SOUTH CENTRAL ALASKA ENERGY FORUM

September 20, 2006

Egan Convention Center

Anchorage, Alaska

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P R O C E E D I N G S

(On record - 8:00 a.m.)

CHAIRMAN NORMAN: Good morning. My name is John Norman. Welcome to the South Central Alaska Energy Forum. This forum is being sponsored by the Alaska Oil and Gas Conservation Commission, the Kenai Peninsula Borough, the Matanuska-Susitna Borough, and the Municipality of Anchorage.

At the table with me I will acknowledge to my right, immediate right our Governor, Frank Murkowski. At the end Commissioner Dan Seamount, a Commissioner of the Alaska Oil and Gas Conservation Commission. To my immediate left Lieutenant Loren Leman, to his left Mayor Williams and to his left Mayor Anderson. Mayor Begich has sent word that he is in route, but we're going to go ahead so that we don't get behind schedule and he will join us as he can.

We all know, I think, that we face the prospect of an energy shortfall here in South Central Alaska. This promises in one way or another to touch the lives of all of us. The need for a forum like this was identified sometime ago by Governor Murkowski. And I want to acknowledge all of his support and encouragement in the planning of this event as well as the support that we've received from our three co-sponsoring municipalities. In particular, I would like to thank Bill Popp who's with the Kenai Peninsula Borough for a significant amount of very valuable assistance and input.

This conference has been on the drawing board since the beginning of this year, but the other shoe had to drop on several events and contingencies such as the Agrium Coal Gasification study before the timing would be right to hold it. Those events have happened and now we are ready to proceed.

We have an information packed two day program ahead of us. We're going to plunge right into it. At the start, however, I would like to ask you to, please, turn off your cell phones. Also on breaks when you go to get coffee try not to congregate in front of the coffee pots, get the coffee and move on so others can also take their turn at the coffee line.

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GOVERNOR FRANK MURKOWSKI

CHAIRMAN NORMAN: I'll now introduce and then call upon Governor Murkowski to formally open this event. Frank H. Murkowski, is the 10th Governor of the State of Alaska. In 1980 he was elected to the United States Senate where he served us for 22 years. During his tenure in the Senate he served as Chairman of the Energy Committee and a subcommittee chairman of the Pacific and East Asian Affairs Committee of the Foreign Relations Committee. In addition, he served as a member of the Finance, Indian Affairs and Veterans Affairs Committees.

He was appointed as Ambassador Plenipotentiary to the United Nations in 1996 where he initiated a U.N. resolution on the ban of drift net fisheries. During his Senate career he crafted the Omnibus Presidio Bill which is among the most extensive national parks and refuge bills ever to pass through Congress. He also led the successful effort to ban drift nets from the High Seas. He's worked to stop salmon piracy and also to end the ban on exported North Slope crude oil. He's won major legislation to improve conditions in Alaska Native communities and he's a recognized authority on topics such as energy policy, fossil fuel, electricity restructuring.

During his long years of public service his commitment to Alaska has always been to build a strong foundation that will support an expanding economy to provide the highest quality of life for Alaskans. Please join me in welcoming our Governor, Frank Murkowski.

GOV. MURKOWSKI: Thanks very much, John. And my compliments to you and your associates for the effort that's gone into this. This has been a long time in the making. I think initially we planned to have this in July, but there was another conflict, but we're very pleased that you're here. And my role is to welcome you and I'm going to pretty much stick to that.

I want to recognize our Lieutenant Governor, Loren Leman, and Mayor Begich who's joined us, good morning. Mayor Williams, Mayor Anderson, Counsel Uchiyama of the Japanese Government present here, as is Consul Matthias of the Canadian Government.

We have a special guest, I'm told, Brandon Amico who is a 49th State Fellow and a student at the University of Alaska here in Anchorage. And you might want to know what that's all about. Is he here? He had a little problem getting an excuse to skip class, we hoped that he would find a good-natured instructor, but in any event we're going to recognize him because the significance of what this program is all about.

The 49th State Fellows are young people who have distinguished themselves as leaders while in high school in Alaska. The University of Alaska created this program to encourage young folks to cement a career in Alaska and this program encourages them to stay by offering them challenging opportunities in the area of energy. They take select classes together. He is paired with a mentor and they are given other opportunities to learn about leadership, government and issues important to Alaska, so we did want to recognize the contribution associated with the University and the special 49th State program.

John, thanks for the invitation. My wife and I took our boat -- well, it's really her boat, I just contributed a little of my loose change and beyond, from Juneau down to Seattle. It took us nine days and last night we flew back in three hours, so I don't know what that's got to do other than it took a lot of energy and a lot of expensive diesel fuel, but that goes with the price of admission, I guess.

I did want to note for your edification the realities that what goes around comes around. And I was rather restless on the airplane last night so I picked up the Wall Street Journal. And on the front page it said how giant bets on natural gas sank brash head trader fund. And it says up in summer, Brian Hunter lost $5 billion in a week in hedges on gas as a market turned on this young trader. It's -- the article is rather humorous. It's entitled “A Low Profile Life in Calgary.” And it simply goes to show that, you know, the expectations that our gas, our energy are spiraled up to a point that can justify all imaginations isn't necessarily true and the recognition that a lot of bright people are speculating on the price of energy and some of them are conservative and doing quite well and others who are speculating run the risk of Hunter.

And I thought it would start your hearts a little bit to reflect on how he must look at today, a day of opportunity or a day of pessimism. But in any event I would like to simply indicate how significant this particular meeting is because I think it's the first time that this conference has ever been convened in the sense of bringing together representatives of Alaska's industry, utilities, oil and gas producers, land owners, and government representatives to confront a very challenging situation relative to our state.

I don't need to tell you that we're here because we are unconcerned. We're here because we are concerned. We know that we do face a potential natural gas shortage in South Central Alaska. And it's going to take a significant effort by everyone working together to meet this challenge. We're going to need innovation. We're going to need hand holding. We're going to need the influence of government working with the private sector.

And I think that in looking over your program, John, the fact that you're going to do a little reminiscing at noon, I see my good friend, Tom Kelly here. Tom was former Commissioner of Natural Resources when I was Commissioner of

Economic Development a few years ago. And he can do a little quick flashback on the history of the Cook Inlet Basin. And it's kind of interesting because at that time the basin was awash in natural gas and that is a situation that clearly the market could not absorb. Well, the market developed with the Agrium plant, the ammonia urea facility which I'm going to talk a little bit more about, and then, of course, the LNG facility as well.

The abundance of this gas led to the development of significant industries and really cemented, if you will, the economy of the Kenai Peninsula which is very, very important and it's absolutely necessary that we pursue every means possible to ensure that there's an adequate supply of gas for those facilities down there because we've seen what happens when the supply is cut off. One only has to look at Sitka and Ketchikan when the U.S. Forest Service basically cut off the timber supply then two facilities closed in spite of the fact that some felt they'd reopen. They never did.

Well, we no longer have a surplus of gas in this region. We're rapidly depending on the known reserves. What we are here to discuss a little bit are the prospects of the unknown reserves. What kind of incentives might be necessary for further exploration. And I think we're all very much aware of the reality associated with how projects of this nature come together. The economics have to be favorable. You can put all the emotion into the discussion you want, but if the economics don't favor the investment it isn't going to happen.

As John indicated a couple of years ago we became very concerned about the prospects of losing the Agrium facility and what that might mean to the economy to Kenai, and the recognition that the Greater Anchorage Bowl areas was so dependent on a declining supply of gas. And I'm pleased to report, of course, that as a result of efforts by many, many people in the audience that the Agrium group did suspend its plans, at least for the time being, to close this important facility and it continues to operate today. And I commend those of you who were active in that effort because it certainly has paid off.

The energy challenges that we face, however, go far beyond the needs of a single facility. We all use and consume energy in one form or another. And we all have expectations of the future and what it might hold. As you're aware, we've been very committed in our administration to bring the huge gas reserves on the North Slope to market. And one of the fundamental points of our negotiation and one that we've insisted upon is that any gas pipeline must have takeoff points to supply the needs of our state. And that provision is in the draft contract to takeoff points at the Yukon River and another at Fairbanks and Delta and one at Glennallen.

The prospects for a spur line to bring North Slope gas into the Rail belt area is one of, I think, the topics that's going to be undertaken today. And it's going to be very, very, I think, interesting to evaluate the economic prospects of just how much gas we have to move and the recognition of the role of the two plants down in Kenai that would basically be at the end of the line as major consumers of that gas if, indeed, it can be priced at a range that the economics support the acquisition of the gas as well as the marketing of the products that they provide.

There's also a promise of coal gasification and liquefaction and the potential use of coal to generate electricity. I'm pleased to see that that's a discussion that's going to be underway today. Therefore, my expectation for this conference and my, I guess, challenge to you this morning is to consider all the options as honest and candid as possible in your assessments. I think there's a common goal here and that's to identify the most efficient economic way of delivering energy to future generations of Alaskans.

And one of the discussions, of course, is just at what point do we incentivize gas development in Cook Inlet as we recognize that there are undiscovered reserves out there. One of the concerns that we have is pricing to Alaskans for utilization of gas from Cook Inlet. As you know, we have the Henry Hub issue and should Alaskans recognize and expect to have to pay a transportation charge that fundamentally is an incentive as opposed to a legitimate charge because the gas doesn't move obviously on a Henry Hub route from the Louisiana area.

It moves from the Cook Inlet area, but it carries a Henry Hub price. And I would hope that we could find a way to encourage additional exploration and bring that gas to market without putting that additional burden on Alaska. As we all know, Alaska is a high cost state, but where we have sources of energy next to the marketplace is it necessary that we apply a Henry Hub price structure which obviously is passed on to the consumer and brings Alaska gas and Alaska energy much of which is already priced with a transportation charge to a market other than Alaska. And that's one of the things that we insisted upon in the negotiations on our gas pipeline that gas would be priced in Alaska at wellhead plus transportation. Transportation to point of consumption. Well, obviously in the case of Fairbanks that suggests a very favorable rate.

In any event, I wanted to ad lib that, John, because it's very dear to my heart that once we submit and cement in a price structure that provides basically, obviously an incentive on one hand, but a burden on Alaska consumers on another to pay a transportation charge that basically is not in a legitimate recognition of a true transportation charge. We're somewhat kidding ourselves. If we want to call it that then we should recognize it for what it is.

So, in conclusion, I want to thank the AOGCC and for sponsoring. I want to thank the municipalities because I think this is a very important conference from the standpoint of future policy decisions to be made by government and municipal utilities as well as other interested Alaskans, I look forward to the forum and reviewing the ideas and information. And, again, it's good to see many of you here today because you are experts in the area of Alaska energy and your contribution is going to be immeasurable, so have a good conference. And I'll look forward to spending as much time as I can with you. Thanks, John.

CHAIRMAN NORMAN: Thank you, Governor Murkowski. And I, again, want to acknowledge the support and encouragement that was given to us by Governor Murkowski in bringing together all of the parties here. The Governor has indicated that at some point this morning I believe he said he has another commitment so, Governor, we hope you'll be able to stay with us as long as you can, but if you do need to leave we understand.

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MAYOR MARK BEGICH

CHAIRMAN NORMAN: I will now briefly introduce and then call upon each of the Mayors to say a few words. Mark Begich was first selected to the Anchorage Assembly in 1988 at age 26. During his 10 years in elected municipal office he has focused on strengthening Anchorage's economy, creating new opportunities for young Alaskans, and sound fiscal management.

Mayor Begich is the son of the late Nick Begich, Alaska's third Congressman. From his parents Mark learned the values of hard work, strength of family, and commitment to community. These are values he has applied to a successful business career and record of public service. Mayor Begich was twice named Alaska's Top Elected Municipal Official by his statewide colleagues first in 1997 and then in 2004. Please welcome Mayor Begich.

MAYOR BEGICH: Thank you very much, John, and thank you to the Commission for sponsoring this. Thank you, Governor Murkowski, and the State for helping organize this conference.

It is an honor to be here to help kick off this conversation on one of the most important issues our region and state are looking at in developing a long term secure energy policy. I'm also pleased to be here with my fellow South Central Mayors, Mayor Anderson of Mat-Su and Mayor Williams of Kenai.

About a year ago the three of us formed the Tri-Borough

Commission because we see our economies and our areas are so closely tied together. We realized working together on important issues as a single entity can mean improved public services and new economic opportunities for our citizens. Speaking for Anchorage I can boast that the community is truly thriving right now. We're enjoying our 18th year of consecutive economic growth. We'll probably set a new record this year in construction permits. Standard & Poor's, the national credit rating agency, boosted our bond ratings for the first time in five years.

I want to note these good numbers to make a point that the prospects are very, very bright for South Central, yet there truly is a storm cloud forming which, I believe, presents a serious threat, to progress in our region, the entire state, a looming energy crisis. Our region has long been blessed with cheap, abundant source of natural gas from Cook Inlet. This has warmed our homes, fueled our businesses, and grown our industries. Now gas production from Cook Inlet is in decline and known reserves are not sufficient to meet demand, residential, commercial and industrial beyond this next decade.

I believe a critical question facing South Central Alaskans is where will our energy supplies come from and at what price? Extremely high energy costs will reduce our region's attractiveness to new businesses and expanding of our businesses and industry or cost us existing industry as we already have seen.

I believe we must focus on two fronts. First, encourage additional exploration and production in Cook Inlet. There's enormous potential there in the stake in Alpine encouraging production and maintaining newly passed incentives.

Our second area of focus must be getting North Slope gas to South Central. We're sitting on North America's largest natural gas reserves. All we want to do is get it to market. Alaskans need it to heat our homes, build our business, and create a healthy economy. And I have to tell you I don't really care what the route is, I just want gas delivered here to South Central.

I want to commend the conference. And as I look at the schedule you're going to be very busy just as the Governor said. I look forward I know as the other Mayors do for what your results will be, what your recommendations will be and how we as a Tri-Borough Commission, as Mayors can help you and us achieve energy for the South Central region.

Thank you very much for taking the time and being part of this great conference today. Thank you very much.

CHAIRMAN NORMAN: Thank you, Mayor Begich.

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MAYOR TIM ANDERSON

CHAIRMAN NORMAN: I will next introduce Mayor Tim Anderson. Mayor Anderson is 29 year Alaskan. He's been a resident of the Mat-Su Valley for the past 20 years living in Talkeetna and the Palmer/Wasilla area.

Mayor Anderson was first elected Mat-Su Borough Mayor in October 2000 and then reelected for a second term in October 2003. Prior to this he served seven years on the Matanuska-Susitna Borough Planning Commission serving three years as chair. He has worked extensively on transportation, environmental and economic development issues.

He served as president of the Alaska Conference of Mayors for two years and on the Alaska Municipal League Board. In 2005 he was awarded the Vic Fisher award for Distinguished Service to the Local Government by the Alaska Municipal League. Please welcome Mayor Anderson.

MAYOR ANDERSON: Thank you, John. Guests, I really want to welcome everyone here today. And on behalf of the Mat-Su Borough we're extremely proud to be a co-sponsor of this event. I think this is probably going to be one of the most important events that we do. As the Governor before me and Mayor Begich and I'm sure Mayor Williams who will speak after me will tell you energy in South Central is critical.

We are, you know, the fastest growing area in the state, almost in the nation for the Mat-Su Borough, but what that equates to basically is, you know, our energy demands are continuing to increase and we've been having meetings and seminars and whatever with the energy producers, with the users, with Enstar, with the utility companies. And the news hasn't been good, basically. You know, the news is we're running out of gas and we need to address it now. And I think it's critical that we are doing that to continue to have a reliable, affordable source of energy for this area.

As I stated, the Mat-Su Borough is the fastest growing area in the state. And it's even hard, in my six years as Mayor, it's hard to imagine the growth. From 2000 to 2005 we grew by 25 percent. Our population topped 80,000 this year. We are the second largest school district in the state. We probably will surpass Fairbanks as the second largest municipality in the state within the year. We've had many meetings with Neil Fried and Mr. Goldstein about economic growth. And I always like to throw this one at Mark 'cause it's kind of cool to me. It's like in the year 2045 they're predicting Anchorage -- I mean Mat-Su will exceed Anchorage in population, so we're coming.

MAYOR BEGICH: We might annex you.

MAYOR ANDERSON: Might annex us. We'll annex you. But what this means basically is we have a continued energy use and, you know, we need to continue that supply. We have new businesses springing up all over the borough. We have, you know, a huge labor force and a lot of it comes down here to work in South Central. It's related to the energy.

So I would like to briefly touch on the Tri-Borough Commission. That's a very great relationship that we started several years ago, I'm quite proud of that. Coming together on issues like this it puts like I think our numbers are we say we represent about, what, 60 to -- 60 something percent of the population of the state of Alaska with these three boroughs. And that's significant. And when you look at the energy use that would probably be even higher than that. We would probably have a much higher percentage of the energy use of this state.

But it's been a very good coordination we've come across. We had some floods up in the borough recently. Anchorage was quick to lend a hand on the very first day. I was down here and I was getting calls from all over the borough about flooding issues and we needed sand bags. And I just happened to be at the Mayor's office for something else and I talked to Mark and he immediately offered sand bags. We transported them up to the borough, you know, and we went through that. The Governor was there the next day helping us with the same thing.

It's, you know, great to have that type of support. And we're demonstrating that the three boroughs working together is really a benefit to the region. It demonstrates, I think, what our issue is that we are a combined economy for South Central Alaska.

I want to also reiterate that we have to have access to an adequate fuel supply. As we've had meetings in the past and as this meeting goes on I want to say the same thing that the Governor has said and that Mayor Begich has said and I'm sure Mayor Williams will say is that we have to have the source here regardless of what pipeline agreement or what pipeline location or route we choose, we have to have a spur for South Central.

I also think we have to continue promoting exploration in this area and other areas nearby to provide the gas we need for our consumption and for Agrium and for everything else. We shouldn't be in a situation where one has to shut down because of the other one.

The other thing we would like to see with a spur line to the South Central region is that we feel that not only providing for our current uses, but we've developed a regional economy around our port down at Point McKenzie which is a complimentary port to the port of Anchorage. And we have set aside about 9,000 acres there for industrial businesses that need gas. It's been kind of interesting in my six years as we've developed this port as we talked to people they say what do you have in the way of raw materials, utilities. And we're just now bringing gas to the port, but we never had gas there. And it's important that we have gas in large supplies to help this port develop into what it can be.

So we feel that the port has potential for all types of things like we have in Kenai now, exporting liquefaction, various things that can happen with natural gas. So we've completed our deep dock draft report there which we can bring in the big panamack ships. We have the open space. You know we have planned this area well and we're ready to move on that.

The other thing I want to briefly touch on is later on in this forum you're going to talking about the coal and the Healy coal especially. And this is another thing we'll tie into our port. We would like to look at exportation of the coal and any other value added parcels of coal at our port also, which means we need a rail spur. And we're working with the Alaska Railroad and our federal delegation and our state delegation to bring a rail spur from Willow down to the port and that along with our area that we're going to be putting into service next year will provide transportation links, but the key to the rail spur is we have to have a major transportation source to the port by rail to move the raw materials in and out of this state.

Again, I'd like to thank you for attending the forum. With your presence you're demonstrating your commitment to South Central's long range energy needs and we will continue our partnership in the Tri-Borough area to remain focused on the energy needs we have here, and I'm looking forward to the report that comes out of this forum. Thank you.

CHAIRMAN NORMAN: Thank you very much, Mayor.

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MAYOR JOHN WILLIAMS

CHAIRMAN NORMAN: I'll now introduce Mayor John Williams of the Kenai Peninsula Borough. Mayor Williams was elected Mayor of the Borough in November of 2005. He's lived in Alaska since 1962 and was involved in construction and the petroleum industry as a process instrument technician for many years. He retired from the University of Alaska in 1978 after 17 years instructing petroleum technology and process instrumentation at the Kenai Peninsula College

Previously Mayor Williams was the Mayor of the City of Kenai from 1987 to 2004. He is a past president of the Alaska Conference of Mayors, past member of the Alaska Municipal League Board of Directors, was the 1998 recipient of the Alaska Municipal League Elected Official of the Year Award, received a Mayor Emeritus Award from the Conference of Cities Conference, and has received numerous other recognitions and awards. Mayor Williams.

MAYOR WILLIAMS: Thank you for that introduction. It's a pleasure to be here once again visiting with many of my friends and colleagues from years gone by. And I do bring you greeting this morning from the oil capital of Alaska and, of course, that's Kenai. For many of you now may not recall, the oil capital of Alaska was the designation given to us by then Governor Hickel when, in fact, the only producing area for oil and gas was the Kenai. And I think back to those days when the constant revenue stream to the State that was being derived from the Cook Inlet was well recognized. And I shudder to think in our early days where we might be had it not have been for that revenue stream.

However, today things are a little bit different. We're still a thriving industrial community and we still depend on oil and gas. And, of course, all of the tremendous discussion that's been evolving over the issue of the gas line which Governor Murkowski has been so eloquent in producing and so hard working in trying to get to us are still central in our thinking. But it's a pleasure to be here today at this important forum for the energy future of the communities of South Central Alaska.

I am pleased to be part of this conference and I'm equally pleased to be a part of the Tri-Borough Mayors Association along with myself, Mayor Begich and Mayor Anderson. We brought the three communities of Anchorage and the Mat-Su and the Kenai Peninsula Borough together as co-sponsors of this event because of our deep interest in not only the oil and gas that's there presently, but for the future as well. Together our three communities, as you've heard, represent over 400,000 citizens of the state of Alaska, but I caution everyone that together our citizens have the most to lose if future local, state and federal policies and incentives are not developed in the very near future to address our energy security.

Policies that promote new oil and gas exploration in Cook Inlet and other as yet undeveloped regions of Alaska. Policies that promote enhanced recovery efforts in our existing aging oil fields in Cook Inlet, and policies that promote the delivery of North Slope gas to the Cook Inlet. Policies that promote responsible conservation and that develop economically viable new alternative forms of energy to better diversify our mix of energy sources. And, finally, we must develop these policies and initiatives in consultation with the energy industry who will be making the billions of dollars in investments in the coming decades to secure our energy future in South Central Alaska.

Together our communities stand to benefit tremendously if we can achieve a strategic and common sense thinking in our government policy. This strategic thinking must provide low cost energy that will make South Central Alaska an even more attractive region for industries, businesses and, of course, for the families to operate those industries and businesses to locate in.

I believe that in the coming decades the cost of energy will become one of the single greatest economic issues facing the citizens of our entire state and, of course, South Central Alaska in general. It is a challenge that if not addressed correctly will stifle that growth and will place a tremendous financial burden on all of our citizens especially the low income and our beloved seniors.

Alaska has always been known as the land of opportunity. That's what brought me to Alaska. That's what brought many of you to Alaska. And we're all familiar with many of those successful people who came to this land of opportunity. In the Kenai Peninsula Borough we have enjoyed the many opportunities that inexpensive energy sources have provided over the last 40 years. Inexpensive heat and light, economic growth through oil and gas development, major manufacturing facilities that rely on low cost natural gas, oil and the general economic growth based in no small part on the availability of all of that low cost energy.

I believe our future is bright. I believe it's bright in South Central Alaska and the entire state. I believe we are on the verge of entering the next great wave of new development efforts in the energy sector with the eventual construction of the North Slope Gas Pipeline, with major new exploration all across Alaska, and with major mine projects beginning construction and underway in development in several regions of our state.

And with this great wave of development I believe we also are on the brink of a new generation of migration of people into our state of Alaska, because together when you put all these projects next to each other we're going to need all the help we can get to staff the construction and the operation and the maintenance, the long term viability of these projects. But this development is at risk if we cannot secure reasonable priced energy to fuel this growth. Reasonable priced energy to heat and light our homes and businesses, and to supply the huge power needs of these major projects. We must come together to address these problems now. We cannot delay.

The energy forum is an important step towards addressing these challenges. I believe that this is an outstanding group of individuals, agencies and companies that have gathered here today and they are fully capable of undertaking this very important dialogue and carrying it towards the future. I also recognize that this event can become lost in a myriad of conferences and forums that have already been held in the past.

In that light, I challenge all of the speakers today to speak your mind, not necessarily what is safe. We no longer have time to play it safe in these important decisions. We need candor. We need fact. We need a serious dialogue between you and the audience and to the audience when your opportunity comes I challenge you to ask hard, but fair questions. Don't be shy.

You need to keep our speakers on their toes. You need to keep them honest. And we need everyone's participation to make this a truly meaningful event that will look towards the future of Alaska.

My thanks to Commissioner Norman, Commissioner Seamount for giving me this opportunity to share these thoughts with you today. This should be an outstanding event. I want to thank my fellow Mayors and the Alaska Oil and Gas Conservation Commission for making the forum possible. And of course, my thanks to all of you who are taking the time out of your busy lives to participate. Thank you very much.

CHAIRMAN NORMAN: Thank you, Mayor. Governor Murkowski has to leave now for another commitment, but can we all give him a round of applause for his many, many years of service to Alaska. And another round of applause for these three great Mayors that are here to support us in this endeavor.

As we've been trying to work through this issue Commissioner Seamount and I both said that we were reminded of the children's story, the fable of the three blind men describing an elephant in trying to quantify the challenge that we have and come up with solutions as you talk with different very knowledgeable people each has a slightly different perspective on this. And therein, I believe, lies the value of a conference like this.

We purposely are going to have some redundancy in the conference, but if speaker after speaker comes up without having compared notes with each other and makes a similar presentation that would indicate, at least, that that's the conventional wisdom on the challenge we face and the solution. Conversely, if speakers disagree that's what we would like to see because that would bring into sharper focus the issues that we face.

There's an old saying among aviators never run out of altitude, air speed, and ideas at the same time. And that came to mind as Mayor Williams was talking when he said we would like all presenters to be candid and straight forward, and we are running out of time. And if you equate time with the altitude and you equate gas, natural gas has been our air speed that's kept us going for these years, we know that our reserves are being depleted. What we've got to do is have some ideas that come out of a conference like this, so we look forward to a frank exchange of the information.

A transcript will be made of these proceedings. And I also want to acknowledge the participation of ISER, which is the Institute of Social & Economic Research. A summary of the proceedings will be prepared and distributed to all participants and then broadly through a broad distribution list following these proceedings.

I'm now going to turn the microphone over to my co-Commissioner Dan Seamount who will take charge of the program and move it forward from here on.

Dan Seamount, Jr., has served as one of the three Commissioners of the Alaska Oil and Gas Commission for over six years. The Commission's main emphasis is regulation of underground drilling, reservoir development operations to ensure conservation of resources, and the protection of correlative rights, the rights of respective owners to develop their fair share of a resource.

For 27 years prior to that Dan Seamount worked in exploration and development geology at different times for Chevron, Marathon and Unocal in California, the Rocky Mountains, the Mid Continent and Alaska. He holds a Master of Science degree in Geology from the University of California Riverside, and is a licensed professional geologist in Texas and Alaska. While a Commissioner he also served as associate representative of the Governor of Alaska to the Interstate Oil and Gas Compact Commission. Commissioner Seamount, your microphone.

COMMISSIONER SEAMOUNT: Thank you, John. It's starting to get kind of lonely over on this side and I talk to John too much too often, so I need some more company, so I'd like to call up the first few speakers to sit up here. Could we have Dr. Charles Thomas, Arlon Tussing, and Bill Popp I guess that should give us enough company for now.

We have a star studded agenda today. We're hearing from experts from industry and government. Many of you have heard these different experts at different times and different places, but we've gathered them all here today so that as has already been stated so that all of their candid ideas can get out.

Some of the presenters have authored outstanding papers about the South Central Alaska energy situation. Others have dealt with it in the past and continue to deal with it. And these others will be key to providing the areas' future energy supplies. The main purpose of this meeting is just for information. You will want to take this information away with you.

The first question is do we have a looming problem or is it just a challenge to be dealt with using some sort of transition solutions? The next question is what are our options and are there alternatives to natural gas? The final question and it would be a miracle if it was answered in this meeting today is how do we make those options and alternatives realities in time to avert a crisis?

The agenda has been modified today. This is the one you probably received in the mail. This is the one we're going to go off of. There's a lot of speakers in this forum. And in the interest of timeliness we reserve the right to stray even from this agenda, but I promise that we're going to try to keep to it, stick to it as much as humanly possible.

If you have any questions of any of the presenters because of the time crunch we have and the numerous presenters what we're asking is that you write the question down and hand it to one of our people out here. You know, any -- John or I or Jody or any of the people from DNR who are graciously helping us out.

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CHARLES, THOMAS, Ph.D.

COMMISSIONER SEAMOUNT: Okay. Our first technical presenter is Dr. Charles Thomas. Dr. Charles Thomas has a B.S. in Mechanical Engineering from Auburn University and a Masters and Ph.D. in Engineering Mechanics and Applied Mathematics from the Georgia Institute of Technology.

He began his career in 1968 with Phillips Petroleum Company as a research engineer and progressed to division reservoir engineering manager. He moved to Idaho National Laboratory in 1989 where he has a science and engineering fellow. He was director of the Petroleum Recovery Research Center at New Mexico Tech in 1997. Since 2002 he's been manager of Science Applications International Corporations, that's SAIC, Alaska Energy Office in Anchorage.

Charles has authored or co-authored 25 technical papers and reports and has four patents. He was a Society of Petroleum Engineers' distinguished lecturer in 2002 on methane hydrates. He has been the project manager and co-author of six Department of Energy Reports on Alaska oil and gas resources from 1990 to 2006 two of which will be the basis for these presentations at this forum. And I've read the two and they're outstanding documents. In any case, let's welcome Dr. Charles Thomas.

DR. THOMAS: Thank you. It's a honor and a privilege to be here and on this panel with all of the distinguished speakers, and the Lieutenant Governor and the Commissioners. I look forward to participating in this as well as presenting our presentations of which there will be several.

South Central Alaska Energy Forum, we're going to talk about natural gas supply. The reports that these are based on were sponsored by the U.S. Department of Energy over several years. They're shown on the screen there as well as the locations where you can find them. The web sites are listed there.

The first one on the left, there are a few copies outside of the executive summary and the CDs that go with it. The other two are on the web site. The one on the right, Beluga coal, which you won't hear too much about at this conference I don't think, will be posted any day now. It has been cleared for posting. You'll also find, I think, Bill Popp always puts these on his web site, so it's locally available as well.

I will talk to you about Cook Inlet gas supply options to meet projected demand, the ultimate reserves as we have looked at them, potential for increased reserves, and then compare the gas reserves and demand forecast, and then give you some conclusions and summary statements.

Why are we here today? You'll probably see this or something like it. You've already heard it referred to. You'll see it many times or hear it referred to. I don't believe this -- the lights will go that far. That's fine. You can see the fall off.

(Whispered conversation)

I was trying to use it as a laser pointer. That's okay. You'll just have to do without the laser pointer I think.

But we see the decrease in reserves in the forecast. This is the Department of Natural Resources forecast. And just as a reminder this is the consumers, you know, power, natural gas supply, or industrial activities, and operations in the Cook Inlet are shown there as well. About 200 -- a little over 200 Bcf a year.

Just to show that we are not unique in Alaska, this is a slide out of the National Petroleum Council report in 2003. You'll see up from the bottom up through the pink layer there that is U.S. production. Above that is Canada, reserves that come in the U.S. and Canada. And you'll see the expectation that there will be natural gas from the North Slope of Alaska. And the rest of the U.S. demand filled by LNG imports.

If you look at the U.S. production, you look at the bottom part of that curve, that's proved reserves. The lighter color will require new drilling. And you'll see that there's a great anticipation in the Lower 48 that there will be a lot of new gas discovered and produced for the use of the Lower 48 to meet those demands, otherwise it'll have to come from LNG imports. That's meant to be a question.

I guess the reference I want to make for you is that most of what we are looking at in our forecast, the Division of Oil and Gas and us, is primarily the bottom piece. It's essentially proved reserves with a small amount of reserves growth. That's what we're here to talk about off and on the next two days.

In the Lower 48 you get the same demand sectors. They've got the same problems. We have the same problems, I guess, you would say for the nation. That industrial use of natural gas may have to decrease to satisfy the needs.

Many of you have seen this figure out of our report. Supply and demand. This is back when Agrium was expecting to have to shut down at the end of 2005. The blue is the LNG export LNG plant. And its export license ends currently in 2009. And then the utility gas and gas, you know, power use.

And then the curve, the top one there is -- was our forecast for the dry gas pools. And indicating that somewhere in the not far distant future we have a potential problem on our hands. And recognize just that these are yearly averages and we all know we have fluctuations in use that -- around this. So the certain times of the year in the winter we may have issues earlier as we had last year that we're aware of.

So looking at not only Alaska, you think about the Lower 48. Where can our gas come from? Conventional gas resources either through reserves growth in existing fields or through new fields that are found through exploration. And then there's the unconventional gas that we're aware we have maybe very large resources in the Cook Inlet Basin. Coal bed methane with all of the issues that relate to those, to the development of that resource.

The other option is like the Lower 48, we import gas from outside of South Central Alaska. In our case that can be a spur pipeline from the North Slope or import LNG from outside of Alaska.

Other potential contributing factors. I think we all -- it has been recognized that gas storage is certainly something that help with the seasonal demand variations and allow us to plan better.

Conservation increased efficiency. I think we all recognize that and should consider that as part of our agenda.

We can reduce industrial use or convert to some other source. And we know Agrium is looking at this. Convert to coal for its resource to continue its industrial activity.

Power generation alternatives other than to offset natural gas use would be coal, wind, geothermal, hydro power, biomass. All of those opportunities are something we can consider in the future.

A quick review of this. You're going to hear a lot more about this. I don't want to get too much into it. But oil and gas exploration and gas field discoveries in Cook Inlet, from the beginning there have been 240 exploration wells. Exploration activity decreased over time by virtue of all the fields found by 1970. All exploration until the mid '90s for oil and gas was found as part of that activity.

The recent activity in say the last five years has focused on gas. There's been approximately 10 trillion cubic feet of original gas in place discovered and the economic ultimate recovery of that or estimated ultimate recovery is about 8 1/2 trillion cubic feet.

There are 28 gas accumulations and eight oil accumulations. And you see that map as to where they are located on basically two trends.

I'm not going to go into this. You'll hear a lot more tomorrow. David Hite is going to discuss our analysis that came up with this, but what we did was some statistical analysis looking at known fields and were based on analogies with other basins around the world, you would expect there to be other fields. And he will go into that in detail.

