Fairbanks to Anchorage Spur Report - Updated Analysis

June 2004

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Overview

- ***Project description***
- Earlier findings / conclusions
- Current analysis efforts
- Updated findings
- Implications of ownership / timing
- Work in progress to finalize report

Project overview

- Analysis of requirement for and feasibility of constructing a spur line from the main Alaska Natural Gas Pipeline to the Anchorage region
- Analysis considered:
  - Supply/demand projections for Anchorage region
  - Pipeline construction capital costs
  - Rate methodology for transportation on Alaska Natural Gas Pipeline and Spur pipeline
  - Price projections at AECO, North Slope, Anchorage region
- Analysis period was defined as 2005 to 2025

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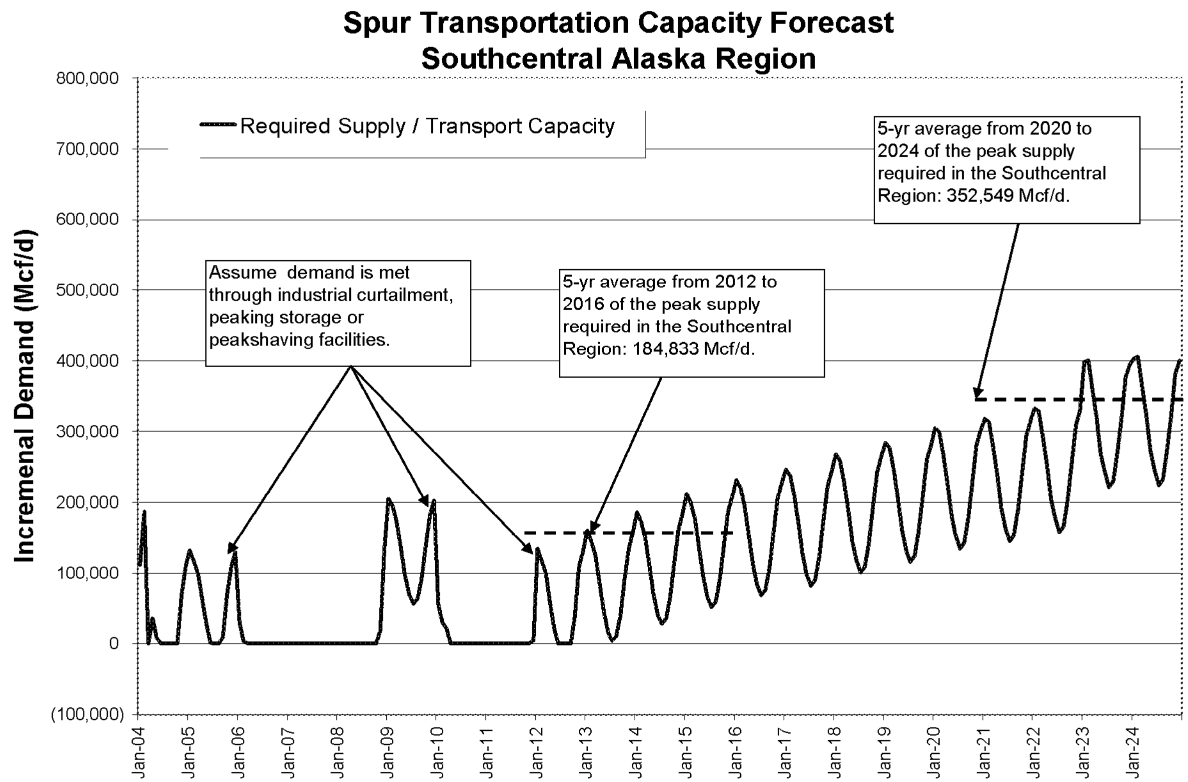
Earlier Draft Findings – Need for incremental supply by 2004

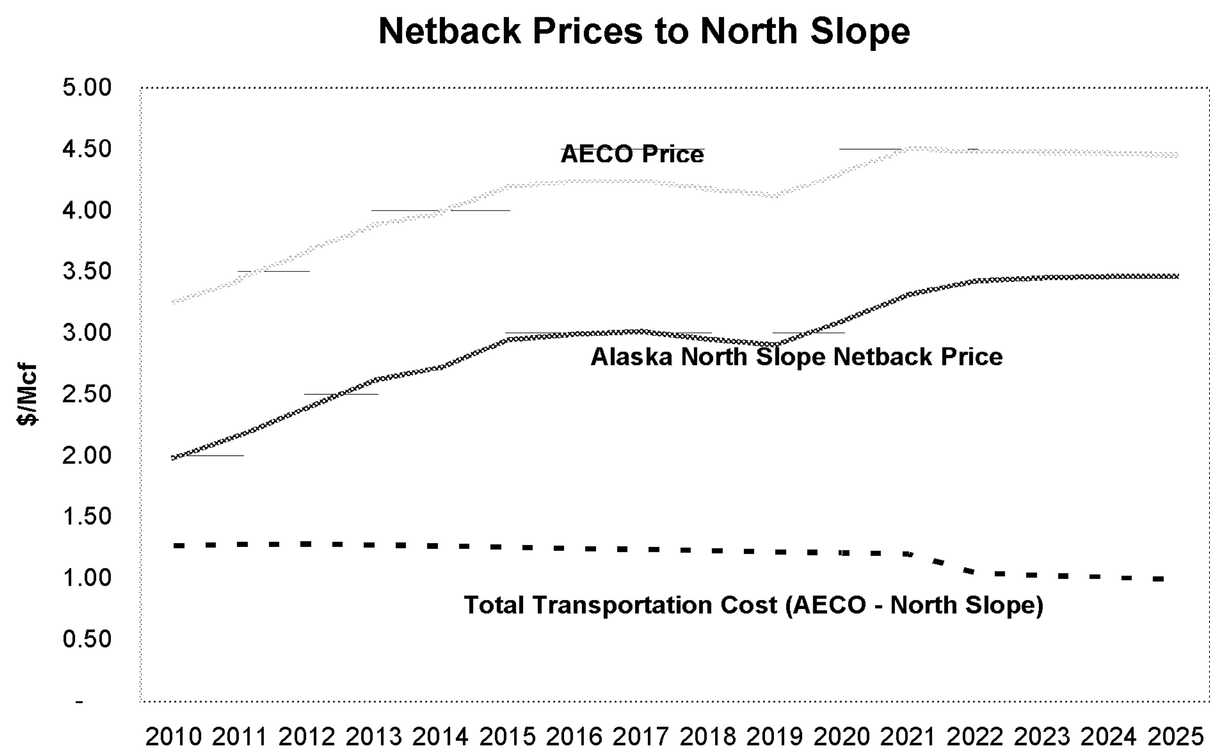
- Incremental supply, or curtailment of existing load is required as early as 2004 to meet existing residential, commercial, electric utility and industrial demand in the South-central region of Alaska with average weather.
- Supplies are required into the region during summer and winter periods on a consistent basis starting in 2013



Earlier Draft Findings – Netback prices to North Slope range from $1.99 to $3.46 during analysis period

- Rate design models were developed to determine the netback cost of gas.

- North Slope netback was determined by removing the two portions of transportation charges from the AECO Hub gas price forecast:
  - Canadian rate ($0.57 USD/Mcf, including $0.15/Mcf for transportation on NOVA system)
  - Alaskan rate ($0.50 USD/Mcf)
  - 2.5% fuel cost



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Earlier Draft Findings – Transportation rates for Spur Project expected to range from $0.92 to $1.07/Mcf

- A zone-based transportation rate was applied from the North Slope to the Spur at Fairbanks and on the Spur from Fairbanks to the Anchorage area
- Various pipeline diameters (and therefore varying capital costs) were selected and two rate methodologies were applied – a rolled-in Spur rate and an incremental Spur rate
- Incremental rate is expected to be applicable

	30" Spur	24" Spur *Case #1 - 0.350 Bcf/d capacity*	24" Spur *Case #2 - 0.310 Bcf/d capacity*	16" Spur
Capacity (Bcf)	0.350	0.350	0.310	0.110
Incremental Rates				
Zone 1 Rate	$ 0.357	$ 0.357	$ 0.357	$ 0.357
Spur Rate	$ 0.715	$ 0.567	$ 0.644	$ 1.451
Total	$ 1.072	$ 0.924	$ 1.001	$ 1.808
Roll-in Rates				
Zone 1 Rate	$ 0.379	$ 0.372	$ 0.375	$ 0.375
Spur Rate	$ 0.255	$ 0.251	$ 0.252	$ 0.249
Total	$ 0.634	$ 0.623	$ 0.626	$ 0.623

Earlier Draft Findings – Delivered cost of gas into the Anchorage area is expected to be comparable to alternatives

- Delivered cost of gas into Anchorage area based on North Slope price and cost of transportation on Alaska Natural Gas Pipeline and the Spur is $3.54 to $3.69/Mcf in 2013, the first year during which supplies are needed for summer and winter periods into the region

- This delivered cost of gas to the Anchorage region is less than ENSTAR's current gas supply agreement with Unocal that is pegged to Henry Hub prices

- Although a more detailed review is needed, the delivered cost is also expected to be less than or competitive with other alternatives for gas delivered into the Anchorage region going forward

