aside of at least 10 percent of the gas sold under APL-5 come from smaller independent gas producers and that it be sold on the same terms as are enjoyed by the primary seller.[102] Sales by small producers to the ENSTAR market on the same terms as are provided for in a primary seller contract will create economic incentive for exploration and production companies to risk investment capital in gas projects in the Cook Inlet Basin.[103]

<u>Comments by Non-parties</u>

A number of interested individuals and entities commented on APL-5 after issuance of our public notice. While these individuals and entities did not participate in the public hearing, we consider their comments important to our review.

For example, C. Grey objected to the production and transportation costs that would be paid to the producer.[104] Daniel Donkel urged broader competition and asked that the RCA assure that competitors be given a fair share of the ENSTAR gas market.[105] Gregory Micallef requested a 25 percent set aside gas market for smaller producers to encourage new competition amongst major oil companies and mid sized independents.[106] G. Scott Pfoff, the president of Aurora Gas, LLC, cited the commission to two major areas of concern with regard to APL-5: (1) a potential negative impact on exploration and (2) a negative impact on the Moquawkie Contract that Aurora has with ENSTAR.[107] AARP asked that the gas pricing provision of APL-5

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[102] *Id.* at 2.

[103] *Id.* at 3.

[104] E-mail from C. Gray to RCA, filed in TA139-4, December 12, 2005.

[105] Letter from D. Donkel to RCA filed in TA139-4, November 28, 2005.

[106] Letter from G. Micallef to RCA filed in TA139-4, December 23, 2005.

[107] Letter from G. Pfoff to RCA filed in TA 139-4, December 22, 2005.

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be investigated including the appropriateness of the index to which the prices are to be tied, and other price components.[108]

Standard of Review

ENSTAR asked us to find that APL-5 is in the public interest and allow the costs that ENSTAR incurs under the agreement to be recovered in ENSTAR's rates.[109] ENSTAR's focus in this proceeding was on supply. "ENSTAR's main focus is having a secure supply of gas now and in the future." According to ENSTAR, that's the main issue for its customers and Southcentral Alaska.[110]

We believe ENSTAR's position that supply is the "main issue" does not give enough weight to the cost of that supply. ENSTAR ratepayers, not ENSTAR, bear the cost of natural gas supplies that ENSTAR's obtains in its negotiations with the gas producers.[111]

The AG observed,

> "[f]irst, to be consistent with the public interest, any proposed GSA must help provide ENSTAR with a reliable supply of gas. And second, gas sold under APL-5 must be 'reasonably priced.' Both requirements must be met, and a finding of reliability does not trump the need for ENSTAR to also show any proposed GSA is "reasonably priced".[112]

We adopt the Attorney General's observations as our standard of review because it achieves the proper balance between the needs of the utility and the needs of the ratepayers. We will approve APL-5 if we find that it achieves a reliable supply at

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108 Letter from AARP to RCA, filed in TA139-4, December 22, 2005.

109 *ENSTAR's Issue Statement and Witness List*, filed June 28, 2006, at 1.

110 T-8 (Dieckgraeff) at 26.

111 Tr. at 205.

112 *Comments of the Attorney General,* filed in TA-139-4.December 22, 2005)

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a reasonable price. Only if both of these factors are met can we find that APL-5 is in the public interest.

Discussion

In the words of ENSTAR's witness Goldsmith, these are times of "unprecedented market uncertainty" in Cook Inlet.[113] Indeed, we cannot predict from the record presented by the parties whether, in the next decade, Cook Inlet will continue to export gas, as it has for almost 40 years, or whether it will import gas, or both. During the latter years covered by APL-5, ENSTAR's customers could, for example, burn exclusively local gas or a mixture of local gas and foreign LNG or even North Slope gas.

We realize from the record that ENSTAR's alternatives for gas supply today in Cook Inlet are limited. The many transportation options and availability of multiple suppliers that exist in the contiguous 48 states are not present in the Alaska market. ENSTAR witness Izzo stated that from a long-term perspective there are three other ways to bring gas to ENSTAR's pipeline system, coalbed methane, conventional gas from interior basins, and import of LNG.[114] On the possibility of North Slope Gas from a spur line, Izzo stated, "[t]he earliest that North Slope gas might be available to ENSTAR would be right around the time that APL-5 expires, approximately 2016, and that's only if everything goes perfectly."[115]

ENSTAR witness Goldsmith testified that the concern over the fall in Cook Inlet gas reserves led us to approve the Unocal and NorthStar contracts.[116] Marathon informed us that it has taken deliberate steps to prove up gas reserves in response to

[113]T-6 (Goldsmith) at 3.

[114]T-1 (Izzo) at 16.

[115]T-2 (Izzo) at 6.

[116]T-5 (Goldsmith) at 18.

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the perceived market signals given to gas producers with ENSTAR's Unocal and NorthStar contracts.[117] Marathon stated it spent substantial sums of money since 2002 which clearly demonstrates that Marathon "reacted in the same way as Unocal and NorthStar to find and develop Cook Inlet gas."[118] Goldsmith explained to us that new fields have been discovered and brought into production and production companies that are new to Cook Inlet and Alaska have been exploring for gas.[119] ENSTAR states its experience with paying higher market-based prices has resulted in Unocal finding over 130 Bcf of gas it committed to ENSTAR.[120] ENSTAR believes that unless new reserves are discovered, it will soon not have enough Cook Inlet gas to meet the needs of the community.[121]

ENSTAR's case in support of APL-5 is based on an assumption that ENSTAR's current ratepayers should, by themselves, pay prices for natural gas high enough to incent future exploration and development in Cook Inlet. Among the recitals in APL-5 is one that reads:

> WHEREAS, Buyer believes that it is in the best interest of its customers to encourage and promote additional Gas exploration and development to meet the Gas demands of the Cook Inlet in 2009 and beyond;[122]

It is evident from that recital, as well as ENSTAR's testimony in support of APL-5,[123] that ENSTAR's case hinges on the assumption that it would be acceptable for its ratepayers to pay more for gas than others pay in the belief that paying extra would help Cook Inlet

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[117]T-9 (Webber) at 3.

[118]T-10 (Webber) at 4-5.

[119]T-5 (Goldsmith) at 17.

[120]T-8 (Dieckgraeff) at 10.

[121]T-1 (Izzo) at 3.

[122]APL-5, at 1.

[123]T-8 (Dieckgraeff) at 9.

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exploration and development along. While it may be advantageous for a public utility's shareholders to promote specific kinds of economic development, we cannot allow ratepayers to bear the cost of this laudable goal alone.

Ratepayers should pay the going price in the regional market from which they buy, a price that secures for them a gas supply with the appropriate swing they need. They should not be required to pay a premium to achieve general economic goals, although it might be acceptable under limited circumstances to acquire particular supplies.

Ratepayers want gas at the lowest price they have to pay to get it. While as Alaskans, they may prefer gas from nearby fields, which benefit the state and local economies, as ratepayers, the price of gas is more important to them than its place of origin. If foreign gas from a reliable source is cheaper, a public utility should not force its captive ratepayers to pay for more expensive, Alaska gas. At this time, foreign gas is not an option for ENSTAR or its ratepayers but, in the longer term, including many of the years covered by APL-5, that option is viable.

The exploratory activity we believed that would lead to additional Cook Inlet reserves as a result of our orders in Unocal and NorthStar has not materialized. In the United States as a whole, the reserves-to-production ratio has historically been about 10:1. In 1970 in the Cook Inlet, it was 30:1.[124] By 2002, the reserves-to-production ratio had fallen to 10.7:1, close to the rest of the U.S. gas market.[125]

ENSTAR stated that January 1, 2006, reserves compare unfavorably with the Department of Natural Resources Cook Inlet reserves as of January 1, 2004.[126]

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[124] *Id.* at 13.

