8.0 Appendices

Appendix A. *Demand Response Roadmap for the PJM Region*

Demand Response as a Supply Resource

Endorsed by the Mid-Atlantic Distributed Resources Initiative (MADRI) in 2007

Introduction

PJM held a symposium on demand response (DR) in May 2007 that was attended by a broad mix of stakeholders and subject matter experts. One of the most prominent themes to emerge from the symposium was the need for coordination between retail and wholesale markets in order to increase demand response participation in PJM's markets. The participants at the PJM Symposium on Demand Response identified nine 'top priority opportunities.' These are shown in the next slide.

Introduction

1	A regional approach to the development of standardized platforms, communication protocols, investments in enabling technologies, and wholesale-retail DR integration issues
2	New retail rate structures that better reflect wholesale market pricing strategies
3	Pricing that captures the full value of DR and mechanisms for customers and service providers to get access to all relevant revenue streams
4	Direct load control for all residences, perhaps through state legislation, and modification of building codes for new residences so that they include specifications for technologies that accept/address dynamic pricing signals
5	Advanced metering infrastructure (AMI) available to all customers who want it and price responsiveness with little or no manual intervention
6	Exposure for all customers to hourly wholesale prices
7	Establishment of quantitative (MW) regional goals for DR
8	Adjustment of the 25% cap that currently exists in PJM's synchronous reserves DR program
9	Full responsibility taken by PJM for metered data and calculations used in determining customer baseline loads (CBL)

Development of the Demand Response Roadmap

The symposium participants also emphasized the need to properly allocate responsibility for addressing some of these opportunities. In essence, some are areas in which the retail market should take a leading role, some are areas in which the wholesale market must take a leading role, and others required a joint retail/wholesale commitment.

The combination of priority opportunities overlaid by the mix of retail and wholesale responsibilities lead to suggestions for the development of a coordinated plan, a Demand Response Roadmap, to guide the way.

The Roadmap is organized into a series of functional areas which collectively form the basis for creating a DR roadmap.

* Dispatch of demand resources

* Data management

* Settlement of demand response activity

* Demand response in the planning process

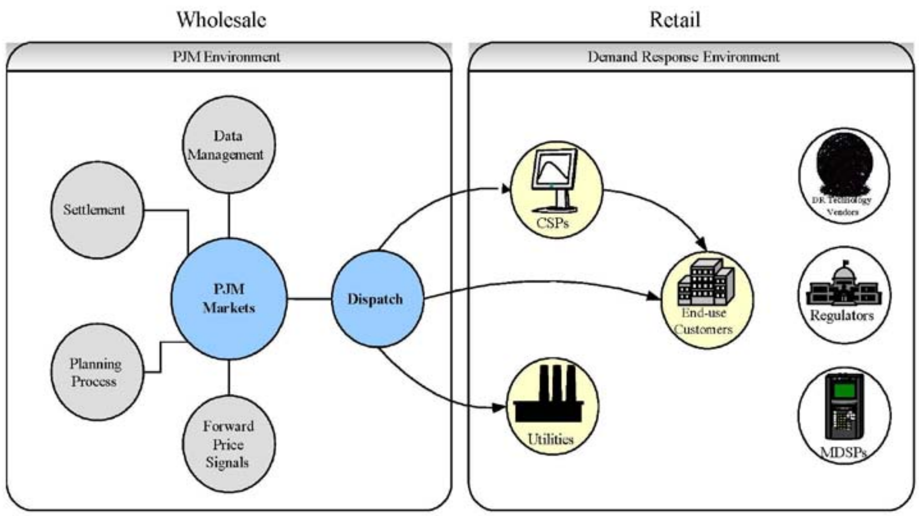
* Forward price signals for demand response

Organization of the Demand Response Roadmap

Each section includes a table that identifies items and actions for the retail environment and for the wholesale environment. This material was assembled from a variety of sources. These include MADRI's initiatives, recommendations from PJM Symposium on Demand Response, state commission DR working groups, PJM's Demand Side Response Working Group and the NARUC/FERC demand response collaborative.

The MADRI Steering Committee has endorsed this Demand Response Roadmap as the starting point for coordinated retail/wholesale efforts to grow DR market participation.

Figure 1. Coordination of Dispatch Activities



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Activities Table 1. Dispatch Considerations by Market

WHOLESALE	RETAIL
1. Enable Real Time availability for both economic and emergency Demand Resources (2009) 2. More reliable economic demand resources in Real Time (on-going) 3. Real-time Unit Dispatch System dispatch of DR (2007) 4. Implement nodal dispatch of Demand Resources in Real Time and for emergencies by identifying nearest 115kV and above pnode name (partial) 5. Maintain a voluntary, self-schedule Real-Time Energy Market option for Demand Resources (on-going)	1. DR that is dispatchable based on price and location 2. Region-wide measurement and verification protocols 3. Decoupled distribution rates or alternative for distributor to recover revenues lost as the result of DR 4. Critical Peak Pricing/other retail rates more aligned with LMPs 5. Retail rate design that provides customers with real savings opportunities (not revenue neutral) 6. AMI deployed 7. Standard interconnection standards and rules for distributed generation

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Figure 2. Coordination of Data Management

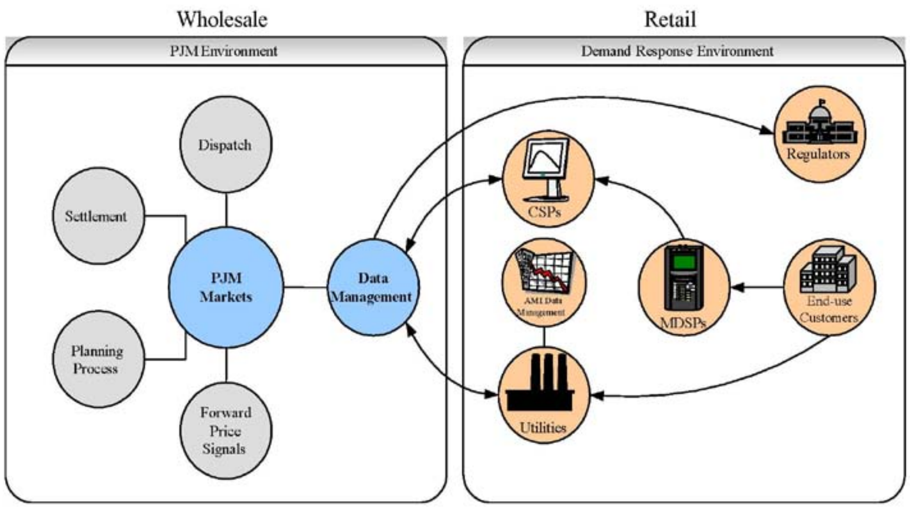

Table 2. Data Management Considerations by Market

WHOLESALE	RETAIL
1. Direct data management by PJM a) Enable the aggregation of demand resources (2009) b) Consider proper interface between eLoadResponse and eMarket (2009) c) Load Response application enhancements including hourly availability of DR and speedier settlements (2009) d) Electric distribution company (EDC) provide directly key customer information 2. Management of data provided directly to PJM electronically a) Develop meter data service provider (MDSP) certification standards (2009) b) Determine appropriate communication technologies for meeting business need to obtain real market data 3. Status quo provision of data to PJM by curtailment service providers (CSPs) for subsequent review by utilities (EDCs and LSEs) [on-going]	1. End-use customer and authorized agents unambiguous right to meter data at reasonable cost 2. Metering devices requested by CSP on behalf of customers installed within 10 business days 3. Meter data directly accessible by PJM and CSP at least daily 4. Standard electronic data interchange (EDI) transactions developed to accommodate full market participation by Demand Resources 5. Minimize stranded cost of deployment 6. Shorter more appropriate depreciation rates for meter data management software

Figure 3. Coordination during the Settlement Process

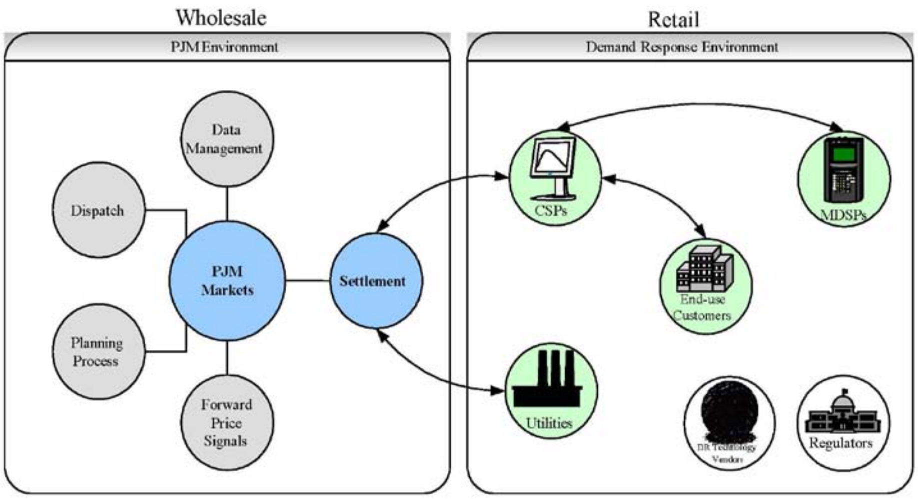

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Table 3. Settlement Considerations by Market

WHOLESALE	RETAIL
1. Speed up settlement for demand reduction (2009)	1. Codification of end-use customer's right to sell unused electricity
2. Automate the settlement adjustment process (2009)	2. Codification of customer baseline (CBL) calculation and rules
3. PJM calculates the CBL (2009)	3. Cost effective and timely (daily) access to meter data
4. PJM direct access to meter data based on regional standards for communications protocols	4. No longer need to routinely review and settlement (spot checks to verify MDSP standards maintained)

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Figure 4. Coordination during the Planning Process

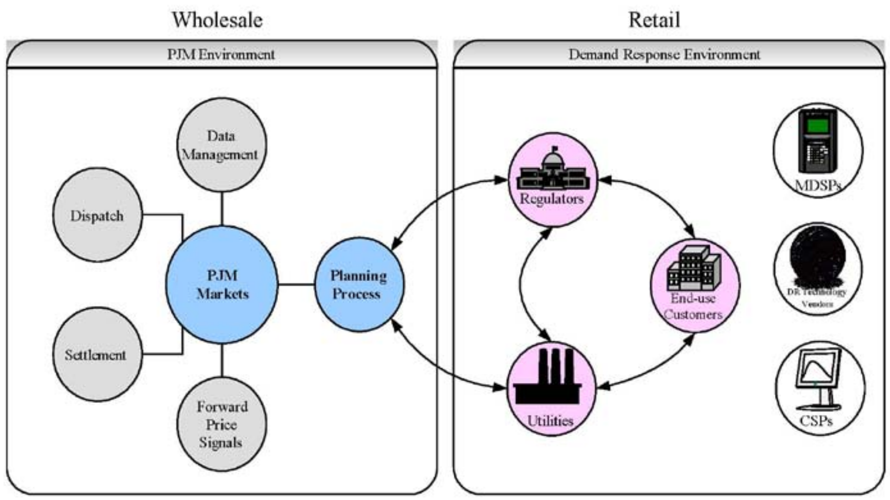

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Figure 4. Planning Process Considerations by Market

WHOLESALE	RETAIL
Integrate DR into RTEP and Economic Transmission processes by: 1. Publishing DR needed as temporary/permanent substitute for transmission enhancements (2007) 2. Developing queue for Planned DR 3. Including planned DR in annual update of the Load Forecasts (2007)	1. Product tests to measure system impact value and customer acceptance before broad deployment 2. Update load data that reflects the impact of Demand Resources including planned DR 3. Implement resource procurement strategy that includes economically viable DR 4. Build infrastructure for quick to market DR

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Figure 5. Coordination of Forward Price Signals

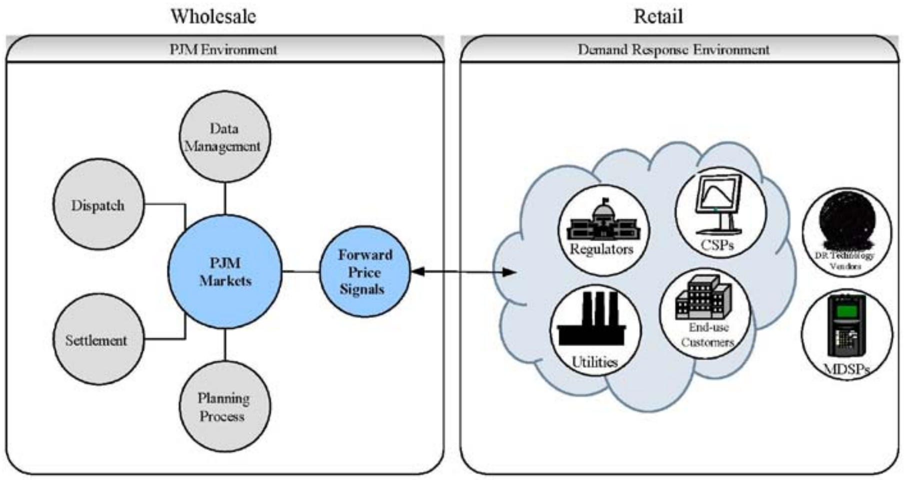

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Table 5. Forward Price Signals Considerations by Market

WHOLESALE	RETAIL
1. Reliability Pricing Model for emergency/reliability (2007)	1. Establish a regional (MADRI) DR goal of 3 percent
2. Capture maximum forward capacity market value for energy efficiency (2009)	2. RFP for "virtual peaking capacity"
	3. Portfolio standards with a requirement for demand resources

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Demand Response Participation on the Load Side of the Market

Price Responsive Demand (DR 3.0)

"Price Responsive Demand can be characterized as a third generation of demand response or DR 3.0. First generation demand response would include interruptible rates and direct load control, and RTO Demand Response programs would be a second generation of demand response."

Commissioner Paul Centolella
Ohio Commission 2009

"Dynamic pricing offers customers new options to manage their utility bills, as well as the potential to reduce wholesale power costs as customers respond to high peak prices."

Commissioner Rick Morgan
DC Commission in the March 2009 Public Utilities Fortnightly

"The integration of Price Responsive Demand in the wholesale and retail markets will increase the efficiency and robustness of the marketplace for electricity."

Andrew L. Ott
Sr. V.P. Markets, PJM 2009

Figure 1. Impact of Price Responsive Demand on Dispatch

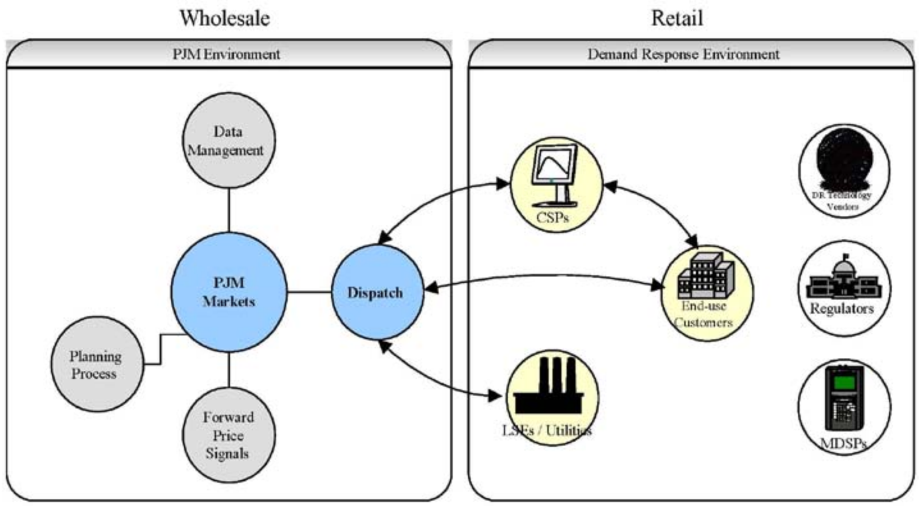

Table 1. Load that Responds Predictably to Dynamic Prices

WHOLESALE	RETAIL
1. Implement a look-ahead load forecast that includes the expected locational load level as a function of price that is documented in a Forecast Demand Response Curve 2. Revise Unit Dispatch System to take account of load levels as a response to price 3. Implement Scarcity Pricing through an Operating Reserve Demand Curve framework so that: a) Price impacts of varying quantities of operating reserve shortage are transparent b) Account for Scarcity Pricing revenues paid to capacity resources c) Load reduction capability can be deployed in response to price: i. before emergency actions ii. coincident with emergency actions	1. Retail rates that change daily or hourly in response to LMPs or other Energy Market conditions 2. Metering capable of recording usage on an hourly or sub-hourly basis: a) Competitive Supplier access b) Curtailment Service Provider access 3. Billing system capable of accurately and timely billing of dynamic retail prices 4. Enabling cost effective technology that: a) Communicates price signals b) Automates response c) Incorporates standards developed by the National Institute of Standards and Technology (NIST) process 5. Smart grid and dynamic prices education for policy makers, regulators and consumers 6. Measurement and reporting of resulting changes in load

Figure 2. Coordination of Data Management

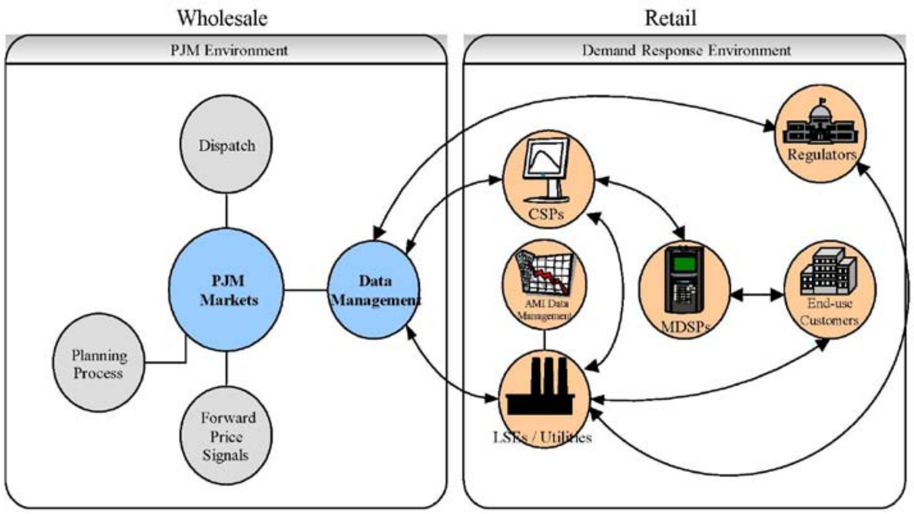

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Table 2. Measurement, Quantification and Reporting of Price Responsive Demand

WHOLESALE	RETAIL
1. Create Forecast Demand Response Curve for each zone (aggregate or node) using price / quantity data provided by Load Serving Entities. Locational granularity of price/quantity data must be determined 2. Use Forecast Demand Response Curves: a) to improve accuracy of load forecast and system dispatch both day-ahead and in real-time b) to inform the planning process and capacity procurement 3. Pending development of an integrated forecasting model, PJM will use price elasticity data from pilots and accepted statistical tools, including the Pricing Impact Simulation Model (PRISM), to develop forecasts for actual Price Responsive Demand.	1. Quantify and report actual Price Responsive Demand by location in a consistent and accurate manner 2. Provide price elasticity data obtained through on-going and recently conducted pilots in PJM (See, for example, Residential Smart Metering Pilot – PowerCentsDC in PEPCO, Smart Energy Savers Program pilot in BG&E, Energy Smart Pricing Program pilot in ComEd, AMI pilot program in PPL, myPower Pilot Program in PSE&G, AMI pilot program in PECO, and South Bend, Indiana Pilot in AEP) 3. Electric Distribution Company provides the LSE with the end-use customer's actual hourly usage rather than the customer class average so that: a) LSE supplies the actual aggregated load of its end-use customers in each hour b) LSE can offer dynamic prices to customers and capture the value of its customers' corresponding reductions in load

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Figure 3. Impact of Price Responsive Demand on the Planning Process

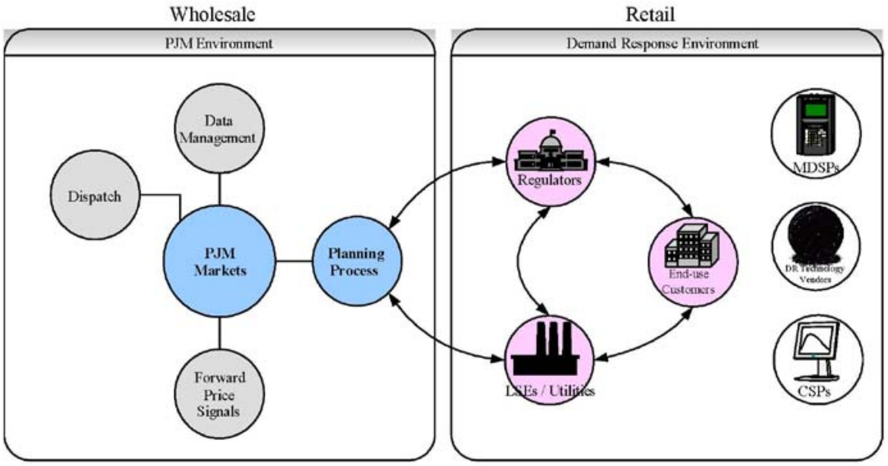

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Table 3. Price Responsive Demand as a Variable in the Load Forecast

WHOLESALE	RETAIL
1. Process in consultation with the Planning Committee and the Load Analysis Subcommittee to: a) Calculate unrestricted peak b) Use PRD data provided by LSEs to quantify the impact of price responsive demand (PRD) c) Subtract MW of PRD from unrestricted peak d) Use energy efficiency data provided by LSEs to quantify the impact of retail energy efficiency (EE) goals e) Subtract MW of actual unanticipated EE from unrestricted peak f) Avoid double counting g) Account for location of price responsive demand (PRD) 2. Process expected to evolve over time as PRD quantity grows and experience is gained 3. Experience with PRD expected to lead to improved calculation of the value of lost load	1. Implement dynamic prices that affect zonal load at peak: a) Critical peak prices b) Critical peak rebate c) RT and DA LMP d) Block and Index 2. Quantify reduction in firm demand, which is the residual demand after taking account of price responsive demand (PRD), during peak load conditions 3. Quantify reduction in firm demand during peak load conditions that is attributable to actual unanticipated energy efficiency

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Figure 4. Impact of Price Responsive Load on Forward Procurement of Capacity

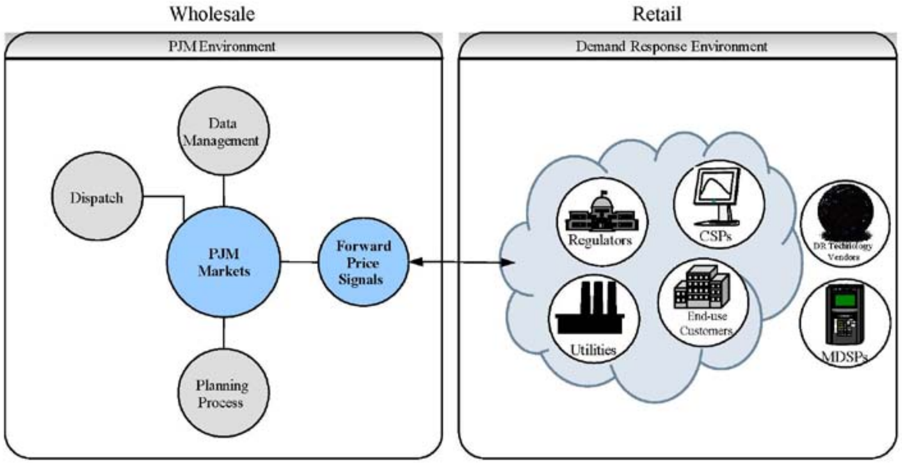

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Table 4. Capacity Commitments of Load Serving Entities must be Enforceable

WHOLESALE	RETAIL
1. Transition through 2012/2013 planning year: a) PRD registered as interruptible load for reliability (ILR) through 2011/2012 planning year b) PRD offered as a Demand Resource (DR) in incremental auctions through 2012/2013 2. Ability to reflect PRD in forecast of firm demand in incremental auctions held after May 2010 for planning years 2010/2011, 2011/2012 and 2012/2013 3. Ability to reflect PRD in forecast of firm demand in procurement for 2013/2014 planning year available for the base residual auction in May 2010 4. Develop ability to implement involuntary curtailment in a non-discriminatory manner 5. Develop penalties/consequences for LSEs that exceed capacity entitlements during emergency events	1. Load Serving Entity must ensure that load does not exceed its capacity obligation during system peaks or emergency events by: a) Implementing dynamic pricing that predictably reduces load b) Using capability of advanced metering infrastructure (AMI) to target, implement and confirm curtailment c) Procuring "extra" capacity as a hedge against non-performance d) Developing "extra" generating capacity as a hedge for PRD and intermittent resources e) Procuring "extra" capacity as needed bilaterally through the Power Contracts Bulletin Board or Incremental Auctions

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Appendix B. PJM Symposium on Demand Response III Agenda

As of November 5, 2009

PJM SYMPOSIUM ON DEMAND RESPONSE III
- Integrating Price Responsive Demand -

The purpose of PJM Symposium on Demand Response III, scheduled for November 9-10, 2009, is to consider the challenges posed by and plans for integrating Price Responsive Demand into the wholesale and retail markets. Price Responsive Demand (PRD) refers to end-use customers that adjust their demand for electricity based on retail rates that change daily or hourly in response to Locational Marginal Price or other Energy Market conditions. Symposium participants will learn about the wholesale and retail markets' plans and timelines for integrating PRD. Participants will also have opportunity to provide input for the *Demand Response Roadmap* for the PJM Region that has been updated and expanded since the last symposium to include the integration of PRD.

TIME	ACTIVITY	HOST / PARTICIPANTS	LOCATION
November 9, 2009	**Day 1**	**All Participants**	**Hotel Space**
11:00 am – Noon	Registration	All Participants	Salon 1 & 2
Noon – 1:30 pm	**WORKING LUNCH**	All Participants	Salon 3
	Opening Remarks	Stu Bresler, PJM	
	Symposium Overview	Susan Covino, PJM	
	Keynote Address	Roger Levy, Levy Associates	
1:30 – 1:40 pm	*"Expanding Opportunities for Demand Response through Price Responsive Demand"*	Terry Boston, CEO, PJM	Salon 1 & 2
1:40 – 2:00 pm	***Price Responsive Demand Fundamentals***	Ahmad Faruqui, The Brattle Group	
2:00 – 3:00 pm	***AMI Pilots***	Paul Sotkiewicz, PJM – Moderator	Salon 1 & 2
	Focus Question: *"What Do They Show about Price Responsive Demand in the PJM Region?"*	Potential Panelists: • Residential Smart Metering Pilot – PowerCents DC (Steve Sunderhauf, PEPCO) • Smart Energy Savers Program – (Neel Gulhar, BG&E) • Residential Real Time Pricing Program – (James Eber, ComEd/CNT Energy)	

As of November 5, 2009

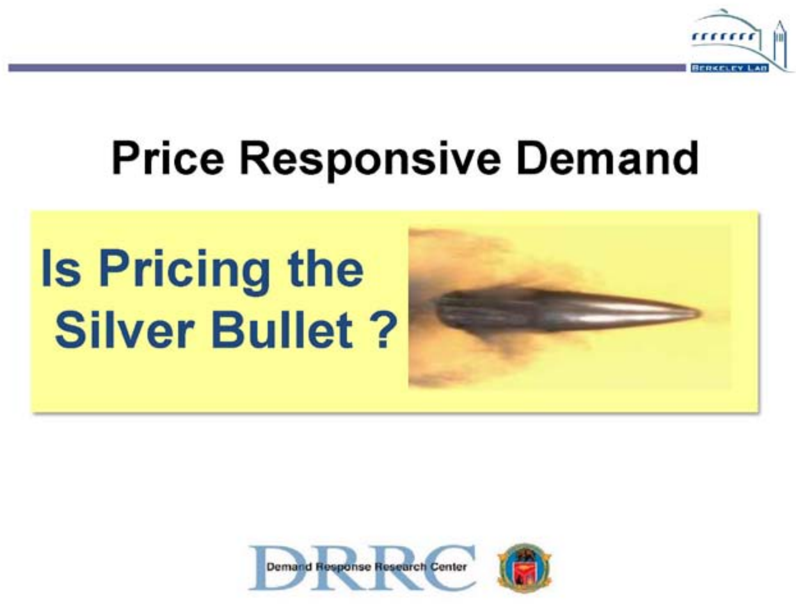
TIME	ACTIVITY	HOST / PARTICIPANTS	LOCATION
3:00 – 4:00 pm	***Integrating PRD: Wholesale Market Requirements***	Moderator – Ahmad Faruqui, The Brattle Group Panelists:	Salon 1 & 2
	RPM / Capacity Market	Andy Ott, PJM	
	Scarcity Pricing	Adam Keech, PJM	
	Market Operations	Stu Bresler, PJM	
	Planning	Tom Falin, PJM	
4:00 – 4:15 pm	Break	All Participants	Foyer
4:15 – 6:00 pm	***Integrating PRD: Making the Case, Retail Plans & Timelines***	Moderator – Lisa Wood, Institute for Electric Efficiency Panelists: • Commissioner Centollela (OH) • Chairman Nazarian (MD) • Consumer Advocate Stippler (IN) • Commissioner Elliot (IL) • President Fox (NJ)	Salon 1 & 2
6:00 – 6:30 pm	***The Demand Response Roadmap for the PJM Region*** Update and Inclusion of PRD	Susan Covino, PJM	Salon 1 & 2
6:30 – 8:00 pm	**HOSTED RECEPTION & DINNER**	All Participants	Salon 3
	Presentation: *"Development of an All-In Hourly Real Time Price"*	Marc Montalvo, ISO New England	
November 10, 2009	**Day 2**	**All Participants**	**Hotel Space**
7:00 – 8:00 am	Continental Breakfast & Networking	All Participants	Salon 3
8:00 – 8:20 am	***What a Difference A Year Makes*** Survey Questions using the voting boxes	Jan Brinch, Energetics	Salon 1 & 2
8:20 – 10:40 am	***Implementing Improved Demand Response in PJM: PRD and DR Roadmap***		Salon 1 & 2
	Process and Goals	Jan Brinch, Energetics	
	Table Discussion and Report Outs on PRD Roadmap	All Participants	

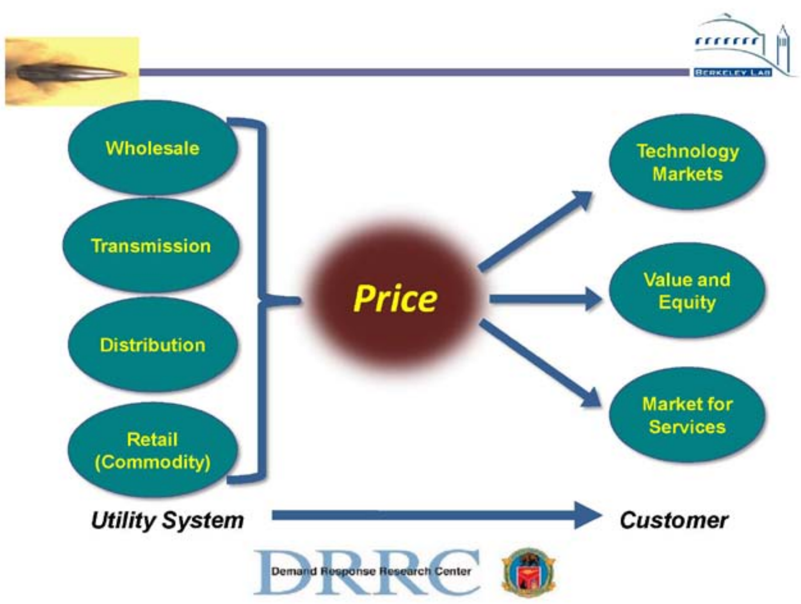
As of November 5, 2009

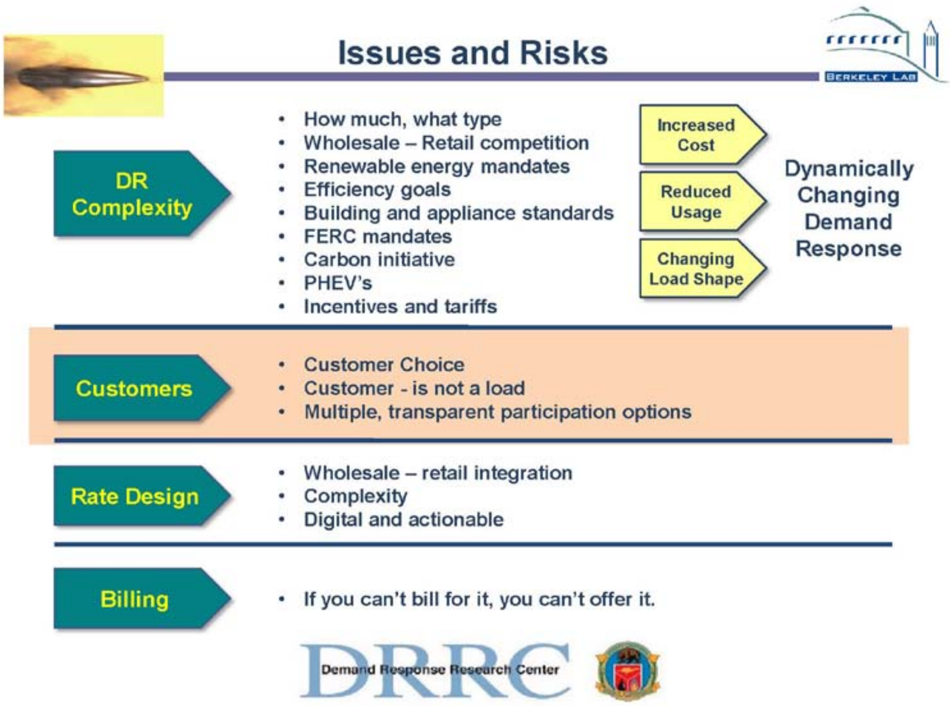
TIME	ACTIVITY	HOST / PARTICIPANTS	LOCATION
10:40 – 11:00 am	Break	All Participants	Foyer
11:00 – Noon	***Demand Response / Storage / Renewables: Complications or Compliments***	Moderator – John Kueck, Oak Ridge National Laboratory Panelists: • Michael Munson, Metropolitan Energy, LLC BOMA case study (Chicago, Illinois) • Paul Mitchell, Energy Systems Network PHEV case study (Indiana)	Salon 1 & 2
Noon – 12:30 pm	Closing Remarks	Susan Covino, PJM	Salon 1 & 2
12:30 – 1:30 pm	Box Lunches Provided for Participants	All Participants	Foyer

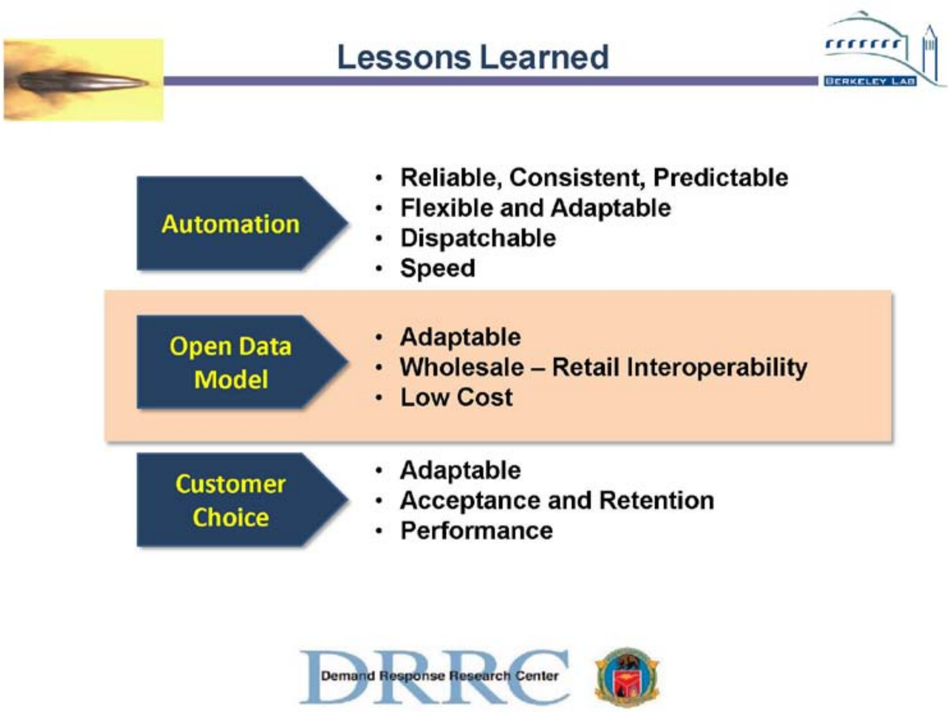
Appendix C. PJM Symposium on Demand Response III Presentations

1. Price Responsive Demand: Is Pricing the Silver Bullet? Roger Levy, DRRC






Issues and Risks
BERKELEY LAB
DR Complexity
How much, what type
Wholesale – Retail competition
Renewable energy mandates
Efficiency goals
Building and appliance standards
FERC mandates
Carbon initiative
PHEV's
Incentives and tariffs
Increased Cost
Reduced Usage
Changing Load Shape
Dynamically Changing Demand Response
Customers
Customer Choice
Customer - is not a load
Multiple, transparent participation options
Rate Design
Wholesale – retail integration
Complexity
Digital and actionable
Billing
If you can't bill for it, you can't offer it.
DRRC
Demand Response Research Center


Lessons Learned
BERKELEY LAB
Automation
Reliable, Consistent, Predictable
Flexible and Adaptable
Dispatchable
Speed
Open Data Model
Adaptable
Wholesale – Retail Interoperability
Low Cost
Customer Choice
Adaptable
Acceptance and Retention
Performance
DRRC
Demand Response Research Center

Low Cost

OpenADR Automation Results
Average One-Time Cost / kW Peak Reduction

Seattle City Light Sites	Controls Vendor	Controls Cost ($/kW)	Commissioning DR Strategies ($/kW)	Total ($/kW)
Office Building #1 (hardware client)	ATS	180	51	$231
High Rise Office Tower	Siemens	8	2	$10
Retail Stores (2)	ALC	33	0	$33
University Office Tower	ESC	23	9	$32
Average costs		61	21	$76

DRRC Demand Response Research Center

Adaptable, Flexible, Performance

OpenADR Results
CAISO Participating Load Pilot

Forecasted vs Actual Ramp Time (MW/ min)	Forecasted vs. Actual Average Hourly Shed (kW)			
	HE 15:00	HE 16:00	HE 17:00	HE 18:00
0.002 / 0.006	20/72	80/86	40/51	30/49
Percent Performance	360%	108%	128%	163%

DRRC Demand Response Research Center

"….we argue that dynamic pricing that reflects varying system conditions over locations as well as time is the path to realizing the full benefits of active participation of final demand in the wholesale market".

