

ALASKA STATE LEGISLATURE
SENATE RESOURCES STANDING COMMITTEE

April 7, 2016

3:30 p.m.

MEMBERS PRESENT

Senator Cathy Giessel, Chair
Senator Mia Costello, Vice Chair
Senator John Coghill
Senator Peter Micciche
Senator Bert Stedman
Senator Bill Stoltze
Senator Bill Wielechowski

MEMBERS ABSENT

All members present

COMMITTEE CALENDAR

HOUSE BILL NO. 247

"An Act relating to confidential information status and public record status of certificates from the oil and gas tax credit fund; relating to a minimum for gross value at information in the possession of the Department of Revenue; relating to interest the point of production; relating to lease expenditures and tax credits for municipal applicable to delinquent tax; relating to disclosure of oil and gas production tax credit entities; adding a definition for "qualified capital expenditure"; adding a definition for information; relating to refunds for the gas storage facility tax credit, the liquefied "outstanding liability to the state"; repealing oil and gas exploration incentive credits; natural gas storage facility tax credit, and the qualified in-state oil refinery repealing the limitation on the application of credits against tax liability for lease infrastructure expenditures tax credit; relating to the minimum tax for certain oil and expenditures incurred before January 1, 2011; repealing provisions related to the gas production; relating to the minimum tax calculation for monthly installment monthly installment payments for estimated tax for oil and gas produced before payments of estimated tax; relating to interest on monthly installment payments of January 1, 2014; repealing the oil and gas production tax credit for qualified capital estimated tax; relating to limitations for the application of tax credits; relating to oil and expenditures and

certain well expenditures; repealing the calculation for certain lease gas production tax credits for certain losses and expenditures; relating to limitations for expenditures applicable before January 1, 2011; making conforming amendments; and nontransferable oil and gas production tax credits based on oil production and the providing for an effective date." alternative tax credit for oil and gas exploration; relating to purchase of tax credit

- <PENDING REFERRAL> -

SENATE BILL NO. 130

"An Act relating to confidential information status and public record status of certificates from the oil and gas tax credit fund; relating to a minimum for gross value at information in the possession of the Department of Revenue; relating to interest the point of production; relating to lease expenditures and tax credits for municipal applicable to delinquent tax; relating to disclosure of oil and gas production tax credit entities; adding a definition for "qualified capital expenditure"; adding a definition for information; relating to refunds for the gas storage facility tax credit, the liquefied "outstanding liability to the state"; repealing oil and gas exploration incentive credits; natural gas storage facility tax credit, and the qualified in-state oil refinery repealing the limitation on the application of credits against tax liability for lease infrastructure expenditures tax credit; relating to the minimum tax for certain oil and expenditures incurred before January 1, 2011; repealing provisions related to the gas production; relating to the minimum tax calculation for monthly installment monthly installment payments for estimated tax for oil and gas produced before payments of estimated tax; relating to interest on monthly installment payments of January 1, 2014; repealing the oil and gas production tax credit for qualified capital estimated tax; relating to limitations for the application of tax credits; relating to oil and expenditures and certain well expenditures; repealing the calculation for certain lease gas production tax credits for certain losses and expenditures; relating to limitations for expenditures applicable before January 1, 2011; making conforming amendments; and nontransferable oil and gas production tax credits based on oil production and the providing for an effective date." alternative tax credit for oil and gas exploration; relating to purchase of tax credit

- HEARD & HELD

PREVIOUS COMMITTEE ACTION

BILL: SB 130

SHORT TITLE: TAX CREDITS;INTEREST;REFUNDS;O & G

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

01/19/16	(S)	READ THE FIRST TIME - REFERRALS
01/19/16	(S)	RES, FIN
04/04/16	(S)	RES AT 3:30 PM BUTROVICH 205
04/04/16	(S)	Heard & Held
04/04/16	(S)	MINUTE(RES)
04/05/16	(S)	RES AT 3:30 PM BUTROVICH 205
04/05/16	(S)	Heard & Held
04/05/16	(S)	MINUTE(RES)
04/06/16	(S)	RES AT 3:30 PM BUTROVICH 205
04/06/16	(S)	Heard & Held
04/06/16	(S)	MINUTE(RES)
04/07/16	(S)	RES AT 3:30 PM BUTROVICH 205

WITNESS REGISTER

JARED GREEN, President
Enstar Natural Gas Company
Anchorage, Alaska

POSITION STATEMENT: Related history of Enstar's presence in Cook Inlet, how that market is different than the Lower 48 market, and the effects of SB 130 and tax credits there.

MOIRA SMITH, Vice President and General Counsel
Enstar Natural Gas Company
Anchorage, Alaska

POSITION STATEMENT: Related Enstar's complicated demand/supply system in Cook Inlet and its effect on gas contracts.

BOB PICKETT, Chairman
Regulatory Commission of Alaska (RCA)
Anchorage, Alaska

POSITION STATEMENT: Related how gas regulatory issues affect Cook Inlet consumers relative to SB 130.

TONY IZZO, General Manager
Matanuska Electric Association (MEA)
Palmer, Alaska

POSITION STATEMENT: Commented on the Railbelt utility industry relationship with the gas industry in Cook Inlet relative to SB 130.

RANDY HOFFBECK, Commissioner
Department of Revenue (DOR)
Anchorage, Alaska

POSITION STATEMENT: Available for questions on SB 130.

KEN ALPER, Director
Tax Division
Department of Revenue (DOR)
Anchorage, Alaska

POSITION STATEMENT: Explained the impact of tax credits on the North Slope, Cook Inlet and Middle Earth relative to SB 130.

ACTION NARRATIVE

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CHAIR CATHY GIESSEL called the Senate Resources Standing Committee meeting to order at 3:30 p.m. Present at the call to order were Senators Stedman, Micciche, Coghill, and Chair Giessel.

SB 130-TAX;CREDITS;INTEREST;REFUNDS;O & G

[Contains discussion of companion bill HB 247.]

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CHAIR GIESSEL announced consideration of SB 130 [version 29-GS2609\A was before the committee]. She said today the committee would hear from the utilities and the Regulatory Commission of Alaska (RCA) before going back to the Department of Revenue (DOR) for more fiscal numbers. She welcomed the Enstar Natural Gas representatives to the table.

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JARED GREEN, President, Enstar Natural Gas Company, Anchorage, Alaska, said Enstar is the largest purchaser of natural gas in the Cook Inlet. Ultimately their customers are a beneficiary of the tax credit program that has been in place since 2012. Their customers depend on natural gas from Cook Inlet to heat their homes, their businesses, their schools, hospitals, and industries. Fundamentally, Enstar's interest is in fostering a stable and appealing natural gas environment in the Cook Inlet. Their number-one priority is safe reliable service to its 140,935 natural gas customers.

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SENATOR STOLTZE joined the committee.

MR. GREEN said, on average, their customers burn 33 Bcf/year (power corporation load is separate), but this varies from as little as 30 Bcf to 35 Bcf/year. He said overall production coming out of Cook Inlet is about 80 Bcf/year.

