

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

3100 SCOMM 143: SENATE SPEC.COMM.ON NATURAL GAS DEV. 2005-2006



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SCOMM 143: SENATE SPECIAL COMMITTEE ON NATURAL GAS DEVELOPMENT,
2006

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Contents: 4 files: 2 files for 2nd special session, and 2 files
for 3rd special session.

LIST OF FILES (PAGE 1)

MICROFICHE #

1. ALASKA PORT AUTHORITY PRESENTATION,
8/3-8/4/06
2. SB 2003
3. SB 2004
4. SB 3002
5. HB 3001

SCOMM

143:1



Alaska Gasline Port Authority

Presentation to Senate Special Committee on Natural Gas Development



Project Economics

August 3-4, 2006



Important Notice About Financial Projections

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

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Overview

- Introduction of the Analysis
- Price Assumptions
- LNG Project Concept and Gas Volumes
- Cost Assumptions
- Netback Calculations
- Upstream Returns to the Producers
- PTU Case
- Comparison of State Revenues
- Conclusions / Questions



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Introduction of the Analysis



Project Component Terms

- Upstream
 - Lease production activities

- Midstream
 - Feeder lines
 - GCP
 - Alaska pipeline(s)
 - LNG Facility
 - Canadian pipeline(s)

- Downstream
 - LNG marine transportation
 - Regasification and takeaway pipelines to market
 - NGL extraction in Alberta



Project Component Terms (continued)

- AGPA project components: owned, built and financed by AGPA
 - Pipeline(s) from Prudhoe Bay to Valdez and possibly to Canadian Border
 - LNG Facility in Valdez
- Producer project components: owned, built and financed by Producers
 - GCP
 - Feeder pipelines
 - Upstream production activities
 - Canadian route components (if not provided by Third Parties)
- Third Party project components: provided by third parties
 - LNG marine transportation
 - Regasification and downstream takeaway pipelines to market
 - Canadian route components (if not provided by Producers)



Price Assumptions

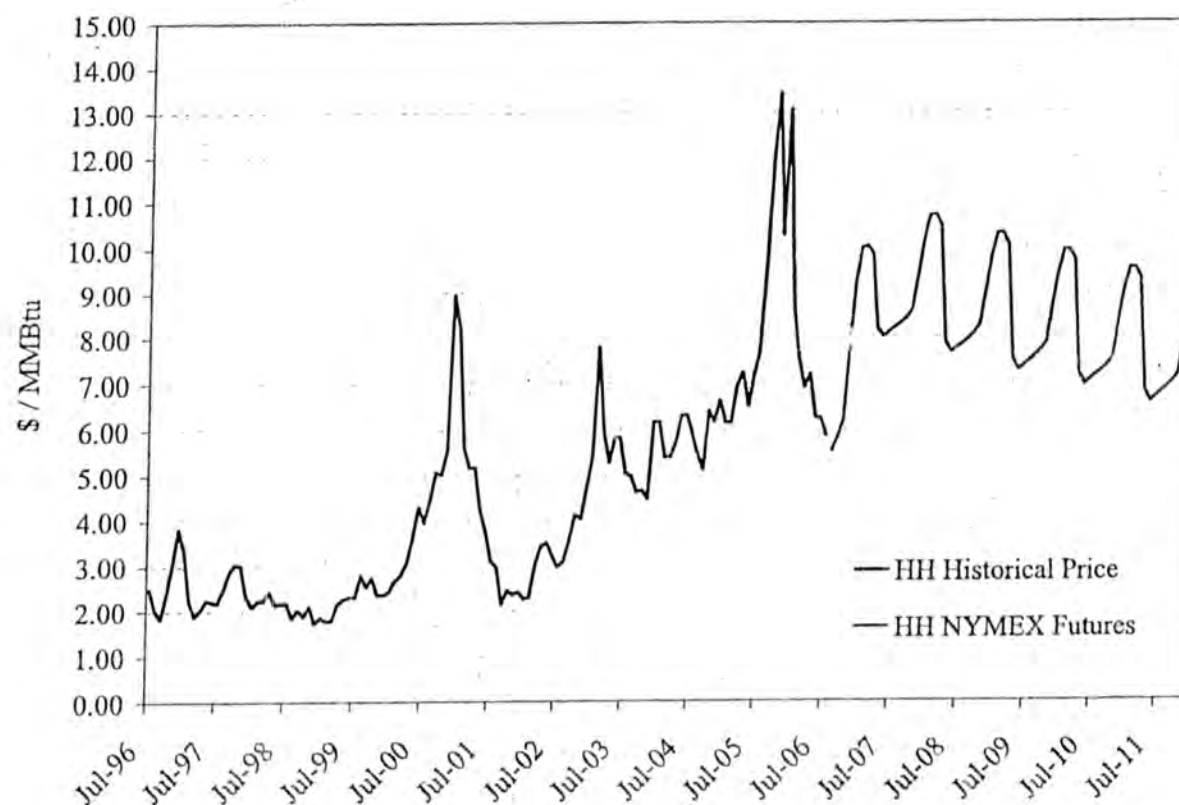


Gas Price Assumptions

- Henry Hub price:
 - considered the benchmark U.S. gas price
 - most forecasts for U.S. gas prices refer to Henry Hub pricing
 - used for the benchmark NYMEX physical and financial gas price futures contracts
- Regional gas prices are typically expressed as a differential above or below Henry Hub pricing (“basis”)

Henry Hub Price Assumption

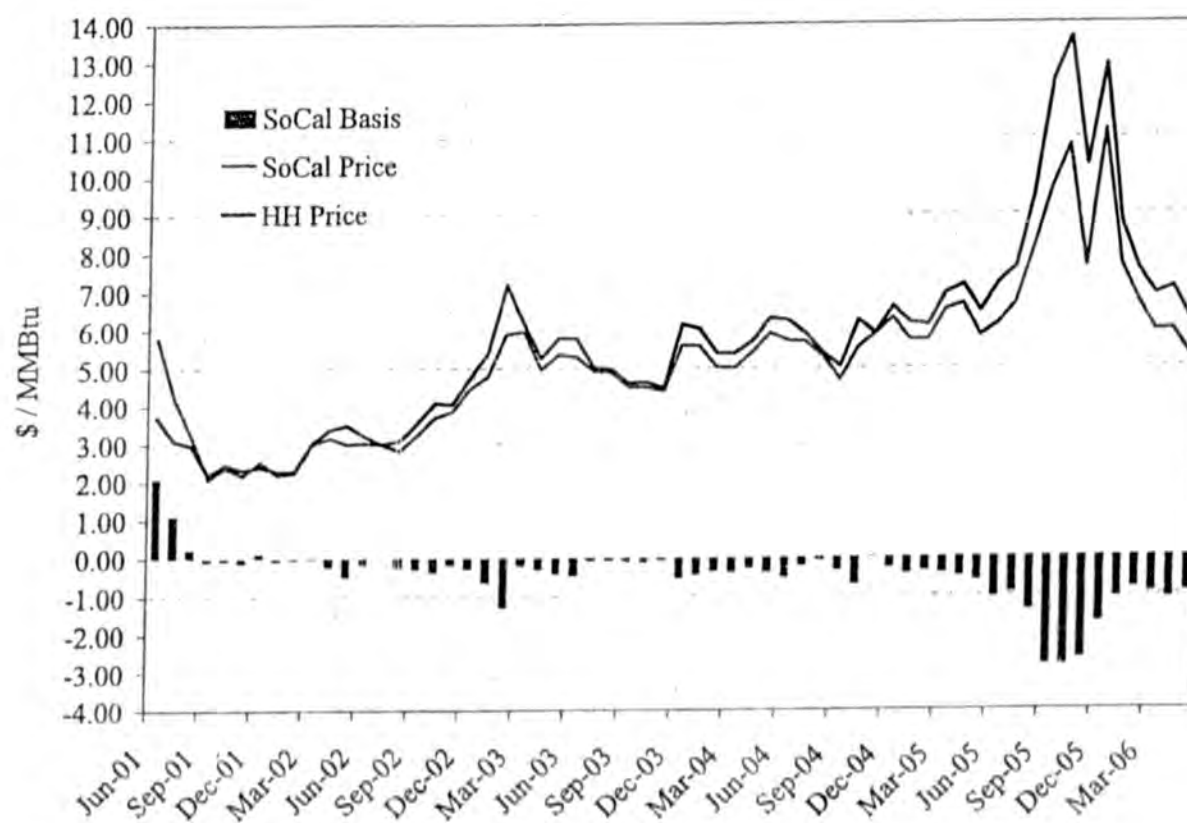
- Henry Hub historical 5-year average price: \$5.68 per MMBtu
- Current forward pricing on NYMEX: \$7.70 per MMBtu (average of distant 12 months)
- AGPA base case assumption: \$5.50 per MMBtu (constant 2005 dollars)



Source: Bloomberg, NYMEX

SoCal Gas Price Assumption

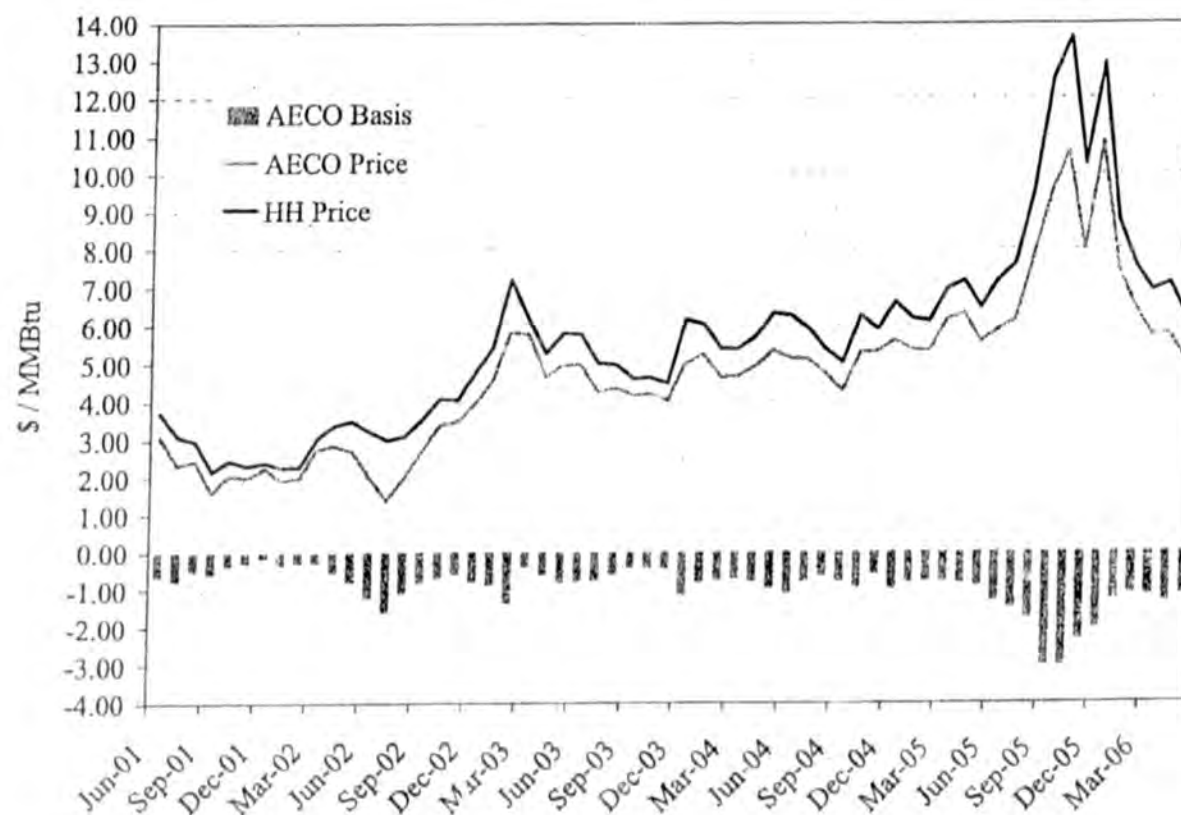
- 5-year average SoCal basis: \$(0.47) per MMBtu discount to HH
- After an increase to over \$(2.00)/MMBtu, SoCal basis has been narrowing and is expected to decrease further
- AGPA base case assumption: \$(0.47) per MMBtu discount (flat nominal terms)



Source: Bloomberg

Alberta Gas Price Assumption

- 5-year average AECO-C basis: \$(0.93) per MMBtu discount to HH
- AGPA base case assumption: \$(0.93) per MMBtu discount (flat nominal terms)



