next calendar year.

Section 29 AS 43.55.023(e)

Conforming changes to changes made in the proposed legislation.

Section 30 AS 43.55.023(g)

Conforming changes to changes made in the proposed legislation.

Section 31 AS 43.55.023(l)

This new section clarifies that an entity which is exempt from tax under the chapter cannot apply for a transferable tax certificate (for example the Alaska Natural Gas Development Authority or the Alaska Gasline Port Authority.) See section 40

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

Section 32 AS 43.55.024(a)

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

Section 33 AS 43.55.024(c)

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

Section 34 AS 43.55.024(e)

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

Section 35 AS 43.55.024(g)

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

Section 36 AS 43.55.025(a)

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

Section 37 AS 43.55.025(b)

This section changes the date for expenditures for work performed to be eligible for a production tax exploration credit from July 1, 2003 to December 31, 2007. (That is, even if this bill becomes law, the old rules will apply through December 31, 2007.)

This section adds the obligation that a well must be "completed or abandoned" at the time the explorer claims the exploration credit. Application would not be allowed prior to finishing the well.

This section would exempt costs arising from gross negligence or violations of Health Safety & Environmental statutes or regulations from expenditures that qualify for the exploration credit.

Section 38 AS 43.55.025(c)

The current law requires a well to be drilled 3 miles away from a preexisting well to be eligible for a credit, except in CI, where DNR can certify that the well tests a "distinct exploration target". The proposed law would require

- (1) That the well be drilled to a structural or stratigraphic trap that is distinctly separate from any trap that has been tested by a preexisting well, with this determination made by the commissioner of DNR before the well is spudded;
- (2) The existing three mile requirement for all wells not in the CI, and
- (3) The commissioner of DNR to determine, after the well is completed or abandoned that the well adequately achieved the explorer's stated objective.

Section 39 AS 43.55.025(f)

This section defines what data would be necessary to be submitted to claim an exploration credit. The new language clarifies the obligation of the explorer to provide the DNR with all seismic data, on state lands and off state lands, within and outside unit boundaries.

In the case of well data the proposed legislation reduces the time period the data is required to be kept confidential from 10 years to 2 years. In addition AS 31.05.035(c) allowed an explorer to request the DNR to extend the time of confidentiality from 2 years for as long as necessary. The proposed legislation in (D) prohibits the explorer from requesting an extension if they want the credit.

This section also explains that the certificate issued will be two certificates, each for half the credit, one to be used whenever the explorer wants and one not to be used before the next calendar year. All certificates will have the date on which the information required to be submitted will be released.

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

Section 40 AS 43.55.025(g)

This new section clarifies that an entity which is exempt from tax under the chapter cannot transfer a transferable tax certificate (for example the Alaska Natural Gas Development Authority or the Alaska Gasline Port Authority.) See section 31

Section 41 AS 43.55.025(h)

Proposal changes law so .025 credits cannot be applied against the tax floor in .011 (f).

Section 42 AS 43.55.025(i)

Proposal changes law so .025 credits cannot be applied against the tax floor in .011 (f), and recognizes the proposed change from a monthly to an annual tax.

Section 43 AS 43.55.025(k)

This section changes the definition of preexisting well from a well spudded more than the 150 days to 540 days in the proposed legislation. In other words, it expands the window to qualify as an exploration well from one season of work to two seasons, and thus may include delineation wells.

Section 44 AS 43.55.025(l)

This new section would allow the DNR approve a credit for seismic shot prior to July 1, 2003 if the Commissioner of DNR finds it in the best interest of the state to acquire the seismic for public distribution. The credit would be 5% of the old investment expenditure.

Section 45 AS 43.55.028

This section would create an oil and gas tax credit fund to purchase certain transferrable credit certificates issued under AS 43.55.023. The amount of revenue deposited into the fund would be based on the average price value forecast by the DOR of ANS oil sold on the West Coast. For \$60 or higher the percentage is 10%; for less than \$60 the percentage is 15%. For example,

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

the current forecast by the DOR for 2008 is \$51.25; so 15% of all revenues production tax received during 2008 would go to the fund after deposits to the CBR. Production tax revenues for 2008 are forecast to be \$995.4 million; so, the deposit to the fund would be approximately \$150 million. If the DOR projections are wrong or the tax is increased, the amount going into the fund would be different.

The department would be able to use the fund to purchase tax certificate but the purchase could not exceed the amount incurred by the applicant for qualified capital expenditures or lease bonuses in the 24 months subsequent to the application. The applicant's total production cannot exceed 50,000 BTU equivalent barrels per day, thus excluding the 3 largest taxpayers. All the qualifications currently found in AS 43.55.023 (f) (which is repealed under this proposal) have been retained, except the maximum of \$25 million a year to each taxpayer

Section 46 AS 43.55.030(a)

This section would amend what a tax payer is required to file by March 31st of the following year. It makes explicit the requirement to submit the costs for transportation of the oil and gas, qualified capital expenditures, and lease expenditures under AS 43.55.165 and 170, the production tax value of the oil and gas, and any claims for credits.

Section 47 AS 43.55.030(d)

This section defines the penalties of up to \$1,000 a day for not filing the required reports.

Section 48 AS 43.55.030(e-f)

Section (e) would add a reporting obligation to explorers that do not produce oil or gas.

Section (f) details what the department could require of a producer, explorer, or operator on a monthly basis.

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

Section 49 AS 43.55.040

This section would add a clause to the powers of DOR giving them the right to require a producer, explorer or operator to file reports that are "considered necessary" to forecast state revenue under AS 43.55. To the degree that this lines up with statutory authority (37.07.060 (b) (4), the forecast is for the current and next fiscal year; however the limitation is not explicit.

The section also provides for penalties of up to \$1,000 a day for a person that does not file the reports "considered necessary" by the department.

Section 50 AS 43.55.075

This section was referred to in the legislative intent language of the proposed legislation – which recognizes that historically most production tax audits took longer than 3 years and relied on AS 43.05.260(c) (3) which permits a longer audit if the "taxpayer ... consented in writing". The proposal requires the amount of tax imposed by this chapter to be assessed within 6 years after the latest return is filed. The section also details various filing time period obligations.

Section 51 AS 43.55.110(e-f)

Section (e) allows the department to require electronic filing

Section (f) allows the department to require electronic payments

Section 52 AS 43.55.160(a)

This section is a simplified rewrite of existing law, a consequence of no long having to do monthly calculations for progressivity.

Section 53 AS 43.55.160(b)

Continues the simplification from the prior section

Section 54 AS 43.55.160(e)

The proposal would expand section (e) to include among the costs that may be used to generate loss carry forwards those costs associated with leases of a producer that are not producing oil and gas or are on lands where the producer does not own an operating or working interest.

Section 55 AS 43.55.160(f-i)

This section deals with allocations of costs that a taxpayer incurs in one lease or property against revenues from another lease or property. Proposed North Slope rules are in (f), New Area Development rules are in (g) and Cook Inlet rules are in (h) and (i). This section would import regulatory language into the statute:

Section (f) clarifies that costs subject to the floor in AS 43.55.011(f) could not be allocated to other leases or properties. Otherwise costs must be allocated to producing properties

Section (g) applies to leases outside the North Slope and outside Cook Inlet, in other words costs that qualify for the .024 new area development credit. Those expenditures must be applied to leases outside the North Slope and outside Cook Inlet.

Section (h) deals with CI allocations and which costs (defined as "Cook Inlet excess adjusted lease expenditures") can be used in calculating carried-forward annual loss These rules are currently found in regulations in 15 AAC 55.235.

Section (i) sets forth the calculations for determining the carried-forward annual loss in (h), using rules currently found in regulations in 15 AAC 55.223.

Section 56 AS 43.55.165(a)

Section (a) is rewritten and would delete the "typical industry practices and standards" language in the current legislation. The language that is deleted from (a) is inserted in (b).

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

Section 57 AS 43.55.165(b)

Section (b) was modified by deleting reasonable allowance language that was inserted in 165(a).

Section 58 AS 43.55.165(e)

The current law allows for the costs for dismantlement, removal, and surrender or abandonment (DR&R) to qualify as lease expenditures if they are incurred after April 1, 2006. The proposed legislation would disallow all dismantlement, removal and surrender or abandonment costs to qualify as lease expenditures.

Section (19) was added to (e). It would disallow costs incurred for repair, replacement, or deferred maintenance that is undertaken in response to a failure or problem that results in an unscheduled interruption or reduction in the rate of oil or gas production.

Section (20) was added to (e). It would disallow costs of refineries or crude oil topping, plants, including those on the North Slope that produce fuel for North Slope production operations. Instead a taxpayer will be allowed a deduction for what it (and the State's auditors) reckons is the "fair market value" for refinery products less the underlying value of the oil used in the refinery.

Section 59 AS 43.55.165(h)

The original language of this section directed the department to write regulations where (as in CI under .011(j) and .011(k)) lease costs need to be allocated between oil production and gas production. The proposed change would expand that directive to include any required allocation of costs.

Section 60 AS 43.55.170(a)

This section would delete qualifying language regarding payment or credit that has already been subtracted in calculating billable or billed costs under AS 43.55.165(c) or (d).

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

Section 61 AS 43.55.890

This is a new section regarding the disclosure of tax information. It would allow the department to publish certain information if the information is aggregated from three or more producers or explorers. The potential impact of this change was previously discussed in Section 12.

Section 62 AS 43.55.900

This section adds the definitions of "non-unitized reservoir", "pool", "producer", and "unit".

Section 63 Repeals

This section would repeal the following:

AS 43.55.023(f), (State purchase of certain credits),

AS 43.55.165(c), (Use of operating agreements)

AS 43.55.165(d), (Use of audits under operating agreements)

AS 43.55.011(l), (Ordering of CI taxes against credits)

AS 43.55.023(i), (Transitional Investment expenditure credits),

and AS 43.55.160(c), (Monthly allocation of annual costs).

Section 64 Uncodified Laws

This section stipulates the applicability dates for each of the sections. In general, the new rules would become effective January 1, 2008, except for the deferred maintenance/corrosion provisions of .165 (e) (19) which would be retroactive to April 1, 2006.