He said that Enstar has high seasonality gas needs with a ratio of 12:1 winter/summer gas along with substantial daily variability due to weather. With their current customer base, there is a potential daily demand of 287 mmcf/day and that is most likely to occur on a cold January date of any given year, but, depending on weather, that same January date could be under 100 mmcf/day.

When Enstar plans its natural gas portfolio it looks many years in advance, Mr. Green said. It operates in a closed supply system and, therefore, very long lead times are needed. Firm gas contracts need to be lined up and in place at least two years in advance. Anything less than that puts their 141,000 customers, over half the population of Alaska, at risk of supply shortages. To put the customer count in context, that number represents over half of the South-central population in Alaska.

There is no doubt Cook Inlet is challenged, he said, and between the producers and Cook Inlet Natural Gas Storage Alaska (CINGSA), 287 mmcf/day needs to be available, although it is not needed every day. This means producers need to have the operational capability to ramp up production, but also the capability to throttle it back when it's not needed.

MR. GREEN said Cook Inlet is a very different world than what is in the Lower 48. With the integrated transmission and storage network, producers down south can simply drill a well and open up their taps and the large market simply absorbs the gas. The utilities have an easy role also: they have a line-up of marketers who are trying to sell them gas from various places and if a contract that a utility has is not being fulfilled, the utility simply goes back to its marketing stream, and source gas from any one of the thousand other producers who are willing and able to supply them gas. Cook Inlet does not have that luxury; it is a very small and illiquid marketplace.

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SENATOR COSTELLO joined the committee.

MR. GREEN said Cook Inlet has a handful of buyers and an even smaller number of suppliers. The fact that ConocoPhillips is selling its assets to ML&P will take another supplier out of the

marketplace, but then ML&P will be self-supplied. That places Enstar in a somewhat delicate position with respect to supply.

However, Enstar is in a much better position now than in 2012. They have transitioned from a time of supply and deliverability shortages to signing a contract with Hilcorp that takes them out through 2023. However, that 2023 date would be just outside the range of short-term planning. This contract is now before the Regulatory Commission of Alaska (RCA) for approval.

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Enstar has fairly good visibility for gas needs out through 2021, Mr. Green said. With continued activity by Hilcorp and Furie along with hopeful growth and added stability from Cook Inlet Energy and AIX, and the new players - BlueCrest Energy and others - he is optimistic that he can see the supply horizon moving out into the 2025s. But that hinges on fostering an environment that keeps both existing and new producers engaged.

MR. GREEN said he feels strongly that the utilities in the Cook Inlet have a very large responsibility for providing reliable gas, and Enstar has designed its portfolio to balance their number-one priority of safe, reliable gas service with the need to foster the long-term viability of the Inlet. Enstar has put their support behind Furie's development of the Kitchen Lights Unit and signed a three-year contract with them that is now before the RCA. This is a core underpinning to their development. Enstar has left about 10 percent of its supply portfolio open for other producers to be able to come in.

He said that since 2012, the state has provided huge support to the viability of Cook Inlet gas supply and that Enstar is conscious of the state's budget crisis. They would love to see the state continue to encourage this marketplace in whatever form it can to keep it an attractive investment for producers.

MR. GREEN said finally, Cook Inlet is in a good place right now, but they have had the advantage of two very warm years in a row and 2016 looks like another. If Alaskans had experienced three cold years in a row, the current facilities might have been stretched. Today there is only one well in the Kitchen Lights Unit and there are no gas production wells in the Cosmo Unit, as BlueCrest is purely focused on oil. Cook Inlet has four large fields, which are aging every year. With cold weather or even if one of the existing platforms or fields had an issue, it has no large contingency of backup alternatives. As this committee knows, Mr. Green said, Alaska has no interties to the Lower 48

or Canada; it is 100-percent dependent on this small, illiquid market to keep half of the state's population warm.

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MOIRA SMITH, Vice President and General Counsel, Enstar Natural Gas Company, Anchorage, Alaska, said slide 3 was an actual representation of daily supply/demand in each day in 2014 and 2015 and illustrates why Enstar is a complicated customer. She noted the extreme daily variability and how their job is to have the gas in the pipeline to meet the customers' demand when they turn the thermostats up or down in winter and summer.

MS. SMITH said they have contracts with AIX (succeeding Buccaneer's bankruptcy), with Cook Inlet Energy, with Anchor Point Energy (which sold its assets to Cook Inlet Energy), with Hilcorp and ConocoPhillips. All of those contracts supplied their customers in each of the days in 2014/15.

She also noted how injections from the Cook Inlet Natural Gas Storage Alaska (CINGSA) plays a critical role in Enstar's ability to meet its customers' needs on a day-to-day basis by allowing them to inject gas in the summer time.

CHAIR GIESSEL asked if CINGSA is owned by Enstar.

MS. SMITH replied that Enstar's parent company, SEMCO, owns 65 percent of CINGSA, along with First Alaskan Cook Inlet Region, Incorporated, and a subsidiary of Berkshire Hathaway. She said the top of the chart reflects the maximum daily peak deliverability Enstar requires from the marketplace in the event of a super-cold day.

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This event comes along every once in a decade and has only happened four times in Enstar's history, but when that day comes, Enstar's obligation is to ensure that the gas is there for its customers, Ms. Smith said.

Slide 4 is a further illustration of the seasonality of Enstar's demand on an average day in each of the months in 2019 through 2021. She noted that the dark blue lines represent firm volumes Enstar will take under the Hilcorp contract. Optional volumes, represented by light blue, are stacked on top and are also from the Hilcorp contract. The dark green are the firm volumes take from the Furie contract and then light green, which are optional volumes from Furie.

MS. SMITH said Enstar worked very hard in their new gas supply portfolio to ensure that they not only have their base load contracts in place, but options for more volumes. So, on any day they can choose to withdraw from CINGSA instead of drawing on the firm volumes. This allows the flexibility to manage their storage volume and ensure they have sufficient storage to get them through each winter, but at the same time buy from the market as needed. The expected daily injections from CINGSA were represented in orange on the chart.

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She said slide 5 illustrates what Enstar was thinking when they sat down in 2014 to issue their request for proposal (RFP) for supply contracts through 2023. Enstar's gas portfolio for 2016 and 2017 consisted of relatively small contracts, and because they knew that every gas supply contract would expire in 2018, in late 2014, they sent out an RFP to all comers in Cook Inlet who were either actually producing gas, had publically stated their intention to produce gas, or even were in the process of doing seismic work or exploring for oil, to try to ensure that anyone who might have gas available was able to respond.

Then, Ms. Smith said, Enstar engaged in intensive and protracted negotiations with these entities throughout 2015/16, the first priority being to secure an anchor contract at reasonable prices, which would form the foundation for gas supply in the post-2018 world. These negotiations took over one year and resulted in APL-14, the new contract with Hilcorp that was filed with the RCA in February.

She explained that APL-14 was signed on December 23 and represents approximately 70 percent or 110 Bcf of Enstar's gas supply needs from 2018 through 2023. It will supply around 22 Bcf/year. The contract has optional volumes, which allow Enstar a great degree of flexibility to manage the weather variability they deal with not only on a daily basis but also on an annual basis.