Market Surveillance Committee of the California ISO, F.Wolak, J.Bushnell, B.Hobbs, June 24, 2009.

Is Pricing the Silver Bullet ?

DRRC Demand Response Research Center

Roger Levy,
Consultant to the
Demand Response Research Center
Lawrence Berkeley National Laboratory

Levy Associates
Sacramento, CA
Phone: 916-487-0227
Email: RogerL47@aol.com

http://drrc.lbl.gov/

DRRC Demand Response Research Center

2. Fundamentals of Price Responsive Demand
Ahmad Faruqui, Ph. D., The Brattle Group

Introduction

- Many utilities, state commissions, ISOs/RTOs are investigating ways to reduce energy costs for end-use customers while preserving system reliability
- An attractive option for achieving this goal is to pass through real-time pricing costs to end-use customers and to let the load serving entities bid in price-responsive demand curves into the energy market
- This presentation shows how that task can be accomplished

PJM Symposium on Demand Response III 2 *The Brattle Group*

We simulate the impact of real-time pricing (RTP) rates on a Midwestern utility

- For the simulations, we use the architecture of the Pricing Impact Simulation Model (PRISM) which grew out of California's statewide pricing pilot (SPP)
- We tailor PRISM for this application by first converting it from a two-period pricing model to an hourly pricing model and by replacing California price elasticities with those derived from an experiment in northern Illinois that was carried out by ComEd
- We then simulate the impact of RTP on several variables for the average customer:
  - Percent change in average critical hour consumption
  - Percent change in average monthly consumption
  - Percent change in average monthly bill

PJM Symposium on Demand Response III 3 *The Brattle Group*

For demonstration purposes, we have forecasted price responsive demand for 36 different scenarios

Scenarios are driven by:

- Level of RTP series
- Value of price elasticity
- Existence of enabling technology
- Market penetration of dynamic pricing

Scenario Driver	Number of Sensitivities	Detail
Price	3	Historic, High, Spiky
Technology	2	w/ and w/o Technology
Elasticity	3	Low, Base, High
Market Penetration	2	Universal, Opt-in
Total Number of Scenarios	**36**	

PJM Symposium on Demand Response III 4 *The Brattle Group*

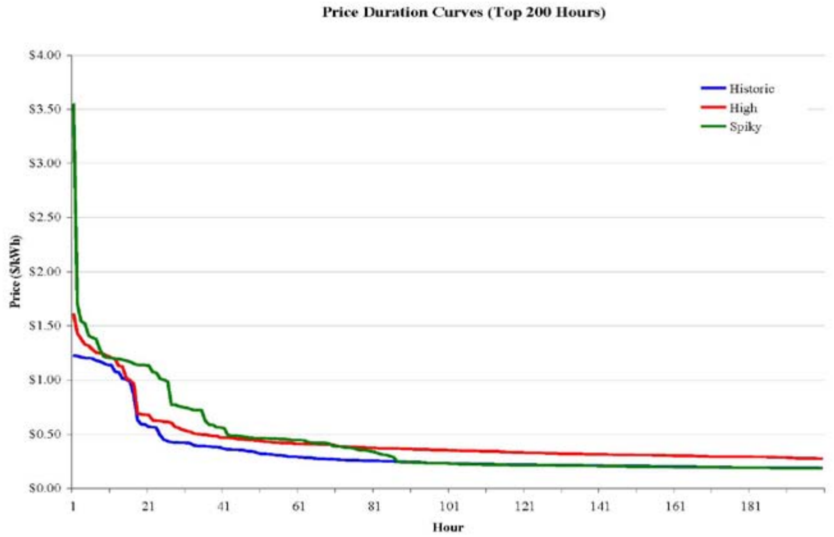
Driver 1: Level of RTP series

We simulated the impact of three price series:

1. Historic Prices
   - A Midwest utility's RTPs between January 1, 2007- December 31, 2007
2. High Prices
   - 2 x Historic prices
3. Spiky Prices
   - We developed this series based on the historic RTPs
   - Prices for the top 40 hours of the historic RTP duration were increased dramatically to illustrate a crisis year

PJM Symposium on Demand Response III 5 *The Brattle Group*

Price Duration Curves



PJM Symposium on Demand Response III 6 *The Brattle Group*

Driver 2: Value of price elasticity

We simulated the impacts under three assumptions:

1. Base elasticity
   - ComEd RTP 2006 elasticities
2. Low elasticity
   - Base elasticities reduced by 30 percent
3. High elasticity
   - Base elasticities increased by 30 percent

Elasticity Assumptions

	Low	Base	High
Normal Day (Price <$0.13)	-0.033	-0.047	-0.061
High Day (Price >$0.13)	-0.057	-0.082	-0.107
High Day (Price>$0.13) w/ TECH	-0.069	-0.098	-0.127

PJM Symposium on Demand Response III 7 *The Brattle Group*

Driver 3: Existence of enabling technology

We simulated the impacts under 2 enabling technology assumptions:

1. Without enabling technologies
2. With enabling technologies

Technology impacts are modeled through higher elasticities that are shown in the elasticity assumptions table

PJM Symposium on Demand Response III 8 *The Brattle Group*

Driver 4: Market penetration of dynamic pricing

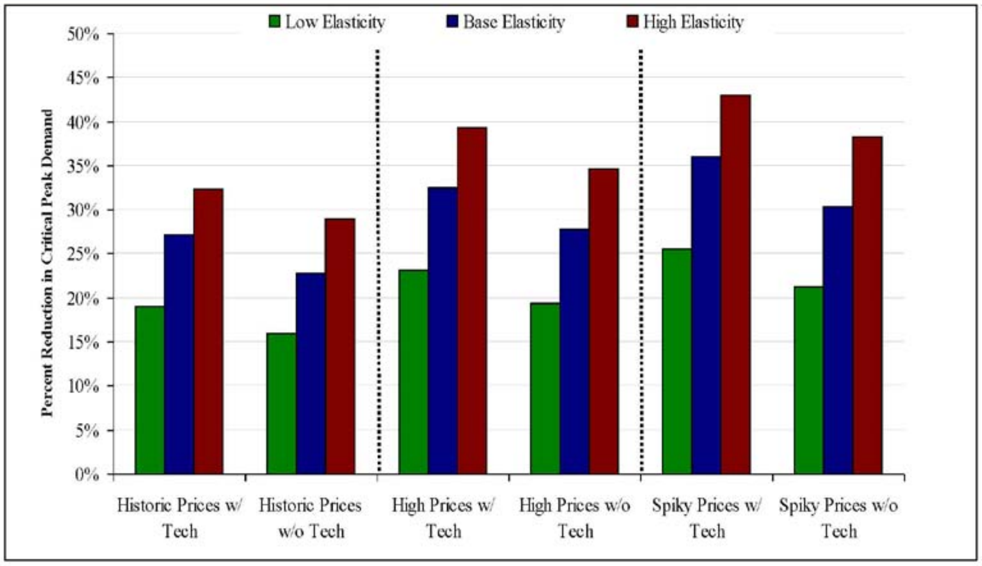
We constructed price responsive demand curves under 2 market penetration assumptions:

1. Universal deployment (High Penetration)
   - 100 percent of customers are subject to RTP prices
2. Opt-in deployment (Low Penetration)
   - 20 percent of customers volunteer for RTP prices

Implementation

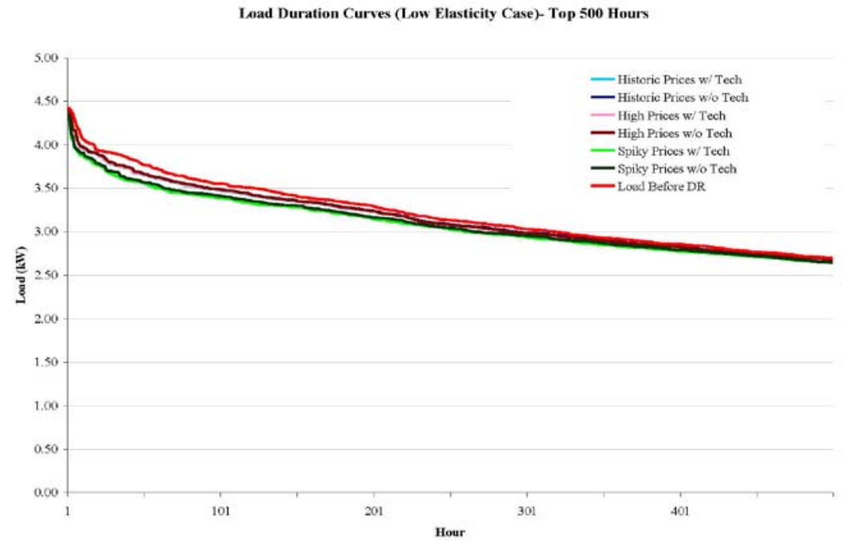
- We used illustrative data from the Midwest
  - Load profile of an average non-space heat customer
  - Existing (non-RTP) prices
- We ran our simulation under the specified scenarios
  - Obtain percentage demand reduction in average critical period load (kWh/hour)
  - Critical period is defined as top 100 hours in terms of the prices
- We constructed price responsive demand (PRD) curves
  - Total number of residential customers is used to construct market demand curves- 370,294 customers in 2007 corresponds to:
    - 370,294 residential customers under "Universal Deployment Scenario"
    - 74,059 residential customers under "Opt-in Scenario"

Forecast demand response impacts



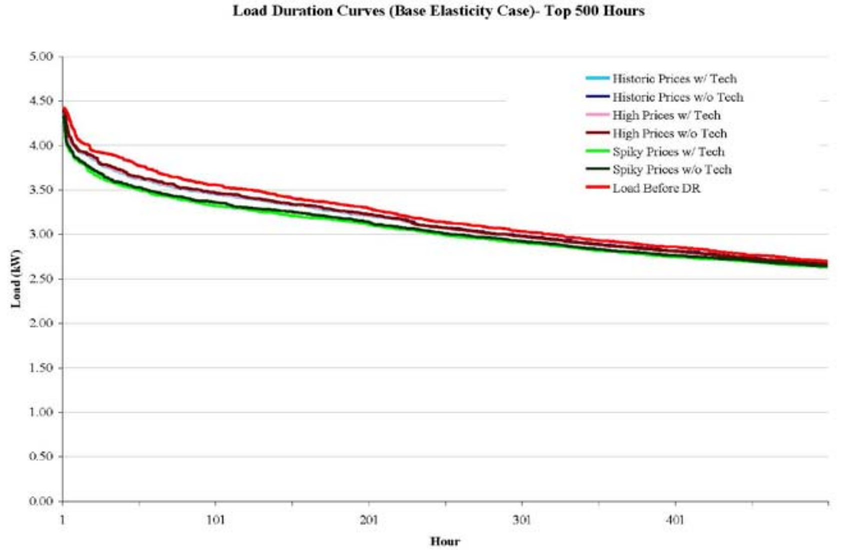
PJM Symposium on Demand Response III 11 *The Brattle Group*

Load Duration Curve for the Average Customer (Low Elasticity Case)



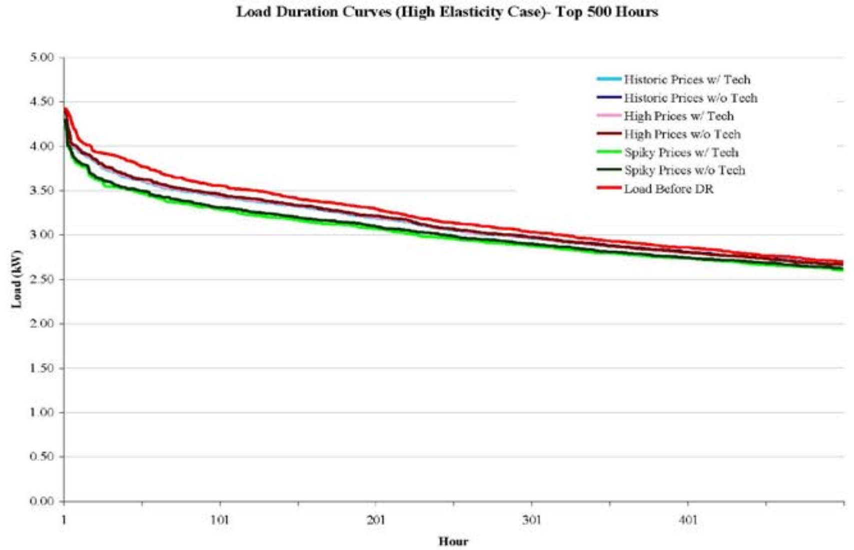
PJM Symposium on Demand Response III 12 *The Brattle Group*

Load Duration Curve for the Average Customer (Base Elasticity Case)



PJM Symposium on Demand Response III 13 *The Brattle Group*

Load Duration Curve for the Average Customer (High Elasticity Case)



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Summary of the Simulations

- Impacts are in the range of 16 to 43 percent
  - The lowest impact is from the scenario with "low elasticity + Historic Price + w/o Tech"
  - The highest impact is from the scenario with "high elasticity + Spiky Price + w/ Tech"
- Availability of enabling technologies increase demand response, as do the higher price elasticities and higher prices

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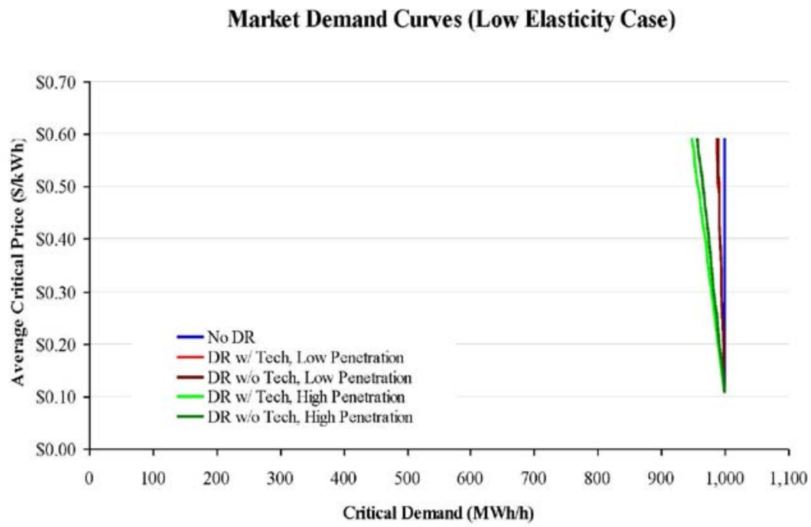
PRD Curve based on "Low Elasticity" Assumption



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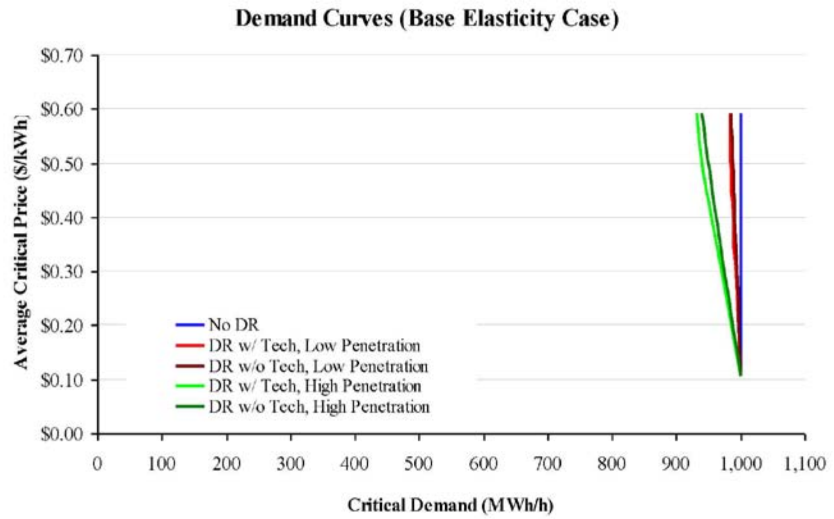
PRD Curve based on "Base Elasticity" Assumption



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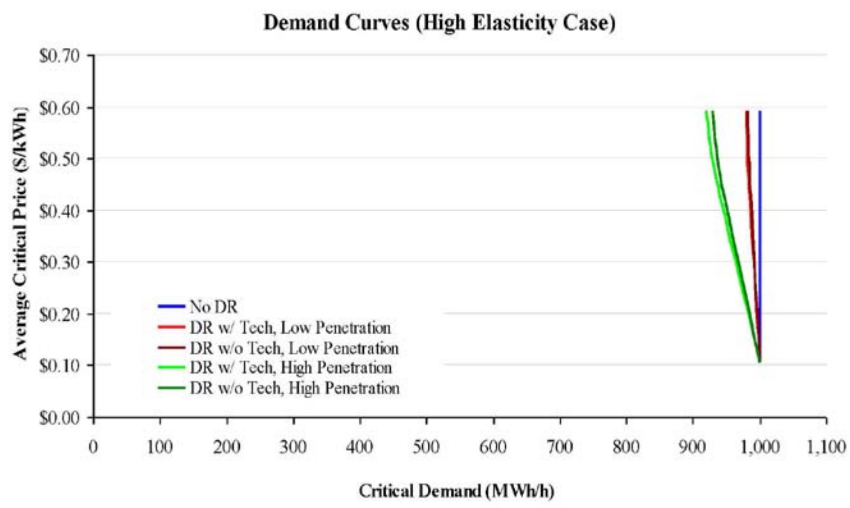
PRD Curve based on "High Elasticity" Assumption



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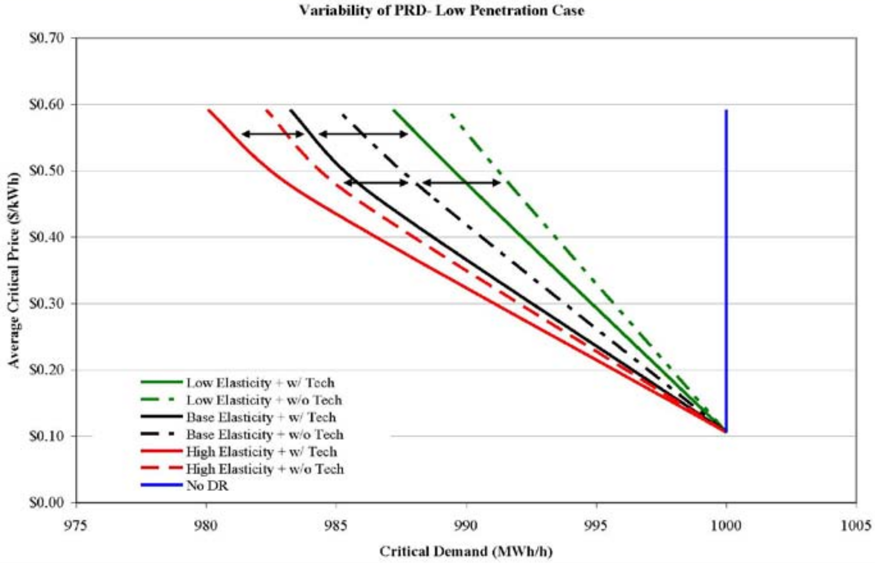
Variability of PRD- Low Penetration Case



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Conclusions

- Models and data are available to simulate customer response to dynamic pricing
- In our simulations, real-time pricing has been shown to elicit significant amounts of demand response ranging from 16 to 43 percent per customer
  - The lowest impact is from the scenario with "low elasticity + Historic Price + w/o Tech"
  - The highest impact is from the scenario with "high elasticity + Spiky Price + w/ Tech"
- Availability of enabling technologies increase demand response, as do the higher price elasticities and higher prices

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References

- "Household response to dynamic pricing of electricity–a survey of the experimental evidence." With Sanem Sergici. http://www.hks.harvard.edu/hepg/
- "Inclining toward efficiency," Public Utilities Fortnightly, August 2008. http://www.fortnightly.com/exclusive.cfm?o_id=94
- "Transitioning to dynamic pricing." With Ryan Hledik, Public Utilities Fortnightly, March 2009. http://ssrn.com/abstract=1336726
- "The power of dynamic pricing," With Ryan Hledik, The Electricity Journal, April 2009. http://ssrn.com/abstract=1340594

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Biographical information

Ahmad Faruqui is a principal with *The Brattle Group*. He led a state-by-state assessment of the potential for demand response for the Federal Energy Regulatory Commission and is assisting FERC in the development of a national action plan. Last year, he performed a national assessment of the potential for energy efficiency for the Electric Power Research Institute and wrote a report on quantifying the benefits of dynamic pricing for the Edison Electric Institute. He has worked on fostering economic demand response for the Midwest ISO and ISO New England and on load management standards for the California Energy Commission. Since the year 2000, he has been assisting utilities and commissions throughout the US and Canada assess the economics of dynamic pricing, demand response and advanced metering. This has often involved the design and evaluation of innovative pilot programs. Early in his career, he wrote an evaluation of 14 experiments with time-of-use pricing which is cited in Professor Bonbright's text on public utility rates. The author of four books and more than a hundred papers on energy policy, he holds a doctoral degree in economics from the University of California at Davis. He is based in *Brattle*'s San Francisco, California office and can be reached via email at ahmad.faruqui@brattle.com or by phone at (925) 408-0149.

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3. District of Columbia PowerCentsDC^{TM} Program Update Steve Sunderhauf, Pepco Holdings Inc.

pepco

District of Columbia PowerCentsDC^{TM} Program Update

11-09-09

Steve Sunderhauf

Pepco Holdings Inc.

PJM Demand Response Symposium

Pepco Holdings Inc 1

pepco

Background Information

- Residential Smart Meter Pilot Project in the Nation's Capital
- Governed by "Smart Meter Pricing Pilot, Inc."
  - DC Public Service Commission
  - DC Office of People's Counsel
  - DC Consumer Utility Board
  - IBEW
  - Pepco
- Vendors
  - AMDS/Sensus – Smart Metering System
  - Comverge/White Rodgers – Smart Thermostats
  - Honeywell – Smart Thermostat Installation
  - Mincom – Billing and Data Validation Services
  - eMeter/Utilipoint – Day-to-Day Project Management
  - Dr. Frank Wolak, Stanford University – Evaluator

Pepco Holdings Inc 2

pepco

Background Information

- Funded by Pepco through a Merger Settlement Agreement at a Level of $2 Million
- Voluntary Participation by Invitation/Opt Out Provision
  - CPP/HP $100 Incentive to Participate – $50 Initially, $50 at Conclusion
  - Installation of Smart Thermostat offered
- Residential Standard Offer Service Customers Only
- Duration of Dynamic Pricing – July 2008 to Nov. 2009
- Pilot Designed to Test Market Receptivity to Three Pricing Alternatives (Supply Portion Only)
  - 1. Hourly Pricing
  - 2. Critical Peak Pricing (Approx. $0.78 per kWh)
  - 3. Critical Peak Rebate (Approx. $0.67 per kWh)
- Day ahead notification after 5pm via Phone, Email, Text Message, or Smart Thermostat, – for next day event from 2 to 6 pm

Pepco Holdings Inc 3

pepco

Pilot Sample Size

Active Participants	By Usage
Rate Code	**Count**
All Electric	215
Not All Electric	642
Total	**857**

Active Participants	By Income Level
Income Level	**Count**
Low-Income	118
Non Low-Income	739
Total	**857**

Active Participants	By Rate Code
Rate Code	**Count**
Control	388
CPP	236
CPR	387
HP	234
Total	**1245**

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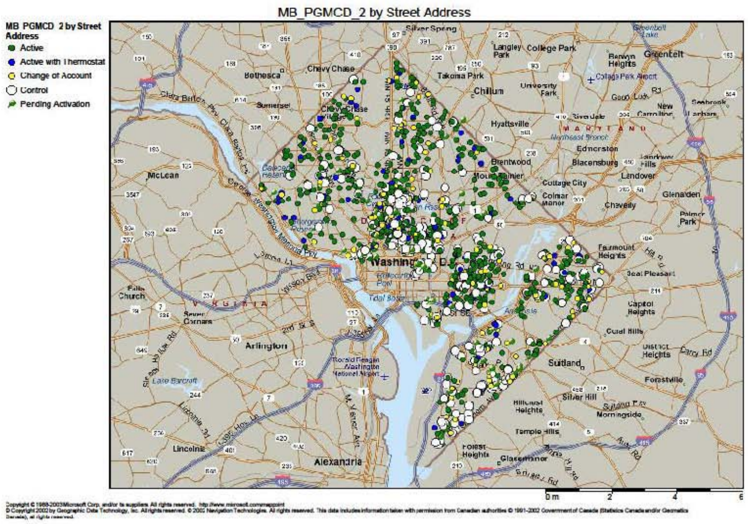
SMPPI Sites



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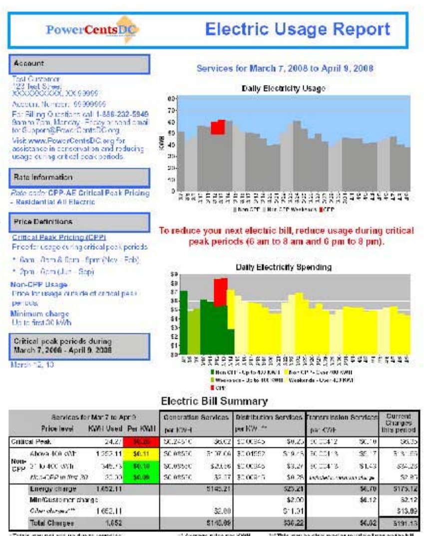
pepco

Customer Electric Usage Report

- Provided each month with bill
- Shows more detail on energy usage and energy costs
- Colorful graphs allow quick reference



Pepco Holdings, Inc 6

pepco

PowerCentsDC™

- Consumer engagement software

- Automated HVAC control with messaging; energy pricing and bill to date

Pepco Holdings Inc 7

pepco

Overall 2008 Summer & 2008/09 Winter Results

Rate Plan	Summer Peak Reduction	Winter Peak Reduction
CPP	25%	10%
CPR	11%	(n/s)
HP	4%	4%

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pepco

Rate Impact Breakout – 2008 Summer & 2008/09 Winter

Customer Type	Population Weight	Peak Reduction Summer			Peak Reduction Winter		
		CPP	CPR	HP	CPP	CPR	HP
Regular (R)	73%	24%	10%	3%	7%	n/s	n/s
All Electric (AE)	19%	30%	19%	8%	21%	n/s	20%

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pepco

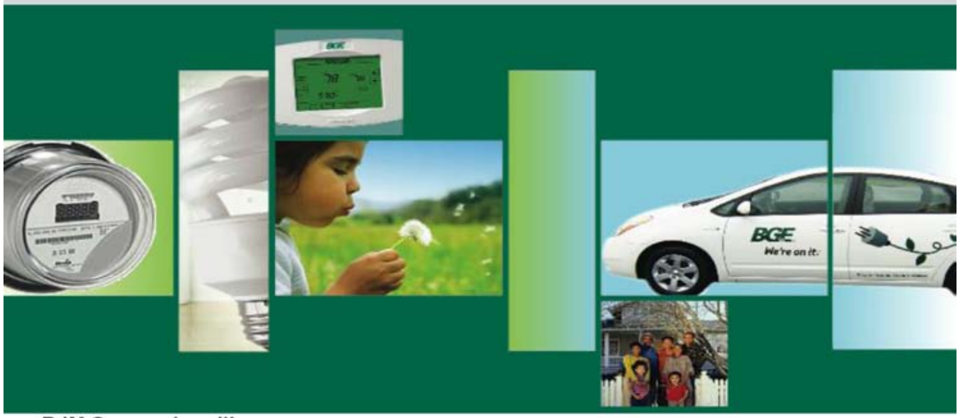
Impact of Smart Thermostats

Customer Type	No Smart Thermostat		With Smart Thermostat	
	CPP	CPR	CPP	CPR
Regular (R)	22%	9%	34%	n/s
All Electric (AE)	29%	15%	50%	26%

Pepco Holdings Inc 10

4. BGE Smart Energy Pricing: "Customers are making it work" Neel Gulhar, BGE

BGE Smart Energy Pricing: "Customers are making it work"



PJM Symposium III

November 9, 2009
Neel Gulhar
Project Manager, Smart Energy Pricing

BGE
We're on it.

Smart Grid History for BGE

- 2006 – Concerns raised over electric demand outstripping supply in eastern and southeastern MACC (PJM). MD importing 40% of electricity consumed from outside the state. Nearing transmission import capability limit.
- Jan '07 – BGE files Smart Energy Savers Program, including aggressive residential DRI program, new energy efficiency programs and new Smart Grid program.
- Mar '08 – MD legislature passes EmpowerMD legislation seeking 15% reduction in both electric use per customer and in peak demand by 2015 vs. a 2007 baseline. Utilities tasked with achieving 67% of use/customer goal and 100% of peak reduction goal.
- Summer '08 – BGE conducts both an AMI meter pilot (5,300 customers) with two vendors and a Smart Energy Pricing Pilot (SEP) with over 1,300 customers
- Summer '09 – Second year of residential SEP pilot; commercial SEP pilot started; In-home display evaluation
- July '09 – BGE files for approval of full roll-out of Smart Grid initiative and new SEP rate schedule
- Aug '09 – BGE files for DOE Smart Grid stimulus grant
- Oct '09 - BGE receives $200M ARRA grant for Smart Grid roll-out
- Nov '09 – MD PSC Hearings on BGE's Smart Grid proposal

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Focus Groups were the First Step

In 2007 BGE conducted focus groups with different segments of customers:

- Low-income Customers
- Educated Customers
- Energy Conscious Customers

Findings were essential to development of pilot program.

- Customers wanted to save only if savings were substantial, or "enough to buy to lunch."
- More customer education was essential: "What's a kilowatt?"
- Customers had to be notified of critical peak events well in advance in order to "plan and tell my children to not turn the lights on."
- Some customers were wary of BGE, and thought they were being ripped off – "what's the catch?"

