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EXECUTIVE SUMMARY

OVERVIEW AND SCOPE

The Legislative Budget and Audit Committee ("LBA") of the Alaska State Legislature is in the process of reviewing Senate Bill 5005 ("SB5005") that was put forth in an effort to make changes to some core components of the oil and gas production tax detailed within AS 43.55.011 of the Alaska tax statutes. Stratas Advisors ("Stratas") was engaged by LBA to provide analysis around the proposed changes outlined in SB5005 ("the Analysis"). The following report provides the detail around the Analysis.

The following three changes were introduced via SB5005:

1) Phase out Net Operating Loss ("NOL") Credits
2) Adjust the marginal rates relating to the Minimum Tax liability
3) Remove the ability of companies to use intra-year production-related credits to lower the total amount owed when calculated at an annual true-up.

All three adjustments would make the production / profit tax ("Profits Tax" or "PTax") paid to the state more beneficial to the state and less beneficial to current and/or prospective investors. However, by far the largest impact relates to Item (1), and even more specifically to new investors that have very little to no production on the North Slope. The enclosed analysis provides details around the relative impacts of implementing this aspect of SB5005.

All else equal, the relative impacts of Item (2) and Item (3) would be immaterial to the perceived competitiveness of the Alaskan system. The impact of Item (2) will make already low value new projects slightly less valuable. The value of new profitable projects would be unaffected. The impact of Item (3) has been covered by a previously submitted report wherein, depending on the intra-year volatility of ANS pricing, the cumulative effect of this change could increase PTax payments to the state. If prices within the year stay relatively stable, this change would have minimal impact to the cash flow profile of a project. Because of the importance of Item (1), relative to that of either Item (2) or Item (3), the focus of this report will be entirely on Item (1), the phasing out of the NOL Credit.

FISCAL STABILITY

The primary impact of implementing any of the items, including Item (2) and Item (3), relate to the perceived lack of fiscal stability in Alaska. It is from this perspective that the concept of "materiality" relating to any change is almost rendered moot. Obviously, larger impacts will face a stronger reaction by industry. However, in a regime that demonstrates a relatively volatile approach to executing fiscal legislation, even small changes can be met with more evident frustration than they otherwise would. All sovereigns at any level clearly have the right to manage and optimize the value of the natural resources that lie within its borders. However, this right must be exercised with extreme caution and sensitivity. Although taxation is controlled by the state, monetizing the resources is fundamentally at the discretion of the private sector. Of course, depending on the regime in question, the sovereign has the option of funding its own exploration and development program, but most regimes around the world work hard to balance the need for private International Oil Company ("IOC") expertise and capital against the regime's internal budgeting pressures.

Prior to investing discretionary cash flow, most investors seek to develop some vision of how much cash the prospective project might generate as a return. There are clearly many highly volatile and impactful assumptions that one is forced to make when estimating future cash flows. Typically, management does not tend to include relative tax liability in that set of unknowns. There are clearly examples of regimes that have retroactively implemented tax increases that create increased risk profiles for regimes. For example in 2011, Israel almost doubled its government take when Noble Energy discovered the Tamar gas field in the Mediterranean Sea. The IOC community was outraged at the retroactive efforts by the government to change the business deal under which Noble had been exploring. However, the underlying reserves of Tamar and, even more so, the much larger Leviathan field were of such size that all parties decided to push forward and complete the developments.

The successful change in Israel is interesting, but the issues surrounding it were quite different than what confront Alaska. One of the main differences is that Alaska is trying to attract investment in light of extremely tight capital spending budgets as well as relatively higher risked costs exploring in the North Slope. The fall in oil prices in late 2014 raised a significant hurdle to economically developing reserves in cost-challenged areas like the North Slope. There have been notable examples of companies abandoning development plans in places like the Chukchi Sea and opting instead for less costly or risky alternatives. In the interest of competing for discretionary cash flow, many regimes would view this as a possible catalyst to relaxing some provisions of government take. Tightening terms, particularly in such an environment, is likely to create more challenges to attracting investment than they would during times of more lucrative prices.

Regardless of the global examples of changes, the investing community typically finds unilaterally and retroactively executed increases to government forms of taxation to be highly troubling. Usually, the US is considered a relatively “safe” haven relating to fiscal stability. The point is not that terms never change. The point is that changes by the government do not change very often, and when they do, the final terms are known ahead of making a decision to invest. For example, even when royalty rates increase in the Gulf of Mexico, the new rates are not applied retroactively. They only apply to the blocks released in the respective bid round. It is in this way that an investor can make at least a reasonable estimate of the amount of economic rent that must be paid to the government. Changes to broader, legislated terms such as income tax rates (that affect all companies and are considered “retroactive”) certainly happen at times, but the changes are far less frequent.

The number of changes that have been implemented in Alaska over the last several years stands as a stark contrast to the otherwise stable environment that many consider to be “the United States”. Larger changes such as Item (1) above will most certainly impact the perceived attractiveness of Alaska, but so will smaller changes like Items (2) and (3). If support can be found to approve the funds needed to at least make whole those companies who have already started spending under the current terms (and would be materially impacted by changes), the expected backlash would likely be at least mitigated.

KEY FINDINGS

The key findings of the Analysis are summarized below.

1) Overview of the suggested change
   a. Currently, the state takes on the obligation to effectively (see first bullet below) reimburse up to almost 1/3 (depending on Capex phasing) of the capital expenditures ("Capex") incurred for new "first" North Slope Projects ("NSPs").
      - The statute does not reference a reimbursement. It only allows for the use of losses, and those losses for first NSPs are typically large during the development phase because the calculation of the taxable base assumes the expensing of, as opposed to the depreciation of, all capital expenditures. Written differently, for first NSPs, development capex is spent, but because production has not started, there is no taxable income against which to apply those costs. This situation creates a loss, approximately 30% of which can be requested by the developer (if below a certain size within the ringfence) in the form of a cash payment. The immediate recovery of this cash serves as a de facto reimbursement of capital. A developer would decide to invest knowing ahead of time that the state would be covering a material portion of a very large cost base.
      - For income tax calculations (i.e. "net tax" calculations), recognition of costs almost always includes Capex, but it usually[1] comes in the form of depreciation. That depreciation typically starts at "in-service" dates (i.e. close to when production starts). This approach to calculating taxable income more closely aligns expenses and revenue, with a lower probability of generating highly negative taxable income.
   b. Because of this method of expensing capital, new, first NSPs usually record substantial tax losses, particularly during their development phases.
   c. These losses create a current cash value that, under the current system for Small Producers, can be recognized/collected immediately instead of carrying the losses forward to offset future tax bills.
   d. Companies investing in first NSPs would lose the tax shields that the early Capex would normally create.
      - SB5005 would remove the tax benefit for those who are unable to use the losses in the years in which they occur. Those companies that have existing production and taxable income (i.e. those currently in a tax paying position) inside the ringfence (i.e. the North Slope) will still be able to benefit from the expenses in question because those companies have income against which the expenses can be applied.
      - The value of the tax benefit will be phased out such that for 2017, only 15% of the losses will be able to be monetized or carried forward, and the benefit would be eliminated starting in 2018.