Another key element of this contract is its reasonable price. In 2013, the State of Alaska entered into a consent decree, which resolved an anti-trust investigation and set price caps that escalate at 4 percent annually. The weighted average annual price under APL-12, which is Enstar's contract with Hilcorp that was based on the consent decree prices, during its last contract year will be \$8.33 mcf. By contrast, the weighted average annual price per firm delivery during the first contract year of APL-14 will be \$7.56 mcf, almost a 10-percent decrease.

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SENATOR STEDMAN asked if a conversion for a btu equivalency to oil was available.

MS. SMITH said yes and that she would follow up on that. She noted that importantly, this contract doesn't meet all of Enstar's gas supply requirements and as of December 23, 30 percent of their portfolio was left open for other producers to fill. As a public utility, Enstar values safety and reliability above all else, but they also understand that in the Cook Inlet market they have to have a diversified portfolio. This contract not only diversifies supplier risk, but it also helps to foster investment and drilling, which are good for the long term stability of Cook Inlet supply.

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SENATOR WIELECHOWSKI joined the committee.

MS. SMITH said that Enstar also entered into a second contract with Furie, which begins at the same time as APL-14 and goes for three years. It will supply 20 percent of Enstar's annual gas supply needs, and like the Hilcorp contract, it offers both firm and optional volumes. Both contracts are pending before the RCA for approval. These two contracts ensure that Enstar has 90 percent of its needs met through 2021. To ensure the entire market had yet another opportunity to participate in selling gas to them, Enstar sent another RFP to producers at the end of February to recruit participants for the remaining 10 percent of their open portfolio starting in 2018.

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MS. SMITH said they believe that the Hilcorp and Furie contracts, if approved, represent a huge measure of stability in the Cook Inlet gas market. They will be the most significant gas contracts entered into in 15 years, laying the foundation of Enstar's gas supply well into the next decade. Given where they were just three years ago, they consider this to be very good news.

MR. GREEN added that they are working in a very delicate market with a small number of buyers and a very small number of producers. Enstar has contracts that meet most of its needs out to 2021 and 2023, but extensions will have to be negotiated in the next couple of years. It is important to all of Southcentral Alaska to have a capable producer marketplace to be there to

provide the gas and the deliverability that their customers need.

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SENATOR COSTELLO said over the state's history, gas contracts have spanned decades and asked him to explain how things have changed with the shorter contracts.

MR. GREEN replied that a few decades ago, from Enstar's perspective, the utility was in "the place that a utility wants to be." They were a tiny percentage of what the overall marketplace was producing and buying, and their significant seasonal needs were easily absorbed by the large assets and large production that was occurring with the big players in the marketplace. They were almost inconsequential to the load challenges that were going on. With that, opportunities were available for very long term contracts. They were also sitting with four very large reservoirs of significant reserves that were easily developable, especially along with the large wells coming off of both Agrium and the LNG export facility.

Today, Agrium is closed and only a couple of loads of LNG went out in the last couple of years. He was surprised when LNG hit the high \$8-range and then went down to under \$5, recently. Enstar is now the largest buyer in the marketplace, and its variability requirements make it a challenge to be there. It's tough for producers to commit to make their assets available to hit the peaks for a 10, 15, or 20-year period, because the production Enstar actually pays them for is significantly less than that. He said it makes longer term contracts a little more difficult and Enstar is very happy with the five-year contract they have in place, because it is significantly longer term than what they could see back in 2012. This contract is showing a measure of stability, and a 20-year commitment just isn't available right now.

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BOB PICKETT, Chairman, Regulatory Commission of Alaska (RCA), Anchorage, Alaska, said he had been a commissioner since 2008 and that the RCA is involved in a number of very critical proceedings regarding Cook Inlet gas. They have the Hilcorp purchase agreement with extension options before them, a five-year agreement that covers 106 Bcf/gas, and a three-year Hilcorp/Enstar contract with extension options of approximately 19 Bcf. In a little over a week, the RCA will have a hearing concerning Municipal Light and Power's (ML&P) and Chugach Electric's proposed purchase of ConocoPhillips's interest in the

Beluga River Unit, so he would not be able to comment on those matters.

He said the RCA does not have a position on the specifics of SB 130, but it's fair to say, that the commission realizes the positive role the tax credits have played in the Cook Inlet gas market over the last few years. A couple of years ago the conditions were much different and conditions in 2009/10 were much worse.

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The RCA absolutely does not regulate the producers of natural gas in Cook Inlet, Mr. Pickett said, nor do they regulate the well head price of natural gas. However, they do evaluate gas sale agreements between the utilities and the producers. In the standard review they consider whether the utility acted in a prudent manner, whether the terms of the gas supply agreement are reasonable, whether the process to secure offerings to provide gas to the various utilities was reasonable, and whether the gas supply agreement assures reliable and reasonably-priced utility service.

A big contention in Cook Inlet historically is that it has not been an open and transparent natural gas market, particularly in 2001-2009. In 2001, the RCA approved what was termed a "Henry Hub Order," which included a variety of pricing proxies that were considered by the utilities, the producers, the attorney general, and the RCA. But from 2001 to 2009, not a single one of those pricing proxies resulted in an RCA-approved gas supply agreement that delivered gas to utility customers. That led to a bit of a marketplace issue that was reflected in investment and the number of wells being drilled, and ultimately, and the exit from the marketplace of Marathon and Union. In 2010, the utilities were concerned about where they would get their gas, and in 2010 Enstar, Chugach Electric and ML&P contracted with PetroTechnical Resources of Alaska for a study. The conclusions at that time were quite alarming. In part, the legislature responded by giving direction to the commission as to how to evaluate gas supply agreements and modified a section of AS 42.05.141 dealing with the general powers and duties of the commission adding section (d) as follows:

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Section (d) when considering whether the approval of a rate or a gas supply contract proposed by a utility to provide a reliable supply of gas for a reasonable prices in the public interest, the commissioner shall

(1) recognize the public benefits of allowing a utility to negotiate different pricing mechanisms with different gas suppliers and to maintain a diversified portfolio of gas supply contracts to protect customers from the risks of inadequate supply or excessive costs that may arise from the single pricing mechanism; and (2), consider whether a utility could meet its responsibility to the public in a timely manner and without undue risk to the public if the commission fails to approve a rate or a gas supply contract proposed by the utility.

MR. PICKETT said this general guidance has been helpful over the past six years and a number of gas supply agreements were approved within that timeframe with a great variety of pricing and peaking mechanisms, as evidenced by the most recent contracts before them. He commended the utilities for recognizing the importance of leaving a slice of business open for the smaller producers to become part of the solution to the needs picture.

He shared Mr. Green's concerns about where they will be in 2023, because it will take significant investment for gas to continue being produced in Cook Inlet.

SENATOR STOLTZE asked what some of the triggers are that concern him as an advocate for consumers and what cautions should legislators consider on a policy level.