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- Project description
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- ***Current analysis efforts:***
  - ***Price assumptions***
  - ***Demand assumptions:***
    - ***LNG market analysis - Marathon/ConocoPhillips LNG***
    - ***Agrium***
    - ***LDC load profile & supply assets***
  - ***Supply assumptions***
  - ***Updated ANGP & Spur rates***
- Updated findings
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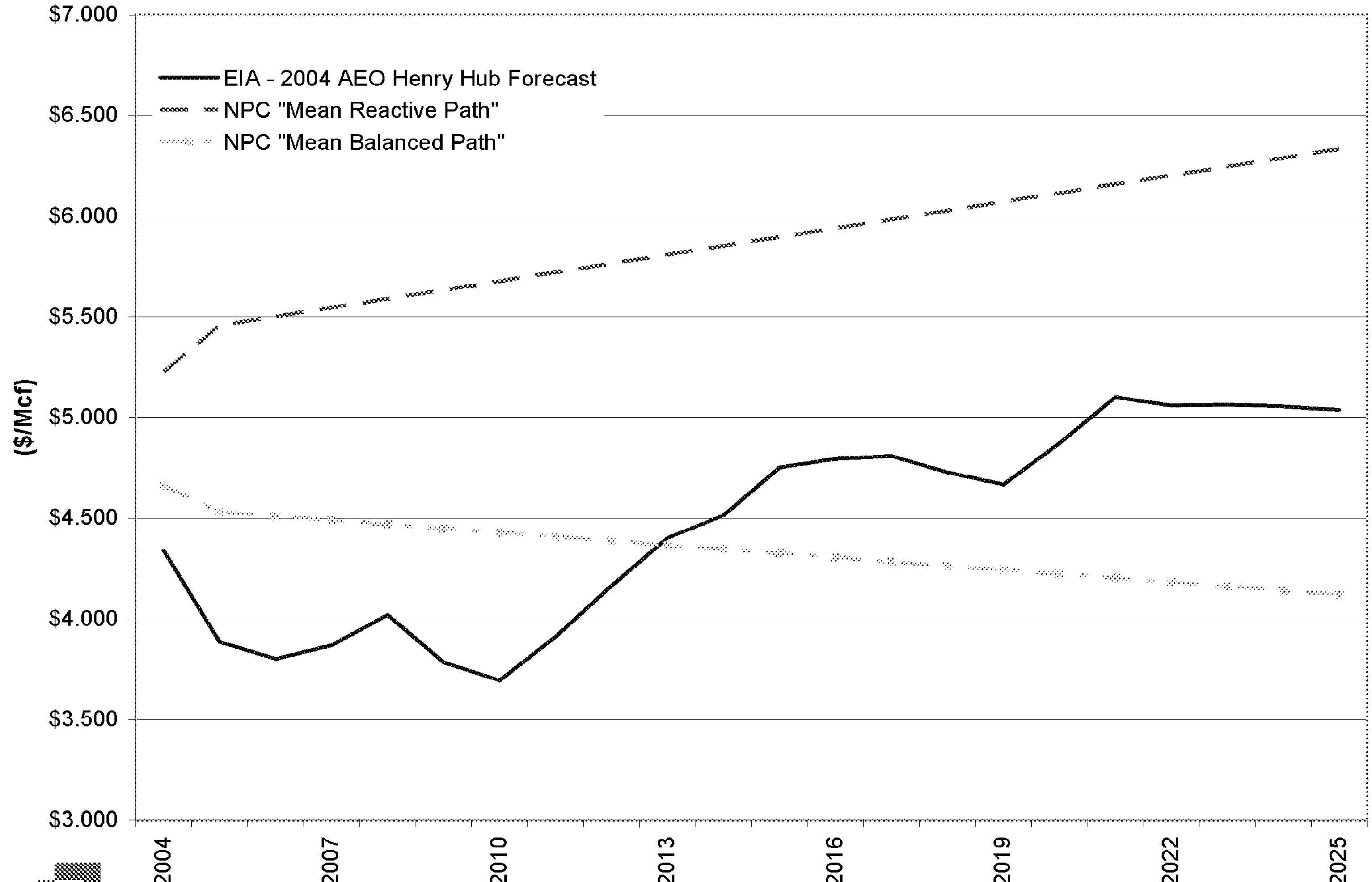
Henry Hub price assumptions



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LNG market analysis – Most likely future scenarios for Marathon/ConocoPhillips LNG facility

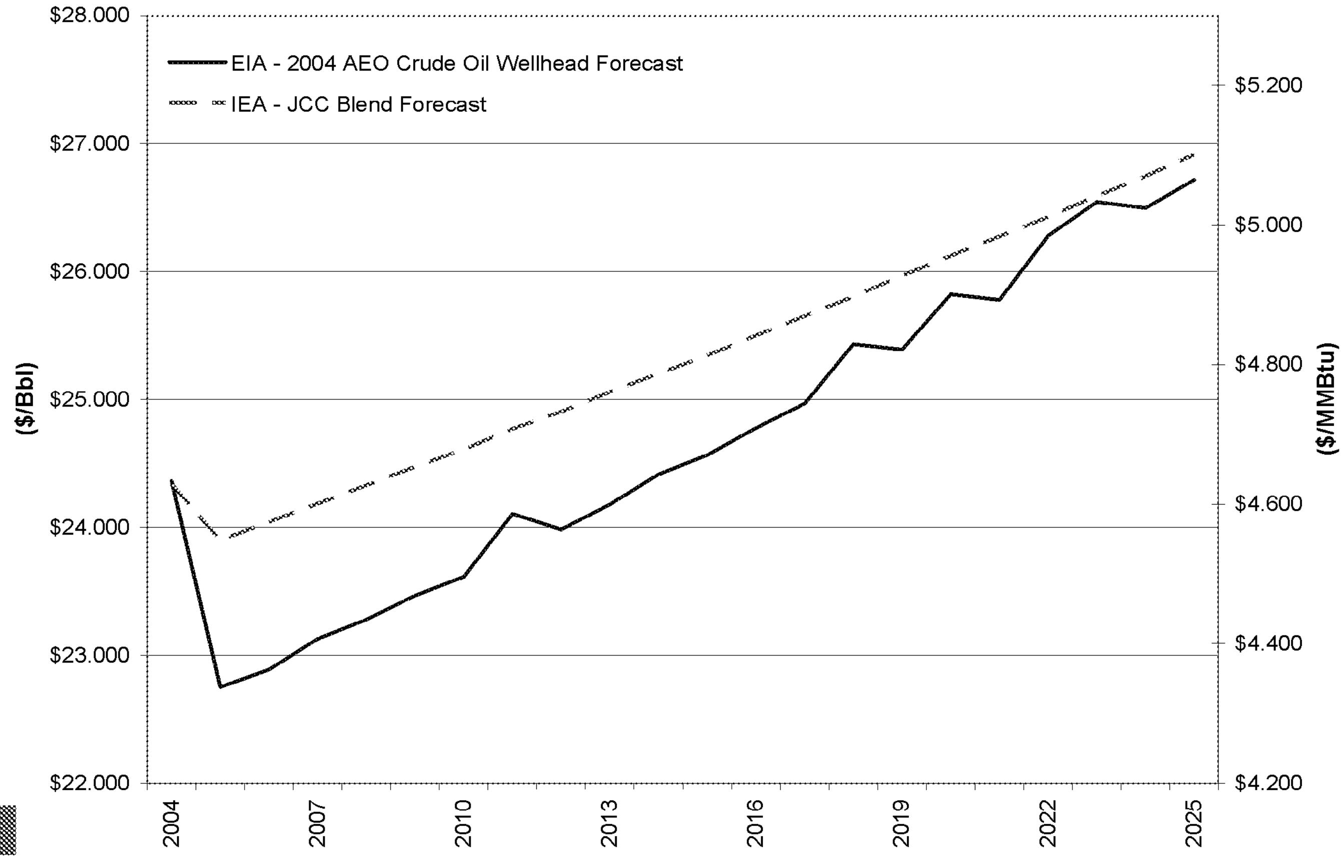
- Extension of current Japanese contract where LNG prices are tied to JCC:
  - Projections of JCC and hence delivered LNG price
  - Low likelihood of contract renewal considering changes in Pacific Basin LNG market – increased competition, less desire for long-term contracts

- Competing in open market in Asia-Pacific region for contracts:
  - Projected oversupply in region – exaggerated if developing markets of China and India are slow to emerge
  - Larger trains coming online in Australia and Indonesia – already closer to markets
  - Pacific Basin shift towards a more openly competitive market – expected to drive LNG prices to $3/Mcf, which is below that tied to JCC

- Establish new contracts with possible Western U.S. LNG import terminals:
  - Timing and likelihood of completion of West Coast import terminals
  - Shipping issues

Updated LNG Analysis – JCC price projections

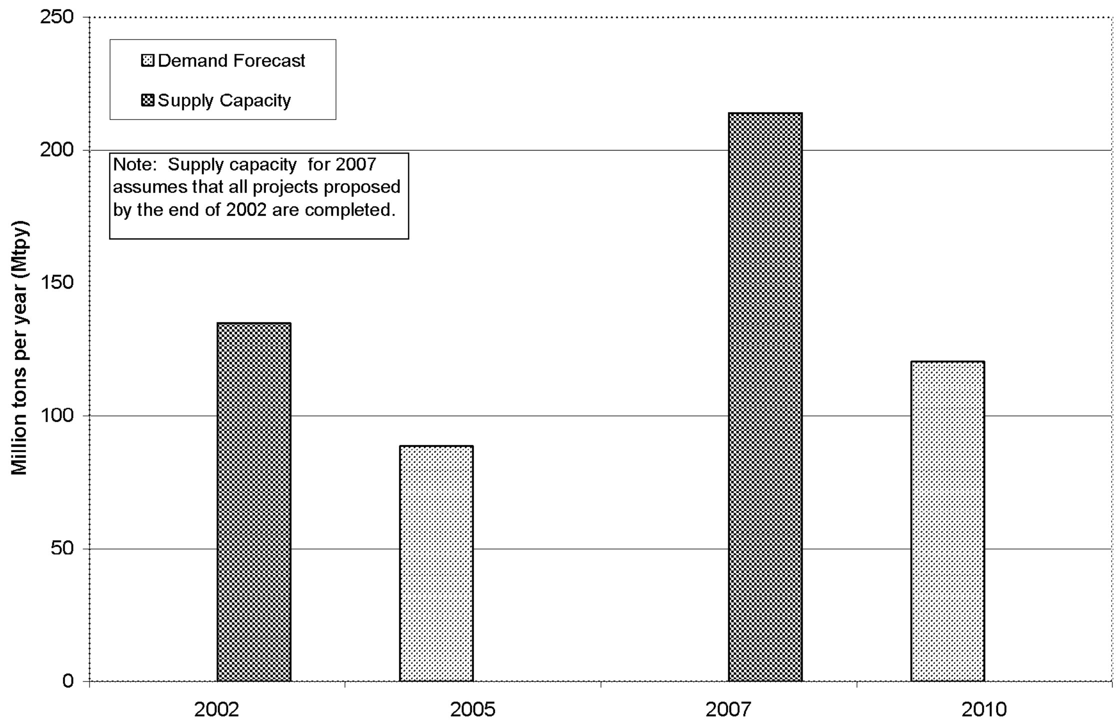
- The projected rise in JCC prices over the next 20 years may encourage Pacific Basin importers to move away from basing LNG delivered prices on the JCC



Updated LNG Analysis – Oversupply in region likely to keep LNG prices low

- Petroleum News' May 2, 2004 – "China and India…are signing up for future LNG deliveries at $3 per thousand cubic feet or less, at least $1 under what Japan is paying."

