

**ALASKA STATE LEGISLATURE  
HOUSE SPECIAL COMMITTEE ON OIL AND GAS**

January 17, 2002

10:03 a.m.

**MEMBERS PRESENT**

Representative Scott Ogan, Chair  
Representative Hugh Fate, Vice Chair  
Representative Fred Dyson  
Representative Mike Chenault  
Representative Gretchen Guess

**MEMBERS ABSENT**

Representative Vic Kohring  
Representative Reggie Joule

**OTHER LEGISLATORS PRESENT**

Representative Joe Green

**COMMITTEE CALENDAR**

OVERVIEW AND UPDATE BY THE DIVISION OF OIL & GAS

OVERVIEW ON STATE OFFERING TO SELL "ROYALTY" GAS

**PREVIOUS ACTION**

No previous action to record

**WITNESS REGISTER**

PAT POURCHOT, Commissioner  
Department of Natural Resources  
400 Willoughby Avenue, Fifth Floor  
Juneau, Alaska 99801-1724

POSITION STATEMENT: Gave brief overview, introduced speakers from the Division of Oil & Gas, and answered questions.

MARK MYERS, Director  
Division of Oil & Gas  
Department of Natural Resources  
550 West Seventh Avenue, Suite 800  
Anchorage, Alaska 99501-3560

POSITION STATEMENT: Gave overview of oil and gas activities and answered questions.

KEVIN BANKS, Petroleum Market Analyst  
Division of Oil & Gas  
Department of Natural Resources  
550 West 7th Avenue, Suite 800  
Anchorage, Alaska 99501-3560

POSITION STATEMENT: Answered questions relating to the contract between Unocal and ENSTAR [Natural Gas Company].

WILLIAM NEBESKY, Petroleum Economist  
Division of Oil & Gas  
Department of Natural Resources  
550 West 7th Avenue, Suite 800  
Anchorage, Alaska 99501-3560

POSITION STATEMENT: Offered information relating to gas supplies in Cook Inlet.

BONNIE ROBSON, Deputy Director  
Division of Oil & Gas  
Department of Natural Resources  
550 West Seventh Avenue, Suite 800  
Anchorage, Alaska 99501-3560

POSITION STATEMENT: Gave overview addressing the state's process for a royalty-in-kind sale in the event of a major gas sale off Alaska's North Slope; answered questions.

#### **ACTION NARRATIVE**

TAPE 02-1, SIDE A  
Number 0001

CHAIR SCOTT OGAN called the House Special Committee on Oil and Gas meeting to order at 10:03 a.m. Present at the call to order were Representatives Ogan, Dyson, Fate, and Guess. Representative Chenault arrived as the meeting was in progress.

CHAIR OGAN reminded members that the legislature must approve any sale of gas. He noted that the producers had issued a letter [dated January 15, 2002] saying they are not in support of such a sale at this time.

#### OVERVIEW AND UPDATE BY THE DIVISION OF OIL & GAS

Number 0151

PAT POURCHOT, Commissioner, Department of Natural Resources (DNR), offered general comments as a prelude to discussion by Mark Myers and Bonnie Robson of the Division of Oil & Gas. Despite recent news of layoffs by some companies that operate in Alaska, he said "we have a lot of good news in the oil and gas industry in Alaska." He pointed out Alaska's tremendous, proven reserves of both oil and gas, "of national scale."

COMMISSIONER POURCHOT referred to a handout, "Alaska Oil and Gas Activities," dated January 2002. He highlighted that [Alaska] has 36 percent of the total U.S. oil reserves, in the amount of 8 billion barrels of oil; has 17 percent of the total U.S. gas reserves, in the amount of 35 trillion cubic feet of gas, almost entirely on the North Slope; and is producing 20 percent of the total U.S. oil production [the packet mentioned 1.04 million barrels of oil a day]. Although production is greatly reduced from earlier days, last year oil production increased for the first time in many years. Commissioner Pourchot mentioned the Alpine field, Northstar, and some smaller satellite fields that are adding to the production and countering the decline in the Prudhoe Bay field.

COMMISSIONER POURCHOT referred to the page of the handout titled "The State Revenue Pie, Petroleum Revenue sources, (FY 2001)." He clarified that DNR is responsible for the "royalty side of the picture," whereas the Department of Revenue collects the tax, particularly severance and corporate tax. Last year saw a 10 percent increase in state revenue from royalties, with about \$1.1 billion collected. While the amount of production and the price of oil clearly have much to do with that, DNR's Division of Oil & Gas has some very skilled, experienced people doing a lot of the day-to-day negotiating, unit work, leasing work, defining of lease terms, calculating of valuation, and audit of the royalty function. Commissioner Pourchot told members that all of those functions contribute significantly to Alaska's getting its fair share of oil and gas royalties.

Number 0473

COMMISSIONER POURCHOT offered general remarks about the current status of the state's royalty gas sale. He noted that in the last legislative session, the legislature was presented with a proposal by a group called Netricity and took a keen interest in the possibilities of using natural gas on the North Slope for electrical generation to run a computer server. The legislature had passed a resolution urging DNR to look into ways of perhaps

providing gas on the North Slope for that activity, with the mention of a royalty gas sale. He commented:

We always have the ability, under our oil and gas leases, to take either our oil or gas in-kind, which is to take delivery of gas or oil - our, the state's, royalty share, about, in most cases, an eighth - and do what we will with it. ... In the past, on the oil, for example, we've sold to Tesoro. We currently have a fairly large commitment of ... royalty oil to Williams up in the Interior for [refining]. And so, in the case of gas, we have those options also. Otherwise, we say what we term "in-value," which is ... we just allow our royalty to be shipped along with the producers' oil, in this case, to market, and then we get a netback price on the sale of our oil as the producers sell ... their oil.

Number 0607

So, beginning this summer after the session we continued to meet with Netricity. There were legal issues involved in just taking our gas without the producers' gas. We urged them to talk to producers, which they did. They began negotiations and discussions with producers for possible gas sources on the North Slope. We have not heard from them recently ... any further on their desires for North Slope, Alaska-owned, state-owned gas.

However, at the same time we were hearing from producer groups about the possibility of an open season for bidding or nominating capacity in a potential gas line, ... last summer it was told to us that it could occur as early as January or February or the first quarter of '03, today.

We also were hearing from companies who were interested in participating in an open season who were explorers at this time, who may not have proven gas reserves, who wanted some ability to bid in an open season, on the assumption that they might produce gas or have gas available that they would want to ship seven or eight years from now, and were interested in the state's royalty share, bidding on that, as a backstop for bidding gas.

We also heard from some companies interested in just marketing gas, having gas coming through a pipeline and marketing it into their distribution system in the Lower 48. Also, Williams had mentioned and expressed some interest in the possibility of utilizing royalty gas like they use royalty oil for some potential petrochemical development, particularly in Interior Alaska. So, we had a number of different kinds of interests, and we are also facing a possible open season the first quarter of calendar year '03.

COMMISSIONER POURCHOT, noting that there is a statutory process if the state is to sell royalty gas, told members:

It was our determination, to preserve all options, that we should start that process this last fall, which we did. We went through a best-interest finding, we finalized a best-interest finding under the Act in December, we held a royalty board hearing, we took public comment, we took public testimony, and ... at the end of last month we went out to a formal invitation for proposals ... that is running now and will end at the end of January.

We don't know who ... may participate or make a proposal. We don't know what the proposals might consist of. But we will be entertaining those offers, and we are not committed to making an acceptance of a proposal. Those proposals will be available publicly. ... And as you stated, Mr. Chairman, if we were to accept a proposal, if we were to then follow up and do a contract with a company, that contract would be brought back to the legislature under state law for debate and approval - or not.

Number 0847

CHAIR OGAN asked whether Commissioner Pourchot anticipates it will happen before the end of the current legislative session.

COMMISSIONER POURCHOT said the schedule allows for that; the timeframe probably would be around the end of March, no later than the first of April.

Number 0877

COMMISSIONER POURCHOT introduced Mark Myers, Director, Division of Oil & Gas, and Bonnie Robson, Deputy Director.

CHAIR OGAN noted the presence of Representative Joe Green.

Number 0922

REPRESENTATIVE DYSON requested a synopsis regarding Cook Inlet's present and future gas reserves. He asked whether recent discoveries have altered that picture.

COMMISSIONER POURCHOT deferred to Mark Myers, but added that Cook Inlet activity has increased, with "interesting things" being found there and interest being shown by a number of companies. He also noted that using money appropriated by the legislature last year, [the department] has been conducting an in-state demand study for gas; the results focus on overall supply and potential demand for gas if there were a gas line to the Interior, but also address questions relating to Cook Inlet. The study's results should be finalized the middle of next week, and [DNR] will provide this committee with copies of that study.

CHAIR OGAN complimented the commissioner on the level of professionalism in the Division of Oil & Gas, especially in upper-level management; he mentioned Mr. Myers and Ms. Robson.

COMMISSIONER POURCHOT expressed pride in DNR's personnel, then expressed thanks that the legislature has been willing to provide funding to allow an increase in salaries of some of DNR's most seasoned, experienced professional people; before that, the salary structure was far below the private sector's, and retention and recruitment was difficult for key people.

CHAIR OGAN remarked that DNR's personnel still work for less than they could receive in the private sector. He welcomed Mr. Myers and Ms. Robson to the witness table.

