North American Natural Gas: Plausible Prices and Their Impact

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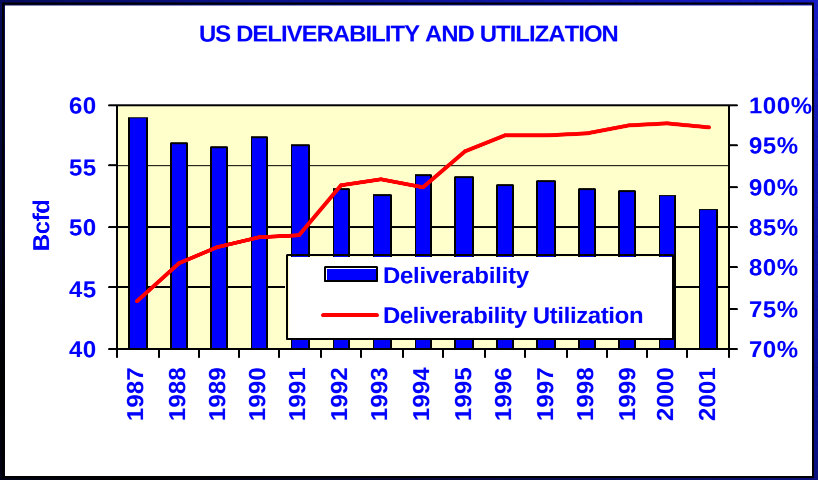
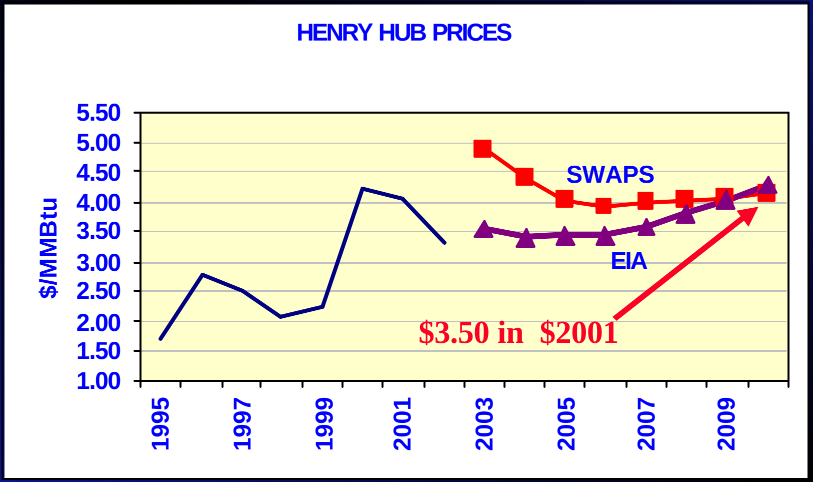
North American Natural Gas: Plausible Prices and Their Impact

- Overview of market expectations
- Demand
  - Response to price
  - New Source Review
  - Industrial sector
- Supply
- Alternative transitions to LNG

"The Future Ain't What It Use to Be"
Yogi Berra

- **1973: The Department of the Interior called the Gulf the "Dead Sea."**
- **1978: Oil prices were forecasted to reach $100 per barrel by 1990.**
- **Coal was going to be the solution to the world's energy needs.**
- **1996: Forecasts predicted that growth in supplies from the Gulf and Canada would cause a gas bubble by 2000.**
- **Now: Henry Hub prices for 2010 are trading at $4.50 to $4.75 per MMBtu.**

