Title
Decision Support For Demand Response Triggers: Methodology Development and Proof of Concept Demonstration

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Publication Date
2010

FINAL PROJECT REPORT

DECISION SUPPORT FOR DEMAND RESPONSE TRIGGERS: METHODOLOGY DEVELOPMENT AND PROOF OF CONCEPT DEMONSTRATION

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Date: November, 2010

A CIEE Report

ACKNOWLEDGEMENTS

This report was prepared by

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This draft report describes research sponsored by the Electric Power Research Institute (EPRI) and the California Energy Commission through the Public Interest Energy Research (PIER) Program. The contract for this research project was administered and managed on the behalf of the PIER Program by the California Institute for Energy and Environment, at the University of California. The work was also supported through the participation of the three major California investor-owned utilities (SCE, PG&E, and SDG&E), the California Department of Water Resources, and the California Independent System Operator.

This publication should be cited in the literature in the following manner:

Chuang, A. 2010. *Decision Support for Demand Response Triggers: Methodology Development and Proof-of-Concept Demonstration (A Report on Connecting Retail to Wholesale Electricity Markets).* EPRI, Palo Alto, CA; California Energy Commission, Sacramento, CA. 1020311. CEC-500-01-043.

PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Decision Support for Demand Response Triggering is the final report under contract 500-01-043, conducted by the Electric Power Research Institute (EPRI). The information from this project contributes to PIER's Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

ABSTRACT

This report describes a project conceptualized and executed to help bridge a financial disconnect between retail and wholesale electricity markets. Although wholesale electricity costs vary hourly with wholesale market and grid conditions, retail customers are predominantly disconnected from wholesale conditions by fixed retail tariffs, and generally lack incentive to respond to wholesale market changes in a timely manner. Demand response (DR) programs have been developed at the retail level by both load serving entities (LSEs) and Demand Response Providers (DRPs), also known as Curtailment Service Providers (CSPs), in an attempt to bridge the gap by incentivizing customers to adjust their usage in the short term. However, wholesale market participants who represent LSEs lack timely (day-of and day-ahead) demand-side valuation information to help them understand the financial value or impact of triggering demand response to capture wholesale benefits.

Under the DR Triggers project, the project team developed a methodology and prototype for a decision support tool to help wholesale electricity market participants understand and quantify the value of triggering demand response at the retail level to mitigate wholesale supply-side procurement costs. A live demonstration illustrated how the devised trigger methodology could assist wholesale market participants in making operational decisions in day-ahead and day-of timeframes, using DR as a market resource. The methodology helps market participants determine the wholesale financial impact of triggering a megawatt of demand response by time interval and by location. By focusing on value-add for market participants on the demand-side of electricity markets, the approach has the potential of revealing the impact of DR and its market value at any time during the year based on latest market conditions.

This project begins to bridge the gap between wholesale and retail electricity markets by clarifying the financial value of dispatching demand-side resources in response to wholesale market conditions. The methodology described in the report may help market participants make informed decisions about triggering DR in day-of and day-ahead operational timeframes. Project results bring California a step closer to realizing the full potential value of DR. The value to be captured by DR includes the ability to not only reduce peak demand for LSEs, but also to maximize financial benefit from triggering DR in support of wholesale electricity market needs

Keywords: Demand response, trigger methodology, market integration, settlement charge code, value capture, demand response triggers, demand-side integration.

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EXECUTIVE SUMMARY

Project in Brief

"Demand response (DR) is a dynamic change in electricity usage coordinated with power system or market conditions."[3] Understanding the impact of DR on wholesale settlements can help electricity market participants trigger DR in a fashion that financially connects retail load with wholesale markets.

This project developed a methodology and a prototype decision support tool to help electricity market participants understand and quantify the value of triggering demand response (DR) to avoid wholesale settlement costs. Project results bring California a step closer to realizing the benefits of DR, including the ability to manage customer load not only to reduce peak demand but as a dispatchable resource as though it were the output from a power plant.

With further refinements, the Demand Response Triggers Decision Support Tool could be used in operational timeframes (day-of and day-ahead) to establish a financial link between retail incentives for demand response and actual wholesale market conditions. By clarifying the value of triggering DR to market participants, the decision support tool offers the potential to provide multiple benefits, such as:

- Clarify the financial impact of triggering demand response and resulting benefits to energy retailers that schedule load in wholesale markets.
- Enable market participants to quantify the impact of triggering DR on their wholesale settlements with an Independent System Operator (ISO).
- Allow energy retailers to mitigate wholesale market settlement charges.
- Inform energy retailers of estimated wholesale settlement costs that DR can help avoid.
- Offer the potential to enhance power system operational flexibility using demand response commensurate with financial impact.

The project was conceived to address a persistent problem: the financial disconnect between wholesale electricity markets and retail electricity tariffs and rates. Although wholesale electricity costs vary with wholesale market and grid conditions, retail customers are generally disconnected from wholesale conditions and lack incentive to respond in a timely manner. Moreover, the wholesale market participants who schedule load lack timely (day-of and day-ahead) information to help them understand the financial consequences and impact of triggering DR on wholesale settlements.

The California Energy Crisis of Years 2000-2001 was a stark reminder of the perils of disconnected wholesale and retail markets. The crisis contributed to financial shock to net buyers of electricity, who incurred unprecedented wholesale charges revealed over a month after the fact— too late to take action. The California crisis highlighted the need for clarity on wholesale charges in time for the demand-side to act, and for a tool to inform energy retailers of wholesale settlement costs that demand response can help avoid.

The project begins to bridge the gap between wholesale and retail electricity markets by clarifying the financial value of triggering DR to help market participants make informed decisions about triggering DR in day-of and day-ahead operational timeframes.

Project Objectives

The project’s objectives were to specify, develop, and demonstrate a methodology for energy retailers to trigger demand response in a fashion that financially links retail with wholesale electricity markets. The initial objective is to develop a methodology to form a basis for a decision support tool that can be used to inform energy retailers of the impact of triggering demand response on wholesale settlement costs, and charges that DR can help avoid. A subsequent project goal is to design the tool to be used in operational timeframes using latest information available on wholesale market conditions. The ultimate objective is to demonstrate the decision support tool and how it can capture value for market participants that schedule load.

Approach

To bring a multifaceted perspective to bear on the project goals, EPRI assembled a cross-functional group of wholesale market participants, energy retailers, and information technologists including personnel from the four largest load-serving entities (LSEs) in California and the California Independent System Operator (CAISO). Engaging this array of industry experts with targeted expertise and information access proved critical to the project’s success in bridging gaps between wholesale and retail market operations.

The project’s first phase, the subject of this report, was to develop and prove feasibility of the concept. Major project stages included (1) DR Trigger Methodology Development, (2) Information Technology Specification, and (3) Proof-of-Concept Demonstration.

In Stage 1, DR Trigger Methodology Development, the project team identified and classified charge codes allocable to loads and relevant to DR. Charge codes were ranked based the combination of 1) relevance of DR and 2) significance of the charge code on actual settlements charged to market participants that schedule load.

In Stage 2, Information Technology Specification, the team specified and prioritized software requirements based on input from project participants and potential users of the DR Trigger Decision Support tool. Requirements were gathered on desired functionality and user interface contents. Sample input data was collected revealing useful data formats. Project participants also prioritized the resulting specified requirements.

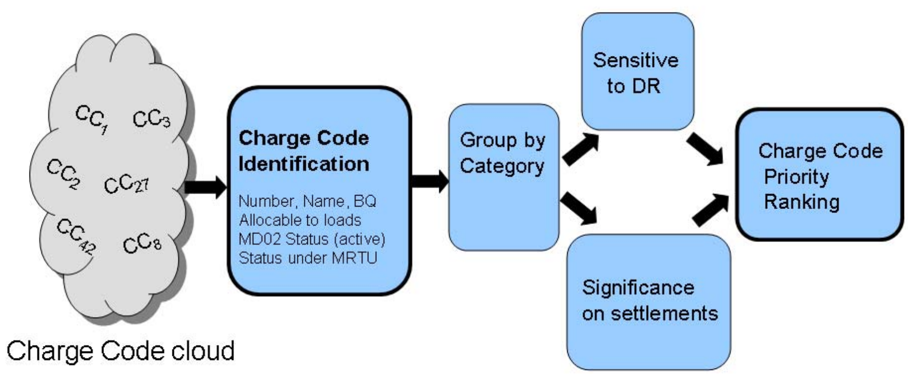
In Stage 3, Proof of Concept Demonstration, the project team conducted a live demonstration of the prototype decision support tool’s value-added capabilities. The demonstration was given at a final project workshop held with project participants and funders at a face-to-face meeting hosted by the Energy Commission in Sacramento. The workshop presentation and demonstration were also shared through a live webcast that was open to public participation.

At the conclusion of the final workshop, EPRI led a meeting with the project participants to discuss next steps. The next steps form the basis for a detailed implementation plan being proposed for the project’s second phase.

Findings and Results

The project team developed an operational approach and tool to support value capture for energy retailers that schedule load and can trigger demand response in day-to-day operations. The tool’s target users are short-term procurement personnel from day-of and day-ahead trading desks. By focusing on value-add for market participants on the demand-side of electricity markets, the approach has the potential of revealing value at any time during the year based on latest market conditions. In short, the approach helps market participants to determine the financial impact of applying a megawatt of demand response by resource and location at a given time.

In contrast to traditional DR programs that require an external source to fund incentive payments, this project's approach identifies market-based financial incentives for DR by clarifying wholesale settlement charges that DR can help reduce. Strategies with such a market connection are applicable on a persistent basis for revealing incentives for demand response. Such incentives are revealed in the project by carefully examining the settlement impact of metered load deviations from scheduled load[1].



The project's approach focuses on the highest priority charge codes: those that are both most sensitive to DR and have the most impact on settlements. These codes—identified in the project's first stage through analysis of aggregated historic settlement data from market participants who schedule load—are the basis for the DR trigger methodology and the decision support tool.

The decision support tool enables short-term procurement personnel to compare DR program resource costs with the impact of triggering each MW of demand response on wholesale settlements for the analyzed charge categories. In other words, the market participant representing load is empowered for the first time with information on charges that can be reduced on wholesale settlements from "self-supply" of procurement short-falls (below daily demand forecasts) using DR resources. The combination of equipping them with trigger impact information plus the ability to compare against DR program resource costs enhances day-ahead and day-of decision-making for triggering demand response. The Day-ahead and Day-of screens illustrate types of information that can be provided to support decision-making based on which resources, in what locations, how much is available, and when to trigger them.

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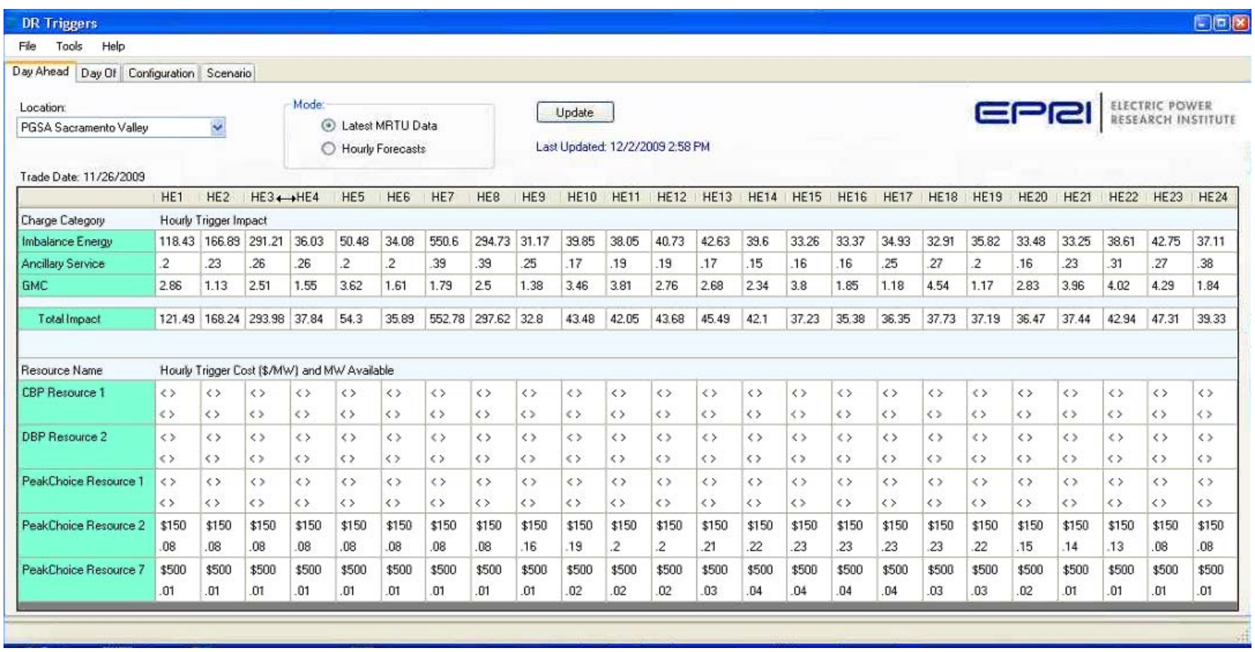
1 Scheduled load is the resulting 24 hour demand committed in a wholesale market as a result of a scheduling or bidding process between a market participant that represents load and the independent system operator that manages the wholesale markets.

The project team held a live demonstration of the proof-of-concept decision support tool in December 2009. The tool was explained in the context of the day in the life of short-term procurement personnel, beginning at the day-ahead desk, followed by the day-of desk. The demonstration highlighted information provided by the prototyped tool that supports decision-making beyond the status quo of information available to these users. In particular, the tool provides trigger impact information alongside program cost information, so that the market participant can readily discern time intervals when dispatching demand response was estimated to "be in the money" (i.e., when the trigger impact is estimated to be greater than the cost of dispatching DR).

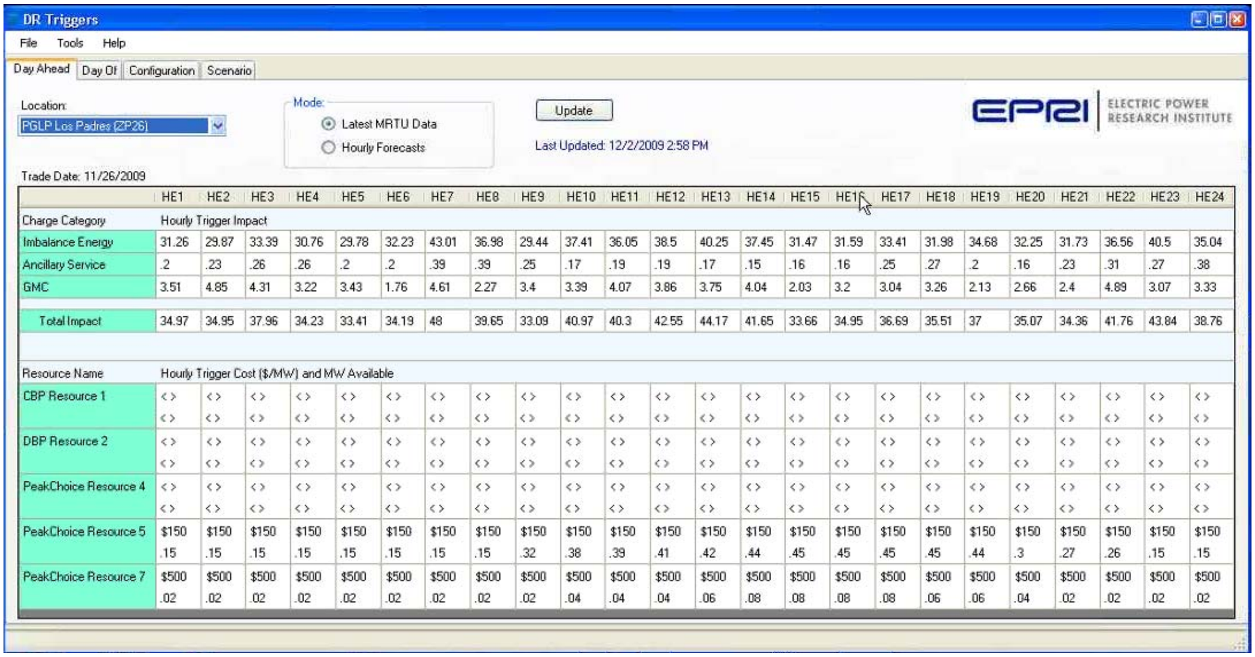
The following screenshots from the live demonstration highlights differences in triggering decisions by location for trade date November 26, 2009. Close examination of results reveals that triggering at $500/MW is in the money during hour ending interval 7 in the Sacramento Valley location. In contrast, there are no time intervals for which triggering demand response is in the money for any resource listed in the Los Padres location on the same trade date.

Day-ahead trigger impact results for trade date 11/26/10 and Sacramento Valley location



	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category	Hourly Trigger Impact																							
Imbalance Energy	118.43	166.89	291.21	36.03	50.48	34.08	550.6	294.73	31.17	39.85	38.05	40.73	42.63	39.6	33.26	33.37	34.93	32.91	35.82	33.48	33.25	38.61	42.75	37.11
Ancillary Service	.2	.23	.26	.26	.2	.2	.39	.39	.25	.17	.19	.19	.17	.15	.16	.16	.25	.27	.2	.16	.23	.31	.27	.38
GMC	2.86	1.13	2.51	1.55	3.62	1.61	1.79	2.5	1.38	3.46	3.81	2.76	2.68	2.34	3.8	1.85	1.18	4.54	1.17	2.83	3.96	4.02	4.29	1.84
Total Impact	121.49	168.24	293.98	37.84	54.3	35.89	552.78	297.62	32.8	43.48	42.05	43.68	45.49	42.1	37.23	35.38	36.35	37.73	37.19	36.47	37.44	42.94	47.31	39.33
Resource Name	Hourly Trigger Cost ($/MW) and MW Available																							
CBP Resource 1	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>
DBP Resource 2	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>
PeakChoice Resource 1	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>
PeakChoice Resource 2	$150 .08	$150 .08	$150 .08	$150 .08	$150 .08	$150 .08	$150 .08	$150 .08	$150 .16	$150 .19	$150 .2	$150 .2	$150 .21	$150 .22	$150 .23	$150 .23	$150 .23	$150 .23	$150 .22	$150 .15	$150 .14	$150 .13	$150 .08	$150 .08
PeakChoice Resource 7	$500 .01	$500 .01	$500 .01	$500 .01	$500 .01	$500 .01	$500 .01	$500 .01	$500 .01	$500 .02	$500 .02	$500 .02	$500 .03	$500 .04	$500 .04	$500 .04	$500 .04	$500 .03	$500 .03	$500 .02	$500 .01	$500 .01	$500 .01	$500 .01

Day-ahead trigger impact results for trade date 11/26/10 and Los Padres location



	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12
Charge Category	Hourly Trigger Impact											
Imbalance Energy	31.26	29.87	33.39	30.76	29.78	32.23	43.01	36.98	29.44	37.41	36.05	38.5
Ancillary Service	.2	.23	.26	.26	.2	.2	.39	.39	.25	.17	.19	.19
GMC	3.51	4.85	4.31	3.22	3.43	1.76	4.61	2.27	3.4	3.39	4.07	3.86
Total Impact	34.97	34.95	37.96	34.23	33.41	34.19	48	39.65	33.09	40.97	40.3	42.55
Resource Name	Hourly Trigger Cost ($/MW) and MW Available											
CBP Resource 1	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >
DBP Resource 2	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 4	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 5	$150 .15	$150 .15	$150 .15	$150 .15	$150 .15	$150 .15	$150 .15	$150 .15	$150 .32	$150 .38	$150 .39	$150 .41
PeakChoice Resource 7	$500 .02	$500 .02	$500 .02	$500 .02	$500 .02	$500 .02	$500 .02	$500 .02	$500 .02	$500 .04	$500 .04	$500 .04

	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category												
Imbalance Energy	40.25	37.45	31.47	31.59	33.41	31.98	34.68	32.25	31.73	36.56	40.5	35.04
Ancillary Service	.17	.15	.16	.16	.25	.27	.2	.16	.23	.31	.27	.38
GMC	3.75	4.04	2.03	3.2	3.04	3.26	2.13	2.66	2.4	4.89	3.07	3.33
Total Impact	44.17	41.65	33.66	34.95	36.69	35.51	37	35.07	34.36	41.76	43.84	38.76
Resource Name												
CBP Resource 1	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >
DBP Resource 2	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 4	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 5	$150 .42	$150 .44	$150 .45	$150 .45	$150 .45	$150 .45	$150 .44	$150 .3	$150 .27	$150 .26	$150 .15	$150 .15
PeakChoice Resource 7	$500 .06	$500 .08	$500 .08	$500 .08	$500 .08	$500 .06	$500 .06	$500 .04	$500 .02	$500 .02	$500 .02	$500 .02

Through application of the decision support tool, energy retailers and wholesale market participants that represent loads can gain insight to improve their strategic market positioning of DR resources. They can also improve their readiness to accommodate market changes and regulatory mandates. In particular, early adopters can better position their organizations to maximize demand response resources in meeting California's Loading Priority Order requirements. They can gain a better understanding on how to trigger DR as a physical mechanism for hedging financial market risk, as a form of insurance against excess market charges. In this way, application of the developed methodology and specified tool is expected to enhance flexibility when most needed during day-to-day operations.

Recommendations

A second project phase is recommended to clarify market integration concepts and support full implementation of the decision support tool screens and functionality specified in Phase 1. Formulations are needed for triggering based on impact to other charges codes that have been identified as priority. Analyses of input data availability and methods to connect to live data feeds also need to be developed for priority charge codes.

Recommended next steps include full implementation of specified functionality for the Day-ahead, Day-of, and What-if Scenario screens, beyond the limited-function proof-of-concept prototype. Moreover, existing functionality can be extended to include consideration of bidding and counterparty trades. This would help to develop an overall perspective of the value of triggering DR, considering wholesale charges and revenues from both market and counterparty trades.

CHAPTER 1: Introduction

This report describes a project conceptualized to address the prevalent disconnect between retail and wholesale electricity markets that persists in regions that have undergone restructuring of the electric power industry, including California. A decision support tool is needed to inform energy retailers of wholesale settlement costs that demand response can help avoid. The report describes an innovative methodology for triggering demand response to capture value for wholesale market participants, embodied in a Demand Response Triggers Decision Support tool. Such a tool could be used in operational timeframes to establish a financial link between retail incentives for demand response and actual wholesale market conditions.

1.1 Background and Foundation for the Work

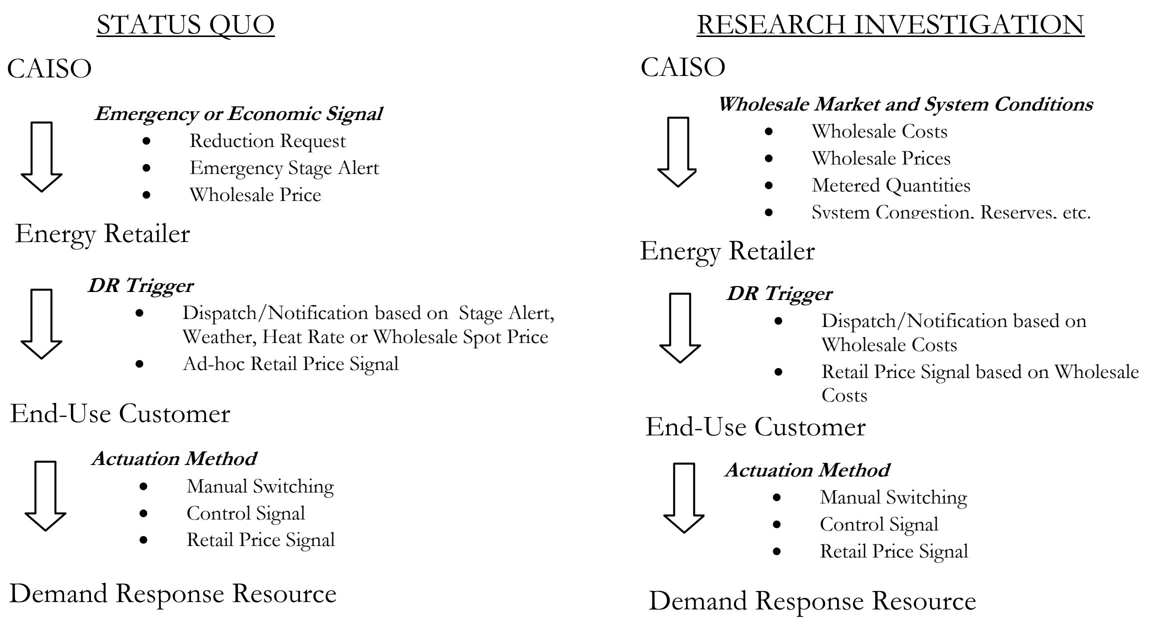
Since the early 1980s, EPRI has managed collaborative RD&D programs to support demand-side integration, including the electric power industry's migration towards load management and demand-side response. Despite the growing recognition of the importance of demand-side response, widespread implementation has yet to be realized, including in restructured electricity markets.

Enabling technology initiatives exist to target needed metering, communications, and control infrastructure for measuring and actuating demand response. Moreover, dynamic pricing initiatives address retail tariff structures that encourage demand response through time-varying prices. The California Energy Commission (CEC) and the California Public Utility Commission (CPUC) are targeting Critical Peak Pricing (CPP), Real-time Pricing (RTP), and Time of Use (TOU) as default tariffs for California end-use customers. These tariff structures are envisioned to provide a financial mechanism to incentivize demand response according to dynamic triggers, price signals, or pre-designated hours of the day. Careful design of such dynamic triggers or information signals is critical in connecting financial consequences of wholesale electricity markets with retail incentives for demand response. Nevertheless, a prevalent disconnect exists between retail and wholesale electricity markets. This situation is particularly evident in restructured regions, where wholesale electricity costs vary with wholesale market and grid conditions, yet retail customers are disconnected from wholesale conditions and lack incentive to respond in a timely manner.

Furthermore, present implementations of demand response (DR) are limited. Under status quo as depicted in Figure 1, demand response is predominantly triggered based on pre-set physical system conditions (e.g., emergency stage alerts, temperature, weather, etc.) or pre-set market-driven economic conditions (e.g., spot energy price, heat rate, etc.). In contrast, the project described in this report investigates a combination of both wholesale market and system conditions for triggering demand response, which together determine overall wholesale costs. That is, the project investigates a broader scope of costs by analyzing various components that comprise costs (e.g., prices and quantities from a series of markets). In contrast to the status quo, project findings have the potential of supporting both dynamic pricing and traditional demand response programs by providing a tool for energy retailers to coordinate the triggering of demand response considering an array of wholesale costs.

Previous work in [1] suggests enhanced benefits to be captured from applying real-time information technology tools to dispatch resources based on latest power system and market conditions. It follows that benefits can also be derived from triggering demand-side resources based on latest information available on the day of operations. Furthermore, [2] suggests demand response may be applied to avoid premiums in wholesale costs during times of supply shortfall in competitive electricity markets. This report details execution of a plan to investigate the suggested financial connection between demand response and wholesale market costs, and to investigate supporting information technology that enables capture of avoided costs. By enhancing the energy retailers' understanding of wholesale cost impacts of demand response and how to capture wholesale cost savings, the project is designed to reveal benefits that can be passed onto end-use customers to help incentivize demand response.

Figure 1: Status quo for triggering demand response contrasted with proposed research investigation



1.2 Project Objectives

The project seeks to devise and demonstrate a method of triggering demand response that captures value for market participants that schedule load. To do so, EPRI envisioned bringing together a collaborative project team from retail and wholesale organizations across the electric power industry to define a decision support tool for informing energy retailers of various wholesale settlement costs that demand response can help avoid. Such a tool would be used in operational timeframes to provide a financial link between retail incentives for demand response and actual wholesale market conditions.

The project addressed these objectives by investigating the following underlying research questions:

- What operational approach to triggering demand response will enable energy retailers to mitigate wholesale market settlement charges?
- What decision support tool will enable energy retailers to create demand response triggers based on impact to wholesale settlement costs?

Overall, the purpose of the project is to develop an operational approach and supporting information technology that will substantially bridge the current disconnect between wholesale and retail electricity markets. The outcome envisioned is a new operational methodology and decision support tool enabling energy retailers to coordinate the triggering of demand response based on impact to wholesale settlement costs.

1.3 Project Funders

The project is a joint effort funded by the California Energy Commission's PIER Program and CIEE, as well as EPRI. Substantial in-kind services were provided by Southern California Edison, Pacific Gas & Electric, the California Independent System Operator, the California Department of Water Resources, and other project participants. The rationale of co-funding the research reported in this document is to leverage the extensive body of work and personnel expertise required for the development of a DR Triggers Decision Support Tool.

1.4 Report Structure

Section 1 introduces the background and objective of the project. The project team's approach to addressing the objectives are structured into tasks described in Section 2. The development of the DR Trigger methodology is captured in Sections 3 and 4. The information technology specification is summarized in Section 5 and potential benefits in Section 6. Section 7 describes the proof of concept development and demonstration. Section 8 identifies the project's next steps. Section 9 outlines project conclusions.

CHAPTER 2:
Project Approach

2.1 Cross-Functional Team

EPRI assembled a cross-functional group of wholesale market participants, energy retailers, and information technologists to inform stages of the project as appropriate. Engaging the industry experts who possessed targeted expertise and information access was a critical factor to the success of the project. The resulting team of project participants included personnel from the four largest load-serving entities (LSEs) in California and the California Independent System Operator (CAISO). The project approach to engage personnel from both procurement and retail organizations of the LSEs resulted in a team exceptionally well qualified to bridge gaps between wholesale and retail operations. Besides EPRI technical development resources, the principal investigator was assisted by subcontractors with targeted expertise in wholesale settlements.