[1] In the US, most of Intangible Drilling Costs ("IDC") can be expensed. The amount that is allowed for this treatment is lower for integrated companies than it is for companies without refining capacity. Other regimes also allow for expensing of certain capital items.

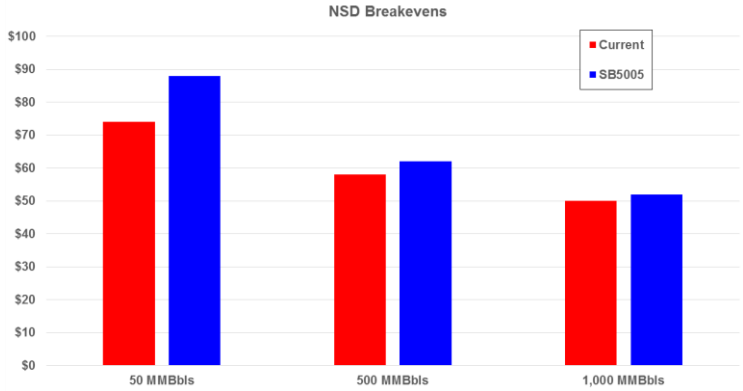
- There is no provision to allow the companies to carry the losses forward as either deductions or credits.
- The option that Small Producers have of collecting cash for the NOL Credits will be changed from those with less than 50 MBOE / d to those with only 15 MBOE /d.
- Regardless of whether the NSP is a first project or a developer has several other projects, if the developer is in a position of only paying the minimum amount of tax required under the law, that company will lose the tax shields that it would have otherwise been allowed to collect, at least over time (assuming future profits).

2) Notwithstanding the aforementioned risk to perceived attractiveness, this suggested change would unwind for Small Producers what most economists would have considered to be a relatively unique provision of a "net tax" system that is highly beneficial for the investing community. The current system is relatively unique for all companies in as much as it allows for the expensing of all costs. Most net tax systems include at least some form of depreciation. However, the system is particularly unique for Small Producers because of the cash reimbursement of tax losses that they enjoy. SB5005 would remove this benefit, but would also seek to introduce a new provision that would still be considered relatively unique; however, the uniqueness would benefit the state instead of industry.
    a. Usually, systems that tax the profits of a business, as opposed to the revenue, are doing so in order to offer a form of risk mitigation around investments. To that end, these systems usually allow all costs to be applied against revenue, including the upfront capital. This application usually comes in the form of depreciation over time and usually starts when the assets are "in service".
    b. The current PTax system allows for the expensing of all capital in the years incurred, which is itself a very beneficial provision (relative to most other net tax systems), and SB5005 would leave this benefit in place. However, the practical result would be that this benefit would go unused for companies that do not have any other income against which to apply them. The expensing would create losses, and the losses would not be allowed to be carried forward in any form.
3) Net Result – expected economics for first, new NSPs would degrade if SB5005 is implemented.
    a) The weighted average PTax rate over an NSP's life would increase.
        a. Small projects
            i. Small projects will be impacted more than large projects.
            ii. When prices are low, the effective rate for small projects would move from negative (i.e. a net reimbursement by the state) to zero or positive (i.e. a net obligation to the state).
            iii. The point at which the rate indicates a sum total net payment to the state (over the project life) would shift downward from the mid-$80 range to the mid-$50 range.
            iv. When prices are high, the effective rate would move from a relatively low rate below 10% to a materially flat rate that is above 30%.
        b. Large projects
            i. When prices are low, the effective rate for large projects would move from negative (i.e. a net reimbursement by the state) to zero or positive (i.e. a net obligation to the state).
            ii. The point at which the rate indicates a sum total net payment to the state (over the project life) would shift downward from the low-$60 range to the low-$30 range.

iii. When prices are high, the effective rate would move from a relatively low rate to a slightly progressive rate that hovers around the low 30% range.

b) The weighted average Government Take ("GT") over an NSP's life would increase.
   a. Small projects
      i. Overall government take would increase by approximately 7% points from approximately 60% to approximately 67%.
   b. Large projects
      i. Overall government take would increase by approximately 2% points from approximately 60% to approximately 62%.
   c. All else equal, Government Take would be slightly less progressive under SB5005.

c) As illustrated in the following chart, the ANS oil price required to breakeven at a given discount rate would likely increase by up to $10/Bbl for small projects and by up to $2/Bbl – $4/Bbl for larger projects.



OVERVIEW OF ASSUMPTIONS

KEY CHANGES

The following is a summary of how SB5005 differs from the currently approved system that was most recently amended and in effect at the beginning of 2016 via House Bill (HB) 247.

Impacted Provision	Pre-HB247	HB247	SB5005
Net Operating Loss Credits ("NOL Credits")	NOL Credits based on post-GVR PTV (support above actual losses)	NOL Credits based on pre-GVR PTV (support according to actual losses)	NOL Credits based on pre-GVR PTV (higher PTV)
	NOL Credits accrue based on 100% of NOL value	NOL Credits accrue based on 100% of NOL value	2017: NOL Credits accrue based on 15% of NOL created 2018+: NOL Credits do not accrue, and NOLs cannot be carried forward as either deductions or credits
	Cash Reimbursement[2]: - 100% of NOL Credits payable in year of loss - Producer must have consolidated production in the ringfence less than 50 MBbls/d	Cash Reimbursement[2]: - $61mm annual cash payment ceiling - Producer must have consolidated production in the ringfence less than 50 MBbls/d	Cash Reimbursement[2]: - $61mm annual cash payment ceiling - Producer must have consolidated production in the ringfence less than 15 MBbls/d
Minimum Tax Liability ("MTL") as a % of Production Tax Value ("PTV")	Top tier = 4% when ANS is greater than $25/Bbl	Top tier = 4% when ANS is greater than $25/Bbl	Top tier = 5%, when ANS is greater than $55/Bbl The rate drops to 4% when ANS is between $25 and $55
Annual True-Up of PTax after Production Credits	Annual true-up with monthly PTax estimated payments allows for the use of any "excess" credits that might have accrued during the year	Annual true-up with monthly PTax estimated payments allows for the use of any "excess" credits that might have accrued during the year	Excess production credits in any given month are not used in annual true-up calculation Unused production credits from any given month are lost

