

AK LEGISLATURE SPECIAL COMMITTEE FILES SCOMM 155 331 79/

order, where land acquisition is required. The absence of a detailed process in the NPA for acquiring required land rights may impede the process of acquiring necessary land rights for the Project, which could have an unfavourable impact upon the construction and operation of the Project. It is expected that TransCanada would seek to rely on the NEB land acquisition process to address such issues.

While the NPA does not specify a process by which a pipeline company could acquire the lands needed for the pipeline, we note that section 7 of the NPA stipulates that the Designated Officer may, in respect of the pipeline, exercise and perform such of the powers, duties and functions of the Board (with certain specified explicit exemptions), as may be delegated to him by the Board. The powers of the NEB relating to land acquisition are not listed among the express exclusions. Therefore, it appears to be open to the NEB to delegate to the Designated Officer the powers required to assist TransCanada in acquiring land. While we cannot speculate on what would be required for the NEB to make such a delegation of its powers (or what process would be used), it seems that TransCanada could explore this option if it could not otherwise acquire the necessary lands. This approach would only apply in a situation where TransCanada was seeking to rely upon the NPA and not otherwise involve the NEB directly.

9. Fulfillment of Existing NPA Terms and Conditions

Even if TransCanada were successful in confining the process for examining the Project to the "single window" approach advanced by the NPA, there is the matter of the extensive Terms and Conditions attached to the existing approvals. For example, as discussed above, the Designated Officer under the NPA can require that additional environmental information be filed in support of the Application. As such, it is possible that even if TransCanada were to succeed in technical arguments (likely following lengthy debate) that CEAA or YESAA do not apply, the Designated Officer could impose a similar process to ensure that a complete environmental assessment is conducted for the length of the pipeline in Canada. In fact, there may be significant pressure to ensure that such an approach is followed.

Additionally, TransCanada will be required to meet other extensive conditions prior to commencing construction. The exact process for a consideration of the information filed regarding these matters is uncertain, but could be the source of debate if a full public vetting of this matter is not accommodated.

10. Litigation

In our view, there are likely to be a significant number of "trigger points" which could provide the basis for a Court challenge. As noted at the outset, there has already been litigation regarding the NEB's Northern Pipelines Decision involving First Nations and Environmental groups. Past experience suggests that such parties are well versed in their legal rights and have little hesitation in seeking recourse to the Court system when they are aggrieved. Likewise, commercial parties seldom hesitate to commence litigation if they are not satisfied with the outcome of commercial discussions. As noted, there has already been litigation involving a past Foothills Pre-Build application.

11. Conclusion

In our view, any single item identified above, or the risks acknowledged by TransCanada in its AGIA Application, could result in a material delay to the schedule detailed by TransCanada in its Application. Given the circumstances that one could reasonably expect to evolve following a TransCanada filing, it is foreseeable that several of these potential concerns identified above could become a reality. Again, much will depend on how TransCanada approaches these matters. Therefore, we consider the TransCanada proposed schedule to be aggressive, in the sense that it will be difficult to achieve in the time available. While we fully appreciate that TransCanada, as the project proponent, may wish to push the shortest possible timeline, it is our view that a more realistic schedule would allow time to accommodate delays associated with the risks identified in the TransCanada AGIA Application, as well as, the above identified considerations. While we agree that the NPA approvals are of value to TransCanada (and give it an advantage over any Third Party proponent), it is our view that the five and one-half years proposed by TransCanada for securing major Canadian pre-construction approvals following the issuance of the AGIA License, represents a

"best case" scenario and would likely be difficult to achieve. It is our view that a timeframe of seven to eight year is more realistic, as it is seen as reasonable to expect that at least certain of the issues identified will be raised during the preparation and regulatory approval phases of the Project, with the resultant impact on timing. In this regard, a seven year timeline may be viewed as a "base case" scenario, with the highest probability of success and the eight year end of the range providing a more pessimistic view.

With regard to timing, we would also note that the NP Agency appears to have been largely dormant for many years, with only a skeleton staff being employed. While public information indicates that the NP Agency has been attempting to have discussions with a number of bodies in light of the revived interest in an Alaskan pipeline project, there is little tangible evidence to indicate that any material work has been done to date. In our view, an extended period of time (up to 18-24 months) could be required in order to complete the necessary coordination in order to have all administrative bodies in the various jurisdictions address a TransCanada Application in an efficient manner. While TransCanada could obviously do some preliminary work prior to the establishment of such a coordinated process, it appears that the process has not yet commenced and, hence, the starting point for TransCanada's timeline may be delayed beyond what it currently expects.

As stated above, the timeframe required for TransCanada to complete the Project and reach its in-service date will be materially impacted by the strategy it employs in seeking the required approvals and the process that is adopted for the consideration of these matters. If TransCanada proposes or encourages a process that is inclusive of all stakeholders and which seeks to address relevant issues and concerns, it will enhance the prospect of TransCanada being able to maintain an expedited timeline for the Project. In any event, given the significant issues that will have to be addressed and the numerous risks that will surround the Project, we consider it reasonable to conclude that a certain amount of slippage will occur in TransCanada's proposed schedule.

We would caution that, while a seven to eight year period does incorporate a certain measure of delay associated with recourse to the Courts or review by another Government or Regulatory body, this may not be the "worst case" scenario, as there are several events which could trigger litigation that are not mutually exclusive. There could be several challenges at different points along the process timeline that could cause distinct delays before the specific issues are resolved. While we acknowledge that litigation, in and of itself, does not automatically result in delay, it would require some party to assume the litigation risk, if the Project is to continue to move forward while these matters are being resolved. Additionally, the above assessment does not take into account the timing consequences of any litigation against TransCanada being successful. If this were to occur, an extended period may be required to remedy any deficiency that was found by the Courts to exist. In our view, much will be impacted by the strategy adopted by TransCanada and whether or not this strategy is designed to minimize the process and procedural delays that would be available to intervening parties. To the extent that this is done, many of the potential negative impacts to the project timeline could be avoided.

While we consider TransCanada's proposed schedule optimistic, even an extended schedule for TransCanada as detailed herein may well be materially shorter than any Third Party proponent could achieve. In fairness to TransCanada, it is not "starting from scratch", as would be the case for any other proponent with a "Greenfield" pipeline proposal. While this is an advantage, our overall view is that it is unlikely to allow TransCanada to complete the Project approval phase within the timeframe it has outlined. As stated above, much will depend upon the overall approach adopted by TransCanada in moving the Project forward. In the end result, it is seen as reasonable for the State of Alaska to also examine a timeline of approximately seven years for the completion of the required approval processes as part of its overall assessment, in addition to the five and one-half period reflected in TransCanada's AGIA Application.

In summary, we would attach a low probability to the five and one-half year timeframe, but one cannot rule it out completely. If TransCanada adopted an expansive approach in its APP filing, that reflected not only current legislative and judicial

standards, but also facilitated the open participation of all impacted stakeholders, it is likely that TransCanada could minimize the risks associated with certain of the concerns identified herein. This scenario could enable it to complete the process in a timely manner.

In this regard, we agree that the timeline provided by TransCanada is longer than that required for a "typical" facilities approval process. In our view, this reflects TransCanada's reasonable acknowledgement that an Alaska Pipeline Project Application will certainly not be "typical" and will raise a broad spectrum of issues that will take time to address.

E. RATES AND ACCESS

1. New Versus Existing Facilities

An issue has arisen with respect to whether or not TransCanada could be required to make use of existing, underutilized facilities instead of constructing a new pipeline to facilitate the transportation of Alaskan natural gas. TransCanada's AGIA Application appears to acknowledge that infrastructure requirements in Alberta may well be influenced by the amount of available capacity at the time the Project is scheduled to be in-service. A key input into this determination is the forecasted decline of Western Canadian sedimentary basin sourced natural gas. At this time there appears to be a strong consensus that WCSB natural gas will continue its recent decline trend, with the direct result that existing pipeline facilities serving certain domestic and export market areas will be underutilized by the time the Project would come onstream. The degree to which additional facilities are required to service certain market areas, such as the Fort McMurray oil sands industry, and the timing of such requirements is fairly uncertain at this point in time.

It is also noteworthy that in its Application TransCanada speaks favourably of the option of using Transportation by Others, at least as it relates to its own Alberta system. What is unclear is whether TransCanada would be as eager to contract Transportation by Others on third party pipelines, such as the Alliance Pipeline. In our view the failure to consider using third party pipelines could be a source of contention that would cause

such parties to actively intervene in the Project process and urge the NP Agency, the NEB and the respective Governments to ensure that existing infrastructure, with available capacity is utilized to the maximum extent possible. In our view, to the extent that the NEB is involved in this aspect of the decision making process it would encourage TransCanada to adopt the most economic and efficient manner to transport the subject natural gas. The strategy employed by TransCanada with respect to such third parties will greatly influence the degree to which this becomes a controversial matter in any Alaska Pipeline Project proceeding. As discussed above, to the extent TransCanada is required or opts to use an NEB process for intra-Alberta facilities, there will clearly be a forum available for parties to advocate the use of existing facilities. In reality, this may not be a bad thing as otherwise these parties may be forced to seek alternative venues (NP Agency or the Courts) which may not have efficient processes to consider this issue.

2. Return on Equity

TransCanada's Application appears to suggest that it would be seeking a Return on Equity ("ROE") of 14% for both the U.S. and Canadian portions of the Project. This ROE would be substantially in excess of the level of return awarded by the NEB under its Generic Cost of Capital Decision. While there is precedent for the Board awarding a "Greenfield" pipeline project a higher return than that determined by the GCC formula, it is our view that 14% would be seen as being on the high side in today's return environment. The degree to which this becomes a significant issue in any Alaska Pipeline Project proceeding will be influenced to a large degree by whether or not TransCanada is able to arrive at a Negotiated Settlement for rates as will be discussed below. TransCanada may have put this rate on the table because U.S. returns have traditionally been higher than for Canadian pipelines and it gives some flexibility in negotiations.

3. NEB Rate Setting Approach

As with Regulatory Tribunals in many jurisdictions, the NEB's rate setting authority is contained in its governing legislation and requires that the NEB establish

"just and reasonable" rates for the services provided by the various pipelines under its jurisdiction. Traditionally, this rate setting authority relied upon a Cost of Service model, whereby the rates were set following a litigated process in which the various forecasted costs (O&M, Taxes, Depreciation, Return, etc.) were examined, debated and ultimately decided upon by the Board. While the NEB's approach to ratemaking shares several common elements which the structure utilized by the FERC, there are some material differences.

The NEB's ratemaking legislation expressly contemplates the concept of "negotiated rates" which would see the subject pipeline company reach an agreement with shippers/affected parties on the rates to be charged for firm transportation and other services. While the NEB is not obligated to accept such a negotiated settlement, as it must still make a determination that the subject rates are fair and reasonable, it is our experience that a highly supported Negotiated Settlement stands a very good chance of receiving approval from the NEB, as filed. In the past, the NEB has accepted a variety of negotiated settlements and, in fact, has largely regulated the Group 1 Oil and Gas Pipeline Companies (the larger companies such as TransCanada, Enbridge, etc.) on this basis for an extended period of time. To a large degree the Negotiated Settlement process has replaced the litigated cost of service approach that was representative of NEB regulation in the past.

Therefore, while the NEB has no real experience with a "recourse rate" concept, as that term is used before the FERC, it is our view that a similar end result can be achieved via a negotiated settlement process. We would observe that the past Negotiated Settlements accepted by the Board have been in a variety of different forms; and the Board has exhibited considerable flexibility in this regard. Additionally, for "Greenfield" pipeline projects the Board has been willing to accept fixed rates that vary depending on the duration of the commitment made by shippers and has been willing to give priority or guaranteed access to shippers making such firm commitments.

It is unlikely the NEB will depart from past practice to the extent that it would set rates within a range and allow the pipeline the ability to discount at its discretion. This

model has not been adopted to date by the NEB, although it has permitted pipelines the flexibility to respond to market conditions when setting interruptible service rates.

Likewise, the concept of levelized rates has not become a common practice before the NEB. Notwithstanding, the Board has allowed new pipelines to charge less than a Cost of Service rate in the early years (due to market constraints) and then charge above Cost of Service rates in later years (when the market can accommodate the increases). In short, there is a willingness on the part of the NEB to accept various methods of meeting its underlying legislative requirements; and we are of the view that a number of reasonable alternatives would be acceptable to the Board. We note that, in the context of the Project, there are certain rate making issues addressed in the NPA that may influence the final outcome of this issue.

4. Open Season

While not a common occurrence regarding NEB regulated pipelines, the Board has experience with the Open Season concept regarding a number of new pipeline projects. The fundamental underpinning for the conduct of an Open Season is the requirement that all potential shippers be offered the service under the same Terms and Conditions. Therefore, should an initial Open Season result in follow-up negotiations with certain Interested Parties, and amendments to the slate of services/benefits being offered shippers to induce them to execute Long-Term Firm Transportation Service Agreements, it would be necessary for TransCanada to conduct a supplementary Open Season (in order to ensure that all parties were offered the transportation service on precisely the same Terms and Conditions). Such a supplementary Open Season could be conducted quite expeditiously and should not delay the process in a material way. In our view, as long as these fairness requirements were met, the NEB would be prepared to accept the results of the Open Season process and consider the results as support for the subject pipeline proposal.

5. Import and Export Requirements

In recent years parties exporting natural gas from Canada to the United States have chosen to rely upon Short-Term Export Orders (maximum two year duration) instead of seeking approval for Long-Term Export Licenses (maximum term twenty-five years). The move away from Long-Term Licenses, which was prevalent up to the mid-1980s, was largely influenced by two factors. First, the process for obtaining Long-Term Licenses had become quite complex because of the involvement of Intervenor Groups who sought to expand the scope of the investigation conducted by the NEB into a consideration of upstream environmental impacts. While a standard approach was developed to deal with these applications, many parties opted to simply rely upon Short-Term Orders and avoid the more lengthy and complex process. The second reason was a fundamental change in the approach utilized by the NEB and shippers with respect to the requirements to make long-term commitments to support pipeline expansions and downstream projects. In the past, buyers relying upon the gas supply to support their projects (such as downstream pipeline facilities or cogeneration plants) required a demonstration of long-term approvals in order to be comfortable with the security that the supply would in fact be there. Additionally, pipelines required a long-term license as a demonstration of supply availability to meet the long-term commitments being made by shippers for pipeline transportation service. Finally, financial institutions viewed the long-term approval as confirmation of the economic viability of the proposed venture and support for the funding they would advance to either the pipeline or the downstream project proponent.

