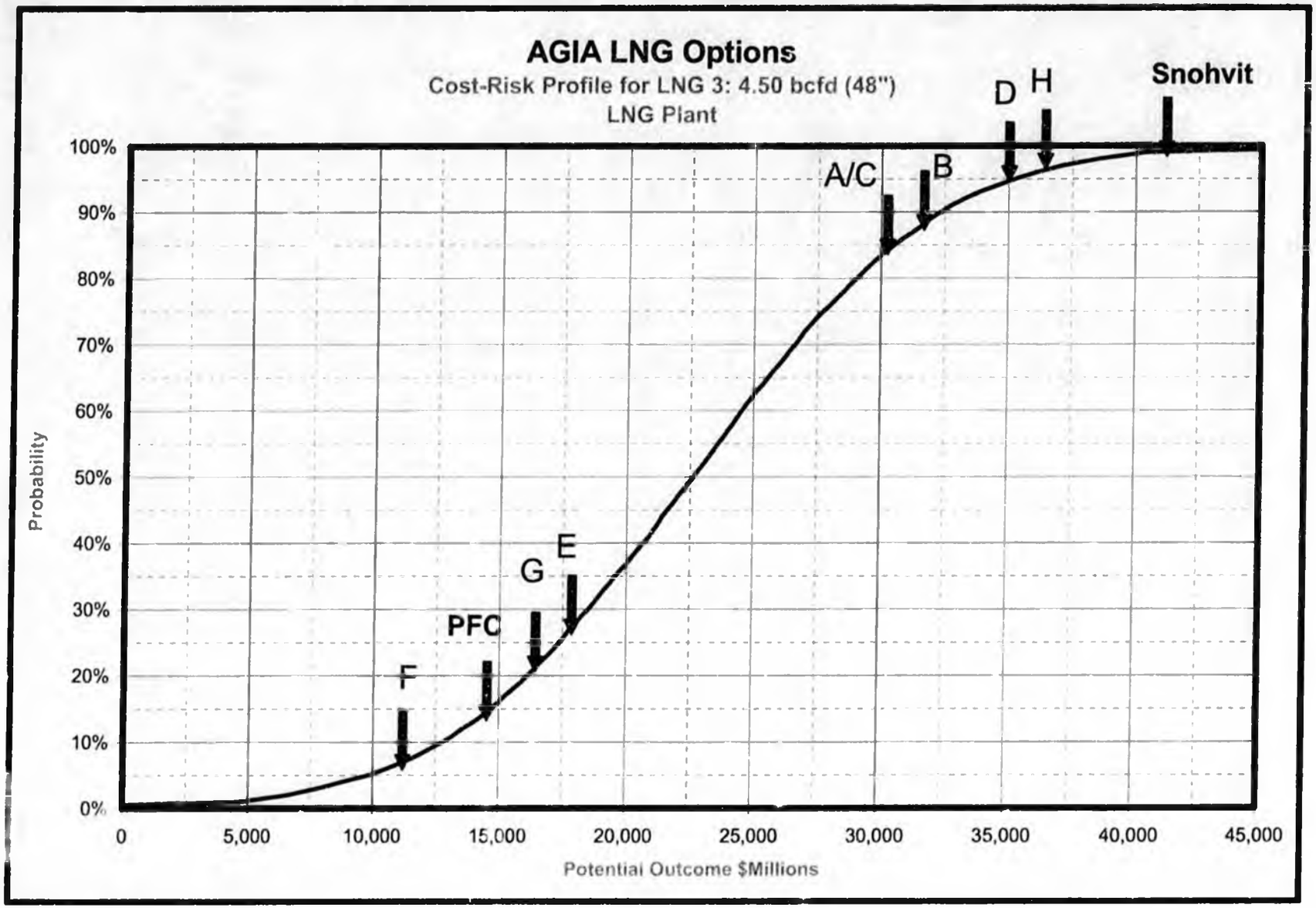
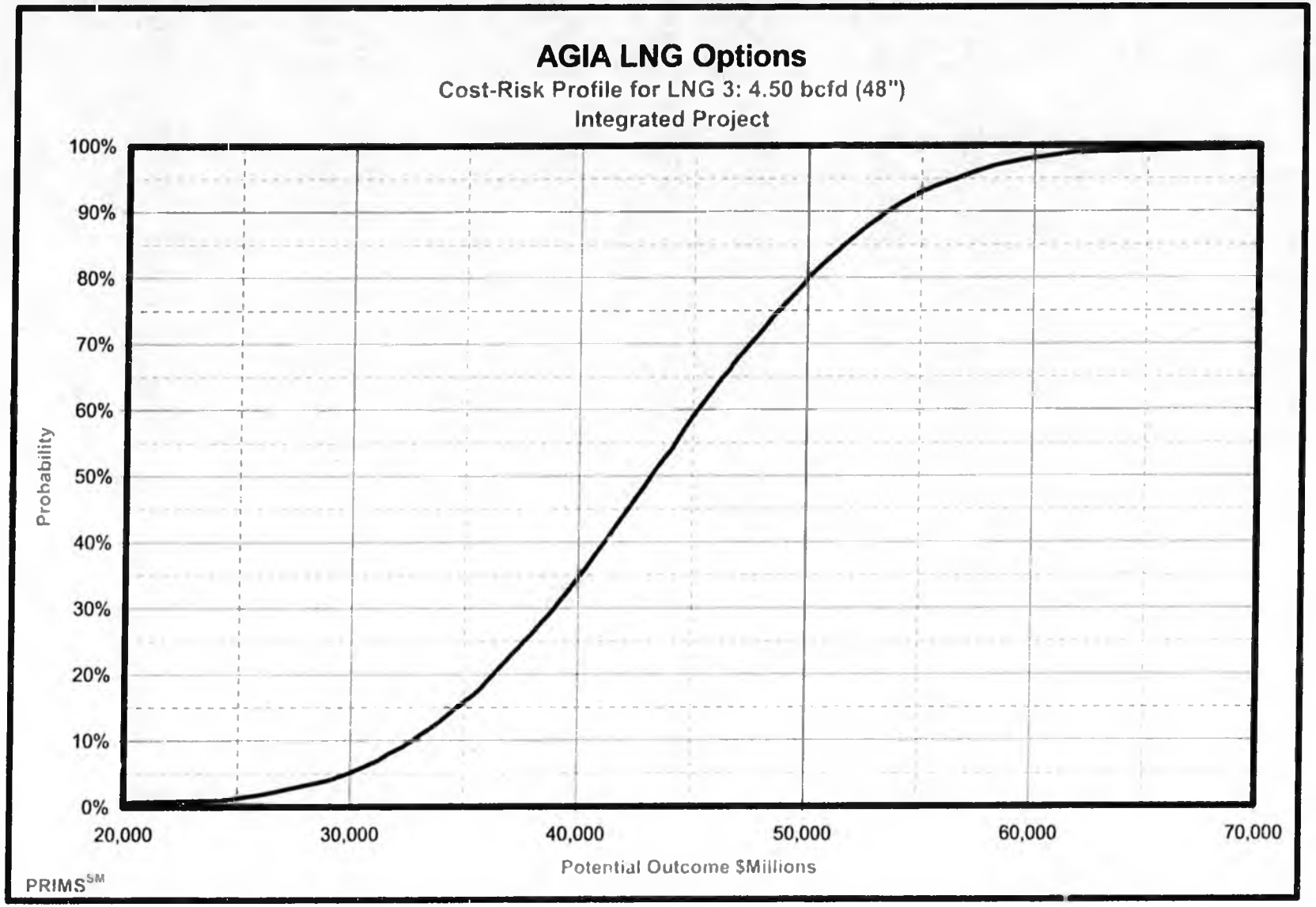
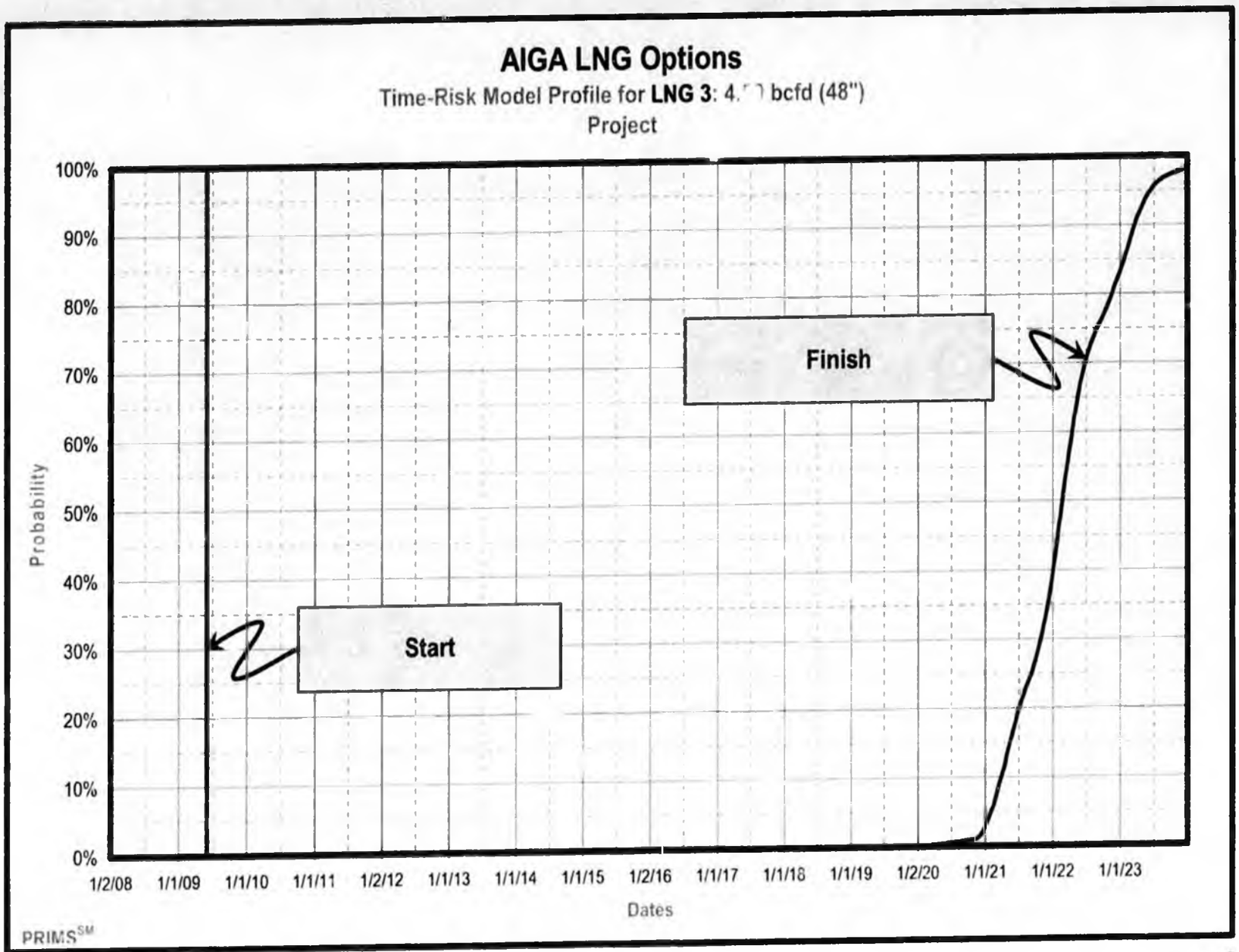
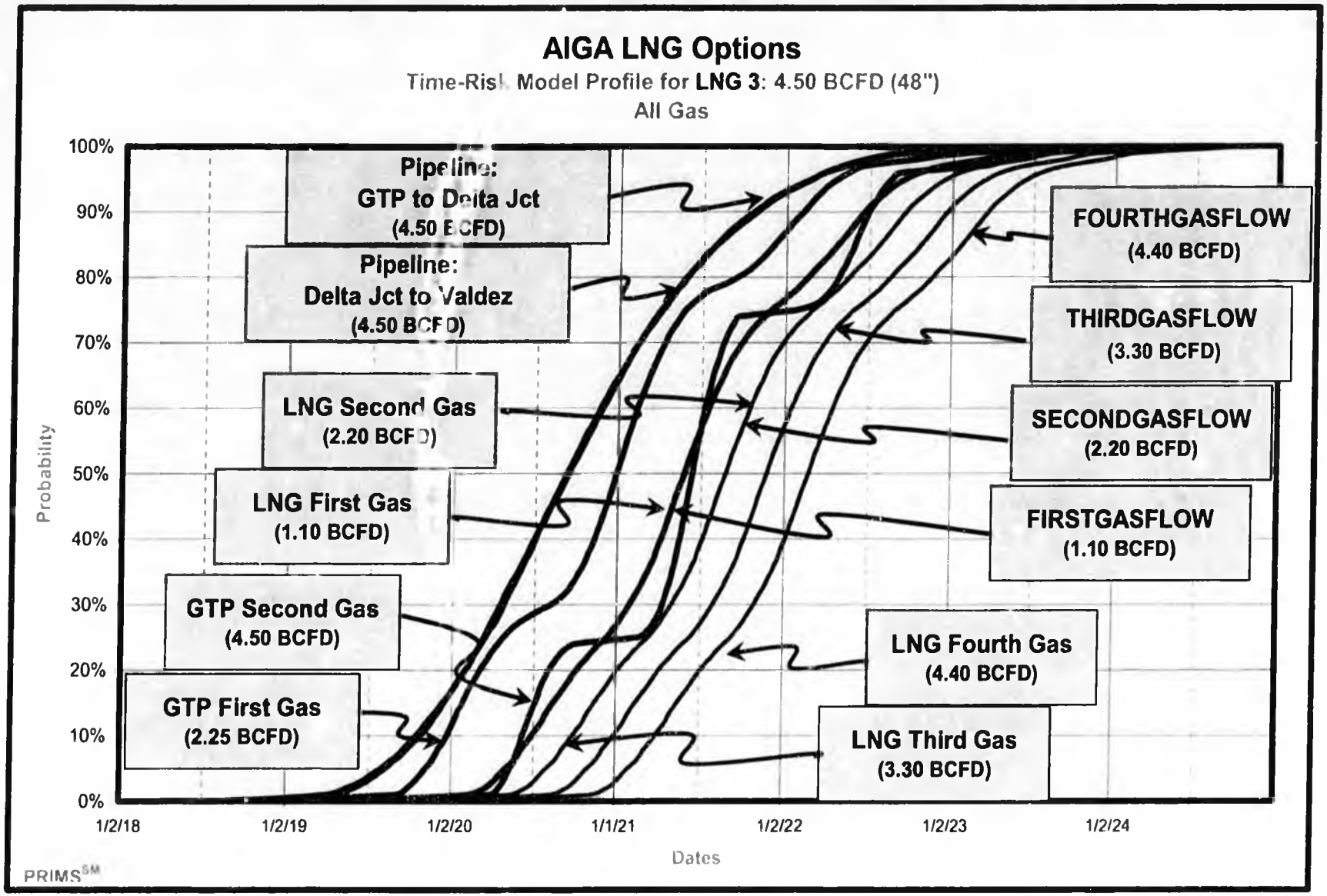
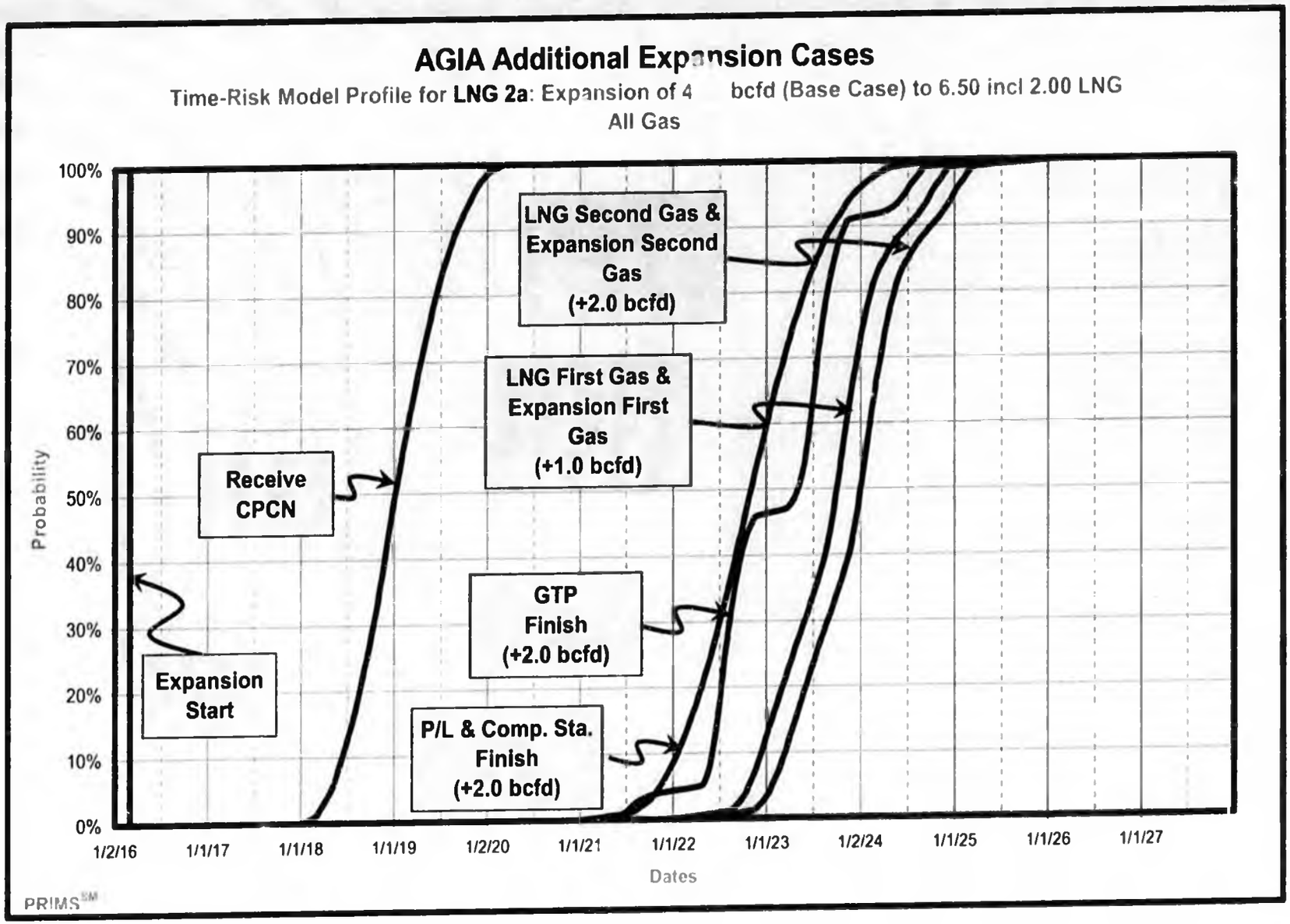
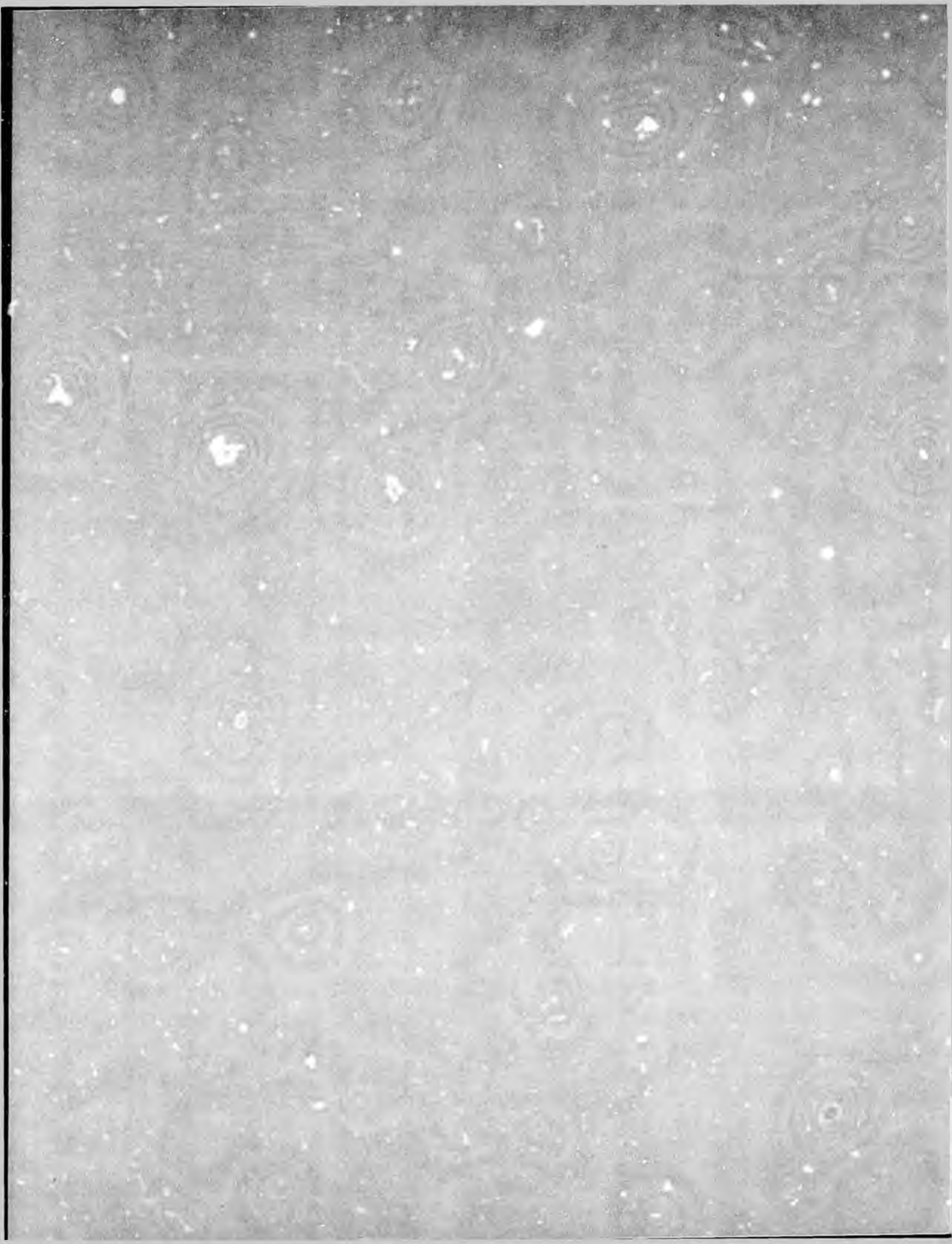