MR. PICKETT answered that one of the most important things on a policy level is to make decisions that encourage stability and movement towards a more competitive gas market in Cook Inlet. One of the things that has helped the Cook Inlet natural gas market is the rationalization of the pipeline system, which was very fragmented, Balkanized system. That will make it easier over time for smaller producers to access the pipeline system and to know what the rules of the road are and what the aggregate tariff is on that.

It would be nice to have more competition, too, Mr. Pickett said, but the RCA has to play the hand that it is dealt. The legislature has strongly cautioned the commission to not reject contracts on the belief that something better may come when there actually is nothing better in the timeframe for which the contracts are being proposed. It is a very tough thing to say, because at the end of the day it is the ratepayers who end up paying.

MR. PICKETT also said he would be cautious with the tax credits and that the RCA had not taken a position on SB 130. But the existing investment decisions that have been made in the Inlet are based on the fact that they can get utility contracts they can count of for some reasonable extended period of time. The credits paid a role in those investment decisions.

SENATOR STEDMAN asked if he knew the Btu crossover is between natural gas and oil, so they could have an idea of a benchmark in the price of the energy source.

MR. PICKETT responded that he didn't know off the top of his head, but he would get that information in the next day.

CHAIR GIESSEL thanked Mr. Pickett for taking the time to talk with the committee today and invited the next presenter to testify.

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TONY IZZO, General Manager, Matanuska Electric Association (MEA), Palmer, Alaska, said he had been in the utility industry for 30 years and was with Enstar Natural Gas from 1999 through 2007 and was president for a period of time.

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His PowerPoint presentation was labelled "MEA, Natural Gas Supply, Senate Resources Committee, April 7, 2016." Mr. Izzo said MEA is the oldest electric co-op in the Railbelt and will celebrate its 75th anniversary this year. They are now serving the second largest population center in the State of Alaska with over 62,000 customers, a service area the size of West Virginia. Their generation portfolio is 90 percent gas and 10 percent hydro.

He said the last two bullets provide some perspective in terms of how much gas MEA buys. It is somewhat unfortunate, based on his experience, that MEA is the third largest gas buyer in the Cook Inlet today. It is a reflection of the fact that even Enstar was kind of background noise in comparison to the two large industrial users, the Kenai LNG plant and the Agrium facility. At 6 to 6.5 Bcf, for MEA to be the third largest electric utility is significant. Their annual cost is in the \$45-to-\$46 million range, not including the transportation. This is a significant number for a utility like MEA, because it represents 40 percent of the total cost of a kilowatt hour for a customer.

MR. IZZO said he would answer three questions (slide 3):

1. What is MEA's gas supply forecast?
2. What has changed in the Inlet over the past five years?
3. How have tax credit programs in Cook Inlet affected gas supply?

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He said MEA is coming off a period when it was very difficult to contract for up to two years of supply (slide 4). They have all the supply they need through March 31, 2018 (green), and that is the year the unmet requirements (red) start, going out to 2026.

MR. IZZO said MEA negotiated a supply contract that has board approval, and they are preparing a filing for RCA approval that will fill up the red through 2022 and the first quarter of 2023.

He said slide 5 addresses what has changed in the last 5 years in Cook Inlet. Five years ago, gas supply was available in small quantities and for short terms. He was at Enstar in 2001 when they signed an agreement that was linked to the Henry Hub that was capped at 450 Bcf. This large agreement was linked to a three-year trailing average of the Lower 48 prices. In response to some concerns, in 2005, they filed their next agreement, which was a 12-month trailing average of Lower 48 prices that would have filled up all of the gas utilities' needed requirements through 2016. That contract was not approved in 2005/6. If those were in place today, prices in the Lower 48 are in the \$2 range and South-central utilities are currently paying in the \$7.42 range, which is the consent decree price negotiated by the Attorney General.

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MR. IZZO said the reason he raises the issue is when the contract was rejected, Marathon and others slowly decreased investment and interest in the region, eventually devolving to a point where they left the Inlet entirely once their contractual obligations were either met and/or sold to others. That's what took them to the point of five years ago, but it's an important point, because he would hate to repeat history. Utilities could not support things like extended LNG export, industrial growth, or exporting gas to other parts of the state. It was not a sign of success; it was a sign of dysfunction. A market is needed that is growing, expanding, and attracting investment.

The most significant positive change in the last five years has been the Hilcorp investment and the consent decree. The best

price he could get four or five years ago was \$10 for 20 percent of MEA's supply. He also joined with the other utilities in looking for LNG imports. However, another significant change brought multiple new players into the Inlet who have invested significant capital, one of them being Hilcorp.

MR. IZZO said all of the gas MEA has under the existing contracts are through 2018, and maybe beyond. They are from the same three or four mature fields that were discovered in the late 50s and 60s. It's Hilcorp's core completeness in increasing production from mature aging fields combined with the investment that has made the significant change in Cook Inlet.

MR. IZZO said all can agree that what has not changed is that they know where gas is in Cook Inlet: the Cosmopolitan Field off of Anchor Point and the Kitchen Lights Unit, which Furie has begun producing. The concern he has as a buyer is that he has to look at gas in terms of if it's behind pipe and commercially available for him to get deliverability.

He said that slide 6 illustrated the impact of the tax credit program on Cook Inlet. The good news is that multiple new investors are available for gas supply discussions, the lives of mature fields have been extended, and some additional proven reserves have been put behind pipe. Another bit of good news is energy security, but that is temporary. Part of the bad news in terms of the impact of the tax credits is that significant new reserves are not behind pipe and doing so will require significant current and future investment, and very long lead times. The impact of the tax credits has brought on access to gas that has been behind pipe for a long time and maybe wasn't producible or economic to produce and simply required a lot of investment.

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MEA is an island in the sense of energy infrastructure (slide 7). They are the only climate with both seismicity and a sub-Arctic climate, which means curtailing rolling blackouts to preserve supply, which most Lower 48 markets find unacceptable. Finally, he summarized that uncertainty is the enemy of energy (security). Exploration and production risks are not typical core competencies of a regulated utility.

MR. IZZO stated that if he finds himself in a situation like four or five years ago, where it's going to take \$4-5 million for exploration and production and a pipeline connection to maybe get gas into an area where he has no core competence

versus importing LNG for a price that is a little bit higher, he believes - as he did prior to the consent decree - that importation would be in the best interest of his customers.

He said that bringing new gas reserves to the point that they can be prudently purchased by a regulated utility requires extensive investment and many years. Because he spent so much time in the private sector part of this investor-owned utility business, he believes in metrics. If a program is designed to deliver a result, there should be some key metrics to determine what the results are. In terms of Cook Inlet and the impact of the tax credits the real metric is investment, and when that went away in 2005/6, there were rolling blackouts and energy curtailment drills. The Cook Inlet Recovery Act and CINGSA turned things around. He doesn't want investment to go away, because getting it back will take a long lead time and be a capital intensive activity.

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SENATOR STOLTZE asked Mr. Izzo for a narrative about cooler winters and the dynamics that will lead to MEA's ability to provide power if there is a shortage. Is there a prioritization of how the utilities supply for space heating over electricity?

