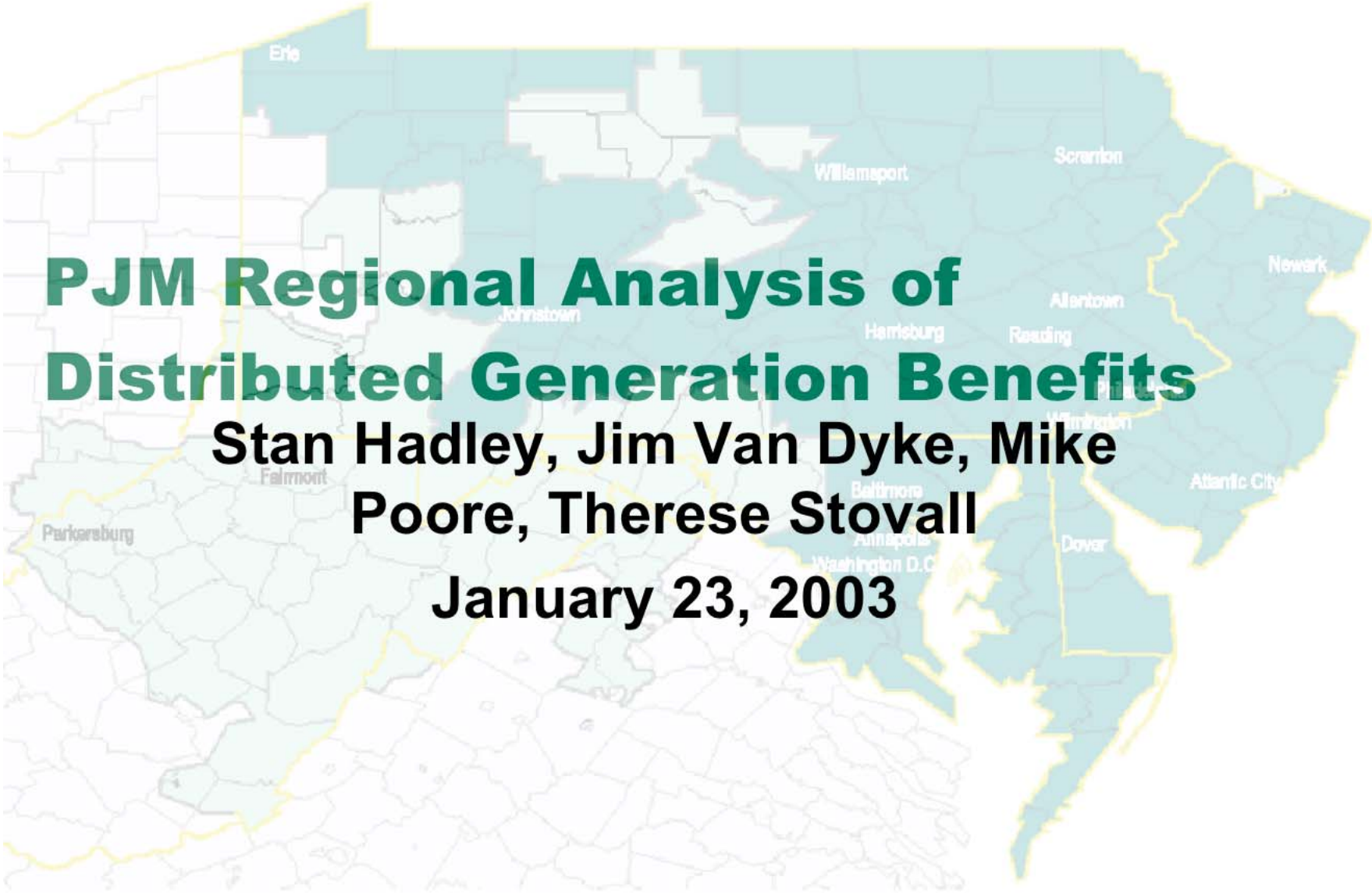



# PJM Regional Analysis of Distributed Generation Benefits

Stan Hadley, Jim Van Dyke, Mike Poore, Therese Stovall

January 23, 2003

OAK RIDGE NATIONAL LABORATORY
U. S. DEPARTMENT OF ENERGY

UT-BATTELLE

# Matrix of Benefits Analyzed

| Benefit | Owner | Utility | Society |
|---|---|---|---|
| Lower Cost | **Savings based on electricity and thermal savings versus cost of DER** | **Savings based on marginal cost reduction versus rate savings** | **Savings based on marginal cost reduction and cost of DG** |
| Reliability | | **Multiple small sources lower needed reserve for equivalent reliability** | |
| Ancillary services | **Selling ancillary services in market adds revenue** | **DG may be lower cost source of ancillary services** | |
| Emissions reductions | **Owner may get credit for net reductions in area emissions** | **Utility needs fewer emissions permits to meet caps** | **Lower overall emissions if DER is cleaner than alternative** |
| T&D expansion postponement | | **Savings based on marginal cost of expansion versus embedded cost** | **Delays disruptions and cost of added T&D infrastructure** |

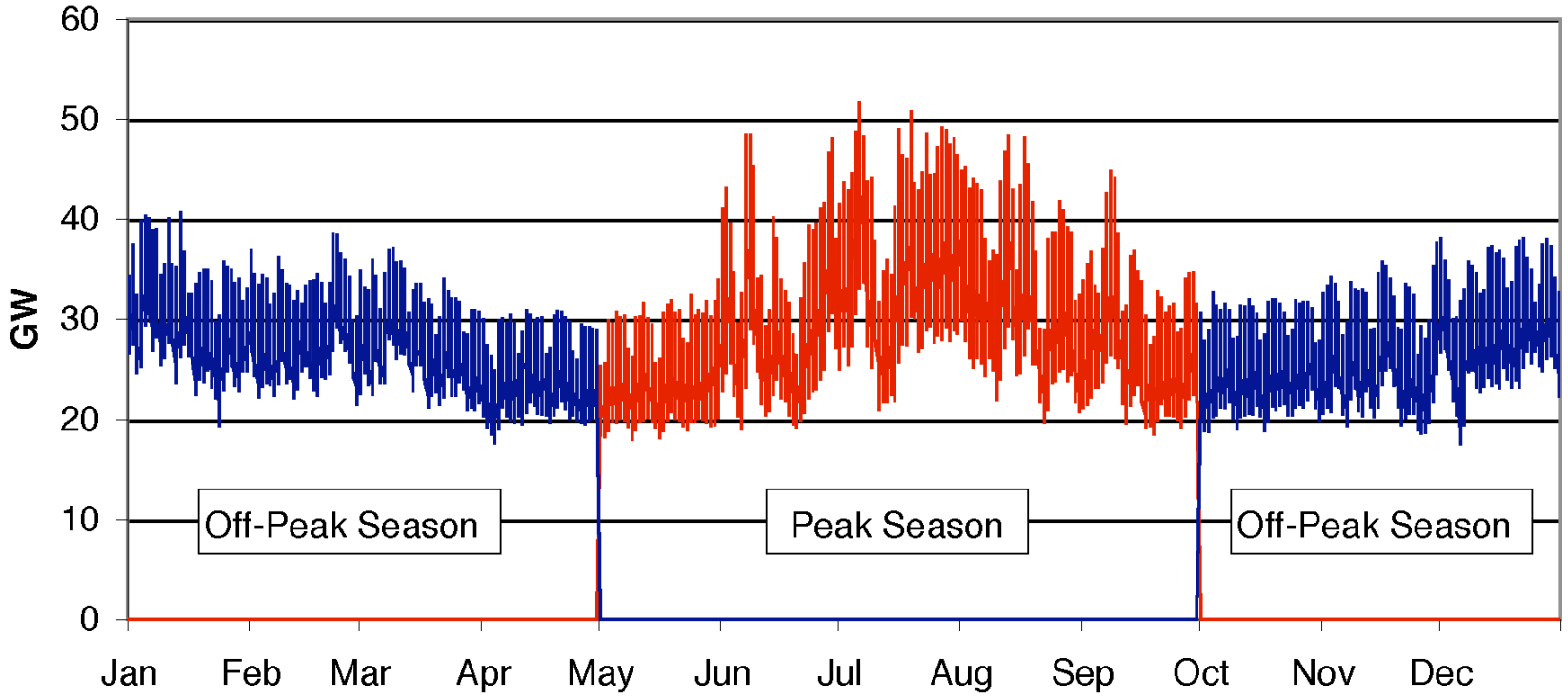
# Multiple Methods Used to Find Benefits

- Bulk power dispatch of regional power plants
  - Marginal cost of avoided generation
  - Emissions saved
  - Ancillary services market defined
- T&D costs and financial asset values
  - Incremental and average cost of T&D
  - Value of diversity of DER supply in deferring T&D
- Utility prices and DER costs
  - Economic value of DG to owners
  - Net revenue loss to utility
  - Relative value of ancillary services and emissions markets

