

**ALASKA STATE LEGISLATURE
HOUSE SPECIAL COMMITTEE ON ENERGY**

April 11, 2012
7:08 a.m.

MEMBERS PRESENT

Representative Neal Foster, Co-Chair
Representative Lance Pruitt, Co-Chair
Representative Bob Lynn
Representative Dan Saddler
Representative Pete Petersen
Representative Chris Tuck

MEMBERS ABSENT

Representative Kurt Olson

OTHER LEGISLATORS PRESENT

Representative Mike Chenault
Representative Kyle Johansen
Representative Bob Miller
Representative Charisse Millett
Representative Paul Seaton

COMMITTEE CALENDAR

HEARINGS RELATED TO THE SHORT- AND LONG-TERM STABILITY AND
RELIABILITY OF GAS FROM THE COOK INLET FIELD

- HEARD

PREVIOUS COMMITTEE ACTION

No previous action to record

WITNESS REGISTER

PAUL DECKER, Petroleum Geologist
Resource Evaluation Section Manager
Division of Oil and Gas (DOG)
Department of Natural Resources (DNR)
Anchorage, Alaska

POSITION STATEMENT: Provided a PowerPoint presentation
entitled, "Cook Inlet Activity and Natural Gas Resource Update"
dated 4/10/12, and answered questions.

ROBERT (BOB) SWANSON, State Geologist and Director
Division of Geological & Geophysical Surveys (DGGS)
Department of Natural Resources (DNR)
Fairbanks, Alaska

POSITION STATEMENT: Participated in the PowerPoint presentation entitled, "Cook Inlet Activity and Natural Gas Resource Update" dated 4/10/12, and answered questions.

TOM WALSH, Managing Partner
Petrotechnical Resources of Alaska (PRA)
Anchorage, Alaska

POSITION STATEMENT: Provided a PowerPoint presentation entitled, "Cook Inlet Gas Supply Study Update" dated 4/10/12, and answered questions.

ACTION NARRATIVE

[7:08:06 AM](#)

CO-CHAIR LANCE PRUITT called the House Special Committee on Energy meeting to order at 7:08 a.m. Representatives Pruitt, Foster, Tuck, Petersen, Saddler, and Lynn were present at the call to order. Representatives Chenault, Johansen, Miller, Millett, and Seaton were also present.

HEARINGS RELATED TO THE SHORT AND LONG TERM STABILITY AND RELIABILITY OF GAS FROM THE COOK INLET FIELD

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CO-CHAIR PRUITT announced that the only order of business would be hearings related to the short and long term stability and reliability of gas from the Cook Inlet field.

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PAUL DECKER, Petroleum Geologist, Resource Evaluation Section Manager, Division of Oil and Gas (DOG), Department of Natural Resources (DNR), provided a PowerPoint presentation entitled, "Cook Inlet Activity and Natural Gas Resource Update" dated 4/10/12. He said the presentation would begin with the high points of two natural gas studies conducted within the past two years on Cook Inlet exploration activity. The first study was completed in 2009, and took an engineering and geological approach to determine how much gas remains in the 28 known and producing gas fields in Cook Inlet. The emphasis of this study

was on reserves of potentially recoverable resource and examples of undeveloped gas leads. The 2009 study did not attempt to include an estimate of undiscovered gas resources in the basin. The 2011 study covered the commerciality of developing the reserves for market to meet the existing demand. This was done by generating dozens of development scenarios using hard data and Monte Carlo simulation to model the reserve resource's commerciality and production outcomes.

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MR. DECKER displayed slide 3 entitled, "Cook Inlet Natural Gas Reserves and Resources Hypothetical Production Forecast" which was a forecast of different volumes of gas identified with various types of geologic engineering analysis from 2010 forward. The most conservative forecast identified a volume of 863 billion cubic feet (bcf) remaining in existing wells throughout the basin. Furthermore, a material balance analysis revealed more reserves from remediated wells in the amount of 279 bcf throughout the basin. Additional volumes were from reserves identified by geologists as the category of natural gas volumes recoverable from reservoir sandstone layers that meet all the criteria used to identify viable production (PAY category). Other volumes were forecast by looking at well logs from PAY category reserves, and from "less confident" identification of PAY on the well logs, which is discounted at 50 percent risk. Finally, prospects from exploration leads were included in the forecast.

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REPRESENTATIVE TUCK observed that all of the decline curves are consistent.