[125] T-5 at 15.

[126] T-8 (Dieckgraeff) at 5.

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Reserves are lower by nearly the amount of production that occurred during the two-year period, decreasing by 439.1 Bcf.[127]

Despite ENSTAR's ratepayers funding millions of dollars in an "exploration and development" incentive plan, Cook Inlet reserves have declined. No party presented evidence that Henry Hub pricing resulted in more reserves for ENSTAR. ENSTAR witness Goldsmith described supply curtailments that occurred in the winter of 2005-2006 and stated that those incidents suggested that the reserves-to-production ratio is lower than it should be and that it is due to insufficient incentives to invest in new reserves.[128]

No party presented evidence to us that would suggest how much price incentive ENSTAR ratepayers must pay to increase Cook Inlet reserves.[129] Marathon witness Henning affirmed that no company ever made an investment exclusively off a pricing signal.[130]

We must reluctantly conclude, based on this record, that the now five year old economic experiment promoted by ENSTAR in both the Unocal and NorthStar contracts has not produced noticeable results. There have been no net reserves added

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[127] *Id.*

[128] T-5 (Goldsmith) at 19.

[129] We also cannot ignore the parts of this record that tell us that exploration (as distinct from development of existing reserves) in Cook Inlet cannot be incentivized at any price, that the possibility of a spur line from the North Slope trumps any monetary effort ratepayers could make. And always in the back of producers' minds is the possibility and expected price of imported LNG. ENSTAR offering a price above that expected amount is unlikely to incent general exploration and development, although it might elicit the desired behavior as to particular gas for which ENSTAR pledges to pay its uniquely high price.

[130] Tr. at 1466.

to Cook Inlet. In fact, what ENSTAR tells us today is that reserves replacement is not keeping up with production.[131]

We note from the record there seems to be only one driver that spurs substantial increases in Cook Inlet reserves—the export of LNG to Japan. Tesoro witness Schlesinger stated, "[t]he export sale of Cook Inlet gas as LNG to Japan also represents Marathon's primary alternative market for its gas sales."[132] Cook Inlet reserves additions were reported in only 3 years between 1977 and 2004.[133] In 1986, Cook Inlet reserves increased by 1,400 Bcf, in 1996 reserves increased by 955 Bcf, and in 1997 by 439 Bcf.[134]

Phillips Alaska Petroleum Gas Corporation and Marathon Oil Company (the owners of the LNG plant) sell LNG to utility companies in Japan. On April 11, 1988, two years after Cook Inlet reserves were increased by 1,400 Bcf, the LNG owners filed an application with the Economic Regulatory Administration (ERA), requesting a fifteen-year export license extension to March 31, 2004[135]

Eight years later, on December 31, 1996, the owners of the LNG plant filed an application requesting that the DOE extend their authorization to export LNG for

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[131]T-8 (Dieckgraeff) at 5.

[132]T-19 (Schlesinger) at 8.

[133]T-5 (Goldsmith) at 16.

[134]H-2 at 71.

[135]H-60 at n.3 referencing DOE/ERA Opinion and Order No. 261, *Order Amending Authorization to Export Liquefied Natural Gas to Japan* (Order No. 261).

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five years through March 31, 2009.[136] In 1996 and 1997, Cook Inlet reserves increased by nearly 1,400 Bcf. The export license was extended through March 31, 2009.[137]

We observe with interest this correlation between Cook Inlet reserves growth and requests for extension of LNG exports[138] revealed in this record. The record before us provides little more than speculation that the use of Henry Hub by one utility provides sufficient incentive to result in Cook Inlet reserves growth.

Reliable Supply of Gas

ENSTAR stated that it applied the following criteria for new gas purchases, (1) full requirements (if possible) (2) full swing, (3) fair price, (4) proven reserves and (5) diversified supply.[139] ENSTAR stated its first priority is always to obtain a reliable, long-term gas supply at the lowest possible price.[140]

ENSTAR witness Izzo stated,

> I see APL-5 as a bridge contract that will give ENSTAR a high level of supply security during a very, very uncertain transition period. APL-5 provides us with an assured supply at a reasonable, market-based price, provided by a highly reliable and responsible supplier that ENSTAR has been able to trust to meet its requirements for over 40-years."[141]

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[136]H-60 at 2.

[137]H-60 at 57.

After taking into consideration all of the information in the record..., we find a five-year extension of the authority.... to export LNG to Japan has not been shown to be inconsistent with the public interest. In particular, the record shows here is a sufficient regional supply of natural gas to satisfy local and export demand through the extension period. Furthermore, we believe the extension will continue benefits provided by the export to the Alaskan economy, energy production, and international trade.

[138]T-5 (Goldsmith) at 16).

[139]T-7 (Dieckgraeff) at 11).

[140]*Id.* at 12.

[141]T-2 (Izzo) at 7.

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ENSTAR bears the burden of proving that this contract will provide that high level of supply security. We test ENSTAR's statements against the record compiled in this hearing.

ENSTAR believed that Marathon has committed to supply ENSTAR's unmet requirements through 2016.[142] It maintained that:

> ENSTAR's most recent major gas supply contract, the Unocal contract was not backed by proven reserves, but rather imposed an exploration obligation on Unocal and it has been quite successful. As a result Unocal has found, and is developing, significant new quantities of gas on which ENSTAR has "first call". ENSTAR believes however that is prudent that the next layer of gas supply be based on proven reserves."[143]

This commitment is embodied in APL-5 contract at Section 2.3, Full Requirements Supplier, which states. In part,

> 2.3 Full Requirements Supplier. The Parties acknowledge and agree that Seller has made the Initial Annual Commitments in such amounts as are necessary, in light of Buyer's current projections, to 'reduce Buyer's Unmet Requirements .to zero (0) for each Contract Year beginning in Contract Year 2009 and ending in Contract Year 2016, and that, for those Contract Years, Seller will be "Buyer's Full Requirements Supplier.[144]".

Section 2.7.4 of the Contract discusses the priority of ENSTAR's position in relation to other of Marathon's gas sales contracts and states, in part,

> 2.7.4 Seller shall not commit to dispose of Gas from Seller's Proven Reserves if such commitment would have a 'material adverse effect on Seller's ability to meet the obligations of Seller under this Agreement. *Except for Seller's Third Party Commitments,* Buyer has first call on Seller's Gas delivered into the Cook Inlet Area necessary to meet Seller's obligations to make Gas available to Buyer under this Agreement. Any agreement' (including an amendment to Seller's Third Party Commitments or exercise of an option under Seller's Third Party Commitments) made on or after October 14, 2005 by Seller to dispose of Seller's Gas from its Proven Reserves during the Term of this Agreement must recognize that Seller has committed

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[142]T-7 (Dieckgraeff) at 14.

[143]*Id.*

[144]H-1B at 9.

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to make Gas available to Buyer under this Agreement and that Buyer has prior call on that Gas to satisfy the obligations of' seller to make Gas available to Buyer.[145]

A list of fifteen contracts or agreements between Marathon and third parties are included at Exhibit E to the contract.[146] Several of the contracts appear to be related to Marathon's LNG export activities as well as what appear to be gas supply contracts with Agrium, Tesoro, Chugach Electric Association, XTO Energy, and others.

During the hearing we became aware that ENSTAR had not fully evaluated the effect of Section 2.7.4 on its committed supplies from Marathon.[147]

ENSTAR has relied on Marathon's representations "about not letting the town to go dark while industrials operated"[148] and has required a reserves letter from Marathon but has not yet fully evaluated it.[149] ENSTAR maintained that it takes a lot of comfort from its 40-plus year relationship with Marathon.[150]

ENSTAR stated that its criteria for new gas purchases are based on full requirements, proven reserves, and diversified supply.[151] We have established a standard of review which requires that APL-5 provide a reliable supply of gas at a reasonable price.