The conclusion was basin endowment we estimate it could be between 25 and 30 trillion cubic feet original gas in place of which 10 have been found. However, I would point out one of those questions we all ask sure, you're saying there's a lot there, but where is it? Our statistical analysis like this does not tell you where it is. You have to go talk to your geologist and drill some wells.

So in summary there, we're saying approximately 25 to 30 trillion cubic feet of gas in place. If that is true the Cook Inlet Basin's undiscovered conventional recoverable resources are on the order of 15 trillion cubic feet. However, to realize this potential is dependent on number one, having access to prospective areas, two, it's going to require very significant capital investment. There's going to have to be a drill ship for Cook Inlet exploration. And I think we're all pleased to at least understand that is on its way and could happen early next year. And then, of course, all the new technology, 3-D seismic, long reach drilling, all those things that make this exploration possible.

The access issue, this is a map from our 2004 report. You see all of the special use lands, the Kenai Natural Wildlife Refuge. All of those issues that would tend to make it difficult to drill anywhere you may think there will be gas. So there could be quite a bit of this potential resource that is at the moment at least inaccessible.

We're not unique in Alaska in that. I thought you ought to see that in the Lower 48, you can see these areas highlighted there that are also impacted by access restrictions. So, you know, we're all basically in the same boat as a nation.

Historical Cook Inlet gas prices. The red line is the

Lower 48 U.S. wellhead prices, and the dark line is the Cook Inlet prevailing value. You can see that we have always enjoyed lower prices than Lower 48. However, ours are trending up just like in the Lower 48. And, of course, we see that spike going up to $15 or so and it has dropped back down very recently. I think we've already had that referenced and what that means. Now where it goes in the future I expect Dr. Tussing will tell us more about that.

This is a forecast, I put the Department of -- Division of Oil and Gas forecast on this one. This is a demand forecast from our June 2006 market and needs study showing the fertilizer, the LNG I left the way it had been in the past.

The up dip in the green line there is where we included power for Pebble Mine. Originally we had this -- our analyst had this starting in 2009. I think we feel that's rather optimistic so I moved it out to 2014, but again, we've got to look at, you know, those issues related to power and commercial use and facilities as well as industrial. So, again, we're seeing that there's been some increase out to maybe 2015 or so.

This is another slide from our 2004 report where we had put on some reserves growth from existing fields of about 1.4 Tcf, which would indicate that you could meet basic demands plus some industrial needs just with that level of discovery.

I won't ask you to read this, but we're currently doing an update of this and we're looking out here at the undeveloped fields.

In the next picture you see a rather busy slide, but in the last few years there right around history and forecast we're seeing some uptake, so we are getting some reserves growth in the Cook Inlet already. And I guess what we're saying is what's it take to continue that?

Reserves additions in 2004 to 2006, our analysis this would be the dry gas fields. That we've added about 260 Bcf in our estimates. And if you look at what's been consumed in 2004 and 2005 it's about 416. So it's we haven't quite replaced our reserves, but, you know, we also see that there's a lot of potential for reserves growth in our analysis of these data.

So in conclusion, our base case that conventional gas will meet commercial and residential consumer demand until about 2012 with existing reserve base, but that would require, you know, curtailing the industrial use as we had assumed then. Current estimates suggest maybe on the order of 2014 and 2015 with the somewhat limited reserves growth. E&P efforts have been successful in replacing a portion of the reserves, but much more is required. Exploration reserves growth or some combination can provide, I'll suggest, the additional supply needed, but it will not be cheap. Our estimates were anywhere from 50 to 75 cents per Mcf depending upon where you are in the Cook Inlet.

So just as an example, finding and development costs of even 50 percent of that estimated 15 trillion out there over the next 20, 25 years could require an almost 4 to $6 billion investment by the industry. So it's not cheap and it will impact, of course, the price of the gas. Our reserves growth might, you know, start satisfying our needs.

Observations. Aggressive and successful Cook Inlet exploration has the potential to support basic needs and some industrial base for 25 to 30 years. A spur pipeline will, of course, assure supply from the North Slope for the life of the Alaska Gas Pipeline from North Slope resources. LNG import is an option just like it is in the Lower 48. Alternate energy sources, I think I've already mentioned this, I think all of those are important components of a sound energy policy so.....

And one other question I'll leave you with and we'll all think about as we go through these presentations, what are the trade-offs between these supply options and how do they relate to each other? And maybe one more thing, I don't think we're running out of gas, but we are probably running out of cheap gas. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Dr. Thomas.

Presentation not to be submitted to Forum

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ARLON R. TUSSING, Ph.D.

COMMISSIONER SEAMOUNT: Our next talk will be on gas pricing by Dr. Arlon R. Tussing. He's been affiliated since 1965 with the University of Alaska as Professor of Economics in the Institute of Social and Economic Research or ISER, one of the groups that's helping sponsor this meeting today.

He's had other positions and specializes in oil and gas, natural resources and environmental policy. He has authored, co-authored or been editor of more than 300 books, articles or reports on economics and public policy in the energy and natural resource industries. And that publication list is about that thick. I was looking through it yesterday. Particularly noteworthy, Dr. Tussing is principal author of the Natural Gas Industry Evolution, Structure and Economics published in 1984 and 1995 with co-author Bob Tippee who's now the editor of the Oil and Gas Journal.

From 1966 to 1970 Dr. Tussing was staff economist for the Federal Field Committee for Development in Alaska and through the 1970s served in Washington, D.C. as consultant and chief economist at the U.S. Senate Committee on Energy and Natural Resources under Washington Senator Henry M. Jackson. In these capacities he helped draft the federal legislation that settled the Alaska Native Claims, authorized construction of the Trans-Alaska Pipeline, and also worked on helping draft the State's Permanent Fund Dividend Program.

In September 2005 he received the 2005 Senior Fellow Award of the United States Association for Energy Economics in recognition of his outstanding insight and foresight regarding the evolution of U.S. and global energy markets.

Dr. Tussing is a third generation Alaskan and lifelong resident of the Pacific Northwest. He holds undergraduate degrees from the University of Chicago and Oregon State University, and a Ph.D. in Economics from the University of Washington.

With that I'd like to welcome Dr. Tussing and thank you for attending.

DR. TUSSING: I'm in a little predicament here. There's a proceeding pending before the Alaska Regulatory Commission concerning pricing of natural gas, specifically is a price that Enstar proposes to pay Marathon Oil for gas and charge to its consumers just and reasonable. And I've been a witness on behalf of the Alaska Department of Law with regard to the ratepayer and public interest in this issue.

And when John Norman approached me about speaking in this forum I felt I had to check with the Attorney General's office who's sponsoring me in the proceeding and with the Commission as to the propriety or the possibility of conflict of interest and to avoid creating any impression that I was trying to litigate or lobby this matter ex parte. In other words, other than in the proceeding, but nobody contemplate that the hearing would not have concluded with the decision by the Commission. And so the Commission has extended its date for decision to the 28th of this month.

And although other parties here from the Governor to the utilities are free there's no impropriety on speaking our minds, I still feel constrained. And so I will not deal with specific pricing issues that are involved in the hearing. The hearing record is in the public domain and I presume those who are interested can go into the Commission offices and read my testimony and that of the other parties and interveners.

So I'll go on and talk about some issues of pricing. The big picture issues and things that extend over a longer period than the proposed contract between Enstar and Marathon. There is in the Lower 48 and all but two Canadian provinces a fully integrated pipeline system that is capable of delivering gas throughout that -- most of the entire continent so that at least to some extent and theoretically any increase or decrease in sales or purchases of gas anywhere in North America except for Alaska and a few other isolated areas will affect the others.

And virtually all gas is produced or marketed, is produced and marketed, within this larger part of North America, flows into the system, is commingled so that one can speak of a representative gas price at a particular -- in a particular state or a particular market area, load center, producing area. And it includes all the gas that is coming from or going to every other area through that area. The gas that is being measured and that is being priced includes gas that is destined for parts of the continent that has cold winters like Duluth or Winnipeg which are colder than Anchorage, they are colder and probably longer, colder winters than Anchorage or Miami.

Places that have what we call winter peaking loads and those that have summer peaking loads particularly southeast and southwest where the largest category of consumption is electric generation for air conditioning in the summer peak, industrial users and households served by local distribution companies. And so it's meaningful to talk about gas prices in general. And so when we talk about gas prices we're referring to a price in a particular place that includes all the uses, all relevant or gas origins, the producing basins that serve that area are all relevant and end uses. And there is in a sense that every -- almost everybody who talks about it knows what they mean generally by talking about the gas price. It's a number. It's a volumetric price for a commodity attached to a certain place and a certain time.

In Alaska, Alaska is not a part of this continental market. The natural gas commodity itself has virtually no commercial tie to that market, nor is there a clear -- nor do we know what we mean when we talk about a gas price. More than half historically and at any point in time including the present, more than half of the gas that's produced in the Cook Inlet area and almost half of the gas sold in Alaska including that gas that's produced on the North Slope and sold among the producers for various field operations, for pipeline fuel and things like that, almost the greatest portion is sold in large contracts to large customers, most of them outside of the state.

The second biggest consumer of gas in Cook Inlet and in the state is for fertilizer manufacture and mostly for export. So the -- in terms of an actual market integration if the Alaska gas producing industry is part of an integrated chain it belongs in -- it's part of the Japanese economy presumably or in a wider sense some kind of trans-pacific or Pacific Basin economy. And the pricing there is, of course, a big part of the revenues of gas producers. The pricing there is generally tied to an oil index. And that is not to any gas index in the United States or the CPI or any other U.S. thing. There's a logical reason for it.

This gas was originally bought by Japanese utilities to replace heavy fuel oil or bunkers in electricity generation that were conventional old fashion steam plants and that was the alternate fuel. Now, a number of them are now -- or a number of the plants served are now combined cycle gas turbine based machines and the alternative fuel if there is one would be a distillate oil or a lighter cleaner oil, but the pricing formula has changed over time to reflect that. And so to what extent is this relevant?

You know, what is the price of gas in Alaska? You've got to take account of that. And then there are other smaller local sectors, electricity generation within Alaska, mostly by combustion turbines and combined cycle plant. And the other big consumer, of course, is for distribution to residential and small commercial or institutional customers whose demand is dominated by, but not exclusively, space heating.

So what are we talking about? We don't have a full natural gas economy here. And so we talk about pricing. We talk about why is the price of gas bought by and sold by Enstar essential. And that's recognizable because the gas supply and the gas demand of local distribution companies with a mixed consumer base is well known. Enstar is a pretty typical LDC, local distribution company, in terms of its mix of customers. And it is, of course, a winter peaking utility because of the climate here and the role that space heating occupies in its customer portfolio.

Well, that being said gas in the sense that people talk about it in the Lower 48 or in Canada the market is a competitive commodity market. And it fluctuates from time to time taking up the practice that old J.P. Morgan had when people would come and try and hit on him for advice on the stock market and they said well, what's the market going to do. What's the market for some -- do or not do. He says it's going to fluctuate. And when people ask me where's the gas market or what's the gas price doing? It's going to fluctuate.

One of the things that is both the biggest lesson to me and one of the most important things I've insisted to my students and clients is authoritative forecasts of gas prices have, in my lifetime anyway, always been wrong. And they've been disastrously wrong. We take examples like EIA's annual short-term forecast. Over the majority of years which since they've been issued the prices have moved in the wrong direction. And that's not an unusual outcome.

And a couple of my observations as to why this is true don't have to do with the specific institutional biases is that the biggest systematic error is the systematic under-estimation of the elasticity of supply and the elasticity of demand. That's one thing that they don't understand or appreciate or learn how unexpectedly the amount demanded can be diminished by a price increase or the amount supplied could be increased by an oil price. The current -- the biggest errors, the ones that persist for over a generation, perhaps, were the failures to take into account impending change to the structure of the market.

And if I had time to give a lecture here it would be -- it's fascinating to talk about the change and the errors that occurred around 1970 when almost nobody, I think nobody realized that the fundamental change that the gas industry in the United States had always up to then been powered by resources that were discovered incidental to the search for oil and which in the accounting scheme of the days weren't afforded any cost, but which the state and federal regulators insisted that it be given a Btu proportional cost assigned a share of the cost of the joint product oil and gas.

And there was very little awareness that beginning sometime around say the decade surrounding 1970 to add more gas reserves and to continue the growth of -- the continuing growth of demand would require recognition of the cost of looking for gas rather than just having the producers flog it off at some -- anything above incremental costs of listing to gas utilities who could substitute it for the synthetic gas they'd been made with coal and at a lower price.

I think the next biggest systematic error was in the late '70s and early '80s when there was no realization of how under-utilized the existing gas resources, the known and discovered, the producible gas resources had been made by the regulatory system. In the middle of the '80s Canada did not realize how the rules imposed both by the federal government and by Alberta to the necessity in one case for 27 or 31 years of reserves to back up any incremental exports. In the case of the Province of Alberta just the reserves that were required to back up any long term contract more than doubled the effect of cost of a unit of gas. And once those were removed there was a real boom of Canadian gas available to the North American market at roughly a dollar Canadian per Mcf or gigatherm.

Well, I think one of the current blind spots particularly in Alaska that in general is to realize how complete and profound a change may be coming as a result of the globalization of the gas market. Unlike crude oil there has never yet been a world gas market although Japan, the world's fifth largest consumer of natural gas, it imported most of its gas or all its gas as LNG, but there was never a market for LNG or for the re-gasified gas in Japan. Almost all of that LNG came into terminals. There were at last count 22 LNG receiving terminals, almost all of them owned by particular electric companies and they were located for the convenience of their power plants and there was no pipeline -- never a pipeline grid built to joint them.

There was really until oh, about 10 years ago some colleagues and I started pushing for some demonstration projects of selling gas out of a pipeline between two power stations. It never occurred to anybody that they could have a competitive market. Or that they could serve the 85 percent of the geographical extent of Japan's main islands that were out of reach from natural gas.

The Japanese model of LNG development was actually invented in Alaska in the 1960s and it's been replicated all over the Pacific Basin, not just for Japan, but for Korea and Taiwan who have abandoned or tried to create -- both of which have tried to create integrated national markets.

One of the things bound to happen with the U.S. push to import LNG is that you expose the international LNG producers and traders at the U.S. border to the intimately and totally competitive U.S. pipeline based markets. And it's going to change both of them.

Now it's counter-productive in Alaska to think about importing LNG, but give a little bit of thought and this is probably the most promising and ultimately, after people overcome their initial shock and awe, the best and the most secure, the most probably successful strategy for the Cook Inlet Railbelt market. I've talked about this elsewhere and I think other people are looking at it. But assuming that the flow of imports into the West Coast of North America does commence, Alaska is going to be in that stream. Anchorage is less than 200 nautical miles from the Great Circle Route between Sakhalin and Los Angeles, between Thailand and Los Angeles. And the technical, that is the non-regulatory lag time for getting an LNG receiving terminal in operation or a conventional one, a FERC certified one is probably about three years with a offshore loading, offshore regasification plant you'd probably get it down to two years.

Now, I'm not an advocate of converting the existing plant, but taking advantage of the fact that the Kenai area is probably the only site in western North America that would almost totally lack NIMBY type opposition and has sufficient experience with the moving of these tankers.

Now, one of the problems that I think you're going to have to face and there have been people that have said we ought to go for all options that these options you do follow suck the wind out of the others. I've considered the spur line. Actually it's probably the apparent determination of the energy and political establishment in Alaska to promote that regardless of its number of problems including the potential cost of getting gas from the North Slope into this region is it's a very powerful deterrent to additional exploration, particularly of exploration for new pools in Cook Inlet. But one can build a spur line in about the time it would take to find, develop and equip a new Cook Inlet field.

Well, who's going to do that if there's going to be if instead of the existing -- the long term surplus of unsold reserves that we've lived with for 40 years or so. Instead of that you have hanging over the market for Cook Inlet gas that whole monster in -- at Prudhoe Bay plus the economies of scale involved in a pipeline connection.

I'm not taking sides one way or another. I say there are things that have got to be considered, but I don't think anybody else has thought about the degree to which a credible thrust or even the sense that there is political and industry momentum to build a spur line how that's going to have the impact that it's going to have incentives to do more in Cook Inlet than to develop the existing known reserves. Now I shouldn't go further on that because I took that up in some testimony that you should get from the testimony. I shouldn't say any more until the Commission has made its determination And I think I've taken my time.

Anyway, we'll all be around and have an opportunity to talk about some of these things, but on the basis of several decades of work in these areas I do anticipate and worry about some major terms that are going to be missed and the need for some deeper thought and perhaps some very painful choices. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Dr. Tussing.

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BILL POPP

COMMISSIONER SEAMOUNT: Our next speaker will be Bill Popp. He's the oil and gas and mining liaison for the Kenai Peninsula Borough. He's going to be talking about the Kenai Peninsula Borough Perspective.

Mr. Popp has been responsible for all aspects of oil and gas and mining policy for the borough. This includes development and advocacy for oil and gas and mining related legislative initiatives and policies at the municipal, state, and federal levels of government.

In addition, Mr. Popp is responsible for industry and community relations and support of the continued growth and health of the oil and gas and mining industry within the Borough and Cook Inlet Basin. Mr. Popp currently serves as the vice-chairman of the Alaska Gas Stranded Act, Municipal Advisory Group and is also responsible for coordinating work force development initiatives for the borough. He was previously appointed as a co-chair of Governor Murkowski's Agrium Task Force which was charged with advising the Governor on policy proposals to help preserve the Agrium nitrogen plant in Nikiski.

He's been involved in many other important matters that he asked me to not go into at the moment, but they are very important including being on the Assembly, but with that, Mr. Popp.

MR. POPP: Good morning, everyone. It's a pleasure to be here today. I appreciate the invitation from Commissioner Norman and Commissioner Seamount to be part of organizing this particular conference and to be one of the first speakers you hear from today to kind of set the stage for the many presentations that we're going to get over the next two days.

And I'll tell you I've been wrestling with this. This is going to be a conference that can have great impact on policy decisions at the state and federal and local level for many years to come if we pull it off right. And in that vein I have revised this PowerPoint about a half dozen times including last night up until about 1:00 o'clock in the morning because I've been trying to refine this down to the core issues that I think are important for this conference to consider.

And my job today is not to set out solutions, but to point out the base line facts as we see them from the Kenai Peninsula Borough, to offer some perspectives on some of the concerns that we have on some of the issues that have started to develop over the last several years, and to perhaps offer for some sharp operators in the audience some opportunities for new ideas and new investments to address some of these issues. And I'm hoping that this will go beyond this conference. I see a number of Legislators in the room, I see a number of company officials in the room, municipal officials, agency officials, and I think it's important that this conference set the stage for the dialogue going forward.

And so with that in mind I've entitled this presentation Oil, Gas, Dollars and Workers because I think those are the core issues that are going to drive a lot of these policies over the coming years.

Now, forgive me, the printer at the hotel was not available at 1:00 o'clock in the morning so I don't have my speech in front of me. And as is the case with all of us who are showing a little gray at the temples my vision isn't what it used to be, so I'm doing this all from memory and trying to read the slides from what I believe is a great distance. So with that in mind we're going to talk about some basic topics that are going to kind of weave throughout this whole presentation this morning.

First of all, we're going to talk just a little bit about the Kenai Peninsula Borough which is the first oil and gas province of the state of Alaska in lot of ways. We are also going to talk a little bit about the Cook Inlet hydrocarbon industry today. We're going to delve off into some issues and concerns as we go through this presentation, and then we're going to talk just briefly about what the future issues are on the horizon.

As I said, we are the first province. We have 150 year history of oil and gas exploration in the Kenai Peninsula

Borough from the first sightings of oil seeps in the state of Alaska ever recorded by Russian explorers in the 1850s in the lower part of the Cook Inlet in the borough to several decades later the first attempt to drill for oil in the state of Alaska right across the bay from Homer at the Iniskin Peninsula using rough cut lumber, wood derricks drilling down to the grand total depth of 500 feet on those oil seeps. Didn't work out.

Almost six decades later it finally did work out in the Swanson River field with the discovery of oil that pushed us over the top into Statehood with the Swanson River field. And more recently in this decade the attempts to find new oil discoveries using directional drilling technology that previously had not been used in the Cook Inlet Basin at the Cosmopolitan Prospect by ConocoPhillips and, hopefully, again in the future by our new leading partner in that venture Pioneer Natural Resources, so we have a long history. We kind of know oil and gas down on the peninsula.

There's a visual representation of that history. This is a time line of exploration based on number of wells drilled annually going back into the -- excuse me, we just turned off, going back into the 1950s. Boy, I can get the laser pointer to work. I guess I'm not too blind.

Going into the peak of production and exploration in the late 1960s and early '70s, and then the long slow decline into malaise for several decades. We never saw that second wave of drilling that we should have seen and upward spike here by the independents that would have followed on the majors. They went north. They all went heading up elephant hunting on the North Slope. But recently I think we can now pronounce that that second wave has finally taken place since the year 2000 with the significant increase in the last half decade of natural gas exploration on the Kenai Peninsula and in the Cook Inlet Basin, all in search of a resource that has finally become in demand. The balance and demand scales have balanced and now we have an equation that actually promotes exploration.

Okay. I don't know what that one was.

This is the Kenai Peninsula Borough. We're bigger than eight U.S. states including West Virginia. There's a little over 50,000 of us. We're getting older and we have fewer kids in school and we've got about $10 billion in gross estimated property valuations in the borough. That's the base line.

That's our top 10 property taxpayers based on assessed valuations in the Kenai Peninsula Borough. If you look very closely only one of them is not involved in the hydrocarbon industry, the phone company right there in the middle. Every other one of them in our top 10 are based in the hydrocarbon industry.

Looking at employment, way over on the left-hand side that's our oil and gas employment right there. The big one in the middle is government. That's state, federal and local government, and then all the other sectors that make up our total employment of a little over 18,000 people.

Now that oil and gas employment figure may not seem all that important. It looks pretty small, but when you start digging into the nuts and bolts of what those numbers mean in terms of the assessed valuations and the employment numbers that's 7.4 percent of our employment picture, generates 18 almost 19 percent of the reported payrolls in the Kenai Peninsula Borough. And the property tax valuations in the Kenai Peninsula Borough oil and gas accounts for about 1 out of every 4 property tax dollars we collect.

Why does it generate so much in payroll? It's because the median wage of a Cook Inlet hydrocarbon worker is about 89,000 a year compared to our borough median wage of about 35,000. It's big numbers. It's why we pay so much attention to the oil and gas industry in the Kenai Peninsula Borough.

So let's start talking about the basics. We'll start out with oil. We used to have a lot, we don't have as much. In fact, it's a pale shadow of what it used to be. At our peak we produced 90 million barrels in 1972. Last year we produced seven. That equates to about 230,000 barrels in 1972. To put it in perspective this year we're going to be lucky to hit 16,000 barrels. That is a big deal and I'm going to talk about that in just a moment.

We have had reserves replacements that have come on line through development drilling that's been taking place in our existing oil fields. We've got XTO doing some new work. Chevron formerly Unocal has done some work. And we now have seen the numbers go up from two years ago, the last Division of Oil and Gas report said 80 million barrels of proven reserves. We've gone up to 94 million barrels. So we've had some reserves replacement come on line. We've kind of stretched it out a little bit. And those are the operators that are out there trying to work oil, but the problem is this curve.

Here we are, if I can get the laser pointer to work. Well, you can see it. There's the peak back in the '70s. You can see the vertical line that shows where we are today and the slow descent into nothing in the very near future unless we turn this trend around.

Why is that important? Well, we had a wake-up call recently. And it's a wake-up call that really hasn't gotten a lot of attention in the public theater because we dodged the bullet with this particular issue. There's a lot of attention focused on the dollars and cents to the State coffers, a very important issue, but there was a secondary issue that could have been catastrophic for the State of Alaska if we hadn't been able to realign supply streams for our refineries in the state. A lot.

Well, when you look at the four refineries that serve the state of Alaska's commercial and military markets, you've got the Flint Hills Refinery and the PetroStar Refinery in Fairbanks, both totally reliant on North Slope crude oil. You've got the PetroStar Refinery in Valdez, again, 100 percent reliant on North Slope crude oil. And then you've got the Tesoro Refinery which has a diversified portfolio of supply mixes.

This is a big deal because if something had happened in a catastrophic way to that upstream flow from the North Slope well over 50 percent of our refinery capacity in the state of Alaska would not have had the option to switch to other oil supplies. That is a disaster waiting to happen because as you dig into these issues, you know I'm on the wrong slide, these are -- okay, that was the slide I was meaning to talk about. I'm telling you the distance is killing me.

You go back now and we look at why that is such a cataclysmic problem. And that is refinery production capacity in the state of Alaska. We are net importers of major fuel supplies in the state of Alaska. In particular, jet fuel.....

UNIDENTIFIED VOICE: Do you want to use this?

MR. POPP: If I could, I'd love it. Is it on? You know what I'll work it. I'm going to keep talking here 'cause I know these numbers by heart. Gasoline, the Tesoro Refinery and the Flint Hills Refinery actually produce a surplus.

So we're net exporters in the state of Alaska based on the latest Department of Energy numbers that just came out about three weeks ago that show us as a net exporter of a little over 2 million barrels a year of gasoline. It's a byproduct of the more valuable fuel that these refineries are targeting which are distillates, diesel fuels and jet fuel. Jet fuel we are the fourth largest consuming state in the United States of jet fuel. 46 other states don't consume as much as we do. We consume 31 million barrels a year as of 2004 of jet fuel. That makes us a net importer from sources outside the state of Alaska of nearly a third of that, just shy of 10 million barrels.

Now, that doesn't seem like a big deal until you recognize the fact that the West Coast region as defined by the Department of Energy, Pad 5, for those of you who track this kind of thing, has a net importation unto itself of 4 million barrels. There is not excess refinery capacity in the West Coast region of the United States that could serve our needs if we had a shortfall, so there we are hat in hand out on the world markets. We already are.

Distillates, we are a net importer of nearly 8 million barrels after we deal with the refinery capacities we have in state. That's the fuels that heat homes and generate power in the rural communities of the state of Alaska. And I guarantee you the Kenai Peninsula Borough within 24 hours of the Prudhoe

Bay announcement of being potentially shut in, with the lack of information that we had and starting to look at these numbers more closely, we were calling our communities telling them top off the tanks because we did not know what was going to result.

Was there going to be a shortfall? Was there going to be a major price spike? Was there going to be both? We didn't know, but luckily things seem to have aligned out and the supply stream has been maintained. But this is an issue that we have to address in the state of Alaska in the coming years especially here in the South Central region considering just how important that jet fuel picture is for driving the economy of Anchorage.

Taking a little closer look at the Tesoro picture, this is another interesting hidden story that people are not focusing on because they, quite frankly, don't know about it. The Mayor asked us to be candid and I'll be candid. Alaskans are smug when it comes to their belief that we are totally self-sufficient in terms of the fuels that we need because we have all the crude oil we could possibly need.

Well, the Tesoro Refinery kind of pokes a hole in that balloon. We get 25,000 barrels at day for the Tesoro Refinery from the North Slope, luckily from Kuparuk. They were not affected by the shut in. We also get about 16,000 barrels a day from Cook Inlet, but for several years over a third of their supply and about 16 percent of the state's supply of crude oil consumed for refined fuels has come from foreign sources, Indonesia, Africa and in the distant past Russia.

That's a big deal. We are dependent on the vagaries of world oil prices. And this percentage is going to continue to grow unless we turn it around. Combine that with the lack of ability to switch to other crude supplies at over 54 percent of our refinery capacity in the state and this has all the hallmarks of future disaster.

Just a quick note on terms of pricing. This is a recent update from the U.S. Department of Energy on gasoline pricing in the state of Alaska, the West Coast and the U.S. average. The green line on the top is Alaska average pricing for regular gas excluding taxes. The black line is the West Coast pricing. And the U.S. average is represented in red. And as you can see even though we have an over abundance of gasoline in the state of Alaska we do pay more for it.

And that is borne out, again, by Triple A. There's our average price of 2.96 a gallon for regular pump. A year ago it was 2.77. And Alaska's highest average regular grade price was 3.06 back in May of this year. And, again, we rank 50th in gasoline consumption out of the 50 states.

Jet fuel pricing, this is an interesting one because I think in no small part because of the volumes that we purchase, those prices track within a few cents of the U.S. average and the West Coast average, but you can also see that fairly meteoric rise over the last decade in jet fuel prices.

We're going to turn now to natural gas. This is a topic that's going to get talked about a lot, but I thought that oil was important because it is a key piece of our economy. But in talking about natural gas I think Chuck did a great job of talking about the past statistics. My numbers come from the Department of Natural Resources, but they closely match his.

We used to have a lot of gas, we don't have as much now. We've consumed over 7 trillion cubic feet. We've got about 1.6 trillion cubic feet in remaining proven reserves. And we've shown reserves replacement since the year 2000 of about 353 billion cubic feet based on the data from the State of Alaska. So that's a positive. That's why that supply stream crossing point has been pushed out a couple of years. And those are the operators that we have in Cook Inlet.

Again, this is the graph that shows the cliff we stand on. That long descent into nothing unless we turn that around with new discoveries or alternative supplies.

The price of gas in Cook Inlet is also an interesting story. This is based on the one known market indicator that's public in the Cook Inlet Basin, the prevailing values for utilities, and that's in blue, versus the average price for Henry Hub in red. As you can see, we have been tracking upwards somewhat slowly but that climb is starting to steepen.

4.71 is the current guesstimate based on the previous three-quarters for this year for where prevailing values might land in 2006 compared to the estimated $7.69 that the Department of Energy is estimating for 2006 which would, again, spike up to over $8 next year.

Current pricing trends not taken into account in that particular estimate. We're waiting for their next estimate next month. So those are some significant climbs in price though considering where we were back in 1994 at a $1.40.

I'm not going to steal too much of Enstar's fire, but I love these slides because they show why it's important. $6.70 for a million btu's of home heating versus the alternatives -- for natural gas versus the alternatives the next cheapest being fuel oil $18.77 for a million btu's of heating. Natural gas is still a deal. My wife gives me hell every time she opens that gas bill and she's asking me right now where's it going. Well, I'll tell her after this conference is over. We'll see what our good friends at Enstar have to say.

Again, we're a deal compared to the rest of the United States. I'm not going to spend a lot of time on that slide. I'll let Enstar talk about that.

There's another representation of that graph that Chuck brought to us today. I appreciate him updating that graph for us because it does show that that crossing point between demand and supply statistically looks like it's been pushed out a couple of years although the unknown in this is peaking. Peak demand days in the winter, we don't know where that's going to take us over the next few years. And that's a significant issue that we're watching how new gas storage is going to address.

The point I want to focus on here is what Chuck talked about in terms of the statistical potential reserves in Cook Inlet. His 13 to 17 trillion cubic feet which he split down the middle at 15, if you were to go out and try and find half of that I take his number at about $5 billion in expense to go find that natural gas. But, simplistically because people want to know, well, geez, that sounds like way too much money to invest in terms of exploration, maybe we should just look at something cheaper.

Well, maybe it is cheaper to look at other alternatives, but maybe there's an economic case for going out and investing that money. I don't know the answer to that question. That's going to be a function of the market. But to try and quantify that for folks who ask me that question I took the prevailing value of natural gas this year and multiplied it by that volume of gas and you come up with a number just north of $37 billion at face value, simplistic terms.

Will it be worth that much in 10 years, 15 years? I don't know, but it's a good way to try and think about it in terms of the fact that there may be a case to be made for some significant new investments in Cook Inlet.

So the future. I don't want to scare, Dan. I just wanted to list these topics. I'm not going to talk about all of them, but there's a shopping list of issues that affect our energy picture in Cook Inlet. A lot of these are going to be addressed over today and tomorrow and I hope quite candidly because they are significant. Every one of them will impact the price of energy in Cook Inlet in one form or another whether it's to restrict development, whether it's to encourage development, whether it's to pay for development, whether it's to find alternative fuels or sources of energy.

This shopping list is a pretty big deal, but I will touch on one topic and that's the last one on the list. And that's a look forward at the workers. To do all the things that we need to do to resolve our energy issues for the next 20 years, 30 years is going to require a huge work force demand in a market this is growing tight every day. I love people when they buttonhole me on the gas pipeline or other projects and say those out of state workers are going to take our jobs.

Well, I'm trying to get them to think a little differently about that. And that's the fact that we're going to need those out of state workers to even begin to attempt to do the job to complete these projects. Because there is a growing shortage in North America and in the world scale that's creating a massive upward pressure on labor costs. And you can see some of the headlines from our good friends at the Petroleum News, the Oil and Gas Journal. The oil sands alone is $75 billion U.S. in booked projects today. With demands that could push as much as a 400,000 worker shortage in the next two decades in Canada, 400,000.

We're going to need to train every worker we can in Alaska, absolutely, but the problem we're going to face is we can't do it all on our own. We can't even begin to come close because when you start to stack those projects on top of each other, and this was our attempt to try and kind of visualize what we face just in the next decade of possible projects you can see the time line across the top going out to 2016. You can see the list of projects on the left that encompass oil and gas, construction, mining projects that are all proposed.

And in talking with the companies they're looking at media accounts, these are the estimated direct jobs resulting from those projects, from those issues, from those initiatives you come up with a grand total of over 44,000 workers that are going to be required in the next decade if all these projects were to go forward. Now let's just say if half of them go forward. Let's say if only one out of four goes forward 'cause a bunch of these are probably going to fall off the table. We all know how these mega projects work. But even so that is a huge demand on the in state work force.

How many of you in this room who are involved in the industry know of a pool of two or 3,000 workers qualified to work in the oil and gas industry that are just sitting around readily available? They're not there. They are not there. And we are already taking steps in the Kenai Peninsula Borough and I know the Municipality of Anchorage is taking steps, Mat-Su Borough is taking steps, the State is taking steps to train our youth to start taking these jobs, but we're not even going to come close if even a quarter of these projects go forward to meeting the job demands to make sure that these projects go forward in a cost effective manner. And that affects our ability to solve our energy problems. So these are issues that we all need to be thinking about, talking about and pushing for solutions on.

I want to thank everybody for your time and your attention. Tried to be brief. And you can find this PowerPoint on the Borough's web site at cookinletoilandgas.org.

And with that I love to throw this photo in. I'll ask the industry guys in the room how many safety violations do you see in this photo? Where's the Mustang suits. Here's the obvious one. This was from the first flight out with a bunch of local folks out to the King Salmon Platform back in the 1960s so a little bit of fun piece of history that just came my way and I thought I'd share that. Don't you just love that photo?

