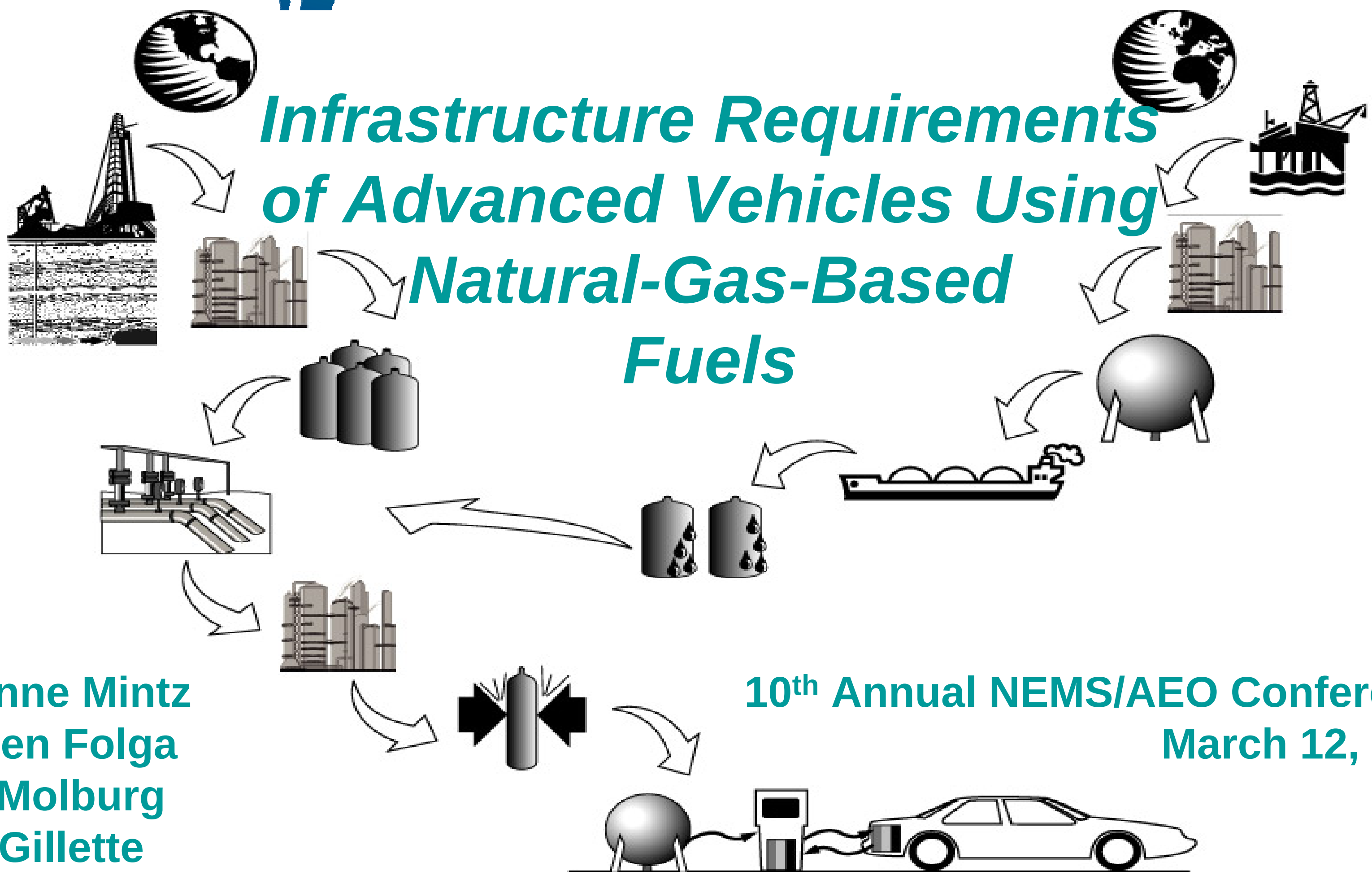
Infrastructure Requirements of Advanced Vehicles Using Natural-Gas-Based Fuels



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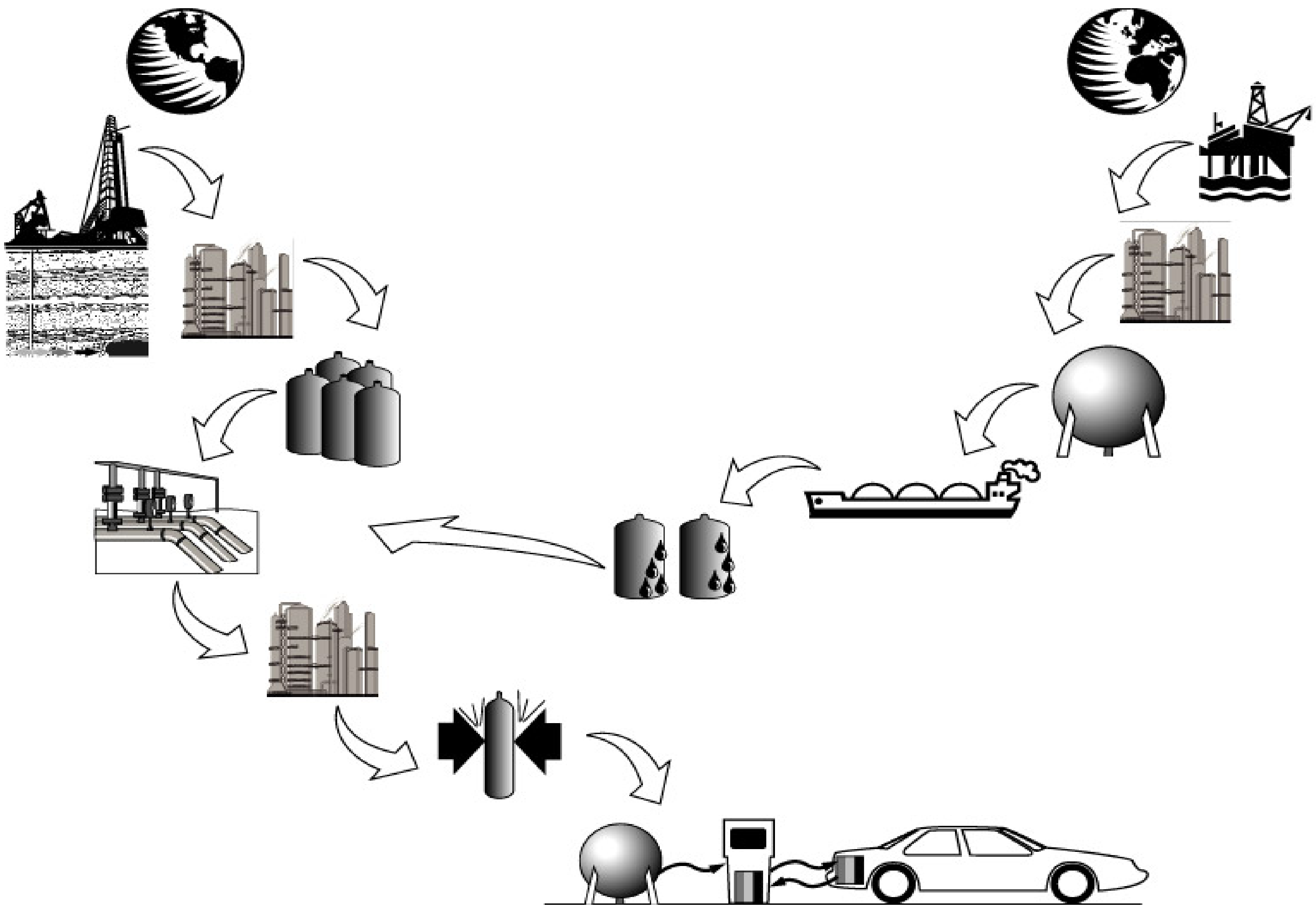
Boundaries of This Presentation

- Long term (2030)
- Light-duty vehicles
- Capital costs of fuel production and distribution infrastructure (excluding exploration)
- Technically feasible propulsion systems with potential for substantial improvement over conventional ICE fuel efficiency (hybrids and fuel cells)
- Natural-gas-based motor fuels (methanol, LNG, Fischer-Tropsch diesel (FTD) and hydrogen)

