# Business Case for New Nuclear Power Plants

*Bringing Public and Private Resources Together for Nuclear Energy*

## Mitigating Critical Risks on Early Orders for New Reactors

David Berg, National Energy Policy Office
for ELCON
February 2, 2005

# *Sections of Business Case Analysis*

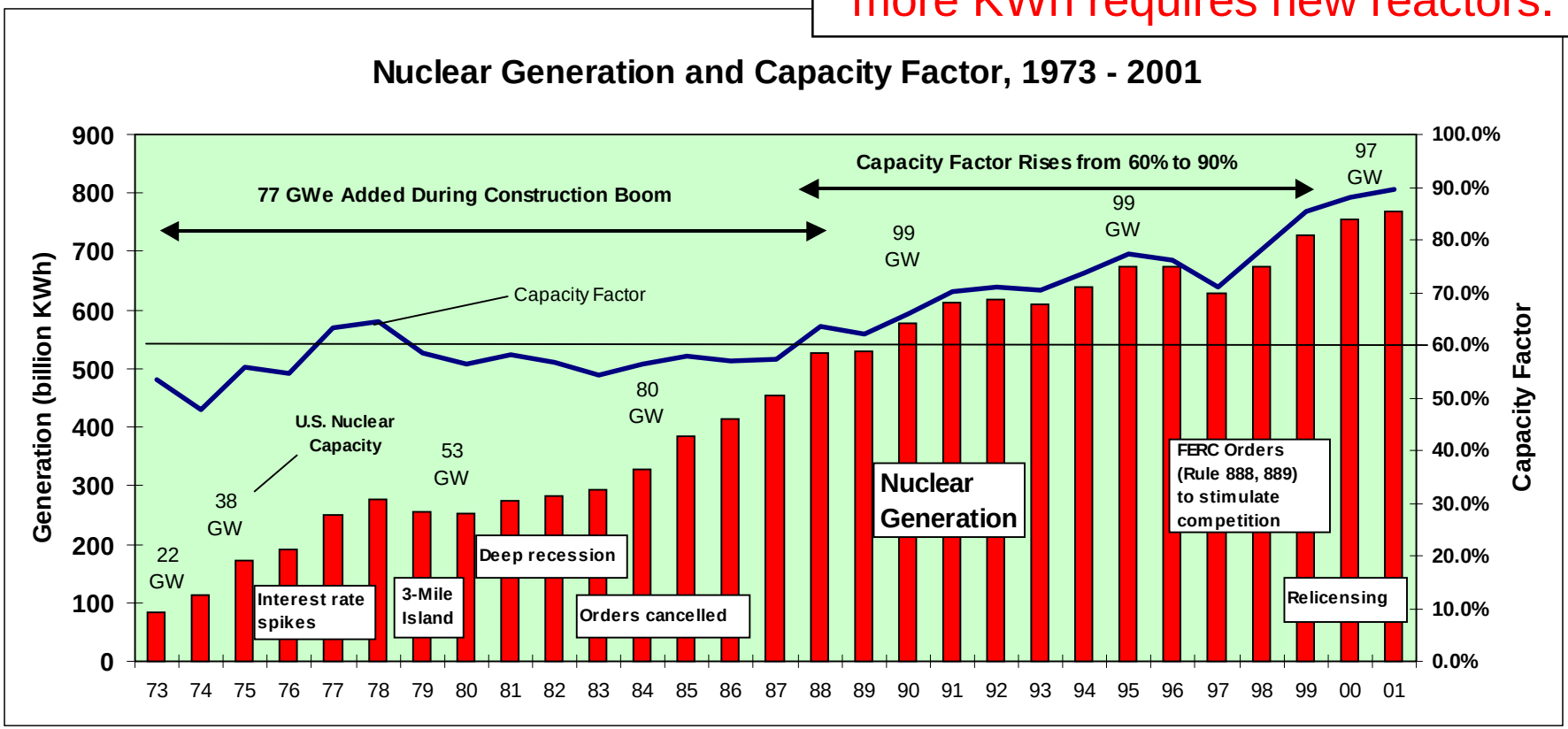
1. Introduction & Policy Background: Why a Business Case?
2. Shift of Market Factors for Nuclear Power
3. Risk Framework and Industry Survey
4. Financial Modeling and Sensitivity Analysis
5. Use of Risk-Targeted Federal Credit Tools
6. Findings and Conclusions

# 1. Introduction and Policy Background

- **National Energy Policy** (May 2001): **President should support expansion of** low-cost, safe, environmentally clean **nuclear energy** as "major component of national energy policy".
- **Energy Secretary Abraham** (February 2002): **Yucca Mountain should be formally considered for disposal** of nuclear spent fuel. Congress voted to proceed with licensing phase (July 2002).
- **President Bush announced** "Clear Skies" (2/02) to **reduce GHG/ carbon intensity** in American economy, including nuclear power.
- FERC rulemakings (2003–2005) on Standard Market Design and Regional Transmission Organizations (RTOs) could change market dynamics and regional planning.
- Energy bill could affect market dynamics.
- "Business Case" outlined business risks, recommended risk management strategies to better target financial assistance and reduce budget cost.

# U.S. Nuclear Power Generated, Capacity Factor, 1973–2001

- Baseload nuclear power produced: 768 billion KWh in 2001 v. <100 billion KWh in 1973. 77 GWe of capacity added between '73 and '87.
- Commercial orders cancelled in late '70s and early '80s: high interest rates, TMI accident, and recession. Last unit finished in 1980s.
- U.S. fleet-wide capacity factor rose from 60% in '87 to >90% in '01. Upratings could add another 7 GWe before 2010.
- U.S. nuclear fleet is approaching capacity factor ceiling. To get more KWh requires new reactors.



# 2. Shift of Market Factors for Nuclear Power

**Shifts on several key issues improve prospects for nuclear power:**

| *Then (1970s – 1980s)* | *Now – 2010* |
|---|---|
| Regulatory | Regulatory |
| • Greenfield sites opposed after TMI (1979) | • Next reactors (~18 – 24) built on current sites in supportive locations |
| • License renewals not considered | • More than 16 reactors renewed through 2003 (8 sites in 7 states) |
| • Uncertain regulatory approval; separate construction and operating licenses | ★ NRC defining COL rules (Combined "Construction & Operating License") |
| • Spent fuel disposal sites being reviewed: No resolution | ★ Congress approved licensing phase for Yucca Mountain (July 2002) |
| • Price-Anderson indemnification | ★ 1-year renewal for P-A |
| Environmental | Environmental |
| • Concern about urban air pollution, not about greenhouse gases | • Nuclear role in SIPs<br>• Global concern about GHG levels |

★ Deal-breaker issue, now leaning favorable

# *Shift of Factors for Nuclear Power (cont.)*

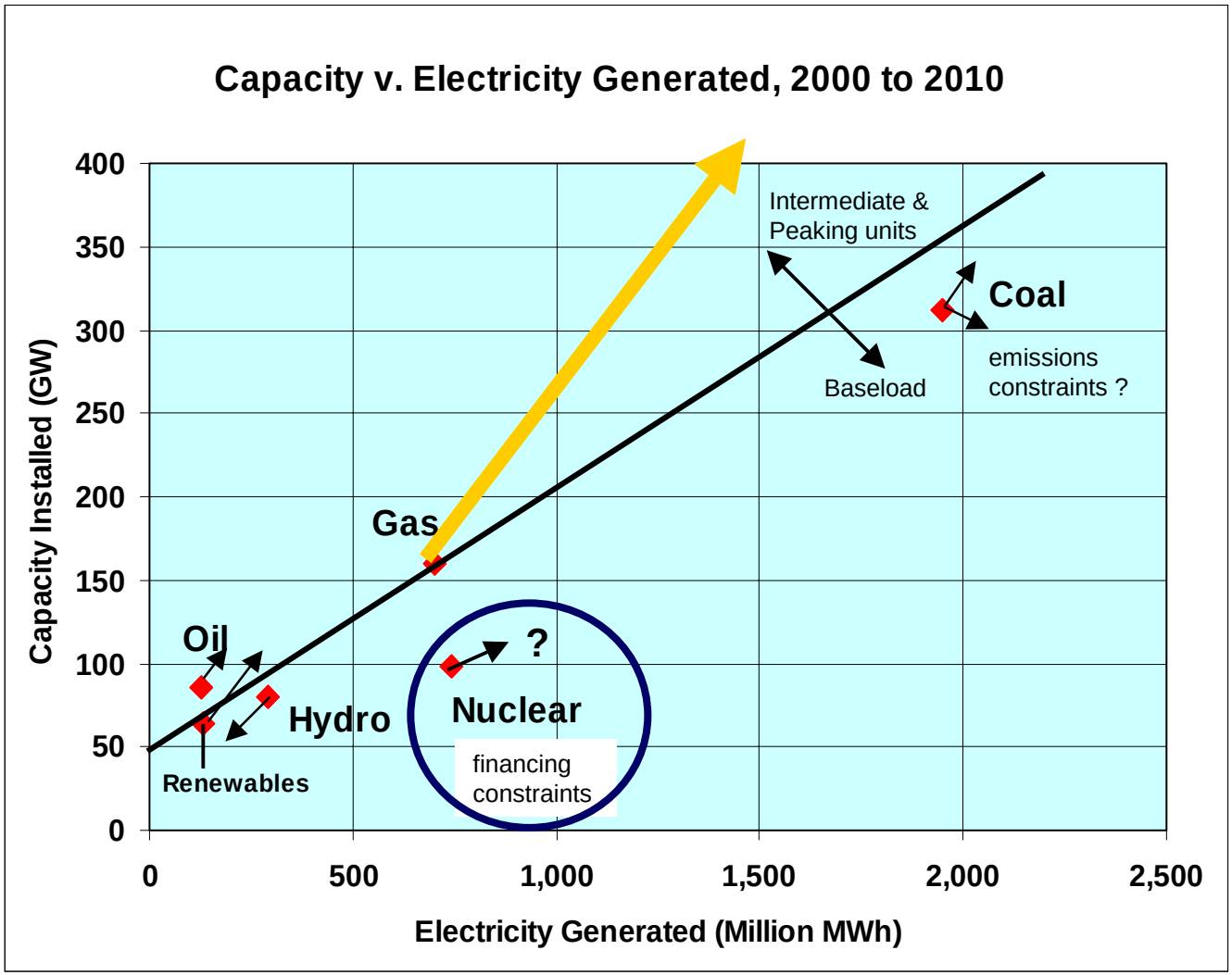
## Shifts on several key issues improve prospects for nuclear power:

| ***Then (1970s – 1980s)*** | ***Now – 2010*** |
|---|---|
| Economics | Economics |
| • Low capacity factors fleet wide (<60%) | • Capacity factors >90% in 2001 |
| • Uranium cost: 2x – 3x current prices | • Stable fuel prices at $5 / MWh |
| • Regulated gas prices | • Gas prices are higher (>$4/MMBtu) and are volatile |
| • Capital costs covered in rate base | • Capital costs reviewed by PUCs |
| Finance | Finance |
| • No standard plant designs; no CAD/CAM | • Pre-certified designs; CAD/CAM |
| • High interest rates (12%–18 %) | • Interest rates down to ~5%–8% |
| • Many owners and inefficient staffing; some public owners had limited capital | • Consolidation of ownership (75% of fleet owned by ~12 operators); financially healthy operators |
| • Electricity prices approved by PUC | • Mixed pricing; baseload contracts |

Note: Project cancellations began *before* TMI (1979); interest rates rose (1974–1975).