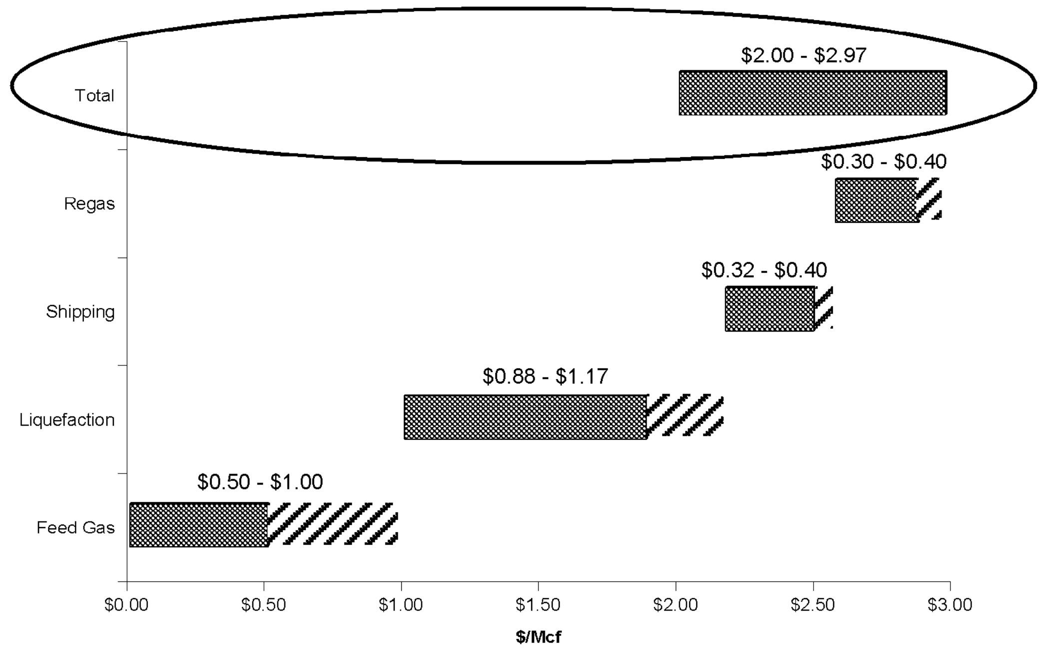
Demand Growth, 2005-2010 vs. Supply Growth, 2002-2007



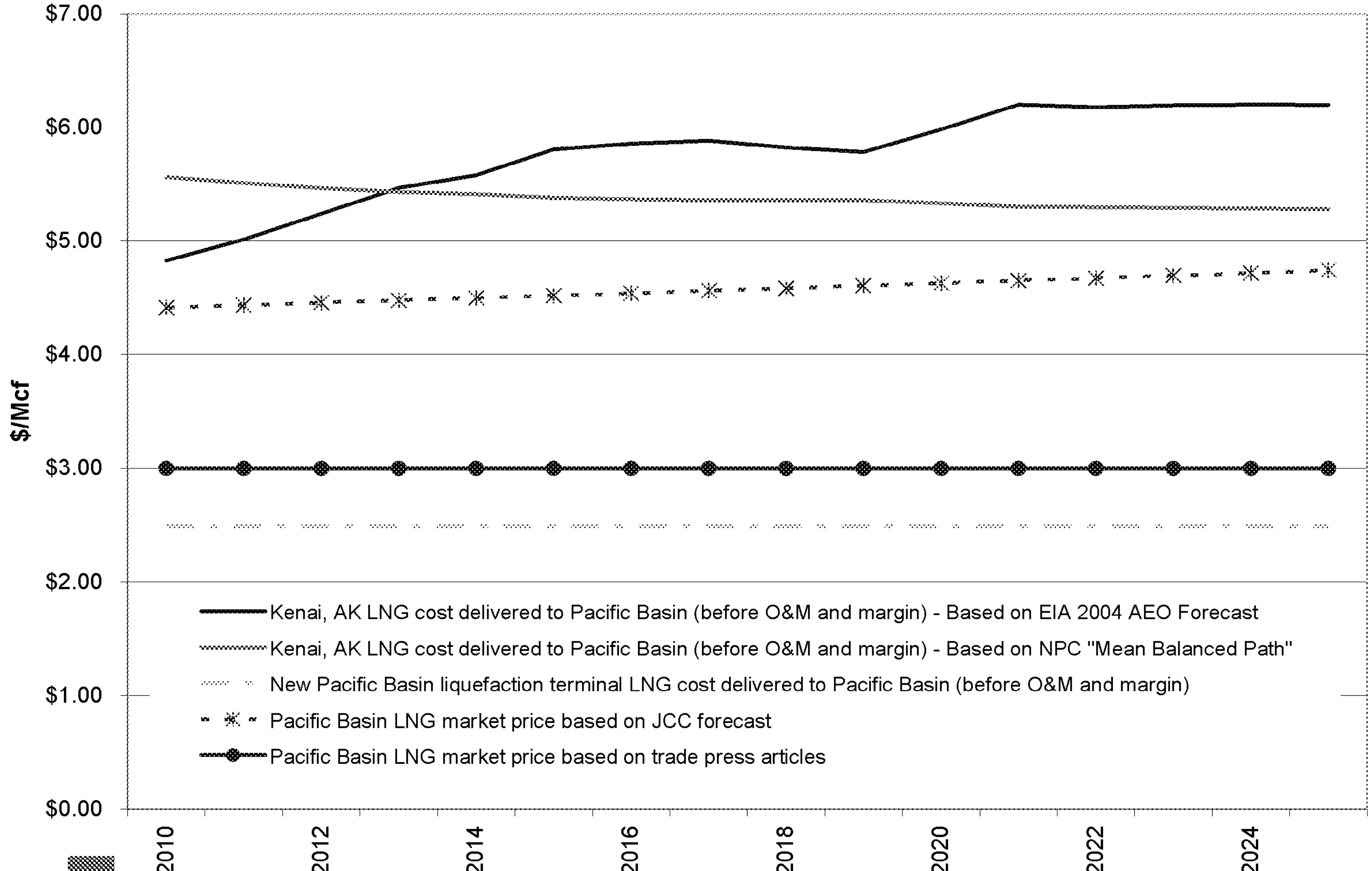
Sources: International Petroleum Encyclopedia 2002, pp. 188 and Thackeray, Fred *Surplus supply, fierce competition*, in Petroleum Economist (November 2002)

Updated LNG Analysis – New Pacific Basin LNG export terminal value chain economics

- The value chain for the new LNG export terminals in the Pacific Basin have changed due to
  - Scale efficiencies
  - proximity to market
  - vertical integration of supply chain



Updated LNG Analysis – Estimated LNG supply and demand prices in the Pacific Basin region