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[145]H1-B at 12 (emphasis added).

[146]H-1B, at 58.

[147]Tr. at 151-157.

[148]Tr. at 1016.

[149] Tr. at 1019.

[150]Tr. at 1017.

[151]T-7 (Dieckgraeff) at 3.

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We find that ENSTAR did not meet its burden of proof that APL-5 provides a reliable supply of gas because it has not sufficiently reviewed possible commitments of Marathon's reserves prior to bringing the contract to us for approval.[152]

Were this the only deficiency in ENSTAR's case in support of APL-5, we would be able to conditionally approve APL-5, subject to ENSTAR's submission of further information curing this defect.

Our Unocal and NorthStar orders have been read too broadly by ENSTAR.[153] We have not decided that Lower 48 market prices are a reasonable proxy for Cook Inlet market prices under all circumstances and we certainly have not decided that we will allow ENSTAR or any other public utility to pay Lower 48 market prices plus transportation plus production taxes for all Cook Inlet gas.[154]

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[152] *Id.* at 11 and Tr. 1016-1020.

[153] For example, Marathon's witness Henning testified that "[w]hen the Commission approved the pricing provisions of the Unocal contract with ENSTAR, it sent a clear price signal that the market for natural gas in Alaska would be linked with the broader North American natural gas market." T-14 (Henning) at 12.

[154] Henry Hub prices have departed fundamentally from the basic economics of Cook Inlet since the time of the Unocal contract and the NorthStar contract. Even if our orders could reasonably be read to generally endorse Henry Hub prices, which we do not believe they can, it would be necessary for us now, solely because of that departure, to reexamine that policy decision.

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ENSTAR has told us there is no other company that can provide what Marathon offers to provide in APL-5.[155] Thus, there is no competition for this piece of ENSTAR's gas supply.[156] Competition is what holds down price. In the absence of competition, it is only our review that serves to hold down price. Marathon has every incentive to negotiate for itself the highest price it believes ENSTAR would pay or we would allow ENSTAR to pay. We must carefully assess the agreed-upon price.

The price in APL-5 is not a negotiated price. ENSTAR and Marathon decided not to negotiate a price but rather to select an index and allow that index to set the price of the contract, with add-ons for transportation and production taxes. A market price is not a negotiated price. In that way APL-5 is like the Unocal and NorthStar contracts and unlike the ENSTAR supply contracts that preceded the Unocal and NorthStar contracts. Those legacy contracts contained negotiated prices, based on market conditions in Cook Inlet. The negotiated prices of the legacy contracts are adjusted annually according to an agreed upon index.

<u>Evaluation of APL-5 Price</u>

We evaluate the reasonableness of the pricing terms of APL-5 as a whole rather than picking apart the elements and assessing the reasonableness of each element separately, as we did with the Unocal and NorthStar contracts. We now recognize that pricing terms are negotiated as a whole, that each element is adjusted

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[155]T-7 (Dieckgraeff) at 10.

[156]We are not certain there is any meaningful competition for ENSTAR's business. The gas supply in Cook Inlet is largely tied up in long-term contracts. A workably competitive environment for ENSTAR's supply would be one in which producers sold gas on short-term contracts and there was common carrier storage available to take care of ENSTAR's swing requirements. Only under those conditions could small and large producers be on equal footing to compete for ENSTAR's business.

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and fine-tuned to counterbalance each other element of the contract to arrive at terms the contracting parties can embrace. If we were to assess individual items with the intent of conditioning our approval on a change in one or more individual elements, we would be disturbing that balance.

We believe the fairer and wiser course is to approve or disapprove pricing terms as a whole. We take the price of APL-5 and superimpose the changes Marathon offered (none of which ENSTAR objected to) in response to some of the intervenors' concerns and assess the resulting pricing terms as a whole. We cannot find that either the original pricing terms of APL-5 or the pricing terms as revised by Marathon assure that ratepayers will pay no more than a reasonable price for the gas bought for them under APL-5.

The other Marathon contracts entered into evidence in this proceeding (and given confidential status) demonstrate that the price of APL-5, at present Henry Hub 12-month trailing average prices plus 25¢ for transportation plus production taxes,[157] is a radical departure from the basic economics of Cook Inlet. ENSTAR has not sufficiently justified that radical departure in this record.

The best proxy we have for the Cook Inlet market price for gas with the same variable deliverability and swing required by ENSTAR is ENSTAR's own WACOG. The WACOG, by its very nature, represents a diverse base of suppliers, both willing and able to meet ENSTAR's deliverability and swing. ENSTAR's WACOG is also comprised of a blend of legacy pricing based on proven reserves combined with the exploration-driven Henry Hub, through Unocal. That WACOG is currently approximately $5.00 for calendar year 2006. The 2006 price of APL-5 (if in effect, which it is not) is

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[157]If ENSTAR were taking gas under APL-5 today the price of gas would be $7.50 plus production taxes. Tr. 924.

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$7.50 plus production taxes. The APL-5 price for proven reserves represents at least a 50 percent increase over ENSTAR's current WACOG. That is an unacceptable divergence because ENSTAR is currently receiving supplies from both proven reserves and exploration efforts at a much lower price.

ENSTAR has not sustained its burden to prove that the price of APL-5 is reasonable. We reject APL-5 based on our conclusion that the price, to the extent that it increases ENSTAR's WACOG, is not reasonable.

We give guidance to the contracting parties on what pricing terms we might be able to accept. In doing so, we do not seek to interfere with future negotiations or second-guess past negotiations. The APL-5 pricing terms are simply too divergent from other prices in Cook Inlet. They must be conformed in some way to the realities of the Cook Inlet market.

As evidenced in our earlier discussion, we have difficulty approving pricing terms if the parties' goal in entering into those terms is to change the Cook Inlet market by paying a higher price than is necessary to obtain the gas needed. We believe ENSTAR should pay prices appropriate to the existing market, considering its deliverability and swing requirements. ENSTAR is likely to need to pay a higher price than other buyers in Cook Inlet because of those requirements but needs to create an adequate record on which we can base our decision in support of that need.

The use of Henry Hub or another market index with or without discounts requires the parties to justify use of the index for their contract and must reconcile use of the market index with Cook Inlet market conditions. Assuming they do so, use of such an index might be acceptable, but only if transportation and production taxes are not added on and if there is a meaningful cap.

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The record reveals that, generally, sellers pay transportation to the hub at which gas is priced and buyers pay transportation away from the hub.[158] Whether transportation should be added on to a hub market index price depends upon the pricing point to which the market price index is applied. In this instance, the only points which make sense under the configuration in Cook Inlet are the KPL junction (where a number of pipelines, including ENSTAR's eastside pipeline, come together) and the inlet to ENSTAR's westside pipeline in the Beluga River field.

The only reasonable alternatives to those points are the wellheads in each field. We believe wellheads are inappropriate pricing points at which to apply a market index. The evidence tells us that sellers pay transportation from the wellhead to the hub.

We do not believe a reasonable price would include a transportation cost added on to a price determined directly by a market index. Transportation was not added on to ENSTAR's legacy contracts. The Unocal contract did provide that a fee would be added on to the market price if gas was shipped through a newly constructed pipeline. A transportation fee was also to be added on to the market index price in the NorthStar contract. The Unocal and NorthStar contracts are distinguishable from the current contract because the pricing terms in those contracts were approved as exploration incentives. We would not allow a transportation fee to be added to a market index price in APL-5.