2.2 Top-Down Approach

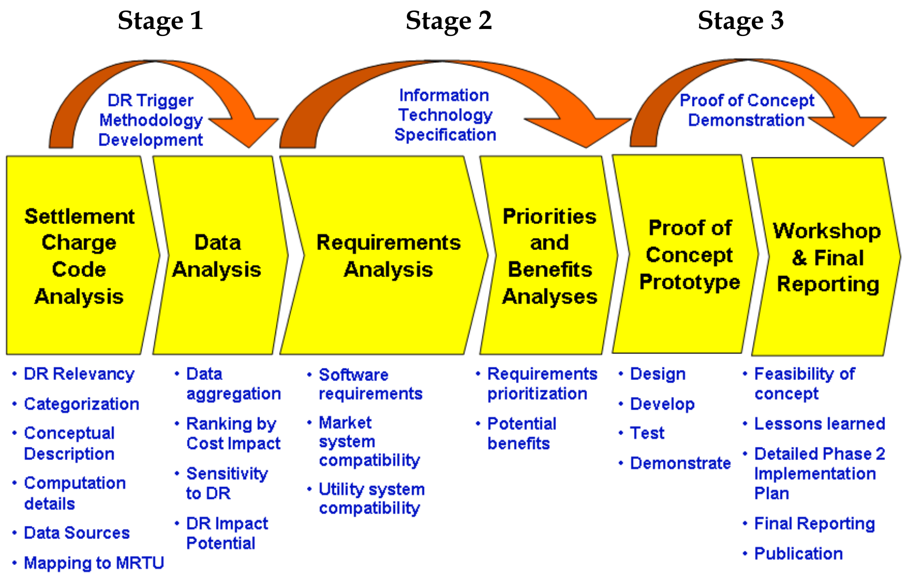
The project team executed Phase 1 of a two-phased approach for the overall DR Triggers project. Phase I of the project, the subject of this report, was to develop and prove feasibility of the concept. Major project tasks included trigger methodology design, information technology specification, and proof of concept development and demonstration. A future Phase II of the project would focus on implementation and demonstration of the decision support tool specified in Phase I.

A systematic, four-step approach was followed in executing the project to achieve the stated objectives. Major project tasks included:

- DR Trigger Methodology Development
- Information Technology Specification
- Proof-of-Concept Demonstration
- Reporting and Publication

Figure 2 depicts the process steps followed in executing the project under three major project stages.

Figure 2: Process followed in the DR Triggers project



In Stage 1, DR Trigger Methodology Development, the project team identified and classified charge codes allocable to loads and relevant to demand response (DR). The team assessed the potential impact of DR and ranked each one by high to low value application of DR. DR impact assessment was performed utilizing aggregated historic settlement data from market participants that schedule load. Charge codes were ranked based the combination of 1) relevance of DR and 2) significance of the charge code on actual settlements charged to market participants that schedule load. Charge code ranking was an essential step for establishing priorities for further investigation in Task 2 of methodologies to reduce the most problematic charges. Prerequisite data and other requirements for estimating the impact of demand response by charge code were also identified, along with concrete examples of the potential impact of DR on settlement charges.

In Stage 2, Information Technology Specification, the team specified and prioritized software requirements based on input from project participants and potential users of the DR Trigger Decision Support tool. Substantial in-kind services were provided by utility personnel to support this task. Requirements were gathered on desired functionality and user interface contents. Sample input data was collected revealing useful data formats. Project participants also prioritized the resulting specified requirements.

In Stage 3, Proof of Concept Demonstration, the project team targeted a limited subset of the specified requirements for proof-of-concept development, testing, and demonstration. The team discussed various scenarios for demonstration. A subset of scenarios was selected to demonstrate value-added capabilities during a live demonstration of the prototyped decision support tool. The demonstration was given at a final project workshop held with project participants and funders at a face-to-face meeting hosted by the Energy Commission in

Sacramento. The final project workshop presentation and demonstration were also shared through a live webcast that was open to public participation.

At the conclusion of the final workshop, EPRI led a meeting with the project participants to discuss next steps. The next steps form the basis for a detailed implementation plan being proposed for a subsequent phase of the project. The implementation plan and findings from each task of the project are shared in this report.

2.3 Value Capture for Energy Retailers

The project approach emphasizes developing a methodology and tool to support value capture for energy retailers that schedule load and can trigger demand response in day-to-day operations. By focusing on value-add for market participants on the demand-side of electricity markets, the approach has the potential of revealing value at anytime during the year based on latest market conditions.

As market participants positioned between end-use customers and wholesale electricity markets, energy retailers (or their affiliates that schedule load) are well-positioned to facilitate a connection between retail load and wholesale markets. However, these market participants may require tools to augment their decision-making capabilities and to clarify what value can be derived from triggering demand response. The project approach focuses on clarifying the financial impact of triggering demand response and resulting benefits to energy retailers that schedule load in wholesale markets.

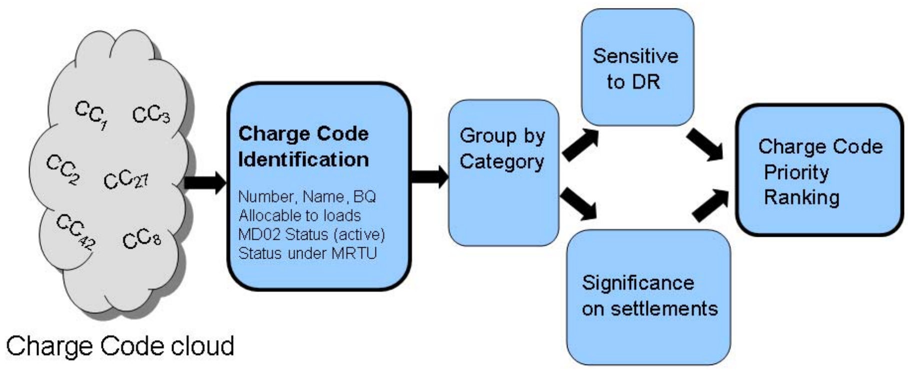
By triggering demand response to achieve savings on wholesale electricity market charges (in both ISO and bilateral markets), retail markets become inherently integrated with wholesale markets. Savings discovered at the wholesale level in turn provide a source of retail incentives for demand response. This is unlike traditional demand response programs that require an external source to fund demand response incentive payments. In contrast, the project approach has the potential of revealing persistent strategies for wholesale cost reductions, by identifying market-based financial incentives for demand response. Strategies with such a market connection are applicable on an ongoing 24x7 basis for revealing incentives for demand response. Therefore, the project approach focuses on devising a flexible tool that enables energy retailers to connect retail load to wholesale markets, by clarifying the impact of demand response on wholesale settlement charges.

CHAPTER 3: Settlement Charge Code and Data Analyses

This section summarizes findings from analyses conducted under Stage 1 of the project. The project commenced with analyses of charge codes and settlement data. The goal was to prioritize charge codes for further investigation.

The charge code and data analyses work followed the process depicted in Figure 3. The process began with identifying the charge codes most sensitive to demand response and information sources required as inputs to their calculations. The analyses focused on charge codes that were in effect prior to the California Market Redesign and Technology Upgrade (MRTU) in April 2009. A mapping was also performed between existing (pre-MRTU) and new charge codes introduced by MRTU that are relevant to DR. The task continued with aggregation of settlement data in order to determine the most significant charge codes based on historical data. The final step of the analyses was to rank charge codes based on sensitivity to demand response and significance on settlements for market participants that schedule load. The next four subsections detail findings from the analyses.

Figure 3: Charge code and data analysis process



3.1 Charge Code Identification and Categorization

The project team identified and categorized pre-MRTU and MRTU charge codes relevant to Demand Response. Charge codes can be identified by identification number, name, category grouping, and billable quantity, as illustrated in Figure 4. Pertinent information captured also includes time period the charge code is in effect, status of the charge code (i.e., active or inactive at the time of analyses), and status under MRTU (i.e., charge code to be replaced, retired, or newly introduced with MRTU). Results are summarized in the table in Appendix B-1. The table includes a list of billable quantities that serve as inputs to the calculations of charges per charge code. Results also include a preliminary mapping between existing and new charge code introduced by MRTU that are relevant to demand response. Figure 4 provides a partial listing of charge codes as an example of how they can be identified and categorized. Appendix B-1 provides a full list of charge codes identified and categorized at the time of investigation before the California market transitioned to MRTU.

Figure 4: Example table structure for identifying and categorizing charge codes

* MD02 Charge Code Number	MD02 Charge Code Name	Group	MD02 Status	MRTU Status	Billable Quantity	Dispatchable-Participating Load: - Pump Storage Load - Single Pump - Aggregated Pump	Non-Dispatchable / Non-Participating LOAD	Prior Charge Code	Start	End
2	Day Ahead Non-Spinning Reserve due SC	AS	Active	Replaced	Day Ahead Non Spin Capacity Awarded	X			4/1/1998	Open
4	Day Ahead Replacement Reserve due SC	AS	Active	Retired	Replacement Reserve Accepted Bid Quantity	X			4/1/1998	Open
24	Dispatched Replacement Reserve (Bid-In) Capacity Withhold	AS	Active	Retired	Amount of 'bid-in' Replacement Reserve capacity that has been dispatched by ISO	X			8/1/2001	Open
52	Hour Ahead Non-Spinning Reserve due SC	AS	Active	Replaced	Hour Ahead Awarded NonSpinBid Capacity	X			4/1/1998	Open
54	Hour Ahead Replacement Reserve	AS	Active	Retired	Hour-Ahead additional Replacement Reserve accepted Bid Quantity	X			4/1/1998	Open
111	Spinning Reserve due ISO	AS	Active	Replaced	Spinning Reserve Obligation MW	X	X	101	8/18/1999	Open
112	Non-Spinning Reserve due ISO	AS	Active	Replaced	Non-Spinning Reserve Obligation MW	X	X	102	8/18/1999	Open
114	Replacement Reserve due ISO	AS	Active	Retired	Replacement Reserve Obligation	X	X	303	8/18/1999	Open
115	Regulation Up Due ISO	AS	Active	Replaced	Regulation Up Oblig MW	X	X	103	8/18/1999	Open
116	Regulation Down Due ISO	AS	Active	Replaced	Regulation Down Obligation MW	X	X		8/18/1999	Open
124	Dispatched Replacement Reserve (Self-Provided) Capacity Withhold	AS	Active	Retired	Amount of Excess Self-Provided Replacement Reserve capacity that has been dispatched by ISO	X	X		8/1/2001	Open

The charge code identification list also indicates which charge codes are relevant to demand response. Different charge codes are applicable to different resource types. The charge codes relevant to demand response are those allocable to dispatchable participating load and non-participating load, as indicated by an "X" in Figure 4 and in the table under Appendix B-1. A full list of resource types is given below, with the types relevant to demand response shown in italics.

- Generators
- Pump Storage Gen
- *Dispatchable participating load*
- *Non-participating load*
- Import
- Dynamic Import
- Export
- INTER-SC Trade
- Metered Subsystem
- Participating Transmission Owner
- UDC
- FTR/CRR
- Transmission Ownership Rights

Column three of the charge code listing captures the outcome of grouping charge codes by category. This column shows the grouping that each charge code falls under. A full list of charge code categories and their associated abbreviated term is shown below.

- AS - Ancillary Service related charges
- IE - Imbalance energy related charges
- GMC - Grid Management Charges
- BCR - Bid Cost Recovery or Unit Cost Recovery related charges
- CONG - Transmission Congestion related charges
- HVAC - High Voltage Access related charges
- FERC - FERC related fees
- Neutrality –CAISO charges to remain cash neutral
- Uplift - Market Uplift related charges
- RMR - Reliability Must Run related charges
- DRP - Demand Response Program related charges
- Penalty - Interest and Penalty related charges

3.2 Charge Code Sensitivity to Demand Response

Charge codes were also analyzed to identify which ones are most sensitive to demand response. Charge code sensitivity to demand response is expressed as high (H), medium (M), or low (L) sensitivity in the example shown in Figure 5. Ranking by sensitivity was based on settlement expert opinion from analyses of formulations for each charge code investigated. For example, charge codes that are calculated in proportion to metered load (e.g., based on load ratio share) are ranked with high sensitivity to demand response. Medium sensitivity rank applies to charge codes with additional factors that lessen the impact of demand response on resulting settlement charge computations. On the other hand, charge codes that lack billable quantities based on metered load are ranked with low sensitivity (e.g., fixed fee charges). Full results are shown under the “Sensitivity to DR” column in the charge code table under Appendix B-1.

Figure 5: Example ranking of charge codes by sensitivity to demand response

Pre-MRTU Charge Code Number	Pre-MRTU Charge Code Name	Group	Pre-MRTU Status	MRTU Status	Billable Quantity	Sensitivity to DR	Dispatchable-Participating Load	Non-Dispatchable / Non-Participating LOAD	Prior Charge Code	Start	End
2	Day Ahead Non-Spinning Reserve due SC	AS	Active	Replaced	Day Ahead Non Spin Capacity Awarded	M	X			4/1/1998	Open
4	Day Ahead Replacement Reserve due SC	AS	Active	Retired	Replacement Reserve Accepted Bid Quantity	M	X			4/1/1998	Open
7	Demand Relief Monthly Capacity Payment	DR	InActive	Retired	Commited Capacity for the participation in the Demand Relief Program	M	X	X		6/15/2002	10/15/2001
24	Dispatched Replacement Reserve (Bid-In) Capacity Withhold	AS	Active	Retired	Amount of 'bid-in' Replacement Reserve capacity that has been dispatched by ISO	M	X			8/1/2001	Open
52	Hour Ahead Non-Spinning Reserve due SC	AS	Active	Replaced	Hour Ahead Awarded NonSpinBid Capacity	M	X			4/1/1998	Open
54	Hour Ahead Replacement Reserve	AS	Active	Retired	Hour-Ahead additional Replacement Reserve accepted Bid Quantity	M	X			4/1/1998	Open
111	Spinning Reserve due ISO	AS	Active	Replaced	Spinning Reserve Obligation MW	H	X	X	101	8/18/1999	Open
112	Non-Spinning Reserve due ISO	AS	Active	Replaced	Non-Spinning Reserve Obligation MW	H	X	X	102	8/18/1999	Open
114	Replacement Reserve due ISO	AS	Active	Retired	Replacement Reserve Obligation	H	X	X	303	8/18/1999	Open
115	Regulation Up Due ISO	AS	Active	Replaced	Regulation Up Oblig MW	H	X	X	103	8/18/1999	Open
116	Regulation Down Due ISO	AS	Active	Replaced	Regulation Down Obligation MW	H	X	X		8/18/1999	Open
124	Dispatched Replacement Reserve (Self-Provided) Capacity Withhold	AS	Active	Retired	Amount of Excess Self-Provided Replacement Reserve capacity that has been dispatched by ISO	H	X	X		8/1/2001	Open

3.3 Charge Code Significance on Settlements

Settlement data aggregation and analyses was performed to determine the significance of individual charge codes on settlements. Available data from one settlement system was initially aggregated in a pre-specified format for analyses. A data request was also submitted to the CAISO to obtain aggregated settlement data, in order to develop a California-wide perspective on charges. A significant amount of data was analyzed under this task of the project after establishing technical feasibility with the CAISO. This task required first partitioning Scheduling Coordinators (SC) by identification number into one of four bins (i.e., retail, generation, trader, and other). Data was then aggregated to produce a California-wide perspective of aggregated settlement charges for scheduling coordinators that schedule load. Monthly aggregated results were analyzed for the period of January 2006 through June 2008, which represents the time period for which data was available during the time of investigation.

Charge codes were then ranked by significance to identify the most hefty charges for market participants that schedule load. The rankings were based on aggregated settlement charges during the period January 2006 through June 2008. Resulting priorities are listed under the "Significance" column in the charge code table under Appendix B-1. The most significant charge codes are ranked as high (H), followed by medium (M), and low (L), depending on the magnitude of total charges to SCs in California that schedule for loads.

3.4 Charge Code Priority Ranking

A priority rank for each charge code was determined based on preliminary rankings and feedback from market participant. Load serving entities were asked to first consider preliminary rankings that resulted from charge code sensitivity and significance analyses. If a charge code ranked high in terms of both sensitivity to DR and significance on settlements, then it automatically received the highest preliminary rank of 1. The overall scoring system used to develop preliminary priority rankings is shown below.

Sensitivity	Significance	Priority Rank
H	H	1 (highest)
M	H	2
H	M	3
M	M	4
other	other	5 (lowest)

Practical experience of LSEs participating on the project further informed the direction of focus. The preliminary scores were adjusted and finalized based on input received from multiple load serving entities. The charges codes that emerged with the highest priority rankings (i.e., 1 through 3) are listed in Figure 6. The charge code identification number and name is shown along with any updated identification number and name under MRTU. These charge codes were deemed to embody the highest potential impact of demand response on settlements, and were established as priorities for further focus in developing methods to trigger demand response based on impact to settlement charges.

Figure 6: Charge codes with the highest priority rank (2008)

Pre-MRTU Charge Code Number	Pre-MRTU Charge Code Name	MRTU Charge Code Number	MRTU Charge Code Name	Priority
2	Day Ahead Non-Spinning Reserve due SC	6200	Day Ahead Non Spinning Reserve	1
52	Hour Ahead Non-Spinning Reserve due SC	6250	HASP Non-Spinning Reserve	1
111	Spinning Reserve due ISO	6194	Spinning Reserve Obligation Settlement	1
112	Non-Spinning Reserve due ISO	6294	Non-Spinning Reserve Obligation Settlement	1
115	Regulation Up due ISO	6594	Regulation Up Obligation Settlement	1
116	Regulation Down due ISO	6694	Regulation Down Obligation Settlement	1
372	High Voltage Access Charge due ISO	372	High Voltage Access Charge Allocation	2
660	FERC Fee	550	FERC Fee Settlement due Monthly	2
1401	Imbalance Energy Offset	6477	Real Time Imbalance Energy Offset	3
4401	Instructed Energy	6470	Real Time Instructed Imbalance Energy Settlement	1
4406	Unaccounted for Energy	6474	Real Time Unaccounted for Energy Settlement	1
4407	Uninstructed Energy	6475	Real Time Uninstructed Imbalance Energy Settlement	1
4487	Allocation of Excess Cost for Instructed Energy	6486	Real Time Excess Cost for Instructed Energy Allocation	3
4501	GMC-Core Reliability Services Non-Coincident Peak	4501	Core Reliability Services – CRS Peak Demand	2
4505	GMC-Energy Transmission Services Net Energy	4505	Energy Transmission Services – Net Energy	2
4534	GMC-Market Usage Ancillary Services	4534	Market Usage – Awarded AS	2

About 75 charge codes out of 183 analyzed at the time of investigation in 2008 were identified as relevant to DR. Out of the 75 charge codes, 16 highest priority charge codes were to continue or be replaced under MRTU.

CHAPTER 4: Demand Response Trigger Methodology Development

4.1 Foundation

This section describes the theoretical foundation for a method developed under the project to trigger demand response in a way that connects retail load to latest wholesale cost conditions. Based on the priorities identified earlier, the project team developed a methodology for determining the impact of demand response on highest priority charges. The methodology applies a basic definition of demand response. Namely, "demand response is a dynamic change in electricity usage coordinated with power system or market conditions" [3]. Therefore, the impact of demand response on any particular settlement charge is the derivative of the charge with respect to demand (or metered load).

To determine the impact of demand response on overall market settlements for any particular SC that schedules load, one would compute the derivative of the sum of settlement charges allocable to the SC with respect to the SC's metered load. Since the derivative of a sum is equal to the sum of the derivatives (as in Equation 1), it follows that the impact of demand response on an SC's settlements can be computed as the sum of demand response impacts on each charge code allocable to the SC.

Utilizing a top-down approach to direct further project focus, the project team proceeded according to the priorities identified in the previous project task. That is, the team derived analytical formulations for computing the derivatives of highest priority charge codes that received a ranking of 1. As indicated in Figure 6, these highest priority charge codes include Ancillary Service related charge codes (e.g., Charge Code 2, 52, 111, 112, 115, 116, and 4534) and Imbalance Energy charge codes (e.g., Charge Code 4401, 4406, and 4407). The remainder of this section summarizes the resulting derived formulations.

The basic principle from Calculus shown in Equation 1 is applied in subsequent derivations. In words, the equation states that the derivative of a sum of charges, denoted by C_i and expressed as a function of metered load L, is equal to sum of the derivatives with respect to metered load L.

Equation 1: The derivative of a sum of is the sum of the derivatives

$$\frac{\partial\left(\sum_i C_i(L)\right)}{\partial L} = \sum_i \frac{\partial C_i(L)}{\partial L}$$

4.2 Analytical Derivations

Analytical derivations for ancillary service charge codes are given next. The formulas identified below can be used to compute "a change in charge due to a change in metered load" for the charge codes specified. These formulas were derived through careful analyses and domain expert knowledge of the operations and settlements process of the California electricity markets. The derivations were distributed to personnel on the wholesale side of participant organizations for a second opinion as well. Results are summarized below.

The impact of demand response on Ancillary Service charges, as a collective category of charges, can be computed as follows.

Let $Charge_{ASGroup} = Charge_{Spin} + Charge_{NSpin} + Charge_{RegUp} + Charge_{RegDown} + Charge_{GMCMktUsageAS}$.

Then

$$\frac{\Delta Charge_{ASGroup}}{\Delta Load} = \frac{\Delta Charge_{Spin}}{\Delta Load} + \frac{\Delta Charge_{NSpin}}{\Delta Load} + \frac{\Delta Charge_{RegUp}}{\Delta Load} + \frac{\Delta Charge_{RegDown}}{\Delta Load} + \frac{\Delta Charge_{GMCMktUsageAS}}{\Delta Load}.$$

Since $\dfrac{\partial\left(\sum_i C_i(L)\right)}{\partial L} = \sum_i \dfrac{\partial C_i(L)}{\partial L}$ "The derivative of a sum is the sum of the derivatives"

That is, the impact of demand response on each Ancillary Service charge is first computed taking derivatives. The results are then summed. The resulting analytical formulations for approximating the derivative of each Ancillary Service charge code are shown below for Charge Codes 111, 112, 115, 116, and 4534. Assumptions that were made to simplify the derivative computations are also listed. Detailed step-by-step derivations are provided in the Appendix of this report.

The formulations below were derived before the California market transitioned under Market Redesign and Technology Upgrade (MRTU) in April 2009. They are provided here as examples of applying the DR trigger methodology to determine the impact of triggering demand response based on Ancillary Service charges. Additional formulations have been subsequently derived for charge codes that have come into effect under MRTU, in order to support proof-of-concept development stages of the project.

Equation 2: Derivation for Charge Code 111 ("Spinning Reserve due ISO")

$$\frac{\Delta Charge_{111}}{\Delta Load} \approx \frac{SpinRate * \left(SpinReqDA + SpinReqHA + TotalEffSelfProvSpin\right)}{TotalBaseOpReserveReq} * \frac{\Delta BaseOpReserveReq}{\Delta Load}$$

Let $Netload = MeteredLoad + Export - Import$.

If $Netload >= Hydro$, then

$$\frac{\Delta Charge}{\Delta Load} \approx \frac{SpinRate * \left(SpinReqDA + SpinReqHA + TotalEffSelfProvSpin\right)}{TotalBaseOpReserveReq} * 0.07$$

If $Netload < Hydro$, then

$$\frac{\Delta Charge}{\Delta Load} \approx \frac{SpinRate * \left(SpinReqDA + SpinReqHA + TotalEffSelfProvSpin\right)}{TotalBaseOpReserveReq} * 0.05$$

Assumption made in the derivation above include:

1. The following variables assumed to be independent of demand response: *SpinRate, InterSCSpinSold, InterSCSpinBought, EffectiveSelfProvidedSpin, SpinReqHA, SpinReqDA, TotalEffSelfProvSpin*
2. The change in SC's *BaseOpReserveReq* due to a change in its Load is negligible compared to the sum of the BaseOpReserveReq of all other SCs.

Equation 3: Derivation for Charge Code 112 ("Non Spinning Reserve due ISO")

$$\frac{\Delta Charge_{112}}{\Delta Load} \approx \frac{NSpinRate * \left(NSpinReqDA + NSpinReqHA + TotalEffSelfProvNSpin\right)}{TotalBaseOpReserveReq} * \frac{\Delta BaseOpReserveReq}{\Delta Load}$$

Let $Netload = MeteredLoad + Export - Import$.

If $Netload >= Hydro$, then

$$\frac{\Delta Charge}{\Delta Load} \approx \frac{NSpinRate * \left(NSpinReqDA + NSpinReqHA + TotalEffSelfProvNSpin\right)}{TotalBaseOpReserveReq} * 0.07$$

If $Netload < Hydro$, then

$$\frac{\Delta Charge}{\Delta Load} \approx \frac{NSpinRate * \left(NSpinReqDA + NSpinReqHA + TotalEffSelfProvNSpin\right)}{TotalBaseOpReserveReq} * 0.05$$

Assumption made in the derivation above include:

1. The following variables assumed to be independent of demand response: *NSpinRate, InterSCNSpinSold, InterSCNSpinBought, EffectiveSelfProvidedNSpin, NSpinReqHA, NSpinReqDA, TotalEffSelfProvNSpin.*

2. The change in SC's *BaseOpReserveReq* due to a change in its Load is negligible compared to the sum of the BaseOpReserveReq of all other SCs.

Equation 4: Derivation for Charge Code 115 ("Regulation Up due ISO") and Charge Code 116 ("Regulation Down due ISO")

$$\frac{\Delta Charge_{115}}{\Delta Load} \approx \frac{RegUpRate*\left(RegUpReqDA + RegUpReqHA + TotalEffSelfProvRegUp\right)}{TotalLoad}$$

$$\frac{\Delta Charge_{116}}{\Delta Load} \approx \frac{RegDownRate*\left(RegDownReqDA + RegDownReqHA + TotalEffSelfProvRegDown\right)}{TotalLoad}$$

where $Rate_{product} = \frac{\left(PayTotalDA_{product} + PayTotalHA_{product}\right)}{ReqDA_{product} + ReqHA_{product}}$

The above derivation assumes that the following variables are independent of demand response:

1. For 115, they are: *RegUpRate, EffectiveSelfProvidedRegUp, RegUpReqDA, RegUpReqHA, TotalEffSelfProvRegUp*.

2. For 116, they are: *RegDownRate, EffectiveSelfProvidedRegDown, RegDownReqDA, RegDownReqHA, TotalEffSelfProvRegDown*.

Equation 5: Derivation for Charge Code 4534 ("GMC Ancillary Service Market Usage")

Let $TotalReq_{product} = ReqDA_{product} + ReqHA_{product} + TotalEffSelfProv_{product}$.

$$\frac{\Delta Charge_{4534}}{\Delta Load} \approx MarketUsageASRate*\left\{\frac{\Delta BaseOpReserveReq}{\Delta Load}*\frac{\left(TotalReq_{Spin} + TotalReq_{NSpin}\right)}{TotalBaseOpReserveReq} + \frac{\left(TotalReq_{RegUp} + TotalReq_{RegDown}\right)}{TotalLoad}\right\}$$

If $Netload >= Hydro$, then

$$\frac{\Delta Charge_{4534}}{\Delta Load} \approx MarketUsageASRate*\left\{0.07*\frac{\left(TotalReq_{Spin} + TotalReq_{NSpin}\right)}{TotalBaseOpReserveReq} + \frac{\left(TotalReq_{RegUp} + TotalReq_{RegDown}\right)}{TotalLoad}\right\}$$

If $Netload < Hydro$, then

$$\frac{\Delta Charge_{4534}}{\Delta Load} \approx MarketUsageASRate*\left\{0.05*\frac{\left(TotalReq_{Spin} + TotalReq_{NSpin}\right)}{TotalBaseOpReserveReq} + \frac{\left(TotalReq_{RegUp} + TotalReq_{RegDown}\right)}{TotalLoad}\right\}$$

Assumptions used in the derivation above include:

1. The same assumptions used in the derivations for Charge Codes 111,112,115,116.
2. Billable Quantities for Spin, NonSpin, RegUp, RegDown are all non-negative.

Equation 6: Derivation for Charge Code 4407 ("Uninstructed Energy")

$$\frac{\Delta Charge_{4407}}{\Delta Load} = -P_{ex-post}$$

For this derivation, the variables assumed to be independent of demand response included: *Hour-Ahead Schedules (S), Instructed Imbalance Energy (IIE), Instructed Imbalance Regulation Energy, Total Instructed Imbalance Energy, 5-min Zonal Price, Resource Specific Price,* and *Zonal Ex-Post Price*.

4.3 Summary of Demand Response Trigger Method

The charge codes of interest are the ones most sensitive to demand response and most significant on settlements. Having reviewed results of the settlement and data analyses conducted, market participants informing the project identified Imbalance Energy charges and Ancillary Service charges as the highest priority categories of charges for further investigation under Phase 1 of the project. This section summarizes the methodology developed for triggering based on imbalance energy charges (e.g., Charge Code 4407) and Ancillary Service charges (i.e., Charge Codes 111, 112, 115, 116, 4534).

Although Charge Codes 4401, 2, and 52 also fall under the highest priority categories, the project team decided to not include them in developing a trigger method, given that these charge codes are used to account for revenue sources to market participants. Since these charge codes account for revenues "due SC", they rely on other factors like bidding strategy of market participants, which was decided not the focus under Phase 1. Rather, the team focused on actual charges that can be avoided through demand response coordinated with system or market conditions.

After determining the highest priority charge codes to develop a trigger methodology for, the project team then considered availability of information sources required as inputs to the derivative calculations. Input data available in operational timeframes was also assessed and identified in order to support operational decision-making. The resulting demand response trigger methodology is summarized in algorithm form below, using the highest priority charge code categories as examples.

<u>Triggering based on Ancillary Service Charges</u>

1. Understand settlement charge formula for each priority Ancillary Service charge code

- Express billable quantity and rate as a function of load. That is, Charge = Rate(Load) * BillableQuantity(Load).

