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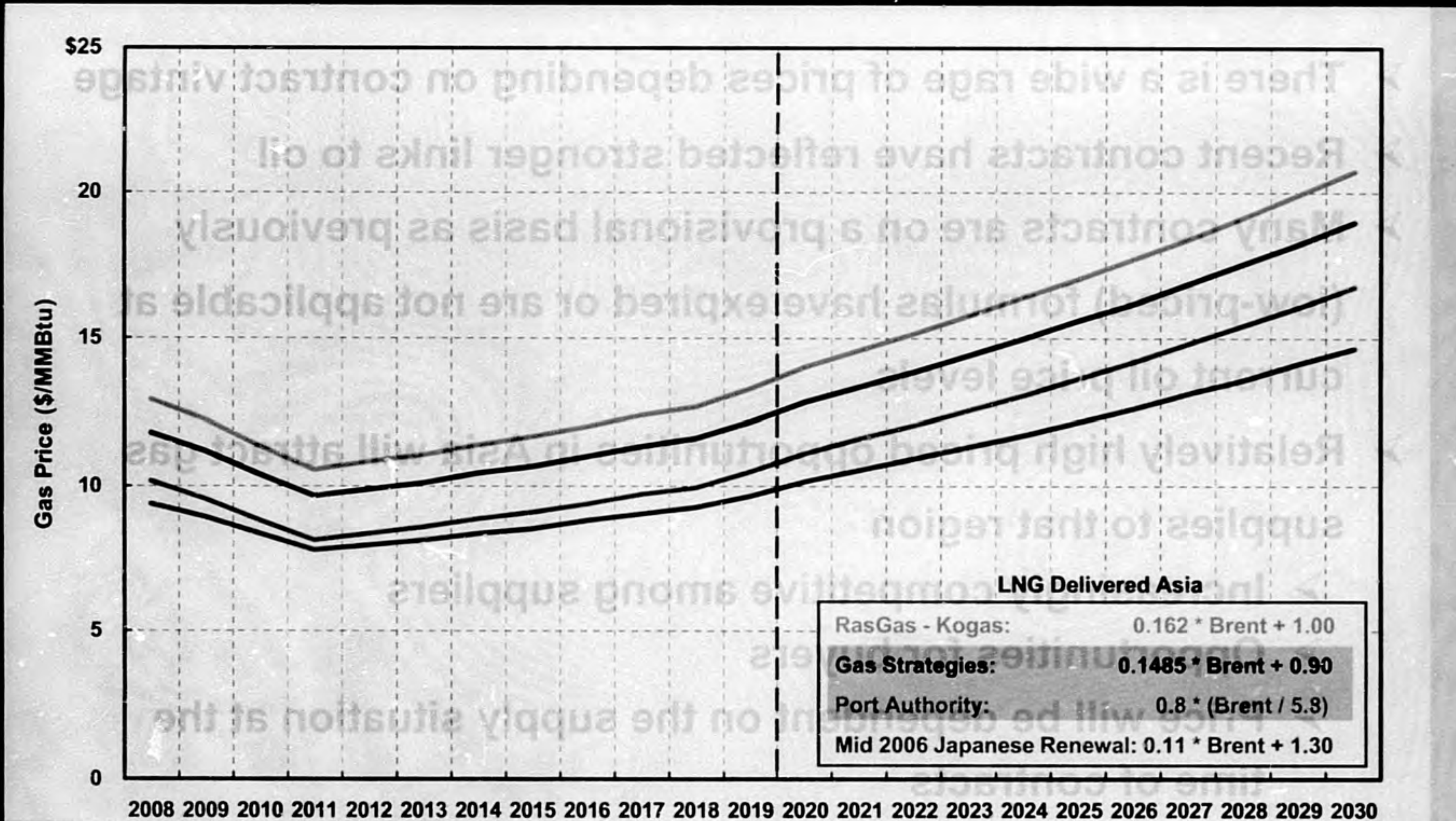
1718

Gas Price Forecasts Used in Analyses

(Using Wood Mackenzie Oil Price Forecast)



= More Likely Price Scenarios

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Prospects for U.S. Gas Prices

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

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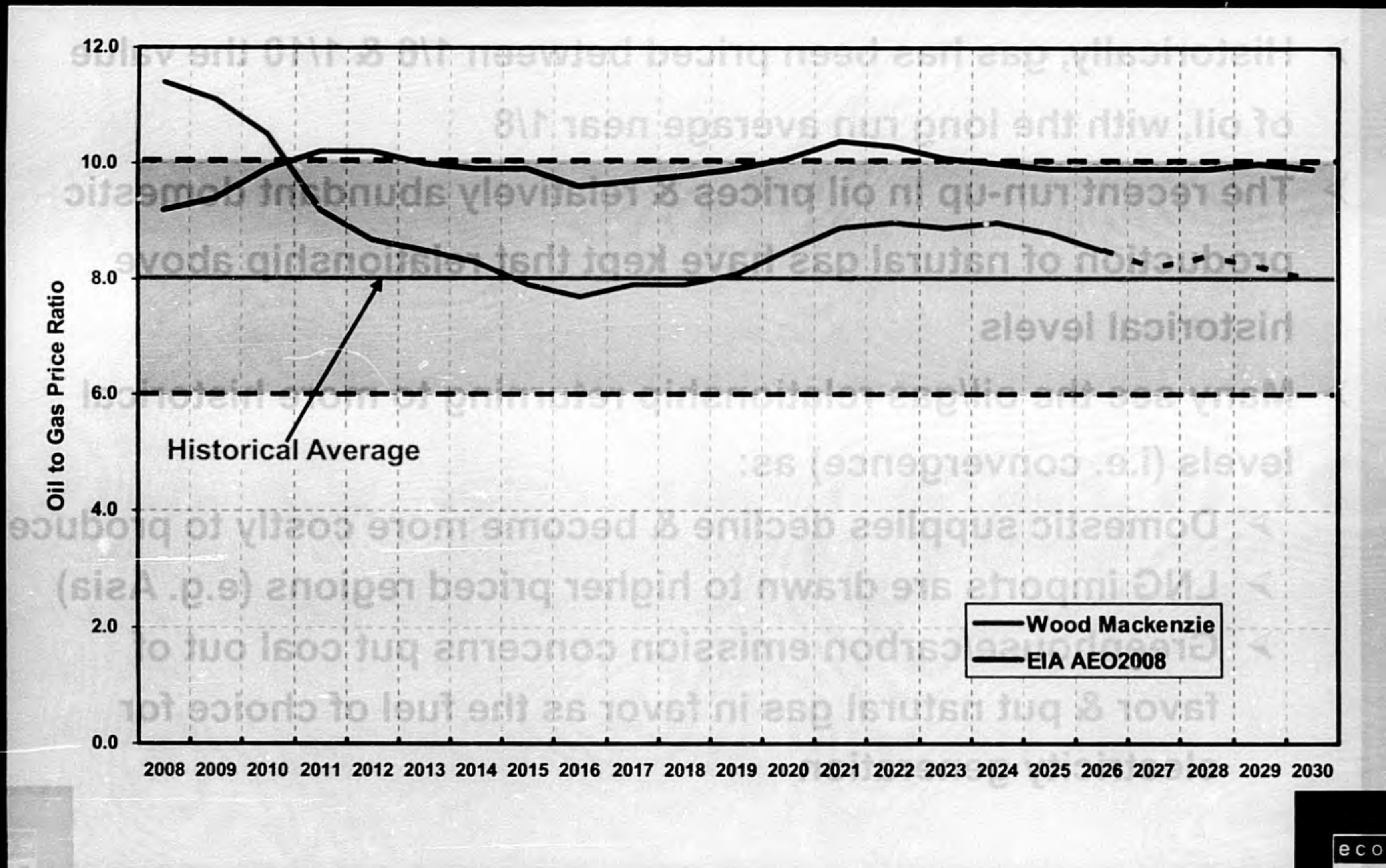
Ratio of Forecasted U.S. Oil and Gas Prices



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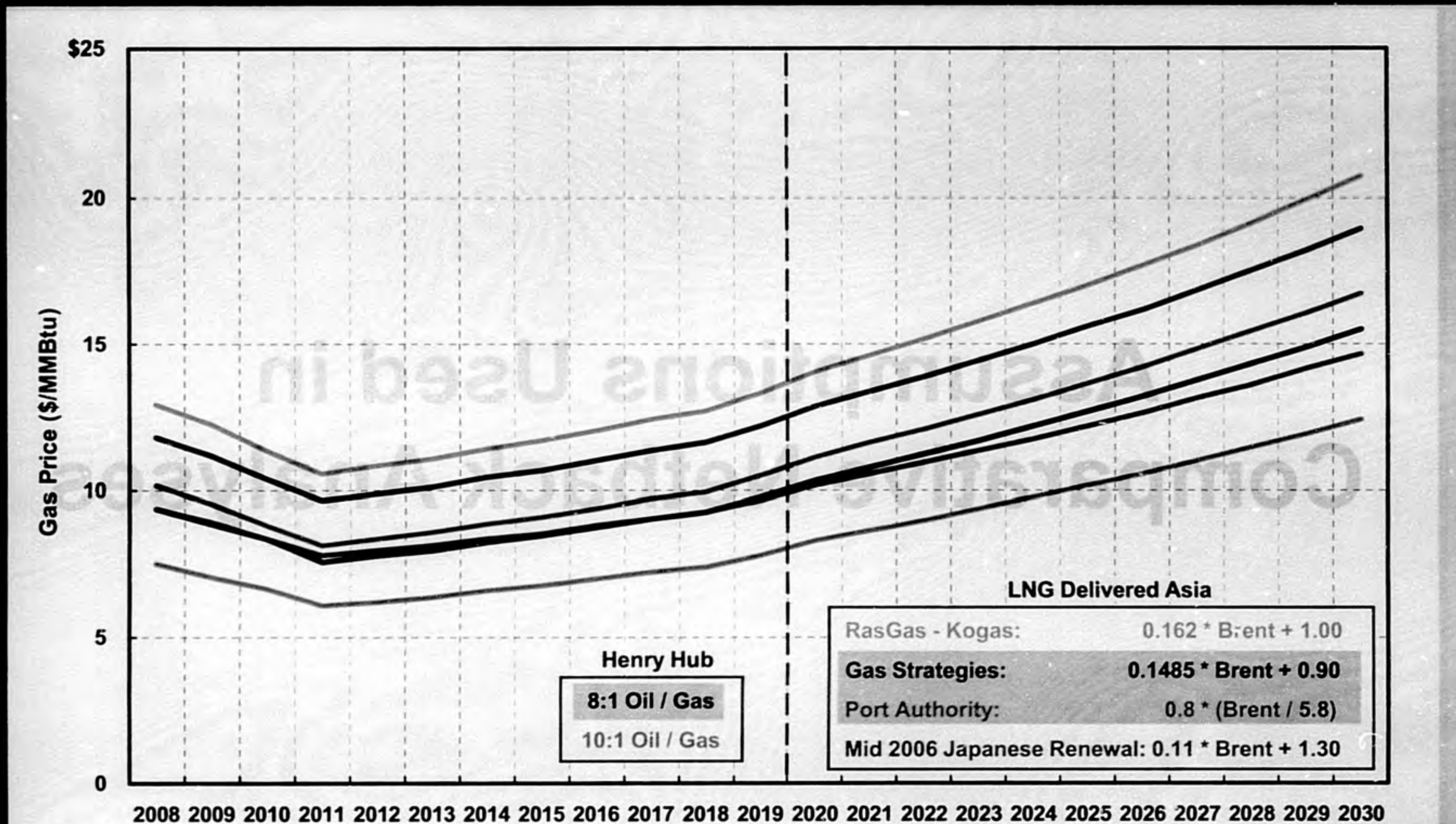
Gas Price Forecasts Used in Analyses
(Using Wood Mackenzie Oil Price Forecast)