MR. DECKER advised the rate of decline is determined by the rate of consumption. He pointed out that the graph shows the volumes as sequential; however, production and exploration could occur at the same time. Slide 4 entitled, "2011 DNR CI Gas Production Cost Study" illustrated how commercial the projects were by the sort of investment; for example, existing wells with no capital investment should recover about 660 bcf, and compression additions should recover about 288 bcf. Material balance and geologic analyses were included in the new well development estimate of resources of 638 bcf, and exploration leads were estimated at resources in the amount of 248 bcf. Mr. Decker noted that these figures are the "mean case," specifically identified with concrete projects, before the completion of the

commercial analysis. Slide 5 entitled, "Summary and Conclusions 2011 DNR Study" indicated: The Cook Inlet basin is capable given sufficient investment of continuing to supply the regional natural gas needs until about 2018-2020 with attractive rates of return. He opined this should spur investment, but the reason exploration is not seen in Cook Inlet has to do with its unusual gas market - which is not attached to the spot market - and suffers from huge seasonal swings in demand.

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MR. DECKER displayed slide 6 entitled, "Illustrative South-Central Alaska Daily Demand" which indicated the differences in wintertime and summertime demand: Demand on a peak winter day is nearly twice what it is on an average basis. He expressed his belief that natural gas storage will play an increasing important role in commercial deliverability and in spurring investment in the basin. Slide 7 entitled, "Gas Storage Design Rate & Capacity" indicated there are six approved gas storage projects in the inlet; three are currently online, the largest of which is the Marathon Kenai Field Pool 6 storage that has six bcf of storage capacity and sixty million cubic feet per day (MMcf/d) deliverability into the gas system. The CINGSA/SEMCO Cannery Loop Sterling C sands is the biggest new project which will add storage in the amount of 11 bcf of capacity and 150 MMcf/d of deliverability. He advised that adding storage and deliverability is "a big step" in tempering the effect of the seasonal swings by creating a year around market for gas. Slide 8 entitled, "Cook Inlet 2011 Lease Sale Results" described the successful 2011 lease sale that sold over 100 tracts totaling 575,202 acres for over \$11,000,000. Apache Alaska Corp. was the largest bidder, investing \$9,000,000. Slide 9 entitled, "Cook Inlet Oil and Gas Activity 2012" indicated there are present activities by companies such as Apache, Hilcorp, Furie, Buccaneer, Nordaq Energy, Anchor Point Energy, Cook Inlet Energy, CIRI, Linc Energy, and the expanded gas storage facilities.

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MR. DECKER displayed slide 11 entitled, "Alaska Exploration Wells Per Year 1960-2011" which indicated there was a lot of activity in Cook Inlet in the 1960s; there was an increase in drilling from 2002 to 2005; and there is an upswing now.

CO-CHAIR PRUITT asked what created the spike from 2002 to 2005.

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ROBERT (BOB) SWANSON, State Geologist and Director, Division of Geological & Geophysical Surveys (DGGS), explained in the early 2000s a lot of wells were drilled on the Kenai Peninsula looking at "bypassed pay" along the Kenai gas field, and offshore in a structure near Nikiski.

MR. DECKER displayed slide 12 entitled, "Cook Inlet Development Wells Per Year 1950-2011" which indicated many wells were drilled in the late '60s. He opined the tapering-off of development activity in the last few years is "not unlike we've seen in the past, but I think it has to do with uncertainty as to whether there is going to be additional capacity in the market." Slide 13 entitled, "Oil and Gas Resources vs. Reserves" explained the difference between resources and reserves: Resource is undiscovered and technically recoverable oil and gas estimated to exist in accumulations that have never been found by drilling. In addition, if resource is found, it can be produced using current technology. An unknown fraction of this category is commercial thus it is also known as prospective resource, because it does not occur in oil and gas fields, but in prospects.

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REPRESENTATIVE PETERSEN asked whether tax incentives provided by the state will encourage companies to look for prospective resource.

MR. DECKER said yes, this is part of the reason the jack-up rig was brought to Cook Inlet basin.

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REPRESENTATIVE TUCK understood that much of the Cook Inlet exploration was for oil, and gas was a byproduct. Because the new incentives from the state are now for gas, he asked how many of the explorers listed on slide 9 have indicated interest in the last five years.

MR. DECKER said most of them. Many independents have come into the basin, and the role of the major producers in exploration has decreased.