# Capacity v. Generation: Gas Share Surged

## U.S. must consider nuclear, not just renewables, to make GHG progress.




- U.S. coal fleet (capacity >300 GWe), delivers >50% of electricity, but faces increasing emissions constraints.
- New gas-fired capacity will be used mostly for intermediate demand. New nuclear plants would be baseload.
- New renewable and biomass plants will barely offset decline in hydropower through 2020. Renewables are not well-suited to baseload.

*Source: EIA*

# Key Assumptions: AEO 2003, Business Case

**Shifts on several key issues improve prospects for nuclear power:**

## Key AEO Assumptions on Nuclear

- Reference case: No new units built to 2025; only 4,200 MWe in uprates
- "Greenfield", 1000 MWe projects
- Capacity factor 92% (2010)
- $2100/KWe for first reactor
- $1500/KWe for a reactor (>15+)

"Advanced Nuclear Case":

- Overnight capital costs lower ($1500/KWe); $1200/KWe by 2020
- Only 1,700 MWe built by 2020; 14,300 MWe added by 2025

## *Business Case* Key Assumptions

- 1100 MWe unit at current site
- Capacity factor of 90%
- Sensitivity analysis on range of capital costs: $1455/KWe ($1943/KWe with financing costs) to $909/KWe ($1247/KWe), including 7.5% "buyer's contingency
- 50 : 50 debt : equity financing with debt at 8% over 25 years
- Target IRR threshold: 10% (after-tax)
- Ave. electricity price of 3.5 ¢/KWh

# Some Issues and Questions

- How does gas prices outlook (level, volatility) affect prospects for nuclear power? Would nuclear units displace gas peaking units?
- Do air emission benefits of nuclear power accelerate plant orders (<2020)? How could the benefits be monetized?
- Do emissions constraints for coal plants open door for nuclear?
- Does mixed picture for electricity market reform affect new orders?
- Why assume first reactors will be "greenfields" when companies can add 20,000+ MWe at current sites in regulated territory?
- Several studies show first reactors could be built in range $1400–$1800/KWe. Is recent construction experience overseas relevant to U.S. construction costs?
- What construction cost risks are vendors prepared to guarantee?
- How could energy bill or DOE programs best address key issues associated with new orders?

# *So, Why Are Utilities Not Ordering New Nuclear Plants?*

# Investment in Current Reactors, >1998

Technical and financial performance has improved with ownership consolidation. Larger owners can finance new units based on larger balance sheet, total asset value.

| Date Done | Buyer | Owner | Nuclear Unit | Type | Year Start | MW | Deal Size ($Mil) |
|---|---|---|---|---|---|---|---|
| Jun-99 | Entergy | Boston Edison | Pilgrim / MA | BWR | 1972 | 665 | $13 |
| Jun-99 | Amergen (Exelon + British Energy) | Unicom | Clinton / IL | BWR | 1987 | 930 | $23 |
| Dec-99 | Amergen (Exelon + British Energy) | GPU | Three-Mile Isle 1 / PA | PWR | 1974 | 790 | $23 |
| Mar-00 | Entergy | NYPA | Indian Point 3 / NY | PWR | 1976 | 980 | A) $967 |
| Mar-00 | Entergy | NYPA | Fitzpatrick / NY | BWR | 1974 | 816 | A) $967 |
| Jun-00 | Amergen (Exelon + British Energy) | GPU | Oyster Creek / NJ | BWR | 1969 | 650 | $10 |
| Aug-00 | Dominion | Northeast Utilities | Millstone 2 / CN | PWR | 1975 | 858 | B) $1,300 |
| Aug-00 | Dominion | Northeast Utilities | Millstone 3 / CN | PWR | 1986 | 1150 | B) $1,300 |
| Aug-00 | Entergy | Yankee Nuclear | Vermont Yankee / VT | BWR | 1973 | 522 | $180 |
| Nov-00 | Entergy | ConEd | Indian Point 1 & 2 / NY | PWR | 1974 | 957 | $602 |
| Dec-00 | Constellation | Niagra Mohawk | Nine-Mile Point 1 / NY | BWR | 1969 | 614 | C) $815 |
| Dec-00 | Constellation | Niagra Mohawk | Nine-Mile Point 2 / NY | BWR | 1988 | 1140 | C) $815 |
| Jun-01 | PECO | Delmarva | Peach Bottom 2&3/NJ | BWR | 1974 | 330 | $7 |
| Oct-01 | PSEG | Atlantic Energy | Salem 1 & 2 / NJ | PWR | 1980 | 383 | $10 |
| Apr-02 | Florida Power | NA Energy Srvc | Seabrook / NH | PWR | 1990 | 1150 | $580 |
| | TOTAL | | 18 Units | 9P / 9B | 1977 | 11,935 | |

*Source: NEI*

# 3. Risk Framework and Industry Survey

***The Business Case for DOE:***
***Risk Framework Drives Options for Early Orders***

# Overview and Approach to Risk Framework

Diagram depicts logic flow and approach to analysis.

**Power Plant Project Development Timeline** → **Risk Analysis of Project Development Stages** → **Rating and Ranking of Risks** → **Evaluation, Application of Risk Mitigation Mechanisms**

Timeline Evaluation

- Delineation of key development stages for power plant
- Matching of development stages with financing events

Risk Analysis by Stage of Project Development

"Showstoppers":
- Disposal
- Accident
- Commissioning

Major Risk Categories
- Technology / Design
- Development / Siting
- Regulatory
- Construction
- Operating
- Fuel price, supply
- Demand
- Dispatch
- Transmission

Interview and Rating Approach

- Design of survey instrument
- Definition of criteria for interview candidates
- Selection of interview candidates
- Contact of candidates
- Interviews, risk ratings
- Evaluation of risks
- Two workshops

Evaluation of Mitigation Mechanisms

- Financial model and sensitivity analysis
- Delineation of mechanisms
- Matching of possible mechanisms to risks
- Evaluation of risk coverage for each stage
- Determination of measures, legislation needed to implement

The risk framework approach builds on the key barriers identified in DOE's Near Term Deployment Roadmap, October 2001.

# Industry and Financial Participants

## Utilities

- Constellation Energy
- Dominion Resources
- Entergy Nuclear
- Exelon
- PSEG
- Southern Nuclear
- Tokyo Electric Power

## Engineering & Construction

- Bechtel Nuclear
- Sargent & Lundy

## Electricity Grid

- PJM Interconnect

## Reactor Systems & Services

- Framatome ANP
- GE Nuclear
- BNFL Westinghouse Nuclear

## Financial Community

- ANZ Investment Bank
- Citibank
- Credit Suisse First Boston
- Credit Lyonnais
- Deutsche Bank Securities
- Goldman, Sachs & Co.
- Lehman Brothers
- Merrill Lynch
- Morgan Stanley & Co.
- Zurich-American insurance

