Division 2-20

Request:

Refer to page 7 of Chapter 4 – AMF in PST-1, where it states that after the transition to TVR, "the Company will continue to work with customers to educate them about their bills and assist them in accessing and using the tools available to understand and control their energy use." Please provide descriptions of the programs that the Company intends to implement to assist customers in understanding their bills and the tools available to them.

Response:

Please refer to *Section 6.1 Customer Engagement (Education & Outreach)*, beginning on Page 20 of Schedule PST-1, Chapter 4 – AMF (Bates Page 88 of PST Book 1), and specifically *Section 6.1.2 Supporting Communications and Tactics*, beginning on Page 22 of Schedule PST-1, Chapter 4 – AMF (Bates Page 90 of PST Book 1), which provide details on the different types of communication channels and methods that will be used in the education and outreach efforts prior, during, and post installation of meters, including the education of customers about time varying rates.

Additionally, the Energy Management Portal is a tool that the Company will promote to customers to help them better understand and control their energy usage and costs. Details of the Energy Management Portal are provided in *Section* 1.3.3 *Customer Engagement Products and Services* on Page 10 of *Appendix 4.1 – AMF Technology & BCA, REDACTED* (Bates Page 11 of PST Book 2).

Furthermore, the Company, where appropriate, will leverage its existing energy efficiency programs to assist customer understanding of bills and the tools available to them.

(This response is identical to the Company's response to Division 8-20 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-21

Request:

Refer to page 9 of Chapter 4 – AMF in PST-1 regarding joint deployment of AMF.

a. Has the Company evaluated potential joint AMF deployment with National Grid's Massachusetts affiliate instead of joint deployment with Niagara Mohawk? If so, please provide all workpapers, workbooks, and calculations from these evaluations in machine-readable format with formulas intact.

b. Has the Company evaluated potential joint deployment scenarios between Rhode Island and multiple National Grid affiliates? If so, please provide all workpapers, workbooks, and calculations from these evaluations in machine-readable format with formulas intact.

c. Please provide all workpapers, workbooks, and calculations in machine-readable format with formulae intact that were used in the development of Table 4-1: Estimated Costs for the Rhode Island Only Scenario and Table 4-2 Estimated Costs for the Multi-Jurisdiction Scenario.

Response:

a. No, the Company has not evaluated potential joint AMF deployment with National Grid's Massachusetts affiliates instead of joint deployment with Niagara Mohawk Power Corporation.

b. No, the Company has not evaluated potential joint deployment scenarios between Rhode Island and multiple National Grid affiliates.

c. Please see Attachment DIV 1-1-1 and Attachment DIV 1-1-2 provided in the Company's response to Division 1-1.

(This response is identical to the Company's response to Division 8-21 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-22

Request:

Refer to page 10 of Chapter 4 – AMF in PST-1, in which the modern grid experience is discussed as needing to address six customer needs: Reliability, Affordability, Visibility, Control, Choice, and Convenience. Please provide descriptions of how the proposed AMF deployment will address each of these customer needs.

Response:

The Advanced Meter Functionality (AMF) proposal addresses each of those customer needs in the following ways:

Reliability: AMF will provide the Company with better visibility into outages, improving the efficiency of the restoration operations, and the outage experience for customers. Details on these operational improvements are provided in Appendix 4.1 – AMF Technology & BCA, REDACTED, Page 19 (Bates Page 20 of PST Book 2).

Affordability: The Company will provide more pricing options enabled by AMF and develop tools to help customers better manage their energy bills to achieve cost savings. Time varying pricing (TVP), as described on Page 22 of Appendix 4.1 – AMF Technology & BCA, REDACTED (Bates Page 23 of PST Book 2), will give customers the opportunity to shift their energy usage to lower cost periods. The Energy Management Portal (Portal), as described on Page 10 of Appendix 4.1– AMF Technology & BCA, REDACTED (Bates Page 11 of PST Book 2), will provide customers with greater visibility into their energy usage, insights, and high bill alerts, allowing customers to take action to adjust their consumption patterns before the bill arrives.

Through its Smart Energy Solutions AMF pilot program in Worcester, Massachusetts, National Grid found that customers achieved bill savings when provided with TVP and more visibility into their consumption. Please refer to "Lessons from our Smart Energy Solutions Pilot in Massachusetts" on Pages 18 -19 of Schedule PST-1, Chapter 4 - AMF (Bates Pages 86-87 of PST Book 1). In the Smart Energy Solutions AMF pilot, residential customers who enrolled in the default time-varying rate (time of use with critical peak pricing) achieved average per-customer bill savings of $236 over the two years of the pilot[1] and those who utilized the customer-centric energy management portal saved an incremental 10 percent in peak energy load during critical peak pricing hours, as well as an incremental 3-5 percent in annual energy savings, compared to those who did not access the portal.[2]

[1] Schedule PST-1, Chapter 4 - AMF, Page 18 (Bates Page 86 of PST Book 1).
[2] Appendix 4.1 – AMF Technology & BCA, REDACTED, Page 10 (Bates Page 11 of PST Book 2).

Prepared by or under the supervision of: John Leana

Visibility: National Grid customers will have access to relevant and actionable information as part of the AMF deployment through the development and implementation of the Portal. The web portal will provide timely, granular interval data and insights that are easily accessible and personalized to best enable behavioral changes and customer actions.

Control: The Company's expanded portfolio of customer engagement product and services will provide customers with better control over how and when they use and manage energy. The Portal itself and the broader platform, the Customer Engagement Management Platform, within which it will reside, will not only provide customers with access to personalized energy usage information, but also options to enroll in programs and services (such as energy efficiency, demand response, adoption of distributed generation and electric vehicles, and TVP) that leverage the more granular data provided by AMF deployment. Please refer to Page 12 of Appendix 4.1 – AMF Technology & BCA, REDACTED (Bates Page 13 of PST Book 2) for information on Customer Engagement Management Platform.

As noted on Page 12 of Schedule PST-1, Chapter 4 - AMF (Bates Page 80 of PST Book 1), AMF will allow customers to manage their energy consumption through the use of smart devices, which can also be integrated with home energy management systems. Customers will be able to control their energy remotely or via automation as well as authorize the Company or third-parties to adjust energy consumption in response to pricing signals and calls for curtailment.

Choice: AMF technology will enable the Company to provide customers with a greater level of choice for customers: from energy management to clean energy solutions to pricing options, as elaborated above. Customers can also customize when, how, and through which channels they receive information. In addition, customers will have expanded access to third party services.

Convenience: The web-based and mobile-based applications of the various customer engagement product and services will allow customers to conveniently access information "anytime, anywhere" to manage and optimize energy usage. The National Grid Contact Center channel will continue to be available to customers, providing information on energy use and programs offered, and offers tailored to their consumption patterns. The Company also plans to provide information through the channels that customers are already using, including social media.

(This response is identical to the Company's response to Division 8-22 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-23

Request:

Please describe the features of the energy management portal that is proposed on page 11 of Chapter 4 – AMF in PST-1.

Response:

For a description of the features of the proposed energy management portal, please see *Section 1.3.3 Customer Engagement Products and Services* on Page 10 of Appendix 4.1 – AMF Technology & BCA, REDACTED (Bates Page 11 of PST Book 2).

(This response is identical to the Company's response to Division 8-23 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-24

Request:

Please describe the ways in which AMF can offer insight into where and when DERs can provide the most value, and how the Company proposes to evaluate and compensate DERs for their locational and temporal values.

Response:

AMF provides interval customer usage data that can be aggregated by area, substation, feeder, or feeder segment to provide hourly load and voltage profiles to support distribution planning and the integration of distributed energy resources (DERs). AMF meter data can improve the accuracy of distribution feeder load flow analysis for DER interconnection studies, hosting capacity analysis, and the evaluation of DER as solutions to distribution needs, referred to as non-wires alternatives.

With respect to compensating DERs for their temporal values, the AMF data will assist in setting appropriate time-varying rates. For locational values, the data collected above will be used, along with other information (i.e., reliability and operational needs, projected cost of wires investments, etc.), to determine appropriate locational costs of and/or compensation to DERs. The exact process to determine these costs and/or compensation is not currently known, but the Company has committed in the recently approved 2018 System Reliability Procurement plan to develop this process going forward

(This response is identical to the Company's response to Division 8-24 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-25

Request:

Please provide a list of third-party companies that have expressed interested in acquiring customer data through the Green Button Connect My Data functionality.

Response:

The Company does not maintain a formal list of third-party companies that have expressed interest in acquiring data through the Green Button Connect My Data functionality.

(This response is identical to the Company's response to Division 8-25 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-26

Request:

Refer to page 17 of Chapter 4 – AMF in PST-1, which states: "the Company has reviewed the option to deliver time-varying rates through the existing AMR meters. […] the Company has found that, while delivering a basic time-varying rate option is technically feasible with AMR infrastructure, there are significant operational challenges and necessary capital upgrades that when compared to investment in AMF may make this option less beneficial to customers overall." Please provide the following in machine-readable format with formulas intact:

a. All workpapers, workbooks, and calculations that contributed to the conclusion that delivering time-varying rates through the existing AMR meters is less beneficial to customers than through investment in the Company's proposed AMF solution.

b. All operational challenges and necessary capital upgrades involved in delivering a basic time-varying rate option with AMR meters.

Response:

a. As outlined in Attachment DIV 2-26, the Company has 1,234 time-of-use AMR meters installed. The remaining installed AMR meters cannot support any form of time-varying rate options as there is no way to effectively communicate energy usage information from the meters to the office to support billing.

b. Please see the Company's response to Division 2-27.

(This response is identical to the Company's response to Division 8-26 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Electric Time-of-Use Meters by Rate Class		
Rate	Description	Count
A16	Elec A-16 Residential-Std Ofr	3
B32	Elec B-32 C&I 200 kW Back Up Svc-Std Ofr	5
B32	Elec B-32 T&D C&I 200 kW Back Up Svc	2
C06	Elec C-06 Small C&I-Std Ofr Fixed	65
C06	Elec C-06 Small C&I-Std Ofr Variable	1
C06	Elec C-06 T&D Small C&I	5
G02	Elec G-02 Large C&I-Std Ofr Fixed	1
G02	Elec G-02 Large C&I-Std Variable	40
G02	Elec G-02 T&D Large C&I	59
G32	Elec G-32 200 kW Dem PK/OP-Std Ofr	130
G32	Elec G-32 200 kW Dem PK/SH/OP-Std Ofr	125
G32	Elec G-32 T&D 200 kW Dem PK/OP	383
G32	Elec G-32 T&D 200 kW Dem PK/SH/OP	399
G62	Elec G-62 3000 kW Dem PK/OP-Std Ofr	2
G62	Elec G-62 T&D 3000 kW Dem PK/OP	5
G62	Elec G-62 T&D 3000 kW Dem PK/SH/OP	4
X01	Elec X01 T&D Elec Propulsion	1
ZZZ	Elec C0Z Company Use-Std Ofr	1
ZZZ	Elec G3Z Company Use-Std Ofr	3
	Total:	**1,234**

Division 2-27

Request:

Refer to page 18 of Chapter 4 – AMF in PST-1, which states: "A comparison of the costs and benefits of a triple ERT approach may provide lower net benefits to customers than the proposed AMF deployment." Has the Company or any of its consultants conducted a benefit-cost analysis of the upgrade to a triple ERT meter discussed on page 17 of Chapter 4 – AMF in PST-1? If so, please provide all workpapers, workbooks, and calculations of the analysis in machine readable format with formulas intact.

Response:

The Company's assessment of the merits of delivering time varying rates through AMR meters as compared to the proposed AMF solution was performed on a qualitative versus quantitative basis. Therefore, there are no workpapers, workbooks, and calculations that support the Company's conclusion. The following qualitative factors were considered by the Company in reaching its conclusion:

i. As outlined in Attachment DIV 2-27 provided with the Company's response to Division 2-27, the Company has 1,234 time-of-use AMR meters installed. The remaining installed AMR meters cannot support any forms of time-varying rate options as there is no way to effectively communicate time-based energy usage information from the meters to the office to support billing.

ii. New triple-ERT AMR meters could be installed but provide limited pricing options, must be manually programmed, and carry a comparable unit cost to AMF meters if purchased in similar volumes. The triple ERT meters only support basic time of use (TOU) rates as compared to AMF meters that can be configured for any desired pricing design including hourly and critical-peak pricing. Additionally, the triple ERT AMR meters must be manually programmed, requiring field visits to the meter to implement new TOU rate periods as compared to AMF meters that require no reprogramming due to the nature of interval data collection.

iii. An AMR solution does not provide the broader customer and grid-side benefits of AMF such as more actionable customer real-time granular usage data, robust pricing options, third-party product and services enablement, improved customers service, improved outage management, and distributed energy resource integration enablement to advance the Docket 4600 goals as outlined in Schedule PST - 1, Chapter 4 - AMF, Page 14 (Bates Page 82 of PST Book 1).

(This response is identical to the Company's response to Division 8-27 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Electric Time-of-Use Meters by Rate Class		
Rate	Description	Count
A16	Elec A-16 Residential-Std Ofr	3
B32	Elec B-32 C&I 200 kW Back Up Svc-Std Ofr	5
B32	Elec B-32 T&D C&I 200 kW Back Up Svc	2
C06	Elec C-06 Small C&I-Std Ofr Fixed	65
C06	Elec C-06 Small C&I-Std Ofr Variable	1
C06	Elec C-06 T&D Small C&I	5
G02	Elec G-02 Large C&I-Std Ofr Fixed	1
G02	Elec G-02 Large C&I-Std Variable	40
G02	Elec G-02 T&D Large C&I	59
G32	Elec G-32 200 kW Dem PK/OP-Std Ofr	130
G32	Elec G-32 200 kW Dem PK/SH/OP-Std Ofr	125
G32	Elec G-32 T&D 200 kW Dem PK/OP	383
G32	Elec G-32 T&D 200 kW Dem PK/SH/OP	399
G62	Elec G-62 3000 kW Dem PK/OP-Std Ofr	2
G62	Elec G-62 T&D 3000 kW Dem PK/OP	5
G62	Elec G-62 T&D 3000 kW Dem PK/SH/OP	4
X01	Elec X01 T&D Elec Propulsion	1
ZZZ	Elec C0Z Company Use-Std Ofr	1
ZZZ	Elec G3Z Company Use-Std Ofr	3
	Total:	**1,234**

Division 2-28

Request:

Refer to page 19 of Chapter 4 – AMF in PST-1, which states: "New Meter and Communications Technology—This deployment will use the latest generation meter technology, which includes new features such as load disaggregation and locational awareness."

a. Please define "load disaggregation" as used in this context, and provide an example.

b. Please define "locational awareness" as used in this context, and provide an example.

Response:

a. Load disaggregation refers to the ability to separate the consumption profile of various devices from an aggregate energy signal. This process uses statistical approaches to identify and extract the individual device profiles, and does not require any direct communication with the device. For example, a residential meter with load disaggregation capabilities may be able to identify how much energy is being used by the refrigerator and at what times the refrigerator is drawing power.

b. Locational awareness refers to the ability for the meter to identify where on the distribution network it sits in relation to other grid assets. This is achieved through the continuous monitoring of the characteristic of the electrical signal and peer-to-peer communications with other meters. An example of a benefit of locational awareness is the ability to quickly identify affected meters and transformers in an outage event and provide reliable information back to the utility.

(This response is identical to the Company's response to Division 8-28 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-29

Request:

Refer to page 21 of Chapter 4 – AMF in PST-1, which states: "National Grid will use advertising and other communications mechanisms in the months leading up to market activation and meter installations." Please describe the other communications mechanisms that the Company intends to use to introduce customers to AMF technology.

Response:

Please refer to *Section 6.1.2 Customer Engagement Supporting Communications and Tactics*, beginning on Page 22 of Chapter 4 – AMF in Schedule PST-1 (beginning on Bates Page of PST Book 1), which provide details on the different types of marketing channels and tactics that will be used in the education and outreach efforts prior to, during, and post installation of meters. Examples include digital channels, physical collateral such as bill inserts and brochures, appropriate call center support, and in-person engagement such as community meetings.

(This response is identical to the Company's response to Division 8-29 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-30

Request:

Please provide all workpapers, workbooks, and calculations contributing to the results shown in Table 4-6: Rhode Island Only Implementation Societal Test Benefits and Costs and Table 4-7: Rhode Island and New York Joint Implementation Societal Test Benefits and Costs on page 28 of Chapter 4 – AMF in PST-1 in machine-readable format with formulas intact.

Response:

The Rhode Island Only Implementation AMF BCA Model is provided as Attachment DIV 1-1-1 (Confidential) in response to Division 1-1. The Rhode Island and New York Joint Implementation AMF BCA Model is provided as Attachment DIV 1-1-2 (Confidential) in response to Division 1-1.

(This response is identical to the Company's response to Division 8-30 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-31

Request:

Refer to page 3 of Appendix 4.1 – AMF Technology & BCA, which states: “While we did not account for devices with these capabilities [integration with distributed generation and load control devices; improved granularity of voltage and consumption data; and location awareness and communication with other meters] in our analysis, we will be looking to procure the latest technology to maximize value for our customers.” Please provide:

a. The rationale behind the decision to not account for devices with these capabilities.

b. An updated version of Tables 4-2 and 4-3 accounting for devices with these capabilities.

Response:

a. The Company did not account for AMF functionalities that are in a market development stage in the AMF benefit-cost analysis as the Company does not have cost information and benefit models for these functionalities. The Company plans to evaluate AMF vendor solutions, including advanced functionalities, through a procurement exercise in Fiscal Year 2019 as described in Schedule PST-1, Chapter 4 - AMF, Page 5 (Bates Page 73 of PST Book 1).

b. Please see the Company’s response to part a. above.

(This response is identical to the Company’s response to Division 8-31 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-32

Request:

Refer to page 4 of Appendix 4.1 – AMF Technology & BCA, which states, regarding the cost for AMF electric meter storage: "An inventory level of 2.5% is assumed and will be allocated consistent with the AMF meter deployment schedule." Please provide the rationale behind the assumed inventory level of 2.5%.

Response:

The inventory level of 2.5 percent is an internal assumption established through the course of developing the AMF benefit-cost analysis filed in the 2017 Niagara Mohawk Power Corporation (Niagara Mohawk) rate case (Cases 17-E-0238 and 17-G-0239). Meter inventory averages (i.e. 40,000) were obtained for Niagara Mohawk and compared to the number of Niagara Mohawk electric customers (i.e. 1.69 million) to derive a 2.5 percent inventory level. The Niagara Mohawk estimate was applied to Narragansett Electric as the Company determined that the results would be very similar.

(This response is identical to the Company's response to Division 8-32 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-33

Request:

Please provide the expected number of field operations personnel that will be needed for the deployment of AMF meters.

Response:

The Company estimates the following number of field operations personnel will be needed for the proposed 18-month AMF meter deployment phase:

Field Installers FTEs	109
Supervisors FTEs	5
Chief Foreman FTEs	4
Quality Assurance/Quality Check FTEs	3
Lead FTEs	1
Clerical FTEs	4
Total:	**126**

(This response is identical to the Company's response to Division 8-33 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-34

Request:

Please provide the expected number of supplemental back office and clerical personnel (that is, personnel hired to support increased workload) that will be required to support the AMF implementation.

Response:

The Company estimates the following supplemental back office and clerical personnel will be required for the proposed 18-month AMF meter deployment phase:

Department	FTEs
Call Center	23
Account Maintenance and Operations	18
Meter Data Services	8
Billing and Systems	2
Customer Engagement	1
Total:	**52**

(This response is identical to the Company's response to Division 8-34 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-35

Request:

Please provide the expected number of legacy AMR meters that will need to be disposed during the deployment of AMF meters.

Response:

The Company expects to replace 100 percent of its existing installed AMR electric meter population, approximately 484,284 meters, with an AMI/AMF deployment.

(This response is identical to the Company's response to Division 8-35 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-36

Request:

Please provide a list of outside service vendors that the Company has spoken to, or is interested in speaking to, regarding a contract to host the proposed meter data management systems (MDMS).

Response:

The Company spoke with Itron and plans to engage additional vendors during the detailed Planning and Procurement phase of the project in Fiscal Year 2019.

(This response is identical to the Company's response to Division 8-36 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-37

Request:

Please explain the rationale behind contracting an outside service vendor to host the MDMS rather than the Company hosting the MDMS.

Response:

National Grid assumed a hosted solution to estimate the cost of this function for the AMF component of its Power Sector Transformation Plan filing. The Company has not made a final decision to contract an outside vendor to host the MDMS. A review and comparison of external versus internal hosting solutions must first be performed before a final determination can be made. National Grid will evaluate all potential alternatives as part of the Detailed Planning and Procurement phase in Fiscal Year 2019. This process will include a review of the costs and benefits for each of the viable alternatives with the results being captured in a sanction paper that will be brought forward to the US Sanctioning Committee for approval.

In the event an outside vendor is selected to host the MDMS, the Company believes several benefits could be realized, including faster implementation and enhancement adoption, fewer upgrades to legacy infrastructure, easier upgrades when needed, reduced risk of obsolescence in the future, and the opportunity to enhance security. A Software as a Service (SaaS) solution also provides strategic advantages by facilitating external interfaces with third party partners and can be more easily scaled for additional capacity when required to enable growth.

(This response is identical to the Company's response to Division 8-37 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-38

Request:

Refer to page 10 of Appendix 4.1 – AMF Technology & BCA, which states: "The Company will apply learnings and best practices from these two [customer engagement portal] programs to ensure that customers are provided with a "best in class" portal experience that leverages AMF deployment. Please list the learnings and best practices that Company will use from these two programs.

Response:

The Company has utilized a customer engagement portal in each of its two AMF pilot programs in Massachusetts and New York. A detailed customer evaluation report for the Company's AMF pilot in Massachusetts was provided as Attachment DIV 1-45-1 in the Company's response to Division 1-45. Details on the customer engagement portal, referred to as the "WorcesterSmart web portal", are described throughout that customer evaluation report. Examples of learnings from the AMF pilot in Massachusetts that may be utilized include, but are not limited to establishing and maintaining easy access for customers to an established web-based portal, as well as highlighting the value of a portal before, during, and immediately following critical peak pricing events when customers are most likely to obtain value from receiving personalized energy insights.

The AMF pilot in New York began in mid-2017 and is expected to be ongoing for a number of years. Learnings and best practices will be utilized as those findings become available.

(This response is identical to the Company's response to Division 8-38 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-39

Request:

Please refer to page 14 of Appendix 4.1 – AMF Technology & BCA, which states: "Cloud Computing & Data Lake – Rather than hosting these data management capabilities on servers within National Grid data centers, greater efficiency, redundancies, and security regimes can be cost effectively procured by outsourcing this function." Please provide all workpapers, workbooks, and calculations used to make this assessment.

Response:

The Company assumed a hosted solution to estimate the cost of this function for its Power Sector Transformation Plan filing (Docket No. 4780). National Grid hired Accenture to develop cost estimates for the each of the Company's Information Service (IS) grid modernization projects. Accenture assumed that the Company would pursue a hosted solution based on their experiences working with other utility clients and National Grid's IS Service Strategy and Architecture functions indicating that Cloud Computing was an integral part of the Company's strategic direction. Although National Grid believes there are potentially significant benefits in outsourcing the function, a review of each of the alternatives still needs to be performed before a final decision can be made.

As part of the sanctioning and governance process, National Grid's IS team will evaluate all potential alternatives, beginning mid-Fiscal Year 2019. This process will include a review of the costs and benefits for each of the viable alternatives, with the results being captured in a sanction paper that will be presented to the US Sanctioning Committee for approval. To the extent that additional vendor information is required, IS will issue requests for proposals and engage in competitive and strategic negotiations with vendors to determine which alternative provides the best value for customers.

For copies of the IS work books for each of the grid modernization projects including the Cloud Computing and Data Lake project, please refer to Attachment DIV 2-4-2.

(This response is identical to the Company's response to Division 8-39 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-40

Request:

Please provide versions of Tables 4-6 and 4-7 in which the Information Technology Infrastructure costs are excluded, to reflect the fact that the AMF allocation of these projects have been removed from the schedule of AMF costs in the total Revenue Requirement for the Plan.

Response:

Please see the tables below that exclude the costs allocated to AMF for the following IT infrastructure capabilities:

i. Telecommunications - Enhancements are required to expand existing backhaul capabilities and bandwidth to support data transfer.

ii. Enterprise Service Bus - To implement several of the AMF and Advanced Distribution Management System use cases, systems in the new distribution enterprise service bus will need to communicate with legacy systems that currently use a corporate enterprise service bus.

iii. Information Management and Advanced Analytics - Costs in this category allow data ingestion, data quality, and analytic capabilities to be configured and deployed. The big data analytics capabilities will allow for the analysis of the data gathered from existing and third-party data sources to provide valuable output reflecting current state as well as predictive and prescriptive outcomes.

iv. Cloud Computing and Data Lake - Rather than hosting these data management capabilities on servers within National Grid data centers, greater efficiencies, redundancies, and security regimes can be procured cost effectively by outsourcing this function. This cost element captures the costs associated with setting up a cloud data lake environment.

Prepared by or under the supervision of: John Leana

Table 4-6 (Revised): Rhode Island Only Implementation Societal Test Benefits and Costs

Category	**Component**	**Scenario 1 Opt-in w/ Low Savings**	**Scenario 2 Opt-in w/ High Savings**	**Scenario 3 Opt-out w/ Low Savings**	**Scenario 4 Opt-out w/ High Savings**
Costs 20 Yr NPV *($ Million)*	Meter Equipment and Installation	$83.58	$83.58	$83.58	$83.58
	Communication Equipment and Installation	$7.58	$7.58	$7.58	$7.58
	IT Platform and Ongoing IT	$107.06	$107.06	$107.06	$107.06
	Project Management and Ongoing Business Operations	$30.80	$30.80	$30.80	$30.80
	Total Costs	$229.02	$229.02	$229.02	$229.02
Benefits 20 Yr NPV *($ Million)*	Avoided O&M Costs	$52.64	$52.64	$52.64	$52.64
	Avoided AMR Costs	$66.49	$66.49	$66.49	$66.49
	Customer	$68.99	$122.61	$87.44	$162.02
	Societal	$16.40	$35.01	$22.65	$47.50
	Total Benefits	$204.52	$276.74	$229.22	$328.65
B/C Ratio	Societal Cost Test	0.89	1.21	1.00	1.44

Prepared by or under the supervision of: John Leana

Table 4-7 (Revised): Rhode Island and New York Joint Implementation Societal Test Benefits and Costs

Category	**Component**	**Scenario 1 Opt-in w/ Low Savings**	**Scenario 2 Opt-in w/ High Savings**	**Scenario 3 Opt-out w/ Low Savings**	**Scenario 4 Opt-out w/ High Savings**
Costs 20 Yr NPV *($ Million)*	Meter Equipment and Installation	$82.68	$82.68	$82.68	$82.68
	Communication Equipment and Installation	$7.06	$7.06	$7.06	$7.06
	IT Platform and Ongoing IT	$57.72	$57.72	$57.72	$57.72
	Project Management and Ongoing Business Operations	$29.09	$29.09	$29.09	$29.09
	Total Costs	$176.55	$176.55	$176.55	$176.55
Benefits 20 Yr NPV *($ Million)*	Avoided O&M Costs	$52.64	$52.64	$52.64	$52.64
	Avoided AMR Costs	$66.06	$66.06	$66.06	$66.06
	Customer	$68.99	$122.61	$87.44	$162.02
	Societal	$16.40	$35.01	$22.65	$47.50
	Total Benefits	$204.09	$276.31	$228.79	$328.22
B/C Ratio	Societal Cost Test	1.16	1.57	1.30	1.86

(This response is identical to the Company's response to Division 8-40 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-41

Request:

Please provide the expected number of personnel that will compose the following components of the project management team:

a. Internal project management leadership.

b. Internal business support.

c. External support.

Response:

a. Internal project management leadership:

Project Director	1
Project Manager	1
Financial controller	0.5
Total:	**2.5**

b. Internal business support:

Customer Metering Services/Field Collections	1
Call Center	1
Credits and Collections	0.5
Meter Data Services	2
Billing	1
Customer Engagement	1
Communications	0.125
Procurement	0.5
Meter Engineering/Lab	0.5
Telecom	0.5
Stakeholder engagement	0.25
Total:	**8.375**

Prepared by or under the supervision of: John Leana

c. External support:

Total External Vendor FTEs	2.5
Total Business Unit Staff Augmentation FTEs	1.5
Total:	**4**

(This response is identical to the Company’s response to Division 8-41 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-42

Request:

Refer to page 17 of Appendix 4.1 – AMF Technology & BCA, which states: "AMF meter replacement cost recognizes that over time meters will need to be replaced for a number of reasons, including damage or failure."

a. Please provide the expected life (in years) of an AMF meter.

b. Please provide the expected failure rate for AMF meters.

Response:

a. The expected life of an AMF meter, according to the manufacturer, is 20 years.

b. The Company is using an expected failure rate for AMF meters of .5 percent.

(This response is identical to the Company's response to Division 8-42 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-43

Request:

Please refer to page 17 of Appendix 4.1 – AMF Technology & BCA, which states: "A subset of electric meters are located in rural areas with insufficient density to form a stable and consistent mesh." Please provide the number of electric meters located in these areas.

Response:

The Company's Protection & Telecommunications Engineering department through consultation with external meter vendors estimated that five percent (or 26,000) of the electric AMF meters would need to consist of cellular transmitting meters to accommodate rural areas with insufficient density to form a stable and consistent mesh. Formal meter propagation studies and communication assessments will be conducted to determine where cellular meters are actually required as part of the meter deployment process.

(This response is identical to the Company's response to Division 8-43 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-44

Request:

Please provide the annual number of anomalous situations that required visits to the meter for manual meter investigations in the last five calendar years.

Response:

The Company tracks the annual number of anomalous situations that require visits to the meter for manual meter investigations by fiscal year. Please see Attachment DIV 2-44 for the requested information for last five fiscal years.

(This response is identical to the Company's response to Division 8-44 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Job Code	DESCRIPTION	Final Workplan FY 2013	Final Workplan FY 2014	Final Workplan FY 2015	Final Workplan FY 2016	Final Workplan FY 2017
6	METER - Read	1,766	1,539	1,320	1,634	1,367
12	METER - Read (Pick Up Read)	250	508	168	286	444
124	INVESTIGATION - Use On Inactive	7,299	6,173	6,300	5,596	4,943
	Total	**9,315**	**8,220**	**7,788**	**7,516**	**6,753**

Division 2-45

Request:

Please provide the annual number of connects and disconnects, by service rate, in the last five calendar years.

Response:

The table provided on Attachment DIV 2-45 provides the requested information for calendar year 2017. The Company cannot provide the number of connects and disconnects by service rate for the four-year period prior to 2017 because the data is not available in the requested format at this time. In place of the requested information for the period 2013-2016, a second table is provided below that includes the number of connects and disconnects in the aggregate by calendar year.

Connects and Disconnects by Calendar Year:

Calendar Year	Connects	Disconnects
2013	27,580	27,568
2014	32,345	35,256
2015	31,914	37,765
2016	33,579	42,365

(This response is identical to the Company's response to Division 8-45 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Rate Class	Code	Description	Connects	Disconnects	Grand Total
Residential	A16	Elec A-16 Residential-Std Ofr	21,319	22,416	43,735
		Elec A-16 T&D Residential	1,159	1,184	2,343
	A16 Total		22,478	23,600	46,078
Residential- Low Income	A60	Elec A-60 Resi Low Income-Std Ofr	2,688	2,967	5,655
		Elec A-60 T&D Resi Low Income	224	225	449
	A60 Total		2,912	3,192	6,104
Large Demand Back-up Service Rate	B32	Elec B-32 C&I 200 kW Back Up Svc-Std Ofr	1		1
	B32 Total		1		1
Small C&I	C06	Elec C-06 Small C&I-Std Ofr Fixed	1,787	4,621	6,408
		Elec C-06 Small C&I-Std Ofr Variable	1	4	5
		Elec C-06 T&D Small C&I	28	151	179
	C06 Total		1,816	4,776	6,592
Small C&I	C08	Elec C-06 Sm C&I Unmetered-Std Ofr Fixed	1		1
	C08 Total		1		1
General C&I	G02	Elec G-02 Large C&I-Std Ofr Fixed	19	19	38
		Elec G-02 Large C&I-Std Variable	303	834	1,137
		Elec G-02 T&D Large C&I	13	49	62
	G02 Total		335	902	1,237
Large Demand C&I	G32	Elec G-32 200 kW Dem PK/OP-Std Ofr	5	11	16
		Elec G-32 200 kW Dem PK/SH/OP-Std Ofr	3	3	6
		Elec G-32 T&D 200 kW Dem PK/OP	2	1	3
	G32 Total		10	15	25
	Grand Total		27,553	32,485	60,038

Division 2-46

Request:

Please provide the average life of an AMR meter.

Response:

The electromechanical AMR meters are expected to see a similar life span to the non-AMR meters previously used by the Company, approaching 30 years estimated in service life. The manufacturer's life expectancy claim for solid state AMR meters is 20 years.

(This response is identical to the Company's response to Division 8-46 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-47

Request:

Refer to page 22 of Appendix 4-1 – AMF Technology & BCA, which states: "To address the potential uncertainty of the benefit estimate for the Energy Management Portal, the company has calculated a low and high benefit of one percent and three percent, respectively." Please provide the rationale behind the use of one percent and three percent for low and high benefit scenarios, respectively.

Response:

The Company assumed both low (1 percent) and high (3 percent) energy load reduction assumptions for the energy management portal to provide a reasonable estimated range of savings. Research by EPRI, Section 5.1 of Attachment DIV 2-47, indicates a considerable range of results for 35 pilots. The EPRI research divides the pilots into two categories, one defined as indirect feedback where energy use feedback is provided periodically, such as monthly, through the bill or other means. The second category is direct feedback where energy use feedback is provided on a near-real time basis through AMF. The average annual household kWh reductions savings was 8.4 percent for the indirect feedback pilots, and 11.5 percent for the AMF-enabled direct feedback pilots. Therefore, the incremental difference in average kWh reduction savings between these two categories of feedback is approximately three percent, which was used as the higher bound of the AMF-enabled energy management portal savings range. One percent was chosen as the lower bound to provide a reasonable estimated range of savings.

(This response is identical to the Company's response to Division 8-47 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

ELECTRIC POWER RESEARCH INSTITUTE

Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments

Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments

1017006

Topical Report, July 2008

EPRI Project Manager
B. Neenan

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REPORT SUMMARY

Smart Metering can reduce labor requirements and other costs inherent in non-automated processes, but it can also produce benefits that accrue directly or indirectly to electricity consumers and societal in general, which is why they are referred to as "societal" benefits. Because they accrue to consumers, rather than show up as cost savings on the utility ledger, identifying and monetizing these benefits in a business case can be a challenging task. This report reviews how utilities have estimated societal benefits in regulatory filings and develops a framework that describes how societal benefits could be characterized and quantified systematically and thoroughly.

Background

The installation of Smart Metering technology by itself does not produce societal benefits. Rather, Smart Metering serves an enabling role when combined with other initiatives, such as the implementation of demand response programs, revised outage restoration practices, and the adoption of devices that communicate consumption and price/event information to consumers and the utility. Additional benefits may be attributable to the energy and demand changes that result from these initiatives, including lower environmental impacts and improvements in employment and wages in the local economy. Quantifying societal benefits requires sorting these benefits streams in a way that characterizes them by source and initial manifestation of the benefits so that an appropriate value transformation function can be applied. If this characterization is accomplished, benefits emanating from different changes in the physical nature of electric service can be potentially monetized and therefore added together.

Objectives

To characterize and quantify the societal benefits that result from Smart Metering.

Approach

The project team reviewed pilots and state jurisdictional filings to study how utilities have estimated the societal benefits of Smart Metering and justified these estimates. They also reviewed a wide range of subject matter and topical material to synthesize economic principles and identify analytical practices for measuring societal benefits. The team then developed a framework for identifying and monetizing societal benefits using well-understood economic methods.

Results

The report identifies and discusses six potential sources of societal benefits that may accrue from Smart Metering:

1. Demand response programs that provide consumers with inducements to modify their electricity consumption through price or other incentives, thus providing them with a opportunity to reduce their electricity costs
2. Feedback made available to consumers about electricity consumption in an actionable and timely fashion that may result in reduced electricity consumption and bill savings
3. New products and services that can create opportunities to use electricity more efficiently and effectively
4. Service quality enhancements that may reduce the duration of outages
5. Macroeconomic benefits may arise from changes in the expenditure patterns of utilities and consumers that can enhance regional employment and raise wages
6. Reduction of externalities, which are potentially adverse impacts of electricity usage on the environment or society that are not explicitly reflected in electricity prices but whose reduction benefits all consumers

For each of these benefits, the report describes one or more transformation functions, protocols, or algorithms that convert the physical manifestation of benefits into monetary terns. Examples of the application of these functions, not all of them associated with Smart Metering business case analyses, are provided to illustrate the effort required and the results each produces. In most cases, the benefits generated by Smart Metering extend beyond the consumers that undertake behavioral changes.

EPRI Perspective

EPRI prepared this study for a consortium comprised of four Ohio utilities: American Electric Power, Dayton Power and Light, Duke Energy and FirstEnergy. Although the members of the Consortium agree in principle with the goals of this study and view it as helpful in illustrating generic methodologies that can be used to assist individual Consortium members in quantifying the societal benefits associated with Smart Metering, nothing in this report should be construed as the position that an individual Ohio Consortium member would necessarily take; and, therefore, none of the contents of this report is to be viewed as binding upon any member in any current or future proceeding.

Keywords

Smart Metering
Advanced Metering Infrastructure (AMI)
Business cases
Demand response
Price elasticity
Societal benefits

EXECUTIVE SUMMARY

EPRI prepared this study for a consortium comprised of four Ohio utilities — American Electric Power, Dayton Power and Light, Duke Energy and FirstEnergy (hereinafter "Ohio Consortium"). The Ohio Consortium commissioned this study to provide background on various methodologies relating to societal benefits in the context of Smart Metering initiatives.[1] The study develops a framework that describes how societal benefits can be characterized by the ways they generate benefits and identifies, where feasible, potential methods for their monetization.

The members of the Ohio Consortium agree in principle with the goals of this study and view it as helpful in illustrating generic methodologies that can be used to assist individual Consortium members in quantifying the societal benefits associated with Smart Metering. However, by commissioning this study, the members of the Ohio Consortium are in no way adopting as their own the opinions, methodologies, or positions presented by EPRI in this report. Accordingly, nothing in this report should be construed as the position that an individual Ohio Consortium member would necessarily take; and, therefore, none of the contents of this report is to be viewed as binding upon any member in any current or future proceeding.

Societal benefits are benefits that accrue primarily as a result of actions undertaken by consumers. For example, providing consumers with access to readily available metered electricity usage information may help them evaluate when and how they use electricity. This knowledge could possibly result in lower bills or enable participation in demand response programs. Thus consumer behavioral changes should realize direct benefits that can probably be quantified. Changes in power usage can also have secondary impacts on market prices or utility costs that may indirectly benefit all consumers.

Societal benefits can be associated with Smart Metering, but that attribution is not always exclusive or without ambiguity. Smart Metering is an enabler, possibly opening up new ways of changing how electricity is provided and used in a manner that may benefit consumers; but it does not assure that these benefits are actually realized. Consumers must be induced to change the way in which they use electricity, and achieving those behavioral changes may require investments beyond those directly associated with Smart Metering, such as incentives or inducements offered by the utility.

Smart Metering serves an enabling role when combined with other initiatives, such as the implementation of demand response programs, revised outage restoration practices, and the

[1] Smart Metering, also referred to as Advanced Metering Infrastructure (AMI) Technology, includes a two-way system for providing price and/or control signals and measuring and communicating time sensitive usage and/or demand.

adoption of devices that communicate consumption and price/event information to consumers and the utility. Additional benefits may be attributable to the energy and demand changes that result from these initiatives, including lower environmental impacts and improvements in employment and wages in the local economy. Quantifying societal benefits requires sorting these benefits streams in a way that characterizes them by source and the initial manifestation of the benefits so that an appropriate value transformation function can be applied. If this characterization is accomplished, benefits emanating from different changes in the physical nature of electric service can be potentially monetized and therefore added together.

Quantifying the Societal Benefits Attributable to Smart Metering

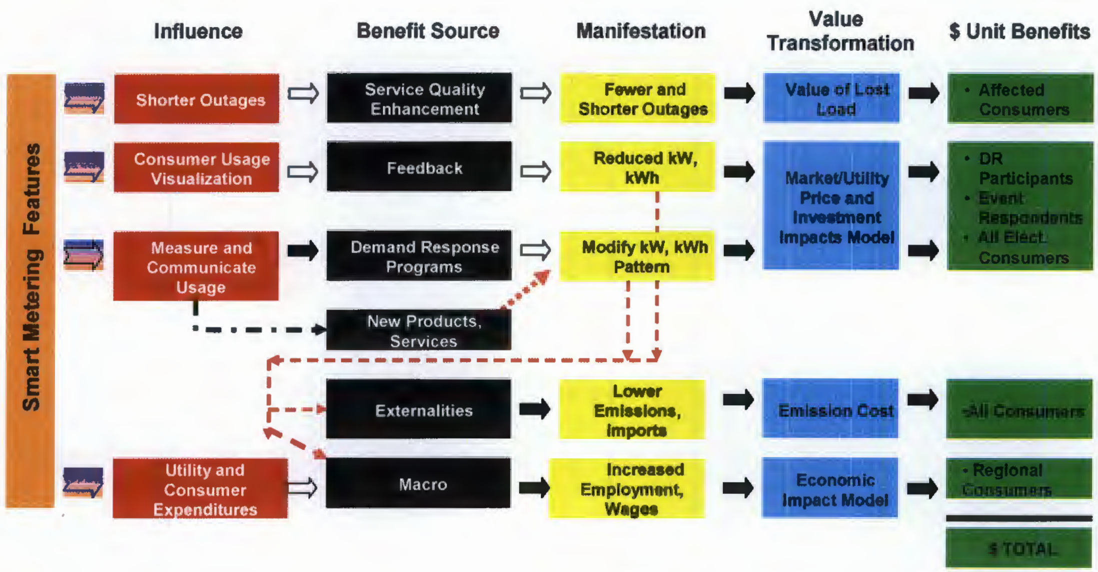

Figure 1
Source and Measurement of Societal Benefits

Figure 1 illustrates the processes by which these benefits are generated and shows to whom they accrue. Influences refer to changes in the physical nature of electric service that may be attributed to a Smart Metering investment. Benefit Sources defines the nature of the benefits that may result from these Influences. Benefit Sources can be classified in one of six ways:

1. Service quality enhancements that may reduce the duration of outages.
2. Feedback made available to consumers about electricity consumption in an actionable and timely fashion that may result in reduced electricity consumption and bill savings
3. Demand response programs that provide consumers with inducements to modify their electricity consumption through price or other incentives, thus providing them with a opportunity to reduce their electricity costs
4. New products and services that can create opportunities to use electricity more efficiently and effectively

5. Reduction of externalities, which are potentially adverse impacts of electricity usage on the environment or society that are not explicitly reflected in electricity prices but whose reduction benefits all consumers
6. Macroeconomic benefits may arise from changes in the expenditure patterns of utilities and consumers that can enhance regional employment and raise wages

For each of these benefits, the report describes one or more transformation functions, protocols, or algorithms that convert the physical manifestation of benefits into monetary terns. Examples of the application of these functions, not all of them to Smart Metering business case analyses, are provided to illustrate the effort required and the results each produces. In most cases, the benefits generated by Smart Metering extend beyond the consumers that undertake behavioral changes. Indeed, they are termed societal benefits because they accrue to all consumers and to society as a whole.

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1 BACKGROUND AND OVERVIEW

1.1 Introduction

EPRI prepared this study for a consortium comprised of four Ohio utilities — American Electric Power, Dayton Power and Light, Duke Energy and FirstEnergy (hereinafter "Ohio Consortium"). The Ohio Consortium commissioned this study collectively to provide background on various methodologies for characterizing and monetizing the societal benefits that may be attributed to Smart Metering initiatives. This study develops a framework that describes how societal benefits can be characterized according to how benefits are generated and, where feasible, identifies potential methods for their monetization.

Each utility will determine which categories are justified for inclusion in its Smart Metering business case, selecting a method for quantifying them, and applying that method to its customer and market circumstances. To preserve this autonomy, the study strives to be comprehensive and objective so that the range of available sources of benefits is recognized and the relative merits of alternative monetization methods are evaluated. Accordingly, in demonstrating some of the methodological alternatives that can be employed, synthetic data are employed that have no intentional correspondence to any Ohio circumstances.

