# HB 3001

# SB 3001

# 6/20/08

# SPECIAL SESSION DOCUMENTS

**WORK DRAFT**

**HOUSE BILL NO.**

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY -FIFTH LEGISLATURE -FIRST SESSION

BY

Introduced:
Referred:

A BILL

FOR AN ACT ENTITLED

**"An Act relating to oversight of North Slope natural gas pipelines by the Regulatory Commission of Alaska under the Alaska Pipeline Act; repealing statutory limitations on the conduct of open seasons for the transport of North Slope natural gas for in-state use; and repealing a requirement that the Regulatory Commission of Alaska treat the regulation of intrastate rates for a North Slope natural gas pipeline as if the pipeline were a public utility."**

**BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

* **Section 1.** AS 42.06.240(f) is repealed.

* **Section 2.** AS 42.06.230(b) is amended to read:

(b) The commission's jurisdiction and authority extend to

(1) an oil or gas pipeline facility operating in a municipality, whether home rule or otherwise; if a conflict between a certificate, order, decision, or regulation of the commission and a charter, permit, franchise, ordinance, rule, or regulation of **the** [SUCH A] local governmental entity occurs, the certificate, order, decision, or regulation of the commission prevails; and

(2) the intrastate transportation of [NORTH SLOPE] natural gas

through a [NORTH SLOPE] natural gas pipeline **to the extent not preempted by federal law, rule, or regulation.**

* **Section 3.** AS 42.06.370(c) is repealed.

Purpose

The purpose of this legislation is to remove potential impediments to timely state regulatory approval of a natural gas pipeline delivering North Slope natural gas to in-state users. Currently, AS 42.06.240(f) provides specific directives regarding how the Regulatory Commission of Alaska is to allow access to a pipeline for the transport of North Slope natural gas for in-state use. This provision has never been implemented by the RCA. Both the Alaska Natural Gas Development Authority and the RCA support removal of this provision from Alaska statutes to allow maximum flexibility in designing a regulatory structure for access to the pipeline by shippers that meet market requirements.

Similarly, AS 42.06.370(c) directs that a pipeline transporting North Slope natural gas shall establish rates as if it were a public utility regulated under AS 42.05. The purpose for repeal is to allow maximum discretion in establishing just and reasonable rates to meet public interest requirements.

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

Kate Giard, Chairman
Dave Harbour
Mark K. Johnson
Anthony A. Price
James S. Strandberg

| | |
|---|---|
| In the Matter of the Proposal from the Alaska Natural Gas Development Authority to Repeal AS 42.06.240(f) and AS 42.06.370(c) | P-05-10 |
| | ORDER NO. 2 |

**ORDER CLOSING DOCKET**

BY THE COMMISSION:

Summary

We support the Alaska Natural Gas Development Authority's (ANGDA's) proposal to repeal AS 42.06.240(f) and AS 42.06.370(c). We close this docket.

Background

At ANGDA's request, we decided to open this docket to receive comments from interested parties on the impact of ANGDA's proposal to repeal AS 42.06.240(f) and AS 42.06.370(c).[1] We held a public hearing on ANGDA's proposed statutory revisions on September 8, 2005.

[1]Order P-05-10(1), *Order Scheduling Public Hearing and Requesting Comments*, dated August 29, 2005.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

## Discussion

We received comments from Steve Pratt, Consultant, on behalf of ANGDA, Flint Hills Resources Alaska, LLC; Anadarko Petroleum Corporation; and ENSTAR Natural Gas Company, a division of SEMCO Energy, Inc.

We sent a letter to Governor Murkowski stating, in part, that: Based on our review of the record in Docket P-05-10, we support ANGDA's proposal. AS 42.06.240(f) contains very specific requirements for the timing and substance of intrastate capacity commitments made in connection with a North Slope natural gas pipeline. We believe that detailed requirements of that kind are more appropriately made by regulation, not in a statute. AS 42.06.370(c) is problematic because under it we are required to set rates of an entity which by statute must be certificated under AS 42.06 as though it were an entity certificated under AS 42.05. We believe that requirement raises uncertainties that should not be interjected into the rate setting process.

We support ANGDA's proposal to repeal AS 42.06.240(f) and AS 42.06.370(c). We attach the February 28, 2006 Commission letter to Governor Murkowski to this order as an Appendix. We close this docket.

**Regulatory Commission of Alaska**
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

# STATE OF ALASKA

**DEPARTMENT OF COMMERCE**
**COMMUNITY AND ECONOMIC DEVELOPMENT**
*REGULATORY COMMISSION OF ALASKA*

***FRANK H. MURKOWSKI, GOVERNOR***

*701 WEST EIGHTH AVENUE, SUITE 300*
*ANCHORAGE, ALASKA 99501-3469*
*PHONE: (907) 276-6222*
*FAX: (907) 276-0160*
*TTY: (907) 276-4533*
*WEBSITE: www.state.ak.us/rca/*

February 28, 2006

The Honorable Frank H. Murkowski
Office of the Governor
Alaska State Capitol, Room 430
Juneau, Alaska 99801-1182

Dear Governor Murkowski:

At the request of Harold Heinze, Chief Executive Officer of the Alaska Natural Gas Development Authority (ANGDA), we internally reviewed, publicly noticed, and received public comment orally and in writing on the revisions to AS 42.06 (Pipeline Act) proposed by ANGDA. ANGDA proposed to repeal AS 42.06.240(f) and AS 42.06.370(c). *See* attachment.

Based on the record, the RCA supports the proposed revisions by ANDGA to AS 42.06. Both AS 42.06.240(f) and AS 42.06.370(c) were part of changes made to AS 42.06 in 2000 that defined and added special provisions relating to a "North Slope natural gas pipeline." A North Slope natural gas pipeline includes all the facilities of a total system of pipe, including gas processing plants, used to transport "gas that is produced from the area of Alaska lying north of 68 degrees North latitude and that, but for a pipeline subject to regulation under this chapter, had not been committed for sale and delivery in a commercial market due to the prevailing costs or price conditions." (AS 42.06.630(12)).

In addition to defining a North Slope natural gas pipeline and adding the provisions ANGDA seeks to repeal, the 2000 enactment added provisions that deal with the extension or expansion of a North Slope natural gas pipeline (AS 42.06.310(d)) and that permit a North Slope natural gas pipeline to have two classes of service, firm and interruptible (AS 42.06.350(c)). *See* attachment.

In 2003, AS 42.06.350(c) was amended to make it applicable to all natural gas pipelines rather than only to a North Slope natural gas pipeline. Thus, any natural gas pipeline may now offer firm and interruptible service. If AS 42.06.240(f) and AS 42.06.370(c) are repealed, as proposed by ANGDA, AS 42.06.350(c) (extension and expansion) will be the only portion of statute requiring special treatment for a North Slope natural gas pipeline and the only portion making it necessary to retain the North Slope natural gas pipeline definition and jurisdictional subsections (AS 42.06.630(12), (13), and (14) and AS 42.06.230(b)(2)).

We held a public hearing on ANGDA's proposed statutory revisions on September 8, 2005. We enclose a copy of the transcript from that hearing. At the public hearing,

Steve Pratt, Consultant, spoke on behalf of ANGDA. Mr. Pratt testified that the statutory provisions ANGDA sought to repeal contained ambiguities, which might lead to uncertainty, which translates to risk, and that increased risk translates into increased costs. He stated the provisions unnecessarily limited the discretion of the RCA to act in the public interest. No other person spoke at the public hearing.

We received written comments on the proposed statutory revisions from three entities: Flint Hills Resources Alaska, LLC; Anadarko Petroleum Corporation; and ENSTAR Natural Gas Company , a division of SEMCO Energy, Inc. We enclose a copy of each of those comments.

Flint Hills agreed with ANGDA that the statutes proposed for repeal might create an impediment to the expansion of the intrastate North Slope natural gas market and might also limit the authority of the RCA to protect the public interest. Flint Hills stated that the requirement of AS 42.06.240(f) that shippers provide three-year take-or-pay contracts as proof of intrastate firm transportation commitments is a very heavy burden on the customer. Flint Hills stated that AS 42.06.370(c) would limit the discretion of the RCA and limit the capacity of carriers, shippers, and customers to propose, debate, and develop creative rate models.

Anadarko stated that its understanding was that the proposed revisions would serve to clarify the Pipeline Act and give the RCA greater discretion to resolve intrastate transportation issues on a North Slope natural gas pipeline. Based on that understanding, Anadarko supported ANGDA's proposed revisions.

ENSTAR stated in its filing that it was not ready to comment on the specific proposal. It observed that the interrelationships between the statutory and regulatory provisions that will govern development of North Slope natural gas were not simple. ENSTAR wanted a better explanation from ANGDA of the need for repeal and the consequences for the RCA's regulatory oversight of future gas pipelines.

ANGDA submitted a filing documenting the legislative history of the provisions it seeks to repeal. ANGDA also submitted the remarks of former Alaska Attorney General Charlie Cole on this subject at a July 28, 2004 Legislative Budget and Audit Committee hearing on stranded gas. In those remarks General Cole explained why he believe AS 42.06.240(f) was problematic as applied to possible providers of natural gas to Fairbanks. However, he recommended revision of the subsection rather than repeal.

Based on our review of the record in our Docket P-05-10, we support ANGDA's proposal. AS 42.06.240(f) contains very specific requirements for the timing and substance of intrastate capacity commitments made in connection with a North Slope natural gas pipeline. We believe that detailed requirements of that kind are more appropriately made by regulation, not in a statute. AS 42.06.370(c) is problematic

because under it we are required to set rates of an entity which by statute must be certificated under AS 42.06 as though it were an entity certificated under AS 42.05. We believe that requirement raises uncertainties that should not be interjected into the ratesetting process.

Sincerely,

REGULATORY COMMISSION OF ALASKA

Kate Giard
Chairman

Enclosures: Applicable Statutes
Transcript of Public Hearing
Public Comments

cc: Harold Heinze, Chief Executive Officer
Alaska Natural Gas Development Authority

**AS 42.06.240(f)**

(f) In addition to other requirements of (a) - (e) of this section, the provisions of this subsection apply to a certificate of public convenience and necessity for a North Slope natural gas pipeline carrier or person that will be a North Slope natural gas pipeline carrier under this chapter:

(1) the person making application shall dedicate a portion of the pipeline's initial capacity sufficient to transport the total volume of North Slope natural gas that has been committed by producers and shippers of North Slope natural gas to tendering for intrastate firm transportation service at the time that the operation of the North Slope natural gas pipeline commences;

(2) upon receipt of the certificate application under this subsection, the commission shall issue a public notice inviting prospective intrastate shippers of North Slope natural gas to file requests for service; a request for service submitted by a shipper in response to a notice issued under this paragraph must include a proof of the shipper's commitment to use the North Slope natural gas pipeline for intrastate firm transportation service, specifying the volume of North Slope natural gas that the shipper will tender for initial intrastate firm transportation service;

(3) in its review of an application submitted under this subsection,

(A) for purposes of evaluating the total volume of intrastate transportation of North Slope natural gas to be accepted for initial intrastate transportation, the commission shall determine total volume based upon written commitments to tender North Slope natural gas for intrastate firm transportation service continuously for a period of not less than three years after the operation of the North Slope natural gas pipeline commences as follows:

(i) each request for service by an intrastate shipper that is a public utility, as that term is defined in AS 42.05.990, for the purpose of furnishing natural gas for ultimate consumption within the state by its customers that individually consume an average annual volume of less than 20,000,000 standard cubic feet of gas per day shall be supported by a written commitment by the public utility that sets out the utility's best current estimate of the average annual volume that the utility will require during the three-year period;

(ii) each request for service by an intrastate shipper that is not a public utility, as that term is defined in AS 42.05.990 and each request for service by a public utility for the purpose of furnishing natural gas for

ultimate consumption within the state by a customer that individually consumes an average annual volume of 20,000,000 or more standard cubic feet of gas per day, that purchases North Slope natural gas from a North Slope natural gas producer, must be supported by one or more contracts for the purchase of the North Slope natural gas on a take-or-pay basis that extends for a period of not less than three years after the operation of the North Slope natural gas pipeline commences;

(iii) the commission may consider peak volumes specified in the written commitments of North Slope natural gas producers and purchase contracts; and

(B) the commission shall set out in its order granting a certificate of public convenience and necessity the total volume of intrastate North Slope natural gas that the North Slope natural gas pipeline carrier shall accept for intrastate transportation; the total volume may not exceed the volume substantiated by written commitments and contracts that comply with the requirements of this chapter;

(4) if the North Slope natural gas pipeline carrier wants to transport North Slope natural gas within the state in excess of the amount set out in the statement of total volume in the pipeline carrier's certificate of public convenience and necessity, the pipeline carrier may apply for authority to transport a greater volume of North Slope natural gas within the state than the carrier is required by the commission to transport in its order entered under (3)(B) of this subsection; the commission shall grant the authority requested by the pipeline carrier if the commission determines that the pipeline carrier's transportation of a greater volume is consistent with public convenience and necessity.

**AS 42.06.370(c)**

(c) Rates demanded, observed, charged, or collected by a North Slope natural gas pipeline carrier for intrastate service shall be designed as if that portion of the North Slope natural gas pipeline were a public utility regulated under the provisions of AS 42.05.

**AS 42.06.310(d)**

(d) The requirement of (c) of this section does not apply to a North Slope natural gas pipeline carrier to the extent that the capacity of the carrier's North Slope natural gas pipeline does not allow for expanded capacity, and does not apply to require a North Slope natural gas pipeline carrier to enlarge or extend its North Slope natural gas pipeline system. However, the commission may require a North Slope natural gas pipeline carrier to

expand, enlarge, or extend its North Slope natural gas pipeline system if, after notice and opportunity for hearing, the commission determines that

(1) a person making a request for expanded, enlarged, or extended service by a North Slope natural gas pipeline carrier has made a firm contractual commitment to the North Slope natural gas pipeline carrier to transport North Slope natural gas; and

(2) the expansion, enlargement, or extension will not result in

(A) substantial injury, including economic injury, to the North Slope natural gas pipeline facility or its customers;

(B) substantial detriment to the services furnished by the North Slope natural gas pipeline facility; or

(C) the creation of safety hazards.

**AS 42.06.350(c) [as it read when enacted]**

(c) In its tariff filed with the commission under (a) of this section, a North Slope natural gas pipeline carrier may charge separate rates for firm transportation service and for interruptible transportation service. A North Slope natural gas pipeline carrier

(1) may, in addition, impose a reservation fee or similar charge for reservation of capacity in a North Slope natural gas pipeline as a condition of providing firm transportation service; the reservation fee or charge imposed by the carrier may not include any variable costs or fixed costs that are not attributable to the provision of firm transportation service;

(2) may not impose a reservation fee or similar charge for reservation of capacity in a North Slope natural gas pipeline for interruptible transportation service.

# STATE OF ALASKA

**DEPARTMENT OF LAW**

*OFFICE OF THE ATTORNEY GENERAL*

*FRANK H. MURKOWSKI, GOVERNOR*

*1031 WEST 4TH AVENUE, SUITE 200*
*ANCHORAGE, ALASKA 99501-5903*
*PHONE: (907)269-5100*
*FAX: (907)279-8644*



October 19, 2005

*Hand Delivered To:*

Regulatory Commission of Alaska
701 West 8th Avenue, Suite 300
Anchorage, Alaska 99501

Re: Docket No. P-05-10 – In the Matter of the Proposal from the Alaska Natural Gas Development Authority to Repeal AS 42.06.240(f) and AS 42.06.370(c)

Dear Regulatory Commission of Alaska:

Per the Commission's request, enclosed you will find an original and 10 copies of the legislative history of AS 42.06.240(f) and AS 42.06.370(c), prepared on behalf of ANGDA, for filing in Docket No. P-05-10. Thank you.

DAVID W. MÀRQUEZ
ATTORNEY GENERAL

By: Alan Birnbaum
Alan Birnbaum
Assistant Attorney General

AB/drj
Enclosure
cc: Harold Heinze
Steve Pratt

**Legislative History of AS42.06.240(f) & AS42.06.370(c)**
**(HB 290 - 56 SLA 2000)**

Chapter 58 SLA 2000

Bill History/Action

**Bill Versions**
A. House Bill No. 290
B. House Bill No. 290 (O&G)
C. House Bill No. 290 (RES)
D. House Bill No. 290 (FIN)

**Committee Minutes**
House Oil & Gas Committee
1. 1/27/00 Minutes
2. 2/1/00 Minutes
3. 2/10/00 Minutes
4. 2/17/00 Minutes

House Resources Committee
5. 2/21/00 Minutes
6. 3/1/00 Minutes

House Finance Committee
7. 3/23/00 Minutes
8. 3/24/00 Minutes
9. 3/28/00 Minutes

Senate Finance Committee
10. 4/15/00 Minutes

**Committee Bill Files (Printed from Microfiche)**

**Recorded Cassette Tapes - Committee Hearings (Total 12 Tapes - not included in binder located in DOL Oil, Gas & Mining Section)**
House Oil & Gas Committee
1/27/00 Tape 1 of 2; Tape 2 of 2
2/1/00 Tape 1 of 1
2/10/00 Tape 1 of 1
2/17/00 Tape 1 of 2; Tape 2 of 2

House Resources Committee
2/21/00 Tape 1 of 1
3/1/00 Tape 1 of 1

House Finance Committee
3/23/00 Tape 1 of 2; Tape 2 of 2
3/28/00 Tape 1 of 1

Senate Finance Committee
4/15/00 Tape 1 of 1

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners: Kate Giard, Chairman
Dave Harbour
Mark K. Johnson
Anthony A. Price
James S. Strandberg

| | |
|---|---|
| In the Matter of the Consideration of Regulations Classifying Pipelines Based upon Differences in Annual Revenue, Assets, Nature of Ownership, and Other Appropriate Distinctions | R-05-11<br><br>ORDER NO. 1 |

**ORDER OPENING DOCKET AND SEEKING COMMENTS**

BY THE COMMISSION:

Summary

We open this docket to seek comments on whether we should establish two or more classes of pipelines under AS 42.06, and the reporting, accounting, and other regulatory requirements that we should prescribe for each class.[1]

Discussion

We recognize that the cost of regulation can be prohibitive for small, producer-owned pipelines and that full regulation of small pipelines could discourage exploration and development of Alaska's resources. We should consider simplified

[1] *See* AS 42.06.620 which states: The commission may by regulation provide for the classification of oil or gas pipeline facilities based upon differences in annual revenue, assets, nature of ownership, and other appropriate distinctions and as between these classifications, by regulation, provide for different reporting, accounting, and other regulatory requirements.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

regulation if current regulation is unduly burdensome and adversely affects the development of Alaska's oil and gas resources. However, we must balance the need for such regulatory charge with the public interest in open access to pipelines and reasonable transportation rates.

At our November 4, 2005, Public Meeting, we decided to open this docket to seek comments from interested persons on whether we should consider regulations establishing two or more classes of pipelines. In particular, we are interested in whether we can ease the burden of regulation on small, producer-owned pipelines that ship only the producer's products, while still adequately protecting the interests of unaffiliated producers, end-users and the public.

We seek comments on whether we should establish two or more classes of pipelines under AS 42.06. We also seek comments on the reporting, accounting, and other regulatory requirements we should prescribe for each class and how implementation of comments will encourage development, provide cost-effective regulation, provide open access to pipelines, and allow for reasonable transportation rates while protecting the public interest.

Comments must be filed by 4 p.m., January 13, 2006, with reply comments due January 27, 2006. We request that commenters reference Docket R-05-11. Since this is a regulations proceeding, commenters are not required to serve their comments on the other entities set out on the service list of this Order. We will post copies of all filed comments on our web site.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

STATE OF ALASKA

ALASKA NATURAL GAS
DEVELOPMENT AUTHORITY

FRANK H. MURKOWSKI, GOVERNOR

411 WEST 4TH AVENUE
ANCHORAGE, ALASKA 99501
TELEPHONE: (907) 257-1317
FACSIMILE: (907) 646-5005

May 24, 2005

FILE COPY

Kate Giard
Chairman, Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, AK 99501-3469

Re: Statutory Changes to AS 42.06

Dear Chairman Giard:

As you know, the Alaska Natural Gas Development Authority (ANGDA) is reviewing the feasibility of constructing a pipeline to transport natural gas to various users, including Alaskan consumers. Should construction prove feasible, ANGDA anticipates applying to the Regulatory Commission of Alaska (RCA) for a Certificate of Public Convenience and Necessity. Since certification is required prior to commencing construction, any delay in certification could prove detrimental to the project.

Our review of AS 42.06 has raised concerns that the Commission may not have at its disposal the tools required to efficiently process our application within the statutory six-month time frame. Therefore, ANGDA would like to work with the RCA to advocate statutory changes that increase the RCA's discretion in streamlining certification proceedings for jurisdictional natural gas pipelines owned by the state that transport North Slope natural gas. The proposed changes, which we will be considering at our June 27th meeting, are detailed below. ANGDA invites the RCA's input regarding any concerns with these changes that we hope you will join us in advocating.

We consider this a matter of some urgency since Governor Murkowski has indicated that the Alaska Legislature could have the matter of moving North

Slope gas to market before it within a few months. We believe that these issues could and should be part of any special session that is called.

1. **Grant the RCA discretionary authority to exempt a pipeline owned by the state, or a public corporation owned by the state, from any provision of AS 42.06.** Currently, full regulation of pipelines is mandatory under AS 42.06.140(a)(1) regardless of any pu lic interest determination the RCA might make with respect to any particula applicant, circumstance, or statutory provision. We believe that RCA forbearance authority will allow the Commission to fit its regulatory regime to the dictates of individual circumstances while effectively meeting public interest requirements.

2. **Exempt pipelines owned by the state, or by a public corporation of the state, from AS 42.06.240(f).** In addition to being unclear as to how it might be implemented, which could lead to delay in and of itself, this section of the statute specifies criteria the RCA shall use in determining the maximum and minimum amounts of gas a pipeline transporting North Slope natural gas shall be authorized to transport. ANGDA, considering the needs of potential shippers as well as potential financiers, needs the flexibility to propose to the RCA its own rules for determining whom it will transport gas for, how much gas it will transport, the terms and conditions for offering various levels of service, and how each type of offered service will be defined. ANGDA and the RCA should have the authority to rely on input from market participants to make these determinations rather than relying on what we believe to be obsolete statutory dictates.

3. **Repeal AS 42.06.370(c).** This provision requires that the structure of prices charged by a pipeline transporting North Slope natural gas be designed as if the pipeline were a distribution utility regulated under AS 42.05. ANGDA financial goals and optimal just and reasonable rate design may differ from a typical gas or electric distribution utility. ANGDA and the RCA should have maximum flexibility to design rates to meet public interest goals. It is unclear to us why flexibility in rate design for a North Slope natural gas pipeline should be more restrictive than that applying to other pipelines.

Chairman Giard, we appreciate your assistance in helping us to advance the goals of the Stranded Gas Act as well as Ballot Proposition Number 3 that brought ANGDA into existence. The ANGDA Board has expressed its interest in meeting with representatives of the RCA to discuss these proposals further.

**Stranded Gas Hearings**
(0407281315 Minutes)

**Access to Capacity for Alaskan Communities**
*Charlie Cole, Board of Directors, Alaska Gasline Port Authority, July 28, 2004.*

MR. CHARLIE COLE, Board of Directors, Alaska Gas Pipeline Authority, said he wanted to talk about the Gas Act's provisions at Fairbanks.

I have to say preliminarily that I have some hesitation about speaking critically, you might say, about an item of legislation that passed the legislature by a vote of 20 – 0 in the Senate and 38 – 0 in the House. Obviously, any bill that passes the Alaska Legislature with votes like that has strong support and is viewed by informed legislators as good legislation for this state. So, with that caveat and that reservation, I want to speak a little bit today about the effect of that bill as I see it on Fairbanks and other Interior communities and in a sense, communities down river.

One, Alaska is cold and Fairbanks is, on occasions, very cold. It is one of the restraints on growth that we have in Alaska and we'll always have in Alaska – is the cold weather. With that given, low cost economic energy is vital for the economic development of, certainly, Interior Alaska and, as we have seen, how vital and how beneficial that has been to the Anchorage area. But, Fairbanks has not had that benefit and Fairbanks continues to struggle economically as respects quality of life for the high cost of energy there.

So, if one looks to the future of Fairbanks, if Fairbanks is going to have any economic growth... it must have cheap economic energy to offset the costs of living there.

The second given is that these Alaska resources should be primarily for the benefit of Alaskans. Isn't that what Governor Murkowski said? He said one of the fundamental purposes of the use of these resources of Alaska should be to benefit Alaskans.

Senator Seekins would know at times in Fairbanks when it's 50 degrees below zero, we have people there who buy 50 gallons of fuel oil to heat their house, to keep it from freezing, because that's all they can afford, if you can believe that. One of the givens for the Fairbanks community is we really need gas. There's only one place we're going to get that gas and that's off this gasline, if it's ever built. Presumably, it's going to be built.

Also, if we want to keep the military bases in Fairbanks – you know those base closure proceedings come up every once in a while. One of the criticisms we talk about keeping Eielson and Fort Wainwright there is how much it costs to keep those bases open. If we're trying to reduce the defense budget, maybe we're trying to, I'm not really sure that we are, but if we are, we've got to reduce the cost of power and heating at those bases. So, that should, in my view, be given as a policy.

So, what did the Stranded Gas Act do for Fairbanks in that regard? Given I think those unanimous policies – lets just read what AS 42.06.240 says in that regard.... starting with section (f).

In addition to the other requirements of (a) through (e) of this section, the provisions of this section shall apply to a certificate of public convenience and necessity for a North Slope natural gas pipeline carrier or a person that will be a North Slope natural gas pipeline carrier under this chapter.

(1) The person making the application shall dedicate a portion of the pipeline's initial capacity sufficient to transport the total volume of North Slope natural gas that has been committed by the producers and shippers of North Slope natural gas to tendering for intrastate firm transportation service at the time that the operation of the North Slope natural gas pipeline commences.
(2) Upon receipt of the certificate application under this subsection, the [RCA] shall issue a public notice inviting prospective intrastate shippers of North Slope natural gas to file a request for service. A request for service submitted by a shipper in response to the notice issued under this paragraph must include a proof of the shippers commitment to use the North Slope natural gas pipeline for intrastate firm transportation service, specifying the volume of North Slope natural gas that the shipper will tender for initial intrastate firm transportation service.
(3) In its review of an application submitted under this subsection:
(A) For the purpose of evaluating the total volume of intrastate transportation of North Slope natural gas to be accepted for initial intrastate transportation, the [RCA] commission shall determine the total volume based upon written commitments to tender North Slope natural gas for intrastate firm transportation service continuously for a period of not less than three years after the operation of the North Slope natural gas pipeline commences as follows (the RCA has to determine the total volume based upon written commitments (before the certificates of public

convenience and necessity are issued and before pipeline construction begins – day one):

(i) Each request for service by an intrastate shipper that is a public utility, as that term is defined by statute, for the purpose of furnishing natural gas for ultimate consumption within the state by its customers that individually consume an average annual volume of less than 20 million standard cubic feet of gas per day shall be supported by a written commitment by the public utility that sets out the utility's best current estimate of the average annual volume that the utility will require during the three-years period.

MR. COLE emphasized that a written commitment gives the sense of something that is binding and obligatory, but after reading the next sentence, it may not mean contract.

(ii) Each request for service by an intrastate shipper that is not a public utility, as that term is defined by law, and each request for service by a public utility for the purpose of furnishing natural gas for ultimate consumption within the state by a customer that individually consumes an average annual volume of 20 million or more standard cubic feet a day, that purchases North Slope natural gas from a North Slope natural gas producer must be supported by one or more contracts for the purchase of the North Slope natural gas on a take or pay basis that extends for a period of not less than three years after the operation of the North Slope natural gas pipeline commences.

MR. COLE explained that means that anybody who wants this natural gas, if it is not a public utility or it is a public utility with more than 20 million standard cubic feet per day, you have to reach a contract now to buy natural gas from the carrier on a take or pay basis. Fairbanks has no natural gas distribution system or facilities for converting natural gas to electrical energy; so, who in Fairbanks would enter into a contract like this, he asked. He didn't know how such a project would be financed and supposed that it would be impossible.

CO-CHAIR OGAN interrupted to say that LNG is being shipped from the Matanuska Valley to Fairbanks at $7 per thousand CF and it wouldn't take too much to set up a turbine to turn the natural gas into electricity.

MR. COLE responded that it wouldn't be very practical to enter into a contract now without knowing what rates the RCA will set and approve as just and reasonable. Fairbanks needs a whole distribution system for homes to be heated and no one knows what that would cost and no one would finance it. However, he noted that was only part of the dilemma. The next section says:

(iii) The RCA may consider peak volume specified in written commitments

of the North Slope natural gas producers and purchase contracts; and

(B) The commission shall set out in its order granting a certificate of public convenience and necessity the total volume of intrastate North Slope natural gas that the North Slope natural gas pipeline carrier shall accept for intrastate transportation.

MR. COLE said that means the certificates of public convenience and necessity shall say the total volume of intrastate gas may not exceed the volume substantiated by written commitments and contracts that comply with the requirements of the chapter. Commitments have to be in place, then the RCA in the certificate of public convenience and necessity says, "You've got to send out X, but you can't ship any more for intrastate transportation."

He emphasized that it gets worse:

If the North Slope natural gas pipeline carrier wants to transport gas in excess of the amount set forth in the statement of total volume of the pipeline carrier's certificate of public convenience and necessity, the pipeline carrier may apply for authority to transport more.

MR. COLE explained that means the carrier has to see if it can get authority to do that.

We're looking at a gasline that's going to potentially be running by Fairbanks for the next 30 years. How are we ever going to, for example, entice anyone else to come to Fairbanks and utilized this natural gas for a petrochemical facility? What about supplying natural gas to Fort Wainwright? Converting those bases? And how are we going to furnish natural gas to Eilson Air Force Base? Once, ten years down the road, it then becomes up to the gasline to decide whether they want to increase the intrastate capacity for Fairbanks. And I'm not talking just about Fairbanks and Eilson and Fort Wainwright, I'm talking about Tok, I'm talking about Delta Junction on the way down the Highway, but I'm also talking about the development of propane facilities to be able to ship propane down river to these other communities. I mean, once you do this, [it] is locked in. Then it's up to the pipeline, itself, to decide whether it wants to increase the capacity – and that's over the next 10, 20 or 30 years or maybe 50 years.

This is legislation, which I think is ill-advised, if I may say. That's a little strong for people who voted 58 – 0; I realize that. But, I think for the reasons I've given you, this Legislature should take a look at it and decide whether it needs to be revised. Probably 90 percent of what you hear in these hearings you have no control over. It's under the control of FERC.

*"Connecting Alaskans To Their Natural Gas"*

# Legislative Hearing - AGIA

**Anchorage on June 20, 2008**

***In-State Use of North Slope Gas***

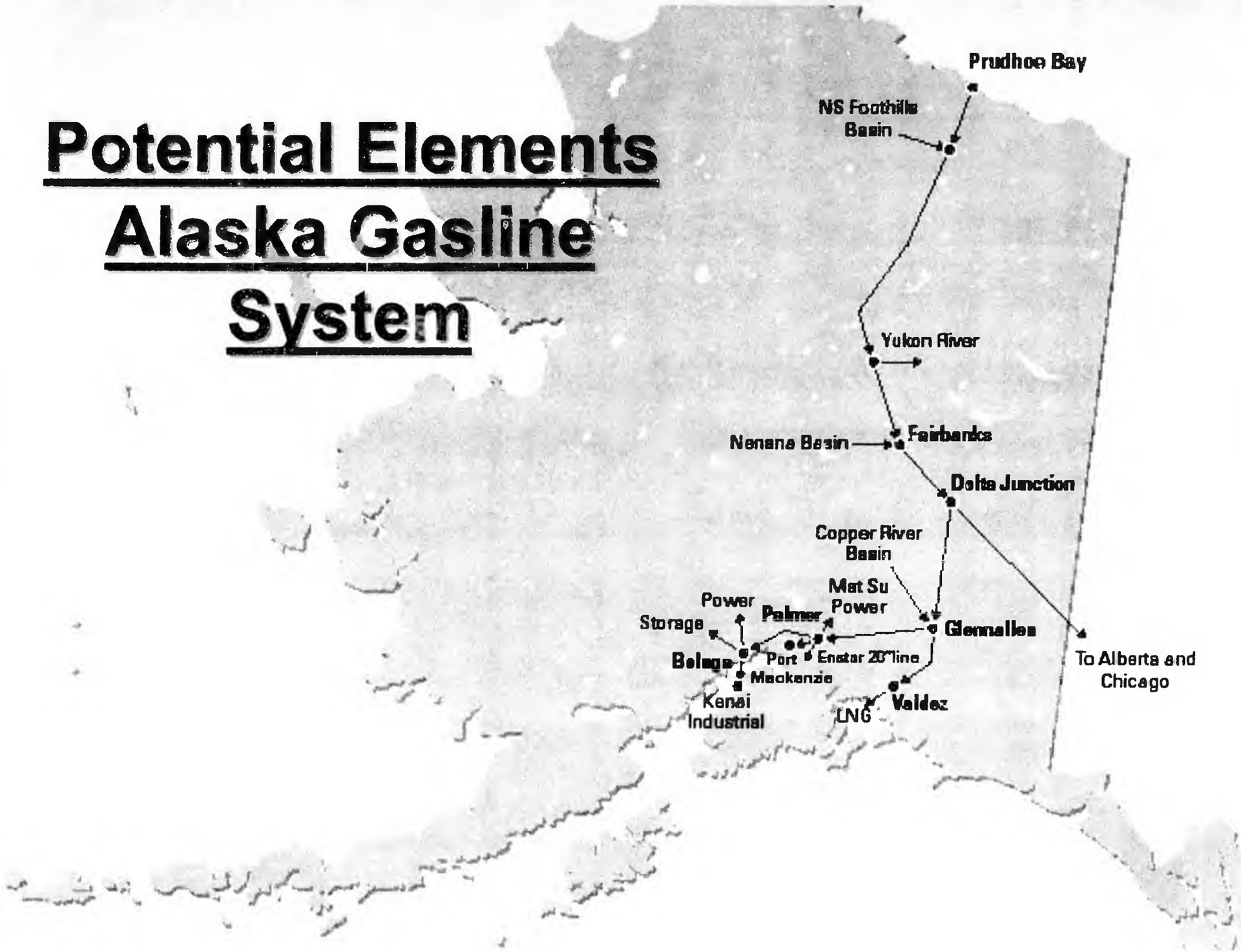
# *"It's the Open Season ..."*

Alaska
Natural Gas Development Authority

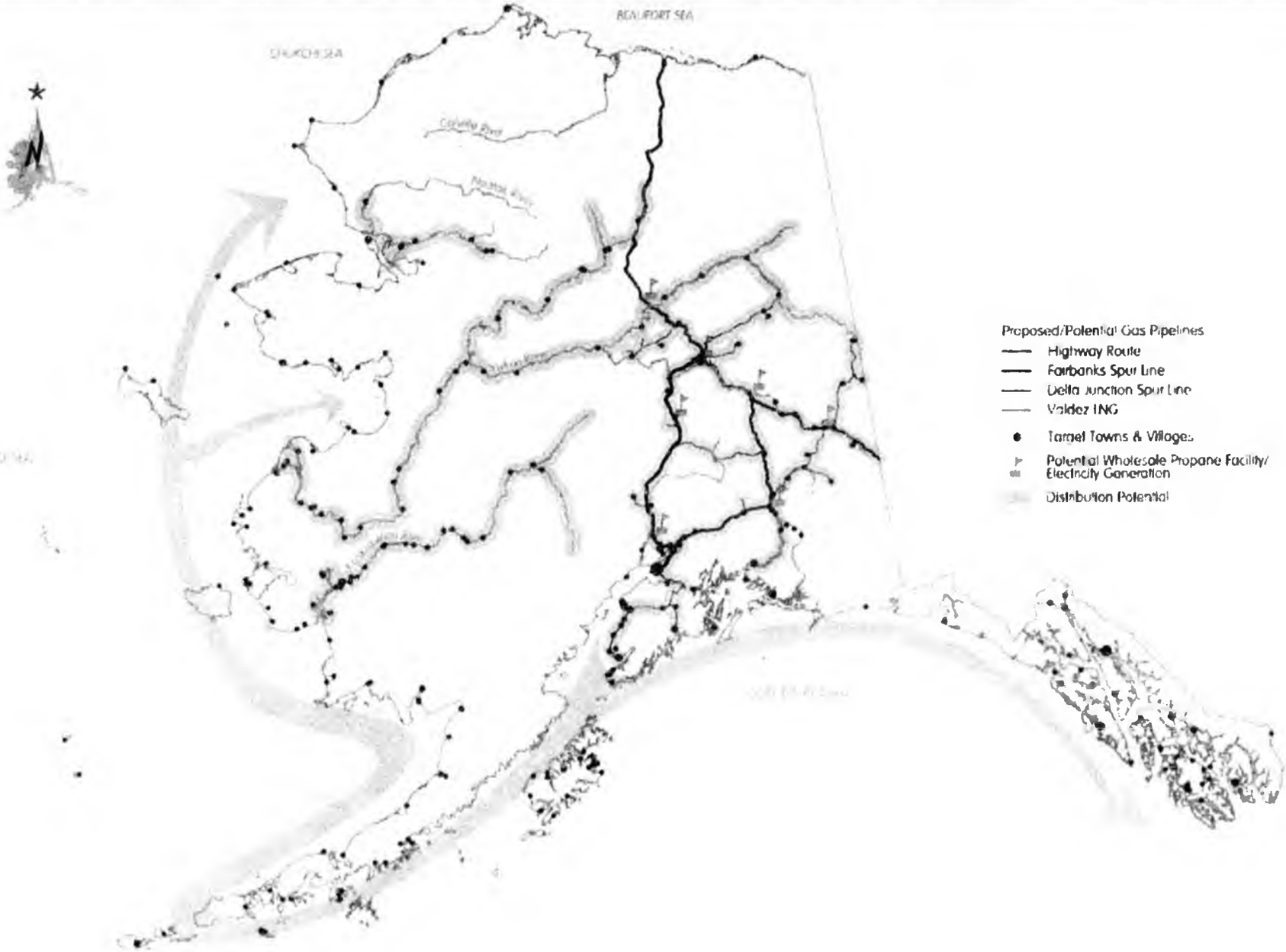
# In-State Gas Issues

- **ANGDA "Spur Line" from Delta Junction to Beluga via Glennallen** (370 miles of 20")
- **Alaska utility gas needs (250 mmmscfpd) & potential industrial demand**
- **In-State Project threshold & tariff sensitive to throughput commitments**
- **Changes needed in RCA Open Season Statute**
- **Preserve potential for gas based "value added" industries**

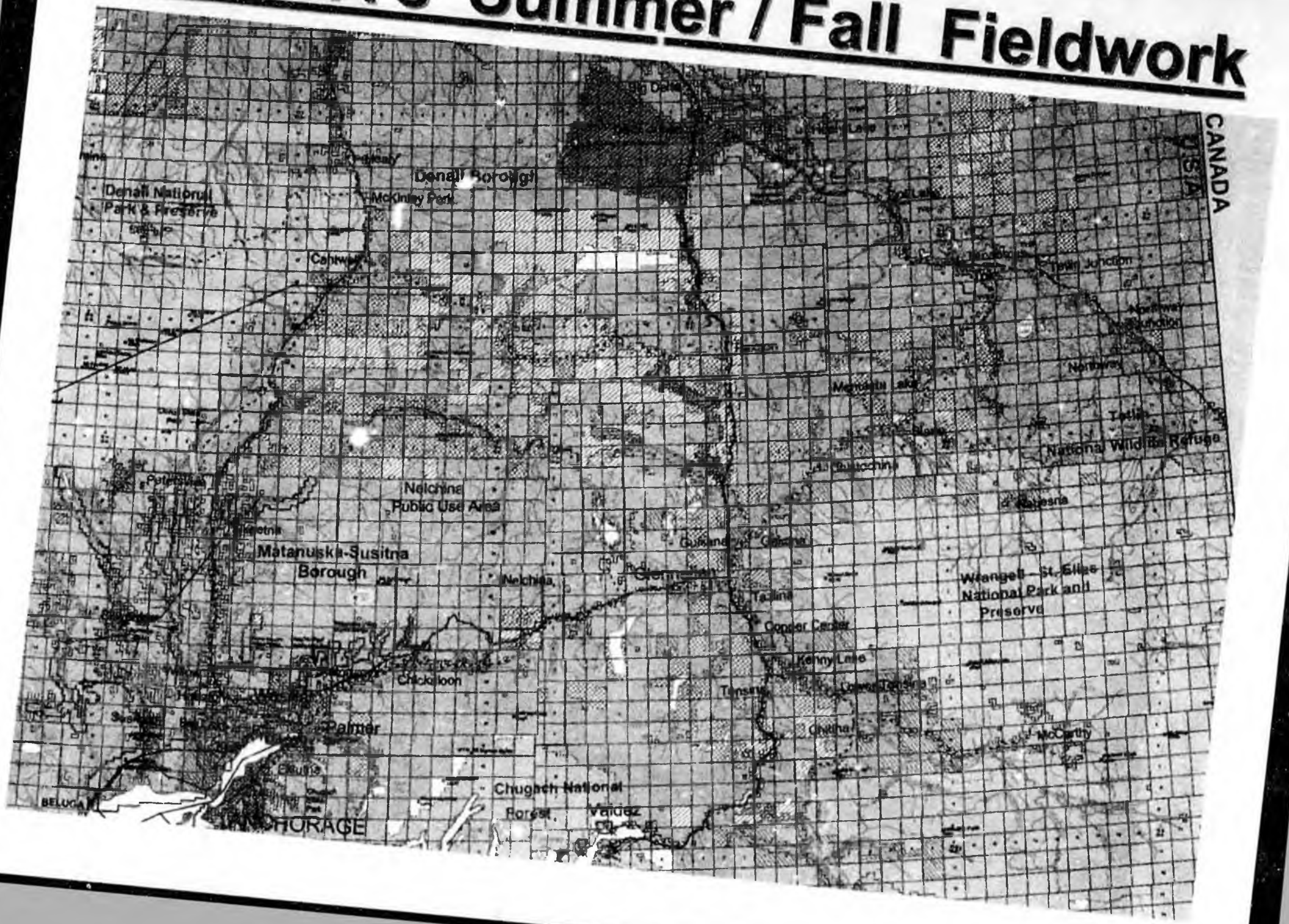
# Potential Elements Alaska Gasline System



# "Connecting Alaskans To Their Natural Gas"



# ANGDA's Summer / Fall Fieldwork



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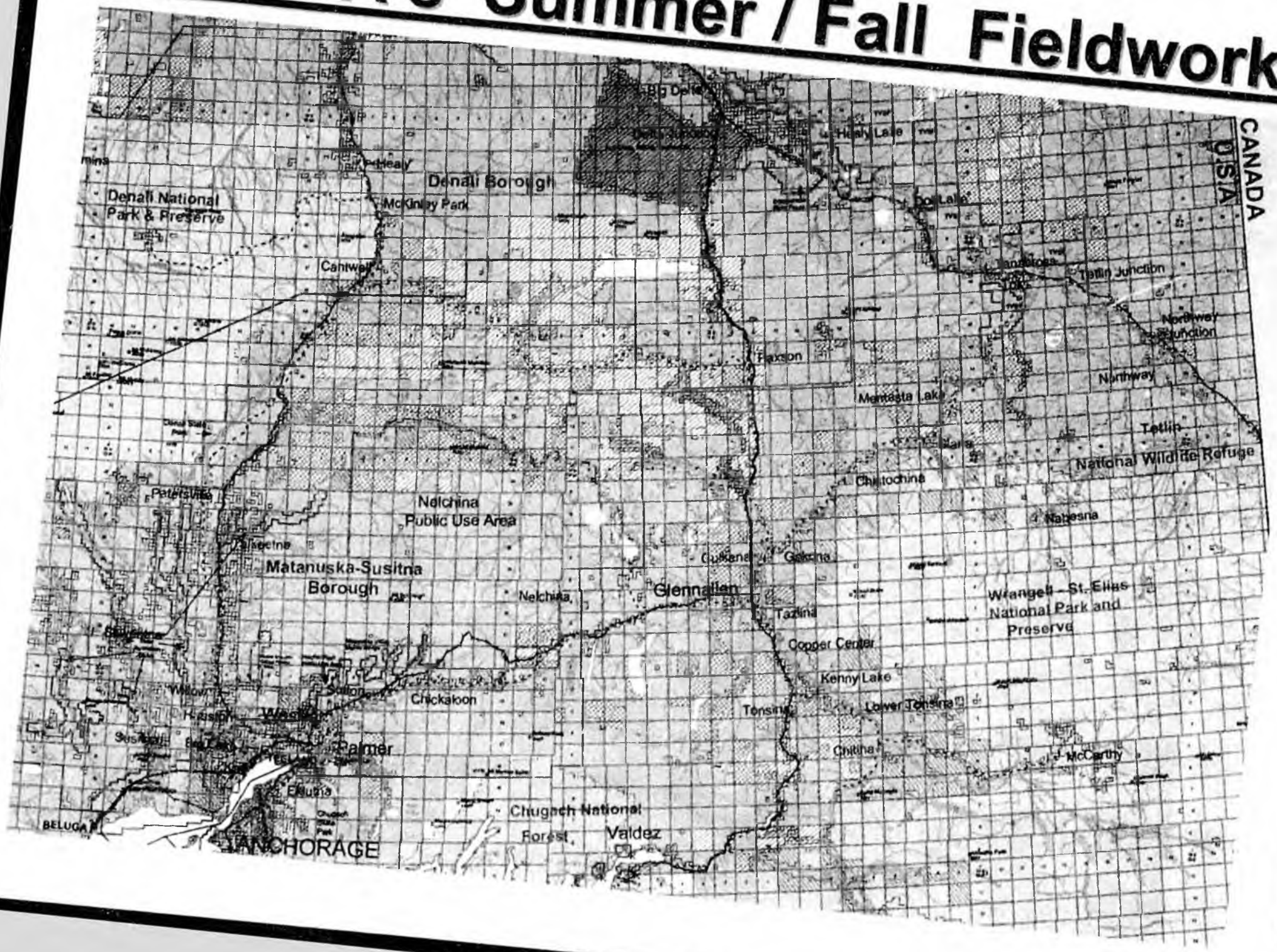
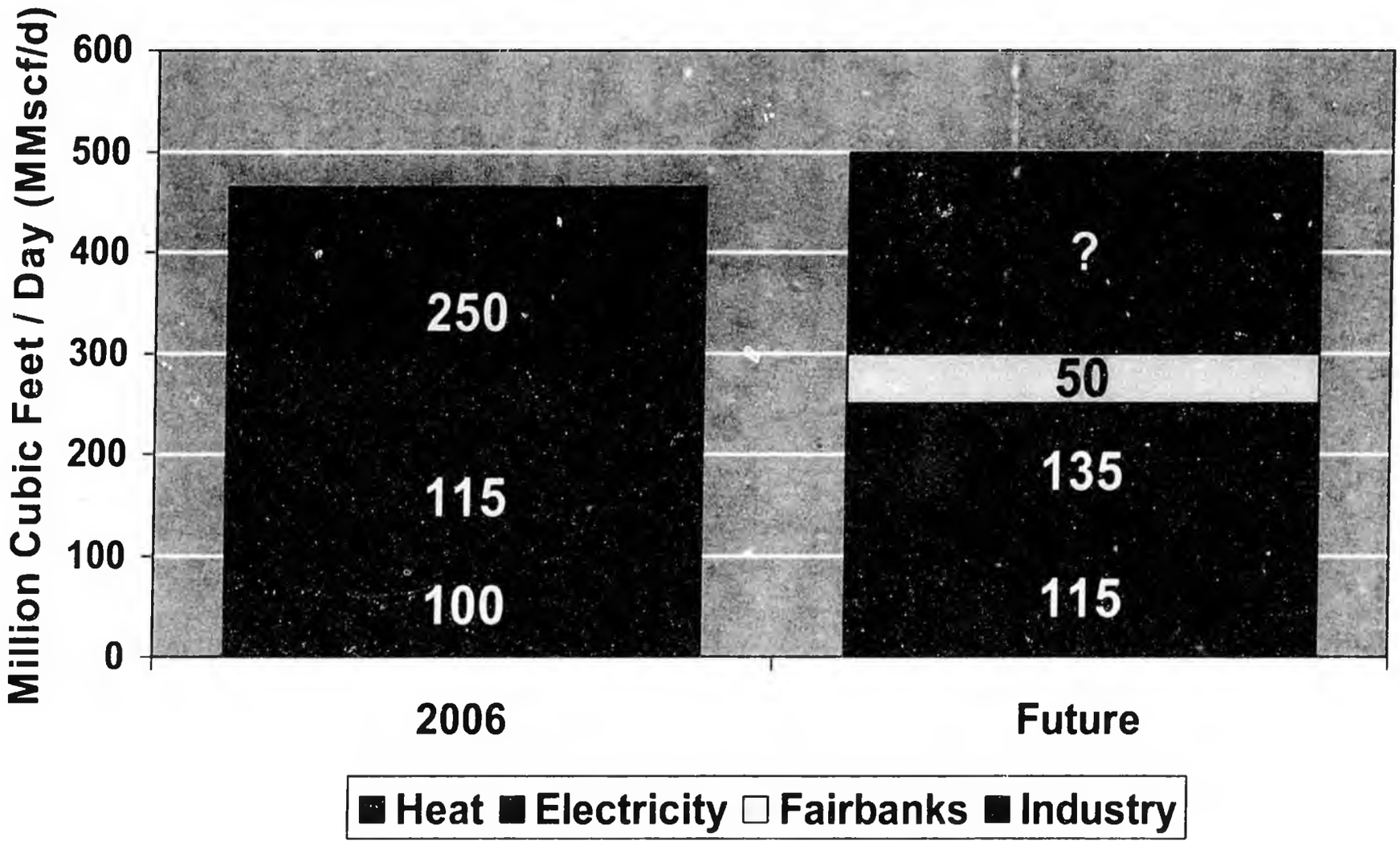
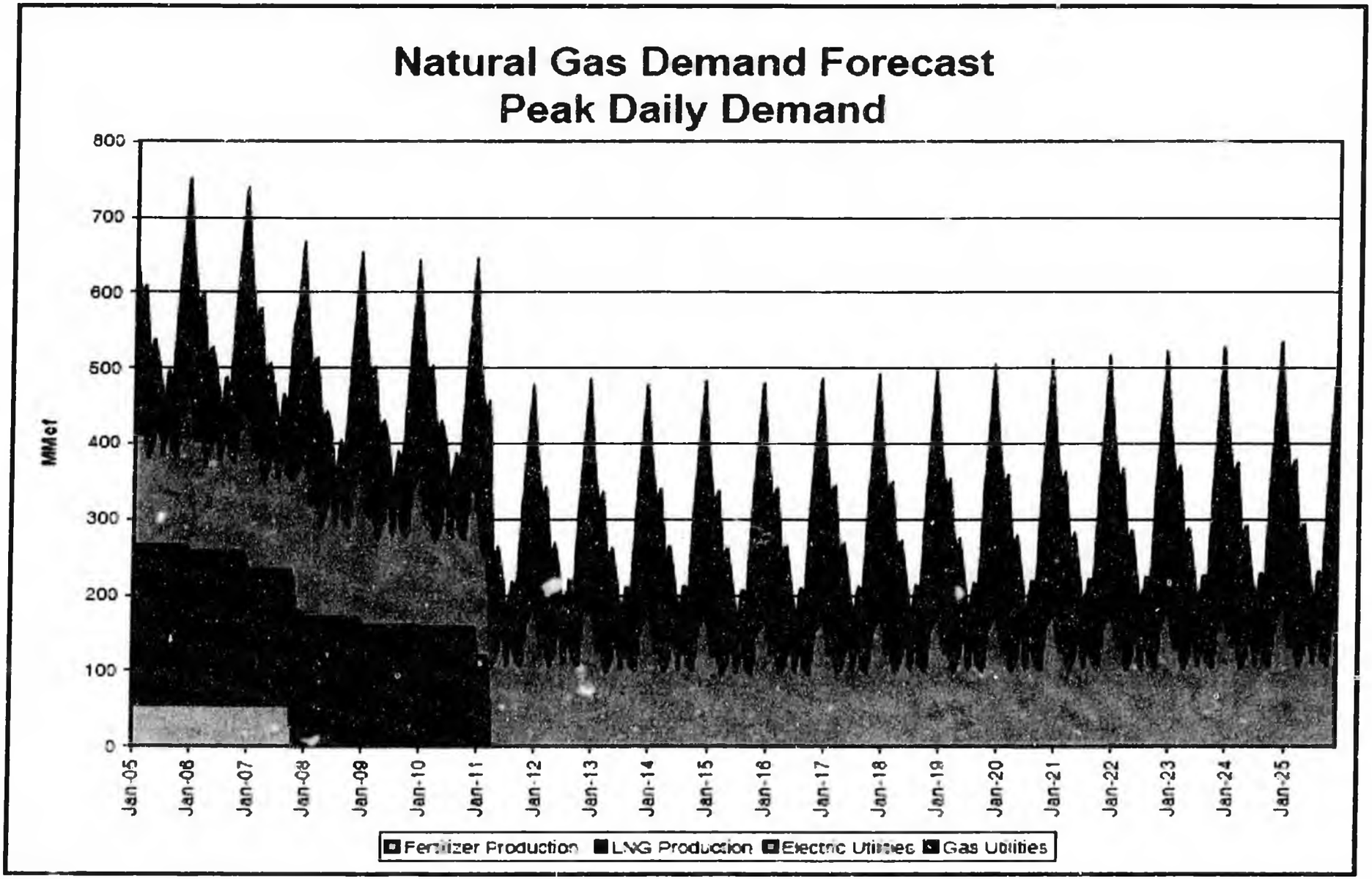


# Average Daily In-State Gas Uses (mmscf/d)



# Peak Daily Demand



# Gas Pipeline Cost of Service Estimates ($/mmbtu)

| | 100 mmscfpd | 250 mmscfpd | 500 mmscfpd |
|---|---|---|---|
| **Fairbanks** | | | |
| **Bullet Line** | **$10.00** | **$3.50** | **$2.00** |
| **Big Pipe** | **$1.25** | **$1.25** | **$1.25** |
| **Cook Inlet** | | | |
| **Bullet Line** | **$15.00** | **$5.25** | **$3.00** |
| Big Pipe | $1.50 | $1.50 | $1.50 |
| Spur Line | $5.00 | $1.75 | $1.00 |
| **Total Spur** | **$6.50** | **$3.25** | **$2.50** |

***Pipeline Costs Only - Comparable B & V Estimate would be $3.50 to Alberta***

# "It's the Open Season ..."

- At the In-State Open Season:
  - The gas demand volume profile for various Alaska utilities will be known
  - Long term utility gas purchase and shipping commitments could exceed $10 billion
  - An aggressive time line will allow Alaska utilities to strike the "best negotiated deals" before the FERC open season

# Average Daily In-State Gas Uses (mmscfpd)

| | 2006 | Future |
|---|---|---|
| • Home Heating | 100 | 115 |
| • Electric Power | 115 | 135 |
| • Fairbanks | | 50 |
| • Industrial | 250 | ? |

# ANRTL PRESENTS AN ALASKA NORTH SLOPE GAS TO LIQUIDS (GTL) OPTION

## "A LEGACY DECISION for ALASKA"

**PREPARED FOR LEGISLATIVE BUDGET & AUDIT COMMITTEE**

THE COMPETITION AGIA PROMISED BUT DID NOT DELIVER

June 20, 2008

# AGIA Response to GTLs

- Gas-to-Liquids (GTL) is a promising technology.
- However, various market, cost, and technological issues (as demonstrated in the Cook Inlet pilot project) make the future of GTL technology uncertain.
- Further evaluation will be needed as this technology advances.
- It is important to recognize that the AGIA process was designed as commercial vehicle for getting Alaska gas from the North Slope to market.