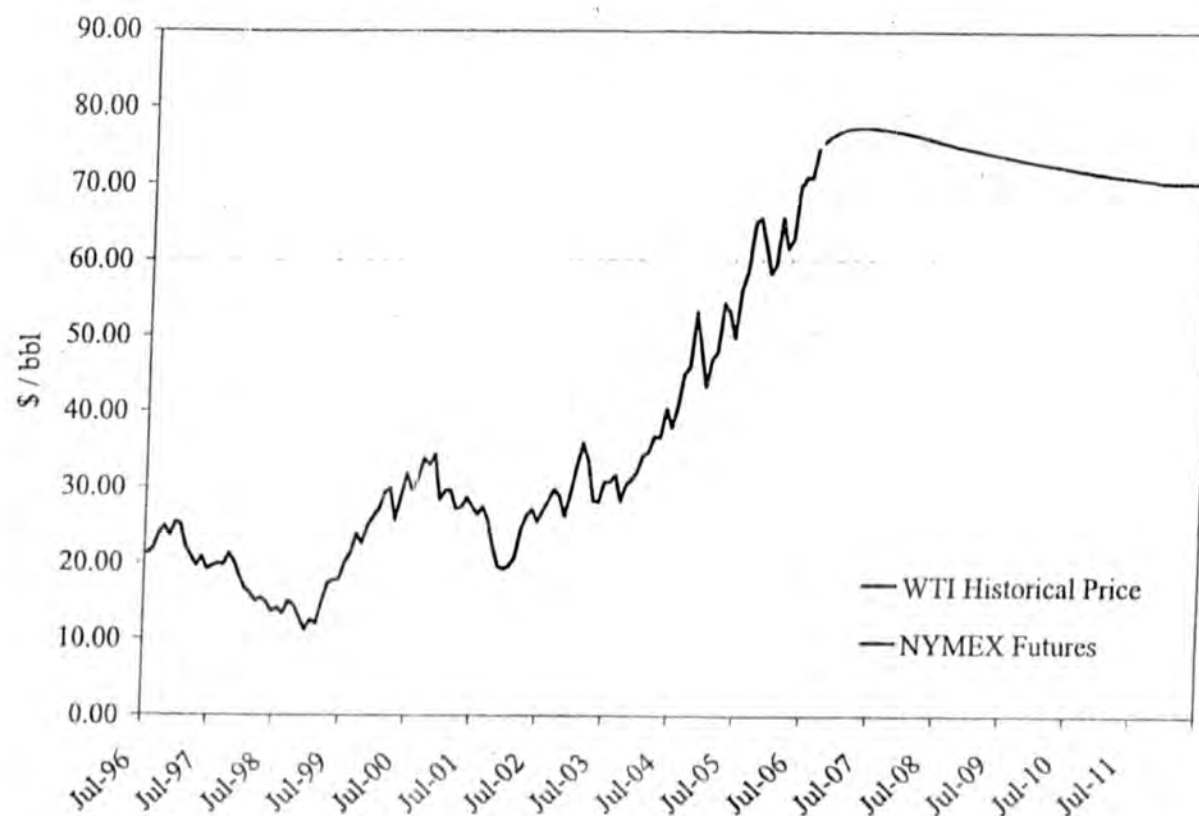
Source: Bloomberg



Crude Oil Prices

- WTI historical 5-year average price: \$40 per bbl
- Current forward pricing on NYMEX: ~ \$70 per bbl

- What is a reasonable WTI price assumption consistent with a certain Henry Hub gas price assumption?



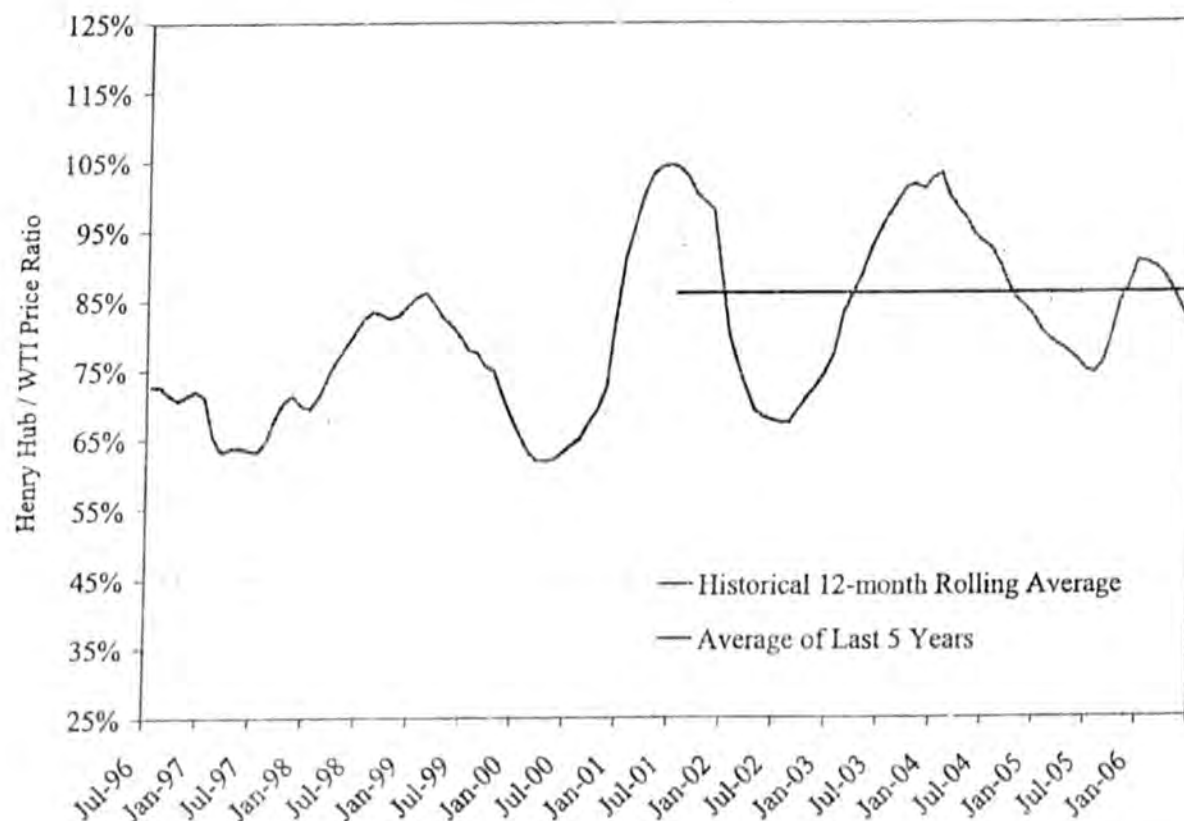
Source: Bloomberg, NYMEX

Crude Oil Prices (continued)

- Henry Hub prices and oil prices historically have not been closely correlated
- Henry Hub / WTI historical 5-year average price ratio: 86%

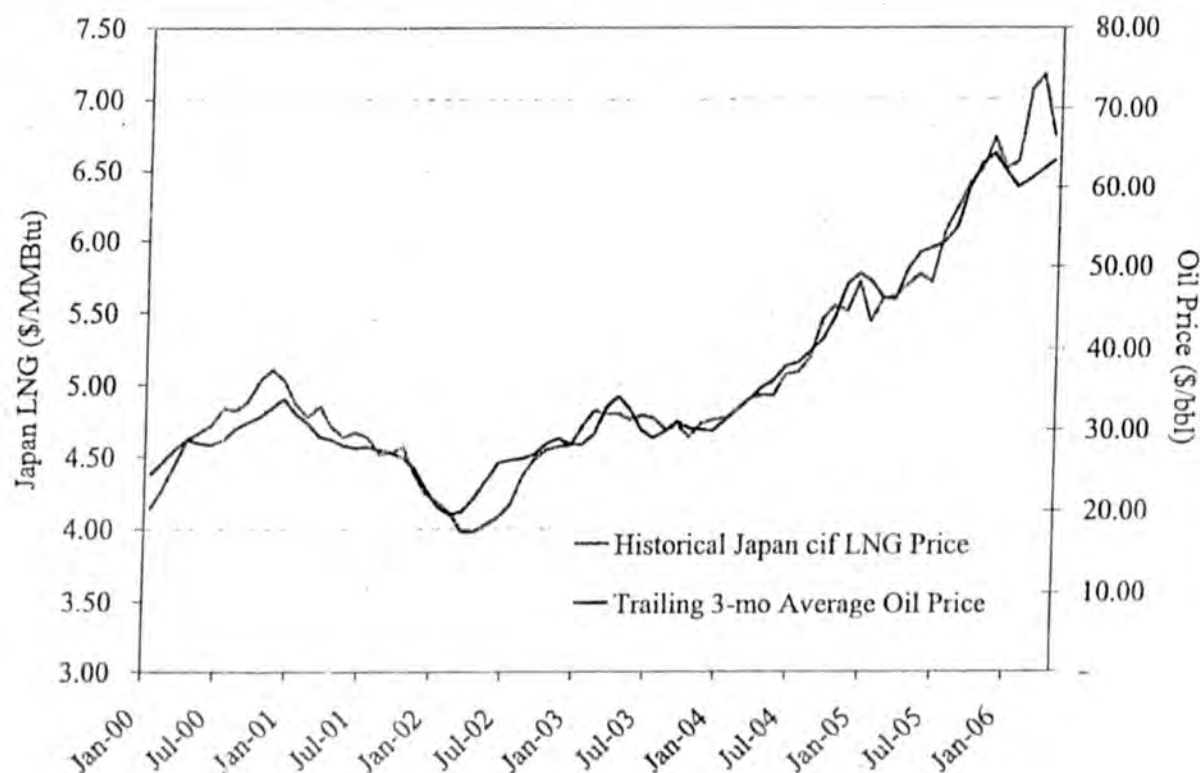
- A \$5.50/MMBtu Henry Hub assumption would be equivalent to a WTI assumption of \$37/bbl, assuming a 86% HH to WTI price ratio

- AGPA WTI base case assumption: \$36/bbl



Japan LNG Prices

- Japan LNG sales prices are typically expressed in contract formulas indexed to JCC (basket of crude oil imports to Japan)
- Japan LNG prices, therefore, are closely correlated with oil prices
- The AGPA model calculates Japan LNG prices on the basis of the assumed oil price and the historical price relationship



Source: Bloomberg

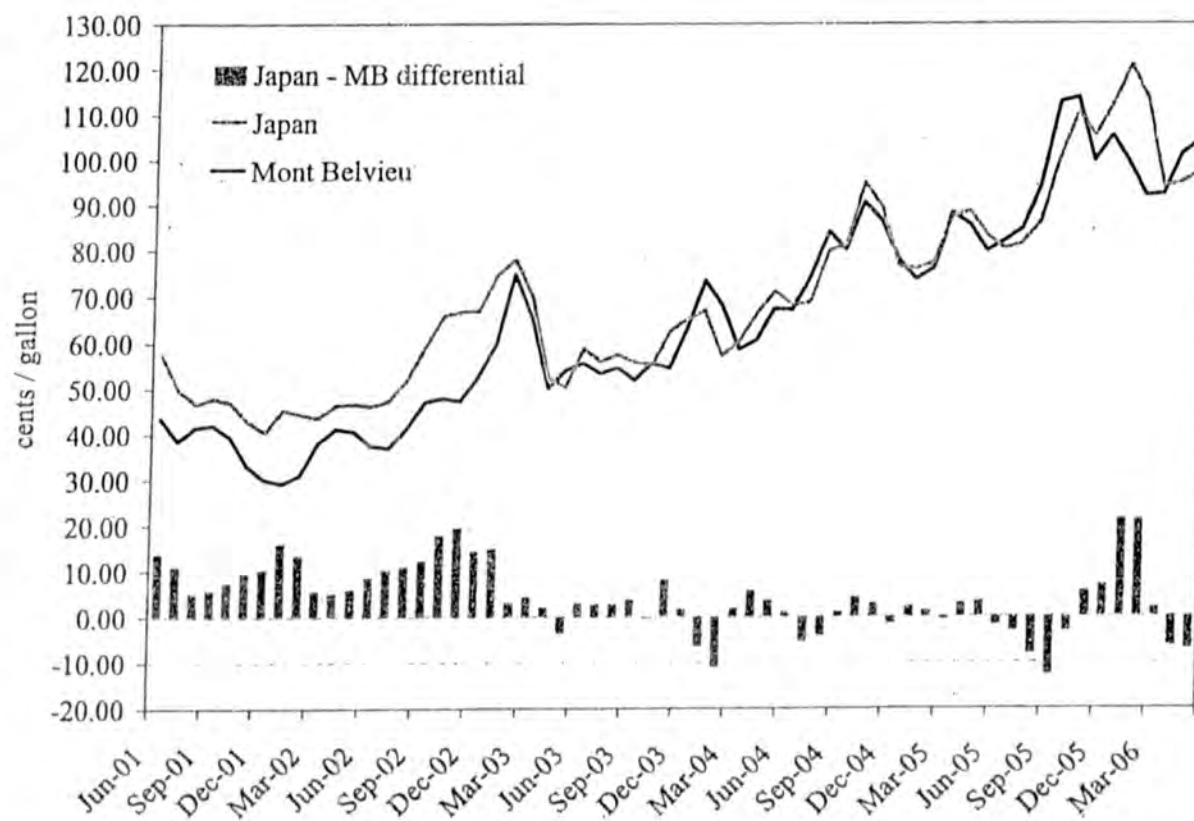


Propane Price Assumptions

- Mont Belvieu propane price:
 - benchmark U.S. Gulf Coast price
 - Mont Belvieu is the deepest propane market in the U.S.
 - used for the NYMEX propane futures contract
- MB propane prices have been historically correlated with both WTI and Henry Hub prices
- AGPA's financial model calculates Mont Belvieu propane prices on the basis of the assumed WTI and Henry Hub prices, using the historical price relationship
- Regional propane prices are assumed on the basis of historical premium/discount to Mont Belvieu