Folks, thank you very much. I appreciate your attention. And I hope that this conference proves to be very useful for you. I know that you've got the ability to take a lot away from this and help us out to solve these problems. Thank you very much.

COMMISSIONER SEAMOUNT: Okay. I would like to call our next panel up. That would be the utility gas users. And that'd be Dan Dieckgraeff, Jim Posey and John Cooley.

We're behind on the agenda. If you look at the time when we're supposed to take a break we're just going to float right through that break. You guys, everybody if you need to go out and take a break go ahead. I don't think you'll hurt anybody's feelings.

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DANIEL DIECKGRAEFF

COMMISSIONER SEAMOUNT: Okay. Our first presenter is Daniel Dieckgraeff. He's manager of regulatory and gas supply for Enstar Natural Gas Company. It's a division of SEMCO Energy, Incorporated. He is responsible for Enstar's gas supply and for all of Enstar's regulatory matters before the Regulatory Commission of Alaska. He's also responsible for monitoring the Enstar contracts with its large customers.

He has served in supervisory and managerial positions responsible for regulatory matters since his employment with Enstar in 1982 and since 1981 he has been directly involved in all of Enstar's gas supply negotiations. He has been the company lead's negotiator for gas supply since 2000.

He lives in Anchorage with his wife Denise Thanepohn and their four children. Let's welcome Daniel Dieckgraeff.

MR. DIECKGRAEFF: Good morning. Most of you have, I think all you have a black and white presentation in front of you. This was yesterday's version. We picked up a typo late last night. Mr. Popp was not the only one that was working late last night.

This presentation will be on line on Enstar's web site later this week for those of you that want the color version and a little larger type to read.

Like Dr. Tussing I, too, was a participant in a proceeding in front of the Commission. Fortunately for me most of the items that I don't need or shouldn't address because of that proceeding were not going to be in my comments, we'll avoid most of that.

All right. Most of you know who we are. You write a check or we take it out of your bank account or somebody credits your credit card for a bill every month, but for those of you that don't Enstar's been around sine 1961 when we started service. Enstar actually consists of two companies, Enstar Natural Gas Company which is the one most of you are familiar with. We are the distribution part of the arm -- or distribution arm of the company, but also there's Alaska Pipeline Company that owns the pipes that brings the gas from the fields to the population centers. We served about 340,000 customers through 125,000 meters. I'm sorry, we serve about 340,000 Alaskans through about 125,000 meters.

We have 3,000 miles of transmission and distribution pipe in the ground in South Central. We calculate their direct impact on the Alaska economy of about $230 million. We have 168 employees. We're the largest energy utility in Alaska. We added 4,200 customers last year. This just goes to show the number of meters we have and how we do rank with the other energy utilities. Utilities tend to count customers by meters. So when we count people usually there are more than one person in a household that gets the gas, but that's how we rank. We're almost twice the size of Chugach Electric and the others that you'll see down there.

This looks a little bit -- shows you a little bit about our service area. We actually have gas service now from Houston up in the Mat-Su Valley over to Whittier and down as far south as Ninilchik. The bulk of our customers, of course, being in Anchorage, Mat-Su and the Kenai Soldotna area, but we do cover a lot of territory.

The blue pipes that you see there are Enstar's pipes. Those are the main pipelines. Red are major pipelines, the gas pipelines owned by others primarily producers. And then the yellow pipes are smaller pipelines also gas pipelines in the system. The original pipeline was built from the Kenai field just south of Kenai to Anchorage in 1960, '61. In 1984 Enstar constructed the line from Beluga through the Mat-Su Valley and coming into Anchorage from the north so that we could feed Anchorage from both sides.

In the 1990s there was a piece of pipe built to connect our Beluga line to the producer's system that was on the west of side of the Cook Inlet so there was a complete circle in Cook Inlet. And with recent changes in the regulatory structure and the ownership of these producer pipelines gas can now flow in a complete circle in Cook Inlet and has flowed back and forth in Cook Inlet.

This is what the structure of the gas in Cook Inlet looks like or the buyers and users of gas in the Cook Inlet.

This is from the 2004 DOE report. You'll see different versions of this throughout the day. In fact, I think Dr. Thomas has already shown a different version. But primarily you've got LNG at 39 percent, ammonia urea using 27 percent. Gas utility, and where that says Enstar that is not just Enstar, and I'll cover that in a moment, but traditional gas utility use about 18 percent and then power generation, Chugach and ML&P make up the rest. 67 percent of the electricity produced in South Central is produced with natural gas.

And we cover about 324,000 Alaskans with the gas utility part. The electric utilities pick up about 473,000 customers. Customers from Homer and Seward all the way to Fairbanks use electricity generated by gas from Cook Inlet.

I've already seen this shown twice and it'll probably be shown a lot more before this day is over. This is from the 2004 DOE study that Dr. Thomas was part of. Enstar Natural Gas actually secured the congressional funding for this report. We went to our congressional delegation and sought funds to look at what is going on and what is going to go on for energy in the Cook Inlet. The DOE study and the later DOE study was funded with that as well as spur line work that's being done in relation to the stuff coming down on the Parks Highway side.

Looking at this, again as Dr. Thomas mentioned, this shows annual usage. This does not show the fluctuations that you see, what we call deliverability. For some odd reason our customers tend to use more energy in the wintertime than they use in the summertime. I had a RCA Commissioner talk about wanting to take hot showers in the middle of the winter when it's cold. That's a good analogy. I mean that's what we've got. We've got more use, about two to three times on peak days of what the average use is.

As Dr. Thomas talked about this shows crossing the line of utility demand in 2012 if you look at all the fields. And if you're just looking at the fields that are dedicated to utility use we cross the line in 2009.

I want to stop and talk a little bit more about deliverability here. We've had plenty of gas, and you'll hear early -- or more about that later on in the presentation. Dr. Thomas and Dr. Tussing have already talked about that. We've had plenty of gas in the past. The annual usage problems are going to occur later on, but we're already in the deliverability problems. Last year was the first year that everyone didn't get what they wanted in cold weather when everything was operating normally. We've had system disruptions in the past when there's been a failure of a compressor here or there's been a well freeze-up there and people have moved things around. That didn't occur last winter.

What occurred last winter was we didn't have enough gas for everybody when it got cold. Everything operating normally, we didn't have enough gas. That situation will be magnified this winter. Agrium's new agreement according to press reports or new agreements according to press reports presupposes that they will be off line during a good portion of the winter because the gas deliverability is not available. That's the life that Enstar has to deal with on a daily basis in the wintertime and the other energy utilities.

We've also seen this graph quite a bit. And I'm sure we'll see it a lot more. I won't go into a lot of detail, but this is from the DNR. The straight line's where we were in 2009. What I want to do is concentrate on what happens from 2006 going out to 2022. These are layered from the different major fields.

The important thing I want to look at is that green line on the top. These are proven fields. But the green line on the top is undeveloped and under-developed fields. These are fields where we have -- the producers have to spend a heck of a lot more money to get those reserves on line and in the pipe to serve us and the electric utilities and the industrial customers.

The dotted line you see there across the bottom is Enstar's projected demand. This is based on Enstar's gas supply customers. A moment ago I talked about the fact that when you talk about traditional utility usage that's not just Enstar. Enstar serves most of the residential and commercial load, but over the last 10 years about one-third of the traditional utility load has been picked up by direct marketing through various producers and a third party marketer. That's represented by that line. You can see that if you just look at our load and the gas utility, the other gas that's supplied, we run into problems with the known reserves about 2017. If that gas under-development doesn't show up like people plan the problem occurs a lot sooner.

The Agrium plant's problems was forecasted back in the '90s. They said when looking at long term supplies that because of the pricing structure that Agrium needs to be able to compete in the world market they were going to be the canary in the mine. They were going to be the first ones to have real problems. The next one appears to be this gas between what we supply and commercial people have gone out and purchased from other parties. Those purchases have been done on a relatively short-term and we're already seeing those customers having problems getting gas and trying to return to the supplies that Enstar have had under contract.

This is an issue that is before the Commission and is a grave issue. Long term supplies for utilities and for utility customers are essentially. Unfortunately, not everyone has them at this point in time.

This is what our long term supply looks like. The bottom line, I'm trying to look at the colors because for some reason they always look different when going through a different projector. Enstar's -- the bottom line there which I think is a lime green is our Legacy Beluga contract. It expires in 2009. The next layer above that is a Legacy Marathon contract. That is stepping down. Will go flat about 2010, 2011 and remain till we run out.

The next one is the Moquawkie contract with Aurora Gas. There's an issue concerning that right now that I'm not going to get into. It's a matter of a court case.

The next line, the kind of the magenta, I guess, to use the Microsoft official color name, is our contract with Union Oil of California now part of Chevron. It was signed in 2000. We started taking deliveries in 2004. Under that contract Union tells us five years out what they're going to do for the sixth year in keep rolling average. So what you see here is not a gas that's been committed to Enstar to date. The gray on top of that is the amount that Unocal has the option to commit to us in the future under the terms of our contract.

The light green on the top is the Marathon Gas Supply contract that Dr. Tussing referred to that's now before the Commission. If this is approved by the Commission then we see that we have all of our long term requirements under contract to 2016. Starting in 2017 we're going to need to find other amounts. That's the red. But that's a lot different than where we were just not very many years ago. That red started in 2003 before we did the Unocal contract.

Okay. Mr. Popp wanted to know what prices to expect for the upcoming year. Well, here it is. This is based on our most recent forecast. Our contracts are still indexing. This is the make-up of our gas contract supply portfolio that we anticipate as of 2000, January 1, 2000. 55 percent of it under the Unocal contract which uses a 36 month average of NYMEX prices.

The remainder Marathon and the Beluga contracts which use crude oil. The crude oil contract index has finished indexing. We're looking at $72 oil for that index period that we have for those contracts this year. So that's the breakdown of what our gas supply costs will be for 2007. Again, this is an estimate. We're not finished indexing. It could be slightly higher. It could be slightly lower. This is our best guess. We'll know at the end of October.

Most people just look at the bill from Enstar. They don't look at what makes up the bill. They look at the total bill. The red on this graph is the cost of gas. This is what we pay directly to the producers. No mark up. This is what it costs us and this is what's passed through to the customers.

The blue is what Enstar gets to recover its costs, its investment in those 3,000 miles of pipes and operating and its return. The blue portion has actually dropped in the last 10 years. We had a decrease in 2002 and 2003 and the component that we get to charge the customers to recover our costs and our return. The cost of gas is what's been the big driver of the costs over time. And this kind of breaks it out.

You wanted to see what the comparison was with other energy costs. Again, this is showing our estimated costs for 2007. The other energy comparisons here are based on prices that were this summer. We do not have estimates from them of what their 2007 would be. We're still -- yes, we're higher. We have the gas It's secure. And we're still a heck of a lot cheaper than the alternatives.

Finally, how do we compare with the rest of the United States? You have our estimate there for Alaska. The other numbers are estimates from the Department of Energy's energy information agency of what the projected price for 2007 in the other regions of the United States for gas supply will be. Again, yes, we're seeing an increase, but we continue to remain among the cheapest in the country and a heck of a lot cheaper per unit than most of the other places in the country.

Again, this presentation will be available on our web site later this week. Thank you very much. And we'll save the questions for the messages that they'll pass up to us. Thank you.

COMMISSIONER SEAMOUNT: For those of you that want lunch and haven't already bought a take they're available for $18. And I think at noon the lunches ought to be ready out there so if we stay over the agenda a bit around noontime we could take about a five minute break for everybody to go out there and grab their lunches and then come back. Okay.

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JAMES POSEY

COMMISSIONER SEAMOUNT: Our next speaker is Mr. James Posey. On January 3rd, 2003 Jim Posey was appointed as a general manager for the Municipal Light & Power by Mayor George Wuerch. In 2000, Jim Posey was the director of the Cultural and Recreational Services Department.

Governor Knowles appointed him as Commissioner for the Alaska Public Utilities Commission and that ran from 1996 to 1999.

And I believe you were a land man for ARCO Kuparuk field when it originally started in 1979.

He was born and raised in Beaumont, Texas. After a stint in the Air Force he attended Wichita State University where he graduated in 1971. He graduated from law school at the University of Kansas in 1975.

Mr. Posey has been a board member and past chairman of Alaska Junior Achievement. He was also a member of the Academic Policy Committee Family/Partnership Charter School.

He is a board member for Alaska Public Telecommunications, Incorporated.

He and his wife Sandi have five children and young adults and have lived in Alaska for 25 years. Let's welcome Mr. Posey.

MR. POSEY: You know, Mr. Cooley and I decided we'd try and get you back on schedule because almost all of the charts that you've seen, you know, basically cover our numbers, how much we use. And it's more important for us to find out where we are going to be in the next 10 to 12 years in our deliverability as well as what we can find in Cook Inlet to continue to power.

You know, basically I'd like to talk to you about numbers. The first number is 1932. 1932 is the year that ML&P basically started. And that'll be our 75th year next year. But the more important number is the 200 plus Bcf that we purchased in 1996 when Shell was exiting the state and we paid, I think, about twice what the other oil industry folks thought the gas was really worth, but we ended up with 200 Bcf plus and that has set the day and the trade for us as to our supply. We thought that that would last to 2026.

Brings up the next number. 1996 to 2026 is no longer a reality. We're probably looking at 2018, 2020 for that supply. So, therefore, we are very interested in what we're going to do starting in 2017 to 2018 to 2020 just as Mr. Dieckgraeff is for Enstar because those are the critical years for us when we have to have additional supply because we're looking at making some rather expensive investments in new generation. And the only supply, the only way we can look at it now given the time frame we have is gas fired turbines.

Last night while these guys were rewriting their speech I was out watching the open heart surgery we're doing in our most productive unit, our Unit No. 7 'cause we took it down to trade out parts and buy new parts and put them in over the next four weeks. And it's a big project and it's an expensive project for us, but it's an investment in what we think we have to do in order to supply reliable power to the folks here in Anchorage all the way up to Fairbanks at times also. To us that reliability is important.

We're also in the early part of next year going to install LM 2500 plus which is a racehorse type turbine that we can spin up and spin down once a day to take our peak shaving requirements. And that will be installed by April of next year. So we're making those investments in increments of 25 to $50 million, but by 2011 our integrated resource plan has us spending in excess of 200 million on new generation, not resource but heavy load types, 6Bs, 6FAs, that will take us out for another 20 years.

What's more important is the number that that brings to the table. We expect to use 13 Bcf a year of gas of that 200 that we purchased, you know, that's a good number. But more importantly, if we make that investment by 2011 we can realize a 30 percent reduction in the use of that gas because our usage would go down to about 9.5 Bcf a day (sic). So conservation for us is going to be important, but like everything else you've heard today we're talking about real dollars for any change in what you're doing, but the real cost of installing something that's 30 percent more efficient is you can basically pay for it in seven to 10 years on gas savings alone.

You know, our real job is just keeping the lights on, computers working, hospitals open and commerce healthy because we serve as is indicated on the chart about 30,000 customers. About 8 or 9,000 of those meters are basically for the commerce industry from Tudor Road all the way back down to the center of downtown. So we have all of the hospitals, military bases, midtown to downtown and residential area just north of here. So that's a rather small area, but a critical base for the commerce, university med district, for us as well as our security around the world that involves Fort Rich and Elmendorf, both of which shut their high cost plants down within the last two years. We picked up that load for them.

Investing in that new efficient equipment is very important to us, but also working with Enstar, CEA, Golden Valley, Homer in looking at how we're going to supply power out in the future and that includes investing in wind power, additional gas generation, and, hopefully, if we work with Golden Valley and others in the state getting Healy Clean Coal back on line. I don't want to say that that investment was a complete toss. I think DOE made a big investment in that as did the state.

Getting it started is very important and we worked hard at that this year and we hope that something can come between now and the end of the year where we will see agreements come into place so that can re-start, but that is as important. It's another 40 megawatts. We installed 33 megawatts as a racehorse unit, and being involved and supplying 473, 478,000 residents with clean reliable power is one of the most important things that's done in the state with our partners from Enstar to CEA, Homer and Golden Valley we think we can get it done.

But most of all, finding additional gas for that gap of 2011 when we need peaking gas in individual years and through 2018 when we'll have to start buying more significant volumes of gas is an answer that we would hope that all the participants will help us answer because if the gas line doesn't get to us by 2017 or 2018 we're all looking at dust for power supply and that is not a good option for us, so finding real answers out of this conference, real recommendations because we made a bet 10 years ago on buying gas.

I don't know what bet we can make today, but I'm sure there's some options out there. We're going to be right with the rest in making sure that the answer is always positive that we will be able to meet the load. And number two, we will have the help of the Kenai and the North Slope producers to get us there. With that, John.

COMMISSIONER SEAMOUNT: Thank you, Mr. Posey.

JOHN S. COOLEY

COMMISSIONER SEAMOUNT: Our next speaker is John S. Cooley. He's the director, power control. He's been that since 1977. Responsible for the reliable and economic scheduling of generation resources for the safe and reliable operation of the electrical system, for bulk energy sales and services, and he's responsible for the administration of natural gas resources.

Prior to that he was manager of planning for Chugach Electric. That was 1991 to '97.

From 1981 to 1991 he worked for Anchorage Municipal Light & Power as the manager of power management. He was design engineer from 1981 to 1994.

From 1981 to 1990 he was with the United States Naval Reserve as a commanding officer and executive commanding officer.

From 1968 to 1980 he was with the United States Navy as executive officer. Before that department director. Before that engineering officer. And finally in the beginning engineering division officer.

He has an MS in Operations Research with distinction, U.S. Naval Post Graduate School, Monterey, California in 1969.

He has a Bachelor's in Science from the U.S. Naval Academy at Annapolis, Maryland in 1968.

He's a registered professional engineer in Alaska, a captain, U.S. Naval Reserve retired captain, and chairman of the U.S. Intertie Operating Committee. Please welcome, Mr. Cooley.

MR. COOLEY: You also didn't mention I was born in Fairbanks and other than the time I was in the Navy I've been here in Alaska working for the last 25 years.

And I, too, will try to make this short to help us catch up.

A couple of things I wanted to cover is where we get our electricity or where we make it, some of our existing gas contracts, where we think we're going in the future gas contracts, some potential gas issues, and our view of the future.

Chugach Electric is highly gas dependent. We produce 85 percent of our electricity from gas fired generation. That's probably the highest gas dependent utility in the country. And so we sort of have all our eggs in one basket. The other source is hydroelectric. We do have some of that, about 15 percent of our production.

Everybody has a slightly different number. I think we use about 12 percent of the current production of gas in the Cook Inlet.

Pictures of our plant, Beluga Power Plant is our biggest one. It's over near Tyonek, actually near the Beluga River gas field. Probably produces 80 percent of the energy that we produce. We have smaller gas fired plants down at -- one here in town right near the airport. One at Bernice Lake which is near Nikiski. And we have a couple of hydroelectrics that we are part owners. One's the Eklutna Hydroelectric project out on the Glenn Highway and Cooper Lake which is on the back side of Kenai Lake. And then we also buy power from the State from the Bradley Lake hydroelectric project.

We currently have four gas contracts. We buy gas from the three Beluga producers which includes ML&P and Marathon. They're all requirements type contracts. In other words, we made a deal that said with certain exceptions we'd produce all our power using gas and then in return the gas companies would deliver all the gas that we need.

We have about 122 Bcf remaining under contract which we think will last till about 2011 for us. And our prices are based on a running average of three indices, crude oil futures, consumer price index of fuel oil and the producers' price index of natural gas. And currently that's about $5 what we're paying for an Mcf currently.

Future. We're talking with the Beluga producers. The contracts that we currently have were all signed about 1990. And they had a period 3 sort of gas that was reserved, they reserved 120 Bcf of gas for our use, but they said we'll determine all the terms when we get to that time. We're at that time and so we're trying to figure out if we can come up with the right terms to secure that 120 Bcf. We're also talking with Marathon to get additional volumes past what they have currently agreed to supply us.

Deliverability has been mentioned. We're fairly flat. Our peak daily usage is about 160 percent of our average use which is a lot flatter than Enstar because we do have hydro to help flatten our load.

Commercial storage is not yet a fact in the Inlet. There's some people working on it, but you just can't, you know, walk out and say I want to store something for such and such. Those terms aren't quite developed yet.

Open access. That's sort of an electrical term, but that's another part that's in initial stage of development here in the Cook Inlet that the gas pipelines, you know, everybody can use them and how we assured that if we put our gas in that we get ours at the other end, or somebody else doesn't take it. All those rules and how all that works on a daily basis is getting better and better and has really come a long way, but it's still in its infancy.

What are we going to do? One, we're going to have more efficient gas generation within the next probably three years. We're going to have to -- we intend to put in a new gas fired generation probably here in town. Exact size and partners is not yet determined, but it'll be definitely much more efficient than our current fleet.

We're investigating wind power. Probably the biggest detractor there is that you've got to put the towers somewhere outside of town and, therefore, the cost to get transmission lines to wherever that is, Fire Island being the prime candidate, that's the biggest hurdle is to build a transmission line out to Fire Island. That's a significant cost.

New hydro resources. We're looking at those. They are also very capital intensive. Bradley Lake was built for like $350 million. Any future ones are probably at least, you know, orders of mag- -- not orders, but maybe twice as much as that, so that's a lot of money.

Coal generation is also the initial capital costs are very expensive and it's being considered, but I guess the bottom line is that we think gas is going to continue to be available here. Not really sure exactly how it's going to be. New discoveries. People are working on that. There's always LNG imports are a possibility that, if you know, if you need gas here and they can't find any you could always bring it in. And then there's a possibility of the pipeline from the north.

So I guess we're still heavily gas dependent and we haven't found a way to economically choose a different path. Thank you.

COMMISSIONER SEAMOUNT: Thanks, John. That concludes our panel on utility gas users.

Now we'll move on to industrial user needs and plans.

And if you look at that section you see there's a glaring absence and that would be LNG people, ConocoPhillips, but no need to worry 'cause they're coming on. Scott Jepsen is coming on this afternoon to talk about their operations. So is William Nebesky here? Okay. And Christian Sonnichsen and Tim Johnson.

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WILLIAM NEBESKY

COMMISSIONER SEAMOUNT: Our first speaker is William Nebesky. He will be giving an overview of natural gas demand.

William Nebesky works as a commercial analyst with the Alaska Division of Oil and Gas which is part of the Department of Natural Resources. And I need to mention that he's been a great help in this, he's done a lot of work on this meeting himself. And also a lot of other people from the Department of Natural Resources are helping out with some of the administrative and logistics.

William joined the division in 1996. He is responsible for analyzing commercial arrangements for oil and gas positions and evaluation of changes in market structure on producer commercial arrangements and state royalty interests. He provides commercial support to division interdisciplinary teams that include resource evaluation, unit management, leasing administration and royalty accounting.

Much of his attention over the past year has been directed to Alaska's interest in natural gas, including the impacts of changing gas markets in Cook Inlet and in matters relating to commercialization of North Slope gas. He holds a Ph.D. in Economics from Oregon State University and teaches classes in economics and in business forecasting at the University of Alaska Anchorage. Welcome, William.

DR. NEBESKY: I want to thank the Oil and Gas Conservation Commission for the opportunity to speak on the topic of demand for natural gas in the Cook Inlet Basin. My talk is organized really, I want to cover three major points. The structure of demand, meaning the players and their relative size. The determinants of demand, what are the drivers that underlie demand in the basin among these various players. And then a few comments on the outlook and policy implications.

First, I want to see if everyone has been paying attention to some of the comments by earlier speakers and ask or invite you to participate in an exercise. This gray circle, this pie represents the total consumption of natural gas in the Cook Inlet Basin about 207 billion cubic feet in 2005. How would you slice the pie among the three major groups represented there? Residential and commercial, electric power generation, and industrial. And by residential and commercial I'm talking mainly the demand for natural gas as a space heating energy for both households and businesses and institutions. The electric power generation is natural gas used in generating electricity, of course. And finally, the industrial sector consists of not only the fertilizer and LNG plants at Nikiski, but also the Tesoro Refinery, field operations in the Cook Inlet Basin and some smaller industrial activities.

The residential and commercial group accounts for about

20 percent of that pie. Electric power represents about 16 percent of the pie. And the industrial comprises the other almost two-thirds of the total demand picture.

This slide just provides a little bit of background and more detail on the absolute amounts of consumption by these various players including a decomposition of consumption of the major industrial users for 2005. And on the right-hand side shows the averages over the period, the 10 year period 1996 to 2005.

And we can see that the picture is not static over time. The top three layers in this slide represent the industrial sector and the bottom two the residential and commercial what I call the utility gas in this slide. It's the dark blue. And power generation is the tan of the very bottom layer. We see that the overall consumption of gas in the basin has stabilized at just above 200 Bcf per year. And that there's a certain amount of churning, if you will, that's going on. Again, the consumption is not static among the players.

I'd like to basically drill into a couple of these major groups and talk about their structure and the components that are driving demand. Of course, the economy is the underlying driving force among the residential and commercial users of gas. These users depend almost entirely on natural gas which arises out of its cost effective and use value as a clean, efficient fuel. It would take an awfully high price of natural gas to render the next best alternative, fuel oil, as a competitive alternative as we've already seen in the earlier slides.

Here we have the population expansion in the South Central region divided into the three major population centers. And I want to address the topic of deliverability and seasonality which has been touched on by other speakers. In this slide here we see that, indeed, the consumption, the usage of natural gas among resident and commercial users is tightly correlated on a daily basis with the weather. This chart shows a four year period of the cycles of decline and peak usage in step with heating degree days. And we see as Dan Dieckgraeff stated the swing is enormous. And we'll come back to this point a little further in the slides, but I wanted to at least show what that looks like.

And, you know, today residential and commercial consumers pay about $5 an Mcf for gas. That is in step with the Department of Revenue's reported prevailing value represented in the blue line in this chart. And superimposed on the chart is also the Lower 48 Henry Hub spot bench mark of gas. And we see that there's a bit of a disconnect historically. A lot of volatility in the Lower 48 markets whereas less so with respect to the prevailing value statistic. And these data are monthly averages.

Now, I'm going to make a bold assumption here. Let's assume that the U.S. Department of Energy, Energy Information Administration is correct with respect to its projection of oil and gas prices going into the future. That's reflected, the DOE projections are reflected in the dashed lines, red reflecting the WTTI spot price, and blue the Henry Hub price.

Now, if we take those projections and combine them with the formulas and terms of the contracts that make up the Enstar system gas supply, I've come up with estimates that are in the neighborhood of what Mr. Dieckgraeff indicated. Today we pay about $5. We see some steep increase in the future based largely on the forecast that I've drawn from the Department of Energy rising to about $6.30 and then on up to $6.72 before there's some flattening based on that forecast.

Economists have a metric that Professor Tussing mentioned called the price elasticity of demand. It's an idea, a notion that attempts to characterize how consumers respond to prices and changes in prices. And I've attempted to sort of illustrate how the price elasticity of demand might pan out for the residential and commercial consumers of gas. The blue curve shows the historic consumption in this sector again. And I fitted a curve to that and then projected what demand might be going into the future, the dotted red line. And then superimposed confidence in our boundaries above and below that line. In this case it suggests that I've got an 80 percent confidence interval represented here, so the true demand or consumption in this sector should fall within those boundaries about 80 percent of the time.

And they illustrate what might happen in a low or high price environment. If prices, indeed, rise to levels that we're already anticipating or perhaps even further, then we might see that the actual demand as a result of the consumers' adjustments, ability to substitute, use of alternatives may, in fact, level out or fall toward the lower boundary of this confidence interval. On the other hand, if gas prices are surprisingly to residential and commercial customers are surprisingly below the estimates for the future, then we could see the demand increase consistent with the measures of the elasticity response.

Let me turn for a couple of moments to the electric power generation sector. We've already, I think, have a sense of the structure and composition. 25 power plants totaling about 1,000 megawatts of power generation capacity. And that basically translates into that 16 percent yellow slice of the pie that I showed you at the beginning. As we see, the infrastructure is almost entirely gas based. There is some hydroelectric capacity.

And the comments from the earlier speakers indicate that they're thinking about the long term supply situation and about the need for generator equipment periodic replacement. And that, of course, raises questions about whether they stay with traditional gas fired generation, make investments in higher efficiency gas fired generation, or look towards alternatives such as coal based, hydro, co-gen, and even fuel oil.

The seasonal cycles of gas consumption in the electric power sector are less pronounced than those in the residential and commercial sector. This is a similar diagram. It shows the red heating degree day cycles, but here the gas consumption in the power sectors is still cyclical but less so than we've seen in the earlier residential and commercial example. And, again, I'm going to come back to the question of seasonal swing and deliverability a little bit later.

Let me just touch on the industrial sector for a moment. This is the big two-thirds piece of the pie. It's driven by export markets in contrast to the residential and commercial power sectors that are driven by local and regional economic forces. It depends on cheap, base load gas supply. And I would argue and I think it's becoming clearer that, indeed, the demand for gas in this sector is supply and price constrained.

Today the Division of Oil and Gas estimates that there's about 1.6 trillion cubic feet of proven developed reserves in the basin. And at current production or consumption rates of about 200 plus Bcf a year there's about eight years of remaining reserves. And we see that this reserves to production ratio, the RP ratio, has declined from a high of 24 in earlier periods of time. And the trend in the RP ratio, of course, reflects the underlying structural change in the demand and supply for gas in the Cook Inlet Basin.

The familiar slide, again, we translate proven and developed reserves plus a small amount of activity that's under-development into a forecast of production by field. And I'll draw from this in some later slides. I think we're all familiar that this sort of represents the problem.

But let me just speak briefly to the two major industrial users. The Nikiski LNG plant serves Japanese markets and it represents the largest slice of that pie, 36 percent of the total pie and over half of that gray area. And there's a pending export license extension decision that we are aware of and that is, I think, tied to studies that are underway now by the operators. And whatever the outcome of that decision, whether they, Marathon and ConocoPhillips, decide to go forward with an export license application extension it'll be controversial.

If they do it could mean a perceived impact on the availability of gas to other users in the basin. And if they don't it implies a pretty substantial structural change in the composition of the industry sector in South Central Alaska. But for whatever might come to pass in the future we can certainly understand why LNG occurred in the past.

The brown curve here represents the destination value received for LNG dispositions in Japanese markets over time. And as long as that value is higher than the value that the entity could receive for dispositions in the Cook Inlet Basin represented by the blue prevailing value curve is sufficiently higher to cover the transportation costs it makes sense to move that gas to those premium export markets. And so this helps us understand that this business has been profitable in the past.

The Nikiski fertilizer plant recently succeeded in securing gas supply through October 2007. The plant is expected to operate at 75 percent capacity, but that'll vary depending on the particular time period and what's going on with the weather and other consumption in the basin. As earlier speaker mentioned the plant experienced curtailment in a deep cold period back in January of this year. And this problem of the system's ability to deliver gas during peak periods of usage driven by cold temperatures is one that may occur with greater frequency and greater duration in the future. Agrium's looking at -- well, and it's worth pointing out that gas storage actually helped combat that problem in this particular instance last year.

They're looking hard at coal gasification. And in terms of product prices I think it's worth mentioning that the price of fertilizer products has been strong in recent past and that's probably helped to keep the fertilizer plant operating in its struggle to find gas to fuel its operations.

And that's reflected in this diagram. The green line shows the spot price of hydrous ammonia, FOB New Orleans. And it's a reasonable proxy for the value of wholesale fertilizer products. And we can see that in recent years the time frame of this is it's monthly data from 1991 through most of this year, is that the past several years have experienced very strong product prices which I think is important to the fertilizer plant's success in continuing to keep its doors open.

Now in the last few minutes I'd like to return to the matter of deliverability. And you'll recall the slide here that shows the swings and residential and commercial seasonal gas consumption. We have four years of data plotted on this chart. And what I want to do is talk about the system's capacity, capability to deliver in these periods of extreme peak usage. I'd also speak to the role that the industrial users play as a backstop in the event that the system of fields and pipelines are not able to serve the residential and commercial demand during periods of peak.

So for a moment just take one yearly slice out of this four sign wave graph of the blue, daily consumption cycles. Just say grab 365 days out of those four years and let's recast that seasonal swing from the days of highest consumption shown on the left-hand side of the chart to those of the lowest consumption on the right-hand side. So the horizontal axis in this diagram are the 365 days of the year, but we don't have them organized by sequential calendar date. Instead we have them organized by what days were peak at the left-hand side rolling down to the consumption in the residential and commercial sector during periods of lower usage, probably the 4th of July or summer solstice represents those data points on the extreme right-hand side of this slide.

And I've actually superimposed several years of data on this slide, the 1972 picture, the 1999 picture, and then an average over many years which is the darker line that's a little bit lower over on the left-hand side of the chart.

Now today in 2006 our system of fields and pipelines is pretty much able to cope with even the highest usage that is driven by extreme cold weather. But there is actually one curve that goes a little higher than the system's deliverability capacity and here's where curtailment would factor in.

Now as we look to the future as our reserves are proved and developed reserves decline in making the assumption that there are no additional major discoveries of gas in the basin we see that by 2012 the system's ability to serve this load duration is diminished, is expected to be diminished. And incidentally over time those load curves if the economy continues to move and propel itself forward as it has in the recent past, those curves are actually going to move up to the right while the red capacity deliverability line will continue to fall.

And herein lies the role of gas storage. Gas storage along with the backstop role of the industrials will help to fill in and support those periods when the systems of pipe and fields are unable to deliver during periods of peak usage. And you'll hear more about gas storage later this afternoon. Brian Havelock from the Division of Oil and Gas is going to come and talk a little bit more about that so these slides, in part, are intended to set up that discussion.

So, in conclusion, are we in for a sea of change or a steady state? I think we can all agree that the pendulum has swung. The era of excess gas supply is behind us and we now recognize that the decline in proved and developed reserves is going to continue, that the challenges of peak deliverability are with us and likely to increase in frequency and duration. We see that pricing pressure in the basin is positive. That there is evidence of a greater linkage with Lower 48 spot markets in more recent contracts and proposed contracts.

And I'd like to suggest that this is not a problem of market failure. It's actually an indication that the market is working in ways that we might like to see. That it's signaling the supply issues that are before us. And that we can expect there will be some responsiveness into price among the residential and commercial sectors, but probably not in the form of major sea of change, but just in line with our estimates of the elasticity metric that economists use.