There is no evidence in this record that buyers at Henry Hub or at any other hub with a market index pay sellers' production taxes. Production taxes are a normal cost of producing gas, like compressors, salaries, and office overhead. Market prices are a function of supply and demand and have no relationship to costs of

[158]T-13 (Elder) at 6-8.

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production. ENSTAR did not provide any support for the tax add-on in APL-5 except to say that the provision is in all its other contracts and that producers preferred it that way.[159] Contrary to our decision in NorthStar, we now find on the basis of the existing record in this proceeding insufficient justification to add production taxes on to market index prices, which already compensate sellers for costs of production.

Prices established on Henry Hub might be acceptable in the presence of a meaningful cap. Neither the $15.00 cap nor the $14.00 cap proposed protects ratepayers from anything other than circumstances in Lower 48 markets that are so dire as to be almost unimaginable. The devastating storms of 2005 resulted only in price spikes to $15.00. The yearly average for 2005 was in the $9.00 range. We find that in this market even a cap of $9.00 does not ensure that ENSTAR's ratepayers will pay a reasonable price when we see other buyers in Cook Inlet paying less than half that amount. Even the Japanese utilities taking Cook Inlet gas pay $2.00 less than this $9.00 cap at the receiving point in Japan. If a contract is priced to another market, there must be a meaningful cap that prevents the price paid by ENSTAR's ratepayers from diverging too far from the price paid by others in Cook Inlet unless that divergence is due to and in proportion with differing deliverability and swing requirements.

We understand that the price of natural gas is rising, in step with crude oil. There is evidence in the record that natural gas prices have been steadily increasing in the Pacific Basin.[160] There is evidence in the confidential record that non-utility contracts for gas supplies have been increasing. We are not opposed to recognizing in APL-5 economically rational price increases that reflect the realities of Cook Inlet's gas market.

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[159]T-8 (Dieckgraeff) at 19.

[160]T-19, Ex. BSA-5.

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Conclusion

On the basis of the evidence in this record we conclude that ENSTAR has failed to meet its burden of proof that APL-5 achieves a reliable gas supply at a reasonable price. Accordingly, we reject the addition of TA139-4 as a base supply contract having the effect of increasing the current average cost of system gas supply as proposed by ENSTAR. We note, however, that ENSTAR's tariff allows it to add base supply contracts having the effect of decreasing the cost of system gas without our approval. We allow ENSTAR to add TA139-4 to its base supply under those limited conditions.

Final Order

This order constitutes the final decision in this proceeding. This decision may be appealed within thirty days of the date of this order in accordance with AS 22.10.020(d) and the Alaska Rules of Court, Rule of Appellate Procedure (Ak. R. App. P.) 602(a)(2). In addition to the appellate rights afforded by AS 22.10.020(d), a party has the right to file a petition for reconsideration as permitted by 3 AAC 48.105. If such a petition is filed, the time period for filing an appeal is then calculated under Ak. R. App. P. 602(a)(2).

ORDER

THE COMMISSION FURTHER ORDERS:

1. TA139-4, as presented by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., is rejected as discussed in the body of this order.

2. TA139-4 , as presented by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., may otherwise go into effect immediately without further approval, provided it has the effect of decreasing the current average cost of system gas as per tariff Sheet No. 90, Section 708f.

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3. By 4 p.m., November 1, 2006, should ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., choose to have TA139-4 take effect under Ordering Paragraph No. 2 above, it must file any revisions to its contract terms and perfect its supply commitments under Section 2.7.4 of APL-5.

DATED AND EFFECTIVE at Anchorage, Alaska, this 28th day of September, 2006.

BY DIRECTION OF THE COMMISSION
(Commissioners Dave Harbour and Mark K. Johnson, dissenting.)

(S E A L)

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Appendix
ENSTAR Weighted Average Cost of Gas 2002 – 2006

2002 Contract	Price	Vol. BCF	Total $ Millions
APL-4[1]	2.46	21.0	51.67
Beluga[2]	2.43	3.0	8.01
Moquawkie[3]	2.99	1.3	3.84
Unocal[4]	-	-	-
		25.6	63.52
Adjustments			0.28
Total Gas Costs			63.80
Total Sales Volume (BCF)			25.46
Weighted Average Cost of Gas			2.5059

2003 Contract	Price	Vol. BCF	Total $ Millions
APL-4	2.40	19.0	45.69
Beluga	2.42	3.3	7.99
Moquawkie	3.00	4.2	12.64
Unocal	-	-	-
		26.5	66.32
Adjustments			1.14
Total Gas Costs			67.46
Total Sales Volume (BCF)			26.38
Weighted Average Cost of Gas			2.5575

2004 Contract	Price	Vol. BCF	Total $ Millions
APL-4	2.69	17.0	45.68
Beluga	2.78	2.1	5.83
Moquawkie	2.98	2.9	8.70
Unocal	4.74	5.3	25.31
		27.4	85.51
Adjustments			(0.84)
Total Gas Costs			84.67
Total Sales Volume (BCF)			27.20
Weighted Average Cost of Gas			3.1123

2005 Contract	Price	Vol. BCF	Total $ Millions
APL-4	3.38	15.0	50.64
Beluga	3.56	1.6	5.70
Moquawkie	3.02	1.9	5.74
Unocal	5.10	9.2	47.06
		27.7	109.15
Adjustments			(0.87)
Total Gas Costs			108.28
Total Sales Volume (BCF)			27.54
Weighted Average Cost of Gas			3.9321

2006 Contract	Price	Vol. BCF	Total $ Millions
APL-4	4.43	13.0	57.58
Beluga	5.12	1.1	5.64
Moquawkie	3.04	1.8	5.47
Unocal	6.49	10.7	69.32
		26.6	138.00
Adjustments			(6.00)
Total Gas Costs			131.99
Total Sales Volume (BCF)			26.39
Weighted Average Cost of Gas			5.0009

Source: Exhibit H-39, as corrected by RCA Staff

[1] APL-4 Gas Purchase Agreement with Marathon Oil Company, dated May 1, 1988, and approved by the Commission in U-88-49(6), dated July 20, 1989.

[2] Beluga Gas Purchase Agreement between Shell Western E&P, Inc. and Alaska Pipeline Company, approved by the Commission in docket U-83-2(6), dated June 3, 1983. The Commission approved an amended contract, Beluga Schedule 3, in U-92-7(3) dated December 7, 1992.

[3] Moquawkie Gas Purchase Agreement with Anadarko Petroleum Corporation and Phillip's Alaska, Inc., dated May 16, 2000, and approved by the Commission in TA114-4, dated July 27, 2000.

[4] Unocal Gas Purchase Agreement with Union Oil of California Inc., approved by the Commission in U-01-7 dated October 25, 2001.

APPENDIX C

ENSTAR
Natural Gas Company

3000 Spenard Road
P.O. Box 190288
Anchorage, AK 99519-0288
www.enstarnaturalgas.com

January 19, 2007

RECEIVED

JAN 1 9 2007

STATE OF ALASKA
REGULATORY COMMISSION OF ALASKA

Regulatory Commission of Alaska
701 West 8th Ave., Suite 300
Anchorage, Alaska 99510

Re: U-06-002

Dear Commissioners:

Marathon Oil Company has notified ENSTAR Natural Gas Company that Marathon is exercising its rights to terminate the 2005 Gas Supply Agreement (commonly referred to as APL-5) under Section 10.1.2 of the Agreement because the Agreement was not approved by the RCA. The contract was the subject of docket U-06-002. A copy of Marathon's letter to ENSTAR is enclosed.

Marathon and ENSTAR have scheduled a meeting during the week of January 22 to discuss ENSTAR's gas supply needs.