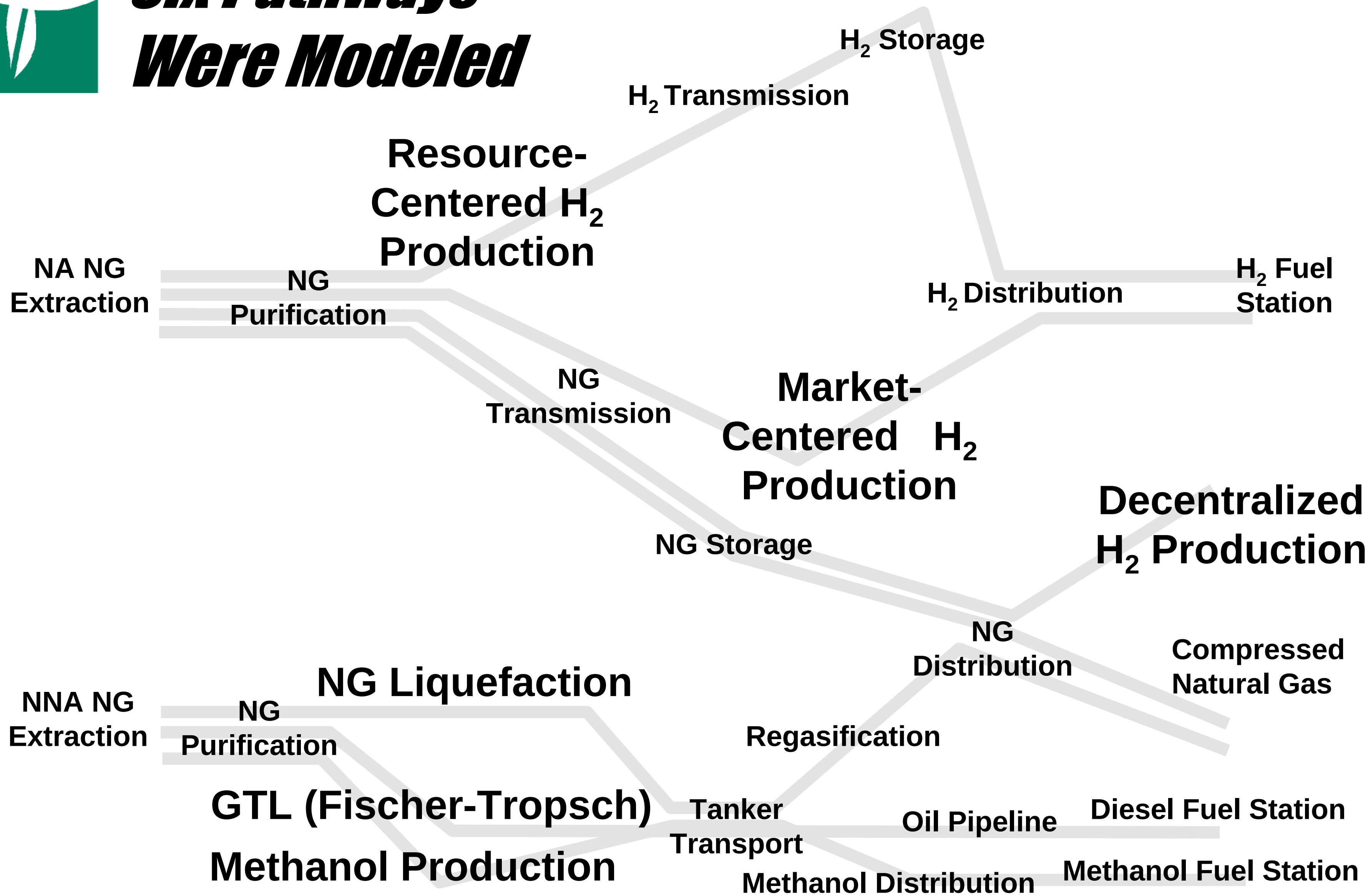
Cost Modeling Was Conducted Via a Five-Step Process

- Define paths
  - North American (NA) or non-North American (NNA) natural gas
  - NG production, compression, storage and transport; conversion to alternative fuel, transport and dispensing
- Determine "tank-in" fuel requirement
  - Market penetration
  - Vehicle and pathway efficiencies
- Size pathway components
- Estimate component costs
- Calculate pathway costs (NICC model)

Natural Gas-Based Fuels Could Take Several Paths from "Well" to "Tank"

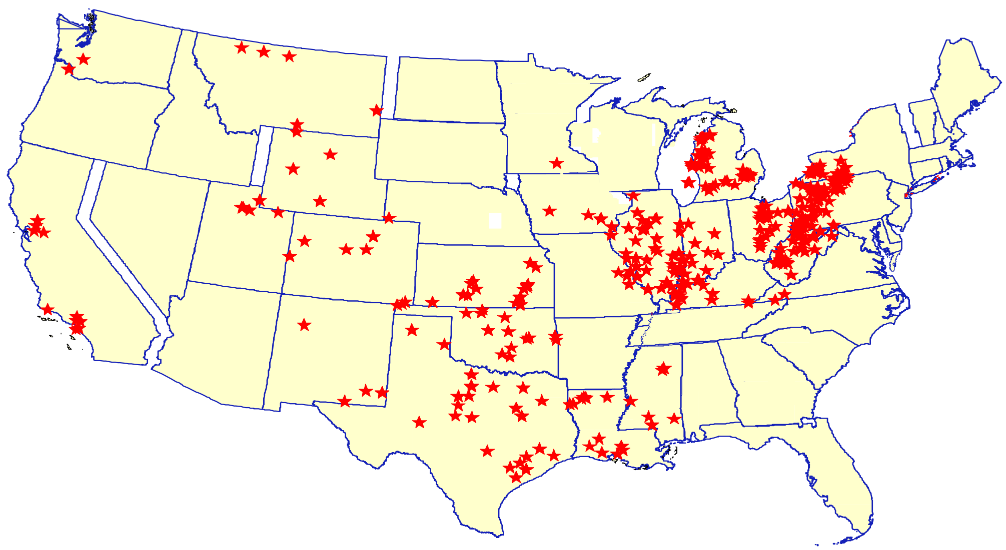


Six Pathways Were Modeled



All Pathways Include Underground Storage

At the end of 1998 there were 410 underground natural gas storage sites in the U.S.

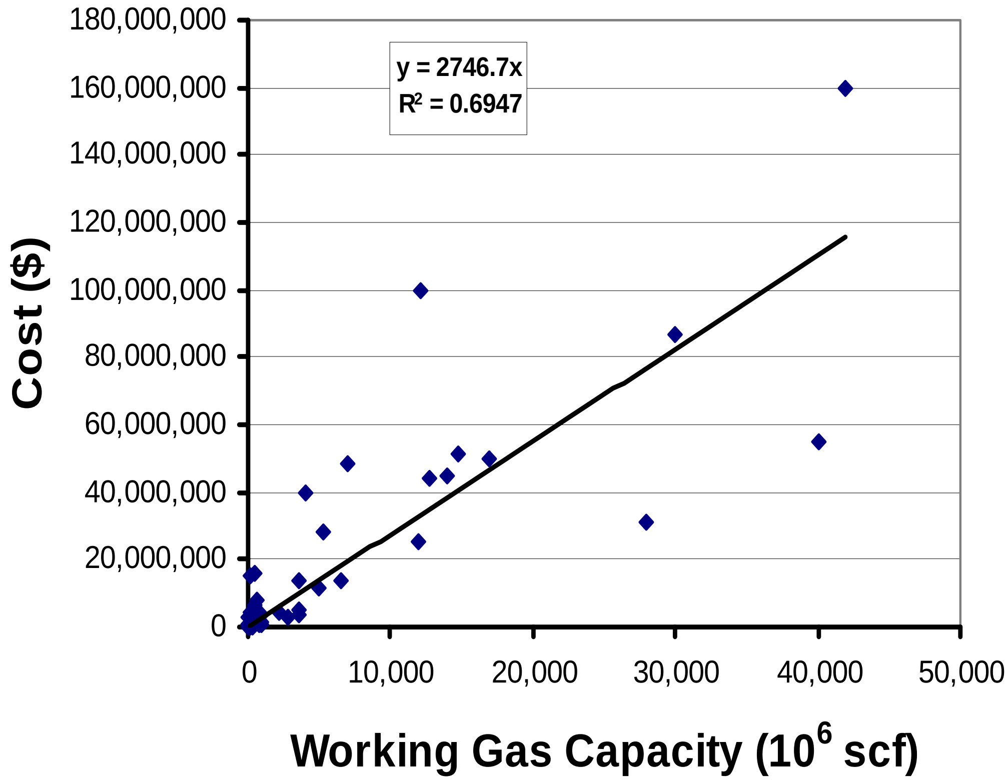


With 76 Bcf per day of Withdrawal Capability and 3,933 Bcf of Working Gas Capacity