AGIA LNG Options
Cost-Risk Profile for LNG 3: 4.50 bcfd (48")
LNG Plant
Snohvit
D
H
A/C
B
E
G
PFC
F
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Probability
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
45,000
Potential Outcome $Millions


AGIA LNG Options
Cost-Risk Profile for LNG 3: 4.50 bcfd (48")
Integrated Project
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Probability
20,000
30,000
40,000
50,000
60,000
70,000
Potential Outcome $Millions
PRIMS℠


AIGA LNG Options
Time-Risk Model Profile for LNG 3: 4.[illegible] bcfd (48")
Project
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Probability
Finish
Start
1/2/08
1/1/09
1/1/10
1/1/11
1/2/12
1/1/13
1/1/14
1/1/15
1/2/16
1/1/17
1/1/18
1/1/19
1/2/20
1/1/21
1/1/22
1/1/23
Dates
PRIMS[SM]


AIGA LNG Options
Time-Risk Model Profile for LNG 3: 4.50 BCFD (48")
All Gas
Pipeline:
GTP to Delta Jct
(4.50 BCFD)
Pipeline:
Delta Jct to Valdez
(4.50 BCFD)
LNG Second Gas
(2.20 BCFD)
LNG First Gas
(1.10 BCFD)
GTP Second Gas
(4.50 BCFD)
GTP First Gas
(2.25 BCFD)
FOURTHGASFLOW
(4.40 BCFD)
THIRDGASFLOW
(3.30 BCFD)
SECONDGASFLOW
(2.20 BCFD)
FIRSTGASFLOW
(1.10 BCFD)
LNG Fourth Gas
(4.40 BCFD)
LNG Third Gas
(3.30 BCFD)
Probability
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1/2/18
1/2/19
1/2/20
1/1/21
1/2/22
1/2/23
1/2/24
Dates
PRIMS℠


AGIA Additional Expansion Cases
Time-Risk Model Profile for LNG 2a: Expansion of 4 bcfd (Base Case) to 6.50 incl 2.00 LNG
All Gas
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Probability
LNG Second Gas & Expansion Second Gas (+2.0 bcfd)
LNG First Gas & Expansion First Gas (+1.0 bcfd)
Receive CPCN
GTP Finish (+2.0 bcfd)
Expansion Start
P/L & Comp. Sta. Finish (+2.0 bcfd)
1/2/16
1/1/17
1/1/18
1/1/19
1/2/20
1/1/21
1/1/22
1/1/23
1/2/24
1/1/25
1/1/26
1/1/27
Dates
PRIMS℠



BUILDING A WORLD OF DIFFERENCE®

BLACK & VEATCH

Net Present Value (NPV) Analysis

June 10, 2008

Key Conclusions

- 4.5 Bcf/d TransCanada Proposal has Positive NPV Benefits to All Stakeholders
- Tariffs for Smaller Pipeline Configurations Increase by 13% to 21% Relative to the 4.5 Bcf/d Proposal Base Case
- NPV for Key Stakeholders Indicates Positive NPV for the Conservative Base Case
- NPV Results are Sensitive to Many Factors with Commodity Prices being the Most Significant
  - Producer NPV Remains Positive with Low Market Price Assumptions
- Production from Proven Reserves Drive Positive Stakeholder NPV
- Smaller Initial Pipeline Capacity and Contract Period for Smaller Pipeline Configurations Reduce Reserve Risk Relative to the Proposal Base Case

Impact of the Gasline: Cash flows and NPV calculated are the *difference* between oil+gas and oil only operations.

Oil + Gas $$

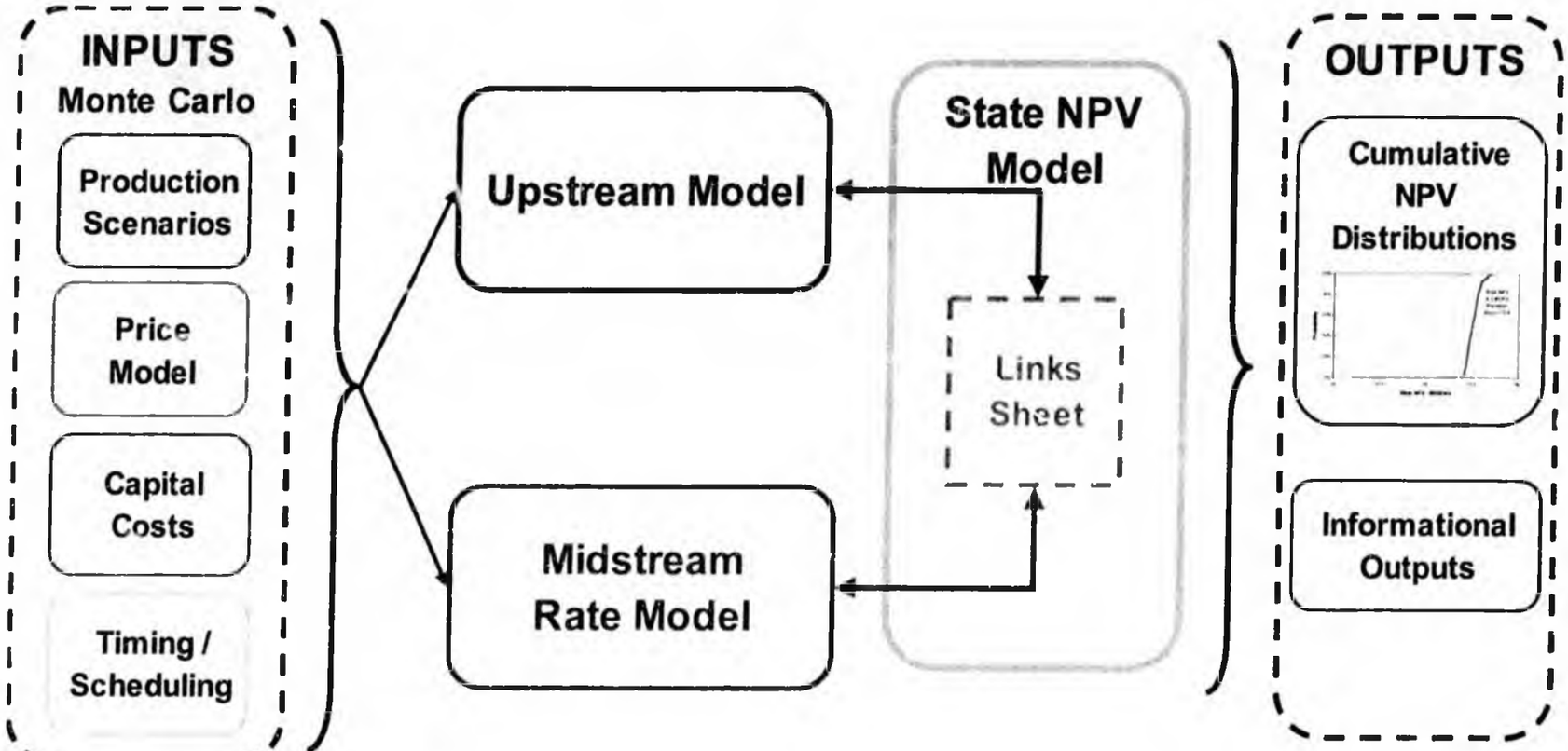
–

Oil Only $

=

Cash Flows from Gas $

The NPV Modeling Approach Utilized by Black & Veatch



Overview of Natural Gas Price Assumptions Utilized in the NPV Analysis

- Gas delivered to different locations has different prices: Henry Hub vs. AECO
- Prices dependent on the supply/demand balance and pipeline infrastructure
- Forecasts are required to evaluate the project from 2020 to 2045+
- Relied on range of forecasts
  - EIA
  - Wood Mackenzie
  - B&V
  - Others
- Wood Mackenzie is the base case for analysis
  - Independent market assessment
  - Projects an AECO price

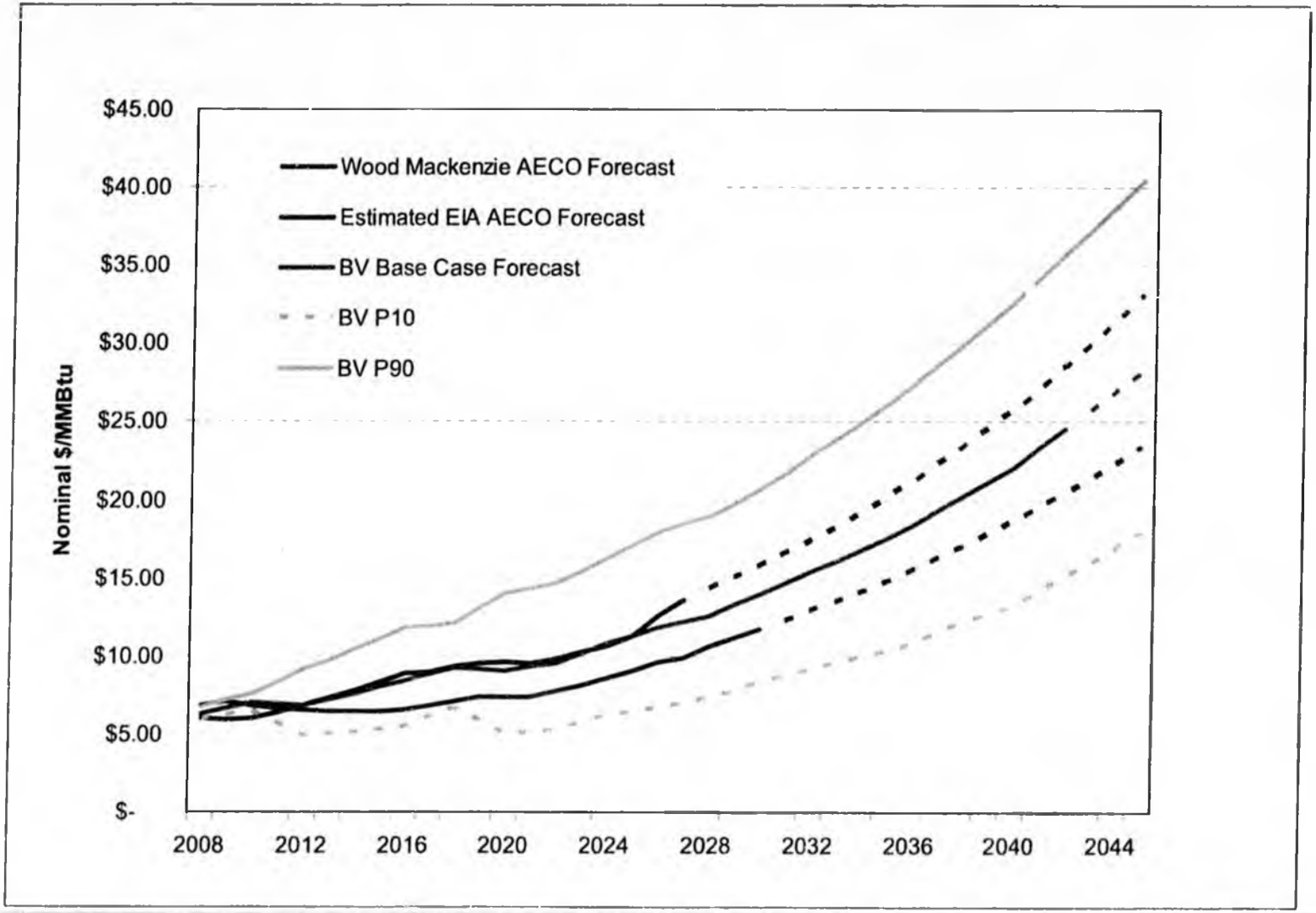
Understanding the Factors that Lead to Future Prices

- Forecasted prices are "point" estimates, all dependent on a specific set of assumptions
- None are expected to be on the dot "correct"
- Price uncertainty and associated risks could be better illustrated using a forecasted price distribution:

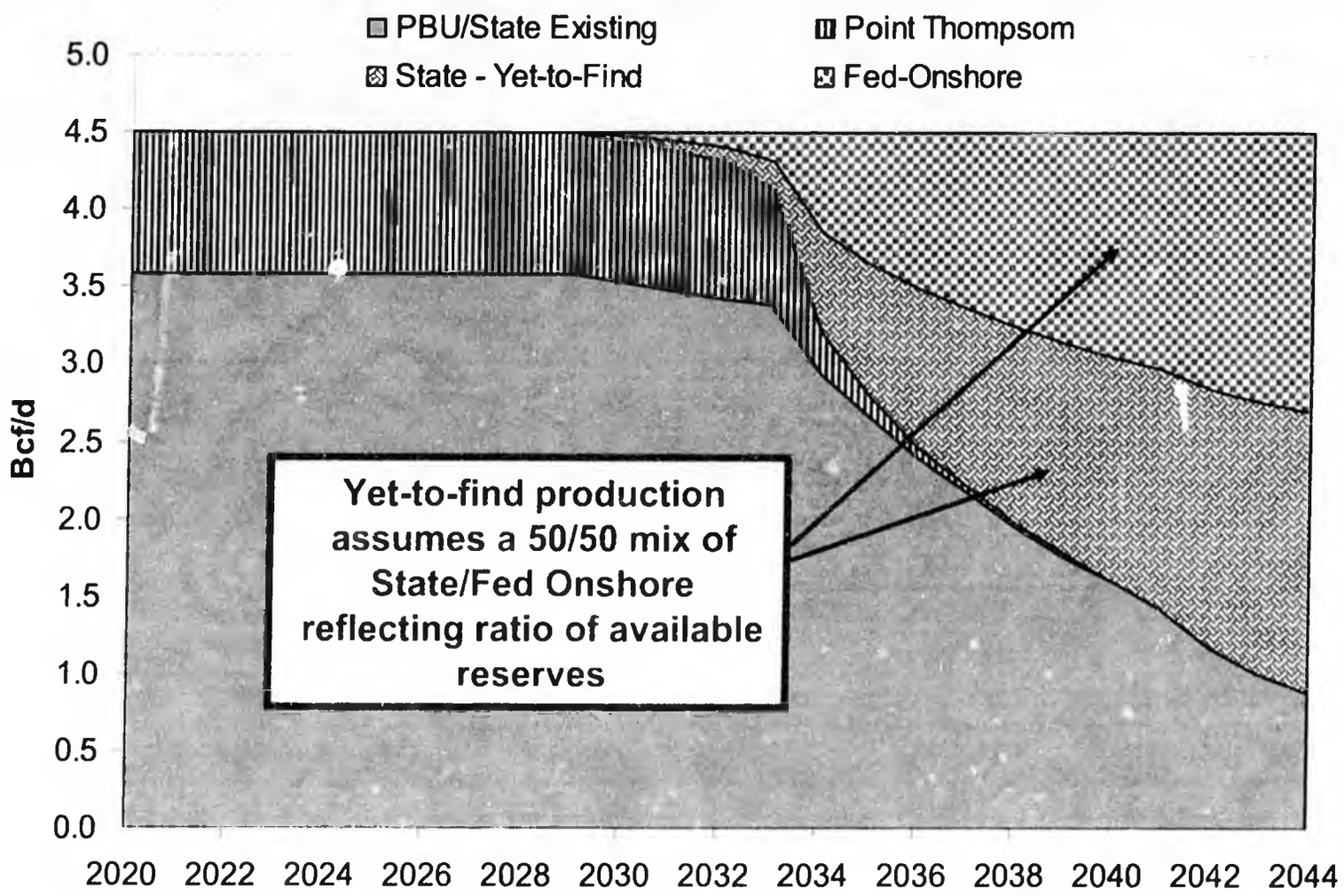
- Black & Veatch assumes that the majority of price risks comes from uncertainty in fundamental factors:

- Finding & development costs
- Technological improvement
- LNG imports
- Power generation demand
- US industrial demand
- CDN industrial demand

