Alaska State Legislature

House Democratic Caucus
Senate Democratic Caucus

State Capitol
Juneau, AK

August 26, 2013

Mr. John Larsen, Audit Master
Alaska Department of Revenue
via email: john.larsen@alaska.gov

Dear Mr. Larsen,

On behalf of the House and Senate Democratic caucuses, thank you for the opportunity to comment on the draft regulations implementing Senate Bill 21. This is an important process with potentially far-reaching implications for the state's future economic health.

As you know, our members opposed SB21. The bill gives away too much of Alaska's resource wealth without adequate guarantee for a reasonable return on our investment. But, as long as it is now the law of the land, it is important to establish fair and consistent regulations that protect the state's interests, prevent further unnecessary revenue losses, and avoid long-term manipulation.

The department appears concerned about the potential for over breadth and abuse in these regulations, as it should be. However, the proposals from both the industry and the department regarding the definition of "new" oil from acreage added to existing fields (AS 43.55.160(f)(3)) are problematic and could lead to payment delays, fiscal uncertainty, and unnecessary under taxation of "old" oil that would be produced anyway.

The statutory provision regarding new oil from legacy fields is a classic example of what former Senator Jay Kerttula used to call "lazy law." It leaves key items undefined and leaves regulators and other executive employees too much latitude for making policy determinations. Defining what is "new" oil from old fields with no clear criteria in statute and hundreds of millions of dollars in revenue at stake is an impossible task and in many ways a fool's errand the Legislature has forced on state regulators.

Having said that, we commend the Department of Revenue (DOR) for the job they have done. The draft regulations try to minimize harm to the state by creating a relatively narrow path to getting oil defined as "new." The thrust of industry's comments is an attempt to widen that path as it knows how valuable small changes to this definition can be. We strongly recommend DOR resist any pushback from industry seeking to broaden the definition of new oil.

With the uncertain direction from the statute, significant technological challenges, and fundamental disparity between the positions of the industry, departments and the Legislature, we recommend DOR defer all of the regulations related to the Gross Value Reduction (GVR) and “new oil” until they can be heard and publicly vetted before the Administrative Regulation Review and other appropriate committees during the 2014 session. In addition, the department should defer all regulations concerning “new” oil from legacy fields, especially related to AS 43.55.160(f)(3), until DOR can better evaluate the geological and technological conditions necessary to creating fair, coherent, and workable regulations.

“New” oil from Legacy Fields

The primary debate during the session, and the public’s primary concern, regards the general level of taxation on current production and the degree to which tax cuts would incentivize new investment. However, the emphasis in the draft regulations, the supporting explanatory memo, and the published public testimony has been on what will and will not qualify for the Gross Value Reduction [GVR] or “New Oil” provisions, specifically qualification for new oil within expanded acreage to existing participating areas, the AS 43.55.160(f)(3) provision.

Industry is actively seeking to maximize the amount of oil that can be categorized as “new” under the law. Given the asymmetries of information between industry and the state, we encourage DOR not to over rely on industry testimony. Every barrel of oil that can be redefined from “old” to “new” is worth $7 per day to industry, assuming the 20% GVR category and current prices. Reclassifying just one well that produces 1,000 barrels per day would be worth $2.6 million in <u>additional</u>, after-tax profits. The stakes are huge in this part of the regulations, and Alaska cannot afford overbroad definitions that grant incentives for what the Legislature did not intend to incentivize.

We have heard the general comment in multiple venues, and not just from opponents of SB21, that “eventually it will all be new oil.” It is in all of our interests to make sure this does not become true. During the legislative debate on SB21, there was an important switch from the version of AS 43.55.160(f)(3) which passed the Senate to the version introduced in the House Resources Committee. This switch, from a “well based” to an “area based” standard, resulted in a decrease in that section of the fiscal note from a potential cost of $250 million each year down to $50 million.

