

SENATE FINANCE COMMITTEE  
March 18, 2022  
9:22 a.m.

9:22:07 AM

CALL TO ORDER

Co-Chair Stedman called the Senate Finance Committee meeting to order at 9:22 a.m.

MEMBERS PRESENT

Senator Click Bishop, Co-Chair  
Senator Bert Stedman, Co-Chair  
Senator Lyman Hoffman  
Senator Donny Olson  
Senator Bill Wielechowski  
Senator David Wilson

MEMBERS ABSENT

Senator Natasha von Imhof

ALSO PRESENT

Dan Stickel, Chief Economist, Economic Research Group, Tax Division, Department of Revenue; John Crowther, Deputy Commissioner, Department of Natural Resources; Ryan Fitzpatrick, Commercial Analyst, Division of Oil and Gas, Department of Natural Resources.

PRESENT VIA TELECONFERENCE

Heather Heusser, Natural Resource Specialist, Division of Oil and Gas, Department of Natural Resources; Maduabuchi Pascal Umekwe, PhD, Commercial Analyst, Division of Oil and Gas, Department of Natural Resources.

SUMMARY

SB 62           GAS LEASES; RENEWABLE ENERGY GRANT FUND

SB 62 was SCHEDULED but not HEARD.

PRESENTATION: COOK INLET UPDATE BY DEPARTMENT OF NATURAL RESOURCES AND DEPARTMENT OF REVENUE

9:22:52 AM

AT EASE

9:23:01 AM

RECONVENED

Co-Chair Stedman relayed that the committee would not hear SB 62. The committee would consider updated presentations from the Department of Revenue (DOR) and the Department of Natural Resources (DNR) on the topic of a Cook Inlet update.

^PRESENTATION: COOK INLET UPDATE BY DEPARTMENT OF NATURAL RESOURCES AND DEPARTMENT OF REVENUE

9:23:56 AM

DAN STICKEL, CHIEF ECONOMIST, ECONOMIC RESEARCH GROUP, TAX DIVISION, DEPARTMENT OF REVENUE, discussed the presentation "Cook Inlet Update - Senate Finance Committee" (copy on file). He relayed that the purpose of the presentation was to provide information about production investment and state revenue, specific to Cook Inlet oil and gas.

Mr. Stickel looked at slide 2, "Acronyms":

ANS - Alaska North Slope  
AOGCC - Alaska Oil and Gas Conservation  
Commission  
Avg - Average  
Bbl - Barrel  
BOE - Barrels of Oil Equivalent  
CI - Cook Inlet  
CIT - Corporate Income Tax  
CY - Calendar Year  
Acronyms  
DNR - Department of Natural Resources  
DOR - Department of Revenue  
FY - Fiscal Year  
GVPP - Gross Value at Point of Production  
mcf - Thousand cubic feet  
mmcf - Million cubic feet  
PTV - Production Tax Value  
Ths - Thousands

Mr. Stickel spoke to slide 3, "Agenda":

- Oil and Gas Revenue Sources
  - Production tax and January 1, 2022 changes
  - FY 2020 - FY 2024 Cook Inlet oil and gas revenues
- Cook Inlet Oil and Gas Prices
- Cook Inlet Oil and Gas Production
- Non-North Slope Lease Expenditures
- Non-North Slope Tax Credits
- Petroleum Revenue by Land Type

Mr. Stickel expanded that he would discuss some of the activity and company spending related to tax credits. He noted that the chart at the end was included for reference and summarized that "not all oil is equal" in Cook Inlet just as on the North Slope.

Mr. Stickel referenced slide 4, "Oil and Gas Revenue Sources

- Royalty - based on gross value of production
  - Plus bonuses, rents, and interest
  - Paid to Owner of the land: State, Federal, or Private
  - Usually 12.5% or 16.67% in Alaska, but rates vary
- Corporate Income Tax - based on net income
  - Paid to State (9.4% top rate)
  - Paid to Federal (21% top rate)
  - Only C-Corporations\* pay this tax
- Property Tax - based on value of oil & gas property
  - Paid to State (2% of assessed value or "20 mills")
  - Paid to Municipalities - credit offsets state tax paid
- Production Tax - based on "production tax value"
  - Paid to State - calculation to follow

\* C-Corporation is a business term that is used to distinguish the type of business entity, as defined under subchapter C of the federal Internal Revenue Code.