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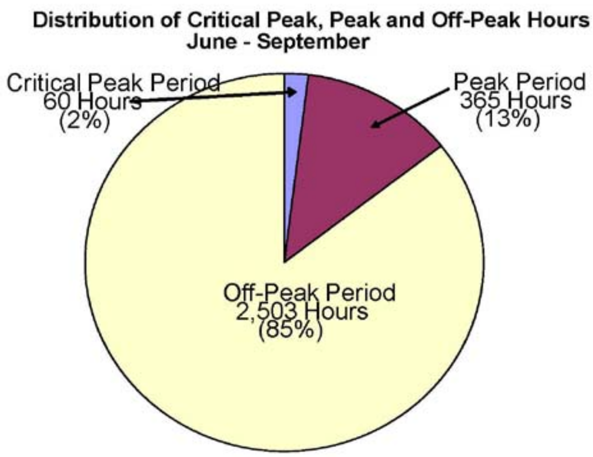
Distribution of Summer Hours for Price Signals



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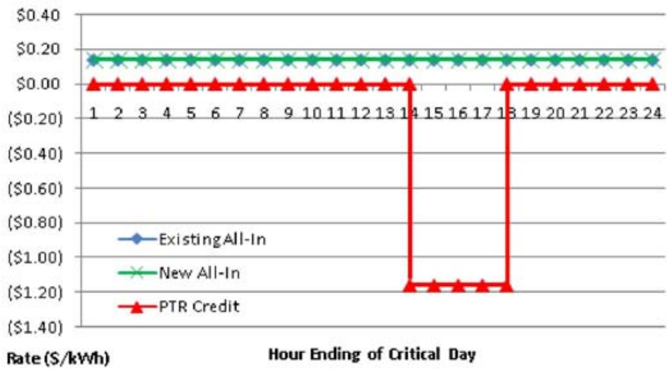
Peak Time Rebate - Overview

A Mirror Image of the DPP Rate

- Schedule R summer rates were ~$0.14 / kWh for all summer hours
- Rebate offered on up to 12 critical peak days (2-7PM)



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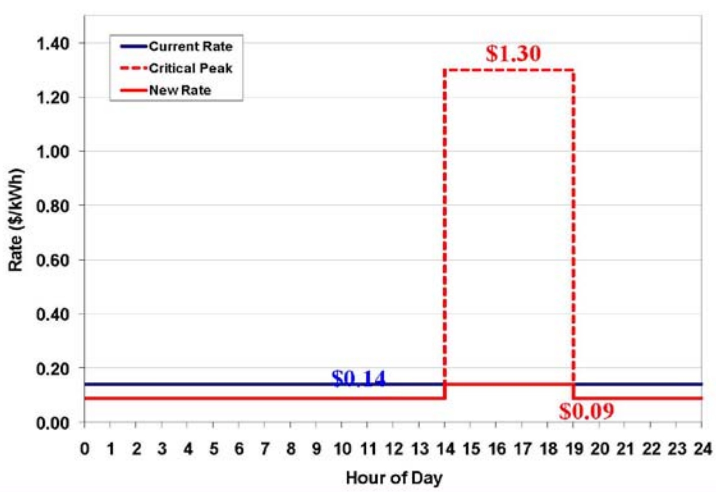
Dynamic Peak Pricing: Weekdays (excluding Holidays)



Pilot Pricing All – in Rate*

Critical $1.30425
Peak $0.14425
Off-Peak $0.09425

*** Includes generation, transmission and delivery**

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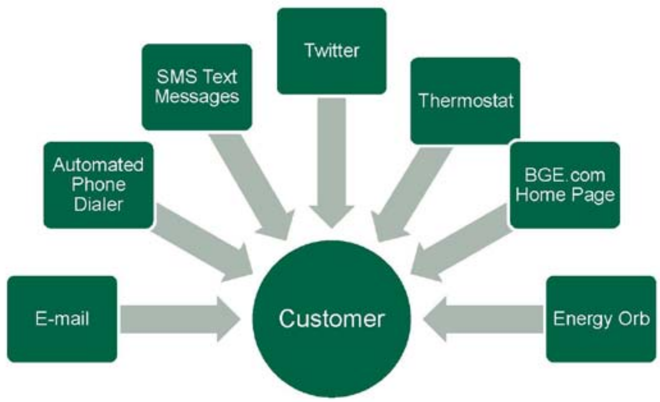
Critical Event Notifications During Pilots

Notifications occurred the day before starting at 6PM



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Smart Energy Pricing (2008) Pilot Design

Group	Total	PTR $1.16 Rebate	PTR $1.75 Rebate	Dynamic Peak Pricing	Control Group
Without Enabling Technology	675	125	125	125	300
With Orb Technology	250	125	125	0	0
With Orb and AC Switch Technologies	375	125	125	125	0
Total	1300	375	375	250	300

2009 Pilot Design only include PTR at $1.50/kWh

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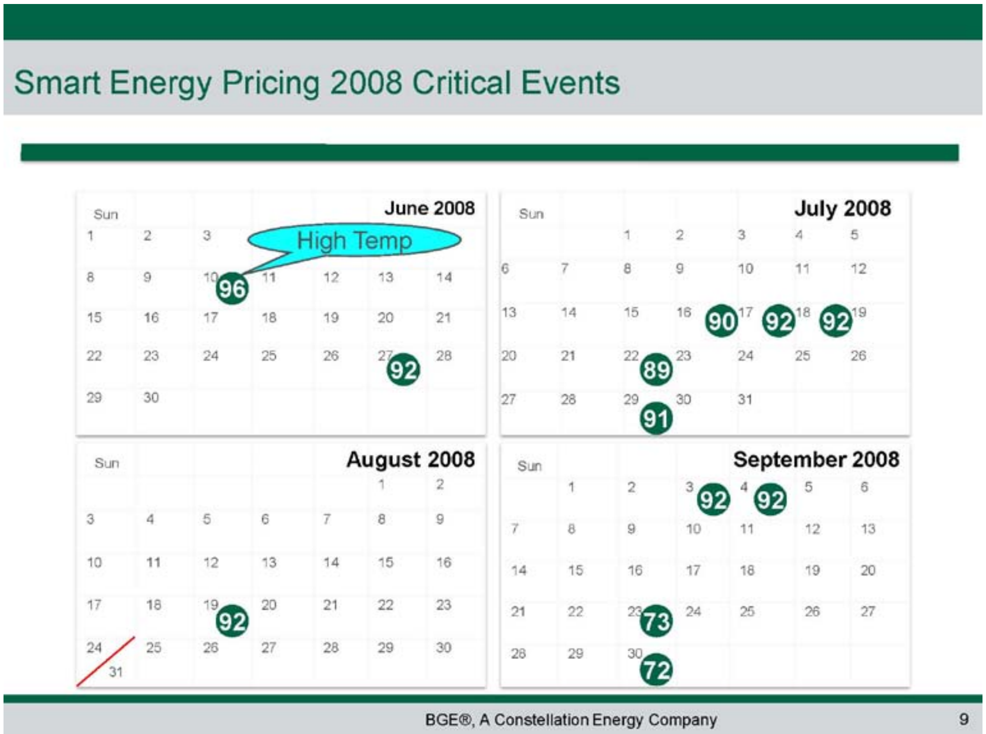
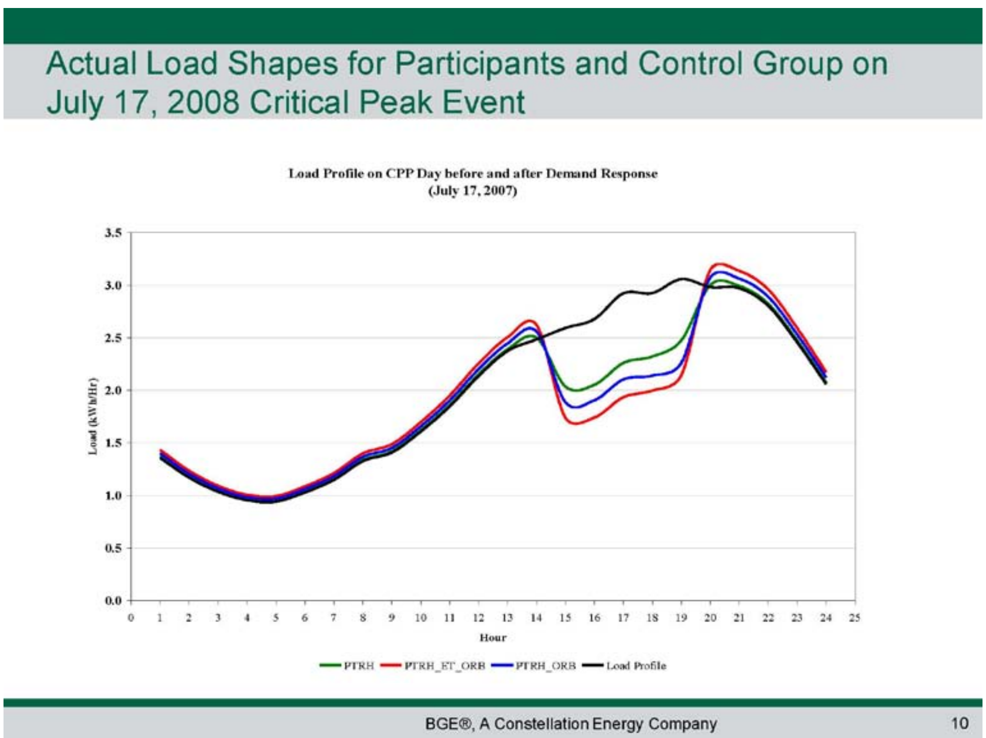

Smart Energy Pricing 2008 Critical Events
June 2008
High Temp
96
92
July 2008
90
92
92
89
91
August 2008
92
September 2008
92
92
73
72
BGE®, A Constellation Energy Company
9


Actual Load Shapes for Participants and Control Group on July 17, 2008 Critical Peak Event
Load Profile on CPP Day before and after Demand Response
(July 17, 2007)
Load (kWh/Hr)
Hour
PTRH
PTRH_ET_ORB
PTRH_ORB
Load Profile
BGE®, A Constellation Energy Company
10

Critical Event Savings Reports

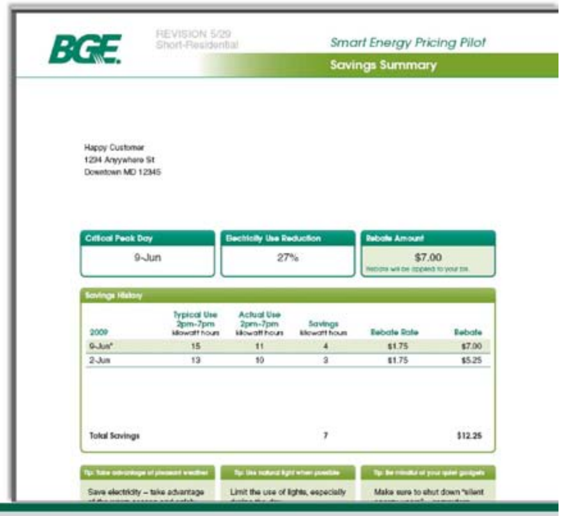
- Immediate feedback on savings is essential to successful program.

-Customers who saved a lot take notice, and will continue to perform on future events.

- Customers who did not save, need to be made aware of how much others are savings!

- *Future Idea: add localized comparisons of savings ("The average savings in your zip code were $12 on the last event)*

- Push this report to customers at first, and let them realize the value


BGE
REVISION 5/29
Short-Residential
Smart Energy Pricing Pilot
Savings Summary

Happy Customer
1234 Anywhere St
Downtown MD 12345

Critical Peak Day	Electricity Use Reduction	Rebate Amount
9-Jun	27%	$7.00

Savings History

2009	Typical Use 2pm-7pm kilowatt hours	Actual Use 2pm-7pm kilowatt hours	Savings kilowatt hours	Rebate Rate	Rebate
9-Jun*	15	11	4	$1.75	$7.00
2-Jun	13	10	3	$1.75	$5.25
Total Savings			7		$12.25

Save electricity – take advantage
Limit the use of lights, especially
Make sure to shut down "silent

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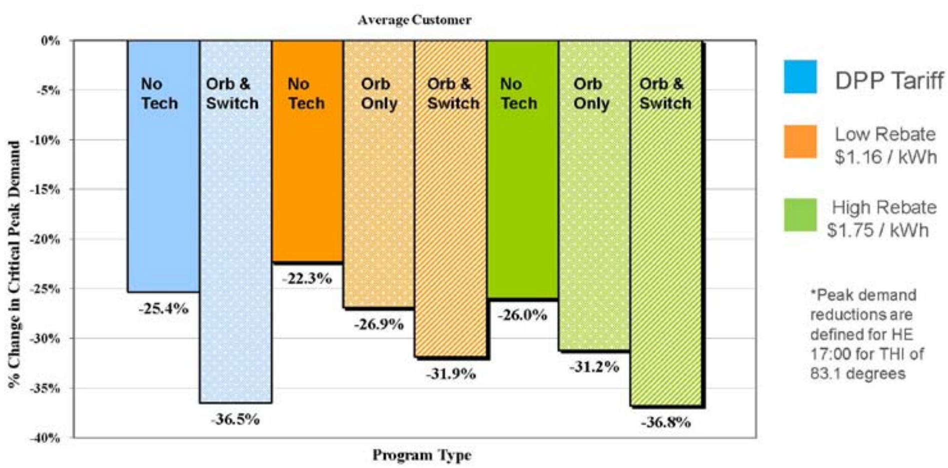
Summer 2008 Pilot- Peak Demand Reductions*



*Peak demand reductions are defined for HE 17:00 for THI of 83.1 degrees

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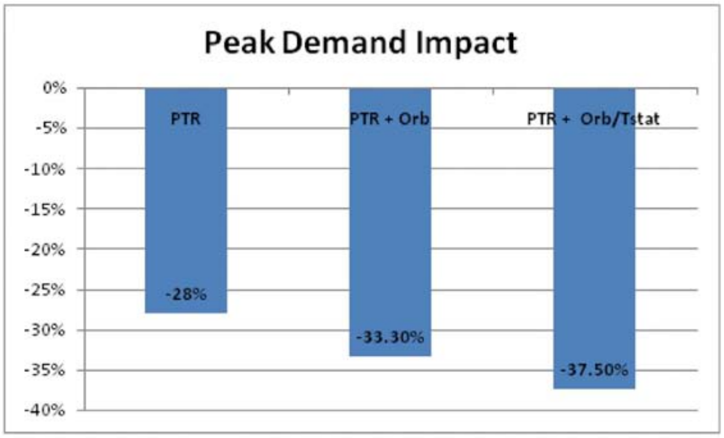
SEP 2009 Pilot - Peak Demand Reductions

- Demand impacts for residential PTR ($1.50/kWh) in 2009 pilot range from 28%-38%
- Overall results show persistency and increase in impacts from 2008



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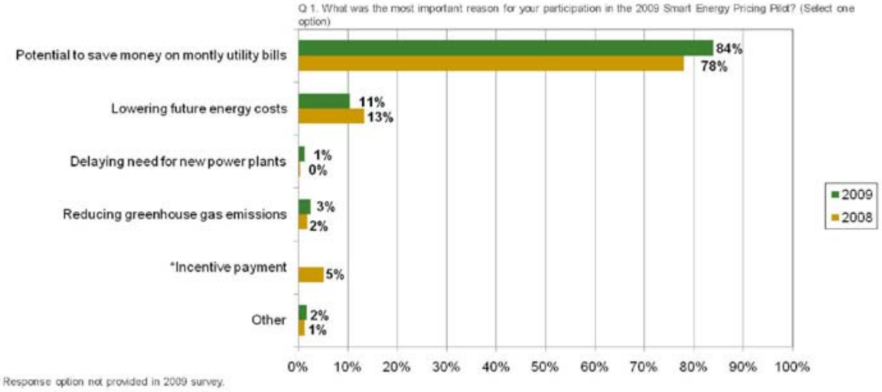
Program Participation and Satisfaction

The *potential to save money on monthly utility bills* was the primary motivation behind customers' participation in the Smart Energy Pricing Pilot.



* Response option not provided in 2009 survey.

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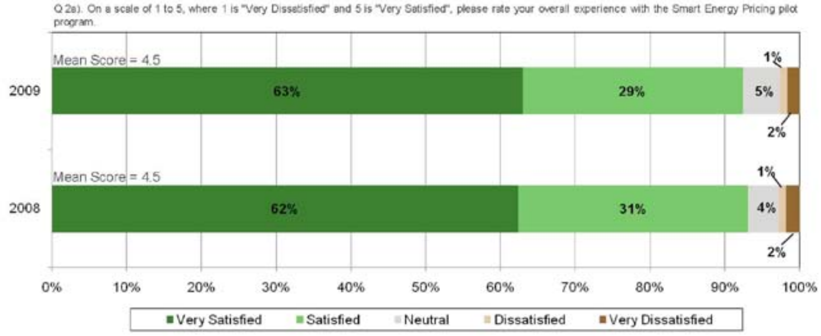
Program Participation and Satisfaction (cont)

Satisfaction with the SEP Pilot Program remained consistently high, with two thirds of the participants claiming to be 'Very Satisfied' with the pilot program, and nine out of ten participants stating they are at least 'Satisfied'.

The mean score was a 4.5 out of a 5 point scale during both summers.



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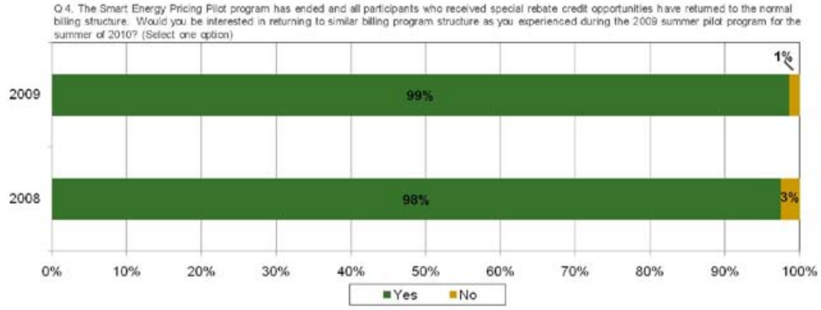
Program Participation and Satisfaction (cont)

Participants in each year's SEP Pilot Program – 99% in 2009 and 98% in 2008 – were overwhelmingly interested in returning to a similar pricing structure the following summer.

Further, 93% of 2009 study participants believe the opportunity to earn rebates for reducing energy usage during Critical Peak periods should be standard for all BGE customers . Similarly, 80% of 2008 study participants believe a variable rate program should be standard for all BGE customers who reduce energy use during critical times.



* Questions were asked too dissimilarly for direct comparisons to be made.

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Conclusion

DOES PRICE RESPONSIVE DEMAND WORK ?

Yes, but only if implemented properly:

- Simple program design (walk before you run)
- Customer education
- Timely feedback and information to customer
- Robust price signals

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SMART ENERGY PRICING: "Customers are making it work!"

QUESTIONS?

Gulhar, Neel
BALTIMORE GAS & ELECTRIC CO
Program Manager

(410) 470-1336 Work
(443) 248-3560 Mobile
Neel.Gulhar@constellation.com

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5. Dynamic Pricing AMI Pilot
Jim Eber, ComEd

ComEd
An Exelon Company

**Dynamic Pricing
AMI Pilot**

PJM DR Symposium

**Jim Eber
November 9th, 2009**

ComEd Overview 2

- Part of the Exelon Corporation
- Distribution company to the northern third of Illinois
- Westernmost PJM member
- Active in DR since mid ’90s
- DR portfolio can reduce 1000 MWs of peak demand
- Operate in a competitive retail environment as an Integrated Distribution Company
- Have had a hourly dynamic price product for residential customers for seven years

ComEd
An Exelon Company

Residential Real Time Pricing

3

- With CNT Energy, launch first residential hourly pricing program in 2003
- Full scale program offered 2007
- Supply charge portion of bill
- Not designed to be revenue neutral, market price risk shifted to consumer
- Promoted as an optional rate
- $2.25 participation fee
- Currently have 8,000 participants
- Evaluating economic benefits 2010

ComEd
An Exelon Company

What have we learned

4

✓ Four years (2003 – 2006) of Energy-Smart Pricing Plan pilot program plus three years of full scale program has demonstrated
  - Good demand response (15 to 20% cuts in peak demand)
  - Increased energy efficiency
  - Bill savings (~10%) and strong customer interest/satisfaction
  - Value to a range of customer types
  - Customers can survive an occasional bad year (2005)

✓ Illinois now exploring if residential RTP will
  - Lower prices for everyone?
  - Create meaningful customer choice?
  - Develop a platform for technological innovation to encourage conservation and efficiency?

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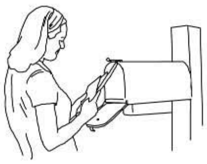
An Exelon Company



AMI Pilot Program

Pilot Background

6

- ✓ Commission order of AMI Pilot (Operations)
- ✓ Stakeholders approached us to discuss the addition of customer application trials to be included in the scope of the AMI Pilot
- ✓ Discussions with ICC Staff confirm this could be appropriate scope addition
- ✓ Start working customer applications design in conjunction with, and parallel to workshop process
- ✓ Formed a working group of various stakeholders to collaborate on design process
- ✓ As a result of several "white board" sessions with working group, two workshops, and individual meetings with stakeholders, we arrived at the current view of what became a consensus portfolio of customer applications
- ✓ Plan filed, proposed order released, ICC approval Mid-Oct

ComEd
An Exelon Company

ComEd AMI Pilot

7

A subset of the 130,000 residential customers receiving Smart Meters beginning Fall 2009 will be offered enrollment in a Pilot study beginning in June 2010 and ending in May 2011. The randomized controlled field trial (RCFT) includes 8000 customers who will be offered one of 24 combinations of rate and enabling technologies.

Rates:

- Existing Flat Rate
- Customer-specific Increasing Block (**IBR**)
- Time-of-use (**TOU**)
- Day Ahead Real-time Pricing:
  - Day Ahead Real-time (**DA-RTP**)
  - Critical Peak overlaid on DA-RTP (**CPP/DA-RTP**)
  - Peak-time Rebate overlaid on DA-RTP (**PTR/DA-RTP**)

Enabling Technologies:

- **Web Portal**
- Basic In Home Device (**B-IHD**)
- Advanced In Home Device (**A-IHD**)
- Programmable Communicating Thermostat (**PCT**)

The goal of this study is to provide insight into how these two primary variables influence a customer's behavior in terms of:

- Energy Efficiency & Conservation
- Demand Response
- Load Shifting

Customer usage and demographic data will be analyzed during the Measurement and Validation (M&V) phase to determine what combination of primary and secondary variables has the greatest impact on:

- Society
- Regulation
- the Utility
- the Customer

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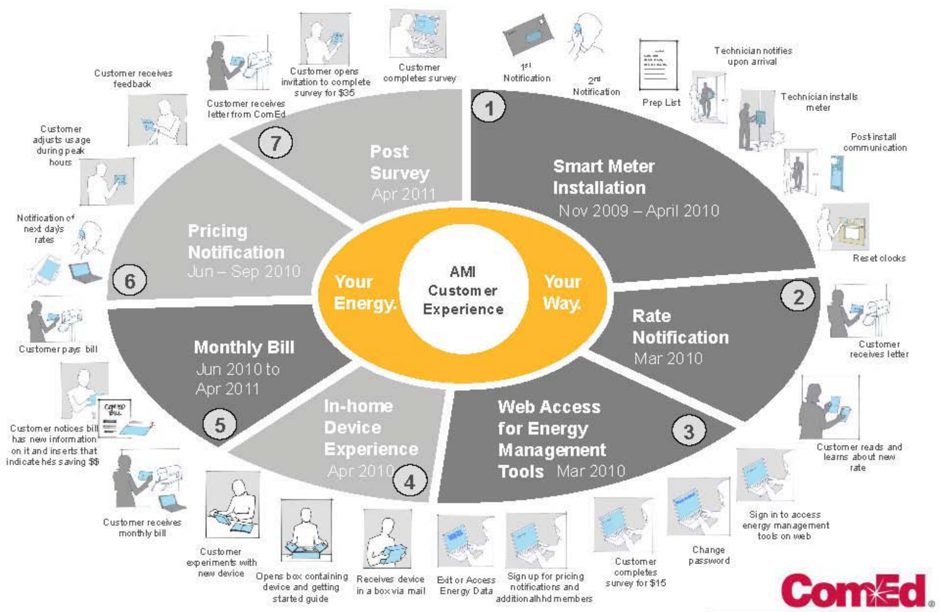
AMI Customer Experience Model

8



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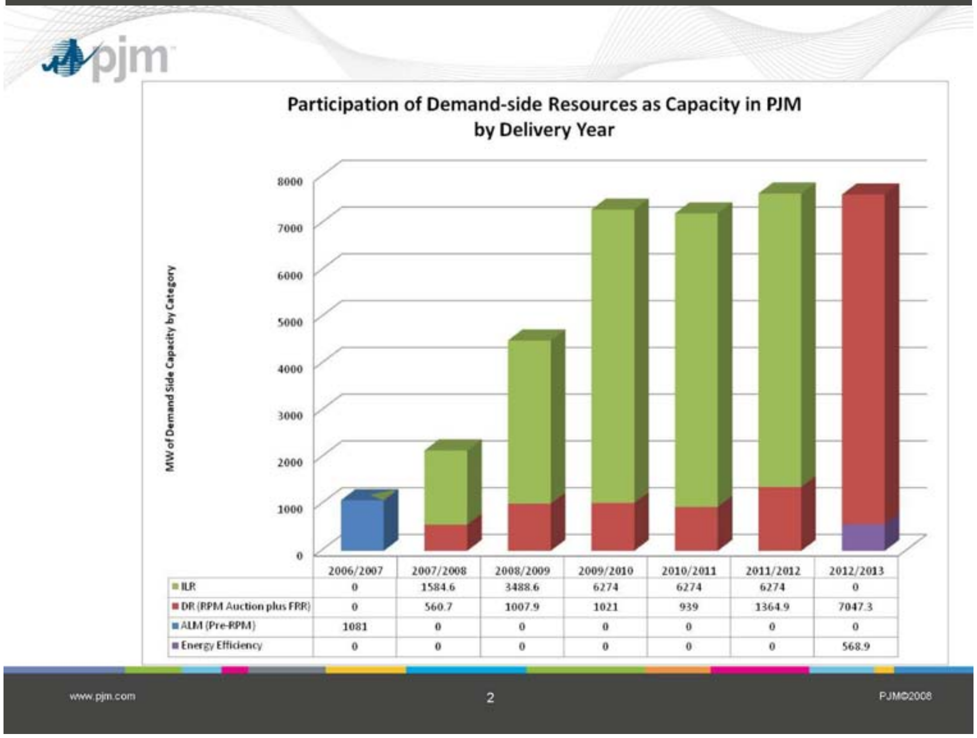
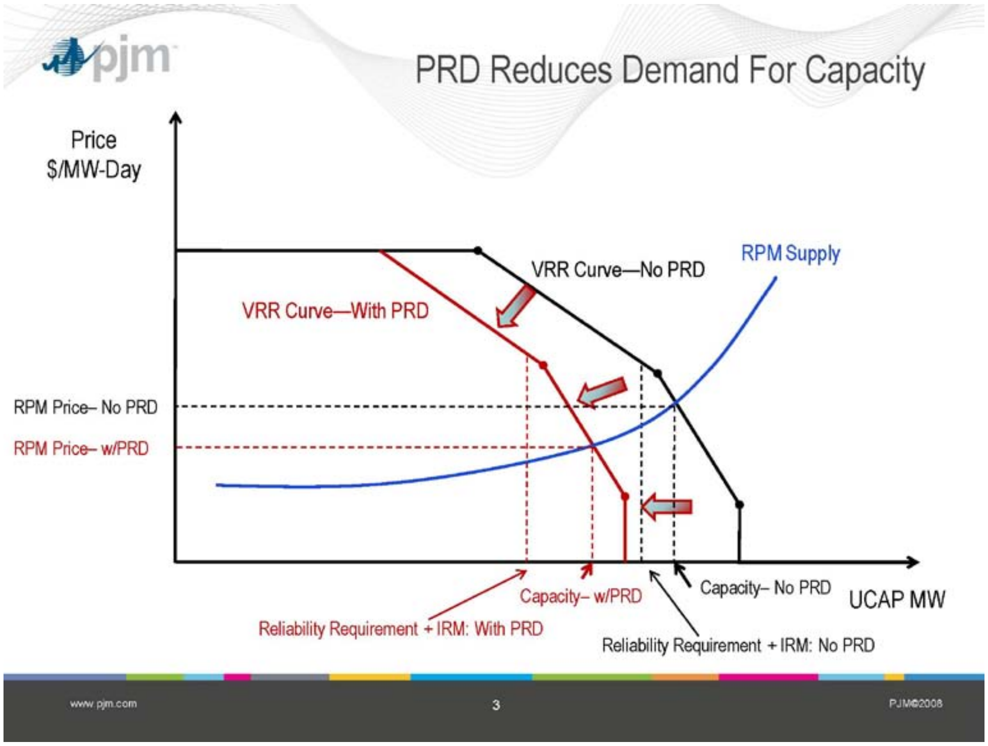
6. Price Responsive Demand: Impact on Capacity Markets
Andrew L. Ott, PJM



	2006/2007	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013
ILR	0	1584.6	3488.6	6274	6274	6274	0
DR (RPM Auction plus FRR)	0	560.7	1007.9	1021	939	1364.9	7047.3
ALM (Pre-RPM)	1081	0	0	0	0	0	0
Energy Efficiency	0	0	0	0	0	0	568.9