2. Take derivative of charge formula with respect to load
   - Derive equation to compute a change in charge with respect to a change in load
   - Identify assumptions
3. Determine which input data are available in operational timeframes to market participants
   - Timeframe available (operational timeframe desired)
   - Source of input data (systems)
4. Estimate data not available in operational timeframes
   - Historical data (e.g., from settlements or other input sources)
   - Fixed fees/prices by FERC/CAISO
   - Consider constancy of input data for accuracy
5. Compute change in charge for change in load for CC111, 112, 115, 116, 4534 (due ISO)
   - Sum results for group of charges
6. Refine method by considering
   - Demand response participation as NonSpin Load based on impact to CC 2, 52 (due SC)
   - Potential of tool (size of program participation, limitations on triggering

<u>Triggering based on Imbalance Energy Charges</u>

1. Understand settlement charge formula for each priority Imbalance charge code
   - Express billable quantity and rate as a function of load. That is, Charge = Rate(Load) * BillableQuantity(Load).
2. Take derivative of charge formula with respect to load
   - Derive equation to compute a change in charge with respect to a change in load
   - Identify assumptions
   - Transform discontinuous charge equations to continuous equations by identifying various options
3. Determine which input data are available in operational timeframes to market participants
   - Timeframe available (operational timeframe desired)
   - Source of input data (systems)
4. Estimate data not available in operational timeframes
   - Historical data (e.g., from settlements or other input sources)

- Fixed fees/prices by FERC/CAISO

- Consider constancy of input data for accuracy

5. Compute change in charge for change in load for CC4407, 6475 (under MRTU)
    - Sum results for group of charges

6. Refine method by considering
    - Demand response participation based on impact to CC 4401 (due SC)

    - Potential of tool (size of program participation, limitations on triggering

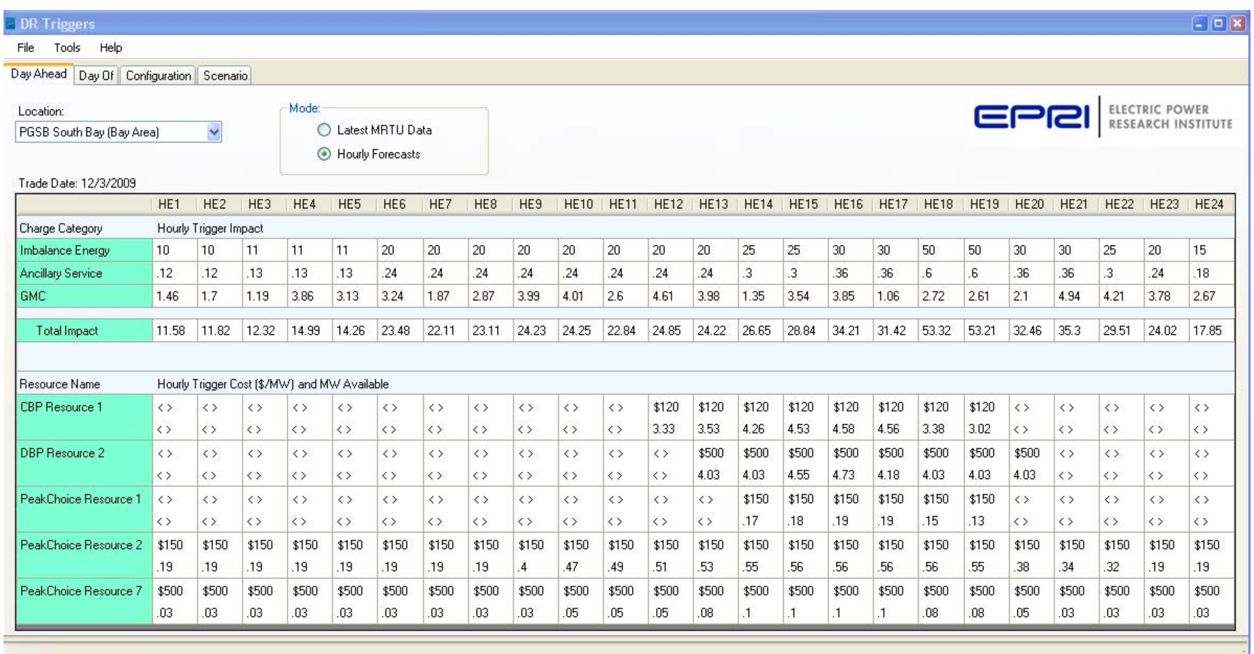
CHAPTER 5: Information Technology Specification

5.1 Day-Ahead and Day-of Functions beyond Status Quo

The target users of the decision support tool are short-term procurement personnel from day-ahead and day-of trading desks. The new functionality provided by the specified tool is the capability of computing demand response Trigger Impact by charge category. This type of information is illustrated in the upper half of the Day-ahead and Day-of screens in Figure 7 and Figure 8, respectively.

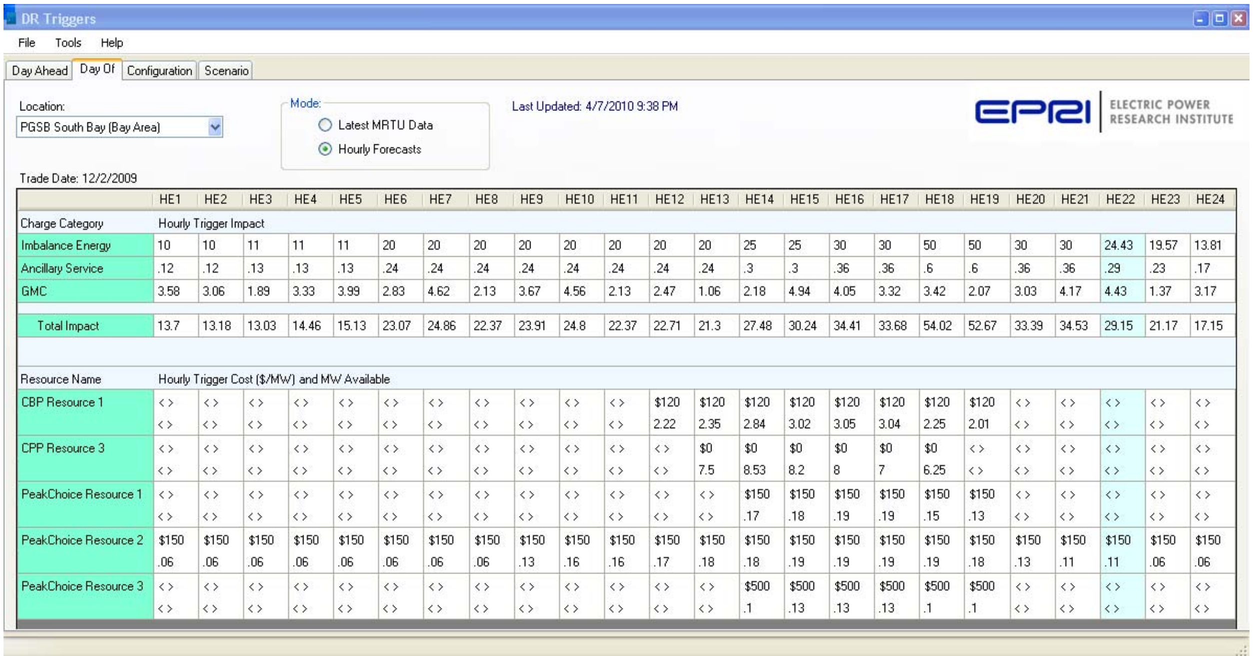
Currently, market participants consider market price (i.e., supply alternatives from bilateral counterparties or the ISO) weighed against demand response program resource costs. That is, the target user currently has DR program cost and MW availability information, as shown on the bottom half of the DA and Day-of screens as an example. Beyond current capabilities, the DR Trigger System Decision Support tool enables short-term procurement personnel to compare the DR Program Resource Costs with the impact of triggering each MW of demand response on wholesale settlements for the analyzed charge categories. In order words, the user is empowered for the first time with information on charges that can be reduced on wholesale settlements from "self-supply" of procurement short-falls (below daily demand forecasts) using demand response resources. The combination of being equipped with Trigger Impact information plus the ability to compare against DR Program Resource Costs provides new information to the user in support of day-ahead and day-of decision-making for triggering demand response. The Day-ahead and Day-of screens illustrate types of information that can be provided to support decision-making based on which resources, how much, and when to trigger them.

Figure 7: Day-ahead screen



	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category	Hourly Trigger Impact																							
Imbalance Energy	10	10	11	11	11	20	20	20	20	20	20	20	20	25	25	30	30	50	50	30	30	25	20	15
Ancillary Service	.12	.12	.13	.13	.13	.24	.24	.24	.24	.24	.24	.24	.24	.3	.3	.36	.36	.6	.6	.36	.36	.3	.24	.18
GMC	1.46	1.7	1.19	3.86	3.13	3.24	1.87	2.87	3.99	4.01	2.6	4.61	3.98	1.35	3.54	3.85	1.06	2.72	2.61	2.1	4.94	4.21	3.78	2.67
Total Impact	11.58	11.82	12.32	14.99	14.26	23.48	22.11	23.11	24.23	24.25	22.84	24.85	24.22	26.65	28.84	34.21	31.42	53.32	53.21	32.46	35.3	29.51	24.02	17.85
Resource Name	Hourly Trigger Cost ($/MW) and MW Available																							
CBP Resource 1	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$120 3.33	$120 3.53	$120 4.26	$120 4.53	$120 4.58	$120 4.56	$120 3.38	$120 3.02	< > < >	< > < >	< > < >	< > < >	< > < >
DBP Resource 2	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$500 4.03	$500 4.03	$500 4.55	$500 4.73	$500 4.18	$500 4.03	$500 4.03	$500 4.03	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 1	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$150 .17	$150 .18	$150 .19	$150 .19	$150 .15	$150 .13	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 2	$150 .19	$150 .19	$150 .19	$150 .19	$150 .19	$150 .19	$150 .19	$150 .19	$150 .4	$150 .47	$150 .49	$150 .51	$150 .53	$150 .55	$150 .56	$150 .56	$150 .56	$150 .56	$150 .55	$150 .38	$150 .34	$150 .32	$150 .19	$150 .19
PeakChoice Resource 7	$500 .03	$500 .03	$500 .03	$500 .03	$500 .03	$500 .03	$500 .03	$500 .03	$500 .03	$500 .05	$500 .05	$500 .05	$500 .08	$500 .1	$500 .1	$500 .1	$500 .1	$500 .08	$500 .08	$500 .05	$500 .03	$500 .03	$500 .03	$500 .03

Figure 8: Day-of screen



	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category	Hourly Trigger Impact																							
Imbalance Energy	10	10	11	11	11	20	20	20	20	20	20	20	20	25	25	30	30	50	50	30	30	24.43	19.57	13.81
Ancillary Service	.12	.12	.13	.13	.13	.24	.24	.24	.24	.24	.24	.24	.24	.3	.3	.36	.36	.6	.6	.36	.36	.29	.23	.17
GMC	3.58	3.06	1.89	3.33	3.99	2.83	4.62	2.13	3.67	4.56	2.13	2.47	1.06	2.18	4.94	4.05	3.32	3.42	2.07	3.03	4.17	4.43	1.37	3.17
Total Impact	13.7	13.18	13.03	14.46	15.13	23.07	24.86	22.37	23.91	24.8	22.37	22.71	21.3	27.48	30.24	34.41	33.68	54.02	52.67	33.39	34.53	29.15	21.17	17.15
Resource Name	Hourly Trigger Cost ($/MW) and MW Available																							
CBP Resource 1	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	$120	$120	$120	$120	$120	$120	$120	$120	< >	< >	< >	< >	< >
	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	2.22	2.35	2.84	3.02	3.05	3.04	2.25	2.01	< >	< >	< >	< >	< >
CPP Resource 3	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	$0	$0	$0	$0	$0	$0	< >	< >	< >	< >	< >	< >
	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	7.5	8.53	8.2	8	7	6.25	< >	< >	< >	< >	< >	< >
PeakChoice Resource 1	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	$150	$150	$150	$150	$150	$150	< >	< >	< >	< >	< >
	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	.17	.18	.19	.19	.15	.13	< >	< >	< >	< >	< >
PeakChoice Resource 2	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
	.06	.06	.06	.06	.06	.06	.06	.06	.13	.16	.16	.17	.18	.18	.19	.19	.19	.19	.18	.13	.11	.11	.06	.06
PeakChoice Resource 3	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	$500	$500	$500	$500	$500	$500	< >	< >	< >	< >	< >
	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	.1	.13	.13	.13	.1	.1	< >	< >	< >	< >	< >

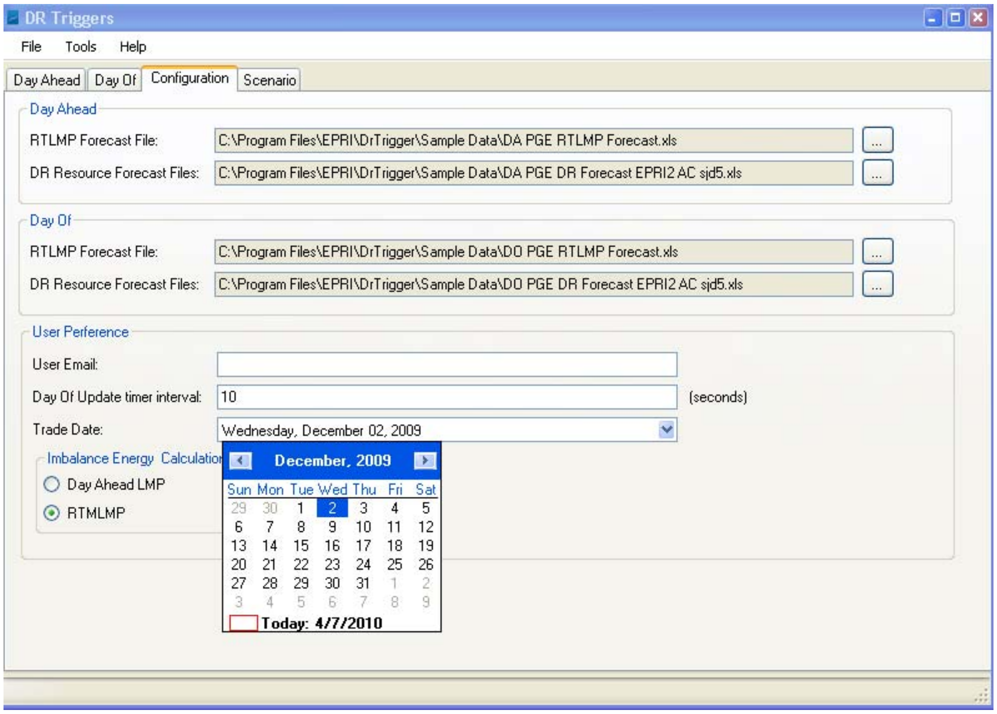
5.2 Configurable Settings

The Configuration screen supports user selection of input data utilized on the Day-ahead and Day-of screens. Real-time locational marginal price (i.e., RTLMP) forecasts and DR program costs for triggering each DR Resource are contained in data files specified by the user on this screen. Resources available day-ahead may vary from resources available day-of. Likewise day-ahead price forecasts can vary from day-of forecasts. Therefore, separate data sources can be specified on this screen as input data for the Day-ahead and Day-of screens, respectively. In the initial specification the data sources were assumed to spreadsheet files, with configurable filenames and directory paths as shown on the top half of Figure 9.

User configurable preferences also include identification of the current user's email addresses (e.g., for tracking the identity of the last user to adjust configuration settings) and trade date of interest. Upon application start-up, the default trade date is the current system date. However, the user may select an alternate trade date from the calendar option shown Figure 9 on the Configuration screen. This feature is useful for viewing historical trigger impact and program cost information using the specified tool.

To support live demonstration, the specified tool also includes a user-configurable update time interval. This setting controls the frequency of update when viewing the Day-of screen, so that the program can be sped up to facilitate live demonstration. That is, the user entry for update time interval is taken as the number of seconds of actual time that passes before the proof-of-concept prototype refreshes the Day-of screen to simulate an hour of demonstration time.

Figure 9: Configuration screen



5.3 What-if Analyses

The What-if screen supports decision-making through user definition and comparison of distinct scenarios. What-if calculations consider DR program incentive costs versus market price for resources procured through bilateral or ISO market alternatives, given the trigger impact for user-selected DA or Day-of timeframes.

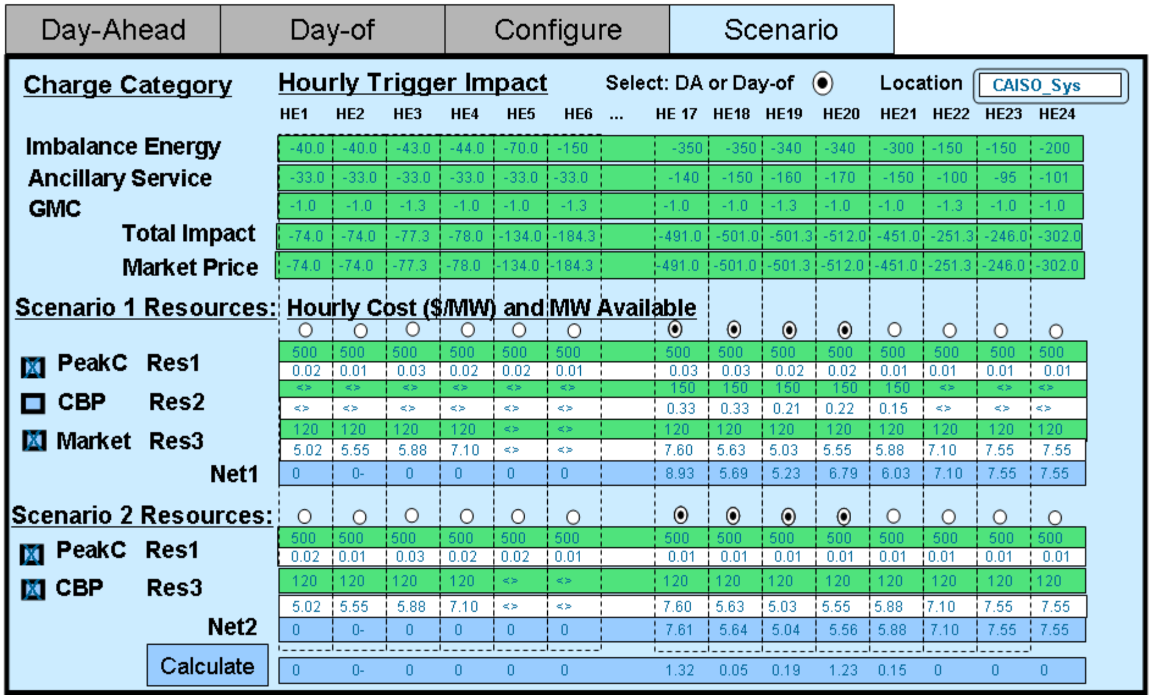
The location option in the upper right hand corner of the screen allows selection of the location of resources that will show on the screen. This option determines the location for the Hourly Trigger Impact calculations as well.

As illustrated on the lower half of Figure 10, the What-if screen allows the user to define multiple scenarios. The user selects the name of resources to consider under each scenario and the MW quantity of each resource. The user clicks on the option “Calculate” to compute and show Net results for each user-defined resource scenario. The difference between Net results of the two defined scenarios is computed and shown on the last row on the screen, for comparison purposes. The Net calculation includes the hour-ending intervals with radio buttons clicked for the resources that are checked by the user. The tool can compute the Net for each hour-ending interval as:

Net = SumoverselectedDRResources{(TotalImpact+DRProgramCost)*MW_DRResource}

+ SumoverselectedMarketResources{(MarketPrice*MW_MktResource)}

Figure 10: What-if analysis



Further details on the requirements specified for the Demand Response Trigger decision support tool are given in Appendix B-3 of this report. The requirements were gathered through a series of conference calls and meetings with market participants during the summer of 2009. Initial screen designs are included in the Appendix with further details on how the graphical user interfaces and tool should behave.

CHAPTER 6: Potential Benefits

The trigger method developed was applied against historical data to assess potential benefits of triggering based on impact to Ancillary Service and Imbalance Energy charges. Potential benefits were assessed using historical data based on the trigger impact equations derived in Section 4.

6.1 Potential Impact on Ancillary Service Charges

The investigation commenced with analysis of the impact of triggering demand response based on Ancillary Service charges during the top intervals of the period of interest. The period analyzed was from January 1, 2008 through November 30, 2008. Top intervals during this period are the hourly intervals for which demand response is determined to have the greatest charge savings.

Figure 11 lists values (in red) for the trigger impact resulting from the derivative calculations using historical data. The figure also lists the factors and components (shown in black numbers) that comprise the trigger impact calculations. Each row shows components and resulting calculations for a one-hour interval on a specified date during the period of analyses.

Figure 11: Hourly potential benefit calculations for triggering based on ancillary service charges (1/1/08-11/30/08)

Date	Hour	Delta_RegDown_Charge / Delta_Load	(RegUpReq+TotSelfProv)/TotLoad	Delta_RegUp_Charge / Delta_Load	(SpinReq+TotSelfProv)/TotBaseOpResReq	Delta_Spin_Charge / Delta_Load	(NspinReq+TotSelfProv)/TotBaseOpResReq	Delta_NonSpin_Charge / Delta_Load	Factor	Delta_CC4534_Charge / Detla_Load	Delta_AS_ChargeGroup / Delta_Load	Top 24 Interval?	Value of Trigger (during Top 24 Intervals)
11/29/2008	9	0.0161141	0.01842748	0.2029347	0.499996724	0.1359373	0.499997	0.043107	0.07	0.06415398	0.462247617		
11/29/2008	10	0.0223867	0.0159364	0.1289674	0.49999364	0.1264277	0.499994	0.047099	0.07	0.06398327	0.388863739		
11/29/2008	11	0.0243477	0.01600547	0.2162329	0.5	0.0688265	0.5	0.045584	0.07	0.06400516	0.418996277		
11/29/2008	12	0.0225561	0.01510108	0.1867445	0.499993693	0.0874563	0.499994	0.044751	0.07	0.06393366	0.405441715		
11/29/2008	13	0.013915	0.01537605	0.1902084	0.5	0.073834	0.5	0.047107	0.07	0.06395566	0.389019734		
11/29/2008	14	0.015273	0.01619876	0.2188293	0.500006376	0.0670259	0.500006	0.047737	0.07	0.0640236	0.412888523		
11/29/2008	15	0.0185965	0.01585847	0.1961673	0.500003209	0.0687013	0.500003	0.0462	0.07	0.06399026	0.393655761		
11/29/2008	16	0.024604	0.0157945	0.1953655	0.499993612	0.0687622	0.499994	0.045359	0.07	0.06399006	0.398081005		
11/29/2008	17	0.0180779	0.01420142	0.1756979	0.500002887	0.073109	0.500003	0.051021	0.07	0.06388138	0.381787465		
11/29/2008	18	0.0080859	0.01438266	0.4162167	0.499997131	0.3232901	0.499997	0.051828	0.07	0.06382445	0.863244693		
11/29/2008	19	0.0081658	0.0141992	0.3749168	0.499994157	0.3307369	0.499994	0.051347	0.07	0.06381351	0.828980204		
11/29/2008	20	0.0086262	0.01731128	0.3371634	0.5	0.0954718	0.5	0.051167	0.07	0.06401522	0.556443228		
11/29/2008	21	0.026365	0.01416703	0.3167917	0.500003265	0.2898097	0.500003	0.049983	0.07	0.06390814	0.746857835		
11/29/2008	22	0.0601742	0.0158289	0.5144441	0.500006748	0.2744363	0.500007	0.048585	0.07	0.06409938	0.961738551		
11/29/2008	23	0.0215956	0.01556682	0.3915481	0.499996546	0.2971299	0.499997	0.049981	0.07	0.06407699	0.824331242		
11/29/2008	24	0.0528538	0.01686871	0.3543364	0.500003661	0.0829144	0.500004	0.03756	0.07	0.06420038	0.591864811		0
11/30/2008	1	0.0173174	0.01814851	0.2929192	0.5	0.0732441	0.5	0.028727	0.07	0.06406149	0.476269298		0
11/30/2008	2	0.0184223	0.01860145	0.3002541	0.5	0.0275087	0.5	0.027982	0.07	0.06408877	0.438255453		0
11/30/2008	3	0.0231514	0.01863784	0.3007715	0.5	0.0275823	0.5	0.027953	0.07	0.06409466	0.443552517		0
11/30/2008	4	0.0289464	0.01860963	0.3002646	0.5	0.0275943	0.5	0.027952	0.07	0.06411914	0.448876931		0
11/30/2008	5	0.0286196	0.01841132	0.2971728	0.500007604	0.0275284	0.500008	0.028035	0.07	0.06410611	0.445461699		0
11/30/2008	6	0.0243934	0.0178338	0.2878573	0.499996344	0.0276945	0.499996	0.02819	0.07	0.06408334	0.432218738		0
11/30/2008	7	0.0401997	0.01929217	0.4543499	0.49999635	0.2737025	0.499996	0.036176	0.07	0.06420474	0.868633125		0
11/30/2008	8	0.0687394	0.01738759	0.2151141	0.499989471	0.0732315	0.499989	0.036112	0.07	0.06421992	0.457416615		0
11/30/2008	9	0.0460403	0.01633918	0.2697519	0.5	0.0730557	0.5	0.04266	0.07	0.06405478	0.49556307		0
11/30/2008	10	0.0285098	0.01584338	0.2991313	0.499996777	0.0715785	0.499997	0.044345	0.07	0.06394406	0.507509121		0
11/30/2008	11	0.0445404	0.01591222	0.3799558	0.499996816	0.0698725	0.499997	0.046341	0.07	0.06401083	0.604720537		0
11/30/2008	12	0.0595576	0.01527507	0.4417376	0.499996845	0.0728219	0.499997	0.046939	0.07	0.06400436	0.685060122		0
11/30/2008	13	0.0568312	0.01488242	0.4461265	0.499996847	0.0742054	0.499997	0.047466	0.07	0.06400261	0.688631832		0
11/30/2008	14	0.0571641	0.01487505	0.4494084	0.5	0.0742215	0.5	0.04796	0.07	0.06400252	0.692755995		0
11/30/2008	15	0.074458	0.0148763	0.3375215	0.500003211	0.0742101	0.500003	0.048311	0.07	0.06404029	0.598541121		0
11/30/2008	16	0.0475144	0.01477266	0.3368189	0.499996835	0.0741975	0.499997	0.048679	0.07	0.06402567	0.571235613		0
11/30/2008	17	0.0327491	0.01760865	0.2440432	0.499997084	0.2084063	0.499997	0.052347	0.07	0.06412072	0.601666709		0
11/30/2008	18	0.0066153	0.01718603	0.3561132	0.499991209	0.2130438	0.499991	0.046019	0.07	0.06395204	0.685742915		0
11/30/2008	19	0.0032526	0.01517627	0.4797026	0.499997045	0.256356	0.499997	0.046021	0.07	0.06380145	0.849134082		0
11/30/2008	20	0.0162344	0.01505155	0.3424057	0.500003006	0.250628	0.500003	0.045357	0.07	0.06385536	0.71848079		0
11/30/2008	21	0.0178264	0.01516274	0.5541564	0.499990831	0.2321718	0.499991	0.053173	0.07	0.06386946	0.921196905		0
11/30/2008	22	0.0106962	0.01438235	0.5276437	0.500003159	0.2621757	0.500003	0.048922	0.07	0.06378262	0.913219834		0
11/30/2008	23	0.0310788	0.01596061	0.3621086	0.499996649	0.0742245	0.499997	0.047553	0.07	0.06396044	0.578925181		0
11/30/2008	24	0.0548768	0.01784529	0.3951278	0.49999633	0.0717247	0.499996	0.046471	0.07	0.06418625	0.632386606		0
													2,155

15.5151525
15.69150878
16.3107934
16.32150501
16.59660689
17.1071083
17.65775665
18.09549313
18.47529603
19.09316355
20.33608731
21.1108606
21.11828318
22.25749953
23.85866343
24.63045605
25.16193539
26.91920874
27.37883259
28.58108561

Results are summarized below and represent the potential benefit of triggering 1 MW of demand response during the highest impact hourly intervals across the eleven month period of analyses.

<u>**Intervals Triggered Avoided Ancillary Service Charge ($/MW)**</u>

317 intervals, each with Trigger Value>$2.5/MW	2155.28
53 intervals, each with Trigger Value >$10/MW	836
37 intervals, each with Trigger Value >$12.5/MW	652.76
24 intervals, each with Trigger Value > $14.75/MW	472.22
All intervals during 11 months (8015 hourly intervals)	7266.81

From the data analyses, 1 MW of demand response (i.e., a change in load) can capture thousands of dollars in avoided Ancillary Service Charges during the top 317 hours of impact for triggering demand response. Potential savings exceed $0.2M for 100 MW of demand response applied during the top 317 intervals during the period January 1, 2008 through November 30, 2008.

The potential benefit from triggering DR to reduce charges in this category is distinct and separate from revenues earned from providing ancillary services. The potential benefit assessed from historical data represents the amount of allocable charge avoided based on reductions in metered load during the high cost intervals. Consequently, these savings are incurred independent of participating loads in ancillary service markets. That is, the potential benefits can be accrued without requiring load to curtail in any ancillary services market as participating load. The benefit is achieved through avoided costs for the capacity portion of operating reserves. Because such charges are allocated as a function of metered load, by reducing the metered load through demand response at targeted intervals, the scheduling coordinator's allocated charges for ancillary services are reduced.

6.2 Potential Impact on Imbalance Energy Charges

The trigger method developed was applied against historical data to assess the potential benefit of triggering demand response based on Imbalance Energy charges. Potential benefits were computed using historical data available across a 13-month period. The investigation computed the impact of triggering demand response based on imbalance energy charges during the top price intervals from January 1, 2008 through January 31, 2009.

