Alaska Oil and Gas Association

121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907) 221-1481 Fax: (907) 279-8114

ALASKA OIL AND GAS ASSOCIATION
TESTIMONY ON HOUSE BILL 72
TO THE HOUSE RESOURCES COMMITTEE

February 18, 2013

Good Afternoon. For the record, my name is Kara Moriarty and I am the Executive Director of the Alaska Oil and Gas Association, commonly known as "AOGA". AOGA is the professional trade association that represents 15 member companies who account for the majority of oil and gas exploration, development, production, transportation and refining of oil and gas onshore and offshore in Alaska. These comments regarding House Bill 72 have been reviewed by all members and were approved unanimously.

The greatest, and most urgent challenge facing Alaska today is the decline of oil production from the North Slope. And the greatest, most urgent issue facing this Legislature is how you will address this problem.

For someone who is happy and content to see Alaska continue along the path it is headed on, the answer to this question is — do nothing; leave the present tax system alone.

But most Alaskans would disagree that this is the future <u>they</u> want. They hope for a robust industry on the North Slope beyond their own lifetimes. They want their children and grandchildren to have the benefits from the oil industry that this generation of Alaskans, and the one before, have enjoyed. They want the good jobs that the industry offers to continue, and they want industry to continue to support the education and skills training that are needed to qualify for many of those jobs. They want their friends and neighbors who work for the industry to stay here. They want all the volunteer community services to continue that industry employees perform, and that companies themselves do directly. The want the activity and growth in the Alaskan economy that industry stimulates to continue. And, of course, they like the fact that industry pays for a great majority of the costs of government and hope that this, too, will continue.

The role of AOGA, and of individual companies doing business here, is not to tell Alaska how much it ought to collect from oil and gas, nor should that be our role. Rather, we should tell you about how Alaska's tax regime is affecting our businesses, about the parts of the present tax laws that are not working as intended, and about ways to improve the tax structure to get more of the intended results. With that knowledge, you can then make sound, informed decisions about how much tax to collect, how to collect that amount, and when to collect it.

For several years there has been a red herring in the public discussion about oil taxes. This is the notion that any change in tax structure that reduces tax revenues below the projections in the Revenue Sources Book is a "giveaway." This reflects an assumption that those forecasted oil and gas taxes are somehow a "given" — something like money already in the bank, and all the State Treasury needs to do is wait for it to be deposited into the State's account. The fact, however, is that industry has to spend roughly <u>$2 billion dollars each year</u> just to slow the production decline from what it would naturally be, in order even to approach the level of production published in the Revenue Sources Book. And just like any other investment industry makes here, these production-sustaining investments have to beat the competition elsewhere for those investment dollars: they are both not a "given."

Worse, the "tax giveaway" argument assumes the production in the Revenue Sources Book is all that will be produced. These critics factor in nothing for <u>any</u> additional production and revenue resulting from a tax reduction. Instead it looks only at the downside and ignore the upside. The upside, though, is real. If a tax reduction makes investments here more competitive, companies will want to make more investments here for that upside. And they will do so even though they, like the State, lack the gift of prophecy and cannot know beforehand exactly what the upside will turn out to be for any particular investment.

As you consider solutions to the momentous challenge that production decline creates, it will be wise and useful to identify the principles you want the tax system to embody, and the specific goals you want it to achieve. AOGA believes Governor Parnell's four "core principles" offer an excellent cornerstone for this:

- "First, tax reform must be fair to Alaskans."
- "Second, it must encourage new production."
- "Third, it must be simple, so that it restores balance to the system."
- "Fourth, it must be durable for the long term."

We believe a fifth such principle will be prudent as well, because the challenge facing Alaska is not that there are too many companies pursuing opportunities they see here, but that there are too few. Alaska should therefore avoid tax changes that artificially create "winners" and "losers."

With respect to House Bill 72, there are four major features in it that we wish to address, and the Bill omits several others that we would like to draw your attention to.

The major features in the Bill are the elimination of progressivity, changes to the present system of tax credits, a "gross revenue exclusion" for certain new production, and the timing for these changes to occur. Here are our thoughts on them.

1. Repeal of Progressivity. AOGA endorses the elimination of progressivity. First, progressivity directly attacks and destroys one of the few strategic advantages that Alaska has, which lies in its economic remoteness. It costs $9.42 on average to ship a barrel of oil from the North Slope to the West Coast, according to the Fall 2012 Revenue Sources Book, Appendix D-1b. This means Alaska starts off with a disadvantage of $9.42 a barrel against Outside competition, so other parts of an Alaskan investment must be pretty strong in order to overcome this disadvantage. Otherwise they won't be made.

