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Potential Role of Demand Response Resources in Maintaining Grid Stability and Integrating Variable Renewable Energy under California's 33 Percent Renewable Portfolio Standard

Prepared for:
California's Demand Response Measurement & Evaluation Committee (DRMEC)

Prepared by:

Bruce Perlstein, Ph.D.
Erik Gilbert
Frank Stern
Karin Corfee
Lindsay Battenberg
Robin Maslowski
Stuart Schare
Ryan Firestone, Ph.D.

Navigant Consulting, Inc.
One Market Street, Spear Tower, Suite 1200
San Francisco, CA 94105
415.386.7189
www.navigant.com

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1. Executive Summary

This white paper, which Navigant Consulting, Inc. (Navigant) prepared at the request of California's Demand Response Management and Energy Committee (DRMEC),[1] evaluates the potential for using investor-owned utility (IOU) demand response (DR)[2] resources to facilitate the integration of the renewable energy that will be needed to achieve California's recently established 33 percent Renewable Portfolio Standard (RPS).

Much of the renewable energy required to meet that 33 percent RPS goal by 2020 will be obtained from intermittent resources with variable generation patterns, such as wind and solar, that are difficult to predict accurately. As the state increases its reliance on variable renewable energy, it will be harder for the California Independent System Operator (CAISO) to maintain the stability of the state's electricity grid. California's current fleet of generation units, such as natural gas-fired fast-start combustion turbines (CTs), will be increasingly called upon to ramp up or down to balance the variability of those renewable resources. [3] The system will also need more regulation services to maintain grid stability and meet North American Electric Reliability Corporation (NERC) reliability standards, although it is not yet clear how much additional new capacity will be required to meet those needs.[4]

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[1] The DRMEC is composed of staff from the California Public Utilities Commission (CPUC) and California Energy Commission (CEC), as well as representatives of the state's three investor-owned utilities (IOUs) – Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).

[2] Demand response refers to actions by customers that change their consumption (demand) of electric power in response to price signals, incentives, or directions from grid operators. In its February 2006 report to Congress, the U.S. Department of Energy (DOE) defined demand response as:

> *…. changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

Source: U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005. (February 2006 DOE EPAct Report): p. 6.

[3] CAISO 2010 Five Year Strategic Plan.

[4] For example, see: CAISO, Exhibit 1, attached to July 1, 2011 *(Corrected) Direct Testimony of Mark Rothleder on Behalf of the CAISO*, in CPUC Rulemaking 10-05-006.

At the time this white paper is being written, the effort to forecast the amounts and types of capacity that will be needed to achieve California's 33% RPS target is still underway. See: Rothleder, Mark. *CEC Workshop Strategies to Minimize Renewable Integration Costs and Requirements and Improve Integration Technologies*. California Independent System Operator Corporation, 11 June 2012.

DR resources have typically been used to reduce peak demand and, more recently, reduce load when wholesale electricity prices are unusually high. However, more and more attention is now being paid to the possibility that certain types of DR resources could also play a role in integrating growing amounts of variable renewable energy into the electricity grids of jurisdictions that are trying to obtain more power from "green" resources.

Although those types of DR resources might be able to play that role by providing ancillary services similar to those provided by "quick start" combustion turbine generation units, there is a significant uncertainty about the extent to which DR resources can used to meet the CAISO's growing renewable energy integration (RI) needs and whether the DR programs of the California IOUs can or should be adapted to meet those needs.

1.1 Project Scope and Objectives

The primary objectives of this whitepaper are to:

- » Identify and evaluate the potential ability of the existing and planned DR resources of each of California's IOUs to meet the RI needs of the CAISO;
- » Identify changes that would improve the ability of existing IOU DR programs to meet the future renewable integration needs of the CAISO, as variable renewable resources account for a growing share of the state's resource portfolio; and
- » Evaluate and compare the ways several other jurisdictions are using or plan to use DR resources in maintaining grid stability and/or integrating variable renewable energy.

To assess what resources the state will need to achieve its 33 percent RPS target, the DRMEC asked Navigant to rely on the forecasts the CAISO and IOUs submitted in the California Public Utilities Commission (CPUC) Long-Term Procurement Plan (LTPP) proceeding.[5] Those forecasts were prepared for four "base case" scenarios:[6]

- » A "Trajectory Scenario," which assumed California will achieve its 33 percent RPS by 2020 based primarily on the contracts signed by California utilities through 2010;

[5] Track I of CPUC Rulemaking 10-05-006

[6] The standardized assumptions for each of those scenarios included, among other items:

- Estimates of the monthly demand reduction capacity (i.e., ex ante load impacts) of the demand response (DR) resource portfolios of each IOU that were filed in April 2011;
- IOU-provided load and demand forecasts that reflected the latest CPUC-adopted estimates of the load impacts of energy efficiency programs; and,
- CPUC-adopted assumptions regarding:
    - o the retirement or retrofits of once through cooling (OTC) fossil fuel generation capacity by 2017; and,
    - o the amounts of distributed generation capacity that will be available in each year.

- An "Environmentally Constrained Scenario," which assumed California will achieve its 33 percent RPS by 2020 while minimizing environmental impacts according to an Aspen Institute/CPUC environmental scoring methodology;
- A "Cost-Constrained Scenario," which assumed California will achieve its 33 percent RPS by 2020 while minimizing ratepayer costs estimated by using the CPUC's approved RPS Calculator; and
- A "Time-Constrained Scenario," which assumed California will achieve its 33 percent RPS even earlier than 2020 according to timelines established by the CPUC's RPS Calculator.

However, the CAISO and IOU forecasts of the types and amounts of energy, and capacity that will be needed in 2020 under each of these scenarios did not distinguish between those that will be needed due to the variability of incremental renewable generation, and those that will be needed due to the variability in both load and existing (renewable and conventional) generation. Nor would the CAISO make that distinction in procuring and/or scheduling those resources.

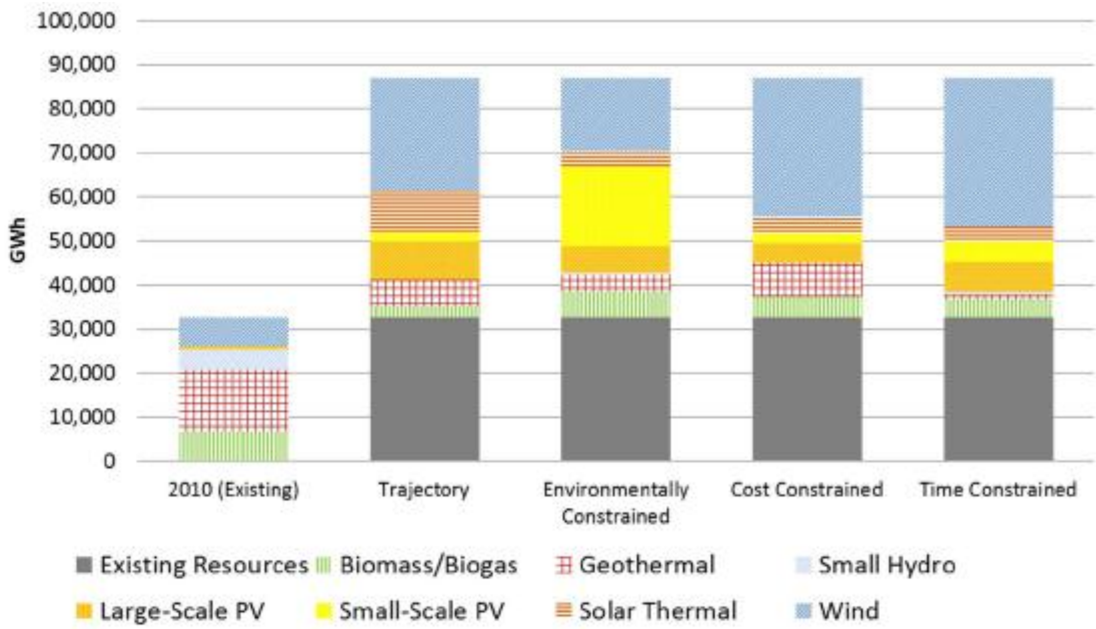
Therefore, this white paper covers dispatchable DR resources that would be capable of providing the types of ancillary services and flexible capacity products that will be needed to manage the overall stability of the state's grid in 2020, rather than only those that will be needed to manage the instability due to the variability of the incremental renewable energy needed to meet the state's 33 percent RPS goal.

1.2 *Renewable Energy Integration*

Figure 1-1 below summarizes the Joint IOUs' April 29, 2011 forecast[7] of the renewable energy that will be obtained in 2020 from different types of incremental renewable resources under each of the base case scenarios cited above.

[7] **Source**: April 29, 2011 Joint IOU Submission to the CPUC, "2010 Long-Term Procurement Plan System Analysis Preliminary Results", in CPUC R. 10-05-006.

Figure 1-1: Total Statewide RPS Resources in 2020 by Scenario and Type (GWh)[8]



As Figure 1-1 demonstrates, wind and solar resources (PV and thermal) are expected to provide the bulk of the incremental renewable energy that will be needed in 2020 to achieve California's 33 percent RPS target. The variability of those renewable resources will increase the difficulty of maintaining the stability of the grid in the CAISO's control area.

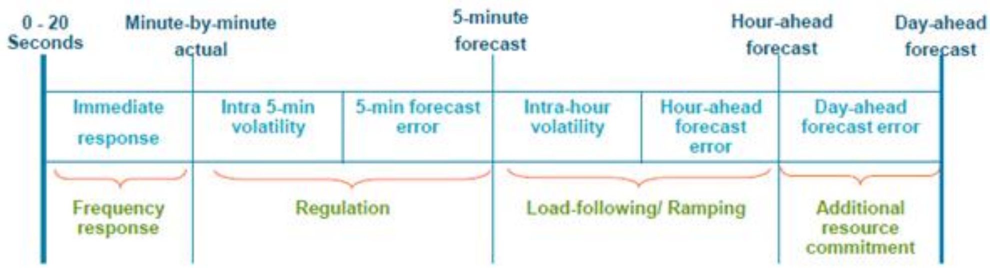
1.3 *Grid Stability and Ancillary Services*

The challenges in maintaining the stability of the electrical grid are due to the uncertainties created by the volatility of demand, the variability of supply, and the difficulty in accurately forecasting both supply and demand over different time intervals. A supply-demand balance must be maintained at all times through frequency control (i.e., maintaining system frequency within a tight range) in order to ensure that the power system is reliable and secure.[9] Figure 1-2 summarizes the sources of the uncertainties within each time interval, and the types of products that grid operators use to deal with those uncertainties.

[8] Ibid.

[9] As in other parts of the country, California's power grid operates at a frequency of 60 hertz (Hz). The allowable deviation in frequency of a 60 Hz system is small (normally ±0.035 Hz for large systems). If the system frequency deviates too far from that level, load shedding protection mechanisms will operate to drop load and restore the frequency. If the frequency deviation cannot be corrected through those load shedding mechanisms, generating units will trip (i.e., disconnect), running the risk of a cascading failure and, in the worst-case scenario, system brownouts or blackouts.

Figure 1-2: Grid Flexibility Needs and Services[10]



Grid operators use ancillary service products to manage wholesale power markets by maintaining the stability of the grid in the face of dips and surges in the balance of electricity demand and supply. The CAISO currently acquires and schedules four types[11] of ancillary service products to manage that uncertainty as follows: [12]

» **Spinning reserve**: "Spinning reserve is the portion of unloaded capacity from units already connected or synchronized to the grid and that can deliver their energy in 10 minutes and run for at least two hours."

» **Non-spinning (or supplemental) reserve**: "Non-spinning (or supplemental) reserve is the extra generating capacity that is not currently connected or synchronized to the grid but that can be brought online and ramp up to a specified load within ten minutes."

» **Regulation up and regulation down**: "Regulation energy is used to control system frequency that can vary as generators access the system and must be maintained very narrowly around 60 hertz. Units and system resources providing regulation are certified by the ISO and must respond to 'automatic generation control' (AGC) signals to increase or decrease their operating levels depending upon the service being provided, regulation up or regulation down."

All other things being equal, increases in reliance on variable renewable energy will lead to increased need for regulation energy and operating reserves, including spinning and non-spinning reserves, which

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[10] Source: Antonio Alvarez (PG&E), "*A planner's insights about the need for operating flexibility reserves for higher penetration of variable generation*", WECC Webinar presentation (October 2011).

[11] Unlike most other ISOs/RTOs, the CAISO procures regulation up services separately from regulation down services. Source: http://www.caiso.com/market/Pages/ProductsServices/Default.aspx.

[12] The following definitions are the ones used by the CAISO. See: http://www.caiso.com/market/Pages/ProductsServices/Default.aspx

make it harder to control frequency and to maintain the stability of the grid.[13] The variability of the energy provided by variable generation resources over various time intervals, illustrated in Figure 1-3 below by using wind as an example, will increase the amounts of those resources needed to maintain the stability of the grid in the CAISO's control area.

Figure 1-3: Grid Management Attributes of Variable Renewable Energy Resources[14]

Variable Generation Production Characteristics	Abbreviated Name	Example of Wind Variability (% of Nameplate Capacity)
Changes in output over very short time scales	<1-minute variability	0.1%-0.2%
Changes in output over short time scales	1 minute to 5-10 minute variability	3-14%
Imperfect ability to forecast generation output for time horizon of 10-120 minutes	<2 hour forecast error	3-25%
Changes in a single direction for multiple hour periods	Large multiple hour ramps	50-85%
Imperfect ability to forecast generation output for time horizon of multiple hours to days ahead	>24 hour forecast error	6-30%
Deviations from the average daily generation profile in actual day to day generation	Variation from average daily energy profile	25-60%
Average daily energy profile generation characteristics depending on the season	Average daily energy profile by season	30-50%

In particular, significant increases in California's reliance on variable renewable energy are likely to:

» Increase the need for regulation, spinning reserve, and load following resources;
» Result in steeper system ramping requirements;
» Increase the frequency and magnitude of over-generation events; and
» Result in less efficient dispatch of conventional resources.

As a result, the CAISO recently asked the CPUC to approve new "flexibility capacity" products, and add those "capacity" products to the types of capacity each IOU and other Load Serving Entities (LSEs) must have in 2013 and beyond to meet their respective monthly (system and local) resource adequacy (RA)

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[13] At the time of this writing, there is an ongoing debate about whether increased reliance on variable renewable resources will increase the need for spinning and non-spinning reserves. For example, comments provided in a review of the draft of this white paper included the following statements:

"The only situation where greater penetration of wind/solar resources will affect contingency reserves is if weather events (wind stops blowing or sun stops shining over large areas) cause a group of wind/solar generators to reduce their output…greater than the current single largest contingency event on the system."

"As penetration grows, the wild card will be MW ramping events that regulation reserves will not cover, that is why Spin and Non Spin will be a larger part of the equation."

[14] **Source:** Peter Cappers, Andrew Mills, Charles Goldman, Ryan Wiser, Joseph H. Eto, *Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study*. LBNL-5063E (October 2011).

requirements.[15,16] Those flexible capacity products would have to meet certain criteria on the following attributes:

- **Maximum continuous ramping:** "Maximum continuous ramping is the megawatt amount by which the net load (load minus wind and solar) is expected to change in either an upward or a downward direction continuously in a given month."

- **Load following:** "Load following is the ramping capability of a resource to match the maximum megawatts by which the net load is expected to change in either an upward or a downward direction in a given hour in a given month..."

The CAISO also asked the CPUC to add regulation services capacity to the monthly RA requirements of each IOU for 2013. The CAISO currently defines regulation capacity as:[17]

> *… the capability of a generating unit to automatically respond during the intra-dispatch interval to the ISO's four-second automatic generation control signal to adjust its output to maintain system frequency and tie line load with neighboring balancing area authorities.*

The key objective of the CAISO is to develop a flexible capacity product called Flexi-Ramp, which the CAISO needs to better manage load deviations between real-time unit commitment, which occurs up to 15 minutes before the real-time market opens, and the real-time dispatch that takes place at five-minute intervals before the real-time market. Therefore, unlike the 10-minute ramping requirements for other ancillary services, Flexi-Ramp would be capable of ramping within 5 minutes.

Other stakeholders agree with CAISO on the need for flexible capacity products. For example, as summarized Figure 1-4, the Pacific Gas and Electric Company (PG&E) recommended adding new flexibility products that would have attributes similar to those the CAISO proposed, including:

- **Frequency response:** immediate response (up to 20 seconds) in response to contingencies;
- **Regulation:** manage uncertainty in 5 to 10 minute ahead forecasts;
- **Following/ramping:** manage remaining intra-hour uncertainty; and
- **Additional resource commitment:** manage deviations between day-ahead and hour-ahead schedules.

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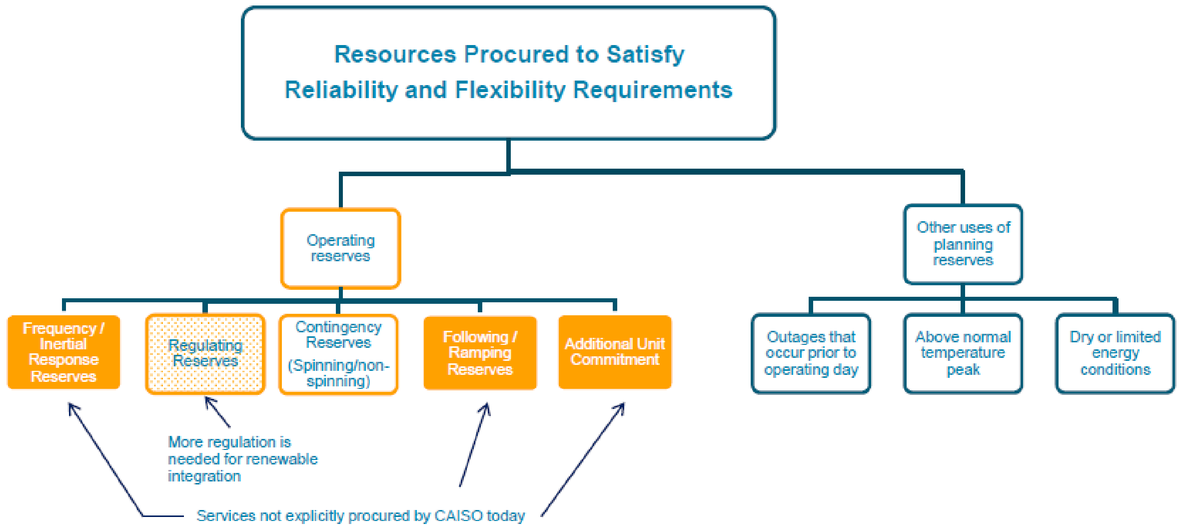
[15] January 12, 2012 CAISO filing in the CPUC's Resource Adequacy (RA) proceeding (R. 11-10-023).

[16] The CPUC allows California IOUs and (LSEs) to use the capacity of dispatchable demand response (DR) resources as well as supply-side resources to comply with their respective monthly Resource Adequacy (RA) requirements. Those DR resources also can be dispatched to reduce the demand for energy in the CAISO's day ahead, hour ahead, and real time markets.

[17] CAISO, *2013 Flexible Capacity Procurement Requirement: Supplemental Information Proposal*. March 2, 2012. http://docs.cpuc.ca.gov/efile/RESP/162107.pdf

Figure 1-4: Resources Needed to Satisfy Grid Reliability and Flexibility Requirements[18]



Although neither the CAISO nor PG&E's proposals have been approved by the CPUC, their proposals provide reasonable indications of the types of balancing products that California is likely to need as variable renewable energy penetration increases in the state.

In order for a resource to be eligible to provide energy, capacity, and/or an ancillary service in CAISO wholesale markets, the resource must have been certified as having the ability to meet certain technical requirements. The matrix in Figure 1-5 summarizes the types of entities that now provide each type of ancillary service, energy, and capacity product in wholesale markets (including the flexible capacity product recently proposed by the CAISO), as well as the technical attributes that each must have under CAISO tariffs.

[18] **Source**: Alvarez, Antonio (PG&E), *A Planner's Insights about the Need for Operating Flexibility Reserves for Higher Penetration of Variable Generation*, WECC Webinar presentation (October 2011)

Figure 1-5: Attributes of Energy, Capacity, and Grid Management Resources

Products/Services Providing Energy, Capacity and/or Maintaining Grid Stability	Providers		Required Attributes							Reliability	
	IOUs and other LSEs	Other Generators	Products/Services Procured and Scheduled by CAISO	Products/Services Self-Scheduled by IOUs and/or Other LSEs	Minimum Resource Capacity	Advance Notice of Deployment	Speed of Response to Control Signal	Required Duration of Response	Frequency of Response	Range of Permissible Deviation from Schedule	Penalty for Failure to Deliver
Spinning reserves	x	x	Day Ahead, Hour Ahead, Real Time Markets	Yes	500 kW	~ 1 minute	< 10 min	30 minutes	~20-200 times/year	Max of 5MW or 3% of max output. Dynamic resources only	Uninstructed Deviation Penalties based on LMP
Non-spinning reserves	x	x	Day Ahead, Hour Ahead, Real Time Markets	Yes	500 kW	As quickly as possible	< 10 min	30 minutes	~20-200 times/year	Max of 5MW or 3% of max output. Dynamic resources only	Uninstructed Deviation Penalties based on LMP
Proposed Flexi-ramp product	x	x	Day Ahead, Hour Ahead, Real Time Markets	Currently Being Developed							
Regulation (proposed by ISO to be part of RA)	x	x	Day Ahead, Hour Ahead, Real Time Markets	Yes	500 kW	None	< 10 min	30-60 minutes	Continuous	Max of 5MW or 3% of max output. Dynamic resources only	Uninstructed Deviation Penalties based on LMP
Energy	x	x	Day ahead, hour ahead, real-time	Yes	None	Scheduled	Scheduled	Scheduled	As Scheduled	Max of 5MW or 3% of max output. Dynamic resources only	Uninstructed Deviation Penalties based on LMP
"Traditional" Resource Adequacy Capacity (local and system)	x		Not Applicable	90% year ahead, 10% month ahead	None	Day ahead	1 hour	Multiple hours	As Required	Not Applicable	None
Proposed Load-following Resource Adequacy Capacity (local and system)	x		Not Applicable	Per Proposed RA Requirements	Currently Being Developed						
Proposed Maximum Ramping Resource Adequacy Capacity (local and system)	x		Not Applicable	Per Proposed RA Requirements	Currently Being Developed						

Note: Attribute descriptions for each product assume the product would not be scheduled or procured from a resource unless that resource was available.

SOURCE: Navigant prepared this matrix based upon material obtained from the following sources:
[1] Peter Cappers, Andrew Mills, Charles Goldman, Ryan Wiser, Joseph H. Eto, *Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study.* LBNL-5063E (October 2011)
[2] CAISO tariffs (as of March 15, 2012)
[3 California Independent System Operator Corporation Proposal on Phase 1 Issues submitted to the CPUC regarding Rulemaking 11-10-023, Order Instituting Rulemaking to Oversee
[4] CAISO Flexible Capacity Procurement- Market and Infrastruture Policy Straw Proposal (March 7, 2012) Presentation
[5] CAISO, 2013 Flexible Capacity Procurement Requirement, Supplemental Information to Proposal (March 12, 2012)
[5] Karl Meeusen (Market Design and Regulatory Policy Lead), CAISO, Flexible Capacity Procurement Straw Proposal (March 12, 2012)
[6] 2011 FERC Summary of ISO/RTO Wholesale Power Markets, available at: https://www.midwestiso.org/Library/Repository/Tariff/FERC%20Filings/2011-08-

1.4 *Need for Ancillary Services and Load Following Capacity*

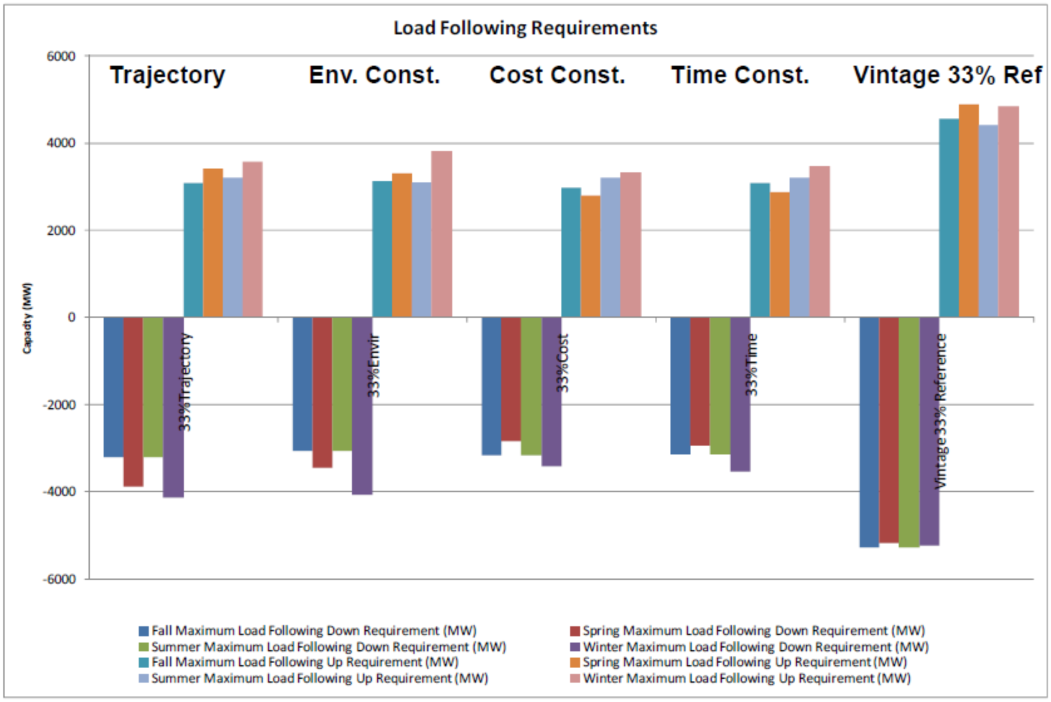
Figure 1-6 (below) summarizes the CAISO's July 1, 2011 estimates of the amount of regulation capacity that will be required in 2020 under each scenario to manage the stability of the grid in light of that increased reliance on variable renewable energy:

Figure 1-6: CAISO Estimates of Hourly Regulation Capacity Requirement in Each Season of 2020 under Each Scenario, Based on Single Highest Hourly Seasonal Requirement in Each Season[19]

Figure 1-7 (below) summarizes the CAISO's July 1, 2011 estimates of the amount of the load following capacity that will be required in 2020 under each scenario to manage the stability of the grid in light of that increased reliance on variable renewable energy:

[19] Source: Exhibit 1 attached to July 1, 2011 Direct Testimony of Mark Rothleder on Behalf of the CAISO in CPUC Rulemaking 10-05-006.