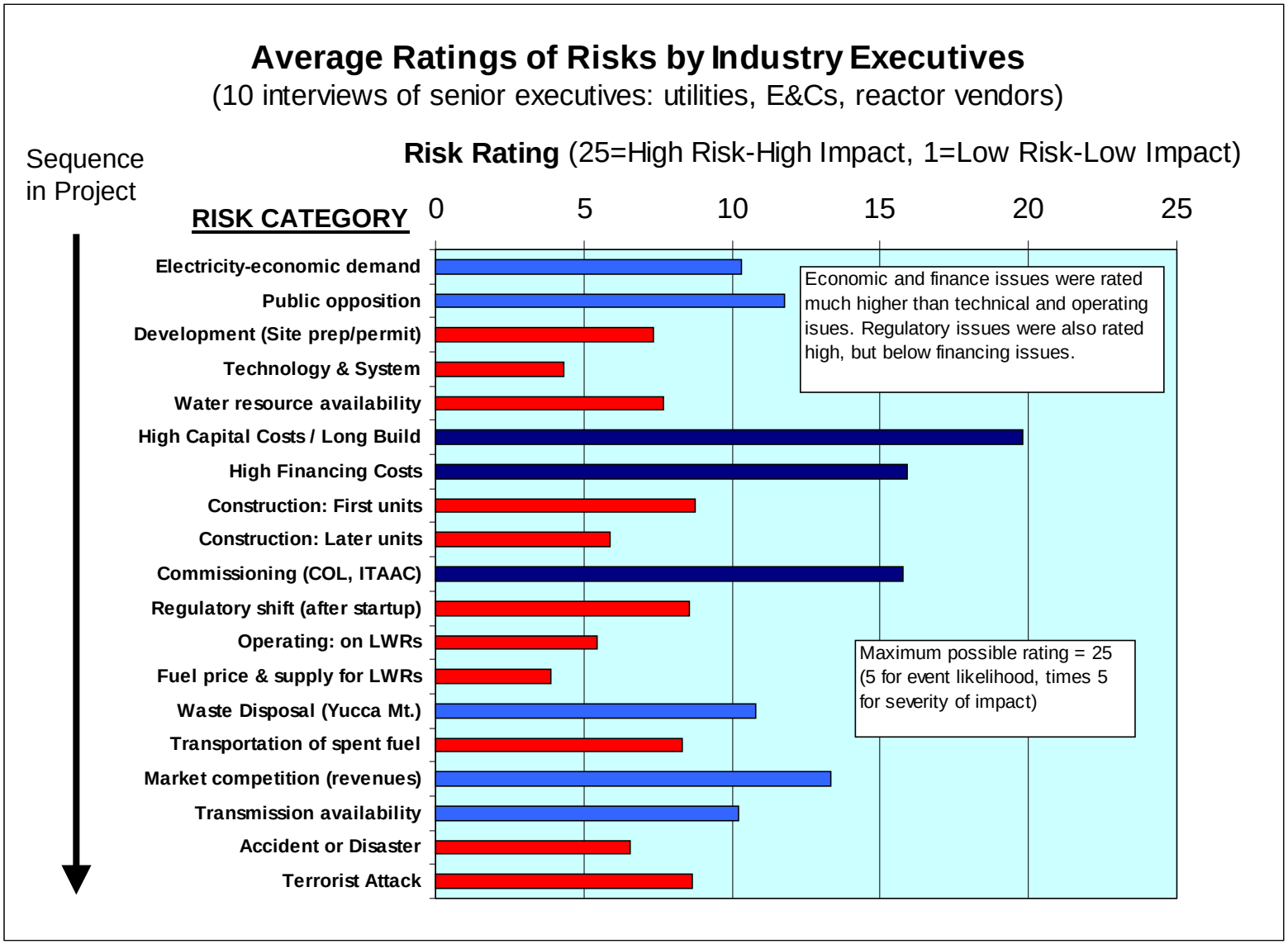
## Non-Governmental Organizations

- National Defense University
- Natural Resources Defense Council
- Nuclear Control Institute
- Union of Concerned Scientists

## Government

- Nuclear Regulatory Commission

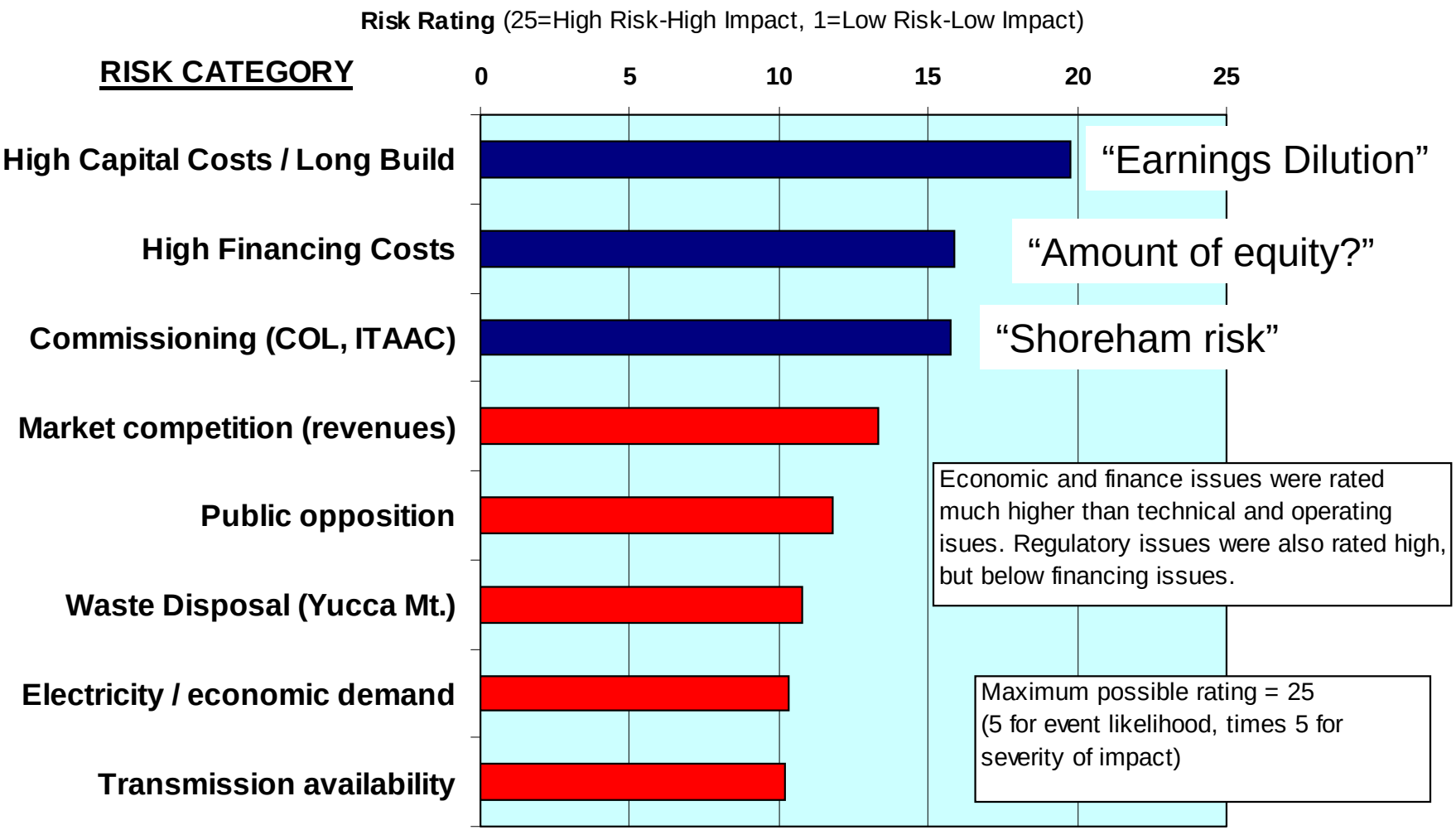
# Industry Risk Ratings Summary, Oct. 2002



# Highest Risks in U.S., Rated by Industry

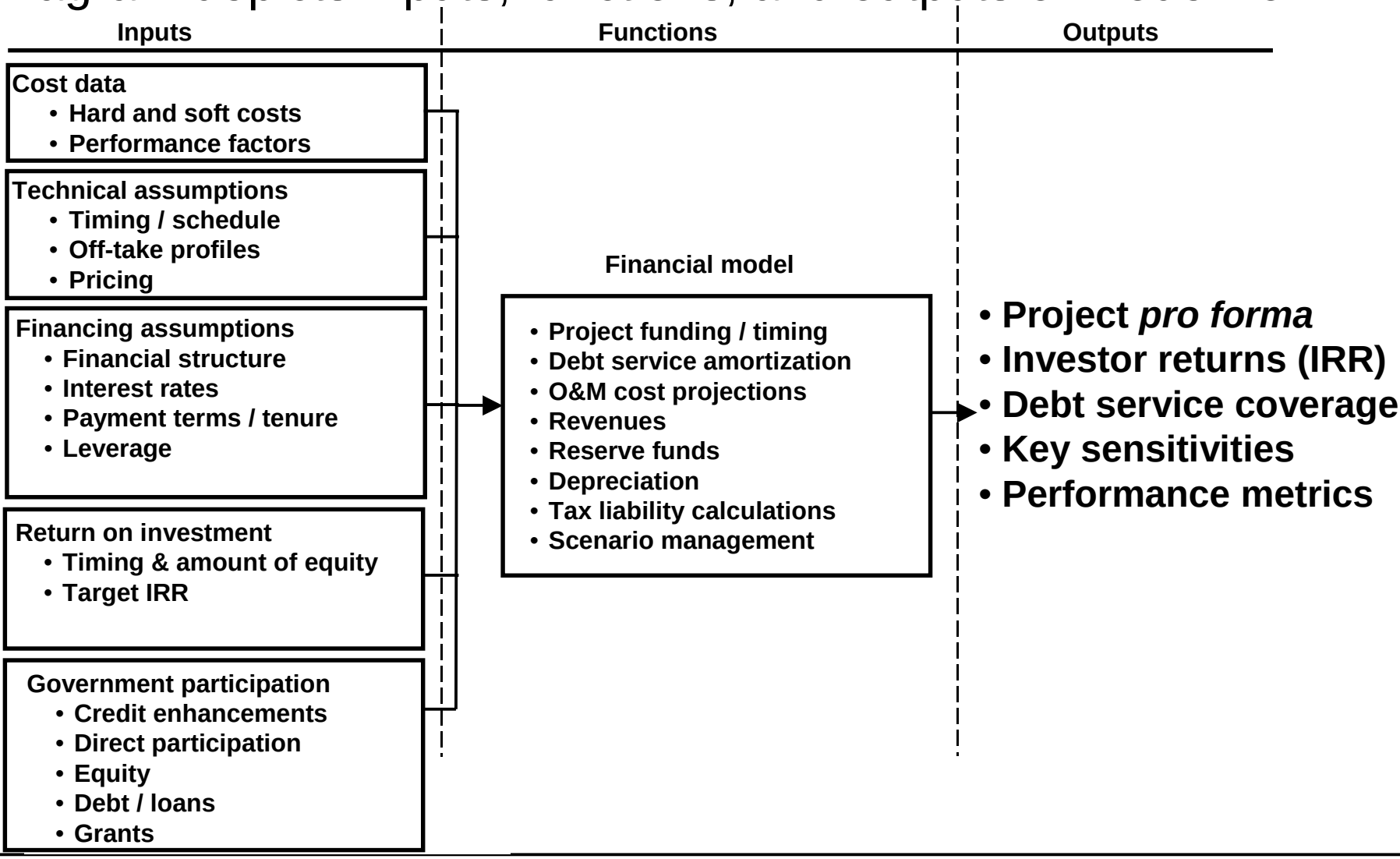
## Average Ratings of Risks by Industry Executives, Oct. 2002

(10 interviews of senior executives: utilities, E&Cs, reactor vendors)



# 4. Financial Model, Sensitivity Analysis Data Flow

Diagram depicts inputs, functions, and outputs of model flow.