Propane Price Assumptions: Japan

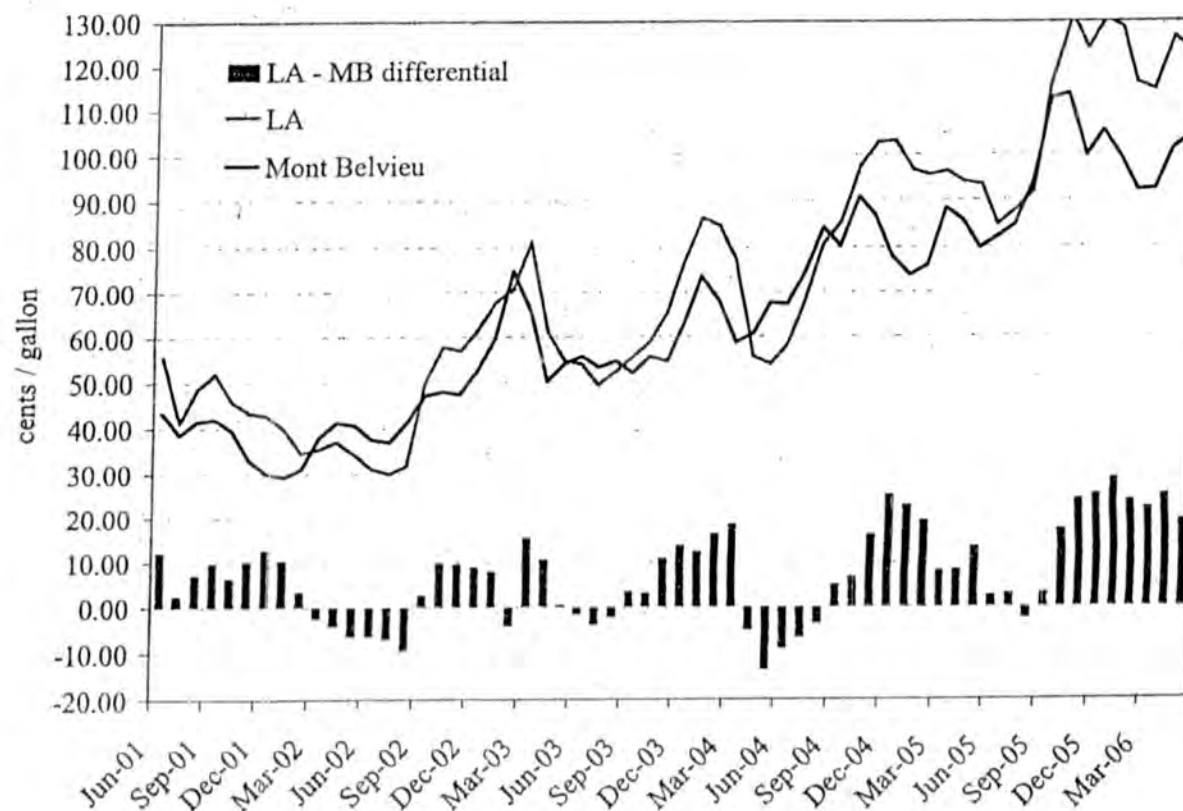
- 5-year average Japan premium to MB: 4.4 cents/gallon
- AGPA assumption: 4.0 cents/gallon premium over MB



Source: Bloomberg

Propane Price Assumptions: LA

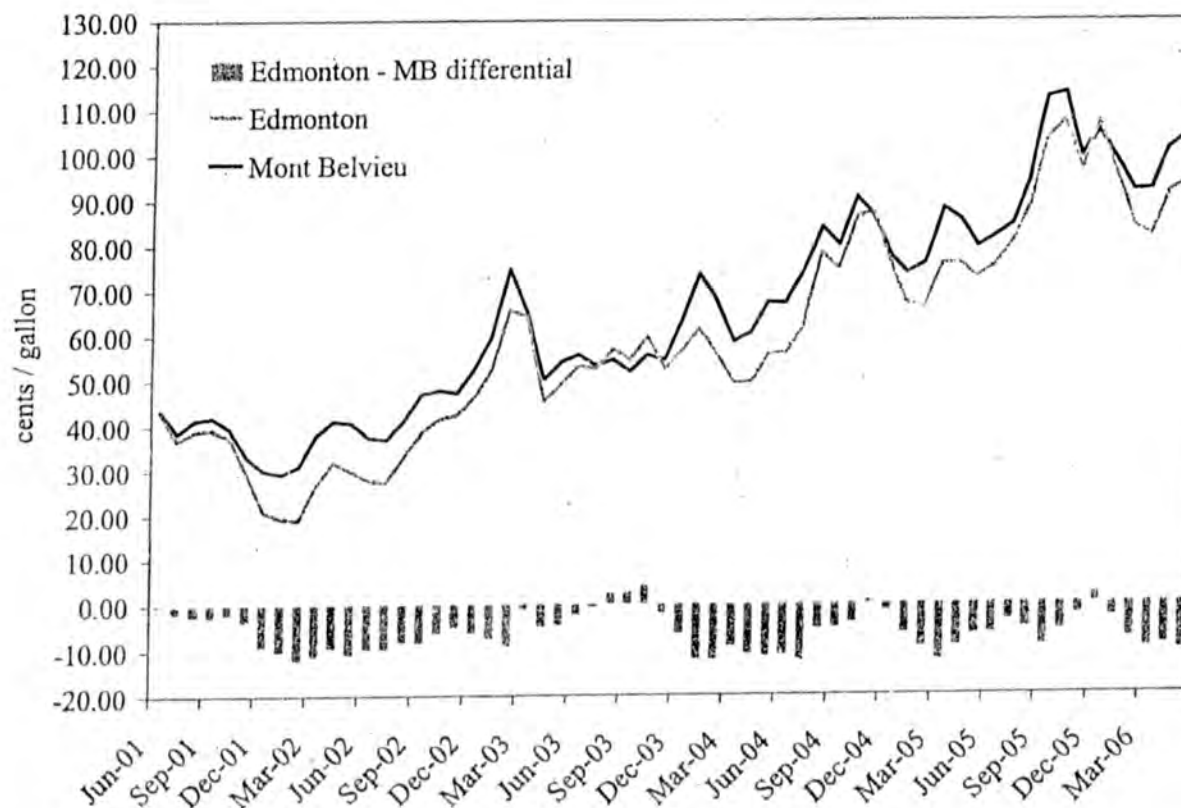
- 5-year average LA premium to MB: 7.6 cents/gallon (flat nominal terms)
- AGPA assumes most LPGs will go to East Asia, but there is opportunity for higher premium in LA market



Source: Bloomberg

Propane Price Assumptions: Alberta

- 5-year average Alberta discount to MB: (6.2) cents/gallon (flat nominal terms)
- AGPA assumption: (6.0) cents/gallon discount to MB



Source: Bloomberg, Duke Energy



Butane Prices

- Assumed on the basis of historical differential between butane and propane in respective markets (East Asia and Alberta)
- Japan butane – propane differential: 9 cents/gallon (flat nominal terms)
- Alberta butane – propane differential: 10 cents/gallon (flat nominal terms)



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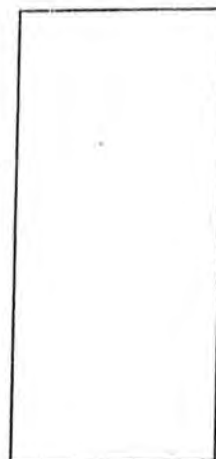
LNG Project Concept and Gas Volumes



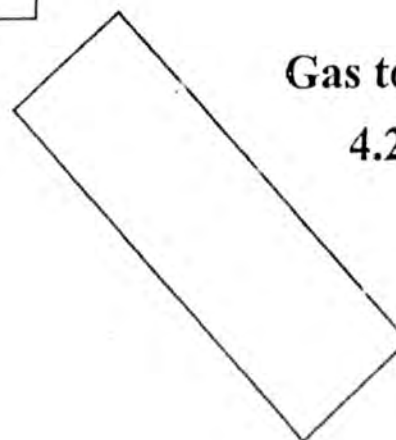
Highway Project Proposal

Year: 2016

4.3 Bcf/d



Pipeline from Prudhoe Bay



Gas to Canada

4.2 Bcfd

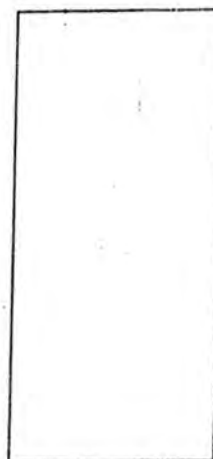


AGPA Proposal: Immediate Implementation

Year: 2012

1.2 Bcf/d

Pipeline from Prudhoe Bay



Alaska LNG

1.1 Bcfd





AGPA Proposal: Immediate Implementation (continued)

- The AGPA project can be implemented immediately
- Brings value to State and Producers during the period 2012 – 2016+ that would not be otherwise created
- The Highway Project can be implemented at a future date, when ready
- How will volumes be distributed if and when the Highway Project is ready to proceed?



AGPA Proposal: Y-Line Scenario A – Constrained Volume

Year: 2016

4.3 Bcf/d

No reason to limit total volume to 4.3 Bcf/d

Pipeline from Prudhoe Bay

Reduction in volume to Canada results in a potential value reduction due to loss of economy of scale

Alaska LNG
1.1 Bcf/d

Gas to Canada
3.1 Bcf/d

AGPA Proposal: Y-Line Scenario B – Incremental Volume

- It has been suggested that AGPA's Y-Line proposal is disadvantageous because the reduction of volume to Canada results in a loss of economies of scale, and hence, lower value for the gas
- This reasoning is premised on limiting total volume at the pipeline inlet to 4.3 Bcf/d (the same amount as under the Highway Project proposal)
- There is no reason to limit the total volume to 4.3 Bcf/d
 - LNG volumes could be in addition to the 4.3 Bcf/d to Canada
 - total volume at pipeline inlet in Prudhoe Bay: 5.5 Bcf/d
 - the Highway Project at 4.3 Bcf/d requires 49 Tcf over 30 years
 - a 5.5 Bcf/d Y-line project would require 62Tcf over 30 years
 - the known discovered resource on ANS is 35 Tcf
 - the Highway Project would require substantial new discoveries to proceed (both as a stand-alone project and part of a Y-line)
 - the stand-alone LNG project, however, can proceed immediately



AGPA Proposal: Y-Line Scenario B (continued)