[9:26:50 AM](#)

Mr. Stickel turned to slide 5, "Cook Inlet Production Tax: Before and Starting January 1, 2022," which showed a table.

He noted that there had been some recent changes to the production tax in Cook Inlet, which worked differently than the North Slope. For the Cook Inlet in particular, a company nominally paid a tax rate of 35 percent of production tax value. He explained that the production tax was the gross value of the oil and gas produced less allowable lease expenditures. There were no per-taxable barrel credits in Cook Inlet, and there was no minimum tax floor. There was a tax ceiling of \$1 per barrel of oil produced, and a tax ceiling averaging \$17.7 cents per thousand cubic feet of gas produced. The gas ceiling varied by property.

Mr. Stickel continued to address slide 5. He recounted that in 2016, HB 247 was passed and repealed most of the tax credits in Cook Inlet. The credits were phased out by January 1 of 2018. The change that took effect on January 1 of 2022 had to do with how gas was taxed. Prior to 2022, oil and gas were subject to net tax. A company that produced both oil and gas would allocate its lease expenditures between oil and gas in calculating the net tax.

Mr. Stickel continued his remarks. The change that happened in the current year was that gas production was now subject to a 13 percent gross tax, and all lease expenditures were now allowed to be deductible against the oil tax calculation. The change was in place as part of SB 138, which passed in 2014 and intended to support a major gas sale. The changes to the statutes for gas was taxed and how lease expenditures were allocated applied statewide.

Co-Chair Stedman asked Mr. Stickel to touch on the gas tax rate of 13 percent of gross value of point of production.

Mr. Stickel noted that prior to January 21, 2022, oil and gas were both taxed at 35 percent of production tax value with a tax ceiling in place. Beginning on January 31, 2022 oil was still taxed at 35 percent of production tax value, and the \$1/bbl tax ceiling still applied. Starting in the current year gas was taxed at 13 percent of gross value, and the \$17.7 cents per thousand cubic feet tax ceiling still applied.

Co-Chair Stedman asked if future presentations would show the tax ceilings.

Mr. Stickel informed that slide 6 would show a history and forecast of revenue for Cook Inlet.

[9:30:25 AM](#)

Mr. Stickel considered slide 6, "Cook Inlet Oil and Gas Revenue: Five-Year Comparison," which showed a table depicting two full years of history, the current fiscal year, and two years of forecast. He noted that the five years was broken out to see two full years with and without the recent tax changes. The property tax shown represented the state share of property tax only, and there was a similar amount of property tax levied by municipalities as well. The corporate income tax represented the total estimated corporate income tax for non-North Slope. The production tax did incorporate the tax changes that took effect on January 1.

Mr. Stickel continued that the department was forecasting that the tax ceilings would apply for gas. The estimate was that gas would be paying the \$17.7 cents per thousand cubic feet tax ceiling. The department was forecasting that oil would be paying only the private landowner royalty and hazardous release surcharge. The 35 percent net tax calculation was not expected to generate an oil tax liability for production tax. He pointed out that the shift to the 13 percent gross tax resulted in a tax increase for Cook Inlet. The state had been receiving a little under \$1 million per year in production tax, which was expected to increase to around \$7 million per year starting in FY 23.

Mr. Stickel addressed royalties, which included bonuses, rents, and interest, as well as the Permanent Fund and School Fund shares, which were the largest source of state revenue from Cook Inlet. He informed that DNR did not forecast Cook Inlet oil price or gas price explicitly. For Cook Inlet oil price, the department used the North Slope oil forecast as a proxy, because the values of the oils were fairly similar in the market. For gas prices the department used the prevailing value published by DOR, and assumed that the prices would increase with inflation going forward. He noted that DNR did produce an oil production forecast specific to Cook Inlet. For gas production, DNR took the most recent fiscal year production and assumed there would be stable production.

Co-Chair Stedman asked about slide 7.