REPRESENTATIVE TUCK then asked whether the legacy companies are no longer interested in exploration because they seek oil and not gas.

MR. DECKER advised that Cook Inlet, when compared with other areas of the world, does not have a sufficient rate of return to hold the focus of large companies.

MR. DECKER returned to slide 13, saying that proved reserves are oil and gas which by analysis of geological data and engineering can be estimated with reasonable certainty to be economically producible, sometimes with a 90 percent certainty.

CO-CHAIR PRUITT observed "economic" means many different things.

MR. DECKER agreed; however, proved reserves are those that "producers want ... out of the ground," and developed reserves are one step higher in that they are proved reserves that can be expected to be recovered through existing wells without significant new investment. Slide 14 entitled, "Reserves and Resources Terminology" indicated the steps from undiscovered prospective resources to discovered commercial reserves, beginning with seismic data that identifies a prospective resource. After identification, the land is acquired, and drilling begins. If - as in 10-20 percent of the time - the drilled well makes a discovery, the resource becomes a contingent resource; one that is known, but the commercial value is unknown. After additional drilling, the project is refined, modeled, and sanctioned with cost analysis, environmental, permitting, and investor approval, and the resource is elevated to the category of reserves. Finally, after development, the category becomes proven and developed reserves.

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MR. SWANSON directed attention to the U. S. Geological Survey (USGS) estimates of technically recoverable resources in the basin. The USGS has been working with the state for five years to understand the geology in the basin and perform its analysis. He explained the statistics of gas exploration in the basin through time:

- 85 percent was discovered in the '60s during oil exploration until Prudhoe Bay was discovered and attention was turned north.
- Only structural traps were being prospected and drilled as the quality of the seismic at that time was poor, but

prospects now are "difficult to miss" with present technology.

- Nearly one in ten fields is greater than 2 trillion cubic feet (tcf) of gas.
- Four of the largest fields have 86 percent of the current known reserves.
- Field-size distribution lacks the size of discoveries between 300 bcf and 1.3 tcf.

MR. SWANSON displayed slide 16 entitled, "Cook Inlet Resource Potential USGS Resource Assessment 2011" and explained the work done by USGS was identifying the undiscovered technically recoverable oil and gas that does not have an economic filter, meaning that the USGS estimates include resource that may not be produced economically. A portion of the resource may be produced, and the estimates are referred to in "an arithmetic mean of a distribution." Mr. Swanson stressed that the range of possibilities is important; in fact, USGS is changing how it reports estimates and is now including the range of possibilities. In the Cook Inlet basin, USGS estimated an arithmetic mean of probabilistic distribution of about 600 million barrels of oil located in two assessment units: 372 million barrels in the tertiary sandstone play, from which all of the current oil production comes; and 227 million barrels in the Mesozoic sandstone play, which is a deeper part of the section. For gas, USGS assessed two conventional units: 12.2 tcf in the tertiary sandstone play, from which all of the current gas production comes; 1.5 tcf in Mesozoic sandstone; and two unconventional units: 0.6 tcf in the Mesozoic tight sandstone play; and 4.7 tcf in the tertiary coalbed play.

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MR. SWANSON displayed slide 17 entitled, "USGS Assessment of Cook Inlet Undiscovered Technically Recoverable Resources" and pointed out the mean for undiscovered resources of gas in tertiary sandstone was 11,992 bcf of gas; however, there is a wide range between the low and high estimates of 2.8 tcf and 24.4 tcf, which suggests that these estimates are based on limited information. Importantly, when the range of estimates is narrow around the mean that suggests there is a tremendous amount of information from 3-D seismic data and many wells. He cautioned that when looking at the estimate currently getting a lot of attention - total undiscovered gas resources of 19,037 bcf - one must understand that there are many assessment units contributing to that number, and pay attention to the wide range around the mean.

CO-CHAIR PRUITT clarified that recoverable is different from economical, in that the mean might be 19 tcf, but the total may be only a portion of that.

MR. SWANSON indicated yes, this estimate represents the potentially technically recoverable resource and not what will be found, what is economic, or what is accessible.

REPRESENTATIVE PETERSEN surmised there is a 95 percent chance that there is 2.8 tcf of gas, and at the current rate of consumption that supply would last close to 30 years.