The members of the Ohio Consortium agree in principle with the goals of this study and view it as being helpful and illustrative in a general sense of the methodologies which can be used to assist the individual Ohio Consortium members. These members view this study as containing guidelines and considerations relating to the means by which to quantify the societal benefits associated with Smart Metering. By commissioning this study, the members of the Ohio Consortium are in no way adopting as their own the opinions, methodologies, or positions presented by EPRI in this report. Accordingly, nothing in this report should be construed as the position that an individual Ohio Consortium member would necessarily take and, therefore, none of the contents of this report is to be viewed as binding upon any such member in any current or future proceeding.

1.2 Societal Benefits

The application of Smart Metering technology is not limited to productivity improvements that translate into cost savings for the utility. Some of its capabilities produce benefits that accrue directly or indirectly to consumers rather than show up as cost savings on the utility ledger. Societal benefits are another source of benefits that could be incorporated into Smart Metering business cases. As discussed in Section 3.0, business cases filed by some U.S. utilities with their regulatory bodies have cited societal benefits as part of the rationale for proposing to deploy Smart Metering.

Societal benefits accrue to customers, either explicitly or implicitly, and therefore are not available directly to the utility to cover the system cost unless provision is made to do so. Smart Metering can enable customers to realize greater value from the investment in the electric system, provide ways to reduce bills, and contribute to accomplishing environmental goals. Virtually all societal benefits imply some change in market circumstances that benefit some, or in many cases, all consumers of electricity, but not necessarily to an extent directly proportional to their electricity usage pattern or level. The pluralistic nature of many (but not all) of these benefits explains why they are commonly referred to as societal benefits.

Many of the sources of benefits attributable to Smart Metering do not require the universal deployment of that technology. For example, as discussed in Section 4.0, demand response programs have been offered by utilities for over three decades and nationally comprise over 3% of the total resources used to serve electricity demand reliably and cost effectively. These programs have been implemented by installing the requisite metering equipment at only those premises that elect to participate in a demand response offering, rather than at all premises as most Smart Metering initiatives contemplate. Moreover, the programs involved implementing meter reading, billing, and support systems sufficient to support only a relatively small percentage of total consumers, rather than the entire population of customers, as is envisioned in many Smart Metering applications.

As discussed in Section 4.0, Smart Metering should be viewed as an enabler of demand response that makes it possible to expand the scale and scope of participation and to increase the level of performance. This theme extends throughout the discussion of Smart Metering in the subsequent sections that discuss other potential sources of societal benefits.

In almost every instance, the realization of benefits requires more than the installation of the Smart Metering technology. It requires institutional changes in utility operating practices, regulatory changes to accommodate new services, and acceptance and adoption of new behaviors by consumers, all of which involve a sustained effort for many years and in many cases require additional expenditures. Accordingly, in evaluating the stream of benefits enabled by a Smart Metering investment, it is important to account fully for both benefits and costs to properly estimate the net benefits that can be anticipated.

While this report is meant to provide a structure for assessing societal benefits, it certainly is not intended to be the last word on the subject. EPRI anticipates that this framework will be refined and enhanced as it is employed in a wide range of circumstances.

1.3 Sources of Societal Benefits

Technology vendors, technology analyst, utilities, and public policy analysts have proffered an expansive list of the sources of societal benefits that may result from Smart Metering. However, there is no universal agreement on what constitutes a societal benefit or how individual classes of benefits can or should be measured. Therefore, devising an overarching framework requires first categorizing the sources of sources of benefits in a way that reflects both how they are manifested—what physical change in electric service is observed—and how, if possible, those manifestation can be transformed into additive monetary values. Moreover, a categorization must avoid double counting benefits while making sure that all benefits are accounted for.

Defining the societal benefits attributable to Smart Metering requires invoking an important distinction: operational versus societal benefits. Smart Metering operational savings are measurable reductions in the cost of providing customers with electric service in accordance with established safety and commercial service standards. These savings include the reduced labor and transportation expenses associated with the conventional practice of on-premise metering reading. Another source of operational savings may involve capital cost savings (sometimes referred to as avoided costs) associated with reduced levels of, or longer lifetimes for, the equipment and materials required to operate and maintain the electric system that are the result of a Smart Metering investment.

An Important Distinction

Operational savings are discernable and measurable reductions in the utility's overall cost of meeting its service obligations that serve to offset some or all of the Smart Metering investment costs.

Societal benefits accrue to consumers in the form of lower bills, and enhanced electric services, and sector adjustments that accrue directly to some consumers and indirectly to others.

Figure 1-1
An Important Distinction Regarding Smart Metering Benefits

All of these operational savings reduce the utility's net cost to deploy Smart Metering. In contrast, the societal benefits attributable to Smart Metering do not generally correspond to specific utility cost savings, even though they represent value to consumers and can be accounted for to fully portray the Smart Metering investment's consequences, for example in a business case.

Societal benefits are benefits that accrue primarily as a result of actions undertaken by consumers. For example, providing consumers with access to readily available metered electricity usage information may help them evaluate when and how they use electricity. This knowledge could possibly result in lower bills or enable participation in demand response programs. The result is that the consumers that undertake behavioral changes should realize direct benefits that can probably be quantified. Additionally, as discussed in Section 4, the usage changes can result in secondary impacts on market prices or utility costs that may indirectly produce benefits that accrue to all consumers.

These secondary or derivative demand response benefits have the property that they impact utility cost prospectively: they represent future (implied) costs that are avoided, not a reduction in a current cost.

Other benefits may be harder to measure and monetize, but they too contribute to the benefits consumers realize from Smart Metering investments. Faster restoration from a service outage reduces the inconvenience that households and business are exposed to. It thus has value: but that value is implicit, not explicit, and measuring it requires constructing hypothetical value transformation functions. Some contend that robust demand response behavior by consumers is a necessary condition for realizing the full benefits of competition in wholesale retail markets. Smart Metering may be a necessary condition for achieving this outcome. Others maintain that the expanded service choices enabled by advanced metering and communication technology are essential if consumers are to realize the full benefits of wholesale competition. These theoretical but potentially important benefits can be hard to measure in practice, because some involve hypothetical transactions that consumers have not encountered before.

Clearly, an insightful and comprehensive framework for evaluating the societal benefits attributable to Smart Metering should distinguish between benefits sources that can be traced back to utility cost savings and are associated with directly measured consumer bill savings from those that result from indirect or secondary impacts on consumers.

Societal benefits may be associated with Smart Metering, but this attribution is not always exclusive or without ambiguity. That's because Smart Metering enables societal benefits, but does not assure that they are realized. Thus if the small time-step interval recording and data transmission functions that are part of even the most rudimentary Smart Metering configuration are universally deployed, every consumer, regardless of size and location, can participate, at least in principle, in a demand response program, possibly without incurring an additional metering cost. Nevertheless, Smart Metering would make universal participation possible, not inevitable; and the actual benefits that could be attributed to Smart Metering in demand response programs would be marginal in nature. As noted above, existing demand respond programs accomplished with relatively rudimentary enabling technology already account for 3 -8 % of ISO/RTP peak loads and involve tens of thousands of end-use customers with a substantial positive impact on market performance.[2]

Smart Metering is an enabler; it provides several paths to changes in how electricity is provided and used that benefit consumers, but does not assure their realization. The responsibility for asserting the provenance and veracity of the claimed benefits properly remains with those that are evaluating a Smart Metering system.

1.4 Are All Benefits of Equal Relevance?

The distinction between operational savings and societal benefits may be critically important from a public policy perspective if the operational savings attributed to Smart Metering configuration are less than the costs of that system. Business case analysts often estimate the savings that could be realized in a specified system configuration that involves specific functions (or functionality in the common parlance) based on 1) the functions of devices or systems that are available and ready to install, 2) speculative assessments of how functions might become

[2] ISO/RTO Council Markets Committee. October 16, 2007. Harnessing the Power of Demand: How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets.

valuable later on, and 3) concerns about obsolescence. Smart Metering systems are commercially available with many features already bundled based on the manufacturer's determination of what will sell. However, specifying a system independently of the marginal value of the functions added could result in a system configuration whose operational savings do not exceed the cost and are not otherwise substantiated by an offsetting stream of other benefits.

If societal benefits are real, consumers should be willing to pay for them; presumably they would pay at a price commensurate with the level of those benefits. Some societal benefits are financial in nature and therefore are readily incorporated into an enterprise-level cost benefits analysis. Others are less objective or not easily monetized but nonetheless are benefits that accrue to consumers, so counting them would seem to be legitimate. However, the benefits are realized over time and may be realized unevenly by consumers, which renders them a public good and thus raising the difficult policy issues associated with free riders and distributional impacts.[3]

1.5 The Need for a Framework to Guide Characterizing and Quantifying Societal Benefits Attributable to Smart Metering

The issue of whether a utility should invest in Smart Metering technology has become a public policy issue that will be resolved in many cases in state Public Service Commission (PSC) venues. PSCs will be asked to consider whether the societal gains attributable to Smart Metering are of sufficient level and character, when taking into account the temporal and distributional aspects of their realization, to warrant authorizing the utility to undertake the investment with assurance of recovery of the difference between the cost of implementing the system and the realized operational savings. Many PSCs will require that utilities provide them with a comprehensive description of the costs and benefits they expect will be attributable to a Smart Metering investment. Guidance on establishing operational savings is available from several sources, and there are several prototype and filed business cases that provide examples of how this has been accomplished in particular market circumstances. Characterizing and quantifying the societal benefits is less well developed.

As discussed in Section 2, a few business case filings have indicated that a proposed investment will generate societal benefits. However, many of these analyses are either lacking in detail to clarify how the values proffered were derived or use methods that, while intriguing, are not sufficiently rationalized to serve as a precedent for subsequent filings. The shortcomings of methods to characterize and value societal benefits can have substantial consequences. Review and resolution of Smart Metering investment proposals may be expedited by clarifying the various ways those societal benefits can be manifested.

In this report, EPRI set out to provide the Ohio Consortium with a framework that will characterize how societal benefits can be classified according to how the benefits are generated and discuss alternative ways those benefits can be quantified. Section 2 develops the framework for characterizing societal benefits in a mutually exclusive and exhaustive manner. Avoiding

[3] Kiesling, L., Giberson, M. undated. Electric Network Reliability as a Public Good. Paper submitted to CMU conference; Electricity Transmission in Deregulated Markets. O'Sheasy, M. December 2003. Demand Response: Not Just Rhetoric, It can Truly Be the Silver Bullet. Electricity Journal, Vol. 16., Number 10

double counting is as important as accounting for the full range of possible benefits streams. Section 3 provides a review of business cases that have been filed with state Public Service Commissions. The section shows what analytic methods have already been used to quantify societal benefits and demonstrates the need for a general framework for characterizing such benefits. Sections 4 though 9 discuss each benefit category individually, focusing on establishing how they such benefits are measured and how a monetary value can be attached to them. Section 10 summarizes the framework and offers recommendations for how it can be further refined.

1.6 A Final Qualification

EPRI devised this framework for quantifying the societal benefits of Smart Metering to assist those that have determined to undertake such an endeavor. Its purpose is informational, instructional, and demonstrative. It draws upon a large body of analytical protocols and tools that have been used to conduct cost/benefits analyses in other contexts. EPRI anticiapates that they will useful to stakeholders evaluating Smart Metering proposals. The final determination as to what constitutes the proper basis for making Smart Metering decisions rests with each utility and its stakeholders, including its investors, consumers, and regulators.

2
A FRAMEWORK FOR CHARACTERIZING AND QUANTIFYING THE SOCIETAL BENEFITS OF SMART METERING INVESTMENTS

A useful and defensible framework should provide a systematic means for characterizing the societal benefits that can be attributed to a Smart Metering investment. The first order of business is to define what constitutes societal benefits, and the second is to devise a classification scheme that is mutually exclusive and exhaustive of those benefits.

2.1 A Framework for Categorizing Smart Metering Societal Benefits

A wide range of benefits other than operational savings have been attributed to Smart Metering investments. The list in Figure 2-1 is indicative, but not exhaustive of the purported benefits.

Potential Benefits Attributed to Smart Metering

- Increased utility EE, DR and PR participation
- More stable and robust markets
- Expanded product offerings from competitive retailers
- Faster outage service restoration
- More accurate bills
- Faster bill dispute resolution
- Avoided capacity costs
- Avoided energy costs
- Reduced outage costs
- Reduced impact of disruptive technologies
- More equitable and fair rates
- Enable demand-side generation technologies
- Facilitate revolutionary technologies like Plug-in Hybrid Electric Vehicles and on-site renewable generation
- Ameliorate the impacts of potentially disruptive technologies
- Improve customer satisfaction
- Conservation effect on energy usage from direct feedback
- Improved productivity in all sectors of the economy
- Foster robust competition
- National security - reduced reliance on foreign oil
- Environmental improvements – lower emissions
- Modernization of electricity industry
- Accelerate adoption of more efficient electric devices and technologies

Figure 2-1
Potential Smart Metering Benefits

Some benefits imply monetary measurement, such as avoided energy and capacity costs, because those terms are equated with widely used protocols for measuring the impact of investments by utilities on the customer's side of the meter. Some relate to commonly cited factors that are an important part of utility service, but are seldom monetized: examples include improved customer satisfaction, reduced outage costs, faster service restoration and bill dispute resolution, and more accurate and informational bills. Still others relate to changes in the nature of the industry that are enabled by Smart Metering, such as the accelerated adoption of efficiency devices and the enabling of demand-side generation and plug-in hybrid electric vehicles (PHEVs). Smart Metering is seen by some as leading to more stable and robust markets. Others point to its making it possible for utilities and others to provide consumers a greater variety of service options, including opportunities to participate directly in wholesale markets. Finally, some lists of Smart Metering benefits include reducing the environmental impact of producing electricity and improving national security by diminishing energy imports.

It is important to identify the full array of potential benefits from Smart Metering. However, using them both purposefully and objectively in a Smart Metering business case requires establishing a categorization of societal benefits that achieves the following objectives:

- It must fully distinguish between operational and societal benefits to avoid redundancy. If there are benefits that are jointly realized, then these must be identified and methods devised to allocate the benefits fully and responsibly between the distinct categories.
- It must be constructed to avoid double counting of benefits or provide a means for allocating benefits among the categories.
- It must apportion benefits by customer segment and be capable of distinguishing among consumer segments where appropriate.
- It must group benefit streams homogeneously according to how the benefits are measured so that the proper protocols can be established.
- It must include a monetization of the benefits so they can be aggregated.
- It must anticipate differences in how measured impacts are monetized either directly or indirectly.

A framework that achieves these requirements involves six categories, as illustrated in Figure 2-2. For each category, the figure indicates the manner in which the benefits are manifested (how they are observed or recognized) and how they are measured. The categories, which are more fully defined in Sections 4-9, are as follows:

1. Demand response products: These are time-varying prices tied to system marginal supply costs and call options on consumers' rights to electricity service. The former ties consumption decision to marginal costs and thereby result in more efficiency and effective resource utilization compared to conventional, uniformly priced rates. The latter allows load management capabilities of consumers to be integrated into the electric system as resources to reduce investment costs, improve reliability, and reduce market price volatility. Universal deployment of Smart Metering enables greater demand response by making all consumers potential participants in demand response products. Its communication and control capabilities increase the degree to which consumers can participate in demand response programs.

2. Improved service utilization: This benefit may be achieved by providing consumers with timely and readily available information about their electricity usage pattern and its corresponding cost, knowledge that will result in a reduction in the overall use of electricity. Smart Metering enables this outcome by providing the technology than can provide consumption feedback.

3. Other products and services: These may become viable as supplemental services enabled by Smart Metering functions. Examples include separate metering associated with charging PHEVs and tracking energy produced by on-site renewable energy resources.

4. Enhanced service quality: This benefit comes about if Smart Metering capabilities enable the utility to reduce the frequency or duration of electrical outages.

5. Macroeconomic impacts: These are the changes in regional economic output, such as employment and wages, attributable to Smart Metering investments. Examples include the elimination of meter readers but the increased utilization of engineers, business analysts, and purchases of labor-intensive materials and services and changes in household consumption patterns resulting from changes in electricity consumption that were induced by Smart Metering. These are secondary benefits associated with adjustment in economic activity that are the result of the Smart Metering investment.

6. Externalities: These are impacts from the production of electricity that may have a deleterious impact on consumers, but whose costs are not explicitly included in the price of electricity. Reductions of externalities are secondary benefits associated with kW and kWh impacts attributable to another benefit source, such as demand response or feedback.

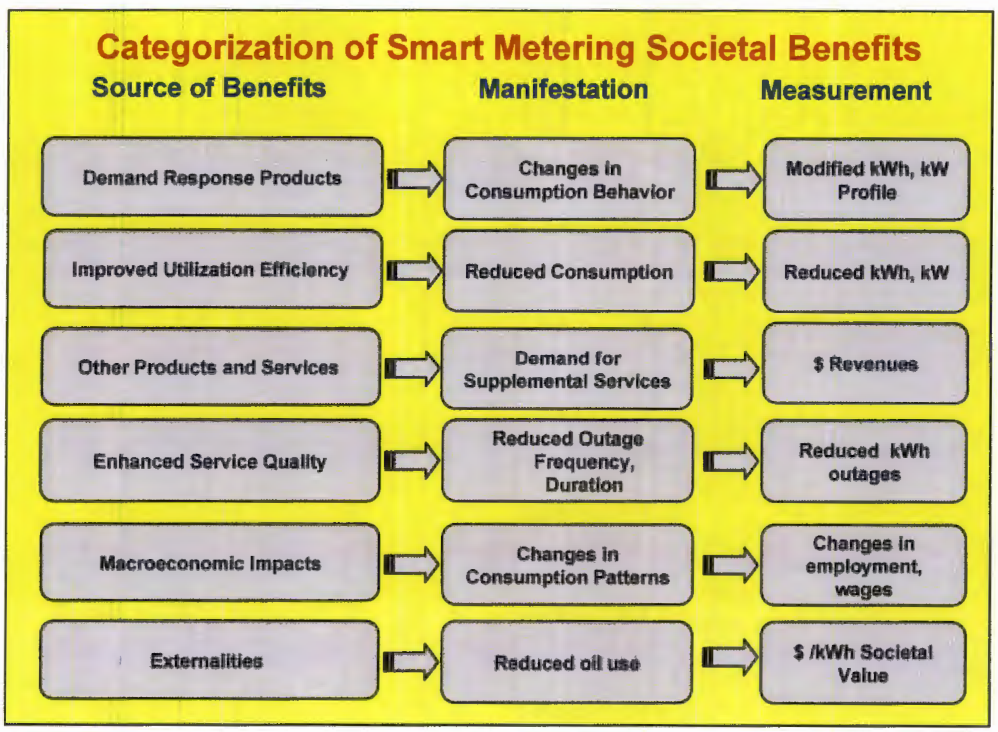

Figure 2-2
A Framework for Smart Metering Societal Benefits

This categorization accommodates mapping all of the benefits individually listed in Figure 2.1 either because they can be specifically associated with a category or they represent how the benefits are realized. An additional requirement of the framework is that it recognizes differences in how the measured benefits streams are monetized. There are three primary factors that determine how the benefits are monetized and evaluated:

- Transformation function— defines how the benefits measured in physical terms— kW, kWh, service demand, utility and consumer expenditures, reduced outages, environmental impacts—are converted into monetary values that can be compared and aggregated
- Nature of the benefits— defines whether the monetary benefits accrue to (a) individual consumers that either undertook some changes that Smart Metering enabled (they adjusted kW or kWh) or are beneficiaries of service improvements that result from the investment, or (b) to some or all consumers of electricity (or all consumers in general), including those that are not directly responsible for the benefits being realized. This last distinction is important because if a steam of benefits accrues exclusively to those consumers that are the source of its manifestation, then the cost of the provision of that service should be born by those consumers. However, if there are spillover or collateral impacts so that other consumers are beneficiaries, then these collective benefits may be considered as justifying recovery of those cost through rates, which is referred to commonly as socialization. This distinction is primarily applicable to Smart Metering-enabled demand response benefits because not all customers are likely to respond to inducements to adjust load and macroeconomic impacts and externality benefits are, by their nature, inherently collectively realized.
- Distribution of the benefits—benefits potentially accrue to all consumers, but not necessarily uniformly, a fact which has implications for how rates should be set to recover some of the societal benefits. In fact, the definition of an equitable distribution is subjective, as it requires some judgment as to what constitutes the proper basis for measuring equality. Would an equitable distribution be in proportion to kWh consumption, to the amount paid for electric service, to the time of day of use, or to the purpose for which the electricity was consumed? This determination will be made by those who are responsible for allocating the resulting rate adjustments.

Sections 4-9 discuss in greater detail how Smart Metering enables the manifestation of benefits described in each category and describe methods and protocols than can be used to transform their physical manifestations into monetary terms.

2.2 Summary

The Smart Metering framework organizes societal benefits according to how they are manifested, which makes it possible to monetize the resulting benefits consistently. Because the methods that are available for quantifying benefits vary considerably among the six categories, each is discussed separately in the sections that follow, beginning with demand response because it involves measurement protocols (changes in kW and kWh) that are employed to quantify the value of many of the others. First, however, it is instructive to compare how others have characterized and quantified Smart Metering societal benefits, as it serves as a way to validate the framework devised herein and as an introduction to the issues attendant to monetizing diverse societal benefits.

3
SMART METERING REGULATORY ACTIVITY

This section reviews the activity that has taken place in the regulatory jurisdictions across the United States with respect to the review and approval of proposals for the wide-scale deployment of Smart Metering. The approach is to identify jurisdictions and utilities that made such filing; sort out those that have included societal benefits in the justification for Smart Metering deployment; and summarize the sources, manifestation, measurement, and monetization of these benefits in terms of the framework introduced in Section 2.

On August 8, 2005 the President signed into law the Energy Policy Act of 2005 (EPAct 05), which added five new standards to the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Energy Policy Act of 1992 (EPAct 92). Among these new standards was consideration of the wide-scale deployment of Smart Metering technology as specified in Section 1252. In response, most regulatory jurisdictions in the United States are evaluating the new standard and determining whether they should be adopted. The United States Demand Response Coordinating Committee (DRCC) has monitored and tracked the implementation by state regulatory commissions of Section 1252 of the EPAct 05 and found that as of July 1, 2007 there were 11 state jurisdictions that rejected implementation of the PURPA standard outright.[4] The other jurisdictions have either accepted the standard or are still considering the appropriateness of adoption.

3.1 Overview of Pilots and State Jurisdictional Filings

While many utilities may be evaluating Smart Metering in detail, only those that have filed a business case and a proposal with a regulatory body are available to characterize how societal benefits are being treated. As result, the accounting of who is doing what requires constant updating to be inclusive. The discussion below reflects filing activities that were resolved or ongoing in the spring of 2008.[5]

In reviewing the jurisdictions that have adopted the PURPA standard, there are several different paths that regulatory jurisdictions have taken with regard to deployment of Smart Metering:

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[4] Federal Energy Regulatory Commission, Assessment of Demand Response and Advanced Metering, Staff Report, September 2007.

[5] FERC is currently updating its 2006 survey of Smart Metering and demand response activity across the country. This update is expected in the late summer of 2008. The results may provide a better perspective on the level of analytical activity, but probably will not provide the detail needed to improve substantially the estimation of societal benefits

- Accept and begin deployment of a Smart Metering system immediately without any further study
- Implement a pilot to refine and clarify technical or economic aspects of an initial business case
- Require utilities to quantify the benefits and costs of smart metering deployment.

As illustrated in Figure 3-1, 20 states have approved Smart Metering pilots or full-scale deployment; but, as shown in Figure 3-2, there are only 11 utility filings in 6 jurisdictions that included societal benefits explicitly in their Smart Metering business case filings. However, as Figure 3-3 shows, only filings in four states employed an explicit methodology to quantify any aspect of the societal benefits that were claimed to be attributable to their Smart Metering proposal. The rest indicated a dollar value, but offered no support for how it was derived.[6]

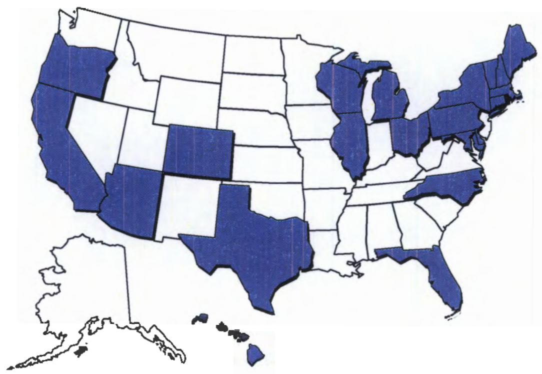

Figure 3-1
States with Smart Metering Pilots or Implementations

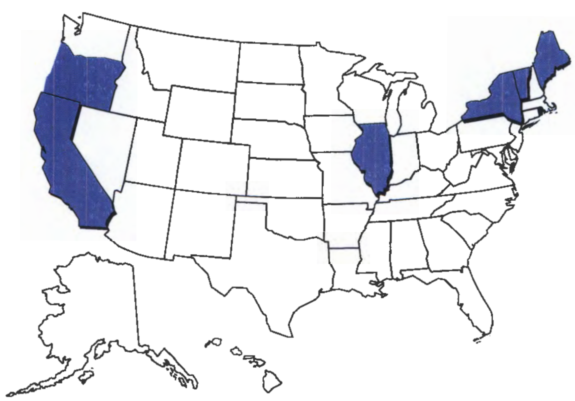

Figure 3-2
State Filings that Include Societal Benefits

[6] Some of these filings may have been purposefully vague in anticipation of later filings that would buttress the values claimed.

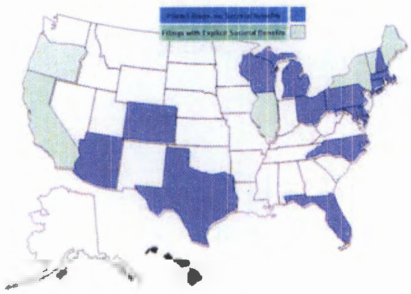

Figure 3-3
Filings where Societal Benefits are Explicitly Specified

3.2 Filings that Include Societal Benefits Explicitly

Table 3-1 provides a synopsis of filings that explicitly include societal benefits. The table indicates the filing dates and the nature and extent of the societal benefits analysis. The analyses in these filings are discussed below, organized around the characterization of societal benefits that was employed.

Table 3-1
Overview of Filings Including Demand Response Benefits

	File Date	Status	DR Benefits Analysis	DR-Related Benefits	Other
SCE (CA)	3/30/2005	Approved 12/1/2005	Included in Supplemental Filing	$481 M	None Included
PG&E (CA)	6/16/2005	Approved 7/20/2006	Avoided Cost	$338 M	Qualitative
SDG&E (CA)	3/15/2005	Approved 4/12/2007	Avoided Cost	$502 M	$32-$43 M
Central Hudson (NY)	12/28/06	Pending	Qualitative Discussion	Not Quantified	Qualitative
National Grid (NY)	1/31/2007	Pending	Qualitative Discussion	Not Quantified	Qualitative
ConEd (NY)	3/28/2007	Pending	Avoided Cost	$224 M	$45 M
Energy East (NY)	2/1/2007	Pending	Qualitative Discussion	No Quantified	Qualitative
CMP (ME)	11/9/2007	Pending	Avoided Cost	$51 M	None
Vermont	Report for Staff 3/2008		Avoided Cost	$25 M	$21 M
Oregon	3/2006	Approved 5/2008	Avoided Cost	$3 M - $27 M	$9 M - $33 M
ComEd (IL)	3/12/2008	Pending	Avoided Cost	$400 M	None

Approvals for Smart Metering filings are limited to three in California and one in Oregon. Eight of these filings included societal benefits explicitly, including all four of those approved. The California filings attribute 90% or more of societal benefits to demand response enabled by Smart Metering will enable, with net present values ranging from $338 - $481 million. Oregon reported societal benefits of $12 to 60 million, in approximately equal parts from demand response and other sources. Only one of the four New York Smart Metering filings included quantified societal benefits. Filings in Maine, Illinois, and Vermont also include societal benefits, with the Vermont filing the only one that reported benefits—50% of the total—outside of those attributable to demand response.

3.2.1 California

Table 3-2 provides detail on the types of analyses performed for the three California IOUs: Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison. Of these utilities, PG&E and SDG&E have received approval by the California Public Service Commission (CPUC), but the SCE request is still being evaluated. These analyses are notable for the variety of ways that societal benefits were characterized:

- PG&E assumed that critical peak pricing (CPP) rates would be implemented for households and smaller businesses and used the results of the state's pricing pilot to estimate participation in CPP and the response (kW and kWh) that would be exhibited. These results were monetized by applying avoided costs values ($/kW and $/kWh) approved by the California Public Service Commission (CPUC) that were in part linked to expectations for wholesale prices during the study period.
- SDG&E chose to base societal benefits on a peak time rebate (PTR) program, estimating a participation rate using a constructed relationship between awareness (using results from the state pilot) and participation. The CPUC elected to use a different formulation to monetize these benefits.
- SCE assumed that the combination of time-of-use (TOU) rates, CPP, and a programmable controllable thermostat (PCT) would induce demand response and valued the load changes at its determination of avoided costs.

The California filings rely on demand response to produce societal benefits, but they differ in which specific demand response plans are used as the bassi fro the calculation of societal benefits show those changes were monetized.

s – California Utilities

	Program	Participation & Response	Valuation of Response	Other Benefits
	CPP rates approved by the CPUC for residential customers and for its small commercial and industrial customers with maximum demand of less than 200 kW	Uses the results of the CA SPP to assume participation in dynamic pricing. Elasticities are based primarily on the results from the California Statewide Pricing Pilot.	The CPUC ruled on a particular level to use in the DR benefits estimates based on all of this evidence. The market price referent played a prominent role in setting this level.	No other benefits were quantified. A party to the case qualitatively recognized a number of other benefits.
s	Peak-time rebate program for residential and C&I customers with maximum demands less than 200 kW	CPUC set PTR awareness at 50%. Elasticities are based primarily on the results from the California Statewide Pricing Pilot.	CPUC weighed evidence in the case to set a $/kW/yr avoided capacity value. Annual future costs used for avoided energy.	Improved public safety and environmental benefits were estimated without transparent method.
	Default TOU and Optional CPP for residential and small commercial. Also direct load control with PCTs.	CA SPP to used assume participation & response to dynamic pricing. Assumes 25% enrollment in DLC and 50% awareness with PTR.	SCE filed detailed description of avoided capacity cost using CT proxy adjusted for dispatch qualities of DR program. Marginal energy costs used.	Discussed briefly but not quantified.

3.2.2 New York

Table 3-3 demonstrates the relative sparse nature of the New York utility Smart Metering filings. While Consolidated Edison quantifies societal benefits, it offered no substantiation of the nature of the calculations that produced those results.

Table 3-3
Detail on the Analyses – New York Utilities

Utility	Program	Participation & Response	Valuation of Response	Other Benefits
ConEd	Details of analysis not provided.	Details of analysis not provided.	Details of analysis not provided.	Details of analysis not provided.
Energy East	N/A	N/A	N/A	N/A
National Grid	N/A	N/A	N/A	N/A

3.2.3 Recent, more detailed Societal Benefits Estimates

Table 3-4 provides details on the types of analyses performed for the three most recent Smart Metering filings that included societal benefits. They employed very similar approaches to estimating the benefits attributable to demand response.

Table 3-4
Detail on the Analyses – Recent Studies

Utility	Program	Participation & Response	Valuation of Response	Other Benefits
Central Maine Power	PTR program for residential and medium C&I with max demands 20-400 kW.	An awareness rate of 50% is assumed based on the level used in the SDG&E analysis approved by the CPUC. Elasticities from CA SPP.	Avoided capacity costs using ISO-NE FCM – inflation of CONE estimate. Avoided energy using projected market prices.	No other benefits quantified.
Vermont DPS Study	PTR program for all residential and medium C&I with max demands 20-200 kW.	Assumed awareness of 50% for residential and 25% for C&I.	Avoided capacity costs using ISO-NE FCM – inflation of CONE estimate. Avoided energy using projected market prices.	Avoided T&D; Environmental; and Reliability enhancements.
ComEd (IL)	PTR program for residential only. Customers on other programs not included.	Assumed a 25% awareness rate. Adjusted elasticities from CA SPP to fit ComEd climate and demographics.	Avoided capacity costs from PJM Reliability Pricing Model inflated. Avoided energy costs based on market.	No other benefits quantified.

- All three recent studies associated benefits with demand response through a Peak Time Rebate (PTR) program for households and small business; however, , the ComEd assessment was limited to households.
- All three used awareness (50% in each case) as the principle indicator of participation, citing the California pilot, and used price elasticities from that pilot to estimate kW and kWh impacts.
- All used avoided capacity costs that were associated with ISO capacity prices and avoided energy costs associated with ISO Locational Marginal Pricing (LMP) prices.
- Vermont was exceptional in attributing benefits associated with improved reliability, utilizing protocols and valuation methods that are discussed in Section 5.

Notably, all these analyses directly relied on market transactions to derive avoided costs, in contrast to the use of administratively determined avoided costs in California, which is both compelling, given the nature of these competitive markets.

3.3 A Higher Resolution Look at one specific Societal Benefits Estimate

The societal benefits monetization approach used for all three of these filings can be understood by examining in detail Com Ed filing's calculations, as follows;

3.3.1 ComEd Smart Metering Deployment Plan

The deployment of Smart Metering and associated infrastructure by Com Ed was assumed to start during the 4th quarter of 2008 and to be completed by the end of 2014. Assuming a 20-year meter life, the last meter will end its useful life in 2033. The benefits analysis took into account the staggered nature of meter installation and lifetime in establishing the benefits stream and corresponding net present value (NPV).

3.3.2 Demand-Response Program Used for Benefits Estimate

The analysis was based on the PTR program that would be made available to all residential customers through the advanced metering system. Commercial and industrial programs were not included because Com Ed asserted that it already has achieved sufficient demand response (1,000 MW) from those sectors. The illustrative PTR program would pay $0.75/kWh to residential customers that reduce demand during the six-hour period from noon to 6 p.m. when requested to do so by Com Ed. Such events would be limited to 12 high demand weekdays during the summer months of June, July and August. Only those that respond to an event declaration would be paid, and a penalty would be imposed on those that elect not to respond.

3.3.3 Estimated Net Benefits

Over the 20-year time horizon, the present value of gross benefits is estimated at $610.2 million. This is offset by the costs of marketing and administration of $48.0 million and the incentive payments to participating customers of $165.3 million, leaving a net societal benefit of $396.9 million attributed to the proposed Smart Metering investment.

3.3.4 Basis for Gross Benefits Estimate

Gross benefits refer to the overall reduction in costs stemming from the capacity obligations and energy payments required to meet customer needs in ComEd's service territory.

MW impacts. If customers reduce demand during high demand periods, ComEd and other competitive load serving entities face a lower capacity requirement in the PJM market to the extent that the PTR reductions correspond to the times when PJM determines the capacity requirement. The PTR program would achieve capacity reductions for ComEd by anticipating the hour in each of the four summer months that is used to establish the monthly system peak (for the applicable PJM zone) and calling for load reductions in that hour. By specifying that events cover the period noon to 6:00 p.m., ComEd increases the likelihood that the load reductions do indeed translate into reduced PJM capacity requirements.

3.3.5 Energy Impacts

ComEd and other load serving entities may pay less for energy purchased from PJM if the load curtailments result in reduced wholesale energy costs.

3.3.6 Benefits Formula

(1) MW Impact = (Average use per customer during peak period on the current rate) x
(% Drop in peak period use per customer given a specified change in price) x

(Number of customers in the target population) x

(Program participation rate)

This equation was used to predict the change in energy use for each event for each year of the forecast horizon.

(2) Total Benefits = [(MW Impact) x (Avoided Capacity Cost)] +

[(MWH Impact by Rate Period) x (Avoided Energy Cost by Rate Period)]

3.3.7 Customer Participation & Awareness

The benefit estimate assumes that the PTR program is part of the default rate for residential customers that did not switch to a competitive supplier or participate in another demand response program. ComEd assumed that between 3.5 – 3.6 million participating customers would be subscribed to the PTR service. It further assumed that the PTR program would achieve 25% awareness among residential customers, where awareness is defined as customers that understand the potential benefits of responding during an announced peak day and as a result respond to events.

3.3.8 Price Responsiveness

The change in energy use during peak periods by respondents on PTR days is based on estimates of the elasticity of substitution and daily price elasticities from California's Statewide Pricing Pilot (SPP), after taking into consideration differences in climate and air conditioning saturations between California and the ComEd service area. The assumed value of the substitution elasticity is between -.115 and -.127. The assumed daily price elasticity value lies between -0.0437 and -0.0524 for event days. Com Ed contends that these values are comparable with those from other pilots involving residential dynamic pricing and therefore are applicable to Com Ed's circumstances.

3.3.9 Avoided Capacity & Energy Cost Estimates

Avoided capacity costs make up 95% of the estimated benefit. Total avoided capacity costs are based on expected capacity costs as represented in PJM's wholesale Reliability Pricing Model (RPM). Lower capacity requirements that result from PTR-induced load modifications translate in savings based on the RPM assumed cost of new generation entry, adjusted for inflation (3.8% per year based)—about $104/kW-year for ComEd.

The reduction in wholesale energy costs resulting from the load shifting and load reductions was calculated based on the wholesale market data for the ComEd zone for PJM. Energy savings are estimated by projecting how load reductions during PTR events would affect PJM LMPs.

3.4 Summary

What is clear from examining these applications is that there are a handful of critical determinants in valuing the benefits of demand response enabled by Smart Metering technology:

- What is the nature of the demand-response program?
  - What are the features of the program itself?
  - Is the program in place, proposed, or assumed?
- What will be the participation levels?
  - What is the basis for enrollment estimates?
- How is demand/price response determined?
  - Internal experience?
  - Transferring results from studies performed elsewhere?
- What is the value of Avoided Generation Costs?
- What is the basis for 20-year series of inputs in presence of DR?

These issues are addressed in the next section. Only two utilities proposed specific benefits from improved reliability, which is discussed in Section 7.0; and only one quantified externalities, the topic of Section 9. None offered any benefits associated with the ability to offer new products and services (Section 6) or macroeconomic impacts (Section 8).

4

VALUING DEMAND RESPONSE PRODUCTS AND SERVICES

Smart Metering's largest influence on electricity markets may turn out to be its role as an enabler of demand response. Electricity markets that lack sufficient demand response to achieve efficient and effective performance do not functional optimally. Achieving the requisite amount of demand response faces barriers starting with the cost of replacing existing metering with program-compatible technology and determining when and how consumers must adjust electricity usage to benefit from the capabilities of the new equipmentniversal Smart Metering removes the first barrier by making every consumer a potential participant. The informational capabilities of Smart Metering may expand the scale and scope of demand response program participation by helping consumers devise and carry out behavioral changes. Characterizing and quantifying these enabler benefits requires a clear definition of how load changes impact electricity prices and investments decisions.

4.1 Introduction

There is a growing body of literature that defines, describes, characterizes, and in some cases quantifies how consumers respond to changes in what they pay for electricity. As noted earlier and verified below, demand response is already prevalent in many parts of the country. Smart Metering can foster even greater levels of demand response in several ways:

- Increasing scope. The relative short notice that accompanies price changes on the declaration of events under load control programs restricts participation, especially by households. Air conditioner dispatch programs have enjoyed acceptance in some circumstances because the utility can invoke the curtailment directly. Smart Metering may expand the appliances in households and the devices in business that can be dispatched directly. Moreover, it may provide a means for conveying event notices more quickly and providing acknowledgement that they were received.
- Expanding scale. The universal implementation of Smart Metering makes every consumer a potential participant, thereby removing a cost and technology barrier and enabling the adoption of opt-out utility tariff design strategies.
- Improving availability and reliability. Smart Metering allows the utility to monitor more precisely the extent to which individual premises respond to prices or event declarations, thus reducing free-ridership and under-payment.
- Improving integration. When Smart Metering is appropriately configured, the system dispatcher can monitor demand response on a near real-time basis, thus allowing resources to be more effectively integrated into system operations and thereby enhancing their value.

For the purposes of valuing the benefits attributable to Smart Metering, it is instructive to first define and examine examples of demand response programs and services (hereinafter programs) that may be enhanced or enabled by Smart Metering technology. Attributing benefits to any program or to a portfolio of programs involves fully characterizing the specific features of the program, specifically the participation decisions involved and the degree of change in usage exhibited by participants.

The analysis must establish how many events the consumer will encounter during the study period, which may involve 10-25 years or more. Smart Metering-induced demand response is measured by changes in the level and pattern of energy consumption (which measures the flow of the source of benefits, changes in kWh usage) and demand (which represents a change in the stock of investment required to serve that flow). Finally, the impact of changes in energy and demand must be transformed into benefit streams that indicate the level and distribution of monetary and other benefits.

To emphasize the need to specify very detailed and verifiable assumptions, characterizing and quantifying participation is discussed first, followed by an examination of how participant price responses are characterized and quantified. This discussion is followed by an examination of methods that have been developed for jointly establishing participation and response, which recognizes that these behaviors share many common factors. The final section reviews methods that have been used to transform the energy and demand changes into monetary streams and identify to whom they accrue.

Demand response programs offered by ISO/RTOs are used prominently in the discussion that follows. Referencing these programs does not constitute an endorsement of any specific ISO/RTO program nor is it an indication that programs integrated into the wholesale market are superior to those that are implemented by utilities or competitive load serving entities or by specialized providers, often referred to curtailment service providers. Studies of the impacts of ISO/RTOs have resulted in a comprehensive portrayal of how price-induced load changes affect market price formation. The result is an analytical framework that provides insights because it traces the level and flow of benefits in a way generally applicable to any market circumstances. Moreover, the manner in which ISOs/RTOs accommodate demand response as a capacity resource illustrates important differences in how demand response provides capacity-avoidance value at the wholesale and retail level.

4.2 A Functional Framework

Demand response is the change in electric consumption from an established pattern undertaken by a consumer (or group or segment thereof) in response to a change in the price it pays or to some other inducement. Smart Metering may enable the implementation of new demand response programs or result in more profound energy and demand changes in existing ones. However, Smart Metering by itself does not advance demand response. Related activities are required, and they may involve additional costs.

Accordingly, in order to assert that Smart Metering is in fact the catalyst for advancing demand response, an analysis must demonstrate that 1) the new sources of demand response would not have been realized in the absence of the Smart Metering technology deployment and/or 2) that

Smart Metering would induce improvements in existing programs that otherwise would not have materialized.

These requirements can be most convincingly accomplished by employing an elemental, systematic, and dispositive framework for quantifying the expected energy and demand impacts that might be attributed to Smart Metering. Elemental refers to breaking the analysis down so that the key behavioral assumptions employed correspond to accepted characterizations of consumer behavior. Systematic implies that it provides an orderly and thorough process. Dispositive refers to utilizing data from pilots and behavioral or impact analyses to support the assumptions about behavior and other subjective or stochastic parameters.

EPRI researchers devised a framework that involves four basic elements, listed here with references to where they are discussed in this report:

- Identifying the demand response product or products that are the focus of the analysis and specifying the character and number of events that is associated with each (Section 4.3)
- Establishing which consumers are likely to participate in the program (Section 4.4)
- Quantifying participants' response to price changes or inducements (Section 4.4 and 4.5)
- Transforming the induced electricity consumption changes (energy and demand) into monetary or other value streams (Section 4.5)

The following sections provide a detailed discussion of how the subject benefits are defined and from where they emanate and how they are transformed into monetary benefits streams. Examples of empirical applications are provided to illustrate what is required to execute the methods and protocols described.

4.3 Demand Response Products and Events

It is essential to achieve clarity about the assumptions used in quantifying the impacts of demand response programs because a wide range of assumptions are involved, many of which are based on consumer behavior and therefore subject to considerable uncertainty. The process of clarifying assumptions begins by distinguishing programs by the features that most influence consumer acceptance and response.