Number 1128

MARK MYERS, Director, Division of Oil & Gas, Department of Natural Resources, noted that on teleconference were other division personnel to answer technical questions. He prefaced his presentation by emphasizing how healthy Alaska's oil and gas industry is, as well as noting the importance of understanding where the division sees gas potential and how the RIK [royalty in-kind] sale fits into the overall scheme of state oil and gas activities.

MR. MYERS returned attention to the handout and referenced the page titled "Historic and Projected Alaska Oil Production, 1975 - 2022." He stated:

We have some very, very good news on this slide. Since 1988, peak production, we've seen North Slope production fall from over 2 million down to 1 million barrels per day. The good news is, we're actually stabilizing and increasing a little bit of production.

MR. MYERS noted that most of Alaska's initial production was from fields at Prudhoe Bay and Kuparuk. Although that is still true, it is a much smaller percentage. There are new fields coming online. Mr. Myers pointed out the significance of this for the state. Two things have happened, he said. First, there have been substantial exploration successes "for smaller, subtle, stratigraphic oil traps." Second, the technology has changed, as has the creative use of technology. The cost structure has been driven down on the North Slope, and it now is affordable to develop these fields, particularly near the infrastructure.

MR. MYERS pointed out that what is needed is a major field to anchor that infrastructure; that was Prudhoe Bay initially, followed by Kuparuk, and now Alpine is having the same effect nearer the NPR-A [National Petroleum Reserve - Alaska] area. "Once we do that, we can see more exploration, and then development, through those existing facilities of smaller satellite fields," Mr. Myers commented. "We're seeing a lot more oil production now coming out of satellite fields, and this graph doesn't totally capture it all."

Number 1260

MR. MYERS referred to the next graph in the handout, "Historic and Projected Prudhoe Bay Oil Production, 1975 - 2022." He pointed out the decline in Prudhoe Bay production, from 1.6 million barrels a day down to the current 507,000 barrels a day; he said Prudhoe Bay has been losing production at an average rate of 8 to 10 percent a year, a significant loss. In order to replace that and stabilize production, an Alpine-sized field must be brought online every other year, or else a Tarn- or Meltwater-type field must be brought online every year. "We're going to be able to do that in the short term," he noted. "We have Meltwater coming online; Northstar came online this year at

about 24,000 barrels per day, ramping up to 60 [thousand]." Mr. Myers emphasized how positive this news is.

MR. MYERS told members that as production spreads away from existing infrastructure and is produced in new participating areas and new units, the overhead for management of these fields - both for the companies and the state - is significantly higher. Whether a unit produces 500,000 barrels a day or 50,000 a day, it often involves nearly the same amount of administrative work.

Number 1324

MR. MYERS, in response to a question from Chair Ogan, said it is usually geologists who name the units, starting at the prospect level; these names typically are unrelated to the geographic locations and often follow a theme.

Number 1401

MR. MYERS returned to the presentation and highlighted the good news regarding the Prudhoe Bay decline: it is "flattening" and companies are having success in finding and developing these smaller fields. The challenge, however, is in administering many more units, over a much broader area.

MR. MYERS turned attention to a map, "North Slope Oil & Gas Activity and Discoveries, 2002." He emphasized that activity is being seen over the entire North Slope. He drew attention to the Alpine field, which is exceeding initial expectations and now is producing almost 100,000 barrels a day. In addition, there are two significant "satellite discoveries" to Alpine: Nanuk to the south and Fjord to the north. Therefore, there is potentially another 100 million barrels of surrounding "satellite oil." Mr. Myers emphasized that once there is an "anchor" field, there will be additional exploration and better economics for smaller fields.

MR. MYERS highlighted a significant event this year, what he termed a landmark agreement between the producers and the state to expand the Point Thomson Unit; critical development targets there need to be met, he noted, including "development drilling." He further noted that Exxon, as the operator, has been going through an "aggressive" permitting schedule now to develop it, and he indicated there is a desire to see the first oil flow from there in 2007 - 2008 or slightly later. Like Alpine, Point Thomson is an anchor field. It also is a very

important part of a [potential] gas line because it is a gas condensate field with an oil rim and a probable gas cap. Mr. Myers informed listeners:

We'll see both liquids and gas potentially produced out of Point Thomson. The current plans are gas cycling, where they leave the gas in the ground and produce only liquids, but it's likely that we will see, in a gas-line scenario, gas sales coming out of Point Thomson. That will prove as an anchor. Not only will that produce ... the 300 million barrels of ... liquids, but also, potentially, up to 8 tcf [trillion cubic feet] or more of gas coming out of that field. A very substantial portion of the North Slope gas reserves are there. [It's] very good news that now we're moving forward with development through ... an aggressive permitting schedule, and we have solid commitments toward development.

Number 1518

CHAIR OGAN asked how far east the current infrastructure exists.

MR. MYERS answered that it currently goes as far as Badami, which has an underutilized oil line that probably will play a significant role in the development of Point Thomson. The "very good news" is that it will open up more exploration for satellite [fields]. There are many known "satellite accumulations" surrounding and internal to the Point Thomson area, he noted.

Number 1544

MR. MYERS pointed out the amount of exploration activity: 12 to 13 wells expected to be drilled this year on the North Slope, with 5 of those to be operated by Phillips in NPR-A, working both on the successes they've had up to this point in terms of delineation of commercial reserves and on new exploration. He stated, "They have announced an Alpine-like equivalency ... in gas, oil, and condensate. So it's very positive news in the effort in NPR-A." He added that the state took a significant role, early on, in addressing federal concerns about having a lease sale. One role of the division, he pointed out, is advocacy for responsible oil and gas development, whether in NPR-A or ANWR [Arctic National Wildlife Refuge].

Number 1586

MR. MYERS continued, noting other exploration activity south of Kuparuk, one on "Arctic slope land" and one on state land in the central foothills, also operated by Phillips. He added that Anadarko is "branching out" and will drill a separate, dedicated well in NPR-A. He said it is "very good news to the state to get as many operators drilling as we can," because it increases competition, capital, and the likelihood of successful exploration.

MR. MYERS referred to offshore areas, noting that north of the Prudhoe Bay Unit is the McCovey prospect; he indicated DNR hopes to see an exploration well drilled offshore there this winter or next winter. Another significant event has been that Alberta Energy Company Ltd., a relative newcomer to the state, is going to operate that well.

MR. MYERS highlighted another positive event: BP [Exploration (Alaska) Inc.] is going to operate a well for Alaska Venture Capital Group to the north of Prudhoe Bay. This is another set of independents who got together, formed a consortium, and are going to drill on the North Slope, Mr. Myers told members. He said the department's effort to try to assist "in every way we can" to get these independent companies and other competition on the North Slope "is an extremely important part of our job." He added:

We take it very seriously, and we're seeing some success. And that is particularly important when you have major companies like BP pulling most of their exploration capital out of Alaska. So, we're trying to balance and backfill the vacuum. I think the commissioner showed you, on the front end, it's very positive that we have very good geology and very high potential. That's our number-one selling point it comes down to, and a very prolific oil basin and gas basin on the North Slope.

Number 1655

MR. MYERS turned attention to Cook Inlet, noting some highly positive developments there. In particular, Unocal, Marathon [Oil Corporation], and Forest Oil [Corporation] have stepped up activities for gas exploration. He indicated four new exploration units have been formed in Cook Inlet. Cosmopolitan, noted on the map in the handout, is being used for oil exploration by Phillips, he noted, which is currently drilling a

well there. Mr. Myers also mentioned the Deep Creek, Ninilchik, and South Ninilchik Units, just recently formed with Unocal, Marathon, and CIRI [Cook Inlet Region, Incorporated] "in various portions in various units"; those are exploration units for gas. Furthermore, Unocal had reached a "pretty lucrative contract for gas" with ENSTAR [Natural Gas Company], which "spurred a lot more desire, higher price levels, it is believed, and ... a lot more exploration for gas in Cook Inlet."

MR. MYERS said the primary oil success to this point has been "Forest Energy - Redoubt Shoals." He explained:

They had a small, known oil accumulation that took a fair amount of substantial risk to go in there and set an actual platform before they'd delineate sufficient reserves. ... They're drilling a fourth well now. They've announced 50 million barrels recoverable, which makes it an [economic] project with a significant upside, perhaps as high as 190 million barrels. So, major new oil production you can expect out of Cook Inlet - very good news on oil, very good news on gas.

Number 1720

MR. MYERS reported that there is an open season proposed now by Unocal for a gas pipeline going as far south as Homer. He commented, "You may see not only more gas produced to the north, but actually local energy supply down to Homer, out of this exploration, should it be successful."

CHAIR OGAN asked whether there is a possibility that the open season will be extended later.

MR. MYERS answered that the pipeline systems under "common carrier" - oil pipelines, basically - involve a nomination process that goes on continually. Gas pipelines, in contrast, are typically called "open-access pipeline." There is a front-end open season during which people commit to capacity on that line, and the line is then built to those specifications. If the pipeline company so chooses, it can build additional capacity on the line, based on the belief there will be additional customers later on. The company can "preplumb for expansion without actually having expansion occur early on," and there are many different options. That commitment to ship gas, however, controls the size of the development of that pipeline. "It also has to be backstopped with sufficient reserves to be

financed for a certain period of time to get approval," he added.

MR. MYERS further answered that the second part of the equation, should additional gas be found, is that people can go to that pipeline company and request that the pipeline be expanded. Expansion could take place through "looping" the pipeline - adding pipe in critical sections - or by increasing compression capacity; in that case, the pipeline [company] must decide whether it is going to expand. Generally, if it's in the pipeline company's economic interest, it will expand the pipeline. "There could be multiple open seasons," he concluded, "but that ... capacity in that pipeline's geared toward the initial nomination in that first open season."