Figure 12 lists resulting values for the computed trigger impact under two different scenarios. Under the first scenario (Algorithm 1), demand response is triggered during the top price hours when imbalance energy prices exceed the indicated threshold, shown in the third column of each worksheet in the figure. The second column in each worksheet shows the number of top priced hours for which imbalance energy prices exceed the listed threshold. Under Algorithm 1, demand response is triggered whenever the imbalance energy price exceeds the given price threshold shown under the third column of the first worksheet. In contrast, under Algorithm 2, demand response is only triggered on days for which there are multiple imbalance energy prices exceeding the listed threshold in the third column of the second worksheet. So Algorithm 2 differs from Algorithm 1 in so far as Algorithm 2 precludes triggering demand response on days for which the price threshold is exceeded during only one hourly interval. The latter algorithm restricts triggering demand response to only those days for which high prices exceed the indicated thresholds across multiple hours.

The last column of the worksheets in Figure 12 show resulting values for potential benefits. Results are given for two different locations: North Path 15 (NP15) in Northern California and South Path 15 (SP15) in Southern California. Results indicate that 1MW of demand response can capture $10,000's in avoided imbalance energy charges during peak prices hours (for imbalance energy) on the top two dozen or so days. Potential savings range from about $1.5M for 100 MW of demand response applied under Algorithm 1, to over $2M for 100 MW applied under Algorithm 2 during the period January 1, 2008 through January 31, 2009. Thus for the time period analyzed, potential benefits from triggering based on imbalance energy costs were assessed at an order of magnitude greater than potential benefits from triggering based on ancillary service costs.

Figure 12: Potential benefit of triggering during top priced intervals based on imbalance energy (1/1/08-1/31/09)

Algorithm 1: Trigger DR during top hours
(when imbalance energy prices exceed threshold)

Location	No. of Top Hrs	with Prices Above ($/MWh)	No. Dates top hours occur across	Trigger impact during top hours ($/MW)
NP15	100	244	58	$30,551
NP15	93	250	55	$28,827
NP15	78	260	47	$25,007
NP15	68	270	42	$22,368
NP15	55	280	36	$18,786
NP15	54	290	35	$18,504
NP15	49	300	33	$17,029
NP15	43	310	29	$15,206
SP15	100	235	56	$27,271
SP15	83	250	49	$25,792
SP15	71	260	42	$22,737
SP15	62	270	38	$20,366
SP15	51	280	32	$17,332
SP15	50	290	31	$17,050
SP15	43	300	27	$14,984
SP15	38	310	24	$13,469

Algorithm 2: Trigger DR during top hours
(when imbalance energy prices exceed threshold
but only on days with multiple top hours)

Location	No. Top Hours	with Prices Above ($/MWh)	No. Days with multiple top hours	No. Top Intervals on these days	Trigger Impact during top intervals on these days ($/MW)
NP15	117	230	29	84	$25,557
NP15	93	250	24	60	$19,492
NP15	78	260	20	52	$17,125
SP15	105	230	24	71	$21,683
SP15	83	250	19	[illegible]	$16,902
SP15	71	260	[illegible]	46	$15,211

CHAPTER 7: Proof of Concept Development and Demonstration

7.1 Market Transition

Proof-of-concept development was based on the information technology specified and the trigger methodology developed in previous tasks. The project team prioritized functionality to demonstrate and was ready to commence proof-of-concept prototype development prior to the California Market Redesign and Technology Upgrade (MRTU) go-live date. However, the group decided to postpone proof-of-concept development work, in consideration of the scheduling coordinators on the project team who were heavily focused on preparations required to operate under MRTU at the time. The project schedule was extended as a result to continue well beyond the scheduled MRTU release date. This decision was the best way to ensure the prototype to be developed would function under MRTU and continue running properly for demonstration purposes after the market transition period.

Although the proof-of-concept stage of the project was postponed to accommodate prototype development under MRTU, the charge code analyses and derivative formulations already conducted were based on pre-MRTU charge codes. This situation necessitated an additional effort to compare the analyses conducted under pre-MRTU against MRTU settlement charge codes. Further analyses revealed distinct differences in input data and corresponding information technology systems that the trigger methodology would rely on. Therefore, a substantial effort was expended beyond the original project plan to analyze MRTU charge codes too, in order to derive the impact of demand response on the highest priority charge categories: ancillary services and imbalance energy charges.

7.2 Select Functionality

A limited function proof-of-concept prototype was developed with the functional capabilities summarized below. The capabilities are summarized considering a software development point of view. Implemented functionality included the following:

1. Three graphical user interface (GUI) screens – the prototype was implemented for the first three screens specified in the Requirements Specification document found in Appendix B-3. Basic functionality was implemented for the screens ‘Day-ahead’, ‘Day-of’, and ‘Configuration’, respectively. The ‘Scenario’ screen was not included in the prototype release, due to budget constraints for the prototype effort.

2. The ‘Day-ahead’ and ‘Day-of screens’ compute and display both the Trigger Impact calculations and the Resource Trigger Cost portions of the screens. Together they provide the essential information useful to the market participants. These screens are illustrated in Figure 13 and Figure 15. A drop-down list of locations enables the user to select the location of interest, as illustrated in Figure 14, and to view results by location.

3. The trigger impact based on Ancillary Service charges was computed based on formulas derived for Ancillary Service charge category and the results shown on the ‘Day-Ahead’ and ‘Day-of’ screens.

4. Rendering of trigger impact based on ‘Imbalance Energy’ depends on user’s selection of ‘Mode’.

   a) If the user selects ‘Latest MRTU Data’ on either the ‘Day-ahead’ or ‘Day-of’ screens, then the application will download latest RT LMP data from CAISO MRTU public market information for display (as detailed under the ‘Day-ahead’ and ‘Day-of’ screen specifications in the Appendix B-3).

   b) Alternatively, if the user selects ‘Hourly Forecasts’, then the application will read forecast data from a local spread-sheet and display the corresponding data matching the user-selected trade date and location. The forecast file used in the ‘Day-of’ screen represents day-of RT LMP forecasts and therefore is different from the Day-ahead RT LMP forecast file used in the ‘Day-ahead’ screen. Note: Both files and their locations are user-specified via the ‘Configuration’ screen shown in Figure 16.

5. The rendering of grid management charges (GMC) for both ‘Day-ahead’ and ‘Day-of’ in the proof-of-concept prototype used mocked-up data instead of live data feeds. The mocked up data for GMC is a small value compared to Imbalance Energy and Ancillary Service values shown on the screens under Trigger Impact. The mocked up data was taken as relatively constant between time intervals, to reflect the relatively constant nature of various grid management charges.

6. The rendering of ‘Total Impact’ was taken as the sum of trigger impact values for ‘Imbalance Energy’, ‘Ancillary Service’ and ‘GMC’, respectively, displayed under the same time interval.

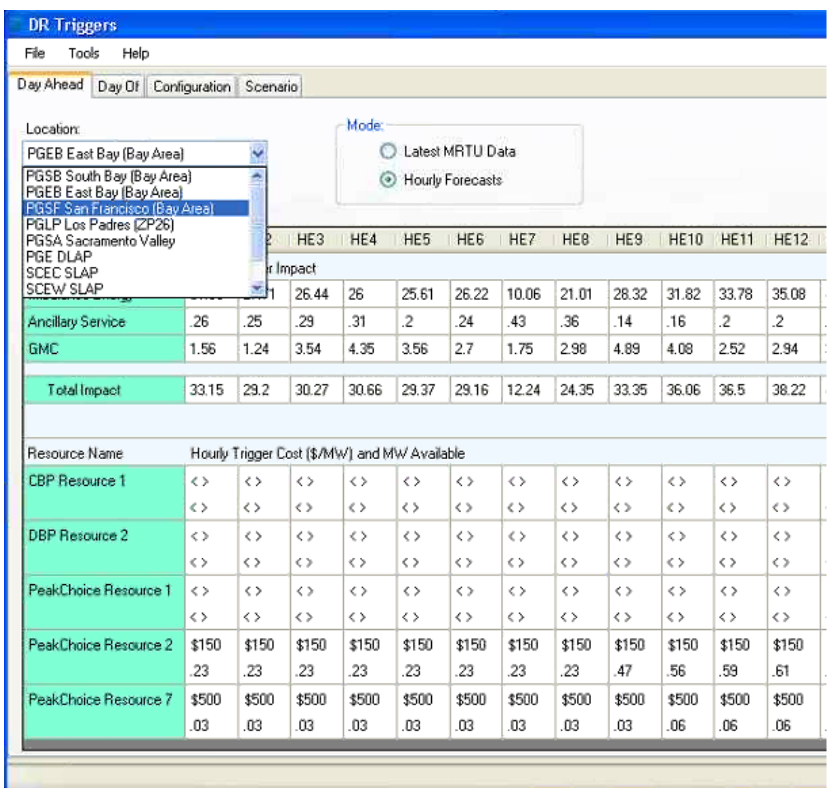
7. Rendering of data under ‘Resource Name’ in both ‘Day-Ahead’ and ‘Day-Of’ was based on the Demand Response Program Cost files for ‘Day-Ahead’ and ‘Day-Of’ program resource costs and MW availability, respectively. Further details on rendering of the Resource Cost section of the screen in given under the “Day Ahead” and “Day-of” screen subsections in Appendix B-3.

8. The ‘Configuration’ screen allows the user to select the trade date associated with the ‘Day-ahead’ and ‘Day-of’ screens. The user may select a historic trade date or return to the current day via a calendar date selection option. User selection of trade date is illustrated in Figure 16.

Figure 13: Day-ahead demonstration screen results on the day of live demonstration (12/2/09)

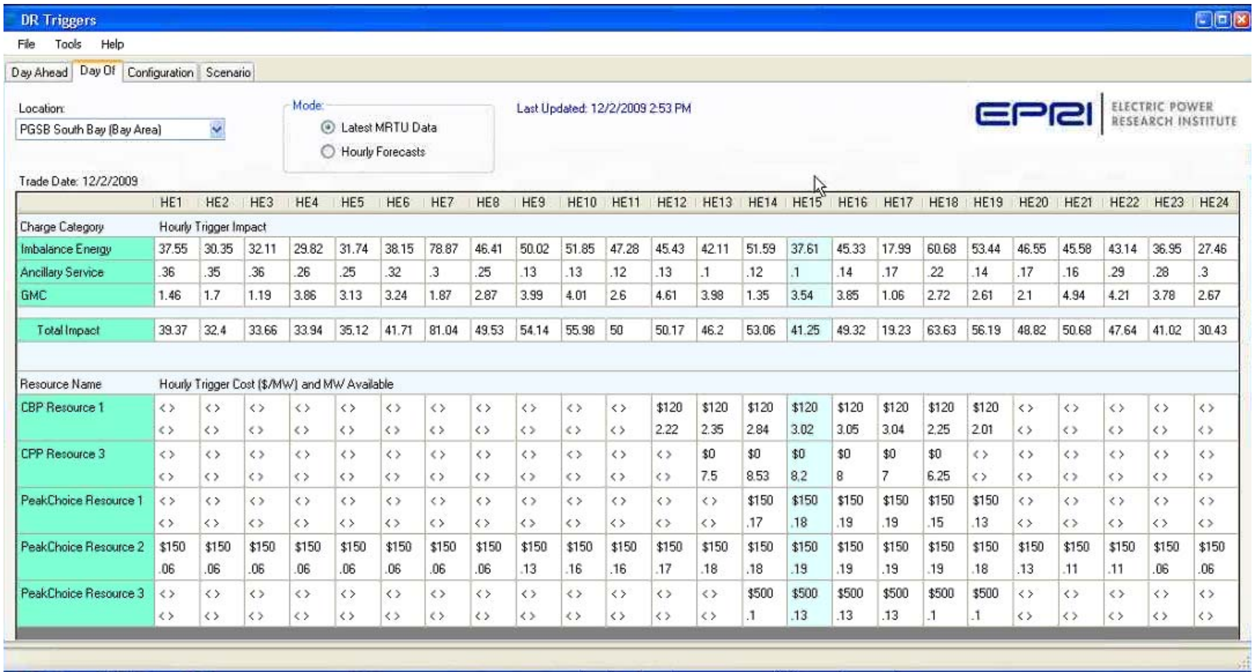
	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category	Hourly Trigger Impact																							
Imbalance Energy	37.3	30.15	31.88	29.62	31.49	37.82	78.12	45.83	49.44	51.31	46.75	44.94	41.92	42.9	38.64	37.01	19.14	60.1	52.93	46.23	45.33	42.86	36.63	27.31
Ancillary Service	.36	.35	.36	.26	.25	.32	.3	.25	.13	.13	.12	.13	.1	.1	.11	.11	.19	.22	.14	.17	.16	.29	.28	.3
GMC	2.87	2.19	3.49	3.59	2.06	2.12	4.32	4.3	3.36	4.94	4.64	1.91	3.78	4.92	1.98	3.14	1.43	5	3.7	1.06	3.3	1.4	1.41	4.2
Total Impact	40.54	32.69	35.74	33.47	33.79	40.26	82.74	50.37	52.93	56.38	51.52	46.97	45.81	47.92	40.72	40.26	20.75	65.32	56.78	47.47	48.79	44.54	38.32	31.8
Resource Name	Hourly Trigger Cost ($/MW) and MW Available																							
CBP Resource 1	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	$120	$120	$120	$120	$120	$120	$120	$120	< >	< >	< >	< >	< >
	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	4	4.23	5.11	5.44	5.49	5.47	4.05	3.62	< >	< >	< >	< >	< >
DBP Resource 2	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	$500	$500	$500	$500	$500	$500	$500	$500	< >	< >	< >	< >
	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	4.83	4.83	5.46	5.67	5.01	4.83	4.83	4.83	< >	< >	< >	< >
PeakChoice Resource 1	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	$150	$150	$150	$150	$150	$150	< >	< >	< >	< >	< >
	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	.2	.21	.23	.23	.18	.15	< >	< >	< >	< >	< >
PeakChoice Resource 2	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
	.23	.23	.23	.23	.23	.23	.23	.23	.47	.56	.59	.61	.63	.65	.68	.68	.68	.68	.65	.45	.41	.38	.23	.23
PeakChoice Resource 7	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
	.03	.03	.03	.03	.03	.03	.03	.03	.03	.06	.06	.06	.09	.12	.12	.12	.12	.09	.09	.06	.03	.03	.03	.03

Figure 14: User selection of location via a pull-down list



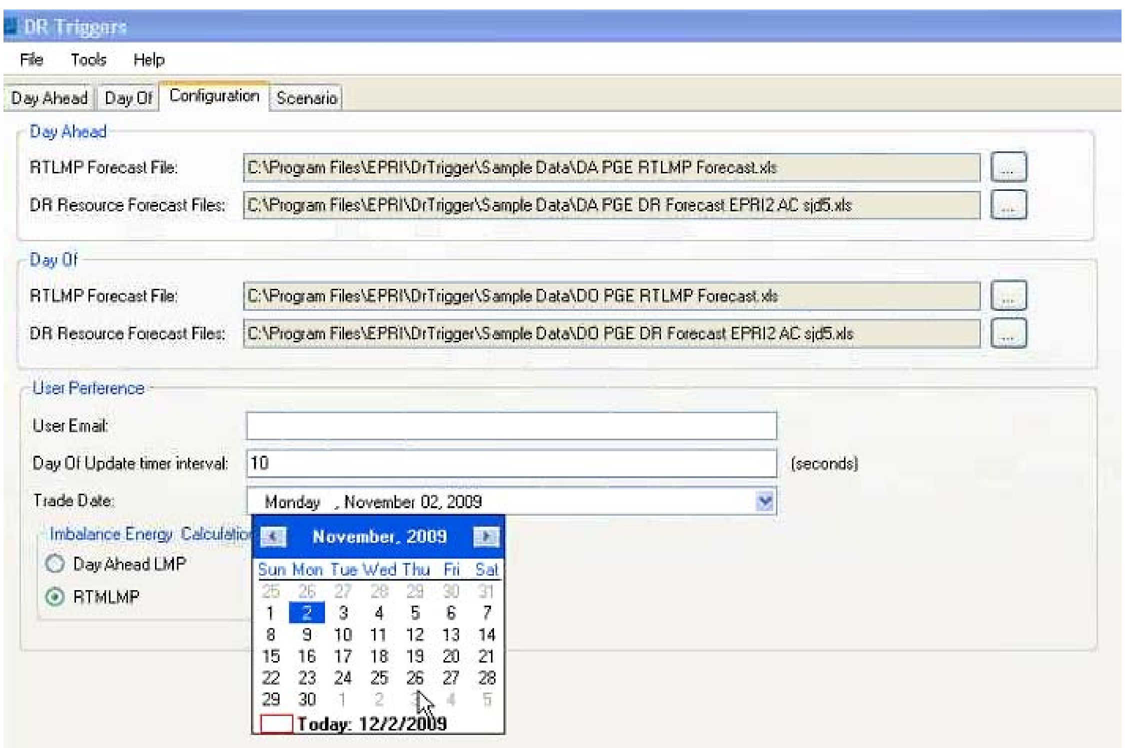
	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12
Charge Category	Hourly Trigger Impact											
Imbalance Energy	[illegible]	[illegible]	26.44	26	25.61	26.22	10.06	21.01	28.32	31.82	33.78	35.08
Ancillary Service	.26	.25	.29	.31	.2	.24	.43	.36	.14	.16	.2	.2
GMC	1.56	1.24	3.54	4.35	3.56	2.7	1.75	2.98	4.89	4.08	2.52	2.94
Total Impact	33.15	29.2	30.27	30.66	29.37	29.16	12.24	24.35	33.35	36.06	36.5	38.22
Resource Name	Hourly Trigger Cost ($/MW) and MW Available											
CBP Resource 1	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >
	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >
DBP Resource 2	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >
	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >
PeakChoice Resource 1	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >
	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >	< >
PeakChoice Resource 2	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
	.23	.23	.23	.23	.23	.23	.23	.23	.47	.56	.59	.61
PeakChoice Resource 7	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
	.03	.03	.03	.03	.03	.03	.03	.03	.03	.06	.06	.06

Figure 15: Day-of demonstration screen results on day of live demonstration (12/2/09)



	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category	Hourly Trigger Impact																							
Imbalance Energy	37.55	30.35	32.11	29.82	31.74	38.15	78.87	46.41	50.02	51.85	47.28	45.43	42.11	51.59	37.61	45.33	17.99	60.68	53.44	46.55	45.58	43.14	36.95	27.46
Ancillary Service	.36	.35	.36	.26	.25	.32	.3	.25	.13	.13	.12	.13	.1	.12	.1	.14	.17	.22	.14	.17	.16	.29	.28	.3
GMC	1.46	1.7	1.19	3.86	3.13	3.24	1.87	2.87	3.99	4.01	2.6	4.61	3.98	1.35	3.54	3.85	1.06	2.72	2.61	2.1	4.94	4.21	3.78	2.67
Total Impact	39.37	32.4	33.66	33.94	35.12	41.71	81.04	49.53	54.14	55.98	50	50.17	46.2	53.06	41.25	49.32	19.23	63.63	56.19	48.82	50.68	47.64	41.02	30.43
Resource Name	Hourly Trigger Cost ($/MW) and MW Available																							
CBP Resource 1	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$120 2.22	$120 2.35	$120 2.84	$120 3.02	$120 3.05	$120 3.04	$120 2.25	$120 2.01	< > < >	< > < >	< > < >	< > < >	< > < >
CPP Resource 3	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$0 7.5	$0 8.53	$0 8.2	$0 8	$0 7	$0 6.25	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 1	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$150 .17	$150 .18	$150 .19	$150 .19	$150 .15	$150 .13	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 2	$150 .06	$150 .06	$150 .06	$150 .06	$150 .06	$150 .06	$150 .06	$150 .06	$150 .13	$150 .16	$150 .16	$150 .17	$150 .18	$150 .18	$150 .19	$150 .19	$150 .19	$150 .19	$150 .18	$150 .13	$150 .11	$150 .11	$150 .06	$150 .06
PeakChoice Resource 3	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$500 .1	$500 .13	$500 .13	$500 .13	$500 .1	$500 .1	< > < >	< > < >	< > < >	< > < >	< > < >

Figure 16: User selection of a historic trade date via a calendar date selection option



7.3 Live Demonstration

The proof-of-concept system was implemented with select functionality to support live demonstration. The decision support tool was explained in the context of the day-in-the-life-of short term procurement personnel, beginning at the day-ahead desk, followed by the day-of desk. The demonstration highlighted information provided by the prototyped tool to support decision-making beyond the status quo of information available to the user. In particular, the tool provides the user with trigger impact information alongside program cost information, so that the user can readily discern time intervals when triggering demand response was estimated to "be in the money".

The live demonstration illustrated how the prototyped tool supports decision-making on when (what interval of the day), which resources, where (what location), and how much demand response to trigger, based on impact to settlement charges. The live demonstration illustrated that it is feasible to estimate demand response impact on settlements in day-ahead and day-of timeframes using latest market data. Not only were the derivative calculations performed automatically during live demonstration using automated data feeds, but also the prototype was robust enough to handle cases of missing data or occasional hang-ups with the MRTU server during data downloads.

Several interesting scenarios were illustrated using the prototyped proof-of-concept system. These scenarios included:

1. Scenario A to illustrate when locations mattered: Trigger impact calculations varied substantially for select locations, so that it made sense to trigger DR resources in multiple locations but not other locations.

2. Scenario B to illustrate when trade dates mattered: On certain trade dates the tool indicated select hours that triggering demand response was estimated to be in the money. But for many other trade dates this was not the case.

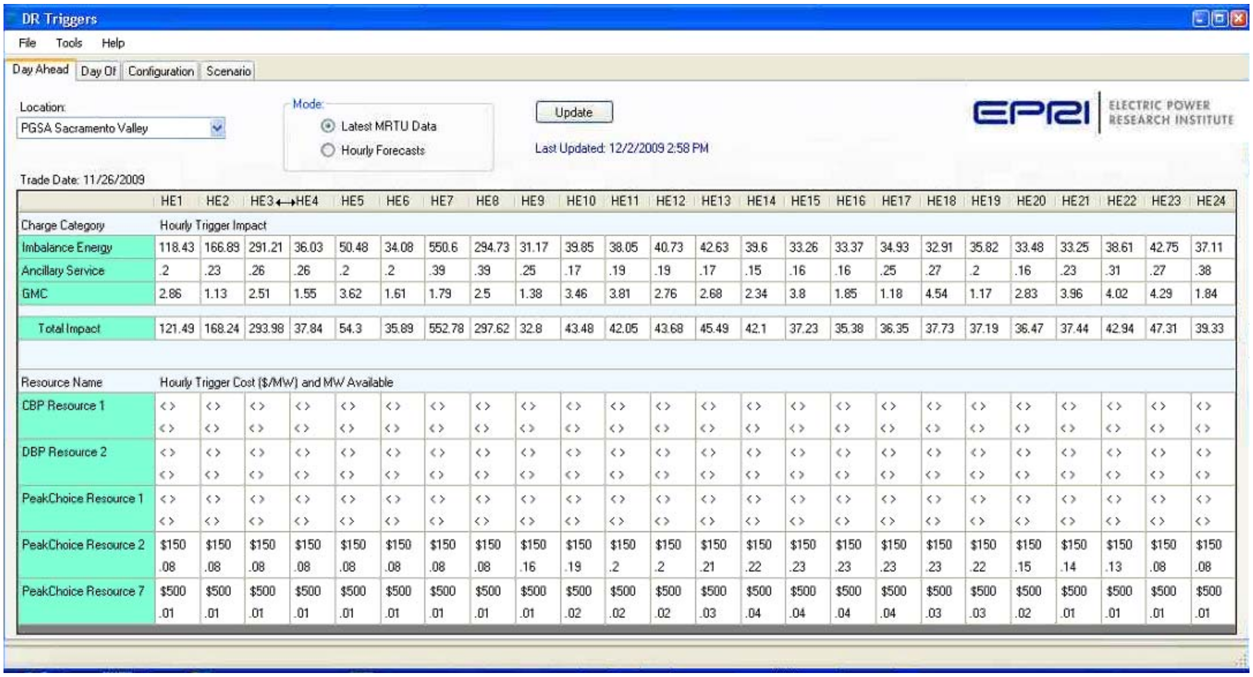
3. Scenario C to illustrate when charge code matters: On certain days the trigger impact calculations for ancillary services was on a greater order of magnitude than on average

Each of these scenarios is illustrated in the following figures.

<u>Live Demonstration of Scenario A</u>

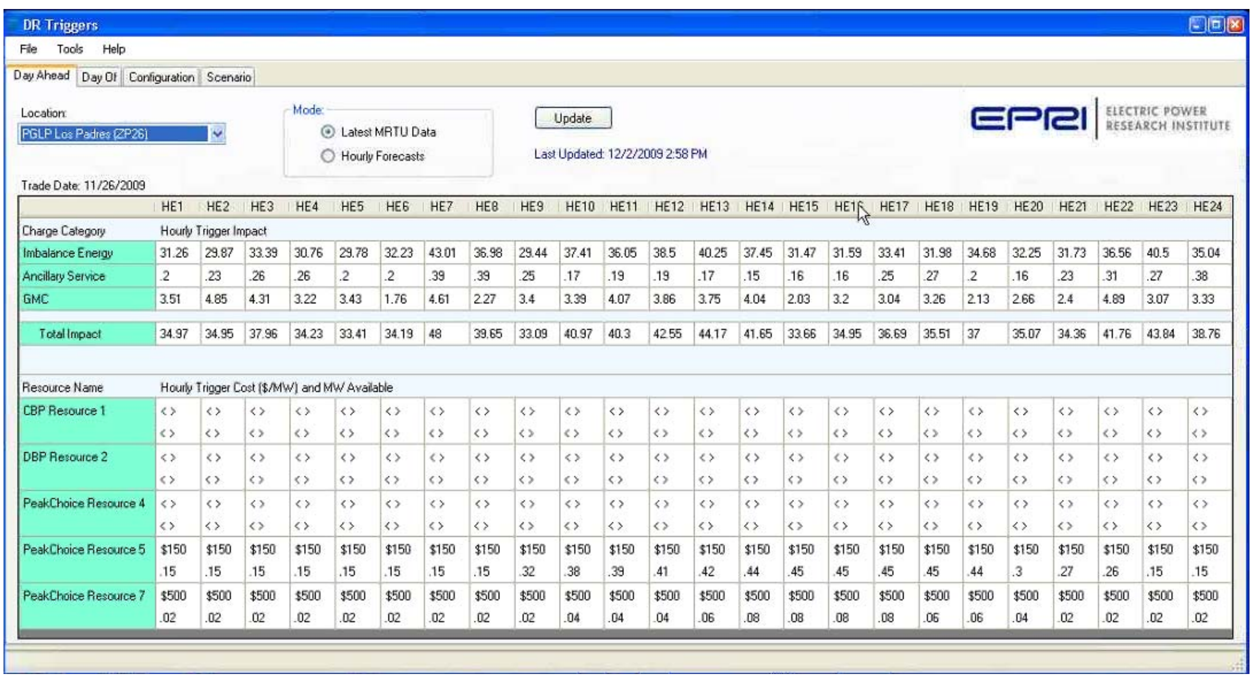
Figure 17 through Figure 20 provide screenshots of the live demonstration highlighting differences in triggering decisions by location for trade date November 26, 2009. Upon close examination of results for the Sacramento (Figure 17), South Bay Area (Figure 19), and East Bay Area (Figure 19) locations, the reader will note that the trigger impact is greater than the trigger costs for at least one resource during hour ending intervals 1, 2, 3, 7, and 8, respectively. Furthermore, trigger impact calculations indicate that triggering PeakChoice Resource 7 at $500/MW is in the money only during hour ending interval 7 in the Sacramento and East Bay Area locations. In contrast, there are no time intervals for which triggering demand response is in the money for any resource listed in Figure 18 for the Los Padres location.