= More Likely Price Scenario(s)

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Assumptions Used in Comparative Netback Analyses

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)

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

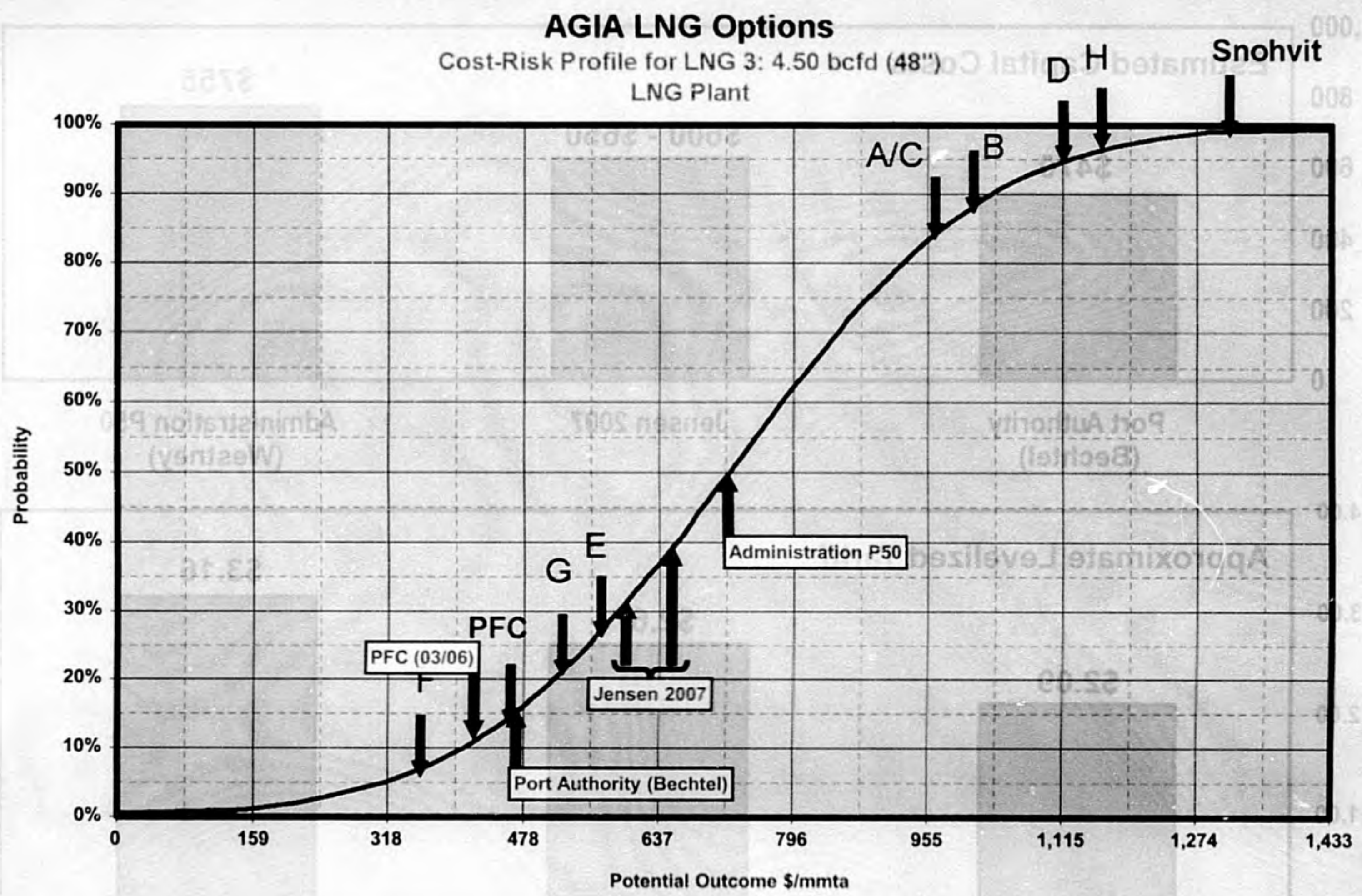
Capital Costs Used in Netback Analyses

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

* Based on $470/mt.

LNG Plant Costs

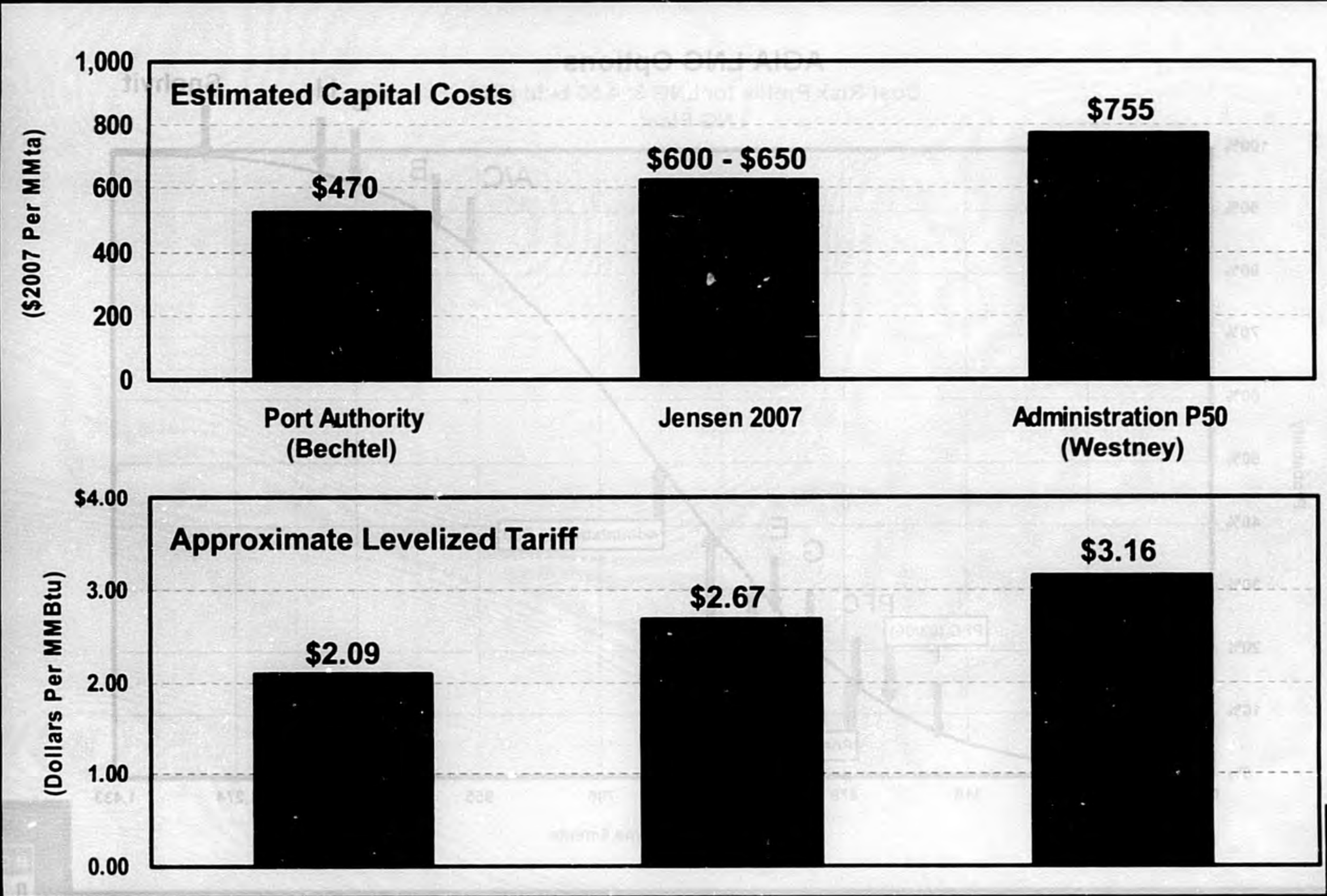
LNG Plant Costs Per Administration (Westney)
($2007 per mmta)