Gas storage is going to play an increasingly important role in the future. The industrials are constrained by supply and price. And as a final point to drill into that just a little bit I have a last slide that speaks to the consequences of erosion of industrial demand. Or said another way, the industrial players exiting from the marketplace. We'll lose the deliverability backstop that they provide currently.

And I must say if I were an explorer I'd have some comfort in knowing that there was one or more large industrial users that could take all the gas that I could possibly deliver if I happen to stumble on a moderate or even major discovery. So the incentive to explore is importantly tied to the presence of these industrial players. They help to share the system costs in a big way. They represent 64 percent of the throughput in the system. And so that will become more concentrated among the rest of the consumers of gas in the event that the industrials exit. But even if they do the solution is only temporary. The problem of the demand supply balance is still with us.

And finally, a point on the spur line question even though I haven't addressed it here. It has come up and I think we expect that we're going to hear more about the spur line, but the industrials we can imagine play an important role in the base load throughput on a spur line linking North Slope gas to the South Central region. And there could be important implications for the loss of this base load throughput in terms of how the economics on a unit cost basis will pencil out for the spur line.

So I'll stop there and just thank you very much for your time today.

COMMISSIONER SEAMOUNT: Thank you, William. Okay.

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CHRISTIAN SONNICHSEN and TIM JOHNSON

COMMISSIONER SEAMOUNT: Our next presentation is a tag team, I believe. And it's Agrium Today and Tomorrow by Christian Sonnichsen and Tim Johnson.

Chris Sonnichsen is the plant manager of Agrium's Kenai Nitrogen Operation. He's worked at the facility for nine years. Chris is a graduate of Washington State University with a Bachelor's degree in Chemical Engineering. And he has been a member of the American Institute of Chemical Engineers since 1984 and currently serves on the board of directors for the Alaska Oil and Gas Association.

Tim Johnson is the Blue Sky Project manager. He is responsible for the commercial and technical development of the Kenai Blue Sky Project. He has worked at Agrium's Kenai Nitrogen Operation for over 13 years in roles of increasing responsibility in both operations and technical services. Mr. Johnson earned his Bachelor's and Master's of Science degrees in Chemical Engineering from the University of Idaho working on biodiesel commercialization for his Master's research. Let's welcome both of them.

MR. SONNICHSEN: Good morning. I'd also like to thank the AOGCC for the opportunity to speak today. And I'll be handling the Today part of the Agrium discussion.

I'd just like to start by just saying a thank you to the Governor, his administration, our congressional delegation, and also our local Legislators for the support they've given us especially over the last couple of years.

Listening to some of the presentations this morning, it looks like Mr. Dieckgraeff from Enstar left, but I thought maybe I should have wore a yellow suit or a yellow shirt or something since we're the canary of the Cook Inlet gas situation, but unfortunately that's really what we are.

I'm going to spend a few minutes this morning giving a brief history of our Kenai nitrogen operation and discuss where our operations are today. So a little history. Agrium purchased the Kenai Nitrogen Operations in October of 2000 from Unocal along with a long term gas contract. As I am sitting and thinking about this and I was a Unocal employee before the purchase was made and a couple of us at that time as we were waiting for the sale to finalize were, you know, contemplating what the future was going to look like. And I think we came to the conclusion that it was going to be a lot different than it had been. And I can tell you it has.

About one year after the purchase we were notified that the long term gas outlook was changing. And over the next couple of years the gas that was available to us continued to decrease and, unfortunately, we ended up in some litigation with Unocal over the gas contract. In December of 2004 a settlement on the gas contract was reached with Unocal and this settlement allowed for contract gas to be supplied to Agrium through October of 2005. At that time the long term gas contract would terminate.

We were not sure we could acquire sufficient gas to operate the facility past this October 2005 point in time, so we announced that the plant would shut down unless we were able to acquire additional gas. As you know, we have been able to acquire gas for operation in 2006 and we recently announced that we were able to acquire gas for operation in 2007.

So what does our operation look like today? Since November of 2005 we have been operating at 50 percent of capacity which means one ammonia plant and one urea plant. Two of our plants have been shut down due to the unavailability of gas, our Prill Urea plant was shut down October of 2004 and our older ammonia plant was shut down in November of 2005. In addition as been mentioned, last winter we had to shut down the entire complex for 10 days during a very cold stretch of weather due to the deliverability problem of gas.

Now during this coming winter we're anticipating that we will have an extended shutdown again due to deliverability of gas during the cold winter months. Our plan for our 2007 gas year which goes from November of 2006 to October of 2007 is that we will operate around 75 percent of the time. So in 2007 we will operate at 50 percent of capacity 75 percent of the time.

I guess just one of the things I'd like to add is a year to year operation like this is a very difficult environment, very difficult for our employees. Our employees have gone in the last two summers and probably will again next summer without knowing whether they'll have a job after October. In this environment our facility has still had some of the safest and most reliable operation in its history. And this is just a huge credit to our employees, their professionalism, dedication, and integrity.

Here's a graph showing our annual gas consumption since 2002 in billion standard cubic feet. 2001 was the last year that we ran at capacity, consumed about 53 billion cubic feet. As you can see, 2002 to 2005 we were 46 billion in 2002 and then around 40 for the next three years. 2006 we're projected to consume about 21 billion cubic feet and in 2007 about 15. This drop in our gas consumption is directly related to the availability of gas for us to purchase in Cook Inlet.

And we are the entity that is at the end of the Cook Inlet gas food chain. As gas availability in Cook Inlet tightens we are the first to get squeezed as happened last winter. Our operators describe us as the trim on the gas pipeline.

The Cook Inlet is a changing marketplace. Gas exploration is ongoing but the market remains short. Our view along with others is that the deliverability in Cook Inlet is declining by about 50 million cubic feet per day each year. At the same time gas prices are increasing with pricing now being indexed at NYMEX.

Our operation has been and continues to be threatened. We are a significant piece of the state and Kenai Peninsula Borough economy. If the facility is forced to close then we would lose $25 million in payroll, $95 million in purchases which drive $250 million in economic impact. So what are we doing to stay in business?

We are continuing to encourage exploration by being a gas purchaser and steady consumer. We have evolved to year to year contracts for gas that fits the needs of the gas producers. We are successfully juggling purchasing gas from a number of producers with a variety of different transportation agreements.

And I would like to just thank Cook Inlet gas producers, many of them here today, for working with us over these last few years in particular.

And in our continuing effort to make sure we leave no stone unturned to keep our business going we are looking at an alternative feed stock to natural gas, coal gasification. But that doesn't necessarily mean we are done looking for gas.

Our facility and our employees have been a part of Alaska for the past 38 years and we hope to be contributing neighbors for many more.

At this time I'd like to turn it over to Tim Johnson.

He'll continue on about our Kenai Blue Sky Project.

MR. JOHNSON: All right. Thank you, Chris, and thank you to the Commission for a chance to be here and to talk about our coal gasification project.

When I looked at the agenda and I realized that I was the second to the last speaker before lunch I was concerned that the greatest interest in the presentation might be how quickly I can get through it, but I'll endeavor to be as concise as possible at the same time I'll warn you that I'm passionate about what gasification can mean for Alaska.

Gasification is gaining interest across the country and around the world because of its ability to supply a solution for the increasing price and the decreasing availability of natural gas. At Agrium we feel that that is the opportunity that we need for the Kenai plant and the gasification may be a solution for our long term needs.

We started this effort back in 2004 and we made an announcement in 2005 that we were doing a phase I feasibility study. And just recently we announced that we had passed the first stage of the feasibility assessment and we're now moving on into the second step of that study.

And so what our project is really based on capitalizing on a long term supply of low cost coal that's available in Alaska. We see that as a great opportunity for providing feed stock for our plant. And as this forum looks to provide a solution, an answer, for the problems of energy in South Central Alaska this abundance the coal resource calls for coal to be somewhere part of that solution.

There's also a large number of compelling project drivers that come together to make this project work. First of all is the Agrium's K&O facility. It's the second largest nitrogen manufacturing complex in the United States. It's truly a world class facility. We've got as we've heard this morning a need for power in South Central Alaska that is increasingly relying upon gas for generation. We need to provide a low cost alternative to that. And there's also 13 existing oil production facilities that are nearing the end of their life and with the carbon dioxide that's available from this project to use as enhanced oil recovery it provides an opportunity to secure and recover an additional potentially 300 million barrels of oil from those existing facilities.

So for Alaska what that means is that we get to continue to build and grow one of the largest value added businesses in Alaska. We have the ability to provide a low cost power into this high cost power market. We have the chance to really produce a showcase operation. Our project would be a very large scale gasification facility providing multiple products in a true polygeneration sense that would be leading and where the world wants to go in terms of providing new feedstocks for industry.

It does give a significant opportunity to develop enhanced oil recovery which is at work and in place in the Lower 48 and Canada. There are many fields that are currently increasing their production from this technology. And this is very strategic for both the federal and state government in terms of jobs and economic development.

So this slide shows the location, the geography that you'll be familiar with. Our plan is to take the coal feed stock from the existing coal mine in Healy, Alaska working with Usibelli Coal Mine. Our project will consume somewhere between 2 1/2 to 3 million tons as it's currently envisioned. We plan to bring the coal from Healy by rail to somewhere in the Anchorage area where it would be transferred by barge and then shipped to our facility in Nikiski.

We see the Beluga coal field on the west side of the Inlet also as a tremendous coal resource. With the advantage of being able to work with coal from Healy is that our project is not tied to the commercialization and the start-up of a new coal mine in Alaska.

This picture shows our existing facility. In the foreground is the current Kenai Nitrogen Operations complex where there are two ammonia production facilities and two urea production facilities. The open field in the foreground is where we will site the new coal gasification facility. The engineering work that we have done will allow that all the new facilities will fit in that available land space including our coal storage area.

This is a slide that you need to watch out for when you have someone trained in engineering speaking to a slide with lots of blocks and arrows running around. But basically the lay-out for gasification, there are four key boxes. The heart of this project is the gasifier. That's where coal comes into a high pressure vessel and is mixed with oxygen and burns but not completely. It's called partial combustion. And that partial combustion is provided through oxygen which comes from the air separation unit at the top of the drawing. That's a traditional air separation plant where oxygen is purified and brought into the gasifier.

In the gasifier we form hydrogen by mixing the resulting products with water. The hydrogen is the product we need for our plant. In addition to hydrogen formed in the gasifier there's excess nitrogen from the air separation unit, the perfect building blocks from ammonia that is already produced in our plant.

But the gasifier and the air separation unit are both energy intensive units and they require a lot of additional power and steam. And that's the reason for building of a power plant along with the gasifier and the air separation unit. So power is provided to all of these other blocks both in the form of electrical energy and in steam and this offers the opportunity to deliver excess power to the grid to provide low cost power generated from something other than gas in South Central Alaska.

When you look at this project you can see just from this drawing that there's a tremendous amount of process and energy integration. And that really explains the reason why the is project needs to be located directly adjacent to our plant. As we've talked about this project there has been a lot of questions about why not site the plant at a mine mouth. And the reason really is because of the existing fertilizer plant that's in Nikiski right now. With all the integration that's there none of those pieces can be decoupled from the other one in order to make the project work and move forward.

So the approach that we have is to use a very disciplined investment approach to move forward. We've completed phase I, that was our feasibility study where we did initial engineering, initial environmental feasibility work and our initial commercial work. We passed that hurdle. We're moving forward into the next phase, phase II.

This is also a stepped process where we will look at engineering concerns, commercial concerns and start our environmental permitting. We want to make sure as we develop this project that it's done both responsibly from an environmental standpoint and from an economic standpoint ultimately concluding in phase IV with the construction and the start-up.

So as we look at the Blue Sky Project and our efforts into coal gasification we're very busy as we move into phase II. I'd like to thank again as Chris said the support from Governor Murkowski, his leadership and support of Agrium from the congressional delegation and from the State Legislature, DOE, Usibelli and many, many others.

As I think about closing remarks the comment about the old aviator saying today really struck home for Agrium. You never want to run out of altitude, air speed and ideas at the same time. Well, our air speed has definitely has been cut. Our altitude is shrinking, but we've got solid and strong ideas and we're looking forward to the future. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Chris and Tim.

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LIEUTENANT GOVERNOR LOREN LEMAN

COMMISSIONER SEAMOUNT: Oh, my gosh, we're ahead of schedule. What we'd like to do now is ask Lieutenant Governor Leman for some remarks.

Lieutenant Governor Loren Leman is completing a four year term as Alaska's eighth Lieutenant Governor, during which time he has spoken nationally on Why America Needs Alaska's Oil and Gas. Before this office, he served in the Alaska Legislature for 14 years where, among other leadership positions, he chaired the Senate Resources Committee and served as Senate Majority Leader. He led a number of legislative initiatives to enhance the wise use of Alaska's resources and increase opportunities from Alaska's oil and gas.

Loren Leman is also a civil engineer and fisherman. His family's history in Alaska traces back more than 200 years to a marriage in Kodiak between a Russian shipbuilder and an Alutiiq woman from Afognak. Gold miners, Alaska Natives, fishermen, and missionaries have figured prominently in his family. He is the first person of Alaska Native ancestry to be elected to statewide office in Alaska.

And I have to tell you that I had an insight into his family two summers ago when my daughter and I were eating lunch in Ninilchik Cafe and these two people came up and introduced themselves as Loren's parents. And they were the nicest people and they were so interesting and we spent about 30 minutes talking and most of the talk was about Loren. They were so proud of him for good reason.

He grew up in Ninilchik where he graduated from high school. He received his Bachelor's degree in Civil Engineering from Oregon State University and his Master's in Civil and Environmental Engineering from Stanford University. He has also studied arctic engineering at the University of Alaska Anchorage.

Loren and his wife Carolyn have three children, Joseph, Rachel and Nicole. Let's welcome Lieutenant Governor Leman.

LT. GOVERNOR LEMAN: Well, thank you, Dan, for that introduction and thank you also to Commissioner John Norman, both of you for organizing this as well as the many other people who have participated in it.

Let me just take this time to thank the many State employees. And, Bill, thank you for your presentation. And I know you represent so many more and there will be others later today.

I know the Governor would be quick to say this and I say it, we can't possibly do our jobs without the many people who help us do it. And so thanks to the many fine State employees who are helping us to be able to do our job.

And while I'm at it I don't think we've acknowledged, but my aging eyes have noticed several Legislators in the audience and I think some have come and some have gone, but let me just note that Representatives Paul Seaton, Landslide Curt Olson and Norm Rokeberg and Berta Gardner and Sharon Cissna over here and Senator Gary Stevens and Fred Dyson. And if I missed somebody else which I did the other day -- oh, Mark Neuman slipped in from the Valley. Thanks for being here.

As you heard in my introduction, you know, my background in Alaska is from the Kenai Peninsula. And so I have actually seen during my growing up years the industry, both oil and gas develop from the first discoveries in the Swanson River to the exploration and development of Cook Inlet. And now as Enstar talked about the extension of its lines down as far as Ninilchik actually a little bit beyond Ninilchik. And I might note to those from Enstar if you're still here the folks in Ninilchik are anxious to be more than just a place where the line goes through. They actually want to get some of that gas and I hope that you're able to get that distributed at a reasonable price.

I can't help but think about some of the times we went through during the '90s when during much of that time we had low prices. And we were looking at challenges in the industry. And when I chaired the Senate Resources Committee we did a number of things, things that I think you'll hear later on today from others that have had an effect. And obviously since I've left the Legislature, the Legislature continues to work on things that have helped like area wide leasing, both on Alaska's

North Slope and in Cook Inlet. Exploration licensing. Exploration investment credit. And another one that is huge, I think, is dispute resolution.

You know we were going through times where we had disputes backed up for not only hundreds of millions of dollars, but to billions of dollars and coming up with ways to resolve those and ways to streamline dispute resolution has been huge, but we also dealt with the concept of negotiated royalties during times when it may be appropriate and dealt with the Stranded Gas Act. And then this past year the Legislature in dealing with changes to oil taxes recognized the importance of stability in the Cook Inlet region and dealt with it appropriately.

And so there have been some huge things have been done, but I think as we've seen today we continue to have challenges. And, you know, one of the things that we have and it's actually a good thing to have, we have challenges of the different competing uses, but we see how important it is to have the industry. Bill Popp very eloquently presented why it's important for the Kenai Peninsula to have a tax base and to have workers that are well paid that are part of their educational system, and part of our economy and part of our culture. We see that across Alaska.

These people are our neighbors. They attend our schools. They go to our churches. They buy at our supermarkets. They attend ball games. And these are people that we want to have as part of our culture in Alaska, but it also creates conflicts that we have to deal with. And so, you know, with these challenges also come opportunities.

A couple of things I just want to note that I heard today. One is the Governor got into a discussion and talking about market pricing and, you know, especially his discussion I heard was at the wholesale level, but I've heard the same thing at the retail level. It's, you know, why does it cost more for -- to buy gas at the pump right next to the refinery. I hear this from folks at North Pole. I heard it from folks on the Kenai Peninsula. And you know, the Governor talked about it and how we price. And getting into that gets into the challenges of the marketplace. And it's very complex. And for government to get into it in any substantial way creates some challenges.

And so, you know, I'll just put out that cautionary note and I know that there are those of you who know far more about this than I do, but it creates some real conflicts that'll have to be worked through.

The others, I heard a lot of synergies today, a lot of agreement. And I recognize that there's also conflict and there's also litigation, you know, ongoing with these things. And they're huge. But one of the things I couldn't help but kind of smile at is after a very fine presentation by Dr.

Thomas. He was followed by a very thought provoking presentation by Dr. Tussing. And Dr. Thomas had presented all of this information and these projections and then Dr. Tussing comes behind him and says that one thing we know is that projections have always been wrong and sometimes hugely wrong.

I remember when I was a Legislator I participated in the Energy Council, one of the finest of our national organizations that Legislators participate in. And I went to one conference and there were international experts there and they all agreed over the near term the next probably year or two years we weren't going to see any substantial change in the world wide price of oil and gas. Well, what do you know? Within six months the price of oil had doubled. And so here we have some of the finest in the world, you know, making their predictions and, you know, we don't always know.

And so, we need to be vigilant. And I would say to the organizers and to those of you who are attending let's stay vigilant. I believe Alaska is still is a great place, a place of great opportunity. And I think the one thing, you know, that's real clear to me today is that we have the people who are capable of getting this solved and many of them are in the room today. So thank you so much for inviting me to be a part of this group.

COMMISSIONER SEAMOUNT: Thank you, Lieutenant Governor Leman. I'm now going to turn the mike over to

Chairman Norman.

CHAIRMAN NORMAN: Thank you, Dan. And you've done a great job of keeping us right on schedule. In fact, we've got a little bit of extra time. And you need to know when we were discussing this we knew if we pulled together an army of the best minds that we could find to work on this problem in keeping with what Napoleon said an army travels on its stomach and you've had to be fed, so we talked about what sort of lunch to have. And Dan wanted chateaubriand and creme brulee and I said no, that's kind of unseemly at a time when we're facing a tough, tough situation a climate of austerity. And so we did finally agree that your lunch is going to be out of a cardboard box and you'll bring it in here and you'll no sooner get seated and then we're going to charge straight ahead and keep information coming at you, but we do have two great speakers.

Our one concession to frivolity, if you will, will be a single oatmeal cookie which Bill Popp who broke the tie insisted on if we were going to have the box lunches. So either with your name tag or handed to you, you should have a lunch ticket. And if you'll now go through the back doors we'll take a 10 minute break, get your lunches, return, and then we'll have a working lunch. Thank you.

(Off record)

(On record)

CHAIRMAN NORMAN: Folks, we're going to go ahead and move forward now. Please, keep eating. That's the intention is that this will be a working lunch, but please do go forward.

A few preliminary matters. Lieutenant Governor Leman indicated that he has an announcement that he would like to make so, Lieutenant Governor.

LT. GOVERNOR LEMAN: The first thing is I recognized several Legislators earlier and we've been joined by a man who's never been a Legislator but he's been everything else. Twice Governor of the State of Alaska and former Secretary of Interior Wally Hickel. And Governor Hickel continues to have a very strong interest in oil and gas.

I was going to mention in my comments and it just slipped my mind that I have with me some of Alaska's Constitutions. This is the 50th anniversary of the writing of our Constitution and its adoption. And these are available if you'd like to have one either see me afterward or we'll get some on the back table. And I've just called over to the office because I think we'll probably need more. By a show of hands how many of you are interested in picking one up. Okay. Good. We'll get plenty and have them out back. This is a great document. A good reminder of why we're doing what we're doing.

And when it comes to resources go to Article 8 and you'll realize that the writers of our Constitution did something pretty special. They wrote into our Constitution that we're to manage our resources for the maximum benefit of our people. And, you know, that's why we're here today because we all, I believe, really want to provide that maximum benefit to our people. So please, pick one up and read it.

CHAIRMAN NORMAN: Thank you, Lieutenant Governor. And, Governor Hickel, it's an honor to have you with us here today, sir.

I also want to recognize just briefly a couple of other people. We have one gentleman here that when I began working in this area a long time ago, 35 almost 40 years ago, he was a model for me of how a person ought to behave in public service. He's our Commissioner Emeritus over at the Commission. He's also an eminent geologist and the geologist that was responsible for making the decision to select the North Slope area that produces so much wealth for the State of Alaska. Tom, would you stand and be recognized.

And I saw earlier Dr. Mark Myers. Word was publicly released a few days ago that he's been confirmed by the Senate as the Director of the United States Geological Survey. That's quite an honor not just for Dr. Myers but for all of Alaska. So when he comes in I'll try to note it and perhaps we can hold our applause now and when he comes in we'll let him know that we celebrate that achievement that he has attained.

We have had a number of members of the press in and out. And I would like to encourage the members of the press as we grapple and tackle with this issue the press is an integral part of this process because they're the only way that we can communicate with the public and help the public understand the changing and evolving energy picture here in South Central Alaska. I'd ask all of the presenters to, please, even though the time has been short to, please, make yourselves available to members of the press and I'd encourage members of the press to not be hesitant to come up later and have a one on one interview or get business cards because this is a complicated puzzle that we're embarked on. And you're an essential piece of it. And even though time may not permit now for the presenters to give a full presentation, I think that you by being able to follow-up can do so.

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THOMAS E. KELLY

CHAIRMAN NORMAN: We now have two very interesting speakers coming up. And I'll introduce them in the order that they're going to come. It's a special treat to be able to introduce an old friend, Tom Kelly who was our Commissioner of Natural Resources here and served under Governor Hickel years ago whenever I originally came to Alaska.

Tom Kelly is now a retired consulting geologist. He's a 24 year resident of Seattle, but in reality he identifies himself as a displaced Texan out of Alaska where he spent 20 of his younger years in the oil and gas business.

Tom worked as a well site geologist and explorationist on the Kenai Peninsula in the late 1950s. He was Commissioner of Natural Resources in the late 1960s during the first administration of Governor Hickel. He was president of the Anchorage Borough School Board, the Anchorage Chamber of Commerce, and ran one time for Governor in 1978.

Tom spent the next 25 years as a geological consultant primarily working for several of Alaska's Native corporations, most notably the Arctic Slope Regional Corporation.

Tom when he first came up here was in charge of legendary oil wildcatter Michael Halbouty's Kenai's Drilling Ventures and the discovery of the West Fork gas field. Please welcome former Commissioner of Natural Resources Tom Kelly.

MR. KELLY: Introductions are always quite embarrassing, but in any event thank you very much, John. And I want to thank particularly the Alaska Oil and Gas Conservation Commission for inviting me to participate in this forum, and especially you, John, who is certainly my old friend and professional colleague for many, many years back.

It's great for me to be back in Alaska as always and to share with you a moment of history which I feel very fortunate to have been a small part of. It's very obvious to me today after having been almost a quarter of a century removed from the Alaska scene that the great bulk of Americans in the Lower 48 state do not really understand Alaska. They don't understand what makes it tick, but as Lieutenant Loren Leman said a few minutes ago, it is the people of this great state that really make it something to be proud of. And I'm certainly proud to have been a resident for more than 20 years.

History is a great thing to talk about. It's based on facts so it doesn't provoke dissension or disagreement. It brings back cherished memories that still bring pride and pleasure, perhaps like no other thing we can think about. I was asked to talk about Cook Inlet in the early days with some emphasis on natural gas, gas which is on everyone's mind today in Alaska as we see the supply problems in the future in somewhat of a clouded perspective.

History has a unique characteristic, it repeats itself. Times differ and the players are all different, but their experiences are similar and in many instance identical. I'd like to make a small analogy or a simple analogy in order to illustrate some aspects of history and to compare beginnings. Without any debate I believe students of the history of oil and gas would agree that where it all began was at Spindletop, Texas, January 10, 1901.

On that cold winter morning the Lucas gusher exploded 150 feet into the air which heralded the beginning of petrocarbons as the most efficient and effective form of energy that has ever been found. I wouldn't hesitate to say that mankind will never know anything better at least as long as I'm around to observe what's going on.

We have alternative sources of energy and certainly that's something we have to and we must pursue, but as far as the prime energy that we seek today and it's hard to replace it, it's oil and gas. The players in Beaumont in 1901 pre-stage what happened in Alaska 50 years later. The prophet in Texas as a fellow by the name of Patillo Higgins. He was a logger turned oil explorationist. While it was Patillo Higgins' dream and prediction that oil would be found on what was referred to as that time the, quote, hill, about four miles south of Beaumont, Texas which was no more than a topographic expression of a very shallow piercement salt dome which was uplifted to within 250 feet of the surface.

There was another individual at that time by the name of Captain Anthony Lucas, and he was a believer as well was Patillo Higgins, but he was a doer. He was able to raise the money, hire a couple of drillers from Corsicana, Texas and drill the discovery well which was known from then on as the Lucas Gusher. Within a few months of the discovery there were six wells at Spindletop which flowed 185,000 barrels a day most of it straight up in the air which exceeded all of Russia's production at that time. And at that time in 1901 Russia was the largest oil producing country in the world. And here it was overnight virtually relegated to a poor second position.

But back to the analogy, the other part of the beginning was South Central Alaska as far as the oil and gas industry as we know it which is punctuated certainly by rich fields, discovery at Swanson River in August of 1957. There were early exploration episodes at different locales in Alaska. The facts are covered in a wonderful chronology referred to or known as Crude Dreams, a publication written by Jack Roderick who is one of the very early persons here in the oil and gas leasing and land business. And, of course, is our former borough mayor and I assume is still around in Alaska these days.

About the time of Spindletop in 1901 the British had a drilling program at Katalla on the Gulf of Alaska. And by 1910 there were four wells which produced a relatively small amount of oil, but they had built a refinery and it processed to my knowledge about 60 barrels of oil a day. And over the period from 1902 to 1934 when the refinery burned down the total cumulative production from the field was less than what would have been two days production from Spindletop. A few years later there were a number of wells that were drilled near oil seeps on shore from Cold Bay on the Alaska Peninsula.

And very sporadically for the next 50 odd years independents and companies including Standard of California and Richfield probed about a 600 square mile area east of Becharof Lake which is, those of you who have been there, a rainy, windswept muskeg covered region dotted with many volcanoes. There were countless oil seeps and shoals but nothing resembling a commercial discovery was ever found.

Closer to this area in Cook Inlet a California based wildcatter named Russ Havenstrite was convinced that the Iniskin Peninsula was most promising of any place in Southeastern Alaska. Around the turn of the century on the peninsula, the Iniskin Peninsula, a small company named Alaska Petroleum had chased the oil seeps at Bowser Creek, but to no avail.

At the south end of Chinitna Bay near the mouth of Fitz Creek there's a gigantic exposed surface anticline, probably one of the most imposing features if you're flying southward on the west side of the Inlet that you will ever see. It was very impressive to Russ Havenstrite and for the next 20 years, which included World War II he promoted the merits of the Iniskin as a place to find oil. He had interestingly enough a lot of Hollywood contributors and backers and they drilled several wells in the area of Iniskin, unfortunately they were just about out of gas and the end of their rope right about the time of the Richfield discovery.

There are several other areas that were explored in the Houston area and the Upper Matanuska Valley and in the Eureka area of the eastern -- or western Copper River by individuals who are covered so well in Jack Roderick's book and so I won't get into 'em at this time.

The Cook Inlet and the North Slope leasing pays in the late 1950s were quite active. Most independent land men and major companies were either filing or buying lease applications in the remote Interior basins since most of the Kenai had already been leased or was committed to a development contract at that time, but as I recall there was an awful lot of interest in both the Tanana and the Kuskokwim and the Copper River and the Susitna areas as well as the Gulf of Alaska and Bristol Bay.

There was quite a land rush at that time and wining and dinning of some of the Kenai homesteaders many of which who had mineral rights if they had proved up their homesteads in the early -- by the 1950s. In the later years, of course, they were not -- they did not receive mineral rights to the lands that they proved up for agricultural purposes.

Alaska's Patillo Higgins by analogy in my opinion was a gentleman who was a salesman at John McManamin's and Glenn Miller's Army Navy Store, a fellow by the name of Locke Jacobs. The main difference between Locke Jacobs and Patillo Higgins was that Locke was in part Anthony Lucas a doer in addition to being the visionary as was Patillo Higgins.

Jack Roderick referred to Locke Jacobs' group of people as the Anchorage Leasehold Club. It was a group of Anchorage top businessmen who met frequently at the Elks Club on a weekly basis and were guided by Locke Jacobs in filing lease applications all over Alaska, but especially on the Kenai Peninsula.

About the time I arrived in Alaska in the late '50s someone had dubbed the group the Spit and Whittle Club. It consisted of Anchorage's most prominent -- some, I should say, some of Anchorage's most prominent movers and shakers, Bob Atwood the publisher and owner of the Times, Elmer Rasmussen, the CEA of the National Bank of Alaska, Willard Nagley, owner of the Anchorage Westward, Fred Oxford a well known jeweler and many other Anchoragites.

I say some because one of Alaska's all time movers and shakers is with us here today, I speak of former Governor Hickel who not only was an outstanding and still is developer, but found time to be Governor twice and Secretary of the

Interior one time. And Governor Hickel has long since -- or long retains the -- in my mind as a person that I look to as my mentor. I'm certainly glad to see him here today.

Locke Jacobs kept current the records that he had from the BLM serial sheets and on behalf of the Spit and Whittle Club, who incidentally I think was probably somewhat of a misnomer. I don't think anybody whittled and I can't conceive of Bob Atwood or Elmer Rasmussen spitting at all, so I think that was not, perhaps, the most appropriate thing for the club, but anyway, some of the filings that were made by -- at the direction of or the recommendations of Locke Jacobs fell within the boundaries of the soon to be discovered oil and gas at Swanson River, Kenai and Beaver Creek.

The story of the Swanson River discovery in August of 1957 has some of the romance of the Spindletop discovery. Richfield geologist, Bill Bishop and Ray Arnett were at the well which was drilling below 10,000 feet. They were about ready to call it quits, as the story goes, and preparing to abandon the well, but decided to make one or two more connections and then you know what the story was.

A well came over the shaker and the discovery was not as dramatic as at Spindletop. No 150 foot black plume of oil arched above the crown block, but in Alaska and the offices of oil men throughout the country the image of Alaska as the new oil frontier was more than just a little bit exciting.

The Swanson River Number 1 penetrated over 100 feet of oil saturated hemlock sand and conglomerate and was estimated to produce about 250 barrels of oil per day which is not a barn burner in anyone's mind, but that was just the beginning of the story. The discovery was located on the extreme north plunge of the anticline. The width of the producing interval in that area is less than a mile on the very north end of the structure.

The number 2 well and the number 3 well were, I don't recall exactly, but one of 'em was dry and the other one was very marginal, so there were three wells on the -- within the Swanson River Unit and -- or three wells drilled in 1958 which was followed by a Texas independent oil man, that was in part of the introduction John made, a vee (ph) by the name of Mike Halvey who had made a deal with a fellow out of Wichita Falls, Texas by the name of Fred King. And he in turn had some relationship or taken a lease with some New York investors in what was known as the Alaska Oil and Minerals Company and they farmed out to Halbouty two 2,560 acre lease blocks which were five miles southwest of Swanson River and the second block about another 12 blocks due south.

Halbouty was the first independent wildcatter to venture on the Kenai. The terms of his farm out carried two well obligations in order to earn an interest in the 5,000 plus acre tracks. The first well had to be drilled by January of

'59 and the main problem was that Halbouty had no rig, had no experience in Alaska drilling and had no basic geologic or engineering or geophysical data. He only had a hunch and the fact that both farm out blocks were on trend, that is, more or less a little bit east of north/south with Swanson River and virtually all the other trends -- structural trends that were on existing USGS maps at that time.

So Halbouty went to Bakersfield and cut a deal with Coastal Drilling Company for a brand new Emsco 500 rig which was fabricated, trucked to Long Beach, shipped to Seward in less than 90 days. The rig arrived in Alaska on a cold December morning in 1958 and was trucked to Nap Town and then over the Swanson River Road for 16 miles before it was -- it intersected a three mile pilot road just south of Swanson River.

The extreme cold of that time or that winter was a godsend because the new road found very little gravel and it was essentially no more than a frozen ice road covered over with snow.

If Patillo Higgins was dismayed, disillusioned, disheartened by lack of success before the Spindletop discovery, it was nothing compared to how Halbouty felt when he drilled the Halbouty King Number 1 well to a depth of over 11,000 feet and it was a dry hole. It penetrated 400 feet of beautiful hemlock massive sand and conglomerate and it was all wet from top to bottom.

The well log did show an eye popping fact, however. The Halbouty well which was easily correlative with the Swanson River discovery to the north was 400 feet structurally high to the Swanson River well which obviously pinpointed a large, uplifted area that was somewhere between Mike Halbouty's well and the discovery well to the north of Richfield. By that time it was Standard of California.

Pete Jester (ph) was the gentleman with Standard of California those days who was the exploration manager in Anchorage and he quickly realized the likelihood of a more favorable location east of the Halbouty well on the SoCal leases.

The Soldotna Creek number 1 well was drilled about three-quarters of a mile immediately east of the Halbouty well and penetrated 300 feet of oil sand and came in producing over 4,500 barrels a day. That was the real bonanza that was the Swanson River/Soldotna Creek history and that's what catapulted Alaska in my mind into a major producing state because they had now discovered a giant oil field, one in excess of 100 million barrels.