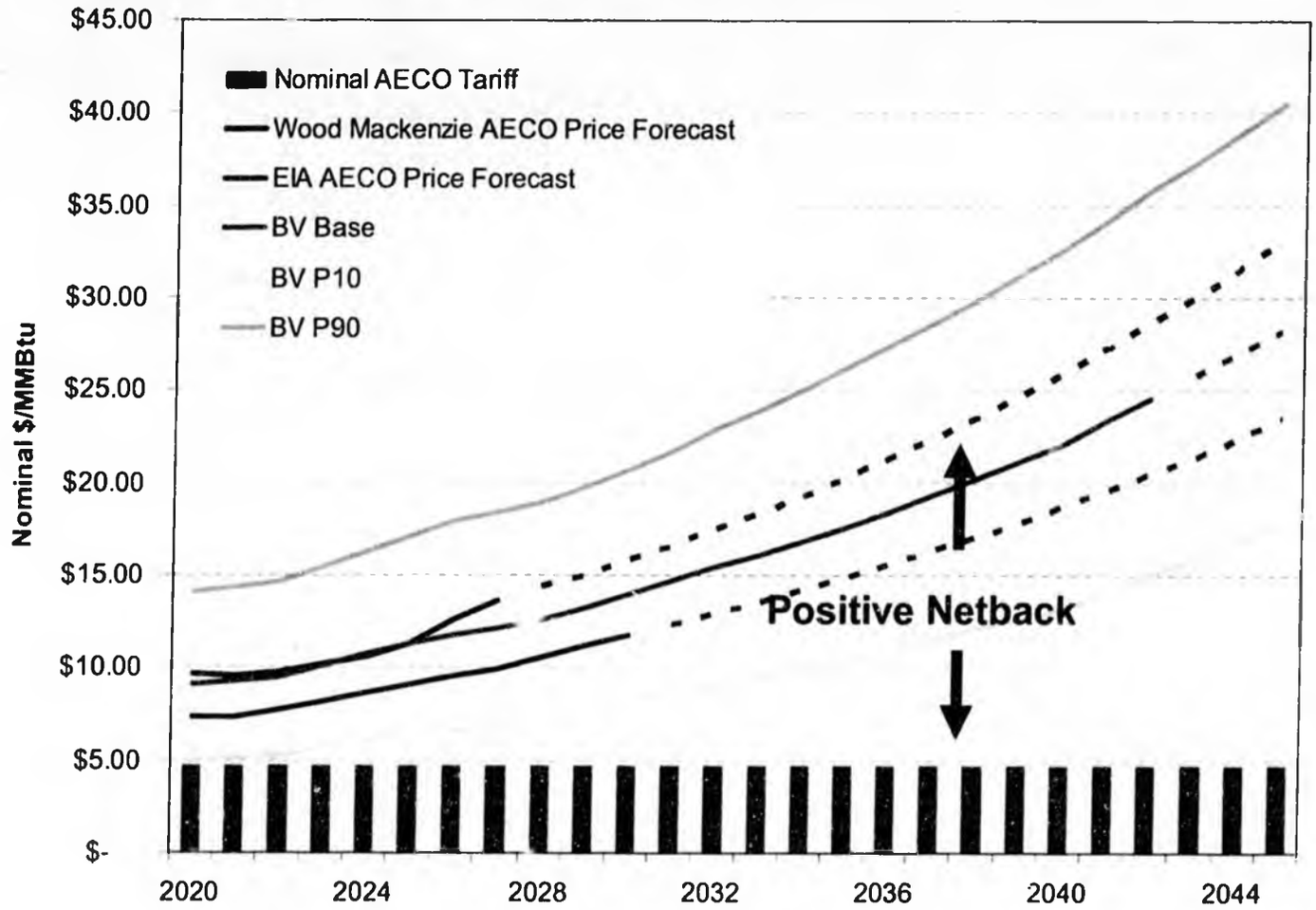
Real Price Growth at AECO is Expected Under All Price Forecast Scenarios due to Increasing Costs



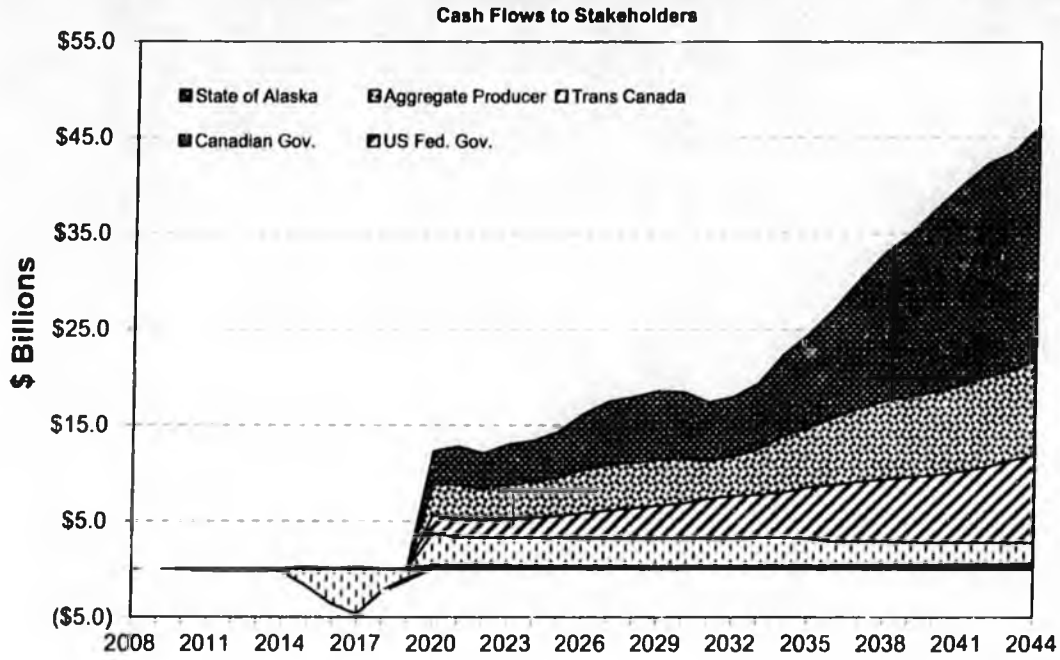
Production Assumptions: 4.5 Bcf/d Proposal Base Case

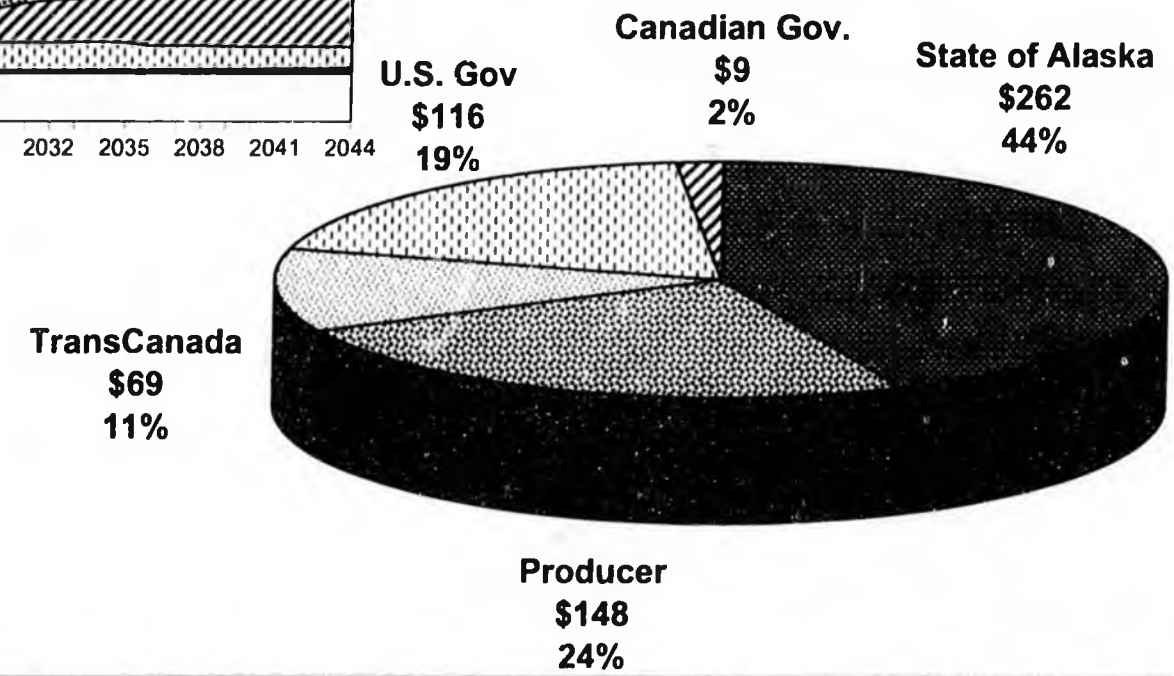


Positive Netbacks Are Expected Under All Price Forecasts

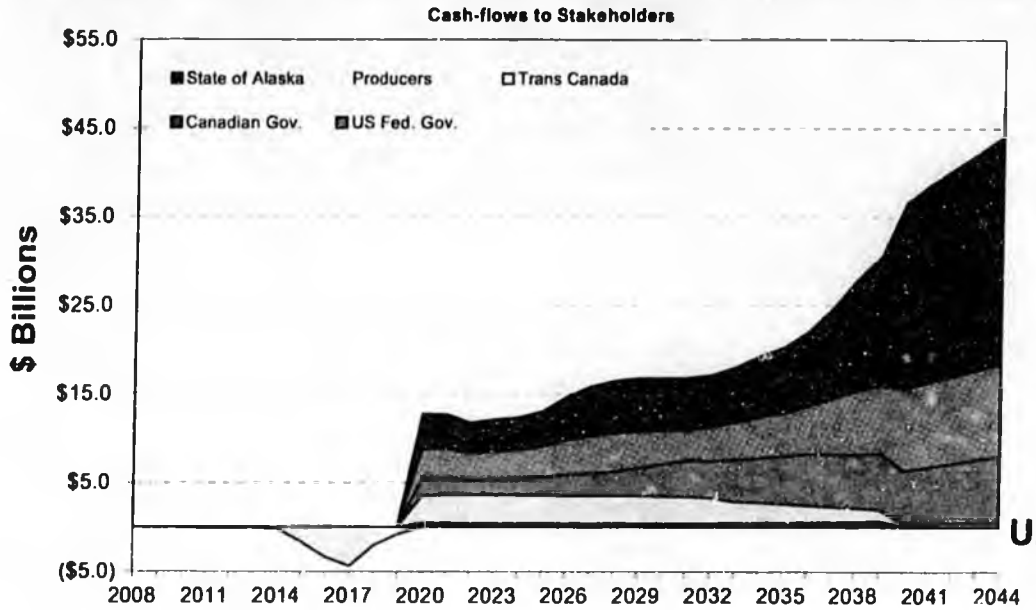


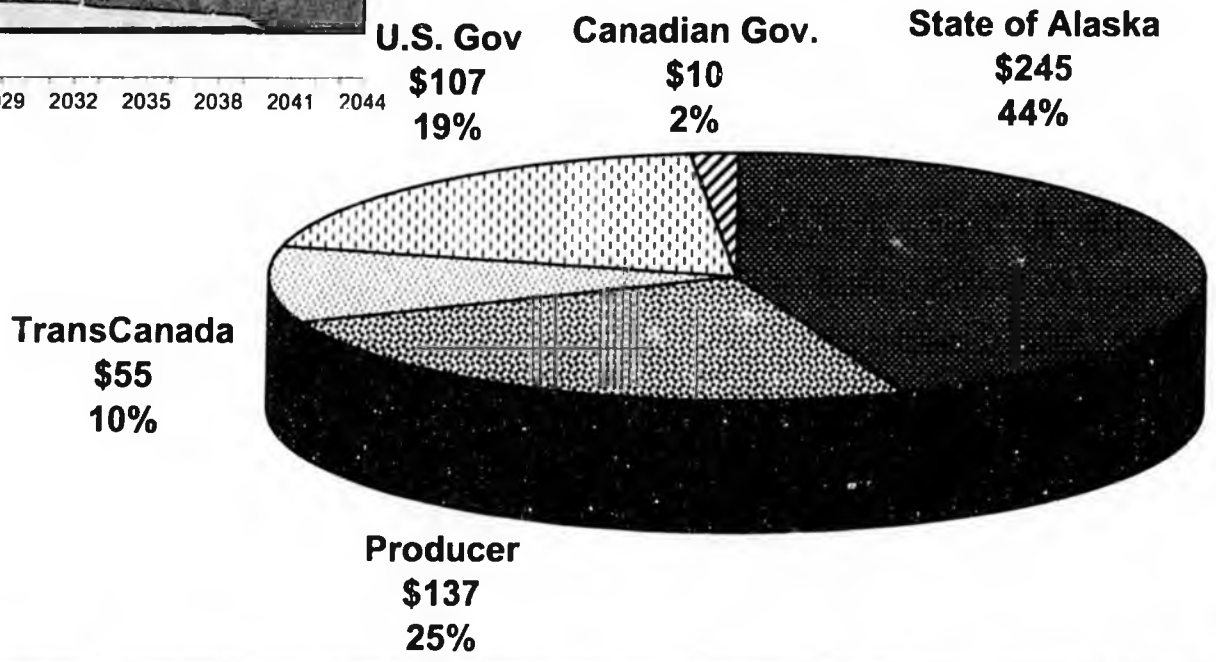
Cash flows from 4.5 Bcf/d Proposal Base Case