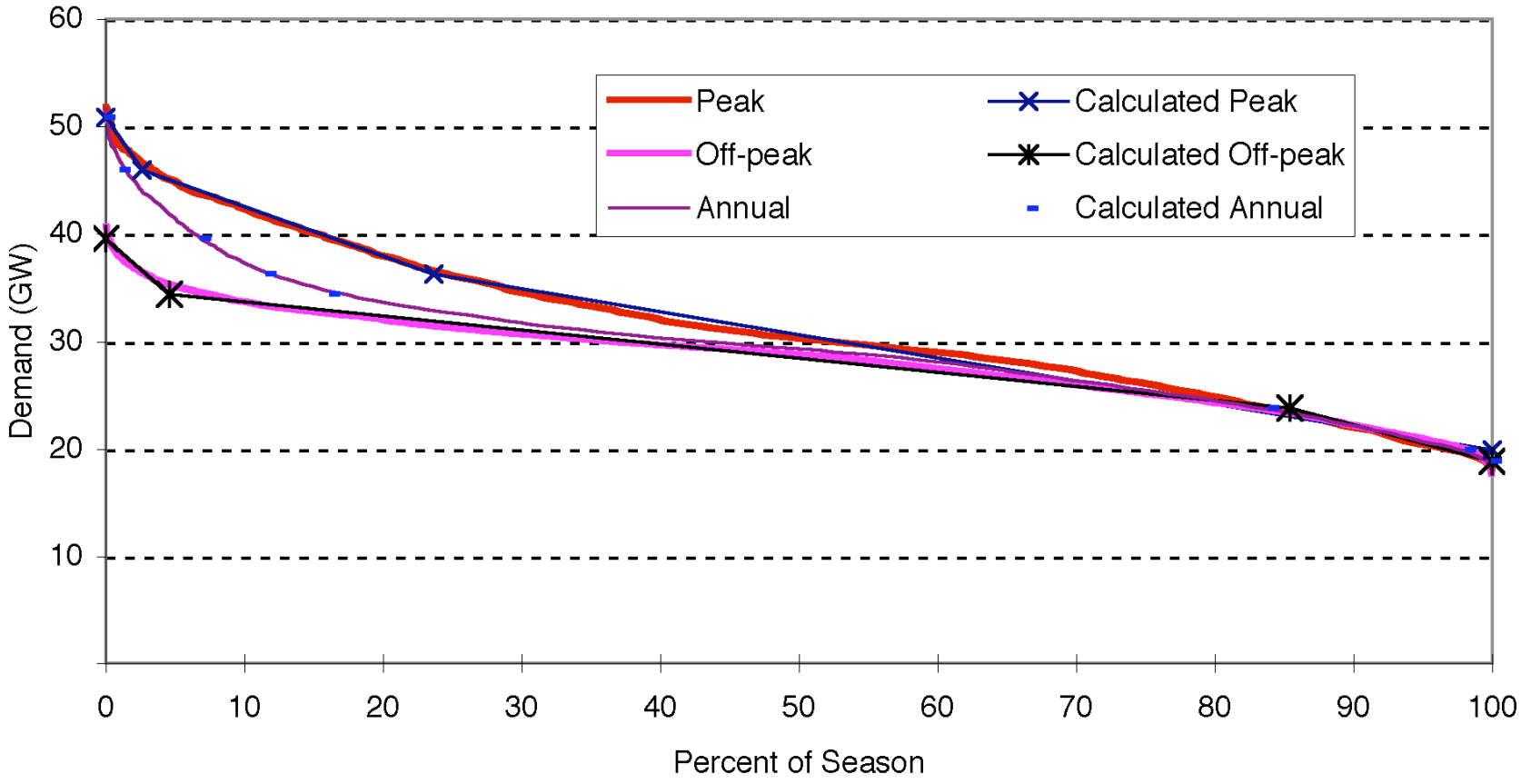
# Resources used in this study – all specific to PJM region

- Hourly System Loads for 1999
- Power plant inventory: costs, fuel, efficiency
- Prices – fuel and electricity
- FERC historical utility cost datasets
- Current Distributed Energy Technology Characteristics