Over time, as the gas supply supporting export transactions moved more to a spot market, or hub, pricing approach (versus long-term Purchase and Sale Agreements) and pipeline expansions (which were decreasing over this time period) were supported by corporate warranty type agreements, parties concluded that short-term approvals were adequate for these purposes. Additionally, the stability of the NEB's regulatory regime and the comfort that short-term Orders would be renewed without any significant measure of difficulty reinforced the view that the short-term

authorizations were indeed adequate to support the associated commercial undertakings.

Notwithstanding the above, in circumstances where significant financial commitments are being made and the project is of a long-term duration, it may be considered desirable to secure such long-term approvals. It is our experience that a 9-12 month period would typically be required to obtain a long-term license. A short-term order can normally be obtained in less than a week and with minimal supporting information.

SCOMM

155:25

Alaska State Legislature

Senator Charlie Huggins, Chair
Senate Special Committee on Energy
State Capitol, Room 119
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Phone: 465-3878
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Representative John Harris, Chair
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Fourth Special Session
Twenty-Fifth Legislature

Gymnasium
Terry Miller Building, Juneau Alaska

Monday July 14, 2008

9:00 a.m. - 8:00 p.m.

Joint Meeting AGENDA

- SB 3001/HB 3001 Approving AGIA License for Natural Gas Pipeline Project as proposed by TransCanada Alaska Company, LLC and Foothills Pipelines Ltd. (TC Alaska) to the State of Alaska.

-9:00-5:00 FERC Issues:

Jeff Wright, Deputy Director, Office of Energy Projects, FERC
(by teleconference) (has 2pm, AK time, commitments)

Bill Mogel, LB&A Consultant

Tony Palmer, VP AK Business Development, TransCanada
Curt Moffatt, Van Ness Feldman

Pat Galvin, Commissioner, Department of Revenue

Don Shepler, Greenberg Traurig

Loyola Keough, Bennett Jones LLP, (possibility to reach by phone if Canadian
NEB or Department of Energy process questions arise)

Testimony: By Invitation

-6:00-8:00 Statewide Public Testimony

Time Limit May Be Set

SB/3001
HB/3001

Public Testimony
7-14-2008

HRLS / SENR
Juneau, AK
House Rules &
Sen. Spec. Cmte on Energy

Natural Gas in Alaska - enough to support the world for 100 years

It started in 1985, and one source for this information was in the National Geographic, it stated, "There is one hundred trillion cubic feet of natural gas in Alaska. That is enough to support the world for one hundred years."

Natural gas burns pure, it will eliminate pollution, in a matter of time it will end the green house effect. The Arctic, Antarctica, and Greenland are considered very big weather conditioners for the world.

In the last twenty years Exxon and BP have provided propaganda that there is no market for Alaska natural gas (example is attached, 2002).

Exxon is attempting to get permission from congress to build the gas pipeline. They will abandon their own property publicly for the last twenty years, and the property goes back to the owner.

Economy - Natural gas would cost about \$1.50 at the pump and a car would get twice as much mileage then the gas we use today. This means the average family in the USA would save about 300%.

Our Alaska leaders claim that the 1700 mile gas pipeline would cost only 30 billion dollars. In 1975, the oil pipeline cost 8 billion dollars and was 800 miles. If that oil pipeline was built today it would cost 28 billion dollars.

A 1700 mile gas pipeline today would cost 55 billion dollars. The only way to make a 30 billion dollar pipe line is if Canada uses it own steel mills, iron ore, labor, and truck drivers. Then they can build a 30 billion dollar pipeline.

It is Alaska natural gas and the first 800 miles of gas pipeline are in Alaska, so Alaska should retain the majority interest in the project, because it is Alaska's natural gas. Since Canada will own all that is on Canada land or about 2800 miles, Alaska will have to go 50/50.

When Alaska Natural gas hits the market there will be trillions of dollars to split with Canada.

It would be better to deal with United States of America, to build our gas pipeline and give the USA fifty percent. Alaska will be out sourcing the entire USA.

Henry J. Stevens

Henry J. Stevens
Alaskan Democrat

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Monday's Money section
offer a good relaxing and beautiful incentive
much excitement around a lighter, fun way can
you now find a certain spirit's peace or other
THE LUC BOAT



REPUBLICAN PLATFORM (2000)

The year 2000, President Bush make many promises to get elected

I want to emphasize on several of those Promises:

President Bush was to find ways to make the U.S. independent of foreign oil, no more effort was ever made except to open more land in Alaska to drill for more oil.

United States does not need oil! U.S. needs Alaska Natural Gas.

There is one hundred trillion cu. Yards of natural gas in Alaska, that is enough to support the world for one hundred years.

In the last 20 years, I have read that there is no market for Alaska natural gas, this is only propaganda.

Our main market would be ourselves!

- 1) The entire U.S. Army, Navy, Marines would save billion's of dollars a year.
- 2) The entire transportation service would benefit, trucking, buses, cabs, private cars.
- 3) Hotels, restaurants private homes, factories, all together would save hundreds of billions of dollars a year.

There is three hundred million moving vehicles in the U.S., which causes 60% of the air pollution in the U.S., all private homes, hotels would almost extinguish air pollution in the U.S.

In conclusion:

Alaska Natural Gas would cost about 80 cents a gallon and also Alaska natural gas can get twice the mileage as the gas we use today.

This means trucks can transport Construction material all the way to Alaska and save about 60% of its expense.

SUB-MITTED AND REQUEST TO BE PUT INTO RESOLUTION FORM...
Henry Stevens Alaska Native Democrat

Henry J. Stevens

P.O. BOX 1234 - Jena - 99802 -

Phone - 463-0119

THE LUG BOAT

You won't find a casino, shuffle board or other fancy amenities aboard a freighter, but they can offer a good, relaxing, and possibly inexpensive alternative to cruise ships.

Sunday's Money section.



MONEY

ANCHORAGE DAILY NEWS • www.adn.com

SATURDAY, JUNE 29, 2002

North Slope gas 'not competitive'



FRAN DURNER / Anchorage Daily News

■ **PIPELINE:** BP chief executive says project wouldn't be cost effective.

By **WESLEY LOY**
Anchorage Daily News

BP chief executive Lord John Browne, speaking in Anchorage on Friday, deflated a roomful of business people by saying conditions still aren't right to pipe the North Slope's vast natural gas reserves to market.

He went on to describe the deteriorating economics of Alaska's oil patch, where production is falling and costs are rising.

Although billions of barrels of oil remain to be pumped, Alaska production faces relentless competition from other prospects around the globe — including big gas fields closer to grow-

ing markets like Asia, he said.

"At the moment it is not competitive," Browne said of Alaska's gas.

Further dampening chances of production are taxes and royalties that would strip away all profit for BP and other oil companies, he said.

"This is not a debate about subsidy," Browne said. "We are not asking for any subsidy. We do not want corporate welfare."

Rather, he suggested incentives and "setting taxes in such a way that all projects with intrinsic economic merit can proceed."

Browne made his comments at a breakfast at the Sheraton sponsored by the Resource Development Council for Alaska, the Alaska Support Industry Alliance and the Anchorage Chamber of Commerce.

Browne's infrequent visits to Alaska always

are a big deal. Because he is head of one of the world's largest corporate oil giants and one of the state's two biggest producers, Alaskans involved in oil field drilling and support tend to hang on his words as though he were Alan Greenspan.

Small-statured with a ruddy face and regal accent, Browne was utterly humorless Friday, his speech painting a mostly distressed situation for Alaska's oil industry.

"Alaska is now a mature and much smaller oil province," he said, noting that oil production today is half what it was in 1988 — and declining. To compensate, London-based BP has tried to wrench every dollar of excess cost out of its Alaska operations, cutting its Anchorage work

See Page D-4, BP

SPOTLIGHT: RESOURCES

WorldCom ties to create certainty

doubled
in local

thing."

WorldCom is the nation's second-largest long-distance company. On Tuesday it re-

IN IRAQ



CHARLES REX ARROGAST / The Associated Press

Fort Campbell, Ky. More than 600 troops from the 101st ent.

Global warming could wipe out 37% of species

■ STUDY: Researchers say greenhouse gases must be reduced soon.

By GUY GUGLIOTTA
The Washington Post

In the first study of its kind, researchers from northern Britain to the wet tropics of northeastern Australia and the Mexican desert said Wednesday that global warming at currently predicted rates will drive 15 percent to 37 percent of living species to extinction by mid-century.

Dismayed by their own results, the researchers called for "rapid implementation of technologies" to reduce emissions of greenhouse gases and warned that the scale of extinctions could climb much higher because of mutually reinforcing interactions between climate change and habitat destruction caused by agriculture, invasive species and other factors.

"The midrange estimate is that 24 percent of plants and animals will be committed to extinction by 2050," said ecologist Chris Thomas of Britain's University of Leeds. "We're not talking about the occasional extinction — we're talking about 1.25 million species. It's a massive number."

The study marks the first time scientists have produced a global analysis with concrete estimates of the effect of climate change on habitat. Previous work focused on smaller regions or limited species.

Thomas led a 19-member international team that surveyed habitat decline for 1,103 plant

and animal species in five regions: Europe; Queensland, Australia; Mexico's Chihuahua Desert; the Brazilian Amazon; and the Cape Floristic Region at South Africa's southern tip. The study is being published today in the journal *Nature*.

The regions encompass 20 percent of the Earth's surface and "include a fair range of terrestrial environments," said Thomas.

"Obviously it would be valuable to expand the scope, but there's no reason to think that doing so would change our results tremendously," he said.

Researchers said the wide geographical scope also overcame outside factors that might affect a single region only: "A prolonged drought might cause one instance of a dieback" but be offset by changes elsewhere, said climate change biologist Lee Hannah, who worked in South Africa. "When you see the broader context, the regional blips drop out."

While there is little dispute that the Earth's temperature is rising, debate over the reasons and speed of change remains contentious. Still, most scientists accept that much of the warming is due to the cumulative effects of greenhouse gases that trap and hold heat in the atmosphere.

William O'Keefe, president of the George C. Marshall Institute, a conservative science policy organization, raised criticisms of the study, saying the research "ignored species' ability to adapt to higher temperatures" and assumed that technologies will not arise to reduce emissions.

ws to cut taxes

the entire middle class. Dean it is wider the mid-

at he has a tax rate fairer for their fair to do so onents for easing in the center election

2n. Wesley Massachusetts and cut, seek

ing to present themselves as the more centrist, electable alternatives to Dean, are hitting the issue hard in Iowa and New Hampshire.

"I don't want to go back to being the old Democratic Party that doesn't get it," Kerry said in an interview Wednesday. "I've been fighting all year to protect middle class taxpayers." Kerry has advocated eliminating the tax cuts that benefit the wealthiest Americans, but preserving those for the middle class. His campaign is planning a television spot in Iowa faulting Dean for not doing the same.

Adding to the pressure within the Democratic Party are the first maneuverings of the general election campaign. The Bush camp and its allies clearly look forward to campaigning against their eventual opponent as a throwback to the old tax-and-spend days of the party.

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Dec 22 culations, an expert approved finally an

Department suspended pending further action by Sullivan.

Mark Zaid, a Washington lawyer who filed the suit challenging the program, called Sullivan's decision lifting the preliminary injunction a temporary setback and said his clients would prevail at trial in challenging the anthrax vaccine.

Zaid said he will soon ask Sullivan to re-issue an order blocking mandatory anthrax inoculations because the FDA's approval of

CORRECTIONS

A headline on a University of Alaska Anchorage hockey story on Page C-1 of Tuesday's Sports section erred in saying Matt Hanson was lost to the team because he was "flunking." Hanson was declared academically ineligible but is not flunking.

A correction that ran on Page A-3 in the Dec. 21 newspaper mistakenly said that low income and elderly Alaskans received prescription drug benefits through the state's Senior Care program. None currently gets drug benefits through the program. There is a proposal to give very low income seniors the option of drug benefits instead of cash payments and to provide a limited drug benefit to seniors with slightly higher income levels.

A headline on Page B-1 of Wednesday's newspaper that said small amounts of marijuana would be OK for cars and

JAN

TRANSCANADA: Firm says it offers experience

Continued from A-1

Palin's gas team is evaluating the confidential applications and is expected to announce soon which ones qualify to contend for financial incentives and a license under a new law Palin pushed last year, the Alaska Gasline Inducement Act.

To some industry observers, TransCanada already stands out as the leader among the five AGIA applicants.

"You don't need to see what's in their proposal to know they know what they're doing," said Ken Boyd, a former state oil and gas director now working as an industry consultant.

TransCanada says it offers experience building big pipelines, expertise in northern construction, and a clear understanding of the politics in Canada, through which much of an Alaska pipeline would run.

The company also has spent years lobbying in Alaska, and has a link to the head of Palin's gas pipeline team.

The state incentives and license wouldn't guarantee actual construction. Rather, they would obligate the winner to make its best effort toward a risky megaproject costing \$30 billion or more depending on its route and length.

Aside from TransCanada, the other contenders include Chinese energy giant Sinopec, a newly created Alaska firm called AEnegria, and two governmental organizations with in-state pipeline ideas.

TransCanada has a special attraction to Alaska gas, which would feed into the company's web of pipelines in Alberta and the Lower 48, making those lines more profitable. Kvisle declined to discuss other specifics of TransCanada's bid.

ALASKA INFLUENCE

TransCanada, headquartered in a gleaming 35-story glass tower in downtown Calgary, bills itself as the largest gas transmission company in North America and one of the largest pipeline players in the Lower 48.