Year: 2016

Incremental value
in addition to
Highway Project

5.5 Bcf/d

Shared line improves cost for
both destinations

Alaska LNG
1.1 Bcfd

No loss of value relative
to Highway Project

Gas to Canada
4.2 Bcfd



Stand-Alone LNG Project Concept

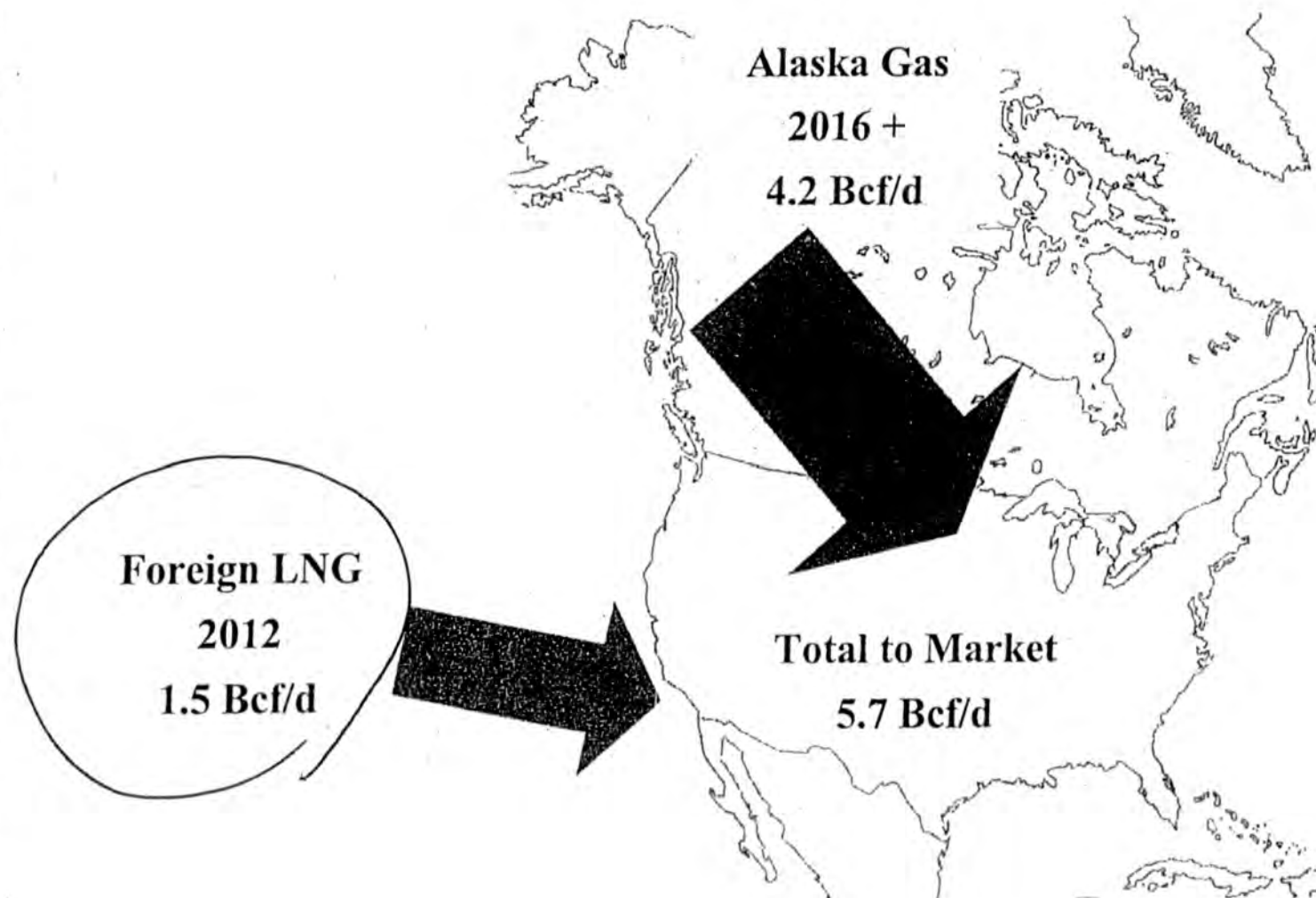
- The issue is whether the AGPA project is economic on a stand-alone basis, as there will be no guarantee in 2012 that the expansion volumes from the Highway Project will ever materialize
- The subsequent sections elaborate on the economics of the stand-alone LNG project
- The projections show robust economics, with both high returns for the Producer and revenues for the State that would be incremental to the revenues from a potential Highway Project to be implemented later

The Market Context

- Does a combined Y-Line of 5.5 Bcf/d deliver too much gas to market?
- The total gas to market is likely to be the same, but Alaska would capture a larger share, which would otherwise go to foreign LNG suppliers

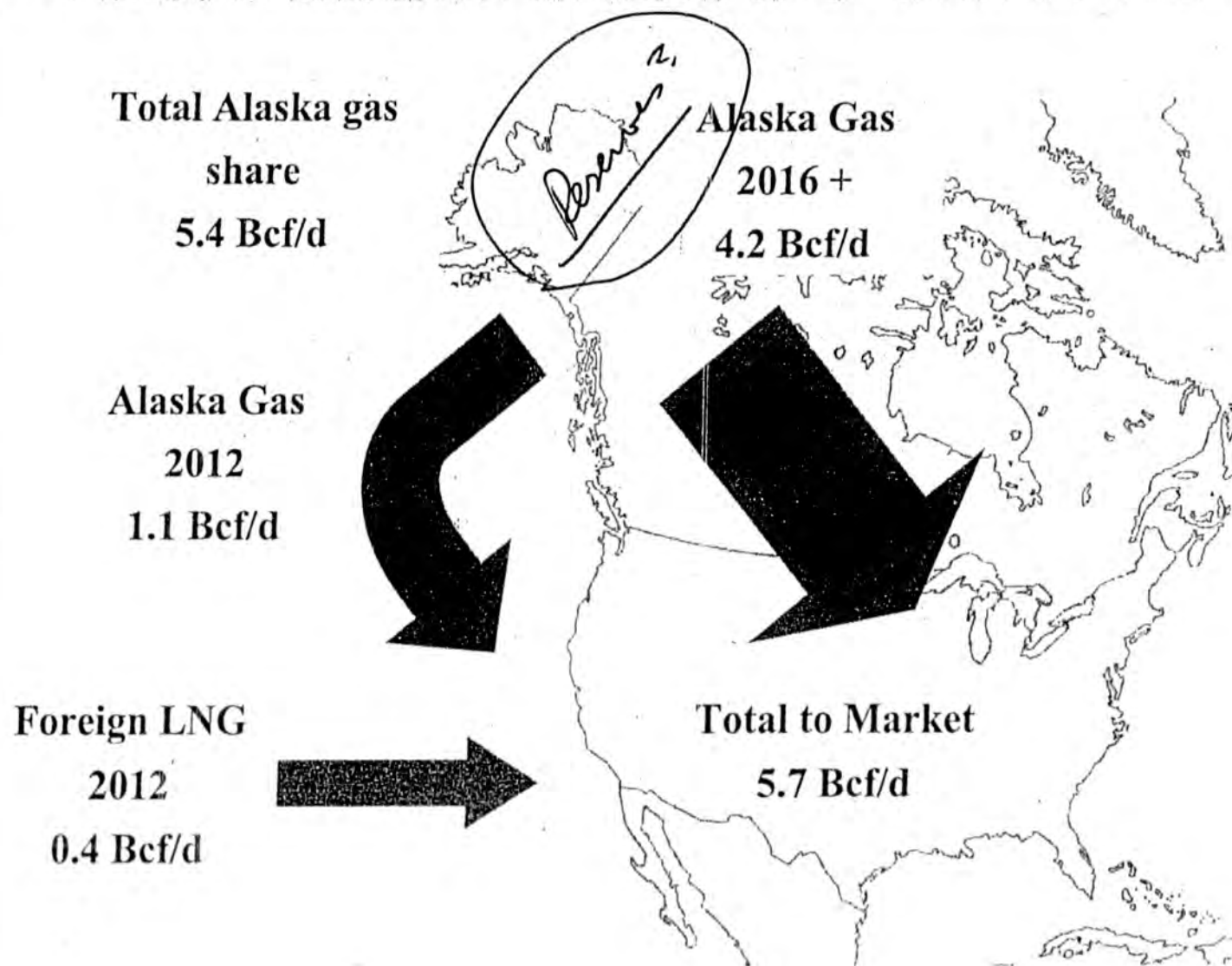


Gas Flows to North America Under the Highway Proposal



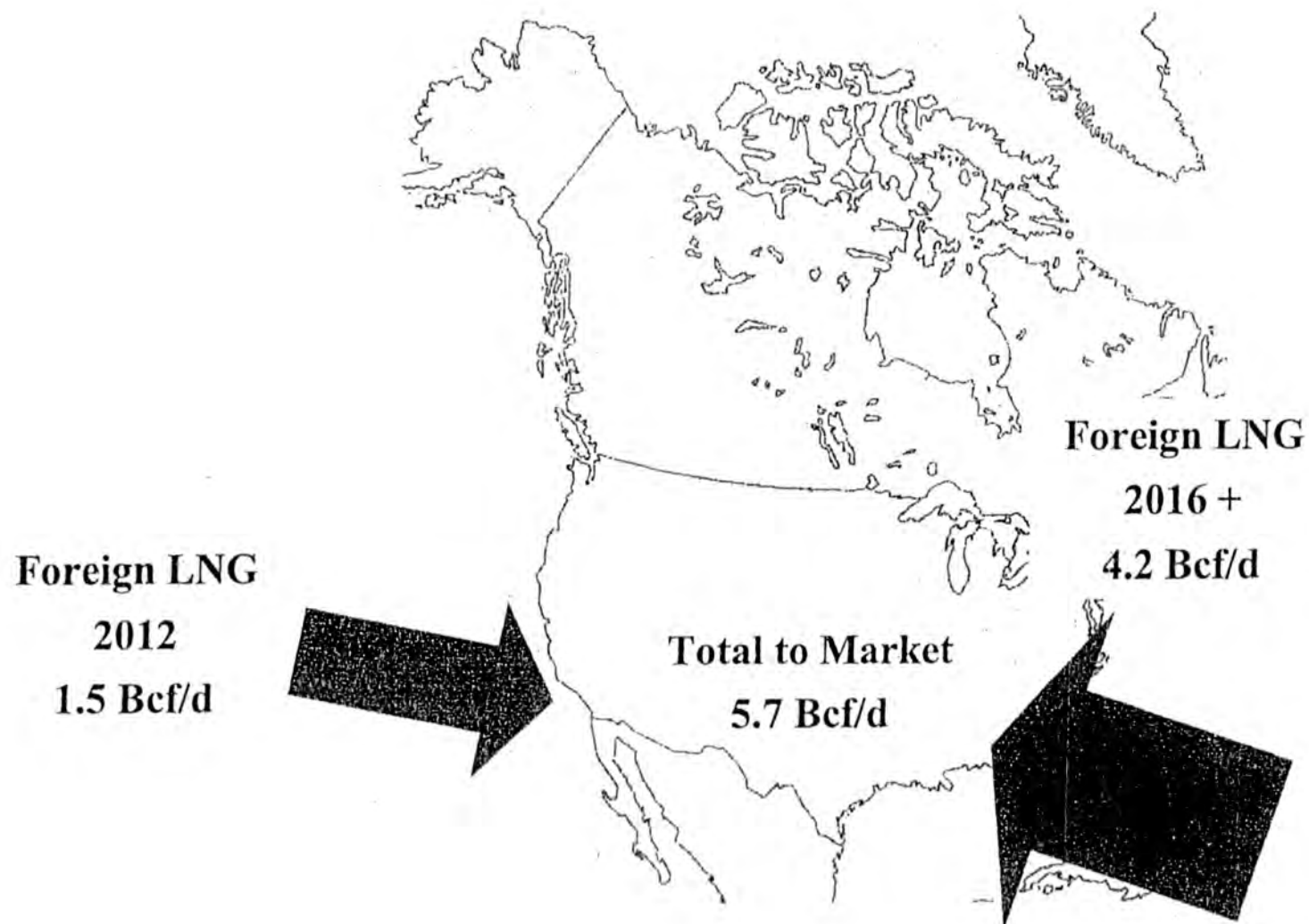


Gas Flows to North America Under AGPA Proposal





Alaska's Risk: A Real Possibility?





Additional Strategic Considerations

- Full commercialization of the Alaska gas resource requires a large scale project and additional exploration
- Independent explorers have expressed concern that they will be shut out of a potential Alaska gasline
- Without certainty as to whether pipeline capacity will be available, an explorer will not have an incentive to spend capital for exploration
- An AGPA line sized to accommodate future expansion and Y-line volumes will send a signal that there is free capacity and will spur exploration which will not occur otherwise

More AGPA
by future
AGPA



Additional Strategic Considerations (continued)

- The LNG project will make the implementation of the Highway Project more likely
- The Producers will have an incentive to participate in the value of the LNG Project and to take steps to fill the spare capacity of AGPA's pipeline
- The LNG project will give Alaska access to additional markets that would not be accessible to the Highway Project



Additional Markets for Alaska LNG

LNG to
Japan/East Asia

?