4.3.1 A Distinction between Demand and Price Response

The terms demand response and price response are often used interchangeably, which causes no confusion when the discussion is very general in nature and the intent is to refer generally to the cause or the consequences of a behavior change that affects the profile or level of electricity usage. Confusion and ambiguity arise when the reference is to a specific program, tariff, or pricing structure that motivates the behavior. Behavioral changes can be accomplished using any one of the many combinations of features that make up a program. As illustrated in Figure 4.1 these features may include:

- The price or incentive, which can include a penalty, that induces or is used to induce a behavioral change. Prices can be derived directly from streaming wholesale spot market prices to reflect recurring wholesale market diurnal patterns; or they can be set equal to a utility's forecast (avoided) or actual cost of supply (marginal or average marginal); or the prices can be synthetic or set administratively to achieve a specific and desired result, for example, to achieve a specified level of load reduction. Incentives can be in the form of up-front option payments, payments based on event load curtailment performance, payments in kind (such as equipment that enables or augments response), or all of these.

- Performance penalties used to ensure compliance to load curtailment obligations. They can be defined relative to the prevailing price (often as a multiple of it) or relative to the up-front lump sum incentive. They can be set synthetically high to achieve a high level of compliance or low to encourage participation.
- The circumstances when a price change or incentive is induced, such as how often (per day, week, month season, year), with how much notice, and for how long that situation continues before the price returns to a more typical level routine.
- The contract obligation (term and minimum participation level), which may include requiring that the participant install and pay for the requisite metering and communication equipment and agree to performance tests and other certifications.
- How the participant responds, including deciding which (if any) actions the participant takes on its own to reduce load, when response is voluntary, and which loads to commit to control exercised by the participant or by the program operator.

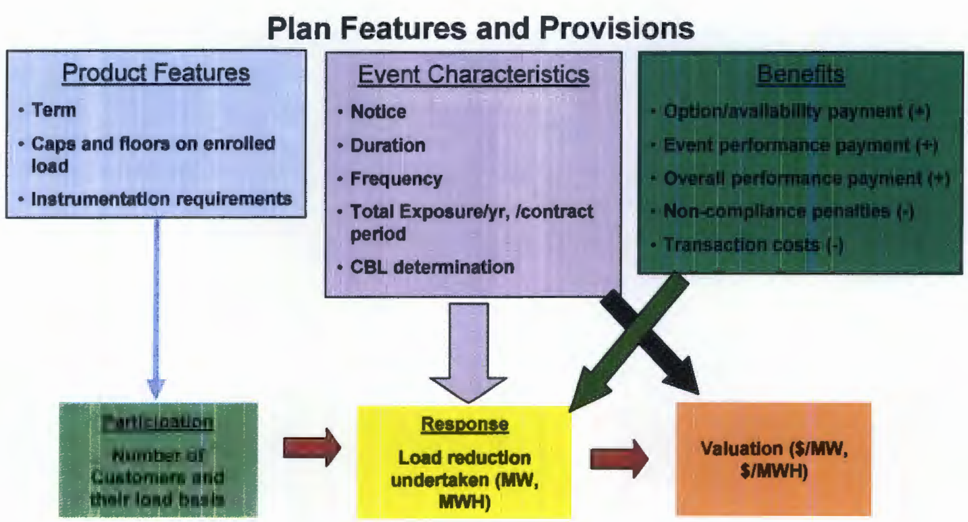

Figure 4-1
DR Program Features

Because the behavioral response is likely to differ depending upon the character of the demand response program being evaluated, it is important in developing a Smart Metering business case to make sure that the attribution of benefits uses methods that recognize these distinctions. For example, a program that issues a new price schedule each afternoon based on prevailing day-ahead wholesale prices that is applicable to all electricity consumed in the corresponding hours of the next day—often called real-time pricing or RTP— most likely induces a different behavioral response than one that involves the utility installing a control device that allows it to shut off a specific device on the consumer's premise such as an air conditioner or loads the consumer designates whenever it deems it is necessary for reliability purposes or is in its interest for commercial reasons.

The discussion in the following sections of how to establish the benefits of demand response-induced behavioral changes assumes that the programs under evaluation have been fully specified so the analyst can account for the influence of the many factors that come into play. Before leaving the topic of the important differences among demand response programs, however, it is useful to lay out a hierarchical framework that sorts demand response programs according to the features that have the largest influence on the behavior of the consumers they serve.

4.3.2 Demand Response Hierarchy

A useful hierarchy of demand response programs should identify the primary distinguishing features that drive behavioral changes. It must sort programs into groups that share the same primary motivations for a price change and thereby allow the analyst to focus on portraying that behavior under representative or alternative event circumstances with a high degree of confidence that if the assumptions employed are correct, the synthesized results will likely to be realized.

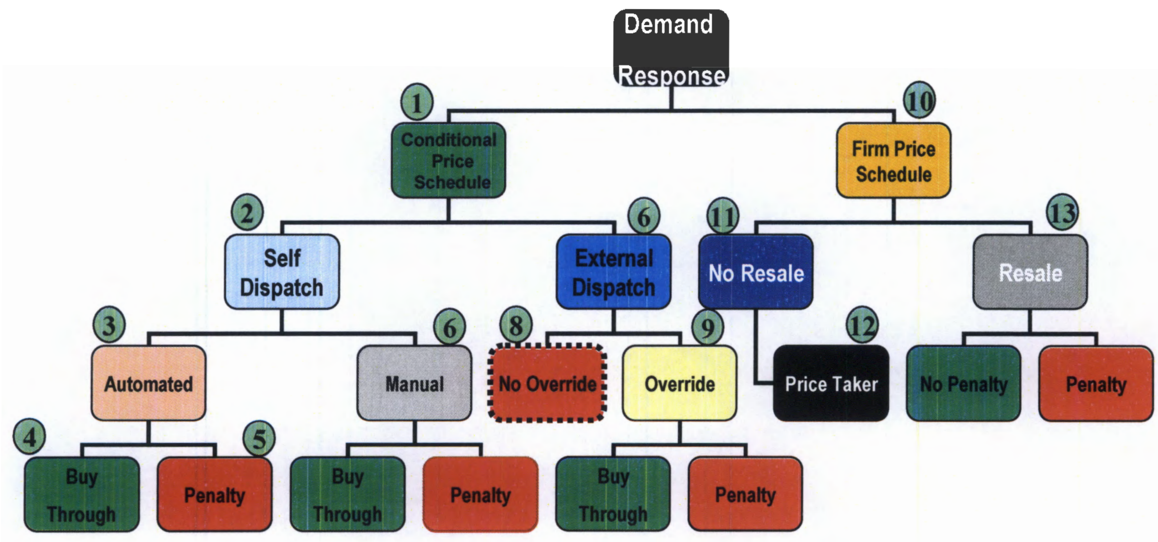

Figure 4-2
Hierarchy of DR Programs

Figure 4-2 portrays such a hierarchy, which sorts demand response programs according to distinguishing criteria. These criteria are as follows, with references to Figure 4-2 by category and a distinguishing number:

The primary behavioral differentiator involved when the price schedule is firm or conditional:

(1). **Firm Price schedule.** The consumer receives prices that apply to all metered consumption for a specified period, with no constraint on the amount consumed or when it is consumed. Note that the term "Firm" does not imply fixed. The price schedule can change hourly, daily or less frequently or be fixed for several years and can apply to each hour or to cumulative energy consumed over a specified period. Conventional uniform tariffs that fix rates for extended periods fit this category, as do RTP programs that post firm prices a day ahead or an hour ahead.

(10) **Conditional Price Schedule.** The price schedule the consumer receives applies to all usage except when some or several states of the world arise, in which case the schedule price is replaced with another, different price. A critical peak-pricing (CPP) program is an example of such a schedule, because the critical peak price replaces the otherwise applicable schedule price, which often is TOU-based but can be a uniform or inverted rate. A wide variety of other demand response program designs perform in a similar manner, such as Peak Time Rebates (PTR) and load control programs.

The rest of the hierarchy can be explained best by proceeding down each major paths, starting with the conditional followed by the firm price schedule category:

1. **Conditional** pricing schedule are further subcategorized as follows:

2. Self Dispatch – the consumer decides how to reduce consumption.

3. Automated Dispatch – self-dispatch is accomplished through activation by the consumer of a controlling device that shuts off designated devices or loads. The controller may take action automatically on receipt of a price signal or other activation message, or the consumer may activate the controller when conditions warrant.

4. Buy-through – indicates that the demand response program makes provision for the consumer to pay a specified price for energy that was obligated to be curtailed but was not curtailed during an event. That price may be specified in advance, as is the case with CPP, or specified for each event, which is the case with some ISO/RTO energy bidding programs.

5. Penalty – indicates that a penalty applies for the failure to reduce load by the agreed to amount, which is a provision of call option-type programs.

6. Manual Dispatch – self-dispatch is achieved by the consumer manually turning down or off devices and turning them back on after the event transpires.

7. External dispatch – the controlled device or devices are turned off by the program operator when it requires the load reduction:

8. No Override – there is no provision for the participant to override a shut-off command issued by the program operator, or

9. Override – the participant may override the command, in which case either a buy-through price or penalty apply for failure to comply to the event curtailment obligation.

10. **Firm** pricing programs are further and uniquely subcategorized as follows:

    11. No resale – the consumer cannot offer its electricity purchase right to another entity, for example as bid curtailments into the ISO/RTO wholesale energy markets.

        12. Price taker – as a consequence of the prior condition, the consumer is a price taker, the usual role for consumers in competitive markets. It takes prices as given, they are determined by forces outside its control, and optimizes its well-being accordingly.

    13. Resale - the consumer can offer its electricity purchase right to another entity, for example as bid curtailments into the wholesale energy market. Non-compliance results in penalties or the payment of specified prices for failure to meet the obligation.

This demand response hierarchy sorts demand response programs into groups that share in common how prices are established. The hierarchy demonstrates the pervasive role of price in determining how consumers respond to demand response program incentives. Therefore, quantifying the impacts of demand response should focus on how price influences participant behavior. The influence of price on behavior is covered below.

4.3.3 Demand Response Events

An event, in the context of a demand response program, is defined as a period when a price change is of sufficient magnitude to induce a consumer to adjust its electricity consumption. In the case where the consumer has turned over control of a device to the utility, an event is when power to that that device is curtailed by the utility.

Under a Firm price Schedule demand response program, events are determined not by the utility (or other entity providing the service), but by the consumer. The participant determines what level of price change warrants an adjustment in electricity usage, either a shift of load from one time to another or curtailing discretionary consumption or both. Participants taking advantage of resale opportunities they are afforded, for example by offering a curtailment as a supply source in the ISO/RTP spot energy market or responding to an offer of payment for curtailments either from the ISO/RTO or the utility, are also price takers as they decide when to bid (and thereby invoke an event) and when to curtail (when to accept participation in an event).

Defining events under these conditions therefore requires establishing the price at which participants undertake load changes. Events and response are jointly determined, so modeling expected response to a specific program requires not only forecasting prices at the same level of time differentiating that is used in the price schedule, but also determining the participant's response to that price. This topic is the subject of Section 4.6.

Conditional price schedules involve the imposition of price changes under specified conditions, which amount to an event declaration by the utility or program managing entity. Estimating the program impact requires determining how many times the conditions that trigger events will be encountered and how long those conditions will last at each instance. If the event triggering conditions are related to conditions that conform to a pattern or distribution, for example temperature, then historic data can be used to establish annual expected event profiles. If the trigger is defined by dynamic system conditions, for example when the annual system peak is likely to be set or the historic peak exceeded, then the occurrence of at least one event is assured; but in all likelihood several events have to be declared to actually correspond an event with the specified conditions.

Quantifying demand response impacts requires specifying the number of events the participants will face over the study period. This requirement can be a daunting aspect of a Smart Metering business case because that period is 10- 15 years or more. Forecasting event frequency and duration over such a long period is fraught with uncertainty about the nature of both demand and supply. The analyst is well advised to develop a characterization of the range of market circumstances and employ analytical protocols and modeling techniques to portray the distribution of the corresponding demand response benefits outcomes and allow decision makers to decide how to treat the inherent risks.

4.4 Measuring Participation

Smart Metering can generate demand response benefits if consumers can be induced to undertake three actions: enroll in a program, commit (implicitly or explicitly) some of their typical electricity consumption for curtailment, and respond to opportunities and obligations to curtail. Clearly, enrollment is a necessary condition to attributing benefits. Defining the intended or target population is the first step.

If Smart Metering is deployed universally, all consumers can participate in demand response programs, at least in principle, because the metering is in place. This removes a cost barrier to participation, but consumers still must be engaged to consider enrollment. Some demand response proponents, evoking Thaler's and Sunstein's (2008) concept of libertarian paternalism (nudging), argue that the Smart Metering should be universally configured to enable participation and all consumers should be automatically enrolled in the program, thus requiring them to take some action to un-enroll or opt-out. This arrangement may result in a higher level of participation because it overcomes barriers that may cause consumers to make decisions less than optimal to their interests. However, implementing this scheme may encounter opposition from those concerned with the plight of special circumstances consumers.

Alternatively, demand response program participation can be estimated from the bottom up by identifying consumer characteristics that are conducive to participation—for example, experience with energy management, degree of operational flexibility, availability of control devices—and estimating how many consumers in the population have those characteristics. This approach implies that participation depends on a few critical and measurable consumer characteristics.

The discussion that follows reviews the body of experience related to estimating demand response participation according to whether it reflects actual market choice decisions (revealed preference) or utilizes a synthesis of the decision process constructed around consumer responses to hypothetical decision situations (stated preference).

4.4.1 Revealed Preferences

Actual program participation rates and product choices provide guidance for establishing participate rates for specific demand response programs. However, since most of the available data reflect targeted marketing, these results should be employed carefully. A synopsis of several studies to summarize experience with participation rates underscores this point.

4.4.1.1 National Estimates of Participation

The IRC (IRC 2007) produced a summary of demand response program participation in the summer of 2007. The 10 member ISOs/RTOs (Independent System Operators/Regional Transmission Operators) reported the MW of load enrolled in four categories: capacity, energy-price, energy-voluntary, and ancillary services. The programs comprise all the ways in which consumers are provided opportunities to participate in wholesale electricity markets. The report provides results for all ten ISO/RTOs, but for the purposes herein, results are only displayed for the seven United States ISOs/RTOs.

Figure 4.3 displays the level of enrolled MW by ISO/RTO market; Figure 4.4 shows enrollment by product; and Figure 4.5 shows the aggregate demand response resources as a percentage of the each market's summer peak demand. Collectively, the U.S. ISO/RTOs reported having over 20 GW of coincidently available curtailable load enrolled in their programs. Capacity program participation in 2007 was the predominant category, comprising 68% of total demand response. Smaller amounts were enrolled in ancillary services (17%) and energy-price (12%) programs. Only 4% was enrolled in energy-voluntary programs, which were available only from PJM and New York Independent System Operator (NYISO) in 2007.

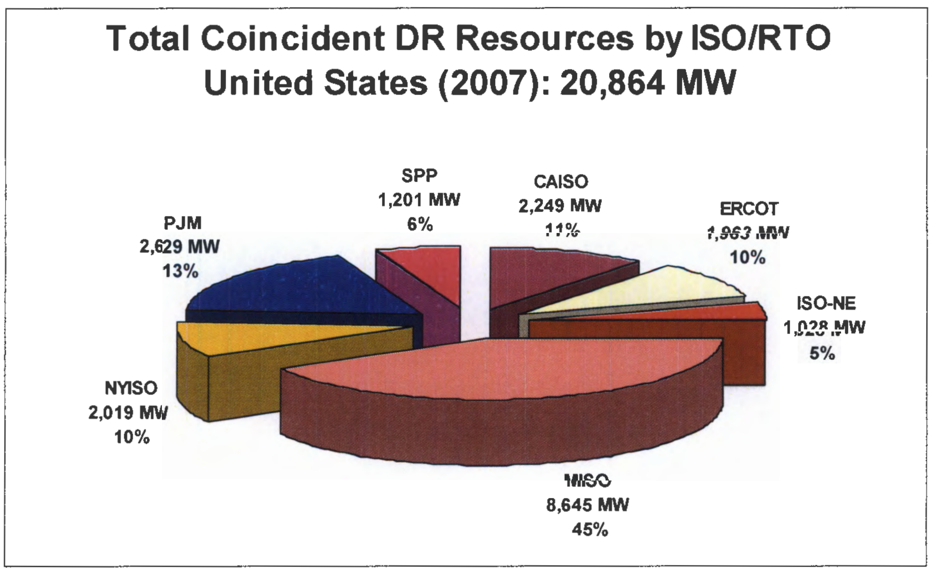

Figure 4-3
DR Resources by Region –IRC Study

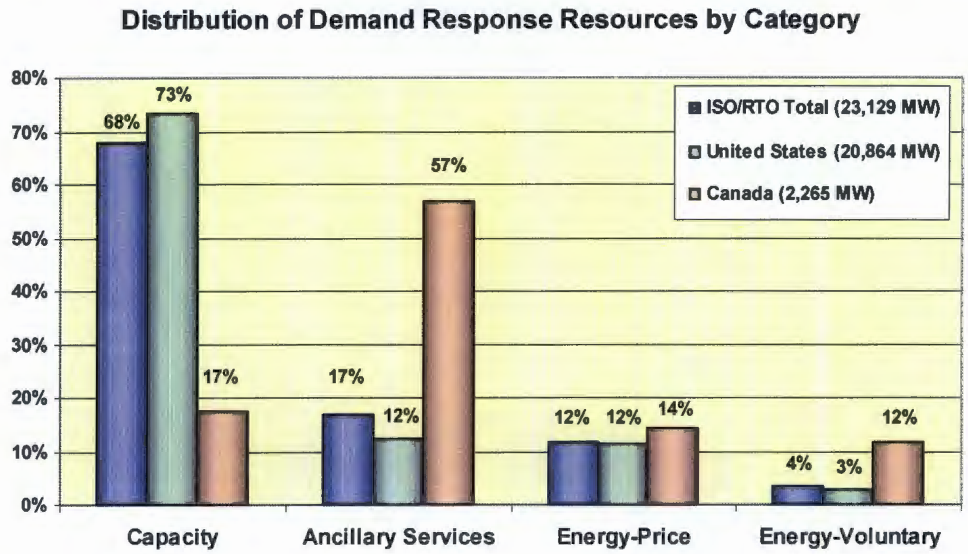

Figure 4-4
DR Resources by Type – IRC Study

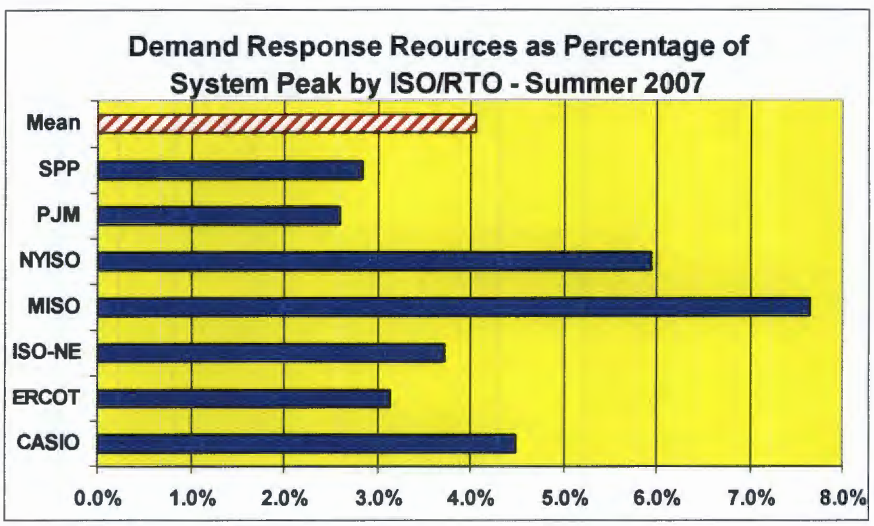

Figure 4-5
IRC Estimates of DR Resources as Percentage of Peak

The preference for capacity programs is due to a few critical drivers. First, all of the ISOs/RTOs, except ERCOT (Electric Reliability Council of Texas) and MISO (Midwest Independent System Operator) , offer consumers opportunities to supply capacity to meet the market's capacity obligation. The NYISO and PJM Interconnect (PJM) programs commenced soon after the market's formation in the late 1990s. End-use consumers in these markets have had several years of experience to construct expectations for what level of benefits and exposure to curtailment events they can expect.

A new class of aggregating marketers has emerged, called curtailment service providers, which specialize in helping customers evaluate participation and in some cases offer support services such as helping develop and carry out load curtailment actions when events are declared. Together, these factors have resulted in almost 2,500 MW enrolled in capacity programs in these markets.

Ancillary services have attracted over 800 MW of load in ERCOT, and similar programs are being launched in several other of the ISO/RTO wholesale markets, demonstrating that there are some customers that find the rewards from receiving market-based prices worthwhile despite the very short notice they receive of an obligation to curtail. However, many of the ERCOT participants had pervious experience with utility programs that resulted in their installing equipment to accommodate short-notice or in some cases no-notice events; this experience may not be easily or quickly replicated in other markets.

The benefits of participating in capacity programs are generally higher than those available in energy-only or energy-voluntary programs. Participants in the energy-only program bid load curtailments into the day-ahead or real-time market. If they are scheduled, effectively displacing equivalent generation, they are paid the prevailing LMP (locational marginal price). Price volatility has declined in recent years, which may render price-responsive bidding less profitable. The recent upswing in payments made through some of these programs appears to be in large part due to opportunistic bidding from some participants taking advantage of shortcomings in the program design. Corrective actions are under consideration or have been proposed through ISO/RTO filings.[7]

Voluntary compliance programs have appeal to consumers that are not willing to expose themselves to non-compliance penalties in order to receive capacity payments. Participants decide on an event-by-event basis whether or not to curtail. However, there is no assurance that events, which constitute opportunities to realize benefits, will come about.

ISO demand response program filings and reports provide a somewhat more detailed characterization of program participation. They enumerate participants by program and zone (which defines pricing distinctions) and in some provide cases additional detail such as the distribution of enrollments by entity (utility or curtailment service provider) or how the participant meets a curtailment obligation or takes advantage of a curtailment opportunity, for example, by reducing load or dispatching on-site generation. The most recent FERC filings by ISOs/RTOs provide historical detail, which provides insight into participation by individual resource category and overall program growth. In addition, they report performance in terms of actual kW and kWh curtailed of resources during events.[8]

[7] Federal Energy Regulatory Commission. August 2005. Demand Response and Advanced Metering. A report to Congress. Staff Report, Docket No: AD-06-2-000

[8] Annual reports filed with FERC on demand response are available on the ISO/RTO web pages.

However, except for a few in-depth studies, the performance of individual resources has not been evaluated.[9] Moreover, little or no information about participant characteristics, such as business activity or household size, is made available to more fully evaluate what factors seem to be associated with participation and program performance.

In summary, the experience of ISO/RTOs in operating demand response programs offers some insight into the distribution of preferences for various demand response products, For example, the total resources available in a market today may fall in the range of what reported by IRC, from 2.5 to over 8% of system peak load (Figure 4.5). Considering the circumstances under which these enrollments were realized, the results should be extrapolated with caution to other program designs. Circumstances may differ in terms of features, the levels of payments and penalties involved, and market structures. For example, some of the programs were offered by a vertically integrated utility in a non-restructured state using administratively determined avoided costs.

The Federal Energy Regulatory Commission (FERC) conducted a census of demand response programs in 2005—the census is currently being updated with results expected to be released in late summer of 2007. The FERC census reported a demand response enrollment nation-wide of over 32 GW.[10] The results are summarized in the following figures:

- Figure 4.6 reports resources by resource type (11different designations) to provide one perspective on market shares. Like the IRC report, the FERC study indicates MW enrolled but not the number of participating consumers.[11]
- Figure 4.7 illustrates the total demand response resources as a percentage of system peak demand for each region. FERC reports a wider range of values (3-20%) than what was reported by IRC, but the findings are comparable (3-7%) if the one outlier value (MRO's reported 20%) is excluded.
- The FERC census provides overall program-specific performance data, as illustrated in Figure 4.8, and 4.9. Differences among regions—from low to over 40%—are to be expected, which may also explain the large variation among products (Figure 4.9) due to a high degree of correspondence of products and circumstances.

The FERC data, like that of the IRC, provide insight into the nature of program participation. But, participation is reported at too high a level to be of useful in estimating participation in

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[9] RLW Analytics, Neenan Associates. December 2004. An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2004. Annual Demand Response Program Evaluation submitted to FERC. Available at http://www.ISO-NE.com.: Neenan Associates, Lawrence Berkeley National Laboratory, Pacific Northwest National Laboratory. January 2003. How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance. Available at http://www.bneenan.com.

[10] Federal Energy Regulatory Commission. August 2005. Demand Response and Advanced Metering. A report to Congress. Staff Report, Docket No: AD-06-2-000

11 No attempt appears to have been made to reconcile the differences in the IRC and FERC total resource levels. It is due in part to the fact that IRC markets serve only about 80% of United States while FERC sought to include the entire country. Another factor may that the IRC specified coincident resources while the FERC numbers do not appear to have been fully controlled for the enrollment of some resources in more than one program.

specific utility programs that differ very much from those offered by the ISO/RTOs or ones implemented in other markets with different consumer circumstances.

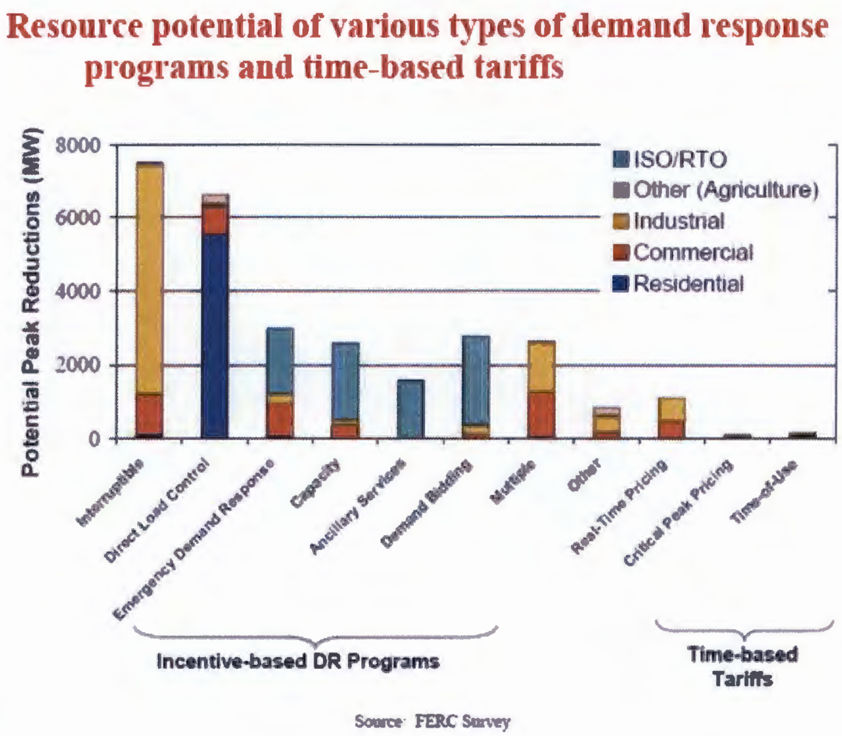


Figure 4-6
DR Resource Potential by Type – FERC Study

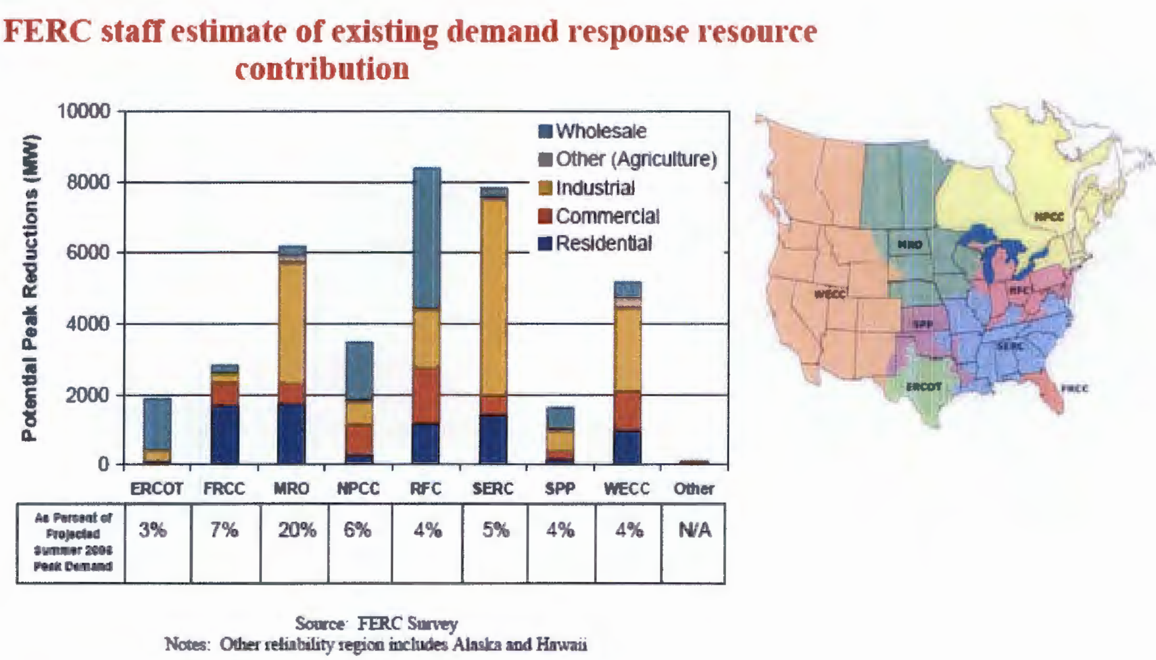
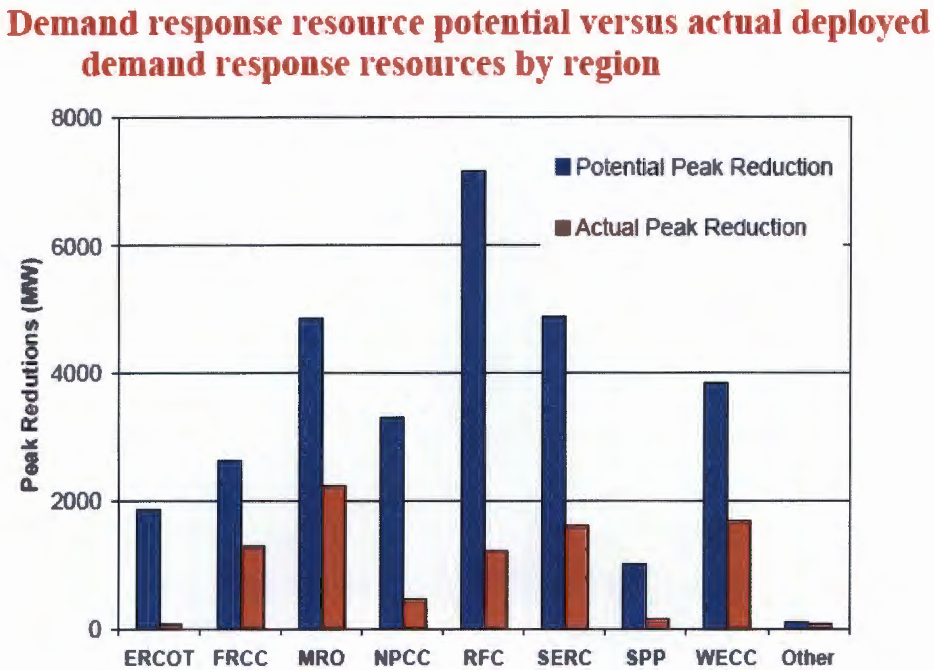


Figure 4-7
DR Contributions to System Resources – FERC Study



Source: FERC Survey
Notes: Other reliability region includes Alaska and Hawaii

Figure 4-8
Regional DR Participation Rates –FERC Study

Ratio of actual deployed demand response resource to demand response resource potential by program type

Program Feature	Sample Size	Median Value
Direct Load Control	440	.56
Interruptible/Curtailable	195	.39
Emergency Demand Response	25	.01
Capacity Programs	10	.14
Demand Bidding	12	.10

Source: FERC Survey

Figure 4-9
DR Participation and Performance

4.4.1.2 Pilot Participation Rates

As part of the California Statewide Pricing Pilot (SPP), research was conducted to ascertain the market potential for a variety of demand response plans, including ones that correspond generally to those offered by ISOs/RTOs, although there were key feature differences in terms of the incentives offered and the expectations for when events would occur. Figure 4.10 summaries the estimates of market potential that resulted from surveys and other primary research efforts with the state's residential consumers. Participation was estimated (quite uniformly) to be in the range of 33-47% for Time-of-Use (TOU), demand subscription, and Critical Peak Pricing (CPP).[12] The range of estimated participation rates for commercial consumers was tighter, 34-38%. Estimated participation rates are compared in the table to actual program experience in the SPP and other California program initiatives.

Steady State Participation Rates for Sample DR Rate/Program Offerings

		Momentum Based (Assumes 100% awareness, 0 Transaction Costs, No Measurement of Intention)		Actual Program Experience	
Sector	Rate/Program Design	Lower Bound	Upper Bound	Lower	Upper
Residential	TOU Rate	33.0%	47.0%	6%	10%
Residential	Tier w/ PCT or Switch			5%	15%
Residential	Demand Subscription	34.0%	47.0%	5%	10%
Residential	CPP-F	34.0%	47.0%	5%	10%
Commercial	PCT w/ Override			3%	10%
Commercial	Emergency			1%	
Commercial	CPP	34.0%	39.0%	5%	10%
Commercial	Demand Subscription	34.0%	39.0%	5%	10%
Industrial	I/C - Customer Control			5%	20%
Industrial	I/C - Utility Control			0%	10%
Industrial	Real Time Pricing			1%	3%

Source: Energy and Environmental Economics. January 2007. DR Rate and Program Design *RON-02 Phase 1 Results* R Rate and Program Design *ON-02 Phase 1 Results.*

Figure 1

Figure 4-10
Estimated and Realized Participation Rates

Note that the realized participation rates are one-third or less of the lower range value for estimated participation. The divergence may in part be due to the tendency for surveys to overestimate consumers' intent to act on stated beliefs, and in part because many consumers have yet to be exposed to a demand response program option.

Another way to derive demand response participation rates is to look at the success rates for enrolling pilot participants. Two New York utilities, in summarizing their experience with recruiting participants for an air conditioner control program, reported that only about one in five people contacted agreed to participate.[13] That comports with the rate reported for the SPP and by others recruiting residential consumers for demand response programs.[14]

[12] Energy and Environmental Economics, Freeman Sullivan, Neenan Associates, Lawrence Berkeley National Laboratory, January 2006. DR RON-01 Phase 2 Research Proposal, "Proposal to Create a Standard Practice for Valuation of Demand Response and Other Dispatchable Resources in California." Prepared for the Demand Response Research Center, Lawrence Berkeley National Laboratory

[13] Consolidated Edison, Long Island Power Authority. April 2004. Presentations to NYISO Price Responsive Load Working Group, Albany, NY.

These rates should be treated as qualified since in most cases the pilots involved incentives to the participants that all but assured that they would be no worse off from participating and would be likely to come out ahead. The incentives may not have influenced the participants' response to events, as many claim; but they likely exerted an influence on the decision to participate.[15] These data are another example of a source of participation rates that appears to be useful because of its specificity. However, they should be employed cautiously just because of their specificity: the results have not been replicated under a wide variety of circumstances.

Lawrence Berkeley Laboratory has conducted several in-depth studies to more fully characterize what distinguishes demand response participants from other consumers and to identify the characteristics that can be used to estimate the rate of population participation in the long run. A comprehensive review of over 40 RTP programs across the country, for the most part involving larger commercial and industrial customers, revealed that program participation was low in all but 3 or 4 cases (Barbose et al. 2005).[16] The rate of participation was not driven so much by the program design features, which varied somewhat but not substantially, but by the level of promotional effort undertaken by the utility.

Georgia Power's concerted and sustained promotional effort resulted in over 40% of the load of the eligible customer class joining a revenue-neutral RTP rate.[17] While a few of the other programs reported participation rates in the 10-20% range, most enrolled what amounted to under 1% of the eligible load. Many program mangers attributed the low participation rate to the lack of a concerted effort to recruit customers, as opposed to consumers rejecting a well-articulated value proposition.

An in-depth study of what factors were instrumental in larger businesses' (over 2 MW) decision to either pay RTP-type prices or secure a hedged alternative concluded prior experience with a similar pricing plan was a key driver, along with the availability of control technology or on-site generation.[18] An additional factor was the presence of an internal champion to take responsibility and risks. A study for Duke (2006) concluded that on-site generation was a key driver of participation but that as price volatility rose, participation declined—an outcome several RTP program managers have also reported (Barbose 2005).[19]

[14] The authors have been involved in or briefed on several program recruitment efforts the results which were not made public.

[15] IBM Global Business Services; Strategic Consulting. July 2007. Ontario Energy Board Smart Price Pilot- Final Report.

[16] Barbose, G., Goldman, C., Neenan, B. December 2004. A Survey of Utility Experience with Real-Time Pricing. Lawrence Berkeley National Laboratory Report No. LBNL-54238. Available at http://www.lbl.gov/.

[17] The rate was designed so that the consumer could be hedged against hourly price volatility by consuming at the specified level of load specified in it customer baseline load (CBL).

[18] Goldman, C., Hopper, N., Sezgen, O., Moezzi, M., Bharvirkar, R., Neenan, B., Pratt, D., Cappers, P., Bosivert, R. August 2005. Does Real-Time Pricing Deliver Demand Response? A Case Study of Niagara Mohawk's Large Customer RTP Tariff. Lawrence Berkeley National Laboratory Report No. LBNL-54974. Available at http://www.lbl.gov.

[19] Schwarz, P., Taylor, T., Birmingham, M., Dardan, S. 2002. Industrial Response to Electricity Real-Time Prices: Short Run and Long Run. Economic Inquiry, Vol. 40, No. 4, pp. 597-610.;Barbose 2005, op cit.

In developing a framework for estimating demand response potential for commercial and industrial customers, the LBL team's researchers elected to develop parameters using a combination of sources and methods including the results of ISO/RTP programs and utility pilots, along with informed judgment to assign participation rates, as described in Table 4.1. The result was what they refer to as "seed elasticity values" that they recommend analysts employ in the absence of any locally derived price response values. [20] However, the scope of their effort to establish seed values for elasticities was limited to establishing those applicable to businesses.

Table 4-1
Methods for Estimating Participation in Demand Response Programs

Method	Description	Issues
Delphi	Solicit estimates from individuals with experience or insight.	What constitutes an expert? How are the divergent estimates weighted or otherwise condensed or resolved?
Experience – similar market segment	Use realized participation rates from a market with similar supply conditions.	Does it matter how prices are set— ISO versus a Vertically Integrated Utiltiy—or do customers respond to prices? To what extent do different market structures produce different price topologies that influence participation?
Experience – similar target customer population	Use realized participation rates from a similar market segment.	Is participation largely driven by factors outside of market circumstances, such that all that really counts is the customer's circumstances? Are there important regional or climatic factors that would lead to differences in participation among customers with the same business activity?
Experience – similar product	Use realized participation rates from a market with similar supply conditions.	Are product features alone sufficient to determine participation? How important are customer and market circumstances?
Benefit threshold	Set a minimum level of benefit required for a customer to participate.	How would the threshold be determined for different customer segments or customers within a segment? This approach requires benefits to be estimated first at the customer or representative customer level.
Choice Model	Develop a comprehensive characterization of the factors that drive participation.	Provides a very robust means for estimating participation at a fine level of detail. Where do the sources of the data needed to estimate the base model come from? How are the odds of participation converted into participation rates and enrolled curtailable loads?

[20] Goldman, C., Hopper, N., Bharvirkar, R., Neenan, B., Cappers, P. January 2007. Estimating Demand Response Market Potential Among Large Commercial and Industrial Customers. Lawrence Berkeley National Laboratory Report No. LBNL-61498

EPRI prepared summaries for TOU and CPP participation rates by gleaning data from reports and filings, with the intent that they could be used to define a point estimate around which the analysts could develop a distribution that fits his or her assessment of the uncertainty inherent in such values. Figure 4.11 portrays those values for TOU, and 4.12 portrays them for CPP. The values support a participation rate for residential customers of 10-20% for TOU and 20% or perhaps higher for a CPP rate. Because of the incentives involved with the CPP pilots, which included incentives that all but assured gains from participation, the expected level of participation may be higher than for programs that are less generous.

Time-of-Use Pricing Plans			
	Design	**Subscription/Participation Rate**	**Notes**
1. Salt River Project -	Voluntary TOU, design favors larger customers and an eight (8) hour summer day peak.	About 180,000 participants out of 950,000 residential customers. **18% Subscription rate.**	Program has been heavily promoted since early 1980s. Especially attractive to residences with discretionary loads like pool pumps and AC.
2. Competitive retailer	TOU that applies peak prices to summer afternoon hours. Required paying an additional monthly customer charge of about $5.00.	About 1 in 5 of those contacted signed up for one-year term. **20% Subscription rate**	Under 500 participants in a one-year trial.
3. Florida, Gulf Power	TOU with CPP provisions. Required paying an additional monthly customer charge of about $5.00.	Over 6,000 subscribers, representing 20% of targeted population. **20-30% Subscription rates**	Result of directed marketing over last 6-7 years.
4. California State-Wide Pricing Pilot	Revenue neutral TOU that included a $75 participation incentive.	About 1 in 5 of those contacted, using a representative random sampling process, participated. **20% Subscription rate**	One year term. Subscription rates in the CPP treatments were about identical. Two mailings plus follow-up phone calls.
5. France-Electric de France	System state condition pricing using a TOU with three tiered peak price schedule (low, medium and high) announced daily.	Reported 80% or more of the residential population. **80% Subscription rate**	Some form of TOU has been offered since early 1980s which is the default rate unless the customer opts out.

Figure 4-11
Participation in Time-of-Use Plans

Critical Peak Pricing Plans			
Location	**Design**	**Subscription/Participation rate**	**Notes**
6. New York, Con Ed and LIPA	AC control imposed during periods of reserve shortfalls. Participants receive consideration (about $20/year) and the set back thermostat	Reported **15-20% Subscription rate**	CPP structure imposed on conventional uniform rate. Exposure to curtailments averages 15 hours/yr.
7. Ontario Energy Board	Residential TOU and CPP trials with $75 participation incentive	Report lists **25% - 28% Subscription rate**	Single mailing. Participants cite impending mandatory TOU as a motivation to get started early though the trial
8. Idaho Power	Residential TOU	**3.5% Subscription rate**	Single mailing.

Figure 4-12
Participation in Critical Peak Pricing Plans

4.4.1.3 Summary

While there has been an increase in the number of pilots involving demand response and these have contributed to a reduction in the uncertainty about residential price response, they have contributed little to the understanding of what motivates or drives consumers to participate and what observable or obtainable characteristics are reliable predictors of participation. As a result, analysts should consider portraying participation as a particularly subjective element of the estimation of the impacts of demand response and offer a range of outcomes that characterize the distribution of outcomes.

4.4.2 Stated preferences

In the absence of actual experience with demand response, some analysts have conducted primary research involving surveys administered to consumers to characterize how they would act if they were offered a participation opportunity. This kind of research produces what are referred to as stated preferences. The reliability of these intentions is difficult to ascertain since the decision situation is hypothetical, and the consumer has nothing at stake, except maybe a perceived moral obligation to respond truthfully to the survey. Nonetheless some of these studies provide deeper insight into what drives participation in demand response programs because they fill a void.

EPRI and Central and Southwest Services (CSW) collaborated on a study to estimate consumer preferences for alternative ways to buy electricity.[21] A survey administered to over 800

[21] Neenan, B., January 2008. Eom. J. Price Elasticity of Demand for Electricity; Price Elasticity of Demand for Electricity: A Primer and Synthesis. EPRI, Palo Alto, CA: 2007, 1016264.

residential customers and 500 business customers of Public Service of Oklahoma asked respondents to cardinally rank (1st, 2nd, etc.) their preferences for five pricing plans, which were defined as follows:

- The currently applicable PSC tariff that involved a declining block in the summer and an inclining block in the winter for residential and small business consumers and an energy and demand rate for larger business
- A uniform rate for all energy consumers
- A TOU rate that defined the peak hours as the weekday summer afternoon and early evening hours
- A RTP rate with hourly prices posted the day before
- A block and swing rate whereby the consumer designated an amount of load for which the flat rate applied with any variations from that level reconciled at the posted hourly RTP price

The survey instrument provided descriptions of each pricing plan, including examples to ensure that the respondent understood the features of each before indicating its preference. The results were analyzed in two steps. The first choice of respondents was recorded by product, and a strength of conviction index was created. These results are portrayed in Figure 4.13, with residential results on the top and businesses (commercial and industrial) on the bottom of the figure. The circle associated with each product indicates the percentage of respondents that chose that product as its first choice. The values illustrated in the adjacent thermometers are the corresponding strength of conviction index values.