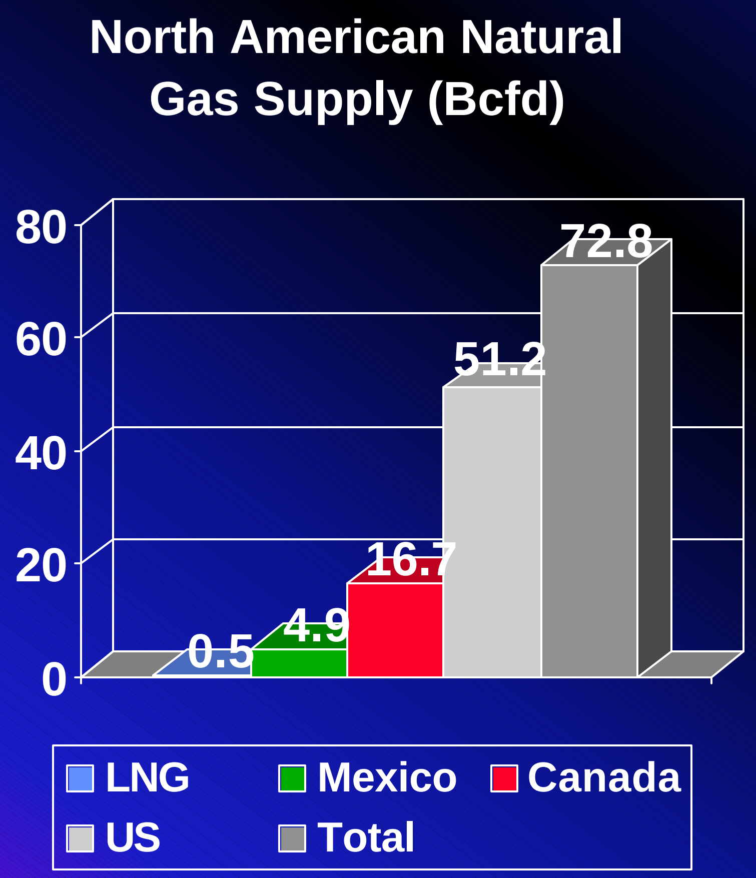


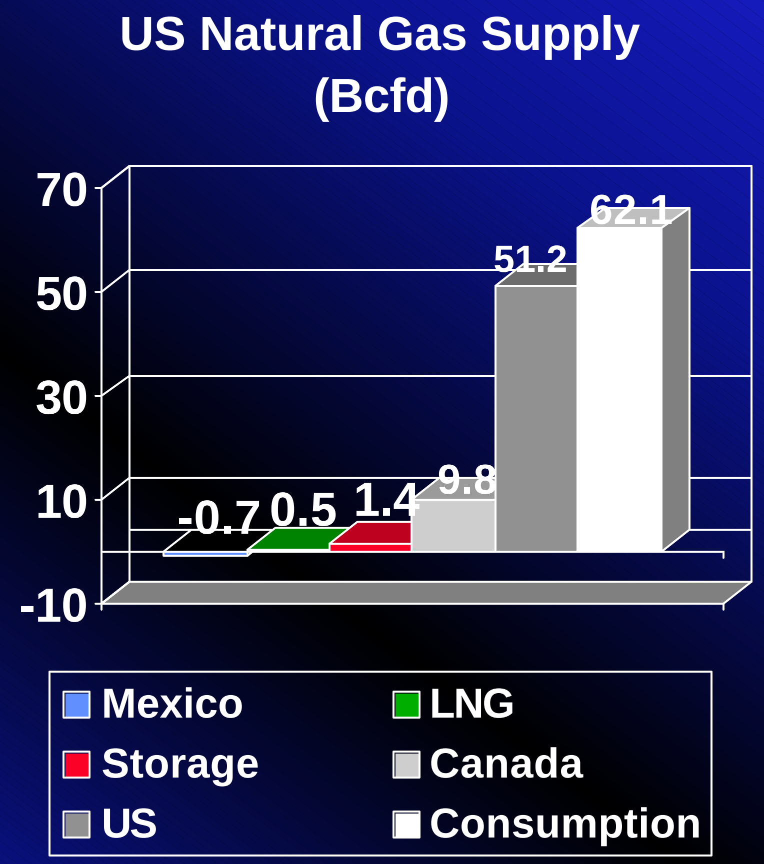


The current view of most analysts is for high prices and a difficult transition to a period when LNG will account for 10% to 15% of US supplies.

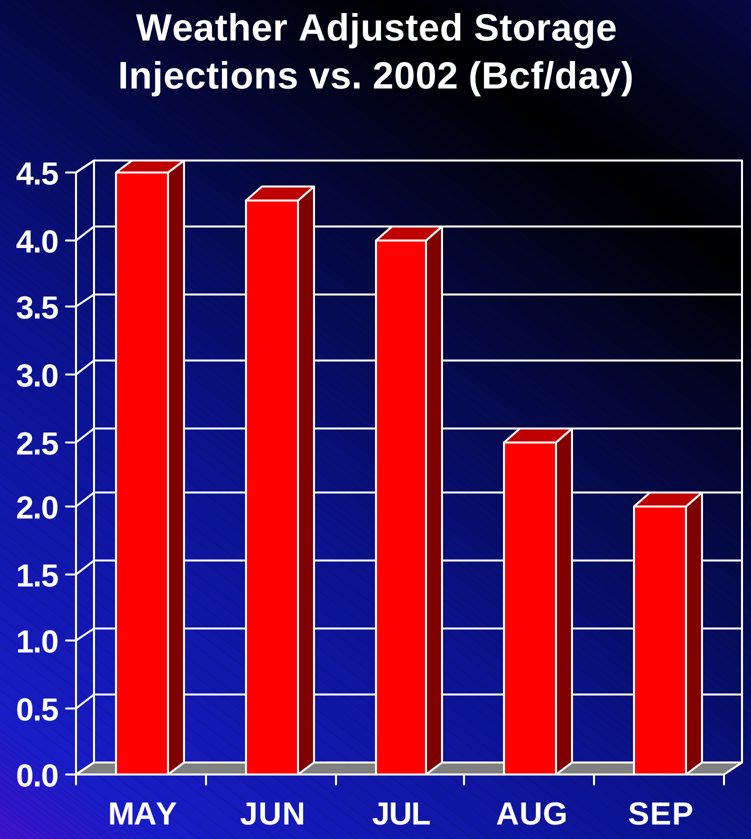
- US production will be down 1% in 2003. US production is at the same level as five years ago.
- Canadian production will be down 2% to 4% in 2003 and probably flat in 2004 and 2005.
- Availability of ships, LNG terminal capacity, and liquefaction capability will limit increased LNG imports until 2007 or later.
- Gas consumption for power generation will cause gas demand to grow 1% to 2% per year.
- Henry Hub prices average between $4.00 and $6.00 per MMBtu through 2010.
- Alaskan supply will require $4 to $5 prices. (Developed in 2015)
- Most LNG supplies can be imported at less than $3.50 per MMBtu.
- Conventional Alberta supplies have peaked (EUB).
- Mackenzie Delta gas will be needed for bitumen production and to offset the decline in Alberta.

