HB 3001
SB 3001
6/18/08
SPECIAL SESSION DOCUMENTS

BUILDING A WORLD OF DIFFERENCE®

BLACK & VEATCH

Overview of the Methodology Utilized to Determine the Net Present Value to Stakeholders

State of Alaska – Anchorage Special Session

June 18, 2008

What are the key factors to determine NPV?

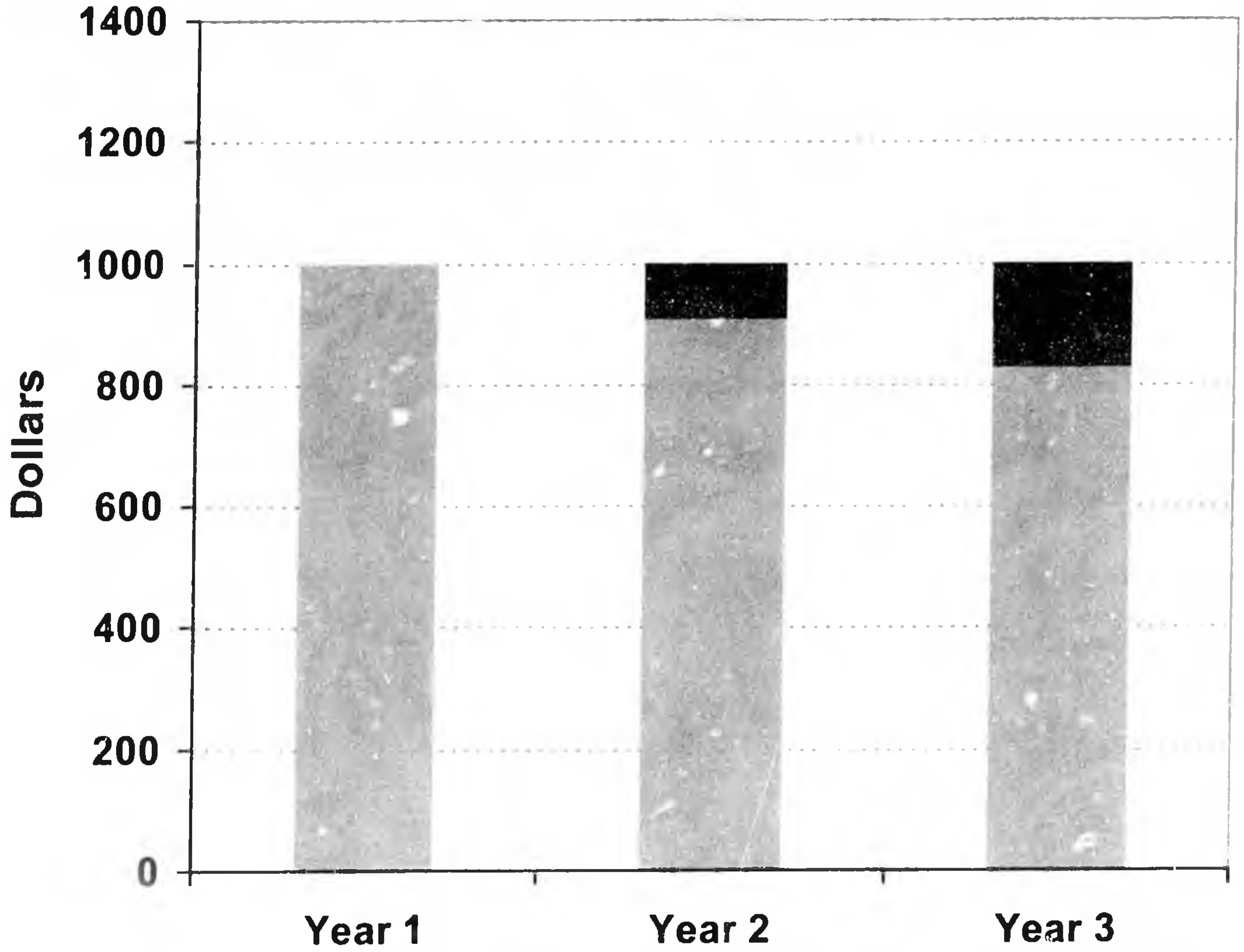
1. An estimate of cash flows, net, by year:
   - Includes capital expenditures, operating expenses and revenue
2. An assumption about the discount rate.

A discount rate is needed to calculate NPV for each project stakeholder.

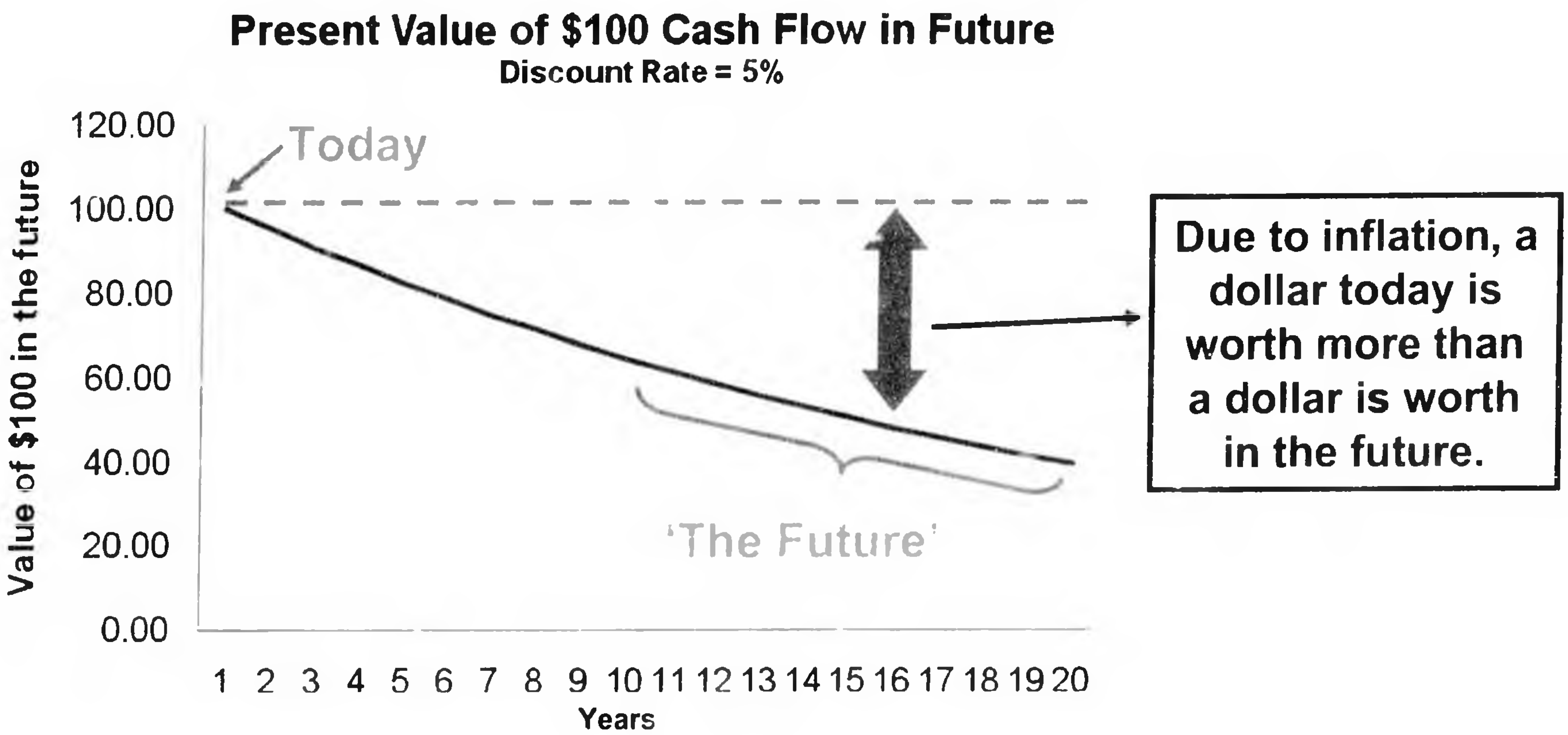
- Discount rate is a price. It is the price associated with waiting to get a benefit, versus getting a benefit today.
- Many factors can influence the price of waiting (discount rate). These include: alternative investment returns, ones cost of capital, general inflation conditions, concern for the well being of future generations
- Discount rates[1] vary by stakeholder:
  - State – 5% (Sensitivities of 0%, 2%, 6%, 8% were also used)
  - TransCanada – 8.8%
  - Producers – 10% and 15%

[1] See Section 4.1 of NPV Report for discussion of discount rates used in NPV analysis.

Discounting Example



Net Present Value (NPV) calculates how much a stream of future cash flows are worth today.



\$245 billion of Cash Flow ➔ \$61 billion of NPV_5

- NPV_5 of State's cash flow for a 4.0 Bcf/d project is \$61 billion.
- Total State Net Cash-flow (undiscounted) is \$245 billion.
- These results indicate that the State is indifferent to:
  - Having \$61 billion *today* (Remember - NPV is a measure of what future dollars are worth today)
  - and having \$245 billion of cash flow starting in year 2020 extending through 2044.

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Net Present Value (NPV) Analysis

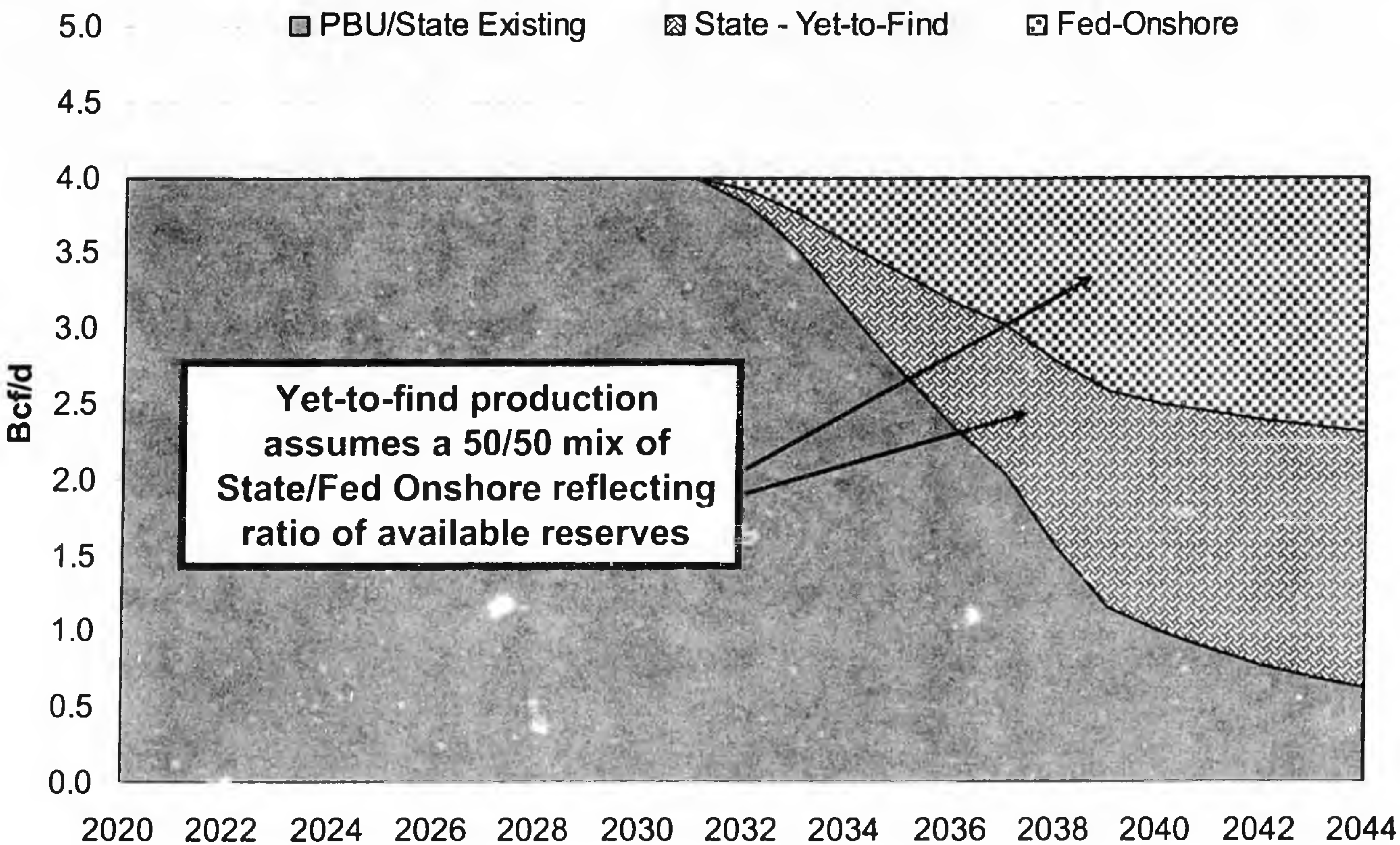
State of Alaska - Anchorage Special Session

June 18, 2008

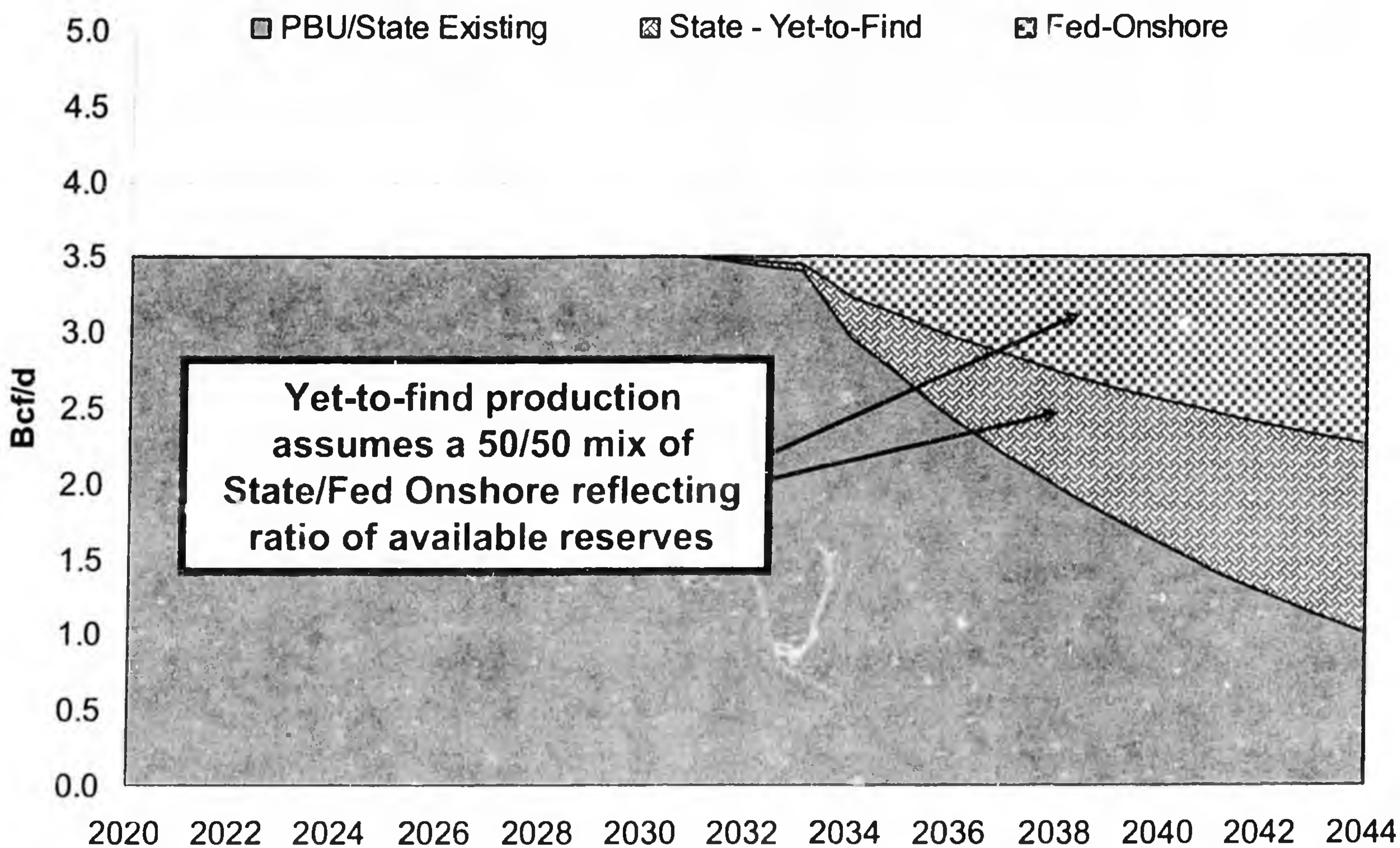
Project Economics are Robust

- NPV for Key Stakeholders Indicates Positive NPV for 4.0 Bcf/d project that does not rely on Pt Thomson
- NPV Results are Sensitive to Many Factors with Commodity Prices being the Most Significant
  - Producer NPV Remains Positive with Low Market Price Assumptions
- 4.0 Bcf/d project has acceptable netback risks, lower reserve risk than 4.5 Bcf/d project with Pt Thomson gas
- NPV positive across wide range of project cost outcomes, cost escalation scenarios
- Tariffs for Smaller Pipeline Configurations (4.0 & 3.5 Bcf/d) Increase by 13% to 21% Relative to the 4.5 Bcf/d Proposal Base Case