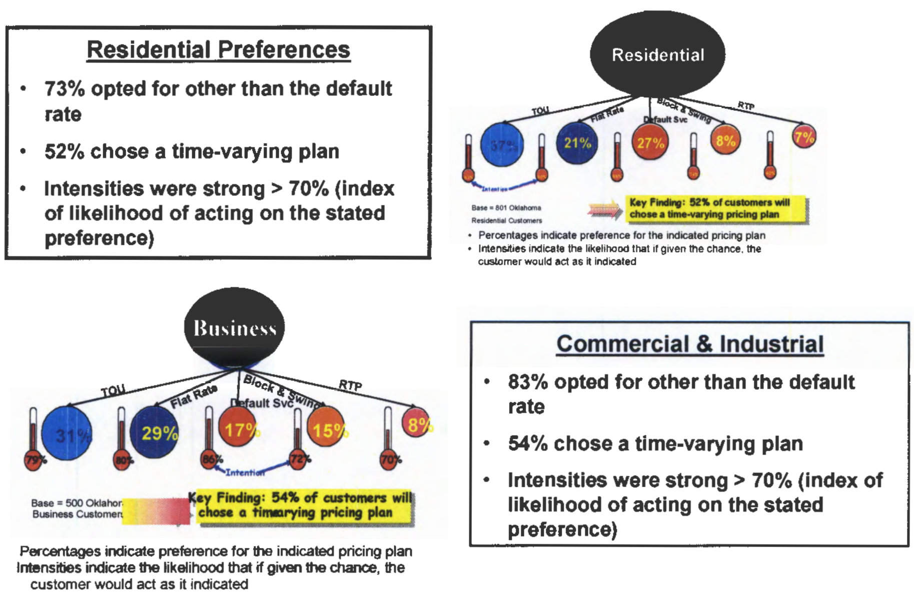
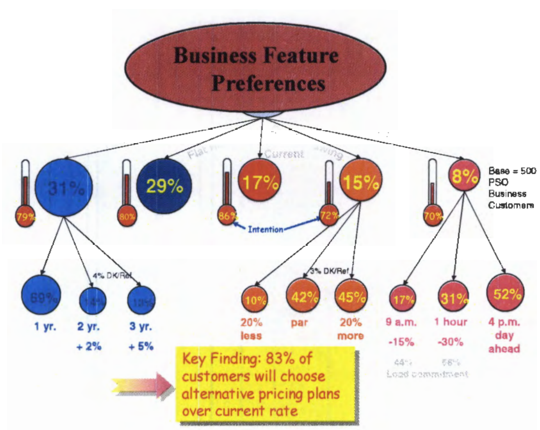


Figure 4-13
Residential Pricing Product Preferences

Over 52% of residential respondents selected some form of time-varying pricing as their first choice; 37% selected TOU, 8% block and swing and 7% RTP. The intent metric values were all over 60%, indicating that there is a modest to strong likelihood that if they actually were confronted with such a choice, these consumers would act as they stated. Approximately the same overall preference (54%) for time-varying rates was found for businesses with a greater preference for the block and swing product (15%) and less for TOU (31%).

A secondary indication of the strength of this conviction is revealed by examining the second choice of respondents. Most customers that selected a time-varying rate as the first choice selected another such plan as its second choice. This was the case with both business and residential preferences and further suggests that the consumers' stated preferences would likely be observed if they were confronted with such a choice.

Some of the plans involved secondary preference selections for a range of product features. The results are illustrated in Figure 4.14 for business customers. In the figure, the secondary set of colored circles under some products indicates respondents' preferences for the individual feature alternatives offered, which survey respondents also ranked. The adjacent thermometers show the accompanying intensity of strength metric values. Among those that preferred TOU, a majority (69%) indicated a strong preference for a one-year contract, as opposed to paying premium to lock the prices in for two (14%) or three (13%) years. The fact that one-third of respondents prefer a hedge against price volatility is an indication that there are some customers that want the security of a fixed price schedule.



TOU

- Strong preference (69%) for short (one-year) contracts

Block and Swing

- 42% set block at historical CBL
- 45% a block 20% above the CBL
- 10% chose block 10% below the CBL

- **RTP**
- 52% chose day-ahead posting
- 31% chose one-hour ahead posting
- 15% chose 9:00 a.m. same day posting

Figure 4-14
Business Customer Product Feature Preferences

Among those that preferred the block and swing product, 42% indicated that they preferred to set the initial (fixed price) block of energy at their historical usage level (labeled par in the figure); an almost equal number (45%) indicated that they preferred a block larger than that amount, in effect buying a hedge against price volatility; and 10% wanted to set the block below that level and speculate on RTP prices, which may indicate an intent to manage usage in response to price changes. Half of those preferring RTP were satisfied with a base feature that offered day-ahead price posting, but about one-third (risk takers) indicated that they would rather receive real-time prices that are lower on average, but more volatile and a few (17%) selected prices that would be posted that morning.

The EPRI/CSW study findings indicate that over half of respondents prefer some form of time-varying rates. These results might serve as an upper bound on individual product preference and overall demand response participation to employ in a business case for Smart Metering.

4.5 Measuring Price Response

Quantifying the energy and demand impacts of how consumers respond to electricity price changes requires a metric that converts a price change into a change in consumption. Price elasticity is such a metric as it defines the percentage change in usage that results from a one percent change in the price. Price elasticity in consumer demand theory summarizes how expenditures are adjusted among goods as the price of one good changes. It relates the marginal value derived from the consumption of each good to its price. Its application to household and business electricity consumption has evolved to reflect changes in how electricity is priced.

4.5.1 Different Elasticities for Different Pricing Structures

Uniform or flat electricity price structures are subject to only occasional price changes. Accordingly, studies that estimated short-run or long run response generally have focused on annual or monthly electricity price changes and employ the own-price elasticity of demand concept.

The own-price elasticity captures the influence of a price change, assuming that all other explanatory factors such as household income and the prices of substitutes remain constant. If electricity is a normal good, a one-percent increase (decrease) in electricity price will induce electricity usage to decline (increase), all other things being equal. Accordingly, behaviorally consistent estimates for own-price elasticity are negative values. Because it is a relative value, the elasticity involves the change in kWh divided by the initial (per-price change) kWh, the own-price elasticity of electricity takes on values between zero and a very large negative number.

The interpretation of an elasticity value of zero is obvious; the consumer's electricity use is insensitive to price changes. Very low elasticity values, say below -0.05, indicate a high degree of price insensitivity. That is plausible for many consumers in the short run because there are no immediate substitutes for electricity to power household and business devices. However, if the price changes drastically or persistently or both, the result can be a transformation of electricity demand that results in a reduction in electricity expenditures and an increase in other expenditures. That transformation may involve installing automated controls on specific devices or changing out the stock of electric devices for ones that provide the same or equivalent service, but use less electricity in doing so. Alternately, it could result from the adoption of renewable and other on-site generation technologies, in effect creating a substitute for grid-delivered electricity.

An elasticity value of one (absolute value) serves as a useful reference point. It indicates that the quantity change is exactly proportional to the price change; price and quantity move together in unison. An own-price elasticity value that exceeds one signifies that a price change induces more than a proportional usage change. Under these conditions, price is a potent driver of electricity usage. Most estimates of short-run electricity price elasticity fall between values of zero and one.

Time-of-use (TOU) or real-time pricing (RTP) plans transform electricity into two or more time-distinguished electricity goods, which complicates the measurement of how price differentials or ratios induce changes in relative period usage. Some studies have attempted to estimate both the influence of own-price elasticity associated with changes in the TOU rate schedule and the shifting effects of the peak and off-peak prices.[22]

If electricity is subject to hourly price changes (RTP) or follows a diurnal price schedule (TOU), consumers may treat electricity usage in these time periods as substitute goods. The degree to which shifting of usage is induced by the price differential(s) is measured by the substitution elasticity. The substitution elasticity indicates the percentage change in the ratio of electricity usage among time periods that arises in response to a one percentage change in the ratio of those period's electricity prices, all other factors held constant. Instead of individual quantity and price values, which are how the own-price elasticity is formulated, the operators in the substitution elasticity are ratios of quantities and prices.

Behaviorally consistent estimates for the elasticity of substitution are positive. This is because for a given peak to off-peak price ratio the consumer chooses consumption that defines the equilibrium off-peak to peak consumption ratio. If the peak price were to increase, peak consumption would become more expensive, as indicated by the increase in the ratio of the peak price to the off-peak price. Accordingly, off-peak consumption would be substituted for peak consumption, thereby increasing the off-peak to peak consumption ratios. Both operators have positive signs associated with the measured change, so the substitution elasticity metric takes on positive values.[23]

The interpretation of specific values of substitution elasticities parallels that of own-price elasticity, but the focus is on the ratio quantities and prices. If the elasticity of substitution is less than one, a given percentage increase in peak to off-peak price ratio leads to a less than proportional percentage increase off-peak to peak consumption ratio. Generally, researchers report substitution ratios to characterize shifting of electricity usage within a day, as occurs with a TOU price schedule. However, as discussed below, some have also characterized substitution of electricity usage among hours of the day or among days of the week.

4.5.2 An Overview of Electricity Price Elasticity Estimates

A recent EPRI metastudy reviewed over 100 studies that provide estimates of price response.[24] Many of these studies report the average or individual observed changes in usage associated with a price change, but do not estimate the implicit or explicit price elasticity. This is especially true of studies of demand response programs where the price is implicit, not explicit, for example,

[22] Faruqui, A., George, S. May 2005. Quantifying Customer Response to Dynamic Pricing. Electricity Journal, Vol. 18, No. 4, pp. 53-63. Elsevier Science Inc.

[23] Some researchers report substitution elasticities as negative values, which reflects using an inverse, but value-preserving transformation.

[24] Neenan, B.. Eom, J. January 2008. Demand for Electricity: A Primer and Synthesis. Palo Alto, CA: 2007, 1016264.

residential AC or thermostat control programs in which the consumer allows the utility to control the device in return for a lump-sum payment or other concession. As demonstrated in the categorization of demand response programs (Figure 4.1), virtually all demand response programs involve an implicit or explicit price that drives consumer behavior.

Appendix A provides a summary of the most important aspects of price response, including how it is measured and interpreted. Some have particular relevance for demand response valuation.

4.5.3 Comparative Anatomy of Price Elasticity under Time-Varying Pricing

EPRI focused on elasticity estimates that were estimated statistically from actual pilot or program data using a theoretically consistent representation of consumer behavior. These 18 studies produced a total of 46 individual elasticity estimates for different customer segments and their response to different pricing plans. All elasticity values are reported as absolute values to facilitate a comparison of intensity.

Figure 4.15 displays the frequency distribution of all these elasticity estimates, which include both own-price and substitution elasticity values. The medium value is around 0.12, and the values are skewed toward zero.

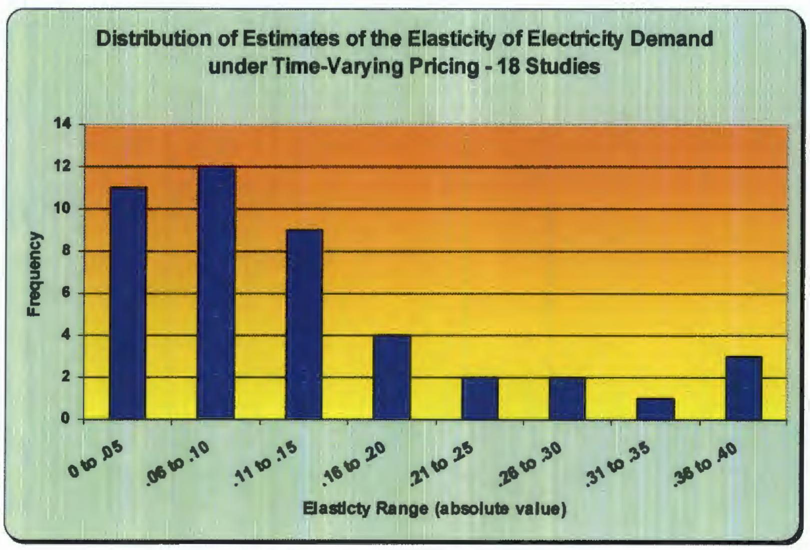


Figure 4-15
Distribution of Price Elasticity Estimates

Figure 4.16 expands the resolution of the estimated values to illustrate the range of reported values and to portray their central tendency of them taken collectively. It plots for each of the 18 studies included in this synthesis the range of reported elasticity estimates and the central mass point.[25] The range of estimates for price response is indicated as a colored line for each study,

[25] Note that, for simplification, Figure 15 reports the ranges of estimates for individual customer samples being examined in the literature.

with the point indicated by a square on that line representing the central mass estimate. The central mass is either the average elasticity provided by the study, or an interpretation of the same made by the authors of this study. For example, the first bar indicates that the range of estimates for Study 1 is 0.12 to 0.37; and the central mass is about 0.17. Study 2 provided only a single elasticity estimate, which is plotted in Figure 4.16 as a point (0.38) with no range indicator.

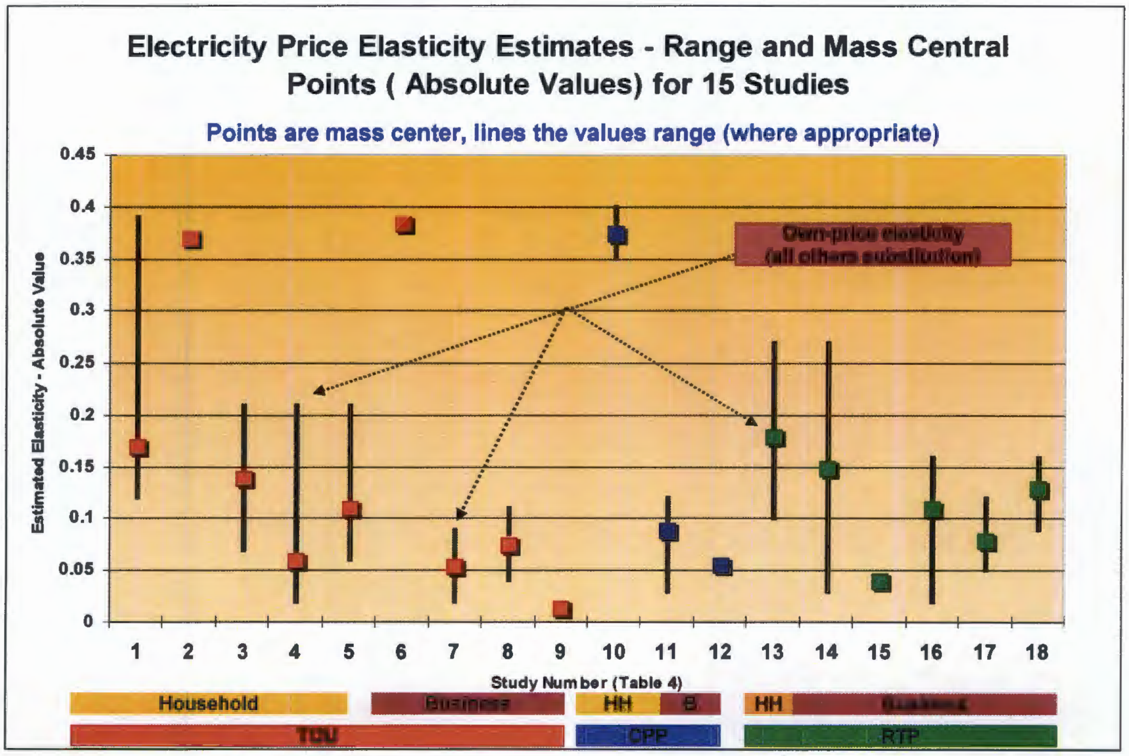


Figure 4-16
Synopsis of Price Elasticity Estimates

The colored-coded key at the bottom of Figure 4.16 delineates the several aspects that distinguish the estimates, as follows:

- The segment to which elasticity values apply, either household (HH) or business (B)
- The pricing from which they were derived: time-of use (TOU), critical peak pricing (CPP), or real-time pricing (RTP)

Most of the elasticities portrayed in the figure are substitution (shifting) elasticities, but in three cases they are estimates of the own-price elasticity of demand. For convenience of exposition, all elasticity values in Figure 4.16. are listed as positive values, although some of those listed represent own-price elasticities and are so indicated in the figure.

Some important insights about the level and character of electricity price response to time-varying rates emerge from this graph. First, despite the variety of factors that would seem to result in considerable disparity amongst the value, when plotted together the range of values is relatively low—from near zero to around .40. These are short-term elasticities that reflect consumers' and firms' ability and inclination to respond to price changes. Values at the high end of that range can be attributed primarily to enabling technology, as is the case for values above the upper end of that range. Perhaps analysts already have a good idea of what to expect from the implementation of voluntary participation time-varying pricing plans, at least in the short term.

Comparing the substitution values in terms of the pricing plans they were derived from, the greatest dispersion of values is for CPP; but the variance is associated with segment differences ranging from a low of around 0.04 for Business to a high of 0.40 for Household.

The residential TOU central mass elasticity estimates, with one exception, are quite tightly bunched around a central tendency range of about 0.05 - 0.15. The outlier value (Study 2) comes from a mid-1980s study at PG&E involving voluntary TOU. The recent California SPP trials found values about one-fifth as high. Perhaps the earlier PG&E study did not control for all the influences that affect how customers use electricity or involved too high an aggregation to allow sorting price effects, as Bohi anticipated (1981). Or, as the authors of the SPP study speculated, the character of electricity demand has been reshaped over the past 20 years.[26]

The business central mass substitution estimates are even more tightly bunched and lower in value; and the range of reported values is less, compared to those of residential consumers. The central mass elasticity values estimated for RTP vary by a factor of 4 (0.04 to about 0.18). The most robust estimates, corresponding to studies # 13 and # 14, involved a relatively large (over 100) number of consumers of similar size (over one MW) that had paid RTP prices for over five years. Both studies exhibit a wide range of estimates, which the researchers attributable to differences among individual customer responses. Nevertheless, at the portfolio level (all RTP participants), the average response for both studies is about 0.12.

The increased interest in fostering price response was the primary motivation for conducting the syntheses reported in this metastudy. A compelling conclusion is that a wide variety of consumers exhibit price response when provided an opportunity to do so. While there are differences among individuals and groups that are useful for singling out those that are most likely to benefit and should be singled out for early a participation, the relative tight bunching of elasticity estimates from a variety of dynamic pricing pilots, despite involving different customer segments under different market circumstances, suggests that price response impacts can be estimated quite confidently and accurately. This finding should embolden those that are already inclined to launch new pricing initiatives and serve to motivate those that have remained skeptical to take another hard look at the benefits of efficient pricing of electricity.

[26] Charles River Associates. March 16, 2005. Impact Evaluation of the California State-Wide Pricing Pilot. Final Report. Available from the California Energy Commission web site.

4.5.4 Price Elasticity or Price Impact?

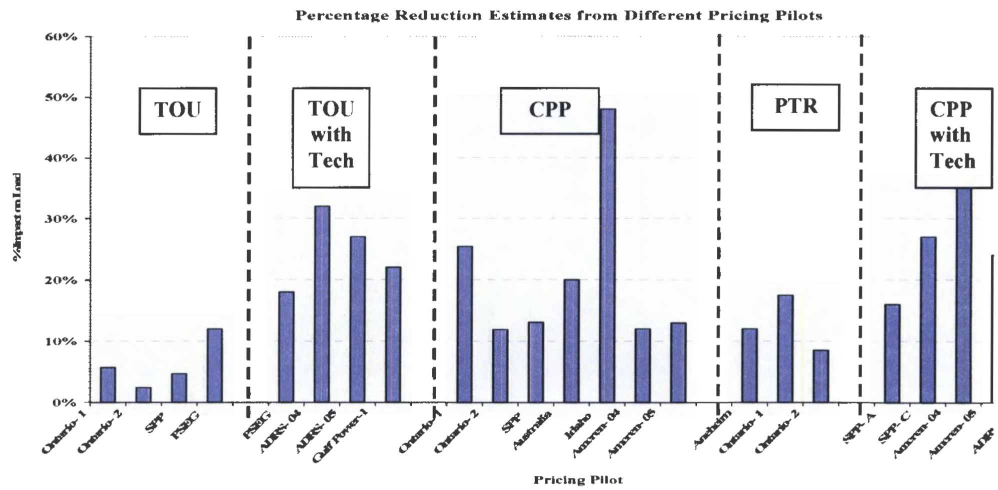
The advantage of using price elasticity to characterize how consumers respond to price changes is that it provides the impact over the full range of prices or price ratios that consumers might experience. An elasticity estimate under one set of circumstances, say a price change from 10¢ to 40¢ (a price ratio of 4:1), can be applied to circumstances where prices take on different values or ratios, as long as the underlying demand relationship is deemed to be applicable.

Many recent pilots were conducted under experimental protocols to accommodate testing for changes in participant's load during events. The analysis of the pilot results involved a statistical test to establish if participants' event load differed significantly from that of control customers, which were households selected specifically to represent the population of customers. If the test of means on event loads indicated that the difference was significant, then the measured event response of participants was reported as the price impact, either in terms of kWh or percentage change, from what the consumer otherwise would have consumed. Since no demand equation was estimated, no corresponding price elasticity is available to characterize the results.

Faruqui et al. (2008) summarized the results of pilots that presented the price impacts in terms of the percentage change in electricity usage during events. Figure 4.17, derived from that report, summarizes the results organized by the pricing plan that was the subject of the pilot: all innovated residential consumers. Visually, this portrayal suggests that there are substantial differences among the plans and even within plans. This is to be expected since they represent different designs intended and expected to invoke different responses. TOU rate schedules are designed to reflect persistent patterns on diurnal supply costs. CPP and RTP pricing plans focus on inducing price response on specific days and specific times. As a result, the participant gets very short notice of the price change, which in most cases is considerable larger (as high as 10:1) than any TOU peak/off-peak price ratio (usually around 3:1 to 4:1).

Elasticities can be employed to quantify the impacts of price changes by constructing a simulation model that derives the price response across the range of possible consumption levels, as Faruqui et. al, suggest. Such a response curve has its base at the level the customer is assumed to be using before the price change is encountered. Price increases lead to reductions in electricity usage, but at a decreasing rate as energy consumption approaches zero. For price decreases, the energy usage increases; but it must also be bound by some upper limit that reflects the highest likely usage level. Figure 4.17 illustrates such a simulated residential response curve derived by Faruqui et al. for a residential customer with and without a central air conditioner (CAC) under a critical peak pricing.

Figure 2. Estimated Demand Response Impacts by Experiment
(from: Faruqui, A.,
Sergici, S. The Power of Experimentation, April 4, 2008)



Notes:
*Percentage reduction in load is defined relative to the different bases in different pilots. The following notes are intended to clarify these different
Definitions . TOU impacts are defined relative to the usage during peak hours unless otherwise noted. CPP impacts are defined relative to the usage during peak
hours on CPP days unless otherwise is noted.

1- Ontario- 1 refer to the percentage impacts during the critical hours that represent only 3-4 hours of the entire peak period on a CPP day.
2- Ontario- 2 refer to the percentage impacts of the programs during the entire peak period on a CPP day.
3- TOU impact from the SPP uses the CPP-F treatment effect for normal weekdays on which critical prices were not offered.
4- PSEG programs are represented in the TOU section even though they are CPP programs. The reason is that there were only 2 CPP events during the
entire pilot period and more importantly % impacts were only provided for the peak period on non-CPP days.
5- ADRS- 04 and ADRS- 05 refer to the 2004 and 2005 impacts. ADRS impacts on non-event days are represented in the TOU with Tech section.
6- CPP impact for Idaho is derived from the information provided in the study. Average of kW consumption per hour during the CPP hours
(for all 10 event days) is approximately 2.5kW for a control group customer. This value is 1.3kW for a treatment group customer. Percentage
7- impact from the CPP treatment is calculated as 48%.
8- Gulf Power-1 refers to the impact during peak hours on non-CPP days while Gulf Power- 2 refers to the impact during CPP hours on CPP days.

Figure 4-17
Comparison of DR Plan Event Impacts

4.5.5 Summary

Price elasticity is a useful measure of how price changes impact electricity consumption because it isolates the price effect from other influences. As a metric, a price elasticity value is an indicator of the intensity of price response that allows for comparison among consumers and among different pricing structures. A synthesis of some of the more rigorously conducted empirical studies indicates that price response is relatively low for all consumer segments, around 0.10: a doubling of the price results in a relative adjustment (overall reduction of shift) in usage of 10%. However, there are indications that enabling technology amplifies price response as is the case with information feedback. Since these are forces that Smart Metering can enable, wide-scale implementation of this technology may increase price response.

4.6 Jointly Determined Participation and Performance

An alternative approach to quantifying participation and price response impacts separately is to assume that there is a direct relationship between whether a consumer elects to participate in a demand response program and the benefits it expects to realize. In other words, participation and response are jointly determined. Analyzing joint determination requires specifying the features of the demand response product or products being evaluated, determining the characteristics of the events that will precipitate a response, and employing a simulation model that applies specified levels of price elasticity to representative consumer circumstances over the set of events to produce an estimate of the expected load changes. Finally, screening criteria must be established to determine which consumers are assumed to participate. The characteristics of these participants, in turn, then define the energy and demand impacts associated with the demand response program.

Several screening criteria are available;

- Minimum elasticity threshold – First, elasticities are assigned to the population of consumers being evaluated. One approach is to sort customers into groupings according to observable characteristics, such as business activity and consumption level, and then to assign elasticities using values appropriate for each based on their characteristics. Every member of a subsector can be assigned the same (group mean) value. Alternatively, if the nature of the distribution of elasticities over the group's members is available, then the consumers in each grouping are assigned elasticity values that preserve the nature of the distribution. Once all consumers have been assigned an elasticity, a threshold is imposed and only those segments or parts thereof are assumed to participate.
- Segmentation - for residential consumers, segmentation may be accomplished according to demographics, like income, residents' daily habits, square footage, or appliance holdings. Once sorted that way, elasticities can be assigned that reflect differences in the likely level of price response—higher elasticity value to households with certain appliance holdings, for example. Once all consumers have been assigned an elasticity (explicitly or implicitly through the segments), a threshold is imposed and only those segments or parts thereof are assumed to participate. These become the basis for subsequent simulations in which they are the determinant of consumers' price response to specified price changes and event characteristics.
- A minimum benefit threshold – a shortcoming of the elasticity threshold method is that participation is determined *a priori* by consumer characteristics, and therefore the characteristics of the demand response product or events do not come into play. A minimum benefit threshold combines price elasticity with the prices associated with the event. This approach is implemented by simulating the response of each elasticity-distinguished segment over a specified period, which can be a year or several years, and then portraying the benefits for each segment as the present value of the total expected benefits or as a percentage of the prototype consumer's bill. Applying a threshold, for example that the benefits must equal or exceed 2% of the electricity bill, then separates participants from nonparticipants.

The selection of a screening criterion, which is required in the first and third methods, is necessarily subjective because of the paucity of information about what drives consumers to participate. A relatively simple survey instrument might provide the data needed to establish a credible first-approximation of the appropriate level to set for the screening criteria.

A study of the expected benefits for demand response provides an example of this simulation and screening approach.[27] The objective was to ascertain the impacts of a portfolio of demand response products available to all customers. Elasticities were assigned to segments (residential, commercial, and industrial) using distributions constructed from the results of pilot studies. Simulations were then run for each demand response product and for each consumer class. Participation was resolved by applying a threshold based on simulation benefits as a percentage of the annual electricity cost. Figure 4.18 illustrates the results.

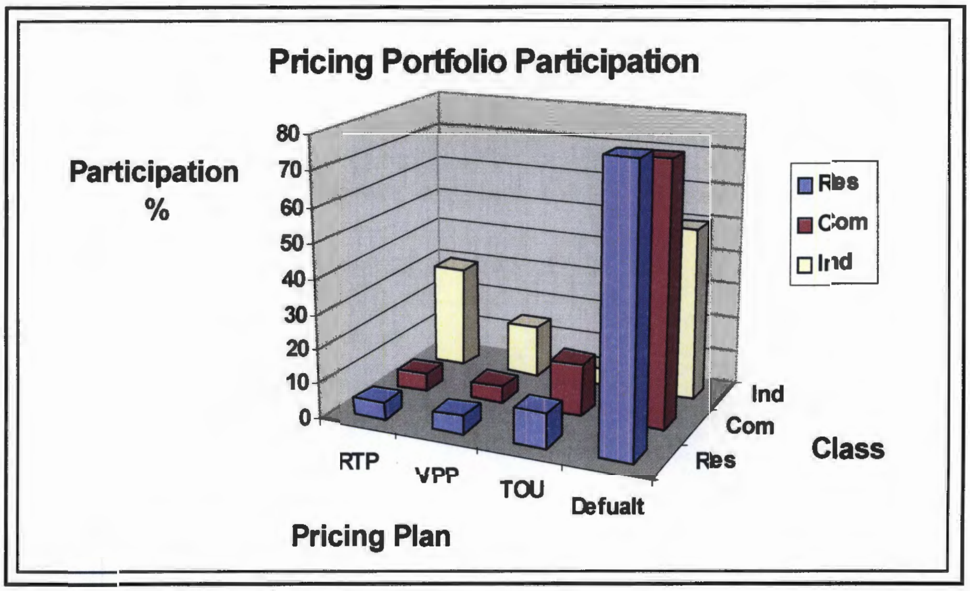


Figure 4-18
DR Plan Participation Rates

The simulated benefits for a majority of consumers fell below the threshold value, so they were deemed to be nonparticipants that stay on a uniform default rate. The rest were assumed to enroll in a specific demand response program and respond to price changes. Industrial customers were assumed to participate in demand response programs at a higher rate (about 50% overall were assumed to enroll in a time-varying rate) and particularly at a higher rate in RTP programs (almost 30%). TOU participation was the predominant manner of demand response for residential and commercial customers, about 10 and 14%, respectively, with much smaller numbers realizing sufficient benefits to justify participation in the Variable Peak Pricing or RTP plan.

This approach provides high level of resolution of the impacts of offering a portfolio of demand response products. However, the results depend on a combination of assumptions, each by itself subject to ambiguity and uncertainty.

[27] The results presented herein were modified somewhat from those in the study.

4.7 Methods and Models for Valuing Price and Demand Response

4.7.1 Introduction

The previous four sections discussed ways to quantify demand response and involve establishing the kW and kWh changes associated with a specific demand response program or a portfolio of programs. The final step is establishing the corresponding monetary value attributable to the energy and demand changes.

Several analytical frameworks are currently being used to accomplish this monetization, ranging from using available avoided cost estimates that were developed through an Integrated Resource Planning (IRP) process, an approach often used to evaluate energy efficiency measures, to comprehensive spatial and temporal simulations to characterize how demand response would impact market supply and demand conditions. The avoided cost method has been employed to estimate societal benefits in some Smart Metering filings, as was discussed in Section 3.0. The more comprehensive market impacts models have seen extensive application in evaluating the benefits of individual demand response programs at the utility, regional, and national level.

Before turning to a comparison of methods and the benefits stream they produce, it is instructive to first establish a general, principled framework for quantifying how kW and kWh changes impact electricity markets. This preliminary step provides a means of defining and classifying the level and source of the impacts.

Economics is the study of how markets operate, specifically, how equilibrium prices are determined in competitive markets and the consequences for consumers and producers. Price formation under competitive conditions is achieved when output is such that the marginal cost of supply is equal to the marginal value of consumption. Any additional supply would go untaken because demand is downward sloping and any additional demand goes unfulfilled because supply is upward sloping. If the character of supply and demand is portrayed in a price/quantity space, then the level of the equilibrium price can be resolved. This solution can be represented graphically to demonstrate the principles of how factors that influence supply and demand such as those invoked by demand response programs affect price formation.

That is the approach described in the next section. The graphic representation in price/quantity space provides the foundation for a richer mathematical characterization that incorporates the influences of factors other than price, which in turn provides a means for developing an empirical representation of price formation in electricity markets, examples of which are reviewed in Section 4.7.3.

4.7.2 Economics of Demand Response

The role of demand response in the efficient and effective operation of spot electricity markets has been laid out in detail in several sources. Ruff (2002) and Braithwait (2003) provided a clear exposition of the economic principles that describe how demand response effects prices and causes adjustments in market supply.[28] They make a point of emphasizing that some of the impacts are not in fact benefits in the sense that everybody is better off. Boisvert et al. acknowledged the same distinction earlier when they established a framework for evaluating the impact of ISO-based demand response bidding programs.[29] Bornstein further clarified the long-run impacts of demand response assuming that generation capacity adjusts immediately to changes in consumption due to demand response, in which case the equity issue is not germane.[30]

The discussion that follows is a synopsis of those more detailed treatises. It focuses first on price formation in wholesale spot markets operated by ISOs because the impact of demand response can be derived quite definitively and clearly from competitive market supply and demand conditions that are becoming wide spread and are therefore likely to apply to a majority of demand response programs. An additional advantage is that this price formation framework has been developed to characterize actual demand response programs that derive price changes from wholesale market transactions, which, as the next section of this report illustrates, can be verified using historical data.[31]

Economics is the study of disequilibrium because the focus of many policy directives is to correct market malfunctions that prevent competition from thriving. Accordingly, a measure of the adverse implications and consequences of disequilibrium is required. Consumer and producer surplus and social welfare serve that role. They can be usefully defined from a market perspective as follows (refer to the graphic in Figure 4.19):

- Consumer surplus is the collective gain that accrues to all consumers by virtue of paying the same price for the same good. Some value the good more than others, which is why the demand curve for the good is downward sloping. Consider the consumer that corresponds (hypothetically) to point L^V on the demand curve (Demand) in Figure 4.19. The value it receives (and therefore what it would pay) is determined by the price that corresponds to that point, point P^V in the figure, but it only pays the much lower equilibrium price LMP, so it realizes value equal to the difference between P^V and LMP on that level of consumption. Now consider the consumer that represents the point on the demand curve where supply and demand are equated, and which results in price LMP. It pays exactly the value realized.

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[28] Ruff, L. December 2002. Demand Response: Reality versus Resource. Energy Journal, Vol. 15, No. 10, pp. 10-23: Braithwait, S. June 2003. Demand Response Is Important-But Let's Not Oversell (or Over-Price) It. Electricity Journal, Vol. 16, No. 5, pp. 52-65. Elsevier Science Inc.

[29] Boisvert, R., Cappers, P., Neenan, B. April 2002. The Benefits of Customer Participation in Wholesale Electricity Markets. Electricity Journal, Vol. 15, No. 3, pp. 41-51. Elsevier Science Inc.

[30] Borenstein, S. 2005. The Long-Run Efficiency of Real-Time Pricing. Energy Journal, Vol.26. No. 3, p.96.

[31] For a description of these bidding programs and their participation see: ISO/RTO Council Markets Committee. October 16, 2007. Harnessing the Power of Demand: How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets. A description of participant savings can be found in: Neenan, B., Boisvert, R., Cappers P. April 2002. What Makes a Customer Price Responsive? The Electricity Journal, Vol. 15, No. 3, pp. 52-9. Elsevier Science Inc.: Goldman, C., Hopper, N., Sezgen, O., Moezzi, M., Bharvirkar, R., Neenan, B., Pratt, D., Cappers, P., Bosivert, R. August 2004. Does Real-Time Pricing Deliver Demand Response? A Case Study of Niagara Mohawk's Large Customer RTP Tariff. Lawrence Berkeley National Laboratory Report No. LBNL-54974. Available at http://www.lbl.gov/

Everybody in between realizes an intermediate level of value. The sum of the values above when the consumer pay is called consumer surplus because it reflects the additional value consumers realize over what they would be willing to pay because all purchases are made at the market-clearing price. Graphically, consumer surplus is the area below the demand curve and above the price line, the prices consumers pay.

- Producer surplus is the flip side valuation. The supply cost represents the cost of supply, but all suppliers get the equilibrium price LMP. Those with a lower cost of supply (those operating to the left of the equilibrium supply—L in the figure) realize a surplus earning over cost, which is called producer surplus and is so labeled in the figure). Graphically, producer surplus is the area below the price line and above the supply curve.
- In competitive equilibrium, the character of supply and demand—where they are located in price/quantity space and their slopes—determines the relative level of consumer and producer surplus. However, as long as price is determined by the intersection of total market supply and demand, that distribution represents the optimal allocation of societal resources. [32]

What happens when a market is not in equilibrium, specifically, when the price consumers pay to consume electricity is not equal to its marginal cost of supply? In the case where the LMP exceeds the price (a fixed rate) consumers pay, then there is a reallocation of consumer and producer surplus. In addition, because societal resources are not being used optimally resources are wasted, which is referred to as deadweight loss and which can be depicted using the same graphically illustrated concepts.

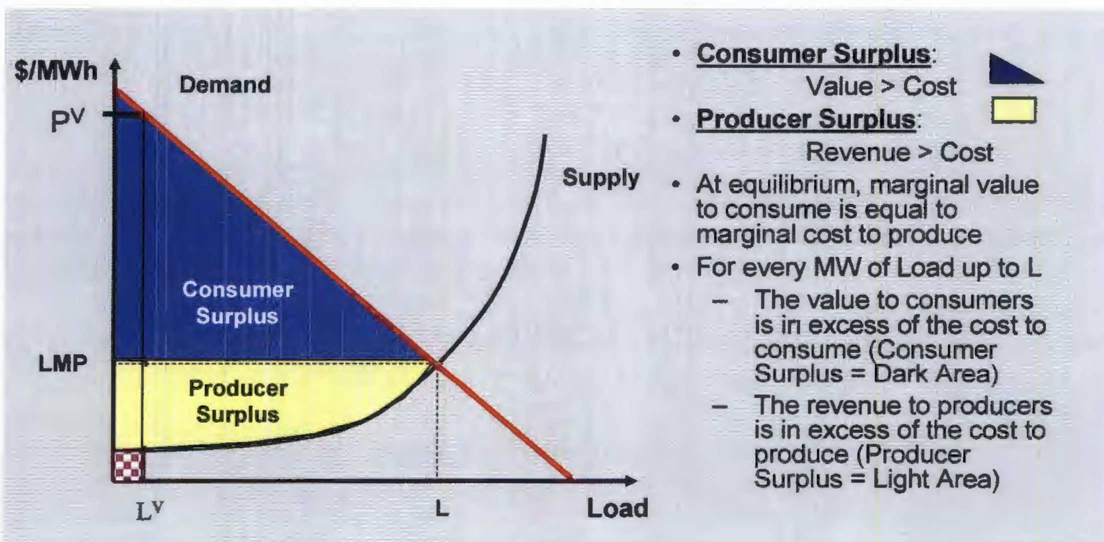

Figure 4-19
Consumer and Producer Surplus

[32] Competitive equilibrium defines what is called static equilibrium in the short run and dynamic equilibrium in the long run, the difference being that the former assumes that consumers and producers must cope with the technology available and the latter allows for readjustments that result from changes in technology.

Figure 4.20 depicts the case where consumers pay a fixed tariff rate (T) for consumption despite the fact that the cost of supplying electricity (LMP^{DE}) is above that tariff rate, at least in some periods (assuming that the uniform price T is the load weighted average cost of supply). The consequences are as follows:

- In some periods the quantity consumed (L^{DE}) is above the equilibrium quantity (L) and as a result producer surplus grows and consumer surplus shrinks by a corresponding amount. Disequilibrium results in a transfer in the relative benefits associated with market transactions.
- The consumption associated with the difference between L^{DE} and L in Figure 4.20, reflects resources that are not optimally allocated. The area between L and L^{DE} and below the supply curve and above the demand curve is referred to as the deadweight loss, a monetary measure of the adverse consequences of market disequilibrium.

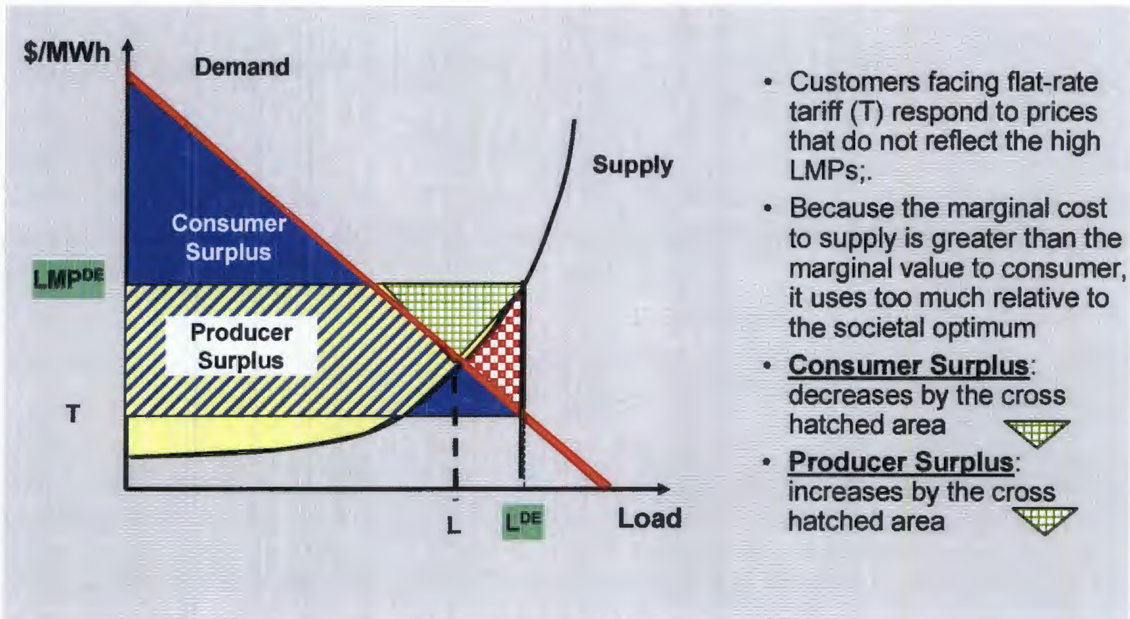

Figure 4-20
Adjustments in Consumer Surplus in the Absence to DR

What happens if some consumers pay LMP instead of T and therefore adjust their usage according to the demand curve? Equilibrium is restored, which beneficially affects the distribution of surplus between consumers and producers and eliminates deadweight losses as shown in Figure 4.21:

- Demand in Figure 4.21 is depicted as being downward sloping and therefore elastic over part of the total load (L^{DE} to L). So, the consumers facing LMP^{DE} respond by reducing consumption to where marginal cost and value are equated, which is defined by the change from L^{DE} to L in the figure; and the resulting equilibrium price is LMP:
- The impacts on consumers are that the market price is now lower, so they pay less and they recoup consumer surplus;

- The price responsive consumers realize a bill savings defined by the price change times the load reduction they undertook, the shaded area labeled *Participant Gross Savings* in the figure. The savings are qualified as gross because they must be adjusted for the costs the price responsive consumers incur in adjusting consumption to the high price. These costs include: 1) increases in non-electricity operating costs to accommodate shifting usage from high to lower price times; and 2) the cost of purchasing make-up electricity at another time if doing so is required to maintain business obligations or household needs—studies suggest that half or more of the price response exhibited by participants in demand response program involves shifting usage from a high price period to another, lower-priced period.[33]

- LMP is reduced, but the benefit is realized immediately only by load being purchased in the market at that time (load serving entities that are purchasing energy to fill the gap between the demand they are serving and the generation output for which they have contacted). Typically only 20-30% of retail load requirements are purchased in the wholesale spot market; the rest is contracted for under bilateral contracts and therefore are unaffected, at least in the short term, by wholesales spot market price fluctuations. Accordingly, the actual bill savings are that fraction of the system load times the price change, which is represented by the box labeled as Short-Term LMP Savings in Figure 4.21.

- Responding to high prices reduces LMPs, which in turn reduces price volatility. Lower price volatility reduces the risks LSEs face by buying their energy from the spot market. They therefore can be expected to demand and receive lower risk premiums for the bilateral services they contract for. As a result, they pay lower hedging premiums, which gets passed on to consumers in lower bilaterally hedged prices. These savings inure to those consumers that are served under hedged prices. The area labeled *Long-Term Bill Savings* illustrates a small change in bilateral price applied to the load served there under.

- Finally, the deadweight losses were eliminated because competitive equilibrium was restored. Societal resources are once again optimally allocated to the electricity sector and other sectors of the economy, which benefits all consumers. The wedge labeled *Social Welfare Improvement* in Figure 4.21 represents the equivalent monetary benefit.