MR. SWANSON agreed. He turned attention to the amount of work put into the assessment, noting USGS performs analyses on many basins around the world. For example, assessment input is garnered from fields, seismic, the study of geologic features such as rocky outcrops and reservoir distributions, detailed rock analysis, and stratigraphic understanding. After the data is compiled, USGS compares the petroleum system models to a global database of known basins. Slide 19 entitled, "Log Normal Distribution of Gas Accumulation Size" was an example of the distribution of field sizes in the model, thus revealing how many fields of what size make up the total resource base.

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MR. SWANSON, in response to Representative Saddler, explained that continuous oil and gas resources such as shale gas and oil plays and coalbed methane are often seen in the Lower 48; instead of migrating into a reservoir, the hydrocarbon is in place where it was generated. He returned attention to slide 19, saying a key part of the study is the size of the field which is compared to known basins. Most of the fields globally are small; however, in Alaska - on the North Slope and in Cook Inlet - the fields are huge. Slide 20 entitled, "New Gas from New Exploration Play Types" pictured oil and gas trapping structures: anticline, normal fault, stratigraphic, and thrust fault. Mr. Swanson advised that the more complicated structures in Cook Inlet such as normal fault, stratigraphic, and thrust fault, have not been explored for gas. Slide 21 entitled, "'New' Gas in Existing Fields" illustrated discontinuous sands that have not been tapped by the existing wells, such as those found at the Beluga River gas field. Slide 22 was seismic data from the northwest side of the basin which showed a very large structure approximately two and one-half miles deep. Large

structures like this were easily found in the '60s, but the very subtle plays in the footwalls of the folds of the large structures have not been explored because of the expense.

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MR. SWANSON further explained what is unexplored in the basin are the plays that are stratigraphically-controlled sand bodies not found in a large structure. Their existence is detected by USGS from seismic lines, features, and signs in the layers of rock. Another very important part of the story is exploration maturity. Slide 25 was a depiction of the exploration activity in Wyoming compared to that of Prudhoe Bay. Wyoming has 70,000 exploration wells, Prudhoe Bay has 500, and Cook Inlet has 350; thus the level of exploration in Alaska is miniscule compared with other resource-rich areas. The tight level of exploration that is seen in Wyoming resulted in a dramatic increase in its proved reserves and additional gas produced from "unconventional" continuous-type resources such as sands and coalbed methane. Mr. Swanson stressed the key issue: To get to a proven reserve requires significant investment to advance from identified prospective resources. Hurdles to this process are: the market; whether there is more than one commodity such as oil and gas; and surface access to land. Slide 29 illustrated the ownership of the land in the basin by several entities, and closures due to Beluga habitat protection.

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CO-CHAIR PRUITT agreed that land ownership in the basin adds complexity to exploration.

MR. SWANSON returned to the subject of field sizes. Slide 31 listed the field sizes for 22 units in Cook Inlet, ranging from 6 bcf to 2,425 bcf. A chart of Estimated Ultimate Recovery (EUR) Field Size Distribution illustrated that fields which fall between a range of 301-400 bcf and 1,100-1,200 bcf in size have not yet been identified in Cook Inlet. In fact, USGS exactly predicted a field size of 35 bcf as the most common occurrence, and the chances of finding huge fields of 2-3 tcf are slim. Mr. Swanson then turned to the price of natural gas by state. Slide 34 entitled, "2007 Average Gas Price to American Consumer" showed that Alaska paid the lowest price for natural gas nationwide in 2007 - Alaska consumers have been paying the cheapest price for natural gas for the last 30 years - but this changed when shale gas became available. During the period from 2007 to 2010, shale gas production tripled, imports were reduced

by 11 percent, and the use of shale gas increased from 5 percent to 20 percent of the total volume used in the Lower 48. Recently, the Henry hub price for natural gas was \$2, and the price now paid by Alaskans is similar to what is paid in the Lower 48. In conclusion, he agreed with others that even though understanding resources in the basin is complex, there is a lot of undiscovered gas in the Cook Inlet basin; however, to access gas will take a tremendous amount of work and economics will come into play. He noted the next state lease sale is scheduled for May, 2012.

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REPRESENTATIVE PETERSEN asked whether increasing demand and the market by building a gas pipeline to Fairbanks and the refinery at North Pole, would make a positive difference in the amount of exploration.

MR. SWANSON suggested anytime there is an increase in demand and a constant market, there will most likely be an increase in exploration, but he could not say for sure.