Production Assumptions: 4.0 Bcf/d Case



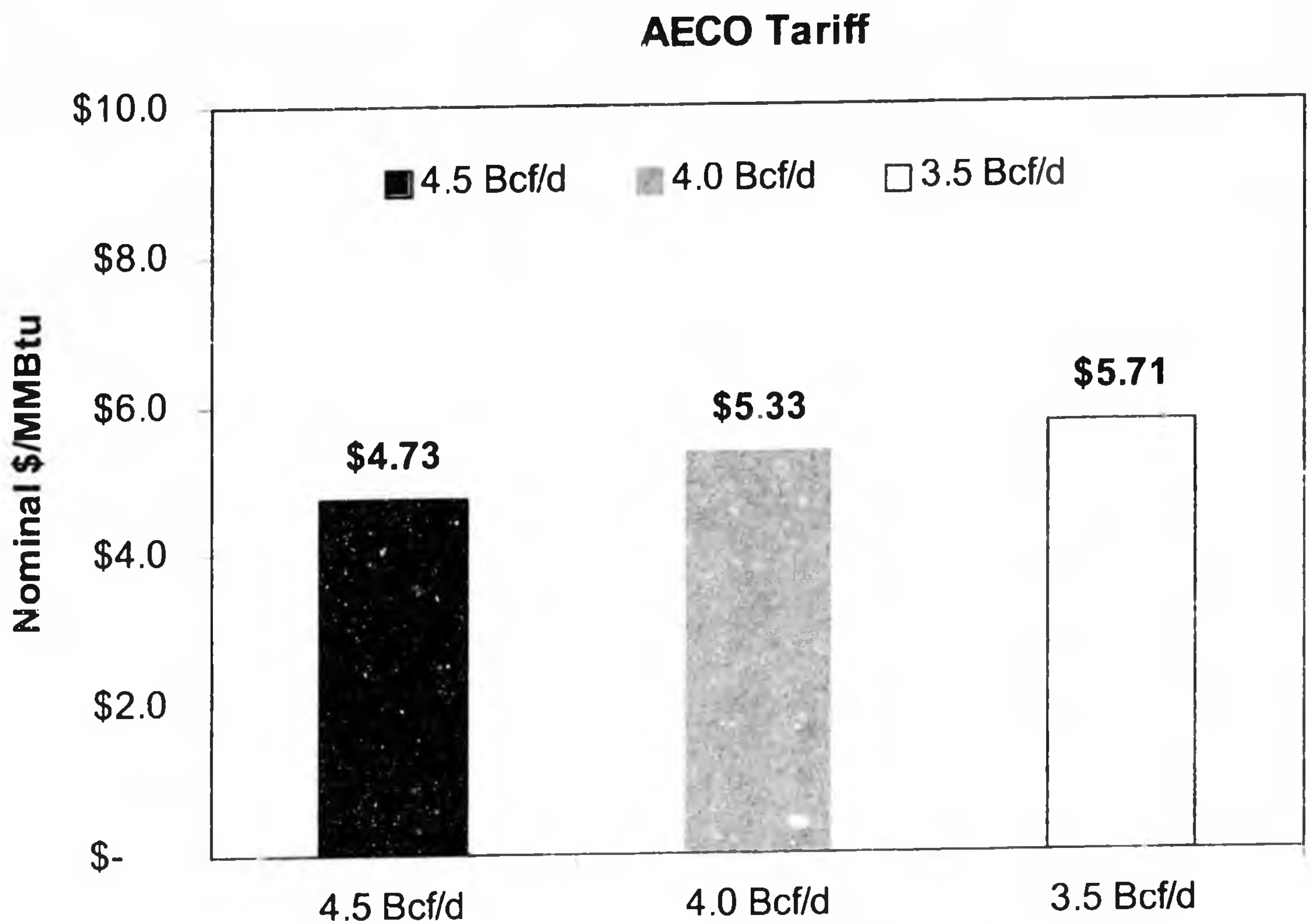
Production Assumptions: 3.5 Bcf/d Case



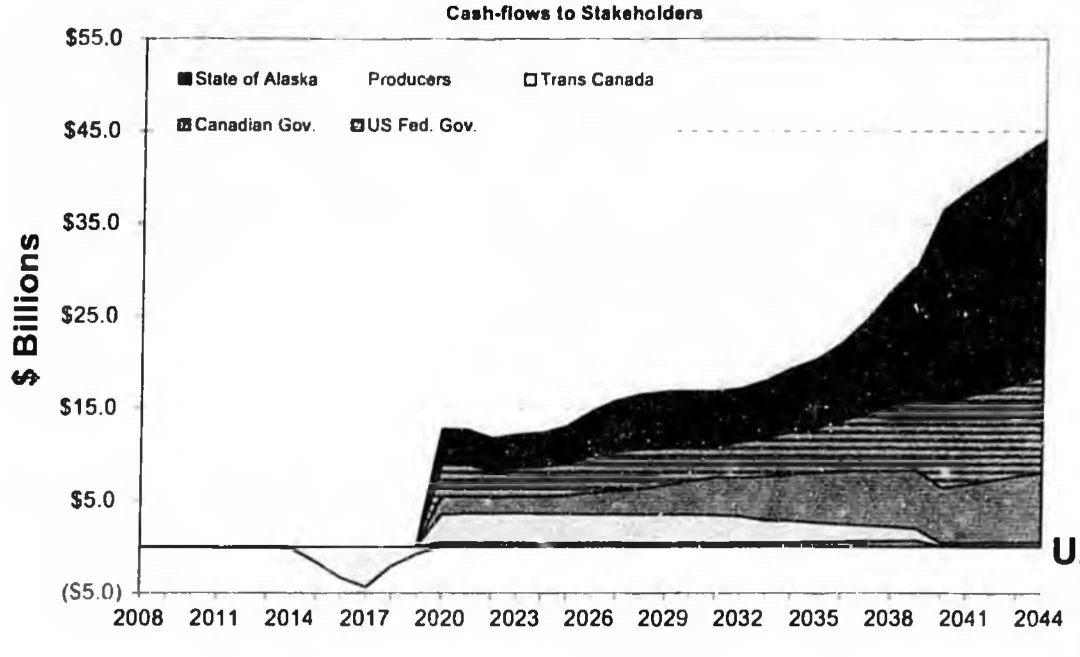
Production Assumptions used in the NPV Analysis for the 4.0 Bcf/d Conservative Base Case

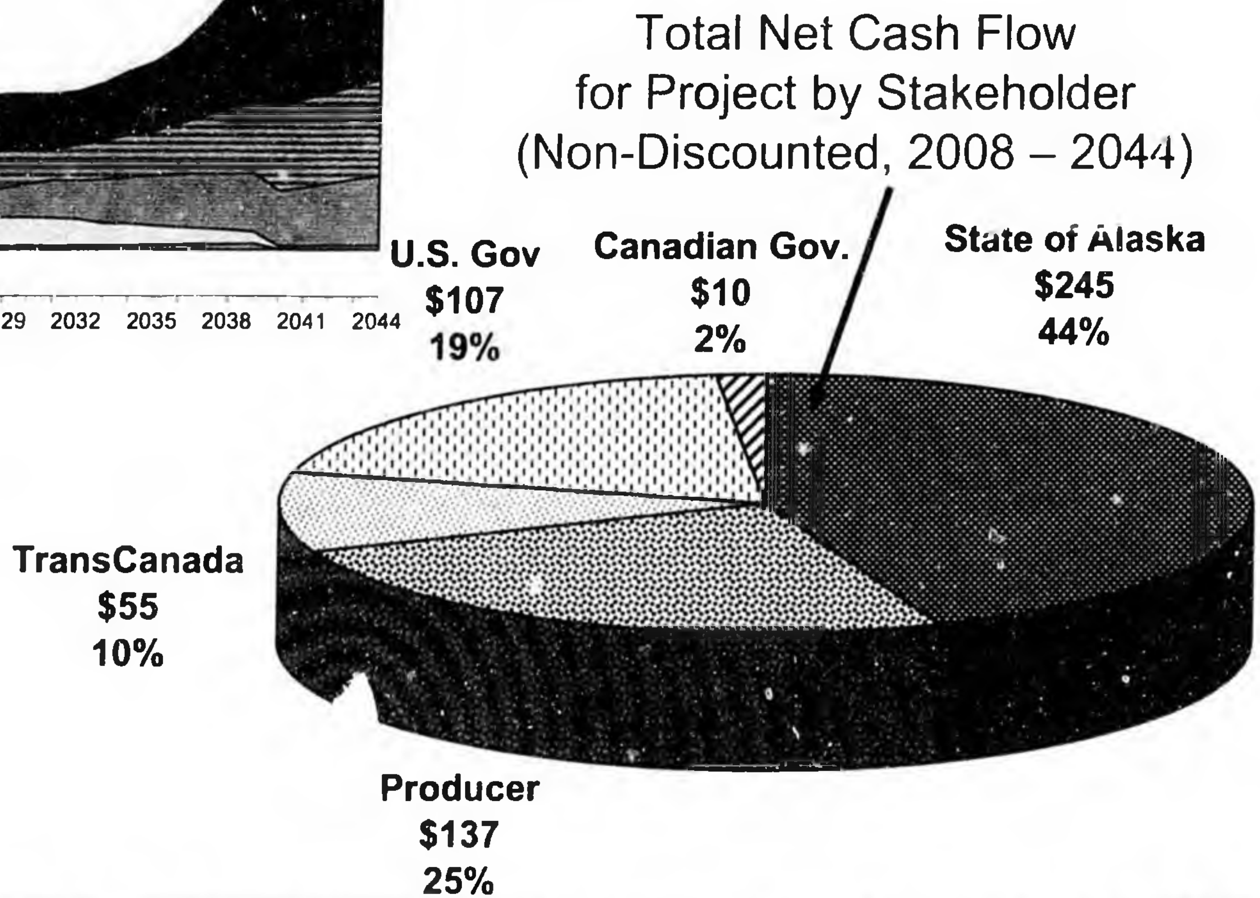
- Prudhoe Bay:
  - 24.5 Tcf
  - Initial production rate – 3.5 Bcf/d
- State existing:
  - 3.7 Tcf:
    - Colville River – 0.4 Tcf
    - Duck Island – 0.8 Tcf
    - Kuparuk – 1.2 Tcf
    - Northstar – 0.5 Tcf
    - GPMA – 0.9 Tcf
  - Initial production rate – 0.5 Bcf/d
- Note – this case assumes <u>NO</u> Point Thomson production