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[33] Goldman, C., Hopper, N., Sezgen, O., Moezzi, M., Bharvirkar, R., Neenan, B., Bosivert, R., Cappers, P., Pratt, D. June 2004. Customer Response Day-Ahead Wholesale Electricity Prices: Case Study of RTP Program Experience in New York. Lawrence Berkeley National Laboratory Report No. LBNL-54761. Available at http://www.lbl.gov/;

Neenan Associates, Lawrence Berkeley National Laboratory, Pacific Northwest National Laboratory. January 2003. How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance. Available at http://www.bneenan.com

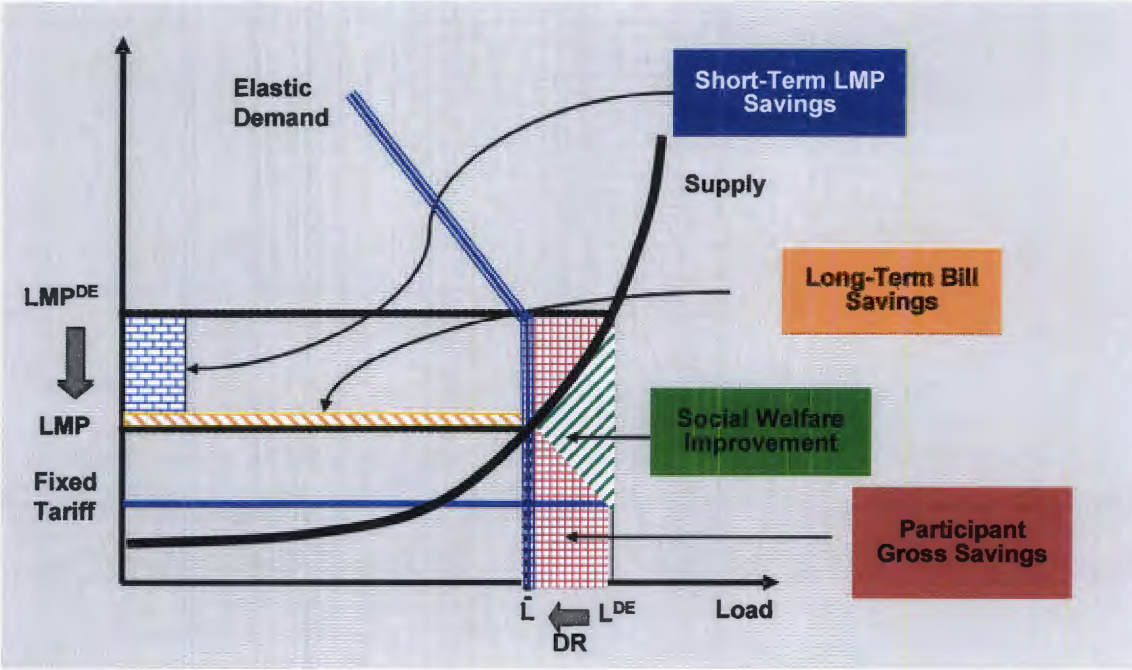

Figure 4-21
LMP Impacts of DR

The illustration of how demand response impacts market price formation defines the sources of benefits attributable to those load changes and to whom they accrue, as follows:

- Bill savings to those consumers that responded to prices when they are high
- Short-term bill savings on load purchased to serve retail consumers (by load-serving entities) during the period when otherwise the LMP would have been higher
- Long-term bill savings due to lower LMP volatility
- The elimination of deadweight losses.

There are two additional important sources of benefits that are not depicted in this characterization of spot market price formation, as follows.

- If high LMPs correspond to the how the system peak is measured for the purposes of establishing system capacity requirements, then there may be savings from the reduction in that requirement. How this transpires is demonstrated in the next section.
- Consumers that pay LMPs instead of buying a hedged service stand to pay less because they trade the hedge cost for the price risks. If they can curtail during the highest price periods and use more at other times, their total bill will be less than that of a hedged service. This saving is explicitly accounted for in some of the demand response benefits studies that are reviewed below in Section 4.7.

4.7.2.1 Another Perspective on the Benefits of Demand Response

The benefits streams defined above correspond to the price formation mechanism of wholesale spot energy markets. Therefore they define what to expect from demand response programs that influence spot energy markets, like the day-ahead and real-time markets operated by ISOs/RTOs. As detailed below, this portrayal of demand response benefits has been used by ISOs/RTOs to both design programs that allow consumer participation in wholesale energy markets and evaluate their performance. This framework would also apply to programs offered by load-serving entities (LSEs), both utilities providing default service and competitive retailers, to reduce their hedging costs. Such programs may include provisions for some of the benefits to be retained by the LSE to offset its costs, and if appropriate, to provide an incentive to make such service available.

In order to accelerate participation in demand response programs, utilities and their regulators as well as the ISO/RTOs and FERC have been looking at incentive mechanisms to induce more demand response. These include providing participants with subsidized metering and administrative costs and providing them with equipment that enhances their ability to respond to wholesale price changes.[34] Since these programs involve market intervention, the usual practice is to conduct a benefit/cost analysis to demonstrate that the subsidy is justified. Most stakeholders would condone such a study, but not all agree on what properly constitutes a benefit for such a policy analysis.

Ruff articulates the exception that some take to counting short-term and long-term participant bill savings as benefits.[35] He acknowledges the welfare improvements, i.e., reduced deadweight loses, are a legitimate source of benefits that could be used, for example, to justify a Smart Metering investment to enable demand response. However, he argues that the bill savings that other consumers realize are not net societal benefits, but instead transfers of the distribution of gains of market transactions from producers to consumers. Under classical economic interpretation of welfare economics, which is the formal name for the study of the level and distribution of benefits of competition, only societal benefits (reduced deadweight losses) are properly used in conducting a benefit/cost assessment of a policy that involves market interventions. Transfers represent changes in an individual's relative circumstances and any judgment about them would involve a judgment about individual welfare, which is beyond the scope of traditional welfare analyses.

In fact, Ruff views sanctioning transfers to induce energy market-based demand response as a destructive policy since the gains to consumers come at the expense of producers that rely on scarcity rents associated with occasional high prices to realize adequate return on their generation investments, especially investments in peaking units that are run only a few hours a year to meet peak loads. Investors count on elevated LMPs a few hours a year to rationalize the investments. If demand response is induced through incentives or subsidized investments in enabling technology that are predicated on counting transfers to consumers as benefits, Ruff predicts that there will be a generation investment shortfall that may produce short-term bill

[34] New York State Energy Research Authority has offered such programs for several years.

[35] Ruff 2002, op cit.

savings to consumers, but will inevitably result in LMPs that are even more elevated and occur more frequently thus raising everyone's bills.

Some counter that Ruff is splitting hairs on the policy's approach. He approves of natural or autonomous demand response, which describes load adjustments undertaken by consumers that continuously face prices that are derived from wholesale market LMPs (for example market-based RTP or TOU rate structures), because their actions reflect their marginal value of electricity, as is the case in most markets where consumers are price takers. The result is that producers receive less revenue and consumers benefit from bill savings, the same what happens under a subsidized program. Is there an explanation for why one is acceptable and the other is not?

This debate quickly becomes both technical and nuanced. The important aspects can be summarized by making the following distinction:

- If consumers respond to the prices that pay for electricity without an additional inducement or payment, the actions they take in their own self interest unequivocally benefit themselves and others, as was demonstrated above. The realignment of transfers reflects the need for a downward adjustment of investment in the electricity sector to reflect consumer value. If no incentives are offered and no costs are involved, then and the role of transfer is moot as they reflect societal-improving changes in supply and demand. However:
- If consumers receive an inducement to respond to price changes or costs must be incurred to bring about price response such as payment to respond or Smart Metering investments, then the policy under scrutiny merits the detail of a benefit/cost assessment. The role of transfer as benefits must be resolved by those responsible for designing and administrating the market.

Some regulators and stakeholders have already faced the issues of what constitute a benefit of demand response. Some have determined that promoting demand response is beneficial on so many levels that a strict interpretation of welfare economics is not warranted, at least in the short run. Section 4.7 reviews some of these circumstances.

4.7.2.2 Capacity-Adequacy

Consumers' load curtailment capabilities can be used to substitute for or complement generation resources that comprise the system capacity adequacy requirement. The capacity adequacy requirement, which is defined in terms of the system peak load, establishes the amount of capacity that load serving entitles (utilities and other retailers) must procure the rights to for each system planning period (typically six months or a year). The system requirement is the forecast system peak load plus a contingency margin. The margin, which varies among regions between 12-18%, is set to make provision for the loss of the largest single unit in the system. If that unit were to be lost during the peak demand period, there would still be sufficient capacity available to serve load baring other contingencies.

Load serving entities fulfill their capacity obligation by purchasing the capacity rights of generators or constructing and operating their own units. Many states that have adopted a competitive electricity market structure required utilities to divest themselves of their generation (or move it to a subsidiary), and therefore they must rely on purchases through bilateral contracts or in ISO/RTO- managed spot capacity markets.[36] Capacity spot markets are operated by the ISO/RTO to resolve adequacy shortfalls of load serving entities through the unsold capacity of generators. A portrayal of how capacity prices are derived, using economic principles, serves to illustrate how demand response generates benefits that have measurable monetary equivalents.

Demand Response as a Capacity Obligation Abatement Resource

In a competitive market, a load serving entity can reduce its peak load obligation and save the cost of the equivalent capacity by enlisting consumers to reduce load when directed to do so. The utility realizes the benefit if it can anticipate the hour or hours when the system peak is established and used for allocating the next year's capacity obligations and induce its demand response participants to reduce load at those times.

The savings are equal to the capacity reduction achieved times the cost of purchasing that capacity. Figure 4.22 portrays the result in price/quantity space, in this case where capacity supply and demand is depicted. In the figure, the vertical line labeled CAP Demand represents the fixed system capacity obligation at the system level. The market supply of capacity is represented by the curve Cap Supply and the market-clearing price for capacity is the intersection, which produces the price CAP $. If the utility can induce demand reductions equal to the amount ($CAP - C^{DR}$) depicted by the highlighted box labeled *DR Value* in the figure, the net savings are less by the amount the utility has to pay consumers as an inducement to undertake the curtailments. The inducement could be a cash payment based on pledged load ($/MW) or services and equipment in kind that enable the consumer to curtail or both. However, the total expenditures on inducements must be less than the capacity price for there to be a net benefit in terms of the cost of meeting the capacity adequacy requirement.

As described above, capacity savings are realized only if the utility calls for and gets curtailments coincident with the system peak. Failure to predict the peak results in no value, even if participants were asked to and did curtail at other times that turned out not correspond to when the system peak would have been set in the absence of the demand response. Moreover, the value the utility realizes is in the subsequent year when its proration of peak system peak is adjusted downward. Under these circumstances, the utility has to engage in a pay-it-forward curtailment that involves uncertainty about the value of capacity in the year its value is actually realized.

[36] Two ISOs/RTOs have centralized the purchase of capacity for the entire market, the cost of which is prorated to the individual load serving entities based on their contribution to the system peak. However, they contract bilateral for capacity as a hedge against the market price produced by the central auction the ISO/RTO uses to acquire the required resources.

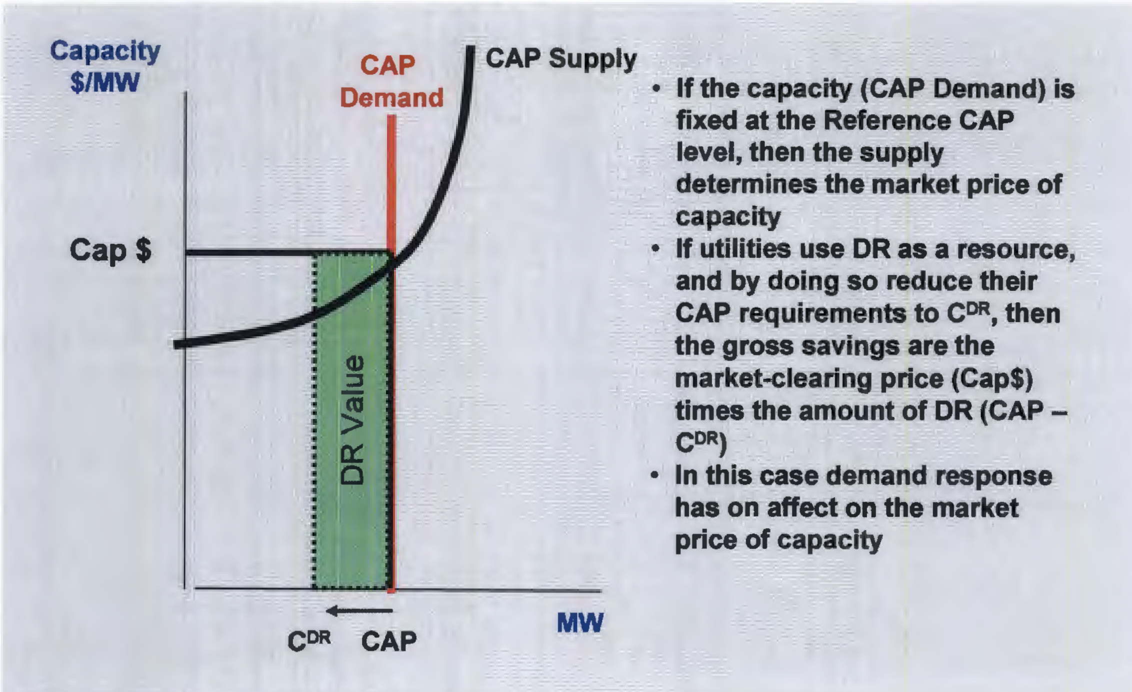

Figure 4-22
DR as a Capacity Offset

Demand Response as a System Capacity Resource

Alternatively, demand response could be treated as a system resource by allowing consumers to offer their load curtailment capacity to LSEs or submit it to the ISO/RTO capacity auction. The effect is to augment the supply of capacity available to meet LSE adequacy requirements, as illustrated in Figure 4.23. If some of the demand respond capacity is priced below that of generation (labeled CAP^{DR} in the figure), then the result is that the supply curve is shifted rightward (labeled *CAP Supply B* in the figure) and the demand response capacity displaces an equivalent amount of generation resources (labeled *Displaced Generation* Capacity in the figure).

Because the market supply of capacity is increased, the clearing price falls and the cost of all capacity purchased, including that from generators, is reduced. As a result, the total purchase cost of capacity is lower and therefore so is the expenditure on capacity by the amount depicted by the colored and hatched square labeled *DR Value* in the figure.[37]

The advantage of this arrangement is that all consumers benefit and the utility does not undertake the risk associated with deciding when to call for curtailments. The ISO/RTO determines when

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[37] Some ISO/RTO markets employ a downward-sloping capacity demand curve that can result in the purchase, through the centralized capacity auction, of more than the established capacity amount. This adds a complication. because the price of capacity goes down, but more is purchased. The net result in terms of overall capacity expenditures depends upon the character of the capacity demand curve, which is administratively determined.

curtailment by participants is warranted and is responsible for verifying performance. Moreover, the utility makes no explicit outlays to realize benefits for all its consumers. The demand response participants receive their inducement from either a load serving entity or the capacity auctions, the cost of which are recovered from all consumers, which may include ones not served by the LSE.

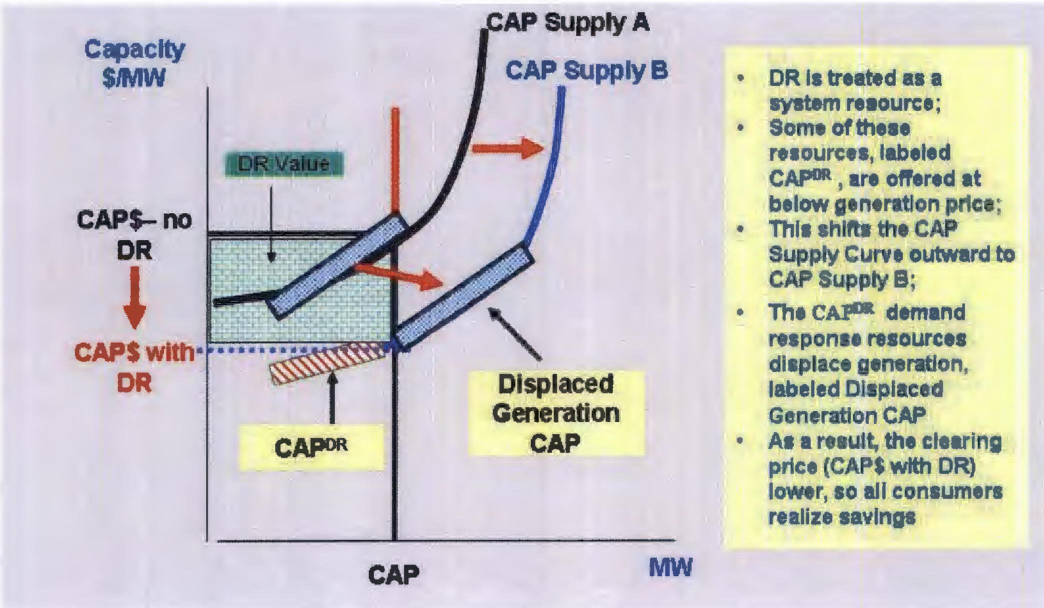

Figure 4-23
DR as a Capacity Resource

Demand Response as an Integrated Enterprise Capacity Resource

A vertically integrated utility operating in a market that has no centrally imposed capacity requirement still has to arrange to fulfill capacity obligations set by local reliability councils (under NERC's coordination) and often enforced by a state or other regulatory body. Under these circumstances, utilities establish those capacity requirements through introspective (as opposed to market-wide) analyses that characterize enterprise capacity resource availability and demand forecasts, which may incorporate aspects of wholesale market prices. But, because the planning perspective is that of the utility, the marginal value of capacity to the utility depends on what resources are available and how the utility dispatches them to meet its load obligations.

The Department of Energy (DOE) report on the value of demand response describes the nature and character of the differences in how the value of demand response capacity is determined by a vertically integrated utility that holds a localized retail monopoly.[38] Section 4.6 below

[38] U.S. Department of Energy. February 2006. The Benefits of Demand Response in Electricity Markets and Recommendations for achieving Them. A Report to U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005.

summarizes through case studies some of the analytical protocols that are used to establish the avoided cost associated with demand response-provided capacity in these markets.

Summary

The value of demand response in reducing or avoiding capacity costs or obligations depends on the market structure in which the utility operates. The value can vary substantially from year to year depending on the prevailing supply of generation in competitive markets. Moreover, until recently, ISO/RTO markets only made provision for capacity price formation on a monthly or semiannual annual basis, which exaggerates the price volatility and may reduce consumer interest in participating or raise participants' threshold for the inducement required to participate. Recently PJM and ISO-NE have created centralized capacity procurement markets that purchase requirements forward three years. This results in somewhat greater price certainty that may attract more demand response.[39] Attributing capacity reduction to demand response involves making assumptions about market price formation mechanisms that are not fully understood and therefore subject to considerable uncertainty.

4.7.2.3 Capacity- Emergency

Another role for demand response is to provide a stock of emergency resources that can be deployed to forestall imposing forced outages on consumers. Such circumstances arise when the supply of generation resources is not sufficient to meet what is needed both to serve load and to provide for reserves to account for contingencies such as the unexpected unavailability of one of the largest generation units. ISOs/RTOs and utilities have developed protocols for how to respond to these circumstances. At some point, short-term load shedding (forced outages to retail consumers) is necessary to avert encountering conditions that would result in far more devastating results.

Introduction

To deal with low probability circumstances (contingencies) whose outcome could result in a substantial and undesirable impact on electricity consumers, ISOs/RTOs have created a new resource category, Emergency Demand Response (EDR) resources, which are dispatched to alleviate pending or realized reserve shortfalls. They are intended for use in situations where all available generation resources have been exhausted—both those available locally and imports from another market—and operating reserve shortfalls are anticipated.

Generally, EDR resources are not counted as capacity for determining system capacity adequacy, unlike curtailable load enrolled as adequacy reserves. They are not treated as dispatchable to meet energy or ancillary needs; any loads participating in that capacity (bidding into energy markets as an energy supply) will have already been accounted for in determining operating

[39] ISO-NE reported that in it inaugural qualification of resources for its Forward Capacity Market auction (to procure capacity for 2010), almost 2,500 MW of demand response was accredited to bid, which is twice the amount currently participating.

supply availability. EDR resources are held in abeyance to use during system emergencies to avoid imposing forced outages on some consumers.

A Theoretical Valuation Framework

EDR resources do not contribute to adequacy or energy supply, so the wholesale market does not produce prices or other means for directly monetizing their value.[40] If consumers value reliability at the margin (deviations from the system-design level), then when system reliability is compromised, consumers receive less than the level of service reliability that they desire. They should, in principle, be willing to pay to have reliability restored in the amount that reflects their marginal value of service reliability.

EDR resources provide value because the load curtailment provided by participants is used to improve system reliability when it is compromised, but how is the improvement measured and valued? One measure of reliability is the loss of load probability (LOLP), which equates the supply of operating reserves to the likelihood of encountering circumstances that would lead to a forced outrage being imposed on some consumers.

If dispatching EDR resources reduces LOLP, then consumers benefit. So, the first element of a valuation function is to measure how demand response affects LOLP. If LOLP reductions can be equated to consumer value, then the value of EDR resources can be derived, at least implicitly.

One candidate for the value-generating function for EDR resources is as follows:

(1) VEUE = VOLL * (Change LOLP) * (% Load at Risk) * (System Load).

> * = the multiplication operator
> VEUE = value of expected unserved energy ($), what consumers presumptively would pay to have reliability restored to the design level
> VOLL = Value of Lost Load ($/kWh), the cost consumers incur during a forced outage
> LOLP = Loss of Load Probability, the likelihood that system conditions would require imposing a forced outage to maintain overall system reliability, which takes on values between near 0 (little change of an outage) and 1.0 (an outwash can not be avoided)
> Load at Risk = the amount (%) of load that would be blacked out without the dispatch of EDR resources
> System load = system load served (MW) at the time of these circumstances

LOLP is defined as the likelihood of an outage. However, in order to value the consequences, the extent of the outage (% system load) must be specified to arrive at a measure to which value can be assigned, the amount of MW that is at risk.

For given assumptions about the values for VOLL, Load at Risk, and System Load, the value of curtailments undertaken by EDR resources is determined by the change in LOLP they produce. In order to quantify the benefits, it is necessary to establish a relationship between reserves and

[40] This section draws upon the more detailed discussion in: New York ISO. December 2004. NYISO 2003 Demand Response Programs (Attachment I) Compliance Report to FERC. Docket No. ER01-3001-00. Available at http://www.nyiso.com/public/index.jsp

LOLP and to measure the change (reduction) in LOLP associated with the dispatch of EDR resources. Figures 4.24 – 4.26 illustrate how the dispatch of EDR resources results in benefits to consumers from reduced exposure to outages that otherwise might be imposed by the ISO to maintain system reliability.

The graph labeled in Figure 4.24 depicts the relationship between the availability of operating reserves (labeled *Operating Reserves*) and the loss of load probability (*LOLP*). The Point D in Figure 4.24 represents the situation where operating reserves are sufficient to maintain system reliability at its design criteria. Note that at that level of reserves (D in the figure), LOLP is small but not zero, though at a level that is acceptable. Additional levels of operating reserves produce very small increases in LOLP, but decreases in operating reserves contribute to LOLP at an increasing rate.

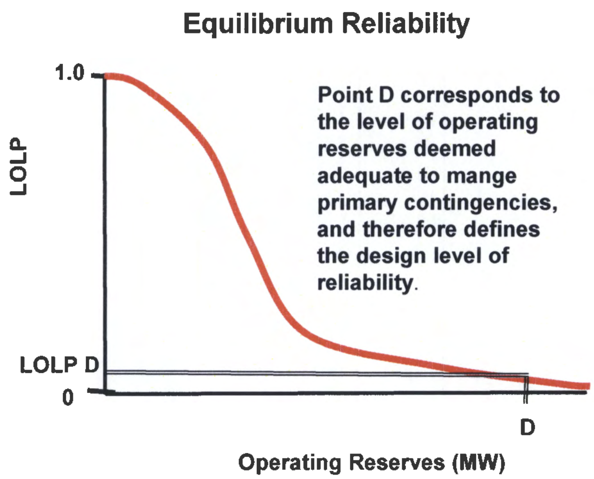

Figure 4-24
Operating Reserve and LOLP

A shortfall of operating reserves, for example as depicted by Point *C* in Figure 4.25, results in an increase in the LOLP above the design level, depicted by $LOLP^C$ in the figure. In these circumstances, dispatching EDR resources would reduce the LOLP. If there are enough, the gap can be eliminated; but if too many are dispatched then the LOLP target will be overshot.

Figure 4.25, illustrates the impacts of EDR resources being dispatched. Figure 4.26, displays the LOLP/Reserves relation as before, with the addition of Panel B to depict the supply curve for EDR resources (labeled S^{EDR}). The supply of EDR is depicted as upward sloping, meaning that as EDR participants are offered a higher price, the amount of load curtailed increases. How much of this resource should be deployed?

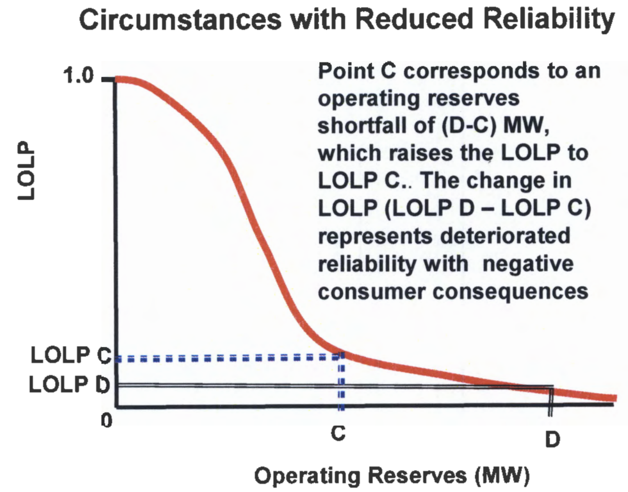

Figure 4-25
Using DR to Restore Reliability

Consider the case where the price offered to EDR participants is P^A (in Panel A of Figure 4.26) and as result virtually all the available curtailments are undertaken, as shown in Figure 4.26. Price P^A results in curtailments that increase operating reserves to point A, which is above the design level. This outcome is generally considered to be an unintended consequence of indivisible demand response resources.[41]

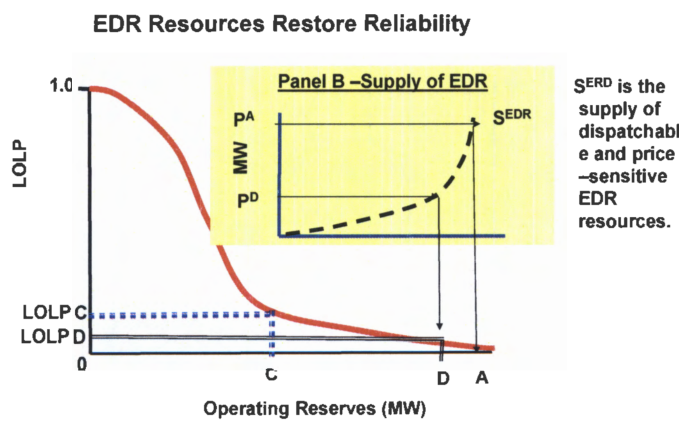

Figure 4-26
Using DR to Restore Reliability Optimally

However, the curtailments exceed what is needed to restore LOLP to the amount indicated by Point D on the LOLP curve. By offering the price P^D, the amount of curtailed load is just sufficient to restore system equilibrium at operating reserve level indicated by Point D.

The graphic depiction illustrates the relationship between the available supply of EDR resources and establishing reliability equilibrium. The improvement in reliability is measured by the

[41] ISOs/RTOs and utilities usually make provision for dispatching demand response resources incrementally.

change in LOLP attributable to EDR resources, which corresponds in Figure 4.26 to LOLP C – LOLP D. If this change can be expressed as a probability, the corresponding value of the reliability improvement can be quantified.

To illustrate this process and how it might be monetized, assume that the change in LOLP in the illustrated example is equal to 0.10. Further, assume values (all for an event of one hour) for the other variables that comprise the value transformation function (VEUE) as follows:

- VOLL = $5,000 MWH
- Load at Risk =5%
- System Load =30,000 MW

The Value of Lost Load (VOLL) has been the subject of controversy as to how well it corresponds to how consumers value electricity service, at the margin and the level of effort to quantify that value, which have produced a wide range of values from near zero to hundreds of dollars per kWh. Section 6.0 discusses these issues in greater detail. Valuing VOLL is also a critical aspect of quantify improvements in service reliability associated with faster service restoration, the topic of Section 6.0. That section provides a more detailed discussion on how the value of lost load can be quantified.

The gross benefits are three-quarters of a million dollars under these hypothetical event circumstances. Typically, payments ($/MWH curtailed) are made to those that curtail under this design, so the net benefits are less. Assume further that the LOLP improvement was realized by the dispatch of 25% of the total supply of EDR resources, which is assumed to be 500 MW. Payments for curtailments would be $625,000 (125 MWH * $5,000/MWH), resulting in a net gain to consumers of $100,000.

Measuring LOLP under such circumstances is challenging, as it requires a close examination of system dispatch conditions that are difficult to recreate. Ambiguities in measuring LOLP can have a large impact in the value that is estimated. Moreover, valuing VOLL is a subjective enterprise, which is discussed in more detail below. Even if these acceptable measures were agreed upon, inducing consumers to reduce load under these circumstances most likely would require that the amount they would be paid be specified in advance, which is the practice of NYISO and PJM both pay the higher of $.50/kWh or the prevailing LMP. In other words, the value has to be imputed in advance.

As shown in the example, to achieve positive net benefits EDR resources must be called upon when the combined effect of the change in LOLP and Load at Risk comport with that value. Since the inception of its variation on EDR, the NYISO has conducted annual assessments to estimate the benefits associated with each event and compare them to the amount paid to realize the curtailments.[42]

[42] See for example: New York ISO. December 2002. NYISO 2002 Demand Response Programs (Attachment I) Compliance Report to FERC. Docket No. ER01-3001-00. Available at http://www.nyiso.com/public/index.jsp

In summary, markets do not explicitly value the availability of supplemental, emergency operating reserves. Yet, consumers value reliable electric service, and thereby they implicitly value the reliability improvements that can result from the dispatch of emergency resources. Historically, utilities have relied upon public appeals to achieve load reductions to forestall forced outages. Some ISOs/RTOs (NYISO and PJM) have created a mechanism whereby the value of improved reliability can be monetized by combining changes in system reliability with assumptions about their consequential impacts and the value consumers attribute to marginal reliability improvements. The extent to which net benefits are realized is dependent on assumptions about market circumstances that are fraught with subjectivity *ex ante* and can be difficult to calibrate *ex post*. Nevertheless, the experience to date at NYISO suggests that these resources can be used to the benefit of all consumers.

4.7.2.4 Summary

Applying economic theory to electricity markets provides a characterization of how load changes influence price formations and a way to trace through the subsequent impacts on all market participants. Applying this framework to actual market conditions monetizes the benefits that may be attributable to Smart Metering.

4.7.3 Empirical Applications

The principles of the economics of demand response have been applied to actual market circumstances to quantify and monetize the level and distribution of benefits both retrospectively and prospectively. The three sections below discuss some of these analyses to provide a perspective on how large the benefit streams are likely to be and what is required to quantify them.

4.7.3.1 Elemental Method of Estimating Demand Response Benefits

This section discusses an elemental method for estimating the potential benefits that may emanate from demand response programs enabled by the Smart Metering technology. The term "elemental" is used to describe this approach because the analytical process involves the multiplication or division of several individual parameters. It may be intuitively appealing, at least as a first approximation, because it is functionally simple in it construction: the analysis can be conducted using a spreadsheet. This transparent transformation focuses the analysis on the values assigned to the functional elements. The result can be easily traced back to the individual assumptions employed: who is assumed to participate, how much they respond to the incentives offered, the level of those incentives, the resulting load changes, and the value assigned to them.

The elemental analysis, which is applicable to monetizing the load changes resulting from a specified demand response program, for example CPP, TOU, or RTP, is illustrated in Figure 4.27.

The critical inputs required of the elemental transformation functions are as follows:

- The nature of the events that characterize the demand response program
- The number of customers that will participate in the program organized by rate class or some other segmentation criteria
- Load profiles for each segment at the level of time differentiation consistent with events
- The average price paid by customers in each segment
- The prices or other inducements and penalties (if applicable) that characterize the demand response program
- Estimates of the price elasticity of demand, cross-price elasticity of demand, or elasticity of substitution by rating period and customer class or event-specific load reductions (kWh or percentage of load at the time)
- The coincidence of events with the system
- The market or avoided cost of generation capacity and energy
- Estimates of the costs of program implementation

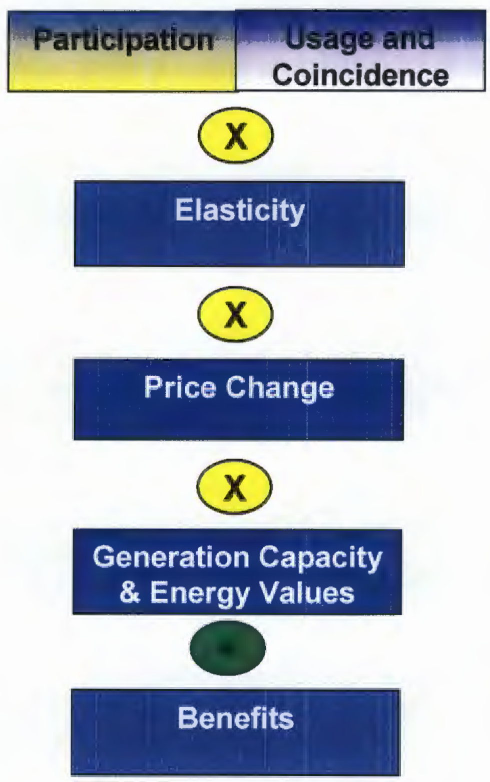

Figure 4-27
Steps in the Elemental DR Benefits Estimation

A brief summary of each of these inputs is provided in the topical sections that follow.

Specification of the Demand Response Program

Specifying the character and features of the demand response program establishes the degree of granularity by which price changes or inducements are imposed and load response is measured. Section 2.0 provided a characterization that sorts demand response plans in order to make these important distinctions. Each data element must be specified for each year of the study period, which can be 15-20 years in the case of a Smart Metering business case. Current period data may be readily available, but projecting each parameter into the future can be challenging and fraught with uncertainty and subjectivity.

Population of Eligible Customers

The number of customers in the target population, broken down by consumer segments, defines the maximum level of enrollment. Typically, utilities sort consumers for rate making purposes into households and businesses, the latter often broken down further to reflect the level of energy and demand used and other factors. Current commercial account records provide base-year data, which must be projected into the future years of the study.

Load Profiles

To forecast the change in energy use and demand that a price change induces, load profiles must be prepared for each segment. The level of temporal distinction depends on the demand response program. TOU requires only a typical daily profile by month, while RTP and in most cases CPP require an hourly load profile.

Prices Before and After Demand Response Program

Demand response is driven by changes in prices: consequently, the analysis requires specifying the base price and the price or prices specific to the events that typify the demand response program. The prices currently paid by customers, which are the bead or reference prices, can be a class load-weighted average that reflect what the consumers would pay if they didn't participate. The event prices are determined by the type of demand response program that will be implemented. RTP requires estimating hourly prices for each study year. CPP event prices are usually specified in advance; but in most cases somewhat arbitrarily or purposefully, for example to achieve a specified level of event load reduction.

Participation Rates

The customer participation rate is a critical input for determining the benefits from a demand response program.[43] Therefore careful assumptions need to be made regarding the number of customers that will subscribe to a particular program. These assumptions can be based on the results that have been experienced elsewhere, for example pilots or other rollouts of a similar program, combined with the specific marketing and information plans associated with the

[43] The importance and difficulty in predicting customer participation rates is discussed above in Section 4.3.

program being evaluated. As seen with the ComEd analysis that was summarized above, participation rates for the peak-time rebate programs have been characterized differently from TOU or CPP programs. With universal Smart Metering, all customers can be automatically subscribed to the PTR program. The key analytical question is who will decide to actually respond to event. One approach is to associate response with the proportion of customers that have sufficient knowledge of the program to make the decision as to whether to respond, referred to in the ComEd filing as the awareness rate.

Price Responsiveness

The price responsiveness of the participating customers is another critical input in estimating the benefits as it directly determines the MW and MWH reductions resulting from a price change. Although there is a wealth of information from previous studies on price elasticities for electricity (see Section 4.4 above) there have been limited applications of such demand response programs such as CPP and PTR. As discussed in Section 3, many of the Smart Metering business cases focus on residential demand response programs and utilize the elasticity results derived from those of the California Statewide Pricing Pilot.

Marginal Cost (Avoided Cost) of Generation

The marginal cost of generation, which in some contexts is equated to an avoided cost, transforms the estimates of MW and MWH reductions into money terms. Avoided capacity costs can be derived from planning exercises that involve detailed simulations of system operation over the study period. Such a study would also provide a detailed characterization of the generation cost savings attributable to a demand response program. Conducting such a detailed simulation for each demand response program requires a substantial undertaking, which may be justified because it provides a characterization of the inherent risks, as discussed below.

To simplify and standardize evaluating programs like energy efficiency and demand response, the convention in many jurisdictions is to use the levelized cost ($/MW) of a peaking unit as the avoided capacity cost. These values must be projected out for the duration of the study horizon, which can be as many as 20 years.

The approach used to estimate these values may be determined by the market structure of the region in which the utility operates, as discussed in Section 4.6.2. For example, in the New England market, demand response resources can participate as a supply side resource in the Forward Capacity Market (FCM) and collect capacity payments. In PJM, load serving entities' expected capacity costs should reflect the structure of the market's Reliability Pricing Model (RPM).

Marginal (avoided) energy costs can also be derived from a comprehensive simulation that traces the implications of supply and demand over a range of possible circumstances. The marginal costs savings of demand response programs may be understated by highly averaged values that ignore the consequences of extreme events.

Cost of Program Implementation

The cost of program implementation is deducted from the estimated benefits of a demand response program to derive the net benefits attributable to Smart Metering. These include the cost of marketing the rates and creating the awareness levels that define participation as well as the cost of installing and operating systems to support program enrollment and administration.

Sensitivity of the Analysis to the Critical Inputs

A number of parameters must be specified to make a elemental transformation function operational. However, a few of these are especially important because their influence on the outcome is the greatest and because they are subject to so much uncertainty: (1) the price elasticity of electricity demand, (2) the relative prices that distinguish events, (3) the participation rate, and (4) the level of the avoided energy and capacity costs. The following exercise demonstrates the sensitivity of the elemental transformation to the level of these variables. For this example, the focus in on estimating the capacity benefit for a demand response program in which events are declared primarily to achieve a reduction in the system peak demand to reduce system capacity costs.

First, the elasticity estimate and the price differential (between the standard rate and the event price) are multiplicative in the elemental transformation function. They can be viewed as alternative ways to achieve results. For any given level of elasticity, higher event prices produce greater load changes. Conversely, for an given event price (relative to the base price), higher assumed elasticities produce a greater response. Table 4.2 demonstrates the range in response rates that result from variations in the elasticity value and the magnitude of event price changes in an illustrative elemental transformation function. For this simple example, the arc elasticity formulation is used to calculate the percentage reduction in load given an elasticity measure and a price increase.

The arc elasticity calculates the price response rate at the midpoint along the demand curve between the base and event price. This average response formulation constrains price responsive behavior to a rational set of outcomes: as the price ratio rises, all other things equal, the reduction load increases at a decreasing rate.[44] The arc elasticity used has the following formulation:

$$\varepsilon = \frac{Q_1 - Q_0}{(Q_1 + Q_0)/2} \div \frac{P_1 - P_0}{(P_1 + P_0)/2}$$

Where:

ε is the price elasticity of electricity demand
Q_1 and Q_2 are the base and event usage levels
P_1 and P_2 are the corresponding base and event prices

[44] Applying a series of ever larger price elasticity (for example, 0.10, 0.20, 0.30) values to a specified initial load and price ratio or a series of ever higher price ratios to a specified load and elasticity at some point produces a load change that implies load falls below zero, which is illogical. The arc elasticity imposes a mathematical structure that ensures that this does not result, regardless of the size of the elasticity or price ratio used.

The impact of variations in these key assumptions is portrayed in Table 4.2. The columns entries correspond to different levels of price elasticity, the row entries indicate different price changes that might be associated with events, and the table values associated with each elasticity/price change pair are the corresponding percentage reduction in load. For this example, an event is defined as a single hour and the impact is a change (MW) in the participant's demand in that hour.

Table 4-2
Change in Quantity for Different Price Increases and Elasticities

	Elasticity						
%ΔP	**0.025**	**0.05**	**0.1**	**0.15**	**0.175**	**0.2**	**0.25**
10%	0.24%	0.48%	0.95%	1.43%	1.67%	1.90%	2.38%
20%	0.45%	0.91%	1.82%	2.73%	3.18%	3.64%	4.55%
30%	0.65%	1.30%	2.61%	3.91%	4.57%	5.22%	6.52%
40%	0.83%	1.67%	3.33%	5.00%	5.83%	6.67%	8.33%
50%	1.00%	2.00%	4.00%	6.00%	7.00%	8.00%	10.00%
60%	1.15%	2.31%	4.62%	6.92%	8.08%	9.23%	11.54%
70%	1.30%	2.59%	5.19%	7.78%	9.07%	10.37%	12.96%
80%	1.43%	2.86%	5.71%	8.57%	10.00%	11.43%	14.29%
90%	1.55%	3.10%	6.21%	9.31%	10.86%	12.41%	15.52%
100%	1.67%	3.33%	6.67%	10.00%	11.67%	13.33%	16.67%
200%	2.50%	5.00%	10.00%	15.00%	17.50%	20.00%	25.00%
300%	3.00%	6.00%	12.00%	18.00%	21.00%	24.00%	30.00%
400%	3.33%	6.67%	13.33%	20.00%	23.33%	26.67%	33.33%
500%	3.57%	7.14%	14.29%	21.43%	25.00%	28.57%	35.71%
600%	3.75%	7.50%	15.00%	22.50%	26.25%	30.00%	37.50%
700%	3.89%	7.78%	15.56%	23.33%	27.22%	31.11%	38.89%
800%	4.00%	8.00%	16.00%	24.00%	28.00%	32.00%	40.00%

For example, if the price elasticity is 0.1 and the price change is 300%, according to table 4-2 the result is that consumption is reduced by 12%. At the 300% price change level, increasing the elasticity results in a higher percentage load reduction; and fixing the elasticity at 0.1 but increasing the percentage price change also increases the percentage reduction in load. This example demonstrates how the values assigned to these variables in the elemental transformation function can have a profound and discernable impact on the assumed load change.

The consequences of the assumed level of price elasticity can be further illustrated by holding the price change constant (at 300%), assigning values to the other variables in the transformation function, and then varying the price elasticity and the participation rate values. For illustrative purposes, consider a population comprised of 100,000 households with an average annual usage of 14,700 kWh, of which 65% is used during the peak. Given an elasticity value and an assumption about the coincidence of the event and the system peak, the kW load reduction can be derived for various participation levels and response rates, as illustrated in Table 4.3 below.

The columns in Table 4.3 correspond to elasticity values, as is the case in Table 4.2, but the rows indicate different participation levels, the percentage of the 100,000 households that are assumed to participate and respond at the specified elasticity value. The table values are the corresponding kW reduction for each elasticity/participation rate pair. For example, a 20% participation rate and -0.1 elasticity results in a 2,618 kW reduction in peak demand. Increasing the elasticity to -0.15 (holding participation constant) increases the kW reduction to 3,927 kW, and increasing the participation rate to 50% (holding elasticity constant at 0.1) increases the load reduction to 6,545 kW. These values all correspond to a 300% price change. A similar table can be constructed for each price change level, which demonstrates one of the shortcomings of the elemental approach: comparing the results of sensitivity cases is cumbersome because only two effects can be evaluated at a time.