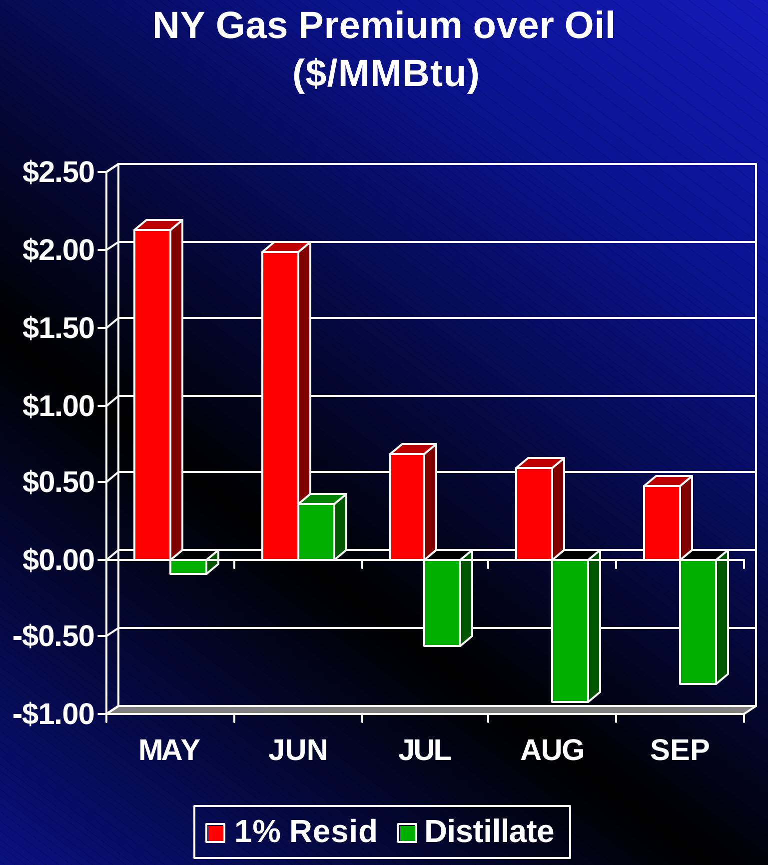
2002 North American Natural Gas Supply was 72.8 Bcfd and US Consumption was 62.1 Bcfd.