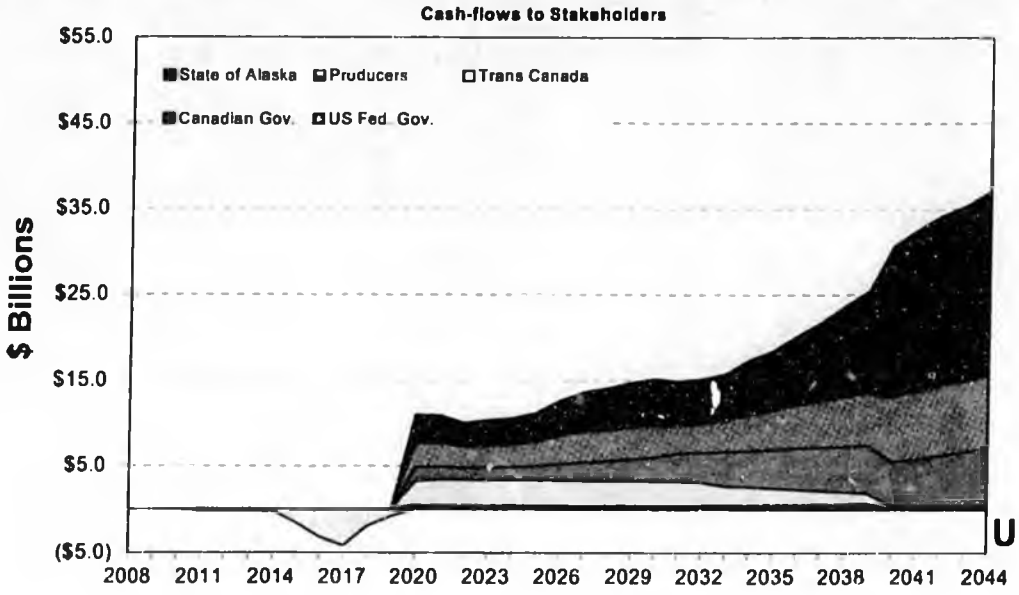


4.0 Bcf/d Conservative Base Case Cash Flows





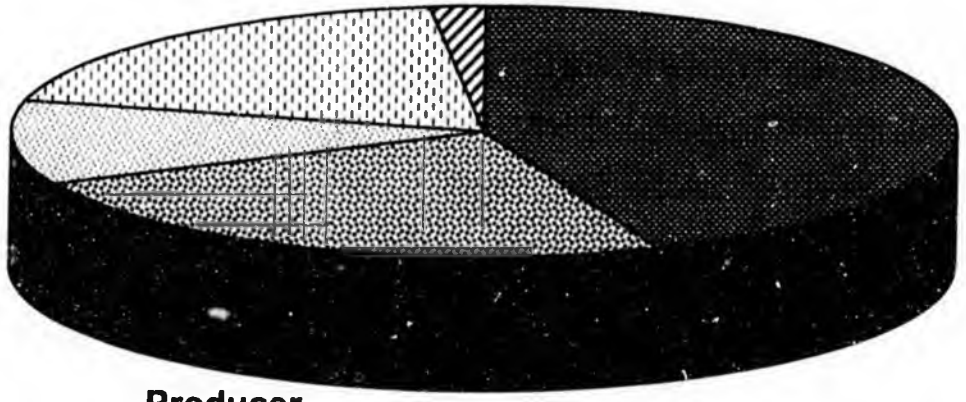
3.5 Bcf/d Low Volume Sensitivity Case



U.S. Gov
$91
19%

Canadian Gov.
$9
2%

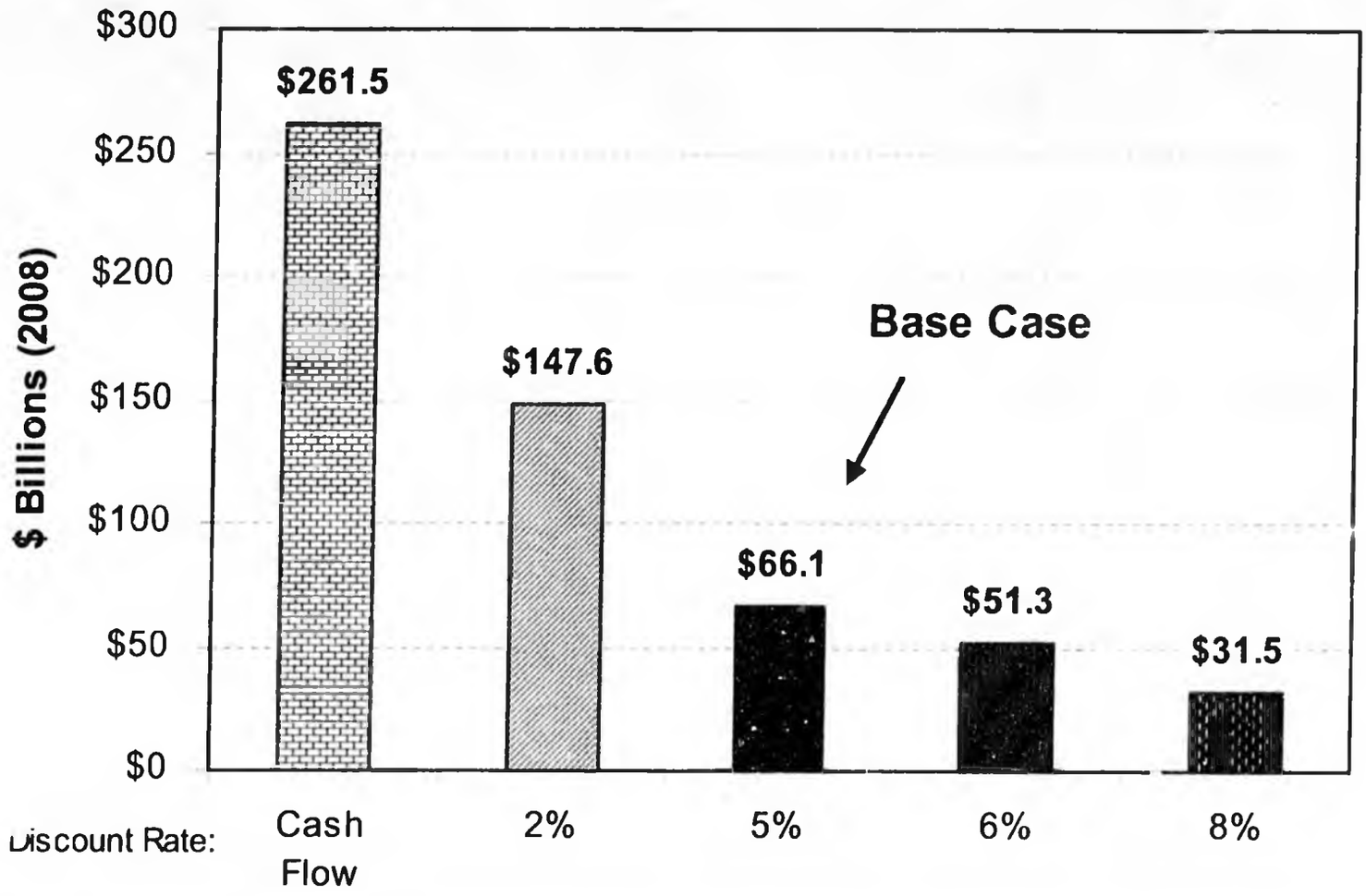
State of Alaska
$209
44%



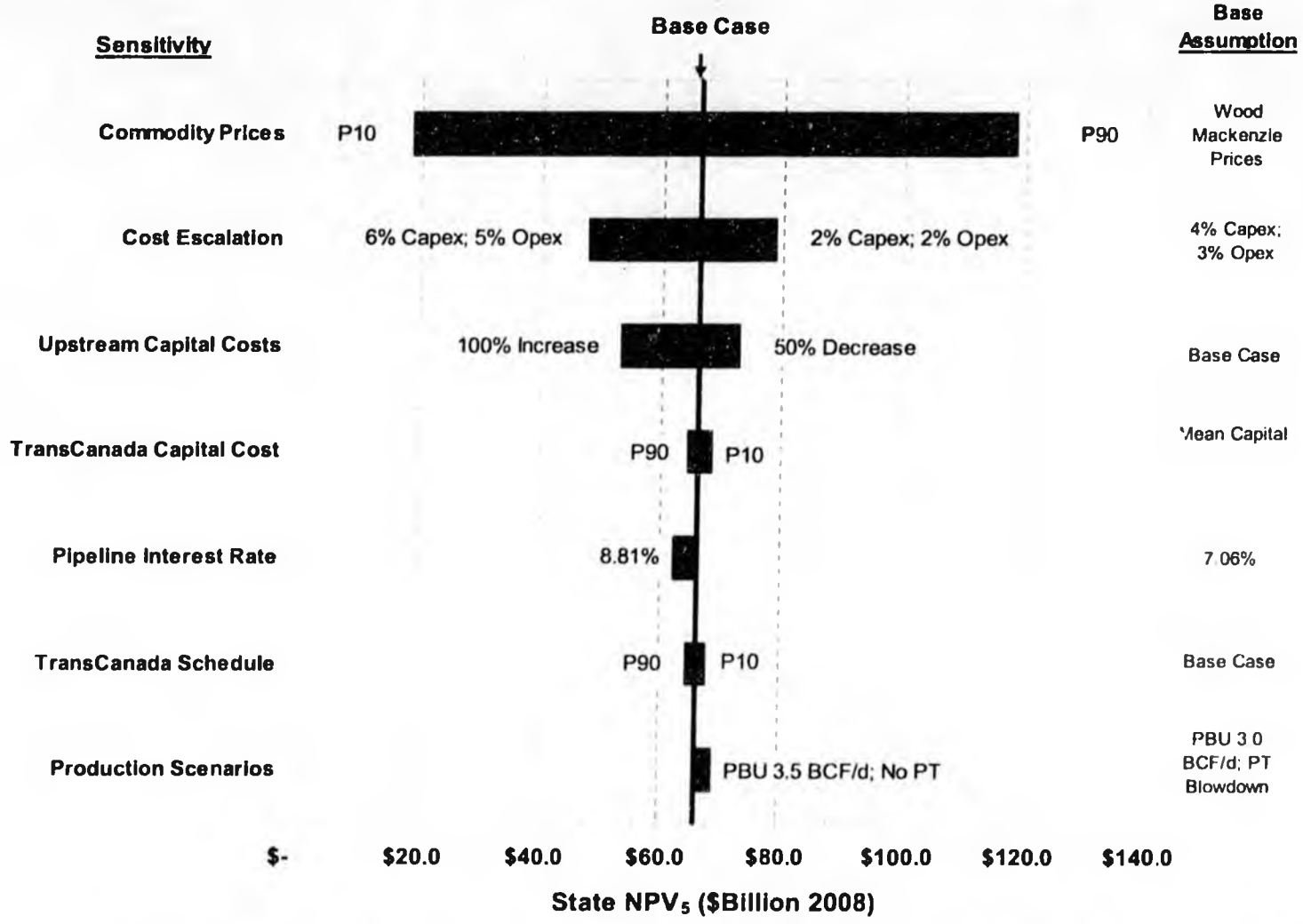
TransCanada
$52
11%

Producer
$116
24%

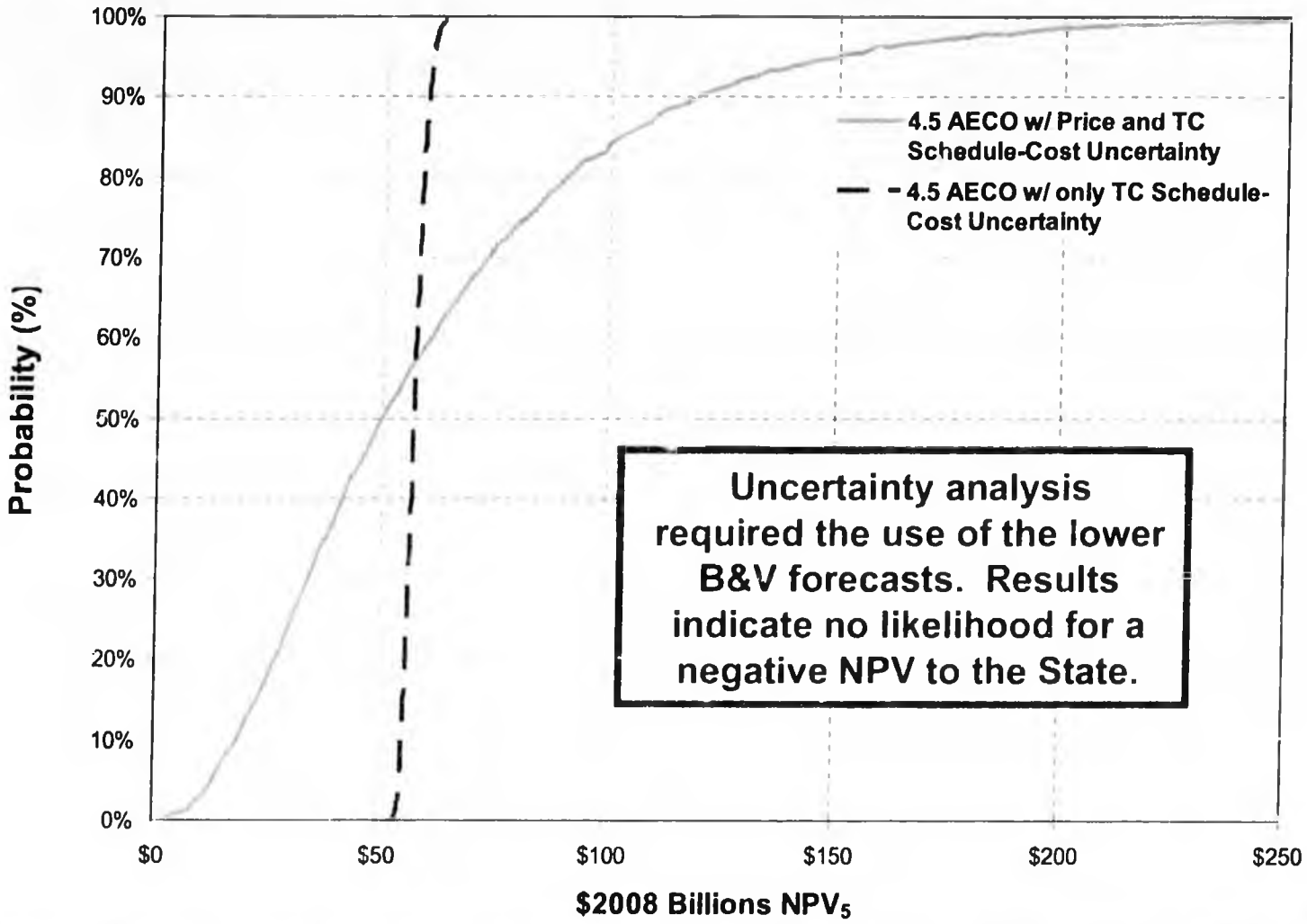
Expected State of Alaska NPV_5 is $66.1 billion



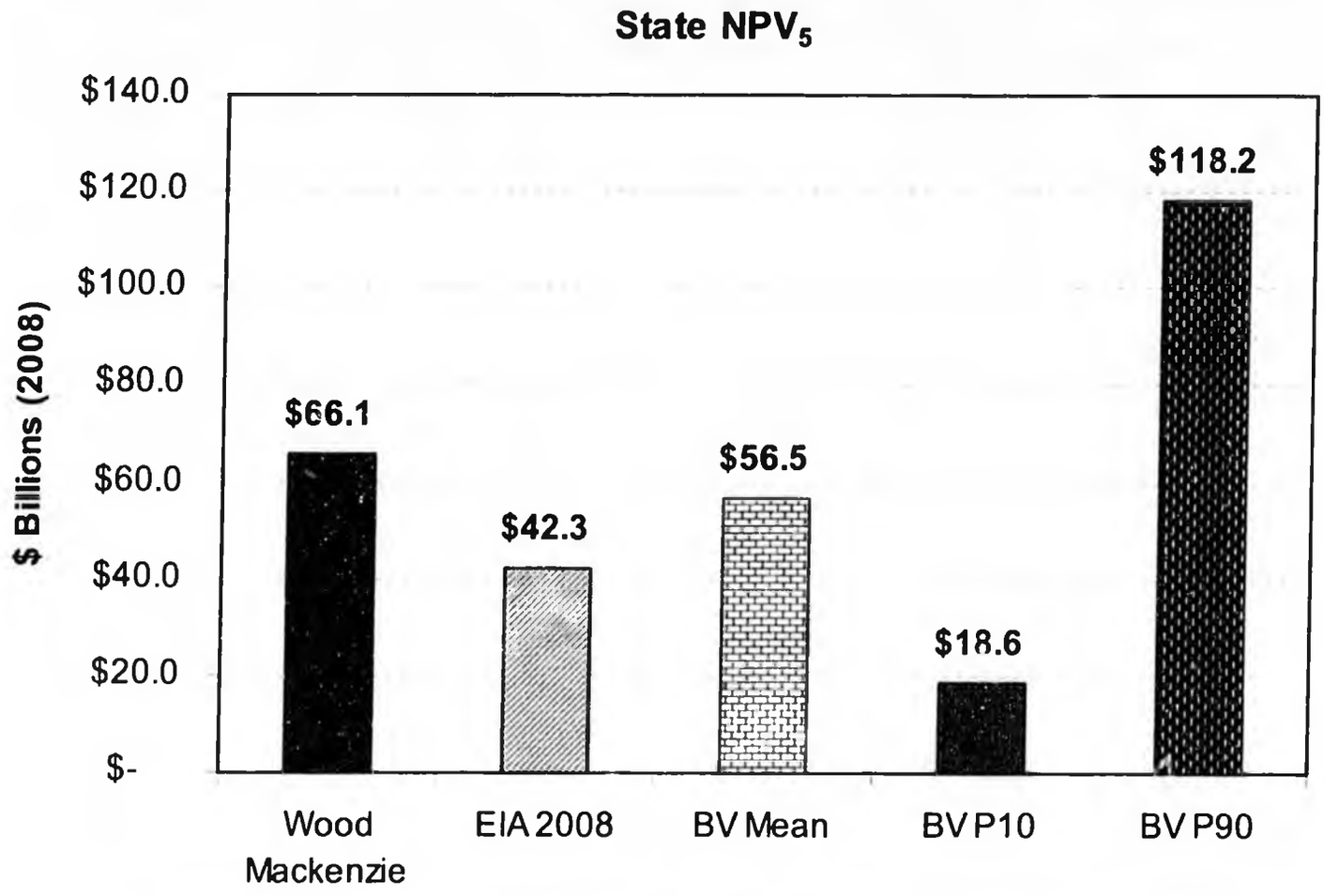
Price is a Key Driver to Variations in the NPV_5 to the State of Alaska



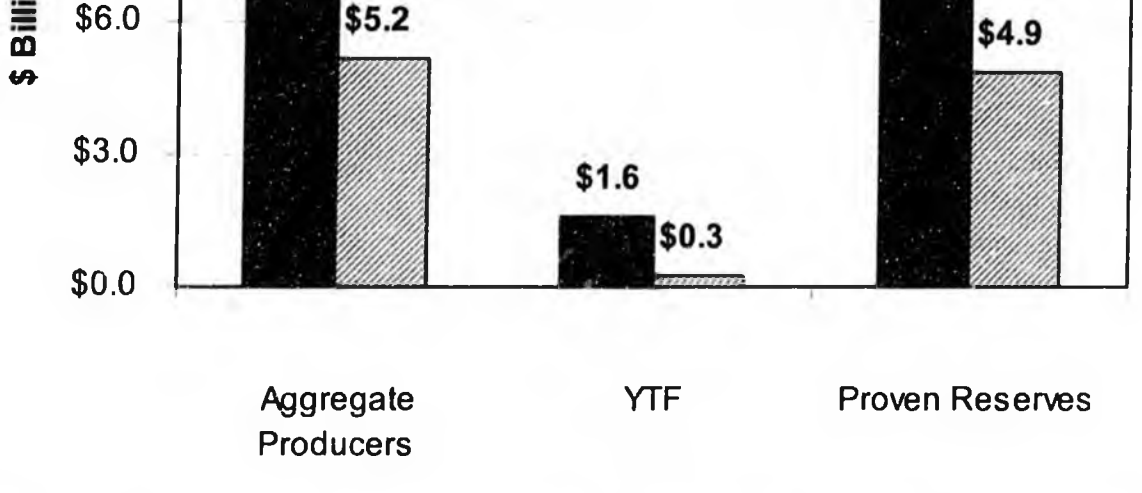
The impact from price uncertainty swamps estimated capital cost and schedule uncertainty.



NPV for the State is Expected to be Positive Under all Price Scenarios

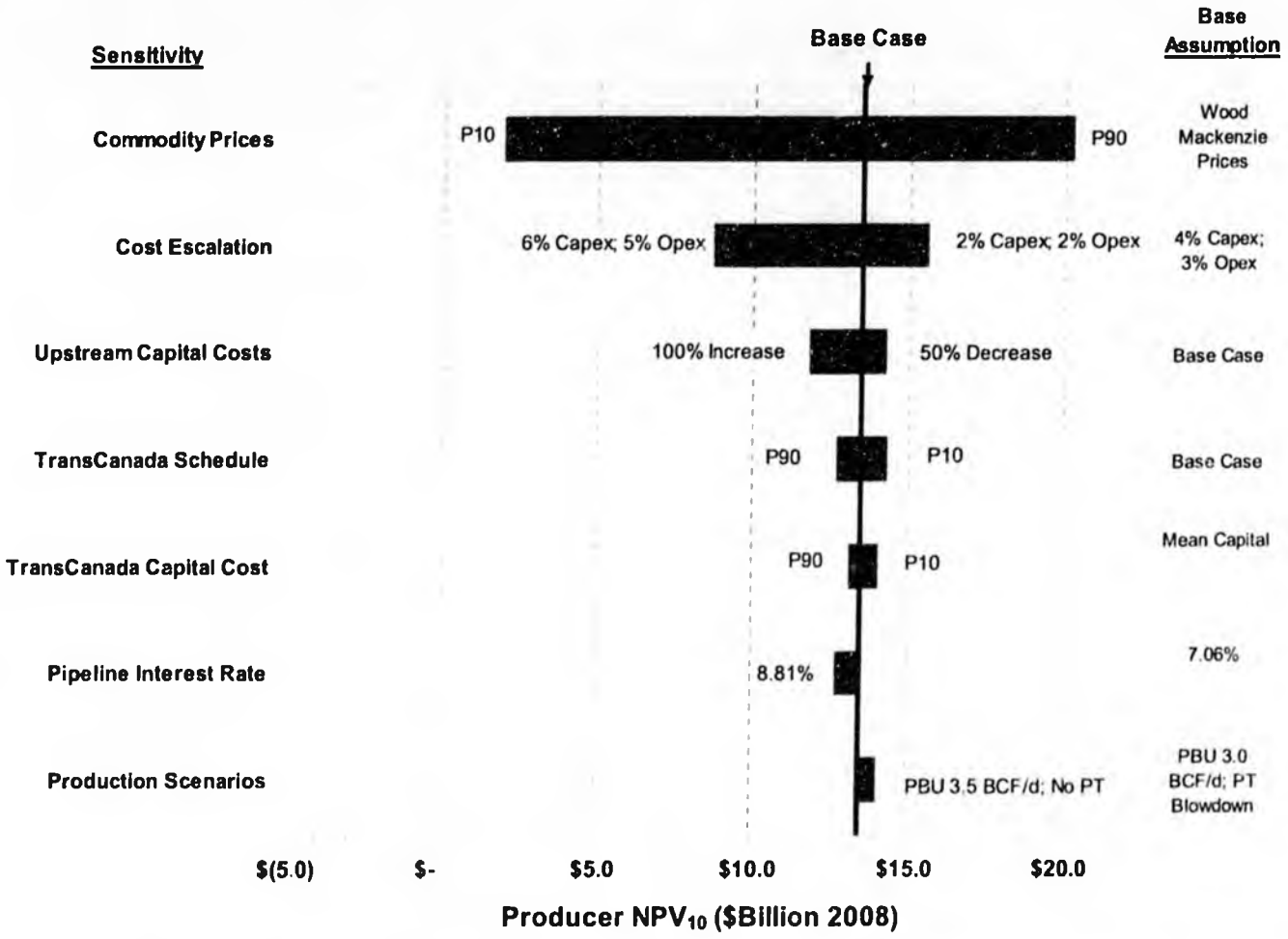


Like the State, NPV for the Producers is Expected to be Substantial under Base Case Assumptions

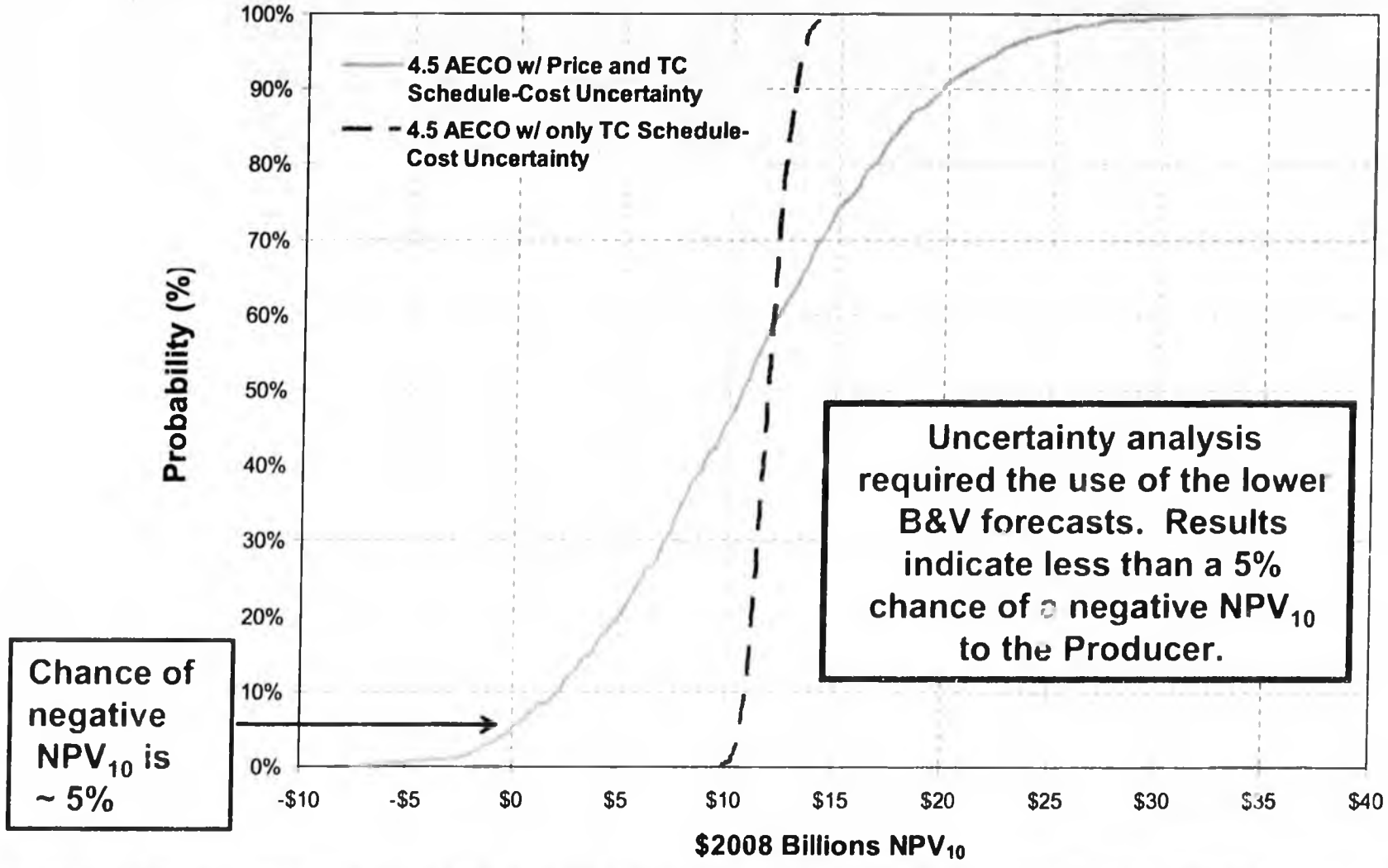


- Existing reserves provide the greatest amount of NPV benefit to the producers due to the low expected capital outlay required to flow into the Gasline.
- YTF NPV is understated due to the analysis life of 25 years. If the analysis is expanded to 35 years, YTF NPV improves to $3.9 billion at a 10% discount rate.