The Halbouty dry hole had clearly indicated where the most prospective area of the Swanson River/Soldotna Creek lease block was likely. The interesting part about it SoCal, because of a bottom hole contribution had all of Halbouty's information. Mike Halbouty never had a glimpse of any of the wells that were drilled, either the 1, 2 or 3 Swanson River wells before he drilled his dry hole. In those days a tight holing was everything and tight holing as it may be still today is alive and well and not necessarily to the likes of those of us who didn't have any information.

Halbouty faced several other problems not the least of which was the commitment to 10 wells with that one rig. Less than 10 and he was required to ship the rig back and pay a sizeable penalty at his sole cost. That set the stage for frantic, what I refer to as a phone-a-thon or a lot of opportunities to wine and dine various companies and individuals in order to see if they would take at least one of the remaining drilling obligations off of Halbouty's hands.

And thank goodness for the visionaries, some several visionaries with Union Oil Company of California who were a dynamic bunch of oil moguls of the '50s, Fred Hartley, Sam Grinsfelder, Charlie Smith, and here in Alaska Hal Leon. They agreed to take the rig off Halbouty's hands and also let him have it back in the summer of 1960 to drill the West Fork block which was a discovery gas field, the only discovery that Halbouty could ever really call his own.

After plugging the Halbouty King Oil number 1, the coastal rig was moved to Kalifonsky Beach and drilled the discovery well of Alaska's largest gas field before Prudhoe Bay which is the Kenai gas field, a multi-trillion cubic foot field and the one that changed the way people live in Anchorage, as well as the communities in the North Kenai. Natural gas came into its own basically with the discovery of the well at Kenai gas field.

In the summer of 1960 the coastal rig was, as I mentioned earlier, trucked back to the second 2,560 acre lease block that Halbouty had taken from Fred King and they drilled a well to 1,419 feet which was the second deepest well in Alaska at that time. The objective, of course, in those days was oil and the hemlock was not productive. The well was plugged back and completed in a shallow, sterling gas sand about 5,000 feet deep.

At that time some people thought that was the continuation of what Union had found at Kenai field, but later stratigraphic evidence pointed out -- or rather 3-D evidence pointed out that there was no more than stratigraphic equivalent, but it certainly wasn't correlative.

As it was in the 1960s and it is today there are three major giant gas fields in the entire Cook Inlet Basin, that's Kenai, North Cook Inlet, and Beluga. There are several smaller, but significant deposits at Beaver Creek, Cannery Loop, Moquawkie and Ninilchik and, perhaps, a dozen or more other accumulations of smaller size which are in a developmental stage and may one day contribute significant amounts of gas, but are not likely to reach the giant category.

In the '60s, '70s, '80s and '90s, the same as today, there are eight fields. Eight oil fields in the basin which are in various categories. Three -- or five of which are in the hundred million barrel category or classified as a giant field. What is, perhaps, the most jarring statistical revelation to me is that there has only been one major oil find of any great significance on the entire Kenai Peninsula.

Oil was discovered nearly 50 years ago and to this date nothing of great significance has ever occurred not counting, of course, the gas discoveries that are located, one of which on the Kenai. I don't -- I find it very hard to believe that Swanson River is the only major oil accumulation to exist on the Kenai Peninsula or on the Kenai lowland.

Everyone knows the primary reason that we have only one Swanson River, and that's what's also perplexing and maybe that will change also, obviously the lack of access to the most prospective areas on the Kenai and the lack of land and leasing opportunities that could lead to new exploration discoveries particularly on the wildlife refuge are something that the future holds.

Another reason that is sometimes given for lack of new discoveries is the dominance of large oil companies on the scene and the paucity of independent explorationists. And to be quite honest the role of an independent in Alaska is difficult.

It has always been. Oil and gas exploration in Alaska, as it is almost everywhere today, is very costly and there are not the opportunities everywhere available. The lack of infrastructure particularly in Alaska and difficulty of access presents real obstacles.

Among the early experienced independent land men who had been highly successful in Texas was a team that came to Alaska in the early 1970s. A gentleman by the name of Baylor Van Meter and John Overby who were ex-Pure Oil Company land men. They came to Alaska at the beginning of the '70s backed by Hollywood personalities which included Bob Hope, among others, and they spent over five years trying to break into Alaska's oil and gas business.

One frustration led to another with an interlude, basically it was selling locally built house trailers, which Van Meter referred to irreverently as wobbly boxes. In any event without any measurable success in the oil patch, the team split up. I illustrate that only because they tried hard and they didn't make it.

Both men and their families were outstanding citizens and contributed unsuccessfully -- or contributed unselfishly to the community. And countless others in the oil business have come and gone, but most left a lot more in the state than they took out in the category of good will. Those in the industry, I think, have left a great deal in Alaska.

Our concentration largely for the last 20 years has been focused on the Arctic and particularly now in the Arctic National Wildlife Refuge or range. No one is that really fired up about the Kenai National Wildlife Refuge and yet if you look at a map the prospective area of the Kenai lowland is probably larger than what we are looking at for on the Arctic Coastal Plain east of Kaktovik.

One of the largest potential stratigraphic accumulation of oil and gas may be located along the western flank of the Kenai Mountains and how many structures lie uncharted on the area of the Kenai lowland. It's somewhat ironic, is it not, that in this day of critical energy supplies there is no concentrated effort to really, in effect like we always used to say, open up the moose range. It's been well managed always from an environmental standpoint and certainly that should be the case today if lands are made available for exploration.

This is about the end of my story. I do want to, once again, emphasize that if gas is obviously and potentially in short supply as we know it is today in Cook Inlet, it seems to me that one of the logical places to see if there's not a possibility to remedy the situation would be to, once again, encourage all the exploration efforts we could on the Kenai lowland. It's a lot easier to drill regardless of the other obstacles on land than it is offshore.

Patillo Higgins had the perseverance to continue despite many disappointments along the way. Locke Jacobs similarly faced a lot of doubters as he pushed to see Alaska's resource potential unfold. Their attitudes are unique and they're what makes this nation so great and second to none in the world in productivity. I think and I am confident in knowing Alaska's people that it will happen again. Thank you.

CHAIRMAN NORMAN: Thank you, Tom. One of the great things about Alaska is we are truly a young state and it is still possible to have people that were here and were making things happen and hear about it first hand.

I can remember in the late '60s, all of you can that were here, when you would fly into Anchorage the Inlet was aglow, too, from the gas flaring and at that time our counterpart, the Alaska Oil and Gas Committee and the three Commissioners Tom Marshall, Easy Gilbreath, Homer Burrell held sometimes contentious hearings and finally the gas flaring was stopped. But I do remember in leafing through a lot of the Orders in 1970 from Granite Point field alone there were nine billion cubic feet that were simply flared, burned, went up in smoke. Why, because it had no value. In fact it was a liability to figure out what to do about it and, of course, now fast forward almost 40 years and here we are today saying how can we get gas. And that illustrates how there is a trap that you can fall into at any given time by thinking this is the way it's always going to be.

And sometimes I'm asked to explain what the Alaska Oil and Gas Conservation Commission does and our job the way we think of it is to be looking far out on the horizon and asking the question 40 years from now what will that generation say about the way reservoirs are developed today in the same way that we can look back on that flaring which at the time made sense to the companies 'cause it had no value.

I also remember Tom Kelly, he was a very colorful, flamboyant person and he was the Commissioner that was in charge of the first huge lease sale that we had ever had under Governor Hickel in 1969. I believe I'm correct, am I not Governor, you had not gone back to the Department of Interior yet, had you? Yes. And I remember Tom was a tough, hard negotiator. I just remember everybody in Alaska had a feeling of confidence that we had an oil man that was capable of holding his own with the companies through those times.

In fact, I think there was a big editorial in the paper. I remember it said, cool hand. There was a movie, Cool Hand Luke and everybody -- that they applied that application to Tom Kelly, cool hand, because of his approach to getting the best deal he could for Alaska.

I'm going to now move to our next speaker who likewise has a very interesting presentation and came along a little bit after Tom Kelly, but has a long and distinguished career of service here in the area of oil and gas with Alaska.

BILL VAN DYKE

CHAIRMAN NORMAN: Bill Van Dyke's current position is as acting director of the Division of Oil and Gas. He was born and raised in Pennsylvania. He earned a Bachelor of Science Degree in Petroleum Engineering from Pennsylvania State University. He worked for Chevron Oil Company in Louisiana and for Gulf Oil Company in both Pennsylvania and Texas. He's held various petroleum engineering positions and has focused on reservoir engineering, enhanced oil recovery and field depletion planning.

Bill moved to Alaska in 1978 and at that time began work with the Division of Oil and Gas' Reservoir Engineer. Since then he's held a variety of positions with the Division of Oil and Gas with increasing job responsibilities up to the present time where he is today our acting director of the Division of Oil and Gas. Please welcome Bill Van Dyke.

MR. VAN DYKE: Thank you, John. I think most of you noticed that there's a job fair going on upstairs and I hope that that's just a coincidence and not someone's cynical view of the energy industry here in South Central Alaska.

I have two handouts. I think some of them have been distributed. Peggy and Sheila, if you still need one raise your hand, we'll make sure you get one. And if you don't we will -- it'll be posted on our web site, hopefully, by next week.

I'd just mention if you're a real history buff for oil and gas in Alaska, as Tom mentioned, Jack Roderick's book is a very good book. Also, I think it was about 10 years ago Petroleum News published a book. It was called Katalla to Prudhoe Bay. That's also a very good compilation of the oil and gas history in Alaska and I think that's still available, but you'll have to contact the folks at Petroleum News, but that's also another good reference source in addition to Jack Roderick's book.

So let's get started. I have some time lines. I'm certainly not going to cover all the information on each of the time lines. I think folks have discussed that in the early 1900's down at Katalla folks were, you know, chasing oil seeps, drilled some wells. Also over in the Iniskin Peninsula 1898, 1902.

And I think what's interesting about that is that's just literally west of Homer. It's across Cook Inlet on the other side of the Inlet, but just west of Homer so folks were -- they were so close, yet so far away in the early 1900s to a major oil and gas sedimentary basin. They were chasing oil seeps and that's what made sense at that time, I think, but obviously there was more to learn about the Cook Inlet Basin.

You know, around 1920 there was a shallow well drilled up here in Anchorage. 1928 there was a well drilled up near Chickaloon, that's north of Palmer. You know, these were 30 years before the Swanson River discovery, so there certainly was some activity up here in Cook Inlet before Swanson River. Swanson River certainly wasn't the first well, by any means, to be drilled.

Just other interesting facts, 1923 is when the National Petroleum Reserve in Alaska was established, so even in the early 1920s folks were already beginning to look north.

Obviously the rigs back then were a little more primitive than they are today. You've seen some earlier pictures of early rigs. People's ways of well testing was a little different, probably certainly wouldn't measure up to today's standards. I don't think the Oil and Gas Conservation Commission would let folks test wells in this manner today. That's over on the Iniskin Peninsula.

Jump up to the 1950s as Tom's already talked about. Probably one of the most exciting times in the state with respect to oil and gas and exploration really did shift to the Kenai Peninsula. And I've asked -- over the years I've asked a lot of people well, you were down on the -- folks were down on the Iniskin Peninsula, why did they come to the Kenai Peninsula? There weren't any big gas seeps on the Kenai Peninsula.

What brought them up here? And it may be just as simple as you've heard the phrase I'm sure, you know, the best place to find oil is next to an existing oil field. Well, maybe the thought was the best place to find oil was next to an existing oil seep so folks moved north from the Iniskin Peninsula. I think they were chasing those same rocks.

They obviously realized it was a sedimentary basin in Cook Inlet. It was a tertiary section. A young section of rock, but I think -- at least I believe from the information I've been able to collect, that they were really chasing again the older rocks for the most part. They were hoping to find oil in the same rocks that they saw at Iniskin. They were going to drill through the tertiary and find oil in the Mesozoic. Well, we know what happened at Swanson River.

And the Kenai Peninsula was -- it was open to leasing. There was land available. It was open. It was the Federal Non-competitive Leasing Program. You know, there weren't federal sales as we know today, the BLM type sales, competitive sales. The state -- the state hadn't reached Statehood yet so there was no state competitive sales so it was over the counter. It was wide open. You just had to file on the land and the land was available.

And as Tom mentioned it was very much people driven. People believe that there was a good chance to find oil and gas on the Kenai Peninsula and that was local people, oil company people, people out in field parties, you know, riding horses across the countryside. Helicopters were just coming to Alaska about that time in the 1950s, Carl Brady, so a lot of real good effort by individuals to really bring the oil and gas industry to the Kenai Peninsula, but again, there really were no oil seeps, no big gas seeps. It's sort of an interesting story, what brought them there.

Again 1955, again, before Swanson River, there was a well drilled over at Knik, you know, across Cook Inlet here across from Anchorage. There was also a well drilled up by Houston, Alaska, the Rosetta well. There was actually a couple Rosetta wells drilled over the years, but again, 1955 before Swanson River.

Well, then comes 1957, you know, Swanson River discovery, 1959 Kenai and, you know, it all -- the big rush starts at that point. Statehood, we had our first big state Cook Inlet oil and gas lease sale in late 1959. It's my understanding that the offshore was not available under the federal program so the offshore became available after Statehood. So really the leasing rush and the land rush began in Alaska in the late '50s. The records indicate there was probably over 100 companies active here in southern Alaska, something like 18 million acres under lease.

1960s were kind of interesting. Exploratory drilling activity levels just exploded. I'll show you a slide in a minute. You've seen it earlier actually in another presentation. What's interesting is by 1966 all the big, known fields, the fields that we know of today, by 1966 they'd all been discovered and you'll see that exploratory drilling was still going on much longer than that, but by 1966 all the big fields had been discovered.

The late '60s -- or the mid '60s saw the platforms being installed. Production wells being drilled and then oil and gas production from Cook Inlet.

Also in the '60s we certainly can't forget 1968, discovery of Prudhoe Bay was announced and in some ways I think that is a -- it certainly hasn't helped Prudhoe Bay (sic) because it drew away many of the industries best and brightest. They began to look north certainly and for a reason, but I think the discovery of Prudhoe Bay it helped draw away some of the people and certainly a lot of the budget because oil and gas activity is expensive. We've seen the numbers. You know, if your exploration budget moves north you're not going to -- what are you going to do here in Cook Inlet.

Here's that slide, so again, by the end of 1965 which is if you have the handout, you can see it's about at the year before the peak in exploration drilling. All the known fields had actually been discovered. The exploratory drilling actually peaked in 1966, you know, a year after the last big, known fields were discovered.

I guess what's interesting, you know, folks back in the '60s also were just beginning to understand the Cook Inlet Basin, the sedimentary basin, the architecture and its petroleum systems so a lot of these wells were drilled on real sketchy data as Tom mentioned. Most of the wells were tight, seismic was hard to get. It was certainly not as sophisticated as 3-D seismic today so a lot of the wells were drilled on real sketchy information which at least in my view allows for lots of additional drilling opportunity today. There's certainly a lot of prospects still out there.

Here's a graph of just development well drilling. It peaked in 1968. Again, the platforms had been set. All but two of the platforms in the Inlet had been set so development well drilling had peaked in 1968 and it was primarily oil driven.

This one just shows when the Cook Inlet platforms were set. Again, primarily in the mid 1960s. I think it's not so much exploration observation, but if you look at some of the wells that were drilled from these platforms they really, certainly for the day, were just incredible feats of science. You know, they were really world class record, extended reach wells so these Cook Inlet drillers were really some of the early pioneers for extended reach drilling. You look at some of the horizontal deviations on the wells out on those Cook Inlet platforms in the 1960s and they're really world class wells.

We've seen a couple pictures of the platforms. That's one of the four legged varieties. The one legged variety we have out there, really good science and really good engineering that went into construction of these platforms.

Jump up to the 1970s, you know, folks were looking out there in federal waters around Alaska, you know, the Gulf of Alaska. Pretty inhospitable place to drill at times. Certainly exploration in the late '70s, I'll take a little bit different position than one of the speakers. I think there certainly was a real good pulse of gas exploration in the late 1970s.

I think if you were around you'll remember there was an LNG project folks were trying to promote and there wasn't enough local gas to really bring on a big, new LNG project so there was a thrust to find more gas in the late '70s to support that project. There was an iron ore reduction project. People shopped around for awhile and that needed gas, a long term supply of gas. So there really was a good pulse of gas exploration in the 1970s. No big, major fields discovered though.

There was a lot of exploration in Lower Cook Inlet, you'll remember in the federal waters out there. Also in Cook Inlet using jack-up rigs, you know, the Kalgin Island wells, the Fire Island wells, some wells -- S.R.S. over there by the East Forelands so exploration was still ongoing certainly, but also in the '70s, 1977 TAPS was completed so folks -- there still was this tug of war for people and for budgets between northern Alaska and southern Alaska and I think that really has had some influence and still has some influence today on the levels of activity here in Alaska.

1990s we saw some new players come in then. I think a really good -- good, new pulse of players, Anadarko, Union Texas came in, Forest Energy came in. Also I think some real good science in the 1990s. We all remember the Sunfish wells that ARCO drilled out in Cook Inlet. At least in ARCO's view they were not a commercial success, but that really was good science.

ARCO went back and really looked at the depositional environment in Cook Inlet, the petroleum systems and that science is still being used today to generate prospects so there was really a -- while that particular drilling campaign didn't come up with a prospect that ARCO wanted to develop, it certainly was some good science that we still have on hand today.

Late in the 1990s the -- I think you'll remember there was quite a debate, quite a gnashing of teeth when the LNG export license was extended and certainly between the LNG export and the ammonia urea plant that gas consumption has whittled away at the gas bubble in Cook Inlet between the 1990s and now into the 2000s and between that consumption and the commercial and residential consumption we are where we are today.

And I think there's been, you know, some criticism over time whether, you know, you should export ammonia urea or export LNG. We'd be in the same spot sooner or later because there was only so much gas in the gas bubble and it was going to get whittled away and then we need some more exploration so we're here today. We would have been in the same spot just a few years later, I think, anyway.

Just a slide on state leasing in Cook Inlet. These are the Cook Inlet lease sales that were not blended with North Slope lease sales, but you can see we've had some different pulses of leasing in the Inlet, but certainly in the 1980s there was a pretty good leasing effort before the Sunfish type wells were being drilled. The South Cook Inlet wells being drilled.

There was a real good leasing effort in the 1980s. And in the 1990s good leasing effort as was mentioned by Bill Popp. You'll see a pretty good spurt in drilling here in the 2000s. And I think good leasing we see here in the last five years indicates that the folks believe there are still prospects here in Cook Inlet. We wouldn't have this leasing activity if folks weren't expecting to go out and drill.

Just a few words about the 2000s. We've had a lot of new companies come in these last five or six years. Companies like Aurora and Stormcat, Pelican, Escopeta, Rutter & Wilbanks, Benchmark, Geopetro, Swift. We have -- there certainly continues to be a lot of interest in Cook Inlet. Union and Marathon certainly have ongoing, continued interests on the lower Kenai Peninsula in their gas development projects.

Just obligated to say something about Evergreen's activity up in the Mat-Su Valley. You know, that's another project that resulted in a lot of great science, you know, it's a coal bed methane project. They really didn't come up with a commercial project, but they did generate a lot of good science so at least in my view certainly within Cook Inlet area in general there's still plenty of running room for a coal bed methane project. Not all these projects start out as winners on day one and Evergreen although they didn't come up with a commercial project, they did generate a lot of good science.

And I'll just quick close with this slide again, it shows the exploration drilling activity by year and just look at the far right you'll see, you know, there has been a resurgence of drilling activity. There's a couple more wells to add on there that aren't current right now so the graph will look better in this last year coming up, but folks are interested in Cook Inlet.

Both oil and gas prospects are being explored for and there's certainly plenty of potential remaining in Cook Inlet and people out in this room are the people that are going to make it happen. Thank you.

CHAIRMAN NORMAN: Thank you, Bill. I think from Tom's talk and Bill's talk with the history, I hope it left you with an understanding that there is a belief that there's still plenty of both oil and gas to be discovered right here in Cook Inlet. The trick, of course, is to find it.

We're going to take now about a five minute break. Let everybody stretch. We'll clear the clutter off the tables that you have and then we'll pick up with our afternoon program.

(Off record)

(On record)

CHAIRMAN NORMAN: A few days here is going to focus primarily upon the supply side and the industrial users, but I want to remind everyone that the middle name of the Alaska Oil and Gas Conservation Commission is conservation and there is a conservation side to this that we try at the Commission to keep an eye on to make sure that our resources are not wasted. And this also extends beyond the production and the development and exploration stage, but it extends to how people utilize energy.

In Oklahoma there's an excellent booklet that's been prepared and if any of you want a copy of it give your business cards to one of the staff out there and we'll see that you get it, but it talks about how life is filled with simple ways to save and it emphasizes that the average family, it discusses the expenses and by doing a number of simple things they have carefully calculated that energy costs could be cut by up to 30 percent.

If any of you do want a copy of this or several copies of it courtesy of the State of Oklahoma, we've obtained them and all you have to do is leave your cards out there at the front desk and we'll see that it gets to you.

I'm going to turn the microphone over to Commissioner Seamount now and we'll proceed with the afternoon portion of the program.

SCOTT JEPSEN

COMMISSIONER SEAMOUNT: Thank you, John. Our first speaker on this panel is Scott Jepsen of ConocoPhillips. He's a graduate of the University of Texas at Austin where he received his Bachelor's and Master's and Science Degrees in Chemical Engineering. There are a lot of presenters at this conference from the University of Texas at Austin so I'm impressed.

He began his career in Denver in 1980 working for ARCO and since then has held various positions in oil and gas engineering and management. In 2001 he assumed his current position as manager of ConocoPhillips Cook Inlet Business Unit. The Cook Inlet Business Unit consists of ConocoPhillips interests in the Beluga River Unit, the Cook Inlet Unit and the Kenai LNG plant. And Mr. Jepsen wins the award for the shortest bio submitted.

MR. JEPSEN: Thanks, Dan. Well, this afternoon I hope to give you guys a slightly different perspective on oil and gas supply in Cook Inlet. Rather than focus on discrete numbers I'm going to move up to about the 50,000 foot level and just talk about market forces and just how to maybe look at gas supply from a slightly different point of view.

Go to the next one. You can go to the next slide. Oh, I'm sorry. My fault.

Of course I have to show you this cautionary statement and the point to this is do not rely on anything that I say that's forward looking. That's probably a very safe thing to do when it comes to Cook Inlet gas supply.

This is an overview of what I'm going to talk about. Before we get into the meat of it I want to talk briefly about ConocoPhillips' Cook Inlet assets and then sort of frame the gas supply from maybe a different perspective, talk a little bit about supply and management issues and then some observations that I have.

You've probably seen this map before. The map on the left shows the major oil and gas assets in Cook Inlet. ConocoPhillips operates three of them. We operate the Beluga field on the west side. That field today produces about 150 million cubic feet of gas. We have two other owners of that, Chevron and Municipal Light & Power.

We also operate the North Cook Inlet Unit, that's a field that we own 100 percent. That's the northern most platform in Cook Inlet. Today that's producing about 110 million cubic feet.

And then we also operate the Kenai LNG plant which is located in Nikiski and our partner there is Marathon and that's a 70/30 partnership.

Just as an observation if you take a look at those purple lines on that map those are the gas pipelines in Cook Inlet and as you notice they all come together at Nikiski.

People at various times have talked about gas hubs in Alaska, there's truly one gas hub in Alaska and that's Nikiski, Alaska. That's where all the pipelines come together.

Next slide. I'm sorry, brain dead. At any rate, this next plot is attempting to demonstrate some supply and demand issues and one of the perils of taking a look at things strictly from a numbers point of view. The blocks on the plot show demand by consumers in millions of cubic feet per year. The lines show the projected deliverability that's been published in various DOE reports in, again, millions of cubic feet per year.

What typically happens is people look at this plot and they say wait a second, there's a crossover there in 2013 or 2014 or whatever and they assume immediately that we're going to run out of gas. We're not going to have enough gas to supply just the utilities in that time frame.

Well, there's several problems associated with this approach. One, there's no allowance for exploration in any of these deliverability curves, but beyond that there's information which really nobody has access to except the oil and gas companies that are operating in these fields. There's no allowance for reserve appreciation. In the mid-1990s there was a huge reserve appreciation in Cook Inlet, but it was just a function of taking a look at deliverability and remaining reserves. That can't be accounted for in these sorts of analyses.

Secondly, there's no accounting for development of proven, undeveloped reserves. All of these -- or the three big gas fields are giant gas fields in Cook Inlet, the Kenai gas field, the Beluga and North Cook Inlet Unit and one thing about big gas fields and big oil fields there's always lots of opportunity. And what you don't know unless you're inside the oil companies or gas companies that own and produce these fields is what data we have and what sort of opportunities we have to develop additional resource in those existing fields.

And I can tell you there is significant resource out here. Up until recently there's been no reason to chase any of it. The market has been fully satisfied and if you went and developed gas there was no place to sell it. That's another problem, a sort of simplistic view of looking at gas and supply.

The other thing is to take a look at the market itself and this is really zooming up. This has nothing to do with how much the demand is or what we have to sell, it's just want is the market demanding.

If you assume that Agrium can't exist much beyond 2007 and if one assumes that the LNG plant can't extend its' export license past 2009, you're left with just the utilities. Well, if I went to Enstar today and said Enstar, I want to sell you gas they'd say, talk to me in 2017. If I talked to Municipal

Light & Power with their interest in Beluga they're good till 2015 and maybe beyond if there's some additional investment made in Beluga.

The only one out there that has an RFP in the street is Chugach Electric and they're looking for gas from 2011 to 2020 and based upon all the signals they're giving off, they're getting sufficient in their RFP to make me believe that's going to be satisfied.

So you pull that together and you say is there an issue really out here? Is there really a near term issue when it comes to supply? And my deduction from looking at all of this is that the supply issue and the demand issue that we have is not a near term issue. That's not to say we'll never have it, but it's not going to happen in the next five or six years. In fact, if I were to quit making LNG today and tried to put it into the market I'd be able to sell just a dribble of it and that's all probably for the next 10 years or so.

Another way to look at it is to look at the reserves production ratio in Cook Inlet. This is sort of a yard stick that the industry uses to try to get some idea of how much gas we might have. It's not really accurate. It has problems like the last curve has, but it's sort of a handy sort of tool that's used.

What it is, is it's total reserves that you have in the basin, millions of cubic feet on this plot. And then on production it's divided by billions of cubic feet per year consumed and that gives you your dimensional ratio or R to P ratio.

If you go back to the 1980s you can see that Cook Inlet was looking at R to Ps in the 20 to 30 and it's kind of bounced up and down over time as new fields have been brought on stream or people have had big reserve appreciation events like we did in the mid 1990s. With the reserve to production ratio that high there's absolutely no incentive to look for gas.

As Bill mentioned earlier there might have been a little bit of a push when the LNG plant was first coming on stream, but other than that if you'd gone out and looked for gas and found it, you either would have had to give it away or leave it shut in until additional demand came on the market.

What's happening right now is our R to P ratio with Agrium kind of limping along and the LNG plant still in operation is it's down in that range of about seven to 10 and that's actually where the Lower 48 has been for about the last 30 years. There's been no panic in the Lower 48. Instead investment has risen to the occasion.

This is just an empirical deduction on my part, but it looks as though when you get into that seven to 10 range, that's probably where the market gets to the point where it can start buying gas from people who go out there and look for it and produce it.

Now, when the LNG plant, assuming that it doesn't operate past 2009, R to P ratio goes back up to about that 10 to 11 spot which is about where we're at today.

So my point here is that we finally have a market that looks like it's opening up and can buy gas if gas is found, but one of the critical things is to maintain that market and I'll come back to that point in just a minute.

Here's the R to P ratio for the Lower 48. This is just to kind of back up my contention that when you're in that seven to 10 range that seems to be the point at which the market is indicating it's going to buy gas. We've been there in the Lower 48 since the mid-'70s. The curves diverge there in the mid-'70s. You have the solid line and the dashed line -- and the bubble line.

What happened there was when Prudhoe Bay was discovered people accounted for the gas cap at Prudhoe and put it in reserves and then by the mid '90s they said well, you know, it's not going to happen so it went back into the resource category and came out of the reserves category. And since that time we've had huge investments in natural gas in the Lower 48 since the mid '70s.

We had high gas prices in the '80s. We had gas price controls to try to control the price of gas which just killed gas exploration and production, but eventually that was removed. We have a free market operating down there now.

We have infrastructure that was built to move the gas from the basins to the markets and pretty vibrant gas exploration and production business, but people are forecasting larger demand for gas than what we see being able to be produced in North America and so what you're seeing now is the next phase which is LNG imports and that makes sense.

There's lots of LNG stranded around the world. Lots of natural gas stranded around the world at shoreline and it's relatively inexpensive to produce and transport at the kind of gas prices we're seeing now. It's very competitive. So it's, kind of, the next wave is starting to augment organic production in the Lower 48 with imported gas.

Another sort of framing chart is one that Bill showed. This has a little bit more parsing to it. This tries to separate out gas exploration wells from oil exploration wells. The gas exploration wells are the red ones and the oil exploration wells are the green ones. And then on the right-hand side you have gas price as a function of time.

And when gas was first discovered in Cook Inlet this was truly a stranded gas basis. Gas had very little value. It was being sold for about 20 cents. Of course, those were 1950 dollars. Who knows what they are today, but it was basically being given away and people had to get creative to find ways to use it, that's the reason the LNG plant was built. That was basically through some invention on the part of ConocoPhillips and then you had the fertilizer plant that was built also.

One could kind of look back and say that if we hadn't built these plants probably the North Cook Inlet Unit would never have been developed, Beluga probably wouldn't have been developed. All that exploration that we saw going on in the mid '70s and lately, none of that would be happening because this market would have been fully satisfied by some of those early discoveries.

But what this slide does point out is one of the points I was making earlier is we get that R to P ratio where there seems to be a little bit more of a balance between supply and demand, prices have gone up and people have reacted to it. We're seeing more exploration wells being drilled in Cook Inlet.

I don't have any data for 2004 and beyond and that's because I couldn't find any available, but people are still looking for gas. Exploration wells are still being drilled.

Let me touch just briefly about supply and management issues. I've contended that we don't have a chronic shortage of gas anywhere near a near time frame, but there are other issues out there. This chart tries to portray the seasonality and demand. Again, it assumes that the LNG plant can't get its' export license extended and then it just goes to utilities and you see that very spiky nature there. That's largely the result of a swing that Enstar has. They have very high seasonal swings from winter to summer.

In order to meet that in the past all we had to do was crack a valve. We had so much gas available in Cook Inlet if you wanted to triple production you call up the operator at Beluga, the operator at the Kenai gas field and say open up three wells and boom, you got the gas that you need.

Well, these fields are older. They're 40 years older. They're in the last quarter to third of their life and we're starting to put in compression. Almost all the big gas fields, in fact, I think all the gas fields now are on compression. What that means is there's a mechanical device that limits how much gas that we can get into the gas system at any point in time. That's just natural and that's what happens to all gas fields, but it does put a constraint on the system so now you have to start looking at other things.

You have to look at things like gas storage and some Companies like Unocal and Marathon are looking at gas storage. Unocal has an active gas storage project at Swanson River now. Those aren't cheap. You have to get gas in the ground in the summertime when you don't need it. You store it there. It's inventory. There's a cost of storing your inventory. So it's part of the next evolution, but it's not a free part of trying to develop and produce gas. In the past just turning that value was pretty inexpensive, it didn't cost anything. Gas storage does cost.

On the compression side, I mentioned the fact that we have compression, but there's a whole lot of compression that still needs to be added. If you take a look at the old gas fields in the Lower 48 some of them are on vacuum. You take a look at the suction pressure to the compressors and it's blowout (indiscernible) pressure.

I don't think we'll get quite that low in Cook Inlet. Our reservoirs probably won't support that, but we're not done spending tens and fifties and millions of dollars to add compression in order to get the existing resource out of the ground.

So there's a tremendous amount of money that has to be invested in order to make our deliverability to meet our demands. And one of the other key components of this is that we have to be able to get a reasonable price for the gas. There seems to be a belief that because these are older fields, because they've been discovered, because a lot of the infrastructure is in place that getting that next increment of gas out of the ground is inexpensive.

Quite frankly, we're going to probably spend more money on developing these existing resources than people are going to spend on exploration. ConocoPhillips has easily spent 100 million dollars over the last five to six years adding infrastructure and well deliverability to its' existing resources.

I'm not so sure we've seen that much money spent on exploration so there's definitely a difference from the public perception versus the reality of what it's going to take to continue delivering gas and that's one of the reasons why when gas companies, oil companies come and try to deal with the existing buyers of gas here we say we need a market price for gas. What does that mean?

Well, market price has different meanings to different people but, frankly, even though we're not connected to the worldwide gas market through a pipeline, the entire worldwide gas market competes for our dollars. And I don't care if you're an independent from Kansas or if you're a major, integrated oil company you have options. You don't have to invest in Alaska. And if what you find up here is that this is a depressed gas market, well, you go elsewhere. It's that simple.

So what are the struggles that we have to -- one of the things we have to wrestle with up here is we're out of this era of basically free gas, inexpensive gas, gas that's easy to deliver and we're starting another real world.

I'm going to conclude with just a few observations. I mentioned that we need to struggle with the issue of price up here and I think we're progressing along those lines, but it's going to take some time and it's going to take a little bit of getting used to.

The second point I have on there is that the industrial consum- -- customers, the fertilizer plant and the LNG plant are probably more important to maintaining gas supply than they would be if they went away. Now there are those who would say well, you know, if we didn't have these things we'd have a longer lasting gas supply.

Well, I would maintain that what's happened with these plants is two things. One they create demand. Demand that far exceeds what the utilities need. As I described earlier the utilities don't need a lot of gas for quite some time to come. If you want to keep exploration and development in Cook Inlet vibrant you have to have a base load customer and that's what the industrial consumers provide.

The other thing that they provide is essentially free spinning, spare capacity. On a cold day if Enstar needs gas or Chugach needs gas and their existing suppliers can't provide that gas the fertilizer plant and the LNG plant divert gas away from their businesses into the local market.

Again, that's part of that free supply of gas or low investment cost to the consumers that the industrial plants provide. If you don't have these plants around, this base load around, if you will, you won't have that any longer and that's going to be a fairly large blow to the local market if you don't have that kind of capacity available to you.