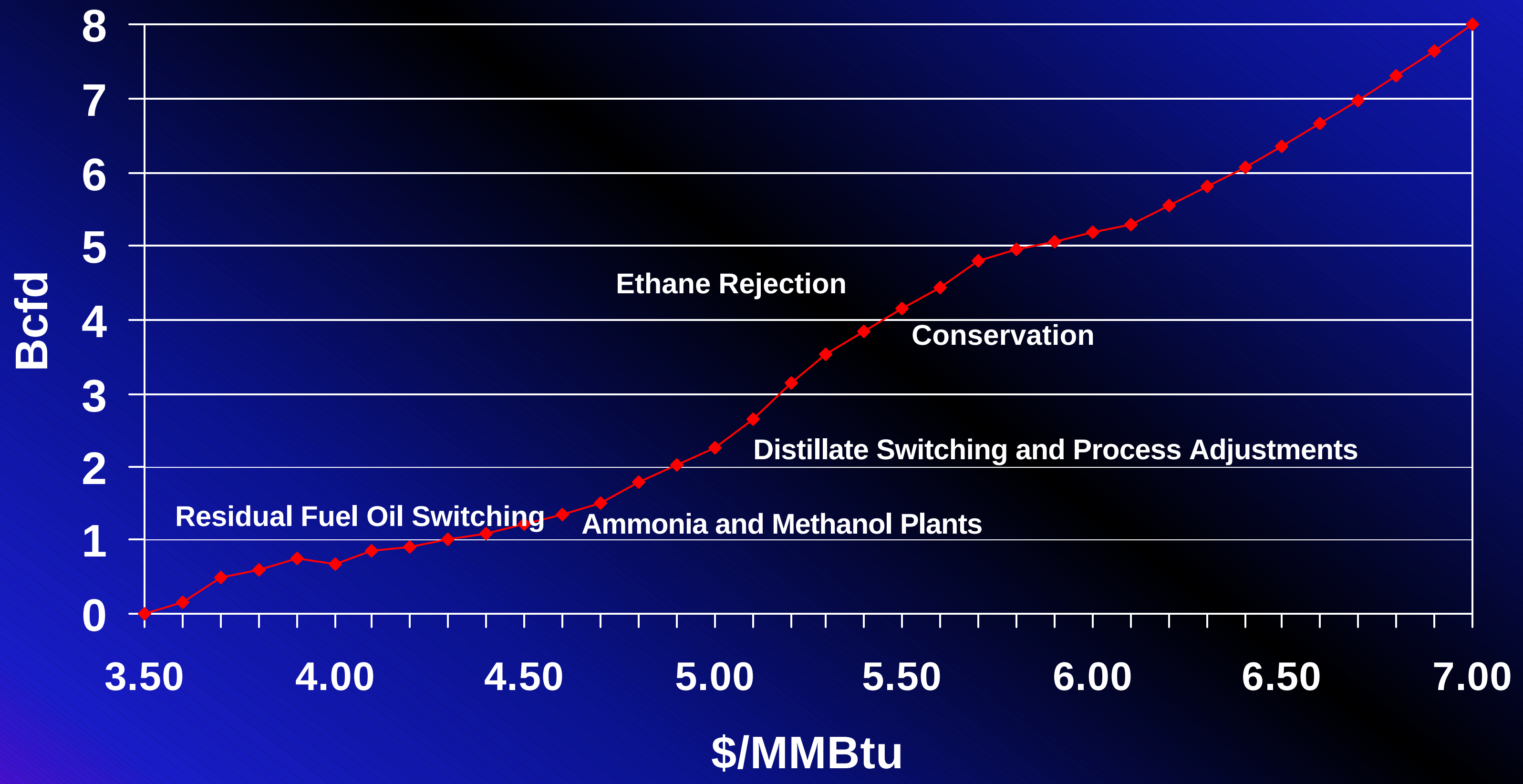


Prices above distillate cause substantial losses in gas consumption. Even with lower gas prices, weather adjusted storage injections are running 2 Bcfd above last year.

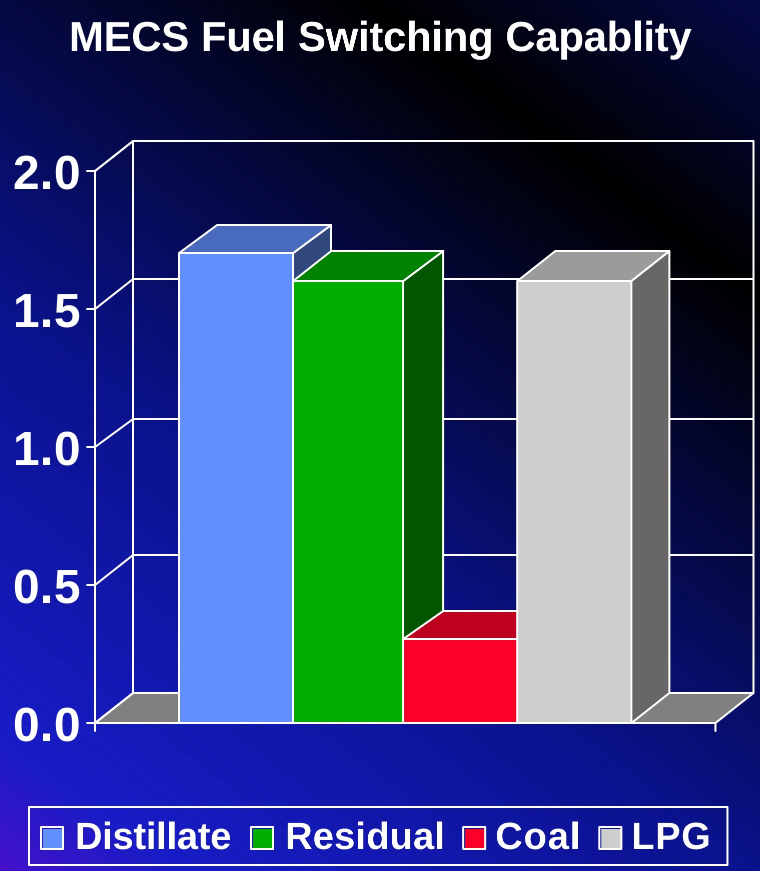




Demand Loss versus Henry Hub Price (WTI=25$/barrel)