# AGIA Response to GTLs

- Alaska Gasline Inducement Act does not dictate market destinations or the use of particular technologies, but allows for these issues to be decided by the market.
- Does anyone see the irony in this statement? "The Alaska GASLINE Inducement Act does not dictate the use of a particular technology".
- Then why not call it the Alaska Gas Development Inducement Act.

# The main points we will make:

- It is important for the Legislature to know that there are other options for monetizing North Slope gas than with a gas pipeline, and that GTLs may well result in:
  - a much higher wellhead value for gas than a pipeline,
  - more long term jobs for Alaskans and
  - a larger tax base in Alaska.
- A GTL plant would most likely be built in stages, which has several important advantages.
- From the standpoint of Alaska employment and economic development the construction would be spread over a minimum of 14 years.

# The main points we will make:

- The plant would require a substantial construction workforce. Although not as large as that needed for a gas pipeline, the construction workforce would be employed in Alaska for many more years.
- The GTL plant operations workforce would be much more substantial than that for a gas pipeline.

# The main points we will make:

- All of the liquids remain in Alaska for marketing.
- Natural gas liquids can be transported through the TAPS pipeline along with GTL products.
- While a GTL project could use 2, 3, 4, 5, 6 billion cubic feet of gas/day or more if desired, the plant can be sized to use less gas, leaving gas production that could be transported south through a smaller "bullet" pipeline.

# The main points we will make:

- If you are going to tax the Producers natural gas at a quasi crude oil price equivalent the Producers might as well convert their natural gas to a liquid product and actually receive a premium price above crude oil.
- We believe the GTL option gives Alaska high value transportation fuels badly needed in the U.S. along with economic benefits and flexibility not offered with a just gas pipeline.

# Abbreviations

- GTL - Gas to Liquids
- CTL – Coal to Liquids
- BTL – Biomass to Liquids
- F-T – Fischer-Tropsch
- NGLs - Natural gas liquids ($C_3$ +)
- LNG – Liquefied Natural Gas
- CNG – Compressed Natural Gas

# Abbreviations

- KW – 1,000 watts of electric power
- KW-HR – 1,000 watts for 1 hour
- Heat Rate - Btu's needed per kilowatt hour of power produced
  (example 8,500 btu's will produce 1,000 watts of electricity for 1 hour)
- Vapor Pressure – pressure a product exerts at a specific temperature
  - Butane ($C_4H_{10}$) has a vapor pressure of 47 psig at 110°F
  - Propane ($C_3H_8$) has a vapor pressure of 204 psig at 110°F
  - Ethane ($C_2H_6$) has a vapor pressure of 850 psig at 110°F

# Abbreviations

- 1 cubic foot of natural gas has 1,000 Btus
- 1 MCF of natural gas has 1 million Btus
- 1 Barrel of Crude Oil has ~ 6 million Btus
- Crude Oil Price Equivalent
  - Multiply the value of 1 MCF of gas by 6 or
  - Divide the value of 1 barrel of crude oil by 6
- 1 Barrel of F-T products has ~ 5.3 million Btus
- F-T Price Equivalent
  - Multiply the value of 1 MCF of gas by 5.3 or
  - Divide the value of 1 barrel of F-T by 5.3

# CONVERTING NORTH SLOPE NATURAL GAS RESERVES INTO

"PROVEN"

F-T TRANSPORTATION FUELS

&

PETROCHEMICAL FEED STOCKS

WHILE SEQUESTERING $CO_2$

"GREEN AS IT CAN BE"

# A GTL/CTL PLANT PRODUCES FISCHER-TROPSCH (F-T) TRANSPORT FUELS

## SOME OF THE CLEANEST FUELS IN THE WORLD

## BUT WHAT IS THE F-T PROCESS?

# The Fischer-Tropsch Synthesis

$$2\,CO(g) + H_2(g) \rightarrow (\text{-}CH_2\text{-})_n(l) + CO_2(g) + H_2O$$

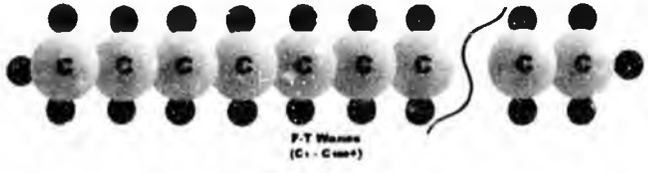
Okay, don't let the chemistry scare you!

Let's take a look.....

# Three Steps in GTL/CTL/BTL Refining to make F-T Fuels

GTL/CTL/BTL Processes use 3 distinct steps, all commercially proven to convert a gas, liquid or solid into synthetic transport fuels:

- Step 1 - Syn-Gas generation ($H_2$ & CO) + 
- Step 2 - The F-T reaction (long paraffin chains ➡ wax)



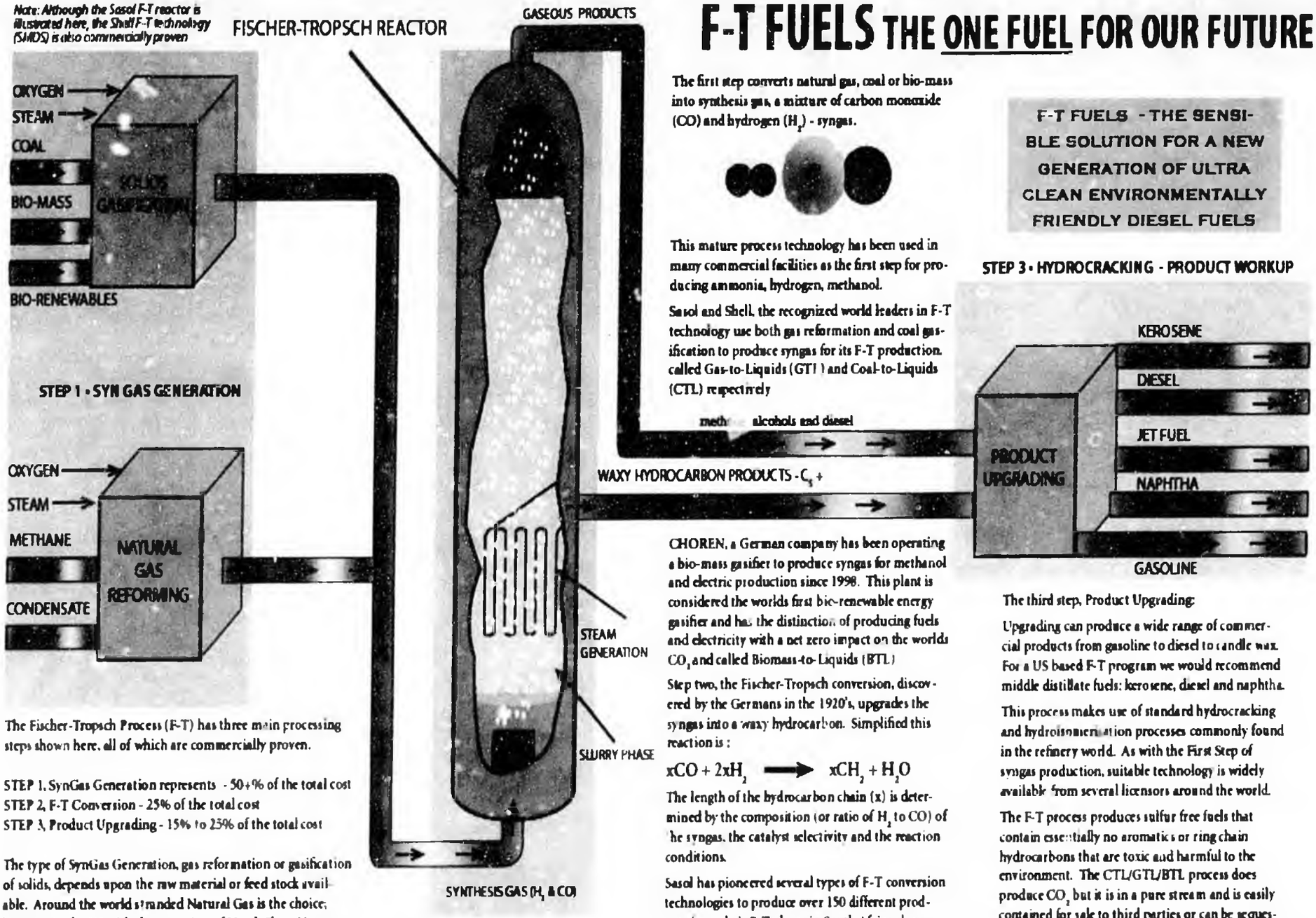

+  (water)

- Step 3 - Product upgrading (hydrocracking of the long chain F-T paraffin to produce the desired end product – similar to a crude oil refinery)
  - Kerosene – Diesel – Gasoline - Jet Fuel – Naphtha

$C_{10}$-$C_{13}$ $C_{14}$-$C_{20}$ $C_5$-$C_{10}$ $C_{10}$-$C_{13}$ $C_4$-$C_{10}$

# F-T FUELS THE ONE FUEL FOR OUR FUTURE

*Note: Although the Sasol F-T reactor is illustrated here, the Shell F-T technology (SMDS) is also commercially proven*




The first step converts natural gas, coal or bio-mass into synthesis gas, a mixture of carbon monoxide (CO) and hydrogen ($H_2$) - syngas.



This mature process technology has been used in many commercial facilities as the first step for producing ammonia, hydrogen, methanol.

Sasol and Shell, the recognized world leaders in F-T technology use both gas reformation and coal gasification to produce syngas for its F-T production. called Gas-to-Liquids (GTL) and Coal-to-Liquids (CTL) respectively

meth alcohols and diesel

CHOREN, a German company has been operating a bio-mass gasifier to produce syngas for methanol and electric production since 1998. This plant is considered the worlds first bio-renewable energy gasifier and has the distinction of producing fuels and electricity with a net zero impact on the worlds $CO_2$ and called Biomass-to-Liquids (BTL)

Step two, the Fischer-Tropsch conversion, discovered by the Germans in the 1920's, upgrades the syngas into a waxy hydrocarbon. Simplified this reaction is :

$$xCO + 2xH_2 \longrightarrow xCH_2 + H_2O$$

The length of the hydrocarbon chain (x) is determined by the composition (or ratio of $H_2$ to CO) of the syngas, the catalyst selectivity and the reaction conditions.

Sasol has pioneered several types of F-T conversion technologies to produce over 150 different products from their F-T plants in South Africa alone. The hydrocarbon stream ($xCH_2$) is sent to product workup and the water ($H_2O$) is sent to the water recovery unit.

**F-T FUELS - THE SENSIBLE SOLUTION FOR A NEW GENERATION OF ULTRA CLEAN ENVIRONMENTALLY FRIENDLY DIESEL FUELS**

The third step, Product Upgrading:

Upgrading can produce a wide range of commercial products from gasoline to diesel to candle wax. For a US based F-T program we would recommend middle distillate fuels: kerosene, diesel and naphtha.

This process makes use of standard hydrocracking and hydroisomerization processes commonly found in the refinery world. As with the First Step of syngas production, suitable technology is widely available from several licensors around the world.

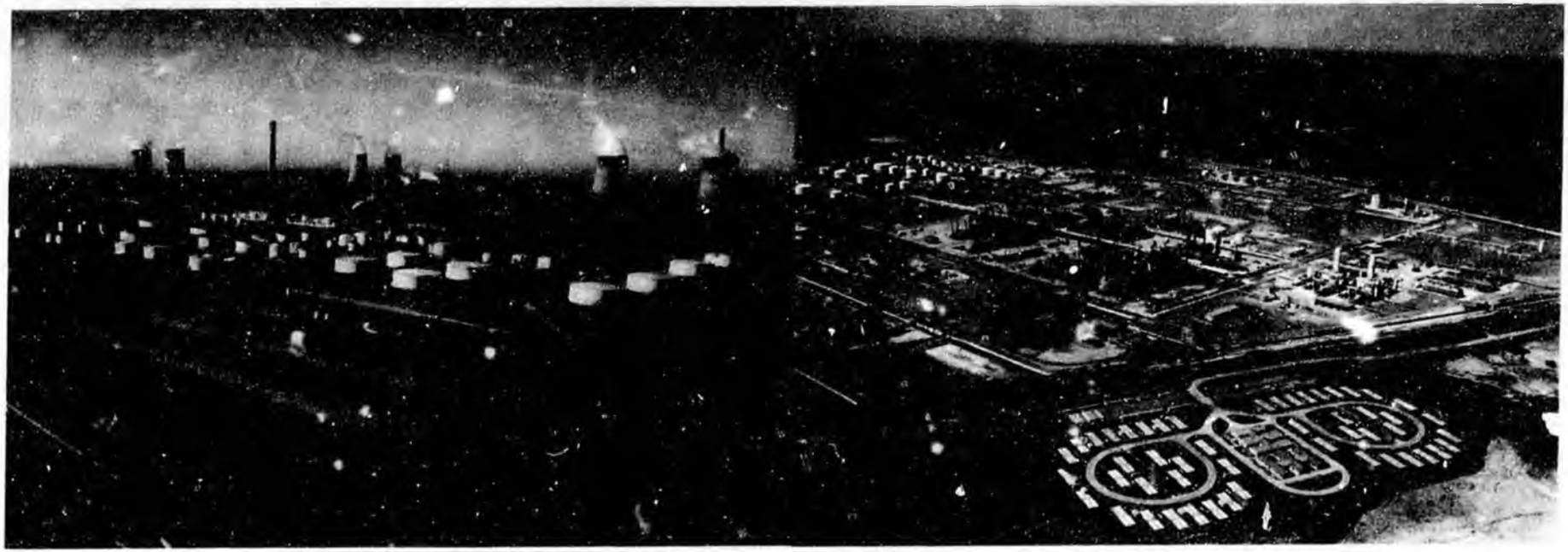
The F-T process produces sulfur free fuels that contain essentially no aromatics or ring chain hydrocarbons that are toxic and harmful to the environment. The CTL/GTL/BTL process does produce $CO_2$ but it is in a pure stream and is easily contained for sale to third parties or can be sequestered for injection into underground wells.

F-T Fuels, clean fuels for our future that will reduce US dependence on foreign crude oil and products.

The Fischer-Tropsch Process (F-T) has three main processing steps shown here, all of which are commercially proven.

STEP 1, SynGas Generation represents - 50+% of the total cost
STEP 2, F-T Conversion - 25% of the total cost
STEP 3, Product Upgrading - 15% to 25% of the total cost

The type of SynGas Generation, gas reformation or gasification of solids, depends upon the raw material or feed stock available. Around the world stranded Natural Gas is the choice; however, in the US with the exception of North Slope Natural Gas, coal, bio-mass (garbage), bio-renewables (trees and plants) represent the majority of available feedstock for a US based F-T program!



South African Secunda 150,000 BPD Coal to Liquids (CTL)

South African Mossgas 47,000 BPD Gas to Liquids (GTL)

Shell Bintulu 15,000 BPD Gas to Liquids (GTL)

# THE F-T PROCESS IS COMMERCIAL

**260,000 bbl/d already proven and operational in South Africa & Malaysia**

**500,000 bbl/d coming soon to Qatar**

**230,000+ bbl/d coming soon to China**

**China and India proposing 1+ million bbl/d in new CTL plants**

# SYNTHETIC DIESEL

## F-T DIESEL
## AS CLEAN AS CNG

**U.S. EPA***
**APPROVED**

**NON-TOXIC**

**ZERO SULFUR**

**ZERO AROMATICS**

**>70 CETANE**

**$PM_{10} \leq$ CNG**

*EPA Water Docket, EB 57 located at 401 M Street SW Washington DC, 20460 Reference Docket No. W-98-26 in UNOCAL data file 4.A.a.3, Vol 13

# GTLs
# Facts and Fiction

# GTL FACTS and FICTION

- Majors not pursuing F-T technology
- F-T Process not Efficient
  - Value vs Efficiency
- Costs of F-T too high
- TAPS - Batching/Pigging can't be done
- American needs natural gas (market)
- Value of Alaska Natural Gas
  - Do the people know Alaska gas isn't going to be cheap?

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# WHERE ARE THE MAJORS ON GTLs?

1. In December 2003 ConocoPhillips and in July 2004 ExxonMobil both signed agreements to build 160,000 bbl/day and 150,000 bbl/day GTL plants in Qatar.

   They would not have made these commitments if they did not believe in GTLs and possess the skills to build world-scale GTL plants.

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2. Shell, a new player in Alaska, has a 15,000 bbl/d GTL plant in Malaysia, is building a 140,000 bbl/d GTL plant in Qatar as well as designing a 70,000 bbl/d CTL plant in China.

3. Chevron, Sasol's world wide GTL partner, is building a 34,000 bbl/d GTL plant in Nigeria and had proposed a 130,000 bbl/d GTL expansion with Sasol and a new 120,000 bbl/d GTL plant both in Qatar.

4. Marathon completed a pre-FEED study for a 120,000 bbl/d GTL plant in Qatar in 2003.

5. BP and Statoil are working on barge mounted GTL plants.

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5. BP and Statoil are working on barge mounted GTL plants.

**Clearly, the North Slope majors possess all the skills necessary to build GTL (F-T) plants worldwide including in Alaska.**

# GTL FACTS and FICTION

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- F-T Process not Efficient
  - Value vs Efficiency
- Costs of F-T too high
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- American needs natural gas (market)
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  - Do the people know Alaska gas isn't going to be cheap?

# PROCESS EFFICIENCY

Some say the GTL process is not efficient with only 65% of the energy contained in the natural gas reaching the end market in the form of transportation fuels.

Like any manufacturing process that "adds value" to its products, the transportation fuels resulting from a GTL plant have a higher value.

Also of importance is that the "lost" 35% really isn't lost.

It is captured as waste heat and is used to generate electricity, heat buildings and run other processes that need heat, saving valuable natural gas for other purposes.

# GTL vs LNG

## VALUE ($) VS EFFICIENCY

IS THE LNG PROCESS MORE EFFICIENT - WITH 80 % OF THE WELL HEAD ENERGY REACHING THE MARKET ?
IS THE GTL PROCESS LESS EFFICIENT - WITH 65 % OF THE WELL HEAD ENERGY REACHING THE MARKET ?

TECHNICALLY, LNG IS A MORE EFFICIENT PROCESS IF YOU JUST LOOK AT DELIVERED ENERGY TO THE MARKET
IT IS HOWEVER TOTALLY FALSE IF YOU LOOK AT THE VALUE ($) OF THE DELIVERED ENERGY IN THE MARKET

LNG BEGINS LIFE AS NATURAL GAS AND ENDS LIFE AS NATURAL GAS

GTL BEGINS LIFE AS NATURAL AND ENDS LIFE AS A REFINED PRODUCT SUCH AS DIESEL

WHILE BOTH ARE CARBON BASED, THEIR VALUES ($) ARE TOTALLY DIFFERENT

AS AN EXAMPLE:

A LUMP OF COAL AND A DIAMOND ARE BOTH CARBON BASED. UNDER TREMENDOUS PRESSURE AND HEAT (A MANUFACTURING PROCESS), A LUMP OF COAL CAN BECOME A DIAMOND. WHICH HAS MORE VALUE, A LUMP OF COAL OR A DIAMOND? DOES IT MATTER THAT A DIAMOND IS A FRACTION OF THE SIZE OR WEIGHT OF THE ORIGINAL LUMP OF COAL?

IF GTL PRODUCED DIESEL IS MORE VALUABLE THAN LNG DERIVED NATURAL GAS SHOULD YOU CARE IF THE GTL PROCESS IS LESS EFFICIENT IN CONVERTING ENERGY SO LONG AS THE VALUE RECEIVED FOR THE ORIGINAL ENERGY IS GREATER.

**WHICH WOULD YOU PREFER ?**

**A LUMP OF COAL**

**LNG PRODUCED NATURAL GAS**

**OR A DIAMOND**

**OR GTL PRODUCED DIESEL**

**THE CHOICE SHOULD BE SIMPLE**
**GO FOR THE HIGHER NETBACK VALUE ($)**

# GTL FACTS and FICTION

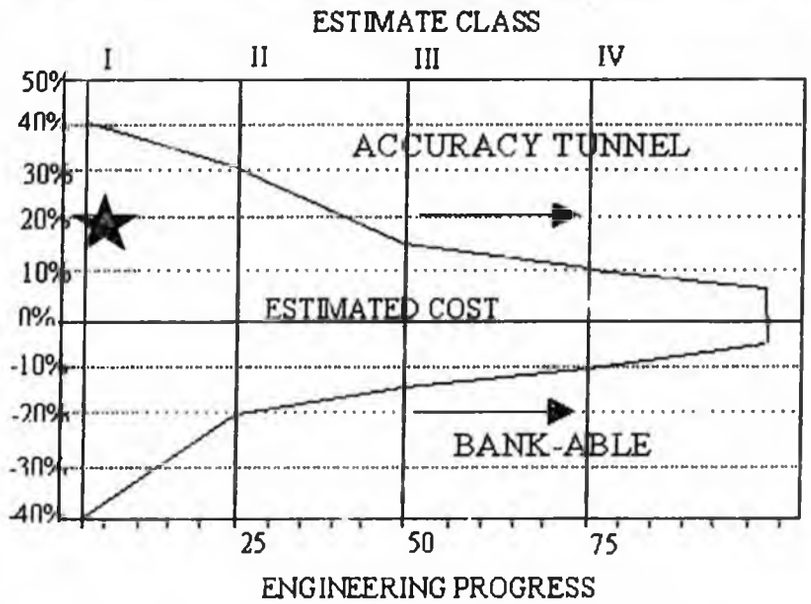
- Costs of F-T too high

# GTL PROJECT COSTS?

- 2003 estimate $25,000/installed barrel
- 2007 actual cost $32,000/installed barrel
- 2008 Shell Pearl GTL plant $60,000/ installed barrel (under construction today)
- ANRTL completed a $1.5 million Pre-Feasibility study for an 80,000 bbl/d CTL project for the Cook Inlet in February 2008. Cost estimates have risen from $4.6 to $12 billion from 2005-08.
- The CTL project still pencils out because product prices have risen even more.

# GTL PROJECT COSTS?

- Some of the estimated costs of this Cook Inlet CTL project were derived from the $250 million Sasol/China engineering study completed in late 2007.
- North Slope GTL plant ~300% higher than the recently completed Sasol GTL plant in Qatar – we use a $92,000/ installed barrel cost.
- If anything, we believe the projected costs of a North Slope GTL plant program are high.

| MINIMUM INFORMATION REQUIRED TO DEVELOP ESTIMATES | | | | | |
|---|---|---|---|---|---|
| ESTIMATE CLASS | I | II | III | IV |  |
| ESTIMATE TYPE | PRELIMINARY FEASIBILITY | FEASIBILITY BANKABLE | DEFINITIVE | DETAILED | |
| ACCURACY RANGE | +40% To -40% | +30% To -20% | +15% To -15% | +10% To -10% | X = Info Required to Obtain Stated Accuracy Range |
| PURPOSE | Screen | Study | AFE | AFE | |
| GENERAL PROJECT SCOPE | X | X | X | X | Project Scope, Design Basis, and Execution Strategy |
| | X | X | X | X | General Geographic location and Site Requirements |
| | X | X | X | X | Special Considerations that Impact Project Costs |
| | X | X | X | X | Utilities and Other Infrastructure Requirements |
| | | | X | X | Detailed Project Schedule |
| PROCESS | X | X | X | X | Block Flow Diagrams w/Primary Flow Steams and Utilities |
| | | X | X | X | Preliminary PFDs w/Heat & Material Balance |
| | | X | X | X | Engineered PFDs w/Heat & Material Balance, and Preliminary P&IDs |
| | | | X | X | Engineered P&IDs |

# GTL FACTS and FICTION

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- F-T Process not Efficient
  - Value vs Efficiency
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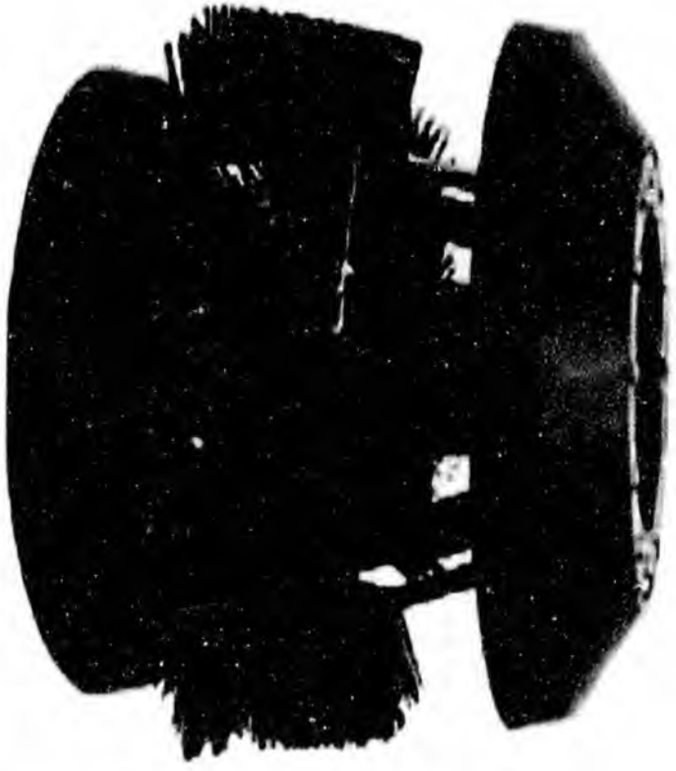
- American needs natural gas (market)
- Value of Alaska Natural Gas
  - Do the people know Alaska gas isn't going to be cheap?

# BATCHING / PIGGING
## Facts and Fiction

- Batching –Won't work - You can't pig in TAPS
- Batched products will be contaminated
- NGLs with high vapor pressure can't be moved in TAPS
- Ethane – what do you do with it?

# BATCHING / PIGGING

- **YOU CAN'T PIG IN TAPS**



Typical cleaning Pig

- **THEY RUN PIGS IN TAPS TODAY**

# BATCHING / PIGGING

- There is no question that the TAPS line can be operated as a dual/multi products/crude pipeline.
- Explorer Pipeline, owned by several major oil companies has successfully operated a 1,400-mile large diameter pipeline carrying a full slate of refined products and crude oil. In fact the Explorer Pipeline model is used in many pipelines in operation today.
- Explorer Pipeline has offered to bring their expertise to Alaska to assist with the design and conversion of TAPS.

# BATCHING / PIGGING

- Batching F-T products and NGLs (Products) without a physical separation between the Products and the ANS crude oil will not work. Further batching of the Products without a physical separation between individual products is not recommended.


**"THE PIG TRAIN"**

- Physical Pigging will allow batch shipping of Products from the North Slope to Valdez.
- The outstanding question is how far can you batch/pig down the TAPS before you need to replace the pig due to wear?

# BATCHING / PIGGING

- TAPS line can remain viable for moving crude oil produced on the North Slope to Valdez for 50 to 100 or more years.
- GTLs will provide the minimum throughput volumes to keep the TAPS line flowing.
- Incremental GTLs and NGLs will help lower the TAPS tariff resulting in a higher netback price and a higher revenue stream to the State.

# BATCHING / PIGGING

- Once TAPS is modified to carry both crude oil and products, the currently recycled gas stream can be processed to extract additional NGLs for batching to Valdez.
- This allows for the receipt of this NGL revenue stream within a few years, certainly long before a GTL plant could be on line or a gas line to the lower 48 could be built.

# BATCHING / PIGGING

- It is our opinion that the market for North Slope NGLs will be considerably higher at Valdez than at ACEO in central Alberta if for no other reason than the tariff on TAPS is at least 1/3 of the cost to ship on the proposed AGIA gas line.
  - TAPS tariff $5/bbl (83.3¢/million btu)
  - AGIA tariff $3/million btu ($18/bbl)
  - AGIA tariff $4/million btu ($24/bbl)

# BATCHING / PIGGING

- The interior of Alaska operates on a liquid energy economy.
- Batching products down TAPS will provide Interior Alaska with the opportunity to receive lower cost fuels at new delivery points along the pipeline without having to replace their existing energy infrastructure.

# BATCHING / PIGGING

**Batched products will be contaminated**

- One of the biggest advantages with a TAPS batching /pigging program is that butanes have been extracted from the gas stream and spiked into the crude oil stream since first flows.
- This same volume of butane will be placed in the front end of the pig train and used to clean the pipe walls of contaminants.

# BATCHING / PIGGING

**Batched products will be contaminated**

- The "dirty" butanes will be blended with the ANS crude oil at Valdez.
- If any batched products behind the "cleaning" butanes are also contaminated, the batching program will provide for additional processing at Valdez to remove sulfurs and color.

# BATCHING / PIGGING

**NGLs with a high vapor pressure can't be transported in TAPS**

- The lightest products we would recommend for shipping on the TAPS would be propane $C_3H_8$. Propane has a vapor pressure of 207 psig at 110°F. This is far below the operating pressure of TAPS.
- Keep ethane in the natural gas as there is no petrochemical industry on the US West Coast. Ethane will be converted into F-T products.

# BATCHING / PIGGING

Batching / Pigging in TAPS could benefit the AGIA gas line if a gas line is the best option

- Modifying the TAPS line to batch crude oil and products will eliminate the need to transport liquids in the gas line.
- This will reduce the cost of the gas pipeline and make its operation easier, plus make delivery of in-state gas less complicated as you are not dealing with a dense phase gas.

# GTL FACTS and FICTION

- Majors not pursuing F-T technology
- F-T Process not Efficient
  - Value vs Efficiency
- Costs of F-T too high
- TAPS - Batching/Pigging
- America needs natural gas (market)
- Value of Alaska Natural Gas
  - Do the people know Alaska gas isn't going to be cheap?

# OIL & GAS NEEDS IN THE U.S.

- The need for imported (additional) natural gas in the U.S. pales in comparison to the need for reducing imported crude oil and adding refining capacity.
- Natural gas has historically sold at a discount to the value of crude oil. Today that disparity is wider.
- Diesel has historically sold at a price at or below regular gasoline. Today diesel sells at a premium to gasoline.
- F-T diesel has in addition to the higher value of crude oil, the value of the refining margin plus a lower tax rate resulting in a market price premium of between $33 to $55/bbl over the value of crude oil. *($6.2 to $10.3 / mcf)*

# OIL & GAS NEEDS IN THE U.S.

- Virtually anyone we talk to has a different opinion on the volumes of natural gas, crude oil and refined transportation products produced, consumed or imported in the U.S. For the purposes of this report, we use information gathered from independent two sources.
- U.S. Energy Information Administration (www.eia.doe.gov/); and
- The BP Statistical Review of World Energy June 2007 (www.bp.com/productlanding.do).

*This latter document is an excellent summary of world energy and BP should be commended for providing this public service update each year.*

# OIL & GAS NEEDS IN THE U.S.

- If we look at the six month period from August 2007 through January 2008 (the latest EIA numbers) the U.S. on average produced slightly more than 5 million barrels per day of oil. (note: the EIA data does not include NGLs in the crude oil).
- During the same time period the U.S imported over 10 million barrels per day of crude oil and another 3 million barrels per day of refined products.
- The significance of the latter number is that the nation lacks over 3 million barrels per day of refining capacity to meet current U.S. transportation fuel demands.

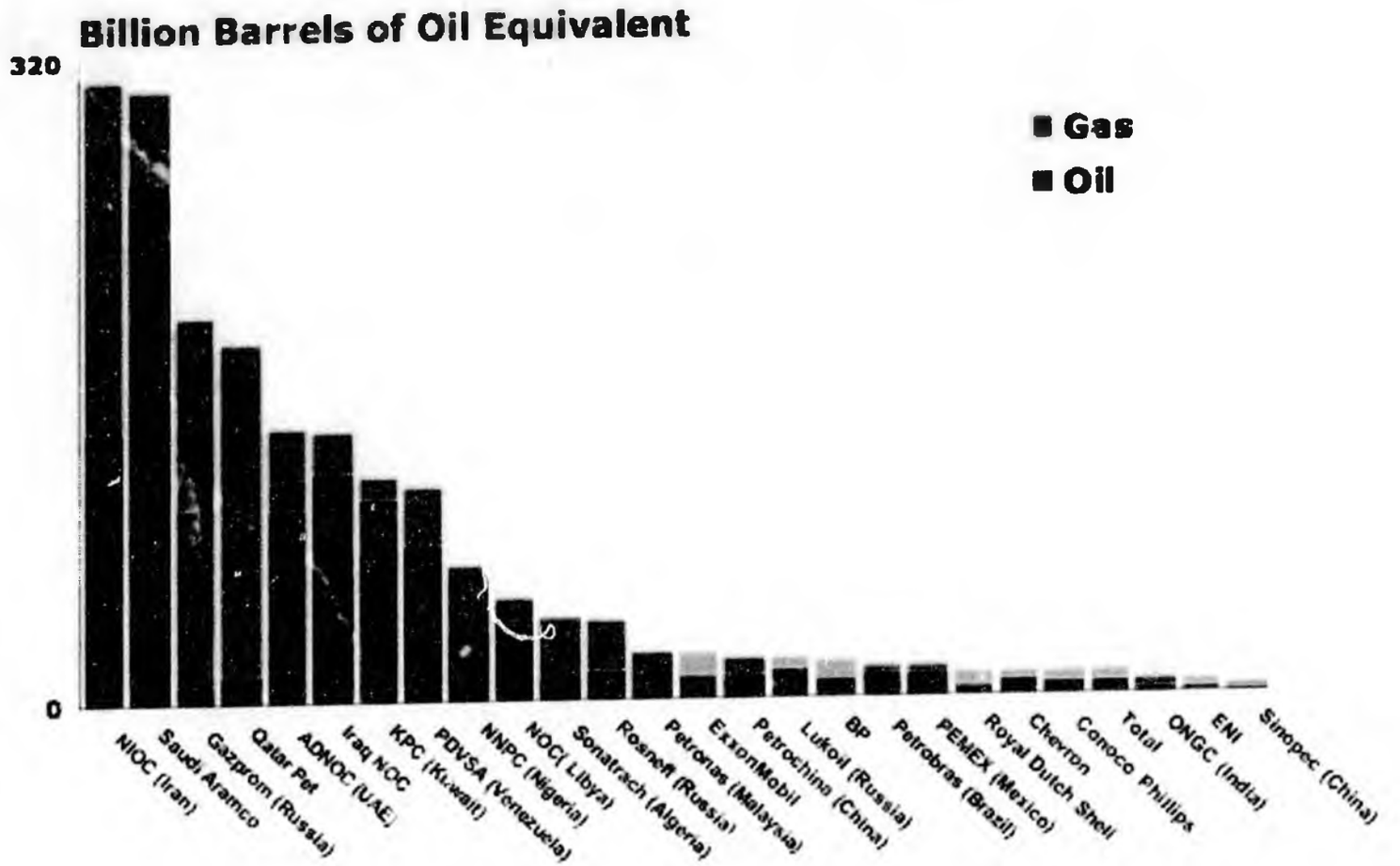
# OIL & GAS NEEDS IN THE U.S.

- While U.S. refiners have been adding capacity to existing refineries with process efficiency upgrades, no new refinery has been built in the U.S. since the 1970's.
- This could possibly be one of the reasons why refinery margins have crept up from the $5 to $6/bbl range in 1970 - 2000 era to over $30/bbl in 2007.
- A North Slope GTL plant represents new refining capacity for the U.S. and a potential threat to these higher margins, especially on the U.S. West Coast.
- This is one potential reason GTL's are not be in the forefront of North Slope majors' gas development plans.

# OIL & GAS NEEDS IN THE U.S.

- The U.S. currently (2008) imports roughly 70% of its crude oil/transportation needs. With approximately 13 million bbl/d of transportation fuel demand almost 29% of this demand (approximately 3 million barrels per day) is imported in the form of finished products.
- On an energy content equivalent scale this represents approximately 18 bcf/d of natural gas being imported just to meet the U.S. refinery shortfall.
- This is four times the volume of gas to be delivered through a natural gas pipeline.
- ~78 bcf/d for total transportation needs – 20 times

# Chart 9:
# National Oil Companies Control 94 Percent of World's Reserves




*Source: Credit Suisse First Boston*

# OIL & GAS NEEDS IN THE U.S.

- During this same time period the U.S. was producing approximately 64 billion to 65 billion cubic feet per day bcf/d) of natural gas and importing approximately 9 to 10 bcf/d of natural gas, primarily from Canada.
- Of this, approximately 1.6 to 1.8 bcf/d of the total U.S. natural gas is being imported as LNG.
- Thus 14.7% of U.S. natural gas consumption is imported, with LNG representing approximately 2.4% of total U.S. natural gas needs.

# OIL & GAS NEEDS IN THE U.S.

- Historically natural gas HAS sold at a lower Btu equivalent price compared to crude oil.
- From 2002 to 2007, natural gas averaged 68% of the WTI price of crude oil (i.e. 32% below crude oil).
- In April 2008, the NYMEX closing price for May 2008 deliveries of natural gas was $10.60/mcf or, a crude oil equivalent price of $63.60, some 45% below the then crude price of $115/bbl.
- We believe that there was a fundamental severing in the price of natural gas compared to crude oil once oil hit the $60 to $70/bbl range.

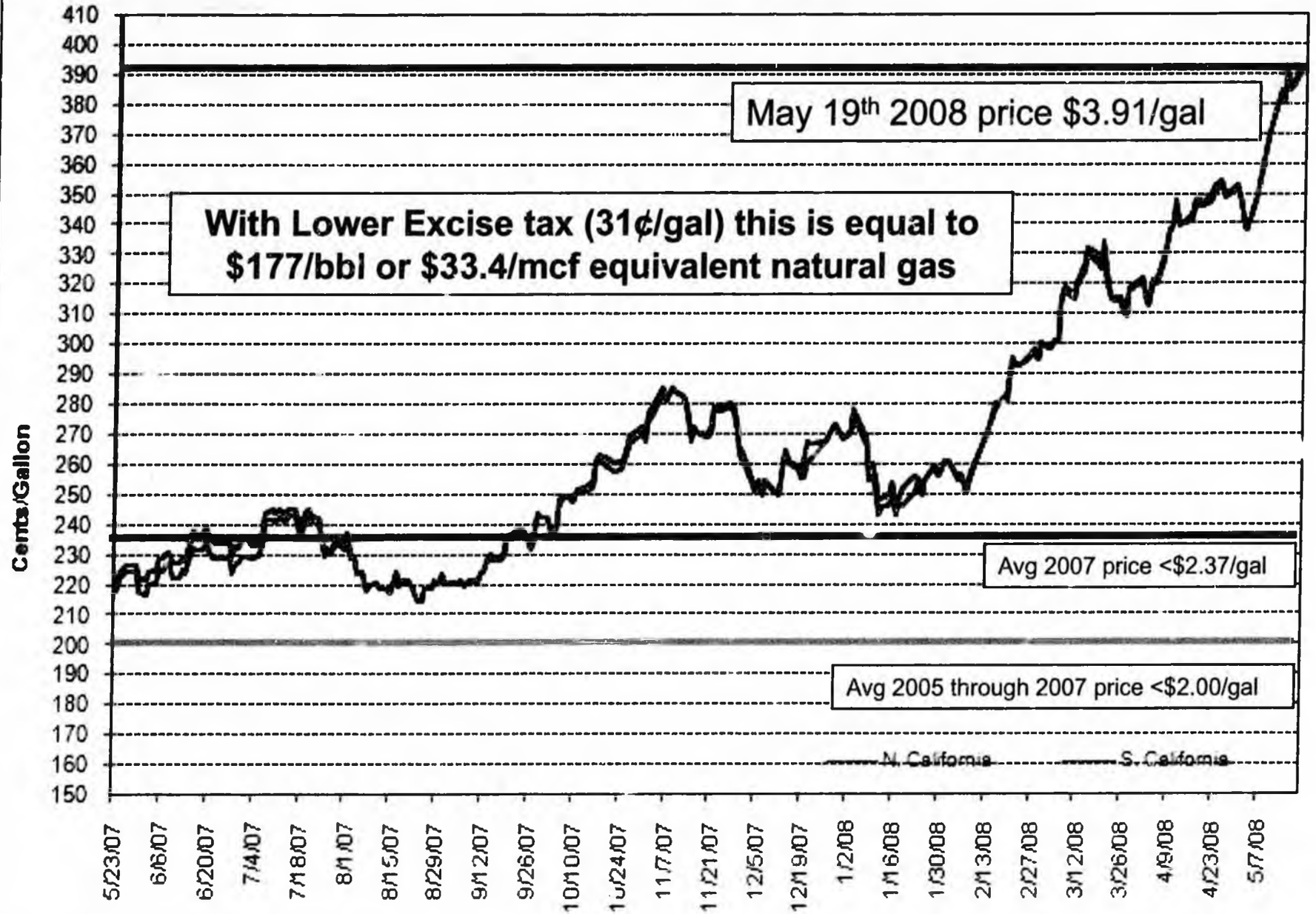
# OIL & GAS NEEDS IN THE U.S.

- All of the energy consumers who could have switched off crude-based products have done so but the gas industry is still able to meet demand.
- In fact, little LNG is currently being imported into the U.S. because markets elsewhere in the world, especially those linked to the price of crude oil, are paying much higher prices and few want U.S. dollars.
- If one compares a California ultra-low sulfur diesel price with an equivalent natural gas price one quickly sees a potentially greater return for Alaska in selling F-T products than selling natural gas.

# OIL & GAS NEEDS IN THE U.S.

- April 2008 California CARB diesel wholesale price of $3.30/gallon ($138.60/bbl) plus the tax advantage of selling a natural gas based fuel in the transportation market of $13.02/bbl, one has a market gas equivalent price of $28.6/mcf.
- Compare this to the April NYMEX number and one can see that the gas price would have to increase by 270% to equal that of diesel.
- On May 19th , the wholesale price of California diesel hit $3.91/gal or a mcf equivalent price of $33.4/mcf.

# CARB Diesel Fuel Average Rack Prices
## (As of 5/19/08)




Source: Oil Price Information Service

# OIL & GAS NEEDS IN THE U.S.

- We point these facts out to show that the greatest energy need in the U.S. is not natural gas; it is replacing crude oil imports and more importantly adding domestic refining capacity.

- U.S. natural gas is not priced on a world crude oil equivalent as it is in many other parts of the world. U.S. transportation fuels are, however, priced based upon the world price of oil.

- Plus in some areas, such as the U.S. West Coast, transportation fuels are priced at a premium due to higher quality requirements.

# GTL FACTS and FICTION

- Majors not pursuing F-T technology
- F-T Process not Efficient
  - Value vs Efficiency
- Costs of F-T too high
- TAPS - Batching/Pigging can't be done
- American needs natural gas (market)
- Value of Alaska Natural Gas
  - Do the people know Alaska gas isn't going to be cheap?

# NETBACK FROM CALIFORNIA TO PRUDHOE BAY

## THREE CASES TO CONSIDER:

- CASE A - Average California 2007 refinery wholesale rack price **$2.37/gallon**
- CASE B – May 19th 2008, California refinery wholesale rack price **$3.91/gallon**
- CASE C – Projected 2014 crude oil price of $200/bbl and $40/bbl refinery margin resulting in **$5.71/gal**

**Assume a $2/bbl shipping cost Valdez to Market and a $5/bbl TAPS Tariff for a total $7/bbl Prudhoe Bay to California**

**Assume 5.3 million btu/bbl of F-T and 1 million btu/mcf of natural gas**

**Assume a debt service / equity recovery cost of $31.75/bbl**

**Assume a GTL plant operating cost of $18/bbl**

# CASE A
# 2007 AVG Wholesale Rack Diesel Price in California (OPIS) RED LINE

**$2.37/gal = $99.5/bbl**

**F-T diesel same as CNG for road tax $99.5 /bbl+ $13/bbl = $112.5/bbl**

**Minus all costs ($112.5/bbl-$56.75/bbl= $55.8/bbl @ Prudhoe Bay )**

**Mcf equivalent -- $55.8 ÷ 5.3 = $10.5/mcf (GTL Plant Outlet)**

**F-T Diesel treated same as CNG then transportation tax is reduced by 31¢/gal ($13/bbl)**

# CASE B
# May 15 Wholesale Rack Diesel Price in California (OPIS) BLUE LINE

**$3.91/gal = $164.2/bbl**

**F-T diesel same as CNG for road tax $164.2 /bbl+ $13/bbl = $177.2/bbl**

**Minus all costs ($177/bbl-$56.75/bbl= $120.5/bbl @ Prudhoe Bay )**

**Mcf equivalent -- $120.5 ÷ 5.3 = $22.7/mcf (GTL Plant Outlet)**

**F-T Diesel treated same as CNG then transportation tax is reduced by 31¢/gal ($13/bbl)**

# CASE C (Tomorrow)
# Assume $200/bbl crude oil price and $40/bbl refining margin in 2014 2014 Wholesale Rack Diesel Price in California (OPIS) $5.71/gai

**$5.71/gal = $240/bbl**

**F-T diesel same as CNG for road tax $240 /bbl+ $13/bbl = $253/bbl**

**Minus all costs($253/bbl-$56.75/bbl= $196.1/bbl @ Prudhoe Bay)**

**Mcf equivalent - $196.1 ÷ 5.3 = $37/mcf at GTL Plant Outlet**

**F-T Diesel treated same as CNG then transportation tax is reduced by 31¢/gal ($13/bbl)**

# THESE NEXT POINTS ARE CRITICAL TO UNDERSTAND AND IT IS A POINT THAT OPPONENTS OF CTL/GTL OFTEN USE

**The F-T process converts carbon contained in the natural gas into finished transportation fuels and heat. Approximately 65% of the Btus contained in the natural gas will end up in the transportation fuels. Much of the Btu's contained in the natural gas will be captured either in the F-T fuels or waste heat to produce power. We further reduce the final number by 12% because all products don't receive the diesel price and have excise tax reductions.**

**Thus we reduce the mcf equivalent value of the F-T products to take into consideration the F-T (GTL) conversion process and not all the products are diesel.**

**Case A - $10.5/mcf x .65 x .88 = $6.01/mcf natural gas at Prudhoe Bay GTL Plant Inlet**

**$2.37/GAL IN CALIFORNIA - $6.01/MCF NATURAL GAS AT GTL PLANT INLET**

**Case B - $22.7/mcf x .65 x .88 = $12.98/mcf natural gas at Prudhoe Bay GTL Plant Inlet**

**$3.91/GAL IN CALIFORNIA - $12.98/MCF NATURAL GAS AT GTL PLANT INLET**

**Case C - $37/mcf x .65 = $21.16/mcf natural gas at Prudhoe Bay GTL Plant Inlet**

**$5.71/GAL IN CALIFORNIA - $21.16/MCF NATURAL GAS AT GTL PLANT INLET**

# AGIA Gas Price Projections

- A Prudhoe Bay price approaching $18 to $27 per mmbtu over 25 years.
- 2017 to 2042. WOW
- What do Alaskan's think they will be paying for natural gas?
- These AGIA projected gas prices are 300% to 400% higher than the 2007 prices in the Cook Inlet. This isn't "cheap" gas!

# WHO RECEIVES THE MOST VALUE FROM THE GAS SALES?

- Tax the Producers natural gas at a crude oil price equivalent and the Producer may only receive a fraction of the value of the natural gas.
- At today's $120/bbl crude oil price the PPT on natural gas would be:
  - .25 + ((97.5-30)x .004)+(120-97.5 )x.001= .543 or 54%
  - With a 1/8 Royalty (12.5%) + 54% = 66.5% of the value goes to the State – the Producer receives 33% (+ pays other taxes to the state and federal government)

# WHO RECEIVES THE MOST VALUE FROM THE GAS SALES?

- At $200 crude the % of value to the State would exceed 75%
- You can easily see why the Producer who is expected to take all of the pipeline risk isn't excited about AGIA
- Ask yourself, "Why isn't the market guaranteeing the gas line payout instead of the Producers"?

# Who Should be Buying Firm Capacity Supply or Market?

If Natural Gas truly was in short supply or its projected short supply were real, then the people who need natural gas, have no other choice but to use natural gas (market) would be coming to Alaska to buy this "proven" gas resource. THEY would be contracting with TC Alaska for firm capacity to their market.

Do You See This Happening?

# ENERGY CONSERVATION

## Its Impact on a Gas Line

# ENERGY CONSERVATION

## Its Impact on a Gas Line

- 300 million people in America
- Take 1/3 or 100 million people
- Turn off two – 100 Watt light bulbs or
  don't run a PC for half a day
- Save 480 billion watts per day or 20,000 MW-HR
- Assume a modern heat rate of 8,500 Btu/kw-hr
- Save 4.08 billion cubic feet per day of natural gas

**THAT'S THE ALASKA GAS LINE CAPACITY IN A FLICK OF THE SWITCH**

# ENERGY CONSERVATION
## The Nuclear Threat

- We are told that Toshiba is looking at installing up to 5 of their small nuclear power plants in Alberta to supply the tar sands projects with heat and electricity that would be $CO_2$ free energy.
- Helps Canada meet its Kyoto obligations.
- There goes 1 to 2 bcf/d of gas market.
- Canadian supplied gas will have to flow into the U.S. r arket competing with Alaska AGIA gas.

# MORE THAN JUST A GTL PROJECT

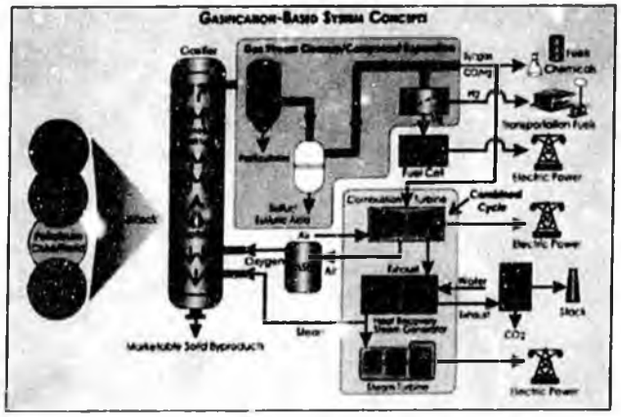
## HUNDREDS OF VALUE ADDED BUSINESSES ARE POSSIBLE

## Manufacturing on a Grand Scale.

**The beginning of a new era for Alaska and Alaskans. Suppiying the world with high value finished goods instead of basic natural resources.**

# VALUE ADDED INDUSTRIES

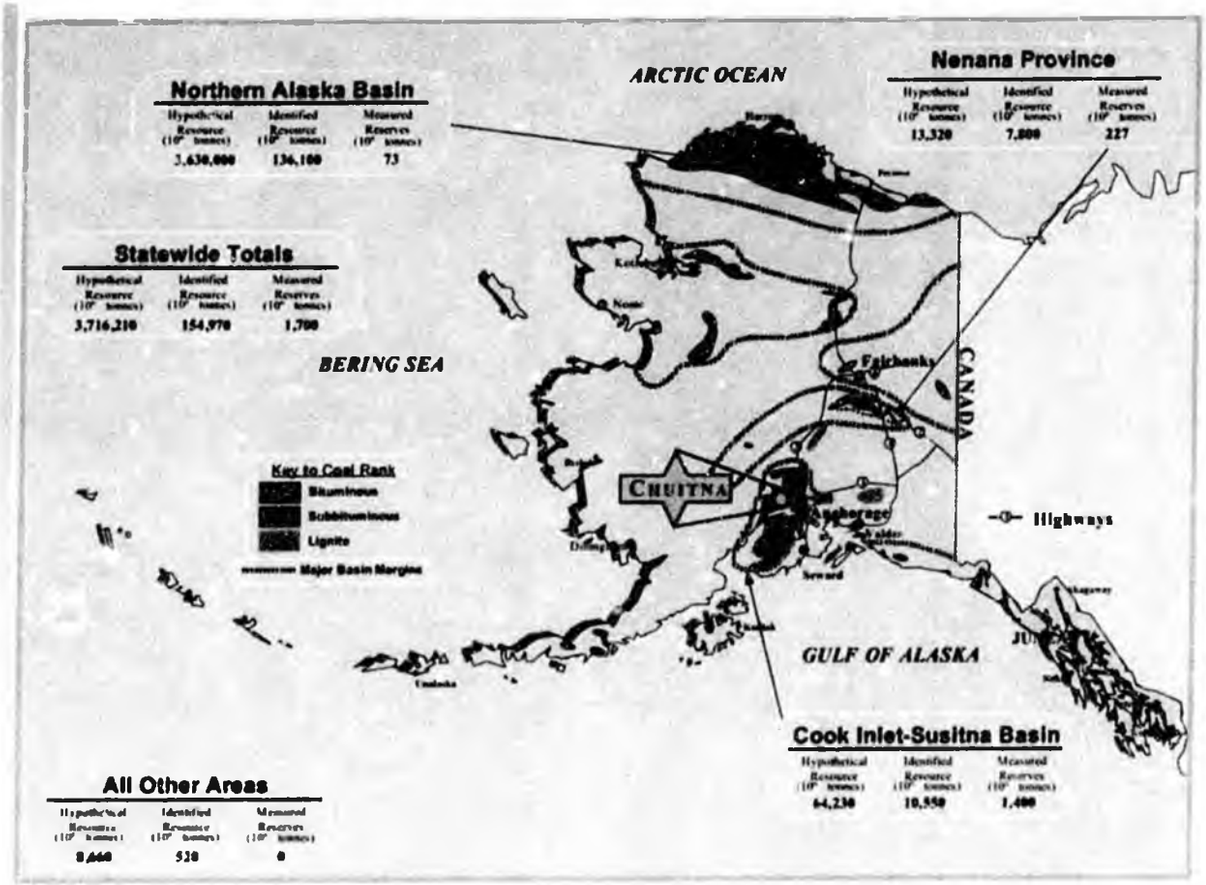
- The Sasol CTL plants in South Africa produce over 150 different value added products from effluent streams.
- The North Dakota Gasification plant uses the Lurgi process to convert 6 million tons per year of lignite coal to syngas and liquids. The average daily production at Great Plains is about 160 million cubic feet of high quality pipe line natural gas.
- Many by-products are also produced at the plant, including: ammonium sulfate, anhydrous ammonia, carbon dioxide, dephenolized cresylic acid, krypton and xenon gases, liquid nitrogen, naphtha, phenol, and methanol.