Figure 1-7: CAISO Estimates of Hourly Load Following Capacity Required in Each Season in 2020 under Each Scenario, Based on Single Highest Hourly Seasonal Requirement in Each Season[20]



In written testimony submitted to the CPUC in July 2011, the CAISO reported that these forecasts, based on the standardized assumptions and base case scenarios the CPUC adopted for the Long-Term Procurement Plans submitted by the IOUs, indicated the following:

» Although there would some hours in 2020 with load following down shortages (Figure 1-8), no additional capacity would be needed to meet that shortage. Other measures, such as generation curtailment, would be able to address that issue.[21]
» There would be no need for additional upward ancillary service and load following capacity in 2020 (Figure 1-9).[22]

However, the CAISO also evaluated a "stress case" based on a load forecast that was 10 percent higher than the one used in the CPUC base case scenarios, and concluded that under that scenario 4,600 MW of additional Regulation Up services and Load Following capacity would be needed in 2020.

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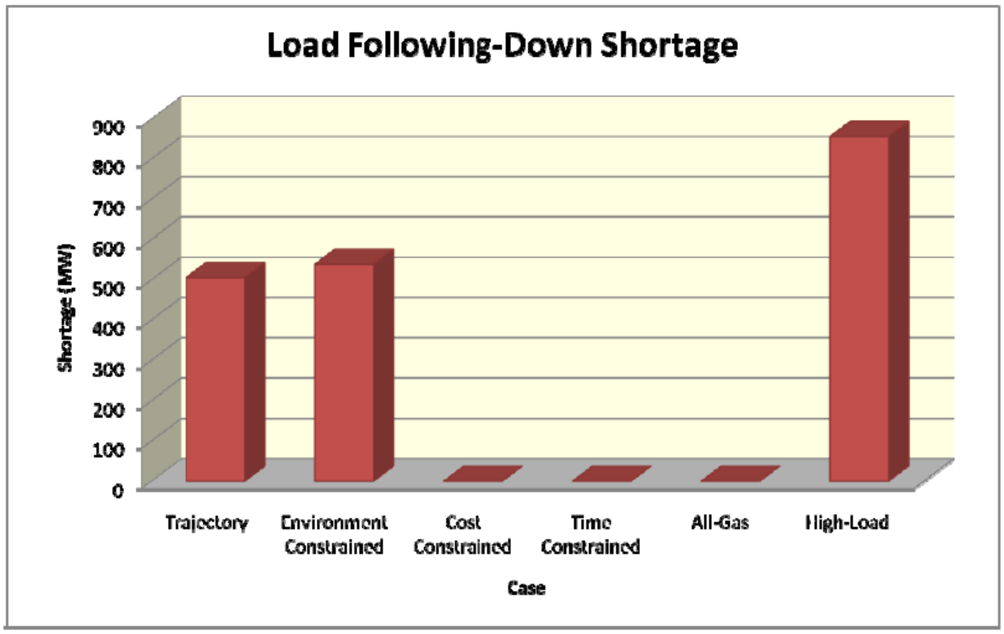
[20] Source: Exhibit 1, attached to July 1, 2011 *(Corrected) Direct Testimony of Mark Rothleder on Behalf of the CAISO*, in CPUC Rulemaking 10-05-006.

[21] Ibid., slide 10.

[22] Ibid., slide 11.

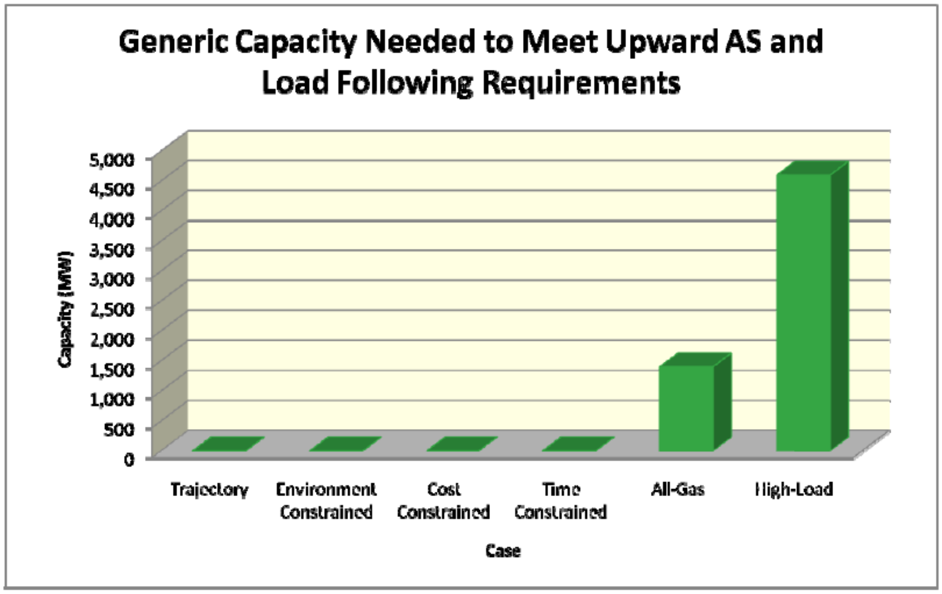
Based on that additional analysis, the CAISO stated that it could not conclude that no additional capacity would be needed in 2020 to achieve the 33 percent RPS target.[23]

Figure 1-8: July 11, 2011 CAISO Forecasts of Load Following Down Needs in 2020 under LTPP Base Case Scenarios



[23] Source: July 1, 2011 *(Corrected) Direct Testimony of Mark Rothleder on Behalf of the* CAISO in CPUC Rulemaking 10-05-006: pp. 44-45.

Figure 1-9: July 11, 2011 CAISO Forecasts of Capacity Needed to Meet Upward Ancillary Services and Load Following Requirements



1.5 *Using IOU DR Programs for Grid Management and Renewable Energy Integration*

The types of dispatchable DR resources that could be used for grid management are a subset of the current array of DR resources. As Figure 1-10 indicates, "reliability" DR programs used to avoid system emergencies and avoid overloading the grid tend to be larger and more numerous than "price-responsive" or "economic" DR programs that reduce demand in response to an external price signal, such as a spike in wholesale electricity prices, or a proxy for higher wholesale prices, such as hot weather conditions or a "market heat" rate.[24]

As currently configured, only a subset of those economic DR programs might have the attributes needed to provide non-synchronous, non-spinning reserves.[25] An even smaller subset might have the attributes needed to provide synchronized non-spinning reserves. [26]

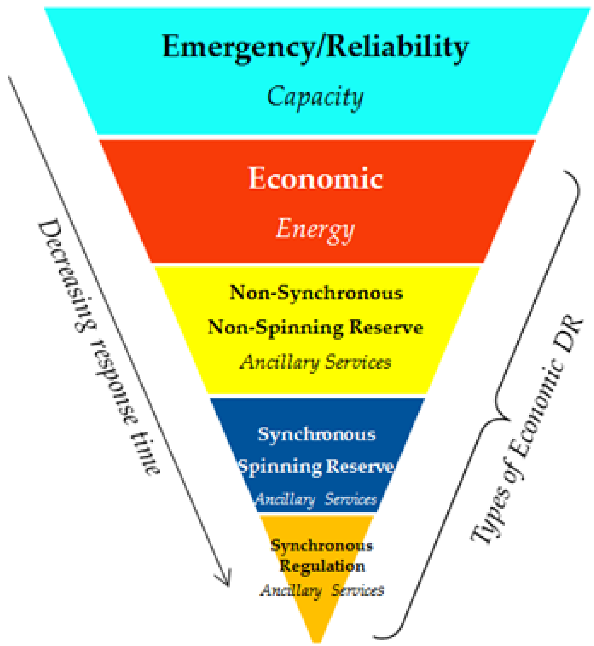
The smallest subset of all consists of those that might have the attributes needed to provide regulation up services (and, if coupled with energy storage, regulation-down services as well).

[24] A market heat rate is the ratio of wholesale electricity price ($/kWh) to the price of natural gas ($/MMBtu).

[25] The current characteristics of most reliability DR programs (e.g., triggers, availability, etc.) would not allow them to provide services that facilitate the integration of variable renewable energy.

[26] Generally, if load can provide spinning reserve, then it can also provide non-spinning reserve.

Figure 1-10: Typology of DR Resources



The most important factors that affect the ability of DR resources to assist in grid management, and the sections of this white paper in which they are discussed in detail) include:

- **Automated response –** The benefit of automated response is that it can execute DR more quickly than manual response, potentially making it a key ingredient for the more rapid response required for ancillary services. (Section 4.1.1)
- **Dynamic pricing –** Non-automated dynamic-pricing programs are unlikely to be sufficiently reliable and predictable to be used in integrating variable renewable resources. (Section 4.1.2)
- **End uses capable of providing DR-based grid management services -** The characteristics of end use loads, in addition to the degree of automation used in controlling them, play a key role in determining which of the ancillary services DR ought to, or in some cases would even be able to provide using those end use loads. (Section 4.1.3)
- **Location of loads providing ancillary services -** If DR resources are to provide ancillary services to help balance intermittent renewable uncertainty, geographic location should be considered in designing and implementing those DR resources. (Section 4.1.4)

1.5.1 Ability of Existing DR Programs to Provide Grid Management Services

Section 5 of this white paper assesses the potential for using the DR programs of California IOUs to assist in the integration of variable renewable energy, by comparing the attributes of each program to the five most important attributes required by the CAISO tariffs for each of the ancillary service products the

CAISO currently uses to support grid management: non-spinning reserves, spinning reserves, and regulation up, and regulation down: [27]

- » Duration of response (Duration);
- » Frequency of response (Frequency);
- » Advanced notice of deployment (Notice);
- » Speed of response to control signal (Speed); and
- » Permissible deviation (Reliability).

Figure 1-11 demonstrates that on average, the current portfolio of IOU DR programs is closest to the required **duration** of response, which is not surprising because DR has generally been used for reliability and economic purposes in California, and DR program events usually are at least several hours long, more than enough time to provide ancillary services. The **frequency** of those events is a greater limitation for most of the existing IOU DR programs, because many programs are limited to one event per day or a dozen or so events per year. The required lack of or limited advance **notice** and **speed** of response are problematic for most DR programs as well, since manual, non-automated response typically cannot provide ancillary services. In particular, it would be difficult for manually controlled loads to participate in those ancillary services markets, due to the short advance notification requirements and the need for rapid response to load control signaling. The maximum permitted **deviation** requirement is also a difficult standard for most of the current IOU DR programs, since few of those programs require the real-time metering and automated response needed to monitor and adjust load response within a narrow band.

[27] As load curtailment programs, California's existing DR programs are not capable of providing regulation down services. Pilot programs in the Pacific Northwest and elsewhere suggest that DR holds potential to provide regulation down.

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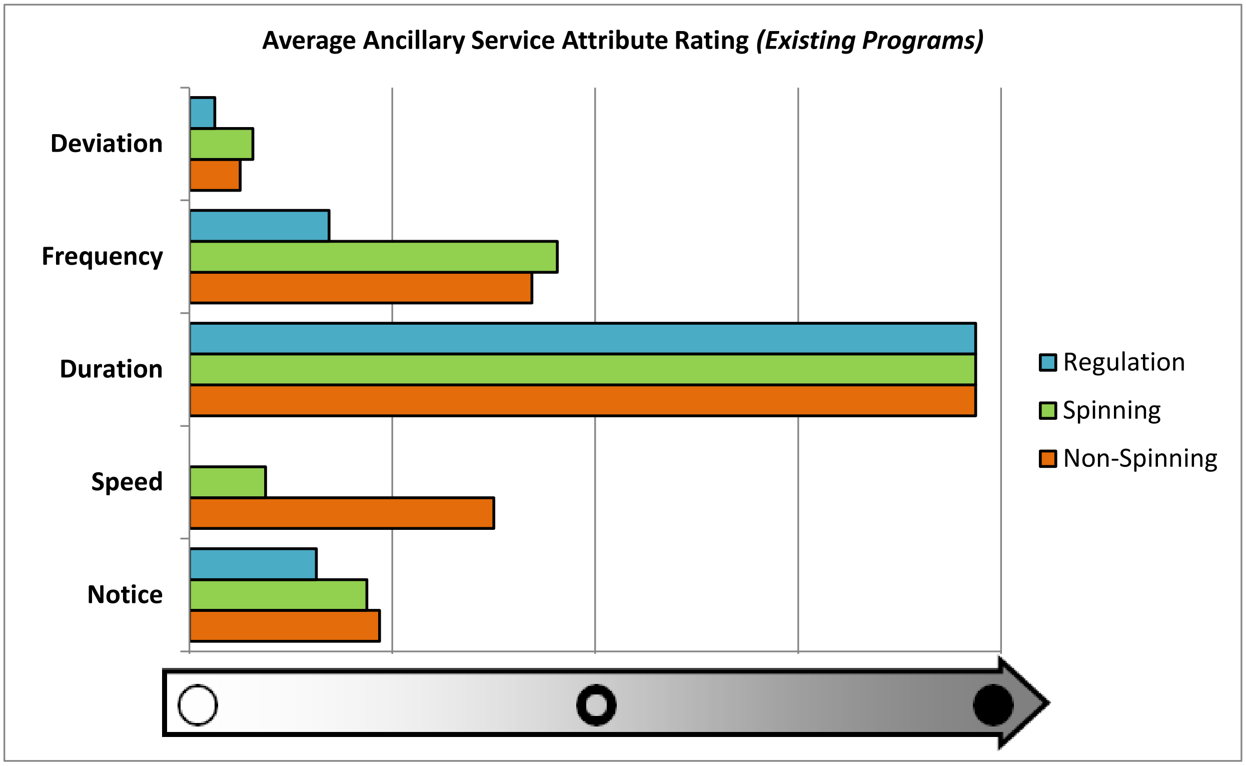
Figure 1-11: Capability of DR Programs to Meet Ancillary Services Requirements

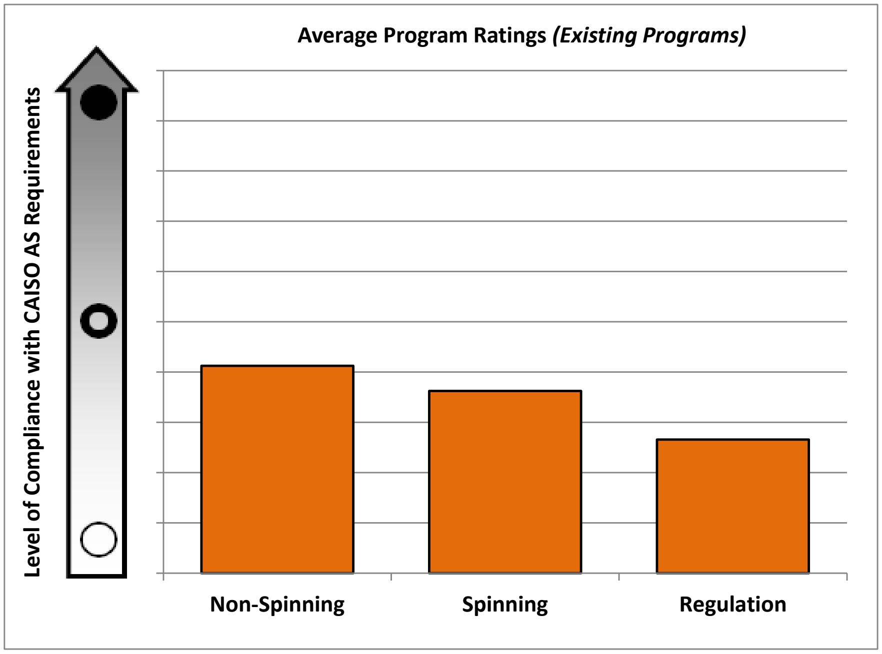


● Meets CAISO requirements
O Partially or nearly meets CAISO requirements, or some participating load may meet requirements
○ Does not meet CAISO requirements

Source: Navigant analysis

Navigant's analysis of the current DR programs of each IOU indicates that those programs, on average, have slightly more potential to provide non-spinning reserves than spinning reserves, and even less potential for providing regulation services (Figure 1-12).

Figure 1-12: Ancillary Service Evaluations of Current IOU DR Programs



● Meets CAISO requirements
o Partially or nearly meets CAISO requirements, or some participating load may meet requirements
○ Does not meet CAISO requirements

Source: Navigant analysis

1.5.2 Ability of Modified DR Programs to Provide Grid Management Services

Despite the apparent inability of the existing IOU DR program portfolio to meet CAISO grid management ancillary product requirements, there are modifications to certain programs that would increase their ability to provide products with the technical attributes required for certain ancillary services. In general, the most important program improvements that would be required in order for a DR program to be used by the CAISO in managing the stability of the grid include:

» Use of telemetry for real-time communications, metering, and control;
» Reduced notification time;
» Automated response to control signals; and
» Increasing the number of times and frequency with which the program could be dispatched.

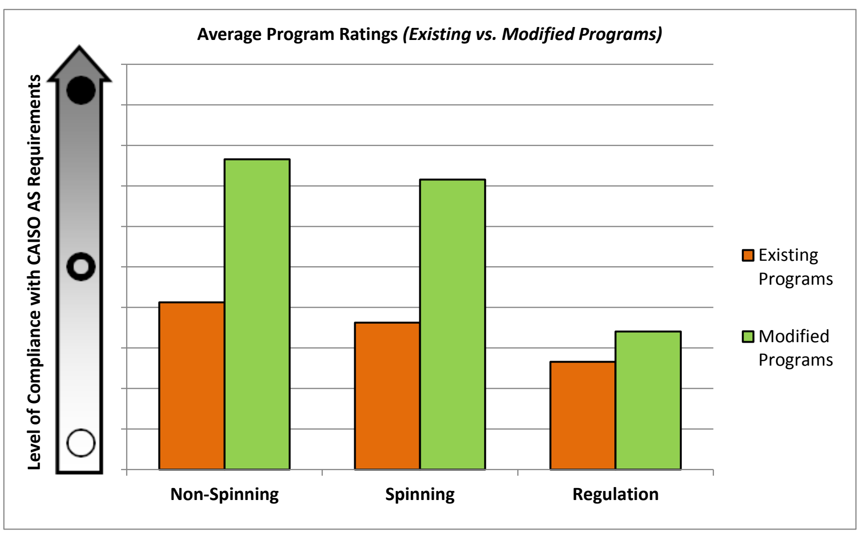
Some of those modifications might significantly reduce the number of customers willing or able to participate in that DR program. Other changes would fundamentally alter the nature of the program or be incompatible with the design of that program.

If these changes are adopted, some of the existing IOU DR programs could contribute to the integration of variable renewables by participating in CAISO's ancillary services wholesale markets, and perhaps by also providing the yet to be fully defined ramping and/or load following products intended to support renewables integration.

Other existing IOU DR programs - such as real-time pricing (which does not have discrete "events") and the Optional Binding Mandatory Curtailment (OBMC) programs (which are designed to interrupt whole circuits only on those rare occasions when a rolling blackout is imminent) - could not be modified in these ways without changing the fundamental functioning of the program.

Based on an assessment of the modifications that could reasonably be made to the existing DR programs of each IOU, Navigant re-rated the programs using the same rating approach described above, comparing the DR programs "as is" to "as modified" DR programs. If the program modifications needed to better align those DR programs with grid management needs are adopted, the DR program portfolio of the IOUs would be much better suited to provide ancillary services, particularly non-spinning and spinning reserves (Figure 1-13).

Figure 1-13: Ability of Modified DR Programs to Provide Ancillary Services



● Meets CAISO requirements
o Partially or nearly meets CAISO requirements, or some participating load may meet requirements
○ Does not meet CAISO requirements

Source: Navigant analysis

Only a few of the DR programs can be modified in ways that would enable them to help maintain the stability of the grid and facilitate the integration of the variable renewable energy needed to attain California's 33 percent RPS target in 2020.

If the necessary modifications are adopted, five of the IOU DR programs might be able to meet all of the CAISO requirements for the provision of non-spinning reserves. Four programs might also provide spinning services, and three might also provide regulation services.

The best-suited programs are San Diego Gas & Electric 's (SDG&E's) and PG&E's Aggregator Managed Portfolio programs and Southern California Edison (SCE's) Demand Response Contracts program, which by their nature can be customized to attract only the customers and loads able and willing to automate and respond in a manner that would provide regulation services. SCE's agricultural pumping load program and SDG&E's Peak Generation program are the most likely to be able to provide spinning and non-spinning reserves, respectively.

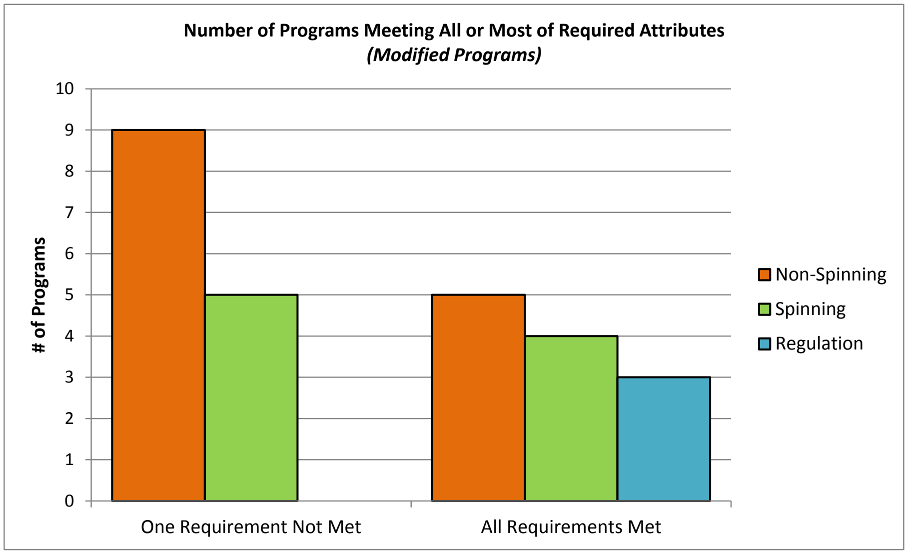
The programs that could be modified in ways that would enable them to provide products covered by current CAISO tariffs are listed in Table 1-1.

Table 1-1: IOU DR Programs that Might Be Modified to Provide Ancillary Services

IOU	Program Name (Modified)	Ancillary Service
PG&E	Aggregator Managed Portfolio	Non-Spinning Reserves
SCE	Agg. & Pump Interruptible	Non-Spinning Reserves
SCE	Demand Response Contracts	Non-Spinning Reserves
SD G&E	Aggregator Managed Program	Non-Spinning Reserves
SD G&E	Peak Generation	Non-Spinning Reserves
PG&E	Aggregator Managed Portfolio	Spinning Reserves
SCE	Agg. & Pump Interruptible	Spinning Reserves
SCE	Demand Response Contracts	Spinning Reserves
SD G&E	Aggregator Managed Program	Spinning Reserves
PG&E	Aggregator Managed Portfolio	Regulation
SCE	Demand Response Contracts	Regulation
SD G&E	Aggregator Managed Program	Regulation

The results also are shown graphically in Figure 1-14, along with the number of programs that meet all but one of the five attributes required by current CAISO tariffs for each ancillary service.

Figure 1-14: Number of Current DR Programs Meeting All or All But One Requirement for Provision of Each Ancillary Service



Source: Navigant analysis

Modified versions of the residential direct load control programs of each IOU and SDG&E's non-residential Summer Saver program would be most likely to be able to provide *spinning reserves if it were not for uncertainty over their ability to monitor and control loads precisely enough* in a short time interval to meet CAISO's Maximum Allowable Deviation requirements. In all, five of the IOU DR programs, once modified, could probably provide spinning reserves, and four more programs could provide *non-*spinning reserves, if they were able to comply with the maximum allowable deviation requirements or another single requirement for those services.

The assessment presented in this report should be viewed as a broad indicator of the degree to which the DR programs of the California IOUs are likely to be able to support the integration of variable renewable energy.[28] Assessments of specific DR programs are subject to significant uncertainty, and should not be viewed as a "yes" or "no" determination of a program's ability to provide specific ancillary services.[29] Rather, the assessments are more appropriately evaluated in the aggregate, and provide a basis for

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[28] Coordination between CAISO and the IOUs will become even more important if there is increased reliance on A/S provided by using distribution system based DR resources. The development and use of those A/S resources also will have implications for distribution planning and operations that IOUs will need to address.

[29] More detailed and extensive assessments of for the potential ability of individual DR programs to provide various A/S should performed before investment decisions are made for those programs. For example, apparently similar DR programs at different IOUs could provide differing responses due to differences between the mix of customers enrolled in those programs.

determining the specific types of programs, customers, and loads that would provide a DR program portfolio tailored to meeting California's future renewable energy integration needs.

1.6 *Obstacles to Using DR to Facilitate Renewable Energy Integration*

1.6.1 Program-Related Limitations

Many of the barriers to the ability of DR programs to provide grid management services stem from the attributes of the programs themselves, including the following:

» **Required technical attributes.** In order for a retail DR program to provide ancillary services in CAISO wholesale markets that would facilitate renewable energy integration, it would presumably have to meet the CAISO technical requirements for ancillary services products, including any new ramping/load following products developed for purposes of integrating variable renewable energy. As discussed in an earlier section, many of the current IOU DR programs simply lack the required advance notification and event frequency attributes, or do not utilize the automation technology needed to ensure sufficiently rapid responses to control signals. Many programs (e.g., price-responsive programs) also are designed in ways that would make it very difficult for them to provide ancillary services. New program designs, coupled with modifications to CAISO ancillary service product attribute requirements and/or the introduction of new CAISO grid management products (e.g., Flexi-Ramp) might allow more DR programs to provide ancillary services.

» **Size/Resource Availability.** The sizes and availability of the end-use loads enrolled in DR programs can limit the ability of those programs to serve as grid management resources, particularly near real-time ancillary service products such as regulation services and spinning reserves. As illustrated in Figure 4-1, only a fraction of end-use loads are likely to be available for DR, and an even smaller portion would be capable of providing the various ancillary service products. Furthermore, the nature of the end-use loads enrolled in DR programs limits their temporal availability. That is one of the reasons why the load reduction capacities of some programs are only available in afternoons, or in the summer, or for a limited number of events or hours per year, and why the load reductions that occur in some hours tend to be lower than those that occur in other hours. That is also one of the reasons why the average load reduction capacity (MW) available from a given DR resource can be significantly higher or lower than the ancillary services capacity that DR program could provide in certain hours. In essence, a DR program's capacity to provide ancillary services at any given time is likely to vary, because of differences between the temporal availability of the end-use loads enrolled in that program.