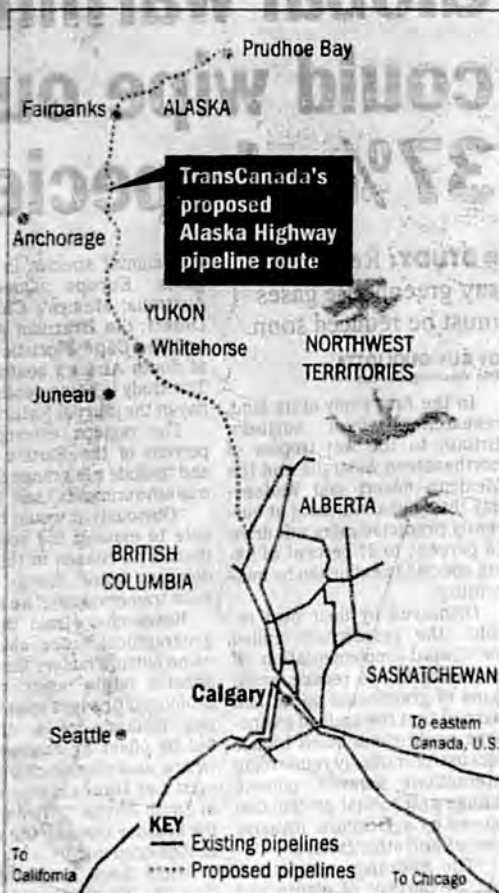
Its experience chasing an Alaska pipeline is as deep as a Prudhoe Bay well, and TransCanada touts that as an advantage.



Kvisle

In the late 1970s, just as Prudhoe crude began flowing through the trans-Alaska oil pipeline, many assumed builders soon would lay a gas line.

The U.S. and Canadian governments awarded a partnership that included TransCanada



Source: TransCanada Corp. RON ENGSTROM / Anchorage Daily News



TransCanada

- **THE BUSINESS:** A top Canadian pipeline and power company with 36,500 miles of natural gas pipelines across Canada, the U.S. and Mexico.
- **HEADQUARTERS:** Calgary
- **WORKFORCE:** 3,550 employees
- **CHIEF EXECUTIVE:** Hal Kvisle
- **2006 FINANCIALS:** \$1.1 billion profit on \$7.5 billion in revenue
- **WEB SITE:** www.transcanada.com

Source: TransCanada Corp.

ing proposal from Conoco, BP and Exxon Mobil, died under Palin's predecessor, former Gov. Frank Murkowski.

Now, TransCanada is bidding once again.

The company has worked behind the scenes to bolster its position in Alaska.

One of its lobbyists, lawyer Tom Roberts of Washington, D.C., was chief counsel and legislative director for Murkowski from 1985 to 1990 when Murkowski was a senator.

For the 2005 deal, TransCanada negotiated with Marty Rutherford, a deputy natural resources commissioner under

NO GAS, NO PIPE

All the bidders come into Palin's pipeline competition with some handicaps.

For TransCanada, the company lacks what any viable pipeline must have — North Slope natural gas.

Most of the Slope's 35 trillion cubic feet of gas is controlled in roughly equal shares by Conoco, BP and Exxon Mobil, the latter two opting not to bid last month.

Canadian industry analysts say TransCanada's long pursuit of an Alaska gas line is easy to understand. With western Canada gas fields expected to produce much less in 20 years, the company wants new supplies to keep its vast pipeline network filled, said Bill Gwozd of the Calgary consulting firm Ziff Energy Group.

As a company, TransCanada is highly regarded, analysts say.

"They have an excellent management team that has a track record of successfully executing large projects," said Daniel Shteyn of Desjardins Securities in Montreal.

Kvisle, the TransCanada chief, said he doesn't need Alaska's gas. But the gas presents a chance for new profits, and the extra volume could lower pipeline fees for all customers, he said.

Before construction can start, the oil companies controlling the gas must commit to use the pipeline, Kvisle said.

"We can't make this project go on our own," he said.

MEGAPROJECT EXPERIENCE

During legislative hearings this year, TransCanada executives fought one important AGIA bidding requirement — that the winner of the state license promise to seek an expensive federal pipeline certificate even if North Slope gas producers decline to use the pipeline.

Whether TransCanada has made that commitment — that is, whether its application is complete — remains to be seen.

Kvisle said he's optimistic the oil companies will come along. He ticked off projects on which his company and the oil majors are partners, not rivals, such as a \$5 billion oil pipeline TransCanada and Conoco are planning between Alberta and Oklahoma.

In its proposal to the state, Conoco told Palin it would be willing to have a pipeline company share ownership in an Alaska gas line.

As for the job of actually building a superpipe across rugged northern terrain, TransCanada is most qualified

PIF

say

contract the stat million tion mor Steve ski and l Republi ing agai al, callin ington a security topics in "It w atic if th clude th cation i goes for "It's)

level. I difficult leagues should t the poin domestic r Youn "Whi decision line, and come a said. "V porting too gre: domesti used do

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3 minute Time Limit

7-14-2008
SB/3001 HB/3001

- Bill Leighty - Leighty Foundation - Juneau
Creedy Foundation

6:30:45 - James Williams

Bring to Valdez - sell to Canadians or anyone else!
Valdez

6:36:10 - Henry Stevens

Juneau

6:43:15 - Al Keatch

To K

vote yes for AG1A

- Bill Warren

yes for AG1A

Nikolskye

6:48:40

- Paul Kennell
favors AG1A - NOW!

Anch

6:55:45

Alfred McKinley (yes on Valdez)
AK Native Brotherhood - Chair legislative Centre
problem w/ these having had DWI cannot go work or
go in to CANADA

Juneau

7:00:25

Merritt Pearce for ALL AK LINE

Fairbanks

Self - but ANGPA member
Please listen to Alaskanos - Support AK line

7:10:15

John Sandoz All AK Line to
Valdez!

Juneau 80,000 people
in SE AK

1953 came to JUNU

former Regional Forester - USFS & former DEC Commissioner

7:13:00

Jerry McCutcheon no on AG1A
it's premature

Anchorage

7:18:30

Tom Lakosh

Anchorage

7:36:30

George Brown "think about the
children"

Juneau

10 minute standby - to see if anyone else
signs up.

SCOMM

155:26

ALASKA STATE LEGISLATURE

Sen. Charlie Huggins, Chair
Sen. Bert Stedman, Vice Chair
Sen. Kim Elton
Sen. Lyda Green
Sen. Lyman Hoffman
Sen. Lesil McGuire
Sen. Donald Olson
Sen. Gary Stevens
Sen. Joe Thomas
Sen. Bill Wielechowski
Sen. Fred Dyson
Sen. Thomas Wagoner



State Capitol, Room 119
Juneau AK 99801-1182
907-465-3878
Fax: 907-465-3265
800-862-3878

Fourth Special Session
Twenty-Fifth Legislature

Senate Special Committee on Energy

Tuesday July 23, 2008

Senate Finance Room 532

1:00-4:30 p.m.

➤ **SB 3001 Approving AGIA License for Natural Gas Pipeline Project as proposed by TransCanada Alaska Company, LLC and Foothills Pipelines Ltd. (TC Alaska) to the State of Alaska**

- **Alaska Gasline Port Authority LNG proposal: Export License Issues; Project Economics and Feasibility**
Continued from 7/22

Bill Walker, Project Director, AGPA
Craig Richards, Attorney, AGPA
Radoslav Shipkoff, Financial Advisor, Greengate LLC

- **Administration - LNG Analysis and Issues**
Participants To Be Announced
- **TransCanada - LNG Commitments & Options**
Tony Palmer, VP AK Business Development

Teleconference
Testimony - By Invitation

SEN R
Juneau
rm 532

SB 3001

presented 7-23-08
AGIA license hearing

PHONE (808) 594-1888

FAX (808) 594-1865



STATE OF HAWAII
OFFICE OF HAWAIIAN AFFAIRS
711 KAPI'OLANI BOULEVARD, SUITE 500
HONOLULU, HAWAII 96813

July 18, 2008

The Honorable Lyda Green
Senate President
State Capitol, Room 111
Juneau, AK 99801-1182

Dear Senator Green:

Hawai'i and the Native Hawaiian community are especially vulnerable to rising energy costs. For that reason, the Office of Hawaiian Affairs (OHA), a semi-autonomous state agency and trust created by the people of Hawai'i to better the conditions of Native Hawaiians, has been investigating potential cost savings to Native Hawaiian beneficiaries from lower electricity costs and revenue-generating opportunities for OHA from being involved in the importation, storage and distribution of natural gas from Alaska.

Recognition of natural gas' significant cost savings and environmental advantages to oil and renewable fuels first led to serious analysis of its use in Hawai'i by state and local policymakers in 2004. In 2006, OHA formed a partnership with the Hawai'i Natural Energy Institute (HNEI), the Hawai'i Energy Policy Forum to update the 2004 study with a comprehensive analysis in April 2007 featuring natural gas from Alaska. The study was supervised by Dr. Fereidun Fesharaki, Chairman and CEO of FACTS Global Energy, an internationally renowned energy consultant.

The findings of the analysis, initially reported at the OHA-sponsored 2007 Hawaiian Business Conference and Economic Expo, demonstrated great promise for the Native Hawaiian community and all of Hawai'i from the importation of natural gas from Alaska. With infrastructure, shipping, and storage costs to be borne by the private sector, Alaska natural gas could replace approximately 95% of the fuel oil that Hawaiian Electric Company (HECO) currently uses in power generation on Oahu.

According to the study, natural gas substitution in the power sector in Hawai'i would be approximately 1.35 million tonnes in 2013, increasing to 1.8 million tonnes in 2022. Hawai'i's natural gas demand exceeds the 1 million tonnes per annum that allow for reasonable economies of scale. Importing Alaska natural gas could reduce oil's share of the primary energy mix statewide by approximately 20% within 4-7 years of a decision to move forward.

Using natural gas instead of maintaining current fuel plans would reduce the global warming potential of Oahu's power generation by approximately 25% in 2013 and roughly by an average of 23.5% per annum through 2020. Most importantly, there are significant savings to be gained from using natural gas. The study pointed out that potential annual fuel savings to consumers would translate to tens of millions of dollars as the price of natural gas to the power plants would be less than the price forecasted for the low sulfur fuel oil (LSFO) it will replace.

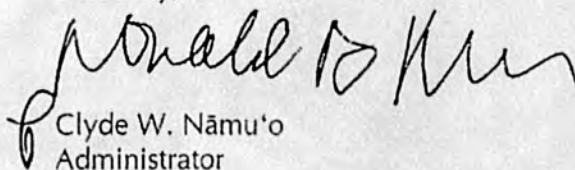
Based on these findings, I wish to inform you that OHA supports the development of the natural gas pipeline from Prudhoe Bay to Valdez together with a liquefied natural gas (LNG) facility to enable shipment of LNG to other domestic markets in the US, such as the West Coast and Hawai'i, and to the growing markets in Asia.

OHA believes a Prudhoe Bay to Valdez pipeline offers significant mutual benefits to both Alaska and Hawai'i. The short transportation distance from Valdez to the Hawaiian market makes Alaska LNG a highly competitive source of energy relative to other fuels. Since Hawai'i is located along the route from Asia to these markets, potential synergies exist in the LNG shipping capacity by serving Hawai'i along the way. There are huge existing markets for LNG in Japan and Korea, and the enormous potential markets of China, India and the continental US. At the same time, Alaska natural gas helps Hawai'i achieve a number of policy objectives regarding global warming, energy and economic security, air quality improvement, consumer savings, and transition to a future renewable and hydrogen energy economy.

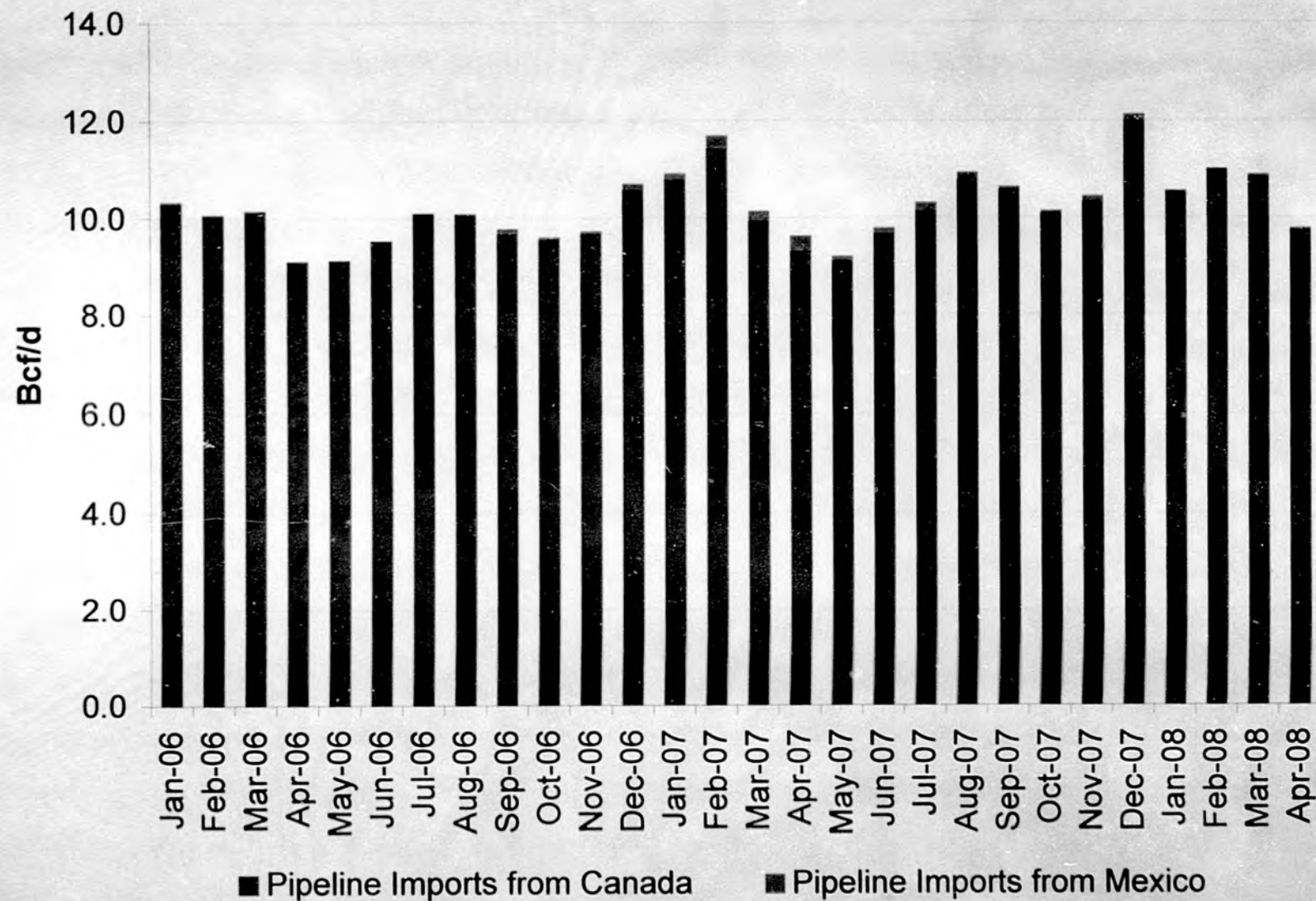
If such a pipeline project were to proceed, OHA would be interested in working with Alaska to secure long-term natural gas contracts that could provide a reliable and affordable supply of energy for years to come.