www.eia.doe.gov
Energy Information Administration

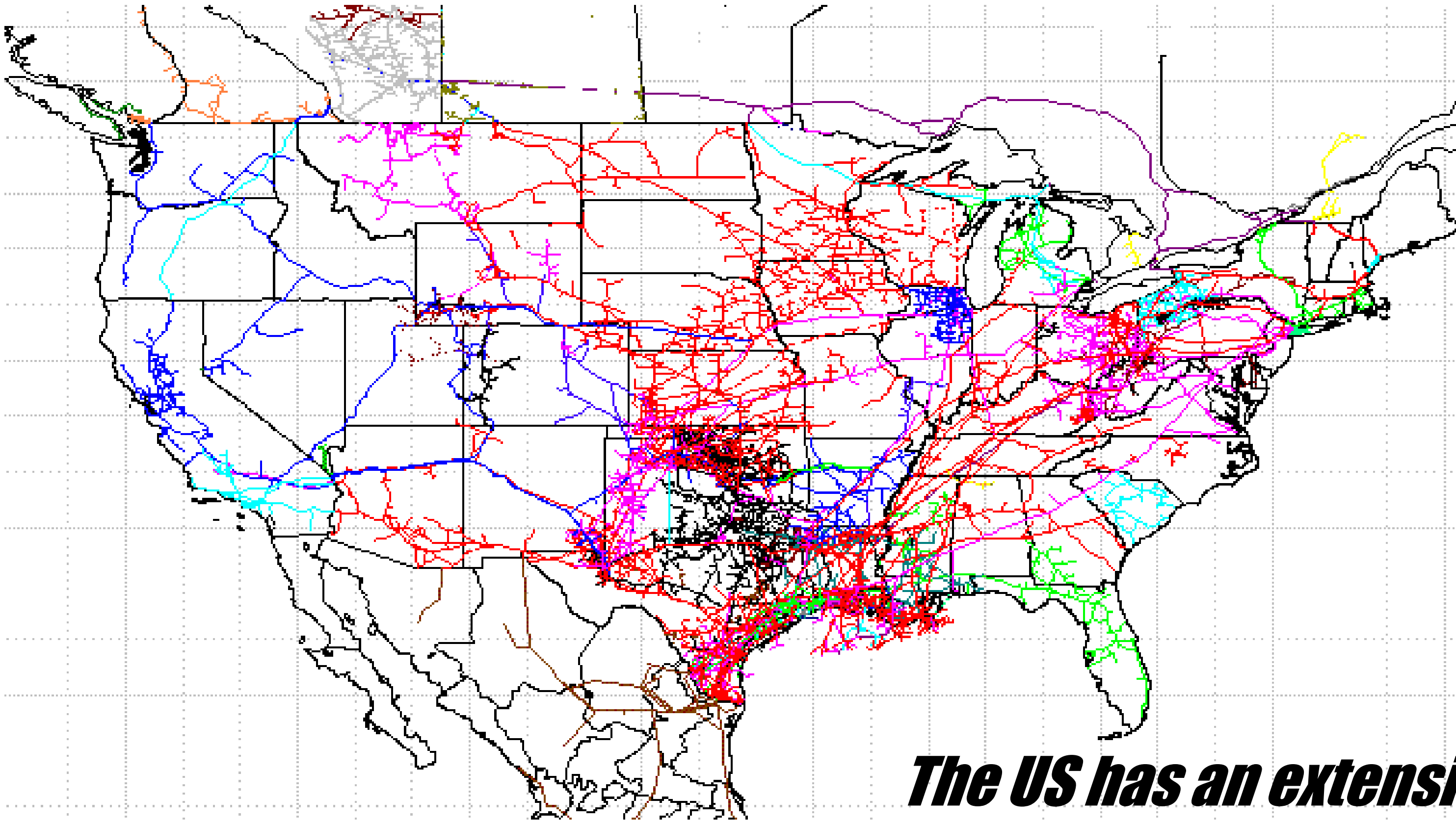
USAID

The Cost of Underground Storage of Natural Gas Is a Function of Working Gas Capacity



- Linear relationship for underground storage (projects with 2001-04 completion, 1999$)
- Working gas capacity per field: 5 x 10^9 scf
- Unit O&M cost: $0.224 per 10^3 scf delivered (Young Storage Field, CO)

All Pathways Require Additions to the Existing Natural Gas Transmission Infrastructure

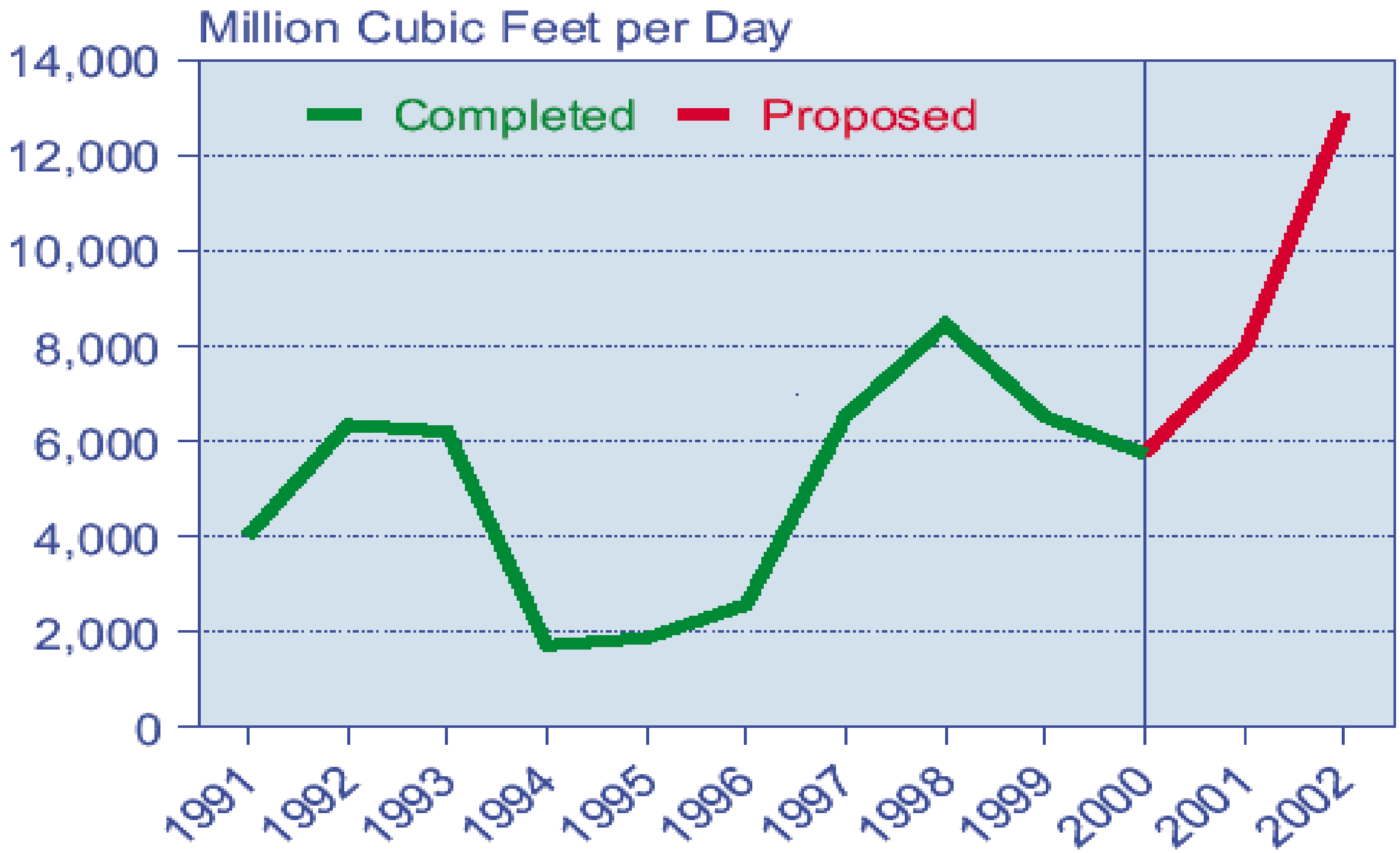


The US has an extensive in-place NG transmission infrastructure ....