If oil prices turn out to be higher than what they were projected to be in the investment analysis, nearly 100% of each extra dollar in price flows directly into the Gross Value at the Point of Production (GVPP) and then, after royalties and taxes, flows straight into the investor's bottom line. This, in turn, improves the economic performance of an Alaskan investment relative to an equally competitive one Outside, because the Alaskan baseline was $9.42-a-barrel lower and an additional dollar in price is a larger percentage of that baseline than for the percentage for the Outside investment. This can be particularly significant for potential investors who are bullish on oil prices.

Currently, progressivity in conjunction with a 25% base tax will take half of each dollar from higher prices when the West Coast price is $132.38 (using the Fall 2012 Source Book numbers) — a price that has already been seen, although somewhat higher than today's. So, even for investors who are bullish on oil prices, progressivity destroys half of the one strategic advantage that Alaska's economic remoteness provides. And the more bullish they are, the more this advantage is undone because they will see higher rates for progressivity at those prices in their investment analysis.

Second, progressivity brings extraordinary complexity to the tax, not only in calculating what the tax is, but also in analyzing what the amount of the progressivity is for any particular item that affects a taxpayers Production Tax Value (PTV). This complexity exists because the tax rate for progressivity depends on the taxpayer's PTV per barrel, and then the resulting rate is applied to the very same PTV that set the rate. This circularity in the tax calculation leads to bizarre effects. For instance, simply the fact that oil prices fluctuate during a year instead of remaining perfectly flat increases the tax even though the average of the fluctuating prices is the same as the flat price — and the greater the fluctuation, the greater the tax from progressivity becomes. There is no objective economic or financial reason for the tax to go up; instead, this occurs entirely because the progressivity calculation is circular.

2. Tax Credits

In general, tax credits, whether they be for drilling a well, building a facility to gather new oil or the pipe to build a flowline, represent a direct reduction in the amount that a potential investor puts at risk by spending money on the equipment and facilities. It is important to reinforce that there is no tax credit liability for the State at all until an investor invests here. So it costs nothing to offer the credit until the investment is made here, and at that point the tax credit has already succeeded in what it is supposed to do – namely to attract investment dollars here.

A. Repeal of the Qualified Capital Expenditure ("QCE") Tax Credit.

Even while the elimination of progressivity would improve the competitiveness of Alaskan investments from the present ACES tax, the elimination of the QCE Credit would claw back a big chunk of that money and undo a significant part of that competitive improvement. This is because the benefit of the QCE Credit depends only on how much is invested here, while the benefit from ending progressivity depends on the price of oil relative to a producer's lease expenditures. For every producer, there is a price below which the lost QCE Credit would start to outweigh the benefit from the end of progressivity, and exactly where that crossover comes would depend on factors that are specific to each individual producer, such as how much oil it produces, where it sells the oil, its costs to deliver it there, and its lease expenditures.

AOGA fears the repeal of the QCE Credit is likely to create "winners" and "losers" artificially among producers, and we see no sound tax policy justification for doing so.

B. Small-Producer and Exploration Credits. AOGA endorses the proposal in HB 72 to extend the small-producer tax credit under AS 43.55.024 from the present sunset dates at the start or middle of 2016 to 2022 and encourages the same extension the exploration tax credits under AS 43.55.025. The State had sound policy reasons for creating these tax credits, and those reasons are just as valid today as they were then.

The purpose of the small-producer tax credit was to attract new players to Alaska who might otherwise have been deterred from coming here by its remoteness, northern climate, and the resulting challenges of higher-than-average costs and expenses. The success of the credit in doing this is a fact that cannot be denied. AOGA sees this success in its own membership, and in other companies that have come here and are active. The importance of having a healthy contingent of smaller producers comes from the facts, first, that they often have a different perspective about the opportunities around them, and second, that no company or group of companies can have a monopoly on good ideas and innovation. For both reasons, the continuing and increasing presence of these smaller producers strengthens and improves the Alaskan petroleum industry. We know from testimony that the small-producer tax credit has made a material difference in individual companies' decisions to do business and invest in Alaska.

The purpose and justification for the exploration tax credits under AS 43.55.025 are equally plain and clear. Huge geographical swaths of this state remain unexplored for oil and gas, or have been explored in little more than a rudimentary way. If exploration is to occur in a timely fashion so any resulting production can be transported through existing infrastructure, the exploration tax credits are a direct way of bringing that exploration about and these type of credits should be extended as well. Just as with the QCE credits for capital investments, there is no exploration tax credit without real money having first been spent on exploration work that qualifies for these tax credits.