» **Locational limitations.** DR resources usually have a geographic advantage because their capacity tends to be located in or close to major load centers. However, that is also a limitation in that DR programs cannot be sited where loads do not exist, even if there is a need for grid management services in those locations. CAISO has defined two system geographic regions and eight sub-regions that are used to place regional constraints on the procurement of ancillary services.[30] The current set of IOU DR programs were developed independently of those geographic regions. However, if demand response resources are to provide ancillary services to help maintain the stability of a system that obtains a significant share of its energy from variable renewables, these boundaries might have to be considered in designing and implementing those DR resources. Newer automation technology, which can allow large numbers of individual loads to be independently addressed and controlled, can help address any locational issues by allowing control within pre-defined geographic boundaries. Therefore, those technologies could enable DR programs to span several ancillary services sub-regions, and still provide ancillary services.[31]

- **Limited ability to provide regulation-down services.** Management of the grid requires both regulation up (increased generation or load curtailment) and regulation down (decreased generation, increased loads, and/or energy storage). Although the need for regulation up is usually greater than the need for regulation down, the need for both regulation up and down is likely to increase due to California's growing reliance on variable renewable energy. While generation resources that provide ancillary services can readily ramp both up and down, virtually all existing DR resources can provide only load curtailment, which can be used only for regulation up. Thus, DR in its current form cannot provide one of the four ancillary services the CAISO needs for integrating variable renewable energy. Pilot programs in the Pacific Northwest[32] and elsewhere are testing new technologies that might hold enable DR to provide regulation-down services, but nothing that is significantly effective has been demonstrated yet, especially on a large scale.

1.6.2 Technology Barriers

There are a number of technology barriers to using DR resources to provide ancillary services. Those barriers include the following issues:

- Millions of Smart Meters have been deployed in California. Typically, processing the load data obtained through Smart Meter systems typically takes at least a day before those interval meter data can be accessed. Because of that delay, the data cannot be used to monitor the real-time (or near real-time) performance of a DR event.

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[30] See "Business Practice Manual for Market Operations, Version 25," CAISO, April 9, 2012, p.70 for discussion of AS Regions.

[31] This does not necessarily imply that the design of new DR programs would have to be based on the nodes used for locational marginal prices.

[32] Bonneville Power Administration is sponsoring three pilot programs to test residential, commercial, and industrial end use storage for wind integration. Sources: Ken Nichols, EQL Energy, "End Use Energy Storage and Renewable Integration," Peak Load Management Alliance (PLMA) spring conference, May 2012; Ken Corum, Northwest Power and Conservation Council , "Wind Integration from Demand Response: Load that Moves Both Ways," PLMA fall conference, November 2010; Lee Hall, BPA, personal communication, April 26, 2012.

» Aggregators that provide DR services typically obtain data from a customer meter, or separately sub-meter the controlled load, and provide their own telemetry that allows them to monitor event performance in real-time. The performance speed requirements for providing balancing or regulation services are even higher. In order to provide regulation using demand side resources, it could be necessary to provide four-second interval reads from the load, and sometimes capture more than only energy consumption (e.g., instantaneous power, reactive power, and other process characteristics).[33] Accomplishing that requires a high-speed communications overlay, as well as fairly direct access to load controls (i.e., working through a large building Energy Management System (EMS) may add too much delay for effective control of the resource for some uses). Without telemetry for real-time, automated response and verification of loads, DR cannot be an effective resource for ancillary services.

» Because real-time meter data are needed to provide ancillary services, the discussion of DR programs in Section 1.4 above presumes that telemetry would be available for all programs. Telemetry might not be needed for price-responsive DR programs or for mass-market DR programs—where reductions generally are not mandatory and where many individual small loads provide a statistically predicable range of response. However, these programs have limitations that probably would limit them to providing only non-spinning reserves, if they are capable of providing any ancillary services at all.

» Unless a DR resource can provide automated load response, it will be unable to respond fast enough to a control signal to provide ancillary services. However, the cost of automation can be a significant barrier to the willingness of customers to provide load curtailment through a DR program. That is due to the fact that automation usually provides only non-essential benefits to customers (e.g., improved control of building systems or remote control of isolated loads), and the revenues they obtain from providing load curtailment to ancillary services markets might not be significantly greater than those they can obtain from providing manual load reductions under "traditional" DR programs. For example, although SCE offers incentives of up to $300 per kW for the purchase and installation of qualifying DR-enabling equipment,[34] the result might still be a net cost to the customer.

1.6.3 Market Barriers

There also a number of significant market barriers to the provision of ancillary services by IOU DR resources. Those market barriers include the following issues:

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[33] Some vendors that are now implementing DR for regulation services (e.g., Enbala) have concluded they need two-second interval reads to verify that their load response meets requirements.

[34] Source: SCE, *Technology Assistance and Technology Incentives* fact sheet, 2010. Also see: http://www.sce.com/b-rs/large-business/technical-assistance-technology-incentives.htm

» **Customer Willingness to Participate.** The combined load reduction capacity of the DR programs of the California IOUs has not exceeded 5 percent of the CAISO's system-wide peak load. Even PJM's most recent capacity reserve auction - which attracted more than 14,800 MW of DR - implied a DR penetration equal to only 11 percent of PJM's peak load.[35] Compared to using DR to reduce demand in order to avoid overloading the grid, using DR to provide ancillary services needed for renewable energy integration requires greater automation, little or no advance notification, many more events, and more flexibility in changing loads from moment to moment at different times of the day. Based on all of these factors, the limited willingness of customers to participate in DR programs providing ancillary services could significantly limit the grid management capacity that DR programs could provide.

» **Potential Conflicts with Other DR Programs.** DR resources that provide grid management services for renewable energy integration probably could, and for economic reasons also ought to provide emergency/reliability DR capacity to avoid overloading the grid. In fact, for DR resources to be economic, they almost certainly would have to provide more than just ancillary services. However, when a load is providing demand reductions in response to an actual or imminent grid emergency, it would not be available to help mitigate the impacts of variable renewables on system stability. That situation is analogous to Con Edison's Distribution Load Relief Program (DLRP), which has participants that are also enrolled in the New York Independent System Operator's (NYISO's) reliability DR programs. When the NYISO calls an event in the same hours as a DLRP event, Con Edison pays participating customers only for the amounts by which their load reductions exceeded the demand reduction commitments those customers had made under NYISO's reliability DR program.[36]

1.6.4 Economic Feasibility

Although the scope of this project did not include an evaluation of the economic feasibility of these modified DR programs, and their ability to compete with traditional supply-side sources of ancillary services, CPUC policies would require those programs to be cost effective.

Some of the modifications that would be needed to enable certain DR programs to provide ancillary services that have the technical attributes required by CAISO tariffs would require IOUs and/or the customers enrolled in those programs to incur significant costs. The extent to which modified DR resources will be used to provide some of the ancillary services needed to integrate variable renewables that would otherwise be provided by generation resources will depend upon the relative costs of those two types of resources, and on supply and demand conditions in California's wholesale markets for ancillary services.

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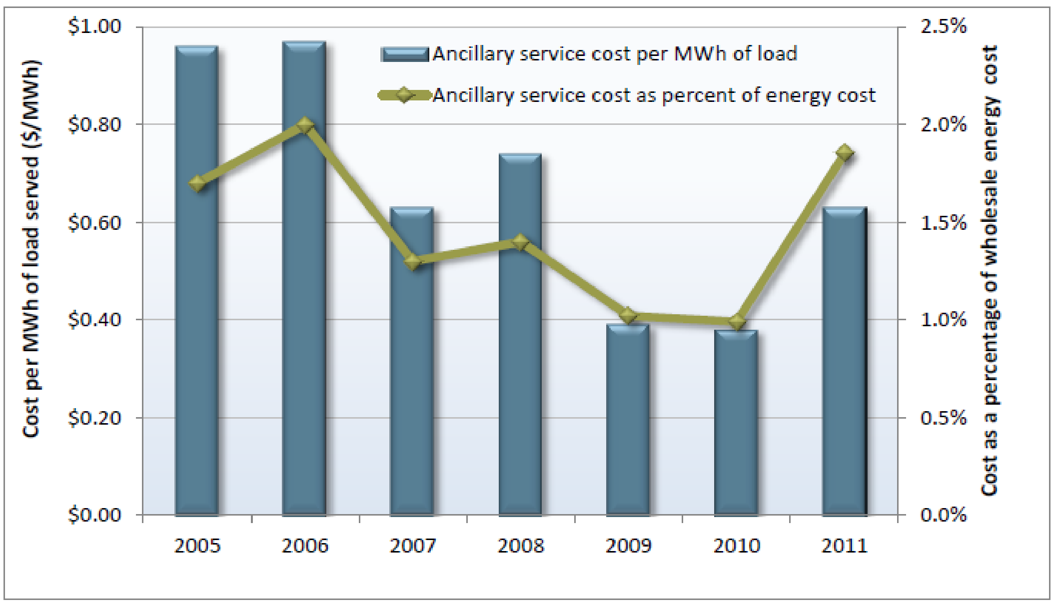
[35] PJM's 2015/2016 capacity reserve auction cleared 164,561.2 megawatts (MW) of capacity, 20.2 percent of which was reserve margin. DR represented 14,832.8 MW, or roughly 11 percent of forecasted load. Source: PJM, *2015/2016 RPM Base Residual Auction Results*, PJM Docs #699093, May 2012.

[36] Source: Con Edison Rider U tariff, Distribution Load Relief Program, issued October 22, 2010.

The total cost of the ancillary services provided in 2011 was about $139 million, which was 61 percent higher than it had been in 2010. In addition to the cost of the ancillary services procured by the CAISO, that total includes the estimated $33 million value of the ancillary services that California IOUs and LSEs provided for themselves in 2011, compared to only $13 million in 2010.[37]

However, the total cost of the ancillary services that were procured or self-provided in 2011 only accounted for about 1.9 percent of California's total wholesale energy costs in that year, compared to just 1.0 percent in 2010 (Figure 1-15).

Figure 1-15: Ancillary Service Wholesale Market Prices and Costs in California[38]



When a resource is given an ancillary service award in the CAISO's wholesale market for an ancillary services product (i.e., the resource sells an option for the provision of that service) in either the day-ahead or real-time market, the resource receives a capacity payment that compensates the resource for the opportunity cost of not providing energy. That ancillary service capacity payment is equal to the expected profit from selling energy to the CAISO.

[37] IOUs and LSEs can reduce their ancillary service procurement requirements by self-providing ancillary services. While this is not a direct cost to the load-serving entity, self-provided ancillary services have an economic value. The CAISO estimate of the value of self-provided ancillary services that is reported here, is based on the costs those IOUs and LSEs would have incurred if they had instead purchased those ancillary services at the clearing prices in CAISO's wholesale market for ancillary services.

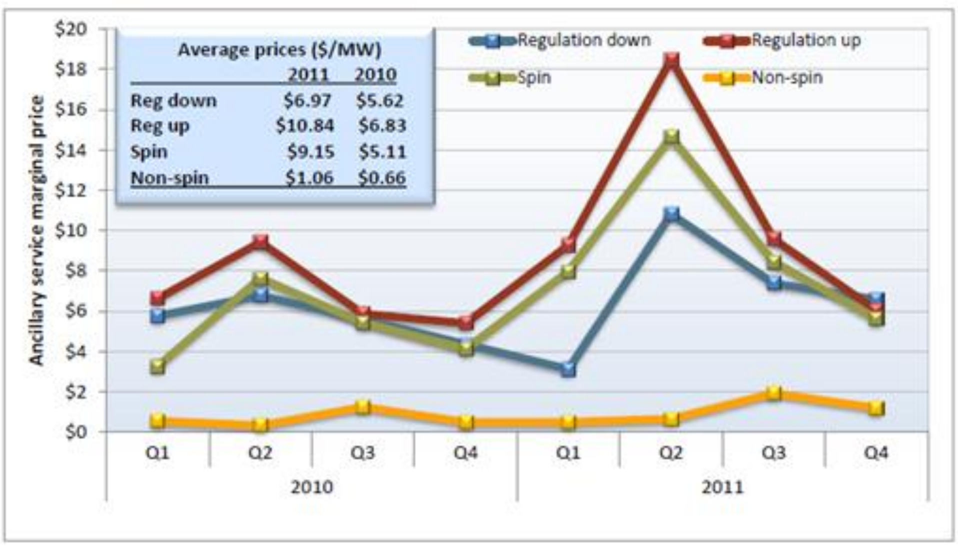
[38] SOURCE: *CAISO's 2011 Annual Report on Market Issues & Performance*, available at http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf

If the resource is actually called upon to provide energy in the real-time market as an ancillary service, the resource also is paid the real-time locational marginal price (LMP) for providing the energy, over and above that ancillary services capacity payment.

Capacity payments in the real-time market are only for incremental capacity in excess of the day-ahead procurement. Consequently, the volume of procurement in the real-time ancillary services market is very limited, accounting for less than one percent of CAISO's total procurement. (Capacity payments in the real-time market for ancillary services are only for incremental capacity above the day-ahead award.)

Figure 1-16 reports the weighted average market-clearing prices for each ancillary service capacity product by quarter in the day-ahead market in 2010 and 2011.

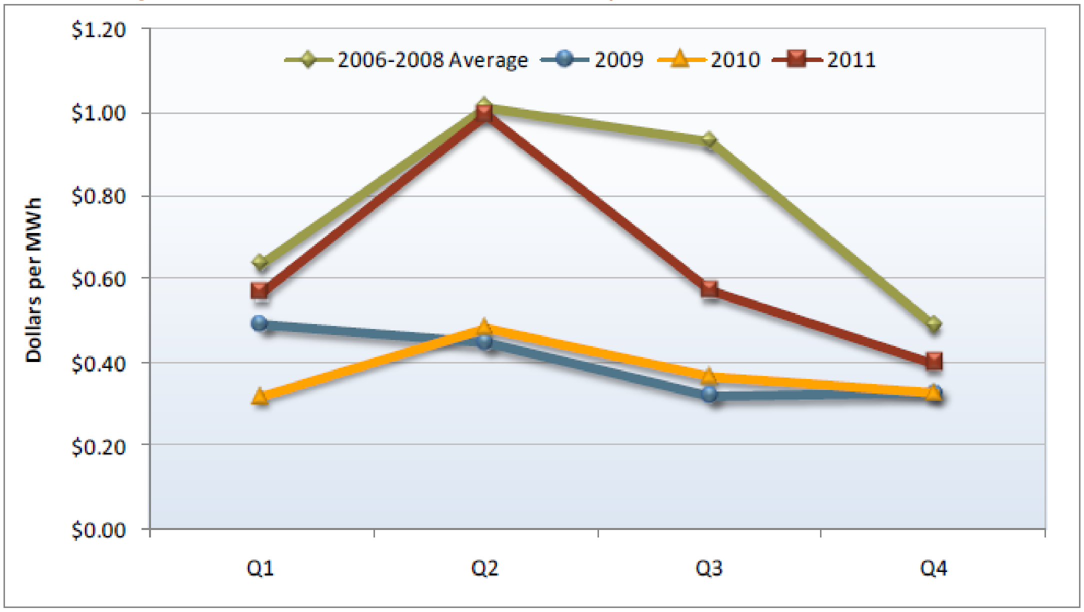
Figure 1-16: Day-Ahead Wholesale Market-Clearing Prices for Ancillary Services[39]



Although average ancillary service prices dropped somewhat after the recession began in 2008, they recovered to pre-recession levels by the last quarter end of 2011 (Figure 1-17).

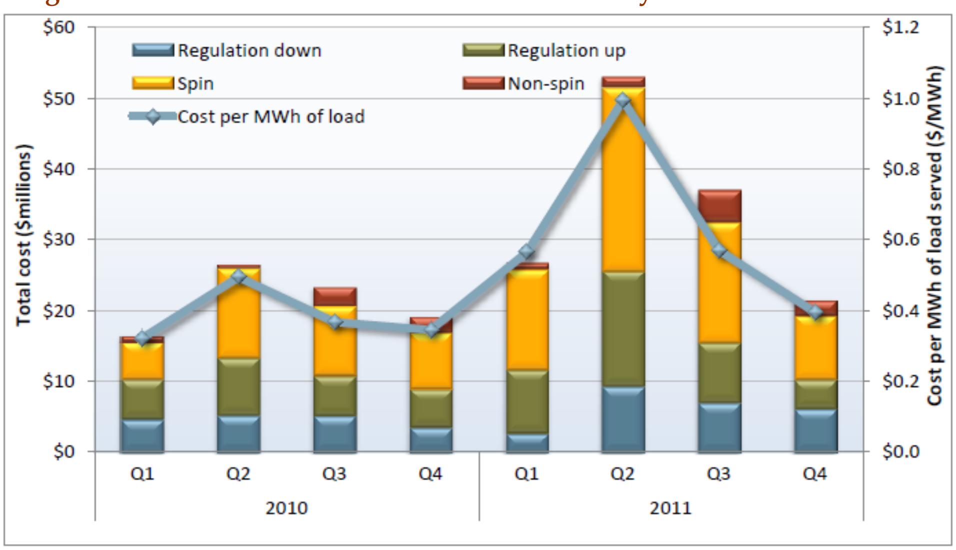
[39] Ibid.

Figure 1-17: Historical Trends in Ancillary Service Prices in California[40]



Spinning reserves accounted for the largest share of the total cost of ancillary services in 2010 and 2011. Regulation up services accounted for the second largest share of that cost (Figure 1-18).

Figure 1-18: Wholesale Prices and Costs of Ancillary Services in California[41]



[40] Ibid.

[41] Ibid.

1.6.5 Regulatory Barriers

As noted above, California's "loading order preference" policy[42] requires IOUs to first procure cost-effective DR and energy efficiency resources, then renewable resources, and only then conventional generation resources. As a result, under the policies adopted by the CPUC, IOU DR programs must be cost-effective. In order to be cost effective, an IOU DR resource that has the technical ability to provide ancillary services would have to provide those services at a lower cost than the generation resource that would otherwise provide them.

In addition, third parties (e.g., DR aggregators) are likely to provide DR resources only if they expect them to be profitable.

The extent to which modified DR resources rather than generation resources will be used to provide some of the ancillary services used to integrate variable renewables will depend largely upon the differences between the costs and technical attributes of the ancillary services provided by those two types of resources. That is likely to become increasingly important because of the steps the CPUC has taken to introduce and promote competition between IOU DR resources, third party DR aggregators, and end-use load customers in the CAISO's wholesale markets (as described in Sections 4.2 and 4.3).

That market competition-based determination of the mix of DR and generation resources used to provide the amount of ancillary services the CAISO requires would be limited if the CPUC adopts policies that restrict the mix of DR and generation capacity that IOUs are required to have to meet any flexible capacity and/or regulation services Resource Adequacy requirements adopted by the CPUC.

In addition, the CPUC already allows IOUs (and other Load Serving Entities (LSEs) in California) to use dispatchable DR resources as well as supply-side resources to comply with their respective monthly Resource Adequacy (RA) requirements. Although those DR resources also can be dispatched to reduce the demand for energy in the CAISO's day ahead, hour ahead, and/or real time markets, existing IOU DR programs are usually dispatched for only a few hours per year at most. Therefore, avoided RA capacity costs now account for the bulk of the benefits provided by DR programs. IOU DR resources that have the technical attributes required by CAISO tariffs for ancillary services would be much more likely to be cost-effective and competitive if they also enabled IOUs to avoid some of the generic generation capacity needed to comply with Resource Adequacy requirements established by the CPUC.

1.7 Recommendations

Demand response can play a role in renewables integration in California if existing programs are modified in ways that would enable them to provide ancillary services, and if new DR programs are

[42] State of California Energy Action Plan (2003), page 2. http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF. Also, see State of California Energy Action Plan II, September 21, 2005, available at: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

specifically designed to participate in CAISO's ancillary services (and future flexible capacity) markets.[43] Both the modified and new DR programs would need to be capable of providing services whose technical attributes would be somewhat different from the reliability DR programs used to avoid system emergencies, and the economic DR program services designed to reduce or shift peak loads from high wholesale energy price hours.

Figure 1-19 (below) summarizes the program changes that would enhance the ability of a number of the existing DR programs of the IOUs to support the integration of variable renewable energy.

Figure 1-19: Recommended Changes to Existing IOU Programs[44]

Program	Telemetry	Reduced Notification	Automated Response	Increase in Events	Extended Hours/Seasons
Aggregator DR program portfolios	X	X	X	Varies	X
Mass-market direct load control (DLC) programs*	X			X	X
Agricultural pumping	X			X	
Base Interruptible Program (BIP)*	X	X	X	X	
Capacity Bidding Program (CBP)	X	X	X	X	X

* Mass-market DLC programs include residential direct load control (DLC) programs as well as commercial programs that allow direct/automated control of loads (e.g., SCE's Summer Discount Plan (SDP) programs).

** The CPUC has placed a "cap" on the combined capacity of Base Interruptible Programs (BIP) and other IOU DR reliability programs. The evaluation of the DR programs presented above assumes that the CPUC would modify that limitation, if the design of the program was changed in ways that would enable it to provide ancillary services and/or flexible capacity products.

In addition to modifying several of the existing DR programs of the IOUs in ways that would enable them to provide ancillary services, new DR programs could be designed from scratch specifically to help the CAISO manage the stability of a grid that relies more heavily on variable renewable energy. In order to be cost-effective enough to compete with other sources of ancillary services in the CAISO's wholesale

[43] It will also be important for CAISO to consider the characteristics and potential future characteristics of DR programs, in addition to generation capabilities, when updating the technical attributes required under market rules for current A/S products and in developing rules for any new flexible capacity products that will be used to help maintain grid stability.

[44] If the CPUC had not prohibited IOUs from counting the load reduction capacity of programs that use customer-owned fossil-fueled back up generation in complying with their Resource Adequacy requirements, this table would have indicated that extending the hours and seasons in which SDG&E's CleanGen program is available would allow that program to provide ancillary services. See: CPUC Decision 11-10-003 (October 6, 2011), pp. 22-30 available at http://docs.cpuc.ca.gov/published/Final_decision/145022.htm.

market, those new DR programs probably also would have to able to provide emergency or economic demand response, even though renewables integration was the primary goal of the program's design, rather than an after-the-fact ancillary services capability benefit.

New DR programs might provide certain current ancillary services products, including spinning and non-spinning reserves and regulation, as well as the continuous ramping and load following products that are currently being developed through a CAISO stakeholder process. Although some of the new DR programs might be designed to optimize their ability to provide one specific ancillary services product, most would also have to be capable of providing products with less stringent technical requirements.

As a rule, new DR programs could be designed primarily to provide one of the following three types of products:

» **Spinning and non-spinning reserves.** These products have considerably more stringent *response* requirements than the ramping and load following products proposed by the CAISO, and therefore would require DR programs capable of providing rapid and flexible responses. However, these products would be similar in some ways to the peak load reduction services provided by "traditional" DR programs.

» **Regulation.** The provision of regulation services would entail a significant leap forward in terms of the required attributes, including near-instantaneous response and precise control of ramping. Regulation-down services (i.e., DR resources capable of increasing loads) would also be required.

» **Maximum continuous ramping/load following.** This category of flexible grid management products includes the non-regulation products under consideration by the CAISO to meet the challenges presented by an increase in renewables penetration. Those products would have slower required response times and slower ramp rates than the CAISO's current ancillary services products. However, providing these capabilities with DR resources would involve considerably more operational complexity. For example, orchestrating and maintaining a multi-hour ramp using a portfolio of DR resources will require technical and load management capabilities that are outside the realm of those traditionally considered in DR program design.

Figure 1-20 summarizes the attributes that DR programs would need to provide each of these ancillary services products.[45]

[45] **Source**: CAISO, *2013 Flexible Capacity Procurement Requirement: Supplemental Information to Proposal, March 2, 2012.*

Figure 1-20: Desired Attributes of DR Programs Supporting Renewables Integration

Attribute	Continuous Ramping/ Load Following	Spinning & Non-Spinning Reserves	Regulation
Telemetry	Required	Required	Required
Response time	Less than one hour, but some resources taking 10 hours or more could be used	Less than 10 minutes; less than 10 second to begin ramping is desirable	Less than a minute
Automated response	Required	Required	Required
Event limitations	10 hours or more duration, minimum of one hour	Dozens to more than 100 events lasting at least one hour each	Continuous availability desired
Daily/seasonal availability*	24x7 year-round, with seasonal variation	24x7 year-round	24x7 year-round
Target end uses	Commercial lighting and HVAC	Agricultural and municipal pumping, electric water heat (if available)	Temperature controlled warehouses, industrial motor loads on variable frequency drives

* Not every resource has to be available 24x7 in all seasons, or even be available for multiple events in a day or for 100 or more events per year. A balanced portfolio of renewable integration DR programs can collectively perform similarly to a generator.

1.8 Conclusions

It is clear that certain types of DR resources could play a key role in renewable energy integration in California, if the right regulatory framework exists and the programs are cost-effective enough to compete with other sources of integration services. The IOUs are well positioned to construct a portfolio of DR programs that would provide many of the ancillary services products the CAISO needs, as well as the newly proposed flexible capacity products capable of maximum continuous ramping and load following. That portfolio could be comprised of both existing programs (most with modifications) and new programs.

1.8.1 Key Findings

The key findings of this research project include:

» The difficulties in maintaining the stability of the grid are due to the volatility of demand, the variability of supply, and the difficulty in accurately forecasting both supply and demand over different time intervals.

» Cost effective DR (together with cost-effective are energy efficiency) at the top of the state's loading order policy, and potentially could play a role in to the integration of variable renewable energy in a cost-effective and flexible manner, by providing non-spinning reserve, spinning reserve, flexible capacity ramping and, to a lesser extent, regulation services.

» Utilizing DR resources to provide these services would provide a number of benefits, including:

  - Avoiding the capacity costs associated with the additional conventional generation capacity, primarily natural gas-fired CTs, that might be required to provide ancillary services that could instead be provided by certain DR resources;
  - Reducing greenhouse gas (GHG) emissions, by reducing the use of conventional fossil-fueled generation to provide ancillary services;
  - Reducing exposure to fuel price volatility, by using DR rather than conventional fossil-fueled generation to provide ancillary services and flexible capacity;
  - Reducing operations and maintenance costs of conventional fossil-fueled generation units, by reducing the number of starts per year;
  - Greater flexibility to meet local reliability needs, including offsetting the adverse impacts of retiring once-through-cooling generation capacity;
  - Enhancing the ability of IOU ratepayers to obtain the benefits associated with widespread deployment of advanced metering infrastructure (AMI) and smart grid technologies, including initiatives funded by California ratepayers and American Recovery and Reinvestment Act of 2009 (ARRA) grants.