# ADDITIONAL BENEFITS OF A NORTH SLOPE GTL OPTION

- Benefits of GTLs at Prudhoe Bay
  - $CO_2$
  - Electricity
  - Water for people and EOR
  - Synthetic drilling fluids
  - Batching NGLs – Lower TAPS tariff
  - Liquids in Fairbanks

# THINK OUT SIDE OF THE BOX
# Alaska's Coal Resources & Reserves



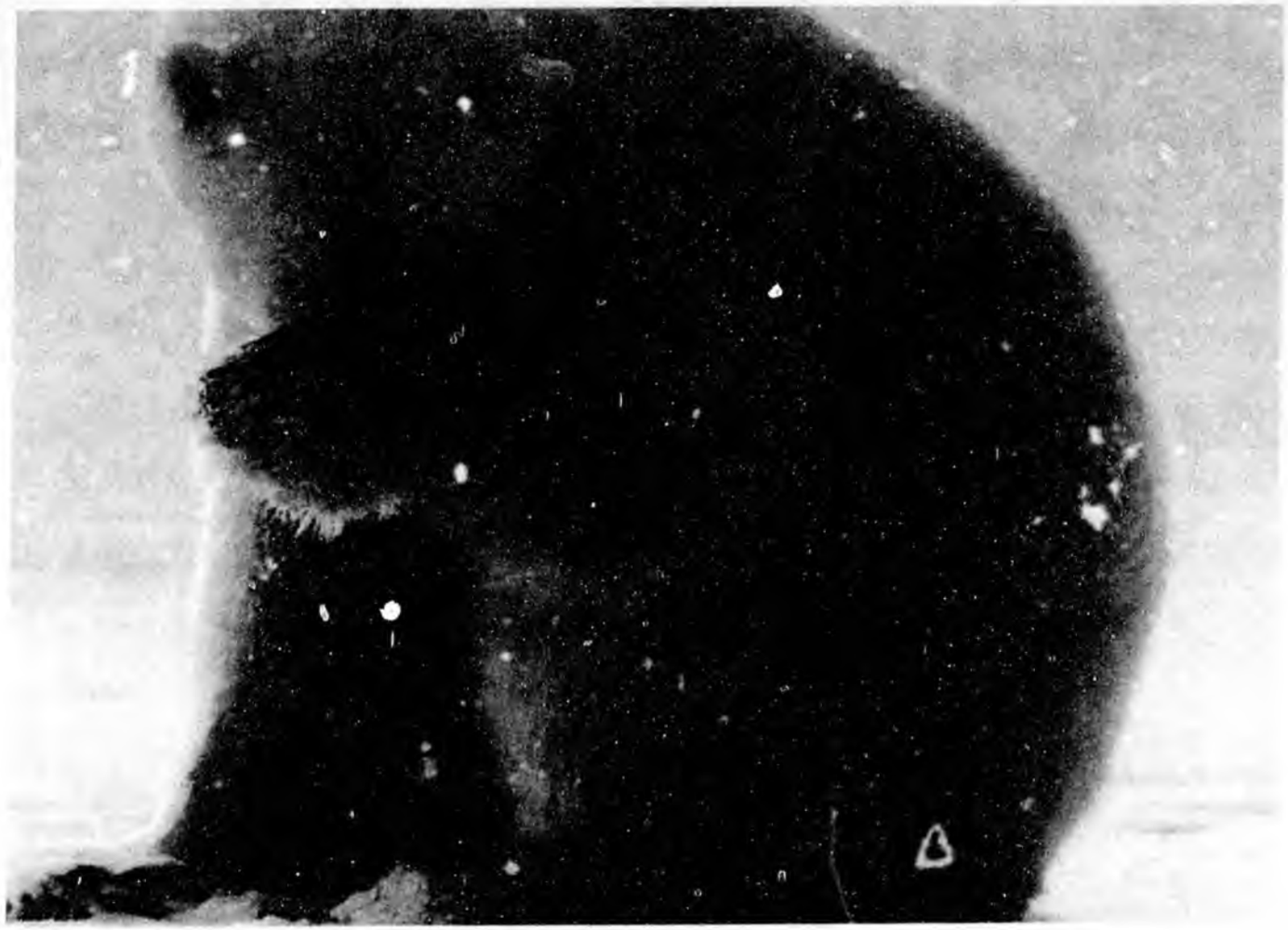

## ALASKA LEGACY PROJECT

**Estimated Recoverable Coal Reserves**

($10^9$ tonnes)

| | |
|---|---|
| World Total | 1,038 |
| North America | 256 |
| United States 246+Alaska | |
| Alaska (measured) | 2 |
| Alaska Estimated | 200 |
| CHUITNA (measured) | >1 |

Note: The Northern Alaska Basin could potentially have upwards of 1.5 to 2.5 trillion tons of bituminous coal reserves – more coal than the total proven reserves in the world today!



# THANK YOU FOR LISTENING TO THE GTL STORY

# CONTACT DETAILS

Alaska Natural Resources To Liquids, LLC
310 K Street, Suite 200
Anchorage, AK 99501
(907) 264-6709

Richard Peterson
Managing Member
rpeterson@angtl.com

Peter Tijm
Member
Tijmp@aol.com

# Comparison of Netbacks from Potential LNG Project with ALCAN Pipeline Project

**June 20, 2008**


**Barry Pulliam**
**Senior Economist**
**Econ One Research**

*5th Floor*
*601 W 5th Street*
*Los Angeles, California 90071*
*213 624 9600*

*Suite 1280*
*2321 Rosecrans Avenue*
*El Segundo, California 90245*
*310 727 9916*

*Suite 2825*
*Three Allen Center*
*333 Clay Street*
*Houston, Texas 77002*
*713 228 2700*

*Suite 100*
*555 University Avenue*
*Sacramento, California 95825*
*916 576 0366*

*Suite 501*
*805 15th Street, N.W.*
*Washington, D.C. 20005*
*202 289 7620*


ECON ONE

# Econ One Review

- Analyzed economic assumptions & netback values associated with potential LNG and pipeline projects
  - Port Authority proposal
  - Other potential LNG configurations
  - TransCanada proposal
- Reviewed Port Authority proposal, assumptions and analysis
- Reviewed Administration analysis of LNG and pipeline netbacks
- Reviewed information from various LNG specialists and government agencies

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# Econ One Review
(cont'd)

- Analyzed netback @ the inlet to GTP
  - $ / MMBtu
  - Total value of netback
    - Nominal $
    - Real ($2008)
    - NPV-10
- Project that "maximizes" the netback creates highest value for resource owners
  - Producers
  - State

# Project Netback Analyses

## LNG Exports to Asia

- 2.7 Bcf/d (Port Authority proposed)
- 4.5 Bcf/d (Little Susitna proposed)

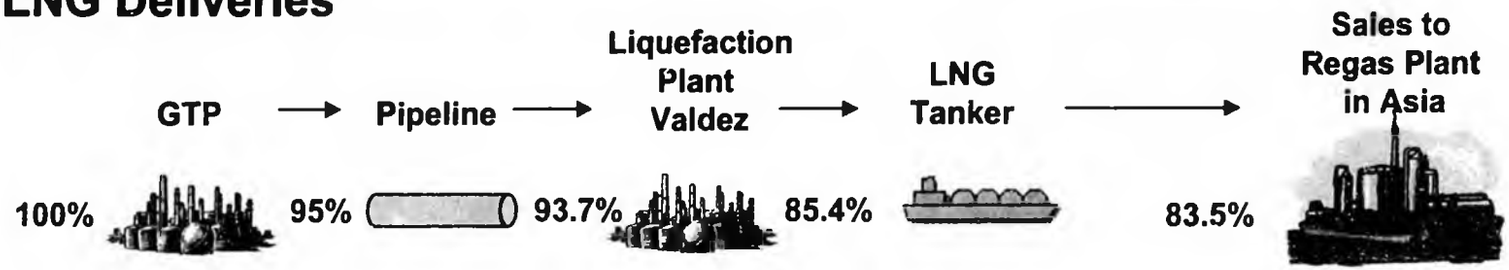
## Pipeline to Alberta

- 3.5 Bcf/d (TransCanada minimum volumes)
- 4.5 Bcf/d (TransCanada base volumes)

# Overview of LNG v. Pipeline Delivery

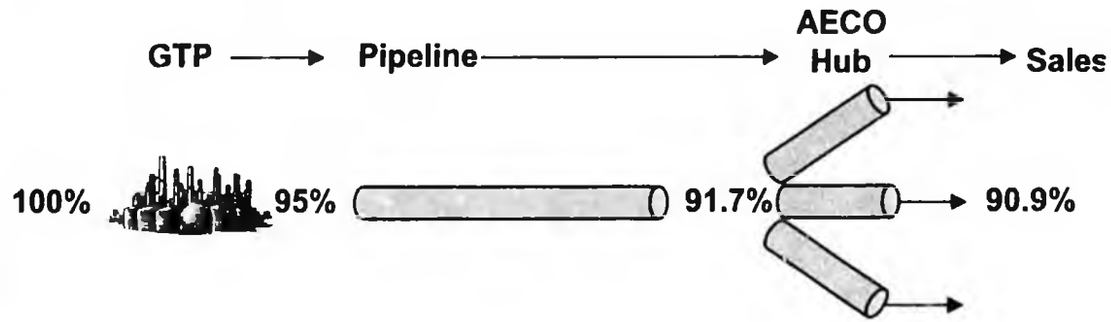
# LNG and Pipeline Delivery Chain

## LNG Deliveries




**Aggregate Loss: 16.5%**

## Pipeline Deliveries




**Aggregate Loss: 9.1%**

# Supply / Demand

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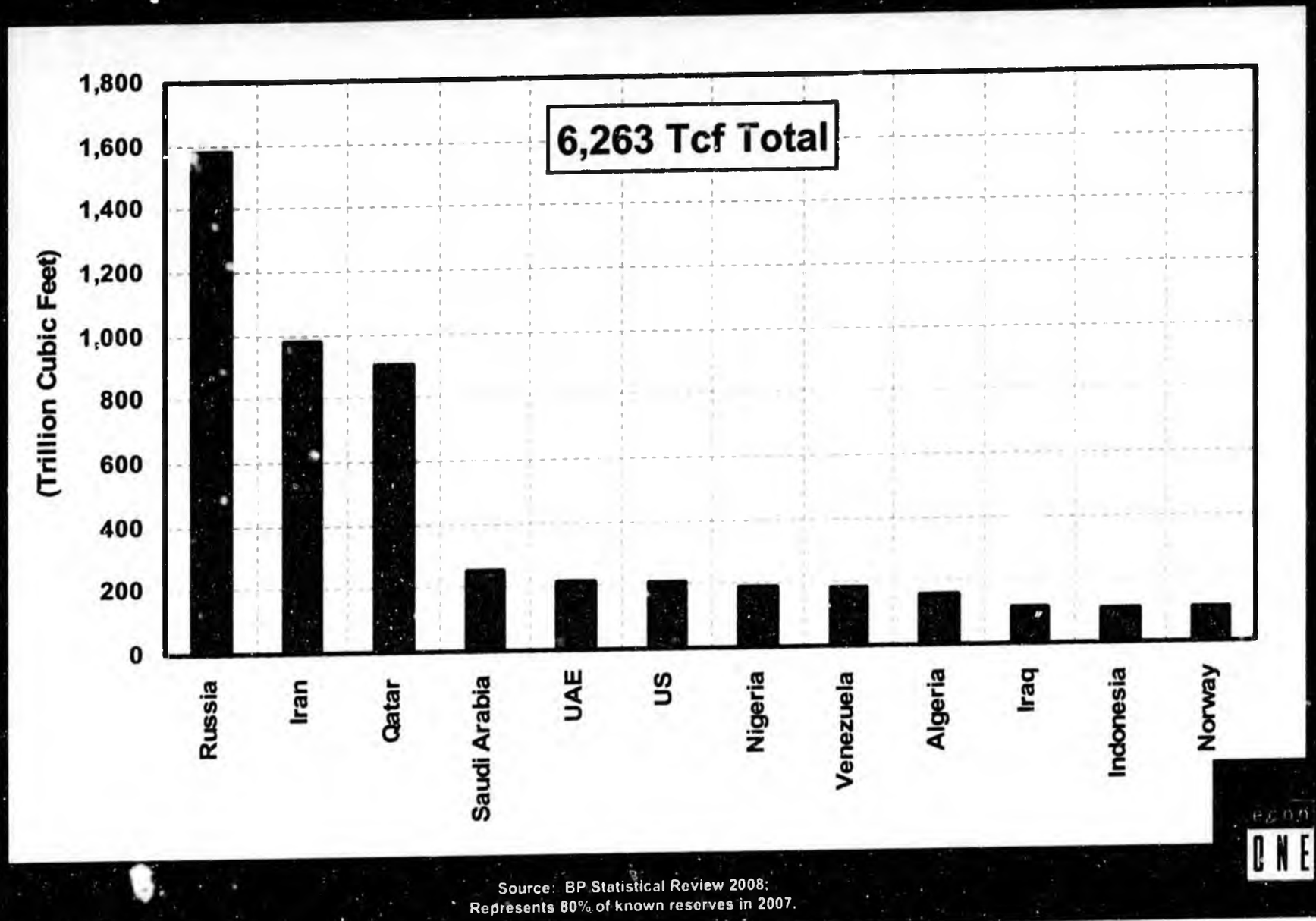
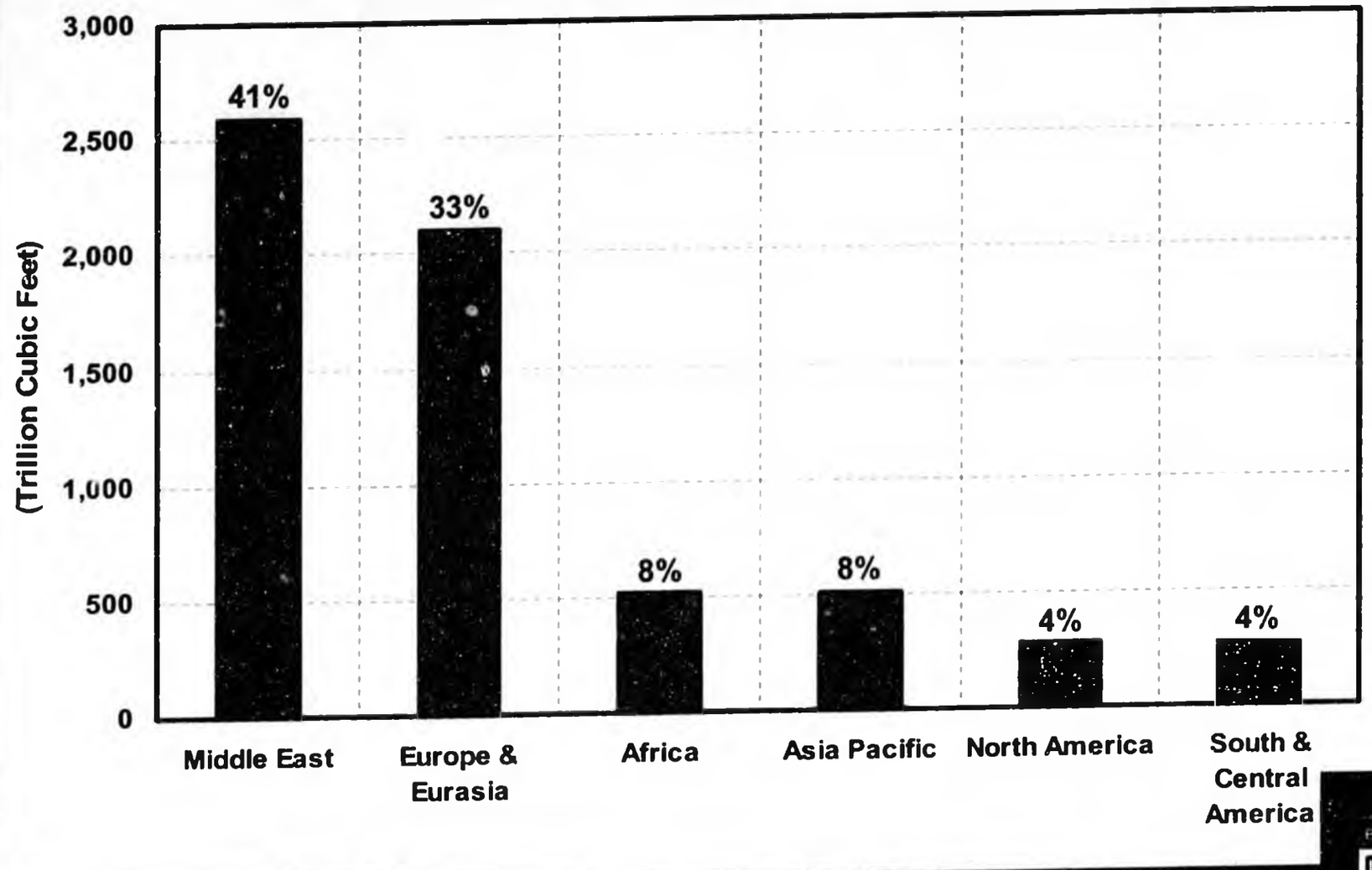
# Worldwide Proved Gas Reserves




Source: BP Statistical Review 2008;
Represents 80% of known reserves in 2007.

# Worldwide Proved Gas Reserves by Region




Source: BP Statistical Review 2008.

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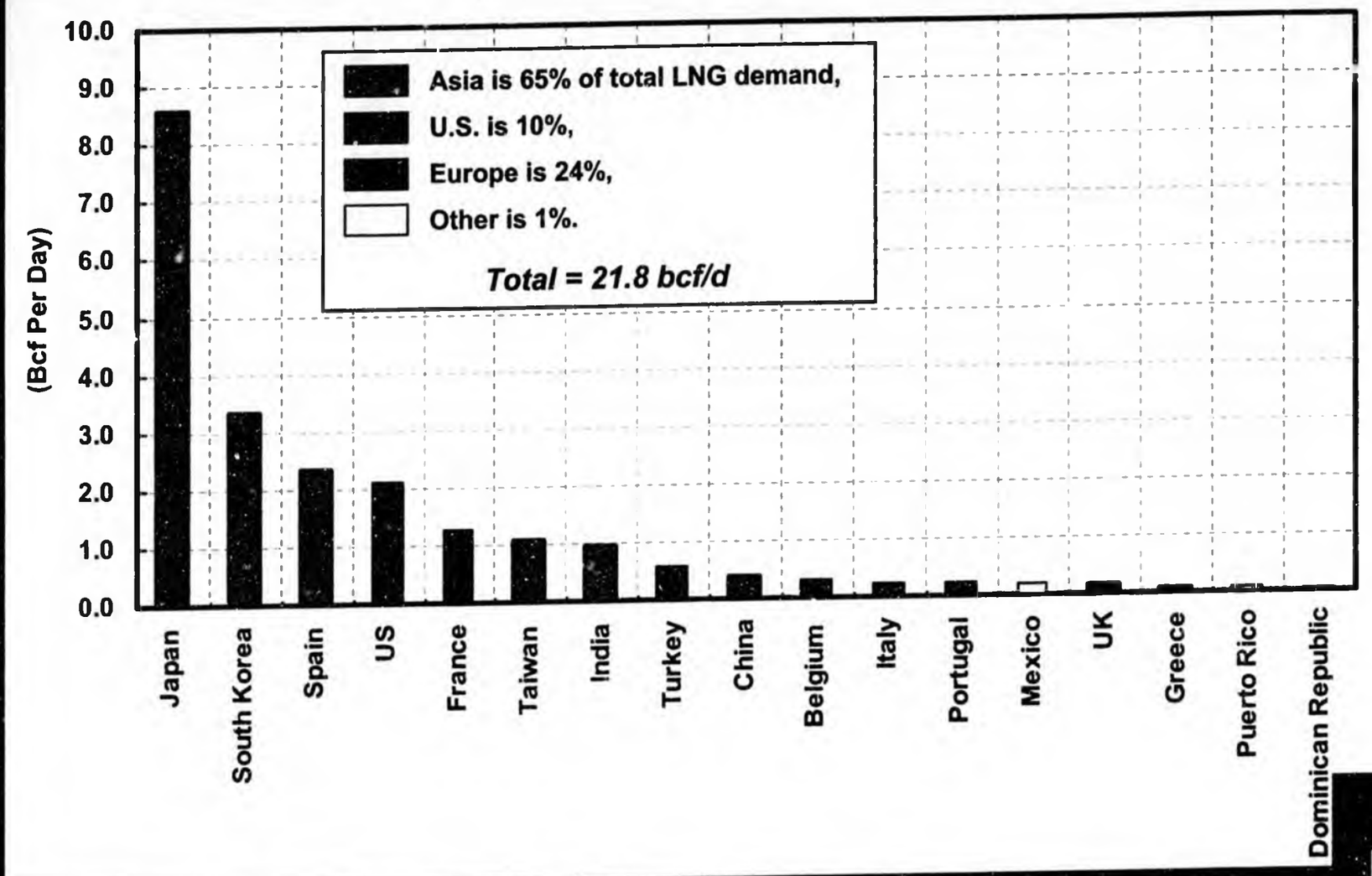
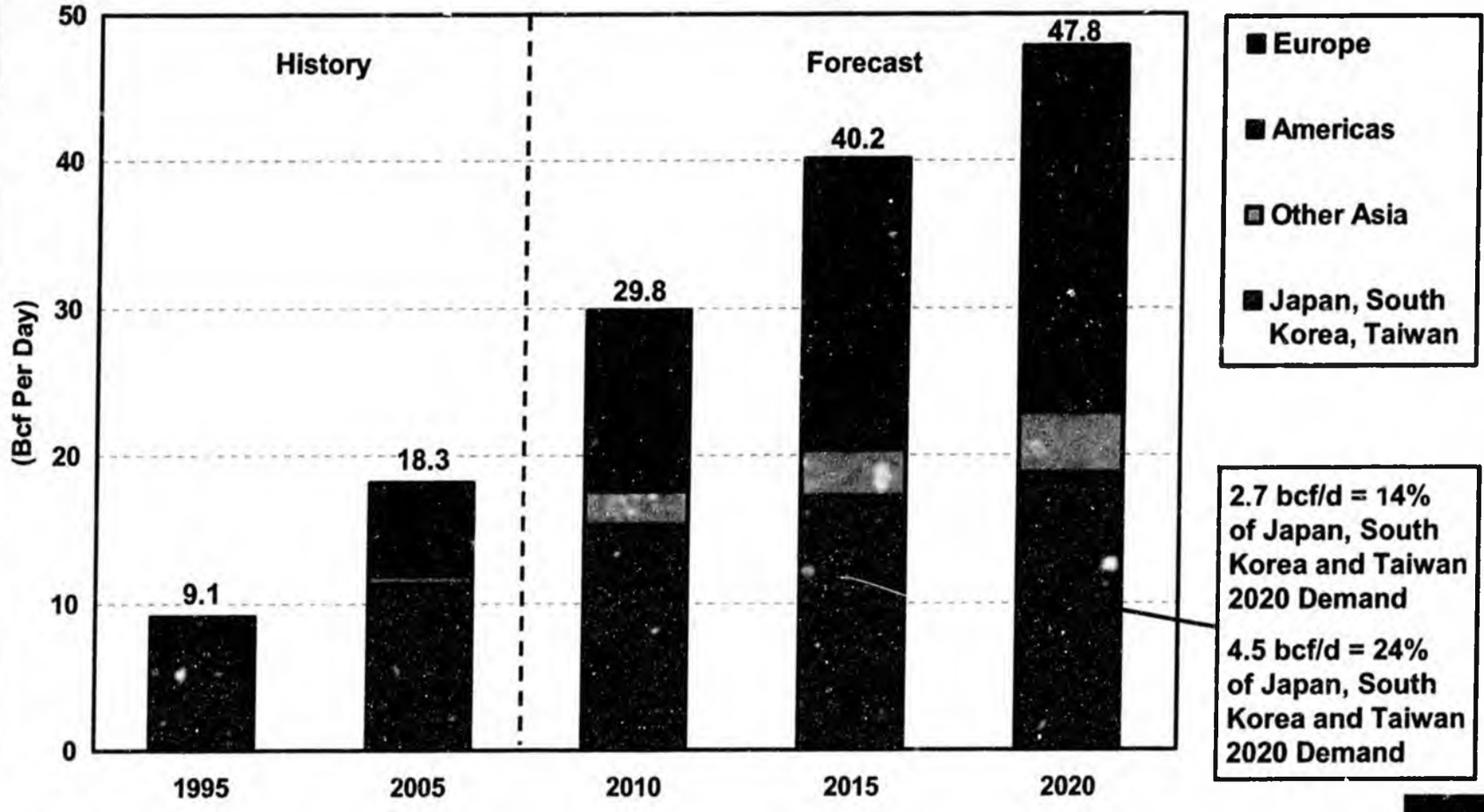
# Current Worldwide LNG Demand




Source: BP Statistical Review 2008.

# Projected LNG Demand by Region




Source: National Petroleum Council ; Jensen Associates, August 2007

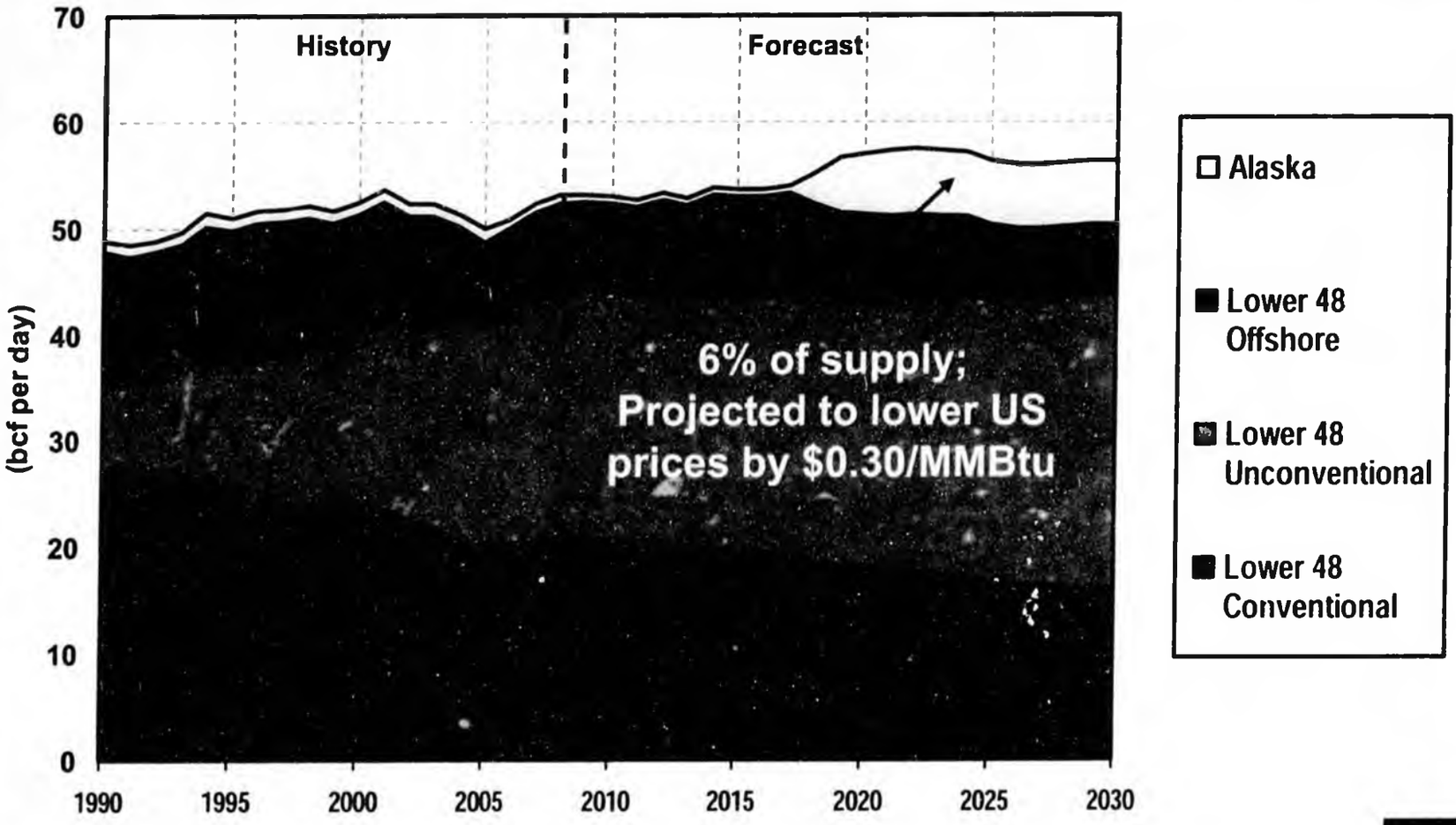
# Liquefaction Plant Capacities by Region
(Pacific Trade)

| Pacific Basin | |
|---|---|
| Category | Capacity (Bcf/Day) |
| (1) | (2) |
| Operating | 9.85 |
| Under Construction | 3.50 |
| Under Consideration | 6.24 |
| ***Total*** | ***19.59*** |

| Middle East | |
|---|---|
| Category | Capacity (Bcf/Day) |
| (3) | (4) |
| Operating | 6.06 |
| Under Construction | 6.84 |
| Under Consideration | 4.63 |
| ***Total*** | ***17.53*** |

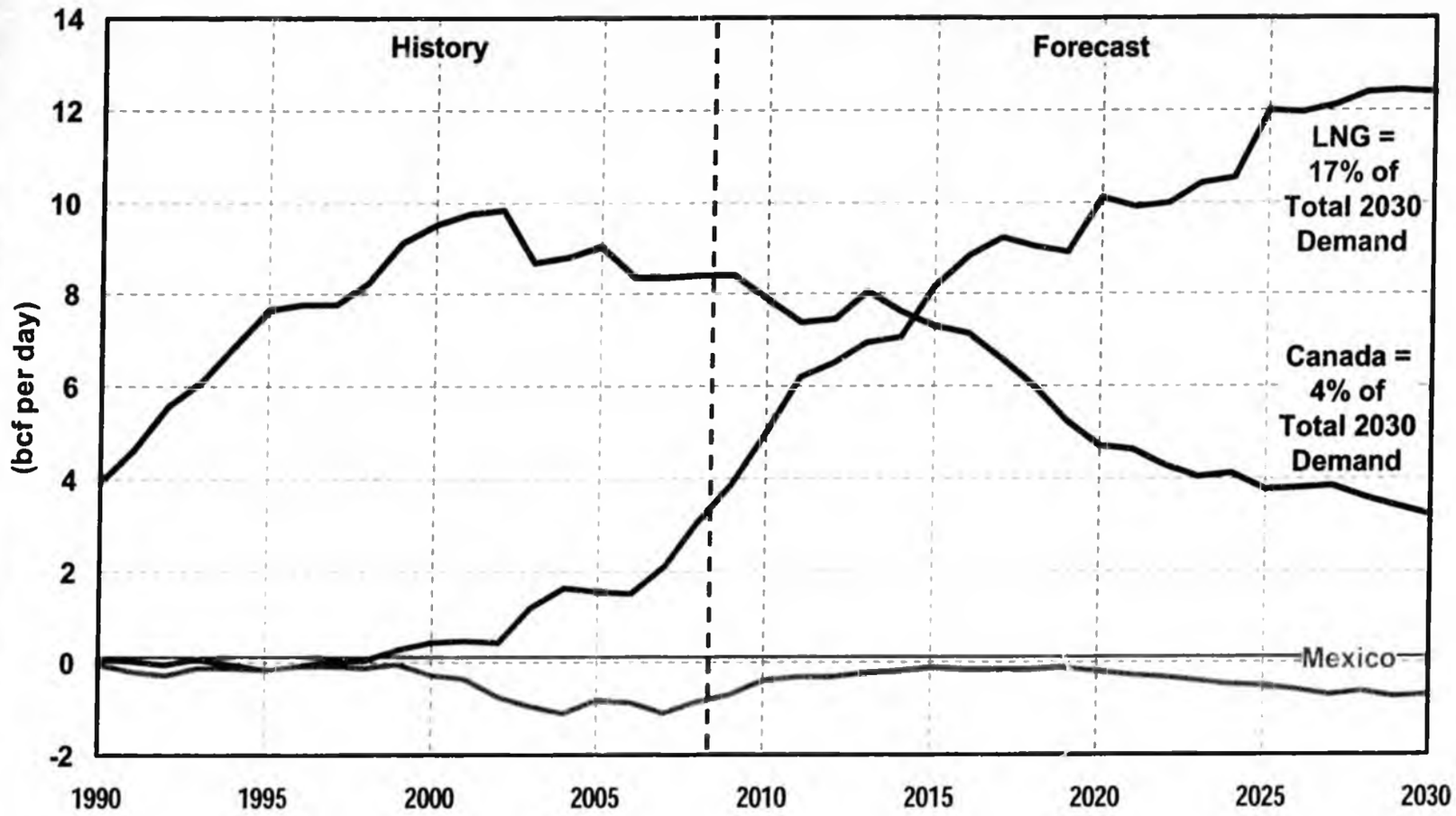
Source: Facts Global Energy. "Evaluating Natural Gas Import Options for the State of Hawaii". April 2007.

# U.S. Gas Production by Source
(1990 - 2030)




Source: EIA AEO 2007

# U.S. Net Natural Gas Imports
(1990 - 2030)




Source: EIA AEO 2007.

# Historical Pricing

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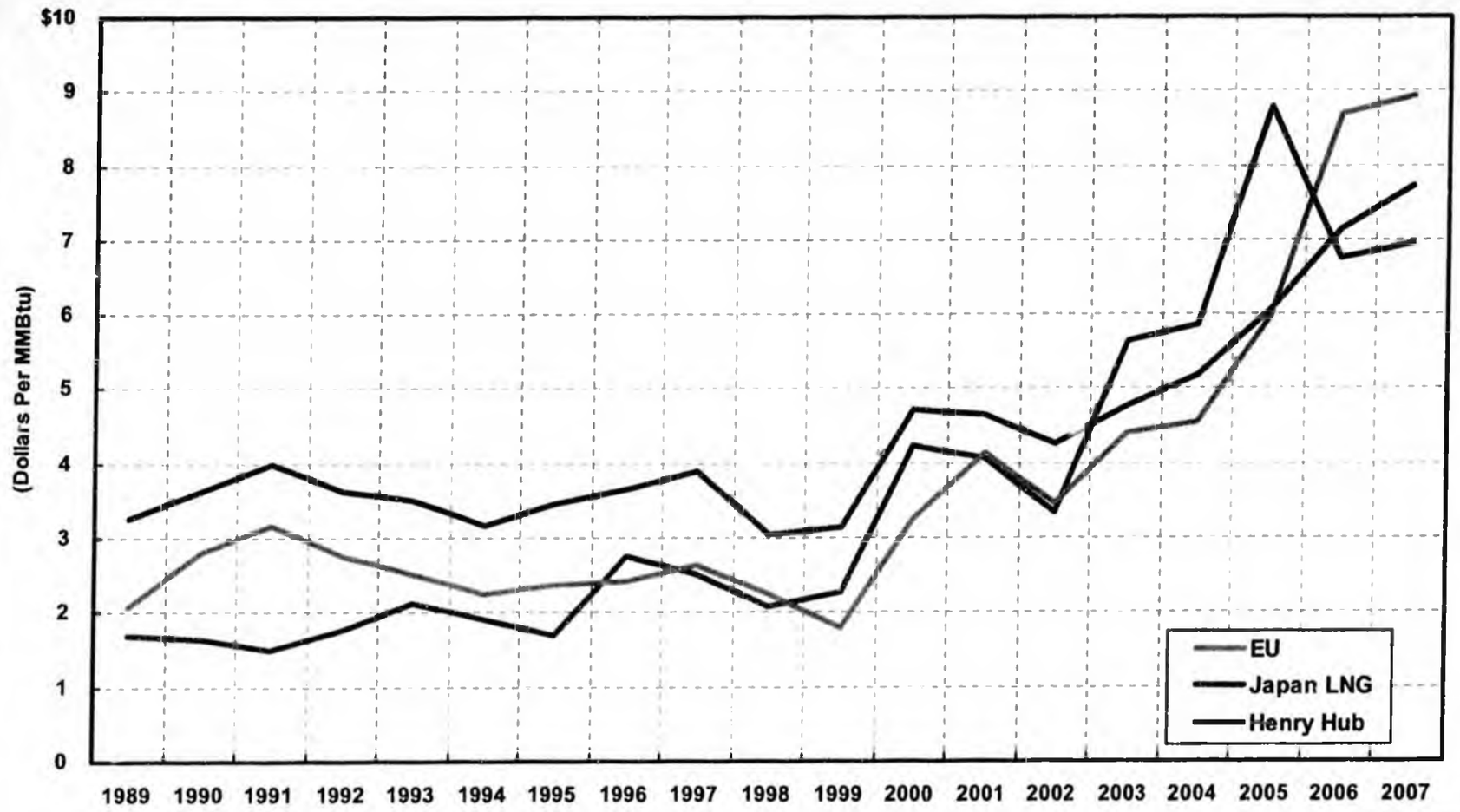
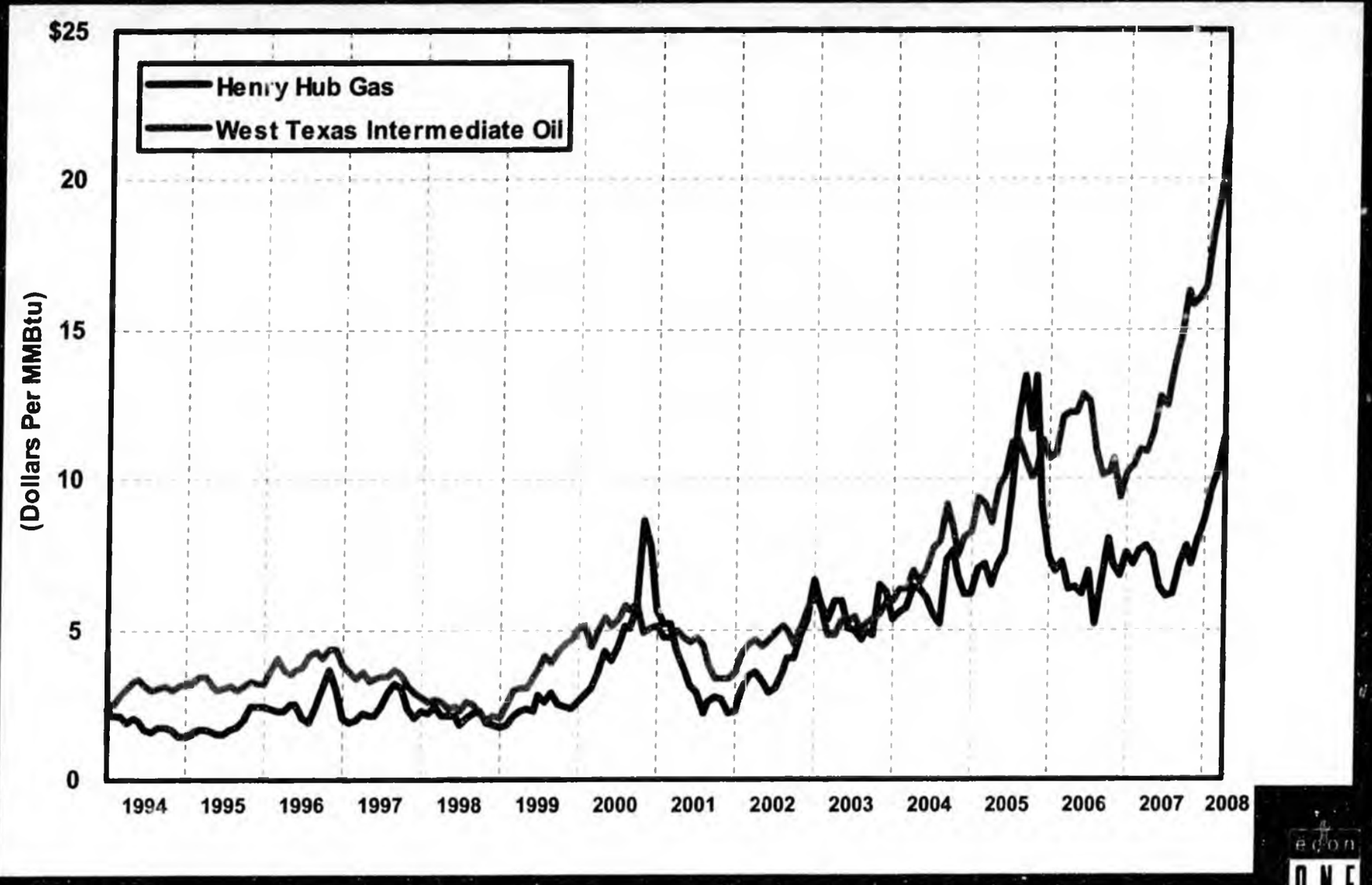
# Historical Gas Prices
## (U.S., Japan and Europe)

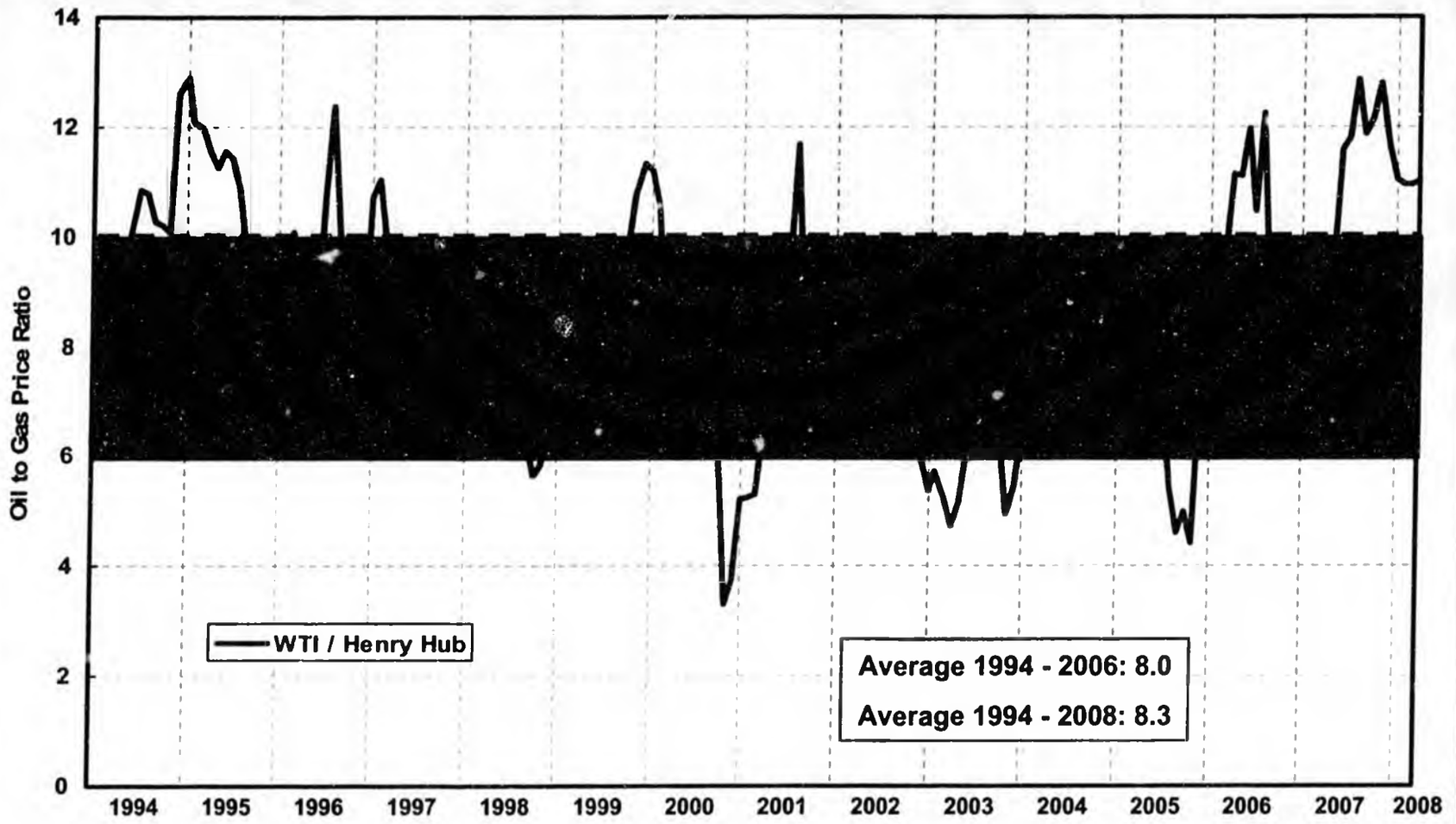


# U.S. Natural Gas and Crude Oil Prices

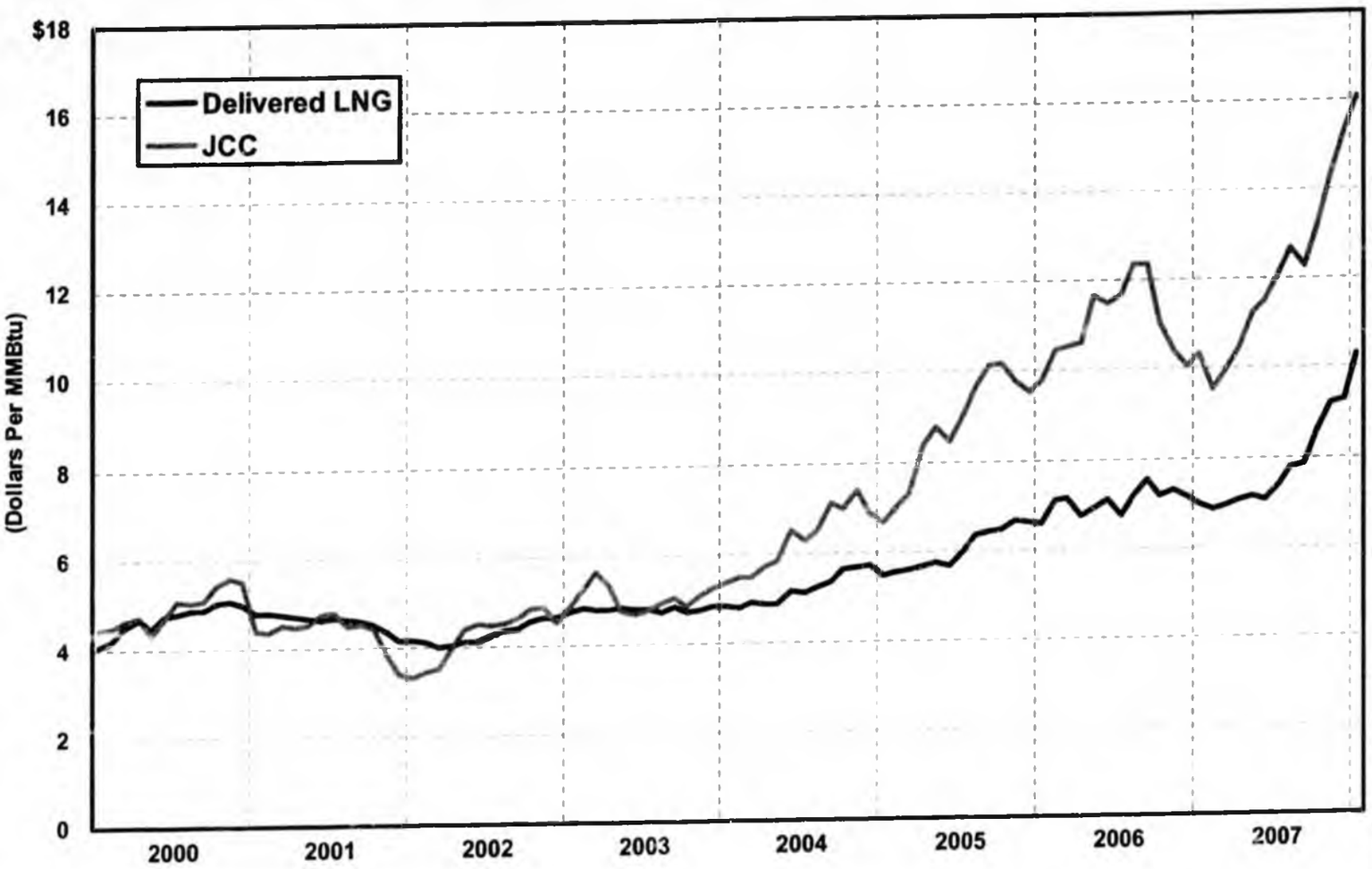
(1994 - 2008)



# Historical Relationship Between Oil and Gas Prices in the U.S.

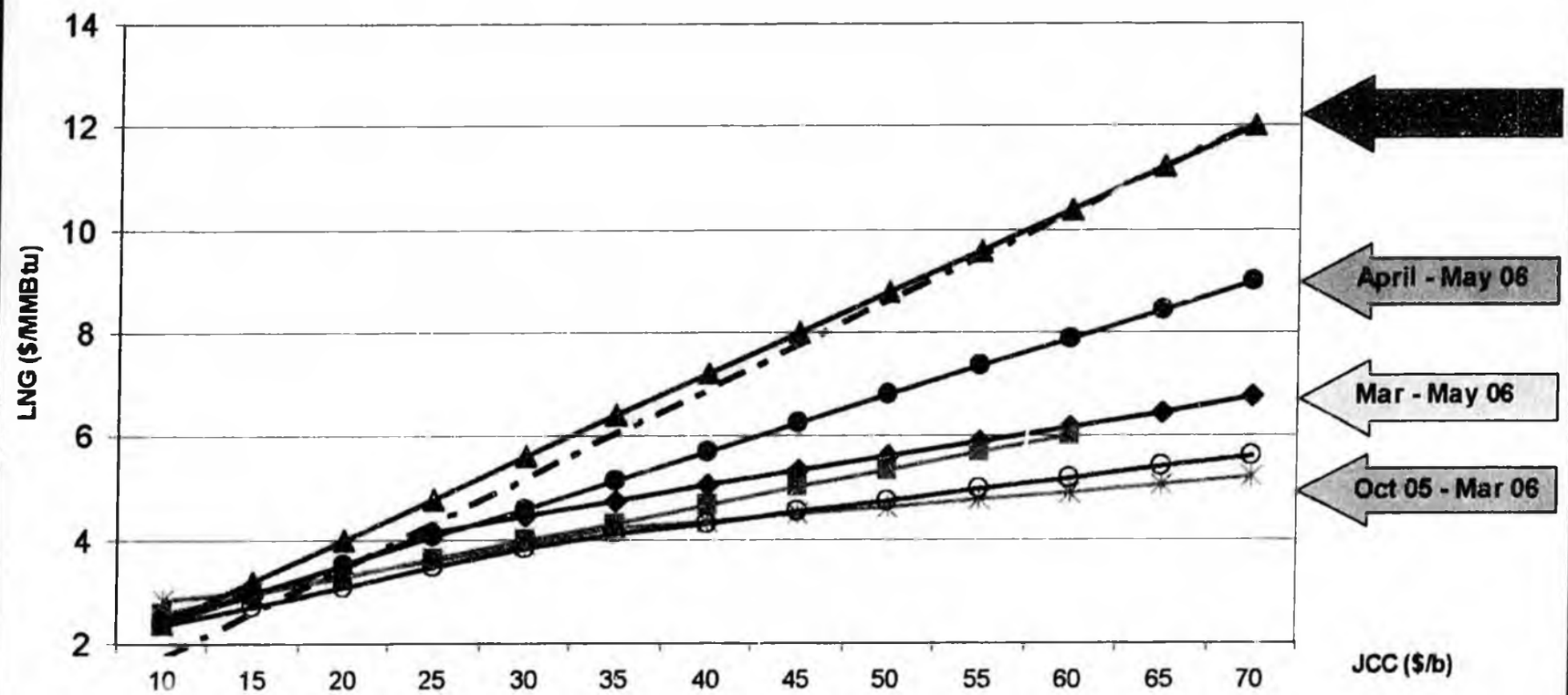


# Japanese Crude Oil and Gas Prices
(2000 - 2008)



# Evolution of LNG Pricing in Asia

## (Relationship of Gas to Oil Prices Seen in Recent Contracts)




Source: Facts Global Energy, "Evaluating Natural Gas Import Options for the State of Hawaii", April 2007.