REPRESENTATIVE PETERSEN recalled previous testimony that the size and age of Cook Inlet should have led to two or three times more drilling and, if so, more gas would have been produced.

MR. SWANSON observed that by 1968, 8.2 tcf of gas had been discovered in Cook Inlet, but there was no market. Afterward, the market was developed by the Agrium Inc., fertilizer plant, liquefied natural gas (LNG) exports, and local demand, but exploration efforts were turned to oil.

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REPRESENTATIVE SADDLER asked whether Cook Inlet basin is unique in the world.

MR. SWANSON advised Cook Inlet basin is not unique, but is not common either. It is a forearc basin, which means it is in front of the volcanic arc and contains volcanic detritus. What is relatively unusual is its thickness, which is all nonmarine.

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The committee took an at-ease from 8:04 a.m. to 8:06 a.m.

[8:06:30 AM](#)

TOM WALSH, Managing Partner, Petrotechnical Resources of Alaska (PRA), stated PRA is an oil and gas consulting firm in Anchorage which was commissioned in 2009 by ENSTAR, Chugach Electric, and Anchorage Municipal Light & Power (ML&P), to study the remaining Cook Inlet gas supply in existing fields. The purpose of the study was to determine when there would be a shortfall in the supply of gas. The study allowed the utilities to better understand: the impact and drivers of drilling/development; the results of an impending report by DNR; and when another source of gas would be needed. In 2012, PRA updated the supply study. Mr. Walsh returned to the 2009 study, and gave the reasons that utilities care about gas supply: ENSTAR is 100 percent reliant upon Cook Inlet gas for its consumption, which was 32.5 bcf in 2009; Chugach Electric is 90 percent reliant upon Cook Inlet gas for its consumption, which was 26 bcf in 2009; and ML&P is 88 percent reliant upon Cook Inlet gas for its consumption, which was 10.8 bcf in 2009. The total 2009 consumption by Cook Inlet utilities was approximately 90 bcf of gas.

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REPRESENTATIVE TUCK recalled in 2010 Cook Inlet exploration was incentivized by legislation, and pointed out that gas storage is now available. He asked whether the utilities' concern dates back to 2009, or is present today.

MR. WALSH advised the 2012 update was to the forecast; however, the concern from 2009 remains today. Although there is gas storage in the basin operated by the producers, and gas is flowing into the reservoir, the issue is not resolved in the long-term.

CO-CHAIR PRUITT clarified that gas is flowing into the reservoir, but the system is not fully online.

MR. WALSH presented slide 4 entitled, "Cook Inlet Fields" which was a map showing 2011 gas production. Major producers were: Beluga River Unit, 27 percent; Trading Bay Unit (TBU), 21 percent; North Cook Inlet (No. CI), 13 percent; Ninilchik, 11 percent; Kenai Unit, 11 percent; and others, 15 percent. He stated the study concentrated on producing assets - their current production and history - in order to forecast their future production. Slide 5 entitled, "2009 Combined Utility Met and Unmet Gas Demand" illustrated the growing uncontracted demand beginning in 2011, and increasing through 2019. Mr. Walsh said this projection of "giant" unmet demand is a driver

for Cook Inlet gas development. Slide 6 entitled, "Annual Supply - DNR 2009 Report" showed the historical gas production from 1995 to 2010, which serviced not only local electrical usage and heating demand, but also supplied exported LNG and the Agrium plant. The PRA study primarily looked at the decline curve analysis provided by DNR, focusing on the existing fields and what the existing fields are producing. Exploration potential or other future activities on the horizon were not considered.

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MR. WALSH stated the objectives of the study:

- Review DNA reserve analysis: DNR conducted a comprehensive geologic study, looking at the potential of what might exist in the basin; however, PRA was looking at very short-term supply options which could be brought online from existing assets. The utility companies also asked PRA to review and provide prospective to DNR's analysis.
- Review the deliverability of Cook Inlet gas wells drilled from 2001-2009: PRA looked at how rapidly the wells have declined to create a forecast for future production. The consideration of well history is a standard means of determining future production.
- Forecast deliverability of existing and future gas wells: From the aforementioned review, PRA forecast the existing well-set, what the wells could produce in the future, and what could be recovered from drilling additional wells.
- Analyze timing required for delivery of non-Cook Inlet gas sources: Bringing gas to Cook Inlet basin in order for the utilities to continue to operate revolves around importing LNG or obtaining gas from the North Slope.