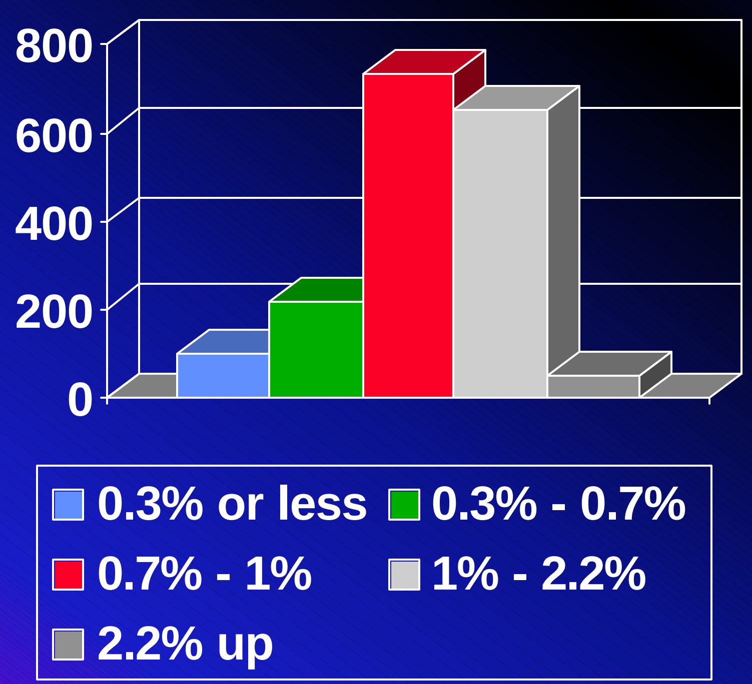
The information on industrial fuel switching capability is very limited.



- The 1998 MECS study switching capability is much higher than actual switching.
- Annual residual fuel oil consumption in the industrial sector is only about .5 Bcfd.
- A Department of Commerce study indicated about 500 Bcf per year of boiler switching capability during 1994-98.
- NPC study suggests boiler switching capability of approximately 200 Bcf per year or less.

Electric power fuel switching is complex. It depends upon the season, dispatch, residual sulfur content, and location. Potential switching is 1 to 2 Bcfd.

Electric Power Residual Fuel Oil (MMcfd)



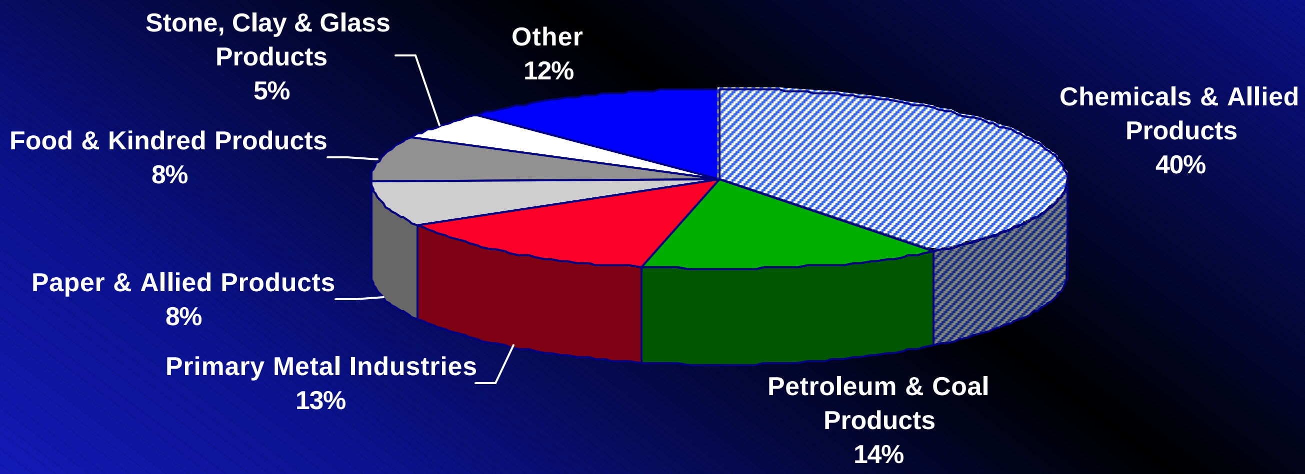
Northeast Fuel Switching Prices

WTI = $30/ bbl	$/MMBtu SEP	JAN
1% Resid NY	3.65	3.65
Taxes & Shipping	0.45	0.45
Delivered NY	4.10	4.10
Basis	0.30	1.00
Henry Hub (Steam)	3.80	3.10
Henry Hub (CC)	5.32	4.34

August EPA ruling could cause the loss of 3.6 Bcfd of gas consumption (three years of gas consumption growth).