Number 1819

REPRESENTATIVE DYSON mentioned a study done by a distributing company indicating the supply could be vulnerable in the 2007 - 2009 timeframe. He asked whether that has been pushed back or otherwise changed.

MR. MYERS noted that the results of the exploration drilling have not been made public, but said [the timeframe] could be pushed back, depending on the results. The two issues are the amount of available gas and how that gas is used. There are three major [uses] currently: the local energy market, which is the highest value per mcf [million cubic feet]; the export of LNG [liquefied natural gas]; and "the fertilizer market, the market for Agrium."

MR. MYERS said the lower-paying part of the market would suffer first, depending on how that gas is allocated to those various resources; it depends on the length of that vulnerability period. A further element is whether there will be additional usage and what the increased amount of demand will be; that is what a demand study will address, in part, which [should be available] Wednesday. Should these discoveries be successful, he added, "we can be assured that that date will be pushed back if existing use and reasonable expansion is taken into account; how far, we won't know until we see the reserve results."

Number 1882

CHAIR OGAN recalled hearing that in 2003 there will be some peak loads.

MR. MYERS replied that there are two issues. First is overall demand on a yearly basis; at certain times in winter the local energy use increases dramatically, and the question is how to meet peak demands. One of the big "drivers" to meeting peak demands is a price structure that rewards the providing of gas during those peak periods. He commented, "I think we have a market-driven structure now, ... with the higher gas prices." He noted that although local consumers pay more for gas under those contracts, [the higher price] spurs exploration and development of additional resources, and it creates additional capacity in the system.

CHAIR OGAN suggested that higher prices are tied to the "Henry Hub" to some extent.

MR. MYERS noted that Kevin Banks could address specific details of ENSTAR's contract, but said basically it is tied to a floor price and then is indexed to Henry Hub.

Number 1935

KEVIN BANKS, Petroleum Market Analyst, Division of Oil & Gas, Department of Natural Resources, added via teleconference, "The most recent contract that we are aware of between Unocal and ENSTAR provides for a Henry Hub index. It starts at a \$2.75 floor, and the Henry Hub index is indexed over a three-year moving average."

Number 1950

REPRESENTATIVE DYSON surmised that Alaska has no secure gas supply for future, expanding industrial use; furthermore, existing fertilizer and LNG uses are in some ways vulnerable in the near term.

MR. MYERS answered, "I don't think in the near term, but in the long term." He mentioned that there are some management issues, but cited positive developments including shallow gas, potential coal-bed methane, additional exploration, and exploration licensing in areas that are "predominantly gas." He said the first response to the need for gas is to "turn up the hunt for supply." He added, "We're seeing that in a lot of different areas. So I think we can find more gas. How do you quantify that? It's difficult, but I think potentially that day could be pushed back significantly." He noted that Will Nebesky was on teleconference to talk about current usage "and when we see needs for ... peak-demand gas versus long-term supply issues."

Number 2002

WILLIAM NEBESKY, Petroleum Economist, Division of Oil & Gas, Department of Natural Resources, told members one way to look at it is that industrial uses of gas have some "exposure" if new reserves are not brought online in Cook Inlet. He agreed that higher prices for gas are probably on the horizon for all Cook Inlet gas consumers. In terms of annual deliverability to users in Cook Inlet, he said "it does become an issue sometime around 2005." He added:

Basically, it would take about another ... 1-tcf discovery of gas, which would add the current approximate 2 to 2-and-a-half (indisc.) of existing reserves in Cook Inlet, would push those deliverability thresholds out about five years; that is, a tcf would probably extend the demand-supply balance problems out about an additional five years from the existing point where demand and supply balance (indisc.) becomes an issue (indisc.).

Number 2070

REPRESENTATIVE DYSON suggested that after [the committee] receives the demand study, members should reconvene on this very subject. He then asked whether the new concerns about homeland security [following the September 11 terrorist attacks] are having any impact in Cook Inlet. He noted that there was a harsher "ice environment" in the upper inlet than before; he asked whether there were any concerns there.

MR. MYERS noted that Commissioner Pourchot is on the committee for homeland security in Alaska. He said there are two thrusts: the state's issues and the military response. However, he said, he didn't know in detail what the concerns were. He acknowledged that "point sources" like LNG plants are of concern, and he reported that the companies have increased security and that the state has been looking at it. As for how it affects exploration and development, he concluded that "we haven't seen any significant effects to it."

Number 2108

REPRESENTATIVE DYSON remarked that in Valdez there is an "exclusion zone" around the port, and he mentioned the U.S.

Coast Guard. He stated his understanding that there hasn't been any of that in Cook Inlet.

MR. MYERS answered, "Not to my awareness, but we're in very close proximity to those F-15s at Elmendorf on alert, so that's some comfort. ... We certainly have the military force to respond." He added that he wasn't the right person to explain the details.

CHAIR OGAN announced that there would be an overview by Evergreen Resources, probably at the end of the month.

MR. MYERS said [the division] would be happy to present the results of the demand study to the committee, if the committee so desires.

Number 2137

MR. MYERS added:

What DNR can do for you is to make sure our leasing program - our unitization issues - work as smoothly as possible, and to accelerate exploration and development. We definitely have some budget issues with dealing with the issues, and I know we have some potential changes we might recommend to the shallow-gas leasing program to help stimulate and bring on more gas. We think these programs are important elements to stimulate more gas for Cook Inlet, as well as making sure ... that the exploration promises the state makes, in terms of ... our speedy unitizations and permitting, take place.

Number 2176

MR. MYERS brought attention to the next "slide" in the packet, which shows the areawide leasing schedule. Noting that there has been an increase to four areawide sales per year, he suggested it shows that the division "delivers what it promises." The sales typically are held in October and May, with two sales at a time; the next sale is scheduled for May 1. There will be four sales [a year] into the foreseeable future.

Number 2187

MR. MYERS turned attention to a graph titled "Cumulative Bonus Bids." He noted that cumulative bonus bids, over a period of

time, bring a substantial amount of income to the state. Last year, for example, the sales brought in about \$25 million. Although the major "driver" is royalties, there is "real money" to the state treasury in the leasing process itself.

Number 2201

MR. MYERS brought attention to the page titled "2001 Areawide Lease Sales." He remarked that the North Slope foothills sale, in the "gas-prone area," had the largest amount of state acreage - almost a million acres for 170 bids - ever sold in a sale. He commented:

One of the important aspects is we were able to diversify our base of resale participants. We have Burlington Resources, Petro-Canada involved, Unocal, Albert Energy, Anadarko, as well as Phillips. So we're ... starting to be able to diversify [the] industry base, which, again, is a critical component to ... having a healthy industry.

MR. MYERS referenced the North Slope sale highlighted on the same page; he noted that Shell had bid on that and remarked, "It's tremendous to get another ... competing 'major' up there - a high-quality company like Shell." He also noted that some successful "independents" have come in; in the case of Alaska Venture Capital Group, some have even drilled a well on the North Slope. He emphasized that a major part of the division's job is not only working to diversify the industry, but also "getting quality companies up here."

Number 2247

CHAIR OGAN asked Mr. Myers whether he foresaw any problems with operating up there, since "the big three" [producers] operate up there. He asked whether that is going smoothly.

MR. MYERS answered:

I think there's always large commercial issues in facility-sharing agreements that need to be ironed out. ... I'd like to see the state take a proactive role in the process and support that facilities get used to their maximum, that facility charges are reasonable. But ... those are primarily commercial negotiations between the parties.

The state has limited authority to do something about it, but it is an area of concern, to make sure that independents are ... treated fairly [and] the playing field is level. I think that's what the state can do, one thing that's crucial. It's all it can do to assure that everyone has fair access, whether it be to pipelines, oil, or gas, or whether it be to processing facilities.

Number 2283

CHAIR OGAN asked whether there is a statutory reference to that.

MR. MYERS answered that basically the unitization statutes deal with [DNR's] ability to expand units when necessary, to maximize production and use of facilities. A lot depends on the "interconnectibility" of reservoirs and exploration processes. It is very difficult to "force-unitize" an area unless the geology suggests it is appropriate for unit expansion to occur, because of reservoir management issues.

MR. MYERS emphasized that the state must be highly aware that in order to get more companies on the North Slope, access to the existing infrastructure is of critical importance. That includes exploration rigs and permitting expertise, for example. One thing the state can do positively is to educate, "spending time with these folks in the permitting process, [and to] have a clear, level, understandable permitting process to go forward, in all cases." In addition to education, the state certainly can process applications as quickly as possible in order to accelerate development and eliminate uncertainty. To that end, [DNR] is asking in the budget for an additional "permitter/inspector."

MR. MYERS cited some successes, including Meltwater, which proceeded from discovery to production within two years; he said that is "remarkable" and is a credit to both Phillips and the state. Some areas, however, perhaps more environmentally sensitive, present major challenges. He restated the importance of DNR's helping people understand the "playing field" and doing what it can to assure people of access to facilities.

Number 2354

MR. MYERS, in response to a question from Representative Green about the cooperation of state and federal agencies, said:

I think that level of cooperation varies at different times. I think the other agencies are well-intentioned. I think there is coordination through DGC [Division of Governmental Coordination] at some level. We have to remember, though, that other agencies have very different statutory requirements, and they have to honor those statutory requirements. ... [The Alaska Department of] Fish and Game, for example, whose job is to protect the habitat -- certainly you can't develop oil without some habitat disruption. So right there, there's always going to be room for conflict and negotiation about what's reasonable.

