

**SCOMM**

**155:16**



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**FOR RELEASE ON JUNE 20, 2008**

## **MITSUBISHI CORPORATION JOINS ALL ALASKA GASLINE / LNG PROJECT**

Fairbanks, AK – June 20, 2008 – The Alaska Gasline Port Authority (AGPA) announced today a new major participant in its consortium to advance the development of the All-Alaska Gasline / LNG Project. Japan's largest general trading company, Mitsubishi Corporation (MC), has joined AGPA in its efforts to assure the delivery of Prudhoe Bay gas to Valdez where it would be liquefied and shipped on tankers to the Asian market, the West Coast and Hawaii.

The Y-line concept is frequently used to describe what many proponents contend is the ideal strategy for developing Alaska's massive gas reserves. "The Prudhoe to Valdez LNG leg of the Y-line can go long before the Canadian leg of the line," stated Bert Cottle, AGPA Chairman and Mayor of the City of Valdez. Citing the ten years of studies, economic modeling and permit acquisition by AGPA, Cottle continued, "Proceeding with the LNG project now will assure gas to Alaskans first. Statewide, we are suffering an energy crisis of epic proportions. Alaska first, Alaska now has to be our top priority." Cottle credited Governor Sarah Palin's AGIA strategy as the catalyst for generating world wide interest in commercializing Alaska's gas.

In a recent letter to Governor Palin, Mitsubishi Corporation stated, " We understand that the constitution of the State of Alaska requires that Alaska's natural resources be used for the maximum benefit of the citizens of Alaska. We believe that an LNG Project best meets this constitutional imperative by providing for rapid development, local [utilization] of gas supplies, in-state operations that will generate employment, and economic advantages associated with selling into both domestic and international markets." Mitsubishi Corporation emphasized that they have the ability to off-take a considerable volume of LNG from Valdez for distribution on a flexible basis to buyers in the United States and abroad.

A Fortune Global 500 company, Mitsubishi Corporation has over 500 subsidiaries and affiliates and more than 200 bases of operations in eighty countries worldwide. Mitsubishi Corporation enjoys a significant presence in various industries worldwide, including energy, metals, machinery, chemicals, foods and general merchandise. Mitsubishi Corporation is also engaged in the production, liquefaction, sale, and logistics of natural gas through a number of LNG projects, handling approximately one-half of Japan's LNG imports.

#### Board of Directors:

Mayor Bert Cottle, Chairman · Dave Cobb, Vice-Chair · Merrick Peirce, Treasurer ·  
Luke Hopkins, Secretary · Jim Whitaker · Dave Dengel · Rex Rock · Randy Hoffbeck · Harold Curran

# ALASKA STATE LEGISLATURE

**Senator Charlie Huggins, Chair**  
Senate Special Committee on Energy  
State Capitol, Room 119  
Juneau, AK 99801  
Phone: 465-3878  
Fax: 465-3265



**Representative John Harris, Chair**  
House Rules Subcommittee on AGIA  
State Capitol, Room 208  
Juneau, AK 99801  
Phone: 465-4859  
Fax: 465-3799

Third Special Session  
Twenty-Fifth Legislature

Howard Johnson Plaza, Anchorage

**Friday June 20, 2008**

9:00-5:00 p.m.

## **Joint Meeting AGENDA**

Presentations: Review of AGIA Findings and Determination; Natural Gas Pipeline Project as proposed by TransCanada Alaska Company, LLC and Foothills Pipelines Ltd. (TC Alaska) to the State of Alaska.

➤ **AK Natural Gas Development authority**

Harold Heinze, CEO  
Delma Bratvold, Science Applications International Corp. (SAIC)

➤ **Enstar Natural Gas Company**

Gene Dubay, Sr. V.P. & COO, Continental Energy Systems  
Colleen Starring, Regional V.P., Enstar  
*John Lau, Director of Engineering, Enstar Nat Gas*

➤ **AK Natural Resources to Liquids LLC**

Richard Peterson, Managing Member  
Peter Tijm, Member

➤ **Econ One Research**

Barry Pulliam, Senior Economist, LB&A Consultant  
*Washington Lemm, Consultant*

➤ **AK Gasline Port Authority**

Bill Walker, Project Manager & General Counsel

**Testimony: By Invitation**  
**Teleconference – Listen Only**

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6-20-08  
Presenters

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Gene Dubay, SVP & COO  
Continental Energy Systems  
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**Econ One Research**

Barry Pulliam, Senior Economist  
LB&A Consultant

**AK Gasline Port Authority**

Bill Walker

*presented 6-20-2008*

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

**June 20, 2008**

**Barry Pulliam  
Senior Economist  
Econ One Research**

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601 W 5th Street  
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213 624 9600**

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Three Allen Center  
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713 228 2700**

**Suite 501  
805 15th Street, N.W.  
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202 289 7620**



# 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**

# 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

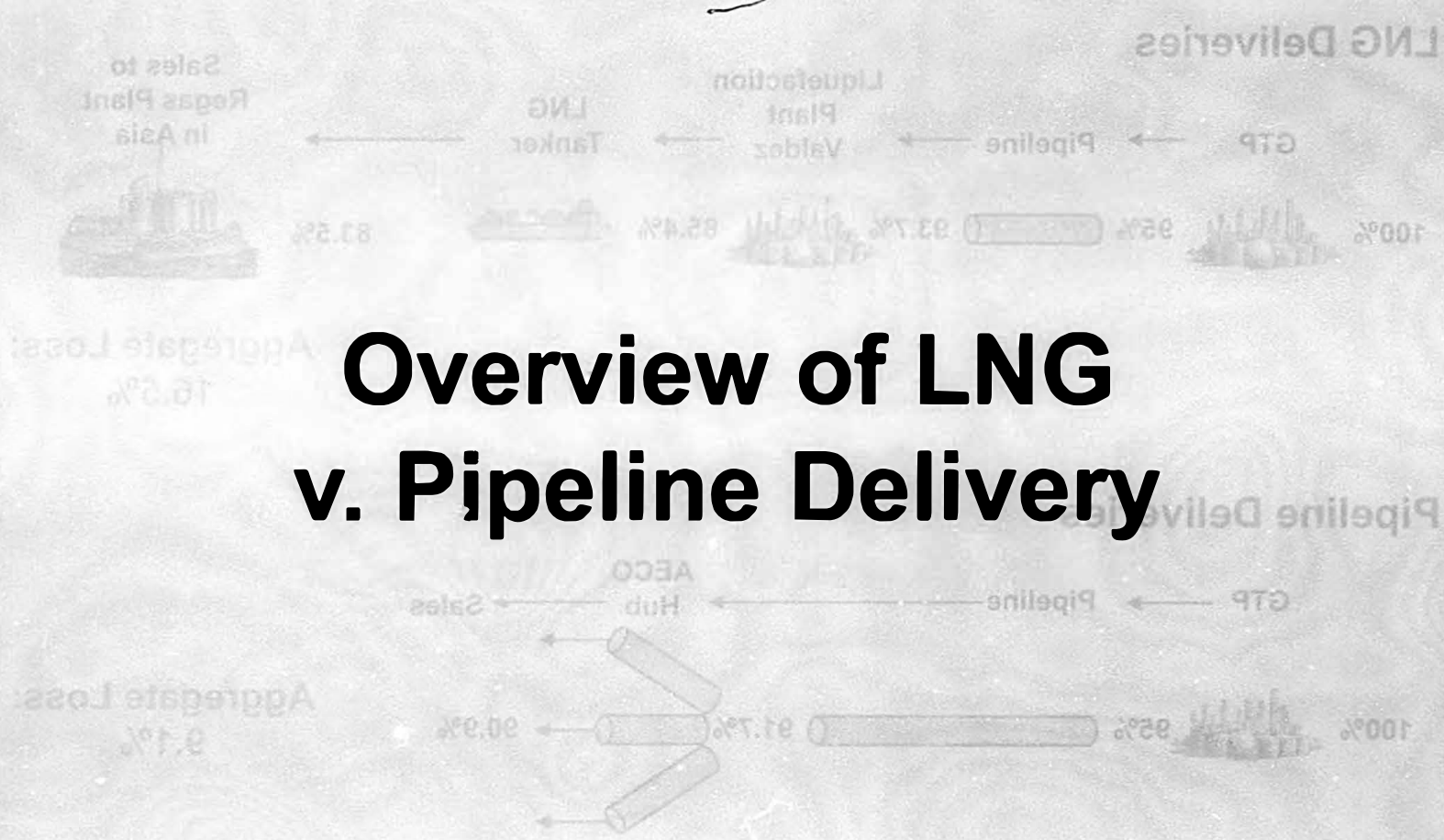
## LNG Exports to Asia

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

## Pipeline to Alberta

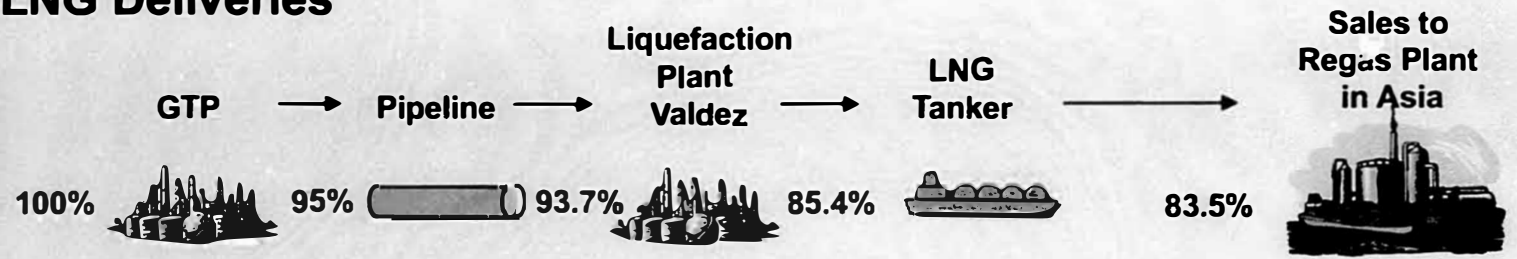
- 3.5 Bcf/d (TransCanada minimum volumes)
- 4.5 Bcf/d (TransCanada base volumes)

# Overview of LNG v. Pipeline Delivery



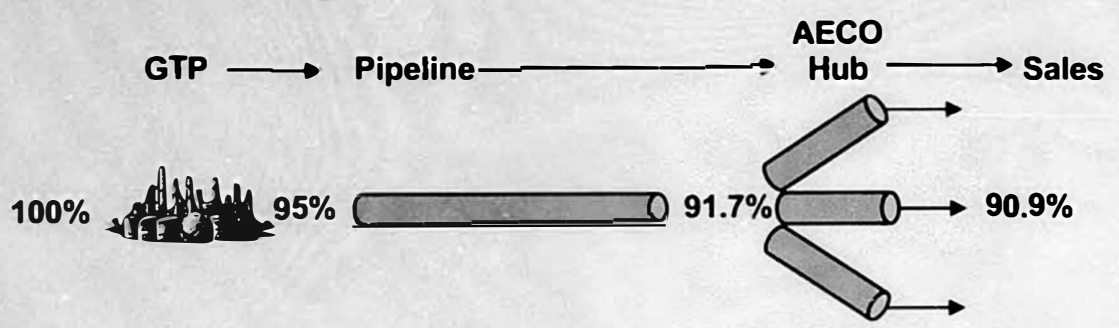
# LNG and Pipeline Delivery Chain

## LNG Deliveries



Aggregate Loss:  
16.5%

## Pipeline Deliveries

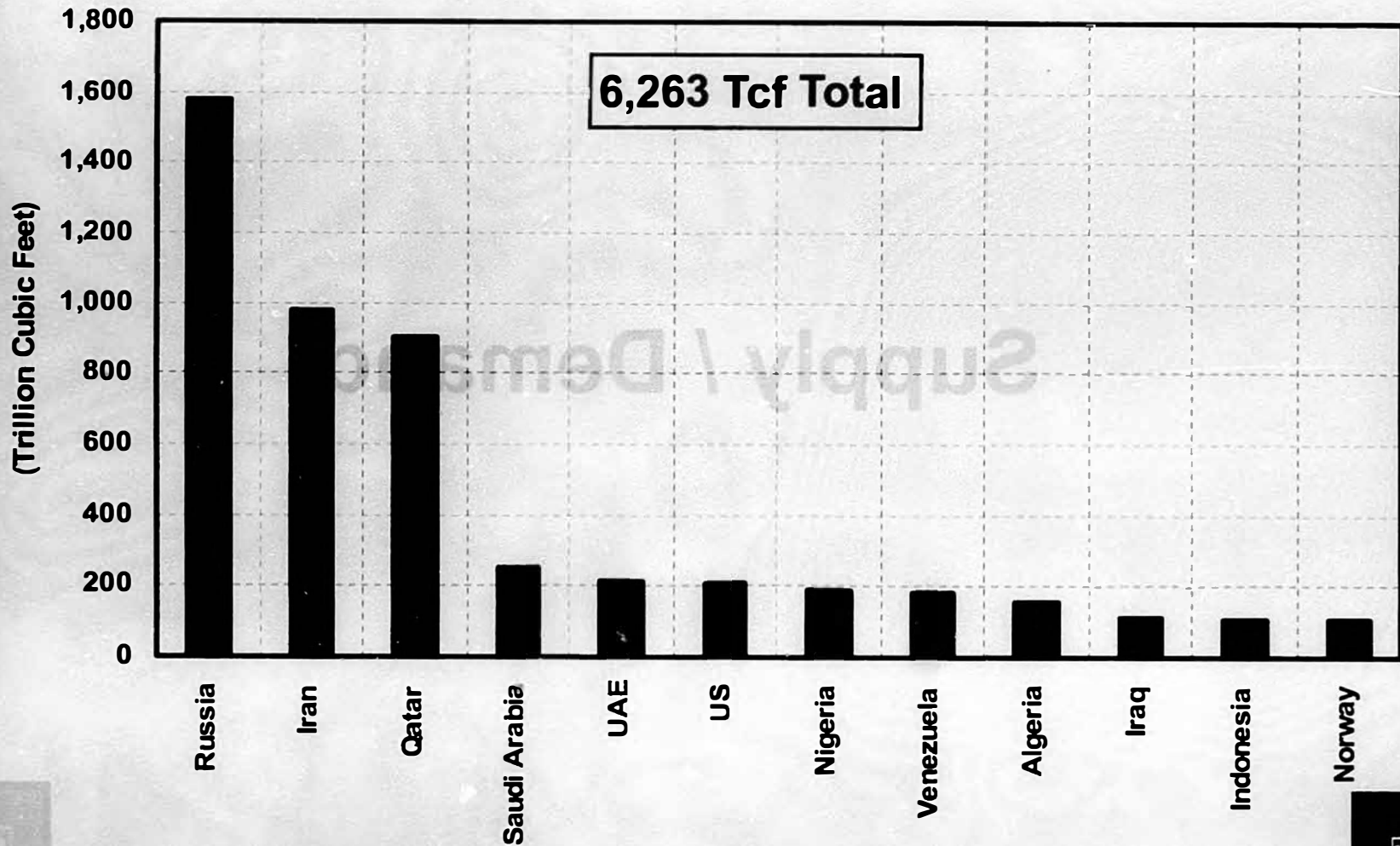


Aggregate Loss:  
9.1%

# Supply / Demand



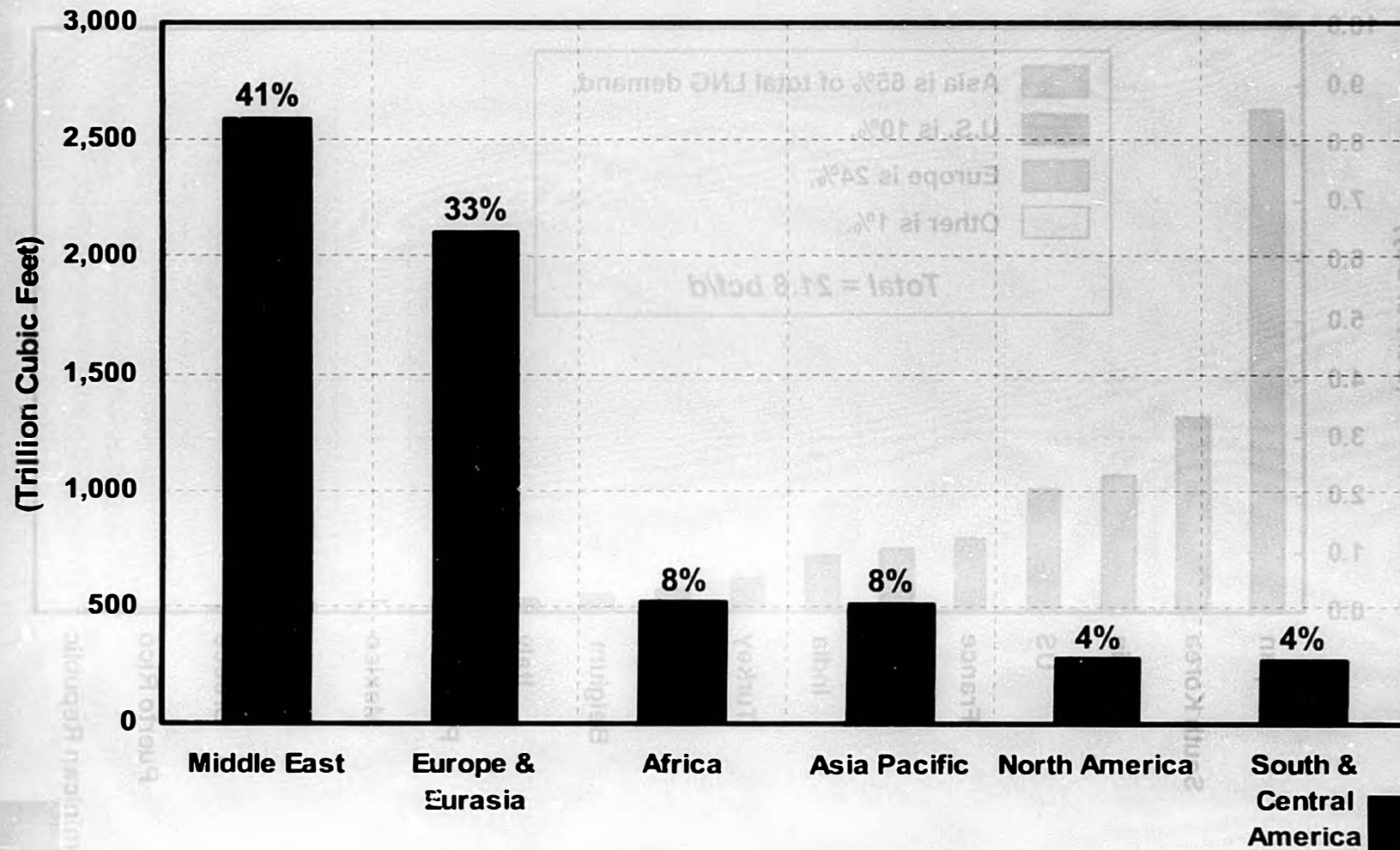
# Worldwide Proved Gas Reserves



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



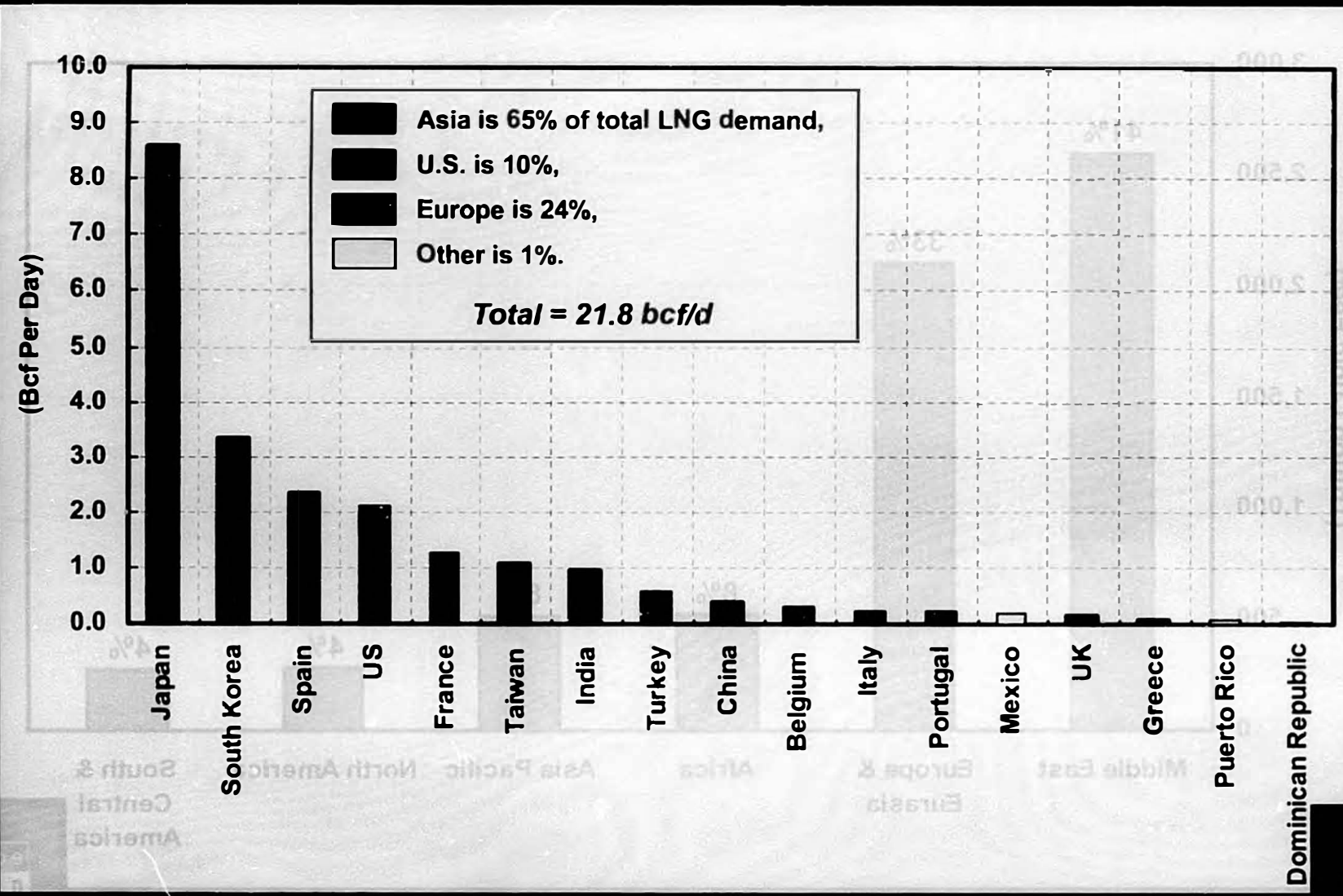
# Worldwide Proved Gas Reserves by Region



Source: BP Statistical Review 2008.



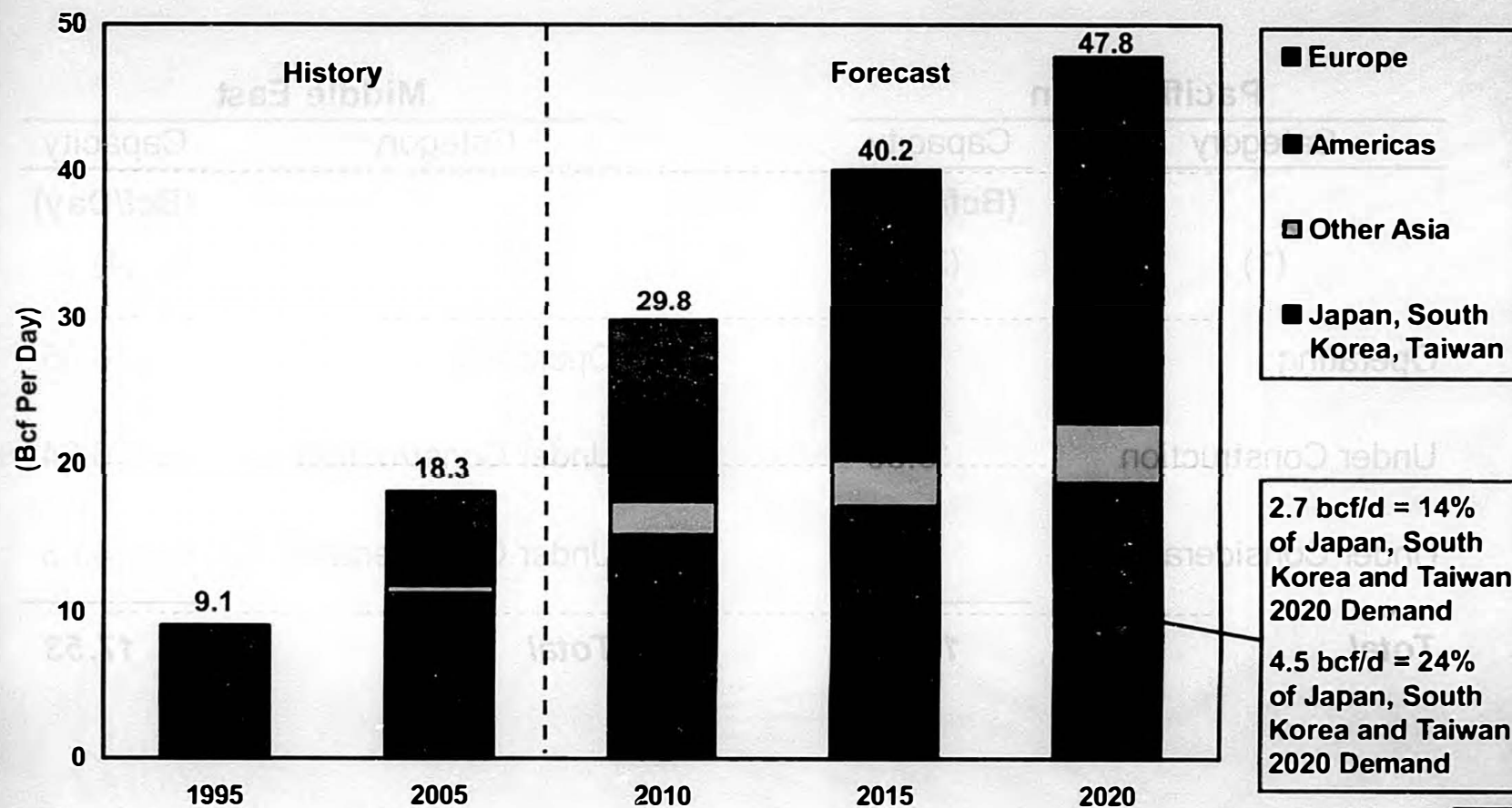
# Current Worldwide LNG Demand



Source: BP Statistical Review 2008

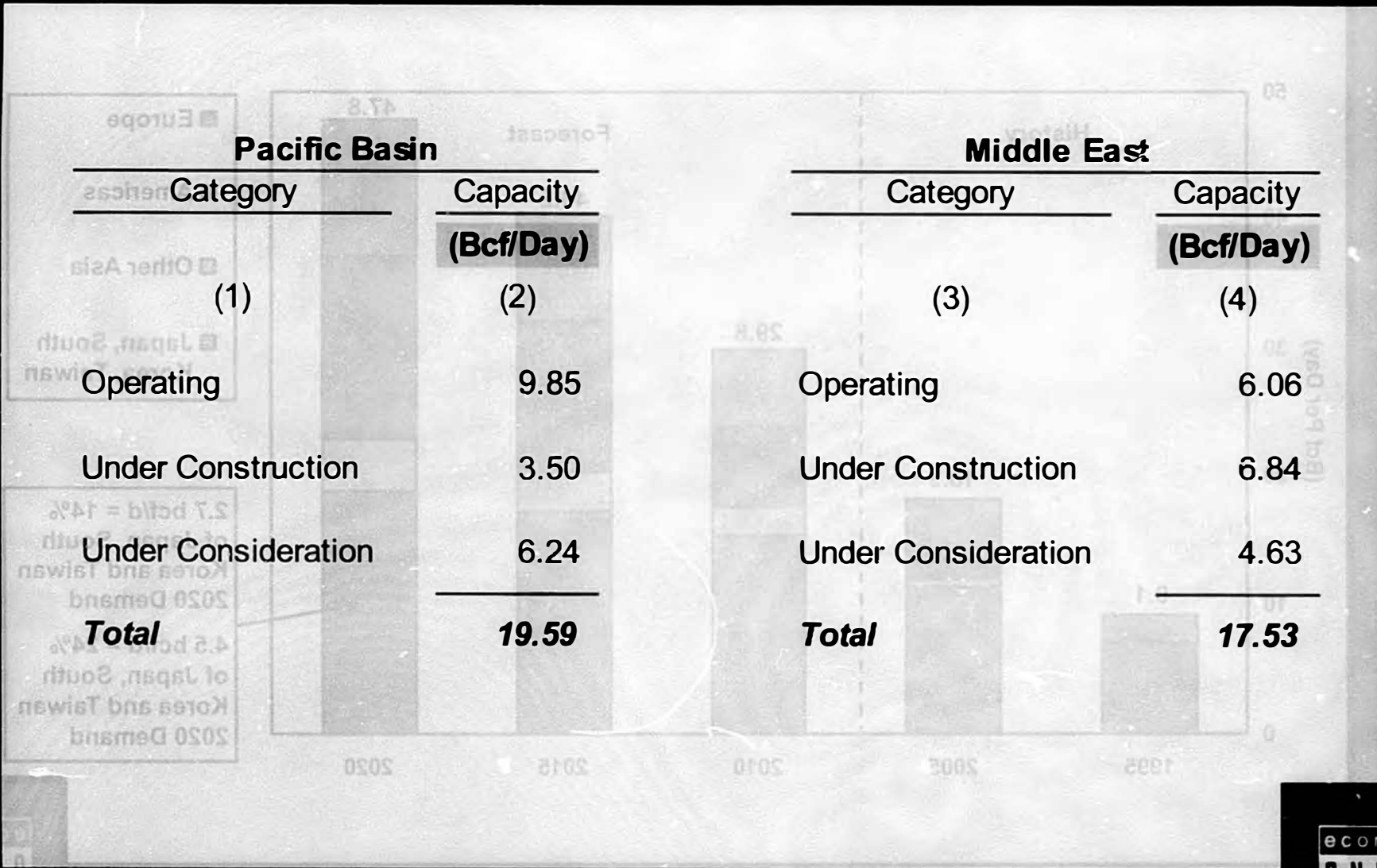


# Projected LNG Demand by Region



Source: National Petroleum Council ;  
Jensen Associates, August 2007

# Liquefaction Plant Capacities by Region (Pacific Trade)

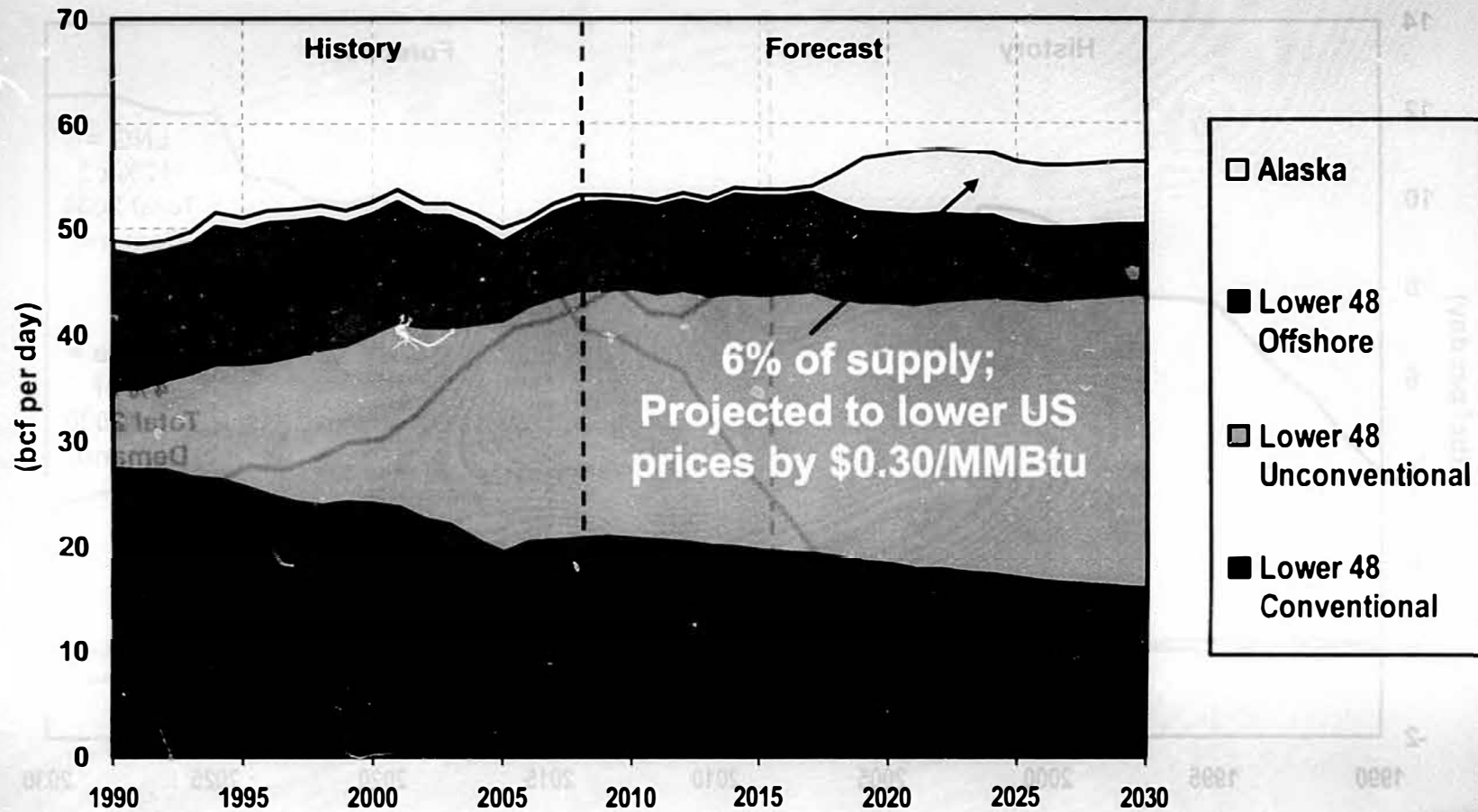


Source: Facts Global Energy, "Evaluating Natural Gas Import Options for the State of Hawaii", April 2007



# U.S. Gas Production by Source

(1990 - 2030)

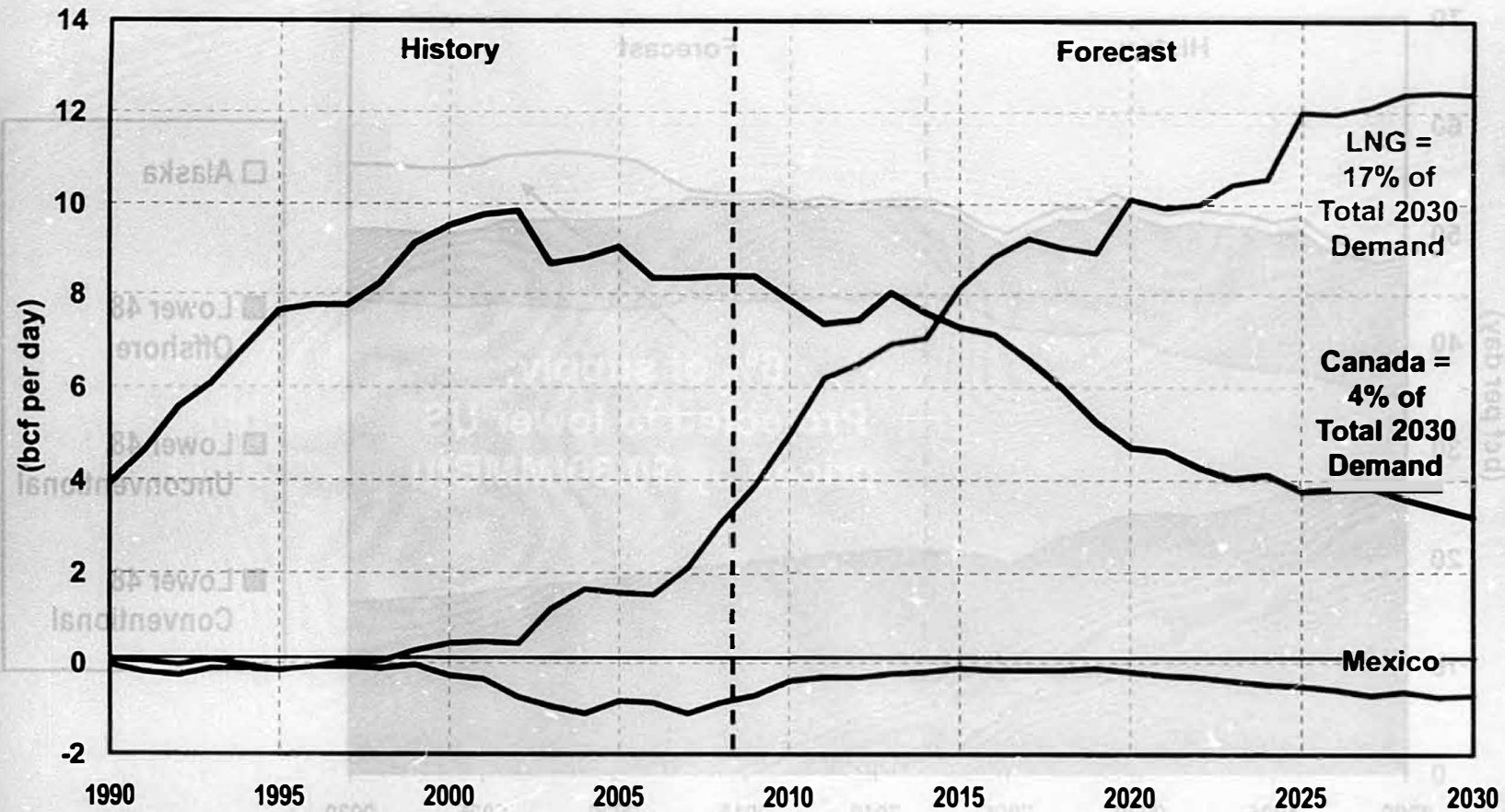


Source: EIA AEO 2007.

econ  
ONE

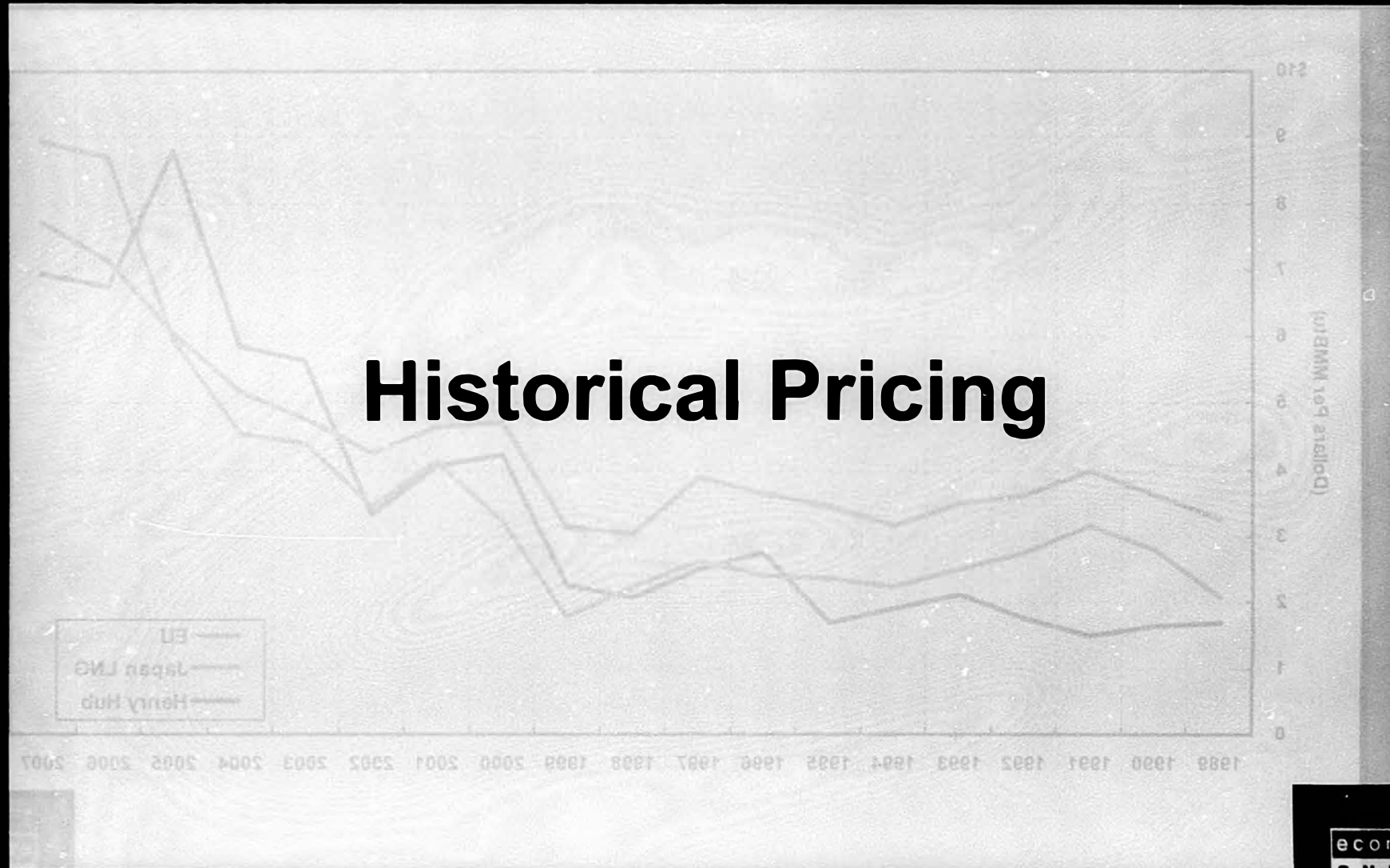
# U.S. Net Natural Gas Imports

(1990 - 2030)



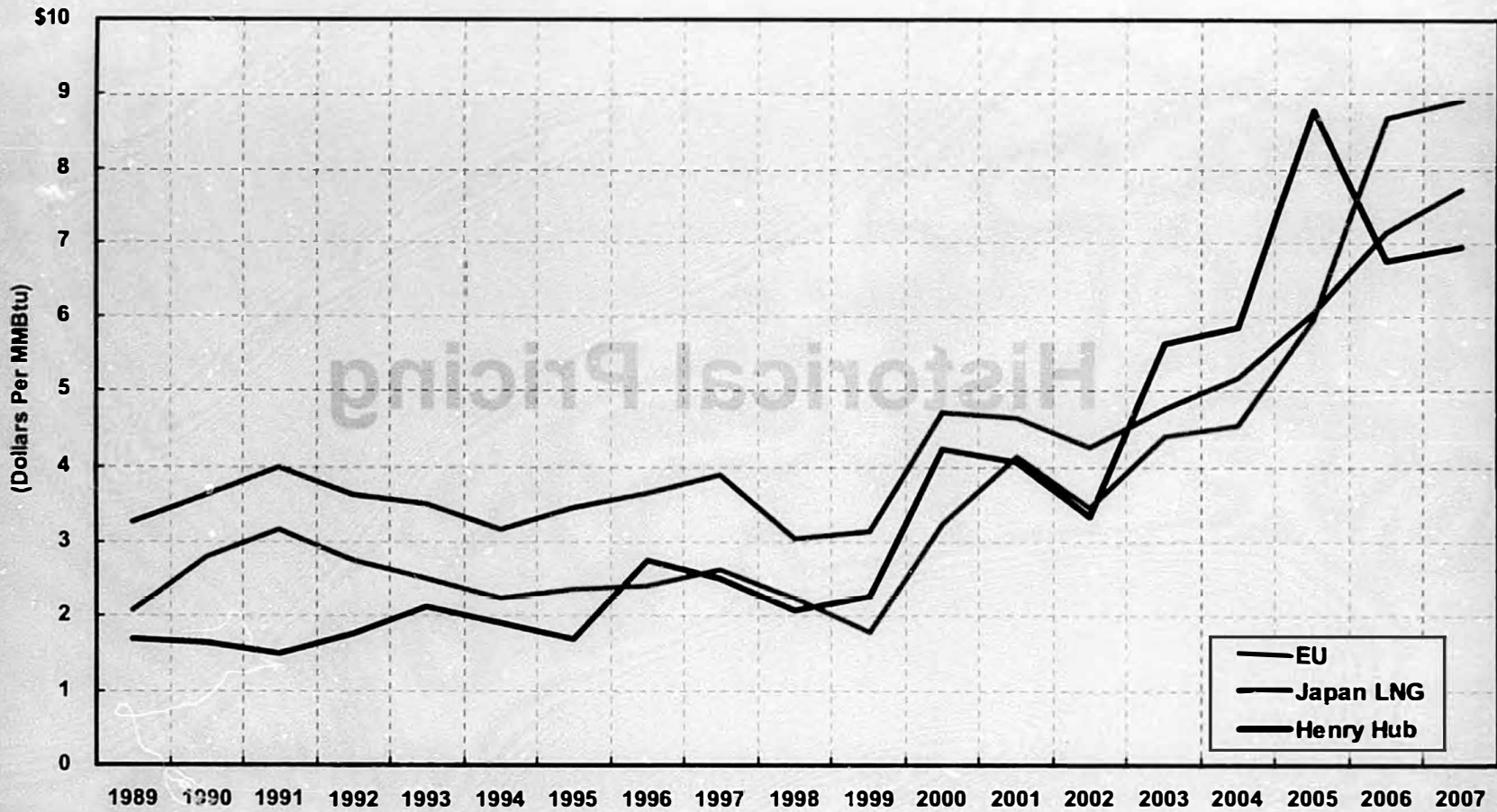
Source: EIA AEO 2007

# Historical Pricing

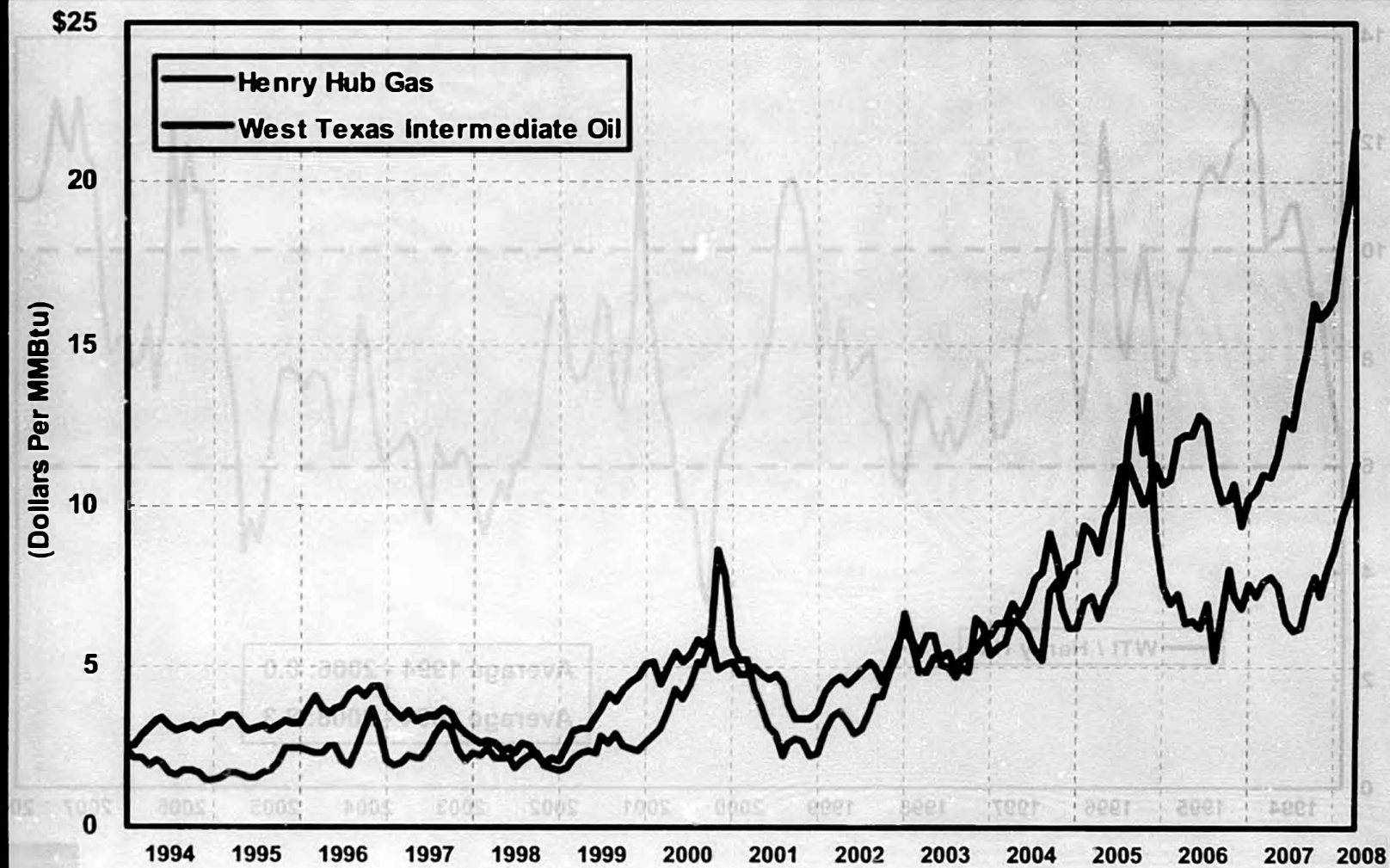


# Historical Gas Prices

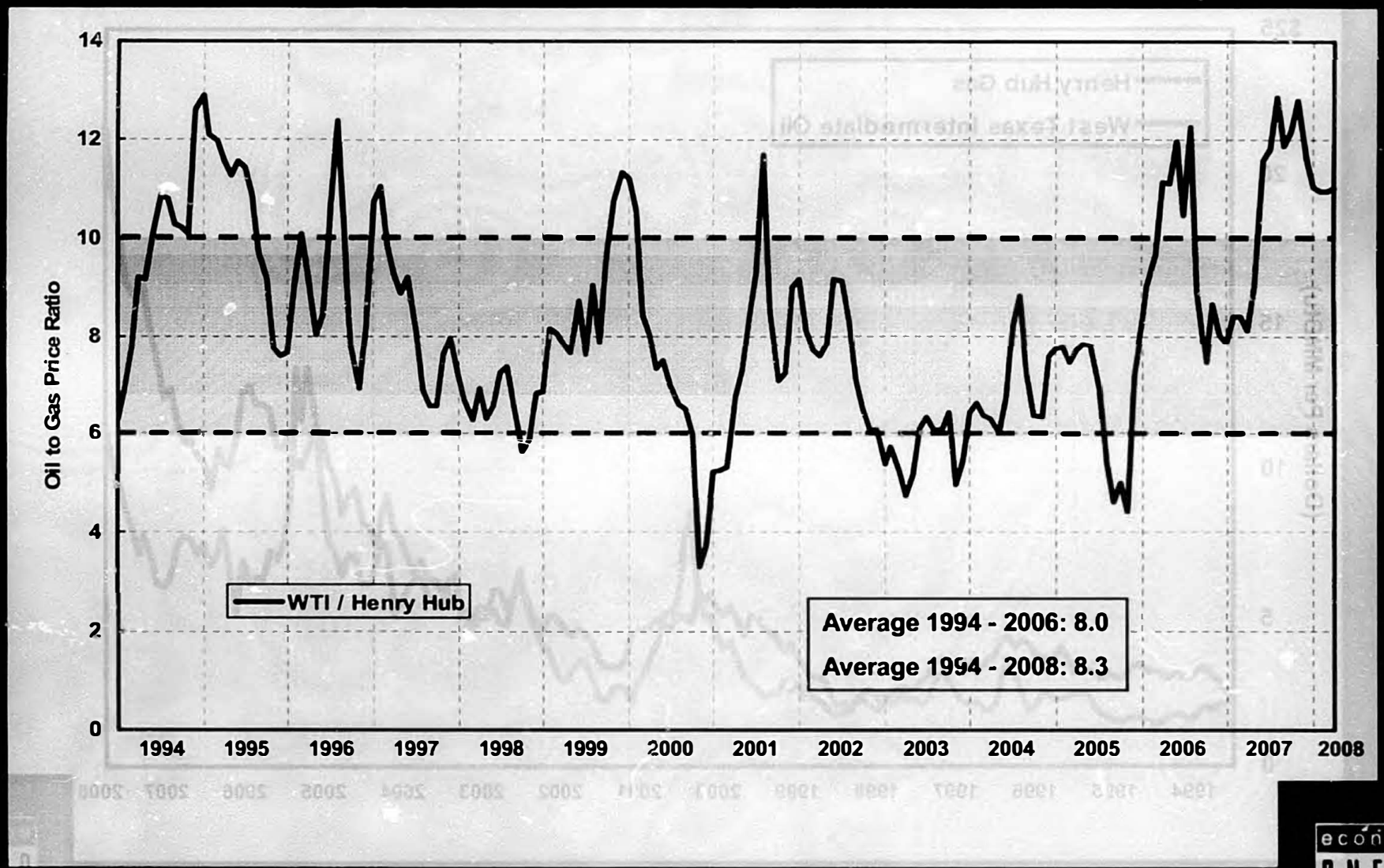
(U.S., Japan and Europe)



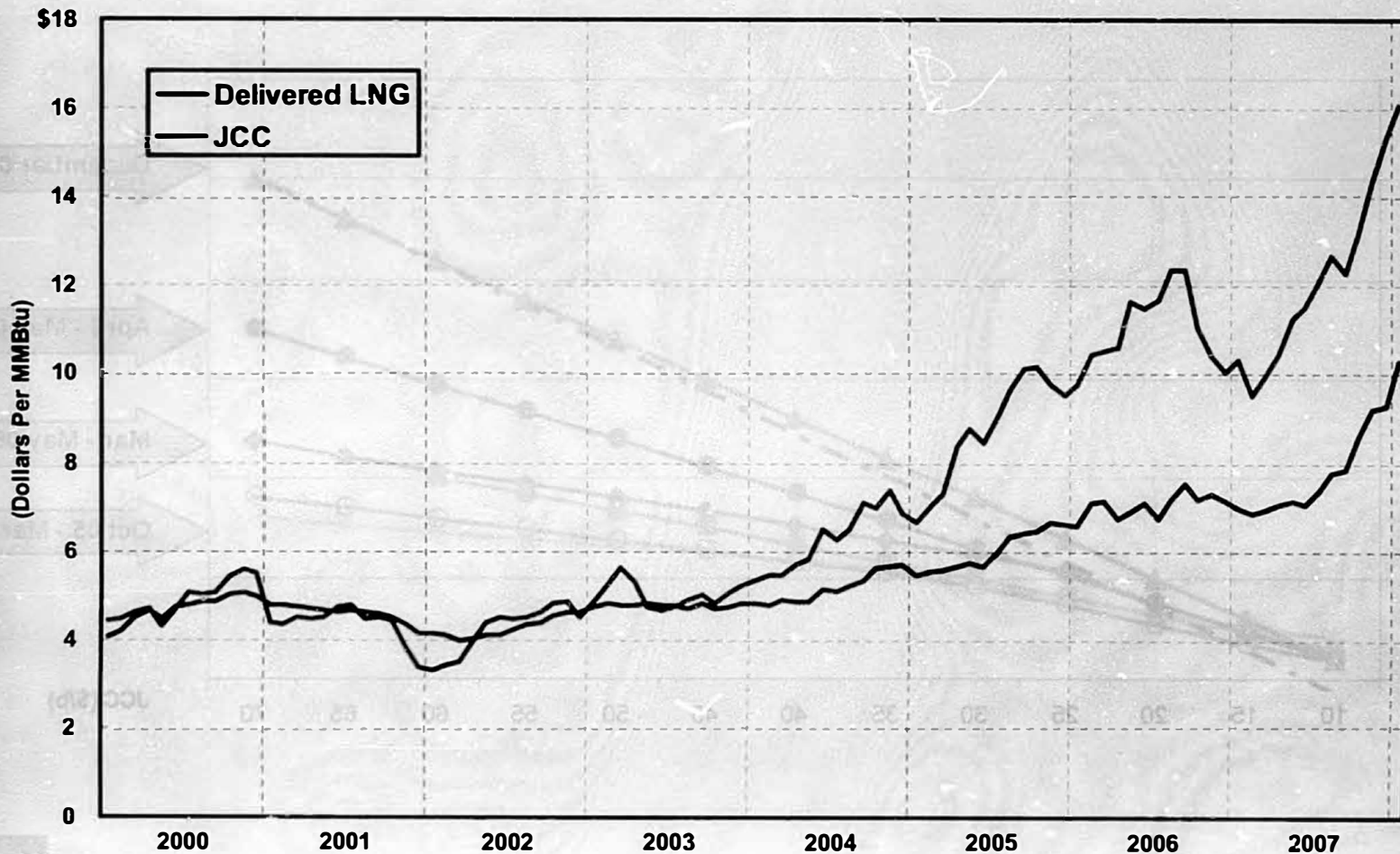
# U.S. Natural Gas and Crude Oil Prices (1994 - 2008)



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

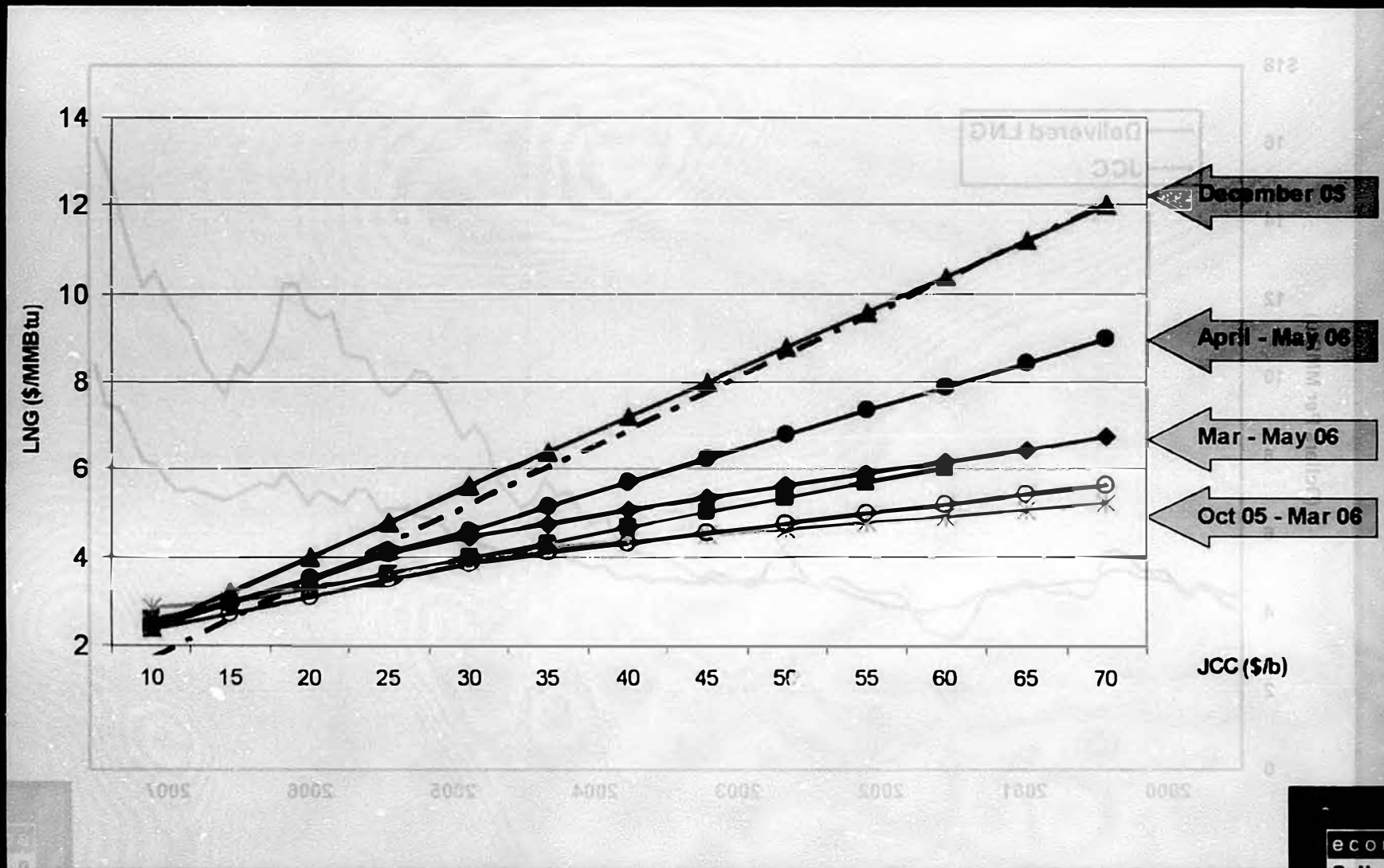


# Japanese Crude Oil and Gas Prices (2000 - 2008)



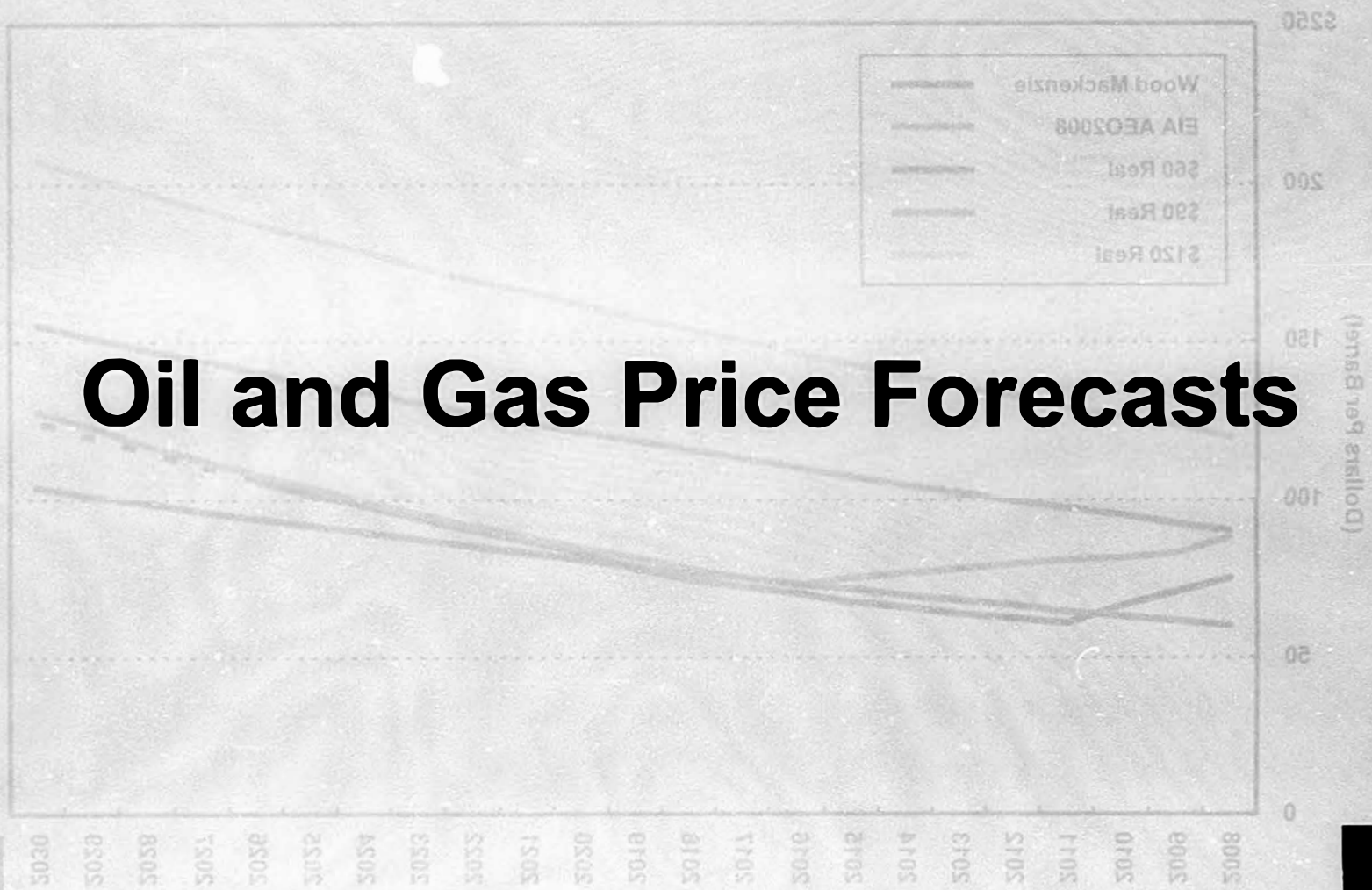
# Evolution of LNG Pricing in Asia

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

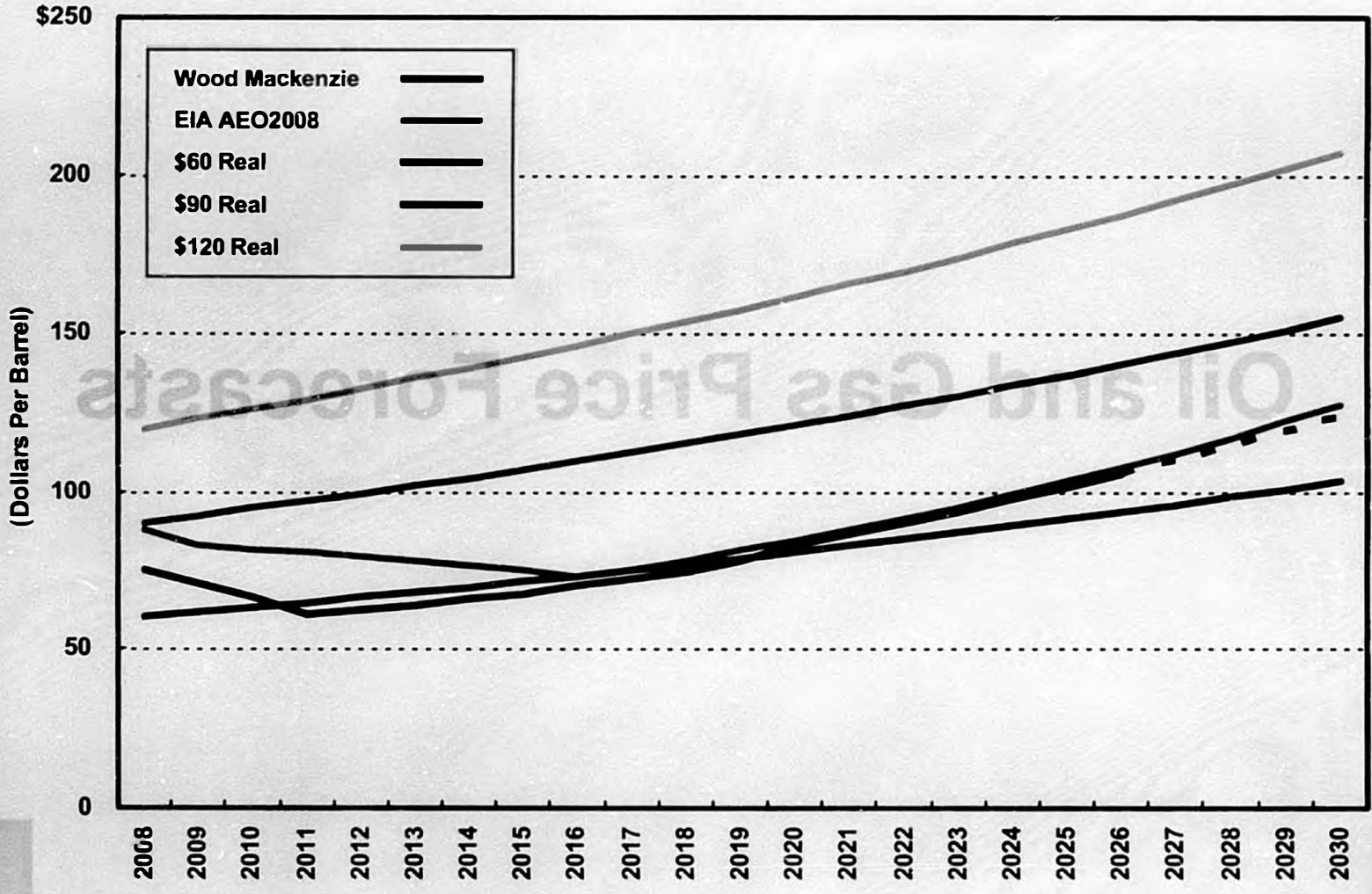


Source: Facts Global Energy, "Evaluating Natural Gas Import Options for the State of Hawaii", April 2007.