Note – draft, subject to revision

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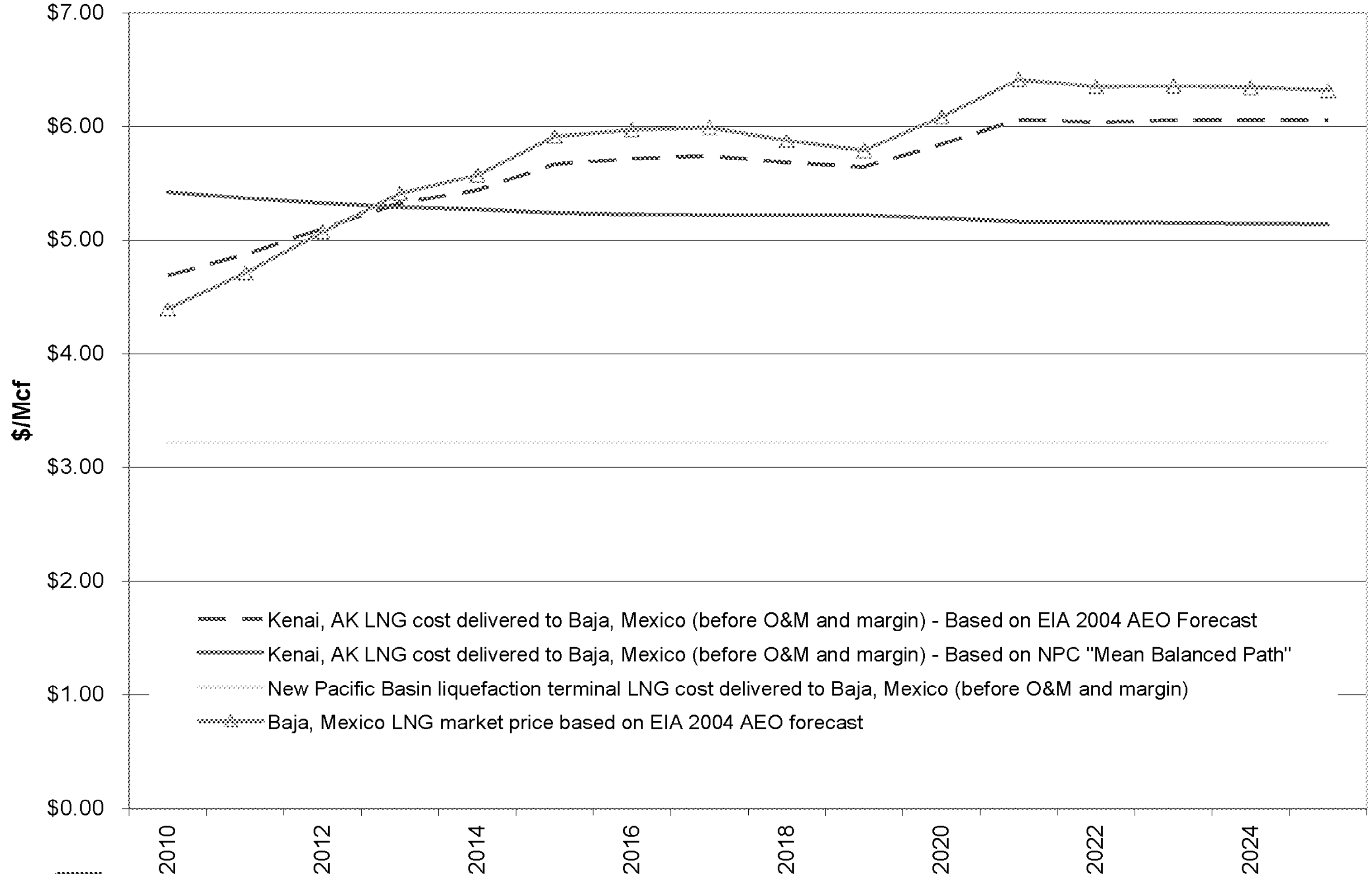
Updated LNG Analysis – Estimated LNG supply and demand prices in the West Coast U.S. / Baja Mexico region



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Agrium - Summary of worldwide nitrogen fertilizer manufacturing

- Agrium's Kenai facility manufactures anhydrous ammonia and urea for export to Pacific Rim markets
- Natural gas can represent 70% to 90% of the cash costs associated with manufacturing nitrogen based fertilizers
- International nitrogen fertilizer production has traditionally relied upon stranded gas reserves:
  - Agrium competes against plants in FSU, South America, Trinidad & Pacific Rim that have gas costs of $0.60 to $1.30/Mcf
- U.S. is a net importer of nitrogen fertilizer
- High gas prices in the U.S. has forced closures and curtailment of nitrogen fertilizer manufacturing facilities:
  - 9 U.S. ammonia plants closed between 1999 and 2002 - 13% of U.S. capacity
  - 5 U.S. urea plants closed between 1999 and 2002 – 7% of U.S. capacity

Agrium – Current status

Current status:

- Q4 2003, Agrium wrote down $140 million of Kenai facility carrying cost due to uncertainty in utilization and access to gas supply
- Dispute with Unocal on Agrium facility gas supply contract (current supply price approx. $1.40/Mcf)
- Utilization rates in 2003 – 71%
- Projected utilization rate in 2004 and 2005 – 50%

Future issues:

- Resolving Unocal dispute
- Obtaining additional gas supply
- "Incentives" to continue operations
- Worldwide nitrogen fertilizer prices
- Potential to obtain new markets – U.S. (would have similar manufacturing cost position as Agrium's Alberta facility)

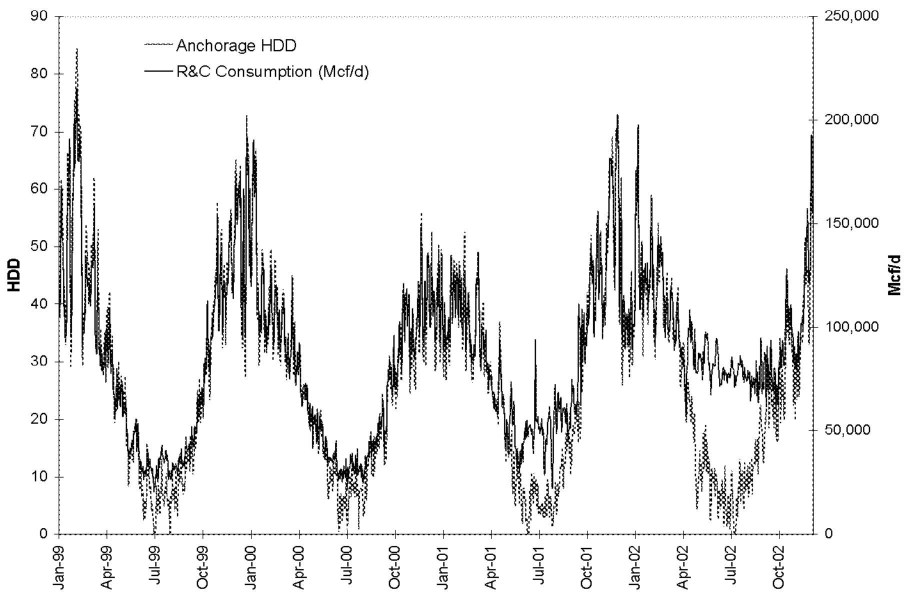
Study Implications:

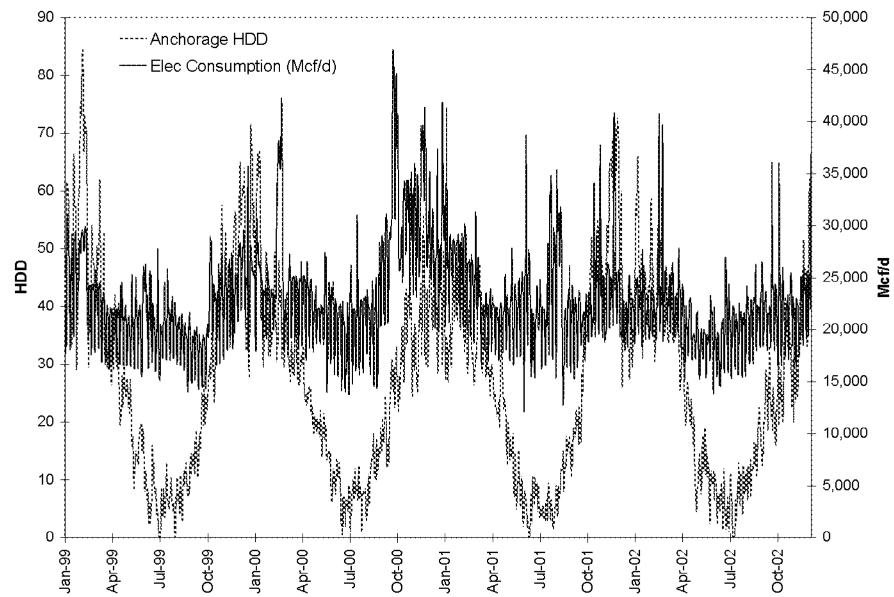
- Detailed study / analysis required to fully understand long term viability of Kenai facility
- Many future scenarios possible
- Not unrealistic to expect plant to continue operating (higher probability at a reduced rate)

Demand assumptions – Analysis of demand based on weather

- Performed regression analysis on 1999 – 2002 ***daily*** Enstar demand data and ***daily*** Anchorage HDD data
- R&C demand demonstrated a significant relationship to Anchorage HDD
- Electricity demand did not have a statistically significant direct relationship to Anchorage HDD, but the demand exhibited different seasonal averages
- Industrial demand assumed to be unrelated to weather due to lack of actual industrial consumption data

Demand assumptions – Weather related components of demand (R&C and Electric demand)