» Some of California's existing DR resources can contribute to the integration of variable renewables by participating in CAISO's ancillary services wholesale markets, including the yet to be fully defined flexible ramping and/or load following products that are being developed to support renewable energy integration. Most of those IOU DR programs would require at least modest modifications in order to participate in those markets, and to provide the technical responsiveness needed for effective grid management. In general, the most important necessary program improvements are:

  - Use of telemetry for real-time communications and metering;
  - Reduction or elimination of advance notification time;
  - Automated response to control signals;
  - Less stringent restrictions on the number and frequency of DR events; and
  - Expanded hours or seasons of availability.

» The existing IOU DR programs that are most likely to be capable of contributing to the integration of variable renewable energy are:

  - Aggregator Managed Portfolio DR programs;
  - Mass-market (i.e., residential) direct load control programs; and
  - Agricultural pumping load programs.

» Generally speaking, the more lenient the technical requirements for a given ancillary services product, the easier it will be for DR programs to provide that product. While a few of the IOU

DR programs, as currently designed, could provide ancillary services, CAISO's proposed maximum ramping and load following flexible capacity products could provide an opportunity for DR resources to support renewable energy integration by providing those products. Modified versions of two of the current statewide IOU DR programs would likely to be capable of providing those flexible capacity products:[46]

  - Base Interruptible Program (BIP);[47] and,
  - Capacity Bidding Program CBP).

- Response time and response precision requirements are the most significant limits on the ability of DR program to provide current ancillary services. Non-automated event-based dynamic-pricing programs such as peak time rebates (that do not require a response and are neither automated now nor capable of precise load response) are very unlikely to capable of providing effective grid management support. However, automated dynamic pricing programs might be able to play a larger role in grid management if future CAISO rules allow ancillary services products that meet less stringent requirements than those required for current ancillary services products.

- New DR programs might provide some of the current ancillary services products, including spinning and non-spinning reserves, and perhaps regulation, as well as the continuous ramping and load following products that are currently being developed through a CAISO stakeholder process. Although some of the new DR programs might be designed to optimize their ability to provide a specific ancillary services product, most would also have to be capable of providing products with less stringent technical requirements.

- Key market barriers include cost of automation and real-time communication devices and customer willingness to participate.

- Stakeholder opposition can be a factor, particularly with respect to direct load control programmatic initiatives.

- Regulatory policies and tariffs will play a key role in helping to facilitate DR taking a stronger role in supporting renewable energy integration in California. It will be important for the

[46] If the CPUC had not prohibited IOUs from counting the load reduction capacity of programs that use customer-owned fossil-fueled back up generation in complying with their Resource Adequacy requirements, this report would have indicated that extending the hours and seasons in which SDG&E's CleanGen program is available would allow that program to provide these flexible capacity products. See: CPUC Decision 11-10-003 (October 6, 2011), pp. 22-30 available at http://docs.cpuc.ca.gov/published/Final_decision/145022.htm.

[47] The CPUC has placed a "cap" on the combined capacity of Base Interruptible Programs (BIP) and other IOU DR reliability programs. The evaluation of the DR programs presented in this white paper assumes that the CPUC would modify that limitation, if the design of the program was changed in ways that would enable it to provide ancillary services and/or flexible capacity products.

CAISO to continue eliminating regulatory and market barriers that limit the ability of IOU DR programs to compete with other resources in CAISO wholesale ancillary services markets, and develop new regulations and policies which would facilitate that increased participation.

» As noted above, California's "loading order preference" policy [48] requires IOUs to first procure cost-effective DR and energy efficiency resources, then renewable resources, and only then conventional generation resources. As a result, under the policies adopted by the CPUC, IOU DR programs must be cost-effective. In order to be cost effective, an IOU DR resource that has the technical ability to provide ancillary services would have to provide those services at a lower cost than the generation resource that would otherwise provide them.

» In addition, third parties (e.g., DR aggregators) are likely to provide DR resources only if they expect them to be profitable.

» The extent to which DR resources rather than generation resources will be used to provide some of the ancillary services used to integrate variable renewables will depend largely upon the differences between the costs and technical attributes of the ancillary services provided by those two types of resources. That is likely to become increasingly important because of the steps the CPUC has taken to introduce and promote competition between IOU DR resources, third party DR aggregators, and end-use load customers in the CAISO's wholesale markets (as described in Sections 4.2 and 4.3).

» That market competition-based determination of the mix of DR and generation resources used to provide the amount of ancillary services the CAISO requires will be limited if the CPUC adopts policies that restrict the mix of DR and generation capacity that IOUs would need to comply with any flexible capacity and/or regulation services Resource Adequacy requirements the CPUC might adopt.

»

» In addition, the CPUC already allows IOUs (and other Load Serving Entities (LSEs) in California) to use dispatchable DR resources as well as supply-side resources to comply with their respective monthly Resource Adequacy (RA) requirements. IOU DR programs that have the technical ability to provide ancillary services are more likely to be cost-effective (or profitable enough in the case of DR-based ancillary services provided by aggregators) if those programs also avoid generic RA capacity costs.

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[48] State of California Energy Action Plan (2003), page 2. http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF. Also, see State of California Energy Action Plan II, September 21, 2005, available at: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

1.8.2 Next Steps

The next steps and research activities that would help facilitate increased usage of DR resources for the purposes of supporting the integration of renewable resources and the ancillary services market in California include:

» Conducting a statewide study that will evaluate the technical and economic market potential for DR to provide ancillary services (i.e., identify market potential of loads that can provide automated load changes in response to control signals, and be available for increased number of events and extended hours and seasons).

» Conducting an assessment of regulatory market barriers that impair widespread utilization of DR in the ancillary service market in California.

» Developing pilot programs in each service territory that test new DR program designs aimed at providing different ancillary services products (spinning reserves, non-spinning reserves, regulation, and possible new flexible capacity products).

» Increasing coordination between IOU DR Program Administrators and CAISO to help shape the new wholesale DR products capable of facilitating the integration of variable renewable generation, taking into account the ways in which wholesale and retail markets for DR products are converging.

» Conducting a consumer behavior study to assess the relationship between end-user costs and customer willingness to participate in new and/or modified IOU DR programs designed to meet the requirements of the ancillary services market.

» Performing cost-effectiveness and portfolio optimization evaluations of different options for supporting renewable energy integration, including DR-provided ancillary services and flexible capacity products, fast-response battery storage, and conventional generation.

» Assessing the market for Smart Grid technologies that can facilitate automated DR, as well as the benefits and costs associated with deploying these technologies

2. Introduction

In January 2012, California's Demand Response Measurement & Evaluation Committee (DRMEC)[49] asked Navigant Consulting, Inc. (Navigant), to prepare a white paper that would evaluate the possibility of using investor-owned utility (IOU) DR resources to facilitate the integration of the renewable energy that will be needed to achieve the state's 33 percent Renewable Portfolio Standard (RPS) goal by 2020. California's RPS, originally established in 2002 and modified in 2006, originally required the state's IOUs, electric service providers (ESPs), and Community Choice Aggregators (CCAs) to obtain 20 percent of the electricity delivered to their retail customers from renewable resources by 2010. Later, former Governor Schwarzenegger's Executive Orders S-14-08 and S-21-09, and Senate Bill X1-2, signed in April 2011, established a more ambitious RPS goal of 33 percent renewable energy by 2020, and extended mandatory RPS requirements to publicly owned utilities (POUs).

Figure 2-1: California RPS Scope and Targets

	Previous RPS	Current RPS
Targets & Timing	Increased by 1 percentage point per year, to 20% by 2020	At least 20% by 2013, At least 25% by 2016 At least 33% by 2020
Covered Entities	Investor Owned Utilities (IOUs) Electric Service Providers (ESPs) Community Choice Aggregators (CCAs)	Investor Owned Utilities (IOUs) Electric Service Providers (ESPs) Community Choice Aggregators (CCAs) Publicly-Owned Utilities (POUs)

As the state increases its reliance on renewable energy, the California Independent System Operator (CAISO) will need additional resources to maintain the stability of the state's electricity grid. Much of the additional renewable energy required to meet the state's 33 percent RPS target will be obtained from wind and solar resources, which are highly variable and very difficult to forecast accurately. The intermittent nature and relative unpredictability of wind and solar generation presents many challenges in maintaining reliable system operations. Our traditional fleet of generators such as natural gas-fired fast-start combustion turbines (CTs) will be increasingly called upon to ramp up or ramp down to mitigate the variability of these renewable resources. According to the CAISO, the system will also need more regulation energy to maintain grid stability and meet NERC reliability standards.

Demand response (DR) resources may be capable of meeting part of the CAISO's growing renewable integration (RI) needs. This paper describes the types of DR resources that could provide ancillary services, as well as flexible capacity and load following, which would otherwise be provided primarily by quick start, natural gas-fired combustion turbine generating units (CTs). That use of DR capacity

[49] The DRMEC is composed of CPUC and CEC staff, as well as representatives of the state's three investor-owned utilities (IOUs) – Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).

would be consistent with the state's loading order, which calls for utilizing cost-effective DR before resorting to conventional generation.[50]

2.1 Project Scope and Objectives

The primary objectives that the DRMEC asked Navigant to achieve in this white paper are to:

- Identify and evaluate the potential ability of the existing and planned DR resources of each of California's IOUs to meet the renewables integration needs of the CAISO;
- Identify changes that would improve the ability of IOU DR programs to meet the renewable integration needs of the CAISO, which will increase as variable renewable resources account for a growing share of the state's resource portfolio; and,
- Evaluate and compare the ways several other jurisdictions are using or plan to use DR resources in maintaining grid stability and/or integrating variable renewable energy, in order to help the members of the DRMEC design more effective DR programs and identify barriers that might impede those improved program designs

To assess what resources California will need to achieve its 33 percent RPS target by 2020, the DRMEC asked Navigant to rely on the forecasts for 2020 that the CAISO and IOUs submitted in Track I of the California Public Utilities Commission (CPUC) Long-Term Procurement Plan (LTPP) proceeding (Rulemaking 10-05-006). Those forecasts were based on the set of publicly available standardized planning assumptions and four "base case" scenarios for 2020 the CPUC required the IOUs to use in filing their respective Long-Term Procurement Plans (LTPPs) in Track II of that proceeding:[51]

- A "**Trajectory Scenario**", which assumed California will achieve its 33 percent RPS by 2020 based primarily on the contracts signed by California utilities through 2010
- An "**Environmentally Constrained Scenario**", which assumed California will achieve its 33 percent RPS by 2020 while minimizing environmental impacts according to an Aspen Institute/CPUC environmental scoring methodology
- A "**Cost-Constrained Scenario**", which assumed California will achieve its 33 percent RPS by 2020 while minimizing ratepayer costs estimated by using the CPUC's approved RPS Calculator
- A "**Time-Constrained Scenario**", which assumed California will achieve its 33 percent RPS even earlier than 2020 according to time lines established by the CPUC's RPS Calculator

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[50] State of California Energy Action Plan (2003), page 2, available at: http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF. Also see State of California Energy Action Plan II, September 21, 2005, available at: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

[51] Most of the renewable generation resources procured under existing RPS programs displace natural gas-fired generation capacity. Therefore, in that Track I evaluation, the additional cost of achieving a 33 percent RPS by 2020 under projected costs under each base case scenario was estimated, by comparing the projected costs under that scenario, to the forecasted costs that would be incurred under an "All Natural Gas" scenario.

The standardized assumptions for each of those scenarios included, among other items, the following:

- Estimates of the monthly demand reduction capacity (i.e., ex ante load impacts) of IOU DR resources that each IOU filed in April 2011
- IOU-provided load and demand forecasts that reflected the latest CPUC-adopted estimates of the load impacts of energy efficiency programs
- CPUC-adopted assumptions regarding:
    - The state-mandated retirement or retrofits of once-through cooling (OTC) fossil fuel generation capacity by 2017; and,
    - The amounts of distributed (i.e., "behind-the-meter") generation capacity that will be available in each year.[52]

The forecasts for the amounts of ancillary services, energy, and capacity that will be needed in 2020 under each of these scenarios did not distinguish between those that will be needed due to the variability of incremental renewable generation and those needed due to balance the entire system in 2020. Therefore, this white paper covers DR resources that could provide the types of ancillary services, energy, and capacity products that will be needed to manage the overall stability of the state's grid in 2020, rather than only to manage the instability due to the variability of new or incremental renewable energy generation resulting from the 33 percent RPS.

2.2 *Organization of this White Paper*

The remaining sections of this white paper are organized as follows:

- Section 3 - Grid Stability, Ancillary Services, and Renewable Energy Integration
- Section 4 – Demand Response Programs
- Section 5 – Potential Use of DR Programs for Renewable Energy Integration
- Section 6 – Possible Obstacles and Limitations to the Use of DR for Grid Management
- Section 7 – Recommendations
- Section 8 – Conclusions and Next Steps

- Appendix A. Bibliography
- Appendix B. Interviews Conducted for this Project
- Appendix C. Summaries of Evaluations of IOU Demand Response Programs
- Appendix D. Other ISOs/ RTOs and Non-ISO Utilities
- Appendix E. Detailed Evaluations of Each IOU DR Programs
- Appendix F. Demand Response Program Assessment Methodology

[52] Distributed generation also is likely to increase the variability of load in a manner that is hard to forecast over short time intervals, thereby increasing the need for ancillary services.

3. Grid Stability, Ancillary Services, and Renewable Energy Integration

This section explains the relationship between grid stability, ancillary services, and renewable energy integration, both in general and in California in particular.

- Section 3.1 explains how supply and demand imbalances affect the stability of power grids. Section 3.2 describes the generator-provided ancillary services the CAISO and other grid operators use to maintain grid stability. Section 3.3 explains how variable renewable energy affects grid stability, and how ancillary services are used to manage those impacts (i.e., renewable energy integration).

- Section 3.4 describes how the CAISO procures and schedules ancillary services. Section 3.5 summarizes CAISO forecasts of how the need for ancillary services in 2020 will be affected by the growing amounts of variable renewable energy required to achieve California's 33 percent RPS.

  Section 3.6 compares trends in wholesale ancillary service prices to wholesale energy prices in California. Section 3.7 compares the total cost of ancillary services to the total wholesale cost of electricity in California.

- Section 3.8 provides an overview of the flexible capacity product the CAISO has proposed, as well its proposal to add flexibility capacity and regulation services capacity to the generic Resource Adequacy capacity requirements that apply to the state's investor-owned utilities.

- Section 3.9 summarizes the technical attributes that CAISO tariffs now require for ancillary resources provided by generators.

- Section 3.10 describes the ways other ISOs and non-ISOs outside California have begun, or plan to begin using load reductions achieved by certain types of DR programs to provide some of the ancillary services needed for frequency control, now that improved and more widely available communications systems have made this easier to accomplish and more reliable.

3.1 *How Supply and Demand Imbalances Affect Grid Stability*[53]

Managing grid stability requires balancing supply and demand variation in real-time. The system operator is responsible for maintaining that balance. Load is constantly varying and all generation resources are subject to unplanned outages. Growing reliance on variable renewable energy generation will make grid stability management a bigger challenge.

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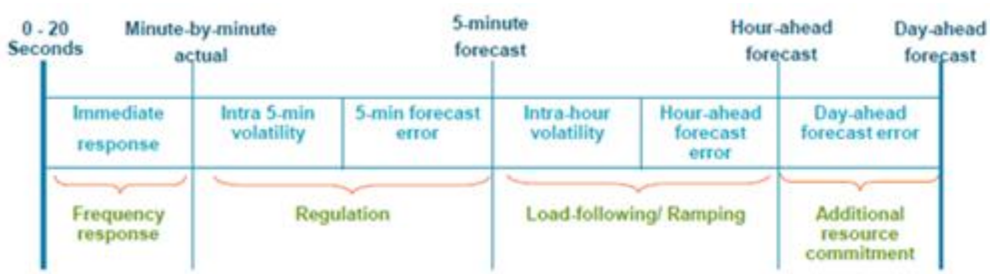
[53] The following discussion is based in part on: U.S. Department of Energy (Office of Energy Efficiency and Renewable Energy), *Load Participation in Ancillary Services , Workshop Report* (December 2011), available at http://www1.eere.energy.gov/analysis/pdfs/load_participation_in_ancillary_services_workshop_report.pdf

Electric power systems in the U.S. are all designed to run at a nominal frequency of 60 Hz. In order to maintain the reliability of any electricity power system, supply and demand must always be in balance in every instant. If an imbalance occurs, the speed of the system (i.e., frequency) will deviate from that 60-Hz standard. Frequency will fall below 60 Hz if demand exceeds supply, and frequency will exceed 60 Hz if supply exceeds demand.

The allowable deviation from that 60-Hz system frequency is small (normally ±0.035 Hz in large systems). If the system frequency deviates too far from that level, load shedding protection mechanisms will operate to drop load and restore the frequency. If the frequency deviation cannot be corrected through those load shedding mechanisms, generating units will trip (i.e., disconnect), running the risk of a cascading failure and, in the worst-case scenario, system brownouts or blackouts. Therefore, a supply-demand balance must be maintained at all times through frequency control (i.e., maintaining system frequency within a tight range) in order to ensure that the power system is reliable and secure.

The challenges in maintaining the stability of the grid are due to the uncertainties created by the volatility of demand, the variability of supply, and the difficulty in accurately forecasting both supply and demand over different time intervals. Figure 3-1 summarizes the sources of the uncertainties within each time interval, and the nature of the products that grid operators use to deal with those uncertainties.

Figure 3-1: Grid Flexibility Needs and Services[54]



3.2 *Ancillary Services Used to Manage Grid Stability*[55]

Within the shortest time intervals, automatic mechanisms must be used to regulate supply-demand balance and respond instantaneously to imbalances like the sudden loss of a large generator or a major transmission line.[56] These automatic mechanisms are referred to as ancillary services to distinguish them

[54] Antonio Alvarez (PG&E), "*A planner's insights about the need for operating flexibility reserves for higher penetration of variable generation*", WECC Webinar presentation (October 2011).

[55] The following discussion is drawn from: U.S. Department of Energy (Office of Energy Efficiency and Renewable Energy), *Load Participation in Ancillary Services , Workshop Report* (December 2011), available at http://www1.eere.energy.gov/analysis/pdfs/load_participation_in_ancillary_services_workshop_report.pdf

[56] Power systems also require other forms of control—in particular, voltage control, a much more localized ancillary service that demand response resources are highly unlikely to have the technical ability to provide.

from other energy products. Although ancillary services products do provide small amounts of energy, their real value is not in the energy component, but rather in their ability to respond reliably and quickly to maintain the balance between system supply and demand.

Regulation, spinning reserve, and non-spinning reserve are three ancillary services that grid operators use to provide frequency control, and thereby maintain the reliability of the system.

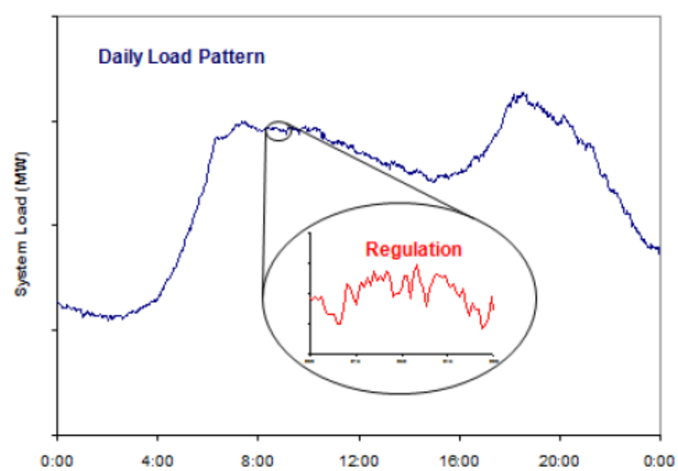
3.2.1 Regulation

The Federal Energy Regulatory Commission (FERC) defines **regulation** as: [57]

> *… the capability to inject or withdraw real power by resources capable of responding appropriately to a system operator's automatic generation control (AGC) signal in order to correct for actual or expected Area Control Error (ACE) needs..*

Regulation, which operates on time scales that are shorter than the shortest time interval in which generating units are dispatched, is used to compensate for the random, minute-to-minute variations in aggregate system load that occur too rapidly to be offset by the economic dispatch of the generation units. Regulation reserves respond to an AGC signal from the system operators that are sent out as frequently as every four seconds. The CAISO currently purchases regulation up and regulation-down services with a required response time of 1 to 10 minutes, for durations ranging from 15 to 60 minutes.

Figure 3-2: Variations in Aggregate System Load Managed by Regulation Services[58]



[57] FERC Order 755, *Frequency Regulation Compensation in Organized Wholesale Power Markets*, Federal Energy Regulatory Commission, Washington, D.C. (October 2011).

[58] Brendan J. Kirby, *Demand Response for Power System Reliability*: *FAQ*, ORNL/TM 2006/565, Oak Ridge National Laboratory (December 2006).

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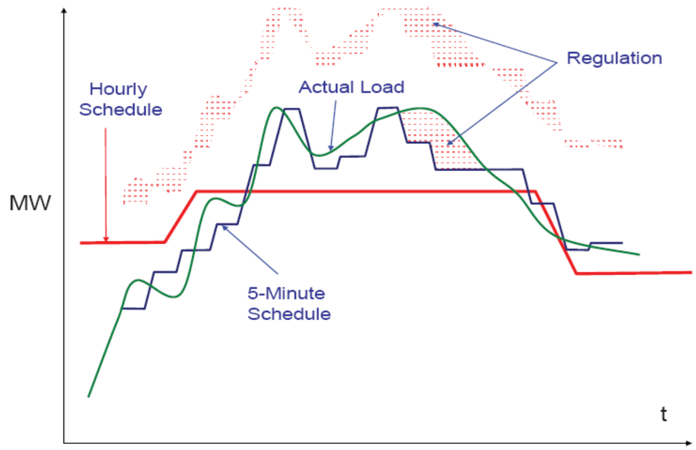
Figure 3-3: Use of Regulation to Balance Supply and Demand[59]



3.2.2 Spinning Reserve

CAISO defines **spinning reserves** as "the portion of unloaded capacity from units already connected or synchronized to the grid and that can deliver their energy in 10 minutes and run for at least two hours."

Spinning reserves respond directly to system frequency deviations or to system operator commands, depending on the severity of the contingency, to help restore the balance between generation and load after a severe event. Although the duration of the spinning reserve response is usually about 10 minutes, it may last up to 30 minutes in the case of rare, serious events. While regulation is adjusted continuously based on the automatic generation cycle (e.g., 4 seconds), spinning reserve is called upon relatively infrequently (e.g., every few days in some areas and once a week or less in others).

3.2.3 Non-Spinning Reserves

The CAISO defines **non-spinning reserve** as "the extra generating capacity that is not currently connected or synchronized to the grid but that can be brought online and ramp up to a specified load within ten minutes."

Non-spinning reserve provides a backup to spinning reserve. In an emergency operating condition, as additional spinning reserve is dispatched, more non-spinning reserve will be called on line. The following types of resources can provide non-spinning reserve: [60]

- Off-line generation that qualifies as non-spinning reserve
- Load which can be interrupted within 10 minutes of notification
- Interruptible exports

[59] Source: CAISO Integration of Renewable Resources (November 2007)

[60] Source: Western Electricity Coordinating Council, *Minimum Operating Reliability Criteria (2005) Available at:* http://www.wecc.biz/library/WECC%20Documents/Publications/WECC%20Glossary%2012-9-2011.pdf

» On-demand rights from other entities or control areas
» Spinning reserve in excess of requirements

3.3 *Impact of Variable Renewable Energy on Grid Stability*

Wind and solar resources are expected to provide most of the renewable energy that will be needed in 2020 to achieve California's 33 percent RPS target. The variability of those resources and the difficulty in forecasting them over various time intervals will increase the difficulty of maintaining the stability of the grid in the CAISO's control area. Figure 3-4, for example, summarizes the variability of wind as a percent of nameplate capacity over a variety of time intervals.

Figure 3-4: Grid Management Attributes of Variable Renewable Energy Resources[61]

Variable Generation Production Characteristics	Abbreviated Name	Example of Wind Variability (% of Nameplate Capacity)
Changes in output over very short time scales	<1-minute variability	0.1%-0.2%
Changes in output over short time scales	1 minute to 5-10 minute variability	3-14%
Imperfect ability to forecast generation output for time horizon of 10-120 minutes	<2 hour forecast error	3-25%
Changes in a single direction for multiple hour periods	Large multiple hour ramps	50-85%
Imperfect ability to forecast generation output for time horizon of multiple hours to days ahead	>24 hour forecast error	6-30%
Deviations from the average daily generation profile in actual day to day generation	Variation from average daily energy profile	25-60%
Average daily energy profile generation characteristics depending on the season	Average daily energy profile by season	30-50%

All other things being equal, increases in reliance on variable renewable energy might create additional need for operating reserve, including spinning and non-spinning reserves, which would make it harder to control frequency and thereby maintain the stability of the grid. In addition, significant increases in reliance on variable renewable energy tend to do the following:

» Increase the need for regulation, spinning reserve, and load following resources
» Result in steeper system ramping requirements
» Increase the frequency and magnitude of over-generation events
» Result in less efficient dispatch of conventional resources
» Suppress wholesale energy market prices

3.4 *Ancillary Services Scheduling and Procurement*

Like other grid operators, the CAISO uses ancillary service products to manage California's wholesale (i.e., bulk) power markets, by maintaining the stability of the grid in the face of dips and surges in the

[61] Source: Peter Cappers, Andrew Mills, Charles Goldman, Ryan Wiser, Joseph H. Eto, *Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study*. LBNL-5063E (October 2011).

balance of electricity demand and supply.[62] The CAISO currently acquires and schedules the following four types[63] of ancillary service products to manage that uncertainty. (Unlike other ISOs, the CAISO procures regulation up separately from regulation down.)[64]

» Spinning reserve
» Non-spinning (or supplemental) reserve
» Regulation up
» Regulation down

The CAISO's procurement requirements for each of those ancillary services meet or exceed the minimum operating reliability criteria adopted by the Western Electricity Coordinating Council (WECC) as well as the control performance standards adopted by the North American Electric Reliability Corporation (NERC).