C. Limiting the transferability of "carried-forward annual loss" tax credits. We have some reservation about the proposal in HB 72 to bar almost completely the transferability of the current "carried-forward annual loss" tax credits under AS 43.55.023(b). These credits arise every year for any active explorer until it finds something and finally has production that has a tax to apply the credit against. At present explorers can only realize immediate benefit from these credits by selling them to other taxpayers or cashing them in at the state Oil and Gas Tax Credit Fund established in AS 43.55.028.

Such sales and cash-ins would stop for North Slope explorers under the Bill, who instead would be able to hold the credit for up to 10 years for possible use against tax on their own production, assuming they find something to produce. During this 10-year shelf-life the unused credits would increase at an annual rate of 15 percent, compounded annually. The same would apply for a North Slope producer with a year resulting in a "carried-forward annual loss."

The Bill's only exception to this ban would be for a transfer made in conjunction with a sale or other transfer of an "operating right, operating interest, or working interest" in a lease or property—the person acquiring that interest could also acquire a proportionate share of the lease-or-property's annual-loss credits arising before that transaction.

To prevent taxpayers from deliberately hoarding these credits instead of using them in order to get the 15% annual increase, the Bill would deny the 15% increase for each year when they could use their credits but don't. We believe this would be an effective deterrent against abuse that might otherwise occur.

In general, if sales and transfers of these annual-loss tax credits are to be limited at all, then the limitations proposed in HB 72 would be a reasonable way to do it. Our major concern of the proposal is that the 10-year shelf-life for using a credit is unrealistically short. If all the stars, planets and constellations are in just the right alignment, it might be possible for an explorer to go from exploration and discovery to production in just 10 years. But that is not the norm — particularly on the North Slope, where the limitation on transferability would apply. We think 15 years would be more in line with actual experience.

The geographical limitations on where the tax credits must arise in order still to be freely sold or transferred may have unintended consequences, but because of confidentiality considerations, they are not appropriate matters to be discussed within a trade association like AOGA. We must therefore leave this for individual companies to address if there is a problem.

Of course, without the 15% annual increase in the unused credits, AOGA would oppose the ban on transferability because it would destroy the incentives which the credit is supposed to provide to explorers.

3. Gross Revenue Exclusion. This is the most innovative feature in HB 72, and our major substantive concern is that it is too narrowly focused.

The Gross Revenue Exclusion (GRE) would, in calculating the taxable Production Tax Value, exclude 20% of the Gross Value at the Point of Production of what we'll call "non-legacy" production. Bill Section 24 calls it production "from a lease or property that does not contain land that was within a unit on January 1, 2003[,]" or if it does have land that was in a unit before 2003, "the oil or gas is produced from a participating area established after ... 2011 [that] does not contain a reservoir that had previously been in a participating area established before ... 2012."

What this means is, the fields that are likely to lose out on getting any GRE under HB 72 are Prudhoe Bay, Kuparuk, Lisburne, Milne Point, Endicott, Niakuk, Point McIntyre, and Alpine; as well as the Prudhoe Bay satellite fields Aurora, Borealis, Midnight Sun, North Prudhoe Bay, Orion and Polaris and the Kuparuk satellites Meltwater, NEWS, Tabasco, Tarn and West Sak.

Econ One Research, Inc. made a presentation to this committee just last Wednesday entitled *Analysis of Alaska's Tax System, North Slope Investment and The Administration's Proposal, HB 72*. In Slide 6 of that presentation Econ One showed oil and gas resources described as "Economically Recoverable @ $90/bbl" totaling 29.1 billion barrels of oil and barrel-equivalents of gas. Of this total, the slide shows that 10.4 billion are in ANWR and the National Petroleum Reserve–Alaska, another 9.9 billion in the Chukchi Sea Outer Continental Shelf, 5.8 billion in the Beaufort Sea OCS, and 3 billion in the central North Slope where all the producing fields are that I just named.

To us, the slide shows that more than half — 54% — of this 29.1 billion-barrel resource lies in the federal OCS, outside Alaska's sea-ward boundary and beyond its jurisdiction to tax. Current federal law does not provide for any OCS revenue-sharing with Alaska, and even though Alaska's Congressional Delegation is trying to change that, for now the only direct revenues that the State stands to see from OCS production are property taxes on the in-state portion of a pipeline linking the OCS fields to TAPS, and an increase in North Slope "wellhead" values resulting from the greater TAPS throughput.