# Sensitivity: EPC Cost v. Electricity Rate

- **The sensitivity analysis shows that IRR improves as capital costs are reduced.** Over the range evaluated and with wholesale electricity rates held constant at $35 / MWh, IRR increased from 7.3% to 9.3% for early plants, reaching 10.7% for a plant with EPC costs of $1.0 billion.
- IRR rose rapidly when EPC costs were held constant and electricity rates were increased. **Among the major variables, electricity rate is one of the factors IRR is most sensitive to.**
- For example, for a $1.2 billion EPC (overnight) cost plant, a $2 / MWh change in electricity rate (a 6% change) causes a 1% change in after-tax IRR.
- **If wholesale electricity rates are projected at less than $35 / MWh, then early orders of nuclear plants would not likely be attractive investments.** On the other hand, at the highest electricity rates examined, even the most expensive nuclear plant can meet IRR targets.
- Even the highest-cost plant tested, costing more than $1,700 / KWe, can achieve an adequate IRR if electricity rates rise sufficiently (i.e, to a point significantly higher than today's market rates, which range widely but are most frequently in the $20 – $40 / MWe range).
- **The table below shows that rising electricity rates or rate augmentation can create a relatively large zone of investment feasibility.**

| $ / KWe (1100 MWe) | EPC + (A) + Financing | EPC Cost | Electricity Rate ($ / MWh) $25 | $30 | $35 | $40 | $45 |
|---|---|---|---|---|---|---|---|
| | | | IRR → | | | | |
| $1,943 | $2.14B | **$1.6B** | 2.5% | 5.1% | 7.3% | 9.4% | **11.4%** |
| $1,708 | $1.88B | **$1.4B** | 2.8% | 5.8% | 8.2% | **10.5%** | **12.7%** |
| $1,475 | $1.62B | **$1.2B** | 3.4% | 6.6% | 9.3% | **11.9%** | **14.4%** |
| $1,247 | $1.37B | **$1.0B** | 4.2% | 7.6% | **10.7%** | **13.7%** | **16.6%** |

(A) Development, Startup, Buyer's Contingency

# 5. Use of Risk-Targeted Federal Credit Tools

# *Primary Findings and Conclusions*

- **New nuclear plants can be competitive** @ ~$1100 / KWe.
- **Three unresolved key barriers could prevent new orders:**
  - Spent fuel disposal, including transportation.
  - Reauthorization of accident indemnification.
  - Clear, finite NRC licensing processes, particularly for commissioning.
- **Early-plant capital costs are to too high**:
  - Capital costs (financing included) may be >$1600 / KWe for first plants, declining to ~$1200 / KWe for $4^{th}/5^{th}$ plants.
  - So, orders of first plants could require government aid.
  - Government aid could cost less if assistance were risk-targeted (compared with cost-sharing, tax credits).

# *Risks and Risk Mitigation Techniques*

- **Through effective use of several mitigation techniques, DOE could help industry manage critical "risk gaps" for the first several plants.**
- **Key risks to address in early plant strategy:**
  - **Unique regulatory risks:** Standby tools (interest maintenance, debt principal buy-down, and equity options to support financing in event of process delays).
  - **Construction cost overrun risk:** Standby loans after warrantee.
  - **FOAKE risk:** Co-funding; Government direct loans.
  - **High capital costs:** Direct loans; Investment tax credits; Accelerated depreciation.
  - **Revenue augmentation:** Power purchase agreements; Production tax credits; Carbon emissions credits that include nuclear energy.
  - **Earnings dilution:** Investment tax credits.

# *Risks and Risk Mitigation Techniques*

**Through effective use of several mitigation techniques, DOE could help industry manage critical "risk gaps" for the first several plants.**

| Mitigant | Description | Estimated Subsidy Amount |
|---|---|---|
| **1. Standby Default Coverage** | Addresses regulatory- and intervener-caused start-up delays leading to non-commissioning. | **$18.7 million** |
| **2. Standby Interest Maintenance** | Addresses regulatory- and intervener-caused commissioning delays. | **$10.8 million** |
| **3. Direct Loan / Loan Guarantee** | Creates leverage to improve plant financial returns. | **$63.8 million** for $350 million loan |
| **4. Power Production Incentive Loan** | Reduces market risk and addresses high cost of early plants. | **$50 million** based on a $0.015/KWh payment for 50% of production for 10 years |
| **Total if all four mechanisms are used for one plant.** | | **Total: $143.3 million** |

# Recommended Credit-Based Risk-Mitigants

## 1. Standby Default Coverage

- Addresses *only* NRC and intervener-caused commissioning delays for first plants, not construction delays or utility decisions—for 5 years.
- Covers cost of plant (debt + equity?); only for non-commissioning.

## 2. Standby Credit Facilities (Lines of Credit)

- Provides interest payments during delays (convert to loans).

## 3. Direct Loans (non-recourse, sub-debt)

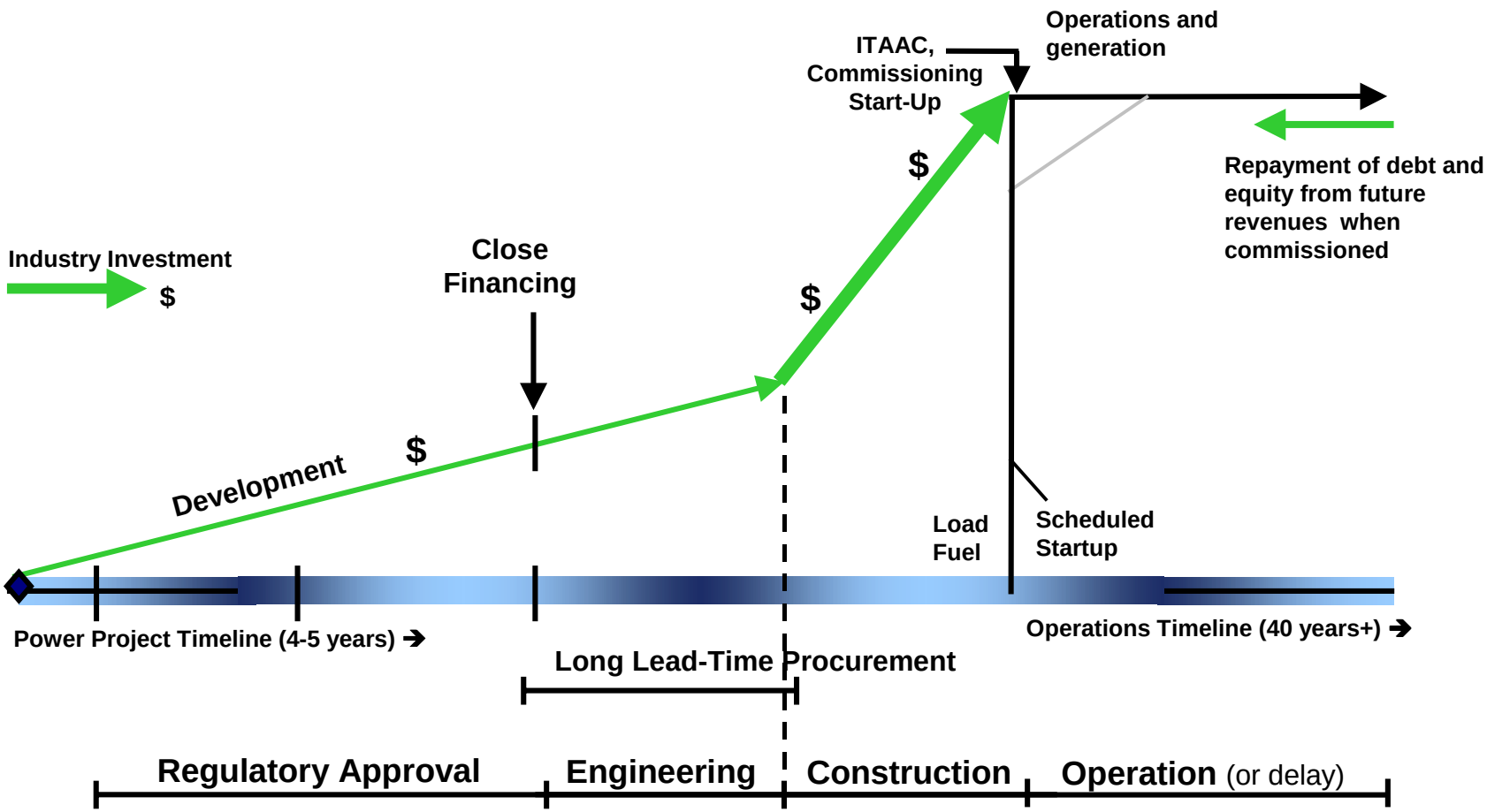
- Government loan during engineering and construction helps offset higher capital costs of first plants and catalyze private lending.

## 4. Power Production Incentive

- Production payment catalyzes private lending by reducing market risk; offsets high cost of first plants by adding premium to power generated (e.g., $15/MWh).
- PPI payments convert automatically to project (subordinated) loans.