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

Range of LNG Liquefaction Costs and Tariffs

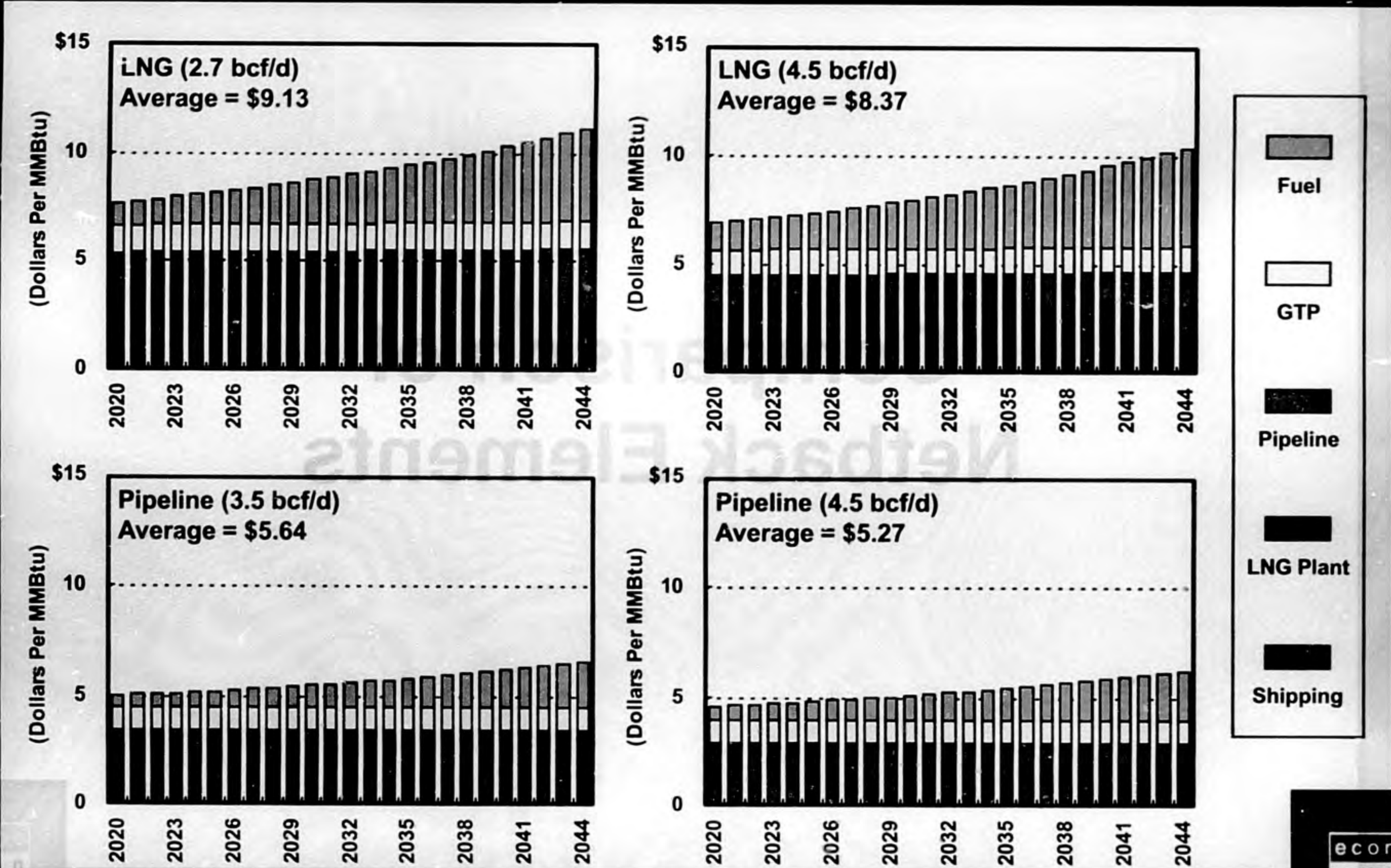
(2.7 bcf/d LNG Project)



Comparison of Netback Elements

Comparison of Potential Costs

LNG Project v. Pipeline Project
2020 - 2044



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

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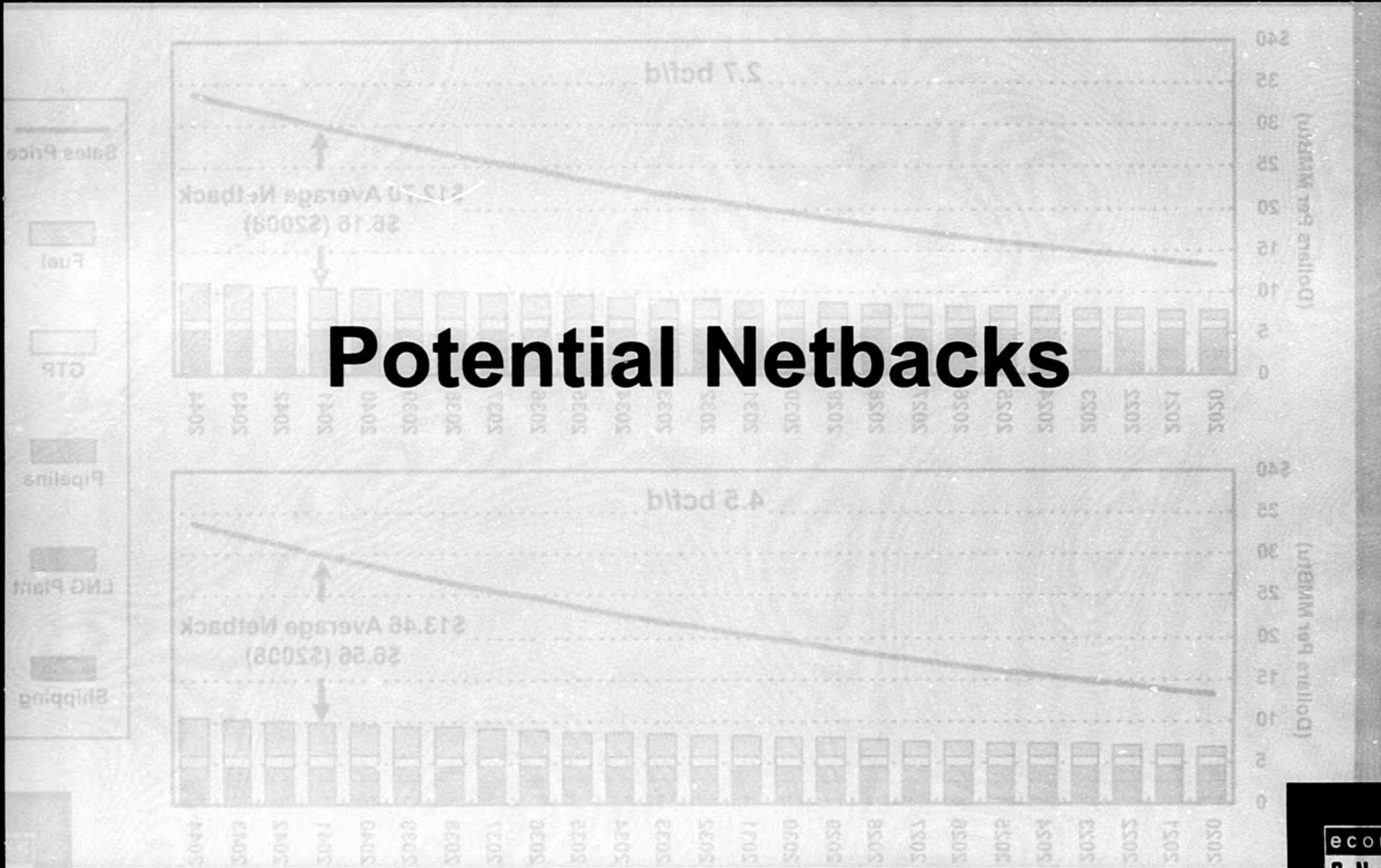
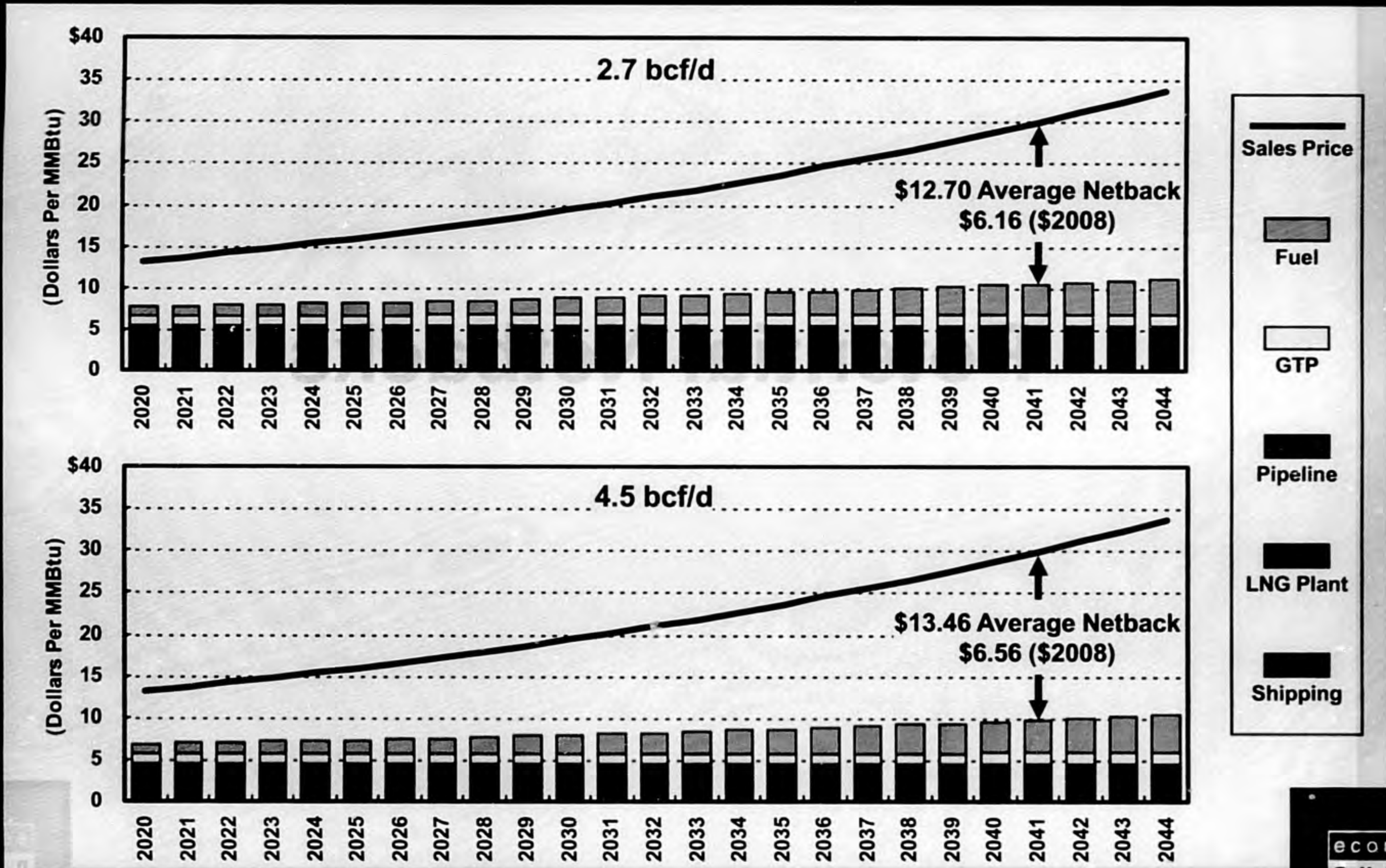
Potential Netbacks