[2] Assuming an appropriation is made in full to the Oil and Gas Tax Credit Fund

MODELING

Our analysis assumes the following:

1) Development of a hypothetical NSP.
2) The NSP is an oil-only project
3) Any NSP is the "first" development for an investing consortium
4) The NSP qualifies as "New Oil"
5) Final Investment Decision ("FID") occurs on, and capital spending starts on, January 1, 2017.
6) The valuation is done from the perspective of "Development-Forward". The point of value is based on the post-FID spending. This assumption means the analysis excludes time and money associated with exploration and appraisal activities.
7) Any credits associated with the PTax will be fully funded by the state of Alaska.

Exhibit A lists the assumptions around the operating and spending profiles for three NSPs of varying size. We recognize that these definitions will not necessarily line up with different opinions of how to qualify size. For example, one might consider an NSP that is 500 MMBbls to be a "Large" project, not a "Medium" project. However, the distinction is purely academic. The analysis will provide results around which one can form an assessment of interpolated results relating to any size NSP.

Exhibit B presents the most important valuation-related points of the current system, herein referred to as HB247 or "Current".

Exhibit C presents the most important valuation-related points of the system after taking into effect SB5005.

ANALYSIS DETAILS

The change relating to the very fast (within one year) phasing out of the accrual and usage of NOL Credits is the most fundamental issue that most economists would analyze when studying SB5005. Currently, producers (small ones in particular) benefit from a very attractive law within the system that allows them to offset a material amount of the investment risk, laying this risk off to the state of Alaska. Producers that own less than 50,000 barrels per day of production ("Small Producers") can submit to the state a bill wherein the state is obligated to reimburse the producer for the tax losses incurred. This effectively turns out to be approximately 30% of the Capex during the development phase. Even if the company produces more than the minimum, the ability to expense the capital and carryforward the NOL Credits carries considerable value when estimating the future equity cash flow of the project.

The calculation of the NOL assumes the expensing of Capex during the development phase of an NSP. Given that there is no production, there is no revenue. Therefore, the only items to fill in on a PTax return at the end of a given development year relate to development related expenditures. This misalignment between income and cost recognition creates a loss for tax purposes, which is then turned into a credit. If the producer is not below the (currently) 50 MBOE / d threshold (which would decrease to 15 MBOE / d under SB5005), the credit can be carried forward in order to offset future PTax liabilities. Small Producers can submit a certificate to the state with a face value of $70 million in any one year. Assuming available funds, the state pays to the producer a total of $61.25 million (see Exhibit B, Sec. 5(e)(iii)). This benefit is currently less valuable than what had been in place when there was no ceiling on the amount that could be requested by any one company. However, it is still quite valuable, both from a cash flow perspective, as well as from a risk mitigation perspective. Some have even successfully used this expected benefit as a form of collateral with various lenders. Even if the company is not a Small Producer, the losses still accrue, and the credit can be carried forward to offset future tax liabilities.

This concept of effectively helping to manage the upfront cash funding needs (even if just for the Small Producer[3]) puts Alaska in a fairly small group of comparable tax regimes. The vast majority of regimes around the world will only allow for the deduction of losses against future taxable income, with a large degree of variation around the point when those carryforward amounts will expire if left unused. There are examples of regimes paying out cash for specific expenses, but our experience has not uncovered systems that rebate in cash the tax values of entire losses, regardless of what generated the losses. One of the closest examples of a regime providing for rebates is in Norway. In this country, the government will allow for the expensing of exploration capital, and the government will also reimburse (in cash) 78% of the exploration costs incurred (assuming the producer makes that election). The main difference between Norway's policy and HB247 is the scope of coverage. In calculating the Production Tax Value ("PTV"), all costs are expensed under

[3] For larger producers, the ability to offset future tax obligations using losses from the current year is fairly common.

HB247, including Capex relating to development drilling and construction of facilities. Norway's policy is specifically limited to exploration costs. Development capital is excluded.

Regardless of the ubiquity of the policy around the world, the fact is that Alaska does have the policy in place, and SB5005 would seek to remove the ability to recognize the cash value of losses. Relative to other regimes, this change related to Small Producers (i.e. removing the cash funding provision) would be unremarkable simply because of its uniqueness. However, relating to other net tax systems around the world and the ability to carry forward the credits, the uniqueness would shift in the other direction. Losses incurred beyond 2017 will simply have no value to a producer. Not being able to recover capital in a net tax system, even if in the form of loss carryforwards, is very uncommon.

From a pure "valuation" perspective, whether or not a company would see the change as negative is specifically related to whether or not that producer is able to offset existing income using losses from the new project. The valuation perspective is noted because another impact that has been publicly raised is the fact that certain operators have been able to post the NOL Credits as a form of collateral in their dealings with different lenders. The removal of this benefit could create difficulties for some companies. However, it is outside the scope of this analysis.

The purpose of this report is to analyze the impact to an overall industry, which would encompass a broad set of possible companies, without regard to the method those companies have chosen to finance their investments. The average cost of capital that companies expect to pay varies widely, often based on a large number of factors. SB5005's impact to discount rates / hurdle rates that would be used to benchmark projects may go up for some, but it may be of minimal impact to others. Attempting to guess how these changes would filter through to project valuations would be academic at best because of the varying capital structures and discount rates. Therefore, although it is true that removing this benefit may decrease the availability of, or increase the cost of, sourcing the required capital, the economic impact of SB5005 at an industry level is most appropriately captured in the changes that would impact the forecasted after-tax cash flows.