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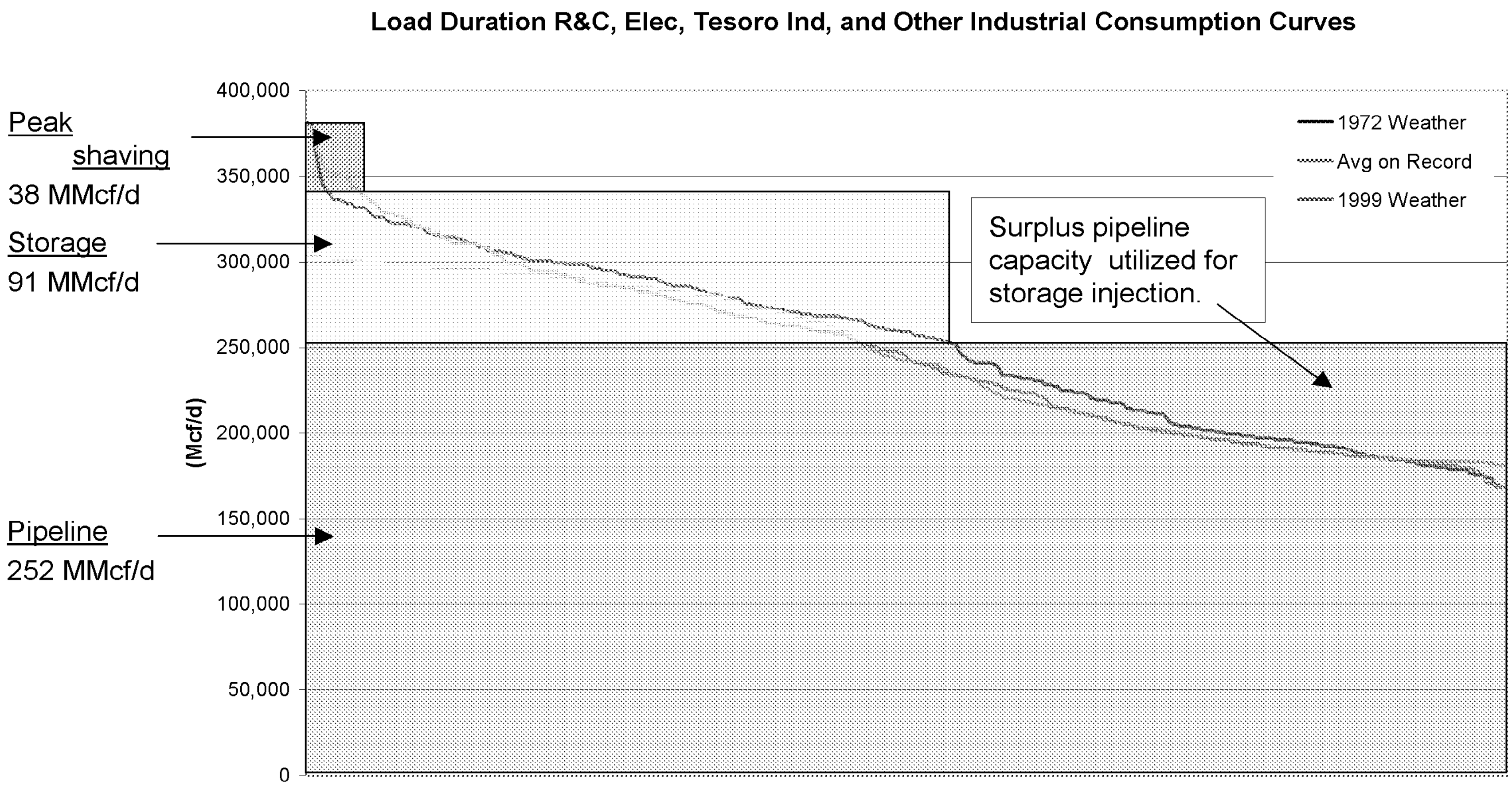
LDC load profile & supply assets

- Load duration curves constructed for three scenarios – average weather, 1972 weather (2nd coldest on record), and 1999 weather (coldest in last 20 years) – based on regression analysis
- Applied "typical" LDC supply portfolio ratios of 50/40/10% – pipeline, storage, and peak shaving, respectively – to the load duration curves
  - Because of the shape of the curves, pipeline capacity not enough to fill storage
  - Therefore new LDC portfolio had to be designed for these type of load duration curves
  - Assumed a LDC supply portfolio of 66/24/10%

LDC load profile & supply assets (all South Central Alaska demand except Agrium & LNG facility)



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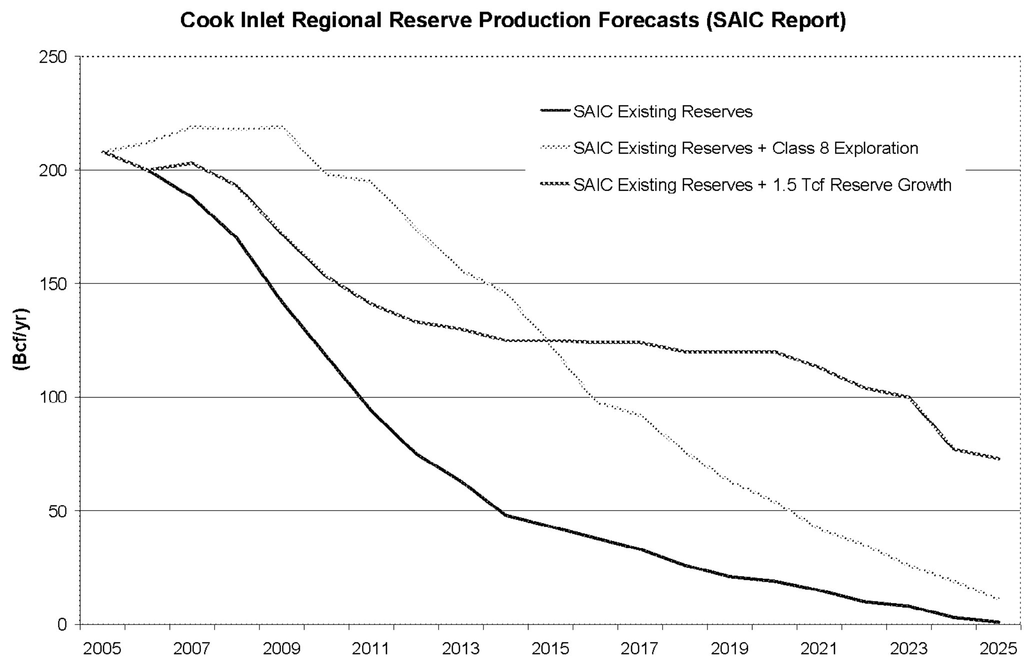
Supply assumptions – based on SAIC report

- SAIC reports various production forecasts for the Cook Inlet region
- LEG chose three production forecasts for the pipeline spur analysis
  - Base Supply (existing reserves in Cook Inlet only)
  - Base Supply + 1.5 Tcf reserve growth
  - Base Supply + 1.5 Tcf reserve growth + Class 8 exploration



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ANGP & Spur pipeline rates

	24" *2014* *.3 Bcf/d*	20" *2019* *.2 Bcf/d*
Spur Capacity (Bcf)	0.300	0.200
Incremental Rates		
Zone 1 Rate	$ 0.359	$ 0.359
Spur Rate	$ 0.952	$ 1.365
Total	$ 1.311	$ 1.724
Roll-in Rates		
Zone 1 Rate	$ 0.387	$ 0.389
Spur Rate	$ 0.259	$ 0.258
Total	$ 0.646	$ 0.647

	ANGP
Capacity (Bcf)	4.500
Alaska Rate - Levelized	
Rate	$ 0.500
Fuel (est.)	$ 0.030
Total	$ 0.530
Canadian Rate	
Rate (Year 1)	$ 0.560
Fuel	$ 0.030
Total	$ 0.590
NOVA rate to AECO	$ 0.150
Total (with fuel) to AECO	$ 1.270

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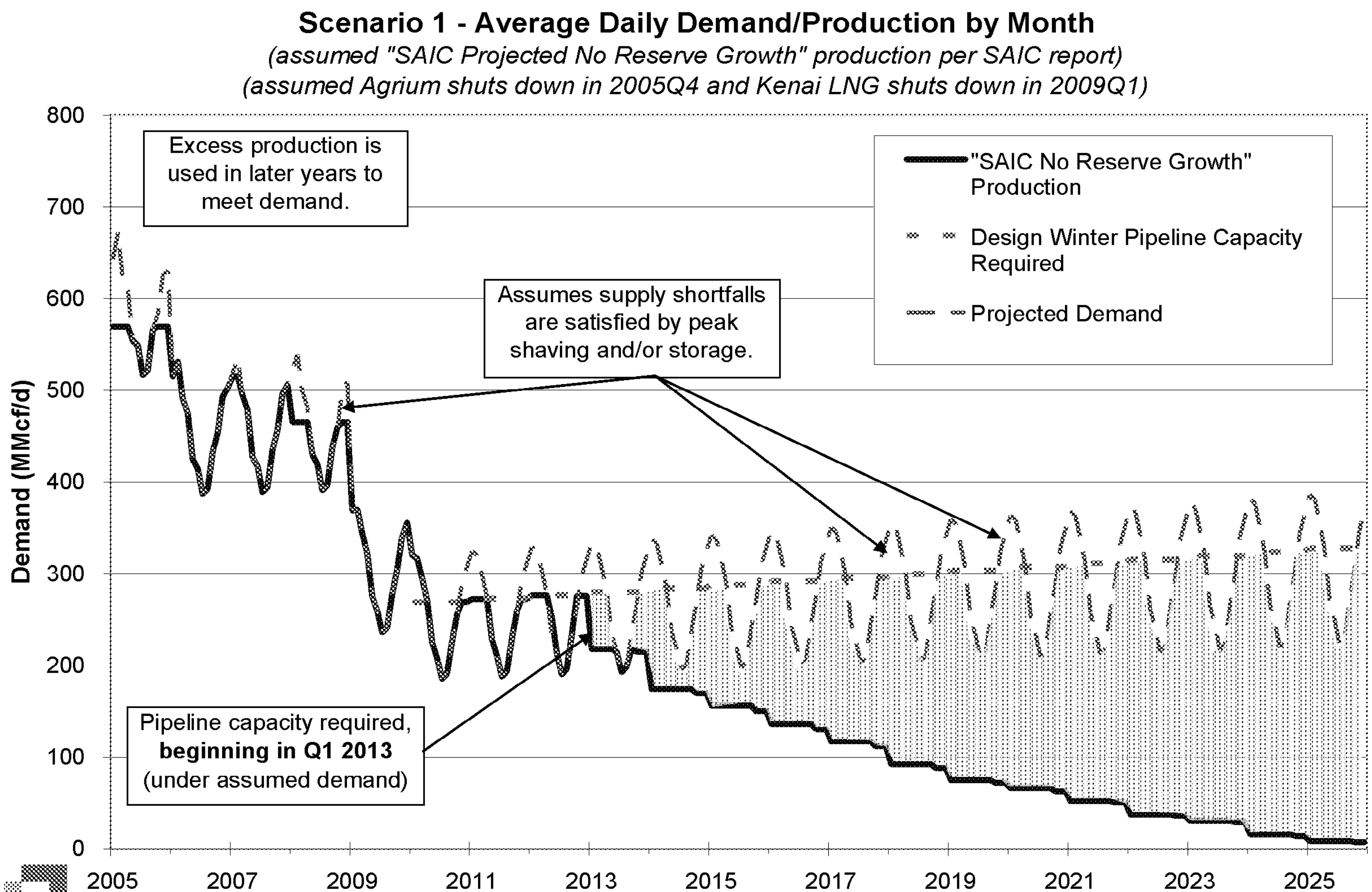
Scenario 1 results - Pipeline supply required in 2013