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

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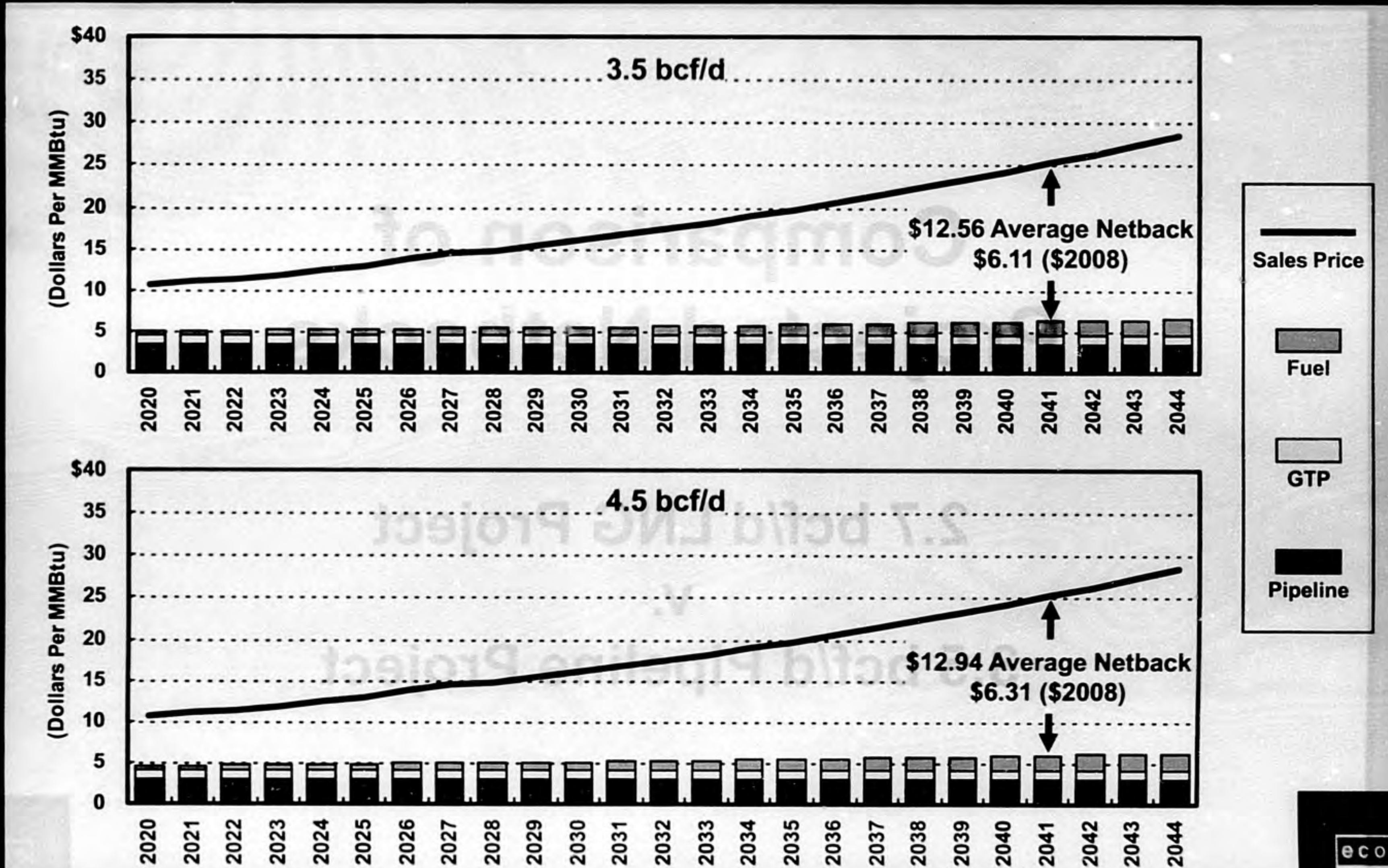
Potential Netbacks for AECO Pipeline Delivery

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



Note: Oil Prices per Wood Mackenzie forecasts.

Comparison of Projected Netbacks

2.7 bcf/d LNG Project

v.

3.5 bcf/d Pipeline Project

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

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

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

= More Likely Price Scenario(s)

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Comparison of Projected Netbacks

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

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

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

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

= More Likely Price Scenario(s)

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Comparison of Projected Netbacks

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

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

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

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

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

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Sensitivities

- High Sustained Oil Prices
- Impact of Project Delay

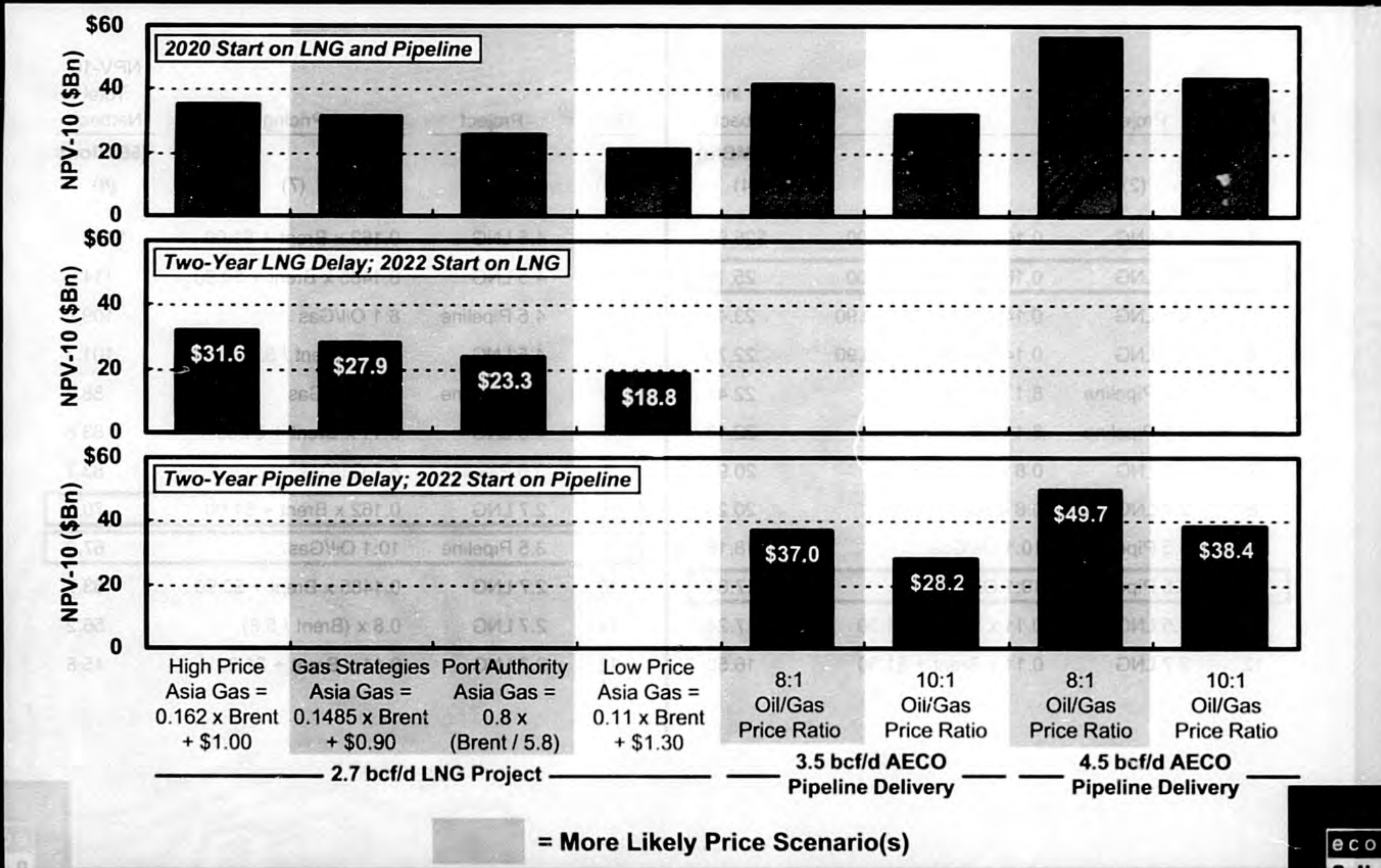
Projected Netbacks Under Alternative Projects
(High Price Case: Fixed $120 Real WTI in $2008)

Rank (1)	Project (2)	Pricing (3)	GTP Inlet Netback ($/MMBtu) (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 (5)	Project (6)	Pricing (7)	NPV-10 Total Netback ($Billion) (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



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LNG Export Issues

LNG Export Issues

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

LNG Export Issues
(cont'd)

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

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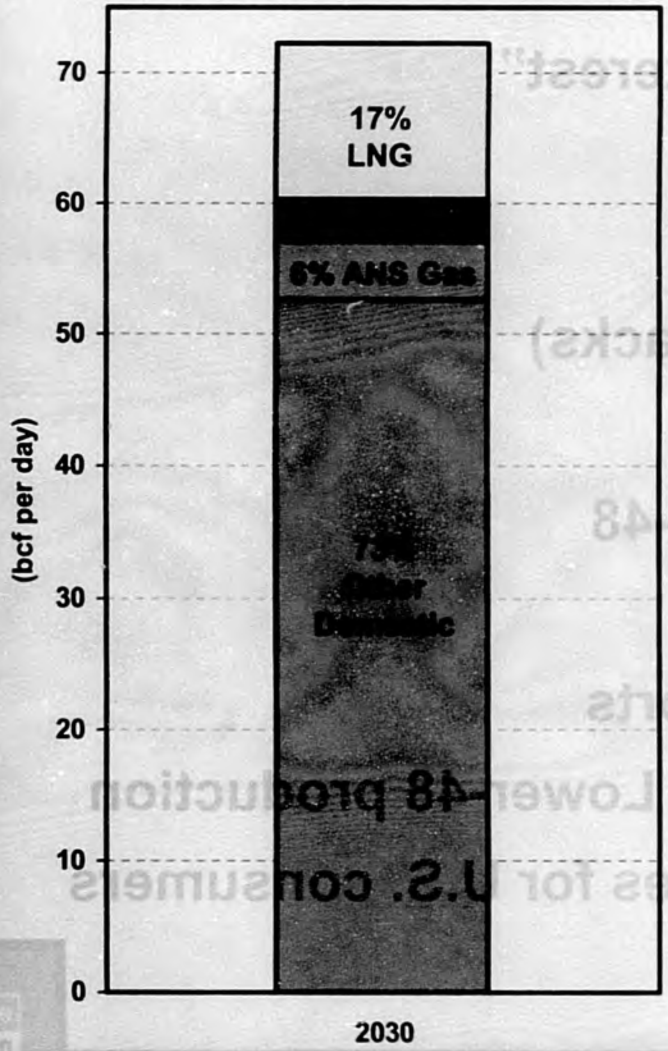
Will D.O.E. Find LNG Exports in the Public Interest?



