



---

***Demand Response  
Cost-Effectiveness  
Determination --  
A PHI Utility Perspective***

***MADRI Distributed Energy Resources Workshop,  
Trenton, NJ -- June 5, 2006***

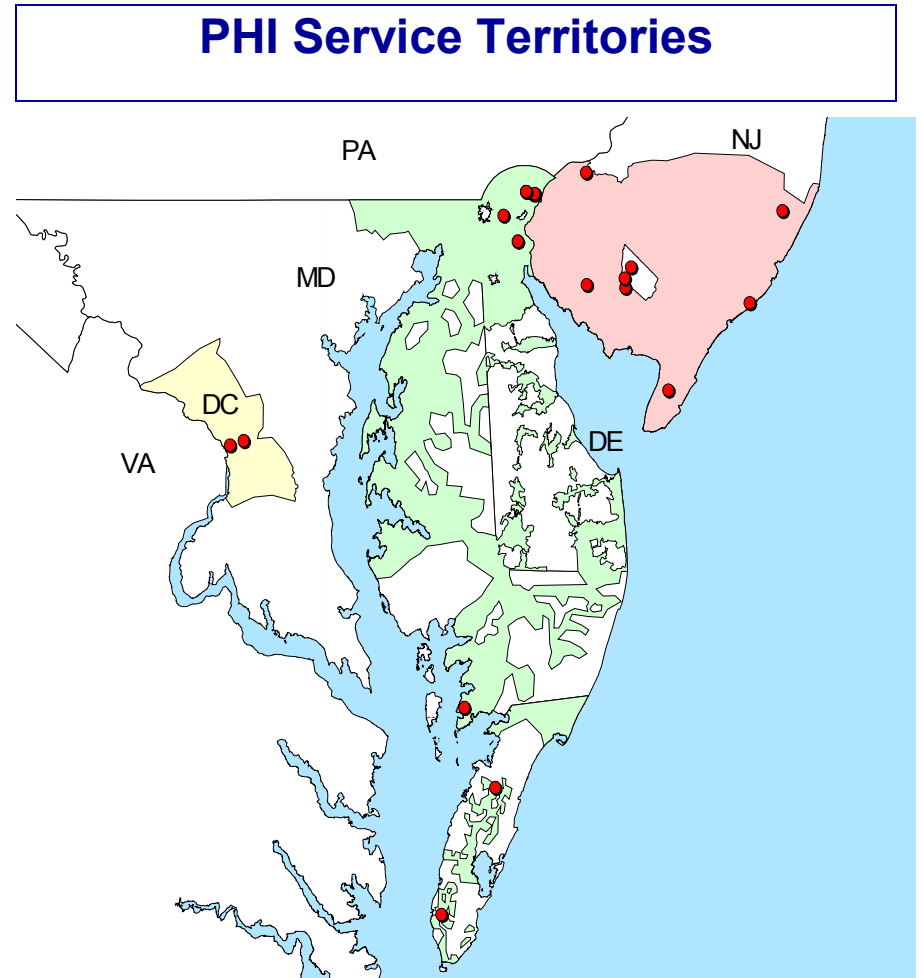
# *Pepco Holdings, Inc.*

## PHI Electric Distribution Companies:

- Atlantic City Electric
- Delmarva Power & Light
- Pepco
  - 1.8 Million Customers
  - 13,850 MW of Zonal 2005 Peak Demand (unrestricted)
  - 5 Regulatory Commissions
  - 4 MADRI Jurisdictions
  - All Within the PJM Footprint

## Competitive Affiliates:

- Pepco Energy Services
- Conectiv Energy



# *PHI Demand Side Management Activities*

- Significant Utility Experience with DSM Programs – both energy efficiency and demand response.
  - Numerous historic energy efficiency programs.
  - More than 225,000 res./small com. participants in direct load control programs.
  - Various large customer demand response programs.

# *PHI DSM (continued)*

- Recent Demand Response Initiatives
  - Residential Smart Metering Pilot Program in DC in partnership with other stakeholders
  - Exploration of Additional Demand Response Opportunities in Downtown DC
  - Proposed Smart Thermostat Program in Delaware
  - Proposed Internet Demand Response Enabling Platform for Commercial Customers
  - Ongoing DER Related Regulatory Proceedings in Various Jurisdictions -- cogeneration, renewables, net metering, interconnection requirements, energy efficiency, demand response, and smart metering

# *PHI Viewpoint on Demand Response*

- General consensus in the mid-Atlantic Region that existing demand response activities are inadequate in the PJM market.
- The PJM market alone is unable to motivate/sustain sufficient demand response resources at this time, therefore an alternate funding mechanism is necessary.
- What is the demand response role of electric distribution companies?
  - EDCs no longer own/operate/build generation units.
  - Competitive market determines generation construction/retirements/availability.
  - Competitive market determines electric energy prices and rate design.