LNG to West
Coast

2012

1.1 Bcf/d

Foreign LNG

2012

0.4 Bcf/d

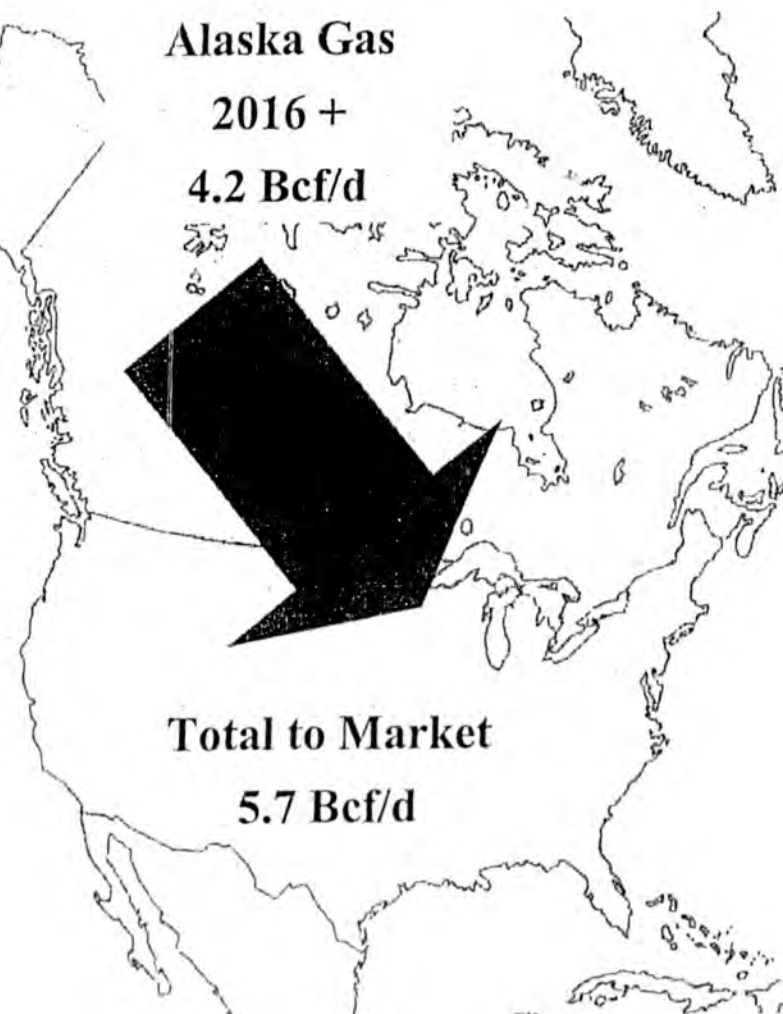
Alaska Gas

2016 +

4.2 Bcf/d

Total to Market

5.7 Bcf/d





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Cost Assumptions

1. 本報告は、2014年10月1日現在の状況に基づき作成されたものである。2015年10月1日現在の状況については、別途報告する。



Consistency of Capital Cost Assumptions

- Importance of consistency of capital cost numbers across project components
- Same components for different projects should have the same assumed costs in a comparison
- AGPA pipeline cost assumption in April 2005 (Sempra and AGPA proposal to State and Producers):
 - 3.0 Bcf/d, 48-inch diameter
 - \$8.4 billion EPC cost (2005 detailed cost update)
- FIF assumption (May 2006) for Alaska component of Highway line:
 - 4.3 Bcf/d, 52-inch
 - \$5.9 billion capex



Consistency of Capital Cost Assumptions (continued)

- Why are the capital costs estimates so different?
 - the mileage difference of Highway route vs. Valdez route of 8% clearly cannot alone explain the 42% higher cost of AGPA's *smaller* line
- Difference in methodology of estimate and cost inclusions
 - date of estimate
 - accuracy of estimate
 - contingencies included
- Some comparisons between the AGPA project and the proposed Highway Project (FIF, PFC) have failed to make an adjustment for consistency across capex numbers
- The following slides describe the appropriate adjustments that need to be made for a proper comparison of alternatives



Consistency of Capital Cost Assumptions (continued)

- AGPA's previously publicized capital cost figures include:
 - Contractor's contingencies ranging from 10% to 15%, depending on project component
 - Contractor's escalation allowance during construction period
 - Contractor's profit and risk premium
 - Owner's contingency in addition to Contractor's contingency
 - Owner's insurance cost during construction
- It appears that the above items have not been included in the capital cost estimates made public in the FIF
- A comparative analysis should use the same approach for both projects, as the risk mitigation and related cost premiums and contingencies associated with a given contracting strategy would be available to both projects



Consistency of Capital Cost Assumptions (continued)

- The magnitude of such consistency adjustments is significant:
- AGPA has previously used a \$2.1 billion estimate for the LNG Facility
- Stripping away the various risk premiums and allowances (both contractor's and owner's) that are not included in estimates for an alternative project reduces the capital cost assumption to \$1.5 billion

How Reliable are the Cost Estimates?

- AGPA's cost estimates are the result of extensive engineering work performed by Bechtel in 2000, with a detailed cost update study performed in 2005
- The technical details of Bechtel's work have been shared with the State's consultants
- There appears to be considerable uncertainty surrounding the publicized cost estimates for the proposed Highway project

Project Component	2001 Producer Estimate	2006 FIF Assumptions
GTP	\$2.6 billion	\$2.6 billion
Pipeline from Prudhoe Bay to Alberta	\$11.0 billion	\$11.6 billion

Source: Fiscal Interest Findings; Presentation titled "Alaska Producer Pipeline Presentation May 2002" and 2004 SGDA testimony by Producer group

AGPA Base Case Capital Cost Assumptions

■ Midstream components (2005 dollars):

- LNG Facility: \$1.5 billion
- pipeline from PB to Valdez (initial 1.2 Bcf/d capacity): \$5.3 billion
- expansion of PB-Delta Junction segment to accommodate incremental volume: \$0.9 billion
- Delta Junction to Alberta pipeline: \$8.5 billion
- GCP: based on the \$2.6 billion assumption in the FIF, adjusted for volume
- all midstream components include a 10% capex contingency and a 5% owner's contingency
- real 2005 numbers are escalated at 2.5% p.a.

■ Upstream (PBU, PTU, other ANS fields and yet-to-find gas): \$8.4 billion

~~\$18.8 billion~~

\$10.3 bill



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Netback Results

Netback Pricing

- Tariff Assumptions on midstream components
 - debt to equity ratio 80:20
 - interest on debt 5.50% (assumes Federal guarantee under ANGPA)
 - pipelines ROE 14%
 - LNG facility ROE 12%

*regulated
rate of
return*

14% Pipeline
12% LNG

- Combined pipeline and LNG facility tolls:
 - \$2.50 per mmBtu nominal terms in 2012
 - \$2.17 per mmBtu in real 2005 terms

*total
\$3.47*

Downstream components plus total fuel consumption and losses:

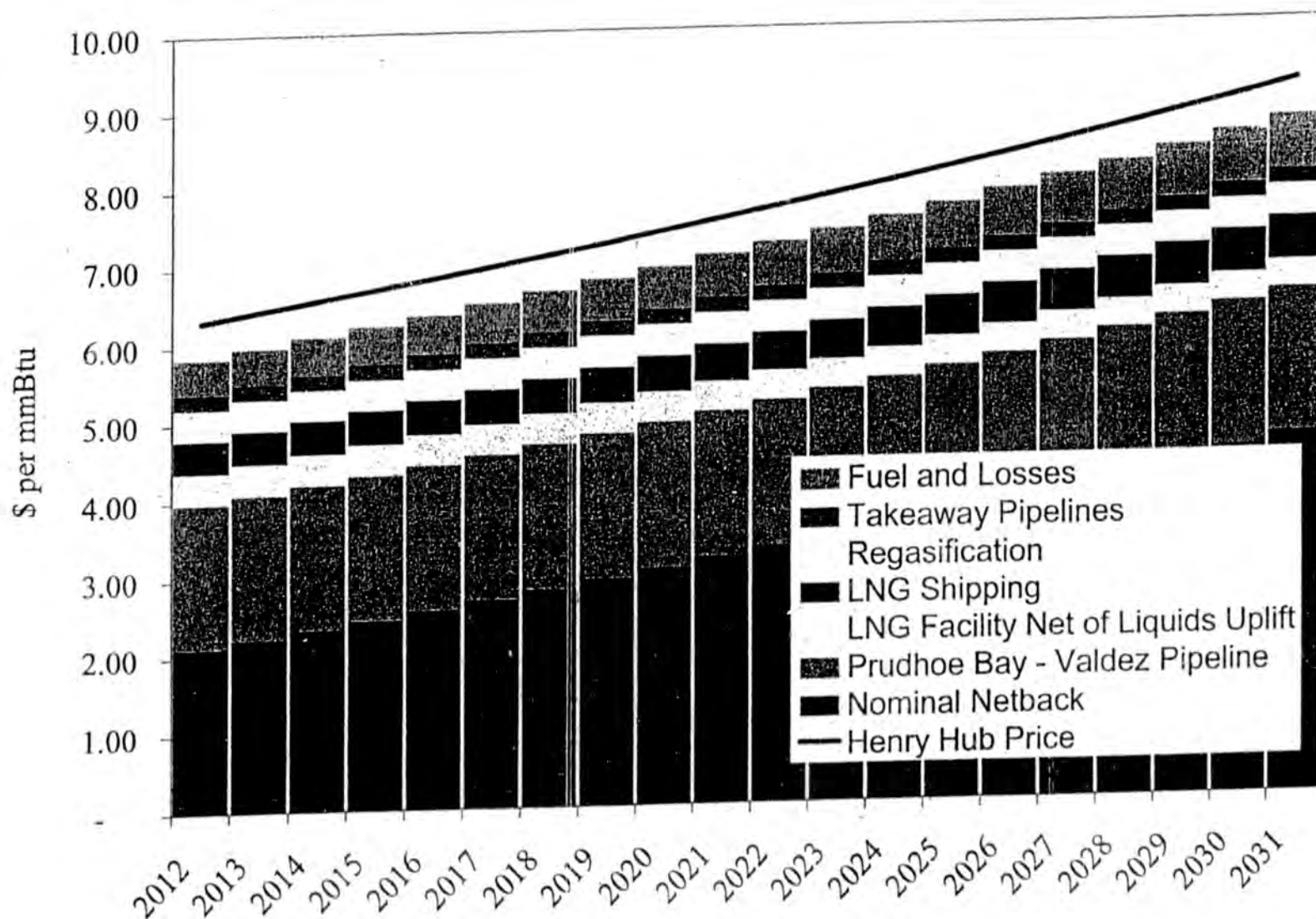
- \$1.50 per mmBtu nominal terms in 2012
- \$1.30 per mmBtu in real 2005 terms



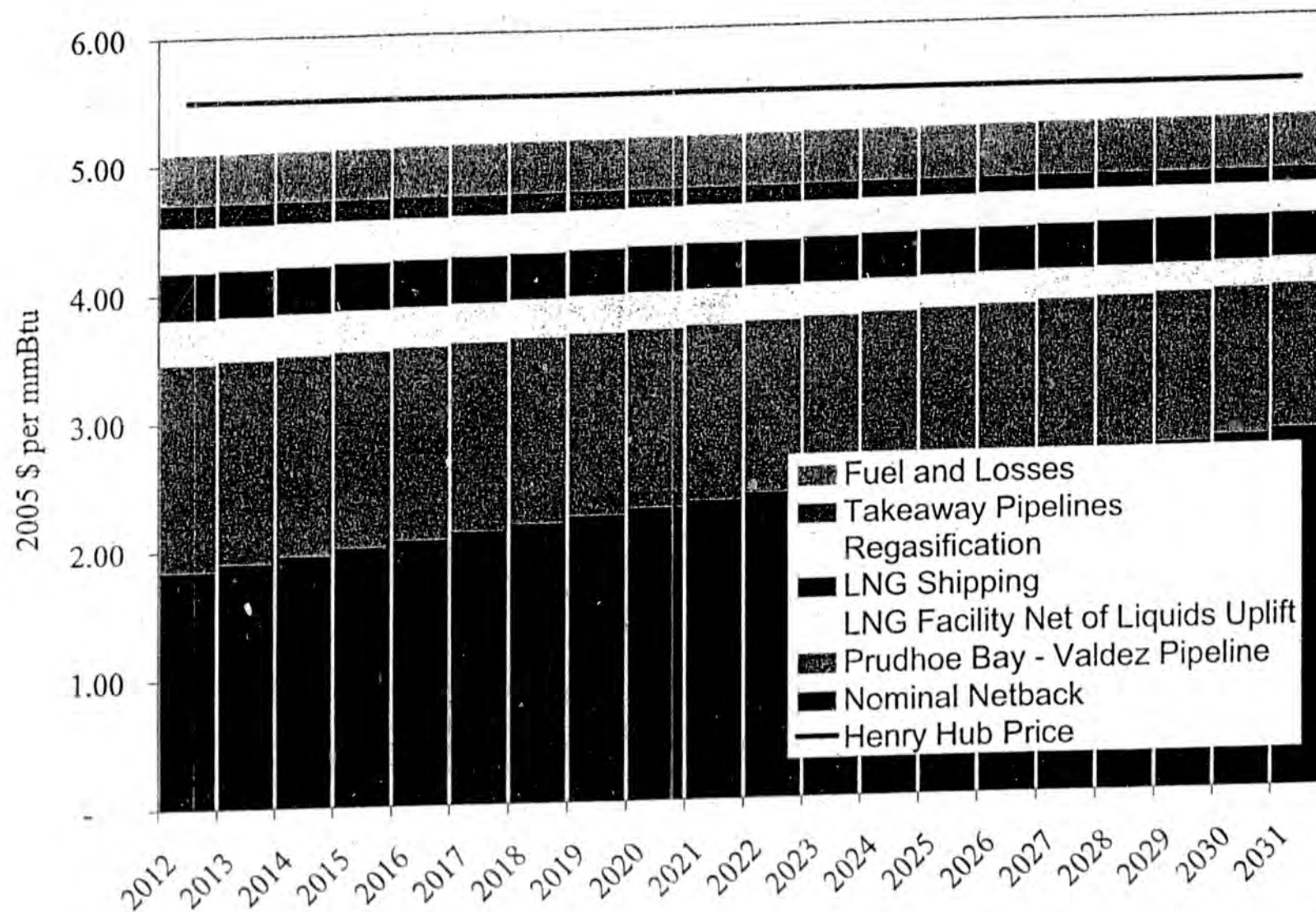
Netback Pricing (continued)