Expected Tariffs from the North Slope to the AECO Market

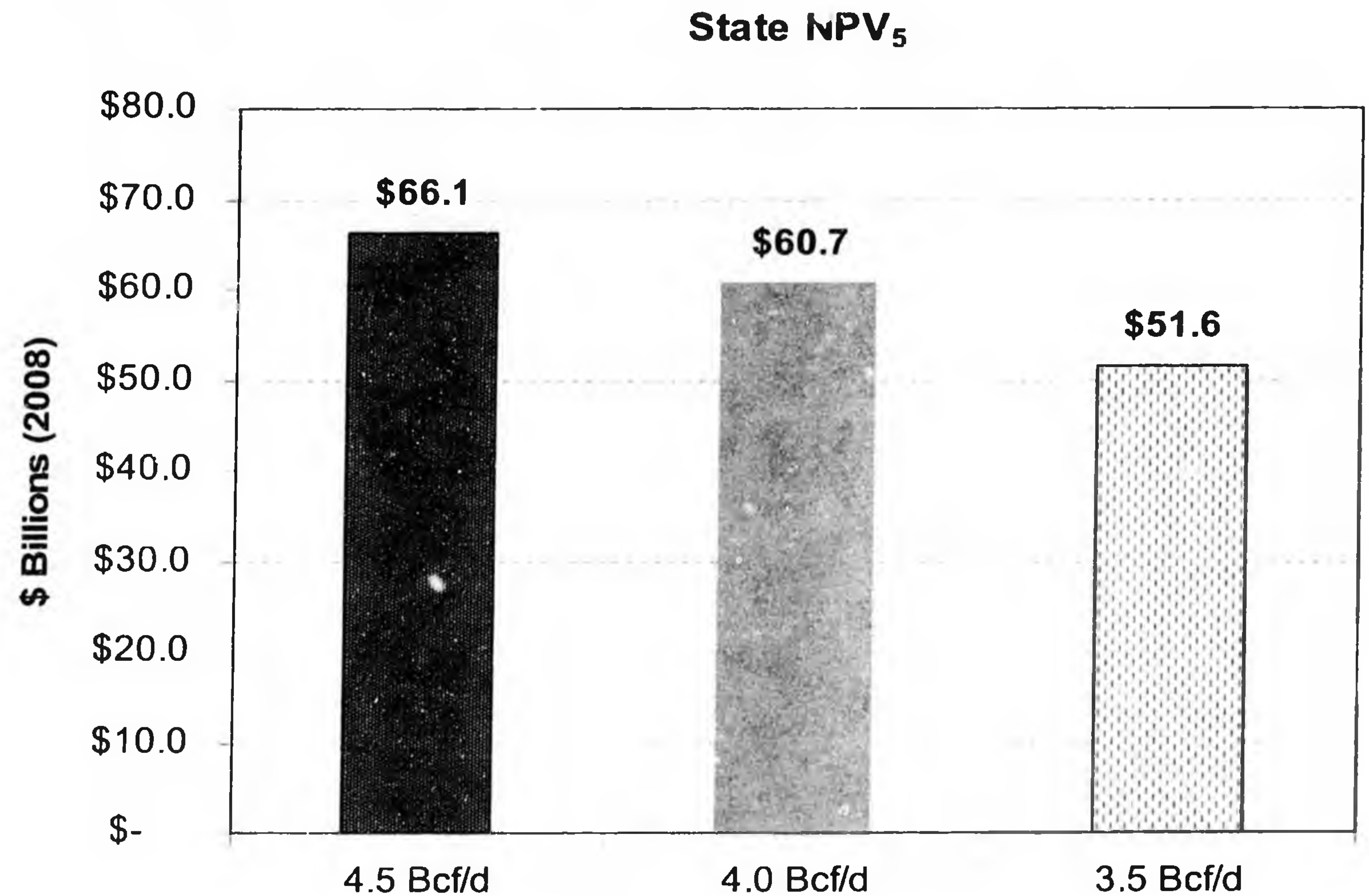


4.0 Bcf/d Conservative Base Case Cash Flows

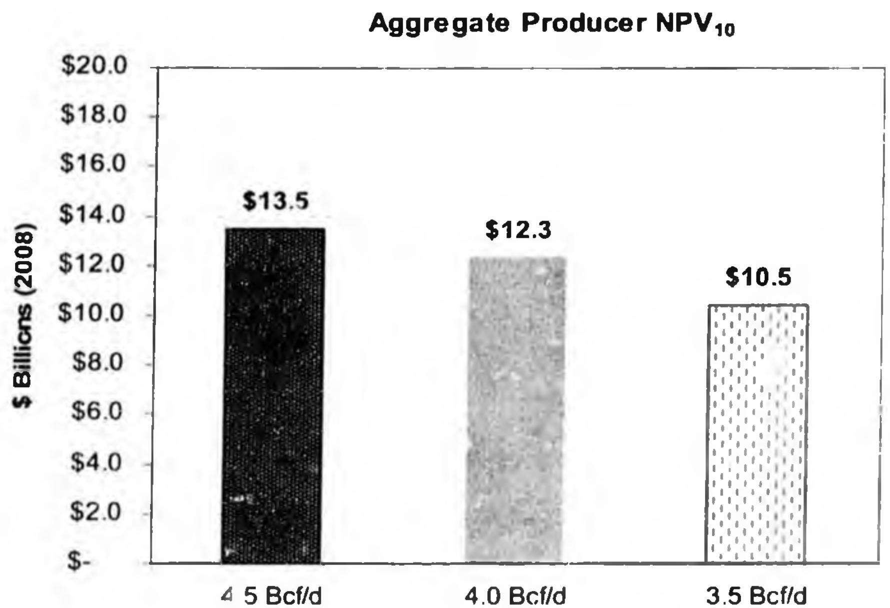


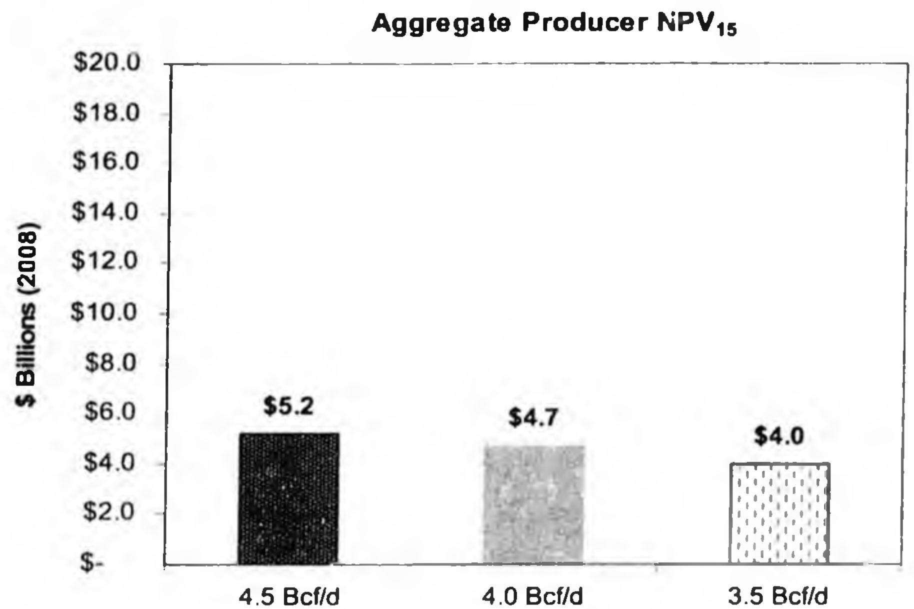


The State's NPV_5 is Lower with Smaller Project Capacity but Remains Significant



Producer NPV Shows a Similar Trend When Compared to the State



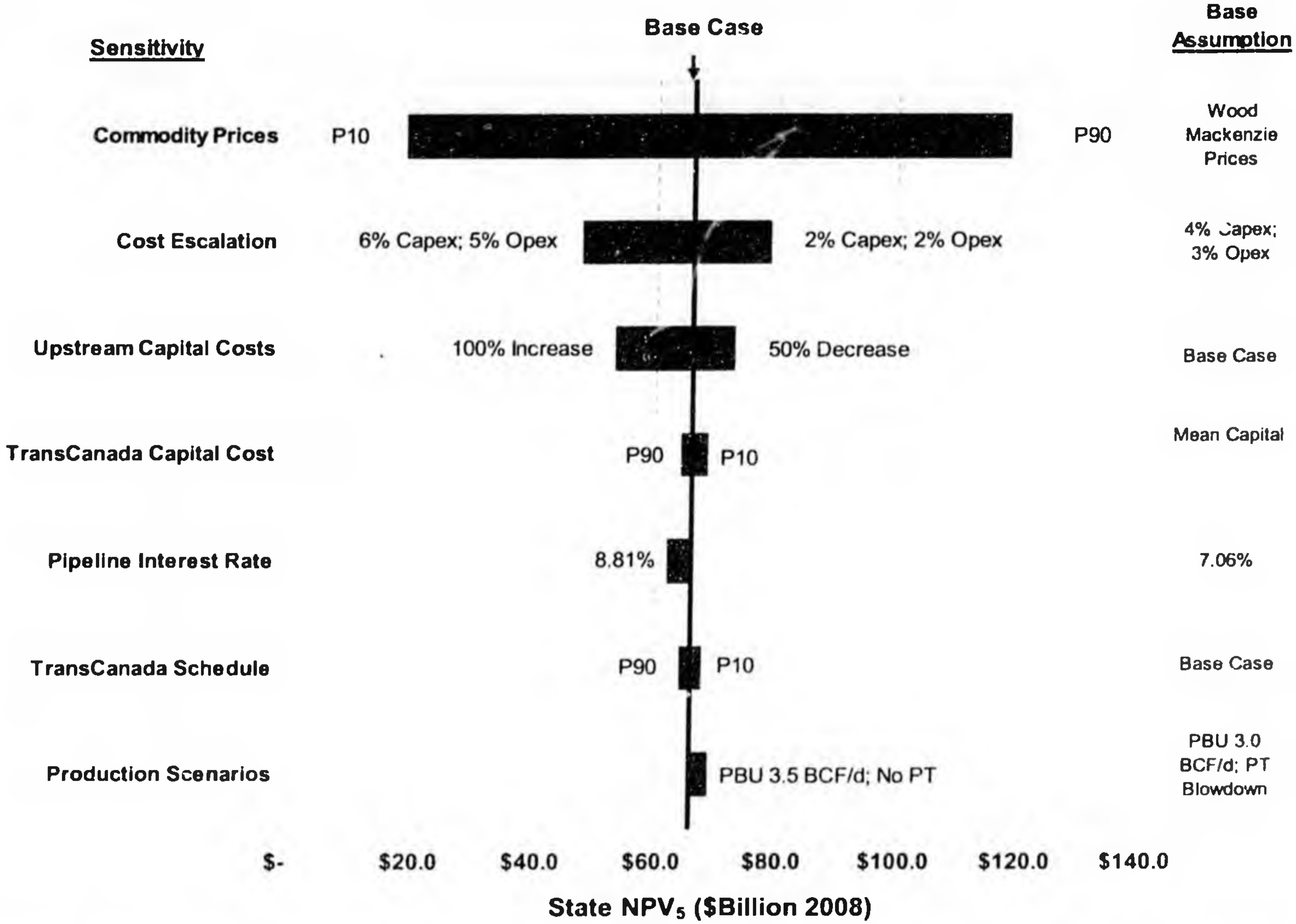


Project NPV is Affected by Many Factors

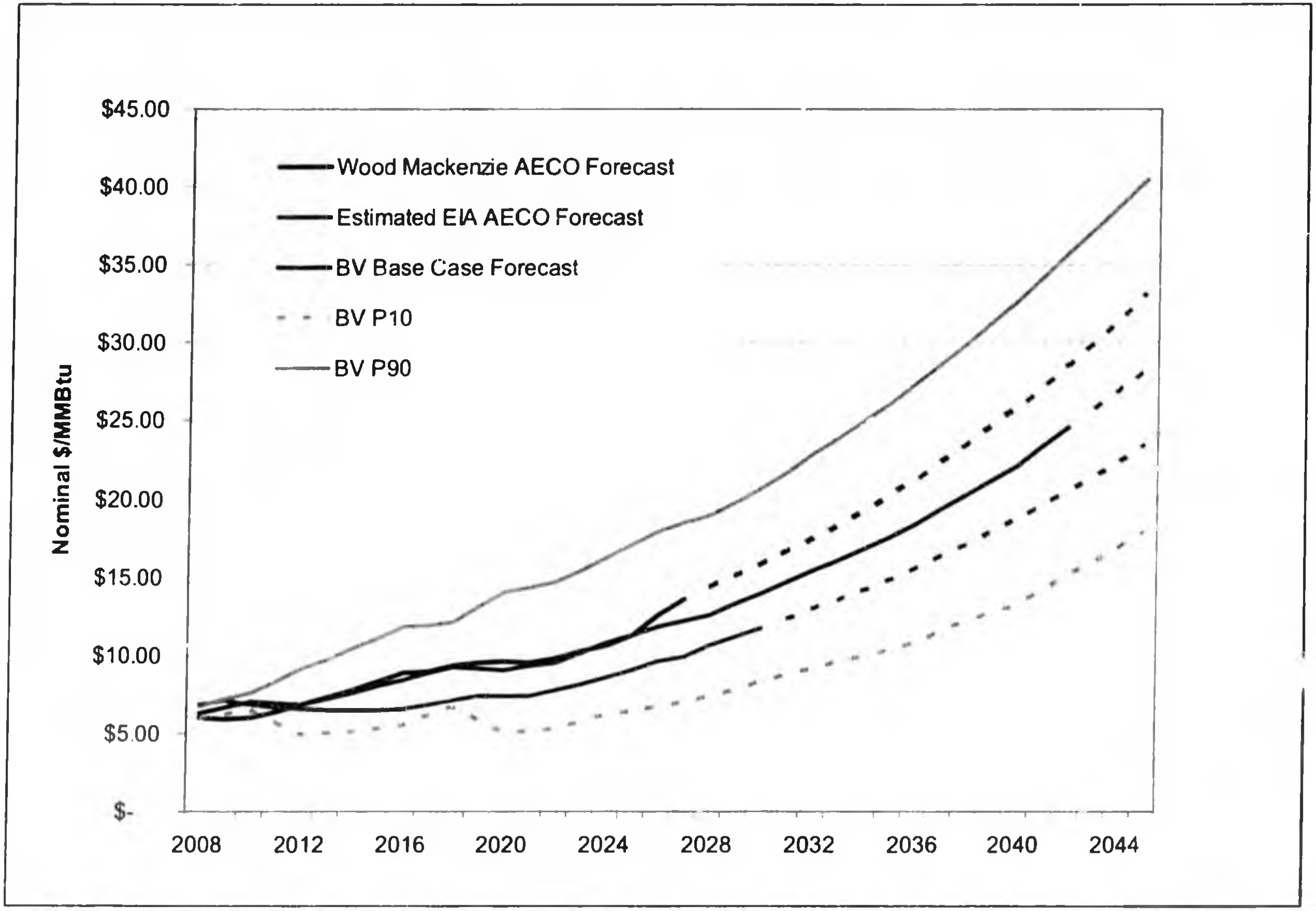
- Prices
- Project cost
- Project cost escalation
- Interest rates
- Cost of finding and developing “new gas”
- Etc.

<u>Bottom line</u>: Understanding how project economics are affected by uncertainty in inputs that affect cash flows.

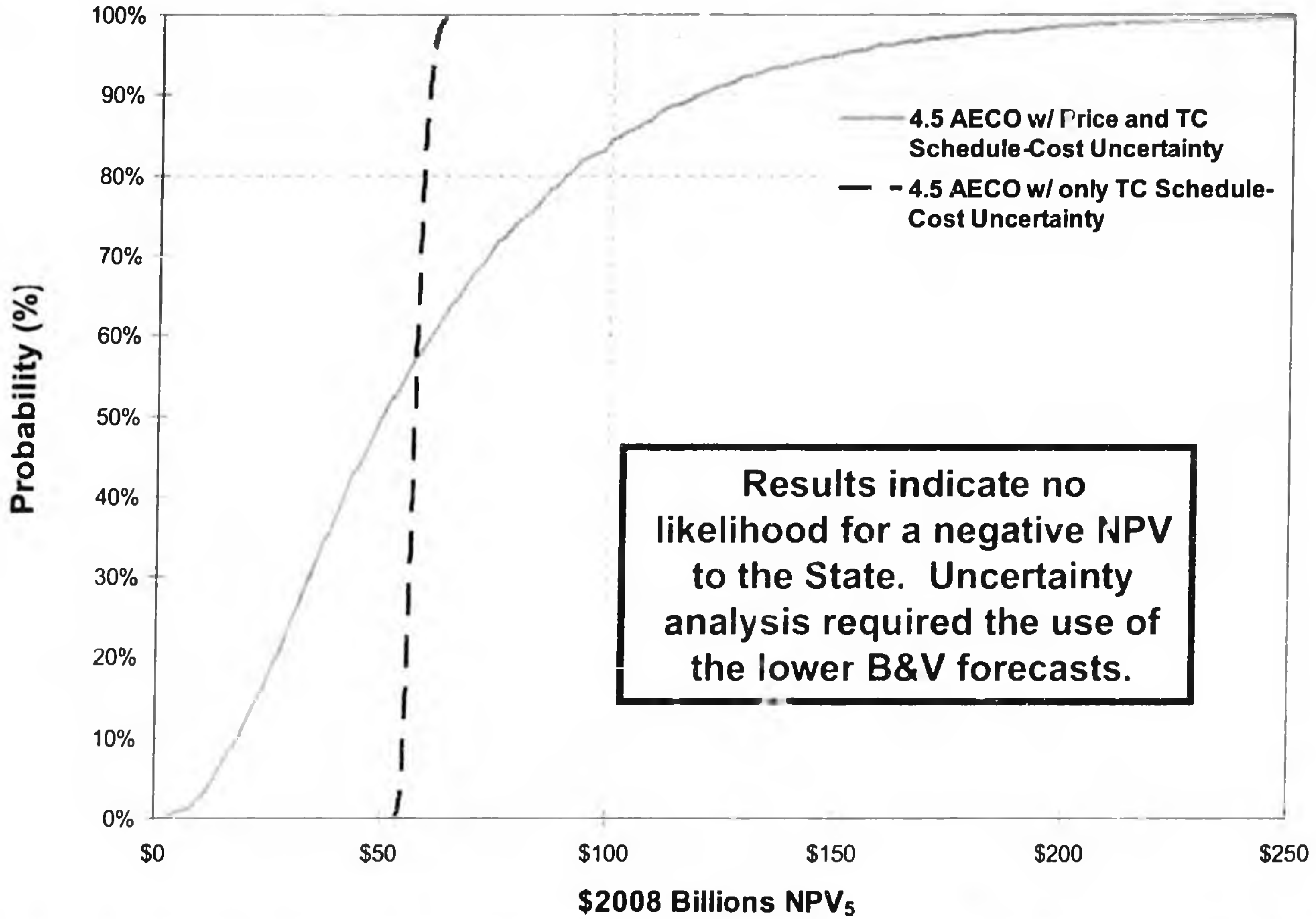
Price is a Key Driver to Variations in the NPV_5 to the State of Alaska