Mr. Stickel displayed slide 7, "Cook Inlet Oil and Gas Prices," which showed a graph with two lines depicting the price of oil and gas over time from 2018 to 2031.

Co-Chair Stedman asked about a hypothetical scenario in which the price of oil stayed level at \$80/bbl, and whether the gas tax would also run horizontally.

Mr. Stickel explained that for DOR's forecast, the department estimated that, given that all the lease expenditures were deductible for oil, the department was not forecasting a net profits tax payment from oil. The department was forecasting very little in tax from oil, and that the \$17.7 cents per thousand cubic feet tax ceiling would essentially be the gas tax that was paid. He explained that slightly higher or slightly lower oil or gas forecast would not significantly impact the production tax revenue for Cook Inlet, but it would impact royalty.

Mr. Stickel explained that slide 7 showed a history and forecast of Cook Inlet gas and oil prices with oil price values on the left axis and gas price values on the right axis. He reiterated that the department used the forecast for Alaska North Slope oil as a proxy for Cook Inlet oil, and then assumed consistent growth with inflation for gas prices.

[9:35:19 AM](#)

Co-Chair Stedman asked for more discussion related to the forecast oil and gas prices and how it was tied to inflation.

Mr. Stickel relayed that for gas prices, DOR published the prevailing value for Cook Inlet gas prices. He continued that DNR used an official inflation assumption of 2.25 percent, which was incorporated into the forecast. He acknowledged that inflation was running a little higher lately. He summarized that the department took the most recent year of published prevailing value and assumed gas prices would increase by 2.25 percent.

Co-Chair Stedman understood there were long-term contracts in Cook Inlet, which meant production was tied up for several years. He asked if the contracts dictated what the

gas would be worth coming out of the ground. He added that Cook Inlet was a closed basin.

Mr. Stickel affirmed that the gas forecast was a "naïve forecast" with assumptions around production and price given the relatively small impact on state revenue. He acknowledged that there were definitely reasons gas prices could be higher or lower than the forecast.

Co-Chair Stedman doubted that there would be gas prices to the citizenry climb with inflation in perpetuity. He did not think it seemed logical with a closed basin and long-term contracts.

Mr. Stickel highlighted slide 8, "Cook Inlet Oil and Gas Production," which was a similar chart to the previous slide but for oil and gas production. He relayed that Cook Inlet was Alaska's first oil and gas basin, began producing in the 1950s, and peaked at 230,000 barrels per day of production in the early 1970s. The inlet had supplied the Southcentral gas market for many years with exporting gas to Asia. More recently for oil production, there had been a pretty significant increase when Hilcorp entered the inlet in 2012, which had coincided with some very generous tax credits offered by the state at the time.

Mr. Stickel continued that generally production of oil had been declining since 2015, since the bump in production. He noted that DNR forecasted Cook Inlet oil production and foresaw new projects that would stabilize production over the next decade. He reiterated that DOR and DNR did not explicitly forecast natural gas production, but assumed it would be stable going forward. He understood some reserves existed, so that companies could supply the market for the next several years. He thought the forecast was a reasonable assumption for modelling purposes.

[9:38:46 AM](#)

Co-Chair Stedman asked to go back to slide 7. He wanted to gain clarity on the concept on ever-increasing price increases based on inflation in a closed basin with long-term price contracts. He asked if the Regulatory Commission of Alaska (RCA) got involved in pricing of gas and utility issues in the Railbelt.

Mr. Stickel explained that the concept of the inflation adjustment was that in current dollar terms, the cost of the gas would be unchanged. The cost of operation and the cost of producing the gas would be similar. The only adjustment being made was for general inflation in the cost of anything. If the chart was shown in real terms, it would reflect a flat price.

Mr. Stickel looked at slide 9, "Non-North Slope Lease Expenditures," which showed a graph. He expanded that the story told by the graph was that if there were high oil prices, low taxes, and generous state support, there would be investment. There was significant capital investment in Cook inlet in the early and mid-2010's, spurred by the Cook Inlet Recovery Act in 2010 and provided very generous tax credits for drilling and exploration in the inlet. Coinciding with the act, Hilcorp entered the inlet in 2012 and had a focus on renewing and extending field life. More recently there had been a capital investment decline that followed the decline in oil prices starting the second half of 2014 as well as the repeal of most of the tax credits in Cook Inlet in 2016. The forecast expected fairly modest capital spending going forward. He commented that operating costs had been fairly stable, with a slight decline during the Covid-19 pandemic as some activities were scaled back. The department was expecting that the activities would bounce back in the current year and stabilize at a little over \$300 million per year.