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REPRESENTATIVE TUCK asked whether PRA's analysis shows how much gas is available for consumers in Alaska, now that the Agrium plant is no longer in operation and LNG is no longer exported.

MR. WALSH said yes, that is reflected in the decline of the demand curve shown during the 2012-2013 timeframe. He continued to slide 9 entitled, "Study Methodology" which indicated the following:

- Field-level decline curve analysis: PRA looked at Alaska Oil and Gas Conservation Commission (AOGCC) records of production for gas fields which show what the fields have

produced on an annual basis, and from that projected production and the remaining reserves for those fields.

- Individual well decline curve analysis on the five largest fields: Studied to get a better feel for what could be expected from new wells.
- New well initial production (IP) decline through time: PRA looked at the decline curve analysis from individual wells and predicted what new wells would contribute to future production based on the acceleration of production from existing assets.
- Calculate activity required to meet future demand: Sought to determine the number of wells needed to be drilled every year to continue to operate utilities.
- Plan of Development (POD) review: Studied the plan for each field that deals with what development might occur to ascertain what operators might be doing in the next year.
- Analysis of business drivers: Searched for what is driving the producers to drill more wells and spend more money in Cook Inlet basin.

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MR. WALSH displayed slide 10 entitled, "Cook Inlet Drilling Results" and explained that the drilling results were split into two periods to show whether there were changes in the amount of gas discovered per well. From 2001-2009, 128 gas wells were drilled and 105 were completed, of which initial production was an average of 3.6 MMcf/d per well. From 2007-2009, 34 wells were drilled and all were completed, and the average production was 3.1 MMcf/d per well. This is significant because as wells are drilled in a mature basin, less gas is expected from each well, and the level of decline is factored into the analysis.

REPRESENTATIVE PETERSEN surmised the areas where the new jack-up rigs are drilling are areas where there is no current production, thus would not be subject to the decline curve.

MR. WALSH said correct, successful exploration by the jack-up rigs was not involved in this analysis.

REPRESENTATIVE TUCK referred to slide 10 and asked whether the wells depicted there are new wells drilled into existing fields, or wells drilled beyond existing fields.

MR. WALSH responded that these are new wells into existing, producing fields. Some also represent production from intervals that were not producing before, and some may intersect layers of sediment that have not been produced, which would be virgin pressures. However, most are infield wells drilled into producing zones.

REPRESENTATIVE TUCK referred to slide 4, and asked whether the existing fields are all attributed to the five major producers, or whether the 15 percent produced by other companies is also represented.

[8:24:32 AM](#)

MR. WALSH said the reported activity does include the 15 percent of production by other companies. Slide 11 entitled, "Cook Inlet Gas Development" illustrated the expected downward trend in the number of cubic feet of gas produced by each well during the 2001-2009 time period. Slide 12 entitled, "Cook Inlet Gas Production Forecast from Decline Curve Analysis, PRA and DNR 2009 Studies" compared the results of the DNR and PRA studies. Generally, forecasts from both studies are close; in fact, PRA agrees with DNR in terms of what is expected to be produced from existing assets. He said there were no discrepancies between the studies and both found that - according to the 2009 data - supply problems will arrive by 2013. The PRA study concluded that significant new activity is required to keep production at a level that will support the utilities in the future. Slide 14 entitled, "Annual Supply and Demand" indicated that the demand forecast is about 90 bcf per year, and the supply forecast drops below the demand forecast during 2013, which is the date the utilities needed to know. The drop in the demand forecast from 2009 to 2011 is due to a reduction in LNG exports and the closure of the Agrium plant, which, in turn, were due to the disappearance of excess gas supply. Mr. Walsh pointed out the Southcentral market for gas is too small to interest companies such as ConocoPhillips, Marathon, and Chevron. The two drivers for this commodity are cost and the size of the market, and creating a larger market will attract interest.

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CO-CHAIR PRUITT asked for the potential effects of the loss of the export market on exploration and production.

MR. WALSH advised that in the past the LNG export served as gas storage, in terms of keeping gas wells flowing during low demand

from Southcentral. The export of LNG is a great anchor tenant, and he opined the export of LNG may happen again in the future if exploration is successful and gas can be stored during the summer.

REPRESENTATIVE TUCK observed there will always be a field consistently in decline. He asked how many wells have been discovered from 2009-2012.

MR. WALSH said that information will follow.