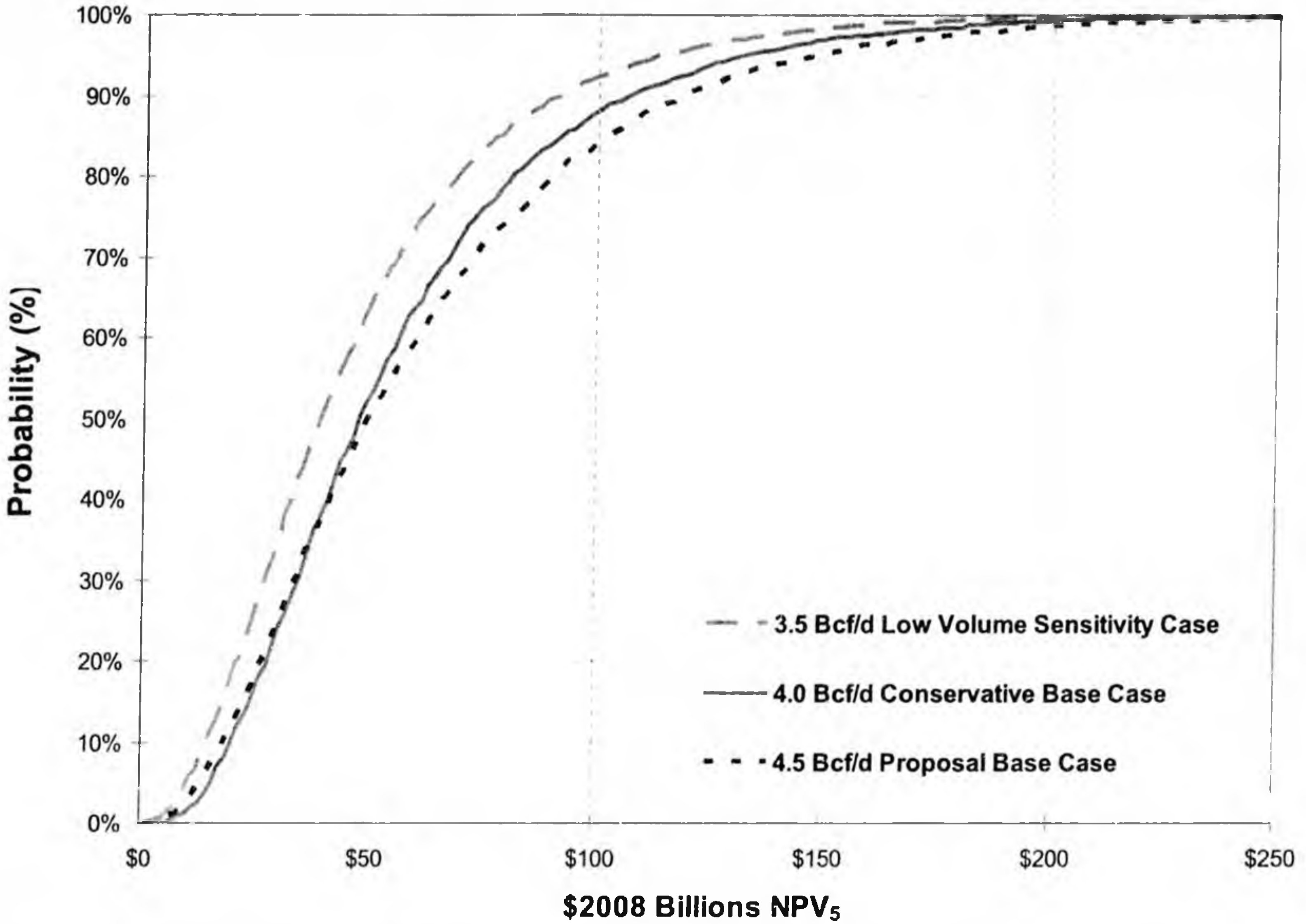
Various Price Forecasts were Considered in Analysis



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

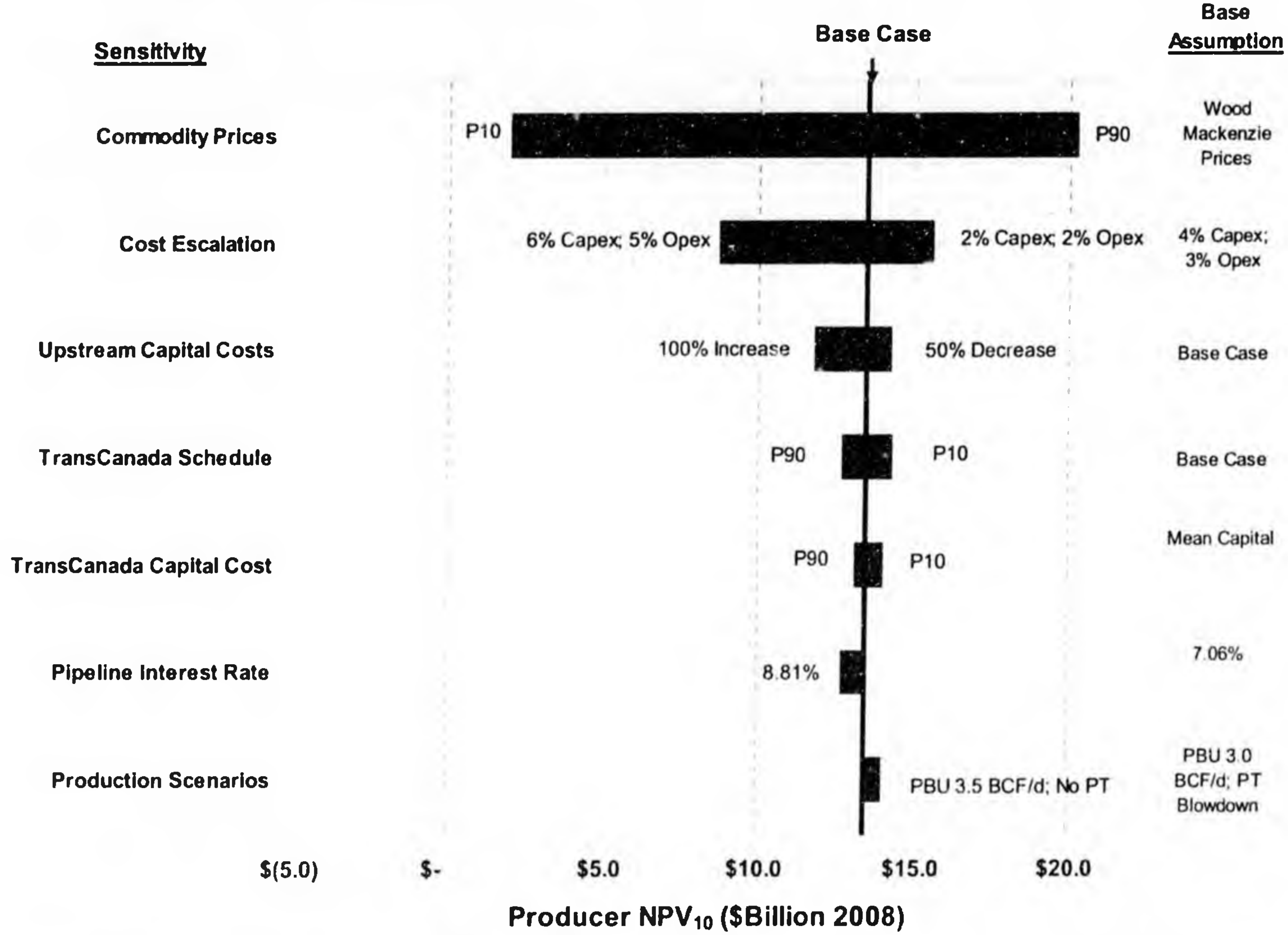


Lower Project Volumes yield similar State NPV results

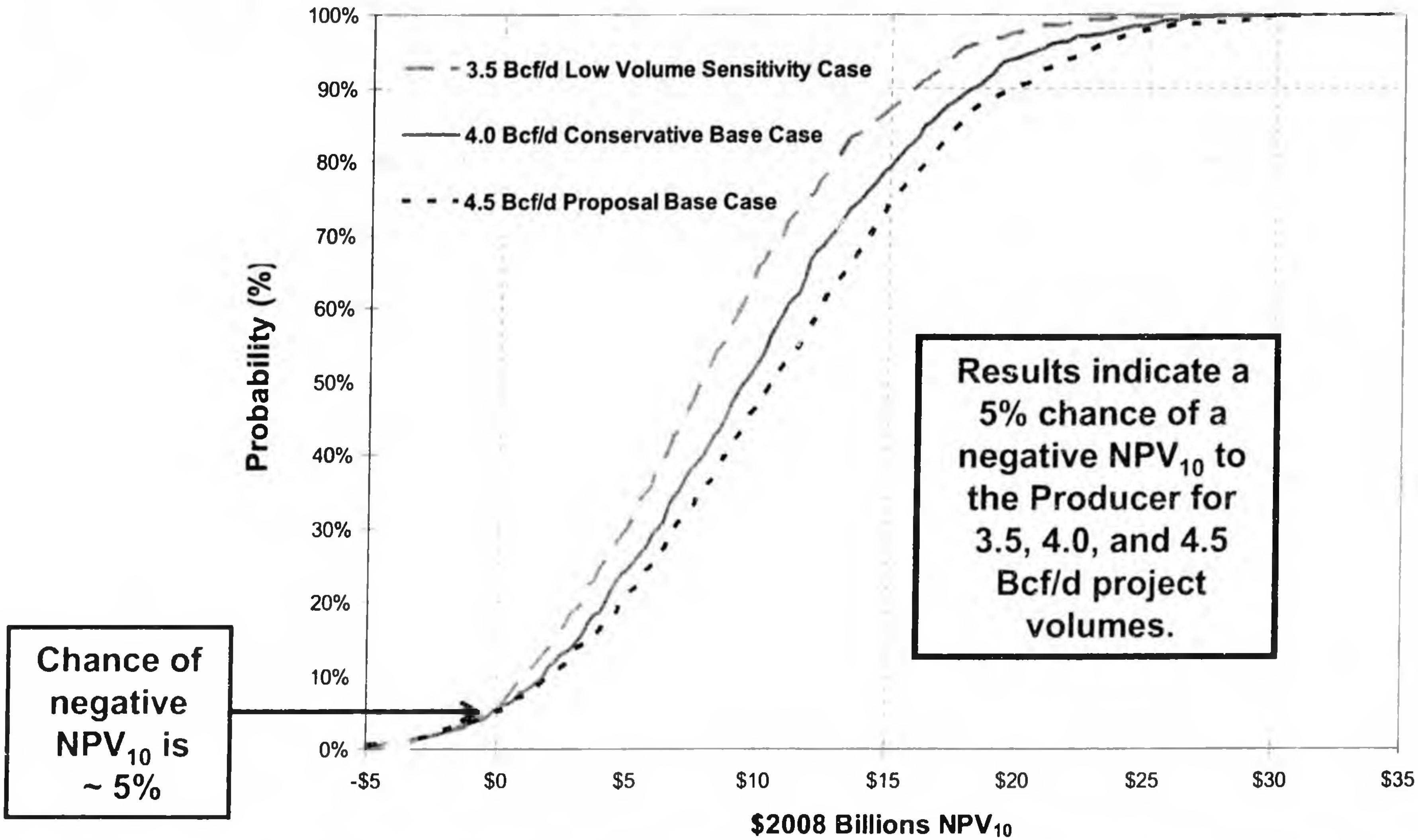


Results shown are with both Price Uncertainty (B&V Price Scenarios) and TC Schedule / Cost Uncertainty

Producer Sensitivity to Key Variables is Similar to that seen in State Results



The producers have a very low likelihood for a negative NPV_{10}, even with lower project volume of 3.5 or 4.0 Bcf/d.



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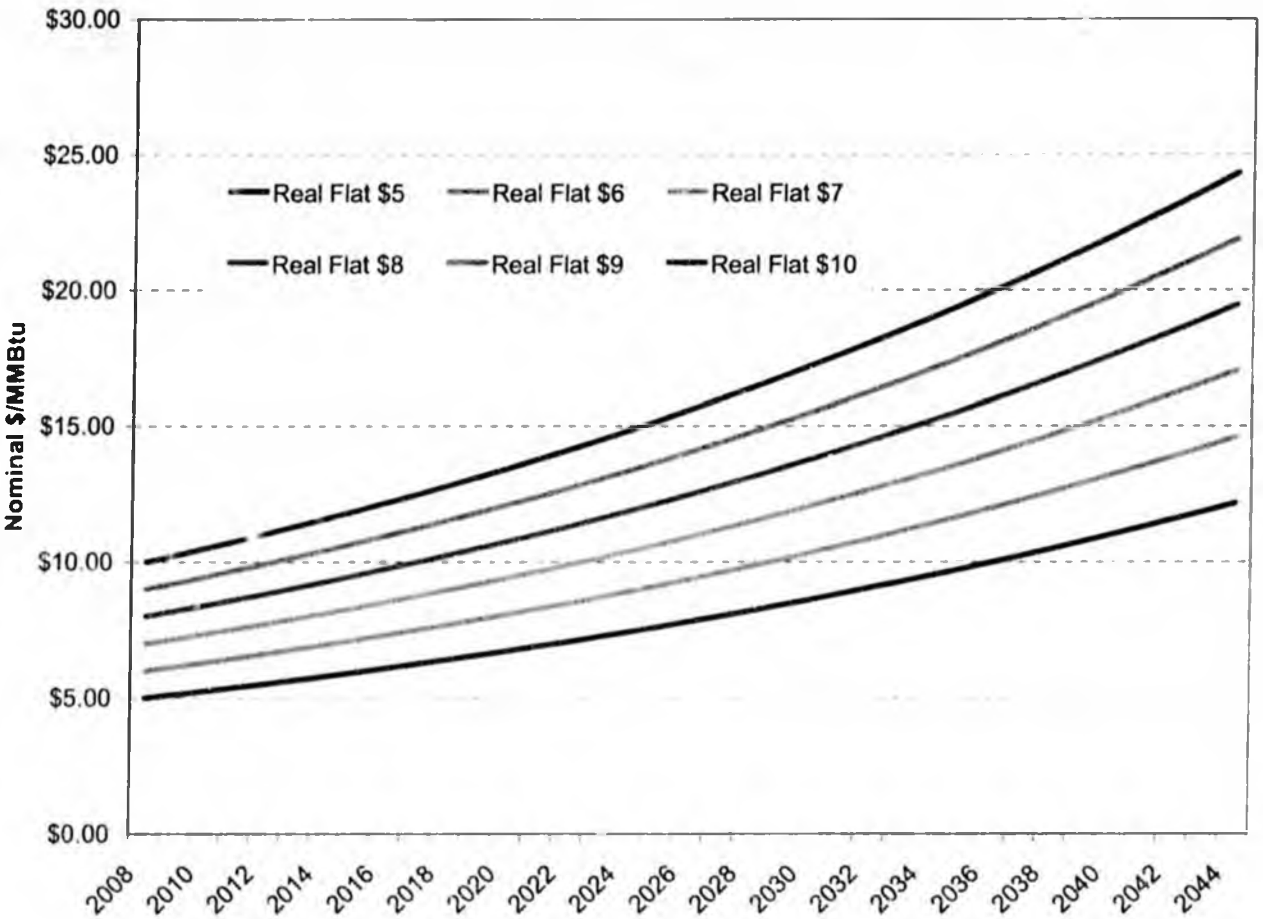
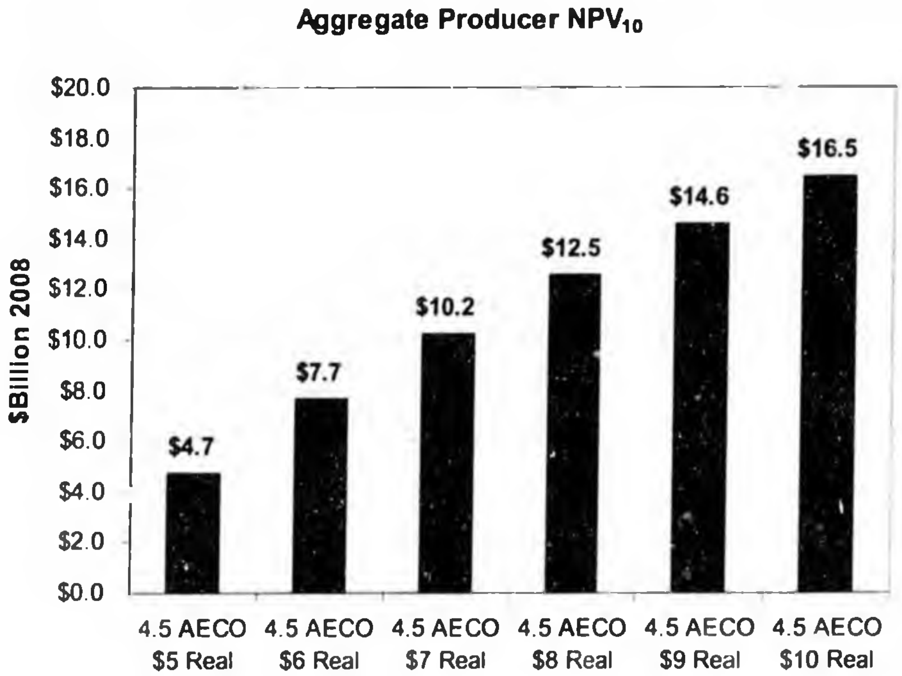
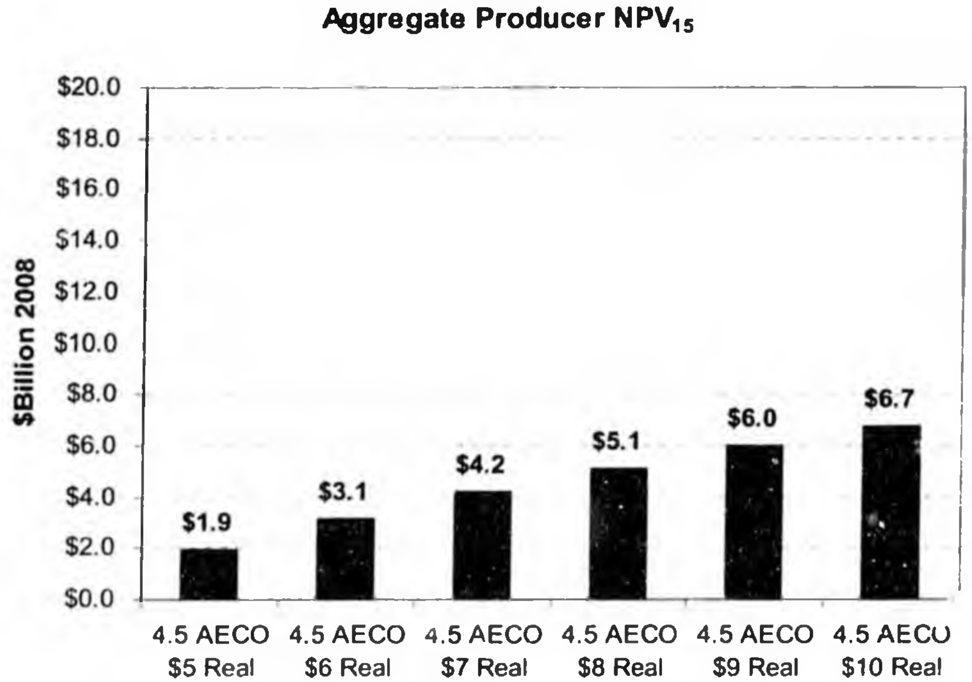
Analysis of Impact of Price Levels - Flat Real Prices