So I think the ability to do that depends on several things, [such as] the willingness of the agencies and the individuals in the negotiation. It also depends on [the] funding level for those organizations as well as ours. So overall we encourage cooperation, and ... certainly at the governor's level I've seen ... a strong desire to see this accelerated oil and gas development.

Number 2405

MR. MYERS referred to the next page in the handout, "Oil and Gas Leases Sold." He highlighted the long-term trend since 1996 of an overall increase of leases sold. He noted that the areawide sales are helping greatly, and added that "our ability to administer the program is incredibly important."

MR. MYERS turned attention to the next page, "Leases Issued." He pointed out the huge overall increase, despite a couple of "low" years. He highlighted the large number of leases issued last year [2001] and the number of shallow-gas leases. He noted that the new programs coming online are a challenge because [DNR] hasn't increased staffing in order to deal with either shallow-gas leasing or exploration licensing.

MR. MYERS referred to the next page, a series of maps titled "Shallow Natural Gas Leasing Program." He noted that these are primarily in the Matanuska-Susitna area and in the Big Delta/Fairbanks area, with a few leases in the Red Dog area, as well as some in the lower Kenai Peninsula. With these shallow-gas leases, he remarked, "we've seen a pattern that suggests that the primary use of these leases will be for commercial gas development - again, important to Cook Inlet and the users down

there, but also a program that we think needs some modification into ... a more commercial-related program." He expressed the hope of seeing some legislative changes to that effect.

Number 2453

REPRESENTATIVE DYSON asked whether the administration would produce legislation this session regarding that.

MR. MYERS answered:

The administration won't, but ... we're hopeful that the legislature will have ... a friendly approach to this. We have some suggested language that we're working through a few legislators to see if they're willing, but as of yet we don't have a sponsor.

MR. MYERS emphasized that the program is about three times as active as in the past. One consequence is it takes longer to issue leases - now 12 months on the average. This slows exploration and development on these leases, and it causes delays.

TAPE 02-1, SIDE B  
Number 2481

MR. MYERS indicated DNR has a \$500,000 proposal to solve that bottleneck; it would allow DNR an additional inspector/permitter and a reservoir engineer. "We think, again, this is a moneymaking proposition for the state," he told listeners. "And we can demonstrate that."

MR. MYERS referred to the next page in the handout and said to the department's credit, DNR can routinely put out four sales a year despite a very small staff; he credited DNR's lease-sale personnel. Saying the process is "somewhat torturous, but necessary," he told listeners:

There are a few critical bottlenecks in that process, and that's what we're looking at for the increment. So we're targeting specific positions in areas we know will speed up the process. So we're not just asking for money, but we're targeting it very, very specifically. And we recognize that we've streamlined the process as much as we can, and to that end, I think we're having quite good success. But ... it's

good news/bad news. ... We're a victim of our own positive success in the lease-sale process.

Number 2441

MR. MYERS brought attention to the next page of the handout, "Title Work." He highlighted the significant amount of new title work [required] because of the new programs - the exploration licenses and the shallow-gas leasing. In some cases, he noted, those [new programs generate] the majority of DNR's title work from year to year. "We expect that majority to continue," he added.

Number 2414

MR. MYERS noted that he would skip over the pie chart on the next page [titled "New Shallow Gas Leasing & Exploration Licensing Programs Dramatically Increase Division Workload"].

MR. MYERS turned attention to "Lease Assignments in Alaska." He told listeners that one important element is that once [DNR] issues a lease, the department has a need to administer it. He mentioned reorganizations; mergers; "new independents"; leases being transferred and reassigned; and the workload over time, going up dramatically. He remarked, "Again, within that \$500,000 increment is a position for lease administration to deal with that issue."

Number 2401

MR. MYERS addressed the next graph, "Unit Actions." He pointed out the long-term upswing in "unit actions" over six years, with a fourfold increase from 1995 to the present. He commented:

We expect this to fully continue. We formed seven new oil and gas units this last year, which are the core, basic units for exploration and development. We formed four new participating areas, which are the core elements for production. So now ... the state has 42 separate oil and gas units and 54 participating areas for production.

MR. MYERS turned attention to the next page, "What Are The Common Lease/Unit Administration Actions?" He informed the committee that once the units and participating areas are created, these are the basic building blocks of how [the state] gets its royalty revenue. These are extremely important,

complex agreements. He explained, "We use a commercial asset team of geologists, geophysicists, engineers, petroleum land managers, commercial analysts, with assistance from the Department of Law, to create and administer these units. These are really big deals." He lauded division personnel - enough people for one asset team - for the ability to manage 42 units; he added that the [Division of Oil & Gas] personnel listening on teleconference deserve a lot of credit for this.

Number 2352

MR. MYERS referred to the next page, "Different databases and data managed and merged to create 3-D [three-dimensional] pictures of oil fields and royalty share." He reported that as technology has evolved, the division has strived to "keep in place with the latest and current technology." Last year, he indicated, the legislature provided money for 3-D seismic [technology]; he said he would show the committee how that money has been used, if there is time during the briefing.

MR. MYERS pointed out that in order for DNR to interpret what the state's royalty share in the subsurface is, as well as "what our vulnerabilities are in these negotiations," that data must be integrated with engineering data; with seismic data; with geophysical data from wells; with geological data; with core data; with current geographic databases; and with the lease ownership position, which is constantly changing and evolving with each lease sale [because of] ownership changes and shifts by companies. The division does that. It has a series of digital databases that integrate into a main section.

MR. MYERS told members, "This is one of our successes, that we have to duplicate what an oil company does in order for us to be effective in our management and negotiation. And I invite all of you, at this time, to come into the division to see how we do it." He noted that Chair Ogan already had come to the division

MR. MYERS reported that one of [DNR's] critical weaknesses is lack of enough engineering support. He added, "We clearly need a dedicated, modern, current reservoir engineer to integrate into our staff. And in that \$500,000 request ... the last position is a reservoir engineer."

Number 2285

MR. MYERS turned attention to the next page, "Gas Cap Mechanisms." He said another reason [DNR] needs quality

reservoir engineering support is that anytime there is a major change in reservoir management - such as a potential gas sale at Prudhoe Bay - the effects are huge. He explained:

They affect us in terms of royalty. They affect us in terms of proper management. We share information on these issues with the AOGCC [Alaska Oil and Gas Conservation Commission], but we still need to have internal expertise on managing the effects to the reservoirs. We also need a determination of what the producible part of the oil is, based on royalty tract variation.

So, again, we have a lot of sensitivity as to not only that oil is ... correctly produced, but the state receives its fair share of royalty because of the allocation of that production from various ... leases.

MR. MYERS turned attention to the page titled "PBU [Prudhoe Bay Unit] Mechanisms." He described the reservoirs as "almost living, dynamic organisms." If one thing changes, it changes everything in the reservoir. Understanding that and adjusting to it is a very needed specialty within the engineering profession "that we badly need to get some more assistance on."

Number 2234

MR. MYERS turned to the next graph, "Seismic Data Status, 1990 - 2001." He told legislators:

You gave us money to acquire additional -- we had a huge backlog in 2-D and 3-D seismic, which is critical for interpretation. The line in red and green shows you just how much data we collected with that incremental money: we collected over 10,000 miles of 2-D and over 2,000 square miles of 3-D data. And we [collected] very little of that in the past. So we said that was a critical component of capturing that data before we lost it, and the state has a right, via permit. We went back, took that money, and got aggressive on collecting this critical seismic data.

Number 2214

MR. MYERS referred to a page titled "C35-T4.1 Window Far Offset Maximum Amplitude," which he said was provided with the permission of Phillips Alaska. He noted that it shows 3-D

seismic [data] over the Meltwater discovery. He emphasized how incremental the picture is, as well as how critical that [information] is in all aspects of exploration on the North Slope, in development and in equity determinations. He concluded that capturing that data upfront, for the state, pays huge dividends in all aspects of business.

MR. MYERS turned attention to the page titled "Layered lobe deposits consisting of waning flow high-density turbidities." He commented:

You gave us ... some money for doing geologic fieldwork, to analyze ... potential supply in the ... North Slope foothills. We dovetailed the money we got to work with the state survey and geologic field studies. So another element in the foothills, in particular, is integrating surface geology, in addition to the subsurface information. ... This is information we can make public, which is very useful in the process of promoting and getting new companies ... up on the North Slope. It helps us in our analysis. So it serves multiple ... functions.

I'd like to commend, too, the work the state geologic survey does on the North Slope as an integral part of this ... effort to promote understanding and development of North Slope resources. ...

We work as closely as we can with the [Alaska] Oil and Gas Conservation Commission so we don't duplicate effort on issues. ... Sometimes statutorily we're required to be separate, but when we can compare notes, work together, and share expertise - and where we have common interests - we do. And I'm very pleased with our relationship with the AOGCC at this point in time. I think it's a credit to the commissioners and to the staff ... that our good working relationship is there.

CHAIR OGAN recalled that it wasn't always so; he said it is good to see.

MR. MYERS noted that some money for gas-line studies was joint funding. For example, [the legislature] gave DNR \$50,000 for part of a larger study on reservoir mechanisms for which the AOGCC is trying to get \$500,000. He added, "We haven't spent the money until AOGCC gets coordinated. We wanted to spend it

jointly, to get the maximum value from the studies. That's an example of the coordination. We also do a lot of data coordinating on information." He mentioned creating digital files together as an example.