PRD Reduces Demand For Capacity
Price
$/MW-Day
VRR Curve—No PRD
RPM Supply
VRR Curve—With PRD
RPM Price– No PRD
RPM Price– w/PRD
Capacity– w/PRD
Capacity– No PRD
UCAP MW
Reliability Requirement + IRM: With PRD
Reliability Requirement + IRM: No PRD
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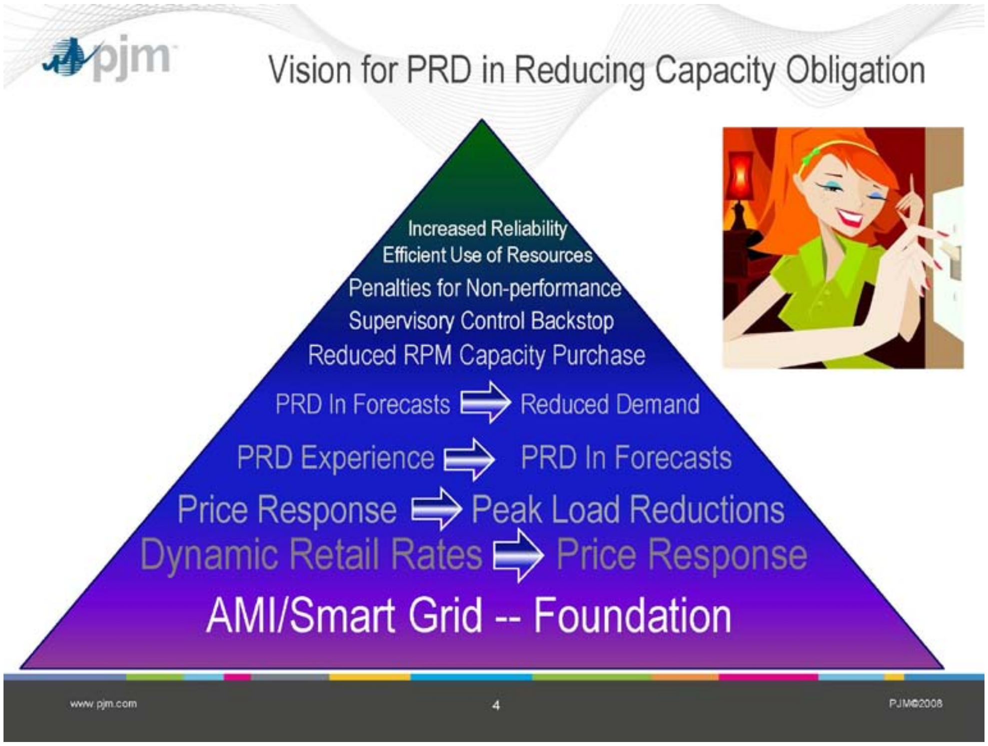
Vision for PRD in Reducing Capacity Obligation
Increased Reliability
Efficient Use of Resources
Penalties for Non-performance
Supervisory Control Backstop
Reduced RPM Capacity Purchase
PRD In Forecasts ⇨ Reduced Demand
PRD Experience ⇨ PRD In Forecasts
Price Response ⇨ Peak Load Reductions
Dynamic Retail Rates ⇨ Price Response
AMI/Smart Grid -- Foundation
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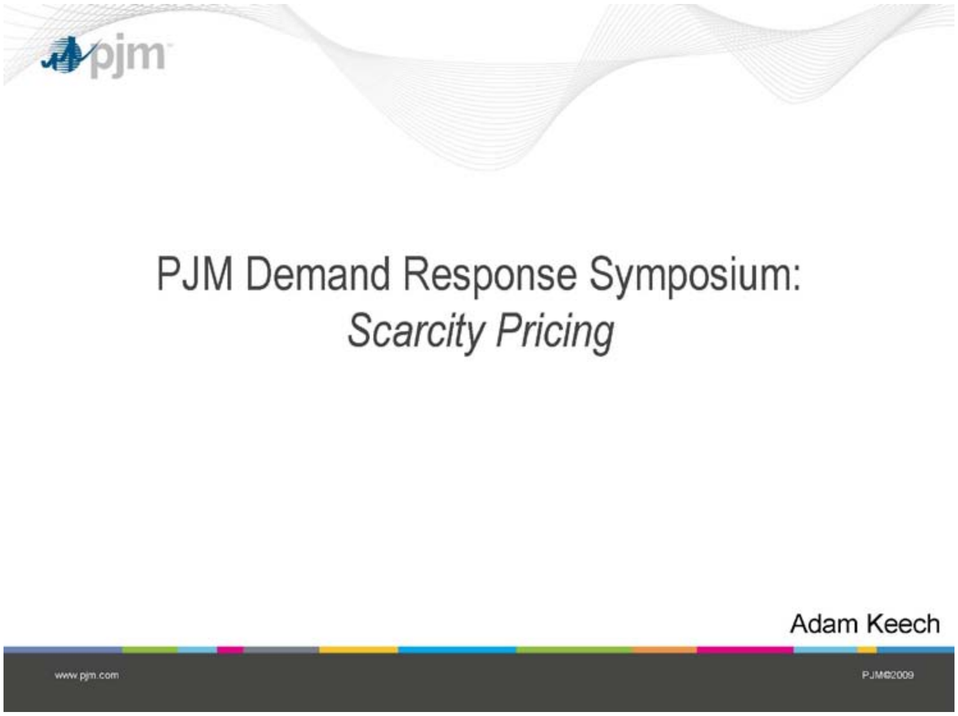
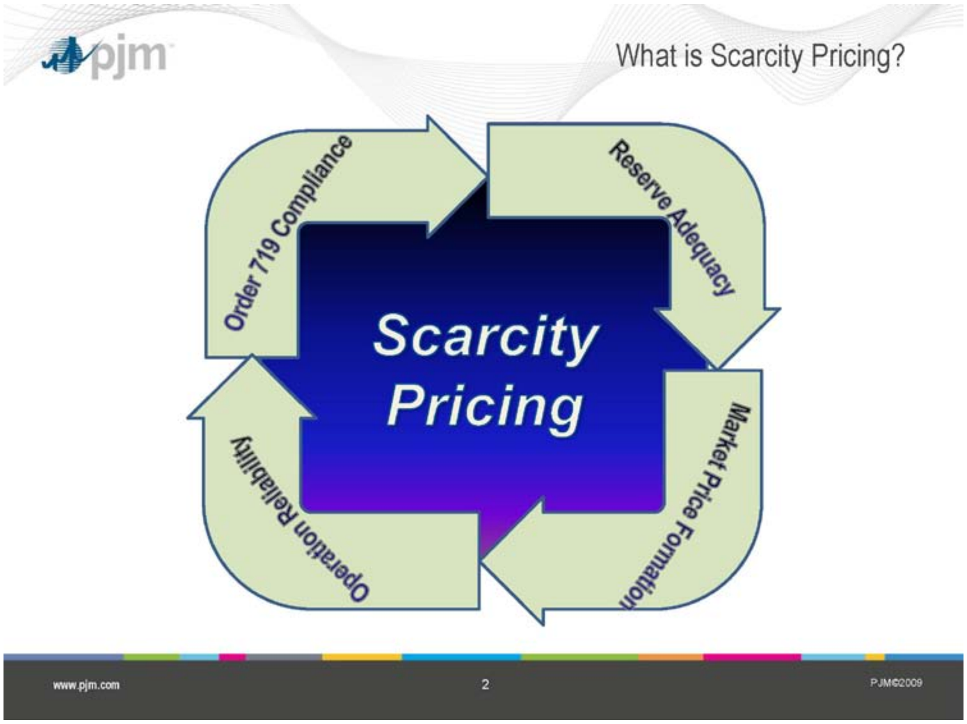
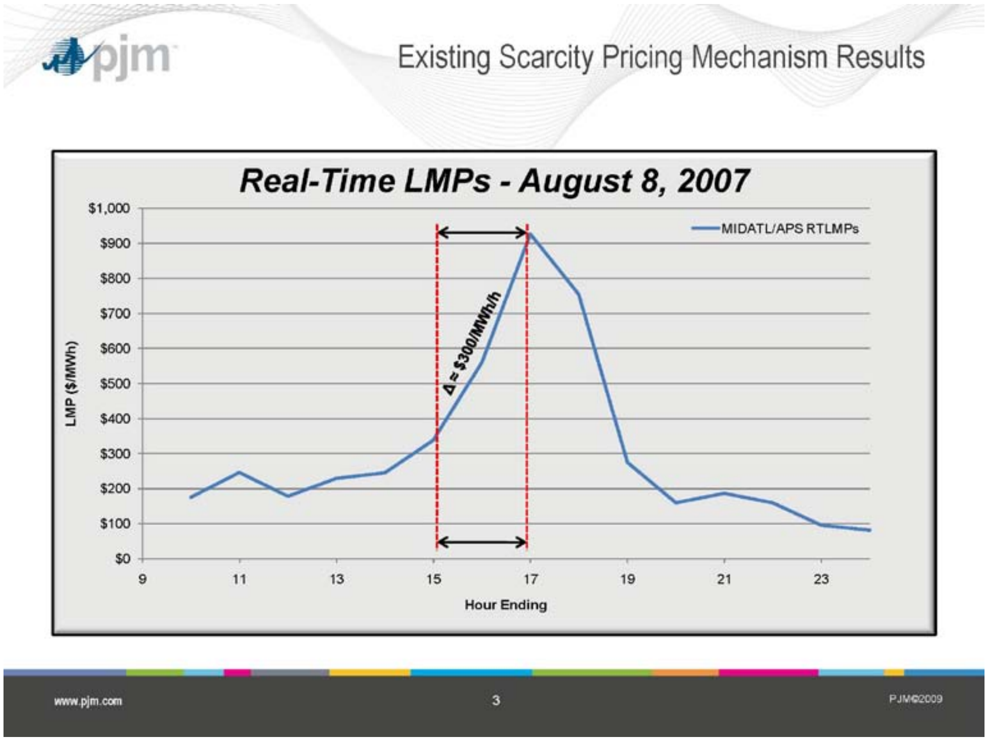
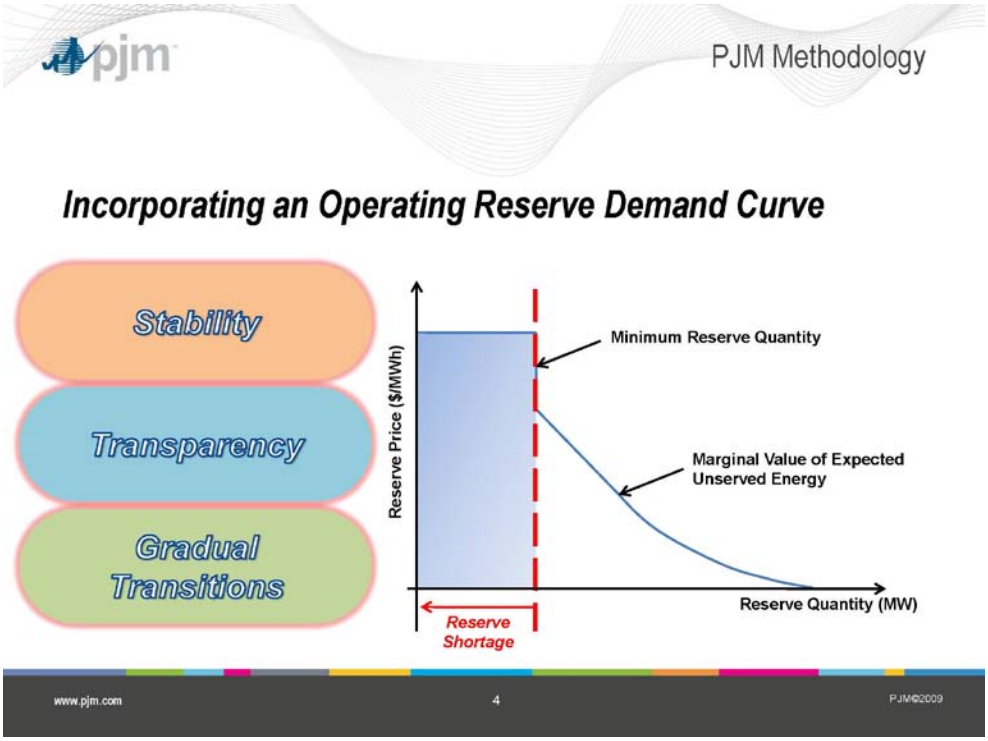
7. PJM Demand Response Symposium: Scarcity Pricing
Adam Keech, PJM






Existing Scarcity Pricing Mechanism Results
Real-Time LMPs - August 8, 2007
MIDATL/APS RTLMPs
LMP ($/MWh)
Hour Ending
Δ ≈ $300/MWh/h
www.pjm.com
3
PJM©2009


PJM Methodology
Incorporating an Operating Reserve Demand Curve
Stability
Transparency
Gradual Transitions
Reserve Price ($/MWh)
Minimum Reserve Quantity
Marginal Value of Expected Unserved Energy
Reserve Quantity (MW)
Reserve Shortage
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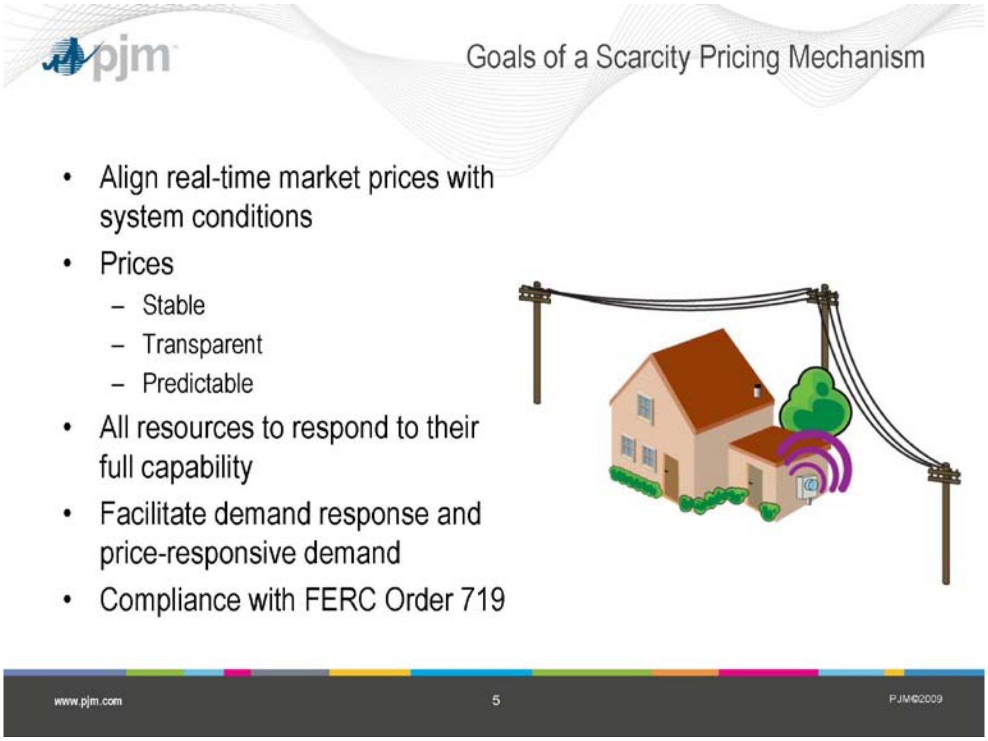
Goals of a Scarcity Pricing Mechanism
• Align real-time market prices with system conditions
• Prices
– Stable
– Transparent
– Predictable
• All resources to respond to their full capability
• Facilitate demand response and price-responsive demand
• Compliance with FERC Order 719
www.pjm.com
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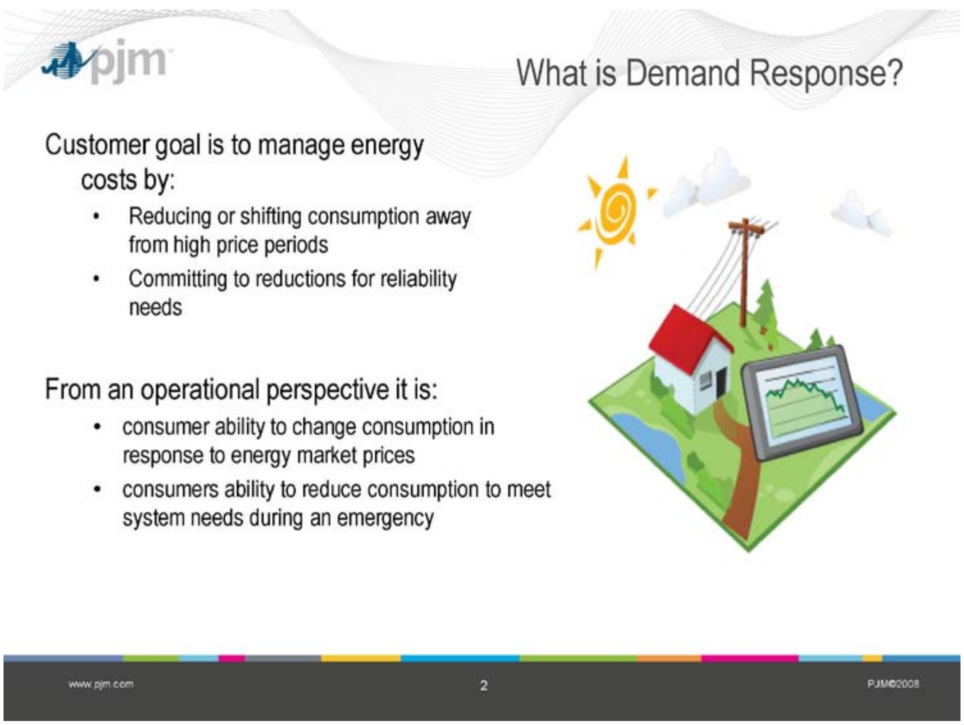
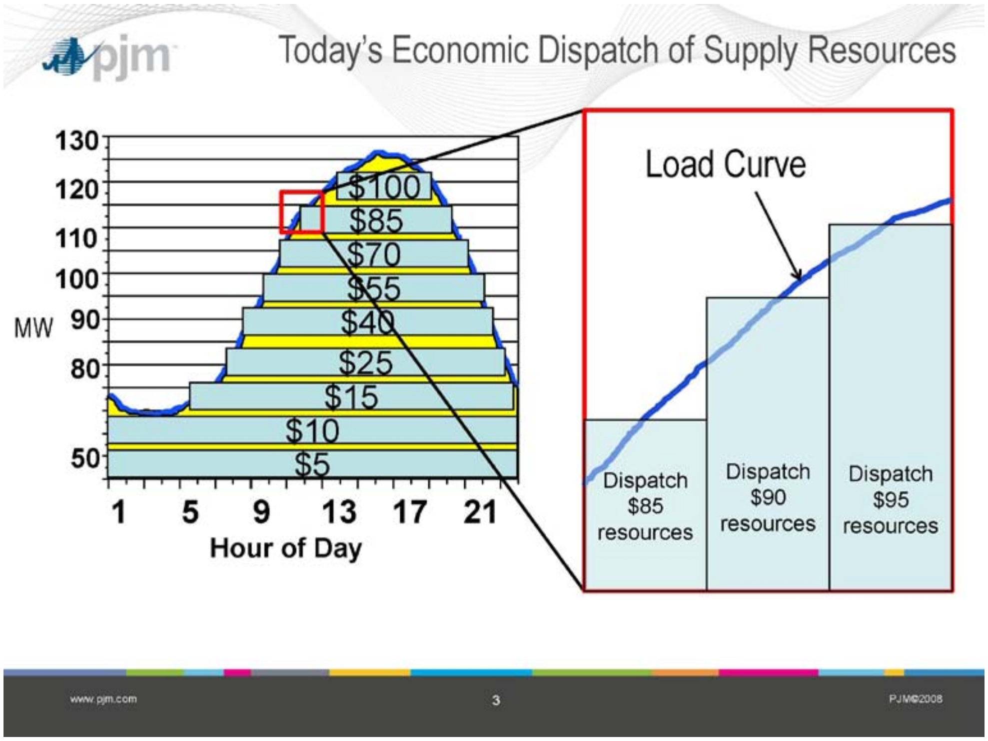
8. Price Responsive Demand: Impact to Market Operations
F. Stuart Bresler, III, PJM




Today's Economic Dispatch of Supply Resources
130
120
110
100
MW 90
80
50
$100
$85
$70
$55
$40
$25
$15
$10
$5
1 5 9 13 17 21
Hour of Day
Load Curve
Dispatch $85 resources
Dispatch $90 resources
Dispatch $95 resources
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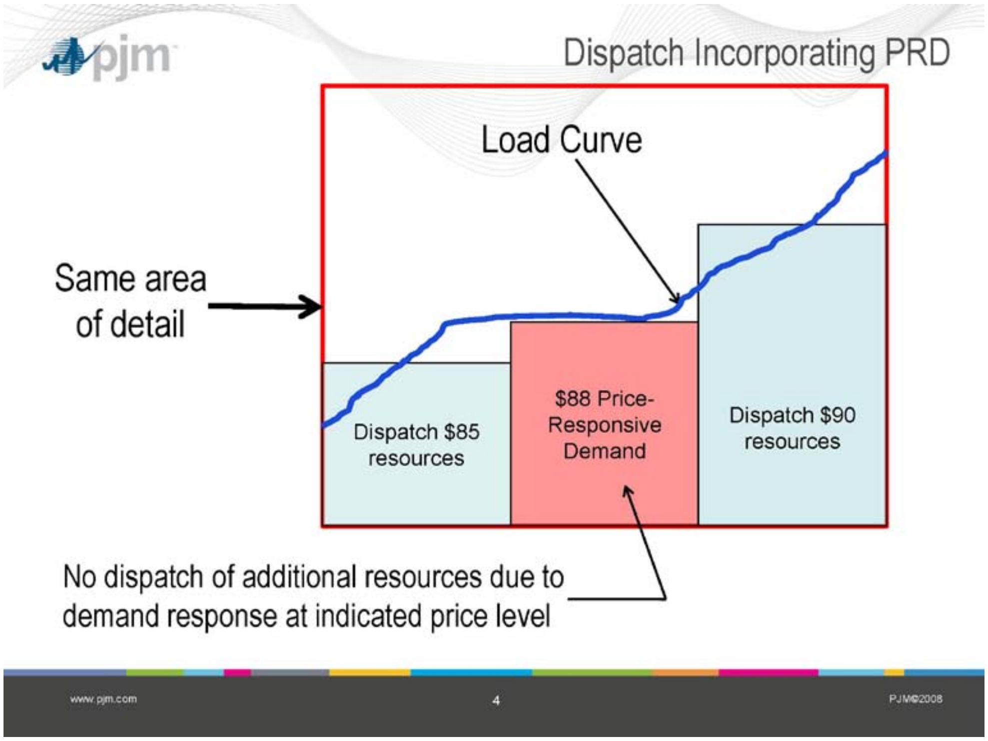
Dispatch Incorporating PRD
Load Curve
Same area of detail
Dispatch $85 resources
$88 Price-Responsive Demand
Dispatch $90 resources
No dispatch of additional resources due to demand response at indicated price level
www.pjm.com
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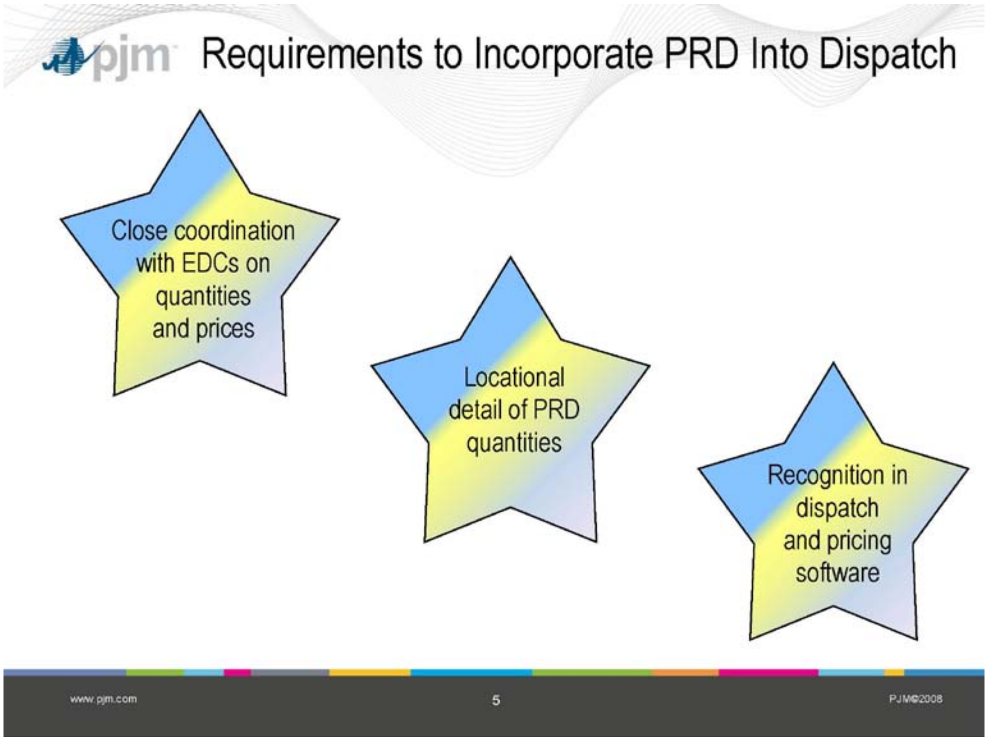
Requirements to Incorporate PRD Into Dispatch
Close coordination with EDCs on quantities and prices
Locational detail of PRD quantities
Recognition in dispatch and pricing software
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5
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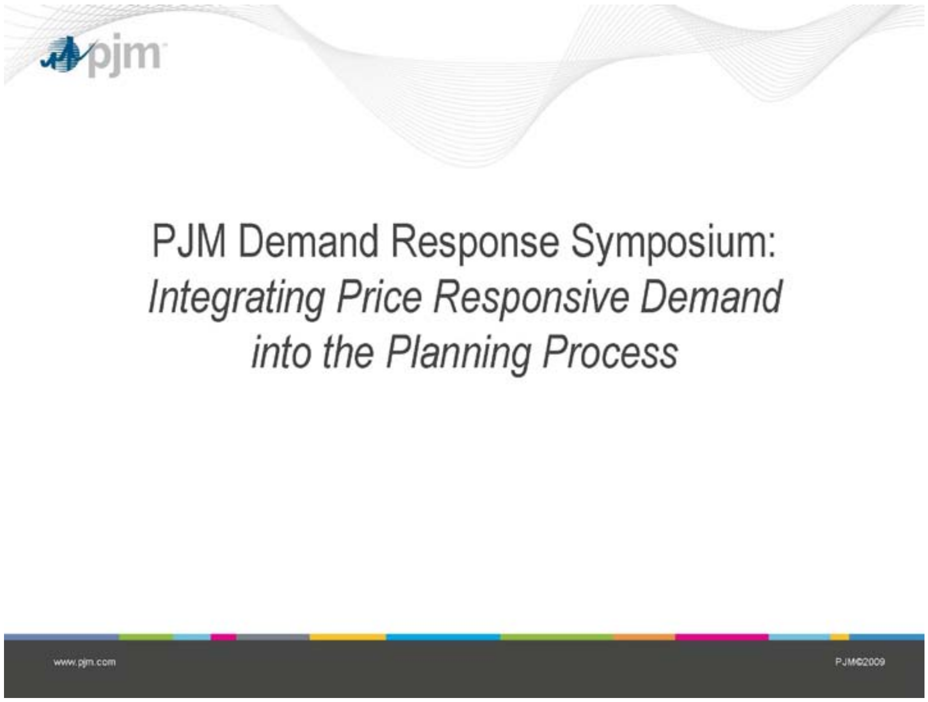
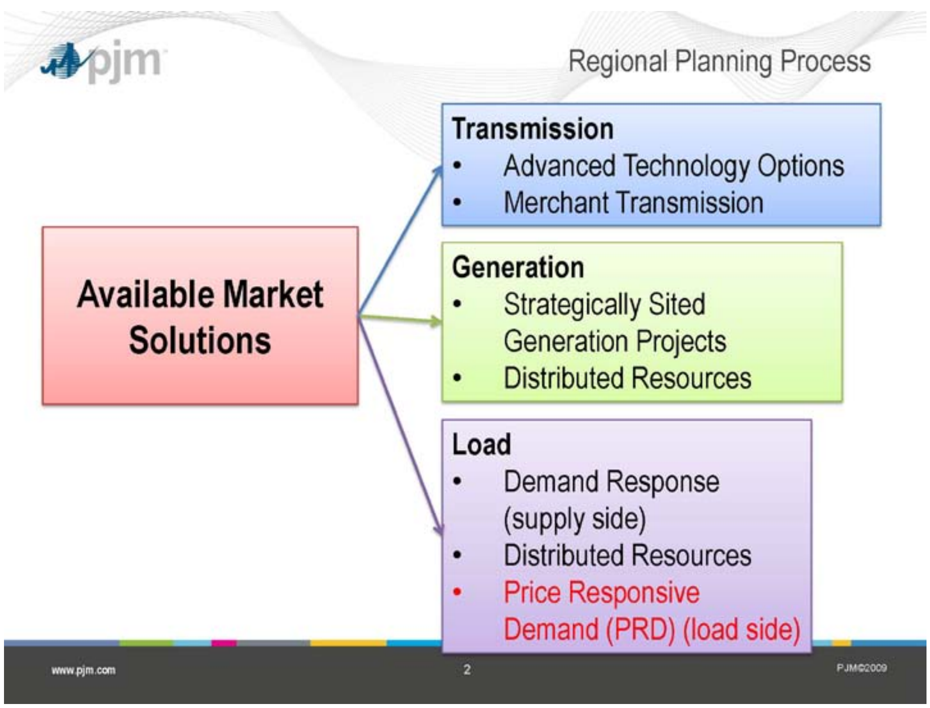
9. PJM Demand Response Symposium: Integrating Price Responsive Demand into the Planning Process
Tom Falin, PJM





Committed Price Responsive Demand

- Accounted for as a reduction to the unrestricted peak 3 years in advance for Base Residual Auction or for Incremental Auctions
- Subject to measurement and verification process
- All PJM approved committed PRD will be netted from unrestricted load forecast
- Load net of committed PRD will be modeled in RPM auctions and RTEP studies
- Avoid counting the same load reduction capability on both the supply side and the load side of the market for planning purposes
- Account for location of PRD

Uncommitted Price Responsive Demand

- Similar to Economic Load Response
- Lowers metered load
- Reduced metered load history feeds into future load forecast
  → Will result in lower load forecast over time
- Impact on RTEP studies is indirect

Potential Modeling of PRD in RTEP Studies

Market Efficiency
- Develop relationship between LMP and trigger to interrupt PRD

Reliability Analyses
- Develop relationship between load and generator availability and trigger to interrupt PRD
- Load Deliverability
  - Model PRD similar to DR
- Generator Deliverability and NERC Category C
  - Likely would not interrupt PRD

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Price Responsive Demand in Planning Process

- Process expected to evolve over time as PRD quantity grows and experience is gained
- Process changes will be developed through Planning Committee and Load Analysis Subcommittee
- Experience with PRD expected to lead to improved understanding of relationship of price to peak load

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10. Integrating PRD: Making the Case, Retail Plans & Timelines Lisa Wood, Institute for Electric Efficiency

The Edison Foundation | Institute for Electric Efficiency

Integrating PRD: Making the Case, Retail Plans & Timelines

Lisa Wood
Executive Director

PJM Symposium on Demand Response III

November 9-10, 2009

Over 58 million smart meters will be deployed to mass market customers over next 5 to 7 years (excluding $4.5 billion in DOE stimulus funds)

Utility-Scale Smart Meter Deployments, Plans & Proposals*
September 2009

*This map represents smart meter deployments, planned deployments, and proposals by investor-owned utilities and some public power utilities

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http://www.edisonfoundation.net/IEE/

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Multiple residential customer dynamic rate pilots and deployments are underway across the U.S. (IEE)

IOU-administered residential customer dynamic pricing pilots and programs by state (November 2009)

The EDISON FOUNDATION | INSTITUTE FOR Electric Efficiency

3

The EDISON FOUNDATION | INSTITUTE FOR Electric Efficiency

For more information, contact:

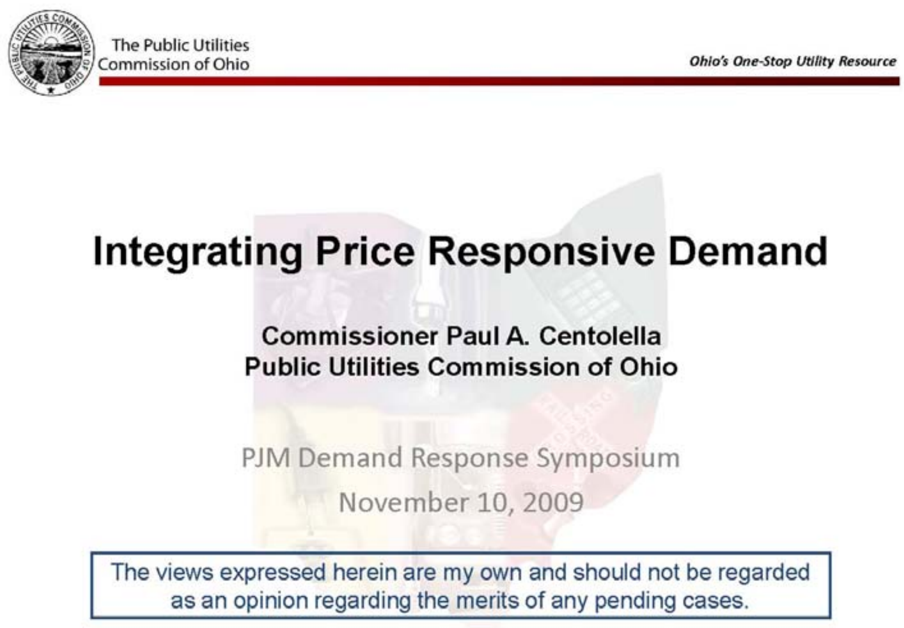
Lisa Wood
Executive Director

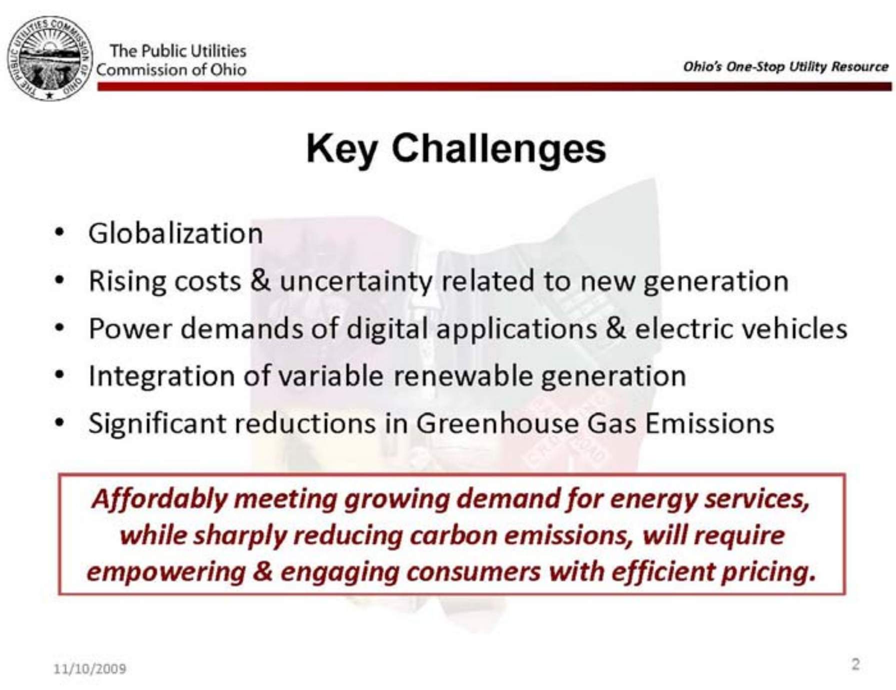
Institute for Electric Efficiency
701 Pennsylvania Ave., N.W.
Washington, D.C. 20004-2696
Office: 202.508.5550
Mobile: 202.257.5040

lwood@edisonfoundation.net
www.edisonfoundation.net/IEE

4

11. Integrating Price Responsive Demand Commissioner Paul A. Centolella, Public Utilities Commission of Ohio

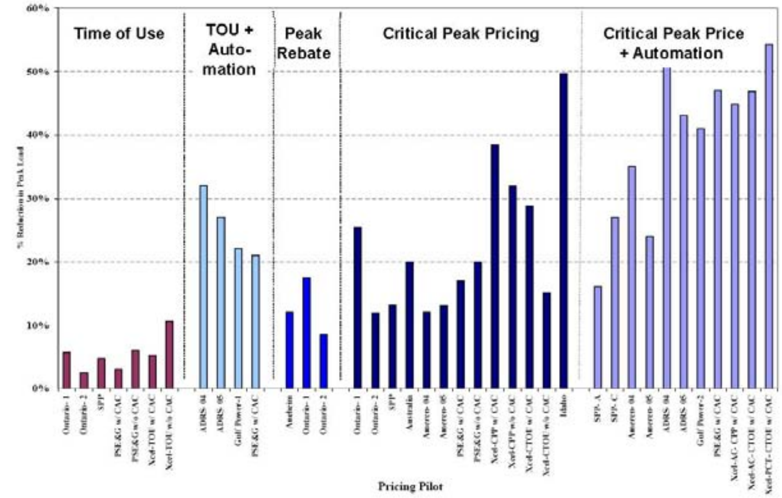




The Public Utilities Commission of Ohio

Ohio's One-Stop Utility Resource

Estimated Household Demand Response



Source: A. Faruqui & S. Sergici, *Household Response to Dynamic Pricing of Electricity A Survey of Seventeen Pricing Experiments* (2008)

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Ohio's One-Stop Utility Resource

Price Responsive Demand

- The Predictable Response to Changes in Wholesale Prices by Consumers on Dynamic or Time-Differentiated Retail Pricing
  - Examples: Critical Peak, Critical Peak Rebate, & Real-Time Pricing
- Necessary Coordination of Wholesale & Retail Markets
  - Mass Market PRD Will Not be Offered & Dispatched as a Resource
  - Expansion Depends Upon Significant AMI Investment
- Price Responsive Demand is Characteristic of Efficient Markets

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Ohio's One-Stop Utility Resource

Ohio's 2008 Electricity Law

- Price Responsive Demand
  - State policy to encourage time-differentiated retail pricing
  - Ohio Peak Demand Reduction Standard: 7.75% by 2018
- Smart Grid
  - State policy to encourage AMI
  - Authorized single issue & incentive ratemaking for grid modernization
  - Required development of distribution quality of service standards
- Energy Efficiency
  - Ohio Electric Efficiency Standard: 22%+ reduction by 2025

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Ohio's One-Stop Utility Resource

PUCO Supported Development of Dynamic Pricing

AEP Smart Grid Project Approval:

"For customers, the ability to have real-time price information and the ability to respond to such prices means that they may develop consumption patterns that both save them dollars while helping the utilities shave their peaks. ... The essence of this project is an infrastructure that embraces the following elements: advanced metering, dynamic pricing, information feedback to consumers, automation hardware, education, and energy efficiency programs."