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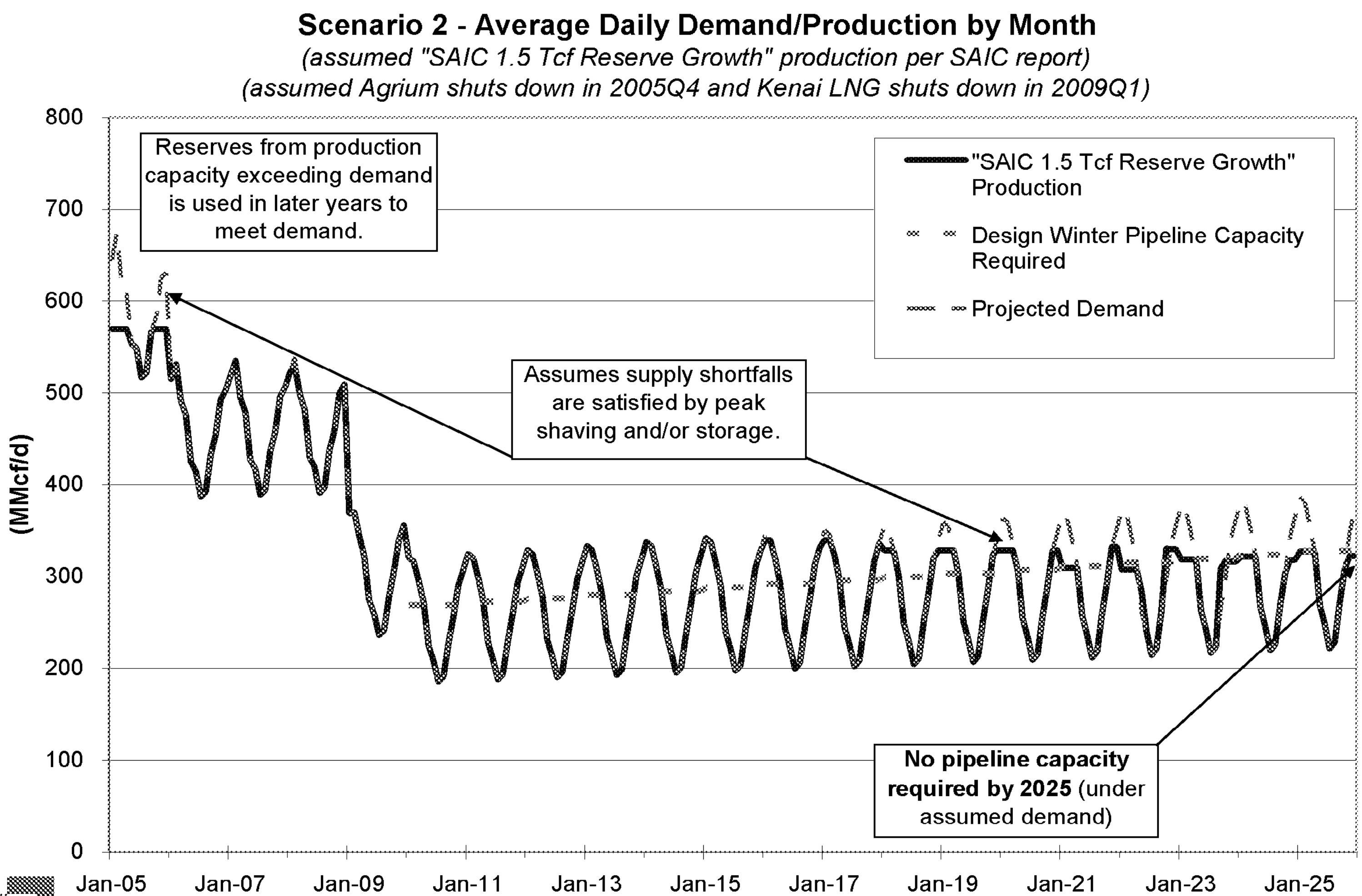
Scenario 2 results – Production sufficient to meet demand through 2025



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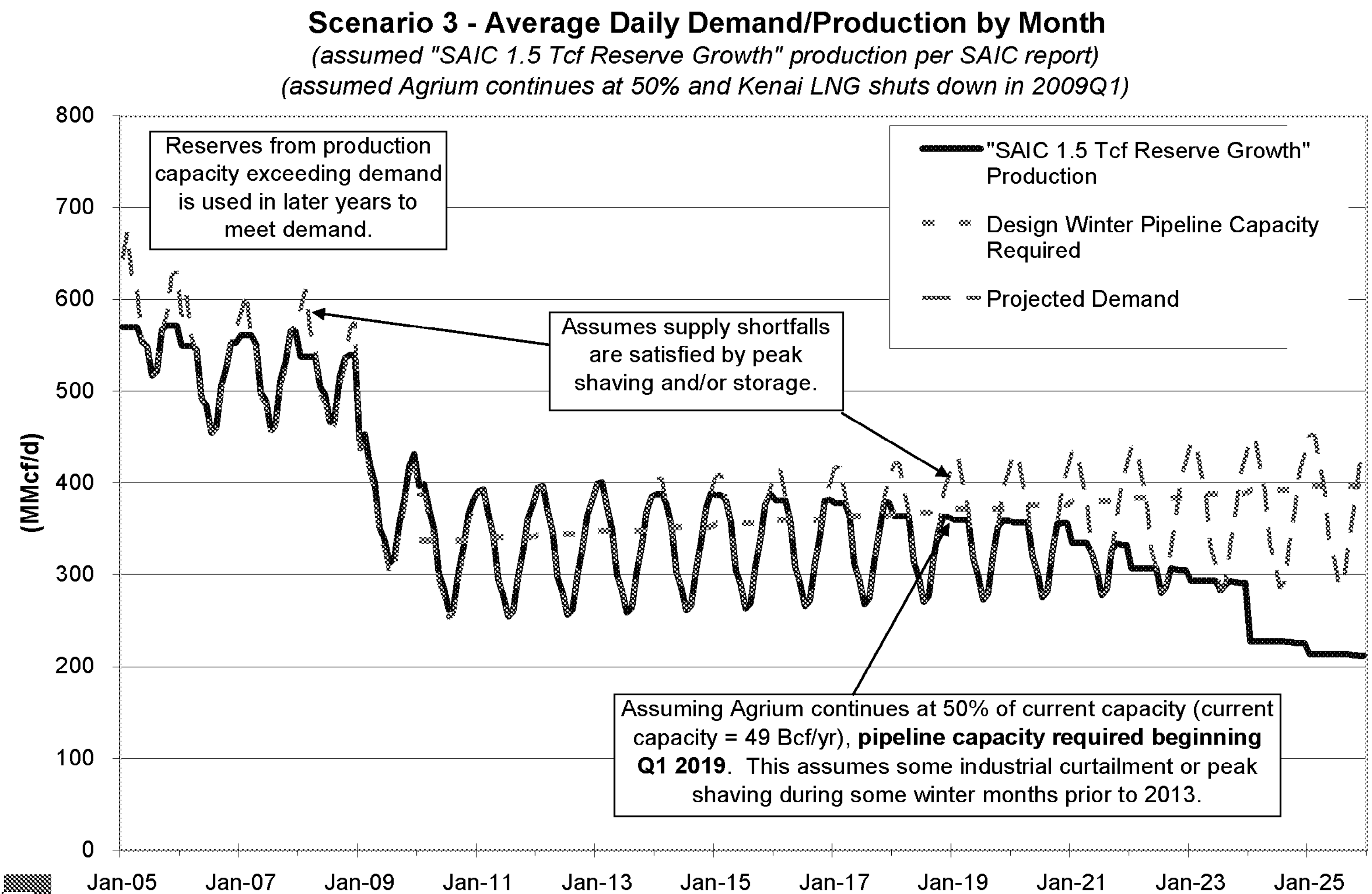
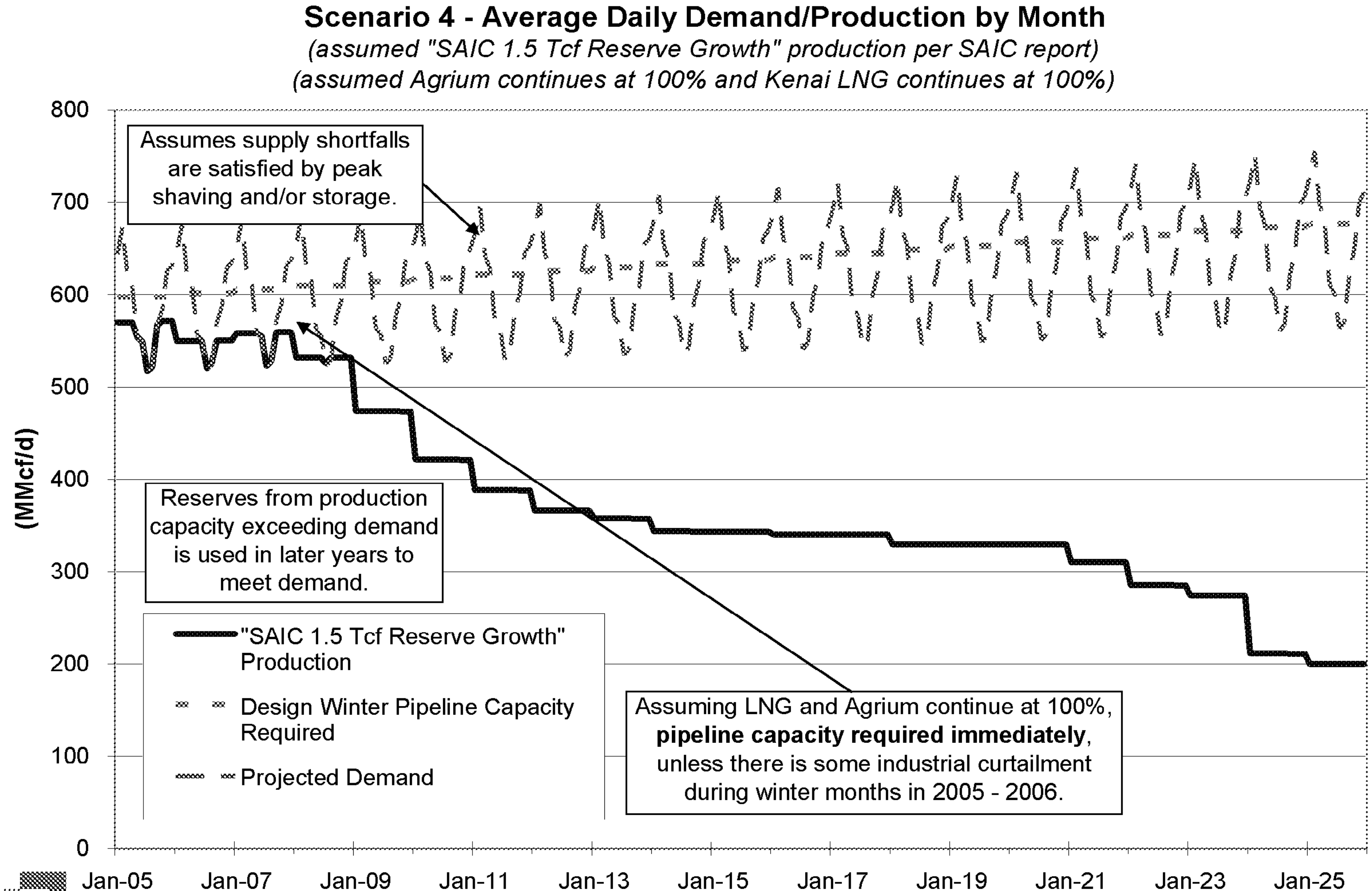
Scenario 3 results – Pipeline supplies required in 2019