Due to the above consideration, I urge you to advance the development of the All-Alaska Gasline/ LNG Project. Please do not hesitate to contact me if you have any questions or if I can be of service in any way.

Sincerely,

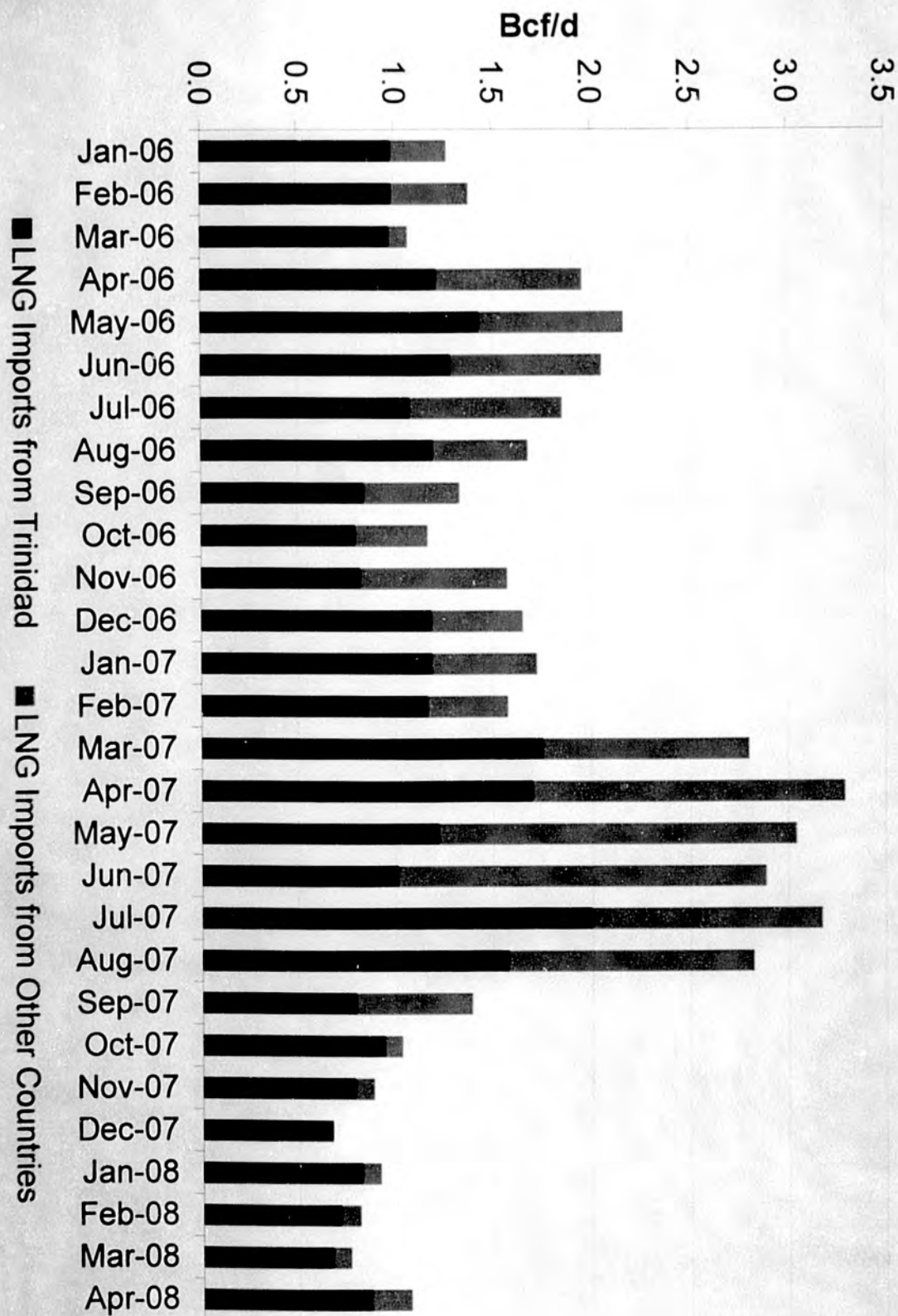


Clyde W. Nāmu'o
Administrator



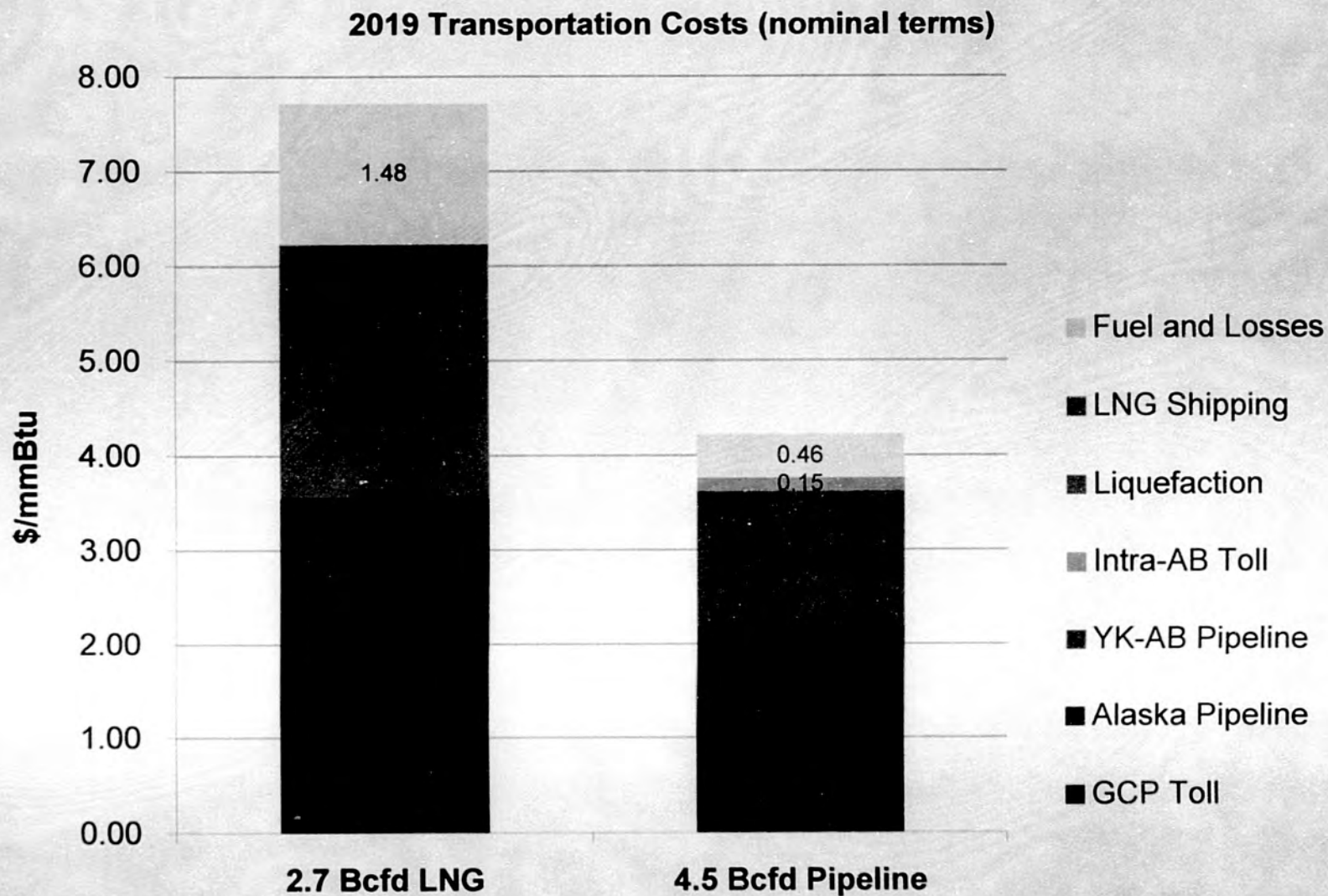
Source: EIA

U.S. Imports of LNG



Source: EIA

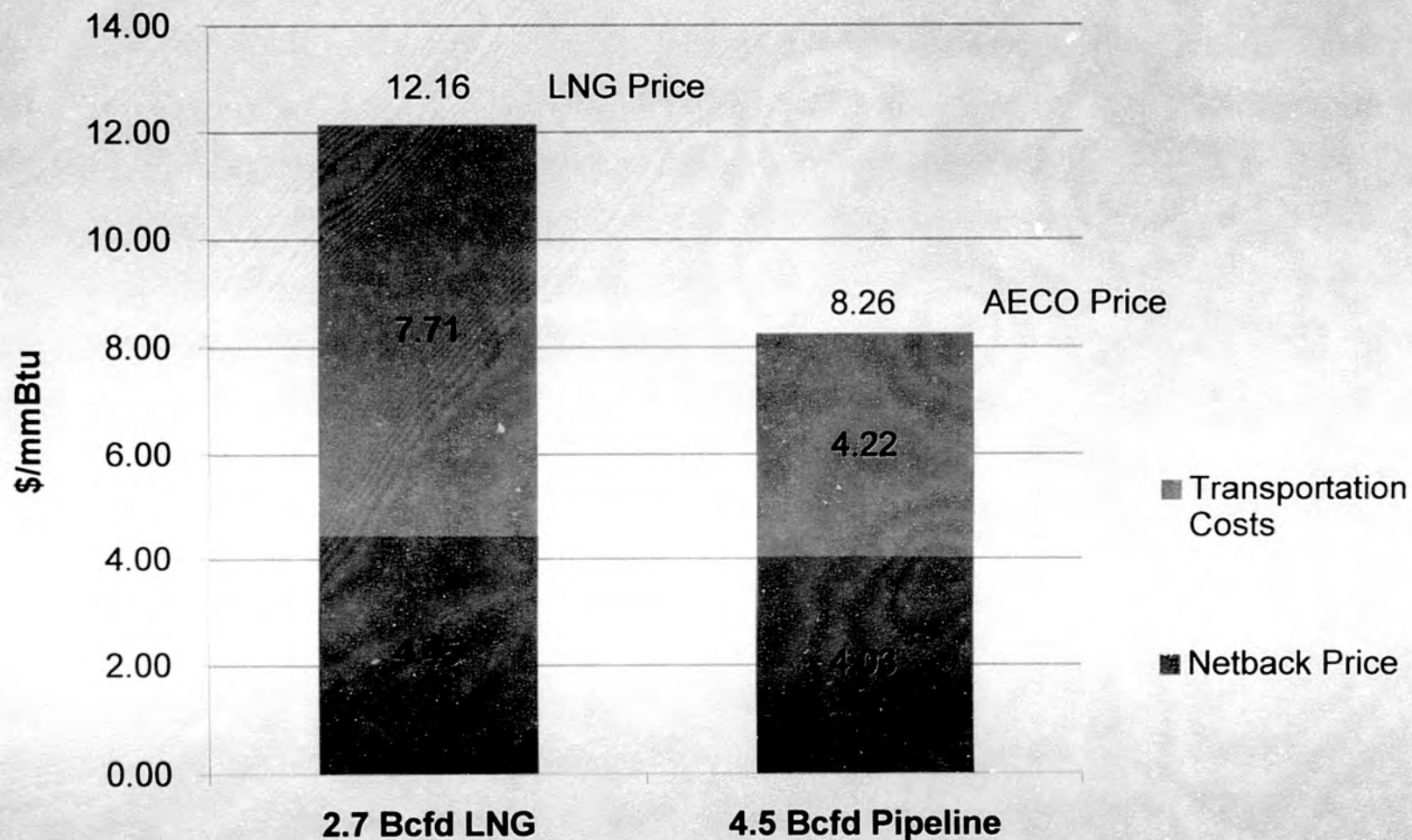
Transportation Cost Comparison (2019)



Netback Pricing at GCP Inlet (2019)



2019 Nominal Transportation Costs and Netback Pricing at GCP Inlet



Financial Projections Disclaimer



The purpose of this presentation is to provide background information and assist the recipients hereof in obtaining a general understanding of the Alaska Gasline Port Authority's ("AGPA") project. This document is not intended to form a sole basis of any investment decision or other decision to participate in the AGPA project and should not be considered as a recommendation or invitation by AGPA to make such decision. Each recipient hereof must make (and will be deemed to have made) its own independent assessment and appraisal of AGPA and its project after making such investigation, as it deems necessary in order to determine its interest and independently (and at its own cost) to have formed its own opinions and views.

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This presentation includes certain estimates and projections of the anticipated future performance of the AGPA project. Such estimates and projections reflect various assumptions made by AGPA and its advisors, concerning anticipated results, which assumptions may or may not prove to be correct. The actual outcome may be affected by changes in economic and other circumstances that cannot be foreseen or have not been anticipated. The reliance that can be placed upon the projections and forecasts is a matter of commercial judgment. No representation is made by the AGPA or its advisors as to the accuracy of such estimates or projections or as to the reasonableness of any assumptions used. The financial projections contained herein have been prepared and set out for illustrative purposes only and should not be taken as a commitment as to future performance.