# Oil and Gas Price Forecasts



# Oil Prices Used in Analyses



Note: 2.5% annual price inflation

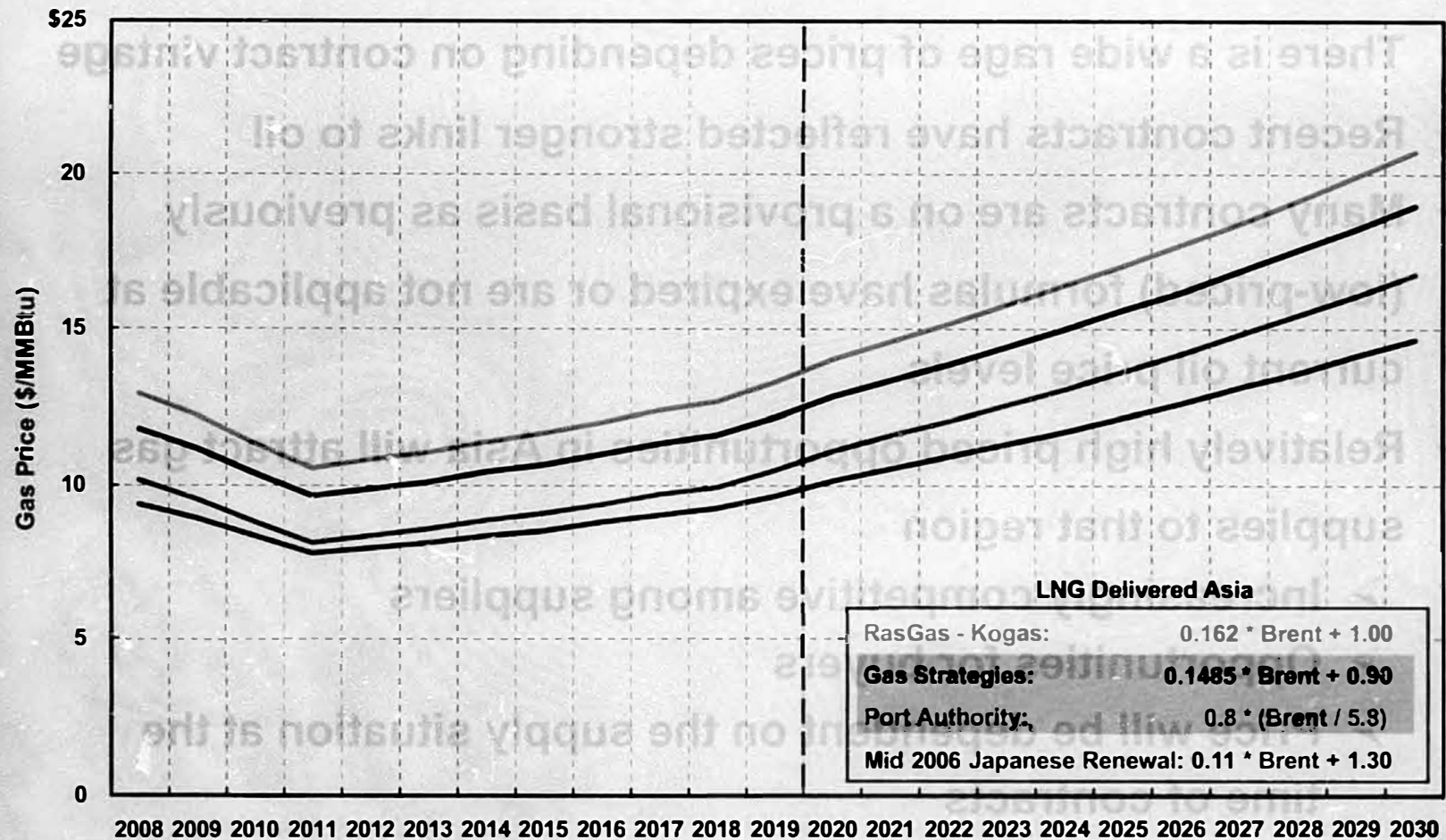


# Prospects for Asian LNG Prices

- There is a wide range 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)

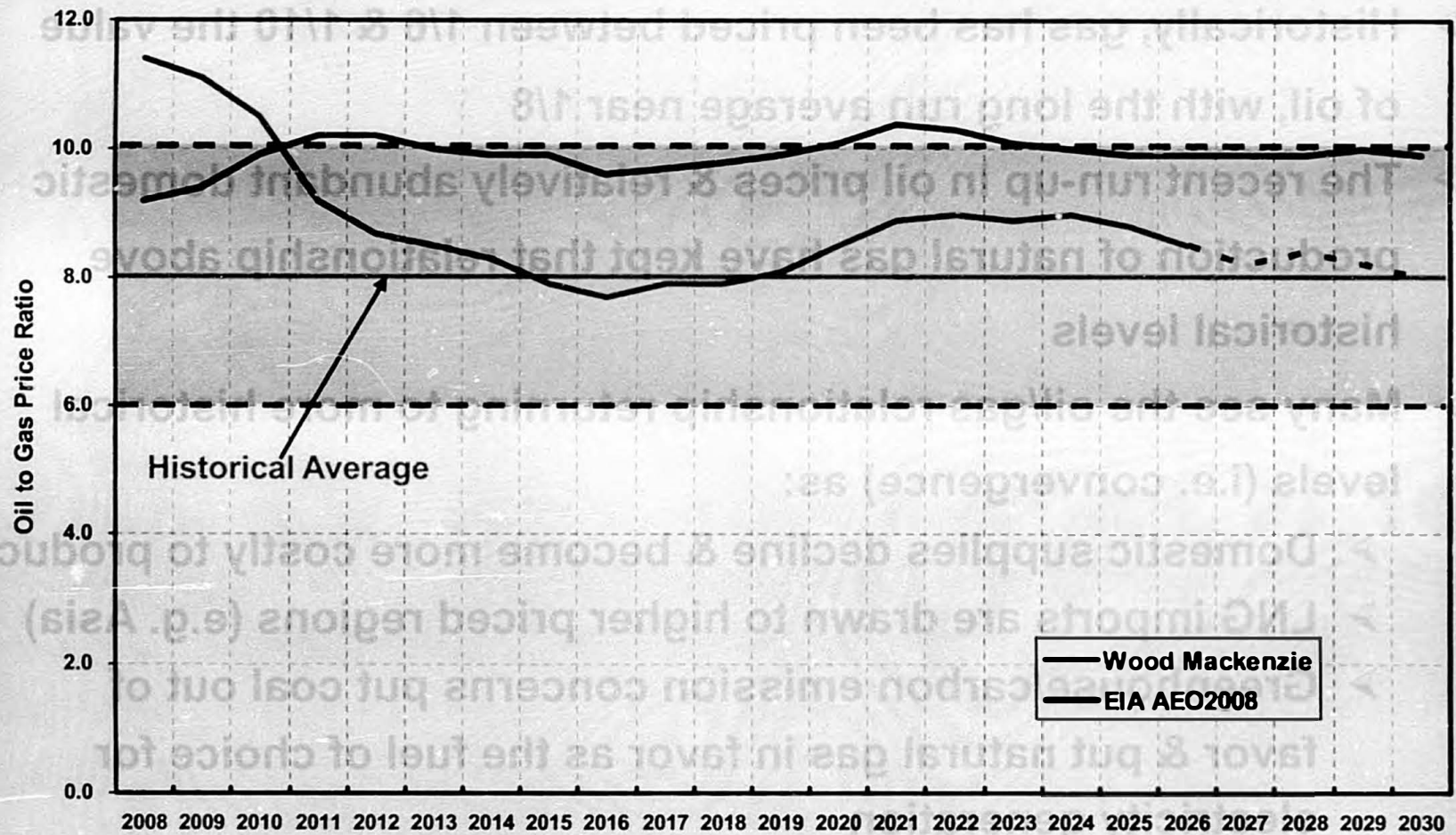


**■ = More Likely Price Scenarios**

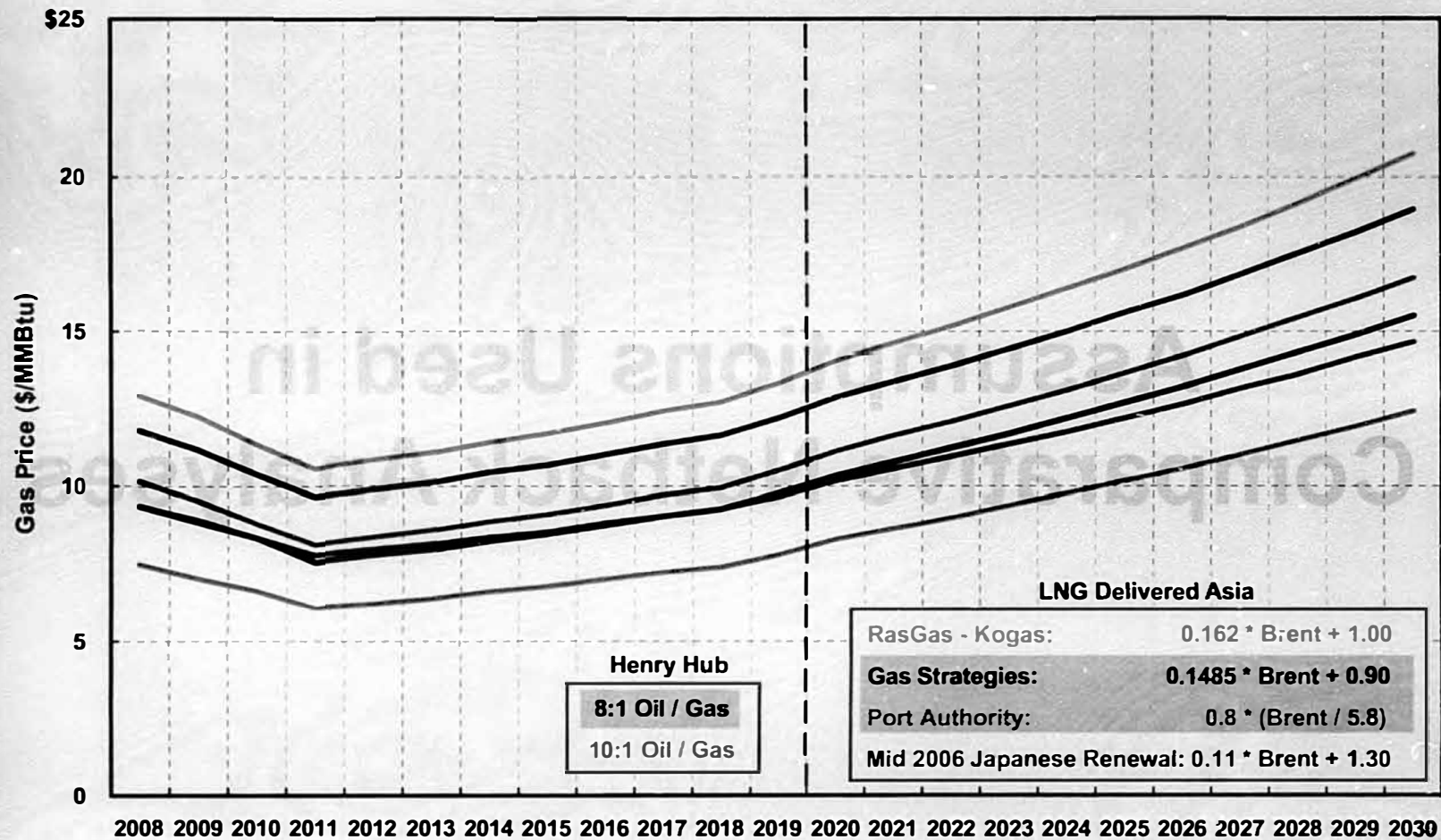
# Prospects for U.S. Gas Prices

- 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

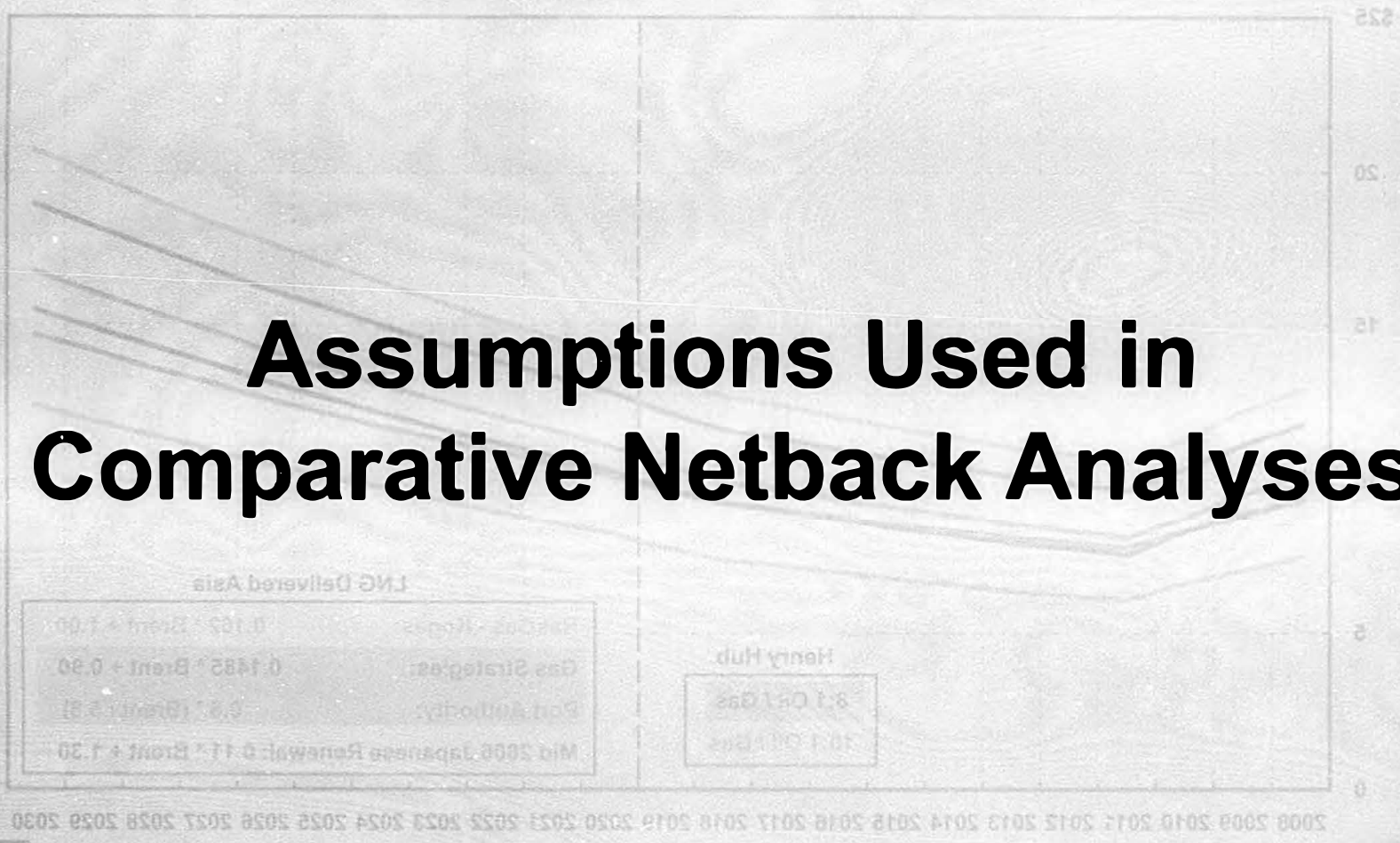


# Gas Price Forecasts Used in Analyses (Using Wood Mackenzie Oil Price Forecast)



**[Shaded Box]** = More Likely Price Scenario(s)

# Assumptions Used in Comparative Netback Analyses



= More Likely Price Scenario(s)



# Assumptions Used in Comparative Netback Analyses

- **First Gas** 2020
- **Capitalization** 70% Debt; 30% Equity (pre-operation)  
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  
Port Authority (Bechtel): LNG plant  
Sensitivity at higher costs
- **Fuel Use** Administration (Westney) for GTP/pipeline segments  
Port Authority (Bechtel) for LNG plant
- **Shipping Costs** Port Authority: Approximately \$0.75/MMBtu + Fuel
- **Gas Composition & NGL Extraction** 1.118 MMBtu / mcf  
Full Extraction @ Alberta  
Partial Extraction @ Valdez (LNG case)

# Comparison of Capital Costs for LNG Project (2.7 bcf/d LNG Project)

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

# 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)
<b>GTP</b>	<b>\$5.0</b>	<b>\$8.3</b>	<b>\$6.5</b>	<b>\$8.3</b>
<b>Pipeline</b>				
<b>Alaska</b>	11.5	12.6	10.2	10.9
<b>Canada</b>	-	-	11.6	12.6
<b>Total Pipeline</b>	<b>\$11.5</b>	<b>\$12.6</b>	<b>\$21.7</b>	<b>\$23.5</b>
<b>LNG Plant (Bechtel)</b>	7.9	13.7*	-	-
<b>LNG Plant (Westney)</b>	12.7	21.1	-	-
<b>Total (Bechtel LNG)</b>	<b>\$24.4</b>	<b>\$34.6*</b>	<b>\$28.2</b>	<b>\$31.8</b>
<b>Total (Westney LNG)</b>	<b>\$29.2</b>	<b>\$42.0</b>	<b>\$28.2</b>	<b>\$31.8</b>

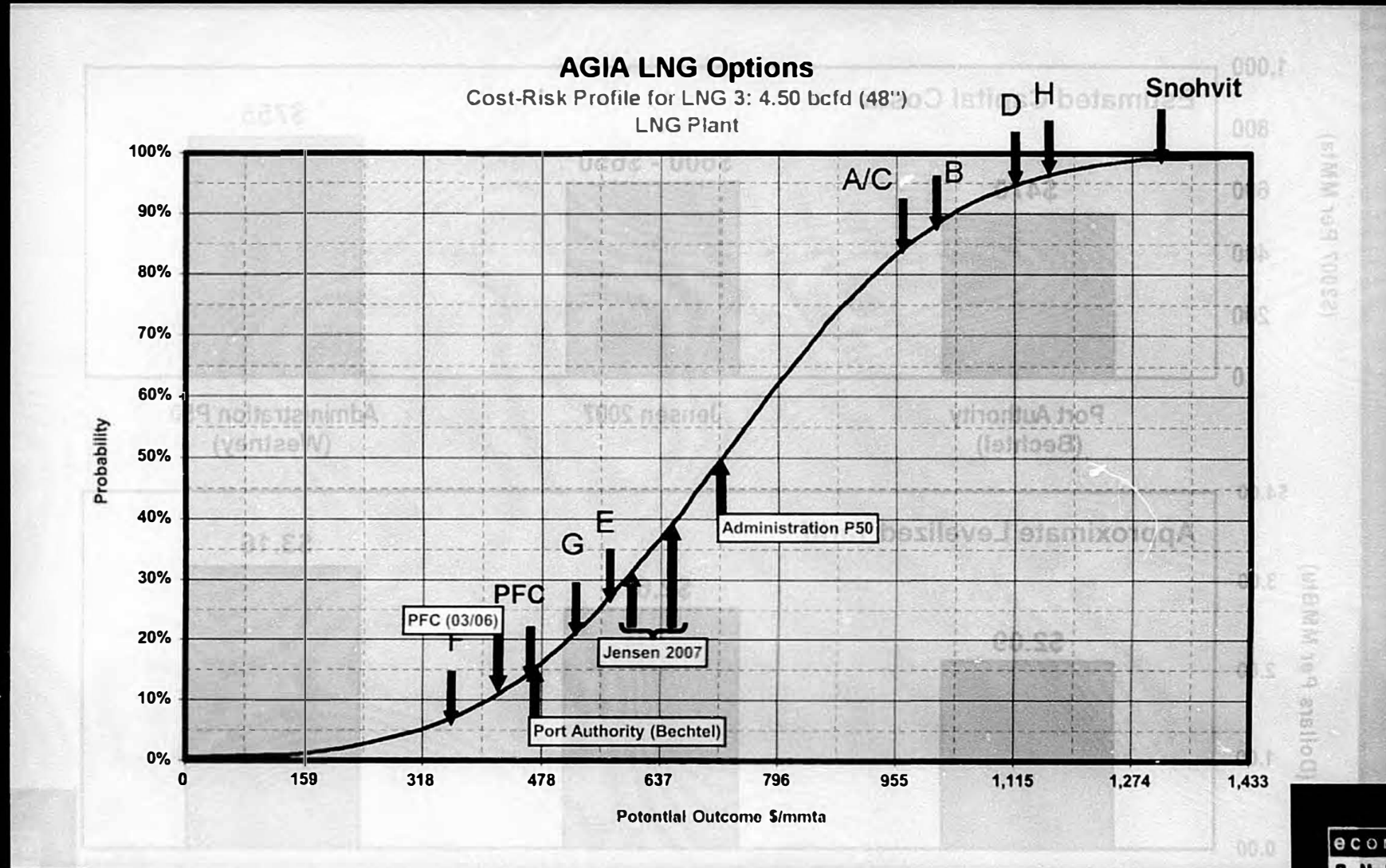
\* Based on \$470/mt.

Pipeline Project		LNG Project	
4.5 bcft/d	3.5 bcft/d	4.5 bcft/d	2.7 bcft/d
(4)	(3)	(2)	(1)
\$8.3	\$8.5	\$8.3	\$8.0
10.9	10.2	10.8	10.2
12.6	11.6	11.6	11.6
\$23.5	\$21.7	\$21.6	\$21.5
-	-	13.7*	7.9
-	-	21.1	12.7
\$31.8	\$28.2	\$34.6*	\$24.4
\$31.8	\$28.2	\$42.0	\$29.2

# LNG Plant Costs



# LNG Plant Costs Per Administration (Westney) (\$2007 per mmta)

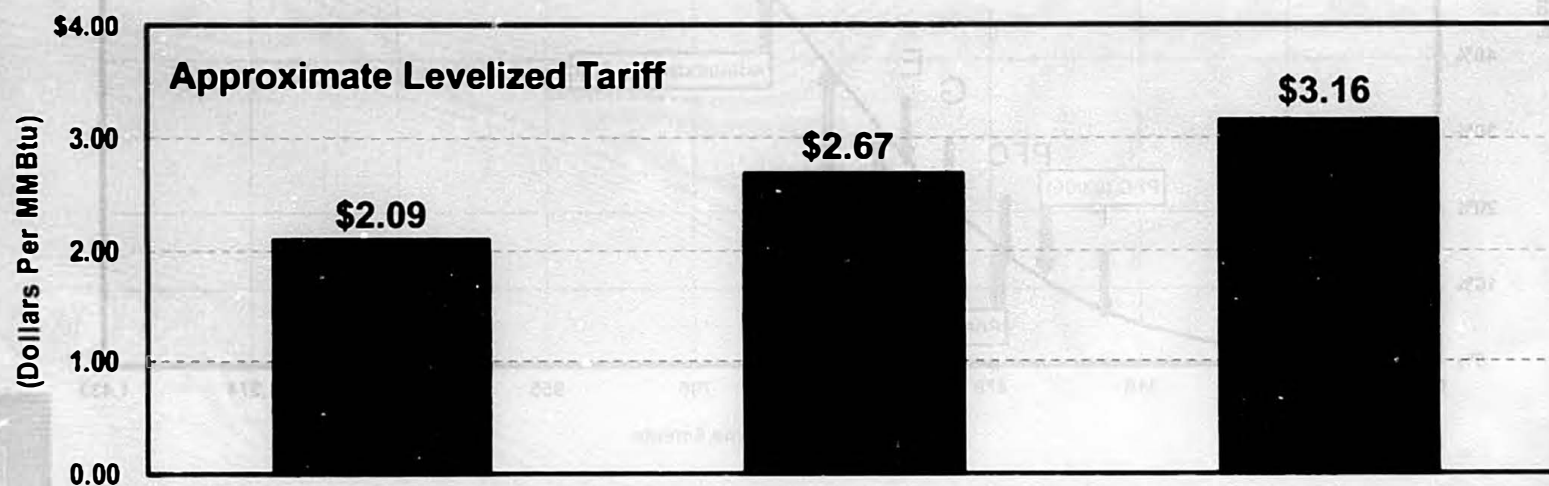
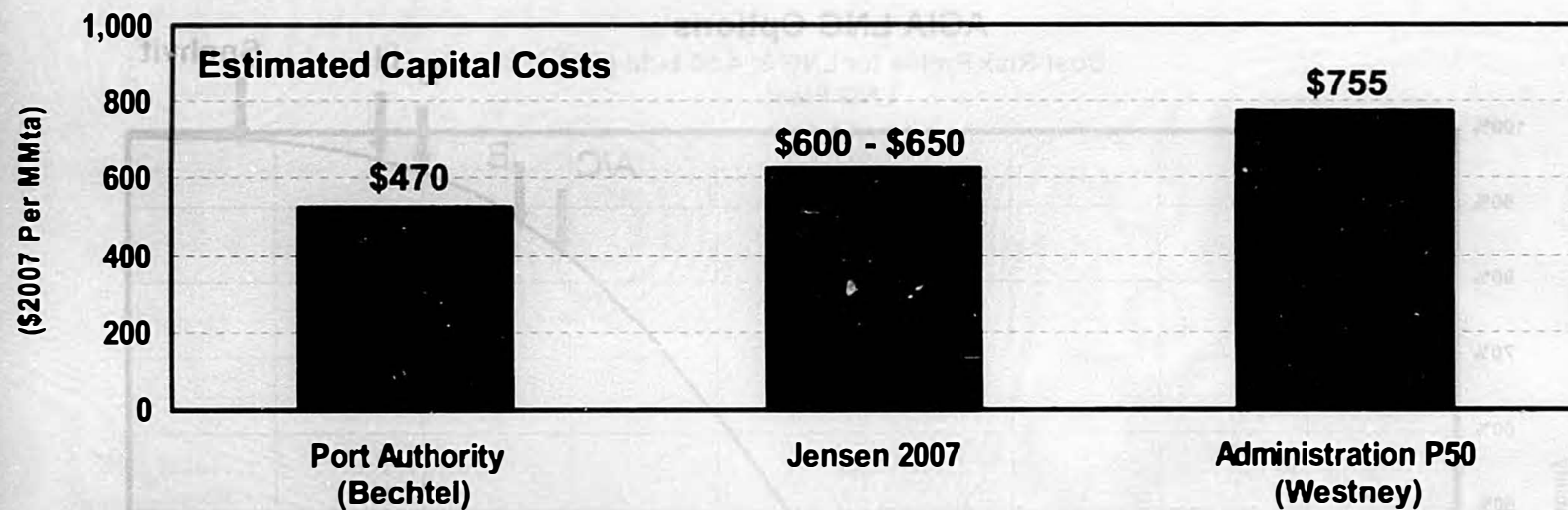


Source: AGIA Analysis Technical Team, "LNG Project Costs/Schedule", June 9, 2008.

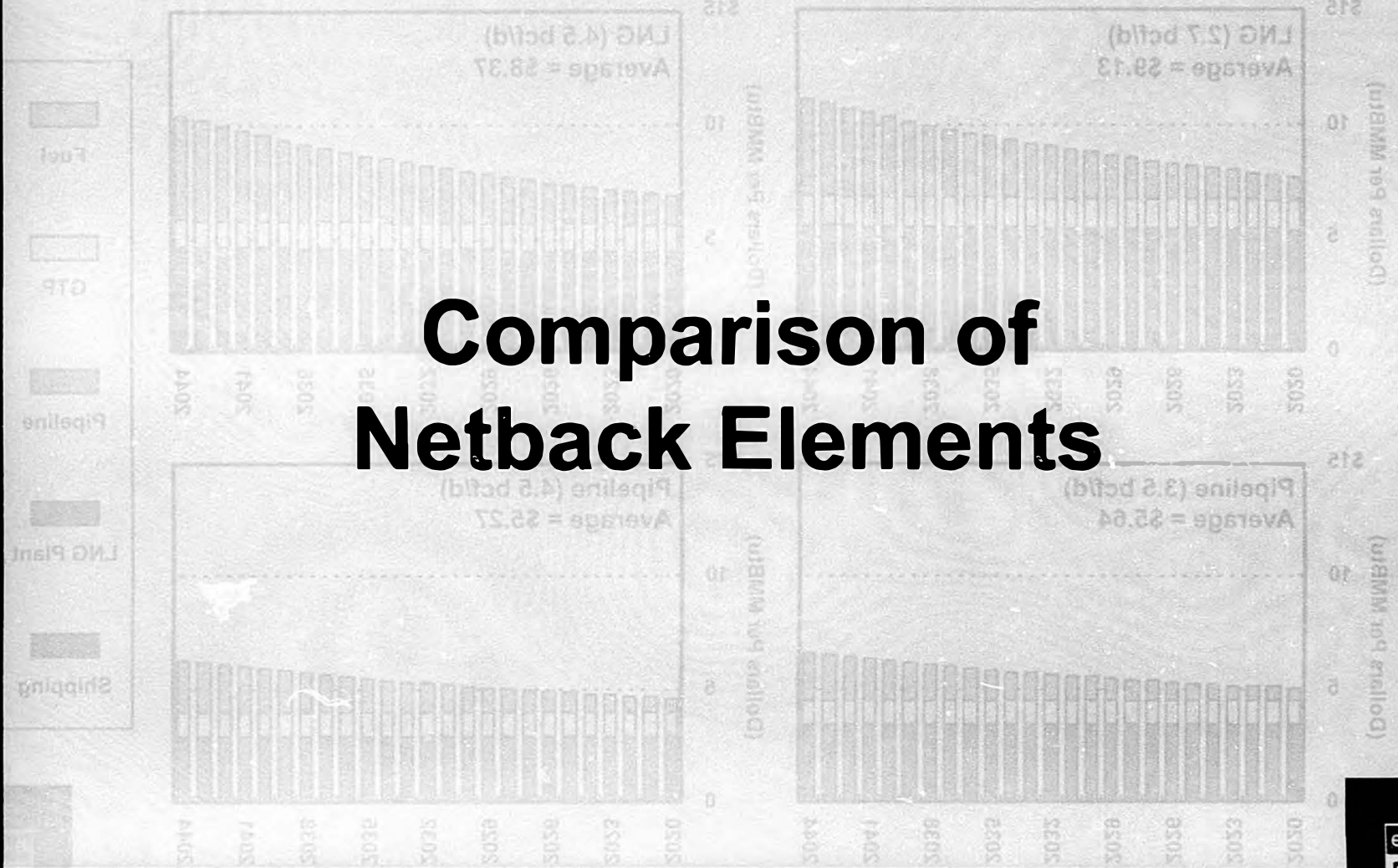


# Range of LNG Liquefaction Costs and Tariffs

(2.7 bcf/d LNG Project)

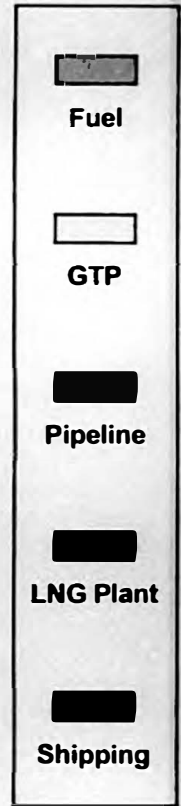
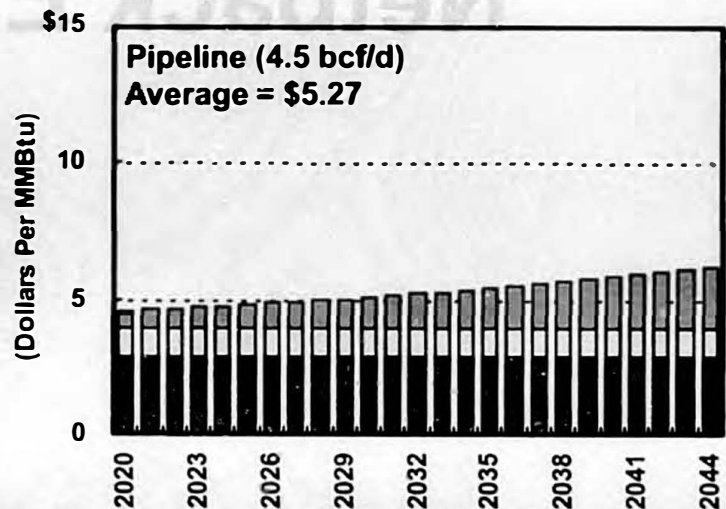
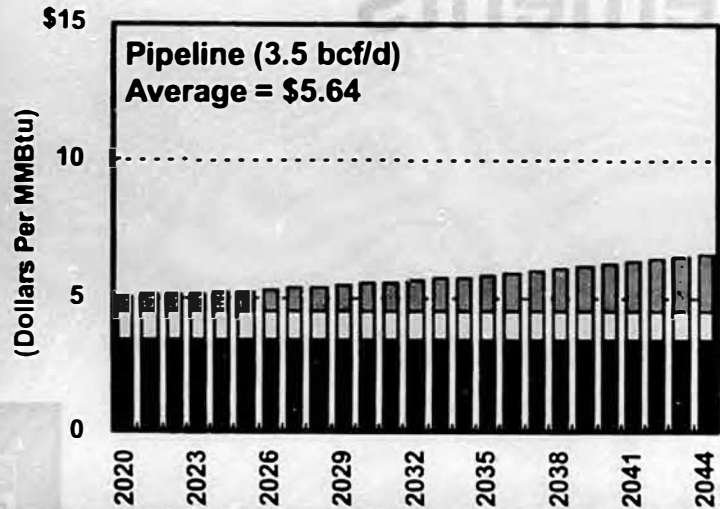
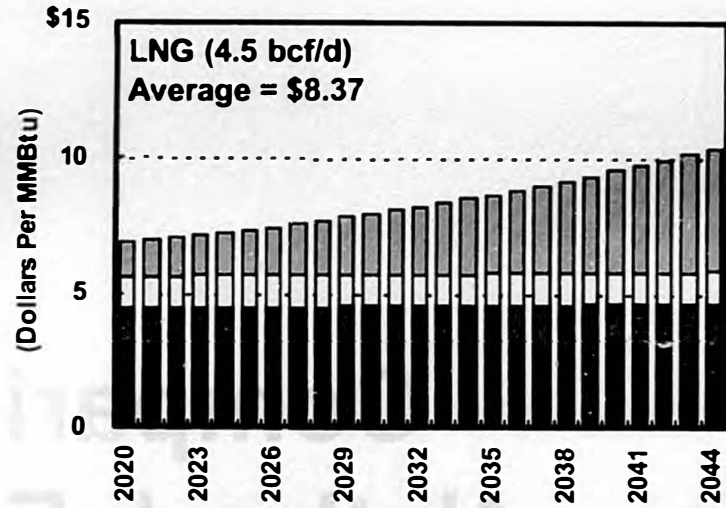
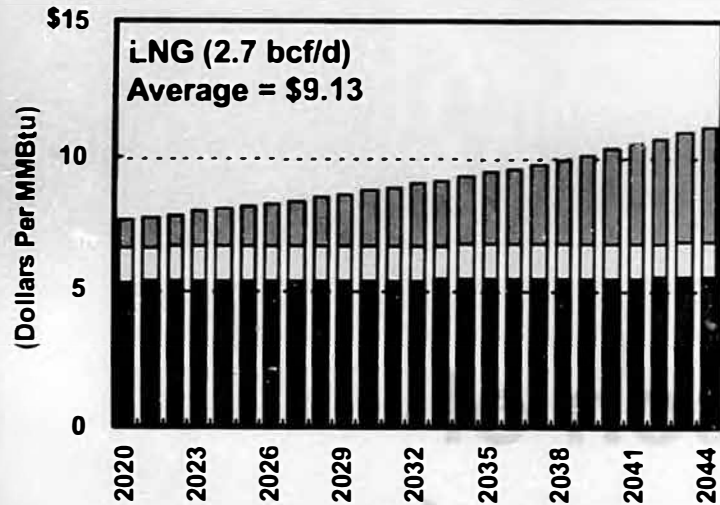


# Comparison of Netback Elements



# Comparison of Potential Costs

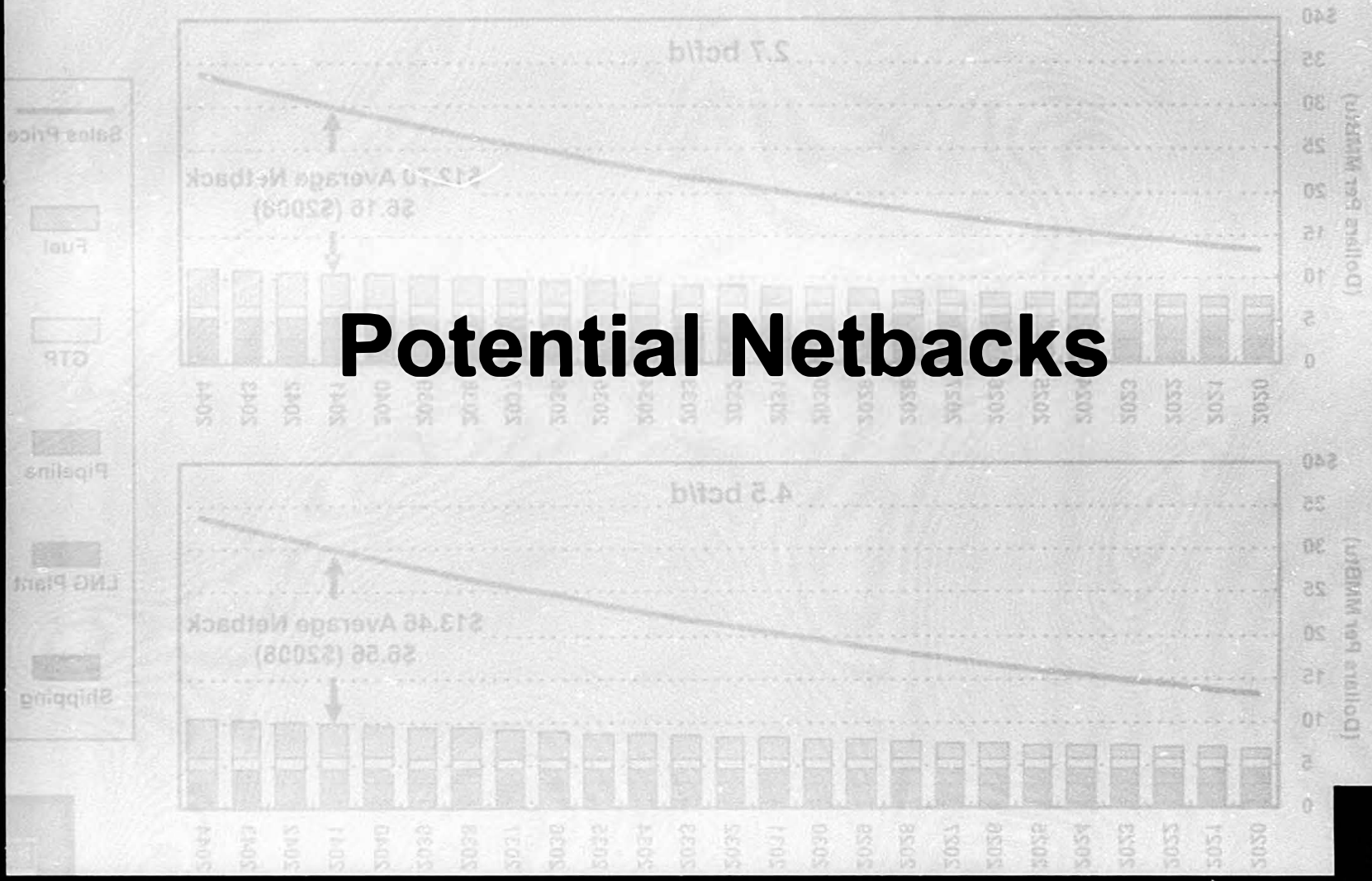
## LNG Project v. Pipeline Project 2020 - 2044



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

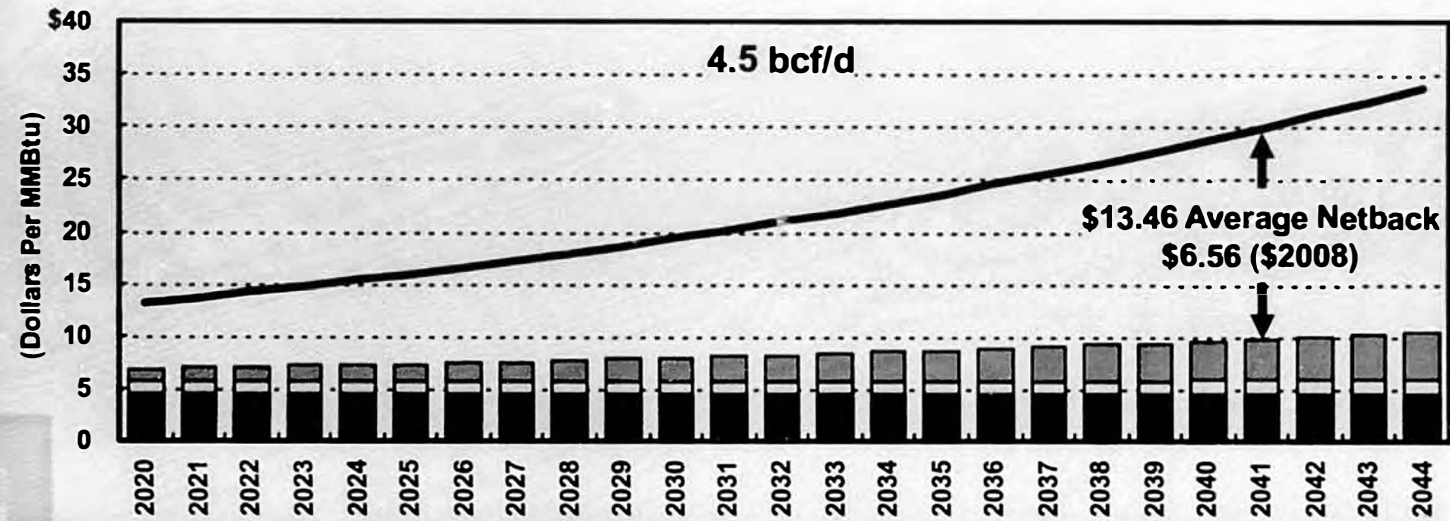
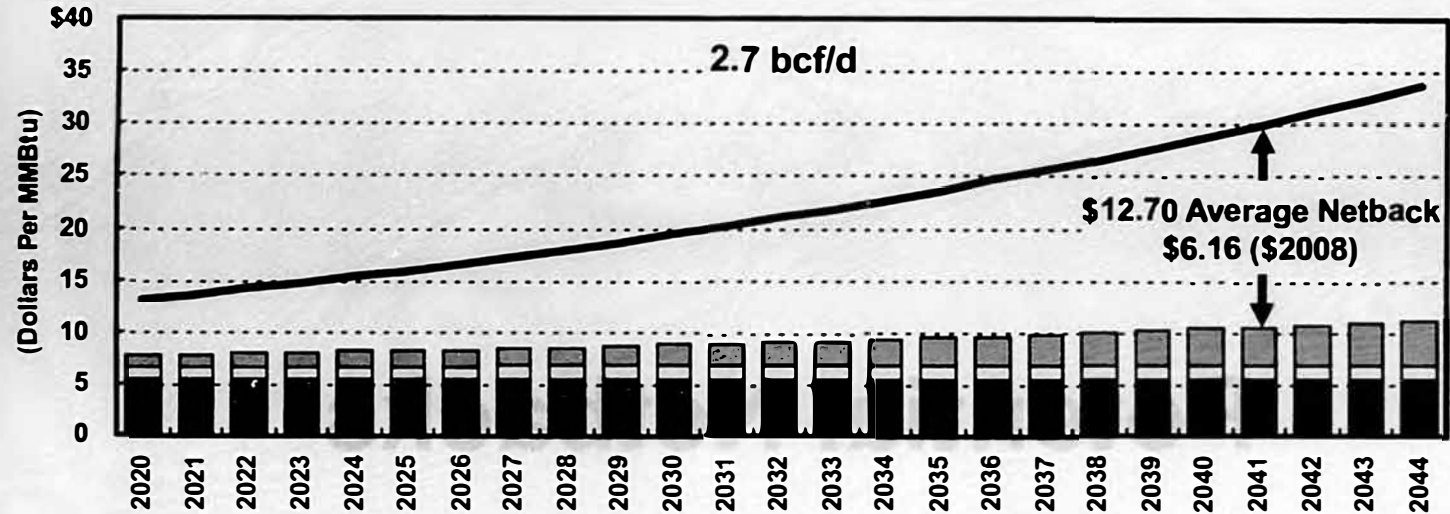


# Potential Netbacks



# Potential Netbacks for LNG Delivery to Asia

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

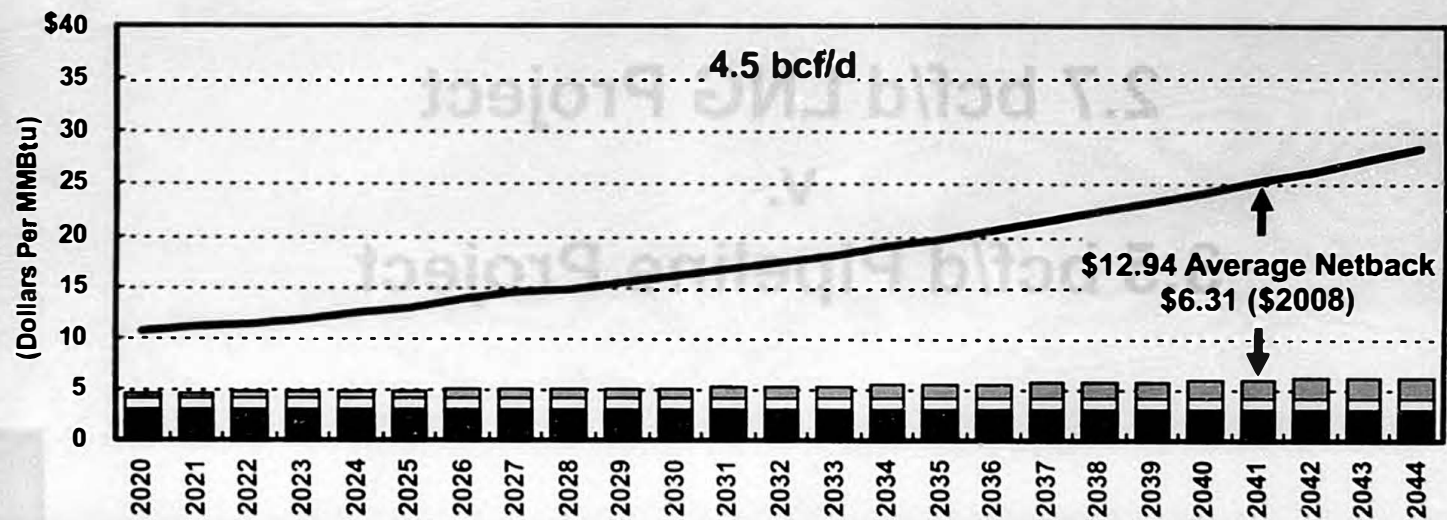
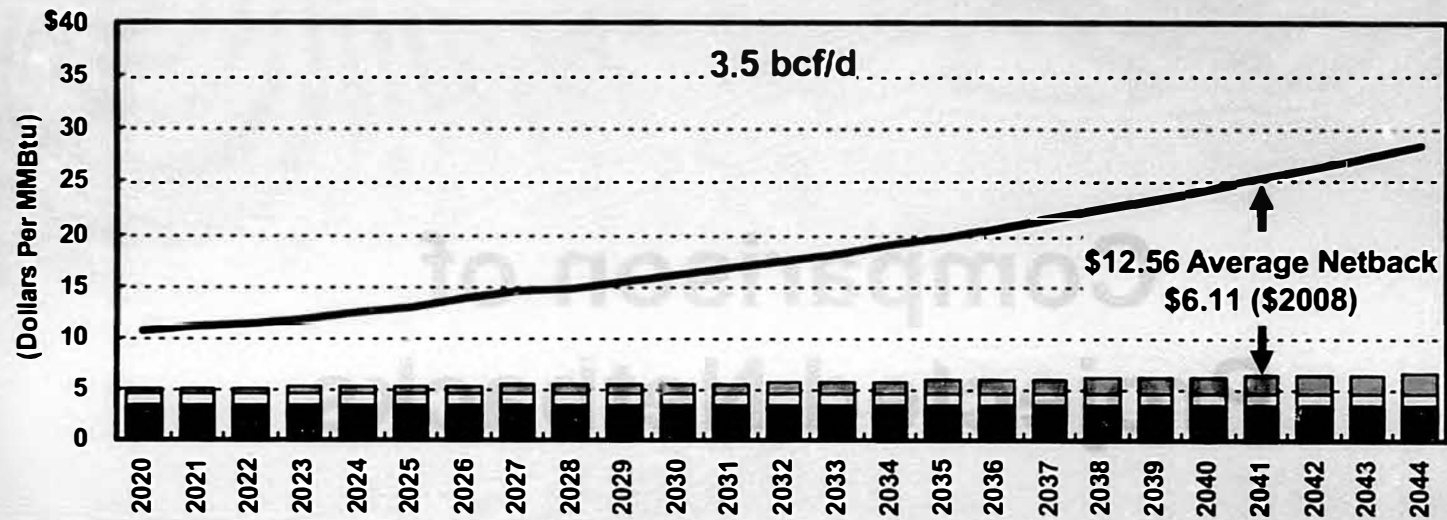


Note: Oil Prices per Wood Mackenzie forecasts:  
LNG Plant cost of \$470/mmta per Port Authority application.



# Potential Netbacks for AECO Pipeline Delivery

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



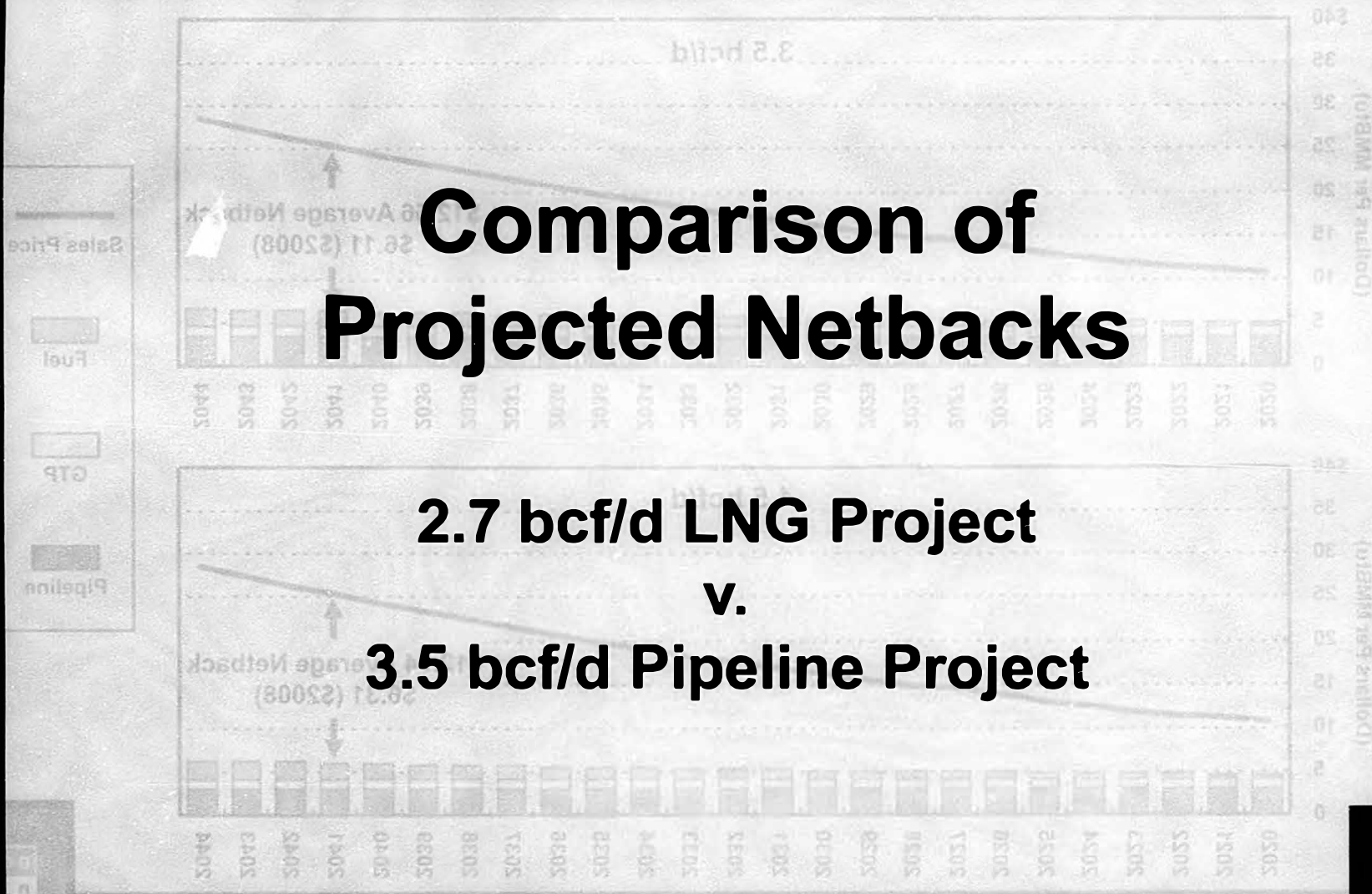
Note: Oil Prices per Wood Mackenzie forecasts.

# 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 (1)	Gas Strategies Asia Gas = 0.1485 x Brent +\$0.90 (2)	Port Authority Asia Gas = 0.8 x (Brent / 5.8) (3)	Low Price Asia Gas = 0.11 x Brent +\$1.30 (4)	8:1 Oil/Gas Price Ratio (5)	10:1 Oil/Gas Price Ratio (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
<b>Netback in \$2008 dollars (per MMBt)</b>	<b>\$6.93</b>	<b>\$6.16</b>	<b>\$5.22</b>	<b>\$4.25</b>	<b>\$6.11</b>	<b>\$4.75</b>
	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)

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

3.5 bcf/d  
AECO Pipeline Delivery  
10.1 Dth/Gas  
Price Ratio

(6)	(5)
212.20	218.27
(6.98)	(6.84)
29.82	212.88
24.75	28.11
(5)	(3)
2389.1	2472.0
178.8	229.8
31.8	41.8
(3)	(1)

# Comparison of Projected Netbacks

## 2.7 bcf/d LNG Project

v.

## 4.5 bcf/d Pipeline Project

= More Likely Price Scenario(s)



# 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 (1)	Gas Strategies Asia Gas = 0.1485 x Brent +\$0.90 (2)	Port Authority Asia Gas = 0.8 x (Brent / 5.8) (3)	Low Price Asia Gas = 0.11 x Brent +\$1.30 (4)	8:1 Oil/Gas Price Ratio (5)	10:1 Oil/Gas Price Ratio (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 ①	\$6.16 ③	\$5.22 ④	\$4.25 ⑥	\$6.31 ②	\$4.96 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 ③	31.0 ④	25.6 ⑤	20.9 ⑥	55.9 ①	43.3 ②

③ ④ ⑤ ⑥ = More Likely Price Scenario(s)

# Comparison of Projected Netbacks

4.5 bcf/d LNG Project

v.

4.5 bcf/d Pipeline Project

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

4.5 bcf/d AECO Pipeline Delivery		4.5 bcf/d LNG Project	
Price Ratio	Price Ratio	Price Ratio	Price Ratio
(6)	(5)	(4)	(3)
\$18.20	\$18.20	\$18.20	\$18.20
(4.99)	(5.28)	(5.28)	(5.28)
\$10.25	\$10.25	\$10.25	\$10.25
\$4.98	\$4.98	\$4.98	\$4.98
(5)	(2)	(6)	(1)
\$193.5	\$193.5	\$193.5	\$193.5
239.5	239.5	239.5	239.5
43.3	43.3	43.3	43.3
(2)	(1)	(8)	(4)

= More Likely Price Scenario(s)

# 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 (1)	Gas Strategies Asia Gas = 0.1485 x Brent +\$0.90 (2)	Port Authority Asia Gas = 0.8 x (Brent / 5.8) (3)	Low Price Asia Gas = 0.11 x Brent +\$1.30 (4)	8:1 Oil/Gas Price Ratio (5)	10:1 Oil/Gas Price Ratio (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
<b>Netback in \$2008 dollars (per MMBt)</b>	<b>\$7.33</b>	<b>\$6.56</b>	<b>\$5.63</b>	<b>\$4.66</b>	<b>\$6.31</b>	<b>\$4.96</b>
	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
<b>NPV-10 (\$Bn)</b>	<b>65.3</b>	<b>58.2</b>	<b>49.0</b>	<b>40.7</b>	<b>55.9</b>	<b>43.3</b>
	①	②	④	⑥	③	⑤

**[Shaded Area]** = More Likely Price Scenario(s)



# 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 AECO Pipeline Delivery		4.5 bcf/d LNG Project	
Oil Price (\$/bbl)	Price Ratio	Oil Price (\$/bbl)	Price Ratio
100	1.00	100	1.00
120	1.20	120	1.20
140	1.40	140	1.40
160	1.60	160	1.60
180	1.80	180	1.80
200	2.00	200	2.00
220	2.20	220	2.20
240	2.40	240	2.40
260	2.60	260	2.60
280	2.80	280	2.80
300	3.00	300	3.00
320	3.20	320	3.20
340	3.40	340	3.40
360	3.60	360	3.60
380	3.80	380	3.80
400	4.00	400	4.00
420	4.20	420	4.20
440	4.40	440	4.40
460	4.60	460	4.60
480	4.80	480	4.80
500	5.00	500	5.00
520	5.20	520	5.20
540	5.40	540	5.40
560	5.60	560	5.60
580	5.80	580	5.80
600	6.00	600	6.00
620	6.20	620	6.20
640	6.40	640	6.40
660	6.60	660	6.60
680	6.80	680	6.80
700	7.00	700	7.00
720	7.20	720	7.20
740	7.40	740	7.40
760	7.60	760	7.60
780	7.80	780	7.80
800	8.00	800	8.00
820	8.20	820	8.20
840	8.40	840	8.40
860	8.60	860	8.60
880	8.80	880	8.80
900	9.00	900	9.00
920	9.20	920	9.20
940	9.40	940	9.40
960	9.60	960	9.60
980	9.80	980	9.80
1000	10.00	1000	10.00

- High Sustained Oil Prices
- Impact of Project Delay



# Projected Netbacks Under Alternative Projects

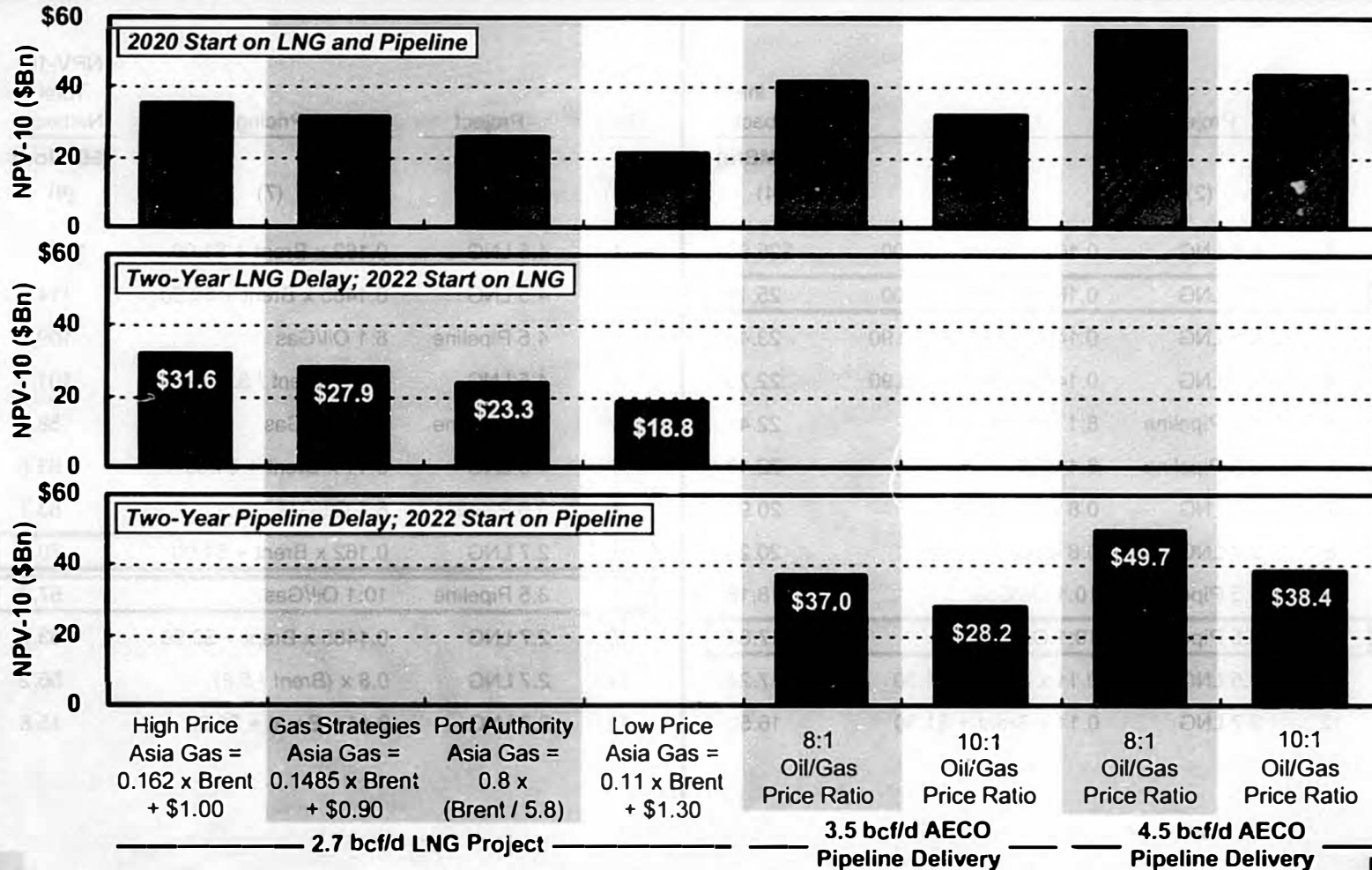
(High Price Case: Fixed \$120 Real WTI in \$2008)

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



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

2.7 bcf/d LNG Project      3.5 bcf/d AECO Pipeline Delivery      4.5 bcf/d AECO Pipeline Delivery

**■ = More Likely Price Scenario(s)**



# LNG Export Issues

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

# LNG Export Issues

- **Yukon Pacific permit for export**
  - **Issued in 1989**
  - **14mmta (~1.9 bcf/d) to Japan, South Korea, Taiwan**
  - **25 years from 1<sup>st</sup> 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**

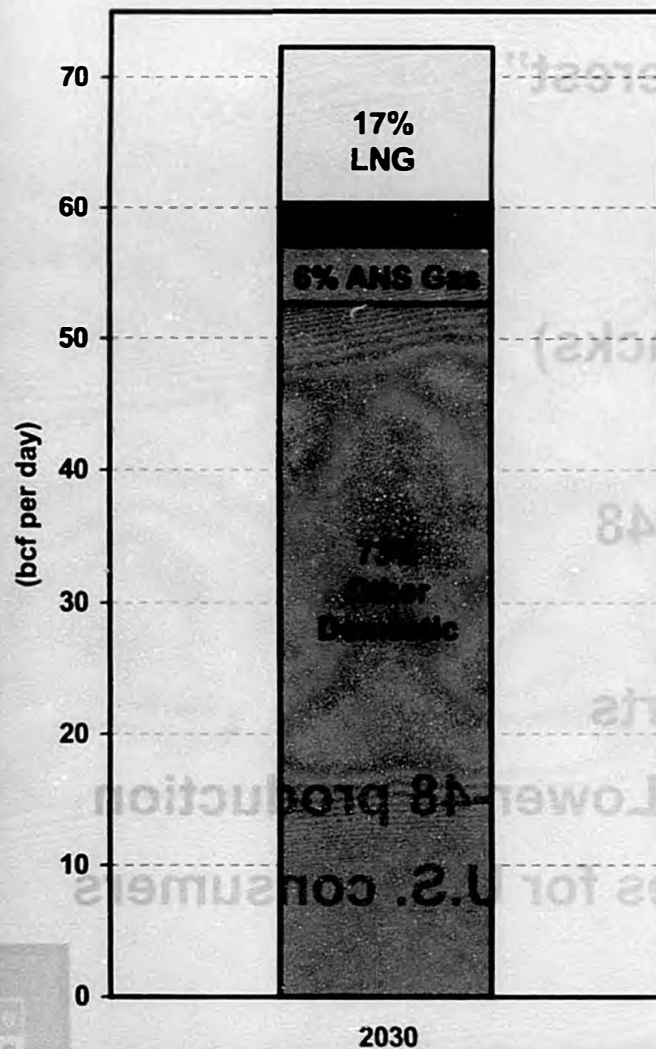
# LNG Export Issues

(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.

# 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

- > 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

- **Gas prices in 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 in 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**



## Presentation to the Alaska Legislature

June 20, 2008

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OF  
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**TAB**

**A**

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 **Mitsubishi Corporation**



**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 → \$9 Billion TransCanada withdrawn partner "liability"

# 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

**TAB**

**B**











**TAB**

**C**



**Department of Energy**  
Washington, DC 20585

JUN 13 2008

The Honorable John Harris  
Speaker of the House  
Alaska State House of Representatives  
State Capitol, Room 208  
Juneau, AK 99801-1182

Dear Mr. Harris:

Thank you for your letter of March 6, 2008 regarding the status of the authorization issued by the Department to the Yukon Pacific Corporation. On November 16, 1989, Yukon Pacific Corporation was granted authorization to export liquefied natural gas (LNG) from Port Valdez, Alaska in DOE/FE Opinion and Order No. 350. That Order was modified by DOE/FE Opinion and Order No. 350-A, issued March 8, 1990. The authorization, as modified, permitted LNG exports for sale to Japan, South Korea, and Taiwan in an amount up to 350 million metric tons of LNG at an average annual volume of 14 million metric tons for a period of twenty five years beginning on the date of first delivery. This authorization was transferred from the Yukon Pacific Corporation to Yukon Pacific Company, L.P. in DOE Order No. 350-B on August 4, 1992. Since that action, the Department has had no substantive correspondence or communication with Yukon Pacific Company, L.P. concerning any interest in ascertaining the status of the now nineteen year old authorization.

Under the terms of Opinion and Order No. 350, Yukon Pacific Company, L.P. is required to notify the Department within 48 hours after the first export begins. To date, the Department has received no notification that the predicates for utilization of the authorization have occurred, a precondition contained within the authorization. If Yukon Pacific Company, L.P. contacts the Department regarding this authorization, the Department would address at that time what, if any, further reviews and actions would be required should Yukon Pacific Company, L.P. seek to use the authorization.

If you require additional information, please contact me at (202) 586-9460, or have a member of your staff contact Mr. Scott Shiller, Deputy Assistant Secretary for Congressional and Intergovernmental Affairs at (202) 586-5450.

Sincerely,

Robert F. Corbin  
Manager, Natural Gas Regulatory Activities  
Office of Oil and Gas Global Security and Supply  
Office of Fossil Energy



**TAB**

**D**

arrangements approved by DOE,<sup>4</sup> would provide Conoco with blanket import approval, within prescribed limits, to negotiate and transact individual, short-term purchase arrangements without further regulatory action. The fact that each arrangement will be voluntarily negotiated, short-term, and market-responsive, as asserted in Conoco's application, provides assurance that the transactions will be competitive with other gas supplies available to Conoco. This arrangement, therefore, should enhance competition in the marketplace.

After taking into consideration all the information in the record of this proceeding, I find that granting Conoco blanket authority to import up to 20 Bcf of natural gas from Canada during a period of two years, under contracts with terms of two years or less, is not inconsistent with the public interest.

#### ORDER

For the reasons set forth above, pursuant to section 3 of the Natural Gas Act, it is ordered that:

A. Conoco Inc. (Conoco) is authorized to import up to 20 Bcf of natural gas from Canada during a two-year period beginning on the date of the first delivery.

B. This natural gas may be imported at any point on the international border

where existing pipeline facilities are located.

C. Within two weeks after deliveries begin, Conoco shall notify the Office of Fuels Programs, Fossil Energy, FE-50, Room 3F-056, Forrestal Building, 1000 Independence Avenue, S.W., Washington, D.C., 20585, in writing of the date that the first delivery of natural gas authorized in Ordering Paragraph A above occurs.

D. With respect to the imports authorized by this Order, Conoco shall file with the Office of Fuels Programs within 30 days following each calendar quarter, quarterly reports indicating whether imports of natural gas have been made, and if so, giving, by month, the total volume of the imports in MMcf and the average purchase price per MMBtu at the international border. The reports shall also provide the details of each import transaction, including the name of the purchaser if other than Conoco, estimated or actual duration of the agreement(s), transporter(s), point of entry, and, if applicable, the per unit (MMBtu) demand/commodity charge breakdown of the price, any special contract price adjustment clauses, and any take-or-pay or make-up provisions.

Issued in Washington, D.C., on November 3, 1989.

### ¶ 70,259

Yukon Pacific Corporation (ERA Docket No. 87-68-LNG), November 16, 1989.

#### DOE/FE Opinion and Order No. 350

#### Order Granting Authorization to Export Liquefied Natural Gas from Alaska

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<sup>4</sup> See, e.g., *Grand Valley Gas Company*, 1 FE ¶ 70,239 (August 25, 1989); *Potomac Energy Corporation*, 1 FE ¶ 70,237 (August 24, 1989); *Cascade Natural Gas Corporation*, 1 FE

¶ 70,225 (June 12, 1989); and *Wisconsin Public Service Corporation*, 1 FE ¶ 70,230 (June 19, 1989).

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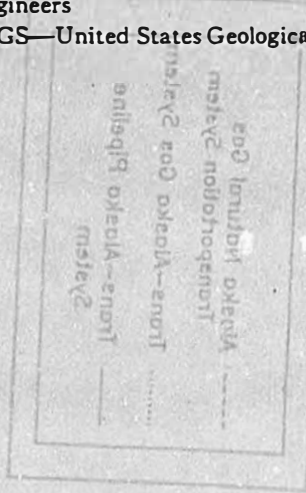
#### Glossary of Abbreviations

ADNR—Alaska Department of Natural Resources  
 AGA—American Gas Association  
 AGCF—Alaska Gas Conditioning Facility  
 Agreement on Principles—"Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline"  
 Alaskan Northwest—Alaskan Northwest Natural Gas Transportation Company  
 Alcan—Alcan Pipeline Company  
 Alyeska—Alyeska Pipeline Service Company  
 ANGTA—Alaska Natural Gas Transportation Act  
 ANGTS—Alaska Natural Gas Transportation System  
 ANGTS sponsors—Alaska Northwest Natural Gas Transportation Company and Foothills Pipe Lines (Yukon) Ltd.  
 AOGCC—Alaska Oil and Gas Conservation Commission  
 Argonne—Argonne National Laboratory  
 bbls—Barrels

Bcf—Billion cubic feet  
 BLM—Bureau of Land Management  
 Btu—British thermal unit  
 CERI—Canadian Energy Research Institute  
 Decision—"Decision and Report to Congress on the Alaska Natural Gas Transportation System"  
 D&M—Dames & Moore and Decision Focus, Inc.  
 DOE—Department of Energy  
 DOE Act—Department of Energy Organization Act  
 DRI—Data Research Institute  
 EIA—Energy Information Administration  
 EIS—Environmental Impact Statement  
 ERA—Economic Regulatory Administration  
 Exxon—Exxon Corporation  
 Exxon U.S.A.—Exxon Company, U.S.A.  
 FEIS—Final Environmental Impact Statement  
 FERC—Federal Energy Regulatory Commission  
 Finding—"Presidential Finding Concerning Alaska Natural Gas"  
 Foothills—Foothills Pipe Lines (Yukon) Ltd.  
 FPC—Federal Power Commission  
 GCF—Gas Conditioning Facility  
 GRI—Gas Research Institute  
 Jensen—Jensen Associates, Inc.  
 LNG—Liquefied Natural Gas  
 Mcf—Thousand cubic feet  
 MMBtu—Million British thermal units  
 NEB—Canadian National Energy Board  
 NEPA—National Environmental Policy Act of 1979  
 NGA—Natural Gas Act  
 NGPA—Natural Gas Policy Act of 1978  
 NPC—Northwest Pipeline Corporation  
 OFI—Office of Federal Inspector  
 OPEC—Organization of Petroleum Exporting Countries  
 PG&E—Pacific Gas and Electric Company  
 PGI—Pacific Gas Transmission Company  
 quad—quadrillion British thermal units  
 R/P ratio—Ratio of proved natural gas reserves to production  
 Reorganization Plan—Reorganization Plan No. 1 of 1979  
 Statoil—Statoil North America, Inc.

State Department—United States  
 Department of State  
 TAGS—Trans-Alaska Gas System  
 TAPS—Trans-Alaska Pipeline System  
 TAPS Carriers—the seven companies  
 that own the Trans-Alaska Pipeline Sys-  
 tem

Tcf—Trillion cubic feet  
 USACE—United States Army Corps of  
 Engineers  
 USGS—United States Geological Survey

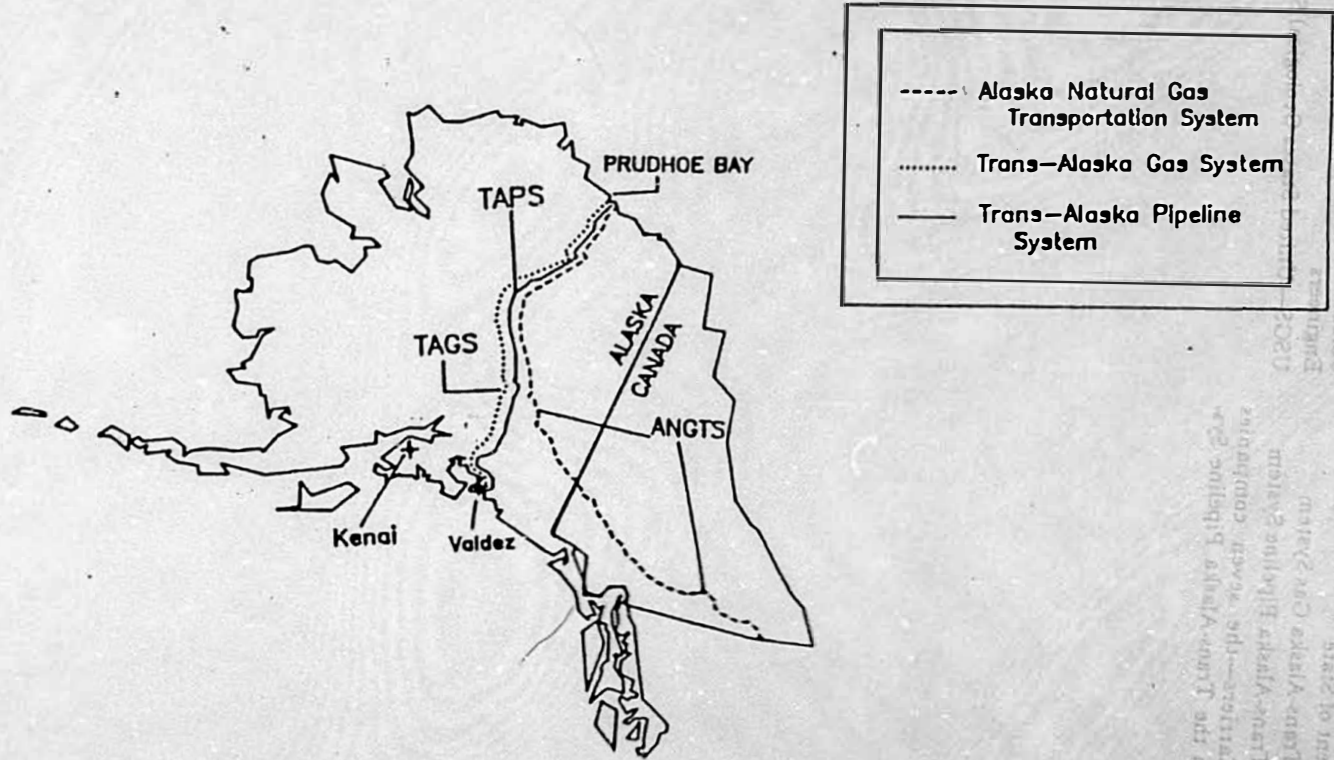


АЛАСКА ЭНЕРГЕТИКА

# ALASKA ENERGY PROJECTS

70,259

Federal Energy Guidelines



71,118

Opinions and Orders

688 12-18-89

### I. Summary

The Department of Energy (DOE) is granting the application of Yukon Pacific Corporation (Yukon Pacific) for authorization under section 3 of the Natural Gas Act (NGA) to export natural gas from the North Slope of Alaska to the Pacific Rim countries of Japan, South Korea, and Taiwan by means of the proposed Trans-Alaska Gas System (TAGS). The DOE has concluded that this export will not be inconsistent with the public interest. In particular, the DOE finds that this gas supply is not needed to ensure American consumers adequate supplies at reasonable prices. In addition, the DOE expects the TAGS export project to provide important benefits in the areas of energy security, energy production, international relations, trade deficit reductions, and the Alaskan economy.