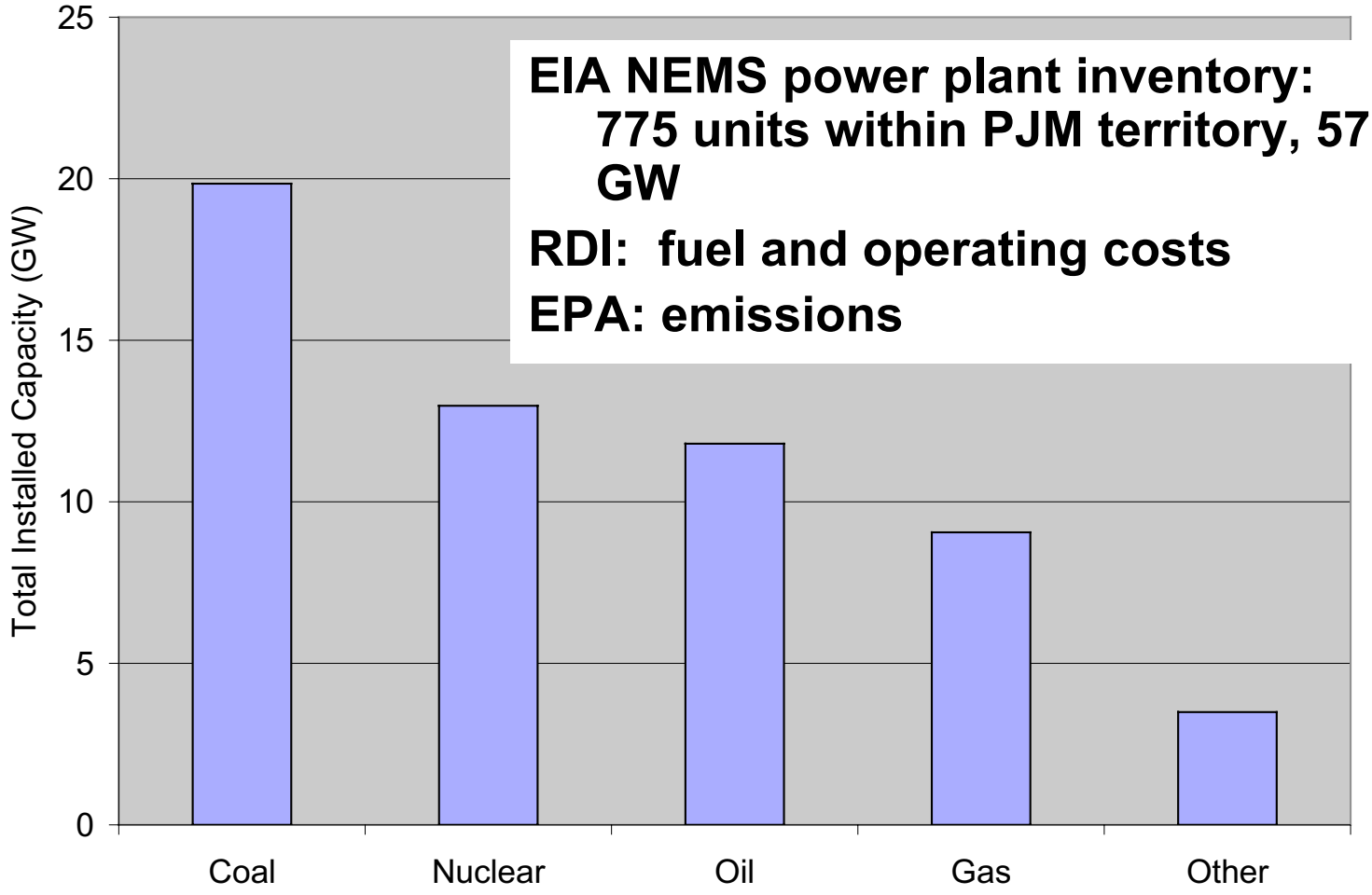
# PJM Hourly System Demand for 1999



# Bulk Power Dispatch: Hourly Loads from 1999 Are Aggregated into a Load Duration Curve



# PJM Power Plant Data

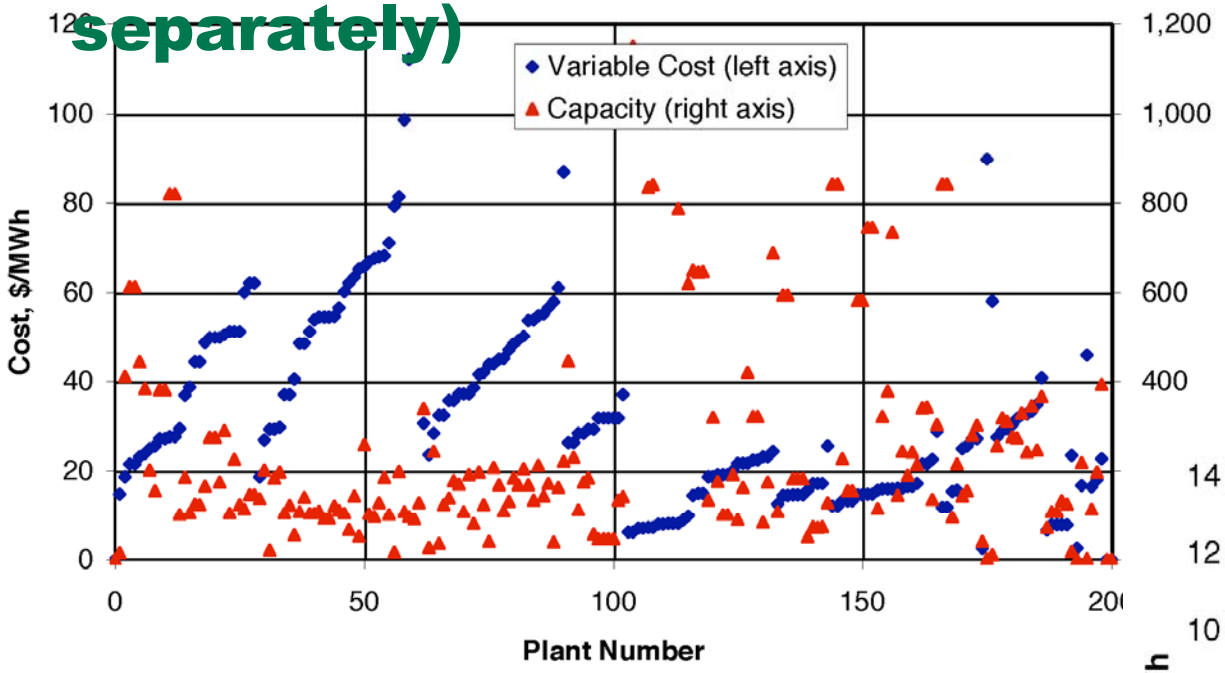



**EIA NEMS power plant inventory: 775 units within PJM territory, 57 GW**

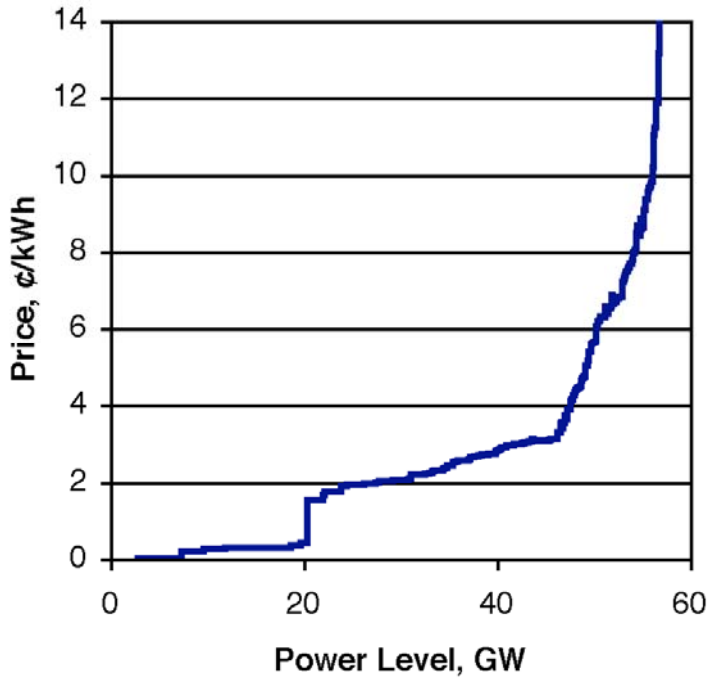
**RDI: fuel and operating costs**

**EPA: emissions**

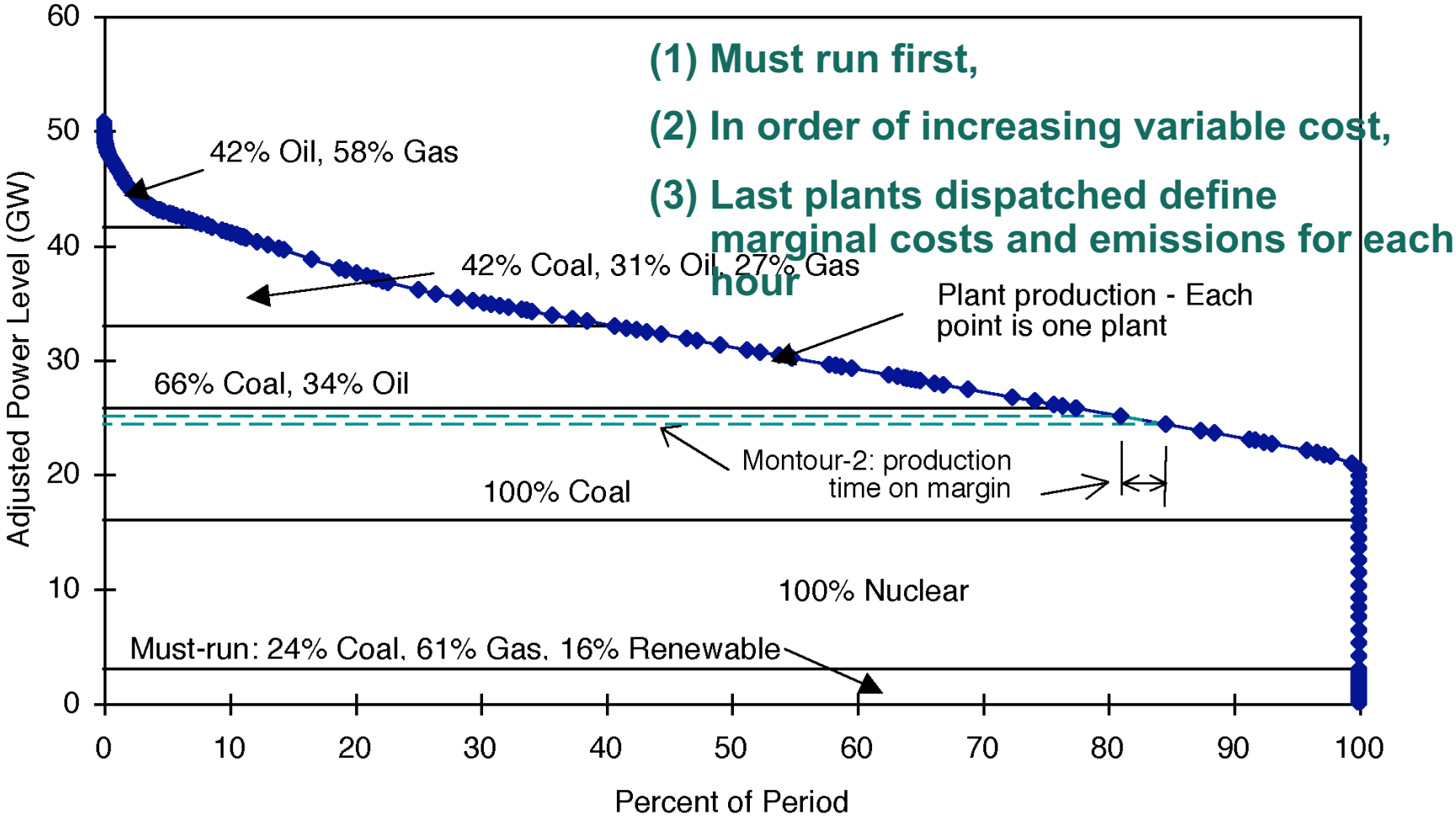
# Bulk Power Dispatch: Plants are dispatched according to variable cost (fixed costs treated separately)




- Plants are aggregated into 200 bins based on type and cost (above)
- Resulting plants stacked in order of increasing cost (right)