Number 2120

MR. MYERS reported that another weakness in DNR is the ability to analyze commercial pipeline terms. "We badly need a commercial analyst to look at pipelines," he noted. For an explanation, he referred to the page of the handout titled "Alaska Regulated Pipelines"; it shows that the number of regulated pipelines in which the state ships royalty gas is increasing dramatically. For example, in 2002 there are 16 different regulated pipelines. The reason is that exploration and development take place increasingly farther away, requiring interconnecting pipelines.

MR. MYERS explained that this is important to DNR and the state because the royalty value - and to some degree, the tax value - is based on netback value. Transportation costs are subtracted from what [the state] receives as its royalty share. It is in the state's interests, therefore, to pay as little in transportation costs as possible.

Number 2070

MR. MYERS referred to the graph titled "Projected Pipeline Tariffs as a Percent of ANS [Alaska North Slope] Wellhead Price." He said as the Trans-Alaska Pipeline System (TAPS) ages, as its throughput decreases, and as additional pipelines are needed to get gas to market, "our cost of tariffs, versus our royalty value, is going up dramatically." Now at 20 percent, it is projected to rise to more than 30 percent in the relatively near future. Therefore, he said, the state needs to negotiate and understand its commercial position "so that when we are represented before regulatory agencies that set rates, we understand our commercial position that, then, the Department of Law will negotiate for us."

MR. MYERS explained DNR's need for a full-time specialist. Having such a specialist would bring [the state] a lot more money in "on the tariff issue," he suggested. He pointed out that one penny per barrel on TAPS is equal to about \$800,000 a year to the state. He added:

It's reasonable the state pay its fair share of costs. We just have to make sure that that's exactly what we are paying in these negotiations. So, in many of these pipelines, the pipelines are owned by the producing companies, and we are a paying client on those pipelines, in effect. So, again, commercially, it's a very important part of our asset team to ... include this expertise....

CHAIR OGAN suggested a pipeline company has a lot of incentive to keep the costs up, then, because they are subtracted from the netback, resulting in less royalty.

MR. MYERS responded:

Any good business has a desire to maximize their rate of return ... and it's our incentive to pay the minimum tariff that's reasonable. So therein is a commercial negotiation, or at least ... a commercial understanding of the position, so when those tariffs are negotiated before the proper regulatory [agency], the state fully understands its commercial position.

Number 1968

MR. MYERS turned attention to a page depicting seismic data "over ANWR," prepared by the United States Geological Survey (USGS). He reported that the Division of Oil & Gas has taken an active role in promoting the opening of ANWR [to exploration and drilling]. For example, he made five or so trips to the North Slope with various groups last year, and he and staff have participated in national debates, addressed congressional delegations, and provided key support to Arctic Power [a lobbying organization that receives money appropriated by the legislature for the opening of ANWR]. He added that even national publications like The New York Times have used [DNR's] graphics to develop "frontline articles" and illustrations. He credited the cartographers, in particular, as well as others including technical experts who testify. He said:

I've been told by congressional delegations, time and time again, what's of extreme value that comes out of the Division of Oil & Gas is that ... we have the technical expertise to back up, we've done the geologic fieldwork, we have the engineering expertise, we have the leasing background. So when we speak, generally, we seem to have a fair amount of

credibility before those congressional delegations and before our key business leaders. ...

We have permitted ... so many oil and gas developments in sensitive areas, we have credibility there. ... It doesn't always get recognized, but these folks in the division - our technical experts - get called on a lot to testify or to provide information to key government officials and ... even to Arctic Power and certainly to industry groups.

Number 1894

CHAIR OGAN pointed out that the USGS data was from 1984 to 1985, the Dark Ages as far as seismic work goes.

MR. MYERS noted that the data is shown as a 2-D grid of relatively low-quality data, compared to that of modern times. Modern 3-D [seismic data] clearly is needed for a full assessment. In response to a comment from Chair Ogan, he noted that it would take congressional action in order to allow such an assessment of ANWR and to determine the actual reserve potential there. On the other hand, if there were leasing now, the first activity of a company would be "shooting 3-D seismic" in order to assess value.

MR. MYERS emphasized the necessity of 3-D data. He pointed out that exploration successes have risen on the North Slope, from 3 or 4 percent to about 40 percent. In addition, a 3-D shot allows one to customize and target facilities ahead of time; he cited Meltwater as a classic example of that, indicating there was little waste of effort or disturbance of the tundra beyond that absolutely necessary for development. "So it's a great tool in minimizing environmental impact and for adding geologic certainty," he concluded.

Number 1817

MR. MYERS referred to the next page, "Division of Oil & Gas Organizational Links Affect the Bottom Line." As an agency, the division recognizes the need to mimic an oil company-type structure, with an access team, he said. The weakest links are engineering and some areas of commercial analysis; those need to be strengthened. Overall, however, the system works well. He expressed pride in the division's personnel and their ability to negotiate these highly technical issues with a high level of professionalism.

MR. MYERS brought attention to the page titled "Recent Dynamic Changes in Alaska's Oil and Gas Business REQUIRE a Transformation of the Division of Oil and Gas." Referring to budget requests from the previous year, he noted the need to retain highly skilled people; he thanked [legislators] for their support on that.

MR. MYERS reported that the biggest challenge in the future is not so much in the exempt professional ranks; rather, it is in the "professional, union, natural resource manager-officer series" and other series. He expressed the hope of seeing some changes in the way that structure is created, "in terms of having a professional technical ladder that is equivalent to the management ladder for these nonexempt employees." He added, "We think that's absolutely critical for us to maintain high-quality staff"; he cited permitting personnel, lease-sale personnel, and highly skilled natural resource officers as being especially important in this regard.

Number 1731

MR. MYERS addressed the last page of the handout, "Alaska's Onshore Basins." He emphasized that Alaska's potential isn't limited to just the North Slope, particularly for gas. He said for early exploration in the Interior basins, for the most part, the biggest problem was "oil-source-prone source rocks." The strong evidence was that many of these basins had "very strong gas-prone source rocks"; he mentioned "coals" and other rocks, as well as "thermal maturities that are higher in some of the more oil-prone rocks, which would have generated gas." He stated:

We believe there's a lot of potential in the Interior basins, and certainly a lot of potential in North Slope foothills. I think access to that potential is one of the issues that is important in the southern [gas] line consideration. It's also a very important consideration that when a gas line gets built, that we have access, that other parties that are exploring can get access to the transportation system - for without transportation, there is no exploration. ... No one can expend the millions of dollars it takes an exploration program, and the hundreds of millions it takes to put major developments online, if they're not going to have reasonable assurance they can get into a pipeline system.

MR. MYERS continued with concerns about access, noting that gas pipelines work differently from oil pipelines. He stated:

One of our major concerns in DNR is a viable, long-term industry for oil. And as we see the oil maturing in the ... long-term future, we see gas taking over. ... There's a history of that, whether it be in the Alberta basin or other basins that are mature. It goes through a cycle of oil exploration followed by a major cycle of gas.

[Looking] at a long-term perspective of Alaska's oil and gas industry, the gas starts growing bigger and bigger as an element. And to do that, again, it's absolutely critical that if we get only one distribution system, which is the most likely scenario, that that distribution system has reasonable access so we can continue the exploration process that we are so encouraged about today, based on leasing patterns, based on new companies coming in.

MR. MYERS concluded by saying the concern about the access issue and open-season timing of the pipeline was one major reason for the timing of the RIK [royalty-in-kind] sale that [Ms. Robson] would talk about. Obviously, he said, "you have to get the system built." He advised members that the importance of having that system provide fair, level access cannot be overestimated.

#### OVERVIEW ON STATE OFFERING TO SELL "ROYALTY" GAS

Number 1631

CHAIR OGAN turned attention to the overview regarding the state's offering to sell royalty gas. Noting time constraints, he suggested there could be another hearing in a week in order to address royalty-in-kind issues in more depth. He asked that members hold questions until that time.

Number 1580

BONNIE ROBSON, Deputy Director, Division of Oil & Gas, Department of Natural Resources, referred to a handout titled "Alaska Royalty-In-Kind Gas Sale," prepared by the division and dated January 2002. She noted that she had been asked to address the state's process for a royalty-in-kind sale in the event of a major gas sale off Alaska's North Slope.

MS. ROBSON discussed information on the first page of the handout. She explained that "royalty" is a share of oil and gas production; it is reserved for the state at the time that an oil and gas lease is issued by the state. Typically, it is one-eighth of production (12.5 percent), but there are instances in which it is one-sixth (16-2/3 percent) or one-fifth (20 percent). This royalty share reserved for the state may be taken in-value or in-kind.

MS. ROBSON explained royalty taken in-value. It simply means that the production is left with the producers, who take [the state's] share - typically 12.5 percent - to market along with their own 87.5 percent share. It is marketed, therefore, as an undivided 100 percent of production; [the producers] then pay the state 12.5 percent of the net proceeds or the market value of that gas or oil, whichever is higher.

CHAIR OGAN requested confirmation that it is the netback on the wellhead price.

MS. ROBSON affirmed that. She then explained royalty taken in-kind. Under this option, the state physically takes possession of the oil or gas in the field and sells it, then and there, to a buyer; this is typically done under a contract of some duration, made well in advance of the time when the state actually takes physical possession of the oil or gas.