Figure 17: Day-ahead trigger impact results for trade date 11/26/10 and Sacramento Valley location



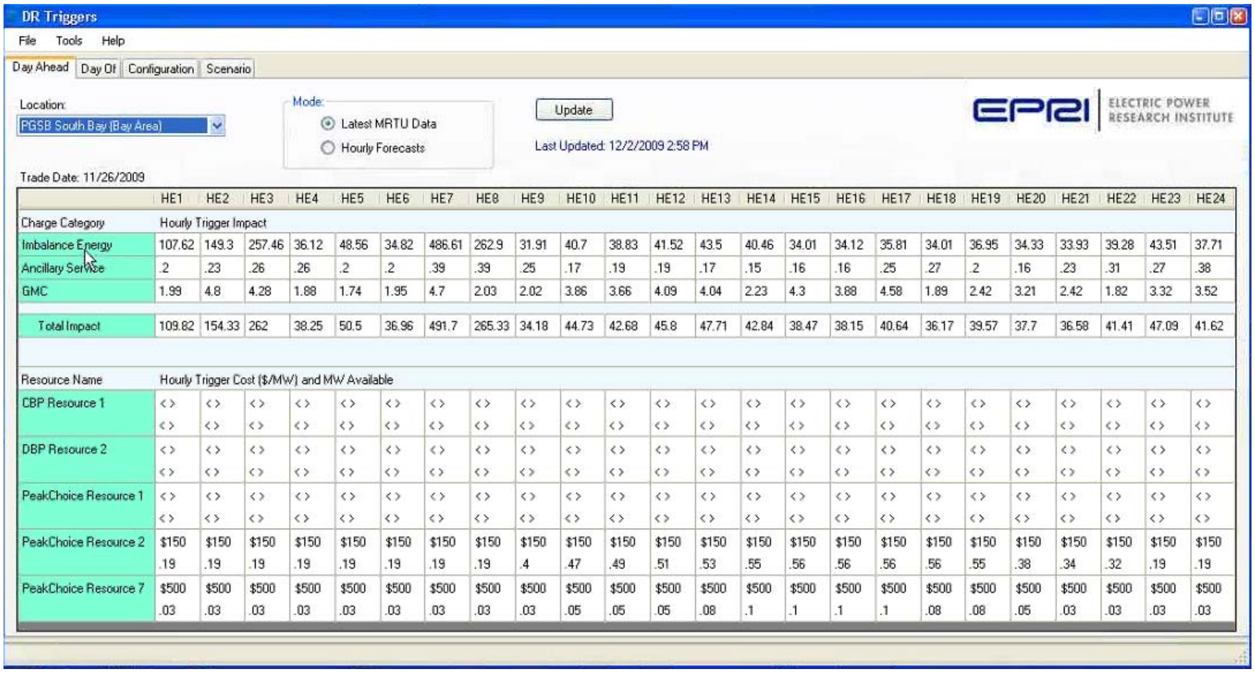
	HE1	HE2	HE3⟷	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category	Hourly Trigger Impact																							
Imbalance Energy	118.43	166.89	291.21	36.03	50.48	34.08	550.6	294.73	31.17	39.85	38.05	40.73	42.63	39.6	33.26	33.37	34.93	32.91	35.82	33.48	33.25	38.61	42.75	37.11
Ancillary Service	.2	.23	.26	.26	.2	.2	.39	.39	.25	.17	.19	.19	.17	.15	.16	.16	.25	.27	.2	.16	.23	.31	.27	.38
GMC	2.86	1.13	2.51	1.55	3.62	1.61	1.79	2.5	1.38	3.46	3.81	2.76	2.68	2.34	3.8	1.85	1.18	4.54	1.17	2.83	3.96	4.02	4.29	1.84
Total Impact	121.49	168.24	293.98	37.84	54.3	35.89	552.78	297.62	32.8	43.48	42.05	43.68	45.49	42.1	37.23	35.38	36.35	37.73	37.19	36.47	37.44	42.94	47.31	39.33
Resource Name	Hourly Trigger Cost ($/MW) and MW Available																							
CBP Resource 1	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>
DBP Resource 2	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>
PeakChoice Resource 1	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>
PeakChoice Resource 2	$150 .08	$150 .08	$150 .08	$150 .08	$150 .08	$150 .08	$150 .08	$150 .08	$150 .16	$150 .19	$150 .2	$150 .2	$150 .21	$150 .22	$150 .23	$150 .23	$150 .23	$150 .23	$150 .22	$150 .15	$150 .14	$150 .13	$150 .08	$150 .08
PeakChoice Resource 7	$500 .01	$500 .01	$500 .01	$500 .01	$500 .01	$500 .01	$500 .01	$500 .01	$500 .01	$500 .02	$500 .02	$500 .02	$500 .03	$500 .04	$500 .04	$500 .04	$500 .04	$500 .03	$500 .03	$500 .02	$500 .01	$500 .01	$500 .01	$500 .01

Figure 18: Day-ahead trigger impact results for trade date 11/26/10 and Los Padres location



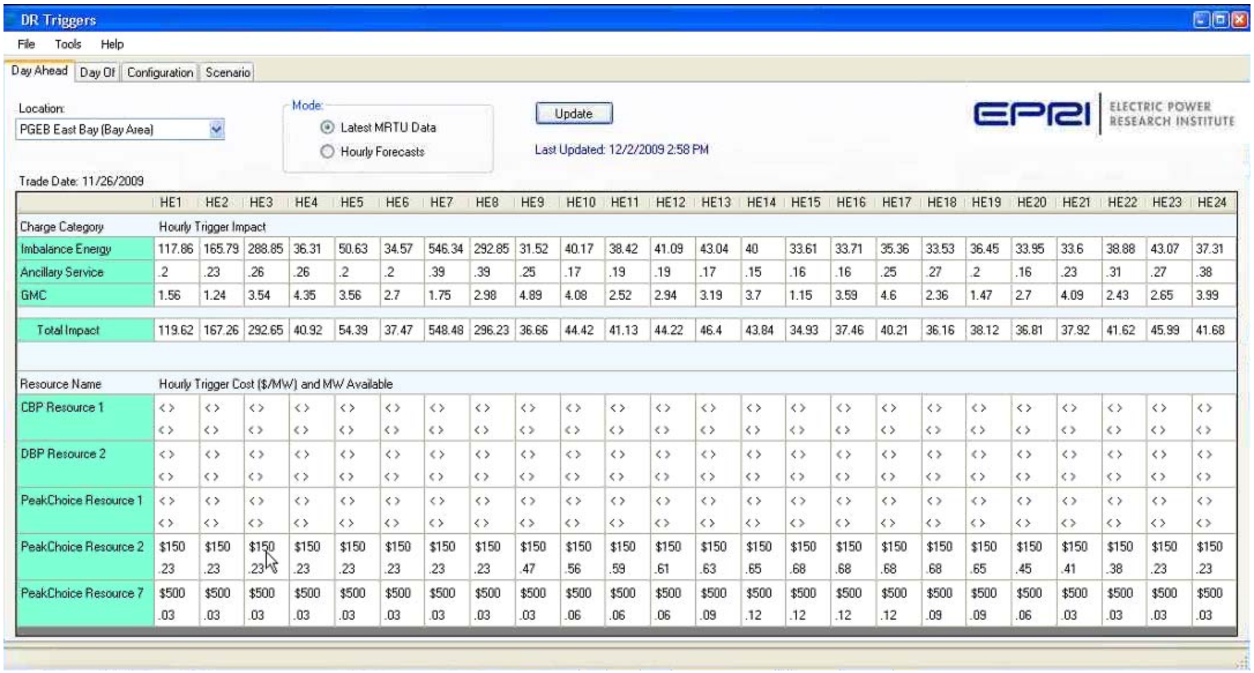
	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category	Hourly Trigger Impact																							
Imbalance Energy	31.26	29.87	33.39	30.76	29.78	32.23	43.01	36.98	29.44	37.41	36.05	38.5	40.25	37.45	31.47	31.59	33.41	31.98	34.68	32.25	31.73	36.56	40.5	35.04
Ancillary Service	.2	.23	.26	.26	.2	.2	.39	.39	.25	.17	.19	.19	.17	.15	.16	.16	.25	.27	.2	.16	.23	.31	.27	.38
GMC	3.51	4.85	4.31	3.22	3.43	1.76	4.61	2.27	3.4	3.39	4.07	3.86	3.75	4.04	2.03	3.2	3.04	3.26	2.13	2.66	2.4	4.89	3.07	3.33
Total Impact	34.97	34.95	37.96	34.23	33.41	34.19	48	39.65	33.09	40.97	40.3	42.55	44.17	41.65	33.66	34.95	36.69	35.51	37	35.07	34.36	41.76	43.84	38.76
Resource Name	Hourly Trigger Cost ($/MW) and MW Available																							
CBP Resource 1	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>
DBP Resource 2	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>
PeakChoice Resource 4	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>	<> <>
PeakChoice Resource 5	$150 .15	$150 .15	$150 .15	$150 .15	$150 .15	$150 .15	$150 .15	$150 .15	$150 .32	$150 .38	$150 .39	$150 .41	$150 .42	$150 .44	$150 .45	$150 .45	$150 .45	$150 .45	$150 .44	$150 .3	$150 .27	$150 .26	$150 .15	$150 .15
PeakChoice Resource 7	$500 .02	$500 .02	$500 .02	$500 .02	$500 .02	$500 .02	$500 .02	$500 .02	$500 .02	$500 .04	$500 .04	$500 .04	$500 .06	$500 .08	$500 .08	$500 .08	$500 .08	$500 .06	$500 .06	$500 .04	$500 .02	$500 .02	$500 .02	$500 .02

Figure 19: Day-ahead trigger impact results for trade date 11/26/10 and South Bay Area location



	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category	Hourly Trigger Impact																							
Imbalance Energy	107.62	149.3	257.46	36.12	48.56	34.82	486.61	262.9	31.91	40.7	38.83	41.52	43.5	40.46	34.01	34.12	35.81	34.01	36.95	34.33	33.93	39.28	43.51	37.71
Ancillary Service	.2	.23	.26	.26	.2	.2	.39	.39	.25	.17	.19	.19	.17	.15	.16	.16	.25	.27	.2	.16	.23	.31	.27	.38
GMC	1.99	4.8	4.28	1.88	1.74	1.95	4.7	2.03	2.02	3.86	3.66	4.09	4.04	2.23	4.3	3.88	4.58	1.89	2.42	3.21	2.42	1.82	3.32	3.52
Total Impact	109.82	154.33	262	38.25	50.5	36.96	491.7	265.33	34.18	44.73	42.68	45.8	47.71	42.84	38.47	38.15	40.64	36.17	39.57	37.7	36.58	41.41	47.09	41.62
Resource Name	Hourly Trigger Cost ($/MW) and MW Available																							
CBP Resource 1	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
DBP Resource 2	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
PeakChoice Resource 1	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
PeakChoice Resource 2	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
	.19	.19	.19	.19	.19	.19	.19	.19	.4	.47	.49	.51	.53	.55	.56	.56	.56	.56	.55	.38	.34	.32	.19	.19
PeakChoice Resource 7	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
	.03	.03	.03	.03	.03	.03	.03	.03	.03	.05	.05	.05	.08	.1	.1	.1	.1	.08	.08	.05	.03	.03	.03	.03

Figure 20: Day-ahead trigger impact results for trade date 11/26/10 and East Bay Area location



	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category	Hourly Trigger Impact																							
Imbalance Energy	117.86	165.79	288.85	36.31	50.63	34.57	546.34	292.85	31.52	40.17	38.42	41.09	43.04	40	33.61	33.71	35.36	33.53	36.45	33.95	33.6	38.88	43.07	37.31
Ancillary Service	.2	.23	.26	.26	.2	.2	.39	.39	.25	.17	.19	.19	.17	.15	.16	.16	.25	.27	.2	.16	.23	.31	.27	.38
GMC	1.56	1.24	3.54	4.35	3.56	2.7	1.75	2.98	4.89	4.08	2.52	2.94	3.19	3.7	1.15	3.59	4.6	2.36	1.47	2.7	4.09	2.43	2.65	3.99
Total Impact	119.62	167.26	292.65	40.92	54.39	37.47	548.48	296.23	36.66	44.42	41.13	44.22	46.4	43.84	34.93	37.46	40.21	36.16	38.12	36.81	37.92	41.62	45.99	41.68
Resource Name	Hourly Trigger Cost ($/MW) and MW Available																							
CBP Resource 1	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
DBP Resource 2	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
PeakChoice Resource 1	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>	<>
PeakChoice Resource 2	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
	.23	.23	.23	.23	.23	.23	.23	.23	.47	.56	.59	.61	.63	.65	.68	.68	.68	.68	.65	.45	.41	.38	.23	.23
PeakChoice Resource 7	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
	.03	.03	.03	.03	.03	.03	.03	.03	.03	.06	.06	.06	.09	.12	.12	.12	.12	.09	.09	.06	.03	.03	.03	.03

Live Demonstration of Scenario B

The Day-ahead, Day-of, and Configuration screens were used to view results on different trades dates to illustrate Scenario C (i.e., when trade date matters). Results from the date of live demonstration (12/2/09) were shown first, followed by results for the trade date 11/25/10. Figure 13 and Figure 15 show the magnitude of trigger impact calculations on the Day-ahead and Day-of screens, respectively.

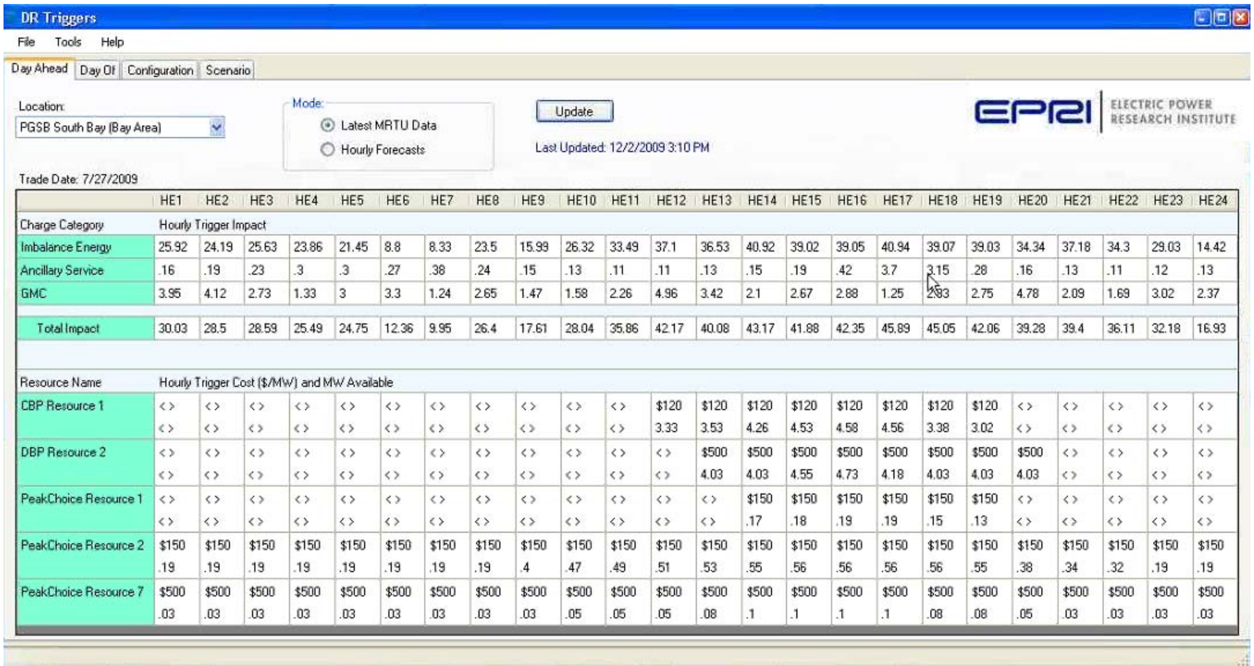
On the day of live demonstration (i.e., 12/2/09), the Day-ahead screen was demonstrated to provide estimates day-ahead for the next trade date 12/3/09, whereas the Day-of screen was demonstrated to provide trigger impact results for the current trade date 12/2/09. On both screens showing results for the day of live demonstration, there were no intervals for which triggering demand response was in the money for the default location. Different locations were selected using the drop-down list (shown in Figure 14) to conclude the same.

Results for the historic trade date 11/26/10 were also examined by selecting 11/25/10 using the calendar option under the Configuration screen (Figure 16), and then proceeding to the Day-ahead screen to view results for the next trade date 11/26/10. As explained under Scenario A, multiple hours were identified for which triggering demand response was in the money on this trade date for at least one resource in different locations.

Live Demonstration of Scenario C

Figure 21 provides a screenshot of the live demonstration of Scenario C, highlighting an instance when charge code-specific results matter. For the selected trade date 7/26/10, the Day-ahead screen was demonstrated to provide estimates of trigger impact calculations for the next trade date 7/27/10. In particular, the trigger impact values for ancillary services were an order of magnitude greater than on average during hour ending intervals 17 and 18. This example was used to highlight the situation of uncertainty surrounding system reliability and associated ancillary service charges when reliability is at stake. The California Energy Crisis of 2000-2001, which has been described as a crisis of reliability [2], was used to reinforce the notion that real-time system reliability costs can be unpredictable, and therefore must also be considered in overall demand response trigger impact calculations.

Figure 21: Live demonstration showing historical results with higher ancillary service charges



	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12
Charge Category	Hourly Trigger Impact											
Imbalance Energy	25.92	24.19	25.63	23.86	21.45	8.8	8.33	23.5	15.99	26.32	33.49	37.1
Ancillary Service	.16	.19	.23	.3	.3	.27	.38	.24	.15	.13	.11	.11
GMC	3.95	4.12	2.73	1.33	3	3.3	1.24	2.65	1.47	1.58	2.26	4.96
Total Impact	30.03	28.5	28.59	25.49	24.75	12.36	9.95	26.4	17.61	28.04	35.86	42.17
Resource Name	Hourly Trigger Cost ($/MW) and MW Available											
CBP Resource 1	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$120 3.33
DBP Resource 2	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 1	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 2	$150 .19	$150 .19	$150 .19	$150 .19	$150 .19	$150 .19	$150 .19	$150 .19	$150 .4	$150 .47	$150 .49	$150 .51
PeakChoice Resource 7	$500 .03	$500 .03	$500 .03	$500 .03	$500 .03	$500 .03	$500 .03	$500 .03	$500 .03	$500 .05	$500 .05	$500 .05

	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category												
Imbalance Energy	36.53	40.92	39.02	39.05	40.94	39.07	39.03	34.34	37.18	34.3	29.03	14.42
Ancillary Service	.13	.15	.19	.42	3.7	3.15	.28	.16	.13	.11	.12	.13
GMC	3.42	2.1	2.67	2.88	1.25	2.93	2.75	4.78	2.09	1.69	3.02	2.37
Total Impact	40.08	43.17	41.88	42.35	45.89	45.05	42.06	39.28	39.4	36.11	32.18	16.93
Resource Name												
CBP Resource 1	$120 3.53	$120 4.26	$120 4.53	$120 4.58	$120 4.56	$120 3.38	$120 3.02	< > < >	< > < >	< > < >	< > < >	< > < >
DBP Resource 2	$500 4.03	$500 4.03	$500 4.55	$500 4.73	$500 4.18	$500 4.03	$500 4.03	$500 4.03	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 1	< > < >	$150 .17	$150 .18	$150 .19	$150 .19	$150 .15	$150 .13	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 2	$150 .53	$150 .55	$150 .56	$150 .56	$150 .56	$150 .56	$150 .55	$150 .38	$150 .34	$150 .32	$150 .19	$150 .19
PeakChoice Resource 7	$500 .08	$500 .1	$500 .1	$500 .1	$500 .1	$500 .08	$500 .08	$500 .05	$500 .03	$500 .03	$500 .03	$500 .03

At the conclusion of the live demonstration, during questions and answers, participating team members from short-term procurement reinforced the value-add they perceived from the DR Triggers decision-support information layout. Being able to compare avoided settlement cost against costs of calling demand response by resource, by location, and by interval of the day was confirmed as valuable to day-to-day decision-making in short-term procurement operations.

It was noted by a project participant representing short-term procurement that from an operational perspective, the decision to trigger demand response also depends on what short-term procurement personnel believe costs would be to trigger demand response in the future, if trigger allowances were used upfront. That is, whether triggering is economic on one day also depends on what the decision-maker believes will be the economics for triggering on a future date. An example was given by the participant. Namely, if the trigger impact is high for both imbalance energy and ancillary services during multiple time intervals on a particular day, then this may be more indicative than if just the trigger impact for imbalance energy were high.

CHAPTER 8: Future Work

8.1 Expanded Scope

Phase 1 of the project focused on methodology design and development of a limited function proof-of-concept system to demonstrate feasibility of the conceived trigger impact assessment method. A subsequent project phase (Phase 2) is envisioned with expanded scope, to include investigation of additional charge codes and broad implementation of the functionality specified in Phase 1 (in Appendix B-1) for the DR Trigger decision support tool.

The broader investigation proposed for Phase 2 includes development of a conceptual framework for estimating the financial impact of demand response under distinctly different methods of integration within wholesale markets. The financial impact of demand response varies depending on the integration method assumed. Possibilities include:

1. demand response integration in wholesale markets on the supply-side2, substituting for generation supply,
2. self-use within market participant portfolios (e.g., using demand response within the market participant's own portfolio to avoid supply-side procurement); and
3. demand response integration in wholesale markets on the demand-side, as elastic demand enabling the ISO to avoid excess procurement (beyond aggregate customer demand).

The assumed method of integrating demand response influences wholesale cost and settlement outcomes. So Phase 2 investigations would be conducted considering mutually exclusive methods of integration, including newer paradigms being discussed in industry, possibly enabled through deployment of smart grid infrastructure.

Results will be reported within a broad context of integration paradigms, utilizing the conceptual framework, which will be useful for relating different methods of integrating demand response within wholesale markets.

8.2 Conceptual Framework Development: Descriptive Framework Relating Wholesale Integration Methods

Connecting retail to wholesale markets involves a continuum of requirements, including cooperation of end-use customers themselves who provide demand response. 3 Recounting

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[2] For example, California wholesale electricity market programs accommodating load participation include Participating Load (PL), Proxy Demand Resource (PDR), and Reliability Demand Response Program (RDRP).

[3] Currently retail customers receive more compensation to participate in DR than the wholesale market is valuing DR on the basis of the cost of energy. This is understandable since the retail rate is higher than wholesale procurement cost and customers want to be compensated more than their base rate to participate in DR.

instances that demand response program rules compelled triggering DR at times of low or no perceived value, market participants on the project team emphasize triggering flexibility is important. Though beyond the scope of the project to design markets and DR programs, a subsequent phase of the project could clarify what methods exist for integrating demand response with wholesale markets and what critical integration challenges are being addressed by the project. These could be described within a common framework that relates existing methods as well as associates integration challenges with the methods.

Phase 2 would commence with development of a conceptual framework to describe and relate distinct methods of integrating demand response in wholesale markets. Both status quo and newer methods being discussed in industry and referenced in literature will be included in the descriptive framework. The framework will be useful for presenting overall Phase 2 findings within a common context. It will also assist the reader to quickly relate research results and identify their applicability, considering the plethora of implementations and types of demand response programs and integration methods that exist.

Another important question for Phase 2 that was identified by utility project participants is how DR programs can be linked to the developed DR Triggers Decision Support tool, in order to address the full continuum of requirements involving customers that provide the DR resources. To secure customer cooperation, customers need to understand what they are providing and why (in the form of demand response). However, currently there is a wide gap in understanding with respect to wholesale market outcomes and impacts on customers. Phase 1 of the DR Triggers project provided an initial step to bridge the gap in understanding and to clarify the financial connection between retail and wholesale markets, through the impact of demand response. Further steps to bridge the gap are needed in future work. Among conceptual gaps, Phase 2 of the project develops clarity in several critical areas described below.

Needs for conceptual clarity expressed by project participants include:

1. Clarity surrounding the connection between distinct wholesale market products and electric service received by customers, from the customer perspective.
2. The added dimensions and facets available in markets, including the choice to bid participating load resources or self-use demand response within a market participant's portfolio.
3. As markets develop as well as enabling technologies like smart grid infrastructure, could resource adequacy requirements be reduced, and how to justify?

Considering the feedback received from project participants, the following topics to clarify conceptually are proposed for a subsequent project phase:

1. How to decompose components of electric service (including reliability) into different components that a customer can appreciate
2. How to avoid wholesale charges that would otherwise be allocated, by triggering DR.
3. How developments that could be supported by project findings link to resource adequacy requirements. For example:

- As markets develop and different methods of integrating demand response are considered, what types of demand-side resources will meet the industry's objectives for resource adequacy? How could resource adequacy requirements be reduced, and how to justify?
- Currently all DR resources qualify for resource adequacy (e.g., 115% qualify whereas generation resources qualify 1MW for 1MW). As wholesale integrated DR increases in participation, is there a way to quantify the amount of resource adequacy requirement that can be reduced?

8.3 Expanded Methodology: Design, Specification, Implementation, and Demonstration

Market participants noted that Phase 1 of the project broadened perspectives on charge codes and demonstrated the value of tracking additional charge codes. Beyond just looking at imbalance energy prices, the project showed the significance of considering ancillary service and other categories of charges too. The project team proposes to investigate more charge codes, beyond those studied in Phase 1. By investigating types that account for revenue sources as well as charges due to the ISO, Phase 2 will investigate additional dimensions and facets in markets, include the choice to bid or self-use demand response.

This subsection describes the steps for design, specification, implementation, and demonstration of an expanded methodology for assessing the financial impact of triggering demand response. Derivative formulations need to be developed for triggering demand response based on impact to other charge codes that have been identified as priority under Phase 1. Analyses will be conducted to identify input data, availability, and methods to connect to live data feeds, in order to support full implementation. Implementation will demonstrate specified functionality for the Day-ahead, Day-of, and What-if Scenario screens, beyond the limited-function proof-of-concept prototype. Moreover, expanded functionality will be specified in order to consider counterparty trades. The expanded scope proposed supports forming an overall perspective of the value of triggering DR, considering avoided wholesale market charges and potential revenues from both market and counterparty trades.

Step 1 (Theoretical analysis of priority charge codes for charges "due ISO"):
The goal is to augment the trigger methodology based on next highest priority charge codes. This begins with calculating the derivatives of the remaining priority charge codes, in order of priority 1 through 3. In particular, analyses have yet to be conducted for the following charge codes that were identified under Phase 1:

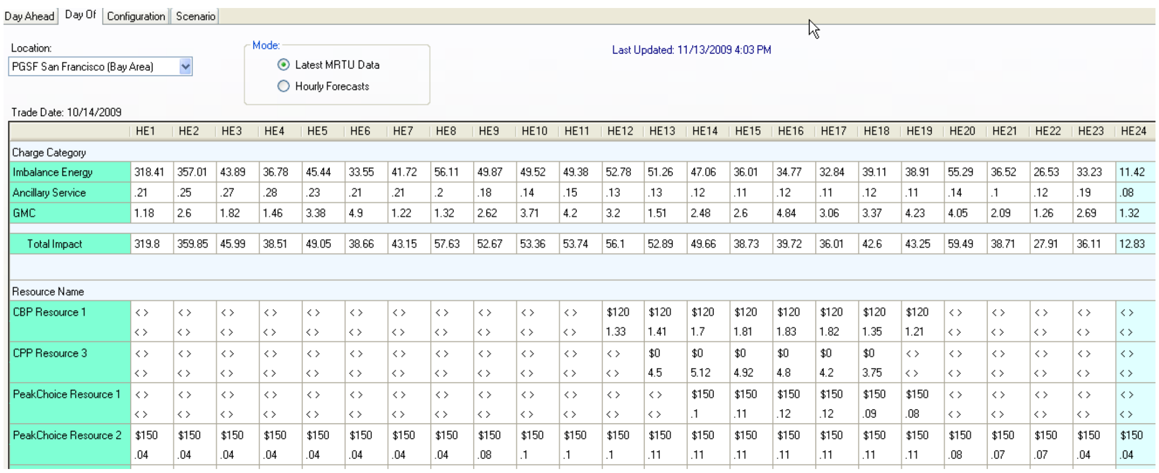
- Unaccounted for Energy (6474) is priority 1
- Grid Management Charge (4501, 4505) and HVAC (372) are priority 2
- Allocation of Excess Cost for Imbalance Energy (6486) and FERC Fee (550) is priority 3

Table 1: Highest Priority Charge Codes to be included in Phase 2 of the DR Triggers Project

Pre-MRTU Charge Code Number	Pre-MRTU Charge Code Name	MRTU Charge Code Number	MRTU Charge Code Name	Priority
2	Day Ahead Non-Spinning Reserve due SC	6200	Day Ahead Non Spinning Reserve	1
52	Hour Ahead Non-Spinning Reserve due SC	6250	HASP Non-Spinning Reserve	1
111	Spinning Reserve due ISO	6194	Spinning Reserve Obligation Settlement	1
112	Non-Spinning Reserve due ISO	6294	Non-Spinning Reserve Obligation Settlement	1
115	Regulation Up due ISO	6594	Regulation Up Obligation Settlement	1
116	Regulation Down due ISO	6694	Regulation Down Obligation Settlement	1
372	High Voltage Access Charge due ISO	372	High Voltage Access Charge Allocation	2
660	FERC Fee	550	FERC Fee Settlement due Monthly	2
1401	Imbalance Energy Offset	6477	Real Time Imbalance Energy Offset	3
4401	Instructed Energy	6470	Real Time Instructed Imbalance Energy Settlement	1
4406	Unaccounted for Energy	6474	Real Time Unaccounted for Energy Settlement	1
4407	Uninstructed Energy	6475	Real Time Uninstructed Imbalance Energy Settlement	1
4487	Allocation of Excess Cost for Instructed Energy	6486	Real Time Excess Cost for Instructed Energy Allocation	3
4501	GMC-Core Reliability Services Non-Coincident Peak	4501	Core Reliability Services – CRS Peak Demand	2
4505	GMC-Energy Transmission Services Net Energy	4505	Energy Transmission Services – Net Energy	2
4534	GMC-Market Usage Ancillary Services	4534	Market Usage – Awarded AS	2
		6011	Day-ahead Energy/Congestion/Loss	1
		6774	Real-time Congestion Offset	3

Table 1 identifies the highest priority charge codes for inclusion in the DR Trigger method. In Phase 2, analytical derivative calculations would be performed for Priority 2 and 3 charge codes, as well as for the remaining Priority 1 charge codes: Unaccounted for Energy (UFE) and Day-ahead Energy/Congestion/Loss Settlement. The former charge code was traded out in order to include GMC Ancillary Service Market Usage charge code in the Phase 1 analyses. The latter charge code did not exist before MRTU. Nevertheless, all priority charge codes are important to analyze and consider in the overall trigger methodology.

Step 2 (Specification for automation of trigger impact calculations):
The next step is to determine input data availability and specify the trigger methodology for the additional charge code derivations. Results will be displayed in place of the placeholder row labeled "GMC" in the screen below, in order to present details that expand beyond what was developed in Phase 1.