Scenario 4 results – Pipeline supply required immediately (2005)



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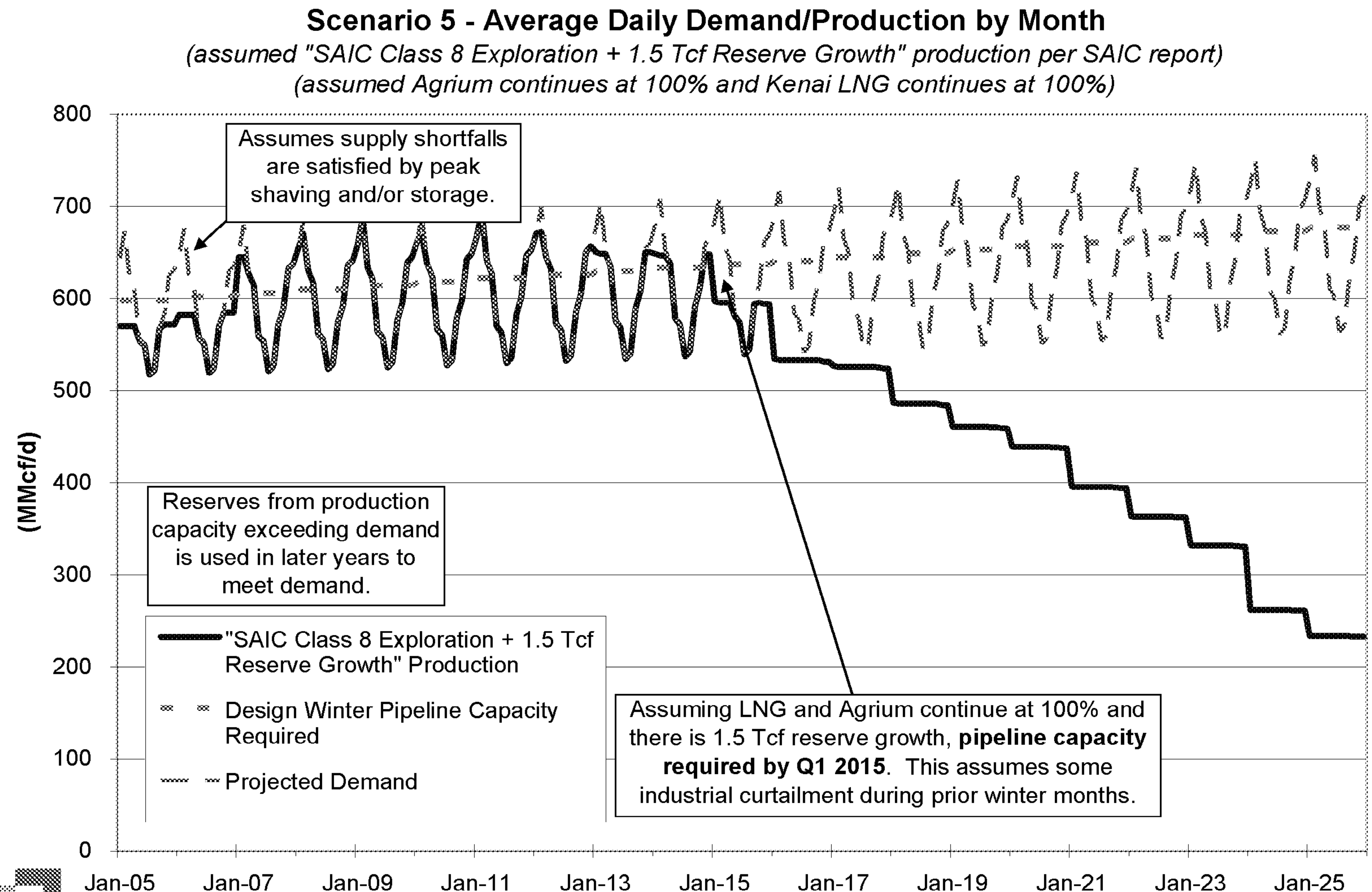
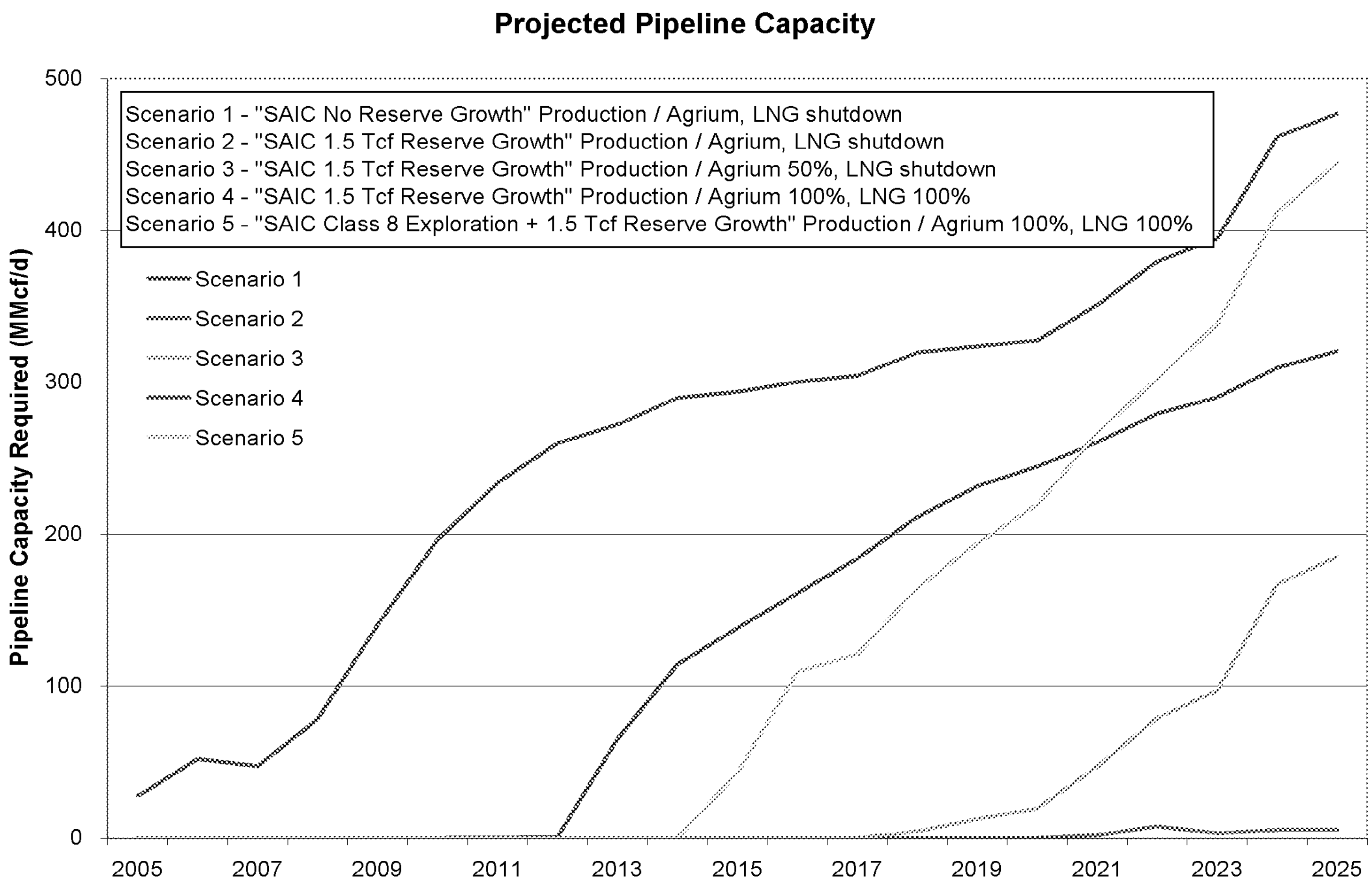
Scenario 5 results – Pipeline supplies required in 2015