This large drop in cost, from eliminating the broader definition, is backed up by DOR Special Assistant Mike Pawlowski’s testimony in the House Resources Committee on March 28, 2013. Mr. Pawlowski said, “The other body's intent in developing the provision was to expand the realm of possible application of the GVR/GRE to target as much potential new production as possible.” Additionally, in public testimony to the House Resources Committee on April 1, Tara Sweeney of Arctic Slope Regional Corporation testified “If the state wants new oil, then any new well should count for that exclusion.”

These comments from Mr. Pawlowski and Ms. Sweeney highlight the potential cost of allowing large numbers of new wells to qualify as “new oil.” It is the sort of over-broad definition that leads to the inflated fiscal note and the “eventually it’s all new oil” comments. We believe the House committees were wise to narrow the standard for qualification, and the industry testimony on the proposed regulations is in effect industry attempting to force a de-facto return to the looser Senate standard.

All regulatory processes are limited by the intent of the Legislature in passing the underlying bill. Legislative intent in SB21 was to have a narrow definition of what would qualify as new oil in legacy fields. This is evident from two key issues:

1. First, SB21 chose to allow broad and retroactive application of new units under AS 43.55.160(f)(1), which allows currently producing fields such as Oooguruk and Nakaitchuk to qualify for GVR. However, no similar provision was provided for the new or expanded participating area language in AS 43.55.160(f)(2) or (3). Therefore, the Legislature must have desired that only "new" new oil in these categories should qualify.
2. Second, the final version of the bill took out the broader Senate language described above, which would have allowed many new wells to qualify for the GVR. This implies that the Legislature only wants oil to qualify that truly comes from this "added acreage" as described in AS 43.55.160(f)(3).

Attempts by the industry to restore the broader Senate language and to allow a wide definition of new wells disagrees with both legislative construction and legislative intent.

The stated industry concern that too-tight new oil rules will stymie new production is disingenuous. The baseline tax cut of SB21, which eliminated progressivity, added a generous per-barrel production credit, and will cost the treasury nearly $1 billion per year at projected prices, was expressly designed to improve project economics and to encourage expanded development within mature fields. Industry is implying that SB21, without the GVR, doesn't satisfactorily do this. If so, we should repeal the underlying tax changes in SB21 and simply keep the GVR sections for new oil. The bottom line is that under SB21 and its legislative intent, the regulations must be kept very narrowly drafted considering what will be "new" oil in old, legacy fields.

Other sections of law and regulation

<u>Apportionment</u>

There are several places within the draft where regulators will face a problem of apportioning oil into "old" and "new" categories. The statute gives no clear direction as to how regulators should accomplish this task.

One example, again concerning the AS.55.160(f)(3) production, refers to a well which is drilled outside the new acreage but is intended to substantially drain oil from the new acreage. This is a potential concern for the Shark's Tooth addition southwest of Kuparuk. How does one determine "those amounts of oil and gas are reduced to exclude oil and gas produced from those wells but drained from outside the acreage added?" (15 AAC 55.213(b), p. 16)

We have great concern that the answer will be what is called a "sub-methodology," (15 AAC 55.213(c), p. 17) a percentage-based apportionment system based on reservoir simulation models, with the calculation burden placed on the producer. Without great care taken to prevent it, it is likely that these sub-methodologies will over time lead to an erosion of revenue much like the state experienced under the Economic Limit Factor (ELF) tax structure as every year a slightly larger portion of production is classified as "new." <u>We suggest strengthening the regulatory language that describes how a sub-methodology must be revisited annually.</u> The department's authority should be broadened to ensure regulators have access to the reservoir simulation models, and must retain authentic power to modify a producer's proposed calculations and prevent gamesmanship.

Anything short of this puts the state at risk of the same "inexcusable trustfulness" the court admonished it for in the *Amerada Hess* ruling.

It appears the department is attempting to minimize circumstances in which a well could produce both GVR qualifying and non-qualifying oil. Minimizing these circumstances is essential. Interconnectivity in and of itself, as described in 15 AAC 55.213(a), implies a well would not qualify for AS 43.55.160(f)(3); if the targeted oil can flow towards currently producing oil it is by definition part of the currently producing reservoir.