With respect to the valuation impact of this provision in SB5005, most analysts and economists would consider it effectively to be moving the tax from a tax on net profit to a tax mostly on Operating Income, often referred to as "Earnings Before, Interest, Taxes, Depreciation & Amortization" ("EBITDA"). Again, ignoring financing structure and analyzing on an unlevered basis, Interest is assumed to be zero. Most importantly, because there is no provision to allow for Depreciation & Amortization, and there is no provision to carry forward the losses, the net result would be such that the cash generated on which the tax would be paid would be as follows:

	Gross Value at the Point of Production ("GVPP")
Less:	Royalties
Less:	Ad Valorem Taxes
Less:	Operating Costs
	EBITDA
Less:	Minimum of Capex or EBITDA[4]
	Production Tax Value ("PTV") (i.e., Taxable Cash Flow)

The large upfront investment that is required to generate the Operating Income would, effectively, not be allowed to be recovered for first NSPs. There is a 15% allowance of NOL Credits during 2017, but from a planning perspective, the above is the structure to which SB5005 would be moving. Another consideration is that during past negotiations, there have been efforts to add certain non-cash deductions to reduce taxable income. For example, the Gross Value Reduction ("GVR") allows for a deduction equal to 20% of GVPP. Subsequent changes limited the duration of this deduction. Also, there is a production-based credit ("ProdCredit") that is a flat $5 per barrel while the GVR is in place. After the GVR expires, the ProdCredit reverts to a sliding scale of $0 – $8 per barrel, depending on GVPP per barrel. All of this is subject to the Minimum Tax Liability ("MTL"), except for when the GVR is in place. The GVR deduction can reduce either the PTax or the MTL, meaning it can reduce the taxable income to zero. Depending on the relative cost of the NSP, these deductions would have made up for at least a material part removing such a large portion of capital recovery. However, the issue at hand is that currently, producers have both the deductions/credits and the capital recovery, and SB5005 would remove the much larger of those two benefits.

CURRENT VS. NON-CURRENT TAXPAYERS

One way to think about the impact to a given company is to consider how effectively the company will be able to absorb the losses created by the expensing of development capital. Whether or not a company will be able to utilize the losses to offset taxes depends on whether or not that company is a "current taxpayer" within the ringfence. If the producer is already paying taxes (ie, they are a "current" tax payer[5]), then there is income against which they can apply these incremental costs. So on a consolidated basis, the value of the losses relating to the early years of a new NSP can be fully captured. In this situation, the producer operating under HB247 would be able to use the incremental losses (i.e. Capex), and that producer would be also able to use the incremental losses under SB5005. Therefore, the difference between the two scenarios would be zero. However, when the producer is a "non-current" tax payer, the elimination of this benefit is fundamental. When a producer is not currently paying taxes (or paying the legislated minimum), there is no income

[4] Except for during 2017, there would be no value of calculating PTV lower than zero under SB5005.
[5] The assumption when using the phrase "current taxpayer" is that the consolidation of a new NSP into a portfolio of other projects would allow for the complete use of the subject company's losses. In other words, the company would be current both before and after the consolidation.

against which they can apply incremental Capex. This situation would most typically apply to companies building an initial project on the North Slope.

Analyzing this impact requires an understanding of the cost structure of the NSPs. For this report, three different sized projects were analyzed at multiple ANS price assumptions. The cost structures for those projects are assumed to be as follows:

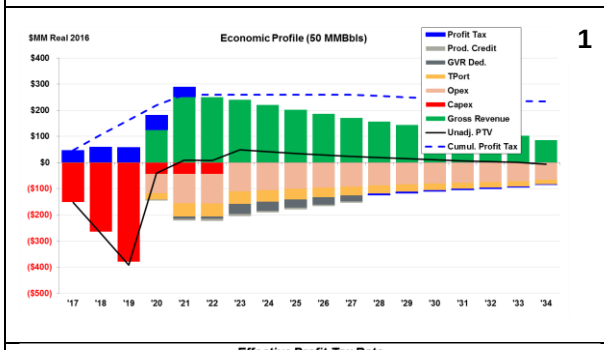
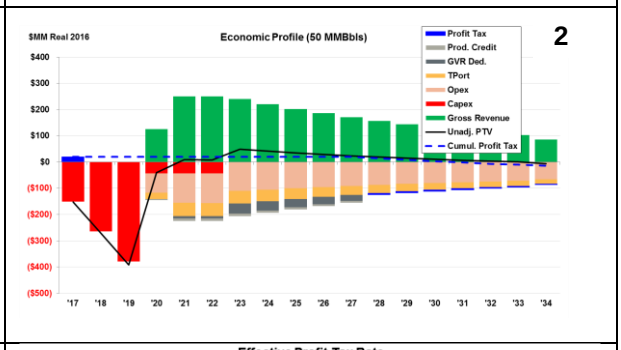
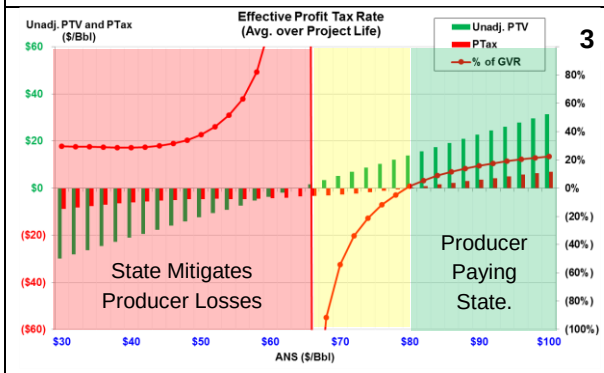
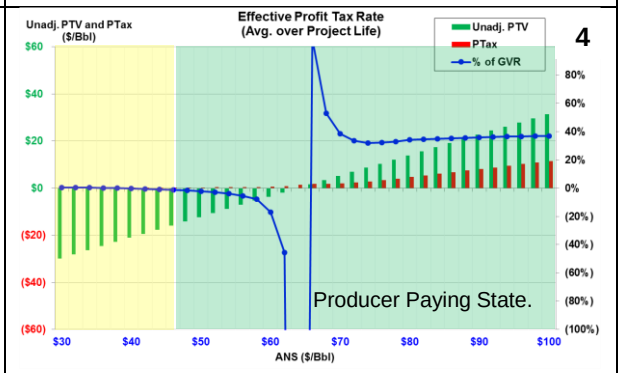
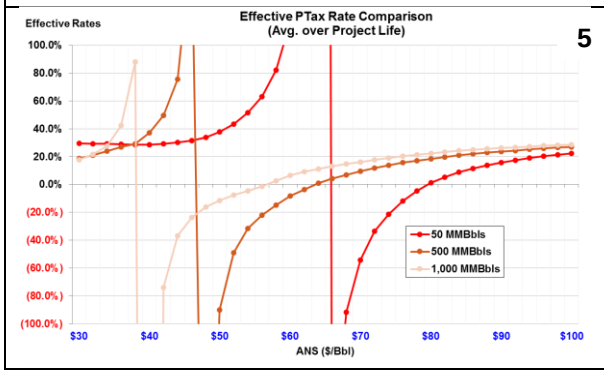
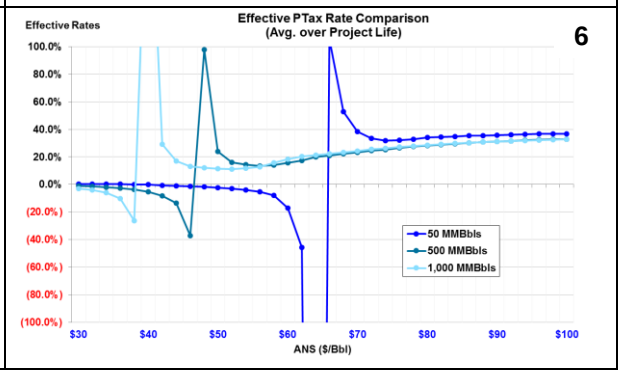
	$ / Bbl Avg. Over Project Life in 2016 Dollars		
Cost	**50 MMBbl Field**	**500 MMBbl Field**	**1,000 MMBbl Field**
Capex	18.2	11.6	9.5
Opex	26.9	18.7	14.5
T-Port	10.0	10.0	10.0
Ad. Val.	2.3	2.7	2.5
Total	57.4	43.0	36.5