CAISO uses a day-ahead procurement requirement that is equal to 100 percent of the estimated requirement for the following day. Consequently, the CAISO procures most ancillary services in the day-ahead rather than the real-time market.[65]

The average hourly real-time operating reserve requirement, which includes spinning and non-spinning reserve, was 1,617 MW in 2010 and 1,712 MW in 2011, which is about 6 percent higher than it was in 2010. That procurement requirement is typically set as five percent of the forecasted demand that will be met by hydroelectric resources plus seven percent of the forecasted demand that will be met by thermal

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[62] Due to the short-time scales associated with voltage balancing and power quality and the difficulty for demand response resources to provide this service, DR resources are unlikely to provide voltage balancing and power quality ancillary services, even though variable generation can affect the need for those services in bulk power system operations.

[63] Source: http://www.caiso.com/market/Pages/ProductsServices/Default.aspx.

[64] In the terminology used by the CAISO, regulation energy is "used to control system frequency that can vary as generators access the system and must be maintained very narrowly around 60 hertz. Units and system resources providing regulation are certified by the ISO and must respond to 'automatic generation control' (AGC) signals to increase or increase their operating levels depending upon the service being provided, regulation up or regulation down."

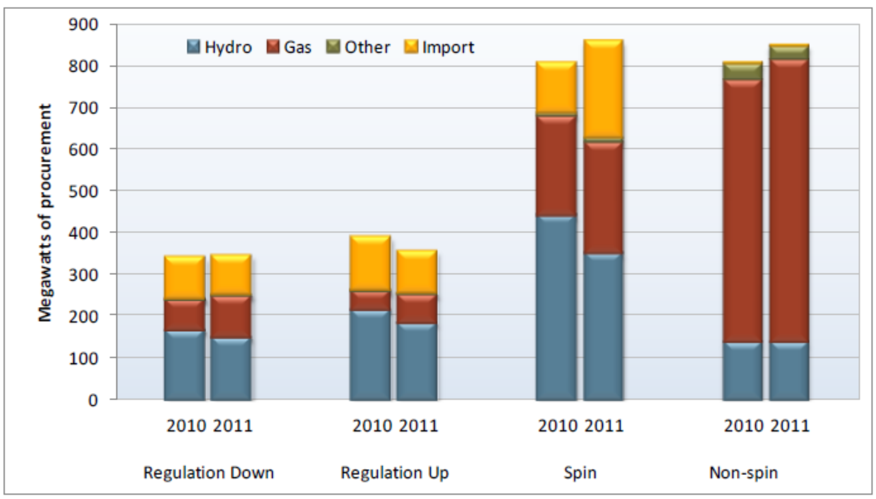
[65] Incremental procurements of ancillary services in the real-time market occurs under two scenarios. One is when ancillary services requirements in the real-time market have changed, due to a change in the real-time load forecast. The other is when a unit that was scheduled in the day ahead market to provide an ancillary service, is unable to provide that service in real-time, in which case the market would automatically procure additional services to replace that service.

resources.[66] Thus, the requirements follow a seasonal load pattern with higher requirements during the peak load months.

The average hourly requirement for regulation up and regulation down was slightly lower in 2011 than in 2010. The procurement requirement for regulation up and down is determined by using an algorithm that is based on inter-hour forecast and schedule changes. The average hourly real-time regulation-down requirement was 341 MW in 2011, compared to 330 MW in 2010. The average hourly real-time regulation up requirement was 339 MW, compared to 356 MW in 2010.

Figure 3-5 (below) summarizes the sources from which the CAISO procured ancillary services in 2010 and 2011.[67] Any DR-provided ancillary services presumably would have had to compete with the ancillary services provided by those hydroelectric resources and natural gas-fired (combustion turbines and steam turbine) resources. Although the CAISO's ancillary service procurement requirements can be met by a combination of internal resources and imports, those imports are indirectly limited by the minimum requirements set for procurement of ancillary services from within the CAISO control area.

Figure 3-5: Sources from Which CAISO Procured Ancillary Services in 2010 and 2011[68]



[66] Because of the magnitude of demand, the 5 and 7 percent requirements are usually larger than the single largest contingency, which can also set the procurement requirement.

[67] Some IOUs and LSEs also provide ancillary services for themselves, and are therefore somewhat hedged from higher ancillary service costs by the hydroelectric and natural gas-fired generation resources they control.

[68] Source: Section 5.2 of the *CAISO's 2011 Annual Report on Market Issues & Performance*, available at http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf

3.5 Forecasts of Ancillary Service Capacity Needed in 2020

Since 2006, the CAISO has been evaluating the effect that the increase in renewable energy generation needed to achieve an RPS target will have on system reliability and the need for ancillary services capacity, as new renewable resources displace fossil-fueled generation and as OTC fossil-fuel generation units are retired or retrofitted by 2017.

Since 2010, that evaluation has been combined with a similar effort in Track I of the CPUC's 2010 LTPP proceeding (CPUC R. 10-05-006). The order that initiated that rulemaking divided it into three concurrent tracks.[69] The objective of Track I was to identify the CPUC-jurisdictional needs for new resources to meet system or local resource adequacy under the state's 33 percent RPS, and to "consider authorization of IOU [investor-owned utility] procurement to meet that need…"

Both the CAISO and the IOUs submitted forecasts of the cost of achieving the state's "33 percent RPS by 2020" target, including the cost of the types and amounts of any additional capacity that would be needed by that year to offset the impact of heavier reliance on intermittent renewable energy on the stability and flexibility of the grid in the CAISO control area (i.e., renewable energy integration).

Those evaluations were based on the set of standardized planning assumptions[70] and the four base case scenarios for 2020 the CPUC required the IOUs to use in developing their respective "bundled service customers" LTPPs that were filed in Track II of that proceeding:[71]

» A "Trajectory Scenario", which assumed California will achieve its 33 percent RPS by 2020 based primarily on the contracts signed by California utilities through 2010

» An "Environmentally Constrained Scenario", which assumed California will achieve its 33 percent RPS by 2020 while minimizing environmental impacts according to an Aspen Institute/CPUC environmental scoring methodology

» A "Cost-Constrained Scenario", which assumed California will achieve its 33 percent RPS by 2020 while minimizing ratepayer costs estimated by using the CPUC's approved RPS Calculator

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[69] Source: February 21, 2012 proposed decision of ALJ Allen in R. 10-05-006, page 2.

[70] The standardized assumptions for each of those scenarios included, among other items:

- » Estimates of the monthly demand reduction capacity (i.e., ex ante load impacts) of the demand response (DR) resource portfolios of each IOU that were filed in April 2011;
- » IOU-provided load and demand forecasts that reflected the latest CPUC-adopted estimates of the load impacts of energy efficiency programs; and,
- » CPUC-adopted assumptions regarding:
  - o Retirement or retrofits of OTC fossil fuel generation capacity by 2017; and,
  - o Amounts of distributed generation capacity that will be available in each year.

[71] Most of the renewable generation resources that will be procured to achieve California's 33 percent RPS target will displace natural gas- fired generation capacity. Therefore, in that Track I evaluation, the additional cost of achieving a 33 percent RPS by 2020 under each base case scenario was estimated, by comparing the projected costs under that scenario, to the forecasted costs occur under an "All Natural Gas" scenario.

» A "Time-Constrained Scenario", which assumed California will achieve its 33 percent RPS even earlier than 2020 according to time lines established by the CPUC's RPS Calculator

Figure 3-6 below, which summarizes the Joint IOUs' April 29, 2011 forecast of the renewable energy that will be obtained in 2020 from different types of renewable resources under each of the base case scenarios, demonstrates that variable renewable energy resources (large- and small scale photovoltaics (PV), solar thermal, and wind) will provide the bulk of the renewable energy obtained in 2020 from resources acquired after 2011:

Figure 3-6: Total Statewide RPS Resources by Scenario and Type (GWh)

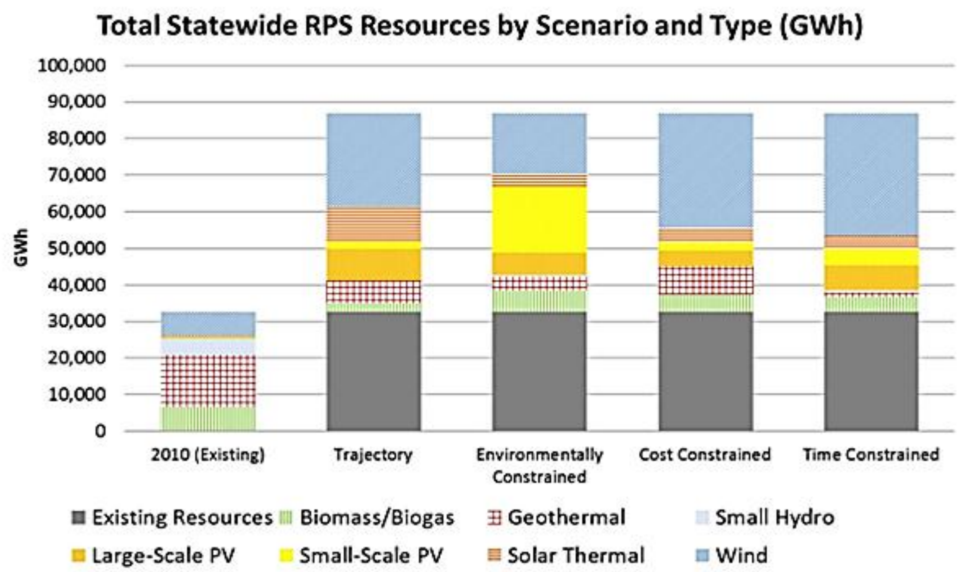


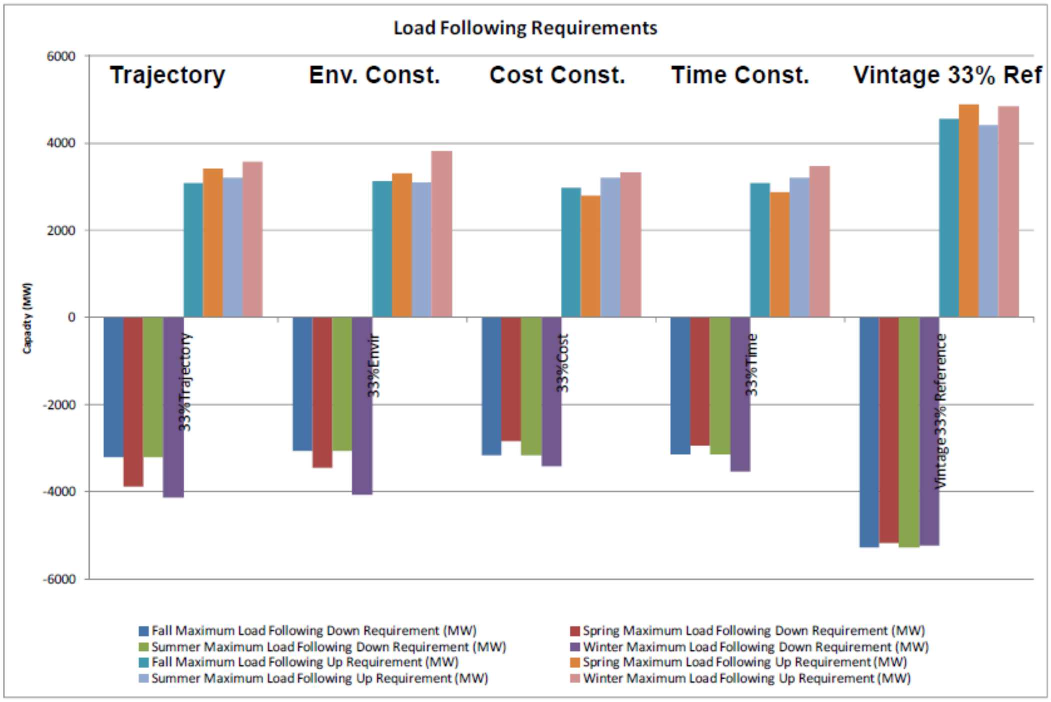
Figure 3-7 (below) summarizes the CAISO's July 1, 2011 estimates of the amount of regulation capacity that will be required in 2020 under each scenario to manage the stability of the grid in light of that increased reliance on variable renewable energy:

Figure 3-7: CAISO Estimates of Hourly Regulation Capacity Requirement in Each Season of 2020 under Each Scenario, Based on Single Highest Hourly Seasonal Requirement in Each Season[72]

Figure 3-8 (below) summarizes the CAISO's July 1, 2011 estimates of the amount of the load following capacity that will be required in 2020 under each scenario to manage the stability of the grid in light of that increased reliance on variable renewable energy:

[72] Source: Exhibit 1 attached to July 1, 2011 Direct Testimony of Mark Rothleder on Behalf of the CAISO in CPUC Rulemaking 10-05-006.

Figure 3-8: CAISO Estimates of Hourly Load Following Capacity Required in Each Season in 2020 under Each Scenario, Based on Single Highest Hourly Seasonal Requirement in Each Season[73]



In written testimony submitted to the CPUC in July 2011, the CAISO reported that these forecasts, based on the standardized assumptions and base case scenarios the CPUC adopted for the Long-Term Procurement Plans submitted by the IOUs, indicated the following:

» Although there would some hours in 2020 with load following down shortages (Figure 3-9), no additional capacity would be needed to meet that shortage. Other measures, such as generation curtailment, would be able to address that issue.[74]
» There would be no need for additional upward ancillary service and load following capacity in 2020 (Figure 3-10).[75]

However, the CAISO also evaluated a "stress case" based on a load forecast that was 10 percent higher than the one used in the CPUC base case scenarios, and concluded that under that scenario 4,600 MW of additional Regulation Up services and Load Following capacity would be needed in 2020.

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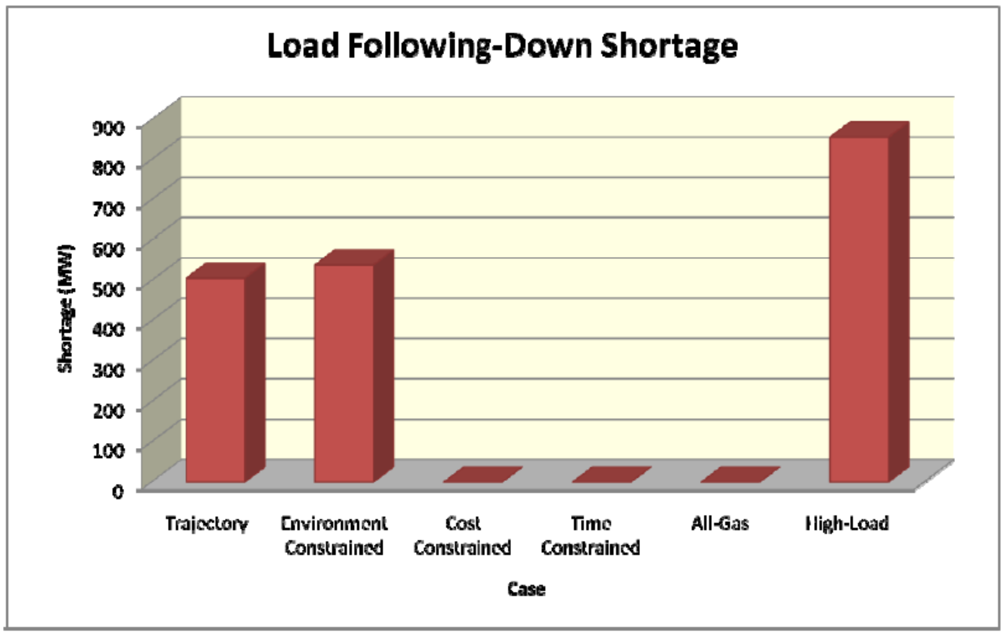
[73] Source: Exhibit 1, attached to July 1, 2011 *(Corrected) Direct Testimony of Mark Rothleder on Behalf of the CAISO*, in CPUC Rulemaking 10-05-006.

[74] Ibid., slide 10.

[75] Ibid., slide 11.

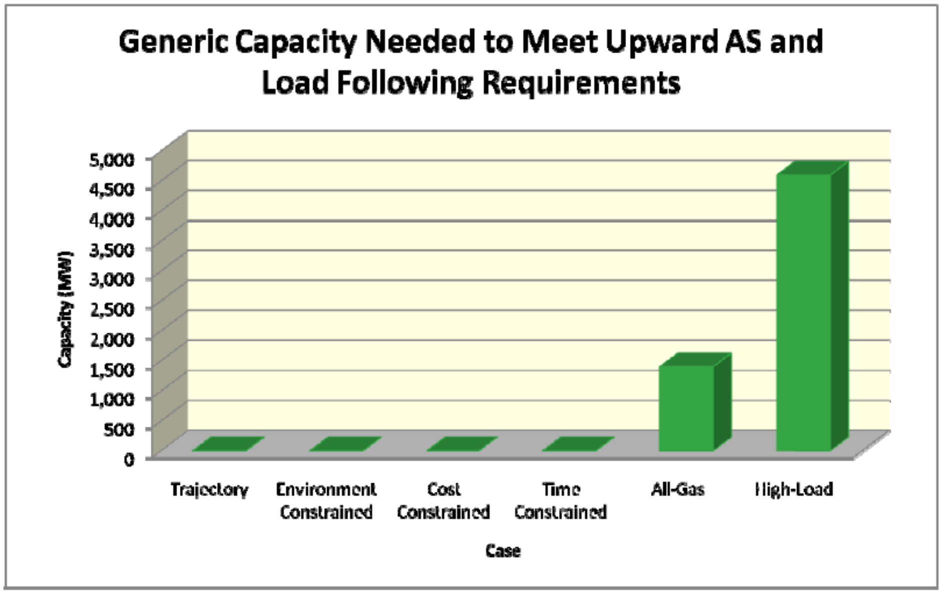
Based on that additional analysis, the CAISO stated that it could not conclude that no additional capacity would be needed in 2020 to achieve the 33 percent RPS target.[76]

Figure 3-9: July 11, 2011 CAISO Forecasts of Load Following Down Needs in 2020 under LTPP Base Case Scenarios



[76] Source: July 1, 2011 *(Corrected) Direct Testimony of Mark Rothleder on Behalf of the* CAISO in CPUC Rulemaking 10-05-006: pp. 44-45.

Figure 3-10: July 11, 2011 CAISO Forecasts of Capacity Needed to Meet Upward Ancillary Services and Load Following Requirements



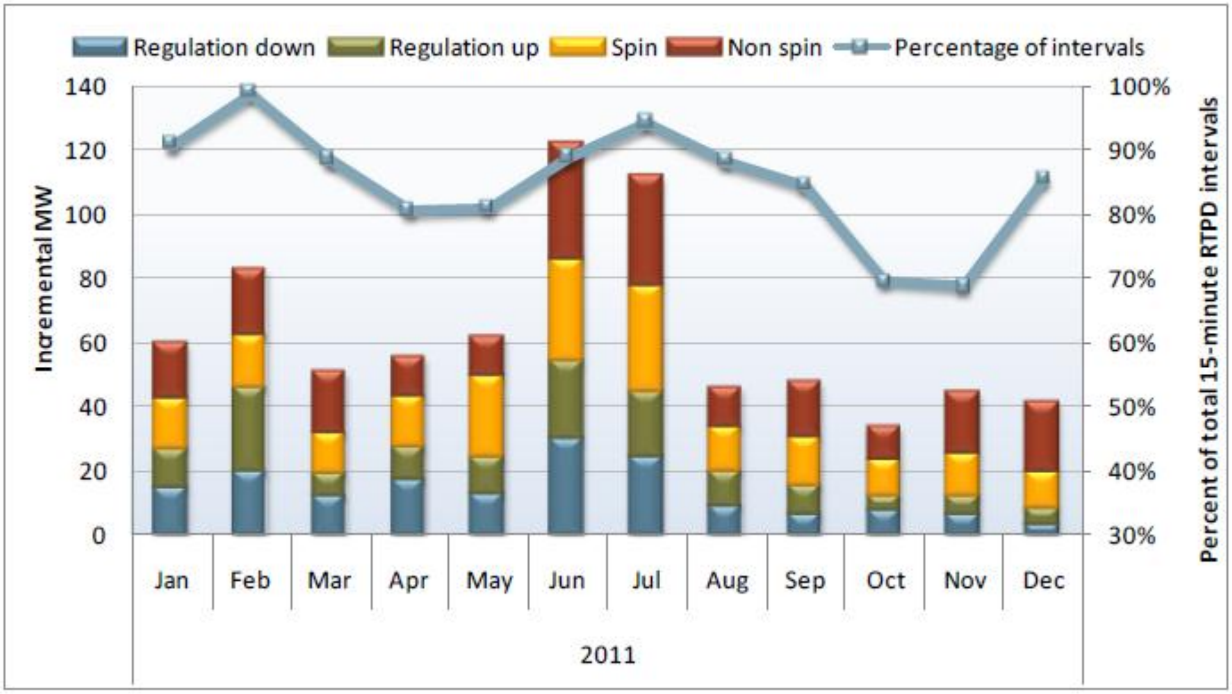
3.6 *Ancillary Services Prices*

When a resource is given an ancillary service award in the CAISO's wholesale market for an ancillary services product (i.e., the resource sells an option for the provision of that service) in either the day-ahead or real-time market, the resource receives a capacity payment that compensates the resource for the opportunity cost of not providing energy. That ancillary service capacity payment is equal to the expected profit from selling energy to the CAISO in that market.

If the resource is then actually called upon to provide energy in the real-time market as an ancillary service, the resource also is paid the real-time locational marginal price (LMP) for providing the energy, over and above that ancillary services capacity payment.

Capacity payments in the real-time market are only for incremental capacity in excess of the day-ahead procurement. Consequently, the volume of procurement in the real-time ancillary services market is very limited, accounting for less than one percent of CAISO's total procurement. Figure 3-11 shows the average amount of additional megawatts procured in real-time during intervals of incremental ancillary service procurement.

Figure 3-11: Monthly Average Additional Ancillary Service Capacity CAISO Procured in Real-Time Market for Ancillary Services[77]



[77]Source: *CAISO's 2011 Annual Report on Market Issues & Performance,* op. cit.

Although average ancillary service prices dropped somewhat after the recession began in 2008, they recovered to pre-recession levels by the last quarter end of 2011 (Figure 3-12).

Figure 3-12: Historical Trends in Ancillary Service Prices in California[78]

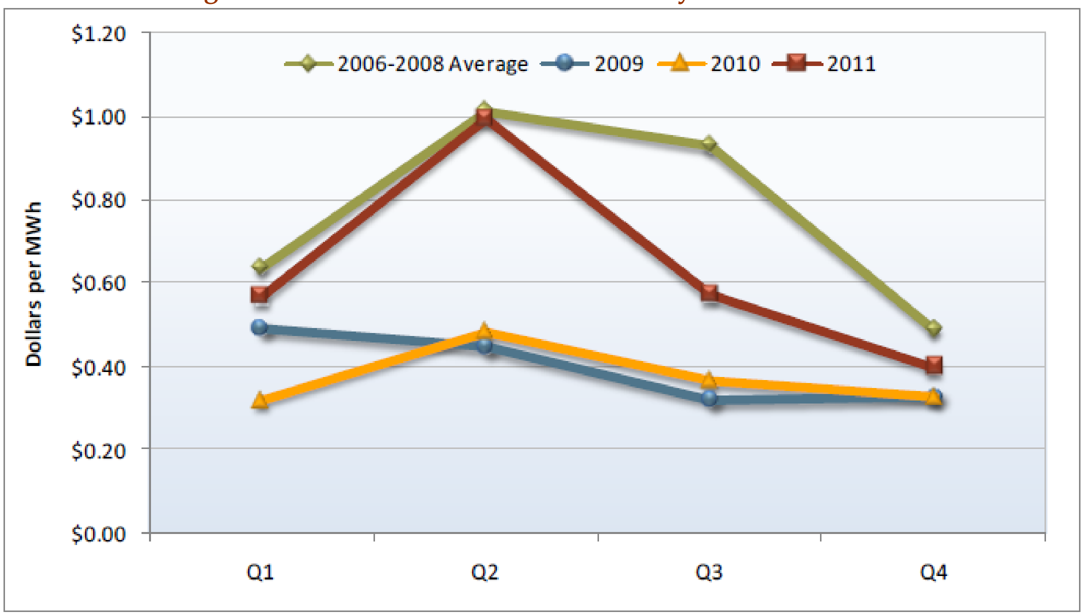
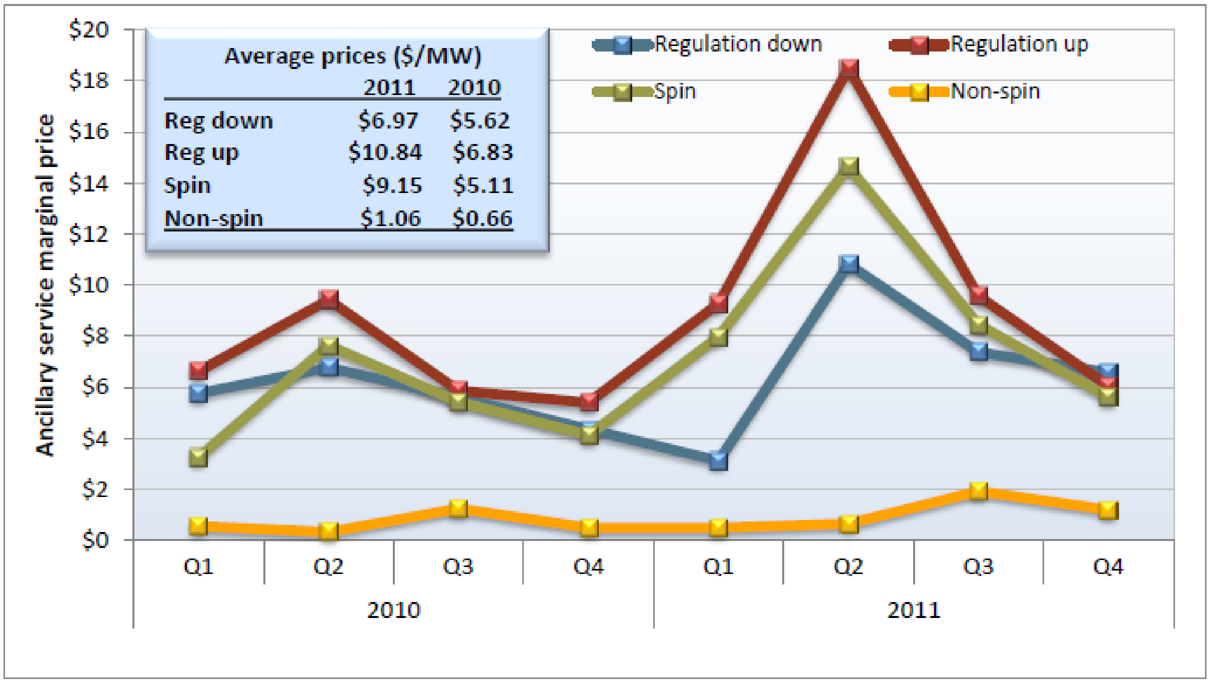


Figure 3-13 and Figure 3-14 below show the weighted average market-clearing prices for each ancillary service product in the day-ahead and real-time markets in each quarter of 2010 and 2011.