<u>Metering</u>

The Legislature made a conscious decision to move away from a "metering" standard for AS 43.55.160(f)(3) when the Senate language was changed in House Resources. We are concerned that DOR, in attempting to impose a metering standard by regulation, is backsliding and going against legislative intent. If the state does go forward with a metering system, the department should resist industry efforts to relax the standard of +/- 5% accuracy.

The accuracy of the meter, or meters may be irrelevant if the end result would be "oil and gas... commingled... then mechanically separated and... allocated back, proportionally." (Explanatory Overview of Proposed Regulations, page 6, footnote #4) This, along with the unwieldy formula in 15 AAC 55.213(e)(3), is another slippery slope that leads to another unacceptable situation similar to ELF.

Truly, the <u>clean answer that best reconciles with the actual language in SB21 would be to absolutely limit the definition of "new oil" in added acreage based on geology. The department should limit this definition to new wells penetrating added acreage with targets below that acreage which can be proven to be truly non-interconnected with the larger body of the reservoir.</u> For a group of wells, either all of them should qualify in their entirety under this standard, or none of them should at all. It appears that the 0.1% standard in 15 AAC 55.213(a) is designed to put a burden of proof on the producer to justify any migration whatsoever into what is purely a GVR-qualifying production. Any standard broader than this is yet another slippery slope.

<u>Non-Metering Methods</u>

Although most of the attention has been given to the metering standards in 15 AAC 55.213(a) through (e), we recognize that the regulations also allow for non-metering methods in 15 AAC 55.213(f) and (g). The problem is the draft gives no guidance as to what these might be, nor does there appear to be a method of applying for, or criteria for receiving, departmental approval. Does DOR have examples of potential alternative methods? Again, the simplest answer, described in the previous paragraph, is likely the best.

<u>Field Gas</u>

In 15 AAC 55.213(h), language references excluding gas used in the operation of the field and anticipates having to pro-rate a unit's excluded gas into the "GVR and "non GVR" categories. As we read that section, we believe it should read "may not be more than" the pro-rata share rather than "...less than."

Double Dipping / Negative Value

Our reading of 15 AAC 55.211(f) is that it clarifies that a producer may not take multiple GVRs. It also says that GVR may not be taken "if the gross value at the point of production (GVPP) is negative." We believe this phrasing is not quite right, and that in fact the intent of the statute is that GVR "may not be used to bring adjusted GVPP below zero." This is an important distinction because the latter language could allow partial use of GVR in some circumstances.

Confidentiality

The draft regulations are unclear whether a written determination of qualification for GVR is necessary or merely optional. Ms. Marie Evans of ConocoPhillips raised this issue in her testimony, page 27. We suggest that the determination must be in writing. Also, it should be clearly stated in regulation that a determination in writing that a particular lease, unit, participating area, etc. is or is not qualified for GVR should be a public document. Confidential technical information could, if necessary, be redacted, but the public deserves to be able to see the Department's reasoning as to what does and does not qualify for these valuable benefits. If for no other reason, the potential for arbitrariness and the inevitability of lawsuits should make this information as broadly accessible as possible. At minimum, the Department must be required to publish aggregated information, by unit and producer, of how much production in a given year does and does not qualify for GVR.

Issues not addressed in the draft regulations

1. Concern with 30% GVR / high royalty issue: To qualify for the larger 30% GVR under AS 43.55.160(g), all leases within a unit must have a royalty rate greater than 12.5%. One under-development unit, Beechey Point, has all but one of its underlying leases at 16.67% with the one ExxonMobil lease at 12.5%. This could allow a producer to petition DNR to voluntarily increase their royalty rate to, say, 12.6% in order to qualify the full unit for a higher GVR. The department should add a good faith provision in the regulations to prevent this from occurring.
2. Stair step concern: This was not discussed in the draft regulations but raised by the Alaska Oil and Gas Association (AOGA)'s Tom Williams during his public testimony. We agree there is legitimate concern and uncertainty regarding the full-dollar leaps described in SB21, 43.55.024(j). Essentially, if a producer who when audited five years after paying the tax finds that their tariff should have been 2 cents lower, could face a one dollar decrease in their per-barrel credit. This would have been an easy fix in statute, to replace the stair step with a smooth line formula; this was recommended by both the administration's and the Legislative Budget and Audit Committee's consultants in the House Finance Committee. On the floor of the House, Rep. Geran Tarr offered

amendment #13 that would have solved the problem. If possible, a regulatory fix should be considered, but we strongly recommend that the administration support a clean-up bill along the lines of the Tarr amendment. Because of the pending referendum, this bill should wait until the 2015 session.