SENR

Juneau
Rm 532

presented
7-22 & 23-2008

REPORT TO THE STATE OF ALASKA
LEGISLATURE ON THE FEDERAL LAW GOVERNING
EXPORTATION OF NORTH SLOPE GAS

Prepared by

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Craig Richards

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731 N Street
Anchorage, Alaska 99501
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On Behalf of

Alaska Gasline Port Authority
411 4th Ave., Suite 200
Fairbanks, Alaska 99701
(907) 474-2011

This report analyzes the law relevant to the export of Alaska North Slope natural gas. As will be discussed, two federal actions are required. Unique to North Slope gas, the President of the United State ("U.S.") must find the quantity, quality and price of the energy supplies available to U.S. consumers will not be effected by export. Additionally, for all domestically produced gas the Department of Energy ("DOE") must authorize export to any country for which the U.S. does not have a free trade treaty (e.g., not Canada or Mexico).

Authorization to export North Slope gas has been addressed solely in the context of the export license granted to the Yukon Pacific Corporation ("YPC") in 1989. After the requisite Presidential finding, DOE authorized the export for sale to Japan, South Korea, and Taiwan a total of up to 250 million metric tons ("MMT") of liquefied natural gas ("LNG"), at an average annually volume of 14 MMT – a bit less than 2 billion cubic feet per day ("bcfd") – for a period of 25 years beginning on the date of the first delivery.¹ The only other authorizations to export U.S. gas to a country to which the U.S. does not have a free trade treaty that the authors could locate involve the export of Cook Inlet natural gas from the ConocoPhillips/Marathon facility in Kenai, meaning the controlling precedent for DOE export approval involves export of Alaskan gas.

I. Legal Standards Under Which DOE Authorizes Export of North Slope Gas.

A. The Natural Gas Act.

Section 3 of the Natural Gas Act, 15 U.S.C. § 717b (2006) ("NGA"), provides the Secretary of Energy shall allow the export of gas unless he finds it will not be consistent with the public interest. If the export is to a country with which the U.S. has a free trade agreement covering natural gas, the export is deemed to be in the public interest and approved automatically.² If not, the DOE must consider whether the export is in the public interest.

"Section 3 creates a rebuttable presumption that a proposed export of natural gas is in the public interest and that [DOE] must grant such an application unless those who oppose the application overcome that presumption."³

DOE has issued a set of guidelines to help interpret Section 3, the goals of which "are to minimize federal control and involvement in energy markets and to promote a balanced and mixed energy resource system."⁴ "In effect the guidelines represented a determination that it is in the public interest to let market forces, with a minimum of

¹ *Order Granting Authorization to Export Liquefied Natural Gas from Alaska*, Department of Energy Order and Opinion No. 350, 1 F.E. 71,115, 71,144-45 (November 16, 1989), as amended by *Order Denying Requests for Rehearing and Modifying Prior Order for Purpose of Clarification*, Opinion and Order No. 350A, 1 F.E. 70,303, 71,273 (March 8, 1990).

² 15 U.S.C. § 717b (2006).

³ *Order Granting Authorization to Export Liquefied Natural Gas from Alaska*, Department of Energy Order and Opinion No. 2500 at 43 (June 3, 2008).

⁴ Order No. 2500 at 44.

regulatory constraints, define efficient energy production and consumptions.”⁵ Although the guidelines were originally promulgated for cases relating to the import of natural gas, DOE subsequently held the same policies will be applied to natural gas export applications.⁶

The federal government’s primary responsibility in authorizing imports [or exports] will be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.⁷

DOE has also stated that “the principal focus of this agency’s review of export applications in decisions under current delegated authority has continued to be the domestic need for the natural gas proposed to be exported.”⁸

For YPC, and presumably for another North Slope export project, DOE set forth a three-pronged approach for evaluating domestic need.

First, the DOE determines whether national or regional demand can reasonably be expected to exceed anticipated available domestic supplies over the term of the proposed export. If there is a reasonable expectation of demand in excess of available domestic supplies, the DOE determines the extent to which this excess demand can be met by other energy sources as or more efficiently than the proposed export. If there are sufficient alternative sources, the DOE analyzes whether there is any reason the public interest requires the proposed export, in particular, be used to meet the excess demand.⁹

As to the last prong, although “[d]omestic need is the only explicit public interest consideration identified by DOE in Delegation Order No. 0204-111 . . . the Department considers the potential effects of proposed exports on other aspects of the public interest. These other considerations include Alaskan interests, international effects, and the environment.” DOE has in the past also looked at the effect of the export project on energy security.¹⁰

B. ANGTA and the Reagan Findings.

⁵ Order No. 350, 1 F.E. at 71,121.

⁶ Order No. 2500 at 44 (citing Order No. 1473 at 14 and citing Yukon Pacific, Opinion and Order No. 350, 1 F.E. 70,259 at 71,128).

⁷ Order No. 2500 at 44 (quoting *New Policy Guidelines Relating to the Regulation of Imported natural Gas*, 49 Fed. Reg. 6684 (February 22, 1984) (brackets in original)).

⁸ Order No. 2500 at 44-45 (citing DOE Delegation Order No. 0204-111 which, although no longer in effect, directed in part that exports be regulated based on a consideration of the domestic need for the gas to be exported and such other matters as found in the circumstances of a particular case to be appropriate).

⁹ Order No. 350, 1 F.E. at 71,129.

¹⁰ *Id.* at 71,134.

The Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. § 719j (2006) ("ANGTA"), provides that before exportation of Alaska gas "to any nation other than Canada or Mexico, the President must make and publish an express finding that such exports will not diminish the total quantity or quality and not increase the total price of energy available to the United States."

In 1998 President Reagan issued a finding that export of North Slope gas would not affect adversely the quantity, quality or price of the energy supplies available to U.S. consumers.¹¹

In particular, the President found that 'there exist adequate, secure, reasonably priced supplies of natural gas to meet the domestic demand of American consumers for the foreseeable future.' The president acted to let 'the marketplace undertake a realistic consideration of various options concerning Alaska natural gas' by allowing 'any private party to develop this resource' and setting 'up competition for this purpose.' The President's Findings stated that 'operation of market forces is the best guarantee that Alaska natural gas will be developed efficiently and that there will be incentive to find additional reserves.'¹²

If an off-slope LNG project sought a new export license, rather than to update the one issued to YPC in 1989, a new Presidential finding appears necessary. However, Congress granted the President broad power to limit natural gas exports (whether from Alaska or other locations) in the Energy Policy and Conservation Act of 2005, 42 U.S.C. § 6212 (2006), significantly diminishing the significance of an upfront Presidential finding for export of Alaska natural gas under ANGTA.¹³

As to YPC's export license, DOE determined a North Slope export proposal will be viewed in light of ANGTA, and in fact a significant condition called the "ANGTA Condition" on the YPC export license prevented YPC from taking any action that would compel change of the ANGTA route or project timing.¹⁴ DOE expressly stated, however, that the ANGTA condition did not apply to market decisions relating to access or development of North Slope reserves, and it instead related to increased costs of ANGTA infrastructure resulting from the export project.¹⁵

Since, in order to avoid the multi-billion dollar liability associated with the ANGTA project legacy, TransCanada is no longer sponsoring an ANGTA project in Alaska, and the Alaska Natural Gas Pipeline Act of 2004, 15 U.S.C. § 720a(a) (2006) ("ANGPA), specifically authorized non-ANGTA Canadian highway projects, it would

¹¹ *Presidential Finding Concerning Alaska Natural Gas*, 53 Fed. Reg. 999 (January 15, 1988).

² Order No. 350, 1 F.E. at 71,122 (emphasis eliminated).

¹³ Section 6212 provides that the President may restrict exports of: "(1) coal, petroleum products, natural gas, or petrochemical feedstocks, and (2) supplies of materials or equipment which he determines to be necessary (A) to maintain or further exploration, production, refining, or transportation of energy supplies, or (B) for the construction or maintenance of energy facilities within the United States."

¹⁴ Order No. 350, 1 F.E. at 71,128, 142.

¹⁵ *Id.* at 71,142.

appear ANGTA no longer has relevancy to the exportation of North Slope gas and will be ignored in this analysis except as to the requirement of a Presidential finding.

III. Various Parties' Position Before DOE Regarding a YPC Export License.

In analyzing various arguments that could be made today about why an export license should or should not be issued for North Slope gas, it is helpful to understand some of the positions of the same parties before DOE almost 20 years ago. Many arguments that would be made today have already been addressed and decided by the department.

A. TransCanada.

TransCanada's predecessor sponsors of the Alaska Natural Gas Transportation System ("ANGTS") Canadian highway line, Alaskan Northwest and Foothills (hereinafter "TransCanada"), held the right to build the Alaskan portion of the highway line under ANGTA. TransCanada was the only major opposing party to the issuance of a YPC export license, and it prosecuted its case vehemently.

For instance, TransCanada said YPC's application did not contain enough information to be evaluated since YPC did not have gas purchase or resale contracts, sufficient details on project infrastructure, a completed environmental impact statement or a description of all the project's participants.¹⁶

TransCanada also asserted North Slope gas would be needed in the lower-48.

They contend that the excess demand in the lower-48 states cannot be met by other energy resources as or more efficiently than by the proposed export volumes. The ANGTS sponsors assert that substitute fuels for North Slope gas, such as coal and oil, would be environmentally inferior to natural gas, which burns cleaner. They maintain that increasing dependence on coal and oil would contribute to ozone layer depletion in the atmosphere, 'acid rain', and the 'greenhouse' problem of global warming, and alternative gas supplies, such as development of Canadian frontier gas, would be more costly. In addition, they assert that the commitment of North Slope gas reserves to foreign interests would jeopardize national energy security by depriving the U.S. of a source of available reserves to offset the declining energy base in the lower-48 states, and by increasing U.S. dependence on oil imports.¹⁷

TransCanada additionally argued that an LNG project would impair completion of a Canadian line because "there are not enough proven reserves of gas on the North Slope to support both . . . projects."¹⁸ The Canadian government through the State Department

¹⁶ *Id.* at 71,125.

¹⁷ *Id.*

¹⁸ *Id.* at 71,125.

shared similar concerns.¹⁹ TransCanada actually sought a condition on the export license that its project have "first call on North Slope gas for delivery to the lower-48 states, if needed to meet contractual obligations and to preserve the project's economic viability[.]"²⁰

Finally, TransCanada urged "that any final authorization issued be subject to suspension, modification, or revocation upon a showing that continuation of the proposed export is no longer in the public interest."²¹ That is, TransCanada wanted YPC's export license to be subject to future reopening for additional public interest before export occurred. As will be seen, DOE rejected all of these arguments.

B. State of Alaska and Exxon.

The State of Alaska intervened on behalf of an export license because of the benefits to Alaska that an off-slope pipeline would bring. However, it had no preference for an LNG versus Canadian project asserting that the market would decide which (or how many) systems get built, and opposed the imposition of conditions on export that would favor one gas development project over another.²²

Exxon supported President Reagan's Findings for export and urged market-responsive development of Alaskan natural gas. It asked that DOE not impose terms and conditions "that would, in effect, place a stamp of approval on only one project or approach to development of Alaskan resources and discourage other projects or approaches."²³

C. Statoil.

Statoil, the Norwegian national oil company, stated its LNG exports and those of other over-seas suppliers would be able to meet any U.S. gas demand that might go unserved if North Slope gas was exported.

IV. DOE's 1989 Decision Authorizing Export of North Slope Gas.

Unfortunately since 1989 little has changed in the debate about whether DOE should allow the export of North Slope gas. On the bright side, risks associated with seeking an export license have been significantly reduced given DOE has already addressed many of the arguments a party opposing export can make. It is thus useful to review in detail DOE's rationale for issuing YPC an export license under Section 3 of NGA.

¹⁹ *Id.* at 71,126.

²⁰ *Id.*

²¹ *Id.*

²² *Id.*

²³ *Id.* at 71,126-27.

A. Use of Economic Studies.

YPC and TransCanada both presented to DOE economic studies regarding when North Slope gas would become competitive in the lower-48. Quoting TransCanada, DOE held such studies were not useful in assessing the future of a particular project because the world was too complex and subject to change to forecast 12 or 20 years into the future.²⁴ "In fact, the inherent imprecision of using economic studies to predict the performance of a particular project is one reason that led to the shift from a government-mandated regulatory approach to a market-oriented approach that leaves private commercial parties with the flexibility to determine the basics of their projects."²⁵

DOE also rejected out of hand that the need for North Slope gas in domestic markets is evidenced by the many economic models predicting North Slope gas will be used to meet domestic demand.

Unlike the real world where private parties take a hard look at the actual costs of bringing competing supplies to market, an economic model selects the 'competitive' supply on the basis of assumptions . . . In the case of ANGTS, most economic models put the cart before the horse since they automatically assume North Slope gas will be used in the domestic market and then speculate when producers, pipeline sponsors, and financial institutions will agree that the market justifies the commitment of billions of dollars to provide the means necessary to make this 'a priori' modeling assumption feasible in the real world.²⁶

However, although DOE did not find economic forecasts and studies useful in evaluating specific projects, DOE did find their information on supplies of various energy sources and anticipated demand helpful in evaluating domestic need as required under NGA Section 3.

B. Domestic and Regional Need.

As previously stated, in looking at future domestic need over the life of the license, DOE first looks at whether national or regional demand will exceed domestic supplies over the term of the proposed export. If so, DOE looks at whether excess demand can be met with alternative energy sources as efficiently as by the proposed export. Finally, if there are sufficient alternative energy sources, DOE analyzes the public interest nonetheless requires the proposed exported gas to be used to meet excess domestic demand.

1. Regional Need.

²⁴ *Id.* at 71,129-30.

²⁵ *Id.* at 71,130.

²⁶ *Id.* at 71,129 n. 36. See also Order No. 350A, 1 F.E. at 71,270 (reaffirming that the inclusion of North Slope gas in various economic studies does not demonstrate a domestic need for it).