Senator Hoffman thought the chart on slide 9 did not take into consideration what was happening in Russia, where sanctions were shutting down 600 million barrels of oil per day. He asked how the graph might be affected into the future if the sanctions continued.

Mr. Stickel stated that to some extent, the impact of what was happening in Russia was reflected in a higher expected oil price forecast. The department had made some adjustment to the lease expenditures forecasts to account for the potential that cost across the industry would be inflated a bit with the higher oil price forecast. He considered protracted disruptions to the market, and thought it was possible that a demand for more investment or a tighter market for services could potentially increase the cost of doing business.

[9:42:58 AM](#)

Mr. Stickel addressed slide 10, "Non-North Slope Tax Credits," which showed a chart of ten years of history and forecast for tax credits for non-North Slope. He cited that the chart was consistent with figure 8-4 of the Spring 2022 Forecast. He explained that DOR aggregated the data from Cook Inlet with all other activity outside of the North Slope for confidentiality purposes. The credits against tax liability included capital expenditure credits, net operating loss credits, well-lease expenditure credits, and small producer credits. Most of the credits had been entirely phased out for Cook Inlet. The "credits purchased" shown on the graph included capital expenditure credits, net operating loss credits, well-lease expenditure credits, exploration credits, gas storage credits, liquid natural gas (LNG) storage credits, and refinery investment credits. The large suite of credits available to non-North Slope had all been repealed and sunset. There were capital expenditure and net operating loss credits that remained available outside of Cook Inlet and outside of the North Slope in the remaining area of the state colloquially known as "Middle Earth."

Mr. Stickel noted that the changes put in place in 2016 led to the phase-out of the availability of the credits by 2018. Given the state budget issues over the previous several years, the full value of the credits available for purchase had not been appropriated each year. For FY 22, there was \$54 million appropriated for purchase of tax credits, \$18 million of which went to non-North Slope credits. The outstanding balance as of the end of FY 22 was expected at \$264 million for non-North Slope credits, out of \$532 million statewide. The chart showed how the remaining tax credits specifically for non-North Slope credits would be paid off, assuming the statutory appropriation for tax credits were made beginning in FY 23. He pointed out that given the higher price and revenue outlook in the spring forecast, he expected the entire balance of the credits would be retired by 2024.

Co-Chair Stedman expected the committee would not use the forecast to calculate the credits.

Mr. Stickel understood. He noted that the appropriation would be slightly less with a lower oil price.

Co-Chair Stedman relayed that the matter would be worked out at a later time depending upon what the members wanted to do. He thought he thought there would be a meeting dedicated to the subject.

[9:46:39 AM](#)

Senator Olson agreed with Co-Chair Stedman. He asked about the non-North Slope tax credits and asked if the reasoning for getting rid of the credits was due to the ability to sell the credits or if it was to do with net operating losses.

Mr. Stickel thought he should not speak to the policy decisions behind repealing the credits.

Co-Chair Stedman followed up on Senator Olson's question. He thought the slide showed substantial credits in Cook Inlet. He mentioned that many members were concerned about the negative cash flow from Cook Inlet around 2012 through 2015. He asserted that the legislature wanted to assist the industry in staying viable, but still had to have some revenue coming in the door. He thought there was negative cash flow shown on the chart. He requested some data points from what Non-North Slope revenue had come into the state during the time, to see how policies had affected revenue and production, so there was a more realistic view of the matter. He recalled that the review of the escalating credits in Cook Inlet relative to the cash flow coming in had created a conversation with DNR and brought forward the issue of adjusting the credits. He thought the numbers were staggering.