MR. IZZO answered that Mr. Green's 12:1 ratio swing between summer and winter load is consistent with his experience. He has seen an extreme case of almost 19:1. For an electric utility like MEA that is 94 percent residential customers, the difference in demand between summer and winter follows daylight almost more than weather. For that they see a 2:1 ratio.

He explained that prioritization is subject to a number of factors, but deliverability is king. That is the measure of being able to get the volume of gas at the moment that is needed. Sometimes it's based on production at a well, or compressor capacity, or pipeline capacity. It can be based on where the demand is located. Most jurisdictions in the Lower 48 use a variety of measures. One thing is for sure, if the gas goes out, there is a much longer process of shutting off, repairing, purging, reintroducing gas, and unlocking meters. Therefore, MEA would curtail power, because it is the right thing to do. He said MEA is not a signatory to what is called the 2009 Gas Emergency Letter, an agreement amongst the utilities that rather than let the gas system go out, they would attempt to reduce demand through a process of rolling blackouts a couple of hours at a time, and moving it around the system. If that were to occur, his members and ratepayers would become much

more concerned about what plans are in place to address that. The Lower 48 gas utilities have access to imports from Algeria to Massachusetts, and it can be trucked and stored for when it is needed on those coldest days.

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MEA is designed differently for a variety of reasons, Mr. Izzo said, and they probably wouldn't build a second one like it, but their engines are dual fuel and are run at an efficient range of RPMs. It's ultimate efficiency, unlike others, does not occur when the plant is running full throttle. They store about 1 million gallons of diesel, which would provide enough backup power for approximately 4.5 days of peaking days and to offset any rolling blackouts. And if it's not too presumptuous, because it is something they purchase, he stated that one needs 7.3 gallons of diesel for 1 million Btus to equate to 1 Mcf/gas. He is buying diesel right now in the range of \$1.38, which means he is paying about the equivalent of \$10.07/8 per Mcf for an equivalent Mcf of gas, which is costing him \$7.42.

SENATOR STOLTZE said up until sometime in 2015, he attended regular meetings of the Energy Security Committee led by the Municipality of Anchorage and MatSu Borough and asked if those types of meetings are still being held or if the crisis is over.

MR. IZZO answered that he was chair of the mayor's Energy Task Force and always appreciated seeing Senator Stoltze there. With the change in administration, that group was able to shift its initial focus away from the immediate crisis, partly because of having the availability of supply, and the Municipality of Anchorage utilities continue to meet in unprecedented cooperation for contingency planning. He feels very comfortable because all of their generation units are linked; each unit can see what the other is doing. The daily number of transactions - buying and selling the most efficient energy back and forth - has increased from zero or one a year ago to five and seven per day. These transactions are purely based on win-win economics between the electric utilities. If that coordination continues, he is confident in their ability along with Enstar to address any type of emergency.

SENATOR STOLTZE said he appreciated the information.

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SENATOR STEDMAN commented that energy supply is clearly a function of price; when the price gets low the supply dries up and vice versa. If the gas into the Railbelt is somewhere around

\$1.00, the so-called cheap hydro energy in Southeast is still about \$3.50/oil. He remarked "if \$3.50/oil is cheap, \$1/oil must be free!" He said that places like Iceland have a flat energy price around their whole island to levelize the economic advantages or disadvantages that each section has.

CHAIR GIESSEL thanked Mr. Izzo for joining the committee today.

[4:33:55 PM](#)

CHAIR GIESSEL invited the Department of Revenue (DOR) representatives to continue their presentation from the previous meeting on oil and gas tax credit reform in SB 130 labelled "Additional Modeling and Scenario Analysis." She noted that legislators have a "quick reference" summary of the statutes addressing the credits.

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RANDY HOFFBECK, Commissioner, Department of Revenue (DOR), introduced himself.

[4:35:13 PM](#)

KEN ALPER, Director, Tax Division, Department of Revenue (DOR), introduced himself and related that he had added a column for North Slope production beginning in FY09 and forecasted forward through FY25 onto slide 4, which made it slightly more complex but maybe more understandable. Because they had an "alternative reality" that was leading to FY16, they then said, if they are going to really forecast, they have to reset the present day to zero and look at the issues of stacking-up, carried-forward, and net operating loss (NOL) credits from there. The new orange row is FY16 as it is and what the future will look like based on certain assumptions.

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MR. ALPER said yesterday they talked about the history and what would have happened had they only appropriated money per the cap through the guideline language in AS 43.55.028. The general idea was to endow a fund and build up a balance approaching \$600 million, spend that down in FY15, and then be right around where they are in FY16, the difference being perhaps a different level of expectation and assumption as to the nature of the state's role in funding ongoing tax credits. He had updated this slide with information from the final version of the spring forecast, which the commissioner released at about 2:00 today. It doesn't make a whole lot of difference, just some small differences in revenue assumptions.

Looking down into the FY17 row at the end of FY16, no matter what is done, the credit account will be zero. The governor vetoed the number at \$500 million last year and \$500 million was transferred to the fund. By the end of the year it will have been spent. There will be roughly \$775 million of claimed credits in FY17. Should the legislature appropriate either the \$73 million that is in the current budget or the \$29 million that is the revised figure from the credit cap, obviously the fund would be highly short-funded by over \$700 million.

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Continuing along those lines, Mr. Alper said, the forecasted credit spend (column known as "Actual Claimed Credits") starts to stack up. The appropriated column is called the "Credit Cap per AS 43.55.028," and the credits that are owed by the state start to stack up going from year to year. Meanwhile, happening almost in parallel to this, is the idea of non-cashable NOL credits, the credits earned by the major producers. Those numbers have a couple of small revisions. The department switched from an accrual system to a more cash-based system. In other words, they are not going to count any credits that are earned at the end of FY16 until the end of calendar year 2016 (CY16), because they are NOLs. Because of that, there is a zero in the FY16 row. The \$618 million NOLs represent the operating loss credit really for CY16. Those credits will have to be paid some day indirectly, meaning that once the price of oil recovers, the major producers will subtract that number from their production taxes to the state.

When will that money be paid? The chart indicates roughly in FY21/22, when the big numbers go down from \$600 million to \$100 million. In those years the difference is there will be a tax liability to subtract the NOL credits from and the taxes will be paid in smaller rates as the NOLs are "billed down."

MR. ALPER said the last column on the right is the sum total of both the cashable credits plus the non-cashable credits that are awaiting the return of higher oil prices. At the end of the day, the state would owe \$2.8 billion in FY25.

SENATOR WIELECHOWSKI said it looks like the FY17 numbers have been revised to the actual claimed credits of \$775 million. Then the state receives a production tax of \$59 million, which leaves the state paying out \$715.6 million more in tax credits than it is receiving in production taxes. He asked if this math is correct.

MR. ALPER answered yes; so long as he is just talking about the production tax.

SENATOR WIELECHOWSKI asked if any other jurisdiction in the world pays out more in credits than it receives in taxes.