Summary of projected pipeline capacity



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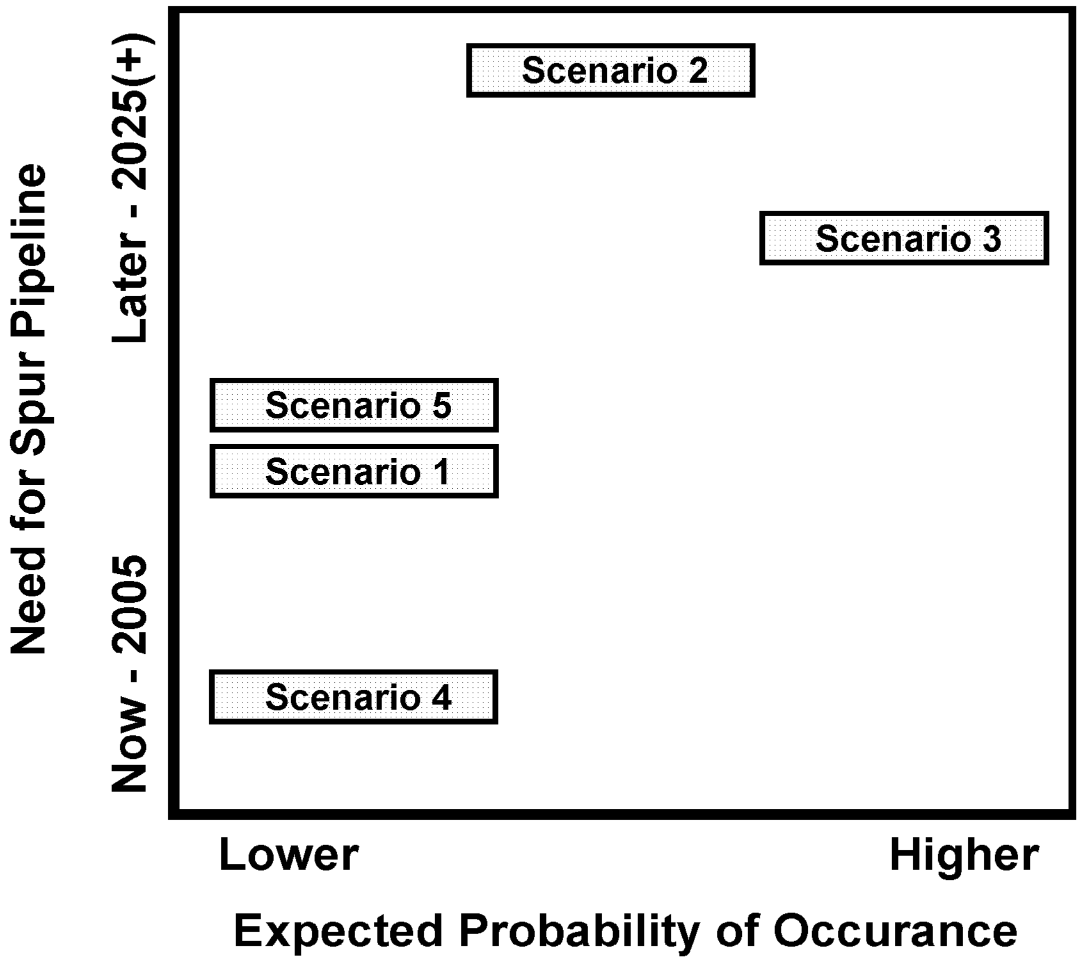
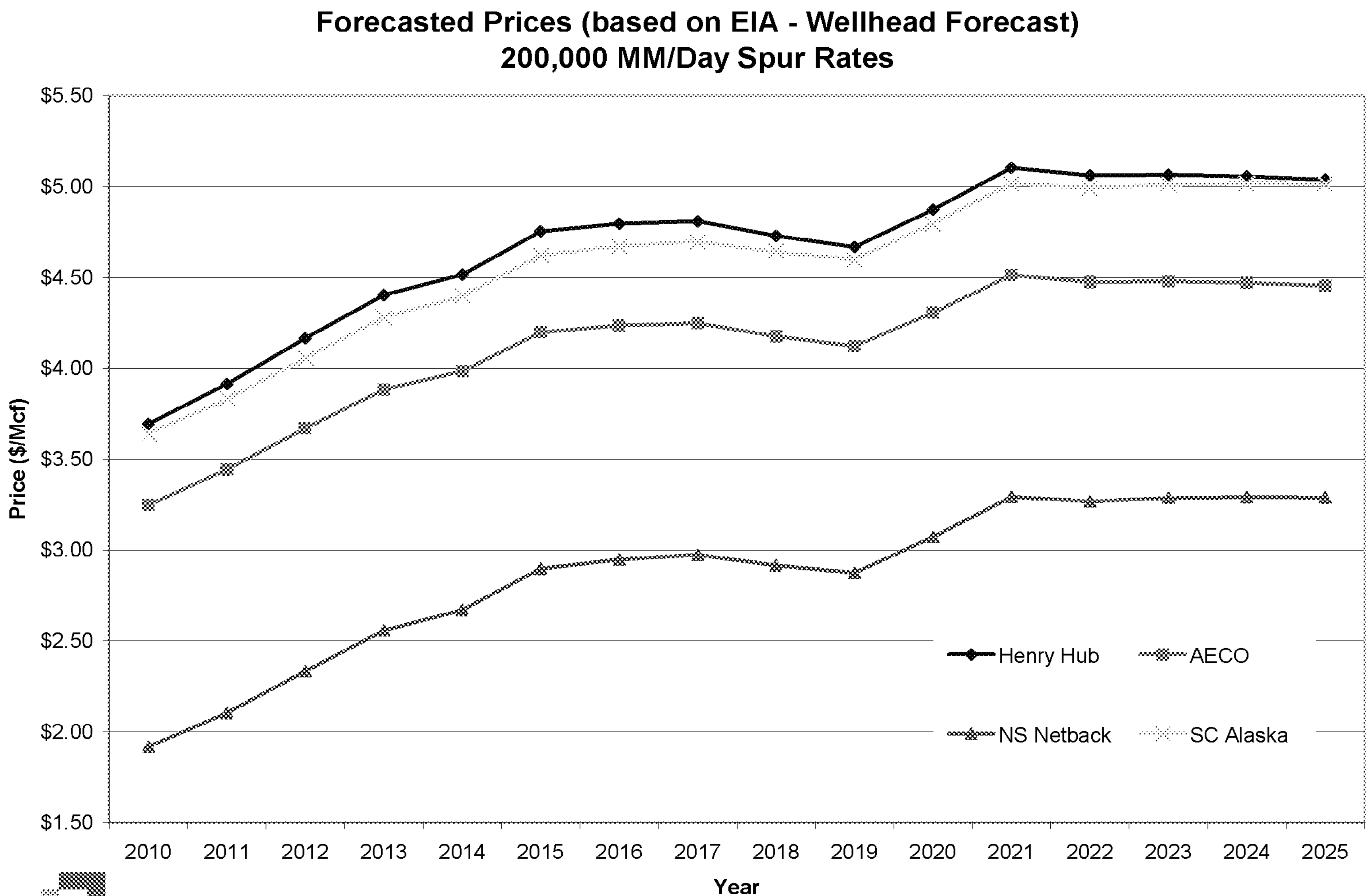
All scenarios do not have an equal chance of occurrence. LEG assessment of probability:



NS netback prices & South Central Alaska delivered prices



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U.S. Senate Energy Bill

Section 375:

- Expansion service at rates designed to ensure the recovery of expansion costs
  - Rolled-in, or
  - Incremental
- Existing shippers are not required to subsidize expansion shippers

Section 378:

- Any facility receiving gas from the ANGP, deemed an LDC:
  - If spur is part of the ANGP, rates regulated by FERC
  - If not, considered an LDC and rates regulated by State

Implications - if ANGP builds Spur as part of initial project (assuming FERC regulation)

Positive (from State's perspective):

- Rate-making flexibility:
  - Ability for main pipeline to allocate lower costs to spur
- Leverage greatest for State during current negotiations (?)
- Immediate access to new gas supplies
- Benefits from project scale – lower construction costs
- Potential operating cost savings
- Access to guaranteed debt (lower rates)

Negative:

- Is incremental supply needed in 2012?
- Potential cost over-runs for ANGP and "spill over" to spur
- Lower State influence for future expansions and spur operations

Implications - if ANGP builds Spur as an expansion

<u>Positive (from State's perspective):</u>

- Limited rate-making flexibility:
  - Incremental or rolled-in
- Build when supply/demand picture is clearer
- Lower risk / allocation of ANGP cost overruns
- Potential operating cost savings

<u>Negative:</u>

- Lower State influence for future expansions and spur operations
- May require pipeline to re-design rates
- If no incremental production - compete with AECO market for North Slope supplies

Implications - if Spur constructed as an stand-alone pipeline

Positive (from State's perspective):

- Build when supply/demand picture is clearer
- Operated for benefit of State, consumers & producers
- Simpler management and construction of pipeline

Negative:

- If no incremental production - compete with AECO market for North Slope supplies
- May require pipeline to re-design rates

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Activities / information required to complete report

- Obtain updated pipeline cost estimate (Paragon?)
- Update spur rates & ANGP rates
- Update Alaska netbacks:
  - Utilize High, medium & low scenarios developed to analyze LNG viability
- Complete report