[9:49:19 AM](#)

Mr. Stickel explained that for the presentation, the slide showed two years of revenue history. He pointed out an estimated total Cook Inlet oil and gas revenue to the state was \$68 in FY 20 and \$65 million in FY 21. He did not have the exact numbers going back farther, but could confidently say that for the years from FY 13 to FY 16 the credits purchased would have significantly exceeded state revenue from Cook Inlet.

Co-Chair Stedman suggested that in the future when the legislature made policy changes, it would be helpful to look back at numerics. He informed that the legislature had

been trying to stimulate gas production in Cook Inlet to alleviate potential brownouts. The component that was not reflected in the data was the changes Regulatory Commission of Alaska had made in allowing the price to move. Once the price moved, there was more gas than could be used from Cook Inlet. He opined that the state had overstimulated Cook Inlet by hundreds of millions of dollars. He asked Mr. Stickel to go up to FY 25 with the additional data points for the graph. He asked Mr. Stickel to use fair discretion about presenting the credits against revenue.

[9:52:24 AM](#)

Mr. Stickel advanced to slide 11, "Non-North Slope Tax Credits: Key Statistics":

- FY 2007 through CY 2021, \$0.1 billion of credits applied against production tax liabilities
- FY 2007 through CY 2021, \$1.6 billion of credits earned and eligible for state purchase
  - \$1.3 billion purchased through end of CY 2021
  - \$265 million outstanding as of end of CY 2021
- Legislative action has eliminated most Cook Inlet credits:
  - Qualified Capital Expenditure Credit, Well Lease Expenditure Credit, Net Operating Loss Credit all repealed January 1, 2018.
  - Eligibility for In-State Refinery and LNG Storage Facility Credits ended January 1, 2020.
  - Small Producer Credit remains: applicable to tax liability only, phasing out completely by 2024.
  - No per-taxable-barrel credits or carried-forward loss for Cook Inlet.

Co-Chair Stedman requested that Mr. Stickel back up the cash flow data to 2007 so it would match the time span on slide 11.

[9:53:59 AM](#)

Mr. Stickel looked at slide 12, "Non-North Slope Tax Credits: Correlation with Company Activity":

- For the \$1.3 billion of credits purchased through CY 2021:

- o Non-North Slope lease expenditures for companies receiving the credits totaled \$4.8 billion through CY 2020
    - Credit support averaged 27% of lease expenditures
  - o \$1.1 billion to companies with production by the end of CY 2020 (includes production by acquiring companies)
    - Total Non-North Slope production through CY 2020 of 154 million BOE
    - Credits to producers equate to \$7/ BOE or \$1.18/ mcf
  - o \$215 million to companies without regular production
- Credits per unit of production and as a share of lease expenditures will decrease over time due to additional production and spending

Mr. Stickel explained that slide 12 looked at the \$1.3 billion in tax credits for non-North Slope that were purchased and looked at what activity was seen from the companies that received the credits. The companies that received the \$1.3 billion in credit had \$4.8 billion in non-North Slope lease expenditures through the end of 2020. The credits amounted to about 27 percent of lease expenditures. He noted that for companies that had production there were about \$1.1 billion in credits that went to NNS companies that were in production, which worked out to about \$7/bbl equivalent, or about \$1.18 per cubic feet of gas equivalent. Additionally, there was about \$215 million that went to companies that did not have non-North Slope production. Some of the companies could have production in the future, but even if not there were benefits to the state from the activity that was done through DNR's data collection.

Co-Chair Stedman was a little concerned about companies that came forward for credits after producing nothing, and considered policy adjustments in the future to ensure the state got something back.

Mr. Stickel showed slide 13, "Non-North Slope Tax Credits: Correlation with Company Activity," which showed a chart showing how state petroleum revenues varied by land type. He cited the concept "not all oil is equal." He explained that production tax, corporate income tax, and property tax

applied everywhere in the state except federal waters three miles offshore. Royalty rates varied by ownership of the type of land it was on.

Co-Chair Stedman thanked Mr. Stickel for a response to the committee regarding the order of operations. He recommended that Mr. Stickel include the information on the effective tax rate and accumulation of credits year by year in the fall revenue forecast. He thought there was a couple billion in accrued credits, and he thought the information would help the legislature keep track of and understand the information.