- 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

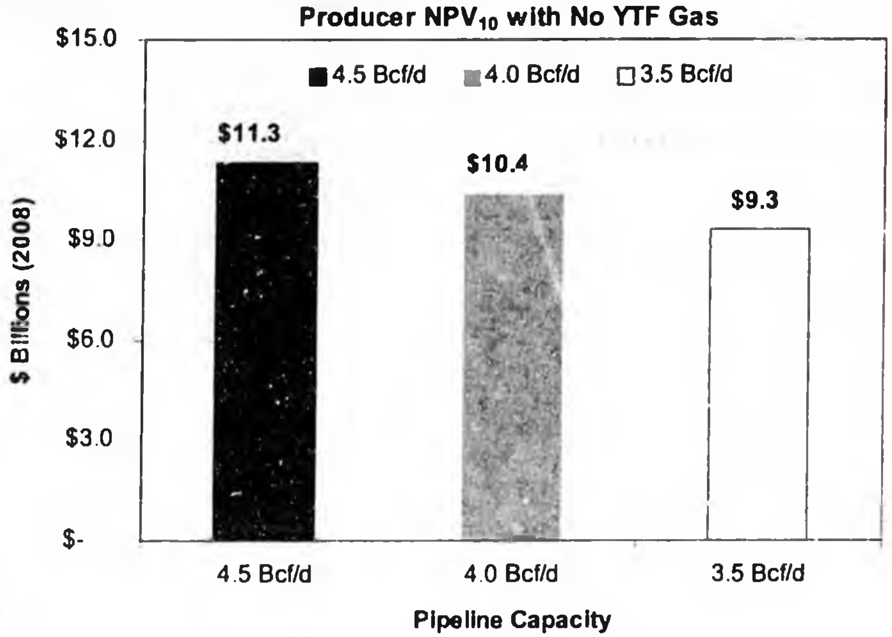
Price levels have a significant impact on Producer NPV. NPV_{10} remains positive with real prices in \$5-\$10/MMBtu range for the 4.5 Bcf/d case.

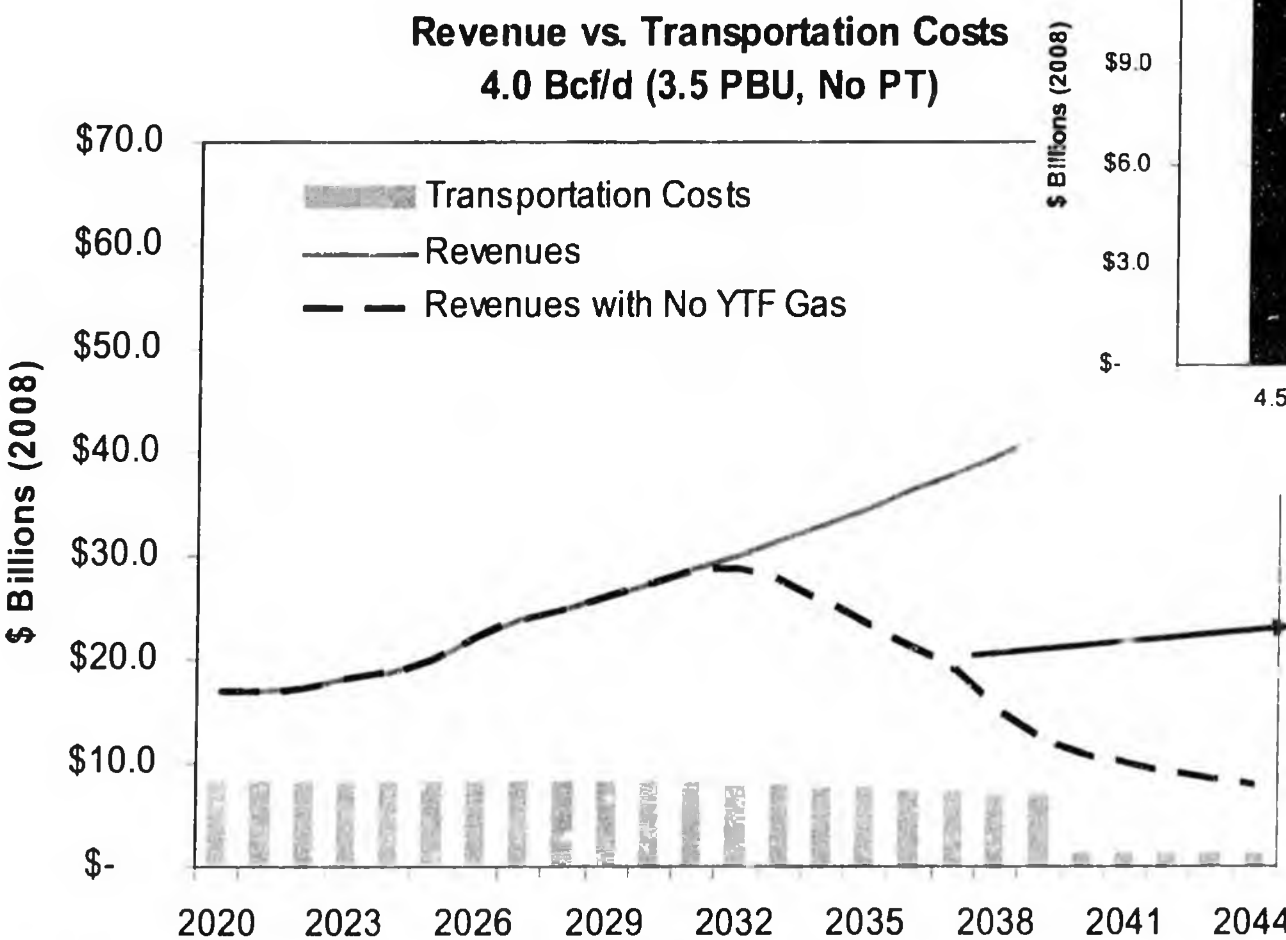




Even at very low future prices, Producer NPV remains positive.

Producer NPV (for 4.0 Bcf/d) is Expected to Remain Positive if No YTF Gas is Produced





Producer NPV_{10} is equal to \$10.4 billion with No YTF Gas at 4.0 Bcf/d

Appendix

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 $

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

Overview of Natural Gas Price Assumptions Utilized in the NPV Analysis

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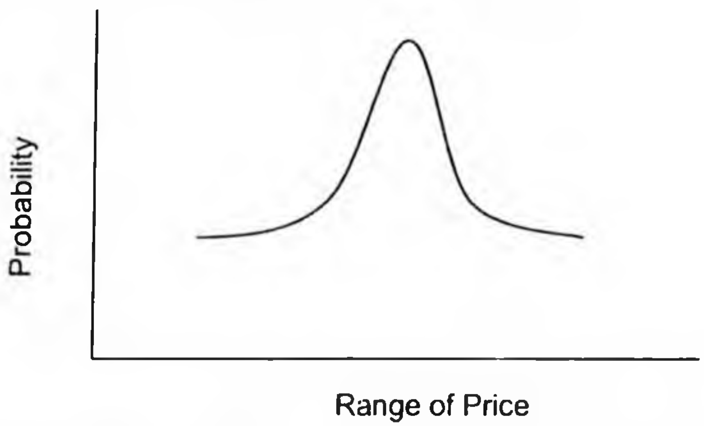
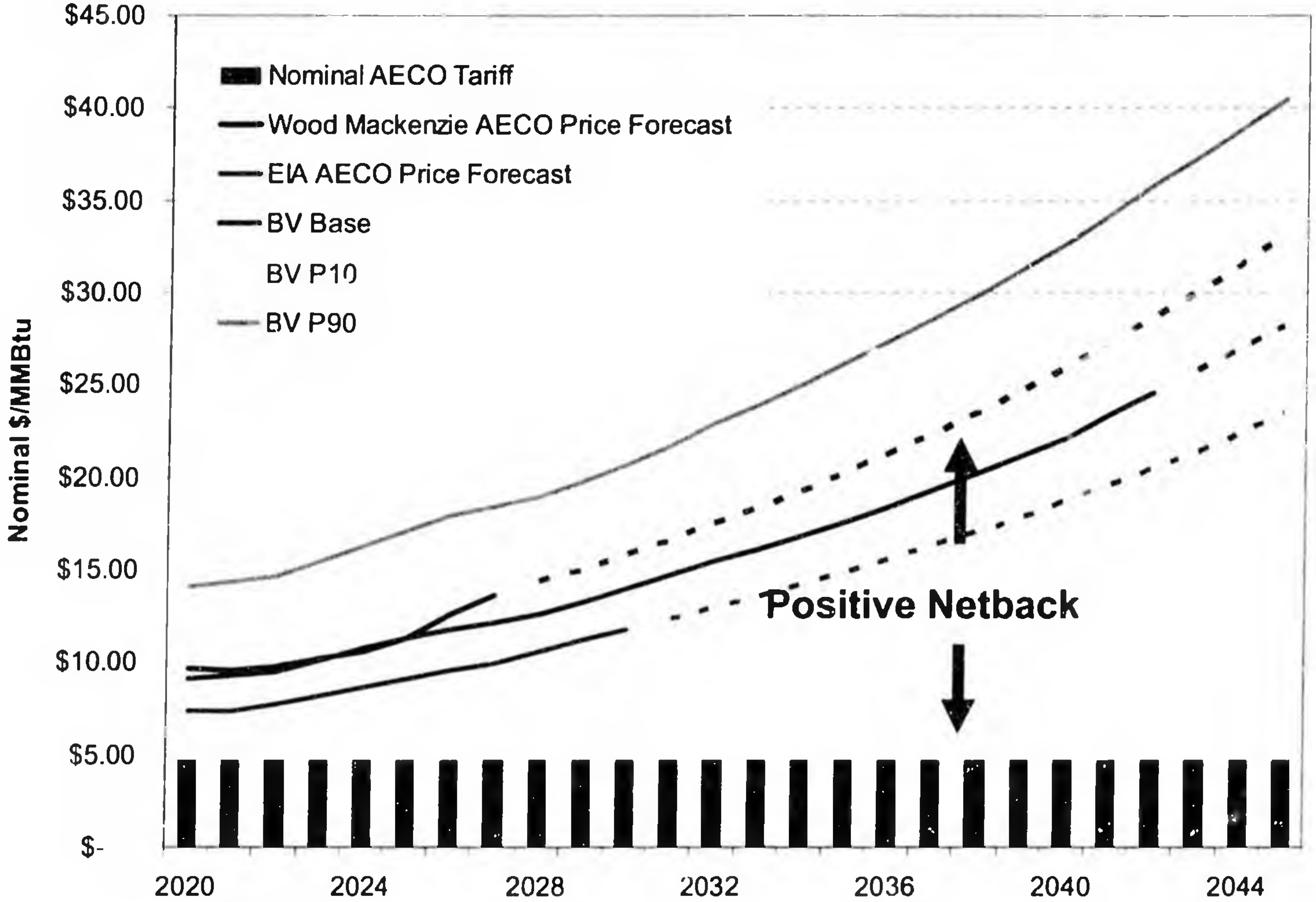
Understanding the Factors that Lead to Future Prices

- 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:

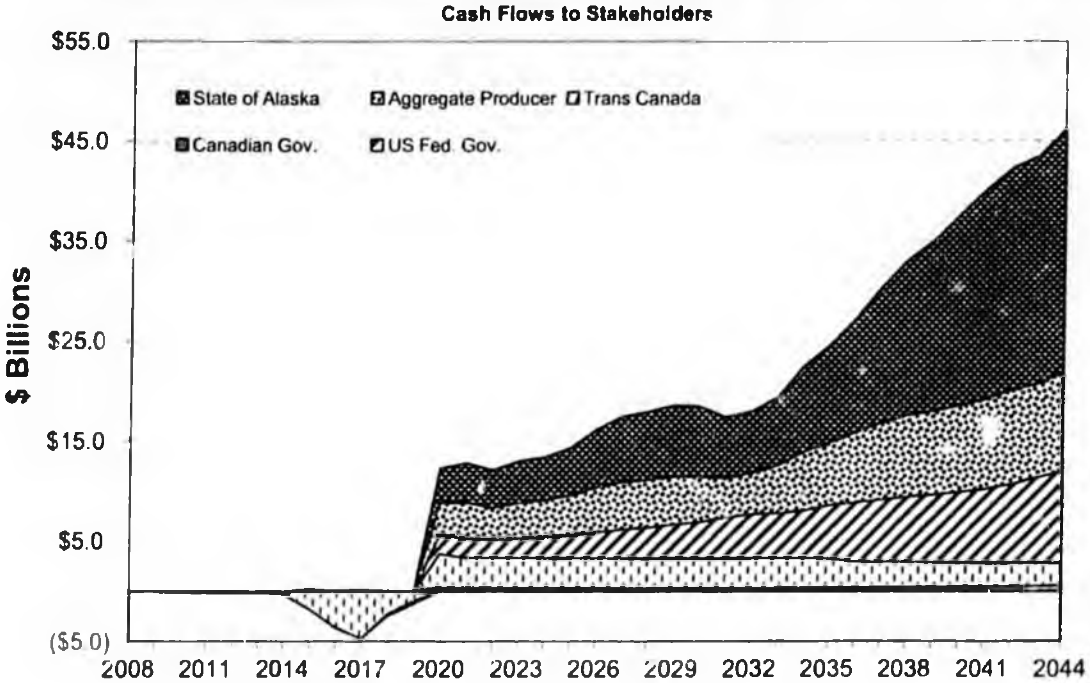


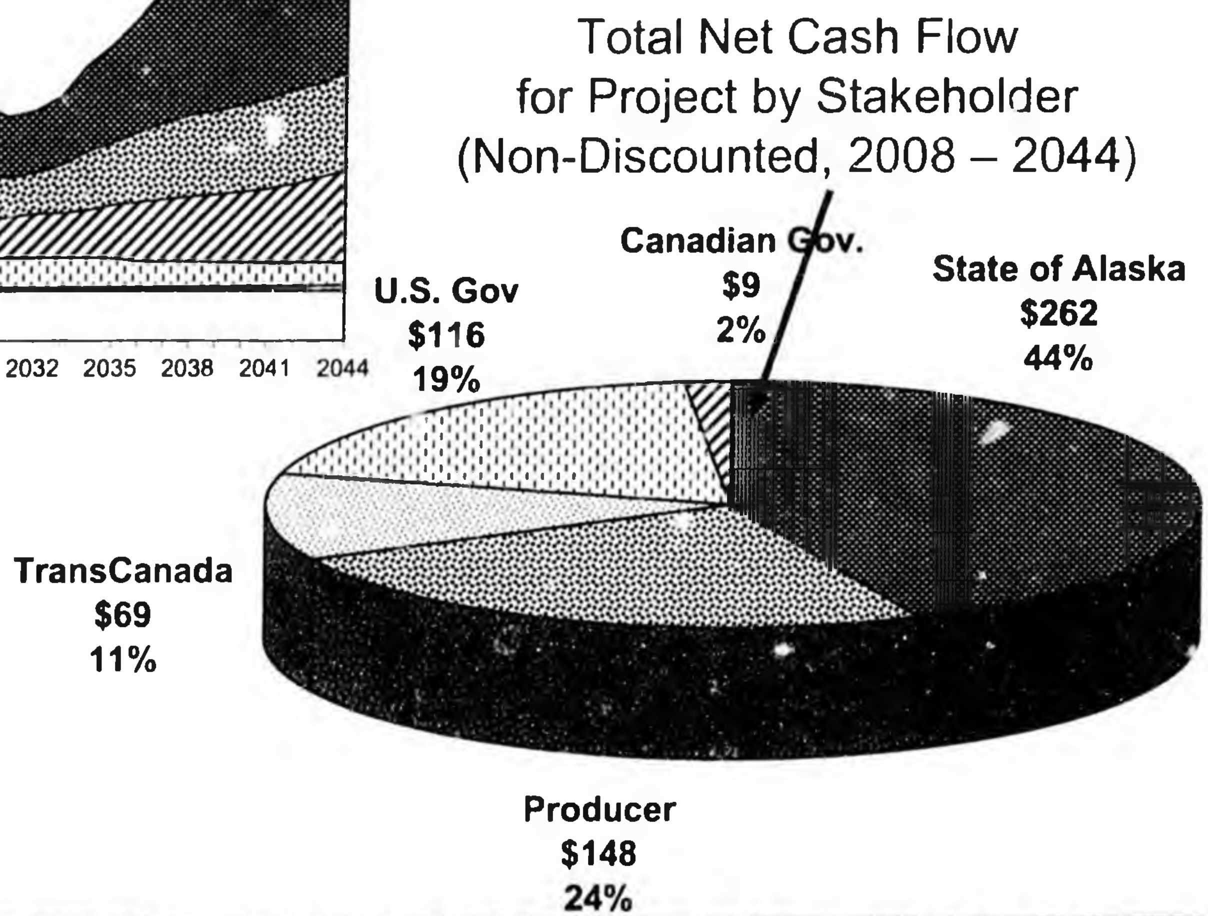
- Black & Veatch assumes that the majority of price risks comes from uncertainty in fundamental factors:
  - Finding & development costs
  - Technological improvement
  - LNG imports
  - Power generation demand
  - US industrial demand
  - CDN industrial demand

Positive Netbacks Are Expected Under All Price Forecasts

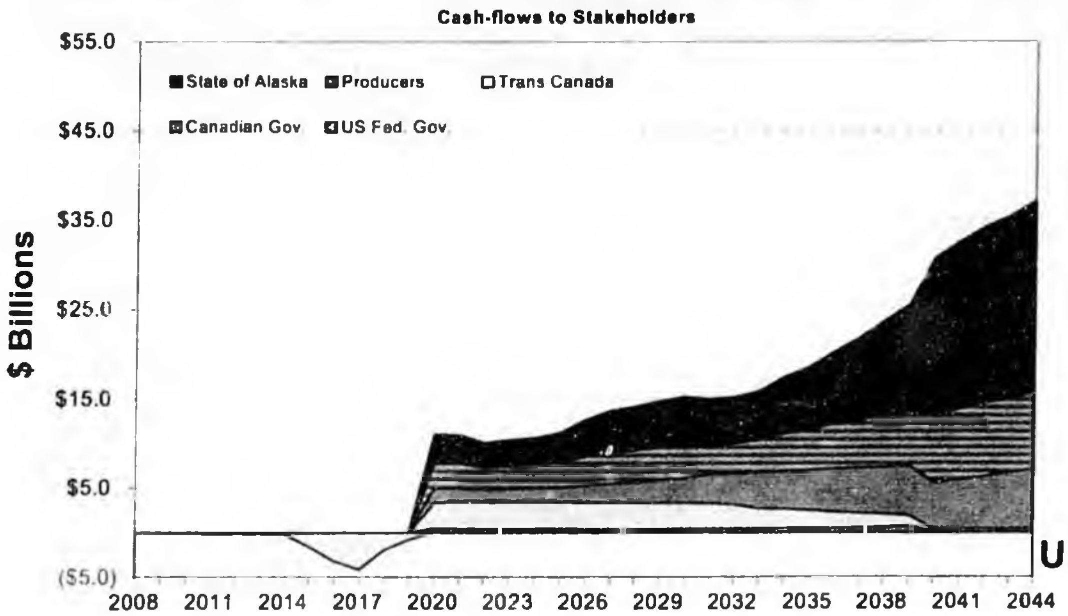


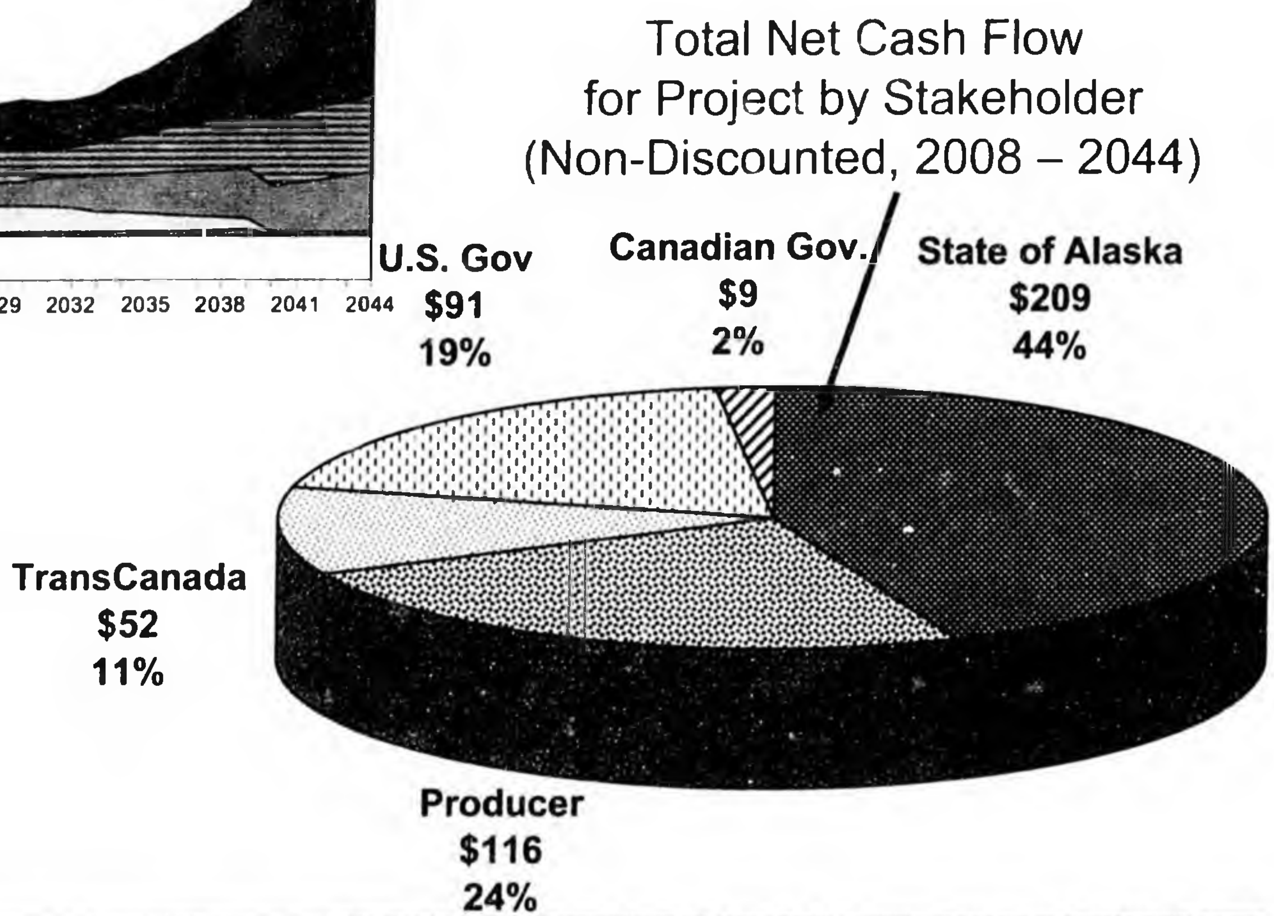
Cash flows to from 4.5 Bcf/d Proposal Base Case