- Uplift from liquids extracted in Valdez:
 - \$0.23 per mmBtu nominal terms
 - \$0.20 per mmBtu in real 2005 terms
- Nominal netback prices at the pipeline inlet are in the range of \$2.11/mmBtu in 2012 to \$7.87/mmBtu in 2041
- Real at the pipeline inlet are in the range of \$1.84/mmBtu in 2012 to \$3.86/mmBtu in 2041
- Nominal prices at the point of production (net of GCP toll and shrinkage and feeder pipeline costs) are in the range of \$1.47/mcf to \$7.16/mcf

Nominal Netback at Pipeline Inlet



Real Netback at Pipeline Inlet (2005 \$)



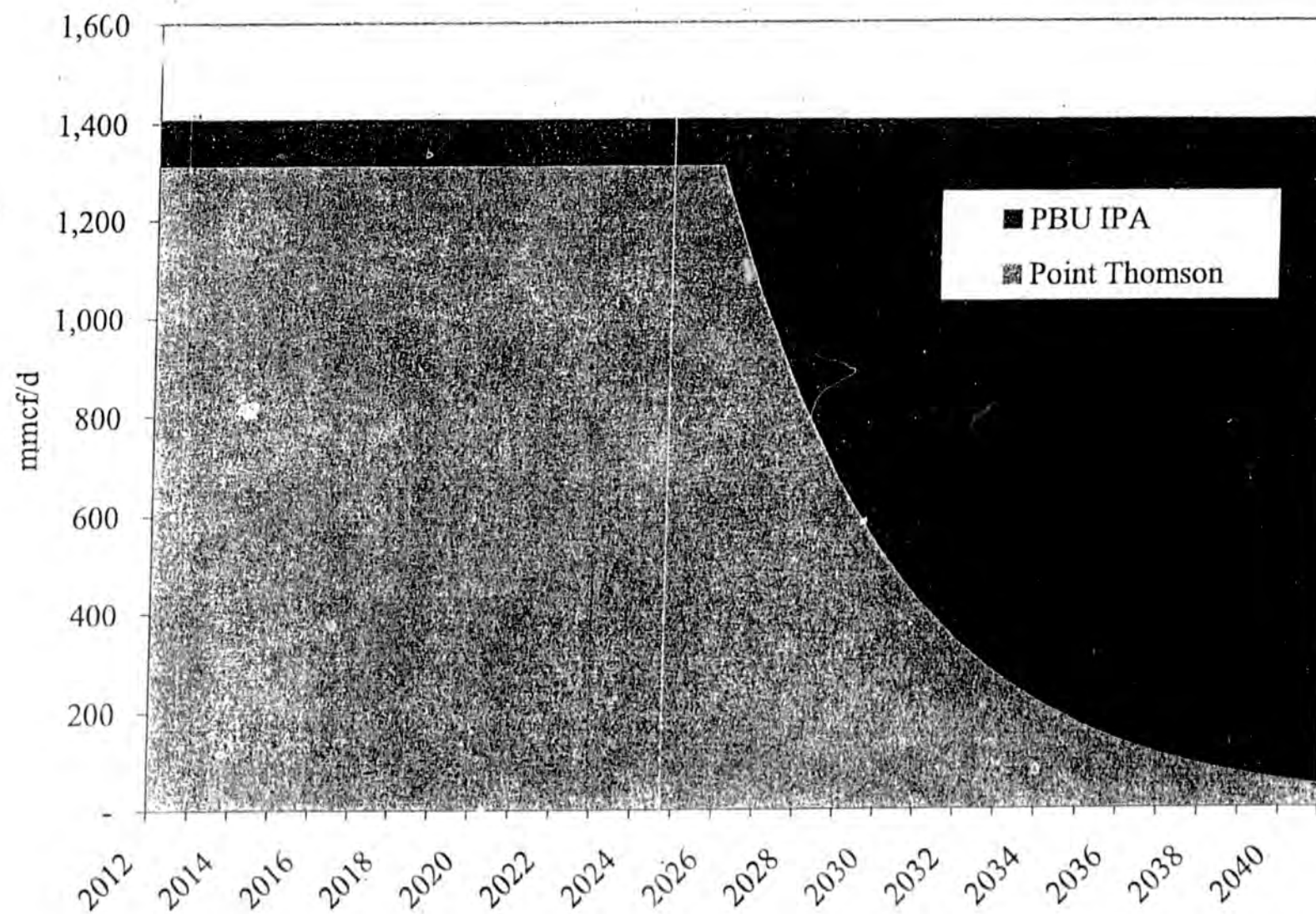


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Producer Results



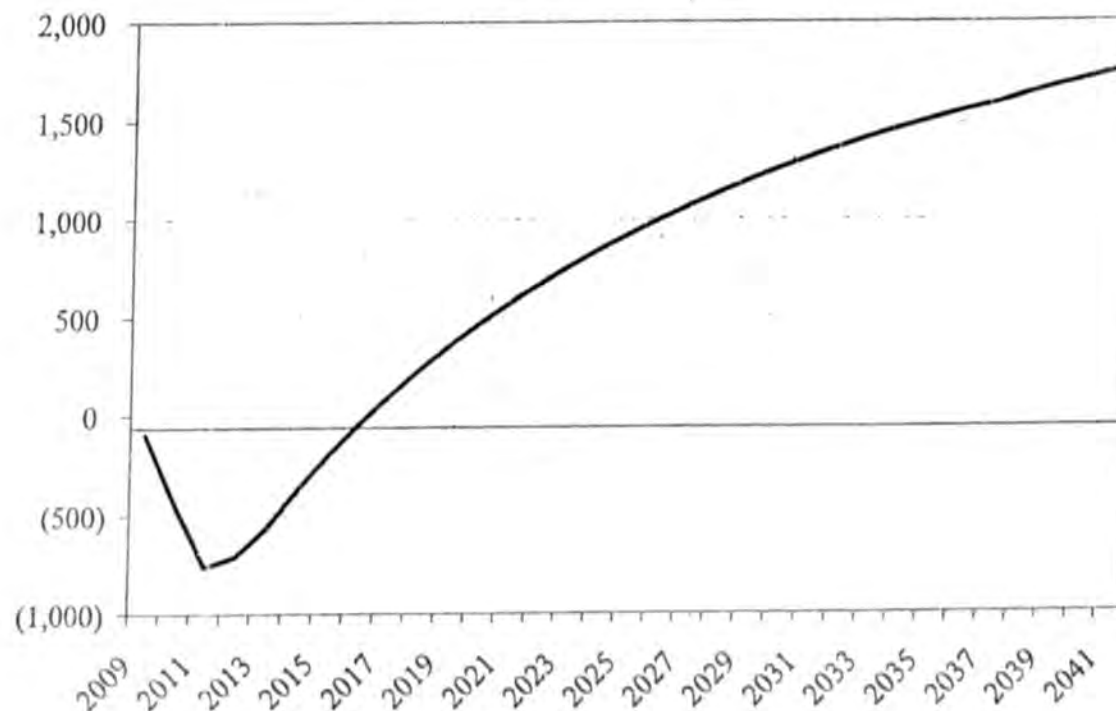
Assumed Upstream Production



Producer Returns

- Upstream Producer returns at the Base Case Henry Hub price of \$5.50/mmBtu
 - NPV @ 12% discount rate: \$1.7 billion
 - IRR: 27.4%

Producer Upstream NPV@12



- Discounted payback is achieved rapidly – within the first six years of operations



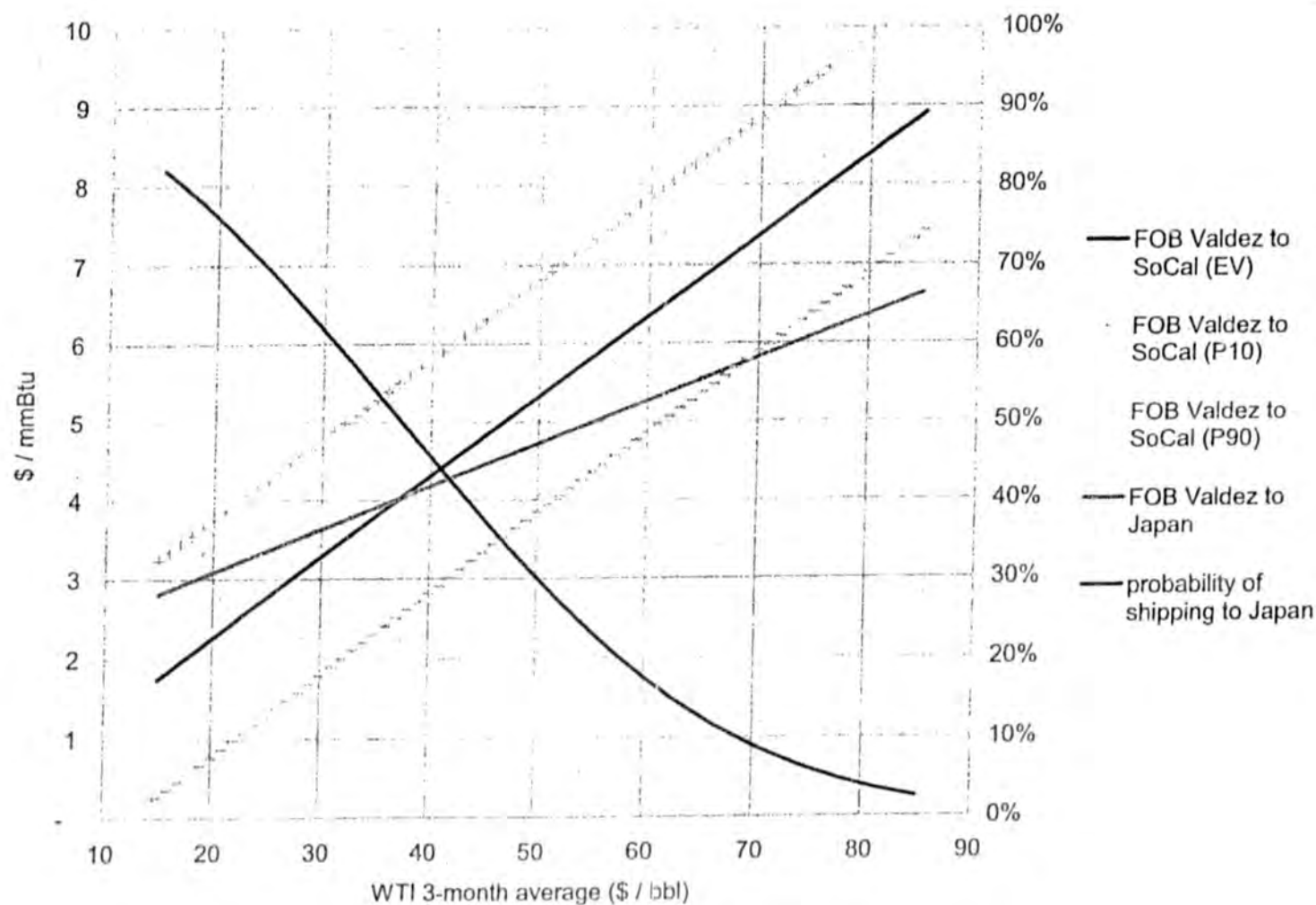
Sensitivity of Producer Returns

- Producer upstream returns at the high price scenario (\$7.70/mmBtu Henry Hub and \$70/bbl WTI):
 - NPV @ 12% discount rate: \$4.6 billion
 - IRR: 52.4%
- The breakeven Henry Hub price (at which the Producer IRR equals 12%) is \$4.30/mmBtu
- At the low prices scenario (stress case) (\$4.00/mmBtu Henry Hub and \$27/bbl WTI), the netback from Japan is significantly higher:
 - \$1.55/mmBtu at the pipeline inlet and \$0.95/mcf at the point of production in 2012 (nominal terms)
- The LNG project's option to divert production to higher value markets (e.g., Japan) has a significant value