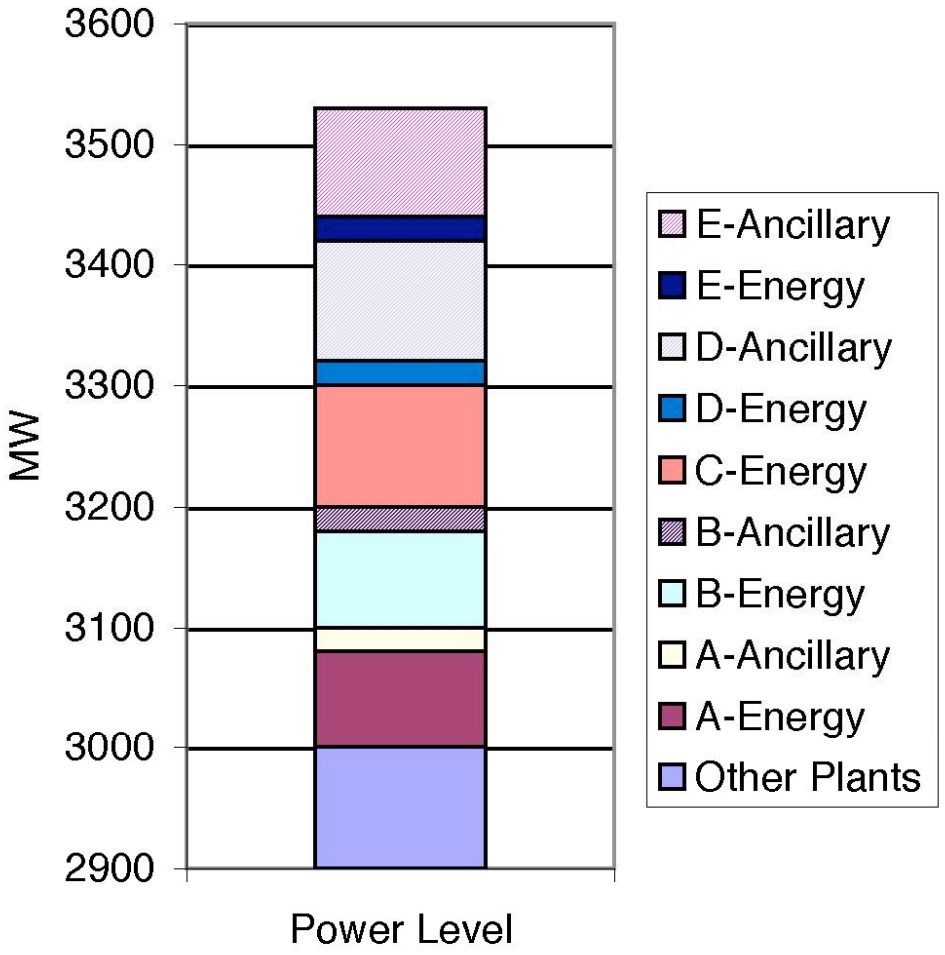
# Plants dispatched until load is met



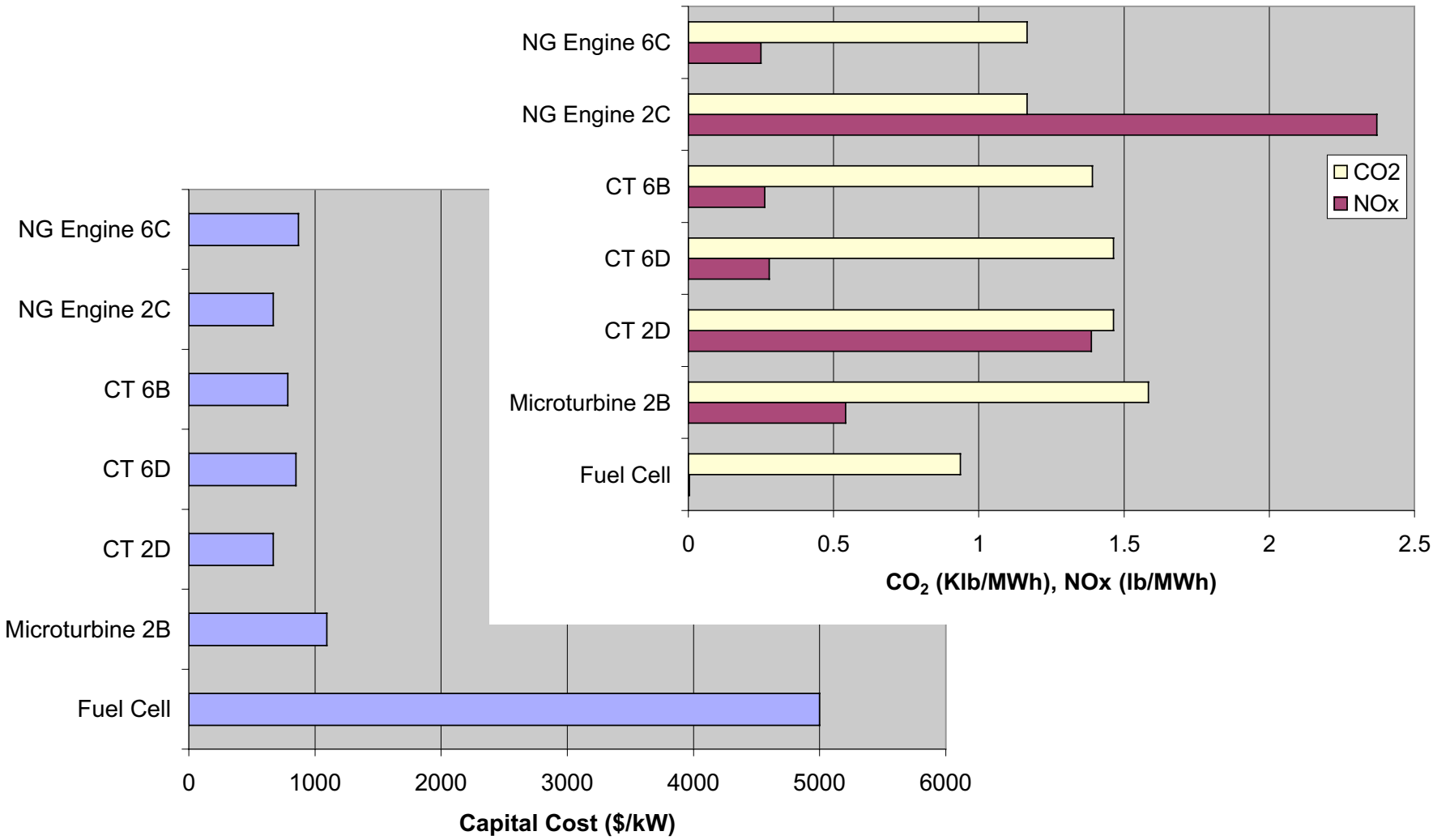
# Ancillary Benefits: Reserves Price based on revenue foregone

- **Minimum run requirements**
- **Maximum reserve capacity**
- **Max difference between market and bid price sets reserves price**

Example of 7% reserves requirements with 3300 MW demand level. C–A price sets reserves price



# DER Technology Characteristics Used



# PSE&G Commercial Rates Used for Customer Economic Evaluation

| | Energy ¢/kWh | Demand $/kW-month |
|---|---|---|
| June thru September | | |
| 8am to 10 pm Weekdays | 8.23 | 8.76 |
| 8am to 10 pm Saturday | 7.21 | 1.17 |
| All other times | 5.58 | 1.17 |
| October thru May | | |
| 8am to 10 pm Weekdays | 8.23 | 7.61 |
| 8am to 10 pm Saturday | 7.21 | 1.17 |
| All other times | 5.58 | 1.17 |

**Standby Cost is $3.86 per kW and is determined by the maximum self-generation capacity that is used**

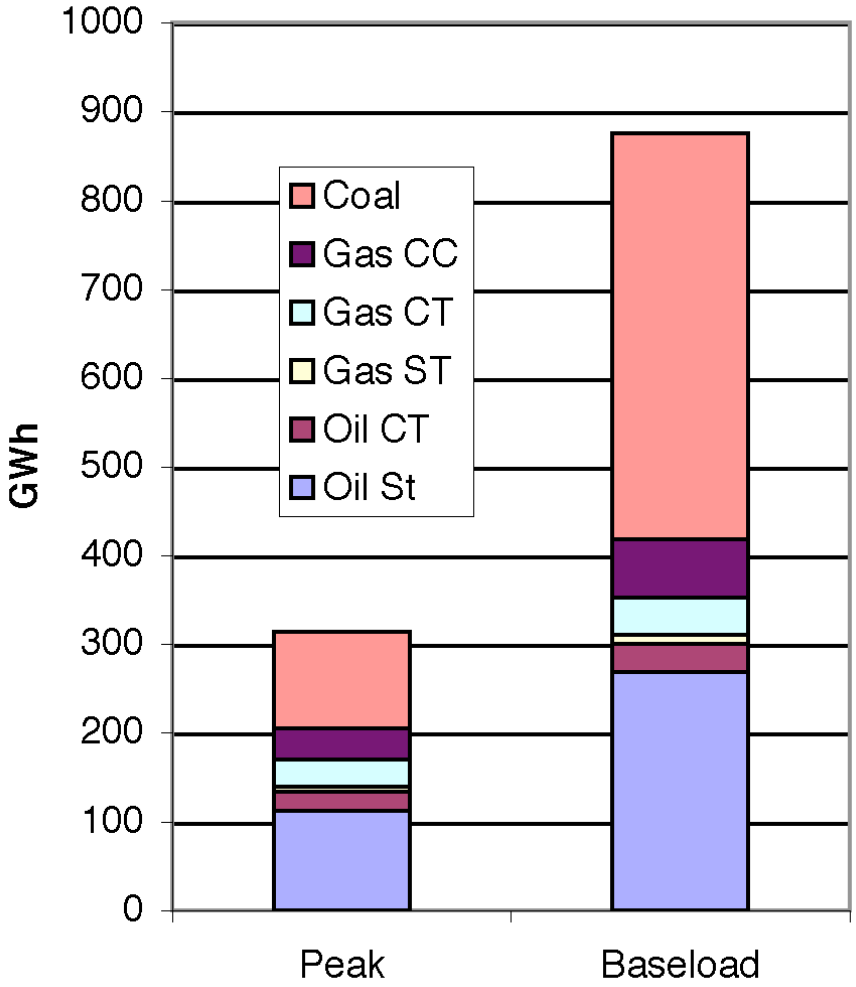
# DER Incorporation into System Dispatch

- DG represented as reduced load
  - Base load operation removes demand over all hours
  - Peak load operation removes demand 8-8 weekdays
- 100 MW chosen to show impact without greatly affecting reserve margins or generation mix
- New load curve generated for each operating mode
- Difference in system generation shows marginal impact of DER

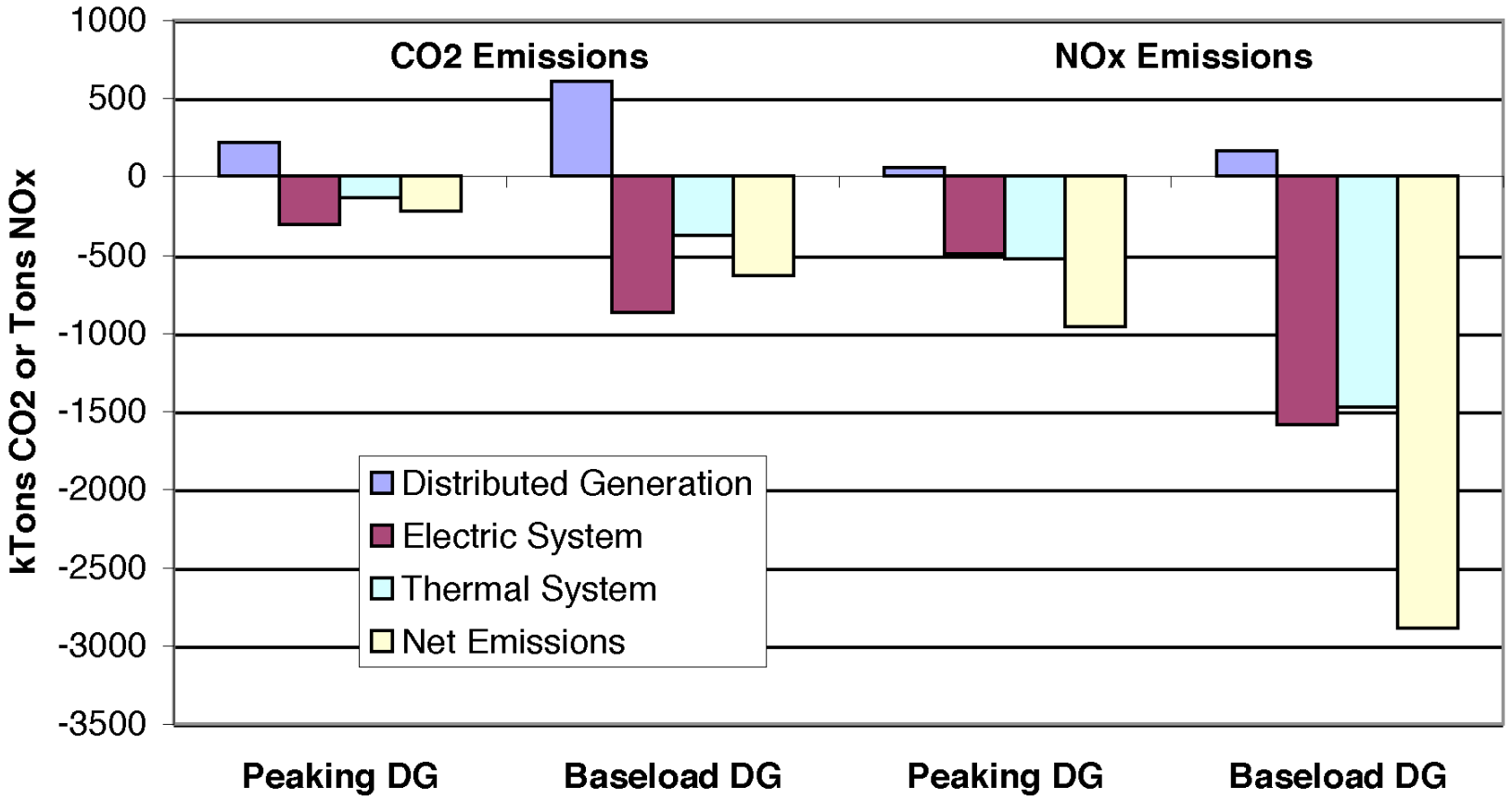
| Characteristics of Displaced Power | | |
|---|---|---|
| | Peak DG | Base-load DG |
| Energy, GWh | 313 | 876 |
| Avg Efficiency | 31% | 32% |
| $NO_x$, lb/MWh | 3.03 | 3.59 |
| $SO_2$, lb/MWh | 9.67 | 13.1 |
| $CO_2$, lb/MWh | 1,938 | 1,972 |
| Avg. Marginal Cost¢/kWh | 2.99 | 2.62 |