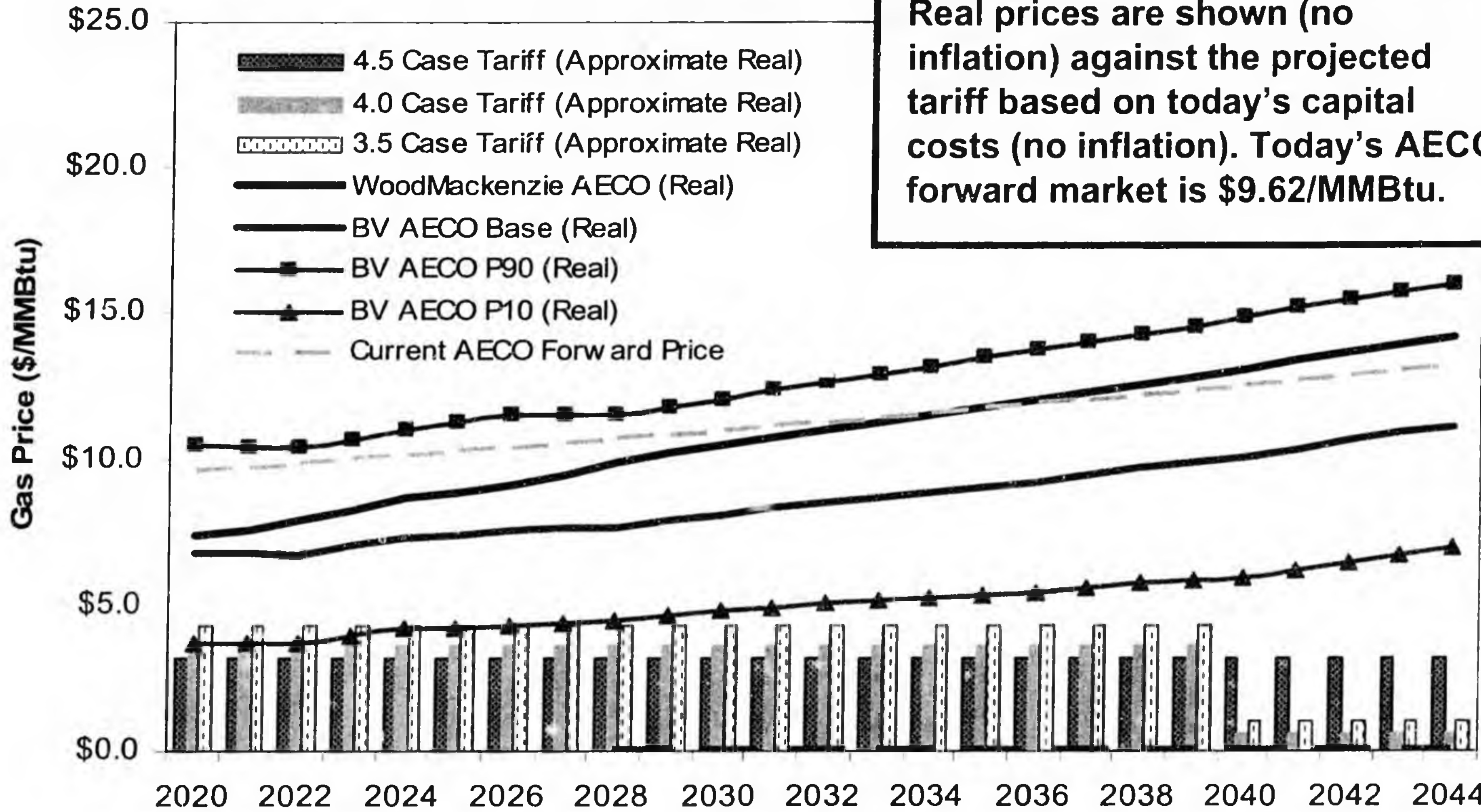


3.5 Bcf/d Low Volume Sensitivity Case



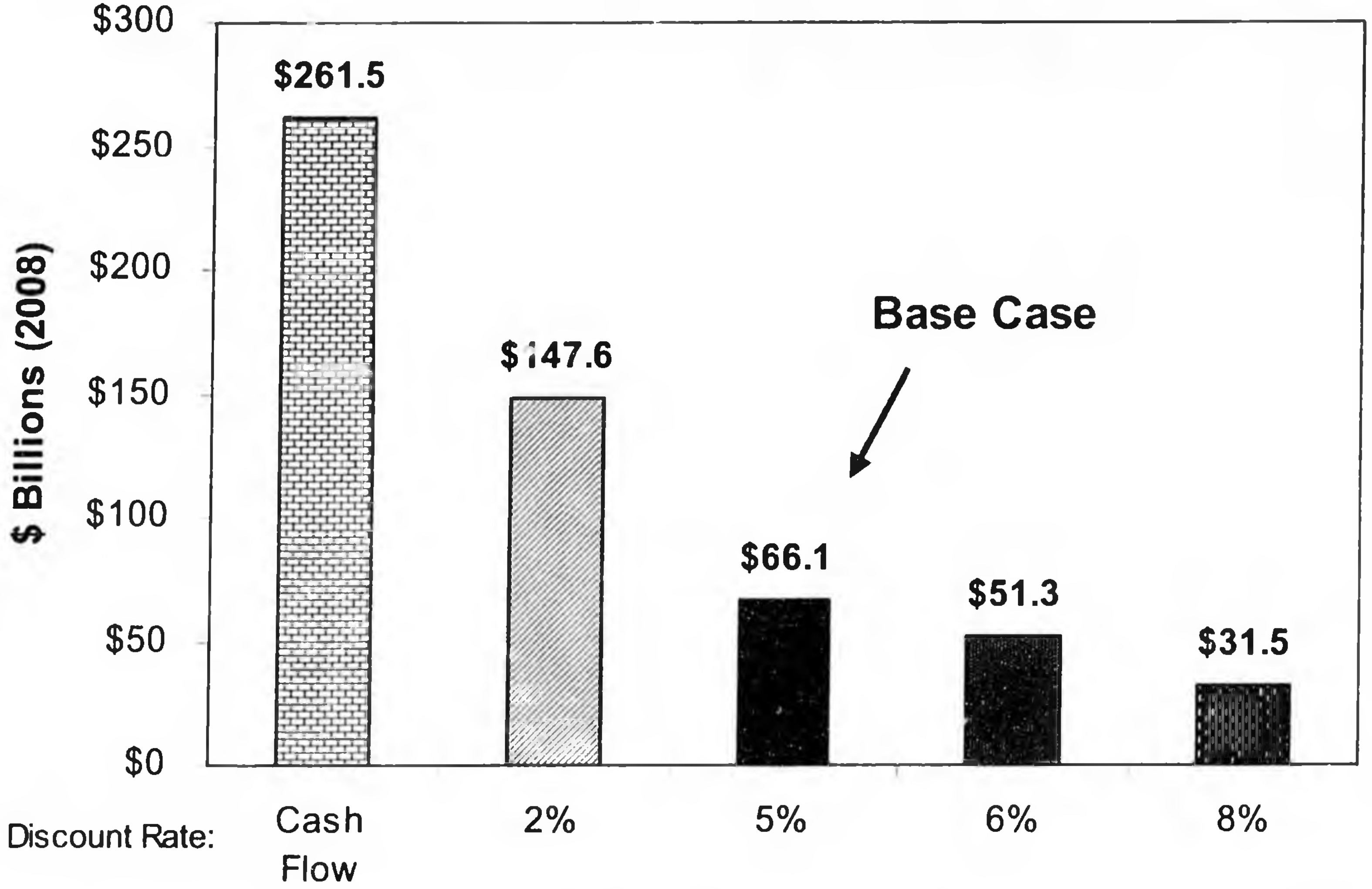


Project Cash Flows are Favorable if Built Today

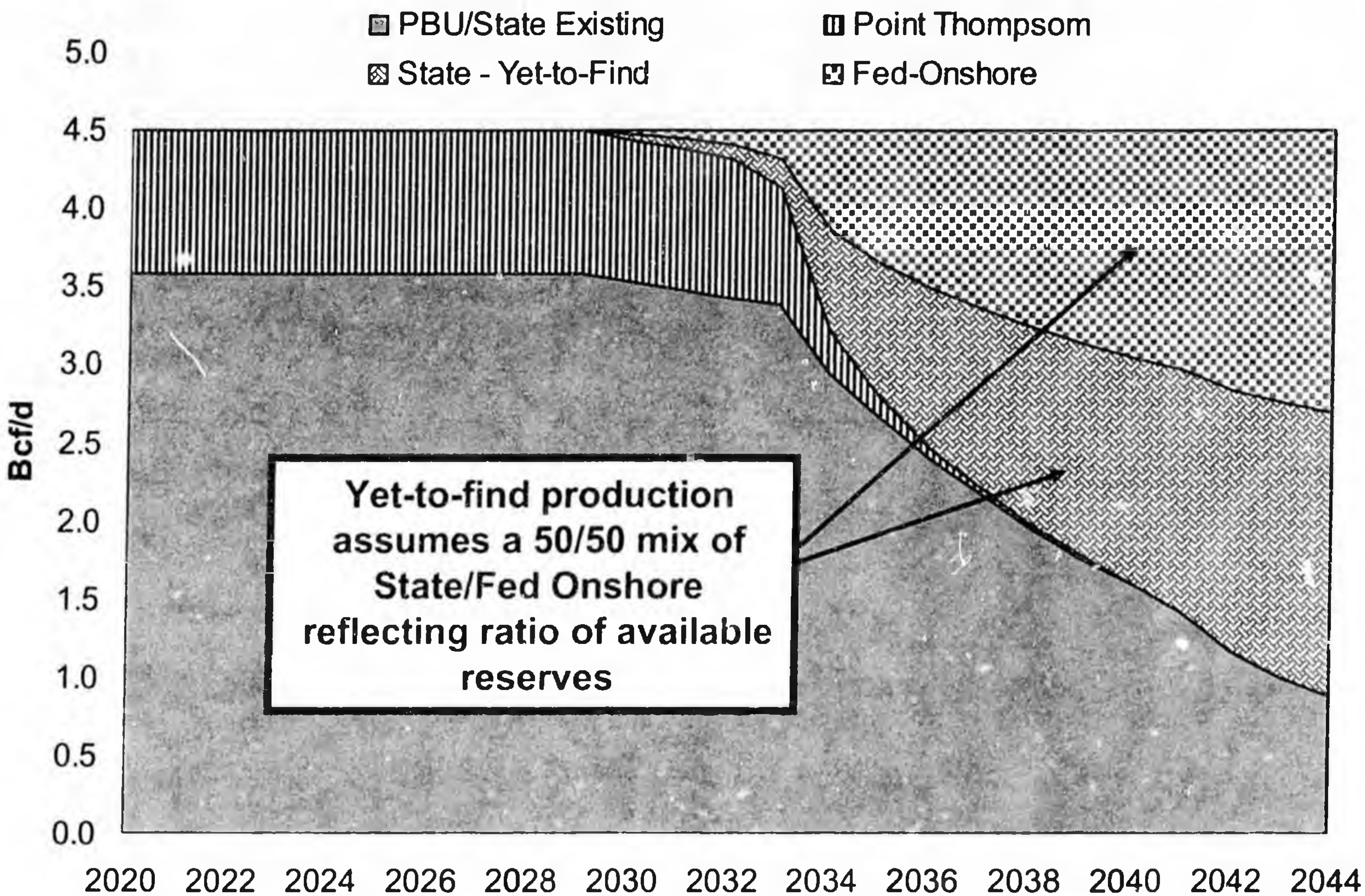


Real prices are shown (no inflation) against the projected tariff based on today's capital costs (no inflation). Today's AECO forward market is $9.62/MMBtu.

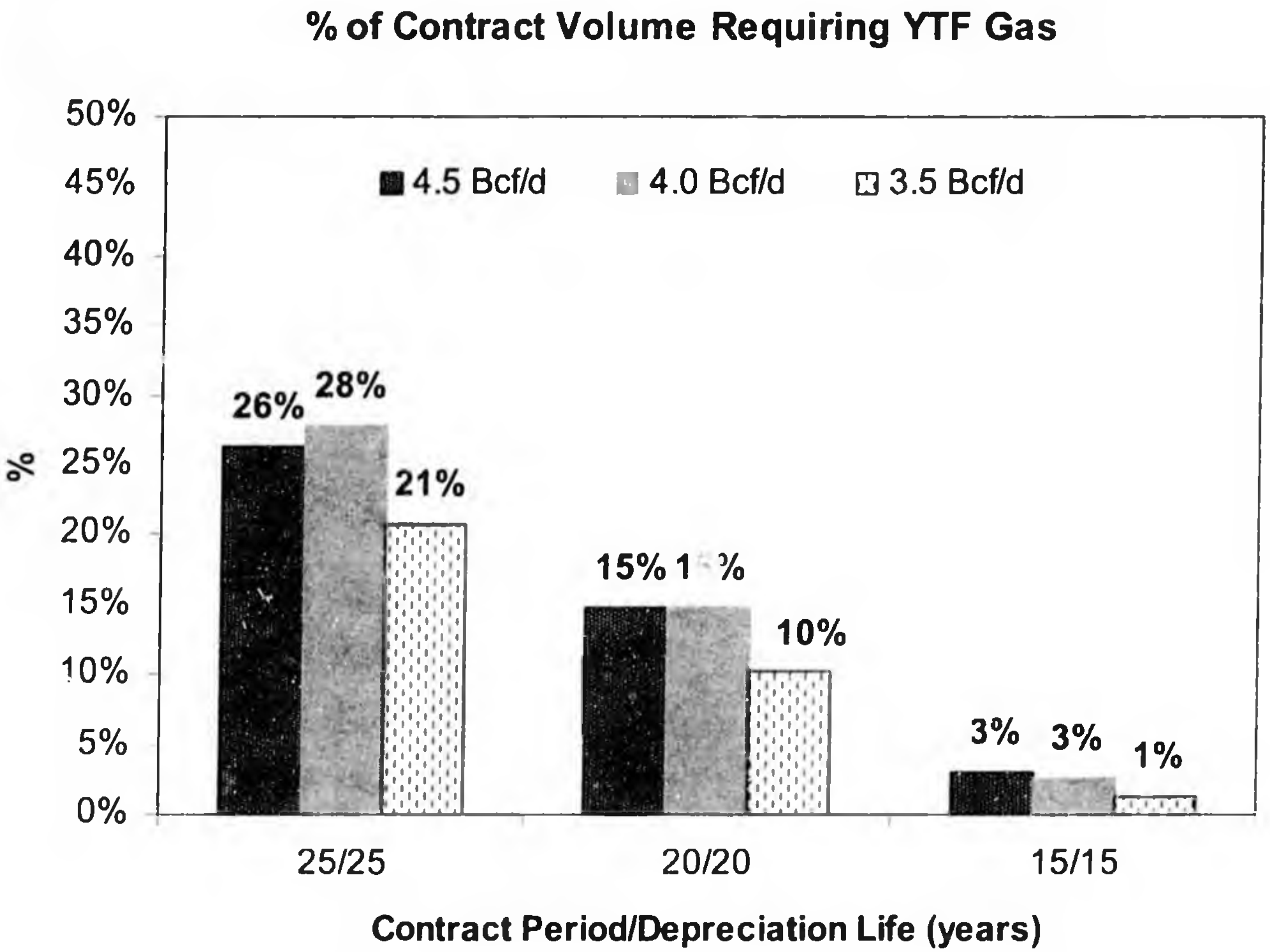
Expected State of Alaska NPV_5 is $66.1 billion



Production Assumptions: 4.5 Bcf/d Proposal Base Case



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



Why does a delay increase 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

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Response to Testimony and Q/A Discussions Held on June 17, 2008

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Do we have enough data in Point Thomson to define a Full Field Plan of Development for both the oil and gas reserves?

- 19 wells have been drilled
- 14 wells penetrated Point Thomson reservoirs
- 3600 ft of high quality core has been taken and analyzed
- 20 well tests have been completed, defining rates and pressures
- Eight 3D seismic surveys have been acquired and interpreted
- Multiple fluid samples have been taken and fluid property evaluations have been conducted
- Conclusion: The type and amount of reservoir data is sufficient to develop a Full Field Plan of Development for oil and gas development at the Point Thomson Field

Response to Exxon Presentation

- Exxon presented yesterday that they did not see a reduction in Pt Thomson well productivity due to condensate dropout.
- Their own published work on the Arun Field in Indonesia (with a condensate yield of 65 STB/MMSCF shows a 50% reduction in well productivity occuring during blowdown.
- As a result, Exxon initiated lean gas injection in Arun, as soon as production began, to minimize liquid drop out and to maximize condensate recovery.
- In a blowdown scenario, 2 to 3 times the number of wells will be required to maintain the same rate. Producing oil earlier, will require fewer number of wells in the long term.
- Condensate will be trapped in the reservoir in a blowdown scenario, thereby reducing liquid recovery.

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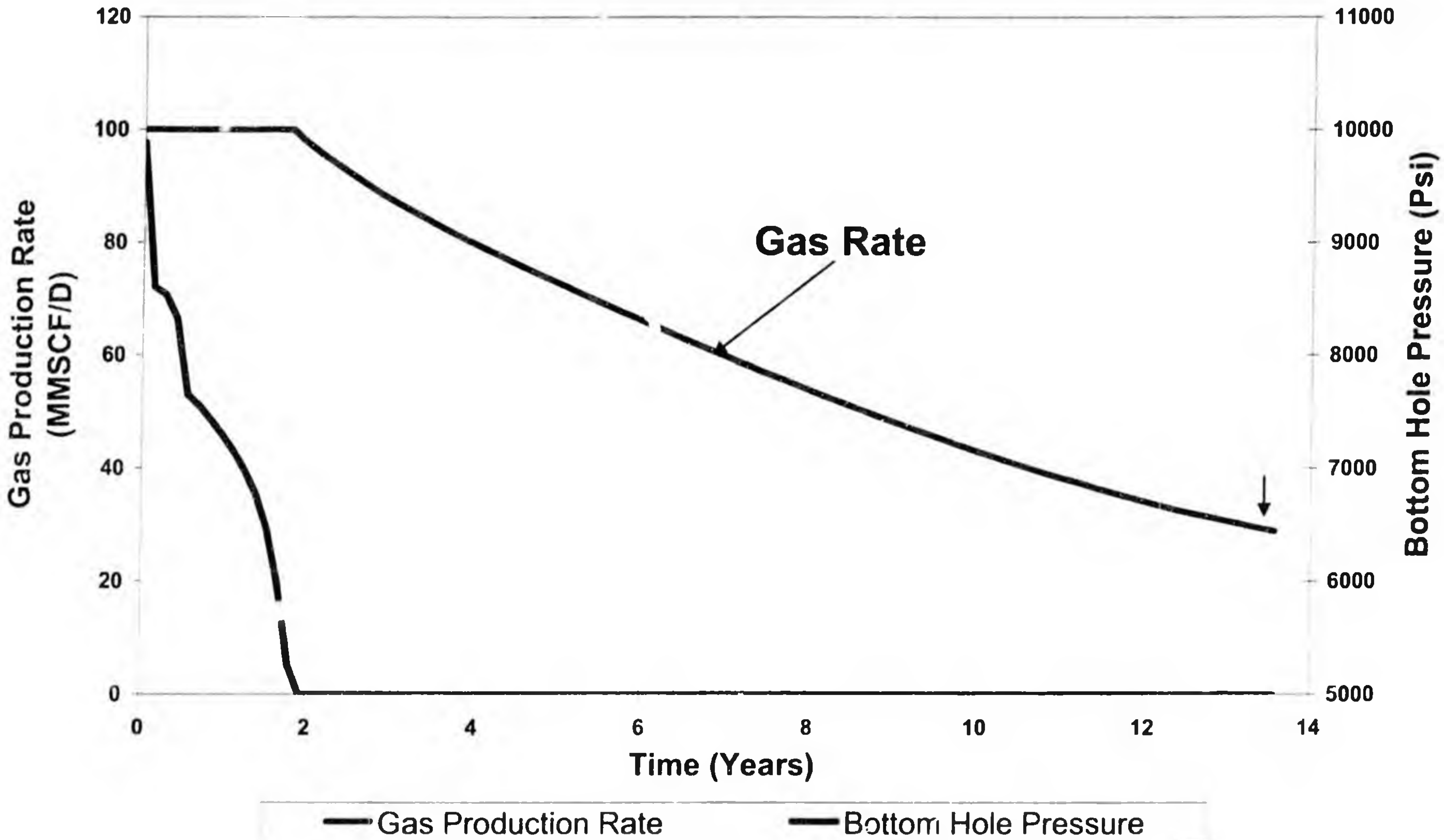
Point Thomson Well Productivity During Blowdown

Drainage Area 3400 Acres, k=120 md, thickness = 200 ft,
Initial Pressure = 10,200 psi



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Take Home Point
Point Thomson Blowdown

- It will require very aggressive additional drilling schedule ($100 Million/well) for up to 50 wells to maintain a stable gas rate for the pipeline for the next twenty-five years.

- This is because of the condensate dropout and the drop in reservoir pressure over time.

Exxon Description of Gas Cycling

- "What do we mean by cycling gas to produced condensate? The cycling of gas requires two wells; a production well and an injection well. These wells will be placed four miles apart in the heart of the reservoir to provide a true test on the effectiveness of cycling gas at Point Thomson...."

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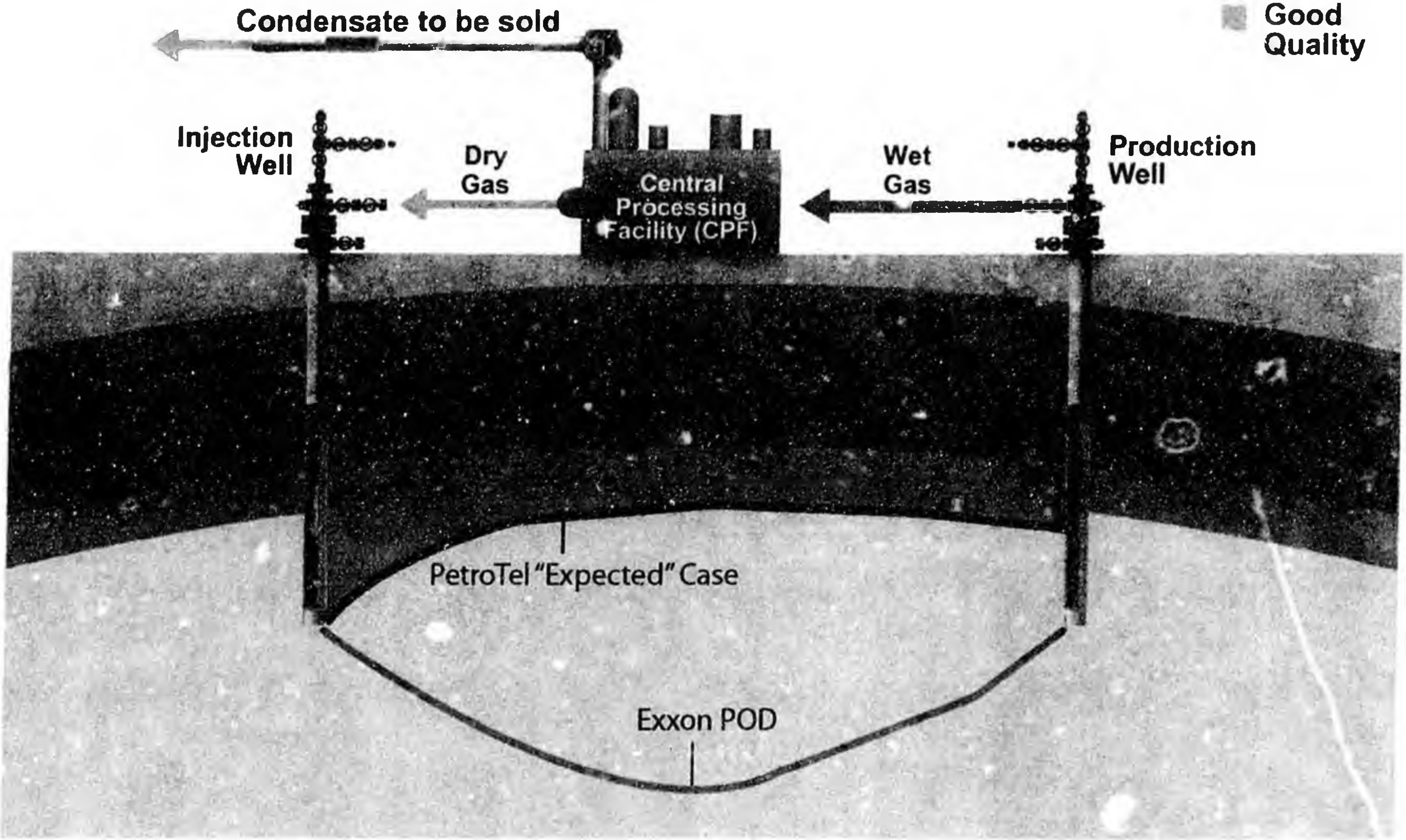
Gas Cycling



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What is Gas Cycling?