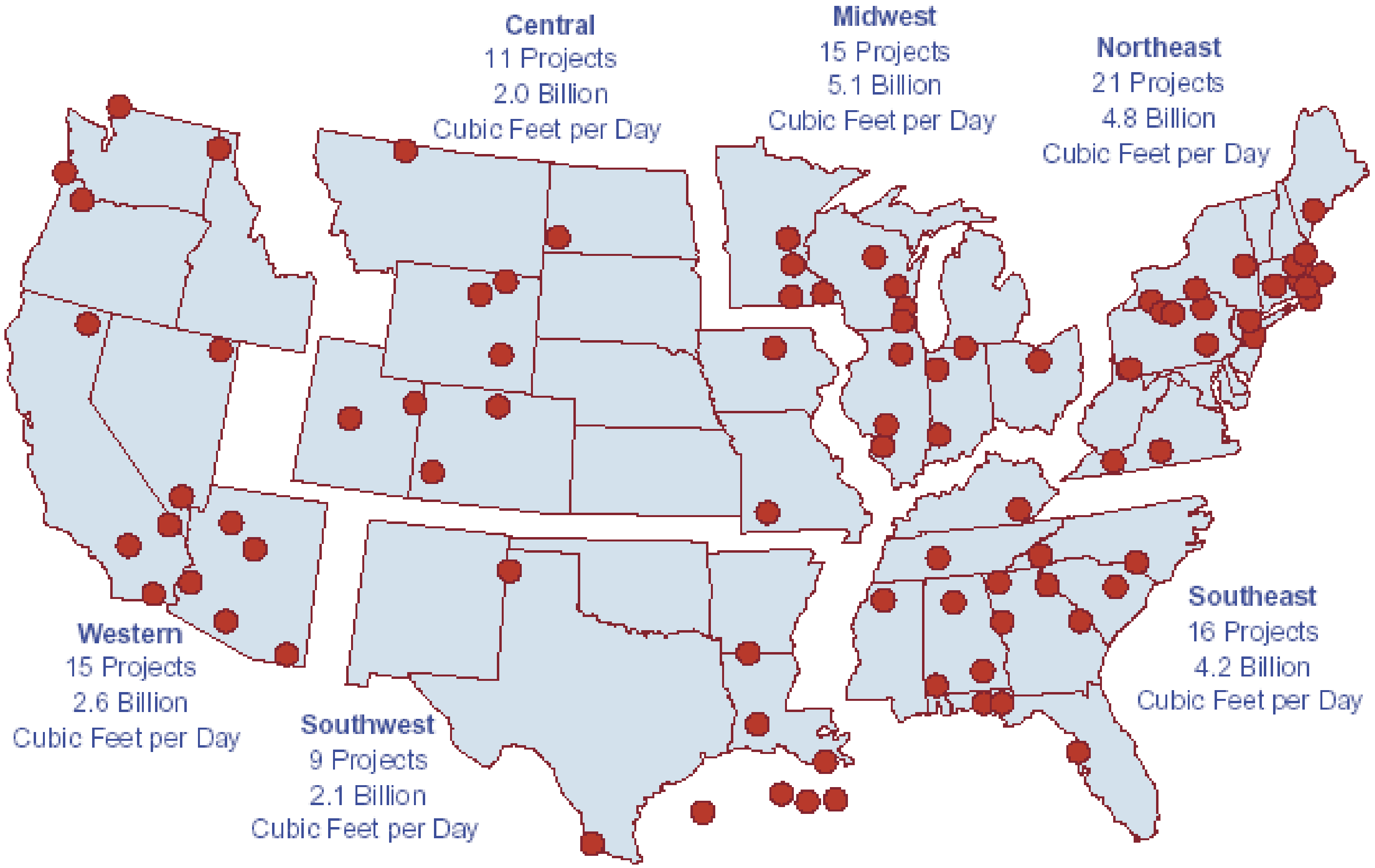
And a Track Record of Continually Expanding Transmission Capacity

- New pipelines
- Additional compression
- Looping
- All of the above

1991-2000 Annual Capacity Additions Averaged > 4 x 10^9 scfd; Proposed Additions Are Higher

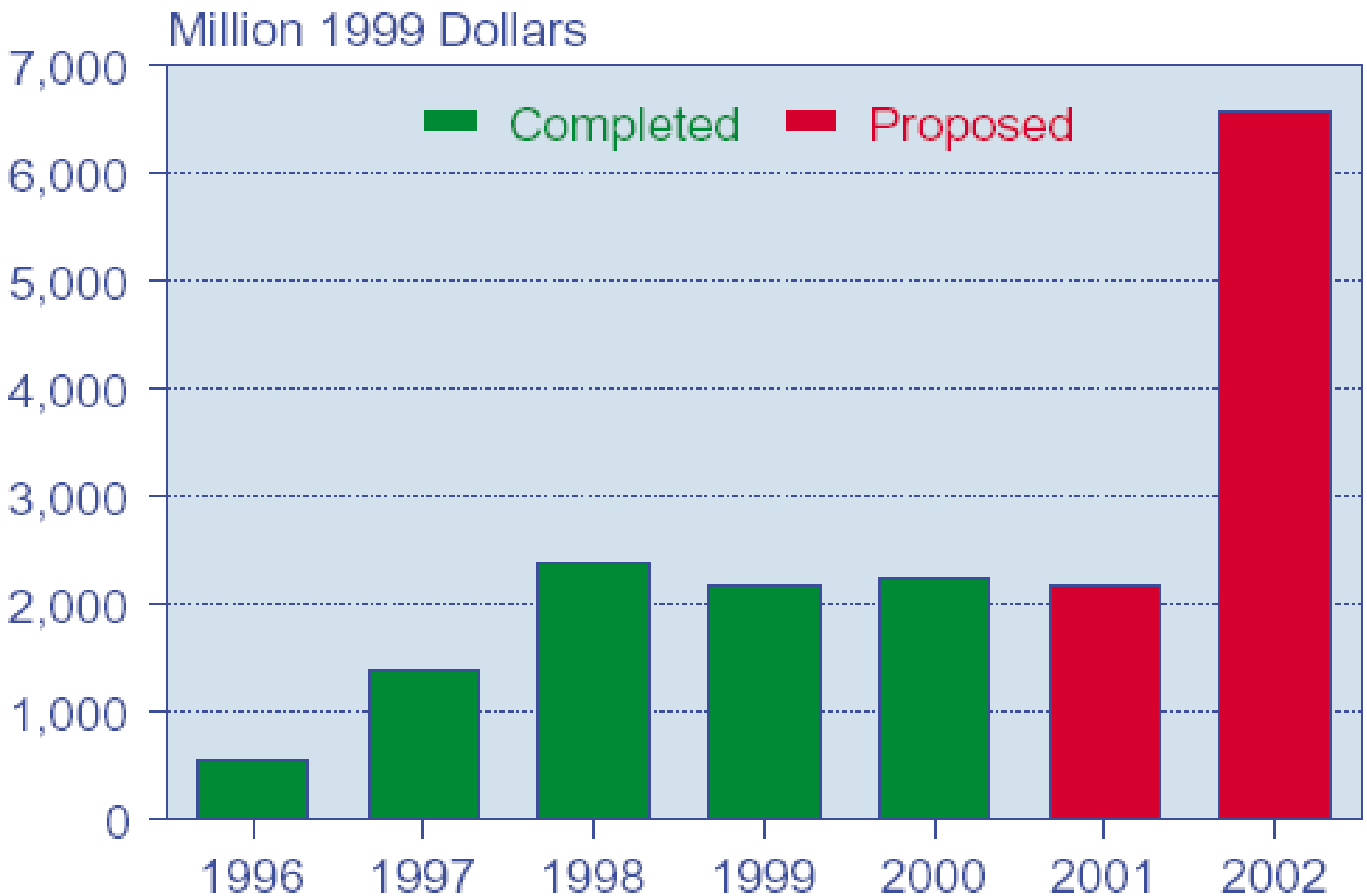


Yearly Capacity Additions Could Rise to 10 x 10^9 scfd in 2001-2002



Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Proposed Pipeline Construction Database (as of March 2001).

According to EIA, Over $6 Billion Will Be Spent on Pipeline Expansion in 2002



Source: Energy Information Administration, EAGIS-NG Geographic Information System, Natural Gas Proposed Pipeline Construction Database (as of March 2001).