Section 65 Auditors

This section would assign oil and gas auditors to exempt service.

Sectional Analysis of Governor's October 1 2007 Production Tax Legislation

Section 66 Retroactivity of Regulations

This section stipulates the dates on which the regulations implementing this statute could apply.

Section 67 Pending Applications

This section stipulates how to handle credit applications that are currently pending before the Department and have not been approved.

Section 68 Regulations

This section would grant DOR and DNR the authority to adopt regulations necessary to implement this legislation.

Section 69 Retroactivity

This provision explicitly provides that certain provisions of the act are retroactive to specific dates.

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

<u>Issue</u>	<u>Bill Section</u>	<u>Statute Section</u>	<u>Current Law</u>	<u>Governor's 10/1/2007 Proposal</u>
Statute Section is AS 43.55.xxx unless other wise indicated				

Base Rate

Base Rate	15, 17	.011(e) & (g)	22.5%	25%
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Tax on Private royalties under .011 (i) not changed (section 23 corrects reference)

Progressivity

Difference subtracted from net (Production Tax) Value to Arrive at Price Index - (i.e. progressivity starting point)	17, 18	sec .011(g) & (h)	\$40	\$30
Progressivity Tax per dollar of Price Index	17, 18	.011(g) & (h)	0.25%	0.20%
Progressivity Calculation Averaged over what Period?	17, 18	.011(g) & (h), .160 (a)	Month	Year

Floor

sections 15,16, and sections 32-36, 41-42 to remove ability to apply credits

Base	16	.011(f)	Entire North Slope collectively, before application of credits	Prudhoe & Kuparuk, Individually (no other fields come close to 1 billion barrel standard), after application of credits
Gross Calculation Rate	16	.011(f)	No change: Gross Value at Point of Production	
	16	.011(f)	ranges from 0% to 4%	10%
Can credits be applied to further reduce tax if floor applies?	16	.011(f)	Exploration (.025) and Non Transferable (.024) credits can be applied against floor, Investment and all other .023 credits cannot	No
Status of credits not used because of floor	16	.011(f)	implicit: can be carried forward, or applied to non North Slope areas	explicit: only applied against that legacy field: when carried forward

Credits

Investment & Loss Forward Credits (.023 Credits)

Investment Credits	26	.023(a)	Taken in year of investment	Maximum of 50% of any year's credits taken in that year.
Applied against tax due under floor?	26	.023(a)	No change: .023 credits cannot be applied against tax due calculated under the floor	

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

<u>Issue</u>	<u>Bill Section</u>	<u>Statute Section</u>	<u>Current Law</u>	<u>Governor's 10/1/2007 Proposal</u>
Statute Section is AS 43.55.xxx unless other wise indicated				

Investment & Loss Forward Credits (.023 Credits) cont.

Loss Carry Forward Credits	27	.023(b)	20%	25%
Restrictions on use of Loss Carry Forward Credits	27	.023(b)	no similar restriction	explicit: if costs occurred in legacy field subject to floor, loss can only be applied against that field.
Restrictions on use of Purchased Credits	28,29	.023(d)	Can be taken any time although cannot be applied against more than 20% of tax due	50% of credit cannot be taken until following year. (retains 20% rule)
Transitional Investment Credits	63	.023(i)	Qualified investment from 2001 - 2006 used as a credit at 10% if matched by new investment.	eliminated

Nontransferable Credits (.024 Credits)

Applied against tax due under floor?	41,42, 32-36	.024 (a),(c),(e), (g)	Yes	No
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Exploration Credits (.025 Credits)

Applied against tax due under floor?	36, 41	.025(a) & (h)	Yes	No
Disallowances	37	.025(b)	"administration, supervision...management... community relations or environmental costs..." not allowed	adds "costs arising from gross negligence or violations of health, safety, or environmental statutes or regulations" to costs not allowed
DNR approval and 3 mile rule for 40% credit	38	.025(c)	Bottom whole must be more than 3 miles from previously drilled bottom hole, except in CI, if DNR determines "distinct exploration target"	Before drilling DNR must make determination that new target "distinctly separate from any trap that has been tested by preexisting well," and after drilling DNR must determine well achieved objective and if not in CI bottom hole must be 3 miles from previously drilled bottom hole.

note: .025(d) and (e) unchanged

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

<u>Issue</u>	<u>Bill Section</u>	<u>Statute Section</u>	<u>Current Law</u>	<u>Governor's 10/1/2007 Proposal</u>
Statute Section is AS 43.55.xxx unless other wise indicated				

Exploration Credits (.025 Credits) Cont.

Data Explorer must submit to DNR	39	.025(f)(2) (A)&(B)	explorer must provide DNR with list of "data sets available"	Detailed list of data
Confidentiality of Well Data	39	.025(f)(2) (c)	10 years	24 months
note: Seismic data still at 10 years				
Applicability of Credit Certificates	39	.025(f)(5)	Can be used immediately	2 certificates, each for 1/2 of amount, one certificate cannot be used until the following calendar year
Non Confidential Information	39	.025(f)(5)	under general tax confidentiality rules	Explorer, location and date of work and when it will become public is public
Tax Exempt Entities Ability to Sell Credits	31,40	.025(g)	not mentioned	not allowed
Applied Against Tax Due under Floor?	36, 41,42	.025(a), (h) and (i)	Yes	No
Definition of Pre-Existing Well - in Effect Whether Delineation Wells Qualify for Credits	43	old .025 (c)(2)(a) new .025(k)4	preexisting well is one that was spudded more than 150 days and less then 35 years earlier. Limits ability to come back next season and get credit for delineation well.	preexisting well is one that was spudded more than 540 days and less then 35 years earlier. Allows two seasons worth of work to qualify for credit.
note: .025(i) appears to have also been rewritten for clarity in section 42 and definitions are moved to (k) in section 43 or added in 62				
"DNR TIE" Seismic Credits	44	.025(l)	none	If DNR deems "best interests of state" served by acquisition and distribution of seismic data shot before 2003, a 5% credit allowed for cost.

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

<u>Issue</u>	<u>Bill Section</u>	<u>Statute Section</u>	<u>Current Law</u>	<u>Governor's 10/1/2007 Proposal</u>
Statute Section is AS 43.55.xxx unless other wise indicated				
Allowable Lease Expenditures				
.160 great simplified in sections 52, 53 and 63 as monthly reporting calculations no longer needed.				
Carry Forward of Unused Lease Expenditures	54	.160 (e)	Lease expenditures that would reduce production tax values below zero can be used to establish a loss carry forward credit under .023(b)	Adds two more categories that can be used for carry forward credit: costs not associated with production or ownership interests
.165 Reorganized for clarity and as to between what is in (a) and what is in (b) in sections 56 & 57				
Cost must allowed in department's regulations?	56	165(a)	no	yes
Use Portions of Existing Cost Sharing Agreements or intra-producer audits to determine costs?	63	.165(c) & (d)	allowed	not allowed
DR&R Allowed?	58	.165(e) (15)	allowed for portion allocated to production after April 1, 2006	not allowed at all
Deferred Maintenance allowed?	58 & 64	new .165(e) (19)	Allowed	not allowed if undertaken in response to an problem which required a reduction in production, unless caused by something unavailable even to someone exercising due care.
Field Topping Plants allowed?	58	new .165(e) (20)	Allowed	not allowed; however a deduction for the 'fair market value' of the products from the topping plant will be allowed.

State Purchase of Credits

Funding of Purchase of .023 and .025 Credits by State	30,45	new.028 replaces .023(f)	"subject to appropriations made by law"	Creates the oil and gas credit fund, which is funded by 10% or 15% of production taxes depending on whether ANS WC is forecast (when?) to above \$60 or below \$60. Credits are purchased from fund.
Limits on Purchase of .023 and .025 Credits by State	30,45	new.028 replaces .023(f)	Entity receiving refund had to (i) have been producing fewer than 50,000 bbls a day (currently all but big three); (ii) reinvest that money in state, (iii) had no other delinquent taxes and (iv) was limited to \$25 million a year	Same restrictions except \$25 million cap eliminated

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

<u>Issue</u>	<u>Bill Section</u>	<u>Statute Section</u>	<u>Current Law</u>	<u>Governor's 10/1/2007 Proposal</u>
Statute Section is AS 43.55.xxx unless other wise indicated				

Information

Required Reporting of Forward Looking Information	49	.040 (5)	none	requires taxpayer "to file report and copies of records that are considered by the department as necessary to forecast state revenues under AS 43.55". For unit with multiple working owners limited to unit budget matters. Penalty of not more than \$1000 a day. Not clear how far in advance data must be disclosed to avoid penalty.
Disclosure of Tax Information	61	old 43.05.230 new .890	Published information must combine data. so as to "prevent the identification of particular returns."	As long as data is aggregated among 3 producers 11 categories of data can be made public (production, taxes, effective tax rates, gross value, costs, production tax value and credits). Such aggregation is explicitly "irrespective of whether the information...prevents[s] the identification of particular reports." (i.e. one large taxpayer aggregated with two very small taxpayers)
DNR Sharing Royalty Information with DOR	2-9 & 11	royalty statutes	limited ability	expanded ability
DOR Sharing Tax Information with DNR	12-13	AS 43.05.230	limited ability	expanded ability
Required Reporting	46	.030(a)	"The person paying the tax..." will report "with other information required" certain data	Producer (whether tax due or not) will report same information plus certain cost, credit and monthly data. Penalty of not more than \$1000 a day.
Required Reporting	48	.030(e) & (f)	some requirements in regulations	in statute: thorough reporting of costs, volumes, sales, monthly estimates and other information required by department

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

<u>Issue</u>	<u>Bill Section</u>	<u>Statute Section</u>	<u>Current Law</u>	<u>Governor's 10/1/2007 Proposal</u>
Statute Section is AS 43.55.xxx unless other wise indicated				

Statute of Limitations

Statute of Limitations	1, 14, 50	old 43.05.260 new .075	3 Years for all Taxes	6 years for Production Tax
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DOR Auditors

Are DOR auditors exempt employees?	10,65,67	new AS 39.25.110	no	yes
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Other Administrative Provisions