Overall, as Figure 3-13 indicates, average quarterly day-ahead market-clearing prices in 2011 for each ancillary service ranged from approximately $0.50/MW to $18.50/MW, peaking during the second quarter. High hydro conditions caused the high prices for regulation and spinning reserves in the second quarter of 2011, because the reserve capacities from hydro units that typically bid relatively low prices were reduced when those hydro units provided energy instead. As a result, the CAISO had to procure more ancillary service capacity from non-hydro units at a higher price.

[78] Ibid.

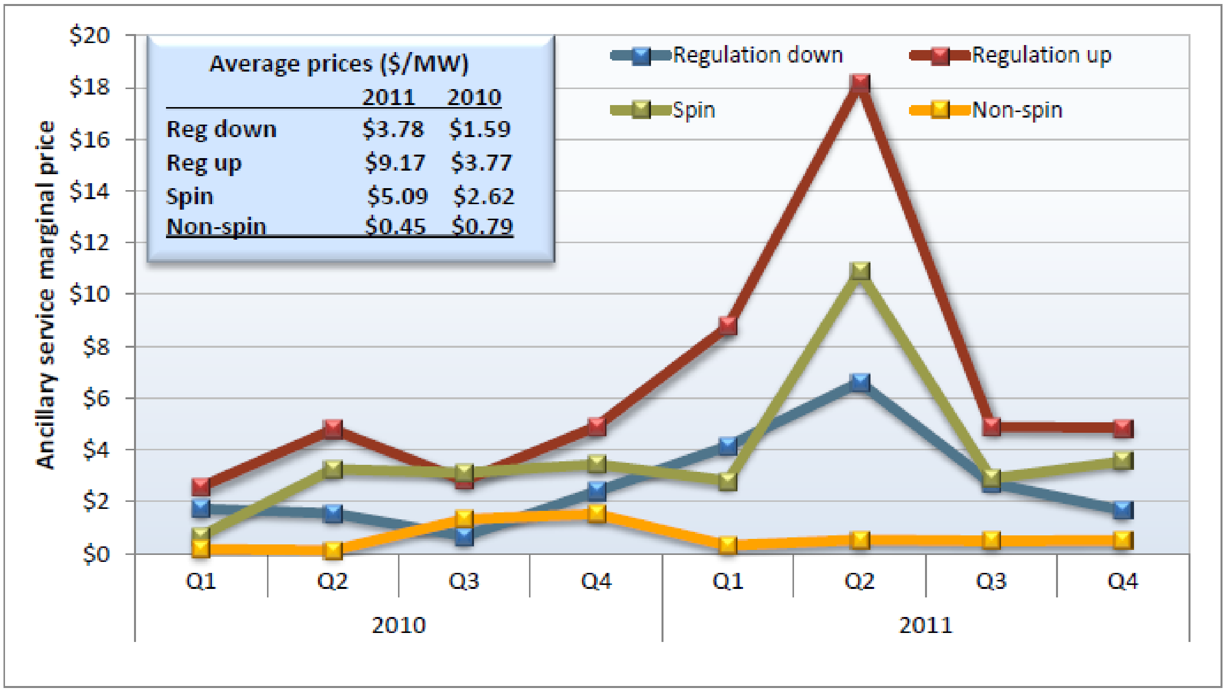
Figure 3-13: Day-Ahead Market-Clearing Prices for Ancillary Services[79]



Trends in real-time ancillary service prices (Figure 3-14) have generally been the same as those in day-ahead ancillary service prices. Monthly average real-time market-clearing prices for ancillary services ranged from $0.30/MW to $18.20/MW. The real-time ancillary service price spikes, reaching almost $1,000/MW, which occurred during some 15-minute intervals, were mostly the result of high opportunity costs from 15-minute real-time energy price spikes. However, as noted above, the volume of procurement in the real-time ancillary services market is very limited, accounting for less than 1 percent of CAISO's total procurement. Consequently, these real-time ancillary service price spikes did not have a significant impact on overall ancillary service costs.

[79] Source: *CAISO's 2011 Annual Report on Market Issues & Performance*, op. cit.

Figure 3-14: Real-Time Market-Clearing Prices for Ancillary Services[80]



3.7 *Ancillary Services Costs*

Figure 3-15 shows the total cost of procuring ancillary service products by quarter along with the total ancillary service cost for each MWh of load served. The total cost of the ancillary services provided in 2011 was about $139 million, which was 61 percent higher than it had been in 2010. In addition to the cost of the ancillary services procured by the CAISO, that total includes the estimated $33 million value of the ancillary services that California IOUs and LSEs provided for themselves in 2011, compared to only $13 million in 2010.[81]

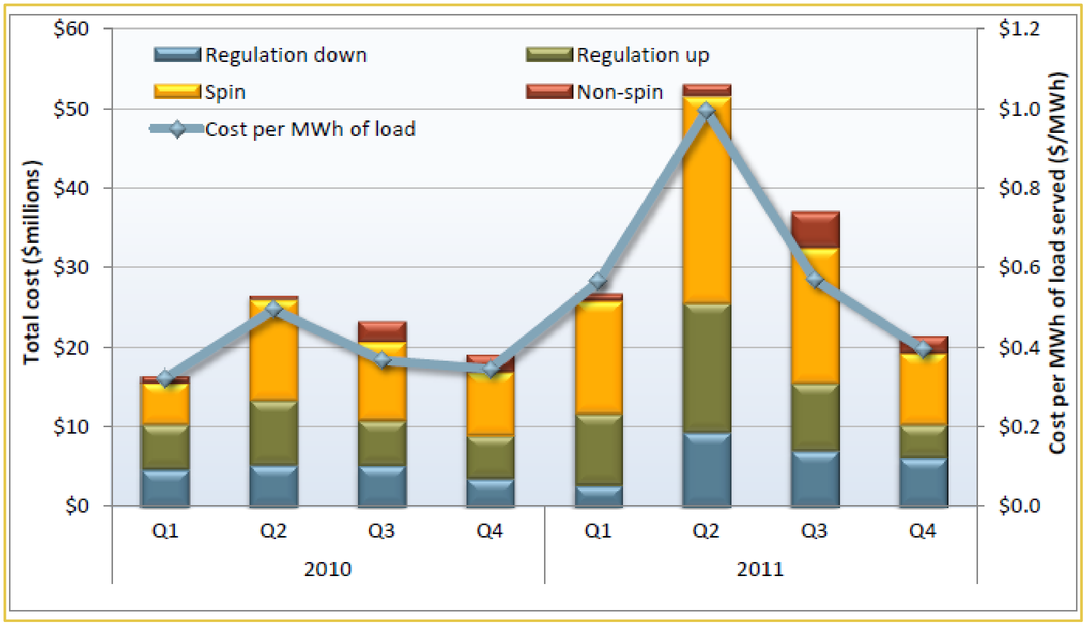
However, the total cost of the ancillary services that were procured or self-provided in 2011 only accounted for about 1.9 percent of California's total wholesale energy costs in that year, compared to just 1.0 percent in 2010.

[80] Ibid.

[81] IOUs and LSEs can reduce their ancillary service procurement requirements by self-providing ancillary services. While this is not a direct cost to the load-serving entity, self-provided ancillary services have an economic value. The CAISO estimate of the value of self-provided ancillary services that is reported here, is based on the costs those IOUs and LSEs would have incurred if they had instead purchased those ancillary services at the clearing prices in CAISO's wholesale market for ancillary services.

Total ancillary service costs peaked during the second quarter of the year, largely because above-average snow-pack conditions caused hydroelectric generation resources to provide energy instead of ancillary services.

Figure 3-15: Total Cost and Cost per MWh of Ancillary Services[82]



3.8 *New Flexible Capacity and RA Requirements Proposed by CAISO*

In a January 12, 2012 filing in the CPUC's Resource Adequacy (RA) proceeding (R. 11-10-023),[83] the CAISO asked the CPUC to approve new "flexibility capacity" products, and add those "capacity" products to the types of capacity each IOU and other Load Serving Entities (LSEs) must have in 2013 and beyond to meet their respective monthly (system and local) RA requirements.[84]

Those products would have to meet certain requirements on the following attributes:

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[82] Ibid.

[83] The following description is based on that filing and Navigant's May 14, 2012 phone conversation with John Goodin of the CAISO.

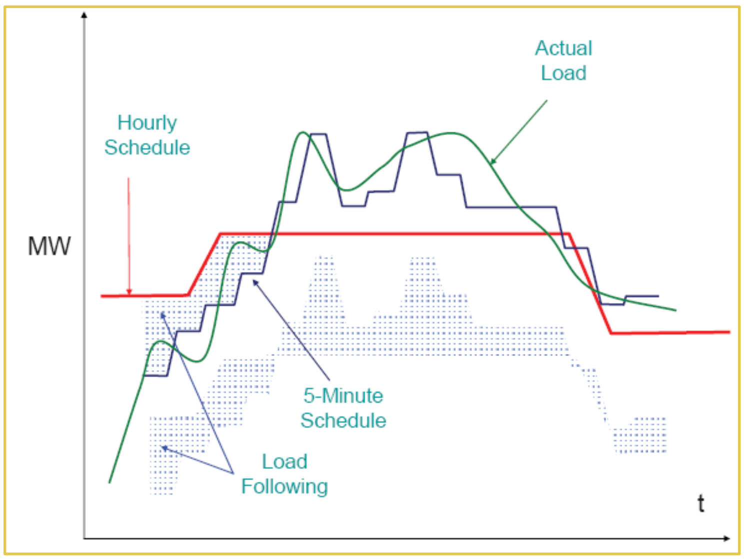
[84] The CPUC allows California IOUs (and LSEs) to use the capacity of dispatchable demand response (DR) resources as well as supply-side resources to comply with their respective monthly Resource Adequacy (RA) requirements. Those DR resources also can be dispatched to reduce the demand for energy in the CAISO's day-ahead, hour-ahead, and real-time markets.

» **Maximum continuous ramping:** "Maximum continuous ramping is the megawatt amount by which the net load (load minus wind and solar) is expected to change in either an upward or a downward direction continuously in a given month."

» **Load following:** "Load following is the ramping capability of a resource to match the maximum megawatts by which the net load is expected to change in either an upward or a downward direction in a given hour in a given month..."

Figure 3-16 (below) illustrates how a load following resource can offset the mismatches between scheduled energy and actual demand.

Figure 3-16: Use of Load Following Resource Over Time to Offset Supply and Demand Differences



In March 2012, CAISO also asked the CPUC to add regulation services capacity to the monthly RA requirements of each IOU for 2013. The CAISO currently defines regulation capacity as:[85]

"… the capability of a generating unit to automatically respond during the intra-dispatch interval to the ISO's four-second automatic generation control signal to adjust its output to maintain system frequency and tie line load with neighboring balancing area authorities."

The CAISO initiated a stakeholder process to develop tariffs for each of these new products, which must be approved by the FERC. Figure 3-17 (below) summarizes the CAISO-proposed requirements for the key attributes of these flexible capacity requirement products. The objective of the CAISO-initiated stakeholder process is to develop a flexible capacity product called Flexi-Ramp, that would provide the flexible ramping capability that the CAISO needs to better manage load deviations between real-time unit commitment, which occurs up to 15 minutes before the real-time market opens, and the real-time

[85] Source: http://docs.cpuc.ca.gov/efile/RESP/162107.pdf

dispatch that takes place at 5-minute intervals before the real-time market. Unlike the 10-minute ramping requirements for other ancillary services, Flexi-Ramp products must be capable of ramping within 5 minutes.

Figure 3-17: Attributes of Flexible Capacity Products Proposed by the CAISO[86]

Maximum Continuous Ramp	Load Following	Regulation
Maximum Capacity (MW): Maximum Continuous Upward Net Load Ramp for the Month **Ramp Rate (MW/min):** Maximum Capacity/Ramp Duration	**Capacity (MW):** Maximum 1-hour upward Change in Net Load **Ramp Rate (MW/min):** Maximum Capacity Change in 1-hour/60	**Capacity (MW):** Maximum 5-minute Change in Net Load **Ramp Rate (MW/min):** Maximum 5-minute Change in Net Load/5
Requirement is determined by largest continuous ramping period in the relevant month.	Requirement is the 1-hour capacity need and the 60-minute ramping capability need in the relevant month.	Requirement is the need for 5-minute capacity expressed as a MW/min ramp rate in the relevant month.
Unit must respond to ISO dispatch instructions. Renewable generation and base load units are not eligible to provide this capacity.	Unit must respond to ISO dispatch instructions.	Units must be regulation certified.
Each resource's contribution is ramping capacity over the time period: • NQC – Pmin if the unit cannot start within the maximum continuous ramping period. • NQC if the unit starts and reaches NQC during the maximum continuous ramping period.	Each resource's contribution is the minimum of: • NQC - Pmin • Ramp Rate(/minute) * 60 minutes • Ramp Rate based on the MW weighted average ramp-rate of the resource for a resource with different ramp-rates for different operating ranges (i.e., use the megawatt size of the operating zone to weight the ramp rate for that zone).	Each resource's contribution is: • Ramp rate based on the MW weighted average ramp rate of the resource for the operating ranges where it can provide regulation. • No regulation requirement set for 2013.

3.9 *Required Technical Attributes*

In order for a resource to be eligible to provide energy, capacity, and/or an ancillary service in CAISO wholesale markets, the resource must have been certified as having the ability to meet certain technical requirements. The matrix in Figure 3-18 summarizes the types of entities that now provide each type of ancillary service, energy, and capacity product in wholesale markets (plus the flexible capacity products recently proposed by the CAISO, as well as the technical attributes that each must have under CAISO tariffs):

[86] California Independent System Operator, proposal on Phase 1 Issues submitted to the CPUC in Rulemaking 11-10-023, *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Rulemaking 11-10-023 Local Procurement Obligations.*

Source: http://www.caiso.com/Documents/2012-01-13_Phase1Proposal_FlexCap.pdf

1) **CAISO Procurement or Scheduling:** How long in advance of need does/ (will) the CAISO procure and schedule that product/service (i.e., in the real-time, hour-ahead, or day-ahead market)?
2) **Self-Schedule for CAISO:** Indicates whether an IOU or other LSE entity self-schedules that resource.
3) **Minimum Resource Capacity:** The minimum capacity that a resource must have to provide that product/service
4) **Advance Notice of Deployment:** The minimum amount of time that must elapse between the receipt of notice of deployment from the ISO, and the receipt of a dispatch signal
5) **Speed of Response to Control Signal:** The maximum amount of time that can elapse between the receipt of a dispatch signal from the CAISO, and the provision of the product/service
6) **Duration of Response:** The minimum amount of time for which the resource must be able to provide the product/service each time that resource is dispatched
7) **Frequency of Response:** The frequency with which a particular resource will be dispatched to provide that product/service
8) **Reliability Requirement:**
   a) **Range of Permissible Deviation from Schedule:** The maximum permitted deviation between the amount of that product/service a resource was scheduled to deliver, and the amount of that product/service the resource actually delivered (i.e., an uninstructed deviation)
   b) **Penalty for Failure to Deliver:** The penalty imposed on a resource that delivered an amount of that product/service which deviated from the scheduled amount by more than the maximum permitted deviation

Figure 3-18: Attributes of Energy, Capacity, and Grid Management Resources

Products/Services Providing Energy, Capacity and/or Maintaining Grid Stability	Providers		Required Attributes								
										Reliability	
	IOUs and other LSEs	Other Generators	Products/Services Procured and Scheduled by CAISO	Products/Services Self-Scheduled by IOUs and/or Other LSEs	Minimum Resource Capacity	Advance Notice of Deployment	Speed of Response to Control Signal	Required Duration of Response	Frequency of Response	Range of Permissible Deviation from Schedule	Penalty for Failure to Deliver
Spinning reserves	x	x	Day Ahead, Hour Ahead, Real Time Markets	Yes	500 kW	~1 minute	< 10 min	30 minutes	~20-200 times/year	Max of 5MW or 3% of max output. Dynamic resources only	Uninstructed Deviation Penalties based on LMP
Non-spinning reserves	x	x	Day Ahead, Hour Ahead, Real Time Markets	Yes	500 kW	As quickly as possible	< 10 min	30 minutes	~20-200 times/year	Max of 5MW or 3% of max output. Dynamic resources only	Uninstructed Deviation Penalties based on LMP
Proposed Flexi-ramp product	x	x	Day Ahead, Hour Ahead, Real Time Markets	Currently Being Developed							
Regulation (proposed by ISO to be part of RA)	x	x	Day Ahead, Hour Ahead, Real Time Markets	Yes	500 kW	None	< 10 min	30-60 minutes	Continuous	Max of 5MW or 3% of max output. Dynamic resources only	Uninstructed Deviation Penalties based on LMP
Energy	x	x	Day ahead, hour ahead, real-time	Yes	None	Scheduled	Scheduled	Scheduled	As Scheduled	Max of 5MW or 3% of max output. Dynamic resources only	Uninstructed Deviation Penalties based on LMP
"Traditional" Resource Adequacy Capacity (local and system)	x		Not Applicable	90% year ahead, 10% month ahead	None	Day ahead	1 hour	Multiple hours	As Required	Not Applicable	None
Proposed Load-following Resource Adequacy Capacity (local and system)	x		Not Applicable	Per Proposed RA Requirements	Currently Being Developed						
Proposed Maximum Ramping Resource Adequacy Capacity (local and system)	x		Not Applicable	Per Proposed RA Requirements	Currently Being Developed						

Note: Attribute descriptions for each product assume the product would not be scheduled or procured from a resource unless that resource was available.

SOURCE: Navigant prepared this matrix based upon material obtained from the following sources:

[1] Peter Cappers, Andrew Mills, Charles Goldman, Ryan Wiser, Joseph H. Eto, *Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study*. LBNL-5063E (October 2011)

[2] CAISO tariffs (as of March 15, 2012)

[3 California Independent System Operator Corporation Proposal on Phase 1 Issues submitted to the CPUC regarding Rulemaking 11-10-023, Order Instituting Rulemaking to Oversee

[4] CAISO Flexible Capacity Procurement- Market and Infrastruture Policy Straw Proposal (March 7, 2012) Presentation

[5] CAISO, 2013 Flexible Capacity Procurement Requirement, Supplemental Information to Proposal (March 12, 2012)

[5] Karl Meeusen (Market Design and Regulatory Policy Lead), CAISO, Flexible Capacity Procurement Straw Proposal (March 12, 2012)

[6] 2011 FERC Summary of ISO/RTO Wholesale Power Markets, available at: https://www.midwestiso.org/Library/Repository/Tariff/FERC%20Filings/2011-08-

3.10 *Use of Demand Response to Maintain Grid Stability*[87]

Although using load to maintain the supply-demand balance on a system has long been possible in theory, traditionally load was taken as fixed and only supply-side resources were used to provide the ancillary services needed for frequency control. In extreme emergencies, of course, load is shed from the system using under frequency load-shedding schemes that help to preserve supply-demand balance and avoid system collapse. However, that type of load shedding is both involuntary and uncompensated, and used only as a last resort under very unusual circumstances.

More recently, some systems have begun, or plan to begin using load reductions achieved by certain types of DR programs to provide some of the ancillary services needed for frequency control. Improved and more widely available communications systems have made this easier to accomplish and more reliable.

Ancillary services programs in some ISOs/Regional Transmission Organizations (RTOs) now allow customers or third party aggregators (including IOUs, LSEs, and entities such as EnerNOC and Comverge) to bid load curtailments in wholesale markets as operating reserves (i.e., ancillary services). If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.

In order to participate in these ancillary service markets, these customers (or third parties) must be able to adjust load quickly when an event occurs. The response duration depends on the nature of the event and the type of reserve being supplied, but is typically provided in minutes rather than the hours required when DR programs reduce peak load and/or or respond to wholesale market energy price signals. There is usually a higher minimum size for load reductions and participants are usually required to install advanced real-time telemetry. These short timeframes and program requirements limit the type of demand side resources that can participate. These resources could include large industrial processes that can be safely curtailed quickly without harm to equipment (e.g., electric arc steel furnaces, large water pumping loads), or remote automatic direct load control (DLC) of appliances such as air conditioners.

Section 4.5 and Appendix D provide more complete descriptions of the developments that have occurred in five other ISOs, as well as at the Bonneville Power Administration and Hawaiian Electric Company (whose island-based grids are not interconnected with any other grid).

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[87] The following discussion is drawn from two sources:

U.S. Department of Energy (Office of Energy Efficiency and Renewable Energy), *Load Participation in Ancillary Services , Workshop Report* (December 2011), available at http://www1.eere.energy.gov/analysis/pdfs/load_participation_in_ancillary_services_workshop_report.pdf

FERC (Docket AD 06-2-000), *Assessment of Demand Response & Smart Metering, Staff Report* (Revised 2008), available at: http://www.ferc.gov/legal/staff-reports/demand-response.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp_o=1,100000,0

4. Demand Response Programs

Certain types of DR resource might be used to help maintain grid stability in general, and in particular manage the imbalances due to increased reliance on variable renewable energy.

Section 4.1 discusses overarching issues that affect the ability of DR to aid in grid management and the integration of variable renewable energy resources. Next, Section 4.2 describes the CAISO tariffs under which some types of IOU DR programs can participate in CAISO wholesale markets. Section 4.3 then describes the steps the CPUC has taken to promote competition between IOU DR programs, third party DR resources, and generation resources in CAISO wholesale markets. Section 4.4 briefly summarizes the DR resources of each of California's IOUs.

The final part of this section (Section 4.5) describes the extent to which several other ISOs/RTOs (PJM, ISO-New England, and the Electric Reliability Council of Texas [ERCOT]) and several utility systems outside of ISOs/RTOs (Bonneville Power Administration [BPA] and Hawaiian Electric Company [HECO]) use or plan to use DR resources to provide ancillary services used to maintain grid stability, which in some cases involves integrating variable renewable energy. Appendix D contains more complete descriptions of what is occurring in each of those jurisdictions, and lists the sources on which each of those descriptions is based.

The section which follows (Section 5) assesses the potential for using the DR programs of California's IOUs for renewable energy integration by comparing the attributes of each program, to the required attributes of the ancillary services CAISO uses to manage the stability of the grid—in particular non-spinning reserves, spinning reserves, and regulation up services. It also discusses the extent to which modifications to some of those DR programs might make them capable of providing those ancillary services.

4.1 Overarching Issues

The types of DR resources that could be used for grid management are a subset of the current array of DR resources.

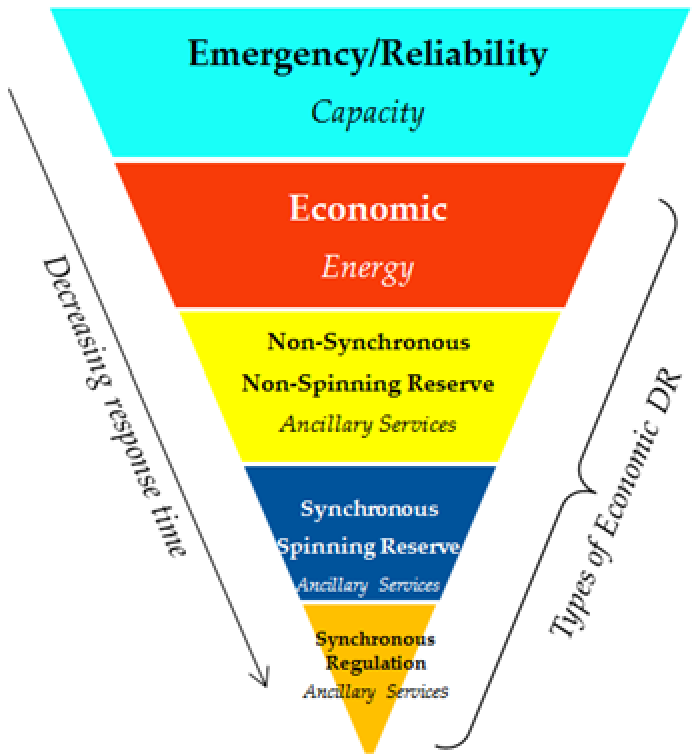
As Figure 4-1 indicates, partially for historical reasons, "reliability" DR programs used to avoid system emergencies and avoid overloading the grid, tend to be larger and more numerous than "price-responsive" or "economic" DR programs, that reduce demand in response to an external price signal, such as a spike in wholesale electricity prices, or a proxy for higher wholesale prices, such as hot weather conditions or a "market heat" rate.[88]

Only a subset of those economic DR programs might have the attributes needed to provide non-synchronous, non-spinning reserves. An even smaller subset might have the attributes needed to provide synchronized non-spinning reserves.[89] The smallest subset of all consists of those that might

[88] A market heat rate is the ratio of wholesale electricity price ($/kWh) to the price of natural gas ($/MMBtu).
[89] Generally, if load can provide spinning reserve, then it can also provide non-spinning reserve.

have the attributes needed to provide regulation up services (and, if coupled with energy storage, regulation-down services as well).

Figure 4-1: Typology of DR Resources



Although DR resources might be capable of facilitating the integration of variable renewables, a variety of factors and attributes make some program designs more effective than others. The factors and attributes discussed below cover most of the issues that enable DR programs to provide ancillary services as well as those that limit their ability to serve as replacements for generator-based ancillary services. In some cases, the attributes of those programs reflect a tradeoff between the technical attributes needed to support grid management (e.g., automated response, year-round availability) and participation flexibility that makes customers more likely to enroll in DR programs (e.g., the option of opting out of events and limits on the number and frequency of events).

Key issues related to the ability of DR to provide services that help operators maintain the stability of the grid are:

1) Automated response
2) Dynamic pricing
3) End uses capable of providing DR-based grid management services, and
4) Location of loads providing ancillary services

4.1.1 Automated Response

Automated response refers to the ability for technology, including interface to demand resources, telemetry, and intelligence, to respond to an event or a change in price without a "human in the loop." Once the technology has been set up and programmed properly, no further human action is required to curtail loads in response to a control signal. This is in contrast to *manual response*, which requires human action to respond to a specific event or price change. This is typically done with a phone call, email, text or other messaging to specified customer personnel, who are then responsible for turning down various loads for some period of time.