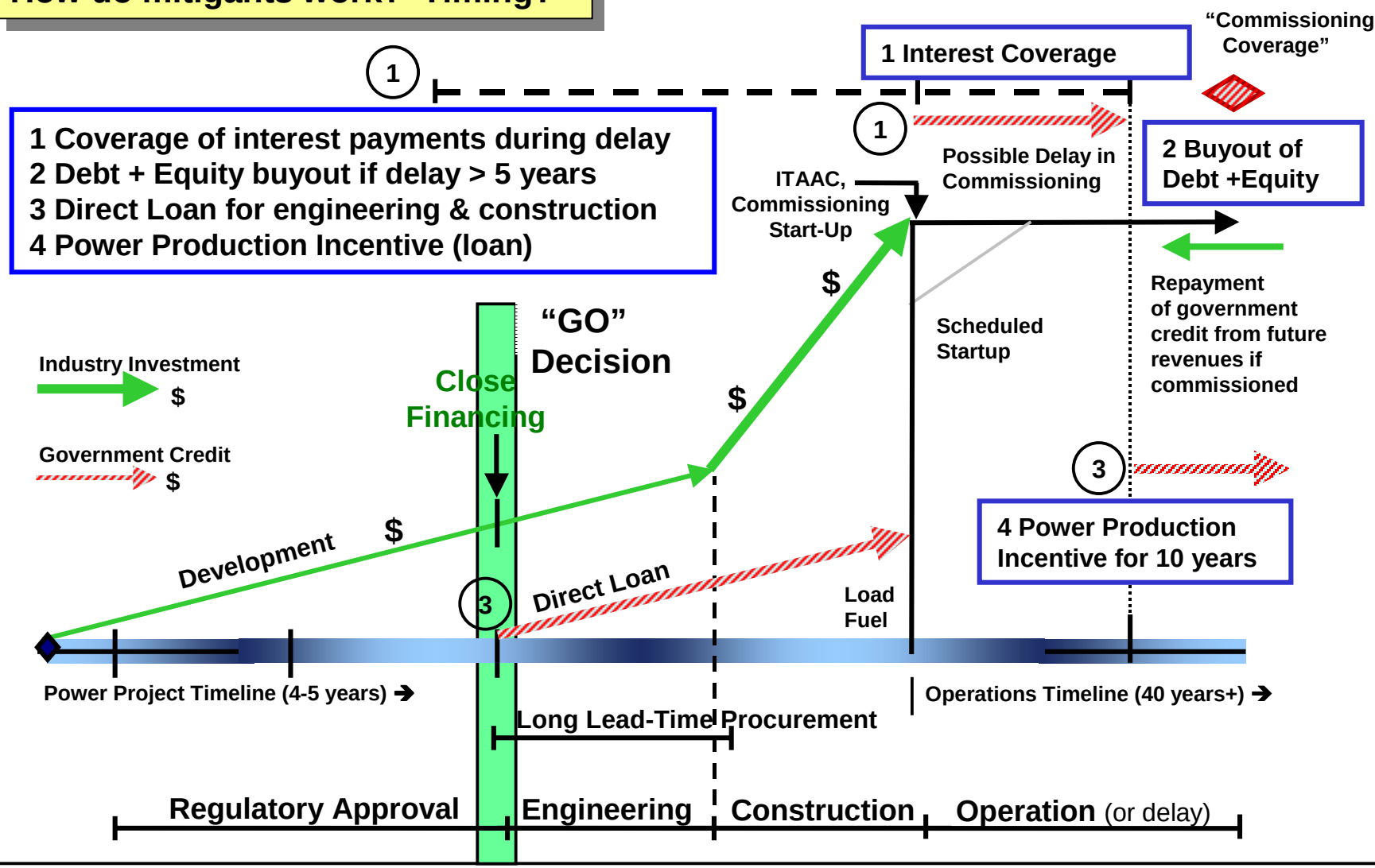
# Power Project Timeline

Risks differ at each phase of a power project, so target assistance tools to address specific critical risks.



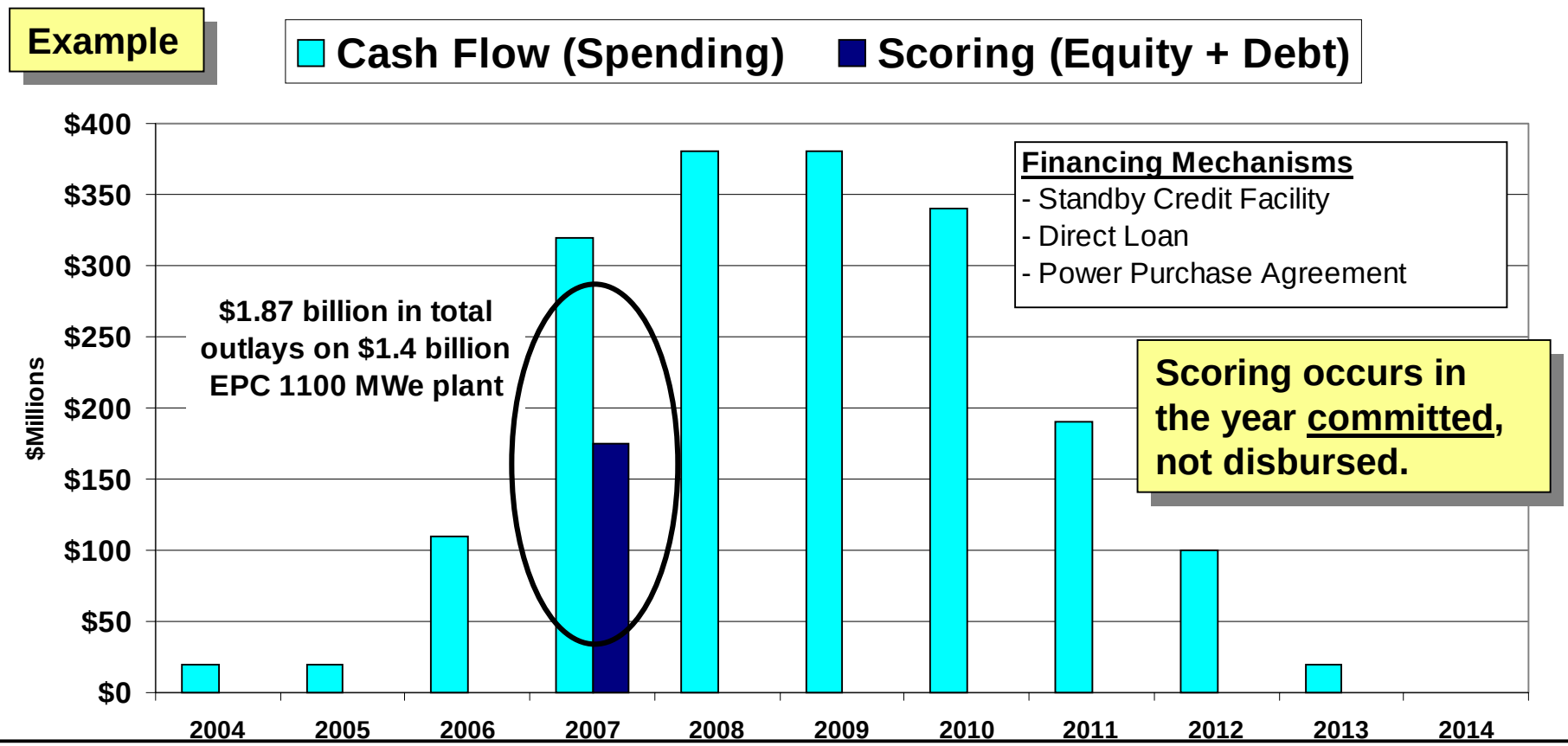
# Risk Mitigant Timing: Combined Measures

**How do mitigants work? Timing?**



# Budget Scoring Leverage Using Credit

Scoring based on principles under Federal Credit Reform Act, assuming use of all four mitigants for a single plant. Support limited to what is necessary to reach investment goal of 10% IRR.



# 6. Primary Findings

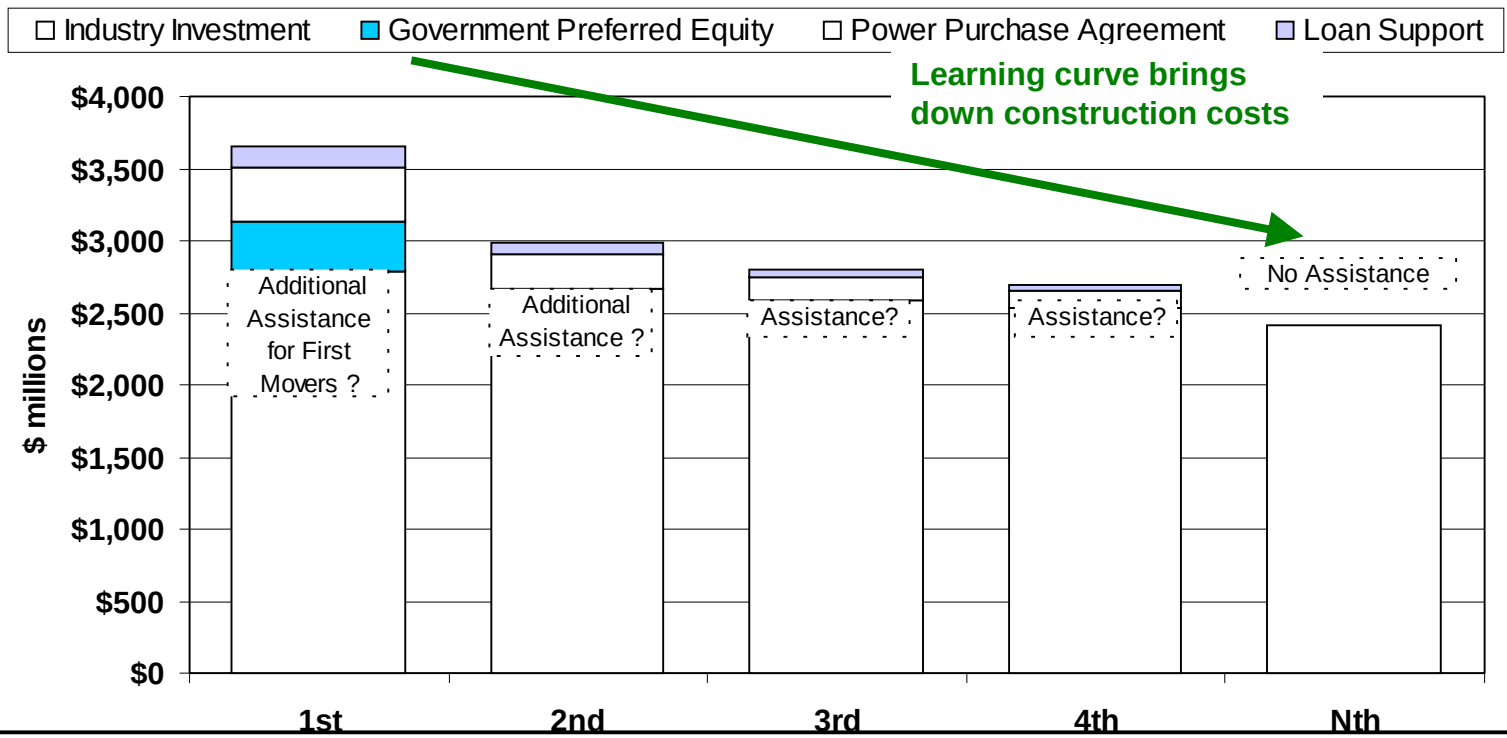
- **Outlook for nuclear power has improved since 1990** due to several market and industry developments, particularly:
  - A sharp rise in fleet capacity factor (65% in 1990; nearly 90% in 2000);
  - Lower marginal cost of nuclear power produced relative to competing sources;
  - Lower interest rates; and
  - Good safety record and improved public sentiment in several regions.
- **New nuclear plants can be competitive** @ “Nth” plant costs = ~$1100 / KWe.