Value of Diversion Option

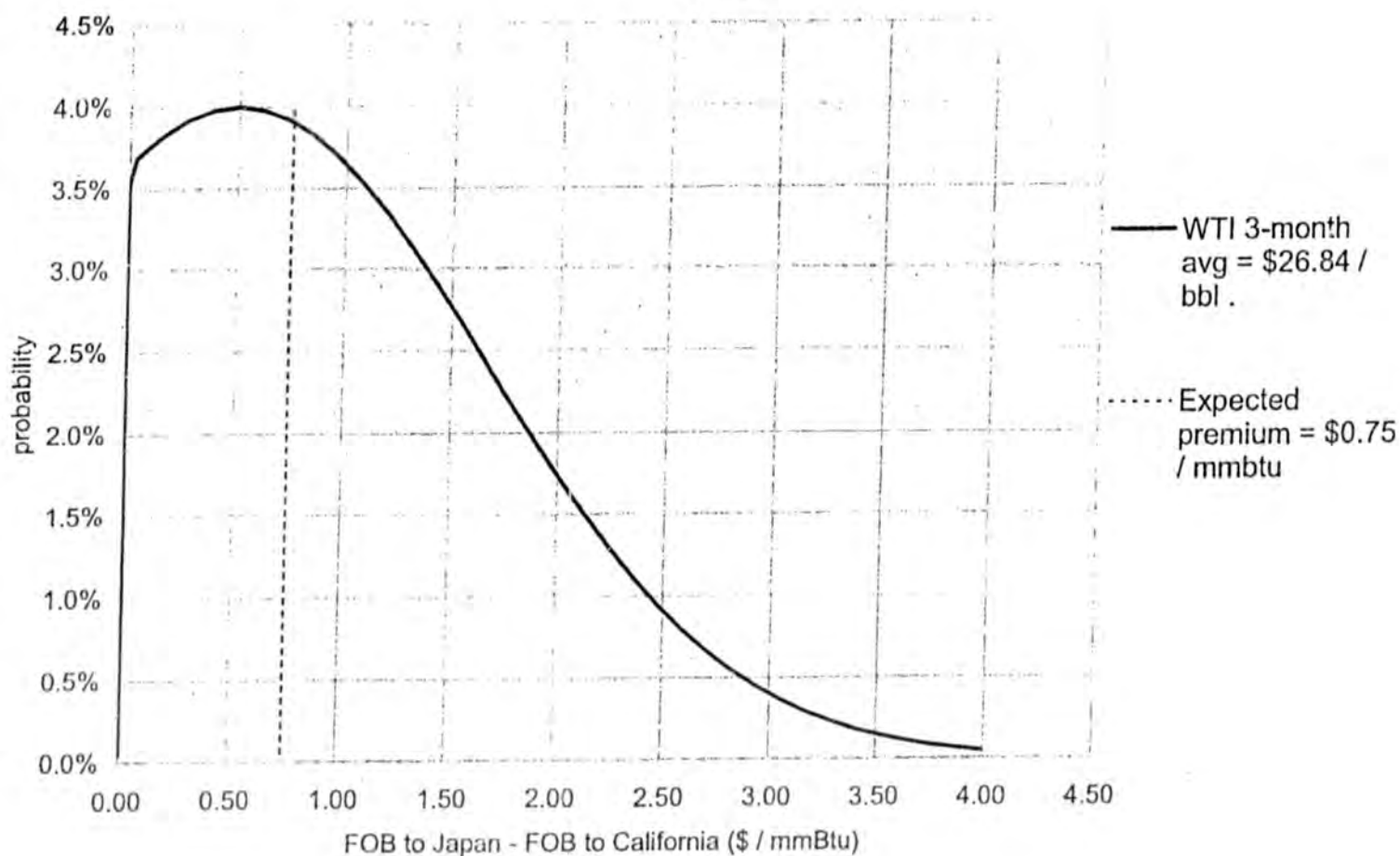
- Japanese LNG c.i.f. prices are highly correlated with oil prices (R^2 of 0.96)
 - primarily due to contractual linkages to JCC
- US gas prices (including SoCal) are not highly correlated with oil prices, and by extension, Japanese LNG prices
- This low correlation gives increases the likelihood that prices in Japan will be high during periods of low U.S. prices, making it worthwhile to divert cargoes
- An analysis has been performed using both an algebraic approach and a Monte Carlo simulation to estimate the value of this option to divert cargoes to the high-prices market
- At AGPA's base case prices, the expected value of the diversion option is estimated to be \$0.49 per mmBtu of LNG produced

Value of Diversion Option (continued)

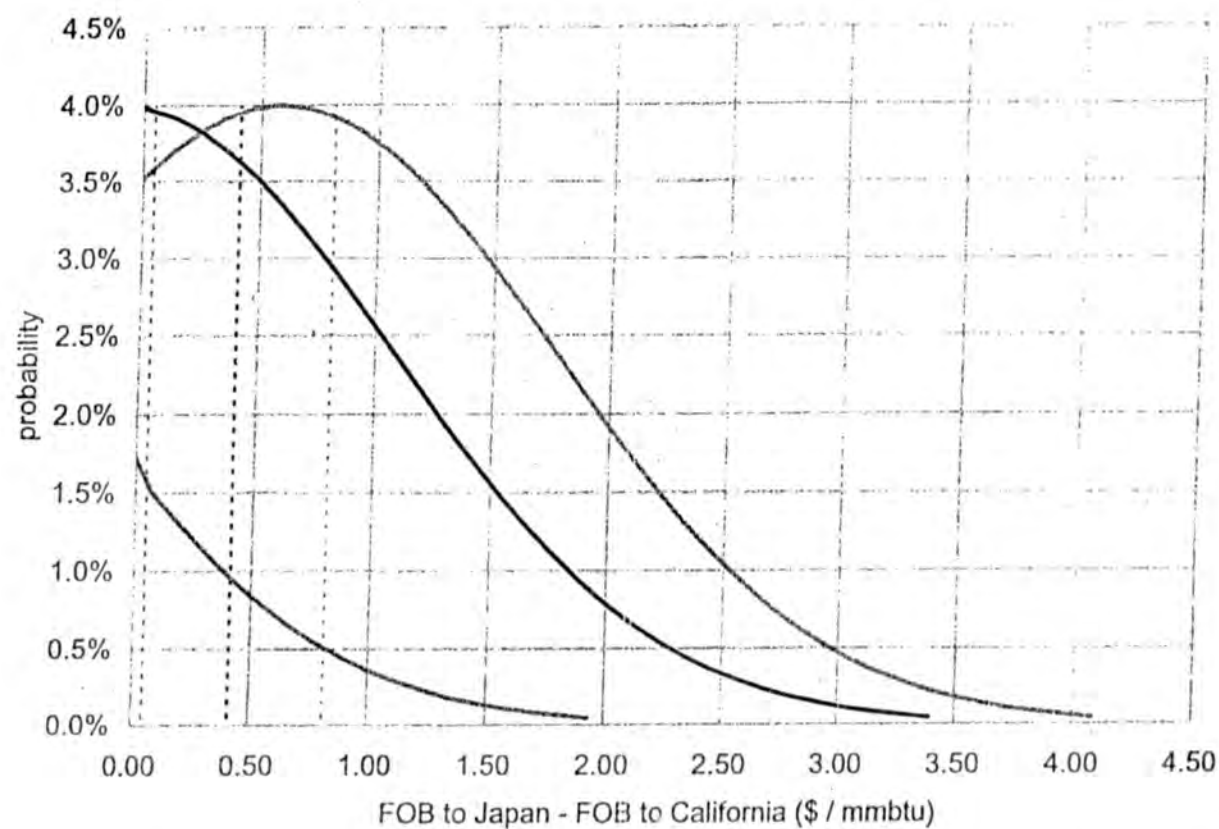


Value of Diversion Option (continued)

Example of diversion option value at a given oil price (\$26.84/bbl in this case)



Value of Diversion Option (continued)



— WTI 3-month avg = \$25.00 / bbl .

— WTI 3-month avg = \$39.36 / bbl .

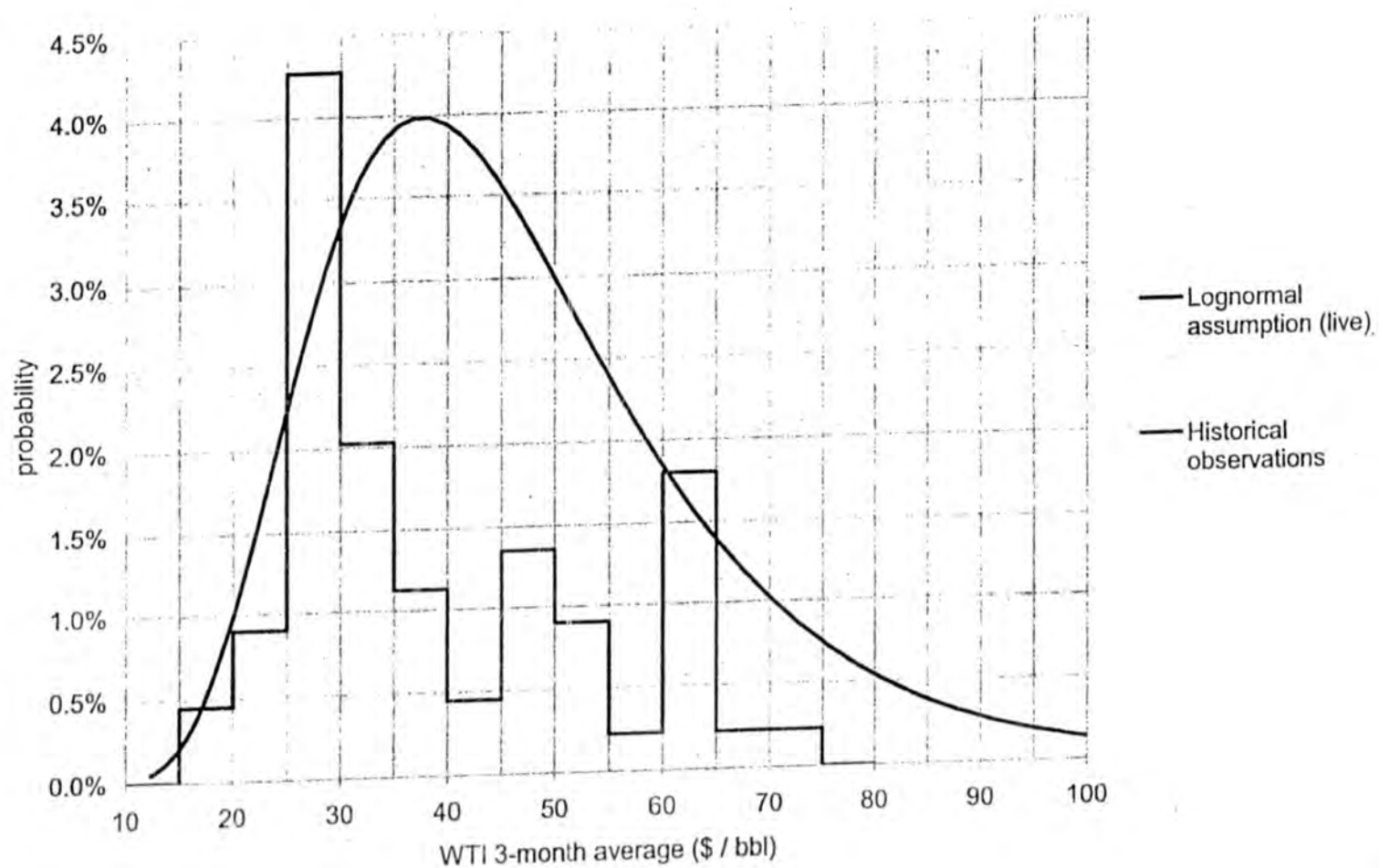
— WTI 3-month avg = \$70.00 / bbl .