Sincerely,

Daniel M. Dieckgraeff
Manager, Regulatory and Gas Supply

Natural Gas Marketing & Transportation

Marathon Oil Company

P.O. Box 3128
Houston, TX 77253-3128
Telephone 713/629-6600

January 3, 2007

Mr. Tom East
ENSTAR Natural Gas Company
3000 Spenard Road
P.O. Box 190288
Anchorage, AK 99519-0288

Re: Termination of Gas Sales Agreement, dated October 14, 2005, between Marathon Oil Company and Alaska Pipeline Company

Dear Mr. East:

As you know, the Regulatory Commission of Alaska (the "Commission") issued Order U-06-02(15) on September 28, 2006, which rejected the Gas Sales Agreement, dated October 14, 2005 (the "Agreement"), between Marathon Oil Company ("Marathon") and Alaska Pipeline Company ("ENSTAR") as a base supply contract to the extent that it would increase the current average cost of ENSTAR's system gas supply. Both Marathon and ENSTAR sought reconsideration of Order U-06-02(15), with Marathon citing several deficiencies in Order U-06-02(15) and requesting that the Commission "vacate its rejection of the [Agreement], and issue an order approving [the Agreement] as offered to be modified by Marathon at the hearing". ENSTAR sought reconsideration of Order 15 asking for "additional guidance and additional time to secure the [Agreement] gas on terms acceptable to all Commissioners," seeking specific guidance on the portion of the order that approved the Agreement as a base supply contract to the extent that it would decrease the current average cost of system gas supply (the "WACOG option") and several statements made by the Commission regarding provisions it did not find acceptable as the basis for an agreement.

On December 29, 2006, the Commission issued Order U-06-02(17) which granted reconsideration with respect to several points raised by Marathon in its Petition for Reconsideration, but ultimately denied Marathon's request that the Commission approve the Agreement. In Order U-06-02(17), the Commission also denied ENSTAR's petition, declining to "clarify the WACOG option", and electing not to offer any definitive guidance on the modifications to the Agreement that it might find acceptable. In effect, therefore, the Commission reaffirmed the ruling in Order U-06-02(15) that the Agreement be rejected as a base supply contract and that the costs related to the Agreement not be recoverable in ENSTAR's gas cost adjustment.

These Orders were the culmination of over two years of diligent effort on the part of both our companies, which included a substantial investment of time and money during the Agreement negotiation process and the ensuing efforts required to achieve regulatory approval. As we documented and testified to the Commission, Marathon also made a substantial investment in developing the proven reserves that would have been committed to its performance under the Agreement. Marathon is very disappointed in the Commission's rejection of the Agreement, as we believed that it represented reliable and reasonably priced gas supply for ENSTAR's customers and, therefore, should have been found to have been in the public interest.

Section 10.1.2 of the Gas Sales Agreement states that "if the RCA does not approve all the terms of this Agreement or if it imposes terms and conditions unacceptable to Buyer or Seller, Buyer or Seller may terminate this Agreement by giving notice of termination within thirty (30) days of the date the RCA's order is served." As discussed above, Order U-06-02(15) and Order U-06-02(17) result in the failure of the RCA to approve all the terms of the Agreement. Therefore, pursuant to Section 10.1.2 of the Agreement, MOC regrettably terminates the Agreement effective as of the date of this letter.

Based on the most recent long term supply forecast that ENSTAR delivered to Marathon, we understand that ENSTAR needs to acquire additional gas supplies to offset unmet requirements that exist commencing in 2009. However, Marathon cannot justify continuing to fund the investments necessary to service ENSTAR's unmet requirements without a mutually acceptable and Commission approved sales contract that underpins the expenditures. Further, it appears to Marathon that embarking on a new gas sales contract with ENSTAR is highly problematic considering the uncertainty created by the Commission's decision in this proceeding. This is true not only because the outcome of such a proceeding cannot be reasonably predicted, but also because Marathon cannot afford to restrict, as it did in the Agreement, its ability to market its proven reserves of natural gas to other customers for the expected duration of another Commission proceeding. Any ability for Marathon and ENSTAR to come to an agreement to meet such unmet requirements is also in doubt due to the potential priority rights to supply such requirements accorded to Union Oil Company of California under its agreement with ENSTAR.

Marathon remains committed to its natural gas marketing program to ENSTAR and other customers in Southcentral Alaska. However, in order for Enstar to secure long term gas sales contracts there needs to be both clarity of the circumstances and conditions under which ENSTAR can secure future supplies, and Commission support for such an approach. We are happy to provide you with our input and support as you embark upon the challenges of securing additional, reliable natural gas supplies for your customers.

Sincerely,

David Kisser
Manager, North American Natural Gas Marketing

cc:	Gene Dubay	William R. Holton	Daniel Dieckgraeff	C. Leslie Webber
	Patrick J. Kuntz	John A. Barnes	Charles Hermandez	

APPENDIX D

STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners:

Kate Giard, Chairman
Dave Harbour
Mark K. Johnson
Anthony A. Price
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska

PUBLIC MEETING

January 24th, 2007
9:00 o'clock a.m.

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point presentation and that's very helpful and we certainly do now have the transcript to look forward to, but I wondered if you had any further written -- a white paper on the issue or is this presentation what you want to be filed with the Commission now?

ACTING CHAIR JOHNSON: If I might, Commissioner Giard, it's my understanding from their presentation is that they are not making a filing with the Commission at this time.

CHAIRMAN GIARD: Right, I understand. But in terms of an overall, kind of, presentation I just didn't know whether they also handed out, you know, a white paper or a written description.....

ACTING HAIR JOHNSON: No, I think.....

CHAIRMAN GIARD: .....or any (ph) other materials (simultaneous speech).....

ACTING CHAIR JOHNSON: We have the power point -- yeah.

CHAIRMAN GIARD: Yeah, that's good.

ACTING CHAIR JOHNSON: Okay. With that, if there's nothing further on this side of the room (ph), we will be in recess until 11:00 o'clock. And off record. Thank you.

(Off record - 10:46 a.m.)

(On record - 11:03 a.m.)

ACTING CHAIR JOHNSON: We are back on record after a relatively short and painless break. The next item on our agenda is a presentation by Dan Dieckgraeff of Enstar Natural

Gas Company. And the presentation is apparently entitled Winter Operations Update. Mr. Dieckgraeff.

MR. DIECKGRAEFF: Thank you very much. The Commissioners and the Court Reporter have hard copies of this presentation, but this presentation is going to mainly focus on some maps that are in the presentation and they have some animations, so I would suggest that you follow the power points 'cause you may -- what ends up when we print out the power point slides is you get the last thing on there.

Commissioner Giard should also have a copy of the power point presentation. It was e-mailed to her along with the AEL&P presentation earlier. Since it does have maps I am going to, with the Commission's permission, use the mobil mic and move up around because I want to point out some things on here. It's a little easier if I'm closer to the screen.

(Off record comments)

MR. DIECKGRAEFF: Not knowing to the extent of the audience we'd have today, I just wanted to quickly point out who we are. Enstar Natural Gas was established in 1961. We serve southcentral Alaska from Houston in the north to Kenai/Soldotna/Ninilchik on the south to, of course, the Anchorage bowl, Eagle River, Girdwood and on to Whittier to the east.

We serve over 125,000 meter, I think in 125,000 location which is how we count customers in our business. And based on average households we calculate we serve 340,00 Alaskans in our service area.

We have over 3,000 miles of distribution mains and transmission mains taking case. Most of those are high density plastic. Of course, the big pipes, the transmission pipes are steel. We figure that we have an impact of about $302 million on Alaska's economy with about 168 employees. We're the largest energy utility in the state. And we added about 3,500 customers last year.