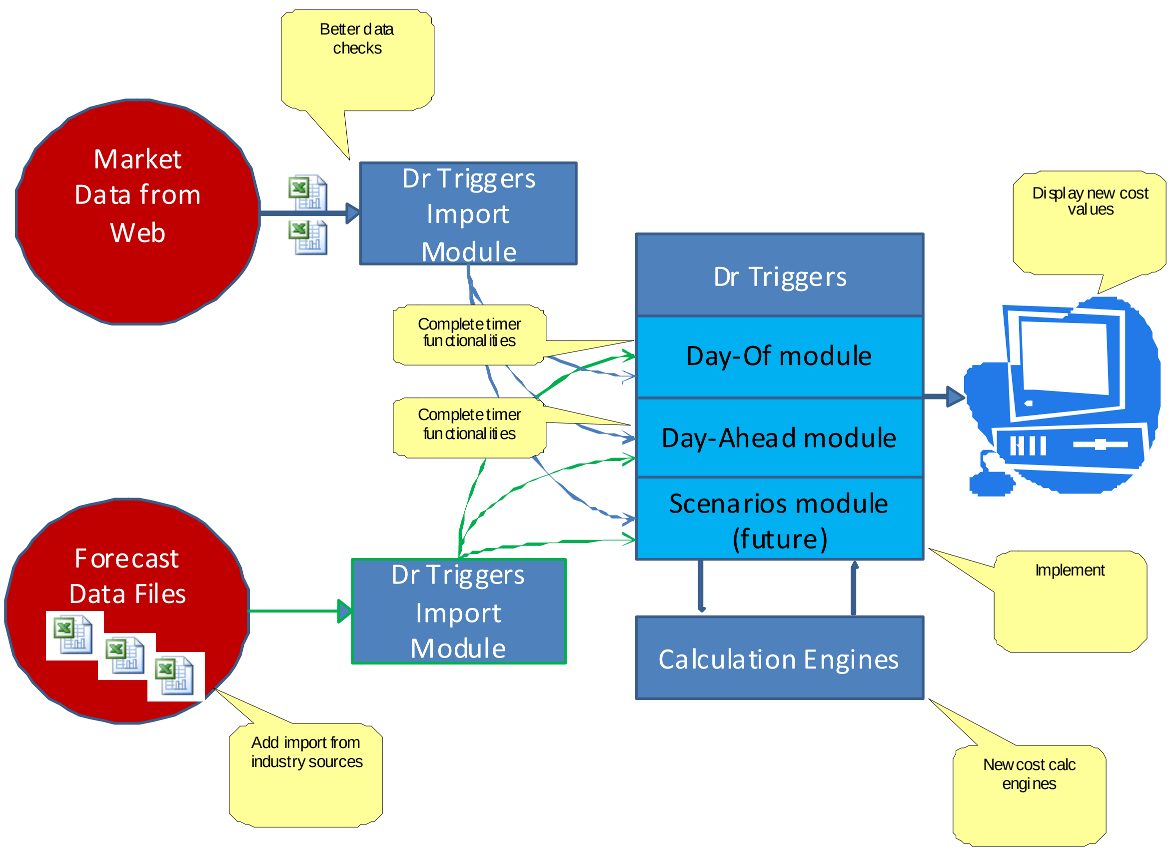


	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Charge Category																								
Imbalance Energy	318.41	357.01	43.89	36.78	45.44	33.55	41.72	56.11	49.87	49.52	49.38	52.78	51.26	47.06	36.01	34.77	32.84	39.11	38.91	55.29	36.52	26.53	33.23	11.42
Ancillary Service	.21	.25	.27	.28	.23	.21	.21	.2	.18	.14	.15	.13	.13	.12	.11	.12	.11	.12	.11	.14	.1	.12	.19	.08
GMC	1.18	2.6	1.82	1.46	3.38	4.9	1.22	1.32	2.62	3.71	4.2	3.2	1.51	2.48	2.6	4.84	3.06	3.37	4.23	4.05	2.09	1.26	2.69	1.32
Total Impact	319.8	359.85	45.99	38.51	49.05	38.66	43.15	57.63	52.67	53.36	53.74	56.1	52.89	49.66	38.73	39.72	36.01	42.6	43.25	59.49	38.71	27.91	36.11	12.83
Resource Name																								
CBP Resource 1	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$120 1.33	$120 1.41	$120 1.7	$120 1.81	$120 1.83	$120 1.82	$120 1.35	$120 1.21	< > < >	< > < >	< > < >	< > < >	< > < >
CPP Resource 3	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$0 4.5	$0 5.12	$0 4.92	$0 4.8	$0 4.2	$0 3.75	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 1	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	< > < >	$150 .1	$150 .11	$150 .12	$150 .12	$150 .09	$150 .08	< > < >	< > < >	< > < >	< > < >	< > < >
PeakChoice Resource 2	$150 .04	$150 .04	$150 .04	$150 .04	$150 .04	$150 .04	$150 .04	$150 .04	$150 .08	$150 .1	$150 .1	$150 .1	$150 .11	$150 .11	$150 .11	$150 .11	$150 .11	$150 .11	$150 .11	$150 .08	$150 .07	$150 .07	$150 .04	$150 .04

Step 3 (Trigger Methodology development considering revenue "due SC"):
The next step is to expand the trigger methodology, considering installed capacity procured through counterparty trades in the bilateral market, as well as Ancillary Service supply offers by Participating Loads (i.e., Charge Codes 6200 and 6470). Considering these possible revenue sources, the task is to specify functionality and supporting information to be displayed. These must be of value to short-term procurement personnel, in order to be included for implementation.

Step 4 (Implementation and Demonstration)
A subsequent step focuses on design and implementation of the Phase 2 demonstration system. Components of the system are illustrated in Figure 22 for reference. Additional features and functionality beyond the Phase 1 proof-of-concept demonstration system are also called out in the figure. In Particular, "complete timer functionalities" refers to the implementation of different cases for input data availability. Automatic updates are performed for information shown on the day-ahead and day-of screens, based on distinct cases of input data availability identified under Step 2. For example, the previous day's data will be utilized to inform results shown on the day-ahead screen until a certain time when the next days' day-ahead data is available or posted by the CAISO during a specified time window (e.g., 1 to 3pm).

Figure 22: Proposed Reference Design for Phase 2 Demonstration System



8.4 Reporting

A final report will document results of conceptual framework development, analyses, and specifications. The DR Trigger Decision Support tool's full design, implementation, and demonstration will also be documented. Potential benefits and value-add applications will also be illustrated as well as participant insights gathered through experience in testing and demonstrating the implemented system. The experiences and value perceptions of procurement personnel serving to test the tool will also be documented.

CHAPTER 9: Conclusion

This report describes the development of a demand response trigger methodology based on impact to settlement charges. Priority was established through careful analyses of over 100 charge codes, which were narrowed down based on sensitivity to demand response and significance on settlement statements of scheduling coordinators that schedule load in California. Potential Benefits were assessed for triggering demand response using the developed methodology. Hard data was gathered to develop examples showing numerical results from applying the trigger methodology. Requirements specifications were drafted for a decision support tool that embodies the trigger methodology and performs automated trigger impact calculations based on live data streams. Findings were presented to the public via webcast at a final project workshop.

Throughout the project, numerous conference calls and a few face-to-face meetings were held with project participants. The participants included the CAISO, procurement personnel from the four largest load serving entities (LSEs) in California, and representatives from the retail organization of the major IOUs in California. The participants provided substantial in-kind effort, from aggregated data provision and requirements specification to proof-of-concept demonstration. The project benefited from the interdisciplinary expertise of the project team working in collaboration, all the way from the wholesale markets end down through market participant and the retail load serving end. The cross-cutting representation of participants on the project team was a vital ingredient towards project success in clarifying one necessary step in bridging the huge gap between retail and wholesale electricity markets.

The project addresses the financial disconnect between wholesale market conditions and retail incentives for demand response. By triggering demand response to achieve savings on wholesale electricity market charges (in both ISO and bilateral markets), retail markets can become inherently integrated with wholesale markets. Savings discovered at the wholesale level in turn provide a source of retail incentives for demand response. This is unlike traditional demand response programs that require an external source to fund demand response incentive payments.

The project demonstrates the feasibility of the developed methodology and a decision-support tool designed to reveal persistent strategies for capturing electricity cost savings, by identifying market-based financial incentives for demand response. Strategies exposed by the DR Trigger method have an inherent market connection. The method is applicable on an ongoing 24x7 basis for revealing incentives for demand response. In this way, a flexible tool has been designed and demonstrated that enables wholesale buyers of electricity to assess and avoid excess wholesale electricity charges.

The project developed charge code categorizations and a methodology for understanding the impact of demand response on wholesale market charges. The project identified charge code categories most sensitive to DR and assessed potential savings achievable through demand response. Ranking charge code categories from highest to lowest potential impact enabled concentration of efforts in areas of greatest potential impact.

Findings reveal groupings or categories of charges that can inform tariff design, including dynamic tariff designs. For example, the methodology could be applied in triggering a CPP event. Alternatively, numerical results from the analyses may support a rationale for unbundling retail rates to reveal reliability as a cost component distinct from energy in rate structures. Furthering conceptual clarity in such areas to support full market integration of demand response is proposed for investigation in a subsequent project phase.

The project supports improved public education on the connection between wholesale and retail markets. Concrete examples of charge reduction methods were provided towards improving understanding of market charges, which are allocated to SCs and ultimately passed down to customers that receive electric service. Project tasks address fundamental analysis needed to provide decision-makers with a better understanding of market charges and the impact of demand response on financial outcomes. Project findings assist energy retailers in assessing financial consequences of demand response and comparing resource options in sufficient time to impact settlement outcomes.

Through application of the proposed decision support tool, SCs that schedule load will gain insight to improve their strategic market positioning of demand response resources. They can also improve their readiness to accommodate market changes and regulatory mandates. In particular, early adopters can better position themselves to maximize demand response resources in meeting California's Loading Priority Order requirements. They can gain a better understanding on how to trigger DR as a physical mechanism for hedging financial market risk, and as a form of insurance against excess market charges. In these ways, further investigation and application of the developed methodology and specified tool is expected to provide a flexible means to increase resource availability when most needed in real-time power system and market operations.

CHAPTER 10: References

1. Chuang, A.S., "Value of Real-time Information in Competitive Generation Markets", *Proceedings of IEEE Power Engineering Society Winter Meeting*, New York, January 2002.

2. Chuang, A.S., "Assessing the Impact of Resource Availability on Electric Service Reliability Cost", *Electricity Journal*, March 2004.

3. Chuang, A and Gellings, C., "Demand-side Integration for Customer Choice through Variable Service Subscription", *Proceedings of IEEE Power and Energy Society*, Calgary, Canada, July 27-30, 2009.

CHAPTER 11: Glossary

The following table lists acronyms found in the report and provides some explanations.

AB	Assembly Bill. A state law passed by the legislature.
CAISO	California Independent System Operator. The regional transmission and market system operator of the state of California.
CEC	California Energy Commission.
CIEE	California Institute for Energy and Environment.
CPP	Critical Peak Pricing. A variant of time-based electricity rates. The critical peak period is characterized by a significantly higher price that is invoked for only a few hours or days a year during the most extreme peak demand periods**.**
CPUC	California Public Utilities Commission.
DER	Distributed Energy Resources. Electric energy sources dispersed in nature that typically include distributed generation and storage and may be interconnected with the power system at transmission or distribution level voltages.
DG	Distributed Generation. Active energy sources dispersed in nature, such as a microturbine, diesel backup generator, or other standby generation that may be interconnected with the power system at transmission or distribution level voltages.
DR	Demand Response. A dynamic change in electric load regarded as a valuable service to a system operator, such as customer response to prices, notifications, controls, or other signals designed to coordinate changes in electric power demand.
DSR	Demand Side Resource.
DRETD	Demand Response Enabling Technology Development.
EPRI	Electric Power Research Institute.
ESP	Energy Service Provider.
GHG	Green House Gas. A gas when in high concentrations in the atmosphere contributes to the greenhouse effect and global warming.
IEPR	Integrated Energy Policy Report. A 2007 report that provides an integrated assessment of the major energy trends and issues facing the California's electricity, natural gas, and transportation fuel sectors, and provides guidance on state energy policy.
ISO	Independent System Operator. A regional system operator responsible for the reliable operation of the bulk electric transmission system in its FERC-approved geographic territory.
IT	Information Technology.
kW	Kilowatt. A unit of measurement of power equal to 1000 watts.
LSE	Load Serving Entity.
MD02	Market Design 2002.
MRTU	Market Redesign Technology Upgrade.
MVA	Megavolt Ampere.
MW	Megawatt.
PG&E	Pacific Gas and Electric.
PIER	Public Interest Energy Research.
POC	Proof of Concept.
PV	Photovoltaic.
RD&D	Research, Development, and Demonstration.

RON	Research Opportunity Notice.
RPS	Renewable Portfolio Standard.
RTO	Regional Transmission Organization. A regional system operator responsible for the reliable operation of the bulk electric transmission system in its FERC-approved geographic territory.
SC	Scheduling Coordinator. a registered market participant with the independent system operator.
SCADA	Supervisory Control And Data Acquisition.
SCE	Southern California Edison.
SDG&E	San Diego Gas and Electric.
UDC	Utility Distribution Company.
UI	User Interface.

APPENDIX A:
Final Workshop Attendee List

Over sixty individuals participated in-person or registered to participate by webcast for the December 2, 2009 final project workshop. In-person attendees are listed in Table 4 and webcast participants are listed in Table 2.

Table 2: Webcast Participants

Name	Affiliation
Daniel C. Engel	Freeman, Sullivan & Co.
Suresh Vadhva	California State University, Sacramento
Russ Tatro	California State University, Sacramento
Mohammad Vaziri	Pacific Gas & Electric Co.
Mark S. Martinez	Southern California Edison
Mark McGranaghan	Electric Power Research Institute (EPRI)
Terry Mohn	BAE Systems/GridWise Alliance
Ralph Martinez, PhD	BAE Systems
Donya He	BAE Systems
Matt Wakefield	Electric Power Research Institute (EPRI)
John R. Domingos	Negawatt Finance Associates
Carol Fisher	Elster Group
Robert (Bob) B. Frazier	CenterPoint Energy
Chantal Jones	Commonwealth Edison Company (ComEd)
David A. Chambers	California Energy Commission
Don Nichols	American Electric Power
Dr. Gordon K. Lee	San Diego State University
Art M. Altman	Electric Power Research Institute (EPRI)
H. Walter Johnson	KEMA, Inc.
Jim Stoupis	ABB Inc.
Chip Tenorio	ComEd
Chris Bell	EnergyHub
Lorraine Hwang	California Institute for Energy & Environment
Lily Kidd	CPS Energy
Adiel Guinzburg	The Boeing Company
Thomas M. Overman	The Boeing Company
David Drew	Emerson Climate Technologies
Matthew Forshey	American Electric Power
Salman Mohagheghi	ABB Inc.
John Hayn	The Boeing Company

Table 3: Webcast Participants (continued)

Name	Affiliation
Ann Segesman	Pacific Gas & Electric Co.
Umesh Singh	GE Energy T&D Automation
Joe Lang	Lincoln Electric System
Belvin Louie	Pacific Gas & Electric Co.
Ron Hofmann	California Institute for Energy & Environment
Shiva Swaminathan	City of Palo Alto
Glenn Goldbeck	Pacific Gas & Electric Co.
Alva Svoboda	Pacific Gas & Electric Co.
Patrick Duggan	Con Ed
Patrick Mantey	UC Santa Cruz
Jeff Crowe	Electric Power Research Institute (EPRI)
Mary Ann Piette	LBNL
Dave Michel	California Energy Commission

Table 4: In-Person attendees

Name	Affiliation
Bryan Neff	California Energy Commission
Chris Scruton	California Energy Commission
Consuelo Sichon	California Energy Commission
David Chambers	California Energy Commission
Jamie Patterson	California Energy Commission
Matt Coldwell	California Energy Commission
Norm Bourassa	California Energy Commission
Pedro Gomez	California Energy Commission
Steve Ghadiri	California Energy Commission
Charles Mee	California Department of Water Resources
John Goodin	California ISO
Muir Davis	Southern California Edison
Jeremy Laundergan	Southern California Edison
Trey Howard	Southern California Edison
Mark Ward	Sempra Utilities
Gaymond Yee	CIEE
Farrokh Rahimi	OATI
Angela Chuang	Electric Power Research Institute (EPRI)

APPENDIX B:
Milestone Deliverables

Appendix B-1: Charge Code Listing

Pre-MRTU Charge Code Number	Pre-MRTU Charge Code Name	Group	Pre-MRTU Status	MRTU Status	Billable Quantity	Sensitivity to DR	Significance	Dispatchable-Participating Load	Non-Dispatchable / Non-Participating LOAD	Prior Charge Code	Start	End
2	Day Ahead Non-Spinning Reserve due SC	AS	Active	Replaced	Day Ahead Non Spin Capacity Awarded	M	M	X			4/1/1998	Open
4	Day Ahead Replacement Reserve due SC	AS	Active	Retired	Replacement Reserve Accepted Bid Quantity	M	#N/A	X			4/1/1998	Open
7	Demand Relief Monthly Capacity Payment	DR	InActive	Retired	Commited Capacity for the participation in the Demand Relief Program	M	#N/A	X	X		6/15/2002	10/15/2001
24	Dispatched Replacement Reserve (Bid-In) Capacity Withhold	AS	Active	Retired	Amount of 'bid-in' Replacement Reserve capacity that has been dispatched by ISO	M	#N/A	X			8/1/2001	Open
52	Hour Ahead Non-Spinning Reserve due SC	AS	Active	Replaced	Hour Ahead Awarded NonSpinBid Capacity	M	L	X			4/1/1998	Open
54	Hour Ahead Replacement Reserve	AS	Active	Retired	Hour-Ahead additional Replacement Reserve accepted Bid Quantity	M	L	X			4/1/1998	Open
111	Spinning Reserve due ISO	AS	Active	Replaced	Spinning Reserve Obligation MW	H	H	X	X	101	8/18/1999	Open
112	Non-Spinning Reserve due ISO	AS	Active	Replaced	Non-Spinning Reserve Obligation MW	H	H	X	X	102	8/18/1999	Open
114	Replacement Reserve due ISO	AS	Active	Retired	Replacement Reserve Obligation	H	L	X	X	303	8/18/1999	Open
115	Regulation Up Due ISO	AS	Active	Replaced	Regulation Up Oblig MW	H	H	X	X	103	8/18/1999	Open
116	Regulation Down Due ISO	AS	Active	Replaced	Regulation Down Obligation MW	H	H	X	X		8/18/1999	Open
124	Dispatched Replacement Reserve (Self-Provided) Capacity Withhold	AS	Active	Retired	Amount of Excess Self-Provided Replacement Reserve capacity that has been dispatched by ISO	H	L	X	X		8/1/2001	Open
253	Hour-Ahead Inter-Zonal Congestion	CONG	Active	Retired	SC's Hour-Ahead additional New Firm Use (NFU) import into a Zone	M	M	X			4/1/1998	Open
256	Hour-Ahead Inter-Zonal Congestion Debit to SCs	CONG	Active	Retired	SC's Day-Ahead Path Utilization in the Congested Direction	M	H	X			4/1/1998	Open
372	High Voltage Access Charge due ISO	HVAC	Active	Continue	HVAC Daily Metered Load Quantity	M	H	X	X		1/1/2001	Open
550	FERC Fee	FERC	Active	Continue	Measured Demand	M	H	X	X		1/1/2001	Open
591	Emissions Cost Recovery	BCR	Active	Continue	Metered Load within the CAISO Control Area and real time gross exports to other in-state control areas	M	L	X	X		6/21/2001	Open
592	Start-Up Cost Recovery	BCR	InActive	Retired	SC in-state metered Load	M	M	X	X		6/21/2001	39416
593	Emissions Cost Due Trustee	UPLIFT	Active	Retired	Total in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas)	M	#N/A	X	X		6/21/2001	Open
594	Start-Up Cost Due Trustee	UPLIFT	Active	Retired	Total in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas)	M	#N/A	X	X		6/21/2001	Open
1011	Ancillary Service Rational Buyer Adjustment	AS	Active	Retired	SC's user payment for Ancillary Services	H	L	X	X		8/18/1999	Open
1030	No Pay Provision Market Refund	UPLIFT	Active	Retired	SC's Metered Demand in the Control Area	M	M	X	X		8/18/1999	Open
1101	Black Start Capacity due ISO	AS	Active	Continue	SC's Metered Demand in the Control Area	M	#N/A	X	X		4/1/1998	Open
117	Demand Relief Monthly Capacity Charge	DR	InActive	Retired	SC's Metered Demand excluding and non-PTO load under ETC in the Control Area	M	#N/A	X	X		6/15/2002	37179
1120	Est. Summer Reliab. Contract Capacity Pymt/Charge	DR	Active	Retired	SC's Metered Demand	H	#N/A	X	X		5/1/2001	Open
1121	Adj. Summer Reliab. Contract Capacity Pymt/Charge	DR	Active	Retired	SC's Metered Demand	H	#N/A	X	X		5/1/2001	Open
1210	Existing Contracts Cash Neutrality Charge/Refund	Neutrality	InActive	Retired	SC's Metered Demand	M	L	X	X		4/1/1998	36769
1273	FMU Adder Allocation	IE	Active	Retired	SC's Metered Demand in the Zone	M	L	X	X		7/20/2006	Open
1277	Real-Time Intra-zonal Congestion Charge/Refund (Grid Operations Charge)	CONG	Active	Retired	SC's Metered Demand in the Zone	M	H	X	X	452	10/30/2002	Open
1391	Minimum Load Cost Neutrality TCPM Due ISO	AS	Active	Continue	Prorata Measured Demand	M	#N/A	X	X		4/1/1998	Open
1397	Tier 1 MLCC Allocation of TCPM for System Needs	AS	Active	Continue	SC's monthly absolute total of Settlement Interval Net Negative Uninstructed Imbalance Energy (UIE) in the Control Area	M	L	X	X		4/1/1998	Open

Pre-MRTU Charge Code Number	Pre-MRTU Charge Code Name	Group	Pre-MRTU Status	MRTU Status	Billable Quantity	Sensitivity to DR	Significance	Dispatchable-Participating Load	Non-Dispatchable / Non-Participating LOAD	Prior Charge Code	Start	End
1399	Allocation of MLCC for Inter-Zonal Congestion for TCPM	BCR	Active	Retired	SC in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas)	M	#N/A	X	X		6/1/2008	Open
1401	Imbalance Energy Offset	IE	Active	Replaced	SC's Metered Demand in the Control Area	H	M	X	X		8/1/2003	Open
1596	FERCMOO Capacity Payment Neutrality Allocation	BCR	InActive	Retired	SC in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas)	M	L	X	X		6/1/2006	39599
1597	FERCMOO Capacity Payment System Allocation	BCR	InActive	Retired	SC's monthly absolute total of Settlement Interval Net Negative Uninstructed Imbalance Energy (UIE) in the Control Area	M	M	X			6/1/2006	39599
1680	Unrecovered Cost Neutrality Allocation	Neutrality	Active	Retired	SC's Metered Demand in the Control Area	M	M	X	X		10./1/2004	Open
1691	Minimum Load Cost Neutrality Allocation Due ISO	BCR	Active	Retired	SC in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas)	M	L	X	X		10./1/2004	Open
1697	Tier 1 MLCC Allocation for System Needs	BCR	InActive	Retired	SC's monthly absolute total of Settlement Interval Net Negative Uninstructed Imbalance Energy (UIE) in the Control Area	M	M	X			10./1/2004	39599
1699	Allocation of MLCC for Inter-Zonal Congestion	BCR	InActive	Retired	SC's Metered Demand in the Zone	M	H	X	X		10./1/2004	39599
1791	Minimum Load Cost Neutrality Allocation for Resource Adequacy Due ISO	BCR	Active	Retired	SC in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas)	M	#N/A	X	X		6/1/2006	Open
1797	Tier 1 MLCC Allocation of Resource Adequacy for System Needs	BCR	Active	Retired	SC's monthly absolute total of Settlement Interval Net Negative Uninstructed Imbalance Energy (UIE) in the Control Area	L	M	X			6/1/2006	Open
1799	Allocation of MLCC for Inter-Zonal Congestion for Resource Adequacy	BCR	Active	Retired	SC's Metered Demand in the Zone	M	H	X	X		6/1/2006	Open
3472	Demand Relief Energy Payment	DR	InActive	Retired	Reserved Demand for participation in the Demand Relief program [per SC, per location]. Fixed per month; could change if Contracted Load changes the Reserved Demand mid-month	H	#N/A	X			6/1/2001	37165
3473	Discretionary Load Curtailment Program (DLCP) Energy Payment	DR	InActive	Retired	Performance measurement submitted to the ISO based on the DLCP Participant's approved Measurement Plan [per SC, per plan]	H	#N/A	X			6/1/2001	37165
3482	Demand Relief Energy Charge	DR	InActive	Retired	SC's Metered Demand excluding any non-PTO load under Existing Contracts in the Control Area [Per SC]	H	#N/A	X			6/1/2001	37165
3483	Discretionary Load Curtailment Program (DLCP) Energy Charge	DR	InActive	Retired	SC's Metered Demand5 excluding any non-PTO load under Existing Contracts in the Control Area [Per SC]	H	#N/A	X			6/1/2001	37165
4142	Compliance No Pay Charge - Non Spinning Reserve	AS	Active	Replaced	Amt of unfulfilled capacity	M	L	X		142	10/1/2004	Open
4144	Compliance No Pay Charge - Replacement Reserve	AS	Active	Retired	No Pay Replacement Reserve Quantity	M	L	X		144	10/1/2004	Open
4401	Instructed Energy	IE	Active	Replaced	Stlmt Interval Total Instructed Imbalance Energy	H	H	X		401	10/1/2004	Open
4406	Unaccounted for Energy	IE	Active	Replaced	UFE Quantity	H	H	X	X	406	10/1/2004	Open
4407	Uninstructed Energy	IE	Active	Replaced	Sum of Uninstructed Energy	H	H	X	X	407	10/1/2004	Open
4450	Transmission Loss Obligation	IE	Active	Retired	Metered Energy less self x (1 - GMMa) for each resource	L	H	X			10/1/2004	Open
4470	Negative Uninstructed Deviation Penalty	IE	Active	Continue	SC's Negative Uninstructed Energy Quantities	H	#N/A	X			10/1/2004	Open
4480	Positive Uninstructed Deviation Penalty	IE	Active	Continue	SC's Positive Uninstructed Energy Quantities	H	#N/A	X			10/1/2004	Open
4481	Excess Cost for Instructed Energy	IE	Active	Replaced	Instructed Energy having a bid segment > Ex Post Price	H	L	X		481	10/1/2004	Open

Pre-MRTU Charge Code Number	Pre-MRTU Charge Code Name	Group	Pre-MRTU Status	MRTU Status	Billable Quantity	Sensitivity to DR	Significance	Dispatchable-Participating Load	Non-Dispatchable / Non-Participating LOAD	Prior Charge Code	Start	End
4481	Excess Cost for Instructed Energy	IE	Active	Replaced	Instructed Energy having a bid segment > Ex Post Price	H	L	X		481	10/1/2004	Open
4487	Allocation of Excess Cost for Instructed Energy	IE	Active	Replaced	SC's Net Negative Uninstructed Energy in the Control Area	H	M	X		487	10/1/2004	Open
4501	GMC-Core Reliability Services Non-Coincident Peak	GMC	Active	Continue	Peak Demand	M	H	X	X		1/1/2004	Open
4502	GMC-Core Reliability Services Non-Coincident Off Peak	GMC	Active	Continue	Off-Peak Demand	M	L	X	X		1/1/2004	Open
4505	GMC-Energy Transmission Services Net Energy	GMC	Active	Continue	Net energy Load and Exports	M	H	X	X		1/1/2004	Open
4506	GMC-Energy Transmission Services Deviations	GMC	Active	Continue	Absolute value of Net Uninstructed Deviations	M	M	X	X		1/1/2004	Open
4511	GMC - Forward Scheduling	GMC	Active	Replaced	All final hour schedules of load, export, Gen, Import, Awarded AS, and Awarded RUC	M	M	X	X		1/1/2004	Open
4534	GMC-Market Usage Ancillary Services	GMC	Active	Replaced	Absolute value of SC's purchases and sales of AS in all markets (IFM, Hour Ahead, RTM)	M	H	X	X	534	1/1/2004	Open
4535	GMC-Market Usage Instructed Energy	GMC	Active	Continue	Absolute value of SC's Instructed energy in RTM by resource + deviations against instructions	M	#N/A	X	X		1/1/2004	Open
4536	GMC-Market Usage Uninstructed Energy	GMC	Active	Continue	Absolute value of SC's uninstructed deviations being netted by settlment interval	M	M	X	X		1/1/2004	Open
4575	GMC-Settlements, Metering, and Client Relations	GMC	Active	Continue	Assessed if there is any settlement charge activity within the month	L	L	X	X	575	1/1/2004	Open
4660	Above Ex Post Price Payments for Hourly Pre-Dispatched Resources	BCR	Active	Retired	Net Instructed Pre-dispatched IIE quantities that are elibible for above Unrecovered Cost Pmt	H	L	X			3/24/2005	Open
4680	Unrecovered Cost Payment	BCR	Active	Retired	Net Instructed IIE quantities that are elibible for Unrecovered Cost Pmt	H	M	X			10/1/2004	Open
4999	Neutrality Adjustment	Neutrality	Active	Continue	SC's Metered Demand in the Control Area	M	L	X	X		8/1/2003	Open
5911	Emissions Cost Recovery - Neutrality Allocation	BCR	Active	Retired	SC in-state metered Load	M	#N/A	X	X		7/1/2004	Open
5917	Emissions Cost Recovery - Tier 1 Allocation	BCR	Active	Retired	SC's monthly absolute total of Settlement Interval Net Negative Uninstructed Imbalance Energy (UIE) in the Control Area	M	#N/A	X			7/1/2004	Open
5919	Emissions Cost Recovery - Inter-Zonal Congestion Allocation	BCR	Active	Retired	SC's Metered Demand in the Zone	M	#N/A	X	X		7/1/2004	Open
5921	Start-Up Cost Recovery - Neutrality Allocation	BCR	Active	Retired	SC in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas)	M	#N/A	X	X		7/1/2004	Open
5929	Start-Up Cost Recovery - Inter Zonal Congestion Allocation	BCR	Active	Retired	SC's Metered Demand in the Zone	M	#N/A	X	X		7/1/2004	Open
6490	NERC/WECC Reliability Charge	NERC	Active	Retired	NERC/WECC Metered Demand, control area	M	M	X	X		1/1/2005	44196
6457	Declined Hourly Pre-Dispatch Penalty Allocation	Pre-Dispatch	Active	Retired	SC's Metered Demand in the Control Area	M	L	X	X		5/1/2008	Open

Appendix B-2: Derivations

CC111 Derivation (Spin Reserve due ISO)

$$Charge = BQ * SpinRate$$

$$SpinUpRate = \frac{SpinPayDA + SpinPayHA}{SpinReqDA + SpinReqHA}$$

$$BQ = InterSCSpinSold + InterSCSpinBought + EffSelfProvSpin + BaseSpinOblig$$

where

$$BaseSpinOblig = \frac{BaseOpReserveReq * (SpinReqDA + SpinReqHA + TotalEffSelfProvSpin)}{TotalBaseOpReserveReq}$$

$$\frac{\Delta Charge}{\Delta Load} = \frac{\Delta BQ}{\Delta Load} * SpinRate + BQ * \cancelto{0}{\frac{\Delta (SpinRate)}{\Delta Load}}$$

$$= SpinRate * \frac{\Delta (BQ)}{\Delta Load}$$

Let $CAISOTotalReq = SpinReqDA + SpinReqHA + TotalEffSelfProvSpin$

$$\frac{\Delta (BQ)}{\Delta Load} = \cancelto{0}{\frac{\Delta InterSCSpinSold}{\Delta Load}} + \cancelto{0}{\frac{\Delta InterSCSpinBought}{\Delta Load}} + \cancelto{0}{\frac{\Delta EffSelfProvSpin}{\Delta Load}} + \frac{\Delta BaseSpinOblig}{\Delta Load}$$

$$= CAISOTotalReq * \frac{\Delta\left(\frac{BaseOpReserveReq}{TotalBaseOpReserveReq}\right)}{\Delta Load} + \cancelto{0}{\frac{\Delta CAISOTotalReq}{\Delta Load}} * \frac{BaseOpReserveReq}{TotalBaseOpReserveReq}$$

assuming $\Delta Load$ has no effect on $SpinReqDA$, $SpinReqHA$, and $TotalEffSelfProvSpin$

$$= CAISOTotalReq * \frac{\Delta\left(\frac{BaseOpReserveReq}{TotalBaseOpReserveReq}\right)}{\Delta Load}$$

$$\approx (SpinReqDA + SpinReqHA + TotalEffSelfProvSpin) * \frac{1}{TotalBaseOpReserveReq} * \frac{\Delta BaseOpReserveReq}{\Delta Load}$$

assuming $\Delta BaseOpReserveReq$ for SC is negligibly small compared to the sum of $BaseOpReserveReq$ of all SCs.