Monthly filings	22, 24,25	0.02	ambiguity (tried to resolve in regulations) about interaction between annual tests and credits and monthly filings	Clear and separate rules for (i) non CI, not subject to floor under (f), (ii) CI, and (iii) subject to floor under (f).
Penalty for Failure to Report (when no tax is due)	47	.030(d)	none (penalty was tied to tax being due)	up to \$1,000 a day under departments regs
Retroactive Changes Require Payment	50	new .075	Regulatory provision 15 AAC 55.200	Incorporated into Statute
Electronic Payment and Filing	51	.110(e)& (f)	silent	DOR may require

sections 66 & 67 are transitional rules

Cook Inlet - no substantive change, however regs imported into statute

CI Allocation Rules	19 - 21, 55, 59	new .165(f)- (i)	Allocations and trying to fit all the other terms of the statute into the statutory ceiling language found in 15 AAC 55.360, 15 AAC 55.223 & 15 AAC 55.235.	adopted into statute
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Effective Date

General Rules	64, 69			Jan 1 2008
Deferred Maintenance Rules	64	new .165(e) (19)		Apr 1 2006

Summary Comparison between Governor's October 1, 2007 Production Tax Proposal and Current Law

<u>Issue</u>	<u>Current Law</u>	<u>Governor's 10/1/2007 Proposal</u>
Base Rate	<i>AS 43.55.011 (e) & (g)</i>	<i>Bill Sections 15 & 17</i>
Base Tax Rate	22.50%	25%
Progressivity	<i>AS 43.55.011(g) & (h)</i>	<i>Bill Sections 17,18</i>
Starting point	\$40	\$30
Tax/\$ of Price Index	0.25%	0.20%
Average Value over	month	year
Gross Value Floor	<i>AS 43.55.011(f)</i>	<i>Bill Section 15, 16, 31-36, & 41-42</i>
Base	Prudhoe & Kuparuk	North Slope
Rate	ranges from 0% to 4%	10%
Credits further reduce floor tax?	Yes	No
Credits	<i>AS 43.55.023 and 55.025</i>	<i>Bill Section 26-28, 38-44 & 63</i>
Investment Credits	Taken in year of investment	1/2 in each of two years
Loss Carry Forward Credits	20%	25%
Transitional Investment Credits	Yes	No
Exploration Credits	<i>AS 43.55.025</i>	<i>Bill Section 36 - 44</i>
DNR approval required?	In CI, to avoid 3 mile limit	Always
Confidentiality of well data	10 years	2 years
Pre-existing well	One drilling season	Two consecutive drilling seasons
"DNR TIE" Credits for pre 2003 seismic work?	no	5%
Allowable Lease Expenditures	<i>AS 43.55.165</i>	<i>Bill Sections 52-64</i>
Use producer audits of operators?	Yes	No
DR&R Allowed?	Some	No
Deferred Maintenance allowed?	Yes	No
Field Topping Plants allowed?	Yes	No

Summary Comparison between Governor's October 1, 2007 Production Tax Proposal and Current Law

<u>Issue</u>	<u>Current Law</u>	<u>Governor's 10/1/2007 Proposal</u>
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
Information	AS 43.05.230 and royalty statutes	Bill Sections 2-9, 11-13, 49 & 61
forward looking information required	none	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 w/2 other producers
DNR sharing royalty information w/ DOR	limited ability	expanded ability
DOR sharing tax information with DNR	limited 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
DOR Auditors	As 39.25.100	Bill Sections 10, 65, 67
DOR auditors exempt employees?	no	yes
Effective Date		Bill Section 64
Generally		Jan 1 2008
Deferred Maintenance Rules		Apr 1 2006

REPORT TO THE ALASKA STATE LEGISLATURE

on the

PRELIMINARY ESTIMATE OF THE FY 2008 REVENUE EFFECTS OF FOUR CHANGES PROPOSED BY GOVERNOR SARAH PALIN TO THE OIL AND GAS PRODUCTION TAX, AS 43.55, ON SEPTEMBER 4, 2007 AND OCTOBER 1, 2007

Dan E. Dickinson, CPA, CMA
October 3, 2007

Executive Summary

On September 4, 2007, the Palin Administration proposed changes to Alaska's oil and gas production tax (AS 43.55). Also handed out at that time was a chart demonstrating estimated FY 2008 production tax revenues under different scenarios. That chart showed that at a price level of \$70 dollars a barrel, a revenue estimate under current law and cost and volume assumptions to be roughly:

- a billion dollars higher than revenues had the ELF-based tax still been in place; however,
- a billion dollars lower than under current law and summer of 2006 cost and volume assumptions; and
- 800 million dollars lower than under the Governor's plan also using summer of 2006 cost and volume assumptions.

On October 1, 2007, the Administration made public a work draft of a bill incorporating these and other changes. This paper analyzes four of the proposed changes. If implemented for all of FY 2008, these four changes proposed by the Governor would have large and immediate revenue impacts, and in fact account for the 800 million dollar difference identified above:

The tax rate would go from 22.5 to 25%. At currently predicted volumes and costs, that would generate a revenue increase of about 37.5 million dollars if oil is at \$30 a barrel for the entire year and 342.5 million dollars if oil remains at \$80 for the entire year.

Progressivity – a mechanism that imposes an additional tax when net values are very high - is changed so that in most circumstances at prices greater than \$55 dollars a barrel it will raise up to roughly 190 million more dollars a year than current law. However, because the Administration has opted for the administratively less complex method of calculating progressivity on an annual rather than monthly basis, in cases of short duration spikes in price the proposal may capture fewer dollars.

Preliminary Estimate of Four Proposed Changes on FY 2008 Revenues
Dan E. Dickinson
October 3, 2007

The TIE (Transitional Investment Expenditure) credits would be eliminated. Those credits allowed producers that are making both current investments, and had been making investments in the period 2000 through 2005, to "supercharge" their current investment credits from 20% to 30%. In FY 2008, eliminating TIE credits will increase revenue by about \$190 million a year.

A fourth proposed change will likely have a large revenue impact in its first year but little impact thereafter. It will require capital credits to be taken over two years instead of in the year of investment. If the change were effective July 1, 2007, the State would receive a revenue boost of about 190 million dollars in FY 2008, but would notice little change thereafter.

Analysis

On September 4, 2007, the Palin Administration proposed 10 changes to Alaska's oil and gas production tax (AS 43.55) summarized in a 150 word handout. Also handed out at that time was a chart handout entitled "FY 2008 Production Tax Estimates." This chart showed FY 08 production tax revenues over a range of oil prices between \$30 and \$70 using the four following sets of assumptions:

- (a) Current law and production and cost assumptions;
- (b) Current law using production and cost assumptions from the summer of 2006;
- (c) The Governor's proposed changes; and,
- (d) The ELF-based tax as though it were still in place.

At a price level of \$70 dollars a barrel¹, the revenue estimate shown under current law and assumptions is roughly:

- A billion dollars higher than revenues had the ELF-based tax still been in place; however,
- A billion dollars lower than under current law and summer of 2006 cost and volume assumptions; and
- 800 million dollars lower than under the Governor's plan also using summer of 2006 cost and volume assumptions.

On October 1, 2007, the Administration made a work draft of a bill public. This paper analyzes four of the proposed changes from that bill. Using a very simple one page model (Attachment One), the Governor's proposed changes are compared with existing law using the same cost and volume assumptions. If implemented for all of FY 2008, these four changes proposed by the Governor have large and immediate revenue impacts, and, in fact, account for the 800 million dollar difference identified above between current law and the proposal. The four changes are:

- A change in tax rate on net profits from 22.5% to 25%;
- Two of the three changes proposed for the method of calculating progressivity;
- Elimination of the TIE credit, and
- Requiring taxpayers to take investment credits over two years.

On September 4, 2007, when the chart was released the Commissioner of DOR stated that he did not know when the bill would become effective. However the analysis that

¹ Although on September 4, 2007, the ANS price was in the mid seventies, according to archival price data at DOR's website, it had been 70.76 as recently as August 22 (Site accessed October 2, 2007:

<http://www.tax.state.ak.us/programs/oil/prices/monthlydata/2007/Aug07.xls>

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best fits the September 4 handouts, and that is presented in this paper is driven by a July 1, 2007, effective date. The work draft of the bill, however, has proposed a January 1, 2008, effective date. Using the effective dates in the Governor's proposed legislation would cut the 800 million difference for FY 2008 roughly in half to \$400 million.

"25% Tax Rate on Net Profits"

AS 43.55.011(e) levies a tax of 22.5% on the "production tax value of the taxable oil and gas." The proposed change found in sections 15 and 17 of the October 1, 2007, work draft modifies AS 43.55.011(e) and (g) to up that figure by an additional 2.5% to 25%. The effect of this change on 2008 revenues is modeled on the table below.

Simple Model of FY 2008 Production Tax Revenue: Base Rate							
Price Scenarios on Sept 4 Handout	Annual Volumes (w/o royalty)	Total Destination Value of non Royalty Barrels	Less Downstream costs from RSB	Less Upstream costs (capex and opex) from RSB	Resulting Production Tax Value	Tax Rate	Base Tax Calculation at 22.5% and 25% and difference
\$/bbl	MM bbls	MM \$	MM \$	MM \$	MM \$	%	MM \$
A	B	C= (A * B)	D	E	F= (C+D+E)	G	H= (F*G)
Under Current Law							
			7.22 per bbl				
30	244	7,320	(1,762)	(4,058)	1,500	22.5%	337.6
40	244	9,760	(1,762)	(4,058)	3,940	22.5%	886.6
50	244	12,200	(1,762)	(4,058)	6,380	22.5%	1,435.6
60	244	14,640	(1,762)	(4,058)	8,820	22.5%	1,984.6
70	244	17,080	(1,762)	(4,058)	11,260	22.5%	2,533.6
80	244	19,520	(1,762)	(4,058)	13,701	22.5%	3,082.6
Under Changes Indicated in Sept 4th handouts							
30						25.0%	375.1
40						25.0%	985.1
50						25.0%	1,595.1
60						25.0%	2,205.1
70						25.0%	2,815.1
80						25.0%	3,425.1
Incremental Change: Proposal less Current Law							
30							37.5
40							98.5
50							159.5
60							220.5
70							281.5
80							342.5

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The format of this table will be repeated several times in this report excerpting columns from the entire table which can be found as Attachment One. The table is divided into three horizontal sections. Within each section the analysis is shown at prices that range from \$20 a barrel up to the today's price of \$80. (Note – when comparisons are made to the Governor's chart, the analysis uses the Administration's assumptions and only goes up to \$70.) The first section is based on current law. Below it, the second section is based on the Governor's September 4, 2007, proposals. Finally, the third section is just the difference between the first two sections – the incremental dollar effect of implementing the change.