Another 34% of the resource is in ANWR — which, again, we hope the Delegation will be able to open up, although even Ted Stevens was unable to achieve it despite four decades of dedicated effort. Another 1.7% is in NPRA, which — if the Interior Department gets its way — will have its best prospective acreage turned into a bird sanctuary despite being a "Petroleum Reserve".

So, of the 29.1 billion barrels of potential reserves identified by Econ One, only the 3 billion in the central North Slope has any potential to contribute significantly to Alaska's economic well-being in the near and mid-term future. In other words, of the 29.1 billion barrel resources, only a tenth of it is within the State's power to do anything about. And of this 3 billion barrels, 2.5 billion or more stands to come from Prudhoe Bay, Kuparuk and other legacy fields already in production. The Governor's second "core principle" for tax legislation is that "it must encourage new production." But, in order to get results from such encouragement, the tax legislation must reflect the opportunities that Alaska has for getting results. Maybe the present Gross Revenue Exclusion in HB 72 can get results, in some small way. But in terms of what it attempts to "encourage," it leaves out at least 80 – 90 percent of the 3 billion-barrel opportunity in the central North Slope that Econ One has identified as "Economically Recoverable @ $90/bbl[.]"

AOGA is continuing to search for ways to adapt the Gross Revenue Exclusion to include legacy fields in a way that might be acceptable to the Administration and the Legislature. It may turn out, however, that a different approach may be necessary to "encourage new production" from legacy fields.

For now, though, all we can say is, not enough is being done in HB 72 to improve the economic competitiveness of legacy fields, and for the coming decade or so these legacy fields will be the "trunk" that supports all the rest of the North Slope "tree." Until there is significant production from the Arctic OCS, the tree cannot survive very long without the trunk production to keep per-barrel transportation costs down and necessary infrastructure in place. It would be a mistake to let that trunk wither.

4. Issues that HB 72 does not address. There are several significant problems in the present ACES tax that are not addressed in HB 72.

A. Minimum tax for North Slope production. AS 43.55.011(f) sets a minimum tax that is targeted solely against North Slope production. That tax is based on the gross value of that production instead of the regular tax based on "net" Production Tax Value. The rationale for adopting it was to protect the State against low petroleum revenues when prices are low.

The minimum tax only complicates potential new investors' analyses of what their tax would be if they invest here instead of someplace else, and consequently it has, if anything, driven investments away. AS 43.55.011(f) should be repealed.

B. Statute of limitations & statutory interest. Here we have two concerns that are interrelated, but not in an immediately obvious way.

The statute of limitations under AS 43.55.075(a) is six years from the date when the tax return was filed for the tax being audited, while the limitations period for other taxes under AS 43.05.260(a) is three years from the filing date of the tax return. Under both statutes, the period may be extended by mutual consent of the taxpayer and the Department of Revenue (DOR).

The statutory rate of interest under AS 43.05.225(1) for tax underpayments is "five percentage points above the annual rate charged member banks for advances by the 12th Federal Reserve District as of the first day of that calendar quarter, or at the annual rate of 11 percent, whichever is greater, compounded quarterly as of the last day of that quarter[.]" Currently the Federal Reserve rate is very low, so 11% APR is the applicable rate.

Taxpayers are required under AS 43.55.020(a)(1)-(3) to make monthly estimated tax payments for each calendar month's taxable production during a year, but the final tax amount for the entire year is reported on March 31 of the following year under AS 43.55.030(a). And AS 43.55.020(a)(4) requires any additional tax to be paid at that time. The statutory interest under AS 43.05.225(1) starts to accrue on any underpayment from that March 31st true-up date.

In practical terms, what these various statutes all mean is this.

For each dollar of underpaid tax that the Department of Revenue may claim after an audit, statutory interest on that dollar at the end of three years would be —

$$\$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times 3 years})} - 1] = \$1.00 \times [1.38478 - 1]$$
$$= \$0.38.$$

After six years the statutory interest on the dollar would be —

$$\$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times 6 years})} - 1] = \$1.00 \times [1.91763 - 1]$$
$$= \$0.92.$$

Thus, for each dollar of uncertainty there is in what the taxpayer reports on its March 31st true-up for a given year, there is about 38 cents of additional uncertainty due to statutory interest under a three-year statute of limitations, but 92 cents under a six-year statute.