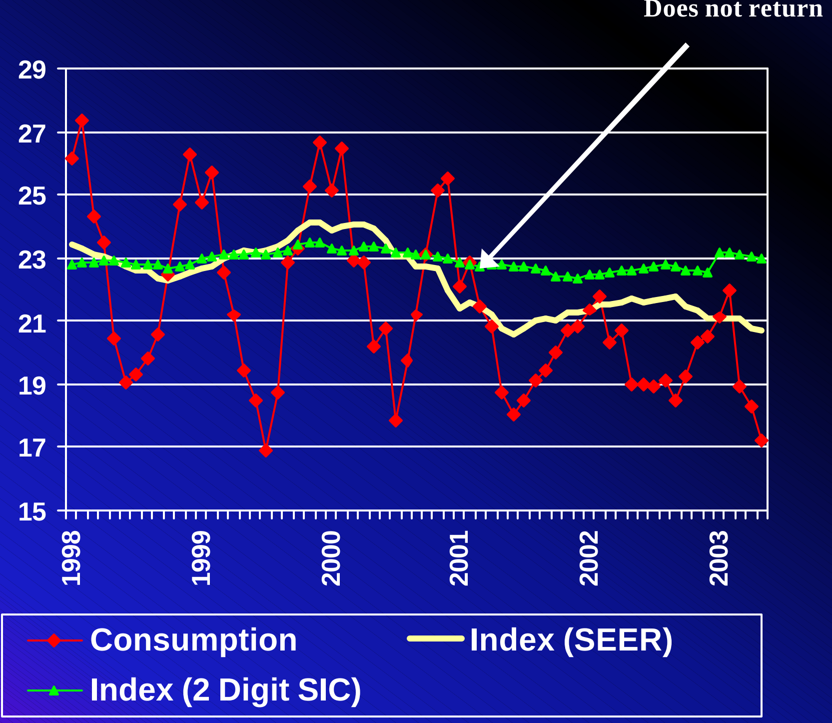
- Ruling applies to grandfathered plants that were not required to install Best Available Control Technology - BACT (1977 Clean Air Act).
- The ruling would allow up to 20% of cost of the plant to be spent on maintenance and not be subject to New Source Review (NSR).
- Approximately 110 GW of coal fired plants could increase capacity by 15% to 25%. 70 GW could be expanded within one year. The interpretation of this ruling is controversial.
- The ruling is being challenged in the courts and the probability is high that it will be overturned.
- Still, some power plants are expanding capacity.

Industrial gas consumption is about 20 Bcfd. It accounts for one-third of US consumption Two-thirds of consumption is in the Chemicals, Petroleum and Primary Metals sectors.

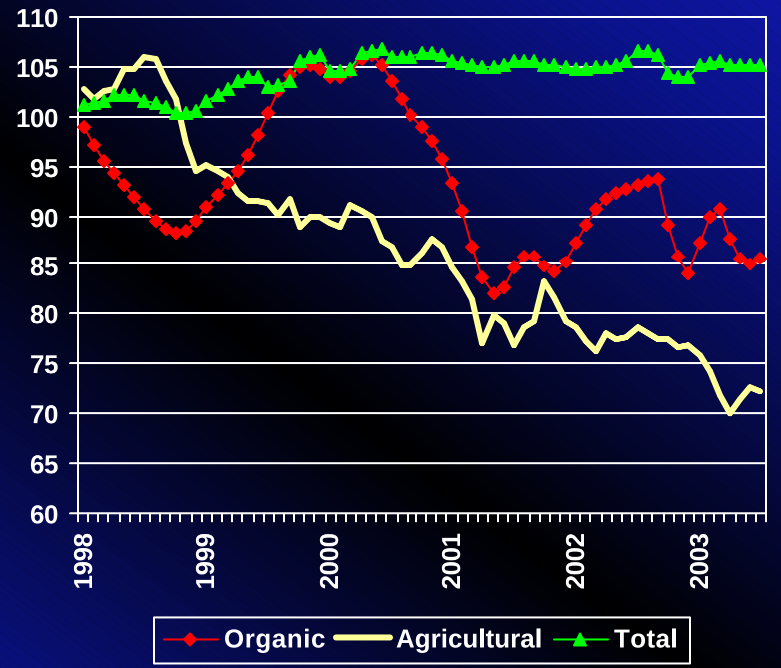


Industrial gas consumption is not likely to grow and could continue declining.