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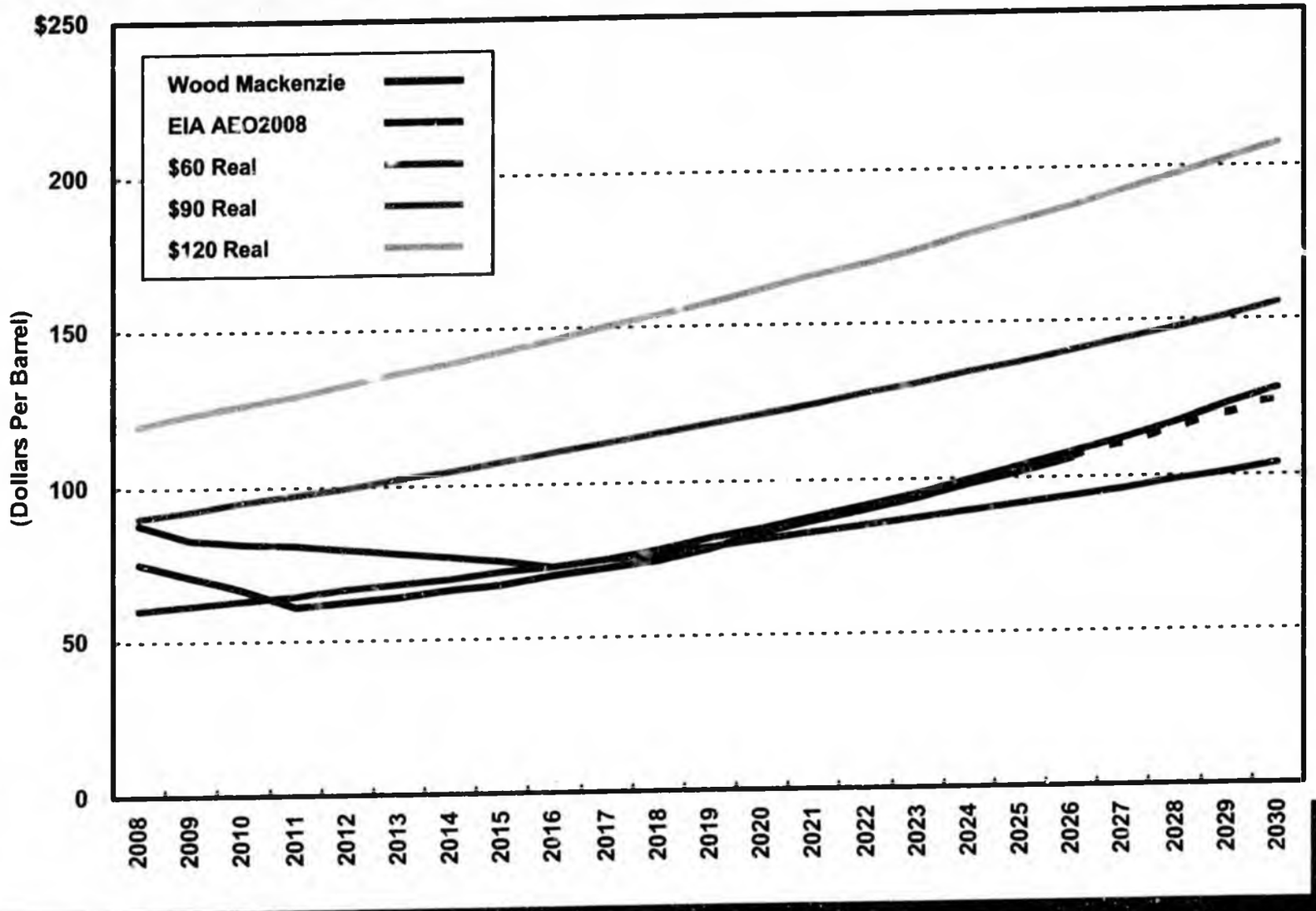
# Oil and Gas Price Forecasts

# Oil Prices Used in Analyses




Note: 2.5% annual price inflation

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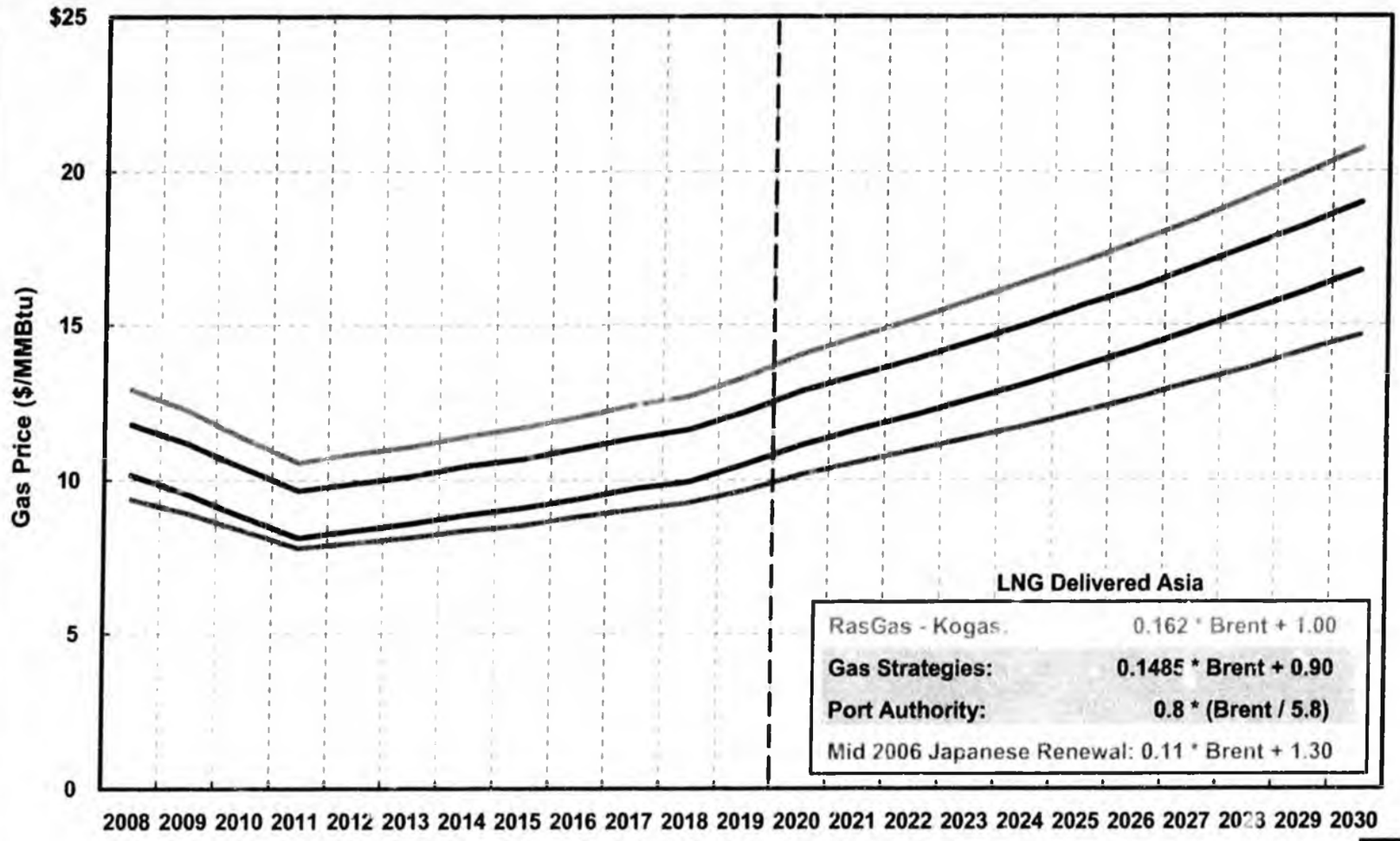
# Prospects for Asian LNG Prices

- There is a wide rage of prices depending on contract vintage
- Recent contracts have reflected stronger links to oil
- Many contracts are on a provisional basis as previously (low-priced) formulas have expired or are not applicable at current oil price levels
- Relatively high priced opportunities in Asia will attract gas supplies to that region
  - Increasingly competitive among suppliers
  - Opportunities for buyers
  - Price will be dependent on the supply situation at the time of contracts

# Gas Price Forecasts Used in Analyses
## (Using Wood Mackenzie Oil Price Forecast)

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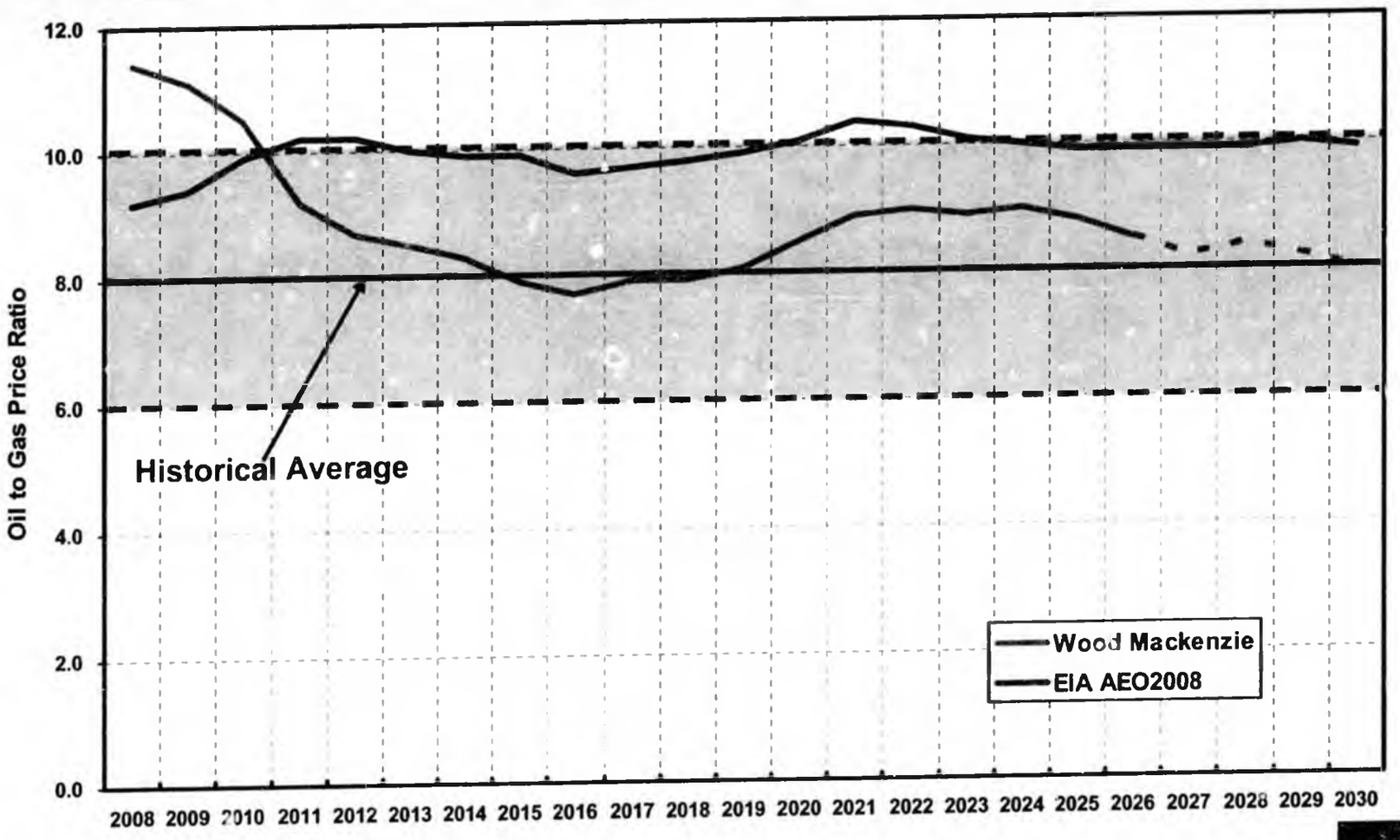
# Prospects for U.S. Gas Prices

- Historically, gas has been priced between 1/6 & 1/10 the value of oil, with the long run average near 1/8
- The recent run-up in oil prices & relatively abundant domestic production of natural gas have kept that relationship above historical levels
- Many see the oil/gas relationship returning to more historical levels (i.e. convergence) as:
  - Domestic supplies decline & become more costly to produce
  - LNG imports are drawn to higher priced regions (e.g. Asia)
  - Greenhouse/carbon emission concerns put coal out of favor & put natural gas in favor as the fuel of choice for electricity generation

# Ratio of Forecasted U.S. Oil and Gas Prices

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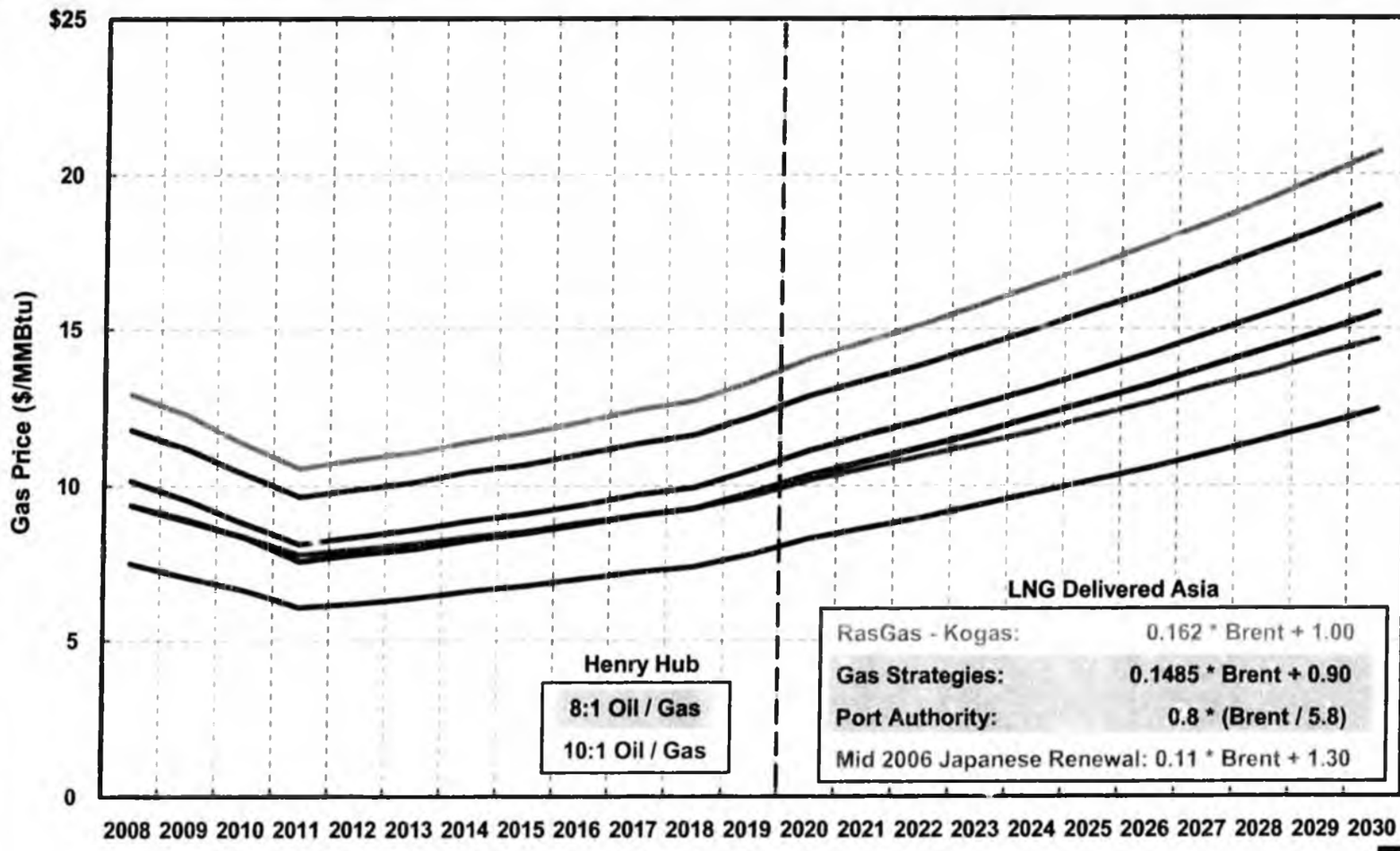
# Gas Price Forecasts Used in Analyses
## (Using Wood Mackenzie Oil Price Forecast)




= More Likely Price Scenario(s)

# Assumptions Used in Comparative Netback Analyses

# Assumptions Used in Comparative Netback Analyses

| | |
|---|---|
| ➢ First Gas | 2020 |
| ➢ Capitalization | 70% Debt; 30% Equity (pre-operation)<br>75% Debt; 25% Equity (post-operation) |
| ➢ Debt Costs | 5.5% Guaranteed; 7.0 % Non-Guaranteed |
| ➢ Equity Returns | 14% |
| ➢ Capex/Opex | Administration (Westney): GTP & pipeline segments<br>Port Authority (Bechtel): LNG plant<br>Sensitivity at higher costs |
| ➢ Fuel Use | Administration (Westney) for GTP/pipeline segments<br>Port Authority (Bechtel) for LNG plant |
| ➢ Shipping Costs | Port Authority: Approximately $0.75/MMBtu + Fuel |
| ➢ Gas Composition & NGL Extraction | 1.118 MMBtu / mcf<br>Full Extraction @ Alberta<br>Partial Extraction @ Valdez (LNG case) |

# Comparison of Capital Costs for LNG Project

(2.7 bcf/d LNG Project)

| | Port Authority (Bechtel) | Administration (Westney) |
|---|---|---|
| GTP | $3.4Bn | $5.0Bn |
| Pipeline | $13.1Bn | $11.5Bn |
| Total GTP/Pipeline | $16.5Bn | $16.5Bn |
| LNG Plant | $7.9Bn ($470/mmta) | $12.7Bn ($755/mmta) |
| Grand Total | $24.4Bn | $29.2Bn |

# Capital Costs Used in Netback Analyses

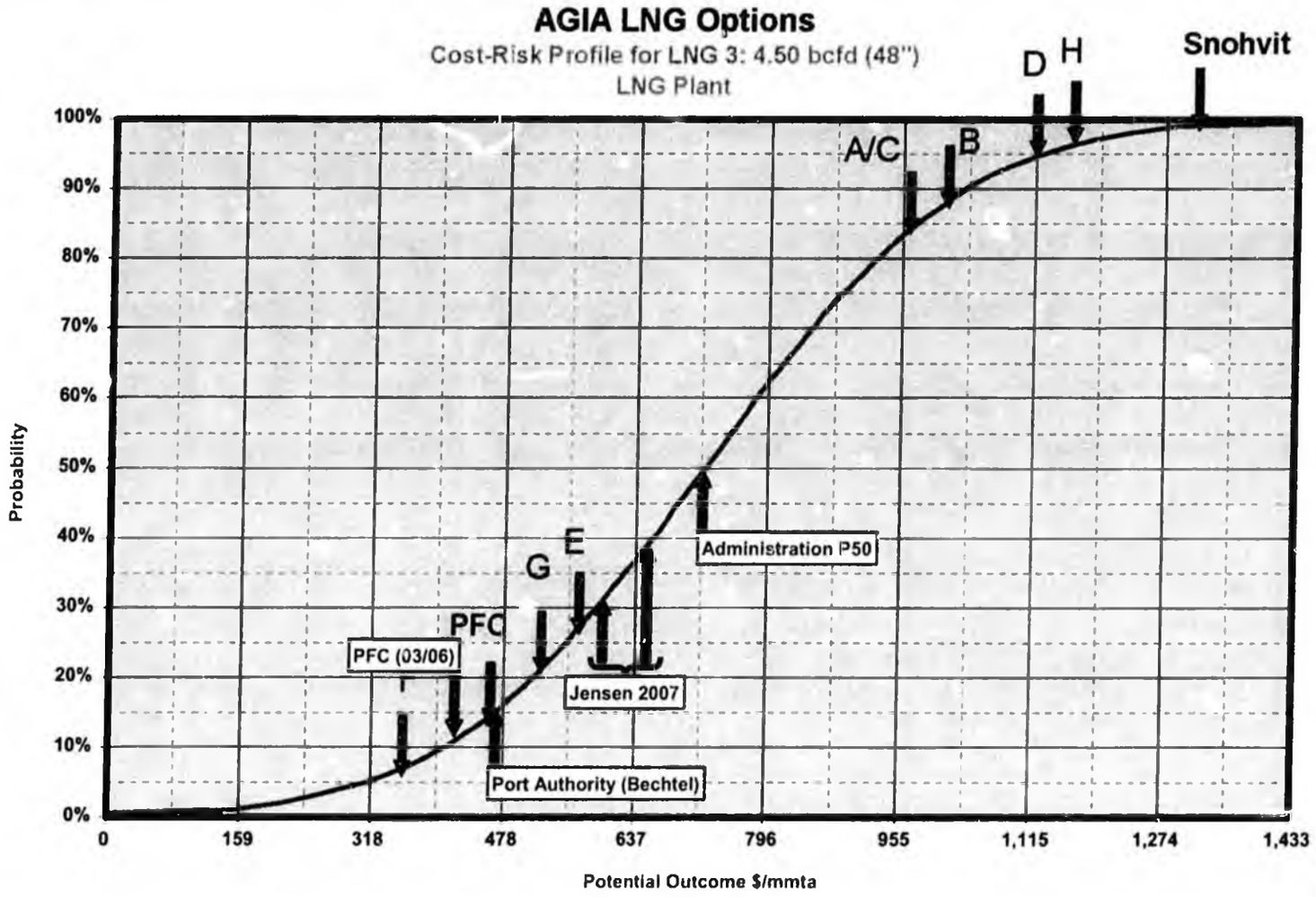
| | LNG Project | | Pipeline Project | |
|---|---|---|---|---|
| | 2.7 bcf/d | 4.5 bcf/d | 3.5 bcf/d | 4.5 bcf/d |
| | (Billion $2007) | | | |
| | (1) | (2) | (3) | (4) |
| GTP | $5.0 | $8.3 | $6.5 | $8.3 |
| Pipeline | | | | |
| Alaska | 11.5 | 12.6 | 10.2 | 10.9 |
| Canada | - | - | 11.6 | 12.6 |
| Total Pipeline | $11.5 | $12.6 | $21.7 | $23.5 |
| LNG Plant (Bechtel) | 7.9 | 13.7* | - | - |
| LNG Plant (Westney) | 12.7 | 21.1 | - | - |
| Total (Bechtel LNG) | $24.4 | $34.6* | $28.2 | $31.8 |
| Total (Westney LNG) | $29.2 | $42.0 | $28.2 | $31.8 |

* Based on $470/mt

# LNG Plant Costs

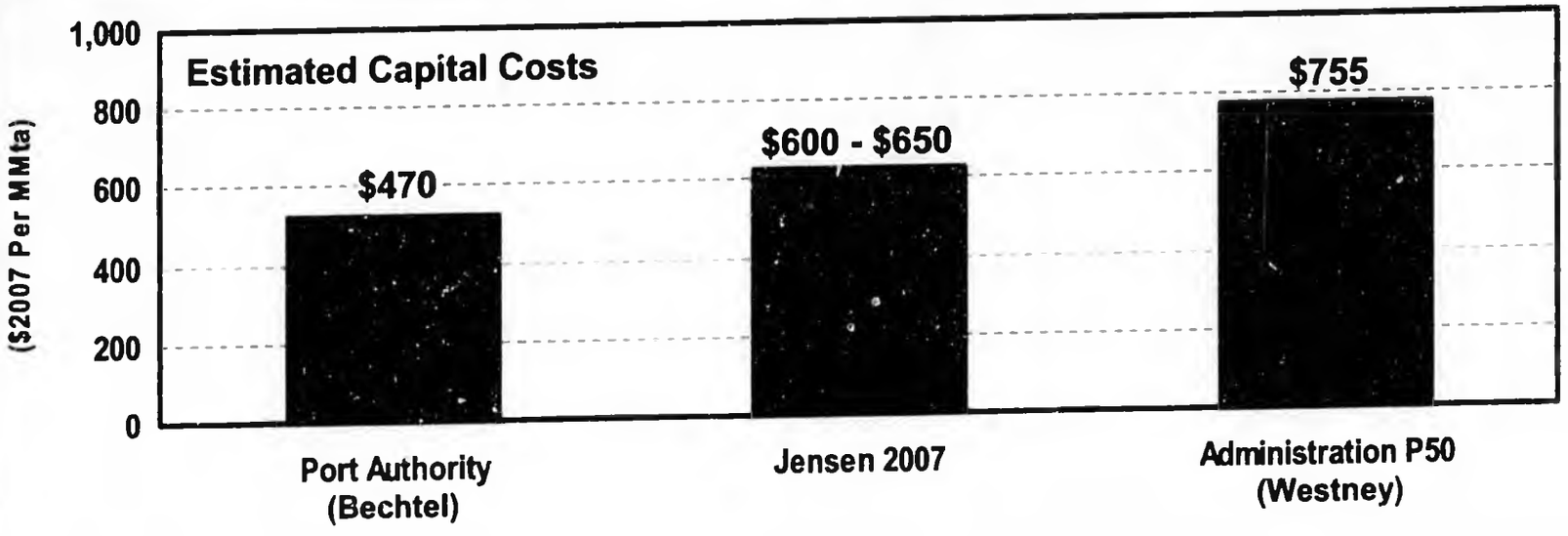
# LNG Plant Costs Per Administration (Westney)

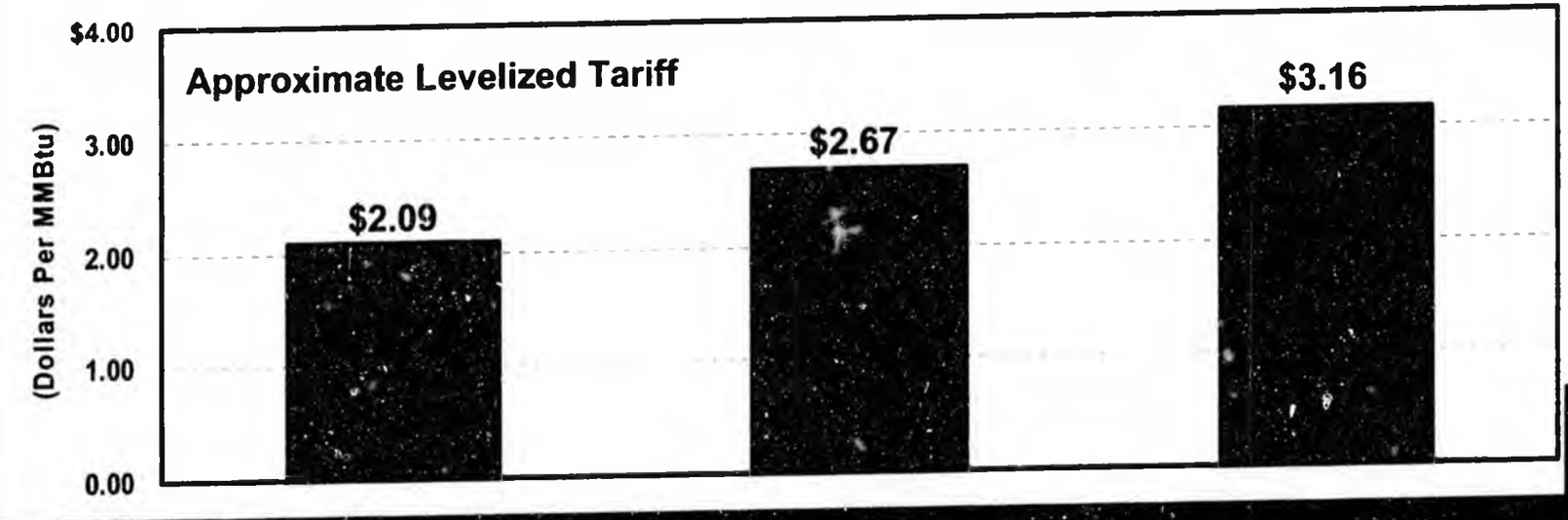
## ($2007 per mmta)




Source: AGIA Analysis Technical Team, "LNG Project Costs/Schedule", June 9, 2008

# Range of LNG Liquefaction Costs and Tariffs
## (2.7 bcf/d LNG Project)

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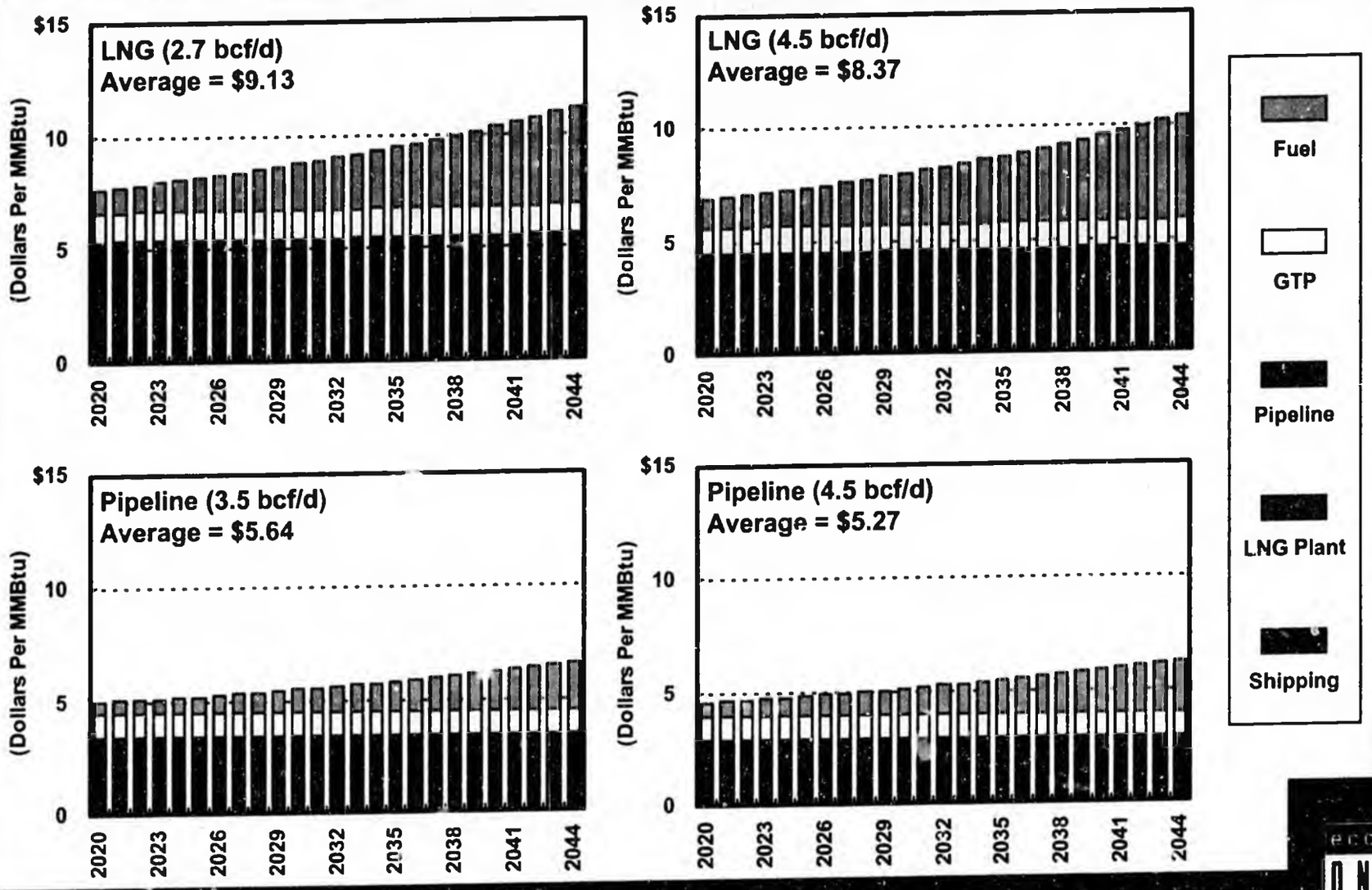
# Comparison of Netback Elements

# Comparison of Potential Costs

## LNG Project v. Pipeline Project

## 2020 - 2044




Note: Oil Prices per Wood Mackenzie forecasts with 8:1 Oil/Gas Price Ratio
LNG Plant cost of $470/mmta per Port Authority application:
Asia Gas Price = 0.1485 x JCC + $0.90 (Gas Strategies)

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# Potential Netbacks

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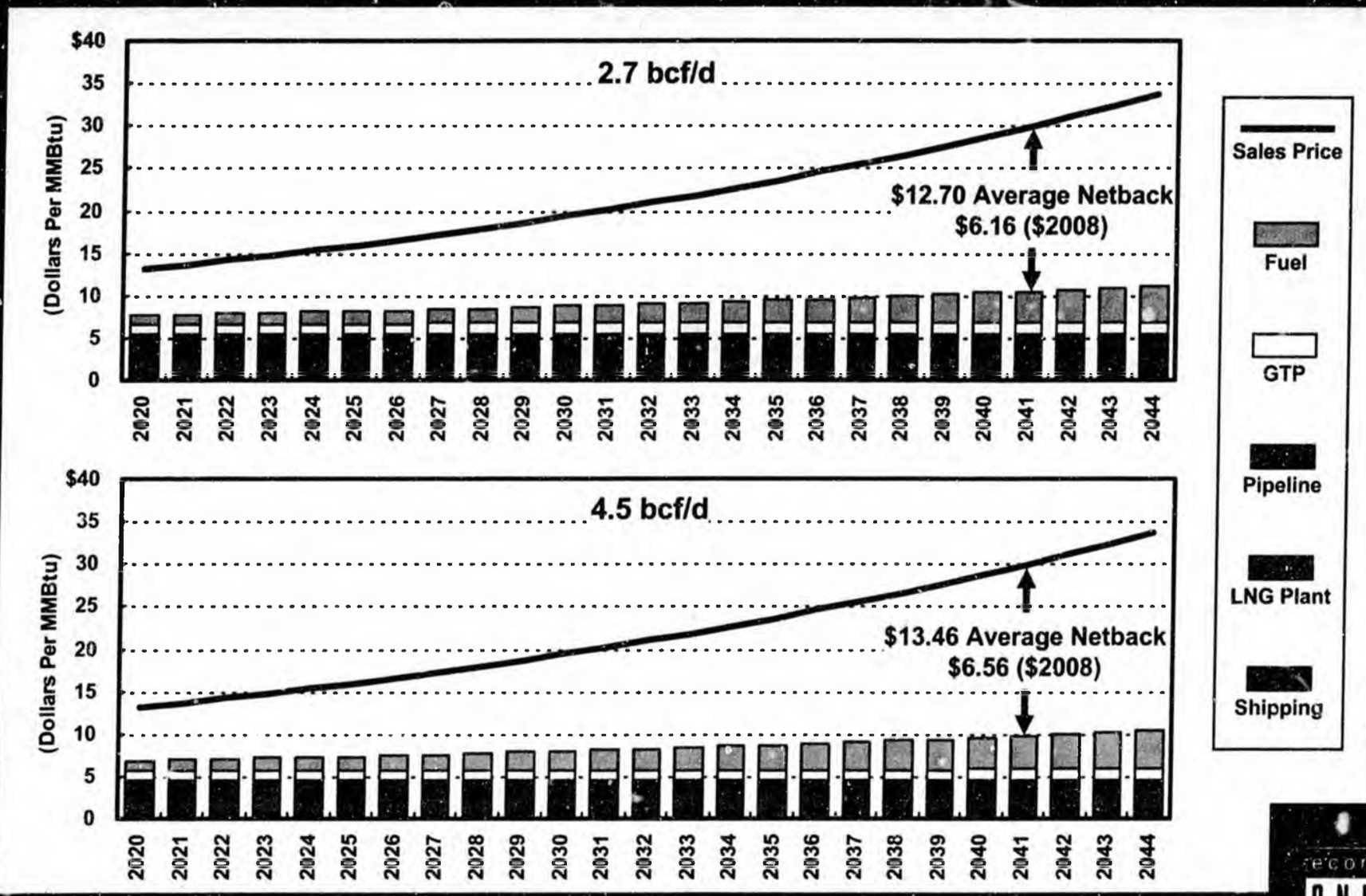
# Potential Netbacks for LNG Delivery to Asia

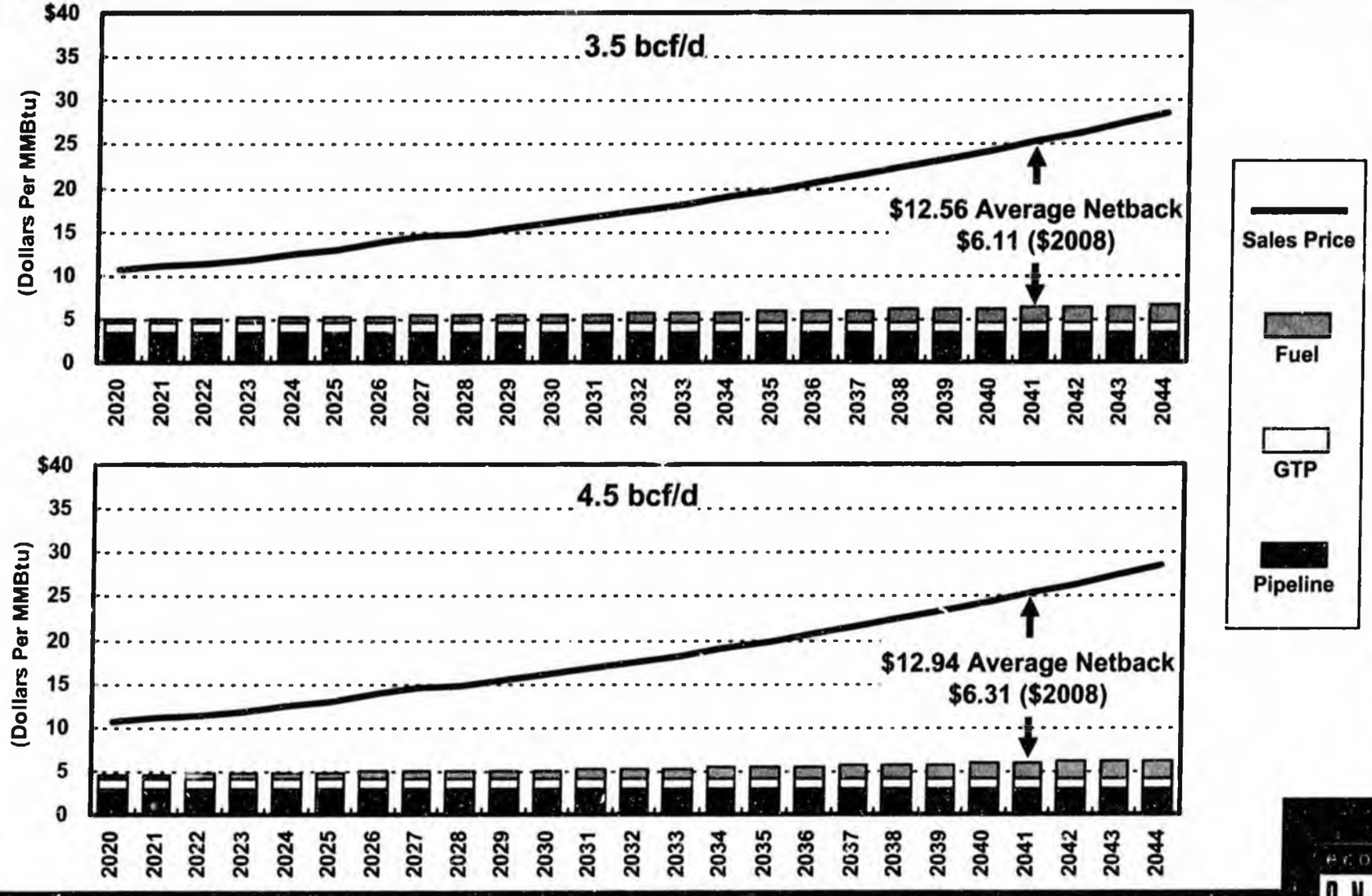
(Gas Strategies: Asia Gas Price = 0.1485 x Brent + $0.90)




Note: Oil Prices per Wood Mackenzie forecasts;
LNG Plant cost of $470/mmta per Port Authority application.

# Potential Netbacks for AECO Pipeline Delivery

(8:1 WTI Oil/Henry Hub Gas Price Ratio)




Note: Oil Prices per Wood Mackenzie forecasts.

# Comparison of Projected Netbacks

## 2.7 bcf/d LNG Project
## v.
## 3.5 bcf/d Pipeline Project

# Projected Netbacks Under Alternative Projects
## (Port Authority LNG Plant Costs -- $470/mt)

### Oil Prices per Wood Mackenzie Estimates
### 2.7 bcf/d (LNG Project) v. 3.5 bcf/d (Pipeline Project)
### 2020 - 2044

| | 2.7 bcf/d LNG Project | | | | 3.5 bcf/d AECO Pipeline Delivery | |
|---|---|---|---|---|---|---|
| | High Price Asia Gas = 0.162 x Brent +$1.00 | Gas Strategies Asia Gas = 0.1485 x Brent +$0.90 | Port Authority Asia Gas = 0.8 x (Brent / 5.8) | Low Price Asia Gas = 0.11 x Brent +$1.30 | 8:1 Oil/Gas Price Ratio | 10:1 Oil/Gas Price Ratio |
| | (1) | (2) | (3) | (4) | (5) | (6) |
| Gas Sales Price ($/MMBtu) | $23.67 | $21.83 | $19.61 | $17.21 | $18.20 | $15.20 |
| Delivery Costs ($/MMBtu) (Including Losses) | (9.42) | (9.13) | (8.77) | (8.39) | (5.64) | (5.38) |
| Netback ($/MMBtu) | $14.25 | $12.70 | $10.84 | $8.82 | $12.56 | $9.82 |
| **Netback in $2008 dollars (per MMBt** | **$6.93** | **$6.16** | **$5.22** | **$4.25** | **$6.11** | **$4.75** |
| | ① | ② | ④ | ⑥ | ③ | ⑤ |
| Total Netback Dollars | | | | | | |
| In Nominal Dollars ($Bn) | $396.2 | $353.1 | $301.3 | $245.2 | $472.0 | $369.1 |
| In $2008 dollars ($Bn) | 192.7 | 171.3 | 145.1 | 118.1 | 229.5 | 178.5 |
| **NPV-10 ($Bn)** | **35.1** | **31.0** | **25.6** | **20.9** | **41.8** | **31.9** |
| | ② | ④ | ⑤ | ⑥ | ① | ③ |

= More Likely Price Scenario(s)

# Comparison of Projected Netbacks

## 2.7 bcf/d LNG Project
## v.
## 4.5 bcf/d Pipeline Project

# Projected Netbacks Under Alternative Projects
## (Port Authority LNG Plant Costs -+ $470/mt)

### Oil Prices per Wood Mackenzie Estimates
### 2.7 bcf/d (LNG Project) v. 4.5 bcf/d (Pipeline Project)
### 2020 - 2044

| | 2.7 bcf/d LNG Project | | | | 4.5 bcf/d AECO Pipeline Delivery | |
|---|---|---|---|---|---|---|
| | High Price Asia Gas = 0.162 x Brent +$1.00 | Gas Strategies Asia Gas = 0.1485 x Brent +$0.90 | Port Authority Asia Gas = 0.8 x (Brent / 5.8) | Low Price Asia Gas = 0.11 x Brent +$1.30 | 8:1 Oil/Gas Price Ratio | 10:1 Oil/Gas Price Ratio |
| | (1) | (2) | (3) | (4) | (5) | (6) |
| Gas Sales Price ($/MMBtu) | $23.67 | $21.83 | $19.61 | $17.21 | $18.20 | $15.20 |
| Delivery Costs ($/MMBtu) (Including Losses) | (9.42) | (9.13) | (8.77) | (8.39) | (5.26) | (4.99) |
| Netback ($/MMBtu) | $14.25 | $12.70 | $10.84 | $8.82 | $12.94 | $10.22 |
| **Netback in $2008 dollars (per MMBt** | **$6.93** | **$6.16** | **$5.22** | **$4.25** | **$6.31** | **$4.96** |
| | ① | ③ | ④ | ⑥ | ② | ⑤ |
| Total Netback Dollars | | | | | | |
| In Nominal Dollars ($Bn) | $396.2 | $353.1 | $301.3 | $245.2 | $625.0 | $493.5 |
| In $2008 dollars ($Bn) | 192.7 | 171.3 | 145.1 | 118.1 | 304.6 | 239.5 |
| **NPV-10 ($Bn)** | **35.1** | **31.0** | **25.6** | **20.9** | **55.9** | **43.3** |
| | ③ | ④ | ⑤ | ⑥ | ① | ② |

**= More Likely Price Scenario(s)**

# Comparison of Projected Netbacks

## 4.5 bcf/d LNG Project
## v.
## 4.5 bcf/d Pipeline Project

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# Projected Netbacks Under Alternative Projects

## (Port Authority LNG Plant Costs -- $470/mt)

### Oil Prices per Wood Mackenzie Estimates
### 4.5 bcf/d (LNG Project) v. 4.5 bcf/d (Pipeline Project)
### 2020 - 2044

| | 4.5 bcf/d LNG Project | | | | 4.5 bcf/d AECO Pipeline Delivery | |
|---|---|---|---|---|---|---|
| | High Price Asia Gas = 0.162 x Brent +$1.00 | Gas Strategies Asia Gas = 0.1485 x Brent +$0.90 | Port Authority Asia Gas = 0.8 x (Brent / 5.8) | Low Price Asia Gas = 0.11 x Brent +$1.30 | 8:1 Oil/Gas Price Ratio | 10:1 Oil/Gas Price Ratio |
| | (1) | (2) | (3) | (4) | (5) | (6) |
| Gas Sales Price ($/MMBtu) | $23.67 | $21.83 | $19.61 | $17.21 | $18.20 | $15.20 |
| Delivery Costs ($/MMBtu) (Including Losses) | (8.67) | (8.36) | (8.00) | (7.60) | (5.26) | (4.99) |
| Netback ($/MMBtu) | $15.00 | $13.46 | $11.61 | $9.61 | $12.94 | $10.22 |
| **Netback in $2008 dollars (per MMBt** | **$7.33** | **$6.56** | **$5.63** | **$4.66** | **$6.31** | **$4.96** |
| | ① | ② | ④ | ⑥ | ③ | ⑤ |
| Total Netback Dollars | | | | | | |
| In Nominal Dollars ($Bn) | $724.7 | $650.3 | $560.9 | $464.1 | $625.0 | $493.5 |
| In $2008 dollars ($Bn) | 353.9 | 316.9 | 271.8 | 225.2 | 304.6 | 239.5 |
| **NPV-10 ($Bn)** | **65.3** | **58.2** | **49.0** | **40.7** | **55.9** | **43.3** |
| | ① | ② | ④ | ⑥ | ③ | ⑤ |

**= More Likely Price Scenario(s)**

# Sensitivities

- High Sustained Oil Prices
- Impact of Project Delay

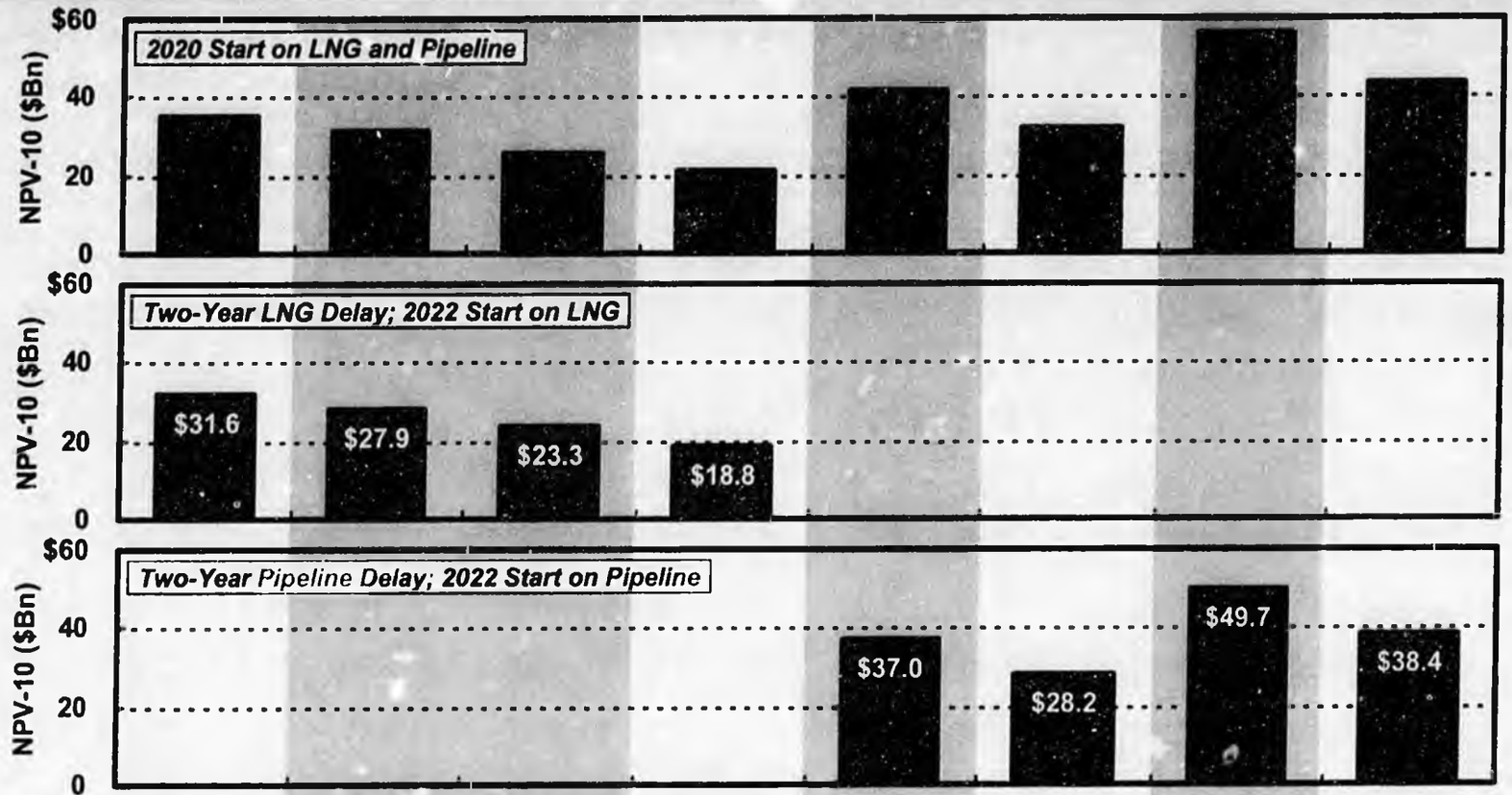
# Projected Netbacks Under Alternative Projects
## (High Price Case: Fixed $120 Real WTI in $2008)

| Rank | Project | Pricing | GTP Inlet Netback ($/MMBtu) |
|---|---|---|---|
| (1) | (2) | (3) | (4) |
| 1 | 4.5 LNG | 0.162 x Brent + $1.00 | $25.86 |
| 2 | 2.7 LNG | 0.162 x Brent + $1.00 | 25.18 |
| 3 | 4.5 LNG | 0.1485 x Brent + $0.90 | 23.48 |
| 4 | 2.7 LNG | 0.1485 x Brent + $0.90 | 22.79 |
| 5 | 4.5 Pipeline | 8:1 Oil/Gas | 22.45 |
| 6 | 3.5 Pipeline | 8:1 Oil/Gas | 22.13 |
| 7 | 4.5 LNG | 0.8 x (Brent / 5.8) | 20.97 |
| 8 | 2.7 LNG | 0.8 x (Brent / 5.8) | 20.26 |
| 9 | 4.5 Pipeline | 10:1 Oil/Gas | 18.18 |
| 10 | 3.5 Pipeline | 10:1 Oil/Gas | 17.84 |
| 11 | 4.5 LNG | 0.11 x Brent + $1.30 | 17.24 |
| 12 | 2.7 LNG | 0.11 x Brent + $1.30 | 16.50 |

| Rank | Project | Pricing | NPV-10 Total Netback ($Billion) |
|---|---|---|---|
| (5) | (6) | (7) | (8) |
| 1 | 4.5 LNG | 0.162 x Brent + $1.00 | $126.5 |
| 2 | 4.5 LNG | 0.1485 x Brent + $0.90 | 114.6 |
| 3 | 4.5 Pipeline | 8:1 Oil/Gas | 109.4 |
| 4 | 4.5 LNG | 0.8 x (Brent / 5.8) | 101.7 |
| 5 | 4.5 Pipeline | 10:1 Oil/Gas | 88.2 |
| 6 | 4.5 LNG | 0.11 x Brent + $1.30 | 83.8 |
| 7 | 3.5 Pipeline | 8:1 Oil/Gas | 83.7 |
| 8 | 2.7 LNG | 0.162 x Brent + $1.00 | 70.6 |
| 9 | 3.5 Pipeline | 10:1 Oil/Gas | 67.0 |
| 10 | 2.7 LNG | 0.1485 x Brent + $0.90 | 63.7 |
| 11 | 2.7 LNG | 0.8 x (Brent / 5.8) | 56.2 |
| 12 | 2.7 LNG | 0.11 x Brent + $1.30 | 45.8 |

Note: LNG plant costs of $470/mmta per Port Authority.

# Impact of Potential Delays on Projects



# LNG Export Issues

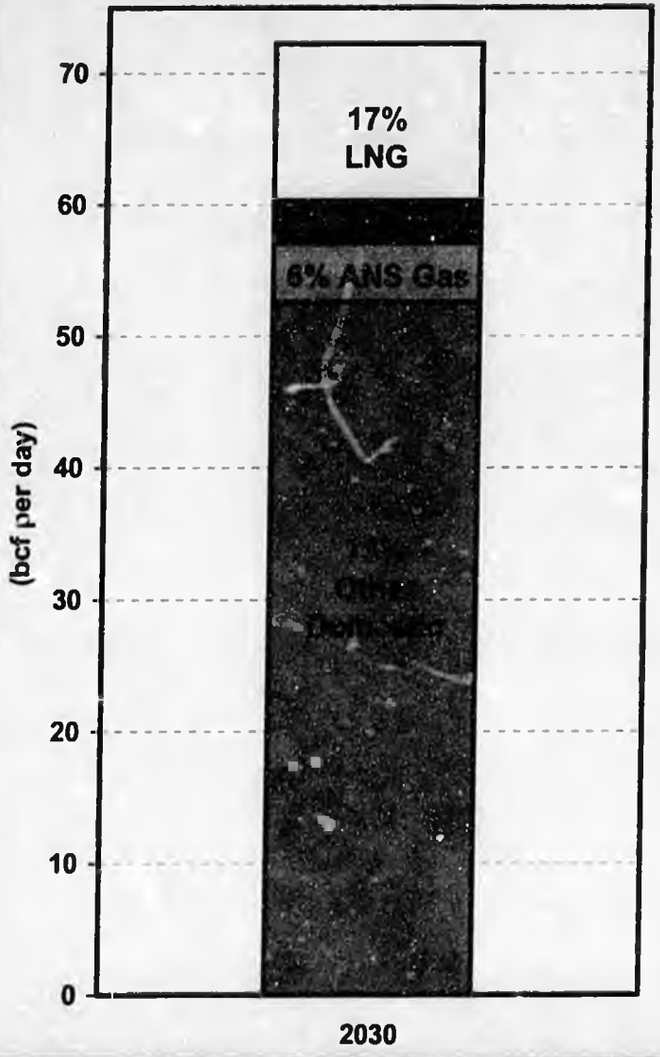
# LNG Export Issues

- Yukon Pacific permit for export
  - Issued in 1989
  - 14mmta (~1.9 bcf/d) to Japan, South Korea, Taiwan
  - 25 years from 1st gas
- Project will require D.O.E. review
  - Different project
  - Time elapsed
  - Different circumstances (e.g., U.S. is net importer of gas)
  - Political
- Is recent Kenai decision comparable?
  - Smaller / shorter window
  - No perceived issues outside Alaska
  - Lengthy multi-year process for renewal
- Experience with oil
  - Initial ban on exports
  - 1996 lifting of export ban, but too late to benefit Alaska
  - Still significant perception issue at Federal political level

# LNG Export Issues
(cont'd)

- Exports must be "in public interest"
- Pros
  - Free trade
  - Efficiency (i.e., higher netbacks)
  - Balance of payments
  - More production for Lower-48
- Cons
  - Will lead to more LNG imports
  - Will lead to more high-cost Lower-48 production
  - Will lead to higher gas prices for U.S. consumers

# Will D.O.E. Find LNG Exports in the Public Interest?




- If ANS gas is exported, it will not be available for domestic markets.
- Requires "replacement" with more expensive domestic gas or LNG imports.
- Forecasts indicate that ANS supplies @ 4.5 Bcf/day will reduce U.S. gas price by ~ $0.30/MMBtu.
- At projected US consumption of 70 bcf/d in 2030, this is ~ $7.5 billion annually.