It is the combination of a six-year statute of limitations plus a minimum statutory interest rate of 11% APR that is so harmful for a taxpayer and any would-be investor. Each dollar of uncertainty in the amount of tax will nearly be doubled by statutory interest after six years.

When we speak about uncertainty and audit assessments six years after the filing of tax returns, many people will think the oil companies could calculate their correct tax liability under the ACES tax if they wanted to. Frankly, so did I before I got this job. So let us take a few moments to illustrate why this is not the case.

As amended by ACES, AS 43.55.150 (captioned "Determination of gross value at the point of production") says the Gross Value at the Point of Production (GVPP) "is calculated using the actual costs of transportation" from the field to market unless the "shipper ... is affiliated with the transportation carrier[,]" or the "contract for the transportation ... is not a[t] arm's length[,]" or the "method or terms of

[the] transportation ... are not reasonable in view of existing alternative transportation options." "If the department finds that" any of these situations exists, then the GVPP "is calculated using the actual costs ... or the reasonable costs of [the] transportation ..., whichever is lower."

The immediate questions about the statute are — How does the Department of Revenue get the information to make such a finding? What is the procedure for making them; is there a hearing, an investigation or what? How does a taxpayer ascertain what the Department has found?

15 AAC 55.193 is the regulation with an important part of the Department's answers to these questions. Before getting to those answers, we note that subsection (a) seems to disregard the statutory distinction between "actual" and "reasonable" costs, by declaring that "Costs of transportation are the <u>ordinary and necessary costs</u> incurred to transport the oil or gas"[1] — which <u>could</u> get to the same result as the statutory terms, but not necessarily.

Subsection (e) of the regulation starts answering our questions. It says "a tariff rate ... adjudicated as just and reasonable by the Regulatory Commission of Alaska ... establishes the reasonable costs of the pipeline transportation[.]" So, suppose there has been full-blown tariff dispute before the Regulatory Commission of Alaska, and the RCA has "adjudicated [a tariff] as just and reasonable[.]" And suppose also that a producer ships its oil through its pipeline-company affiliate and pays that RCA-approved tariff. Is this "reasonable" cost under (e) of the regulation the same as the "ordinary and necessary" cost for it for purposes of subsection (a)? Apparently so, but the inconsistent terms in the two subsections prevent this from being completely clear. Moreover, if the transportation occurs "later than five years after the end of the test period on which the tariff rate is based[,]" then even subsection (e) says the tariff ceases to "establish [the] reasonable costs" for the transportation. But it doesn't say what the right tariff is after those five years are up, or even how to find out or calculate what it is. It is utterly silent.

The very next sentence in subsection (e) after the one speaking about that five-year period starts, "If a complaint challenging [a] tariff rate has been filed with [the RCA] and accepted for investigation" — this is not a situation involving an already "adjudicated" tariff, but one that deals with a new tariff that has been filed for RCA's approval, which is then challenged. Here, too, the tariff on file is not allowed as the transportation cost under (e) of the regulation. Instead, the cost that is allowed is "103 percent of the costs of transportation <u>calculated by the department</u> using the methodology under 15

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1 Emphasis added.

AAC 55.197, for the period [while the complaint is being heard and adjudicated by the RCA.]"* Note that it is the Department of Revenue, not the taxpayer that makes the calculation under 15 AAC 55.197. It is impossible for the taxpayer to know beforehand what the Department's calculation will turn out to be.

Now it is true that 15 AAC 197(m) says a taxpayer may each year "request in writing the department's determination of the applicable after-tax rate of return under (f) of this section [and t]he department will provide the department's determination to the producer no later than the later of July 1 of the calendar year or 90 days after the department receives the producer's request." But the "after-tax rate of return" that the Department promises to provide is only one of the parameters in the cost-based tariff calculation under 15 AAC 55.197. The taxpayer is left on its own to find the correct numbers for the other parameters. More importantly, subsection (m) applies <u>only</u> to "a producer [that] expects to produce oil or gas the actual costs of transportation of which are required by 15 AAC 55.193(b)(6)[.]" Section -193(b)(6) applies only to "transportation of oil or gas by a nonregulated pipeline facility ... that is owned or effectively owned ... by the producer of th[e] oil or gas[.]" In the situation I'm describing, it is a regulated pipeline, not an unregulated one, so this promise in 197(m) does not apply.