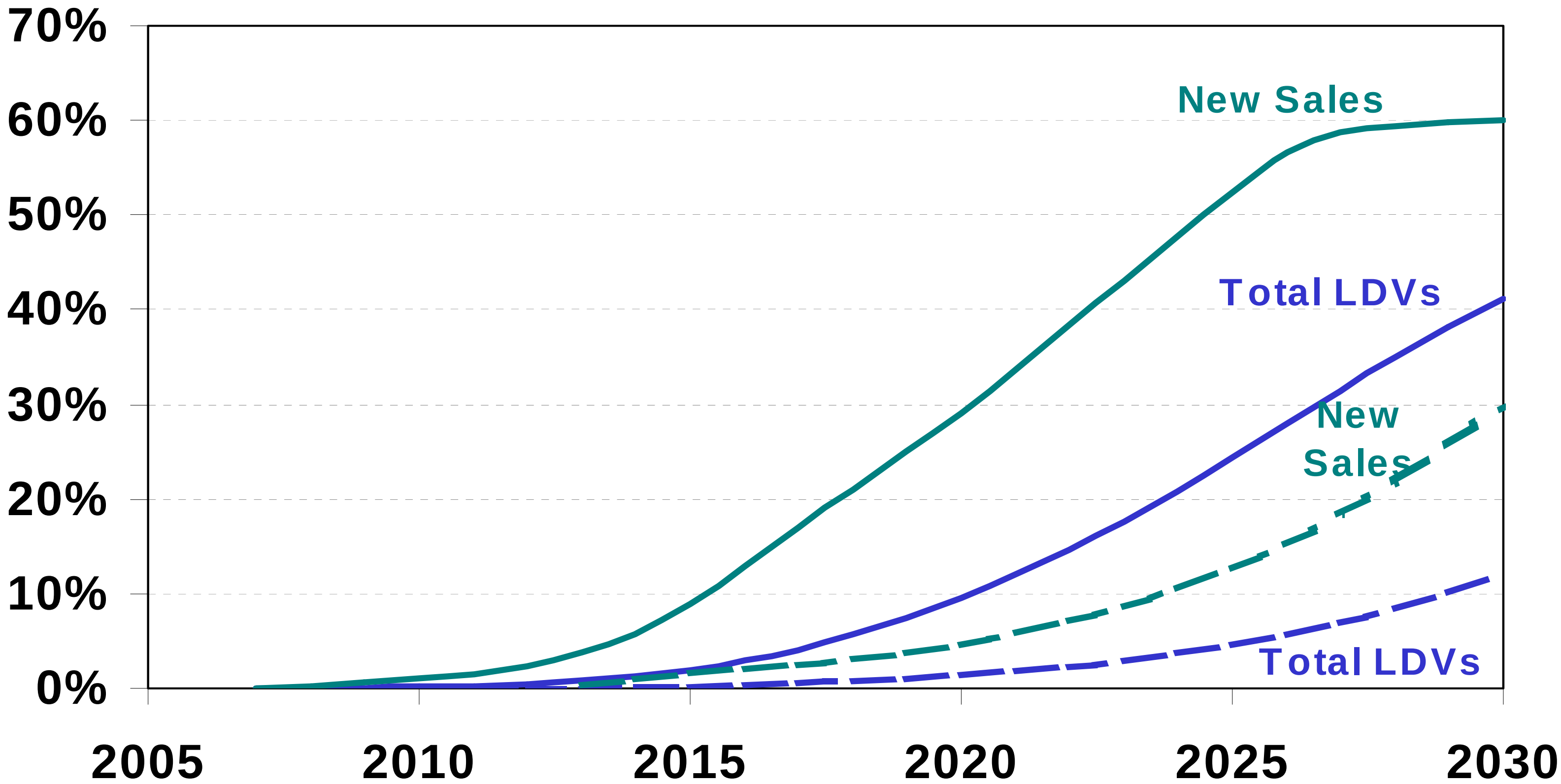
Expansion Reflects Shifts in the Structure of the Industry and Its Resource Base

- **Increased production in deep-water Gulf of Mexico and in western and offshore eastern Canada**
- **Reduced production in mature provinces**
- **Shippers seeking greater access to alternate sources of supply**
- **Producers seeking greater access to non-traditional markets (market integration)**
- **Increased use for power generation with resulting shifts in seasonal demand patterns**

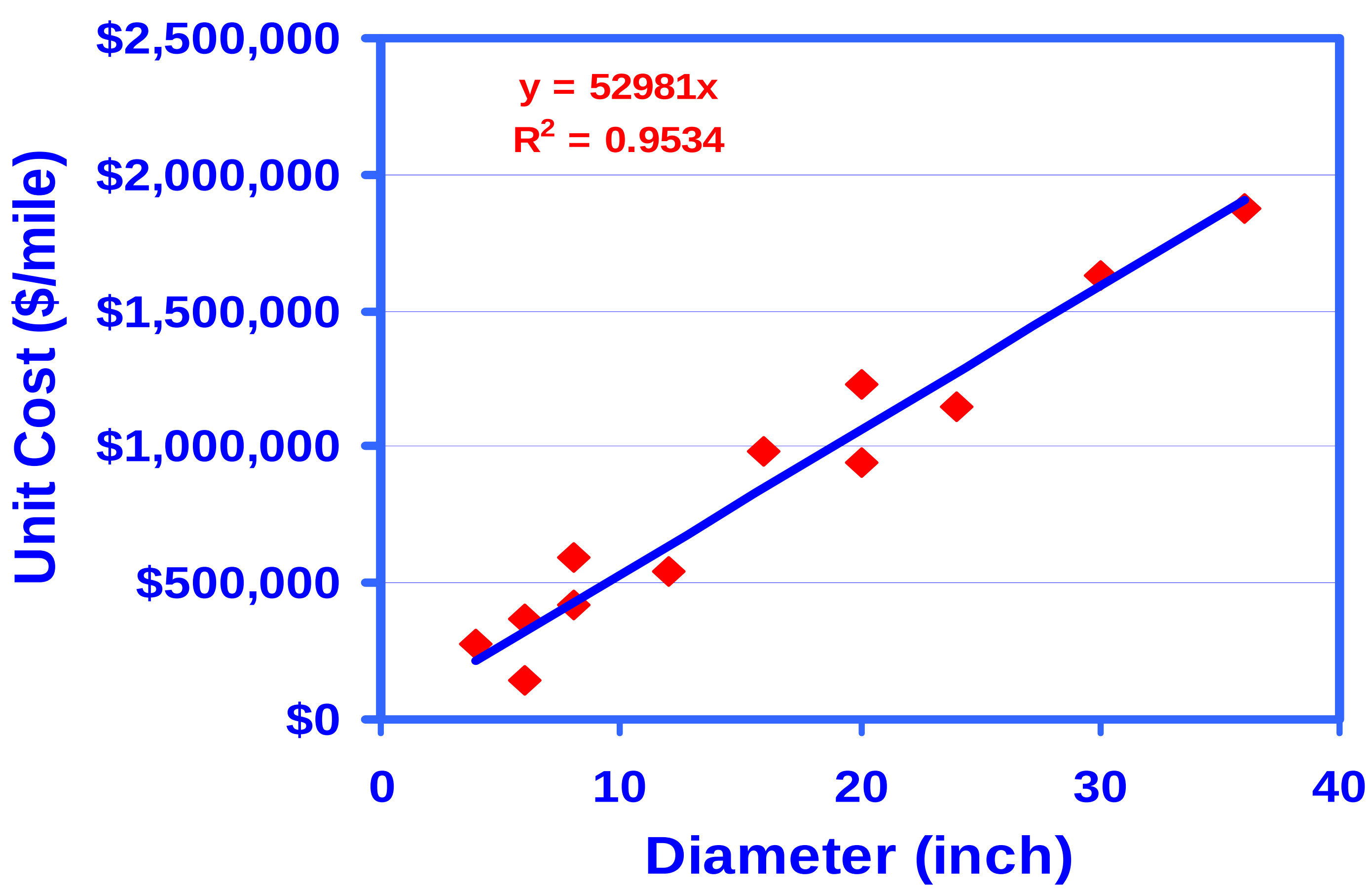
But Given the Scale of Motor Fuel Demand, Is It Reasonable to Expect Additional Expansion?

NG System Component	Capacity Additions	Unit Cost (10^6)	Capital Cost (10^9)
Pipelines •Transmission •Distribution	 6000 mi 630,000 mi	 $1.5/mi $0.1-0.2/mi	 $9 $85
Underground Storage	185	$13.7	$2.5
Compressor Stations	38	$12	$0.5
NG Throughput	6 x 10^{12} scf	NA	NA