MR. ALPER answered not to his knowledge, but he didn't claim to have a comprehensive knowledge of world tax regimes. Alaska has an unusual system and it's an unusual time given the collapse in oil prices.

SENATOR STEDMAN said it's a complex subject, so it's nice to see it in black and white. His concern was that in the future, the state would have to pay off its projected liabilities of around \$2 billion, and then it will be hard to explain to public the advancing prices without advancing revenue to the state. How will they deal with that?

COMMISSIONER HOFFBECK responded that the Revenue Sources Book projects revenues separate from expenditures. The cashable credits are not going to show up as a negative against the revenues. A line item shows them as an expenditure.

MR. ALPER added for example, last year when the department anticipated more credits than there was money appropriated, that \$200 million shows up in this year's forecast as part of the \$775 million. Should something similar happen at the end of this year when they are doing the revenue forecasting in the fall, that one-time carry-over number will roll into the FY18 forecast. It is hard to forecast credits more than one year ahead, he said.

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SENATOR WIELECHOWSKI went back to his same question about how much more the state is paying out than it is taking in and said it looks like in FY15 the state paid \$628 million in tax credits and brought in production tax of \$363 million. So, the state lost money in FY15/16, and it is projected to pay out more in production tax credits than it receives in production taxes all the way out to 2024. Is that correct?

MR. ALPER answered yes; that is the way the chart reads.

SENATOR WIELECHOWSKI said then in 2025 the state is projected to pay out \$250 million and to receive \$275 million in production taxes, but then when the credits are applied against

liabilities, the state is still projected to have a loss that year. Is he reading that correctly?

MR. ALPER answered no, and explained that the \$275 million is after subtracting the credits against liabilities. The reason for that is the column to the right of that has \$370 million, which is the tax liability based on the calculation and then the \$95 million would come off of that in various credits against liabilities, and \$275 million would actually be received by the state.

CHAIR GIESSEL asked what percent of decline is being projected.

MR. ALPER answered if the production is at 300,000 barrels in 2025, the difference between 500,000 and 300,000.

COMMISSIONER HOFFBECK added that amounts to a 4-5 percent decline per year.

CHAIR GIESSEL asked if he based the projection on the assumption that companies that are losing money now will continue to invest, and that the state will have the projected 4-5-6 percent decline, when in fact if companies stop work, the state would be looking at 12-15 percent per year decline rate. Has the commissioner taken any of those "rational decisions" that a company losing money would make into account?

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COMMISSIONER HOFFBECK answered some of that is already embedded in the forecasted decline. They only project investment that is currently ongoing or that is planned and sanctioned. Any new investment is not part of the forecast. As for the 15 percent decline, he explained that fields decline at a hyperbolic rate and kind of flatten out as they age. He didn't know where the field is on that decline curve.

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CHAIR GIESSEL said before SB 21, the state was experiencing a 6 percent decline and that was with significant investment to keep that decline at only 6 percent. With the withdrawal of three rigs, which she didn't know was in his calculation, that decline curve will accelerate.

MR. ALPER responded that the spring forecast does somewhat account for the withdrawal of the three rigs announcement made by the Prudhoe Bay operator earlier this spring.

SENATOR COSTELLO said at some point with companies experiencing net operating losses, that the amount of revenue the state will get from royalty will exceed the production tax, and asked if that was correct.

MR. ALPER answered that is currently the case.

SENATOR COSTELLO asked since companies are paying income, royalty, and property tax in addition to the production tax, if it would be possible to have a column showing the complete tax picture of what the state is receiving from the companies.

MR. ALPER answered yes, and added that the numbers had been "thrown around" in the last couple of weeks since the spring forecast and there had been some controversy over what the appropriate numbers are, and he wanted to make sure they have the right ones. Some attention has been paid to the idea of total unrestricted general fund petroleum revenue, because for the first time that number is below the credit forecast. There is also the entirety of petroleum revenue, which includes such things as the Permanent Fund deposits from royalty, CBR deposits from assessments and that kind of thing and his preference was to put both of those additions into columns.

CHAIR GIESSEL said members have the document that was released this afternoon on their desks and revenue coming in from all of those things was on page 14.

MR. ALPER responded yes, and added that the number shouldn't be terribly different from what they had a couple of weeks ago. He just hadn't had time to look at them today.

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SENATOR STEDMAN said in 2012 under Alaska's Clear and Equitable Share (ACES), SB 21 wasn't even a concept; testimony in Senate Finance during that time stated production was approaching the 2-3 percent decline rate, and there was testimony in Senate Finance about the parabolic curve. No testimony was brought forward to the committee at that time about getting off of that parabolic curve. The geology of the basin can't be changed by changing tax codes, he said. This parabolic curve has been studied for decades and it can be brought forward in time, but no more oil can be created in the ground. As policy has changed, production has increased in the near years, but the rate of decline also increased, and that has become a problem with a lot of sovereigns around the planet. That 2-3 percent decline curve was forecasted in testimony in Senate Finance in 2012 and maybe

2011, because they spent two years having hearings on ACES as they tried to restructure it.

SENATOR WIELECHOWSKI recalled the many advertisements saying that the "drop was stopped" after passing SB 21. In fact, the bill was labelled the "More Alaska Production Act." Production in the last year of ACES (2012) was 579,000 barrels and production is forecast to be 302,100 barrels in 2025. He asked if it is fair to say under the More Alaska Production Act the drop was neither stopped nor production added.

COMMISSIONER HOFFBECK responded that the decline has continued but it is not justifiable to say production has not been added. There has been added production, but not enough to totally stop the decline.

CHAIR GIESSEL asked if he was comfortable with the committee checking the Division of Oil and Gas on that statement related to production.

COMMISSIONER HOFFBECK answered absolutely, but he was just trying to parse the difference between the two.

SENATOR WIELECHOWSKI said virtually all production is new production and asked Commissioner Hoffbeck if he would agree that 302,000 barrels of oil being produced in 2025 is less than 579,000 barrels that were produced in the year before the More Alaska Production Act was passed.

COMMISSIONER HOFFBECK answered yes.

CHAIR GIESSEL asked Commissioner Hoffbeck how certain he was of the production forecast out to 2024.

COMMISSIONER HOFFBECK answered that the forecast uses a lot of conservative assumptions.

CHAIR GIESSEL asked if he had considered the Repsol/Armstrong field that is potentially coming on line in the next five years.

COMMISSIONER HOFFBECK responded that it is not in the forecast.

SENATOR COSTELLO asked if he knows the opportunity cost to the state of capping the Tax Credit Fund and not providing cashable credits.

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MR. ALPER answered that it's hard to project what might not happen. Later in this presentation they show how project economics might affect a particular project going forward or not. However, the opportunity cost is only a cost if something doesn't happen and that is what becomes very hard to calculate.

SENATOR COSTELLO asked if he was suggesting that there are no opportunity costs in some scenarios.

MR. ALPER answered no; he was just saying that on one hand there is the opportunity cost of spending money on credits that weren't necessary if the project was going to happen anyway, and then a cost in the other direction is when the state has paid money that it is going to get the same revenue on in the future. He was just saying there are too many variables to conclusively say what will and will not happen with the changes. That is why they have a deliberative process.