The DOE has conditioned the export authorization to minimize any detrimental effects on American consumers, the Alaska Natural Gas Transportation System (ANGTS), and the environment. Specifically, the authorization provides that no costs of the export project can be recovered from American consumers, that no action can be taken in connection with the export project that would impair the construction and operation of the ANGTS project, and that the export project must be undertaken in accordance with all applicable environmental procedures and safeguards.

By granting this application, the DOE is not dictating that a specific project should be undertaken for developing North Slope natural gas. The approval neither commits any natural gas supplies to Yukon Pacific nor creates any regulatory impediments to other North Slope natural gas projects, including ANGTS. Rather, the approval is intended to spur competition to develop North Slope natural gas efficiently, with the marketplace determining the course of development. The public interest lies in bringing this immense energy resource to market in an efficient and timely manner.

<sup>1</sup> For purposes of this order, North Slope natural gas means gas derived from the area of the State of Alaska north of the Brooks Range, including the continental shelf of the U.S. under the Beaufort Sea.

### II. Background

In the winter of 1967-68 a wildcat rig drilling Prudhoe Bay State Well No. 1 on Alaska's North Slope struck a formation that, when later delineated, proved to be the biggest known crude oil deposit ever found in the U.S. and one of the largest accumulations of natural gas. The Prudhoe Bay Field alone contains an estimated 26 Tcf of recoverable gas reserves,<sup>2</sup> more than 13 percent of the proven natural gas reserves in the U.S. While the ultimate gas potential has yet to be determined, total accumulations in reservoirs on the North Slope have been estimated at more than 100 Tcf.

In 1970, the Alyeska Pipeline Service Company (Alyeska) was formed to construct and operate an oil pipeline from Prudhoe Bay to Valdez, a deepwater port in southern Alaska. Pipeline construction of the Trans-Alaska Pipeline System (TAPS) began in the winter of 1974-75 and by 1977 crude oil was being transported through the pipeline for markets in the lower-48 states.

By the mid-1970's, various plans for a transportation system that could bring North Slope gas to the lower-48 states were considered. Between 1974 and 1976, three different projects came before the Federal Power Commission (FPC) for certification. Because Congress was concerned about natural gas curtailments on the interstate transmission system, and feared a permanent supply shortage, it enacted the Alaska Natural Gas Transportation Act (ANGTA) in 1976 to ensure that regulatory action or inaction would not stand in the way of the efforts of private parties to bring North Slope gas to market.<sup>3</sup> The purpose of ANGTA was to streamline the lengthy certification process by authorizing the President to designate a transportation system from among the competing projects, subject to Congressional approval. In addition, in response to the perceived regulatory delays and inefficiencies in connection with the construction of TAPS, ANGTA included provisions designed to expedite the construction and initial operation of the selected gas transportation system

<sup>2</sup> Alaska Department of Natural Resources, *Historical and Projected Oil and Gas Consumption*, January 1989.

<sup>3</sup> 15 U.S.C. 719 et seq.

and to prevent agency actions that would hinder expeditious completion of that system by the project's sponsors.<sup>4</sup>

Although ANGTA removed and minimized regulatory barriers to the permitting and construction of the selected transportation system, responsibility for realizing the project was left to private parties. Likewise, responsibility for efficiently developing North Slope gas reserves was left to the owners of the gas. ANGTA did not mandate the use of this gas in domestic markets. In fact, section 12 of ANGTA expressly permits the export of North Slope gas if the President finds that such exports will not effect American consumers adversely.<sup>5</sup>

On September 22, 1977, following the signing of an agreement on principles with Canada,<sup>6</sup> President Jimmy Carter transmitted to Congress his decision concerning ANGTS.<sup>7</sup> The President's *Decision* and the *Agreement on Principles*

were approved by Congress on November 8, 1977.<sup>8</sup> Because of fluctuations in energy market conditions and the appearance of widespread gas surpluses, the sponsors of the ANGTS project decided in April 1982 to postpone construction of the Alaskan segment of the system. In the absence of a gas transportation system, almost all of the natural gas produced on the North Slope in conjunction with the oil has been reinjected into the reservoirs.

The decision concerning the Alaskan segment can be linked to a fundamental change in circumstances and behavior of natural gas markets in North America during the last decade when the gas shortages of the seventies have been replaced by adequate supplies for the foreseeable future. To a large extent, this change has resulted from decisions to abandon government-mandated price controls and other artificial regulatory restraints on the operation of the market in favor of competition.<sup>9</sup>

<sup>4</sup> In particular, section 9 of ANGTA prohibits actions that "would compel a change in the basic nature and general route of the approved transportation system or would otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system."

<sup>5</sup> Section 12 of ANGTA provides:

Any exports of Alaska natural gas shall be subject to the requirements of the Natural Gas Act and section 103 of the Energy Policy and Conservation Act, except that in addition to the requirements of such Acts, before any natural gas in excess of 1,000 Mcf per day may be exported to any nation other than Canada or Mexico, the President must make and publish an express finding that such exports will not diminish the total quantity or quality nor increase the total price of energy available to the United States.

<sup>6</sup> "Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline," September 20, 1977, U.S.T. 3581, T.I.A.S. 9030, which established the terms and conditions by which the two countries would cooperate to facilitate the construction, by private parties, of a joint gas pipeline system for the transportation of gas from Alaska and Northern Canada.

<sup>7</sup> *Decision and Report to Congress on the Alaska Natural Gas Transportation System*, issued by the President on September 22, 1977, pursuant to section 7 of ANGTA. This decision selected the Alcan Pipeline Company (Alcan) to build and operate the U.S. portion of the ANGTS. Subsequent to the President's *Decision*, the FPC issued certificates of public convenience and necessity to Alcan. Thereafter, Alcan's rights were transferred to Alaskan

Northwest Natural Gas Transportation Company. In the *Agreement on Principles* the two governments designated Foothills Pipe Lines (Yukon) Ltd. as the company responsible for the construction and operation of the Canadian segment of the system. As described in the President's *Decision*, the ANGTS would be a 5,000-mile pipeline originating on the North Slope and traversing Canada to the lower-48 states. The Canadian segment would be 2,000 miles long. To accommodate the growing surplus of exportable Canadian gas from Alberta, the project's construction was scheduled in two phases to enable export of Canadian gas pending the full completion of the system. The first phase of construction commenced in December 1980 with the building of a 1500-mile section that originates at a point just north of Calgary, Alberta, and splits into an Eastern and Western leg as it enters the U.S. The Western Leg terminates at Stanfield, Oregon, and the Eastern Leg terminates at Ventura, Iowa. These "prebuild" segments of the system were completed in 1982 and Canadian gas now flows through them.

<sup>8</sup> Pub. L. No. 95-158.

<sup>9</sup> The shift from regulation to market competition has not been confined to natural gas but has occurred throughout the energy market. For example, in January 1981, President Reagan, through the issuance of Executive Order 12287, removed allocation and price controls from crude oil and refined petroleum products. This action resulted in increased competition between fuel oil and natural gas, which, in turn, caused extensive fuel switching in the industrial market.

In 1978, Congress, through the passage of the Natural Gas Policy Act of 1978 (NGPA),<sup>10</sup> established as national energy policy the movement toward a competitive gas market in the U.S. The NGPA initiated a partial and phased relaxation of wellhead price controls, thereby encouraging producers to find and develop more gas. In July 1989, the NGPA was amended to remove all remaining wellhead price controls by 1993.<sup>11</sup> In addition to the removal of wellhead controls, Congress has acted to remove demand restraints that attempted to dictate how natural gas should be consumed.<sup>12</sup>

In conjunction with these statutory actions, the Federal Energy Regulatory Commission (FERC), exercising functions formerly vested in the FPC, has taken numerous regulatory steps to increase the competitiveness of the natural gas market. The centerpiece of the FERC's regulatory efforts has been the establishment of an open-access transportation system that permits producers and consumers to deal directly and establish market-responsive prices for gas supplies.<sup>13</sup> The FERC also has acted in other areas to remove regulatory barriers to competition.<sup>14</sup>

The shift to a competitive marketplace was not confined to the domestic market. Both the U.S. and Canadian Governments developed a market-based approach to their respective import and export policies. The continuing surplus of gas supplies and, with it, the increasing pressure for greater competition in gas markets in the U.S., led the Secretary of Energy to issue new policy guidelines in 1984 relating to gas imports.<sup>15</sup> The DOE's policy guidelines established new criteria for review of import applications and defined the "public interest" as enhanced competition in markets served by imports, reduced federal intervention in the marketplace, and encouragement of negotiated arrangements between buyers and sellers, thereby allowing greater flexibility in individual contracts. The objective of this policy was to complement domestic initiatives toward market oriented gas regulation by allowing market forces, in lieu of regulatory constraints, to define supply and demand. In effect, the guidelines represented a determination that it is in the public interest to let market forces, with a minimum of regulatory constraints, define efficient energy production and consumption.

<sup>10</sup> 15 U.S.C. 3301 *et seq.* Among other things, the NGPA provided for the phased decontrol of over 50 percent of natural gas at the wellhead. The Supreme Court has characterized the NGPA as a Congressional determination "to move toward a less regulated national natural gas market" which "give[s] market forces a more significant role in determining the supply, demand, and the price of natural gas" and has found that "the change in regulatory perspective embodied in the NGPA rested in significant part on the belief that direct federal price control exacerbated supply and demand problems by preventing the market from making long-term adjustments." *Transcontinental Gas Pipe Line Corporation v. State Oil and Gas Board of Mississippi*, 474 U.S. 409, 422-4. (1986); see also *FERC v. Martin Exploration Management Co.* (NGPA denotes legislative preference for deregulatory treatment rather than regulatory support of practices not responsive to market conditions), 108 S.Ct. 1765 (1988); *Pennzoil Company v. FERC* ("The NGPA is a fundamental change in regulatory outlook."), 645 F.2d 360, 378 (1981).

<sup>11</sup> Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60.

<sup>12</sup> Congress repealed oil and gas restrictions imposed by the Fuel Use Act that prohibited

new electric powerplants and new large industrial boiler facilities from using natural gas or petroleum as a primary source of energy. It also repealed the incremental pricing provisions of Title II of the NGPA. See Pub. L. No. 100-42.

<sup>13</sup> *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol* (Order 436), 50 FR 42408 (October 18, 1985), vacated, *Associated Gas Distributors v. FERC*, 824 F.2d 981 (D.C. Cir. 1987). The FERC issued Interim Order 500 on August 7, 1987, readopting most of the provisions of Order 436, 52 FR 30334 (August 14, 1987). On October 16, 1989, the D.C. Circuit remanded the record for the FERC to issue a final rule within 60 days, 1989 WL 120705.

<sup>14</sup> See e.g., *Final Rule, Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions*, 27 FERC ¶ 61,318 (1984); *Ceiling Prices; Old Gas Pricing Structure*, 51 FF 22168 (June 18, 1986).

<sup>15</sup> *New Policy Guidelines Relating to the Regulation of Imported Natural Gas*, 49 FR 6684 (February 22, 1984).

Paralleling the U.S. move toward greater competition in gas markets, Canada progressively liberalized its procedures for review of natural gas export applications. In 1984, Canada shifted away from regulated, uniform, volumetric prices for exports that had been instituted in 1975, to a policy that offered exporters the option of negotiating the sales price in export contracts. As of 1986, the Canadian National Energy Board (NEB) no longer required that it give prior approval of export prices. In 1987, the NEB adopted new procedures that allowed market forces to determine export levels as long as Canadian needs are served adequately and fairly.

Finally, the U.S./Canada Free Trade Agreement came into force January 1, 1989. It was a reflection of the changes that had taken place in both countries' energy policies. It formalized the principle that free and open trade is in the best interest of the citizens of the U.S. and Canada.

This evolution in natural gas trade has not been confined to Canadian imports. In 1983, President Ronald Reagan and Japanese Prime Minister Yasuhiro Nakasone indicated their interest in private commercial efforts to bring North Slope natural gas to Pacific Rim countries, including Japan. They recognized the benefits in the free trade of energy resources, as demonstrated by the gas export project operated jointly by Phillips 66 Natural Gas Company and Marathon Oil Company which, for about 20 years, has liquefied and shipped gas from the Cook Inlet area of southern Alaska to markets in Japan.<sup>16</sup>

In 1982, Yukon Pacific began exploring the concept of a trans-Alaska pipeline, combined with a liquefied natural gas (LNG) terminal in southern Alaska, for marketing North Slope gas in Japan and other Pacific Rim countries. In 1984, after studying the feasibility of the project, Yukon Pacific applied to the Bureau of Land Management (BLM) and the U.S. Army Corps of Engineers (USACE)

for the necessary permits to build the TAGS pipeline. A right-of-way grant for the TAGS project was issued by BLM on October 17, 1988.

On January 12, 1988, President Reagan removed the section 12 impediment to exports of North Slope natural gas by issuing a finding that such exports would not affect adversely the quantity, quality, or price of the energy supplies available to U.S. consumers.<sup>17</sup> In particular, the President found that "there exist adequate, secure, reasonably priced supplies of natural gas to meet the domestic demand of American consumers for the foreseeable future." The President acted to let "the marketplace undertake a realistic consideration of various options concerning Alaska natural gas" by allowing "any private party to develop this resource" and setting "up competition for this purpose." The President's *Finding* stated that "the operation of market forces is the best guarantee that Alaska natural gas will be developed efficiently and that there will be an incentive to find additional reserves."

In conclusion, North Slope natural gas is a major energy resource whose efficient development has been a goal of U.S. energy policy since its discovery in 1968. In response to changing conditions in the domestic and international energy markets, there have been various proposals for developing this resource. Legislative and regulatory policy changes in the past decade and market forces have combined to increase competitiveness of natural gas in the U.S. market. As of yet, however, North Slope gas has been left undeveloped. It is in this historical context that the DOE considered Yukon Pacific's application to export North Slope gas.

### III. Procedural History

#### A. Application and Project Description

On December 3, 1987, Yukon Pacific filed an application with the Economic Regulatory Administration (ERA),<sup>18</sup> for authority under the Natural Gas Act (NGA) to export up to 14 million metric

<sup>16</sup> Currently, approximately 52 trillion Btu's (52 Bcf) of LNG annually is authorized to be exported by Phillips 66 Natural Gas Company and Marathon Oil Company. See *Phillips 66 Natural Gas Company; Marathon Oil Company*, 1 ERA ¶70,130 (July 28, 1988).

<sup>17</sup> See *Presidential Finding Concerning Alaska Natural Gas*, 53 FR 999 (January 15, 1988).

<sup>18</sup> On January 6, 1989, certain functions, including the regulation of natural gas imports and exports, were transferred from the ERA to the Office of Fossil Energy.

tons of LNG annually (660 Bcf regasified) to the countries of Japan, South Korea, and Taiwan for 25 years, beginning on the date of first delivery. The natural gas would be transported from the North Slope by means of the proposed TAGS pipeline to a tidewater site at Port Valdez, Anderson Bay, on Alaska's southern coast. At Valdez, the gas would be converted to LNG for ocean transport to the Pacific Rim markets.

According to Yukon Pacific, construction of the proposed TAGS facilities will require five years and will commence when all required governmental approvals are obtained and LNG sales contracts are signed with the Pacific Rim customers. The first exports of LNG are expected to occur in 1996 when construction of TAGS is scheduled to be completed and Yukon Pacific would be able to initiate operations. The principal components of the TAGS project are: (1) a 796.5-mile, 36-inch outside diameter, buried and chilled natural gas pipeline from Prudhoe Bay to Port Valdez, with a design capacity of 2.3 Bcf of natural gas per day; (2) ten compressor stations along the pipeline; (3) a liquefaction plant at Port Valdez that would include four LNG processing units to remove impurities from incoming gas, and to reduce the temperature of the gas to -259 degrees Fahrenheit, condensing it to the liquid state for storage and shipping; (4) four LNG storage tanks, each with an individual capacity of 800,000 barrels (bbls); (5) a marine terminal to berth and load two LNG tankers; and (6) 15 LNG ocean transport vessels having individual cargo capacities of a nominal 125,000 cubic meters. In addition to the above facilities proposed by Yukon Pacific for the TAGS project, a gas conditioning plant would be required in the Prudhoe Bay area to deliver to the TAGS pipeline natural gas of a quality suitable for subsequent conversion to LNG at Anderson Bay.

Yukon Pacific states that it has entered into discussions with the owners (certain producers and the State of

Alaska) for their North Slope gas. These discussions are focusing primarily on purchasing gas from the principal reservoir in the Prudhoe Bay Field, the Sadlerochit formation. According to Yukon Pacific, the contract terms with each producer would be established through arms-length negotiations and would be flexible over the term of the agreements to reflect market conditions. The purchase price to be paid to producers would be determined by a formula using a base price per MMBtu adjusted for variations in the LNG price at the point of destination. With respect to the sale of this gas, Yukon Pacific expects to negotiate in arms-length transactions 25-year contracts that would be responsive to international gas market conditions. Yukon Pacific anticipates that the delivered price of LNG sold under the proposed export arrangement would start with a base price per MMBtu and would vary each month according to a formula based upon changes in the average selling price of selected major crude oils.

#### B. Notice and Interventions

The DOE issued a notice of the application on February 1, 1988, inviting protests, motions to intervene, notices of intervention, and comments to be filed by March 11, 1988.<sup>19</sup> Seven timely motions to intervene were filed: by Northwest Pipeline Corporation (NPC), the State of Alaska, Pacific Gas Transmission Company (PGT) and Pacific Gas and Electric Company (PG&E) (jointly), Alaska Northwest Natural Gas Transportation Company (Alaskan Northwest), Foothills Pipe Lines (Yukon) Ltd. (Foothills), the TAPS Carriers and Alyeska (jointly),<sup>20</sup> and the Exxon Corporation. (Exxon). Statoil North America, Inc. (Statoil) filed a late motion to intervene on March 25, 1988. Air Products and Chemicals, Inc., filed comments supporting the TAGS project but did not seek to intervene. The U.S. Department of State (State Department) submitted a letter<sup>21</sup> it received from the Canadian Embassy concerning the application. Alaskan Northwest and

<sup>19</sup> 53 FR 3617, February 8, 1988.

<sup>20</sup> The TAPS Carriers are seven companies that own the Trans-Alaska Pipeline System. They are: Amerada Hess Pipeline Corporation, ARCO Pipe Line Company, Exxon Pipeline Company, Mobil Alaska Pipe Line Company, Phillips Alaska Pipeline Corporation, Sobio

Alaska Pipeline Company, and UNOCAL Pipeline Company.

<sup>21</sup> Letter dated March 9, 1988, from Mr. Leonard H. Legault, Charge d'affaires, Canadian Embassy to Mr. John P. Ferriter, Deputy Assistant Secretary, International Energy and Resources Policy, Department of State.

Foothills opposed the application, requested its dismissal, and in the event that the application was not dismissed, Foothills requested a trial-type hearing and discovery procedures. (Hereafter in this order, where their views coincide, Alaskan Northwest and Foothills are referred to collectively as the ANGTS sponsors.) NPC did not express an opinion on the merits of the export proposal.

#### C. Order Requesting Additional Comments

On July 25, 1988, the DOE issued a procedural order requesting further information from Yukon Pacific, providing opportunity for further comment from all parties, and granting intervention to all eight movants who responded to the DOE's February 8, 1988, *Federal Register* notice of the application. The DOE denied several motions filed by the parties requesting: (1) dismissal of the application; (2) denial of interventions; (3) a trial-type hearing; (4) rehearing; and (5) an opportunity to conduct discovery. The requests for additional procedures were denied without prejudice to the filing of similar requests at a later stage in the proceeding.<sup>22</sup> The procedural order requested submission of comments by August 24, 1988, reply comments by September 23, 1988, and requests for additional procedures by October 10, 1988. The DOE received comments from Alaskan Northwest, Foothills, Yukon Pacific, the State of Alaska, PGT and PG&E (jointly), and Statoil.

#### D. Alaska Public Conference

Following submission of comments in response to the DOE's July 25, 1988, procedural order, Foothills filed a request for a trial-type hearing, or alternatively, a public conference. In addition, Alaskan Northwest renewed its earlier request expressed in its motion to intervene for dismissal of Yukon Pacific's application.

On December 5, 1988, the DOE issued a procedural order that denied the requests for dismissal of the application and for a trial-type hearing but granted the request for a public conference.<sup>23</sup> The

order set January 25, 1989, as the date for the public conference to be held in Anchorage, Alaska. Alaskan Northwest, Foothills, the TAPS Carriers, Exxon, the State of Alaska, and Yukon Pacific filed written statements or made oral presentations at the public conference.

#### E. Other Filings

The State Department submitted on January 11, 1989, a letter to be added to the record from the Charge d' affaires of the Canadian Embassy in Washington D.C., expressing the Canadian Government's renewed concern about the impact of the proposed export project on the ANGTS project.<sup>24</sup> On February 7, 1989, the State Department submitted for the record its reply to the Canadian Charge's letter in which it pointed out that the U.S. had, as originally agreed, undertaken all actions necessary to facilitate construction of the ANGTS and eliminate regulatory obstacles to private financing.<sup>25</sup> Since both the State Department and Canadian Embassy letters merely restate their views that are already part of the record in this proceeding and since no one opposed the inclusion of their correspondence in the record, the DOE hereby admits these letters into the record.

Foothills filed on March 17, 1989, a motion to enter into the record a statement presented to the Alaska State Legislature by an official of Exxon Company, U.S.A. (Exxon U.S.A.), that expressed the view that it is not economically feasible at today's prices to develop North Slope gas for either the domestic or the Pacific Rim markets. Exxon U.S.A. stated that "[a]n assured market and a substantial real growth in energy prices will be required before a project to commercialize North Slope gas reserves can be economic" and that such conditions most likely will not exist until after the year 2000 and then will be much more likely for the domestic market than for the export market.<sup>26</sup> On March 21, 1989, Exxon U.S.A. also filed a copy of this statement to be added to the record. Yukon Pacific requested that the DOE

<sup>22</sup> See the DOE's July 25, 1988, procedural order, at 11-15.

<sup>23</sup> DOE's December 5, 1988, procedural order, at 1-2.

<sup>24</sup> Letter dated January 9, 1989 from Mr. L.H. Legault to Mr. J.P. Ferriter.

<sup>25</sup> Letter dated January 30, 1989, from Mr. J.P. Ferriter to Mr. L.H. Legault.

<sup>26</sup> See statement of Mr. Judd Miller, Vice President of Exxon Company U.S.A., presented to the Senate Special Committee on Oil and

reject the statement on the grounds that the issues enumerated are irrelevant to this proceeding and the statement was filed late. The DOE concludes that admission of the statement would not adversely impact the proceeding or harm any party since it does not contain any relevant material that was not contained in prior submissions. Accordingly, the statement is hereby admitted into the record of this proceeding.

Finally, on June 28, 1989, a letter enclosing a "Third Amendment to Application" was submitted by Yukon Pacific. Although termed an amendment, Yukon Pacific's filing consisted entirely of newspaper and trade press articles concerning prospective LNG trade between Indonesia and certain Pacific Rim countries. On July 27, 1989, the DOE returned Yukon Pacific's filing after determining that it did not qualify as an amendment under the DOE's procedural rules because the information did not constitute a substantial change in the application and the material was not relevant and material to the resolution of the issues in this proceeding.

#### IV. Comments Received

##### A. Alaskan Northwest and Foothills

The ANGTS sponsors opposed the application in their interventions, in their responses to the July 25 procedural order, and at the public conference held in Anchorage. Their positions are fundamentally the same and are based primarily on their view that the proposed export could have an adverse impact on the ANGTS project. They advance several arguments. First, they argue that the application does not comply with the DOE's administrative regulations because it does not contain enough meaningful information for it to be properly evaluated. Specifically, they argue that the application does not include gas purchase or resale contracts, information on the gas conditioning facility expected to be used for the

(Footnote Continued)

Gas of the Alaska State Legislature on March 10, 1989.

<sup>27</sup> Atigun Pass is the highest point to be crossed by the TAGS pipeline in the Brooks Range. It is a narrow pinch point that currently accommodates the TAGS pipeline and a state highway, and is part of the ANGTS pipeline route.

TAGS project, a study regarding the feasibility of constructing both the proposed TAGS and ANGTS pipelines through Atigun Pass,<sup>27</sup> a complete environmental impact analysis of the project, a detailed description of the project's participants, and verifiable data demonstrating that the gas is not needed in the U.S.

Second, based on several energy supply studies and reports submitted with their comments, the ANGTS sponsors argue that North Slope gas would be needed and economically competitive in the lower-48 states by the mid-1990's. They contend that the excess demand in the lower-48 states cannot be met by other energy resources as or more efficiently than by the proposed export volumes. The ANGTS sponsors assert that substitute fuels for North Slope gas, such as coal and oil, would be environmentally inferior to natural gas, which burns cleaner. They maintain that increasing dependence on coal and oil would contribute to ozone layer depletion in the atmosphere, "acid rain", and the "greenhouse" problem of global warming,<sup>28</sup> and alternative gas supplies, such as development of Canadian frontier gas, would be more costly. In addition, they assert that the commitment of North Slope gas reserves to foreign interests would jeopardize national energy security by depriving the U.S. of a source of available reserves to offset the declining energy base in the lower-48 states, and by increasing U.S. dependence on oil imports.

Third, they contend that the TAGS project would impair completion of the ANGTS because there are not enough proven reserves of gas on the North Slope to support both the TAGS and the ANGTS projects. The ANGTS sponsors assert that they need 26-30 Tcf of reserves to justify construction. They argue that such an impairment would violate section 9 of ANGTA and also harm relations between the U.S. and Canada since it would constitute a breach of the

<sup>28</sup> Natural gas produces less carbon dioxide during combustion than does oil or coal, and carbon dioxide is one of the "greenhouse" gases that some scientists believe is a major contributor to possible global climate change. High emissions of sulphur dioxide and nitrogen oxide from burning coal are precursors to "acid rain."

1977 U.S./Canada Agreement on Principles.

Fourth, they contend that the proposed TAGS project would be economically and environmentally detrimental due to construction of the TAGS and the ANGTS in close proximity to each other and due to the duplication of facilities. (The northern portion of the TAGS pipeline would parallel the proposed route of ANGTS). They maintain that the TAGS Final Environmental Impact Statement (FEIS) issued by BLM in June 1988, is incomplete.<sup>29</sup> In particular, they assert that it does not address the environmental impact of or identify the gas conditioning facility that Yukon Pacific plans to use as part of the TAGS project.

Finally, the ANGTS sponsors contend that, if an export authorization is issued to Yukon Pacific, then the following conditions must be attached thereto: (1) that Yukon Pacific files in the record gas purchase, sales, and transportation contracts specifying the gas reserves to be purchased, transported, and sold; (2) that proven reserves needed to supply ANGTS will not be depleted by TAGS; (3) that ANGTS has first call on North Slope gas for delivery to the lower-48 states, if needed to meet contractual obligations and to preserve the project's economic viability; (4) that construction of ANGTS shall have priority over TAGS in order to avoid incurring additional costs that would have to be borne by U.S. customers; (5) that Yukon Pacific submit definitive data on the gas conditioning facility to be constructed and used by TAGS; and that Yukon Pacific also submit definitive data on Atigun Pass demonstrating the feasibility of constructing TAGS at that location; (6) that Yukon Pacific identify any planned simultaneous construction of TAGS and ANGTS, proposed cost sharing and joint use arrangements, and provide a definitive analysis of the net economic benefits of the proposed export; and (7) that any final authorization issued be subject to suspension, modification, or revocation upon a showing that continuation of the proposed export is no longer in the public interest.

#### B. PGT and PG&E (jointly)

<sup>29</sup> The BLM and USACE published a draft EIS for the TAGS project (52 FR 34424, Sep-

tember 11, 1987). An FEIS was issued June 11, 1988 (53 FR 24357, June 28, 1988).

#### C. State of Alaska

The State of Alaska intervened because of its proprietary and governmental interests in the proposed TAGS project. The State supports Yukon Pacific's export proposal because the project would increase employment in the state, develop and broaden the market for North Slope gas, yield revenues to the state from gas royalties and production taxes, and diversify the state's economy from industries servicing the TAGS project. However, it has no preference for TAGS over ANGTS and asserts that the market will decide which (or how many) systems should be built. The State opposes the imposition of conditions on any export authorization issued to Yukon Pacific that would favor one gas development project over another.

#### D. Government of Canada

The Canadian Government expressed concern through the State Department that the TAGS project could impair the financial viability of the ANGTS in that there may not be adequate quantities of North Slope gas to support both the TAGS and ANGTS projects. Canada urged the U.S. to ensure the availability of adequate North Slope gas in order to maintain the commercial viability of the ANGTS project.

#### E. Exxon

Exxon, an owner and producer of North Slope gas, endorsed the President's *Finding* concerning North Slope gas. Exxon

urged that, if Yukon Pacific's application is approved, the authorization should be consistent with open, market-responsive development of Alaskan natural gas and not impose terms and conditions that would, in effect, place a stamp of approval on only one project or approach to development of Alaskan resources and discourage other projects or approaches.

#### F. TAPS Carriers and Alyeska (jointly)

The TAPS Carriers, users of the TAPS facilities, and Alyeska, operator of TAPS, took no position on whether the export authorization should be granted to Yukon Pacific but urged that any authorization be conditioned on review and approval of the engineering details of the TAGS facilities by the TAPS Carriers and by Alyeska. They stated that Yukon Pacific had not presented enough technical details for the commentators to be able to assess whether the proposed facilities would impede the safety, operation, or maintenance of TAPS.

#### G. Statoil

Statoil, which owns substantial reserves of natural gas on the Norwegian continental shelf, and plans to export and market LNG to the U.S. East Coast, stated that its LNG exports and those of other overseas suppliers would be able to meet any U.S. gas demand that might go unserved if North Slope gas is exported.

#### H. Yukon Pacific's Position

In support of its application, Yukon Pacific contends that there is no present or future domestic need for natural gas from the North Slope. To support its argument, Yukon Pacific submitted a study by the consulting firms of Dames & Moore and Decision Focus, Inc. (D&M study).<sup>30</sup> Yukon Pacific asserts that this study demonstrates that there are adequate gas supplies in the lower-48 states, Canada, and Mexico sufficient to meet U.S. demand in the foreseeable future without the Alaska gas that would be exported. The D&M study concludes that there will be no economic need for North Slope gas in the lower-48 states for at

least 30 years and that nearer supplies of Canadian Arctic gas would become competitive before North Slope gas.

Yukon Pacific also maintains that the export of North Slope natural gas to Pacific Rim countries would serve the public interest by reducing the U.S. trade deficit, strengthening international relations, and promoting Alaska's economic development. In addition, Yukon Pacific asserts that authorization of the TAGS project will inject an element of competition into the development of North Slope gas reserves that should prove healthy for both U.S. and Canadian natural gas markets. Further, Yukon Pacific argues that the TAGS project would not be detrimental to the interest of American consumers because the risks and costs associated with the construction and operation of the TAGS project, including the marketing of the gas, would be borne by the project's private sponsors and the foreign purchasers of the gas.

With respect to the availability of North Slope gas for TAGS and ANGTS, Yukon Pacific asserts that TAGS and ANGTS are not competitors since there are sufficient gas reserves on the North Slope for both projects. Moreover, Yukon Pacific asserts that the ANGTS project does not have an exclusive right to or first call on the reserves. Yukon Pacific argues that section 12 of ANGTA demonstrates that the U.S. Congress envisioned that North Slope gas might be exported and that the President's *Finding* determined that the public interest will be served by exports of North Slope gas.

With regard to construction compatibility between TAGS and ANGTS, as well as construction priority and cost allocation for jointly used facilities, such as the proposed Alaska Gas Conditioning Facility,<sup>31</sup> Yukon Pacific contends that these matters are outside the jurisdiction of the DOE. Further, Yukon Pacific states that the gas conditioning facility is not part of the export project because it expects to purchase the gas from the North Slope producers after the gas is conditioned.

<sup>30</sup> See Dames & Moore and Decision Focus, Inc., *Analysis of Alaska Gas Market Potential In The Lower 48 States: Domestic Effect of Yukon Pacific's Proposed LNG Export* (August 22, 1988), included as Exhibit R to *Initial Comments of Yukon Pacific Corporation*, filed August 24, 1988.

<sup>31</sup> As part of the ANGTS, Alaskan Northwest holds a conditional certificate from the FERC to construct and operate a gas conditioning plant, designated the Alaska Gas Conditioning Facility, on the North Slope at Prudhoe Bay.

Yukon Pacific states that it would accept two conditions on any grant of export authority: one condition would require that the LNG sales contracts be filed with the DOE after they have been executed, and the second condition would prohibit Yukon Pacific from passing on to consumers in the lower-48 states any of the risks or costs associated with the TAGS project. Yukon Pacific opposed the other conditions that the ANGTS sponsors requested because those conditions are either outside the DOE's jurisdiction and have no basis in law, or constitute improper government financing assistance to the ANGTS.

Finally, Yukon Pacific asserts that the information submitted in its application meets the requirements of section 590.202 of the DOE's administrative procedures and notes that those procedures give the DOE the flexibility to determine what information is required from an applicant based on the nature of the import or export requested.

#### V. Decision

Yukon Pacific filed its application for authorization to export North Slope gas under section 3 of the NGA.<sup>32</sup> Section 3 creates a statutory presumption in favor of the approval of an export application, a presumption that must be overcome by evidence in the record of the proceeding

<sup>32</sup> Section 3 provides:

[N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order from the [Federal Power] Commission authorizing it to do so. The Commission shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest. The Commission may by its order grant such application, in whole or in part, with such modification and upon such terms and conditions as the Commission may find necessary or appropriate . . . 15 U.S.C. Sec. 717b. With the adoption of the Department of Energy Organization Act in 1977 (DOE Act), Pub. L. No. 95-91, Congress transferred authority for all regulation of natural gas imports and exports under the NGA, including section 3, from the FPC to the Secretary of Energy. See sections 301(b) and 402(i) of the DOE Act, 42 U.S.C. 7151(b) and 7172(f). In Delegation Order No. 0204-127, the Secretary delegated to the Assistant Secretary for Fossil Energy the authority "to regulate natural gas imports and exports, pursuant to the Natural Gas Act." (Issued February 7, 1989, published at 54 FR 11436, March 20, 1989.)

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that the proposed export will not be consistent with the public interest.<sup>33</sup> Opponents of an application bear the burden of overcoming this presumption.

In judging whether to authorize a proposed export, the DOE is guided by Delegation Order No. 0204-111.<sup>34</sup> This order designates domestic need for the natural gas proposed to be exported as the only explicit criterion that must be considered in determining the public interest. In addition to domestic need, the DOE will consider other factors to the extent they are shown to be relevant to a public interest determination. Furthermore, in evaluating exports, the DOE is mindful of the broad energy policy principles set forth in the DOE's natural gas import policy guidelines. While those guidelines deal with imports, the principles are applicable to exports as well. The guidelines establish the policy that market forces will generally bring about results more in the public interest than will extensive regulation.

In addition to the framework of the NGA, this particular export proposal must also be viewed in light of the framework of ANGTA. ANGTA generally affects all actions that might relate to the ANGTS and, in particular, provides an additional statutory requirement for the export of North Slope gas.

<sup>33</sup> In *Panhandle Producers and Royalty Owners Association v. ERA*, 822 F.2d 1105 (D.C. Cir. 1987), the Court found that section 3 of the NGA "requires an affirmative showing of inconsistency with the public interest to deny an application" and that a "presumption favoring . . . authorization . . . is completely consistent with, if not mandated by, the statutory directive."

<sup>34</sup> 49 FR 6690, February 22, 1984. In granting the Assistant Secretary for Fossil Energy the NGA authority over natural gas imports and exports, the Secretary directed the Assistant Secretary to exercise this authority in accordance with the policies and practices that the ERA followed in regulating natural gas imports and exports under Delegation Order No. 0204-111. Thus, while the Assistant Secretary is granted the NGA authority entirely by Delegation Order No. 0204-127, the exercise of this authority takes into account the same factors prescribed by the Secretary to the ERA for consideration in connection with Delegation Order No. 0204-111.

Federal Energy Guidelines

## A. Domestic Need

Yukon Pacific proposes to export up to 16.5 Tcf of gas as LNG over a 25-year period. This amount would be equivalent to about three percent of the total U.S. consumption of natural gas projected between 1996 and 2021. In the July 25 procedural order, the DOE set forth its three-pronged approach for evaluating domestic need. First, the DOE determines whether national or regional demand can reasonably be expected to exceed anticipated available domestic supplies over the term of the proposed export.<sup>35</sup> If there is a reasonable expectation of demand in excess of available domestic supplies, the DOE determines the extent to which this excess demand can be met by other energy sources as or more efficiently than by the proposed export. If there are sufficient alternative sources, the DOE analyzes whether there is any reason the public interest requires the proposed

export, in particular, be used to meet the excess demand.

Yukon Pacific, Alaskan Northwest, and Foothills presented evidence concerning the need for North Slope natural gas. For the most part, this evidence relates to studies which purport to demonstrate when North Slope natural gas would become competitive in the lower-48 states. These studies differ greatly in their findings. In general, the studies submitted by Yukon Pacific indicate that North Slope gas would not be competitive during the entire term of the proposed export, while those submitted by the ANGTS sponsors indicate that it would be competitive as early as the 1990's.

While studies such as those submitted in this proceeding are useful in assessing overall macro-economic conditions and probable market trends under certain scenarios, they are not as useful in assessing the future of particular energy projects.<sup>36</sup> As Alaskan Northwest stated in its reply

<sup>35</sup> Regional need is not an issue in this proceeding since no one asserts North Slope natural gas could be used to meet the energy needs of the populated areas of Alaska. There is no existing or contemplated delivery system to bring North Slope natural gas to these areas.

<sup>36</sup> The DOE is aware that many economic predictions do include North Slope gas as a supply used to meet domestic demand at some point in the future. The DOE does not equate these predictions with a demonstration that North Slope gas is needed in domestic markets. A prediction by an economic model that a particular gas supply will be used to meet demand does not mean that there are not adequate supplies of reasonably priced gas from other sources to meet the demand or that the other supplies may not actually cost less. Rather, it means the economic model has classified that particular supply as more "competitive" than supplies from other sources. Such a "competitive" classification is based entirely on the assumptions of the model and, at best, is only a rough approximation of the decisions that a competitive market actually will make. Unlike the real world where private parties take a hard look at the actual costs of bringing competing supplies to market, an economic model selects the "competitive" supply on the basis of assumptions about the general costs of broad categories of gas, expected exploration and drilling activity, the availability of transportation systems, and other factors, including the anticipated export policies of foreign governments many years in the future. In the case of ANGTS, most economic models put the cart before the horse since they automatically assume North Slope gas will be used in the

domestic market and then speculate when producers, pipeline sponsors, and financial institutions will agree that the market justifies the commitment of billions of dollars to provide the means necessary to make this "a priori" modeling assumption feasible in the real world.

Rather than demonstrate that a gas supply is needed, economic models indicate when the market may consider the use of a particular gas supply. In the case of North Slope gas, this function is especially suspect. Unlike other gas supplies, North Slope gas is predicted to be used in domestic markets not on the basis of comparisons to other supplies, but rather on the basis of the assumption when market conditions will justify the construction of ANGTS. In light of the history of ANGTS, this substitution of conjecture by economists for actual decisions by the private parties directly involved with ANGTS cannot be treated as having a high degree of certainty. ANGTS originally was scheduled to bring North Slope gas to the domestic market by the mid-1980's. Work on ANGTS, however, was suspended in 1982 and no commitments concerning its resumption have been made. Indeed, the uncertainty surrounding when and where North Slope gas will ultimately be used was emphasized in the recent action by the Energy Information Administration of the DOE to drop North Slope gas from U.S. proved reserves "because large uncertainties exist about the availability of a gas transportation system or other marketing alternatives for the bulk of North Slope gas." See advance summary, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquid Reserves, 1988 Annual Report, DOE/EIA-0216(88)*, September 1989, at 1.

comments, "The world is simply too complex, too subject to change from unforeseeable actions by others and from uncontrollable forces to forecast with confidence 20 years or so into the future. Projections even 12 years ahead, to the turn of the century, realistically must be viewed with great caution."<sup>37</sup> In fact, the inherent imprecision of using economic studies to predict the performance of a particular project is one reason that led to the shift from a government-mandated regulatory approach to a market-oriented approach that leaves private commercial parties with the flexibility to determine the basics of their projects.

The submitted studies have been helpful, however, in evaluating domestic need since they all contain extensive information on supplies of various energy sources and anticipated demand. The DOE's review of the studies, set forth below, indicates that there are sufficient energy sources to meet domestic need without the use of North Slope natural gas.

#### 1. Domestic Supplies

The D&M study, which was provided by Yukon Pacific, analyzed and compared several domestic gas resource forecasts published by various agencies and organizations. In particular, the D&M study focused on assessments produced by the DOE's Office of Policy, Planning, and Analysis (DOE/Argonne),<sup>38</sup> the Potential Gas Committee (PGC),<sup>39</sup> and the U.S. Geological Survey (USGS).<sup>40</sup> These three assessments estimate that there is in the lower-48 states a natural gas reserve and resource base that could be recovered ranging from 534 Tcf (USGS) to 1,059 (DOE/Argonne).<sup>41</sup> PGC's estimate of 778.6 Tcf lies between the USGS and DOE totals. The USGS based its estimate of economically recoverable resources on a significantly lower wellhead price

(\$1.80/Mcf) than the price upon which the DOE/Argonne estimate is based. The lower price assumption in the USGS estimate, therefore, reduces the quantity of gas that is economically viable and leads to a lower total resource estimate. In addition, the varying estimates include different components of the resource base.

The DOE made a comparative evaluation of the results of the particular resource appraisals using the DOE/Argonne assessment as a benchmark because it contained resource categories not included in other gas resource estimates. The DOE/Argonne study used a new resource category "reserve growth," which refers to the additions to reserves that result from tapping additional gas sources located within known reservoirs, but not previously counted as reserves. In addition, the DOE/Argonne study estimates the potential for unconventional gas sources. The USGS study, for example, excludes all unconventional gas, including gas from tight sands, Devonian shale, coal seams and enhanced recovery—despite the fact that such gas is now being produced commercially. To put the USGS and PGC appraisals on an equivalent basis with the DOE/Argonne appraisal, 439 Tcf of gas from unconventional reserves and gas from infill drilling was added to the USGS estimate and 180 Tcf from infill drilling was added to the PGC estimate (the PGC estimate already includes an undefined quantity of unconventional resources). Adjusted, the USGS estimate (973 Tcf) and the PGC estimate (958.6 Tcf) are comparable to the DOE/Argonne estimate (1059 Tcf).

The demand forecasts that DOE examined to compare with the USGS, DOE/Argonne, and PGC resource appraisals were developed by the Gas Research Institute (GRI),<sup>42</sup> the American Gas Association (AGA),<sup>43</sup> and the Data

<sup>37</sup> See Reply Comments of Alaskan Northwest, at 27.

<sup>38</sup> *An Assessment of the Natural Gas Resource Base of the United States* (May 1988), prepared by Argonne National Laboratory for the DOE's Office of Policy, Planning, and Analysis.

<sup>39</sup> PGC, *Potential Supply of Natural Gas in the United States*, Colorado School of Mines, December 1986 and April 1987.

<sup>40</sup> USGS Circular 860 (1981), *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*.

<sup>41</sup> See D&M study, at 4-3.

<sup>42</sup> See 1988 Baseline Projection of U.S. Energy Supply and Demand, attached as Exhibit H to Reply Comments of Alaskan Northwest.

<sup>43</sup> See the 1988 American Gas Association T.E.R.A. Analysis (January 15, 1988) attached as Appendix F to Additional Comments of Foothills Pipe Lines (Yukon) Ltd., filed August 24, 1988.

Research Institute (DRI).<sup>44</sup> Portions of the studies by GRI, AGA, and DRI are appended to the comments of Alaskan Northwest and Foothills. Domestic natural gas consumption according to GRI was 17.6 quadrillion Btu (quads) in 1987 (a quad is approximately equivalent to a Tcf).<sup>45</sup> GRI projects consumption to grow at an average annual rate of 0.4 percent and reach 19.4 quads in 2010. According to projections by the AGA and DRI, natural gas consumption by 2010 is expected to be 21.7 quads and 17.6 quads, respectively.<sup>46</sup>

The DOE adopted the highest of the projections for U.S. gas consumption in 2010 of 21.7 quads (that by AGA), which assumes a 1.0 percent increase per year in consumption after 1987, as a basis for comparing available supply to expected demand. Using 18.0 quads for consumption in 1988 as a starting point,<sup>47</sup> if expected growth is 1.0 percent per year, the DOE calculated that annual consumption would reach 25.0 quads by 2021 (the final year of the export project assuming Yukon Pacific begins exports in 1996 and operates for 25 years). Under this premise, cumulative consumption during the period 1988-2021 would be 725 quads (Tcf), well below the most conservative of the resource estimates.

The DOE also considered the economics of exploring for and developing new domestic supplies, focusing on the wellhead acquisition price of gas produced in the lower-48 states. In addition to its estimates for recoverable gas resources, the DOE/Argonne study provided an estimate of their availability by wellhead price. The results of the DOE/Argonne assessment reveal that more than half of the total gas resources evaluated in the lower-48 states, or 583 Tcf of gas, would be economically recoverable (including finding costs) at less than \$3.00/Mcf (1987 dollars). An additional 174 Tcf of gas was judged economically recoverable in a price range of \$3.00 to \$5.00/Mcf.

That would be enough gas (757 Tcf) that could potentially be recovered in the lower-48 states at costs below \$5.00 per Mcf (1987 dollars) to meet projected U.S. demand through the year 2021, whether or not North Slope gas is exported to the Pacific Rim.

The ANGTS sponsors assert that DOE should only consider proven natural gas reserves, rather than estimates of the total resource base, in assessing domestic need because the amount of non-proven reserves is subject to wide disagreement and periodic fluctuation. That approach would represent an overly conservative view of available natural gas supplies. The level of reserve additions, and ultimately the level of reserves, is dependent upon the amount of drilling which, in turn, is sensitive to advances in gas recovery technologies and is stimulated by the price of gas. Gradual shrinkage and eventual disappearance of the present supply surplus or "gas bubble" over the next few years, combined with the prospects for substantial increases in gas demand in certain market sectors should materially improve incentives to drill new wells. In addition, although the USGS, PGC, and DOE/Argonne resource estimates do not address the timing of production or the availability of transportation, all volumes of future natural gas supply beyond proven reserves included in the studies are based on information derived from past and current experience in gas production and reservoir development and reflect a conservative view of recoverability. Gas supply assumptions that focus solely on proved reserves and do not take into account the potential for reserve additions and production experience would severely distort forecasts of domestic need.

To support its argument that the proposed exports will be needed in the lower-48 states, Alaskan Northwest quotes from a report by Jensen Associates, Inc. (Jensen study).<sup>48</sup> Jensen Associ-

<sup>44</sup> See Data Research Institute *Natural Gas Review* (Summer 1988) attached as Appendix G to *Additional Comments of Foothills*.

<sup>45</sup> See GRI *1988 Baseline Projection of U.S. Energy Supply and Demand*, at 5-6, *supra*.

<sup>46</sup> See AGA *T.E.R.A. Analysis*, at 24, *supra*. See also, DRI *Natural Gas Review*, at 7, *supra*.

<sup>47</sup> See DOE, Energy Information Administration, *Natural Gas Monthly*, July 1989, at 6.

<sup>48</sup> See *Assessment of the Domestic U.S. Need For North Slope Natural Gas Reserves*, Jensen Associates, Inc., included as Exhibit A to *Comments of Alaskan Northwest Natural Gas Transportation Company in Response to Order of the Economic Regulatory Administration*, filed August 24, 1988.

ates, Inc., was retained by Alaskan Northwest to analyze Yukon Pacific's application. The quote indicates that by 1996, "at present rates of consumption, the U.S. will have consumed a volume of gas equivalent to 79% of [its] present lower-48 proved reserves," implying that the supply of proven reserves will be nearly depleted.<sup>49</sup> In addition, a second Jensen report indicates that, in each of the last 20 years but one, the gas industry has not added enough gas reserves to replace production and that production is expected to continue to decline in certain regions.<sup>50</sup>

It is true that if there are no reserve additions, then proved reserves would be zero at the end of the next decade. However, no expert we know of expects that U.S. reserves will be depleted by the year 2000. Even the Jensen study conditions the statement about consumed proven reserves by concluding that the existence of a gas surplus in 1996 "will be dependent on the effectiveness of the industry in exploring and developing [the Nation's] remaining gas resource base."<sup>51</sup> The fact is, over time, more reserves are added to offset proven reserves drawdown. As Yukon Pacific points out, "[a forecaster] could have made an alarmist statement back in 1977 that by 1986, 85% of the U.S. proven reserves will be consumed, and that statement would be proven correct."<sup>52</sup> The reality is that, during the same period, additions to proven reserves in the lower-48 states were such that as of December 31, 1988, the amount of proven reserves was 159 Tcf, down only 9 percent from 1977.<sup>53</sup>

<sup>49</sup> *Id.*, at 10. Reserve and production statistics of the DOE's Energy Information Administration (EIA) show that the reserves-to-production ratio (R/P), that is, the relationship between natural gas proved reserves and production rates, over the years 1977-1988 fluctuated between 10 to 1 and 12 to 1 each year (increasing production rates relative to proved reserves or a decline in proved reserves causes a falling R/P ratio). See advance summary, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquid Reserves, 1988 Annual Report*, DOE/EIA-0216(88), September 1989, at 3. With this in mind, all that the 79% figure in the Jensen study actually indicates is that in 1988 the U.S. R/P ratio was about 10 to 1 and, therefore, the U.S. could be expected to consume about 10 percent of its proved reserves each year through 1996.

Furthermore, over the last nine years (1980-1988), proved gas reserves in the lower-48 states in fact declined only a total of about 4 percent.<sup>54</sup> The relatively stable reserve level has been due to the high reserve replacement rate which, during this period, averaged 93 percent in the lower-48 states.<sup>55</sup> The high average gas reserve replacement factor indicates the success of exploration and development activity in adding new gas reserves. Although drilling activity has declined since 1981, the DOE believes that statutory and policy changes in the regulatory framework for natural gas will open up marketing opportunities for companies throughout the industry and, as the "gas bubble" disappears, this should encourage the exploration necessary to stem the downward trend in levels of drilling.

Based on its analysis of the submitted studies, the DOE concludes that domestic need for natural gas during the term of Yukon Pacific's export proposal could be met by production from reservoirs in the lower-48 states without North Slope natural gas.

## 2. Alternative Supplies

The DOE believes that it is not necessary for the purpose of its section 3 determination to find that all future U.S. natural gas demand will be met entirely by production in the lower-48 states. Although gas produced in the lower-48 states is currently the primary source of natural gas supply, imports (mostly from Canada) meet about seven percent of U.S. gas requirements and they are projected to play an increasing role. The AGA, GRI, and DRI forecasts indicate that by

<sup>50</sup> See *A Critique of Yukon Pacific Corporation's Analysis of Domestic Need For North Slope Natural Gas*, attached as Exhibit G to Reply Comments of Alaskan Northwest, at 5.

<sup>51</sup> *Id.*

<sup>52</sup> See Reply Comments of Yukon Pacific, at 26.

<sup>53</sup> See *U.S. Crude Oil, Natural Gas, and Natural Gas Liquid Reserves*, DOE/EIA-0216(87), 1987 Annual Report, at 82; see also advance summary to 1988 Annual Report, at 8.

<sup>54</sup> *Id.*

<sup>55</sup> See *U.S. Crude Oil, Natural Gas, and Natural Gas Liquid Reserves*, (1977 through 1987) annual reports, DOE/EIA-0216; see also advance summary to 1988 annual report, *supra*.

the year 2010, from 3 to 4 Tcf annually of domestic market requirements will be supplied from sources external to the lower-48 states.<sup>56</sup> Yukon Pacific asserts that future domestic need in excess of lower-48 states' supplies can be met by non-Alaskan sources. The ANGTS sponsors maintain that both foreign imports and North Slope gas will be needed to meet future excess domestic need.

Pipeline deliveries from Canada are expected to remain the predominant supplemental supply source, with other imports, such as gas from Mexico or LNG from Algeria, Norway, or other foreign sources also contributing to total U.S. supply. Canada's present natural gas situation may be characterized as one of supply excess to that country's internal needs. The D&M study presented by Yukon Pacific examined assessments and projections of Canada's natural gas supply and resource based published by AGA,<sup>57</sup> the Canadian Energy Research Institute (CERI),<sup>58</sup> the U.S. Office of Technology Assessment,<sup>59</sup> the Canadian NEB,<sup>60</sup> and the Energy Modeling Forum.<sup>61</sup> The CERI report also estimated domestic Canadian demand. The estimates of marketable natural gas range from about 97 Tcf to 197 Tcf. Recoverable resource estimates range from 205 Tcf to 426 Tcf. With a projected domestic demand of approximately 65 Tcf (CERI) between 1985 and 2010 and an R/P ratio of greater than 30, the DOE concludes that Canada has a large quantity of natural gas potentially available for export to the U.S. over the next few decades.

Although Mexico's current energy export policy favors using natural gas for its domestic energy needs while reserving oil for exports, Mexico has a large natural gas resource base potentially available to the U.S. market. Mexico's annual domestic consumption is about 1.25 Tcf.<sup>62</sup> The

D&M study indicates that Mexico's proved reserves totaled 76.5 Tcf in 1986 with a R/P ratio of 61. There are no recent estimates for undiscovered recoverable resources, but they were estimated to be over 289 Tcf in 1985. Mexico's policy of limiting gas exports might well change in the longer term to take into account general gas availability, gas export revenue considerations, and physical limitations on using the gas internally.

Numerous countries are capable of supplying LNG to the U.S. and have expressed a serious interest in doing so. There are four LNG receiving and gasification terminals in the U.S. located on or accessible to the East Coast. They have a combined daily capacity of about 2 Bcf. Of these four, only Distrigas of Massachusetts Corporation's facility at Everett, Massachusetts, is currently operating. It brings Algerian LNG imports into the lower-48 states. Trunkline LNG Company has requested FERC permission to begin operating its facility at Lake Charles, Louisiana, in late 1989 to receive Algerian LNG. There is a potential for further LNG supplies for the U.S. after 1990, especially in the Atlantic region, from Algeria, Norway, Nigeria, Venezuela, and the Caribbean, because of the surpluses that exist in these relatively low-cost production areas. For example, development of the North Sea fields has resulted in vast additional reserves of gas that could be marketed in the U.S. Statoil is in the formulative stages of arranging for importation and marketing of LNG on the East Coast. In the case of Statoil, Norwegian reserves currently amount to about 110 Tcf. Of this total, only 30 Tcf are presently committed by contract to existing purchasers. According to Statoil, "when the U.S. market requires additional gas supplies, Statoil and other over-

<sup>56</sup> See Appendix F to *Additional Comments of Foothills*, the Table entitled "Natural Gas Supply", at 24 and Appendix G, at 7. See also Exhibit H to *Reply Comments of Alaskan Northwest*, at 13.

<sup>57</sup> *The Gas Energy Supply Outlook 1987-2010*, (October 1987).

<sup>58</sup> *Towards a Continental Natural Gas Market: Historical Perspectives and Long-Term Outlook. Executive Summary*, Study No. 26 (February 1988).

<sup>59</sup> *U.S. Natural Gas Availability, Gas Supply through the Year 2000*, February 1985.

<sup>60</sup> *Canadian Energy: Supply and Demand 1985-2005*, October 1986. See also, *National Energy Board Reasons for Decision in the Matter of Review of Natural Gas Surplus Determination Procedures*, September 1987a.

<sup>61</sup> *EMF9 Summary Report-North American Natural Gas Market-Preliminary Draft*, August 1988.

<sup>62</sup> See Exhibit A attached to January 24, 1989, *Prepared Statement of Vernon T. Jones*, Chairman of Board of Partners, Alaskan Northwest, which was submitted at the Alaska public conference, at 9.

seas LNG interests will be able to meet some or all of this demand."<sup>63</sup>

In light of the data submitted by all of the parties, the DOE concludes that there would be sufficient North American and overseas gas supplies to meet potential domestic demand without North Slope gas.

### 3. Effects on Quantity, Quality, and Price

Since the record indicates that available energy supplies are sufficient to meet domestic need, the DOE has considered whether there is any reason that North Slope natural gas, rather than other energy supplies, should be used to meet the anticipated demand. The public interest lies in ensuring the availability of adequate supplies at competitive prices. Therefore, the DOE has considered whether there are any effects on supplies or prices that would result directly and uniquely because of the proposed export. The DOE also has considered whether the proposed export might have a direct and unique effect on matters such as the environment or energy security.

For the most part, the examination of these potential considerations corresponds to the provisions of section 12 of ANGTA, which prohibit exports of North Slope natural gas unless the President finds such exports will not affect American consumers adversely by diminishing the quantity or quality of available energy supplies or increasing the total price of available energy. President Reagan fulfilled this statutory condition precedent in 1988 when he issued the *Finding* in which it was determined that exports of North Slope natural gas will not affect American consumers adversely because there are adequate supplies of secure, reasonably-priced energy available to American consumers. While this generic finding by the President necessarily provides the DOE with significant guidance, the DOE has examined these matters of supply, price, and qualitative effect in the particular context of Yukon Pacific's application under section 3 of the NGA.

#### a. Quantity

The quantity of energy available to American consumers is not necessarily

diminished merely because a particular energy supply is exported. Depending on the market, the alternative to export may be to leave an energy supply unused altogether. Moreover, in the context of global energy interdependence, the export of a certain energy source may, by increasing worldwide supplies of energy, result in making other energy supplies available to American consumers. Accordingly, with respect to North Slope gas, it would be unduly simplistic to conclude that exports will necessarily diminish the quantity of energy available to American consumers. In this case, the alternative to exporting North Slope gas may be that it remains undeveloped, and therefore available to no one; conversely, exporting such gas may make available on the American market gas from foreign sources that would otherwise have gone to the Pacific Rim.

In the final analysis, the question whether the proposed export of North Slope gas will *adversely* affect the quantity of energy available to American consumers depends on whether the export will cause available supplies to be inadequate to meet domestic demand. As discussed previously, there is an adequate supply of domestic gas other than North Slope natural gas to meet domestic need; furthermore, alternative supplies, such as Canadian gas, are more than adequate replacements for any North Slope natural gas that might be exported. The DOE therefore believes that the quantity of energy available to American consumers will not be adversely affected by the proposed export.

#### b. Quality

There is no evidence that the export of North Slope natural gas will diminish the "quality" of energy available to American consumers. Quality is an amorphous term that can denote a wide range of effects. For the most part, the ANGTS sponsors assert that the proposed export could result in detrimental qualitative effects in the areas of the environmental and energy security.

The purported harm to the environment would result from the use of other fossil fuels, such as coal, to meet excess demand. While the DOE does not dispute

<sup>63</sup> See *Initial Comments of Statoil North America, Inc.*, filed August 24, 1988, at 5.

that some excess demand may be met by energy sources other than natural gas, it does not believe the proposed export will be the reason for such a decision. Since the DOE has found that natural gas demand in the lower-48 states can be satisfied by supplies exclusive of the North Slope, any decision by American consumers to use other forms of energy will result from factors that relate to the desirability of natural gas when compared to other energy options, not because the proposed export makes gas unavailable.<sup>64</sup>

The ANGTS sponsors also assert that U.S. energy security would be impaired from consequent importing of natural gas or crude oil if the volumes proposed for export were unavailable to meet domestic demand. Even if the proposed export tends to increase energy imports, the DOE does not necessarily equate such a situation with energy insecurity. Energy security must be viewed in global terms: "Individual nations cannot go it alone; they are inevitably affected by the decisions and reaction of all other major market participants."<sup>65</sup>

Finally, North Slope natural gas is an integral part of the North American energy market resource base. The efficient development of North Slope gas, which includes potential exports, will contribute to the overall performance of the North American energy market. Any decision to export some North Slope gas will result from a market decision that other portions of the energy market can better serve the needs of American consumers. DOE believes that true energy security lies in encouraging the most efficient operation of the North American and global energy market.

#### c. Price

In determining whether the proposed export would result in higher prices to American consumers, the DOE has

focused on the structure of the natural gas market to evaluate the likelihood that the proposed export will affect market conditions so that consumers pay more than they would if North Slope gas were not exported.<sup>66</sup> In general, conditions in the domestic market will establish the price for whatever natural gas is used to meet domestic need, regardless of the source of the gas. Neither North Slope gas nor any other specific supply will be the tail that wags the market price of natural gas. The export of a particular gas supply, such as North Slope gas, would exert upward pressure on the market price only if there were not adequate alternative supplies of energy to meet domestic need at a market-responsive price. Even then, the export would exert upward pressure only if the costs of producing and delivering the exported gas to the domestic market would be less than the costs of the energy supplies actually used to meet the marginal demand.

The DOE's supply/demand analysis indicates there are adequate supplies to meet future demand without North Slope gas. While future market prices will be determined by a variety of factors (including the highly variable cost of crude oil), the DOE believes that it is reasonable to assume that these supplies will be available at a market-responsive price. The DOE/Argonne study indicates that 583 Tcf of gas will be available from reserves in the lower-48 states at less than \$3.00/Mcf, while an additional 174 Tcf of gas will be available in a price range of \$3.00 to \$5.00/Mcf.

Even if imports of gas are used to meet some demand, the DOE does not believe that they would be more costly than North Slope gas. In light of the location of North Slope natural gas and the conditions under which it would be produced and delivered to the lower-48 states, the DOE believes that the costs of producing

<sup>64</sup> A study prepared by Argonne National Laboratory for the ERA was included in the TAGS EIS that analyzed the environmental effects of exporting North Slope gas instead of using it domestically. The analysis concluded that using other fossil fuels, such as coal, to meet a shortfall in supply equivalent to the proposed exports would have minimal effect on air pollution levels. See *An Assessment of the Potential Environmental Residuals in the Lower-48 States Arising from Alaskan Natural Gas Exports* (July 30, 1987), attached as

Appendix D to the draft EIS. The study was incorporated by reference in Appendix K of the FEIS.

<sup>65</sup> U.S. Department of Energy, *Energy Security: A Report to the President of the United States*, March 1987, at 222.

<sup>66</sup> Action under the NGA may "rely on reasonable economic propositions." See *Michigan Consolidated Gas Company v. FERC*, No. 88-1062, slip op., at 14-15 (D.C. Cir. August 18, 1989).

and delivering most alternative supplies, especially Canadian gas, would be comparable to or lower than the cost of North Slope gas. Accordingly, if North Slope gas is exported, there should not be any marginal upward price pressure and thus, there should be no disruption in market conditions which would effect the efficient operation of market forces and result in higher prices to American consumers.

The DOE has reviewed very carefully the economic analyses submitted by Yukon Pacific and the ANGTS sponsors that purport to show whether North Slope gas will be competitive with other gas supplies and whether its price will be higher or lower than other supplies.<sup>67</sup> For the most part, the DOE finds these analyses represent a duel between economists over economic models, rather than a comparison of the actual production and delivery costs of North Slope gas with other gas supplies. Neither Yukon Pacific nor the ANGTS sponsors have analyzed the costs of North Slope gas and alternative supplies in a manner that sets forth the rationale for calculating those costs or the actual cost factors used in the calculations.<sup>68</sup> Their conclusions are not persuasive concerning the comparative costs of North Slope gas and other supplies or the effects of the proposed export on domestic prices and do not constitute the substantial evidence necessary to overcome the DOE's analysis of the fundamental market conditions, the section 3 presumption in favor of export approval, and the President's *Finding*.

In summary, the DOE has determined that North Slope natural gas is not required to meet domestic need because there are adequate supplies of gas available in the lower-48 states, as well as secure foreign supplies, and that the proposed export will not adversely affect the

quantity, quality, or price of energy sources available to American consumers.

#### B. Other Public Interest Considerations

Although domestic need is the only factor specified by Delegation Order No. 204-111, the DOE considered the potential effects of the proposed export on the other aspects of the public interest. In particular, the DOE examined the effects on American consumers, energy production, the State of Alaska, international relations, and the environment.

##### 1. American Consumers

A primary purpose of the NGA is protection of American consumers. In essence, the evaluation of domestic need is an examination of the effects of the proposed export on American consumers. As discussed in Section V.A., *supra*, the proposed export will not result in inadequate supplies or higher prices and thus will not be inconsistent with the public interest because of adverse effects on consumers.

During this proceeding, the ANGTS sponsors asserted that the proposed export may be inconsistent with the public interest because American consumers might somehow subsidize the export project. The DOE believes that those involved in the proposed export should bear the risk of the project and that none of the costs of the project should be borne by American consumers. Yukon Pacific has indicated that it does not expect American consumers to bear any of the risks or costs of the project and will not object to a condition that sets forth this principle. Accordingly, the DOE is attaching a condition to its approval of the proposed export that no cost of the export project may be recovered from American consumers. To assist in monitoring compliance with this condition, the DOE is requiring the submission of all contracts and other documents for the

<sup>67</sup> As discussed previously, "competitive" under the assumptions of an economic model does not necessarily translate into competitive in the real world. See *supra* note 37.

<sup>68</sup> For example, no party has provided any reason to believe that producers (and the State of Alaska) would be willing to receive wellhead prices for North Slope gas that are substantially lower than the wellhead price of other gas supplies. See Table 6-7 of the D&M study. Likewise, the DOE can find no discussion in the record that compares the actual costs of

delivering North Slope gas and Canadian gas to the lower-48 states or that provides a basis for assuming that the same factors that might lower the delivery costs of North Slope gas would not also operate to lower the delivery costs of Canadian gas. Rather than discuss such basic issues, the economic experts representing Yukon Pacific and the ANGTS sponsors chose to spar over whether to use the cost of service tariff for the ANGTS project that is on file with the FERC or a levelized cost tariff.

acquisition, transportation, and sale of North Slope gas in connection with the export project, when these documents are executed.

The DOE recognizes that situations may arise where American consumers could receive natural gas directly as a result of the export project. For example, consumers in Alaska may receive some North Slope natural gas transported through TAGS. The condition against the recovery of costs from American consumers is not intended to prevent Yukon Pacific from receiving payment for the sale of North Slope gas in the U.S. and from recovering the cost associated with those facilities used and useful for supplying such gas to consumers.

### 2. Energy Production

The U.S. public has a strong interest in the efficient production of the Nation's energy resources. While the interest of consumers and producers sometimes must be balanced in proceedings under the NGA, they coincide in this proceeding. Approval of the proposed export will have the beneficial effect of encouraging increased development of energy resources in Alaska.

The ANGTS sponsors question whether competition will spur exploration for and development of North Slope natural gas and they have indicated that the proposed export might result in the non-production of some North Slope gas. The DOE does not accept this contention.

Thirteen years have passed since the passage of ANGTA and no North Slope natural gas has been produced commercially. The introduction of competition will encourage a realistic assessment of the potential of North Slope natural gas and its early and more efficient development. It also will provide an incentive for discovering and developing additional reserves of natural gas on the North Slope. Several estimates have been published concerning the amount of North Slope proven reserves. Estimates published by the DOE's Energy Information Administration (EIA), the Alaska Oil and

Gas Conservation Commission (AOGCC), and the Alaska Department of Natural Resources (ADNR) indicate a range of proven reserves from 22.5 Tcf (AOGCC) to 33.9 Tcf (ADNR).<sup>69</sup> The EIA estimate of 24.6 Tcf lies between the AOGCC and ADNR estimates. The DOE/Argonne appraisal estimates the undiscovered recoverable gas for the onshore and offshore areas of the North Slope to be 89 Tcf. By combining these figures for proven reserves and potential gas reserves, the total gas resources of the North Slope would be in a range of 111.5 Tcf to 122.9 Tcf.

Producers of North Slope natural gas have supported approval of the proposed export. This support has not been based on their involvement in the export project, but rather on their belief that competition for North Slope natural gas is the best means to ensure its expeditious and efficient development. Indeed, Exxon has supported approval of the export in order to spur market competition and development efforts, even though its current analysis indicates the most likely market for North Slope gas is the lower-48 states.

### 3. State of Alaska

In making the public interest determination in this proceeding, the DOE has been especially mindful of the effects of the proposed export on the State of Alaska and its citizens. The State strongly supports approval of the proposed export because it would promote the development of Alaska's natural resources. The State indicates that the export project would provide significant benefits to the local economy through increased jobs, tax revenues, and royalty payments. Specifically, the TAGS FEIS indicated that construction of the TAGS facilities would create up to 7,200 new jobs during the peak year. Operations would employ about 550 people directly, and support over 1,000 more jobs indirectly. Royalty payments, state taxes, and property taxes are expected to produce about \$377 million in state government annual revenues. The benefits to Alaska are undisputed in the record.

<sup>69</sup> See EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1987 Annual Report*, DOE/EIA-0216(87); AOGCC, *Bulletin*, "Estimate of Gas Reserves in Alaska," May 1988, at 4; and ADNR, *Historical and Projected Oil and Gas Consumption*, January

1989, Table 2.1. (Copies of relevant pages attached as Exhibits A-C in Alaskan Northwest's *Supplemental Comments Relating to January 24, 1989 Conference*, submitted February 7, 1989.)

#### 4. International Effects

The international effects of a proposed export may also be significant in the public interest determination. In general, the DOE believes that the public interest is served best through a policy of free trade in energy resources. Such a policy promotes energy interdependence among all nations, rather than energy dependence on a few nations. Competition in world energy markets promotes the efficient development and consumption of energy resources, as well as lower prices, whereas economic distortions can arise from artificial barriers to the free flow of energy resources. Accordingly, the DOE believes that the public interest in free trade generally supports approval of proposed exports.

This particular export project has beneficial international effects in addition to those normally associated with free trade. The export project would serve markets in the strategically important Pacific Rim countries of Japan, South Korea, and Taiwan.<sup>70</sup> By increasing the energy security of these allies, the project, in effect, would strengthen our national security. In addition, the U.S. currently is experiencing a trade imbalance with these Pacific Rim countries: By increasing exports to these

countries, the export project would tend to mitigate this trade imbalance.

Of course, the public interest in international energy markets also requires consideration of the North American energy market. Accordingly, the DOE has given special consideration to the concerns of Canada, our major partner in the North American energy market. The Canadian concerns about the proposed export center on the effects of the approval of the export project on the U.S. Government's commitment to ANGTS.<sup>71</sup>

The U.S. Government has complied fully with its commitment to ANGTS by removing all regulatory impediments to the completion and operation of ANGTS by private parties. Moreover, it has assured Canada that it will not erect new regulatory barriers to the completion of ANGTS by private parties. In particular, the President's *Finding* reaffirmed all existing commitments to support the special regulatory treatment of the "prebuild" segments of the ANGTS, including the minimum revenue stream guarantees.

DOE does not believe approval of the proposed TAGS export to be inconsistent with the U.S. Government's commitment

<sup>70</sup> The U.S. Government has long recognized the potential strategic value of exporting North Slope natural gas to Pacific Rim markets. In 1983, President Reagan recognized the potential importance of North Slope gas to U.S. relations with Pacific Rim countries when he and Japanese Prime Minister Nakasone agreed to encourage private efforts to explore the possible export of North Slope gas. See *Joint Statement of President Reagan and Prime Minister Nakasone on Energy Cooperation*, November 11, 1983. See also June 17, 1983, letter from Secretary of Commerce Malcolm Baldrige to Bill Sheffield, Governor of Alaska in which the Secretary stated "The Administration views the development of Alaska North Slope natural gas as a major contribution to Western energy security, whether the gas is marketed in the United States or abroad, it reduces demand for OPEC and Soviet energy and clearly results in significant benefits to the U.S. economy."

<sup>71</sup> The U.S. Department of State also has considered the Canadian concerns and has found the proposed export would not breach any agreement between the U.S. and Canada. In response to Canadian concerns about the viability of ANGTS, the State Department stated:

The United States Government continues to support development of the ANGTS pipeline based on

private sector financing. Its eventual development is a private sector decision, and must be based on private financing, as stated in the original 1977 Bilateral Agreement and repeated on many occasions since. Decisions on private sector financing can and should reflect the economic potential of the project as determined by market considerations. By the same token, the United States Government will not impede the private sector from developing other initiatives to develop Alaska North Slope gas. Like ANGTS, their development is a private sector decision, explicitly requiring private sector financing, and thus reflecting their economic potential as determined by the market place. . . . Other projects for developing [Alaska North Slope] gas resources will have to rise or fall on their economic merits, as determined by the market. . . . Our policy is that ANGTS, TAGS, or any other project for [Alaska North Slope] gas must be strictly private capital ventures, competing equally in the market place for financing. Such an approach would be consistent with our goal of allowing the market to determine how the gas is developed.