Of course long term there are other options besides exploration. The spur line is an option. The problem with the spur line if you take a look at long term gas supply, is that the timing is very uncertain. Long term demand could also be lower than today's space heating and power demand.

Chugach is talking about switching over to coal. There's talk about a wind farm on Fire Island. If those things come to pass the existing demand that you see right now for utilities goes even lower than it is right now.

And if you don't have the base load of industrial consumers taking gas, then the amount of gas that you have available to ship down that pipeline really diminishes significantly. And then you run into that crossover point where it may not be economical to ship any gas down the spur line 'cause you don't have enough to ship.

There are some potential solutions to this. One, of course, is exploration and if you keep the demand up with the LNG plant and the fertilizer plant you're going to help spur investment sooner and probably to a greater degree than if you don't have those around.

But the other is, once we get done with the LNG plant we have a facility that really is ideal for importing gas in the Cook Inlet. That was kind of like that coals and Newcastle argument. Whenever you mention this politicians in particular, excuse me Lt. Governor, generally run for cover. This is not a particularly popular thing to say in this state that we might actually import gas into Alaska, but bear with me for just a second.

This doesn't necessarily have to be even a long term solution, but there's going to come a point in time where we may have greater peaking demands then what we can supply locally. LNG is a natural peaking gas source. It's used in the Lower 48 all the time.

The LNG plant could probably be converted to a LNG import facility at very low cost. We have the tanks. We have a dock. We have the piping. We're at the gas pipeline hub for South Central Alaska. The take away capacity is huge right there at Nikiski. It's not something that you have to invest in right away because the cost can be incremental and fairly low.

You can wait till you see if you really need it so it doesn't preclude pursuing an ANS gas spur line. It doesn't preclude exploration, but it is an option that we probably ought to consider and keep out there are part of our arsenal to make sure South Central Alaska has sufficient gas.

And, of course, based on sort of the back of the envelope calculations that I've done it looks like imported gas could be very competitive with ANS gas.

The other role that it could play is when you take a look at the ANS spur line if it ever materializes is how do you fill that up. What you'd like to do is start on day one with its full capacity, say, 200, 300 million cubic feet, whatever it's designed for. That might be hard to do unless you have that demand in Cook Inlet.

And the way the demand and production curves work is you just generally have a wedge, so this could actually be a very good transition devise as well. You could wait until you have that demand and then at that point in time cease importing gas if that's the right economical choice to make.

I guess in conclusion one of the things I just wanted to kind of observe is that it looks to me like what we really have are some very challenging, strategic decisions, not so much a shortage of gas. The DOE has done reports that indicate there's lots of resource, lots of potential to find additional reserves, but it's the strategic decisions that we're making now on price, encouraging investment, making sure demand stays there that are really going to determine what Cook Inlet looks like in terms of gas supply for the next 30 or 40 years. That ends my comments, thank you.

Presentation not submitted to Forum

COMMISSIONER SEAMOUNT: Thank you, Scott.

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JOHN ZAGER

COMMISSIONER SEAMOUNT: Our next speaker is John Zager. He's the Alaska general manager for Chevron formally known as Union Oil Company of California. John joined the organization in 1981 and has worked in numerous positions.

He doesn't mention that he used to work in Casper, Wyoming about two doors down from me. I don't understand, your behavior was always stellar, but in any case he began as an exploration and development geologist and the moved to positions in planning and portfolio management for worldwide exploration and international operations, manager of resource development and new ventures manager.

Following that he served as Cook Inlet asset manager. John has a Bachelor of Arts from Gustavus Adolphus College, an MS in Geology from the University of Wisconsin, Milwaukee and an MBA from the University of Houston. He is married with two daughters. Let's welcome, John.

MR. ZAGER: Thanks, Dan, that was very moderated (ph). Appreciate the time this afternoon. At this point in the day it's probably hard to come up with an original thought that hasn't already been discussed, but I'll give it my best.

The part of this talk is extending production so I thought I would get a little more specific on some of the things Chevron is planning to do to extend production both on the oil and the gas side so it's amazing we've gotten to an oil and gas conference. It's almost 2:00 o'clock in the afternoon and we haven't seen a single structure map or log yet so I'll change that a little bit, okay.

Move on to the next side -- oh, Scott, I'm doing the same thing you did. Okay. This is the same map you've probably seen from a lot of other folks. It shows Chevron's asset base in the Cook Inlet. And, I guess, we could just say it's fairly extensive both on the oil and the gas side.

We're the largest oil producer. We operate nine oil platforms in the Inlet and we're the third largest gas producer operating five on shore fields and Steelhead Platform. I'm not going to really discuss our non-operated properties today as I thought the operators would be able to do that.

You can see that our properties range in the north from the west side properties. The main oil assets are in the offshore here. We operate Swanson River and then some of the new fields in the South Kenai. I'll just step through some of those and try to discuss a little bit about what's going on.

Swanson River has been discussed quite a bit both from an historical perspective. It is an oil field originally. Picture here of a very large facilities compression plant, et cetera that exists in the refuge. As we discussed it was discovered in 1956.

The two main reservoirs there, the Hemlock has produced the vast majority of the oil and today we're looking more at the G Zone which is a shallower zone. Peak rate was about 40,000 barrels a day. Today it's under 1,000 barrels a day of production, just to illustrate where it's at in its life on the oil side. And it's never been a real huge gas field.

In the early days -- well, for many years gas was taken from the Kenai gas field and injected in the Swanson River to create a gas cap for pressure maintenance. That was a very successful program. Since then the gas cap has been blown down so we're back to producing pretty much native gas and what oil is left. It's also the location of one of our storage facilities.

So here's a structure map. We discussed earlier the discovery of Swanson. The discovery well was actually way on the north. If it had been just a little bit further north they would have missed the structure. And then you heard about the later discoveries in Soldotna Creek Unit further south where it turned out the bulk of the oil was. Original oil in place about 400 million barrels and we produce well over 200 million barrels today.

If you're an engineer or geologist you know what this is. It's just a production decline curve. The green line is the one you want to pay the most attention to, that's the oil back at its peak of about 40 -- 20,000 barrels, down today to under 1,000.

And this is the shallower gas production at Swanson River. At its peak it did about 20 million a day. You can see this is a lot different ball game here. These reservoirs are small and discontinuous stratigraphic traps in this larger structure. Some are fault bound. And exploring for these in the field is very challenging. We've gone back and we've looked at it. We've had some success and we intend to pursue more work here in terms of identifying additional potential. Total size there is about 100 -- only 100 Bcf of gas in place so far.

This is a big oil field in the Inlet. We've moved offshore. This is a picture of the Grayling gas -- the Grayling platform. There are four platforms producing in the McArthur River field. We can look, this is total original oil in place. Over 1.6 billion barrels and we've produced over 600 million for about a 37% recovery.

You can see there's a lot of talk about drilling deeper in the Inlet for the Jurassic, this is one of the few fields that actually has Jurassic production. Some production there. Very low recovery factor and we think that's a target to go after in the future as well as additional infields. This field has been on water flood for many years. There's areas to go to in fill the water flood and also probably on what we call the northwest feature up here.

The last two wells we drilled were on the northern nose in this area and when we see the production curve you'll see those were -- one of those, I think, was the biggest oil well ever drilled in the Cook Inlet at about 8,000 barrels a day. One of the first horizontal wells though so that kind of accounts for the high rate.

And here you can see the production decline from about 120,000 barrels a day down today and this bump right -- it's kind of hard to see in that light green where it bumps up there in about 2000 or so is the effect of those new wells.

Trading Bay field just north of Trading Bay Unit produced by the Monopod which, I believe, is the worlds only one legged platform. It has worked well, but I guess we decided that there are other ways to do it that work just as well. All the wells, of course, go down through that one big leg. On the other four legged platforms they all go down through the legs as well to help protect from the ice flows.

Say this is a complexly faulted reservoir, but huge pays in this field, over 1,000 feet of pay in the field and I think there's a lot of additional targets to go after here in some of these fault blocks as well as the sub-thrust. It's not shown on this map, but the geometry here there's a section that comes under this field and there's very -- very low recovery factors in the sub-thrust.

Again, this is just the production curve showing where it was back in the day and now it's down to about 1,000 barrels a day.

The last big offshore field is Granite Point field. It has three platforms on it. The northern two are 100 percent Chevron and the southern one is 25 percent Chevron and 75 percent Exxon. We operate all three. Again, there have been pretty good recoveries.

This field has not declined as fast as the other fields. Very asymmetric anticline with the west flank being nearly vertical and we think there's potential for additional infields along the side here and also especially on the west flank. Also deeper potential here in the Hemlock where there's been some production, but a long ways to go. And then this just shows some of the more moderate declines here we're seeing from the Granite Point field.

So let's move on and talk a little bit about gas. This is the Steelhead platform. The last -- well, the only platform set for gas in the Cook Inlet. Originally set by Marathon. We operate it now. We own almost about 49 percent and Chevron has -- or, I mean, Marathon has the remainder. Peak production about 210 million cubic feet a day and down in the 60 to 70 million cubic feet a day range. This past year it passed one Tcf of actual production so it's been a very -- very nice asset out there.

Fault map or a map just showing the structure and location of the wells. And that print is getting so small I can't really read it, but I know we've just gone over a Tcf of production and have a ways to go on that field, but on the production curve you can see here for many years it was plateau basically at the platform's capacity of just over 200 million cubic feet a day.

And these dots represent the pressures. You can see that they were pretty solid and then it started to decline in pressure. All the time the production is remaining the same, but I think as Chris may have mentioned earlier there around 2000 production started to fall off with it.

And what happened here is for the first time we saw water encroachment into the reserve -- into the wells actually hitting the perfs and when that happens a lot of bad things happen because you lose production in that well and you start to produce -- going to start to produce sand. And sand and compressors and platforms don't go very well together so the net effect is that you lose those zones quicker than we thought if they were on just a pressure depletion type scenario.

West side gas field. This is a picture of the Ivan River field on the west side. There's a small group of fields there just north of Beluga River. Beluga River, as mentioned earlier, is one of the big, heritage gas fields which Chevron has one-third interest in, but here we have 100 percent in these smaller fields. In their day they did about 50 million a day and today are doing about five million so, again, in the later stages of life.

We are looking at a gas storage opportunity -- well, we have implemented a gas storage project on the west side at Pretty Creek and this shows the location of these relatively small fields. This is just the north tip of the Beluga River field there. And, again, the decline curve here showing the gas completion.

And then Happy Valley which is the furthest south field, at least the furthest south producing field in the Cook Inlet. It was a follow-up to our -- in our south Kenai exploration program. Initial work was done here at Ninilchik unit which is operated by Marathon and they have 60 percent working interest.

I thought John Barnes was going to be here to talk about that so I don't have any slides on it, but we've had a good program there over the last few years and continued development work at Ninilchik.

Happy Valley was 100 percent Unocal at the time operated field. The discovery was made and it came on production for the first time in 2004. It currently produces about eight million a day from five wells and there's a -- we're still fairly early in the life there. There's more work to do.

Here's a structure map of Happy Valley and, you know, sometimes I think industry is a little guilty of coming in and only talking about all the great things that happen and Happy Valley is, in general, a great thing. I mean, we've got discovery and those eight million cubic feet a day have been vital to keeping a lot of -- a lot of things happening over winter months especially, but if you remember I said there are eight producing -- or there are five producing wells.

If you count up the well locations on that map there are actually 11 wells so you don't have to jump too far to see that we've had some surprises when we drilled Happy Valley. Not that we're proud of it, but that's just the fact that gas exploration and development is not a slam-dunk. It's not easy when you get into these reservoirs that are discontinuous, alluvial type deposition.

Structures are subtle and hard to interpret and you can also have drilling problems because of the faulting and other operational issues, so for those who seem to think that gas is easy to find and develop and you should be able to do it very cheaply, this is one case study where you can say well, things don't always go according to plan, but as an industry we tend to suck it up and get the job done anyway, so that's Happy Valley.

Now, this is a plot just showing our exploration acreage on the south Kenai. We've got very large -- I'm not sure what the number is, but several hundred thousand acres of land south here from the Deep Creek Unit in the Nikolaevsk Unit.

A little field down here called North Fork that's been there for many, many years, is an undeveloped gas asset. We started a fairly aggressive exploration program for gas in this area in 2000, resulted in two currently producing fields as I mentioned being Ninilchik and Happy Valley.

And we also -- one of the last wells we drilled was Red, Red Number 1, that was a successful gas well, that's the good news. It flowed at a fairly good rate, but pressure they had indicated was a pretty small reservoir, so hence it's been sitting there. We've been studying trying to evaluate what to do with Red.

There's been some discussion of late of potentially building a pipeline from Happy Valley all the way down to Homer which could go by Red and potentially North Fork and make those fields then economic to hook up.

Also quite a bit of additional exploration prospects in the area, but a lot of work to do. Again, as a result of this program we did have two successes, maybe you could call it two and a half successes, but we also got six dry holes out of the program, so, again, gas exploration is an expensive and risky business and it's hard to justify unless you've got a really robust set of economics that help and that's ultimately supported by gas price.

So what is Chevron going to do in the near future to help extend production to Cook Inlet. What I've got up here is just a snapshot of what we've done recently working on our budget for the next three years kind of three year plan. These are things that are in our three year plan and you can see it ranges pretty widely.

The green bubbles indicate oil work on the offshore assets there consisting of new drilling wells. Certainly some recompletions improving the facilities trying to extend the life of those platforms and also to lower the operating expense out there.

And then the red you can see projects ranging all the way from the north and on the west side along Swanson River to try to do some more gas work, more work down in the south Kenai area in terms of new wells and develop more work.

And then also out at Steelhead we've got some drilling in the plans and try some other things out offshore in gas so on all we've got a very ambitious work program over the next three years with a significant increase in the amount of capital we're spending here.

And, you know, the challenging part is it's a very tough time to be ramping up a program. It's hard to get access to equipment. It's hard to get access to people. Services are expensive and that's just the way it goes.

When gas prices and oil prices go up everyone thinks that the producers are the ones who make all the money and maybe initially that's true, but pretty quickly, you know, the service companies out there figure it out, too, that there's competition to get access to their services and they pretty quickly figure out how to carve all the mo- -- I should rephrase that. They don't carve all the money out, but they get their fair share at the end of the day when it comes to higher oil and gas prices, so that's just part of the picture and those are our plans to move forward here.

I'll end up with -- maybe like Scott and some others just with a list of a few issues or comments on where we are in the Cook Inlet. I'm going to -- should have been like Bill Popp and just walked over there, I guess, but.....

So, I think, one indisputable fact, I didn't use the disclaimer Scott did 'cause I'm not doing anything forward looking so I'm just talking about where we are today.

All right. Gas supplies are tighter than ever before. I don't think anyone can argue with that. How tight they are, how long that will last could be up for discussion. Gas storage, and I know we've got a gas storage session coming up immediately after this, but it is essential in meeting peak loads.

Gas business is complex and risky. I worked in the Lower 48 and there I don't want to get -- business is not simple anywhere, but there the gas business you kind of find your prospect, you drill your well, you hook it up and you're basically hooked to an infinite market.

Up here things are a lot more complicated. You've got to worry all the time about your market, where the gas is going to go, how it's going to get there because of our special nature of our pipelines which have improved in recent years, but there's always concerns about how to move the gas around and it's just complex. And as I tried to point out a couple examples here, it's risky to go out and put all this money into these wells and then hope that you get the results you've been expecting.

Market base pricing is required to attract capital. I think maybe most of the producers and some of the others have said that, you know, we can all want to live in the '80s. You know, I'd be -- have more hair and be quite a few pounds lighter if we lived in the '80s, but we are where we are today and exactly as Scott said my job and his job is to go down to Houston or wherever else and argue for capital for our assets.

And we've got a lot of risks and challenges already, but then to say we also aren't even getting market -- what we call market prices or competitive prices all makes it just all that much more difficult to get the capital it needs to come up here and help move these projects forward and ultimately grow a reserve base.

The new PPT, the production tax, should encourage initial Cook Inlet exploration and development. I mean, that was the intent of how it was passed. I see some of the Representatives here today who worked very hard on that, but the intent was that status quo taxes in the Cook Inlet, that we wouldn't get higher taxes and that we'd also get an investment credit on top of that so that should overall roll into better economics for gas and oil projects in the Cook Inlet.

We have yet to see that be put into regulation and implemented, but that certainly, I think, was the intent of the Legislature and we intend to follow through that and try to use that as another reason to increase our investments.

And then as a final, I think, we -- that's why we're all here is that Cook Inlet oil and gas production is critical to the South Central economy. And Chevron after taking over Unocal here about a year ago has evaluated and we plan to stay and we plan to invest and we plan to extend production both in the oil and gas side. Thank you.

Presentation not submitted to Forum

COMMISSIONER SEAMOUNT: Thank you, John.

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ED JONES

COMMISSIONER SEAMOUNT: Our next presenter is Ed Jones, executive vice president engineering and operations for Aurora. And Aurora is one of our newer producers in Cook Inlet, but you've been here quite a while now, haven't you?

MR. JONES: Five years.

COMMISSIONER SEAMOUNT: Five years, so it seems like yesterday. He has over 30 years of experience in the petroleum industry in engineering, operations and management since graduating from Colorado State University with a degree in Engineering. He has worked in the Rockies, mid-continent and east coast areas for Texaco and Energy Reserves Group and BHP Petroleum in engineering and management roles.

He's had executive responsibility in several vice president positions for BHP Petroleum Americas and consulted prior to co-founding Aurora Gas in 1999. He is the executive vice president, engineering and operations for Aurora Gas responsible for drilling, construction and production operations and all facets of petroleum engineering so please welcome Ed Jones.

MR. JONES: Well, thank you, Commissioners for inviting Aurora to take some time to tell you about us and what we're doing to extend production here in South Central Alaska. So today I do want to tell you about Aurora Gas first of all, so many of you are unfamiliar with us as Dan said we're fairly newcomer here to the state, but I also want to tell you what we're doing to extend production and then some suggestions and things that need to be done by industry and by government to continue to do so.

Another brief clarification in the bulletin -- or in the schedule. We're listed as Aurora Power and there is such a company here. In fact, we're sort of sister companies, but we are different with common ownership, shared offices and shared support staff so the confusion, but we are two very different and distinct companies with different business objectives.

I wanted to tell you a little bit about Aurora Gas, as I said. Aurora currently operates 12 producing wells in five fields and we have six compression and dehydration facilities in those fields. Our current production is six to 10 million cubic feet of gas per day. Over the past year or so we have been as high as 25. That's somewhat indicative of the problem that we face or the challenge that we face.

We have some pretty severe declines in the type of shallow gas pays that we pursue here in the Inlet. We have seven field employees and five office employees, a couple of whom just joined us. And then we have six shared staff in Houston and Anchorage that comprises Aurora gas. We also rely though pretty heavily on several consulting firms to help us out.

We have an acreage position of 125,000 gross and 78,000 net acres in the Cook Inlet Basin both sides of the Inlet, east and west side and that number -- that net number decreased significantly in a recent deal with Swift Energy who joined us as a partner primarily on the Kenai Peninsula, but throughout the area as well.

This is just a map to show you sort of where we're located. You've heard talk of Beluga River field. It's the large pink area there at the upper right-hand corner of the map there. The five other smaller fields, gas fields, the pink outline there, red outlines, those are our five producing fields all on the west side of the Cook Inlet, all west and south of Beluga River. You can see a bit of a trend there if you look. That's usually known as the Moquawkie area.

Let me tell you a little bit about what we've done recently to extend production and this is indicative of what we want to do in the future as well. In 2005 we drilled six wells at depths from 2,300 to 8,150 feet. These were all shallow gas objectives.

Four of these wells have become producing gas wells including an exploration discovery, the Three Mile Creek Number 1. One of these wells is currently suspended. It has potential for a water disposal well which we are in need of and one was just a plain, old dry hole.

We spent about $18 1/2 million dollars in capital and that's just a breakdown to show you where that money goes.

Most of it goes to drilling, completion and testing of wells. We did spend some money on pipelines and production facilities.

The good news for us is that with the six facilities that we have and a number of miles of pipeline we can easily build on that infrastructure. That was some of the expense and some of the high investment that we put in early on that we can now take advantage of. Then other money as shown there as well.

In 2006 it will look somewhat like 2005. We're pretty well through that program but, first of all, a note that Aurora has no budget. That can be good and can be bad. We work on a project by project basis funded by our primary investor or other investors as well.

On the west side of the Cook Inlet this year so far we have drilled one shallow gas well. It was less than 4,000 feet deep. It was unfortunately a dry hole. It was an exploration well. It had great potential, but that's the business.

We've done four rig workovers since then. We're on our fourth one right now of existing producers three of which have been quite successful. They've been recompletions, adding reserves to the bottom line.

We've installed one satellite facility and flow line to bring another well on at Three Mile Creek. And for the rest of the year we expect to drill one to three more gas wells. Again, it's as funding is available. All of these will be about 5,000 feet deep or less.

We entered a new arena this year with the drilling of Endeavor 1 oil prospect near Anchor Point in May of this year. Unfortunately it was a dry hole, 9,200 Hemlock test with our partner Swift but, nonetheless, that does indicate, perhaps, the direction that Aurora will be going in the future to some extent anyway. So our total capital expenditures for 2006 we expect to be on the order of $18 million at the same level as last year.

Well, since inception we started working in Alaska really in December of 2000 as far as on the ground in Alaska. We have been involved in 18 wells, all on the west side of the Cook Inlet except the Endeavor well and all have been operated.

So, so far in our short history we have drilled five exploration wells. We've drill five development wells. We've re-entered six suspended or plugged and abandoned wells. We have purchased two wells that were ready to produce. One being the Lone Creek Number 1 that we bought from Anandarko and ConocoPhillips. And we have installed facilities and gathering lines there and we've worked over about five wells. We keep fairly busy especially in the summertime and so far in these five years or so we've produced 13 Bcf of gas.

Since our topic today is extending production well, what is it that we need to do. Well, first of all we need to look at what we have to work with in the Cook Inlet Basin. On the plus side we have multiple pays. Some of our wells we are perforated and producing from eight different, separate and distinct sands and that there are often more in addition to that.

However, the reservoir quality is variable. We find permeabilities anywhere from one to 1,000 millidarcies and most of those are unconsolidated reservoirs. Some damage easily, some do not.

The costs here are quite high relative to the Lower 48. Like John just made a comment about, the ease of the business down there compared to up here and I certainly agree with that. We have lower, but improving gas prices as compared to the Lower 48, but we have found and, again, this is our experience, we're drilling mostly shallow gas wells. This is -- and none of the giant fields, just fairly small fields, but we have very steep declines.

Now, there are several reasons for this, for these limited reserves. We're often chasing channel sands, very often stratigraphic traps and complex geology in general structure as well as stratigraphy.

Another thing that we find is we're often producing unconsolidated sands and when the water hits so does the sand so they tend to have sand production along with the water. And one reason for this is they're uncemented and often held together just by the clay content within them.

Well, how do we as operators extend South Central Alaska Production. I'm talking not just about ourselves. These are some things that we have done, but some things that can be done. First of all, we rely heavily on evaluation technology, 3-D seismic while it's very expensive to acquire here in the first place, it's not the panacea. It doesn't answer all the questions, but it certainly is helpful. We have shot two on the west side of the Inlet, but certainly think we need more.

We used enhanced seismic interpretation techniques. We have an office in Houston. Our geology/geophysics are pretty much based out of there so we have close by many companies that do some pretty sophisticated things. We're relying to some extent on some amplitude attribute analyses that we hope to soon drill a well off of that could lead to something.

Another suggestion, something we do is get log data. We tend to run as many as six electric logs per well and that -- our logging costs relative to overall well costs is relatively high. We think this is very valuable to the kind of sands that we're looking at.

And then next make sure you analyze those logs and we use several various methods to do so, computer generated logs of various sorts, but this has given us confidence to test some sands that we otherwise would not have tested and we have normally been successful.

Another way of extending production is to re-enter or re-drill wells. We've done this successfully six times or so, so far. Unfortunately, we're running out of candidates on our acreage. There's a number of wells around though. We'll get around to looking at more of them as the acreage is available, but that's certainly an opportunity for some relatively low cost explorations, so to speak 'cause many of the wells were drilled as oil wells, drilled in the '60s and '70s. The logging technology has come a long way since then so it's something to look at certainly.

Development drilling, we have drilled six development wells so far. Some from seismic, but well performance, pressure performance, shallower zones in old wells, all of these are key indicators that there may be some development available.

In completing completions, recompletions and workovers this is another area that we found quite a number of ways to extend production, so to speak. Many of the wells in the Cook Inlet Basin have not been looked at for recompletions. They've not been worked over for various reasons, primarily because there's always been a huge supply of gas.

Some of the completion techniques that we are starting to use are multiple selectives where we perforate a number of sands in a given well with different pressures, different -- perhaps different producing potentials. We set packers between the perforated intervals to isolate those with fairly common pressures as seen on this diagram.

This particular completion we ran four packers, sliding sleeves between the packers. Usually start from the bottom up producing the most -- the highest pressured zone. As that pressure depletes come up the hole, open another sliding sleeve that has comparable pressure and so forth and in so doing keep your production fairly high without another rig workover.

The other beauty of this that we found in one particular well already is that one of the lower zones goes to water, you set a plug, keep producing the well, didn't need a rig to do the rig workover.

Some other techniques or methods. We have tried stand alone sand control screens which we've had limited success with for various reasons. Two of the workovers -- in fact this summer we pulled sand screens with perforation sized holes in them where the water and sand coming out of the perforation had jetted a nice little hole in them, so it's certainly not the end all cure all, but it does work in some cases.

We are looking more and more because of that at stimulation. Gravel pack which is expensive, frac'ing which is expensive, mud acid blends, all of these have to be evaluated relative to the reservoir in which you're using them and the relative costs.

What's key to us, especially if you go to the tighter reservoirs, the lower quality reservoirs, is to prevent formation damage. We're looking a lot at this. Many of our newer wells, our newer prospects are in the Beluga sands which tend to have 20 percent clays, 30 to 40 percent silts, balance sandstone and the silts and clays are very susceptible to damage so we're working to find better ways to complete those wells.

And as has been mentioned before compression is needed. All of our wells right now are on compression because they're shallow. They start off at pressures barely above line pressure usually so they go to compression right away. We have two stage compression available on almost all our wells so we can pull them down to 100 psi or so and recover as much as 90 percent of the gas in place.

But what we think is needed most in the area and certainly agree with what's already been said by several speakers is exploration is needed in this area. It's an under-explored basin. There's a need for much more seismic to encourage exploration. Seismic is expensive to acquire here.

We need access to lands that are now locked up by wildlife refuges and also at the risk of offending some of my bigger brothers here, lands that are HBU tied up for years without being produced, large blocks of acreage that we have no access to.

So just to -- as I end this wanted to sort of list some of the challenges that we see for us in particular but for the industry in general. Cost control. We pride ourselves in being a low cost producer, a low cost operator and developer, but there's a lot of room for improvement. Some of our biggest issues are drilling waste disposal. It's very expensive. Can easily be 10 percent of the cost of a total well -- of the total cost.

Rig efficiencies, we're always fighting this. We have a sister company that has a rig that we're using. We have a lot of influence over what happens there. Made a lot of progress there, but continue to need to make progress.

Obviously the cost is the more days you're on there the higher the cost. Need to cut the number of days that you're on a well and we have, indeed, made a lot of progress here this year. Some of our workovers rig up to rig down have taken about 25 days which for us has been a real record.

Effective completions, again, the challenges to make effective completion is to prevent this formation damage that will certainly make a potentially productive well non-productive. We need to avoid water and sand production when we can and control it when we can't. And then the need for cost effective stimulation. This is an area that we're looking at very intensively right now.

More challenges here, in the regulatory side of things we would certainly like to see something done as far as the state-wide gas wells spacing is concerned. We think that one gas well per government section is -- is -- at all depths is not -- is not in best interest. Obviously you can get that done, but it takes time and paperwork to do so. We would like to see regulations basing gas well spacing on depth rather than one size fits all.

And secondly, uniform bonding requirements or maybe standard bonding requirements between state agencies. We recently had over a million and a half dollars tied up in CDs supporting bonds to drill a well and that's a lot of money for a company our size when your total budget is less than $20 million a year.

But to extend production we do need to maintain a high level of activity and that's not just Aurora Gas, that's the industry in general. With steep production declines of the smaller reservoirs and coming declines of the larger reservoirs drilling is needed and, of course, that takes money and so capital is needed then to offset declining production.

Improved prices do help, continued improved prices do help more. We need access to opportunities as has been mentioned, wildlife refuges and HBU lands. And for a company our size and for everyone we're fighting for funding. The better the economics look, obviously, the more money we can get, the more that we can do.

In closing Alaska, is a good place to do business on one hand, but it's a very tough environment, a natural environment on the other hand. And we thank all that have supported Aurora Gas over the past few years and we've certainly -- we have certainly been blessed with some good service companies and some good support out there. Thank you for your time.

COMMISSIONER SEAMOUNT: Thank you, Ed. Some of you may have noticed that we gave an inordinate amount of time to the extending production panel and that's because a couple of the invitees declined for good reasons, but we really would like to thank Chevron, ConocoPhillips and Aurora for participating.

And at this time we'll take a 10 minute break. Thank you.

(Off record)

(On record)

COMMISSIONER SEAMOUNT: In the endeavor to finish up early today why don't we get started again. On our next panel Cook Inlet Infrastructure can we get Pat Galvin, Andy Hoge, Brian Havelock and John Zager to the front stage, please?

(Off record comments on microphone)

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PAT GALVIN

COMMISSIONER SEAMOUNT: Okay. Our first speaker is Pat Galvin. He is a petroleum land manager for the Alaska Department of Natural Resources, Division of Oil and Gas. His responsibilities include managing the oil and gas leasing and licensing programs, lease administration and oil and gas permitting for the Division.

His education background includes a Bachelors Degree in Visual Arts and Quantitative Economics from the University of California-San Diego, a Law Degree form the University of San Diego and an MBA from San Diego University.

Prior to his position at DNR, Mr. Galvin, served as Director for the Division of Governmental Coordination overseeing the Alaska Coastal Management Program. Previously Mr. Galvin was a private practice attorney focusing on municipal, corporate, tribal law. And I assume you moved to Alaska to get away from that weather in San Diego, huh? Please welcome Pal Galvin.

MR. GALVIN: Thanks, Dan. I've been asked to come here and talk about aging platforms and just the name brings around thoughts of these old relics sitting out there that we need to find something to do with in the end.

And coincidentally I just actually walked in from a meeting that I participated in regarding my mother-in-law as she transitions into the assisted living situation and things that you tend to find yourself dealing with as people age. And, I think, that it's interesting that as I deal with the issues associated with anticipating future decisions that we're going to be making on her behalf and the expected complications that may come from it and the things that we have to deal with today based upon what we anticipate in the future, that I'm talking about aging platforms because there are a lot of similarities particularly looking at it from the perspective of the landlord.

The state as the owner of the offshore acreage out there has some potential opportunities in looking at the platforms and recognizing that as their usefulness as oil and gas production facilities ends, that we have to decide now what. And what we have to decide today is not necessarily what to do with them, but to make sure that we have the processes in place to be able to make the decision at that point based upon the best information that we have available at that time.

And so my primary purpose today is to make you aware of a proposed set of regulations that's out for public comment right now dealing with the platforms out in Cook Inlet and looking at it from the perspective of what are DNR's concerns today and we really have two primary concerns.

One is we want to make sure that when the decision needs to be made on what to do with these platforms that there is a clear and as efficient decision making process in place so that all the interested parties know how to participate and what to expect their role may be in that decision.

And secondly, the state has an interest in ensuring that if the ultimate decision is to make sure that the platforms are properly removed, that somebody will be able to pay for that cost and it won't have to be borne by the state.

So the regulations propose two different things. They propose a decision making process in which the responsible party for the platform would propose a certain scenario whether it be full removal of the platform, whether it be a partial removal of just the top side and toppling the legs or some other scenario or leaving the platform in place for some other use.

And what DNR recognizes is that there are a variety of interests out there related to these platforms. We've heard from a number of different interests over the years that people have ideas for how these platforms may be used for some non-oil and gas public purpose, some private purpose or potentially some additional oil and gas purpose for horizons or reservoirs that aren't currently being explored.

And there are other interests that want to ensure that unless there is a stated responsible party the platforms are fully removed. And it is with all these interests in mind that we have proposed the decision making process that is contained in that set of regulations.

The second issue regarding the bonding, again, it goes to the state's interest in ensuring that as long as there's an expectation that platforms will be removed there is somebody who will be able to afford it. And if there is concern that we don't have a party who will be financially able to do that, that we gain some form of security now to make sure that we aren't left holding the bag when these platforms need to be removed and so the regulations propose a number of different things in the area of bonding.

First, they include provisions to allow the DNR Commissioner to evaluate the companies that may be responsible for removing the platform to determine whether or not the state can rely on their financial viability and their performance record as enough security to basically make them good for that obligation just on their own word. And, if not, then the regulations establish what the appropriate amount should be to estimate the cost of removal and what the appropriate bond should be.

So in my few minutes that we have on this panel I wanted to make sure that you were aware that these regulations are currently out for public comment. The comment period ends October 2nd. There are sets of the proposed regs, as well as the information on how to comment on them out on the table as you go out on your right.

And we encourage all interested parties in the issue with regard to these platforms to participate in the process of developing these regs because at this point it really is the responsible thing for the state to do to ensure that we have the appropriate rules in place so when the decision time actually comes on these platforms everybody knows how the decision will be made and how they can influence that ultimate outcome. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Pat. Now, Chairman Norman is going to introduce the next speaker.

CHAIRMAN NORMAN: We're indebted to the next speaker for agreeing to step in literally at the eleventh hour. Assistant Attorney General Phil Reeves was down to cover this topic and he has another commitment that was unavoidable and he had to attend to that and so the speaker that I'm going to introduce though is someone that is extremely knowledgeable in the area, but we need to understand that he's had less than 24 hours notice that he was going to be asked to come and speak today.

He did kindly say that is anyone did have questions and if you'll write them down and get them to us he'll do his best to give you a response if in the course of his presentation it isn't adequately covered.

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ANDREW HOGE

CHAIRMAN NORMAN: The person I'm going to introduce is one of Alaska preeminent attorneys in the area of regulatory affairs. He's rates as high AV as an attorney can get. He has practiced here in Alaska since, I believe, 1965 or '66 and has represented a number of companies in their dealings with the regulatory agencies that oversee operations such as a pipeline.