# Reduction in Annual Central Power Generation with 100 MW DER

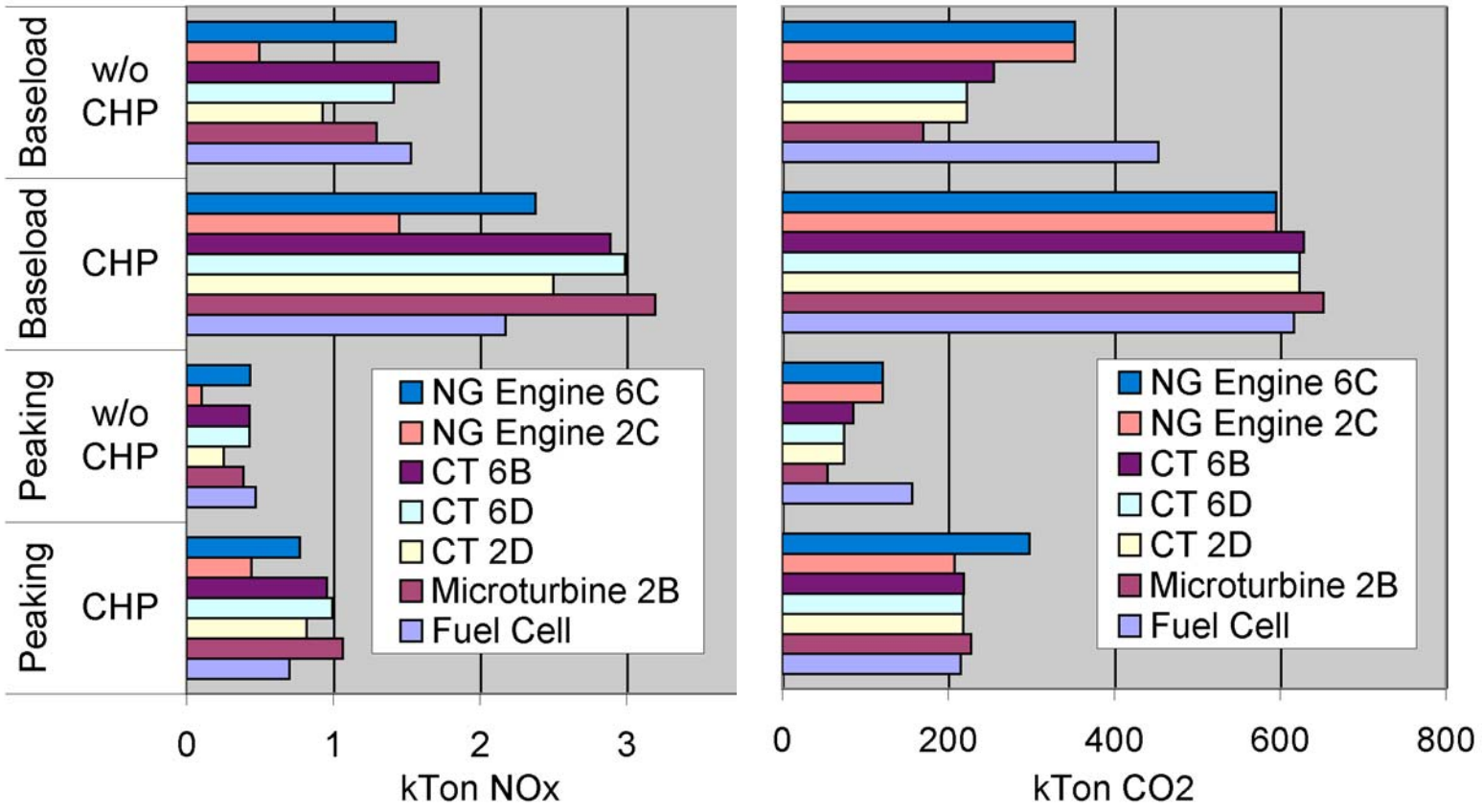
- Peaking DG only operate weekdays
- Baseload operates all hours
- Baseload more heavily displaces coal generation
- Oil relatively heavy supplier on the margin in PJM



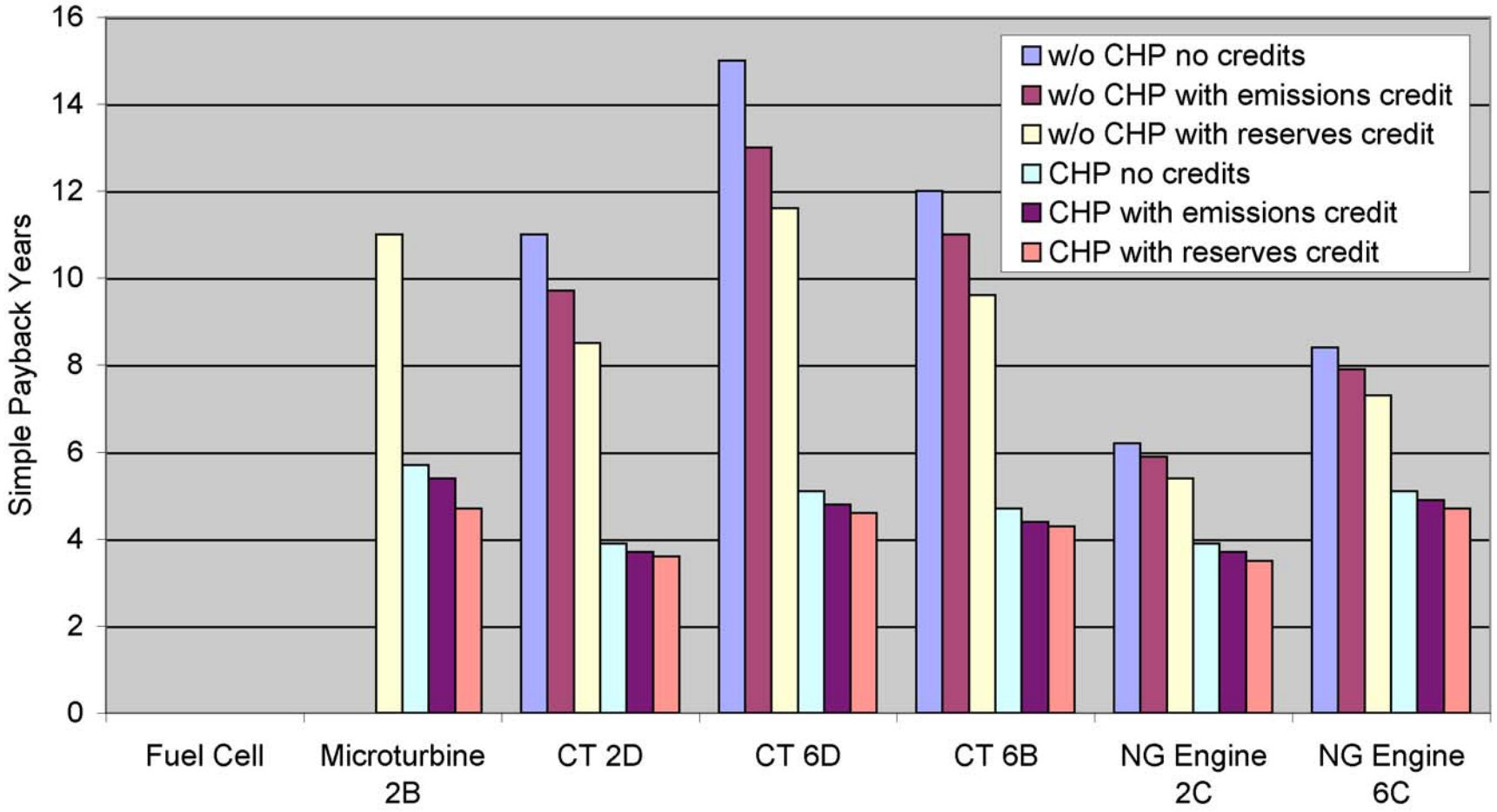
# Emission Changes for 100 MW of CT-6B with CHP