We find nothing else in the calculation-methodology regulation, 15 AAC 55.197, nor in 15 AAC 55.193(e), the transportation-cost regulation, that commits the Department to make the cost-based tariff calculation called for in 193(e) and inform the producer of that result before the producer has to report and pay estimated tax each month, or before it makes its annual true-up on March 31st of the following year. The only deadline for informing the producer of the Department's calculated tariff is the six years under the statute of limitations.

And the same or very similar unknowable answers — including tariff calculations by the Department under 15 AAC 55.197 — arise under 15 AAC 55.193(f) regarding tariffs for new transportation facilities that are just being placed in service, and under -193(g)–(h) regarding tariffs set under a settlement agreement to which the State of Alaska is a party.

And just to prevent any misunderstanding, although I have been testifying about proceedings and adjudications by the RCA, these regulations also apply to proceedings and adjudications by some "other regulatory agency" — which would include FERC.

There is a built-in uncertainty created by these regulations, and others that is beyond a taxpayer's allowed authority to answer and beyond its ability to know before the Department gives the answer. And to see a "Technicolor®" version where essential elements of the tax calculation are being reserved for the Department to "determine" in its discretion with no specific deadline, one should look at all the crucial "determinations" in 15 AAC 55.173 ("Prevailing value for gas") that are reserved for the Department to make regarding the valuation of natural gas that would be transported to markets outside Alaska.

We are not asking for a statutory fix to the regulations. But we are asking that, if the Department chooses to defer making calculations and similar determinations that are necessary in order even to be able to calculate the correct amount of tax at all, then the doubling-up of that uncertainty through statutory interest should be lessened — either by shortening the period for making those "determinations" from six years back to the usual three, or by eliminating the 11% minimum interest rate on the statutory interest rate, or both.

C. Joint-interest billings. Our concern about joint-interest billings is also primarily a problem caused by the approach the Department has chosen to take with its tax regulations. Instead of starting with the joint-interest billings that participants in a unit or other joint operation receive from the operator, the regulations reflect an assumption that each non-operating participant has information, in addition to the operator's billings to them, that allows them to determine which expenditures are deductible as allowed "lease expenditures" under AS 43.55.165 and which are not. This assumption is wholly unrealistic. And even if there were some merit to it, the regulations opt to audit each participant separately regarding that participant's interpretation of which expenditures are deductible and which are not, instead of auditing the system of accounts used by the operator and telling all participants which cost items in that accounting system are deductible and which are not. In other words, instead of one audit of the expenses by a joint venture for any given period, the Department audits each participant separately for its respective share of the same pool of expenses.

Again, we are not asking for legislation to put the Department's regulations on a different track. But there are some in the Department who believe that the repeal by the 2007 ACES legislation of AS 43.55.165(c) and (d) — which specifically authorized the Department to rely on joint-interest billings — means the Department cannot legally rely on them now. While we disagree with this position (which is also at odds with what the Department testified to during the enactment of the 2007 ACES legislation), we do think it would be appropriate to restore language specifically authorizing the Department to rely on joint-interest billings if it chooses to do so.

Conclusion. We support the proposed elimination of progressivity, but we have concerns with what the Bill proposes for tax credits — most importantly with the proposed repeal of tax credits for qualified capital expenditures. The trade-off between repealing progressivity and losing the QCE credit is not a net benefit for industry at low oil prices, although it would be with prices that are high relative to costs.

The concept of the Gross Revenue Exclusion has considerable potential, but its narrow focus in

HB 72 misses 80 – 90 percent of the opportunity in the central North Slope described by Econ One. We will continue to work with you and the Administration to find a fair and reasonable way to expand its scope, or to find an alternative that will address the central North Slope appropriately.

The reasons that led the State to create the small-producer tax credit under AS 43.55.024 and the exploration tax credits under AS 43.55.025 remain valid today. We are pleased that HB 72 will extend the sunset date for the small-producer tax credit and encourage the same extension be applied to the exploration tax credits.

Overall, the Bill as introduced represents a cornerstone for significant and crucial tax reform that move toward Governor Parnell's four "core principles" — fairness for Alaskans, encouraging new production, simplicity with balance, and durability for the long term.

I have not mentioned, until now, the North Slope decline curve that's on the slide I've showed at the beginning, and now here at the end of this testimony. I don't need to mention it. It's the elephant in the room. As I said at the beginning, the greatest, and most urgent challenge facing Alaska today is the decline of oil production from the North Slope. We believe it is up to you, the legislative leaders of our time, and the Governor, to shape a competitive oil fiscal policy that is supported by strong principles and will lead Alaska towards a prosperous future for the long-term. You have a difficult task ahead and AOGA stands ready to assist you throughout this process.