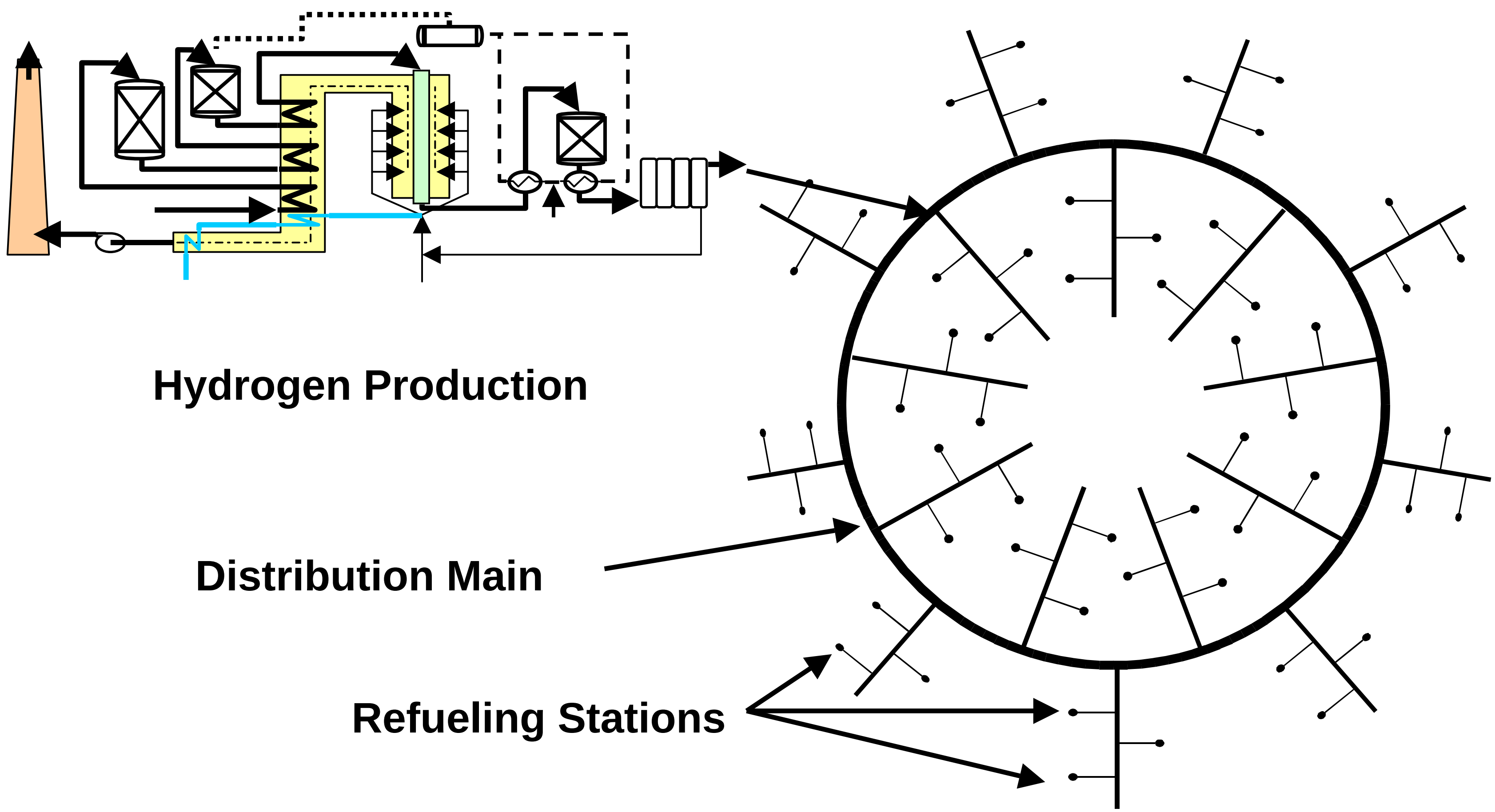
Two Market Penetration Cases Were Modeled



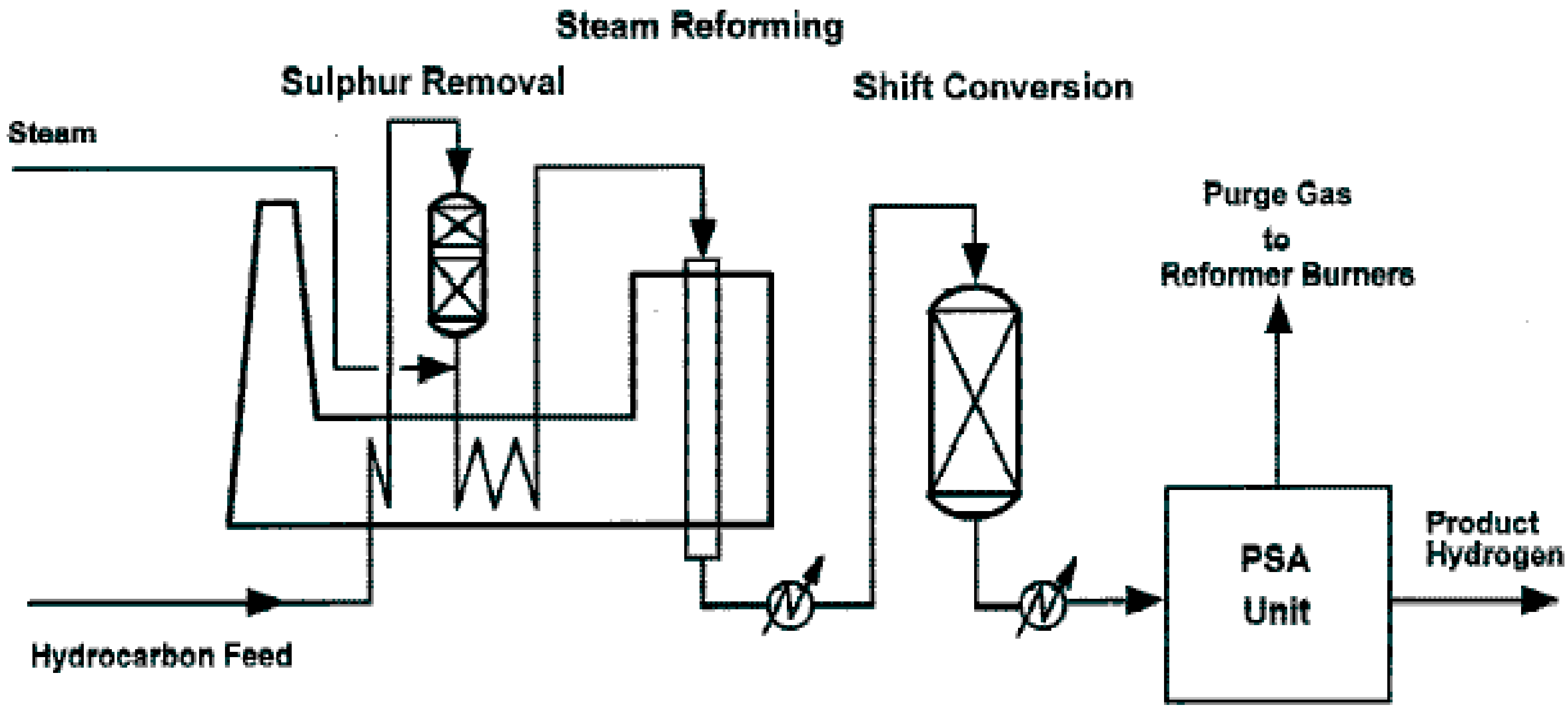
Unit Cost of Natural Gas Transmission Pipelines Is a Function of Diameter



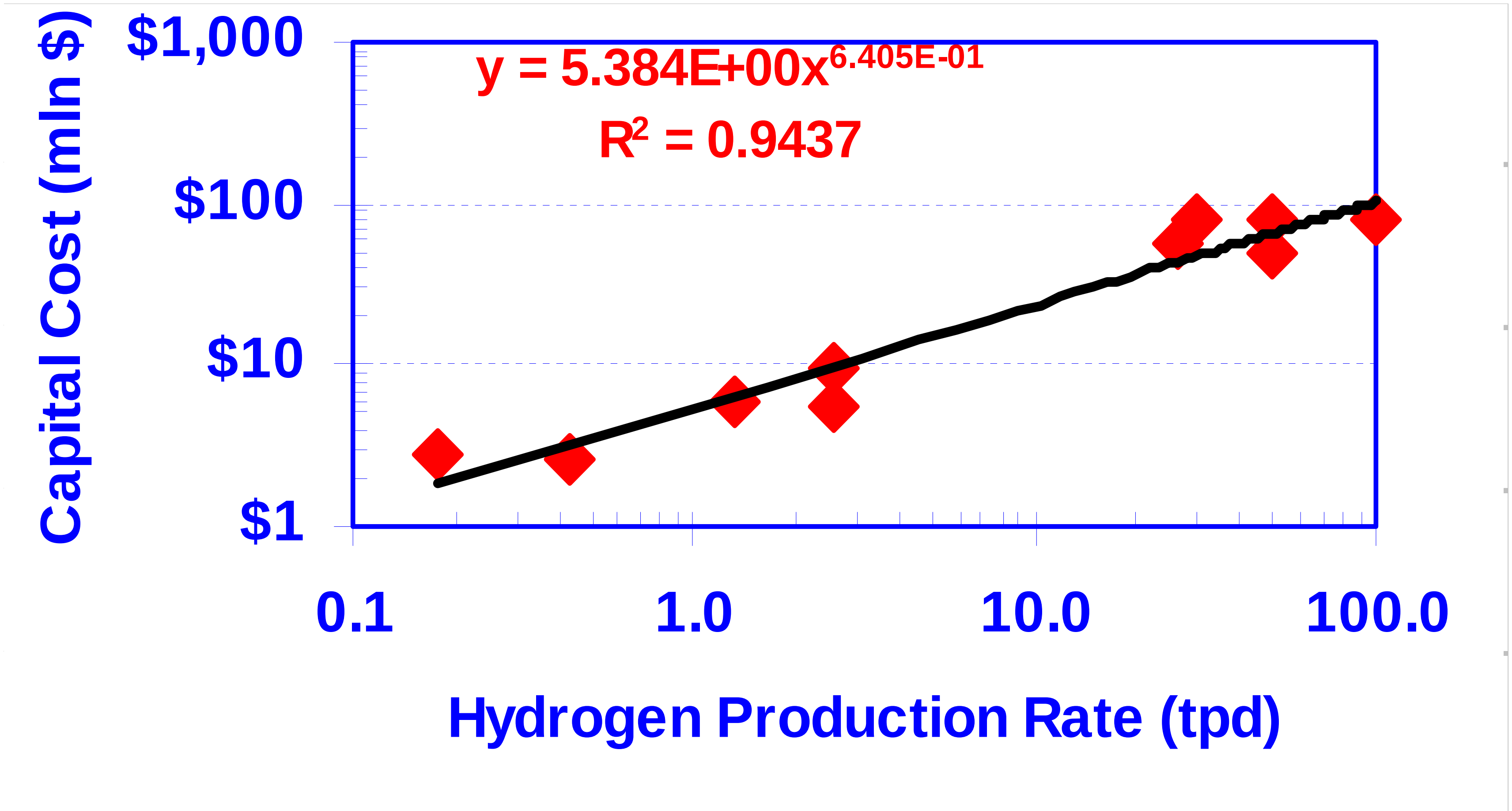
Conceptual Representation of Hydrogen Pipeline Loop Supporting Local H_2 Delivery