Given the above costs, a small project would require around $64 (before 12.5% royalty) in order to breakeven at the real PTV level on a cash basis (before GVR and ProdCredits and not present value). To be in a positive PTV position at today's prices, a project of significant scale would likely be required. Regardless of the costs in total, the core component of this analysis is understanding the economic impact relating to producers incurring the Capex portion without the benefit of reducing future taxable income / tax liabilities with those expenses, either in the form of a deduction or a credit. As with any development, the relative value of a suggested change depends on the perspective of the parties involved. Industry will be most concerned with equity valuation (NPV, IRR) but also in understanding how much of the available "economic rent"[6] is going to the investors as opposed to the government (Government Take or "GT"). On the other hand, the government will be most concerned about cash inflow from taxing mechanisms relative to cash outflow related to credit (and other budgetary) obligations. Similar to industry, the government will also be interested in understanding its relative standing with respect to GT. This insight gives perspective about how onerous the regime is relative to the region's prospectivity and how it competes with other regimes around the world. Particularly in today's volatile and depressed oil pricing environment, investment dollars are under increased scrutiny to maximize return. All else equal, investors will gravitate to the regime with the lowest GT.

[6] Economic Rent is the amount of incremental cash flow available to all parties after paying out the costs to produce and sell the underlying commodity. One can also refer to this figure as Divisible Income ("DI").

PTAX COMPARISONS

The following charts illustrate the impact of SB5005 by showing the range of effective PTax rates, which is defined as total PTax paid divided by PTV before GVR and before ProdCredits ("Unadjusted PTV"). All calculations are shown in real 2016 dollars.

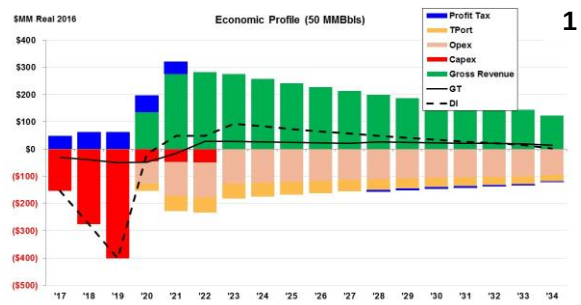
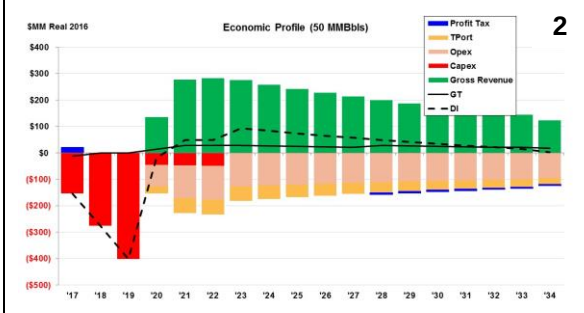
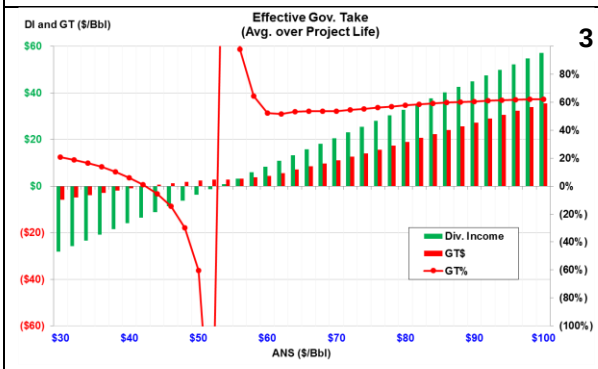
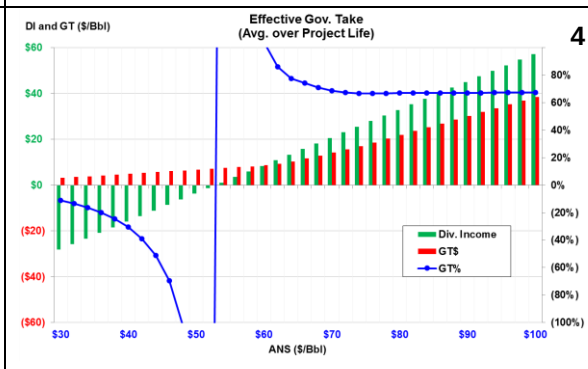
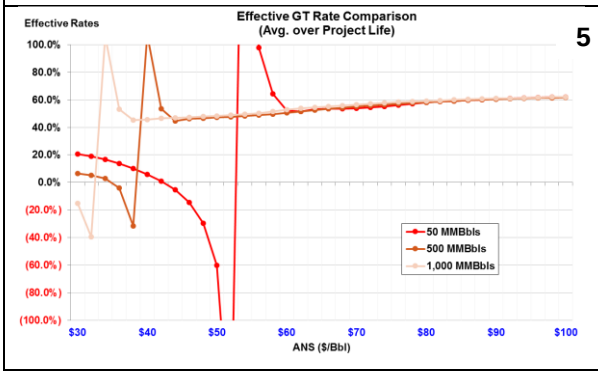
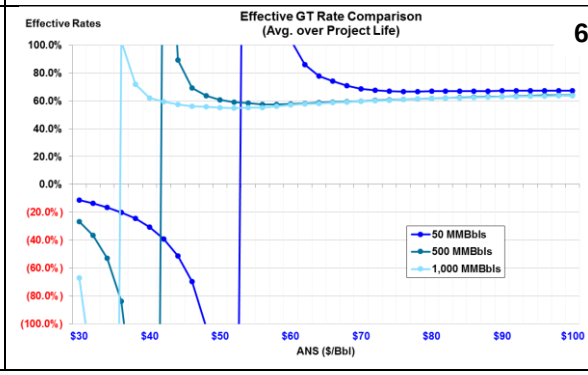
	Current	SB5005
Economic Profile at ANS = $45/Bbl		
Effective PTax rate at multiple prices		
Effective PTax rate at multiple sized NSPs		