I believe also, Andy, correct me if I'm wrong, you did originally also serve in the Attorney General's office as an Assistant Attorney General. So please welcome Andy Hoge who is a senior partner with the firm of Hartig, Rhodes, Hoge, Lekisch, Andy Hoge.

MR. HOGE: Thank you. What I'm going to do is explain to you a little bit about the highway system, as I call it. The highway system is how gas is transported from points of exploration, production and ultimately transported to where the gas is actually used.

And I have about 30 handouts here and I can get more and if you'll give me your business card if you want one of these handouts this is just a smaller version of this graphic and I will get them to you.

So I'll just start a little bit and tell you what the major pipeline system is in and around Cook Inlet and then I'll talk a little bit about the pipelines regulatory status, a little bit of background there.

Pipelines in Alaska are regulated by the Regulatory Commission of Alaska. There are two statutes under which these are regulated, 42.05. The title is 42 and the subsection is .05 deals with utility type regulation and that would be Enstar and Alaska Pipeline are regulated under 42.05.

Trans-Alaska Pipeline, a lot of the pipelines on the North Slope are regulated under 42.06 and it is a pipeline type of regulation. There are some significant differences. From the standpoint of rate regulation it's quite similar and I won't go into detail of that today because there just isn't sufficient time.

So I'm going to -- roughly I'm going to give you an idea of where the pipelines are and their regulatory status and if you have questions you can ask them of me after my presentation.

On the east side of the Inlet is the Cook Inlet Gathering System called CIGGS and at various times you've seen CIGGS in the paper. CIGGS has two segments, a segment here from the McArthur field up into Nicolai in this area. Then it has a dual marine pipeline that comes across the Inlet and it comes into the KPL junction.

The next pipeline again on the east -- I mean, on the west side of the field is the Beluga pipeline. It goes here at this connection point and goes up to the Chugach power plant.

It also interconnects with the north system of the Alaska Pipeline and Enstar or the North system pipeline.

On the east side of the pipeline John Zager talked about the Happy Valley field, that's connected into the KKPL pipeline and that's the Kenai Kachemak Pipeline and that connects Happy Valley, the Ninilchik field and just recently been certified to serve the Kasilof field. That proceeds north to KNPL, the Kenai Nikiski Pipeline and that pipeline again goes north to what's called the KPL junction.

CIGGS joins here, KNPL and KKPL, just down here the Enstar south of the KPL junction there's a junction with Enstar's, what I call their southern system which brings gas into Anchorage.

Here in the KPL junction there's interconnections with Tesoro, Bernice Power Plant, Unocal, Agrium, now nitrogen plant and the LNG plant, so the gas gets kind of centralized here and then is distributed as needed.

A little bit about the regulatory status of these pipelines. KKPL is regulated under 42.06. It has a unique status in that it has a transportation system whereby you as a shipper nominate how much you're going to carry, that's called firm and that is the method used on KKPL. The significance of that is on the North Slope gas pipeline that will be one of the major components when it gets that far where shippers will nominate how much they will commit to carry on that pipeline.

And this is the only pipeline that has the firm commitment.

The other pipelines are really older pipelines, and they are what you might call common carrier pipelines. That is if you have something to transport on it, to the extent that there's capacity, those pipelines can transport the gas.

Cook Inlet was not a regulated pipeline until just recently. It now has entered into a settlement where 40 million cubic feet a day are going to be available for common carriage. Kenai Nikiski pipeline, again an older pipeline, is a common carrier pipeline, that is it will carry what it can carry and it is available for transportation. Beluga pipeline is also a common carrier pipeline. So all of these are common carrier. KKPL is a firm transportation carrier pipeline. Enstar and the Alaska pipeline, the north system and what I call the south system, have rates for transportation only or for transportation for gas. And you would have to go to them if you were trying to arrange transportation on their system.

Most of these systems now are managed by Marathon and if you have any interest in transporting on these pipelines you can contact me or a fellow by the name of Kent Hampton with Marathon who can give you the specifics of how you would transport over those pipelines.

I think whatever the situation is in Cook Inlet there is adequate facilities through these pipelines to transport gas. John Zager mentioned that there's maybe some opportunities with the red drilling pad and to the south of KKPL, but that will await future developments.

The point of all these pipelines are you need to have sufficient gas flowing through them to pay their capital and operating cost. And what has happened in the last few years is these pipelines are all setup now so that there is open access to them. You have to pay the given transportation rate in order to utilize the pipeline, but the pipelines and -- are available and there is capacity.

The important thing of this is -- to understand these pipelines have -- there's been a considerable amount of litigation on all of these pipelines on the terms of carriage, on the rates and there are pending settlements -- well, KKPL has settled and there are now pending settlements with Cook Inlet, Beluga, KNPL, to settle the rates and the conditions for service. I don't mean to scare you here, but this is just the settlement agreement for KKPL and it's several hundreds of pages.

Each pipeline operates under a tariff and the tariff tells you the conditions of service, the quality of gas, when you can transport, what rules you have to follow, so each pipeline in turn has that.

And when I go to these presentations it sounds like somebody just goes out and drills a well or you just sign up for service, it's much more complicated than that. And the point of all of this is the parties, all the interested parties, producers, shippers, the pipeline owners, the state of Alaska, have all come together and over the past two or three years, I think, have come up with a system that is functional for the Cook Inlet. So hopefully the highway system will work, now we just need to have the gas to transport through the system.

I had been prepared to go into a lot of detail about rates and the status of the settlements, but I don't think at this level that's what you want to hear. Just to let you know things like that are in place and as I mentioned you can contact Kent Hampton or me and I will get you the right person if you have any questions about transporting on the pipeline system.

CHAIRMAN NORMAN: Thank you very much, Andy. Double thank you for stepping in on extremely short notice and filling this gap in our presentation. And Andy has some handouts here if any of you want to pick them up. And let me have one for the official transcript here too. Thank you.

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BRIAN HAVELOCK

COMMISSIONER SEAMOUNT: All right. Out next speaker is Brian Havelock, he's a Natural Resource Specialist with the Division of Oil and Gas in Anchorage, Alaska. Mr. Havelock received a bachelor's degree in Geography from the University of Alaska Fairbanks in 1987 and studied postgraduate Fisheries Economics at UAF. After three years as a Fishery Observer in the Bering Sea and the Gulf of Alaska -- you're not on that TV show are you? Okay. He worked for the U.S. Fish & Wildlife Service at Chugach Regional Corporation before signing on with the Division in 1995. He currently manages gas storage activities for the Department and produces the Division's Alaska Oil and Gas Report. He's going to be discussing gas storage permitting and leasing. Welcome, Brian.

MR. HAVELOCK: Thank you, Commissioners, for allowing me the opportunity to speak today at this forum. And I have a presentation. Good, I wasn't sure -- I think I'm the only person that has it in PDF so I wasn't sure if it was going to work. So thank you for allowing me to speak. That was quite an act to follow so consider that huge, if I will regulatory regime and everything I'm going to say is subject to that regime. So my topic today is gas storage in Alaska.

That is too far away for me to see so I'm going to use my own notes. I'm going to speak about gas storage introduction, gas storage in Alaska and the topic of my subject today was permitting and leasing, but I'm going to go into a little more than that, I'm going to talk about briefly the value of storage gas, demand for gas in Cook Inlet, demand for gas storage in Cook Inlet and Alaska gas storage deliverability.

Okay. Underground gas storage is injecting surplus gas production, but not for the purposes of enhanced oil recovery, into a depleted or nearly depleted reservoir for later withdrawal to meet demand. In the U.S. gas is stored underground in salt caverns, depleted oil and gas reservoirs and aquifers. In Alaska it's only stored in underground reservoirs.

Best candidates for storage are reservoirs that are trapped and capped with tank like characteristics, distinct structure and evidence of pressure depletion without support. Good candidates are reservoirs that aren't completely depleted, but still have some remaining native gas or cushion gas and reservoirs that are located strategically along the key delivery points.

Storage facilities are designed for seasonal system supply or base load supply or to meet peak day or hourly demand. We have three storage facilities in Alaska, they're at Swanson River, Pretty Creek and Kenai field. The Kenai facility is located near the bottom of the map at the giant Kenai field. Swanson River facility is in the upper right-hand corner. And the Pretty Creek field is located on the west side, right on the Enstar gas pipeline that is connected to Anchorage.

Some terminology in gas storage. We have total capacity of the reservoir is the total amount of gas that it can hold. Cushion gas is the volume of gas, it's intended as a permanent inventory to support deliverability. And working gas, working gas is the amount of gas that's available to the marketplace and it's cycled in and out of the storage reservoir annually.

And the primary focus today is deliverability of gas. And deliverability is the amount of gas that can be withdrawn from the facility on a daily basis. Factors that affect deliverability are how much gas is in the reservoir, reservoir pressure, the compression capability of the surface facilities, the configuration and capacity of the surface facilities and pipelines and the number and capacity of producers and injector wells.

This is a cartoon showing a depleted and reservoir with injector wells and producer wells. Gas is injected into the reservoir and cycled at rates that depend on the characteristics of the reservoir and operational experience. If working gas is not cycled properly it can be lost. Gas can move from low to high pressure, move into tighter formations and result in loss if it's not cycled properly.

Injection season is from April through September or early October, it's a little bit longer in the Lower 48. Early season cold weather can reduce gas storage in place and deliverability and late season cold can reduce the next season's injection needs.

Weather and gas demand forecasting are a primary focus for storage facility optimization. That's the big focus for utilities. Storage optimization is not always the parent company focus. There's a tradeoff between the working gas and cushion gas in the reservoir, in the Lower 48 it's about 50/50, but the more gas you inject, the higher the compressor has to work so there's some cost associated with that.

These are some milestones for Alaska gas storage. I won't read them all, but Swanson River was the first storage facility in Alaska in 2001. In 2005 DNR approved the Pretty Creek facility and then earlier this year the Kenai facility -- Marathon's Kenai facility was approved. Most notably Agrium has credited staying open during the winter industrial curtailment of 2005/2006 to Swanson River gas storage deliveries.

For authorizing gas storage in Alaska, on all lands you need at least one thing is the storage injection order from the Oil & Gas Conservation Commission. And if it's on federal lands you'll need either a BLM gas storage agreement from BLM or a royalty gas payout agreement. And for state lands you need the DNR gas storage lease and an ACMP consistency review if it's in the coastal zone for state lands. And I apologize to BLM if this slide is a little misleading, the bullets I have for the BLM are -- actually pertain to the royalty gas payout agreement and not the BLM gas storage agreement which is similar to a DNR gas storage lease. They missed that last slide it looks like.

COMMISSIONER SEAMOUNT: You can go back if you want.

MR. HAVELOCK: Well, they're the documents you need to authorize storage.

Principles of gas storage leasing. It's authorized under 38.05 and regulated under 11 AAC 33. The oil and gas lease excludes the right to store gas except for enhanced oil recovery. That's why we have a gas storage lease. Regulations say that the storage operations may not interfere with the oil and gas lease. Storage continues in oil and gas lease. The gas storage lease is limited to specific sands to store, it's not a grassroots lease all the way to the center of the earth. The state lease is only for the state portion of the storage reservoir as in the case of the Kenai which has multiple owners. Royalties must be paid before the gas can be injected. Leasing requires a public notice and a 30 day public comment period, 50 day multi-agency ACNP review, a written best interest finding and at least some mitigation measures and advisories. Finally third party or commercial storage requires a separate agreement with the State.

Some key terms in the storage lease are annual storage development plan, native gas royalty payout schedule which the intent is to simulate what royalty owners would get paid had there been no storage project. A fee or rental of plan of operations permit and bonding. Gas storage utilizes existing facilities and the oil and gas bond can be applied with minor adjustments. There's storage limitation in one lease, required operations and gas measurement and reporting.

The value of storage gas comes from several factors, location, how close you are to the markets, to the supplies, to the main pipelines. It depends on the season value of that stored gas, if there's a summer and winter price differential or a price differential between interruptible or firm service. Depends on the facility capacity, whether it's a peaking or base load delivery facility, how much compression you have, the number of wells and their deliverability. And depends on how much working gas is available. Also value is obtained from the availability of substitutes for storage gas, the cost of the storage and transportation and price volatility which is not a factor in Alaska yet, but it's a big driver in the Lower 48 of storage gas value.

Daily demand for gas in Cook Inlet, this is 2005. Demand is about 572 million cubic feet a day. And this shows the various users of gas in Cook Inlet which you probably can't even read from where you are.

This is the DNR reserves projection and I just wanted to make a note that the -- this tremendous cliff that you see here is kind of -- it's -- there's only so much you can get out of this graph. What we're seeing here is DNR's measure of some proved and some measure of unproven reserves. But the producers don't drill up and prove the reserves unless they can produce them and sell them. And so you wouldn't expect to see the line go flat like -- go straight -- keep on going straight because they wouldn't invest the money in proving up reserves. So it's going to go down like that.

There's a -- historically the gas that was produced and couldn't be exported was reinjected to enhance oil recovery, but as oil production declined the injections did also. Currently production roughly equals demand and so it would be -- I think it would be illogical to invest dollars proving and developing reserves when there's no market for them, that is no market within a year or two of bringing them on line. However storage can provide a market when no one wants to burn the gas.

You've seen this graph, this shows a direct relationship between temperature and demanded gas volume which peaks in the winter and drops way down in the summer. This is the residential and commercial demand volume that we saw in an earlier presentation. The volumes from the preceding chart are ordered from highest to lowest to generate this Cook Inlet demand residential and commercial load profile. On the X axis is days of the year and volume on the Y.

And on the far left you can see there's -- the highest volume is for just a few days out of the year we have this huge peak in demand and then the days are all ordered to create this demand load profile. Total demand for gas includes an even or steady daily consumption for industrial users plus this wildly swinging residential and commercial demand. So the industrial demand portion is added to create a total Cook Inlet demand load profile. And the green there is the industrial portion.

In 2006 DNR forecasted production to be about 206 Bcf and this comes to an annual average of 564 million cubic feet a day. That's what the gray line -- the gray area depicts is the supply of gas and so if we just assume for now that production is constant throughout the year, this is what it would look like over a constant. Then we have a shortage of gas in the winter and then a surplus in the summertime above and below that purple line.

Now, I don't know if you can see it too well, it's perhaps too far away, but this graph is a snapshot of a theoretical storage demand picture. The volume to the right is available for injection and the volume to the left is available for storage withdrawal. And I'm talking about the volume on the left is the blue and the volume on the right is the gray that's above the purple line. If you were to add the two volumes together you would have a deficit of 3 Bcf. So there's -- demand exceeds what available in summer by about 3 Bcf for 2006. So as I said the gray line is actually not flat, the producers in the wintertime they open up the wells wide open and increase production and in the summertime they shut back production. So the gray line would actually be sloping.

So, I guess, the point is -- a final point here is that if there's not enough gas to inject in the next season then we're going to have curtailment. And also if the green line drops suddenly, that is if industrial demand drops suddenly and this appears to be likely based on what Agrium presented this morning, then there will be a short-term surplus of gas, some of which could be stored with existing facilities. But you don't want to store too much if you can't cycle it and sell it and sell it at a profit. So a sudden drop in demand, I think, will result in fields being shut in and production be scaled back rather than actually stored.

This final slide on this load profile just shows the projected supply for 2007, '8 and '9, you can see the supply dropping and it will certainly affect the demand for storage.

I'll go back one slide. The blue line represents the storage demand volume, the maximum base load demand might be about 90 million cubic feet a day. And the little rose colored portion in the far left is the very coldest days of the year, is the demand for peak shaving and at a maximum that could be as high as 47 million cubic feet a day.

This is deliverability of the Swanson River facility, the two wells in Swanson River and you can see those spikes are generally during the wintertime with volumes. So seasonal deliverability at Swanson River.

And let's see, you probably can't see this. These are some deliverability estimates for the gas storage facilities currently in Cook Inlet. There are about 12 wells in Cook Inlet for a total capacity of about 88 million cubic feet a day and that is total daily peak deliverability. The average deliverability is about 43 million cubic feet a day for a total 8.9 billion cubic feet of working gas capacity in Cook Inlet currently.

So to conclude, storage promotes conservation. Currently when there's excess supply wells are shut in and in many instances they're difficult, if not impossible, to bring back on line at the same rates. Shutting wells can also cause formation damage and premature water influx. So from a conservation perspective storage really makes sense. Storage balances seasonal demand swings. I think the key here is just optimizing the storage facilities. In 2006 we have a gas supply deficit of 3 billion cubic feet. With our projected decline in production this deficit should grow to 17 billion cubic feet next year and 154 billion cubic feet by 2016.

Producers will only prove and produce what they can sell. In 2006 production roughly equals demand, supply equals demand. And unlike the Lower 48 we don't have liquid trading centers and seasonal prices that provide incentives to store gas. If we want commercial storage we need excess supply and access to Lower 48 markets.

Base load storage maximum capacity is 88 million cubic feet a day, almost enough to meet demand, but facilities may be only able to deliver about half of that. And maybe the next speaker can speak to that. The current working gas capacity is about 8.9 billion cubic feet, but we need 10 to 14 billion cubic feet of working gas in Cook Inlet to meet the demand swings and we need it in strategic locations, not just in one place like Kenai. Maximum peak shaving demand could be 47 million cubic feet a day on the coldest days, but we don't really know what our peak shaving capacity is currently, but Dan Dieckgraeff said that it's going to worsen coming up this year. So we'll see.

Cook Inlet needs additional working gas capacity and daily, especially peak deliverability, to meet current seasonal demand swings. You'd think that we -- if we had 88 million cubic feet of base load capacity and we only need 90 that we're close to meeting that demand, however the facilities do not deliver they maximum design rates and average rates are probably more likely. And storage projects are also risky, wells don't always perform as expected. And adding to that is the location factor, if you can't get your stored gas to where you need it and when, you have a supply problem. And last, storage can alleviate daily demand swings, but it cannot solve the problem of supply, you can't inject gas you don't have.

If a spur line connects Alaska to the Lower 48, they'll be some increased need for storage here, but I don't think a whole lot more unless we are connected to the Lower 48 market and have the same market structure that they have down there and the same high prices. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Brian.

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JOHN ZAGER

COMMISSIONER SEAMOUNT: Our next speaker was in the last panel session and so I'm not going to re-read his bio for you other than to say that he has -- in addition to his bio he has worked in Houston, Texas in the past. John Zager, General Manger, Chevron USA Alaska.

MR. ZAGER: Thanks, Dan. I was hoping -- I want to see if you could say Gustavus Adolphus College correctly this time.

COMMISSIONER SEAMOUNT: That's why I didn't read it.

MR. ZAGER: Thanks. Well, I think Brian did a really good job covering all the basics and I don't think I can disagree with much of what he said in filling you in so this should be pretty short and sweet.

I'll talk a little bit about gas storage and why do we need gas storage. This is maybe a little bit different perspective on it. This shows the different industries and I think we had a slide similar to this morning. What we're looking at for each of the major consumers of gas is in the light blue bar which is the peak that they will consume on any given day during the year and then the darker blue is the average for the year. So the closer those are together, the less that consumer would need peaking services. So you can see some of these LNG and Agrium are relatively stable.

The field operations is relatively stable. And you can see the big difference comes in the power generation and particularly in home heating. And that should be a surprise if you live in Anchorage that July we don't run any heat and January we're running it pretty much 24/7. And so that represents for heating which is basically the Enstar market, the difference between the average and the peak is about two and a half times. The difference between the minimum in the summer where there might be more like 30 million a day up to 300 million a day is like a swing of 10 to 1. So that's a huge swing that's got to be provided as part of the Enstar market.

And so as was said earlier in the old days we could just open the valve and we could fill that need, but that is -- those days are gone and now we have to look at other ways of doing it and storage is the obvious answer.

This graph is something we compiled from the -- trying to correlate heating degree days with the Enstar load and I think it's a pretty good approximation. If you can see that, that goes back in time, this is a period from 1990 or so for about 10 years. Each dot on there represents the amount of gas consumed on a given day during the year. And you can see that as you expect there's some variation with weather, especially in the winters.

In the summer it's been pretty constant here around 25 million on the warmest days. And then you can see depending on how cold it gets, this was a really cold winter and we had a few days over 200 million cubic feet a day. Here was a pretty warm winter, we didn't get a lot of those cold days. And for planning purposes, of course, sitting here this time of year, we don't know what kind of winter we're going to have so we've got to be prepared for a cold winter.

And, furthermore, we don't know whether the cold's going to come in November like it did last year, it came pretty early, or it's going to come in March. Those are very different issues for a gas storage reservoir because you -- probably in March if you've been drawing on it through the winter you aren't going to have your peak deliverability anymore. So you've got to be prepared for all scenarios and, of course, there's a scenario you'll get cold in November and you get cold in March and maybe February in between. So you've got to have excess capacity built into the system if you're going to be able to reliably deliver gas to your customers regardless of the winter that's going to come at you.

Now I've -- Brian talked about peak shaving and I've put up here that there's basically two kinds -- two reasons you would use storage and these are end points and probably there's shades of gray in between, but one would be peak shaving. We're putting it in place simply to meet those coldest days. And that would mean -- and this is kind of a cartoon, there's nothing magical with that number, but that would mean let's plan that everything above that line we're going to meet out of storage. So there's a number there, 50 or 60 million a day and we know that if we can get to that green line with our sources we can use storage to meet just about any anticipated need. So that would be a peak shaving type service.

Another type of service would be load shifting and this would be the other end of the spectrum. This would say we're going to have so much storage that we can produce our wells constant year round and we'll just be swinging in and out of storage on any given day and the whole system will balance perfectly and we won't need to worry about swing in our production at all.

So today the service that Chevron provides is a peak shaving type system, we don't have the capacity to do the full load shifting even for Enstar. And if we were thinking about this as an industry, those numbers would be much, much larger in terms of the amount of volumes you would need for load shifting.

Where -- as Brian already discussed some of our storage projects, we basically have two areas right now with storage, one is at Swanson River which was the first one installed. We have three separate wells there going into two different reservoirs. And peak deliverability about 55 million cubic feet a day. That's when it's jam packed full, like it is right now because we're getting ready to go into winter. That if we needed for one day we could do 55 million, if we need to do it on the -- you know, on the fifth day we might be down to 50 million because that's reservoir's going to deplete, it's not a real large reservoir. And it has about 3 Bcf of total capacity so as we get more and more depleted that peaking is going to get smaller and smaller, the rates.

And then just recently this summer Pretty Creek, we're injecting into that now, we have one storage well there. We don't know, we've never tried to flow it out at high rates, we're thinking it will do 10 million a day, hopefully, it'll do a little better than that. And we think we can get about 2 Bcf in there, that's total what -- called pad gas and working gas.

So -- and there, of course, the first ones were located here at Swanson River basically on the east side. Pretty Creek was put on the west side just to help diversify the sources, trying to get ready for any scenario. It's pretty much adjacent to Beluga River field so there's a large source of gas there. And we'll look at other capacity in the future, probably the next one will be on the west side as well.

So this storage was developed exclusively by Chevron for Chevron's primary customer which is Enstar. And we're using it 100 percent of the time only for our own needs.

So just a few points here on gas storage. It -- you know, in our view this is critical to meeting our utility contracts. And also in our view this is the highest and best use of storage. Everyone wants to make sure that when they -- your furnace kicks on the gas is there to do it and that's -- this is directly doing that.

Now, it was mentioned earlier, we have -- when we get in a position where we feel comfortable that we've got enough storage to get through the winter, maybe it's starting to get warm out, we will use that to help supply other customers. In fact, this last year we used it on several occasions to keep Agrium up when they were floundering right on the line between having to take the plant down or not. But that is a secondary use for us, our primary use is always focused on the utility market and making sure that we've got high confidence that we'll be able to meet our requirements there.

So that's a peak shaving service and that's what we're doing now. Load shifting will require much larger reservoirs. And if other uses start to come in terms of for other industries, you'll need to look at even larger amounts for load shifting.

Gas storage is costly and it's risky. Brian mentioned some of this, I can assure we put millions and millions of dollars into drilling new wells, compression and other things. And all this is rolled into the Enstar price, it's not added on. So it's part and parcel of it and it, you know, raises the cost of meeting those peaks quite significantly, but it's part of the deal and part of the rationale for getting the higher price for that gas now.

And it's risky and we've had numerous problems with wells, especially the first cycle, you're putting probably tens of millions of dollars of gas in the ground with no real assurance that it's going to come back at you especially not at the rates and volumes that you hope. So it takes pause and a little bit of faith when you decide okay, we've -- it looks like it's going to work, we flow it in, we flow it out a couple days and now let's just go -- let's go plow 2 Bcf of gas in that reservoir and when we call on it in January let's hope it's there.

The other cost is we pay royalties on this gas when it's severed from the lease and then we put it in the reservoir. And if it's a warm winter it may stay there because we can't blow it down really in case it's cold in March and then it gets to March and the other production -- your market's going away. So some of this gas can get in a reservoir and it could potentially stay for a year or a number of years and not be marketed. So the inventory cost on gas storage is also a real cost.

But having said all that, it's part of our responsibility as part of the Enstar contract to meet our requirements and we certainly intend to do that. And we continue to plan to expand gas storage to meet those needs. So thank you.

TOM WILLIAMS

COMMISSIONER SEAMOUNT: Thank you, John. We'll go to our next panel discussion, Effect of Taxes and Incentives and we are quite a bit ahead of schedule so I won't blame you if you're not here, but are Tom Williams, William Nebesky, Greg Bidwell and Mark Edwards in the crowd? I think we have a quorum.

Okay. Our next speaker is Tom Williams. He -- Tom Williams has been a tax attorney for BP Exploration Alaska, Incorporated since 1987. He came to Alaska in 1973 to work on the State's lawsuit against Cook Inlet producers over their State production taxes and royalties. In 1975 he was named director of the Petroleum Revenue Division with responsibility for administering the State's oil and gas taxes. He directed the implementation of Alaska's temporary oil and gas reserves tax in 1976 and '77 and its separate accounting income tax on oil companies in 1978. In 1979 Governor Jay Hammond named him Commissioner of Revenue. Tom was one of the original trustees of the Permanent Fund Corporation. After a year in private practice following the end of the Hammond Administration he became vice president and general counsel for Cook Inlet Region, Incorporated, the native regional corporation for the Cook Inlet area where he worked until he joined BP.

Tom is a graduate of Princeton, has a master's in

History from Harvard and received his law degree from Stanford. Please join me in welcoming Tom Williams.

MR. WILLIAMS: Thank you. Well, we're talking today about the effect of taxes and incentives. And as the effect of taxes is summarized in that very famous slogan about taxes, the power of taxation is the power to create. Wait, no, it's not. It's -- the saying is the power to destroy, right? Well, that illustrates the effect of taxes.

And also it -- in a sense it illustrates the effect of incentives. You have a system of taxes that is in place, incentives can be used to lower the cost of doing business for a company as a way to encourage that company or person to engage in something that the State or the government can't or won't do itself and can't or shouldn't do to force that person to do it.

Mostly we think in terms of incentives in a monetary sense. The most obvious form of incentive is an outright grant or subsidy for people to engage in certain types of conduct, do this and I'll give you $100,000 to help get started. It's usually not what you see with the oil and gas industry, but it is one type of incentive.

Another type of incentive in a monetary nature is you either get a fast write off of your investment or you get a reduction in your tax burden typically through a credit for incurring certain types of expenditures, either investing or engaging in risky or high cost operations.

But incentives are not limited simply to being monetary. Incentives from an industry's point of view can also be created a couple of other ways. One of those ways is to recognize the fact that a dollar next year is not as valuable as a dollar today. The corollary of that is that a dollar next year will be more valuable to a government than it will be to a company because the company is going to pay income taxes when it gets that dollar, the government doesn't.

There are other things too about government that get into one's philosophy of government and social cost of capital in terms of whether there's -- what the time value of money is as a percentage term that you should impute to the State's return on its money or return on money that it doesn't collect today, but collects tomorrow. But regardless of where you come out in terms of what that rate is for the State or any other government, it is less than what that return is going to be for that type of investment for industry because industry is going to pay taxes first and because industry has to pay dividends to its shareholders.

So deferring a dollar from the State's point of view can create value from the company's point of view because it reduces the front end burden of an investment or an activity and thus improves the -- how that looks to the company as an investor. That's the present value of the future income discounted using the industry's rate versus the State's rate. Smaller rate for the state means a bigger pile of money as present value. So when the State keeps its pile the same, it creates value for the companies.

There's another way, too, that the State can create value besides just shifting the timing around of when it will take its tax or its royalty or impose an obligation, the timing of any of those. And that has to do with projects, especially larger ones, where the risk for the investor who you're trying to incent, the risk has material adverse consequence for that investor.

And the best example I can give you is sort of a game. Let's say that you can invest in a roll of the dice, two -- a pair of dice, there's 36 combinations, but only one of those is double sixes. So if you roll boxcars I'll pay you $72. And if you roll anything else you'll pay me $1. Would you play the game? Well, of course you will because the payout is twice as great as the number of chances that you have in the game. So every time you roll the dice statistics will tell you that you can expect to make $2 in this game for a cost of one. Not a bad deal, so you'll play it. But if we raise the cost to $100,000 a throw and still have the reward be 72 times larger or a million dollars a throw and a $72 million reward you won't play the game, at least you shouldn't.

And the reason you won't is because you can't afford to play this game enough times to get the odds on your side. So when you have an investment that is very expensive and has large impacts relative to the resources of the would be investor, the investor gets more and more leery about making that investment.

Now there are different ways that you could deal with trying to make that investment better for the investor. One is to increase the reward, right? But if I go back to my dice game instead of $72 I make it $108. Now it's a three to one payout instead of two to one. That won't make the game better for you at 100,000 or a million dollars a throw because you still can't get over the fundamental problem you can't play the game enough times to get the odds on your side. So you'll go broke before you can get the win, that's statistically what's going to happen. So you wouldn't play the game.

And so when you have this type of large investment with material adverse risk for the investor, sometimes the best thing to do is not to try to subsidize the payout. Sometimes the best thing to do is improve the odds of getting the payout or reducing the cost of getting the payout.

And we see -- I mean, in the context of natural gas we have seen the State consider two different ways, each of these last two ways of dealing with the issue. One is the proposal that the -- was made for the State to own a share of the natural gas pipeline. By owning a share it takes on the risk of building that pipeline and operating it and that it will be a commercial success when it's built. That's one way of reducing the cost then of investing for the others. It makes the materiality of their risk less large.

The other thing it can do is improve the odds and that was this -- the Stranded Gas Act and the proposed contract that was made under that or almost made. The idea there is that you have an exemption from changes in the rules of the game through new taxes after the pipeline is built by saying the pipeline won't pay any of those taxes, instead it will pay a contractual obligation that's comparable in amount to what it would be paying under the regime today or whatever is the regime that would be locked in under that contract. Then you have certainty, you improve the odds, one less risk goes away. And it's an important risk.

I mean, we know from -- as a historic fact that when Prudhoe Bay was discovered it was announced in March of 1968, and by February of 1969 they said -- the companies said we're going to build a pipeline, the decision is a go, we're ordering the pipe. And in September of 1969 the pipe was arriving in Valdez. In the 10 years after 1969 the State changed its oil and gas structure, most often with Prudhoe Bay specifically in mind, 14 times, in that decade. It's a historical fact.

Once you have 20 or $30 billion sunk in the ground you can't move it and so the need to have fiscal certainty or at least fiscal stability, that the rules aren't going to be unexpectedly changed, is an important benefit and important incentive that government can provide when you get to large projects where size and risk of an adverse outcome are material relative to the resources of the would be investor.

Now there's one other thing that I'd like to say and that is obviously in order for an investment or an incentive rather to work as an incentive, it has to be something that the decision maker knows at the time she makes the decision to do the investment or not. If it's based -- if the reward is based on things that you cannot know at that time the incentive may be wasteful or parsimonious depending on whether there are more things that end up being given, in which case it's wasteful, or fewer things than what were expected to be given, in which case it's parsimonious. Either way the uncertainty about what your incentive actually is is undercut, it undercuts the effectiveness of that incentive.

We have seen, for instance, on the books incentives for oil and gas exploration and they have worked, but I don't think they've worked as efficiently as the might have because a lot of the costs that are -- give rise to these tax credits, substantial tax credits, are subject to audit after the fact, did you really incur that $1.29 for, you know, lead pencils and were lead pencils an appropriate cost. I mean, in theory that's the type of thing that the audit can go into after the fact.

The fact that there will be audits, the fact that auditors will have a natural incentive to look like heroes, with all respect to my friends in Revenue, maybe my former friends, you know, their job is to raise questions and part of the audit is to raise questions about allowable cost. But to the extent that you're not looking at what the decision maker was looking at, you're undercutting the value that the State gets from providing the incentive from those unknown and unknowable costs.

So a better way to structure things is to look at the world at the time the decision maker is looking at it and making the decision, that's where the focus should be. Companies do not cook their books when it comes to deciding whether they're going to investment their money and their shareholders' money or not. That is the most honest thing they do, it's to -- it's their own management and their own careers that are on the line, to have a project be effective and efficient and successful. So they're not going try to make that look crummy, they're not going to inflate it so that they could get a higher credit because they've got a big budget for something. Budgets are designed to be lean, budgets are designed to be efficient.

The only thing you have to be worried about from a State's point of view is making sure that the number you see was the actual number that was before the decision maker at the time of the decision. That's the number you can rely on. And when you as a government do rely on that number, then the reward, the incentive is certain and known by the decision maker at the time he or she makes that decision and that gives you the maximum benefit, the maximum incentive effective that is intended to be granted by these incentives.

And I think that's basically it. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Tom. I think I failed to mention that you were Chair of the AOGA Tax Committee. Did I fail to do that? But it's on the agenda so okay.

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MARK EDWARDS

COMMISSIONER SEAMOUNT: Our next speaker is Mark Edwards of the Department of Revenue, Revenue Development. He was born in Alaska and is a graduate of East Anchorage High School. He received his Bachelor's degree from the University of Virginia in Economics and Government. After college he worked as a loan officer for the National Bank of Alaska, completed their management training program and continued master level studies at Alaska Pacific University in Business Administration. He later received a Master's degree with distinction in International Business from Thunderbird, the American Graduate School of International Management in Arizona.