- AEP Electric Security Plans, Case No. 08-917-EL-SSO, Entry On Rehearing (July 23, 2009)

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Ohio's One-Stop Utility Resource

PUCO Supported Development of Dynamic Pricing

AEP Smart Grid Project Approval:

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- AEP Electric Security Plans, Case No. 08-917-EL-SSO, Entry On Rehearing (July 23, 2009)

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Ohio's One-Stop Utility Resource

Integrating PRD in PJM Markets & Operations: The Package of Necessary Elements

- Use Transparent Forecast Demand Curve based on Statistical Relationship of Price & Demand in Capacity Markets, Planning, & Operations
- Scarcity Pricing Reform: Operating Reserve Demand Curve based on the Value of Reserves to Consumers
- Synchronize Capacity Market and Scarcity Pricing so Capacity is a Hedge against Scarcity Prices: i.e. Loads with Adequate Capacity Avoid Scarcity Prices & Resources Cannot Receive Capacity & Scarcity Payments
- Adequacy & Choice: Price Responsive Loads must have Capacity for their Firm Demand after PRD & the Option to Hold Additional Capacity
- Capacity Emergency Procedures: Non-discriminatory Curtailment based on relative Capacity Deficiency

See: P. Centolella & A. Ott, *The Integration of Price Responsive Demand into PJM Wholesale Power Markets and System Operations* (March 2009).

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Ohio's One-Stop Utility Resource

Operating Reserve Demand Curve

- At Minimum Reserves, Shortage Reference Price = Value of Load to Consumers who would be Curtailed
- Shortage Reference Price sufficient to Elicit Voluntary Reductions
    - Australian National Electricity Market: Approximately $6,800(US)/MWh
    - MISO Ancillary Services Market: $3,500/MWh

- Obtain Additional Reserves when Approaching Shortage Up to the Value of Expected Unserved Energy with Added Reserves

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Ohio's One-Stop Utility Resource

Reliability Benefits of PRD

- Beneficial Feedback: Price increases cause an offsetting demand reduction
    - Enhances reliability for any given level of reserves
    - Improves predictability of demand & power flows for operations
    - Facilitates integration of variable resources
- Mass market Price Responsive Demand statistically less variable than large customer demand response or generation
- AMI allows access to more load data, providing an opportunity to reduce forecast uncertainty
- AMI can measure & ensure targeted, rapid, & verifiable load reductions in emergencies

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Ohio's One-Stop Utility Resource

Economic Benefits of PRD

- Consumers empowered to control their bills & are able to hedge price risks consistent with their preferences
  - Consumers can choose how to respond to energy & ancillary service prices
- Consumer costs further reduced to the extent of efficiency gains
  - Revenue shifts from capacity market to energy & ancillary services markets
  - Accurate prices elicit demand response & generation when & where needed
- Demand response enhances market power mitigation
  - Pivotal Supplier Test is retained during shortages
- Regressive cross-subsidies are reduced by efficient retail pricing
- Generation investment decisions can be deferred

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Ohio's One-Stop Utility Resource

BACKUP SLIDES

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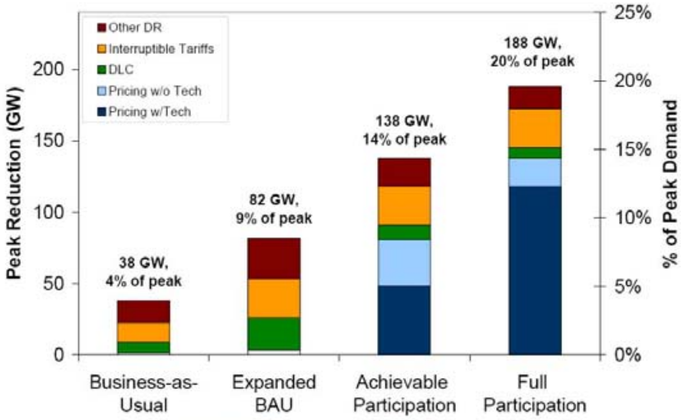
Ohio's One-Stop Utility Resource

U.S. Demand Response Potential



"The largest gains in demand response impacts can be made through dynamic pricing programs when … offered as the default tariff."

Source: The Brattle Group, et al., *FERC Staff Report: A National Assessment of U.S. Demand Response Potential* (June 2009).

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Ohio's One-Stop Utility Resource

Necessity of Retail - Wholesale Coordination on PRD

- Planning and Resource Adequacy
  - Current Forecasting Techniques
    - Do Not Consider Price Responsive Demand
    - Based on Data from Periods without Dynamic Retail Pricing
  - Use of Current Forecasting Would Result in Carrying Capacity & Planning Reserves for Demand that Would not be Present at Higher Spot Prices
    - Resource Adequacy Requirement Eliminates Opportunity to Achieve Capacity Savings – Often the Single Largest Cost Savings in a Business Case for AMI
    - Added Capacity Keeps Spot Prices Too Low to Evoke Significant Demand Response
- System Operations
  - Short-term Forecasts, Unit Commitment & Dispatch Do Not Consider PRD
  - Systems, Operating Procedures, & Bid Caps Prevent PRD from Matching Demand to Available Supply

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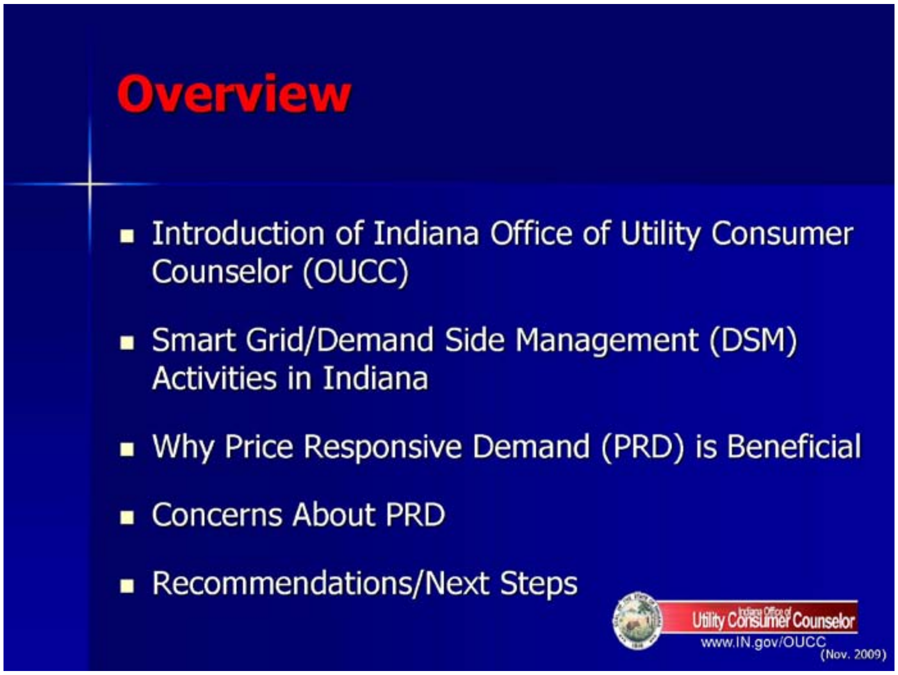
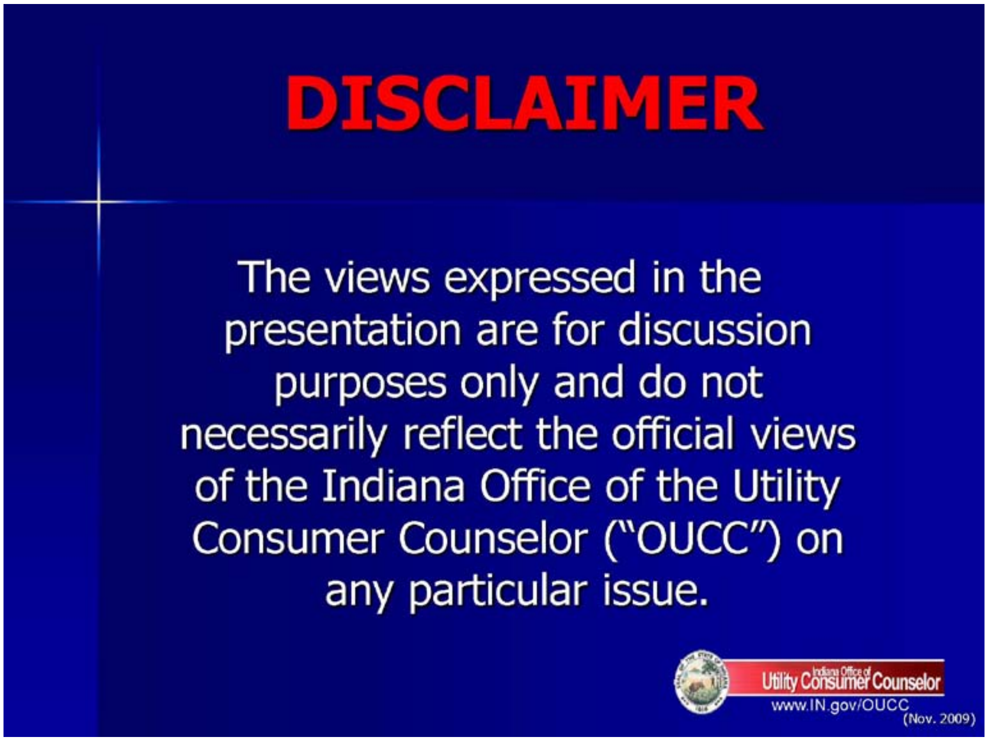
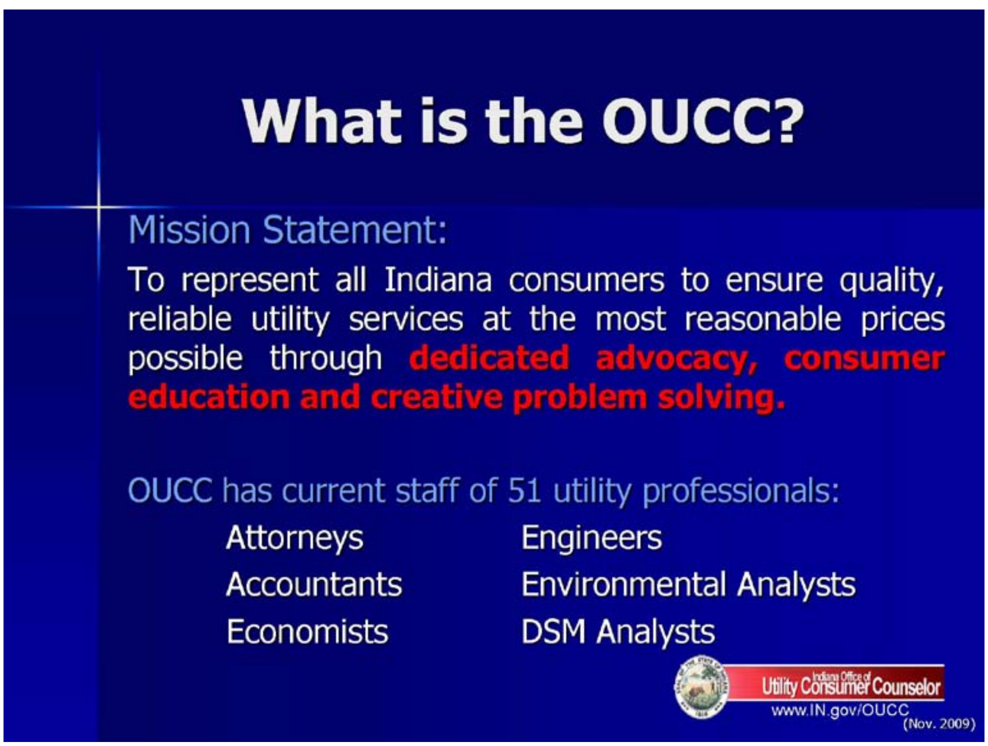
The Public Utilities Commission of Ohio
Ohio's One-Stop Utility Resource
Market Design Assumptions & Compromises
• Assumption #1: Demand Inelastic in Short-run Markets
• Assumption #2: Demand Cannot be Used to Set Prices
• Generator Offers Set Prices
• Cap Generator Offers to Avoid Price Volatility
• Create Capacity Markets to Address "Missing Money Problem"
• Mitigation in "Capacity Markets" leads to Administrative Capacity Prices
• Dilute Energy & Ancillary Service Price Signals
• Need Intermediary (Curtailment Service Provider) for Demand Response
• Limited Demand Participation in the Market
What are the Implications of Changing our Assumptions ?
11/10/2009
15

12. Integrating Price Responsive Demand: Making the Case, Retail Plans & Timelines
David A. Stippler, Indiana Office of Utility Consumer Counselor




DISCLAIMER
The views expressed in the presentation are for discussion purposes only and do not necessarily reflect the official views of the Indiana Office of the Utility Consumer Counselor ("OUCC") on any particular issue.
Indiana Office of Utility Consumer Counselor
www.IN.gov/OUCC
(Nov. 2009)


What is the OUCC?
Mission Statement:
To represent all Indiana consumers to ensure quality, reliable utility services at the most reasonable prices possible through dedicated advocacy, consumer education and creative problem solving.
OUCC has current staff of 51 utility professionals:
Attorneys
Engineers
Accountants
Environmental Analysts
Economists
DSM Analysts
Indiana Office of Utility Consumer Counselor
www.IN.gov/OUCC
(Nov. 2009)

PJM Footprint Diversity

Expansion of Footprint:

- American Electric Power joined PJM in 2004
- PJM was Once Homogenous, Now Contains Both Regulated and Deregulated States
- Indiana is a Regulated State

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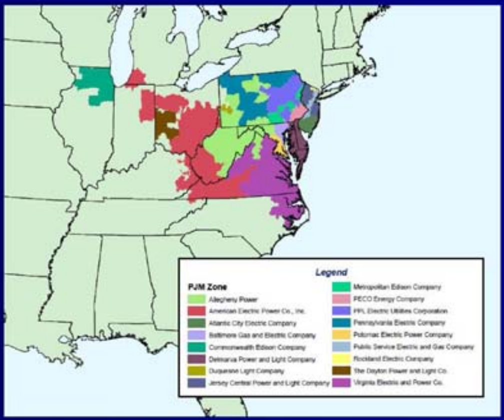
PJM Footprint



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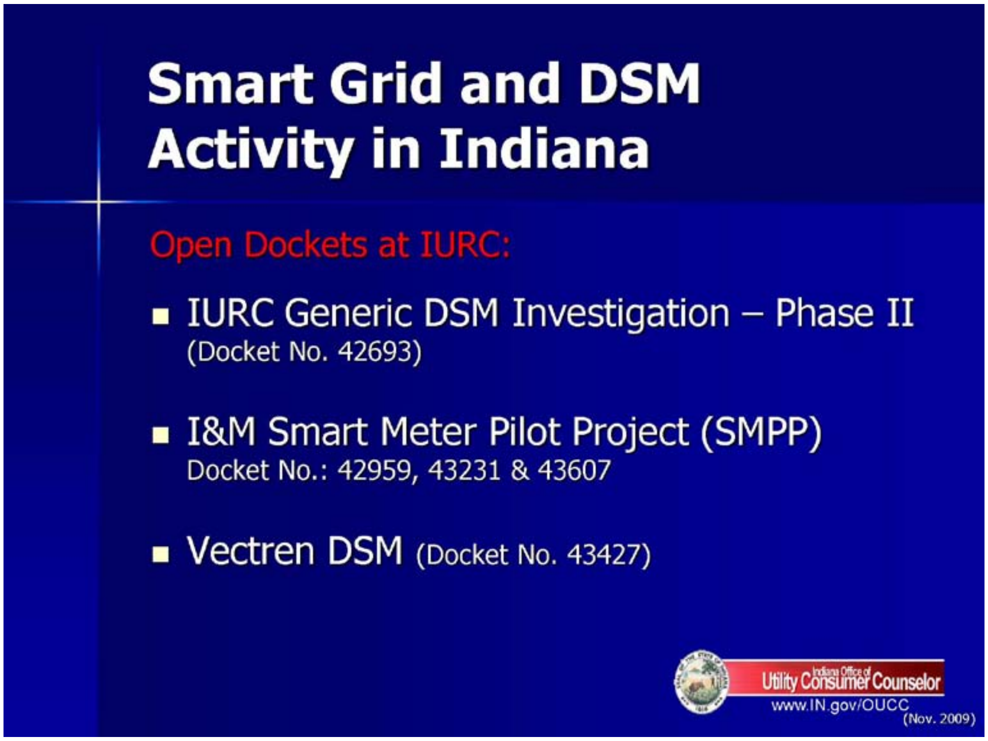
Smart Grid and DSM
Activity in Indiana
Open Dockets at IURC:
IURC Generic DSM Investigation – Phase II
(Docket No. 42693)
I&M Smart Meter Pilot Project (SMPP)
Docket No.: 42959, 43231 & 43607
Vectren DSM (Docket No. 43427)
Indiana Office of Utility Consumer Counselor
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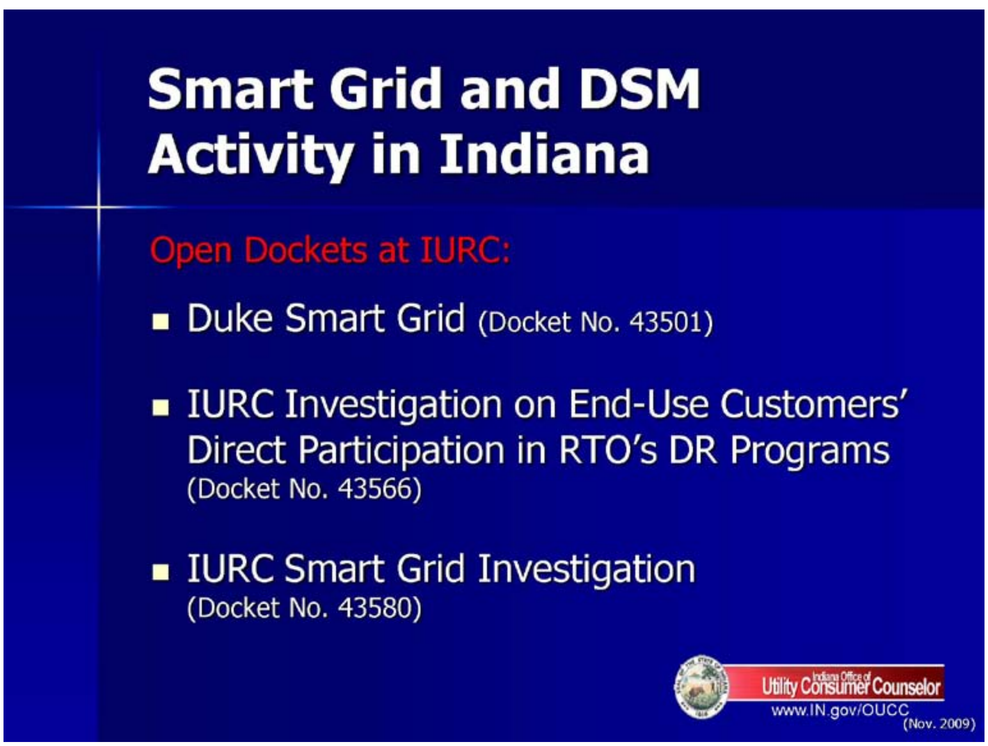
Smart Grid and DSM
Activity in Indiana
Open Dockets at IURC:
Duke Smart Grid (Docket No. 43501)
IURC Investigation on End-Use Customers' Direct Participation in RTO's DR Programs
(Docket No. 43566)
IURC Smart Grid Investigation
(Docket No. 43580)
Indiana Office of Utility Consumer Counselor
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Demand Side Management Activity in Indiana

Open Dockets at IURC:

- Indianapolis Power & Light (IPL) DSM (Docket No. 43623)
- I&M DSM (Docket No. 43769)
- NIPSCO Market Potential Study & Smart Grid Study/Evaluation
- Vectren Smart Grid (Docket No. 43810)

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FERC National Assessment of Demand Response

Indiana's Profile

	Achievable	Full Participation
2014	8%	10%
2019	13%	18.3%

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Why Price Responsive Demand Is Beneficial

- Improves Existing Generation Utilization
- Defers Need for Generation Investment
- Improves System Reliability
- Enhances Market Competitiveness
- Reduces Price Volatility

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Why Price Responsive Demand Is Beneficial

- Reduces Transmission and Distribution Losses
- Maximizes Value from Smart Grid Technology
- Attributes Costs to Causers
- Reduces Environmental Impacts
- Provides Customers Greater Control Over Electricity Usage and Ultimately Their Bills.

Indiana Office of Utility Consumer Counselor
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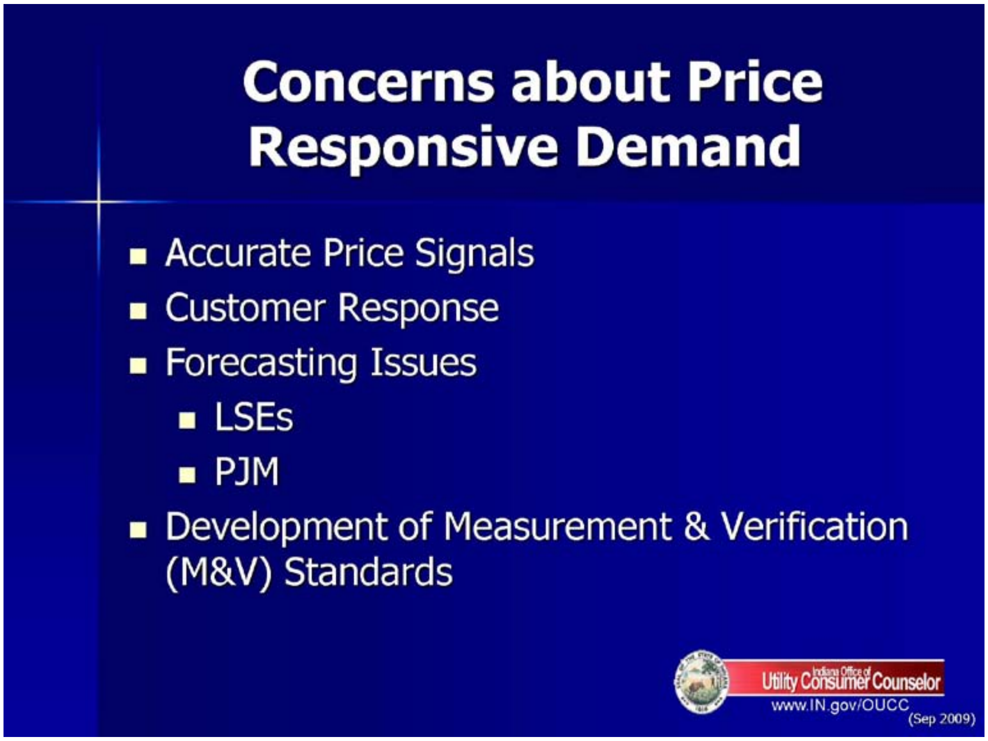

Concerns about Price Responsive Demand
Accurate Price Signals
Customer Response
Forecasting Issues
LSEs
PJM
Development of Measurement & Verification (M&V) Standards
Utility Consumer Counselor
www.IN.gov/OUCC
(Sep 2009)


Recommendations/ Next Steps
Establish Statistical Validity of PRD
Determine Standards for PRD
Establish Accountability for Forecasting
Monitor Reserve Margins
Align State Retail Tariffs with PRD
Gather Customer Response Information to Determine Baseline for PJM Region
Develop Adequate M&V Protocols
Utility Consumer Counselor
www.IN.gov/OUCC
(Sep 2009)

13. Integrating PRD: Making the Case, Retail Plans and Timelines Commissioner Sherman Elliott, Illinois Commerce Commission

Integrating PRD: Making the Case, Retail Plans and Timelines
PJM Symposium
November 9, 2009

Commissioner Sherman Elliott
Illinois Commerce Commission

Disclaimer

- My thoughts today are mine alone and do not necessarily reflect the positions of the Illinois Commerce Commission on any of the issues discussed today

2

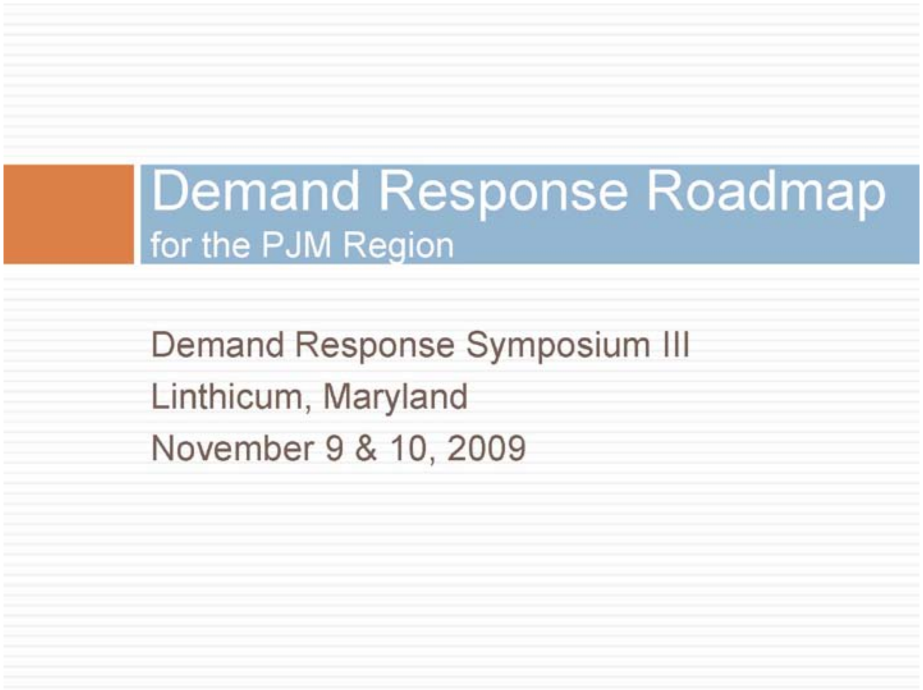
The ComEd AMI Pilot Project

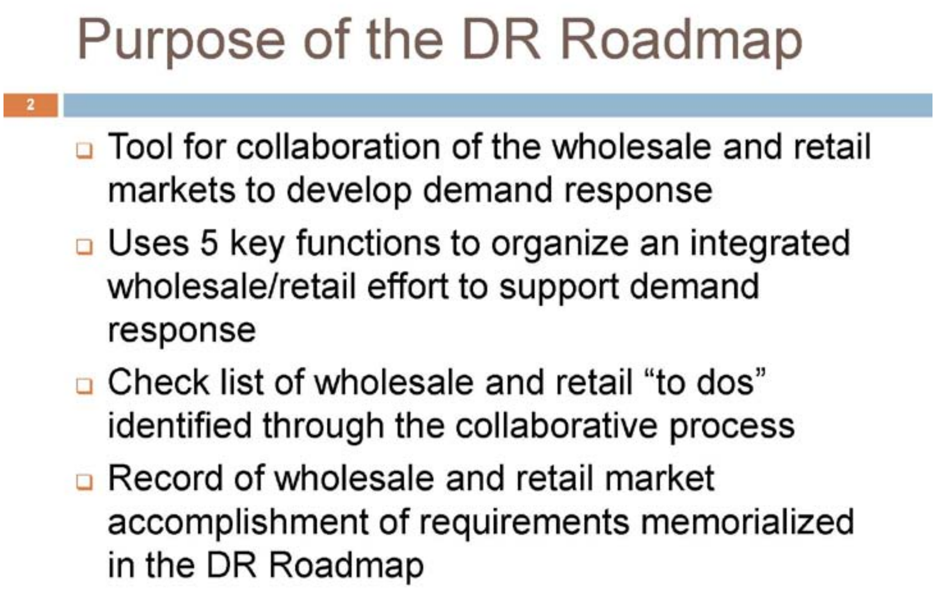
- 141,000 two-way AMI Meters that collect 5 minute interval information
- Customer Applications Program
  - Web-based information feedback, in-home displays, and programmable communicating thermostats
  - Rate designs including day-ahead real time pricing, increasing block rate, time of use, a hybrid of critical peak price and day-ahead real time pricing, and a hybrid of peak-time rebate and day-ahead real time pricing
- Results will be delivered to the Illinois Statewide Smart Grid Collaborative at the end of the 1st quarter in 2011

Real-Time Pricing for ComEd

- Currently there are 7,331 residential customers enrolled in the ComEd RTP Program
  - There are 69 additional customers that will become active after their next bill
  - There are 388 enrollments pending
- The original projection forecasted 213,000 participants by year-end 2013, with a forecast of 75,000 by year-end 2009

14. Demand Response Roadmap for the PJM Region
Susan Covino, PJM





From Guide to Action

3

- The items and actions identified on the wholesale side of the DR Roadmap can only be accomplished through the PJM stakeholder process and FERC review
- The items and actions identified on the retail side of the DR Roadmap can only be accomplished through the regulatory review process established by each state, municipality and cooperative

Evolution of Demand Response to Price Responsive Demand

4

- Interruptible load was DR 1.0
  - No response at all to prices, but response as the LSE/EDC needed it as a capacity resource only
  - Treats DR effectively as a supply-side resource from a planning perspective
- Current wholesale/retail paradigm is DR 2.0
  - Responses to wholesale market prices with activity at the wholesale level as both a capacity and energy resource
  - Little integration and coordination with actions at retail level as CBL and wholesale prices are treated as a proxy for a dynamic retail rate
  - DR still treated as a supply-side resource
- Price Responsive Demand is DR 3.0
  - Integrates and coordinates wholesale and retail needs and activities through AMI and dynamic rates
  - Treats DR as a demand-side resource in considering capacity and energy needs

Adding Price Responsive Demand to the DR Roadmap

5

- Identify key Price Responsive Demand concepts set forth in the March 9, 2009 white paper by Ott and Centolella
- Use the analogue of the existing DR Roadmap to organize the key elements of the white paper
- Obtain critical review and input from state commissions and consumer advocates
- Use the DR Roadmap as a starting point for further collaboration at the Demand Response Symposium

Price Responsive Demand in the Retail Market

6

- Dynamic prices that produce predictable and measurable changes in usage
- Meters capable of recording usage on an hourly or sub-hourly basis
- Automation that implements customer usage decisions in response to dynamic prices
- Communication of price/quantity data to PJM by Load Serving Entities
- Energy and capacity obligations of Load Serving Entities that take account of Price Responsive Demand

Price Responsive Demand in the Wholesale Market

7

- Document the price/quantity data provided by LSEs in a Forecast Demand Response Curve
- Use Forecast Demand Response Curves:
  - to improve accuracy of load forecast and system dispatch both DA and RT
  - to inform planning & capacity procurement
- Implement Scarcity Pricing through an Operating Reserve Demand Curve framework
- Develop penalties/consequences for LSEs that exceed capacity entitlements during emergency events

DR Roadmap: Supply Side AND Demand Side Options for Demand Response

8

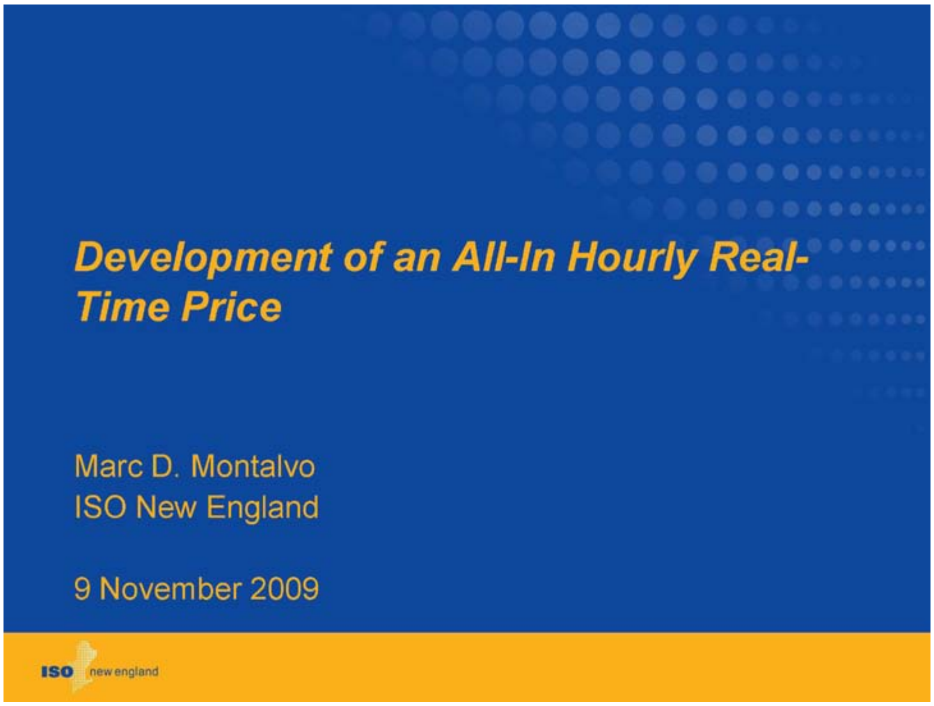
- Demand Response Roadmap more complete in that it provides options for load reduction capability to participate in the market as:
  - Demand Response, a resource that competes with generation and merchant transmission in the energy, capacity, DASR, synchronized reserve and regulation markets; or
  - Price Responsive Demand that changes the quantity of energy consumed and capacity required in response to dynamic prices

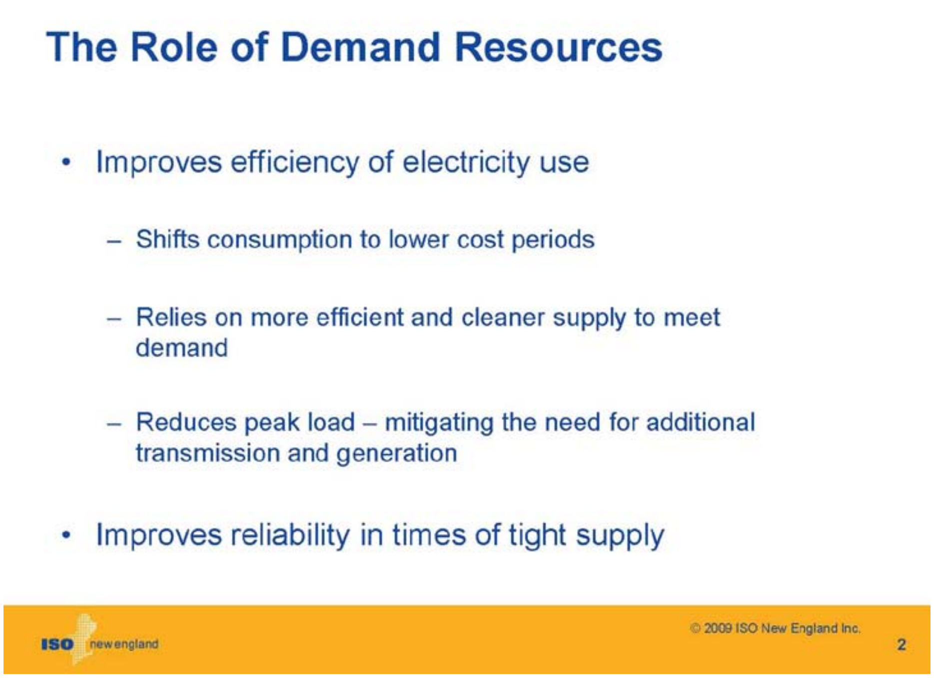
DR Roadmap: Supply Side AND Demand Side Options for Demand Response (*cont.*)