Columns A through F are identical whether under current law or the proposed changes.² The first, column A, is the destination value. The next column has taxable barrels based on the volumes found in the Department of Revenue's spring 2007 Revenue Sources Book (RSB). Column C is the product of the first two. In the next two columns, costs also found in the RSB are deducted. In column D, downstream costs are quoted at \$7.22 a barrel, which must be multiplied by volumes, while upstream costs are given as total dollars in column E. Finally, costs are subtracted to arrive at the "production tax value" shown in column F.

Starting with column G, the section under current law and the section describing the effect of the proposals are different. Current law multiplies "production tax value" times 22.5%, while in the second section the Governor's proposed rate of 25% is used. The "Incremental Change" portion of Column H shows the annual difference this proposed change would make at this year's production levels and it ranges from \$37 million at the \$30 per barrel price level to just under 10 times that or roughly \$342.5 million dollars at the \$80 price level seen today.

"Progressive Feature that Kicks In at \$30 Net Value (annual) and rises at Two-tenths of a Percent per Dollar"

This proposal incorporates three changes to the progressivity feature of which two are incorporated into this model. Under current law, AS 43.55.011(g) and (h), the progressive feature is calculated as an additional tax of two and a half tenths of a percent for every dollar per barrel of net value over the \$40 price index starting point. This proposal, found in sections 17 and 18 of the October 1 work draft, suggests the progressive feature should be calculated as an additional tax of two tenths of a percent for every dollar per barrel of net value over a \$30 price index starting point.

² That is, they are identical in this simple model. The Governor has also proposed some smaller changes described below that would affect the total deductible costs as well; however, they have not been modeled here.

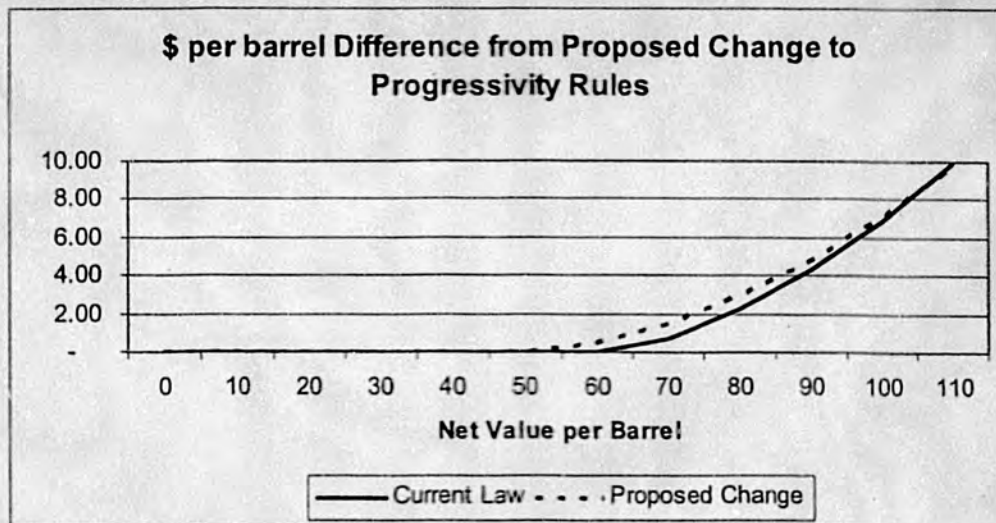
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	Current Law	Proposed Change
Price Index starting point	\$40 per barrel	\$30 per barrel
Rate per \$ in Price Index	.25%	.20%

Put more plainly, under the proposal, progressivity will start at lower per barrel values than under current law. However, once it starts, progressivity will rise more slowly. Until the net production tax value reaches \$80 dollars a barrel, the Administration's suggested change to these two parameters will consistently produce more progressivity dollars than the current statute. At a net of \$80, the suggested changes and current law will yield the same result.³ At net values above \$80, the formula in current law will produce more progressivity dollars.⁴ However, under both the current statute and the Governor's proposal, the total tax rate progressivity is capped at 25% - which occurs at an even higher price.



As might be expected at today's high prices, changes to progressivity are an important part of calculating the overall tax burden and the difference between current law and this proposal. The table on the next page illustrates the dollar effect of these two changes in FY 2008.

This table has the same format as the table described on pages 4 and 5 above -- the table is divided into three horizontal sections for current law, the September 4, 2007, proposals, and, the difference between those two. Within each section the analysis is

³ Because $(80 - 30) \cdot .002 = (80 - 40) \cdot .0025$ for those who care about the algebra.

⁴ To translate \$80 net value into WC market prices total RSB costs of \$23.85 per barrel need to be added meaning the cross over point would be about \$103.85, roughly 20% higher than current prices.

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shown at prices that range from \$20 a barrel up to the today's price of \$80. The computations to reach column F are not reproduced.

Column I converts the column F production tax value back to dollars per barrel by dividing column F dollars by the barrels in column B. Column J shows the starting point for the Price Index as \$40 under current law and \$30 under the Governor's proposal. In Column K, the price index is calculated by subtracting J from I. In Column L, the current and proposed progressivity rates per dollar of price factor are shown as .0025% and .002% respectively. In column M, these are multiplied by the price index to yield the new progressivity rate. Finally, in column N, the dollars of progressivity are calculated by multiplying the column M rate by the same base that was subject to taxation found in column F.

Simple Model of FY 2008 Production Tax Revenue: Progressivity								
Price Scenarios on Sept 4 Handout	Annual Volumes (w/o royalty)	MEMO: Resulting Production Tax Value	Per Barrel Production Tax Value	Adjustment for Price Index Calculation	Price Index	Progressivity Rate per Price Index Dollar	Resulting progressivity rate	Progressivity Tax = Rate Times Value
\$/bbl	MM bbls	MM \$	\$/bbl	\$/bbl	\$/bbl	%	%	MM \$
A	B	F= (C+D+E)	I= (F/B)	J	K= (I-J)	L	M (L*K)	N= (M*F)
Under Current Law								
30	244	1,500	\$ 6.15	40.0				
40	244	3,940	\$ 16.15	40.0				
50	244	6,380	\$ 26.15	40.0				
60	244	8,820	\$ 36.15	40.0				
70	244	11,260	\$ 46.15	40.0	\$ 6.15	0.25%	1.54%	173.1
80	244	13,701	\$ 56.15	40.0	\$ 16.15	0.25%	4.04%	553.1
Under Changes Indicated in Sept 4th handouts								
30			\$ 6.15	30.0				
40			\$ 16.15	30.0				
50			\$ 26.15	30.0				
60			\$ 36.15	30.0	\$ 6.15	0.20%	1.23%	108.5
70			\$ 46.15	30.0	\$ 16.15	0.20%	3.23%	363.7
80			\$ 56.15	30.0	\$ 26.15	0.20%	5.23%	716.5
Incremental Change: Proposal less Current Law								
30								
40								
50								
60				(10.0)	\$ 6.15		1.23%	108.5
70				(10.0)	\$ 10.00		1.69%	190.6
80				(10.0)	\$ 10.00		1.19%	163.4

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When just these two elements are considered, the Governor's proposal can be seen to yield between \$108.5 and \$190.6 million more than the current rules at prices of \$60 or above. (With this set of inputs the maximum difference is close to \$190.6 million.)

However, what these two elements take in higher revenues, a third part of this proposed change may more than give back. To many people in the Legislature in 2006, the purpose of the progressivity was to capture a premium when there were price spikes. Therefore, current law requires the analysis to be done on a monthly basis. (Although now as daily prices hover around the \$80 per barrel level it may seem quaint; but in the summer of 2006 as the current law was being crafted, prices were surpassing \$70 a barrel for the first time and to many that seemed like a spike.) The Administration's proposal would be administratively simpler requiring only an annual analysis. However, this change might reduce taxes by hundreds of millions of dollars.

Consider the price spike preceding the first Gulf War when prices doubled between July and September 1991, and then soon returned to where they had been. The following table illustrates what might happen should FY 2008 have just such a spike in it:

Comparing Annual and Monthly analysis of FY 2008 with hypothetical spike									
	US West Coast Price/ bbl	Per Barrel Total Costs	Per Barrel Production Tax Value	Adjustment Converting Production Tax Value to Price Index	Price Index	Rate per Dollar of Price Factor	Incre- mental Progres- sivity %	Volumes (millions of bbls)	Progres- sivity Tax (millions of dollars)
A	B	C	D= (B+C)	E	F= (D+E)	G	H= (F*G)	I	J= (D*H*I)
Monthly Analysis, \$40 Adjustment and .0025% Parameter under Current Law									
Jul	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Aug	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Sep	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
Oct	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Nov	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
Dec	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Jan	77.15	(23.85)	53.29	(40.00)	13.29	0.25%	3.32%	20.7	36.7
Feb	102.86	(23.85)	79.01	(40.00)	39.01	0.25%	9.75%	18.7	144.2
Mar	77.15	(23.85)	53.29	(40.00)	13.29	0.25%	3.32%	20.7	36.7
Apr	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
May	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.7	-
Jun	51.43	(23.85)	27.58	(40.00)	-	0.25%	0.00%	20.1	-
								244.0	217.6
Yearly Analysis, \$30 Adjustment and .002% Parameter, as Proposed									
Yr	60.00	(23.85)	36.15	(30.00)	6.15	0.20%	1.23%	244.0	108.5

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In the simple model presented on page 7, no progressivity dollars were generated under current law at the \$60 scenario level. Implicit in the model is that the price stays flat at \$60 all year. But, in the model presented on page 8, instead of a flat \$60, the price hovers around \$51.43 for most of the year except for a three month spike⁵. In this hypothetical spike, like in 1991, prices will double over two months and then fall back. The \$51.43 was chosen so that the year's price would average out to \$60 -- and the point would be dramatically illustrated. Under this scenario, the current law would generate \$217.6 million of progressivity over the year -- just about twice what would be generated under the rules the Governor is proposing. (The \$108.5 figure under the Administration's plan can be found in both the tables on page 7 and 8.)