Source: EIA AEO 2007

# LNG Export Issues
(cont'd)

- Chance of Federal intervention
  - Federal government assistance with permitting and loan guarantees in 2004 likely lead to tension re: potential of exports
  - National security concerns
  - Argument that consumers in Lower-48 would be hurt
  - Probably little Federal support for exports if Federal gas is involved
- Pipeline project must also apply for export permit
  - But, 2004 legislation specifically addresses export to Canada

# Conclusions

# Conclusions

- Gas prices is Asia are likely to maintain a premium over U.S. gas prices, though not at current levels
- U.S. prices will likely strengthen relative to Asian and European gas prices as U.S. domestic production becomes more expensive and LNG flows away from the U.S.
- LNG project would likely be viable under reasonable price scenarios, assuming gas can be exported
  - Economics of LNG delivery to U.S. West Coast would be worse than pipeline delivery under any reasonable set of assumptions
- Under the reasonable price scenarios, 2.7 bcf/d LNG project offers $/MMBtu netbacks that are similar to pipeline netbacks
  - Difference is some cases is not large relative to potential estimation error

# Conclusions
(cont'd)

- However, larger volumes for pipeline deliveries produce higher overall values (NPV) for resource owners under more likely price scenarios
  - 3.5 bcf/d pipeline > 2.7 bcf/d LNG by $11Bn to $16Bn
  - 4.5 bcf/d pipeline > 2.7 bcf/d LNG by $25Bn to $30Bn
- LNG project would produce somewhat higher NPVs if in the long run:
  - Oil prices stay high
  - Gas/Oil price ratio in Asia stays strong
  - Gas/Oil price ratio in U.S. remains weak
  - LNG can be exported and project advances at some time earlier than the pipeline

# Conclusions
(cont'd)

- Gaining Federal permission to export LNG to Asia will likely be very difficult
  - D.O.E. permission
  - Potential Federal legislation
- Export via Y-line will face similar challenges
- Federal acceptance of exporting may be more favorable if majority of gas is already flowing to U.S. markets
  - But don't count on it
  - Oil experience along those lines was not particularly favorable

# Conclusions
(cont'd)

- Impact of potential delays
  - Delay in pipeline relative to LNG does not change results under more likely price scenarios
- Does the State have to choose between the two projects?
  - Market-based outcome is more favorable
  - Shippers can nominate to LNG project if they see it is more economic
  - Potential buyers of LNG can go "upstream" and negotiate to buy gas
  - Economics of LNG relative to pipeline not compelling enough to suggest that the State needs to "intervene" to make LNG happen at expense of pipeline

# Comparison of Netbacks from Potential LNG Project with ALCAN Pipeline Project

**June 20, 2008**


**Barry Pulliam**
**Senior Economist**
**Econ One Research**

*5th Floor*
*601 W 5th Street*
*Los Angeles, California 90071*
*213 624 9500*

*Suite 1280*
*2321 Rosecrans Avenue*
*El Segundo, California 90245*
*310 727 9916*

*Suite 2825*
*Three Allen Center*
*333 Clay Street*
*Houston, Texas 77002*
*713 228 2700*

*Suite 100*
*555 University Avenue*
*Sacramento, California 95825*
*916 576 0366*

*Suite 501*
*805 15th Street, N.W.*
*Washington, D.C. 20005*
*202 289 7620*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# Econ One Review

- Analyzed economic assumptions & netback values associated with potential LNG and pipeline projects
  - Port Authority proposal
  - Other potential LNG configurations
  - TransCanada proposal
- Reviewed Port Authority proposal, assumptions and analysis
- Reviewed Administration analysis of LNG and pipeline netbacks
- Reviewed information from various LNG specialists and government agencies

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# Econ One Review
(cont'd)

- Analyzed netback @ the inlet to GTP
  - $ / MMBtu
  - Total value of netback
    - Nominal $
    - Real ($2008)
    - NPV-10
- Project that "maximizes" the netback creates highest value for resource owners
  - Producers
  - State

# Project Netback Analyses

## LNG Exports to Asia

- 2.7 Bcf/d (Port Authority proposed)
- 4.5 Bcf/d (Little Susitna proposed)

## Pipeline to Alberta

- 3.5 Bcf/d (TransCanada minimum volumes)
- 4.5 Bcf/d (TransCanada base volumes)

# Overview of LNG v. Pipeline Delivery

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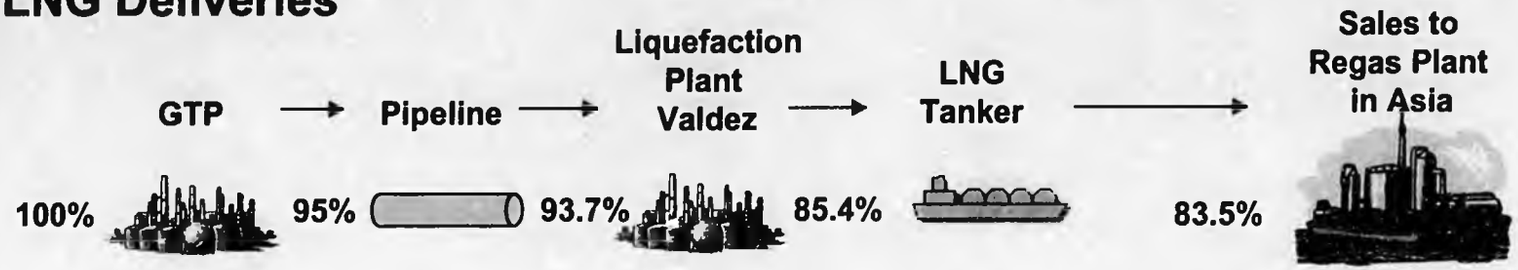
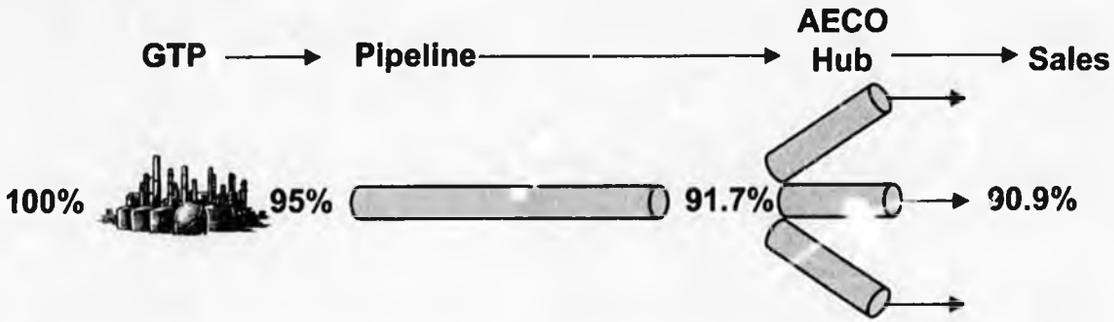
# LNG and Pipeline Delivery Chain

## LNG Deliveries




**Aggregate Loss: 16.5%**

## Pipeline Deliveries




**Aggregate Loss: 9.1%**

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# Supply / Demand

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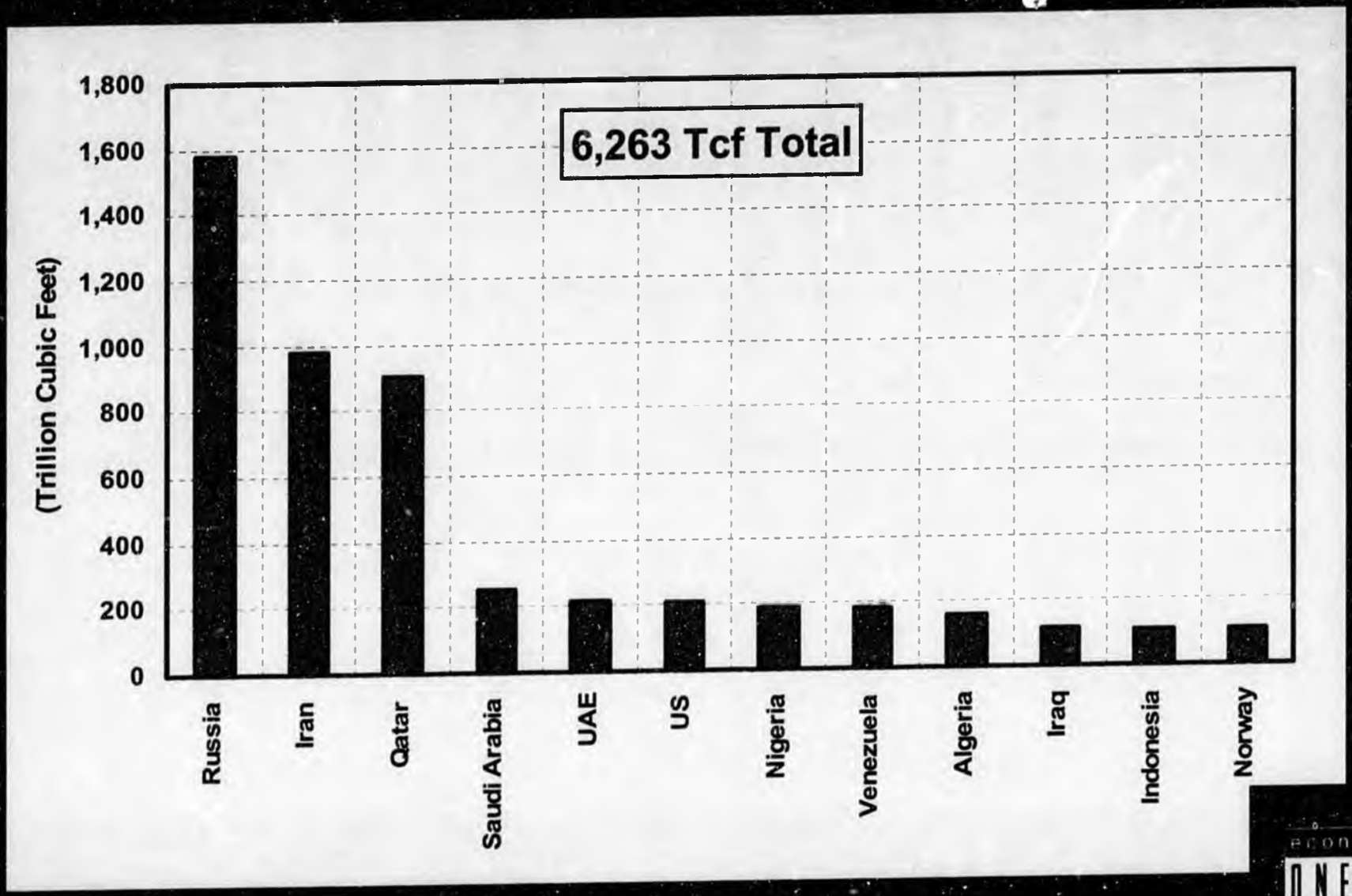
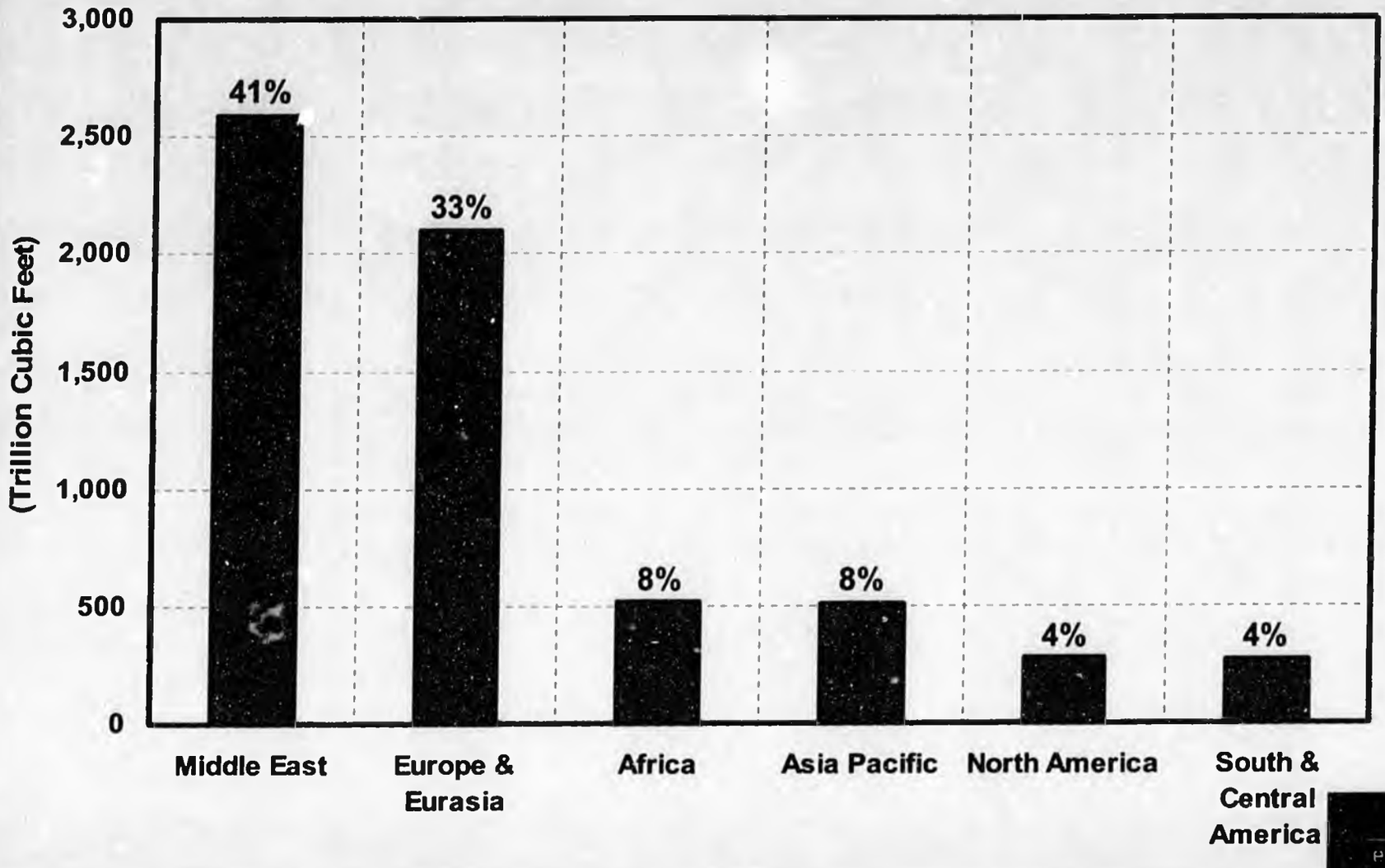
# Worldwide Proved Gas Reserves



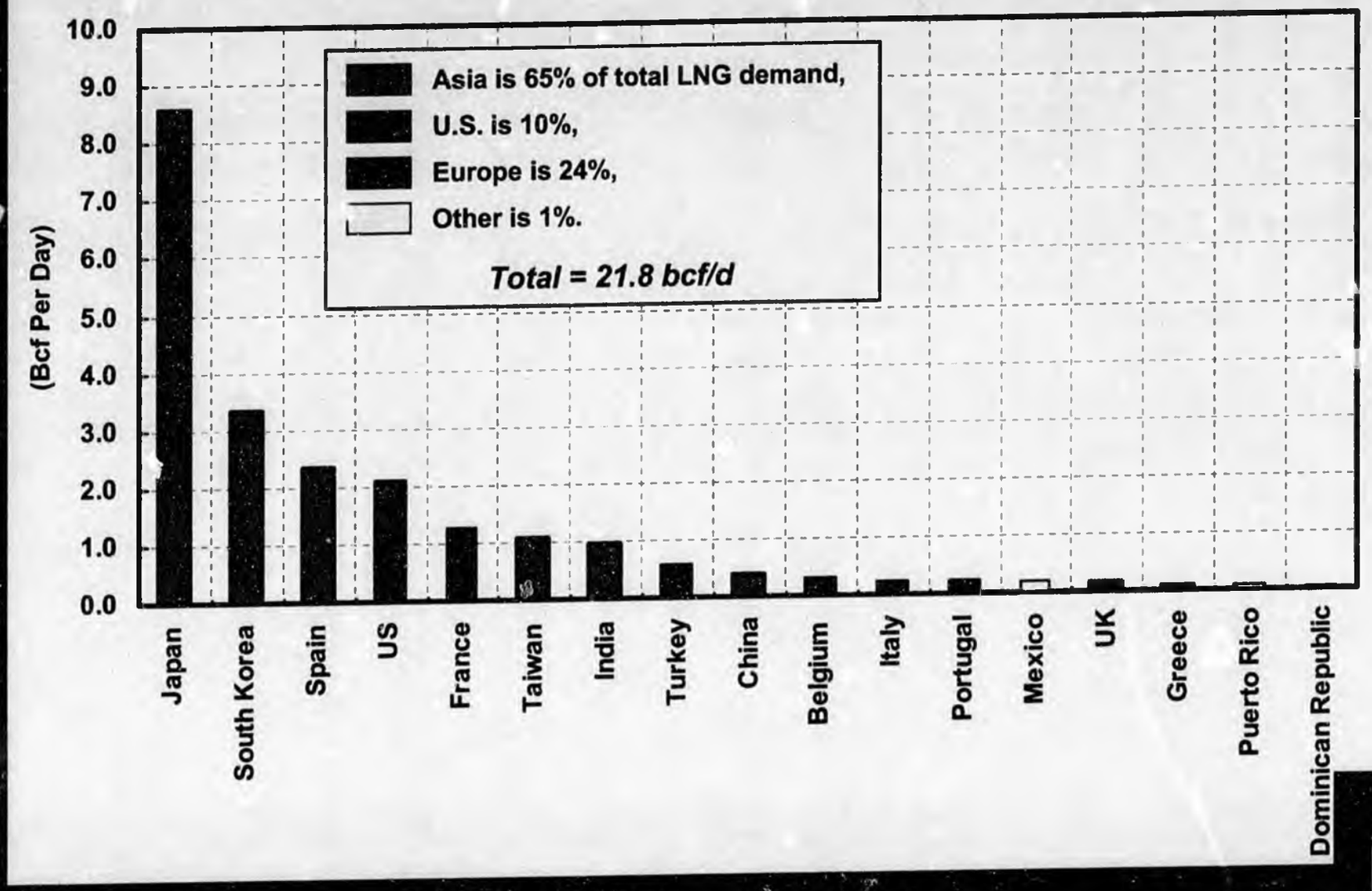

Source: BP Statistical Review 2008;
Represents 80% of known reserves in 2007.

# Worldwide Proved Gas Reserves by Region



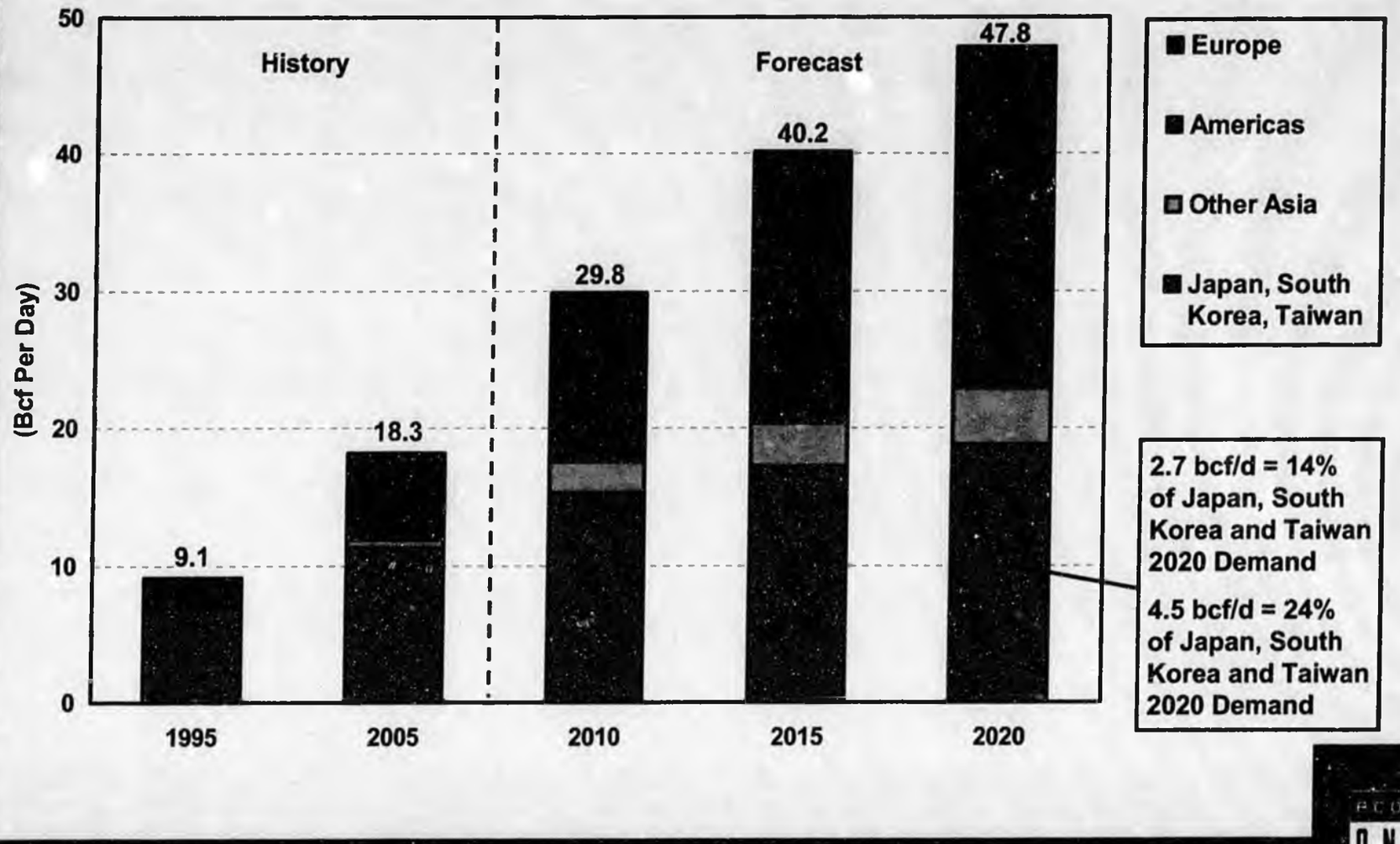

Source: BP Statistical Review 2008.

# Current Worldwide LNG Demand




Source: BP Statistical Review 2008.

# Projected LNG Demand by Region




Source: National Petroleum Council ; Jensen Associates, August 2007

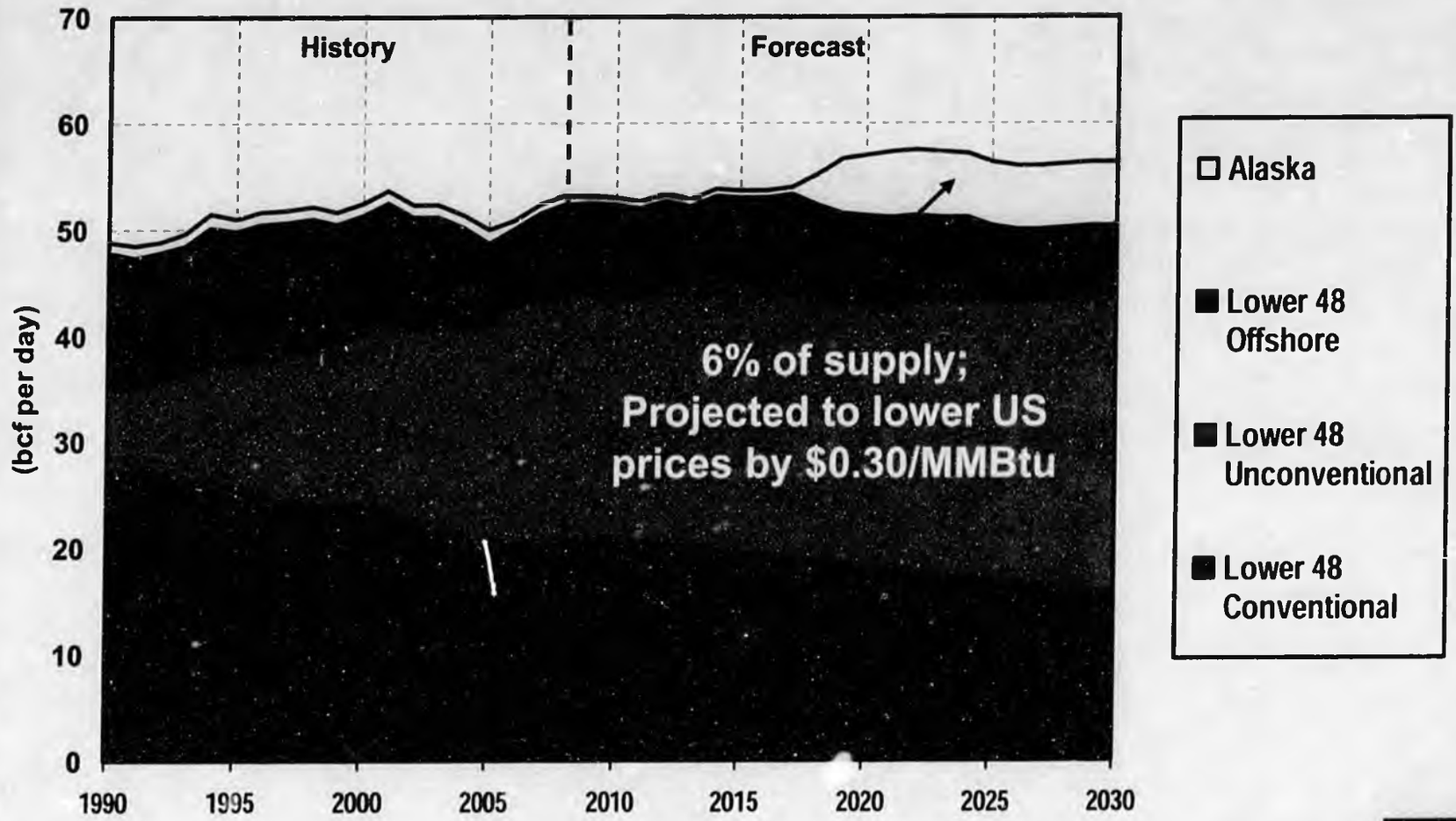
# Liquefaction Plant Capacities by Region
(Pacific Trade)

| Pacific Basin | |
|---|---|
| Category | Capacity (Bcf/Day) |
| (1) | (2) |
| Operating | 9.85 |
| Under Construction | 3.50 |
| Under Consideration | 6.24 |
| ***Total*** | ***19.59*** |

| Middle East | |
|---|---|
| Category | Capacity (Bcf/Day) |
| (3) | (4) |
| Operating | 6.06 |
| Under Construction | 6.84 |
| Under Consideration | 4.63 |
| ***Total*** | ***17.53*** |

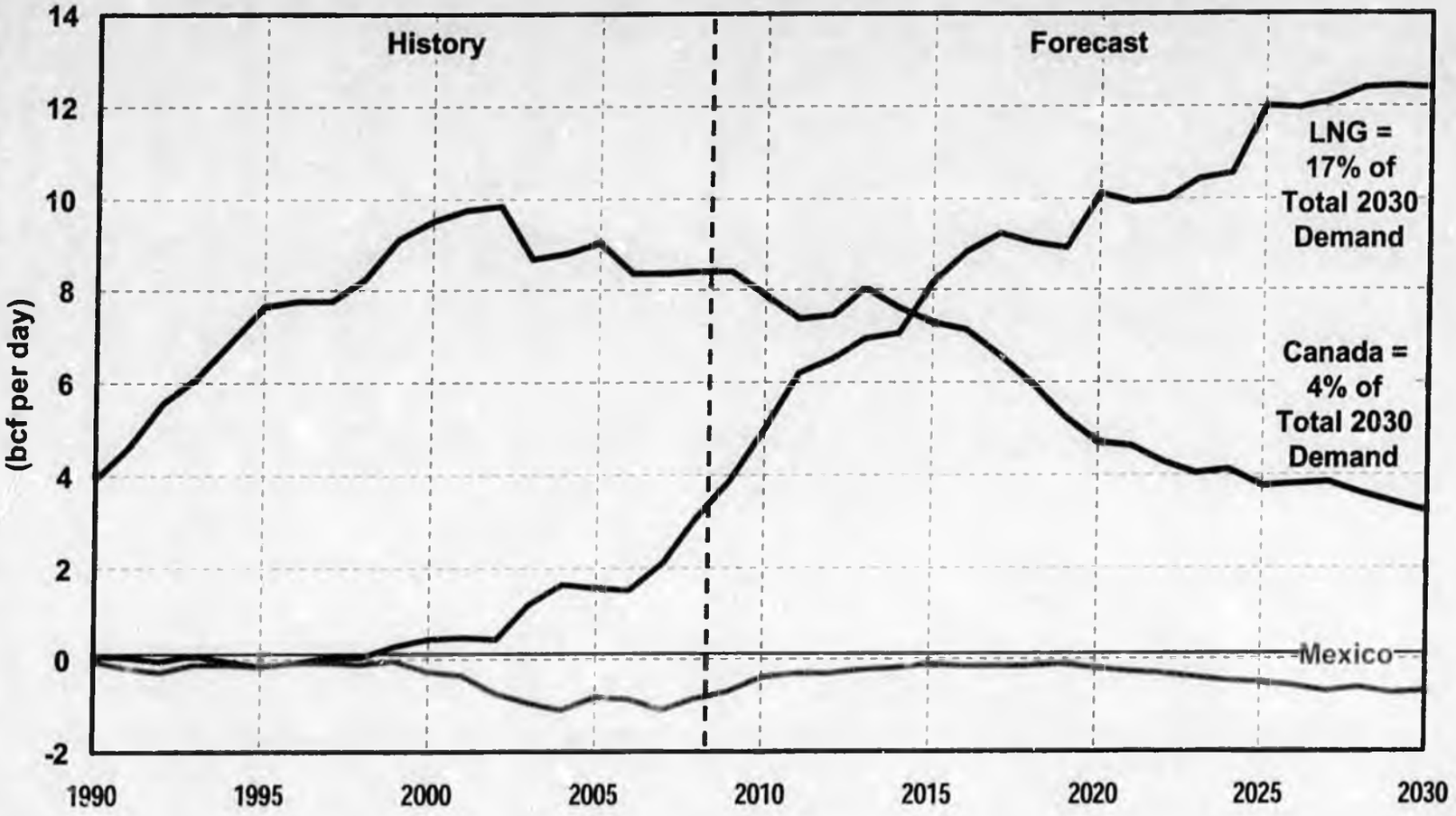
Source: Facts Global Energy, "Evaluating Natural Gas Import Options for the State of Hawaii", April 2007.

# U.S. Gas Production by Source
## (1990 - 2030)




Source: EIA AEO 2007

# U.S. Net Natural Gas Imports
## (1990 - 2030)

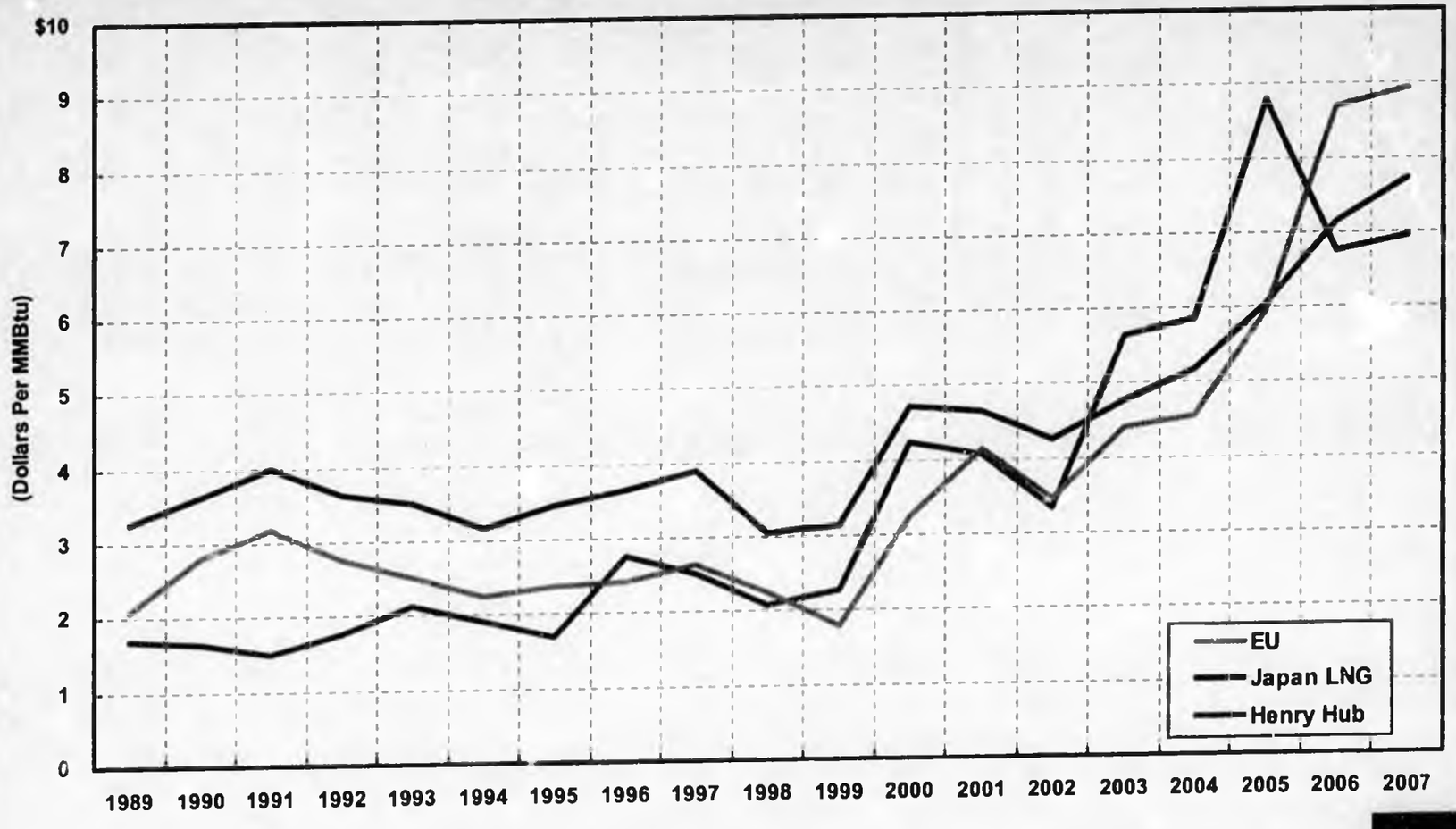



Source: EIA AEO 2007

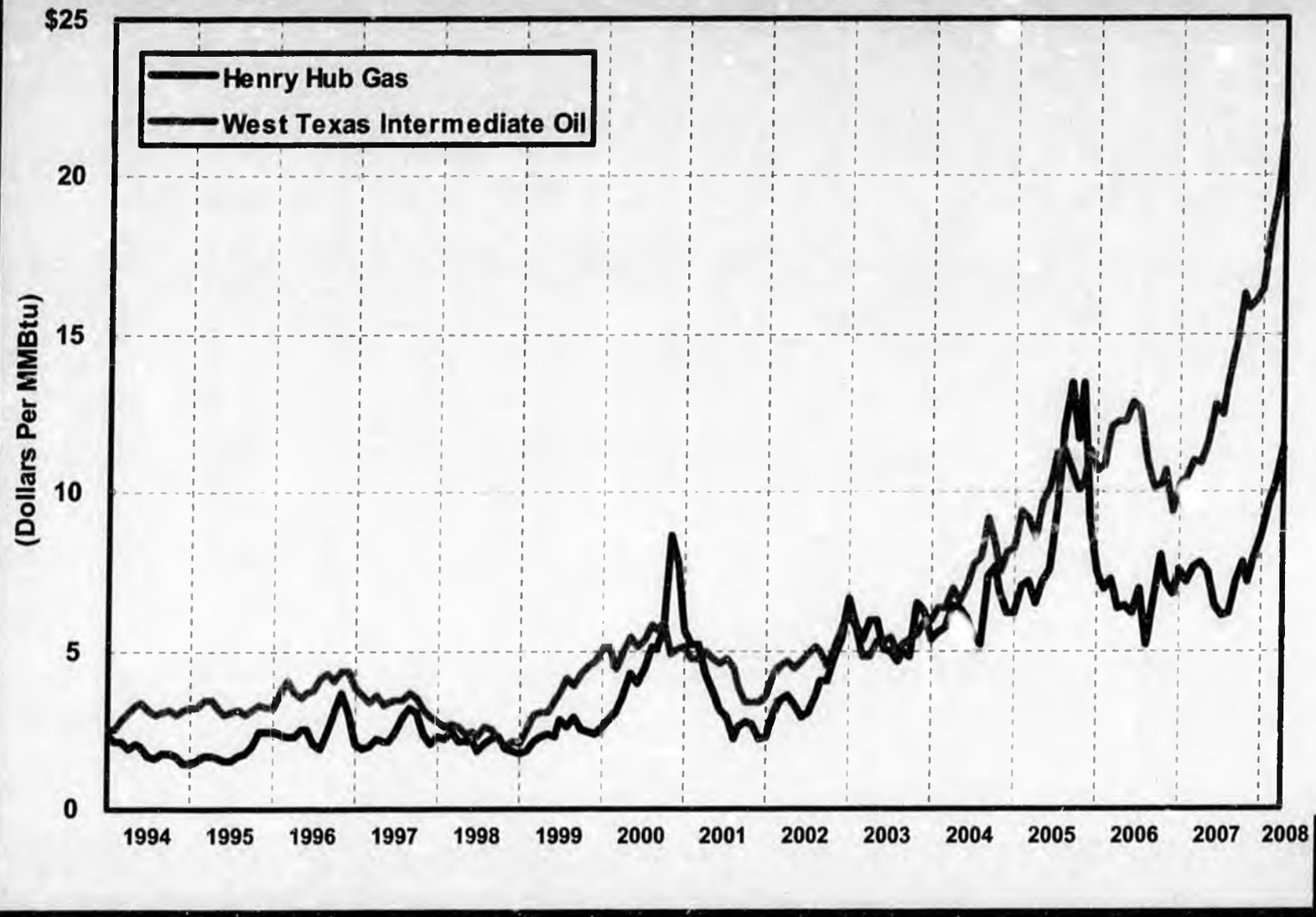
# Historical Pricing

# Historical Gas Prices

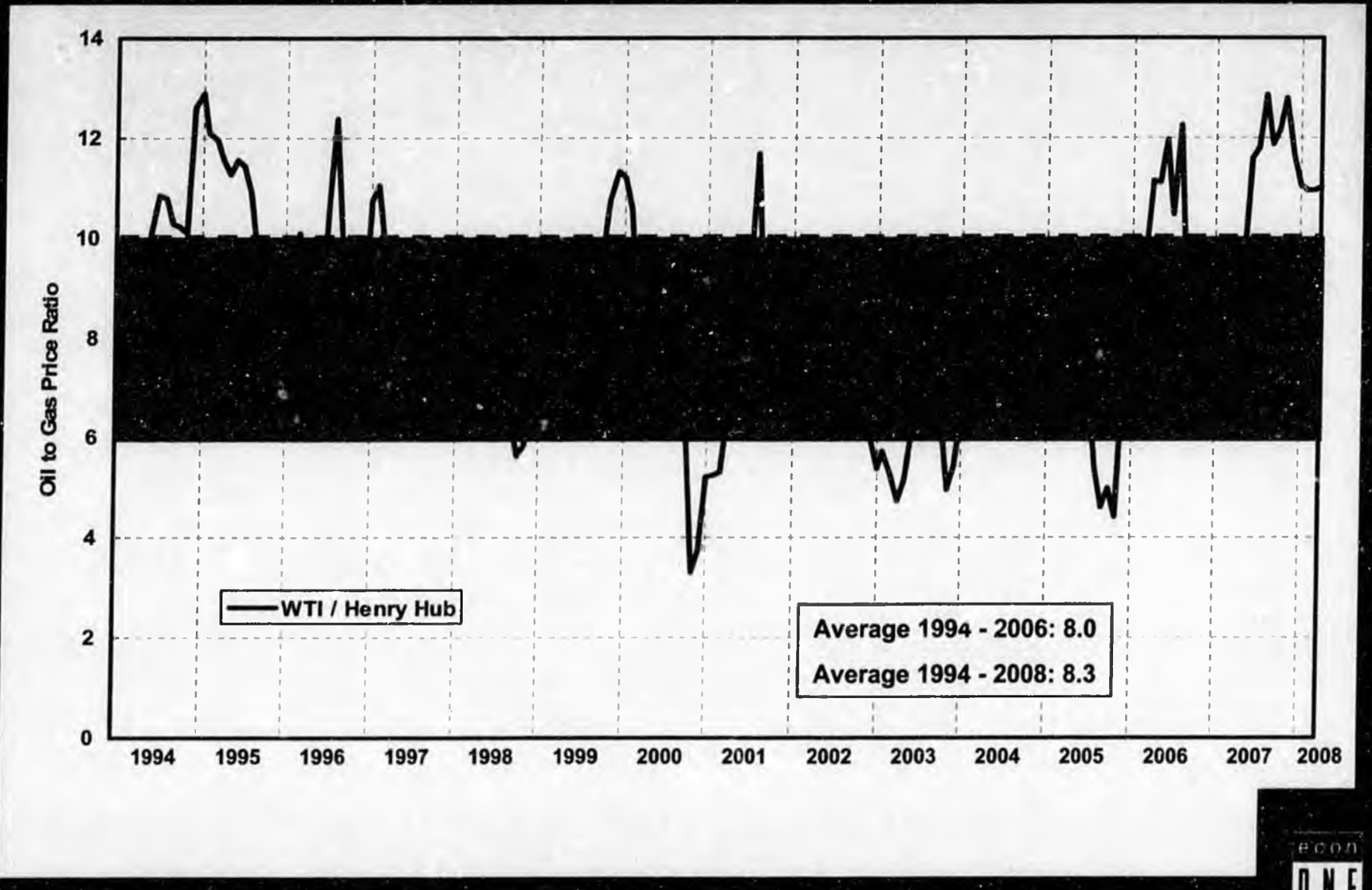
## (U.S., Japan and Europe)



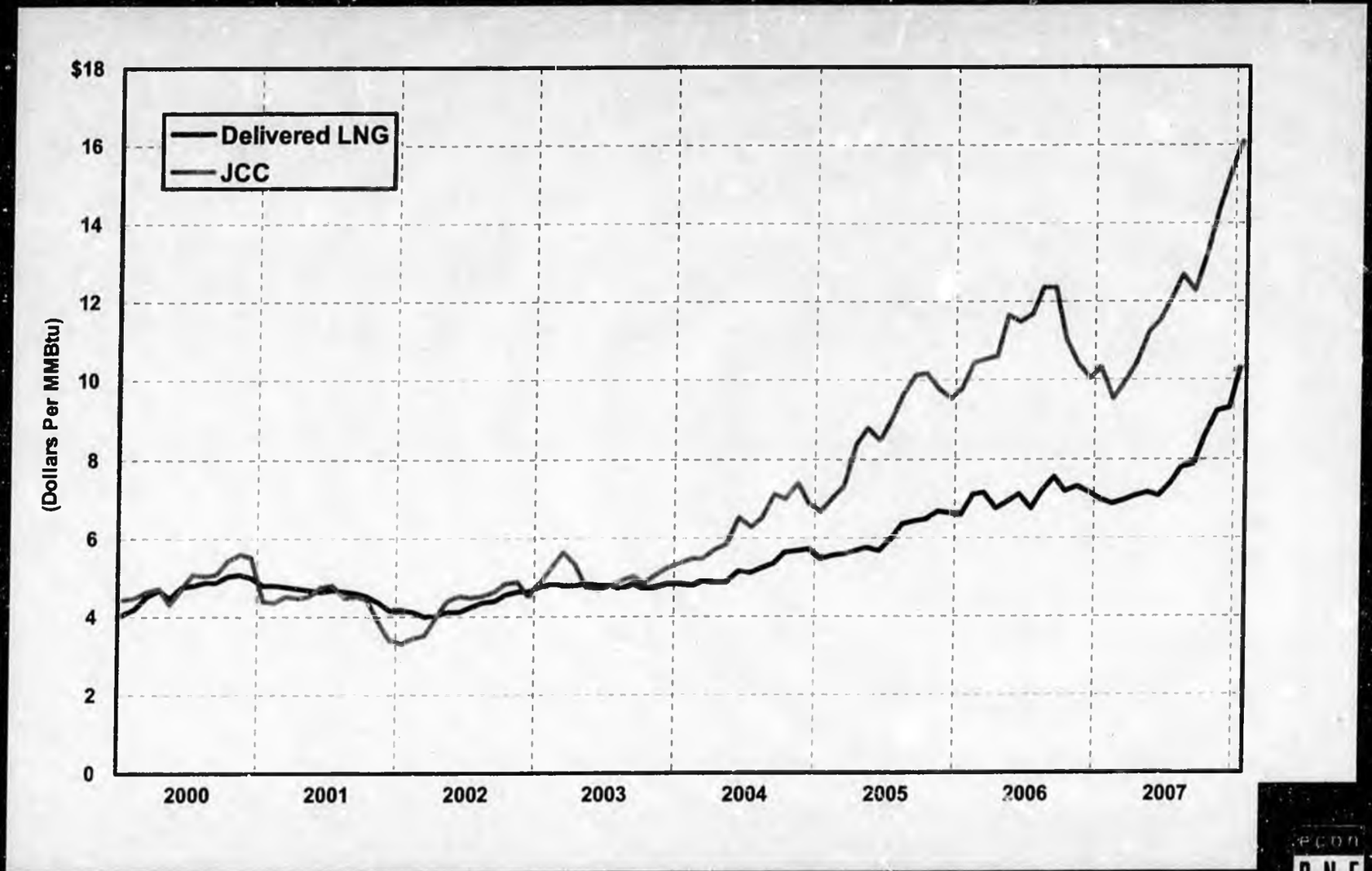
# U.S. Natural Gas and Crude Oil Prices
(1994 - 2008)



# Historical Relationship Between Oil and Gas Prices in the U.S.



# Japanese Crude Oil and Gas Prices
(2000 - 2008)

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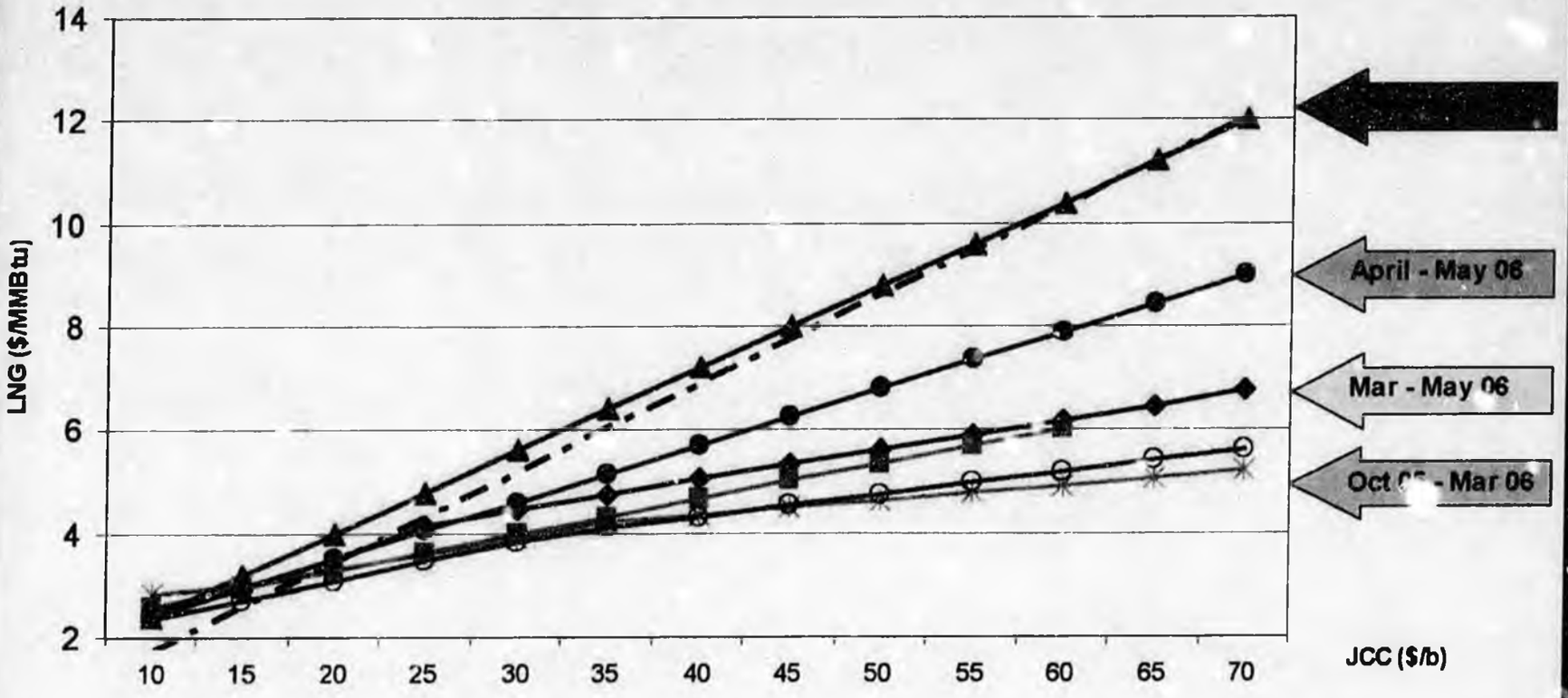
# Evolution of LNG Pricing in Asia

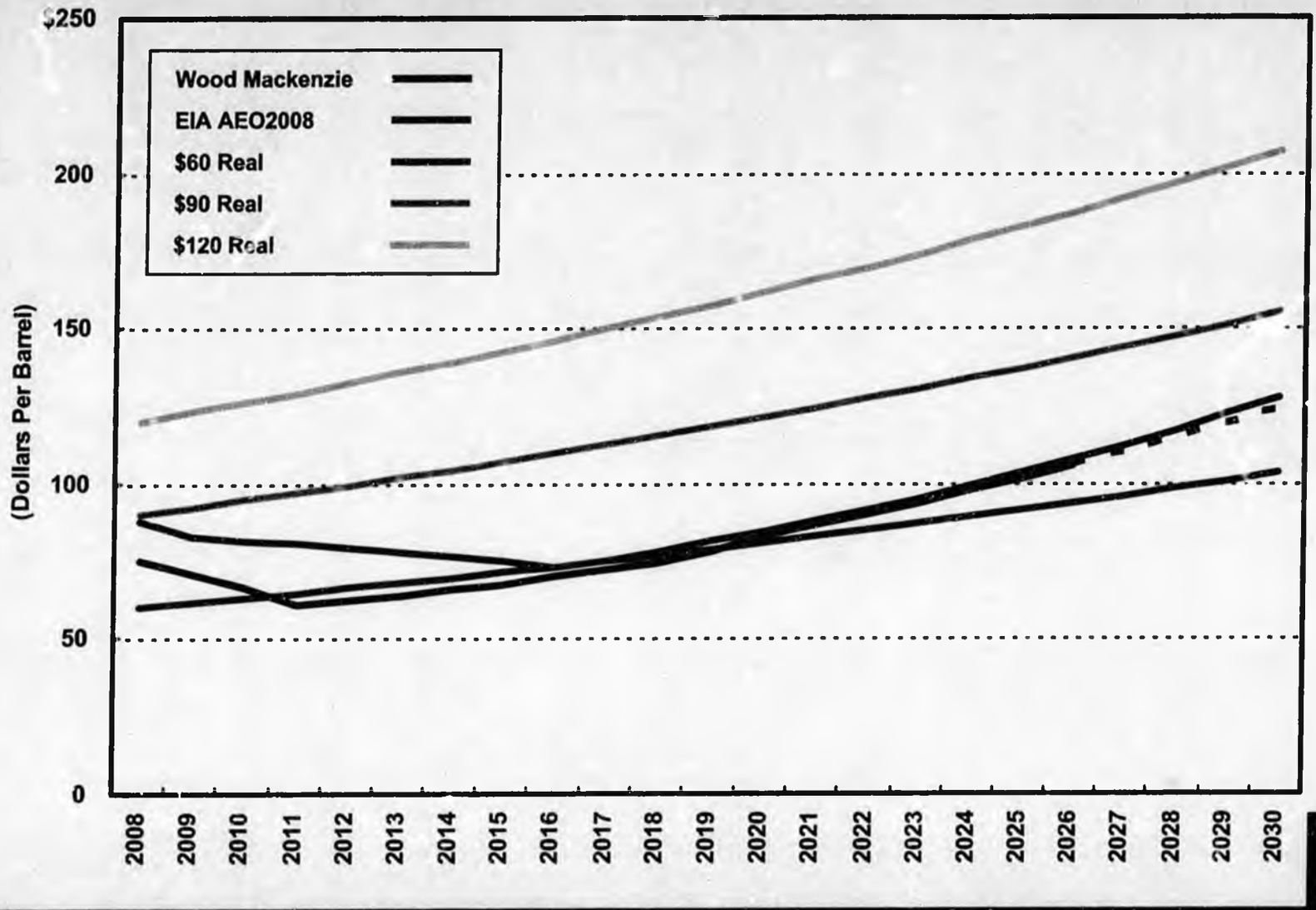
## (Relationship of Gas to Oil Prices Seen in Recent Contracts)




Source: Facts Global Energy, "Evaluating Natural Gas Import Options for the State of Hawaii", April 2007

# Oil and Gas Price Forecasts

# Oil Prices Used in Analyses

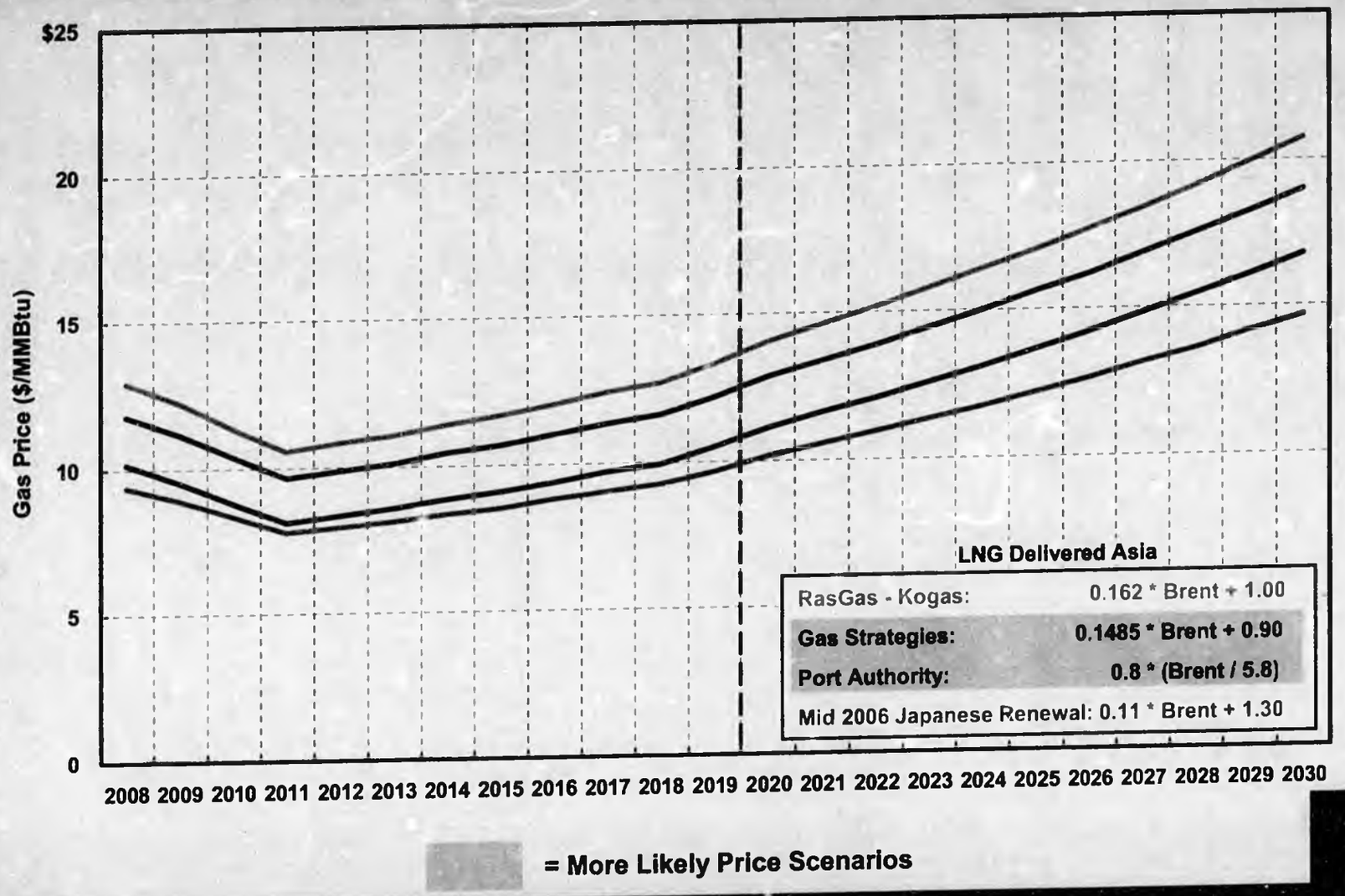



Note: 2.5% annual price inflation.