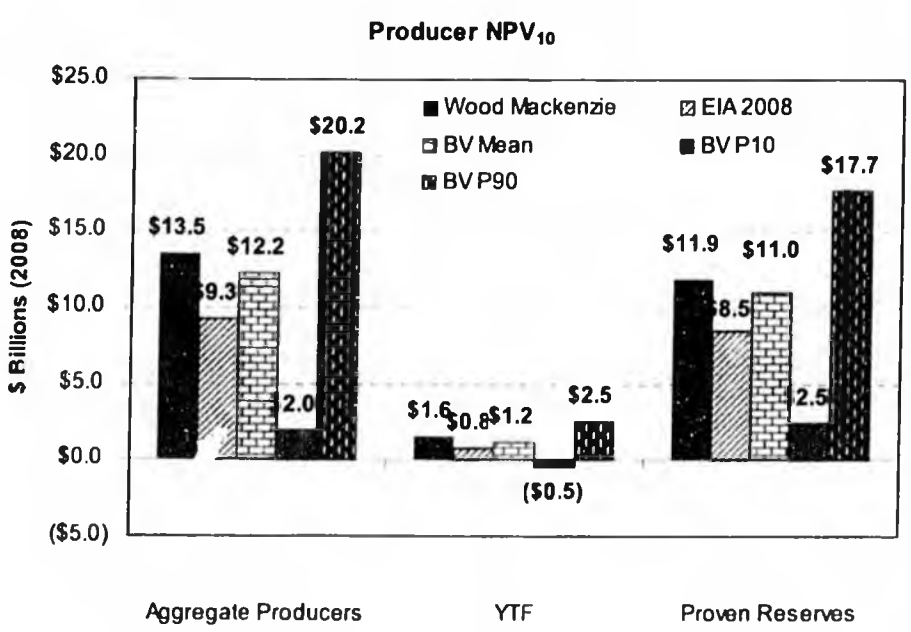
Producer Sensitivity to Key Variables is Similar to the State

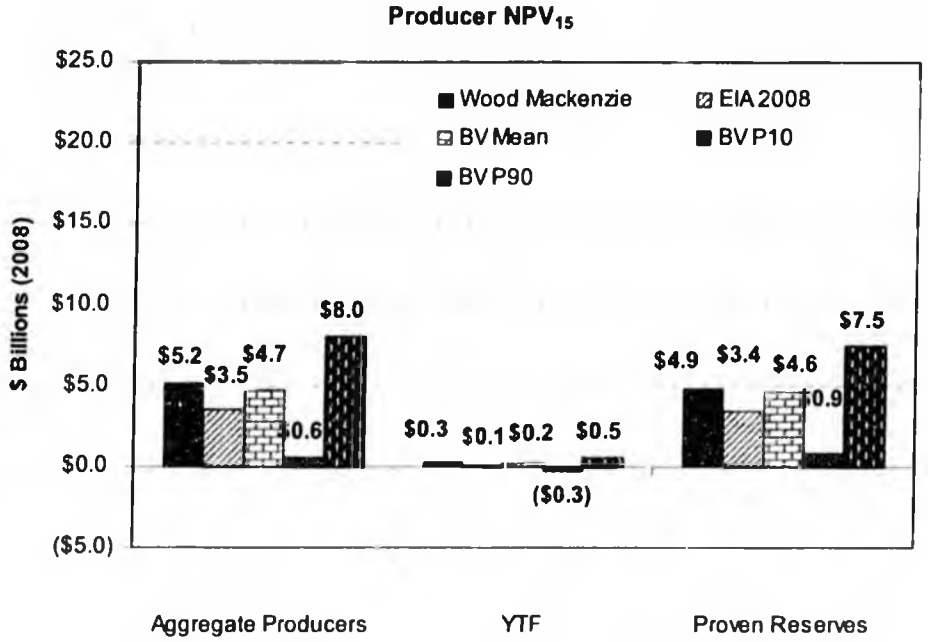


The producers have a very low likelihood for a negative NPV_{10} from low prices, no likelihood from cost scope risk.

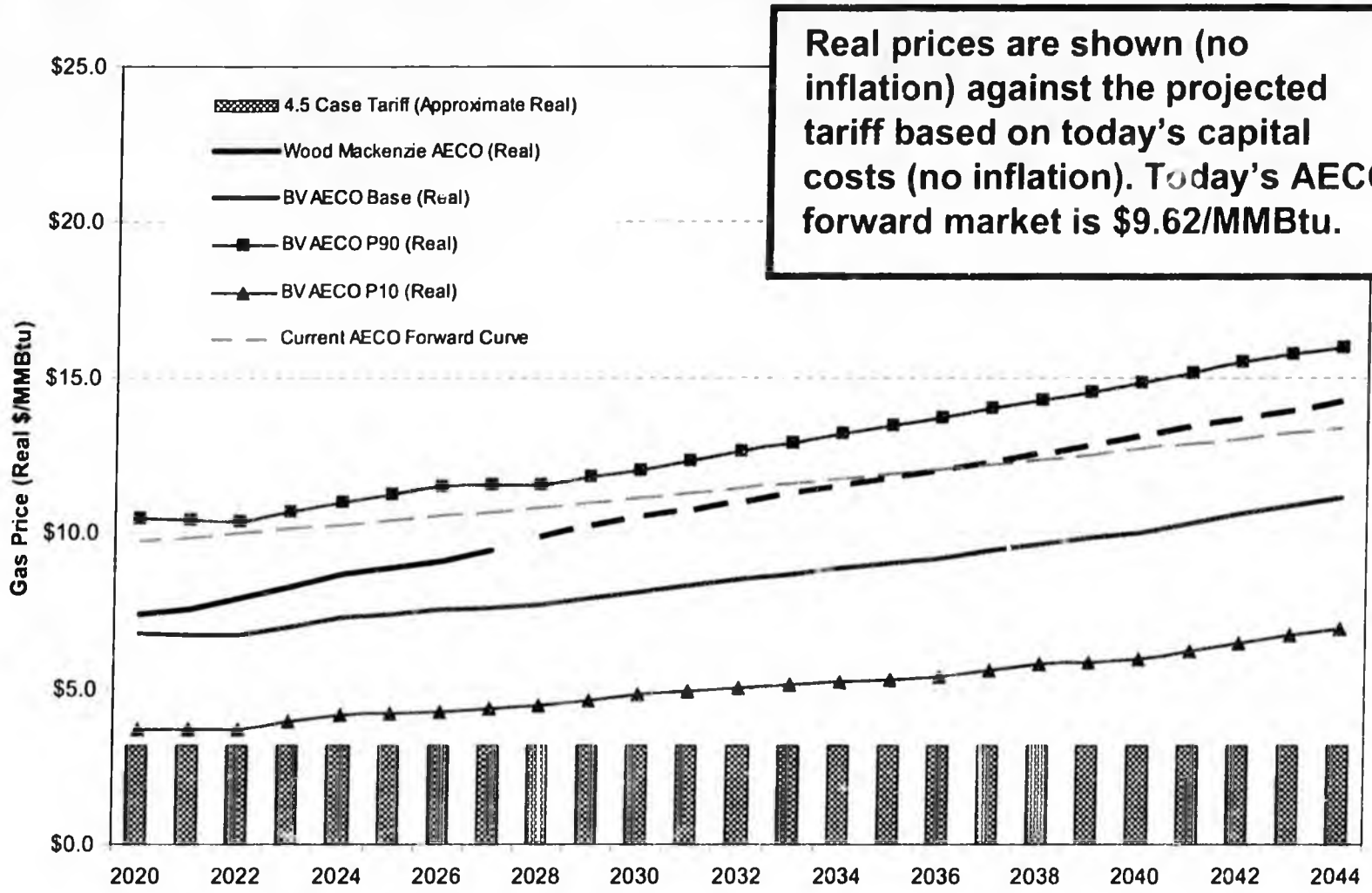


NPV for the Producers is Expected to be Positive Under all Price Scenarios



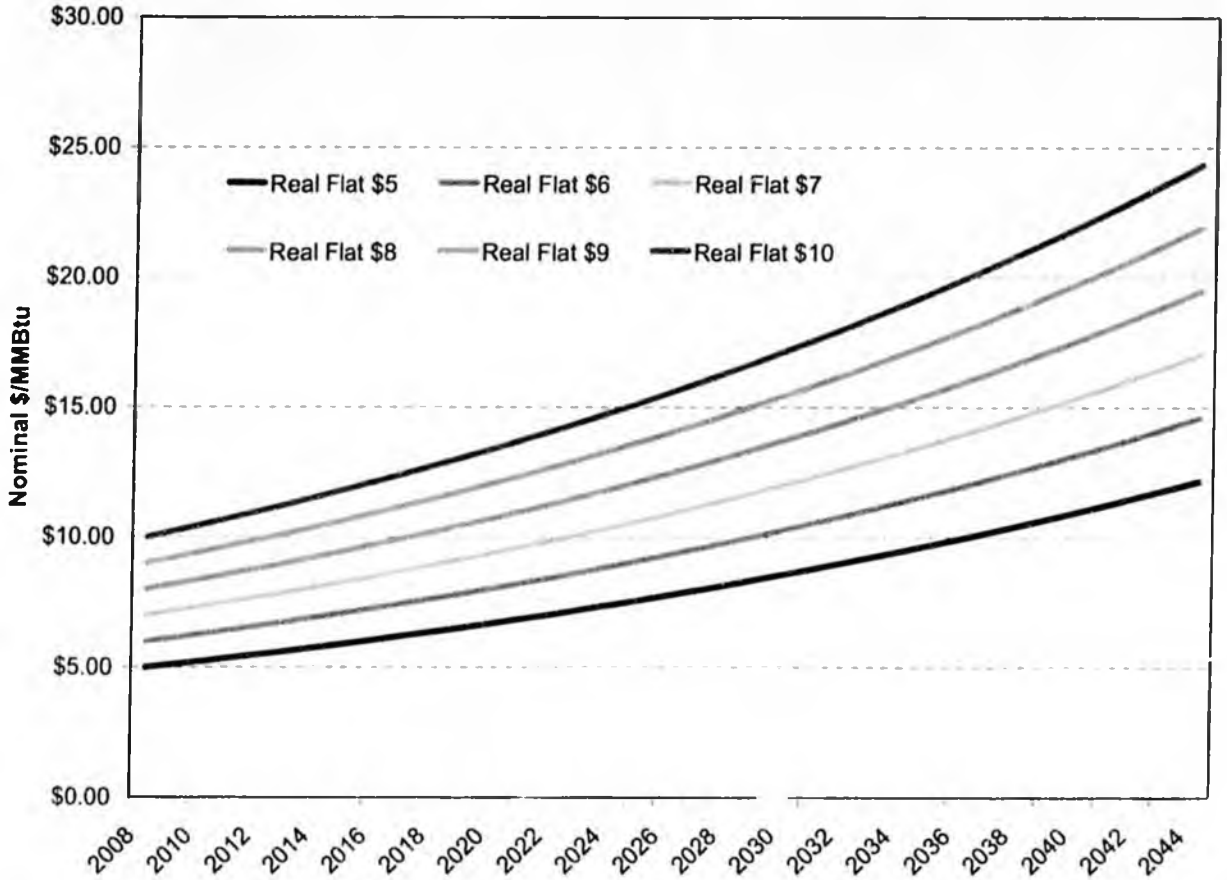


Project Cash Flows are Favorable if Built Today



Real prices are shown (no inflation) against the projected tariff based on today's capital costs (no inflation). Today's AECO forward market is $9.62/MMBtu.

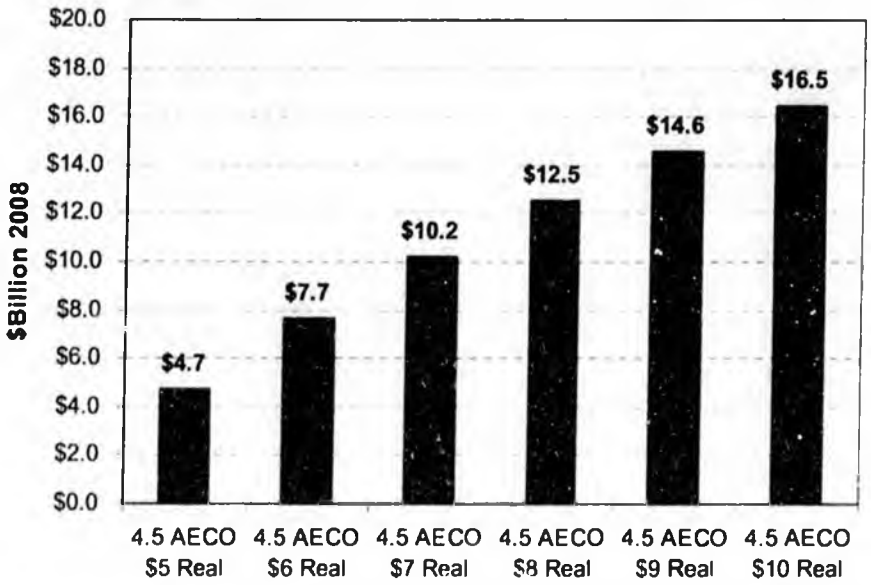
Analysis of Impact of Price Levels - Flat Real Prices



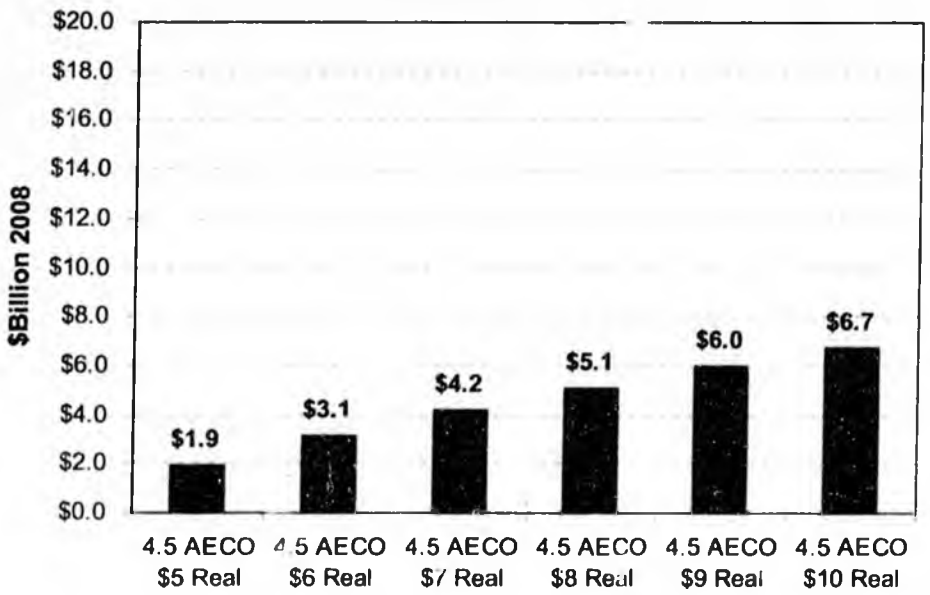
- Analysis investigated the impact of price levels on project economics
- Flat real prices levels from $5/MMBtu to $10/MMBtu were considered for natural gas price at AECO
- 2.5% inflation assumed to estimate dollars of the day prices

Price levels have a significant impact on Producer NPV. NPV_{10} remains positive with real prices in $5-$10/MMBtu range.