CHAIR GIESSEL asked Mr. Alper if he feels that hardening the floor will help or exacerbate the carry-forward issue that is illustrated on his chart.

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MR. ALPER answered that hardening the floor was conceived of as an issue last year when the department realized significant NOL credits were going to be used against the floor. Other states in a gross tax regime (like Alaska) actually get their gross tax, and Alaska might be getting to a place where it might not be getting it. Now suddenly, they are seeing a new variable: the stacking up of carry-forward losses. To answer her question directly, no, hardening the floor actually makes it worse. If company X earns \$500 million in carry-forward losses and they can use \$200 million to offset their minimum tax and therefore carry forward \$300 million, the state would be asking them to carry forward all \$500 million, and therefore the impact in the future when prices go up would be even more. This larger problem of the NOLs is not being addressed in this legislation.

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SENATOR STEDMAN commented the he thought he saw a marginal increase in production since 2011/12 versus what was expected, but it would be interesting to measure how much and compare that to what was going to be done anyway. That is hard to do because corporate politics are involved in slowing down particular projects to get a benefit in the tax structure. Clearly the numbers are going down and even if production were flat at 490,000 or 500,000 barrels it would still lead to the state

taking carry forward OL credits very seriously and there has to be some sort of plan to deal with them.

COMMISSIONER HOFFBECK responded that in regards to the forecast of production, they need to be cognizant of the fact that laying down the rigs and those kinds of things are being driven by the oil price. The state can do very little with credits to overwhelm \$38 oil. The decisions being made are simply because companies can't produce with a profit at \$38/oil. It has nothing to do with the state's tax policy.

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SENATOR STEDMAN said it looks like laying down rigs will impact production at some point, and it would be nice to get a briefing on that just for general knowledge. You can't lay down rigs and have it be beneficial for production; he also understands that getting them up takes a while. It looks like what is going on today will affect production four or five years out, and at the same time the state is trying to deal with the NOLs - "And we end up in the pickle." Maybe that can be mitigated through legislation.

SENATOR STOLTZE apologized since his question was not a hardball question, such as whether 300,000 is less than 500,000. He apologized further, since he forgot the question in light of the complexity of previous questions.

SENATOR MICCICHE said the decline rate for 15 years following FY14 is an absolute flattening for seven years, even with conservatism designed into the model, and if that is the most they accomplish in forward tax policy dealing with some of the credits and hardening the floor and other options, it is certainly a better direction than where we are heading.

CHAIR GIESSEL pointed to 2025 with 300,000 barrels and said, "We will be in a really bad place regardless of what the price is."

SENATOR WIELECHOWSKI clarified he will not ask anymore hardball questions, and asked if companies can write off the cost of laying down rigs or are they eligible for tax credits.

MR. ALPER answered that he knows the department has denied credits for rig standby fees and his expectation is that those sorts of costs won't be allowed to be deductible, but he would find out the precise way that is done.

SENATOR STEDMAN said as long as they were "digging up old bones and throwing them around the table," he would like DOR to run the current tax structure at \$40 relative to the economic limit factor (ELF) and ACES at \$40.

MR. ALPER replied that he would do that and that ELF will probably win at \$40 oil. But one thing the department has stopped doing over the last couple of years is track and project what the ELF multiplier is on a field-by-field basis. So, they are left with a little bit of theory about what the ELF tax rate would have been had it been in place all these years. To the extent they can "fake that a little bit based on past trend lines" they should be able to answer his question.

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CHAIR GIESSEL called the meeting back to order and Mr. Alper continued with slide 5.

MR. ALPER said slides 4 and 5 were both supplemental slides added after questions after he had gone through an analysis of the credit applications that were before the Tax Division on April 2. The request was made to break them out into Cook Inlet and Middle Earth versus North Slope, which was done. They worked from the number of \$675 million in credits, consisting of the so-called older NOL credits versus the older exploration credits. The big pile of credits from the end of last year reverses a little bit of the trend line for the prior two years, which was a very Cook Inlet-heavy spend. In 2015, \$335 million in credits were NOLs from North Slope spending and \$217 million from Cook Inlet and Middle Earth, in general; breaks into about a 50/50 split. Companies that get the drilling credits and can't be split out on a chart, because that would impinge on their confidentiality, because there aren't too many of them.

The last minute exploration credits were tied to the sunset and were particularly relevant in the North Slope area, because it had 85 percent credit support for a limited window of time (40 percent exploration credits, stackable in CY15 with the 45 percent NOL). His sense was that companies were saying if they were going to drill an exploration well in the next few years they might as well do it in 2015, because the system was calibrated to their maximum benefit. The few credits that are going to be refilled are North Slope heavy, but the general thrust is \$422 million versus \$253 million. He offered to keep

the committee updated through the year, but that is the best he knew at the moment.

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MR. ALPER said slides 6 and 7 have the meat and detail of SB 130. Section 7 is on the topic of interest rates, not an oil and gas specific section, but general statutes of the DOR describing how interest is charged and how delinquent taxes are dealt with. The historic interest rate was quite high, 11 percent and compounding in the 70s. SB 21 reduced it from a fixed 11 percent to 3 percent above the federal discount rate. However, there was an awkwardness with SB 21; it did not have enough votes in the Senate to pass an effective date clause. That meant when the bill got to the first House committee, they needed something of a workaround, and "applicability language" was used. It said production prior to January 1, 2014 is X; prior production after January 1, 2014 is Y. The new interest was in the after section, but meanwhile, even though the compounding language found its way through the system in all versions including House Resources. There was a technical error in House Resources. The last committee substitute (CS) in House Finance (slide 8) fixed that technical error, but added back the higher 11 percent language that was in the original law with the compounding language.

He explained that for most big bills after the work draft CS is put on the table there is often a technical amendment by the chair that cleans up a lot of the smaller provisions in the bill that are brought to the chair's attention. This amendment was by Chairman Austerman and contained six or eight different changes, minor things. But in doing so, while eliminating the annual rate of "11 percent whichever is greater phrase" it also deleted the "compounded quarterly as of the last day phrase." No one caught it and the bill passed the House, was concurred with in the Senate, and became law, and lo and behold, Alaska no longer had compound interest on any of its taxes for the first time in 30-some years. So, that is the state Alaska is in now, which is a simple interest calculation on all delinquent taxes. This quarter, the number is 4 percent (1 percent federal discount rate plus 3 percent).

CHAIR GIESSEL asked if this interest rate applies to other industries as well as oil and gas.

MR. ALPER answered that it applies to other taxes as well: corporate income tax, tobacco, mining, fish, etc. etc.

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He said the intent of the legislation was to find middle ground (slide 9) between the historic 11 percent and the current effective 4 percent. The underlying idea is that right now the state is funding the budget out of its savings. That is the reality; therefore a dollar that is not received in taxes is another dollar out of those savings. Consequently, when the state finally gets paid that dollar because it has gone back to the taxpayer in whatever industry and said this is the tax you owe plus interest, the interest should in some way compensate the state for the cost for not having had it in savings for the intervening years, effectively the opportunity cost. So the intent of section 7 was to try to find a number that roughly approximated what the Permanent Fund expected to earn on its money, because that is the biggest savings account the state has that might in the future be used to fund ongoing government operations. The Permanent Fund estimates that number to be about 7 percent right now.