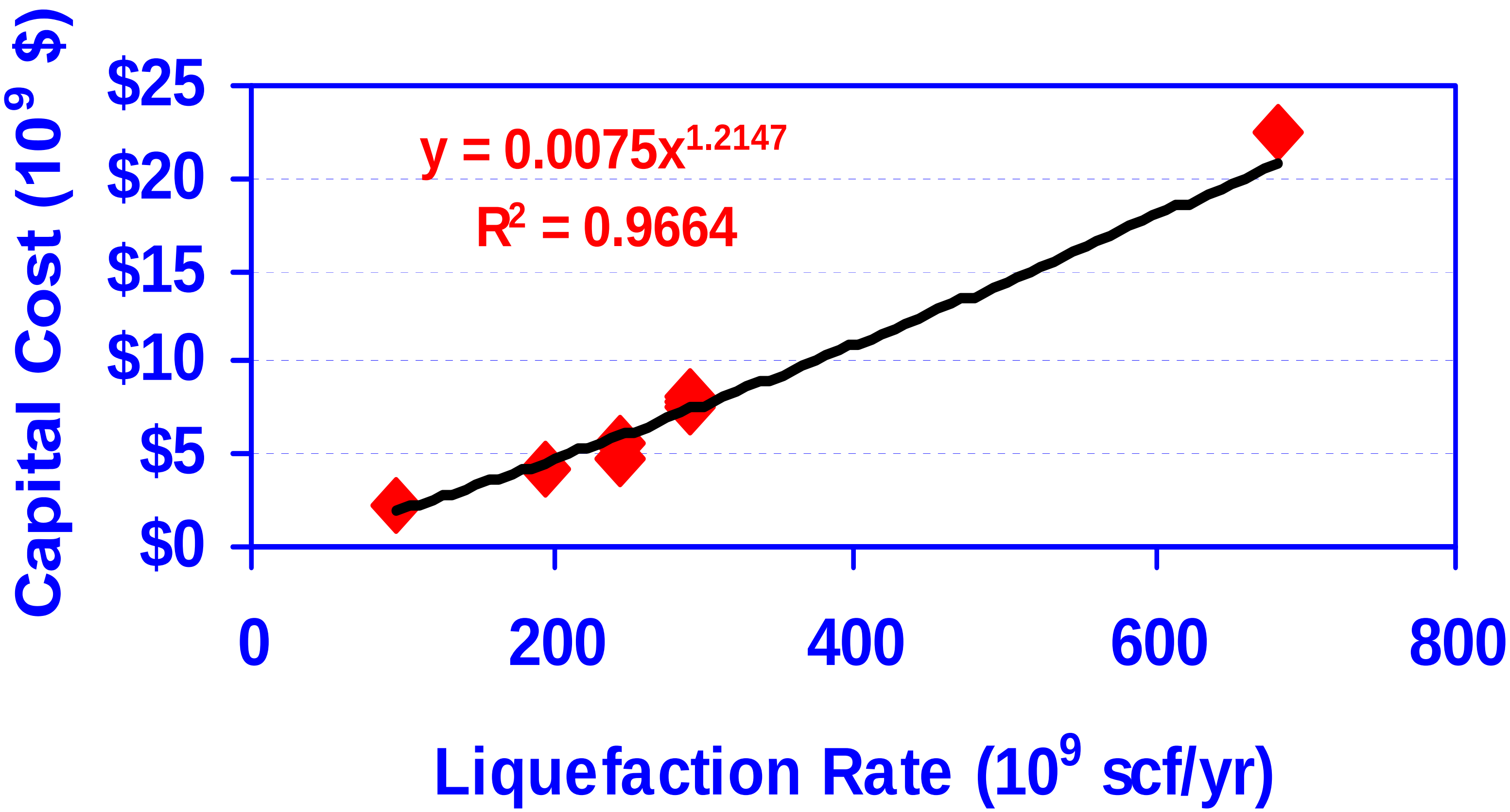
Steam Reforming Inputs Are Water and Hydrocarbon Feedstock; Outputs Are Hydrogen and Purge Gases



Current SMR Plants Have Large Economies of Scale



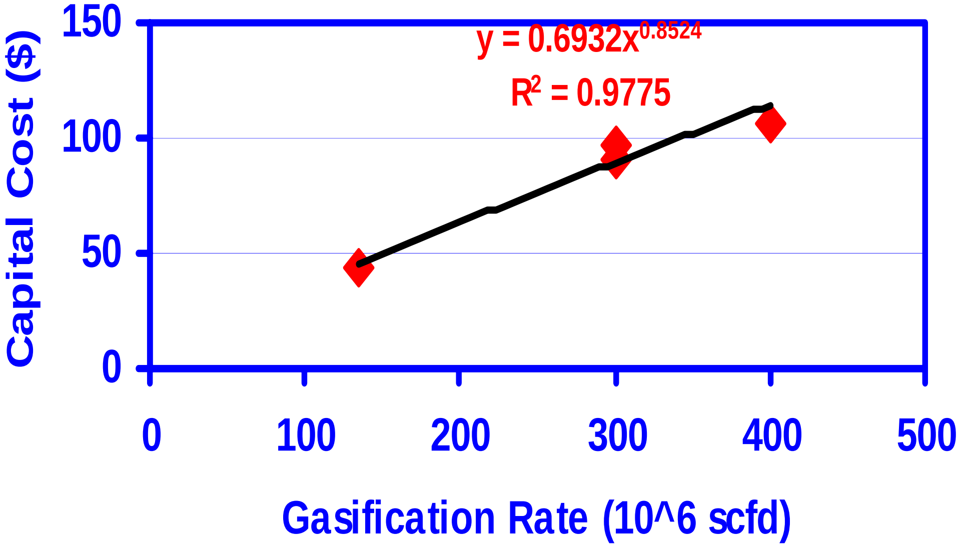
Capital Cost of LNG Liquefaction Is a Function of Liquefaction Rate