Number 1501

MS. ROBSON informed members that the abbreviations used for royalty in-kind and royalty in-value are RIK and RIV, respectively. She pointed out that the state's right to take its royalty share in-kind or in-value is a term of the lease agreement. It is also the lease that allows the state to switch between taking its royalty share in-kind or in-value. Typically, that switch can be made on six months' notice; often, however, the actual switch is done with much more advance notice than six months.

MS. ROBSON turned to page 2 of the handout. She reported that this right to take royalty in-kind or in-value, and to switch between the two, has been a term of every oil and gas lease issued by the state for more than 40 years. The state believes its right to take oil and gas in-kind, and to switch between in-kind and in-value, is a valuable asset owned by the state.

Number 1441

MS. ROBSON explained three reasons the state sees the aforementioned as valuable [page 3 of the handout]. First, in lieu of taking gas in-kind, for example, the state may simply leave it in-value with the producers, who then sell it. The producers are on a self-reporting system for what the proceeds and market value of that gas would be. If the state has any reason to believe the reported numbers don't accurately reflect the actual value of the gas, [the state] has a couple of alternatives. One, it can audit the producer - which it does, although it is an after-the-fact method that often cannot assure the certainty of catching every possible inaccuracy in reporting. Two, it can simply decide to take its royalty share in-kind; it then can offer that gas to the market, to see what price the market will pay for it. It is a mechanism to ensure that the state is capturing the full value of the oil or gas.

MS. ROBSON explained a second reason. There may be an in-state buyer or user of gas who is willing to pay market value for that gas and yet is unable to find a producer willing to sell it. That might happen, for instance, if the buyer is also a competitor of the producers. In that case, the state could step in and sell its royalty share, or some portion of it, to ensure that there is, in fact, in-state access to gas.

MS. ROBSON offered a third reason. It is an opportunity to capture premium value for the oil or gas. This frequently would happen because the state may be willing to offer its hydrocarbons on terms that are somewhat different from the industry standard. For example, if a buyer seeks a long-term supply of oil or gas, but the marketplace isn't willing to offer long-term contracts for that oil or gas, the state may be able to "sell for a long term but capture additional value or some premium on price because it is willing and able to offer terms other than industry provides." She noted that it has happened in Alaska repeatedly in the context of oil. She gave an example:

We do have two large, major refiners, as well as a smaller refiner, in-state. And both Tesoro and Williams and their predecessor have been long-term purchasers at one time or another of the state's royalty share. And that ... certainly has contributed to their success as in-state industry and the providers of in-state jobs and income and tax revenues.

Number 1271

MS. ROBSON referred to page 4 of the handout and asked: Why conduct a royalty-in-kind sale for gas now? She emphasized that the administration hasn't made any decision to sell [the state's] gas; rather, it has decided to preserve the option to do so. She noted that a number of factors have resulted in the administration's having a request for proposals "on the street" now for [the state's] royalty share in the event of a major gas sale. She said:

As the commissioner indicated earlier, last year, in 2001, the legislature passed a resolution encouraging the administration to explore the possibility of a sale of royalty gas to an entity willing to build an Internet data center on the North Slope, who was in the market for anywhere between 8 million and 112 million cubic feet of gas per day. And, of course, we have wanted to be responsive to that. However, we felt it important to not only deal with one potential buyer on gas, but to seek an indication of the range of interest across the spectrum from potential buyers of gas.

Number 1191

MS. ROBSON said a second motivating factor is the potential open season for a gas pipeline. She reminded members that the three major producers formed a team last year; they spent a year and \$100 million on studies regarding the feasibility of a gas pipeline off the North Slope to transport some 4 billion cubic feet a day or more of gas to other markets. [Those producers] indicated, perhaps last August or September, that there could be an open season for pipeline capacity as early as January 2002. Then, in either September or October 2001, to her recollection, they indicated that open season might be pushed back to the second quarter of 2002. She continued:

However, we were privately told that ... the open season could, in fact, be as early as January of 2002, once again. Just within the last couple of weeks, one of the producers [has] indicated that an open season could be in the second quarter of 2002. Also, the pipeline consortium that has been recently reconstituted under Foothills has indicated that if they reach a successful conclusion to their

negotiations with the producers, that an open season could be as early as the second quarter of 2002. Just this past Tuesday, we did receive correspondence from the producers' consortium indicating that they themselves did not have a current intent about an open season in 2002.

Number 1096

MS. ROBSON addressed the question of what is so critical about an open season. She called an open season "a vehicle to get pipeline capacity." Because this gas pipeline would be a contract-carriage pipeline, the entity that constructs a pipeline would - before making an absolute commitment to build that pipeline - conduct an open season in which those interested in shipping on the pipeline must make long-term, irrevocable commitments to pay for capacity on that pipeline, regardless of whether they ship on it or not. The required commitment could be 15, 20, or possibly 25 years. The extent of commitments made during an open season would be a significant factor in deciding pipeline size. Once the parties make irrevocable ship-or-pay commitments and the pipeline is sized accordingly, there may be no additional way to get other gas into that pipeline for 15, 20, or 25 years.

MS. ROBSON addressed possibilities for getting other gas into the pipeline beyond that nominated in the initial open season. First, someone with existing capacity could resell some of that capacity. She commented, however:

We don't think that's particularly likely in this environment, since those North Slope producers, particularly the Prudhoe Bay and Point Thomson producers who are expected to factor predominantly in the open season, have the known gas reserves and will want to move their stranded gas assets off the North Slope in the capacity they nominate. So we do not see them as being significant marketers of secondary capacity.

MS. ROBSON reported that second, there could be an expansion of pipeline capacity. She explained, however:

The problem with expansions of pipeline capacity is that FERC - the Federal Energy Regulatory Commission - has at least no certain ability to compel expansion over the objection of the pipeline owner. It is

arguable that they do have some ability, but there is no certain ability to get an expansion, when and where needed, by those other than those who, in fact, own the pipeline.

Number 0930

MS. ROBSON again emphasized the primary importance of the open season, not only to bring as many parties to the table as early as possible - because they may not have the opportunity later - but also from a royalty-in-kind perspective. Although the state has the opportunity, with as little as six months' notice, to switch from RIV to RIK, it can only sell to a buyer who has "takeaway capacity" in the pipeline, procured in the initial open season, or who can use it on the North Slope, which is a fairly limited market. She added, "There is limited ability for the buyer after this initial open season to say, 'Yes, I want to buy gas - I want to buy royalty gas,' and have the ability to, in fact, deliver that gas to the desired location."

MS. ROBSON concluded that while it's important to the state to have its right for RIK or RIV, and to be able to switch between the two, there will be a severe limitation on the ability to use its right for RIK and to make that switch once this open season comes and goes.

Number 0840

MS. ROBSON highlighted differences between pipelines. Oil pipelines are "common carriers." Oil pipelines such as TAPS allow for a monthly nomination of pipeline capacity; anybody who wants to buy oil on the North Slope now can do that, and can get the capacity and move the oil to the desired location. She explained that first, TAPS is not at maximum capacity; it was always envisioned that TAPS would operate for a short time at maximum capacity, but then would have excess capacity. Second, because TAPS is a common carrier and nominations are done on a monthly basis, [a company] can always at least get its pro-rata share of oil into the pipeline.

MS. ROBSON noted that in contrast, natural-gas pipelines are "contract carriage." Furthermore, this gas line is envisioned as being at maximum capacity for decades to come. And for a gas line, Ms. Robson said, "If you don't participate in the open season, you don't have any right to access to that line, and you could not get your desired share or a pro-rata share of gas into that pipeline at a later date in time."

Number 0744

CHAIR OGAN asked whether it would be prudent for the state and the producers to work together to ensure there is enough capacity - and perhaps even excess capacity - to use a portion for other uses in Fairbanks or Delta, for example, with LNG going to Valdez; perhaps there also could be future access to gas for Anchorage. Referring to testimony in the Joint Committee on Natural Gas Pipelines hearings [in 2001], he voiced his understanding that once one molecule of gas is shipped interstate, FERC will regulate the whole thing. Noting that Ms. Robson is an attorney, he asked whether there is any way to get state control to a hub point, perhaps statutorily moving the wellhead down to Fairbanks, for example, or using another way to ensure that open-season issues [don't prohibit] continuing exploration. He asked: Who will invest in the foothills or anywhere else to buy leases to look for gas if it can't be put into the pipeline? He also asked Ms. Robson whether it would require a change to federal law.

Number 0577

MS. ROBSON answered that she personally hasn't done that research, but understands such research has been done by private counsel retained by the Department of Law. There also has been some examination of the issue by the Regulatory Commission of Alaska (RCA). She offered the following:

Unfortunately, we don't have a lot of good news to offer. We do see that if we are seeking certainty on access in some of these issues, that a change in federal law is the best and perhaps the only way to accomplish that certainty.

The federal government, we think, will retain control over the regulation of this pipeline, and that there is really not the opportunity, as others have suggested, of possibly moving the point of their regulation downstream from the North Slope to, say, Fairbanks or some other location, that they are going to have primary control, that they may allow some input by the Regulatory Commission of Alaska or the state government, but at this stage they are not compelled to give equal voice to the State of Alaska, or primary voice to the State of Alaska. And, also, they have limitations on their ability to do some

things like compel expansions of the pipeline in the future, even if the party comes forward and proves that it's economic to provide that expansion.