# Prospects for Asian LNG Prices

- There is a wide rage of prices depending on contract vintage
- Recent contracts have reflected stronger links to oil
- Many contracts are on a provisional basis as previously (low-priced) formulas have expired or are not applicable at current oil price levels
- Relatively high priced opportunities in Asia will attract gas supplies to that region
  - Increasingly competitive among suppliers
  - Opportunities for buyers
  - Price will be dependent on the supply situation at the time of contracts

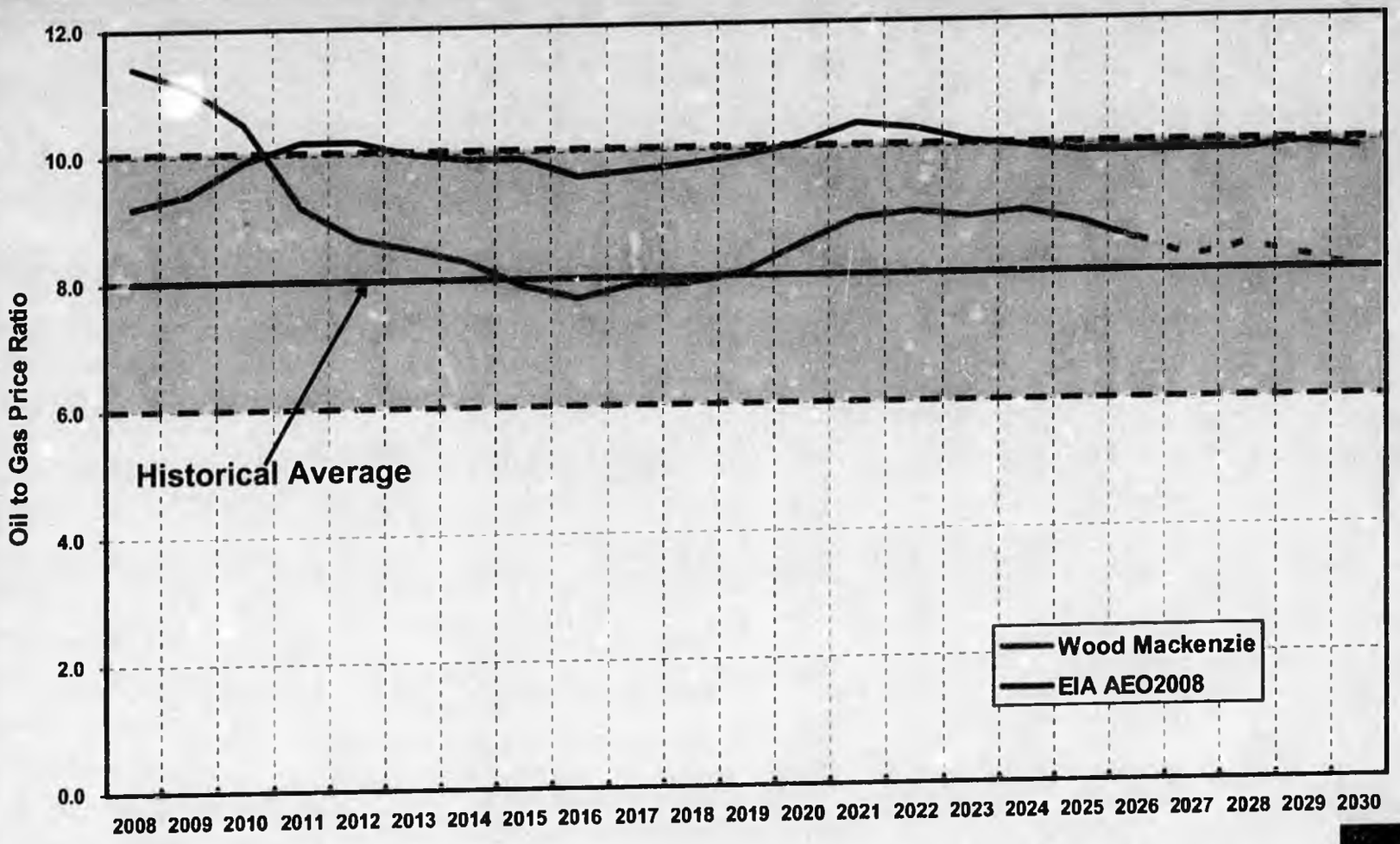
# Gas Price Forecasts Used in Analyses
## (Using Wood Mackenzie Oil Price Forecast)



# Prospects for U.S. Gas Prices

- Historically, gas has been priced between 1/6 & 1/10 the value of oil, with the long run average near 1/8
- The recent run-up in oil prices & relatively abundant domestic production of natural gas have kept that relationship above historical levels
- Many see the oil/gas relationship returning to more historical levels (i.e. convergence) as:
  - Domestic supplies decline & become more costly to produce
  - LNG imports are drawn to higher priced regions (e.g. Asia)
  - Greenhouse/carbon emission concerns put coal out of favor & put natural gas in favor as the fuel of choice for electricity generation

# Ratio of Forecasted U.S. Oil and Gas Prices

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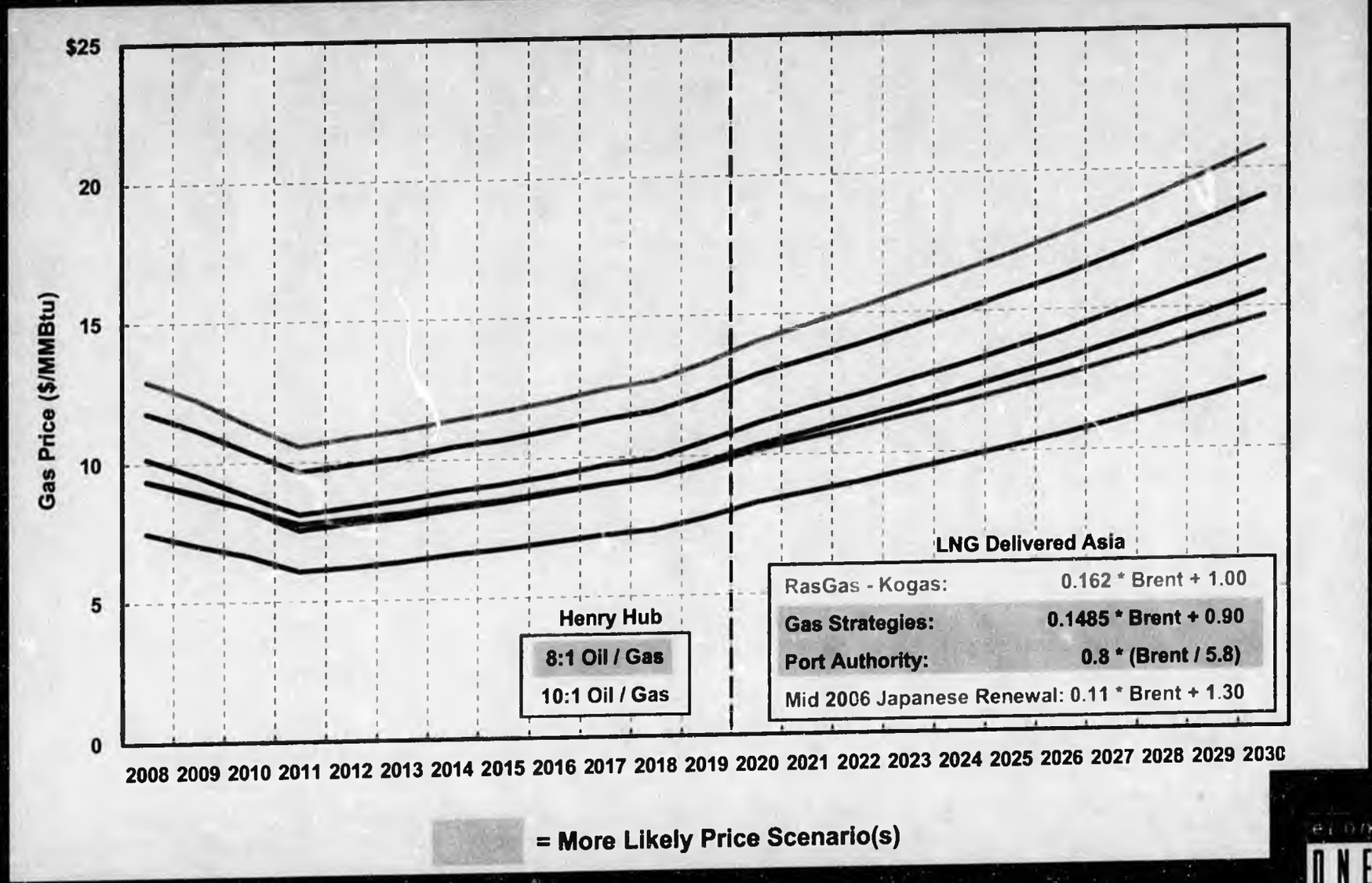
# Gas Price Forecasts Used in Analyses

## (Using Wood Mackenzie Oil Price Forecast)



# Assumptions Used in Comparative Netback Analyses

# Assumptions Used in Comparative Netback Analyses

| | |
|---|---|
| ➢ First Gas | 2020 |
| ➢ Capitalization | 70% Debt; 30% Equity (pre-operation)<br>75% Debt; 25% Equity (post-operation) |
| ➢ Debt Costs | 5.5% Guaranteed; 7.0 % Non-Guaranteed |
| ➢ Equity Returns | 14% |
| ➢ Capex/Opex | Administration (Westney): GTP & pipeline segments<br>Port Authority (Bechtel): LNG plant<br>Sensitivity at higher costs |
| ➢ Fuel Use | Administration (Westney) for GTP/pipeline segments<br>Port Authority (Bechtel) for LNG plant |
| ➢ Shipping Costs | Port Authority: Approximately $0.75/MMBtu + Fuel |
| ➢ Gas Composition & NGL Extraction | 1.118 MMBtu / mcf<br>Full Extraction @ Alberta<br>Partial Extraction @ Valdez (LNG case) |

# Comparison of Capital Costs for LNG Project

(2.7 bcf/d LNG Project)

| | Port Authority (Bechtel) | Administration (Westney) |
|---|---|---|
| GTP | $3.4Bn | $5.0Bn |
| Pipeline | $13.1Bn | $11.5Bn |
| Total GTP/Pipeline | $16.5Bn | $16.5Bn |
| LNG Plant | $7.9Bn ($470/mmta) | $12.7Bn ($755/mmta) |
| Grand Total | $24.4Bn | $29.2Bn |

# Capital Costs Used in Netback Analyses

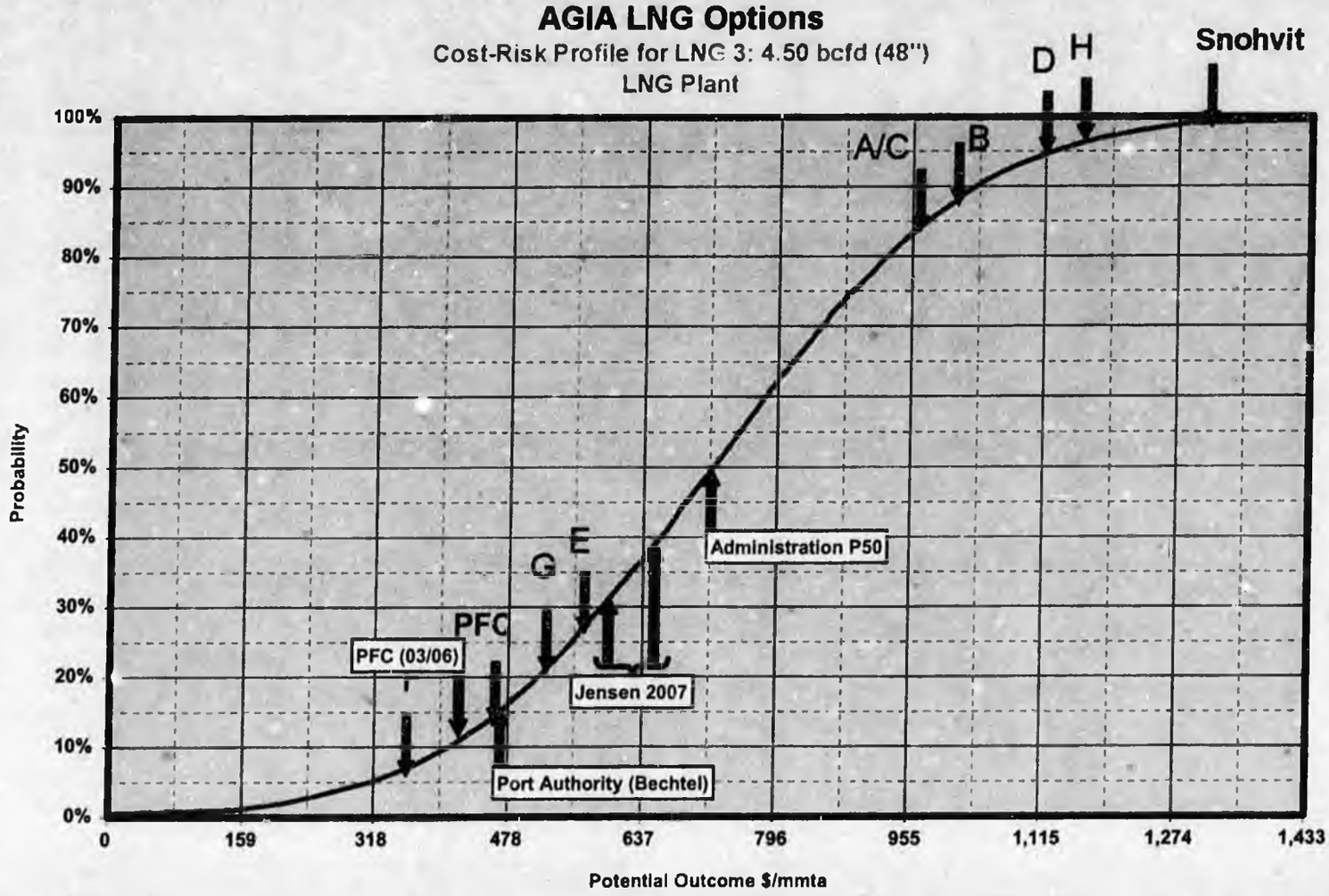
| | LNG Project | | Pipeline Project | |
|---|---|---|---|---|
| | 2.7 bcf/d | 4.5 bcf/d | 3.5 bcf/d | 4.5 bcf/d |
| | (Billion $2007) | | | |
| | (1) | (2) | (3) | (4) |
| GTP | $5.0 | $8.3 | $6.5 | $8.3 |
| Pipeline | | | | |
| Alaska | 11.5 | 12.6 | 10.2 | 10.9 |
| Canada | - | - | 11.6 | 12.6 |
| Total Pipeline | $11.5 | $12.6 | $21.7 | $23.5 |
| LNG Plant (Bechtel) | 7.9 | 13.7* | - | - |
| LNG Plant (Westney) | 12.7 | 21.1 | - | - |
| Total (Bechtel LNG) | $24.4 | $34.6* | $28.2 | $31.8 |
| Total (Westney LNG) | $29.2 | $42.0 | $28.2 | $31.8 |

* Based on $470/mt.

# LNG Plant Costs

# LNG Plant Costs Per Administration (Westney)

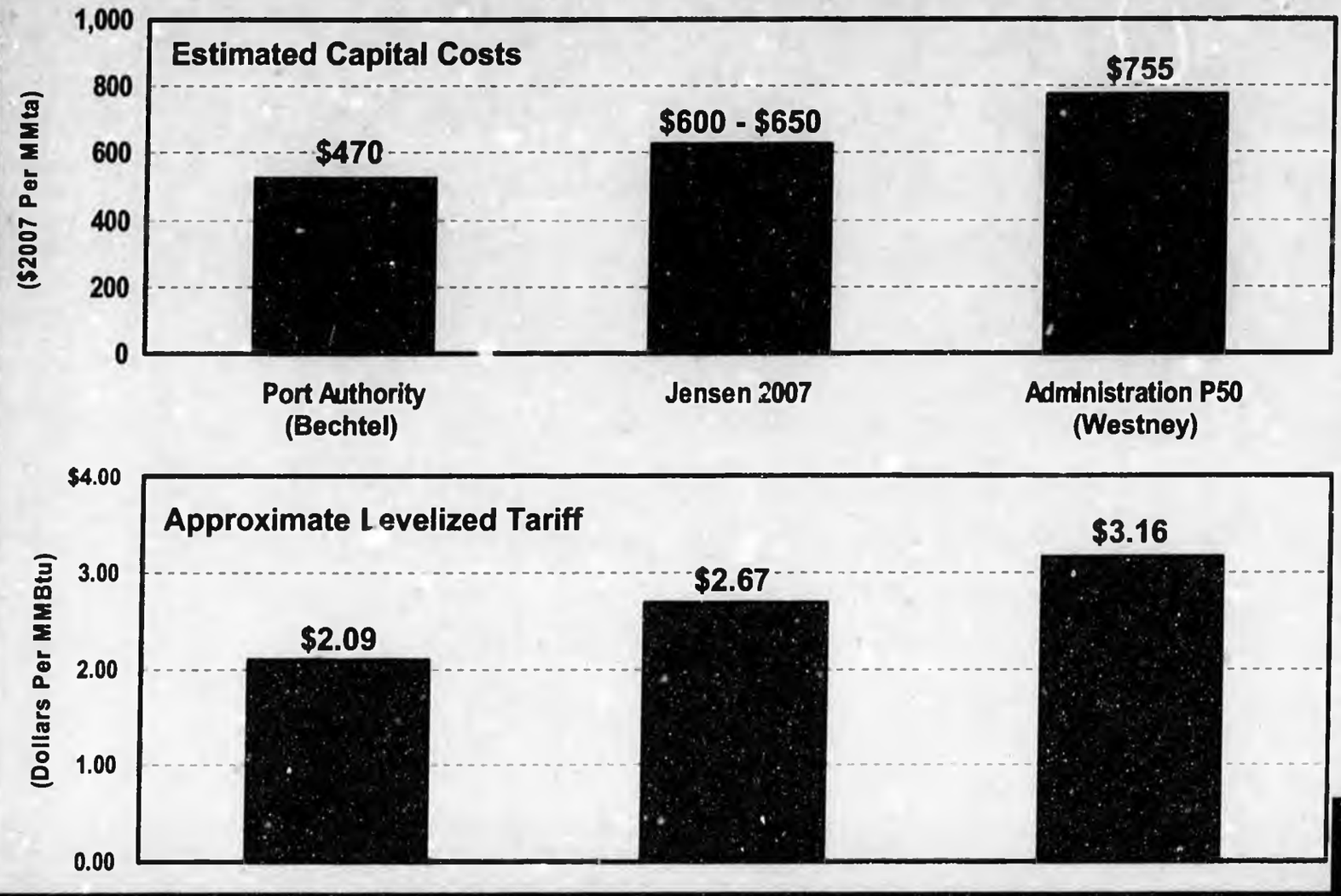
($2007 per mmta)




Source: AGIA Analysis Technical Team, "LNG Project Costs/Schedule", June 9, 2008.

# Range of LNG Liquefaction Costs and Tariffs

(2.7 bcf/d LNG Project)



# Comparison of Netback Elements

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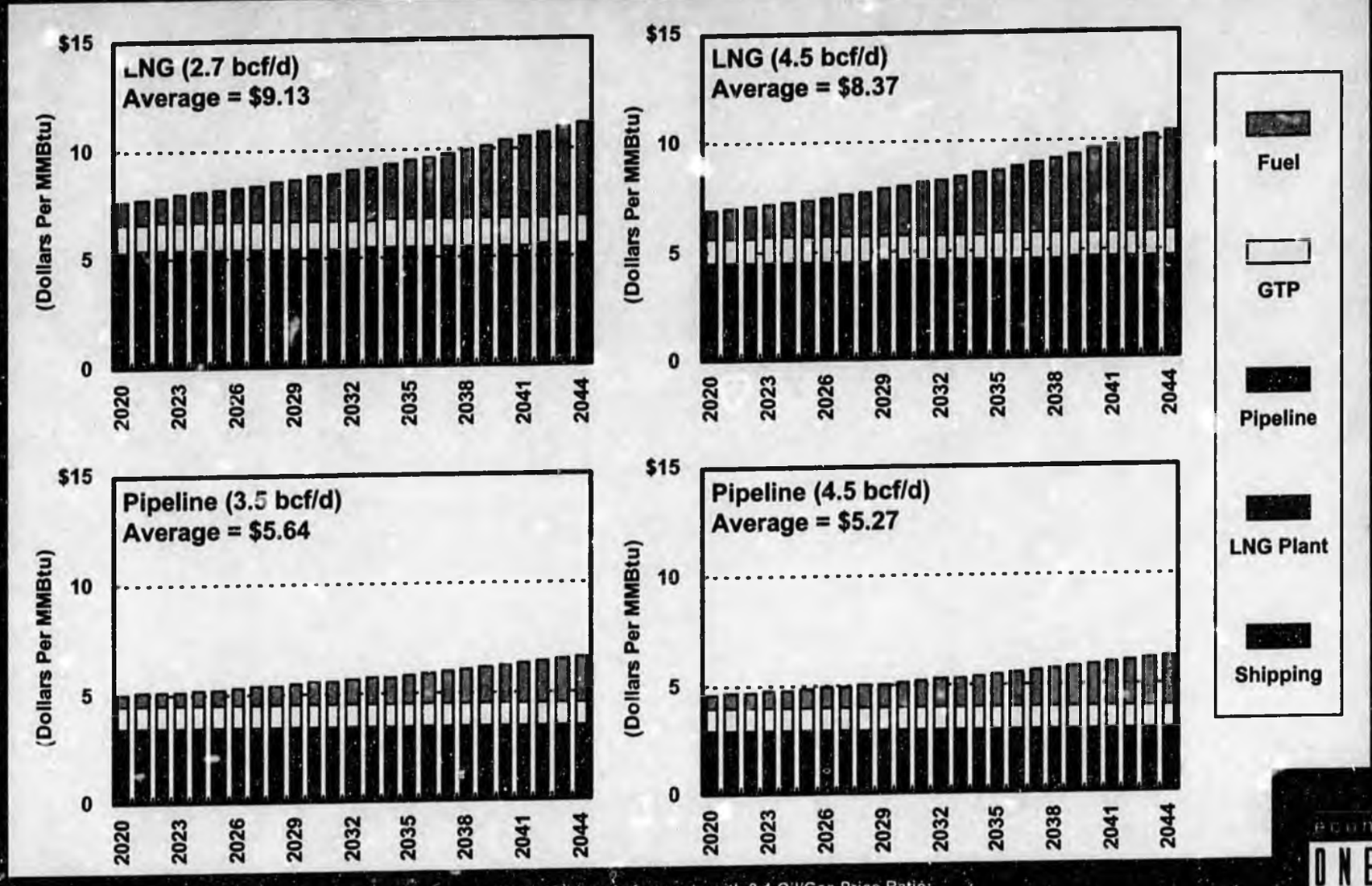
# Comparison of Potential Costs

## LNG Project v. Pipeline Project

## 2020 - 2044

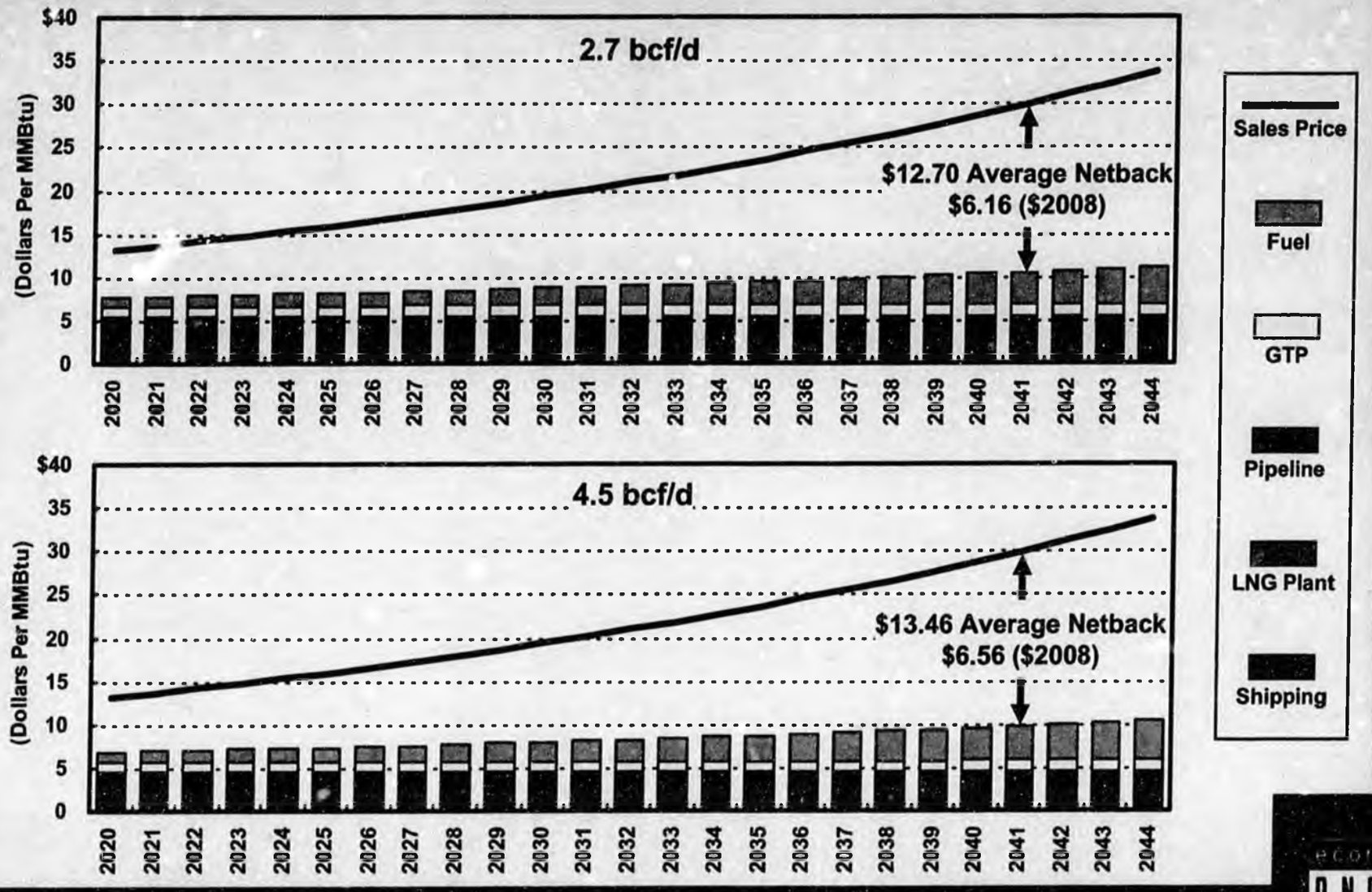



Note: Oil Prices per Wood Mackenzie forecasts with 8:1 Oil/Gas Price Ratio;
LNG Plant cost of $470/mmta per Port Authority application;
Asia Gas Price = 0.1485 x JCC + $0.90 (Gas Strategies).

# Potential Netbacks

# Potential Netbacks for LNG Delivery to Asia

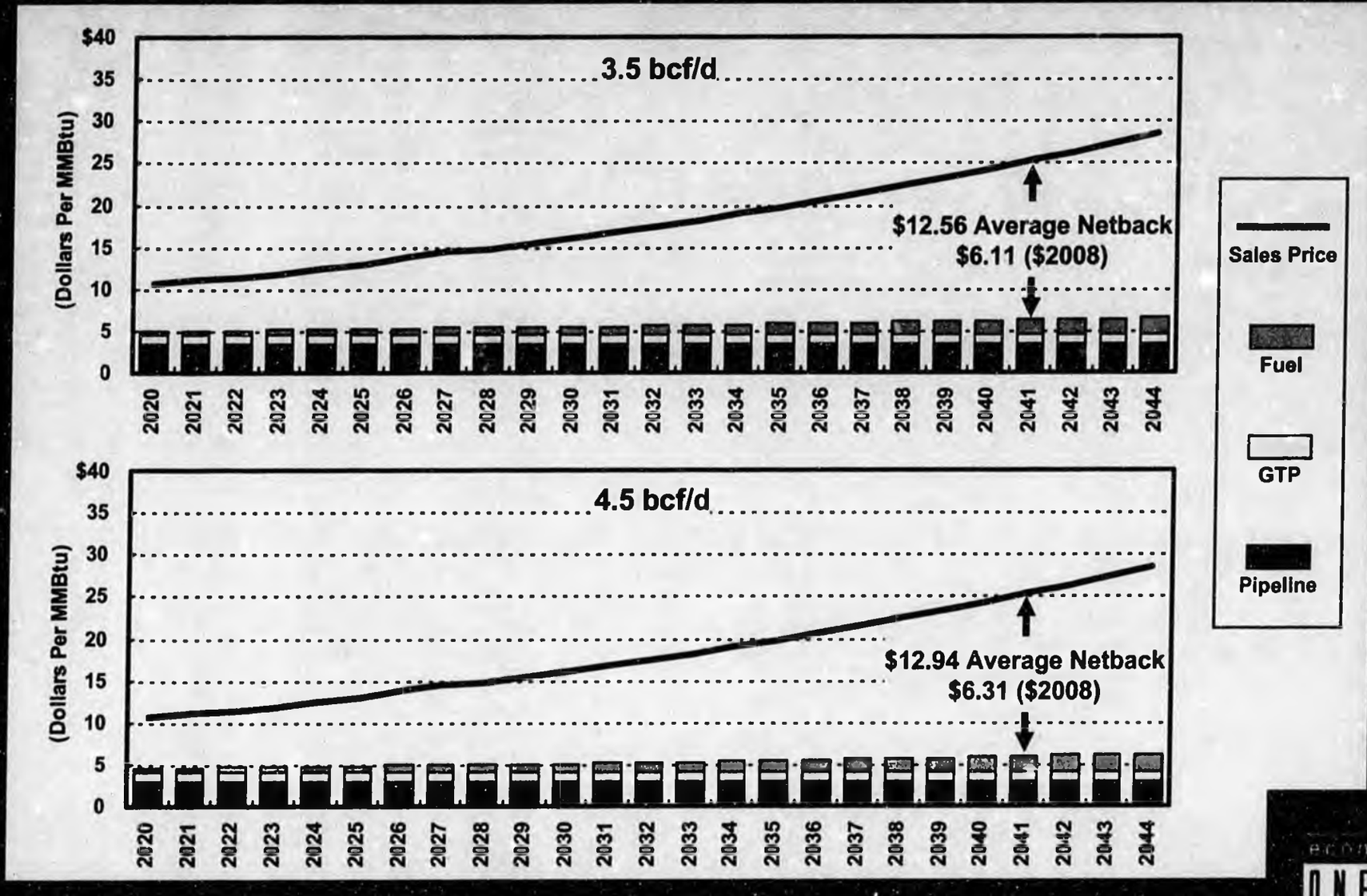
(Gas Strategies: Asia Gas Price = 0.1485 x Brent + $0.90)




Note: Oil Prices per Wood Mackenzie forecasts;
LNG Plant cost of $470/mmta per Port Authority application

# Potential Netbacks for AECO Pipeline Delivery

(8:1 WTI Oil/Henry Hub Gas Price Ratio)




Note: Oil Prices per Wood Mackenzie forecasts.

# Comparison of Projected Netbacks

## 2.7 bcf/d LNG Project
## v.
## 3.5 bcf/d Pipeline Project

# Projected Netbacks Under Alternative Projects

## (Port Authority LNG Plant Costs -- $470/mt)

### Oil Prices per Wood Mackenzie Estimates
### 2.7 bcf/d (LNG Project) v. 3.5 bcf/d (Pipeline Project)
### 2020 - 2044

| | 2.7 bcf/d LNG Project | | | | 3.5 bcf/d AECO Pipeline Delivery | |
|---|---|---|---|---|---|---|
| | High Price Asia Gas = 0.162 x Brent +$1.00 | Gas Strategies Asia Gas = 0.1485 x Brent +$0.90 | Port Authority Asia Gas = 0.8 x (Brent / 5.8) | Low Price Asia Gas = 0.11 x Brent +$1.30 | 8:1 Oil/Gas Price Ratio | 10:1 Oil/Gas Price Ratio |
| | (1) | (2) | (3) | (4) | (5) | (6) |
| Gas Sales Price ($/MMBtu) | $23.67 | $21.83 | $19.61 | $17.21 | $18.20 | $15.20 |
| Delivery Costs ($/MMBtu) (Including Losses) | (9.42) | (9.13) | (8.77) | (8.39) | (5.64) | (5.38) |
| Netback ($/MMBtu) | $14.25 | $12.70 | $10.84 | $8.82 | $12.56 | $9.82 |
| **Netback in $2008 dollars (per MMBt** | **$6.93** | **$6.16** | **$5.22** | **$4.25** | **$6.11** | **$4.75** |
| | (1) | (2) | (4) | (6) | (3) | (5) |
| Total Netback Dollars | | | | | | |
| In Nominal Dollars ($Bn) | $3[illegible].2 | $353.1 | $301.3 | $245.2 | $472.0 | $369.1 |
| In $2008 dollars ($Bn) | 192.7 | 171.3 | 145.1 | 118.1 | 229.5 | 178.5 |
| **NPV-10 ($Bn)** | **35.1** | **31.0** | **25.6** | **20.9** | **41.8** | **31.9** |
| | (2) | (4) | (5) | (6) | (1) | (3) |

= More Likely Price Scenario(s)

# Comparison of Projected Netbacks

## 2.7 bcf/d LNG Project
## v.
## 4.5 bcf/d Pipeline Project

# Projected Netbacks Under Alternative Projects

## (Port Authority LNG Plant Costs -- $470/mt)

### Oil Prices per Wood Mackenzie Estimates
### 2.7 bcf/d (LNG Project) v. 4.5 bcf/d (Pipeline Project)
### 2020 - 2044

| | 2.7 bcf/d LNG Project | | | | 4.5 bcf/d AECO Pipeline Delivery | |
|---|---|---|---|---|---|---|
| | High Price Asia Gas = 0.162 x Brent +$1.00 | Gas Strategies Asia Gas = 0.1485 x Brent +$0.90 | Port Authority Asia Gas = 0.8 x (Brent / 5.8) | Low Price Asia Gas = 0.11 x Brent +$1.30 | 8:1 Oil/Gas Price Ratio | 10:1 Oil/Gas Price Ratio |
| | (1) | (2) | (3) | (4) | (5) | (6) |
| Gas Sales Price ($/MMBtu) | $23.67 | $21.83 | $19.61 | $17.21 | $18.20 | $15.20 |
| Delivery Costs ($/MMBtu) (Including Losses) | (9.42) | (9.13) | (8.77) | (8.39) | (5.26) | (4.99) |
| Netback ($/MMBtu) | $14.25 | $12.70 | $10.84 | $8.82 | $12.94 | $10.22 |
| **Netback in $2008 dollars (per MMBt** | **$6.93** | **$6.16** | **$5.22** | **$4.25** | **$6.31** | **$4.96** |
| | ① | ③ | ④ | ⑥ | ② | ⑤ |
| Total Netback Dollars | | | | | | |
| In Nominal Dollars ($Bn) | $396.2 | $353.1 | $301.3 | $245.2 | $625.0 | $493.5 |
| In $2008 dollars ($Bn) | 192.7 | 171.3 | 145.1 | 118.1 | 304.6 | 239.5 |
| **NPV-10 ($Bn)** | **35.1** | **31.0** | **25.6** | **20.9** | **55.9** | **43.3** |
| | ③ | ④ | ⑤ | ⑥ | ① | ② |

**= More Likely Price Scenario(s)**

# Comparison of Projected Netbacks

## 4.5 bcf/d LNG Project
## v.
## 4.5 bcf/d Pipeline Project

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# Projected Netbacks Under Alternative Projects
## (Port Authority LNG Plant Costs -- $470/mt)

### Oil Prices per Wood Mackenzie Estimates
### 4.5 bcf/d (LNG Project) v. 4.5 bcf/d (Pipeline Project)
### 2020 - 2044

| | 4.5 bcf/d LNG Project | | | | 4.5 bcf/d AECO Pipeline Delivery | |
|---|---|---|---|---|---|---|
| | High Price Asia Gas = 0.162 x Brent +$1.00 | Gas Strategies Asia Gas = 0.1485 x Brent +$0.90 | Port Authority Asia Gas = 0.8 x (Brent / 5.8) | Low Price Asia Gas = 0.11 x Brent +$1.30 | 8:1 Oil/Gas Price Ratio | 10:1 Oil/Gas Price Ratio |
| | (1) | (2) | (3) | (4) | (5) | (6) |
| Gas Sales Price ($/MMBtu) | $23.67 | $21.83 | $19.61 | $17.21 | $18.20 | $15.20 |
| Delivery Costs ($/MMBtu) (Including Losses) | (8.67) | (8.36) | (8.00) | (7.60) | (5.26) | (4.99) |
| Netback ($/MMBtu) | $15.00 | $13.46 | $11.61 | $9.61 | $12.94 | $10.22 |
| **Netback in $2008 dollars (per MMBt** | **$7.33** | **$6.56** | **$5.63** | **$4.66** | **$6.31** | **$4.96** |
| | ① | ② | ④ | ⑥ | ③ | ⑤ |
| Total Netback Dollars | | | | | | |
| In Nominal Dollars ($Bn) | $724.7 | $650.3 | $560.9 | $464.1 | $625.0 | $493.5 |
| In $2008 dollars ($Bn) | 353.9 | 316.9 | 271.8 | 225.2 | 304.6 | 239.5 |
| **NPV-10 ($Bn)** | **65.3** | **58.2** | **49.0** | **40.7** | **55.9** | **43.3** |
| | ① | ② | ④ | ⑥ | ③ | ⑤ |

= More Likely Price Scenario(s)

# Sensitivities

- High Sustained Oil Prices
- Impact of Project Delay

# Projected Netbacks Under Alternative Projects

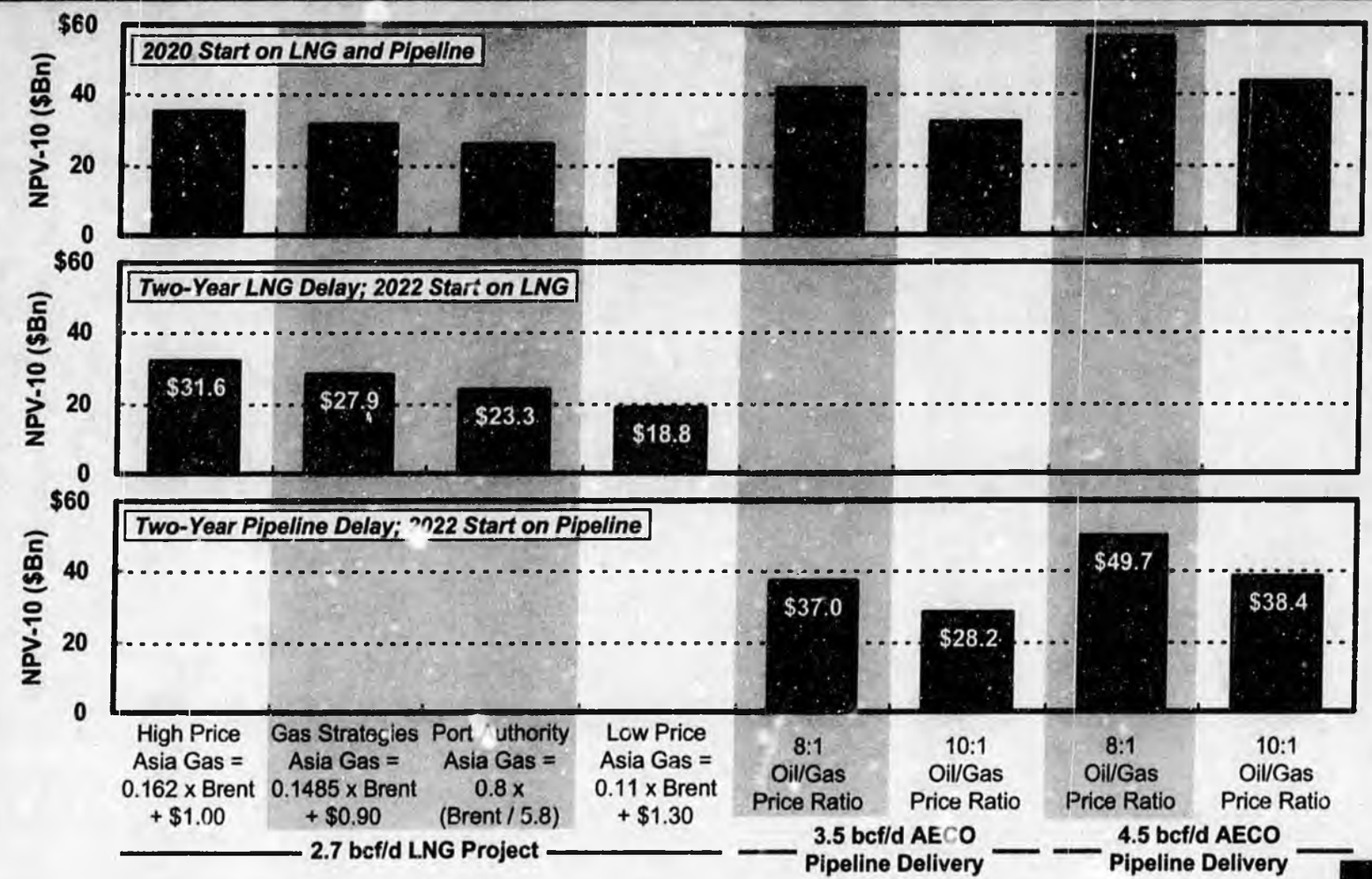
## (High Price Case: Fixed $120 Real WTI in $2008)

| Rank | Project | Pricing | GTP Inlet Netback ($/MMBtu) |
|---|---|---|---|
| (1) | (2) | (3) | (4) |
| 1 | 4.5 LNG | 0.162 x Brent + $1.00 | $25.86 |
| 2 | 2.7 LNG | 0.162 x Brent + $1.00 | 25.18 |
| 3 | 4.5 LNG | 0.1485 x Brent + $0.90 | 23.48 |
| 4 | 2.7 LNG | 0.1485 x Brent + $0.90 | 22.79 |
| 5 | 4.5 Pipeline | 8:1 Oil/Gas | 22.45 |
| 6 | 3.5 Pipeline | 8:1 Oil/Gas | 22.13 |
| 7 | 4.5 LNG | 0.8 x (Brent / 5.8) | 20.97 |
| 8 | 2.7 LNG | 0.8 x (Brent / 5.8) | 20.26 |
| 9 | 4.5 Pipeline | 10:1 Oil/Gas | 18.18 |
| 10 | 3.5 Pipeline | 10:1 Oil/Gas | 17.84 |
| 11 | 4.5 LNG | 0.11 x Brent + $1.30 | 17.24 |
| 12 | 2.7 LNG | 0.11 x Brent + $1.30 | 16.50 |

| Rank | Project | Pricing | NPV-10 Total Netback ($Billion) |
|---|---|---|---|
| (5) | (6) | (7) | (8) |
| 1 | 4.5 LNG | 0.162 x Brent + $1.00 | $126.5 |
| 2 | 4.5 LNG | 0.1485 x Brent + $0.90 | 114.6 |
| 3 | 4.5 Pipeline | 8:1 Oil/Gas | 109.4 |
| 4 | 4.5 LNG | 0.8 x (Brent / 5.8) | 101.7 |
| 5 | 4.5 Pipeline | 10:1 Oil/Gas | 88.2 |
| 6 | 4.5 LNG | 0.11 x Brent + $1.30 | 83.8 |
| 7 | 3.5 Pipeline | 8:1 Oil/Gas | 83.7 |
| 8 | 2.7 LNG | 0.162 x Brent + $1.00 | 70.6 |
| 9 | 3.5 Pipeline | 10:1 Oil/Gas | 67.0 |
| 10 | 2.7 LNG | 0.1485 x Brent + $0.90 | 63.7 |
| 11 | 2.7 LNG | 0.8 x (Brent / 5.8) | 56.2 |
| 12 | 2.7 LNG | 0.11 x Brent + $1.30 | 45.8 |

Note: LNG plant costs of $470/mmta per Port Authority.

# Impact of Potential Delays on Projects



# LNG Export Issues

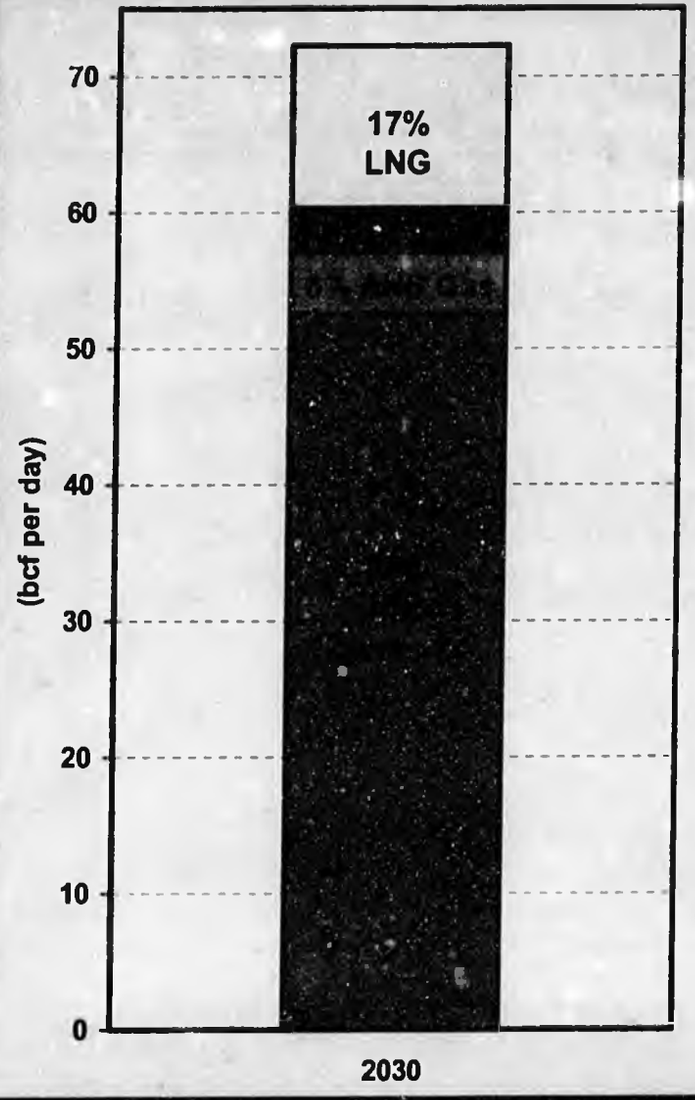
# LNG Export Issues

- Yukon Pacific permit for export
  - Issued in 1989
  - 14mmta (~1.9 bcf/d) to Japan, South Korea, Taiwan
  - 25 years from 1st gas
- Project will require D.O.E. review
  - Different project
  - Time elapsed
  - Different circumstances (e.g., U.S. is net importer of gas)
  - Political
- Is recent Kenai decision comparable?
  - Smaller / shorter window
  - No perceived issues outside Alaska
  - Lengthy multi-year process for renewal
- Experience with oil
  - Initial ban on exports
  - 1996 lifting of export ban, but too late to benefit Alaska
  - Still significant perception issue at Federal political level

# LNG Export Issues
(cont'd)

- Exports must be "in public interest"
- Pros
  - Free trade
  - Efficiency (i.e., higher netbacks)
  - Balance of payments
  - More production for Lower-48
- Cons
  - Will lead to more LNG imports
  - Will lead to more high-cost Lower-48 production
  - Will lead to higher gas prices for U.S. consumers

# Will D.O.E. Find LNG Exports in the Public Interest?




- If ANS gas is exported, it will not be available for domestic markets.
- Requires "replacement" with more expensive domestic gas or LNG imports.
- Forecasts indicate that ANS supplies @ 4.5 Bcf/day will reduce U.S. gas price by ~ $0.30/MMBtu.
- At projected US consumption of 70 bcf/d in 2030, this is ~ $7.5 billion annually.

Source: EIA AEO 2007

# LNG Export Issues
(cont'd)

- Chance of Federal intervention
  - Federal government assistance with permitting and loan guarantees in 2004 likely lead to tension re: potential of exports
  - National security concerns
  - Argument that consumers in Lower-48 would be hurt
  - Probably little Federal support for exports if Federal gas is involved
- Pipeline project must also apply for export permit
  - But, 2004 legislation specifically addresses export to Canada

# Conclusions

# Conclusions

- Gas prices is Asia are likely to maintain a premium over U.S. gas prices, though not at current levels
- U.S. prices will likely strengthen relative to Asian and European gas prices as U.S. domestic production becomes more expensive and LNG flows away from the U.S.
- LNG project would likely be viable under reasonable price scenarios, assuming gas can be exported
  - Economics of LNG delivery to U.S. West Coast would be worse than pipeline delivery under any reasonable set of assumptions
- Under the reasonable price scenarios, 2.7 bcf/d LNG project offers $/MMBtu netbacks that are similar to pipeline netbacks
  - Difference is some cases is not large relative to potential estimation error

# Conclusions
(cont'd)

- However, larger volumes for pipeline deliveries produce higher overall values (NPV) for resource owners under more likely price scenarios
  - 3.5 bcf/d pipeline > 2.7 bcf/d LNG by $11Bn to $16Bn
  - 4.5 bcf/d pipeline > 2.7 bcf/d LNG by $25Bn to $30Bn
- LNG project would produce somewhat higher NPVs if in the long run:
  - Oil prices stay high
  - Gas/Oil price ratio in Asia stays strong
  - Gas/Oil price ratio in U.S. remains weak
  - LNG can be exported and project advances at some time earlier than the pipeline

# Conclusions
(cont'd)

- Gaining Federal permission to export LNG to Asia will likely be very difficult
  - D.O.E. permission
  - Potential Federal legislation
- Export via Y-line will face similar challenges
- Federal acceptance of exporting may be more favorable if majority of gas is already flowing to U.S. markets
  - But don't count on it
  - Oil experience along those lines was not particularly favorable

# Conclusions
(cont'd)

- Impact of potential delays
  - Delay in pipeline relative to LNG does not change results under more likely price scenarios
- Does the State have to choose between the two projects?
  - Market-based outcome is more favorable
  - Shippers can nominate to LNG project if they see it is more economic
  - Potential buyers of LNG can go "upstream" and negotiate to buy gas
  - Economics of LNG relative to pipeline not compelling enough to suggest that the State needs to "intervene" to make LNG happen at expense of pipeline

ENSTAR
Natural Gas Company

# Special Session
## Anchorage, Alaska
## June 20, 2008

Gene Dubay, SVP & COO
Continental Energy Systems

Colleen Starring, Regional Vice President
ENSTAR Natural Gas Company

# Who We Are – ENSTAR Facts

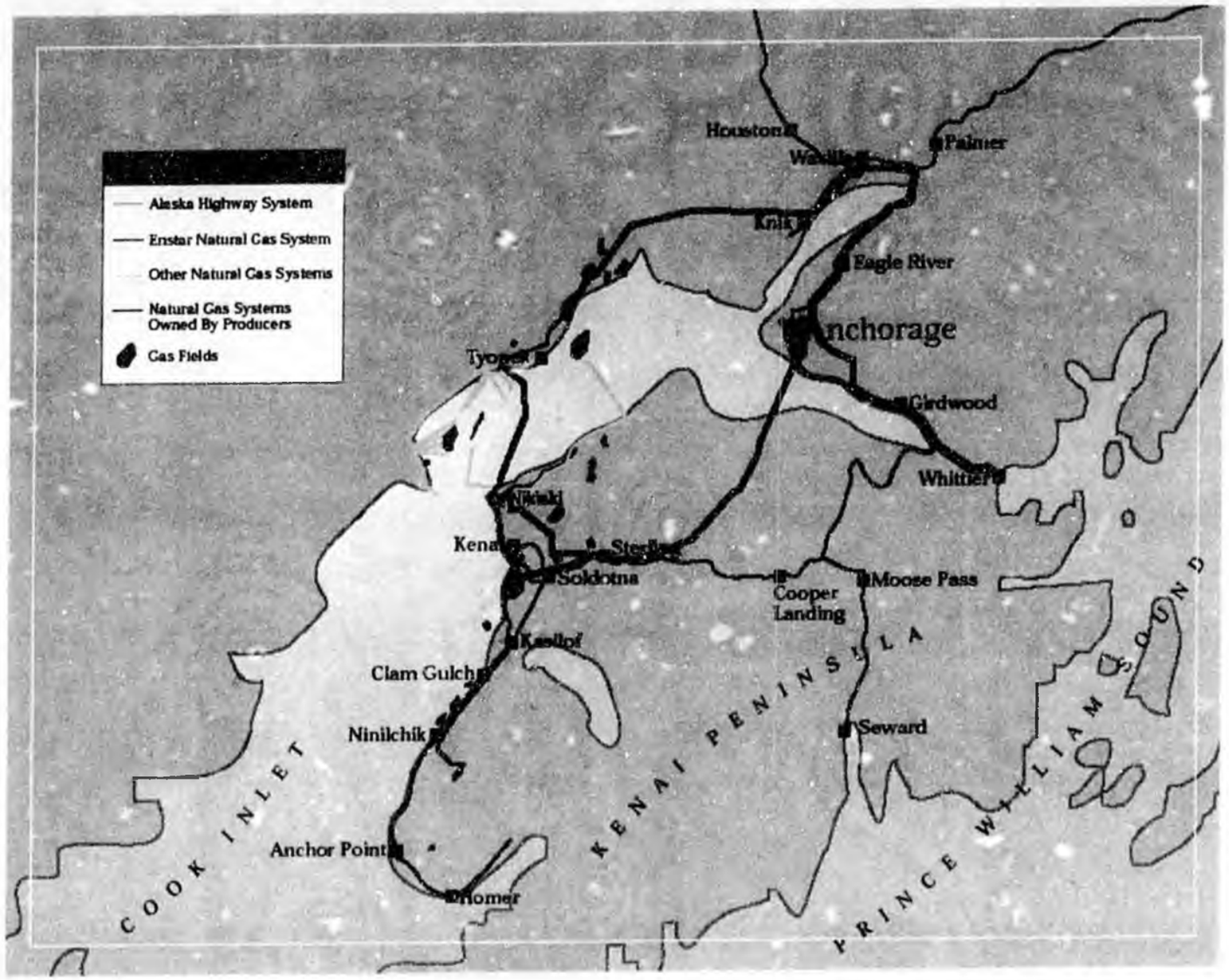
- Established 1961
- Number of Meters – 128,000+
- Number of Alaskans Served* - 345,600
- Miles of Distribution Mains and Transmission Mains – 3,100
- Direct Impact on Alaska's Economy - $306 mil
- Number of ENSTAR Employees – 174
- Rank among Alaskan energy Utilities – 1
- New Customers in 2007 – 2,376

*** 128,000 Meters x 2.7 Alaskan Consumers per Meter**

# ENSTAR
# (Alaska Pipeline Company)

- Engineering/Construction
- 47 Years of Experience in Alaska
- Constructed and Operates 450 miles of Transmission Mains and 2700 miles of Distribution Mains
  - Represents 75% of all gas transmission pipelines in Alaska
  - Represents 100% of distribution mains in South-Central Alaska
- Expertise
  - Compression Plant Engineering & Construction
  - Pipeline Engineering
  - Environmental/Permitting
  - Construction Management

# South Central Gas Distribution




ENSTAR Natural Gas Company

*All Our Energy Goes Into Our Customers*

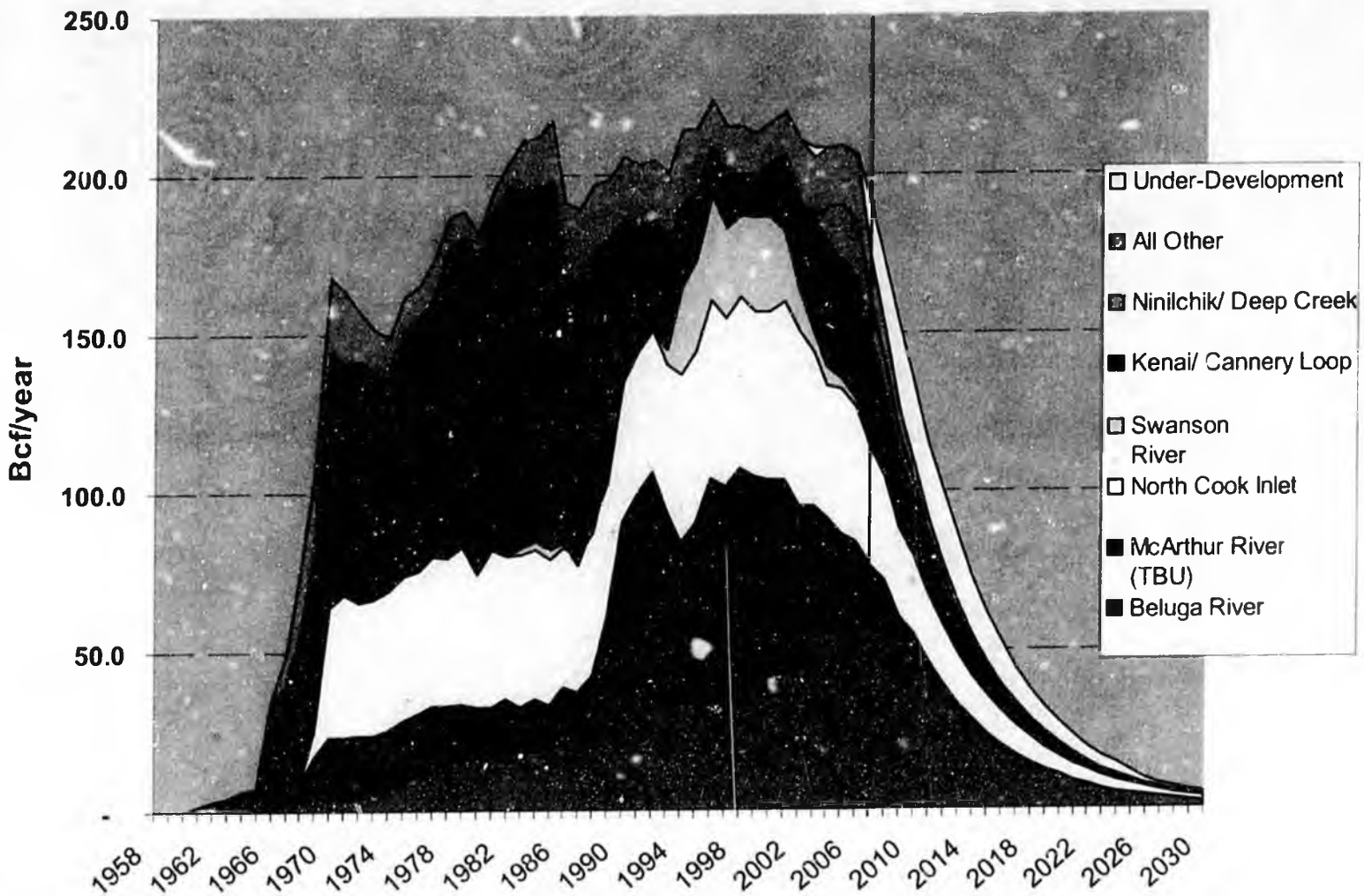
ENSTAR
Natural Gas Company

# ENSTAR In-State Pipeline
# Phase One

# Historic & Projected Natural Gas Production

## (Bcf/Year)

Source: Division of Oil & Gas Report 2006




ENSTAR Natural Gas Company

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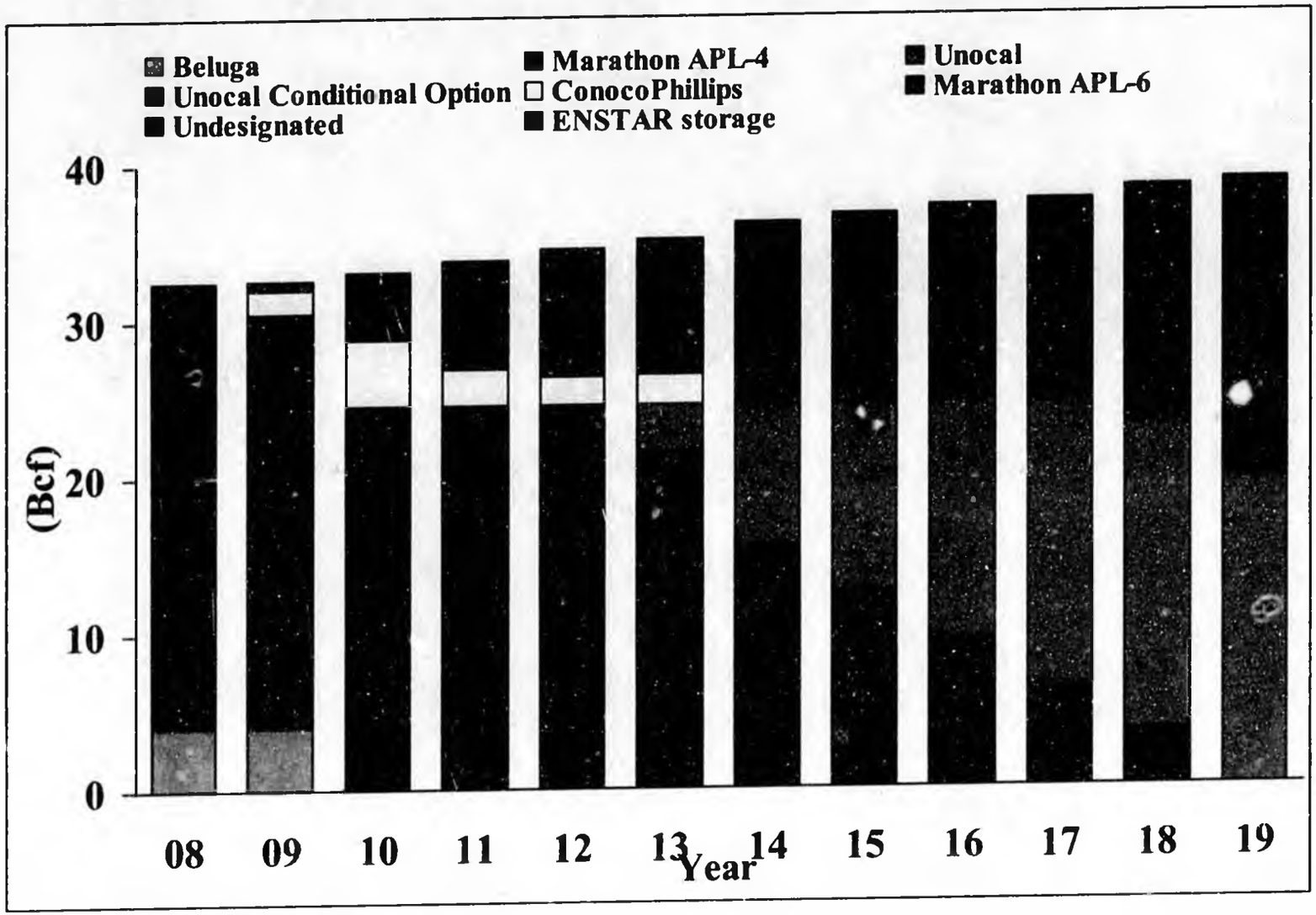
# Gas Supply – April 2008 Outlook