Once Liquefied, Non-North American Natural Gas Is Shipped to LNG Terminals

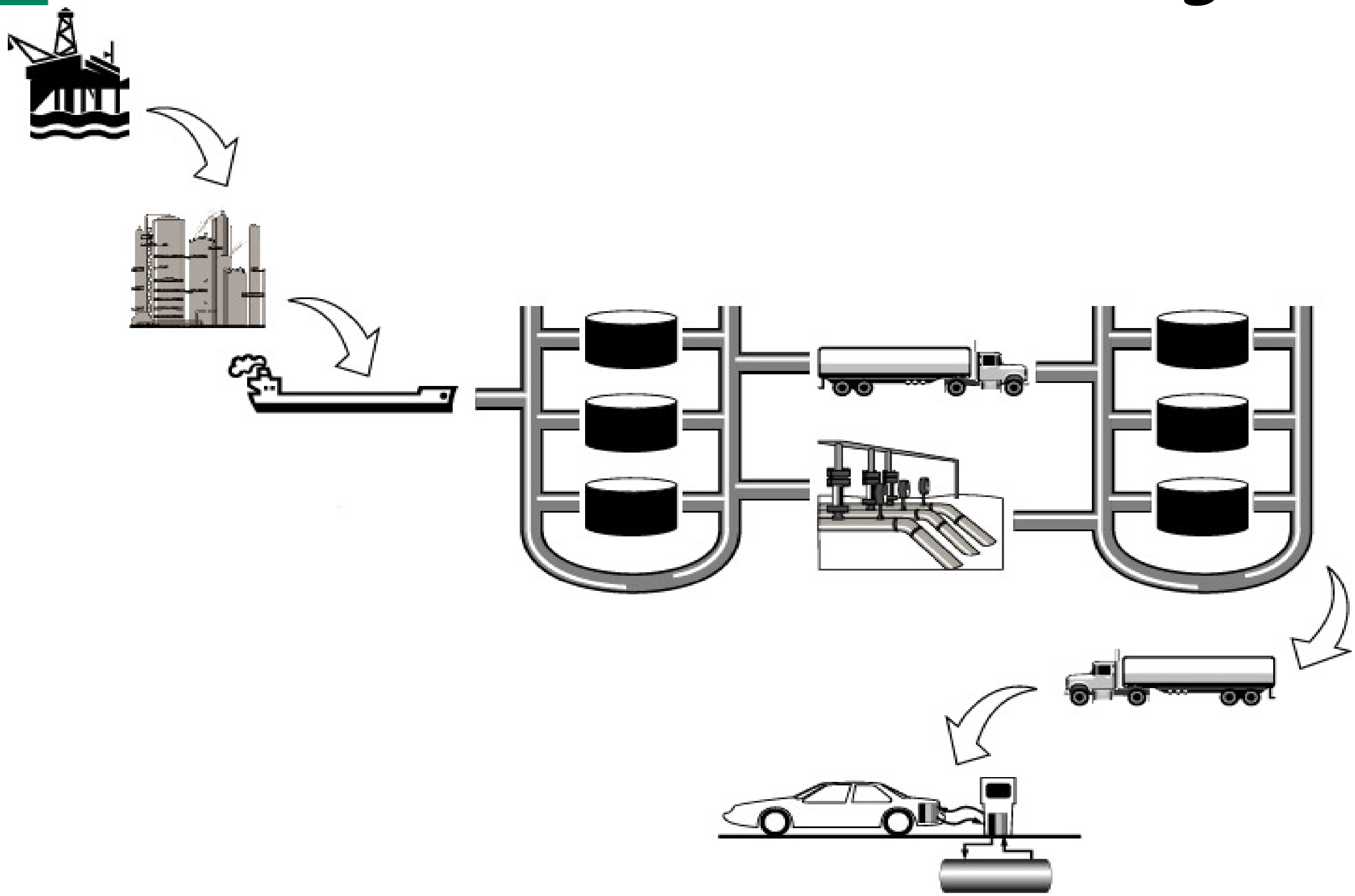
- Capacity of 138,000 m3 with four independent spherical tanks
- Effective lifespan 30-40 years

Characteristics of LNG Terminals



- **Capital Cost: $127,000,000**
- **Annual Capacity Factor: 90%**
- **Capacity: 450 x 10^6 scfd**
- **Unit O&M Cost: $0.30/$10^6$ Btu**

Methanol and FTD Move by Truck or Pipeline from Ports to Terminals and Refueling Stations

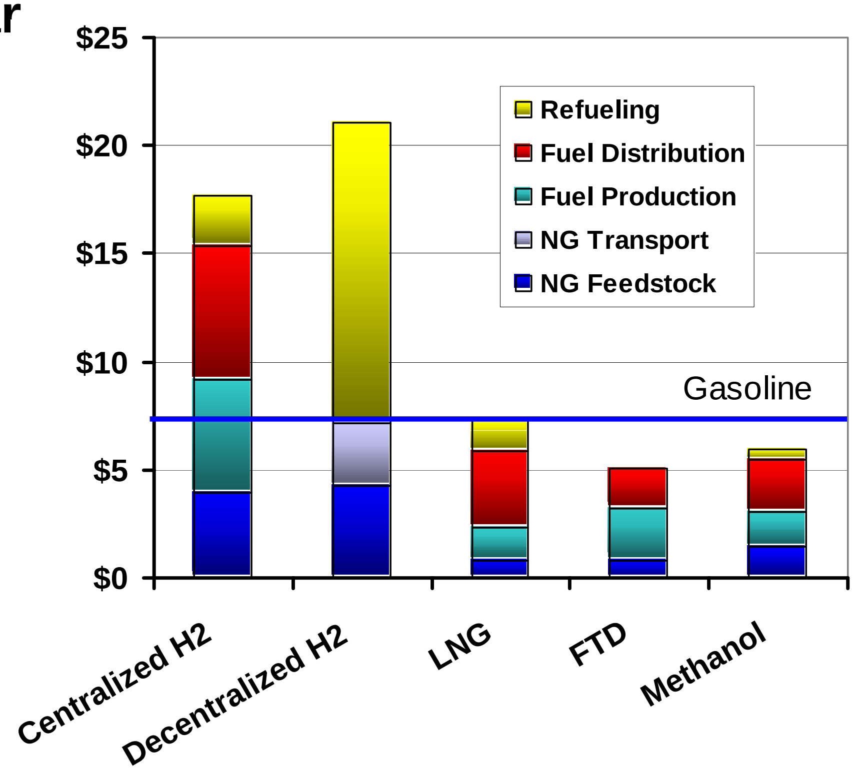


"Tank-In" Fuel Requirement Is a Function of MPGE and Market Penetration

Pathway	Engine Technology	MPGE	High Penetration
Hydrogen	FCV (on-board H_2)	55	4.8×10^9 GJ (4.5 Q)
LNG	ICE	27.5	9.5×10^9 GJ (9.0 Q)
Methanol	FCV (on-board reforming)	41.2	6.4×10^9 GJ (6.1 Q)
FTD	Hybrid	38.5	6.8×10^9 GJ (6.4 Q)

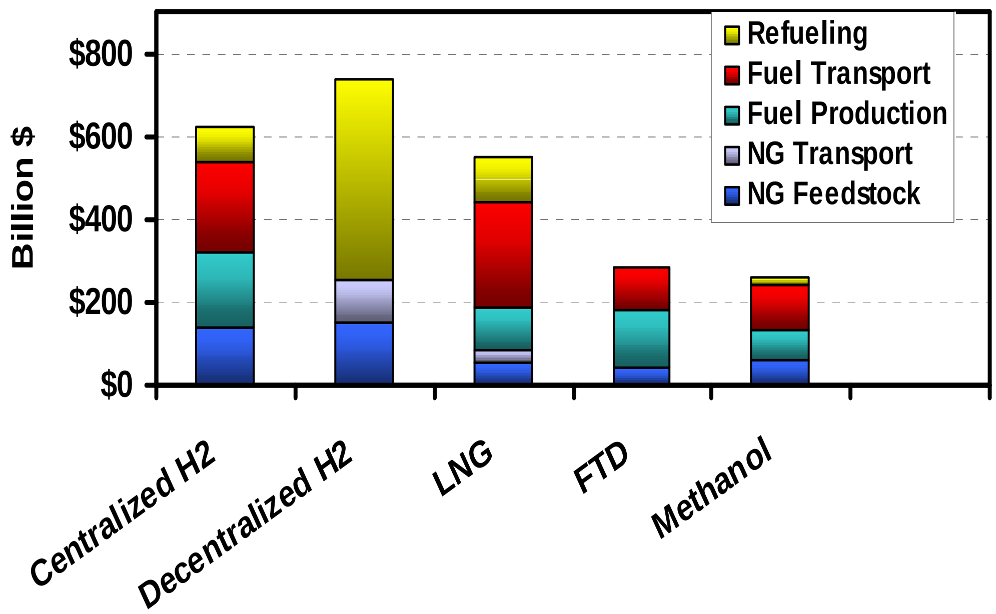
Excluding Profit and Taxes, Unit Cost of NG-Based Fuels Varies from $5 to $21/GJ

- For all pathways, hydrogen is far more costly than LNG, FTD or methanol ($2.00 vs.$0.60-0.80/GGE)
- FTD is the lowest cost alternative, largely because it requires the least infrastructure
- Low-cost, non-North American feedstock makes LNG, FTD and methanol less costly
- Reformers and pipelines further increase hydrogen cost



Total Infrastructure Costs Are Highest for Hydrogen; Lowest for FTD and Methanol

- **Relatively lower mpge, LNG delivery volumes and infrastructure cost.**
- **Higher relative efficiency of hydrogen-fueled vehicle reduces ratio of total cost relative to unit cost to about double**
- **For all three hydrogen pathways, total cost is \$600-\$700 billion; FTD and methanol are about half.**



Some Conclusions:

- With current technologies, on a well-to-tank basis, the unit cost of hydrogen is likely to be 2-3 times that of gasoline.
- To offset this, the mpge of hydrogen-fueled vehicles must be more than double gasoline.
- With current technologies, the hydrogen delivery infrastructure to serve 40% of the light duty fleet is likely to cost over $600 billion.
- With low-cost feedstock and use of in-place infrastructure, FTD is competitive with gasoline.

Conclusions (cont'd)

- **With current technologies, scale economies are large for centralized hydrogen production; small for decentralized**
- **H_2 transport and production are the largest components of all paths examined, hence appropriate focus for cost reduction.**

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Next Steps: Several Additional Technologies and Fuel Options Should Be Examined

- **Additional LNG alternatives, including station reforming and hybrid vehicles.**
- **Mixed cases, incorporating more than one pathway and targeted to market niches that exploit relative advantages.**
- **Additional hydrogen production options, including high-temperature thermochemical water splitting, methane pyrolysis and coal gasification**
- **Transition issues**