There are other possibilities; I think one you mentioned is negotiations with the producers, and certainly this is something that we've ... raised with the producers, and we are optimistic about future conversations with the producers. It would, at least theoretically, be possible that - short of federal legislation - there could be a binding, written commitment by the producers to provide access on terms that are acceptable to the state, in lieu of giving FERC the ability to compel access on terms other than allowed under current law. ... We have encouraged [the producers] to come up with a proposal on what they would be willing to offer, and we have yet to receive such a proposal.

Number 0421

CHAIR OGAN suggested the capacity would have to have been built in from the beginning, however. If the pipeline were full, access issues wouldn't be much of an issue, he suggested.

MS. ROBSON offered her understanding, based on conversations with both the producers and the pipeline consortium, that both groups now are looking at a pipeline with initial capacity of about 4.5 billion cubic feet a day. She added:

Now, you would be able to optimize that pipeline or tweak the system a little bit and raise the capacity up to 4.6, possibly 4.7 billion cubic feet a day. After that, you would be looking at one significant expansion on the order of about 1 billion cubic feet a day, bringing the capacity up to 5.5 - 5.6 billion cubic feet a day. And that would come by putting compressor stations between the existing or initial compressor stations, and the system would be plumbed to make that easy.

That would be an expansion that would be available at a cost roughly equal to the initial cost of providing capacity. That is, if you have a fixed tariff, we can choose any (indisc.) we want for that initially for the 4.5 billion cubic feet of capacity; you could make one one-time, substantial expansion of 1 billion cubic

feet and retain approximately the same tariff. After that, my understanding of what you're looking at is, then, what they call full-line looping - running a duplicate pipe. That's not cheap; you can't do it for small amounts. And so just the very physical nature of this pipeline puts substantial restraints on the ability to put additional gas in at a future point.

Number 0265

For example, if you start out at 4.5-billion-cubic-foot-a-day capacity, you tweak the system a little bit and get up to 4.6, and then you have other groups that come and are ready, willing, and able to pay the exact same tariff to put their gas in the pipeline - but they only have, for instance, in "incremental," 300 million cubic feet a day, or 500 million cubic feet a day, or even 800 million cubic feet a day, that alone is not at a level that may justify an expansion. And it's possible that they could group their gas with incremental gas from the three major producers off the North Slope, but, again, that requires the full cooperation and consent of those producers on the timing and quantity.

So we have very real concerns about access. ... We would like to see some changes made, whether it be in federal law or through agreement with the producers, that it would at least minimize some of these adverse consequences of limitations on access.

Number 0178

CHAIR OGAN requested that Ms. Robson provide a list of suggested changes. He added that perhaps the committee could assist in formulating a resolution, for example.

MS. ROBSON agreed to his request. She then said it raises the question of when the open season is going to be - if it is important to at least proceed with the RIK procedures, prior to an open season, in order to allow any prospective purchaser to participate meaningfully in that open season. She added:

We have, as I indicated, a statement from the producers, two days ago, that they do not currently envision that they will conduct an open season in 2002. There's at least three problems that we have

with just postponing a royalty-in-kind sale, based on that statement. The first is that it's not an absolute guarantee that the producers won't conduct an open season in 2002. So while they do not currently envision an open season this year, that vision may change, for instance, with the passage of federal enabling legislation. As I indicated earlier, it wasn't so long ago that they were looking at an open season in either the first or second quarter of 2002.

The second is that while the producers may not conduct an open season in 2002, they are now in discussions with the pipeline consortium of Foothills, and that entity could conduct an open season in 2002.

The third is that because any royalty-in-kind contract must be approved by ... the legislature, it has to be presented and approved in advance of an open season, to provide the comfort ... [ends mid-speech].

TAPE 02-2, SIDE A  
Number 0001

MS. ROBSON mentioned that December 2002 or January 2003 wouldn't provide sufficient time to take up this issue and still allow certainty to a prospective buyer.

MS. ROBSON highlighted the importance of not taking any action that might delay an open season. For example, if the RIK sale were postponed at this time, based on the producers' statement that they don't currently envision an open season this year, the producers then could obtain the desired federal enabling legislation and their vision would change; in that case, the state wouldn't want to be in the position of asking them to delay that open season. She remarked, "I think the division, and department, has been very conscious of taking no action which would in any way obstruct or delay the construction of ... this pipeline."

Number 0087

CHAIR OGAN reiterated his concern about how the amount of gas produced would affect oil production and the revenue stream as a result.

MR. MYERS responded that [the division] had very little information until recently on how a proposed gas sale would

affect the Prudhoe Bay Unit and oil [production], or on what might be done to mitigate oil loss. He stated:

Very recently, ... we've had people involved, again, with this cooperative effort with AOGCC, with a joint meeting, where we got fairly good information from the producers ... on the effects. And ... it's not an easy equation because it's a very dynamic thing ... that depends on what mitigation measures you do. For pressure loss in Prudhoe Bay, for example, ... gas cap injection of water will keep pressure up and minimize oil loss. So ... that project's going forward, called the "pressure support initiative." That's a good thing to mitigate oil loss either way - either with a gas line or [not] - but particularly with a gas line, it helps mitigate oil loss.

Another big issue is gas has other use on the Slope now, for a miscible injectant to enhance oil recovery. And it's not just in ... Prudhoe Bay, the main reservoir, but it's in lots of reservoirs on the North Slope. So ... the composition of that injection gas varies; it varies not only the recovery rate, but the kind of equipment you use to do that sort of miscible injectant. And we expect, at some point in time, ultimately, the producers would start using more CO2 for miscible injectants ... and then actually produce and sell the gas that they're using. But ... when and how that occurs requires modifications of facilities and optimization, based on production scenarios.

So ... that one diagram I showed about ... a gas sale, that was one of the reasons for showing you the gas cap, the dynamic nature of the changes. There are multiple ways to mitigate it. We're starting to have those conversations. AOGCC and we believe we both have to approve any sort of [gas] offtakes; so that's another reason the engineering part is critical to it. Certainly, ... the higher rate of offtake you do, the more you have to do to mitigate oil loss. But I think we're pretty confident there are ways to ... really lower or make that loss-oil a fairly small number.

In converse, at Point Thomson we really have not had those discussions, so we don't have any idea at Point Thomson. And, of course, we're very early in the development stage.

So, I think those conversations are starting to occur now, for the first time. And ... that's very positive news.

Number 0310

CHAIR OGAN surmised that the Department of Revenue might have to crunch some numbers, depending on the engineering studies, for example, to figure out the loss of revenue. He asked Mr. Myers about it.

MR. MYERS replied that certainly both DNR and AOGCC would have to approve the plan of production for gas offtake. There would be a major discussion of those effects and approval of the plan. Those would be the lead agencies on the issue, he added. He continued:

The tricky thing is, we could start getting involved with very confidential data, and our ability to share that with you is limited. That would have to come ... via the producers, other than general [information]. The Department of Revenue does run a model; the model is entirely too simplistic to answer this question and doesn't necessarily integrate the latest changes in technology the producers are [using]. So we definitely need more than a back-of-the-envelope model ... to deal with this issue.

Number 0376

CHAIR OGAN suggested although the data is confidential, the bottom line of how it will affect production shouldn't be confidential.

MR. MYERS responded:

Well, I think it's an appropriate discussion for the producers to bring up again; where ... we're using confidential data provided by them, we can't really discuss the conclusions of that data, other than the parts of the conclusions we can make public. So I think it's a very appropriate issue to bring up again with the operators of ... both the Prudhoe Bay and Point Thomson fields.

Number 0425

MS. ROBSON returned to page 4 of the handout:

Let me just mention briefly two other reasons why we felt it important to begin with the process for a royalty-in-kind sale now. One is that the governor's policy council on the gas line indicated that the state's right to take in-kind was important, should be retained, and recommended some split of how the state takes its royalty between in-value and in-kind. And, again, to effectuate that recommendation would require selling at a time for a buyer to participate in the open season.

And the final reason is simply that we have had many expressions of interest by potential buyers in conducting a royalty-in-kind sale, and we think it is important to respond to their interest.

Number 0483

CHAIR OGAN remarked that timing is everything with regard to buying or selling. He said, "Basically, what we're doing is we're selling gas that can't be marketed at this point, on speculation that it might be marketed. And would ... we get more money for the gas ... if we waited until we know it could be marketed? It seems to me it would be worth more if they know they have a pipeline." He noted that there has been talk of marketing the gas for 25 years.

MS. ROBSON replied:

In terms of what we obtain for the gas, I think there are a couple [of] elements of the terms on which the gas is being offered ... that play into the consideration that would ... be received. First of all, the floor or base price, in any proposal that might be accepted by the state, would be the royalty-in-value number. So we do not do a royalty-in-kind sale unless we're going to get at least as much or more than we would get if we left the royalty share in-value with the producers (indisc.--coughing).

Now, the producers are sophisticated marketers of their gas. And you can bet that they're going to obtain if not the best price, one of the best [prices] in the marketplace for the gas. And because there are

a number of them, between the several of them you can expect that they're going to be commanding the premium prices in the marketplace when and if that gas gets delivered to market. So if that's our base - that's our floor value for a royalty-in-kind sale - any buyer must pay "that amount plus" to obtain this royalty share.

Number 0603

The second is that we are asking potential buyers to offer a premium - in terms of cents per mcf or mmBtu - on top of the royalty-in-value.