The above comparisons illustrate that SB5005 would shift the payment obligation from the state to the producer. The current system is slightly "more progressive" than SB5005 at what could be considered mid-range prices, but from the state's perspective, it is mostly progressing from a notably negative position. For small fields, the state currently only becomes a net receiver of funds once prices reach somewhere between $75 – $85 / Bbl (shown in chart 3, where the PTax goes from negative to positive). SB5005 would shift that transition point to approximately $45 – $55 / Bbl (shown in chart 4). And prior to that point, the state would only be paying out credits in 2017. Otherwise, the net flows to or from either party would be zero.

The relationship of PTax to Unadjusted PTV at low ANS prices creates opposite profiles under the two regimes. As shown in chart 6, the rates are highly “positive” in the current system because even when prices create a negative Unadj. PTV, the government is still obligated to pay the producer, notwithstanding the fact that in total, the project loses money over its life, and the state will never receive any taxes. This relationship underscores the concept that the state is standing in as a de facto equity partner of the project, but it is only sharing in the upside once prices reach a fairly high rate. In contrast, chart 4 underscores that SB5005 would shift the risk profile to one where the state is not mitigating producer losses when prices are low, but it is also collecting relatively more when prices are high. At pricing points that create a negative Unadj. PTV, the effective PTax rate is only very slightly positive because of the remaining subsidy in 2017. As prices improve, that subsidy becomes smaller than the amount collected in PTax over the remaining years.

GOVERNMENT TAKE COMPARISONS

The following charts illustrate the impact of SB5005 by showing the range of average rates of GT, relative to Divisible Income ("DI"). DI is calculated as Gross Revenue minus Gross Opex – Gross Capex. GT is calculated as DI minus Total Equity Cash Flow. The difference between the cash that is generated by the project and the cash that is received by the investors is what is paid to the non-investors, which in this case are the state and federal governments.

	Current	SB5005
Economic Profile at ANS = $45/Bbl		
Effective GT rate at multiple prices		
Effective GT rate at multiple sized NSPs		

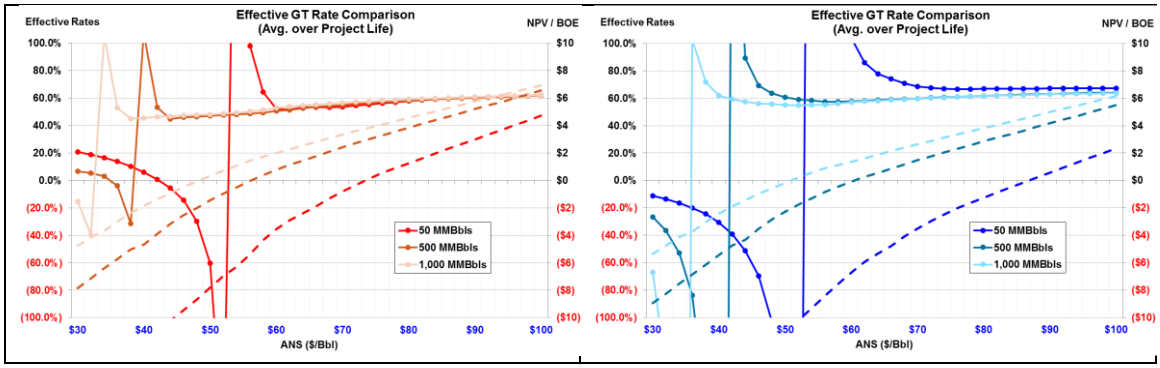
The above comparisons illustrate that SB5005 would make the net obligation to the "governments" (state and federal) slightly more onerous to prospective investors, and it would be very slightly less

progressive based on changes in the price of oil. For small fields, the overall GT would normalize[7] at around 67% at prices that exceed $70 / Bbl. This result is an average of approximately 5% – 7% points higher than the normalized rate under the current system (i.e. for projects that have a positive NPV).

VALUATION COMPARISONS

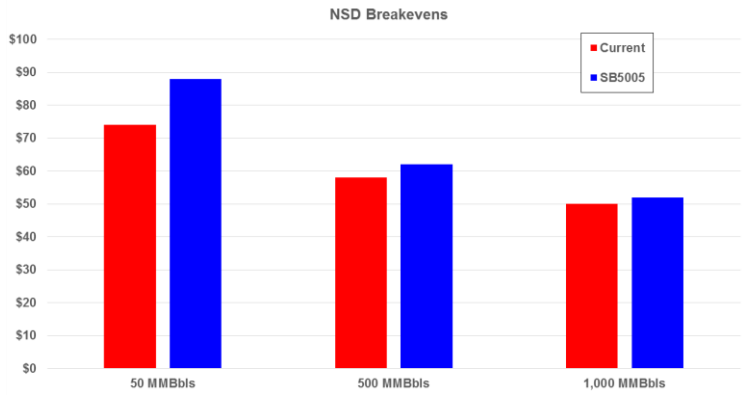
GT comparisons across regimes only make sense when comparing projects that exhibit a positive value to investors when considering all forms of costs. The different terms can obviously push a positive valued project to a negative value, and understanding how big of an impact a new system would have on value is clearly critical. However, that is a separate question. Comparing levels of GT across regimes presumes a project with positive value. The following chart overlays the NPV / BOE onto the previously presented GT comparison charts for all the projects in the form of dashed lines.

Current **SB5005**



As can be seen above, the new terms drive up the breakeven points for the NSPs. The following chart highlights the specific valuation differences.

[7] Projects that have a negative NPV often create GT rates that are materially different than what would be considered a reasonable level of take. Projects with negative DI will also create less meaningful GT rates for analytical purposes. The core question around a GT comparison revolves around understanding how much of the DI the government will extract from successful and profitable projects.



At the cost structures in the hypothetical examples, economics are challenged at today's prices for all sized projects. Moving to SB5005 would raise the bar even further. Regardless of the cost structure, the net impact of SB5005 would be to increase GT and lower projects' values.