In YPC's case, DOE held regional need in Alaska was not a relevant issue for North Slope gas.²⁷ Interestingly, this is exactly the opposite position DOE took in granting the most recent extension for the Kenai export license. For Cook Inlet gas, DOE only looked at regional and not domestic supply and demand dynamics.²⁸ Given the Cook Inlet basin is maturing and will not be able to fully supply South Central – much less the Alaskan Interior – for the term of a Valdez export license (e.g., 25 years from first export), both domestic and regional supply and demand would likely be a factor if DOE revisits whether exportation of North Slope gas is in the public interest. Those advocating export of North Slope gas would argue that an LNG project would help meet projected gas shortfalls from Cook Inlet and would provide gas to new Alaskan markets in a manner more rapid than a project through Canada which would, if accepted by DOE, help the case for export.

2. *Domestic Need – Lower-48 Supply and Reserves DOE Will Consider in its Analysis.*

In analyzing future projected domestic supply of natural gas, DOE rejected TransCanada's argument that only proven reserves in the lower-48 could be counted as available supply. Instead DOE decided it would take a broad view of sources of gas that would be viewed as available to meet projected domestic demand. Thus for instance, DOE included in reserves estimates both unconventional (tight sands, Devonian shale, coal seams, enhanced recovery, etc.) and conventional gas, and for conventional gas included allowances for reserves growth and additional exploration.²⁹

DOE also rejected TransCanada's argument that North Slope gas was needed because its cost of delivery to American consumers on a per molecule basis (i.e., in-field and transportation costs) would be lower than the cost of delivery of many of the other sources of gas included in DOE's estimate of national reserves.³⁰ Rather DOE thought the proper inquiry was whether "the costs of bringing some supplies to market may be so significantly higher than the anticipated market price that their use would be precluded in an efficient market."³¹ So in looking at whether North Slope gas is needed domestically, the DOE will not compare the cost of delivery of North Slope gas vis-à-vis other gas supplies, but whether the non-North Slope supplies can be developed given anticipated market prices.

²⁷ Order No. 350, 1 F.E. at 71,129 n. 35.

²⁸ DOE seemed to accept the applicants' assertions that there was no practical market for Cook Inlet gas in the U.S. because of the Jones Act, a lack of West Coast receiving terminals, and the prohibitive cost of reaching East Coast receiving terminals. Order No. 2500 at 14 ("The Applicants emphasize that the . . . Jones Act, would present a substantial regulatory hurdle. The Applicants also emphasize that there are not existing U.S. west coast LNG receiving terminals and the cost of shipping Kenai LNG to U.S. east coast or gulf coast LNG Receiving terminals would vastly exceed the cost of transporting the same LNG to Japan and/or another customer in the Pacific Rim due to the distances involved.").

²⁹ "Gas supply assumptions that focus solely on proved reserves and do not take into account the potential for reserve additions and production experience would severely distort forecasts of domestic need." Order No. 350, 1 F.E. at 71,131.

³⁰ *Id.* at 71,269.

³¹ *Id.*

After reviewing various studies, DOE ultimately concluded that during the term of YPC's export proposal domestic need could be met by production from reservoirs in the lower-48 states without North Slope gas.³² An argument could be made that DOE might not reach the same conclusion today,³³ although this is a technical decision that DOE would make only after it reviewed projected domestic supply and demand as it did in allowing Kenai and YPC exports.

3. *Domestic Need – Alternative Supply.*

Even though DOE said in 1989 that North Slope reserves were not needed domestically, DOE nonetheless stated that it is not necessary for the purpose of a Section 3 NGA determination that DOE find all future U.S. natural gas demand will be met by production in the lower-48 states. DOE may also look to alternative supplies, particularly gas imports. This includes whether import of LNG from overseas (e.g., East Coast imports), when combined with North American supply, will be sufficient to meet domestic demand without North Slope gas.³⁴

4. *Domestic Need – Public Interest of Domestic Use of North Slope Gas Rather than Available Alternative Supply.*

After examining whether lower-48 and alternative supplies are sufficient to meet domestic demand, DOE next considers whether there is a public interest in the North Slope gas proposed to be exported (rather than other energy supplies) being used to meet any anticipated demand in excess of domestic supply. Harmonizing its NGA analysis with ANGTA Presidential finding requirements, DOE looked at whether the proposed project's export of North Slope gas would have an impact on matters of supply, price and quality of domestic gas.

a. *Quantity.*

A proposed export of North Slope gas will adversely affect the quantity available to American consumers only if it will cause available domestic supplies to be inadequate. Since DOE concluded at the time there were adequate lower 48 and alternative supplies, DOE determined an export of about 2.0 billion cubic feet per day from Alaska would not adversely affect American consumers.³⁵ Additionally, DOE said in the context of global energy interdependence it cannot necessarily be concluded that export of gas would diminish that available to American consumers.

³² *Id.* at 71,130-32.

³³ For instance, in 2004 when ANGA was passed, it was the "sense of Congress" that "gas delivered from Alaskan North Slope will not displace or reduce the commercial viability of Canadian natural gas produced from the Mackenzie Delta or production from the 48 contiguous States." 15 U.S.C. § 7201 (6) (2006). In support of that proposition, it was also the sense of Congress in suggesting a Mackenzie project should go first that "natural gas production in the 48 contiguous States and Canada will not be able to meet all domestic demand in the coming decades[.]" 15 U.S.C. § 7201 (2) (2006).

³⁴ Order No. 350, 1 F.E. at 71,134-35.

³⁵ *Id.* at 71,134.

[W]ith respect to North Slope gas, it would be unduly simplistic to conclude that exports will necessarily diminish the quantity of energy available to American consumers. In this case, the alternative to exporting North Slope gas may be that it remains undeveloped, and therefore available to no one; conversely, exporting such gas may make available on the American market gas from foreign sources that would otherwise have gone to the Pacific Rim.³⁶

Thus even if domestic and alternative supplies of gas were projected to be inadequate over the term of the license, export would still be authorized if it was demonstrated that export would not diminish gas available to American consumers. This might be because, for instance, the gas would remain undeveloped without export, export of Alaskan gas would free up other supplies that would be made available to U.S. markets, or an export project would open the North Slope basin to exploration that would in turn result in additional gas being available to go to U.S. markets (either via LNG or a line through Canada).

b. Quality.

In looking at the impact on the export of North Slope gas on the "quality" of energy available to American consumers, DOE focused on arguments made by TransCanada regarding the effects of export on the environment and U.S. energy security. DOE did not believe export of natural gas from the North Slope would lead to the use of less environmentally friendly energy sources (e.g., coal).³⁷

DOE also rejected TransCanada's argument that export of North Slope gas would increase imports and thereby decrease energy security on the grounds that energy security must be viewed in global terms and the development of North Slope gas would contribute to the overall performance of the North American energy market.³⁸ "DOE believes that true energy security lies in encouraging the most efficient operation of the North American and global energy market."³⁹

c. Price.

In performing the public interest analysis and looking at whether North Slope gas should not be exported, notwithstanding there are sufficient projected lower-48 or alternative supplies, DOE will consider whether American consumers will pay more than they would if North Slope gas was not exported.

In general, conditions in the domestic market will establish the price for whatever natural gas is used to meet domestic need, regardless of the source of that gas. Neither North Slope gas nor any other specific supply

³⁶ *Id.* at 71,134.

³⁷ *Id.* at 71,135.

³⁸ *Id.*

³⁹ *Id.*

will be the tail that wags the market price of natural gas. The export of a particular gas supply, such as North Slope gas, would exert upward pressure on the market price only if there were not adequate alternative supplies of energy to meet domestic need at a market-responsive price. Even then, the export would exert upward pressure only if the costs of producing and delivering the exported gas to the domestic market would be less than the costs of the energy supplies actually used to meet the marginal demand.⁴⁰

In YPC's case, DOE felt export of North Slope gas would not have an impact on domestic prices, and found the presented economic studies "did not constitute the substantial evidence necessary to overcome the DOE's analysis of the fundamental market conditions, the section 3 presumption in favor of export approval, and the President's Finding."⁴¹

B. Other Public Interest Considerations.

In addition to the Section 3 NGA analysis relating to domestic need for North Slope gas, DOE considered a number of other public interest factors.

1. *Export's Impact on North Slope Exploration and Development.*

TransCanada indicated that the proposed export of North Slope gas might result in the non-production of some North Slope gas and questioned whether competition will spur exploration for and development of North Slope gas.⁴² DOE disagreed and stated an export project would spur development of the 100 + trillion cubic feet of stranded proven and potential gas reserves.

Thirteen years have passed since the passage of ANGTA and no North Slope natural gas has been produced commercially. The introduction of competition will encourage a realistic assessment of the potential of North Slope natural gas and its early and more efficient development. It also will provide an incentive for discovering and developing additional reserves of natural gas on the North Slope.⁴³

2. *Alaskan Interests.*

In both the Kenai and YPC export authorizations DOE has recognized that significant benefits accrue to the State of Alaska and its economy from export.⁴⁴

⁴⁰ *Id.*

⁴¹ *Id.* at 71,136.

⁴² *Id.* at 71,137.

⁴³ *Id.*

⁴⁴ Order No. 2500 at 55-57; Order No. 350, 1 F.E. at 71,137.

3. *Environmental Concerns.*

For YPC and Kenai exports it was also found that environmental concerns are not important elements in DOE's public interest analysis.⁴⁵ Rather environmental issues relating to project construction are properly handled in other forums such as proceedings relating to pipeline and export terminal site authorization.

4. *International Effects – Free Trade and Balance of Payments.*

DOE believes international effects of a proposed export project are significant in the public interest determination, and weigh in favor of export. First, increasing exports has a positive effect on the U.S. balance of payments and mitigates trade imbalances with receiving Asian countries (Korea, Japan and Taiwan).⁴⁶

Second, "Competition in world energy markets promotes the efficient development and consumption of energy resources, as well as lower prices, whereas economic distortions can arise from artificial barriers to the free flow of energy resources. Accordingly, DOE believes that the public interest in free trade generally supports approval of proposed exports."⁴⁷

5. *YPC Cannot Pass on Project Cost to U.S. Consumers.*

DOE believes that the primary purpose of its analysis of potential exports under the NGA is to protect American consumers. In that vein, and with YPC's acquiescence, as a condition to its license YPC was prohibited from passing on to consumers in the lower-48 states any of the risks or costs associated with the LNG project.⁴⁸ However, DOE did make clear YPC was not prohibited from sending North Slope gas to U.S. markets.⁴⁹

6. *YPC Must File Gas Sale and Transportation Contracts with DOE.*

To assist in monitoring compliance with the condition (and again with YPC acceptance) that U.S. consumers not bear the cost of the export project, DOE also required the submission of all contracts and other documents for the acquisition, transportation, and sale of North Slope gas when executed.⁵⁰ It is receipt of these contracts that DOE recently stated was the precondition to export that would result in DOE "address[ing], at that time what, if any, further review and actions would be required should [YPC] seek to use the authorization."⁵¹

⁴⁵ Order No. 2500 at 58; Order No. 350, 1 F.E. at 71,139.

⁴⁶ Order No. 2500 at 58; Order No. 350, 1 F.E. at 71,136.

⁴⁷ Order No. 350, 1 F.E. at 71,138.

⁴⁸ *Id.* at 71,136.

⁴⁹ *Id.* at 71,137.

⁵⁰ *Id.* at 71,136-37.

⁵¹ Letter to John Harris, Speaker of the Alaska House of Representatives, from Robert F. Corbin, Manager, Natural Gas Regulatory Activities, Office of Oil and Gas Global Security and Supply, Office of Fossil Energy (June 13, 2008).

Prepared Testimony of Harold Heinze of ANGDA
Before Senate Finance on July 22, 2008

The ANGDA gas spur line project links Delta Junction to the Cook Inlet area through Glennallen. It is integral to the delivery of North Slope gas for in-state utility use from either the AGIA licensee TC Alaska or the producer sponsored Denali pipeline projects.

Strong legislative support and funding has allowed ANGDA to: (1) acquire a conditional state right-of-way between Palmer & Glennallen, (2) conduct field wetland delineation between Beluga & Delta Junction, and (3) publish a myriad of focused studies on in-state gas issues.

ANGDA's strategy has focused on an aggressive time line of activities to assure that the in-state gas needs will be understood and that local utilities will have the best opportunity to participate in the FERC open season of the "big pipeline". In the first quarter of 2009, ANGDA will have the information to conduct a negotiated in-state open season to allow early interaction with the design and contract terms of either of the "big pipeline" project proposals. Alaska's gas needs will only represent 5% of the bigger project and the local utilities are greatly advantaged by being considered up-front as one of the anchor tenants.

With the passage of AGIA the competitive pressure will accelerate the pace of preparations for the FERC open season. Legislative action now on the ANGDA appropriation request of \$25 million will maintain a leadership position to get North Slope gas to Alaskans under the best fiscal terms and under the most favorable timeline.

The requested \$25 million appropriation funds contractor efforts to complete the pre-build preparations related to:

- Route survey and options for rights-of-way acquisition
- Design of access roads & field preparation
- Preliminary pipeline and facility design
- Project management to include a finalized Project Execution Plan
- Logistics planning to include preparation of pipe yards & port improvements
- Materials specifications, materials take-off list, and options on long-lead items
- Finalization of financing and bonding for the project

Past ANGDA funding includes:

Total operating budget expenditures of \$1.6 million total over 5 years

Total capital appropriations of \$11.5 million (includes \$4 million just available)

With \$4.5 million capital appropriation spent or committed at this time

Remaining \$7.0 million capital appropriation is authorized, but not committed at this time is planned for contracting over the next year:

- TAPS proximity design
- Feasibility of high-density plastic pipe as an interim link between Delta Junction and Fairbanks
- Recalibration of cost estimates and project schedule
- LDIR data acquisition
- Preparation of spur line project EIS
- Identification of & engagement with value added industrial companies
- Gas purchase agreements
- Contract and bonding documents for aggregation of utility gas needs
- Local gas take-off point design and preliminary NGL "straddle plant" designs
- Joint venture partnership documents, initial financing plan, request for Certificate of Necessity (demonstrate fit, willing, and able), and letter agreement with shippers
- Design of feeder pipelines from Gubik, Nenana, Point Thomson, Yukon Flats, and Copper River basins
- Propane Distribution Project - Propane purchase on North Slope for "pilot" project & tank rental
- Public outreach

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Will LNG liquefaction project development prosper?