See letter from Mr. J.P. Ferriter to Mr. L.H. Legault, attached as Exhibit T to *Reply Comments* of Yukon Pacific.

to ANGTS. Approval of the proposed export will create no regulatory impediments to the completion and operation of ANGTS.<sup>72</sup> The commitments of the U.S. and Canada to ANGTS did not include any pledges to impose a governmentally-dictated scheme of development on energy resources. To the contrary, the bilateral agreements on ANGTS were important first steps in the recognition that the interests of both countries are best served by letting the marketplace decide the most efficient development of energy resources with minimal governmental interference. The DOE believes that continuation of the commitment to removal of governmental impediments and deference to marketplace decisions eventually will result in the efficient development of North Slope natural gas.

#### 5. The Environment

Environmental concerns are an important element of DOE's public interest consideration. In general, DOE considers environmental issues in the context of the National Environmental Policy Act of 1969 (NEPA).<sup>73</sup> The DOE participated as a cooperating agency during the preparation of and has adopted the TAGS FEIS<sup>74</sup> which examined the environmental effects of constructing and operating the TAGS liquefaction facility, marine terminal, and related project components.<sup>75</sup> The publication of the FEIS

was the culmination of a comprehensive process that began with Yukon Pacific's application for a right-of-way permit in 1984. During the scoping process the DOE participated in six public meetings in Alaska in 1986 designed to identify the environmental issues and concerns related to the project. Additionally, the DOE participated in eight formal public hearings on the draft EIS in 1987 and thoroughly reviewed the draft EIS prior to the issuance of the FEIS. The DOE has concluded that the TAGS FEIS is a complete document that complies with the NEPA process and provides an adequate basis to evaluate the environmental aspects of the section 3 public interest determination concerning the export project.

The DOE used that FEIS, as well as its independent review, in assessing the environmental consequences of granting the proposed export. The DOE's findings are discussed in its *Record of Decision* for the Yukon Pacific project which was issued in conjunction with this order and is being published in the *Federal Register*.<sup>76</sup> The DOE determined that the overall physical impacts anticipated to the natural environment are relatively minor and can be mitigated, and thus are environmentally acceptable, especially when balanced against the substantial economic benefits to be derived from the project.<sup>77</sup>

<sup>72</sup> In fact, the DOE is including in this authorization a specific condition to ensure that the export will not be inconsistent with the framework adopted at the inception of ANGTA. See Section V.C., *infra*.

<sup>73</sup> 42 U.S.C. 4321, *et seq.*

<sup>74</sup> *Trans-Alaska Gas System Final Environmental Impact Statement* (FEIS BLM-AK-PT-88-003-1792-910, June, 1988). DOE/EIS-0139.

<sup>75</sup> The ANGTS sponsors questioned the treatment in the FEIS of the gas conditioning facility (GCF) that would be used by the TAGS project. The FEIS did not consider a GCF in the Prudhoe Bay area as part of the TAGS project. Rather, the FEIS considered the GCF as a connected action to be evaluated with regard to environmental effects when the plant configuration and technology are more certain. The FEIS conceptually described the GCF that would be needed to produce pipeline quality natural gas for TAGS and analyzed and discussed the potential environmental consequences as they presently exist for the construction and operation of the conceptual GCF if it was located at Prudhoe Bay adjacent

to Atlantic Richfield Company's existing Central Gas Conditioning Facility.

As noted previously, the unconstructed ANGTS holds a conditional certificate from the FERC to build and operate the Alaska Gas Conditioning Facility (AGCF) at Prudhoe Bay to support the proposed ANGTS project. The FEIS is based on the assumption that the ANGTS facilities will be built. The FEIS indicated that no significant cumulative effects are expected from the construction and operation of the AGCF and a stand-alone conditioning facility for TAGS located several miles south of the area identified for the AGCF.

<sup>76</sup> The *Record of Decision* was issued under the Council on Environmental Quality Regulations implementing the procedural provisions of NEPA and the DOE's guidelines for compliance with NEPA (52 FR 47662, December 15, 1987).

<sup>77</sup> The DOE notes that the physical impacts associated with the development of North Slope gas may occur regardless of whatever action the DOE takes since the ANGTS sponsors already have legislative and regulatory approval to construct ANGTS. As part of the

The FEIS indicates that the proposed export project can be constructed and operated in an environmentally acceptable manner provided that the specific mitigation measures identified in the FEIS are implemented. These measures include compliance with the tiered review process<sup>78</sup> set forth in the FEIS and any resulting environmental requirements, including the stipulations already required by BLM in the TAGS right-of-way. This compliance would minimize any negative social, economic, and environmental effects and note the positive effects of the proposed TAGS project.

Following issuance of the FEIS, Exxon Shipping Company's crude oil tanker, the Exxon Valdez, went off course and ran aground in Prince William Sound on March 24, 1989, spilling 242,000 bbls of North Slope crude. The resulting damage to shoreline and wildlife has emphasized the need for strict preventive and mitigative measures to maintain transportation safety and protect the environment, as well as for comprehensive monitoring to ensure compliance with these measures. The DOE believes that energy projects can and must be undertaken consistent with environmentally acceptable practices. To ensure this result, the DOE is attaching a condition to the export approval that all aspects of the export project must be undertaken in accordance

(Footnote Continued)

approval process for ANGTS, the Council on Environmental Quality found the physical impacts of ANGTS (similar in nature to those predicted for TAGS) to be environmentally acceptable and this finding was ratified by the President and Congress. (See the President's Decision on ANGTS at 132-133).

<sup>78</sup> Yukon Pacific, BLM, and USACE are using a tiered approval system for the design and construction of the TAGS project. The fundamental approach used in the tiered mitigation process is: the development and approval of design criteria, final design, and the issuance of a "Notice to Proceed." Therefore, the discussion of mitigation measures in the FEIS tend to be generic and refer to site specific designs not yet done. Consistent with that tiered concept, BLM attached stipulations to its grant of a right-of-way for TAGS which specify that Yukon Pacific will submit for governmental approval certain plans and site specific designs before proceeding with field activities. These stipulations and subsequent plans will set forth the standards of performance for construction and operation of the pipeline, and termination of the right-of-way. The

with the appropriate environmental review process and must comply with any and all preventative and mitigative measures imposed by Federal or State agencies.

The DOE expects those agencies responsible for regulating the construction and operation of the proposed TAGS facilities to impose and strictly enforce all necessary measures to preserve and protect the natural environment and to incorporate within these measures the lessons that have been learned from the Exxon Valdez incident. In particular, the DOE is directing the FERC to consider the safety and environmental aspects of the export site and facilities, including the liquefaction plant, the marine terminal, the LNG tankers and their routes in Prince William Sound and U.S. territorial waters, prior to approving any export site or facilities.<sup>79</sup> This consideration should place particular emphasis on the need for the FERC to exercise the full extent of its section 3 authority to regulate the marine transportation of LNG if it approves an export site. Any FERC approval should include all appropriate preventive and mitigation measures to protect the public health, safety, and environment.

### C. ANGTA

In addition to the public interest determination of section 3 of the NGA, the

stipulations cover (1) protection of the environment; (2) integrity of the pipeline system; (3) integrity and protection of adjacent or intersecting facilities, in particular, the TAPS and ANGTS pipelines; (4) public health and safety; and (5) effects on socioeconomic, subsistence, and cultural resources. Mitigation of environmental impacts and monitoring of the project by BLM will be primarily through monitoring, enforcement, and action under these stipulations.

<sup>79</sup> DOE Delegation Order 0204-112 delegated the FERC authority under section 3 of the NGA to approve or disapprove "the construction and operation of [export] facilities, the site at which such facilities shall be located, and the place of . . . exit for exports" of natural gas, as well as the authority to exercise the functions under sections 4, 5, and 7 of the NGA with respect to exports. See 49 FR 6690 (February 22, 1984). Any exercise of authority under this delegation order, however, must be consistent with the terms and conditions under which the DOE authorizes an export and with the DOE's policies.

DOE has considered the proposed export in light of the statutory framework of ANGTA as it relates to exports of North Slope natural gas. Section 12 of ANGTA prohibits the export of North Slope gas in the absence of a finding that the export will not affect American consumers adversely. Section 9 of ANGTA requires the DOE to assess whether a regulatory action would significantly impair the construction or initial operation of ANGTS.

The ANGTS sponsors argue that the proposed export is inconsistent with the framework of ANGTA because it would make completion and operation of ANGTS more expensive or impractical and thus cannot be approved. In particular, they assert that the proposed export would affect ANGTS adversely because (1) there are insufficient proven reserves of North Slope gas to support the proposed export and ANGTS, (2) the export project would increase the costs of ANGTS, and (3) in certain locations, the construction and operation of two natural gas pipelines would be impractical or impossible.

The DOE evaluated these concerns in light of the framework of ANGTA. As discussed in the July 25 procedural order, this evaluation focused on the direct effect that regulatory action might have on the ability of the ANGTS sponsors to proceed with its expeditious construction and operation. ANGTA was intended to remove regulatory roadblocks that could impede the prompt commencement and completion of the ANGTS. However, ANGTA neither contemplates the insulation of ANGTS from all competition nor requires the creation of regulatory obstacles to other North Slope gas projects.

The DOE does not think that ANGTA mandates the rejection of a proposed export because there may be insufficient proven reserves for both the proposed export and ANGTS. Neither does it require the imposition of a condition to set aside certain reserves for ANGTS.<sup>80</sup>

<sup>80</sup> In this regard, DOE notes the statement of Senator Henry Jackson when the Senate approved ANGTA that "ANGTA is a procedural bill which, unless otherwise explicitly stated, does not modify existing rights and obligations of affected persons." 122 Cong. Record 22018, 22023 (July 1, 1976).

<sup>81</sup> Mr. George McHenry, representing Foot-hills, stated at the public conference in

Such actions would be inconsistent with the framework of ANGTA. ANGTA neither grants ANGTS an exclusive license to North Slope gas nor dedicates any particular reserves to ANGTS.<sup>81</sup>

ANGTA was enacted to establish a process for selecting a transportation system to bring natural gas from the North Slope of Alaska to the lower-48 states and to facilitate its construction and operation. Contrary to the assertions of the ANGTS sponsors, ANGTA was not intended to somehow mandate the use of North Slope gas in the domestic market or to limit its export to formal exchanges of energy supplies. In fact, section 12 of ANGTA explicitly addresses the export of North Slope gas and permits the export on the same basis as any other gas once the President finds, as has occurred, that the export will not be detrimental to American consumers. There is no hint in ANGTA or its legislative history that Congress intended *sub silentio* to link the export of North Slope gas to the effect on ANGTS. To the contrary, decisions concerning ANGTS were to be made by private parties on the basis of actual market conditions without any governmental subsidies.

Currently Yukon Pacific, the ANGTS sponsors, or any other private party is free to negotiate and sign contracts with the producers of North Slope gas. Regulatory approval of the proposed export will not change this situation. Rejecting the proposed export or imposing a condition on the proposed export to set aside certain North Slope gas for ANGTS would not be a measure to mitigate the effects of regulatory action, but rather the creation of a regulatory obstacle to competition for North Slope gas. Such action is not mandated by ANGTA and, in fact, would be inconsistent with the explicit language in ANGTA that permits exports of North Slope natural gas if the requirements of section 3 of NGA and section 12 of ANGTA are met.

Anchorage on January 25, 1989, that "we have never suggested that the ANGTS sponsors own the North Slope reserves or they were given by Congress to the sponsors of the ANGTS. What we have said is that producers own those reserves and obviously they have the right to enter into contracts with whomever they please." See *Transcript*, at 148.

Unlike the asserted concerns about reserves, the effects of TAGS on the costs and physical feasibility of constructing and operating ANGTS do come within the intended framework of ANGTA since they could directly impair its construction and operation. The ANGTS sponsors have presented sufficient evidence to demonstrate that the proximity of the TAGS pipeline to ANGTS in many locations creates the potential that ANGTS may become significantly more expensive, or even impossible to construct and operate because of the proposed export. There is no evidence, however, that this potentiality cannot be managed in a manner that permits TAGS to be constructed and operated without impairing the construction and operation of ANGTS.

The DOE does not believe that it is either feasible or necessary to resolve the management of every potential interaction between TAGS and ANGTS prior to the approval of the proposed export. Such an effort would be enormously time-consuming and inefficient since, while a large number of potential situations for adverse interaction between TAGS and ANGTS would be hypothesized, the number of actual situations most likely will be small. The DOE has decided that the export can be approved consistently with the framework of ANGTA, and in particular section 9, if it exercises its plenary authority under section 3 of the NGA to attach to the approval a condition that incorporates the requirements of section 9. In particular, this "ANGTA condition" will prohibit Yukon Pacific from taking any action that would compel a change in the basic nature and general route of ANGTS or otherwise prevent or impair in any significant respect its expeditious construction and initial operation.<sup>82</sup>

<sup>82</sup> The DOE has not included a similar condition with respect to TAPS because the oil pipeline already is constructed and there is no statutory provision for TAPS comparable to ANGTA. Moreover, the TAPS right-of-way, like the ANGTS right-of-way, prohibits any incompatible uses by holders of subsequent rights-of-way on or adjacent to the right-of-way. In addition, the TAGS right-of-way makes the proposed export project subject to the pre-existing rights-of-way for TAPS and ANGTS. Enforcement of these provisions will prevent actions by Yukon Pacific that are incompatible with TAPS.

<sup>83</sup> ANGTA established the Office of Federal Inspector (OFI) to coordinate and monitor

Since the DOE is exercising its plenary authority under section 3, the "ANGTA condition" extends to the pipeline and related facilities, such as a gas conditioning plant or any support facility or resource. It does not extend to natural gas reserves. As discussed previously, the ANGTA framework draws a clear distinction between the construction and operation of ANGTS and market decisions concerning the development of North Slope natural gas.

The DOE does not intend the "ANGTA condition" to be used as a means to delay or otherwise burden the proposed export project unnecessarily. The ANGTS sponsors must demonstrate the adverse effect on ANGTS of an action by Yukon Pacific. This demonstration may not be speculative, but rather should be based on facts which clearly show that an action directly will increase the cost of constructing or operating ANGTS or will make constructing or operating ANGTS impractical. Where the ANGTS sponsors demonstrate increased costs, Yukon Pacific will be presumed to satisfy the "ANGTA condition" if it agrees to compensate the ANGTS sponsors by paying the larger of the increased costs or its proportionate share of the overall costs of the measures necessary to mitigate the effects of TAGS on ANGTS. Where the ANGTS sponsors demonstrate that TAGS will make constructing or operating ANGTS impracticable, Yukon Pacific will be presumed to satisfy the "ANGTA condition" if it agrees to modify its project to avoid the problem or, where appropriate, to construct joint facilities which accommodate the needs of ANGTS.<sup>83</sup>

Federal activity concerning ANGTS. Reorganization Plan No. 1 of 1979 (Reorganization Plan) (44 FR 33663, June 12, 1979) transferred to OFI exclusive responsibility for enforcing all Federal statutes, regulations, and authorizations relevant in any manner to the preconstruction, construction, and initial operation of ANGTS. In areas where TAGS and ANGTS would interact, OFI would have responsibility to determine the compatibility of TAGS with ANGTS, to review and approve designs, plans, and schedules, and to enforce the provisions and requirements of Federal authorizations such as the TAGS right-of-way when it is on or adjacent to the ANGTS right-of-way.

#### D. Other Matters

Section 3 of the NGA provides plenary authority over all aspects of an export where the public interest requires the exercise of such authority.<sup>84</sup> In general, the DOE refrains from exercising the full extent of its section 3 authority unless it determines action is necessary to avoid a regulatory gap inconsistent with the public interest or to preserve the integrity of the export approval and the underlying public interest determination.

The DOE has examined all aspects of the export project to determine the extent to which it should exercise its plenary authority in this proceeding. Since the proposed export project will be subject to comprehensive regulatory oversight by the State of Alaska, BLM, USACE, FERC, and other Federal agencies, DOE has determined that the need to exercise its plenary authority is limited.<sup>85</sup> DOE has determined, however, that there are certain situations where the exercise of this authority is appropriate.<sup>86</sup>

The gas conditioning facilities have been the subject of much controversy in this proceeding. Yukon Pacific asserts that the conditioning plant is not part of its project and should not be considered in this proceeding. The ANGTS sponsors argue that the conditioning plant should be considered because of its potential effects on the environment and because of the issues that would arise if TAGS and ANGTS share a conditioning plant. Since the DOE's regulatory authority over exports extends to the wellhead, the conditioning plant comes within its purview.

(Footnote Continued)

Since the "ANGTA condition" in this authorization is directly relevant to ANGTS, OFI will be responsible for its enforcement. Pursuant to Section 2-202(c) of the Reorganization Plan, OFI is required to follow the policies of the agency that otherwise would be responsible for the enforcement function and the DOE reserves the right to announce specific policy measures to enforce this condition. The DOE emphasizes that its general policy is that this condition shall not be enforced in a manner that unduly delays or hinders any aspect of Yukon Pacific's export project and that expeditious procedures should be followed to resolve any disputes concerning this condition.

<sup>84</sup> In *Distrigas Corporation v. FPC*, 495 F.2d 1057 (D.C. Cir. 1974), cert. denied, 419 U.S. 834 (1974), the court found that section 3 of

The DOE believes that any environmental concerns can be mitigated in an acceptable manner whether TAGS and ANGTS share a gas conditioning plant or they construct separate facilities. DOE expects the tiered process contemplated in the FEIS will take place for all aspects of the TAGS project, including the conditioning plant and production facilities that will be used to supply the gas to be exported. As discussed in section V.B.5 *supra*, the DOE is attaching a condition to the export approval that all aspects of the export project, regardless of whether they are undertaken by Yukon Pacific, must be undertaken in accordance with the appropriate environmental review process, and must comply with any and all environmental preventive and mitigative measures imposed by federal or state agencies.

The potential for sharing a gas conditioning plant also raises another issue for which action by DOE is appropriate. In general, the cost and practicality aspects of sharing such a facility are covered by the "ANGTA condition." However, the question of the jurisdiction of the FERC makes additional action appropriate. The DOE Organization Act gives the Secretary of Energy all NGA authority over natural gas imports and exports. The FERC cannot exercise any authority over imports or exports unless the Secretary assigns such a function to the FERC. While the Secretary has delegated to the FERC some authority over the siting, construction, and operation of import and export facilities and over imports and exports once they are in interstate com-

the NGA provides the authority for "comprehensive regulation" where such power is "responsibly exercised" to protect the public interest. "Section 3 supplies . . . not only . . . the power necessary to prevent gaps in regulation, but also . . . flexibility in exercising that power." 495 F.2d at 1064. The court also made clear that power under section 3 extends equally to imports and exports. 495 F.2d at 1063; see also, *Border Pipe Line Company v. FPC*, 171 F.2d 149 (1948).

<sup>85</sup> See Appendix S to *Initial Comments of Yukon Pacific* at 36-55 for a description of the regulatory oversight by various federal and state agencies to which TAGS will be subject.

<sup>86</sup> As discussed previously, the "ANGTA condition" will extend to all aspects of the export project.

merce,<sup>87</sup> the exercise of that authority is subject to any terms or conditions attached by the DOE to the import or export approval.<sup>88</sup> In order to avoid overlap with enforcement of the "ANGTA condition" and to relieve the export from duplicative and unnecessary regulation, the DOE has decided to exercise its authority to limit any jurisdiction the FERC might otherwise acquire over the export project in the event TAGS and ANGTS share a facility that is subject to the FERC's interstate commerce jurisdiction, such as the Alaska Gas Conditioning Facility proposed by the ANGTS sponsors. The FERC shall only exercise such authority over the export project to the extent necessary to ensure that the shared facility is constructed and operated in accordance with FERC's regulations, including those concerning the environment. The FERC shall have no other authority over Yukon Pacific's export project, including its rates, except to the extent necessary to ensure that Yukon Pacific pays its part of the costs of any shared facility. The DOE intends this limitation on the FERC's authority to apply not only to the gas conditioning plant, but also to any other facility subject to the FERC's jurisdiction that the export project might utilize. This limitation does not apply to the FERC's section 3 authority over the liquefaction plant, marine terminal, and transportation of the LNG.

With respect to the liquefaction plant and marine terminal, the Secretary delegated to the FERC section 3 authority over the siting and construction of new import/export facilities. This delegation stipulates that the FERC cannot approve any site that the DOE disapproves. On the basis of its environmental review, the DOE has concluded that the Valdez export site is preferable to all other export sites that were considered in the FEIS, including the Cook Inlet site. Three factors discussed in the FEIS indicate that Port Valdez is environmentally preferable to the Cook Inlet alternative. First, the Cook Inlet alternative creates new disturbances in Minto Flats, an important sub-

sistence use area. By contrast, the impacts of the proposed project are in an existing transportation and utility corridor. Second, the Cook Inlet alternative crosses Denali National Park and Preserve, and would impact visitors traveling to and from the park. While the proposed project would impact visitors and travelers elsewhere, Denali has the greater concentration. Finally, the Cook Inlet alternative includes a 15-mile subsea crossing, an impact to an ecosystem that does not occur under the proposed project. Accordingly, the DOE disapproves all sites other than the Valdez site. This action should not be interpreted as approval of the Valdez site. As discussed previously in Section V.B.5. *supra*, the DOE is requiring as Departmental policy that the FERC conduct its own examination of the health, safety, and environmental impacts associated with Yukon Pacific's use of the Valdez site for its proposed export project, including the liquefaction plant, the marine terminal, the LNG tankers, and the LNG tanker routes, and that it impose all appropriate conditions to mitigate the environmental effects resulting from the construction and operation of those facilities.

#### VI. Conclusion

After taking into consideration all the information in the record of this proceeding, I find that granting Yukon Pacific authority to export up to 14 million metric tons annually of liquefied North Slope natural gas for sale to the Pacific Rim countries of Japan, South Korea, and Taiwan during a term of 25 years has not been shown to be inconsistent with the public interest.

#### ORDER

For the reasons set forth above, pursuant to section 3 of the Natural Gas Act, it is ordered that:

A. Yukon Pacific Corporation (Yukon Pacific) is authorized to export for sale to Japan, South Korea, and Taiwan a total of up to 14 million metric tons of liquefied natural gas (LNG) annually from the North Slope of Alaska over a 25-year

<sup>87</sup> See DOE Delegation Order No. Q204-112, *supra* note 79.

<sup>88</sup> In *TransCanada Pipelines v. FERC*, No. 87-1229, June 16, 1989, the D.C. Circuit Court of Appeals found "Congress specifically pre-

cluded FERC from exercising its general ratemaking authority over imported [and exported] gas except to the extent that the Secretary expressly delegates the task to FERC." *Slip op.*, at 11; see also *id.*, at 7-9.

period beginning on the date of the first delivery, upon the conditions herein set forth.

B. For purposes of this Order, the "export project" means the Trans-Alaska Gas System (TAGS) and all appurtenant facilities, including production facilities, gas conditioning facilities, liquefaction plant, marine terminal, and LNG tankers.

C. With respect to the place of exportation for the LNG authorized in Ordering Paragraph A above, all locations other than Port Valdez, Alaska, are hereby rejected.

D. No cost of the export project shall be recovered from U.S. consumers of natural gas except to the extent that the cost relates to facilities and natural gas used and useful for supplying North Slope natural gas to the U.S. consumers.

E. No action shall be taken in connection with the export project that would compel a change in the basic nature and general route of the Alaska Natural Gas Transportation System (ANGTS) or otherwise prevent or impair in any significant respect the expeditious construction and initial operation of ANGTS.

F. All aspects of the export project shall be implemented in accordance with all applicable environmental procedures and requirements and shall comply with all preventive and mitigative measures imposed by Federal and State agencies to protect the public health, safety and environment.

G. All contracts and other documents that underlie the acquisition, transportation, and sale of North Slope gas authorized herein shall be filed with the DOE within 30 days of their execution.

H. Within 48 hours after deliveries begin, Yukon Pacific shall notify the

Office of Fuels Programs, Fossil Energy, Room 3F-056, FE-50, 1000 Independence Avenue, S.W., Washington, D.C. 20585, in writing of the date that the first export of LNG authorized in Ordering Paragraph A above occurs.

I. With respect to the exports authorized by this Order, Yukon Pacific shall file reports with the Office of Fuels Programs (1) after the first full calendar month of service, and (2) within thirty days following each calendar quarter, indicating, whether sales of exported natural gas have been made, and if so, giving by month, the total volume of exports in Mcf and the average price for exports per MMBtu delivered to each respective purchaser. The reports shall also provide the details of each export transaction, including the name(s) of the purchaser(s), LNG tankers utilized, volumes sold to each purchaser, and identification of markets served.

J. Except for the authority under DOE Delegation Order No. 0204-112 over the export site, including the liquefaction plant, marine terminal, and related transportation of LNG, the Federal Energy Regulatory Commission (FERC) shall exercise no authority over the export project except to the extent necessary to ensure that (1) any facility used for the provision of natural gas from Alaska to another state and thereby subject to the FERC's interstate commerce jurisdiction is constructed and operated in accordance with the FERC's regulations, including those concerning the environment, and (2) the export project pays its share of the costs of any such facility.

Issued in Washington, D.C., on November 16, 1989.

### ¶ 70,260

Niagara Mohawk Power Corporation (FE Docket No. 89-33-NG),  
November 15, 1989.

#### DOE/FE Opinion and Order No. 351

Conditional Order Granting a Long-Term Authorization to Import  
Natural Gas From Canada and Granting Interventions

Federal Energy Guidelines

¶ 70,260

**TAB**

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allowing commercial parties to freely negotiate their own trade arrangements.

Carson's uncontested export proposal, as set forth in the application, is consistent with section 3 of the NGA and the DOE's international gas trade policy. We believe that the current domestic natural gas supply, coupled with the short-term, market-responsive nature of the contracts into which Carson proposes to enter, indicate that it is unlikely the proposed export volumes will be needed during the term of the authorization. Further, as Carson notes, the export will provide increased tax and related revenues to the individual producer sellers, and benefit gas transporters by increasing pipeline throughput. Finally, Carson's proposal will further the Secretary's policy goals of reducing trade barriers by encouraging market forces to achieve a more competitive distribution of goods between the U.S. and Mexico, and thereby enhances cross-border competition in the marketplace.

After taking into consideration all the information in the record of this proceed-

ing, I find that granting Carson blanket authority to export up to 4,000,000 Mcf of natural gas from the U.S. to Mexico during a period of two years, under contracts with terms of two years or less, is not inconsistent with the public interest.

#### ORDER

For the reasons set forth above, pursuant to section 3 of the Natural Gas Act, it is ordered that:

A. Carson Water Company (Carson) is authorized to export up to 4,000,000 Mcf of natural gas from the United States to Mexico during a two-year period beginning on the date of the first delivery.

B. Within two weeks after deliveries begin, Carson shall notify the Office of Fuels Programs, Fossil Energy, Department recognition that it might be aggrieved because of any order issued in these proceedings.

Issued in Washington, D.C. on February 7, 1990.

### ¶ 70,303

Yukon Pacific Corporation (ERA Docket No. 87-68-LNG), March 8, 1990.

#### DOE/FE Opinion and Order No. 350-A

#### Order Denying Requests for Rehearing and Modifying Prior Order for Purpose of Clarification

##### I. Background

On November 16, 1989, the Office of Fossil Energy (FE) of the Department of Energy (DOE) issued DOE/FE Opinion and Order No. 350 (Order 350).<sup>1</sup> Order 350 granted Yukon Pacific Corporation (Yukon Pacific) authorization under section 3 of the Natural Gas Act (NGA) to export natural gas produced in the North Slope region of Alaska to the Pacific Rim countries of Japan, South Korea, and Taiwan. Yukon Pacific plans to build the Trans-Alaska Gas System (TAGS) to deliver gas from Prudhoe Bay to Port Valdez on Alaska's southern coast, where it would be converted to liquefied natural gas (LNG) and shipped by tanker to

Pacific Rim customers. On December 15, 1989, Alaskan Northwest Natural Gas Transportation Company (Alaskan Northwest) and Foothills Pipe Lines (Yukon) Ltd. (Foothills), sponsors of a competing private commercial project, the Alaska Natural Gas Transportation System (ANGTS),<sup>2</sup> filed individual applications for rehearing of Order 350. On the same date, Yukon Pacific filed a request for clarification.

##### II. Requests for Rehearing

Alaskan Northwest and Foothills specified numerous alleged errors in the DOE's decision. A list of these alleged errors is contained in the appendix of this order.

<sup>1</sup> 1 FE ¶ 70,259.

<sup>2</sup> ANGTS is a project to deliver North Slope natural gas to markets in the lower-48 states

by means of a pipeline across Alaska and Canada.

Their applications restate arguments the ANGTS sponsors urged previously in this proceeding and do not provide any new relevant and material information. Their principal arguments may be summarized as follows: (A) Order 350 is inconsistent with the Alaska Natural Gas Transportation Act (ANGTA),<sup>3</sup> the 1977 bilateral agreement between the U.S. and Canada relating to the ANGTS,<sup>4</sup> and the measures taken to implement these documents (hereafter collectively referred to as the ANGTA framework); (B) Order 350 improperly permits Yukon Pacific to compete for North Slope natural gas reserves that "belong" to the ANGTS project; (C) Order 350 represents a taking of property and violation of substantive due process with respect to Alaskan Northwest's and Foothills' "franchise" to bring North Slope gas to the lower-48 states; (D) the export of North Slope gas is not consistent with the public interest; (E) the DOE did not comply with statutory, regulatory, and procedural due process requirements in issuing Order 350; and (F) Order 350 improperly restricts the regulatory authority of the Federal Energy Regulatory Commission (FERC) and the Office of Federal Inspector (OFI) for the ANGTS.

The DOE has considered carefully all of the arguments made by Alaskan Northwest and Foothills and is not persuaded to change Order 350. Their applications for rehearing fail to overcome either the general presumption favoring export authorizations mandated by section 3 of the NGA or the substantial evidence in the record of this proceeding that exports of North Slope gas would be consistent with the public interest. Therefore, the applications for rehearing are

<sup>3</sup> 15 U.S.C. 719 *et seq.*

<sup>4</sup> *Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline*, September 20, 1977, U.S.T. 3581, T.I.A.S. 9030.

<sup>5</sup> See Alaskan Northwest's stated errors (1)(a), (1)(b), (1)(c), (2), and (6) listed in the appendix of this order; see also Foothills' stated errors (1), (2), (3), and (5)(c). The DOE notes that while Alaskan Northwest and Foothills argue the ANGTA framework somehow imposes additional or different legal requirements on the DOE when it considers the export of North Slope gas, they also take the position "that judicial review of [Order 350] must occur under Section 19 of the Natural Gas Act . . . rather than under section 10 of ANGTA." See

denied in their entirety. In the following paragraphs, the DOE sets forth its views on the principal arguments of Alaskan Northwest and Foothills.

*A. Order 350 is Consistent with the ANGTA Framework and Provides Explicit Protection for ANGTS.*

Many of Alaskan Northwest's and Foothills' arguments flow from the contention that the ANGTA framework requires that any project competing with ANGTS be rejected or at least severely restricted.<sup>5</sup> Prior to the issuance of Order 350, the DOE considered these arguments and found them unpersuasive. The ANGTA framework cleared the administrative path for the construction and operation of ANGTS. It did not guarantee financing for ANGTS or block competition for the development of North Slope natural gas.<sup>6</sup>

The U.S. Government has taken all actions necessary to implement the ANGTA framework. Nothing in Order 350 affects these actions. All the special statutory and regulatory treatment for ANGTS remains intact, ready to be used whenever the sponsors decide, after years in abeyance, to resume its construction.

With respect to the assurances to Canada concerning ANGTS, the DOE again rejects the assertions by Alaskan Northwest and Foothills that authorizing exports of North Slope gas is inconsistent with this aspect of the ANGTA framework. Order 350 stated:

The U.S. Government has complied fully with its commitment to ANGTS by removing all regulatory impediments to the completion and operation of ANGTS by private parties [and] . . .

*Protective Complaint Under the Alaska Natural Gas Transportation Act Challenging Order of the Department of Energy Office of Fossil Energy filed by Foothills with the U.S. Court of Appeals for the District of Columbia on January 12, 1990.* They cannot have it both ways. Since it is clear claims under ANGTA must be litigated under section 10, Alaskan Northwest and Foothills would be in an untenable position if they urged jurisdiction under section 19 of the NGA and also alleged that DOE violated ANGTA.

<sup>6</sup> See Order 350, at pages 38-41, for a full description of the ANGTA framework; see also DOE's procedural order issued in this docket on July 25, 1988, at 19-22.

has assured Canada that it will not erect new regulatory barriers to the completion of ANGTS by private parties.<sup>7</sup>

Order 350 does not conflict with the continuation of this commitment in any way. Mr. Richard T. McCormack, Undersecretary of State for Economic Affairs responded to Canada's concerns about Order 350 in a letter to Mr. Derek H. Burney, the Canadian Ambassador to the U.S.<sup>8</sup> He said:

The United States Government has fulfilled, and continues to fulfill, its commitments to ANGTS . . . [W]e believe it would be inconsistent with market principles if we were to impose regulatory restrictions on private sector projects while advocating a private sector solution for ANGTS. Put another way, if we refused to grant the approvals [to TAGS] we would, in effect, be putting ourselves in the position of allocating gas among projects which, apart from its inconsistency with the principle of market-determined resource allocation, ignores the fact that this gas is owned by private firms and not the U.S. Government.

<sup>7</sup> See Order 350, at 33-34.

<sup>8</sup> Mr. McCormack forwarded this letter of January 29, 1990, to the DOE (and a letter from Ambassador Burney to him dated December 20, 1989) for inclusion in the record of this case. We have done so. In addition, W. Henson Moore, the Deputy Secretary of Energy, received a letter dated December 28, 1989, from Ambassador Burney expressing Canada's concerns about Order 350 and, in particular, its effect on the commercial viability of ANGTS. Ambassador Burney enclosed a copy of his letter to Mr. McCormack. The DOE placed in the record the Ambassador's letter to Mr. Moore and the Deputy Secretary's reply dated January 30, 1990.

On January 5, 1990, Alaskan Northwest and Foothills filed a joint motion for the DOE to lodge in the record the December 20, 1989, letter from Ambassador Burney to Mr. McCormack. This motion is moot because the letter already has been placed in the record.

<sup>9</sup> Order 350 defined the export project to include the pipeline and all appurtenant facilities, including production facilities, gas conditioning facilities, liquefaction plant, marine terminal, and LNG tankers.

<sup>10</sup> Although the "ANGTA condition" repeats the language of section 9 of ANGTA, it is neither duplicative of nor mandated by the ANGTA framework since section 9 only applies to authorizations for the construction and ini-

Moreover, Order 350 invokes the Department's plenary authority under section 3 of the NGA to include the "ANGTA condition." This condition prohibits explicitly any action in connection with the export project<sup>9</sup> "that would compel a change in the basic nature and general route of [ANGTS] or otherwise prevent or impair in any significant respect the expeditious construction and initial operation of ANGTS."<sup>10</sup> The DOE adopted this condition because it determined the public interest would be served by protecting the physical integrity of ANGTS. Even though the policy considerations that led the DOE to adopt this condition overlap, to some extent, those which support the ANGTA framework, neither the condition nor any other action under Order 350 was taken because of, or in violation of, some requirement or limitation in ANGTA.<sup>11</sup> Adoption of the "ANGTA condition" resulted from the same process by which the DOE ordinarily considers the policies that underlie various statutory frameworks, such as the antitrust laws, to the extent they are relevant to the public interest in a particular import or export application, even though

tial operation of ANGTS. Section 9 is a statutory privilege granted the ANGTS sponsors to prevent government agencies from granting or modifying authorizations for the ANGTS in a manner that would hinder its expeditious construction and operation. Section 9 does not apply to authorizations for projects other than ANGTS.

<sup>11</sup> The applications for rehearing filed by Alaskan Northwest and Foothills continue their efforts to modify this NGA section 3 proceeding by reading in requirements from ANGTA. ANGTA, however, did not change the existing process or requirements under section 3 of the NGA for authorization to export natural gas. It only added the requirement for North Slope gas that the President must find its export "will not diminish the total quantity or quality nor increase the total price of energy available to the United States." The decision whether to authorize exports of North Slope gas under section 3 is made independently of the *Presidential Finding Concerning Alaskan Natural Gas* issued on January 12, 1988 (53 FR 999, January 15, 1988). Even though Order 350 considered many of the same factors as did the *Presidential Finding*, its analysis and determinations were made in accordance with the public interest standard of section 3 and must be viewed in terms of compliance with that standard.

the statutes impose no obligation on the DOE either to act or not act.

In sum, the U.S. has removed all regulatory impediments to the private construction and operation of ANGTS. Order 350 in no way conflicts with any U.S. Government commitment to Canada regarding ANGTS. Order 350 does not create any new regulatory impediments to ANGTS and, in fact, takes into account the relevant policy considerations of the ANGTA framework through the exercise of the DOE's authority under section 3 of the NGA.

*B. Order 350 Does Not Affect the Status of North Slope Natural Gas.*

Intertwined with the arguments that Order 350 is inconsistent with the ANGTA framework are arguments that North Slope natural gas somehow "belongs" to the ANGTS project.<sup>12</sup> The DOE, however, still can find no basis for the various assertions by Alaskan Northwest and Foothills that imply: (1) North Slope natural gas is "committed" to ANGTS; (2) Prudhoe Bay reserves must remain in the ground, forever, if need be, until the ANGTS sponsors are ready to secure financing for the ANGTS; (3) the sponsors of ANGTS have an open-ended right of first refusal of North Slope natural gas; or (4) Congress intended North Slope natural gas exclusively for the domestic market and prohibited its export.

There is no provision in ANGTA or elsewhere to support these assertions.<sup>13</sup> In fact, Alaskan Northwest and Foothills have cited no express guarantees or commitments with regard to North Slope reserves but rather have pleaded that a special status should be envisioned. The DOE can find no basis whatsoever for this "vision" of Alaskan Northwest and Foothills. Neither can the DOE see any special status that could be reconciled with the acknowledged fact that "producers own [North Slope] reserves and obviously

they have the right to enter into contracts with whomever they please."<sup>14</sup> Moreover, Alaskan Northwest and Foothills have failed to persuade the DOE that the public interest requires a change in the current unencumbered status of North Slope gas by, in effect, imposing an easement on these reserves in favor of ANGTS.<sup>15</sup>

In any event, the DOE reiterates that Order 350 does not affect any rights of Alaskan Northwest and Foothills to North Slope natural gas. Prior to the issuance of Order 350, Alaskan Northwest and Foothills were free to contract with the North Slope producers for their gas reserves. Following its issuance, they continue to be free to make such contracts. Order 350 does not (1) restrict the rights of Alaskan Northwest and Foothills to contract for North Slope gas, (2) commit any amount of this gas to Yukon Pacific, or (3) grant Yukon Pacific any right to contract for this gas that it did not have prior to issuance.

*C. Order 350 Does Not Represent Either a Taking or a Violation of Substantive Due Process with Respect to ANGTS.*

Closely related to the arguments that Order 350 is inconsistent with the framework of ANGTA and that North Slope natural gas belongs to the ANGTS project is the contention that Order 350 constitutes a taking of property and a violation of substantive due process.<sup>16</sup> Alaskan Northwest and Foothills argue that Order 350 was adopted arbitrarily and without proper consideration of their exclusive and perpetual franchise to develop North Slope gas and to deliver this gas to the lower-48 states and thus deprived them of their property rights and legitimate expectations under ANGTA. ANGTA, however, did not grant the sponsors of ANGTS an exclusive and perpetual franchise or any other shield against competition. Accordingly the authorization of a competing project cannot be equated

<sup>12</sup> See Alaskan Northwest's stated errors (1)(c) and (2) in the appendix of this order; see also Foothills' stated errors (1), (2), (3), and (5)(c).

<sup>13</sup> See Order 350, at pages 38-39, for a discussion of the status of North Slope gas.

<sup>14</sup> *Id.*, note 81, at 39.

<sup>15</sup> For example, Foothills contends that if Order 350 is not rescinded, the DOE should attach a condition to the authorization "which

limits the proposed exports to volumes of Alaskan gas that are demonstrated to be in excess of the proven reserves required to finance and complete the ANGTS. . . ." See Foothills' application for rehearing at 2; see also Alaskan Northwest's application for rehearing, at 6.

<sup>16</sup> See Alaskan Northwest's stated errors (1)(c), (6), and (7) in the appendix of this order; see also Foothills' stated errors (8) and (11).

with either a taking or a violation of substantive due process.<sup>17</sup>

ANGTA was primarily a procedural statute intended to minimize regulatory impediments to bringing North Slope gas to the lower-48 states by the early 1980s. To this end, in lieu of the protracted selection process at the Federal Power Commission, ANGTA substituted a mechanism by which the President, with Congressional approval, could designate the sponsors and the route for a transportation system to bring North Slope natural gas to the lower-48 states. ANGTA also eliminated or minimized certain statutory or regulatory requirements that the persons selected to build and operate the system would otherwise encounter before commencing construction. ANGTA did not provide the sponsors of the approved system with a monopoly franchise that prohibits development of North Slope natural gas until they decide the time is right to get their project underway. Nor did it bar competing developers of North Slope gas from securing the necessary governmental authorizations through the standard permit process without the advantages granted the sponsors of ANGTS.

In sum, ANGTA was intended to expedite development of North Slope natural gas, not to lock up this vast energy resource. ANGTA cleared the administrative path for obtaining the necessary federal permits and authorizations; it did not interdict marketplace competition over North Slope gas. Alaskan Northwest and Foothills have no property right or legitimate expectation on which to challenge Order 350 merely because it authorizes a competing project. The DOE crafted Order 350 so that it does not interfere with any of the statutory privileges granted Alaskan Northwest and Foothills by ANGTA. If these privileges have been diminished in value over time, it is not the result of any action or inaction by the U.S. Government.

*D. Order 350 Is Based on Evidence in the Record That the Export Project Is Not Inconsistent with the Public Interest, Including, the Environmental and Domestic Need Aspects of the Public Interest.*

In addition to their arguments concerning the effects of Order 350 on ANGTS, Alaskan Northwest and Foothills contend that Order 350 is not consistent with the public interest and, in particular, that it misjudges the effects of the export project on the environment and the domestic need aspects of the public interests.<sup>18</sup> They have failed to provide, however, any additional evidence that undermines either the substantial evidence in the record or the statutory presumption that supports the public interest finding in Order 350.<sup>19</sup>

As part of its public interest determination, the DOE weighed the effects of the export project on the environment. Order 350 took into account the Final Environmental Impact Statement (FEIS)<sup>20</sup> on the export project and other environmental considerations such as the implications of the accident involving the oil tanker Exxon Valdez that occurred off Alaska after the FEIS was issued. Order 350 found that the environmental effects of the export project "are relatively minor and can be mitigated, and thus are environmentally acceptable, especially when balanced against the substantial economic benefits to be derived from the project." Order 350 requires the export project to "be implemented in accordance with all applicable environmental procedures and requirements" and to "comply with all preventive and mitigative measures imposed by Federal and State agencies to protect the public health, safety and environment." In conjunction with the issuance of Order 350, the DOE issued a *Record of Decision* pursuant to the regulations of the Council on Environmental Quality (40 CFR 1505.2) and the DOE's guidelines for compliance with the National Environmental Policy Act of

<sup>17</sup> See Order 350, at 39.

<sup>18</sup> See Alaskan Northwest's stated errors (3)(a), (3)(b), (3)(c), (3)(d), and (5) in the appendix of this order; see also Foothills' stated errors (5)(a), (5)(b), (5)(c), (5)(d), (5)(e), (5)(f), (5)(g), and (6).

<sup>19</sup> See Order 350 for a discussion of DOE's findings concerning the public interest, at

pages 18-30 (domestic need), 31 (American consumers), 31-32 (efficient energy production), 32 (State of Alaska), 33-35 (international effects), and 35-38 (environment).

<sup>20</sup> *Trans-Alaska Gas System Final Environmental Impact Statement (FEIS BLM-AK-PT-88-003-1792-910, June 1988) DOE/EIS-0139.*

1969 (NEPA) which documents the manner in which DOE considered the environmental issues in its decision-making process.<sup>21</sup>

The DOE's public interest determination focused on domestic need for North Slope gas. In assessing domestic need, Order 350 did not conclude North Slope natural gas could not or would not be used in the domestic market. Rather, it found there exist large reserves of natural gas in North America within or below the reasonably anticipated cost range of North Slope natural gas that are more than sufficient to meet anticipated domestic need without any significant market distortions, even if North Slope natural gas does not flow to the lower-48 states during the term of the proposed exports. Thus, North Slope natural gas is not needed to meet anticipated domestic demand.

The crux of Alaskan Northwest's and Foothills' domestic need argument is the reliability of resource base estimates for projecting long-term domestic supply. Foothills state that the authorization was "based on a reckless wager that so-called 'potential' reserves will eventually be forthcoming and, if not, the deficiency can always be made up by foreign imports."<sup>22</sup> As demonstrated in Order 350, any projection of long-term supply must incorporate the addition of reserves in the future.<sup>23</sup> Not recognizing this potential would be to ignore decades of historical record in which reserve addi-

tions have occurred year after year. There is nothing to suggest that this process will suddenly terminate in the near future. In addition, any decision based on the current stock of reserves alone would be distorted, if not outright absurd, since it necessarily would have to assume the U.S. will run out of natural gas before the end of the century.

The DOE believes that the gas resource base estimates for the U.S. published by the Potential Gas Committee,<sup>24</sup> the U.S. Geological Survey, and DOE/Argonne National Laboratories (DOE/Argonne) that were considered in the decision to grant the export application are credible.<sup>25</sup> They reflect the consensus in the energy community that additional gas resources beyond proved reserves can be discovered and produced with foreseeable technology and economic conditions.

Alaskan Northwest maintains that North Slope gas is needed domestically because supplies in the lower-48 states costing less than \$3.00 per Mcf wellhead price in 1987 dollars plus potential Canadian pipeline gas and LNG imports are insufficient to meet the DOE's postulated demand of 725 quads through 2021.<sup>26</sup> Alaskan Northwest implies that DOE should not consider as an additional source of gas supply the 174 Tcf in the lower-48 states which the DOE/Argonne estimate indicates would be recoverable in a wellhead price range of \$3.00 to

<sup>21</sup> 54 FR 49337 (November 30, 1989). Alaskan Northwest and Foothills argue that the DOE did not comply with NEPA in issuing Order 350. A section 3 rehearing, however, is not the proper forum to consider compliance with the NEPA process. A section 3 rehearing reviews DOE's public interest determination including the extent to which the determination took into account the environmental aspects of the public interest. In Order 350, consideration of the environmental aspects of the public interest resulted in the inclusion of several environmental conditions. A section 3 rehearing does not review procedural compliance with NEPA. The DOE's compliance with the NEPA process is set forth in the *Record of Decision* which represents final agency action on NEPA procedural matters. There is no provision for an administrative review (such as a section 3 rehearing) of a record of decision. See 40 CFR Parts 1500-1508.

<sup>22</sup> See Foothills' application for rehearing, at 11.

<sup>23</sup> See Order 350, at pages 22-24, for a full discussion of reserves.

<sup>24</sup> The Potential Gas Committee is made up of a group of volunteer industry and governmental experts in the area of natural gas supply.

<sup>25</sup> The DOE notes that the resource amounts of all three appraisals are significantly less than a more recent report in late 1989 (on which Order 350 did not rely) from the American Association of Petroleum Geologists (AAPG). The AAPG report, "New Approaches to Gas Resource Evaluation," indicates the gas resource base in the lower-48 states is 869 Tcf at \$3.00/Mcf or less and 1,399 Tcf assuming \$5.00/Mcf. By comparison, the 1988 DOE/Argonne study estimated that 757 Tcf is recoverable at \$5.00/Mcf or less, of which 583 Tcf is recoverable under \$3.00/Mcf. See AAPG *Explorer*, September 1989, at 9.

<sup>26</sup> See appendix attached to Alaskan Northwest's application for rehearing, at 24.

\$5.00 per Mcf (1987 dollars).<sup>27</sup> In effect, Alaskan Northwest asserts that North Slope gas must be considered "needed" because of its prediction that the ANGTS can deliver gas to the U.S./Canada border at a price of \$3.00 per Mcf (1987 dollars), the sum of the wellhead price at which producers will produce and sell their gas (\$0.54)<sup>28</sup> and the cost of service estimate for pipeline transportation (\$2.46) to the border.<sup>29</sup> This argument is flawed in two significant aspects.

First, this argument reduces the need analysis to predictions about the future prices of various gas supplies. The DOE does not believe need can be determined simply by comparing predicted prices, even if gas prices could be predicted precisely ten to 20 years into the future. The need analysis is primarily an assessment of whether sufficient supplies can reasonably be expected to be available to meet anticipated demand. Of course, this assessment must take into account that the costs of bringing some supplies to

market may be so significantly higher than the anticipated market price that their use would be precluded in an efficient market. Alaskan Northwest and Foothills, however, have failed to demonstrate that the costs of any of the supplies considered by the DOE in Order 350, including gas producible at \$3.00-\$5.00 per Mcf in much more accessible areas than the North Slope, would be so high that they may not reasonably be considered available to meet anticipated demand during the term of the proposed export.

Second, assuming *arguendo* that need for a particular supply were determined solely by comparing predicted prices, Alaskan Northwest and Foothills have not provided credible evidence to permit such a comparison in this case. The price of \$3.00 per Mcf that they assert that North Slope gas delivered by ANGTS would cost at the U.S./Canada border is mere speculation since it is based on a North Slope

<sup>27</sup> *An Assessment of the Natural Gas Resource Base of the United States* (May 1988), prepared by Argonne National Laboratory for the DOE's Office of Policy, Planning, and Analysis.

<sup>28</sup> The \$0.54 figure appeared in a study by Dames & Moore and Decision Focus, Inc., included as Exhibit R to "Initial Comments" filed by Yukon Pacific on August 24, 1988. It was subsequently adopted by the ANGTS sponsors without any further explanation other than its use by Yukon Pacific. The Dames & Moore study did not say how it arrived at this figure.

<sup>29</sup> Alaskan Northwest asserts that the cost of transporting North Slope gas from the U.S./Canada border to Chicago and California would be \$0.50/Mcf. At the same time, it suggests that the costs of transporting lower-48 supplies from the wellhead to the city gate would be \$1.20. (See Alaskan Northwest's application for rehearing, appendix, at 20). Alaskan Northwest posits the \$1.20 figure by subtracting average domestic wellhead prices from average city gate prices. (See Energy Information Administration, *Monthly Energy Review*, July 1989, Table 9.11, at 109). The DOE believes this comparison is not appropriate and is misleading.

The DOE has looked at the current cost of delivering Canadian gas to Illinois and California by means of the Eastern and Western Legs of the prebuild (their present termini are in Iowa and Oregon) and the cost of delivering gas from traditional lower-48 sources. The data was derived from the Dun and Bradstreet "Official Pipeline Guide", a computerized

information system for determining least-cost point-to-point U.S. pipeline transportation charges. The results show that in February 1990 gas could be delivered from the Saskatchewan/Montana border via the Eastern Leg prebuild and certain interconnecting pipelines to central Illinois (Tuscola) for \$1.03/Mcf. It cost \$0.60/Mcf to transport gas from the British Columbia/Idaho border via the Western Delivery System (which comprises the Western Leg prebuild) to the Arizona/California border. Much of the supply for California originates in Texas and New Mexico and production in Oklahoma and Louisiana is shipped to Illinois. Gas could be transported from west Texas and New Mexico to the southern California border for \$0.27/Mcf. To transport gas from Oklahoma and south Louisiana to Tuscola would cost \$0.62 and \$0.46/Mcf, respectively.

In light of the current situation, it is reasonable to assume that there would be comparable transportation costs within the lower-48 states for North Slope gas and alternative supplies. In addition, with the advent of open-access transportation, domestic pipelines will continually be under pressure to keep prices competitive to attract customers. Furthermore, California would be able to acquire supplies from new production regions of the Rocky Mountains through the proposed pipelines of Wyoming-California Pipeline Company and Kern River Gas Transmission Company between Wyoming and California that received final FERC certificates early this year and are expected to begin operation in 1991 with transmission costs of \$0.64 and \$0.99, respectively.

wellhead price of \$0.54 per Mcf.<sup>30</sup> Alaskan Northwest offers no reason in its application for rehearing to persuade the DOE that North Slope producers consider \$0.54 a sufficient price to recover fully their costs. In fact, Alaskan Northwest admits:

One can only speculate about actual wellhead prices, as they will be determined through negotiations between individual producers and purchasers of North Slope gas. . . . [T]he wellhead price of \$0.54 (1987 dollars) . . . may be inaccurate.<sup>31</sup>

In addition, Alaskan Northwest and Foothills also argue that the presence of North Slope gas in various natural gas studies, including those of the Gas Research Institute, Data Research Institute/McGraw-Hill, and the American Gas Association (AGA), constitutes convincing evidence of the need for this gas in the lower-48 states.<sup>32</sup> For example, Foothills' application for rehearing states, "AGA concludes that 'Alaskan gas becomes available before 2000 with the construction of a pipeline system to deliver those supplies.' (Emphasis added)."<sup>33</sup>

The DOE did consider these studies but did not find them convincing concerning domestic need for North Slope gas.<sup>34</sup> They do not conclude that this gas is needed. At most, they conclude that this gas would be available to the domestic market if the ANGTS is built. Such a conclusion necessarily flows from the standard approach used for models involving North Slope gas. Forecasters program this gas supply into the models because they assume that ANGTS will be built and therefore that North Slope gas necessarily will flow through it some day to the lower-48 states. The consumption of North Slope gas in the lower-48 states is, in effect, a foregone conclusion of these models and the only variable is the completion date of

the ANGTS. As such, they reflect an assumption, and the possibility that it may be more efficient not to use North Slope gas in the domestic market is ignored. The DOE does not find the circular reasoning that relies on such studies to be enlightening when examining the domestic need for North Slope gas.

To summarize, Alaskan Northwest and Foothills have presented no new evidence or arguments that persuade the DOE to reconsider its determination that the export of North Slope gas is not inconsistent with the public interest. With respect to the environment, they provide no substantive basis to change the measures in Order 350 to protect the environment. With respect to domestic need, they give no compelling reason demonstrating that the analysis or conclusions in Order 350 were in error. Rather, they seek to confuse the possibility that North Slope gas may be consumed in the lower-48 states with a conclusion that North Slope gas is needed. The DOE's assessment was based on the outlook for natural gas demand, the outlook for supply, the availability of energy supplies with comparable or lower costs than North Slope gas, and the likelihood that the absence of North Slope gas would result in significant distortions in the U.S. energy market. As a result of this assessment, Order 350 concluded that North Slope gas is not needed in the lower-48 states during the 25-year term of Yukon Pacific's proposed export.

*E. Order 350 Was Adopted in Accordance with All Applicable Statutory, Regulatory, and Procedural Due Process Requirements.*

Throughout this proceeding, Alaskan Northwest and Foothills have contended that certain statutory, regulatory, and procedural due process requirements were not followed.<sup>35</sup> The DOE does not agree.

<sup>30</sup> For purposes of argument, the DOE is not questioning the transportation component of the \$3.00 price. However, the cost of service projected by the ANGTS sponsors from Alaska through Canada to the U.S. border of \$2.46, which is based on a June 1988 revised capital cost estimate for the remaining, unconstructed elements of ANGTS, has not been examined, much less approved, by any regulatory body.

<sup>31</sup> See Alaskan Northwest's application for rehearing, at 19 and 23.

<sup>32</sup> See Appendixes D-G attached to Foothills' application for rehearing.

<sup>33</sup> *Id.*, at 39.

<sup>34</sup> See Order 350, at 18-20, particularly note 36.

<sup>35</sup> See Alaskan Northwest's stated errors (7) and (8) in the appendix of this order; see also Foothills' stated errors (4), (6), (9), (10), and (11).

The DOE considered Yukon Pacific's application to export North Slope gas in accordance with all applicable statutory, regulatory, and procedural requirements. In particular, all parties were given the opportunity to submit written comments and reply comments and to participate in a public conference in Anchorage, Alaska. All parties were given ample opportunity to present arguments and data to support their positions and to examine thoroughly the positions of the other parties. Additional procedures were not and are not now necessary to develop more fully any disputed relevant and material factual issue.

Alaskan Northwest and Foothills have not demonstrated that any material issues of fact are genuinely in dispute or that any additional action, including a trial-type hearing, is necessary for a full and true disclosure of the facts. Alaskan Northwest and Foothills are not entitled as a matter of right to a trial-type hearing concerning policy or legal issues.

At every stage of this proceeding, the DOE has acted in accordance with all applicable statutory, regulatory, and procedural requirements. There exists a fully developed record, compiled with due regard for the rights of all parties, on which the DOE made a reasoned decision in Order 350.<sup>36</sup>

*F. Order 350 Does Not Restrict Improperly the Authority of Either FERC or OFI.*

Alaskan Northwest and Foothills argue that Order 350 improperly limits the authority of the FERC and OFI.<sup>37</sup> There is no basis for this allegation.

With respect to the FERC, the DOE Act explicitly grants the Secretary of Energy all authority conferred under the NGA over imported and exported natural

gas. While the Secretary has retained the policy-making aspects of this authority within the DOE, certain technical aspects of this authority, especially in the areas where imported and exported natural gas mix with interstate gas, have been delegated to the FERC. The delegation of authority to the FERC is clear that this delegated authority over imported and exported natural gas must be exercised in accordance with the DOE's policies and any specific conditions in the DOE's import and export authorizations.<sup>38</sup>

Order 350 limits the FERC's jurisdiction over this export project so that it would not exercise unnecessary regulation over the entire project merely because gas molecules destined for foreign countries may be combined with "interstate gas molecules" from ANGTS destined for lower-48 markets. Order 350 does not create any regulatory gap concerning the project and preserves the FERC's authority to regulate shared facilities where it has a legitimate interstate commerce interest. It also preserves the FERC's authority over the export site. By ruling out, on environmental grounds, all export sites except Valdez, Order 350 was exercising the site veto function retained within DOE. Order 350 does not affect the FERC's authority to approve or disapprove the Valdez export site.<sup>39</sup>

With respect to OFI, Reorganization Plan No. 1 of 1987 explicitly provides that the Federal Inspector shall follow the policies of the agency from which the enforcement function the Inspector is exercising has been transferred. Order 350 sets forth DOE's policy that the "ANGTA condition" not be used as a dilatory tactic to impede the export project. Requiring this condition to be enforced expeditiously and on the basis of facts rather than speculation does not abridge the authority of the

<sup>36</sup> See Order 350, at 9-11.

<sup>37</sup> See Alaskan Northwest's stated error (4) specified in the appendix of this order; see also Foothills' stated error (7).

<sup>38</sup> See Order 350 note 18, at 7, note 32, at 16, note 34, at 17, and note 79, at 37. These footnotes detail (1) how the DOE Act granted the Secretary of Energy exclusive jurisdiction to regulate natural gas imports and exports, (2) how DOE Delegation Order No. 0204-127 delegates this broad grant of regulatory authority to the Assistant Secretary for Fossil Energy, (3) how DOE Delegation Order No. 0204-112 delegates the FERC limited authority under

sections 4, 5, and 7 of the NGA to regulate natural gas imports and exports in interstate commerce, subject to the policies of the DOE and any conditions in DOE import and export authorizations, and (4) how DOE Delegation Order No. 0204-112 delegates the FERC limited authority under section 3 of the NGA to regulate export and import sites, subject to the policies of the DOE, any conditions in DOE import and export authorizations, and the veto by the DOE of a particular site. See also *Trans-Canada Pipelines v. FERC*, No. 87-1229, June 16, 1989.

<sup>39</sup> See Order 350, at 41-44.

Federal Inspector to carry out the functions of the office.<sup>40</sup>

### G. Conclusion

The DOE issued Order 350 after a thorough examination of whether exports of North Slope gas would be inconsistent with the public interest. The DOE found that there are sufficient supplies of natural gas available in North America and elsewhere to meet anticipated domestic demand without market distortion if North Slope gas is exported. The DOE also found that the export of North Slope gas would be consistent with other public interest considerations, including protection of the environment.

The applications for rehearing filed by Alaskan Northwest and Foothills did not contain any basis for the DOE to reconsider its findings in Order 350. Alaskan Northwest and Foothills neither refuted the substantial record evidence on which these findings were based nor carried their burden concerning the statutory presumption in section 3 of the NGA that natural gas exports are consistent with the public interest.

Alaskan Northwest and Foothills sought in their applications for rehearing, as they have throughout this proceeding, to infer that this export application was different than other section 3 proceedings. Many of their arguments assert that the ANGTA framework, in effect, reverses the presumption favoring natural gas exports and creates different standards for evaluating exports of North Slope gas. Although the DOE can find no legal basis for such a proposition, it did consider the policy basis of the ANGTA framework in the context of the public interest standard of section 3 of the NGA. This consideration led the DOE to include the "ANGTA condition" in Order 350 to preserve the physical integrity of ANGTS. The DOE crafted Order 350 carefully to ensure that it did not interfere with any of the privileges of the ANGTS sponsors or their ability to negotiate contracts to secure North Slope reserves for ANGTS. Alaskan Northwest and Foothills, however, have not persuaded the DOE that either the public interest or any provision of the ANGTA framework requires it to interdict competition over North Slope gas.

Order 350 does not dictate how North Slope gas will be developed. Those decisions continue to be left to private parties. Order 350 merely complies with the DOE's obligation to authorize natural gas exports where there is no showing such exports would be inconsistent with the public interest. There is no provision in the ANGTA framework or elsewhere that changes this obligation in situations involving competition over North Slope gas.

### III. Request for Clarification

On December 15, 1989, Yukon Pacific requested clarification or, in the alternative, rehearing of Order 350. Yukon Pacific asks the DOE to clarify that, in the event the quantity of LNG exported in a given year is below the annual volume limitation, it is authorized to increase exports in succeeding years to make up the deficiency. Yukon Pacific asserts that this would enhance its ability to develop and initiate long-term sales arrangements and would provide latitude should actual deliveries in some years prove to be smaller than anticipated.

The DOE's imposition of the 14 million metric ton (MMT) annual export ceiling was based on the perceived intention of Yukon Pacific to deliver only up to that volume and is reflective of Yukon Pacific's application. However, it is reasonable that Yukon Pacific be permitted to increase the quantity of LNG exported in succeeding years until it makes up any deficiency in a year in which deliveries did not equal 14 MMT, as long as the aggregate amount during the term of the authorization does not exceed 350 MMT.<sup>41</sup> Accordingly, we are modifying Ordering Paragraph A of Order 350 in a manner that will give Yukon Pacific more flexibility to structure contracts tailored to the individual needs of its customers and to manage deliverability fluctuations.

### IV. Decision

The applications for rehearing filed by Alaskan Northwest and Foothills present no information that would merit reconsideration of our findings in Order 350. Accordingly, their requests for rehearing are denied.

<sup>40</sup> *Id.*, note 83, at 41.

<sup>41</sup> 14 MMT × 25 years = 350 MMT.

The application for clarification filed by Yukon Pacific involves a reasonable modification of the authority in Order 350 that does not affect the DOE's decision to grant the authorization. Accordingly, its request is granted.

#### ORDER

For the reasons set forth above, pursuant to section 3 and 19 of the Natural Gas Act, it is ordered that:

A. Ordering Paragraph A of DOE/FE Opinion and Order No. 350 (Order 350) issued November 16, 1989, to Yukon Pacific Corporation is hereby modified to read as follows:

A. Yukon Pacific Corporation (Yukon Pacific) is authorized to export for sale to Japan, South Korea, and Taiwan a total of up to 350 million metric tons (MMT) of liquefied natural gas (LNG), at an average annual volume of 14 MMT, for a period of 25 years beginning on the date of the first delivery, upon the conditions herein set forth.

B. All other terms and conditions of Order 350 remain in effect.

C. The application for rehearing of Order No. 350 filed by Alaskan Northwest Natural Gas Transportation Company and Foothills Pipe Lines (Yukon) Ltd. are denied.

Issued in Washington, D.C., on March 8, 1990.

#### Appendix

List of Errors in DOE/FE Opinion and Order No. 350 Alleged by Alaskan Northwest Natural Gas Transportation Company and Foothills Pipe Lines (Yukon) Ltd.

##### Ltd.

##### A. Alaskan Northwest\*

(1) DOE's conditional export authorization, by failing to attach protective conditions to ensure compliance with ANGTA, represents an impermissible extension of DOE's statutory authority and, accordingly constitutes legal error in the following respects:

(a) DOE's Order threatens to " . . . compel a change in the basic nature . . . of the approved transportation system or would otherwise prevent or impair in

any significant respect the expeditious construction and initial operation" of the ANGTS and, accordingly, fails to comply with the mandate of section 9 of ANGTA;

(b) DOE's Order authorizes the diminution of the total quantity and quality of energy resources available to the U.S. on a price-competitive basis, in contravention of the mandate of section 12 of ANGTA;

(c) DOE's Order, with respect to its findings of possible future delivery of TAGS export volumes to American consumers, contravenes the exclusive right of the ANGTS to deliver North Slope gas to lower-48 states' consumers.

(2) DOE's Order contravenes the President's September 22, 1977, decision concerning ANGTS and prior U.S.-Canadian commitments.

(3) DOE's findings relevant to the analysis of "public interest" under section 3 of the NGA are (i) not supported by substantial evidence; and/or (ii) represent an abuse of agency discretion. In particular:

(a) DOE's findings respecting "domestic need" are not supported (and are, in fact, undermined) by record evidence;

(b) Insufficient record evidence has been developed to support claimed trade and other international benefits;

(c) DOE's findings with respect to impacts on national energy security, and the equating of national energy security to "global market efficiency" are not supported by record evidence and represent an abuse of discretion; and

(d) DOE's findings respecting environmental impact are incomplete and otherwise not supported by record evidence.

(4) DOE's limitation of Federal Energy Regulatory Commission (FERC) jurisdiction over the Alaskan Gas Conditioning Facility constitutes legal error.

(5) DOE has abrogated its statutory responsibilities under the National Environmental Policy Act (NEPA) by failing to consider environmental consequences associated with, *inter alia*, with: (1) gas

\* See Alaskan Northwest's application for rehearing at 7-10.

conditioning arrangements for volumes proposed to be exported and (2) marine transportation hazards and interactions of LNG and oil tankers at Port Valdez and in transit through Prince William Sound.

(6) The issuance of export authorization to Yukon Pacific, in the absence of protective conditions urged by Alaskan Northwest, deprives the ANGTS sponsors of legal rights and priorities established through prior Congressional, regulatory and Presidential orders, the deprivation of which constitutes an unlawful taking under the Fifth Amendment of the U.S. Constitution.

(7) DOE's Order was issued without regard to requirements of procedural and substantive due process.

(8) DOE's failure to attach informational and filing requirements to mitigate potential regulatory gaps in arbitrary, capricious, and an abuse of discretion.

#### B. Foothills \*\*

(1) DOE erred in finding that approval of the proposed export is consistent with the intent, policies, and framework of ANGTA.

(2) DOE erred in failing to recognize that approval of the proposed export is inconsistent with the Presidential and Congressional decisions approving the ANGTS under ANGTA.

(3) DOE erred in finding that approval of the proposed export is inconsistent with the 1977 U.S.-Canadian agreement on principles and other commitments made by the U.S. to Canada in connection with the ANGTS.

(4) DOE erred in finding that there is a statutory presumption favoring exports of Alaskan North Slope gas.

(5) DOE's approval of the proposed export is arbitrary, capricious, abusive of the government's discretion, and unsupported by either rational findings or substantial evidence of record.

(a) DOE erred in failing to take a hard look at all pertinent issues and to make rational findings with respect to those issues.

(b) DOE erred in approving the proposed export prior to completion and full consideration of the National Energy Strategy.

(c) DOE erred in finding that approval of the proposed export will not significantly impair the expeditious construction and operation of the ANGTS.

(d) DOE erred in finding that North Slope gas will not be needed during the term of the proposed export to provide American consumers with adequate gas supplies at reasonable prices.

(e) DOE erred in finding that the proposed export will not diminish U.S. energy security or otherwise adversely affect the quantity, quality, or price of energy available to American consumers.

(f) DOE erred in finding that approval of the proposed export would benefit American consumers, encourage increased energy production, create benefits for the State of Alaska that would not otherwise be available, and benefit international relations.

(g) DOE erred in finding that the proposed export project is environmentally acceptable.

(6) DOE erred in failing to comply with NEPA and the regulations thereunder.

(7) DOE exceeded its statutory authority in attempting to limit the FERC's jurisdiction over the TAGS project in the event TAGS and the ANGTS share a facility that is subject to the FERC's interstate commerce jurisdiction.

(8) DOE's approval of the proposed export constitutes an unlawful taking of property rights of the ANGTS sponsors.

(9) DOE erred in failing to enforce and follow its own regulations on exports of natural gas.

(10) DOE erred in failing to convene a trial-type hearing.

(11) DOE unlawfully deprived the ANGTS sponsors of procedural and substantive due process.

\*\* See Foothill's application for rehearing at 13-14.

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STATE OF ALASKA  
*ALASKA GASLINE INDUCEMENT ACT*  
TRANSCANADA ALASKA COMPANY, LLC  
and FOOTHILLS PIPE LINES LTD.  
ALASKA PIPELINE PROJECT

**A. EXECUTIVE SUMMARY**

We have been requested to address aspects of the proposed Alaska Pipeline Project (or "Project") application filed by TransCanada Alaska Company, LCC and Foothills Pipe Lines Ltd. (collectively "TransCanada") pursuant to the *Alaska Gasline Inducement Act* ("AGIA") on November 30, 2007. We have been specifically asked to consider matters that could impact the timeline of the Project. As specified in the request for applications, TransCanada's proposal addresses the specific requirements of the AGIA and also included a timetable for the completion of various activities associated with bringing the Project to fruition.

The expected timing of the development phase of the Project is of critical importance in the assessment and quantification of the potential benefits that could result from the proposed Project. As such, it is necessary to understand the rationale underpinning TransCanada's forecasted schedule and the risks TransCanada has taken into account in its evaluation. In addition, we have attempted to identify other potential concerns and issues that could impact overall timing. This Report is restricted to an examination of the Canadian segment of the Project.

TransCanada has adopted a five and one-half year schedule for securing major Canadian pre-construction approvals, following the issuance of the AGIA License. TransCanada has expressed the view that it expects to rely on the *Northern Pipeline Act* ("NPA" or "Act") as the primary legislative vehicle through which necessary regulatory approvals have and will be coordinated in Canada. This is viewed by TransCanada as minimizing the time required to complete the above process. TransCanada has also identified a number of project risks that could result in delay.

While we agree that there are advantages associated with the prior NPA approvals received by TransCanada and the "single window" process provided by the NPA, based on the detailed assessment contained herein, it is our view that the schedule proposed by TransCanada represents a "best case" scenario that may be difficult to achieve.

Given the nature and magnitude of the Project, it is our view that one could reasonably expect that at least certain of the issues identified herein, or by TransCanada in its risk assessment, will be raised during the preparation and regulatory approval phases of the Project, with a resultant impact on timing. In our view, a timeframe of seven to eight years is more realistic, with the lower end of the range (seven years) having a higher probability of being achieved. A seven to eight year timeline, to complete the required pre-construction processes, may be the minimum for a Third Party pipeline project that does not have the advantage of the existing approvals obtained under the NPA.

As will be discussed herein, the strategy and approach ultimately adopted by TransCanada for the execution of its proposal will likely have a significant impact on its ability to achieve the proposed "best case" scenario. By this we mean that TransCanada will face a number of choices with regard to the strategy it will employ on various key project items. If TransCanada adopts a course of action that seeks to address concerns that have previously been expressed it may be able to mitigate the risk of delay identified herein.

By way of illustration, TransCanada maintains that it will pursue the completion of the Project under the NPA, to the exclusion of other legislation that arguably could be applicable to the Project, such as the *Canadian Environmental Assessment Act* ("CEAA") and the *Yukon Environmental and Socio-Economic Assessment Act* ("YESAA"). If TransCanada maintains this approach, it will likely face challenges from a variety of parties that could result in delay.

However, if TransCanada proposes or encourages a process that encompasses the requirements of all applicable legislation (even if under the umbrella of the NPA), it

may be able to materially mitigate the risk of a challenge in this regard. In our view, this could involve TransCanada proposing that the Designated Officer under the NPA adopt the standards and open, public processes embedded in legislation such as CEEA and YESAA, in order to achieve substantially similar levels of review and analysis as would be expected under such legislation; albeit still under the "single window" approach contemplated by the NPA. In addition, TransCanada could minimize inefficiencies and delays by seeking a single, coordinated process that addresses all regulatory and environmental requirements at the outset.

Another example is TransCanada's proposal to make use of only NGTL facilities in Alberta (in addition to the Pre-Build) to transport Alaskan gas. If TransCanada chooses to maintain the exclusive link to the NGTL system, it is likely to face challenges, with resultant delays. However, if TransCanada adopts a more flexible and expansive approach of assessing the most economic and efficient use of all available infrastructure to transport Alaskan gas, as well as accommodating the positions of shippers, it will likely be able to materially mitigate the risk of such challenges and hence the potential for delay.