The reason why I'm coming down and giving you this presentation is in various forums, public meetings and communications during the first half of the winter, kind of, going to inform the Commission of what's going on. We thought we'd, kind of, come down and tell you what happened when we set -- with the last bit of cold weather where we, as well as Chugach Electric and ML&P set system records for throughput and usage.

We did set a record two weeks ago yesterday on January 9th, 292,000 Mcf per day when through our system. Actually the evening of the night before for a period of time we were actually running at over 305 million going through our system.

Of that 292 million cubic feet, 227 were gas purchases by Enstar for its gas sales customers, residential, small commercial, large commercial customers.

We also were moving gas, about 16 and a half million to commercial transport customers, large commercial customers getting transport service on our system primarily served by Marathon. DOD is their largest customers and Aurora.

We also were hauling about 44 million to the power locations. That's primarily ML&P. In fact, I think that was all ML&P on that day. We were also moving about 5 million of firm transport to an industrial customer at that time. The average temperature was 10 below for the day.

I will point out that these are preliminary numbers based on our telemetry and conversations with various parties. At the end of the month when you go out and get the actual reads, look at the actual locations, some of these can shift around a little bit, but this is what we are estimating was going on. We know what the total number was, just the split may be a little different on some of the amounts.

The Commission I know is somewhat familiar with our system, but I'm not sure about the audience so I just want to quickly give you a little history of the transmission system as it exists today. The blue -- heavy blue lines in this slide, and I have switched to the first map slide for Commission Giard, if she's on.

The blue lines are Enstar's transmission lines. The original system was constructed by Enstar in the 1960s and upgraded through the '70s to bring gas from the Kenai field which is the purple blob down by Soldotna up to the Anchorage system. There was a small expansion of that which we refer to as the royalty line that was constructed in the late '70s up to Nikiski to interconnect with some of the pipelines the producers had up there.

In 1983/84 we constructed a 20 inch line from the Beluga field which is over on the west side of the Inlet through the Mat Valley and bring in gas to Anchorage so that we could bring gas from both directions.

Also built are systems that belong to others. The history of the Cook Inlet is that they discovered about -- what we know to be about eight trillion (ph) cubic feet of gas in the '50s and '60s while looking for oil. To monetize that investment various producers built industrial plants to utilize that gas. The LNG plant and the ammonia urea plant were constructed at Nikiski.

There were pipelines build from the fields that were separate from the utility lines. To take that gas to the field there's a 20 inch that runs from the Kenai field down near Soldotna up the coast to Nikiski, the KNPL line which is the subject of proceedings with this Commission in an order, I believe, in December that approved a settlement agreement dealing with that.

There was also a line that you can see in red that runs across the Inlet from Nikiski to Tyonek. That's the marine crossing portion of CIGGS and actually the red -- the yellow line that runs from Tyonek down along the coast is also part of the CIGGS system that is the subject of a proceeding where, I think, the settlement has not yet been approved by the Commission dealing with that line.

In the early '90s there was another line built that connected on the west side that runs from Tyonek to Beluga, that's Beluga Pipeline Company owned by Marathon. That brought gas from the west side up to the Beluga field partially for Chugach Electric needs and interconnected with our system to bring gas around the Inlet.

The last main pipeline construction was done in, I think, 2002/2003 and an extension in 2004/5. The KKPL line that runs -- originally ran from Kenai field, the interconnection between KK- -- KNPL, I'm sorry, and our pipeline down to about halfway between Ninilchik and Clam Gulch was Phase 1 of KKPL to bring the -- primarily the Ninilchik unit on line, but all the other small plac- -- other fields that have been discovered down that way and then Unocal did an extension of that down to Happy Valley. That's, kind of, what we have for the transmission pipeline system today.

We actually set a record earlier this winter on the day before Thanksgiving so we've actually broke two records this year, but I want to step back a little bit and look at our last real record day, our last real cold winter day and that was February 3rd, 1999.

February 3rd, 1999 we moved 272 million cubic feet of gas. The average temperature was 19 below that day. How did that gas get to Anchorage? The bulk of the gas came from the production on the west side of Cook Inlet. I'm now clicking the two animations.

183 million coming from both the Beluga field and from west side gas, Steelhead Platform being the primary producer coming up CIGGS, branching off and coming into our system up the Beluga pipeline interconnecting at the Beluga field and mixing with Beluga field gas and with west side production that Unocal has beyond the Beluga.

The remainder of the gas came up from the south side, the original pipeline system about 89 million cubic feet of gas primarily from the Beaver Creek field and the Kenai field. While we had the ability to take gas through this royalty line, not much gas other than the Beaver Creek field which is right here, halfway between Nikiski and Sterling on the royalty line, the bulk of the gas going in at 1999 was coming from that direction.

Now, I'm going to compare that to what happened on January 9th of this year, two weeks ago. That's the next click and the first animation.

We had 122 million coming through this pipeline from the west side. We had 170 million coming up from the west -- or from the east side. Notice the significant change in where the gas is coming from.

These fields, Beluga field and the field that Steelhead sits on are in decline. There are significant reserves, but they've been producing for 40 years. They're in decline. There's been significant drop in the deliverability from those fields.

The new discoveries have been down here so we have seen a shift from the gas being produced on the west side to the gas being produced on the south side and we're seeing more and more of our cold weather gas coming from there.

There's also another shift that's happened between 200- -- or between 1999 and 2007. 122 million coming up from the west side, eight of that was out of storage coming from Unocal/Chevron's storage facility right about here at Pretty Creek. That's -- this is the first year of this storage facility. I believe that they target having about 10 million available on a daily basis from that.

Also we have storage coming in from the south side so of the 170 million that was coming into the system from the east properties, only 115 of that was coming from storage -- or, I'm sorry, coming from production, 55 million approximately was coming from storage primarily Unocal/Chevron storage at Swanson River that comes in, and comes into our system here.

There's even a little bit more to this picture. What happened, in fact, was the LNG plant was shorted by 35 million.

35 million of gas that would have gone to the LNG plant on this day was diverted for utility use. We had 53 million coming up from KKPL and in something that's happened -- none of this can remember this happening, in fact, there was no gas crossing the marine CIGGS.

All of the west side production was coming up CIGGS, the Beluga line, drop off at Chugach for their needs and to come on into town for the rest of the system needs. No gas coming through here.

Remember me talking a little bit earlier that these producer owned systems were really built to bring gas to the industrial plants, somewhat separate from the system to bring gas in for the community use.

We have this line, an eight inch line, but it reaches capacity at about 55 million. We had 55 million coming out of storage, let alone what was being produced out of Pretty Creek. We have some capacity bottlenecks here to bring this gas into town and we'll talk about that a little bit later as to what we're going to see going on.

I can tell you that there was a very intricate dance going on the night of the 8th going on to the 9th. And first of all I want to applaud and thank every one of the producers for lending a hand and making sure that everything move smoothly as it was.

We had 20 million of capacity that's not available at

Beluga. They're got a compressor that's in installation process, but that is not ready and probably now won't be ready until after the first quarter so we were short 20 million coming into the system from Beluga.

We had some minor well freeze-ups in a couple of the fields that took a few Mcf here -- 2,000 Mcf here, there out of the system, but basic- -- everybody got -- all the gas got to Anchorage, all the power customers had all the gas, but to do that it came out of the LNG plant and as you will see in a moment there was virtually nothing going to the ammonia urea plant.

We were moving gas in places that gas was not designed to move over the current systems we have. It was done with extreme cooperation, with displacement, with trading to get gas, including gas coming from here basically into here through bottleneck lines. We've not seen a winter like this probably since 1999. We haven't had to test the system like we've tested the system for the last -- 1st of November and now.