Industrial Production Indices versus Industrial Production (Bcfd)

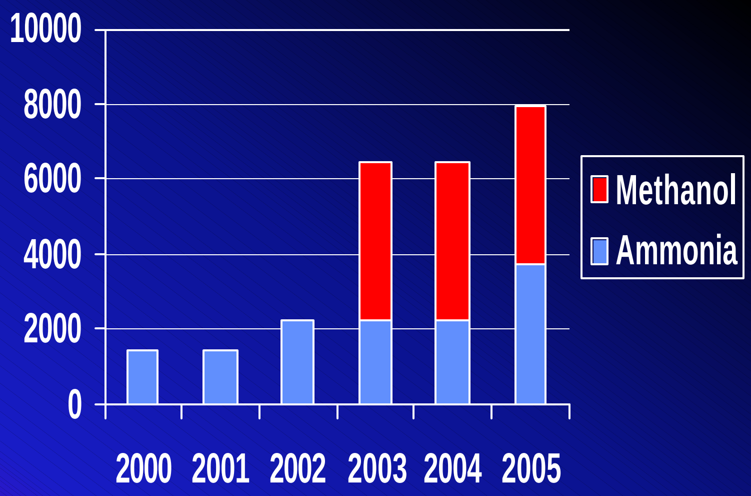


Gas Intensive Chemical Production Indices vs. Total Chemicals

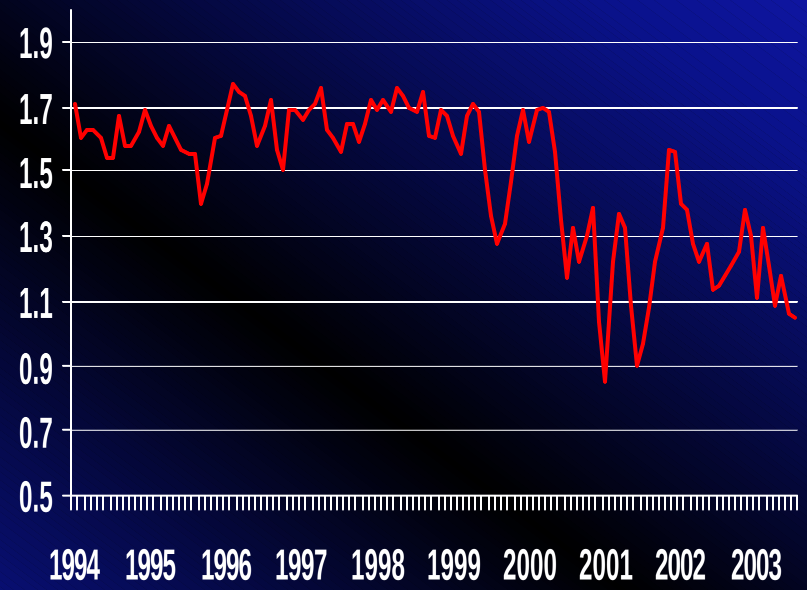


Ammonia and Methanol Capacity in Trinidad and Venezuela is increasing. Proposed capacity amounts to about 1.2 Bcfd of gas consumption. (20% of US Ammonia capacity has permanently closed in past three years).

Million Metric Tons Cumulative



US Anhydrous Ammonia Production (Bcfd)



One million metric tons is 150 MMcfd

There is substantial disagreement about the outlook for production. Quarterly report data shows 1st quarter production was down 2% from last year. EIA shows production up 3.2%.

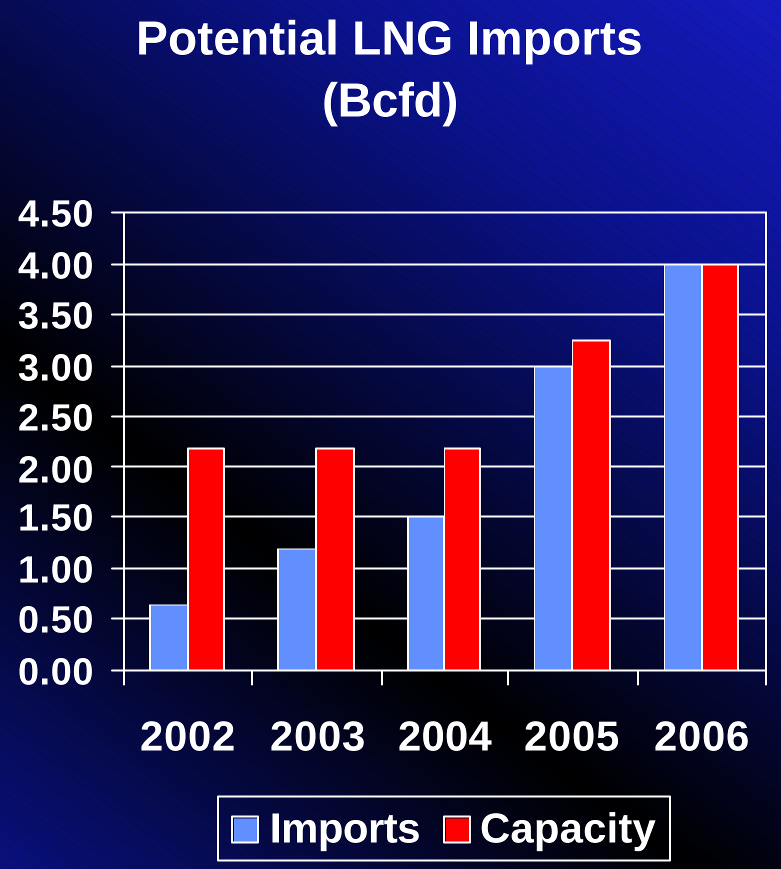
- Quarterly report data is biased – large producers overstate production decline. Some believe the quarterly report data is wrong.
- Last year EIA revised initial production estimates down 2%.
- OCS is the big question. Substantial deepwater came on the 1st quarter. However, the first quarter data are estimates and the rig count has not changed from 2002.
- Texas was up 3% in June, Rockies up close to 1 Bcfd (15%). New Mexico is growing.