# *PHI Viewpoint (continued)*

- EDCs are best positioned to provide the technical framework for a competitive electric energy market.
- EDCs are best positioned to offer and operate demand response programs for small and medium sized customers.
- EDCs should provide demand response enabling services for res./small com. customers and selective services for larger customers.
- EDCs should provide smart metering equipment and services to support hourly or critical peak pricing.
- EDCs should own, maintain, and operate necessary equipment.

# *But, How do We Determine Which Demand Response Resources Make Sense?*

- Goals for demand response should not be set without consideration of the costs necessary to achieve those goals.
- Traditionally our Commissions have determined the appropriate investment in demand side management initiatives through elaborate cost-effectiveness tests.
- Are demand response investments now justifiable without cost-effectiveness evaluation because of their inherent value?

# *Assuming that Cost-Effectiveness Determination is Still Required, Here are Some of the Key Issues*

- What Cost-Effectiveness Test(s) Should be Used?
  - Societal Benefit Test?
  - All Ratepayers Test?
  - Rate Impact Test?
- What Benefits are Included in Each Test?
- What Costs are Included in Each Test?
- How are the Benefits and Costs Quantified?
  - Do the Valuations Differ by Jurisdiction?
- Will the Tests Vary by Jurisdiction?

# *What Benefits Are Included and How Should they be Quantified?*

1. Distribution deferred costs/improved reliability?
2. Transmission deferred costs/improved reliability?
  - Jurisdictional vs. Regional Savings
3. Generation: Mitigation of wholesale market prices spikes (wealth transfer payment)?/Mitigation of market power/improved reliability?/Service territory, state, or PJM region?
  - Previous valuation was based on ability to defer construction of new generation

## *Benefits (continued)*

4. Improved customer control over bills?
5. Potential conservation impact?
  - Previous valuation was based on deferring gen. construction and avoiding energy production.
6. Environmental benefits, such as improved air quality?
  - Are they quantifiable?
  - Regional vs. Jurisdictional?

## *Benefits (continued)*

7. Is there a value for customer exposure to hourly or critical peak energy market prices if a customer does not reduce load?
  - Value of improved equity in pricing?
  - Competitive supply market pricing?
8. Should market earnings be counted as a benefit or possibly a reduction in costs?

# *What Costs Are Included and How Should they be Quantified?*

1. Equipment and Installation costs?
2. O&M Costs?
3. Marketing Expense?
4. Customer Credit Expense (wealth transfer payment)?
5. Customer Inconvenience?
6. Distribution Company Lost Revenues?
7. Costs of Periodic Process and Impact Evaluation Studies?

# *Other Key Cost-Effectiveness Parameters*

## Other Key Parameters

1. Time Period for Evaluation
2. Discount Rate
3. Frequency of Evaluations
  - Impact Evaluations
  - Process Evaluations
  - Cost-Effectiveness Evaluations

# *PHI EDC Possible Approach to Cost-Effectiveness Determination*

- MADRI state Commissions could agree to a similar cost-effectiveness determination approach in the near-term.
  - Agreement will permit more rapid deployment of programs, reduce program costs, and increase regional value.
  - MADRI could facilitate development of a consistent approach.
- Benefits – All quantifiable benefits should be included, including mitigation of energy market price spikes.
  - Existing PJM/MADRI/Industry studies should be used as initial basis for valuation.
  - Benefits of mitigating energy market price spikes should be estimated on a Mid-Atlantic Regional basis rather than on a jurisdictional basis.

# *PHI EDC Possible Approach to Cost-Effectiveness (continued)*

- Costs – All quantifiable costs should be included, including customer credit expense.
- Time period should be limited to equipment life.
- Discount rate should equal EDC cost of capital.
- Cost-effectiveness analyses/process evaluation/impact evaluation studies should be conducted every 5 years.

# *Now That We Have Determined it is Cost-Effective, Who Pays for It?*

- PJM Wholesale Market?
- Base Utility Rates?
- Surcharge on Bills?
- Customer Co-Pay?
- Assessment on All PJM Energy or Capacity Market Transactions