..... Expected premium = \$0.81 / mmbtu

..... Expected premium = \$0.41 / mmbtu

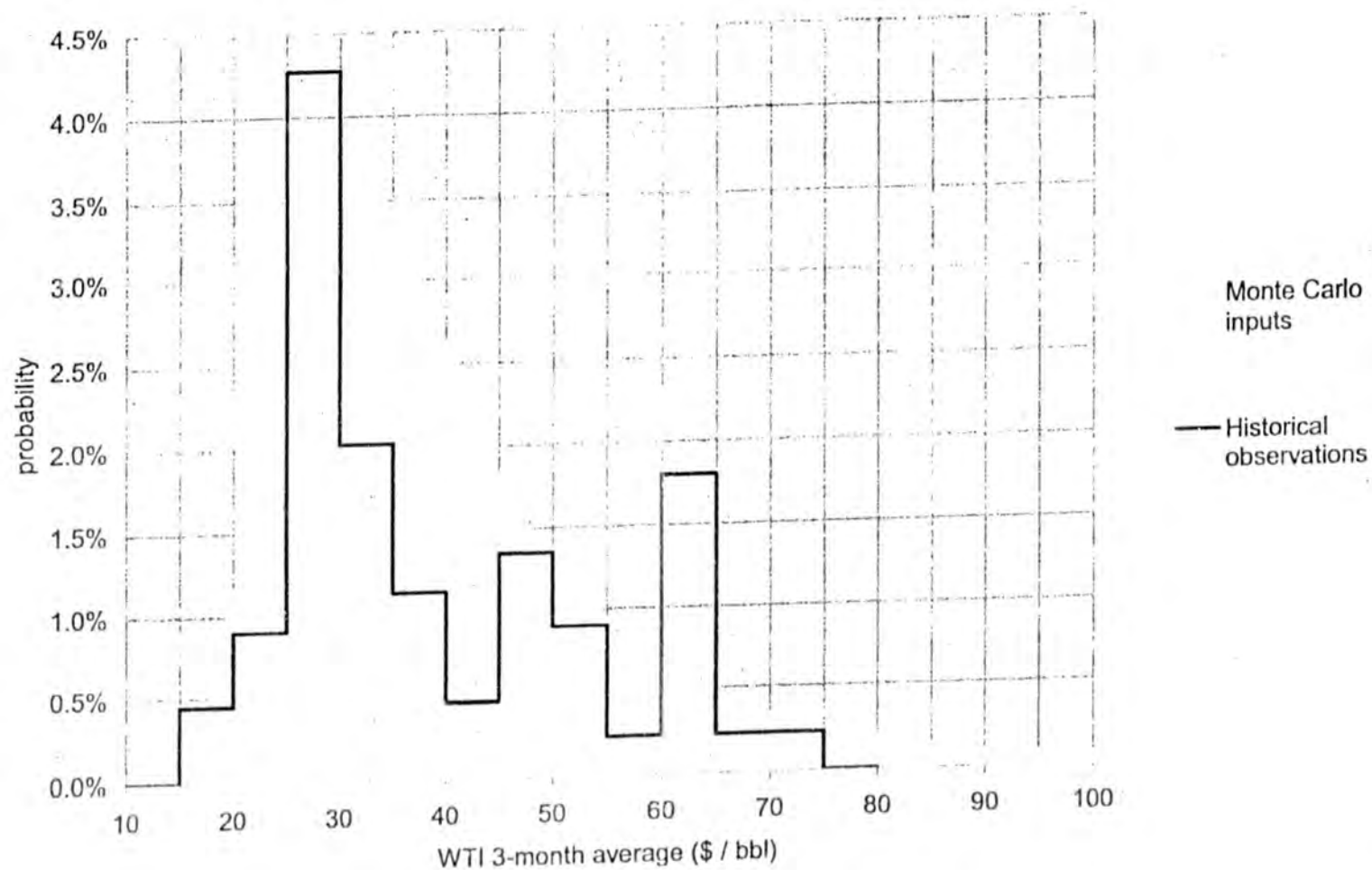
..... Expected premium = \$0.05 / mmbtu

Value of Diversion Option (continued)

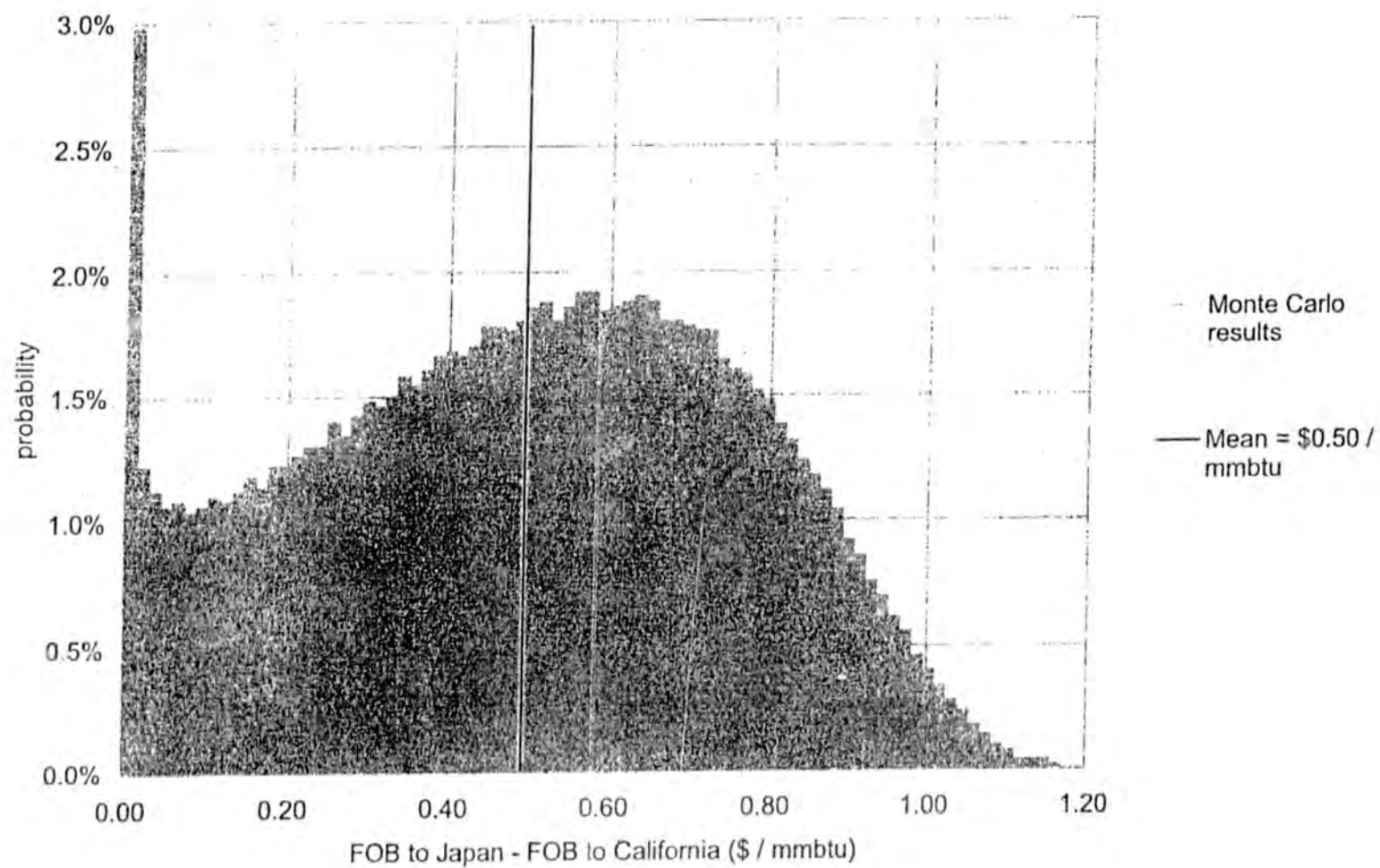




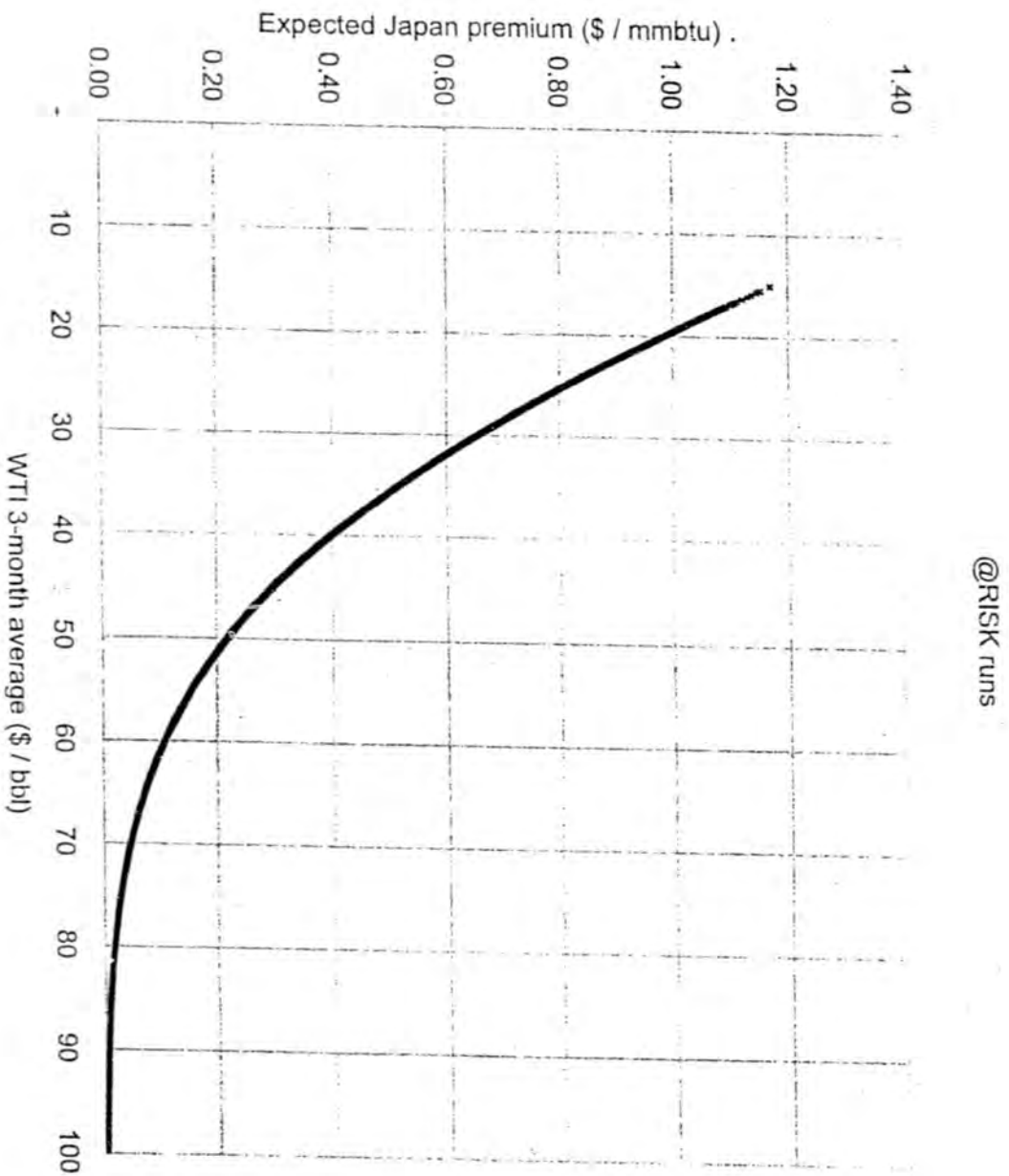
Value of Diversion Option (continued)



Value of Diversion Option (continued)



Value of Diversion Option (continued)



Producer Returns With Diversion Optionality

- The diversion option value enhances the upstream returns significantly
- Upstream Producer returns with option value (Base Case prices)
 - NPV @ 12% discount rate: \$2.2 billion (increase of \$0.5 billion)
 - IRR: 31.9%
- The diversion option reduces the breakeven threshold price
 - breakeven HH price without diversion option: \$4.30 per mmBtu
 - breakeven HH price with diversion option: \$3.74 per mmBtu



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Economics of Y-Line Expansion

Producer Returns and State NPV with Y-Line

- It is assumed that the Highway Project commences operations in 2016
- Producer NPV
 - standalone LNG Project (2012): \$2.2 billion
 - standalone Highway Project (2016): \$10.8 billion
 - Y-Line (1.2 Bcf/d in 2012 + 4.3 Bcf/d in 2016): \$13.1 billion
- Netback price for the Highway Project improves from \$4.23/mmBtu to \$4.34 in 2012 (nominal terms) due to cost savings associated with shared line
- State NPV @ 7% discount rate, assuming status quo fiscal regime
 - standalone LNG Project (2012): \$5.1 billion
 - standalone Highway Project (2016): \$16.5 billion
 - Y-Line (1.2 Bcf/d in 2012 + 4.3 Bcf/d in 2016): \$21.8 billion