He has lived, worked and studied in Spain and Mexico and is fluent in Spanish. He is married to Dr. Irma Edwards, a family practice physician. Mark was previously the State's economist in the Department of Commerce, Community & Economic Development. Later he became the Director of the Office of Economic Development where he worked on diverse issues ranging from economic development in rural Alaska to international exports.

He now works in the Department of Revenue focusing on developing the natural gas pipeline, petroleum tax issues and the State's long-term fiscal plan. Let's welcome Mark.

MR. EDWARDS: Well, hello, everyone. Thank you very much for the introduction. And thank you, Mr. Williams, for that excellent overview incentives, I think it was very thought provoking. And I want to thank Chairman Norman for organizing this event and all the work of your staff. Mr. Norman is someone I've known all my life and I've always looked up to him and I really appreciate this opportunity to be here today. Thank you. And also thank you for everyone else who's still here at the end of the day, I know it's been a long day with a lot of presentations. So it really shows a commitment of everyone in this room to this important topic and we appreciate you all being here to listen even right up to the bitter end. So I thank you for all -- for staying and hopefully I will share with you some good information.

My topic today is on taxes and incentives as we just heard and I think it's a very important issue or maybe it's incentives, aka, less taxes. But as we heard it's even more than that. And I'm going to kind of talk more specifically about the PPT legislation that recently passed. And I do see that there a lot of people in this room, legislators who worked very diligently on making that happen. And I want to thank everyone here who took part in that. It's been a long process and it's been an important one, an important change for the State. So I think we're all here because we all share in the success of the energy industry here in Alaska and we want to make sure that it's vibrant and successful.

And we want to make sure from a revenue perspective as you mentioned that the people who participate in it share in the wealth that's generated by successful exploration and development. And what that means is we need to make sure our fiscal policies are such that people who have the best expertise, the most recent technology and the financial wherewithal continue to invest and explore in our state and, therefore, lead to more production in the future.

I'm -- I want to, you know, mention as we heard earlier, one of the most important things we can do to utilize the assets that we already have here in Alaska is try to produce them, make them earn revenues for the State and we really are blessed with an abundant amount of natural resources. In my prior job I worked more on seafood, timber, mining, those type of issues. Here in energy we literally have billions of dollars worth of assets in the ground and many other states would be jealous of our situation. And it's really getting tougher working on and finding them and producing them.

We do have some issues to overcome as we've heard from many speakers, there's a lot of barriers to successful development whether it's access issues, distance to market, transportation issues. But we can work through them and we have as a State and I do feel that we will continue to do that.

So my focus today is on the fiscal issues and the taxing authority and that's another way that we as a state can affect the business climate here in Alaska in this sector through our taxes and our fiscal policies. And I do feel this change in the PPT legislation has brought new incentives for exploration and development and investment to Alaska and additionally, it's often overlooked, it has preserved and extended other incentives that already did exist and were on the books for even a longer amount of time.

So if I can begin with the first slide here. I guess I need this little gizmo. What I've outlined here are some major benefits that I see from the PPT legislation. I've -- I'll read through them quickly and as I go through my presentation I'll elaborate more on them. So I see new cash flow benefits to explorers and investors, low to zero production tax at low energy prices, enhanced risk sharing by the State, increased incentives for oil with high production costs such as heavy oil, protected Cook Inlet production with an ELF ceiling, improved benefits to new investors.

And here on the next slide I continue, added new area development credits of $6 million, extended the duration of existing oil and gas exploration credits, created more incentives for reinvestment in Alaska, provided options for tradeable and reimbursable tax credits and established a small producer tax credit of up to $12 million. So these are 11 very large and important things that are contained within the PPT legislation that I identified. There are even more than this, but these are ones that I want to focus on that relate to this topic I feel today.

On the next slide I put here we heard a lot of debate, the benefits of net over gross and this became a very hot issue during the special section and obviously both forms do have their positives and negatives. But really the State does have a very comprehensive gross system, the royalty which provides about half of our oil and gas revenues already, the ELF ultimately provided incentives for diminishing profitability in declining fields, but it was really a proxy for costs and the costs associated with those fields.

And the PPT, in my mind, the net, is really more of an actual cost basis and therefore more effective in determining what the real cost of production is in those fields and therefore getting a proper tax rate assigned to that production. And how it does that is that you can deduct your qualified capital and operating expenses from revenue. So what this means is as costs go up relative to your profits on the fields, the net tax paid will be less.

And I'm going to skip one bullet there down to what this means for heavy oil. This significantly benefits high cost production oil such as heavy oil which I really think is going to be critical to the future of the state of Alaska. And how it does that is when you have this high production, high cost oil you're going to receive more deductions, more credits for that high cost production. So it offsets going after that high cost oil. And alternatively as costs decline you can see on the last slide this net system adjusts easily to these changing economic circumstances.

So to give you an example, let's imagine you're going after some heavy oil that has this higher cost. Early on the net PPT effect is going to be is you'll have more deductions because of that high cost of production, more expenses mean more deductions. But let's say technology changes and over 10 years technology greatly improves in the type of field that you're working on and now your costs decline. Well, this system adjusts rather automatically to that, this lower cost of production will mean lower credits, lower amount of deductions and therefore the system adjusts and I think this balance will be very important. There's not as much time delays and there's not much complicated formulas such as in our ELF trying to continue to incentivize declining fields.

And ultimately one of the benefits I see overall is three up from the bottom there, creates more incentives for reinvestment in Alaska. I'm going to get into this more in detail in the next few slides. One of the reasons why I see more reinvestments is the cash flow benefits. Ultimately what we've done is back end loaded our production taxes and we heard just now about the time value of money, everyone, I think, understands that concept. By doing this really conceptually and how I see the PPT working is that early on you're taking the risks in your production by exploring in what may end up being a dry well. And there's a lot of considerable costs in that early exploration. And if it's successful later on you have production and that production earns revenues and you have a positive net present value and that's when you start to see the return on your investment. So your tax payments are lower during your initial capital outlays and then higher as your production responds to that investment.

So it really creates a logical time line for when you pay your taxes, but at the same time there's additional time value of money benefits there because you can monetize some of these credits and deductions earlier on. So for instance, and I'll get into them in more details, if you have a lot of unsuccessful finds and we hope no one here does, that you have additional costs related to those, that means additional deductions. And because of the way some of these credits work, I'll explain in more detail, you can actually monetize them, you can trade them or maybe carry them forward into the future, whatever works best for your financial situation.

So really you're getting some cash back earlier on and there are some limitations, but I'll get into that a little bit later.

The risk sharing by the State, ultimately there are several components to that, but what I'm showing here is they allow you to deduct your exploration cost expenses for unsuccessful wells which are really written off against your successful production. So let's imagine if you're an existing producer and you have some existing production that you're paying your production taxes on, if you start a lot of new exploration and there's cost associated with that, you can write off the cost of that exploration against your current production.

And this is -- ties in directly to what I mentioned earlier, the reasons for more reinvestment potential in the State, you have a good reason now to offset your current production with new exploration and therefore you create a lower tax payment. And the State is, in effect, sharing risks in dry holes through doing this so that investments here in Alaska may be superior to what your options are in other parts of the world. And we mentioned earlier that there are limited budgets here so one of our international consultants, Pedro Van Meurs has driven this point home quite a bit, that what he sees as one of the most successful ways to encourage reinvestment in a State is through tax deductions and tax credits which give you a greater reasoning for investing here over somewhere else.

So we really think that this is going to ultimately lead to a change in the way companies look at their strategic planning for the State of Alaska and then ultimately that increased exploration will lead to more investment and more production in the future. And that's really kind of conceptually a goal here.

So similarly that would -- how it would be affecting a new investor. Your dry hole costs are reduced through credits, you can then monetize those losses. Let's say you have no finds, but you have these loss carry forwards or credits for capital expenditures, you can actually monetize those and get some money back so your ultimate expense is lessened by this type of new PPT tax. And so the state can actually even qualify certain cash refunds up to a limit for smaller producers. And I do get into that new the end of the presentation.

So what I've talked about so far has been conceptually what I see as some of the major benefits of this PPT change. And now I want to get into some of the specific provisions of the law. You can see here at the top where I mention the title, these are all going to be Title 43 if you're interested in looking into it. This particular one is .160 and that reference if you want to write them down at the end, I have a website that I'll give you so you can look into these specific issues in more detail.

For the interests of time I can only explain so much and this will give you the opportunity if one of these topics is of great interest to you, now you can know exactly where to find it in the law.

So to start with I think it's very important to discuss that the PPT legislation has four specific areas in the state and they are treated somewhat differently. It could be related to certain credits or incentives within the bill. So ultimately there's the North Slope both for oil and gas which is north of 68 degrees latitude. Then there's Cook Inlet oil and Cook Inlet gas have separate clauses in the bill and that's in the Cook Inlet sedimentary basin. And then the rest of the State, so areas not in the Cook Inlet or the North Slope.

And let me give you an example of one of those that I was talking about. This is for the Cook Inlet, this is for the ELF ceiling. This ELF ceiling is a very important part for people producing in this region. What you're looking at here are previously producing leases in the Cook Inlet area are going to be based on an ELF baseline that's going to go from March of 2005 to March of 2006. So that baseline is then going to be your rate going forward into the future. And it -- the way that new leases after 2006, after March are treated are slightly different and basically all that happens there is you take an average of current existing leases and what that average is then applies to future. So in both cases there's now a ceiling established.

So what that means is that your taxes will never be higher than this ELF baseline. So for once again strategic planning purposes or accounting purposes, it's always great to know what your upper limit is going to be and then you know what that is. So for the example, you have a certain on maximum payment. If you're calculating what your taxes are going to be for production in the Cook Inlet and you have this ELF baseline and then your PPT rate comes in higher than, you only have to pay the ELF ceiling.

If your PPT comes in lower, you pay the lower amount, you pay the PPT amount. So you really get the best of both worlds in this scenario, you know what your upper limit is and if the PPT happens to be lower, which it could in some cases, you have to pay that lower amount. And so I think is a great incentive or issue related to the PPT legislation, this is good through 2021.

On the next slide we talk more about some of the specific credits. This here is a new area development credit and this is the rest of the State region that I mentioned, the fourth district not in Cook Inlet or the North Slope. So, for instance, I'm very encouraged by some of the lease activity on the Alaska peninsula and also exploration licensing activity in other areas, maybe say the Nenana basin. These areas could apply for this new area development credit and this is an incentive contained within this bill that will help look for more exploration in other areas and hopefully new districts in the state and expand energy capacity in other areas.

What this means is qualified producers in this rest of the State area can apply for a credit of up to $6 million against their production taxes and this incentive is effective until 2016.

The next one is the small producer tax credit. Now this is contained subsection .024. What this is, I wouldn't consider it small production, but production of less than 100,000 btu equivalent barrels a day can apply for a tax credit of up to $12 million and this is also good through 2016. So this new term btu equivalent barrels, a barrel of oil is a barrel of oil, but the gas is converted into what would be considered a heating value of 6 million btu is considered an equivalent barrel. So your company's production on a daily production rate is calculated and then applied to this credit formula.

Basically if your daily production is less than 50,000 btu equivalent barrels, you get the whole $12 million. If not, if it's higher up to 100,000, you apply this formula, it's pretty easy, you just need to know your production and you plug it into a couple quick algebraic calculations there, it's fairly simple. At 60,000 you get 9.6 million, at 75,000 you get half, about 6 million of the credit up to 100,000 and over you do not get this credit. So this is another incentive for smaller producers though I think that's a good amount of production.

The exploration tax credits have been extended to 2016. These are some -- these are tax credits that were originally introduced, I believe, in 2003 in Senate Bill 185 and then later amended in a House Bill last year, 2005. They were good until 2010 and now they've been extended six more years within this legislation. What these are 20 percent credit for exploration wells and for wells no more than three miles from an existing well. And the Cook Inlet is treated somewhat separately because of those revisions.

You can -- if it's closer you can get a statement that certifies that it's a separate target from the State. And then another 20 percent for wells more than 25 miles from an existing unit. And that is, I believe, 10 miles for the Cook Inlet now. And if you qualify for both conditions you could get a total of 40 percent credit. And additionally there's a 40 percent credit for seismic operations that are not associated with a well.

I've got two more here to go, sorry I'm going through a lot of information, this is a very comprehensive bill and I'm trying to get through it in a quick amount of time.

But tradeable capital investment tax credits, what these are 20 percent tax credits for qualified capital expenditures. If they're unused you can -- they can be applied in future years and they are transferable and even re-transferable with a certificate from the state. That is a great benefit, I believe, if it works out for your situation. And smaller producers of less than 50,000 btu equivalent barrels can apply for a cash refund if they meet certain commitments and, hopefully, such as not leaving the state and other aspects.

What this really means in sum is that it's very flexible, these tax credits are good for a wide variety of circumstances so whatever might be best for your company, you know, you might be interested in cashing them out and get those net present value benefits, the cash benefits up front, you might be in negotiations and want to trade them with someone who's got a lot of production or you might want to hold on to them for a rainy day, maybe next year when you feel you might have more production. So really it fits best to your circumstances.

And the last one here I'm going to go over is the transitional investment expenditures or TIES as they're referred to. This one here if we talk again conceptually about the PPT, what we're talking about is you're taking a risk, you're investing in the State, you're exploring, you have a lot of cost up front and you get these credits early on and then later on when you get to production, you're successful, you start paying the production taxes and the State is compensated at that point.

Well, the issue was raised by industry that what happens about the investments that we've made over say the last five years where we've spent a lot of money in the State and now were paying production taxes for production that's starting right now, but we didn't ever get compensated for the credits. This is a way that you can overcome that. What we're talking about here is a pool of investments going from March, 2001 to 2006, for qualified capital investment expenditures that were made over the last five years.

So what you do is, I'm going to give you a quick example here, sorry a little math at the end of the day, but ultimately let's say you're $100 million investor of qualified investments in the State and over this five year period you make a level amount of investment so you've made $500 million worth of these type of expenses over the last five years. You can take 20 percent of that so you're back down to -- I'm sorry, I might have been saying the numbers wrong here. $100 million a year, five years, 500 million, take 20 percent of that you're back to 100 million. So these are your TIE pools that you -- this is a pool of credits that you can use going forward. And then you have until 2013 to utilize them before they expire. So you have a seven year period to utilize these.

Well, let's -- then the next rule is you cannot exceed 10 percent for any one year. So if you take 10 percent of that 100 million -- you can't use more than 10 million, 10 million times seven years you're back up to 70 million. You had a pool of 100 million available, but you've only utilized 70 million of them, you've left $30 million on the table. So I've been in a lot of tough car negotiations and one house negotiation, but I never left 30 million on the table I don't think, but I'm not sure how much. But in this case how do you get the rest of the money, how do you get that other $30 million in credits that you left behind.

Well, you do what we were hoping you do, you reinvest more in Alaska, you increase your CAPX expenditures and the math works out that you need to increase them by a little over 40 percent. And if you do so -- let's look at this example again, your 100 million goes up to 140 million in expenditures, now you get 10 percent of that, that's 14 million, 14 million times seven years is 98 million. So now you can use 98 million out of the 100, that's at 40 percent. So you leave 2 million bucks on the table, but you're getting a lot closer.

So ultimately that's how these work in a nutshell, it's very complicated, but the net benefit is that if you have 20 percent regular expenditures you can get another additional 10 percent of your TIE credits used, you could get a total of 30 percent possible which is a good benefit in my mind.

So, in conclusion here, I told you that there is a web site, you can go to the BASIS system, it's at the legislators' home page there, you can see at the very end it says HB 3001(z), that was the enabled and enacted law. There's a good PDF file if you want to download it and look at any of the subsections that are referenced in my presentation, this is where you can get the legalese and the actual what qualifies and what exemptions there are, et cetera.

And I also put down a DNR web site on programs and incentives. There are a lot of other incentives that are unrelated to this PPT legislation that are included on their website.

And I think that's a good transition to our next speakers because I've talked to you really conceptually about this bill and there's a lot of information, I've tried to give you some specific provisions, but nothing works better than an example and the next gentleman from DNR, a respected analysis there, someone I've worked for the last several years here, William Nebesky, someone I've learned from. And I think in the next 20 minutes or so I'll continue to learn with a good example. So, hopefully, all the legislators in the room I explained this correctly I hope, and we will look forward to seeing this next presentation. Thank you for having me.

COMMISSIONER SEAMOUNT: Thank you, Mark. Okay.

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WILLIAM NEBESKY and GREG BIDWELL

COMMISSIONER SEAMOUNT: Our next two presenters are William Nebesky and Greg Bidwell. I've already read William's bio earlier and I'm not going to risk reading it again. But you all know William by now.

Greg Bidwell is a commercial analyst with the Department of Natural Resources, Division of Oil & Gas. Previously Greg Bidwell worked as a petroleum economist and as a Special Assistant to the Commissioner within the Department of Revenue. Before joining the state he worked as an attorney on the state of Alaska royalty and tax matters. So, please, welcome William and Greg.

MR. NEBESKY: Thank you again, Dan and Commissioner Norman. I'm Will Nebesky, I'm going to lead off here and then pass the microphone to Greg Bidwell. What we thought we would do is continue to focus the discussion on the PPT. And because the devil is in the detail applies so appropriately to this particular piece of legislation it may actually be productive to step through an example. So that's our intent here.

Before doing so I would like to just review a couple of the basics. We're not going to try to cover all the territory that's in this enormously complicated fiscal package, but I do want to cover some of the things that Mark gave some insight into as well. And then I'll turn it over to Greg and he'll walk through an example. And incidentally the example we're going to look at is a static, one time period example where -- we don't want to attempt at this stage in the game to put a time dimension to the analysis, but that is something, of course, that we're working on internally and I know the folks in the Department of Revenue are as well.

The -- there's just a couple of key elements I want to review in terms of establishing the framework for the PPT. It's a tax on the producers net upstream income. What's called the production tax value which is the gross value at the point of production, a net back concept, minus upstream lease expenditures. To that net upstream income concept is applied the PPT tax rate of 22.5 percent. That's applied to the production tax value.

There's also in the background a minimum tax calculation that's going on simultaneously that basically generates a sliding scale tax rate increment when -- that's applied to the point of production in the event that prices get extremely low and that the PPT mechanism is basically zero. So there's a floor that's established in the mechanism, this minimum tax, that applies only to the North Slope area. Cook Inlet has its own special provision that substitutes for this minimum tax point.

Additionally, there's a supplemental progressive tax that is applied to this production tax value. And essentially if price exceeds a threshold amount then there's incremental tax rate amounts levied onto the 22 1/2 percent base tax rates. And it turns out to about a quarter point per dollar of value above a threshold.

Finally, there are the credits that are built into this mechanism and there are several. We'll talk about them very briefly, but I think again it's most helpful to see them in the context of an example.

The -- couple of other quick points. The PPT is -- differs by area as Mark enumerated and very importantly in the case of the North Slope oil and gas are rolled together so there's a single tax rate for these combined energy commodities. And secondly the tax is levied on a company basis so it's a major departure from the existing -- the former production, the ELF based production tax which is a field based mechanism.

And then there's a PPT tax liability in Cook -- the PPT tax liability in the Cook Inlet is capped for oil and gas respectively and separately and that's done on a field basis. So there's some complications that interweave the field based calculations in this mechanism for Cook Inlet in connection with this cap and the company based PPT calculation.

The new areas, as Mark indicated, get their own PPT and it pays to be a small producer in this particular legislation again as Mark pointed out.

So the building blocks, putting them all together we have this concept of gross value at the point of production, lease expenditures which are subtracted from gross value at point of production to get a production tax value. And that's what the tax rate is applied to. There's a minimum tax that's calculated in the background in case the basic tax is -- doesn't apply. And this -- and in the case of the Cook Inlet a cap is substituted for the minimum tax.

There are credits that are available and they're both -- you can classify them as transferable or tradeable and non-transferable. The transferable credits include the qualified CAPX capital and loss carry forward credits. The non-transferable credit are the small producer credits, the new area credits and transition investment credits.

This cap mechanism that is specific to the Cook Inlet is basically a ceiling and as Mark indicated the PPT, the basic PPT, can't rise above this ceiling, if it does the ceiling controls, the ceiling becomes the effective tax. And this ceiling is anchored in the ELF and values that were generated in the prior year, in this case approximately in the 2005/2006 time periods. So those become fossilized in this mechanism and apply to this cap calculation even for production going forward in years beyond this, of course, recent historic period.

The cap applies, again, to oil and gas separately. It applies to the base PPT liability plus the progressive element, they're combined and then they're compared to the cap to determine which was is the controlling. And again the cap establishes a ceiling, if the PPT, the base PPT liability plus the progressive element that is driven by price exceeds that cap the cap controls and that becomes the tax liability.

Finally, the -- one of the things that makes the PPT mechanism so complicated is a number of the interdependencies that are weaved through it. And with -- in particular with the treatment of the credits. If the tax cap is effective for the Cook Inlet Basin, okay, then that implies some kind of savings is generated vis-à-vis the alternative base PPT plus progressive element. And if there's some savings generated because the cap is effective, those savings actually can place limits on the treatment of the credits. So that's the point here that certain transferable credits are limited by savings with the cap is effective. Other transferable credits are not. So it probably will be a little bit clearer when you see how this works in the example that Greg's going to step us through.

I know this is too far away for you to see, but for those of you that have the handout we presented there is a flow diagram that kind of ties together these elements in kind of a logical flow that gets you to basically the net tax liability for any particular company. And the elements that Mark and I have described in sort of establishing this framework are enumerated in the flow diagram here.

So I'm going to turn the mic over to Greg, he's going to sort of setup the problem and step you through how the PPT might work. And I'm going to stand aside and use the laser pointer to point out particular elements in the tables that Greg is going to walk us through. Thank you.

MR. BIDWELL: Hi. Well, I hope you had a good year in 2005 because every time you file your taxes, you sit down to do your taxes in the Cook Inlet over the next 15 years, you're going to be reminded of your 2005 year.

This example -- in this example we're going to look at four fields, you're going to pretend like you're a producer in four gas fields. And these fields are called Field A, Field B, Field C and Field D.

These fields have an ELF, a current gas ELF ranging from zero to .68. This ELF is the ELF in 2005. 2005 price received in each of these fields for gas is $3.50 per Mcf. So you have the gas ELF in 2005 established, you have the 2005 price received at $3.50 established, and those facts will remain with you over the next 18 years when you think about what your Cook Inlet tax liability will be.

The variables that will change in the current year which we'll call Year T which is sometime in the future, from now until 2022, will be the price you receive for the gas, the actual price you sell the gas for in Year T sometime in the future. That can change, prices go up and down, changes.

The capital expenditure that you had in Year T which is also variable, you can imagine investing less, you can imagine investing less. And your volume -- sometimes your gas volumes they could decrease over time. Sometimes you may find some new gas wells and they might increase. So let's get to Case 1.

Case 1 is establishing sort of the parameters for your tax cap. And your tax cap will be basically salvaging a cap on a per unit basis, a dollar per unit basis. You use the same effective tax rate and the same price, the price you pay -- you received in 2005. So your stuck in sort of a ground hog year, every year is 2005.

So in Field A you will be paying 24 cents to Mcf in this example which is the tax rate of 6.8 percent, the effective tax rate, multiplied by the dollars per Mcf in 2005 of $2.50 gives you your tax cap per unit which is sort of a way of thinking about it. And in this example of -- with the volumes that I have, I've added five additional units of volume to each of your fields. You have a tax cap expressed in millions of dollars which has gone up a little bit from what your 2005 tax liability would have been because you're producing more volume. But on a per unit basis your tax cap remains the same.

Okay. Let's move to some other current information like what you sold it for. And what the PPT calculation would like if, for instance, prices rose. So we go to our next slide and here we assume a nice future period where prices have risen to $8 an Mcf. We also assume that you're spending $30 million in CAPX which you see is right there. And we assume that you have -- like in the prior example, you have -- each of your field have had 5 additional Mcf of volume growth. And here we calculate -- we go through the process of calculating your PPT liability as if there were no cap.

And we see that your base tax liability, your 22 1/2 percent plus your supplemental tax liability, your -- the progressive element which adds a couple percent to your tax rate, gives you a total PPT liability of around $46 million. Your taxes have gone up. But the tax cap serves to protect you from the risks that you will pay higher taxes if the price of your commodity that you sell goes up.

As pointed out in the next slide what you do is you compare your tax cap liability that we computed in the first slide with your total PPT liability that we just computed -- we just looked at and then we take the lower of those two to come up with your PPTBC or PPT before credits. And as you see your tax liability is $10 million not that $46 million number we saw before and you have saved $36 million because even though we're in the future and the gas price is $8, you're still paying taxes in a world of 3.50 gas. So you're protected from higher gas prices -- paying higher taxes because of higher gas prices.

Next we go to consider these credits. You receive these credits in addition to receiving a capped tax and this -- these credits are your CAPX credit, your qualified capital expenditure credit. That's 20 percent of your capital expenditure, in our example that's around $5.7 million, slightly less. There's a 30 cents per barrel exclusion that's -- and in this sense is $6 million, you get that CAPX credit even though you're paying taxes on a fossilized pricing ELF, the tax credit still applies because we're encouraging new investment. There's no loss so there's carry forward credit.

We're assuming in this example to make things simple that there's no 025 (ph) or no -- we call it a 20/40 transferable credit, but it's the exploration tax credit. And the small producer credit will attach to the production year if it doesn't amount to 50,000 barrels of oil equivalent and so you receive your small producer credit of $12 million. This is non-transferable, it's a use it or lose it tax that you use to extinguish your $10.1 million of tax liability. Your tax liability for this year is zero with the credits. In a way you get a nice tax break.

Now let's go to another not so pleasant example. Assume that the price instead of going up like it should goes down to $2.50 per Mcf. And let's assume that capital expenditures while they're higher than -- or for some reason you spend more and you're spending $60 million a year. This is sort of a stress case, this is a low peak production tax value case. So we do the calculation here of what your PPT liability will be and you see that the PPT liability -- total PPT liability is pretty low, $3.6 million because your PTV is low, low price, high costs. And then we go and compare that to the tax cap and we see that you haven't saved any money by having the tax cap because your PPT liability is below the tax cap. So as prices go down the tax cap provides you less relief. But still you -- you're getting some relief from the lower PPT liability.

But that is not -- that's only part of the story. Whenever you think about the PPT you have to go to your credits. So here we have your credits and you get a CAPX credit, a very healthy one because you're investing more in our example. You get a loss carry forward credit now to some extent because for some fields you're actually losing some money. And you still continue to get your small producer credit which you use to extinguish the tax liability that you have.

So, in general, you can do a table here and that's what this summary of PPT possible effects does. And we've varied these variables to see what your tax cap savings are and what your credits are, your transferable credits are after all is said and done. And what you can see, I think, is that the PPT bill is a great deal for the Cook Inlet, that your -- that only in the example where you have mid level prices and higher production do you see a possibility where your -- you would be hurt versus an ELF based system.

And why is that? It's because the ELF you're paying by field is based on what your ELF was in 2005. So -- and your production -- so if your production went down, if your -- you still would be paying for a given field, you'd still be paying the same -- you'd still be paying based on the higher ELF, your cap would be based on that higher ELF.

I just want to go to the conclusion, I guess, now which is just to say that in general your PPT tax burden will be lower, that you're going to find that you're not only getting the best of all possible worlds, but that you're getting -- you're basically getting the world that you're living in now in 2000 whatever in Year T versus 2005. And there's a small point you can lose some of your transferable credits if you have excess tax credits, there's a provision dealing with that provision and that will occur only if you have like .025s, you have .025 credits you can lose some of them, but in general the PPT tax bill is a real boon for the Cook Inlet. Thank you.

COMMISSIONER SEAMOUNT: Okay. Thank you Greg and William, very informative talk. That was the last talk of the day. Tomorrow we're going to touch on some more of the energy alternatives, we may not be doing, you know, the other ones justice, but that could be -- those could be a topic for a future meeting where we'd get into more detail on some of the other alternatives. There's at least 16 that will be discussed tomorrow, two or three of them were already discussed today and they'll be touched on some more tomorrow.

We're supposed to -- let's see, we've come to announcement and, John, did you have some announcements?

CHAIRMAN NORMAN: Yeah, thank you very much, Dan. Just touch on a few things. First of all those of you that have stuck with this throughout the day, I found this to be quite a tour de force and a lot of information put out. And let's give all of the speakers a round of applause, what we've seen is the tip of the iceberg. Every one of these presentations took a lot of work and time for people to put into it and I want you to know we do appreciate it.

What have we learned, I mean, what have we learned today as we go through here. I think some things stuck with me. I think we are at a point right now where life as we have known it here in this region is never again going to be the same. I mean, that's a pretty forceful statement I suppose to make, but I've been here and looking back on what Tom Kelly and others said and the Cook Inlet we have known and the surplus of gas, it's going to be very interesting. There may be some things that change, but I think that we are right on the threshold of that change as we move forward.

We tried today to probe this. If you accept my analogy of the elephant, we tried to bring in the wise men all blind, but everyone asks them to push and probe and smell and tell us what's there. And we're all necessarily blind because we see things from our own lifetime experiences and our own disciplines. And we also are creatures that cannot look into the future. Tom Kelly, Bill Van Dyke gave us a good look back over 50 years, but no one can look forward in the next 50 and tell us how it's going to be and yet that really is what we're trying to discern here is what is the energy outlook for this area, what decisions need to be made, what advice and what requests can we make of our legislators and our elected officials.

And as Mayor Williams said this morning when he began, the time is getting shorter in which we have to make these decisions. Governor Murkowski saw a problem and I'll use the word problem although challenge, say it however you want, but we have this creature out there that I've called the elephant and we've been trying to identify it. And once we identify it we've been trying to figure out then how do we move forward and deal with it.

We heard some excellent remarks from a number of the opening speakers, Dr. Charles Thomas gave us a terrific overview of the Cook Inlet Basin. Dr. Arlon Tussing I thought was particularly candid for someone of his years of experience in saying he has never seen an economic gas projection of gas prices that was right in all his years of work. And that's probably very true if you think about it. I think you can hint around at it, but it illustrates the fact that we are like blind men trying to look into the future and discern out beyond the area where we really can't see what will unfold here.

Bill Popp gave a terrific presentation. We then next had the panel of the three utilities. They have their perception and they do see -- they were able -- they showed us the graphs and it looks like a ski slope going down as our gas supplies fall off.

We had then an interesting perspective from ConocoPhillips, Scott Jepsen, who said well, there isn't really a shortage of gas, but you're just going to have to be prepared to pay more. And I don't mean to try to distill their remarks, but I'm giving you strictly -- and I'm not even speaking for the AOGCC, I'm just kind of trying to think what did I take away from today.

John Zager, I thought, gave a terrific presentation and he gave an overview and to me it was heartening to see the amount of activity projected for Chevron in the Cook Inlet Basin. And it was, you know, almost inspiration to see Aurora coming in as a very small operation and probing out and again finding gas.

We had a real good presentation in the afternoon on the infrastructure, those pipeline platforms are older out there, something's going to have to be done with them, but as Commissioner Dan Seamount has said a number of times, they represent valuable infrastructure though and it would almost be a tragedy if they were decommissioned and moved in someway that they're not available until we know that we have fully probed the potential of that basin.

And I'm still waiting to hear from other speakers that we'll have tomorrow to see just what degree we have explored that basin and what potential remains out there.

Gas storage is new to us, but it does offer some hope to kind of flywheel operations and get us through some of these peak periods.

And then the question has been asked what is it going to take to stimulate more exploration. And I think we had a good presentation on some possible taxes and incentives and there might be some others.

But in the final analysis what I took away from today is that the world had changed, it's not the way it was 40 years ago now. The reserves are not there, how alarmed should we be about it? At that point it depends on which one of the blind men that talked today you want to believe. And I say that with no disrespect, I think they are -- they're the best, smartest people we could bring to bear on this, but we're trying to delineate this potential challenge that we have and each person looks at it from a slightly different direction.

Dan talked about tomorrow's program and I hope that you all will be here at the start of it because there are a couple of very interesting studies that are overviews of what are our energy alternatives. And they're far ranging and some of you might be sitting there thinking what about wind power. So there will be some discussion on that tomorrow as an example and other things as we kick off. There will also be some very good presentation on the resource potential of the Cook Inlet Basin going forward as we move into the next 50 years.

And then the second part of the morning will be on exploration, new comers to this basin and we'll get their perspective on what potential they see for the basin and the extent to which they want to share their plans with us.

We all know one option that's been considered is a spur line off of any gas line and we will have a presentation by Harold Heinze and then Dr. Charles Thomas that will discuss and analyze that possibility.

Coal, we heard from Agrium and I think again I'm trying to be real candid, I leave here today encouraged that Agrium is moving into the second phase of the study because if that does go forward from what we have been told that could be a potentially huge project, monetarily and in terms of jobs for that facility. I would have liked to have had a little more detail on -- this is exactly what we know now, I thought they were probably properly guarded and I hope some of us can pull them aside and say can you tell us a little more because that's an important shoe that has to drop, we've got to figure out coal gasification, feed stock, what is the ability to contribute to our electrical generation facility.

And until that other shoe drops it's a question mark that hangs out there. But Agrium was, I thought, very generous in coming forward and outlining what they're able to say now and hopefully we -- as this moves forward we'll be able to learn more about that.

The whole subject of coal will be discussed tomorrow, coal gasification, liquefaction, a representative of Usibelli will be here and Pacific Rim. And then we'll finish up the afternoon and we will finish on time, I promise you, but we'll use the remaining time with a panel discussion to get a number of blind men together and each one of them describe this elephant that we've all been trying to discern.

Tomorrow morning the doors will open at 7:30, coffee will be ready and then we'll kick off at 8:00 o'clock or as soon thereafter as the facilities are up and running here. And we'll move along briskly tomorrow.

At lunch tomorrow we purposely left it open so that you'll be able to get back to your offices, check messages, attend to things, and then return for the completion of the program.

If you have any things that you have marked your own notes on or handouts that you want to retain, which we hope you'll take with you, do take them with you. There are bags that were generously provided by the Alaska Convention & Visitors Bureau for that purpose. And go ahead and load it up and take it with you. Other materials that are left behind here we will collect and they'll be then available for distribution tomorrow. If something's obviously trash it will be gone, but don't leave any of your personal belongings in here because we don't have any way to safeguard them.

Thank you all and thank you and we'll see you tomorrow morning.

(Recessed - 4:45 p.m.)