Since

If let $f(L) = \frac{BaseOpReserveReq}{TotalBaseOpReserveReq} = \frac{BaseOpReserveReq_{SC_i}}{BaseOpReserveReq_{SC_1} + ... + BaseOpReserveReq_{SC_{Ni}}}$

and let $L' = L + \Delta L$.

Then

$$f(L') = \frac{BaseOpReserveReq_{SC_i} + \Delta BaseOpReserveReq_{SC_i}}{BaseOpReserveReq_{SC_1} + ... + BaseOpReserveReq_{SC_i} + \Delta BaseOpReserveReq_{SC_i} + ... + BaseOpReserveReq_{SC_{Ni}}}$$

$$\approx \frac{BaseOpReserveReq_{SC_i} + \Delta BaseOpReserveReq_{SC_i}}{BaseOpReserveReq_{SC_1} + ... + BaseOpReserveReq_{SC_{Ni}}}$$

assuming $\Delta BaseOpReserveReq$ for SC_i is negligibly small compared to the sum of $BaseOpReserveReq$ of all SCs.

$$= \frac{BaseOpReserveReq_{SC_i}}{BaseOpReserveReq_{SC_1} + ... + BaseOpReserveReq_{SC_{Ni}}} + \frac{\Delta BaseOpReserveReq_{SC_i}}{BaseOpReserveReq_{SC_1} + ... + BaseOpReserveReq_{SC_{Ni}}}$$

$$= f(L) + f'(L) * \Delta L$$

So $f'(L) \approx \frac{1}{TotalBaseOpReserveReq} * \frac{\Delta BaseOpReserveReq}{\Delta L}$.

That is,

$$\frac{\Delta}{\Delta Load}\left(\frac{BaseOpReserveReq}{TotalBaseOpReserveReq}\right) \approx \frac{1}{TotalBaseOpReserveReq} * \frac{\Delta BaseOpReserveReq}{\Delta Load}$$

$$\frac{\Delta Charge_{111}}{\Delta Load} \approx \frac{SpinRate * (SpinReqDA + SpinReqHA + TotalEffSelfProvSpin)}{TotalBaseOpReserveReq} * \frac{\Delta BaseOpReserveReq}{\Delta Load}$$

Therefore,

Let $Netload = MeteredLoad + Export - Import$.

If $Netload >= Hydro$, then

$$\frac{\Delta Charge_{111}}{\Delta Load} \approx \frac{SpinRate * (SpinReqDA + SpinReqHA + TotalEffSelfProvSpin)}{TotalBaseOpReserveReq} * 0.07$$

If $Netload < Hydro$, then

$$\frac{\Delta Charge_{111}}{\Delta Load} \approx \frac{SpinRate * (SpinReqDA + SpinReqHA + TotalEffSelfProvSpin)}{TotalBaseOpReserveReq} * 0.05$$

CC112 Derivation (NonSpin Reserve due ISO)

$$Charge = BQ * NSpinRate$$

$$NonSpinRate = \frac{NSpinPayDA + NSpinPayHA}{NSpinReqDA + NSpinReqHA}$$

$$BQ = InterSCNSpinSold + InterSCNSpinBought + EffSelfProvNSpin + BaseNSpinOblig$$

where

$$BaseNSpinOblig = \frac{BaseOpReserveReq * (NSpinReqDA + NSpinReqHA + TotalEffSelfProvNSpin)}{TotalBaseOpReserveReq}$$

$$\begin{aligned}\frac{\Delta Charge}{\Delta Load} &= \frac{\Delta BQ}{\Delta Load} * NSpinRate + BQ * \cancelto{0}{\frac{\Delta (NSpinRate)}{\Delta Load}} \\ &= NSpinRate * \frac{\Delta (BQ)}{\Delta Load}\end{aligned}$$

Let $CAISOTotalReq = NSpinReqDA + NSpinReqHA + TotalEffSelfProvNSpin$

$$\begin{aligned}\frac{\Delta (BQ)}{\Delta Load} &= \cancelto{0}{\frac{\Delta InterSCNSpinSold}{\Delta Load}} + \cancelto{0}{\frac{\Delta InterSCNSpinBought}{\Delta Load}} + \cancelto{0}{\frac{\Delta EffSelfProvNSpin}{\Delta Load}} + \frac{\Delta BaseNSpinOblig}{\Delta Load} \\ &= CAISOTotalReq * \frac{\Delta\left(\frac{BaseOpReserveReq}{TotalBaseOpReserveReq}\right)}{\Delta Load} + \cancelto{0}{\frac{\Delta CAISOTotalReq}{\Delta Load}} * \frac{BaseOpReserveReq}{TotalBaseOpReserveReq}\end{aligned}$$

assuming $\Delta Load$ has no effect on $NSpinReqDA$, $NSpinReqHA$, and $TotalEffSelfProvNSpin$

$$\begin{aligned}&= CAISOTotalReq * \frac{\Delta\left(\frac{BaseOpReserveReq}{TotalBaseOpReserveReq}\right)}{\Delta Load} \\ &\approx (NSpinReqDA + NSpinReqHA + TotalEffSelfProvNSpin) * \frac{1}{TotalBaseOpReserveReq} * \frac{\Delta BaseOpReserveReq}{\Delta Load}\end{aligned}$$

assuming $\Delta BaseOpReserveReq$ for SC is negligibly small compared to the sum of $BaseOpReserveReq$ of all SCs.

Since

If let $f(L) = \frac{BaseOpReserveReq}{TotalBaseOpReserveReq} = \frac{BaseOpReserveReq_{SC_i}}{BaseOpReserveReq_{SC_1} + ... + BaseOpReserveReq_{SC_{Ni}}}$

and let $L' = L + \Delta L$.

Then

$$f(L') = \frac{BaseOpReserveReq_{SC_i} + \Delta BaseOpReserveReq_{SC_i}}{BaseOpReserveReq_{SC_1} + ... + BaseOpReserveReq_{SC_i} + \Delta BaseOpReserveReq_{SC_i} + ... + BaseOpReserveReq_{SC_{Ni}}}$$

$$\approx \frac{BaseOpReserveReq_{SC_i} + \Delta BaseOpReserveReq_{SC_i}}{BaseOpReserveReq_{SC_1} + ... + BaseOpReserveReq_{SC_{Ni}}}$$

assuming $\Delta BaseOpReserveReq$ for SC_i is negligibly small compared to the sum of $BaseOpReserveReq$ of all SCs.

$$= \frac{BaseOpReserveReq_{SC_i}}{BaseOpReserveReq_{SC_1} + ... + BaseOpReserveReq_{SC_{Ni}}} + \frac{\Delta BaseOpReserveReq_{SC_i}}{BaseOpReserveReq_{SC_1} + ... + BaseOpReserveReq_{SC_{Ni}}}$$

$$= f(L) + f'(L) * \Delta L$$

So $f'(L) \approx \frac{1}{TotalBaseOpReserveReq} * \frac{\Delta BaseOpReserveReq}{\Delta L}$.

That is,

$$\frac{\Delta}{\Delta Load}\left(\frac{BaseOpReserveReq}{TotalBaseOpReserveReq}\right) \approx \frac{1}{TotalBaseOpReserveReq} * \frac{\Delta BaseOpReserveReq}{\Delta Load}$$

Therefore,

$$\frac{\Delta Charge_{112}}{\Delta Load} \approx \frac{NSpinRate * \left(NSpinReqDA + NSpinReqHA + TotalEffSelfProvNSpin\right)}{TotalBaseOpReserveReq} * \frac{\Delta BaseOpReserveReq}{\Delta Load}$$

Let $Netload = MeteredLoad + Export - Import.$

If $Netload >= Hydro$, then

$$\frac{\Delta Charge_{112}}{\Delta Load} \approx \frac{NSpinRate * \left(NSpinReqDA + NSpinReqHA + TotalEffSelfProvNSpin\right)}{TotalBaseOpReserveReq} * 0.07$$

If $Netload < Hydro$, then

$$\frac{\Delta Charge_{112}}{\Delta Load} \approx \frac{NSpinRate * \left(NSpinReqDA + NSpinReqHA + TotalEffSelfProvNSpin\right)}{TotalBaseOpReserveReq} * 0.05$$

CC115 Derivation (Regulation Up due ISO)

$$Charge = BQ * RegUpRate$$

$$RegUpRate = \frac{ReqUpPayDA + RegUpPayHA}{RegUpReqDA + RegUpReqHA}$$

$$BQ = EffSelfProvRegUp + \frac{Load}{TotalLoad} * \left(RegUpReqDA + RegUpReqHA + TotalEffSelfProvRegUp\right)$$

$$\frac{\Delta Charge}{\Delta Load} = \frac{\Delta BQ}{\Delta Load} * RegUpRate + BQ * \cancelto{0}{\frac{\Delta (RegUpRate)}{\Delta Load}}$$

$$= ReqUpRate * \frac{\Delta (BQ)}{\Delta Load}$$

Let $CAISOTotalReq = RegUpReqDA + RegUpReqHA + TotalEffSelfProvRegUp$

$$\frac{\Delta (BQ)}{\Delta Load} = \cancelto{0}{\frac{\Delta (EffSelfProvReqUp)}{\Delta Load}} + \frac{\Delta}{\Delta Load}\left(\frac{Load}{TotalLoad}\right) * CAISOTotalReq + \cancelto{0}{\frac{\Delta}{\Delta Load}\left(CAISOTotalReq\right)} * \frac{Load}{TotalLoad}$$

$$= \frac{\Delta}{\Delta Load}\left(\frac{Load}{TotalLoad}\right) * CAISOTotalReq$$

$$\approx \frac{CAISOTotalReq}{TotalLoad} * \frac{\Delta Load}{\Delta Load} = \frac{CAISOTotalReq}{TotalLoad}$$

Assume $\Delta Load$ is so small it has no effect on $\Delta TotalLoad$.

Then

$$\frac{\Delta}{\Delta Load}\left(\frac{Load}{TotalLoad}\right) = \frac{TotalLoad * \cancelto{1}{\frac{\Delta Load}{\Delta Load}} - Load * \cancelto{0}{\frac{\Delta TotalLoad}{\Delta Load}}}{TotalLoad^{2}} = \frac{1}{TotalLoad}$$

Therefore,

$$\frac{\Delta Charge_{115}}{\Delta Load} \approx \frac{RegUpRate * \left(RegUpReqDA + RegUpReqHA + TotalEffSelfProvRegUp\right)}{TotalLoad}$$

where $Rate_{product} = \dfrac{\left(PayTotalDA_{product} + PayTotalHA_{product}\right)}{ReqDA_{product} + ReqHA_{product}}$

CC116 Derivation (Regulation Down due ISO)

$$Charge = BQ * RegDownRate$$

$$RegDownRate = \frac{ReqDownPayDA + RegDownPayHA}{RegDownReqDA + RegDownReqHA}$$

$$BQ = EffSelfProvRegDown + \frac{Load}{TotalLoad} * \left(RegDownReqDA + RegDownReqHA + TotalEffSelfProvRegDown \right)$$

$$\frac{\Delta Charge}{\Delta Load} = \frac{\Delta BQ}{\Delta Load} * RegDownRate + BQ * \cancelto{0}{\frac{\Delta (RegDownRate)}{\Delta Load}}$$

$$= ReqDownRate * \frac{\Delta (BQ)}{\Delta Load}$$

Let $CAISOTotalReq = RegDownReqDA + RegDownReqHA + TotalEffSelfProvRegDown$

$$\frac{\Delta (BQ)}{\Delta Load} = \cancelto{0}{\frac{\Delta (EffSelfProvReqDown)}{\Delta Load}} + \frac{\Delta}{\Delta Load}\left(\frac{Load}{TotalLoad}\right) * CAISOTotalReq + \cancelto{0}{\frac{\Delta}{\Delta Load}\left(CAISOTotalReq\right)} * \frac{Load}{TotalLoad}$$

$$\approx \frac{CAISOTotalReq}{TotalLoad} * \frac{\Delta Load}{\Delta Load} = \frac{CAISOTotalReq}{TotalLoad}$$

Assume $\Delta Load$ is so small it has no effect on $\Delta TotalLoad$.

Then

$$\frac{\Delta}{\Delta Load}\left(\frac{Load}{TotalLoad}\right) = \frac{TotalLoad * \cancelto{1}{\frac{\Delta Load}{\Delta Load}} - Load * \cancelto{0}{\frac{\Delta TotalLoad}{\Delta Load}}}{TotalLoad^{2}} = \frac{1}{TotalLoad}$$

Therefore,

$$\frac{\Delta Charge_{116}}{\Delta Load} \approx \frac{RegDownRate * \left(RegDownReqDA + RegDownReqHA + TotalEffSelfProvRegDown \right)}{TotalLoad}$$

where $Rate_{product} = \dfrac{\left(PayTotalDA_{product} + PayTotalHA_{product} \right)}{ReqDA_{product} + ReqHA_{product}}$

CC4535 Derivation (GMC Market Usage Ancillary Service Charge)

Given $Charge_{4535} = MktUsageASRate * BQ_{4535}$

where $BQ_{4535} = \left|BQ_{Spin}\right| + \left|BQ_{NSpin}\right| + \left|BQ_{RegUp}\right| + \left|BQ_{RegDown}\right|$

If $\mathrm{BQ}_{\mathrm{Product}} \geq 0$ then

$$\frac{\Delta Charge_{4535}}{\Delta Load} = MktUsageASRate * \left\{ \frac{\Delta BQ_{Spin}}{\Delta Load} + \frac{\Delta BQ_{NSpin}}{\Delta Load} + \frac{\Delta BQ_{RegUp}}{\Delta Load} + \frac{\Delta BQ_{RegDown}}{\Delta Load} \right\}.$$

Let $TotalReq_{product} = ReqDA_{product} + ReqHA_{product} + TotalEffSelfProv_{product}$.

From prior derivations for CC111, 112, 115, and 116

So

$$\frac{\Delta Charge_{4534}}{\Delta Load} \approx MktUsageASRate *$$

$$* \left\{ \frac{\Delta BaseOpReserveReq}{\Delta Load} * \frac{TotalReq_{Spin} + TotalReq_{NSpin}}{TotalBaseOpReserveReq} + \frac{TotalReq_{RegUp} + TotalReq_{RegDown}}{TotalLoad} \right\}$$

If $Netload >= Hydro$, then

$$\frac{\Delta Charge_{4534}}{\Delta Load} \approx MktUsageASRate * \left\{ .07 * \frac{\left(TotalReq_{Spin} + TotalReq_{NSpin}\right)}{TotalBaseOpReserveReq} + \frac{\left(TotalReq_{RegUp} + TotalReq_{RegDown}\right)}{TotalLoad} \right\}$$

If $Netload < Hydro$, then

$$\frac{\Delta Charge_{4534}}{\Delta Load} \approx MktUsageASRate * \left\{ .05 * \frac{\left(TotalReq_{Spin} + TotalReq_{NSpin}\right)}{TotalBaseOpReserveReq} + \frac{\left(TotalReq_{RegUp} + TotalReq_{RegDown}\right)}{TotalLoad} \right\}$$

Appendix B-3: Requirements Specification

Summary Software Specification for Demand Response Trigger System (DR Triggers) Decision Support Tool

8/20/09

1. Overview

The requirements specification is based on requirements for the Demand Response Trigger Decision Support tool identified through a series of conference calls and meetings with Market Participants during July and August of 2009. Screen designs documented in the summary slides are included in this document, with further detail on how the graphic user interface should behave.

This document serves to provide more detailed functional descriptions considering the software development point of view. The document is divided into sections that detail the following:

1. Four GUI screens, although the prototype will be implemented for the first three. Namely, the screens are entitled: Day-Ahead, Day-Of, Configure and Scenario screens. The Scenario screen will not be considered in the prototype release, due to budget constraints for the prototype effort.

2. The Day-ahead and Day-of screens requires both the Trigger Impact calculations and the Resource portions of the screens in order to be considered complete and useful to the market participants.

3. The formula for 'Ancillary Service' for both 'Day-Ahead' and 'Day-of' will be made available in September. Although all work to be charged to the project must be completed before September 30, 2009, the drop dead date to receive the AS formulas is to be advised by the developer.

   Rendering of 'Imbalance Energy' depends on user's selection of 'Select Mode'. If the user selects 'Latest MRTU (for day-ahead)' or 'Latest MRTU Data (for day-of)' then the application will download latest RT LMP data from MRTU OASIS for display (as detailed under the DA and Day-of screen specifications). Alternatively, if the user selects 'Hourly Average Forecast', then the application will read forecast data from a spread-sheet (to be provided by PG&E), and display the corresponding data matching date and selected location. The forecast file used in the 'Day-Of' screen represents day-of RT LMP forecasts and therefore is different from the Day-ahead RT LMP forecast file to be used in the 'Day-Ahead' screen. Note: Both files and their locations are user-specified via the Configure screen.

4. The rendering of 'GMC in both 'Day-Ahead' and 'Day-of' in the current release (prototype) will use a mocked-up data instead of live data feeds. The mocked up data for GMC (shown on the screens) is a small value compared to Imbalance Energy and Ancillary Service values shown on the screens for Trigger Impact. The mocked up data is expected to be relatively constant between time intervals.

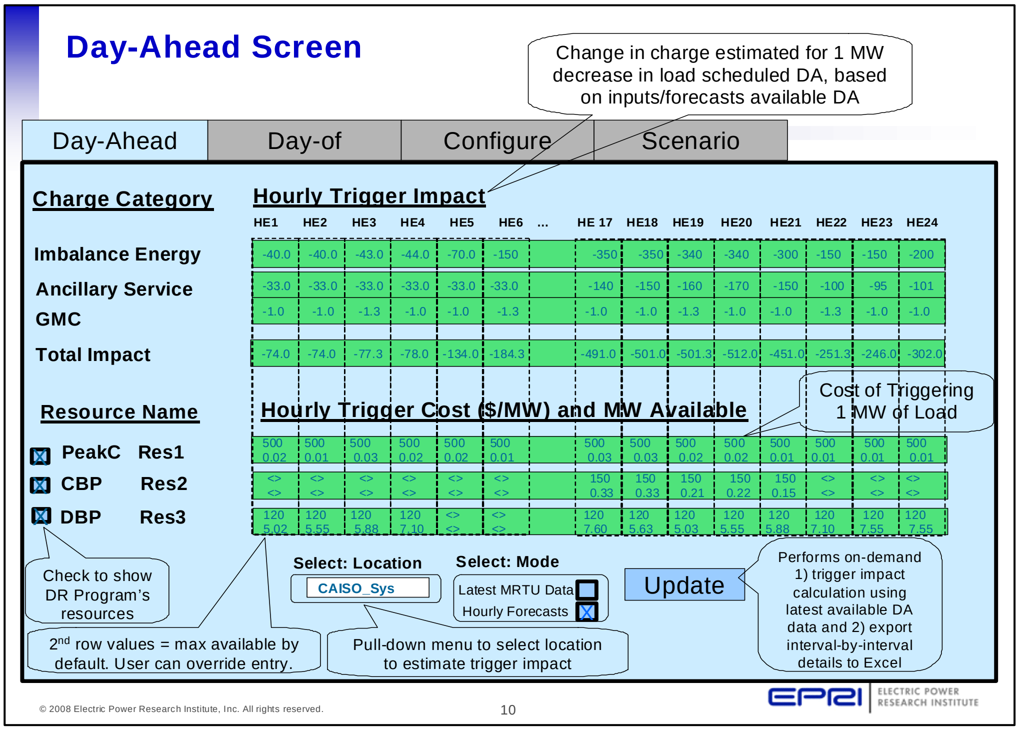
5. The rendering of 'Total-Impact' will take the sum of 'Imbalance Energy', 'Ancillary Service' and 'GMC' and display in the same column.

6. Rendering of data under 'Resource Name' in both 'Day-Ahead' and 'Day-Of' will be based on the DR Program Cost files (provided by PG&E) for 'Day-Ahead' and 'Day-Of' program resource costs and MW availability, respectively. (Further details on rendering of the Resource Cost section of the screen in given under the "Day Ahead" and "Day-of" screen subsections).

2. Target User and Functions beyond Status Quo

The target user of the decision support tool is short-term procurement personnel from the day-ahead and day-of desks. The new functionality provided by the specified tool is the capability of computing Trigger Impact by charge category. This is shown in the upper half of the Day-ahead and Day-of screens. Currently, market participants consider market price (i.e., supply alternatives from bilateral counterparties or the ISO) weighed against demand response program resource costs. Therefore, the target user currently has the DR program cost and MW availability information (shown on the bottom half of the DA and Day-of screens). Beyond current capabilities, the DR Trigger System Decision Support tool enables short-term procurement personnel to compare the DR Program Resource Costs with the impact of triggering each MW of demand response on wholesale settlements for the analyzed charge categories. In order words, the user is empowered for the first time with information on charges that can be avoided/reduced on wholesale settlements from "self-supply" of procurement short-falls (below daily demand forecasts) using demand response resources. The combination of being equipped with Trigger Impact information plus the ability to compare against DR Program Resource Costs provides new information to the user in support of day-ahead and day-of decision-making on triggering demand response (e.g., which resource, how much, and when to trigger).

3. Day-Ahead Screen



Picture 3-1

At application start, all the "green" cells will be blank, until user selects a location on 'Select: Location' pull down and selects a mode under 'Select: Mode', and clicks the button 'Update'.

At the bottom of the screen are the controlling knobs and switches.

The 'Select: Location' pull down will display the 'selectable locations' that are similar to the 'Default Locations' described in the 'Configuration' Screen. The difference is a single selected location specifies the location (used after the user clicks the 'Update' button) for all the Trigger Impact Calculations: 'Imbalance Energy', 'Ancillary Service', 'GMC'.

The 'Select: Mode' control the way of retrieval and displaying the data to the rows under 'Charge Category'. All items under the 'Resource Name' will be filtered by the selected location-code/location-name, and displayed as soon as the user selects a location from the 'Select: Location' pull down.

For 'Imbalance Energy', if the user clicks on 'Latest MRTU Data', the application will download latest MRTU Data from CAISO web service relevant to the Trigger Impact calculations. For the matching location-code data, RT LMP data will be displayed on the Imbalance Energy line. If the user clicks on the 'Hourly Forecasts' mode, then data will be displayed from a Day-ahead RT LMP forecast file.

3.1 Render the RT LMP data for ‘Imbalance Energy’ row under “Latest MRTU Data” mode.

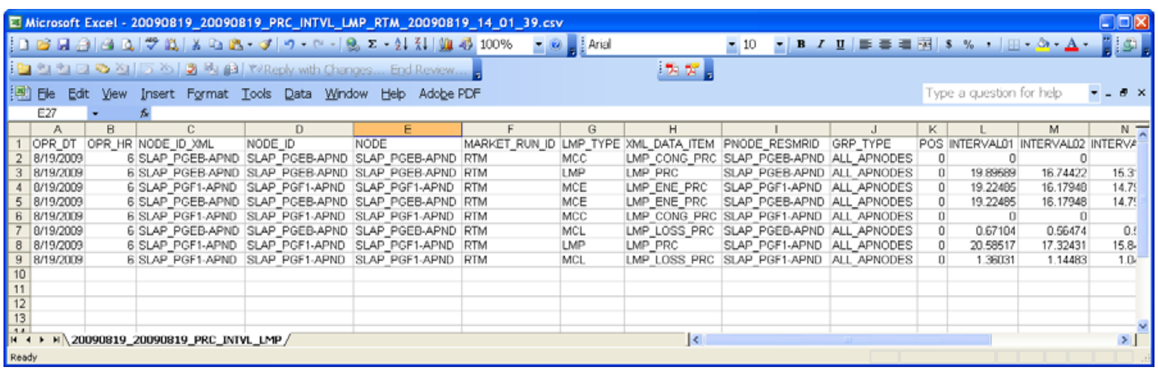
If user selects the ‘Latest MRTU’ data, the application will download RT LMP data from CAISO MRTU site, retrieving data and rendering them on the row for ‘Imbalance Energy’ in the ‘Day Ahead’ screen.

The application downloads ‘Interval Locational Marginal Price (ILMP)’ for the current date and yesterday’s date for the selected location. ‘Select node’ or select location as specified in the Configuration (be default) can be changed by the user’s selection for ‘Location’ in the Day-ahead screen. Note: although not necessary for this particular render function, the application would also download ILMP for each desired SLAP and DLAP location shown in the DR Program Cost file (e.g., PGE_DLAP, SCE_DLAP, SDGE_DLAP), in order to populate the output file resulting from the ‘Update’ function.

Specify both the ‘Date From’ and ‘To’ to today’s date and specify the Hours to be downloaded, then click the button ‘CSV download’. Each hour of data will have 12 (5 minutely) interval data values. The application takes the average of the 12 (5 minutely) interval data values to calculate the hourly average RT LMP. All 12 interval values (zero and-non zero) will be used to compute the hourly average RT LMP.

For example, if the ‘update’ button is clicked at 15:10 (3:10 PM) of a given day, then it will download/display the hourly average for the hours 1-14 of the same day, but display the hourly average data of hour 15-24 of previous day, and populate these values into the ‘HE1 – HE24’ cells of ‘Imbalance Energy’ line.

The downloaded file is assumed to be in zipped format, so will be unzipped to a CSV formatted file, then read by the application. A sample downloaded CSV file has the following appearance:



	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	OPR_DT	OPR_HR	NODE_ID_XML	NODE_ID	NODE	MARKET_RUN_ID	LMP_TYPE	XML_DATA_ITEM	PNODE_RESMRID	GRP_TYPE	POS	INTERVAL01	INTERVAL02	INTERVA
2	8/19/2009	6	SLAP_PGEB-APND	SLAP_PGEB-APND	SLAP_PGEB-APND	RTM	MCC	LMP_CONG_PRC	SLAP_PGEB-APND	ALL_APNODES	0	0	0	
3	8/19/2009	6	SLAP_PGEB-APND	SLAP_PGEB-APND	SLAP_PGEB-APND	RTM	LMP	LMP_PRC	SLAP_PGEB-APND	ALL_APNODES	0	19.89689	16.74422	15.3
4	8/19/2009	6	SLAP_PGF1-APND	SLAP_PGF1-APND	SLAP_PGF1-APND	RTM	MCE	LMP_ENE_PRC	SLAP_PGF1-APND	ALL_APNODES	0	19.22485	16.17948	14.7
5	8/19/2009	6	SLAP_PGEB-APND	SLAP_PGEB-APND	SLAP_PGEB-APND	RTM	MCE	LMP_ENE_PRC	SLAP_PGEB-APND	ALL_APNODES	0	19.22485	16.17948	14.7
6	8/19/2009	6	SLAP_PGF1-APND	SLAP_PGF1-APND	SLAP_PGF1-APND	RTM	MCC	LMP_CONG_PRC	SLAP_PGF1-APND	ALL_APNODES	0	0	0	
7	8/19/2009	6	SLAP_PGEB-APND	SLAP_PGEB-APND	SLAP_PGEB-APND	RTM	MCL	LMP_LOSS_PRC	SLAP_PGEB-APND	ALL_APNODES	0	0.67104	0.56474	0.
8	8/19/2009	6	SLAP_PGF1-APND	SLAP_PGF1-APND	SLAP_PGF1-APND	RTM	LMP	LMP_PRC	SLAP_PGF1-APND	ALL_APNODES	0	20.58517	17.32431	15.8
9	8/19/2009	6	SLAP_PGF1-APND	SLAP_PGF1-APND	SLAP_PGF1-APND	RTM	MCL	LMP_LOSS_PRC	SLAP_PGF1-APND	ALL_APNODES	0	1.36031	1.14483	1.0
10														
11														
12														
13														

Picture 3-3

The application will select only the rows with matching value of ‘LMP’ in column G (LMP Type), and matching location code (for example, ‘SLAP_PGEB-APND’ in column E (Node) – only single row will be selected), and take the values of column L (INTERVAL01) to column W (INTERVAL12). The Hour value will be in the Column B (OPR_HR). The application will take all existing values among INTERVAL01 and INTERVAL12, sum and average against existing field-count as the hourly forecast cost.

3.2 Render data for 'Imbalance Energy' with Select Mode = 'Hourly Forecast'

The values to display are from the file specified in the field 'DA Forecasts' under the 'Configure' Screen.