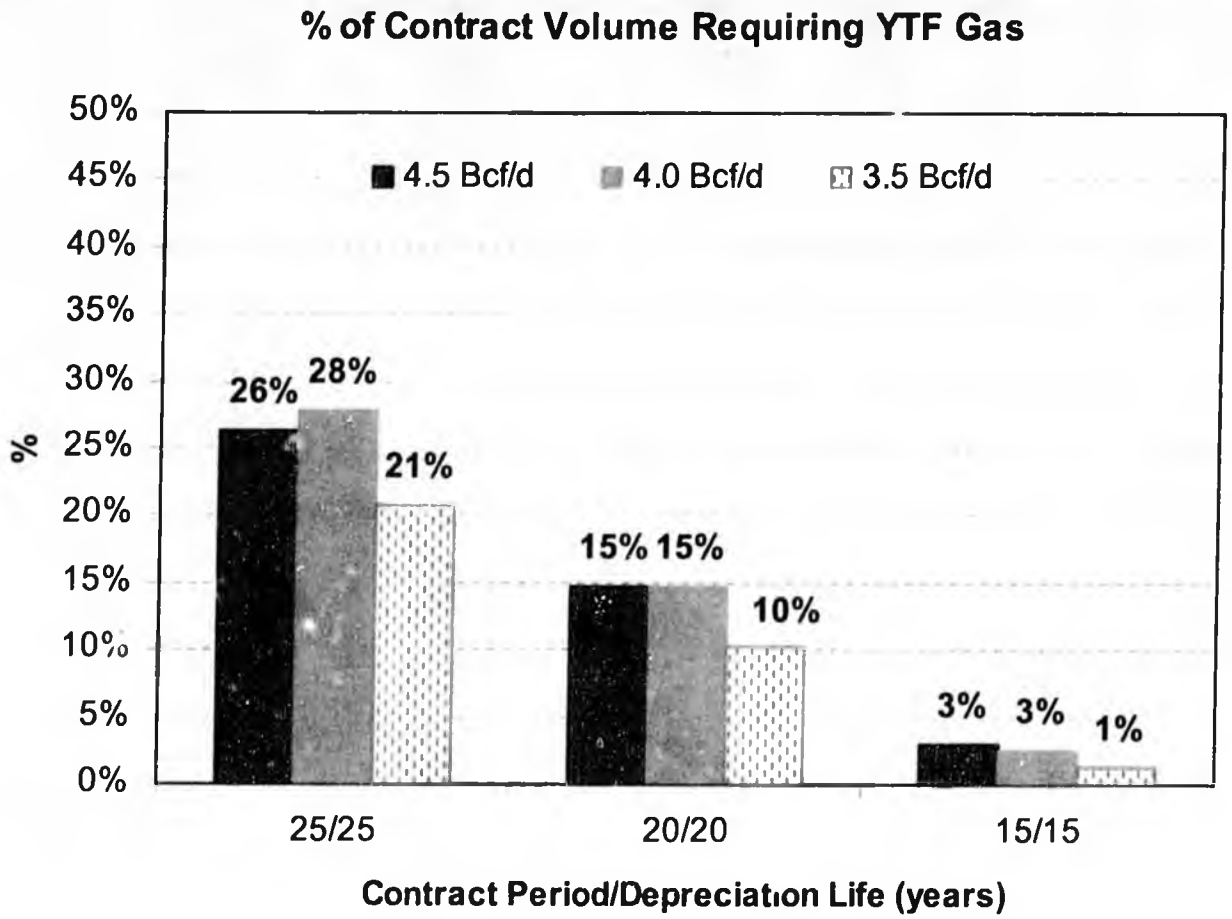
Aggregate Producer NPV_{10}



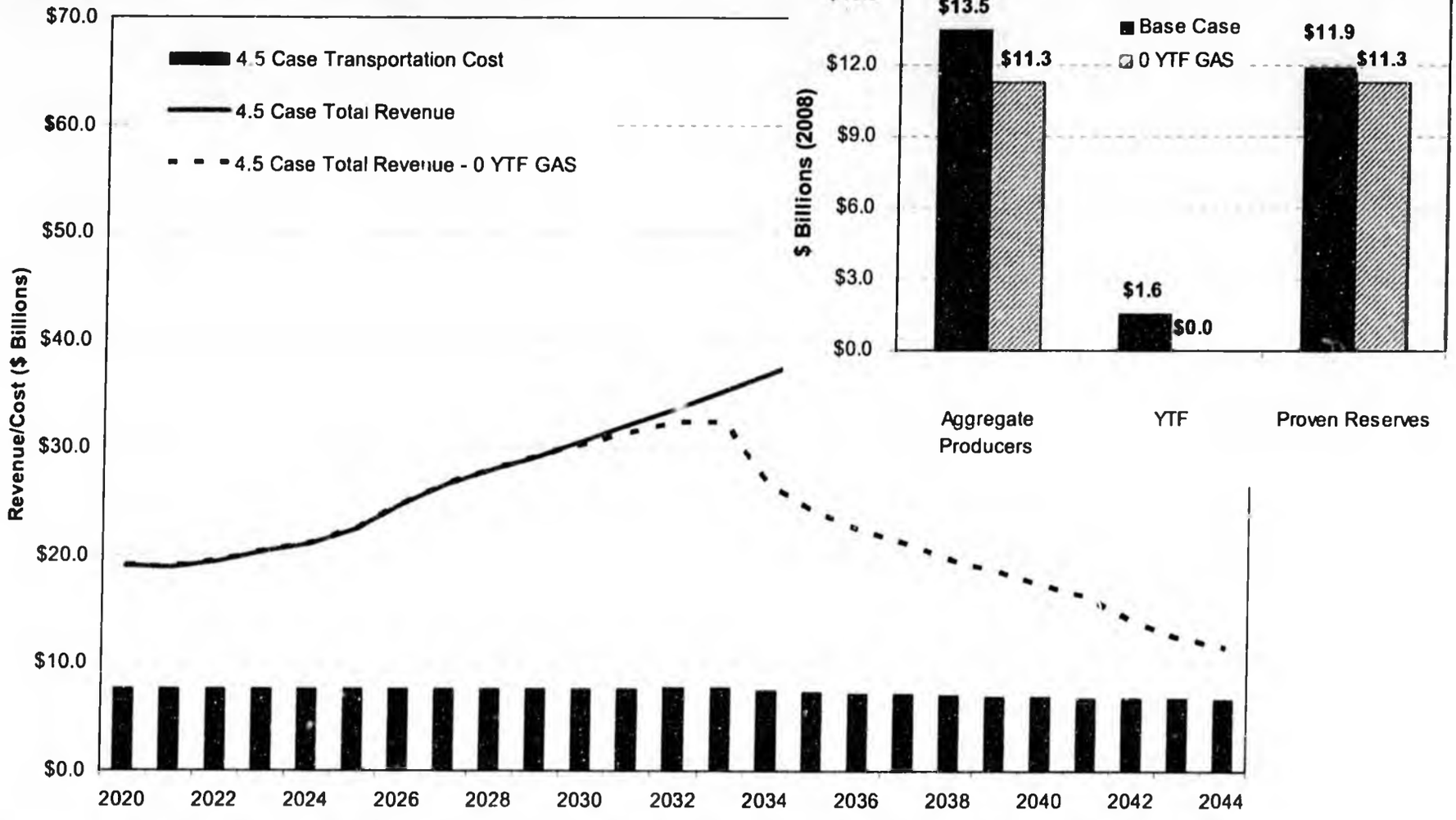
Aggregate Producer NPV_{15}



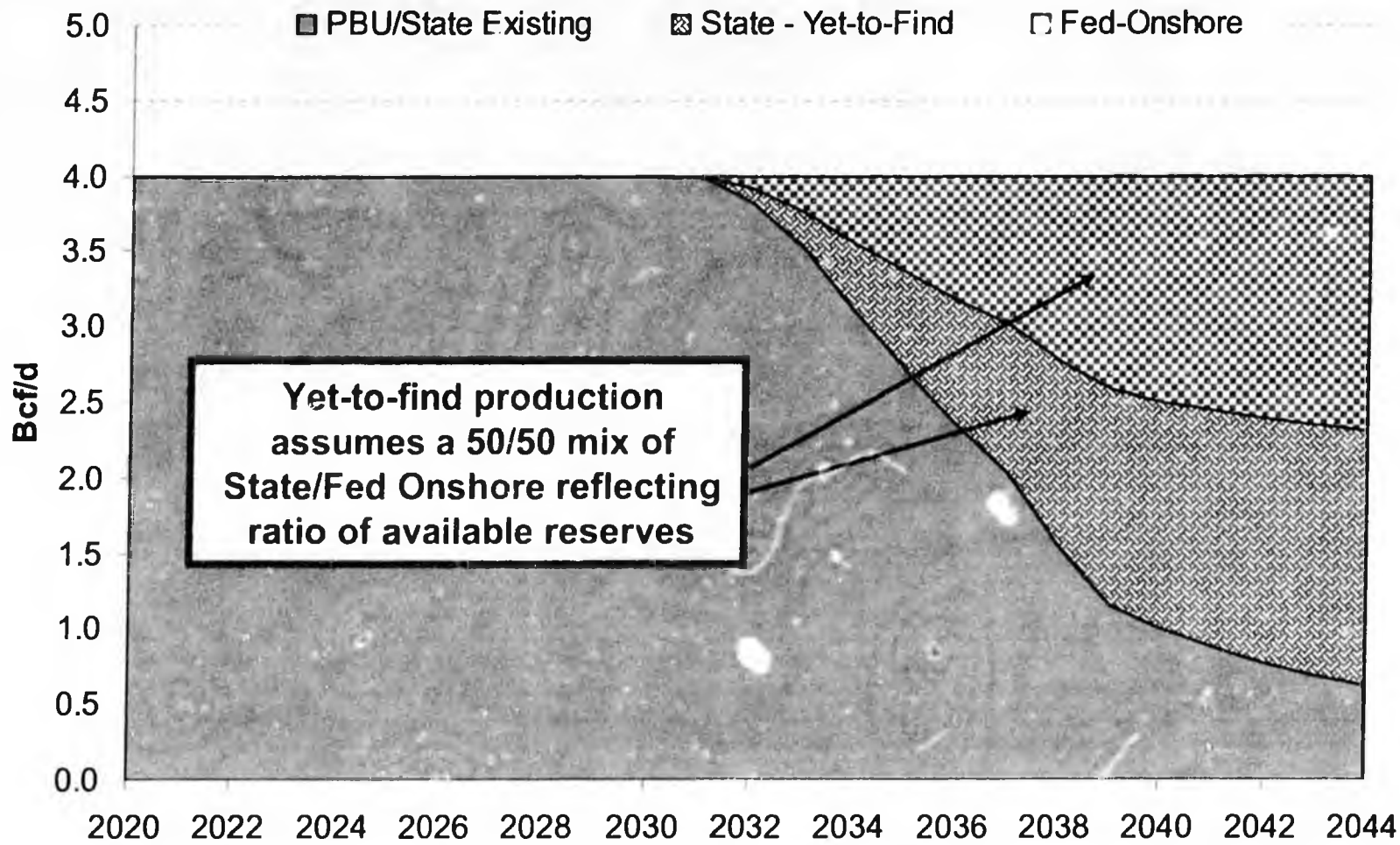
YTF Gas Required to Keep Pipeline Full under Different Contract Periods and for Different Pipeline Capacities



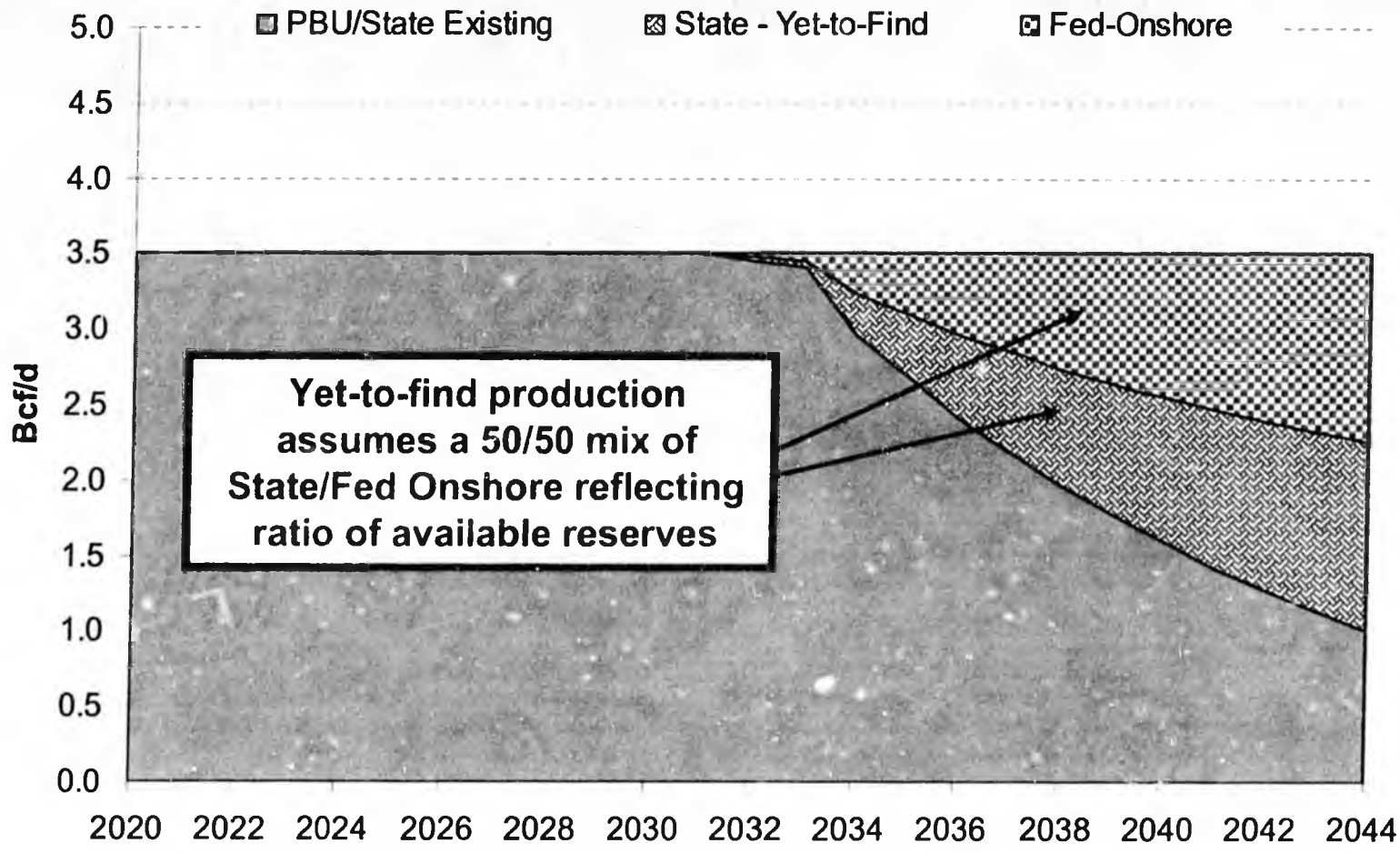
Producer NPV is Expected to Remain Positive if No YTF Gas is Produced