[9:58:19 AM](#)

AT EASE

[9:59:11 AM](#)

RECONVENED

JOHN CROWTHER, DEPUTY COMMISSIONER, DEPARTMENT OF NATURAL RESOURCES, introduced himself.

RYAN FITZPATRICK, COMMERCIAL ANALYST, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, discussed the presentation "COOK INLET GAS MARKET BRIEFING FOR THE SENATE FINANCE COMMITTEE" (copy on file).

Mr. Fitzpatrick showed slide 2, "Agenda":

- Southcentral Gas Demand
- Cook Inlet Field Overview
- History of Cook Inlet Tax Credit Program
- Exploration and Development in Cook Inlet
- Future Production and Gas Reserves

Mr. Fitzpatrick advanced to slide 3, "SOUTHCENTRAL GAS DEMAND: DEMAND BY USER TYPE":

Kenai LNG Plant

- Nikiski liquified natural gas (LNG) facility is operated by, Trans-Foreland Pipeline Co. LLC - which is a sub of Marathon Oil
- Last exported LNG was 2015
- Department of Energy (DOE) authorization for exporting LNG expired in 2018
- Dec 2020 Federal Energy Regulatory Commission (FERC) approved LNG Imports to this facility an

annual capacity up to 1.8 billion cubic feet (bcf) per year.

#### Nutrien Fertilizer Plant

- 2nd largest ammonia/urea plant in U.S.
- Shut down and mothballed in 2007, however Nutrien maintains permits
- Gas prices relative to Lower 48 makes economics difficult
- Potential source for blue hydrogen/blue ammonia

Mr. Fitzpatrick spoke to the graph on the slide entitled 'Demand for Cook Inlet Gas,' which was broken down into different user types. The bottom four layers represented oil and gas operations in the Cook Inlet area. He pointed out that the four layers represented a stable base of about 75 billion cubic feet per year consumption in the Cook Inlet Region. He noted that going back to 2000, there was a little more variability in the power generation use for gas in Cook Inlet, which was due to a number of factors. He described differences in electrical efficiency both in end user level and in power generation. He used the example of a power plant put in place by Chugach Electric.

Mr. Fitzpatrick pointed out the red layer that represented the fertilizer plant, and the light green layer representing the Kenai liquid natural gas (LNG) exports. He noted that the export sources contributed a significant amount to gas demand going back to 2000. The fertilizer plant used gas to create ammonia fertilizer for export, and the Kenai plant was one of the very early LNG plants in the world and exported LNG primarily to Asia.

[10:03:42 AM](#)

Co-Chair Stedman recalled that the LNG plant had exported to Japan.

Mr. Fitzpatrick agreed, and described that the plant began operations in the 1960s, and exported LNG for a long period of time. He believed for a long while it was the only LNG export from the United States into the Asia-Pacific region.

Mr. Fitzpatrick continued to address slide 3. He observed that over time from the 2000's to the 2010's, the two export facilities were responsible for large amounts of the gas demand in Cook Inlet. Starting in the 2010's both uses

fell off rather dramatically and was responsible for a large amount of the decline for demand of gas in Cook Inlet. He made note of the black layer on the top of the graph that started around 2010, which represented a small amount of gas that was diverted from Cook Inlet up into the Interior LNG Project. The gas was liquified in Cook Inlet and exported to Fairbanks for primarily residential use.

Mr. Fitzpatrick continued to read information from the slide related to the fertilizer plant and the LNG plant.

[10:06:44 AM](#)

Mr. Fitzpatrick spoke to slide 4, "COOK INLET FIELDS OVERVIEW: PRODUCTION BY FIELD," which showed a table listing of the current producing fields in the Cook Inlet area. He noted there was a number of currently producing fields, although there were many owners in the inlet, Hilcorp was the predominant owner of many of the units. He pointed out that the table had information on the current 2021 production by field, and that gas production was expressed in billions of cubic feet, while oil was expressed in barrels per day. There were several fields producing oil in Cook Inlet, most of which also produced gas. He thought there was only one or two fields that produced oil but not gas. He noted that the predominance of fields in the inlet that produced only gas was one of the major differences between Cook Inlet and the North Slope basin. He cited that gas-only production was still capital intensive, but not as profitable as mixed oil and gas production, which presented certain challenges for producing gas in the Cook Inlet Area.