And the third is that we're asking that they provide - or indicate whether they are willing to provide - some special commitments to the state that may take the form of in-state investment, whether, as you indicated, in a petrochemical plant or additional exploration in the state, whether it would be for in-state use of gas or supply to in-state buyers of gas.

So we feel that this is actually an optimum time to be offering the gas, because of the keen interest of a number of parties and the ability for those parties to plan ahead ... for the utilization of that gas, as well as the absolute floor on price: we can get no less for our royalty-in-kind than we do for royalty-in-value. And I think we have very good ... protections, in the producers' own marketing practices, providing that floor.

And again, there would be the obstacle, if we decided later we wanted to market it: how do we get the pipeline capacity to move that gas to market?

Number 0694

CHAIR OGAN asked, "Where did you come up with 70 percent?"

MS. ROBSON answered:

That is what we set as the ceiling on what will be sold. There, again, has been no determination to sell any volume at all or, if there are sales, to come up with 70 percent. ... We think it important to keep some in-value, for several reasons. Let's just [look

at] numbers on the 70 percent. If we're looking at a 4-billion-cubic-feet-per-day pipeline - and I use that instead of 4.5, even though that's more probable, because the math is easier with 4 billion cubic feet - the state's royalty share is a half billion cubic feet per day or 500 million cubic feet per day; 70 percent of that is 350 million cubic feet per day. If ... one of your buyers is a large, commercial entity, they need substantial volumes; they may need volumes in that vicinity to be of value to them. So there was one concern of offering enough to attract the largest buyers. ...

The second was that by retaining the 150 million cubic feet per day, we have ample additional gas to sell at a later point in time, if we can overcome these pipeline-capacity problems for in-state use. For instance, the Fairbanks market is envisioned [to perhaps] ... use 10, maybe 20 million cubic feet a day. Again, we'd be reserving 150 million cubic feet a day. Anchorage, if we could get additional gas to it, ... could theoretically take 100 million cubic feet a day. Again, we're reserving 150 million. So there's plenty for incremental, in-state use of future buyers at a later point in time, and yet it is still a quantity that would draw the biggest and most attractive buyers willing to offer the most significant premium or special commitments to the state.

Number 0828

MS. ROBSON continued:

The next slide [page 5] just shows a series of ... processes that are part of any royalty-in-kind sale. And, in fact, we have made a special effort to double up on some of the findings and public comment for this process, to make sure that we get maximum input, maximum interest from potential buyers, and maximum hearing on what is the public's interest, the legislature's interest, [and the] industry's interest in this sale.

We have currently a solicitation of offers on the street requiring the submission of proposals the last day of this month. There will be an opening of those

proposals on the first day of February, to be followed with negotiations based on those proposals, additional public comment period, additional royalty board hearing, additional findings by DNR, and, of course, a submission of any contract to this legislature for approval or disapproval by April 1st for action this year.

Again, one of the terms for the offering is that a contract must be approved, if at all, under this offering by - I believe it is - August 1st of this year; otherwise, we would have to repeat the process at a later point in time, or we could, prior to January 31, extend that deadline.

Number 0911

MS. ROBSON addressed basic terms incident to the offering. She pointed out that the offering is for up to 70 percent of production from the Prudhoe Bay Unit and Point Thomson Unit, which the division understands will be the "cornerstone" for a pipeline. She told members:

The price, as indicated, includes a number of components, the base being the royalty-in-value number, any premium a bidder's willing to offer, as well as a bonus. And the bonus bid, which would be due upfront, is an amount equal to \$1 per 1 mcf of daily delivery.

MS. ROBSON informed members that the terms of sale aren't summarized in the handout, but the offering and a sample draft contract can be found on the division's web page. She noted that there were approximately 100 pages and offered to make hard copies available, if requested. She called it a "detailed solicitation and finding."

CHAIR OGAN said he had a copy but offered to ensure that other members get a copy as well.

MS. ROBSON continued:

I'll just mention a couple of other key terms in our proposed disposition. One is duration. We're asking that those interested in purchasing indicate what duration they are interested in purchasing the gas for. And we are willing to consider sales for as long

as that period for which pipeline capacity nominations are required in the initial open season. We don't know what that period will be yet, but whether it's 15 or 20 years, that is the maximum duration we would consider for initial sale, because a buyer may be constrained by the need to nominate and fill pipeline capacity for that duration. But we are also willing to consider offers for a shorter duration.

The point of delivery for the gas would be on the North Slope, at the same place that the gas is tendered by the producers to the state. So the state never gets in the business of itself transporting the gas.

And finally, another provision that we have put in the request for proposals is - as an accommodation to the producers, as I indicated before - the state has the right to switch between royalty-in-kind and royalty-in-value on six months' notice. Often, a royalty oil or gas purchaser will know well in advance of six months of change in plans that substantially affect how much oil or gas they want to buy. So we built in a mechanism to encourage them to give two years' advance notice of significant changes in the quantity of gas that they do want to take.

Number 1097

MS. ROBSON continued:

I will just touch on one additional point: the remaining ten or so pages [of the handout] all are based around a single scenario, and I don't think we want to explore that scenario this week; you may want to do it at a later point in time. But they are designed to show the impacts of a royalty-in-kind sale on the sizing [of] the pipeline, on the pipeline company itself, and on the Prudhoe Bay and Point Thomson producers.

And I will just summarize the conclusions, and then, if there are specific questions, I'd be happy to address those now or, if you want to go back, take a look at this graphic, have some more conversations, and we can pick up the conversation later.

We think, if anything, that the impact a royalty-in-kind sale will have on ... the sizing of the pipeline is to provide for a larger-size pipe and, ultimately, more flow of Alaska's gas to market at a sooner point in time, and early monetization of our stranded gas resources.

We think there will be no or a positive impact on the pipeline company itself. While there may be some impact on the size of the pipe, what will happen in an open season is there will be nominations for specific quantities of gas, and the pipe will be built to accommodate those quantities. And so the pipeline company will have ship-or-pay commitments for the entire volume, from day one, and so there will not be a negative impact on the pipeline company itself.

There may be an impact on the producers at Prudhoe Bay and Point Thomson. There are some aspects in which the impact would be positive, and there are some possible aspects in which the impact may be negative, although we think any negative impacts could be mitigated.

Number 1205

MS. ROBSON summarized possible impacts, whether positive, negative, or neutral:

First, it's possible that the impact on the Prudhoe Bay and Point Thomson producers might be that ... some portion of their stranded gas reserve could be ... brought to market sooner and they could monetize that stranded asset at an earlier date and time, and due to the time value ..., actually increase the value of the project to themselves.

The second way in which it may affect [the producers] is that if we wind up with a larger pipeline as a result of this royalty-in-kind sale, due to economies of scale the pipeline tariff may, in fact, be less. And that would, of course, work to the benefit of the Prudhoe Bay and Point Thomson producers, as well as all other shippers on that pipeline.

The third way in which they may be impacted is the level of use of the planned gas-treatment plant may be

impacted by a royalty-in-kind sale. And, again, I won't go through the hypothetical here, but we do think there are ways to accommodate or minimize that impact.

So while we do note that the producers have indicated a reluctance for the state to conduct this sale, we do think that it could have a positive or neutral impact on the desirability of the project to the producers. And we do think there is room to accommodate their concerns.

We have also asked the producers to quantify any negative impact that this sale may have, and they have, at this stage, declined to make that quantification. So while there [are] some purported negative aspects of a royalty-in-kind sale to the producers, we are sympathetic to any negative concerns but we want to see a quantification and identification of those negative aspects, and we have yet to receive that.

CHAIR OGAN asked whether [the producers] have indicated they will provide that [quantification or identification].

MS. ROBSON said no.

Number 1326

MR. MYERS added:

Another factor is ... we've had extensive conversations with potential buyers of gas, one of those buyers' groups being a consortium of ... various explorers for gas. They have expressed to us their number-one concern and risk is in exploration for new resources in the sense of finding, discovering, and producing those resources - it's getting those resources to market. ... So it is a risk that's shared by other companies that have a lot of expertise in finding, producing, and shipping gas.

Number 1354

MS. ROBSON concluded:

I do not want to end on a negative note by indicating the producers have not gotten back to us on that issue. We have had a number of conversations with the producers on many issues. I think we are "progressing" the issues in many areas; there are areas where there is still disagreement or [where] interests are different. Access and this royalty-in-kind sale is one of those. But I do think that the interests of the state and the producers are being advanced by the conversations and the cooperation to date.

Number 1387

CHAIR OGAN asked whether there were further questions. He remarked that he would like to hear from the producers and possibly take some public testimony at the next meeting, if anyone wished to speak on the issue.

CHAIR OGAN pointed out that committee packets contain the following: a letter from the Alaska Gas Producers Pipeline Team [representing BP Exploration (Alaska) Inc., ExxonMobil Production Company, and Phillips Alaska, Inc.] to [Commissioner Pourchot of] the DNR, dated January 15, 2002, asking for a reconsideration of the best-interest finding; an e-mail from Ken Thompson [dated January 14, 2002, to committee aide Linda Hay] relating to the issue and some findings from a commission that Mr. Thompson had worked on regarding in-kind sales and so forth; and a copy of [AS 38.05.183] dealing with the sale of a royalty and legislative approval. He requested that committee members become familiar with those materials.

CHAIR OGAN thanked the committee aide for the House Special Committee on Oil and Gas, Linda Hay, for the excellent job she has done.

**ADJOURNMENT**

Number 1495

There being no further business before the committee, the House Special Committee on Oil and Gas meeting was adjourned at 12:01 p.m.