Please note the table on page 8 is not a forecast but an illustration!!! If prices stay relatively flat, incorporating the kind of variation seen in most 12 month periods, the Governor's proposal will produce more progressivity dollars than current law. However, it will not necessarily catch a single peak or spike. Incidentally, as might be expected, if the Governor's two suggested parameter changes are combined with a monthly analysis, then a spike such as that illustrated in the table on page 8 brings in significantly more revenue than current law.

"Eliminates the Transitional Investment Expenditures (TIE) Credits"

The Transitional Investment Expenditures (TIE) credit, AS 43.55.023 (i), was transformed in the Legislative process. As originally introduced by the Murkowski Administration, it permitted capital costs incurred in the prior five years to be used as additional capital credits through 2013 with certain restrictions. The Legislature transformed the idea and required new matching investment before the TIE credits would be allowed. If a producer were in harvest mode and not making any new investments, the TIE would be of no use, whereas a producer that increased its investment by about 40% could take full advantage of the TIE credit. The law allowed certain producers with a good history of investment to "supercharge" their new investments made between 2006 and 2012 and to boost their credit for that investment by an additional 10% from 20% to an effective rate of 30%. To take advantage of this 10% credit, a producer had to have two things -- prior investment and current investment. The credit would have expired in 2013 on its own. The Palin Administration, in section 63 of the October 1, 2007, work draft, proposes ending it sooner -- December 31, 2007 -- which means that TIE credits would still be allowed for half of FY 2008. However, for simple modeling purposes to best match the Administration's September 4, 2007, model, the elimination of the TIE credit is shown for the entire year.

The simple model incorporates the following assumptions. In its August 3, 2007, Petroleum Profits Tax (PPT) Implementation Status Report, the DOR estimates that \$1.9

⁵ Of all the places in the future to place the spoke, February was chosen with only 29 days of production in FY 2008 to model a conservative scenario.

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billion in capital costs will be reported for FY 2008. The model further assumed that in the second year of the TIE program, every dollar invested in FY 2008 still has a match from prior years' investments – that is, all the investment was supercharged from 20% to 30%. Thus, current law allows, and the Governor's proposal will disallow, 10% of \$1,900 million or \$190 million a year regardless of the price of oil. In the table below, column E is a memo column that shows total upstream costs, columns H and N were calculated in previous tables, and column O sums those results together to generate total tax before credits. In column P, under current law, a credit of 10% of 1.9 billion dollars is taken; no credit is allowed under the Governor's proposal. The final column shows the effect of applying the credit in column P against the tax in column O.

Simple Model of FY 2008 Production Tax Revenue: TIE						
Price Scenarios on Sept 4 Handout	MEMO: Less Upstream costs (capex and opex) from RSB	MEMO: Base Tax Calculation at 22.5% and 25% and difference	MEMO: Progressivity Dollars	Total Taxes before credits	TIE Credits	Taxes Due after application of TIE Credit
\$/bbl	MM \$	MM \$	MM \$	MM \$	MM \$	MM \$
A	E	H	N	O= (H+N)	P	
Under Current Law						
30	(4,058.0)	337.6		337.6	(190.0)	147.6
40	(4,058.0)	886.6		886.6	(190.0)	696.6
50	(4,058.0)	1,435.6		1,435.6	(190.0)	1,245.6
60	(4,058.0)	1,984.6		1,984.6	(190.0)	1,794.6
70	(4,058.0)	2,533.6	173.1	2,706.7	(190.0)	2,516.7
80	(4,058.0)	3,082.6	553.1	3,635.7	(190.0)	3,445.7
Under Changes Indicated in Sept 4th handouts						
30		375.1		375.1		375.1
40		985.1		985.1		985.1
50		1,595.1		1,595.1		1,595.1
60		2,205.1	108.5	2,313.6		2,313.6
70		2,815.1	363.7	3,178.8		3,178.8
80		3,425.1	716.5	4,141.6		4,141.6
Incremental Change: Proposal less Current Law						
30		37.5		37.5	190.0	227.5
40		98.5		98.5	190.0	288.5
50		159.5		159.5	190.0	349.5
60		220.5	108.5	329.0	190.0	519.0
70		281.5	190.6	472.1	190.0	662.1
80		342.5	163.4	505.9	190.0	695.9

"Requires Capital Expenditure Costs to be Taken as Credits over Two Years Rather than Immediately"

Under current law, AS 43.55.023 (a), capital investment credits may be taken in the year the investment is made. The proposal, found in section 26 of the October 1, 2007, work draft, will require that for a credit generated in year one, only half can be applied in year one and the rest in year two. In DOR Commissioner Galvin's oral presentation September 4, 2007, he stressed that this change was intended to make annual revenues more stable and predictable. There will, however, be immediate one-year revenue implications and the model below assumes the effective date of the change in the law would be timed so as to maximize the revenue effect on FY 2008.

However, this large revenue effect will essentially be limited to one year. In the next year, the total credits allowed will be half of that year's investment and half of the investment made the year after that and so forth each year forward. If investment stays roughly constant, in subsequent years there will be no revenue effect. Thus from the point of view of the State, this appears to create first year savings only. From the taxpayers' point of view, the value of the credits essentially falls by one half year's time value of money.

In the simple model on page 12, columns E, H, N & O are as they were in the TIE table. In column Q, FY 2008 current law will allow 20% of \$1,900 or \$380 million a year. The Governor's proposal will disallow half of that, 10% of \$1,900 or \$190 million, and allow the other half. Again, this is regardless of the price of oil. In the final column of the table, this amount is subtracted from the taxes derived in the prior two sections.

This model assumes that the tax and forecasting are on the same basis; but, the world is not that simple. The tax system is based on the calendar year, while the fiscal year (FY) runs from July 1 to June 30. Thus the effect of this change on fiscal year revenues will be split between two fiscal years (FY 2008 and 2009) but thereafter will have little revenue effect.

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Simple Model of FY 2008 Production Tax Revenue: Cap Credit						
Price Scenarios on Sept 4 Handout	MEMO: Less Upstream costs (capex and opex) from RSB	MEMO: Base Tax Calculation at 22.5% and 25% and difference	MEMO: Progressivity Dollars	Total Taxes before credits	First Year Capital Investment Credit (full or half)	Taxes Due after application of Capital Investment Credit
\$/bbl	MM \$	MM \$	MM \$	MM \$	MM \$	MM \$
A	E	H	N	O= (H+N)	Q	
Under Current Law						
					1,900.0	
30	(4,058.0)	337.6		337.6	(380.0)	(42.4)
40	(4,058.0)	886.6		886.6	(380.0)	506.6
50	(4,058.0)	1,435.6		1,435.6	(380.0)	1,055.6
60	(4,058.0)	1,984.6		1,984.6	(380.0)	1,604.6
70	(4,058.0)	2,533.6	173.1	2,706.7	(380.0)	2,326.7
80	(4,058.0)	3,082.6	553.1	3,635.7	(380.0)	3,255.7
Under Changes Indicated in Sept 4th handouts						
30		375.1		375.1	(190.0)	185.1
40		985.1		985.1	(190.0)	795.1
50		1,595.1		1,595.1	(190.0)	1,405.1
60		2,205.1	108.5	2,313.6	(190.0)	2,123.6
70		2,815.1	363.7	3,178.8	(190.0)	2,988.8
80		3,425.1	716.5	4,141.6	(190.0)	3,951.6
Incremental Change: Proposal less Current Law						
30		37.5		37.5	190.0	227.5
40		98.5		98.5	190.0	288.5
50		159.5		159.5	190.0	349.5
60		220.5	108.5	329.0	190.0	519.0
70		281.5	190.6	472.1	190.0	662.1
80		342.5	163.4	505.9	190.0	695.9

The table on the next page sums up the results of the four tables presented previously to show the amount of revenue, and revenue differences, accounted for by this simplistic accounting. Column H and N are summed in column O to show total tax before credits. Columns P and Q are the two credits discussed; and, the final result of applying the credits is seen in Column R.

To determine the Administration's estimates under current law and under the Governor's proposal, figures were simply extrapolated off the September 4, 2007, handout table and these are shown in column S. The sole purpose of making this comparison is to suggest that simplistic models of the four items yield most, but not all, of the revenue differences.