Mr. Fitzpatrick noted there was a map on the slide that showed the locations of the different fields in Cook Inlet. He thought the appendices of the presentation also contained the information. He added that there was a link on the slide to the department's website to see the larger map.

Co-Chair Stedman asked about the market saturation due to longer term contracts in the Cook Inlet area. He asked if the market was tied up for multiple years, or if there was huge capacity.

Mr. Fitzpatrick affirmed that the majority of the production in the Cook Inlet area was tied up in long-term

contracts. The majority of the gas production, going primarily to residential and electrical use, was tied up in long term contracts that were approved by RCA. The contracts had different pricing mechanisms, was sometimes there was a flat gas price and sometimes with provisions for escalations in gas price over the term of the contract. He continued that the other types of gas demand in Cook Inlet, for commercial uses and oil and gas operations, may be tied into long term contracts although the contracts were not subject to approval by the RCA.

Co-Chair Stedman wanted to reverse the question. He queried how much gas could be delivered to Anchorage without additional exploration and development in Cook Inlet, whether there was a one-month supply, five-month supply, or twenty-year supply.

Mr. Fitzpatrick thought a later slide would address the question, and would show remaining reserves in Cook Inlet.

[10:11:03 AM](#)

Mr. Fitzpatrick addressed slide 5, "COOK INLET FIELDS OVERVIEW: GAS PRODUCTION HISTORY," which showed two graphs that addressed historical production within the basin. The graph on the left showed the production from state leases by lessee, and the graph on the right showed total production in Cook Inlet by field and included the gross production including state, federal, and private leases.

Co-Chair Bishop asked if the private leases were comprised of pre-statehood homesteads and Native allotments.

Mr. Fitzpatrick affirmed that the number of private leases in Cook Inlet was relatively small, and the majority of the private leases were pre-state homesteading leases.

Mr. Crowther added that there was also some production from Alaska Native corporation owned land.

Mr. Fitzpatrick advanced to slide 6, "HISTORY OF COOK INLET TAX CREDIT PROGRAM: DESIGN AND PURPOSE," which showed a table of primary Cook Inlet credits versus other major tax credits. He cited that DNR's primary interest in the tax credit program was that a number of the credits required submission of data to DNR. He drew attention to the left-hand side of the table, which showed two credits that

required data submission, as well as one credit listed on the right. In order to qualify for the credits, companies had to certify and turn over data regarding the wells or the seismic exploration campaigns undertaken to earn the credits. The data could be used in-house for DNR's evaluations of different basins and fields.

Co-Chair Stedman asked if all the companies produced all the data that was required.

Mr. Fitzpatrick thought there was someone from the department available online to answer the question.

[10:14:49 AM](#)

HEATHER HEUSSER, NATURAL RESOURCE SPECIALIST, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES (via teleconference), answered in the affirmative. She explained that as a condition of the tax credit, companies had to submit the data prior to receiving the credit.

Mr. Fitzpatrick referenced slide 7, "DATA RELEASE THROUGH THE TAX CREDITS PROGRAM," which showed two maps and information regarding the seismic data release status and wellhead data release status of entities that utilized the tax credits program. In addition to being able to use the information within DNR, one of the provisions of the tax credit data program allowed the data to be released to the public. The areas shown in red were surveys that qualified for tax credits through the program, but the data had not reached the statutory holding period by DNR.

Mr. Fitzpatrick continued to address slide 7. The right-hand side showed information about wells using the tax credit program. All the data from the wells was publicly available, and free of charge for research institutions and government entities.

[10:18:23 AM](#)

MADUABUCHI PASCAL UMEKWE, PHD, COMMERCIAL ANALYST, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES (via teleconference), spoke to slide 8, "EXPLORATION & DEVELOPMENT IN COOK INLET: 2000 THROUGH 2021," which showed the count of wells that had been drilled since 2000. He drew attention to the top left, which showed the different categories of wells. On the lower left there was a bar

graph that showed the well count by class over the period. The blue bars showed the exploration wells and rust bars showed stratigraphic test wells, both of which were drilled as part of exploration activity by operators in Cook Inlet.