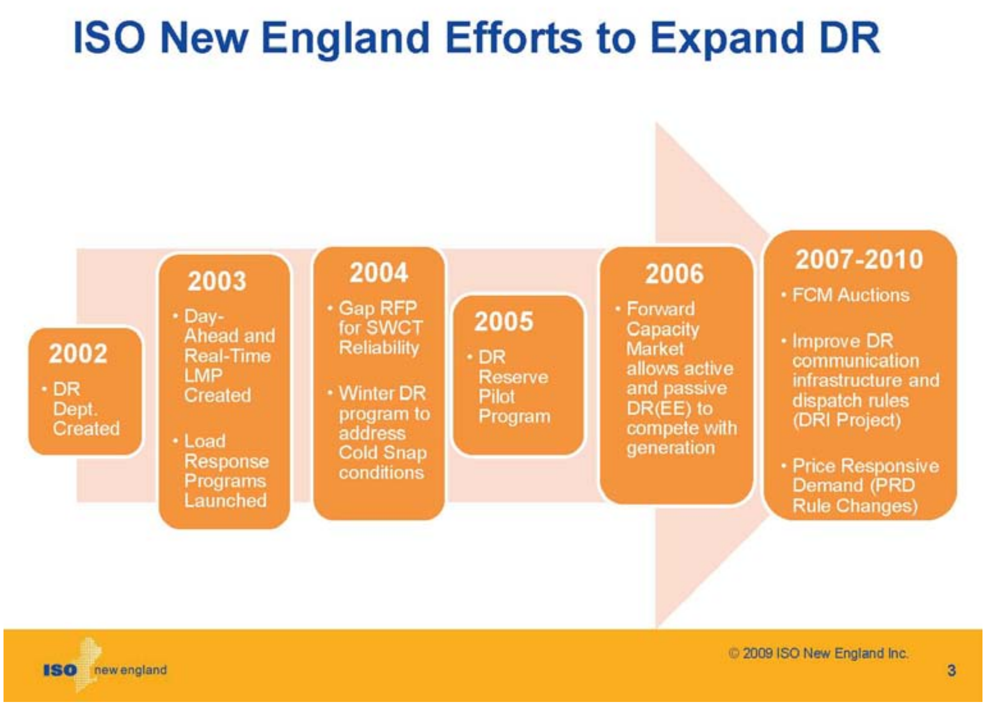
9

- MADRI Commissions' statement of support for the DR Roadmap
  - "The MADRI commissions strongly support the use of all cost effective demand response to reduce capacity and energy costs, assure reliability, and improve the competiveness of PJM administered markets. MADRI encourages PJM to develop a roadmap for fully recognizing retail demand response initiatives in the states"

15. Development of an All-In Hourly Real-Time Price
Marc D. Montalvo, ISO New England






ISO New England Efforts to Expand DR
2002
• DR Dept. Created
2003
• Day-Ahead and Real-Time LMP Created
• Load Response Programs Launched
2004
• Gap RFP for SWCT Reliability
• Winter DR program to address Cold Snap conditions
2005
• DR Reserve Pilot Program
2006
• Forward Capacity Market allows active and passive DR(EE) to compete with generation
2007-2010
• FCM Auctions
• Improve DR communication infrastructure and dispatch rules (DRI Project)
• Price Responsive Demand (PRD Rule Changes)
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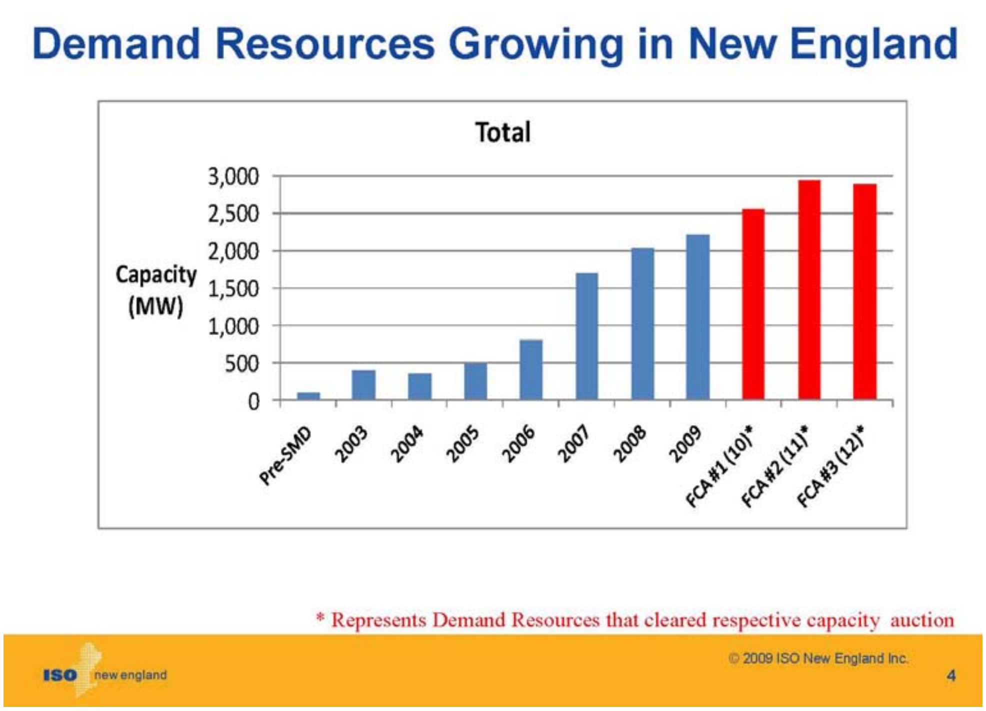
3


Demand Resources Growing in New England
Total
Capacity (MW)
3,000
2,500
2,000
1,500
1,000
500
0
Pre-SMD
2003
2004
2005
2006
2007
2008
2009
FCA #1 (10)*
FCA #2 (11)*
FCA #3 (12)*
* Represents Demand Resources that cleared respective capacity auction
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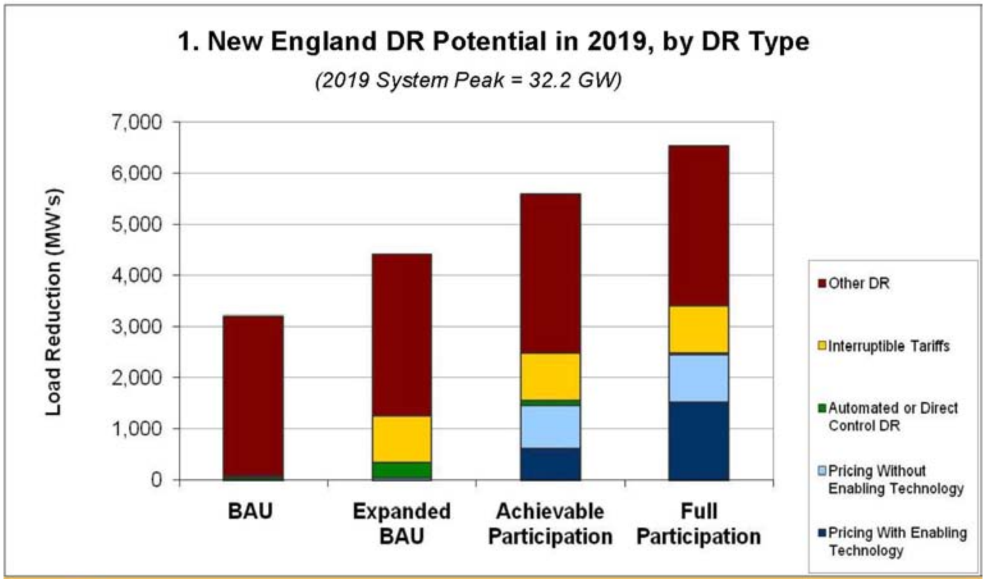
FERC National DR Potential Assessment



ISO new england 5

Integration of Price Responsive Demand

- Allow consumers broader access to the wholesale market, either directly or through intermediaries such as demand response providers
- Preferences of demand is reflected directly in the clearing of the energy markets, with consequent impacts on reserve and capacity markets
- Additional infrastructure is required, technology and policy, to support a transition from the status quo to desired future state

ISO new england 6

Approaches to PRD in New England

- ISO New England has proposed two complementary approaches
  - **Demand-side:** customers change consumption in response to real-time price information
  - **Supply-side:** demand response providers submit and clear demand reduction offers through the market
- Customers with advanced meters and access to dynamic prices can benefit from these approaches

ISO new england

7

Demand-Side Approach to Price-Responsive Demand

- Market Participants may elect to purchase wholesale electricity at a real-time price
- The $/MWh price includes energy and an allocation of capacity charges
- Market Participants that reduce load in high value hours avoid energy charges and enjoy a reduction in future capacity charges

ISO new england

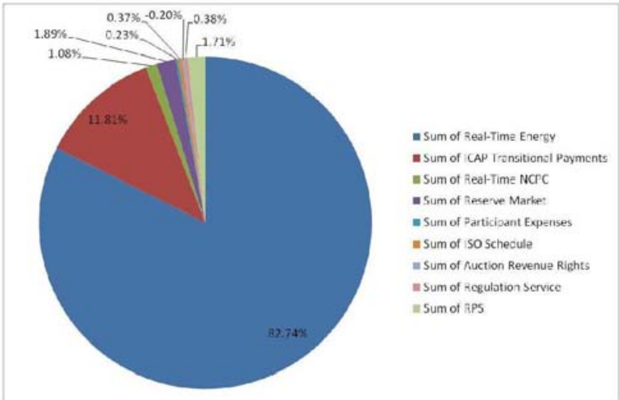
8

Why Price Capacity on a $/MWh Basis?

- The "value" of capacity varies with consumption
- When capacity is short relative to demand, prices should increase until the market clears
- Prices are constrained for a variety of reasons
- Constrained prices dampen incentives for price-responsive demand

ISO new england 9

Energy and Capacity are the Most Significant Part of Wholesale Power Costs*



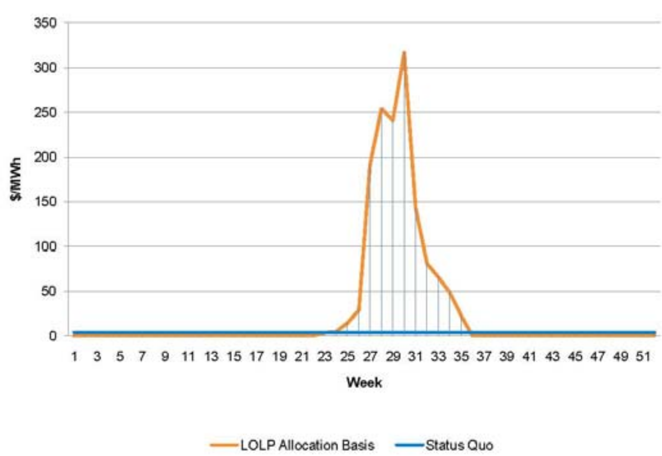
*A matrix describing the major components of a wholesale load customer's bill is located at: http://www.iso-ne.com/stlmnts/cost_comp/index.html

ISO new england 10

Capacity Pricing as Cost Allocation

- Capacity costs are currently allocated on an annual average basis charged monthly
- GOAL: Develop a methodology that allocates costs in proportion to the marginal value of capacity
- ISSUES:
  - Selection of allocation basis
  - Management of cash flow
  - Under/over collection of the revenue requirement
  - Allocation of the under/over collection

Value of Capacity as a Function of System Loss of Load Probability



Capacity Pricing Proposals

- ISO New England has considered two capacity pricing alternatives

1. A method based on expected Loss of Load Probabilities ("LOLPs")
2. A dynamic Critical Peak Pricing ("CPP") method where the ISO calls a critical peak hour based on system conditions at the time

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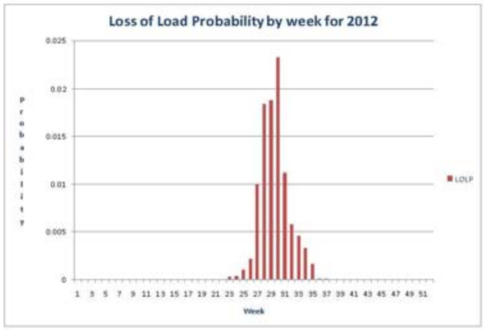
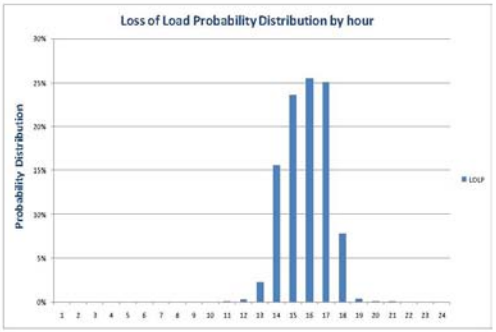
LOLP Approach

LOLPs by Week in 2012



LOLP Distribution by Hour in 2012



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CPP Approach

- The Demand Response Operable Capacity Cap Analysis calculates the expected number of Demand Resource Critical Peak Hours and days within each month
- Demand Resource Critical Peak Hours are assumed to occur during the hours with the highest loads in the month
- Actual Demand Resource Critical Peak Hours in a Capacity Commitment Period will be based on anticipated (day-ahead) or actual (real-time) system conditions

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Advantages and Disadvantages

- LOLP Basis
  - LOLP is a more precise allocation basis that annual system peak
  - Based on historical patterns of consumption, LOLP approach enables customer planning
- CPP Approach
  - Capacity costs are allocated over a small number of hours creating a very strong price signal
  - The capacity rate is “called” in response to actual system conditions
  - CPP may produce greater revenue collection variances

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Complex Issues and Differing Opinions

- Interaction with the Forward Capacity Market
- Estimation of demand elasticity in setting the Capacity Requirement
- Cost shifting
- Perception: the ISO is treading on Load Serving Entity's business

QUESTIONS

16. Integrating Price Responsive Demand: Roundtable Discussions Jan Brinch, Energetics

Integrating Price Responsive Demand

Roundtable Discussions

ENERGETICS
A Subsidiary of VSE Corporation

Purposes

- To build understanding of price responsive demand (PRD) as a new DR Roadmap option and of the underlying assumptions about how PRD will work
- To identify risks and challenges with implementation of PRD and to prioritize them based on importance and time sensitivity
- To identify how best to mitigate the top-priority risks

Four Focus Questions

- Time to answer the questions
- Discuss key ideas and options to provide to PJM

Volunteer Facilitator at Each Table

- Instructions taped on envelope
- Report out at 10:15 a.m.
- Focus on risks and challenges to achieving PRD and mitigation strategies

8:30 a.m. - Focus Question 1

Given your perspective – as customers/ consumer advocates, CSPs/technology companies, utilities/munis/co-ops, RTOs/ISOs, and regulators – **what does successful PRD look like?**

- **5 minutes to jot down ideas**
- **Discussion**
- **Facilitator notes key characteristics of successful PRD**

8:45 a.m. - Focus Question 2

- **Given your perspective** – as customers/consumer advocates, CSPs/technology companies, utilities/munis/co-ops, RTOs/ISOs, and regulators – **what key assumptions underlie your view of successful PRD? Examples include:**
  - Customers and service providers get access to hourly usage information that is comparable to utility access.
  - Service providers have appropriate access to utility smart grid communications and infrastructure to transmit their own pricing information and/or load control signals to customers.
  - No new provisions are needed to protect access to customer information and customer privacy.
  - Competitive retail suppliers provide end-use customers with service that reflects wholesale obligations and settlements based on the actual load characteristics of the individual customers served, rather than class averages, which are currently used.
  - **5 minutes to jot down thoughts**
  - **Discussion**
  - **Facilitator notes key assumptions that underlie successful PRD**

9:00 a.m. - Focus Question 3

What risks do you see that may stand in the way of successful PRD implementation?

- 5 minutes to jot down ideas
- Discussion
- Facilitator writes down risks/challenges
- Table participants note Top 3 risks/challenges
- Facilitator captures this information

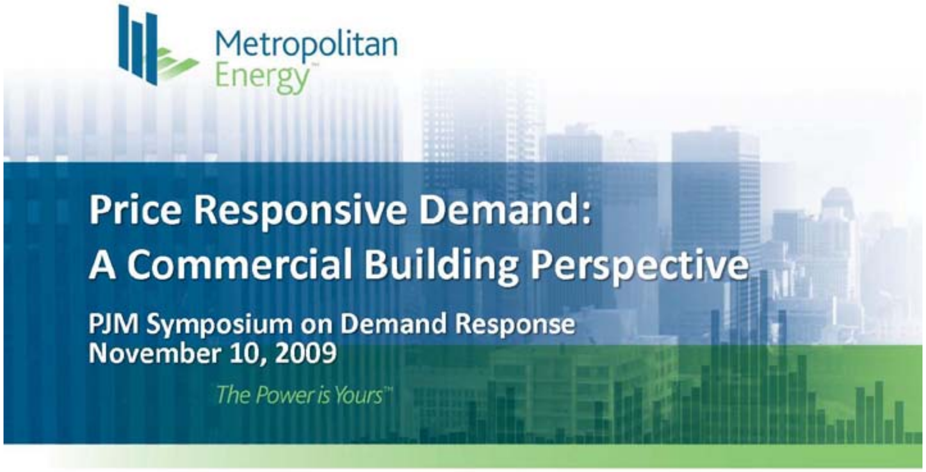
9:30 a.m. - Focus Question 4

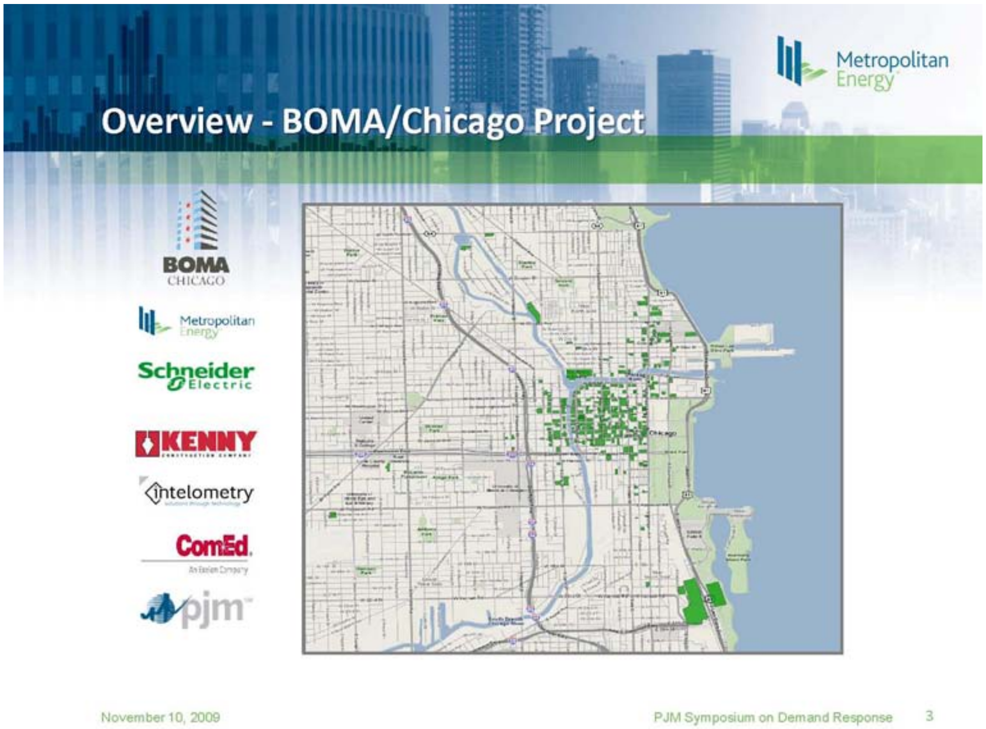
- **For the Top 3 vote getters, how can these risks best be mitigated?**
- **What mitigation strategies will enhance PRD?**
  - Discussion of Top 3 risks/challenges and mitigation strategies
  - Facilitator notes key ideas

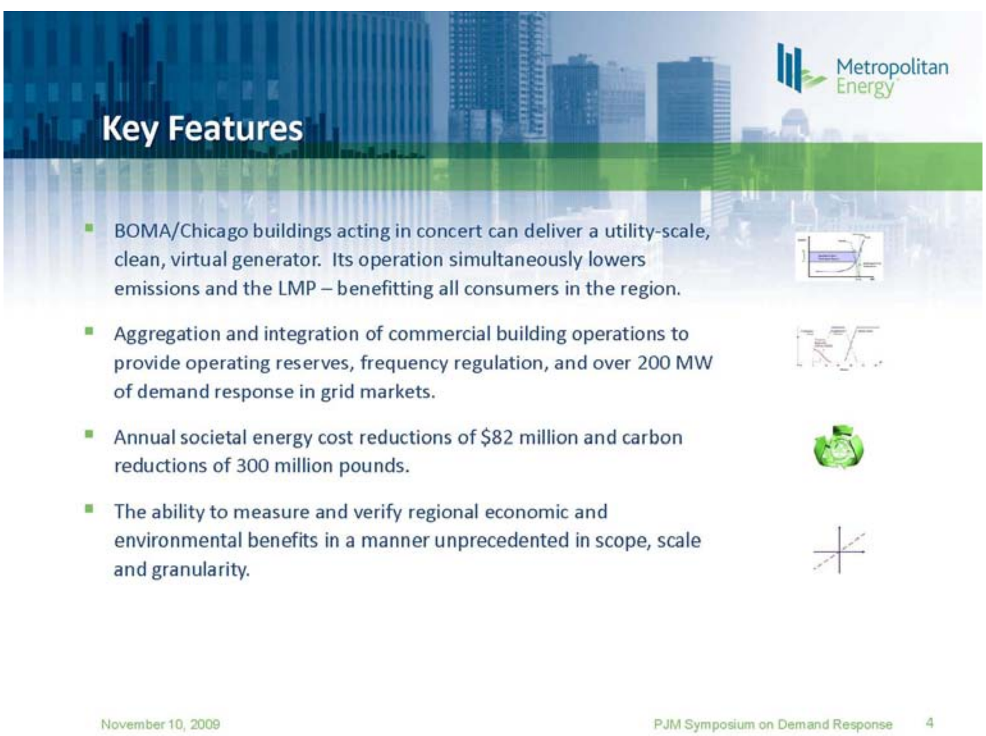
10:15 a.m. - Reports

Facilitator from each table reports on Top 3 risks and mitigation strategies (as time allows)

17. Price Responsive Demand: A Commercial Building Perspective Michael Munson, Metropolitan Energy




Metropolitan Energy
Overview - BOMA/Chicago Project
BOMA CHICAGO
Metropolitan Energy
Schneider Electric
KENNY
intelometry
ComEd
pjm
November 10, 2009
PJM Symposium on Demand Response
3


Metropolitan Energy
Key Features
BOMA/Chicago buildings acting in concert can deliver a utility-scale, clean, virtual generator. Its operation simultaneously lowers emissions and the LMP – benefitting all consumers in the region.
Aggregation and integration of commercial building operations to provide operating reserves, frequency regulation, and over 200 MW of demand response in grid markets.
Annual societal energy cost reductions of $82 million and carbon reductions of 300 million pounds.
The ability to measure and verify regional economic and environmental benefits in a manner unprecedented in scope, scale and granularity.
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Metropolitan Energy

Buildings as Regulation Resources

- In 2006 PJM added the capability of accepting demand response bids in the frequency regulation market. To date, this remains a dormant program.
- Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system by matching generation and load to maintain the desired frequency.
- Commercial building operations using variable frequency drives, direct digital control and automation capabilities can deliver reliability to the grid.

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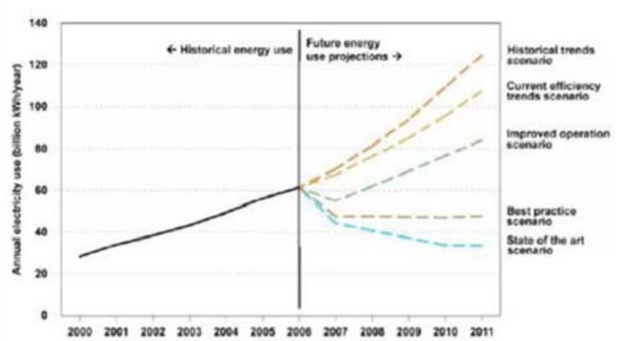
Metropolitan Energy

Energy Efficiency (Demand) Projection

Comparison of Projected Electricity Use, All Scenarios, 2007 to 2011.



Source: EPA Report to Congress on Server and Data Center Energy Efficiency, 2007.

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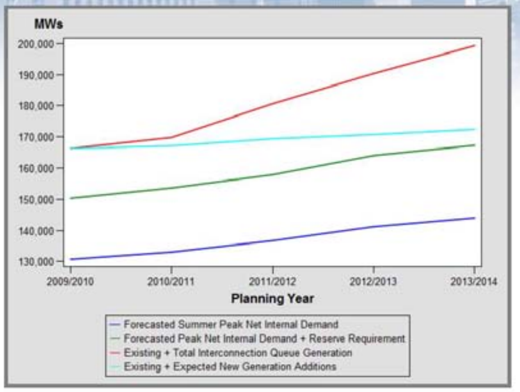
Metropolitan Energy

Energy Supply Projection



Source: Forecasted Reserve Margin PJM RTO (as of 06/08/2009).

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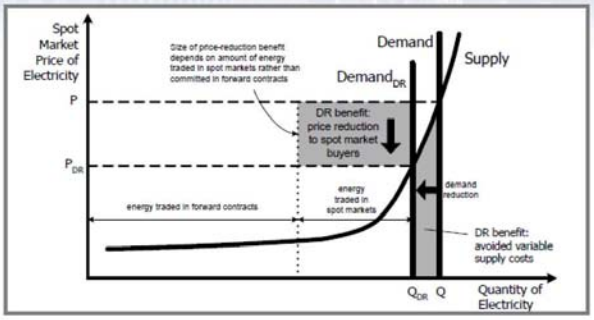
Metropolitan Energy

Integrating Price Responsive Demand



The above graph demonstrates the value of a concentrated DR program to the market as a whole.
Source: *U.S. DOE, Benefits of Demand Response and Recommendations, Appendix B, pg. 69 (Feb. 2006).*

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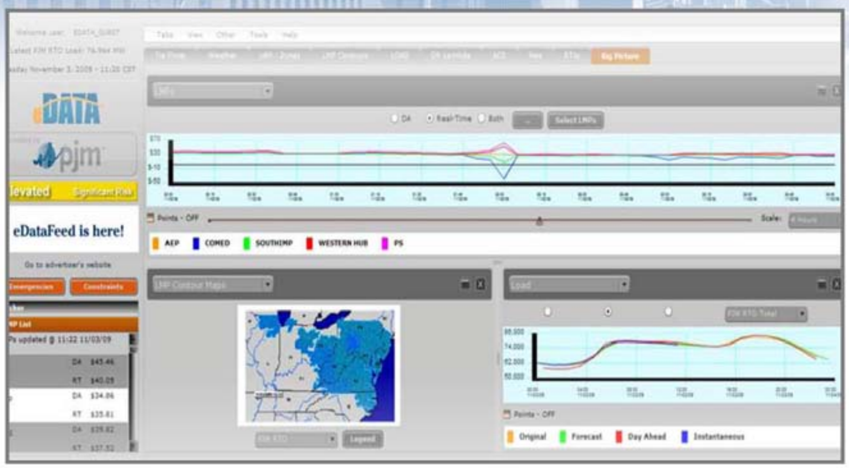
Metropolitan Energy

PJM Market Data



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Metropolitan Energy

Key Risks and Mitigation Factors

- **Information Access**

  The relative intelligence of the grid results from informed decisions based on information analyses. Data is simply a tool that allows for greater measurement and verification of various goals and objectives.

  All stakeholders contribute to the relative sophistication of the grid.

- **Market Transparency**

  Many benefits are identified with PRD; many more are possible that cannot be predicted without data and experience.

  Market efficiency dictates transparent market signals for load to effectively respond to price.

- **Market Design**

  Price signals to incent load participation require information transfer and take into account the dynamic, not static characteristics of demand resources. Commercial buildings cannot be force-fit into generation market constructs that require periods of sustained dispatch.

  Many buildings have sophisticated automation systems with almost unlimited start-stop flexibility. Market design that takes into account load operating characteristics enables PRD.

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18. Building An Energy Ecosystem
Paul Mitchell, Energy Systems Network

ESN
ENERGY SYSTEMS NETWORK

Building An Energy Ecosystem

Energy Systems Network (ESN) provides project development and coordination for joint ventures and cooperative partnerships between network members who are seeking to bring new energy technologies, products, or applications to market .

ESN commercialization projects deliver systems level solutions by drawing on a rich diversity of established and emerging companies and institutions across Indiana and beyond who collectively make up a world-class cleantech cluster with expertise that span the energy ecosystem.

ESN Board of Directors

Joe Loughrey (chair) – retired Vice-Chairman & President, Cummins Inc.
James E. (Jim) Rogers – Chairman & CEO, Duke Energy
Jeff Owens – President, Delphi Electronics and Safety
Dr. John Kelly III – Senior Vice President and Director of Research, IBM
Charles Gassenheimer – Chairman & CEO, Ener1 Corporation
Mike Hudson – President, I-Power Technologies
John Waters – President & CEO, Bright Automotive
Amory Lovins – Chairman & Chief Scientist, Rocky Mountain Institute
France Cordova – President, Purdue University
Thomas Snyder – President, Ivy Tech Community College
Mark Miles – President & CEO, Central Indiana Corporate Partnership

ESN has also formed a world-class Technical Advisory Council with deep knowledge and expertise across the alternative energy sector.

ESN Technical Advisory Council

Dr. Gerry Wilson – Vannevar Bush Professor of Electrical and Mechanical Engineering; Dean of Engineering 1981-91, Massachusetts Institute of Technology

Dr. Richard O. Buckius – Vice President for Research, Purdue University

John Wall – CTO, Cummins Inc.

Dr. Jim Lyons – CTO, Novus Energy Partners; Chief Engineer, GE Global Research (retired)

Bill Wylam – Chief Engineer- Batteries; Director of International Manufacturing, Delco Remy Division of General Motors Corporation (retired)

ESN
ENERGY SYSTEMS NETWORK

PROJECT PLUG-IN

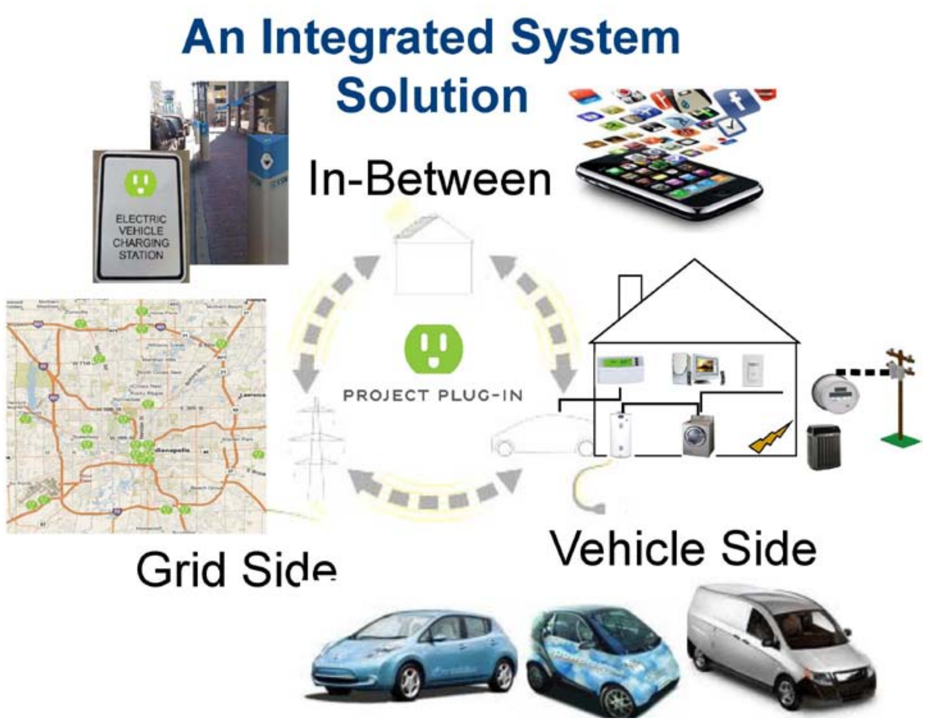
First of its kind commercial scale pilot of plug-in electric vehicles (PEVs) and smart grid technology working together to demonstrate a transportation energy system solution for the Indianapolis area

The pilot will span the service territories of two regulated utilities and will include the development of a model regulatory framework and network architecture needed to take smart grid and plug-in systems to scale

Our plug-in ecosystem will provide an optimal test bed for accelerating the commercialization of plug-in technologies on the vehicle side, grid side, and in-between.

The Indianapolis area is an ideal location for Project Plug-IN because it is approximately 20 miles from all suburbs to the city center (ideal for current battery range) and has no mass transit system . Moreover, Indianapolis is hosting the 2012 Super Bowl where our plug-in ecosystem can be showcased on a global scale.