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

Source: EIA AEO 2007

LNG Export Issues
(cont'd)

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

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Conclusions

Conclusions

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

Conclusions
(cont'd)

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

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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

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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

Mitsubishi Corporation

Alaska Gasline Port Authority

Presentation to the Alaska Legislature

June 20, 2008

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Mitsubishi Corporation

Alaska Gasline Port Authority

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

AGPA Financial Model: Summary of Key Assumptions and Results 07/11/07

Case: Base Case

		units	Avg	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Gas and Liquids Volumes																						
(1)	GCP Inlet Volume (net of CO2)	Bcf/d		2.61	2.61	2.67	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73
(2)	Pipeline Inlet Volume	Bcf/d		2.50	2.50	2.55	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61
(3)	LNG Facility Inlet Volume	Bcf/d		2.46	2.46	2.51	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57
(4)	LNG Production Volume	Bcf/d		2.25	2.25	2.30	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34
(5)	Gas Sales in Alberta Volume	Bcf/d		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(6)	NGL Production in Valdez	mbpd		22.36	22.36	22.85	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34
(7)	NGL Production in Alberta	mbpd		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Nominal Price Assumptions																						
(8)	EIA "Imported Crude Oil"	$/bbl		63.62	65.49	67.74	69.24	71.62	74.17	77.81	80.59	83.44	86.28	88.93	91.65	94.38	97.26	99.16	101.10	103.08	105.09	107.15	109.25
(9)	JCC	$/bbl		67.61	69.55	71.88	73.43	75.89	78.53	82.29	85.17	88.11	91.05	93.79	96.60	99.42	102.40	104.37	106.38	108.42	110.51	112.63	114.80
(10)	Henry Hub	$/mmBtu	9.54	7.23	7.26	7.33	7.60	7.76	8.12	8.48	8.90	9.09	9.32	9.65	10.07	10.43	10.72	10.93	11.14	11.36	11.58	11.81	12.04
(11)	AECO	$/mmBtu		6.81	6.84	6.91	7.18	7.34	7.70	8.06	8.48	8.67	8.90	9.23	9.65	10.01	10.30	10.51	10.72	10.94	11.16	11.39	11.62
(12)	Asian DES Price	$/mmBtu	12.64	9.33	9.59	9.91	10.13	10.47	10.83	11.35	11.75	12.15	12.56	12.94	13.32	13.71	14.12	14.40	14.67	14.95	15.24	15.54	15.83
(13)	Propane CIF Japan	cents/g		110	112	115	117	121	124	129	132	136	140	144	147	151	155	157	160	162	165	168	171
(14)	Propane Edmonton	cents/g		101	103	106	109	112	116	122	126	130	134	139	143	148	152	155	158	161	164	167	170
(15)	Ethane Alberta	cents/g		71	72	74	76	79	81	85	88	91	94	97	100	103	106	108	110	113	115	117	119
	Costs																						
(16)	Unit LNG Shipping Costs	$/mmBtu		0.69	0.69	0.69	0.68	0.69	0.70	0.71	0.71	0.72	0.73	0.74	0.75	0.75	0.76	0.77	0.78	0.78	0.79	0.80	0.81
(17)	Tariff - LNG Facility	$/mmBtu		1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
(18)	Tariff - Pipeline	$/mmBtu		2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54
(19)	Tariff - GCP	$/mmBtu		0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
(20)	Tariff - Feeder Lines	$/mmBtu		0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
(21)	Tariff - AK-Can Pipeline	$/mmBtu		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(22)	Tariff - Canada Pipeline	$/mmBtu		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(23)	Fuel and Losses (net of NGL uplift)	$/mmBtu		0.50	0.54	0.58	0.62	0.67	0.72	0.79	0.85	0.91	0.97	1.02	1.08	1.13	1.19	1.23	1.27	1.31	1.35	1.40	1.44
(24)	Average Price at Point of Production	$/mmBtu	5.43	2.65	2.87	3.15	3.33	3.62	3.92	4.36	4.69	5.03	5.37	5.68	6.01	6.33	6.67	6.90	7.13	7.37	7.60	7.85	8.10
	Cash Flows																						
(25)	Gas and NGL Sales Revenues	USD mm		4,183	8,533	9,010	9,426	9,713	10,048	10,525	10,919	11,263	11,635	11,984	12,374	12,698	13,077	13,326	13,618	13,840	14,105	14,375	14,690
(26)	LNG Shipping Costs	USD mm		301	603	612	623	627	634	642	651	656	663	670	679	685	692	699	707	711	718	724	735
(27)	LPG Shipping Costs	USD mm		6	12	12	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
(28)	NGL Processing Fees in Alberta	USD mm		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(29)	Tariff Payments - LNG Facility	USD mm		770	1,528	1,562	1,600	1,595	1,595	1,595	1,600	1,595	1,595	1,595	1,600	1,595	1,595	1,595	1,600	1,595	1,595	1,595	1,600
(30)	Tariff Payments - Pipeline	USD mm		1,243	2,465	2,519	2,580	2,573	2,573	2,573	2,580	2,573	2,573	2,573	2,580	2,573	2,573	2,573	2,580	2,573	2,573	2,573	2,580
(31)	Tariff Payments - GCP	USD mm		380	753	770	788	786	786	786	788	786	786	786	788	786	786	786	788	786	786	786	788
(32)	Tariff Payments - Feeder Lines	USD mm		103	205	209	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214
(33)	Tariff Payments - AK-Can Pipeline	USD mm		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(34)	Tariff Payments - Canada Pipeline	USD mm		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(35)	Netback Revenue at Point of Production	USD mm	5,781	1,380	2,967	3,325	3,607	3,904	4,232	4,702	5,073	5,426	5,791	6,133	6,499	6,832	7,203	7,446	7,716	7,948	8,205	8,469	8,762
						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(36)	Property Tax	USD mm		609	610	593	572	550	529	5[illegible]8	486	465	444	423	401	380	359	337	316	295	274	252	231
(37)	State Income Tax	USD mm		(90)	175	209	279	332	383	161	182	200	210	229	248	252	258	265	273	313	370	395	405
(38)	State Royalty	USD mm		172	371	416	451	488	529	588	634	678	724	767	812	854	900	931	964	993	1,026	1,059	1,095
(39)	Field Cost Allowance on State Royalty Gas	USD mm		(13)	(27)	(28)	(30)	(30)	(31)	(31)	(32)	(33)	(33)	(34)	(35)	(36)	(36)	(37)	(38)	(39)	(39)	(40)	(41)
(40)	Production Tax	USD mm		212	543	614	669	728	793	885	959	1,028	1,100	1,168	1,240	1,306	1,379	1,427	1,480	1,526	1,577	1,628	1,686
(41)	State Cash Flows	USD mm		891	1,672	1,803	1,942	2,068	2,203	2,110	2,229	2,339	2,444	2,551	2,666	2,756	2,860	2,923	2,996	3,088	3,207	3,295	3,376
(42)	NPV @ 0%	USD mm	93,930																				
(43)	NPV @ 2%	USD mm	53,654																				
(44)	NPV @ 5%	USD mm	24,835																				
(45)	NPV @ 6%	USD mm	19,551																				
(46)	NPV @ 8%	USD mm	12,412																				

AGPA Financial Model: Summary of Key Assumptions and Results 07/11/07

Case: EIA High Price

		units	Avg	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Gas and Liquids Volumes																						
(1)	GCP Inlet Volume (net of CO2)	Bcf/d		2.61	2.61	2.67	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73
(2)	Pipeline Inlet Volume	Bcf/d		2.50	2.50	2.55	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61
(3)	LNG Facility Inlet Volume	Bcf/d		2.46	2.46	2.51	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57
(4)	LNG Production Volume	Bcf/d		2.25	2.25	2.30	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34
(5)	Gas Sales in Alberta Volume	Bcf/d		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(6)	NGL Production in Valdez	mbpd		22.36	22.36	22.85	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34
(7)	NGL Production in Alberta	mbpd		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Nominal Price Assumptions																						
(8)	EIA "Imported Crude Oil"	$/bbl		104.83	109.15	113.87	118.57	122.59	126.29	130.55	135.07	139.73	144.34	149.22	154.28	159.38	164.74	167.96	171.25	174.60	178.02	181.50	185.05
(9)	JCC	$/bbl		110.24	114.70	119.58	124.45	128.61	132.43	136.84	141.51	146.32	151.09	156.14	161.37	166.65	172.19	175.53	178.92	182.39	185.92	189.52	193.20
(10)	Henry Hub	$/mmBtu	11.64	8.42	8.31	8.09	8.59	9.11	9.47	10.06	10.37	10.79	11.39	11.87	12.43	12.95	13.61	13.87	14.15	14.42	14.70	14.99	15.29
(11)	AECO	$/mmBtu		8.00	7.89	7.67	8.17	8.69	9.05	9.64	9.95	10.37	10.97	11.45	12.01	12.53	13.19	13.45	13.73	14.00	14.28	14.57	14.87
(12)	Asian DES Price	$/mmBtu	21.16	15.21	15.82	16.49	17.17	17.74	18.27	18.87	19.52	20.18	20.84	21.54	22.26	22.99	23.75	24.21	24.68	25.16	25.64	26.14	26.65
(13)	Propane CIF Japan	cents/g		165	170	177	183	188	193	199	205	211	217	224	230	237	244	249	253	257	262	266	271
(14)	Propane Edmonton	cents/g		153	158	163	170	176	182	189	195	202	209	216	224	232	240	245	250	255	259	264	270
(15)	Ethane Alberta	cents/g		107	111	114	119	123	127	132	136	141	146	152	157	162	168	171	175	178	182	185	189
	Costs																						
(16)	Unit LNG Shipping Costs	$/mmBtu		0.74	0.75	0.75	0.75	0.76	0.77	0.78	0.79	0.80	0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.89	0.90	0.91
(17)	Tariff - LNG Facility	$/mmBtu		1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
(18)	Tariff - Pipeline	$/mmBtu		2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54
(19)	Tariff - GCP	$/mmBtu		0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
(20)	Tariff - Feeder Lines	$/mmBtu		0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	[illegible]	0.66	0.66	0.66	0.66	0.66	0.66	0.66
(21)	Tariff - AK-Can Pipeline	$/mmBtu		-	-	-	-	-	-	-	-	-	-	-	-	[illegible]	-	-	-	-	-	-	-
(22)	Tariff - Canada Pipeline	$/mmBtu		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(23)	Fuel and Losses (net of NGL uplift)	$/mmBtu		1.36	1.45	1.55	1.64	1.73	1.80	1.89	1.99	2.08	2.18	2.28	2.38	2.49	2.60	2.67	2.73	2.80	2.87	2.94	3.02
(24)	Average Price at Point of Production	$/mmBtu	12.62	7.61	8.13	8.70	9.28	9.76	10.20	10.71	11.25	11.81	12.36	12.95	13.55	14.16	14.80	15.19	15.58	15.98	16.39	16.81	17.23
	Cash Flows																						
(25)	Gas and NGL Sales Revenues	USD mm		6,795	14,021	14,935	15,917	16,401	16,887	17,446	18,088	18,650	19,255	19,895	20,616	21,228	21,932	22,355	22,849	23,226	23,674	24,131	24,665
(26)	LNG Shipping Costs	USD mm		326	654	668	684	690	698	707	718	725	735	745	757	765	776	783	793	799	807	816	827
(27)	LPG Shipping Costs	USD mm		6	12	12	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
(28)	NGL Processing Fees in Alberta	USD mm		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(29)	Tariff Payments - LNG Facility	USD mm		770	1,528	1,562	1,600	1,595	1,595	1,595	1,600	1,595	1,595	1,595	1,600	1,595	1,595	1,595	1,600	1,595	1,595	1,595	1,600
(30)	Tariff Payments - Pipeline	USD mm		1,243	2,465	2,519	2,580	2,573	2,573	2,573	2,580	2,573	2,573	2,573	2,580	2,573	2,573	2,573	2,580	2,573	2,573	2,573	2,580
(31)	Tariff Payments - GCP	USD mm		380	753	770	788	786	786	786	788	786	786	786	788	786	786	786	788	786	786	786	788
(32)	Tariff Payments - Feeder Lines	USD mm		103	205	209	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214
(33)	Tariff Payments - AK-Can Pipeline	USD mm		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(34)	Tariff Payments - Canada Pipeline	USD mm		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(35)	Netback Revenue at Point of Production	USD mm	13,390	3,967	8,403	9,195	10,038	10,530	11,008	11,558	12,174	12,743	13,339	13,970	14,663	15,282	15,975	16,390	16,860	17,245	17,686	18,134	18,643
						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(36)	Property Tax	USD mm		609	610	593	572	550	529	508	486	465	444	423	401	380	359	337	316	295	274	252	231
(37)	State Income Tax	USD mm		75	522	583	689	754	815	161	182	200	210	229	248	252	258	265	273	313	370	395	405
(38)	State Royalty	USD mm		496	1,050	1,149	1,255	1,316	1,376	1,445	1,522	1,593	1,667	1,746	1,833	1,910	1,997	2,049	2,107	2,156	2,211	2,267	2,330
(39)	Field Cost Allowance on State Royalty Gas	USD mm		(13)	(27)	(28)	(30)	(30)	(31)	(31)	(32)	(33)	(33)	(34)	(35)	(36)	(36)	(37)	(38)	(39)	(39)	(40)	(41)
(40)	Production Tax	USD mm		722	1,613	1,769	1,935	2,033	2,127	2,235	2,357	2,469	2,586	2,711	2,847	2,969	3,106	3,188	3,280	3,356	3,443	3,531	3,631
(41)	State Cash Flows	USD mm		1,888	3,768	4,066	4,422	4,623	4,816	4,317	4,515	4,694	4,874	5,074	5,294	5,476	5,683	5,802	5,939	6,081	6,258	6,405	6,557
(42)	NPV @ 0%	USD mm	182,368																				
(43)	NPV @ 2%	USD mm	105,683																				
(44)	NPV @ 5%	USD mm	50,071																				
(45)	NPV @ 6%	USD mm	39,738																				
(46)	NPV @ 8%	USD mm	25,654																				