Table 4-3
Demand (kW) Reductions at System Peak

For a Range of Elasticities and Participation Rates

	Elasticity						
Participation	**0.025**	**0.05**	**0.1**	**0.15**	**0.175**	**0.2**	**0.25**
10%	327	654	1,309	1,963	2,291	2,618	3,272
20%	654	1,309	2,618	3,927	4,581	5,236	6,545
30%	982	1,963	3,927	5,890	6,872	7,853	9,817
40%	1,309	2,618	5,236	7,853	9,162	10,471	13,089
50%	1,636	3,272	6,545	9,817	11,453	13,089	16,361
60%	1,963	3,927	7,853	11,780	13,743	15,707	19,634
70%	2,291	4,581	9,162	13,743	16,034	18,325	22,906
80%	2,618	5,236	10,471	15,707	18,325	20,942	26,178
90%	2,945	5,890	11,780	17,670	20,615	23,560	29,450
100%	3,272	6,545	13,089	19,634	22,906	26,178	32,723

Number of Customers:	100,000
Average Annual Usage:	14,700 kWh
On-Peak Percentage:	65%
Increase in Price:	300%

The final transformation involves assigning avoided cost values to the estimated change in capacity. Table 4.4 transforms the kW reduction values of the Table 4.3 to monetary terms by applying an avoided generation capacity cost, in this example assumed to be $100/kW/year for 20 years to correspond to what might constitute a Smart Metering investment assessment. The Table 4.4 values are the lifetime benefits attributable to the investment for each elasticity/participation rate pair.[45]

[45] For the 20-year time horizon used in this example, it is assumed that the inflation rate for the capacity value is roughly equal to the discount rate in order to simplify the calculations.

Table 4-4
Demand Response Benefits from Avoided Generation Capacity

For a Range of Elasticities and Participation Rates at 300% Price Increase

Participation	Elasticity 0.025	0.05	0.1	0.15	0.175	0.2	0.25
10%	$ 654,452	$ 1,308,904	$ 2,617,808	$ 3,926,712	$ 4,581,164	$ 5,235,616	$ 6,544,521
20%	$ 1,308,904	$ 2,617,808	$ 5,235,616	$ 7,853,425	$ 9,162,329	$ 10,471,233	$ 13,089,041
30%	$ 1,963,356	$ 3,926,712	$ 7,853,425	$ 11,780,137	$ 13,743,493	$ 15,706,849	$ 19,633,562
40%	$ 2,617,808	$ 5,235,616	$ 10,471,233	$ 15,706,849	$ 18,324,658	$ 20,942,466	$ 26,178,082
50%	$ 3,272,260	$ 6,544,521	$ 13,089,041	$ 19,633,562	$ 22,905,822	$ 26,178,082	$ 32,722,603
60%	$ 3,926,712	$ 7,853,425	$ 15,706,849	$ 23,560,274	$ 27,486,986	$ 31,413,699	$ 39,267,123
70%	$ 4,581,164	$ 9,162,329	$ 18,324,658	$ 27,486,986	$ 32,068,151	$ 36,649,315	$ 45,811,644
80%	$ 5,235,616	$ 10,471,233	$ 20,942,466	$ 31,413,699	$ 36,649,315	$ 41,884,932	$ 52,356,164
90%	$ 5,890,068	$ 11,780,137	$ 23,560,274	$ 35,340,411	$ 41,230,479	$ 47,120,548	$ 58,900,685
100%	$ 6,544,521	$ 13,089,041	$ 26,178,082	$ 39,267,123	$ 45,811,644	$ 52,356,164	$ 65,445,205

A 30% participation rate and an elasticity of 0.1 correspond to $5,235,626 in gross capacity savings. To examine the impact of a higher price ratio, the table has to be recalculated, as demonstrated in Table 4.5 where values correspond to a price of 800%, which increases the benefits associated with an elasticity of 0.1 and a 20% participation rate to $6,980,822, an increase of 33%.

Table 4-5
Demand Response Benefits from Avoided Generation Capacity

For a Range of Elasticities and Participation Rates at 800% Price Increase

Participation	Elasticity 0.025	0.05	0.1	0.15	0.175	0.2	0.25
10%	$ 872,603	$ 1,745,205	$ 3,490,411	$ 5,235,616	$ 6,108,219	$ 6,980,822	$ 8,726,027
20%	$ 1,745,205	$ 3,490,411	$ 6,980,822	$ 10,471,233	$ 12,216,438	$ 13,961,644	$ 17,452,055
30%	$ 2,617,808	$ 5,235,616	$ 10,471,233	$ 15,706,849	$ 18,324,658	$ 20,942,466	$ 26,178,082
40%	$ 3,490,411	$ 6,980,822	$ 13,961,644	$ 20,942,466	$ 24,432,877	$ 27,923,288	$ 34,904,110
50%	$ 4,363,014	$ 8,726,027	$ 17,452,055	$ 26,178,082	$ 30,541,096	$ 34,904,110	$ 43,630,137
60%	$ 5,235,616	$ 10,471,233	$ 20,942,466	$ 31,413,699	$ 36,649,315	$ 41,884,932	$ 52,356,164
70%	$ 6,108,219	$ 12,216,438	$ 24,432,877	$ 36,649,315	$ 42,757,534	$ 48,865,753	$ 61,082,192
80%	$ 6,980,822	$ 13,961,644	$ 27,923,288	$ 41,884,932	$ 48,865,753	$ 55,846,575	$ 69,808,219
90%	$ 7,853,425	$ 15,706,849	$ 31,413,699	$ 47,120,548	$ 54,973,973	$ 62,827,397	$ 78,534,247
100%	$ 8,726,027	$ 17,452,055	$ 34,904,110	$ 52,356,164	$ 61,082,192	$ 69,808,219	$ 87,260,274

The results in Tables 4.4. and 4.5 are gross benefits of capacity reductions. Net results must take into account the cost of achieving the load changes. For example, assuming that the program under evaluation is a peak-time rebate program (PTR) implemented when Smart Metering has been installed on all 100,00 households, which involves an investment of $20 million, and assuming $200/household to install the Smart Metering and systems required to support the PTR program, the shaded values in Table 4.5 correspond to elasticity/participation rate value pairs that produce capacity savings that exceed $20 million, the cost associated with the Smart Metering.

If inducements are required to achieve participation and response, then these must also be subtracted from the gross capacity reductions in the tables. Assuming that participation households were paid $20 per year ($4,000 per household and a total of over $40 million the program lifetime), then the values in the table would have to be further adjusted to reduce the savings by that amount. If 100% of households participated, the elasticity would have to be at least 0.15 to generate net benefits. Since that may seem unlikely, net benefits require a higher elasticity value. At the highest level of elasticity shown (0.25), participation would have to exceed 30% to result in net benefits under the collective assumptions of this example.

Summary

The principal advantages to the elemental method of estimating demand response benefits are simplicity and transparency, which may account for its use in several Smart Metering applications as discussed in Section 3. This step-wise process is easy to understand, and the results can be replicated and their implications investigated because the inputs and analytical methods are fully discoverable. However, the credibility of the analysis is entirely dependent on the assumptions underlying the calculations. If the assumptions involved are subject to uncertainty, then calculating the combinations and permutation of outcomes requires constructing and linking several spreadsheets. Even then comparisons are hard to make when several variables are changed simultaneously. More complex characterizations of the interaction of behavior and demand response events make exploration of sensitivities easier and impose on the transformation function important market supply and demand characteristics. Examples are discussed in the next two sections.

4.7.3.2 Market Price Formation

An economic model of demand response traces the impacts of changes in energy and demand on market price formation and also accommodates sorting benefit streams according to when and to whom they accrue. As discussed in Section 4.7.2 above, such a model further distinguishes net societal benefits from transfers, the former representing societal gains and the latter customer gains (bill saving). Two functionally different simulation approaches have been deployed to trace the price formation impacts in wholesale market situations. These are discussed in the sections below.

Market Price Formation Simulation

Market price formation simulations are characterization of how supply and demand changes are resolved through changes in the wholesale prices of electricity. The formation of wholesale spot energy markets in several regions of the country provides the data needed to calibrate such a model, and the implementation of demonstration response programs in some of these markets created a need to quantify how load changes induced by those programs influence locational marginal price (LMP) formation. Model development involves creating an empirical characterization of the price formation mechanisms of the wholesale market and using the model either retrospectively to determine LMP impacts during actual events or prospectively to estimate demand response program impacts under alternative forecast conditions.

<u>Retrospective Simulation of Program Performance</u>

The NYISO developed a price formation simulation model to assess the impacts of its day-ahead bidding program (called DADRP). The program was created to infuse demand into the wholesale market to act as a deterrent to excessive market price volatility and to foil any efforts to manipulate the market price formation process by raising LMPs above the competitive equilibrium. The equivalent in a vertically integrated market would be a utility-sponsored program where consumer bids are compared to the cost of the units in the generation bids stack and scheduled if they reduce the overall cost of meeting demand. Some California utilizes have offered bidding program of this sort, as have utilities in other states. NYISO developed its model specifically to evaluate the performance of the DADRP program, to ascertain to what extent LMPS were influences, and to identify who gained as a result.

Consumers can bid load curtailments as an energy supply resource into the NYISO's day-ahead spot market. If the bid is scheduled, they receive the location marginal price (LMP) as payment granted that they curtail by the bid amount the next day. Like generators, demand response bidders can specify the times for which their bids are offered and the price they require and are assured that if scheduled they receive at least that much, and maybe more if their bid is not the market clearing one.

The price formation model simulates, typically for each day's peak and off-peak hours, how LMPs are impacted by load changes, thus establishing a supply curve for each period to reflect the availability of generation resources. It then imposes system electricity demand to produce the corresponding location marginal prices (LMP). In effect, this simulation is an empirical application of the market economics of demand response.[46]

The characterization of supply is derived statistically using load, weather, generation availability, key tie-line congestion levels, and other factors. The functional equation that results produces a supply curve in price/quantity space that is conditioned on those variables. Different weather conditions, supply availabilities, and similar factors shift or reshape the supply curve. At times it is relatively flat because of generation supply abundance; but at other times it has a very steep slope at higher loads; and it is at these times that demand response can influence LMPs substantially.

Once calibrated, the supply model is parameterized for each day and period of the day in the study period using actual data. The corresponding demand characterization is then comprised of a vertical section corresponding to load that is not price responsive and a downward-sloping section that represents DADRP. The degree of price elasticity is represented by the slope of that section of the overall market demand curve. Once established for each period, the supply and demand characterizations facilitate simulating the impact of scheduled DADRP bids.

The impact of demand response on LMP is quantified by identifying the periods when demand response loads were dispatched. The estimated model already embodies the resulting market-clearing price and therefore the DADRP impact. To isolate that impact, the amount of DADRP-induced load reduction for the period, which is acquired from market settlement data, is added back into and the simulation rerun to estimate how much higher the LMP would have been without the demand response curtailment.

[46] Boisvert, R., Cappers, P., Neenan, B. April 2002. The Benefits of Customer Participation in Wholesale Electricity Markets. Electricity Journal, Vol. 15, No. 3, pp. 41-51. Elsevier Science Inc.

The resulting LMP impacts for each event are: 1) the lower cost of purchasing load in the real-time market (market bill savings), which is the product of the estimated change in LMP due to DADRP and the load transacted in the day-ahead market during that period (typically 30-35% of the total energy transacted); 2) the long-term cost (hedging cost) savings, which are defined as the impact of LMP impact of the DADRP average monthly market LMP associated with the event times the amount of load transacted in the bilateral market; and 3) the net social welfare gains, which are gross welfare savings less the LMP payments to those that curtailed during events.

Figure 4.28 illustrates the result of the 2005 NYISO program bidding activity. Event statistics at the top summarize bidding activity for the year. The benefits are categorized by transfer payments and societal benefits following the traditional welfare distinction. [47]

Demand Bidding Benefits - 2005		
Event Statistics	Performance (MWh)*	3,479
	Payments ($)	$332,941
	Average LBMP ($/MWh)	$96.32
Transfer Benefits	Average Price Reduction ($/MWh)*	$0.10
	Market Bill Savings ($)	$130,988
	Hedge Contract Savings ($)	$210,145
	Benefits to Payment Ratio	1.02
Societal Benefits	Reduction in Deadweight Loss ($)	$117,593
	Benefits to Payment Ratio	N/A 0.35

Figure 4-28
DR Bidding Benefits

The market bill savings (about $130.000) and average LMP reduction ($.10/kWh) are low because the number of schedule bids were few, despite over 300 MW of load registered to bid. LMPs volatility was very low in 2005, resulting in only a few hours where LMPs exceeded 20¢/kWh. Because LMPs were generally low during times when curtailments were scheduled, the societal benefits are relatively small ($117,000) compared to the transfer benefits. The Benefits to Payment ratio compares deadweight loss reductions to payments of LMP to those that curtailed, consistent with the traditional view of welfare economics. Note that if transfers and hedge contract savings (another form of transfer) were counted as program benefits, the resulting benefit/cost ration would be 1.37.

[47] NYISO employs this distinction not to lend it credibility or suggest that it is irreverent, but for the purposes of completeness.

The 2005 performance assessment of DADRP indicates that the program had a very modest effect on LMPs. In previous years the total benefits and LMP impact were higher because LMPs were higher and showed more volatility. Under those conditions, overall and societal benefits were considerable higher.[48]

Retrospective simulations are useful for quantifying the performance of programs, but the estimated benefits may not fully reflect the long-run value of these resources. The value of price-responsive load is to abate excessively high prices associated with supply shortfalls. These resources can therefore be valuable as an insurance against such circumstances. Quantifying this benefit requires a prospective analysis.

Prospective Simulation of Program Performance

ISO-NE commissioned a study to quantify the potential impacts of the implementation of time-varying default service for customers over 500 kW in New England.[49] Under the New England states' competitive market model, which applies to all but Vermont, consumers that do not switch to a competitive supplier for commodity (energy) service are served on a utility tariff-based default service rate. At the time of the study (2005), the default service rates that utilities offered had little, if any, time-differentiation of energy prices, despite the relative high degree of price volatility that at times characterized ISO-NE wholesale spot market prices.

Some viewed the lack of price response as a barrier to achieving an optimal wholesale market. One alternative would be to rely on load biding as resource, like the NYISO's DADRP. Another alternative would be to impose some degree of time-variation in default service prices to induce consumers adjust usage. ISO-NE commissioned a study to characterize how the introduction of dynamic pricing as the default service would impact electricity consumers in New England.

The five-year prospective (2006-2010) study compared the impacts of several time-varying pricing structures using the same basic modeling approach and benefits definition employed by NYISO. A market supply characterization was estimated for the ISO-NE market that, when combined with system demand, produces simulated market-clearing LMPs. To represent the impact of demand response, a elasticity threshold approach was utilized. Above 500 kW consumers in the five New England states included in the study were sorted into two groups: those that were assumed to be price responsive (with an average elasticity of substitution of about 0.10) and those that were not price responsive. The categorization was achieved by using a price elasticity distribution derived from pilots. The price responsive customers, which made up approximately 1/3 of the total, were assumed to elect a dynamically priced commodity service plan; all others were assumed to subscribe to a fully hedged rate from a competitive retailer.

The base supply and demand simulation established the expected level of LMPs over the study period (five years, 2006-2010) without demand response. In contract to a retrospective study, the base simulation in a prospective study is what would transpire without demand response, and the

[48] New York ISO. December 2003. NYISO 2003 Demand Response Programs (Attachment I) Compliance Report to FERC. Docket No. ER01-3001-00. Available at http://www.nyiso.com/public/index.jsp

[49] B. Neenan, Cappers, P., Pratt, D., Anderson, J. December 2005. Improving Linkages between Wholesale and Retail Markets through Dynamic Retail Pricing: Report prepared for New England ISO. Available at: http://www.iso-ne.com/genrtion_resrcs/dr/rpts/improving_linkages_12-05-2005.pdf

subsequent simulations incorporate demand response and calculate the revised (lower) LMP impacts. Consumer response to the various pricing structures evaluated was simulated employing the assigned price elasticities to calculate the corresponding changes in LMP. Daily simulations were conducted for each of ISO-NE's zones to estimate the level and distribution of benefits according to whether they accrued to 1) participants that were assumed to be price responsive, 2) other consumers (non-responders, and in a sense free-riders), or 3) net societal (economic efficiency) benefits.

Figure 4.29 portrays the results by pricing plan and distinguishes who realized the benefits. The plans compared are: 1) a three-part TOU; 2) critical peak pricing (CPP); 3) variable peak pricing, (VPP), which involves a fixed price for off-peak energy consumption and a peak price quoted daily that is the average of the peak hour day-ahead LMPs; 4) day-ahead real-time pricing (RTP); and 5) block and swing whereby the participant nominates some part of its load to TOU and then pays the RTP price for any additional load. The four dynamic pricing plans (CPP, VPP, RTP, and B&S) tie prices closely to ISO-NE wholesale spot market volatility, which explains why they produce benefits two times or more ($195-$275 million over five years) than a TOU schedule ($100 million) that reflects only average diurnal price patterns.

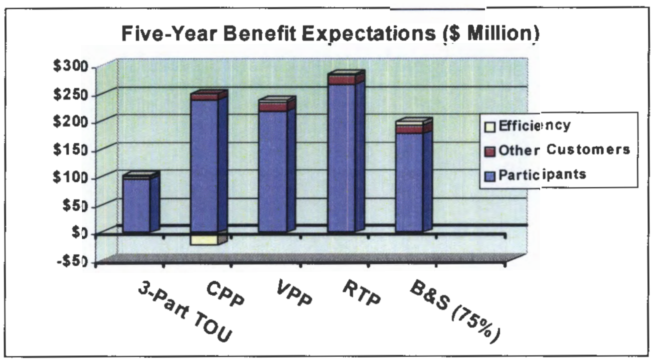

Figure 4-29
Comparison of Benefits from Alternative DR Plans

For each of the five pricing plans, the largest source of benefits is that which price responsive participants realize. This outcome is the consequence of assigning a hedging premium to each product, ranging from 3% for RTP to15% relative to that of a fully hedged uniform rate from a competitive supplier. For example, if a consumer chooses TOU, it realizes a 3% lower base price relative to what it would pay for a fully hedged service. RTP results in a 15% premium, but the consumer faces the risks associated with RTP proxies. The premiums were based on the study authors' experience with retail pricing of competitive services and a study's forecasted LMP volatility during the study period.

The estimated gains from reduced price volatility accrued largely to those that in effect earned them by taking the price volatility risk. The results reflect the assumption that price volatility was modest throughout the study period. Had the forecast included much higher and more frequent price volatility, then the benefits to other consumers would have been substantially higher.

As in other cases, the interpretation of benefits has to deal with the transfers versus welfare gains issue. However, this study revealed an additional issue unique to CP: the simulations produced negative welfare benefits (about $5 million. This anomaly resulted from the relatively low correspondence between peak day-ahead prices, which were used to determine when CPP events would be called and during which respondents were paid 40¢/kWh, and the forecasted real-time LMPs. CPP participants were assumed to respond to the prices they faced regardless of whether or not those prices accurately reflected prevailing ISO-NE supply conditions. CPP demand response at times of low prices produced very little in the way of social benefits, so subtracting payments produced negative welfare. [50]

An analogous prospective price impact simulation was conducted to quantify the benefits expected from making RTP available to Illinois residential consumers. Following a legislative mandate, the Illinois Commerce Commission (ICC) required that the state's utilities demonstrate that there would be net benefits to residential customers as a condition of approving such tariffs.[51] The Citizens Utility Board and the City of Chicago commissioned a seven-year prospective LMP impact-based study to estimate the expected level and distribution of benefits. The study involved characterizing regional supply and making assumptions about how many customers would enroll in RTP and the nature of their price response. These assumptions were then incorporated into a simulation shell like that employed by NYISO and ISO-NE.

The results of the study for the ComEd market are summarized in Figure 4.30. Benefits are comprised of consumer bill savings to participants and long-term hedging savings to non-participants (both transfers) and net social welfare benefits. In its decision, the ICC determined that transfers constituted a legitimate stream of benefits, at least for the purpose of authorizing the RTP service to be made available.

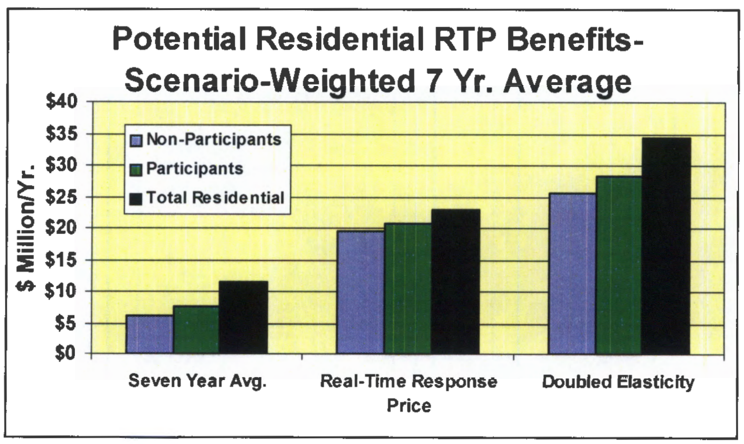

Figure 4-30
Potential Benefits Attributable to Residential RTP

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[50] ISO-NE recently filed for changes in its day-ahead bidding program to avoid scheduling curtailments when the societal benefits are likely to be low: Federal Energy Regulatory Commission. April 4, 2008. Order Accepting Tariff Revisions. Docket No. ER08-538-000, 123 FERC 61,021.

[51] Neenan, B. October 30, 2006. Direct Testimony of Bernard F. Neenan on behalf of Citizens Utility Board. CUB-CITY Exhibit 3.0. Illinois Commerce Commission ICC Docket 06-0617. Available at:www.icc.illinois.gov/e-docket/reports/view file.asp?intIdFile=184620&strc=id

The base simulation assumed that a conventional interval meter would be employed, the contents of which would be available to participants on the monthly summary bill. The first set of bars (labeled *Seven Year Average*) in Figure 4.30 indicates the distribution of gross benefits to non-participants (all consumers), participants (which are residential), and total residential benefits. The second and third sets of bars in the figure reflect the outcome of two additional simulations: 1) instead of day-ahead prices, RTP participants were assumed to pay real-time LMPs; and 2) participants' assumed level or price elasticity was twice that of the initial simulation (about 0.9 instead of 0.045). The results are indicative of the benefits that might be realized from fostering more intensive price response through education and enabling technologies. As such, they are indicators of additional value that might be attributed to Smart Metering by enabling a higher level of price response.

The Connecticut PSC ordered the state's utilities to file a time-of-use default service rate applicable to consumers over 300 kW starting in 2008. ISO-NE employed the modeling framework described above, recalibrated to Connecticut Light and Power's market conditions, to provide insight into the benefits attributable to various forms of time-differentiated pricing.[52] The results are summarized in Figure 4.31.

Exhibit BFN-10D

5-Year (Weights listed in Exhibit BFN-9)						
	Participant Savings		Peak Demand Reduction		Other CT Consumer Savings	
Rate Type	Total ($Millions)	% Due to Price Response	Max Yearly Non-Coincident (MW)	Avg. Monthly Coincident (MW)	Electric Bill Savings ($Millions)	Resource Savings ($Millions)
3-Part TOU	$2.44	3%	7.9	2.1	$1.46	$1.21
VPP	$5.12	7%	49.2	8.9	$5.08	$4.39
RTP	$6.38	7%	44.9	7.2	$6.02	$5.39

Figure 4-31
Comparison of Benefits of DR Plans

As was the case in other studies employing the price formation simulation framework, larger benefits are attributed to pricing plans that more closely reflect the market's price volatility. Also, the participants' savings are largely due to hedge savings and not price response (5% for VPP and RTP), an outcome that reflects the forecast of relatively low LMPs volatility over the five-year study period (2008-2012).

This study was also focused on impacts on peak demand since those savings were in large part the motivation for implementing dynamic pricing as the default service. If the utility's coincident peak were reduced, the cost of serving default service load would decline, which benefits all consumers directly or indirectly. The simulated results indicate that VPP and RTP provide

[52] Neenan, B. February 10, 2006. Prefiled Testimony of Bernard F. Neenan on Behalf of ISO New England, Inc. State of Connecticut, Department of Public Utility and Control, Docket No. 05-10-03, Connecticut Power and Light Time-of-Use, Interruptible, Load Response and Seasonal Rates

capacity savings five times or more than would be expected from TOU-based default service, $4-5 million in resources savings.

Market Dispatch Simulation

Simulating impacts by characterizing market supply conditions for an estimated, and therefore synthesized, supply curve facilitates conducting both retrospective and prospective analyses of the implications of different programs, participation rates, and price responsiveness. The uncertainly of supply is reflected by constructing different supply futures and then expressing the implied impacts through the slope or positioning of the supply curve in price/quantity space. However, the realized impact of demand response depends on the character of supply at the time load changes are undertaken, what units are available and the capacity they are offering, how congestion affects LMPs, and the bidding behavior of suppliers. The price formation simulations are able to capture these effects only at a relatively high degree of granularity as a shift in the base supply relationship at each event. This approach may induce bias, the direction of which is not easily ascertained, because actual generation dispatch deviates from the simulated estimates.

An alternate way to model the price impacts of demand response is to use a dispatch simulation that more realistically recreates market supply and demand conditions and therefore captures the LMP impacts of load changes more closely. If this dispatch model is calibrated so that it represents supply availability and cost quite accurately, as would be the case in a retrospective study, then its characterization of LMP impacts may have greater authenticity because the adjustment in supply can be traced to specific units. In principle, if the ISO/RTO model or utility dispatch model that was actually used to dispatch the system was employed, the impact of demand response would be more accurately represented, resulting LMP impacts that might more closely correspond to what actually transpired (retrospectively) or would occur (prospectively).

MADRI commissioned a retrospective study to assess the benefits of customer participation in PJM's spot markets.[53] A simulation dispatch model was constructed to characterize as closely as possible the market dispatch circumstances that were experienced for a selected year (2005), including actual unit availability, performance, unit marginal operating costs (as a proxy for what the generation unit might have actually bid to supply energy), transmission constraints, and load. Since actual unit bids were not available, bids were synthesized by estimating unit marginal costs based on heat rates and public indices of fuel costs and assuming that bids were equal to that cost.

This comprehensive supply and demand characterization provided baseline hourly LMPs for the study year. Demand response equal to about 3% of zonal demand was assumed to be undertaken in each of the 100 highest priced hours in each zone. The demand in those periods was adjusted accordingly, and the dispatch simulation was rerun to derive LMPs consistent with the lower demand. Two sources of benefits were recognized: bill savings (the LMP change in each event times the entire market volume at the time) and capacity savings attributed to the price response-induced load reductions. An important difference from the studies reviewed above is that the bill savings calculation assumes that entire market volume was transacted at LMP.

[53] Newell, S., Felder, F. January 29. 2007*Quantifying Demand Response Benefits in PJM*, Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI).

The results of the study are summarized in Figure 4.32. Because PJM is an interconnected grid, the benefits generated in the study zones (the eastern states) spill over into other parts of the market. Benefits associated with *Participants* are equivalent to bill savings, and *Non-participants Savings* correspond to net welfare gains. The estimated results are several orders of magnitude more than what retrospective NYISO reported and 4-5 times higher than those reported in the ISO-NE study, even after adjusting for differences in the market size. However, useful inter-study comparisons are hard to devise because of the nature of supply, which is specific to each region's wholesale market characterization; methodological differences; and how benefits are calculated.

Annual Benefits from 3% Load reduction on Top 100 Hours (% MADRI Zones)

Beneficiary	Study Sates	Other PJM States
	$ Million/year	
Participants	$57-182	$7-20
Non- Participants	$9-26	n/a
Capacity	$73	n/a
Total	$138-218	Beneficiary
LMP impact	5-8%	1-2%

Figure 4-32
Demand Response Benefits form the MADRI Study

Including more detailed characterization of supply conditions in a dispatch model responds to many of the objections made to models with a more general characterization of a statistical representation of market price formation process. However, the complexity and cost of calibrating the very detailed and complex dispatch simulation model are drawbacks. Performing prospective stimulations over a range of possible market conditions over several years requires extensive resources and involves a wide range of assumptions that are speculative in nature.

<u>Summary</u>

The advantages of comprehensive price formation simulation over the elemental approach to evaluating Smart Metering-induced are several, including the following:

- It provides a more theoretically accurate characterization of how benefits are generated and to whom they flow.
  - It utilizes a detailed and realistic characterization of wholesale supply market transactions at any level (zonal) that markets employ.
  - The market supply curve is uses conforms to the accepted principles as an upward sloping supply curve whose slope increases at an increasing rate under identifiable generation availability, congestion load, and demand conditions.

- The supply curve is realistic, either
  - Derived empirically from actual market-clearing LMP and load data, and therefore reflective of market realities or
  - Generated from a dispatch model that reflects actual unit availability.
- Price formation is derived from market-clearing conditions, which reflects how wholesale markets actually work.

- It can be applied to any demand response program regardless of its design.
  - Electricity usage can be characterized at the hourly level to factor in weather and other covariate factors and to match exactly market prices or circumstances that would warrant curtailments.
  - It allows partitioning demand into responsive and inelastic categories.
  - Price elasticity can be factored in directly through the slope of the demand curve or indirectly by applying specified responses to depicted loads.
- It can be used retrospectively to evaluate the performance of an on-going program or prospectively to generate benefits stream for proposed or speculative programs.
- Simulations can be conducted deterministically, using fixed value for key parameters, or stochastically to incorporate and quantify the implications of risk and uncertainty.
- These methods have been used in a wide variety of analyses, including:
  - National-level evaluations of demand response impacts (DOE 2005; Faruqui et al, 2007)[54]
  - Regional studies of demand response impacts (Neenan et al. 2006; Newell, et al.); and[55]
  - Studies of the performance of programs over extended periods or specific events (NYISO 2004: ISO-NE 2006) [56] and analyses of program directed at specific customer segments[57]

[54] U.S. Department of Energy. February 2003. Report to Congress: Impacts of the Federal Energy Regulatory Commissions' Proposal for Standard Market Design. DOE/S-0138.

[55] Faruqui, A., Hledick, R., Newell. S., Pfeifenberger, J. May 16, 2007. The Power of 5%: How Dynamic Pricing can Save 36 Billion in Electricity Costs, Brattle Group. Available at: www.brattle.com

[56] B. Neenan, Cappers, P., Pratt, D., Anderson, J. December 2005. Improving Linkages between Wholesale and Retail Markets through Dynamic Retail Pricing: Report prepared for New England ISO. Available at: http://www.iso-ne.com/genrtion_resrcs/dr/rpts/improving_linkages_12-05-2005.pdfNew York ISO. December 2004. NYISO 2004 Demand Response Programs (Attachment I) Compliance Report to FERC. Docket No. ER01-3001-00. Available at http://www.nyiso.com/public/index.jsp: ISO New England, NEPOOL. February 18, 2005. Compliance Filing of the New England Power Pool Participant's Committee and ISO New England. FERC Docket ER04-1255.

[57] Neenan, B. October 30, 2006. Direct Testimony of Bernard F. Neenan on behalf of Citizens Utility Board. CUB-CITY Exhibit 3.0. Illinois Commerce Commission ICC Docket 06-0691, Docket 06-0692, and Docket 06-0693.Neenan, B. February 10, 2006. Prefiled Testimony of Bernard F. Neenan on Behalf of ISO New England, Inc. State of Connecticut, Department of Public Utility and Control, Docket No. 05-10-03, Connecticut Power and Light Time-of-Use, Interruptible, Load Response and Seasonal Rates

The primary disadvantages are the flip side of its advantages: the comprehensive market characterization of price formation and the distribution of benefits comes at a high cost in terms of the complex computer modeling required and the extensive data required to parameterize the model. The statistical model requires several years of market experience to calibrate fully. The dispatch model requires detailed specification on all generation unit operating characteristics and forecasts of fuel costs. Adding in realistic congestion impacts further extends the data requirements.

In addition, modeling demand response at the wholesale market level is appropriate for programs that are tied directly to market pricing and operation. However, if the program is being implemented specifically to benefit an individual utility, then the appropriate scope of a marginal valuation may be the utility's own capacity planning and dispatch circumstances and the specific factors that influence its costs. In these cases, an enterprise-level analysis may be better suited for more comprehensively valuing Smart Metering-induced demand response.

4.7.3.3 Enterprise Demand Response Valuation

The adoption of integrated least cost planning practices by utilities provides a means for valuing the impact on capacity planning and energy supply costs associated with energy efficiency measures. These protocols can be adapted to evaluate demand response.

A production cost model can be used to simulate how available system resources would be used to meet forecasted loads. A revised demand profile is constructed to reflect the impacts of an energy efficiency measure or demand response and then another simulation is performed. The difference in the energy cost between the two cases, the avoided energy cost, can then be imputed as the potential cost savings attributable to the program. The simulation also specifies the reduced capacity requirement associated with such measures and this can be used to develop a corresponding measure of avoided capacity cost. A commonly used convention in energy efficiency studies is to equate the value of reduced capacity to the annual carrying cost associated with acquiring a peak generation unit.

Initially, deterministic simulations in which every factor or variable is represented by a discrete value were conducted over a few representative periods of each year, for example, a month or two weeks, to reduce the computational burden to a manageable level. These methods work quite well in assessing energy efficiency measures whose primary impact is characterized by a systematic and persistent load profile adjustment that affects many hours of the year. Averaging cost over many hours provides a relatively accurate assessment of the impacts at a lower level of resolution, for example hourly.

The development of more efficient solution algorithms made it possible to conduct the simulation at the hourly level to capture the covariance of load with high dispatch costs such as those due to weather to better account for the diverse available and operating characteristics of generation units dispatched to meet system or in specialized studies class loads that exhibit considerable seasonal and diurnal variation.

These same protocols can be applied to demand response, but accuracy in measuring impacts on load change and therefore on benefits may be compromised as a result. As a DOE study on valuing demand response study showed, treating demand response at the same level of time granularity as energy efficiency is likely to result in a bias downward in the level of estimated benefits.[58] Methods that simulate the impacts of demand response on utility enterprise costs at the hourly level and that employ a stochastic characterization of system dispatch provide a more robust and insightful portrayal of the value of demand response resources as part of the supply portfolio.

An Example Stochastic IRP Study

The International Energy Agency's (EIA) Demand Side Programme commissioned a study to explore in greater depth the impacts and value of demand response programs from an enterprise perspective, specifically that of a vertically integrated utility. It identified two key elements of a framework that goes beyond the conventional, deterministic integrated least cost planning (IRP) assessments, as follows:

> "Appropriately incorporating DRR in forward-looking resource plans requires the planning effort to embody two critical capabilities:
>
> 1. *A planning framework with a sufficiently long time horizon to allow for the benefits of DRR to be captured.*
> 2. *The planning framework must explicitly address the uncertainty that is present around key factors that influence the cost of electricity, including fuel prices, weather, and system factors such as transmission constraints and plant operation. If these uncertainties are not dimensioned in the planning process, then the value that DRR offers in terms of risk management cannot be assessed (Violette et al., 2006. p 34).*"[59]

The study employed a stochastic simulation model to demonstrate how to achieve these goals by treating several factors as subject to stochastic influences: fuel costs, peak demand, unit outages and tie-line outages, and unit availability. To capture and portray risk, hundreds of simulations were conducted to quantify the load impacts and cost savings associated with the RTP program evaluated, each one using a single value for each variable drawn from the distribution used to characterize the range of values each variable could achieve. The distribution was constructed to reflect the mean outcome and its variance.

The simulations collectively comprise a view of the topology of outcomes consistent with the characterization of risk, laying out the extent and distribution of the costs that might actually occur. Figure 4.33 illustrates the distribution of the simulated cases. The savings (the change in the Net Present Value (NPV) of total system supply cost over a 20-year period) attributable to demand response vary considerable, which in Figure 4.33 are displayed as the frequency of cases corresponding to NPV bands. The medium frequency was cost savings attributable to RTP in the

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[58] U.S. Department of Energy. February 2006. The Benefits of Demand Response in Electricity Markets and Recommendations for achieving Them. A Report to U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005.

[59] Violette, D., Freeman, R., Neil, C. September 26, 2005. DRR Valuation and Market Analyses, Volume I: Assessing the DRR Benefits and Costs. Prepared for: International Energy Agency, Demand Side Programme.

$1.9 -2.1 billion savings band, but the simulated case savings ranged from $1.3 billion to $2.9 billion. Clearly the outcome is dependent on factors that are uncertain, but how this influences the decision about valuing demand requires further clarification.

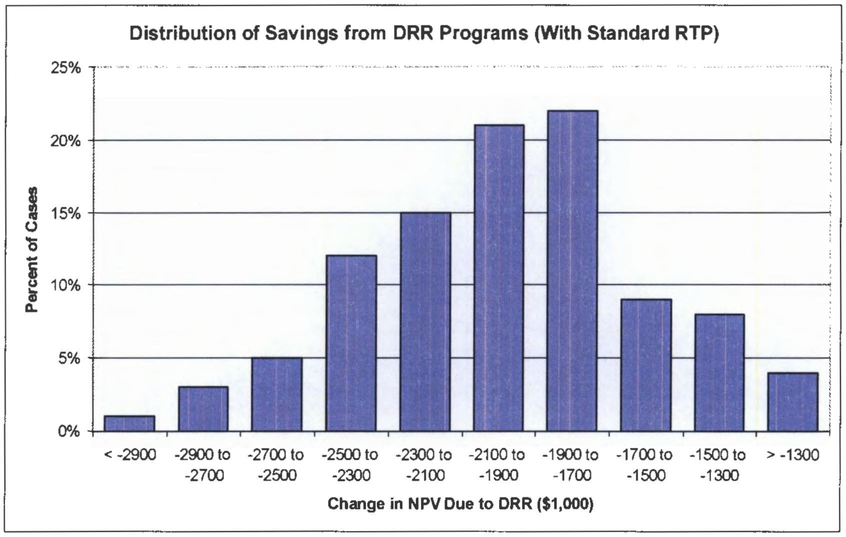

Figure 4-33
Distribution of Demand Response Savings

To quantify the associated risk, the 10% of cases in the EIA study with the highest system supply cost without demand response were compared to the same cases but with demand response (RTP added. The mean twenty-year net present value (NPV) of the savings attributed to demand response (RTP) from all the cases simulated was $1.9 billion. However, the NPV of demand response in the worst 10% of the outcomes (those with the highest supply costs) was over $2.6 billion, which led the study's authors to conclude that the demand response program not only reduces costs, it reduces risk. Their interpretation is that the risk reduction impact can be monetized as the difference between the overall mean savings and those associated with the worst cases. In other words, the RTP program is estimated to provide a risk premium of $700 million.

The policy implication is that because demand response protects against adverse outcomes, the utility should take into account the additional insurance value in conducting a benefit/cost analysis of demand response.

The Northwest Power and Conservation Council (WPCC)

The WPCC took the IRC analysis to another level in the quantification of the risk abatement attributable to demand response. It used the outcomes in the tail of the distribution of simulated system electric supply cases, the worst 10% of the outcomes in terms of the system supply cost, to define what it refers to as planning the efficiency frontier.[60] Each of the worst 10% of the

[60] Corum, K. December 6, 2006. Incorporating DR into Vertically Integrated Planning Exercises: A Northwest Perceptive. Presented at: Western Power Supply Forum San Francisco, CA.

outcomes is associated with an expected cost and associated risk (defined in terms of the variance of the expectation). The efficiency frontier defines tradeoffs between the expected cost of supply cost and risk (the variance of the estimate) that are superior to all other outcomes.

Figure 4.34 illustrates the frontier. The points plotted in the figure are the cost/risk pairs from the worst of the simulated cases, the results of a stochastic simulation of the cost to serve the region's electricity needs over 20 years. The efficiency frontier is comprised of points that define the farthest left hand border of the collective points. Any risk/cost tradeoff on that frontier is superior to that of any point to the right of it, because for the same risk the cost is higher. Likewise, any point on the efficiency curve is superior to any point above it because it would involve more risk for the same cost. Clearly, a rational decision-maker would prefer a point on the frontier to outcomes in the interior.

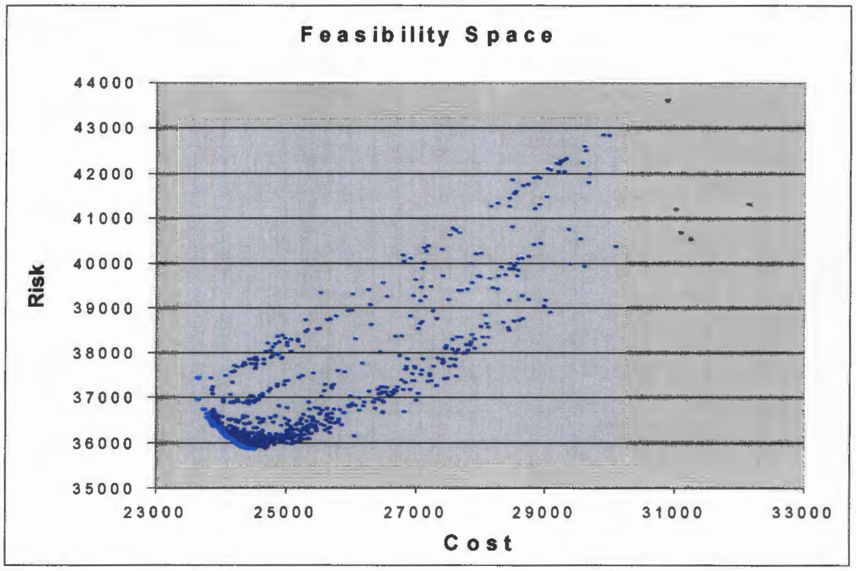

Figure 4-34
Risk/Cost Efficiency Frontier

What are the implications for determining the value of demand response? Once the efficiency frontier was established, the simulations were run, this time with demand response (RTP) acting to reduce load at times when base run prices were high. The results are illustrated in Figure 4.35. Compared to no demand response, 500 MW of demand response shifts the supply cost efficiency frontier leftward, thereby reducing the risks associated with meeting system supply. At the specified level of risk, supply costs are less on the 500 MW demand response curve; and for any specified cost, the risks are less with demand response. The 2,000 MW demand response case provides even more risk reduction since it shifts the frontier even more leftward.

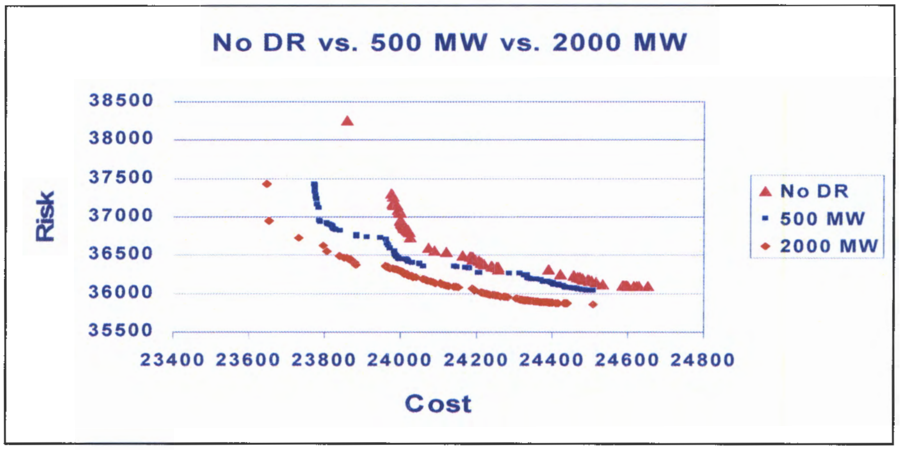

Figure 4-35
Risk/Cost Tradeoffs at Different Levels of DR Resources

The decision of how much demand response to incorporate into the system plan depends on comparing the marginal cost of expanding participation with the cost difference between the base efficiency frontier and that of response. The study did not indicate how such a decision should be made.

4.7.4 Summary

We reviewed two examples of how demand response can be viewed as providing insurance against undesirable outcomes, which can be construed as how to represent the insurance value of demand response. The studies provided different metrics for addressing the risk mitigation attributable to demand response. Other researchers are developing methods for analyzing how demand response reduces supply cost risks to electricity retailers. For example, researcher at Lawrence Berkeley National Laboratory demonstrated how demand response can be viewed as a pure option involving curtailable rights that the utility can exercise when reduced load provides benefits.[61] Integral Analytics has devised alternative ways to derive the option value using the means and variance associated with forecasts or market LMPs and the stochastic relationship between load and LMP.[62]

[61] Sezgen, O, Goldman, C., Krishnarao, P. October 2005. Option Value of Electricity Demand Response. Lawrence Berkeley National Laboratory Report LBNL-56170

[62] Skinner, K. May 10, 2008. Integrating DSM into Long-Run Resource Plans; What are Utility Planners Asking for? Presented to: PLMA Spring 2008 Conference, Baltimore, MD, April 29-May 2.