The benefit of automated response is that it can execute DR more quickly than manual response, potentially making it a key ingredient for the more rapid response required for ancillary services. The benefit of manual response is its simplicity and lower implementation cost.

The majority of California's IOU DR resources have historically relied on manually controlled changes in load, with some notable exceptions (e.g., residential direct load control (DLC) programs). The current DR program definitions for the three IOUs do not require automated response in most cases, and manual response mechanisms are still widespread. The program notification requirement for many of these programs is typically a minimum of 30 minutes, which is probably close to a lower bound that can be expected for manual response programs.

It will be difficult for loads controlled by manual response to participate in current ancillary services markets due to the short notification requirements and the need for rapid response to load control signaling. California has two DR *overlay* programs that are designed to enhance and help automate the operation of various DR programs offered by the IOUs:

- TA/TI—Technological Assistance and Technology Incentives program, which provide assistance to businesses in reducing energy demand
- AutoDR—Automated Demand Response program, which utilizes communications technology to send businesses DR signals and implement load reductions automatically through facility control systems.[90]

These programs are helping automated existing DR programs in California so that they might operate more efficiently and effectively, with quicker response to control signals or pricing, and less human intervention. The use of automated response has been expanding in California, helped by the use of AutoDR, which has seen growing use in the state,[91] as well as the growing use of automated mechanisms used by aggregators operating in the state.[92]

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[90] AutoDR, generically, refers to the automation of control over a demand responsive resource. The resource is connected to appropriate communication, signaling and logic such that its power consumption can be controlled remotely, without local human intervention. For example, traditional residential direct load control that uses a load switch connected to a central air conditioning compressor and turned on and off using a remote paging signal is a form of AutoDR.

[91] For example, the MW of DR capacity managed by SCE surpassed that of non-automated programs in 2010, and has been focused primarily on industrial, commercial, and institutional loads. See presentation "PLMA Workshop, Automated DR at SCE," pg. 9, Anna Chung, PLMA Spring Workshop, April 11, 2011.

Starting in the early 2000s, a specific approach to AutoDR, using standards-based client-server architecture and web services, was developed by the Lawrence Berkeley National Laboratory (LBNL) and others, and was tested in various pilots in California, primarily to control commercial heating, ventilation, and air conditioning (HVAC) and lighting systems. This approach has been published as an open standard called OpenADR. In 2010, LBNL helped form the OpenADR Alliance, with the goal advancing industry adoption of OpenADR, and LBNL formally released the set of protocols to OpenADR for this use. [93]

The current state of OpenADR development (OpenADR 2.0) might not be advanced enough to meet some of the stringent telemetry and metering requirements for regulation services. Aggregation vendors in the marketplace such as Enbala that are managing loads to provide regulation services[94] have chosen not to use OpenADR, and instead developed their own approach to meet those stringent requirements.[95] Thus, it is likely the current OpenADR 2.0 standard will not fully support the requirements of regulation services, but will need to be enhanced with additional technology overlay for speed and performance.

4.1.2 Dynamic Pricing

In dynamic-pricing programs, such as critical-peak pricing (CPP) and real-time pricing (RTP), customers do not have pre-established load reduction targets, and they do not face penalties for failing to respond to an event or a price signal. Although there is a price incentive to reduce load, curtailment is voluntary and load reductions are not firm and predictable enough to be used for the ancillary services defined by current CAISO tariffs.[96] Load reductions may be automated in response to the price signal, but the level

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[92] Aggregators focusing on industrial and large commercial DR have a growing percentage of their managed load (typically less than half) controlled by some form of automated DR, but this has typically not been AutoDR, but has been based on proprietary solutions.

[93] For more detail on OpenADR and its use with various control systems, see: Ghatikar, Girish, Aimee McKane, Sasank Goli, Peter Therkelsen, and Daniel Olsen (Lawrence Berkeley National Laboratory). 2011. *Assessing the Control Systems Capacity for Demand Response in California Industries*. California Energy Commission. Publication Number: CEC-500-2011-026.

[94] For example, see the material on Embala's website at http://www.enbala.com/, a firm that has sold demand response regulation services into PJM markets (see http://pjm.com/markets-and-operations/demand-response/dr-regulation-market.aspx).

[95] CAISO requirements for resource connection and telemetry to provide ancillary services can be found in "Business Practice Manual for Direct Telemetry, Version 2.0," California ISO, 12/14/11. Performance requirements are provided on p.19 of that manual.

[96] See: U.S. Department of Energy (Office of Energy Efficiency and Renewable Energy), *Load Participation in Ancillary Services, Workshop Report* (December 2011), page 9.

and duration of response is at the customer's discretion. Therefore, even automation does not ensure adequacy for ancillary services in the absence of an obligation backed by sufficient penalties.

As a result, even automated dynamic-pricing programs might not be reliable and predictable enough to facilitate integration of variable renewable energy under current CAISO tariffs for ancillary services, because the programs takes too long to initiate a load response and are unable to adjust the required response precisely and quickly enough to provide those services.

4.1.3 End Uses Capable of Providing DR-Based Grid Management Services

The characteristics of end-use loads, in addition to the degree of automation used, play a key role in determining which of the ancillary services make sense, or in some cases, which are even possible using the load.

Some DR programs target specific end uses, such as residential load control's focus on air conditioning and Southern California Edison's (SCE's) programs targeting agricultural pump loads.

Residential central air conditioning and pool pumps, some currently enrolled in DLC programs, typically use automation, and can rapidly initiate changes in load in response to control signals. They have potential to meet non-spinning, and perhaps in some cases even spinning reserve criteria. The same should be true of some automated agricultural pumping programs.[97]

To meet the rapid response and control necessary for regulation services, specific types of loads must be automated with high-speed feedback (to monitor response virtually real-time) and control to respond to an AGC signal. These loads must be able to both drop and increase load, based on the needs of the system. Loads that best meet these criteria can include:

» Installed pumping capacity (municipal wastewater treatment, drinking water treatment)
» Installed compressor capacity (food distribution warehouses and processing plants, arenas/stadiums/convention centers, data centers, hospitals, universities)
» Large ventilating fan capacity (e.g., manufacturing with volatile organic compound or particulate processes, auto painting)

Once set up appropriately for regulation, these loads might also provide spinning and non-spinning reserve ancillary services, or serve along with a broader range of more traditional DR resources as capacity resources that can bid into the market.

Available at
http://www1.eere.energy.gov/analysis/pdfs/load_participation_in_ancillary_services_workshop_report.pdf

[97] Oak Ridge National Laboratory, *Spinning Reserve from Pump Load: A Technical Findings Report to the California Department of Water Resources*, ORNL/TM-2003/99, November 2003.

4.1.4 Location of Loads Providing Ancillary Services

DR can be provided only where there are active loads. Thus, geographic constraints for balancing intermittent renewables will need to consider the location of these resources. For centralized wind or solar facilities, which are often located far from load centers, demand resources need to be located with consideration of transmission constraints between the intermittent resources and the load center served. For distributed solar resources, transmission constraints will be less of an issue.

CAISO has defined two system geographic regions and eight sub-regions that are used to place regional constraints in the procurement of ancillary services.[98] Existing DR programs have been developed largely independently of these geographic regions.

If demand side resources are to provide ancillary services to help balance intermittent renewable uncertainty, however, geographic boundaries must be considered in program design and implementation.

Newer automation technology, which can allow large numbers of individual loads to be independently addressed and controlled, should help solve this issue by allowing control within pre-defined geographic boundaries. Thus, DR program boundaries may be able to span several ancillary services sub-regions and still work appropriately to provide ancillary services.

4.2 CAISO Tariffs for Proxy Demand Response and Participating Load[99]

Through its stakeholder process, CAISO has developed two new tariffed wholesale market DR products: (1) Proxy Demand Resource (PDR) and (2) Reliability Demand Response Resource (RDRR).

PDR enables DR participation as a single resource or an aggregation of resources in the wholesale day-ahead and/or real-time energy markets and in the ancillary services market. Before those tariffs were established, end-use customers were only able to provide DR through programs offered by their electric utility.

In July 2010, FERC approved CAISO's PDR tariff. RDRP enables emergency responsive DR resources to integrate into the CAISO market and operations. However, on February 16, 2012, FERC rejected the CAISO's proposed RDRR tariff and provisions.

The entities that participate in a PDR resource could include:

- » a large end-use customer acting as its own DR provider; or
- » a Demand Response Provider (DRP) that aggregates end-use customer loads.

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[98] See "Business Practice Manual for Market Operations, Version 25," CAISO, April 9, 2012, p.70 for discussion of AS Regions.

[99] The following description is based primarily on the CAISO document titled "Demand Response & Proxy Demand Resource – Frequently Asked Questions," dated June 24, 2011.

A PDR product is a load or an aggregation of loads that are capable of measurably and verifiably reducing their electric demand. PDR resources can bid their customer end-use DR loads into the CAISO's wholesale day-ahead market, Residual Unit Commitment (RUC) market, Real-Time energy wholesale market, and non-spinning reserve ancillary services wholesale market, and respond to dispatches at the direction of the CAISO.

Although the minimum load size for a PDR resource is 0.1 MW (100 kW), smaller loads may be aggregated together to achieve the 0.1 MW threshold. The DR bid segments may be as low as 0.01 MW (10 kW).

Although end users can participate in more than one DR program, there must be a one-to-one relationship between an end use customer and a PDR resource (as well as a DRP). A PDR resource also may be eligible to participate in retail DR programs (e.g., IOU critical peak pricing, air-conditioning cycling, and Capacity Bidding Programs, etc.).

The prices paid to PDR resources in the wholesale market are based on the day-ahead or real-time market Locational Marginal Price (LMP), depending on the market in which the PDR resource is participating. If a PDR is located at a single node, then the price is the LMP at that node. If the PDR is a custom aggregation of loads, then the price it is paid is the weighted average of the LMPs at the nodes where that PDR load is located. The price that is paid for an aggregated Default PDR is the LMP at the sub-Load Aggregation Points (LAP) where the PDR loads are located. The ISO will settle payments to PDRs through the Scheduling Coordinator at one of these respective prices, depending on the PDR configuration.

There are no non-performance penalties for PDR resources. However, there are settlement payment consequences for non-performance for ancillary service resources, as they would have received capacity payments for energy that they did not deliver. The "No-Pay" consequences for undelivered capacity, unavailable capacity, and undispatchable capacity ensure that the market will not pay for services that were not provided.

The PDR product allows end-use customers to work through a DRP in order to bid DR services directly into the CAISO markets. Only end-use customers within the CAISO control area are allowed to do that. All resource types are offered into CAISO markets through a Scheduling Coordinator (SC). Therefore, to bid proxy demand resources into the CAISO markets, a DRP must be a SC or hire the services of a CAISO-certified SC to submit bids and schedules on their behalf.

The SC represents a PDR resource in the CAISO market for the DRP. The DRP enters into a Proxy Demand Resource Agreement with the CAISO. Through the CAISO's DR System, the DRP will request a Proxy Demand Resource ID to represent the end-use customer(s) providing the DR. The DRP must use a CAISO-certified SC to interface with the CAISO.

The CAISO does not define the specific agreements that are needed between the DRP and the LSE/utility that serves the end-use customers used in a PDR resource. The required agreements between these entities have instead been defined by the CPUC.

An end-use customer's load at one location can only be represented in a single Proxy Demand Resource at a time. As required by the CPUC, an end-use customer can only be represented by one LSE at a time, regardless of participation in a PDR product.

If an end-user would like to participate directly with the CAISO, that end-use would first need to become a DRP. After that, the end-use would need to use a SC that is certified to submit Settlement Quality Meter Data to interface with the CAISO. A DRP can be or become a SC, or can retain a certified SC.

The CAISO does not prescribe the communications that must take between the LSE/DRP and the end-user in order for the entities to achieve the required DR. The PDR resource must meet the communication requirements of the service that is being provided (for instance, telemetry and the capability to receive a CAISO dispatch is required in order to provide non-spinning reserve). The PDR resource must be able to perform based on awards from the market.

Telemetry data are not used for market settlements. For market settlement, the CAISO requires that the end-use customers have interval meters that meet CPUC requirements. For market services that require telemetry (non-spin ancillary services and curtailable load of greater than 10 MWs), the telemetry must meet the CAISO's technical requirements.

Direct Access customers can currently participate in the CAISO market through a PDR resource. However, bundled service customers of IOUs could not participate in PDR until the CPUC developed ratepayer protections and other relevant rules.

4.3 CPUC Policy on DR Participation in Wholesale Markets[100]

The context in which DR might provide ancillary services in California is changing due to the CPUC policies aimed at moving toward establishing wholesale DR market competition between IOUs and their customers.

Initially, the CPUC focused on the readiness of utilities to bid DR into wholesale markets. In R.07-01-041, the Commission stated that it would consider modifications to DR programs needed to support CAISO's efforts to incorporate DR into wholesale market design protocols. The CPUC is actively participating within the CAISO stakeholder process to achieve that goal. The utilities have developed modifications to their current DR programs to allow the DR programs to be compatible with the CAISO's market products.

[100] This section is based on the account provided in CPUC Decision 12-04-045 (April 26, 2012).

The CPUC also encouraged the IOUs to participate in the CAISO's PDR. In 2009, the CPUC ordered the Utilities to modify existing DR programs such that at least 10 percent of their DR programs would comply with the requirements of PDR. In December 2010, the Commission authorized the IOUs to operate pilot projects that could participate in PDR.

More recently, the CPUC has focused on the next phase of DR wholesale integration: "direct participation" in CAISO whole electricity markets. The CPUC defines direct participation as the ability of bundled retail electric customers, either on their own or through an aggregator or third party DR provider, to bid DR directly into CAISO wholesale electricity markets.

In 2009, the CPUC opened Phase 4 of R.07-01-04123 in response to FERC Order 71924, which required CAISO to allow direct participation if state laws and rules do not prohibit such bidding. In D.10-06-002, the CPUC barred direct participation by IOU customers in the CAISO's wholesale market until the development of ratepayer protections and other relevant rules. In doing that, however, the CPUC noted ".... acting expeditiously to allow end-use customers or aggregators to bid DR resources directly in [CAISO's] markets…is consistent with our identification of DR as one of the state's preferred means of meeting growing energy needs."

The CPUC is currently working to develop a new retail tariff rule, Rule 24, which will govern the terms and conditions of retail customers' participation in wholesale DR transactions. In 2011, CPUC Staff issued a draft of Rule 24, and stakeholders subsequently provided comments. The CPUC has deferred adopting a final version of Rule 24 pending resolution of ongoing litigation at FERC over compensation rules for PDR resources. While some questions remain unresolved, the CPUC now believes it is in a position to move forward with consideration of Rule 24 and expects to issue a decision in the near term.

The next question the CPUC intends to address is the extent to which it will embrace competitive procurement of DR and the timeline in which this transition will occur. Historically, only IOU's procured demand DR, in some cases through bilateral contracts with aggregators. That has been the only role third party aggregators have played in California DR. However, the CPUC's position is that this model is changing. The CAISO's market upgrades and regulatory changes now underway at the CPUC Commission will soon make it possible for aggregators to play a much larger role in the procurement of DR at both the retail and wholesale levels.

The CPUC has stated that it believes that third party aggregators can provide additional innovation and services to the market, yielding additional, uncaptured potential benefits to DR in California, and intends intend to take up this question in a new DR policy guidance rulemaking to be opened later in 2012.

The CPUC is also taking steps to update its current Resource Adequacy program rules to conform to the CAISO's wholesale market and place DR on an equal footing with generation resources.

- In D.11-10-003, the CPUC directed that beginning in 2013, retail non-dynamic pricing DR resources must be dispatchable locally in order to qualify for local Resource Adequacy credits.

- The CPUC is also working to harmonize its Resource Adequacy counting method with the approach used for conventional supply side resources.
- In D.11-10-003, the CPUC stated that it intended to move away from its historical approach to Resource Adequacy accounting for DR in which the Resource Adequacy value attributed to DR programs has been “taken off the top” or used to reduce a utility’s Resource Adequacy obligation, although the CPUC would continue to use that approach for dynamic pricing programs, which are not dispatchable locally.
- In addition, the CPUC announced that beginning in 2013, it would create a new Maximum Cumulative Capacity bucket for DR consistent with Resource Adequacy counting conventions for generation.

4.4 IOU DR Programs

The figures in next three sub-sections provide an overview of the DR programs of each IOU as of 2011. The assessments in Section 5 of the potential ability of each program to provide ancillary services are based on the most recent information available on the detailed attributes of each program, prior to the April 26, 2012 CPUC Decision 12-04-045. Appendix E contains tables that summarize the results of the detailed assessment of each of those programs.

4.4.1 PG&E DR Programs[101]

Figure 4-2: Pacific Gas & Electric Demand Response Programs as of 2011

	Southern California Edison Demand Response Programs as of 2011									
	Eligible Program Participants							Possible Program Usage, Based Program Triggers &/or Price Signals		
	Residential Customers	C&I Customers	Agricultural Customers	Bundled Service Customers	Direct Access (DA) Customers	Community Choice Aggregator (CCA)	Participation Through Aggregator	Emergency/ Reliability	Price Responsive	Dynamic Pricing
Base Interruptible Program (BIP)		✓	✓	✓	✓	✓	✓	✓		
Agricultural & Pumping Interruptible (API)		✓	✓	✓				✓		
Non-Residential Summer Discount Program (SDP)		✓		✓				✓		
Residential Summer Discount Program (SDP)	✓			✓				✓	✓	
Capacity Bidding Program (CBP)		✓		✓	✓	✓	✓	✓	✓	
Demand Response Contracts (DRC)		✓		✓	✓	✓		✓	✓	
Demand Bidding Program (DBP)		✓		✓	✓	✓		✓	✓	
Real Time Pricing (RTP)		✓	✓	✓					✓	✓
Critical Peak Pricing (CPP) - Large C&I and Agricultural Customers (> 200 kW)		✓	✓	✓				✓	✓	✓
Critical Peak Pricing (CPP) - Medium & Small C&I and Agricultural Customers (< 200 kW)	✓	✓	✓	✓				✓	✓	✓
Peak Time Rebate (PTR)	✓			✓				✓	✓	✓

[101] The following descriptions of PG&E's DR program are based on Section 2 of the March 11, 2011 prepared testimony and exhibits PG&E submitted to the CPUC on March 11, 2011 in support of its 2012-2014 Demand Response Programs and Budgets application to the CPUC (Application: 11-03-001 (U 39 E)).

4.4.2 Southern California Edison DR Programs[102]

Figure 4-3: Southern California Edison Demand Response Programs as of 2011

	Pacific Gas & Electric Demand Response Programs as of 2011									
	Eligible Program Participants							Possible Program Usage, Based Program Triggers &/or Price Signals		
	Residential Customers	C&I Customers	Agricultural Customers	Bundled Service Customers	Direct Access (DA) Customers	Community Choice Aggregator (CCA)	Participation Through Aggregator	Emergency/Reliability	Price Responsive	Dynamic Pricing
PeakChoice Program		✓	✓	✓	✓			✓	✓	
Peak Day Pricing (PDP) Program		✓	✓	✓				✓	✓	✓
Demand Bidding Program (DBP)		✓		✓				✓	✓	
Base Interruptible Program (BIP)		✓		✓	✓	✓	✓	✓		
Aggregator Managed Portfolio (AMP) Program				✓	✓	✓	✓	✓	✓	
Capacity Bidding Program (CBP)		✓		✓	✓	✓		✓	✓	
SmartAC - Residential Customers	✓			✓	✓	✓		✓	✓	
SmartAC - Small & Medium Non-Residential Customers		✓	✓	✓					✓	
SmartRate	✓			✓				✓	✓	✓
Peak Day Pricing (PDP) Program		✓	✓	✓				✓	✓	✓

[102] The following descriptions of SCE's DR programs are based on prepared testimony and exhibits SCE submitted to the CPUC in support of its 2012-2014 Demand Response Programs and Budgets application to the CPUC (Application: 11-03-001 (U 39 E)).

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4.4.3 San Diego Gas & Electric DR Programs[103]

Figure 4-4: San Diego Gas & Electric Demand Response Programs as of 2011

	San Diego Gas & Electric Demand Response Programs as of 2011									
	Eligible Program Participants							Possible Program Usage, Based Program Triggers &/or Price Signals		
	Residential Customers	C&I Customers	Agricultural Customers	Bundled Service Customers	Direct Access (DA) Customers	Community Choice Aggregator (CCA)	Participation Through Aggregator	Emergency/Reliability	Price Responsive	Dynamic Pricing
Peak Time Rebate (PTR) Program		✓		✓				✓	✓	
Summer Saver Program	✓	✓		✓				✓	✓	
Demand Bidding Program (DBP)		✓		✓	✓	✓		✓	✓	
Base Interruptible Program (BIP)		✓		✓				✓		
Critical Peak Pricing (CPP - E) Program		✓		✓				✓		
Critical Peak Pricing (CPP - D) Program		✓	✓	✓				✓		
Capacity Bidding Program (CBP)		✓		✓	✓	✓	✓	✓	✓	
Aggregator Managed Portfolio (AMP) Program		✓	✓	✓			✓	✓	✓	
Scheduled Load Reduction Program (SLRP)		✓	✓	✓				✓		
Optional Binding Mandatory Curtailment (OBMC)	✓	✓		✓				✓		
Peak Generation (RBRP)		✓	✓	✓				✓		

[103] The following descriptions of SDG&E's DR programs are based on prepared testimony and exhibits SDG&E submitted to the CPUC in support of its 2012-2014 Demand Response Programs and Budgets application to the CPUC (Application: 11-03-001 (U 39 E)).

4.5 Other Jurisdictions

In addition to using DR for reliability, a number of other ISOs and RTOs have been using DR to manage variability in supply and demand. In some ISOs, renewable energy integration has been one of the motivations for that use of DR. NERC has estimated that ancillary service needs increase when systems approach 20 percent wind penetration, suggesting that ISOs/RTOs will begin to look for least-cost solutions to increased ancillary services needs if wind penetration approaches that level. Wind energy in ERCOT has already exceeded 22 percent of the instantaneous power on the grid at times,[104] and generation queues at the ISOs and RTOs in the Northeast suggest that wind capacity could approach or exceed 20 percent of existing demand in the coming years.

The key way in which other jurisdictions are using DR for renewables integration is through existing ancillary service products that maintain grid stability. In order to explore and increase the use of DR for renewables integration, these jurisdictions have focused primarily on demonstrating DR's abilities to provide ancillary services, and removing market barriers to increase DR participation in ancillary service products. The DR ancillary service products that other jurisdictions are using to maintain grid stability include regulation, spinning reserves, and non-spinning reserves, as shown in Figure 4-5.

Figure 4-5: Summary of DR Participation Options in Other Jurisdictions

	Use of DR for Ancillary Services			Use of DR to Avoid Capacity	Use of DR to Avoid Energy
	Spinning Reserves	Non-Spinning Reserves	Regulation		
ERCOT	Yes (50% cap)*	Yes	Yes	Not Applicable	Yes
NYISO	Yes	Yes	Yes	Yes	Yes
PJM	Yes (25% cap)*	Yes	Yes	Yes	Yes
ISO-NE	No	No	No	Yes	Yes
MISO	Yes (10% cap)*	Yes	Yes	Yes**	Yes
BPA* **	No	No	Pilot Program (Load Following)	Yes	Not Applicable
HECO* **	No	Pilot Program	No	Yes	Not Applicable

Yes/Pilot Program = DR is able to participate, although participation may still be limited (e.g., virtually no DR participates in ERCOT's non-spinning and regulation markets).
No = Market/service exists in that jurisdiction, but DR is not able to participate.

[104] Electric Reliability Council of Texas. "ERCOT sets new wind record two consecutive days." 8 March 2012.

Not Applicable = Market/service does not exist in that jurisdiction.
* Maximum percentage of ISO/RTO's spinning reserve requirements that DR is allowed to provide
** Voluntary market
*** No organized markets

The exact specifications of those ancillary services products, minimum size requirements, eligibility of aggregated resources, and method of compensation differ to some extent from one ISO to another, and are described in more detail below.

System balancing products must provide specific amounts of resource (i.e., inject energy into or extract energy from the grid) within specific time-constraints. Furthermore, the performance of these resources must be verifiable. As a result, the DR products used to provide these ancillary services tend to be based on AutoDR, which enables fast, precise response to system operator signals. In addition, the associated infrastructure costs of telemetry, controls, and measurement and verification are relatively independent of resource size, suggesting that the largest resources will have the lowest per-unit cost. As a result, the largest industrial loads have tended to be the first to provide DR resources for system balancing. At the same time, these fixed costs present a large barrier to using smaller commercial and residential loads to provide these types of services. However, the mass deployment of interval meters and Smart Grid infrastructure, and broader trends toward reduced information technology costs and increased capabilities, are making it easier for smaller DR resources to provide these services.

Unlike DR load reductions for reliability, some ancillary services require both increases and decreases in supply (i.e., regulation up and regulation down). These regulation services also are used much more frequently, for much shorter durations, than the DR services used for system reliability. For this reason, loads coupled to thermal storage are attractive candidates for the provision of regulation services. For example, refrigeration systems, electric water heaters, air conditioners, and process heat loads all have some flexibility in the timing of the use of electricity and can adjust loads higher or lower. That flexibility is being used to balance both surges and dips in net supply on the grid. Pump loads have also been targeted.

Most jurisdictions have taken a cautious approach to establishing DR ancillary services, beginning with pilot programs or limiting the portion of balancing services that can be provided by DR resources. Over time, in some jurisdictions those DR resources that demonstrate the necessary levels of reliability and precision have been permitted to provide a larger share of these ancillary services.

The remainder of this section looks at the approaches several ISO and non-ISO jurisdictions have used to establish DR ancillary services, and what can be learned from their experiences. The key lessons learned from these jurisdictions are as follows:

1) **The Electric Reliability Council of Texas (ERCOT):** ERCOT has demonstrated that DR is capable of providing close to 50 percent of ERCOT's spinning reserve requirements. However, these DR resources are rarely dispatched and are primarily comprised of large industrial loads that are not as common in California. DR participation is still minimal in ERCOT's other

ancillary service markets due to the frequent deployment, ramping requirements, and pricing structures in these markets.

2) **New York ISO (NYISO):** To minimize barriers for DR participation in ancillary service markets, the NY ISO revised market rules to allow participation from aggregated DR resources and is currently developing systems to remove technical barriers, such as direct communications specifications to facilitate aggregation and a Demand Response Information System (DRIS) to automate program processes.