REPRESENTATIVE TUCK heard previous testimony in 2009 from Armstrong Oil Company that Cook Inlet fields are typical to other fields, and that new wells will produce more gas. Since the state has taken action to incentivize the exploration for gas, he inquired as to whether there will be a proliferation of drilling, as in Wyoming.

MR. WALSH answered that the major difference between Cook Inlet gas and Wyoming gas is Wyoming's direct link to market via pipelines; however, now there is too much gas for the market in the Lower 48. Alaska's market is limited, and completely disassociated with the Lower 48 market; in fact, the PRA study revealed that a small market prevents large companies from exploring and developing gas. The state's incentives for exploration and production have brought jack-up rigs to Cook Inlet, but the big issue is the market. Slide 15 entitled, "Scenario in 2009 Study" indicated that if the current trends in drilling success rates continue, an estimated 185 new wells must be drilled between now and 2020 to meet the demand of the utilities. Slide 16 entitled, "Cook Inlet Supply and Demand PRA Forecast December 2009" indicated if there is development and 185 wells are drilled, the demand curve will be met to 2020. Slide 17 entitled, "185 Wells Completed 2012 to 2019 Meet Demand Through 2020" illustrated that no wells were completed in 2010 and 2011, thus an average number of 13.6 wells per year must be drilled in the subsequent years. Mr. Walsh estimated the cost of drilling and development to meet demand in the coming decade is \$1.9 billion \$2.8 billion. Moreover, higher production costs will lead to higher local prices for natural gas. The 2009 study also found that near-term drilling must be successful or gas resources from outside the Cook Inlet could be required as early as 2013; in fact, the only viable option is importing LNG. He stressed that this is the bottom line - there is no other means; however, the need to import LNG could be temporary because the USGS and DNR have established that gas is available in Cook Inlet. Slide 20 entitled, "2009 Summary" illustrated

the gap between the supply and demand, based on the decline curve analysis by DNR and PRA.

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CO-CHAIR PRUITT clarified that the estimated cost of \$1.9 billion to \$2.8 billion in investment is only to meet the supply of the Southcentral utilities, and does not include supplying gas for LNG exports, Fairbanks, or Donlin Creek.

MR. WALSH said correct. Slide 22 began the 2012 update by PRA, which was tasked by Cook Inlet utilities to look at the results from the drilling campaign of the last three years and repeat its forecast. The update found that due to drilling activity and compression additions since 2009, the predicted shortfall from existing fields has changed from 2013 to 2014. Slide 23 entitled, "Forecast Changes since 2009 Study" illustrated two graphs that showed a slight increase in the supply forecast due to investment in drilling activity and the added compression, and a slight decrease in the demand forecast until Donlin Creek comes online in 2019. Slide 24 entitled, "Changes in Supply Forecast" showed the material increases in the supply forecast were due to performance in wells mainly in the Beluga River, Trading Bay, and Ninilchik Units where a total of eight new wells have been drilled and compression has been added to bring gas to pipeline pressure. Slide 25 entitled, "2009-2011 Drilling Activity and Production Adds" indicated that between 11/09 and 10/10 five new completions added 18.5 MMcf/d to production, and between 11/10 and 10/11 six new completions added 9.9 MMcf/d to production. Mr. Walsh concluded that production from significant new wells pushed out the shortfall to 2014. Turning to changes in the forecasted demand, he said PRA expects reductions after the three or four final cargoes of LNG in 2012, and because of a new, more efficient Chugach Electric Association, Inc., (CEA) plant. Additional demand will be for Homer Electric Association, Inc. (HEA), Matanuska Electric Association (MEA), field fuel and flare, and the Donlin Creek startup in 2019. Thus a shortfall of 7.3 bcf per year is now predicted to occur in 2014. Slide 28 entitled, "Sensitivity: Current Fields plus 3-4 New wells per year going forward" indicated that even with three to four new wells drilled each year in the next seven years - resulting in ten MMcf/d of gas - there would still be a shortfall in 2014. However, six to eight new wells per year pushes the shortfall out to 2015.

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CO-CHAIR PRUITT questioned whether storage, although helpful during periods of peak demand, will help meet the annual demand of gas.

MR. WALSH explained the study "assumed perfect storage" which means the study looks at annual averages of production, not peak periods. As a matter of fact, Southcentral has come close to not meeting peak demand already.

REPRESENTATIVE PETERSEN has heard that 10 to 12 new wells will be drilled this year with more expected. He projected this would push the shortfall to 2018.