5
IMPROVED UTILIZATION EFFICIENCY

The old saying "You can't manage what you can't measure" has found currency among those that contend that consumers, especially residential electricity users, lack sufficient information about their consumption pattern to make rational economic decisions about when and how to use electricity. Under uniform rates, a monthly bill that specifies only total kWhs and the bill amount provides little information about when electricity is being used, making it difficult to associate actions (consuming energy services) with consequences (paying for them). A consequence of this information deficit is that consumers make expenditure erroneous decisions about electricity usage because they can't match value with cost. As a result, their budget allocations are not optimal from a personal or societal perspective.

If consumers were provided more temporally detailed information about when and how they use electricity, perhaps they would reconsider their consumption decision and make adjustments so that the marginal value realized from consuming electricity would be equated to the cost they pay. Such adjustments can come about in several ways. Perhaps consumers would come to realize that leaving the lights on in unoccupied rooms is more expensive than they imagined, and the inconvenience in shutting them off is more than offset by the savings. The same goes for electronic devices, like televisions, radios, and personal computers that may be left on when they provide no useful service and yet result in costs. A more informed consumer may discover that the cost of household air conditioning or heating is higher than they thought and conclude that adjustments like setting thermostats lower that result in bill savings come at a relative low level of inconvenience. All of these savings would be the result of better decision-making.

While in principle feedback may result in consumers finding that electricity is a better buy than they had reckoned and therefore result in increased usage, most of the advocates of providing feedback expect that the net result would be that electricity usage declines. The presumed predominance of a conservation effect, despite the possible increased usage of a few devices at times, may be attributable to Smart Metering and raises the possibility of a benefit stream that can be taken into consideration in evaluating a Smart Metering investment.

Smart Metering is one way to enable providing consumers with more detailed and accurate information about when and how they use electricity, resulting in measurable changes in energy consumption that provides savings to them and maybe benefits to others. Detailed usage information is valuable to all consumers. However, many commercial and industrial customers already have a system for collecting and evaluating information about the stock and flow of electricity usage at a level of detail that improves their ability to manage consumption. They acquired this capability in part because they face rates that have some element of time-differentiated pricing, such as paying a demand charge or buying energy under a time-of-use energy rate, or both. For others, feedback and energy management capability is a derivative of investments into process and safety controls to direct other aspects of the enterprise. The largest benefits from providing feedback through a Smart Metering are likely from households, and therefore the discussion that follows is focused on them.

5.1 The Potential Impact of Feedback

Darby (2000) summarized the results of studies conducted to measure the impact on energy usage attributable to providing consumers with feedback—greater detail about when and how they use electricity.[63] The study categorized feedback mechanisms as being indirect or direct.

Indirect feedback involves organizing and analyzing consumption and cost data periodically, say every month, and providing it to the consumer either along with the bill or by other means. This can be accomplished without any additional investment in equipment at the consumer premise because the data are processed and made available on a schedule that corresponds to the meter reading schedule. Many of the indirect studies that Darby reviewed were conducted prior to 2000 and were focused on better use of available metering technology and reading practices. However, Robinson (2006) reported on a more recent indirect study conducted in Canada contemporaneously (but not in direct coordination with) studies that employed direct feed back, as discussed below.

Direct feedback provides the consumer with readily accessible information about the stock and flow of electricity usage. Many devices are available that monitor electricity inflow at the meter and convey that information to a display device located in the household, providing some or all of the following information: streaming kWh usage (hourly, for example); cumulative kWh (daily, monthly, other specified intervals); and the corresponding billing amounts. Some technologies allow for measuring the usage of individual devices in the household and displaying each device's usage and corresponding cost. An alternative way to accomplish direct feedback is for the utility (or another entity) to retrieve the usage information from the Smart Meter, organize it into a specified format, and deliver the results to the consumer in a timely manner through the internet. Or, the Smart Metering could be configured so that its usage information can be accessed directly by devices in the household and then processed and displayed on PCs, television screens, or on other devices like mobile phones.

Combining Darby's study results with several of those conducted in the past seven years provides a panorama of the collective understanding of the impacts of feedback on electricity consumption. Figure 5.1 displays the reported annual percentage reduction in electricity usage reported by 35 studies, separating those reporting indirect conservation results from those that utilize a direct feedback mechanism. The annual reductions are in many cases extrapolated from the result of pilots or studies that in some cases ran for under a year.

The reported annual household kWh reductions range from zero to 28%. The average for indirect feedback is 8.4 % and that attributed to direct feedback is 35% higher (11.5%). If the average household uses 8,000 kWh, then these studies suggest on average that feedback effect induces a conservation effect of between 657 and 930 kWh/year. The studies did not extrapolate the energy

[63] Darby, Sarah. "Making it Obvious: Designing Feedback into Energy Consumption," Proceedings 2nd International Conference on Energy Efficiency in Household Appliances and Lighting. Italian Association of Energy Economists. (2000).

savings to the implied demand (kW) savings. Assuming a coincidence of 0.40, and that household peak demand (average kW over the afternoon and early evening hours) is two kW, feedback reduces peak household demand by 0.1 to 0.2 kW.

These energy savings are comparable to what is being reported from some demand response plans that pay (implicitly or explicitly) consumers 5-10 times the basis energy rate to curtail. If feedback by itself achieves such savings, then the contribution for demand response and other societal benefits to close the gap between Smart Metering cost and benefits is reduced or maybe even eliminated.

Some Recent Studies on the Impacts of Feedback

- **Meta study on energy bill reductions due to information** (Darby 2006)
  - Direct information (e.g., immediate) = 5-15%
  - Indirect treatments (billing detail) resulted in 0-10% reduction
  - In one case consumption increased
- **Ontario Hydro Board -Direct**
  - Information-only treatments ~225
  - Participants reduced electricity usage by 6.5% on average
- **Newfoundland and Vancouver Residential Feedback Studies - Direct**
  - Follow-up to Ontario Study (same in-home display device)
  - Newfoundland – 18% reduction in usage
  - Vancouver 2.6% reduction
- **California State Pricing Pilot- Direct**
  - Information treatment resulted in no significant difference in electric usage
- **Milton Ontario Feedback Pilot - Indirect**
  - 106 participants information-only treatment 2006-7
  - No discernable change in usage detected, but 64% said they took actions
- **Prepaid Metering- Direct, Balance only**
  - Salt River Project (SRP) - reports 12% average usage reduction among 55,000 (~5% of total) residential prepayment customers
  - Northern Ireland (Darby 2006) – 25% of residential consumers use prepay, and reportedly use, on average, use 3% less electricity
  - Woodstock Hydro (website) – 20-25% of residential customers use prepay and exhibit 15-20% reduction in electricity use

Figure 5-1
Recent Studies on Feedback

Before turning to how these conservation savings can be valued, the size of the estimated impacts deserves closer consideration. First, the studies all purport that what they measured is a conservation effect, not a price effect, because the only treatment was the provision of feedback: the participants did not change rate plans as part of the study. There was also considerable variation in the degree of information provided.

Figure 5.2 provides a summary of some of the more recent studies, which report a wide range of results: no observed reductions from an indirect feedback study (Milton Ontario) and from one direct feedback study (California SPP); from 2.5% (Vancouver) to 18% (Newfoundland) reductions from direct feedback studies in Canada; and 2-25% energy reduction associated with prepaid metering (Salt River in Arizona, Canada, and Ireland).

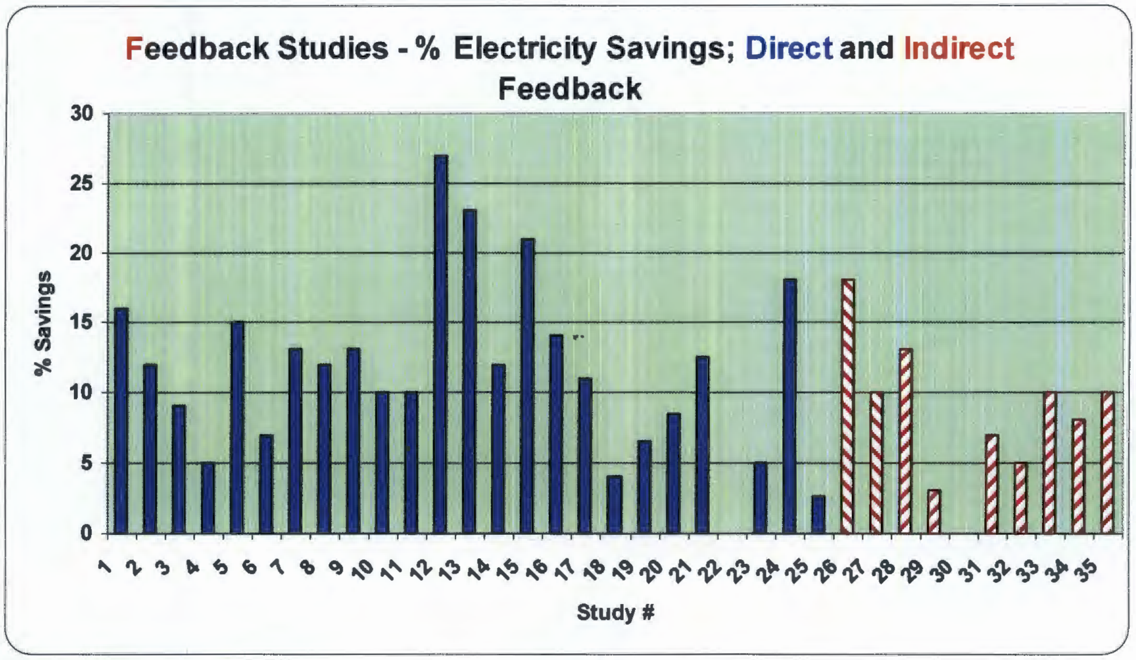

Figure 5-2
Direct and Indirect Feedback Study Savings

Prepaid metering is a special case of feedback because the consumer's service conditions are different—it must monitor the account balance and undertake a transaction to avert a service interruption. These circumstances may result in a higher level of engagement that in turn produces in a higher level of conservation, in effect augmenting the conservation effect of feedback, as is the case with SRP, but not so for Northern Ireland. Moreover, the pre-pay programs are largely aimed at a subset of customers, those with compromised credit ratings or premises where the inhabitants change regularly (for example, college student renters) or frequently (short-term rentals). Their behavior may not be representative of the population of all households.

These study results suggest that there may be a large benefit to providing customer feedback on electricity consumption, especially if that feedback is direct and readily accessible on the premises. The results are surprisingly uniform, which might suggest that they are highly credible. However, the pilot studies vary considerably in the number of participant's from which the results were extrapolated. Figure 5.3 indicates the percentage energy reduction for the studies that involve direct feedback by an electronic display and Figure 5.4 illustrates the corresponding number of participating households in each of the studies enumerated—the numbering of studies is identical to that of Figure 5.2. The highlighted (striped) studies in each figure are those that involved pre-paid metering.

The studies all reported reductions of over 4%, and as high as 18% (Figure 5.3). The simple average of the study is over 9%. However, as Figure 5.4 depicts, only two studies involved more than 500 participants (one had 50,000), the rest had 150 or fewer, some as few as 25. While encouraging, extrapolating these results to an entire population of residential customers because they are provided with Smart Metering and display devices may not be warranted.

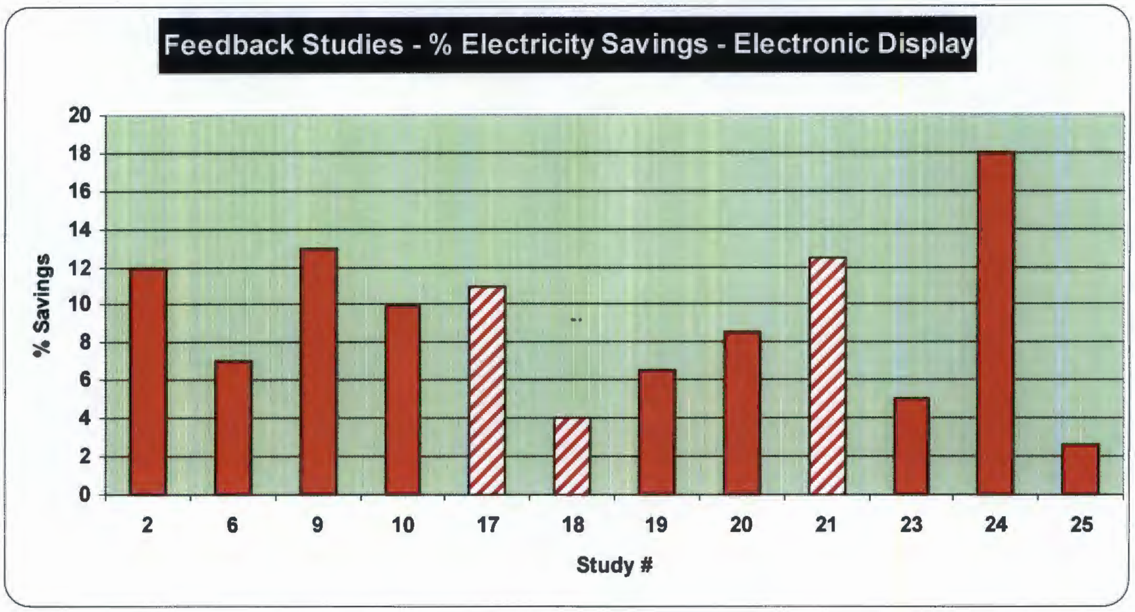

Figure 5-3
Electronic Display Electricity Savings

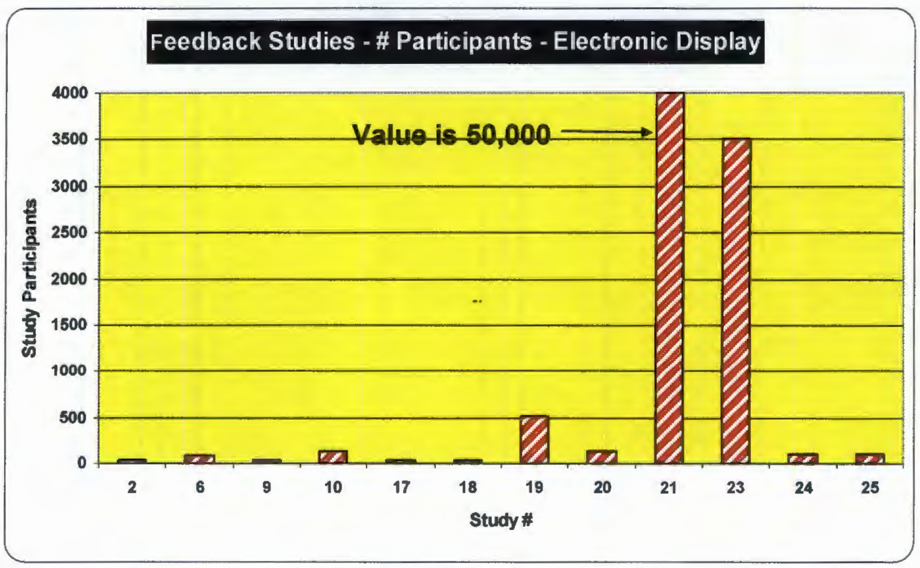

Figure 5-4
Electronic Display Feedback Study Participation

An additional consideration is to what extent these benefits are solely attributable to Smart Metering. In most of the cited recent studies involving direct display, the device was not integrated into the utility's meter or meter reading and data processing system. Commercial devices were employed that attach to the meter or the household's electric circuitry and operate independently of the meter. Perhaps the energy savings associated with this type of conservation can be achieved without the Smart Metering investment or the meter itself does not need to have built into it the ability to be integrated into household devices that process meter usage, but only be configured so that the data stored in the meter can be retrieved by such devices.

5.2 Measuring the Societal Benefits of Feedback

Feedback may induce energy conservation behaviors that otherwise would not have been realized through energy efficiency or price response programs. The benefits are reductions in kW and kWh consumption. However, unlike demand response, they are not price induced, but associated with corrective adjustments in consumption behavior. Therefore the benefits should persist until there is a relative change in electricity price and the prices of other goods and services.

Because the physical impacts of feedback are kW and kWh reductions, they can be valued using protocols established for demand response in Section 4; and the associated environmental benefits can be valued as discussed in Section 9.

6
OTHER PRODUCTS AND SERVICES

6.1 Sources

Smart Metering provides the utility with capabilities to provide services that were too costly under conventional metering to provide selectively to meet the needs of subsets of customers. If these services are indeed valuable to some customers, then there may be a viable market for selling incremental or supplemental service to customers for an addition charge, over and above the base service rate. Examples of such revenue-generating services are as follows:

- Energy information services
- Customized billing frequency and issuance date
- Automatic (debited) bill payment
- Bill aggregation or multiple account management (for example, the ability to track the account status of away-from home college student, elderly relatives, or renters)
- On-demand billing, account activation, and deactivation
- Home automation services (in-home appliance management systems)
- Renewable energy device integration (for example, plug-and-play PV systems to enable net metering and separate measurement of grid and in-site energy supply)
- Plug-in Hybrid Electric Vehicle (PHEV) support services such as wiring garages to separately charge the vehicle and provide usage data separately

6.2 Measurement and Valuation

If these services are provided as supplemental services that consumers can elect and for which they pay a fee, then they represent an additional revenue stream that would contribute to the operational savings in the benefit/cost analysis. However, including them in analyses would require estimating the adoption rate for such devices and establishing a price for each service or for bundles thereof.

An additional complication arises if the cost of altering the Smart Metering configuration to accommodate provision of the services is large. Since the services are self-selecting, the utility may be unable to justify speculating on 100% saturation and adding the feature to all installed meters. If so, the Smart Metering configuration would not include these features, and they would have to be added on as consumers enroll.

Services like energy information and automatic bill payment are back office processes that involve data process operations, not changes in the operation of the meter itself, as long as the services offered comport with the base meter reading frequency and granularity configuration. Services such as on-demand billing and service activation/deactivation may be inherent elements of the meter and therefore also involve only back office processes. As long as the service involves only incremental data and business process activities, then they can be unbundled and provided on a fee basis.

Home automation service involves expanding the scope of the energy service the utility offers. As long as the meter is configured so that its data can be retrieved locally by a controlling device or the utility utilizes a separate communication channel to inform and operate the device, then the service is separable and can be offered separately from basic network access and energy supply services.

Some or all of these services could be incorporated into the Smart Metering configuration and provided to all consumers. It would then be incumbent upon the analysis to compute the implicit value of each service so it can be accounted for in the socialized benefit stream. There is also the possibility that these capabilities would not included in the base Smart Metering configuration; but after operations savings were adjusted to account for societal benefits that were deemed to justify a rate increase to finance them, the resulting net benefits would be large enough to include some or all of these services to all consumers.

6.3 Summary

Smart Metering may open up a new realm of services that utilities can provide to their consumers on a self-selecting basis to supplement basic universal service. These services would produce incremental revenues that may offset the Smart Metering investment. However, these service scale-enhancing opportunities are not limited to the utility. Commercial entities may leverage the informational and communicational capabilities of the Smart Metering and sell directly to consumers' appliances that have built-in controls, lighting that can react to prices or other signals, HVAC systems that anticipate price changes and advance to delay the provision of air conditioning services, and many other services that improve the value of electricity to consumers.

7
VALUING ENHANCED SERVICE QUALITY

Utilities may find that various types of Smart Metering infrastructure enhance the quality of electricity service by increasing the reliability of its delivery. Smart Metering by itself does not prevent outages. The role of enabler involves helping utilities pinpoint the source of outages more quickly, resulting in several derivative sources of benefits, including 1) informing or acknowledging consumers that the utility is aware of an outage at there premise, and 2) reducing the time utility crews spend testing lines and searching for the outage source, which can lead to faster outage restoration. Also, Smart Metering might help reduce outage durations in wide-scale outages by tracing restoration progress at the premise level and informing crews in the field, resulting in more effective crew dispatch and shortening outages. This section discusses the methods that can be used for quantifying the value of this improved service quality if linkages to Smart Metering deployment can be demonstrated.

7.1 Methods for Quantifying the Value of Improved Service

The value of lost load (VOLL), also called the value of service (VOS) has historically been quantified through what are known as customer outage costs studies. These studies are normally performed through various types of surveys on samples of residential, commercial, and industrial customers. In the case of C&I customers, the surveys elicit information on the out-of-pocket and opportunity costs associated with interruptions in electricity service. For residential customers, the surveys tend to focus on value tradeoffs, i.e., willingness to pay to avoid or willingness to accept payment as compensation for interrupted power. Such studies have been conducted by a number of utilities across the United States over the past few decades. As a result of these studies, it has become widely accepted that the level of outage costs for customers is a function of frequency and duration of the interruptions along with other characteristics such as season and time of event and customer characteristics such as size and sector. Outage duration is measured using an industry standard index called Customer Average Interruption Duration Index (CAIDI). Outage frequency is measured using an industry standard index called the System Average Interruption Frequency Index (SAIFI).

There have been a number of applications for the outage cost estimates. They were used by the UK PoolCo and in the Australian Pool as a proxy for capacity value in setting the spot energy prices, for example, setting Price (P) = Marginal Energy Cost + Marginal Outage Cost where marginal outage cost is determined by multiplying the expected unserved energy times the value of lost load. Outage cost estimates have been applied in a similar manner with real-time pricing programs with vertically integrated utilities before discoverable market-clearing wholesale prices were available. Utility outage cost studies have also been used to guide the long-term planning processes for transmission and distribution facilities. However, there appears to be no clear precedent for using outage cost estimates to assess increased value of Smart Metering infrastructure.

7.2 A Simple Transformation

As mentioned above, the two fundamental determinants for assessing the value of increased reliability are (1) frequency of outages and (2) duration of outages. The total outage cost for a customer is estimated by multiplying frequency times duration to derive total hours of outage and then multiplying this by the VOLL (Value of Lost Load) for the total MW affected. This calculation can made individually for customers affected by an outage or as a representative value byaveraging effects across customers. Ideally the survey analysis is performed for each individual utility; however, these studies can be expensive. An alternative is to transfer the results found through surveys conducted at other utilities to estimate the value of increased reliability at utilities for which surveys have not been conducted. These so-called "damage functions" are equations that derive estimates of the cost of an outage for different types of customers based on characteristics of the service territory and the customer base. One example of this approach is described in the next section.

7.3 Damage Functions

In 2002 the U.S. Department of Energy sponsored a study collecting the survey research performed by eight electric utilities across the United States between 1989 and 2002 regarding the economic value of electricity for residential, commercial, and industrial customers.[64] Twenty-four studies were included in all, representing these customers in virtually the entire Southeast, most of the western United States (including California, rural Washington and Oregon), and the Midwest. All variables were standardized to a consistent metric and then incorporated into a meta-database for statistical analysis in order to measure the relationship between customer value and characteristics of an outage. The regions and customer groups included in the Department of Energy study are summarized in Table 7.1.

[64] Leora Lawton, Michael Sullivan, Kent Van Liere, Aaron Katz, and Joseph Eto, "A framework and review of customer outage costs: Integration and analysis of electric utility outage cost surveys" (November 1, 2003). *Lawrence Berkeley National Laboratory.* Paper LBNL-54365. http://repositories.cdlib.org/lbnl/LBNL-54365 (Note: the study was conducted by LBNL and Population Research Systems, a sister company of FSC).

Table 7-1
Summary of Studies Used in the Meta-Analysis

Company	Survey Year	Large C&I	Small/Med C&I	Residential
Southeast-1	1997	X		
Southeast-2	1993	X	X	X
Southeast-2	1997	X	X	X
Southeast-3	1990	X	X	
Southeast-3	1991	X		
Midwest	2002	X	X	
West	2000	X	X	X
Southwest	2000	X	X	X
Northwest-1	1989	X		X
Northwest-2	1999	X	X	X

Note: In cases where the cells are merged, there was one study but the respondents were separated by usage into the respective categories.

The models developed in this study predicted that the average customer value for a 1-hour summer afternoon outage is approximately $3.45 for residential, $1,428 for small commercial and industrial, and $9,758 for large commercial and industrial. The study found that outage costs increase "substantially but not linearly" as the length of the outage increases. Also, the value of loss load during an outage in the winter was higher than during the summer. The Table 7.2 demonstrates this effect for each of the three classes of customer.

Table 7-2
Average Outage Cost by Customer Type, Season and Duration

Season -- Length	Residential	Small C&I	Large C&I
Summer PM – 1 Hour	$3.45	$1,428	$9,758
Summer PM – 8 Hour	$8.57	$5,236	$48,790
Winter PM – 1 Hour	$3.93	$2,142	$23,800
Winter PM – 8 Hour	$9.90	$7,497	$124,950

The models arguably can provide the basis for developing a more generalized estimate of outage costs for individual utilities. The following section provides a case study for estimating decreases in outage costs as a result of new metering infrastructure.

7.4 Comparative Simulation

This section describes the step-by-step process to estimate decreased outage costs from a new type of metering infrastructure using the results of the Department of Energy meta-study described above. In this example, the utility's reliability indices are currently at a CAIDI (average duration) value of 180 minutes and a SAIFI value of 1.07. These values indicate that the *average* utility customer (regardless of customer type) would experience approximately 1.07 power outages per year and the total annual outage time for this customer would be 180 minutes. DOE's published customer damage functions are used to estimate annual outage costs for the utility customers with and without the reliability investments – i.e., with current outage average frequencies and durations and with reduced outage frequencies and durations.

Table 7.3 shows the customer damage function used to estimate residential customer outage costs derived from the Department of Energy meta-study. The residential model expresses customer outage costs as a function of season, duration, household income, annual electricity use, geographical region, and when the outages occur (time of day and day of week). These inputs are used to predict the natural log of outage costs for a single customer. To arrive at the yearly value, the avoided costs per outage are multiplied by the average number of outages experienced by customers during a year.

Table 7-3
Tobit Regression Models for Predicting Residential Customer Outage Costs

Predictor	Parameter	Probability
Intercept	0.2503	0.1468
Duration	0.2211	<.0001
Duration Squared	-0.0098	<.0001
Annual MWh (kWh/1000)	0.0065	<.0001
Log of Household Income	0.0681	<.0001
Morning	-0.0928	0.0061
Night	-0.1943	<.0001
Weekend	-0.0134	0.7454
Winter	0.1275	0.0006
Southeast	0.2015	<.0001
West	-0.1150	0.0228
Southwest	0.5256	<.0001
N	12,057	
Zero Responses	7,319	
Log-likelihood	-20,868	

Source: Leora Lawton, Michael Sullivan, Kent Van Liere, Aaron Katz, and Joseph Eto, "A framework and review of customer outage costs: Integration and analysis of electric utility outage cost surveys", p. 40

Table 7.4 shows the customer damage function for small and medium commercial customers. It is a regression model expressing the cost of an outage as a function of its season, duration, the number of employees at the firm, average annual electricity use, and when the outage occurs (time of day and day of week). Business customer damages do not differ significantly by geographical location so these parameters are not included in the model.

Table 7-4
Tobit Regression Models for Predicting Small/Medium Commercial Customer Outage Costs

	Model One		
Predictor	**Parameter**	**S.E.**	**Probability**
Intercept	6.48005	0.06525	<.0001
Duration (hours)	0.38489	0.01588	<.0001
Duration Squared	-0.02248	0.0013408	<.0001
Number of Employees	0.001882	0.0001749	<.0001
Annual kWh	1.70E-06	1.21E-07	<.0001
Interaction Duration and kWh	9.46E-08	2.55E-08	0.0002
Morning	-0.6032	0.06151	<.0001
Night	-0.91339	0.07035	<.0001
Weekend	-0.52041	0.04657	<.0001
Winter	0.37674	0.04154	<.0001
Number of Observations	12,356		
Zero Response	6,637		
Log Likelihood	-23,855		

Source: Leora Lawton, Michael Sullivan, Kent Van Liere, Aaron Katz, and Joseph Eto, "A framework and review of customer outage costs: Integration and analysis of electric utility outage cost surveys", p. 31

Table 7.5 lists the sample inputs employed in estimating commercial and residential outage costs. For purposes of this example, the baseline scenario uses the average of the outage cost values for the four regions that released outage cost data for the meta-study (the Northwest, West, Southeast, and Southwest). Additionally, the onset times of the outages in this example were assumed to be equally distributed across morning, afternoon, and night periods of the day. Likewise, outages are distributed between weekdays and weekends and winter versus non-winter periods based on the share of total annual hours within those periods. For commercial customers, the average number of employees per company was assumed to be equal to the average number of employees at small and medium commercial companies in the meta-study. For residential customers, the median household income was based on the median household income, as reflected by the U.S. Census 2006 estimate,[65] and adjusted to 2008 dollars ($53,883) using the GDP deflator.[66]

The baseline outage costs for the average residential and commercial customers are obtained by multiplying the input parameters by the regression coefficients, along with the five-year system-wide average CAIDI and SAIFI values (180 minutes and 1.07, respectively). Table 7.6 summarizes the average baseline outage costs experienced by residential and commercial customers for this example. The residential model is used to derive a point estimate of $5.73. The commercial model is used to demonstrate a range of $295 - $475, which incorporates the error terms in the damage function regression models. The table also shows the change in outage costs associated with an incremental change in outage duration.

[65] U.S. Census Bureau, 2006 American Community Survey. Available at: http://factfinder.census.gov/

[66] GDP Inflation Calculator. Available at: http://cost.jsc.nasa.gov/inflateGDP.html

Table 7-5
Inputs Employed in Estimating Customer Outage Costs

INPUT	Residential	Small Commercial
Number of Employees		30
Annual kWh	9,220	100,000
Log of annual income	10.89	
Morning	33.0%	33.0%
Afternoon	33.0%	33.0%
Night	33.0%	33.0%
Weekend	28.6%	28.6%
Summer	50.0%	50.0%

Table 7-6
Baseline Outage Cost Summary

OUTPUT	Residential	Small Commercial
Baseline Cost per Outage	$5.73	$295 - $475
Marginal Cost per CAIDI Minute	$0.01	$5.45

7.5 Summary

Utilities, regulators and/or policy makers may wish to claim enhanced service quality through increased reliability as one of the benefits of mass deployment of smart metering technology. The argument in support of this contention is that the existence of this metering infrastructure may decrease the duration of system outages In order to demonstrate, quantify, and monetize this benefit, it is necessary for the analyst to accomplish three critical steps: (1) demonstrating the linkage between the existence of the metering infrastructure and the improvement in reliability, (2) providing a credible estimate of the change in frequency of occurrence and duration of outages as a result of the new metering technology, and, (3) converting the change in reliability measures to the value added to the customers.

8
MACROECONOMIC IMPACTS

The purpose of this section is to overview the methods that could be used to estimate macroeconomic impacts that stem from the installation of Smart Metering by electric utilities. These macroeconomic impacts refer to the *direct*, *indirect*, and *induced* changes in employment, state-level income, and value added that result from: 1) the direct investment expenditures on Smart Metering; 2) the reallocation of cost savings by the utility, and 3) the changes in the final consumption of goods and services by customers from the bill savings from new products made possible by the investment in Smart Metering, such as conservation and demand response programs.

Since such an analysis would require an input-output (I-O) model of the entire State's economy, this discussion provides a brief discussion regarding the typical modeling software and databases from which such an I-O model could be constructed.[67] As is discussed below, the distribution of these economic impacts is often as important as their magnitude. To appreciate this fact, it is important to understand what is involved in deriving these types of macroeconomic impacts.

Input-output (I-O) analysis, developed in the late 1930s and early 1940s by W. Leontief, has since proven to be an effective way to assess the economic effects from expenditures made as part of economic development and public policy initiatives at the national, state, and local levels. In contrast to more aggregate analyses, I-O analysis has the ability to differentiate the effects of policy initiatives by important economic sectors.[68] The I-O model provides an insightful way to depict and investigate the underlying processes that bind an economy together. Its strengths lie in a detailed representation of: 1) the production (primary and intermediate input requirements), 2) distribution (sales) of individual industries in an economy, and 3) the interrelationships among these industries and other economic sectors of an economy. The methodology's analytical capacity lies in its ability to estimate the *indirect* and *induced* economic effects stemming from the changes in *direct* investment or policy expenditures that lead to additional *indirect* and *induced* purchases by final users in an economy.

[67] Appendix B provides a detailed discussion of the structure of I-O models that could be used to estimate the direct, indirect, and induced economic effects from changes in direct spending patterns that result from the investment in Smart Metering.

[68] As is the case with more conventional macroeconomics, I-O models are a special form of general equilibrium analysis, but they differ in at least one important respect. Conventional macroeconomic models trace changes in aggregate economic indicators such as national income, gross national product employment, and investment due to changes in such factors as taxes and spending. However, these models do not address the composition of these changes by production sector, nor do they trace the resultant effects throughout the economy. Since there is no reason to believe that the effects of the investments in AMI and associated demand response programs are distributed evenly throughout the economy, an I-O analysis is needed to trace these changes throughout the various sectors of the economy.

These *indirect* and *induced* changes in economic activity result from what are now commonly known as "multiplier" or "ripple" effects throughout the various sectors in the economy. An initial expenditure of one dollar in one sector sets in motion a cascading set of impacts in the form of additional expenditures in other sectors by each business whose sales have increased; it is the cumulative impact across all affected businesses or industries that are of most interest. Depending on the nature of the change in initial direct expenditures, these *indirect* impacts could be in the form of additional purchases of a variety of goods and services, for example: 1) raw materials and primary factors of production, 2) semi-finished or intermediate goods, and, 3) capital equipment. Moreover, the initial changes in investment or program related *direct* spending and resultant *indirect* increases in business spending are associated with changes in output or sales; changes in employment and income; and changes in payments to land, capital and other primary factors of production. [69]

. Economic Impacts for AMI and Resulting Demand Reduction Programs

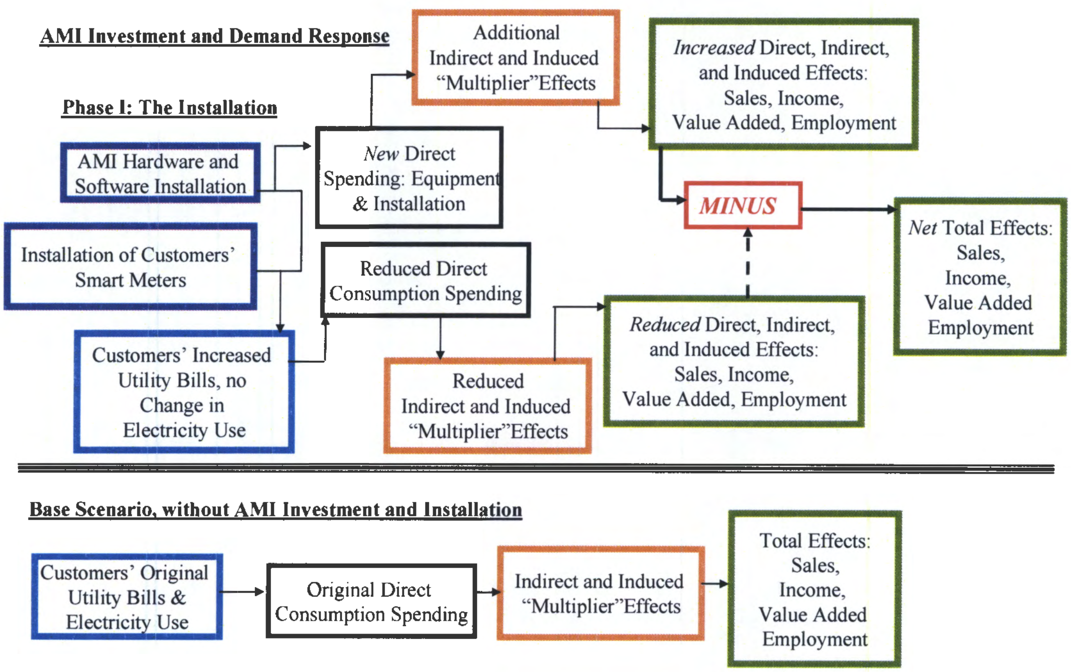

Figure 8-1
Source and Flow of Economic Impacts; Phase I

Part of these *direct* and *indirect* effects is in the form of the increased labor income generated in the economy due to the increased economic activity. To the extent that part or all of this additional income is spent within the economy, there are some additional "ripple" effects that are now commonly referred to as *induced* impacts, and they also can be estimated using the I-O methodology. The magnitudes of both the *indirect* and *induced* effects differ by economic sector. (The analytical details are relegated to the Appendix).

[69] The analytics of the I-O model are detailed in the Appendix.

At the most basic level, input-output models require that the *direct* changes in purchases or expenditures must be specified in the form of additional purchases by final users of products. However, in some impact analyses, some of these *direct* effects may also be in the form of intermediate purchases by production sectors of the economy or changes in consumption patterns by households or input use by firms, particularly energy. Rather than being reflected in changes in sales to final users, these types of *direct* effects potentially change the structure of the input requirements for some sectors of the economy.[70]

Through the use of a couple of well-designed flow charts, it is quite easy to describe the process by which one can estimate the total economic impacts from investments in Smart Metering and the associated DR programs. Three things must be emphasized at the outset: First, while the societal benefits are critical to any comprehensive evaluation of these kinds of initiatives, it is the private benefits and costs – those that translate into specific financial gains or losses—that lead to macroeconomic impacts. Second, in order to evaluate the economic effects, a base scenario that represents the situation without the Smart Metering investment and DR programs must also be identified. Finally, to identify the macroeconomic impacts, it is helpful to think of the implementation of Smart Metering as a process that consists of two distinct phases.[71]

The first is the installation phase in which the central hardware and software are purchased and installed, along with the smart meters for customers. The second phase is where the demand response programs and other new products have been implemented. In reality, these two phases are not absolutely distinct, particularly if some customer classes or regions are given priority for meter installation and DR program implementation. However, the important point is that investment costs and the costs associated with meter installation are one-time expenditures, and the impacts of these expenditures will be short lived. In contrast, the operational savings to the utility once the system is installed and the bill savings from DR programs will persist into the future. Thus, the macroeconomic effects are modeled separately, and an appropriate base scenario is developed for each.

[70] Batista, et al. (1982) addressed similar issues in restructuring the model of the State's economy in an earlier study for NYSERDA to assess the economic impacts from potentially new biomass energy production industries. The study involved estimating the direct, indirect, and induced employment impacts from introducing an entirely new sector into the economy whose technology and input structure were estimated from detailed engineering plant designs. The economic impacts clearly differed by region: they depended on the size of the plants, as well as the extent to which the biomass feedstock could be grown locally or had to be imported from other states. In yet another study, Blandford and Boisvert (1982) were concerned with isolating the direct and indirect employment implications from exporting agricultural commodities in processed verses raw form. This analysis involved examining individual coefficients of the I-O model to identify the raw agricultural commodity component of various processed agricultural commodities so that the direct and indirect impacts for both sectors could be put on a comparable basis. It is clear that the additional employment due to processing differed by region of the country based on where the raw products were grown and where the processing was done.

[71] This strategy was also used by Batista, et al. (1982) where there were separate economic assessments of the construction phase and operations phases.

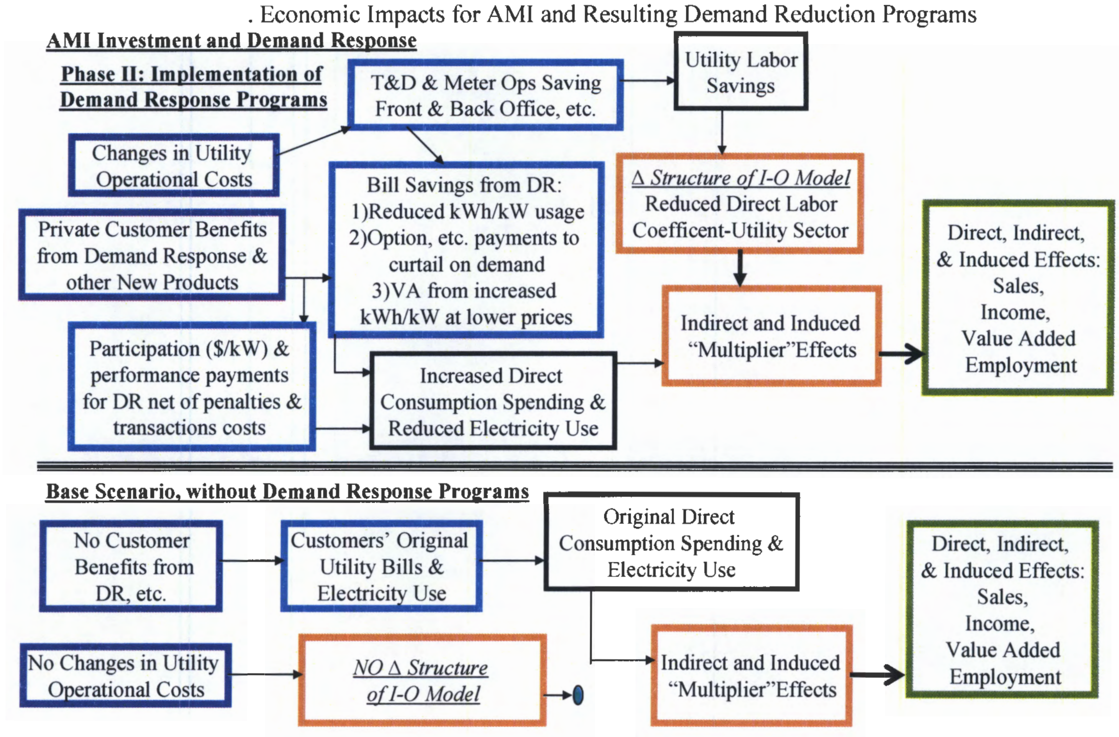

Figure 8-2
Source and Flow of Economic Impacts; Phase II

8.1 Summary

An Input-Output model of the state's economy provides a means to estimate the direct, indirect, and induced macroeconomic impacts that stem from the installation of Smart Metering by electric utilities. These macroeconomic impacts may result from (1) the direct investment expenditures on Smart Metering; (2) the reallocation of cost savings by the utility, and (3) the changes in the final consumption of goods and services by customers from the bill savings from new products made possible by the investment in Smart Metering, such as conservation and demand response programs. These benefits are truly societal as they would be enjoyed by the citizens of the region regardless of individual consumption levels. However, as far as we can determine, no regulatory jurisdiction has thus far used a quantification of secondary macroeconomic benefits in making a case for AMI deployment.

9
EXTERNALITIES

Externalities are costs that are associated with economic activity apart from the costs that are included in and recovered from the price consumer pay for the good or service.[72] Externalities pose a societal problem. Since the price does not reflect the entire cost consumption imposes, consumers make decisions regarding consumption based solely on a price does not factor in all the costs explicitly or implicitly.

Externalities are sometimes associated with market failure; the missing cost element in the good is an indication that the market is not functioning properly because the marginal cost of consumption fails to fully reflect the marginal resource cost. However, such a judgment is inherently subjective since it depends upon the determination that the cost should be reflected in the price.

This section addresses two externalities that have been discussed with regard to electricity pricing: the environmental benefits from reduced emissions associated with supplying electricity demand and increased national security associated with reduced energy, primarily oil, imports. Both are secondary benefits in that they result from behavioral changes invoked by demand response or a feedback mechanism. Installing Smart Metering does not assure that externality costs will be abated. Monetizing the externality costs requires constructing what cost a market would impose if the costs were internalized and included in the price consumers pay.

9.1 Reduced Emissions Benefits

In the case of pollution, negative externalities (unaccounted for costs) are incurred with the generation of electricity because the damage caused by pollutants emitted from power plants is not entirely captured by the cost of production and reflected in the prices paid by consumers. Therefore, society would benefit from clean air and reduced climate change to the extent that conservation measures reduce negative externalities.

The environmental costs of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) are included in the calculations of avoided costs of generation implicitly because generator owners pay penalties for excessive emission and explicitly because they can purchase rights to increase emission above their allowance and must add that as cost to the price they charge.

[72] Although cumbersome, it is important to be precise in the delineation of what constitutes an externality as it can play a significant role in policy making. This is a variation on definitions provided in textbooks on resource economics. See Allan Randall, Resource *Economics: An Economic Approach to Natural Resource and Environmental Policy*, Grid Publishing, Inc., Columbus, Ohio, 1981.