Our Partners



ESN ENERGY SYSTEMS NETWORK

Vehicle Side



- Incorporate multiple PEV (i.e. PHEV, EV) vehicle platforms across the light, medium, and heavy duty spectrum (MD and HD may require HEV systems only)
  - Achieve a critical mass of plug-in vehicles in the 2009 -2010 timeframe (100+ vehicles)
  - Generate sustained consumer interest through corporate and political support as well as public outreach and education
  - Provide an optimal test bed for demo systems or to prove out related plug-in technologies/applications including smart-charging, wireless communication between the vehicle and grid, and two-way vehicle-to-grid power flow.
- Focus will be on safety and performance to ensure a positive customer experience
- Partners bring a broad expertise including batteries and battery management systems, power electronics, communications systems and expertise, and system integration skills that will enable them to monitor/oversee PEV performance

Proprietary E

ESN ENERGY SYSTEMS NETWORK

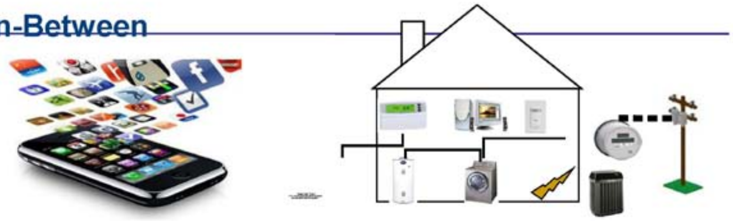
Grid Side

Indianapolis Infrastructure

- Deploy smart grid in homes and businesses across the Indianapolis MSA
- Ensure an open architecture network design that is scalable:
  - Gateway that supports multiple communication protocols
  - Able to adapt as the evolution of technologies progress
  - Allows Internal and external connections to other devices
- Baseline applications will provide immediate benefits to customers including improved energy efficiency and pricing options

Proprietary E

In-Between



- Smart charge infrastructure will be piloted in select homes, businesses, and parking facilities
  - Faster charging sourced from both renewable and grid power
  - Time charging to lower cost and enable valley filling and load leveling
  - Demonstrate next-generation vehicle-to-grid technology
- Test multiple applications with an eye toward scalability
  - Real time analytics and data modeling that improve load management and energy efficiency
  - Integrate software and intelligent devises to increase customer benefits (e.g., virtual thermostat, on-vehicle telematics)
- Transaction Settlement Management System
  - Enhances transparency in billing and allows charging in multiple utility service territories
  - Needed to support mass commercialization of PEVs

Proprietary E

Project Plug-IN will have multiple phases beginning summer 2009

- **Phase 1 – 1 year, Q4 2009 – Q4 2010**
  - HEV to PEV conversions and OEM commercial PEV products (100+ vehicles)
  - Vehicles powered by 240V grid charging installed at homes, malls, and downtown parking facilities
  - Advanced data collection and modeling to support vehicle and charging infrastructure optimization
- **Phase 2 – 1.5 years, Q1 2011 - Q3 2012**
  - Multiple OEM commercial PEV products (1000+ vehicles)
  - Smart Grid with Smart Charge infrastructure installed in select homes, businesses, malls, and parking facilities
  - Analytic modeling, integrated software, and transaction system tested
  - Pilot Smart Charge customer offering with time of use charge tariff
- **Phase 3 – 1 year, Q4 2012 - Q4 2013**
  - Multiple commercial light, medium, and heavy duty PEV products for sale in Indianapolis MSA with high level of early adoption
  - Smart Grid installation launched across Indianapolis MSA with PEV customers offered Smart Charge product options
  - Multiple applications being deployed to enhance Smart Grid and Plug-in system optimization

Appendix D. PJM Symposium on Demand Response III Breakout Group Reports

Note: No participants were at Tables 5 and 14.

Sign-In Sheet for Table #1

Name	Organization	Email
Travis Allen	Federal Energy Regulatory Commission	travis.allen@ferc.gov
Andrew Dorn	Demand Response Partners	adorn@demandresponsepartners.com
Jezabel Aviles	Department of Defense	jezabel.aviles@dla.mil
John Kueck	Oak Ridge National Laboratory	kueckjd@ornl.gov
Sean McNamara	PJM	mcnams@pjm.com
Dan Kerzner	EnerNOC	dkerzner@enernoc.com

Notes from Table #1

Focus Question #1: What does successful PRD look like?
• Quality education to end-use customer. Hourly prices important to customers. Real-time transparent price signals important for CSP's. Good technology exists but pilot programs may be misleading because opt-in customers are not representatives Tech. labs are concerned about smooth demand curves, incorporating wind and low cost electricity. RTO's interested in smart meters and smart rates, energy management systems. Regulators interested in protecting customer data and identity, ensuring reliability.
Focus Question #2: What key assumptions underlie your view of successful PRD?
• Security and cost of implementation are important to customers while good access to price data is important to CSPs. Alignment of wholesale market with retail is important to CSP. Technology lab was interested in a reliable system without price increases, accurate information on payback with rate changes that stay in effect for a long-time. RTO was interested in known and established technology standards. Reg. was interested in fairness in participation and price signals.
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
• Re: billing systems issues, the group saw a risk in reconciling payments if there were billing issues. Other risks included "who maintains new tech. going forward?" and identifying a clear upgrade path. A regulatory concern was "are we trying to do too much?" and questions of cost and economics of DR.

Report Out from Table #1

Risks	Mitigation Strategies	Lead and Support Organizations
1 Billing system issues	• Summary sheet in bill with detail enclosed • Standardization of protocols • Verification department	• CSP's • Standard organizations • LDC
2 Customer interface	• Proper communication of benefits • Education of youth • Customer workshops • Customer service hotlines	• LDCs • Customers (i.e., DoD)
3 Equipment or software obsolescence/stranded costs	• Communication • Education • Quality service/maintenance • Certainty around technology • Definition of clear standards	• LSEs/aggregator • CSPs

Sign-In Sheet for Table #2

Name	Organization	Email
Dean Wight	Federal Energy Regulatory Commission	dean.wight@ferc.gov
Sarah (Sally) Buttner	Consultant to Delaware Division of the Public Advocate	energytransition@comcast.net
Mike Borden	Comverge	mborden@comverge.com
Robert Armstrong	Maryland Public Service Commission	rarmstrong@state.md.us

Notes from Table #2

Focus Question #1: What does successful PRD look like?

• Regulator and consumer advocate – consumers understand PRD, can see how they save, and wide participation
• FERC and technology provider – customers must "want" to do it, cheap enabling technology, prices related to wholesale LMP
• Consensus view
  o Must have opt-out ability, but opt-out should be restrictively or opting out to a default rate which is also TOM
  o Retail prices must fairly closely reflect real time LMP – not sure about CPP
  o Utility cost recovery known prior to launch

Focus Question #2: What key assumptions underlie your view of successful PRD?
• Upfront cost recovery decision for utility (include revenue decoupling) • Privacy, data protection i.e. for financial industry • Customers are educated about DR and cost causation • Customers will only respond to cost incidence for them
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
Others • Consumers will resist change • Interference by legislators • Uncertainty about carbon • RPS standards not met; same concern • Problem for LMP if no RTO • Problem interactions retail and wholesale • Customer's understanding of how to use enabling technology • Falling fuel prices • Baseline gaming

Report Out from Table #2

Risks	Mitigation Strategies	Lead and Support Organizations
1 **Customer interface**	• National Action Plan for Demand Response • Compile pilot lessons learned • Engage consumer advocates in all states in PJM	• FERC • FERC/NARUC • State commissions/Organization of PJM states/NASC Advocates
2 **Outside changes by legislators regarding environment consumer protection**	• Educate/outreach to legislatures • Enlist national environmental organizations to lobby/educate legislators – EE/DR tension	• MADRI speaker's bureau • DRCC
3 **Interaction across wholesale and retail markets**	• File soon initial interaction proposal with FERC • States file positions regarding above	• PJM • State PUCs

Sign-In Sheet for Table #3

Name	Organization	Email
David Ellis	Comverge	dellis@comverge.com
Leanne Khammal	Federal Energy Regulatory Commission	leanne.khammal@ferc.gov
Foroud Arsanjani	North America Power Partners LLC (CSP)	fa@nappartners.com
Laurie Wiegand Jackson	North America Power Partners LLC (CSP)	lwj@nappartners.com
David Stippler	Indiana Office of Utility Consumer Counselor	dstippler@oucc.in.gov
April Paronish	Indiana Office of Utility Consumer Counselor	aparonish@oucc.in.gov
Andy Ott	PJM	ott@pjm.com
Dallas Winslow	Delaware Public Service Commission	dallwinsl@aol.com

Notes from Table #3

Focus Question #1: What does successful PRD look like?
• Automated, or consumer managed, transparent results back to stakeholders • Monetary incentive for appropriate behavior • Price transparency • Performance assessment communication to all stakeholders on expectations • Voluntary customers are satisfied and peak load is reduced • Rules are "just and reasonable"
Focus Question #2: What key assumptions underlie your view of successful PRD?
• Customers are educated • Wholesale and retail tariffs are coordinated • Equitable/sensible funding mechanism • Cyber security issues are addressed • Available to all customer sectors
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
• Political/regulatory risk • Customer interface • Equipment/software obsolescence (stranded cost)

Report Out from Table #3

Risks	Mitigation Strategies	Lead and Support Organizations
1 Political/regulatory risk	• Education and ground work to assure good policies are implemented • Should go to both regulators and politicians • Educate leaders dealing with energy issues primarily • Continuous information exchange • Alignment between federal and state authorities • Clear messages/goals communicated	• RTO/ISO • State commissions • FERC/DOE – K Street • Public advocacy groups • Many other industry stakeholders
2 Customer interface/apathy/pricing	• Education of customers • Comprehensive planning • Ongoing performance evaluations and retuning • Support of open environment for all stakeholders/participants/open and transparent stake	• Utilities • State regulators • Third party suppliers • Consumer advocates
3 Equipment/software obsolescence	• Create open standards and allow competition to meet those standards • Open forums to decide on technologies and implementation thereof	• State regulators • FERC • NIST • Consumer advocacy

Sign-In Sheet for Table #4

Name	Organization	Email
Katie Guerry	Hess Corporation	kguerry@hess.com
David Brown	Dominion Virginia Power	david.brown@dom.com
Larry Fratis	Department of Defense	lawrence.fratis@dk.mil
Glenn Dickerson	PPL Electric Utilities	gfdickerson@pplweb.com
Chris Ashley	EnerNOC, Inc.	cashley@enernoc.com
Stu Bresler	PJM	bresler@pjm.com
Steve Boyle	PJM	boyles@pjm.com
Michael Krauthamer	Maryland Public Service Commission	mkrauthamer@psc.state.md.us

Notes from Table #4

Focus Question #1: What does successful PRD look like?

- Utility: wholesale price signal to retail level – will take work/good market penetration; measurable and verifiable
- RTO: accurate planning; price signals that accurately reflect state of system; seamless implementation for ops/dispatch
- CSP: timely price signals/information or performance; technology enabled; solid M&V; appropriate alignment of industry
- Customer: timely credits and rewards
- Top three:
  - 1) Bring price signal from wholesale to retail efficiency
  - 2) Measure consumption accurately
  - 3) Timely incentives and feedback

Focus Question #2: What key assumptions underlie your view of successful PRD?

- RTO: linkage between wholesale rates and retail rates that causes customers to reduce at times of system need; customer flexibility – manual or automate
- Utility: customer education and consumer buy-in; timely feedback immediate, rewards and communication; customer flexibility – automatic/manual; see not just usage but savings
- Customer: access to real time information – price and usage
- CSP – quantifiable, predictable and transparent so contracts can be structured; transparent penalties; even playing field, access to information, to deliver most efficient outcome
- Top three:
  - 1) Linkage between wholesale and retail
  - 2) Access to real time usage and savings information
  - 3) Flexibility – manual vs. auto

Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?

- Utility: customer interface; billing system issues; load forecasts; security breach/IT; cost recovery
- Customer: complexity
- CSP: customer expectations; load forecasts; billing systems; security breach
- Regulator: state commissions authorizing rate structure for PRD to take off
- RTO: industry inertia
- Top three:
  - Cost recovery/rate structures – commissions
  - Load forecasts
  - Customer interface

Report Out from Table #4

Risks	Mitigation Strategies	Lead and Support Organizations
1 Load forecasting	• Clear documentation of requirements • Supervisory control • Spell out penalty structure • M&V (robust) • Ramping period (committed vs. uncommitted)	• PJM probably lead on load forecasting with LSE, EDC, CSP, etc.
2 Getting rate structure approved/industry inertia	• Stakeholder process (LSE, consumer, CSP, RTO) • National Action Plan – look at national level • Do all utility can on DSM, then look to generators	• Utility and commission level leadership • National stakeholder groups • Legislatures
3 Customer interface	• Effective communication → mass media • Legislative/cost recovery approved • Simple	• Utilities/commission • Technology companies

Sign-In Sheet for Table #6

Name	Organization	Email
David Cavanaugh	ISO New England Inc.	dcavanaugh@iso-ne.com
Richard Whiffen	Wellspring Wireless	rwhiffen@wellspringwireless.com
Ed Tatum	Old Dominion Electric Cooperative	etatum@odec.com
Rob Marmet	Piedmont Environmental Council	rmarmet@pecva.org
Jeanie Schleiden	PJM	schlej@pjm.com
Sherman Elliott	Illinois Commerce Commission	selliott@icc.illinois.gov

Notes from Table #6

Focus Question #1: What does successful PRD look like?
• PRD should accommodate different business models such as coops, munis, local regulatory structure (719) • Rule design incents the right behavior (end user) to respond and allows the system operator enough information to reliably operate the system
Focus Question #2: What key assumptions underlie your view of successful PRD?
• Customer acceptance, voluntary, appropriate education/marketing is done • Deployment of enabling technology and data provision • Transition plan that hedges customer against volatility (initially)
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
• Customer acceptance • Billing system • Load forecasting

Report Out from Table #6

Risks	Mitigation Strategies	Lead and Support Organizations
1 Customer acceptance	• Educate/target customer base that is most vulnerable (fixed income, etc.); low income → price protection • Target lowest load factor end users first • High value/high risk	• Joint venture across multiple organizations (state/federal/utility etc.)
2 Billing	• Transition: shadow pricing/settlement/billing • Timely, accurate • Flash cut/transition?	• ISO/DISCO/coops
3 Load forecasting	• Provided to system operator by location • Planning of system (methodology) should be the same process for allocation o 1 CP day vs. 5 CP, 72 CP hours • Affiliated ownership – adopt gas market and structure; divestiture	• Disco/coops/CSP • (LDC) • ISO

Sign-In Sheet for Table #7

Name	Organization	Email
Matt Nollenberger	American Electric Power	mwnollenberger@aep.com
Ken Roth	Michigan Public Service Commission	rothk@michigan.gov
Melissa Lozano	Federal Energy Regulatory Commission	melissa.lozan@ferc.gov
Jai Ganesh	Mirant Corporation	jai.ganesh@mirant.com
Dale Flaherty	Duquesne Light	dflaherty@duqlight.com
Al Freeman	Michigan Public Service Commission	freemana5@michigan.gov
Bryan McDaniel	Illinois Citizens Utility Board	bmcdaniel@citizensutilityboard.org
Howard Spinner	Virginia State Corporation Commission	howard.spinner@SCC.virginia.gov

Notes from Table #7

Focus Question #1: What does successful PRD look like?
• Generator: integration of retail and wholesale price states, education of consumers, regulatory support for long term • Utility: make it easy to understand, customer needs to see savings, cost effective • Regulator: communicating information (outreach of all stakeholders), let more sophisticated customers do more, cost effective, benefits of reliability (option of PRD at lowest possible cost), no perceived losers, PRD shouldn't double compensate a resource – doesn't affect scarcity pricing in a bad way • Vertically integrated utility: effective integration with wholesale market, mitigate risks for generation business, integration to retail tariff structures, integrity of data
Focus Question #2: What key assumptions underlie your view of successful PRD?
• Utility: customer and service provider get access → customer takes on more of the role as a market participant • Regulator: some customers are more sophisticated than others → graduated transition to PRD, service provider has access to utility, PRD is subject to law of diminishing returns, equitable transport process for moving to PRD • Generator: good sound business ruler that doesn't change all the time • Utility: utility can recover investment, if customer can't save why subsidize?
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
• Regulator: risk of worthless investment, can you get customer to use it?, how will education happen? organization with limited education experience will be found to educate (economic factor could change), PJM stakeholder process isn't effective because nobody knows what they're doing • Generator: customer interface, bad investments or a result of stimulus • Utility: shifting load will lead to increased use of dirty generation, customer apathy

Report Out from Table #7

Risks	Mitigation Strategies	Lead and Support Organizations
1 **Uneconomic investment**	• Go slow, set targets • Sharing of best practices and things that don't work so well • Accountability	• Internet/watchdog groups • State commissions • FERC
2 **Poor education**	• Get customer advocator involved • Engage regular education processes (schools, institutions) • Start small within limited geographic area, apply lessons learned • Make information easy to understand • Look at other market outreach efforts	• Department of Education • Electric Distribution company • Consumer advocates • Commissions
3 **Customer apathy**	• Good education • Show them the money, make sure customer can see how much they saved or what they could have saved • Remove element of complexity	• Mass media • Utility (billing system) • (Commission, FERC, consumer advocates)

Sign-In Sheet for Table #8

Name	Organization	Email
Lopa Parikh	Old Dominion Electric Cooperative	lparikh@odec.com
David Bloom	Baltimore Gas and Electric	david.bloom@constellation.com
Don Blackburn	NTCI	don@blackburn.net
Carrie Pasch	Energy Spectrum	cpasch@energyspec.com
Brian Hoeger	Exelon Energy	brian.hoeger@exeloncorp.com
Paul Miles	PECO Energy	paulw.miles@exeloncorp.com
Tricia Gannon	Delmarva Power	tricia.gannon@pepcoholdings.com

Notes from Table #8

Focus Question #1: What does successful PRD look like?
• ODEC: DR as load resource on demand side seen thru load forecast • Exelon: price drives response: administer ease, forecasting DA & RT: pretend what customers would do • Consul: profitable for consumer and retailer → begin from forecasting • PECO: limited risk in forecast, LSE/EDC retail procurement process, better technology communicated to customers, CSP – baselines methodology • BGE: M&V
Focus Question #2: What key assumptions underlie your view of successful PRD?
• Exelon: LSE participation with menu options, doesn't need to be on RT rates • All: access to data • ODEC: M&V, education • BGE: inclusion in RTEP
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
• Consul: customer apathy – customer interface • DPL: settlement system, routines too burdensome – billing system • ODEC: cost of deployment vs. legacy load control – who pay – stranded costs

Report Out from Table #8

Risks	Mitigation Strategies	Lead and Support Organizations
1 Customer interface	• Results vs. costs – education • “Penalty” (rate increases) mitigation through aggregation of customers	• Utilities, consumer advocates (regulated recovery), retail partners • CSP (LSE)
2 Consistent treatment of utility load forecast	• Historical data is first test • Conservative bids (provisional short term data) • Manage it like wind for planning • Operational reserves on system (solar)	• RTO/ISOs: anyone who works with load shapes • LSEs and utility
3 Stranded costs equipment/software	• Flex/open source technology • Recycling old appliance • Rate recovery	• Regulators through rates

Sign-In Sheet for Table #9

Name	Organization	Email
Andrea Maucher	Delaware Public Service Commission	andrea.maucher@state.de.us
Candace McCrae	Honeywell Utility Solutions	candace.mccrae@honeywell.com
Kriss Brown	Pennsylvania PUC	kribrown@state.pa.us
Jim Musilek	North Carolina's Electric Cooperatives	jm.musilek@ncemcs.com
John Webster	Monitoring Analytics, LLC	john.webster@monitoringanalytics.com
Chris Thomas	Illinois Citizens Utility Board	cthomas@citizensutilityboard.org

Notes from Table #9

Focus Question #1: What does successful PRD look like?

- Lowers demand/reduces cost
- Quick roll out
- Measurable results/verifiable
- Voluntary/mandatory depending upon regulatory structure
- Educated, willing participants
- Revenue neutral (market structure)
- Open and available price information
- Technology available for response

Focus Question #2: What key assumptions underlie your view of successful PRD?

- Reporting to customers
- Supervisory control
- Robust system
- Willing educated consumers
- Automation
- Sufficient benefits
- Open access with customer consent
- Provide tools to customer

Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?

- Customer interface and education – rush deployment
- Technology choice – costs and benefits, stranded costs
- Billing system and security

Report Out from Table #9

Risks	Mitigation Strategies	Lead and Support Organizations
1 Customer interface/ education	• Collaborative message from variety of sources • Manage each aspect of implementation • Capitalization on momentum • Approximately time and coordinated rollout	• No lead – coordinated effort
2 Technology choice (billing meter infrastructure)	• Standards and testing • Universal roll out • Planning for upgrades	• NIST and other national organization • Stakeholder consensus
3 Security	• Balancing security needs with need for innovation • Build in contingencies	• NIST

Sign-In Sheet for Table #10

Name	Organization	Email
Gregory Carmean	Maryland Public Service Commission	gcarmean@psc.state.md.us
Kent Walker	Delaware Department of Justice re: Public Advocate	kent.walker@state.de.us
Christine Falco	PJM	falcoc@pjm.com
Michele Greening	PPL Corporation	mhgreening@pplweb.com
Jim Hebson	Public Service Enterprise Group	james.hebson@pseg.com
Mary Zientara	Reliant Energy	mzientara@reliant.com
Tom Rutigliano	CPower	tom.rutigliano@cpowered.com

Notes from Table #10

Focus Question #1: What does successful PRD look like?

- Strong feedback, do not change baseline too often, used as default
- Legislative, question over what it means
- Automatic response from devices
- Dispatch in real time, visible benefits – want choices, lower cost (higher load factor)

Focus Question #2: What key assumptions underlie your view of successful PRD?

- Assume two way communication, maintain privacy, technology working as promise
- Less demand equals less generation, national standards

Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?

- Customer interface
- Billing system issues
- Security breaches (need to report), added equipment failure

Report Out from Table #10

Risks	Mitigation Strategies	Lead and Support Organizations
1 Customer interface	• Education, education, education • National smart grid standards • Pilot programs • Seek customer feedback	• Open SG • NIST • Utilities – CSPs – all entities
2 Billing system issues	• Data validation • Testing	• Utility
3 Security breaches	• National smart grid standards • Two factor authentication • Encryption	• Transparency – let public know it breached • Industry workgroups • Utilities – PJM

Sign-In Sheet for Table #11

Name	Organization	Email
Mark Brownstein	Environmental Defense Fund	mbrownstein@edf.org
Jane Quin	Rockland Electric Co.	quinj@oru.com
Stacia Harper	Ohio Consumers' Counsel	harper@occ.state.oh.us
Evelyn Robine	PJM	robine@pjm.com

Notes from Table #11

Focus Question #1: What does successful PRD look like?
• Customer finds value → options/choices for customers • Easy to understand • Harmonize wholesale/retail markets • Levels peaks • Creates opportunity for distributed renewables
Focus Question #2: What key assumptions underlie your view of successful PRD?
• Data access/customer owns it, but that's just the start • Policy makers are going to allow technology deployment and recovery
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
• Price exposure risk • Billing system – cost complexity • Diesel generators proliferation

Report Out from Table #11

Risks	Mitigation Strategies	Lead and Support Organizations
1 Price	• Various program designs/choices • Cap and trade	• Third parties offering integrated solutions • Regulators • Congress
2 Billing	• New methods/outsourcing • Simplifying tariff structures? (Contracting out?) • Costs	• No information provided
3 Diesel generators	• Interconnect data into system • OBD for diesel generator sets • Air regulations	• OEPs

Sign-In Sheet for Table #12

Name	Organization	Email
Denise Foster	PJM	fosted@pjm.com
Bri West	Piedmont Environmental Council of Virginia	bwest@pecva.org
Paul Centolella	Public Utilities Commission of Ohio	paul.centolella@puc.state.oh.us
Christopher Hewett	Dominion Virginia Power	christopher.c.hewett@dom.com
Joe Bugica	EnergyConnect	jbugica@energyconnectinc.com
Jayant Kumar	AREVA T&D	jayant.kumar@areva-td.com
Scarp	Old Dominion Electric Cooperative	odec@scarp.info
Mike Kovach	The E Group – FES	makovach@e-grp.com
Amery Pore	Federal Energy Regulatory Commission	amery.pore@ferc.gov
Jackie Roberts	EnerNOC	jroberts@enernoc.com

Notes from Table #12

Focus Question #1: What does successful PRD look like?
• Program that is easy to understand with benefits quantifiable and sufficient to incent participation. Need accompanying retail rate. Have to justify participation to management). The peak reduction must be included in future load forecasts used for RPM. Ensure that the programs can be competitively offered (i.e., not just a utility program) so ensure competition and innovation. Technology may allow individual customers to use optimization programs that have objectives unique to those customers based on their preferences.
Focus Question #2: What key assumptions underlie your view of successful PRD?
• Customers need to see economic benefit to participate • You need a secure interface for customers/CSPs to see usage and prices • Automation for larger customers • Tariff structures that allow right price signal on margin 1) baseline price, 2) LMP based price) • Consumer education, engage consumers (HOA) • Utilities pass savings along – reduce capital investment
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
•

Report Out from Table #12

Risks	Mitigation Strategies	Lead and Support Organizations
1	• Getting all of the projected PRD response built into transparent forecast curve (capacity and transmission)	• PJM load forecast at price variables (include price elasticity in forecasting) but need to ensure don't over forecast because reliability
2	• Partial implementation – get AMI but not the rate structure • Maybe have mandatory simple rate structure as opt out and then allow more complicated structures to develop • Need software upgradeability to address obsolescence • Ensure business (for investment cost) case is established to help develop rate structure for the benefit to be established	•
3	• Education failure (initial failure will hinder future developments) • Need good help desk • Political backlash if don't do education right • Funding issue • Tailor to demographic, e.g., green – baby boomers vs. cost • Industry needs to coordinate the message (that was in FERC's National Action Plan) • Region wide roll out so take advantage of mass education	• Do HOA based meetings (can hit thousands of homes) • Social networking • Get other groups involved (Sierra Club, Environmental Defense Fund, Piedmont Environmental Council) – engage NGOs to help push education • Touchstone to educate at coops and could add program

Sign-In Sheet for Table #13

Name	Organization	Email
Ron Reisman	New Jersey Board of Public Utilities	ronald.reisman@bpu.state.nj.us
Jeremy Hellman	Divine Capital	jeremy@divinecapital.com
Larry Hutchison	American Electric Power	ichutchison@aep.com
Hal Siegrist	Mirant Corporation	hal.siegrist@mirant.com
Bruce Campbell	EnergyConnect	bcampbell@energyconnectinc.com

Notes from Table #13

Focus Question #1: What does successful PRD look like?

- Must be cost effective
- Meaningful acceptance by customers
- Measurable and verifiable results

Focus Question #2: What key assumptions underlie your view of successful PRD?

- Program must be politically acceptable as well as technically feasible
- Customer perception must be that financial benefits of program offset costs

Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?

- Track the dollars
- Infrastructure to make program work
- Massive customer education and outreach effort

Report Out from Table #13

Risks	Mitigation Strategies	Lead and Support Organizations
1	• Upgrading utility billing systems • Standardizing requirements for billing infrastructure across PJM footprint	• IT, developers (internal or external) • State regulators (guided by OPSI)
2	• Develop robust infrastructure consistent with life of components • Develop standardized "plug & play" in-home devices, appliances and control systems	• IT, telecom, end use equipment vendors • Appliance and equipment manufacturers • NIST
3	• Simple, easy-to-understand and repetitive messages • Timely dollar impact • Real-time benchmarking showing financial impact of consumer decisions • One-year tryout – data collection without billing impact	• Utility communicators, state regulators, media

Sign-In Sheet for Table #15

Name	Organization	Email
Paul Wattles	Electric Reliability Council of Texas	pwattles@ercot.com
Stan Timblin	PowerSecure	stimblin@powersecure.com
Keith Dodrill	U.S. Department of Energy/National Energy Technology Laboratory	keith.dodrill@netl.doe.gov
Jeff Bassett	BP Energy	jeffrey.bassett@bp.com
Greg Scheck	Public Utilities Commission of Ohio	gregory.scheck@puc.state.oh.us

Notes from Table #15

Focus Question #1: What does successful PRD look like?
• High prices correlate to scarcity condition – x% of load incentive to curtail rate structure reflects true cost; power metered with rapid feedback
Focus Question #2: What key assumptions underlie your view of successful PRD?
• PRD should contribute to grid stability • Effective communication to customer/customer enabled to effectively perform as expected/commercial, industrial needs to be automated
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
• Billing system issues • Negative experiences that get headlined could hamper implementation • Consistent treatment of utility load forecasts/forecasters must have access to customer information

Report Out from Table #15

Risks	Mitigation Strategies	Lead and Support Organizations
1 Billing system issues - commercial - industrial	• Good vetting/validation of the process o Well tested	• Load serving entity
2 Negative experiences that get a lot of press could hamper implementation	• Consumer education program o Good communication methodologies	• Load serving entity
3 Consistent treatment of utility load forecast	• Transparency for the load forecaster	• Utility or ISO

Sign-In Sheet for Table #16

Name	Organization	Email
Richard Sedano	Regulatory Assistance Project	rsedano@raponline.org
Mike Jesensky	Dominion Virginia Power	mike.jesensky@dom.com
Jonathan Fernandez	Federal Energy Regulatory Commission	jonathan.fernandez@ferc.gov
But Chiu	AREVA T&D	but-chung.chiu@areva-td.com
Ann Tracy	Dominion Virginia Power	anne.m.tracy@dom.com
Don Kujawski	PJM	kujawd@pjm.com
Greg Urbin	Baltimore Gas and Electric	gregory.urbin@constellation.com
Pete Langben	PJM	langbp@pjm.com
Jim Holbery	Grid Mobility	jdh@gridmobility.com

Notes from Table #16

Focus Question #1: What does successful PRD look like?
• Enabling technology and customer training – customers need to be engaged • Data management challenge is huge and important • Interests need to be balanced
Focus Question #2: What key assumptions underlie your view of successful PRD?
• Customers need to be engaged • Realistic capital investment expectations
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
• Consumer interface • Misaligned expectations • Customer value

Report Out from Table #16

Risks	Mitigation Strategies	Lead and Support Organizations

**1
Consumer interface**
	• Educate – more literate
	  o Financial
	  o Societal
	• Too big for one entity
	• A/V media
	  o Utility
	  o Government → schools, brands
	• Simple
	• Willingness to pay
	• Avoid customer confusion with multiple vendors
	• ENERGY STAR analog
	• Comparisons on savings
	• Open standard in key areas
		• Utility
		• Government
		• Equipment manufacturers and retailers

2 Misaligned expectations - politics - mass market - regulatory	• Pilots teach things • Regulators on board • Collaborate with main stakeholders • Educate customers • Be flexible • Goals • Tracking progress on reasonable expectations • Willingness to pay	• Utility • Government • Legislators • Influencers
3 Customer value	• Consistency (not on and off)	• No information provided

Sign-In Sheet for Table #17

Name	Organization	Email
C. Louis Clark	EVAPCO, Inc.	lou.clark2@verizon.net
Jim Benchek	FirstEnergy	jpbenchek@firstenergycorp.com
Barry Trayers	RBS Commodities	barry.trayers@rbssempra.com
Carol Brotman White	Federal Energy Regulatory Commission	carol.white@ferc.gov
James Van Horn	Pepco	jmvanhorn@pepco.com
Deanna Kirn	Dominion Virginia Power	deanna.kirn@dom.com

Notes from Table #17

Focus Question #1: What does successful PRD look like?
• Education a must across all groups – buy-in needed form all • Automation is needed to assist (equipment at all levels) to make it easier to implement • Incentives needed to get started
Focus Question #2: What key assumptions underlie your view of successful PRD?
• Predictable, reliable, controllable • Real-time data – shared • Not everyone wants to play • Rate of return – recovery needed, revenue • Automation will evolve
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
• Add: regulatory jurisdictional gaps (FERC, States, RTOs)

Report Out from Table #17

Risks	Mitigation Strategies	Lead and Support Organizations
1 **Customer interface**	• Educate, educate, educate	• No information provided
2 **Regulatory jurisdictional gaps**	• Bring groups together to discuss (educate) idea exchange – informal	• No information provided
3 **Consistent treatment of utility load forecasts**	• Accountability • M&V • Pre-studied – statistical predictability	• No information provided

Sign-In Sheet for Table #18

Name	Organization	Email
Calvin Timmerman	Maryland Public Service Commission	ctimmerman@pcs.state.md.us
Michael Kane	Penncat Corporation	mkane@penncat.com
Diane Goff	Pepco Holdings, Inc.	diane.goff@pepcoholdings.com
Eric Icart	Federal Energy Regulatory Commission	eric.icart@ferc.gov
Sheirmiar White	OHMS Energy	swhite@ohmsenergy.com
Kim Jones	North Carolina Utilities Commission Staff	kjones@ncnc.net
Kim Barrow	Pennsylvania Public Utility Commission	kbarrow@state.pa.us

Notes from Table #18

Focus Question #1: What does successful PRD look like?
• Easy to understand • Strong price incentive • Flexibility – looking more like command and control than price response • Enabling technology • State policy considerations • Options forecasters
Focus Question #2: What key assumptions underlie your view of successful PRD?
• Foundation of customer specific load and profile finally available to facilitate retail competition and CSP services at mass market level • Information flaw and usefulness critically important
Focus Question #3: What risks do you see that may stand in the way of successful PRD implementation?
• Failure to respond/capture benefits • Bad capacity pricing • Premature obsolescence

Report Out from Table #18

Risks	Mitigation Strategies	Lead and Support Organizations
1 **Failure to respond/capture benefits**	• Pay attention to all the details • Keep it as flexible as possible • Keep it simple for suppliers and customers	• Consumer advocates • Media • Policy makers and leaders • Regulators • Utilities • CSPs • Retail suppliers
2 **Bad capacity pricing**	• Better wholesale ratemaking • Retail pricing follow wholesale costs • Avoid complexity	• FERC • Commissions • REPs • CSPs
3 **Premature obsolescence**	• Shift performance risk to equipment vendor or implementer as much as possible • Staged implementation testing • Low cost scalability even if higher first cost • Wholesale results recognize technical realities	• Utility • PSC