# *Primary Findings (cont.)*

- **Three key barriers could prevent new orders:**
  - Spent fuel disposal, including transportation.
  - Reauthorization of accident indemnification.
  - Clear, finite NRC licensing processes, particularly for commissioning.
- **Early-plant capital costs appear to be too high**:
  - Capital costs (financing included) could be >$1600 / KWe for first plants, declining to ~$1200 / KWe for $4^{th}/5^{th}$ plants.
  - So, $1^{st}$ plant orders could require government assistance.
  - Government should match assistance to key risks.
  - By more negotiating targeted risk-mitigating assistance rather providing than cost-shared grants or tax credits, government can reduce its cost *and* improve results.

# *Challenge: 1st Order Cost Disadvantage*

- First mover penalty creates “Catch-22” challenge: Critical risks + cost premium on 1st units.
- So “1st units" are not likely to be ordered.
- After first orders, assistance costs less to provide.



# *Conclusions: Take Home Thoughts*

- **The outlook for nuclear power has improved since 1990.**
- Plants financed solely by private sector face obstacles:
  - Industry executives list 3 "show-stopper" risks. With progress on Price-Anderson and Yucca Mountain, commissioning remains key.
  - Current electricity market and regulatory conditions challenge electricity demand and price projections to 2010.
  - Long build time, high capital costs cause earnings dilution.
  - Monetizing emissions benefits improves financing prospects.
- **Conclusion: Once first several plants have been built and operated, nuclear power *can be competitive*.**
- **DOE, with effective use of credit tools, could partner with industry to co-manage critical "risk gaps" on early plants.**
- Place 1st units in regions most supportive of nuclear power.

# *For copies of slides/report contact:*

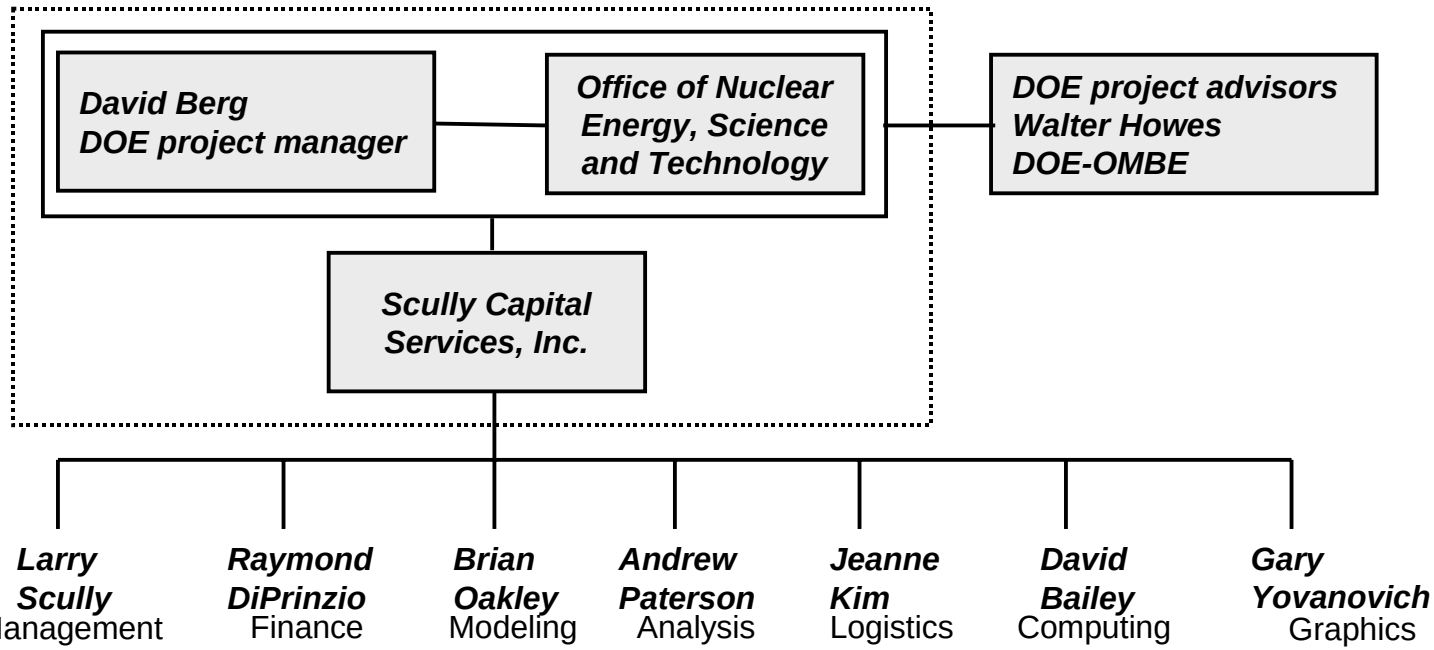
David Berg: david.berg@hq.doe.gov
Andrew D. Paterson: adpaterson@aol.com
Larisa Dobriansky: larisa.dobriansky@hq.doe.gov
Brian Oakley: boakley@scullycapital.com

***The Business Case for New Nuclear Power Plants***
**at www.nuclear.gov**

# *Reference Slides*

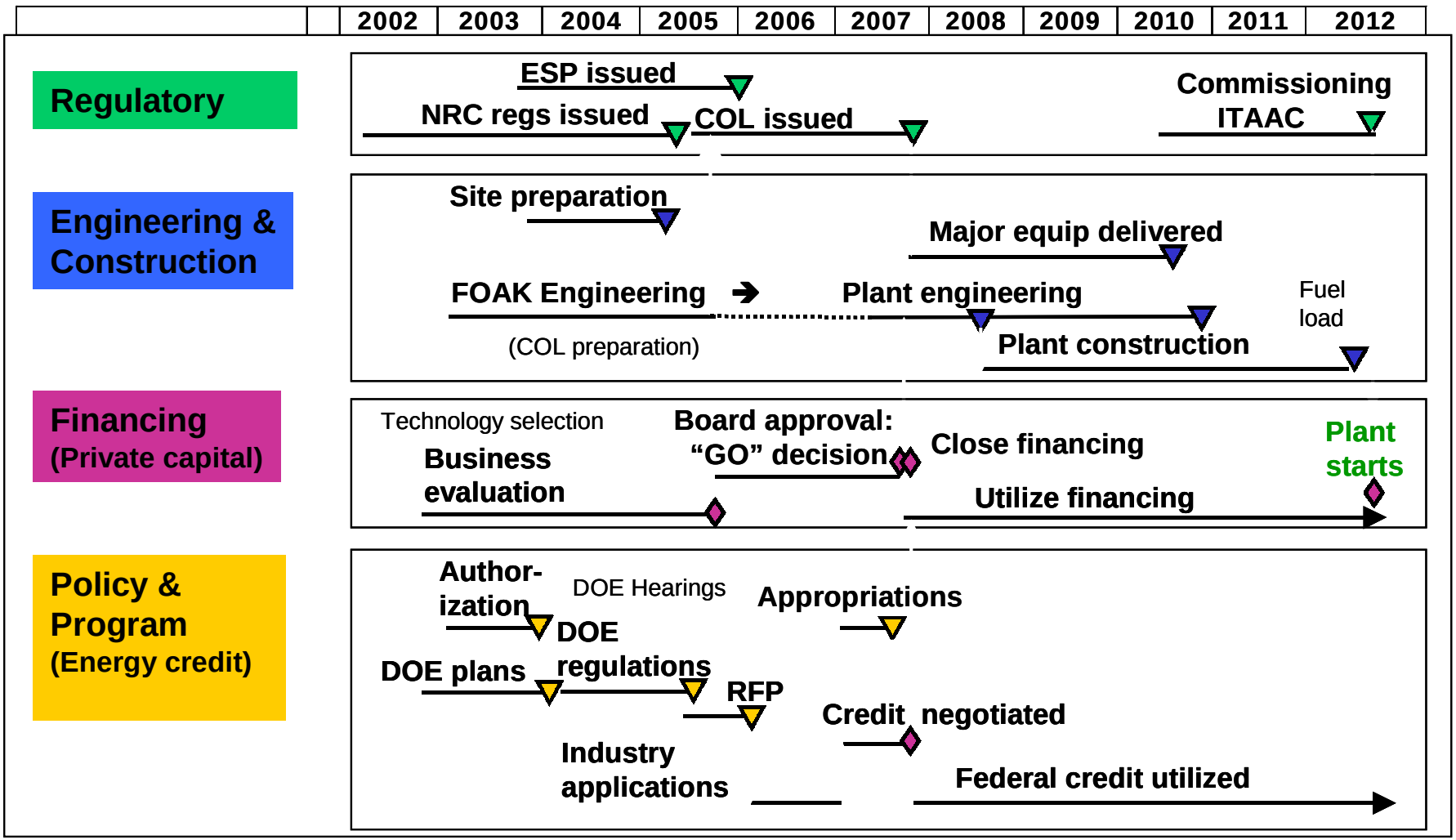
# Integrated Project Team Process

- Integrated project team (IPT) approach facilitates consideration of complex issues, ensures contractor has important DOE data.
- IPT members: DOE project manager, Scully Capital, key NE staff, and advisors.
- IPT met weekly, plus consulted; vetted assumptions; brought combined expertise of team members to bear rapidly and fully.