3.3 Render data for 'Ancillary Service' with Select Mode = "Latest MRTU Data"

TBD

3.4 Render the 'Ancillary Service' with Select Mode = 'Hourly Forecast'

The input data file comes from the file specified in field 'DA Forecasts' field in 'Configure' Screen.

3.5 Render data for 'GMC' row with Select Mode = "Latest MRTU Data"

In the prototype release, the GMC will be retrieved from a mock-up data file, the input file is defined in the 'Sample MRTU Data' field of the 'Configure' screen.

3.6 Render the 'GMC' row data with Select Mode = 'Hourly Forecast'

The input data file comes from the file specified in field 'DA Forecasts' field in 'Configure' Screen.

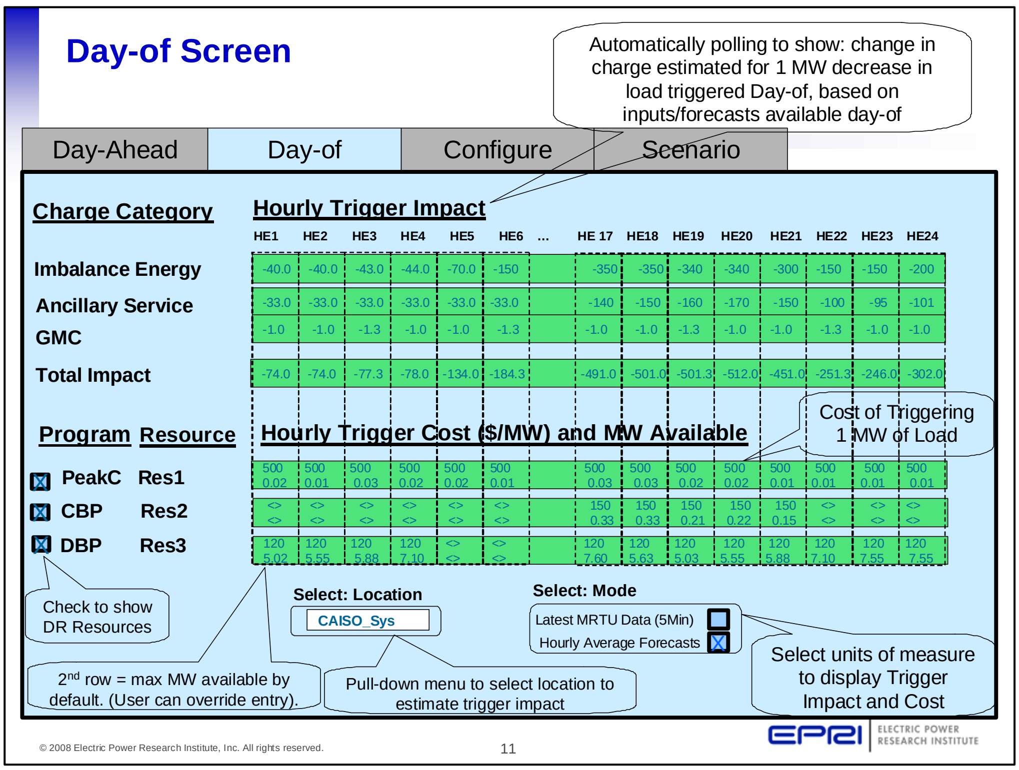
3.7 Render rows under 'Resource Name'

In terms of priority, rendering of this portion will be next to the rendering for 'Imbalance Energy', and before 'Ancillary Service'.

The data rendered under the 'Day-Ahead' screen will be from the input data file specified under the 'DR Program Costs' field of the 'Configure' Screen.

For each Resource, shown in column A (Resource Name), the application will take values of column K (sub_lap_ID) to match column E, as different location, select the ones that match to the 'selected location' specified by user and take rows matching today's date (against column C – date). If there be matching row, then the data with 'Hour Ending' of 1 will be displayed to cell 'HE01', value of 24 will be displayed to cell of 'HE24'. For each Resource name, there will be 2 lines generated: the 'Hour Trigger Cost' will be calculated from the matching row, taking the sum of Column G and Column H; the 'MaxMW Available' is from the Column F of the matching row. All the columns F, G, and H can be translated to numeric values (e.g., null is translated into -000) for ease of programming.

4. Day-Of Screen



Picture 4-1

At the bottom of the screen are the controlling knobs and switches.

The 'Select: Location' pull down will display the 'selectable locations' that are similar to the 'Default Locations' described in the 'Configuration' Screen. The difference is a single selected location specifies the location (used after the user clicks the 'Update' button) for all the Trigger Impact Calculations: 'Imbalance Energy', 'Ancillary Service', 'GMC'.

The 'Select: Mode' control the way of retrieval and displaying the data to the rows under 'Charge Category'. All items under the 'Resource Name' will be filtered by the selected location-code/location-name, and displayed as soon as the user selects a location from the 'Select: Location' pull down.

For 'Imbalance Energy', if the user clicks on 'Latest MRTU Data', the application will download latest MRTU Data from CAISO web service relevant to the Trigger Impact calculations. For the matching location-code data, RT LMP data will be displayed on the Imbalance Energy line. If the user clicks on the 'Hourly Forecasts' mode, then data will be displayed from a Day-of RT LMP forecast file.

Although the screen designs are almost identical, the major difference of this screen and the 'Day-Ahead' screen include the following functions:

- automatic polling in the Day-of screen
- different RT LMP forecast files to use in each screen, since the DA screen uses DA forecasts and the other uses Day-of forecasts of the RT LMPs
- different DR program cost files to use in each screen
- the Day-of Screen shows the latest 5minute RT LMP for current hour-ending (HE) interval on day-of screen's imbalance energy line, when Latest MRTU Data mode is selected. That is for the current HE interval, the application shows in the DA screen the previous day's value for the same interval as the current interval. However, the application shows the latest day-of 5min RT LMP in the Day-of screen for the current HE interval. Note: for the DA screen, the current HE interval is defined to be the HE interval that the user clicks the 'Update' button on the DA Screen.

Under the 'Select: Mode', if 'Latest MRTU Data (5 min)' selected, then this screen will retrieve the latest MRTU data for RT LMP every 5 minutes, and refresh the screen.

Under the 'Select: Mode', if 'Hourly Average Forecasts' selected, then the application will load file defined in the 'Day-of Forecasts:' field in the 'Configure' Screen.

For example, if the current HE cell is HE15 (at 15:10 (3;10PM), the 'Day of' screen will show downloaded ILMP (refer to Picture 3-2) for the current HE interval. Despite whether or not the 12 intervals might not be available in the middle-of-the-hour, the application will display the current RT ILMP in the current HE cell. Average hourly ILMP is computed and shown for the other HE cells.

4.1 Render the OASIS-MRTU data for 'Imbalance Energy' row

The rendering of OASIS_MRTU data for 'Imbalance Energy' row for 'Day-of' is the same as the rendering of OASIS-MRTU data for 'Imbalance Energy' row for 'Day-Ahead'.

Please refer to section 3.1.

4.2 Render the 'Imbalance Energy' row data with Select Mode = 'Hourly Forecast'

The input data file comes from the file specified in field 'Day-of Forecasts' field of the 'Configure' Screen.

4.3 Render the 'Ancillary Service' with Select Mode = 'Latest MRTU Data'

TBD

4.4 Render the 'Ancillary Service' row with Select Mode = 'Hourly Forecast'

The input data file comes from the file specified in the field 'Day-of Forecasts' field in 'Configure' Screen.

4.5 Render data for 'GMC' row with Select Mode = 'Latest MRTU Data'

Please refer to Section 3.5.

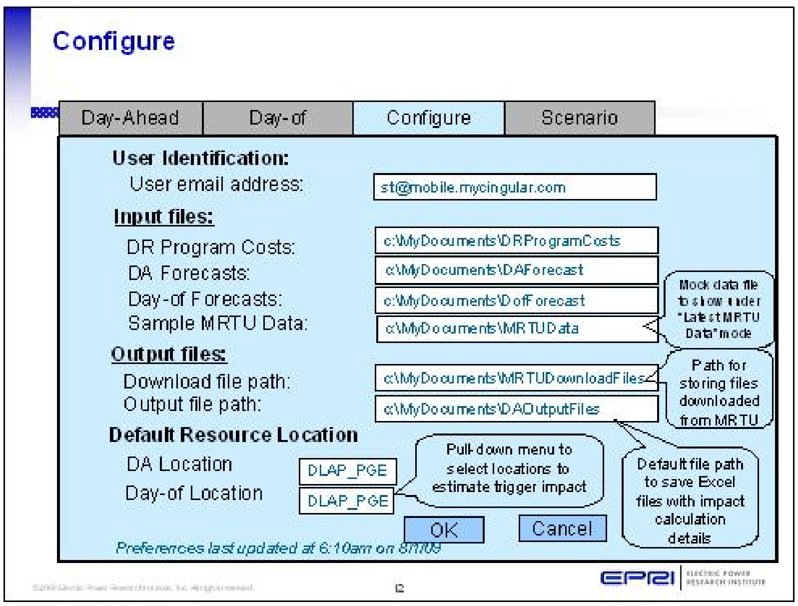
4.6 Render the 'GMC' row data with Select Mode = 'Hourly Forecast'

Please refer to Section 3.6.

4.7 Render rows under 'Resource Name'

This section will mirror that of Section 3.7, except the data displayed will be from the Day-of Forecasts file specified in the Configuration Screen.

5. Configuration Screen



Picture 2-1

The Configuration enables users to configure their preference settings. There might be more 'knobs and switches' than those describe here in order to support the operation.

The 'User Identification' section will keep track of user's email address to identify the last user to change any Configuration settings.

A message displaying "Preferences last updated at <date and timestamp>" will be displayed at the bottom of the screen and settings saved upon the user hitting "OK".

The 'Input File' section will keep track of the location of the input file(s) to be used in the application, for example, the PG&E resources file, the (mock-up) GMC data-file, and the 'Hourly Average Forecast' file.

DR Program Costs File:

The 'DR Program Costs' will be used to store the data under 'Resource Name' (what the 'Function B' refer to in the power-point slides). The name of the resource will come from column A, each resource will have two lines of data displayed – the 'Hourly Trigger Cost' is the sum of Column G and Column H; the second line will be he 'MaxMW Available come from Column F of the file. Column G, H, and F must have numeric only data – space, null or other non-numeric value will cause application fail to read the data.

DA Forecasts:

If user click the 'Hour Forecasts' in the 'Day-Ahead' screen, then the 'Imbalance Energy', 'Ancillary Service' and 'GMC' will be read from the 'DA Forecasts' file. The file will be defined in the field 'DA Forecasts' of the 'Configuration' Screen.

Day-of Forecasts:

If user click the 'Hourly Average Forecasts' in the 'Day-of' screen, then the 'Imbalance Energy', 'Ancillary Service' and 'GMC' will be read from the 'Day-of Forecasts' file. The file will be defined in the field 'Day-of Forecasts' of the 'Configuration' Screen.

The 'Output files' will store the directory path for output the export file (when user request to output the data in excel/csv format).

Download file path:

The 'Download file path' field in the Configure Screen will keep track of the directory-path used for download file from OASIS-MRTU web service. The default directory is 'C:\Temp\OASIS' directory. Under the path, the sub-directory 'download' will store all the original downloaded files (in zip format), after download the zipped file, the application will try to un-zip the file and store them into the sub-directory 'result'. If user do not change the default setting, then the raw data will be downloaded to 'C:\temp\OASIS\download', and the final un-zipped files will be in 'C:\temp\OASIS\result' directory.

Output File Path:

The 'Output File Path' field in the Configure Screen will keep track of the file-path used for the 'Update' function. In the 'Day-Ahead' Screen, when user click the 'Update' button, it will do the download (or read file), then populate all locations of data into the excel files defined in this field.

Default Resource Location:

Store the default location set by user. When user start the application, the default location for that screen will be selected. The selectable locations are from the 'DR Program Costs:' file. Figure 2-2 is from an old version of file. The selectable location data come from column K, L, M, N (column N is not available in the old release of file).

DA Location:

The default location for the 'Day Ahead' screen.

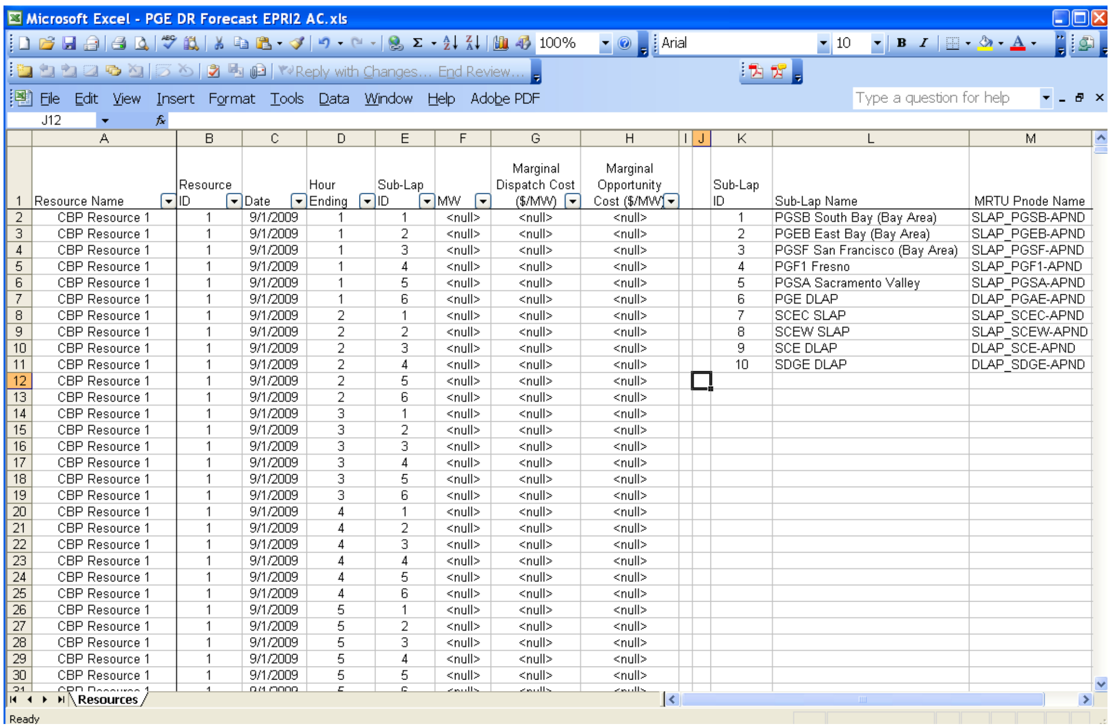
Day-Of Location:

The default location for the ‘Day Of’ screen.

The ‘OK’/’Cancel’ button:

When user make any changes, they need to click the ‘OK’ button to confirm the changes. If user decide to cancel the changes, by clicking the ‘Cancel’ button, the old setting will be shown.

If user makes some changes, and try to switch to other tabs without click either ‘OK’ or ‘Cancel’ button, the application will not allow the tab switch, instead, it will prompt the dialog to ask user confirm between ‘OK’ and ‘Cancel’ to complete the operation.



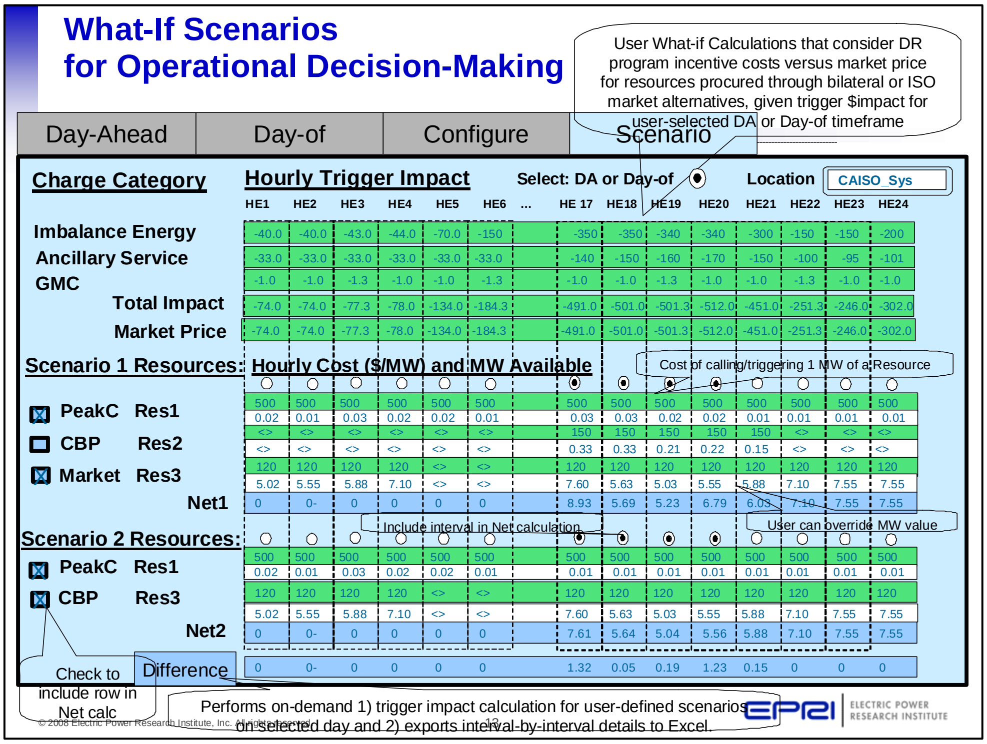
	Resource Name	Resource ID	Date	Hour Ending	Sub-Lap ID	MW	Marginal Dispatch Cost ($/MW)	Marginal Opportunity Cost ($/MW)	Sub-Lap ID	Sub-Lap Name	MRTU Pnode Name
2	CBP Resource 1	1	9/1/2009	1	1	<null>	<null>	<null>	1	PGSB South Bay (Bay Area)	SLAP_PGSB-APND
3	CBP Resource 1	1	9/1/2009	1	2	<null>	<null>	<null>	2	PGEB East Bay (Bay Area)	SLAP_PGEB-APND
4	CBP Resource 1	1	9/1/2009	1	3	<null>	<null>	<null>	3	PGSF San Francisco (Bay Area)	SLAP_PGSF-APND
5	CBP Resource 1	1	9/1/2009	1	4	<null>	<null>	<null>	4	PGF1 Fresno	SLAP_PGF1-APND
6	CBP Resource 1	1	9/1/2009	1	5	<null>	<null>	<null>	5	PGSA Sacramento Valley	SLAP_PGSA-APND
7	CBP Resource 1	1	9/1/2009	1	6	<null>	<null>	<null>	6	PGE DLAP	DLAP_PGAE-APND
8	CBP Resource 1	1	9/1/2009	2	1	<null>	<null>	<null>	7	SCEC SLAP	SLAP_SCEC-APND
9	CBP Resource 1	1	9/1/2009	2	2	<null>	<null>	<null>	8	SCEW SLAP	SLAP_SCEW-APND
10	CBP Resource 1	1	9/1/2009	2	3	<null>	<null>	<null>	9	SCE DLAP	DLAP_SCE-APND
11	CBP Resource 1	1	9/1/2009	2	4	<null>	<null>	<null>	10	SDGE DLAP	DLAP_SDGE-APND
12	CBP Resource 1	1	9/1/2009	2	5	<null>	<null>	<null>			
13	CBP Resource 1	1	9/1/2009	2	6	<null>	<null>	<null>			
14	CBP Resource 1	1	9/1/2009	3	1	<null>	<null>	<null>			
15	CBP Resource 1	1	9/1/2009	3	2	<null>	<null>	<null>			
16	CBP Resource 1	1	9/1/2009	3	3	<null>	<null>	<null>			
17	CBP Resource 1	1	9/1/2009	3	4	<null>	<null>	<null>			
18	CBP Resource 1	1	9/1/2009	3	5	<null>	<null>	<null>			
19	CBP Resource 1	1	9/1/2009	3	6	<null>	<null>	<null>			
20	CBP Resource 1	1	9/1/2009	4	1	<null>	<null>	<null>			
21	CBP Resource 1	1	9/1/2009	4	2	<null>	<null>	<null>			
22	CBP Resource 1	1	9/1/2009	4	3	<null>	<null>	<null>			
23	CBP Resource 1	1	9/1/2009	4	4	<null>	<null>	<null>			
24	CBP Resource 1	1	9/1/2009	4	5	<null>	<null>	<null>			
25	CBP Resource 1	1	9/1/2009	4	6	<null>	<null>	<null>			
26	CBP Resource 1	1	9/1/2009	5	1	<null>	<null>	<null>			
27	CBP Resource 1	1	9/1/2009	5	2	<null>	<null>	<null>			
28	CBP Resource 1	1	9/1/2009	5	3	<null>	<null>	<null>			
29	CBP Resource 1	1	9/1/2009	5	4	<null>	<null>	<null>			
30	CBP Resource 1	1	9/1/2009	5	5	<null>	<null>	<null>			

Picture 2-2

The DR Program Cost file provides data on resource names and marginal costs to trigger as well as maximum MW available. The entry ‘<null>’ in columns F/G/H denotes times the resource is not available.

When the first time the ‘Day Ahead’ screen launched, the lines on ‘Imbalance Energy’, ‘Ancillary Service’, ‘GMC’, ‘Total Impacts’ and all lines under ‘Resource’ will be blank. Upon the user makes a selection for ‘location’, and clicks an option in the ‘Select Mode’ (between ‘Hourly Forecasts’ and ‘Latest MRTU Data’), and then clicks the ‘Update’ button, the application will read all related files, as well as web-download (if required), to populate the selected data onto the screen. The application will display data from the DR Program Costs’ file for the selected nodes/locations.

6. Scenario Screen



Functions supported by Scenario screen include:

A. In addition to information shown on DA/Day-of screens, also show hourly Market Price (from datafile) below Total Impact calculations

B. Allow user to define each of two Scenarios to compare by configuring for each:

1*. Name of Resources in the scenario – selected using a pull down menu of resources

2. MW quantity of resource – through user-override of default max MW available values that show in the white rows

C. Compute and show Net result for each user-defined resource scenario per:

1. Include in Net calculation the HE intervals with radio buttons clicked for resources that are checked

2. Include in Net calculation the resources that are checked

3. Compute Net for each HE interval as:

Net = SumoverselectedDRResources{(TotalImpact+DRProgramCost)*MW_DRResource}

+ SumoverselectedMarketResources{(MarketPrice*MW_MktResource)}

D. Compute and show Difference of Net impact for the two user-defined Resource Scenarios per:

Difference = Net1 – Net2

E. Perform Net and Difference calculations based on user selection of

1. DA or Day-of radio button – to select the context (and data) for scenario comparison
2. Location – to select location of resources that will show on pull-down menu of resources, and that will determine the location for the Hourly Trigger Impact calculations

* Denotes optional feature

Appendix B-4: Published Contribution

The following contribution by the principal investigator was published in the Proceedings of the 2008 CIGRE Paris Session. The contribution provides a response to the question noted below.

Question 1.7

Can utilities comment on the level of adoption of various DSI implementation strategies? Are there practical examples where information signal are used to coordinate demand response with market conditions? What types of trigger signals are being used or are under development?

Title:

Trigger Signals and Adoption Levels of Demand Response Programs in the U.S.

Collectively, Demand-side Integration (DSI) efforts focus on advancing the efficiency and effective use of electricity in support of power systems and customer needs [1] [2]. CIGRE Working Group C6.09 has adopted this term to refer to "the overall technical area focused on the demand-side and its potential as a source of supply, including demand response and energy efficiency." [3] After initial proposal through the author's spontaneous contribution at the CIGRE General Session in 2006 and subsequent adoption by the working group, there has been growing recognition of Demand-side Integration as the underlying technical issue encompassing all aspects of demand-side management in today's restructured industry environment [2][3][4][5].

The subject of trigger signals pertains to DSI implementations focused on achieving demand response**.** Adoption levels for demand response programs in the U.S. are indicated in Figure 23. The total peak reduction potential was approximately 30GW, based on a survey published in 2006 by the Federal Energy Regulatory Commission (FERC). Given a total peak demand of roughly 750GW, the U.S. adoption level was about 4% at the time of the survey.

Figure 23: Demand response potential from 2006 u.s. federal energy regulatory commission survey (source [6])

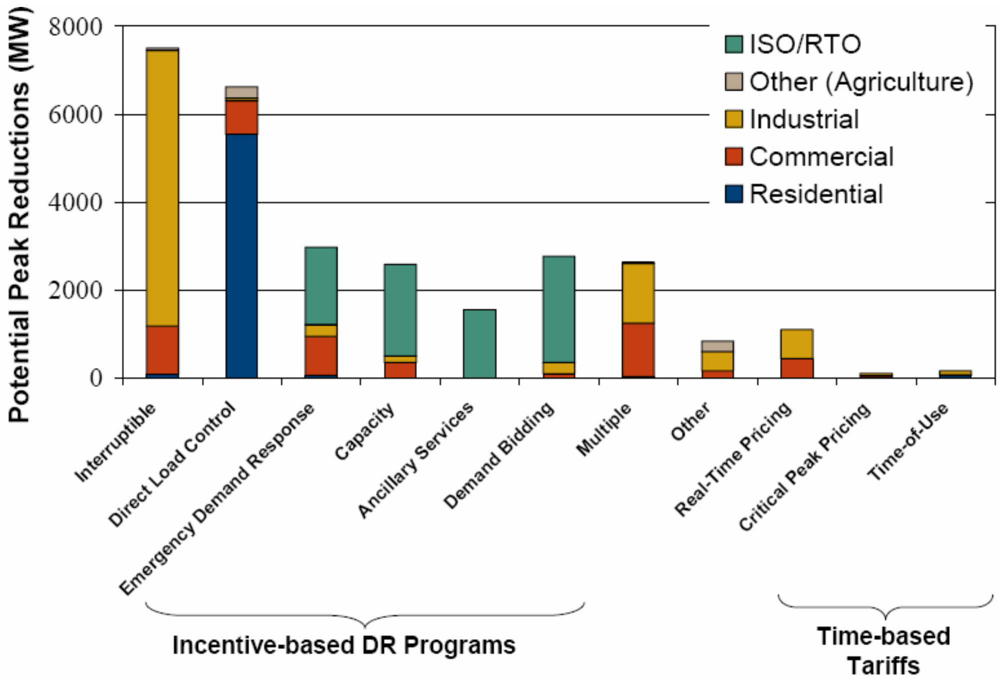
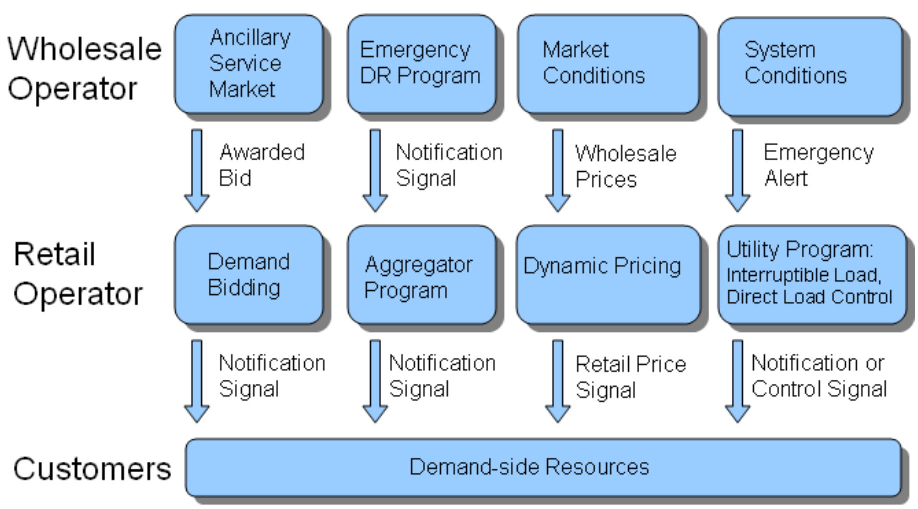


Figure 24 illustrates examples of trigger signals used by wholesale and retail operators to coordinate demand response in the following types of programs:

- Regional System Operator Wholesale Markets
- Regional System Operator Demand Response Program
- Energy Retailer Dynamic Pricing Tariff
- Energy Retailer Demand Response Program

Figure 24: Trigger signal examples



Choice of trigger signals utilized by wholesale and retail operators, respectively, varies by demand response program and depends on the program's defined actuation method. The actuation method dictates information exchange requirements of the particular program, for which the trigger signal is one aspect.

As described in [2] and [4], a demand response program's **actuation method** specifies the

i) **actuator** or entity responsible for actuating a response, and

ii) choice of **trigger** or type of information signal used to coordinate demand response with system or market conditions.

Practical examples of actuation methods include:

- Customer-actuated response to notification signals
- Operator-actuated response via automated controls
- Customer-actuated response to price signals

References:

1. *Advancing the Efficiency of Electricity Utilization-"Prices to Devices™": Background Paper, 2006 EPRI Summer Seminar*. EPRI, Palo Alto, CA. Available at http://www.epri.com.

2. A.S., Chuang, "Demand-side Integration for System Reliability", Proceedings of PowerTech, Lausanne, July 1-5, 2007, pp.1617-1622.

3. A. Baitch, A. Chuang, G. Mauri, C. Schwaegerl, "International Perspectives on Demand-side Integration", Proceedings of the 19th International Conference on Electricity Distribution (CIRED), Vienna, May 21-24, 2007.

4. A.S. Chuang, C.W. Gelling, "Demand-side Integration in a Restructured Electric Power Industry", *CIGRE General Session,* Paris, France, August 24-29, 2008.

5. TSOLID-DER, "Co-ordination Action to Consolidate RTD Activities for Large-scale Integration of DER into the European Electricity Market", 2006, Deliverable D2.1, Work Package II, Task 2.3; Project co-funded by the European Commission within the Sixth Framework Programme (2002-2006). Available at http://www.solid-der.org.

6. "Assessment of Demand Response and Advanced Metering", Staff Report, Federal Energy Regulatory Commission, Docket AD-06-2-000, August 2006.