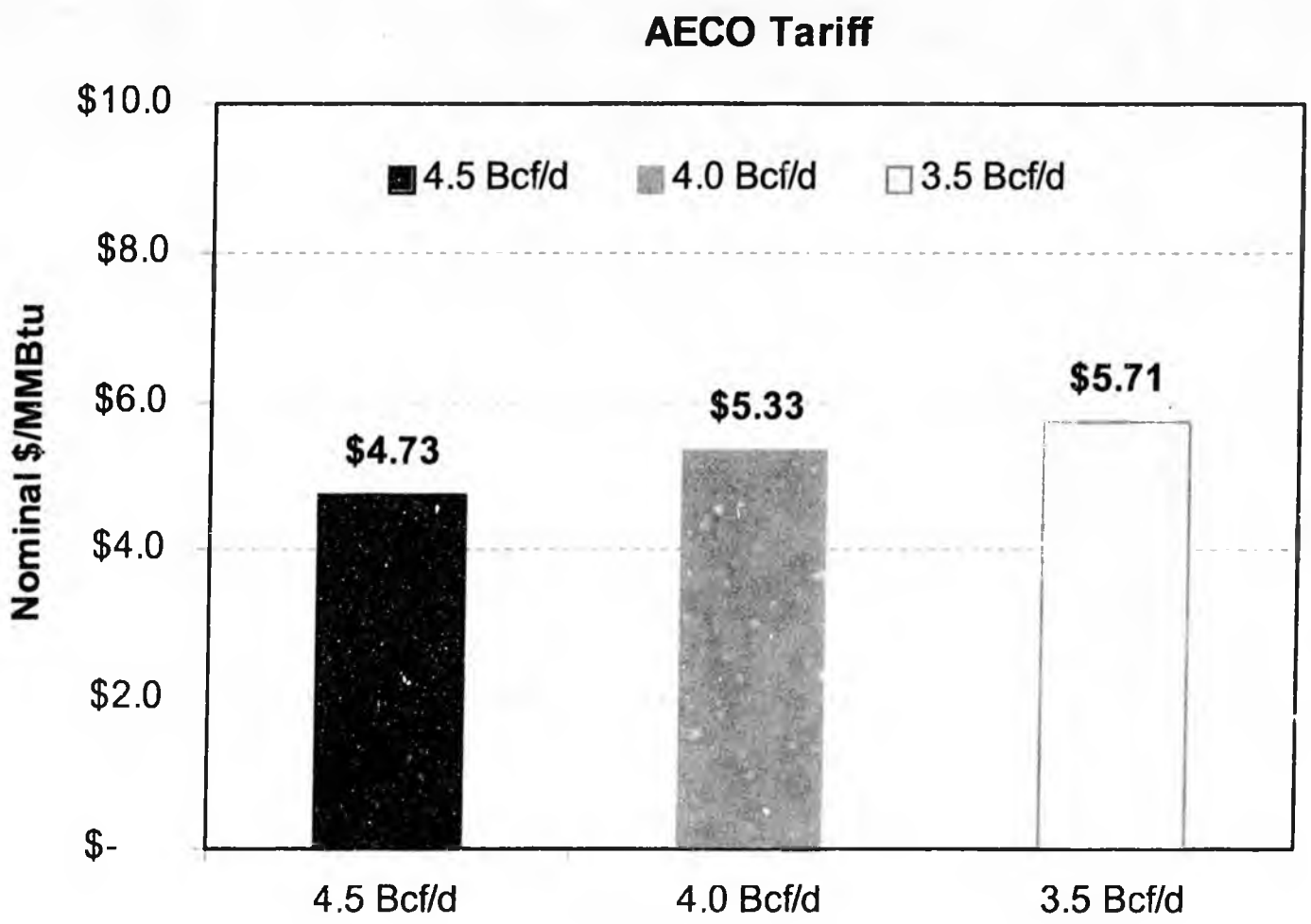
Production Assumptions: 4.0 Bcf/d Case



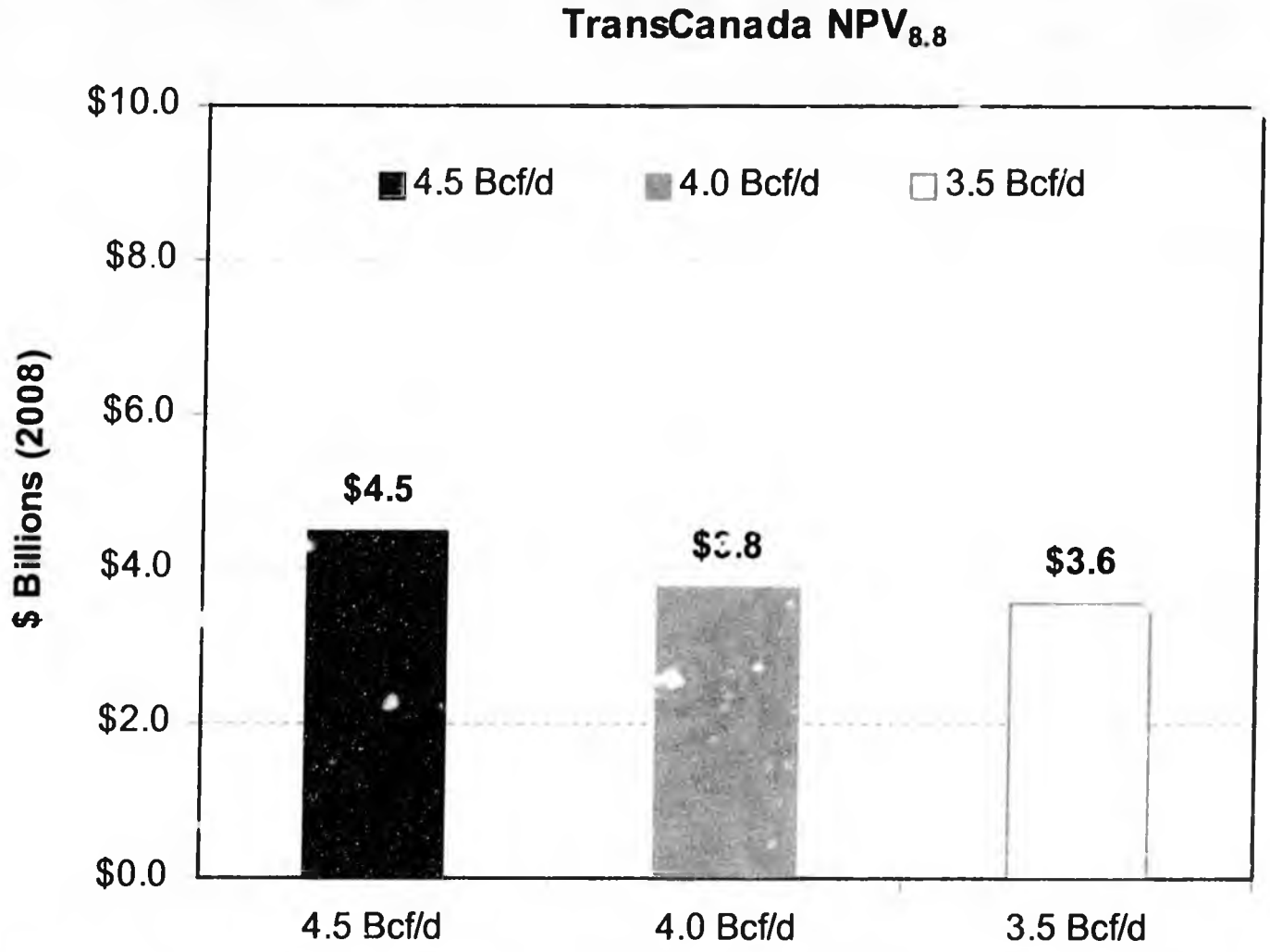
Production Assumptions: 3.5 Bcf/d Case



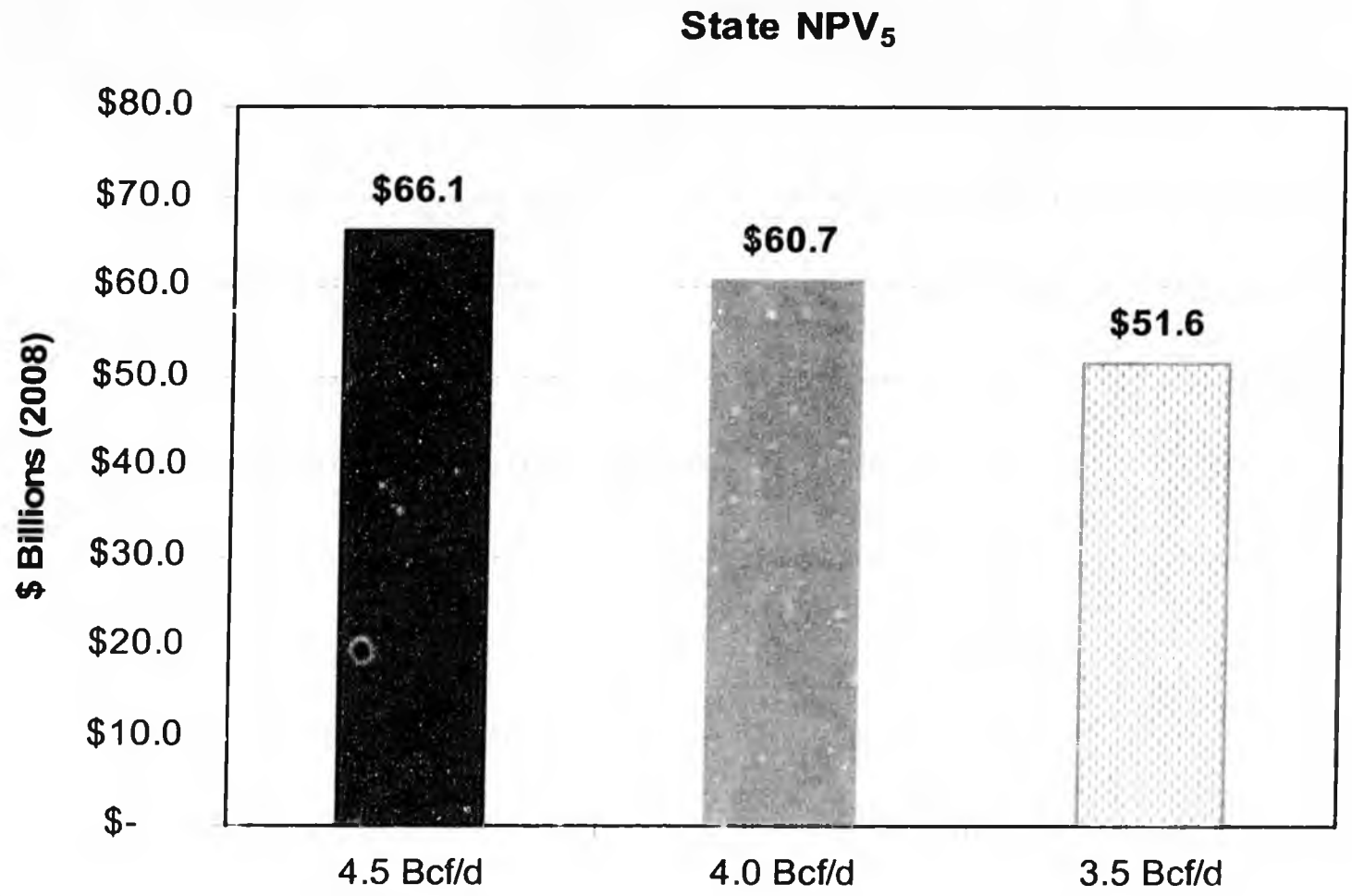
Expected Tariffs from the North Slope to the AECO Market



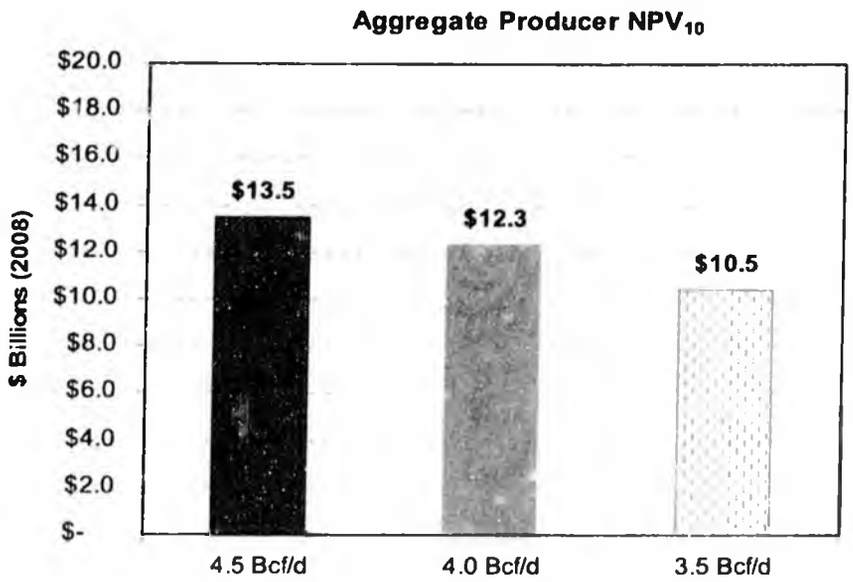
TransCanada $NPV_{8.8}$ is Significant under Proposed Terms and Base Case Assumptions

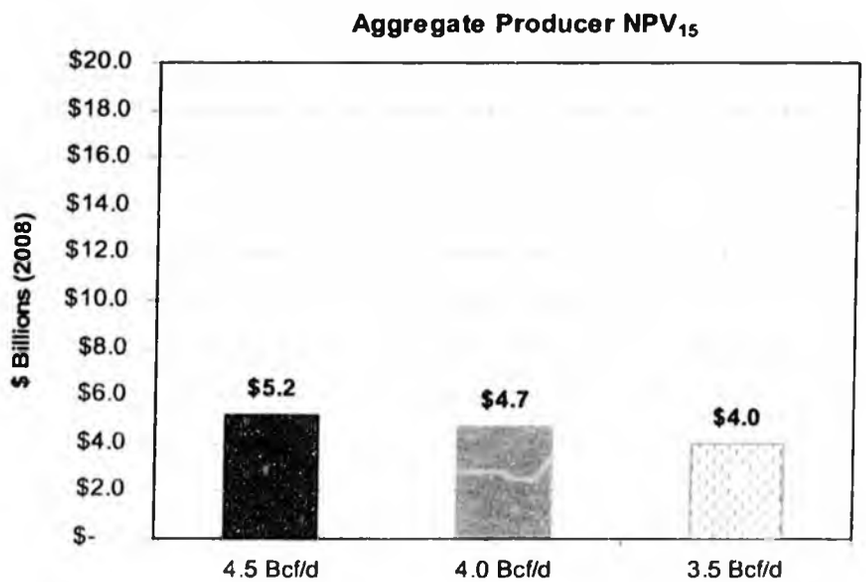


The State's NPV_5 Project is Lower with Lower Project Capacity but Remains Significant



Producer NPV Shows a Similar Trend When Compared to the State and TransCanada





Why does a delay <u>increase</u> State NPV_5?

- Why does a delay increase State NPV_5?
  - Prices increase
  - Progressivity for production taxes increases as prices rise
    - Production Tax in 2020 = ~25%
    - Production Tax in 2045 = ~50%
- Could a delay cause a decrease in the State NPV_5?
  - Yes, if prices increase at a lower rate than the baseline Wood Mackenzie prices, then a project delay would cause a decrease in the State NPV_5

Alaska Gasline Port Authority

Presentation to the Alaska Legislature

June 12, 2008

HB 3001
SB 3001
6/12/08
SPECIAL SESSION DOCUMENTS

The All Alaska Project

Gas Conditioning Plant in Prudhoe Bay

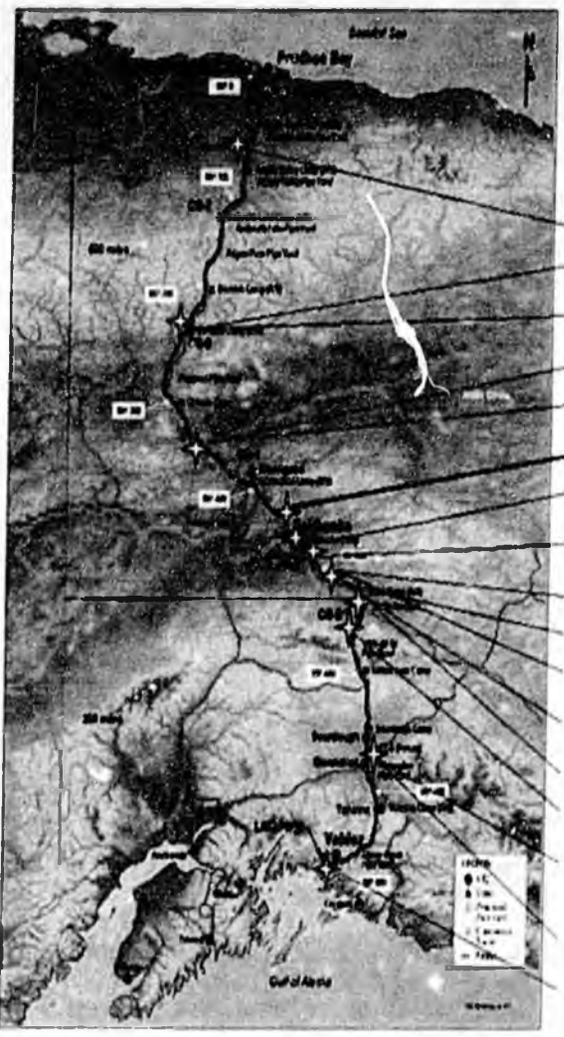
- removes impurities
- compresses and chills gas to pipeline specifications

Pipeline from Prudhoe Bay to Valdez

- pre-build to Delta Junction for later tie-in for the Alaska/Canada Highway Project
- tie-in at Glennallen for a spur line to South Central natural gas grid

LNG Facility in Valdez

- integrated LNG liquefaction and LPG extraction facilities
- includes storage and vessel loading facilities



18 Off-take Points

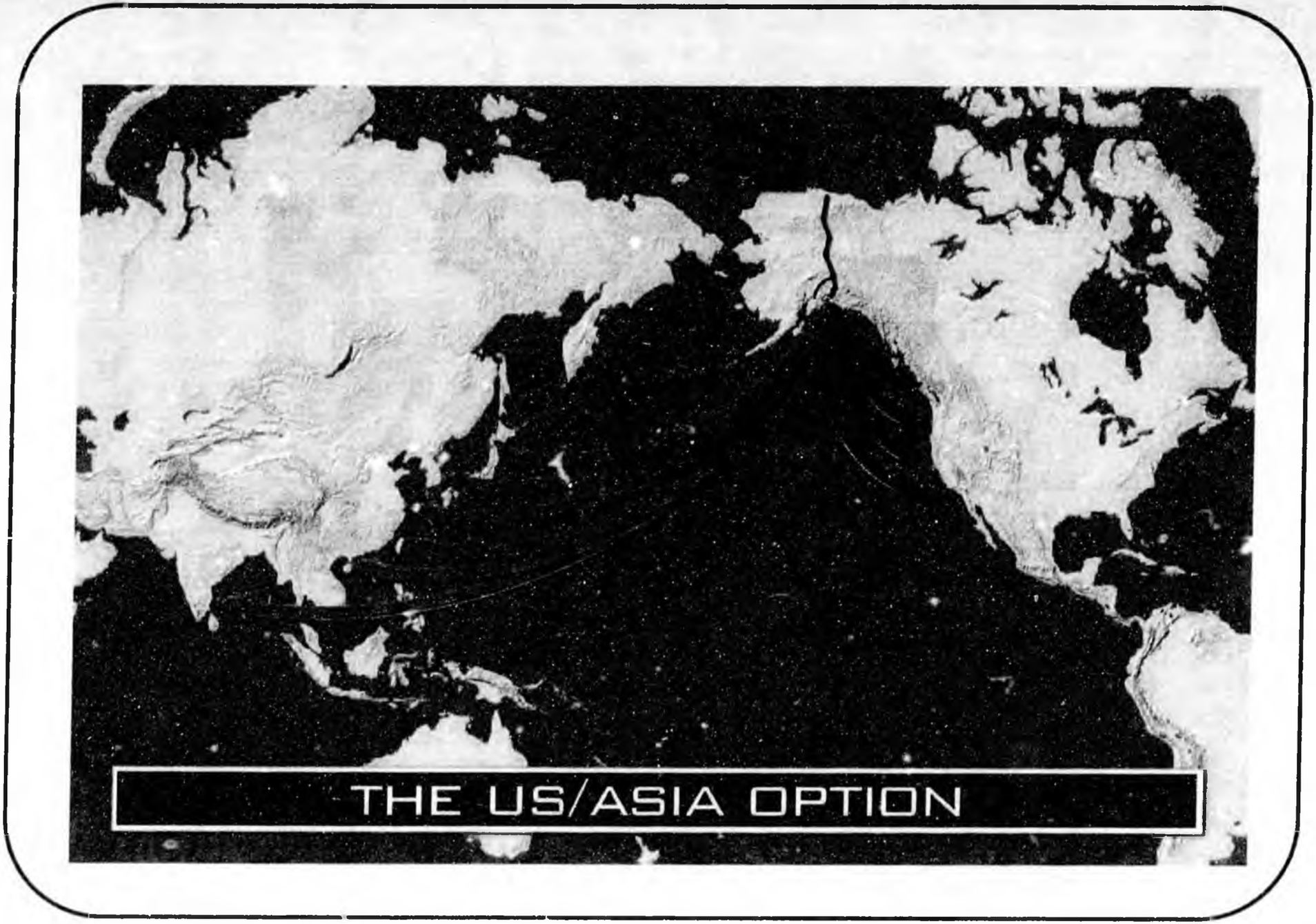
Proposed Offtake Points and Communities / Markets Served

- Toolik Lake Field Research Station
- Wiseman / Coldfoot
- Bettles / Alakaket / Alatna
- Stevens Village / Ft Yukon
- Yukon River Villages
- Ft. Knox Gold Mine
- Fairbanks North Star Borough
- City of North Pole
- Eielson Air Force Base
- Salcha
- Harding Lake
- Pogo Gold Mine
- Delta Junction / Future Canadian Highway line
- Ft. Greely / Missile Defense Base
- Glennallen / Anchorage and South Central through ANGDA Spurline
- Copper Center
- Valdez / LNG Export to Pacific Receiving Terminals

Alaska Gasline Port Authority

Markets

- Port Authority Markets
  - Alaska
  - Asia (Japan, Korea, Taiwan)
  - West Coast
  - Hawaii


THE US/ASIA OPTION

Export License

Alaska Gasline Port Authority

- DOE Viewpoint
  - Presumption of export
  - Allow market to work
  - Balance of payments
- Kenai 1967
  - Renewals: 1982,1987,1988,1999, 2008
- Valdez 1989 (FERC Order 350)
  - 14 MTA 25 years (Japan, Korea, Taiwan)

Btu Content

- ANS gas very high in liquid content (1084 btu/scf)
- Liquids in Alaska for value added – Options
  - LNG base case: extract propane & butane (1060 btu/scf)
    - 23,000 barrels per day
    - 30 x Alaska LPG consumption (30,000 gal)
  - Extract more liquids in Alaska
    - Can also extract ethane for value added
    - In current market environment lean gas to Asia not an issue

LNG imports into Asia: examples of gas composition

HV Level (Btu/scf)		Super Lean		Lean	
		1010-20	1020-40	1040-90	1090-
Project		Kenai	Egypt T&T	Nigeria Abu Dabi Qatar E. Guinea	Malaysia Oman Algeria Brunei Indonesia Australia
Typical Components	C1	99.6	98.1	92.2	90.1
	C2	0.2	1.8	5.1	5.4
	C3+	0.2	0.1	2.7	4.5
Gross Heating Value		1010	1025	1090	1120
Typical Project		Kenai	Egypt	Nigeria	Malaysia

Record of Receiving Lean LNG (Japan)

Most of Japanese Utilities are Capable of Receiving Super Lean Cargoes.

Utilities Capable of Receiving:

Super Lean

(<1040 Btu/scf: Egypt, T&T, Kenai)

- Tokyo Electric
- Tokyo Gas
- Chubu Electric
- Osaka Gas
- Kansai Electric

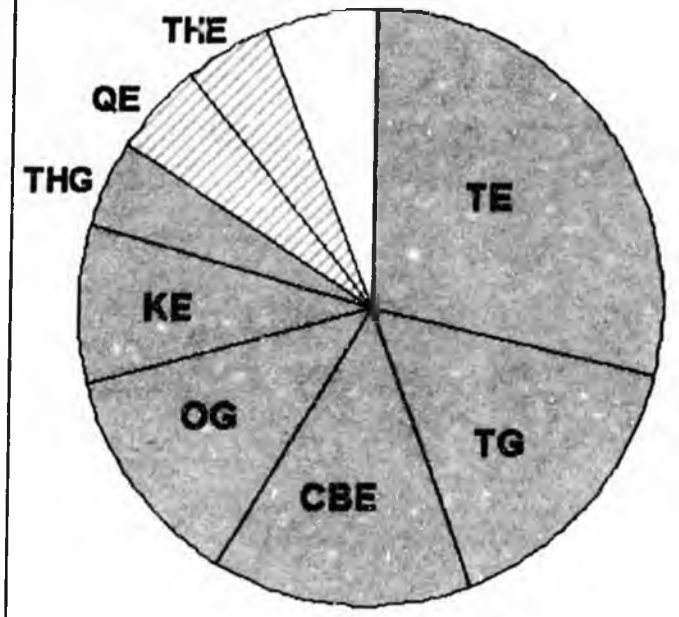
Total LNG Share:
Approx. 85%

Lean

(<1090 Btu/scf: Abu Dabi, Qatar, Nigeria, E.Guinea)

- Tohoku Electric
- Kyushu Electric

Approx. 10%



"LNG Share by Utilities in Japan"

Total (2007) 61,580,000 ton

Record of Receiving Lean LNG (Korea)

All Korean Utilities are Capable of Receiving Super Lean Cargoes.