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Simple Models of FY 2008 Production Tax Revenue: Summary

Dollar figures in millions (except when per barrel)

	Price Scenarios on Sept 4 Handout	Base Tax Calculation at 22.5% and 25% and difference	Progressivity Tax = Rate times value	Total Tax before credits	T/E Credits (Transitional Investment Expenditures)	Capital Costs * 20% or .10%	Tax net of credits	Tax per Price Scenarios on Sept 4 Handout	Unaccounted for in this simple model	Unaccounted for in this simple model (%)
	\$/bbl	MM \$	MM \$	MM \$	MM \$	MM \$	MM \$	MM \$	MM \$	%
A	H=	N=	O=	P=	Q=	R=	S	T	U=	
	(F*G)	(M*F)	(H+N)	(Q/2)		(O+P+Q)		(S-R)	(T/S)	
Under Current Law										
					Total Cost:					
						1,900.0				
30	337.6		337.6	(190.0)	(380.0)	-	-			
40	886.6		886.6	(190.0)	(380.0)	316.6	200	(116.6)	-58%	
50	1,435.6		1,435.6	(190.0)	(380.0)	865.6	700	(165.6)	-24%	
60	1,984.6		1,984.6	(190.0)	(380.0)	1,414.6	1,300	(114.6)	-9%	
70	2,533.6	173.1	2,706.7	(190.0)	(380.0)	2,136.7	2,000	(136.7)	-7%	
80	3,082.6	553.1	3,635.7	(190.0)	(380.0)	3,065.7				
Under Changes indicated in Sept 4th Handouts										
30	375.1		375.1	(190.0)	185.1	200	14.9	7%		
40	985.1		985.1	(190.0)	795.1	800	4.9	1%		
50	1,595.1		1,595.1	(190.0)	1,405.1	1,300	(105.1)	-8%		
60	2,205.1	108.5	2,313.6	(190.0)	2,123.6	2,000	(123.6)	-6%		
70	2,815.1	363.7	3,178.8	(190.0)	2,988.8	2,800	(88.8)	-3%		
80	3,425.1	716.5	4,141.6	(190.0)	3,951.6					
Incremental Change: Proposal less Current Law										
30	37.5		37.5	190.0	190.0	185.1	200	14.9	7%	
40	98.5		98.5	190.0	190.0	478.5	600	121.5	20%	
50	159.5		159.5	190.0	190.0	539.5	600	60.5	10%	
60	220.5	108.5	329.0	190.0	190.0	709.0	700	(9.0)	-1%	
70	281.5	190.6	472.1	190.0	190.0	852.1	800	47.9	5%	
80	342.5	163.4	505.9	190.0	190.0	885.9				

There are many other bells and whistles in the existing law, and their effect on individual taxpayers, or even on the totals, should not be trivialized. However, these numbers suggest, at least at this simple level of analysis, that the four items quantified in this report account for a great deal of the FY 2008 revenue change the Administration suggests will flow from their changes.

Attachment One: Simplistic Revenue Model

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General Calculation:

A: The 5 price scenarios shown in the September 4, 2007, handouts

B: Annual taxable volumes taken from the RSB, where the forecast is for 764,000 barrels a day. This is multiplied by 365 to convert to an annual number and .875 to remove royalty barrels (estimated at 12.5%) to yield 244 million taxable barrels a year.

C: The total value (of non royalty barrels) at destination is the product of price multiplied by taxable volume.

D: The estimate of 7.22 for downstream costs for FY 2008 is taken from the RSB, Table B-2b "Nominal Netback Costs- Forecast." This is multiplied times volumes for a total downstream cost of \$1.762 billion.

E: Upstream costs are listed at page 16 of the RSB executive summary as \$4,058.3 million.

F: The resulting production tax value is calculated at each price level by subtracting costs from destination value.

At this point, every calculation is done under existing law, then in accordance with the changes in the September 4, 2007, handouts, and, finally, the former is subtracted from the latter.

Base Rate:

G: Current law at 22.5% or proposal at 25%

H: Production tax value is multiplied by either 22.5% or 25%

Progressivity:

I: The Production Tax Value is divided through by taxable barrels to generate a per barrel value (Note: same calculation for existing law and proposed changes.)

J: Used to derive the Price Index Calculation. Either \$40 or \$30.

K: The Price Index is calculated where the per barrel value less the factor is positive.

L: The progressivity rate of .0025 or .002 per dollar of Price Index.

M: Price Index times progressivity rate.

N: This rate is then multiplied by the same Production Tax Value (as for the base rate.)

O: The total tax before credits is the sum of the base rate and the progressivity.

P: The TIE is calculated as 10% of the capital investments or as zero.

Q: Capital Investment credit calculated as 10 or 20% of capital investment (from DOR Petroleum Profits Tax (PPT) Implementation Report (August 3, 2007))

R: The two credits are then subtracted from the tax to arrive at the tax net of credits.

S: Tax extrapolated from the DOR handouts, rounded to the nearest 100 million dollars.

T: The difference between the DOR model and my simple build-up is the amount not accounted by the simple build-up.

U: This difference is also measured as a percent.

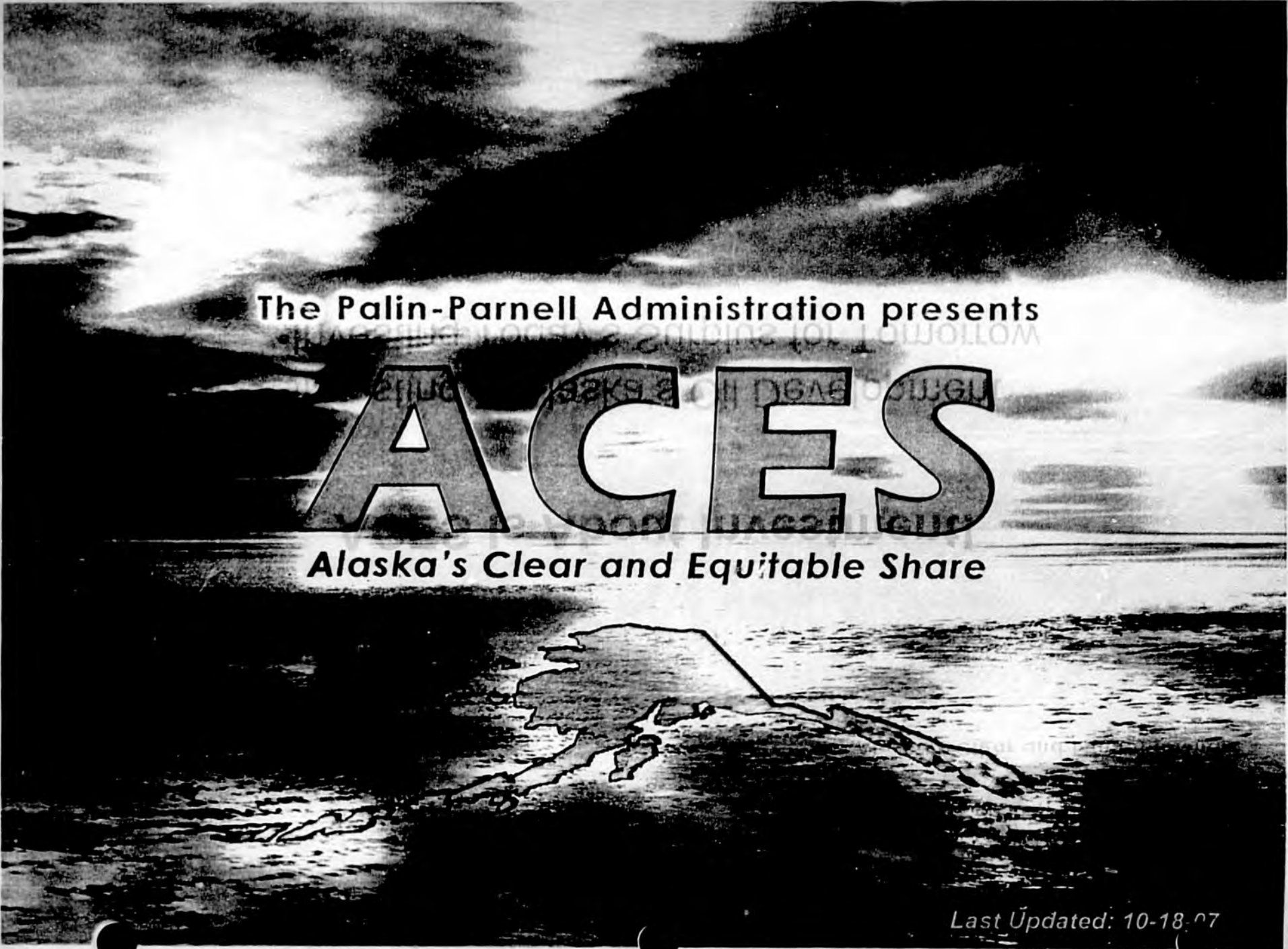
Preliminary Estimate of Four Proposed Changes on FY 2008 Revenues

Dan E. Dickinson

October 3, 2007

Simple Model of FY 2008 Production Tax Revenue to match Administrations Sept 4th Handouts:

		Base Tax					Progressivity					Credits									
		Price Scenarios on Sept 4 Handout Annual Volumes (w/o royalty)					Total Destination Value of non Royalty Barrels					Less Downstream costs from RSB					Less Upstream costs (capex and opex) from RSB				
		Resulting Production Tax Value					Tax Rate					Base Tax Calculation at 22.5% and 25% and difference					Per Barrel Production Tax Value				
		Adjustment for Price Index Calculation					Price Index					Progressivity Rate per Price Index Dollar					Resulting progressivity rate				
		Progressivity Tax = Rate times value					Total Tax before credits					TIE Credits (Transitional Investment Expenditures)					Capital Costs * 20% or .10%				
		Tax net of credits					Tax per Price Scenarios on Sept 4 Handout					Unaccounted for in this simple model					Unaccounted for in this simple model (%)				
\$/bbl	MM bbls	MM \$	MM \$	MM \$	MM \$	%	MM \$	\$/bbl	\$/bbl	\$/bbl	%	%	MM \$	MM \$	MM \$	MM \$	MM \$	MM \$	MM \$	%	
A	B	C=	D	E	F=	G	H=	I=	J	K=	L	M=	N=	O=	P=	Q=	R=	S	T	U=	
		(A * B)					(C+D+E)					(F*G)					(F/B)				