AGPA Financial Model: Summary of Key Assumptions and Results 07/11/07

Case: EIA Low Price

	units	Avg	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Gas and Liquids Volumes												
(1) GCP Inlet Volume (net of CO2)	Bcf/d		2.61	2.61	2.67	2.73	2.73	2.73	2.73	2.73	2.73	2.73
(2) Pipeline Inlet Volume	Bcf/d		2.50	2.50	2.55	2.61	2.61	2.61	2.61	2.61	2.61	2.61
(3) LNG Facility Inlet Volume	Bcf/d		2.46	2.46	2.51	2.57	2.57	2.57	2.57	2.57	2.57	2.57
(4) LNG Production Volume	Bcf/d		2.25	2.25	2.30	2.34	2.34	2.34	2.34	2.34	2.34	2.34
(5) Gas Sales in Alberta Volume	Bcf/d		-	-	-	-	-	-	-	-	-	-
(6) NGL Production in Valdez	mbpd		22.36	22.36	22.85	23.34	23.34	23.34	23.34	23.34	23.34	23.34
(7) NGL Production in Alberta	mbpd		-	-	-	-	-	-	-	-	-	-
Nominal Price Assumptions												
(8) EIA "Imported Crude Oil"	$/bbl		42.46	43.42	44.41	45.37	46.53	47.78	49.00	50.29	51.64	52.94
(9) JCC	$/bbl		45.73	46.72	47.75	48.74	49.94	51.23	52.49	53.84	55.23	56.57
(10) Henry Hub	$/mmBtu	8.06	5.77	5.90	6.08	6.20	6.54	6.95	7.17	7.60	7.70	8.03
(11) AECO	$/mmBtu		5.35	5.48	5.66	5.78	6.12	6.53	6.75	7.18	7.28	7.61
(12) Asian DES Price	$/mmBtu	7.93	6.31	6.44	6.59	6.72	6.89	7.07	7.24	7.43	7.62	7.80
(13) Propane CIF Japan	cents/g		82	83	84	86	87	89	91	92	94	96
(14) Propane Edmonton	cents/g		72	73	75	76	79	82	84	87	89	91
(15) Ethane Alberta	cents/g		50	51	52	53	55	57	59	61	62	64
Costs												
(16) Unit LNG Shipping Costs	$/mmBtu		0.66	0.66	0.66	0.65	0.66	0.66	0.67	0.67	0.68	0.69
(17) Tariff - LNG Facility	$/mmBtu		1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
(18) Tariff - Pipeline	$/mmBtu		2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54
(19) Tariff - GCP	$/mmBtu		0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
(20) Tariff - Feeder Lines	$/mmBtu		0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
(21) Tariff - AK-Can Pipeline	$/mmBtu		-	-	-	-	-	-	-	-	-	-
(22) Tariff - Canada Pipeline	$/mmBtu		-	-	-	-	-	-	-	-	-	-
(23) Fuel and Losses (net of NGL uplift)	$/mmBtu		0.06	0.08	0.10	0.12	0.14	0.17	0.19	0.22	0.25	0.27
(24) Average Price at Point of Production	$/mmBtu	1.45	0.10	0.21	0.34	0.45	0.59	0.74	0.89	1.04	1.20	1.35
Cash Flows												
(25) Gas and NGL Sales Revenues	USD mm		2,842	5,758	6,012	6,285	6,420	6,583	6,743	6,933	7,090	7,261
(26) LNG Shipping Costs	USD mm		289	577	584	593	596	601	606	613	617	622
(27) LPG Shipping Costs	USD mm		6	12	12	13	13	13	13	13	13	13
(28) NGL Processing Fees in Alberta	USD mm		-	-	-	-	-	-	-	-	-	-
(29) Tariff Payments - LNG Facility	USD mm		770	1,528	1,562	1,600	1,595	1,595	1,595	1,600	1,595	1,595
(30) Tariff Payments - Pipeline	USD mm		1,243	2,465	2,519	2,580	2,573	2,573	2,573	2,580	2,573	2,573
(31) Tariff Payments - GCP	USD mm		380	753	770	788	786	786	786	788	786	786
(32) Tariff Payments - Feeder Lines	USD mm		103	205	209	214	214	214	214	214	214	214
(33) Tariff Payments - AK-Can Pipeline	USD mm		-	-	-	-	-	-	-	-	-	-
(34) Tariff Payments - Canada Pipeline	USD mm		-	-	-	-	-	-	-	-	-	-
(35) Netback Revenue at Point of Production	USD mm	1,567.63	51	218	355	496	642	801	956	1,124	1,292	1,457
(36) Property Tax	USD mm		609	610	593	572	550	529	508	486	465	444
(37) State Income Tax	USD mm		(178)	2	20	81	124	164	161	182	200	210
(38) State Royalty	USD mm		6	27	44	62	80	100	119	141	162	182
(39) Field Cost Allowance on State Royalty Gas	USD mm		(13)	(27)	(28)	(30)	(30)	(31)	(31)	(32)	(33)	(33)
(40) Production Tax	USD mm		(16)	(20)	29	57	86	117	148	181	214	247
(41) State Cash Flows	USD mm		408	592	658	742	810	880	905	958	1,008	1,049
(42) NPV @ 0%	USD mm	44,426										
(43) NPV @ 2%	USD mm	24,703										
(44) NPV @ 5%	USD mm	10,934										
(45) NPV @ 6%	USD mm	8,469										
(46) NPV @ 8%	USD mm	5,195										

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
(1) GCP Inlet Volume (net of CO2)	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73
(2) Pipeline Inlet Volume	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61	2.61
(3) LNG Facility Inlet Volume	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57
(4) LNG Production Volume	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34
(5) Gas Sales in Alberta Volume	-	-	-	-	-	-	-	-	-	-
(6) NGL Production in Valdez	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34	23.34
(7) NGL Production in Alberta	-	-	-	-	-	-	-	-	-	-
(8) EIA "Imported Crude Oil"	54.32	55.77	57.20	58.70	59.84	61.02	62.21	63.43	64.67	65.93
(9) JCC	58.00	59.50	60.98	62.52	63.71	64.92	66.16	67.42	68.70	70.01
(10) Henry Hub	8.30	8.56	8.81	9.10	9.28	9.46	9.64	9.83	10.03	10.22
(11) AECO	7.88	8.14	8.39	8.68	8.86	9.04	9.22	9.41	9.61	9.80
(12) Asian DES Price	8.00	8.21	8.41	8.62	8.79	8.95	9.13	9.30	9.48	9.66
(13) Propane CIF Japan	98	100	101	103	105	106	108	110	111	113
(14) Propane Edmonton	94	96	99	101	103	105	107	109	111	114
(15) Ethane Alberta	66	67	69	71	72	74	75	77	78	80
(16) Unit LNG Shipping Costs	0.69	0.70	0.70	0.71	0.72	0.72	0.73	0.73	0.74	0.75
(17) Tariff - LNG Facility	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
(18) Tariff - Pipeline	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54
(19) Tariff - GCP	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
(20) Tariff - Feeder Lines	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
(21) Tariff - AK-Can Pipeline	-	-	-	-	-	-	-	-	-	-
(22) Tariff - Canada Pipeline	-	-	-	-	-	-	-	-	-	-
(23) Fuel and Losses (net of NGL uplift)	0.30	0.33	0.36	0.39	0.41	0.44	0.46	0.49	0.51	0.54
(24) Average Price at Point of Production	1.51	1.68	1.85	2.03	2.16	2.30	2.44	2.59	2.73	2.88
(25) Gas and NGL Sales Revenues	7,443	7,653	7,820	8,016	8,167	8,344	8,477	8,637	8,800	8,991
(26) LNG Shipping Costs	628	635	639	645	650	657	661	666	672	680
(27) LPG Shipping Costs	13	13	13	13	13	13	13	13	13	13
(28) NGL Processing Fees in Alberta	-	-	-	-	-	-	-	-	-	-
(29) Tariff Payments - LNG Facility	1,595	1,600	1,595	1,595	1,595	1,600	1,595	1,595	1,595	1,600
(30) Tariff Payments - Pipeline	2,573	2,580	2,573	2,573	2,573	2,580	2,573	2,573	2,573	2,580
(31) Tariff Payments - GCP	786	788	786	786	786	788	786	786	785	788
(32) Tariff Payments - Feeder Lines	214	214	214	214	214	214	214	214	214	214
(33) Tariff Payments - AK-Can Pipeline	-	-	-	-	-	-	-	-	-	-
(34) Tariff Payments - Canada Pipeline	-	-	-	-	-	-	-	-	-	-
(35) Netback Revenue at Point of Production	1,634	1,823	1,999	2,190	2,336	2,491	2,635	2,790	2,947	3,116
(36) Property Tax	423	401	380	359	337	316	295	274	252	231
(37) State Income Tax	229	248	252	258	265	273	313	370	395	405
(38) State Royalty	204	228	250	274	292	311	329	349	368	389
(39) Field Cost Allowance on State Royalty Gas	(34)	(35)	(36)	(36)	(37)	(38)	(39)	(39)	(40)	(41)
(40) Production Tax	282	319	354	392	420	451	480	510	541	574
(41) State Cash Flows	1,103	1,161	1,201	1,246	1,278	1,314	1,378	1,463	1,517	1,559