The above attempts to illustrate that, to some extent, TransCanada will be the master of its own destiny. While the positions advanced in its AGIA filing may be characterized as TransCanada's "opening position," the degree to which TransCanada exercises flexibility in its business approach will have a direct impact on its ability to achieve the desired schedule. In this regard, we would expect that TransCanada would have an incentive to complete the Project in a timely manner, which should drive it towards minimizing such debates and challenges. TransCanada is a large and successful pipeline company that likely appreciates the dynamics that will be at play. As will be discussed herein, TransCanada has acknowledged that current requirements and standards should be used to assess an Alaska Pipeline Project filing. To the extent this is, in fact, achieved by a TransCanada filing, the above concerns could be mitigated. We have no reason to believe that TransCanada will not ultimately adopt a strategy that will seek to minimize opposition and, hence, maximize its chances of expediting the Project.

It is also important to note that the extended timeline suggested herein would not necessarily disadvantage TransCanada vis-à-vis any Third Party pipeline proponent that may seek to construct a pipeline from Alaska and into Canada. Many of the specific concerns identified herein would apply equally to any such Third Party, such as a detailed assessment of environmental and socio-economic considerations, the duty to consult First Nations, as well as, routing, land rights, and potential litigation. In fact, TransCanada would likely have an advantage due to such things as its existing Certificates, the "single window" approach adopted by the NPA and its easement in the Yukon. We also note that TransCanada has previously asserted that it has the exclusive right to build a pipeline from Alaska into Canada. While not commenting on the validity of this claim, we would expect that TransCanada would seek to enforce this right and oppose any Third Party project. This could result in a significant delay in any such project.

In the end result, based on the information available to this point, it is reasonable to expect that certain delays will be encountered by TransCanada. Consequently, it would appear prudent for the State of Alaska to also examine the somewhat more extended timeline of approximately seven years discussed herein, for the completion of the required pre-construction approval processes; in addition to the five and one-half year period reflected in the AGIA Application, as part of its assessment.

A summary of the significant issues that could impact timing of the proposed TransCanada project is outlined below. Greater detail on these, and other, matters is provided in the body of this Report.

#### **1. Continued Applicability of the NPA Approval**

As reflected in the past submissions of Alliance Pipeline Ltd. ("Alliance") and Enbridge Inc. ("Enbridge"), it is likely that certain parties will challenge the general applicability of the NPA to the circumstances confronting the Alaska Pipeline Project today. This argument also appears to be supported by statements made by producers, including ConocoPhillips and Exxon-Mobil. It is arguable whether certain of the objectives of the NPA are relevant today, given that one of the main purposes was to

facilitate the "efficient and expeditious planning and construction of the [then proposed] pipeline". Nonetheless, it is our view that the NPA and the Certificates awarded thereunder remain valid. Of note is the fact that the NPA was relied upon as recently as 1998 for authority to expand the Pre-Build facilities. As detailed below, the NPA does not provide direct guidance on the process or procedure that would be used to consider an Alaska Pipeline Project filing. Therefore, the challenge for TransCanada will be to encourage and facilitate a process under the NPA umbrella that accommodates current requirements and minimizes the risks of additional delays.

As well, we anticipate that there will be significant political pressure brought to bear for the Governments and regulatory agencies to "do the right thing" and assess such a massive undertaking under current regulations and standards; and not accept an authorization that was granted under circumstances that were very different. There may indeed be some legitimacy to the argument that the information from the distant past is stale and outdated; and that the basis upon which the previous evaluations were conducted no longer remain valid.

In our view, while TransCanada will have certain advantages because of existing approvals and the NPA process, there will likely be political pressure asserted to expose the Project to an extensive regulatory and environmental review process, similar to that employed regarding the examination of the Mackenzie Gas Project. In this regard, it is noteworthy that the Mackenzie Gas Project has taken some eight plus years from initial regulatory process design to anticipated receipt of major regulatory approvals. While these are material differences, the Mackenzie Gas Project process may be viewed as broadly analogous in terms of regulatory complexity to the Alaska Pipeline Project. In our view, there will clearly be an expectation that the Project will be exposed to a rigorous process and not provided any short-cuts because of past approvals.

## **2. Technical Concerns with the Application of the NPA**

In our view, while the deemed Certificates of Public Convenience and Necessity granted to the Foothills affiliates under the NPA contain a measure of flexibility, it is certainly arguable that the new proposal, which reflects a substantially different flow

rate, economic cost and possibly even route changes, is outside the scope of the Project which was certificated pursuant to the NPA. The TransCanada proposal contains information on a number of these parameters which arguably are a "material" change from those previously approved. In our view, these changes in scope, etc. could expose TransCanada to a challenge respecting its reliance on the prior NPA authorizations. To the extent that TransCanada has to seek amendments to either the existing approvals or the governing legislation, to accommodate proposed changes, this could precipitate a protracted debate that could delay the process from moving forward.

### **3. Required Environmental Assessment**

In its AGIA filing, TransCanada characterizes its proposed actions as an "update" to the information previously filed in support of the existing NPA approvals and the Terms and Conditions it must fulfill thereunder. At this time, TransCanada has indicated that it intends to rely on the NPA and is not required to conduct an assessment in accordance with the CEAA or YESAA. If TransCanada attempts to fulfill outstanding requirements via an expedited process that does not include a comprehensive environmental assessment, with full public input as contemplated by these statutes, or meet other applicable requirements, it could face challenges that the above-referenced environmental legislation should apply to the Project.

It is also clear that, absent the NPA, such legislation would indeed apply, and TransCanada would be required to conduct a comprehensive environmental assessment thereunder. As mentioned above, TransCanada has confirmed that it intends to adopt a transparent and public process and, as well, has confirmed that it will be updating the numerous technical environmental reports associated with the construction of the subject pipeline. These actions may in some measure mitigate opposition (and potentially litigation) over the Project. To the extent an open and comprehensive process is employed, the risk of a challenge could be reduced. Conversely, the opposite is also true. Given that the Yukon Government has indicated that it believes YESAA will apply to the Project, TransCanada would appear to have an incentive to accommodate a review process that addresses this concern.

#### **4. Duty to Consult First Nations**

Since the time of the approvals granted under the NPA, the obligations imposed upon both Project Proponents and Governments (Provincial, Territorial and Federal) with respect to the duty to consult First Nations has evolved considerably. As with any project proponent, TransCanada's failure to ensure that the currently recognized obligation to consult is completely fulfilled, would inevitably lead to challenges on behalf of potentially affected First Nations. A failure by the Crown to fulfill this duty has been one of the main stumbling blocks for project proponents when their undertakings could potentially have a significant impact on First Nations. To the extent TransCanada and the relevant Governments fulfill this obligation pursuant to the current requirements the Project risks will be reduced. Nonetheless, history would suggest that this is a likely basis for challenge. We note that this concern is not unique to a TransCanada proposal and would apply to any proposed pipeline project from Alaska that traverses First Nations lands or lands where the First Nations assert traditional uses. In fact, the work conducted by TransCanada to date should provide it with an advantage in this regard. We are not able to comment on the extent to which the relevant governments have engaged in consultation.

#### **5. North American Free Trade Agreement ("NAFTA")**

NAFTA did not exist at the time the NPA approvals were granted to TransCanada and the NPA was not grandfathered under NAFTA. As will be detailed below, certain NAFTA issues could arise which would potentially cause significant delays to the advancement of the pipeline proposal. It is worthwhile noting that the above referenced Joint Alliance/Enbridge submission expressly raises NAFTA issues as an area of concern. As such, it is apparent that these parties, and likely others, are attuned to this basis for challenging a TransCanada Application under the NPA.

#### **6. Alberta Component of the Overall Project**

TransCanada's Application did not describe the precise facilities that will be utilized to transport the Alaskan based gas once it reaches the B.C./Alberta border. While TransCanada identifies certain benefits associated with the use of Transportation

by Others, it appears that these comments are made solely in the context of using TransCanada's "Alberta System". In our view, it is likely that certain other pipeline carriers, including Alliance and Spectra, will argue that excess capacity or economic expandability on existing pipelines should be used for the transportation of Alaskan based natural gas. The information filed in the ongoing Alberta Inquiry into NGL matters, as well as a recent Press Release regarding a report by the Canadian Energy Research Institute on the capacity of the Western Canada Natural Gas Pipeline System, forecast that existing pipelines will have significant excess capacity by the time the Alaska Pipeline Project is proposed to be in-service. To the extent that TransCanada demonstrates a willingness to work jointly with third party carriers, it should be able to minimize debates that could cause material delays in the implementation of the Project. If such a debate arises, to the extent that TransCanada would be relying upon National Energy Board ("NEB") or Alberta Utilities Commission approval for additional facilities in Alberta (versus pursuant to the NPA) there will be a forum for such a debate. Otherwise, recourse to the Courts is likely.

#### **7. Acquisition of Land Rights**

It appears that TransCanada has obtained an "easement" across the Yukon, which should give it a timing advantage over any Third Party pipeline proponent. It also appears that, at this time, TransCanada does not have any secure rights to the necessary rights-of-way across British Columbia and Alberta. The acquisition of such rights in these two Provinces could take TransCanada, or any other project proponent, a considerable amount of time; and provide leverage to affected stakeholders. As such, while the NPA approvals would clearly give TransCanada an advantage over any third party pipeline proposal (particularly in the Yukon), the completion of the outstanding land acquisition process could create material delays. TransCanada's Application does not describe the precise manner in which it proposes to handle these outstanding land acquisition matters.

## **8. Fulfillment of Existing NPA Terms and Conditions**

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

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

## **9. Litigation**

As will be detailed below, there are likely to be a significant number of "trigger points" which will provide the basis for a Court challenge. As noted below, there has already been litigation regarding the NEB's Northern Pipeline Decision involving First Nations and Environmental groups. Past experience suggests that such parties are well versed in their legal rights and have little hesitation in seeking recourse to the Court system when they are aggrieved. Likewise, commercial parties will often commence litigation if they are not satisfied with the outcome of commercial discussions. We also note that there has already been litigation involving a past Foothills Pre-Build application. While the past litigation was not successful, if such a challenge were to occur, it could result in a significant delay. This litigation concern would apply equally to any party seeking to build a pipeline from Alaska into Canada, as the facilities would likely have similar potential impacts on the environment and First Nations, regardless of the project proponent.

In our view, any single item identified above could result in a material delay to the schedule detailed by TransCanada in its Application. Based on the situation one could reasonably expect to evolve following TransCanada's filing, it is conceivable that several of these potential concerns could become a reality, with resultant delays to the schedule. As stated above, the extent to which the matters identified herein, or by TransCanada itself, actually lead to delays in TransCanada's proposed schedule will be impacted to a significant degree by the strategy TransCanada ultimately employs in pursuing the Project.

## **B. INTRODUCTION**

The State of Alaska has requested that we provide our views on a number of issues associated with the November 30, 2007 Application filed by TransCanada pursuant to the AGIA. While a number of issues will be discussed regarding the TransCanada proposal, one of the primary mandates we have undertaken is to identify issues that could arise which would materially impact the proposed timeline for the completion of the pre-construction approvals phase of the Project put forward by TransCanada. After reviewing TransCanada's proposed timeline, we believe that it likely represents a "best case" scenario and is aggressive, in the sense that it will be difficult to complete all the identified tasks in the time allotted. However, we would logically expect a project proponent to adopt such an approach when bringing forth a proposal of this unique nature and magnitude. In essence, TransCanada has put forth a plan which assumes that it will not encounter any significant difficulties or delays in securing the major pre-construction approvals for the Project. In this regard, while we note that the TransCanada Application provides a "Key Risk Assessment and Mitigation" matrix, it does not provide a sensitivity analysis of, or a contingency for, the impacts (including on Project timing) that would be associated with certain events, that are arguably foreseeable, actually occurring. As such, should the matters identified by TransCanada or discussed below become a reality, it is likely that timing delays beyond the period forecast by TransCanada would occur.

In this Report we have attempted to incorporate consideration of a number of issues that could arise in the context of any Application (including a submission in the



In addition, we note that there has already been litigation with respect to the NEB's Northern Pipelines Decision and the application and scope of the NPA related to activities undertaken by Foothills as part of its Pre-Build. While this litigation confirmed the validity of the present authorizations, it may be indicative of the fact that various stakeholders, including Aboriginal and Environmental groups, will not hesitate to become actively involved in the overall governmental and regulatory/environmental process to consider such a Project. In our view, there is likely to be a strong correlation between the number of potential procedural or process challenges and a delay in the proposed schedule.

It is also of note that TransCanada's AGIA Application identifies some forty First Nations groups that it views as legitimate stakeholders in the Yukon and British Columbia, in addition to six regional Environmental groups that would be included in stakeholder consultation. We observe that this list does not address any Alberta based First Nations or Environmental groups; and does not take into account a number of national environmental entities that could easily become involved in a Project of this magnitude. From the above, it appears fairly clear that a large number of potential stakeholders will be very interested in any pipeline proposal ultimately brought forward by TransCanada. Such parties could seek to use any forum available to them to advance their positions, including recourse to the Courts.

In terms of the potential involvement of these parties, other intangible factors must also be considered. The fact that projects of this scope and magnitude do not take place very often, and hence will attract considerable attention, will inevitably act as an impetus for parties to use this venue as an opportunity to pursue public policy issues. This is also true of First Nations and Environmental groups who seldom get such a high profile forum to pursue issues of concern to them.

With respect to First Nations, it has been observed that the initial response of a number of Aboriginal entities located in the State of Alaska has been positive and they appear to be supportive of the Project. In our view, it is possible that a different response will be experienced in Canada. Canadian First Nations groups that could

potentially be impacted by the Project may not see this as a development that will have long term, material benefits for them. Rather, they will see this as a transient opportunity to obtain maximum benefits when their leverage is the greatest, which in our view is during the period when the project proponent is seeking to have the project approved and constructed. We expect that these parties may attempt to obtain commitments regarding such benefits during the approval process, which could lead to material delays. In fact, we would not be surprised to see certain First Nations use this Project as leverage in Land Claims Settlement discussions. History suggests that a common approach is to take actions which serve to impede the development of a project or cast doubts on its viability in furtherance of these objections. This does not mean that these parties are "opposed" to the Project *per se*, as absent the development, they would not get any of the benefits they seek to obtain. Rather, it is a case of attempting to use leverage when it is most advantageous. In our view, these concerns would be equally applicable to any third party pipeline project.

The same can be said of many Environmental groups, who will take a great interest in the potential impacts of the project and use any public forum available to attract attention to the environmental issues they will argue are not being adequately addressed by this development. The fact that a material portion of the Project is proposed to be constructed in proximity to the Alaska Highway is unlikely to deter such parties from vigorously pursuing their positions. While in many circumstances the concept of using a "Utility Corridor" is accepted as an approach that could assist in minimizing environmental impacts (versus another distinct right-of-way), this will not likely reduce the scrutiny of the proposal or allow TransCanada to avoid the full assessment of potential environmental impacts. The end result may well be that locating the Project in proximity to the existing highway will reduce impacts below those that would be experienced in a distinct corridor, but this is not likely to be the focus of concern. Rather, parties will likely focus on the potential impacts the proposed Project may have, as it is proposed. Thus, while locating the pipeline in proximity to an existing disturbance (the Alaska Highway) may be an advantage, it is not likely to diminish the opposition voiced by Environmental groups to any material degree. In this regard, any

proposal which attempts to utilize a route that is materially different from that previously contemplated could face additional challenges, with resultant delays.

### **C. BACKGROUND AND OVERVIEW OF THE NORTHERN PIPELINE ACT**

In order to provide context for the views expressed herein, it is important to understand the background to the development of the *Northern Pipeline Act* and the Northern Pipeline Agency ("NP Agency"), that has been created to administer this legislation in conjunction with the National Energy Board. This will also provide insight into the current "approvals" and the outstanding requirements regarding same.

The NPA was enacted following a number of regulatory and government actions, including execution of the Canada-U.S. Treaty Concerning Transit Pipelines, extensive NEB hearings, and execution of the Canada-United States Agreement on Principles.

#### **1. Canada-U.S. Treaty Concerning Transit Pipelines**

In January 1977, an Agreement between the Government of Canada and the Government of the United States of America Concerning Transit Pipelines was executed (the "Treaty"). The Treaty affects all transit movements of hydrocarbons from and to one of the signatories, across the territory of the other. Under the Treaty, the parties agreed not to, amongst other things, interfere with oil/gas throughputs or discriminate with taxes, fees or charges. Under Article II, for example, "no public authority in the territory of either Party shall institute any measures, other than those provided for in Article V, which are intended to, or which would have the effect of, impeding, diverting, redirecting, or interfering with in any way the transmission of hydrocarbon in transit". The Treaty applies to various pieces of legislation, including the NPA.

#### **2. National Energy Board Hearings**

As noted by TransCanada in its AGIA Application, the NEB issued its 1977 Northern Pipelines Decision<sup>1</sup> in June 1977 following a lengthy (214 days) hearing in which the merits of two competing pipeline proposals for the transmission of Alaskan

<sup>1</sup> National Energy Board, Reasons for Decision, Northern Pipelines, 1977 (GH-1-76, AO-1-GH-2-75). (hereinafter, "Northern Pipelines Decision").

gas through Canada were adjudicated.<sup>2</sup> These proposals were submitted by the Canadian Arctic Gas Pipeline Limited ("CAGPL") and Foothills Pipelines (Yukon) Ltd. ("Foothills"). The CAGPL proposal sought certificates of public convenience and necessity ("CPCN" or "Certificates") for delivery of Arctic Slope and Mackenzie Delta gas through a pipeline constructed along the coastal plain from Prudhoe Bay, Alaska, to the Mackenzie Delta and then south across Canada to Canadian markets and markets in the United States.<sup>3</sup> In contrast, the Foothills proposal sought Certificates to construct pipelines and related works that would transport gas from Alaska through the Yukon along the Alaska Highway then south through Alberta to the United States. That process ultimately resulted in the selection of the proposal put forward by Foothills, now a wholly owned subsidiary of TransCanada Corporation.

The NEB in granting Certificates to Foothills, made them conditional upon Governor in Council approval, stating:

In respect of the Foothills (Yukon) project, although further engineering design, environmental and socio-economic information is to be filed prior to approval of final design, on the evidence the Board finds that it offers the generally preferred route for moving Alaska gas.<sup>4</sup>

In its Decision, the NEB discussed conditions that were to be placed on the Certificates and required Foothills to, amongst other things, alter its proposed route so that it would include the Dawson diversion or realignment (i.e. go near Dawson City) to facilitate construction of the Dempster lateral pipeline for the transmission of Mackenzie Delta gas; and to apply for a Certificate for the Dempster lateral.

In *Yukon Conservation Society and Council for Yukon Indians v. National Energy Board and Foothills Pipe Lines (Yukon) Ltd.* [1979] 2 F.C. 14, an appeal was lodged against the Board's 1977 Northern Pipelines Decision, on the grounds that the Board exceeded its jurisdiction by approving a route that was substantially different than that in

<sup>2</sup> TransCanada AGIA Application, page 2.2-73.

<sup>3</sup> Robin L. Cowling, Canadian Institute of Resources Law, Calgary, Alberta, "Review and Regulatory Processes for Northern Pipeline Projects: Opportunities for Public Involvement", prepared for the Canadian Arctic Resources Committee, Yellowknife, NWT, November 2, 2001 [hereinafter "Review and Regulatory Processes"]

<sup>4</sup> See: Northern Pipelines Decision, page 1-165.

the application. However, Foothills made a successful application for summary dismissal of the appeal on the grounds that the appeal was rendered academic by the *Northern Pipeline Act of 1977*.<sup>5</sup>

### 3. Canada-U.S. Agreement on Principles

Following selection of a project proponent and a route in both Canada and the U.S., the two countries entered into the *Agreement between Canada and the United States of America on Principles Applicable to a Northern Natural Gas Pipeline* (the "Agreement") on September 20, 1977.<sup>6</sup> The Agreement provided for the construction of a gas pipeline to transport gas from northern Alaska and northern Canada to the United States.

Under section 2(a) of the Agreement the parties agreed as follows:

2(a) Both Governments will take measures to ensure the prompt issuance of all necessary permits, licenses, certificates, rights-of-way, leases and other authorizations required for the expeditious construction and commencement of operation of the Pipeline. ...

In this regard, the Agreement sets principles to coordinate and expedite the construction and operation of the pipeline system, and describes the route in general terms, divided into eleven zones (see: Annex I to the Agreement).<sup>7</sup> The pipeline route is generally defined as following the Alaska Highway, with the Dempster lateral extending from a point near Whitehorse to the Mackenzie Delta.<sup>8</sup>

The Agreement also calls for, amongst other things, Foothills to demonstrate proof of financing before construction will be allowed to proceed.<sup>9</sup>

The Agreement specifically refers to the Transit Pipeline Treaty, which as noted, governs all existing and future transit pipelines in the U.S. and Canada and which

<sup>5</sup> A. Black, "Legal Principles Surrounding the New Canadian and American Arctic Energy Debate", *Energy Law Journal*, Vol. 23:81.

<sup>6</sup> TransCanada AGIA Application, page 2.2-74. As amended by exchanges of notes dated June 6, 1978 between the Governments of Canada and the United States of America: See NPA, Schedule I.

<sup>7</sup> Agreement, article 1.

<sup>8</sup> Agreement, Annex II, Zones 10 and 11. See: *Review and Regulatory Processes*, *supra*.

<sup>9</sup> Agreement, article 4(a).

mandates non-discriminatory treatment. The Agreement has a term of thirty-five years and is renewed *automatically* unless a party chooses to terminate it with 12 months written notice.

As noted by TransCanada, in recognition of the magnitude and importance of the Project, the Canadian government took the unusual step of committing to enact specific legislation to statutorily enshrine the regulatory decision of the NEB and the terms of the Agreement:<sup>10</sup>

14. The two Governments recognize that legislation will be required to implement the provisions of this Agreement. In this regard, they will expeditiously seek all required legislative authority so as to facilitate the timely and efficient construction of the Pipeline and to remove any delays or impediments thereto.

The enactment of the NPA fulfilled Canada's obligation in this regard. In Canada there has been no legislation enacted providing for expedited certification of any project other than the Foothills project.<sup>11</sup>

#### 4. Northern Pipeline Act

Shortly after the NEB's Northern Pipeline Decision, the NPA came into force on April 13, 1978.<sup>12</sup> In essence, the NPA created an administrative and regulatory scheme to carry out and give effect to the *Agreement on Principles*. Presumably therefore, the legislation was originally intended to, amongst other things, ensure the "prompt issuance of all necessary permits, licenses, certificates, rights-of-way, leases and other authorizations required for the expeditious construction and commencement of operation of the Pipeline" as agreed by the Governments. As reflected in the objects of the Act, which are set out in Section 4 of the NPA, this was to be accomplished through measures aimed at facilitating efficient and expeditious planning, construction, consultation and coordination. As discussed below, given the significant lapse of time since the NPA came into force, debate may ensue regarding whether the legislation can

<sup>10</sup> TransCanada AGIA Application, page 2.2-74.

<sup>11</sup> *Ibid.*

<sup>12</sup> Proclamation, SI/78-90, 13 April 1978, C. Gaz. 1978.II.2665.

and should be used to further this original purpose, particularly if current regulatory or environmental standards are not met.

The NPA consists of four Parts: Part 1 – Northern Pipeline Agency, Part II – Traffic, Tolls and Tariffs, Part III – Real Property and Part IV – General. It is appended by three Schedules. Schedule I is the Canada-US Agreement, Schedule II is a list of the Foothills companies who have received Certificates under section 21 of the Act, and Schedule III lists the terms and conditions of the Certificates.

Some of the key aspects of the NPA are described below.

**a. Northern Pipeline Agency**

The NP Agency was created with the proclamation of the NPA in April 1978. Its stated purpose is to oversee planning and construction of the Canadian portion of the Alaska Highway Gas Pipeline Project by the Foothills Group of Companies, which is the project conditionally approved under the NPA. Indeed, the Foothills Subsidiaries hold Certificates granted pursuant to section 21(1) of the NPA for each of the zones of the Project in Canada. These CPCN are declared in the NPA to be issued pursuant to section 52 of the NEB Act and are the only existing certificates for the Project in Canada.<sup>13</sup> The pipeline, as certificated, is intended to transport Alaskan and possibly northern Canadian natural gas to southern markets in Canada and the United States.

The mandate of the NP Agency is twofold. It is required to carry out federal responsibilities in relation to the pipeline and facilitate the efficient and expeditious planning and construction of the pipeline taking into account local and regional interests, in particular those of native people. It is also responsible for maximizing the social and economic benefits from the construction and operation of the pipeline for Canadians while minimizing any adverse effect on the social and environmental conditions of the areas most directly affected by the pipeline.<sup>14</sup>

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<sup>13</sup> TransCanada AGIA Application, page 2.2-74. See also: NPA, s. 21(2). The Act states that these Certificates are "deemed to be a certificate issued pursuant to section 52" of the NEB Act.

<sup>14</sup> Northern Pipeline Agency Canada website. Available at: <http://www.infosource.gc.ca>

The NP Agency, working in close conjunction with the NEB, was and arguably still is intended to provide a central regulatory authority or window for the exercise of all federal responsibilities related to planning, monitoring and controlling the system throughout Canada.<sup>15</sup> Indeed, according to *Hansard*, the NP Agency is intended to serve as the only regulatory agency in charge of all federal responsibilities with regard to the Canadian part of the pipeline.<sup>16</sup> According to TransCanada this approach offers advantages. Indeed, in its Application TransCanada states, "by creating a single window through which federal approvals and decision making can be delivered and provincial or territorial approvals can be coordinated, the NPA has proved to be an effective and efficient approach to timely and complete regulatory authorizations".<sup>17</sup>

In reality, the Agency has been essentially dormant for many years and has only "bare bones" staff in place at this time. Yet, as detailed below, in keeping with the Act, many regulatory powers of other federal departments and agencies related to the pipeline project have been delegated to the NP Agency. This is not the case however for those powers reserved exclusively to the National Energy Board or shared between the NEB and the NP Agency.<sup>18</sup>

The relative inactivity of the NP Agency in recent years follows from the fact that its activities are dictated by the timing and pace of construction of the ANGTS in Canada. As noted by TransCanada, while a portion of the ANGTS pipeline has been built in Alberta (the "Pre-Builds") under the authority of the NPA, the majority of this construction occurred in the early 1980's when the price of natural gas fell to levels that made the construction of the entire APP, from Alaska to market uneconomic.<sup>19</sup> These unfavourable economic conditions led to indefinite delays in the completion of the northern portion of the pipeline ("Phase II"). Consequently, the NP Agency's activities have been limited. The most recent expansion under the NPA occurred in 1998 involving the installation of 113 km of 1067mm (42") diameter pipeline and compression and metering facilities downstream of Empress.

<sup>15</sup> See: NPA Preamble; Section 4(b); and Commons Debates, February 13, 1978 at 2789.

<sup>16</sup> Commons Debates, February 15, 1978, page 2892.

<sup>17</sup> TransCanada AGIA Application, page 2.2-75.

<sup>18</sup> Northern Pipeline Agency website available at [http://www.infosource.gc.ca/inst/npa/fed02\\_e.asp](http://www.infosource.gc.ca/inst/npa/fed02_e.asp)

<sup>19</sup> TransCanada AGIA Application, page 2.2-74.

Recently, more favourable market conditions have rekindled Interest in exploring options for bringing Alaskan gas to markets. In response, the NP Agency has reportedly been taking measures to address the commitments of the Government of Canada that are embodied in the NPA.<sup>20</sup> According to a recent Treasury Board of Canada Report, during 2007-2008, it is anticipated that the NP Agency will continue to work with other federal agencies, provincial and territorial governments, First Nations and the public to meet the objectives of the NPA. Furthermore, "in anticipation of receiving detailed project plans from Foothills, the NP Agency has begun reviewing key issues, including environmental concerns and First Nations interests. During 2007-2008, the NP Agency will be occupied with the development of plans to regulate and facilitate the construction of the pipeline."<sup>21</sup> This indicates that the NP Agency is aware that TransCanada may soon be in a position to proceed under the NPA and is in the process of preparing for such an eventuality. While these preparatory actions may serve to facilitate and expedite consideration of the detailed project plans, the status of current initiatives is far from clear given the limited public information available. At present, the approval process that may be followed by the NP Agency and the nature and extent of coordination are not known.

It seems clear, however, that in the event a detailed project plan is received and commercial arrangements to support construction of the project are finalized, the NP Agency would be called upon to significantly increase its activity levels. According to the referenced Treasury Board of Canada Report, the earliest this is expected to occur is 2008-2009. At present, the Agency's budget provides for only two FTE's, although it is recognized that the resource levels for future years may need to be adjusted depending on the actual level of activity in the Foothills project. Interestingly, the costs of the NP Agency are fully recovered from Foothills pursuant to section 29 of the NPA and determined in accordance with section 24.1 of the NEB Act and the NEB Cost Recovery Regulations.

<sup>20</sup> RPP 2007-2008 - Northern Pipeline Agency Canada, Treasury Board of Canada Report, available at: [http://www.tbs-sct.gc.ca/rpp/0708/npa-apn/npa-apn01\\_e.asp](http://www.tbs-sct.gc.ca/rpp/0708/npa-apn/npa-apn01_e.asp).

<sup>21</sup> RPP 2007-2008. *supra*

Likewise, the Treasury Board Report confirms that the NP Agency's jurisdiction extends only to the Foothills project, as authorized under the NPA. While it appears that Foothills intends to file detailed project plans to complete the project, and has asked that the NP Agency "prepare to expeditiously consider these plans and to facilitate construction", the natural gas producers "who hold the rights to extract gas in Alaska, have indicated their interest in applying for new certificates under the NEB Act to build a pipeline to bring the gas to markets south of the 60<sup>th</sup> parallel".<sup>22</sup> Should such a competing Third Party proposal be filed, it would be subject to the NEB and CEEA approval process, typically applied to "Greenfield" pipeline projects, and not the NPA process. While the potential impact of the recently announced Major Projects Management Office can not be assessed with any degree of certainty at this point, it is our view that a third party project could take at least 7 – 8 years to complete. In this regard, we observe that Conoco's November 30, 2007 filing with the State of Alaska contained a timeline, which it characterized as "streamlined", that covered approximately 10 years from the establishment of the necessary framework to pipeline operations. Of this time, it appears that Conoco was allowing approximately 5 ½ years from the present time to the commencement of construction. Conoco described the "streamlined" process as one that is completed "without delay". Given the numerous issues that Conoco or any other third party pipeline proponent (such as the recently announced BP/Conoco proposal) is likely to fail, we do not attach a high probability to actually being able to achieve this schedule.

**b. Organizational Structure**

The organizational structure of the NP Agency is defined by the Act, with specific responsibilities shared between the Minister, Commissioner, Administrator, Designated Officer and NEB. As TransCanada appears to be relying heavily upon the NPA for the requisite approvals, a brief examination of this organizational structure is warranted.

Minister of Natural Resources

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<sup>22</sup> *ibid.*

The NP Agency reports to Parliament through the designated Minister who is responsible for the management and direction of the Agency. At present, the designated Minister is the Minister of Natural Resources ("Minister").<sup>23</sup>

Under Section 10 of the NPA, the Minister is authorized to:

- Exercise the powers, duties and functions of other Minister's or agencies as may be transferred by the Governor in Council;
- Consult with provincial and territorial governments to coordinate and review the activities of the Agency and those governments;
- Enter into agreements with provincial and territorial governments as necessary to obtain the objectives of the Act and to coordinate and review the activities of the Agency and those governments;
- Oversee and survey all aspects of the planning, construction and procurement of the pipeline; and
- Consult with appropriate authorities of the United States for matters arising under the Agreement.

Consistent with the intent that the Agency act as a "single window", the Governor in Council ("GIC") may by order, transfer duties and functions of any federal minister, department or agency to the minister responsible for the NP Agency and that minister may carry out those duties and functions in relation only to the Canadian section.<sup>24</sup> Certain powers, duties and functions of the Ministers of Indian Affairs and Northern Development,<sup>25</sup> Environment<sup>26</sup> and Fisheries and Oceans<sup>27</sup> have been transferred to

<sup>23</sup> NPA at ss. 5(1) and (2). Although originally the Minister responsible for the NPA was the Minister of State for Economic Development, this was changed to the Minister for International Trade, and the Minister of Energy. P.C. 1979-2656, C. Gaz. 1979.II.3663 and SI/95-17. The Agency was transferred to the NRCan portfolio in February 2004.

<sup>24</sup> TransCanada AGIA Application, page 2.2-75. See also: NPA, s. 15.

<sup>25</sup> The transferred powers are those under the *Northern Inland Waters Act* and the *Territorial Lands Act*, P.C. 1980-2316, C. Gaz. 1980.II.3162. See *Review and Regulatory Processes, supra*.

<sup>26</sup> The transferred powers are those under the *Migratory Birds Act*, the *Clean Air Act*, the *Environmental Contaminants Act* and the *Canada Wildlife Act*, P.C. 1980-2316, C. Gaz. 1980.II.3162. See: *Review and Regulatory Processes, supra*.

<sup>27</sup> The transferred powers are those under the *Fisheries Act*, P.C. 1980-2316, C. Gaz. 1980.II.3162. See: *Review and Regulatory Processes, supra*.

the Minister "in relation to the pipeline only". Transfer of such authority is reported to have occurred in 1980. Furthermore, in 1983, the following additional powers, duties and functions were reportedly transferred to the Minister:<sup>28</sup>

- The NEB under Parts I, II and III of the *Gas Pipeline Regulations*;<sup>29</sup>
- The Minister of Indian Affairs and Northern Development to control, manage and administer certain territorial lands required for the pipeline;<sup>30</sup> and
- The Minister of Environment to administer, manage and control those lands in Kluane National Park Reserve required for the pipeline.<sup>31</sup>

This suggests that the Minister will be responsible for issuing a number of different approvals in respect of the pipeline other than those required under the NPA, including for example, approvals under the *Fisheries Act* in relation to the pipeline. As will be discussed below, this could have important implications, as normally such approvals could trigger the involvement of agencies such as the Canadian Environmental Assessment Agency ("CEA Agency"). Moreover, the ability of the NP Agency to undertake these activities will require additional senior staff, likely from other federal departments. In this regard, the GIC on the request of the Minister is authorized under Section 12(5) of the NPA to direct any department or agency of the Government of Canada to second to the NP Agency, for specified periods, officers and employees necessary for the proper conduct of the work of the NP Agency. As well, the Agency may obtain the advice and assistance of any department or agency of the Government of Canada.

<sup>28</sup> Review and Regulatory Processes, *supra*.

<sup>29</sup> P.C. 1981-2412, C. Gaz. 1981.II.2762 and P.C. 1983-1078, C. Gaz. 1983.II.1643. As the author notes in Review and Regulatory Processes, *supra*, these regulations were later repealed when they were consolidated with the *Oil Pipeline Regulations* to create the *Onshore Pipeline Regulations* (P.C. 1988-1719, C. Gaz. 1988.II.3790 and P.C. 1989-1091, C. Gaz. 1989.II.2991; *Onshore Pipeline Regulations*, SOR/99-294). An analysis of whether the Agency Minister has retained powers under the *Onshore Pipeline Regulations* that are akin to those previously transferred is beyond the scope of this research.

<sup>30</sup> *Transfer of Powers, Duties and Functions (Territorial Lands) Order*, P.C. 1983-3690, C. Gaz. 1983.II.4378.

<sup>31</sup> *Transfer of Powers, Duties and Functions (Kluane National Park Reserve Lands) Order*, P.C. 1983-3692, C. Gaz. 1983.II.4380.

The Minister also has a number of specific responsibilities and duties under Schedule III of the NPA that must be satisfied prior to construction. For example, as described by R. Cowling:

"Foothills is required to submit to the Minister a detailed manpower plan and to design a program for Canadian participation and content in procurement of goods and services for the pipeline.<sup>32</sup> The Minister also has responsibilities in relation to approving the financing of the pipeline, overseeing the costs incurred and projected for the pipeline and the progress of the planning and construction of the pipeline, as provided by Foothills in quarterly reports.<sup>33"</sup>

The NPA also requires Foothills to provide proof to the Minister and the Board that the necessary regulatory approvals have been obtained before construction can commence<sup>34</sup>

As noted by TransCanada, the responsible Minister is also authorized to undertake consultations and enter into agreements with the governments of the Provinces and Territories in Canada, as required, to co-ordinate all aspects of the project as they affect different jurisdictions.<sup>35</sup> As mentioned above, while there appears to have been some preliminary discussion regarding coordination of the required process, there is no evidence to support a position that this has been advanced to any meaningful degree. The overall process to coordinate the various bodies that could potentially be involved in the Alaskan Pipeline Project could take a considerable period of time (18-24 months). We would note that this was the recent experience with the Mackenzie Gas Pipeline.

### The Commissioner

The NP Agency has one senior officer, a Commissioner appointed by the Governor in Council.<sup>36</sup> Acting under authority delegated by the Minister, the Commissioner serves as deputy head of the NP Agency in Ottawa and has prime

<sup>32</sup> NPA, Schedule III condition 9-10.

<sup>33</sup> NPA, Schedule III condition 12-15.

<sup>34</sup> NPA, Schedule III condition 17.

<sup>35</sup> TransCanada AGIA Application, page 2.2-75.

<sup>36</sup> NPA, s. 6(1).

responsibility for advising the Minister on matters of policy. The Deputy Minister of NRCan has been Commissioner of the NP Agency since February 2004 (currently Cassie J. Doyle).<sup>37</sup> At present, the only office in the NP Agency that is staffed is the Office of the Commissioner, which maintains a small support staff. The Commissioner has reportedly appointed the Comptroller as Assistant Commissioner of the Agency.

Given the low level of activity, arrangements are reportedly in place whereby the NP Agency relies largely on NRCan for administrative and technical assistance. The NPA also receives policy advice from NRCan and other federal departments.<sup>38</sup>

#### The Administrator and/or the Designated Officer

Provision is made under the NPA for appointment by the GIC of an Administrator to assume responsibility for day-to-day operations of the NP Agency.<sup>39</sup> The GIC can appoint an officer to be called the Administrator or can appoint a member of the NEB to be the Administrator<sup>40</sup>, in which case the person is referred to as the Designated Officer.<sup>41</sup> At the present time, based on the information available, it appears that the Administrator and Designated Officer positions are vacant.<sup>42</sup>

Although the office is currently vacant, it is important to note that the Designated Officer is granted broad powers under the NPA including the power to, in respect of the pipeline, exercise and perform any of the powers, duties and functions of the NEB, as delegated by order of the NEB, except those as exempted under subsection 7(1) of the NPA.<sup>43</sup> The materials examined indicate that a number of NEB Orders were made in 1978 and 1983 to delegate responsibilities to the Designated Officer. However, these

<sup>37</sup> RPP 2007-2008, Northern Pipeline Agency Canada.

<sup>38</sup> RPP 2007-2008, Northern Pipeline Agency Canada.

<sup>39</sup> NPA, s. 6(2).

<sup>40</sup> *Ibid.*

<sup>41</sup> "Designated Officer" is defined in ss. 2(1) and 6(4). See Review and Regulatory Processes, *supra*.

<sup>42</sup> RPP 2007-2008, Northern Pipeline Agency Canada.

<sup>43</sup> NPA, ss. 6(2) and 7(1).

were later revoked in 1985.<sup>44</sup> The result being that these responsibilities again reside with the NEB.

The Act also grants the Designated Officer direct powers. For example, it authorizes the Designated Officer to:

- Certify copies of the approved plan, profile and book of reference, and to certify certain permits under the NEB Act,<sup>45</sup>
- With the concurrence of the Minister, to issue such orders and directions to Foothills and grant such approvals as may be necessary to carry out the terms and conditions of the Certificates,<sup>46</sup> and
- The Board or the Designated Officer may rescind, amend or add to the terms and conditions set out in Schedule III or deemed to be set out therein (with the approval of the Governor in Council).<sup>47</sup>

Furthermore, the NPA authorizes the Minister to transfer Ministerial powers, duties and functions to the Administrator.<sup>48</sup>

### The NEB

As noted, the Foothills Subsidiaries hold Certificates granted pursuant to section 21(1) of the NPA for each of the zones of the Project in Canada. These Certificates are declared in the NPA to be issued pursuant to section 52 of the NEB Act.<sup>49</sup>

<sup>44</sup> See NEB Orders No. NPO-1-78, AO-1-NPO-1-78, AO-2-NPO-1-78 and RO-NPO-1-78. As referenced in: Review and Regulatory Processes, *supra*.

<sup>45</sup> NPA, s. 7(2)(a).

<sup>46</sup> NPA, s. 22(1).

<sup>47</sup> NPA, s. 21(4). See for example, the five Zone Specific Socio-Economic and Environmental Terms and Conditions discussed in more detail below.

<sup>48</sup> NPA, s. 6(3). It is reported that in 1980, certain of the Ministerial powers, duties and functions were granted to the Administrator for the Pre-Build sections only. See: Review and Regulatory Processes, *supra* at 80: "The Minister of State and Economic Development delegated the authority to the Administrator to exercise and perform the Ministerial concurrence required by section 22(1) [then section 21(1)] in regard to some of the orders, directions and approvals issued or granted by the Designated Officer to the Pre-Build sections of the pipeline, see Lucas, Appendix 3."

<sup>49</sup> NPA, s. 21(2). TransCanada AGIA Application, page 2.2-74.

Like the responsible Minister and Designated Officer, the NEB has specific responsibilities under the NPA with respect to the pipeline. These include the power to:

- Rescind, amend or add to the terms and conditions as found or deemed to be in Schedule III of the Certificate, with the approval of the Governor in Council;<sup>50</sup>
- Make orders with respect to traffic, tolls and tariffs;<sup>51</sup>
- Approve, in conjunction with the Minister, Foothills' financing plans;<sup>52</sup>
- Foothills must provide proof to the Board that it has obtained all necessary regulatory approvals prior to construction;<sup>53</sup>
- Grant leave to open the pipeline pursuant to Section 47 of the NEB Act; and,
- Ensure compliance with NEB Act regulations.

The NEB Act also provides the ability of the NEB to recover from Foothills all costs incurred by the regulatory authority in scrutinizing and monitoring the planning and the construction of any pipeline from the time of certification until one year after leave to open the system is granted. As a result, TransCanada will be obligated to cover the related costs of both the NP Agency and the NEB.

Both the NEB and Designated Officer are subject to direction in the exercise of their responsibility by the GIC.<sup>54</sup>

#### Consultative and Advisory Councils

To further assist the Minister in carrying out the NPA's mandate, there is provision for federally-appointed advisory councils. As recognized by TransCanada, the function of these councils is to facilitate communication and consultation.<sup>55</sup>

<sup>50</sup> NPA, s. 21(4).

<sup>51</sup> NPA, Part II modifies Part IV of the NEBA to establish rates, tariffs and tolls.

<sup>52</sup> NPA Schedule III, Condition 12(1). The NEB also has responsibilities in relation to overseeing the costs incurred and projected for the pipeline, the financing of the pipeline, and the progress of the planning and construction of the pipeline, as provided by Foothills in quarterly reports: NPA, Schedule III, Conditions 14-16. As referenced in Review and Regulatory Processes, *supra*.

<sup>53</sup> NPA Schedule III, Condition 17.

<sup>54</sup> NPA, s. 20.

According to the referenced Treasury Board of Canada Report, two such councils were established:

- A council consisting of Aboriginal, business and other parties representing communities in the Yukon; and
- A council for northern British Columbia.

Membership in these councils has however lapsed in view of the limited activities of the Agency in recent years.

### c. Terms and Conditions

Under the NPA, the Certificates are subject to extensive terms and conditions detailed in the legislation. An integral part of the Agency's role is related to addressing these broad terms and conditions. These conditions must be satisfied before construction can commence. As the NPA is silent regarding process, it is unclear how a request for confirmation of compliance would be considered. If however a public process would be involved, which appears likely, this could have timing implications.

The initial legislative bill set out certain general terms and conditions relating to such matters as the input of Canadian manpower, goods and services, the design, specification and routing of the system, and the avoidance or minimization of adverse socio-economic and environmental impacts.<sup>55</sup>

As referenced above, the Foothills companies are also required to submit extensive information and, in many cases, to obtain federal approval with regard to such factors as costs, financing plans, shipper and producer contracts, operating and safety manuals, and collective agreements. The general terms and conditions require Foothills to comply with all undertakings it made before the NEB to achieve the greatest possible economic and social benefits from the project and to minimize adverse social and environmental effects. While we have not had the opportunity to examine in detail

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<sup>55</sup> TransCanada AGIA Application, page 2.2-75.

<sup>56</sup> Commons Debates, February 13, 1978 at 2790.

all of the undertakings made by Foothills during the NEB Northern Pipelines hearing, it could take considerable time and effort to comply with this requirement.

In some cases, these general terms and conditions are supplemented and reinforced by more detailed guidelines and orders under the NPA. These detailed terms and conditions are contained in Schedule III, which sets out conditions relating to matters such as the design and construction of the pipeline, social, economic and environmental matters, remote communities, manpower and procurement, financing, general matters, and the Dempster Line.<sup>57</sup>

Additionally, comprehensive Socio-Economic and Environmental Terms and Conditions ("Zone Specific") were drafted and appended to the five Certificates in 1980 (excluding the Yukon Certificate).<sup>58</sup> These five Zone Specific Conditions are:

- *Northern Pipeline Socio-Economic and Environmental Terms and Conditions for the Province of Alberta* (Order NP-MO-1-80 dated 12 June, 1980);
- *Northern Pipeline Socio-Economic and Environmental Terms and Conditions for Southern British Columbia* (Order NP-MO-2-80 dated 12 June, 1980);
- *Northern Pipeline Socio-Economic and Environmental Terms and Conditions for the Swift River Portion of the Pipeline in the Province of British Columbia* (Order NP-MO-11-80 dated 29 August, 1980);
- *Northern Pipeline Socio-Economic and Environmental Terms and Conditions for Northern British Columbia* (Order NP-MO-12-80 dated 29 August, 1980); and,
- *Northern Pipeline Socio-Economic and Environmental Terms and Conditions for the Province of Saskatchewan* (Order NP-MO-13-80 dated 29 August, 1980).

The Zone Specific Conditions were made by order of the Designated Officer, and approved by Order in Council. The effect of the Orders is to rescind Condition 7 of

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<sup>57</sup> Review and Regulatory Processes, *supra*.

<sup>58</sup> NPA ss. 21(3) and 22(2).

Schedule III<sup>59</sup> as well as those undertakings deemed to be included in Schedule III pursuant to subsection 22(2) of the NPA,<sup>60</sup> and replace these conditions with the five new, and more detailed, Zone Specific Conditions.<sup>61</sup> Again, no set of Zone Specific Conditions was adopted for the Yukon. Therefore, it appears that Condition 7 of Schedule III and Subsection 22(2) of the NPA still apply in respect of this zone.<sup>62</sup>

As explained by TransCanada, "these specific terms establish what conditions must be satisfied and what plans or programs must be developed (and approved) before construction can begin. These plans and programs are intended to ensure protection and enhancement of the environment; provide social and economic benefits and opportunities and, in every case, avoid or mitigate the potential for adverse effects":<sup>63</sup> In essence, they detail the socio-economic and environmental standards that Foothills is expected to achieve in respect of those particular zones. As further explained by R. Cawling:<sup>64</sup>

The Regional Conditions differ for each of the three provinces, with the three British Columbia terms and conditions also containing Environmental Guidelines. Examples of environmental terms and conditions that were common to all five plans are: terrain, landscape and waterbodies; reclamation and revegetation; air quality; noise; agricultural land; wildlife; fisheries; and, special interest areas. Pursuant to the Regional Conditions, Foothills is required to submit a series of plans to the Designated Officer

<sup>59</sup> This condition requires Foothills to comply with the undertaking given to the NEB during the Northern Pipeline hearing, as amended during the hearing or as may be made by orders or directions given by the Designated Officer.

<sup>60</sup> This section states:

Every undertaking given by Foothills Pipe Lines (Yukon) Ltd., the Alberta Gas Trunk Line (Canada) Limited, Westcoast Transmission Company Limited and Alberta Natural Gas Company Ltd. And In the submission of the Alberta Gas Trunk Company Limited to the Board, as amended during the Hearing is deemed to be:

- (a) an undertaking of every company in so far as the undertaking relates to the company and to the portion of the route indicated in the Agreement in respect of that company; and
- (b) a term or condition set out in Schedule III.

<sup>61</sup> An exception to the removal of the requirement to meet the undertakings was the continuing requirement for Foothills to compensate for hunting and trapping losses due to the pipeline activities. See Introduction, page (i) in each of the Regional Conditions.

<sup>62</sup> See: Review and Regulatory Processes, *supra*.

<sup>63</sup> TransCanada AGIA Application, page 2.2-75.

<sup>64</sup> See: Review and Regulatory Processes, *supra*.

indicating how it intends to proceed.<sup>65</sup> These plans are to be made available to the public at the Agency's offices.<sup>66</sup>

For the Yukon, Condition 7 requires that Foothills comply with the undertakings for social, economic and environmental matters given to the NEB, as amended during the hearing or by orders or directions of the Designated Officer. Condition 8 further stipulates that:

8. Prior to the approval of the final detailed design of each section or part of the pipeline, the company shall submit to the Designated Officer:

(a) the results of such further studies in respect of social and economic matters and environmental, fisheries and agricultural concerns as may be ordered or directed by the Designated Officer; and

(b) the recommendations of its environmental consultants for the protection of fisheries, farm lands and the environment.<sup>67</sup>

If the conditions under the NPA are not satisfied, there is an issue regarding whether Foothills has the right to exercise any rights pursuant to the NPA Certificates. As stated above, while the process for the fulfillment of these extensive terms and conditions is not clear, it appears that even if TransCanada can rely solely on the NPA, it has acknowledged that a transparent and public process will be required to examine these matters. In our view, such a process could well be extensive and will have a direct impact on the timing of the Project.

#### **D. POTENTIAL ISSUES AND CONCERNS**

Based on our review of the numerous issues that could potentially arise, including matters previously identified by TransCanada and other parties, there appear to be a number of matters that TransCanada should reasonably expect to encounter. These matters could result in an extension of the five and one-half timeframe identified by TransCanada in the AGIA Application for the completion of the pre-construction approval phase of the Project. TransCanada has clearly indicated that it will rely heavily upon the NPA and the NP Agency for a consideration of its proposal. This approach is

<sup>65</sup> See Introduction, page (II) in each of the Regional Conditions.

<sup>66</sup> See Introduction, page (II) in each of the Regional Conditions.

<sup>67</sup> NPA, Schedule III, at s. 8.

consistent with the "single window" concept reflected in the NPA. However, to the extent that TransCanada places undue reliance upon the NPA, it could actually delay TransCanada's timeline, as it is likely to lead to challenges that will take time to resolve. However, if TransCanada adopts a broad-based approach, of including all potentially impacted agencies, tribunals, and interested parties in the process to examine the Project proposal (while still maintaining that the NPA approvals provide it with a "single window" process for addressing issues) it may diffuse many of the process and procedural arguments that would otherwise be available to parties.

We note that the subject AGIA Application contains certain comments that leads one to believe that TransCanada will adopt a more "all encompassing" approach to seeking required approvals for the Project. In this regard, we observe that in its Application TransCanada has indicated that the Project will meet all "current" standards (see Executive Summary, p. 2) and that it anticipates a transparent and public process to examine its Application (p. 2.2 – 75). TransCanada does not specifically identify the type of process it is contemplating or whether such process would provide a venue to obtain public input from all impacted stakeholders. These will be important considerations for TransCanada to address as it moves forward.

With regard to the potential for delay, TransCanada's AGIA Application, Section 2.7 – Risk Factors enumerates a number of items that would be seen as "risks" for the Project. It is noteworthy that one of the major consequences resulting from any of these identified risk factors coming to pass is a scheduling delay for the Project. This portion of the Application appears to acknowledge the extreme sensitivity of timing to the identified risk factors. TransCanada does not quantify the duration of any delay it would expect to occur if the identified risk(s) came to pass. As will be detailed below, in our view there are a number of additional factors which likewise could impact upon the timeframe outlined by TransCanada in its AGIA Application. As discussed at the outset, the approach adopted by TransCanada in bringing the Project forward will likely have a significant impact on its ability to achieve the desired timeline.

A summary of the major issues that could impact upon TransCanada's proposal is provided below.

#### **1. Continued Applicability of the NPA Approval**

As aptly demonstrated in the past submissions of Alliance and Enbridge, there is a risk that parties will challenge the general applicability of the NPA to the circumstances confronting the Project today. Based on information we have reviewed, this argument also appears to be supported by certain producers, including ConocoPhillips and Exxon-Mobil. In this regard, we note that one of the main purposes of the NPA is to facilitate the "efficient and expeditious planning and construction of the pipeline". One could argue that this objective is of questionable relevance today, given the approximate thirty year delay in advancing the Project. We also anticipate that there will be significant political pressure brought to bear for the Governments and regulatory agencies to "do the right thing" and assess such a massive undertaking under current regulations and standards; and not accept an authorization that was granted under circumstances that were very different.

Over the intervening period, since TransCanada's original filing, not only has the overall policy and regulatory context shifted, but the Canadian environmental assessment policies and processes have matured. Additionally, requirements under other legislation that may be applicable to any Alaska Pipeline Project filing have changed since the time of the original examination. Statutes such as CEAA now mandate a process that includes a full and comprehensive assessment of pipeline projects. The current process is certainly different than at the time the original approvals were granted, which occurred under the then existing Federal Environmental Assessment and Review Process ("EARP"). Additionally, today Aboriginal rights have constitutional protection that guarantees consultation and participation by affected First Nations.

In our view, there will likely be political pressure asserted to expose the Project to an extensive regulatory and environmental review process, similar to that employed regarding the examination of the Mackenzie Gas Project. In this regard, it is noteworthy

that the Mackenzie Gas Project has taken more than eight years from initial regulatory process design to anticipated receipt of major regulatory approvals. Although there are some significant differences between the two projects, the Mackenzie Gas Project process may be viewed as broadly analogous in terms of regulatory complexity to the Project. In our view, there will clearly be an expectation that the Alaska Pipeline Project will be exposed to a rigorous process and not provided any short-cuts because of past approvals. Should TransCanada adopt a proactive approach that seeks to address identified concerns, it may be able to mitigate the risk of delay and enhance the prospect of achieving its "best case" scenario.

One of the main advantages offered by the NPA is the "single window", expedited regulatory approval process. However, at this point in time, it is unclear how much actual coordination is in place and exactly which governments, agencies and tribunals will seek to be involved. Even under the NPA itself there is considerable regulatory uncertainty regarding the approach that would be utilized to examine any TransCanada filing and an extended period may be needed to finalize the structure of the review process. To the extent that TransCanada is able to maintain the "single window" approach, contemplated by the NPA, it should be able to reduce delay and duplication of effort.

## **2. Technical Concerns with the Application of the NPA**

The deemed Certificates of Public Convenience and Necessity granted to the Foothills affiliates under the NPA appear to contain a measure of flexibility. However, reliance on same may be met with opposition on the basis that any residual certificate rights held by Foothills under the NPA are antiquated or that the new proposal is outside the scope of the Project which was previously certificated.

Notwithstanding the potential for debate, the better view appears to be that the NPA and residual Certificate rights remain valid. The legislation by its terms continues to apply. There is no section in the Certificates that limits their validity by way of an expiration date. Although the underlying *Canada-U.S. Agreement on Principles* can be terminated, this can only occur after its initial term of 35 years, with twelve months

written notice by either party.<sup>68</sup> Therefore, the Agreement itself will remain effective until at least 2012.

The continued validity of the legislation and residual Certificate rights in the face of changed circumstances and delay is also supported by the fact that the NPA process has been relied upon as recently as 1998 in respect of the Pre-Build. The failure of Foothills to advance the northern portion of the pipeline for over thirty years, therefore, should not in itself foreclose reliance on the NPA. As explained in Driedger, "A statute is not repealed, nor does it expire, through the passage of time or by reason of non-use or obsolescence. Unless the legislature has fixed a limit for the duration of legislation, it continues in force until it is repealed".<sup>69</sup> Nonetheless, a protracted debate on this issue could well occur.

Assuming the NPA and Certificates remain valid, TransCanada's ability to rely on them will clearly depend on whether the TransCanada proposal is different from the project that was authorized by the NPA. The reasoning being that TransCanada should not have free rein to build a project that is substantially different from that which was considered and certificated<sup>70</sup>. Accordingly, there may be a risk to the extent that the new proposal deviates from the ANGTS template and details of the Canada-U.S. Agreement on Principles.

Based on the information available, it is difficult to determine with certainty the existence and materiality of any inconsistencies between the current Project and that approved under the NPA. However, issues could potentially arise in relation to matters such as the proposed route, flow rate, and system configuration. This concern may also be impacted by the proposed use of TransCanada's Alberta System, to the exclusion of other existing infrastructure.

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<sup>68</sup> Agreement at article 12.

<sup>69</sup>R. Sullivan, Sullivan and Driedger on the Construction of Statutes, 4<sup>th</sup> ed. (Markham: Butterworths, 2002) at 527. As further explained; "Under Anglo-American common law, all English statutes retain their potential for enforcement even though they may be disobeyed or left unenforced. As Shakespeare said "The law hath not been dead, though It hath slept"... Accordingly, the 1977 Northern Pipeline Act remains valid legislation even if the underlying energy policy has shifted in the past twenty-five years": Alexander J. Black, *Legal Principles Surrounding the New Canadian and American Arctic Energy Debate*, 23 ENERGY L. J. 81, 119 (2002).

<sup>70</sup> Alliance letter, *supra*.

With respect to the proposed route, it may be arguable, for example, that the TransCanada proposal seeks to revise the general route of the ANGTS pipeline described under the NPA. Annex I sets out the general route of the ANGTS pipeline. The route specified may be more appropriately termed a "general corridor" as the Terms and Conditions contemplate separate approval of the detailed route; presumably within or along this corridor.

The TransCanada Application defines the Project route with reference to the NPA and underlying Canada-U.S. Agreement on Principles. For example, the Executive Summary provides, at page 4:

The pipeline route will follow the route set out in the Agreement Between Canada and the United States of America on Principles Applicable to a Northern Gas Pipeline ("Agreement on Principles") and the Northern Pipeline Act ("NPA") (1977-78, c. 20 R.S. 1985, c. N-26).

The more detailed sections of the Application pertaining to the route, however, suggest that there may be inconsistencies between the TransCanada proposal and the route set out in Annex I. While TransCanada maintains that the existing authorizations provide it with the necessary flexibility to accommodate its current proposal, it is not possible to confirm that this is the case based on the information available to date. As well, the materials provided by TransCanada make a broad assertion in this regard, but do not provide a detailed explanation of why this is the case.

Similar concerns may surface with respect to what is proposed in relation to the Alberta section of the Project. In this regard, TransCanada proposes the following:

When Alaska's natural gas reaches the British Columbia/Alberta border, Foothills will construct the necessary additional facilities in Alberta to permit Alaskan gas to reach the Alberta Hub by integrating with TransCanada's existing pipeline system in Alberta and connecting to the Pre-Build.<sup>71</sup>

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<sup>71</sup> TransCanada Proposal, Executive Summary.

According to more detailed information contained in Section 2.1 of the Application, the intent is for a portion of the initial Alaska gas to be transported using existing gas pipeline infrastructure downstream of Boundary Lake:

This available capacity in the existing gas infrastructure would be supplemented by new incremental facilities to handle the remainder of the 4.5 bcf/d from Alaska. These new facilities will be built and owned by Foothills under the NPA connecting to the existing Pre-Build and would consist of pipe looping and new compressor stations" (Page 2.1-10).

It is unclear what the use of "available capacity in the existing gas infrastructure" means and whether it is intended to be broader than solely the use of the Pre-Build. This indeed appears to be the case given that TransCanada makes reference to the "Alberta System" in describing its plans:

Currently the Alberta System has a Transportation by Others ("TBO") arrangement for Foothills Pre-Build facilities located within Alberta to transport WCSB gas. Such TBO arrangement between the Alberta System and Foothills would allow the Alberta System to utilize the new and existing Foothills facilities in Alberta to offer transportation to the Alaska Shippers. *When Alaska's natural gas reaches the BC/Alberta border, Shippers could contract with the Alberta System and enter the Alberta Hub.* (Page 2.1-11)

[Emphasis added.]

The "Alberta System" for the purposes of the Application refers to "TransCanada Corporation's wholly-owned, 15,000 mile natural gas transmission system in Alberta which gathers natural gas for delivery to end users and to liquids extraction facilities within the province and for delivery through provincial export locates to major natural gas areas across North America".<sup>72</sup> Therefore, the Alberta System clearly includes more than the Pre-Build, but is limited to facilities which are wholly-owned by TransCanada affiliates.

If capacity exists on existing, alternate pipeline systems, an argument could potentially be made that expansion of the Pre-Build or construction of new facilities is

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<sup>72</sup> TransCanada Application, Glossary.

unnecessary and would result in proliferation of facilities and unnecessary duplication. The forum for such a challenge is not clear, making it difficult to assess the process that would ensue. In any event, should such a challenge be brought, it could arguably result in protracted debate and delay. As mentioned above, should TransCanada demonstrate a willingness to work with other pipelines and gas producers on the optimal use of available infrastructure, this concern would likely be mitigated.

It may be open to interpretation whether the proposed configuration of the Project, including the Alberta Pre-Build, is even contemplated under the NPA.<sup>73</sup> In this regard, TransCanada is proposing that the annual average daily capacity of the Canada Section of the pipeline (northern section and Pre-Build) would be 4.5 bcf/d, with expansion capability (Page 2.1-9 and 2.1-10). This is significantly higher than the "initial" Alaska gas flow capacity of only 2.4 bcf/d contemplated under the Canada-U.S. Agreement on Principles.<sup>74</sup> While the expansion of pipeline capacity is arguably contemplated under Article 3 of the Agreement, this is subject to "regulatory requirements" being met. It is not entirely clear which "regulatory requirements" are to apply to such expansions. However, it is cautioned that there is an "expansion" provision under the NPA that has been referenced as applying to capacity expansions of the Canadian portion and thus potentially requiring a new certificate application to the NEB for any larger-scale project.<sup>75</sup> As discussed herein, the need to seek NEB approval would in turn, likely trigger the public hearing process, as well as a major review under CEAA. Clearly, such additional process, which is not contemplated in the TransCanada Application, could have timing implications.<sup>76</sup>

Similarly, in the event that it is not possible to accommodate the new proposal (and any material changes contemplated thereby to the proposed route, system configuration, etc.) under the NPA or an amendment thereto, then it would be necessary to bring applications pursuant to the NEB Act for approval to construct and operate the

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<sup>73</sup> This proposal calls for the expansion of the Pre-Build through looping and additional compressor stations to handle Alaska volumes not accommodated by the existing gas infrastructure.

<sup>74</sup> NPA, Schedule 1, Section 3.

<sup>75</sup> Alliance Letter, *supra*.

<sup>76</sup> It appears that the Pre-Build Expansions did not trigger this provision since they did not exceed the "Initial" capacity contemplated, although this has yet to be confirmed.

proposed project. In this regard, the need to seek NEB approval for facilities falling outside the ANGTS template is confirmed by the process applied in respect of certain aspects of the Pre-Builds. The decompression/recompression facilities, for example, applied for by Foothills in respect of the 1998 Pre-Build were considered to fall outside the scope of the ANGTS project and hence outside the scope of the NPA, since Alaskan gas was not planned to be stripped of liquids at Empress. Accordingly, the application for the de/re expansion facilities was made pursuant to the NEB Act and a screening performed pursuant to the CEAA.<sup>77</sup> The determination that the de/re facilities fell outside the scope of the ANGTS project was reportedly made following a referral by the Government of Canada to the Department of Justice.<sup>78</sup>

It is noted that the design of the balance of the 1998 Pre-Build expansion project consisting of the installation of 113 km of 42-inch diameter pipeline and various compression and metering facilities, all downstream of Empress on existing right-of-way and station sites was approved by the Northern Pipeline Agency. These facilities had previously been certificated under the NPA as part of the proposed ANGTS.<sup>79</sup>

Likewise, the other Pre-Build expansions appear to have fit within the parameters of the system configuration that was contemplated in the 1970s and therefore were subject to authorization under the NPA.

### **3. Required Environmental Assessment**

As stated above, in its AGIA filing, TransCanada characterizes its proposed actions as an "update" to the information previously filed in support of the existing NPA approvals and the Terms and Conditions it must fulfill thereunder. There is no indication that TransCanada intends to conduct an assessment pursuant to CEAA or YESAA. Depending on the approach ultimately adopted by TransCanada, the process it seeks to employ could be challenged by a number of parties.

It is clear that, absent the NPA, certificates of public convenience and necessity would need to be obtained and the above referenced legislation would indeed apply.

<sup>77</sup> NEB News Release, January 20, 1997, "Foothills secures key regulatory approvals for 1998 Eastern Leg Expansion Project".

<sup>78</sup> Alliance Pipeline letter to the Right Ho. Paul Martin, P.C., M.P., Prime Minister et. al. dated February 22, 2006.

<sup>79</sup> NEB News Release, January 20, 1997, "Foothills secures key regulatory approvals for 1998 Eastern Leg Expansion Project".

TransCanada would be required to conduct a comprehensive environmental assessment thereunder. As mentioned above, TransCanada has confirmed that it intends to adopt a transparent and public process and, as well, has confirmed that it will be updating the numerous technical environmental reports associated with the construction of the subject pipeline (Application p. 2.2 – 75). However, the process for the examination of these reports and the determination of whether or not there are potentially significant environmental impacts has not been detailed. To the extent an open and comprehensive process is employed, the risk of a challenge is significantly reduced. Conversely, the opposite is also true.

Moreover, TransCanada does not discuss the potential applicability of environmental legislation in British Columbia ("B.C.") and Alberta to the Project. While we consider that the better view is that these processes are not applicable to a Federal pipeline, this issue could be debated, particularly if the Project is not exposed to a comprehensive environmental assessment under the referenced Federal legislation. Such debates have occurred in the context of other Federally regulated pipelines.

In this regard, TransCanada acknowledges that there "remains a significant compliance process" for the Project under the NPA "to ensure the Project meets all current standards" (Application Executive Summary, p. 2). TransCanada asserts that the "NPA is the primary legislative vehicle through which necessary regulatory approvals have been and will be delivered or coordinated in Canada for the Project", and that "the NPA provides a single window, expedited regulatory approval process for the continued development of the Project" (Application Executive Summary, p. 11). TransCanada outlines the following as the principal remaining approvals required for construction *and* operation of the Project through Canada (Application Executive Summary, p. 12; Application, p. 2.2-82 to 84):

- Leave to Proceed Order under the NPA [approval of detailed pipeline design and health, safety, employment, logistics, environmental and related plans for the Project].

- Approval of Plans, Profile, and Books of Reference [i.e. detailed route information] under the NPA.
- National Energy Board ("NEB") approval of tolling methodology and tariffs.
- Leave to Open the Project from the NEB [once post-construction safety tests are complete].
- Other Federal approvals, including authorizations under the *Fisheries Act*, R.S.C. 1985, c. F-14, the *Navigable Waters Protection Act*, R.S.C. 1985, c. N-22, and the *Species at Risk Act*, S.C. 2002, c. 29."
- Provincial and Territorial approvals, which TransCanada lists in detail under Appendix P2 of the Application, including approvals for water crossings and land use.

TransCanada further lists a series of Environmental Field Studies that it anticipates will be required in connection with the Canadian portion of the Project. These studies will be in relation to: air quality and noise modeling; soils and geology; fisheries, hydrogeology and hydrology; vegetation and wetlands; wildlife, including species at risk; and archeology and heritage resources (Application, p. 2.2-45 & 46). It appears that TransCanada will rely on the NP Agency to examine and assess these Environmental Field Studies. However, the manner in which public input will occur is not clear.

TransCanada does note that the NPA and construction of the Foothills Pre-Build predated the 1995 enactment of the CEEA, and the specific federal legislation for environmental assessments in Yukon, namely the YESAA, enacted in 2005. TransCanada also points out that a review of the environmental, social and economic impacts of the original Foothills Alaska Pipeline proposal was completed in 1982 under the Federal Environmental Assessment Review process in effect at the time (Application, p. 2.2-75).

TransCanada states (Application, *ibid.*) that:

New and additional information will be required to meet mandatory conditions and prepare required plans and programs. The Foothills Subsidiaries will provide updated project, geophysical, environmental, social and economic information as part of its re-engagement of the NPA process (Intent to Proceed) and *fully expects* that such information and the sufficiency of plans and programs *will be evaluated through a transparent and public process under the NPA and any other applicable federal legislation* before receiving approval...

[Emphasis added].

TransCanada does not, however, provide details on the public process it expects will be held to review a renewed Alaska pipeline proposal. However, it appears that TransCanada is of the view that CEAA and YESAA will not apply.

With respect to the time required to complete the environmental studies and regulatory review process for the proposed Project in Canada, TransCanada does not provide a firm indication of the time it will take to complete such processes and secure necessary approvals for the Canadian portion of the Project. TransCanada states: "With regard to the timing of seeking regulatory authorizations of the Canada Section of the Project, TransCanada will *target* to finalize relevant Canadian approvals by the same date as the FERC Certificate" (Application Executive Summary, p. 12). Assuming that the AGIA License is issued by April 1, 2008, TransCanada *commits* to apply by December 30, 2011 for a FERC Certificate of Public Convenience and Necessity for the Project (Application, p. 2.2-85). The Project Schedule then *estimates* that the FERC Certificate will be issued on August 30, 2013, five years and five months after the issuance of the AGIA License (Application, p. 2.6-2). By extension, TransCanada is targeting completion of "relevant Canadian approvals" for the Project within a five and a half-year period, commencing April 1, 2008. TransCanada describes this period as the "Project Development Phase" which it further divides into: (a) the "Proposal Sub-Phase"—from the issuance of the AGIA License to completion of the planned binding Open Season eighteen months later; and (b) the "Definition Sub-Phase" from the end of the Open Season to the "receipt of all major approvals" anticipated, as noted, by August, 2013 (Application, p. 2.6-1).

The objectives of the NPA discussed above suggest that considerable scrutiny will be given to the Project by regulators under the NPA, specifically the NP Agency (and the NEB), to ensure that these major policy/political objectives are in fact met. The NP Agency, working in close conjunction with the NEB, is intended to provide a central regulatory authority or window for the exercise of all federal responsibilities related to planning, monitoring and controlling the system throughout Canada. In addition, as discussed in detail above, the federal Minister of Natural Resources has considerable responsibilities under the NPA that must be satisfied prior to construction. In addition, these bodies will be charged with ensuring that all applicable terms and conditions are properly fulfilled. As discussed, this could be an extensive undertaking.

As discussed above, to further assist the Minister in carrying out the NPA's mandate, there is provision for federally-appointed advisory councils. The function of these councils is to facilitate communication and consultation. These councils do not appear to be active at this point.

In sum, under the terms and conditions of the NPA, TransCanada will be required to submit extensive information and obtain a series of approvals from the Agency, the NEB, and the Minister of Natural Resources prior to commencing construction. These approvals relate to design and various other technical, environmental, socio-economic and commercial matters, including costs, financing plans, and operating plans. The exact process for determining the extent of information required for submission and the issuance of approvals is not pre-determined by the NPA. Process design will be up to the NP Agency, the NEB, and the Minister of Natural Resources and will require a significant degree of coordination between these bodies to ensure efficiency in requesting information from TransCanada, reviewing such information, allowing for public review/input and ultimately issuing approvals. In our view, coordination between these entities will be the minimum that is required. It is likely that additional bodies may wish to be involved and the process to successfully organize multiple authorities can take an extended period of time. This was recently experienced in the Mackenzie Gas Project.

#### 4. Applicability of the Yukon Environmental and Socio-Economic Assessment Act

At the heart of the regulatory process for projects in the Yukon is the *Yukon Environmental and Socio-Economic Assessment Act*, R.S.C. 2003, c. 7 ("YESAA"). YESAA is a federal law establishing a unique assessment process for projects in Yukon, functionally replacing the application of CEAA to most Yukon projects (section 6), subject to certain exceptions discussed below in relation to the Project. The YESAA process applies to federal, territorial and aboriginal approvals required to enable a project in the Yukon.

The origins of YESAA lie within the land claims settlements between the Federal Government and Yukon First Nations. Chapter 12 of the *Umbrella Final Agreement with Yukon First Nations* called for the establishment by federal legislation of an assessment process that would apply on all lands of the Yukon: federal, territorial, First Nation and private. The Council of Yukon First Nations ("CYFN") and the Yukon Territorial Government agreed to work with the Government of Canada to jointly establish a unique development assessment process for the Yukon. YESAA is administered by the Yukon Environmental and Socio-Economic Assessment Board ("YESAB"), an independent arms-length entity, made up of seven Board members appointed by the Federal Minister of Indian and Northern Affairs, in consultation with the Yukon Government and Yukon First Nations. YESAA and YESAB have been in full effect since November 2005.

There are three criteria that must be met for a project proposal to require an evaluation under YESAA. The project must: occur in Yukon; be captured by the *Assessable Activities, Exceptions and Executive Committee Projects Regulations*, SOR/2005-380 (the "*Activities Regulations*") and not exempted; and, meet one or more of the triggering circumstances listed in section 47 of the Act.