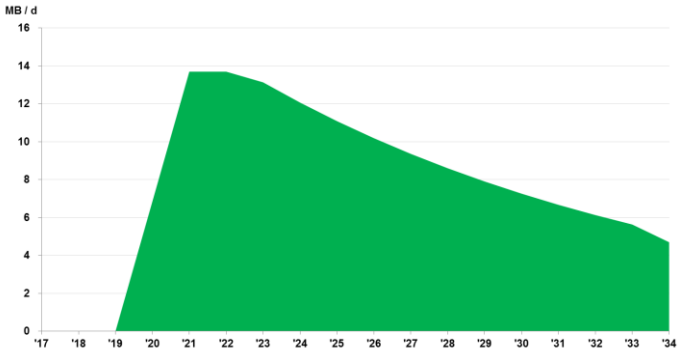
EXHIBIT A: HYPOTHETICAL NORTH SLOPE DEVELOPMENTS

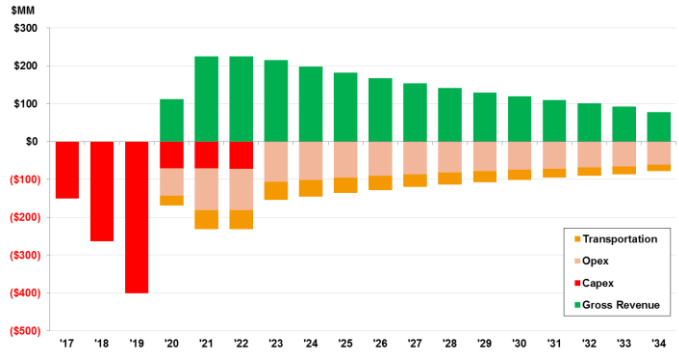
		Small	Medium	Large
Total Reserves	MMBbls	**50.0**	**500.0**	**1,000.0**
Peak Rate	MB / d	13.7	123.3	219.2
Drilling Cost	$MM	270.0	2,520.0	5,040.0
Facilities Cost	$MM	750.0	4,125.0	6,250.0
First Oil		2020	2022	2023
Total Capex	**$MM**	**1,020.0**	**6,645.0**	**11,290.0**
Total Capex	**$/Bbl**	**20**	**13**	**11**
Fixed Opex	$MM/Year	**35.0**	**90.0**	**115.0**
Variable Opex	$/Bbl	**15.0**	**13.0**	**10.0**
Transportation	$/Bbl	**10.0**	**10.0**	**10.0**
Total Opex & T-Port	$MM at Peak	160.0	1,125.0	1,715.0
Total Opex & T-Port	$/Bbl at Peak	32.0	25.0	21.4
Total Costs	**$/Bbl at Peak**	**52**	**38**	**33**

1) Base price of Alaska North Slope ("ANS") oil = $45 / bbl
    a. This is approximate rounded price around which ANS was trading as of the writing of this document
2) All prices and variations assume the price is held flat in real terms
    a. The price in the future escalates with General Inflation
3) Cash flow excludes costs for decommissioning
4) Capex escalates in real terms at 0.5% per annum
5) General Inflation = 2.0% per annum
6) Annual model – impact of monthly vs. annual PTax calculations handled separately