However, emissions of carbon dioxide (CO_2) are not currently restricted. Unless a generator is inclined to raise its price to reflect what it sees as the equivalent environmental damage cost, the market price for electricity does not reflect any costs that CO_2 emission impose on consumers and society. However, a jurisdiction or state may elect to impose such a cost to correct what it sees as a market flaw. For example, a utility, perhaps at the behest of its regulator, might increment the avoided cost of energy, which reflects estimates of future fuel costs, with an adder to reflect CO_2 emission costs to society. This addition would affect market transactions that are predicated not on the tariff rates, but on avoided costs. For example, energy efficiency programs use avoided costs to establish the level of benefits associated with measures that reduce energy and demand. The benefit level in turn establishes the level of incentives that can be offered to consumer to undertake those measures. The addition of the externality cost raises the level of the allowable incentive and therefore, if other factors remain constant, the kW and kWh reductions that are undertaken.

In California, guidelines were promulgated for the inclusion of external environmental costs when comparing the economics of renewable or demand-side resources to other more traditional supply-side generation alternatives.

> Consistent with established Commission policy and the positions of several parties, including PG&E, we adopt a range of values to explicitly account for the financial risk associated with GHG emissions of $ 8 to $25 per ton of CO_2, to be used in the evaluation of fossil generation bids. This range is taken from information in the present record, and is consistent with actions undertaken by other electric utilities across the country. Each IOU will select a value within the adopted range and respond to party comment on the value, before employing the adder in analyzing RFO responses.[73]

Other approaches incorporate the monetized benefit through a ¢/kWh adder for electricity produced or saved. For example, in evaluating demand side programs, the Vermont Department of Public Service employed an environmental adder of 0.87 ¢/kWh (2007 dollars). The adder was applied to the net reduction in energy use due to DR in their analyses.

Other estimates of the ¢/kWh effects have a wide range of values. Synapse Energy Economics recently provided the estimates of pollution costs for generation related to CO_2 emissions ranging from $0.16 to $0.81 per MWH.[74]

9.2 National Security Benefits

Another externality benefit associated with energy conservation that has been cited recently is increased national security. This concept has been advanced by Charles Cicchetti.[75] The

[73] Public Utilities Commission Of The State Of California, Rulemaking 04-04-003,

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning, April 1, 2004.

[74] Biewald, B. January 2006. Forecasting and Using Carbon Prices in a World of Uncertainty. Electric Utilities Environmental Conference, Tucson AZ

Division 2-48

Request:

8-48 Refer to page 22 of Appendix 4-1 AMF Technology & BCA, which states: "The Company has evaluated an opt-out scenario where, by default, a large percentage of customers will be enrolled in time variant pricing programs, as well as an opt-in scenario, in which customers must choose to enroll on the rate." Please provide the expected percentage of customers enrolled in time variant pricing programs for the first five calendar years of time variant pricing program offerings, by service rate, for both the opt-out and opt-in scenarios.

Response:

The expected percentage of customers enrolled in time variant pricing programs for the first five fiscal years of program offerings are as follows:

Electric Customer Enrollment Percentage		
Fiscal Year	**Opt-In**	**Opt-Out**
2023	2.0%	85.0%
2024	4.0%	85.0%
2025	6.0%	85.0%
2026	8.0%	85.0%
2027	10.0%	85.0%

The Company is providing the expected percentage of customers enrolled in time variant pricing programs on a fiscal year basis because the AMF benefit-cost analysis model estimates fiscal year values. Additionally, the adoption rate of time variant pricing programs is provided as a percentage of total customers because it has not been evaluated at a service rate level.

(This response is identical to the Company's response to Division 8-48 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-49

Request:

Refer to page 23 of Appendix 4-1 AMF Technology & BCA, which states: "The level of benefits achieved will be directly related to the […] number of enrolled customers […] and the resulting peak and energy savings." Please provide the expected number of customers enrolled in time variant pricing programs for the first five calendar years of time variant pricing program offerings, by service rate, for both the opt-out and opt-in scenarios.

Response:

The expected number of customers enrolled in time variant pricing programs for the first five fiscal years of program offerings are as follows:

Electric Customer Enrollment Volume		
Fiscal Year	**Opt-In**	**Opt-Out**
2023	10,290	437,337
2024	20,581	437,337
2025	30,871	437,337
2026	41,161	437,337
2027	51,451	437,337

The Company is providing the expected number of customers enrolled in time variant pricing programs on a fiscal year basis because the AMF benefit-cost analysis model estimates fiscal year values. Additionally, the adoption rate of time variant pricing programs is provided as the number of total customers because it has not been evaluated at a service rate level.

(This response is identical to the Company's response to Division 8-49 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-50

Request:

Refer to page 25 of Appendix 4-1 – AMF Technology & BCA, which states: "The estimate for the electric vehicle integration benefit assumes a certain percentage of electric vehicle charging is done during peak periods and can be displaced." Please provide the assumed percentage of electric vehicle charging that can be displaced to off-peak periods.

Response:

Please see the below data for FY25 from the Company's AMF – EV benefit calculation which serves to provide an example calculation of the assumed energy and demand from electric vehicles that can be avoided through off-peak charging.

Energy

	FY25 value
= Energy consumed by EV / PHEV during the YEAR (kWh)	126,681,329
x % of EV / PHEV energy use during on-peak hours	55%
x % of on-peak hour energy charging moved to off-peak	78%
= Energy moved from on-peak charging to off-peak charging in response to TVR	54,291,357

Demand

	FY25 value
Potential Increase in Peak due to EV/PHEV Charging (kW) based on average vehicles during the year	12,069
x % of EV / PHEV vehicles that could be moved off peak with EV / PHEV customer program (%)	79%
= Reduction In Annual demand due to EV / PHEV customer program (kW)	9,544

(This response is identical to the Company's response to Division 8-50 in Docket No. 4770).

Prepared by or under the supervision of: John Leana

See EV Forecast and Load Impacts Tabs

	Comments	FY19 Year 1	FY20 Year 2	FY21 Year 3	FY22 Year 4	FY23 Year 5	FY24 Year 6	FY25 Year 7	FY26 Year 8	FY27 Year 9	FY28 Year 10	FY29 Year 11	FY30 Year 12	FY31 Year 13	FY32 Year 14	FY33 Year 15	FY34 Year 16	FY35 Year 17	FY36 Year 18	FY37 Year 19	FY38 Year 20	Total	
Forecast of EV/PHEVs registered in RI service territory	EV Forecast Tab	4,436	9,177	15,217	21,986	29,412	36,982	44,685	53,936	61,736	69,393	75,463	79,095	81,509	83,096	84,005	84,878	85,619	86,476	87,340	88,214		
x Cumulative % of meter deployment	RI Meter Deployment Schedule	0%	0%	0%	40%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%		
= Cumulative # of EV / PHEV in the utility coverage area with AMI (#)	Calculated Value	0	0	0	8,794	29,412	36,982	44,685	53,936	61,736	69,393	75,463	79,095	81,509	83,096	84,005	84,878	85,619	86,476	87,340	88,214		
Average Maximum Residential Demand per EV / PHEV (kW)	Load Impacts Tab	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32		
x % of Cars Plugged into Residential Chargers during peak (%)	Load Impacts Tab	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%		
= Potential peak demand increase per EV / PHEV (kW)	Calculated Value	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27		
Percentage of vehicles that can be moved off peak in Years 1 to 5 (after program is offered)	Use same as MA Grid Mod	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%	79.08%		
x % of Benefits to be Realized based on EV/PHEV customer program rollout	From Row 6 above	0%	0%	0%	33%	33%	34%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%		
x Cumulative % of meter deployment	From Row 6 above	0%	0%	0%	40%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%		
= % of EV / PHEV vehicles that could be moved off peak with EV / PHEV customer program (%)	Calculated Value	0%	0%	0%	10%	26%	27%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%		
Average Miles Driven on Electricity Per Vehicle (#)	Load Impacts Tab	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100		
/ Miles/kWh	Load Impacts Tab	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9		
x Cumulative # of EV / PHEV in the utility coverage area with AMI (#)	From Row 7 above	0	0	0	8,794	29,412	36,982	44,685	53,936	61,736	69,393	75,463	79,095	81,509	83,096	84,005	84,878	85,619	86,476	87,340	88,214		
= Energy consumed by EV / PHEV during the YEAR (kWh)	Calculated Value	0	0	0	24,932,094	83,382,722	104,844,463	126,681,329	152,908,232	175,021,792	196,728,605	213,936,543	224,233,764	231,078,757	235,577,179	238,154,856	240,629,099	242,731,188	245,158,500	247,610,085	250,086,185		
x % of EV / PHEV energy use during on-peak hours	Use same as MA Grid Mod	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%		
x % of on-peak hour energy charging moved to off-peak	Use same as MA Grid Mod	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%		
= Energy moved from on-peak charging to off-peak charging in response to TVR	Calculated Value	0	0	0	10,685,057	35,735,030	44,932,811	54,291,357	65,531,325	75,008,453	84,311,263	91,686,007	96,099,049	99,032,583	100,960,455	102,065,161	103,125,538	104,026,423	105,066,687	106,117,354	107,178,528		
x Summer Months (4/12)	% of Year	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%		
= Summer Energy moved from on-peak charging to off-peak charging in response to TVR	Calculated Value	0	0	0	3,561,682	11,911,665	14,977,589	18,097,101	21,843,753	25,002,793	28,103,726	30,561,972	32,032,984	33,010,828	33,653,451	34,021,686	34,375,145	34,675,440	35,022,194	35,372,416	35,726,140		
Energy moved from on-peak charging to off-peak charging in response to TVR	From Row 24 above	0	0	0	10,685,057	35,735,030	44,932,811	54,291,357	65,531,325	75,008,453	84,311,263	91,686,007	96,099,049	99,032,583	100,960,455	102,065,161	103,125,538	104,026,423	105,066,687	106,117,354	107,178,528		
x Winter Months (8/12)	% of Year	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%		
= Winter Energy moved from on-peak charging to off-peak charging in response to TVR	Calculated Value	0	0	0	7,123,375	23,823,365	29,955,222	36,194,256	43,687,572	50,005,660	56,207,537	61,124,035	64,066,065	66,021,755	67,307,004	68,043,475	68,750,393	69,350,983	70,044,493	70,744,938	71,452,387		
Cumulative # of EV / PHEV in the utility coverage area (#)	From Row 7 above	0	0	0	8,794	29,412	36,982	44,685	53,936	61,736	69,393	75,463	79,095	81,509	83,096	84,005	84,878	85,619	86,476	87,340	88,214		
x Potential peak demand increase per EV / PHEV (kW)	From Row 11 above	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27		
= Potential Increase in Peak due to EV/PHEV Charging (kW) based on average vehicles during the year	Calculated Value	0	0	0	2,375	7,944	9,989	12,069	14,568	16,674	18,742	20,382	21,363	22,015	22,444	22,689	22,925	23,125	23,356	23,590	23,826		
x % of EV / PHEV vehicles that could be moved off peak with EV / PHEV customer program (%)	From Row 16 above	0%	0%	0%	10%	26%	27%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%	79%		
= Reduction In Annual demand due to EV / PHEV customer program (kW)	Calculated Value	0	0	0	248	2,073	2,686	9,544	11,519	13,185	14,821	16,117	16,893	17,409	17,747	17,942	18,128	18,286	18,469	18,654	18,840		
x Avoided Cost of Demand ($/kW)	Benefit Inputs - CPP Capacity Payment	161.96	110.64	80.42	121.84	114.81	107.88	112.35	123.83	135.56	146.85	158.41	170.84	187.62	195.1	195.1	195.1	195.1	195.1	195.1	195.1		
= Avoided Demand Cost from reduced demand billing rates (Row 170)	Calculated Value	**$0**	**$0**	**$0**	**$30,208**	**$237,997**	**$289,712**	**$1,072,229**	**$1,426,457**	**$1,787,415**	**$2,176,423**	**$2,553,109**	**$2,885,974**	**$3,266,186**	**$3,462,520**	**$3,500,407**	**$3,536,773**	**$3,567,670**	**$3,603,347**	**$3,639,380**	**$3,675,774**	**$40,711,582**	59%
Summer Energy moved from on-peak charging to off-peak charging in response to TVR	From Row 26 above	0	0	0	3,561,682	11,911,665	14,977,589	18,097,101	21,843,753	25,002,793	28,103,726	30,561,972	32,032,984	33,010,828	33,653,451	34,021,686	34,375,145	34,675,440	35,022,194	35,372,416	35,726,140		
x Load Shifting Avoided Cost (Summer)	Use same as MA Grid Mod	0.0440	0.0119	0.0157	0.0136	0.0128	0.0219	0.0181	0.0178	0.0223	0.0198	0.0259	0.0214	0.0232	0.0351	0.0371	0.0392	0.0414	0.0438	0.0462	0.0472		
	Calculated Value	0	0	0	48,377	152,193	328,520	327,317	389,444	557,549	557,410	791,371	686,422	767,137	1,182,770	1,263,315	1,348,550	1,437,118	1,533,355	1,635,963	1,686,526		
Winter Energy moved from on-peak charging to off-peak charging in response to TVR	From Row 30 above	0	0	0	7,123,375	23,823,365	29,955,222	36,194,256	43,687,572	50,005,660	56,207,537	61,124,035	64,066,065	66,021,755	67,307,004	68,043,475	68,750,393	69,350,983	70,044,493	70,744,938	71,452,387		
x Load Shifting Avoided Cost (Winter)	Use same as MA Grid Mod	0.0195	0.0141	0.0076	0.0089	0.0071	0.0088	0.0088	0.0104	0.0122	0.0125	0.0106	0.0108	0.0140	0.0144	0.0153	0.0162	0.0172	0.0183	0.0195	0.0199		
	Calculated Value	0	0	0	63,475	168,470	264,295	318,819	452,955	612,546	702,519	648,106	694,518	925,838	968,395	1,040,005	1,116,293	1,196,208	1,283,443	1,377,032	1,419,591		
Avoided Energy Cost from shifts to off-peak charging	Calculated Value	**$0**	**$0**	**$0**	**$111,852**	**$320,664**	**$592,815**	**$646,136**	**$842,399**	**$1,170,095**	**$1,259,928**	**$1,439,477**	**$1,380,940**	**$1,692,975**	**$2,151,165**	**$2,303,320**	**$2,464,843**	**$2,633,326**	**$2,816,798**	**$3,012,995**	**$3,106,117**	**$27,945,845**	41%
Energy/Demand Benefit	Calculated Value	**$0**	**$0**	**$0**	**$142,061**	**$558,661**	**$882,527**	**$1,718,365**	**$2,268,856**	**$2,957,511**	**$3,436,351**	**$3,992,586**	**$4,266,914**	**$4,959,161**	**$5,613,685**	**$5,803,727**	**$6,001,616**	**$6,200,996**	**$6,420,144**	**$6,652,375**	**$6,781,891**	**$68,657,427**	100%

Division 2-51

Request:

Please provide the expected reduction of greenhouse gas emissions via AMF for the first five calendar years after AMF deployment.

Response:

The Company is unable to provide the expected reduction of greenhouse gas emissions via AMF on a calendar year basis because the AMF benefit-cost analysis model estimates fiscal year values. The projected reduction of greenhouse gas emissions is presented in the below table for the first five fiscal years following AMF deployment for each of the four pricing scenarios evaluated in the benefit-cost analysis. The pricing scenarios are outlined in Appendix 4.1, Section 2.3.3, Page 22 (Bates Page 23 of PST Book 2).

Greenhouse Gas Emission Reduction in Pounds of CO2 (Thousands)				
Fiscal Year	Scenario 1 Opt-In w/ Low Savings	Scenario 2 Opt-In w/ High Savings	Scenario 3 Opt-Out w/ Low Savings	Scenario 4 Opt-Out w/ High Savings
2023	62,199	139,707	63,614	142,537
2024	67,744	148,846	76,259	165,874
2025	72,126	155,760	84,970	181,448
2026	76,693	163,178	93,982	197,755
2027	81,155	170,274	102,897	213,759

(This response is identical to the Company's response to Division 8-51 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-52

Request:

Please provide the number of the thefts of service the Company has documented in the last five calendar years.

Response:

The following table represents an excerpt from the Company's response to PUC 3-3 (in Docket 4770) and provides the number of thefts of service (TOS) the Company has documented in the last five calendar years.

Year	**# of Electric TOS cases**	**# of Gas TOS cases**
2013	40	22
2014	61	23
2015	187	37
2016	225	74
2017	130	78

(This response is identical to the Company's response to Division 8-52 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-53

Request:

Please provide the number of bad debt write-offs the Company has experienced in the last five calendar years.

Response:

The Company has provided the dollar amount of electric and gas bad debt write-offs in the last five years in its responses to Division 2-38 and Division 2-39, respectively, so the Company interprets this request to be asking for the number of customer accounts that were written off. Please see Attachment DIV 2-53 for the requested information.

(This response is identical to the Company's response to Division 8-53 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

# of ACCOUNTS of GROSS W-OFF: W-Off Cntrl Rprt CN878M#A

	RIE		RIG	
	Narr E	% of E	Narr G	% of G
Apr-13				
May-13				
Jun-13				
Jul-13				
Aug-13				
Sep-13	2,106		1,684	
Oct-13	2,785		2,424	
Nov-13	2,598		1,878	
Dec-13	2,400		1,607	
Jan-14	2,641		1,835	
Feb-14	1,933		1,390	
Mar-14	2,220		2,203	
	16,683		13,021	
Apr-14	1,543	5.85%	1,350	6.81%
May-14	1,713	6.50%	1,219	6.15%
Jun-14	1,979	7.51%	1,644	8.29%
Jul-14	2,243	8.51%	1,963	9.90%
Aug-14	2,105	7.99%	1,929	9.73%
Sep-14	2,850	10.81%	2,675	13.49%
Oct-14	2,697	10.23%	2,042	10.30%
Nov-14	2,533	9.61%	1,682	8.48%
Dec-14	2,667	10.12%	1,665	8.40%
Jan-15	2,672	10.14%	1,622	8.18%
Feb-15	1,682	6.38%	961	4.85%
Mar-15	1,676	6.36%	1,075	5.42%
	26,360		19,827	
Apr-15	1,399	6.03%	891	5.44%
May-15	1,396	6.02%	942	5.76%
Jun-15	1,652	7.12%	1,097	6.70%
Jul-15	1,783	7.69%	1,451	8.87%
Aug-15	2,643	11.40%	2,104	12.86%
Sep-15	2,471	10.66%	1,995	12.19%
Oct-15	2,082	8.98%	1,524	9.31%
Nov-15	1,953	8.42%	1,470	8.98%
Dec-15	2,349	10.13%	1,549	9.46%
Jan-16	2,085	8.99%	1,339	8.18%
Feb-16	1,801	7.77%	1,045	6.38%
Mar-16	1,572	6.78%	960	5.87%
	23,186		16,367	
Apr-16	1,419	6.46%	880	5.92%
May-16	1,593	7.25%	1,019	6.85%

# of ACCOUNTS of GROSS W-OFF: W-Off Cntrl Rprt CN878M#A

Jun-16	1,701	7.74%	1,138	7.65%
Jul-16	1,685	7.67%	1,133	7.62%
Aug-16	2,596	11.82%	1,814	12.20%
Sep-16	2,346	10.68%	1,796	12.08%
Oct-16	1,936	8.81%	1,498	10.07%
Nov-16	1,850	8.42%	1,415	9.51%
Dec-16	1,944	8.85%	1,242	8.35%
Jan-17	1,666	7.58%	1,029	6.92%
Feb-17	1,616	7.36%	939	6.31%
Mar-17	1,618	7.36%	970	6.52%
	21,970		14,873	
Apr-17	1,294	5.89%	872	5.86%
May-17	1,541	7.01%	961	6.46%
Jun-17	1,730	7.87%	1,208	8.12%
Jul-17	1,591	7.24%	1,129	7.59%
Aug-17	2,274	10.35%	1,699	11.42%
Sep-17	2,242	10.20%	1,602	10.77%
Oct-17	2,086	9.49%	1,609	10.82%
Nov-17	1,704	7.76%	1,196	8.04%
Dec-17	1,827	8.32%	1,241	8.34%
Jan-18	0	0.00%	0	0.00%
Feb-18	0	0.00%	0	0.00%
Mar-18	0	0.00%	0	0.00%
	16,289		11,517	

Division 2-54

Request:

Refer to page 27 of Appendix 4-1 – AMF Technology & BCA, which states: "Other capabilities and use cases were also contemplated but were determined to be out of scope." Please provide a list of these capabilities and use cases along with the rationales as to why they were determined to be out of scope.

Response:

The "other capabilities and uses cases" mentioned on Page 27 of Appendix 4-1 – AMF Technology & BCA, REDACTED (Bates Page 28 of PST Book 2) are referring to the opportunities to coordinate with other utilities and utility devices outlined in Section 2.6 of Appendix 4-1 – AMF Technology & BCA, REDACTED starting on Page 27 including:

- Joint use with water utilities/municipalities
- AMF for streetlights and ancillary devices
- Gas remote service shutoff valves
- Residential methane detectors

These capabilities and use cases were not incorporated into the AMF benefit-cost analysis as additional investigation and analysis is required to understand their scope and the associated costs and benefits. The Company plans to consider the capability and flexibility of vendor AMF solutions to support these use cases as part of the AMF procurement effort in Fiscal Year 2019.

(This response is identical to the Company's response to Division 8-54 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana

Division 2-55

Request:

Regarding the PST Provision described in Schedule PST-1, Chapter 10, the text states that for "all PST Initiatives except the expansion of Grid Modernization activities, including AMF, the Company's PST-related costs are proposed to be recovered through two cost recovery factors:" the PST Factor and the PST Reconciliation Factors (page 2 of 7).

a. Please confirm that the Grid Modernization and AMF costs will not be recovered through the PST and PST Reconciliation Factors.

b. If the answer to (a) is no (i.e., "not confirmed"), then please explain the meaning of the quote above.

c. If the answer to (a) is yes (i.e., "confirmed"), then how will the Company recover the Grid Modernization and AMF costs?

d. If the answer to (a) is yes (i.e., "confirmed"), then please explain why the subsequent paragraph states that the Company is proposing the PST Factors and PST Reconciliation Factors for Grid Modernization Expansion, including AMF, be based upon the categorization of the nature of the spending of this initiative…" (page 2 of 7).

Response:

a. The Company is proposing to recover the costs of all Power Sector Transformation (PST) initiatives, including grid modernization and advanced metering functionality (AMF) through PST factors. The referenced text in Schedule PST-1, Chapter 10, Page 2 (Bates Page 186 of PST Book 1), which begins the second paragraph on that page, is intended to describe the first set of Power Sector Transformation (PST) factors that would be designed to recover the annual costs of PST initiatives through a per-kilowatt-hour rate that would be uniform across all of the Company's rate classes (both electric and gas). The Company realizes that this introductory sentence could be clarified to indicate this design as follows:

> For all PST Initiatives except the expansion of Grid Modernization activities, including AMF, the Company's PST-related costs are proposed to be recovered through two uniform per-kWh cost recovery factors:

In further support of this clarification, the subsequent paragraph on the same page discusses the Company's proposal to recover the costs of grid modernization, including AMF. The Company is proposing a different structure for the PST factors that are

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proposed to recover these costs to better align how these costs would likely be recovered in base distribution rates, as these costs would eventually be included in the revenue requirement in a general rate case and recovered through base distribution rates after the components of the revenue requirement are allocated to the Company's rate classes. The remainder of that paragraph briefly discusses the Company's proposed approach to the categorization, allocation, and design of the PST factors that would recover the costs of Grid Modernization and AMF.

In addition, the Company's proposed PST Provisions presented in Appendix 10.10 for Narragansett Electric (Bates Pages 276-293 of PST Book 2) and Appendix 10.11 for Narragansett Gas (Bates Pages 295-300 of PST Book 2) both contain the detailed description and calculation of each PST factor. Using Narragansett Electric's proposed PST Provision as a guide, a further understanding of the summary of PST cost recovery presented in Schedule PST-1, Chapter 10, can be developed.

First, Sheet 3 of the proposed PST Provision (Bates Page 278 of PST Book 2) includes the definition of PST Factors, and indicates that each PST initiative will have its own PST factors that are either designed on a per-bill basis or per-kWh basis. The end of this definition indicates that Grid Modernization Expansion (GME), including AMF, has its own PST factors defined as GMEFs. The definition of PST Reconciliation Factors below that of PST Factors reflects a similar definition, but applicable to the reconciliation factors.

Section 6.0 of the proposed PST Provision beginning on Sheet 4 (Bates Page 279 of PST Book 2) presents a very detailed definition of the PST factors for the recovery of costs incurred as a result of activities associated with GME, which includes AMF. The proposed structure and calculation of the PST factors to recover GME costs is presented in detail as the Company's is proposing a categorization and allocation of costs similar to how these costs would likely be recovered in base distribution rates. The Company is proposing this approach to mitigate the rate "shock" on individual rate classes that would likely result if the costs were recovered through a uniform per-kWh factor (i.e., allocated to rate classes on the basis of energy), but their allocation in an allocated cost of service study would change as a result of inherently being part of a larger revenue requirement, and the allocation methodologies employed to determine the rate class revenue requirement upon which base distribution rates would be design would not be the same as that reflected in GMEFs that were designed as uniform per-kWh factors.

Based upon the above discussion, the Company is proposing to recover the costs of all PST initiatives, including Grid Modernization and AMF.

b. Please refer to the response to part a. above.

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c. Please refer to the response to part a. above.

d. Please refer to the response to part a. above.

(This response is identical to the Company's response to Division 8-55 in Docket No. 4770.)

Prepared by or under the supervision of: Melissa Little

Division 2-56

Request:

Regarding the PST Provision described in Schedule PST-1, Chapter 10, please describe in detail the criteria that the Company will use to determine whether an investment is a PST initiative and therefore eligible for the PST Provision.

Response:

The Company's PST Initiatives are defined in this proceeding encompassing five categories on investment programs:

- Grid Modernization Initiatives
- Advanced Metering Functionality
- Electric Transportation Initiatives
- Electric Heat Initiatives
- Utility Owned Storage and Solar Demonstration Initiatives

The costs that will be incurred and recovered through the PST Provision would be the incremental costs to construct, own, operate, and maintain approved PST investments within each PST Initiative, as well as the cost of managing, marketing, and evaluating approved PST Initiatives. By August 1 of each year, the Company will file an annual report with the PUC and Division on the progress of its PST Initiatives, including information on the prior fiscal year's activities.

Schedule PST-1, Chapter 10, Page 2 (Bates Page 186 of PST Book 1), states that the PST Provision is intended to provide for the recovery of incremental costs associated with the Company's PST Plan, as approved by the Public Utilities Commission (PUC). Schedule PST-1, Chapter 10, Page 2, further states that to be eligible for recovery, PST Plan costs must: (1) be pre-authorized by the PUC; (2) include only costs of investing in PST Initiatives; (3) be incremental to those costs that the Company currently recovers through any other rate, charge, or factor; and (4) be prudently incurred.

PST Initiatives will be designated as components of the PST Plan as part of, and through the process of, stakeholder collaboration. All PST Initiatives arising from that process will required the PUC's pre-authorization for cost recovery outside of base distribution rates. Projects submitted to the PUC for pre-authorization would be only those projects that are agreed upon for inclusion in the PST Plan and that have costs that are incremental to costs already recovered in base distribution rates and not recovered through any other mechanism.

(This response is identical to the Company's response to Division 8-56 in Docket No. 4770.)

Prepared by or under the supervision of: Melissa Little

Division 2-57

Request:

Regarding the PST Provision described in Schedule PST-1, Chapter 10, please describe in detail why the PST initiative costs should be treated differently from other costs.

Response:

National Grid provides electric distribution service in three U.S. jurisdictions: Rhode Island, Massachusetts, and New York. In all three jurisdictions, there is recognition that power sector transformation (PST) is occurring and will constitute an effort that will extend over many years, as virtually all elements of the distribution system will ultimately be affected by this transformation.

Separate recovery for PST initiatives is appropriate because: (1) flexibility is needed to undertake new types of investments involving emerging technologies and lessons learned across the industry; (2) flexibility to alter recovery levels annually as the significant investments unfold over the years; (3) opportunity to allow for substantial stakeholder participation in planning and executing on those investments; and (4) separate recovery via a reconciling mechanism would ensure that benefits from sharing costs across jurisdictions are passed back to customers when those approvals are obtained in the other jurisdictions by the respective operating company.

In particular, stakeholder input will be critical. Stakeholder input will assure that future PST investments best meet the goals of state policy, including customer choice and empowerment, while also providing significant market opportunities to make the on-going process self-sustaining, low cost, and efficient for all participants. If the Company were to move forward with these investments without the critical feedback and input of all interested participants, it would not be certain that its investments were appropriately meeting the needs of the State and the Company's customers. Including an annual stakeholder process will provide concurrence and certainty about PST investments before-hand, as opposed to after-the-fact, and result in quicker and more efficient progress to the next generation electric distribution system.

In this context, it is not feasible, practical, or desirable to try to structure cost recovery so as to flow through base distribution rates or another established mechanism. Separation from recovery through base distribution rates will help to provide transparency, flexibility, accountability and ensure shared costs benefits get passed back to customers. The base distribution-rate construct is used to recover routinely occurring operating expenses with which the Company has certainty regarding how they may change over time and a return on rate base on capital investment which the Company also has experience in planning and certainty in its performance of construction activities to meet its capital plan. To enable the collaborative, iterative process that will be required to balance the interests of all stakeholders, including most particularly the interests of the Company's customers, it is necessary to create a mechanism outside of base distribution rates that can allow a greater level of flexibility and transparency to the program implementation, changes in PST activities and costs, and the recovery of these costs.

(This response is identical to the Company's response to Division 8-57 in Docket No. 4770.)

Prepared by or under the supervision of: Melissa Little

Division 2-58

Request:

Regarding the PST Provision described in Schedule PST-1, Chapter 10, please describe in detail why the PST initiative costs should be fully reconciled.

Response:

Separate recovery for the Power Sector Transformation (PST) initiatives is appropriate because: (1) flexibility is needed to undertake new types of investments involving emerging technologies and lessons learned across the industry; (2) flexibility to alter recovery levels annually as the significant investments unfold over the years; and (3) opportunity to allow for substantial stakeholder participation in planning and executing on those investments.

In particular, it is widely acknowledged in Rhode Island (and other jurisdictions) that stakeholder input is critical. Stakeholder input will assure that future PST investments best meet the goals of state policy, including customer choice and empowerment, while also providing significant market opportunities to make the on-going process self-sustaining, low cost, and efficient for all participants. If the Company were to move forward with these investments without the critical feedback and input of all interested participants, it would not be certain that its investments were appropriately meeting the needs of the state and the Company's customers. Including an annual stakeholder process will provide concurrence and certainty about PST investments before-hand, as opposed to after-the-fact, and result in quicker and more efficient progress to the next generation electric distribution system.

In this context, it is not feasible, practical, or desirable to try to structure cost recovery so as to flow through base distribution rates or another established mechanism. Separation from recovery through base distribution rates will help to provide transparency, flexibility, and accountability on the types of investments and expenses that are associated with the PST initiatives. Reconciling recovery will be as important for customers as for the Company. To a large extent, the activities associated with the PST initiatives represent new types of activities for the Company and the associated costs have not been previously reviewed by the PUC or the Division. Some of the costs are significant, particularly when layered on other costs to build and maintain the system. Keeping these costs separate will increase transparency and accountability; allowing an annual reconciliation will assure that customers pay no more and no less than the reasonable and prudent costs to implement the PST initiatives. Conversely, reconciling recovery provides the Company with the resources necessary to move forward with its investment in initiatives designed to serve the various objectives underlying the approved PST activities. In addition, since the PST initiatives and the estimated costs to perform the PST activities needed to accomplish the objectives of the PST initiatives, as well as the rate of progress and spending to complete the PST initiatives are, to some extent, new to the Company, having the flexibility that is provided through a reconciling mechanism to alter recovery levels in response to changing cost profiles, technologies, and pace of performance will provide a level of added assurance that customers are only being charged to recover costs that the Company anticipates incurring as a result of changing information and learnings during deployment. Recovery through base distribution rates does not provide such flexibility that would allow the Company to be more agile in refining its planning over and cost recovery of PST initiatives.

Over time, it is likely that cost recovery will transition to a base distribution-rate structure as these cost become more routine, more levelized, and more certain. However, this transition is several years away given that the Company has yet to embed these types of investments into its traditional planning and procurement processes.

(This response is identical to the Company's response to Division 8-58 in Docket No. 4770.)

Prepared by or under the supervision of: [Sponsor A. Name]

Division 2-59

Request:

Regarding the PST Provision described in Schedule PST-1, Chapter 10, please describe in detail how the Company would prefer to collect these costs if the Commission rejects the Company's proposed PST Provision.

Response:

There are only two ways for the Company to recover costs: through base distribution rates or through a mechanism operating outside of base distribution rates. For the reasons stated in the Company's responses to data requests Division 2-57, 2-58, and 2-59, base-rate recovery of PST costs under the Company's deployment of the PST initiatives and the nature of the spending on these initiatives is not the appropriate path for PST costs given that there is only very limited flexibility to change recovery between rate cases to address the evolving requirements of the program.

Therefore, a mechanism outside of base distribution rates must be established to enable the proposed PST initiatives. Examples exist whereby commissions in National Grid's other jurisdictions have structured various mechanisms to accomplish cost recovery. A structure other than the structure proposed by the Company in this proceeding may be workable and/or appropriate, but a funding mechanism must be established if the Company is going to be able to meet the objectives of stakeholders in Rhode Island and move forward with the PST initiatives that are designed to begin the transformation of the electric distribution system.

(This response is identical to the Company's response to Division 8-59 in Docket No. 4770.)

Prepared by or under the supervision of: Kayte O'Neill

Division 2-60

Request:

Regarding the direct testimony of Melissa Little, page 9, line 13 through page 10, line 5, the question: "What costs are included in the revenue requirements?" Please clarify whether the Company is including each of the following items in its revenue requires:

a. The vegetation-management and inspection and management programs in the ISR Plans.

b. Any other costs in the ISR Plans. If there are any, please describe them.

c. Commodity costs.

d. Energy efficiency costs.

e. Renewable energy growth costs.

f. Any other reconciling mechanisms. If there are any please describe them.

Response:

a. No, the Company has removed the test year level of vegetation management and inspection and maintenance costs from its cost of service. Please refer to the summary of normalizing adjustments shown at Schedule MAL-3 at Page 5 (Bates Page 22 in Book 9) in Columns (c) and (d).

b. As described in the Company's response to PUC 3-31 (in Docket 4770), the cost of the 16 full time employees which is currently being recovered through the Gas Infrastructure, Safety, and Reliability Plan will be recovered through Narragansett Gas' base distribution rates effective September 1, 2018, as those positions are included in the test year-end complement of employees from which Narragansett Gas' rate year labor costs were derived.

c. Commodity costs have been removed from the cost of service. Please refer to the normalizing adjustments shown on Schedule MAL-3 at Page 1 (Bates Page 18 in Book 9) at Line 31 in Columns (e) and (f).

d. Energy efficiency costs have been removed from the cost of service. Please refer to the normalizing adjustments shown on Schedule MAL-3 at Page 1 (Bates Page 18 in Book 9) at Line 18 in Columns (e) and (f).

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e. Renewable Energy Growth (RE Growth) Program non-labor costs have been removed from the cost of service. Please refer to the summary of normalizing adjustments made to Other O&M Expense shown on Schedule MAL-30 at Page 6 (Bates Page 7 in Book 10) in Column (c). However, as stated in the Company's response to PUC 3-32 (in Docket 4770), the Company's intent is to begin recovering the RE Growth Program's labor-related costs (including benefits) in Narragansett Electric's base distribution rates effective September 1, 2018, leaving the RE Growth Factors to recover labor and benefits costs of employees newly added since the end of the test year. Therefore, the Company has proposed an adjustment of $534,199 to increase the Narragansett Electric revenue requirement by the amount of RE Growth Program labor-related costs.

f. The Company believes it has excluded all costs from its base distribution cost of service schedules that would otherwise be recovered through its existing reconciling mechanisms. The Company has not proposed any changes to the operation of its existing reconciling mechanisms as part of this case.

At the PUC's request, for ease of reference, the Company is providing copies of its responses to PUC 3-31 and PUC 3-32 (in Docket 4770) as Attachment DIV 2-60-1 and Attachment DIV 2-60-2, respectively.

(This response is identical to the Company's response to Division 8-60 in Docket No. 4770.)

Prepared by or under the supervision of: Melissa Little

PUC 3-31

Request:

Are the positions currently funded through the Gas ISR Plan being moved into this general rate case for cost recovery purposes and out of the Gas ISR Plan budget for FY 2019 starting in September 2018?

Response:

Yes. The 16 Meter Service Technician positions currently funded through the Gas Infrastructure, Safety, and Reliability (ISR) Plan will cease to be recovered through the Gas ISR factors effective September 1, 2018 and will instead be recovered through base distribution rates effective September 1, 2018.

Prepared by or under the supervision of: Melissa Little

PUC 3-32

Request:

How many positions are currently funded through the Renewable Energy Growth program budget? Will those positions be moved out of the Renewable Energy Growth program budget and associated recovery factor effective September 1, 2018?

Response:

Please see Attachment PUC 3-32 for the positions funded through the Renewable Energy Growth Program budget. This information is the same as that provided on Page 4 of Schedule ASC-2 of the Company's 2017 Renewable Energy Growth Program Factor filing in Docket No. 4707.

These positions will be moved out of the Renewable Energy Growth Program budget and associated recovery factor, and will instead be recovered through base distribution rates effective September 1, 2018. Please note that the current version of the revenue requirement for Narragansett Electric does not include the Renewable Energy Growth Program's test year labor and associated benefits, as the Company inadvertently removed the expense from the cost of service as a normalizing adjustment to Other Benefits on Schedule MAL-30, Page 6, Line 17(c). However, the Company will eliminate this adjustment in the next revision of the cost of service for Narragansett Electric, thereby seeking recovery of the Renewable Energy Growth Program labor and associated benefits through base distribution rates.

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Renewable Energy Growth Program
Estimated Administrative Costs
for the Program Year Ending March 31, 2018

	Summary of Estimated Annual Administrative Expenses	
(1)	Billing System Modifications - Revenue Requirement of Capitalized Costs	$106,618
(2)	Billing System Modifications - O&M Budget Estimate for Additional Modifications	$120,000
(3)	Incremental Labor Resources (1)	$705,273
(4)	Estimated SolarWise Program Implementation/Support Costs	$92,300
(5)	Training on Solar PV Safety and Common Installation Violations	$4,925
(6)	DG Board Expense	$68,000
(7)	DG Installation Quality QA Studies	$190,000
(8)	Revenue Requirement - Meter Investment	$27,051
(9)	Estimated Remuneration	$131,364
(10)	Total	$1,445,531

(1) Schedule ASC-4A, Page 1, sum of Lines (13) through (24)
(2) Estimated O&M budget for billing system modifications required to implement new Shared Solar/Community Net Metering Project classes
(3) Footnote (1) Below
(4) Budget Estimate
(5) 5 hour training course recommended by OER
(6) Docket 4604, Order No. 22765
(7) Docket 4536-B, Order No. 22180; $125,000 approved budget, less $75,000 already invoiced and paid in 2016 Program Year + $140,000 additional budget request for Round 2 Study provided by OER
(8) Schedule ASC-4B, Pg. 1, Line (5), Column (c)
(9) Page 1, Line (1) x 1.75%
(10) Sum of Lines (1) through (9)

		Accounts Processing	Customer Solutions	Customer Solutions	DG Customer Facilitator	Interconnection Consultant	FCM Administration	Energy Procurement	Total
	(1) Detail of Incremental Labor Resources	1	1	2	1	1	1	1	8
(1)	Full Time Employees	$31,699	$71,000	$71,000	$115,000	$85,000	$80,000	$103,646	
(2)	Average Salary	100.00%	50.00%	100.00%	60.00%	50.00%	14.06%	80.00%	
(3)	Percent Dedicated to RE Growth	$31,699	$35,500	$142,000	$69,000	$42,500	$11,250	$82,917	$414,866
(4)	Annual Labor Expense	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	
(5)	Overhead rate	$53,889	$60,350	$241,400	$117,300	$72,250	$19,125	$140,959	$705,273
(6)	Total Annual Incremental Expense								

(1) Estimated
(2) Estimated
(3) Estimated
(4) Line (2) x Line (3)
(5) Company Labor Overheads, excluding pension & PBOP
(6) Line (4) x (1 + Line (5))

Division 2-61

Request:

Regarding the direct testimony of Melissa Little, page 9, line 13 through page 10, line 5, the question: "What costs are included in the revenue requirements?" Please clarify whether the Company is proposing a different approach to including items in the revenue requirements relative to the 2012 rate case and the practices employed since then.

Response:

The Company is not proposing a different approach to including items in the revenue requirements relative to the 2012 rate case and the practices employed since then.

Please refer to the Company's responses to Division 2-60 and Division 2-62 for further clarification.

(This response is identical to the Company's response to Division 8-54 in Docket No. 4770.)

Prepared by or under the supervision of: Melissa Little

Division 2-62

Request:

Regarding the direct testimony of Melissa Little, page 10, lines 3-5, please clarify whether the Company is proposing to permanently stop recovering future vegetation-management and inspection and management programs in the ISR Plans through the ISR Factors. Or, does this text describe a process of moving previously incurred costs from the ISR Factors into base rates at the time of the next rate case.

Response:

The Company is not proposing to permanently stop recovering future vegetation-management and inspection and management programs in the Infrastructure, Safety, and Reliability (ISR) Plans through the ISR Factors. The Company intends to continue recovering vegetation-management and inspection and management programs through the ISR O&M Factors to be reconciled annually. The cited lines should be read together with Lines 20-22 on Page 9 of the prefiled direct testimony of Company Witness Melissa A. Little (Bates Page 13 of Book 8). The full sentence indicates that all ISR Plan costs, except those incurred by Narragansett Electric from its vegetation management activities and Inspection and Maintenance Program, that would normally continue to be recovered through the ISR Plan have been included in the proposed revenue requirements in this general rate case. The phrase "except those incurred by Narragansett Electric from its vegetation management activities and Inspection and Maintenance Program" indicates that the vegetation management costs and Inspection and Maintenance Program costs have not been included in Narragansett Electric's revenue requirement. In addition, Narragansett Electric did not propose any changes to its Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2199 (ISR Provision) included in Schedule PP-5-ELEC (Bates Pages 231-235 of Book 16) regarding the recovery of vegetation management costs and Inspection and Maintenance Program costs and will continue to recover these costs through the ISR Provision.

Rather, this text is describing the process by which the recovery of capital investments previously recovered through ISR Plans plus forecasted levels of ISR-eligible capital investment through the end of the rate year in this rate case (i.e., August 31, 2019) transfers from the applicable electric and gas ISR factors to base distribution rates, as this ISR investment and its associated accumulated reserve for depreciation and deferred federal income tax balances have been included in rate year rate base for both Narragansett Electric and Narragansett Gas. The revenue requirement on this cumulative ISR capital investment is inherently a part of Narragansett Electric's and Narragansett Gas' overall revenue requirement to be recovered through base distribution rates effective September 1, 2018. On this same date, the applicable electric and gas ISR factors that have been recovering the revenue requirement on the ISR capital investment included in the rate year's rate base as shown in Schedule MAL-11-ELEC and

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Schedule MAL-11-GAS (Bates Pages 95 and 116, respectively, of Book 9) will reduce to zero as the recovery of this capital investment will commence in base distribution rates.

The ISR Plans are subject to full reconciliation for actual capital investment and revenue billed through the ISR factors to recover the electric and gas ISR Plans revenue requirements. Therefore, because the Company has reflected an estimate of electric and gas ISR plant additions through the end of the rate year in this general rate case, the Company will include as part of its annual reconciliation filings the difference between the estimated plant additions included in this general rate case in the rate year and the comparable actual ISR plant additions for the ISR Plans to which they relate. The Company will calculate the revenue requirements on any difference in actual and estimated ISR plant additions recovered through base distribution rates, and will include the recovery or refund of the revenue requirement on the difference as part of determining the applicable electric and gas ISR reconciliation factors that would become effective on October 1 for Narragansett Electric and November 1 for Narragansett Gas. Because of the timing of the Company's electric and gas ISR reconciliation periods (its fiscal year ending March 31) and the timing of those filings, and the end of the rate year in this general rate case (i.e., August 31, 2019), this "true up" for actual vs. estimated ISR plant additions included in the revenue requirements recovered through base distribution rates would take place in two ISR reconciliation filings filed by August 1, 2019 (for the fiscal year ended March 31, 2019) and August 1, 2020 (for the fiscal year ended March 31, 2010).

(This response is identical to the Company's response to Division 8-62 in Docket No. 4770.)

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