The Project would be caught by the *Activities Regulations* which includes under Schedule 3, s. 18, "Construction, operation, modification, decommissioning or

abandonment of an oil or natural gas pipeline 75 km or more in length if the pipeline is on a right of way developed for a power line, pipeline, railway line or road".

If a project is developed in the Yukon and subject to the *Activities Regulations*, then the final step to determining the application of YESAA is to determine if any of the triggering circumstances under s. 47 of the Act are met. These circumstances include the need for an authorization or the grant of an interest in land by a (federal or territorial) government agency, the NEB, municipal government or First Nation. The decision making bodies just listed are prevented from taking any decision to enable a proposed activity to proceed, until after the environmental assessment process under YESAA is complete (sections 82-84). The Project will require various regulatory authorizations from federal and territorial agencies (e.g. from the NEB as well as, Fisheries Act approvals federally, and water licenses and land use permits, discussed below, at the Territorial level). Therefore, it is clearly arguable that YESAA should apply to the Project unless TransCanada can successfully argue that the application of the NPA alleviates the requirement to subject the Project to the YESAA. It is also debatable whether a conflict would arise if both pieces of legislation were applied to the Project.

Note that YESAA does not include any transitional provisions equivalent to s. 74(4) of CEAA that would exclude the Project on the basis of its past genesis.<sup>80</sup> Moreover, YESAA expressly includes (section 94 to 101) provisions for the review of "existing projects", defined as a project that had already been undertaken or completed, but would have been subject to assessment under YESAA if proposed today. Consequently, even if it could be argued that the Project was not a new project for the purposes of YESAA, it would still be caught by the Act. It is also instructive that the Government of the Yukon takes the public position that the Project will be subject to YESAA (see: [http://www.emr.gov.yk.ca/pipeline/key\\_pipeline\\_interests.html](http://www.emr.gov.yk.ca/pipeline/key_pipeline_interests.html)), suggesting that an attempt to avoid the YESAA could bog TransCanada down in a dispute with the Territorial Government and likely others.

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<sup>80</sup> YESAA does include certain transitional provisions, but in our view these would not be effective in excluding the APP from the operation of the Act.

If the YESAA is found to apply, the Project would likely be subjected to the most onerous form of assessment under YESAA, namely a public review panel. Ordinarily, as a major activity listed under Schedule 3 of the *Activities Regulations*, the Project proposal would first be submitted directly to the Executive Committee of the YESAB (skipping an evaluation by regional offices, utilized to review lower impact projects). The Executive Committee of YESAB would conduct a "screening" of the proposal. The Executive Committee consists of three designated YESAB members. During the conduct of a screening, the Executive Committee must consult with First Nations, government agencies, and regulatory bodies with an interest in the proposed project. The Executive Committee will also receive public comments during a specified comment period. At the conclusion of the screening process, the Executive Committee must refer a project to hearings—a review panel—if, *inter alia*, the committee concludes that a project is likely to cause significant public concern in the Yukon or involves technology that is controversial or for which the effects are unknown (section 58). In our view, after applying these criteria, the Project is most likely to be referred to a review panel by the Executive Committee. Public concern around the Project is expected to be significant. In this regard, it should be noted that the purpose of a YESAA assessment extends beyond a review of the environmental impacts of a proposed project to include an analysis of socio-economic impacts (section 5). Consequently, even if environmental issues are limited in relation to the Project, which is not expected to be the case, socio-economic issues will likely persist and justify a review panel to address public concern. Moreover, TransCanada states in its Application (p 2.2.-15) that "use of new technologies will be a key factor in efficiently implementing the Project". This use of new technologies in the Yukon would also justify a reference to a review panel to scrutinize the Project.

There are also several mechanisms for direct referral of a proposed project to a review panel under YESAA, thus skipping a screening of the proposal by the Executive Committee of the YESAB. First, the Federal Minister of Indian and Northern Affairs or the Federal Minister of Environment may request the YESAB Executive Committee to establish a panel review for a project where a federal decision maker has a role in enabling the project. Second, the Yukon Government may request a review for a project

requiring its approval. A request for review must be made jointly by the Yukon Government and the Federal Government, if both federal and territorial bodies have jurisdiction in relation to the proposed project (section 60(2)). This is the situation that would apply to the Project. Finally, a Yukon First Nation, with the consent of the Federal Minister of Indian and Northern Affairs and the Yukon Government (for projects requiring territorial approval), may request a panel review of a project. It is quite feasible, therefore, for the Federal and Yukon Governments to expedite the assessment of the Project under YESAA by requesting the YESAB Executive Committee to make a direct referral to a review panel (or permitting a First Nation to make such a request).

A review panel, involving public hearings, can be conducted by YESAB itself. However, when a review panel is required under YESAA, the Canadian Environmental Assessment Act may exceptionally apply in the Yukon. For a Yukon project requiring a YESAA review panel, the federal Environment Minister can require (sections 61 & 62) that YESAB choose between: (a) convening a federal review panel under the Canadian Environmental Assessment Act to replace the YESAB review panel; (b) creating a YESAB-CEAA joint review panel; or (c) establishing a joint review panel between YESAB and another environmental assessment agency with an interest in effects from the proposed project. The Federal Environment Minister can refuse to allow a stand-alone YESAB review panel, and effectively force YESAB to either allow itself to be replaced by a CEAA-convened panel or to compromise with a joint panel (sections 62 & 63). The purpose of these provisions appears to be to ensure a federal role in the review of major projects in the Yukon and to address trans-boundary impacts through a CEAA or joint-panel process to cover impacts beyond Yukon. In our view, these provisions provide an additional opportunity for a CEAA type process to be applied to the Project.

A further exception under which CEAA applies in the Yukon is found at section 6(2) of YESAA:

National Energy Board

Sections 5 to 60 of the *Canadian Environmental Assessment Act* apply in relation to a project, as defined in that Act, that requires an authorization from the National Energy Board in order to be undertaken, but where the project is referred to a review panel under subsection 29(1) of that Act, the Minister of the Environment shall notify the executive committee of the referral, and section 63 of this Act applies as if that Minister had agreed to a request under paragraph 61(1)(b) [emphasis added].

The impact of this provision is that for projects that require an authorization from the National Energy Board —i.e. international or inter-territorial/provincial pipelines or power lines —CEAA applies in the Yukon, with one modification: if the NEB-regulated proposed project is referred to a panel review under CEAA, then the YESAB Executive Committee can request that the review be conducted by a joint CEAA-YESAB panel.

Arguably, the foregoing CEAA-related provisions are not entirely relevant to the Project because there are strong grounds for concluding that CEAA is not independently applicable to the Project, and thus would not be given effect by references within YESAA that give CEAA exceptional operation in Yukon. Assuming CEAA is not applicable, then one of two results seem plausible. Either YESAB would be left alone to conduct a review panel of the Project in the Yukon on a stand alone basis, or pursuant to section 61(1)(c), the Federal Environment Minister could require that YESAB conduct a joint panel review involving the NP Agency, in lieu of a joint YESAA-CEAA process. YESAA does not expressly provide for a joint YESAB-Northern Pipeline Agency process, but s. 67(2)(b) contemplates the creation of a joint panel between YESAB and any "authority having power to examine the environmental or socio-economic effects of the project, or of an activity that is to be taken partly outside Yukon and of which the project forms part." This definition appears sufficiently broad to encompass the creation of a joint YESAA-NPA process.

To date, no YESAA review panel (whether stand-alone or in conjunction with another process) has been held. A review of the *Rules for Reviews Conducted by Panels of the Yukon Environmental and Socio-economic Assessment Board* (the "Rules"), however, gives a limited sense of the time required for a review panel to be

completed. Upon the triggering of a review panel, the Rules give the YESAB Executive Committee up to five and one-half months to issue final guidelines for the preparation of an Environmental and Socio-economic Effects Statement ("ESE Statement") by the proponent for the project. The proponent must then take the time it requires to submit the ESE Statement. The Rules then give the YESAB Executive Committee up to four months to determine whether the information in the ESE Statement is sufficient. From this point, the Executive Committee has up to two months under the rules to convene the Panel (including the appointment of Panel members from amongst the YESAB membership) and to set terms of reference for the Panel. Within 90 days of its appointment, the Panel must commence a technical review of the ESE Statement and also an Information Request Process allowing parties (the proponent and interveners) to question their respective filings; ordinarily the technical review and Information Request process is to be completed within 90 days, but may be extended by the Panel. At the end of this stage, the Panel may seek supplementary information from the proponent, or proceed to the hearing. The duration of the hearing is at the discretion of the Panel. At the conclusion of the public hearing, a YESAB review panel can recommend that a project be allowed to proceed, be allowed to proceed with conditions, or not be allowed to proceed (section 72). The Rules give a panel up to five months to issue its recommendations. The Rules, in short, provide some control over the time required for a YESAB panel, but even so, the Rules contemplate a process of at least two years and potentially longer depending on the time required for the completion of all ESE Statement filings and hearings.

The Rules do not contemplate timing for a joint process between YESAB and another agency, but this would likely be longer than the time line set out in the Rules, to allow for coordination between the conjoined processes.

Once a YESAB review panel (or a joint YESAB panel) issues its recommendations, these must be considered by the relevant "decision bodies", as that term is defined under YESAA (at section 2). Decision bodies relevant to the Project would be the "territorial minister", i.e. the Yukon Government (the Executive Council

Office), and any federal departments that have the power to issue an authorization that is required for the Project to be undertaken.

A decision body in relation to a project must issue its Decision Document, responding to the panel recommendations, within the period prescribed by the *Decision Body Time Periods and Consultation Regulations*, SOR/2005-380: ordinarily, recommendations of a YESAB panel review must be responded to within 90 days (section 4(b)).

If a decision body disagrees with the recommendations of a panel of the YESAB, the decision body must refer the recommendations back to the Panel for its reconsideration (YESAA, section 76). The Panel then issues the recommendations anew (the same recommendation can be made as before), and the relevant decision bodies have a further 60 days to accept, reject or vary the new recommendations (*Decision Body Time Periods and Consultation Regulations*, section 5). Federal agencies are bound by YESAA to implement Decision Documents they issue in relation to a project (section 82). Where the Yukon Government is a decision body in relation to a project, all territorial departments, agencies and municipal governments are bound to implement the Decision Document issued by the Yukon Government (section 83).

In summary, TransCanada appears to be adopting a position that YESAA would not apply to the Project, based on the existing approvals and Project specific requirements of the NPA. As detailed above, there may be arguments why this view should not prevail. To the extent that TransCanada ultimately has to engage in a YESAA process it will likely extend the timeline for the Project. TransCanada should be able to minimize the impacts of any applicable YESAA process if it can take advantage of the opportunity to coordinate with other review processes at the outset.

## 5. Duty to Consult First Nations

Since the time of the approvals granted under the NPA, the obligations imposed upon both Project Proponents and Governments (Provincial, Territorial and Federal) with respect to the duty to consult First Nations has evolved considerably. Failure to completely fulfill the obligation to consult that would be triggered by an Alaska Pipeline Project filing would inevitably lead to challenges on behalf of potentially affected First Nations. A failure by the Crown to fulfill this duty has been one of the main stumbling blocks for project proponents when their undertakings could potentially have a significant impact on First Nations. To the extent TransCanada and the relevant Governments fulfill this obligation pursuant to the current requirements the Project risks will be reduced. Nonetheless, history would suggest that this is a likely basis for challenge. We would note that the matters raised herein would apply equally to a Third Party pipeline proponent. In fact, the consultations conducted by TransCanada, as well as the existence of its Yukon easement, should provide it with an advantage.

TransCanada's Application identifies approximately 40 First Nations Groups in the Yukon and British Columbia who are expected to be active stakeholders in any Alaska Pipeline Project application. In addition, there are several First Nations groups in Alberta who would likely become involved in this matter. First Nations play a unique role in the Canadian Regulatory process as they have an acknowledged constitutional right to be consulted on matters that could potentially impact them. This right has been reinforced repeatedly by recent case law and imposes a direct "duty to consult" on the Federal, Territorial and Provincial Governments involved. It is also arguable the project proponent itself has a duty to consult First Nations as part of its overall stakeholder consultation process. A failure to adequately consult is fatal to a project, as the Courts have consistently found that this provides a valid basis for refusing to allow the subject project to proceed, until this obligation is satisfied. Additionally, there is ample precedent for litigation on this issue taking several years to resolve. In short, this is one of the most critical issues that would face the Project and we do not consider that the NPA will assist TransCanada in reducing the duty to consult that would otherwise apply to it or the relevant Governments. As indicated at the outset, while impacted First

Nations may not "oppose" the Project per se, we are of the view that these groups will use the processes available to them to maximize the benefits to be derived from a project of this magnitude.

One area where First Nations are likely to be active is in land acquisition matters. In this regard, we will examine each of the areas where the pipeline is proposed to be constructed. Based on our review of available government maps, it appears that the Project route will potentially pass through several areas of Yukon where Final Agreements—settling outstanding land claims and clarifying aboriginal land ownership and other rights—have been reached with local First Nations. These areas are the traditional territories (from west to east along the proposed route) of the Kluane First Nation, the Champagne and Aishihik First Nations, the Kwanlin Dun First Nation, the Ta'an Kwach'an Council, the Carcross/Tagish First Nation, and the Teslin Tlingit Council. Two areas of Yukon will be traversed by the Project where land claims remain unsettled. In the west of Yukon, the White River First Nation has not settled its claims within a traditional territory that overlaps 100% with the traditional territory of the Kluane First Nation. In the east of Yukon, the Kaska Nation (comprised of the Kaska Dena Council, Ross River Dena Council and Liard First Nation) have not settled their land claim. It does not appear that Canada or Yukon are currently engaged in settlement negotiations with either the White River First Nation or the Kaska Nation.

In northern British Columbia no land claims have been settled in the area traversed by the Project; and thus persisting aboriginal title may remain on lands required for the pipeline right-of-way. Proving aboriginal title in Court is difficult, requiring the claimant to show occupation of the land prior to the assertion of British sovereignty, a degree of continuity between present and pre-sovereignty occupation, and exclusive occupation by the claimant group (*Delgamuukw v. British Columbia*, 3 S.C.R. 1010 (S.C.C.)). Consequently, aboriginal groups have been reticent to seek Court judgments to determine aboriginal title, and when litigation to prove title does arise, it has consistently taken many years (see for example, *Tsilhqot'in Nation v. British Columbia*, 2007 BCSC 1700, the latest aboriginal title case in Canada, which took some seventeen years). As a result, most First Nations in B.C. have opted to participate in an

ongoing process of tri-partite treaty negotiations with the B.C. and Federal Governments, to seek mutual agreement on aboriginal ownership of lands and other persisting rights to traditional practices. It appears that the following First Nations groups have made claims under the B.C. treaty process to traditional territory that may be crossed by the Project: Kaska Dena Council; Ross River Dena Council; Liard First Nation; Acho Dene Koe First Nation; Teslin Tlingit Council; and the Taku River Tlingit First Nation. These groups are in various stages of the negotiation process, but none is close to a final agreement.<sup>81</sup>

In Alberta, the route of the Project has not been specified in the TransCanada Application, thus it is difficult to identify which aboriginal groups may be impacted by the Project. In Alberta, however, aboriginal land claims were settled under historic treaties signed during the late 19<sup>th</sup> century. Consequently, aboriginal title is not in dispute on lands in Alberta and aboriginal land ownership is limited to clearly delineated reserves. Off-reserve, First Nations may, however, enjoy hunting and fishing rights pursuant to the terms of the historic treaties, and certain rights to other traditional practices, such as berry picking, under constitutional law. It is important to understand that First Nations could seek to participate in any Alaska Pipeline Project process on the basis that such traditional uses and rights will be negatively impacted, even if they do not claim Aboriginal title rights.

TransCanada makes the following statements with respect to the role of First Nations in land acquisition matters for the Project:

- In Yukon, TransCanada's easement rights for the route, and "reservations by notation" for compressor station sites, access roads, stockpiles and borrow pits, discussed above, are "Encumbering Rights" within the meaning of the *Umbrella Final Agreement* settling land claims in Yukon. "Accordingly, these lands have been withdrawn from the First Nation settlement process" and "cannot be eroded through ongoing discussions regarding final agreements with individual Yukon First Nations" (Application, p. 2.2-76 & 2.2 84).

<sup>81</sup> See the website of the B.C. Treaty Commission: <http://www.bctreaty.bc.ca/files/updates.php>.

- In respect of B.C. and Alberta, TransCanada acknowledges that it will require an easement, predominantly on Crown land. "Agreements with First Nations to obtain access to lands are not required, although Foothills is required under the terms of its certificates of public convenience and necessity to consult with, provide opportunities to and address barriers impeding participation of First Nations" (Application, p. 2.2-76).
- Regarding B.C., TransCanada claims the route required for the pipeline is subject to Mineral Reserves and Map Reserves, which do not create legal interests but give notice of intended use to all others. TransCanada further states that these Reserves "effectively remove Provincial Crown land from settlement discussions with First Nations" (Application, p. 2.2-85).
- In addition, TransCanada states "the Crown (federal or provincial) has an obligation to consult with and accommodate the interests of First Nations before taking further action to enable the Project to proceed" (Application, p. 2.2-76).

Based on the above, there are a number of issues that warrant consideration in the context of TransCanada's proposal.

**a. What are the Constitution's obligations imposed on the Crown agencies to consult with First Nations that are potentially impacted by the proposed pipeline?**

TransCanada correctly states in its Application that Crown agencies, both federal and provincial have an obligation to consult with and accommodate the interests of First Nations before taking action to enable the Project to proceed. Consultation is required where there is an assertion of an aboriginal right, either title or right to a traditional practice, which has not been proven at law, but could be impacted by a project requiring government action to proceed (*Haida Nation v. British Columbia (Minister of Forests)* 2004 SCC 73 ("*Haida Nation*"). Consultation is also required where known treaty rights, such as hunting and fishing under the historic treaties in Alberta, may be

impacted (*Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)* 2005 SCC 69). The duty to consult rests with the Crown. However, the Supreme Court of Canada has provided that procedural aspects of consultation may be delegated from the Crown to a project proponent.

The Supreme Court of Canada has held that the scope and content of the duty to consult varies along a spectrum, depending on the *prima facie* strength of the claim to the subject aboriginal right and the seriousness of impacts on that right if the project were allowed to proceed. If a claim to a right is weak and potential impacts limited, then consultation requires notice, disclosure of information, and limited discussion of aboriginal concerns. In contrast, if claims to a right are *prima facie* strong (or proven in the case of existing treaties) and impacts potentially severe, then "deep consultation, aimed at finding a satisfactory interim solution, may be required...entailing the opportunity to make submissions for consideration, formal participation in the decision-making process, and provision of written reasons to show that Aboriginal concerns were considered and to reveal the impact they had on the decision" (*Haida Nation*, p. 43-54).

To the extent that the Project will run in parallel to the existing right-of-way for the Alaska Highway, and not in pristine wilderness areas, it would appear that impacts from the Project on aboriginal traditional practices and title will be comparatively lower, since these rights may already have been affected by the Alaska Highway. This would suggest that consultation duties along the portions of the Route next to the Highway should be lower than would otherwise be the case. However, we would caution that the relevant Governments and TransCanada would be taking a significant risk if they seek to minimize the level of consultation conducted. A conservative approach, erring on more versus less consultation, would clearly be preferred given the significant negative consequences associated with a finding that inadequate consultation had been done.

Often, determining where a situation fits along the consultation spectrum is challenging. There has been considerable litigation in the last several years respecting the adequacy of Crown consultation provided to aboriginal groups, and recently a widespread practice has developed of project proponents reaching agreements with

First Nations in order to avoid litigation over Crown consultation. TransCanada is strictly correct, however, that the duty to consult does not provide an aboriginal group a veto over a project, since aboriginal agreement is not *required* for the Crown to acquit its consultation duty in advance of a project that may impact aboriginal rights (*Haida Nation*, p. 45). Moreover, consultation is a two-way process, and the Courts have held that aboriginal groups must participate in good faith with the Crown (and the project proponent, when the Crown delegates aspects of consultation), or in essence forfeit their right to consultation. Notwithstanding, a failure to conduct adequate consultation is a major concern and in our experience project proponents often have to work with the relevant Government bodies to ensure that they are in fact adequately fulfilling their duty to consult. In the end result, it is the project proponent who will suffer (as their project would be delayed) even if it is the Government(s) that fail to fulfill their obligations.

The duty to consult applies broadly to all government decisions that may impact aboriginal rights. This would include approvals for a project and dispositions of Crown land. The Courts, in the context of the Mackenzie Gas Project, have also held that the Government must consult respecting the *design* of a regulatory and environmental review for a project that may have significant impacts on aboriginal rights, to ensure that aboriginal concerns are adequately reflected in the process (*Dene Tha' First Nation v. Canada (Minister of Environment)* 2006 FC 1354). As discussed herein, this authority will place considerable pressure on the federal Government to consult with aboriginal groups concerning the design of the regulatory process for the Project. There is also authority that once the environmental assessment process issues recommendations and proposed mitigative measures for a project, the Government must consult with First Nations that participated in the environmental assessment *prior* to modifying recommendations and approving a project on this modified basis (*Ka'a'Gee Tu First Nation v. Canada (Attorney General)* 2007 FC 763). Consequently, when the regulatory review process for the Project (under YESAA, CEAA, or the NPA) issues recommendations, the Governments' response to these recommendations must be informed by further aboriginal consultation, where aboriginal rights are at stake.

**b. Are these obligations impacted by the "rights", if any, previously acquired by TCPL?**

The prior issuance of Certificates to Foothills under the NPA and the securing of an easement through Yukon will have limited impact on the current content of the Crown's duty to consult. The case law provides that the consultation duty is owed prior to any government decision that may impact an aboriginal right. Given that multiple government decisions remain in respect of the Project, there will be a number of Crown decision points requiring consultation. These multiple decision points also give First Nations ample opportunities to challenge the adequacy of consultation during the stages of development of the Project, giving rise to the significant risk of litigation discussed herein. As discussed below, the existing easement through the Yukon should arguably simplify, but does not eliminate, Crown consultation duties in Yukon.

**c. What is the legal process for securing access to land that is subject to First Nations ownership or land claims?**

In Yukon, the Umbrella Final Agreement ("UFA") was reached in 1993 between the Government of Canada, the Government of Yukon and Yukon First Nations, as represented by the Council of Yukon First Nations ("CYFN"). The UFA is not itself legally enforceable, but is a policy document providing a common template for completing First Nation Final Agreements. Yukon is home to 14 First Nations. To date, eleven of the 14 Yukon First Nations have signed and are implementing Final Land Claims Agreements. Each of the individual settlement agreements incorporates the UFA, giving its provisions legal effect in the settled traditional territories, along with provisions that apply specifically to individual First Nations, notably lands selection for First Nations ownership within broader traditional territories. Lands included in individual First Nations lands selections are categorized to include: Category A lands for which the First Nations hold the equivalent of fee simple ownership to the surface and sub-surface; and, Category B lands for which they received surface rights only (collectively, "Settlement Lands"). Under Final Land Claims Agreements, Yukon First Nations are empowered: to enact bylaws for the use of and occupation of Settlement Land; to develop and administer land management programs related to Settlement Land; to charge rent or other fees for the use and occupation of Settlement Land; and,

to dispose of Settlement Land. In the first instance, First Nations' permission is required for commercial access to Settlement Lands. If agreement cannot be reached on terms and conditions for voluntary access, then a right-of-entry order can be sought from the Yukon Surface Rights Board. Chapter 8 of the UFA and the Final Land Claims Agreements sets out the jurisdiction of the Yukon Surface Rights Board, requiring it, *inter alia*, to set reasonable terms and conditions for access and compensation.

The UFA and each of the Final Land Claims Agreements provide at their respective sections 5.4.2 that Settlement Lands are subject to the exception and reservation of "any right, title or interest less than the entire fee simple therein existing at the date the land became Settlement Land...". The UFA and Final Agreements define such existing rights as "Encumbering Rights". On the basis of provision 5.4.2, we concur with TransCanada that the Yukon Easement granted to Foothills in November 1983, and discussed in detail above, is an "Encumbering Right" expressly carved out from any lands selected under Final Land Claims Agreements for First Nations ownership. Consequently, even if the Easement traverses Settlement Land, the agreement of relevant First Nations will not be required for access. Moreover, given the consistent policy of relying on the UFA as a template for all land claims in Yukon, the Easement, for so long as it remains valid, is effectively protected from any subsequent lands selection in unsettled areas.

TransCanada also states that its "reservations by notation" for compressor station sites, access roads, stockpiles and borrow pits, discussed above are also "Encumbering Rights" within the meaning of the UFA and Final Land Claims Settlements. On a strict reading of section 5.4.2, we do not agree that reservations by notation would qualify as Encumbering Rights and thus necessarily be excluded from Settlement Lands. This is because reservations by notation do not create legal interests, but are purely for administrative purposes. Nonetheless, we have reviewed each of the Final Land Claims Agreements relevant to the Project in the Yukon and each, in addition to provision 5.4.2, contains the following express exception to lands selected under the Agreements (Appendix A, s. 3.2.11):

Parcels will be subject to the temporary access corridors, permanent access corridors and reservations by notation as shown in the Alaska Highway Gas Pipeline Project (Yukon Section) Route Maps, Revised 88- 07, prepared by Foothills Pipe Lines (South Yukon) Ltd. as if those corridors and reservations were reservations by notation for Northern Pipeline Agency within the meaning of 5.4.2 for the purposes of this Agreement and subject to the Northern Pipeline Act, R.S.C. 1985 c. N-26.

The effect of this provision is to deem reservations by notation, as reflected in Foothills Route Maps Revised 88-07, as "Encumbering Rights" under provision 5.4.2. Consequently, it appears that TransCanada is correct that locations in relation to compressor station sites, access roads, stockpiles and borrow pits have been excluded from Settlement Lands to date and thus First Nation agreement is not required for access. Given the consistent practice of excluding these locations from Settlement Lands to date, it also seems reasonable to expect that locations in Yukon subject to existing reservations by notation for the Project would be excluded from lands selection under any future final settlement agreements.

In sum, TransCanada's Yukon Easement and ancillary pipeline locations reserved by notation are excluded from Settlement Lands under existing Yukon Final Land Claims Agreements, and would most likely be excluded from any future agreements. Three additional points are, however, required in relation to aboriginal land issues raised by the Project in Yukon.<sup>82</sup>

<sup>82</sup> A fourth proviso is mentioned here for completeness. Provision 5.6.10 of the UFA and existing Final Agreements states that:

If Legislation is amended to authorize Government to increase the term permitted for an Encumbering Right, Government shall not increase the term of that Encumbering Right pursuant to that amendment without the prior consent of the affected Yukon First Nation.

As the detailed discussion of the Yukon Easement above explains, under the Easement Agreement it is possible that the Easement could terminate on September 20, 2012 if Foothills does not give prior notice to extend the Agreement or if the rights under the Easement did not "continue to be exercised by", i.e. actively utilized by Foothills. If this were to occur, then the question would become whether the Federal Government could, of its own initiative, extend the term of the Easement. In our view, the Governor in Council has broad discretion to do so under s. 37(1) of the NPA, and this would not require an amendment to "legislation". NPA s. 37(1) provides:

37. (1) If the Governor in Council is of the opinion that lands in Yukon are required temporarily or otherwise for the construction, maintenance or operation of the pipeline including, without limiting the generality of the foregoing, lands required for camps, roads and other related works, the Governor in Council may, by order, after consultation with the member of the Executive Council of Yukon who is responsible for the lands, take the

First, if the Project route differs from the Easement Agreement of 1983, or if ancillary Project locations, i.e. for access roads, differ from those under reservations by notation reflected in Foothills Route Maps Revised 88-07, and TransCanada requires access for the Project on Settlement Lands, then access agreements will be required with relevant First Nations, or resort had to the Yukon Surface Rights Board, potentially adding to the time required for acquiring Yukon land rights.

Second, although Yukon First Nations with Final Land Claims Agreements cannot claim ownership of the Project Easement and ancillary sites subject to reservation by notation, the Crown will nonetheless have a duty to consult with these groups in relation to the Project. Under Chapter 16 of the Final Land Claims Agreements, First Nations members continue to enjoy certain rights within their traditional territory, but off Settlement Lands, notably a right to hunt and fish for subsistence. The Courts have held that the Crown's duty to consult applies to these rights (*Little Salmon/Carmacks First Nation v. Yukon (Minister of Energy, Mines and Resources)* [2007] 3 C.N.L.R. 42). Consequently, when a Government decision respecting the Project may impact rights to hunt and fish, notably the issuance of land use permits for the Project by Yukon, the duty to consult will be engaged, no doubt extending the time for Government to make requisite decisions. It appears that the Yukon Government has formalized consultation protocols with all the First Nations along the route, specifying *inter alia*, requirements for convening consultation meetings, which will provide an administrative basis for conducting consultation for the Project.

Third, with respect to the White River First Nation and Kaska Nation, whose land claims remain unsettled, a robust consultation process will be required, to identify their interests and assess Project impacts thereupon, and to accommodate their concerns to the extent possible. In the absence of Final Agreements with these two groups, consultation will be more complex than with other Yukon First Nations, since locations

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administration and control of them from the Commissioner and transfer the administration of those lands to the Minister.

However, if, unexpectedly, a legislative amendment were held to be required to extend the term of the Easement, then pursuant to provision 5.6.10 of the UFA and Final Agreements, the agreement of First Nations with Settlement Lands, traversed by the Project would be required. If this were not forthcoming, then presumably a new easement across Settlement Lands would have to be negotiated with First Nations, or resort had to the Yukon Surface Rights Board.

where aboriginal ownership of land continue, and the parameters of traditional rights to hunt and fish, for example, will not be as clear. Failure on the part of the federal and territorial Crown to rigorously consult these two groups may be seen to invite litigation. Based on the experience of the Mackenzie Gas Project, it is aboriginal groups without Final Agreements that tend to be the most litigious, presumably because litigation gives them leverage in their protracted negotiations toward final settlements.

This same general point can be made with respect to B.C., where as noted, land claims have not been settled along the route of the Project. It will be necessary for the federal and provincial Crowns to engage relevant B.C. First Nations in a rigorous consultation process, covering all potential government decision points required to advance the Project. It appears that this consultation process will likely have to be designed on an *ad hoc* basis. The B.C. Government is currently negotiating with First Nations leaders for a comprehensive policy setting out standard approaches to Crown consultation in the Province. These negotiations, dubbed the "New Relationship", have however been moving slowly,<sup>83</sup> and based on our research do not appear anywhere near completion.

Certain administrative processes in B.C. already contemplate consultation with First Nations. For example, prior to the issuance of Crown land for energy projects, pursuant to the regulatory process under the *Land Act* discussed above, the Crown, as a matter of course consults with potentially affected First Nations (*Land Use Operational Policy, Oil and Gas*, Crown Land Administration Division, Ministry of Agriculture and Lands, Effective August 16, 2004, [www.al.gov.bc.ca/clad/leg\\_policies/policies/oil\\_gas.pdf](http://www.al.gov.bc.ca/clad/leg_policies/policies/oil_gas.pdf)). The challenge for TransCanada will be to minimize the risk of litigation, by ensuring that the federal and provincial Crowns *adequately* consult at all decision points where Courts may expect aboriginal consultation. This will be an onerous process, potentially adding materially to the time required to secure all approvals and land dispositions for the Project in B.C.

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<sup>83</sup> See for example, *First Nation Consultation and Accommodation: A Business Perspective*, submission to The New Relationship Management Committee from the B.C. Chamber of Commerce, January 19, 2007, [www.bcchamber.org/files/PDF/First Nation Consultation Paper--A Business Perspective.pdf](http://www.bcchamber.org/files/PDF/First%20Nation%20Consultation%20Paper--A%20Business%20Perspective.pdf).

Note that we have considered TransCanada's claim that because the Project route is subject to Mineral Reserves and Map Reserves, lands required for the Project are "effectively" removed from settlement discussions with First Nations (Application, p. 2.2-85). In our view, this is not correct. As discussed above, Mineral Reserves and Map Reserves are administrative tools highlighting intended uses of Crown surface and sub-surface tracts, prior to actual dispositions. They do not create legal interests. Rather, it is a matter of Government discretion. In fairness, it seems highly unlikely that the Government would offer Crown land that is required by the Project as part of aboriginal settlement negotiations. However, it is also not inconceivable that detailed routing may have to be adjusted to avoid particular locations where First Nations make strong claims for ownership. The consultation process required in B.C. will create the forum for identifying such First Nations concerns.

In Alberta, because treaties are settled, there will be considerably less uncertainty respecting what aboriginal rights remain and may be impacted by the Project, as compared to B.C. However, First Nations enjoy hunting and fishing rights pursuant to the terms of the historic treaties in undisturbed areas of the Province and certain rights to other traditional practices, such as berry picking, under constitutional law. To the extent the Project may impact these rights, the Crown's duty to consult is engaged. Consequently, a prudent course would be for the federal and provincial Crowns to engage relevant First Nations in a robust consultation process, covering all potential government decision points required to advance the Project in Alberta.

Administratively, the Government of Alberta conducts aboriginal consultation under the guidance of its *First Nations Consultation Guidelines*, issued September 2006. The Guidelines set out standard procedures for various branches of Government upon receipt of applications that may impact aboriginal rights, including Alberta Sustainable Resource Development—charged with issuing pipeline easements on Crown land. While the Guidelines offer a framework for consultation, project proponents must ensure that actual consultation meets legal standards. For example, the Guidelines tend to extensively delegate consultation to project proponents.

Increasingly, First Nations are arguing that due to the degree of delegation, the Alberta Crown has failed to consult adequately.

#### **6. North American Free Trade Agreement ("NAFTA")**

NAFTA did not exist at the time the NPA approvals were granted to TransCanada and the NPA was not grandfathered under NAFTA. It is possible that certain NAFTA issues could arise which would potentially cause significant delays to the advancement of the pipeline proposal. It is worthwhile noting that the above referenced Joint Alliance/Enbridge submission expressly raises NAFTA issues as an area of concern. As such, it is apparent that these parties, and likely others, are attuned to this basis for challenging a TransCanada Application under the NPA.

As stated, the NPA was not grandfathered with the passing of the continent wide free trade agreement. Therefore, having regard to the current context in which the NPA must operate, the issue arising with respect to the TransCanada Application is whether the provisions of NAFTA could impact the operation of, and thereby TransCanada's reliance on, the NPA. Further, assuming that a challenge was brought in respect of whether the NPA is inconsistent with NAFTA, an issue arises regarding whether such a challenge could impact the timing of the TransCanada proposal. While we have not made a definitive determination as to whether the NPA is inconsistent with NAFTA, it is our view that there is a risk that a challenge could be brought on the basis that the NPA is not consistent with NAFTA. In a submission by Enbridge and Alliance, *Facts about the Alaska-Canada Natural Gas Pipeline*, these parties state:

**Fact:** The NPA preceded the NAFTA by many years, and was not grandfathered under NAFTA.

**Fact:** If the NPA process were to result in preferences for the use of Canadian goods and services, those preferences may be in conflict with Canada's NAFTA and WTO obligations.

**Conclusion:** If the federal government confirms the NPA project on the basis of purported exclusive rights granted to TransCanada/Foothills, any NAFTA investor willing to compete for the right to build the pipeline may have a claim

for damages against the federal government if not given a fair opportunity to compete.<sup>84</sup>

Moreover, we note that NAFTA is not specifically identified in the TransCanada Project Key Risk Assessment and Mitigation chart provided in Section 2.7 of the TransCanada Application. As such there is a risk that any such challenge to the NPA could delay the TransCanada project schedule. The impact of this timing delay would ultimately depend on the basis for the NAFTA challenge, when the NAFTA challenge is brought, and the avenue pursuant to which the challenge is sought to be resolved. Of particular interest with respect to the TransCanada Application are Chapters 11 and 12 of NAFTA. The obligations of a NAFTA member apply to investments, investors and to goods and services providers, pursuant to Chapters 11 and 12 of NAFTA.

One of the underlying principles of NAFTA is non-discrimination. Two fundamental principles of non-discrimination implemented by the NAFTA are the requirements for "national treatment" and the application of most-favoured nations treatment, as noted in the preamble to NAFTA 102. National treatment requires that a member nation such as Canada treat investors and investments, and goods or service providers, of other member nations no less favorably than its own.<sup>85</sup> That is, rules cannot be structured so as to favour local companies, and rules cannot interfere with the conduct of an investment, including the requirement for the purchase of local materials or services. The concept of most-favoured nations requires that a NAFTA country give to other NAFTA members the best treatment that may be given by the NAFTA country to other NAFTA members or to non-NAFTA members. Questions could

<sup>84</sup> Similarly, in a Staff Report of the Federal Energy Regulatory Commission (January 18, 2001): United States Senate Committee on Energy and Natural Resources - Alaska Natural Gas Transportation Act, the FERC itself raised NAFTA stating with respect to international consideration: "The 1979 Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline, ... specifies the route of the ANGTS and contains numerous conditions applicable to the system. ... To the extent that particular proposals either favour or disfavour transportation of either American or Canadian gas supplies, the provisions of the U.S.-Canada Free Trade Agreement and the Northern American Free Trade Agreement might be relevant."

<sup>85</sup> The United States of America and Canada Agreement Concerning Transit Pipelines (in force 1 October 1977) (the "Transit Treaty"), also appears to prohibit discriminatory treatment in respect of a Transit Pipeline or hydrocarbons in transit. For example, Article 3 of the Transit Treaty precludes a public authority in either Canada or the United States from imposing any fee, duty, tax or other monetary charge on or for the use of any Transit Pipeline unless the charge would also apply to other similar pipelines within its jurisdiction. Similarly, Article IV (2) requires that all regulations, requirements, terms and conditions imposed with respect to Transit Pipelines and the transmission of hydrocarbons through a Transit Pipeline shall, under substantially similar circumstances with respect to all hydrocarbons transmitted in similar pipelines, excepting intra-provincial and intra-state pipelines, be applied equally to all persons and in the same manner.

arise regarding whether the existing requirements of the NPA are consistent with the above provisions.

We note that NAFTA 1108 permitted the Parties to NAFTA to make reservations and exceptions from the provisions of NAFTA to identify circumstances where existing non-conforming measures were maintained by a Party at the federal level. Notably, Canada did not make a reservation in Annex I to the NAFTA with respect to the NPA.

As a NAFTA country, Canada must extend to investors and investments of other NAFTA countries national treatment with respect to the establishment, acquisition, expansion, management, conduct or operation of investments.<sup>86</sup> In this regard, NAFTA 1102: *National Treatment* states:

1. Each Party shall accord to investors of another Party treatment no less favourable than that it accords, in like circumstances, to its own investors with respect to the establishment, acquisition, expansion, management, conduct, operation, and sale or other disposition of investments.
2. Each Party shall accord to investments of investors of another Party treatment no less favourable than that it accords, in like circumstances, to investments of its own investors with respect to the establishment, acquisition, expansion, management, conduct, operation, and sale of other disposition of investments.

NAFTA 1103 imposes the most-favoured nation ("MFN") obligation on Canada, requiring that Canada treat investors of other NAFTA countries no less favourably than it treats any investor of a NAFTA or non-NAFTA country.<sup>87</sup> NAFTA 1103: *Most-Favoured-Nation Treatment* provides as follows:<sup>88</sup>

1. Each Party shall accord to investors of another Party treatment no less favourable than that it accords, in like circumstances, to investors of any other Party or

<sup>86</sup> NAFTA 1102.

<sup>87</sup> NAFTA requires a Party to accord to investors of another Party and to investments of investors of another Party the better treatment required by Articles 1102 and 1103.

<sup>88</sup> Pursuant to Annex IV, Canada took an exception to the MFN treatment in respect of bilateral or multilateral agreements in force or signed prior to the entry into force of NAFTA.

of a non-Party with respect to the establishment, acquisition, expansion, management, conduct, operation, and sale or other disposition of investments.

2. Each Party shall accord to investments of investors of another Party treatment no less favourable than that it accords, in like circumstances, to investments of investors of any other Party or of a non-Party with respect to the establishment, acquisition, expansion, management, conduct, operation, and sale or other dispositions of investments.

Further, NAFTA 1106 imposes performance requirements with respect to the establishment, acquisition, expansion, management, conduct or operation of an investment of an investor of a Party in its territory. In this regard, NAFTA 1106 prohibits the imposition or enforcement of certain performance requirements, including the following:

- (i) to export a given level of goods or services;
- (ii) to purchase, use or accord a preference to goods produced or services provided in its territory, or to purchase goods or services from persons in its territory.<sup>89</sup>

Therefore, treatment that favours locals over foreigners that in some form harms the foreigner could be the basis for a claim against NAFTA.

Although NAFTA 1106(6) provides an exception for measures that are necessary to secure compliance with laws and regulations that are not inconsistent with the provisions of NAFTA, as long as such measures are not applied in an arbitrary or unjustifiable manner or do not constitute a disguised restriction on international trade or investment,<sup>90</sup> it is arguable that such an exception is not applicable to the circumstances considered herein.

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<sup>89</sup> NAFTA 1106(1)(c). This provision of NAFTA is the basis for a Notice of Intent to Submit a Claim to Arbitration Under NAFTA Chapter Eleven, brought by Mobil Investments Canada Inc.

<sup>90</sup> NAFTA 1106(6) also provides an exception for measures necessary to protect human, animal or plant life or health or necessary for the conservation of living or non-living exhaustible natural-resources.

NAFTA also imposes requirements with respect to the provision of "cross-border services" pursuant to Chapter 12 of NAFTA. The cross-border provision of a service is defined in NAFTA 1213 as follows:

... means the provision of a service:

- (a) from the territory of a Party into the territory of another Party;
- (b) in the territory of a Party by a person of that Party to a person of another Party; or

- (c) by a national of a Party in the territory of another Party.<sup>91</sup>

NAFTA Chapter 12 also imposes "national treatment" and "most-favoured nations" requirements on member nations. NAFTA 1202 requires the following national treatment:

1. Each Party shall accord to service providers of another Party treatment no less favourable than that it accords, in like circumstances, to its own service providers.
2. The treatment accorded by a Party under paragraph 1 means, with respect to a state or province, treatment no less favourable than the most favourable treatment accorded, in like circumstances, by that state or province to service providers of the Party of which it forms a part.

Further, NAFTA 1203 requires a NAFTA country to extend the most-favoured nation treatment to service providers of other NAFTA Parties. NAFTA 1203 provides as follows:

Each Party shall accord to service providers of another Party treatment no less favourable than that it accords, in like

<sup>91</sup> NAFTA provisions respecting services apply generally to the provision of services, except for financial services covered by NAFTA 14; enumerated air services; procurement by a Party or state enterprise; subsidies or grants provided by a Party or state enterprise.

circumstances, to service providers of any other Party or of a non-Party.<sup>92</sup>

In our view, arguments could be advanced that certain provisions of the NPA, including those contained in the Agreement which is appended to the NPA, are inconsistent with the provisions of NAFTA. Further, arguments exist that the provisions of the NPA which require Canadian participation, and indeed maximum participation of Canadians, are contrary to the NAFTA provisions requiring national treatment in respect of both investors and cross-border trade in services.

While arguments exist to suggest that the NPA is contrary to NAFTA requirements, it is also arguable that the NPA does not provide any advantage to Canadian nationals, investments or investors, or goods and services, and that what the NPA requires is that goods and services be procured on a generally competitive basis, without exclusion of any NAFTA members. For example, while the purposes of NAFTA set forth in Section 4 of the legislation do support the "highest possible degree of Canadian participation", the legislation also arguably requires that the procurement of goods and services be "on generally competitive terms". Arguably, the requirement for competitive terms is not to the exclusion of investors or enterprises of other member nations.

Similar wording respecting the requirement for competitive terms is found in the Agreement between Canada and the United States. That is, while part of the preamble requires the maximization of industrial benefits to the United States and Canada, Section 7 requires the adoption of "generally competitive terms for the supply of goods and services". Arguably, such is not to the exclusion of investors or enterprises of other member nations.

Further, while the *Terms and Conditions* imposed by Schedule III to the NPA on the Certificates granted pursuant to Section 21 of the NPA require Canadian participation, it is debatable whether such provisions provide an advantage to Canadian participation. Indeed, Section 10 which requires the establishment of a procurement

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<sup>92</sup> NAFTA requires a Party to accord to service providers of another Party the better treatment required by Articles 1202 and 1203: NAFTA 1204.

program does not require Canadian participation to the exclusion of others NAFTA members. Rather, the provision requires that Canadians have a "fair and competitive opportunity to participate in the supply of goods and services." The requirement for Canadians to have a fair opportunity to participate does not appear to violate the NAFTA requirements.

Further, the above cited passage from the submission made by Enbridge and Alliance suggests that arguments could be made that NAFTA investors who are not provided a fair opportunity to compete for the project may have a basis for a NAFTA claim. The fact that Foothills was issued the Certificates pursuant to the NPA does not in itself suggest that Foothills was preferred over other investors or that others were not provided a fair opportunity to compete for the pipeline. Indeed, the Certificates were issued to Foothills after a lengthy regulatory process, pursuant to which other parties had an opportunity to participate and present competing proposals. However, it is not clear that such a public process would necessarily preclude a current NAFTA challenge if the Canadian Government took measures to preclude consideration of other proposals, such as a Greenfield option that parties proposed pursuant to a NEB process.

While no final determination is made herein with respect to whether the NPA is inconsistent with the NAFTA provisions, in our view, the NAFTA provides another ground for dispute for interested parties that could result in a delay to the construction and operation of the TransCanada proposal. Of interest is the fact that the joint submission, dated April, 2005, made by Alliance Pipeline and Enbridge Inc. and the FERC Staff Report cited above regarding the Project expressly raised NAFTA issues. In our view, this is indicative of the fact that parties are aware of this ground of dispute and could seek to make use of NAFTA as a basis for challenging TransCanada's Application under the NPA.

## **7. Alberta Component of the Overall Project**

TransCanada's Application is unclear with respect to the precise facilities that will be utilized to transport the Alaskan based gas once it reaches the B.C./Alberta border.

While TransCanada identifies certain benefits associated with the use of Transportation by Others, it appears that these comments are made solely in the context of using TransCanada's "Alberta System". In our view, it is likely that certain other pipeline carriers, including Alliance and Spectra, will argue that excess capacity (or inexpensive expansibility) on existing pipelines should be used for transportation of Alaskan based natural gas. The information filed in the ongoing Alberta Inquiry into NGL matters, as well as a recently released report by the Canadian Energy Research Institute, forecast that existing pipelines will have significant excess capacity by the time the Project is proposed to be in-service. Should TransCanada demonstrate a willingness to work jointly with third party carriers, it may be able to reduce the impacts associated with debates that would likely otherwise ensue. To the extent that TransCanada would be relying upon NEB or Alberta Utilities Commission approved facilities in Alberta (versus pursuant to the NPA) there will be a ready forum for such a debate.

#### **8. Acquisition of Land Rights**

Subject to the issues discussed below, it appears that TransCanada has obtained an "easement" across the Yukon. The same does not appear to be the situation with respect to both British Columbia and Alberta, where TransCanada does not have any secure rights to the necessary rights-of-way across these two Provinces. The acquisition of such rights could take a considerable amount of time; and provide leverage to affected stakeholders. While the NPA approvals would clearly give TransCanada an advantage over any third party pipeline proposal, particularly in the Yukon, the completion of the required land acquisition process could create material delays. Based on its AGIA Application, the precise manner in which TransCanada proposes to handle outstanding land acquisition matters is unclear. A number of specific matters are discussed below.

##### **a. Validity of TransCanada's Assessment of its Land Rights in the Yukon**

As discussed above, TransCanada's Application asserts that an easement has been acquired across Yukon lands for purposes of the Project and further, that certain lands have been reserved by virtue of "reservations by notation". The following sections

provide additional detail on the status of the easement and the reservations by notation in respect of required land rights for the Project through the Yukon, given the importance of these matters.

(i) **The Yukon Easement**

By written grant dated November 28, 1983, Her Majesty the Queen in right of Canada granted to Foothills Pipe Lines (South Yukon) Ltd. ("Foothills") an easement to lay down, construct, operate, maintain, inspect, patrol (including aerial patrol), alter, remove, replace, reconstruct and repair a gas pipeline across the lands which are shown in the plans, profiles and books of reference (the "Easement") as certified by the Designated Officer of the Northern Pipeline Agency.

The grant of Easement was expressly made subject to the terms of a November 24, 1983 Agreement as between Her Majesty and Foothills, as amended (the "Agreement"). Pursuant to the Agreement, Foothills agreed to pay an annual fee to Her Majesty for the right within the right of way to enter upon and clear and lay down, construct, operate, maintain, inspect, patrol (including aerial patrol), alter, remove, replace, reconstruct and repair the pipeline (the "Rights"). These Rights are subject to (1) the payment by Foothills of the annual fee and (2) any rights previously granted with respect to the lands which are the subject of the Easement.<sup>93</sup> Foothills agreed pursuant to the terms of the Agreement that it would not exercise its Rights under the Easement without first having obtained the Minister's written consent to do so (the "Section 1 Consent"). Based on the information available, it does not appear that the Section 1 Consent has been obtained from the Minister at this time.<sup>94</sup> Notwithstanding, we are not aware of any reason that would prevent TransCanada from fulfilling the requirements to obtain the necessary consent.

Based on our review of publicly available documentation, Foothills does appear to hold an easement in the Yukon which it has held since November 28, 1983. The Easement appears to be in the name of "Foothills Pipe Lines (South Yukon) Ltd.", rather than being held on Foothills' behalf by the NP Agency, as suggested by TransCanada.

<sup>93</sup> See page 2 of the Agreement.

<sup>94</sup> The Minister currently responsible for the Northern Pipeline Agency is The Honourable Gary Lunn, P.C., M.P.

Note that while the Certificate of Title 84Y726 dated July 6, 1984 in respect of the Easement does not show any "previously granted rights", we have not at this time undertaken a detailed analysis of the certificates of title in relation to the lands which are the subject of the Easement across the Yukon to assess whether these lands may be subject to any "rights previously granted".

The fact that Foothills has not received the Section 1 Consent may be important for purposes of assessing the term for the Easement. The initial term for the Easement was for a 25 year period from November 28, 1983 (i.e. to November 27, 2008). However, this initial term was subsequently extended by agreement dated November 4, 1992 to 25 years from either the date that the Minister provides Section 1 Consent or September 20, 2012, whichever first occurs. The Easement would then continue at Foothills' option for 24 years, provided that (1) notice to extend is given at least 6 months prior to the end of the 25 year term and (2) the rights under the easement "continue to be exercised by" Foothills. Under the terms, therefore, it is possible that the Easement and all rights, licenses, liberties and privileges granted thereunder could terminate on September 20, 2012 if Foothills does not give notice to extend, Section 1 consent is not given, or if the rights under the Easement did not "continue to be exercised by" Foothills.<sup>95</sup>

Notably, the Easement granted to Foothills is in relation to the following lands:

Those lands vested in [Her Majesty the Queen] in right of Canada in the Yukon Territory, comprising 18,407 hectares, more or less, as shown on the copies of the plans, profiles and books of reference certified by the Designated Officer of the Northern Pipeline Agency pursuant to subsection 6(2) of the Northern Pipeline Act and provided to the member of Our Privy Council for Canada, designated to act as the Minister for the purposes of that Act, by the grantee pursuant to the provisions of subsection 37(2) of the said Act, a copy of which plans, profiles and books of reference has been filed in The Land Titles Office at the City of Whitehorse in the Yukon Territory as Instrument No. 67550.

<sup>95</sup> The Minister may terminate the Easement if the *Agreement Between Canada and the United States of America on Principles Applicable to a Northern Natural Gas Pipeline* is terminated prior to the date on which the Section 1 Consent is given.

[Emphasis added.]

We have been unable to obtain from Yukon Land Titles offices all of the plans, profiles and books of reference certified by the Designated Officer. Therefore, we have not been able to confirm whether the plans, profiles and book of reference certified by the Designated Officer conform to the current route proposed in the TransCanada Application. Should TransCanada's currently proposed route deviate from that certified by the Designated Officer, TransCanada would require additional land rights in the Yukon. This requirement could delay the construction and operation of the pipeline.

We observe that the initial section of the plans, profiles and books of reference show the pipeline entering into the Yukon through Beaver Creek. The NPA and the Agreement describe the route through Boundary and Border City, Alaska. The implications of this discrepancy have not been examined at this point. Further information in the form of the plans, profiles and books of reference, and Certificates of Title subject to the Easement, would be beneficial in further assessing the validity of TransCanada's claims in this regard.

**b. Reservations by Notation**

As discussed above, the TransCanada Application states that certain lands have been reserved for the purposes of the Project by virtue of "reservations by notation". We have been unable to find reference to "reservations by notation" in land documents of the Yukon in order to assess the status or nature of such "reservations by notation".

However, it appears that a "reservation by notation" is essentially the same as a "map notation", which reserves certain lands for a particular purpose. No legal documentation or rights are granted pursuant thereto. Notwithstanding, to the extent therefore, that lands required for compressor station sites, access roads, stockpiles and borrow pits in respect of the Project are subject to a map reserve, or a "reservation by notation", TransCanada's assertion that such lands have been reserved for the Project, may be accurate.

The TransCanada Application, as well as a slide presentation by TransCanada in April 2007,<sup>96</sup> suggest that the "reservations by notation" are held by the NP Agency, rather than Foothills or any other Government department. We have not been able to confirm that the NP Agency, in fact, holds reservations by notation in respect of these lands. Interestingly, we understand that the policy of the Lands Branch is to grant reservations only to Government. As the NP Agency is an agency of the Canadian Federal Government, it is possible that the NP Agency would hold a land tenure other than a "reservation by notation", such as a lease or other form of land tenure in respect of the lands required for compressor station sites, access roads, stockpiles and borrow pits. However, this is not clear from the information available at this time. In our view, further investigation is required in order to confirm the current status of the asserted reservations by notation.

Finally, TransCanada acknowledges that land use permits will still be required for use of the lands which are subject to the reservation by notation.<sup>97</sup> The key point to understand is that these reservations by notation do not provide any legal entitlements to Foothills. Access to vacant Crown land in the Yukon requires that an application be made to the Yukon Government - Lands Branch, which regulates land use permitting.<sup>98</sup>

Further, in addition to the Land Use permits, Section 4 of the Agreement requires Foothills to consult with Her Majesty as to the appropriate location for above ground facilities. It is not clear whether such consultation has taken place between Her Majesty and Foothills with respect to the location of such facilities, or the location of the corresponding reservations by notation, and therefore it is not clear whether locations for compressor station sites, access roads, stockpiles and borrow pits have actually been finalized between Foothills and the Minister.

<sup>96</sup> State of Alaska – Senate Judiciary/House Resources Testimony (April 13/14, 2007).

<sup>97</sup> Section 2.2, Development Plan, Section 2.2.4.2, page 2.2-84. The Yukon Government Lands Branch regulates land use permitting for a variety of uses, including site clearing or earth works; constructing new roads, trails, or access; clearing or installing utility rights-of-way, or conducting geo-technical or hydrological studies. Land use is regulated pursuant to the *Territorial Land (Yukon) Act*, S.Y. 2003, and associated regulations.

<sup>98</sup> Prior to April 1, 2003, land management in the Yukon was handled by the federal Department of Indian and Northern Affairs. These responsibilities have now been transferred to the Yukon Government.

If private lands are required by Foothills in the Yukon, the Yukon Surface Rights Board has the jurisdiction to consider unresolved matters in relation to Yukon lands and may provide an avenue pursuant to which disputes about access on Yukon lands can be resolved.<sup>99</sup> We have not further assessed this option as the TransCanada Application does not make reference to the need for privately held lands in the Yukon.

In conclusion, the status of the reservations by notation is not clear. Assuming that certain lands have been reserved pursuant to "reservations by notation", the reservations may provide a timing advantage to TransCanada, to the extent that such reservations would preclude overlapping interests and delineate locations for such facilities or access roads. However, the reservations do not appear to provide to Foothills any legal interest in the subject lands or any significant timing advantage. TransCanada will still need to proceed with acquiring land rights and other approvals, including land use permits, that could result in timing delays.<sup>100</sup>

**c. Validity of TransCanada's Assessment of Its Land Rights In British Columbia**

The TransCanada Application notes that it will need to obtain rights to Crown and privately held lands in British Columbia.<sup>101</sup> The Application states:

There is a map reserve 1640 yards wide held in the name of Foothills Pipe Lines Ltd.<sup>102</sup>

As well, the Application states:<sup>103</sup>

All Provincial Crown land required for the pipeline is subject to Mineral Reserves under the provincial Mineral Act and the *Mining (Placer) Act*, and Map Reserves under the *Land*

<sup>99</sup> Yukon Surface Rights Board Act, S.Y. 1994, c. 43, c. Y-4.3.

<sup>100</sup> While TransCanada acknowledges the need for a land use permit, there are several other permits that would potentially be required for purposes of constructing and operating the APP: work within right of way permit issued by Department of Highways; explosives storage issued by Natural Resources Canada; transport of dangerous goods issued by Department of Highways; waste storage approvals; timber cutting; permits and authorizations for quarries.

<sup>101</sup> Executive Summary, page 12; Section 2.2, Development Plan, Section 2.2.4.2, page 2.2-85.

<sup>102</sup> Project Description, page 2.1-9.

<sup>103</sup> Development Plan, page 2.2-84 to 85.

Act.<sup>104</sup> While neither instrument creates a legal interest in Foothills, the effect is to give notice of intended use to all others and effectively removes Provincial Crown land from settlement discussions with First Nations.

To perfect its interest in Provincial Crown land Foothills will require a License of Occupation under the *Land Act*.

With respect to the required rights across Crown land in B.C., the TransCanada Application states that a license of occupation will be required under the *Land Act*, R.S.B.C. 1996, c. 245. Section 39 of the *Land Act* in British Columbia states that the Minister "may issue a license to occupy and use Crown land called a license of occupation, subject to the terms and reservations the Minister considers advisable." In our view, Foothills will not only require a License of Occupation entitling it to occupy Provincial Crown land, but may also require a right of way/easement over such lands, pursuant to Section 40 of the *Land Act*. Notably, any person may object to the application for a Crown land disposition at any time before a disposition is made.<sup>105</sup> Further, after a hearing into such objection, an appeal may be taken to the B.C. Supreme Court and then to the B.C. Court of Appeal with leave of a justice of the Court of Appeal, all of which could extend any time frame for obtaining a Crown disposition in British Columbia.

The TransCanada Application states that all Provincial Crown land required for the Project is subject to Mineral Reserves under the *Mineral Act* and the *Mining (Placer) Act*, and Map Reserves under the *Land Act*. However, the TransCanada Application acknowledges that neither the Mineral Reserves nor the Map Reserves creates a legal interest in Foothills. Rather, TransCanada states that the effect of these Reserves is "to give notice of intended use to all others".<sup>106</sup> As such, the required land rights will still need to be acquired.

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<sup>104</sup> The footnote as found in the Application states: Order in Council No. 922, B.C. Regulation 100/1977 and order in Council No. 923, B.C., Regulation 101/1977, made under the *Mineral Act* R.S.B.C. 1960, c. 244, s. 12(5) as amended (repealed and replaced by the *Mineral Tenure Act* R.S.B.C., c. 292); *Placer Mining Act*, S.B.C. 1974, c. 63, s.13 as amended (repealed and replaced by the *Mineral Tenure Act* R.S.B.C. 1996, c. 292). Notwithstanding the repeal or [sic] both the *Mineral Act* and the *Placer Mining Act*, the mineral reserves created by the above referenced Orders in Council remain in full force and effect through 22(3) of the *Mineral Tenure Act*.

<sup>105</sup> Section 63, *Land Act*.

<sup>106</sup> Section 2.2, Development Plan, Section 2.2.4.2, page 2.2-85.

d. **Validity of TransCanada's Assessment of Its Land Rights in Alberta**

The TransCanada Application acknowledges that Foothills will require land rights in Alberta across both Provincial Crown lands and privately held lands for purposes of the construction and operation of the Project in Alberta.<sup>107</sup> The Application states:

Both Provincial Crown (65-75%) and privately held (35-25%) lands are required to construct and operate the pipeline in Alberta. Foothills holds a Consultative Notation with respect to Provincial Crown lands. While this does not establish any form of legal tenure it does identify a pipeline corridor and provides Foothills with the opportunity to review and comment upon any conflicting proposed development near that corridor.

To secure land tenure with respect to Provincial Crown lands, Foothills will be required to enter into a Pipeline Agreement (right-of-way) or a Pipeline Installation Lease (other pipeline facilities) under the *Public Lands Act*.

As the route that would be followed by the Project in Alberta has not been specified, we have not been able to confirm that Foothills holds a "consultative notation" with respect to all Provincial Crown lands in Alberta. While the TransCanada Application recognizes that the "consultative notation" held by Foothills with respect to the Crown lands does not establish any form of legal tenure, the Application notes that the notation "does identify a pipeline corridor and provides Foothills with the opportunity to review and comment upon any conflicting proposed development near that corridor."<sup>108</sup>

In Alberta, a "consultative notation" or "CNT" is used by Governmental agencies to register an interest in certain lands. Where an industry member uses a "consultative notation", the notation is referred to as a "consultative notation company" or "CNC" which records the interest of a non-governmental agency with a justified interest in the land and which wishes to be consulted prior to any commitment or disposition on the

<sup>107</sup> Section 2.2, Development Plan, Section 2.2.4.2, page 2.2-85. See also, Executive Summary, page 12.

<sup>108</sup> Section 2.2, Development Plan, Section 2.2.4.2, page 2.2-85.

land.<sup>109</sup> Therefore, where a surface disposition is proposed, the holder of a CNC in respect of that same land is advised. However, the CNC does not restrict land uses and provides no authority for the holder of the CNC to have any proposed disposition rejected or to have any conditions imposed on the proposed disposition.

It is our view that the "consultative notation" does not provide Foothills with anything more than the right to be consulted if a disposition is proposed in respect of lands for which it holds a CNC. Therefore, Foothills would be required to apply to Alberta - Sustainable Resource Development ("ASRD") to acquire necessary land rights over Provincial Crown Lands and would be required to address concerns raised by First Nations with respect to any impact on their traditional uses and rights. As acknowledged, Foothills would be required to acquire an agreement (for either a pipeline or a right of way installation<sup>110</sup>) and a pipeline installation lease (generally off right-of-way) pursuant to the *Public Lands Act*, R.S.A. 2000, c. P-40 and the *Dispositions and Fees Regulation*, Alta. Reg. 54/2000 made pursuant thereto.<sup>111</sup> Foothills would also require the consent of any landholder/leaseholder should any of the required lands be occupied.<sup>112</sup> From a timing perspective, it is our view that even assuming that the consultative notations are validated, Foothills would still be required to obtain necessary land rights across both Crown and privately held lands for the construction and operation of the Project.

As a more general note with respect to the acquisition of land rights across privately held lands, the TransCanada Application does not make assertions with respect to acquired land rights across privately held lands or the process for acquiring such rights. While we have not undertaken a detailed assessment of the processes required for acquisition of land rights across private lands, we do note that the interplay

<sup>109</sup> See publication of Alberta Sustainable Resource Development – Reservation/Notation Type Codes (Last review/updated February 15, 2006).

<sup>110</sup> "Right of way installation" is defined in Section 98(g) of the *Dispositions and Fees Regulation* as follows: "means any equipment, apparatus, mechanism, machinery or instrument that is incidental to the operation of a pipeline and is within a right of way, including, without limitation, (i) a valve, valve box, drip, blow-down, connection, foundation, bridge or support structure for a pipeline above the surface, scraper trap and cathodic protection apparatus, and (ii) any other installation that the Minister considers to be a right of way installation."

<sup>111</sup> Pursuant to Section 106 of the *Dispositions and Fees Regulation*, the maximum term for a pipeline installation lease is 25 years.

<sup>112</sup> *Dispositions and Fees Regulation*, Section 7(1)(d). Foothills would also require a license of occupation pursuant to the *Public Lands Act* to construct any structures that could have a negative impact on the bed and shore of a waterbody.

between the NEB Act land acquisition provisions and the NPA provisions is not clear in this regard. For example, Section 19 of Schedule III (Terms and Conditions) to the NPA states:

When the company ascertains the lands of a landowner that may be required for the purposes of a section or part of the pipeline, the company shall serve a notice, in a manner and in a form to be determined by the Designated Officer, on the landowner, which notice shall set out the location of the offices of the Agency and the right of the landowner within thirty days of being served to make representations to the Agency respecting the final route of the pipeline for its consideration prior to its approval of the final detailed route.

Notably, beyond this provision and beyond the provisions under Part III of the NPA respecting Real Property in the Yukon, there is very little in the NPA respecting the process for acquiring land rights, particularly with respect to the acquisition of land rights across privately held lands. However, the NEB Act provides for a more detailed land acquisition process that empowers the NEB, pursuant to Section 104 of the NEB Act, to issue an immediate right of entry order in respect of lands that are the subject of the right of entry application. In this regard, Section 104 states:

104(1) Subject to subsection (2), the Board may, on application in writing by a company, if the Board considers it proper to do so, *issue an order to the company granting it an immediate right to enter any lands on such terms and conditions, if any, as the Board may specify in the order.*

[Emphasis added.]

As noted previously, the TransCanada application is, at points, unclear in terms of the process it expects to utilize for consideration of the Project, including the process it would intend to utilize to acquire remaining land rights. Notably, TransCanada is proposing to complete all right-of-way processes and land acquisition as part of its Execution Phase (See Appendix "A"), which is at a critical time for Project development and construction purposes. Although TransCanada appears intent on relying heavily upon the NPA and the NP Agency for consideration of its proposal, we note that the absence of any statutory power in the NP Agency to grant an immediate right of entry

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

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

#### **9. Fulfillment of Existing NPA Terms and Conditions**

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

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

#### **10. Litigation**

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

#### **11. Conclusion**

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

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

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

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

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

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

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

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

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

## **E. RATES AND ACCESS**

### **1. New Versus Existing Facilities**

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

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

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

## **2. Return on Equity**

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

## **3. NEB Rate Setting Approach**

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

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

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

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

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

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

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

#### **4. Open Season**

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

## 5. Import and Export Requirements

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

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

authorizations were indeed adequate to support the associated commercial undertakings.

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

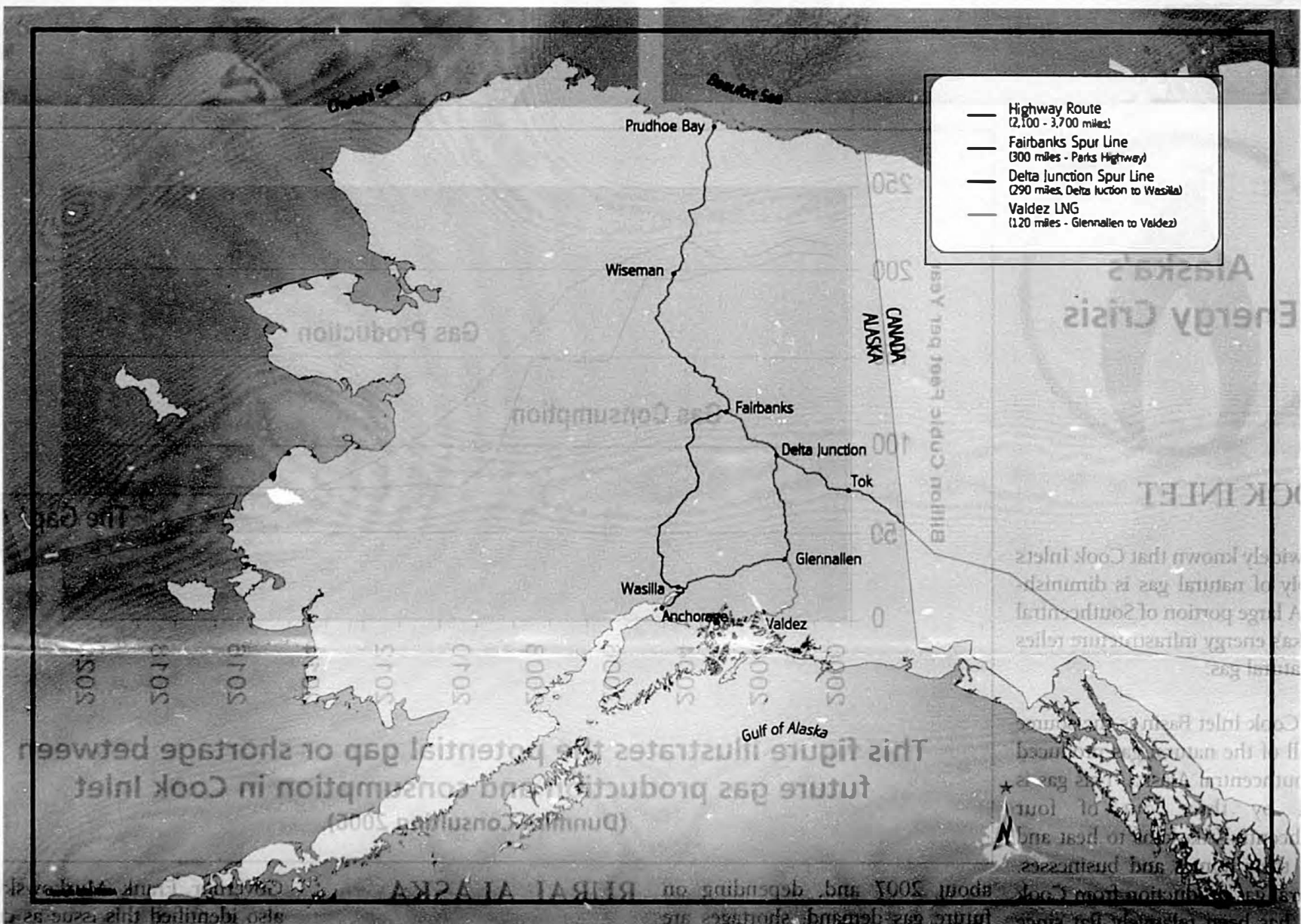
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By Harold Heinze, ANGDA CEO  
& Delma Bratwold, SAIC



# Connecting Alaskans to their Natural Gas

November 2008



## IDEAS TO SOLVE ALASKA'S ENERGY CRISIS

### A Progress Report by the Alaska Natural Gas Development Authority (ANGDA)

This report is an update of the continuing work by the Alaska Natural Gas Development Authority to bring North Slope natural gas to market and Alaskans.

Like oil on the North Slope that was brought to market through a pipeline, there are plentiful supplies of natural gas in Alaska's Arctic that need a pipeline. That gas also is the

key to solving Alaska's energy crisis. Alaskans have felt the impact of higher energy prices over the last two years. Getting North Slope natural gas to the Yukon River, Fairbanks, the Cook Inlet region and a tidewater port allows all Alaskans to share this long-term energy supply.

#### ESTABLISHMENT OF AUTHORITY

ANGDA was created by the People of Alaska through a 2002 General Election Ballot Initiative and is a public corporation (much like the Permanent Fund or Alaska Railroad). With the


support of the Legislature and the Administration, ANGDA started work in 2003 within the Alaska Department of Revenue.

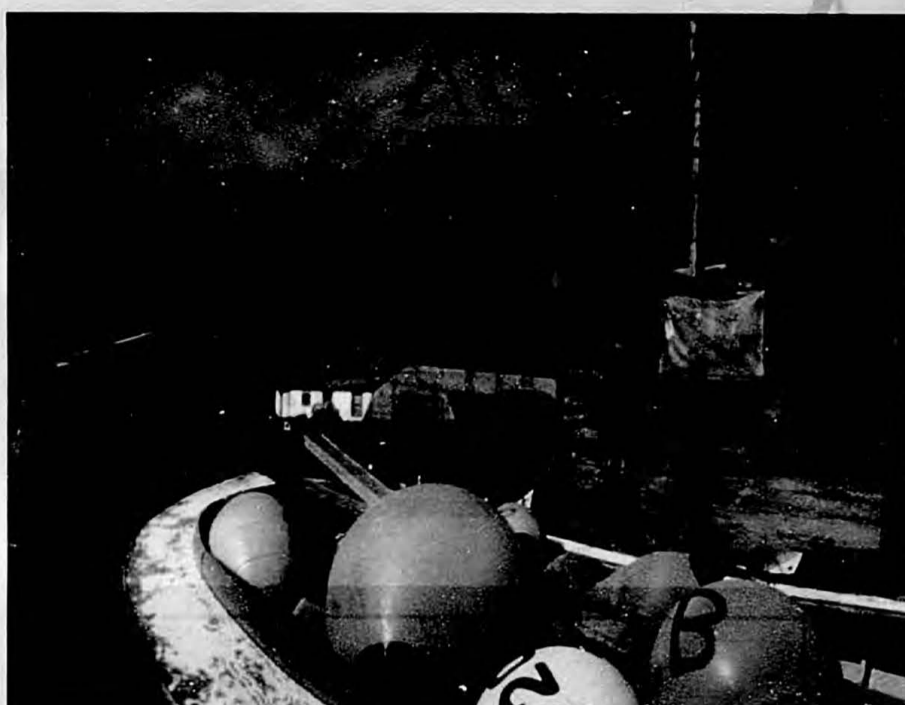
#### ALASKA STATUTE 41.41

Under State law, ANGDA has the authority to facilitate the planning, design and construction of a natural gas pipeline (together with all related property and facilities) extending from Prudhoe Bay to tidewater on Prince William Sound or Cook Inlet with a spur pipeline to the Southcentral gas distribution system. ●



"This first major step toward a connecting gas pipeline will assure the availability of Alaska's gas for generations to come." —Harold Heinze, ANGDA Chief Executive Officer, referring to ANGDA's conditional right-of-way lease.