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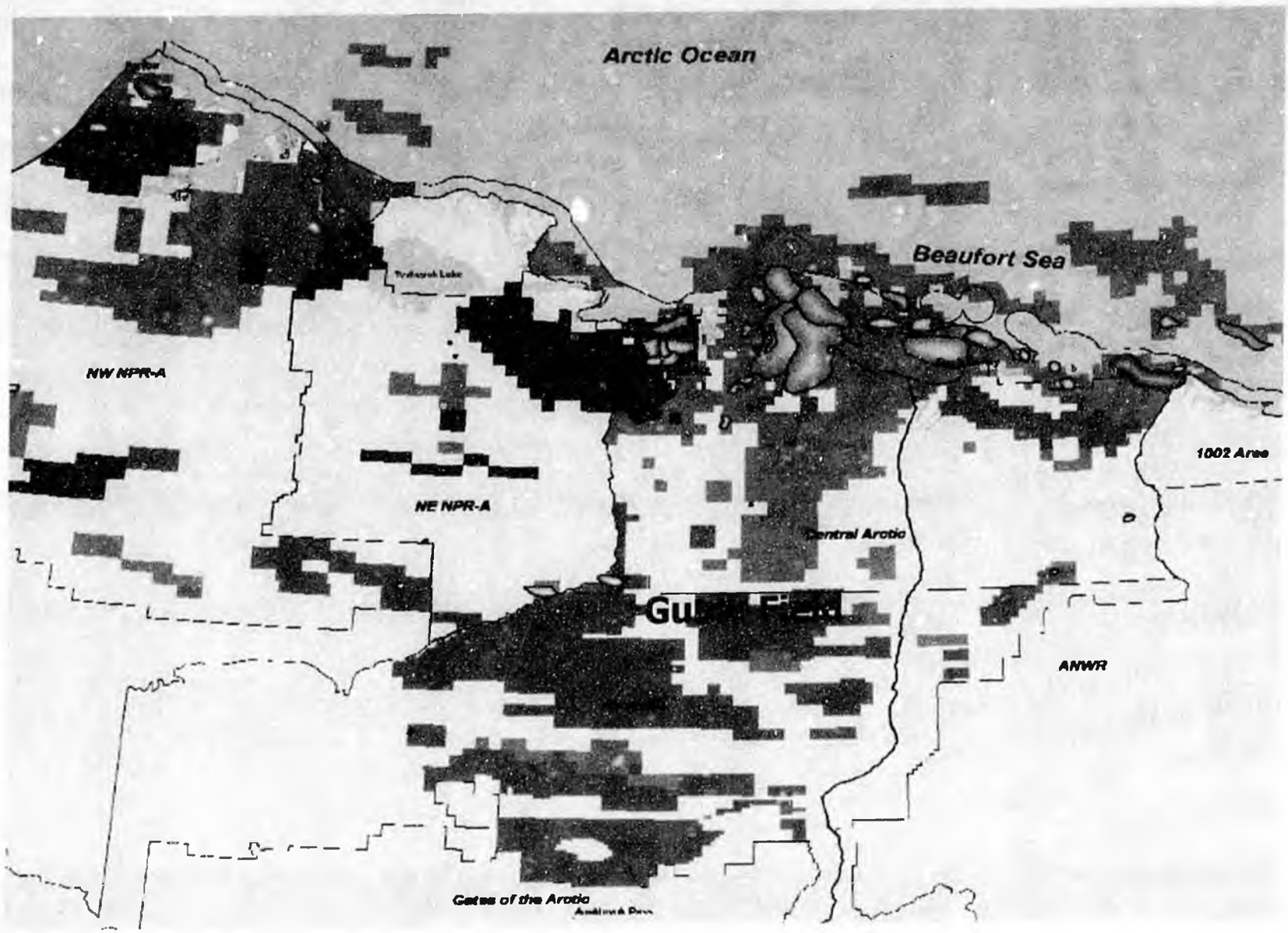
# Foothills Unit Area Map

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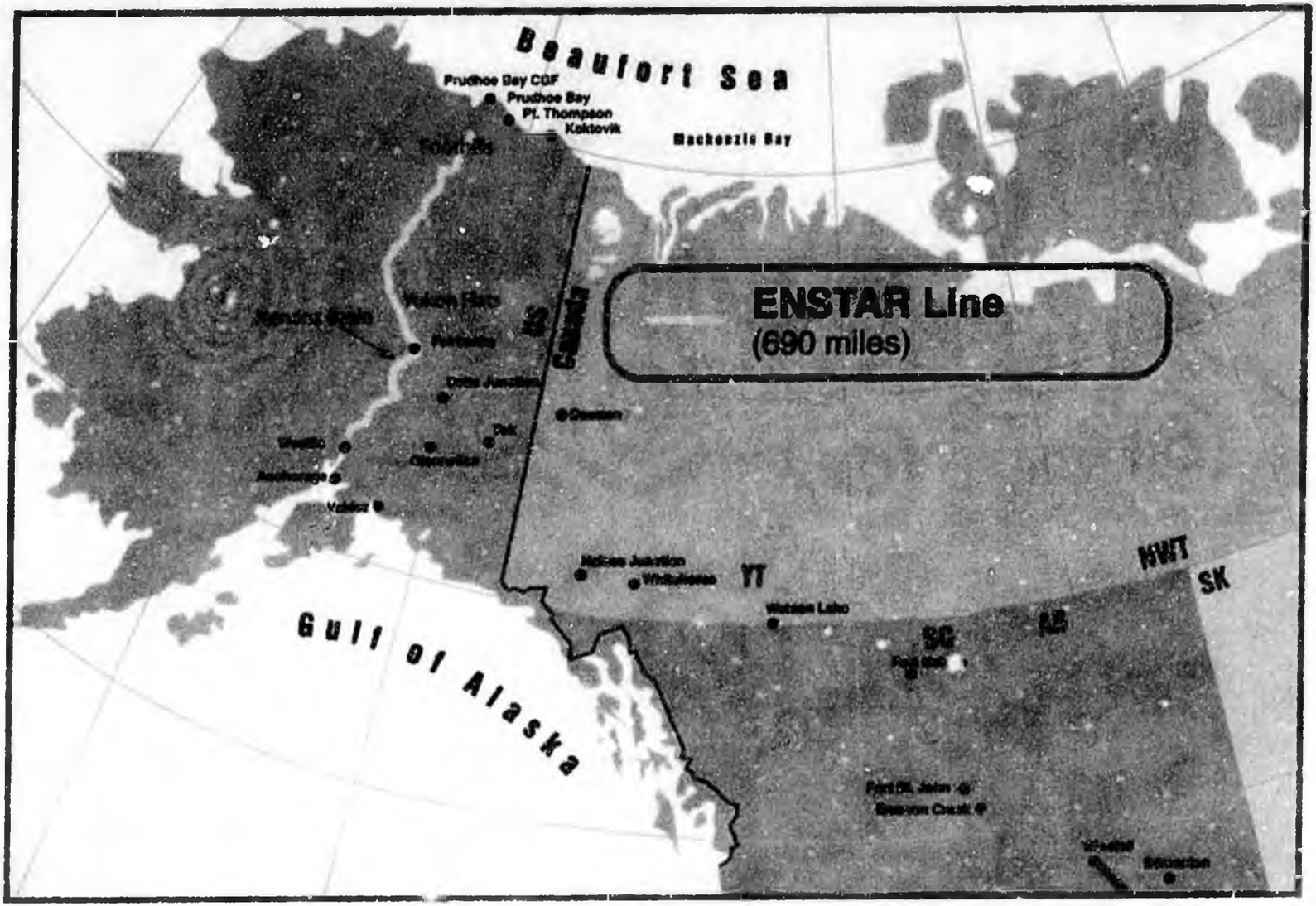
# ENSTAR Line

## Natural Gas for South Central Alaska

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# Pipeline Route & Cost

## Cook Inlet to Fairbanks

- Approximately 320 Miles — Cost $970 million
- Parks Highway Route

## Fairbanks to the Foothills

- Approximately 370 miles — Cost $2.3 Billion
- Dalton Highway Route

**Total Project Cost - $3.3 Billion for 20" Diameter**

Project Timeline – 5-6 Years

2-3 Years of Permitting, Design & Procurement

3 Years of Pipeline Construction

ENSTAR Natural Gas Company

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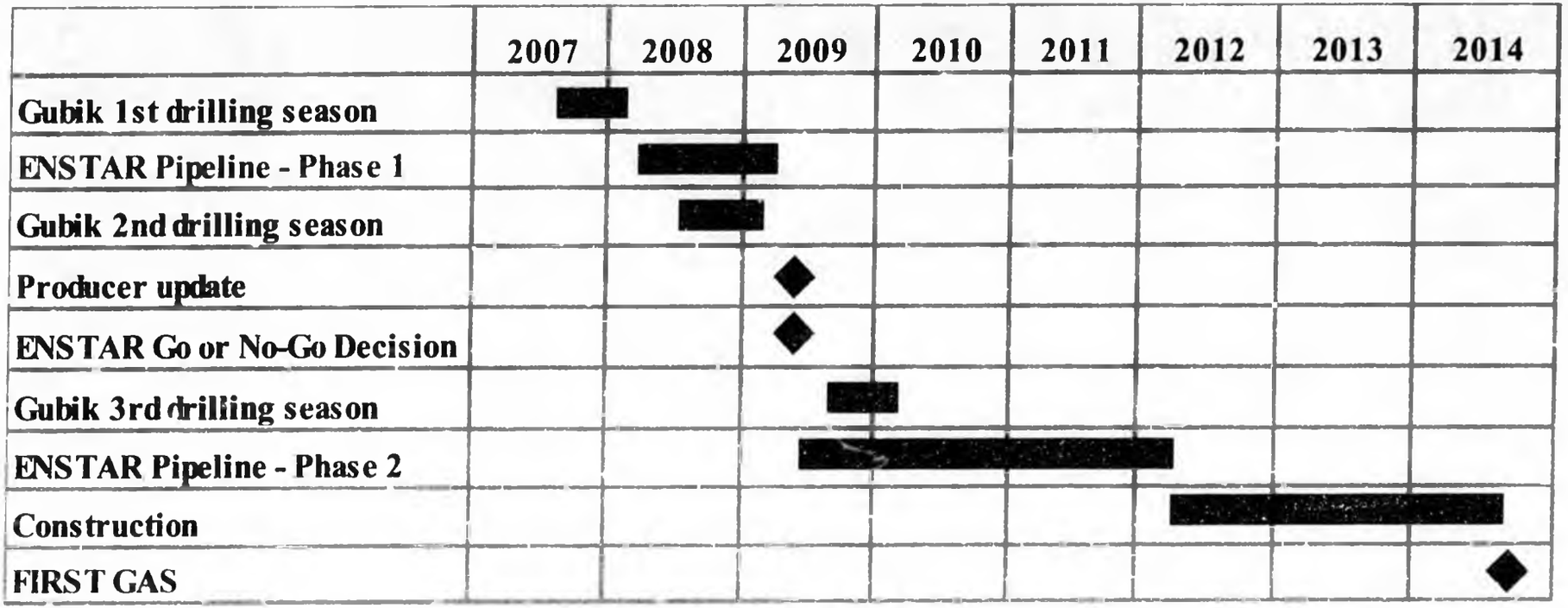
# Foothills Natural Gas Milestones

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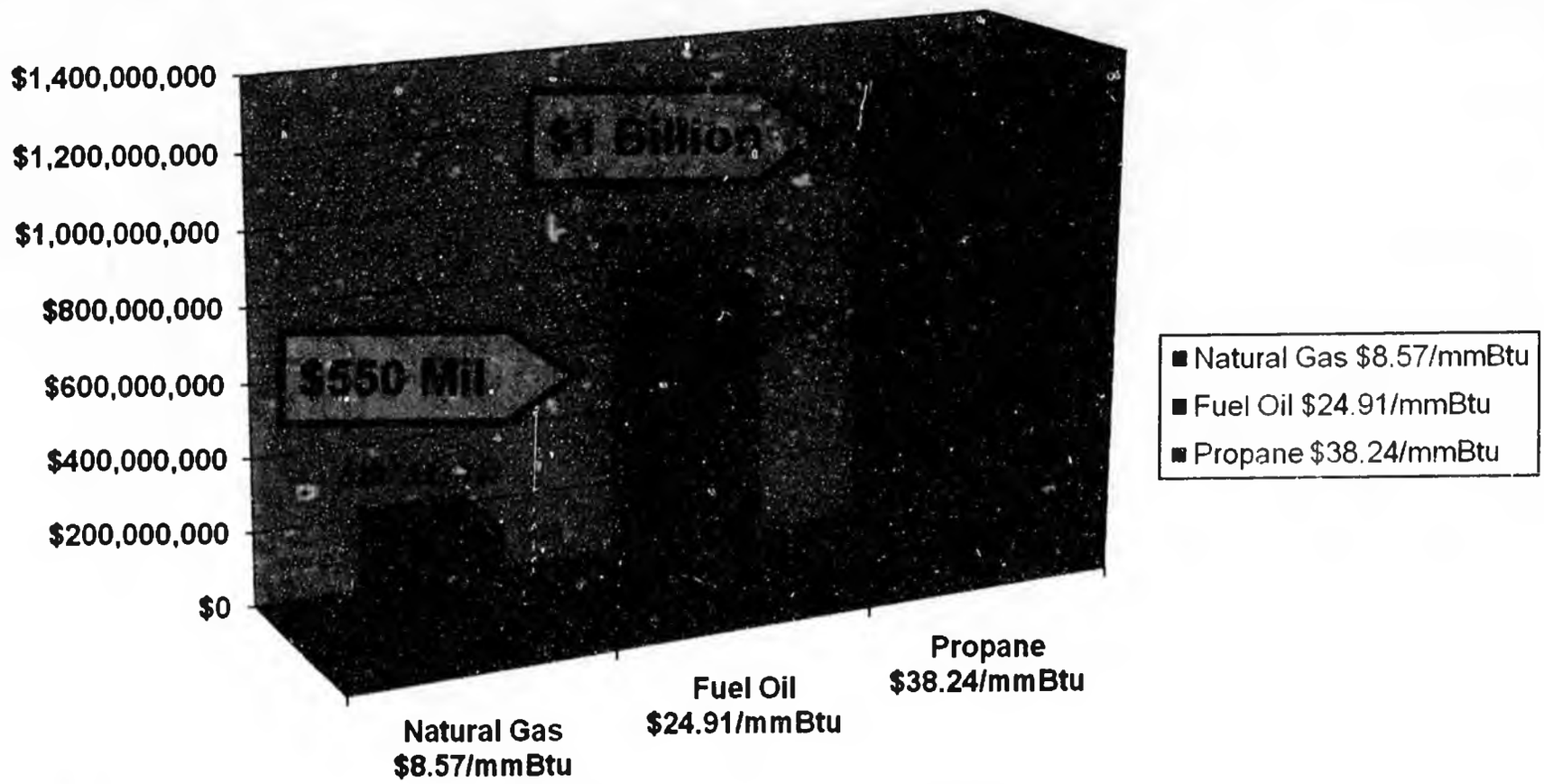
# Advantages of the ENSTAR Line

- Timing (First gas 2014)
- Alaska controls its' own destiny
- Long-term supply solution for the Railbelt communities
- Not mutually exclusive with pipeline to Lower 48
- Compliments AGIA and the DENALI project
- Could revive Agrium plant
- Could extend life of Kenai LNG plant
- Creates opportunities for natural gas-based industrial growth in South Central Alaska
- In-state markets qualify for lower tax burdens under Alaska's ACES
- Achieves reasonable end user pricing for Alaskans
- Ensures sufficient wellhead prices for exploration & development

# Cost to Consumer

## Switching to Alternative Fuels in South Central Alaska

(2008 costs)



# Accessible In-State Market

- ENSTAR
- South-Central Electric Companies
  - Chugach, MLP, MEA, HEA
- Fairbanks Natural Gas
- Military Bases
  - Elmendorf AFB & Fort Richardson
  - Eielson AFB & Fort Wainwright
- Golden Valley Electric
- Tesoro Refinery
- Flint Hills Refinery
- Agrium
- LNG Export

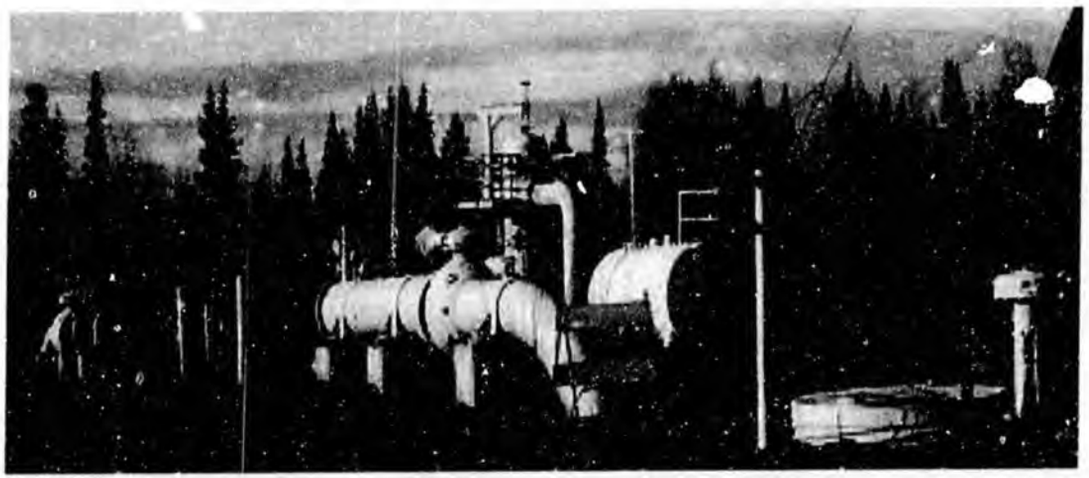
# ENSTAR Pipeline Study

## Throughput and Load Estimates

| Load Profile MMcfd | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| ENSTAR | 93.710 | 95.110 | 96.540 | 97.990 | 99.460 | 100.950 |
| South-Central Electric Companies | 57.000 | 47.200 | 49.200 | 51.200 | 52.200 | 53.200 |
| Fairbanks NG | 6.000 | 10.000 | 18.000 | 20.000 | 21.000 | 22.000 |
| Military Bases and Additional Commercial | 13.000 | 13.000 | 14.000 | 14.000 | 14.000 | 14.000 |
| Golden Valley Electric | 8.770 | 8.770 | 8.770 | 8.770 | 17.530 | 17.530 |
| Tesoro Refinery | 11.000 | 11.000 | 11.000 | 11.000 | 11.000 | 11.000 |
| Flint Hills Refinery | 13.700 | 13.700 | 13.700 | 13.700 | 13.700 | 13.700 |
| Agrium, Inc. | 131.510 | 131.510 | 131.510 | 131.510 | 131.510 | 131.510 |
| LNG Export | 134.250 | 134.250 | 134.250 | 134.250 | 134.250 | 134.250 |
| Total | 468.930 | 464.530 | 476.960 | 482.410 | 494.640 | 498.140 |

# Assumptions

- Project based on utility grade gas
- 20" diameter high grade steel pipeline
- Operating pressure ~2500 psi
- Operating pressure & design allow for additional hydrocarbon spiking



# Current ENSTAR Pipeline Status

- Contracted engineering, environmental, and construction companies to assist with the project
- Update meetings scheduled with Anadarko in Alaska July 15th
- Aerial Photography
  - **Southern Route (FBX to Big Lake)**
    - Approximately 70% of data has been acquired
    - Data processing is just beginning – complete by Aug 31, 2008
  - **Northern Route (North Slope to Fairbanks)**
    - All data has been acquired
    - Processing will be complete in approximately 30-days
- LIDAR Data
  - Approximately 90% of data has been acquired
  - Processing complete by July 11, 2008
- Field Work
  - Work is underway – numerous trips for route reconnaissance, river crossing investigations, pinch point investigations, geotechnical studies, seismic studies, constructability, etc, will occur between now and October 2008.

# Current ENSTAR Pipeline Status

- Agency and Stakeholder Communications
  - Initial communications have occurred with the following agencies or organizations: BLM/JPO, (three regions), ADOT (both Northern and Southern Regions), COE, DNR, National Park Service, NGO's (including National Parks Conservation Association, Alaska Center for the Environment, Trustees for Alaska, and Defenders of Wildlife), CIRI, Doyon, Alyeska Pipeline Service Company, and Conoco Philips.
  - Communications are planned with Fairbanks Northstar Borough, Denali Borough, Mat-Su Borough, Fish and Wildlife, University of Alaska, EPA, USGS, Mental Health Trust, AHTNA, and others.

- Data Gathering
  - Research data is being gathered and stored to a project library. To be used as reference material for the project. Data includes geotechnical, seismic, environmental, regulatory, engineering, and construction design information.

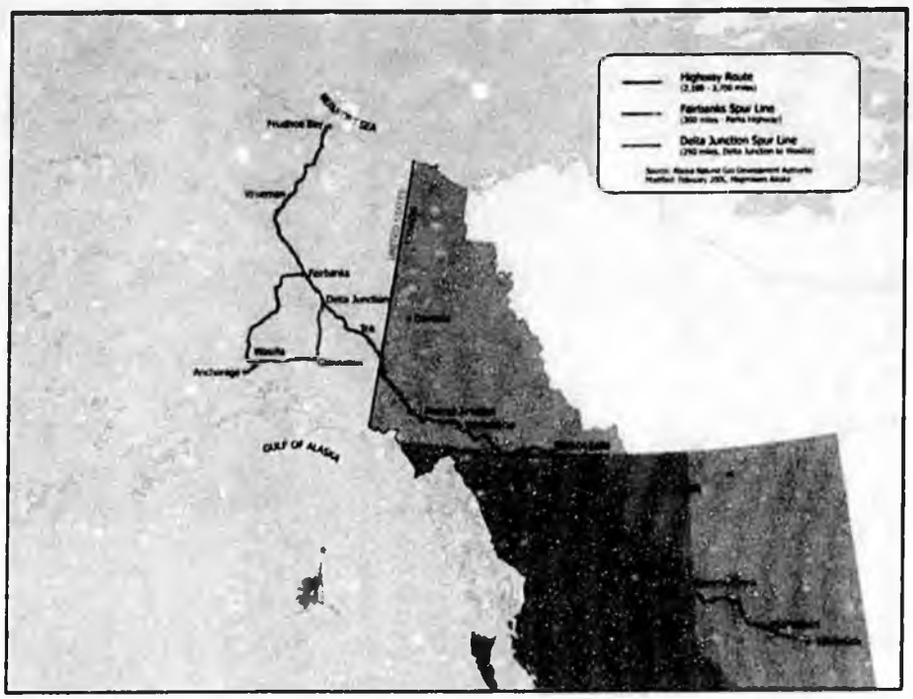
- Document Management System
  - DMS developed to store data (GIS, environmental, regulatory) relevant to the project. Data is stored and is available for all entities that are involved with the project.

# Development Plan Priorities

- Continue regulatory permit acquisition
- Prepare economic & financial models
- Address environmental work
- Public outreach & public involvement
  - Alaska Support Alliance, Fairbanks Economic Development Corporation, Rotary Clubs, South Central Chambers, ASRC, CIRI, Doyon, KTUU, KTVA, Anchorage Daily News, Fairbanks Daily News Miner, Peninsula Clarion, Talk Radio Programs, Platts Gas Daily
  - Continued updates planned
- State ROW application preparation

# Questions and Comments

# Alaska Natural Gas Needs and Market Assessment: 2008 Update of the Industrial Sector




Prepared by
Science Applications International Corporation

For
Alaska Natural Gas Development Authority (ANGDA)

June 2008

## Technical Contributors - SAIC

Charles P. Thomas: Project Manager, Anchorage, Alaska.
Chris Ellsworth: Project Manager, McLean, VA
Christina Davies Waldron
David Friedman
Delma Bratvold

**Disclaimer**

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In preparing this report, SAIC has relied on verbal and written information provided by secondary sources and interviews, including information provided by customer. Because the assessment consisted of evaluating a limited supply of information, SAIC may not have identified all potential items of concern and/or discrepancies and, therefore, SAIC warrants only that project activities under this contract have been performed within the parameters and scope communicated by ANGDA and reflected in the contract. SAIC has made no independent investigations concerning the accuracy or completeness of the information relied upon.

## Table of Contents

# Alaska Natural Gas Needs and Market Assessment: 2008 Update of Industrial Sector

## 1.0 Purpose

The objective of this report is to provide an updated assessment of the potential value of gas-intensive industries in South Central Alaska if a pipeline is constructed that provides Alaska North Slope (ANS) gas to this region. The original study, *Alaska Natural Gas Needs and Market Assessment*, was conducted for the US Department of Energy, National Energy Technology Laboratory, and released in April 2006. The 2006 Study addressed gas supply and demand from all sectors in Central and South Central Alaska, including residential, commercial, power, and industrial needs. Industrial demand included both gas-intensive industries (i.e., LNG, fertilizer, petrochemical, GTL, and LPG), and other industries for which demand is primarily for power. An investment model was applied to assess potential gas-intensive industries, which are particularly sensitive to their feedstock (i.e., gas) prices. Since 2006, oil, natural gas, and product prices have risen considerably, both domestically and internationally, requiring an update to the financial modeling previously performed for gas-intensive industries.

## 2.0 Key Findings

The results of this study suggest the following key findings:

- The recent rise in natural gas and product prices has improved feasibility of the assessed natural gas-intensive industries in South Central Alaska.
- Under base case price assumptions, petrochemicals and liquid petroleum gas (LPG) are potential sources of large increments of natural gas liquids (NGL) demand. They could provide an additional 127,000 barrels per day (bbl/d) of NGL consumption, 201 million cubic feet per day (MMcf/d) of gas equivalent.
- Both the current liquefied natural gas (LNG) export facility in Nikiski and a greenfield gas-to-liquids (GTL) plant may require sales contracts in premium markets for economic feasibility under the low price scenario. Natural gas demand from these industries is estimated at 375 MMcf/d and 464 MMcf/d for LNG and GTL, respectively.
- The investment climates for all assessed industries will remain highly uncertain given ongoing volatility in energy and product prices.
- The greatest uncertainty is associated with GTL due to the combination of evolving market, costs, and technology.

## 3.0 Scope and Assumptions

### 3.1 Gas Pipeline Operation

Natural gas and natural gas liquids (NGL) demand by industry is assessed based on the assumption of a dense-phase wet gas line that delivers ANS natural gas and NGL to South Central Alaska through a spur pipeline that branches off from the proposed Alaska Natural Gas Pipeline (ANGP) that would transport natural gas from the ANS to Canada and the Lower 48 States. The gas-intensive industries assessed in this report are assumed to be located in South Central Alaska due to expected lower operating and capital costs and proximity to export terminals and major trade routes.[1] As determined in the 2006 Study, an NGL-rich stream will generate the greatest level of industrial demand in Alaska.

The route of the pipeline to South Central Alaska is not determined in this update. However, for the purpose of modeling the pipeline tariff, it is assumed that the Alaska Natural Gas Pipeline (ANGP) from ANS to the Lower 48 States is constructed with the spur line branching off in Central Alaska (e.g., Delta Junction, or Fairbanks). As in the 2006 Study's largest wet gas pipeline scenario, pipeline capacity from the ANS to Central Alaska is at least 4.5 Bcfd, and the spur line capacity is approximately 1 Bcf/d, with operations commencing in 2015.

Also as in the 2006 Study, the wet gas spur line is assumed to be enriched with NGL extracted at a separator plant in Central Alaska. Surplus dry gas from the separator (i.e., in excess of South Central needs) is then re-injected into the ANGP for delivery to the Lower 48 States. The extracted NGL are assumed to be transported through a spur line to meet demand from two, new South Central industries: petrochemicals and LPG. The amount of enrichment in the spur line is adjusted based on the main line gas composition to meet the industrial demand for ethane (i.e., the petrochemical industry). In contrast, the LPG industry demand is adjusted based on the average gas composition in the ANGP from the ANS, and the resulting amount of propane and butane in the enriched mixture removed by the Central Alaska separator. Assumed gas composition at the separator inlet and outlet is described in Appendix A.

### 3.2 Industrial Demand

The potential industries represented in this update are the same as those in the original study's largest wet gas spur line scenario, which calculates petrochemical and GTL demand based on sizing and siting "World Class" facilities. In this study, the GTL complex was sized to a 50,000 bpd capacity, which demand 464 MMcfd. LNG industrial demand is based on retrofit of the current, nearly 40-year old plant in Nikiski and expansion to 3.0 MMTPA, demanding 375 MMcfd. Fertilizer industry demand is based on renovation of the 40-year old Agrium-owned facility in Kenai, and would demand 145 MMscfd. The Agrium facility is currently mothballed due to dwindling supply from the Cook Inlet and associated high feedstock prices. LPG industry

[1] The 2006 Study considered industry at Fairbanks and the North Slope, but found that locating industry in South Central Alaska to be the most economically viable. Residential and commercial gas demand growth were the strongest and anchor customers such as the ConocoPhillips LNG terminal and the Agrium fertilizer plant on the Kenai Peninsular were then operational, providing a ready source of demand.

demand is calculated as the amount of extra propane and butane in the wet gas line, which is determined by the spur line volume and liquids content.

Table 1 shows the gas and NGL capacity and demand for the potential industries considered in this update report. Only the LPG industry capacity and demand differs from the 2006 Study. This Study updates ANS gas composition and reflects the "Rich Gas Case" composition described in the Alaska Gasline Inducement Act (AGIA) Request for Applications (RFA), released in July, 2007.

**Table 1: Potential Industry Capacity and Demand for Natural Gas and NGL**

| Industry | Capacity | Demand as MMcf/d methane equivalent (NGL feedstock) |
|---|---|---|
| Fertilizer * | 1.25 MMTPA ammonia, 1 MMTPA urea | 145 |
| LNG ** | 3.0 MMTPA | 212 |
| GTL | 50,000 bpd low sulfur diesel | 480 |
| Petrochemical | 1.27 MMTPA ethylene | 122 (76,000 bpd ethane) |
| LPG | 50,000 bpd LPG | 78*** (41,000 bpd propane, 9,000 bpd butane) |
| | **Total Potential Demands** | **1,041.** |

* Assumes upgrade of the existing fertilizer plant
** Assumed expansion of the existing LNG facility at Nikiski
*** Under the "Lean Gas Case" composition described in the AGIA RFA, LPG capacity and demand would be reduced to approximately 24,000 bpd propane and 4,800 bpd butane, which is equivalent to 45 MMcf/d methane.

In both the 2006 Study and this update, it is recognized that pentanes will also be in the spur line gas stream, and will be separated out in South Central Alaska. Pentanes can likely be readily sold for blending into local gasoline, however their quantity and associated total value is quite small compared to the other gas stream components (i.e., approximately 1,400 bpd pentanes versus over 50,000 bpd LPG), thus pentanes are not further considered in this assessment.

### 3.3 Financial Assumptions

As in the 2006 Study, this update of industrial gas needs is market based and does not include analysis of gas price discounts or special incentives by the state to encourage in-state industrial development. Also as in the 2006 Study, it is assumed that, as a result of the integration of the South Central gas market with Canadian and Lower 48 gas markets, Alaskan gas prices will be based on Lower 48 gas prices adjusted for tariff. Thus, the price of natural gas in South Central Alaska is determined as the market price for natural gas at Henry Hub[2], minus the difference in estimated tariff rates between Henry Hub and South Central Alaska. In this update report, these

[2] This is the pricing point for North American natural gas futures on the New York Mercantile exchange. It is located in Erath, Louisiana.

differences are estimated to be $2.51 and $3.12 in the "Low" and "High" case scena , respectively.

All results presented in this update report are in 2007$ unless specified otherwise. As in the original study, the financial analysis assumes the following for each industry:

- *Project Life* – 20 years. This is a common industrial project life.
- *Discount Rate* – 12% rate. This varies among industries and projects, and may be relatively low for industries with higher risk (e.g., GTL).
- *Federal and state taxes* – were assumed at the rates of 35% and 4.5% of taxable income, respectively.
- *Cost Adjustment* – to adjust for the higher costs in Alaska compared to the Lower 48, construction and operations costs were multiplied by 1.3 for South Central Alaska.
- *Cost of Capital (during construction)* – 6%.
- *Financing* – all projects were assumed to be equity financed as turn-key projects.

The financial analysis of each industry is designed to determine the netback value of the feedstock (i.e., dry natural gas, ethane, or propane) to each industry. Netback value represents the maximum price for natural gas and NGL that each industry can afford to pay given global price for products, transportation costs, capital and operating costs, discount rate, and taxes.

The industry-specific inputs to the financial analysis for capital and operating costs, and shipping costs are the same values used in the 2006 Study after adjustments based on changes in Producer Price Indices from 2005 to 2007, as published by the Bureau of Labor Statistics. Table 2, below, displays the updated cost assumption for each industry assessed – these costs were held constant in both the high and low market price scenarios.

**Table 2: Cost Assumptions for Potential Industries ($ millions)**

| Industry | Capital Costs | Low Price Scenario | | High Price Scenario | |
|---|---|---|---|---|---|
| | | Operating Costs | Shipping Costs | Operating Costs | Shipping Costs |
| Fertilizer * | $257 | $316 | $55 | $589 | $57 |
| LNG ** | $880 | $642 | $128 | $1,271 | $135 |
| GTL | $3,112 | $772 | $103 | $1,504 | $108 |
| Petrochemical | $2,993 | $722 | $80 | $1,046 | $82 |
| LPG | $844 | $440 | $66 | $740 | $69 |

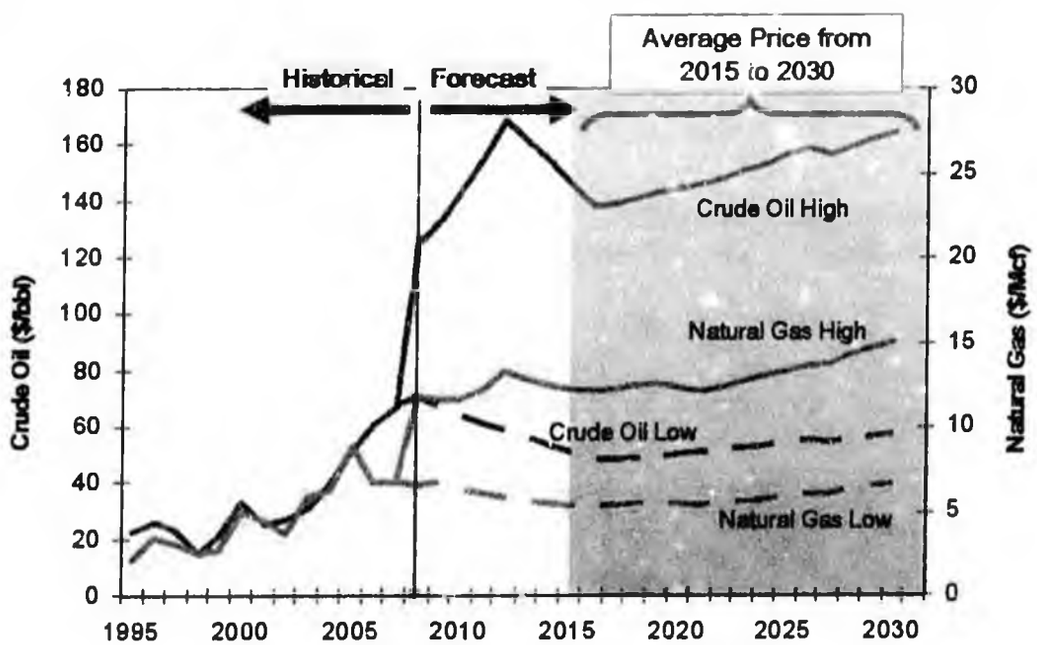
* Assumes upgrade of the existing fertilizer plant
** Assumed expansion of the existing LNG facility at Nikiski

## 4.0 Methodology

This analysis employs the same investment model adapted to each industry that was used in the 2006 Study. Input parameters include facility specifications (i.e., size, efficiency, etc.), production costs, and projected product prices on world markets. Model outputs include the netback value of gas to each industry. As an example, the value of gas to a fertilizer plant is calculated as the average annual price of fertilizer on the world market minus the average annual cost of transportation, and present value of combined capital and operating costs to convert Alaskan natural gas to a fertilizer.

For this update, model input parameters were changed to reflect increases in forecasted gas and oil prices, and related increases is the price of industrial products that would be produced from the modeled industries. Forecast natural gas and oil prices are based on the Energy Information Administration (EIA) forecasts published in the *Annual Energy Outlook 2008* as the "reference" case for Lower 48 prices. The EIA forecast prices for gas and oil are viewed by many energy analysts as conservative, thus this forecast is used as the "low" price scenario in this report. The June 3, 2008 futures prices of natural gas and crude oil on NYMEX for 2012 were used to represent a high price scenario in 2012, with the subsequent high-price scenario forecast through 2030, following the same annual percentage change as in the low price scenario. Historical and forecast prices of Lower-48 natural gas and crude oil are shown in Figure 1.

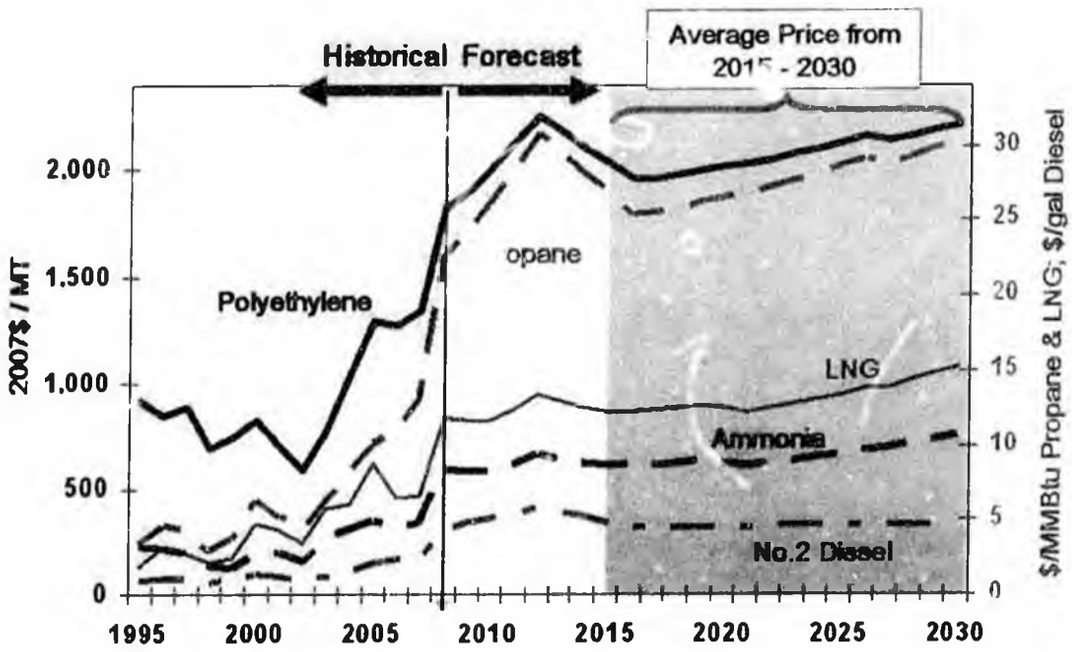
**Figure 1: Lower-48 Crude Oil and Natural Gas Prices: Historical and High and Low Forecast Scenarios (2007$)**



As described in the assumptions discussed above, the price of natural gas in South Central Alaska was determined as the market price for natural gas at Henry Hub, minus the difference in estimated tariff rates between Henry Hub and South Central Alaska..

Forecast product prices for each of the modeled industries are based on their historical relationship with natural gas and crude. Historical natural gas prices have a tighter relationship with ammonia and LNG, thus high and low natural gas price forecasts are the basis of the ammonia and LNG price forecasts. Historical crude prices have a tighter relationship with polyethylene, propane, and diesel; thus high and low crude price forecasts are the basis of the product forecasts for petrochemical, LPG, and GTL industries. Figure 2 shows the high scenario forecast of product prices.

**Figure 2: High Scenario Product Price Forecast for LNG, LPG, Polyethylene, Ammonia. and Diesel (2007$)**




The average low and high forecast product price from 2015 to 2030 is used in the investment model, a summary of these prices is provided in Table 3. Unless specified otherwise, prices in Table 3 represent average world prices -- in general, market locations are specified for prices representing products that may be sold to regions that are expected to have consistent price premiums.

**Table 3: Average Forecast Prices (Model Input): 2015-2030**

| [redacted] | Low Price | High Price |
|---|---|---|
| Natural Gas, Henry Hub ($/MMBtu) | $6.44 | $13.52 |
| Natural Gas, SC Alaska ($/MMBtu) | $3.93 | $10.41 |
| Crude Oil Price ($/Bbl) | $52.26 | $150.69 |
| LPG ($/ton) | $453 | $1,305 |
| Diesel, North America ($/MMBtu) | $11.47 | $33.08 |
| Diesel, Japan ($/MMBtu) | $14.14[a] | $35.75[a] |
| LNG, Southern California ($/MMBtu) | $6.09 | $13.17 |
| LNG, Japan ($/MMBtu) | $7.05 | $16.74 |
| Ammonia ($/ton) | $322 | $676 |
| Polyethylene ($/ton) | $1,097 | $2,081 |

a Based on the world crude oil forecast plus a $0.37/gal premium in Japan based on average prices in 2007.

# 5.0 Industry Investment Analysis Results

## 5.1 Product Markets

Product markets were re-assessed for this update. Japan is identified as a potentially highly desirable market for Alaskan LNG, diesel from the GTL complex, and LPG. These products have been sold at a significant premium in Japan in recent years. Shipping costs from Alaska to Japan are roughly equivalent to, or less than other suppliers competing for the Japanese market. Potential markets assessed in this study are shown in Table 4 for each assessed product.

**Table 4: Potential Markets for Alaskan Industrial Products**

| Product | Modeled Markets |
|---|---|
| Fertilizer | US West Coast, China, Japan |
| LNG | Japan, British Colombia, US / Mexico West Coast, China, Korea |
| GTL (ULSD) | US West Coast, BC, Japan |
| Petrochemical | US Gulf, Korea, China |
| LPG | US West Coast, China, Japan |

The previous markets for Alaskan fertilizer, the US west coast and Asia, are good candidates for future markets. As indicated by the netback analysis shown below, Alaskan fertilizer, petrochemical and LPG industries value natural gas well-within, or above the range of forecasted natural gas market prices in South Central. This suggests favorable economics for these

industries, with flexibility in the regions their product may be sold. China and Korea are viewed as likely markets for petrochemical products, both of which are projected to have increasing demand. Price premiums in Japan make it a very desirable market for LPG. Combined with the relatively larger expected growth in LPG demand in China, the Asian market is viewed as a likely market for Alaskan LPG.

Based on the assumptions used in this analysis, Alaskan GTL and LNG industries may be relatively more sensitive to product prices than the other modeled industries. Under the "low" price scenario and associated assumptions, products from Alaskan GTL and LNG industries may require that sales be to regions that place relatively high premiums on their products (i.e., Japan), or their operation may cease to be economically favorable.

The relatively high capital investment required for the modeled GTL complex in conjunction with its relatively high sensitivity to market prices, and the greater risk associated with this less common technology, may make the development of this industry less desirable than some of the other industrial options.

## 5.2 Netback Results

Based on the assumptions of this updated analysis, the maximum value of natural gas for each of the assessed industries is shown in Table 5. Netback prices that are below the forecast range of South Central natural gas (i.e., the average forecast price for each scenario plus or minus $0.50) suggest particularly risky investments based on the assumptions applied in this study.

**Table 5: Netback price of Natural Gas and Associated Product Prices: 2015-2030**

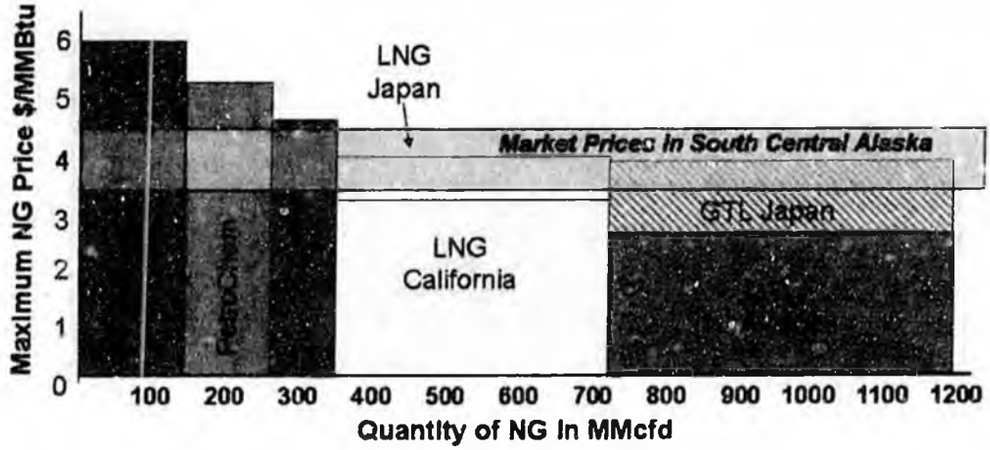
| Industry | Low Price Scenario (SC NG Market Price: [illegible] to [illegible]/MMBtu) | | High Price Scenario (SC NG Market Price: $7.76 to $8.76/MMBtu) | |
|---|---|---|---|---|
| | Product Price | Netback ($/MMBtu) | Product Price | Netback ($/MMBtu) |
| Fertilizer *(Ammonia) | $322 ton | $5.87 | $676/ ton | $13.45 |
| LNG , Southern California | $6.09/ MMBtu | $3.24 | $13.17 | $9.63 |
| LNG, Japans | $7.05/ MMBtu | $4.11 | $16.74/ MMBtu | $12.87 |
| GTL (Diesel), N. America | $11.47/ MMBtu | $2.45 | $33.08/ MMBtu | $14.89 |
| GTL (Diesel), Japan | $14.14/ MMBtu | $3.99 | $35.75/ MMBtu | $16.43 |
| Petrochemical | $1,097/ ton | $5.19 | $2,081. ton | $20.72 |
| LPG | $453/ ton | $4.65 | $1,305/ MMBtu | $19.92 |

The two industries that have the lowest increase in netback under the high price scenario (i.e., LNG and fertilizer) have product price forecasts that are based on natural gas prices (which increase less in the high scenario than crude prices), in addition to relatively low capital

investment. In general, when market prices are relatively high, industries with greater capital investment benefit disproportionately more than industries with lower capital investment.

Figure 3 shows gas and NGL volumes as dry gas equivalents on a thermal basis on the x-axis, and the netback price on the y-axis, where netback price is maximum price of dry gas each of the assessed industries can pay while remaining economically viable under the modeled assumptions. The horizontal bar in Figure 3 represents the expected price range of South Central dry gas (i.e., the average low forecast price of $3.93/MMBtu, plus or minus $0.50). If South Central gas prices are higher than the maximum (i.e., netback) value for gas shown for a particular industry, then gas consumption from that industry will likely be severely curtailed, or may never develop.

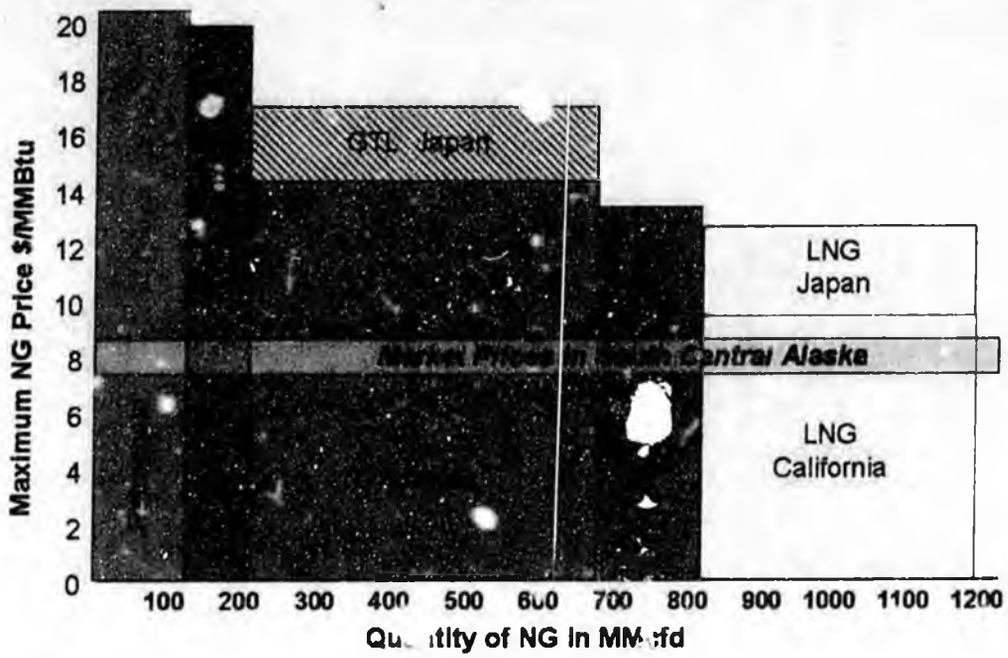
**Figure 3: Estimated Maximum Prices Under Low Product Price Scenarios and Demand for Potential Industries for Dry Gas and NGL (Methane equivalent units) and the South Central Alaska Gas Market Price Band.**




Source: SAIC

Figure 4 shows a similar graph the high market price scenario. In this case, the horizontal bar represents the expected price range of South Central dry gas with the average high forecast price of $8.26/MMBtu, plus or minus $0.50.

**Figure 4: Estimated Maximum Prices Under High Product Price Scenarios and Demand for Potential Industries for Dry Gas and NGL (Methane equivalent units) and the South Central Alaska Gas Market Price Band.**




Source: SAIC

In comparing netback values under the low and high price scenarios, the industries with the greatest increase in netback value under the high price scenario versus the low price scenario are those with products that have price forecasts based on the forecasted price of crude oil (i.e., GTL, petrochemical, and LPG). This is in part, a result of the greater difference between low and high forecasts prices for crude than for natural gas, i.e., high scenario natural gas prices are 2.1 times greater than low scenario prices, while high forecast prices of crude oil are 2.88 times greater than low forecast prices, as shown in Figure 1.

Because these analyses were conducted using assumptions that are inherently uncertain (i.e., projections of average market prices), none of the maximum price values should be considered accurate. However, the *relative* ranking of the industrial netback values in the South Central Alaska locations is not likely to change with modest assumption adjustments, with the possible exception of GTL. GTL is more sensitive to assumption modifications due to the larger gas demand and the higher uncertainty over project costs. The assumptions used in the GTL industry assessment are considerably more speculative than in other industries as a result of the uncertainty surrounding newer GTL technology and the still-emerging ultra-low-sulfur diesel fuel market.

## 6.0 Recommendations

There are many options and combinations of options that may have potential for Alaska with the development of ANGP and a spur pipeline. The relative merits of the options are complex and the long-term price forecasts for natural gas and oil and petroleum products on the world market always have a significant degree of uncertainty. Potential industries could be assessed on more detailed levels, with probabilistic analyses that account for cost and market risk to help provide additional insight into the complex interactions of options and economic benefits. Ultimately, these detailed analyses will likely be performed by serious investors. However, some over-reaching concepts are applicable to multiple industries and their integration, and thus may be best studied at an integrated level. Recommended integrated studies, include the following:

- A large-capacity spur pipeline will impact the design and operation of ANGP and could have significant economic impacts on that project. These issues were not analyzed in this study and could be more fully understood by running sensitivities to determine the impact of different-capacity spur pipelines on the value of ANGP.

- The uncertainties surrounding the completion of ANGP and consequently the spur pipeline are well understood. Alternative supply options exist, such as a smaller capacity bullet line from the ANS to Central Alaska. A comparative assessment of the alternative supply options would determine the costs and benefits of each supply option and help identify the optimal strategy for meeting natural gas demand.

- The potential location of various industries at North Slope or Central Alaska (e.g., GTL or petrochemical) may affect the desirability of further industry development in South Central. If industrial development at North Slope or Central Alaska is pursued further, the effects of industries located closer to the wellhead on state-wide industrial development may warrant further assessment.

- The results of this study suggest that the state of Alaska should explore the level of industry interest in investing in Alaska.