We are on the ragged edge. If we had a major failure the only place the additional gas would have come from would have had to have come from the LNG plant and there's a limitation right now as to how we could get that gas, even with the swapping into the situation. We'll take about that a little bit later as part of the infrastructures, but I want to emphasize that there's not spare, spinning reserve now. We've taken it away from the LNG plant.

I want to compare now just what -- between '99 and '07. 13 (ph) below average temperature in '99, 10 below two weeks ago. Throughput 277 (ph), 292. That 272/292 breaks down to Enstar gas sales in '99 of 187, again this is gas we purchase and turnaround and sell to the residential, small commercial, large commercial customers. 227 two weeks ago. Commercial transport was 29. Calculate commercial transport at being 16 two weeks ago. Power transport 56.

Back in '99 we had the military power plant still here, those have been shutdown. Part of that loads been picked up by ML&P, part of that loads been converted to heat load and being serviced by either commercial or ourselves as gas sales customers. We had some industrial transport on -- firm industrial transport on -- also on the 7th -- or I'm sorry, on the 9th.

This isn't the whole story. This is just what happened on Enstar's system. To take a look at the Cook Inlet you need to look at what happened to the entire Cook Inlet delivery system on that peak day.

I want to thank the various producers and plants for giving me some of these numbers. Again, some of them are approximations and going back to '99 the historical records aren't as good as we'd like to have. Some of this is based on nominations, but this is the best we can point out what the situation was both in 1999 and two weeks.

Again, you have the Enstar system at 272 versus 292. Chugach/Beluga was taking 78 back in '99. Taking 83. These are -- this is stuff that's off Enstar's system. So this is Chugach/Beluga 78 versus 83. Nikiski LNG was taking 224 back in '99, taking about 150 last week. Fertilizer plant 157 back in '99. The latest information I have is this number may be about 1 or 2 or basically just taking enough to keep the buildings warm and keep everything from freezing over there.

Tesoro, it looks like they were taking about 13 and versus six right now so the Cook Inlet deliverability on those peak days back in '99 was 744 versus 531 today.

Now, in discussions with producers and others there was still more gas behind the valves for the deliverability back in '99 and we were not interrupting the fertilizer plant even though through backup agreements we could have done so, and there was not interruption to the LNG plant.

We've lost 200 million in deliverability. Not surprising given the size of the fields that are out there that are in decline. We also had no storage in '99. Storage today.

This one I wanted to talk about, what is going to happen to move gas now and unfortunately the animation here didn't work as well as I wanted it to, but can you please ignore the little yellow for a second. I want to talk about what will happ- -- what could happen if it gets colder -- cold again and we have something break or if it gets colder and we need more gas.

As I talked about on the earlier slide about the only place to get it is the LNG plant and we have limitations as to what we can get through this line and what we can basically move around by displacement and other means to get it through here. Currently there is not a physical connection between the KNPL pipeline and our system here so we can't utilize this 20 inch line with utmost capacity.

With the approval of the Settlement Agreement on KNPL we can now move forward with some projects that will allow us to potentially back-flow KNPL on peak days. There will be an interconnection constructed this year, this summer to physically connect KNPL and APC's pipelines at the Kenai field so we can move gas south, utilize this to help relieve the bottleneck that we have here.

Second of all, there is planned work to be done to better let gas come from the Swanson River field into KNPL. Currently gas goes in -- up KNPL in the summertime into the Swanson field for storage, but it's not set up to take a lot of gas coming back so the modifications will be done on the system. We gerry rigged -- we used existing piping and waste (ph) piping has not been used.

And I say we, I really have to hand it to Unocal/Chevron, Marathon and Agrium for moving gas around in pipes that weren't designed originally to do it that way to get as much as they possibly can into the system or into the LNG plant so that we could get everything we needed on the cold day, so that's a second phase project that on slated to be done this summer.

The other situation is ConocoPhillips has the North Cook Inlet field. It has a dedicated pipeline that goes straight into the plant for this gas. Part of the gas that was used on our peak day actually came from ConocoPhillips under agreements they have with the other producers from this field.

Now, things moved around by paper, but in fact, there is -- other than backing -- taking it to the plant and then backing it out through a small line that we have, there's really no way to get this gas into the system up here to serve everybody.

So the other thing that's planned for this summer is an interconnect between Cook Inlet -- north Cook Inlet line and probably CIGGS, that's going to, kind of, depend on what the regulatory status is, I think, but probably the north end of CIGGS so that in an emergency situation the huge amount of deliverability that's coming off of here can get dumped into the system to bring it either this way, which is already full or this way down and over here.

The other thing I want to talk about just briefly with this as well is in the earlier slides I showed how the production over here is declining and how this pipeline is getting less and less gas moved through it. This pipeline is getting more and more moved through it.

We have compressors stations here at the Kenai field and then right about here to maximize the amount going through this line that's actually parallel coming up, but there is a limitation to the amount of gas that we can bring up this way without putting in more compression or physically looping the pipe -- the line.

Also, we have large loads on the west -- I'm sorry, on the north side of Anchorage, primarily ML&P's generation. It really needs high pressure gas that comes through here. There is discussion among the various parties that at some point in time we may need to put compression either here at Nikiski or compression here at Granite Point so that this line not only would go to zero, the marine CIGGS crossing would go to zero, but in fact, flow backwards and coming in here to bring gas around this way to bring it into the system.

We had a series of meetings with the various producers, transporters and the power customers in November and December laying this out and talking about these solutions to try and get the infrastructure that we have to move the gas to where it's got to go on these cold days.

Again, one of the big surpri- -- you know, we have not had a cold day like this and cold weather like this for many years. I think it surprised some people, especially for the loads that were not Enstar gas supply loads and some of them that weren't Enstar gas supply loads until this winter.

We talked about how much -- we talked about earlier in the year that we were getting gas coming back too as transport customers coming back to us, we have picked up about three and a half billion feet a year of annual load of transport customers that have come back to gas supply.

In November and December when we had the really cold weather one transporter just didn't have enough gas to satisfy their customers and they had to shed an additional 189 customers (ph) and that happened in December, so deliverability is extremely tight. Everybody has other commitments, but we're taking it away from the industrial plants. We're taking it away from other customers.

We do a lot more negotiating on a daily basis for the deliverability because everybody wants to make sure that they're putting their fair share in because they have another market for their fair share. The gas supply has gotten very, very complicated and it's gotten very, very tricky.

In conclusion, just the points we wanted to bring out to you. Cook Inlet deliverability has dropped significantly, but we've kept everybody on. I'm sorry, I'm ahead of myself.

What happens if we have another cold day and we have a problem? We'll go -- we'll try to get as much as we can from the LNG plant. The next steps, and we've actually walked through this scenario three times this winter because we were getting very concerned. The next step would be to ask the power customers to cease making economy energy sales outside of the Cook Inlet.

In other words, please, interrupt the economy energy sales that are going to Fairbanks. Beyond that we start asking them to send power down from Fairbanks, then you start talking about who can generate power with something other than electricity -- or I'm sorry, with gas.

And then we get into scenarios that we don't even want to talk about, but that is the planning scenarios that we've actually walked through with everyone both in a planning meeting and then on a couple of nights so far this winter -- more than a couple of nights so far this winter where things are staring to get really, really interesting.

So here's the take away, first of all, we made everything and the fact that we did make everything with a really cold day has given some of the producers a little bit more confidence of what they've really got, but Cook Inlet deliver -- deliverability understandably has dropped significant.

Natural gas has had to move differently than it's had to do in the past. Demand is not being met on peak days. The indust- -- Agrium is gone. The LNG plant is shorted. The Tesoro plant is shorted.