Since 1995, the volumes of liquefied natural gas (LNG) delivered have risen at a rate of over 7%/yr. Forecasts indicate that LNG deliveries will continue to grow at this rate over the foreseeable future and that LNG market pricing will continue to reach historic levels with recent quotes exceeding long term forecasts by 10%–20%. Consensus is that there will be a shortage of LNG supplies by 2014. Under normal conditions, announcements of new LNG liquefaction projects would follow, in response to these market forces. However, since the beginning of 2006, the only LNG train authorized has been the 4.2 million-tpy Pluto LNG train funded in July 2006. LNG projects continue to experience delays worldwide.

Why is the market reacting in this manner? In a word: RISK. LNG liquefaction projects are large, complex programs located in remote areas requiring significant new infrastructure. The large capacities associated with each proposed project, coupled with future market uncertainties and lengthy times-to-market for newly authorized projects (typically five years from authorization to commercial operation), expose these projects to increased risk relative to competing projects. Unprecedented price escalation further complicates project financial viability. Since 2005, all indications are that LNG project costs have escalated at the same 20%/yr rate as other upstream projects, creating a high degree of economic uncertainty for liquefaction projects.

What are price drivers? What factors are driving these sharp increases in the price of LNG facilities? Demand for engineering, procurement and construction (EPC) services, equipment and material is experiencing record growth, with all sectors of the market rapidly expanding infrastructure after years of neglect. This growth is straining existing resources in several areas. Market conditions impacting LNG facility projects include:

- Doubling of the EPC project technical resource requirements between 2005 and 2007, with CERA reporting a possible 10%–15% deficit of people to staff projects by 2010.
- Average current shop loads at 70%–100% of available capacity, as opposed to 60% average load over the previous 10 years
- Escalation in two key commodities for LNG facility construction—stainless steel pipe, and large compressors and gas turbines—with total increases of 90%–150% and 20%–50%, respectively, during 2006 and 2007. Escalation for 2008 is expected to slow to 10%–20% for stainless steel pipe and 5%–15% for compressors and turbines.
- Constraints on the availability of skilled and unskilled labor to support construction, with a potential shortfall of 15% in skilled labor in 2008.

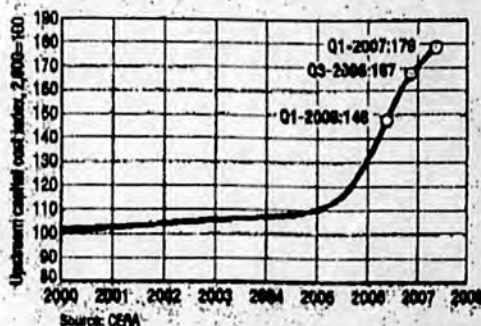


FIG. 1 Upstream capital cost index, 2000=100, from 2000 to 2008. Source: CERA

What are some strategies to mitigate impacts? Strategies to combat and manage cost uncertainties confronting the LNG EPC market and to lower project risks include:

- Commitment of EPC contractors early in the project development cycle to reserve key project management, engineering and construction resources
- Utilization of multiple contractors to broaden access to key resources
- Early purchasing of key materials and equipment
- Early supplier integration to improve supply certainty for critical components
- Streamlined work processes at the site and shifting of labor to a more controlled yard environment through modularization, thereby reducing construction cost risks
- Modification of contracting strategies to improve risk sharing and reduce risk premiums and contingencies.

The use of these strategies will act to mitigate key costs and to schedule risks, improve the economic viability of potential projects and bring a higher degree of certainty to project execution. HP

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Developing mid-scale LNG projects from the contractor's perspective

Modular liquefaction methods reduce construction and operating costs for smaller reserve developments

B. PRICE, J. FOSSELLA, S. HOFFART, Black & Veatch Corp., Overland Park, Kansas

The global market for liquefied natural gas (LNG) continues to grow rapidly. Traditionally, base-load LNG plants have provided the majority of this supply. As the industry has grown, base-load plants have grown increasingly larger. This has normally meant better economies of scale on project cost. Recently, however, base-load plants have become much more complex, and the cost is escalating in an uncontrolled fashion. The growing "diseconomies" of scale for larger units is directing more attention to development of mid-scale LNG projects that could cover the gap between LNG supply and demand.

The appeal of mid-scale projects is that they require smaller reserve bases, less total investment and should allow development in a shorter timeframe. The projects must be robust enough to overcome some infrastructure costs that occur regardless of project scale. The timeframe for development and key decision points, as well as the application of appropriate technology to these projects is necessary to control costs and bring projects online in a timely manner. Mid-scale projects are being developed in a modular fashion to enable rapid deployment and future expansion. Recent cost estimates for a variety of plant throughputs have shown that mid-scale facilities can meet economic hurdles and become reality.

Background. The development of large-scale base-load LNG facilities has dominated the industry for decades. Recent LNG plant designs have become more complex with systems of multiple refrigeration loops and ever increasing capacities. New projects are in the 10 million tpy (MMtpy) size range. This growth in complexity and cost has resulted in project developments requiring large capital expenditures approaching \$1,000/tpy of capacity. Also, with the larger project sizes, development times have stretched from six years to more than a decade, further inhibiting these projects for closing the demand/supply gap. These facilities also pose an enormous risk for the engineering and construction industry. Recent announced losses on major projects are serious issues for those involved.

Operators are broadening the search for LNG capacity by looking at mid-scale projects. Generally, these projects are in the 0.5 MMtpy to 2.5 MMtpy range and involve much smaller reserve bases. Smaller facilities have appeal because of their potential for:

- Lower total magnitude of investment and risk
- Development of multiple smaller trains, staging in production
- Use of standard industry equipment types and sizes
- Shorter development times
- Reduced impact on local labor markets.

There are some issues to be overcome with mid-scale developments. Infrastructure costs for LNG storage, loading systems and jetties must be addressed. In some cases, reliable, long-term gas supply is an issue as owners focus on larger reserves. Finally, the mid-scale project must sell into a large LNG market that is set up for base-load plants with large off-takes and long-term agreements.

To address the issue of mid-scale developments, a less complex and lower cost LNG technology is needed. New LNG liquefaction processes can provide both cost reduction and operational simplicity. These processes can be used on a wide array of LNG facilities ranging from small scale peak-shaving units to base-load developments.

Mid-scale projects can also be developed for floating applications. These concepts benefit from compact, modular units. Ship designs with LNG production units from 1.1 MMtpy to 3 MMtpy have been developed and appear economically feasible. Barge-mounted facilities have been developed from 1.1 MMtpy to 6 MMtpy, representing base-load applications on floating structures.

Process selection. The first step in addressing an economical solution to the mid-scale plant development is selecting the liquefaction process, which best fits the size range of the project. Base-load process designs with multiple refrigerants and extreme complexities do not scale down well to the mid-scale sizes. The objective in mid-scale units is not to chase the last percentage of efficiency but to select a process with good efficiency and with the lowest equipment count. Simplicity of design is a key issue with mid-scale units to achieve low capital cost objectives.

In the small-scale project area, three processes are considered. The first is the *expander process*, which uses high-pressure gas expanded in turboexpanders to drive the process and achieve a partial liquefaction of the feed gas (approximately 18%). The balance of the feed gas has to be disposed of at low pressure. This can work well in peak-shaving applications near transcontinental pipelines. However, in mid-scale developments, the tail gas must be recompressed to conserve this resource. This compression addition makes the expander process not only the highest power consumer but also the highest cost of all the processes considered.

A second process that can be considered is the *nitrogen refrigeration process*. This process is similar to the expander process in that a large circulating gas stream is used to provide refrigeration in addition to using turboexpanders. This method is also very inefficient and has a capital cost comparable with the expander process. Its application has been limited to smaller units.

The workhorse of the small scale LNG industry is the *single-mixed refrigerant* (SMR) process. This process has been proven in numerous applications and a variety of sizes. The SMR process, shown in Fig. 1, represents a streamlined solution to the mid-scale plant design. The process is applied as a single refrigeration system regardless of size. Inherently modular in nature, the SMR process can be used in single or multiple parallel trains over a broad range of project sizes. A comparison of these processes has been covered in detail in previous publications.^{1,2}

A recent industry paper summarized the application of the expander and nitrogen process.³ The example applications covered are compared to the SMR process as summarized in Table 1. In essence, the expander and N₂ processes require about 50% more power than the SMR process. This is in line, but even higher than previously cited.¹ Since refrigeration compressors and drivers are the hearts of liquefaction processes, this large margin represents not only an extreme efficiency deficit but also a major cost deficit for the expander and nitrogen processes as compared to the SMR.

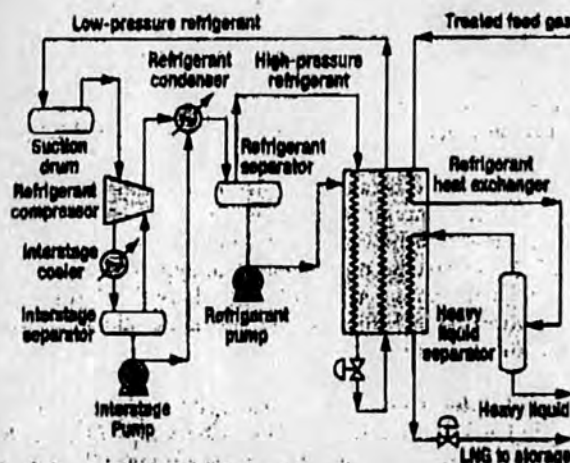


FIG. 1 Schematic diagram of the single-mixed refrigerant process.



FIG. 2 A typical mid-scale LNG liquefaction plant.

Process applications. The two key components in the liquefaction system are the refrigeration compressor and the main exchanger (cold box). In the SMR process, the refrigeration compressor is a single-body, intercooled compressor. Fig. 2 shows a typical unit used in mid-scale applications. Because the compressor is a single case, a barrel-style unit can be used, which facilitates inspection and maintenance activities.

The main exchanger is constructed of plate-fin heat exchangers. A single plate-fin exchanger can be used for capacities up to about 20 MMscfd. For larger sizes, multiple plate fin cores are used in a parallel assembly. A good example of a 1-MMtpy (approximately 130-MMscfd) unit is shown in Fig. 3. This unit has eight plate-fin cores in a single cold box package. This module is 7 m x 8 m x 14 m (w x l x h), weighing about 220 metric tons. For larger capacities, multiple boxes are applied.

In the mid-scale sizes, a variety of gas turbines are used to achieve the desired capacity. Table 2 lists a representative mix of turbines to be considered. While the base-load plants have been dominated by frame turbines, the mid-scale industry is focused on the aero-derivative units due to lower fuel rates and ease of maintenance. Table 3 shows some application examples of turbine drivers and cold box sizes. Up to about 1 MMtpy, a single compressor/exchanger combination is a good choice. For larger units, such as 2-MMtpy units, dual compressors and cold boxes are considered. Thus, virtually any size of unit can be developed in a modular fashion.

Heavies extraction. Depending on the composition of the feed gas to be liquefied, heavy hydrocarbons must be removed to prevent plugging due to solidification at low temperature. For this reason, as shown in Fig. 1, a partially condensed feed gas is drawn out of the main exchanger at a specified mid-point temperature.

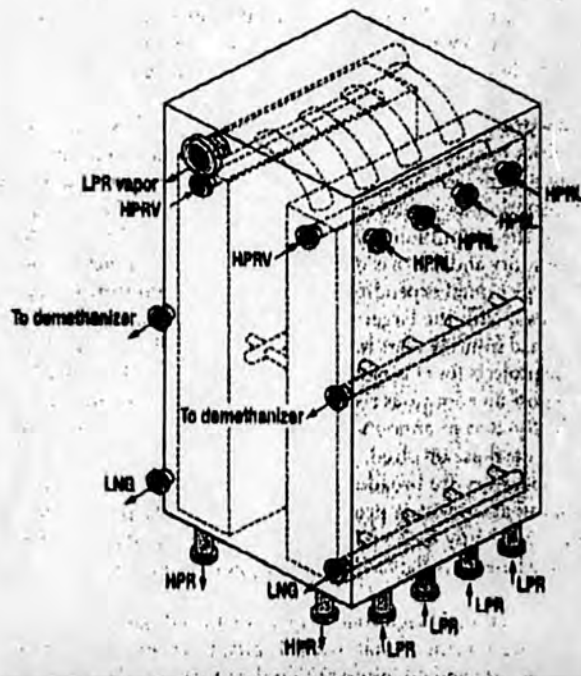


FIG. 3 A typical cold box assembly for a mid-scale LNG liquefaction plant.

TABLE 1. Process efficiencies for expander, nitrogen and SMR liquefaction processes

	Number of LM6000 to make 1.5 MMtpa
Expander with recycle	3*
Nitrogen refrigeration	3*
SMR	2
	LNG production with 2 x LM6000 chilled
Expander with C ₃ refig.	1.5*
SMR	2.1

*LNG Journal¹

After the condensed heavy liquid is separated, the gas is returned to the refrigerant heat exchanger where it is further cooled, liquefied and sub-cooled. If the heavy liquid is of sufficient quantity, fractionation of this liquid into products such as ethane, liquefied petroleum gas (LPG), butanes and gasoline may be economically attractive. These products can also be used for refrigerant makeup. In the majority of cases, a single C₃+ condensate product is the only liquid product. Alternatively, a full-range of natural gas liquid (NGL) products can be produced. The facilities at Skikda, Algeria, recover 60% of the ethane and essentially all C₃+ from the feed gas. Integration of the NGL recovery has been accomplished, as shown in Fig. 4.

Feed gas flexibility. Mid-scale projects are often to be developed for stranded gas assets. As such, the gas may come from associated gas, unassociated gas or pipeline supplies. Also, unconventional sources such as coal-bed methane (CBM) may also be alternative feeds for these plants. Many of the developments underway envision feed gas from several sources. For example, a recent project involved six different feed streams. A process with the flexibility to handle these different feeds is needed. Table 4 summarizes the differences in the various sources. The associated gas tends to be richer in NGLs and heavy hydrocarbons while CBM gas has little or no C₃+ constituents but can be high in nitrogen. The SMR process has been used in multiple instances to span this broad range of feeds.