# *What does it take to build? An "aggressive" Timeline*

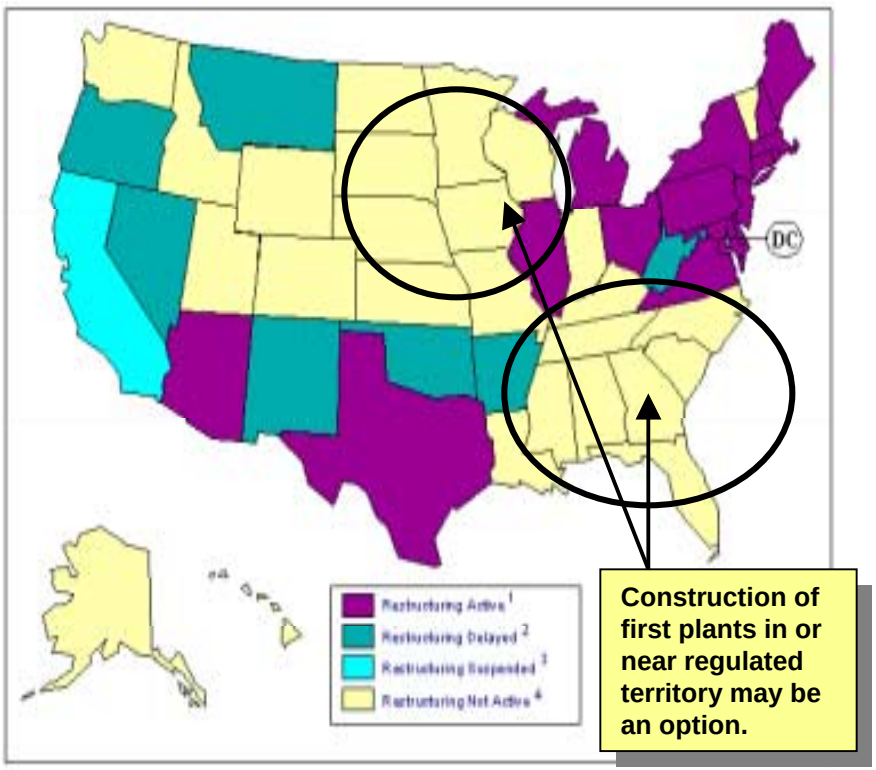
**Several key events in the construction of nuclear plants must be initiated in the near term, and they unfold in four basic areas:**



# First Reactors Could Be Built in Regulated Territory

- Restructuring and deregulation involve separating power generation from power distribution to create competition. However, these processes create uncertainty in planning for new baseload power plants.
- Restructuring and deregulation are focused in certain states and NERC regions, particularly New England (NPCC), except in VT, and MAAC, plus the "Rust Belt" industrial states (IL, MI, OH, PA) in ECAR, and MAIN. Deregulation continues in Texas (ERCOT) and NM.
- Restructuring has been limited in the Southeast (SERC, FPCC, SPP) and in the Plains states (MAPP).
- Restructuring has been suspended or delayed in much of the West (WSCC) and in California.

**Status of State Electric Industry Restructuring Activity Map**




**Retail Access:** Twenty-four states and the District of Columbia have either enacted enabling legislation or issued a regulatory order to implement retail access. Retail access programs are a primary tool for creating competition in power distribution. In retail access programs, the local distribution company continues to provide transmission and distribution (delivery of energy) services. Retail access allows customers to choose their own supplier of generation services. Retail access schedules vary state by state according to the terms of legislative mandates or regulatory orders. The information in the adjacent "Status of State Electric Industry Restructuring Activity Map" was gathered from state public utility commissions, state legislatures, and utility company web pages.

*Source: EIA, May 2002*

# Nuclear Capacity, Trends by NERC Region (U.S. & Canada)

- Nuclear power plants provide 20% of the nation's electricity (2,928 billion KWh), even though they have only 13.5% of the nation's total capacity (767,500 MWe).
- The reliance on nuclear power varies by region of the country, from 7% to 25%, and is even higher in some metropolitan areas (e.g., Chicago, Baltimore).
- Regional population and urban growth trends also vary widely, so different demand drivers for adding new power plant capacity operate in each region.
- The status of electricity deregulation varies widely by region, as shown on the next page. Many states and regions are not deregulating and have no plans to do so.
- The regional grids under the North American Electric Reliability Council (NERC) include Canada, which operates 10,000 MWe of nuclear power (CANDU units) and is contemplating building more units. So, planning for new electricity generation capacity must be addressed regionally, including Canada. (Note that more CANDU reactors are being built overseas, potentially reducing the outlook for their construction cost in North America.)

| | | MWe | MWe | | | billion KWh |
|---|---|---|---|---|---|---|
| **NERC Region (HQ) U.S. & Canada** | **NERC** | **Nuclear Capacity** | **2000 Total Capacity** | **Capacity Nuclear %** | **(Million) Pop'n** | **Power Generated** |
| Mid-American (IL) | MAIN | 14,475 | 58,600 | 24.7% | 21 | 259 |
| Mid-Atlantic Area (PA) | MAAC | 12,796 | 60,700 | 21.1% | 23 | 234 |
| Southeastern (GA) | SERC | 29,103 | 159,400 | 18.3% | 45 | 801 |
| New England (NY)+ E.Canada | NPCC | 11,483 | 62,900 | 18.3% | 51 | 102 |
| Mid-Continent (MN)+ SK, MB | MAPP | 4,439 | 31,200 | 14.2% | 12 | 166 |
| Western (CO) + BC, AB | WSCC | 11,749 | 136,500 | 8.6% | 65 | 178 |
| Florida (FL) | FRCC | 3,046 | 38,500 | 7.9% | 15 | 158 |
| East Central (OH) | ECAR | 8,707 | 112,200 | 7.8% | 36 | 590 |
| Texas (TX) | ERCOT | 4,800 | 64,800 | 7.4% | 18 | 256 |
| Southwest (AR) | SPP | 2,932 | 42,700 | 6.9% | 18 | 184 |
| U.S. + Canada | U.S. | 103,530 | 767,500 | 13.5% | 304 | 2,928 |

*www.nerc.com*

# Nuclear Owners Strengthened Standing in 2002

- Twelve utilities, plus TVA, now own and operate more than 75% of total nuclear capacity and about 2 / 3 of plants.
- Consolidation of the current nuclear fleet under the management of fewer utilities has improved overall technical and financial performance. The larger owners, now with 75% of U.S. capacity, are able to manage a portfolio of units. They can consider financing new units based on a larger balance sheet of total asset value.
- Stock prices of nuclear utilities outperformed non-nuclear utilities in 2002; their credit ratings have remained sound.

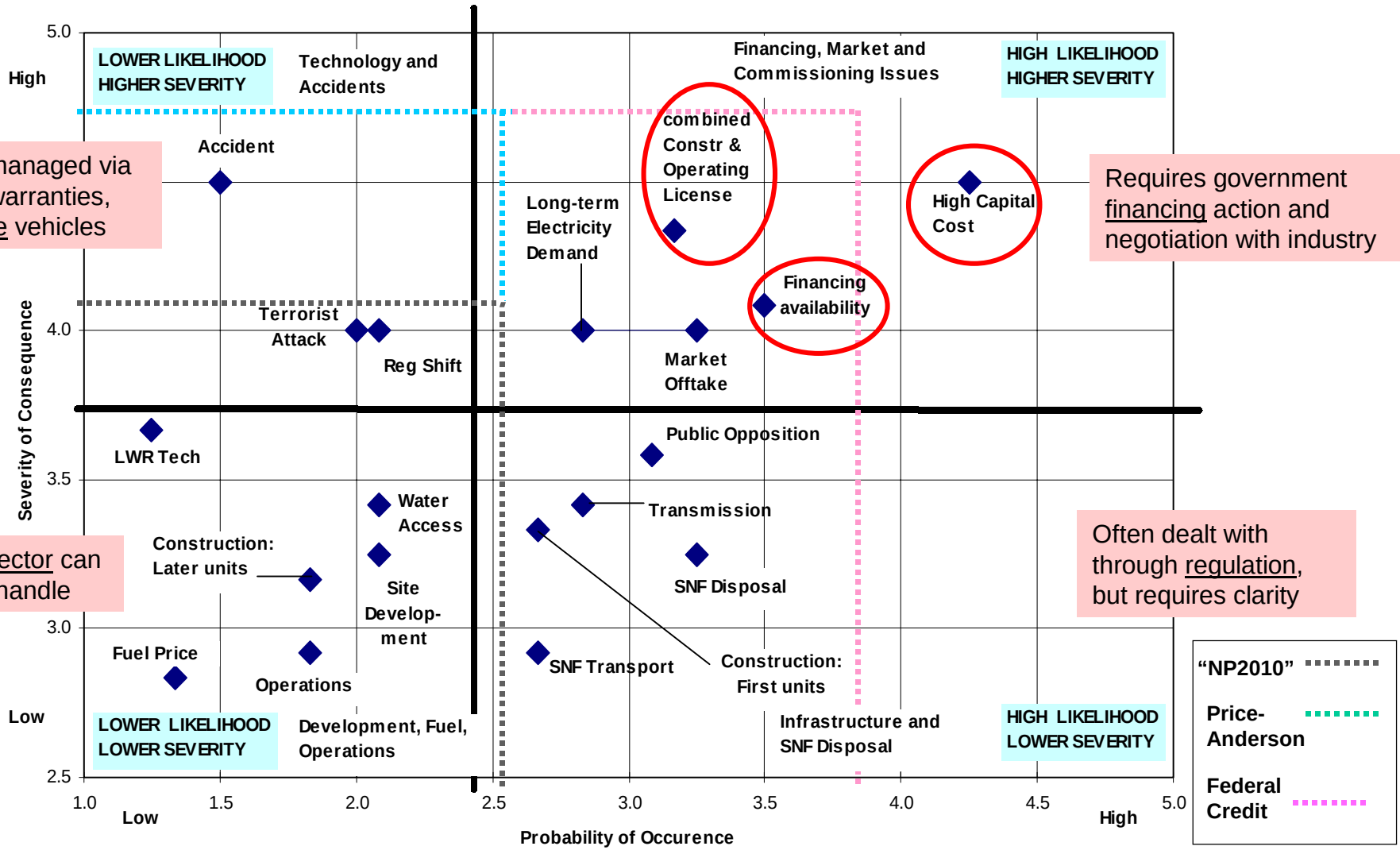
| Symbol | *(Source: NEI)* Nuclear Utility | Region, States | 2001 Revenues (billions) | Units PWR / BWR | MWs Nuclear Capacity | Stock Price 1/1/00 | Stock Price 7/1/02 | Stock Price 9/22/03 | Stock Price Change |
|---|---|---|---|---|---|---|---|---|---|
| EXC | Exelon (PECO, Unicom) | PA, IL | $15.10 | 4P / 10B | 14,191 | $30 | $52 | $62 | 107% |
| ETR | Entergy Nuclear | LA, AR, MS, NY, MA | $9.60 | 5P / 4B | 8,314 | $25 | $42 | $54 | 116% |
| DUK | Duke | SC, NC | $59.50 | 7P | 7,054 | $25 | $30 | $18 | -28% |
| PGN | Progress Energy | SC, FL | $8.40 | 6P / 2B | 6,220 | $30 | $51 | $43 | 43% |
| SO | Southern Nuclear | GA, AB | $10.20 | 4P / 2B | 5,659 | $15 | $27 | $29 | 93% |
| | TVA | TN, MS, AB | $7.00 | 3P / 2B | 5,635 | Gov't | Gov't | | |
| D | Dominion Generation | VA, CN | $10.50 | 6P | 5,405 | $40 | $66 | $61 | 53% |
| WEC | Nuclear Mgmt Co. | WS, MN, MI, IA | $15.00 | 5P / 2B | 4,353 | $20 | $17 | $30 | 50% |
| FE | First Energy | PA, OH | $8.00 | 3P / 1B | 3,726 | $25 | $33 | $31 | 24% |
| CEG | Constellation Nuclear | MD, NY | $3.90 | 2P/2B | 3,363 | $30 | $28 | $36 | 20% |
| FPL | Florida Power Group | FL, NH | $8.47 | 4P | 3,306 | $42 | $59 | $62 | 46% |
| PEG | PSEG Nuclear | NJ | $9.80 | 1P / 2B | 3,243 | $35 | $43 | $42 | 20% |
| TXU | Texas Utilities | TX | $27.90 | 2P | 2,310 | $35 | $51 | $23 | -34% |
| | S&P 500 Index | | | | | 1,470 | 990 | 1,023 | -30% |
| | Subtotal | | **$193.37** | **40P / 25B** | **72,779** | 76% | | | |
| | Others | | $ billions | 38 units | 23,481 | | | | |
| | Nuclear Total (NEI) | | | 103 units | 96,260 | | | | |