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	3 Energy Alternatives	7 Status of Alaska Gas Pipeline Project(s) & In-State Gas Use	
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DEPARTMENT OF COMMERCE, COMMUNITY, AND ECONOMIC DEVELOPMENT



## Alaska's Energy Crisis

### COOK INLET

It is widely known that Cook Inlet's supply of natural gas is diminishing. A large portion of Southcentral Alaska's energy infrastructure relies on natural gas.

The Cook Inlet Basin is the source for all of the natural gas produced in Southcentral Alaska. This gas is used by three out of four Southcentral Alaskans to heat and light their homes and businesses. Natural gas production from Cook Inlet has been relatively flat since its peak production in 1998. Production forecasts for Cook Inlet show a steep decline starting in

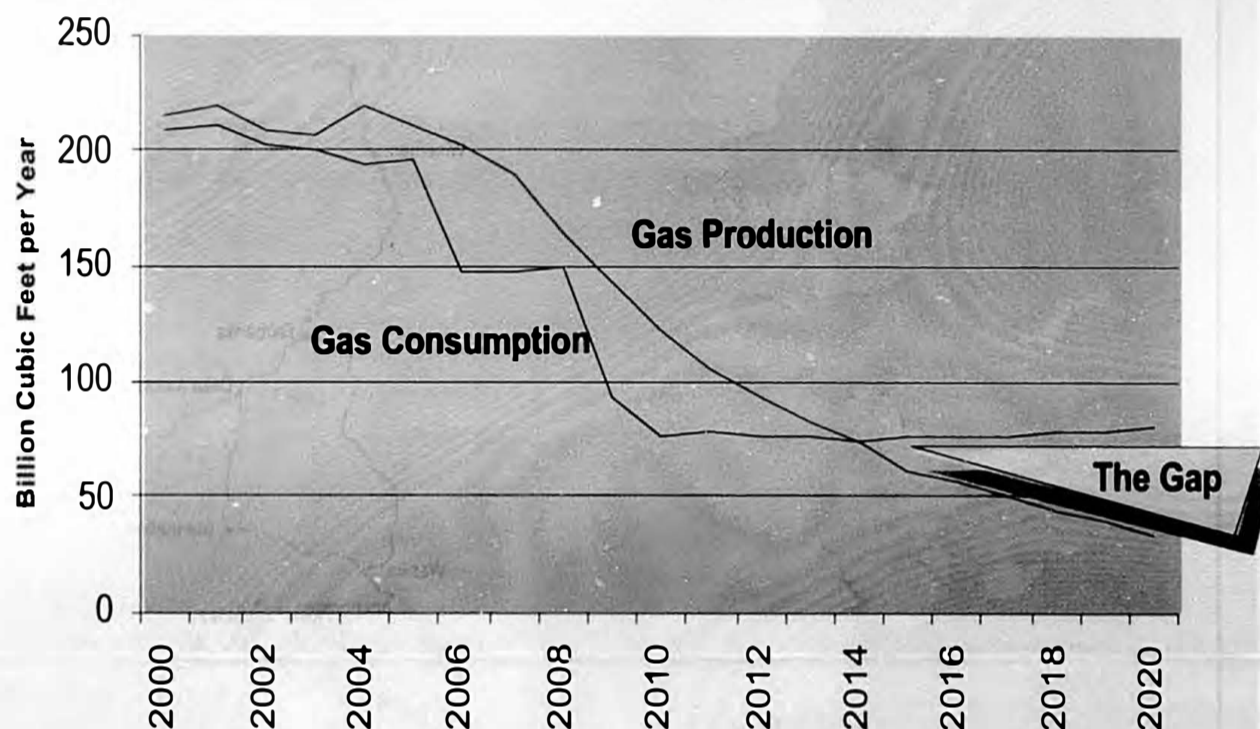


### Voices

*"Alaska is at a crossroads as it faces the need to find solutions to a very serious energy crisis in many of our villages across the state. New thinking is needed to prepare ourselves for ever increasing energy costs in both our smaller and larger communities."*

*"If we do not find answers soon, we will have more of our industries closing down as we see Agrium doing in the Kenai area. We have a large menu of alternatives to evaluate and it is imperative that we come to grips with the reality of our collective energy challenges."*

Nels Anderson  
Alaska Energy Policy Advisor  
Dillingham, Alaska



**This figure illustrates the potential gap or shortage between future gas production and consumption in Cook Inlet (Dunmire Consulting 2006).**

about 2007 and, depending on future gas demand, shortages are expected six to eight years later.

The above figure illustrates the potential gap or shortage between future gas production and consumption in Cook Inlet.

This year, users of natural gas like Agrium's Kenai nitrogen facility have had to curtail their use or shut down. Enstar Natural Gas Co. says in a few years there may not be enough natural gas supplies to hook up new neighborhoods in Southcentral Alaska. Further, in coming years there may not be enough gas to maintain pressure in Cook Inlet's natural gas distribution pipeline system. One of the major electric co-ops wants to replace an old generator but it doesn't have enough gas reserves for bankers to loan the money. It is for reasons like these that Southcentral is on the brink of an energy crisis if new Cook Inlet supplies are not found soon.

### RURAL ALASKA

Energy in rural communities is increasingly expensive and Alaska villages have been hit hard by rising fuel costs.

According to the University of Alaska Fairbanks, fuel costs in rural Alaska have reached extreme highs and the effects are far-reaching. High gasoline prices impact the price of food, heat and subsistence practices, and in some cases affects such basic needs as water delivery.

In some situations, several village families are living together to share heating costs because they cannot afford to heat their own homes.

Unfortunately, due to the high cost of energy in rural Alaska, the choice for many Native Alaskans to stay on the lands where their ancestors lived is increasingly unsustainable. The Alaska Federation of Natives has recognized that the energy situation is impoverishing many native communities and forcing them to relocate to urban areas.

Governor Frank Murkowski has also identified this issue as critical saying, "without a doubt, the number one concern in rural Alaska right now is the high cost of energy." To help solve Alaska's rural energy problems, on October 19, 2006, the Governor appointed long-time Native leader Nels Anderson of Dillingham as Alaska Energy Policy Advisor to lead the efforts in reducing energy costs in Alaska's rural communities. ●



### Voices

*"It was my intention for ANGDA to help bring North Slope gas to market. I am pleased today that ANGDA is also solving Alaska's energy crisis."*

Scott Heyworth  
Vice Chairman, ANGDA  
Board of Directors  
Prime Sponsor, Ballot  
Measure 3 in 2002 General  
Election



DEPARTMENT OF COMMERCE, COMMUNITY, AND ECONOMIC DEVELOPMENT



An energy alternative is defined as any action, program or project that could be implemented to meet future energy demand. There are both SUPPLY and DEMAND alternatives.

Demand alternatives reduce demand for natural gas while supply alternatives increase natural gas supplies.

	Alternative	Description
<b>Supply</b>	<b>Increase Production</b>	Enhance existing gas production and develop new production in Cook Inlet.
	<b>Spur Line</b>	Deliver North Slope gas to Cook Inlet with spur pipeline from a main gas pipeline.
	<b>Bullet Line</b>	Deliver North Slope gas to Cook Inlet with direct Bullet Line.
	<b>Enriched Gas Line</b>	Additional natural gas liquids (NGLs) delivered to Cook Inlet via pipeline.
	<b>CBM</b>	Develop Coal Bed Methane in Susitna Basin.
	<b>Import LNG</b>	Import Liquefied Natural Gas from outside to existing Kenai LNG facility.
	<b>Other Alaska Gas</b>	Develop and deliver gas from Copper River, Bristol Bay or Nenana basins.
<b>Demand</b>	<b>Coal Gasification</b>	Implement coal gasification such as Agrium's Blue Sky Project.
	<b>Coal Power</b>	Replace gas-fired electric generation with coal-fired power (Emma Creek).
	<b>Hydro Power</b>	Replace gas-fired electric generation with small-scale hydro power.
	<b>Wind Power</b>	Replace gas-fired electric generation with wind power (Fire Island Project).
	<b>Nuclear Power</b>	Replace gas-fired electric generation with small-scale nuclear power.
	<b>Tidal Power</b>	Replace gas-fired electric generation with tidal power.
	<b>Gas Conservation</b>	Implement end-use gas conservation programs (weatherization, efficiency).
	<b>Electric Conservation</b>	Implement end-use conservation programs (appliance & light bulb upgrade).
	<b>Distributed Generation</b>	Implement small-scale electric generation including cogeneration and fuel cells at point-of-use to displace central gas-fired electric generation.

**Wind Farm - Kotzebue, Alaska**



**Power Creek Hydroelectric Project - Cordova, Alaska**

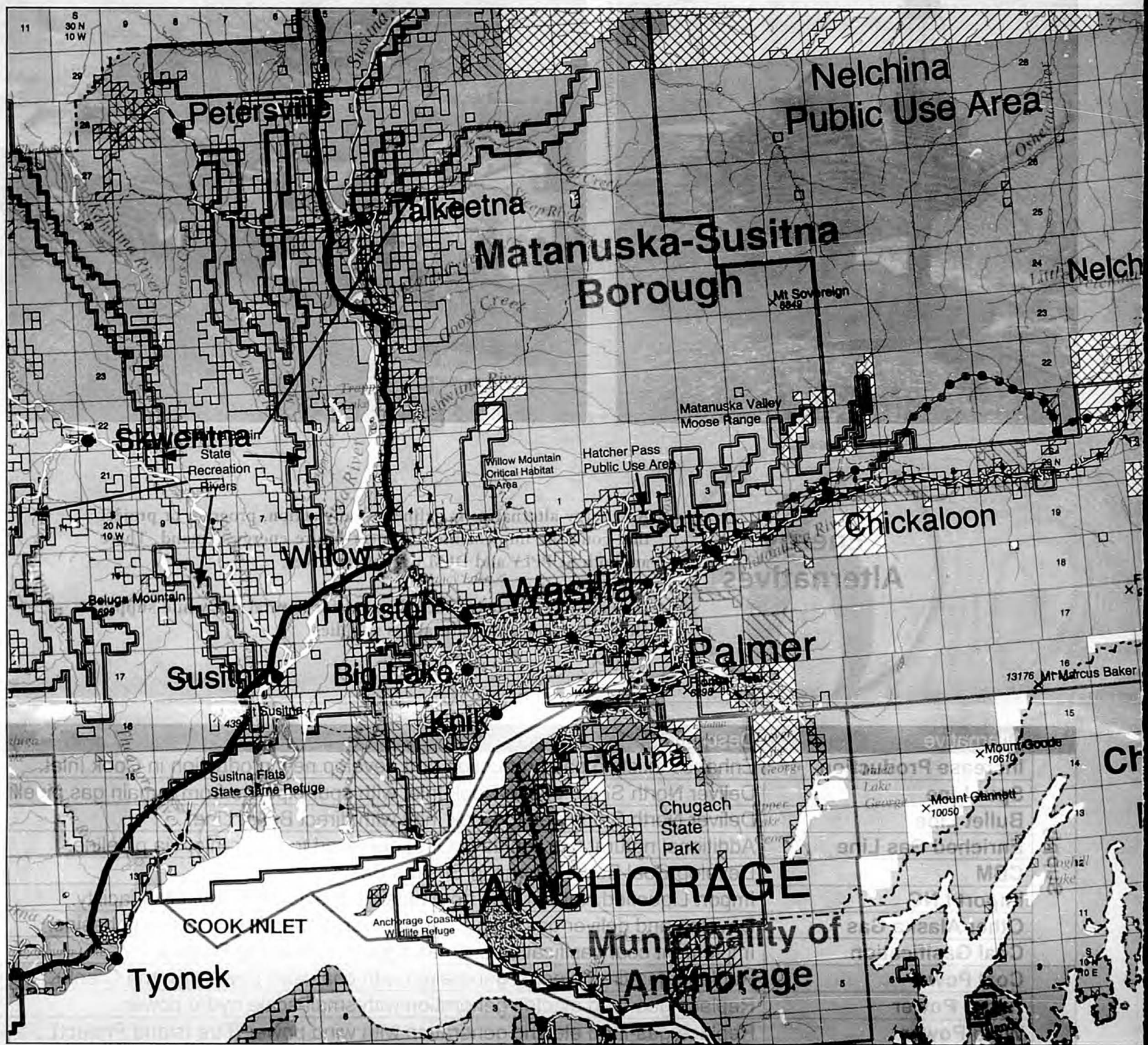


**Bradley Lake Hydroelectric Project - Kenai Peninsula**



HOMER ELECTRIC ASSOCIATION

# Natural Gas Spur



## Voices

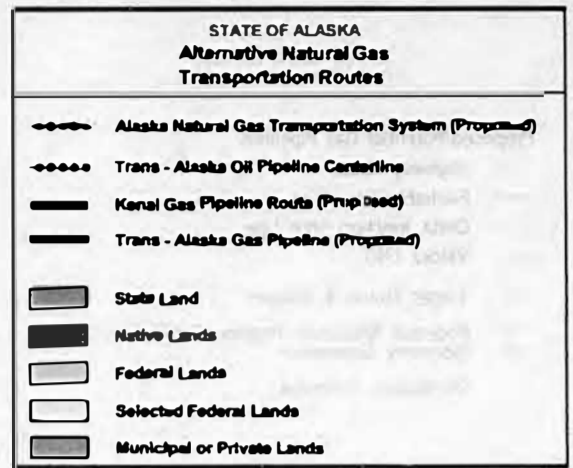
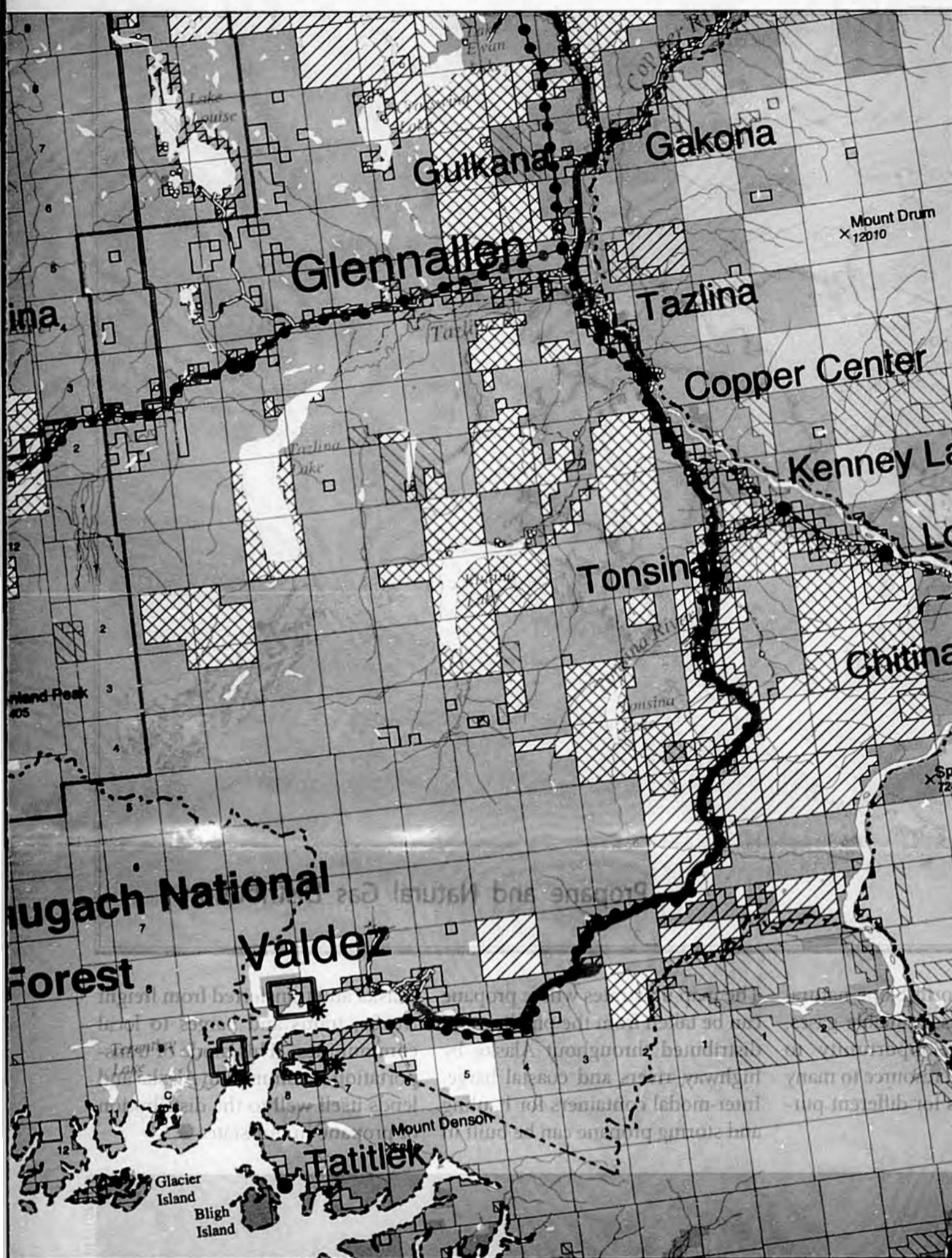
"I have been involved in several controversial utility and natural resource development issues that directly affected the residents of the Matanuska-Susitna Borough over the last decade. I have been impressed with the effort ANGDA has put forth to reach out to residents and local communities that would be affected by their project.

When the project was first proposed they immediately arranged for meetings with local citizens, community organizations and user groups of the land and resources along the proposed route of the pipeline. Since the project's inception they have met with groups at their convenience and whenever requested. Many of the local residents and small communities were skeptical and at times hostile towards what they viewed as a threat towards their chosen lifestyle. Mr. Heinze and the staff of ANGDA took the time to personally attend those meetings, listened to the concerns, and openly discussed ways to mitigate concerns and impacts. This was all done in a positive way, and that kept the proposed project moving forward.

Most of the public outreach they willingly participated in was beyond what was required by law. Their willingness to engage the local citizens and users in a meaningful dialog went a long way towards building trust in the community that their concerns were being addressed. ANGDA has set a standard for other utility companies, natural resource development and utilization companies to use as an example."

Ron Swanson  
Community Development Director  
Matanuska-Susitna Borough

# Alternative Pipeline Routes



## • Delta Junction to Glennallen to Palmer

This route follows the Trans Alaska Pipeline System (TAPS) oil pipeline from Delta Junction to Glennallen; and from there generally follows along the Glenn Highway to Palmer.

## • Fairbanks to Palmer

This route generally follows the Parks Highway corridor from Fairbanks to Palmer.

A U.S. Dept. of Energy feasibility study currently underway has not identified any significant difference between the routes in delivery costs, hazards, wildlife impacts, socio-economic benefits, or permitting/right-of-way conditions.

Two viable pipeline routes (also known as spur pipelines) are being studied to bring North Slope natural gas to the Southcentral region of Alaska. They will connect with the proposed major gas pipeline project(s).

At 24" in diameter, either spur pipeline would tie in to the much larger diameter main pipeline (48" plus). Each route is approximately 300 miles long; will cost approximately \$1B (one billion dollars); and will generate approximately 600 construction jobs over a two year period. ANGDA was granted a "conditional right-of-way lease" from the

Alaska Department of Natural Resources in July 2006 for the Glennallen-to-Palmer segment.

Governor Frank H. Murkowski said the Department of Natural Resources' conditional right-of-way lease demonstrates the state's confidence that ANGDA can eventually build a critical part of Alaska's Gas Pipeline system. ●



"Providing in-state access to the gas is one of the six fundamental principles I followed in negotiating a natural gas pipeline contract. This right of way is one of the options available to us to fulfill my commitment to get Alaska's gas to the people, and I am very pleased to see ANGDA obtain its lease." —Governor Murkowski, referring to the Glennallen-to-Palmer Conditional Right-of-Way Lease granted to ANGDA in July 2006.

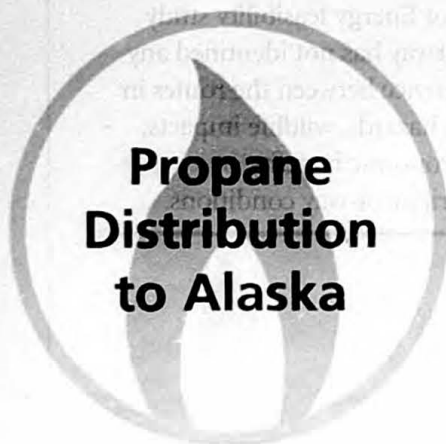
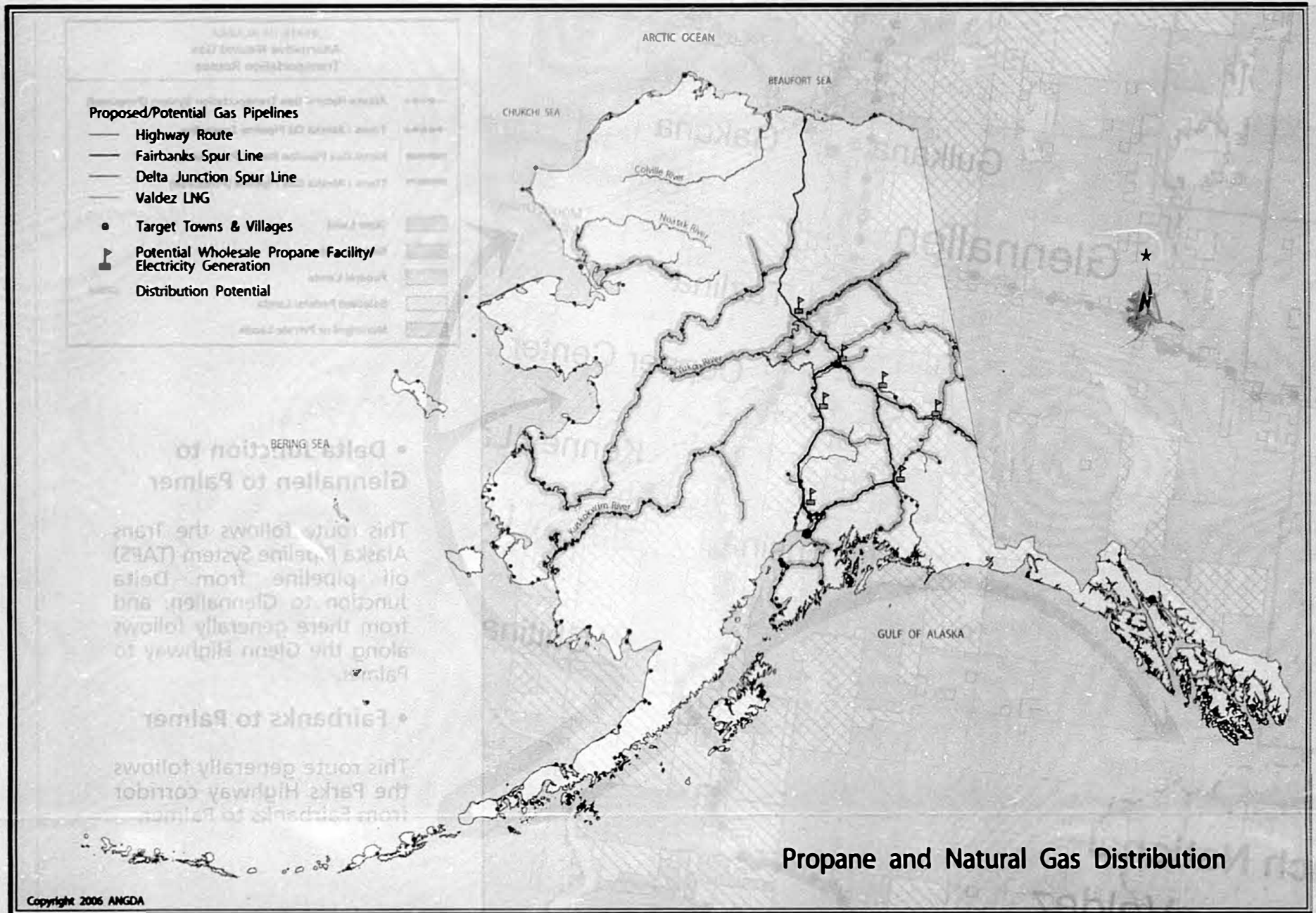
## Voices

*"This lease lays the foundation for a gas pipeline that, when constructed, will bring the benefits of reliable, affordable natural gas and propane to businesses and residents in Southcentral Alaska, the Kenai Peninsula, and rural and coastal communities throughout the state."*

Commissioner Michael Menge  
Alaska Department of Natural Resources

# North Slope Natural Gas

## An abundance of energy for generations

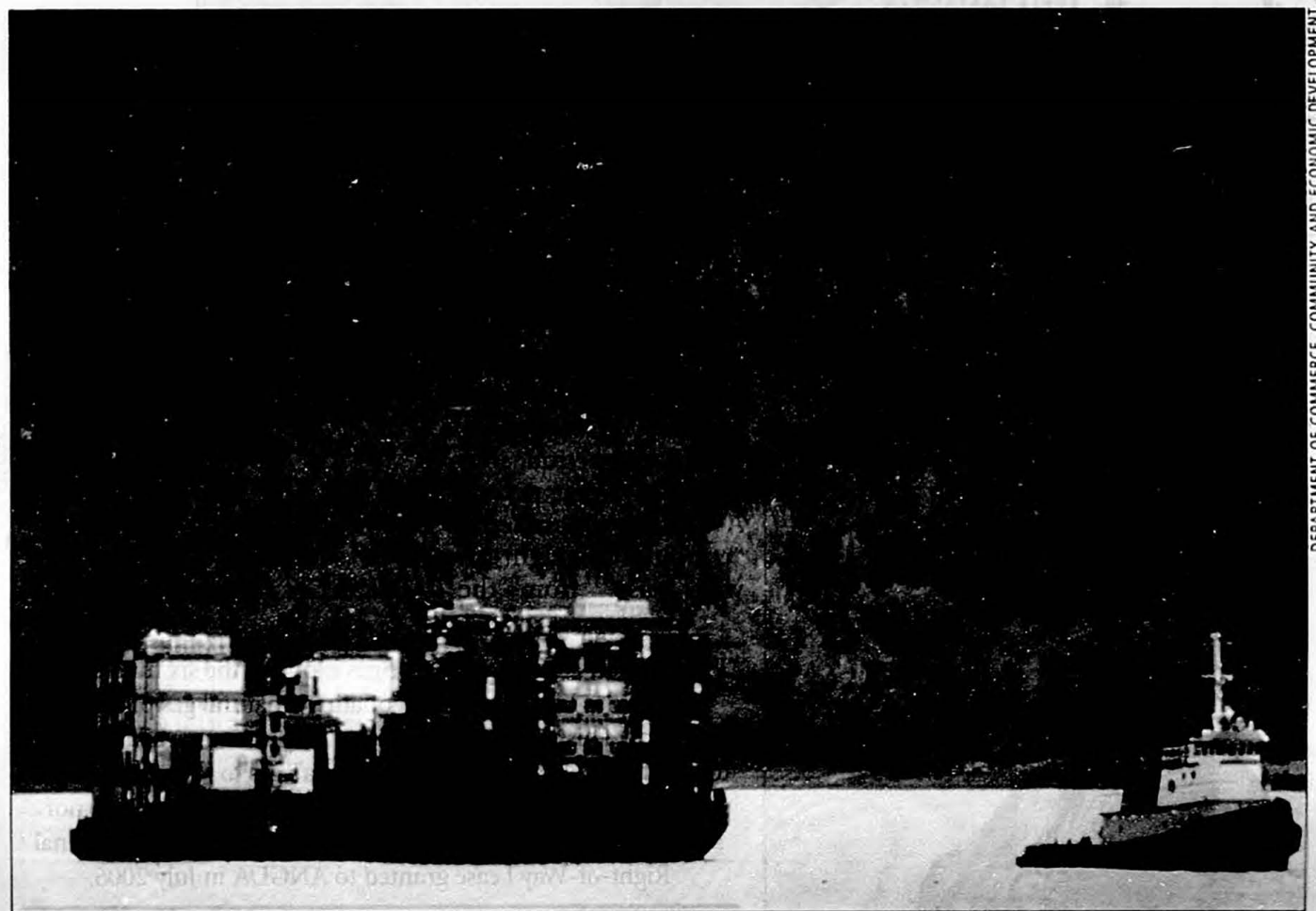


Since Alaska's North Slope natural gas contains these valuable gases, Alaska has the opportunity to bring this natural resource to many different markets for different purposes.

The map illustrates where propane can be taken from the pipeline and distributed throughout Alaska by highway, rivers and coastal barge. Inter-modal containers for hauling and storing propane can be built in

Alaska and transferred from freight trucks, trains and barges to local communities. This mode of transportation is common in Alaska and lends itself well to the distribution of propane in our state. ●

Alaska's North Slope gas is more than just methane. In particular, it contains large amounts of propane that can be used for heating, cooking, clothes drying and generating electricity.





TRANSCANADA PHOTOGRAPH © 2006

## Status of Alaska Gas Pipeline Project(s) & In-State Gas Use

### FEDERAL GOVERNMENT

In September 2004, the federal government (with the help of Senator Ted Stevens, Senator Lisa Murkowski, and Congressman Don Young) passed legislation providing an \$18B loan guarantee for a natural gas pipeline project. The federal government is encouraging Alaska to finalize a pipeline contract soon as the law permits "federalization" of the project. It is increasingly important for Alaska to conclude its gas pipeline contract(s) as both the market and the federal government cannot wait much longer.



### Voices

*"The information that has been gathered through the ANGDA studies will be an invaluable asset for the state as we move toward full evaluation of competing gasline projects. I appreciate the way the ANGDA leadership has worked with communities and business interests to assess in-state needs."*

Senator Gene Therriault, North Pole/Valdez/Richardson Highway

During the summer of 2006, Drue Pearce was appointed by President George W. Bush as Federal Coordinator for the Alaska Pipeline Transportation Project (Alaska Gas Pipeline). Federal studies are currently under way to determine the status of Alaska's gas pipeline project.

### STATE GOVERNMENT

In May 2006, the State of Alaska concluded negotiations with three oil and gas producers (BP, ConocoPhillips, ExxonMobil) for a large natural gas pipeline from Prudhoe Bay through Canada to the midwestern United States. The draft fiscal contract was released by the Alaska Department of Revenue to the public and the State Legislature for review and comment. On October 20, 2006, Revenue Commissioner William Corbus released a summary of comments and responses to public input and subsequent revisions to the gas pipeline draft fiscal contract.

During 2005/2006, ANGDA worked with the Regulatory Commission of Alaska (RCA) to amend statutory regulations that will simplify the in-state acquisition and use of North Slope natural gas. After a public hearing, ANGDA's recommendations were accepted by the Commission and transmitted to the Governor's Office for legislative consideration.

State efforts to make North Slope natural gas available for in-state use by Alaskans took a giant step forward in July 2006 with the Department of Natural Resources' approval of a conditional right-of-way lease to ANGDA for a gas pipeline from Glennallen to Palmer.

ANGDA determined that a main large-diameter, high-pressure natural gas pipeline will carry several hundred thousand barrels of ethane, propane, and butane per day. Extracting the State's share of these gases (also known as NGLs or natural gas liquids) and shipping them in the spur pipeline to tidewater will facilitate a petrochemical industry and LPG (propane) delivery to rural, urban, coastal and river communities of Alaska. The use of NGLs in our state provides business and job opportunities for Alaska, in addition to vital energy sources.

### "OPEN SEASON"

"Open season" is the process by which companies bid on how much North Slope natural gas they want to transport through the pipeline or how much gas they want to purchase at an off-take point along the pipeline route. The "open season" commitments that companies make are the basis for designing and financing the pipeline.

The Federal Energy Regulatory

Commission (FERC) handles the "open season" process for the pipeline transporting Alaska's natural gas to the lower-48 states. The Regulatory Commission of Alaska (RCA) is in charge of the in-state "open season" for natural gas transported through pipelines within Alaska.

During the "open season," bidders must negotiate and commit to multiple-year contracts on a "take-or-pay" or "ship-or-pay" basis. That is, once a bid becomes a contract, the company is firmly obligated to either ship or take the gas they signed up for, or pay for it regardless. There will be contracts for supply (or shipping) and demand (users of natural gas like utility companies).

For Alaska utilities, these commitments to buy and ship natural gas over long periods of time will be very large compared to their financial strength. ANGDA will work with the utilities in preparing for these important decisions and possible future financial support needs. ●



DEPARTMENT OF COMMERCE, COMMUNITY, AND ECONOMIC DEVELOPMENT

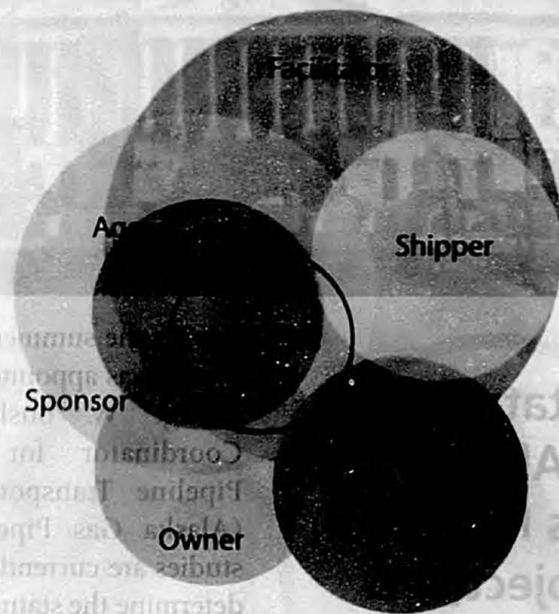


## The Way Forward

ANGDA's challenge is to assure that an abundant supply of relatively low-cost natural gas energy is delivered to Alaskans.

### ANGDA can play many different roles in accomplishing its mission.

Facilitator	Internal project coordination focused on understanding and meeting needs of participating entities.
Sponsor	External project coordination including public process management, government relations, and stakeholder engagement.
Financier	Spur pipeline or other project financing ranging from providing a Letter of Credit to taking an equity position.
Aggregator	Accumulating demand from smaller buyers for purchasing natural gas on the North Slope and potentially aggregating shipping commitments for the spurline and/or main pipeline.
Shipper	Commitment to transport gas through spurline and/or main pipeline.
Owner	Hold deed to spur pipeline or other infrastructure.
Operator	Contract to operate the spur pipeline or other infrastructure.



At this moment Alaska is poised to transition to a new governor. ANGDA's roles will be set by the new administration and the decisions it makes on the major North Slope natural gas pipeline project.

### ANGDA's work plan includes

- Developing the information required for permitting and financing a spur pipeline.
- Demonstrating the feasibility of propane extraction facilities and logistical systems.
- Preparing local utilities to participate in the "open season" process of the major gas pipeline.
- Coordination with the full range of federal and state agencies to assure that Alaska's gas is brought to market for the maximum benefit of Alaskans.



ANGDA Board of Directors

From left to right: Robert Stinson, John T. Kelsey, Scott R. Heyworth (Vice-Chair), Harold Heinze (CEO), Andy Warwick (Chair), Daniel A. Sullivan (Not pictured: David W. Cuddy, Robert C. Favretto)



#### Call or visit

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[www.angda.state.ak.us](http://www.angda.state.ak.us)

This publication was produced by the Alaska Natural Gas Development Authority (ANGDA) and published in Anchorage, Alaska at a cost of \$0.20 per copy to provide information to the public about the Alaska Natural Gas Pipeline Project(s). This notice is provided in accordance with AS 44.99.210

This report was prepared by Harold Heinze and Corrie Young of ANGDA. Thank you to Dan Wilcox and Tom Kearney of Petroleum News and Marilyn Phymire for their coordination.

WORK DRAFT

ANGDA 6-20-2008  
Friday

presented by H. Heinzl  
(C. Huggins - reg. "two chairs"  
of Judiciary Emtees take up  
this issue)

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.

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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).<sup>1</sup> We held a public hearing on ANGDA's proposed statutory revisions on September 8, 2005.

<sup>1</sup>Order P-05-10(1), *Order Scheduling Public Hearing and Requesting Comments*, dated August 29, 2005.

P-05-10(2) - (3/15/2006)  
Page 2 of 3

300 West Eighth Avenue, Suite 300  
Regulatory Commission of Alaska

**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.

# STATE OF ALASKA

DEPARTMENT OF COMMERCE  
COMMUNITY AND ECONOMIC DEVELOPMENT  
REGULATORY COMMISSION OF ALASKA

FRANK H. MURKOWSKI, GOVERNOR

701 WEST EIGHTH AVENUE, SUITE 300  
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PHONE: (907) 276-6222  
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WEBSITE: [www.state.ak.us/rca/](http://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 ANGDA 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.

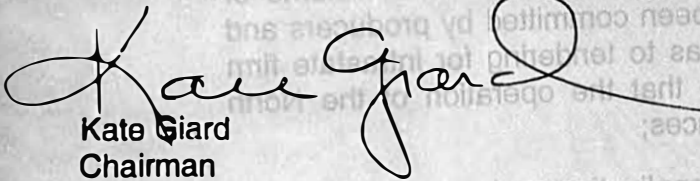
ANGDA submitted a filing documenting the legislative history of the provisions it seeks to repeal. ANGDA also submitted the remarks of former Alaska Attorney General Charlie Cole on this subject at a July 28, 2004 Legislative Budget and Audit Committee hearing on stranded gas. In those remarks General 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.

AS 42.06.350(c)

AS 42.06.350(b)

# STATE OF ALASKA

DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

FRANK H. MURKOWSKI, GOVERNOR

1031 WEST 4<sup>TH</sup> AVENUE, SUITE 200  
ANCHORAGE, ALASKA 99501-5913  
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. MARQUEZ  
ATTORNEY GENERAL

By: 

Alan Bimbaum  
Assistant Attorney General

AB/drj  
Enclosure

cc: Harold Heinze  
Steve Pratt

REC'D  
R.C. APT  
OCT 19 11 14:27

<b>Legislative History of AS42.06.240(f) &amp; AS42.06.370(c) (HB 290 - 56 SLA 2000)</b>
<b>Chapter 56 SLA 2000</b>
<b>Bill History/Action</b>
<b>Bill Versions</b>
A. House Bill No. 290
B. House Bill No. 290 (O&G)
C. House Bill No. 290 (RES)
D. House Bill No. 290 (FIN)
<b>Committee Minutes</b>
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
<b>Committee Bill Files (Printed from Microfiche)</b>
<b>Recorded Cassette Tapes - Committee Hearings (Total 12 Tapes - not included in binder located in DOL Oil, Gas &amp; Mining Section)</b>
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

Regulatory Commission of Alaska  
701 West Eighth Avenue, Suite 300  
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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

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.<sup>1</sup>

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

<sup>1</sup> 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

R-05-11(1) - (12/2/05)  
Page 2 of 3

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

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

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

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

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

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

# STATE OF ALASKA

FRANK H. MURKOWSKI, GOVERNOR

## ALASKA NATURAL GAS DEVELOPMENT AUTHORITY

411 WEST 4TH AVENUE  
ANCHORAGE, ALASKA 99501  
TELEPHONE: (907) 257-1347  
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 27<sup>th</sup> 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 public interest determination the RCA might make with respect to any particular 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 utilize 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.

ANGDA

*"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 ..."***



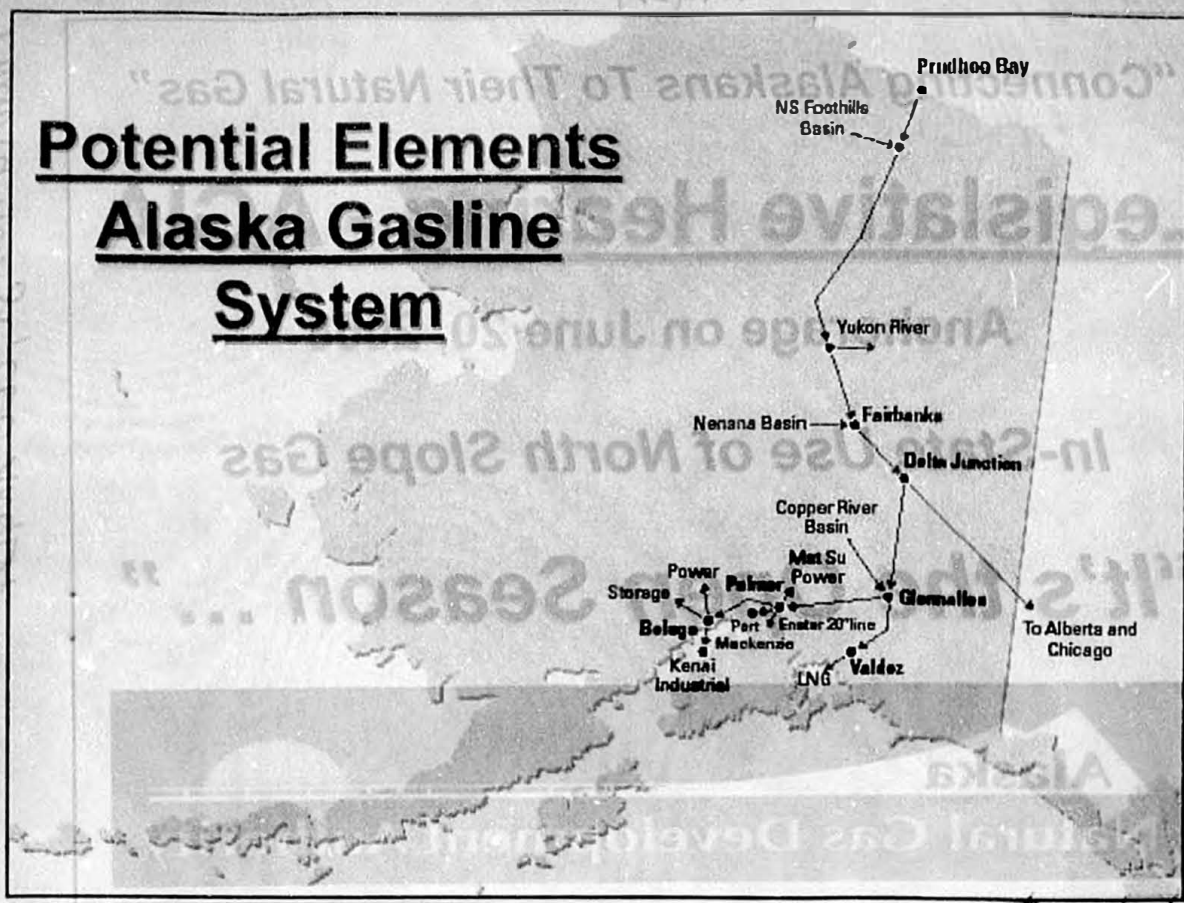
presented: Friday 6-20-2008 Anch, AK. Howard Johnson  
by 9:00 AM  
Harold Henry, CEO ANGDA  
Playa

### **In-State Gas Issues**

- **ANGDA "Spur Line" from Delta Junction to Beluga via Glennallen (370 miles of 20")**
- **Alaska utility gas needs (250 mmscfd) & 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**

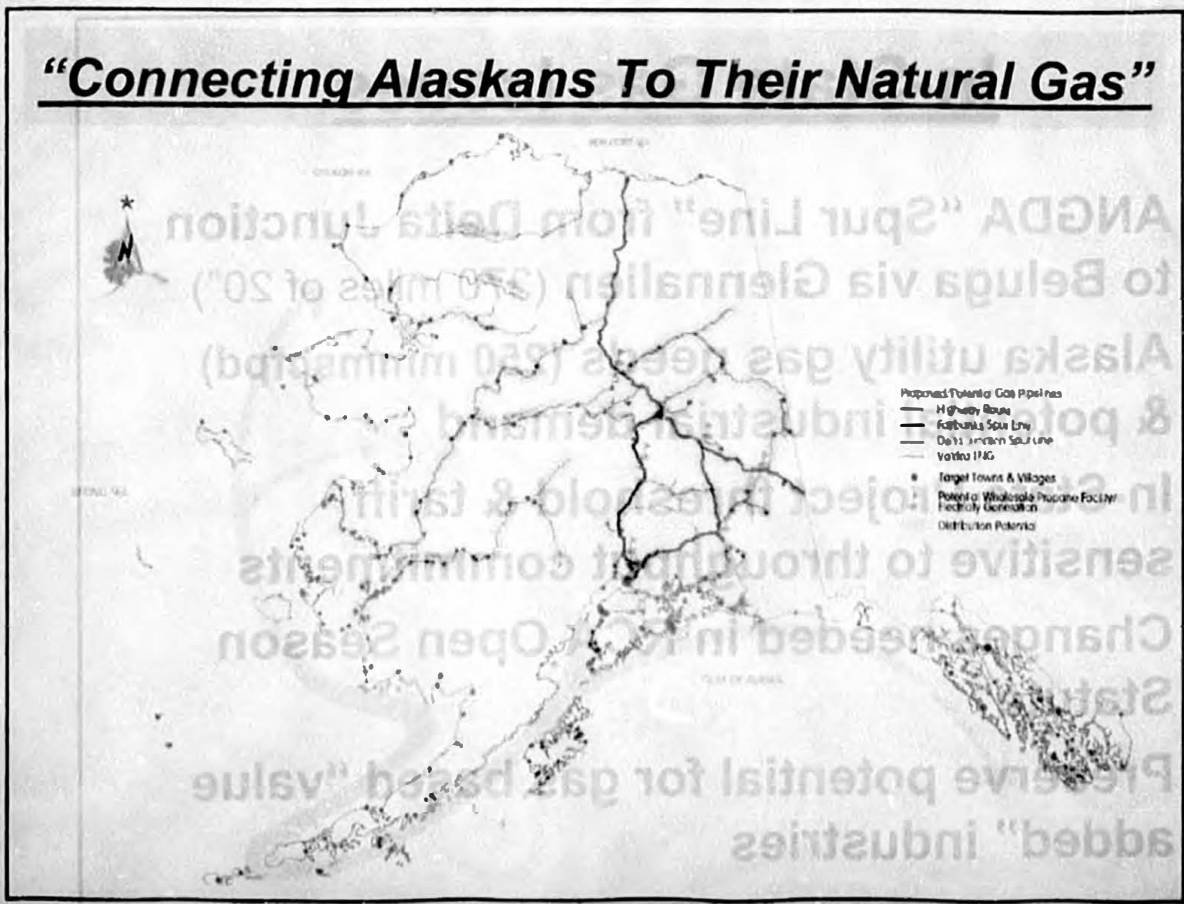
Assessment: February 15, 2008  
 410 NM  
 Alaska Dept. of Natural Resources

# Potential Elements Alaska Gasline System



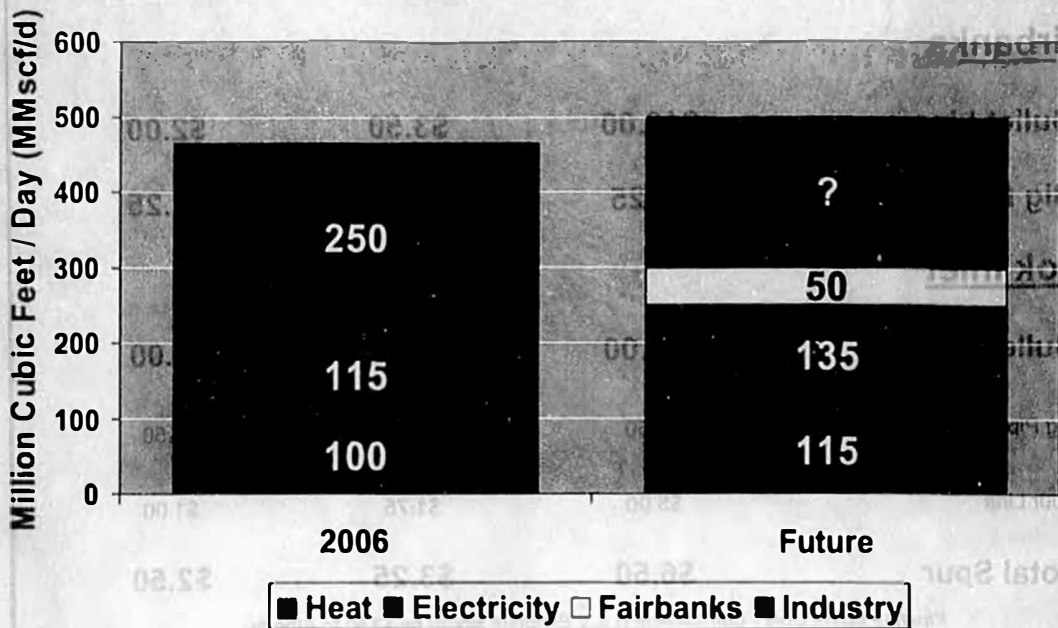
map represents what might exist 20-25 yrs from now.

## "Connecting Alaskans To Their Natural Gas"



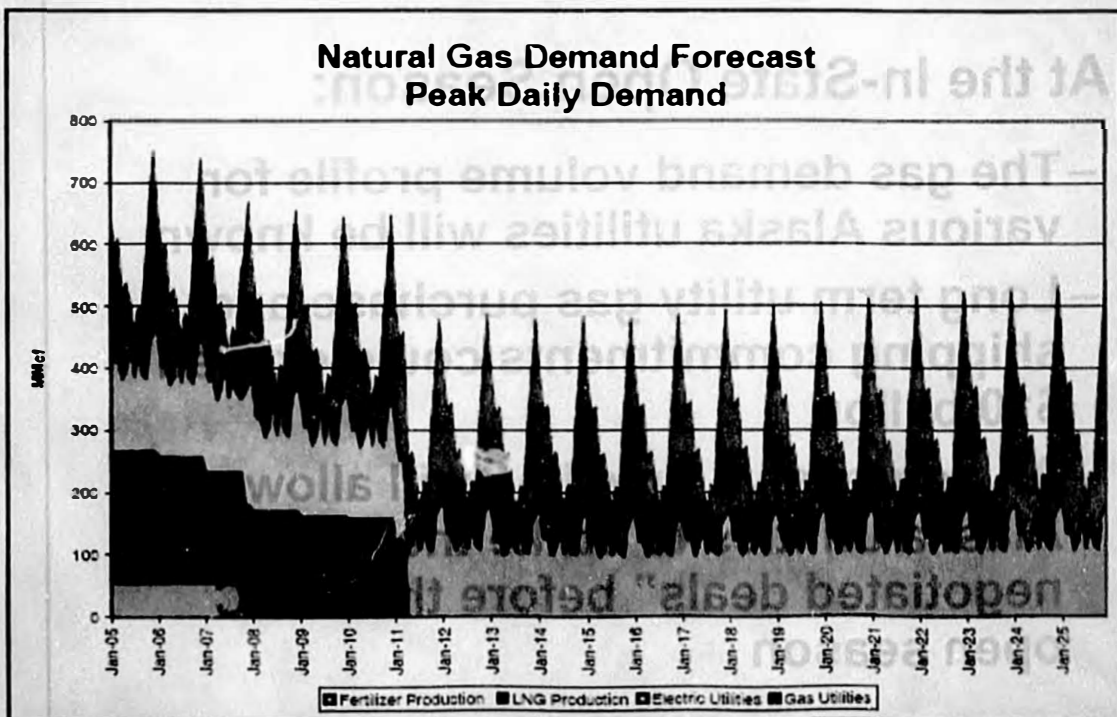
Summer  
 2008 road  
 season  
 Glennallen  
 to  
 Palmer  
 to  
 Beluga

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



*million cubic ft / day use*

## Peak Daily Demand



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

	<u>100</u> mmscfpd	<u>250</u> mmscfpd	<u>500</u> mmscfpd
<b><u>Fairbanks</u></b>			
Bullet Line	\$10.00	\$3.50	\$2.00
Big Pipe	\$1.25	\$1.25	\$1.25
<b><u>Cook Inlet</u></b>			
Bullet Line	\$15.00	\$5.25	\$3.00
Big Pipe	\$1.50	\$1.50	\$1.50
Spur Line	\$5.00	\$1.75	\$1.00
<b>Total Spur</b>	<b>\$6.50</b>	<b>\$3.25</b>	<b>\$2.50</b>

*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

presented: 6-20-2008 by ANGDA

Friday  
Anch. AK

Harold Heinze, CEO  
& Delma Bratvold, SAIC

## ALASKA STATE LEGISLATURE

**Chair:**  
Special Committee on Economic Development,  
Trade, & Tourism

**Vice Chair:**  
Committee on Labor and Commerce

**Vice Chair:**  
Committee on Transportation

**Member:**  
Committee on Community and Regional Affairs  
Committee on Oil & Gas



**Session:**  
Alaska State Capitol  
Juneau, AK 99801-1182  
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Fax: (907) 465-4822  
Toll Free (877) 465-2679

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600 E. Railroad Ave  
Wasilla, AK 99654  
Phone: (907) 376-2679  
Fax: (907) 376-4745

### REPRESENTATIVE MARK NEUMAN

Representative\_Mark\_Neuman@legis.state.ak.us

December 4, 2007

Harold Heinze  
Executive Director  
Alaska Natural Gas Development Authority

Dear Mr. Heinze,

As Chairman of the House Special Committee Economic Development, Trade, and Tourism and a member of the House Oil & Gas Committee, it would be prudent to understand Alaska's potential for a value added industry by processing gas from Alaska's North Slope.

The legislature will consider proposals under AGIA during this next legislative session. I believe it is important to have this information in determining what the maximum economic benefit is as required by our states' constitution. I would like to have the information by February so I can schedule hearings on this issue early in the session.

I would appreciate an analysis that would present the following information:

- the gas composition and volume available under the various AGIA proposals
- the potential products which can be made with these volumes
- a basic description of the physical plant necessary to process these volumes
- the range of prices paid for these feedstock in other jurisdictions
- the number of jobs that could be generated under the various scenarios
- the major markets for these products
- possible location of processing plants in Alaska
- the gross revenues that would be generated from sales of these products
- potential favorable backhaul shipping rates from current Alaskan shippers and vessels on the great circle route
- other information not requested but pertinent to the scope of this request

Please advise me if you are able to complete such an analysis and what the time frame for completion would be.

Thank you for your attention to this matter.

Handwritten signature of Mark Neuman.

Representative Mark Neuman  
Chairman



# Alaska Natural Gas Needs & Market Assessment Update Presentation

Presented in Anchorage on June 20, 2008

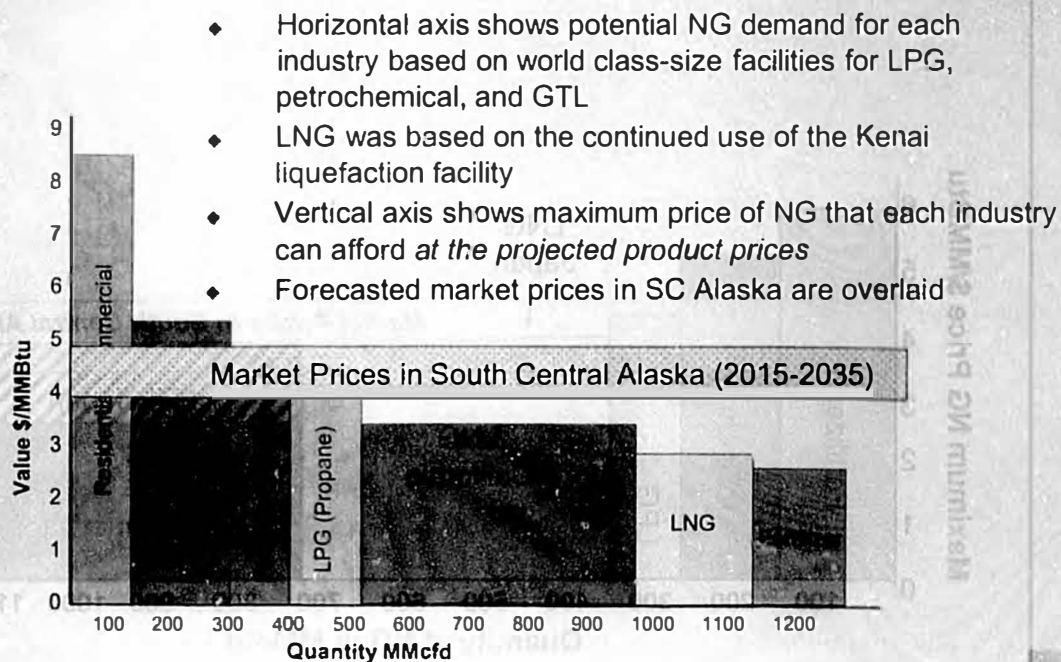
Alaska Legislature



## Sectors Studied

- ◆ Industry
    - LNG
    - GTL
    - Ammonia / Urea
    - Other
    - Petrochemicals
    - Propane
  - ◆ Power Generation
  - ◆ Residential / Commercial
- } DRY GAS
- } NGLs
- } DRY GAS

## 2006 Study Findings: Base Price Scenario



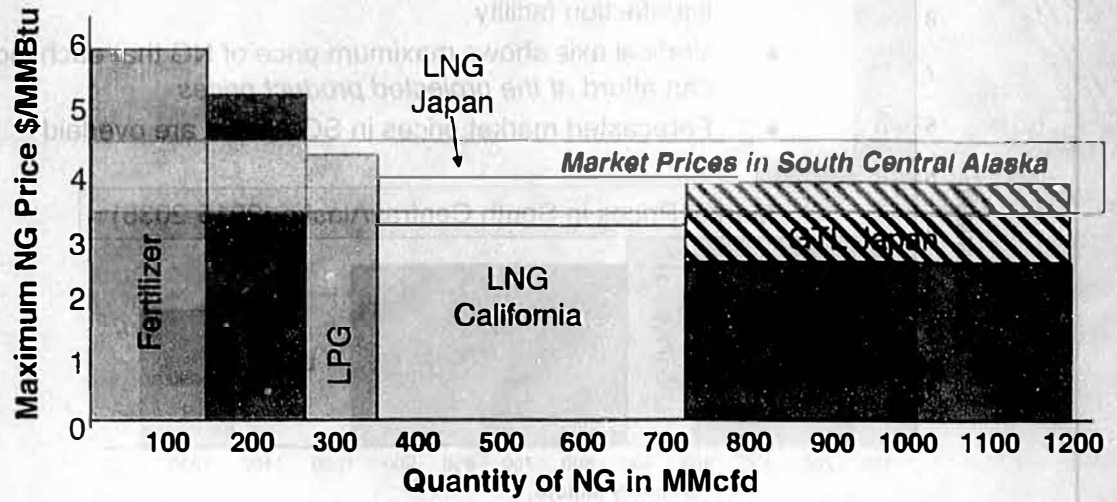
2

## Average Product Price (2015 – 2030)

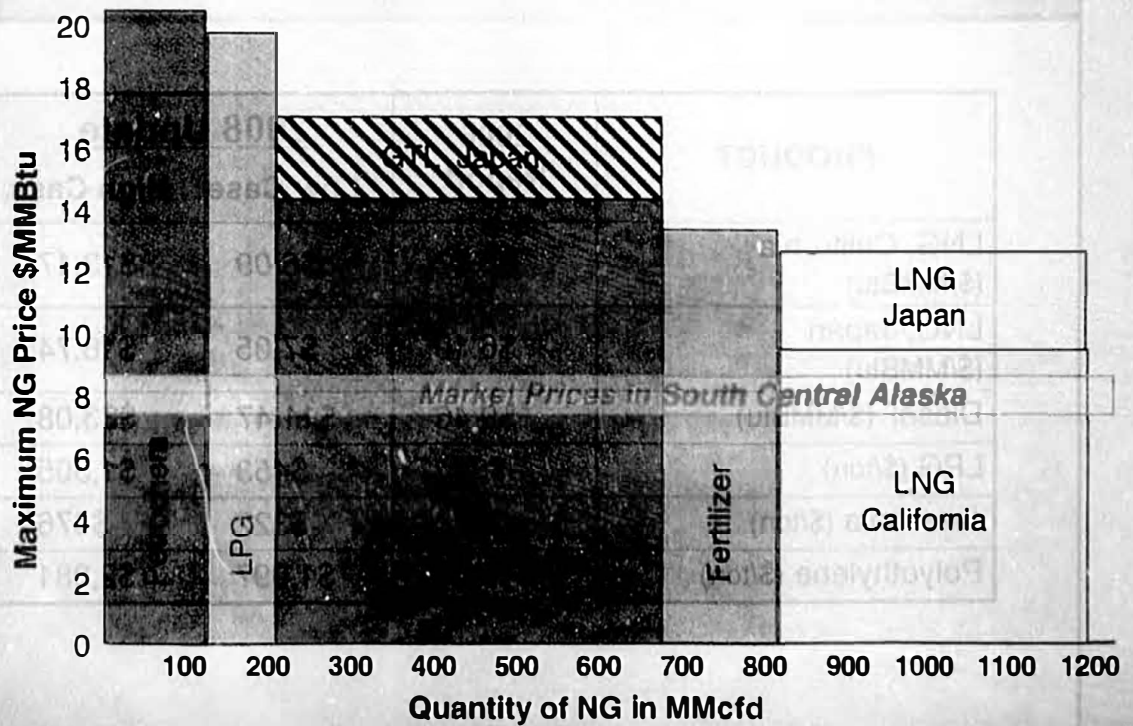
PRODUCT	2006 Report	2008 Update	
		Low Case	High Case
LNG, California (\$/MMBtu)	\$5.07	\$6.09	\$13.17
LNG, Japan (\$/MMBtu)	\$6.10	\$7.05	\$16.74
Diesel (\$/MMBtu)	\$9.46	\$11.47	\$33.08
LPG (\$/ton)	\$383	\$453	\$1,305
Ammonia (\$/ton)	\$224	\$322	\$676
Polyethylene (\$/ton)	\$1,065	\$1,097	\$2,081

3

## Netback Price Findings: Low Case



## Netback Price Findings: High Case



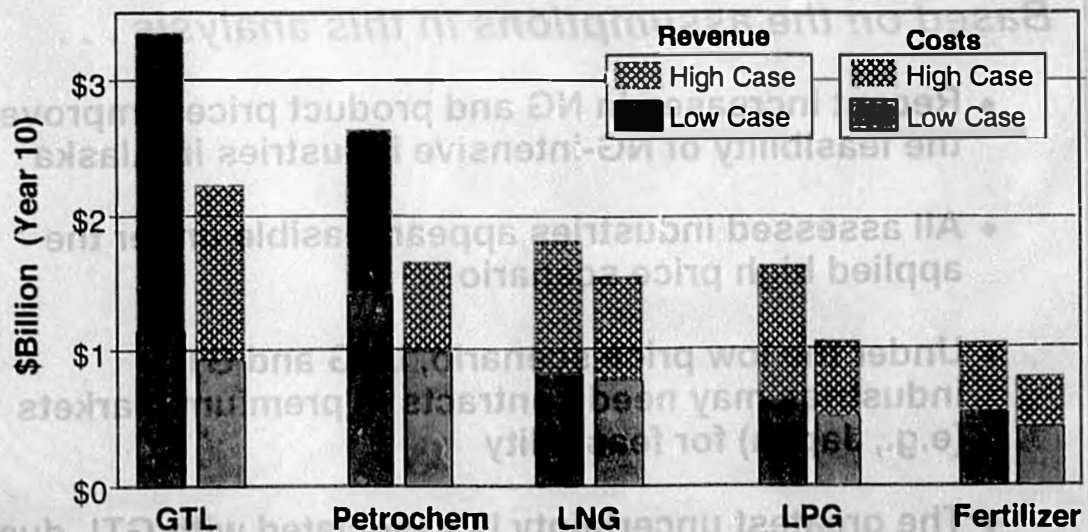
## Capital Costs

### Estimated Capital Costs By Industry

INDUSTRY	\$ Millions
LPG	\$844
GTL	\$3,112
LNG	\$880
Ammonia	\$257
Petrochemicals	\$2,993
<b>Total</b>	<b>\$8,086</b>

6

## Revenue and Cost Estimates, Year 10



7

## Companies that may be interested . . .

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

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

## Summary Findings

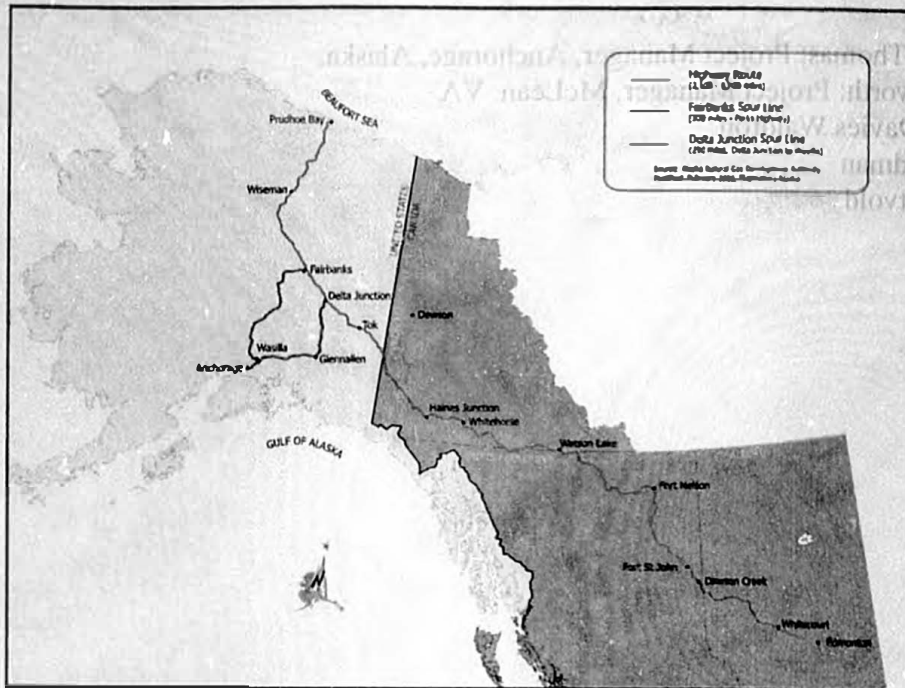
*Based on the assumptions in this analysis . . .*

- ◆ 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

presented: 6-20-2008  
Friday  
Anch AK

by ANGDA  
Harold Heimge, CEO  
& Delma Bratvold, SAIC

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



Prepared by  
Science Applications International Corporation

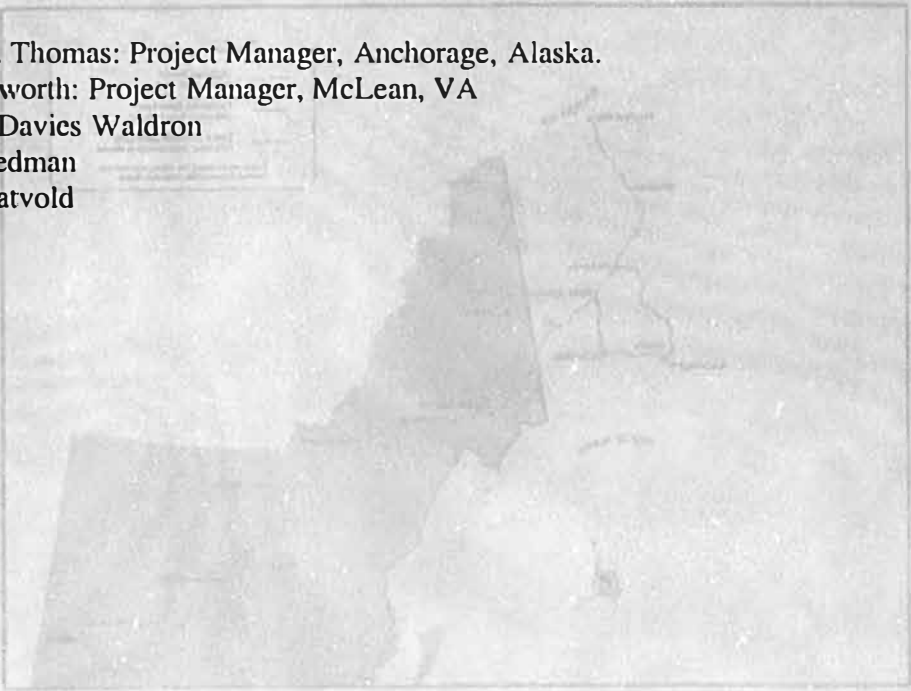
For  
Alaska Natural Gas Development Authority (ANGDA)

June 2008

ANGDA  
Delma Bratvold, SAIC  
Friedman  
Anch, AK  
8005-2008

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

## Technical Contributors - SAIC



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Delma Bratvold

### Disclaimer

This report did not involve the collection or generation of any new or original data. All conclusions and judgments presented in this report are based on information obtained at the time of the assessment. This report is intended to be used in its entirety. Taking or using in any way excerpts from this report are not permitted because, when taken out of context, such excerpts run the risk of being misinterpreted and are not representative of its findings; therefore, any party doing so does so at its own risk.

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.

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## 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.<sup>1</sup> 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

---

<sup>1</sup> 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)
<b>Total Potential Demands</b>		<b>1,041.</b>

- \* 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<sup>2</sup>, minus the difference in estimated tariff rates between Henry Hub and South Central Alaska. In this update report, these

<sup>2</sup> 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 scenarios, 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	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

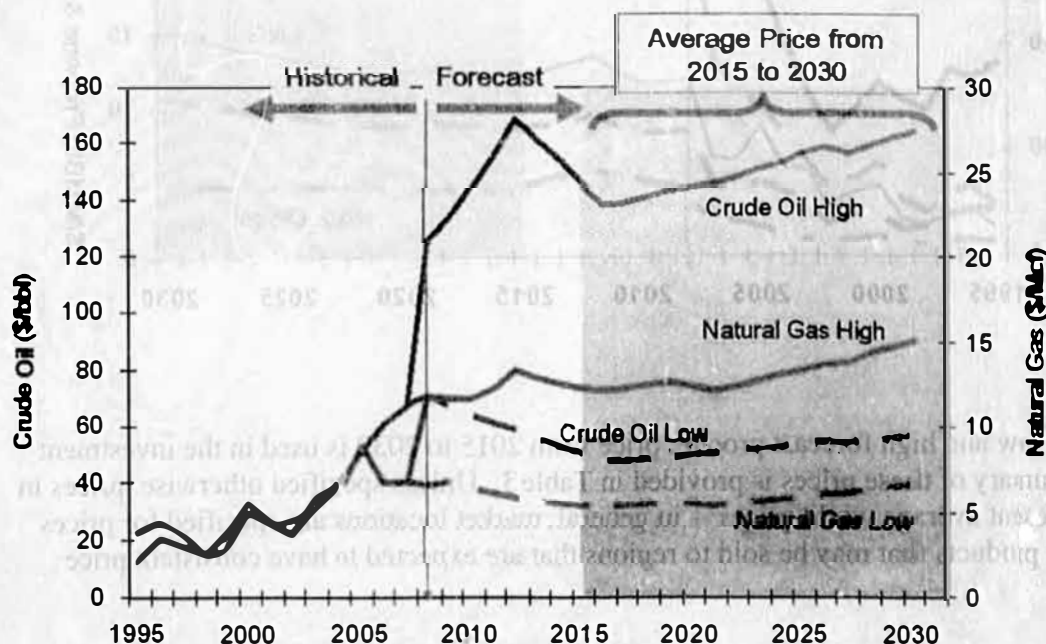
\*\* Assumed expansion of the existing LNG facility at Nikiski

## 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 in 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.

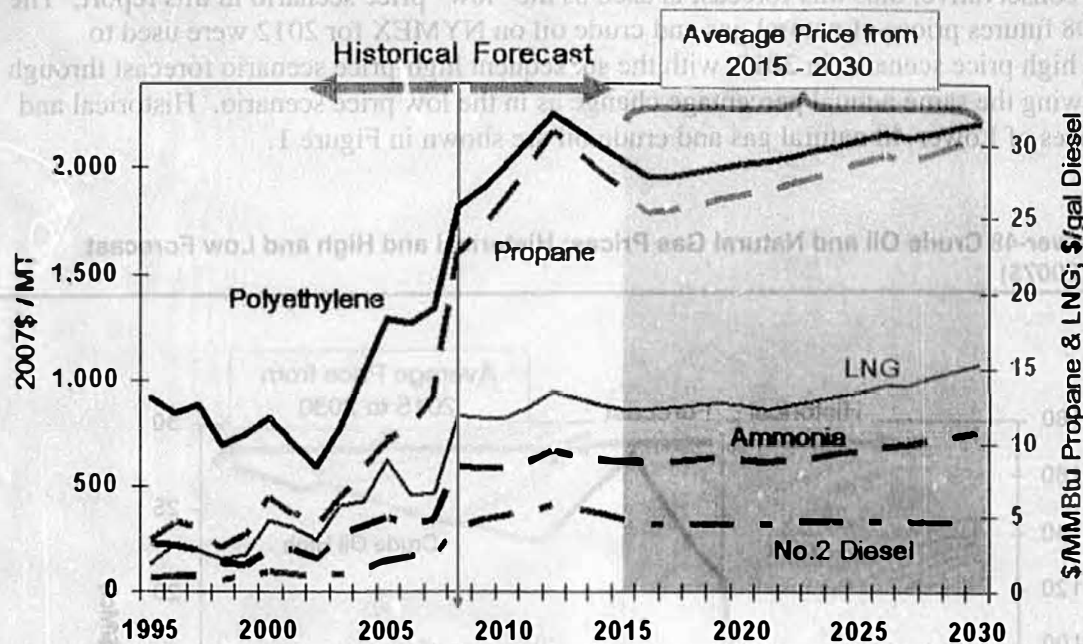
**Figure 1: Lower-48 Crude Oil and Natural Gas Prices: Historical and High and Low Forecast Scenarios (2007\$)**



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**

Commodity	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 <sup>a</sup>	\$35.75 <sup>a</sup>
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

<sup>a</sup> 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**

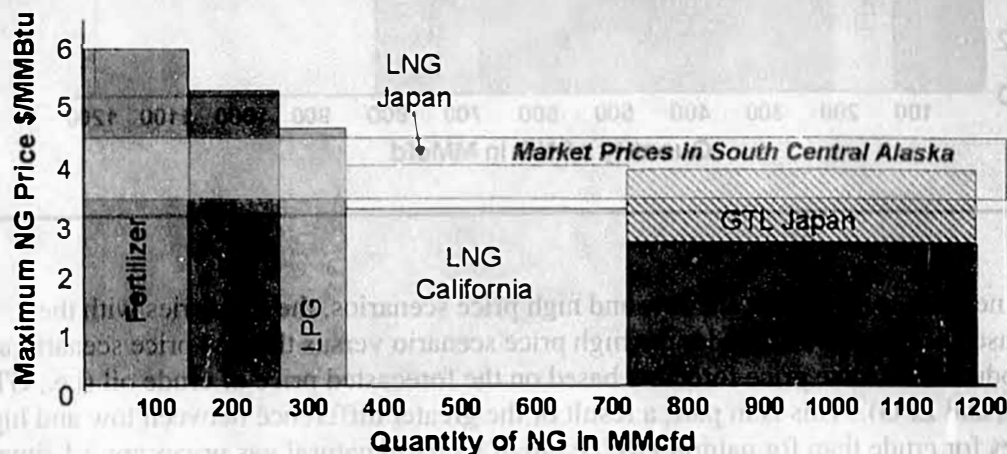
Industry	Low Price Scenario (SC NG Price \$3.45/MMBtu)		High Price Scenario (SC NG Price \$7.75/MMBtu)	
	Product Price	Netback	Product Price	Netback
Fertilizer (Ammonia)	\$322/ton	\$5.87	\$676/ton	\$13.45
LNG, Southern California	\$6.09/MMBtu	\$3.24	\$13.17	\$9.63
LNG, Japan	\$7.05/MMBtu	\$4.11	\$16.74/MMBtu	\$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.