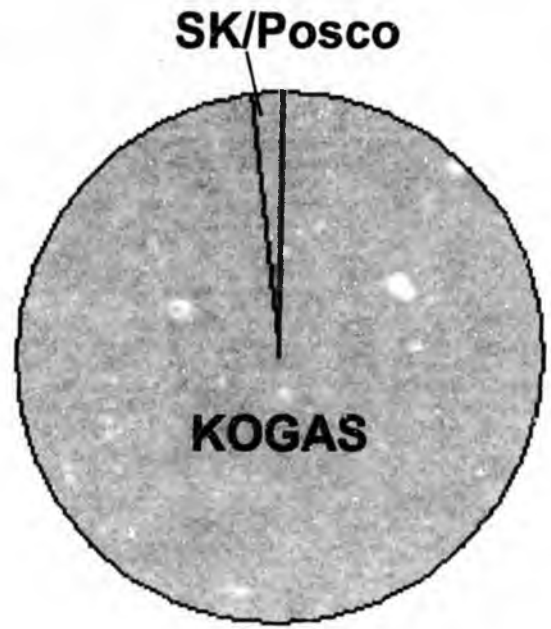
Utilities Capable of Receiving:-

Super Lean

(>1040 Btu/scf : Egypt, T.T, Kenai)

- Kogas
- SK
- Posco

Total LNG Share:
Approx. 100%



"LNG Share by Utilities in Korea"

Total (2007) 25,568,900 ton

Initial Project Volume

Alaska Gasline Port Authority

- All-Alaska project volume 2.7 not 4.5 bcf/d
- Reasons AGPA Chose 2.7 bcf/d
  - AOGCC (PBU Off-take)
  - Market Acceptance
  - Prove up reserves for expansion
- Better fit if no short-term PTU availability

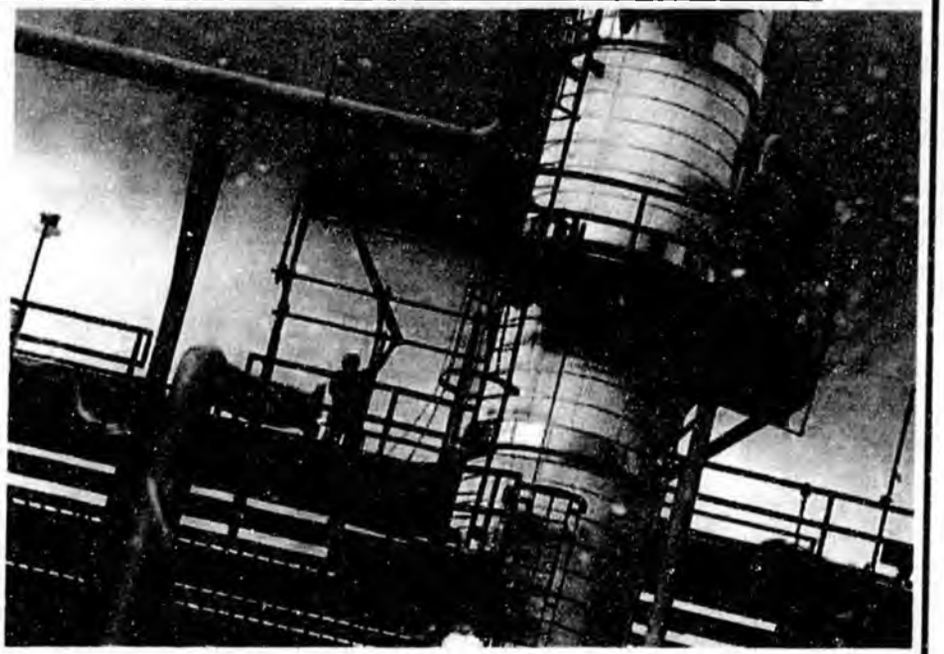
Liquefaction Cost

- Administration costed LNG plant using "comparable worldwide projects"
  - "The Technical Team did not have an AGIA-compliant application to directly evaluate regarding the cost of liquefaction."
  - $22.5 billion (4.5 bcf)

- Dangers of data mining – appears that administration's process
  - May have included upstream costs as part of integrated project costs
  - Missed 40% savings on compression resulting from high pressure of dense phase pipeline and ambient conditions in Valdez

Liquefaction Cost

- Bechtel LNG plants: Kenai, Algeria, Indonesia, UAE, Libya, Egypt, Trinidad, Australia, Angola, etc.
- Only licensee for ConocoPhillips Cascade Process
  - Single most creditable source for cost estimate



4th Train - Trinidad

Liquefaction Cost

- Bechtel's Work for AGPA
  - 2000-05: $8 million cost estimate, 55,000 man hours
  - 2007: $2 million AGIA update, 50+ engineers

- Results - Valdez LNG Plant
  - $7.0 billion* for 2.7 bcf (vs. $22.5 for 4.5 bcf)
  - Bechtel estimates low level of cost overrun risk on liquefaction because proven technology and design
    - Alaska pipeline component has highest capital cost uncertainty because substantially more unknowns

* Excludes owner and financing costs.

Netback

- Econ One (Fall 2006)
  - LNG first on Y-line has higher NPV if LNG 3 years before Canadian leg
  - This was when LNG had inferior netback
- LNG has superior netback, period.
  - ~$1.00 / mmBtu for 2.7 bcf LNG vs. 4.5 bcf Highway
  - Greater advantage for 3.5 bcf Highway
  - Even greater advantage if market optionality considered

All-Alaska Route Permitted

Alaska Gasline Port Authority

- Pipeline 100% within existing TAPS corridor
- No foreign issues
- YPC – 20+ years ($100 million) of permits & process
  - Saves years
  - We know the answer is “yes”

Canadian Delay – Bennet Jones Report

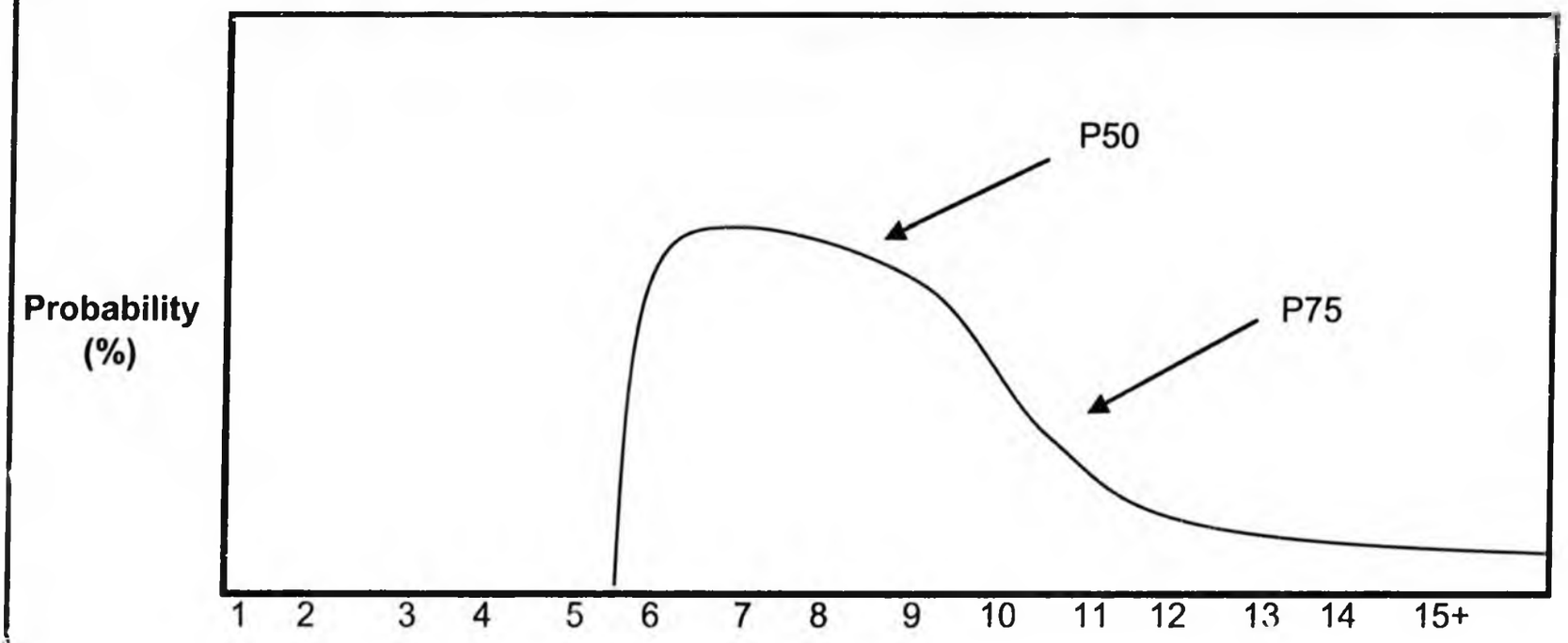
Alaska Gasline Port Authority

- Environmental (NPA vs. Newer Laws)
  - No legal or even identified right-of-way
  - "likely" pressure for review process similar to Mackenzie Gas Project
- First Nations (40+)
  - Constitutional obligation to consult
  - Legal challenge "likely" and take "several years" to resolve
  - Can be "fatal" since they can stop project until adequate consultation
- NPA exclusivity to TransCanada
- Mackenzie goes first

Canadian Delay

Alaska Gasline Port Authority

Hypothetical Timing Profile



Risk

Alaska Gasline PORT AUTHORITY

- LNG vs. Pipeline
- Structural vs. Commercial
- Alaska/U.S. vs. Canada
  - LNG - Alaska controls project risks

Risk

- The greatest risk in the project is Alaska's future

Which Project Goes First

Alaska Gasline PORT AUTHORITY

- Administration states Canadian leg should go first
- AGPA states All-Alaska leg should go first
  - David Keane (BG) testified last session that the LNG project would be the enabler for a later Canadian Highway project
- Let market/shippers decide – eliminate no options

Way Forward Options

- Build All-Alaska gas pipeline now
- Pass AGIA but…
- Take control of Alaska's future
  - State contracts for building of All-Alaska gas pipeline now and begin moving Alaska's gas to Alaskan and other markets.

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

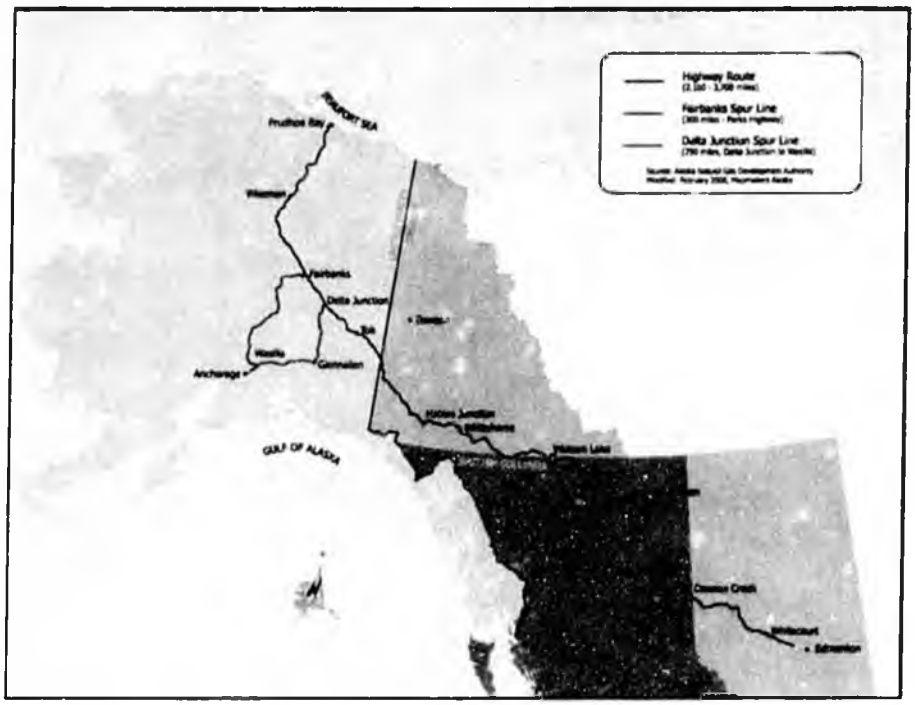


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Table of Contents

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

1.0 Purpose

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

2.0 Key Findings

The results of this study suggest the following key findings:

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

3.0 Scope and Assumptions

3.1 Gas Pipeline Operation

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

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

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

3.2 Industrial Demand

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

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

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

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

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

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

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

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

3.3 Financial Assumptions

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

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

differences are estimated to be $2.51 and $3.12 in the "Low" and "High" case 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 Costs	Low Price Scenario		High Price Scenario	
		Operating Costs	Shipping Costs	Operating Costs	Shipping Costs
Fertilizer *	$257	$316	$55	$589	$57
LNG **	$880	$642	$128	$1,271	$135
GTL	$3,112	$772	$103	$1,504	$108
Petrochemical	$2,993	$722	$80	$1,046	$82
LPG	$844	$440	$66	$740	$69

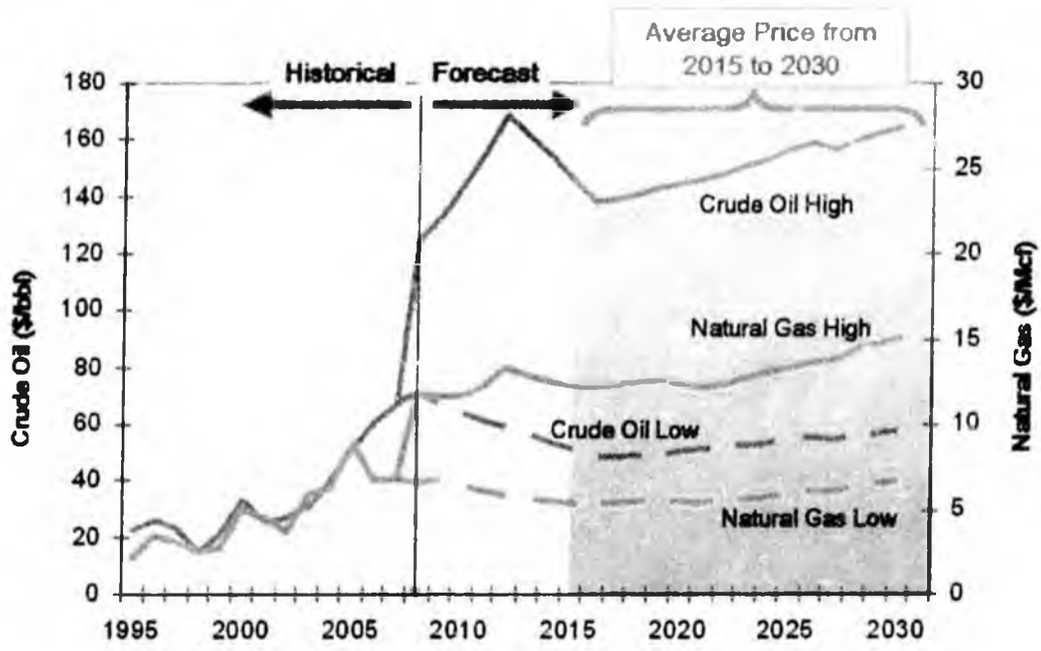
* Assumes upgrade of the existing fertilizer plant
** Assumed expansion of the existing LNG facility at Nikiski

4.0 Methodology

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

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

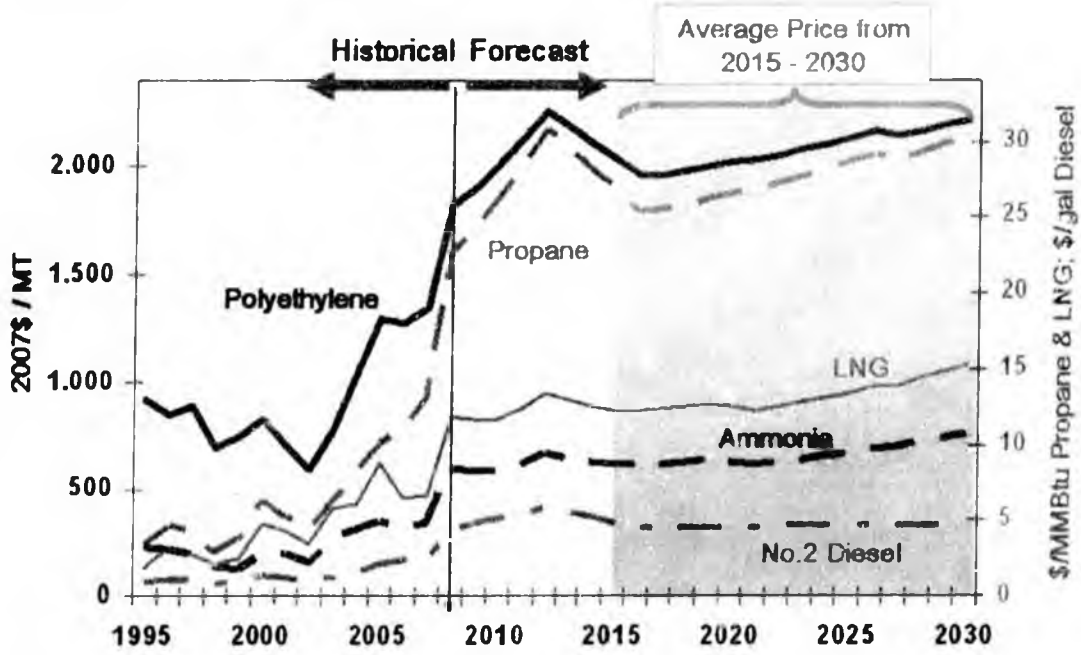
Figure 1: Lower-48 Crude Oil and Natural Gas Prices: Historical and High and Low Forecast Scenarios (2007$)



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

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

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



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

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

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 [a]	$35.75 [a]
LNG, Southern California ($/MMBtu)	$6.09	$13.17
LNG, Japan ($/MMBtu)	$7.05	$16.74
Ammonia ($/ton)	$322	$676
Polyethylene ($/ton)	$1,097	$2,081

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

5.0 Industry Investment Analysis Results

5.1 Product Markets

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

Table 4: Potential Markets for Alaskan Industrial Products

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

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

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

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

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

5.2 Netback Results

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

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

Industry	Low Price Scenario (SC NG Market Price: $3.43 to $4.43/MMBtu)		High Price Scenario (SC NG Market Price: $7.76 to $8.76/MMBtu)	
	Product Price	Netback ($/MMBtu)	Product Price	Netback ($/MMBtu)
Fertilizer *(Ammonia)	$322 ton	$5.87	$676/ ton	$13.45
LNG , Southern California	$6.09/ MMBtu	$3.24	$13.17	$9.63
LNG, Japans	$7.05/ MMBtu	$4.11	$16.74/ MMBtu	$12.87
GTL (Diesel), N. America	$11.47/ MMBtu	$2.45	$33.08/ MMBtu	$14.89
GTL (Diesel), Japan	$14.14/ MMBtu	$3.99	$35.75/ MMBtu	$16.43
Petrochemical	$1,097/ ton	$5.19	$2,081. ton	$20.72
LPG	$453/ ton	$4.65	$1,305/ MMBtu	$19.92

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