Mid-scale applications. Mid-scale plants tend to be considered in the 0.5 MMtpy to 2 MMtpy sizes. Often, the desire is to phase in production in 0.5 MMtpy or 1 MMtpy sizes. In any event, a single 160,000 m³ or 180,000 m³ tank is needed to support commercial sized LNG cargo ships. This size tank can support up to about 2.5 MMtpy of production, depending on the shipping logistics. An example of a two-train layout is shown in Fig. 5. The compactness and simplicity of the process plant aids in developing this process plant on a minimal plot space of

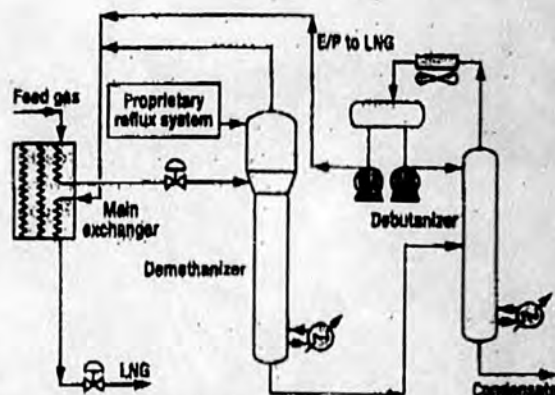


FIG. 4 NGL recovery in a mid-scale liquefaction

about 60 acres. The total schedule for these facilities will generally be driven by the LNG tank schedule. However, in some cases, the marine development can become a critical path item. Timelines of 36–40 months are typical.

Capital cost estimates. Cost estimates have been developed for complete mid-scale liquefaction plants from 0.5 MMtpy to

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2 MMtpy. Fig. 6 summarizes these discrete estimates with a total curve of cost vs. capacity. This curve is intended to include the complete facility with single tank and ship loading. One item, which is very difficult to generalize without site-specific data is the ship-loading jetty. Thus, two curves are shown. One represents a simple, short jetty with minimal dredging, and the second a more complex application with a long trestle and significant dredging. These presented costs are based on Gulf Coast labor rates and are useful for study purposes. Of course, site-specific construction costs and logistics can impact these numbers greatly.

Floating LNG systems. Floating LNG systems have been considered for many years. As gas developments move farther offshore the location of the liquefaction plant on a floating structure has several advantages. The elimination of a harbor and jetty associated with an onshore plant is a significant cost savings. In addition, with an onshore plant, long pipelines from production platforms are necessary. The LNG liquefaction facility can be integrated with the gas production system, thus eliminating production platforms entirely. Offshore systems require compact process designs, which conserve valuable deck space. The modular nature of the SMR process fits well with this objective. The low profile nature of the main heat exchanger and low equipment count are distinct advantages for offshore design. The fact that no pure component refrigerants are involved in the process leads to a small inventory of refrigerant components. This is an important factor in hazard analysis of offshore systems.

TABLE 2. Gas turbine options for LNG projects

Model	ISO Rating, hp (MW)	Fuel, Btu/hphr	Efficiency, %
LM2500	31,200 (23.3)	6,750	37.7
RR 6562	39,600 (29.5)	6,705	38.0
LM2500+	42,070 (31.4)	6,187	41.1
Frame 5D	43,690 (32.6)	8,650	29.4
RR 6761	44,500 (33.2)	6,290	40.5
LM2500+(G4)	45,590 (34.0)	6,175	41.2
Frame 6B	58,380 (43.5)	7,650	33.3
LM6000PC	59,355 (44.3)	5,941	42.8
Trent	70,418 (52.5)	5,939	42.8
Frame 7E	115,630 (86.2)	7,720	33.0



FIG. 5

Two types of floating systems have been developed: ship-based designs and barge-mounted facilities. An example of a 2-MMtpy, two train development footprint is shown in Fig. 7. The offshore environment lends itself to multi-level layouts, which facilitate compactness and the arrangement of equipment.

Barge-mounted systems have also been considered to accommodate LNG production processes. Barges of similar size to the ship-mounted systems have been developed. However, the barge-mounted concept can and has been expanded to accommodate larger LNG liquefaction process facilities. Projects up to 6 MMtpy have been developed using the SMR process and have been covered in previous publications.^{4,5} The process design for 6 MMtpy can be based on integrated trains of 2 MMtpy or 3 MMtpy or multiple trains of 1 MMtpy depending on the client desire for flexibility and phased development. Fig. 8 shows a cross-section of a 2 x 3 MMtpy module.

TABLE 3. Plant capacity ranges

Nominal capacity, MMtpy	Driver example	Hp avail at 30°C	Fuel efficiency at 30°C	Main exchanger no. x cores
0.6	LM2500+	35,000	38.5	1 x 4
0.7	LM2500+(G4)	38,400	38.9	1 x 6
0.8	LM6000	45,200	38.1	1 x 6
1	RR Trent	58,400	40.0	1 x 8
2	2 x RR Trent	2 x 58,400	40.0	2 x 8

TABLE 4. Feed gas ranges

	Associated gas	Non-associated or pipeline gas	CBM
Feed gas pressure	Medium	High	Low
Heavies	Rich to very rich	Some	None
Byproducts			
Condensate	Yes	Minor amount	No
NGL	Yes	No	No
CO ₂	2-12%	2-3%	0.2% and up
Nitrogen	<1%	Low to medium	4-15%

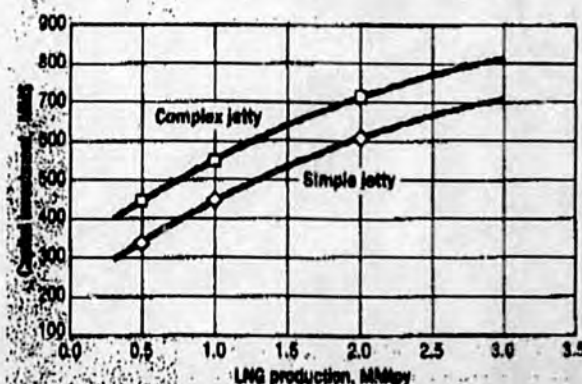


FIG. 6

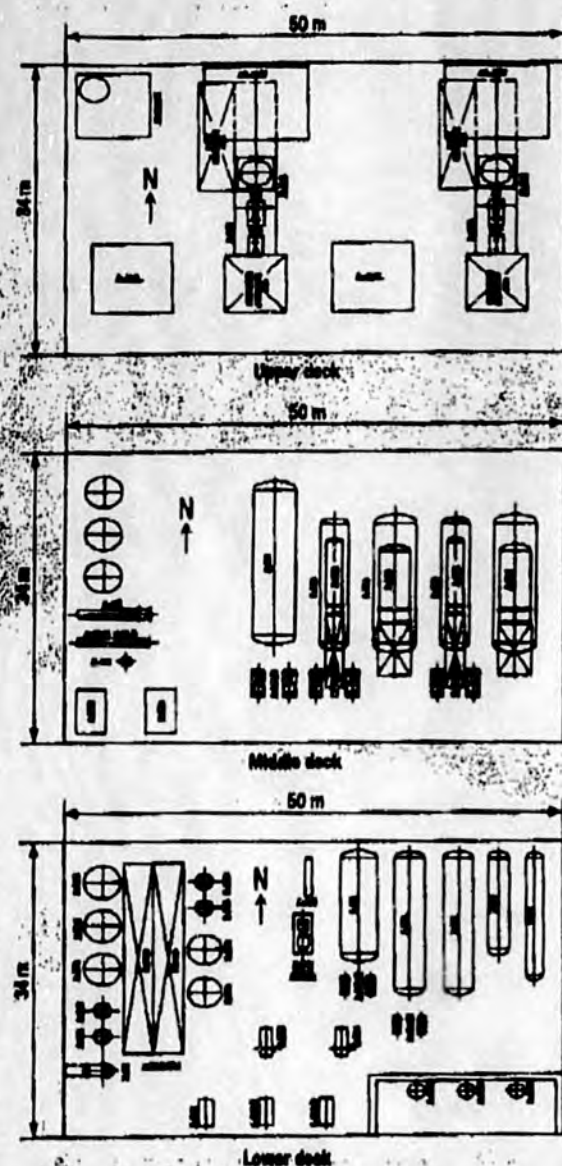


FIG. 7 Comparison of present day peak-shaving liquefaction technologies.

Outlook. Developments of mid-scale and floating LNG process facilities are actively being pursued worldwide to broaden the target reservoirs for gas development. The SMR process, with its compact size and low cost, is an integral part of the equation to make such facilities economically feasible. Facility costs have been developed which now make these projects competitive with larger scale developments. ¹⁰

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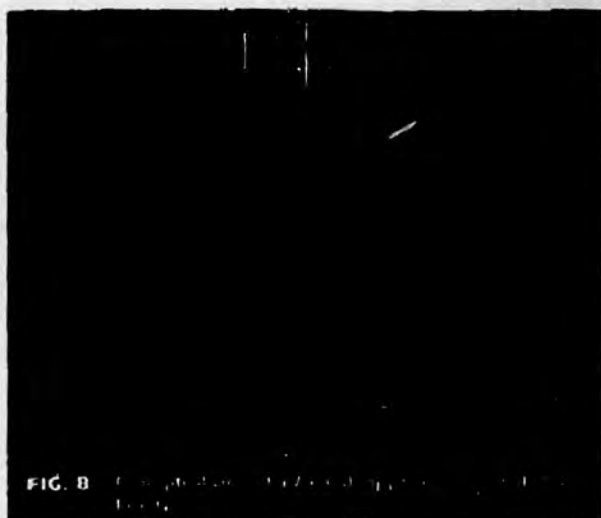


FIG. 8 Comparison of floating LNG process facilities.

² Price, B. and S. Hoffart, "Small scale LNG facility developments," AIChE Spring National Meeting, April 2007, Houston, Texas.

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⁴ Price, B., et al., "Developments in the design of compact LNG facilities," Gas Processors Association Annual Convention, March 2000.

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**Presentation to
Alaska State Senate**

July 22nd, 2008 & *July 23, 2008*
Juneau, Alaska

1. LNG Export Issues

Export License – Overview of Federal Law



- ANGTA requires Presidential finding before North Slope gas can be exported
- NGA requires DOE to authorize all U.S. gas exports
 - Export approval for Canada and Mexico automatic
 - DOE has only addressed export for Kenai and YPC
- 1969 to present DOE authorized Kenai export
- 1990 DOE finalized authorization for YPC to export 14 MMT (~1.9 bcf/d) for 25 years starting at first delivery

Export License – DOE's Market Driven Approach



- NGA creates rebuttable presumption that license will issue
- DOE's stated goal
 - let market forces define efficient energy markets
 - minimize federal involvement

"Competition in world energy markets promotes the efficient development and consumption of energy resources, as well as lower prices, whereas economic distortions can arise from artificial barriers to the free flow of energy resources. Accordingly, the DOE believes that the public interest in free trade generally supports approval of proposed exports." (DOE Order 350).

Export License – Domestic Need



DOE uses a three pronged public interest analysis to determine if the presumption to allow export has been overcome:

1. *Will national or regional demand exceed available domestic supply?*
2. *If insufficient domestic supply, are alternative supplies available to meet demand?*
3. *If there is sufficient domestic or alternative supply, does some other public interest overcome presumption of export?*
 - a. Environment
 - b. Alaskan interests
 - c. Energy security
 - d. International effects
 - e. Impact on North Slope development
 - f. Lower-48 natural gas prices

1. Will domestic demand exceed available domestic supply?

- U.S. supply and demand over term of license estimated
- DOE takes a broad view of available U.S. reserves, including allowance for
 - reserves growth
 - new discoveries
 - non-conventional gas resources
 - E.g., Tight sands, shale, coal seams and enhanced recovery
- In 1989 DOE said domestic supply sufficient to meet anticipated U.S. need
- Today, domestic reserve additions from shale gas have potential to fulfill domestic need

2. Are alternative supplies available to meet demand if DOE projects insufficient domestic supply?

- DOE looks at availability of gas for import including LNG from overseas
- "unduly simplistic to conclude that [ANS] exports will necessarily diminish the quantity of energy available to U.S. consumers"
 - Alternative may be ANS gas is stranded
 - Export will open ANS to exploration and development
 - ANS LNG to Asia may free up other LNG to go to U.S.
- DOE recognizes gas markets are global
- Today, increased global LNG production and U.S. receiving capacity means alternative supplies are available

3. If there is sufficient supply, does some other public interest overcome presumption of export?

Energy Security

- "DOE believes that the true energy security lies in encouraging the most efficient operation of the North American and global energy markets."
- Also since 2005 President has broad authority to stop export of all gas

International Effects

- Competition promotes efficiency and lower prices
- Impact on Asian balance of payments and trade imbalances significant

U.S. Prices

- DOE wants to insure exporting ANS gas will not drive up lower-48 natural gas prices
- DOE does not consider
 - Various projections anticipating ANS gas will go to U.S.
 - Economic studies of Canadian vs. LNG project
- Rather DOE asks whether available non-ANS gas can be delivered given anticipated prices?
- Answer in 1990 and now is yes!
 - By 2030 about half of U.S. demand will be met with non-conventional gas (EIA Annual Energy Outlook 2008)
 - Non-conventional gas, as marginal supplier, will set price
 - ANS gas to the U.S. will not change the cost of meeting marginal demand or thus price to U.S. consumer

Impact on North Slope development

- DOE unsympathetic to argument that proven ANS reserves needed for Canadian pipeline
 - Canadian project does not have right to ANS reserves
 - The market will decide
- DOE noted 13 years had passed since ANGTA and the ANS gas remained undeveloped
- DOE said export will encourage
 - Assessment of ANS potential
 - Earlier development of ANS proven reserves
 - Discovery and development of additional ANS reserves

Export License – Looking Forward



- AGPA strongly believes
 - YPC license will be honored, and
 - Regardless a new license would issue
- YPC license update
 - DOE stated YPC could not pass project costs on to U.S. consumers
 - Filing with DOE all contracts for acquisition, transportation, and sale of gas precondition to export
- New license
 - Presidential finding
 - DOE will undertake same export analysis it did for YPC
 - Circumstances have not materially changed