1st Quarter Production (Bcfd)

AREA	2002	2003	2003 -2002	%CH 03 02
NM	4.17	4.40	0.23	5.4%
LA	3.69	3.59	-0.10	-2.7%
OCS	12.59	12.93	0.34	2.7%
TX	15.85	15.48	-0.38	-2.4%
SUBTOTAL	36.31	36.40	-0.39	0.3%
		EIA		
ROCKIES	6.61	7.19	0.58	8.8%
OK	4.40	4.56	0.16	3.6%
SUBTOTAL	11.01	11.75	0.74	6.7%
TOTAL	47.32	48.15	0.34	1.8%

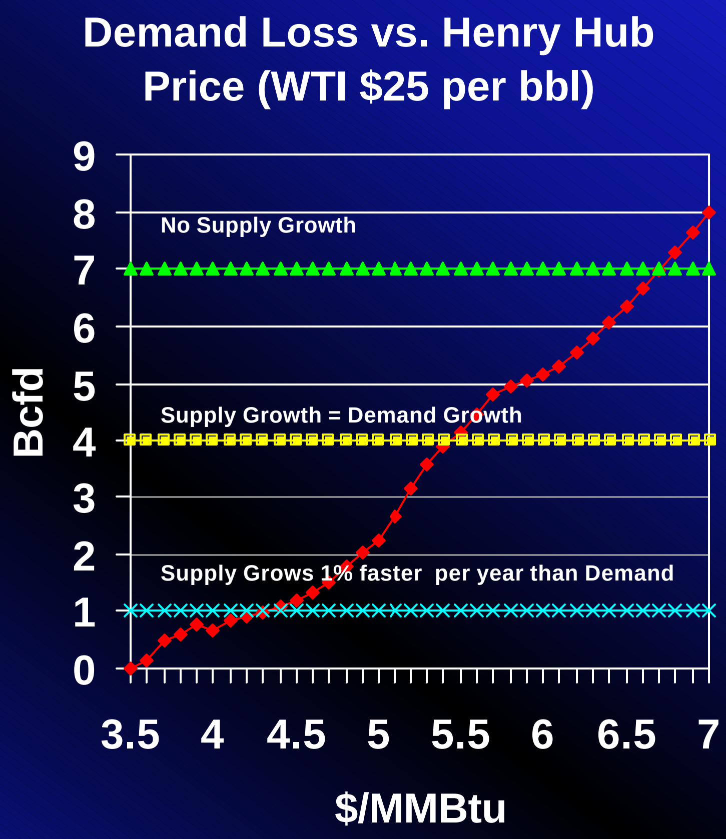
Until 2008 or later, liquefaction capacity is likely to be the greatest constraint on increased LNG imports.

- If demand grows about 1.5% per year, supply will have to increase by 1.0 Bcfd per year.
- Existing terminals <u>could</u> add approximately 1 Bcfd of supply during each the next three years.
- LNG supply would have to be diverted from Europe or Asia. Spain is over-contracted but prices will have to be high enough to attract supply.



Alternative assumptions result in Henry Hub prices ranging from $3.50 per MMBtu to $7.00 per MMBtu.

- Assuming 1% per year demand growth through 2008, Henry Hub prices could range from $4.30 per MMBtu to $7.00 per MMBtu with normal weather.
- Every $/bbl change in WTI is equal to about $.17 cents per MMBtu change in Henry Hub prices.
- NSR path could drive prices down to $3.50 per MMBtu.



New long term supply sources will be available at $3.50 ($2002) per MMBtu or less but the decline in conventional supplies could require much higher prices. The demand response to price will be a key driver.

- Mackenzie Delta at less than $3.00 per MMBtu.
- LNG from marginal sources such as Qatar less than $3.50 per MMBtu
- Alaska 4-6 Bcfd, $3.50 ($2002) per MMBtu (developed about 2015).
- Coal is economic at $4.00 - $4.50 delivered gas.
- Has the most price sensitive part of demand already been lost?

National Petroleum Council (Scenarios)