AGPA Financial Model: Summary of Key Assumptions and Results 07/11/07

Case: Alcan Highway 3.0 bcfd

		units	Avg	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Gas and Liquids Volumes																						
(1)	GCP Inlet Volume (net of CO2)	Bcf/d		3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14
(2)	Pipeline Inlet Volume	Bcf/d		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
(3)	LNG Facility Inlet Volume	Bcf/d		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(4)	LNG Production Volume	Bcf/d		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(5)	Gas Sales in Alberta Volume	Bcf/d		2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75
(6)	NGL Production in Valdez	mbpd		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(7)	NGL Production in Alberta	mbpd		91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57	91.57
	Nominal Price Assumptions																						
(8)	EIA "Imported Crude Oil"	bl		63.62	65.49	67.74	69.24	71.62	74.17	77.81	80.59	83.44	86.28	88.93	91.65	94.38	97.26	99.16	101.10	103.08	105.09	107.15	109.25
(9)	JCC	$/bbl		67.61	69.55	71.88	73.43	75.89	78.53	82.29	85.17	88.11	91.05	93.79	96.60	99.42	102.40	104.37	106.38	108.42	110.51	112.63	114.80
(10)	Henry Hub	$/mmBtu	9.54	7.23	7.26	7.33	7.60	7.76	8.12	8.48	8.90	9.09	9.32	9.65	10.07	10.43	10.72	10.93	11.14	11.36	11.58	11.81	12.04
(11)	AECO	$/mmBtu		6.81	6.84	6.91	7.18	7.34	7.70	8.06	8.48	8.67	8.90	9.23	9.65	10.01	10.30	10.51	10.72	10.94	11.16	11.39	11.62
(12)	Asian DES Price	$/mmBtu	12.64	9.33	9.59	9.91	10.13	10.47	10.83	11.35	11.75	12.15	12.56	12.94	13.32	13.71	14.12	14.40	14.67	14.95	15.24	15.54	15.83
(13)	Propane CIF Japan	cents/g		110	112	115	117	121	124	129	132	136	140	144	147	151	155	157	160	162	165	168	171
(14)	Propane Edmonton	ts/g		101	103	106	109	112	116	122	126	130	134	139	143	148	152	155	158	161	164	167	170
(15)	Ethane Alberta	cents/g		71	72	74	76	79	81	85	88	91	94	97	100	103	106	108	110	113	115	117	119
	Costs																						
(16)	Unit LNG Shipping Costs	$/mmBtu		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(17)	Tariff - LNG Facility	$/mmBtu		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(18)	Tariff - Pipeline	$/mmBtu		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(19)	Tariff - GCP	$/mmBtu		0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
(20)	Tariff - Feeder Lines	$/mmBtu		0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
(21)	Tariff - AK-Can Pipeline	$/mmBtu		2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25
(22)	Tariff - Canada Pipeline	$/mmBtu		2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64
(23)	Fuel and Losses (net of NGL uplift)	$/mmBtu		(2.45)	(0.53)	(0.54)	(0.51)	(0.52)	(0.49)	(0.47)	(0.44)	(0.44)	(0.44)	(0.42)	(0.39)	(0.36)	(0.35)	(0.34)	(0.33)	(0.32)	(0.30)	(0.29)	(0.28)
(24)	Average Price at Point of Production	$/mmBtu	3.42	3.05	1.15	1.23	1.48	1.64	1.97	2.32	2.71	2.89	3.12	3.43	3.82	4.16	4.43	4.63	4.83	5.04	5.25	5.47	5.69
	Cash Flows																						
(25)	Gas and NGL Sales Revenues	USD mm		8,202	8,254	8,358	8,692	8,867	9,290	9,726	10,242	10,450	10,733	11,129	11,650	12,041	12,386	12,636	12,926	13,151	13,416	13,687	14,001
(26)	LNG Shipping Costs	USD mm		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(27)	LPG Shipping Costs	USD mm		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(28)	NGL Processing Fees in Alberta	USD mm		112	114	117	120	124	128	134	140	144	148	153	158	163	168	171	175	177	181	184	188
(29)	Tariff Payments - LNG Facility	USD mm		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(30)	Tariff Payments - Pipeline	USD mm		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(31)	Tariff Payments - GCP	USD mm		429	851	851	854	851	851	851	854	851	851	851	854	851	851	851	854	851	851	851	854
(32)	Tariff Payments - Feeder Lines	USD mm		107	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212
(33)	Tariff Payments - AK-Can Pipeline	USD mm		2,626	2,626	2,626	2,633	2,626	2,626	2,626	2,633	2,626	2,626	2,626	2,633	2,626	2,626	2,626	2,633	2,626	2,626	2,626	2,633
(34)	Tariff Payments - Canada Pipeline	USD mm		3,021	3,021	3,021	3,029	3,021	3,021	3,021	3,029	3,021	3,021	3,021	3,029	3,021	3,021	3,021	3,029	3,021	3,021	3,021	3,029
(35)	Netback Revenue at Point of Production	USD mm		1,908	1,431	1,531	1,844	2,033	2,452	2,882	3,374	3,597	3,875	4,267	4,764	5,168	5,509	5,756	6,024	6,264	6,526	6,793	7,084
(36)	Property Tax	USD mm		592	576	556	536	516	496	476	456	436	416	396	376	356	336	316	296	276	256	236	216
(37)	State Income Tax	USD mm		13	54	85	135	170	217	100	113	124	128	146	165	169	174	180	187	221	256	263	272
(38)	State Royalty	USD mm		252	193	206	246	270	323	377	439	468	503	552	615	666	710	741	775	805	838	872	909
(39)	Field Cost Allowance on State Royalty Gas	USD mm		(17)	(34)	(35)	(36)	(36)	(37)	(38)	(39)	(40)	(40)	(41)	(42)	(43)	(44)	(45)	(46)	(47)	(48)	(49)	(50)
(40)	Production Tax	USD mm		313	237	257	319	356	439	523	620	664	719	796	894	973	1,040	1,089	1,142	1,189	1,241	1,293	1,351
(41)	State Cash Flows	USD mm		1,154	1,026	1,069	1,199	1,275	1,437	1,439	1,590	1,652	1,726	1,849	2,008	2,122	2,216	2,281	2,354	2,444	2,543	2,616	2,698
(42)	NPV @ 0%	USD mm	75,385																				
(43)	NPV @ 2%	USD mm	42,393																				
(44)	NPV @ 5%	USD mm	19,131																				
(45)	NPV @ 6%	USD mm	14,930																				
(46)	NPV @ 8%	USD mm	9,315																				

AUPA Financial Model: Summary of Key Assumptions and Results

Case: Alcan Highway 4.5 bcfd

07/11/07

		units	Avg	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	Gas and Liquids Volumes												
(1)	GCP Inlet Volume (net of CO2)	Bcf/d		4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71
(2)	Pipeline Inlet Volume	Bcf/d		4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
(3)	LNG Facility Inlet Volume	Bcf/d		-	-	-	-	-	-	-	-	-	-
(4)	LNG Production Volume	Bcf/d		-	-	-	-	-	-	-	-	-	-
(5)	Gas Sales in Alberta Volume	Bcf/d		4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12
(6)	NGL Production in Valdez	mbpd		-	-	-	-	-	-	-	-	-	-
(7)	NGL Production in Alberta	mbpd		137.35	137.35	137.35	137.35	137.35	137.35	137.35	137.35	137.35	137.35
	Nominal Price Assumptions												
(8)	EIA "Imported Crude Oil"	$/bbl		63.62	65.49	67.74	69.24	71.62	74.17	77.81	80.59	83.44	86.28
(9)	JCC	$/bbl		67.61	69.55	71.88	73.43	75.89	78.53	82.29	85.17	88.11	91.05
(10)	Henry Hub	$/mmBtu	9.54	7.23	7.26	7.33	7.60	7.76	8.12	8.48	8.90	9.09	9.32
(11)	AECO	$/mmBtu		6.81	6.84	6.91	7.18	7.34	7.70	8.06	8.48	8.67	8.90
(12)	Asian DES Price	$/mmBtu	12.64	9.33	9.59	9.91	10.13	10.47	10.83	11.35	11.75	12.15	12.56
(13)	Propane CIF Japan	cents/g		110	112	115	117	121	124	129	132	136	140
(14)	Propane Edmonton	cents/g		101	103	106	109	112	116	122	126	130	134
(15)	Ethane Alberta	cents/g		71	72	74	76	79	81	85	88	91	94
	Costs												
(16)	Unit LNG Shipping Costs	$/mmBtu		-	-	-	-	-	-	-	-	-	-
(17)	Tariff - LNG Facility	$/mmBtu		-	-	-	-	-	-	-	-	-	-
(18)	Tariff - Pipeline	$/mmBtu		-	-	-	-	-	-	-	-	-	-
(19)	Tariff - GCP	$/mmBtu		0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
(20)	Tariff - Feeder Lines	$/mmBtu		0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
(21)	Tariff - AK-Can Pipeline	$/mmBtu		1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74
(22)	Tariff - Canada Pipeline	$/mmBtu		2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04
(23)	Fuel and Losses (net of NGL uplift)	$/mmBtu		(3.03)	(0.10)	(0.11)	(0.08)	(0.09)	(0.06)	(0.04)	(0.01)	(0.01)	(0.01)
(24)	Average Price at Point of Production	$/mmBtu	4.55	5.14	2.24	2.32	2.56	2.72	3.06	3.40	3.79	3.98	4.20
	Cash Flows												
(25)	Gas and NGL Sales Revenues	USD mm		12,302	12,381	12,537	13,038	13,300	13,934	14,589	15,363	15,675	16,100
(26)	LNG Shipping Costs	USD mm		-	-	-	-	-	-	-	-	-	-
(27)	LPG Shipping Costs	USD mm		-	-	-	-	-	-	-	-	-	-
(28)	NGL Processing Fees in Alberta	USD mm		167	171	176	181	186	193	202	210	216	223
(29)	Tariff Payments - LNG Facility	USD mm		-	-	-	-	-	-	-	-	-	-
(30)	Tariff Payments - Pipeline	USD mm		-	-	-	-	-	-	-	-	-	-
(31)	Tariff Payments - GCP	USD mm		644	1,277	1,277	1,281	1,277	1,277	1,277	1,281	1,277	1,277
(32)	Tariff Payments - Feeder Lines	USD mm		107	212	212	212	212	212	212	212	212	212
(33)	Tariff Payments - AK-Can Pipeline	USD mm		3,047	3,047	3,047	3,055	3,047	3,047	3,047	3,055	3,047	3,047
(34)	Tariff Payments - Canada Pipeline	USD mm		3,506	3,506	3,506	3,515	3,506	3,506	3,506	3,515	3,506	3,506
(35)	Netback Revenue at Point of Production	USD mm		4,832	4,169	4,320	4,794	5,073	5,700	6,346	7,090	7,418	7,836
(36)	Property Tax	USD mm		813	790	763	735	708	681	653	626	598	571
(37)	State Income Tax	USD mm		116	178	223	295	343	409	126	141	154	159
(38)	State Royalty	USD mm		625	542	562	622	657	737	818	912	95[illegible]	1,007
(39)	Field Cost Allowance on State Royalty Gas	USD mm		(18)	(36)	(37)	(37)	(38)	(39)	(40)	(41)	(41)	(42)
(40)	Production Tax	USD mm		809	721	751	844	900	1,023	1,150	1,297	1,362	1,444
(41)	State Cash Flows	USD mm		2,346	2,195	2,262	2,459	2,570	2,811	2,708	2,936	3,027	3,139
(42)	NPV @ 0%	USD mm	126,159										
(43)	NPV @ 2%	USD mm	71,678										
(44)	NPV @ 5%	USD mm	32,774										
(45)	NPV @ 6%	USD mm	25,665										
(46)	NPV @ 8%	USD mm	16,094										