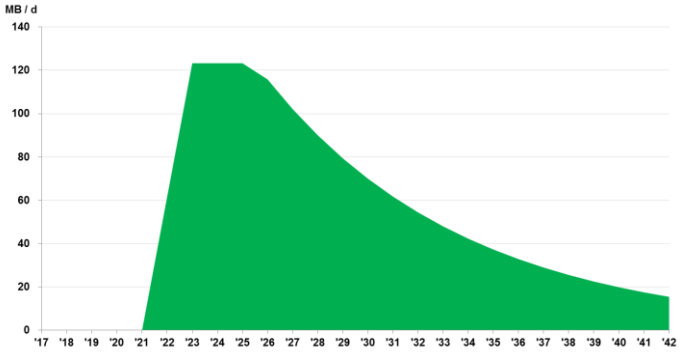
Project Profiles

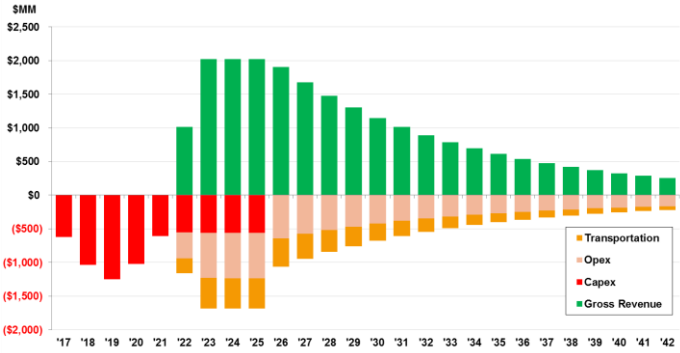
Small – 50 MMBbls



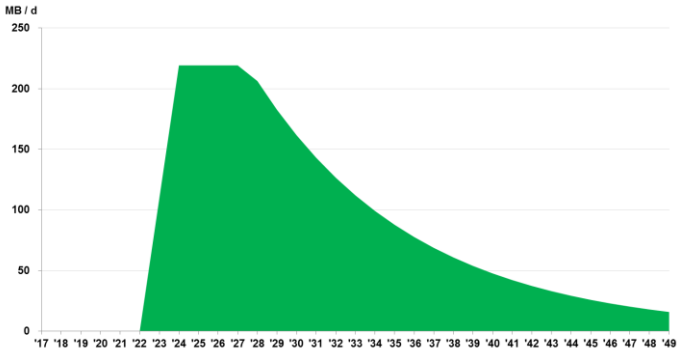


Medium – 500 MMBbls





Large – 1 BBbls



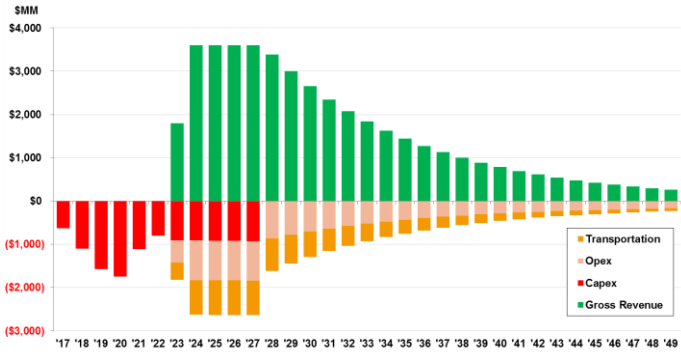


EXHIBIT B: SUMMARY OF KEY TERMS IN CURRENT SYSTEM

1) Wellhead Revenue = ANS – Transportation (marine and pipeline tariffs)
2) Gross Value at Point of Production (GVPP) = Max[0,Wellhead Revenue]
    a. (cannot < 0, 2017+)
3) Ad Valorem Tax = 2% of Replacement Cost New Less Depreciation (RCNLD)
    a. Depreciation for RCNLD based on spreading nominal capital over remaining useful life
4) Royalty = 12.5% of Wellhead Revenue
5) SB21 Production Tax
    a. = Max[(Minimum Tax – Credits), (PTV * 35% – Credits)]
    b. Production Tax Value (PTV)
        i. GVPP
        ii. Less: Royalties
        iii. Less: Capex, net of $0.30 / bbl exclusion
        iv. Less: Opex
        v. Less: Ad Valorem Tax
        vi. Less: Gross Value Reduction (GVR)
            1. Equal to 20% of GVPP (30% if royalty = 1/6)
            2. Cannot reduce PVT below 0 (except in 2016)
            3. Expires at the earliest of:
                a. the end of production year 7 or
                b. the end of the 3rd year (consecutive or not) since first production in which the average price for ANS has been greater than $70/bbl.
    c. Production-based Credit
        i. Rate * [Production – Royalty barrels]
        ii. Rate
            1. When “GVR Eligible” = $5/bbl
                a. Can make tax liability < Minimum (i.e. can be used to reduce either net 35% tax or minimum tax)
                b. Cannot make tax liability < 0
                c. Excess cannot be carried forward

2. When not "GVR Eligible"
    a. Takes effect when GVR expires
    b. Sliding Scale – "stair step" calculation, not weighted average

GVPP / Bbl	Credit $/Bbl
GVPP < 80	8
80 <= GVPP < 90	7
90 <= GVPP < 100	6
100 <= GVPP < 110	5
110 <=GVPP < 120	4
120 <=GVPP < 130	3
130 <= GVPP < 140	2
140 <= GVPP < 150	1
GVPP >= 150	0

    c. Cannot make tax liability < Minimum
    d. Inter-year / Monthly: any excess from any month can be used to reduce total annual tax liability at annual true-up.

d. Minimum Liability
    - 4% of GVPP, if ANS >$25
    - 3% of GVPP, if ANS <=$25 but >$20
    - 2% of GVPP, if ANS <=$20 but >$17.50
    - 1% of GVPP, if ANS <=$17.50 but >$15
    - 0% if ANS <=$15

e. Net Operating Losses (NOL)
    i. Offered only as a credit – producers do not have option to carry forward as future deduction
    ii. Credit Accrual: 35% of negative PTV before application of GVR (2017+)
    iii. Credit Payments via Tax Certificates
        1. Face Value: Max = $70mm per year
        2. Cash paid for certificates:
            a. ½ Face Value * 100% (ie, $35.00mm)
            b. ½ Face Value * 75% (ie, $26.25mm)
    iv. Cash impacts of credit
        1. Small producer (<50,000): subject to 5(e)(iii) above, plus nonfunded credits applied against tax liabilities
        2. Large producer (>=50,000): applied against tax liabilities

EXHIBIT C: SUMMARY OF KEY TERMS WITH SB5005 IMPLEMENTED

1) Wellhead Revenue = ANS – Transportation (marine and pipeline tariffs)
2) Gross Value at Point of Production (GVPP) = Max[0,Wellhead Revenue]
    a. (cannot < 0, 2017+)
3) Ad Valorem Tax = 2% of Replacement Cost New Less Depreciation (RCNLD)
    a. Depreciation for RCNLD based on spreading nominal capital over remaining useful life
4) Royalty = 12.5% of Wellhead Revenue
5) SB21 Production Tax
    a. Petroleum Tax Value (PTV) * 35% – Credits
    b. PTV
        i. GVPP
        ii. Less: Royalties
        iii. Less: Capex
        iv. Less: Opex
        v. Less: Ad Valorem Tax
        vi. Less: Gross Value Reduction (GVR)
            1. Equal to 20% of GVPP (30% if royalty = 1/6)
            2. Cannot reduce PVT below 0 (except in 2016)
            3. Expires at the earliest of:
                a. the end of production year 7 or
                b. the end of the 3rd year (consecutive or not) since first production in which the average price for ANS has been greater than $70/bbl.
    c. Production-based Credit
        i. Rate * [Production – Royalty barrels]
        ii. Rate
            1. When “GVR Eligible” = $5/bbl
                a. Can make tax liability < Minimum (i.e. can be used to reduce either net 35% tax or minimum tax)
                b. Cannot make tax liability < 0
                c. Excess cannot be carried forward

2. When not "GVR Eligible"
    a. Takes effect when GVR expires
    b. Sliding Scale – "stair step" calculation, not weighted average

GVPP / Bbl	Credit $/Bbl
GVPP < 80	8
80 <= GVPP < 90	7
90 <= GVPP < 100	6
100 <= GVPP < 110	5
110 <=GVPP < 120	4
120 <=GVPP < 130	3
130 <= GVPP < 140	2
140 <= GVPP < 150	1
GVPP >= 150	0

    c. Cannot make tax liability < Minimum
    d. Inter-year / Monthly: any excess from any month can**not** be used to reduce total annual tax liability at annual true-up.

d. Minimum Liability
- 5% of GVPP, if ANS >$55
- 4% of GVPP, if ANS <=$55 but >$25
- 3% of GVPP, if ANS <=$25 but >$20
- 2% of GVPP, if ANS <=$20 but >$17.50
- 1% of GVPP, if ANS <=$17.50 but >$15
- 0% if ANS <=$15

e. Net Operating Losses (NOL)
    i. Offered only as a credit – producers do not have option to carry forward as future deduction
    ii. Credit Accrual
        1. 2017: 15% of negative PTV before application of GVR
        2. 2018+: eliminated (no ability to carry forward losses or credits)
    iii. Credit Payments via Tax Certificates
        1. Face Value: Max = $70mm per year
        2. Cash paid for certificates:
            a. ½ Face Value * 100% (ie, $35.00mm)
            b. ½ Face Value * 75% (ie, $26.25mm)
    iv. Cash impacts of credit
        1. Small producer (<15,000): subject to 5(e)(iii) above, plus nonfunded credits applied against tax liabilities
        2. Large producer (>=15,000): applied against tax liabilities

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