CHAIR GIESSEL pointed out that the same also applies if the state has collected too much tax; the state owes it back plus the interest.

MR. ALPER agreed with that and said this applies not just if someone overpays their taxes but if someone pays the amount the state assessed and contests it, goes through the process, wins or even partially wins, and the state pays them back; the same rate of interest from the original assessment is used.

COMMISSIONER HOFFBECK added that the intent was not to make it a revenue source or revenue loss, but to make it as revenue neutral as possible.

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MR. ALPER said slide 10 attempts to model that with the expectation of a July 1, 2016, effective date. For example, if the state had \$1 million in debt for the first two quarters, at 4 percent per year, that is a straight \$10,000 per quarter. So over the six quarters in the current law, there would be \$60,000 worth of interest, but beginning in the third quarter of 2016, with the amended version of the language, first the interest would double to roughly 8 percent and, second, the interest would be applied not to just the original \$1 million, but to the \$1 million-plus interest that was accruing.

MR. ALPER said the committee has to make two decisions in addressing section 7: should the state switch to compound

interest in the first place, the deletion of which he believes was an inadvertent technical error, and secondly, should they increase the rates to make interest something more of a revenue neutral phenomenon for the state.

CHAIR GIESSEL asked how the interest is compounded: monthly, quarterly, annually.

MR. ALPER answered quarterly.

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He said slide 11 summarized the interest change section and that it's hard to quantify revenue impact, because they don't know what they are going to assess. The department completed the CY09 production tax assessments last week and the total was \$132 million, about one-third of that was interest. This is a change that will build up value over time; there is very little near-term impact. When it comes to oil and gas, it doesn't go to the General Fund (GF) anyway. Any tax conflict/appeal money goes to the Constitutional Budget Reserve (CBR). The only GF impact from this change will be the other industry taxes the chair referred to earlier.

CHAIR GIESSEL asked if the Tax Division took the full statutory limit to complete 2009 audits.

MR. ALPER answered yes and explained that they had to slow down their audits for a few years to build up to the new software and catch up with some things. They are doing 2010 and 2011 concurrently and should be caught up one year from now.

SENATOR STEDMAN said when they take money out of the CBR they are technically borrowing it and asked when they put interest back in, does that count as a partial repayment back to the CBR or is the whole amount owed from some other source. It's a nuance and he was curious.

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COMMISSIONER HOFFBECK answered that those would be new deposits to the CBR, so the liability would remain. However, he would confirm that.

CHAIR GIESSEL said she saw another appropriation to upgrade that software more.

MR. ALPER answered that the software contract was in excess of \$25 million originally; the full appropriation was \$34 million

and change to cover other costs involved with implementation and consulting services. The fiscal note for this bill is \$1.2 million. He explained that all DOR bills have some degree of a fiscal note involved in the reprogramming and testing. It is a laborious process. This one is bigger, frankly, because it is a more comprehensive bill, and because they are going to be changing the interest rate formulas in all 25 of the state's taxes makes it more of a comprehensive task.

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MR. ALPER said slide 12 illustrates what increasing the minimum tax does. A couple of different sections of the bill deal with the minimum tax itself, but section 12 is purely about the raise from 4 to 5 percent, as proposed by the governor. This slide shows the 35 percent production tax under SB 21 and both a 4 percent and 5 percent minimum tax after credits for FY17.

SENATOR STEDMAN asked if this slide takes the NOLs into account.

MR. ALPER answered no.

SENATOR STEDMAN said at some point they will want to see the impact from the NOLs.

MR. ALPER responded that if the NOLs were accounted for on this slide, in the second or third year of low prices the revenue would turn out to be about zero. This is a snapshot of the first year. If you start using NOLs against taxes, depending on how high the stack of NOLs is, it's going to drag the overall revenue curve down in the future years. That would not be so much a function of this year's price, but it would be a function of last year's NOLs.

SENATOR STEDMAN said that he therefore shouldn't expect revenue in the millions because at some point the potential couple billion in credits are going to be accounted against the state.

MR. ALPER agreed and said this graph assumes there isn't that drag of the NOLs from the past.

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He explained slide 13 was just more graphics showing the fiscal impact of increasing the minimum tax. Gross value at the point of production is roughly the equivalent of market price minus \$10 for the transportation cost to get it there. About \$160 million taxable barrels per year are produced, so 4 percent of whatever that would be, and then the additional 1 percent at

\$30/oil is about \$20 million, and it goes up as the price of oil increases to upwards of \$80 million at \$75/oil and then it drops off. And the reason for that is past \$75 to \$78/oil they are out of the minimum tax and into the regular tax, and so at higher prices there is no impact from increasing the minimum tax; it's purely an academic exercise.

He related that for all the years the state had a minimum tax, it never kicked in until the last months of 2014. That's roughly the fiscal impact of this specific section of the bill; for simple terms they have called it \$50 million, but it is actually a somewhat variable number tied to the price of oil.

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Meanwhile, elsewhere in the bill, Mr. Alper explained that more complex sections "harden" the minimum tax. He explained that SB 21 made the minimum tax stronger than it previously was, and it did so by saying that the sliding-scale zero to \$8/per-barrel credit for legacy oil on the North Slope (AS 43.55.024(j)) cannot go below the floor (slide 14). However, the other credits (arrows) can in fact under many circumstances go below that number all the way down to the so-called basement, to the zero percent production tax. Those include the Net Operating Loss Credit, the GVR eligible per barrel credit (fixed \$5/barrel for new oil), as well as the small producer credit, and the alternative credit (exploration credit). All of those can go below the floor, and the intent of the bill is to harden the floor, meaning those credits should also be held to 4 percent minimum tax rate.

CHAIR GIESSEL asked if small producer credits and alternative credits are both going away, true or false?

MR. ALPER answered that is true; the small producer and exploration credits would have a very limited short duration impact if the floor were hardened (slide 15).

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He explained that the exploration credits will be gone one year from now except for Middle Earth and the small producer credits will be phased out over the next seven, eight, or as many as nine, years.

MR. ALPER said there are really three different policy decisions before the committee and they all pertain to the North Slope:

1. Should the producers who have an net operating loss credit (NOL) be able to use those to go below the floor and should this

be retroactive to January 1 (the only section of the bill they have asked to be retroactive because of the current circumstance this year of receiving payments below the minimum tax and are hoping to backfill that (in the governor's original proposal))?

2. Should new oil production be allowed to pay at the zero rate?
3. Should everyone be forced to pay the minimum tax and not just the major producers?

CHAIR GIESSEL thanked Mr. Alper and said slide 17 was a good breaking point.

[SB 130 was held in committee.]

[5:30:11 PM](#)

CHAIR GIESSEL adjourned the Senate Resources Standing Committee meeting at 5:30 p.m.