3. We have strong concerns with the potential for abuse of the "new participating area" statute, AS 43.55.160(f)(2). One of the weaknesses of the ELF statute, which was unanticipated at the time of its passage, was the ability of producers to create "satellite" fields that were taxed separately from the core legacy fields. By this method, they were able to avoid paying the higher-multiplier taxes of the core field. We fear that the "new participating area" statute is written loosely enough that companies could parse-out pending projects within legacy fields and call them new participating areas. Below are two examples that should be proactively addressed in regulation:
   - Exxon's Pt. Thomson unit is expected, and contractually obligated, to begin production in the next several years. It is our understanding that this property is considered to be "within a unit on January 1, 2003," and should not qualify for GVR under AS 43.55.160(f)(1). However, we are concerned that this long-held property has never had a producing Participating Area, and thus initial production could be considered "new" under (f)(2) despite the 40-year delay in development. This seems to be an unreasonable reward for delay. We would strongly suggest the regulations be written to ensure any participating area formed in Pt. Thomson not be considered "new" for the purposes of AS 43.55.160(f)(2).
   - BP's I-PAD and Gas Partial Processing Plant projects are both described in the Plans of Development for the Orion Participating Area in western Prudhoe Bay, and have been since at least 2004. Is there any mechanism, under the regulations the way they are written, that would enable an operator to separate this project from the pre-existing Participating Area so as to establish a new Participating Area and qualify for GRE under the terms of AS 43.55.160(f)(2)? We strongly recommend the regulations be written to prevent the possibility of segregating these well-established projects from the currently producing participating area. "Scenario C" of the fiscal note for SB21 describes a new pad and well system very similar to I-PAD, and the fiscal note envisioned this project would <u>not</u> qualify for the GVR.

Conclusion and Recommendations

The vagueness of the new oil provisions in SB21 create a quandary for the state: it creates the potential that regulators could interpret the definition too loosely, drastically harming future revenue, or it opens the potential for drawn-out litigation should the industry disagree with how the department defines what is "new" oil. This and several other provisions of SB21 are recipes for disaster.

Again, we recommend DOR defer implementation of all of the regulations related to the GVR and "new oil" until they can be heard and publicly vetted before the Administrative Regulation Review Committee during the 2014 session. In addition, the department should defer all regulations concerning “new legacy oil” in AS 43.55.160(f)(3) until the department has time to bring in significant geological expertise to ensure the fairness and coherence of the draft rules. The stakes for Alaskans are huge in this part of the regulations, and Alaska cannot afford to risk even more oil revenue due to vague or unworkable definitions.

With the entirety of SB21 on the 2014 ballot and the potential for the bill to be repealed, it would be best to defer implementation of the most controversial and problematic provisions, specifically AS 43.55.160(f)(3), until after that election. If the law should survive, this will enable the Legislature to make any necessary fixes to the definitions during the 2015 legislative session.

Thank you for your work for the people of Alaska, and for your attention. We look forward to working with you as this process continues.

Sincerely,

Sen. Johnny Ellis	Rep. Beth Kerttula	Rep. Chris Tuck
Sen. Hollis French	Rep. Les Gara	Rep. David Guttenberg
Sen. Berta Gardner	Rep. Andy Josephson	Rep. Scott Kawasaki
Sen. Bill Wielechowski	Rep. Jonathan Kreiss-Tomkins	Rep. Geran Tarr

Cc. Angela Rodell, Acting Commissioner, Department of Revenue

Alicia Egan, Legislative Liaison, Department of Revenue