		2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
(1)	GCP Inlet Volume (net of CO2)	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71
(2)	Pipeline Inlet Volume	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
(3)	LNG Facility Inlet Volume	-	-	-	-	-	-	-	-	-	-
(4)	LNG Production Volume	-	-	-	-	-	-	-	-	-	-
(5)	Gas Sales in Alberta Volume	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12
(6)	NGL Production in Valdez	-	-	-	-	-	-	-	-	-	-
(7)	NGL Production in Alberta	137.35	137.35	137.35	137.35	137.35	137.35	137.35	137.35	137.35	137.35
(8)	EIA "Imported Crude Oil"	88.93	91.65	94.38	97.26	99.16	101.10	103.08	105.09	107.15	109.25
(9)	JCC	93.79	96.60	99.42	102.40	104.37	106.38	108.42	110.51	112.63	114.80
(10)	Henry Hub	9.65	10.07	10.43	10.72	10.93	11.14	11.36	11.58	11.81	12.04
(11)	AECO	9.23	9.65	10.01	10.30	10.51	10.72	10.94	11.16	11.39	11.62
(12)	Asian DES Price	12.94	13.32	13.71	14.12	14.40	14.67	14.95	15.24	15.54	15.83
(13)	Propane CIF Japan	144	147	151	155	157	160	162	165	168	171
(14)	Propane Edmonton	139	143	148	152	155	158	161	164	167	170
(15)	Ethane Alberta	97	100	103	106	108	110	113	115	117	119
(16)	Unit LNG Shipping Costs	-	-	-	-	-	-	-	-	-	-
(17)	Tariff - LNG Facility	-	-	-	-	-	-	-	-	-	-
(18)	Tariff - Pipeline	-	-	-	-	-	-	-	-	-	-
(19)	Tariff - GCP	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
(20)	Tariff - Feeder Lines	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
(21)	Tariff - AK-Can Pipeline	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74
(22)	Tariff - Canada Pipeline	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04
(23)	Fuel and Losses (net of NGL uplift)	0.01	0.04	0.07	0.08	0.09	0.10	0.11	0.13	0.14	0.15
(24)	Average Price at Point of Production	4.52	4.91	5.24	5.52	5.72	5.92	6.13	6.34	6.55	6.77
(25)	Gas and NGL Sales Revenues	16,694	17,476	18,061	18,579	18,954	19,390	19,727	20,125	20,530	21,001
(26)	LNG Shipping Costs	-	-	-	-	-	-	-	-	-	-
(27)	LPG Shipping Costs	-	-	-	-	-	-	-	-	-	-
(28)	NGL Processing Fees in Alberta	229	238	244	251	256	262	266	271	277	283
(29)	Tariff Payments - LNG Facility	-	-	-	-	-	-	-	-	-	-
(30)	Tariff Payments - Pipeline	-	-	-	-	-	-	-	-	-	-
(31)	Tariff Payments - GCP	1,277	1,281	1,277	1,277	1,277	1,281	1,277	1,277	1,277	1,281
(32)	Tariff Payments - Feeder Lines	212	212	212	212	212	212	212	212	212	212
(33)	Tariff Payments - AK-Can Pipeline	3,047	3,055	3,047	3,047	3,047	3,055	3,047	3,047	3,047	3,055
(34)	Tariff Payments - Canada Pipeline	3,506	3,515	3,506	3,506	3,506	3,515	3,506	3,506	3,506	3,515
(35)	Netback Revenue at Point of Production	8,423	9,[illegible]75	9,775	10,286	10,656	11,064	11,419	11,812	12,212	12,655
(36)	Property Tax	543	516	489	461	434	406	379	352	324	297
(37)	State Income Tax	185	212	217	223	230	239	278	319	328	339
(38)	State Royalty	1,082	1,177	1,252	1,317	1,364	1,416	1,461	1,510	1,561	1,617
(39)	Field Cost Allowance on State Royalty Gas	(43)	(44)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
(40)	Production Tax	1,560	1,708	1,826	1,927	2,000	2,080	2,150	2,227	2,306	2,393
(41)	State Cash Flows	3,326	3,568	3,739	3,882	3,981	4,093	4,219	4,359	4,469	4,594

TAB

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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

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,[4] 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

Table of Contents

[4] *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).

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
PGT—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

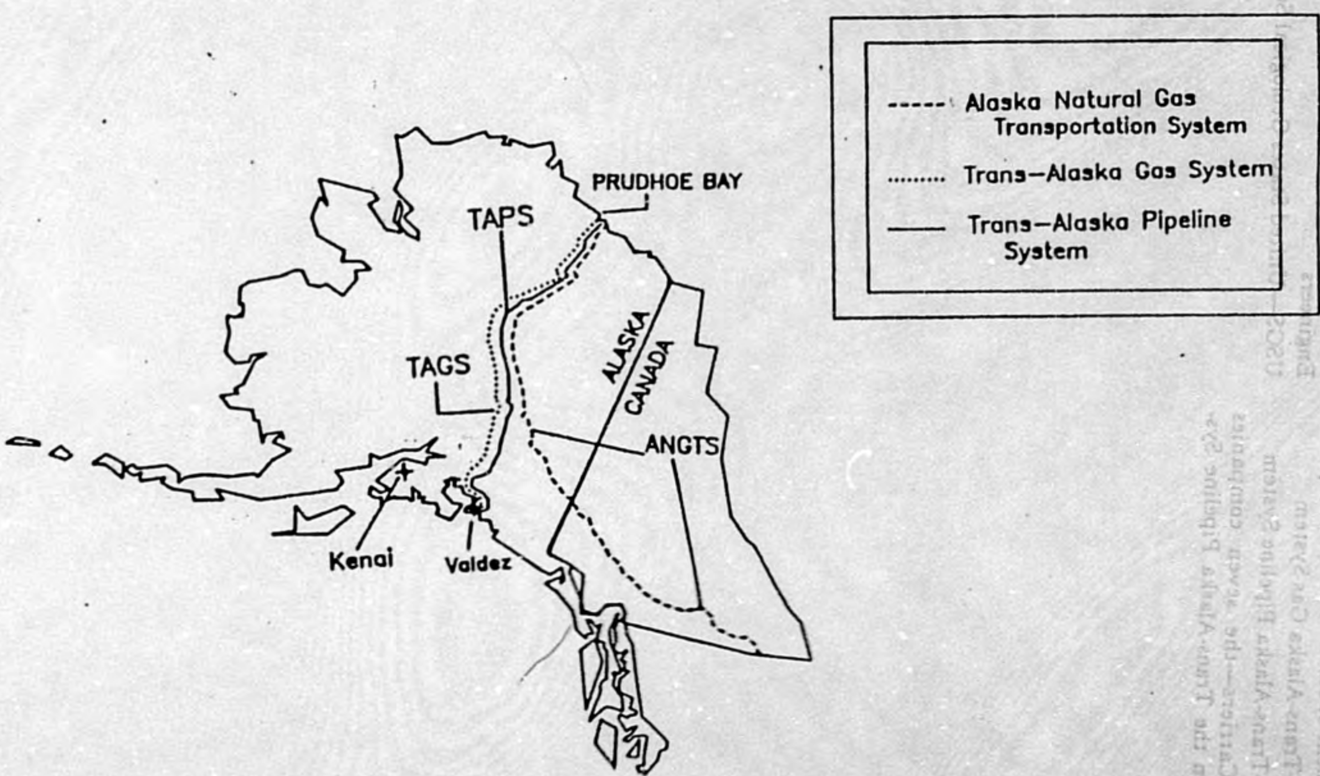
TAPS Carriers—the seven companies that own the Trans-Alaska Pipeline System

Tcf—Trillion cubic feet

USACE—United States Army Corps of Engineers

USGS—United States Geological Survey

ALASKA ENERGY PROJECTS



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.[1] 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.

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,[2] 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.[3] 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

[1] 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.

[2] Alaska Department of Natural Resources, *Historical and Projected Oil and Gas Consumption*, January 1989.

[3] 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.[4]

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.[5]

On September 22, 1977, following the signing of an agreement on principles with Canada,[6] President Jimmy Carter transmitted to Congress his decision concerning ANGTS.[7] The President's *Decision* and the *Agreement on Principles* were approved by Congress on November 8, 1977.[8] 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.[9]

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[4] 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."

[5] 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.

[6] "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.

[7] *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.

[8] Pub. L. No. 95-158.

[9] 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),[10] 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.[11] 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.[12]

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.[13] The FERC also has acted in other areas to remove regulatory barriers to competition.[14]

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.[15] 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.

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[10] 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).

[11] Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60.

[12] 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.

[13] *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.

[14] *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 FR 22168 (June 18, 1986).

[15] *New Policy Guidelines Relating to the Regulation of Imported Natural Gas,* 49 FR 6684 (February 22, 1984).