Additional work is going to be necessary to stem the deliverability decline and infrastructure investments are needed to transport natural gas from where it is to where the load is, the high, critical load is, the residential, commercial and industrial customers. And I think the Commission will probably see some of the interconnect agreements under those various pipelines for this summer's planned work for later on.

And that concludes my presentation. This presentation will be available on our website probably later today or early tomorrow, as all of our public presentations are. And with that I'd be happy to answer any questions.

ACTING CHAIR JOHNSON: Questions for Mr. Dieckgraeff? Commissioner Harbour.

COMMISSIONER HARBOUR: Thanks for being with us, sir. You can sit down if it would be more comfortable for you. Appreciate you standing for the presentation.

Do you recall after 2000/2001, similar in that time frame, the AEDC did a study of Cook Inlet gas supply and, I think, Enstar participated in that study?

MR. DIECKGRAEFF: Enstar participated in the study that was done in 2000/2001. We helped come up with the money to publish it after it was completed among other things.

COMMISSIONER HARBOUR: Okay. And it's that study.....

COURT REPORTER: (Indiscernible - away from microphone).....

MR. DIECKGRAEFF: Okay. Yes.

COMMISSIONER HARBOUR: And in your opinion would I be correct in remembering generally that the type of situation we're encountering now was pretty well projected at that time?

MR. DIECKGRAEFF: Actually it's been projected since the mid-'90s. We did work dealing.....

COMMISSIONER HARBOUR: I understand. I'm just.....

MR. DIECKGRAEFF: ....with the (indiscernible - interrupted).....

COMMISSIONER HARBOUR: .....asking about that.....

MR. DIECKGRAEFF: Yes.

COMMISSIONER HARBOUR: .....particular study though.

MR. DIECKGRAEFF: Yes.

COMMISSIONER HARBOUR: And am I to understand from your presentation -- you talked about declining production, but am I to understand from your presentation that -- well, I don't think you addressed in your presentation that there have been some discoveries, otherwise the decline would have been steeper.....

MR. DIECKGRAEFF: Definitely.

COMMISSIONER HARBOUR: .....over the last five years, is that.....

MR. DIECKGRAEFF: Definitely, there's -- there have been discoveries. The largest one I'm aware of is the Ninilchik Unit down that Unocal and -- Unocal, now Chevron and Marathon made and it's in the several hundred Bcf range, but had those -- and there's been some smaller fields discovered.

COMMISSIONER HARBOUR: Okay. Now, just because we're at a Public Meeting -- and I appreciate the initiative in providing this presentation. I think it's good to do on a regular basis, but I can't let you go without asking you about a statement you made regarding scenarios you don't want to think about.

And I think because you've thought about those and you mentioned them today, the public is entitled to know what are the scenarios you don't want to think about that would be scenarios that would follow those that you did describe such as a shedding of supply from industrial customers to -- in favor of residential customers such as interrupting interruptable supplies to other markets such as bringing in actual new volumes from other markets or power from other markets over and above those -- that list of items that you mentioned that would help satisfy demand in an extreme situation.

Can you identify what are those scenarios that you don't want to think about, but which probably the public ought to be aware of?

MR. DIECKGRAEFF: Well, first of all if we were in an emergency situation we would do like other utilities that have had some supply constraint for whatever reason is get on publicly and ask people to try to conserve and back off their thermostats and do the best they can at that point.

At this point we're already assuming that we're getting everything that we can get into the system from the industrial plants and that we are getting everything we can get from the power customers and power coming down from Fairbanks and having them over -- try to get as much as can from hydro and ML&P switching to fuel oil. That actually would pick up quite a bit at that point. Forty million a day is a pretty big chuck of load that could come from -- perhaps, from the power side being put in.

Beyond that you start considering whether you have to block off portions of the system. I mean, we don't have a button in gas control that can close everybody's value. There are 125,000 meters out there. Essentially we would have to be able to turn people off mandatorily or types of customers off ourself. We would physically have to go to that location and do it.

So what you look at is trying to isolate portions of the system. You do not want to get into a situation where the pressure in the system drops below point and you drop out everybody because that's what, in fact, could happen. And to refer back to a previous discussions before the Commission in other -- in dockets that's where you get into the 100,000 pilot light scenario or now 125,000 pilot light scenario.

COMMISSIONER HARBOUR: Understood, thank you very much, sir, that's all I had.

ACTING CHAIR JOHNSON: I have a couple inquiries. Mr. Dieckgraeff, has the utility -- ideally be prepared to answer this question today, but maybe you weren't, still compile heating degree day numbers for the current year and do you have any knowledge about how the current year compares season to date, if you will, to the average season to date?

MR. DIECKGRAEFF: We're running ahead -- a little bit ahead for January. February was the coldest February since 1999 or 1990. I'm sorry, not February, November was the coldest since 1990. December started out war- -- was warmer in the center, got cold a little bit at the end, but I believe it was still -- ended up being slightly warmer than normal. January, the first part of January, of course, was cold. We have a cold January last year, but month to date, I think, we're still running ahead of the 10, 15 year normal.

ACTING CHAIR JOHNSON: Do you publish the heating degree data on the website anywhere?

MR. DIECKGRAEFF: We don't. The Weather Service does.

ACTING CHAIR JOHNSON: I've looked pretty hard for the Weather Service. I can never dig it out very well.

MR. DIECKGRAEFF: They -- if you go to the sec- -- if you go the forecast office website, the Anchorage forecast office website, they have a link that says climate and you switch over. You click that link. You can see the degree days for that individual day and, kind of, season to date, year to date and half a year to date numbers.

The data is uploaded eventually to the National Climate Data Center in Washington D. C. but.....

ACTING CHAIR JOHNSON: Yeah. And maybe we can talk about that. A little further along the line you can direct me.....

MR. DIECKGRAEFF: There is a graph on their website that sows the temperature also.

ACTING CHAIR JOHNSON: Okay. One thing -- and it's -- I don't want -- and let me start by saying we're not trying to assert jurisdiction anywhere where we don't have it. At the same time I was concerned when you said that in cooperation with the rest of (ph) the produces and users that you had been utilizing some pipe and some facilities in ways in which it had not, perhaps, been designed. I think we have a little additional awareness these days about pipeline safety issues and -- do we have your assurance that at no time was a request made to operate any facility in an unsafe manner?

MR. DIECKGRAEFF: You have our assurance. Everybody was trying to make sure they stayed well within their safety bounds, so -- but everybody has assured us that what they did was safe.

ACTING CHAIR JOHNSON: Okay. Anything further for Mr. Dieckgraeff this morning? Anything further from you, sir?

MR. DIECKGRAEFF: No, not unless we have any more questions.

ACTING CHAIR JOHNSON: Thank you very much.

MR. DIECKGRAEFF: Thank you.

ACTING CHAIR JOHNSON: That brings us to item 6, Other Business, is there Other Business to come before the Commission today?

Not hearing anything, item 7 is an Executive Session. There -- to my knowledge there is an item that could be addressed in an Executive Session. Is it the desire -- and that item pertains to a Petition for Confidentiality. Commissioner Harbour.

COMMISSIONER HARBOUR: Yes, Commissioner Johnson, if there's no objection I would urge that we go into the Executive Session for the purpose of discussion future direction in that matter.

ACTING CHAIR JOHNSON: Okay.

COMMISSIONER HARBOUR: And that the matter to be discussed is confidential information that we have received from a utility.

ACTING CHAIR JOHNSON: Right. Is there a second, just to keep things on the safe side?

COMMISSIONER WILSON: Second.

ACTING CHAIR JOHNSON: It's moved and then seconded that we go into Executive Session for that purpose and that purpose alone. Without objection we will be in Executive Session.

(Off record - 11:43 a.m.)

APPENDIX E