- Exxon's gas cycling description is NOT a gas cycling project by industry definition. Their depiction of fluid movement is wrong by laws of physics. The dry gas will go to the top and gravity tongue. It will breakthrough to high permeability zones to the producing well resulting in poor sweep. They show dry gas which is lighter going to the bottom of the reservoir.

- In PetroTel's design of gas cycling, the injectors are placed at the apex or at the highest points in the structure to maximize sweep.

- Exxon's 4 miles distance (per their written testimony) is too long a distance to observe pressure support in a reasonable amount of time

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Prudhoe Bay Gas Requirements

- Prudhoe Bay is undergoing a major APEX water injection program to maintain pressure
- The purpose of water injection project was to facilitate gas sales.
- AOGCC have quantified the effect of different gas offtakes based on modeling work.
- This work was used to justify the offtake in 2019 for AGIA pipeline requirements from Prudhoe Bay.
- Black and Veatch study shows the AGIA pipeline is still robust without Point Thomson gas.

GE's Oil & Gas business has pioneered the manufacturing and testing of very high pressure sour gas centrifugal compressors. The Karachaganak compressors that were full load tested in 2000 and early 2003 operate at a nominal discharge pressure of 560 bar with gas containing 5% H_2S. They are the first in the world to be used in this challenging application. To achieve this leap in technological capabilities, a substantial research & development effort on materials, gaskets, rotor dynamics and dry gas seals was necessary. Since then we have achieved another milestone with a compression train with a nominal discharge pressure of 630 Bar operating on gas with a H_2S content of greater than 15%. Recently, we have tested a new re-injection train at a discharge pressure of 800 Bar for compression of extremely sour gas (18% H_2S, 5% CO_2).

GE's compressors are designed with special focus on rotor dynamics and gas sealing to avoid, toxic release or overpressure situations. Vibration is minimized at all operating conditions by using very rigid shafts. Gas seals for both the casing and shaft are designed to maximize redundancy and with the greatest possible consideration to safety.

High Pressure Gas Re-injection

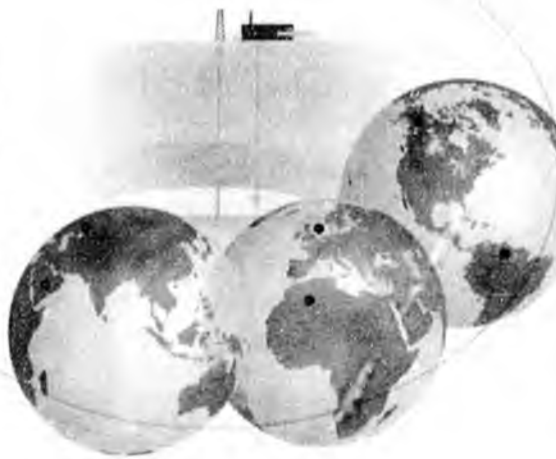
GE's Oil & Gas business is a world leader in compression of natural gas for high-pressure re-injection with over 30 years of experience in this field. The industry's first machine with a discharge pressure of 477 bar was installed by GE's Nuovo Pignone division in the early 1970s at the Hassi Messaoud Plant in Algeria. The innovative design approaches, the extensive testing capabilities and the high reliability demonstrated in all installations have positioned us as the leading manufacturer of compressors for this type of application. The innovation continues today with research and development aimed at designing compression trains with discharge pressures of 1000 bar and higher associated with high content of acid gas.

Over 200 high pressure compression trains with more than 350 compressor bodies have been produced by GE's Oil & Gas business in the last 30 years. About half of these train configurations are driven by GE MS5002 gas turbines and more than 50 have nominal discharge pressures greater than 500 bar. While heavy duty gas turbine drivers have generally been used for compression trains for onshore applications, the majority of our high pressure offshore installations use GE aeroderivative gas turbine drivers.

High-pressure re-injection compressor design is one of the most demanding challenges in the field of turbomachinery. For this reason GE invests continually in research and development efforts focused on producing advanced technology designs and new calculation codes to meet the ever increasing challenges of the industry.
Rotordynamics: The impact of high gas density on impellers and balancing drum seals can cause rotor stability problems potentially leading to subsynchronous vibration phenomena. Maximizing rotor stiffness and bearing damping together with the use of special seals are used to ensure safe lateral behavior in the most critical and challenging high pressure machines.
Rotating Stall: The low flows typical of high pressure applications together with the high gas densities make these machines particularly susceptible to rotating stall. The strong aerodynamic excitations associated with the phenomenon could severely limit the operation of the machine. In order to avoid the occurrence of potential rotating stall problems, pre-designed and tested stages are used. Extensive R&D has been conducted using both computational and experimental techniques to identify advanced solutions to achieving a broader operating range.
To this end, an optimized diffuser shape (pinch) and low solidity vaned diffusers have now been qualified, and compressor internals can be easily adjusted on the basis of test results.
Performance: The extreme pressure and density of the gas make the prediction of performance computationally challenging.
Equations of state have been validated, even in the presence of sour gas, through extensive laboratory programs at pressures up to 1000 bar. The extensive use of validated standard stages completely removes uncertainty in performance evaluation as verified by full load tests conducted at our facilities and site performance.
Shaft end sealing: Recently, dry gas seals (DGS) have replaced oil seals in re-injection applications. The increased reliability of dry gas seals allows differential dynamic pressures up to 425 bar. The use of DGS in high pressure applications is now a standard in compressor technology.
Casing Sealing System: The trend toward high sour gas applications has required major efforts in the design of machines for zero leakage to the environment. This objective has been successfully achieved through the introduction of

- new, more reliable gasket designs,
- new, patented gas leakage recovery system.

GE integrates its equipment (turbines, compressors, expanders, air coolers, valves, etc.) into optimized engineered solutions to meet Customer requirements. Islands are typical solutions for on-shore installations. In addition to the equipment, the GE offering includes system engineering (electrical, mechanical, instrumental), the supply of the necessary balance of plant items (gas separators and coolers, valves, piping, electrical and control systems), start-up/commissioning and project management.
Compression Islands are offered under single source and responsibility, i.e., guarantees and a warranty are given on the entire system instead of on the equipment only. Upon Customer request, the supply and responsibility can be extended to the entire station, adding all necessary auxiliary systems.

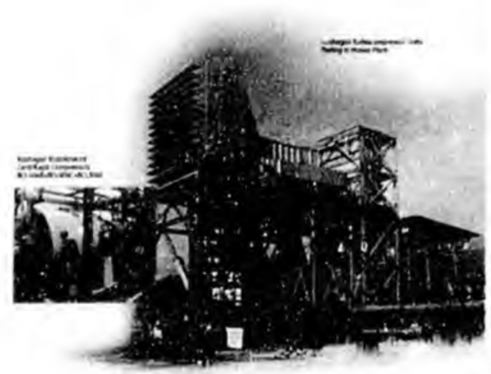


All antisurge control valves are designed, manufactured and tested in-house. A fully balanced design with low friction forces enables fast and smooth operation of these flow control elements. Multistage trims are designed to limit both noise levels and kinetic energy developed during throttling operations. Extensive R&D effort has been devoted to achieving high reliability and extremely low fugitive emission levels for all the operating conditions.

Pipe and Bend Air Cooled Heat Exchangers are manufactured by GE Oil & Gas in Vibo Valentia, Italy. Since the late 60s, we have manufactured more than 10,000 API 661 quality bundles from in-house designs developed to meet the demanding specifications of our Customers. We have the manufacturing experience, capabilities and specialized equipment needed for the production of bundles from special materials (incoloy, titanium, alloy steel, etc.) suitable for high pressure sour gas applications.

Between 1975 (North Sea) and 2005 (Kazakhstan) more than 40 turbocompressor units for re-injection applications with discharge pressures in excess of 200 bar were full load tested by GE's Oil & Gas business. The full load string tests in the outdoor test bed shown in the photos were carried out with all auxiliaries including lube and seal systems, control panels and fully instrumented process panels. The test arrangement must be as close as possible to the final configuration to reproduce mechanical and thermodynamic performance in the field. All of the critical features of the machine are fully verified including:

- Thermodynamic performance (pressure ratio, efficiency, surge limit, etc.)
- Rotordynamics, critical speed and verification of all potential excitation phenomena such as rotating stall
- Shaft end seal behavior and auxiliary systems
- Control system for the complete train
- Coolers



Testimony by the Honorable Walter J. Hickel
Legislative hearing on the state's finding
regarding the TransCanada gasline applic. .ion –
June 18, 2008 - 9 am - Howard Johnson Hotel, Anchorage

Thank you Mr. Chairman.

Let me begin with my bottom line.

The State of Alaska representing all of our people, the owners of the resources on the State lands at the North Slope should build the Alaska natural gas pipeline.

We should hire a pipeline company, perhaps TransCanada, and build it and own it. That's the only way we can keep control of this resource that is worth untold billions.

Anytime you yield control of a public asset to a private company, you have to be content to sit and wait. Because they are in control.

And if you yield control to foreign governments and their regulatory agencies, just move to the back of the bus.

Before I expand on that theme, I want to salute you, Mr. Chairman, and your colleagues for holding these hearings. The issue is how to achieve maximum benefit from North Slope natural gas resources.

That's your assignment under the Constitution. As citizens of our Owner State, all Alaskans also have the obligation to follow this issue and make their views known.

Billions upon billions of dollars are at stake.

We need to get Alaska gas to Alaskans…and to make that gas affordable we need to access the world's markets. That means an All-Alaska gasline to Valdez and LNG exports to the world.

Our neighbor nations on the Pacific Rim are ready to pay twice as much as Alberta or Chicago. This week Japan is paying over $20 per mcf. They are paying $11.69 in Alberta.

The last time I saw you, Mr. Chairman, was in Beijing where we met with leaders in Chinese oil and gas. That was an important trip. We must understand the world. And we need vision. Vision is the key to a pioneering country. And to me the vision is clear, and it is based on our reality.

For 50 years of statehood, Alaska's political ties have been with America…and thank God for that……but out economic ties have been with Asia.

We offered our timber, coal, and LNG to the South 48, but we couldn't get them past Seattle. So we made friends and contacts in Japan and Korea, and we built our young economy based on those relationships. In 1969, we pioneered the first LNG shipments to Japan from anywhere...shipments that continue from Kenai today.

Wake up, America! It's a world economy. Check the labels on your T shirt and the names on your TV and automobile. Chances are they weren't made in America.

Our national economy, that means our standard of living, depends on our productivity and our ability to compete. We won't survive by just playing the stock market. There is no wealth without production.

I commend Governor Sarah Palin for introducing a wide-open, transparent process on the gasline issue. For years, the North Slope producers claimed that Alaska natural gas was not economic. They said there was no market. But AGIA produced 5 eager applicants and the producers changed their tune. They cobbled together yet another public relations campaign about a gasline project that I promise you will never be built.

We've seen this before....over and over. And they still bad mouth LNG.

If LNG is so bad, why are they so heavily involved? ConocoPhillips has invested $60 billion in the largest LNG liquefaction plant in the world in Qatar. BP has an LNG project in Tangguh, Indonesia. And Exxon has a new project in Papua/New Guinea. And that's only part of the story.

Ladies and gentlemen, they don't oppose LNG. They oppose Alaska LNG. Because our LNG competes with their LNG.

And the truth is LNG is changing the world. You can't build a pipeline to Australia, Japan, India or China.

It's no secret that I am opposed to giving an exclusive license to TransCanada. The public thinks that they plan to ship North Slope gas to America. But their goal, and they don't deny it, is to use most of our gas to heat the Alberta tar sands to create synthetic oil.

And they face obstacles and delays beyond our control. And the key word is "control."

They admit that the McKenzie River pipeline, mired in problems, will go <u>ahead</u> of an Alaska gasline. More delay.

The Canadian Supreme Court has ruled, and rightly so, that the Canadian government must "consult and accommodate" even those First Nations that have not resolved their land claims when it comes to issues, such as a pipeline, that impact their traditional territory. More delay.

TransCanada cannot build a 4.5 billion cubic foot per day pipeline without gas from the producers. More delay.

And producer gas carries the bombshell of demands for "fiscal certainty." And you all know what that means.

What's more, without even so much as a mention, TransCanada plans to export millions of barrels of our valuable North Slope gas liquids to Alberta. Those gas liquids should stay in Alaska. Billions of dollars of state revenue and hundreds of value-added jobs for Alaskans for decades rest on this one issue.

There is no reason to hold up the All-Alaska LNG line while we wait for TransCanada to sort out their problems in Canada.

Last week Commissioner Pat Galvin and others from the Palin gasline team informed me that TransCanada is prepared to hold a "simultaneous Open Season." This means that those who control North Slope gas will be invited to reserve space at the same time in either a Canadian pipeline. Or in an All-Alaska pipeline to Valdez.

If the market wants to ship LNG first, TransCanada will build the All-Alaska line first. They didn't mention, by the way, to which route the state will dedicate its gas.

But I was somewhat encouraged by what the Commissioner said, only to learn this week that TransCanada has refused to clarify any such commitment to hold a "simultaneous Open Season."

This illustrates and underlines my message today. If TransCanada is granted a license by the state, the State will lose control.

Alaska appears to be caught between the producers on one side and a bad deal on the other. So what do we do?

Fortunately, there is another option.

Ever since the people of Alaska voted six years ago in favor of an All-Alaska gasline, they have been waiting. And now, with a crisis in Alaska fuel and energy costs, they are getting frustrated. How much longer can they wait?

In Fairbanks last week, you heard loud and clear that we need Alaska's gas for Alaska's people now! And the crisis in rural Alaska is worse. But it's no good to have Alaska gas if its costs are sky high. The way to lower the price is through volume.

We must move our gas in a pipeline big enough to serve large markets. The best way to do that is with an All-Alaska gasline to Valdez.

And the state should own it.

Without the Canadian government or FERC making us jump through a thousand hoops, in 5 to 6 years we can get gas to Alaskans. And the entire project can be completed soon thereafter.

If you will hold a hearing on how the state can build and own our own gasline, please invite me back. It is not rocket science.

So I urge you to deny the TransCanada plan.

If you don't, we will lose control of our gas, and Alaska will be locked into the market at the end of that pipeline in Alberta.

As we meet here, there is a rush going on for new gas plays in Pennsylvania, West Virginia, Texas and the Rockies. Alaska gas in the South 48 will face severe competition in a few years time.

That means that our gas, instead of serving America as Gov. Palin sincerely hopes it will, will stay in Alberta and be used to heat the tar sands.

So let's take the faster, better and more beneficial alternative.

Let's build and own the Alaska gasline ourselves.

With LNG, we will serve the world. We will move our gas to the highest and best markets, and we will keep the jobs here at home.

That's "maximum benefit" for our people. And that's your responsibility. Your opportunity. And the mission of this generation.

Thank you.