Mr. Umekwe thought it was easy to see there were years in which no wells were drilled, around 2007 and 2008, after which there was a surge. He mentioned incentives for exploration. He noted that lately there were more stratigraphic wells drilled, which were a fraction of the cost for full-blown exploration wells. The wells would help with understanding the structure and stratigraphy in areas of interest.

[10:20:38 AM](#)

Mr. Fitzpatrick turned to slide 9, "EXPLORATION & DEVELOPMENT IN COOK INLET: COOK INLET FUTURE PRODUCTION," which showed two different graphs. The top graph represented several gas reserves surveys that had been conducted over a number of years. He observed that updates to studies showed the total estimated production out of the Cook Inlet basin over its expected life. The grey bars represented the amount of gas produced to date. He noted that there was fluctuation in the graphs as the studies used different methodologies or different assumptions. The blue bars at the top represented the estimated remaining amount of gas reserves in Cook Inlet.

He observed that from the 2009 to 2018 studies there was somewhere between 700 billion cubic feet to 1.1 trillion cubic feet was the estimated remaining reserves and expected to be produced out of existing fields, absent reserves replacement due to further exploration activity. Using information from the graph depicting demand, he estimated that there was somewhere between 10 to 15 years gas demand that was able to be supplied out of the Cook Inlet Basin.

Mr. Fitzpatrick continued to address the slide. He explained that the exploration activity contributed to the total gas remaining reserves, which was part of the reason for change over time over the total expected production from the inlet in studies. He cited that starting in 2009, studies showed 8.9 trillion cubic feet of gas expected to be produced out of the basin, up to the most recent study that showed 9.3 trillion cubic feet of gas. He explained

that DNR was going through the process of updating the study with current market conditions and technology.

Co-Chair Stedman asked to advance to the next slide to address exploration and development.

[10:24:43 AM](#)

Mr. Fitzpatrick addressed slide 10, "EXPLORATION & DEVELOPMENT IN COOK INLET: COOK INLET UNDISCOVERED RESOURCE":

- Undiscovered, Technically Recoverable Oil & Gas (USGS, 2011):
  - mean conventional oil 599 MMBO
  - mean conventional gas 13.7 TCF
  - mean unconventional gas 5.3 TCF
- Undiscovered, Technically Recoverable Gas:
  - 1.2 TCF additional mean resource assessed in Southern Cook Inlet OCS (BOEM, 2011)
- In general, access to additional area provides opportunities for locating and commercializing currently undiscovered resources.

Mr. Fitzpatrick explained that the slide showed some estimates of the remaining undiscovered or potential oil and gas reserves in Cook Inlet. He reviewed the numbers on the slide and noted that the Bureau of Energy Management primarily looked at offshore gas reserves in federal waters. He summarized that there was the potential for additional gas exploration, development, and production into the Southcentral market, based on resources the studies indicated were yet undiscovered.

Co-Chair Stedman did not think "technically recoverable" was necessarily the same as "financially recoverable." He asked Mr. Fitzpatrick to comment.

Mr. Fitzpatrick agreed that "technically recoverable" affirmed that the gas was recoverable using existing technology, however the concept did not apply an economic filter to the potential reserves. Although it was possible to technically recover the resource, the cost might be more than the current price of gas the Southcentral market would

be able to bear. He pondered that prices over time would be expected to rise as gas was produced from smaller and more difficult reservoirs that cost more to produce.

Mr. Fitzpatrick explained that it was not possible to quantify the cost to produce undiscovered resources until discovered and quantified with a plan of development. He thought it was possible that there was an undiscovered resource that was large and very cheap to produce, however over time the likelihood was that the gas resources tended to be in smaller or more difficult to produce reservoirs.

Co-Chair Stedman thanked the departments for presenting. He intended to schedule time for the remainder of the presentation.

Mr. Fitzpatrick relayed that the majority of the remaining slides either dealt with the bill that the committee removed from the agenda or were appendices.

Co-Chair Stedman avowed to be in communication on the matter.

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ADJOURNMENT

10:29:56 AM

The meeting was adjourned at 10:29 a.m.