## Appendix A: Gas Composition of a Dense Phase, Wet Spur Line

The spur line will provide a means to deliver a portion of the stranded natural gas at Alaska North Slope to a market. While the primary component of this gas is methane, it also contains a significant amount of natural gas liquids (NGL), i.e., ethane, propane, butane, and pentane. The economics of sending the stranded Alaska North Slope natural gas to market may depend on the inclusion of NGL because these components have a higher value per volume than methane.[3] A non-traditional, high-pressure pipeline allows transport of NGL without development of a separate liquid phase in the line, avoiding the slug flows that occur when a low pressure line includes more NGL than found in dry gas. The pressure of a wet gas line is set based on the NGL composition.

The composition of natural gas components in a wet gas line can vary greatly depending on:

- ***Gas source.*** There are several different potential sources of natural gas at Alaska North Slope, each source has a different proportion of methane and NGL.
- ***Volume of wet gas from which NGL are separated.*** The recovered NGL are used to enrich the South Central Spur line.
- ***Percent recovery of NGL.*** This is determined by the separation technology used for enriching the Spur and used to remove NGL at the end of the Spur (i.e., Anchorage/ Nikiski).

This update assesses each of the two gas compositions described in the Alaska Gasline Inducement Act (AGIA) Request for Applications (RFA), released in July, 2007. Separation efficiency assumptions are based on straddle separator plant efficiencies for recently designed plants in Canada, which have 95% separation efficiencies of ethane, and essentially 100% separation efficiencies of all other NGL. Based on recent designs, extraction of individual NGL from the liquid stream is assumed to be 100%.

The volume of gas from which NGL are separated is assumed to be the volume from which sufficient ethane would be removed to enrich the spur line with enough ethane to meet the demand of a world-class ethylene plant that uses ethane as a sole feedstock (i.e., 70,000 to 80,000 bpd ethane). The volume of raw gas that is transferred to the spur pipeline without processing by the straddle separator is assumed to be the volume that would allow the final spur line methane output to meet the projected dry gas demand for residential, commercial, and power sectors in addition to an industrial GTL complex. The propane and butane associated with the gas needed to meet the ethane and methane demand is the supply available for an LPG industry.

Calculations of spur pipeline composition are provided for both the "Rich" and "Lean" gas cases delineated in the AGIA RFA. Assumed demand includes South Central residential, commercial,

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[3] Michael Baker, Jr., Inc. 2005. Transport of North Slope Natural Gas to Tidewater. Submitted to the Alaska Natural Gas Development Authority (ANGDA), April, 2005.

and power sectors (a combined demand estimated to be 0.26 Bscfd), in addition to continued demand from the Agrium fertilizer plant, expansion of the ConocoPhillips LNG facility, and new development of GTL, petrochemicals, and LPG industries (a combined demand estimated to be 1.18 Bscfd.

Table A1 shows calculations of spur pipeline composition under the Lean Gas Case, in which 930 MMscfd is processed by a straddle plant separator with an ethane removal efficiency of 95%, and 100% removal efficiency of other NGL. Separated NGL are added as enrichment to a 1.4 Bcfd gas spur pipeline. This entire stream is processed by a second straddle separator in Anchorage/Kenai with efficiencies that are the same as those of the first straddle plant.

**Table D1: Lean Gas Case, Spur line gas composition and volume.**[1] *(Assumes ideal gas behavior at 60 F and 14 psia)*

| Raw Gas Component | Raw Gas* | 1st Straddle Input (930 MMscfd) | | 1st Straddle NGL Output to Spur | | Total Spur Input** | | 2nd Straddle NGL Output | |
|---|---|---|---|---|---|---|---|---|---|
| | Mole % | MMscfd | bpd | MMscfd | Bpd | MMscfd | bpd | MMscfd | Bpd |
| Methane | 89.90 | 836 | NA | NA | NA | 1,169 | NA | 0 | NA |
| Ethane | 5.80 | 54 | 60,666 | 51 | 32,150 | 127 | 79,457 | 120 | 75,484 |
| Propane | 1.70 | 16 | 26,019 | 16 | 10,038 | 38 | 24,070 | 38 | 24,070 |
| n-Butane | 0.10 | 1 | 2,254 | 1 | 608 | 2 | 1,459 | 2 | 1,459 |
| i-Butane | 0.20 | 3 | 4,713 | 2 | 1,387 | 4 | 3,325 | 4 | 3,325 |
| Pentanes | 0.10 | 1 | 3,189 | 1 | 723 | 2 | 1,733 | 2 | 1,733 |

* Raw gas mole % based on AGIA RFA, 2007.

** Total spur pipeline input calculated as 1st straddle output plus 1.30 Bcfd gas directly from the main pipeline.

These spur line inputs and straddle plant efficiencies yield roughly 75,000 bpd ethane, meeting the needs of a world class ethylene plant. This line would also supply roughly 25,500 bpd of propane and butane for an LPG industry, and 1,700 bpd pentanes for sale to other users, i.e., for blending into gasoline.[4] In addition, the spur line would yield approximately 1.2 Bcfd dry gas to meet the dry gas demand of the South Alaskan residential, commercial, power and industrial sectors.

Table A2 shows calculation of spur pipeline composition under the Rich Gas Case scenario, in which 450 MMcfd is processed by a straddle plant separator with an ethane removal efficiency of 95%, and 100% removal efficiency of other NGL. Separated NGL are added as enrichment to a 1.4 Bcfd spur pipeline. This entire stream is processed by a second straddle separator in Anchorage/Kenai with efficiencies that are the same as those of the first straddle plant.

[4] Pentane is also referred to as "natural gasoline" because it is a major component of gasoline.

**Table A2: Rich Gas Case, Spur line gas composition and volume.**[1] *(Assumes ideal gas behavior at 60 F and 14 psia)*

| Raw Gas Component | Raw Gas* Mole % | 1st Straddle Input (450 MMscfd) | | 1st Straddle Output to Spur | | Total Spur Input** | | 2nd Straddle NGL Output | |
|---|---|---|---|---|---|---|---|---|---|
| | | MMscfd | bpd | MMscfd | Bpd | MMscfd | bpd | MMscfd | Bpd |
| Methane | 86.40 | 389 | NA | 0 | NA | 1,175 | NA | 0 | NA |
| Ethane | 7.10 | 32 | 20,046 | 30 | 19,043 | 127 | 79,626 | 121 | 75,645 |
| Propane | 3.60 | 16 | 10,286 | 16 | 10,286 | 65 | 41,373 | 65 | 41,373 |
| n-Butane | 0.30 | 1 | 883 | 1 | 883 | 5 | 3,552 | 5 | 3,552 |
| i-Butane | 0.40 | 2 | 1,342 | 2 | 1,342 | 7 | 5,397 | 7 | 5,397 |
| Pentanes | 0.10 | 0 | 350 | 0 | 350 | 2 | 1,406 | 2 | 1,406 |

* Raw gas mole % based on AGAI RFA, 2007.

** Total spur pipeline input calculated as 1st straddle output plus 1.36 Bcfd raw gas.

These spur line inputs and straddle plant efficiencies yield roughly 76,000 bpd ethane, meeting the needs of a world class ethylene plant. This line would also supply roughly 50,000 bpd of propane and butane for an LPG industry, and 1,400 bpd pentanes for sale to other users, i.e., for blending into gasoline.[5] In addition to the NGL streams, the spur line would yield approximately 1.2 Bcfd dry gas to meet the demand for the South Central Alaskan residential, commercial, power, and industrial sectors.

[5] Pentane is also referred to as "natural gasoline" because it is a major component of gasoline.

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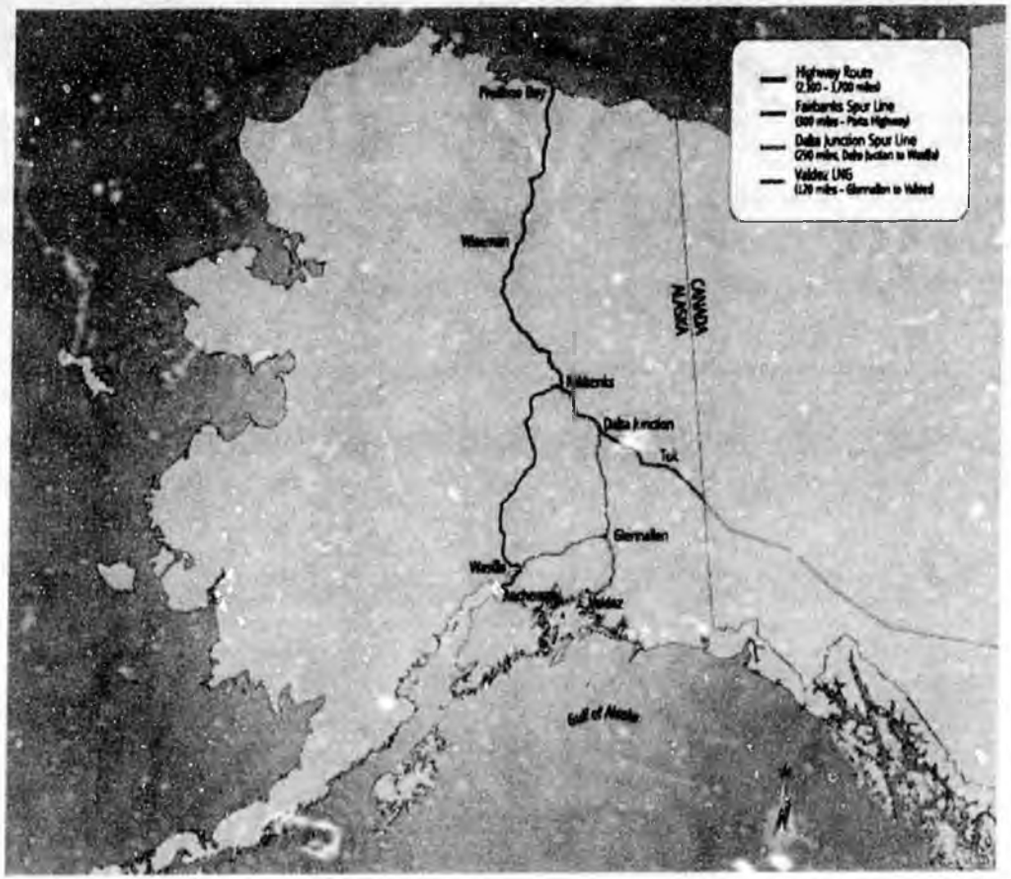



# Alaska Natural Gas Needs & Market Assessment

## Update Presentation

Presented in Anchorage
on June 20, 2008

## Alaska Legislature

# Sectors Studied

- Industry
  - LNG
  - GTL
  - Ammonia / Urea
  - Other
  - Petrochemicals
  - Propane

DRY GAS

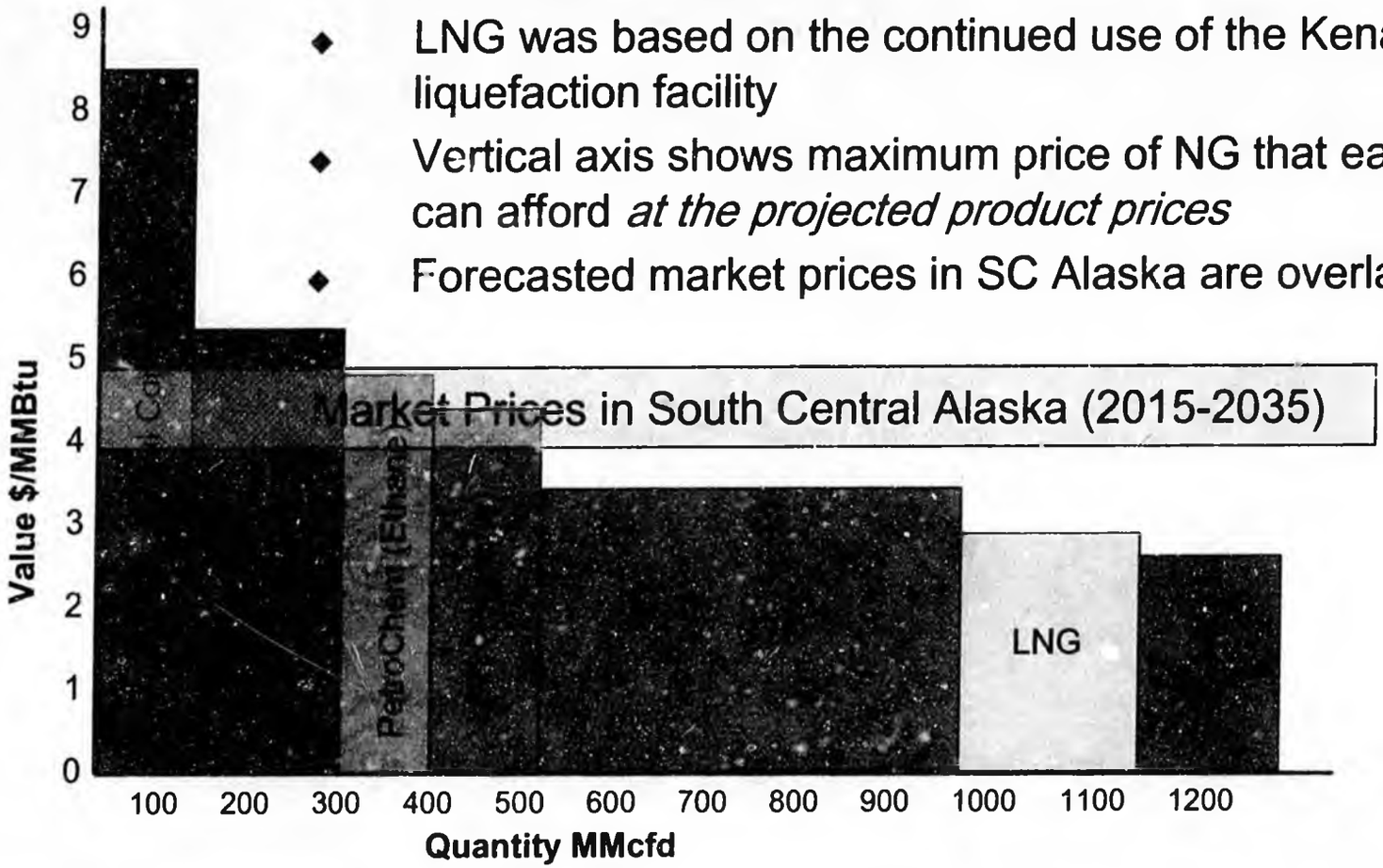
NGLs

- Power Generation
- Residential / Commercial

DRY GAS

# 2006 Study Findings: Base Price Scenario

- Horizontal axis shows potential NG demand for each industry based on world class-size facilities for LPG, petrochemical, and GTL
- LNG was based on the continued use of the Kenai liquefaction facility
- Vertical axis shows maximum price of NG that each industry can afford *at the projected product prices*
- Forecasted market prices in SC Alaska are overlaid

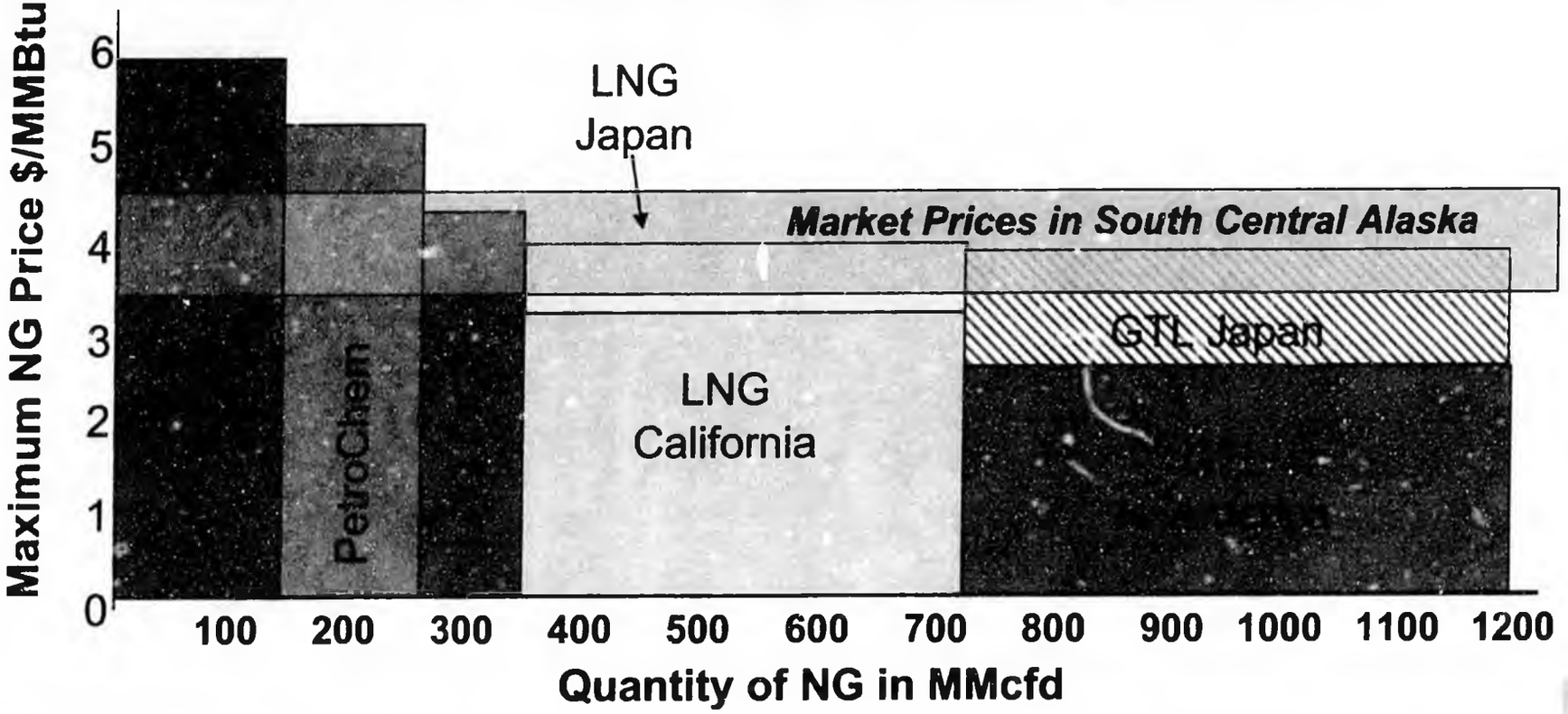


# Average Product Price (2015 – 2030)

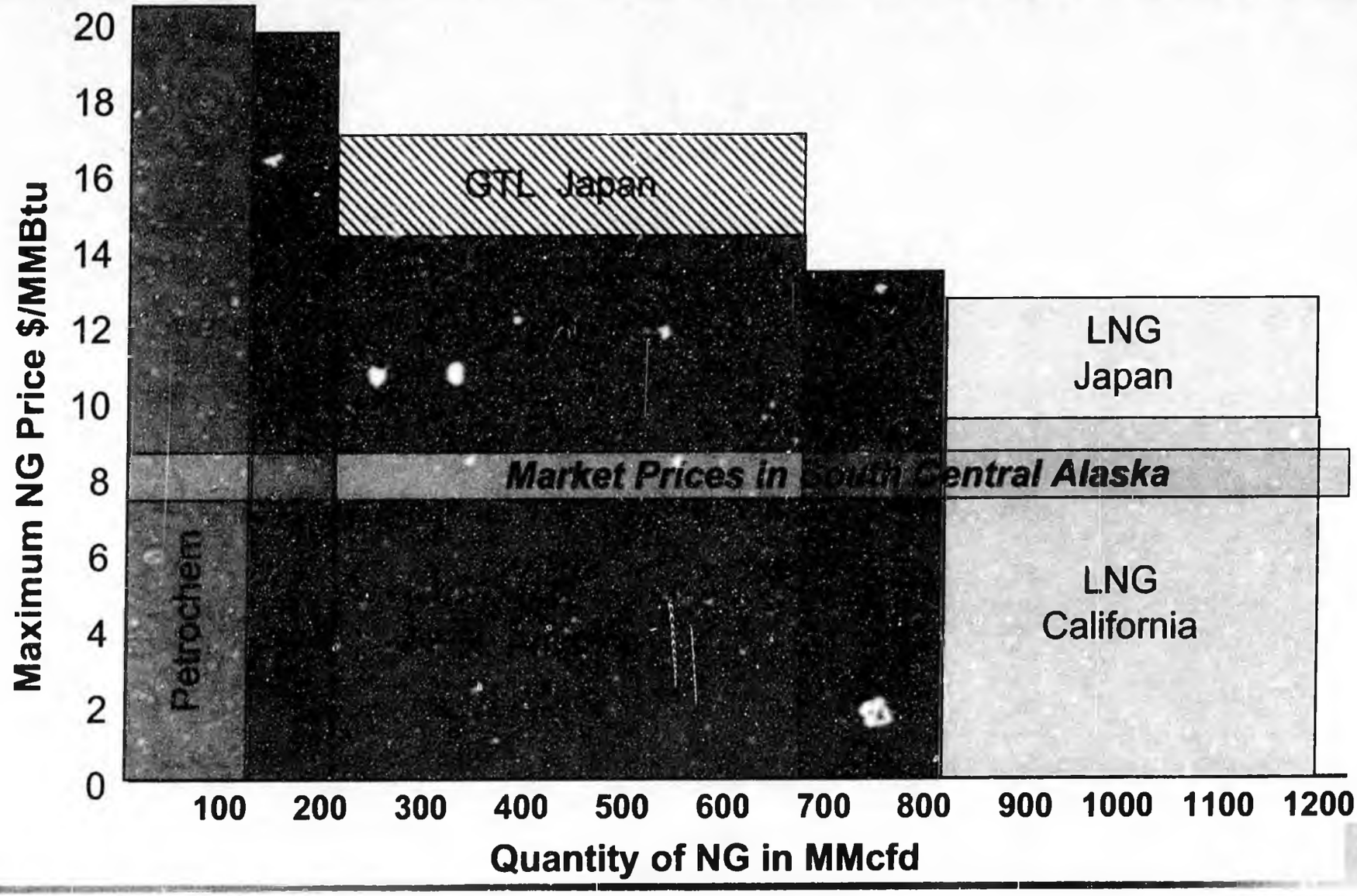
| PRODUCT | 2006 Report | 2008 Update | |
|---|---|---|---|
| | | Low Case | High Case |
| LNG, California ($/MMBtu) | $5.07 | $6.09 | $13.17 |
| LNG, Japan ($/MMBtu) | $6.10 | $7.05 | $16.74 |
| Diesel ($/MMBtu) | $9.46 | $11.47 | $33.08 |
| LPG ($/ton) | $383 | $453 | $1,305 |
| Ammonia ($/ton) | $224 | $322 | $676 |
| Polyethylene ($/ton) | $1,065 | $1,097 | $2,081 |

# Netback Price Findings: Low Case

- Horizontal axis shows potential NG demand, by industry, for new world-class size petrochemical, LPG, and GTL facilities
- LNG and fertilizer are based on upgrades and continued use of Kenai facilities
- Vertical axis is the maximum price of NG each industry can afford
- Low forecast NG prices in SC Alaska are overlaid (horizontal band)



# Netback Price Findings: High Case

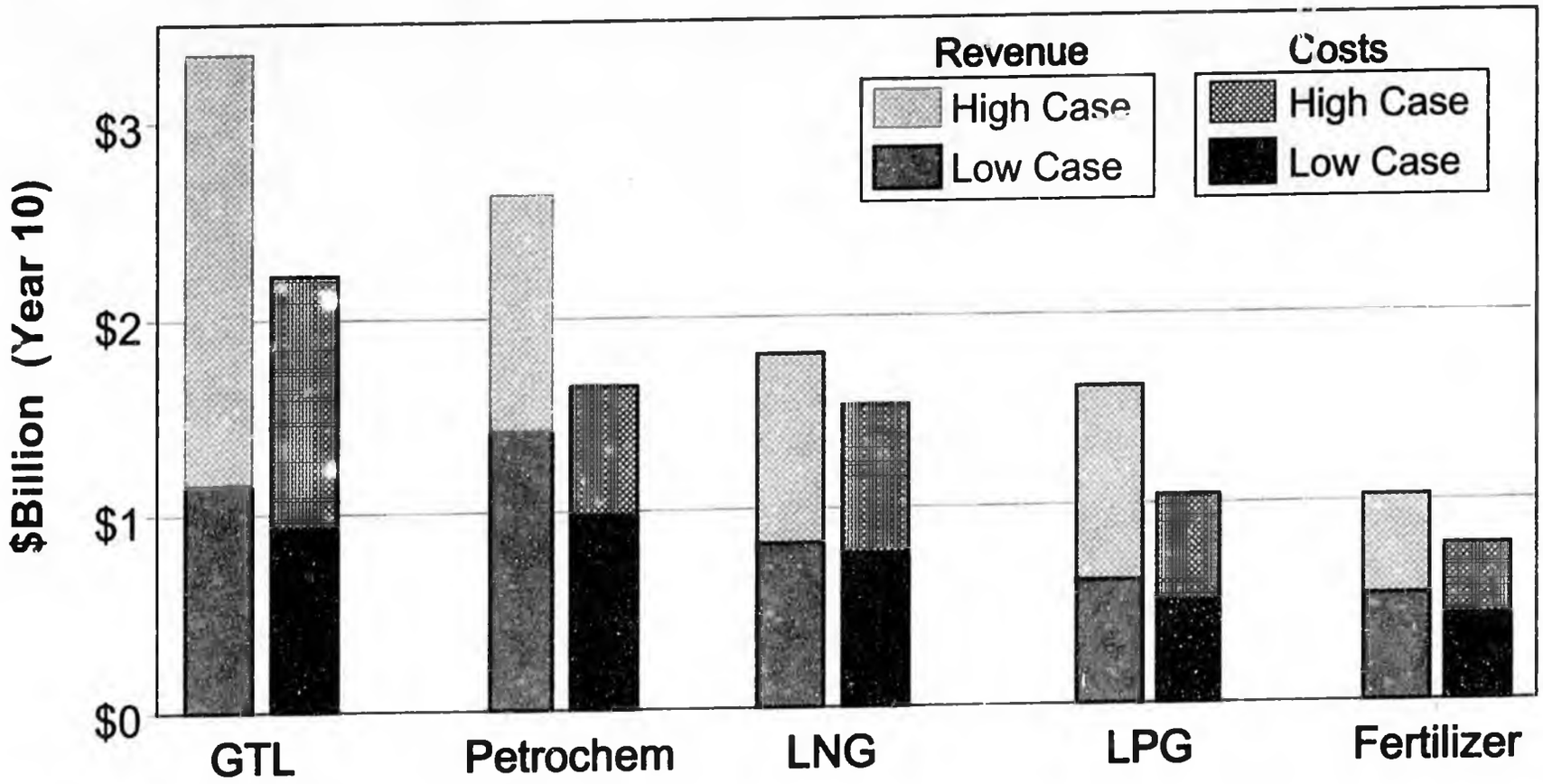


# Capital Costs

## Estimated Capital Costs By Industry

| INDUSTRY | $ Millions |
|---|---|
| LPG | $844 |
| GTL | $3,112 |
| LNG | $880 |
| Ammonia | $257 |
| Petrochemicals | $2,993 |
| **Total** | **$8,086** |

# Revenue and Cost Estimates, Year 10



# Companies that may be interested . . .

*Short List of companies that may be interested in developing Alaskan Industry . . .*

| LNG | LPG | Petochem | GTL | Fertilizer |
|---|---|---|---|---|
| Conoco-Phillips<br>Exxon-Mobil<br>BP | BP<br>Conoco-Phillips<br>AmeriGas | Dow<br>Exxon-Mobil<br>Shell<br>DuPont | Shell<br>BP<br>Sasol | Agrium |

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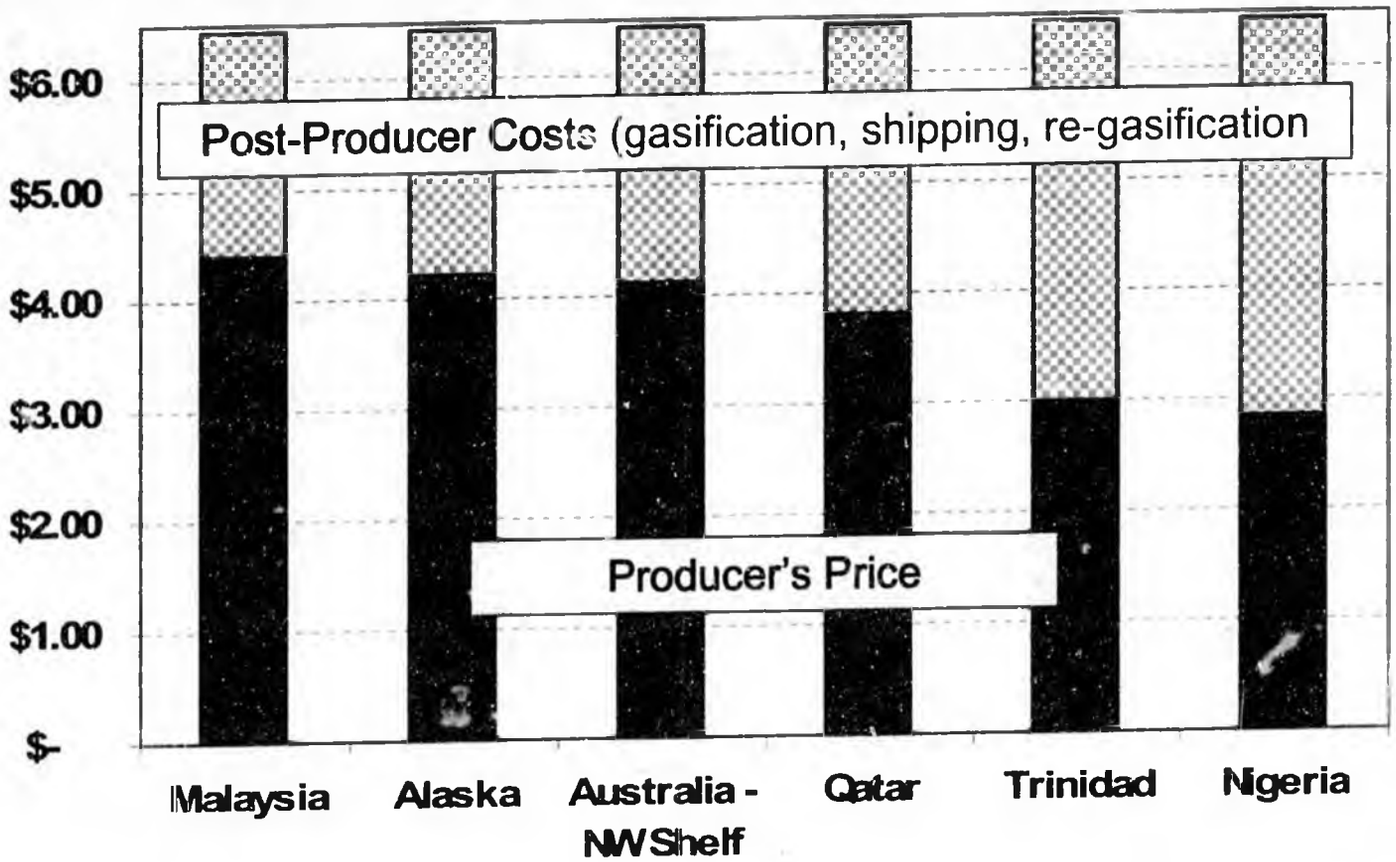
# Summary Findings

*Based on the assumptions in this analysis . . .*

- Recent increases in NG and product prices improves the feasibility of NG-intensive industries in Alaska
- All assessed industries appear feasible under the applied high price scenario
- Under the low price scenario, LNG and GTL industries may need contracts in premium markets (e.g., Japan) for feasibility
- The greatest uncertainty is associated with GTL due to the combination of evolving market, costs, and technology

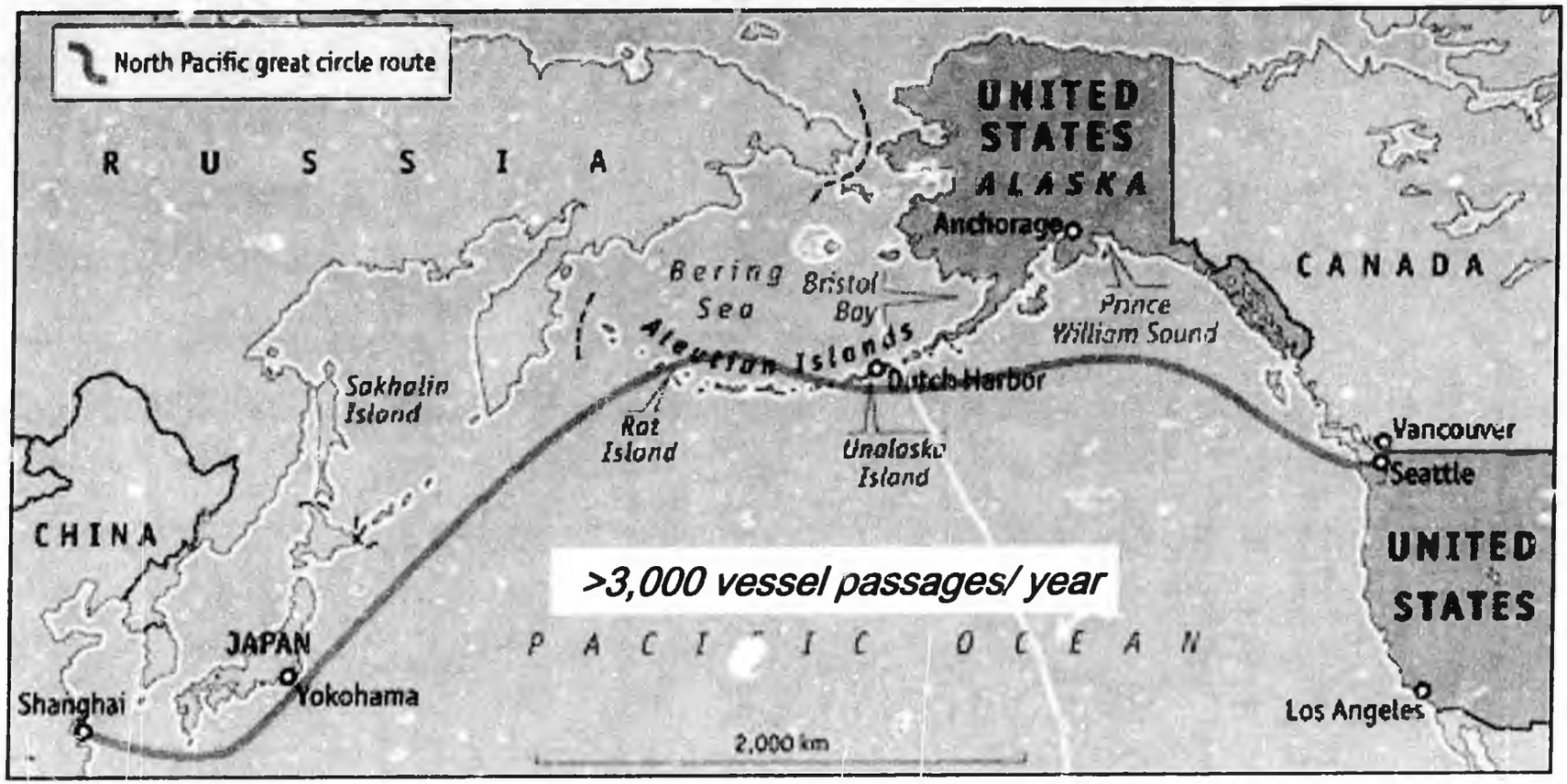
# Competing NG Suppliers

## Producer Price and Post-Producer Costs for Various Suppliers to Sell to Japan at $6.44/MMBtu



# Shipping and the Great Circle

Shortest distance between East Asia and the NW American Coast




*Potential for backhaul shipping (i.e., reduced rates negotiated for return trips that would otherwise not have had cargo) depends on the surplus of imports versus exports for the required vessel type.*



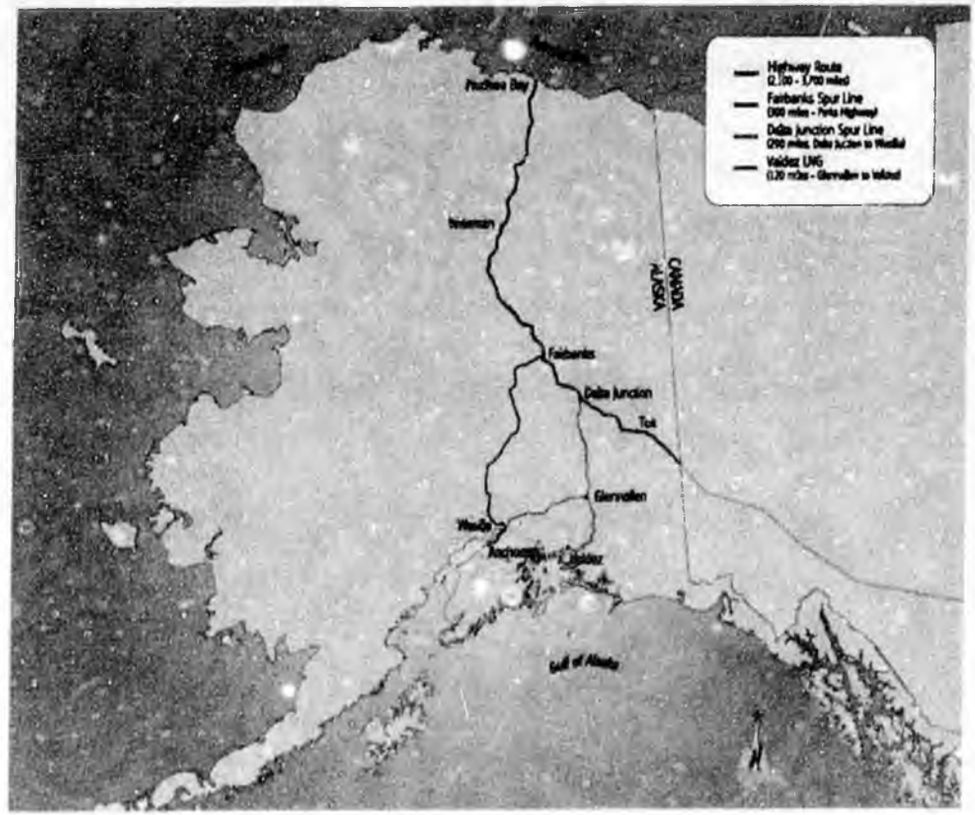
http://benmuse.typepad.com/ben_muse/2007/01/the_great_circ.html

# Agenda

1. Background
2. Study Assumptions & Methodology
3. Study Conclusions
4. Study Update
5. Summary

# 2006 Study: Overall Objectives

- The 2006 spur pipeline feasibility study evaluated:
  - Level of sustainable dry gas & NGL demand in SC Alaska
    - Residential
    - Commercial
    - Industry
    - Power
  - Maximum feasible price of natural gas (NG) by sector in SC Alaska
  - Spur pipeline size, costs, and market storage requirements.
  - Cook inlet gas supply
- This assessment updates the industrial sector analysis



# 2006 Study: Advisory Group

- Assisted DOE and SAIC in understanding and framing the issues
- Assisted in obtaining current and complete data
- Provided critical review of approach, analysis, and results.

| Organization/Member |
| --- |
| Alaska Industrial Development and Export Authority: Ron Miller, Executive Director |
| Alaska Natural Gas Development Authority: Harold Heinze, CEO |
| Anchorage ML&P: James Posey, General Manager |
| ASRC Constructors, Inc.: Marvin Swink |
| Chugach Electric Association: Lee Thibert, GM - Distribution Division / Bradley Evans, GM – Generation and Transmission Division |
| ENSTAR Natural Gas: Tony Izzo, President |
| Fairbanks Natural Gas, LLC: Dan Britton, President |
| Kenai Peninsula Borough: Bill Popp, Oil, Gas and Mining Liaison |

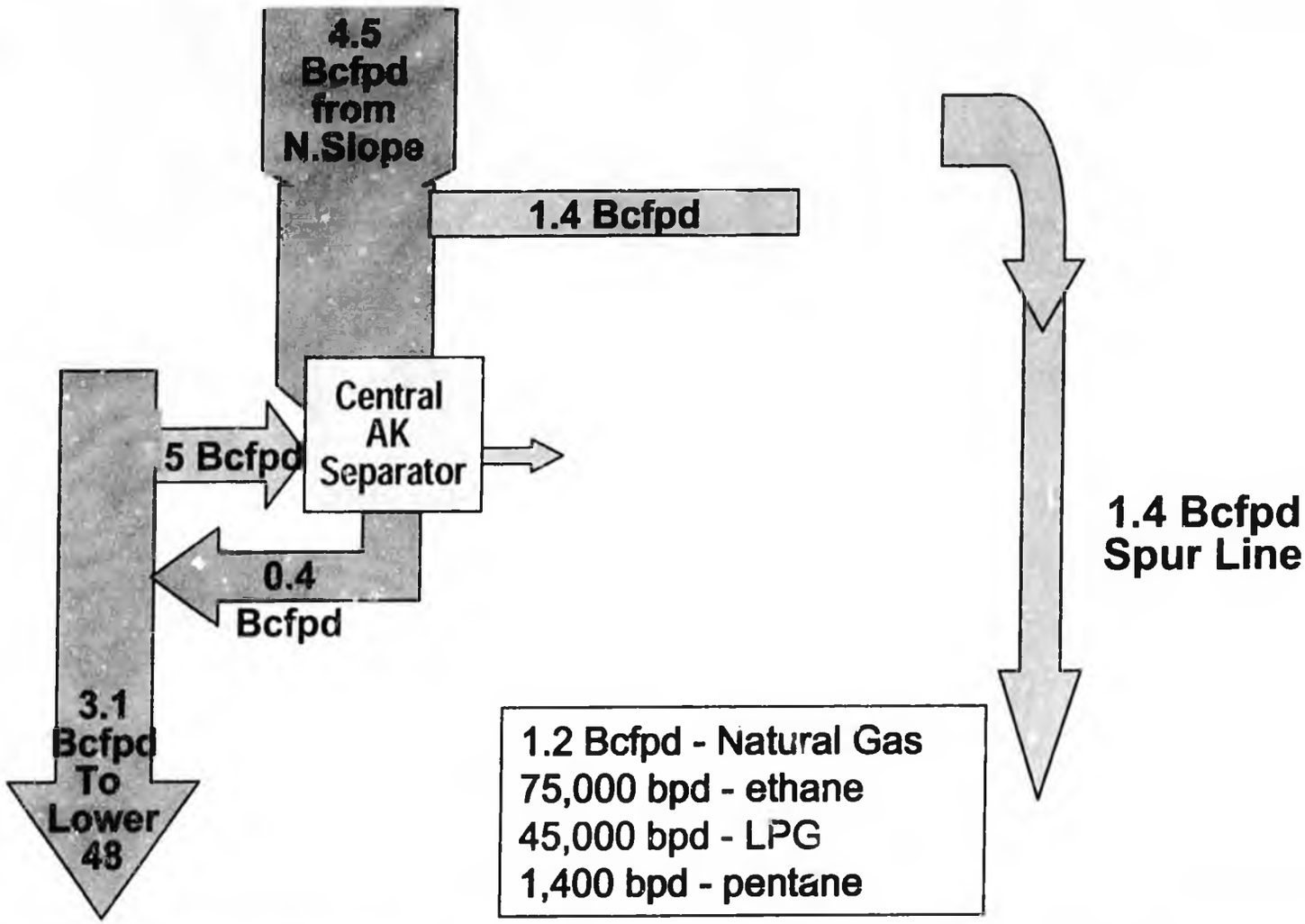
# 2006 Study Methodology

(1) **A Bottom-up Approach** to determine sustainable NG demand
- Current Uses
- New Uses (Blue Sky)

(2) **Integrated Market Analysis** to show the impact of an integrated Lower 48 NG and global product markets on the development of SC Alaska's NG market
- Competitiveness with Lower 48 markets.
- Competitiveness with global product markets.

(3) **In summary** -- Current and potential users of NG (and NG liquids)? What products? In what Quantity? At what price?

# Gas Composition Effects on Spur Volumes
## (Includes 0.3 Bcf for non-industrial demand)

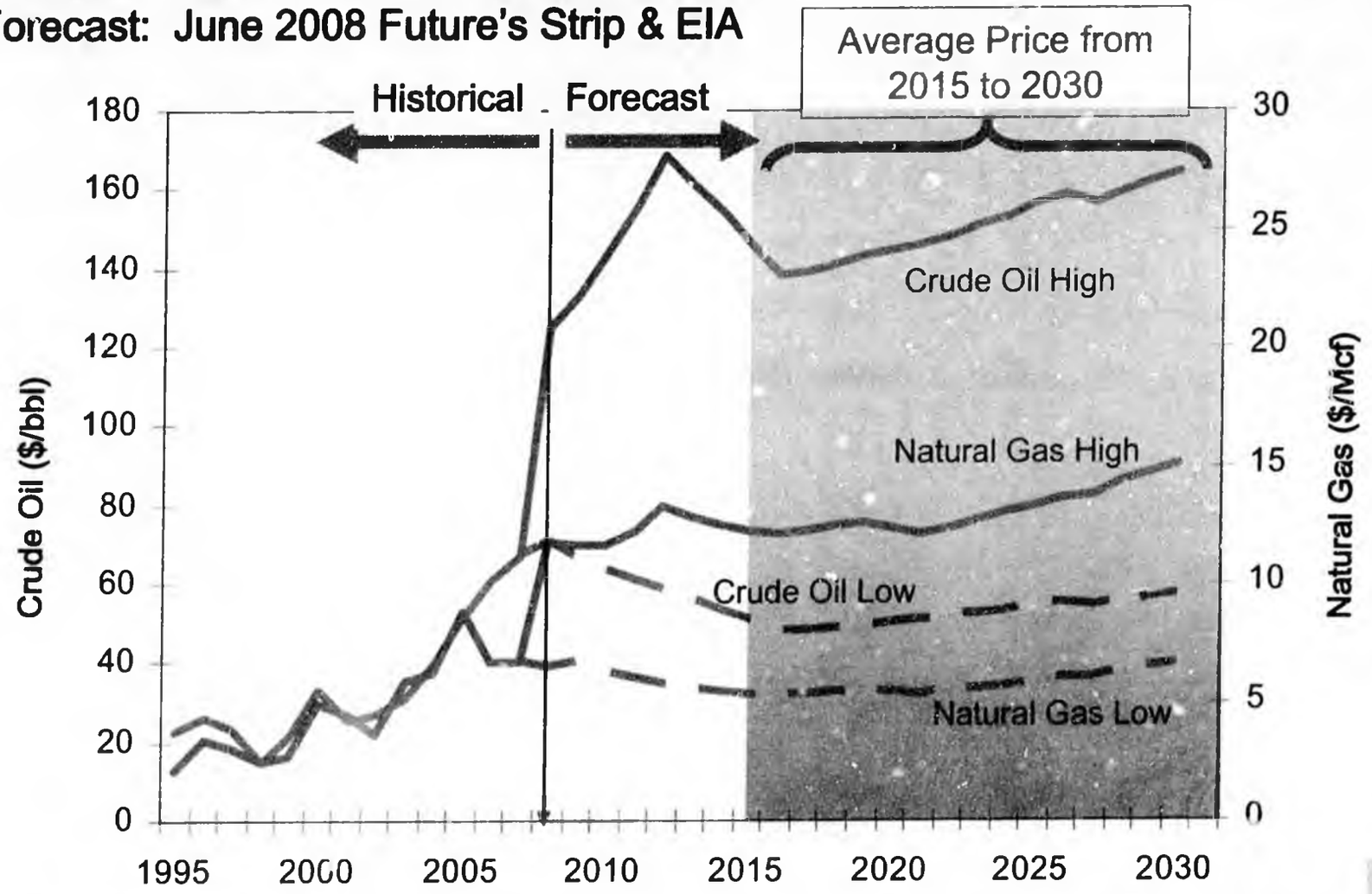


# 2008 Updated Assumptions

- **Industry assumptions updated in 2007$**
  - Capital costs
  - Operating costs
  - Product prices
  - NG feedstock prices
  - NG composition
- **Two price scenarios**
  - Low Case
  - High Case
  - Both scenarios assume a rich NG stream

# NG and Crude Oil Prices: Historical and High and Low Forecasts

**Low Forecast: EIA, Annual Energy Outlook 2008**
**High Forecast: June 2008 Future's Strip & EIA**



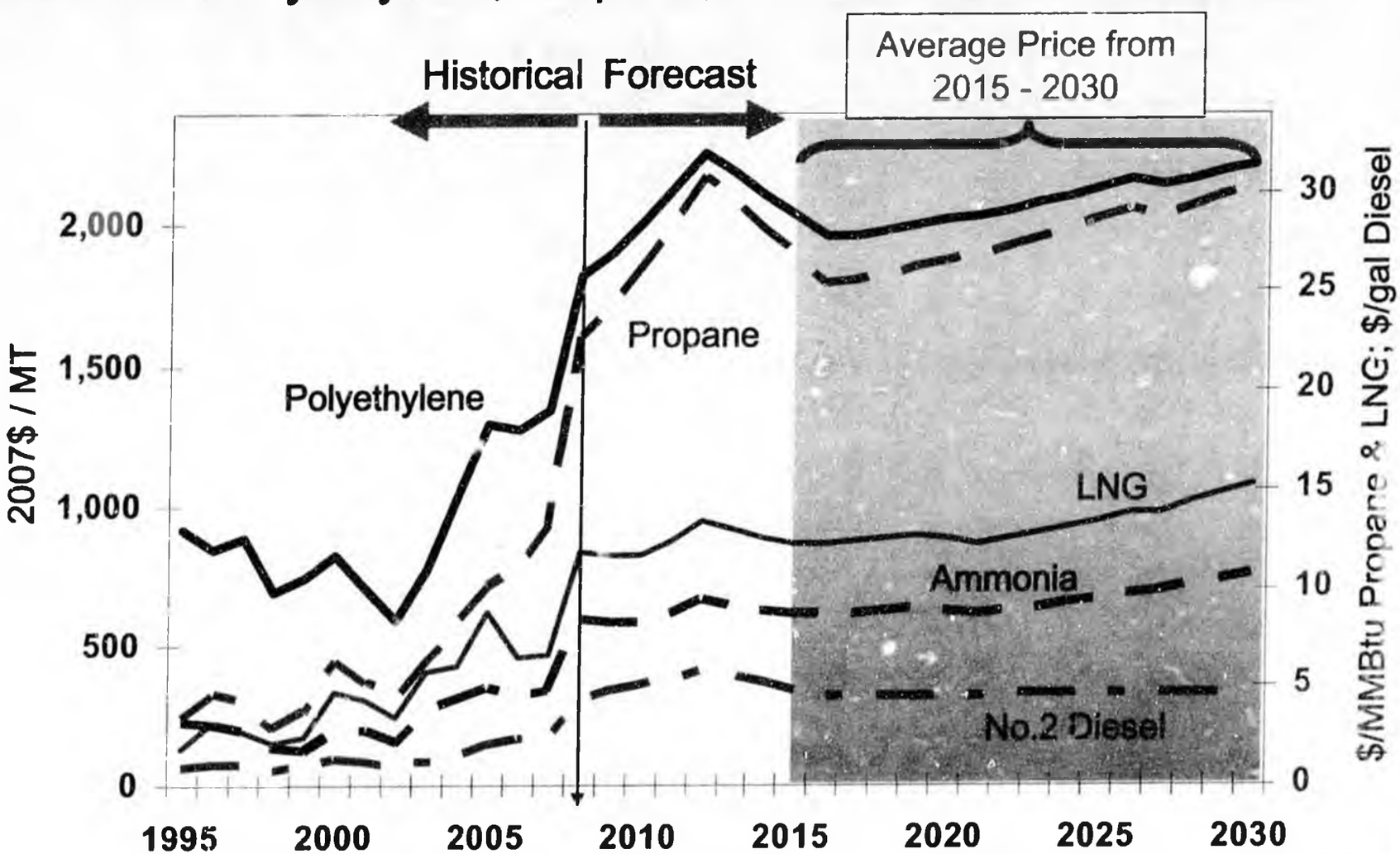
# Average Forecast Fuel Price (2015 – 2030)

Industry feasibility assessment based on economic feasibility when fuel prices are the average forecast price from 2015 to 2030, ± $0.50

| LOCATION | 2006 Report | 2008 Update Low Case | 2008 Update High Case |
|---|---|---|---|
| Henry Hub ($/MMBtu) | $5.60 | $6.44 | $13.52 |
| SC Alaska ($ /MMBtu) | $4.81 | $3.93 | $10.41 |
| World Oil Price ($ /bbl) | $47.83 | $52.26 | $150.69 |

# Product Price Forecast: 15-Year Average

## Prices for Polyethylene, Propane, LNG, Ammonia, and Diesel



# Markets for Products

*Markets with the highest projected demand growth and highest prices were modeled.*

| PRODUCTS | MODELED MARKETS |
|---|---|
| ▫ LNG | Japan, British Colombia, US / Mexico West Coast, China, Korea |
| ▫ GTL (Diesel) | US West Coast, BC, Japan |
| ▫ Ammonia | US West Coast, China, Japan |
| ▫ Petrochemicals | US Gulf, Korea, China |
| ▫ LPG | US West Coast, China, Japan |

# Industrial Capacity and NG Requirements

| INDUSTRY | CAPACITY | | NG DEMAND (MMcfd) | |
|---|---|---|---|---|
| | 2006 Study | 2008 Update | 2006 Study | 2008 Update |
| GTL | 62,000 bpd low sulfur diesel | 50,000 bpd low sulfur diesel | 480 | 390 |
| LNG | 1.7 MMTPA | 3.0 MMTPA | 212 | 375 |
| Fertilizer | 1.25 MMTPA ammonia 1 MMTPA Urea | 1.25 MMTPA ammonia 1 MMTPA Urea | 145 | 145 |
| LPG | 33,000 bpd propane & butane | 50,000 bpd | 116 NG equivalent | 78 NG equivalent |
| Petro-chemical | 1.27 MMTPA ethylene | 1.27 MMTPA ethylene | 120 NG equivalent | 120 NG equivalent |

# 2008 Update

# (2007$)


# Presentation to the Alaska Legislature

June 20, 2008

# All-Alaska Project

- Mitsubishi global LNG player
  - Involved in Kenai for 40 years
  - Very familiar with Alaska LNG
  - Want to add ANS gas to portfolio
- Mitsubishi/AGPA relationship
  - 1 year relationship with AGPA
  - Mitsubishi wanted to follow AGIA process and findings before committing
  - Agreement finalized this week
- Contingent on AGIA not diminishing Mitsubishi's ability to advance project
- Other participants expected

# All-Alaska Project

- Base case project volume 2.7 bcf/d
  - Less gas required at start-up
  - Expansion as reserves proven up
- First Gas to Alaskans
- Timing
  - 2017 not 2020
  - And 2017 ignores YPC permits

# AGIA LNG Findings

## Major Areas of Disagreement

- Project economics
- Cost of liquefaction
- Initial project volumes
- Expansion
- ANS btu content
- Value added
- Alaska jobs
- Jones Act
- LNG is “complex”

# LNG Export Authorization Granted

- DOE Export Analysis
  - Presumption of export
  - Allow market to work
  - Balance of payments
- Valdez Export License (DOE Order 350 & 350-A)
  - Japan, Korea & Taiwan
  - 14 MTA for 25 years, starting at first shipment
  - TransCanada only opposing party
  - "Exxon urged . . . market-responsive development of Alaskan natural gas" and DOE not to "place a stamp of approval on only one project or approach to development of Alaskan resources and discourage other projects or approaches."

# Canadian Permitting Risk – Bennet Jones Report

- Delay
  - Environmental (NPA vs. Newer Laws)
  - First Nations
  - NPA exclusivity to TransCanada
  - Mackenzie goes first
  - Hairball

# Way Forward

- Our overarching principle
  - All Alaska/LNG leg should not wait on resolution of Canadian issues
  - TC must continue to advance LNG on parity with Canadian option until successful open season, or LNG freed from AGIA (i.e., no exclusivity)
- Don't close door on LNG – options:
  - Written Clarification from TransCanada and State; or
  - Amend AGIA; or
  - Don't approve exclusive license