# Key Risk Areas, Approaches, and Status

| | KEY RISK AREAS | APPROACH / TOOLS | STATUS |
|---|---|---|---|
| Finance | Market Competitiveness (including high capital costs, and FOAKE costs) | DOE could consider partial power purchase incentives as BPA uses with wind power. (Nuclear units operate as baseload.) | **Senate evaluating incentives for energy bill.** Still need recognition for emissions benefits of nuclear. |
| | | Consider co-funding of FOAKE, and early unit costs via "preferred equity" or direct loans. | **Congress evaluating funding options.** |
| | Long Construction Cycle (Earnings Dilution) | Pursue investment tax credits, accelerated depreciation to reduce capital costs. | **Under evaluation (from Business Case); Likely requires tax legislation** |
| | | | |
| | Financing Availability (e.g., equity requirements) | Government direct loans or loan guaranteees would reduce financing costs or equity requirements. | **Under evaluation (from Business Case);** Interest rates are much lower than in 1980s. |
| | | | |
| Regulatory | Commissioning (NRC) | Combined Construction / Operating License being defined by NRC to reduce risk of inter-vention after construction investment. | Procedures NOT fully defined, and NOT tested in court. (NEI working with NRC). Staffing shortages at NRC also an issue. |
| | - Licensing (COL) | DOE could offer backup financing tools to cover cost of licensing delays (standby credit). | **Senate evaluating credit provisions; DOE pursuing "NP2010"; working with NRC, NEI, EPRI** |
| | - ITAACs (Inspections, Testing, Analysis, and Acceptance Criteria); Final approval | NEI advocating 10 CFR Part 53 with ITAACs focused on hardware; ITAACs being defined in design certification efforts. | NRC commissioners placed limits on "programmatic ITAACs" (Sept. 2002) |
| | | | |
| Market | Electricity Demand (long-term electricity load growth) | Utilities can work with PUCs in regions still regulated; Petition for cost recovery or long-term rate agreement. | Current overbuilding of gas plants in some regions dissuading construction of new units. Demand gaps possible after 2008. |
| | | | But, gas prices running >$4.00 |
| | | Utilities are making acquisitions in multiple regions to diversify demand exposure (e.g., FPL, Dominion, Entergy, AEP). | 75% of nuclear generation now lies in 12 utilities plus TVA after nearly 12 GW changed hands since 1998. |

# Major Risks: Probability v. Severity of Consequence

**Survey of 10 Utilities: Lowest Variance = Market off-take and High Capital Cost; High Variance = Development**




Can be managed via testing, warranties, insurance vehicles

Private sector can typically handle

Requires government financing action and negotiation with industry

Often dealt with through regulation, but requires clarity

# Base Case Sources and Uses of Funds

- The schedule of sources and uses of funds illustrates the capital structure and use of funds in the $1.2 billion EPC cost base case example.
- In this version of the base case, the $1.21 billion (with inflation added) equates to a $1.44 billion facility cost, including:
  - Development costs: $60.4 million
  - Startup costs: $21.6 million
  - Buyer's contingency: $94.6 million (7.5%)
- The gross funding requirements for this plant rise to $1.62 billion when financing costs of nearly $190 million are added.
- The $1.44 billion installed facility cost for this 1100 MWe reactor equates to $1,307 / KWe.
- Similarly, the $1.0 billion EPC cost plant in the base case has a $1.21 billion total facility cost, with a gross funding requirement of about $1.37 billion, which equates to $1,100 / KWe.

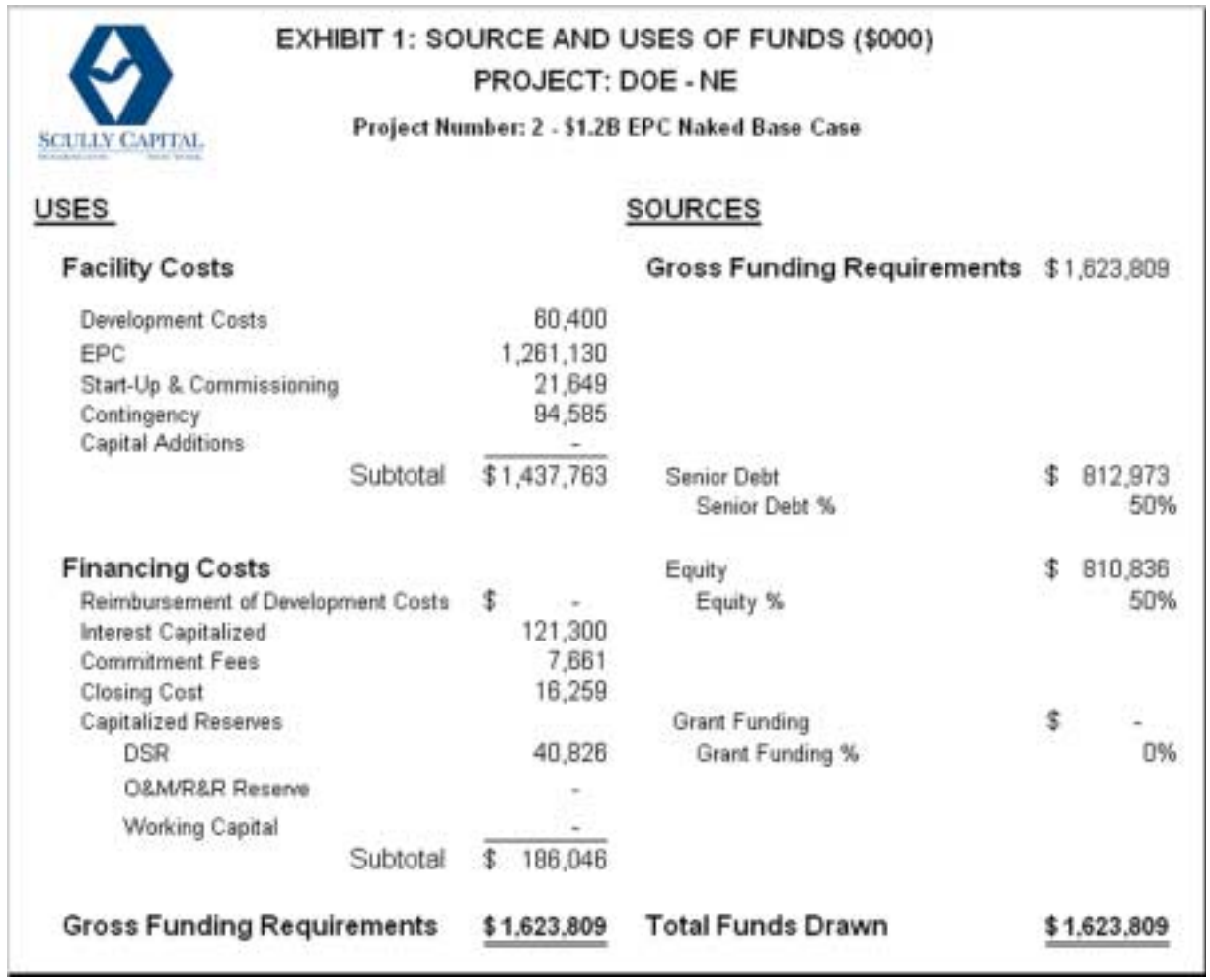


EXHIBIT 1: SOURCE AND USES OF FUNDS ($000)
PROJECT: DOE - NE
Project Number: 2 - $1.2B EPC Naked Base Case

SCULLY CAPITAL

| USES | | | SOURCES | |
|---|---|---|---|---|
| **Facility Costs** | | | **Gross Funding Requirements** | $ 1,623,809 |
| Development Costs | | 60,400 | | |
| EPC | | 1,261,130 | | |
| Start-Up & Commissioning | | 21,649 | | |
| Contingency | | 94,585 | | |
| Capital Additions | | - | | |
| | Subtotal | $ 1,437,763 | Senior Debt | $ 812,973 |
| | | | Senior Debt % | 50% |
| **Financing Costs** | | | Equity | $ 810,836 |
| Reimbursement of Development Costs | | $ - | Equity % | 50% |
| Interest Capitalized | | 121,300 | | |
| Commitment Fees | | 7,661 | | |
| Closing Cost | | 16,259 | | |
| Capitalized Reserves | | | Grant Funding | $ - |
| DSR | | 40,826 | Grant Funding % | 0% |
| O&M/R&R Reserve | | - | | |
| Working Capital | | - | | |
| | Subtotal | $ 186,046 | | |
| **Gross Funding Requirements** | | **$ 1,623,809** | **Total Funds Drawn** | **$ 1,623,809** |