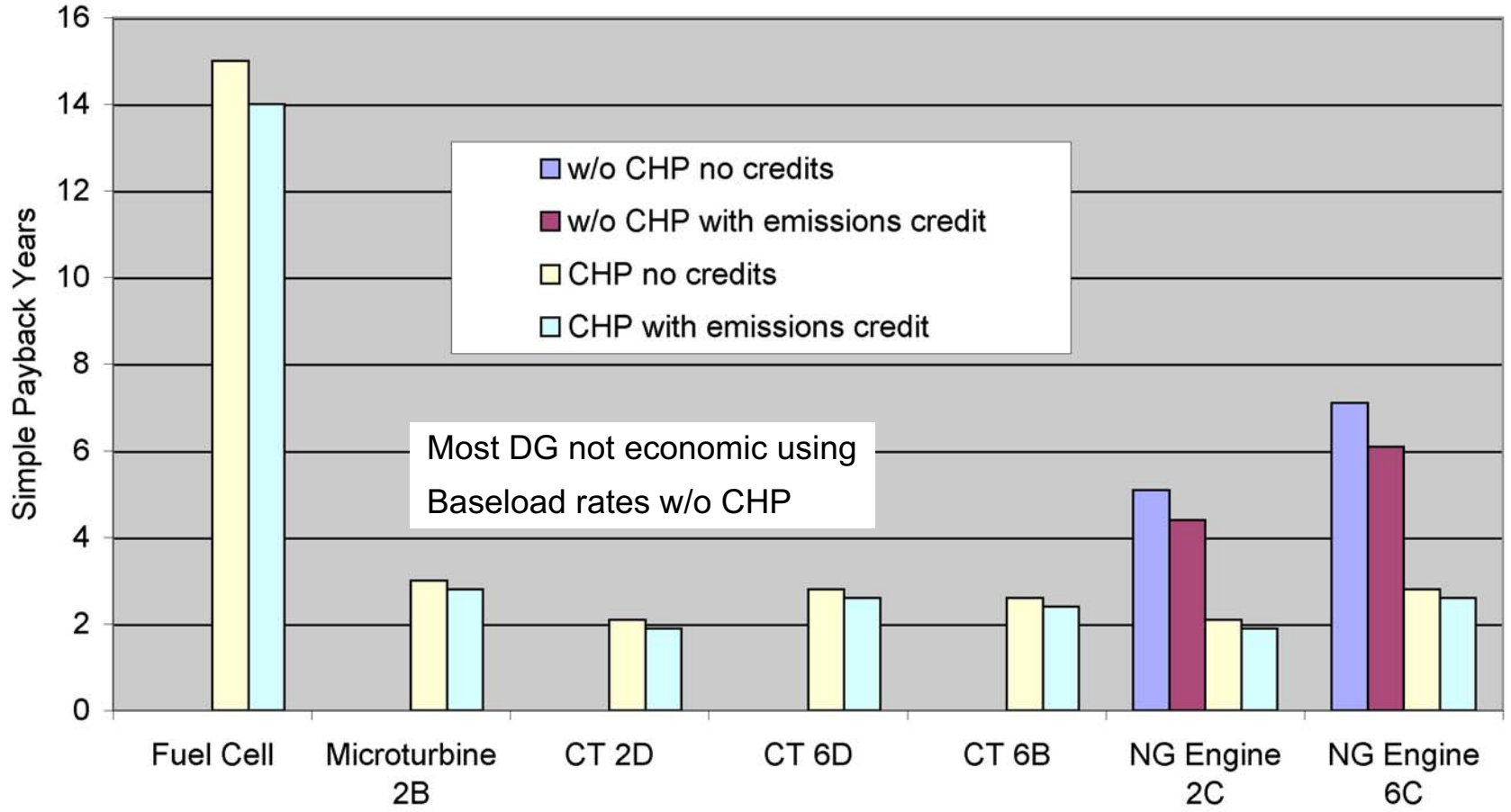
# Emissions Reductions with 100 MW DER



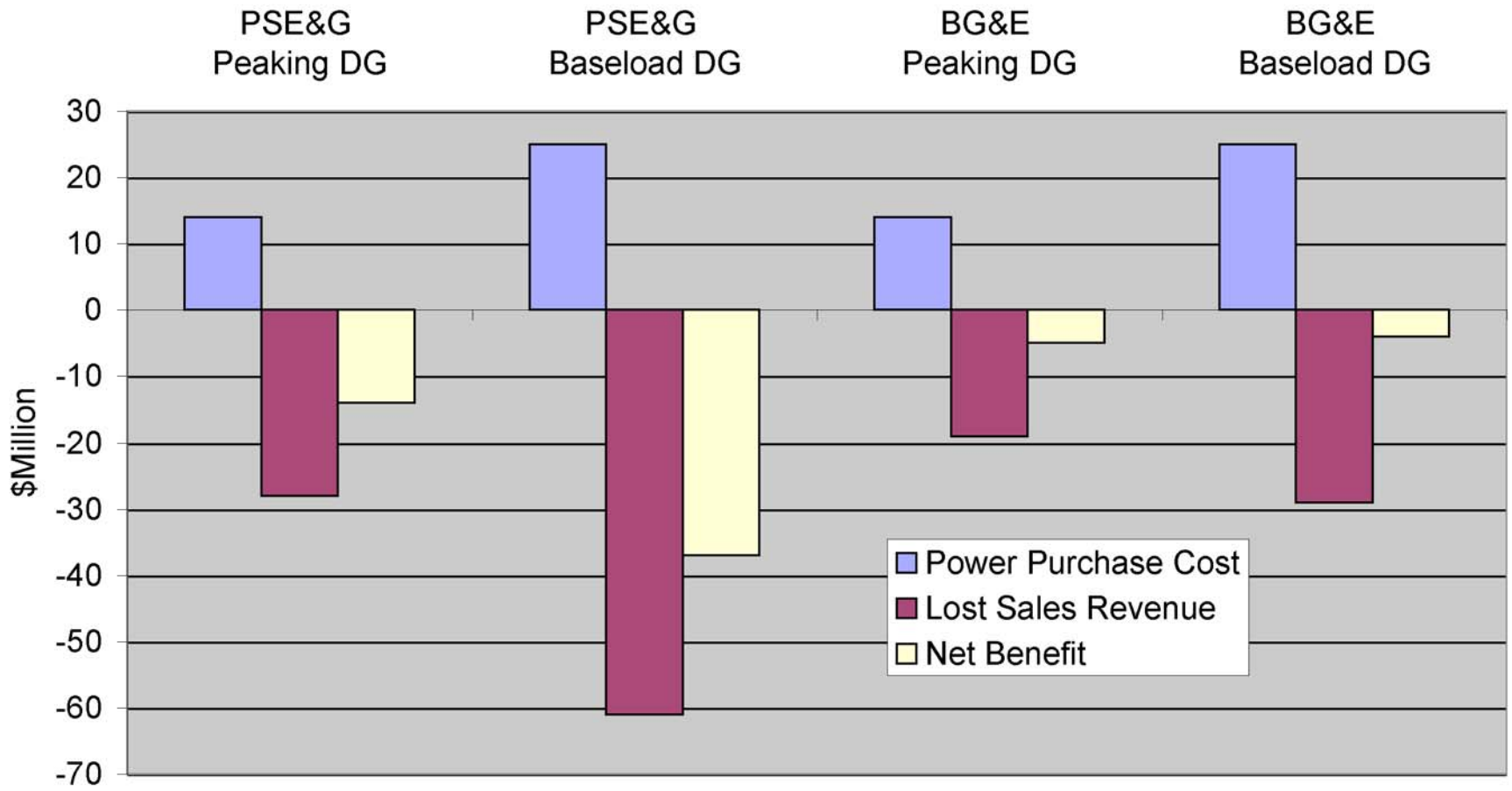
# Ancillary Services and Emissions Credits Can Affect Payback - Peaking Operation and PSE&G Rates



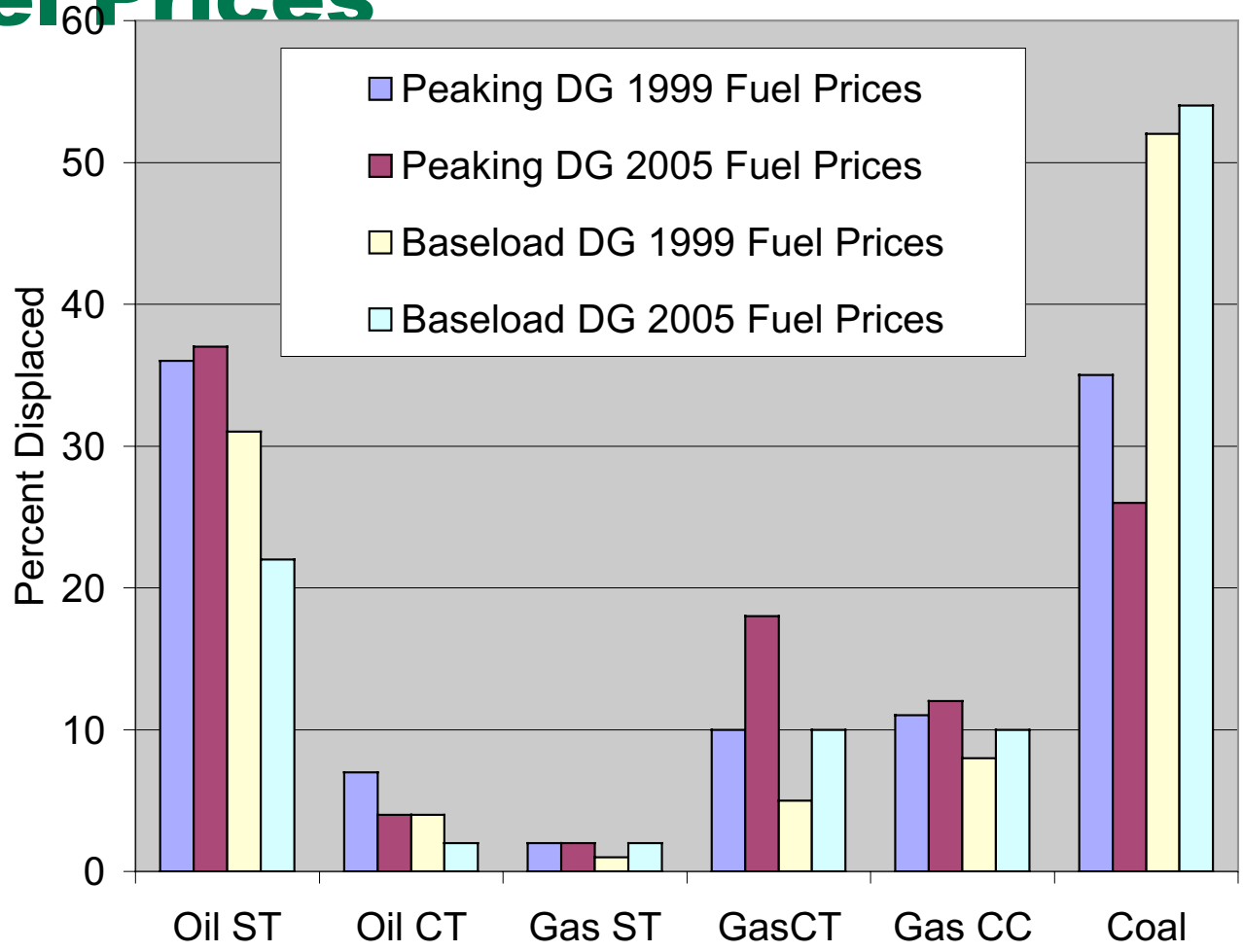
# Emissions Credits Can Affect Payback - Baseload Operation and PSE&G Rates