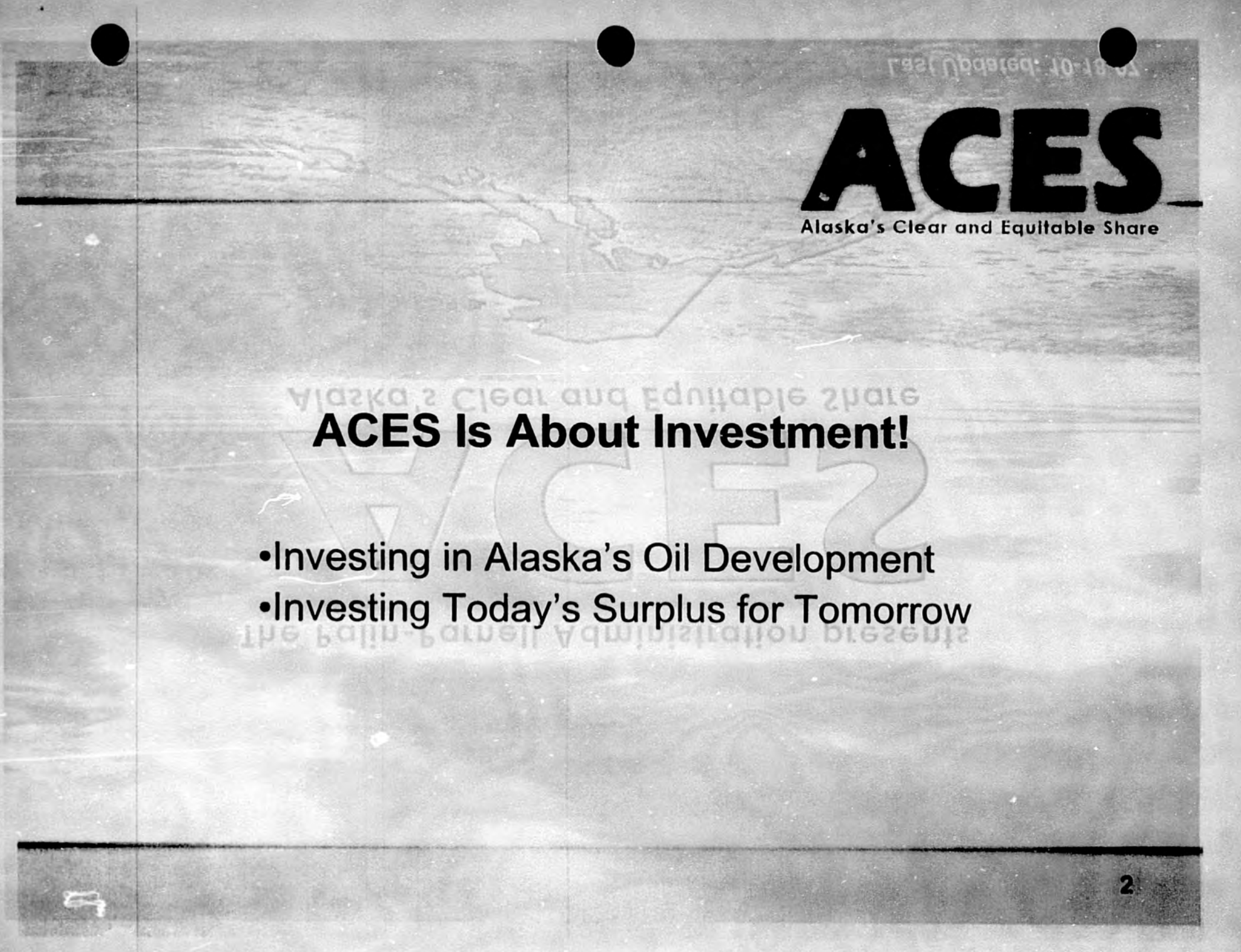


The Palin-Parnell Administration presents

ACES

Alaska's Clear and Equitable Share

Last Updated: 10-18-07



ACES

Alaska's Clear and Equitable Share

ACES Is About Investment!

- Investing in Alaska's Oil Development
- Investing Today's Surplus for Tomorrow

Alaska As Investor in Oil Development

ACES

Alaska's Clear and Equitable Share

- **PPT was a Fundamental Shift in the Relationship between the State and the oil and gas industry**
 - Companies can reduce their tax bill (or receive a State payment) in the amount of 40% to 52 ½% of their capital investments
 - The State of Alaska is the single largest investor in new projects on the North Slope
 - The State is sharing the risks associated with whether these investment decisions pan out

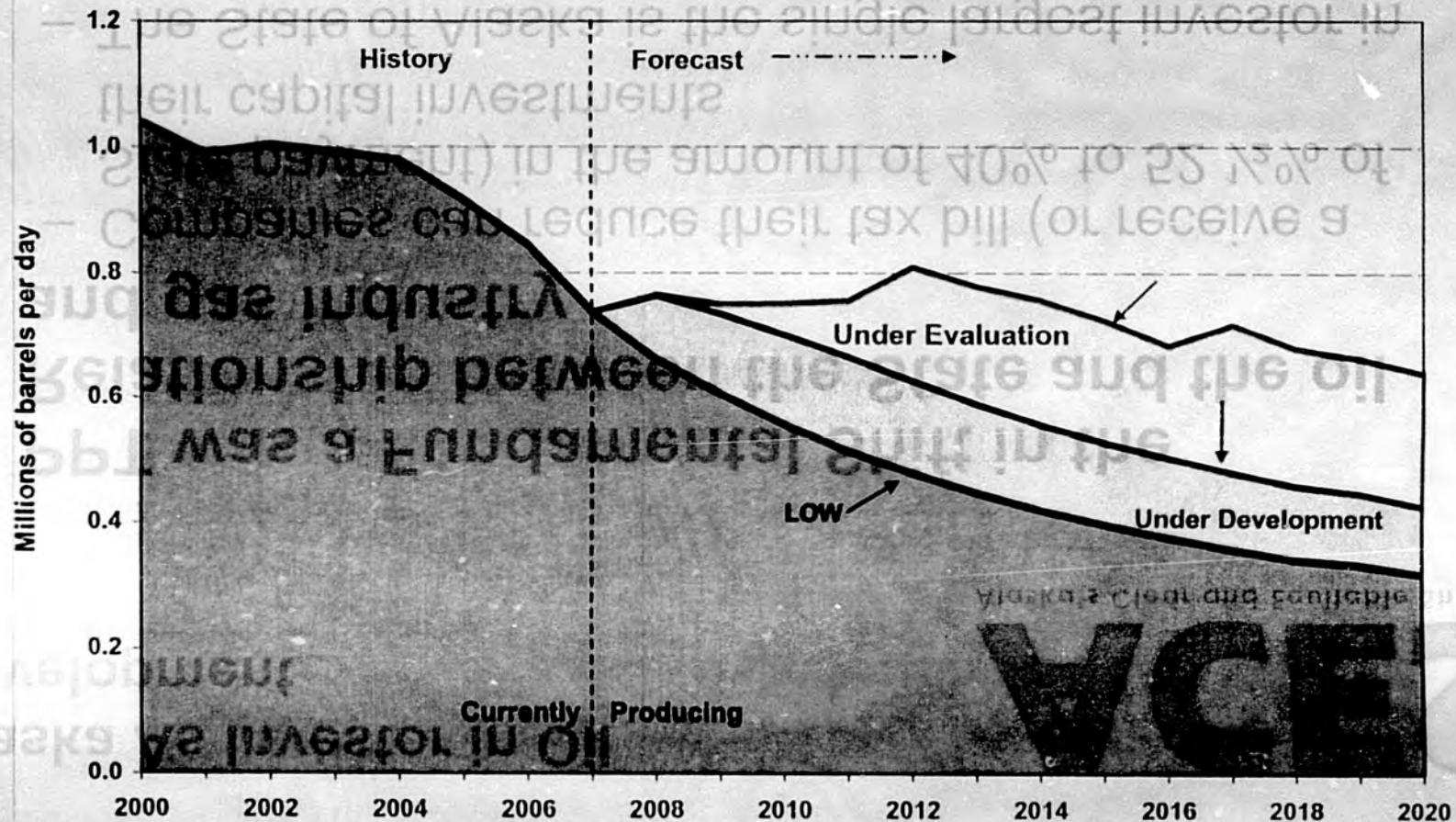
ANS Production Forecast

(Spring 2007)

ACES

Alaska's Clear and Equitable Share

Historical and Forecasted ANS Production Scenarios FY 2000 to FY 2020



Investing Today's Surplus for Tomorrow

ACES

Alaska's Clear and Equitable Share

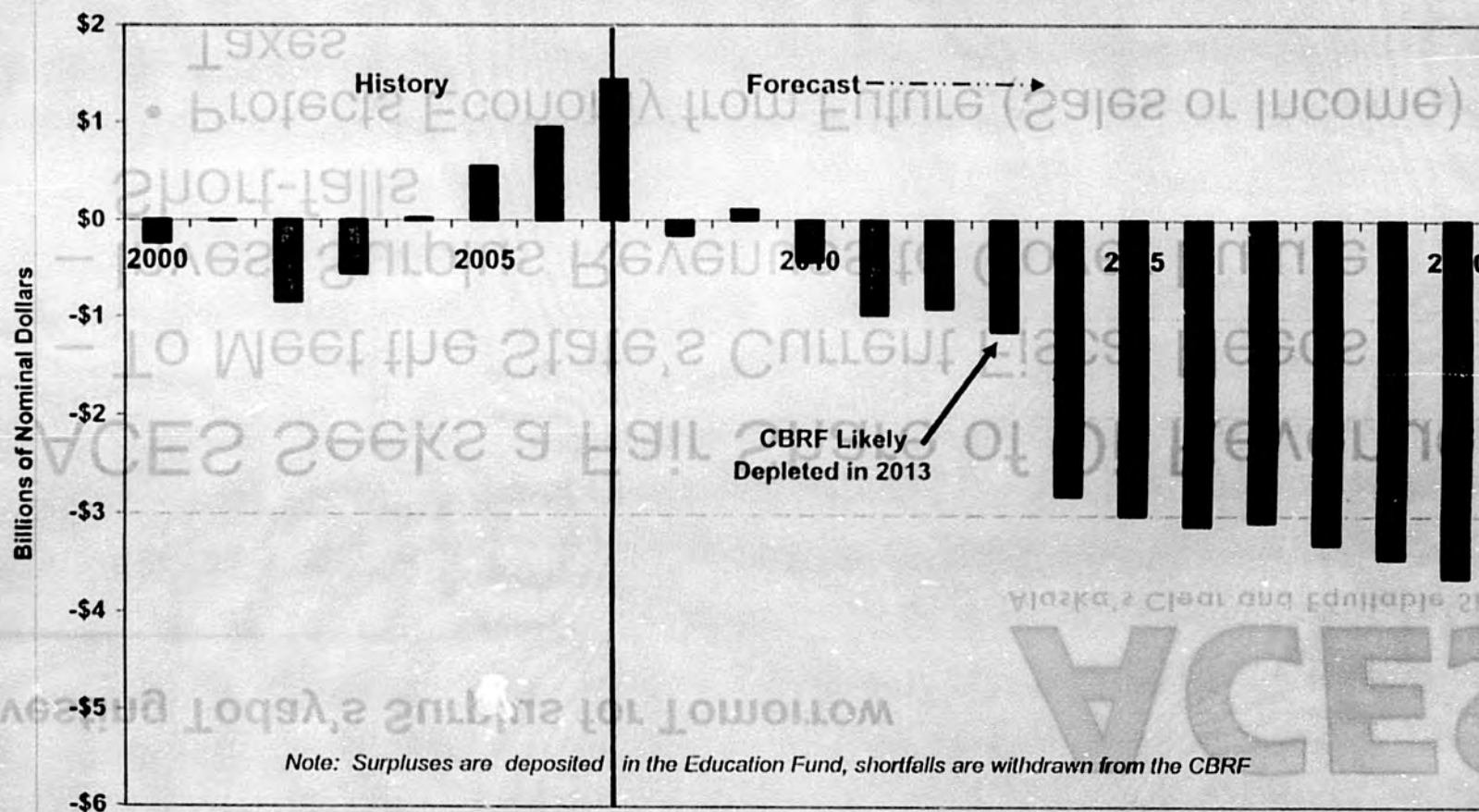
- ACES Seeks a Fair Share of Oil Revenues
 - To Meet the State's Current Fiscal Needs
 - Invest Surplus Revenues to Cover Future Short-falls
 - Protects Economy from Future (Sales or Income) Taxes
 - Provides Stability for Diversification of Alaska's Economy