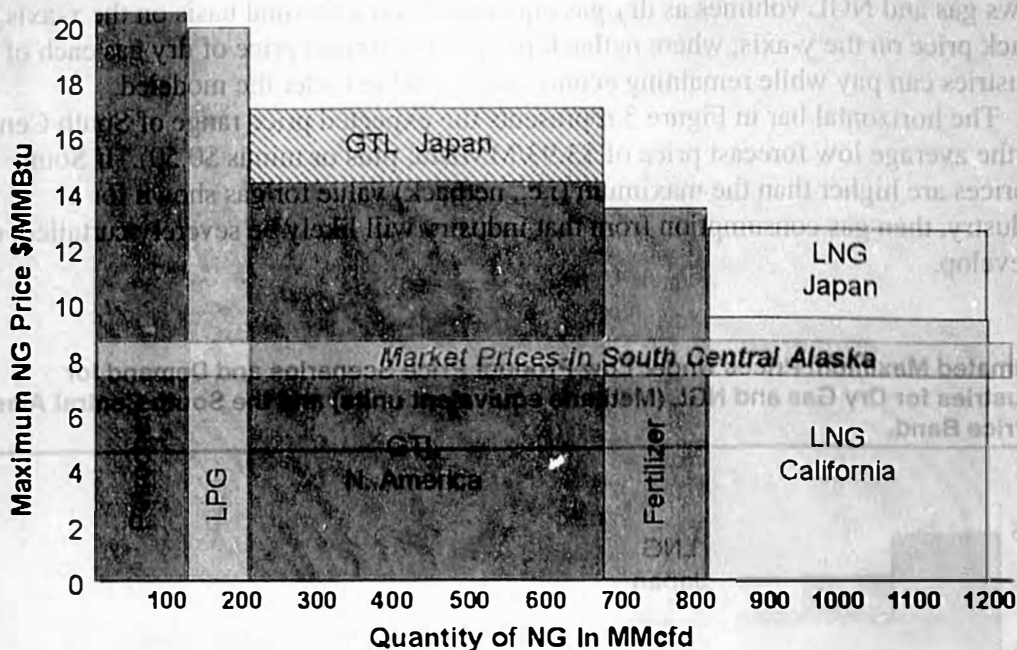
**Figure 3: Estimated Maximum Prices Under Low Product Price Scenarios and Demand for Potential Industries for Dry Gas and NGL (Methane equivalent units) and the South Central Alaska Gas Market Price Band.**



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.<sup>3</sup> 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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<sup>3</sup> 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 Agrum 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.<sup>1</sup> (Assumes ideal gas behavior at 60 F and 14 psia)**

Raw Gas Component	Raw Gas* Mole %	1st Straddle Input (930 MMscfd)		1st Straddle NGL Output to Spur		Total Spur Input**		2nd Straddle NGL Output	
		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 1<sup>st</sup> 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.<sup>4</sup> 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 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 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.

<sup>4</sup> 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.<sup>1</sup> (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 1<sup>st</sup> 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.<sup>5</sup> 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.

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
Methane	86.40	389	NA	1,175	NA
Ethane	7.10	32	20,046	127	79,626
Propane	3.60	16	10,286	65	41,373
n-Butane	0.30	1	883	5	3,552
i-Butane	0.40	2	1,342	7	5,397
Pentanes	0.10	0	350	2	1,406

<sup>5</sup> Pentane is also referred to as "natural gasoline" because it is a major component of gasoline.

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Peter Tijm

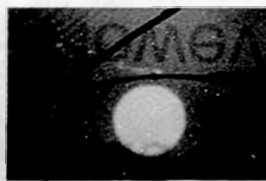
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# ANRTL PRESENTS AN ALASKA NORTH SLOPE GAS TO LIQUIDS (GTL) OPTION

## “A LEGACY DECISION for ALASKA”

PREPARED FOR LEGISLATIVE BUDGET & AUDIT COMMITTEE



THE COMPETITION AGIA PROMISED BUT DID NOT DELIVER

June 20, 2008

GTL - Gas to Liquids  
CTL - Coal to Liquids



## 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.

**PETER J. A. TIJM**

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**SUMMARY PROFILE**

Thirty years of diversified experience in technological and commercial management. Solid leadership, strong expertise in analysis, development and commercialization of synthesis gas conversion, Liquefied Natural Gas technology and commercialization, new design concepts, refinery technology, operations, scheduling, start-up, budgeting and project management. Proven success in building and managing highly motivated professional teams. Excellent communication skills and fluent in 7 languages: Dutch, English, German, French, Swedish, Norwegian and Danish. Understanding of Spanish. Author of over 70 articles and inventor/holder of 11 patent series.

**PROFESSIONAL EXPERIENCE****VICE PRESIDENT – CHIEF TECHNOLOGY OFFICER- 2002-present**  
**PV Enterprises, Inc , Golden, CO**

- Director/Consultant in energy R&D and project development of multi client program.
- Successfully started multi million dollar R&D program and pilot plant facilities.

**DIRECTOR FOR PROJECT DEVELOPMENT 2000-2002**  
**Rentech, Inc., Denver, CO**

- Manage project development, research and product quality aspects for the proprietary Rentech Fischer Tropsch technology.

**MANAGER MARKETING/RESEARCH SYNGAS CONVERSION SYSTEMS 1996-2000**  
**Air Products and Chemicals, Inc. - Allentown, USA**

- Manage Air Products and Chemicals' research and development syngas technology programs, in particular Liquid Phase technology.
- Commercialize Air Products and Chemicals' proprietary Liquid Phase Methanol™ Technology.
- Program manager for the Air Products/Industry/University research and development Programs sponsored by the US Department Of Energy.

**MANAGER OF MARKETING AND RESEARCH 1992-1996****Shell International Petroleum Company, Ltd. - London, United Kingdom**

- Manage Shell International Gas' research and development programs in LNG production and storage, pipeline gas and gas conversion within Shell's Manufacturing Service Company and five laboratories. Annual Budget of U.S. \$10 Million.
- Conduct marketing, gas commercialization and power generation studies for Brunei, Malaysia, China Japan and Nigeria. Promote Shell's US\$850 Million gas conversion project (SMDS).
- Advise in contractual matters in LNG sales between Brunei to Japan and Nigeria to Turkey.
- Launched cost reduction studies in all elements of the LNG production chain, in gas conversion and in pipeline gas; results implemented obtained 15% improvements.
- Maintain and evaluate Shell's patent portfolio in gas conversion technology.
- Author and presenter of papers on Shell technology in gas conversion, LNG technology and cost reduction in world-wide conferences and professional training courses.

**GROUP LEADER COAL GASIFICATION 1990 - 1992****Shell Internationale Petroleum Maatschappij B.V. - The Hague, The Netherlands**

- Directed a 7 person team responsible for up scaling coal gasification technology intended for application in larger size, commercially available gas turbines.
- Initiated Shell/GE/Air Liquide studies into new coal gasification/power generation concepts leading to the successful development of a 450 MWe IGCC power station proposed for Japan.
- Co-ordinated the coal gasification R&D between Shell The Hague, Deutsche Shell, Shell Oil Company and Shell's research laboratories in Amsterdam (KSLA) and Houston, Texas, USA.
- Regular presenter of Coal Gasification technology at international conferences.

**PROGRAM MANAGER SHELL COAL GASIFICATION 1989-1990****Shell Oil Company - Houston, Texas, USA**

- Assisted in commercialisation of Shell Coal Gasification Technology through introduction of presentations to and communication with potential customers.
- Created, implemented and completed a R&D program at Shell's Coal Gasification Demonstration Plant which obtained all design information for the first commercial Shell Coal gasification plant now operational in The Netherlands. Span of control: ~100 people, budget US\$ 25 Million/year.
- Scheduled and agreed with the plant manager the runs on experimental conditions and coal types.
- Member of the EPRI/Shell Advisory Committee for coal gasification.

**SECTION HEAD GASIFICATION AND HYDROCARBON SYNTHESIS 1987-1989****Koninklijke/Shell Laboratorium (KSLA) - Amsterdam, The Netherlands**

- Headed an R&D section tasked to develop the synthesis gas manufacture, coal gasification and hydrocarbon synthesis processes. Work force: ~ 40 people, annual budget of US\$15 Million.
- Established design parameters for new development in the Shell Middle Distillate Synthesis (SMDS) and coal gasification processes, currently operating in Malaysia and The Netherlands, respectively.
- Completed projects successfully through strong interface with the process development and engineering sections in Shell's Oil and Chemical Manufacturing Divisions plus the Catalyst Business.
- Active in recruitment and training of PhD's for Shell.

**REFINERY TECHNOLOGY MANAGER 1984 - 1987****Shell Raffinaderi Aktiebolag - Gothenburg, Sweden**

- Supervised refinery technology, product quality laboratory, refinery inspection and construction services departments. Annual budget of US \$60Million and a work force of 50 people.
- Successfully completed projects under tight schedules, including conversion of the refinery instrumentation system, refinery effluent treatment plants and improvements of the tank farm by installing internal floating roofs and radar level gauges. A very intriguing project was to construct a 80,000 m<sup>3</sup> cavern, next to an existing LPG cavern, under the fully operational refinery.
- Member of the refinery management team especially charged with environmental affairs, refinery concession, permits and external relations.

- Negotiated new contracts for district heat delivery from the refinery to Gothenburg Energy Works.

**SENIOR REFINERY TECHNOLOGIST – Shell, Gothenburg, Sweden 1981-1984**

- Co-ordinated various projects including Total Isomerisation Process, Residue Vacuum Flasher, Steam Boiler and refinery Low Temperature Heat Recovery.
- Performed refinery efficiency studies and long term master planning for the refinery.
- Guided junior technologists, trained new technologists and recruited Swedish engineers for SIPM.

**ASSISTANT PLANT SUPERVISOR/OPERATIONS TECHNOLOGIST 1978-1981**

**Raffinaderie de Cressier S.A. – Shell, Cressier, Switzerland**

- Analysed and recommended measures to improve the refinery availability.
- Implemented various improvements successfully which eliminated problems and/or reduced back-on stream time significantly.
- Handled shift supervision for the total refinery operations, product storage, rail and road car loading as a member of the "Refinery Management Team".
- Implemented and commissioned refinery projects such as the Total Isomerisation Process, Residue Vacuum Flasher and heat-integration.

**TECHNOLOGIST – Shell, Cressier, Switzerland 1977-1978**

- Conducted energy efficiency improvement studies for the refinery.
- Supervised optimum operation and technological aspects of refinery acid gas treating, hydro-treating, platforming processes and refinery environmental performance.
- Advised on catalyst replacement and supervised successful regeneration of the catalysts of hydro-treater, hydrodesulphurizers and platformer.

**DEVELOPMENT ENGINEER 1974-1977**

**Shell Internationale Petroleum Maatschappij B.V. - The Hague, Netherlands**

- Advising engineer to Shell's refineries in design/operation of hydroprocesses and catalytic reforming.
- Designed and developed gas treating processes including acid gas and mercaptans removal, molecular sieve/glycol drying and chloride removal.
- Participated in design teams of the North Scotland gas project and North West Shelf LNG project.
- Commissioned and debottlenecked treating processes in Germany, Pakistan and Venezuela.

**TRAINING/MILITARY SERVICE 1973-1974**

**Shell Internationale Petroleum Maatschappij B.V. - The Hague, Netherlands**

- Served as lieutenant in the Dutch Army charged with supervision of and advise on nuclear, biological, and chemical (NBC) material handling.
- Lectured in NBC matters at the Royal Military Academy of Breda and co-ordinated NBC research.

**EDUCATION**

Master of Science, Chemical Engineering, Delft Technical University (1973):

Bachelor of Science, General Economy, Erasmus University, Rotterdam (1974):

Chairman of Energy Frontiers International, 1996-1998

Author of over 70 articles and inventor/ holder of 10 patent series.

PETER J.A.TIJM -- PUBLICATIONS

**Tijm P.J.A.**, "Gas to Liquids, Fischer-Tropsch Catalysis, Reactors, Products and Process - The Twentieth Century And Beyond". 2005. available on website under [www.booklanddirect.com](http://www.booklanddirect.com)

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**Chapman E.M., Boehman A.L., Tijm P.J.A., and Waller F.J.**, 'Emission Characteristics of a Navistar 7.3L Turbodiesel Fueled with Blends of Di-Methyl Ether and Dicsel Fuel' paper presented at the Fall 2001 SAE Fuels and Lubricants Meeting, San Antonio, TX, September 24-27, 2001.

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**Peng X.D., Toseland B.A., and Tijm P.J.A.**, 'Development and Status of the Liquid Phase Di-Methyl Ether Process (LPDMET<sup>TM</sup>). paper presented at the 6<sup>th</sup> Natural Gas Conversion Symposium, Girdwood, Alaska, June 17-22, 2001.

**E. C. Heydorn, P. J. A. Tijm, B. L. Bhatt, B.T. Smith and R. M. Kornosky**, Liquid phase methanol (LPMEOH) process Development. Energy 2000 Proceedings-US ISBN:1587160161

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**Tijm P.J.A.**, 'Status of the Sand Creek Fisher-Tropsch Fuels Conversion Project', paper given at the Energy Frontiers International Conference, San Francisco, CA, October 11-13, 2000

**Chapman E.M., Bhide S.V., Boehman A.L., Tijm P.J.A., and Waller F.J.**, 'Emission Characteristics of a Navistar 7.3L Turbodiesel fueled with blends of oxygenates and diesel' paper presented at the Fall 2000 SAE Fuels and Lubricants Meeting, Baltimore, MD, October, 2000.

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- Peng X.D., Toseland B.A., and Tijm P.J.A.,** 'Qualitative Analysis of the Syngas-To-DME Reaction System.' Paper presented at the 3<sup>rd</sup> China/USA Joint Chemical Engineering Conference, Beijing, China, Sept. 25-28, 2000.
- Hess H.S., Szybist, J., Boehman A.L., Tijm P.J.A., and Waller F.J.,** 'The Use of CETANER™ for the Reduction of Particulate Matter Emissions in a Turbocharged Direct Injection Medium-Duty Diesel Engine' paper presented at the Seventeenth Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September 11-15, 2000.
- Heydorn E.C., Tijm P.J.A, Bhatt B.L., Smith B.T. and Kornosky R.M.,** 'Liquid Phase Methanol (LPMEOH™) Process Development' paper presented at the GlobeEx 2000 - The Global Energy Exposition, Las Vegas, NV, July 23-28, 2000.
- Moore R.B. and Tijm P.J.A.,** 'Liquid Phase Reactor Technology'. Workshop on Polygeneration Strategies Based on Oxygen-Blown Gasification, Beijing, China, May 11-12, 2000.
- Frye, C. A., A. L. Boehman and P. J. A. Tijm.** A Comparison of CO and NO Emissions from Propane, *n*-Butane, and Dimethyl Ether Premixed Flames. *Energy & Fuels*, 13, 650-654 (1999).
- Peng X.D., Toseland B.A., and Tijm P.J.A.,** 'Kinetic Understanding of the Chemical Synergy under LPDME™ Conditions - Once-Through Applications.' *Chem. Eng. Sci.* (1999), 54, 2787.
- Peng X.D., Wang A.W., Toseland B.A., and Tijm P.J.A.,** 'Single Step Syngas-to Dimethyl Ether Processes for Optimal Productivity, Minimal Emissions and Natural Gas-Derived Syngas' *Ind. Eng. Chem. Res.* (1999), 38 (11), 4381-4388.
- Tijm P.J.A., et al** 'Particulate Matter Emissions Reduction with CETANER™ as a Blend Component for Diesel Fuels with Low Cetane Levels' paper presented at the Windsor Workshop in Toronto, Canada, November, 1999.
- Tijm P.J.A., Armor J.N., Dyer P.N., Waller F.J. and Brown D.M.,** "An overview of Air Products' New Technology Programs in Syngas Generation and Conversion" paper presented at the EFI Gas Conversion Conference in San Francisco, CA, October 20-22, 1999.
- Tijm P.J.A, Heydorn E.C., Diamond B.W., Street B.T., and Kornosky R.M.,** 'Liquid Phase Methanol (LPMEOH™) Project: Operating Experience Update' paper presented at the 1999 Gasification Technologies Conference in San Francisco, CA, October 17 - 20, 1999.
- Bhatt B.L., Heydorn E.C., Tijm P.J.A., and Kornosky R.M.,** 'Direct Applications of Stabilized Methanol from the Liquid Phase Methanol (LPMEOH™) Process' presented at the 16<sup>th</sup> Annual International Pittsburgh Coal Conference in Pittsburgh, PA, October 11-15, 1999.
- Hess, H. S., J. A. Chiodo, A. L. Boehman, P.J.A. Tijm and F.J. Waller.** The Use of CETANER™ for the Reduction of Particulate Matter Emissions in a Turbocharged Direct Injection (TDI) Diesel Engine. Sixteenth Annual International Pittsburgh Coal Conference, Pittsburgh, PA, October 11-15, 1999.
- Heydorn E.C., Stein V.E., Tijm P.J.A., Street B.T., and Kornosky R.M.,** 'Liquid Phase Methanol (LPMEOH™) Project Operational Experience' presented at the EPRI/GTC Gasification Technologies Conference in San Francisco, CA, October 4-7, 1998.

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**Heydorn E.C. and Tijm P.J.A.**, 'Liquid Phase Technology Developments for The New Millennium' paper presented at the EFI Gas Conversion Conference, San Francisco, CA, October 7-9, 1998.

**Miller W.R., Tijm P.J.A., Toseland B.A., and Waller F.J.**, 'Liquid Phase Technology Developments for The New Millennium' paper presented at the Sixth Annual Technical Seminar Promotion of Clean Fossil Energy Technologies in the APEC Region, Reno, NV, October 6-9, 1998.

**Brown, D.M., Tijm P.J.A., Miller, W.R., Toseland, B.A., and Waller, F.J.**, 'CETANER™ a Promising New Diesel Fuel' paper presented at the 12<sup>th</sup> International Symposium on Alcohol Fuels, Beijing, P.R. China, September 21-24, 1998.

**Foster E.P., Tijm P.J.A., Bennett D.L.**, 'Advanced Gas-To-Liquid Processes for Syngas and Liquid Phase Conversion' Proc. of the 5<sup>th</sup> Natural Gas Conversion Symposium in Taormina, Sicily, Italy, September 20-25, 1998, pp. 867-874.

**Tijm P.J.A., Miller D., Brown D.M., Allam R.J., and Goldstone P.G.**, 'Oxygen Production for Floating Production, Storage and Off-Loading Mounted GTL Projects' paper presented at the EFI Gas Conversion Conference in San Francisco, CA, October 7-9, 1998.

**Peng X.D., Toseland B.A., and Tijm P.J.A.**, 'Kinetic Understanding of Chemical Synergy in LPDME™ Process' paper presented at the 15<sup>th</sup> ISCRE in Newport Beach, CA, September 13-16, 1998.

**Brown D.M., Miller D., Allam R.J., and Tijm P.J.A.**, 'Generation of Synthesis Gas Off-Shore: Oxygen Supply and Opportunities for Integration with GTL Technologies' Proc. of the 5<sup>th</sup> Natural Gas Conversion Symposium in Taormina, Sicily, Italy, September 21-25, 1998., pp.949-954.

**Goldstone P.G., Tijm P.J.A., and Miller D.**, 'The Safe & Efficient Provision of Oxygen for Remote, Offshore Conversion of Natural Gas' paper presented at the Gas Processors Association, European Chapter, Continental Meeting, Zurich, Switzerland, September 23-25, 1998.

**Hess H.S., Roan M.A., Bhalla S., Butnark S., Zarnescu V., Boehman A.L., Tijm P.J.A., and Waller F.J.**, 'The Use of Oxygenated Diesel Fuels for Reduction of Particulate Emissions from a Single-Cylinder Indirect Injection Engine' paper presented at ACS National Meeting, Symposium on the Chemistry of Diesel Fuels in Boston, MA, August 23-27, 1998.

**Hess, H. S., M. A. Roan, S. Bhalla, S. Butnark, V. Zarnescu, A. L. Boehman, P.J.A. Tijm, F. J. Waller.** Reduction of Particulate Emissions from a Single-Cylinder IDI Engine with Oxygenated Diesel Fuels. In ACS Preprints, Division of Petroleum Chemistry, 43(4), pp. 593-596 (1998).

**Boehman, A.L. and Tijm P.J.A.**, 'Incorporating Oxygen in Diesel Fuel as a Means of Reducing Engine Emissions' presented at the Diesel Engine Emissions Reduction Workshop, Castine, ME, July, 1998.

**Tijm P.J.A.**, 'Overview of CETANER™ For Diesel Fuel and AET Study of CETANER™ Blended With Low Cetane Diesel Fuel' paper presented at the Windsor Workshop in Toronto, Canada on June 8-10, 1998.

**RICHARD J PETERSON**

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AK Mobile: (907) 360-0909  
CA Mobile: (310) 480-0909

**AREAS OF QUALIFICATION**

Mr. Peterson has spent the last 30 years in the energy business as a CTL/BTL/GTL project developer, an engineer/marketer, including 4 years as a consultant and has worked on projects as diverse as a coal gasification plant using Sasol/Lurgi technology in North Dakota; establishing a market presence in the US and Canada for new gas ventures; developing power generation projects in the US and Central America; and developing GTL, electric power plants, iron ore reduction plants and pipeline distribution systems for commercial gas markets in South Africa.

Mr. Peterson is currently the President of Alaska Natural Gas to Liquids Company in Anchorage, Alaska; a company he formed late 1996 to pursue gas to liquids (GTL), and President of Alaska Natural Resources To Liquids a LLC formed in 2005, to pursue coal to liquids (CTL) and bio-mass to liquids (BTL) opportunities to produce Fischer-Tropsch diesel (FTD) in Alaska. ANGTL/ANRTL evaluate specific project locations, financing options and fuel supply, and then evaluate the best available technology for that specific location. The North Slope GTL project that ANGTL proposed 6 years ago using Sasol GTL technology still remains one of the best options to develop the stranded North Slope gas reserves.

ANRTL is in the early engineering phases for three separate CTL and BTL projects in Alaska using Sasol's, Shell's and CHOREN's gasification technology to produce the syn gas for the F-T diesel process. The first project will use bio-mass, dead or dying spruce trees as a feed stock while the second will be a bio-mass/coal gasification/combined cycle electric generation facility located on the western shores of the Cook Inlet. The third project will site a 500 bbl/d BTL plant on the Yukon River.

**EMPLOYMENT HISTORY**

- President Alaska Natural Gas To Liquids Company, Anchorage, AK, 1997 to present
- Senior Consultant, Hagler Bailly Consulting, Inc., Houston, TX, 1997
- Consultant/Vice President of Business Development, McAlister Enterprises, New Braunfels, TX, 1995-1997
- Manager of Supply, Southern California Gas Company, Los Angeles, CA, 1993-1995
- Proprietor, Peterson & Associates, Woodlands, TX, 1991-1993
- Vice President of Marketing, North Canadian Marketing, Ltd., Houston, TX, Orange, CA, Calgary, Alberta, 1991
- Vice President of Marketing, Enserch Gas Company, Houston and Dallas, TX, 1989-1991
- Manager of Marketing, Anadarko Petroleum, Houston, TX, 1981-1989
- Various Supply and Engineering Positions, Natural Gas Pipe Line Company of America, Chicago, IL and Houston, TX, 1975-1981

**EDUCATION**

- The University of North Dakota, MS, Mechanical Engineering, 1975
- The University of North Dakota, BS, Mechanical Engineering, 1974



## 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.



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## 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.



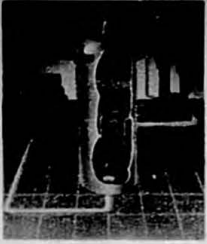
## The main points we will make:

- 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<sub>3</sub> +)
- 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



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**CONVERTING  
NORTH SLOPE NATURAL GAS  
RESERVES INTO**

**“PROVEN”**

**F-T TRANSPORTATION FUELS  
&  
PETROCHEMICAL FEED STOCKS  
WHILE SEQUESTERING CO<sub>2</sub>**

**”GREEN AS IT CAN BE”**



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**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



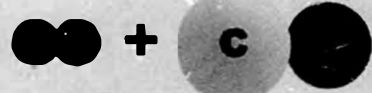

Okay, don't let the  
chemistry scare you!

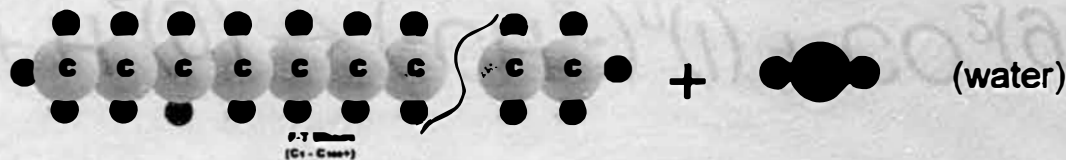
Let's take a look.....



## 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  $\rightarrow$  wax)

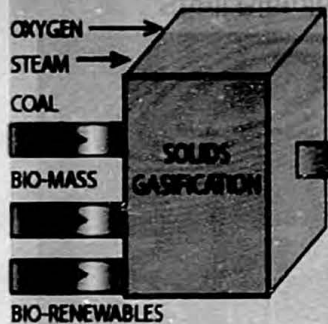


- Step 3 - Product upgrading (hydrocracking of the long chain F-T paraffin to produce the desired end product – similar to a crude oil refinery)

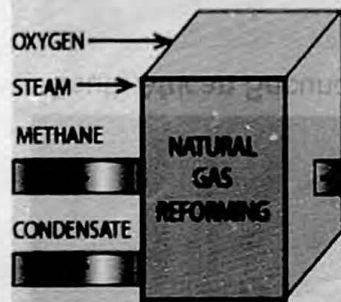
- Kerosene – Diesel – Gasoline - Jet Fuel – Naphtha
- $C_{10}-C_{13}$        $C_{14}-C_{20}$        $C_5-C_{10}$        $C_{10}-C_{13}$        $C_4-C_{10}$

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

## FISCHER-TROPSCH REACTOR



### STEP 1 - SYN GAS GENERATION



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!

GASEOUS PRODUCTS



SYNTHESIS GAS (H<sub>2</sub> & CO)

### STEP 2 - F-T CONVERSION

# F-T FUELS THE ONE FUEL FOR OUR FUTURE

The first step converts natural gas, coal or bio-mass into synthesis gas, a mixture of carbon monoxide (CO) and hydrogen (H<sub>2</sub>) - 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

methane alcohols and diesel

WAXY HYDROCARBON PRODUCTS - C<sub>3</sub> +

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 world's first bio-renewable energy gasifier and has the distinction of producing fuels and electricity with a net zero impact on the world's CO<sub>2</sub> 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:

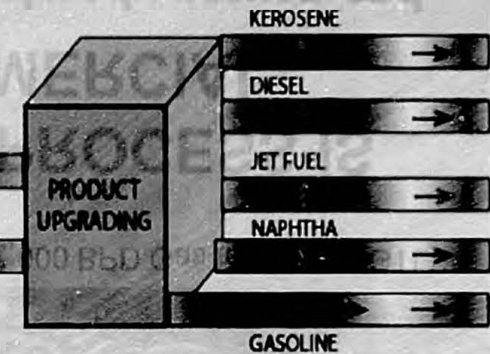


The length of the hydrocarbon chain (x) is determined by the composition (or ratio of H<sub>2</sub> to CO) of the syngas, the catalyst selectivity and the reaction conditions.

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<sub>2</sub>) is sent to product workup and the water (H<sub>2</sub>O) is sent to the water recovery unit.

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

### STEP 3 - HYDROCRACKING - PRODUCT WORKUP



The third step, Product Upgrading:

Upgrading can produce a wide range of commercial products from gasoline 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<sub>2</sub> 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.



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



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# GTLs

## Facts and Fiction

SYNTHETIC DIESEL



# 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.

# WHERE ARE THE MAJORS ON GTLs?

1. In 2003/04 ConocoPhillips and ExxonMobil signed agreements to build 160,000 bb/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.
2. Shell Oil, 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.
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Clearly, the North Slope majors possess all the skills necessary to build GTL (F-T) plants worldwide including in Alaska.



# 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?





# 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**



**OR A DIAMOND**



**LNG PRODUCED NATURAL GAS **

**OR GTL PRODUCED DIESEL **

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



# GTL FACTS and FICTION

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## 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	<b>P R E L I M I N A R Y</b>	<b>F E A S I B I L I T Y</b>	<b>F E A S I B I L I T Y</b> <b>B A N K A B L E</b>	<b>D E F I N I T I V E</b>	<b>D E T A I L E D</b>	
ACCURACY RANGE	+40% To -40%	+30% To -20%	+15% To -15%	+10% To -10%	<b>X</b> = 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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# BATCHING / PIGGING

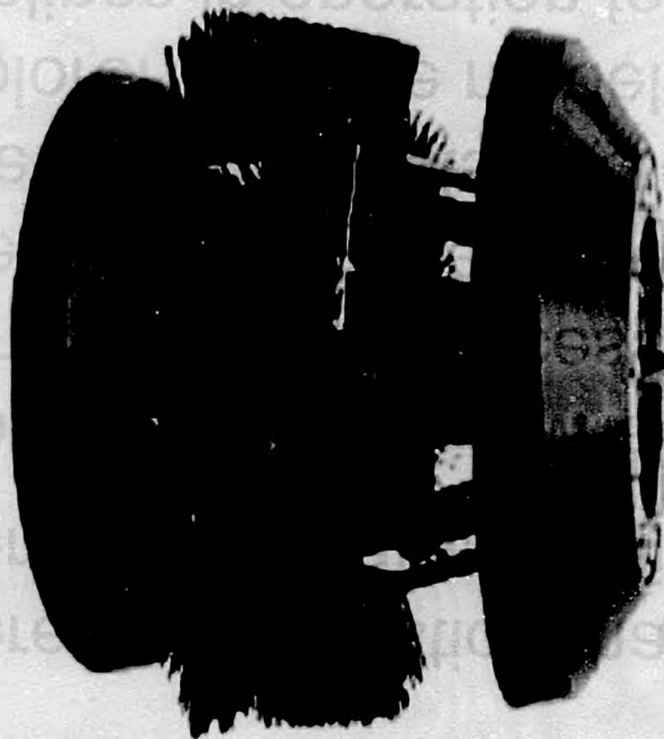
## Facts and Fiction

- 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
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- 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/](http://www.eia.doe.gov/)); and
- The BP Statistical Review of World Energy June 2007 ([www.bp.com/productlanding.do](http://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.

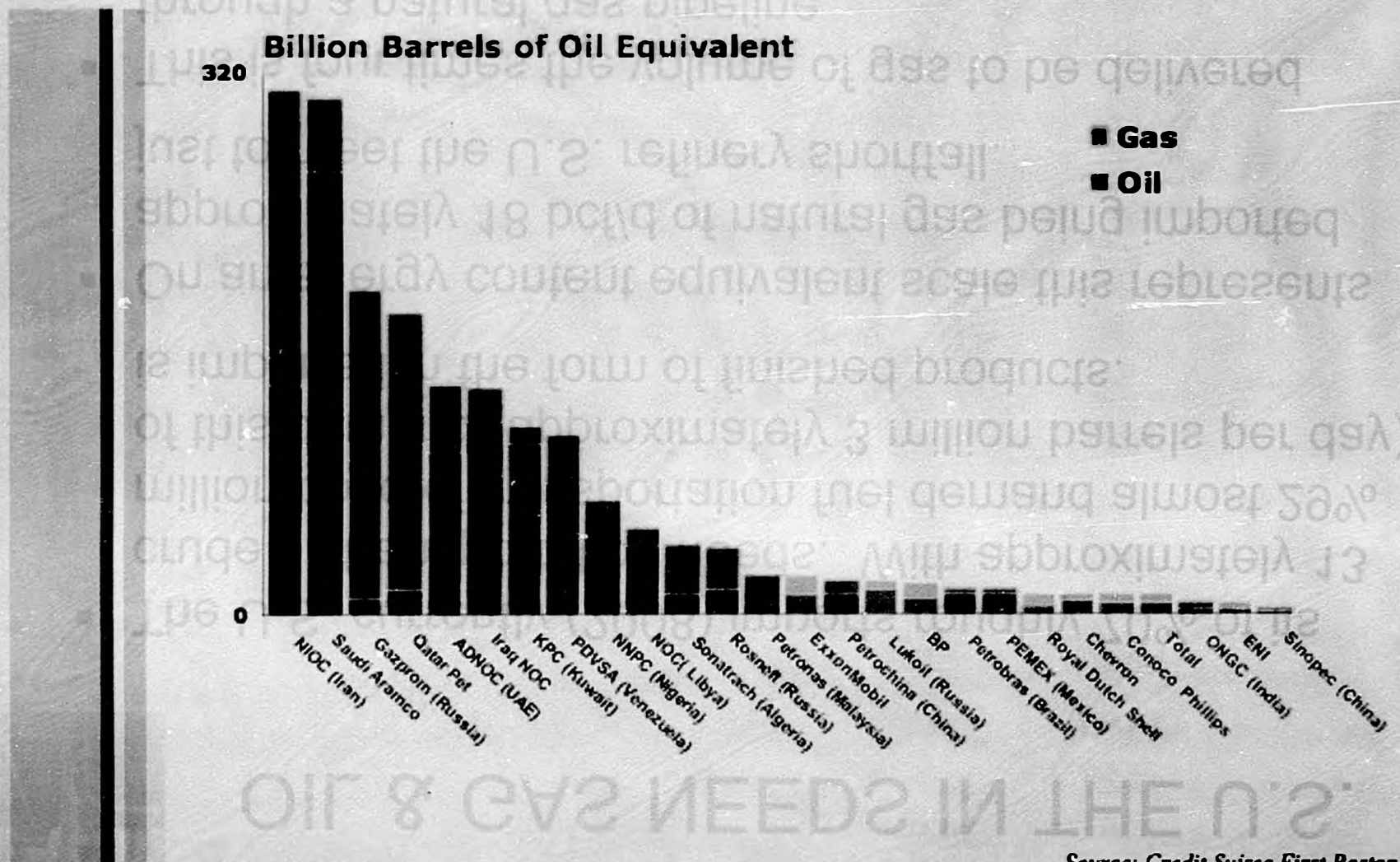
- While U.S. refiners have been adding capacity to existing refineries with process efficiency upgrades, no new refinery has been built in the U.S. since the 1970's.
- This could possibly be one of the reasons why refinery margins have crept up from the \$5 to \$6/bbl range in 1970 - 2000 era to over \$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





## 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.

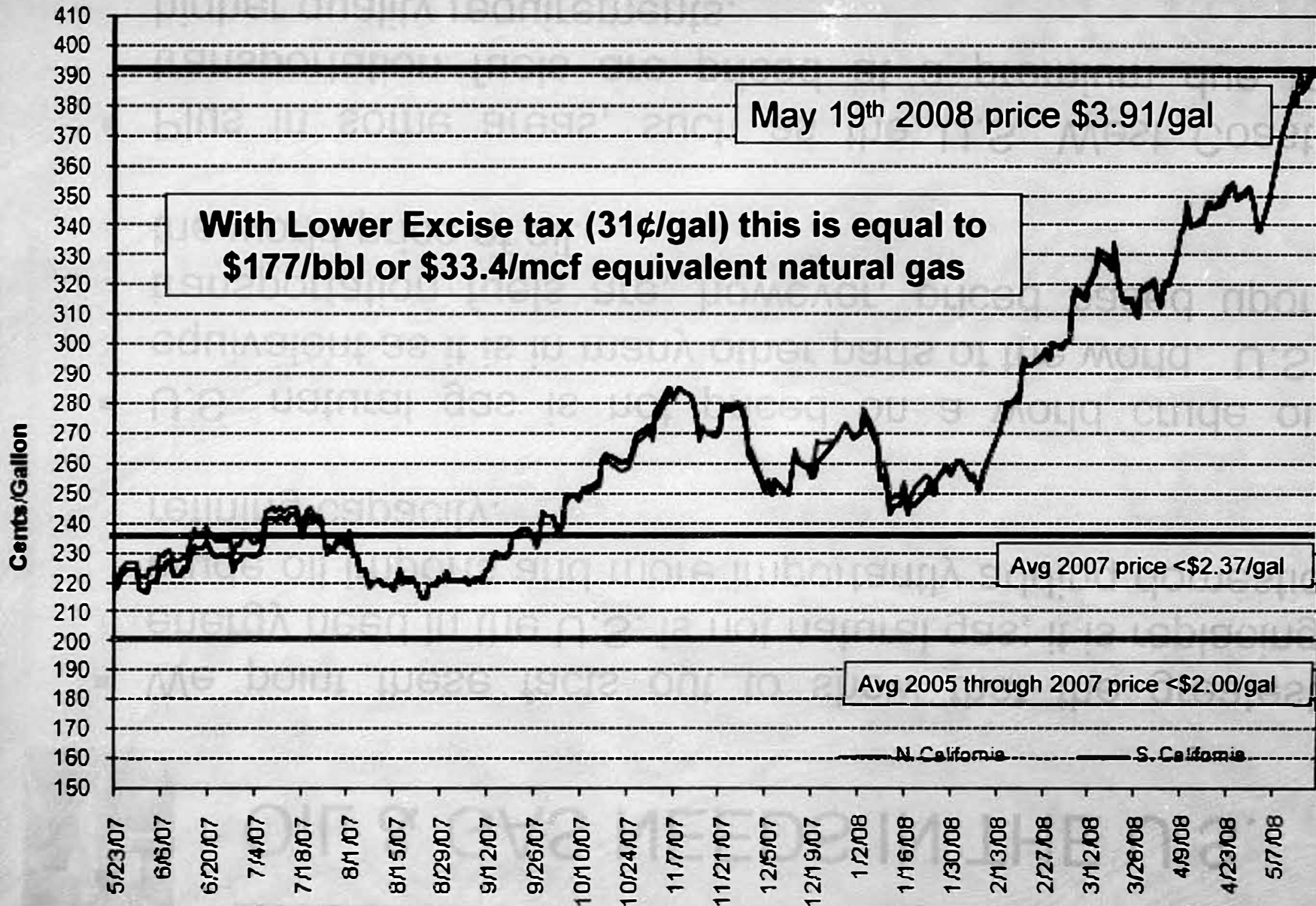
- All of the energy consumers who could have switched off crude-based products have done so but the gas industry is still able to meet demand.
- In fact, little LNG is currently being imported into the U.S. because markets elsewhere in the world, especially those linked to the price of crude oil, are 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 19<sup>th</sup> , 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

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# 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 19<sup>th</sup> 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/incf 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/gal**

**$\$5.71/\text{gal} = \$240/\text{bbl}$**

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

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

**Mcf equivalent -  $\$196.1 \div 5.3 = \$37/\text{mcf}$  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 -  $\$10.5/\text{mcf} \times .65 \times .88 = \$6.01/\text{mcf}$  natural gas at Prudhoe Bay GTL Plant Inlet

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

Case B -  $\$22.7/\text{mcf} \times .65 \times .88 = \$12.98/\text{mcf}$  natural gas at Prudhoe Bay GTL Plant Inlet

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

Case C -  $\$37/\text{mcf} \times .65 = \$21.16/\text{mcf}$  natural gas at Prudhoe Bay GTL Plant Inlet

**$\$5.71/\text{GAL}$  IN CALIFORNIA -  $\$21.16/\text{MCF}$  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:
  - $.25 + ((97.5-30) \times .004) + (120-97.5) \times .001 = .543$  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<sub>2</sub> 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. market competing with Alaska AGIA gas.



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# **MORE THAN JUST A GTL PROJECT**

**HUNDREDS OF VALUE ADDED  
BUSINESSES ARE POSSIBLE**

**Manufacturing on a Grand Scale.**

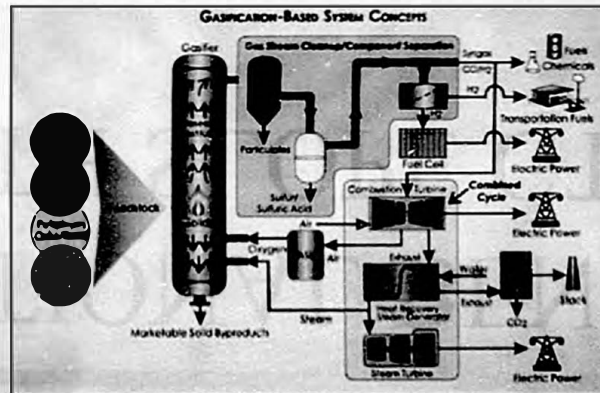
**The beginning of a new era for Alaska and Alaskans.  
Supplying the world with high value finished goods  
instead of basic natural resources.**

**ENERGY CONSERVATION**



# 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.





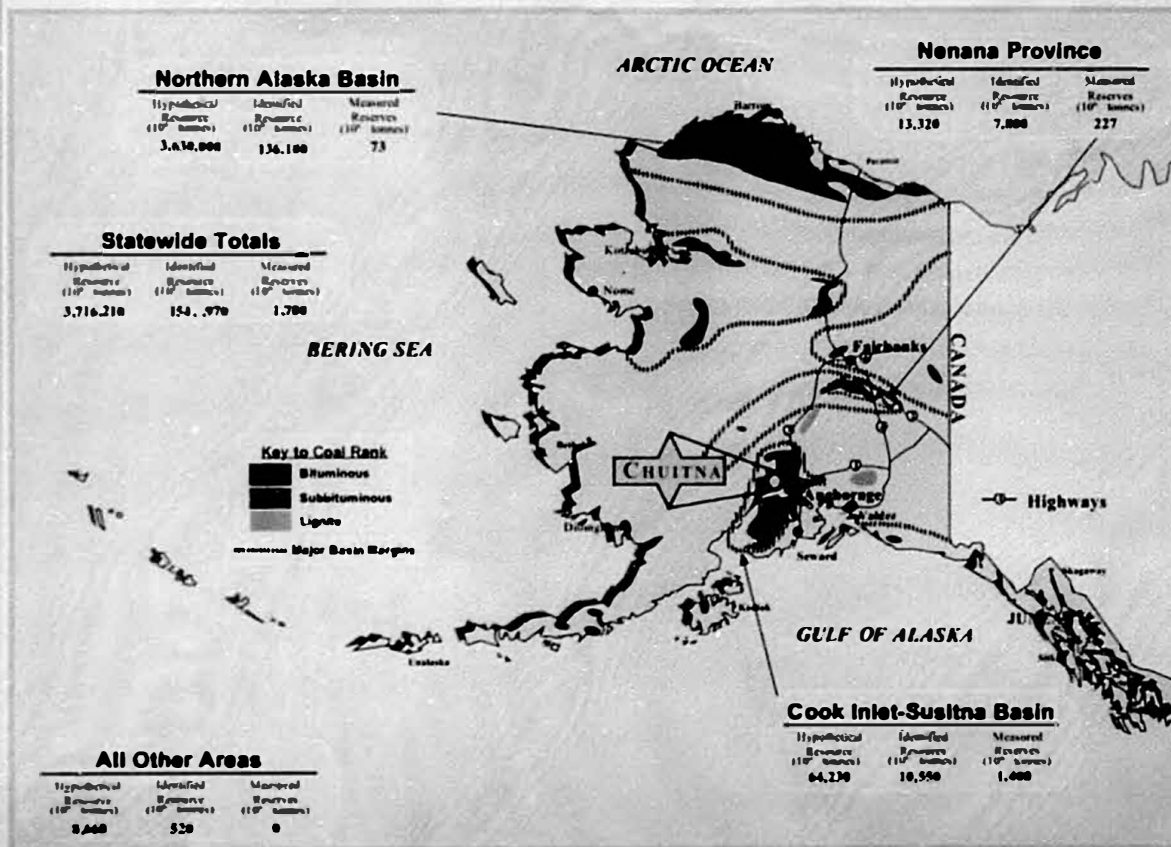
# ADDITIONAL BENEFITS OF A NORTH SLOPE GTL OPTION

- **Benefits of GTLs at Prudhoe Bay**
  - **CO<sub>2</sub>**
  - **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



### Estimated Recoverable Coal Reserves

(10<sup>9</sup> 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!

## ALASKA LEGACY PROJECT



**THANK YOU FOR LISTENING TO  
THE GTL STORY**



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# CONTACT DETAILS

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L7 10:30 AM

6-20-2008 Friday  
printed Anch. AK  
Howard Johnson Plaza



# Special Session

## Anchorage, Alaska

### June 20, 2008

Gene Dubay, SVP & COO  
Continental Energy Systems

Colleen Starring, Regional Vice President  
ENSTAR Natural Gas Company



*All Our Energy Goes Into Our Customers*

# 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

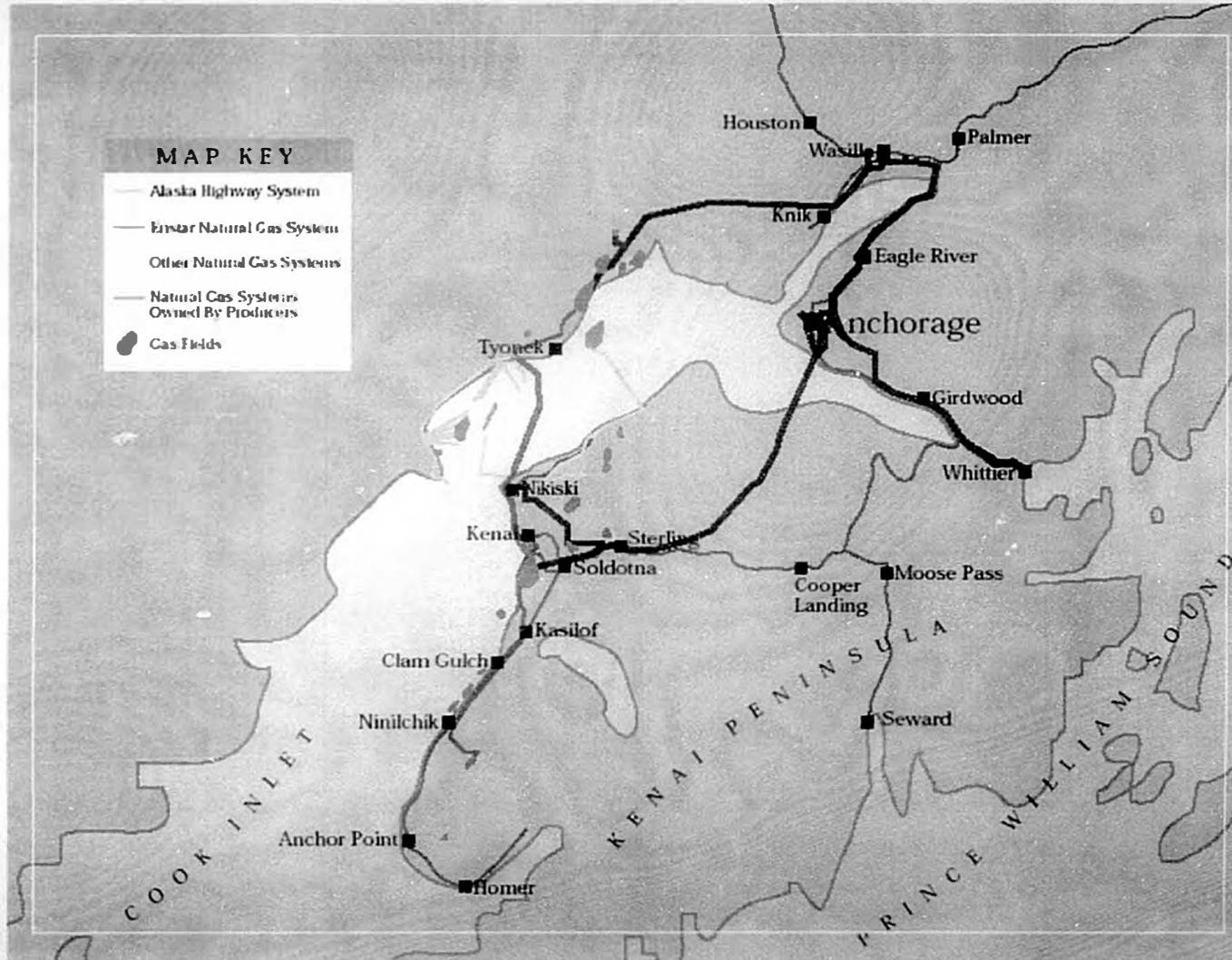
\* 128,000 Meters x 2.7 Alaskan Consumers per Meter

# 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





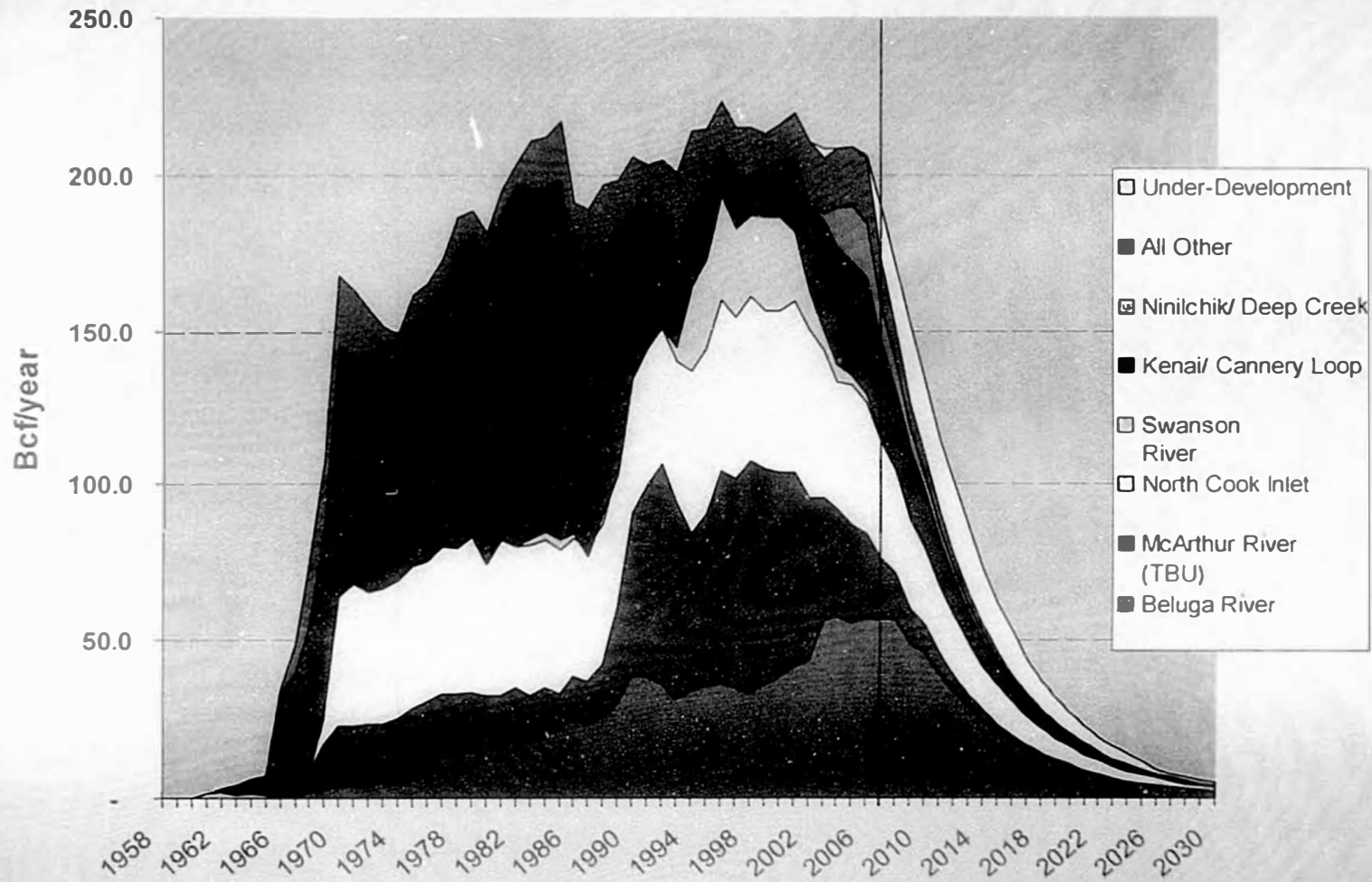
# ENSTAR In-State Pipeline Phase One



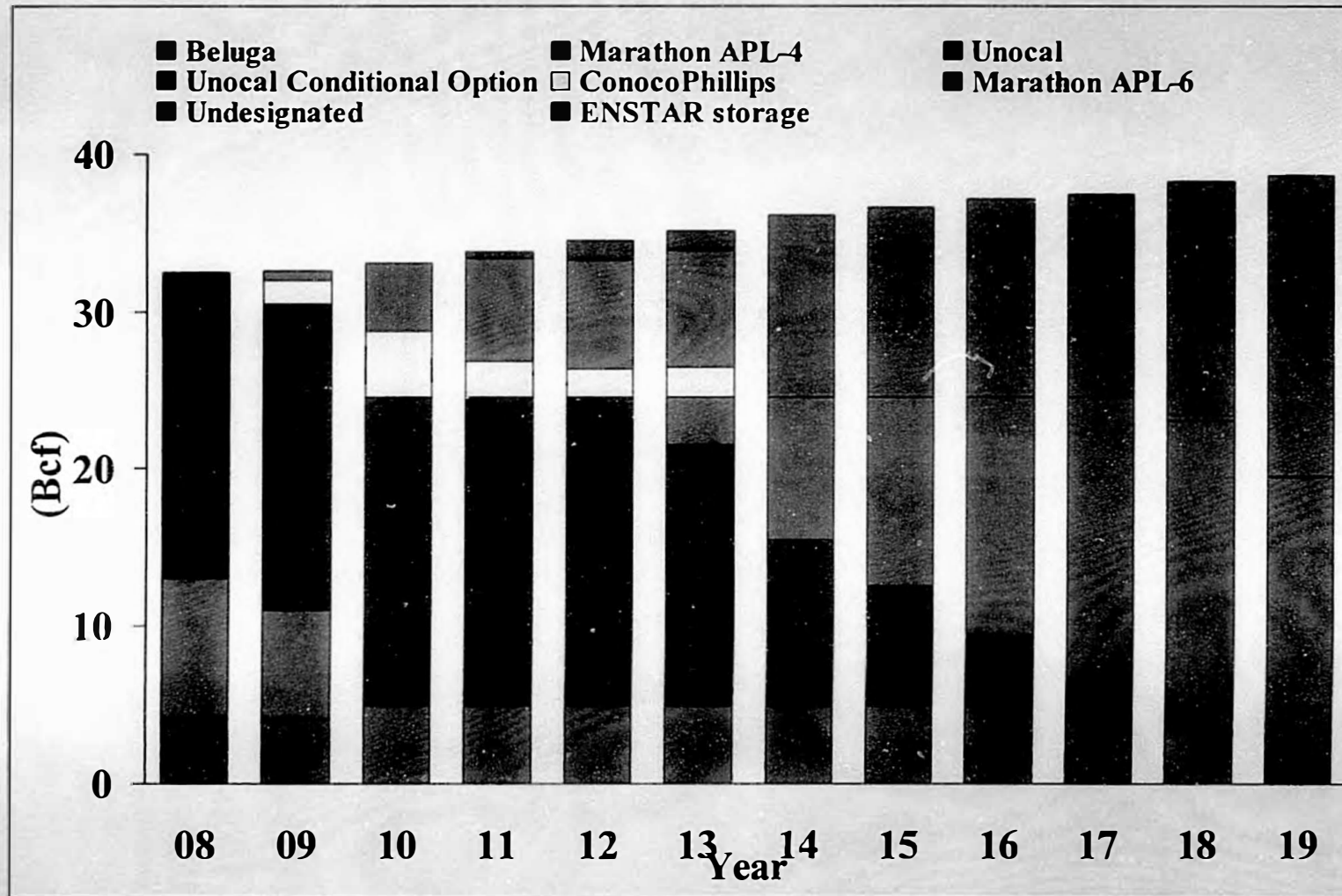
*All Our Energy Goes Into Our Customers*

# Historic & Projected Natural Gas Production (Bcf/Year)

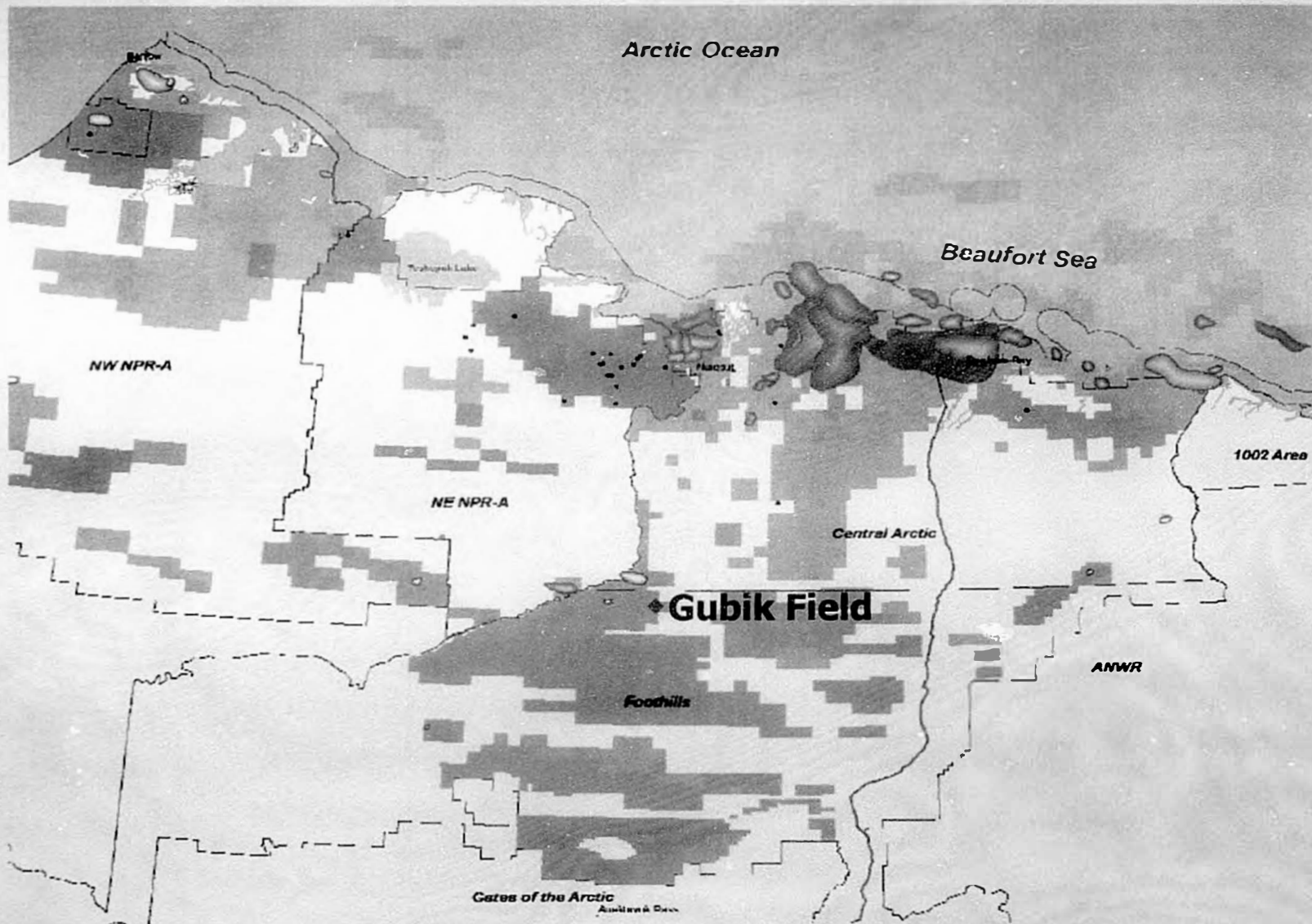
Source: Division of Oil & Gas Report 2006



# Gas Supply – April 2008 Outlook

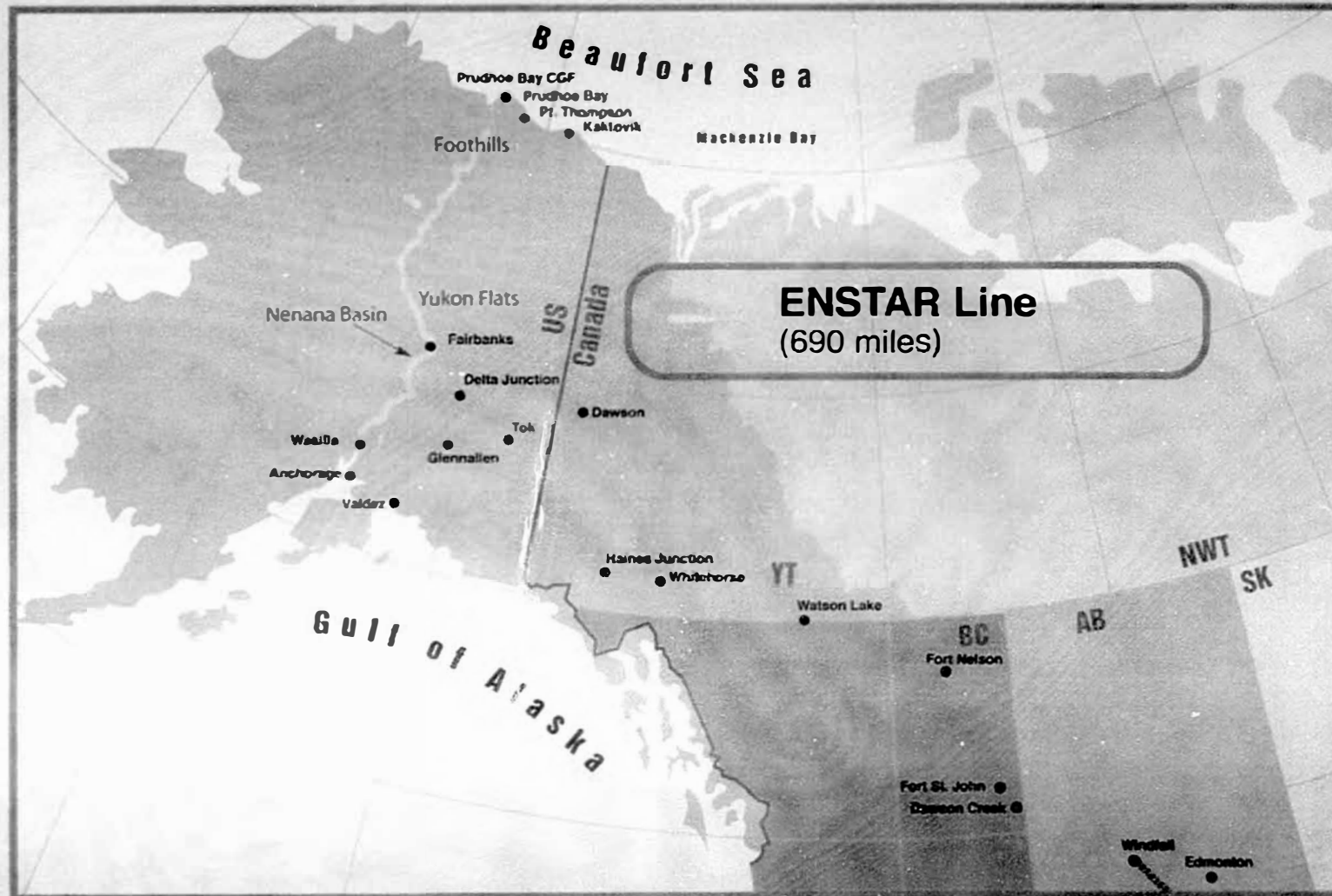


# Foothills Unit Area Map



# ENSTAR Line

## Natural Gas for South Central Alaska



# 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

# Foothills Natural Gas Milestones

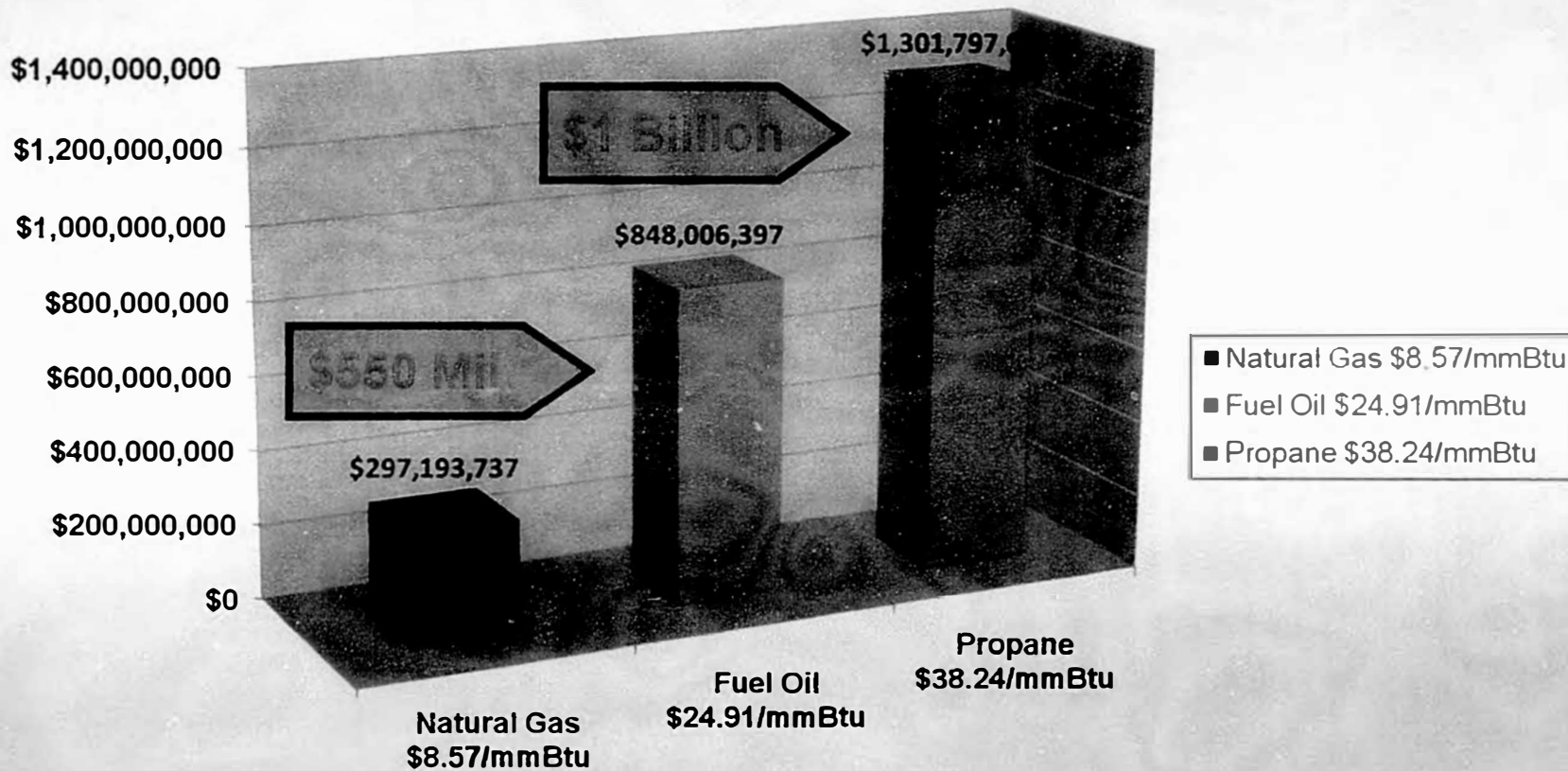
	2007	2008	2009	2010	2011	2012	2013	2014
Gubik 1st drilling season	■							
ENSTAR Pipeline - Phase 1		■						
Gubik 2nd drilling season		■						
Producer update			◆					
ENSTAR Go or No-Go Decision			◆					
Gubik 3rd drilling season			■					
ENSTAR Pipeline - Phase 2			■	■	■	■		
Construction						■	■	■
FIRST GAS								◆

# 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

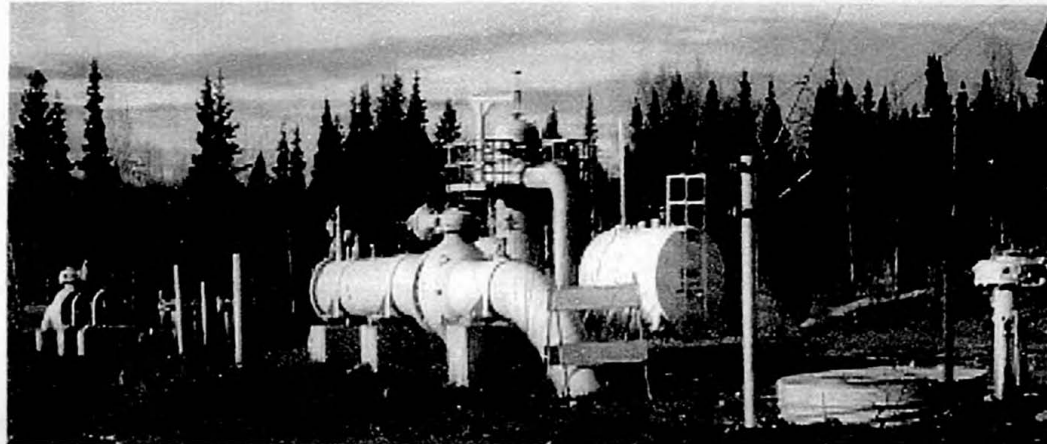
# ENSTAR Pipeline Study

## Throughput and Load Estimates

<b><u>Load Profile MMcfd</u></b>	<b><u>2014</u></b>	<b><u>2015</u></b>	<b><u>2016</u></b>	<b><u>2017</u></b>	<b><u>2018</u></b>	<b><u>2019</u></b>
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
<b>Total</b>	<b>468.930</b>	<b>464.530</b>	<b>476.960</b>	<b>482.410</b>	<b>494.640</b>	<b>498.140</b>

# 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 15<sup>th</sup>
- 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