Appendix E. PJM Symposium on Demand Response III Participant List

PJM Symposium on Demand Response III
November 9-10, 2009
Participant List

Participant	Company/Organization	Sector
Alston, Richard	Old Dominion Electric Cooperative	Electric Distributor
Batta, Michael	Dominion	Generation Owner
Betlejewski, Derek	Champion Energy	Other Supplier
Bhavaraju, Murty	PJM Interconnection	Not Applicable
Black, Garry	NRDC	Not Applicable
Bloom, Brian	Allegheny Power	Transmission Owner
Bowland, Patrick	Integrys Energy Services	Other Supplier
Buffington, Mike	City of Geneva, IL	Generation Owner
Burkmier, Matt	Invaluable Technologies	Not Applicable
Cadoret, Joshua	Potomac Electric Power Company	Electric Distributor
Caron, Scott	Commonwealth Edison Company	Transmission Owner
Caster, Rory	Constellation Energy Commodities Group, Inc.	Transmission Owner
Chin, Brian	Citi	Not Applicable
Cicero, Nick	FirstEnergy Solutions Corp.	Transmission Owner
Clay, Carlos	Federal Energy Regulatory Commission	Not Applicable
Cross, Jason	Public Utilities Commission of Ohio/OPSI	Not Applicable
Currier, Jeff	Virginia Electric & Power Company	Transmission Owner
Doggett, Tom	Calico Energy	Not Applicable
Edwards, Troid	Landis+Gyr	Electric Distributor
Ellis, Jeffrey	Edison Mission Marketing and Trading, Inc.	Generation Owner
Everngam, Scott	Federal Energy Regulatory Commission	Not Applicable
Feierabend, Rick	Dominion	Generation Owner
Ford, Adrien	PJM Interconnection	Not Applicable
Frantz, Robert	City of Geneva, IL	Generation Owner
Garg, Rishi	NRDC/FERC Project	Not Applicable
Glennon, Jim	PJM Interconnection	Not Applicable
Godson, Gloria	Conectiv Energy Supply, Inc.	Electric Distributor
Hamilton, Brian	Uni-Solar	Not Applicable
hanley, maria	US DOE - NETL	Not Applicable
Harwood, Matt	KOREnergy, Ltd.	Other Supplier
Haun, Chris	New Jersey Board of Public Utilities	Not Applicable
Horning, Lynn	PJM Interconnection	Not Applicable
Horstmann, John	Dayton Power & Light Company (The)	Transmission Owner
Huff, Gerald	FirstEnergy Solutions Corp.	Transmission Owner
Huntoon, Stephen	NextEra Energy Power Marketing, LLC	Generation Owner
Hyzinski, Tom	PPL Energy Plus, LLC	Transmission Owner
Jaramillo, Gilbert	Northern Virginia Electric Cooperative - NOVEC	Electric Distributor
Jeremko, Steven	New York State Electric & Gas Corporation	Other Supplier
Kachroo, Harpreet	Invaluable Technologies	Not Applicable
Kampila, Stephen	North American Energy Lines	Not Applicable
Kirchman, Brian	Commonwealth Edison Company	Transmission Owner
Kramskaya, Tatyana	Federal Energy Regulatory Commission	Not Applicable
Krohn, Kerri	OUCC	Not Applicable
Lee, George	BJ Energy	Other Supplier
Leiss, Jeff	Edison Mission Marketing and Trading, Inc.	Generation Owner
McCurley, Paul	NRECA	Not Applicable
McDonald, Mike	Edison Mission Marketing and Trading, Inc.	Generation Owner
Miller, Don	FirstEnergy Solutions Corp.	Transmission Owner
Miller, John	Commonwealth Edison Company	Transmission Owner
Mork, Robert	The Indiana OUCC	Not Applicable

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PJM Symposium on Demand Response III
November 9-10, 2009
Participant List

Participant	Company/Organization	Sector
Nowicki, Linda	New Jersey Board of Public Utilities	Not Applicable
O'Connell, Robert	JP Morgan Ventures Energy Company	Other Supplier
Pizzutelli, Ashley	Allegheny Power	Transmission Owner
Prendergast, Mike	Public Service Electric & Gas Company	Transmission Owner
Raff, Richard	Kentucky Public Service Commission	Not Applicable
Raja, Rajiv	Viridity Energy, Inc.	Other Supplier
Schum, Alice	Illinois Municipal Electric Agency	Electric Distributor
Sfaralev, Mechrudon	Dominion	Generation Owner
Shaughnessy, David	University of Maryland	Not Applicable
Simms, Chris	Downes Associates, Inc.	Other Supplier
Snow, Robert	Federal Energy Regulatory Commission	Not Applicable
Snowberger, Yasmin	PA Public Utility Commission	Not Applicable
Steiner, Evan	Constellation Energy Commodities Group, Inc.	Transmission Owner
Taborkski, Craig	Maryland Public Service Commission	Not Applicable
Thomas, Glenn	GT Power Group	Not Applicable
Tiernan, Tom	Platts	Not Applicable
Varnell, John	Tenaska Power Services Co.	Generation Owner
Vayda, Brian	American PowerNet Management, L.P.	End Use Customer
Vickery, Chris	Acciona	Generation Owner
Wang, David	PECO Energy Company	Transmission Owner
Whitehead, Jeff	Customized Energy Solutions, Ltd.*	Not Applicable
Williams, Jeffrey	PJM Interconnection	Not Applicable
Wisersky, Wisersky	Madison Gas & Electric	Other Supplier
Wright, Payton	Meadow Lake Wind Farm LLC	Generation Owner
Xenopoulos, Damon	BBRS (Law)	Not Applicable
Alesius, Alan	PJM Interconnection	Not Applicable
Allen, Travis	Federal Energy Regulatory Commission	Not Applicable
Anders, David	PJM Interconnection	Not Applicable
Applebaum, David	NextEra Energy Power Marketing, LLC	Generation Owner
Armstrong, Robert	Maryland Public Service Commission	Not Applicable
Arsanjani, Foroud	North America Power Partners LLC	Other Supplier
Ashley, Chris	EnerNOC, Inc.	Other Supplier
Atkins, Robert	Potomac Electric Power Company	Other Supplier
Aviles, Jezabel	DoD	Not Applicable
Barrow, Kim	PA Public Utility Commission	Not Applicable
Bassett, Jeffrey	BP Energy Company	Other Supplier
Benchek, Jim	FirstEnergy Solutions Corp.	Transmission Owner
Bennett, Stephen	Exelon Energy Company	Transmission Owner
Blackburn, Don	NTCI	Not Applicable
Bloom, David	Baltimore Gas and Electric Company	Transmission Owner
Bohmholdt, Andrea	Maryland Public Service Commission	Not Applicable
Borden, Michael	Enerwise Global Technologies, Inc.	Other Supplier
Borlick, Robert	Borlick Associates	Not Applicable
Boston, Terry	PJM Interconnection	Not Applicable
Boyle, Stephen	PJM Interconnection	Not Applicable
Brenner, Lawrence	Maryland Public Service Commission	Not Applicable
Bresler, Stu	PJM Interconnection	Not Applicable
Brinch, Jeannette	Energetics Incorporated	Not Applicable
Broms, J. B.	Accenture	Not Applicable
brown, david	Virginia Electric & Power Company	Transmission Owner

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Participant List

Participant	Company/Organization	Sector
Brown, Kriss	Public Utility Commission	Not Applicable
Brownstein, Mark	Environmental Defense Fund	Not Applicable
Bugica, Joseph	EnergyConnect, Inc.	Other Supplier
Buttner, Sarah	Division of the Public Advocate of the State of Delaware	End Use Customer
Campbell, Bruce	EnergyConnect, Inc.	Other Supplier
Carmean, Gregory	Maryland Public Service Commission	Not Applicable
Carswell, Dave	Ziphany, LLC	Not Applicable
Cavanaugh, David	ISO New England	Not Applicable
Centolella, Paul	Public Utilities Commission of Ohio/OPSI	Not Applicable
Chandler, Priscilla	PJM Interconnection	Not Applicable
Chase, Michael	Energy Curtailment Specialists, Inc.	Other Supplier
Chiu, But	AREVA T & D INC.	Not Applicable
Clark, Lou	Evapco, Inc	Not Applicable
Cohen, Tristan	Federal Energy Regulatory Commission	Not Applicable
Coutu, Ronald	ISO New England	Not Applicable
Covino, Susan	PJM Interconnection	Not Applicable
Davis, Phil	Schneider Electric	Not Applicable
Dessender, Harry	PJM Interconnection	Not Applicable
Dickerson, Glenn	PPL Electric Utilities Corporation d/b/a PPL Utilities	Transmission Owner
Dillard, Janis	Delaware Public Service Commission	Not Applicable
dodrill, keith	US DOE - NETL	Not Applicable
Dorn, Andrew	Demand Response Partners, Inc.	Other Supplier
Dorn, Drew	Demand Response Partners, Inc.	Other Supplier
Dotter, Ray	PJM Interconnection	Not Applicable
Eber, Jim	Commonwealth Edison Company	Transmission Owner
Elliott, Sherman	Illinois Commerce Commision	Not Applicable
Ellis, David	Enerwise Global Technologies, Inc.	Other Supplier
Evans, Kevin	EnergyConnect, Inc.	Other Supplier
Falco, Christine	PJM Interconnection	Not Applicable
Falin, Tom	PJM Interconnection	Not Applicable
Faruqui, Ahmad	The Brattle Group	Not Applicable
Feldman, Brett	Constellation New Energy	Other Supplier
Fernandez, Jonathan	Federal Energy Regulatory Commission	Not Applicable
Filomena, Guy	Customized Energy Solutions, Ltd.*	Not Applicable
Fitch, Neal	RRI Energy Services, Inc.	Generation Owner
Flaherty, Dale	Duquesne Light Company	Transmission Owner
Foster, Denise R.	PJM Interconnection	Not Applicable
Fratis, Larry	Defense Energy Support Center	Not Applicable
Freeman, Al	Michigan Public Service Commissioner	Not Applicable
Fuess, Jay	Premcor Refining Group, Inc. (The)	Generation Owner
Ganesh, Jai	Mirant Energy Trading, LLC	Generation Owner
Gannon, Tricia	Delmarva Power & Light Company	Electric Distributor
Giles, Lauren	Energetics Incorporated	Not Applicable
Gockley, Beatrice	PJM Interconnection	Not Applicable
Godfrey, Crissy	Maryland Public Service Commission	Not Applicable
Goff, Diane	Potomac Electric Power Company	Electric Distributor
Greening, Michele	PPL Energy Plus, LLC	Transmission Owner
Guerry, Katie	Hess Corporation	Other Supplier
Gulhar, Neel	Baltimore Gas and Electric Company	Transmission Owner
Hanks, Marc	Direct Energy Services, LLC	Other Supplier

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Hann, Shannon	ISO New England	Not Applicable
harper, stacia	Ohio Consumers' Counsel	End Use Customer
Hebson, Jim	PSEG Energy Resources and Trade LLC	Other Supplier
Hellman, Jeremy	Divine Capital	Not Applicable
Hewett, Christopher	Virginia Electric & Power Company	Transmission Owner
Hillman, Todd	Unknown	Unknown
Hoeger, Brian	Exelon Energy Company	Transmission Owner
Hogan, Don	Direct Energy Services, LLC	Other Supplier
Holbery, James	GridMobility LLC	Not Applicable
Holbrook, Christopher	Unknown	Unknown
Huber, Ken	PJM Interconnection	Not Applicable
Hutchison, Larry	American Electric Power	Electric Distributor
Icart, Eric	Federal Energy Regulatory Commission	Not Applicable
Iyengar, Raja	EBiz Labs Inc.	Not Applicable
Jesensky, Michael	Virginia Electric & Power Company	Transmission Owner
Jones, Kimberly	NC Utilities Commission	Not Applicable
Kafka, Dick	Potomac Electric Power Company	Electric Distributor
Kane, Michael	Penncat Corporation	Other Supplier
Kerzner, Dan	EnerNOC, Inc.	Other Supplier
Khammal, Leanne	Federal Energy Regulatory Commission	Not Applicable
Killeen, Andrew	EnerNOC, Inc.	Other Supplier
Kimmel, Elizabeth	Kimmel Energy Associates	Not Applicable
Kirn, Deanna	Virginia Electric & Power Company	Transmission Owner
Kovach, Mike	FirstEnergy Solutions Corp.	Transmission Owner
Krauthamer, Michael	Maryland Public Service Commission	Not Applicable
Kueck, John	Oak Ridge National Laboratory	Not Applicable
Kumar, Jayant	Unknown	Unknown
Langbein, Pete	PJM Interconnection	Not Applicable
Lanier, Ivan	Direct Energy Services, LLC	Other Supplier
LaRocque, Matthew	PJM Interconnection	Not Applicable
Lee, Michael	Maryland Public Service Commission	Not Applicable
Levy, Roger	Levy Associates	Not Applicable
Lowe, Will	Potomac Electric Power Company	Electric Distributor
Lozano, Melissa	Federal Energy Regulatory Commission	Not Applicable
Manion, Evelyn	PJM Interconnection	Not Applicable
Marmet, Rob	Piedmont Environmental Council	Not Applicable
Mathias, Richard	PJM Interconnection	Not Applicable
Maucher, Andrea	Delaware Public Service Commission	Not Applicable
McCartha, Esrick	PJM Interconnection	Not Applicable
McDaniel, Bryan	Illinois Citizen Utility Board	End Use Customer
McDaniel, John	Baltimore Gas and Electric Company	Transmission Owner
McDonald, James	Miratech Corporation	Not Applicable
McNamara, Sean	PJM Interconnection	Not Applicable
Messick, Scion	Potomac Electric Power Company	Electric Distributor
Miles, Paul	PECO Energy Company	Transmission Owner
Montalvo, Marc	ISO New England	Not Applicable
Mosier, Kevin	Maryland Public Service Commission	Not Applicable
Mount, Colin	Allegheny Energy Supply	Transmission Owner
Munson, Michael	Metropolitan Energy, L.L.C.	Other Supplier
Musilek, Jim	North Carolina Electric Membership Corporation	Electric Distributor

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Participant	Company/Organization	Sector
Nguyen, Quang	Kentucky Public Service Commission	Not Applicable
Nix, Michael	PJM Interconnection	Not Applicable
nollenberger, matt	Appalachian Power Company	Transmission Owner
Nudell, Ary	Ohms Energy	Other Supplier
O'Neill, Jack	PJM Interconnection	Not Applicable
Parikh, Lopa	Old Dominion Electric Cooperative	Electric Distributor
Paronish, April	Indiana Office of Utility Consumer Counselor (IN OUCC)	End Use Customer
Pasch, Carrie	Energy Spectrum	Other Supplier
Patt, Dan	AREVA T & D INC.	Not Applicable
Pino, William	Baltimore Gas and Electric Company	Transmission Owner
Pore, Amery	Federal Energy Regulatory Commission	Not Applicable
Quin, Jane	Rockland Electric Company	Transmission Owner
Reed, Harvey	Ruxton Consulting, LLC	Not Applicable
Regan, Dennis	PJM Interconnection	Not Applicable
Reisman, Ronald	New Jersey Board of Public Utilities	Not Applicable
Roberts, Jackie	EnerNOC, Inc.	Other Supplier
Robinson, Evelyn	PJM Interconnection	Not Applicable
Roth, Ken	Government	Not Applicable
Rutigliano, Tom	Cpower	Other Supplier
Scarp, na	Old Dominion Electric Cooperative	Electric Distributor
Scheck, Greg	Public Utilities Commission of Ohio/OPSI	Not Applicable
Schleiden, Jeanine	PJM Interconnection	Not Applicable
Sedano, Richard	Regulatory Assistance Project	Not Applicable
Siegrist, Hal	Mirant Potomac River, LLC	Generation Owner
Sotkiewicz, Paul	PJM Interconnection	Not Applicable
Spinner, Howard	Virginia State Corporation Commission	Not Applicable
Stewart, Courtney	Delaware Public Service Commission	Not Applicable
Stippler, David	Indiana Office of Utility Consumer Counselor (IN OUCC)	End Use Customer
Stroup, Kerry	PJM Interconnection	Not Applicable
Sunderhauf, Steve	Potomac Electric Power Company	Electric Distributor
Tatum, Ed	Old Dominion Electric Cooperative	Electric Distributor
Thomas, Chris	Illinois Citizen Utility Board	End Use Customer
Timblin, Stanley	PowerSecure, Inc.	Other Supplier
Timmerman, Calvin	Maryland Public Service Commission	Not Applicable
Tracy, Anne	Dominion Energy Marketing, Inc.	Generation Owner
Trayers, Barry	Sempra Energy Trading, LLC	Other Supplier
Trott, Jed	Customized Energy Solutions, Ltd.*	Not Applicable
Tudor, Daniel	Potomac Electric Power Company	Electric Distributor
Urbin, Greg	Baltimore Gas and Electric Company	Transmission Owner
Van Horn, James	Potomac Electric Power Company	Electric Distributor
Walker, Kent	Division of the Public Advocate of the State of Delaware	End Use Customer
Warner, Andrew	EnergyConnect, Inc.	Other Supplier
Wattles, Paul	Unknown	Unknown
Webster, John	Monitoring Analytics, LLC	Not Applicable
West, Bri	Piedmont Environmental Council	Not Applicable
Whiffen, Richard	Wellspring Wireless	Other Supplier
White, Carol Brotman	Federal Energy Regulatory Commission	Not Applicable
White, Sheirmiar	Ohms Energy	Other Supplier
Wight, Dean	Federal Energy Regulatory Commission	Not Applicable
Winslow, Dallas	Delaware Public Service Commission	Not Applicable

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Wise, Emily	Washington Gas Energy Services, Inc.	Other Supplier
Withrow, David	PJM Interconnection	Not Applicable
Wolfson, Jennifer	Federal Energy Regulatory Commission	Not Applicable
Wood , Lisa	Edison Foundation	Not Applicable
Yeaton, Andrea	PJM Interconnection	Not Applicable
York, Amy	EnerNOC, Inc.	Other Supplier
Zientara, Mary	Reliant Energy	Electric Distributor
Fields, Bill	Maryland People's Council	Not Applicable
Jeffries, Dawn	Merrill Lynch	Other Supplier
McCrae, Candace	Honeywell Utility Solutions	Not Applicable
Mitchell, Miles	Maryland Public Service Commission	Not Applicable
Mitchell, Paul	Energy Systems Network	Not Applicable
Tigue, John	New York State Electric & Gas Corporation	Other Supplier
Wiegand-Jackson, Laurie	North America Power Partners LLC	Other Supplier

Appendix F. AMI Pilot Programs in the PJM Footprint

AMI Pilot Programs in the PJM Footprint *(as of November 4, 2009)*

Energy Smart Pricing Program Commonwealth Edison (ComEd)

Description: ComEd began a voluntary program with 1,500 households in 2003, using Interval Recording Meters.

Contact Information: Anthony Star, 773-269-4017, astar@cnt.org

Start / End Dates: 2003 to 2006

Program Administrator and Contact Information: Community Energy, 773-269-4017

AMI Solution / Product Used: ABB Interval Recording Meters that ComEd already had deployed were used, read once per month manually.

Evaluation Process and Responsible Parties/Experts: Summit Blue Consulting did a third party evaluation to determine whether energy use changed due to peak pricing. Higher prices were found to result in reduced consumption.

Results and/or Lessons Learned: Over the life of the program, average savings were 10%, with peak reductions of 15-20% in addition to a small conservation effect. The Illinois Legislature passed a law in 2006 requiring that the state's two large utilities offer a residential real-time pricing program, subsidize the cost of advanced meters, and make a Program Manager available to interface with customers.

Next Steps: The "Power Smart Pricing" and "WattSpot" programs have been implemented due to the success of the pilot. The programs were implemented in 2007.

Smart Energy Savers Program Baltimore Gas & Electric (BGE)

Description: The AMI Pilot is a part of the BGE Smart Energy Savers Program, a Vision 2020 initiative. AMI is one of four projects aimed at improving BGE's operational efficiency, reducing customer peak energy demand, and reducing customer energy usage. AMI is foundational to other Vision 2020 initiatives such as Customer Experience, Proactive Customer Notification, Advanced Collection Practices, and more. AMI technologies establish two-way communication between the customers' meters and the BGE back office. This technology enables greater levels of functionality and customer service by providing remote daily meter data and on-demand communication access to the meters.

Contact Information: Mitchell Solkowitz, 410-470-1389, Mitchell.Solkowitz@bge.com

Start / End Dates: November 2007 to November 2008

Sponsor(s) and Contact Information: No external sponsors

AMI Solution / Product Used: Aclara RF, Sensus FlexNet, and Oracle MDM

Evaluation Process and Responsible Parties/Experts: An evaluation process will determine how well the AMI technologies have worked based on manufacturers' specifications. Additionally, the process will determine whether the pilot meets the requirements of BGE and the Maryland Public Service Commission (PSC).

Results and/or Lessons Learned: Results are not yet determined.

Next Steps: The pilot program was completed, and BGE submitted its proposal for a full-scale AMI deployment, installing more than 2 million meters, to the Maryland PSC. BGE was awarded a $200 million Smart Grid Investment Grant for this deployment and the grant is contingent upon the proposal being approved by the Commission.

PPL Corporation

Description: This initiative is a summertime rate program targeted at residential customers who consume at least 1,000 kWh/month for the four summer months (June through September). A rate rider applies to the normal residential service charge and replaces the existing declining block service charge with flat, cent-per-kWh on-peak and off-peak charges during these four months.

Contact Information: Doug Krall, 610-774-5736, dakrall@pplweb.com

Start / End Dates: June 2002 to October 2010

Sponsor(s) and Contact Information: No outside sponsors

AMI Solution / Product Used: Aclara TWACS

Evaluation Process and Responsible Parties/Experts: Evaluations take place annually; customer surveys were conducted in the initial years.

Results and/or Lessons Learned: Between 60% and 70% of participants have saved money. Additionally, customers involved in the program have consumed 19% of their kWh during the peak, whereas the average customer of the same type has consumed 24% of their kWh during the peak.

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A small conservation effect may also exist due to participants having a "green ethic."

Next Steps: In June 2008, the pilot doubled in size from 300 to 600 participants. In 2010, a year-round version of the program will be offered. In September 2008, PPL filed with the Pennsylvania Public Utility Commission for approval of another TOU pilot for residential customers. This program would offer year-round (summer and non-summer seasons) on-peak and off peak pricing for 1,200 customers.

Philadelphia Electric Company (PECO)

Description: PECO has deployed 2.2 million advanced meters, both for electricity and gas customers in residential and large commercial/industrial customer classes.

Contact Information: David Glenwright, 215-841-6174, david.glenwright@exeloncorp.com

Start / End Dates: The installation project lasted from 1999 to 2003.

Sponsor(s) and Contact Information: PECO, Cellnet, and VSI performed installation.

AMI Solution / Product Used: The Cellnet Fixed Network solution is used for 2.2 million meters. MV-90 and Metretek is used for 3,000 large C&I customers.

Evaluation Process and Responsible Parties/Experts: Cellnet manages the network, performs meter maintenance, and provides data to PECO. All meters are read daily. Additional features include on-demand reads and event processing.

Results and/or Lessons Learned: AMR has been shown to reduce the number of estimated bills, improve the meter to cash cycle, increase revenue, reduce CAIDI and customer call volumes, and increase asset utilization, among others.

Next Steps: PECO is planning to launch an AMI installation. In August 2009, the company filed their plan with the Pennsylvania Public Utility Commission. The plan is to build an AMI and provide meters for 600,000 customers by 2012 and all 1.6 million customers in 10 years. PECO has been awarded a $200 million federal Smart Grid Investment Grant for part of the cost share of the $650 million project, and the grant is contingent upon the proposal approval by the Commission.

myPower Pilot Program, PSE&G

Description: The objective of the "myPower" pilot program was to understand the potential for changing the way customers think about energy delivery and consumption via the use of two-way communication technologies. This provided customers with additional consumption information and more flexible pricing options (TOU rates) so that customers could make more informed decisions on energy use. Some pilot customers were provided with in-home energy management technology (Smart Thermostats) in order for PSE&G to better understand the value it brings to this two-way communication exchange. The pilot included educational materials to help customers understand the energy consumption "cause and effect" relationship.

Contact Information: Susanna Chiu, 973-430-5719, and Fred Lynk, 973-430-8155

Start / End Dates: June 2006 to September 2007

Sponsor(s) and Contact Information: No outside sponsors

AMI Solution / Product Used: Three different AMI solutions were utilized: Power Line Carrier, RF Fixed Network Solution, and a hybrid solution (RF Page combined with the customer's telephone line).

Evaluation Process and Responsible Parties/Experts: Summit Blue Consulting conducted an executive summary and impact assessment. SRBI conducted customer surveys. PSE&G conducted other analyses (technical, operations, rates and tariff, bill impacts).

Results and/or Lessons Learned:

- "myPower" Pricing participants consistently lowered their energy use in response to price signals across two summers (peak demand reduction of 1.33 kW was observed for those with in-home technology, and 0.32 to 0.43 kW for those without in-home technology).
- During the summer, daily reductions in energy use occurred from 1:00 p.m. to 6:00 p.m. due to on-peak prices associated with the TOU rate.
- During CPP events, customers increased their load reductions during the 1:00 p.m. to 6:00 p.m. period.
- Participants achieved summer period energy savings of 3-4% when compared to the Control Group.
- Technology-enabled customers produced greater reductions in energy use in response to the TOU rates and the CPP events.
- The majority of participants achieved bill savings – 87% of those with in-home technology and 68% of those without in-home technology.
- "myPower" Pricing participants would recommend the program to a friend or relative. The participants believe they saved money, that the program is good for the environment, and that PSE&G should offer more programs similar to myPower.

Next Steps: Key findings from the pilot program will be used to inform the PSE&G AMI business case.

Residential Smart Metering Pilot – PowerCentsDC, Pepco

Description: The District of Columbia Residential Smart Metering Pilot is designed to test three different types of dynamic pricing rates (hourly, CPP, and CP Rebate) coupled with smart thermostat controls. The program's official name is PowerCentsDC.

Contact Information: Chris King, eMeter Strategic Consulting, 510-435-5189

Start / End Dates: Billing began in July 2008, and the duration is approximately two years.

Sponsor(s) and Contact Information: The Smart Meter Pilot Program Inc. (SMPPI) is a consortium formed under a Pepco merger settlement agreement and includes Pepco, DC OPC, DC PSC, DC Consumer Utility Board, and International Brotherhood of Electrical Workers.

- SMPPI: DC PSC Commissioner Rick Morgan, 202-626-5118, serves as Chair
- Pepco: Steve Sunderhauf, 202-872-3507
- DC OPC: Laurence Daniels, 202-727-3071

AMI Solution / Product Used: AMDS/Sensus

Evaluation Process and Responsible Parties/Experts: The SMPPI Board will select this.

Results and/or Lessons Learned: Pending

Next Steps: Start of billing and selection of evaluation contractor

Delmarva Power (Delmarva)

Description: Delmarva began deploying an advanced metering infrastructure, including 10,000 meters, on April 1, 2009. The deployment is part of Delmarva's "Blue Print for the Future" Plan for demand side management, advanced metering, and energy efficiency. Delmarva would like to accomplish a number of targets, including eliminating meter readers and having the ability to remotely access the meters. Initially, however, the company will be manually reading the meters and accurately measuring the usage of the customers.

Contact Information: Len Veck, 302-454-4839

Start / End Dates: The start date was April 1, 2009, with a project duration of approximately two years.

Sponsor(s) and Contact Information: No sponsors

AMI Solution / Product Used: GE Energy Smart Meters

Evaluation Process and Responsible Parties/Experts: Delmarva will initially evaluate the meters by reading them manually.

Results and/or Lessons Learned: Pending

Next Steps: Deployment of the meters and evaluation of the results

AEP (Indiana & Michigan Power)

Description: Indiana & Michigan Power (I&M) began installing nearly 10,000 General Electric Smart Meters in selected homes and businesses in the City of South Bend, Indiana, during the fall of 2008, with intended full deployment by January 1, 2010. The program will include two programs that have rate options: SMART Shift and SMART Cooling. SMART Shift is a time-of-day rate plan, and SMART Cooling is a program that includes a smart thermostat that can adjust air conditioners to conserve electricity. The project will be the first deployment of Smart Grid technologies that AEP could implement in model cities across the company's 11-state service territory. AEP and GE Energy, a business unit of General Electric, will pursue the development, integration, and deployment of advanced energy delivery infrastructure and metering technologies. The Indiana Office of Utility Consumer Counselor is also conducting a part in the pilot project.

Contact Information: Kent Curry, 260-425-2119

Start / End Dates: January 2009 to 2010

Sponsor(s) and Contact Information: No sponsors

AMI Solution / Product Used: GE Energy kV2c Meter Equipped (first deployment of this type of meter) with the Silver Spring Networks PowerPoint Network Interface Module

Evaluation Process and Responsible Parties/Experts: I&M plans to do the evaluation with internal resources.

Results and/or Lessons Learned: No customer lessons have been learned as of yet. Some barriers have been faced due to the new technology, but I&M believes that this is because of the novelty of the system. I&M has continued to work with its vendors to overcome technical issues with the meters and the systems. In large part, things have gone pretty well, and I&M is staying on a timetable that is acceptable to everyone.

Next Steps: I&M intends to go live on the distribution model piece of the pilot. The price tariffs are already available to consumers and have been approved by the Indiana Utility Regulatory Commission (IURC). The next step will be a direct load control program. The IURC has approved the load tariff. I&M is in the direct load control phase of the deployment with programmable thermostats installed in interested customers' homes. These thermostats will be able to communicate with appliances in the customers' homes and cycle-up and cycle-down according to the directions given by the programmable thermostats.

Appendix G. State Goals for Energy Efficiency and Demand Response in the PJM Footprint

State Goals for Energy Efficiency and Demand Response in the PJM Footprint – *as of November 4, 2009*

State	Energy Efficiency (Energy Use Reduction) Goal	Demand Response (Peak Load Reduction) Goal
Delaware	2% by 2011 and 15% by 2015 (base year 2007)	2% by 2011 and 15% by 2015 (base year 2007)
District of Columbia	None in place or proposed	None in place or proposed
Illinois	Incremental energy savings of 0.2% (two tenths of one percent) each year over the prior year from 2008 to 2015 (2% by 2015 and every year thereafter)	Reduction of 0.1% (one tenth of one percent) over the prior year each year for 10 years (starting in 2008) for eligible retail customers
Indiana	None in place or proposed	None in place or proposed
Kentucky[1]	Offset at least 18% of the state's projected 2025 energy demand	Offset at least 18% of the state's projected 2025 energy demand
Maryland	5% by the end of 2011 and 10% by the end of 2015 in per capita electricity consumed in each electric company's service territory during 2007 5% reduction by the end of 2015 in per capita electricity consumed (Maryland Energy Administration)	5% by the end of 2011, 10% by the end of 2013, and 15% by the end of 2015 in per capita peak demand of electricity consumed in each electric company's service territory during 2007
Michigan	0.3% energy savings of 2007 total annual retail electricity sales (2008-2009), 0.5% energy savings of preceding year sales (2010), 0.75% energy savings of preceding year sales (2011), and 1.0% energy savings of preceding year sales (2012 and each year thereafter)	0.3% energy savings of 2007 total annual retail electricity sales (2008-2009), 0.5% energy savings of preceding year sales (2010), 0.75% energy savings of preceding year sales (2011), and 1.0% energy savings of preceding year sales (2012 and each year thereafter)
New Jersey[2]	20% by 2020 (starting in 2010)	5,700 MW[3] by 2020 (starting in 2010)

[1] Goals in statewide energy plan, not legislation
[2] Goals in New Jersey's *Energy Master Plan*, not legislation
[3] A combination of energy efficiency (3,300 MW), combined heat and power (1,500 MW), and demand response programs (900 MW)

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State	Energy Efficiency (Energy Use Reduction) Goal	Demand Response (Peak Load Reduction) Goal
North Carolina	Energy efficiency and renewable energy power savings of 3% of prior-year electricity sales in 2012, 6% in 2015, 10% in 2018, and 12.5% in 2021 and thereafter; energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target (electric public utilities) Energy efficiency and renewable energy power savings of 3% of prior-year electricity sales in 2012, 6% in 2015, 10% in 2018 and thereafter (electric membership corporations and municipalities)	None in place or proposed
Ohio	Savings of at least 0.3% of the total, annual average and normalized kWh sales of the electric distribution utility during the preceding three calendar years to customers in the state, an additional 0.5% in 2010, 0.7% in 2011, 0.8% in 2012, 0.9% in 2013, 1% from 2014 to 2018, and 2% each year thereafter, achieving a cumulative, annual energy savings in excess of 22% by the end of 2025	1% in 2009 and an additional 0.75% each year through 2018
Pennsylvania	1% of 2009-2010 sales by May 31, 2011, increasing to 3% by May 31, 2013 (10% of reductions is to come from federal, state, and local government, including municipalities, school districts, institutions of higher education, and nonprofit entities)	4.5% of 2009-2010 sales by May 31, 2013 (10% of reductions is to come from federal, state, and local government, including municipalities, school districts, institutions of higher education, and nonprofit entities)
Tennessee	None in place or proposed	None in place or proposed
Virginia	10% (from 2006 levels) by 2022	None in place or proposed
West Virginia	Earn credits equivalent to 10% of the electric energy sold in the prior year (2015-2019), 15% (2020-2024), and 25% (2025 and thereafter); one credit earned for each MWh conserved	Earn credits equivalent to 10% of the electric energy sold in the prior year (2015-2019), 15% (2020-2024), and 25% (2025 and thereafter); one credit earned for each MWh conserved

Sources: PJM, ACEEE, FERC, Delaware General Assembly, Michigan Legislature, New Jersey's *Energy Master Plan*, North Carolina General Assembly, Ohio General Assembly, West Virginia Legislature

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Appendix H. Web Links

California Demand Response Research Center: http://drrc.lbl.gov/

Federal Energy Regulatory Commission: www.ferc.gov

Institute for Electric Efficiency, a Program of the Edison Foundation:
http://www.edisonfoundation.net/iee/issueBriefs/index.htm

ISO/RTO Council: www.isorto.org

MADRI: www.energetics.com/madri

National Association of Regulatory Utility Commissioners: www.naruc.org

National Conference of State Legislatures: www.ncsl.org

National Governors Association: www.nga.org

National Institute of Standards and Technology: www.nist.gov

North American Energy Standards Board: www.naesb.org

Organization of MISO States Demand Response & Technology Work Group:
http://www.misostates.org/WG10Activitypage.htm

PJM Demand Response: http://www.pjm.com/markets-and-operations/demand-response.aspx

PJM Demand Response Symposium III: http://www.pjm.com/committees-and-groups/stakeholder-meetings/symposiums-forums/drs.aspx#1

RAP: www.raponline.org

U.S. Department of Energy: http://www.oe.energy.gov/demand.htm