MR. WALSH acknowledged that there is significant activity in the basin; however, exploration activity is too far in the future to boost production immediately. In the long-term, a multi-tcf find would flood the market and exports would have to be reopened. The study seeks development aspects in existing assets.

CO-CHAIR PRUITT expressed his belief that the state's incentives are to benefit assets outside of known areas and that have not been previously explored.

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MR. WALSH said correct. In the short term, those activities are beyond consideration by this report in that they will not help the utilities in the next two to three years. Slide 30 entitled, "Summary of CI Shortfall Cases" indicated that continuing with present production will result in a shortfall of 7.3 bcf per year beginning in 2014; adding 10 MMcf/d from new wells will result in a shortfall of 1.0 bcf per year beginning in 2014; adding an annual average of 20 MMcf/d from new wells will result in a shortfall of 1.6 bcf per day beginning in 2015. Mr. Walsh concluded that absent major new discoveries that can be brought online in one to two years, the current pace of development will mean a shortfall in Cook Inlet supply to meet demand in 2014 or 2015.

CO-CHAIR PRUITT inferred that even with major successful new finds, there will be a shortfall.

MR. WALSH said yes.

REPRESENTATIVE TUCK restated that the 185 wells referred to in slide 15, and the production by the five majors in Mr. Walsh's conclusion are in known fields, and are not new exploration, thus are known. He returned attention to slide 6 and asked whether the green tranche identified as "Geologic Analysis, PAY Category Reserves" represents reserves from known fields.

MR. WALSH affirmed Representative Tuck's first statement. In further response to Representative Tuck, he clarified that the PRA study more closely aligns with the orange tranche, identified as "Material Balance Analysis Reserves" representing existing, producing assets. The DNR study indicated that the reserves represented by the green tranche could be brought on in existing assets, but PRA disagreed. However, he pointed out that the operating companies have aggressively pursued all opportunities to produce more gas from their existing assets.

CO-CHAIR PRUITT observed the green tranche is the difference between the opinions of geologists and engineers.

MR. WALSH, speaking as a geophysicist, opined that there is more gas in Cook Inlet but it may not be economical or online in time to meet demand.

REPRESENTATIVE TUCK restated that the reserves in the green tranche are known fields, and should be started with first.

REPRESENTATIVE SADDLER asked how to characterize the economic impetus for more drilling in Cook Inlet, considering the current relatively low prices for gas.

MR. WALSH said the study indicated that one of the business drivers is the cost of the commodity, and suggested that Southcentral's distinct, local, and small market must find another way to attract companies. Higher prices for gas will incentivize more development, but it is hard to use the export of LNG to grow the market if there is no gas. Also, the recent changes in the operators of Cook Inlet assets are a factor.

REPRESENTATIVE SADDLER asked whether the large demand for manpower and equipment elsewhere will affect the quality and rate of production by the companies in Cook Inlet.

MR. WALSH agreed that there has been a draw by the Lower 48 on manpower and talent out of the state. However, this key factor was not addressed in the study. In further response to Representative Saddler, he said he was unable to assume whether

this factor would affect either way the rates of success or effective, efficient drilling production by the companies.

REPRESENTATIVE PETERSEN directed attention to slide 5, and asked whether the contracts currently approved and under consideration by the Regulatory Commission of Alaska (RCA) are represented.

MR. WALSH said no.

REPRESENTATIVE PETERSEN recalled recent legislation granted 70 percent credits for the reimbursement of drilling costs, and assumed that more companies will show an interest in exploring Cook Inlet.

MR. WALSH related two companies are bringing in jack-up rigs, and expressed his surprise that there was not more immediate activity in response to the incentives.

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CO-CHAIR PRUITT referenced the cost of the investment needed to continue the gas supply and asked whether the cost of gas will stay the same for Southcentral consumers.

MR. WALSH advised gas commodity prices will definitely go up. He suggested that consumers "benchmark" against the costs of other realistic opportunities to bring gas to Cook Inlet, such as a pipeline from the North Slope, or LNG imports. These options will cost "significantly higher than what we are paying for natural gas right now." However, the knowledge that higher prices are coming will incentivize Cook Inlet exploration and development because companies will not be competing against "\$2 gas in the Lower 48."

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ADJOURNMENT

There being no further business before the committee, the House Special Committee on Energy meeting was adjourned at 9:06 a.m.