# Cost to Utilities from Addition of 100 MW DER (T&D deferral savings not



# Displaced Utility Fuel Mix Sensitive to Fuel Prices



# Ancillary Benefits: Reliability Effects of DER Analyzed Using Two Methods

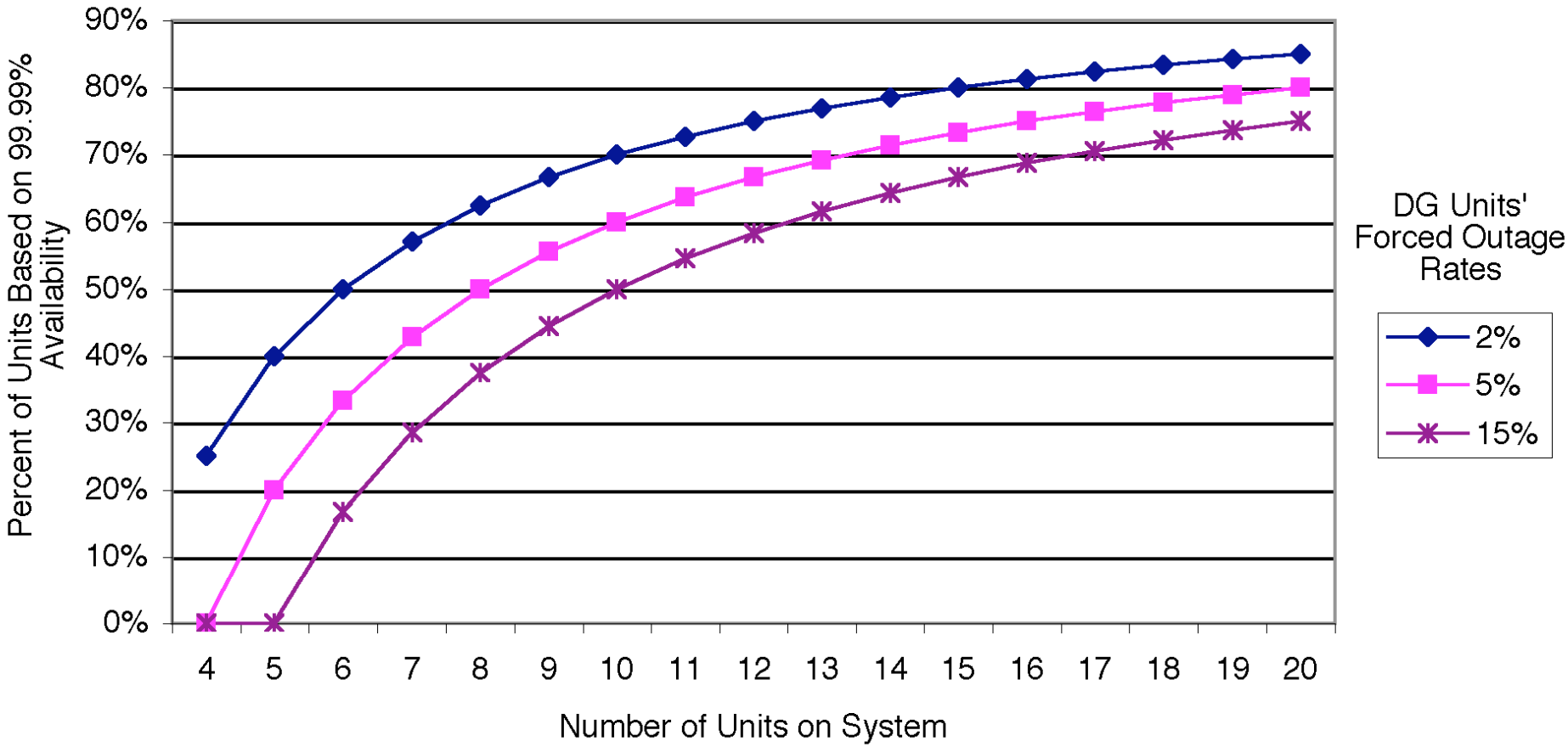
- Loss of Load Probability for Generating Units
  - For fixed reserve margins – multiple smaller units improve reliability
  - For fixed reliability requirement – will reduce need for reserve capacity
- Reduced Need for T&D Considering Diversified DER Reliability
- DER Defers Need for T&D Upgrades

# Marginal versus Average Cost of T&D

- T&D systems priced to all based on average cost
- System expansion is more expensive per kW than the average cost
- DG additions defer need for expansion depending on:
  - Reliability and diversity of DG systems
  - Site-specific characteristics of territory

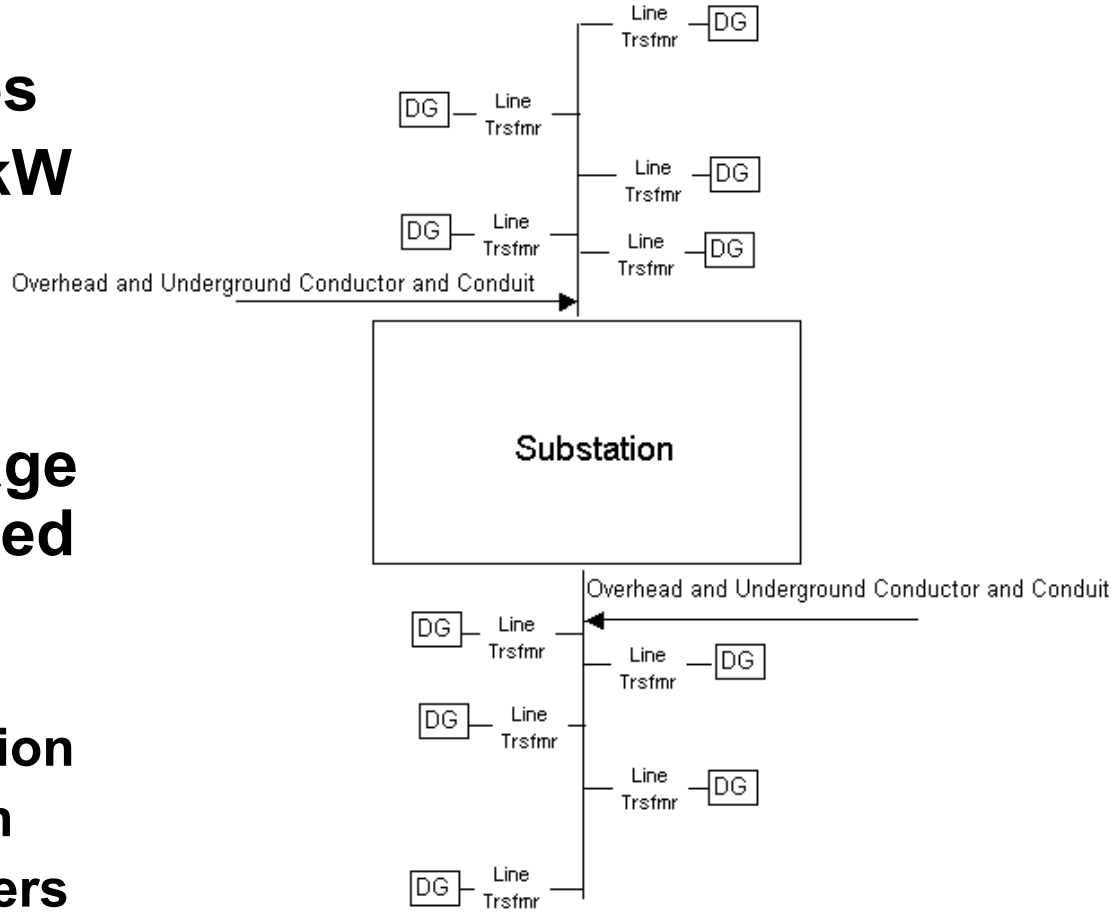
| | Marginal Cost ($/MVA) | | Average Cost ($/MVA) | | Difference ($/MVA) | |
|---|---|---|---|---|---|---|
| FERC Form1 Account | National 1989 to 1998 | PJM 1989 to 1998 | National 1998 | PJM 1998 | National | PJM |
| Dist Total | 290,203 | 374,737 | 137,576 | 180,369 | 152,627 | 194,368 |
| Trans Total | 80,650 | 64,876 | 52,229 | 48,681 | 28,421 | 16,195 |
| Total Dist and Transmission | 370,853 | 439,613 | 189,805 | 229,050 | 181,048 | 210,563 |