State Budget Forecast (Spring 2007)

ACES

1 Eavuable Share

EXAMPLE Revenue Shifting

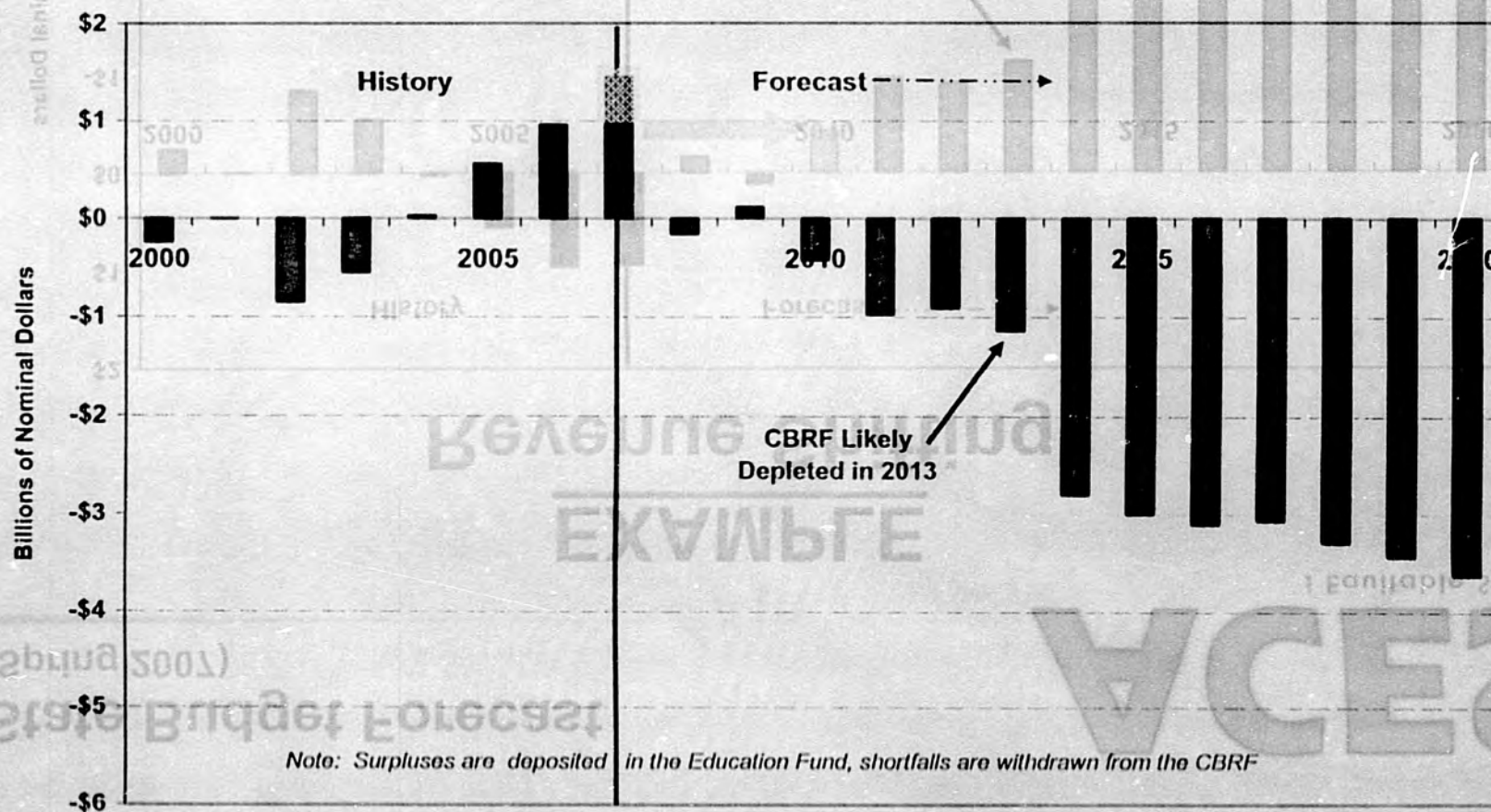


State Budget Forecast (Spring 2007)

ACES

1 Equitable Share

EXAMPLE Revenue Shifting

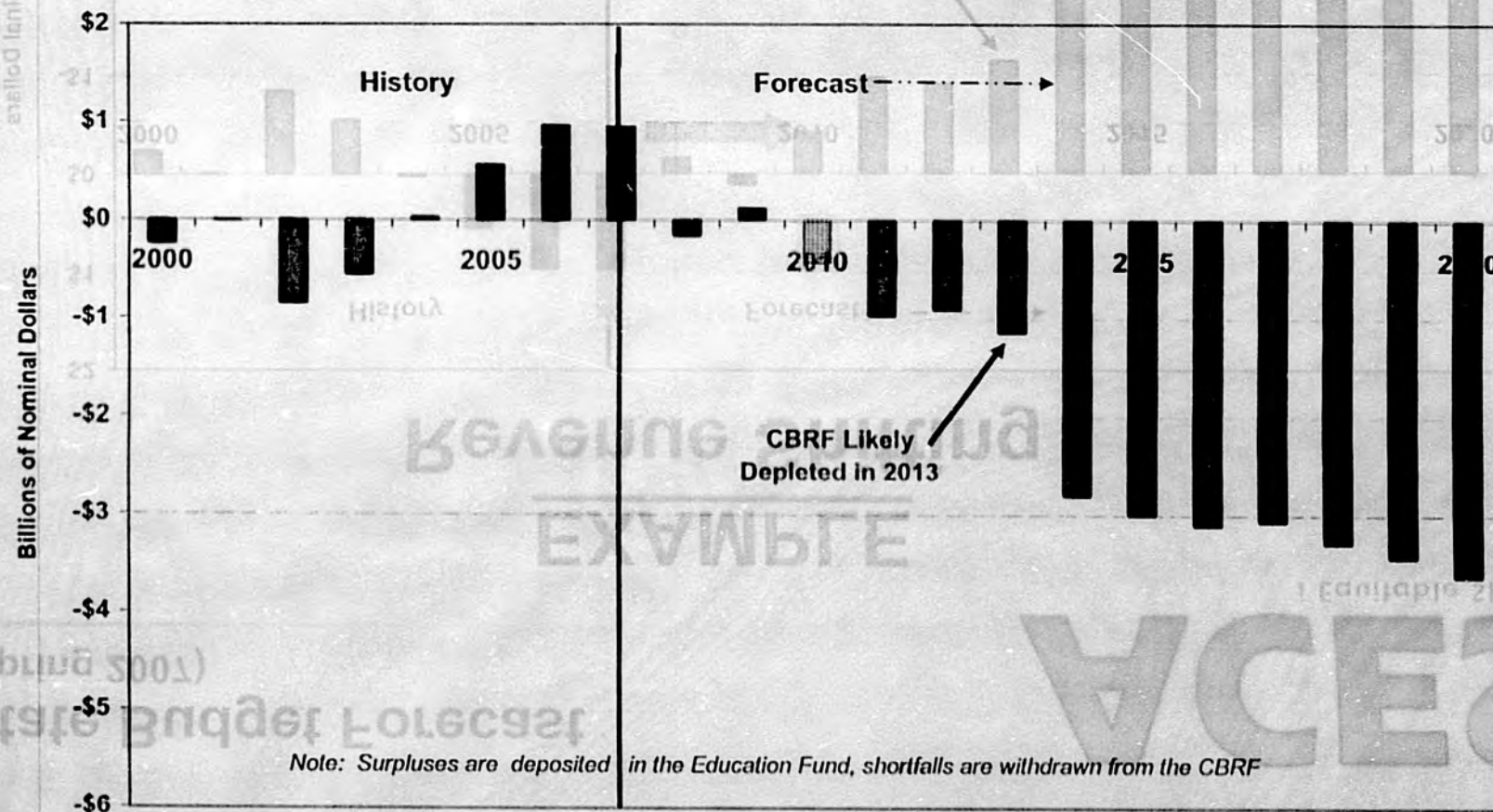


State Budget Forecast (Spring 2007)

ACES

1 Equitable Share

EXAMPLE Revenue Shifting



Balancing Investment Goals

ACES

Alaska's Clear and Equitable Share

- ACES Balances Our Investment Goals
 - Preserves Investment Climate for Oil Development Projects
 - Achieves a Fair Share of Oil Revenues to Maximize Investment in Alaska's Economic Future

Three Days – Three Modules

Alaska's Clear and Equitable Share

ACES