# DER Reduces Need for T&D Only if Able to Meet Reliability Requirements

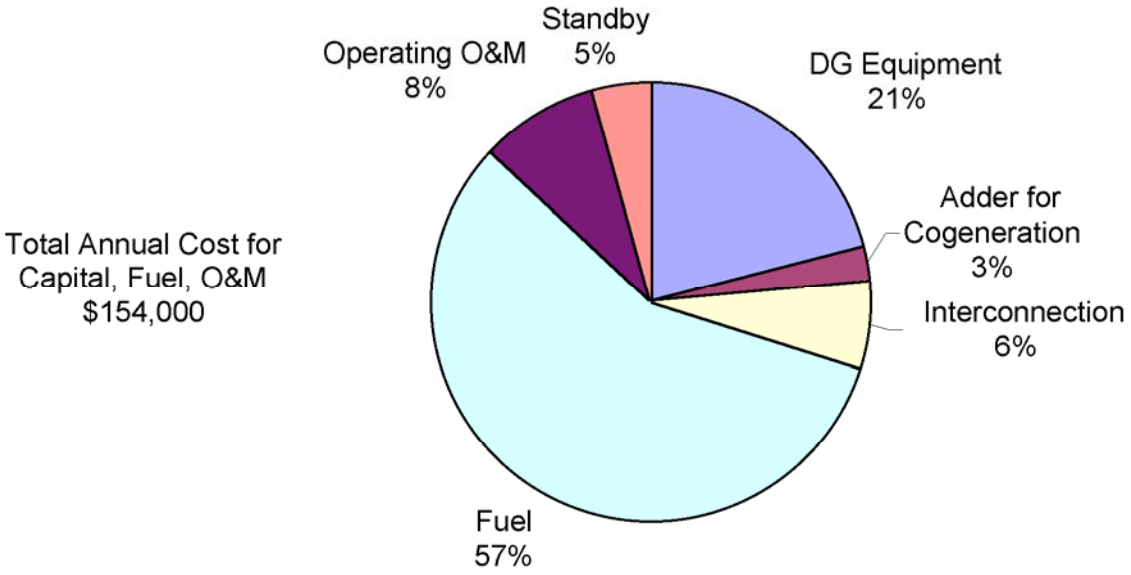


# T&D savings from DER depends on relative placement

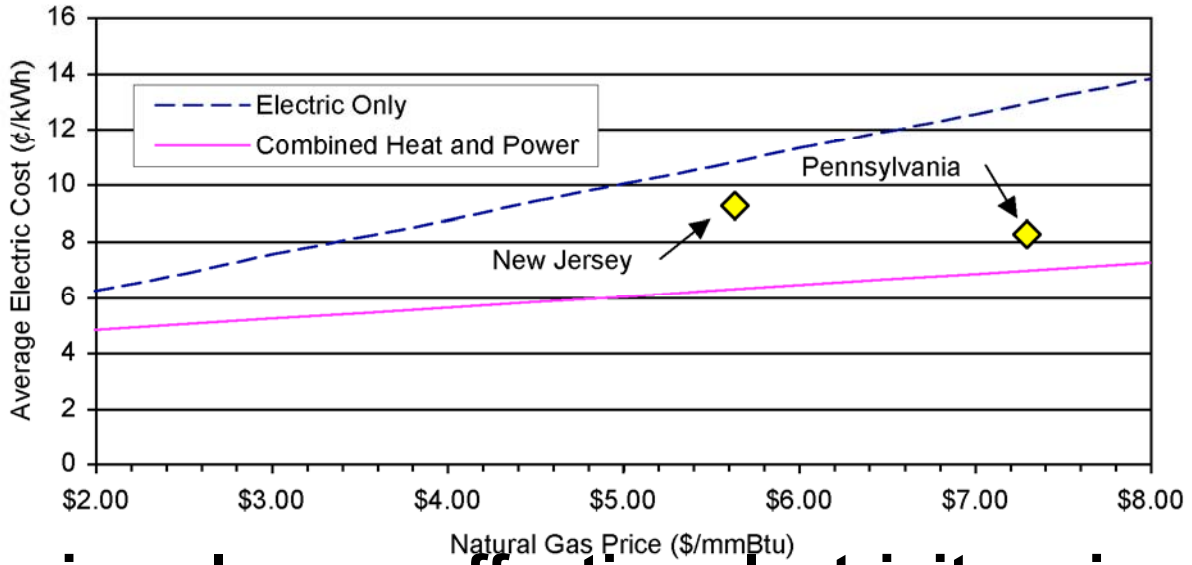
- Assuming mix of DG on feeder lines
- Savings of ~$57/kW for transmission and $90/kW for distribution
- Reliable percentage of capacity credited is lower at local level
  - 80% to transmission
  - 60% to substation
  - 20% to local feeders



# Cost components of 200kW Gas Turbine



# Price of DG electricity as function of gas price




- CHP savings lowers effective electricity price
- Avg. retail prices in each state shown for comparison
- Standby costs will change the economics
  - PSE&G = 0.1¢/kWh while PP&L = 2¢/kWh

# Summary of Results for PJM:

- DER reduces emissions in both baseload and peaking modes.
- DER reduces Loss of Load Probability of supply resources
- DER can provide significant reserve value during off-peak hours
- Displaced central generation type sensitive to fuel costs
- Utilities would net less revenue
- Marginal T&D costs are much greater than average costs
- Deferred T&D capacity depends on number and reliability of DG assets, as well as placement
- Customer economics varies according to competing energy costs and system design

# DER Benefits Analysis: Phase III

- Ancillary Services: Expand value-determination in PJM region
  - voltage support
- Capacity credit (and value) for diversified collection of DG resources.
  - Supply
  - Transmission
  - Distribution
- Program support and coordination

# DER Benefits Analysis: Phase III (expanded)

- Customer economic analysis for 2 specific PJM locations (directly comparable to DTE analysis)
- Compare NEMS market drivers to drivers cited in Phase I survey
- Feeder-specific diversified capacity credit calculations
- Diversified reliability tool

# Extra slides follow

# Bulk Power Dispatch: Plants Grouped Into 200 "Dispatch Bins" and Ranked According to Variable Cost.

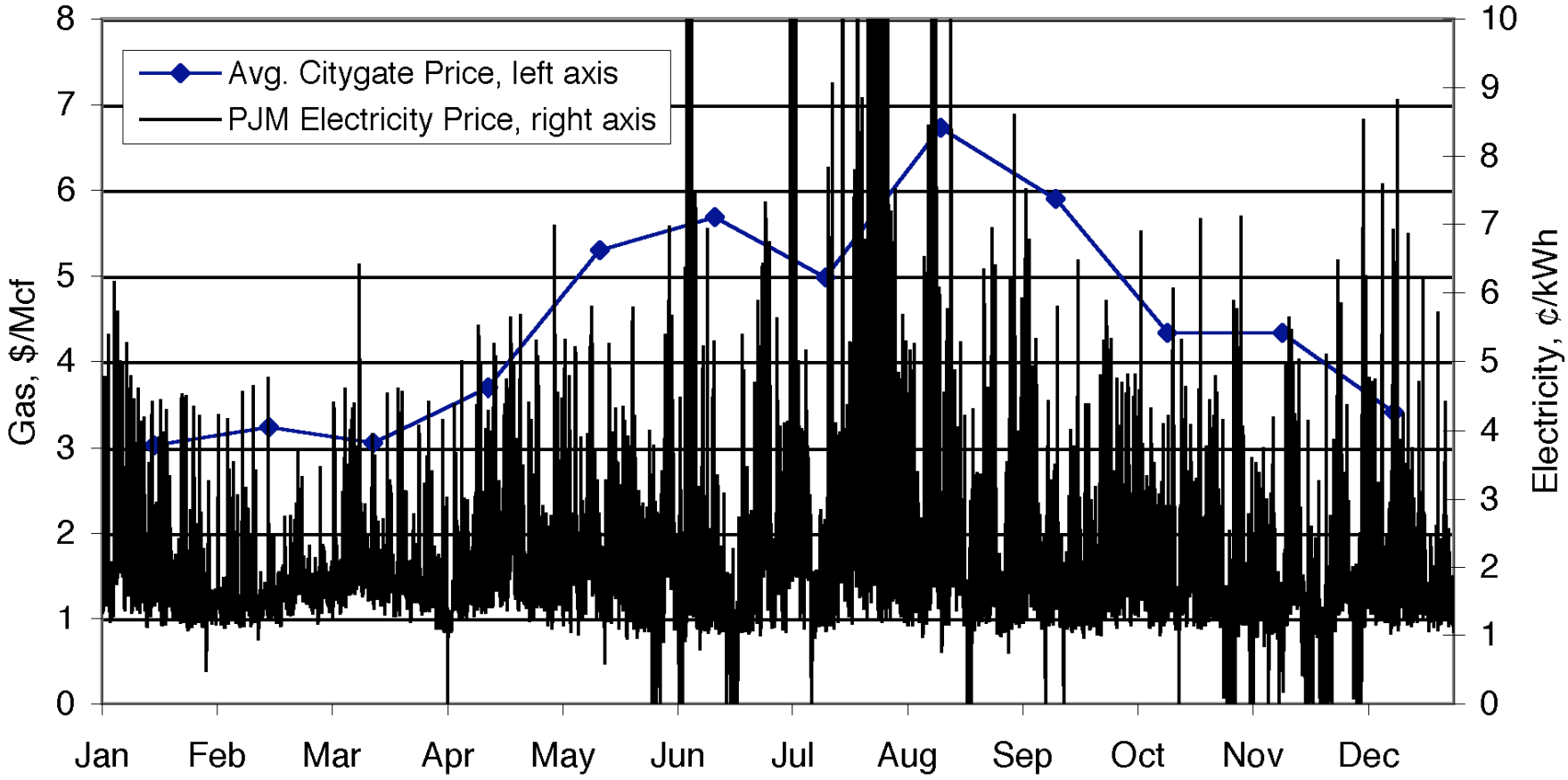
- **Fuel cost, capital cost, operating cost, heat rate, and emissions are weighted average of plants within each bin.**

| Considering Dispatch mode, Technology, Fuel type, Variable cost<br>For Example: | | | |
|---|---|---|---|
| Plant type | Capacity (MW) | Number of units | Number of bins |
| Coal Low S | 5225 | 21 | 17 |
| Gas CT | 4079 | 76 | 28 |
| Must run Gas CC | 2959 | 79 | 10 |

## Fuel Costs for Individual Plants Were Used, but Average 1999 Prices Useful in Understanding Which Plants Are on the Margin.

| Fuel | Price ($/mmBtu) |
|---|---|
| Gas | 2.98 |
| Coal | 1.46 |
| Oil | 2.18 |
| Uranium | 0.52 |

# PJM Releases Hourly Wholesale Prices, EIA Gives Average Citygate Gas Prices for PJM



# CHP Efficiency Depends on Both Electrical Efficiency and Waste Heat Temperature