3) **PJM Interconnection (PJM):** PJM has made numerous market rule changes to allow load to act more like supply and address barriers to DR participation. Some of the key changes for ancillary services include reducing the minimum size requirement for regulation resources from 500 kW to 100 kW, changing compensation methods to pay regulation resources for both capability and performance, and allowing customers with existing contracts in the capacity market to contract with a different aggregator for the ancillary service markets.

4) **ISO-New England (ISO-NE):** ISO-NE's Demand Response Reserve Pilot Program found that *manual* DR cannot provide load-balancing services. To achieve significant penetrations of *automated* DR, ISO-NE would have to aggregate the loads of smaller customers, because there are relatively few large industrial loads in ISO-NE's service territory. Aggregation would require additional communications and controls infrastructure for individual participants, while providing relatively small incentives. Because ISO-NE does not foresee a need for additional balancing resources in the near future, ISO-NE is not taking action to encourage DR resources to participate in its ancillary services markets.

5) **Midwest ISO (MISO):** DR has a smaller presence in MISO than in the other ISO/RTOs due to the lack of a formal capacity market, barriers to aggregator participation, and other market requirements. MISO is removing some of these barriers, such as the requirement that a DR provider must be a load-serving entity. However, other barriers still remain, including relatively low market prices and the lack of a settlement mechanism to compensate aggregators. MISO is beginning to view spinning reserves as the most efficient and economic use of DR, and in the near future might relax the cap that limits DR to providing no more than 10 percentage of MISO's spinning reserve requirements.

6) **Bonneville Power Administration (BPA):** Through a number of pilots BPA is currently conducting to test DR capabilities for renewables integration, BPA is demonstrating the ability of customer loads like water heaters, electric storage furnaces, and cold storage to provide bi-directional load following. BPA's experience thus far points to the need for a "portfolio approach" involving many different load types and to the key uncertainty of whether a resource can be used for both peak load reduction and balancing services.

7) **Hawaiian Electric Company (HECO):** HECO has partnered with Honeywell to demonstrate renewables integration through Fast DR from C&I customer loads that can respond within 10 minutes. This pilot will test both semi-automated and fully-automated DR, and help validate the

technical design and tariffs for a full-scale DR program rollout. As of the date this white paper is being written, that pilot has not yet enrolled any customers.

Sections (4.5.1 through 4.5.7) below present brief profiles of how and to what extent DR programs are used for ancillary services in each of these other jurisdictions. More detailed descriptions for each jurisdiction are provided in Appendix D.[105]

4.5.1 The Electric Reliability Council of Texas (ERCOT)

ERCOT has installed more wind energy capacity than any other ISO, and at times wind energy has provided as much as 22 percent of instantaneous power on ERCOT's grid.[106] To help balance this, ERCOT purchases roughly 2,800 MW of spinning reserves, of which DR can comprise up to a 50 percent cap (1,400 MW) through ERCOT's "Load as a Resource" (or "LaaR") program. While ERCOT has yet to reach this cap, there are 2,400 MW of DR responsive reserves registered and DR offers exceed this cap on most days. The initial cap on LaaRs was 25 percent of ERCOT's spinning reserve requirements, due to concerns about significant penetrations of DR jeopardizing the ability to respond to small deviations in frequency, provide sufficient "physical mass" to stabilize the network, and maintain an acceptable frequency if load tripped-off at the same time. ERCOT raised the cap to 50 percent in 2009 as these concerns abated and strict qualification criteria were introduced to preclude energy consumers whose load level could not be accurately predicted on a day-ahead basis from providing responsive reserves. Currently, approximately 50 large industrial sites provide approximately 80 percent of LaaRs, with nearly all large participants coming from electro-chemical processing, oil field equipment, cement plants, manufacturing, compression, pumping, and data centers. Deployment of these resources is relatively infrequent: from 2006 through October 2011, there were only 21 deployments of LaaRs.

Although DR is eligible to provide regulation up, regulation down, and non-spinning resources in ERCOT, the participation of DR in these markets has been minimal.[107] No DR currently participates in the non-spinning reserve market, due to demanding requirements like 30 minute ramping and deployment several times per week. Furthermore, non-spinning DR resources have no control over the energy price at which they are deployed. In order for this program to expand, the market design would have to be modified to let resources set the prices at which they would be willing to be dispatched. Although Navigant did not inquire about this in interviewing ERCOT personnel, the same might be true for ERCOT's regulation up and regulation down programs.

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[105] These descriptions are based on Navigant's telephone interviews with ISO personnel (cited in Appendix B), and Navigant's review of the documents, studies and reports cited in Appendix E.

[106] Electric Reliability Council of Texas. "ERCOT sets new wind record two consecutive days." 8 March 2012.

[107] Patterson, Mark (Electric Reliability Council of Texas). "Demand Response in the ERCOT Markets." Prepared for DOE Workshop, 25 October 2011.

4.5.2 New York ISO (NYISO)

NYISO foresees a large increase in wind energy in its system in the coming years. To date, NYISO is the only ISO/RTO other than ERCOT that has procured additional ancillary services to address the forecast uncertainty or supply variability of variable energy resources.[108] Currently, DR can participate in NYISO's ancillary services markets for reserves and regulation through the Demand Side Ancillary Services Program (DSASP), as well as NYISO's energy and capacity markets. NYISO is currently working on market rules to allow aggregations of small demand resources to participate in the DSASP program. NYISO is also developing the technical specifications for direct communications for DSASP to streamline program participation requirements and make it feasible for aggregations of small demand resources to participate in ancillary services markets.[109] These specifications include: allowing direct communication with a DSASP aggregator without a connection through the transmission owner to streamline program participation and make aggregation of small resources feasible; limiting DSASP using direct communications to 150 MW initially to allow NYISO to build experience; and developing a Demand Response Information System (DRIS) to automate program processing and enhance event performance, management, and settlement.

4.5.3 PJM Interconnection (PJM)

Renewables provide only five percent of PJM's energy portfolio. However, the capacity of wind and solar plants in the interconnection queues exceeds 15 percent of the installed capacity in the PJM region.[110] PJM has made strides in recent years to reduce barriers to the use of DR for energy, capacity, and ancillary services. Recent tariff and market rule changes approved by FERC include reducing the minimum size requirement for ancillary service resources from 500 kW to 100 kW to be consistent with the energy and capacity markets; revising the tariff to allow year-round DR capacity market participation; changing compensation practices to pay regulation resources based on both their availability to respond and the speed of their response; and allowing customers to contract with one DR provider for ancillary services and a different DR provider for PJM's other markets.[111] These changes are expected to allow load to act more like supply and encourage greater DR participation.

PJM has three ancillary service products that DR is eligible to provide: Synchronized Reserve, Regulation, and Day-Ahead Scheduling Reserve. Most of the DR ancillary services are currently provided by aggregators. DR has contributed as much as 18 percent (approximately 230 MW) to PJM's synchronized reserves. Although PJM has never reached the current participation limit of 25 percent, DR

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[108] ISO/RTO Council, *Variable Energy Resources, System Operations and Wholesale Markets*, August 2011.

[109] New York Independent System Operator. *NYISO 2011 Annual Report on Demand Response Programs*. 17 January 2012.

[110] California Independent System Operator Corporation, ISO New England, Inc., Midwest Independent Transmission Operator, Inc., New York Independent System Operator, PJM Interconnection, LLC, and Southwest Power Pool, Inc. 2011 ISO/RTO Metrics Report. Prepared for Federal Energy Regulatory Commission, 2011.

[111] "FERC approves rule changes to help DR in PJM markets". Smart Grid Today, 6 June 2012.

providers view that limit as a "barrier-to-entry". However, after years of successful deployment, PJM is prepared to lift that ceiling to 35 percent.

PJM is a leader in terms of bi-directional DR participating in regulation markets. In late 2011, a few hundred kW of DR entered PJM's regulation market after FERC approved 100 kW as the minimum size for regulation. These regulation resources must receive and react (within five minutes) to a dynamic regulation control signal, and must have real-time telemetry. Those DR regulation resources currently include water pumps at a wastewater treatment facility in Washington County, Pennsylvania that provides regulation though DR-provider Enbala Power Networks, building load and a behind-the-meter battery in New Castle, Pennsylvania that provides regulation through Viridity Energy, and a 105-gallon electric water heater installed on the PJM campus that can be dispatched in response to regulation signals from PJM. PJM also plans to test the ability of water heaters to provide frequency regulation in the summer of 2012.

4.5.4 ISO-New England (ISO-NE)

To date, DR has been used almost entirely (and extensively) for peak shaving capacity in ISO-NE. ISO-NE has recently completed a Demand Response Reserve Pilot Program that explored the use of *manual* DR to provide operating reserves.[112] The pilot program provided 10 to 60 minute advance notice, and events lasted less than one hour. Approximately 100 events were called over the three-year life of the pilot program. The actual load reductions relative to the expected/committed load reductions varied widely from event to event and, on average, declined over the life of the program. The results of this pilot program seemed to demonstrate that *manual* DR cannot provide reserve services with the responsiveness or precision necessary for load balancing. ISO-NE does not expect renewables to reach levels that would require additional balancing resources in the foreseeable future, and is not taking action to encourage DR resources to participate in its ancillary services markets. ISO-NE staff also indicated that there are relatively few large industrial loads capable of providing balancing in New England. In the absence of large industrial loads, deploying significant penetrations of automated DR would require aggregation, which would require additional communications and controls infrastructure while providing relatively small incentives to each individual participant.

4.5.5 Midwest ISO (MISO)

MISO currently uses DR for energy, capacity and ancillary services, including spinning, non-spinning, and regulation services. In 2010, DR comprised roughly 3.2 percent of installed capacity (12,500 MW), 2.4 percent of MISO's regulation market, and 2.8 percent of MISO's spinning reserve market.[113] MISO is

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[112] See:

Lowell, Jon, and Henry Yoshimura. *Results of Ancillary Service Pilot Program*. ISO New England, 25 October 2011.; and,
KEMA. *Demand Response Reserve Pilot Evaluation*. Prepared for ISO New England, 30 November 2010.

[113] California Independent System Operator Corporation, ISO New England, Inc., Midwest Independent Transmission Operator, Inc., New York Independent System Operator, PJM Interconnection, LLC, and Southwest Power Pool, Inc. *2011 ISO/RTO Metrics Report*. Prepared for Federal Energy Regulatory Commission, 2011.

beginning to view spinning reserves as the most efficient and economic use of DR. Since 2009, DR has been able to provide up to 10 percent of MISO's spinning reserve requirements. MISO anticipates relaxing that cap in the near future.

In general, many barriers still exist for DR in MISO, such as DR program eligibility requirements that vary by utility size. Retail customers of large utilities are eligible for MISO programs on an opt out basis, while retail customers of small utilities are not eligible for RTO programs unless they opt in and the regulator permits participation. Many self-regulating public power entities have declined to opt in.

Additionally, aggregators have historically not participated in any of MISO's markets. As a result, MISO has not seen the growth in new DR that aggregators have generated in other markets. In response to FERC Order 719, MISO has proposed rule changes that are intended to remove some of the barriers to aggregator participation, including eliminating the requirement that a DR provider must be a load-serving entity. Other major barriers that have excluded aggregators include higher costs of participation due to real-time metering requirements, the lack of a settlement mechanism to compensate aggregators, relatively low market prices, and lack of capacity price transparency without a formal capacity market.

4.5.6 Bonneville Power Administration (BPA)

The pace of wind power development in the Pacific Northwest is exceeding BPA's expectations. As of the time this white paper is being written, BPA had more than 3,000 MW of wind interconnected, with 6,000 MW of requests "in-process" and another 15,000 MW of requests "in-discussion."[114] To help address the anticipated challenges of integrating this much wind, BPA is currently conducting several pilot programs to test the use of direct controlled DR for renewables integration.

Two of these pilots, led by Ecofys US, Inc., are using residential and commercial loads as energy storage for bi-directional load following. Testing of residential thermal storage furnaces, residential space heating, residential water heating, and commercial cold storage is currently underway and will continue through 2012. To date, the preliminary results from the residential pilot indicate that the water heaters have more capacity to provide regulation down than regulation up and that their control strategy needs to evaluate energy balance over time to avoid "over-charging" the tanks. The commercial pilot developed by EnerNOC has enrolled and enabled five cold storage facilities, representing roughly one MW of controllable resources able to respond within 10 minutes notice. Through these pilots, BPA hopes to validate the use of load for bi-directional response, test many of the assumptions in the business case prepared by Ecofys, review commercial terms for the sale of balancing services, propose and test dispatch methods and optimization schemes, survey program satisfaction and acceptance, and evaluate distribution system impacts (positive and negative) of large-scale DR deployment.

In another pilot, Mason County PUD #3 is testing water heater controls activated by a renewable energy signal. This pilot will: demonstrate use of automated DR to manage demand in correlation with renewable resources; identify the optimal control and shedding strategies for intermittent renewable

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[114] Davids, Brad, and Margaret Yellott. *Dances with Renewables: Case Studies of Commercial and Industrial Demand Side Resources Providing Ancillary Services*. EnerNOC, Inc.

events, power outages and control system peaking events; and evaluate the economic and socio-economic factors that influence customer participation.

Finally, the City of Port Angeles is working with EnerNOC to develop bi-directional load ramping/load following capabilities for a large industrial customer of up to 41 MW in response to load intermittency due to BPA's significant renewable resources. Fifteen MW of that project "went live" in April 2012, although not yet at a commercial stage.

Through these initial pilots, BPA has identified a number of complexities associated with using DR for renewables integration. For example, a key uncertainty is whether a resource can be used for both peak reduction and balancing services, since using it for both can significantly increase the program's cost-effectiveness from the viewpoint of a participating customer. However, the mechanisms for having a resource do both are not yet clear. [115] In addition, BPA has recognized the need for streamlined, automated infrastructure to scale these pilot programs up to regional resources, which will increase their cost. Furthermore, peak reduction and balancing capabilities will likely be different for each load type, which in the viewpoint of BPA "shows the importance of a portfolio approach" involving many different load types.

Because BPA expects significant increases in the amount of installed wind capacity on its system, BPA has a number of pilots underway to test the capability of DR to facilitate the integration of variable renewables. In particular, several pilots are testing the ability of loads like water heaters to provide bi-directional load following.

4.5.7 Hawaiian Electric Company (HECO)

The small, isolated power grid systems on the Hawaiian islands rely largely on diesel-fired generation and have large portions of wind capacity concentrated in only a few locations. Rapid and difficult to predict changes in wind generation, coupled with the lack of connections to other grids, make managing the stability of Hawaii's grid unusually difficult. As a result, Hawaii has a strong interest in the possibility of using DR resources to support the integration of variable renewable energy. In February 2012, Hawaiian Electric Co. (HECO) and Honeywell announced a pilot program to demonstrate how DR technology can help integrate more intermittent renewable energy (including renewable energy generated on other islands and transferred to Oahu through a planned undersea cable) into the electric grid to serve loads in Oahu.[116] During the two-year pilot, the utility will enroll commercial and industrial customers to test Fast DR technology, which will give the utility the ability to reduce demand within 10 minutes of notification.

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[115] Broad, Diane. Smart DR as Balancing Reserves in the PNWL Smart End-Use Energy Storage and Integration of Renewable Energy. Ecofys for Bonneville Power Administration, 8 December 2011.

[116] See: http://www.elp.com/index/display/article-display/7312771222/articles/electric-light-power/energy-efficiency/demand-response/2012/February/Honeywell__Hawaiian_Electric_to_use_demand_response_to_integrate_renewables.html

The pilot activities will be conducted in two phases. The first phase will focus on enrolling more than six MW of semi-automated load control and connecting these customers to a regional operating center (ROC). These customers will respond to notices sent by HECO to reduce demand within 10 minutes. The second phase will use AutoDR tools from Honeywell, including the Demand Response Automation Server (DRAS) software from Akuacom and a Tridium smart grid controller at each customer facility to poll the DR ancillary services for event signals. When the Tridium controller receives a signal, it will automatically execute load-shed measures the customer sets in advance, such as cycling air conditioners, and turning off non-essential lights, pumps, and motors. The controller will then send data from the facility's electricity meter back to the utility every five minutes, so the utility has immediate feedback on the decrease in demand. These technologies are based on open, industry-accepted standards so they can interact with virtually any building system to enable highly reliable machine-to-machine communication and rapid load reductions.

Customers will be paid a capacity incentive to participate in the program. When Fast DR events are triggered, they will also receive an additional per-kilowatt-hour incentive credit, which could translate into thousands of dollars in annual savings. The pilot is intended to validate the technical design and tariffs for a full-scale DR program that could support Hawaii's overall renewable energy goals.

4.6 *Summary of Lessons Learned from Other Jurisdictions*

With the exception of ISO-NE, each jurisdiction discussed above views DR as a key tool for renewables integration, and plans to expand current DR ancillary service capabilities in response to any expected growth in the need for renewable energy integration. While many questions are still unanswered, such as their ability to and market mechanisms for using a resource for both peak reduction and balancing services, there is a significant amount that California can learn from the early experiences of these other jurisdictions to-date.

In summary, Navigant believes that the following lessons from the non-California jurisdictions should be borne in mind in determining the role DR should play in the CAISO’s wholesale ancillary services market:

» Revise market rules that unfairly disadvantage load resources in comparison to supply resources, like compensation practices, size requirements, technology requirements, etc.

» Encourage the deployment of interval meters and smart grid infrastructure to help reduce information technology costs for smaller DR resources. Large industrial loads have tended to be the first to provide DR resources for system balancing due to the relatively high fixed costs of the infrastructure required to participate (e.g., telemetry, controls, and measurement and verification). These fixed costs have historically presented a barrier to aggregating smaller loads that might actually be better suited to providing services that require frequent and shorter durations of response, like regulation.

» Ensure that market rules allow aggregation of smaller resources, like water heaters, and that the minimum size requirement for aggregated resources is low enough to encourage demonstration-scale resources to participate.

» Because the types of customer load DR uses to provide ancillary services can be quite heterogeneous, employ a portfolio-based approach that includes many different load types to help increase the certainty and decrease the variability of response.

» Insofar as possible, reduce technical barriers by using common standards like open ADR and develop communications specifications that can be used consistently by market participants.

» Make compensation for regulation resources more favorable to fast-responding resources like DR and energy storage, by paying for both capacity (i.e., being available to respond) and performance (i.e., how quickly the resource responded).

» Allow customers that have already contracted with a DR provider to provide capacity or energy to also contract with a different DR provider of ancillary services, and thereby expand the pool of customers eligible to provide ancillary services.

» In order to increase the market penetration of DR, minimize barriers to participation by for DR providers, including removing prohibitions against aggregators acting as DR providers and by revising insufficient or inappropriate compensation structures.

»

5. Potential Use of DR Programs for Renewable Energy Integration and Managing Grid Stability

The DR programs offered by California's IOUs are available, yet unused, for much of the year and most hours of each day. Even a program called for as much as 80 hours annually has an equivalent capacity factor of only about 1 percent, which is well below that of most peaking units. Given that idle capacity, perhaps some of those DR programs might provide more than emergency and economic dispatch, and support renewable energy integration by providing more frequent, shorter-duration ancillary services capacity through the CAISO's ancillary service markets.

The current set of IOU DR programs provide load curtailments primarily for emergency reliability and for economic reasons (i.e., reduce load during hours in wholesale electricity prices are unusually high).

However, the experiences of other jurisdictions in using DR resources to maintain grid stability (described in Section 4.5 and Appendix D) suggest that California's existing and future DR programs could also contribute to the integration of variable renewable energy.

This section assesses the potential for using IOU DR programs to facilitate the integration of variable renewable energy, by comparing the attributes of each program to the five most important technical attributes that CAISO tariffs require for each of the ancillary services the CAISO currently uses to support grid management: non-spinning reserves, spinning reserves, and regulation services (Section 3.9): [117, 118]

1) advance notice of deployment (Notice);
2) speed of response to control signal (Speed);
3) duration of response (Duration);
4) frequency of response (Frequency); and,
5) maximum permissible deviation between actual and scheduled response (Deviation).

Although current CAISO tariffs also include some other requirements beyond those five technical attributes[119] (e.g., the need for telemetry to enable near-instantaneous two-way communications), this

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[117] Because current IOU DR programs are designed to reduce load, those DR programs are not yet capable of providing regulation down services. However, as noted in Section 3.3, the results of pilot programs in the Pacific Northwest and elsewhere indicate that modified DR programs might be able to provide regulation down services.

[118] These requirements are presented in Figure 3-18. One additional criterion was used in the assessment of the ability of a DR program to provide spinning reserves: the CAISO tariff requirement that a resource must be capable of providing 10 percent of its spinning capacity within eight seconds. Source: CAISO, *California Independent System Operator Corporation Fifth Replacement FERC Electric Tariff.* April 1, 2011, http://www.caiso.com/Documents/CombinedPDFDocument-FifthReplacementCAISOTariff.pdf.

[119] Appendix F provides a detailed description of the methodology.

evaluation uses these five attributes to identify the DR programs that are most likely to be capable of supporting renewable energy integration. That assessment, which relies in part on the conclusions on overarching issues discussed in Sections 4.1.1 through 4.1.4 above, describes the DR program attributes that either enable or limit the ability of that program to provide non-spinning and spinning reserves and/or regulation services. The evaluation then compares the specific attributes of each of the current IOU DR programs to the five technical attributes CAISO requires for non-spinning and spinning reserves and regulation services to assess whether that program either already meets those CAISO tariff requirements or could reasonably be modified to meet those requirements.

The assessment *aggregates* the ratings of the ability of the DR programs of all IOUs and of all IOUs combined to provide each type of ancillary services product, and the degree to which those programs have the attributes required by CAISO tariffs. The assessment evaluates both the programs as they currently exist and as they would be if they were modified in the manner described in this section.

This section summarizes the results of that assessment. The tables in Appendix E present the detailed assessment of each program.

Although a uniform and consistent methodology was used to assess the ability of each IOU DR program to provide each of these ancillary services, the assessment also required certain subjective expert judgments. Those subjective judgments were needed due to the fact that while some DR and attributes "map" directly to some of the technical requirements in CAISO tariffs for ancillary services (e.g., advanced notification requirements), others do not (e.g., the speed with which the customer or technology can respond to a control signal). Some subjective expert judgments were also required in assessing whether and how some DR programs would have to be modified in order to have the technical attributes required by the CAISO for each ancillary service.[120]

Therefore, this assessment provides a broad indication of the degree to which each of the DR programs of California's IOUs are likely to be able to support the integration of variable renewable energy. The conclusions from the assessment of a specific program are subject to significant uncertainty, and should not be interpreted as a *black and white* determination of that program's ability to provide specific ancillary services.

Instead, the assessments presented provide broad guidelines for determining the types of DR programs, customers, and end use loads that could contribute to the integration of the growing amount of variable renewable energy that needed to achieve California's 33 percent RPS target.

5.1 Grid Management Capability from Existing DR Programs

The ability of existing IOU DR programs to provide each of the grid management services that the CAISO currently uses to integrate variable renewable energy depends upon the degree to which those

[120] The scope of this project did not include an engineering assessment of the extent to which each of the technical attributes required under CAISO tariffs for ancillary services was based on fixed technical (i.e., engineering) criteria, as opposed to the typical attributes of different types of generation capacity.

programs have five most important technical attributes that CAISO tariffs require for each ancillary services are: advanced notice of deployment (Notice), speed of response to control signal (Speed), duration of response (Duration), frequency of response (Frequency), and maximum permissible deviation (Deviation).

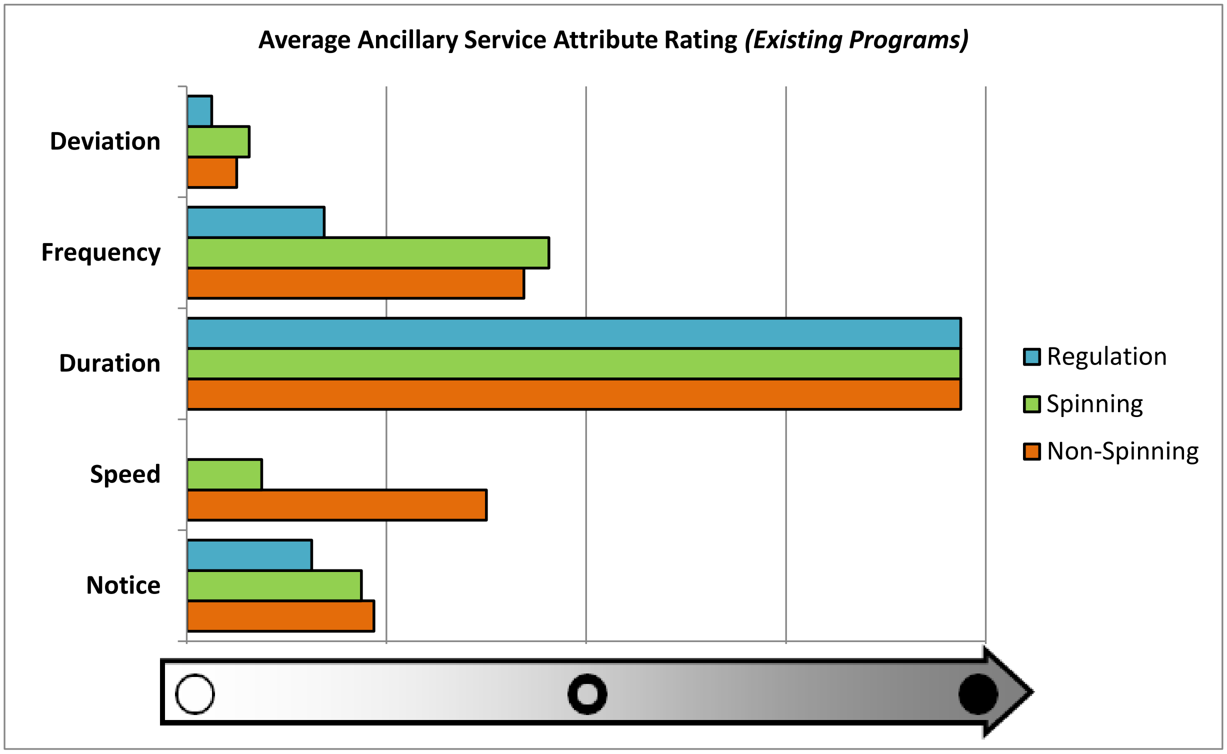
Although most of the existing IOU programs can meet the Duration requirement for each service, few of the programs can currently meet more than one or two of the requirements for the other four attributes.

Figure 5-1 illustrates the relative ability of the programs to meet the requirements of each of the five attributes for each of the three ancillary services products. The length of each bars represent the average ability of all programs to comply with the CAISO tariff requirement for each attribute. *Some individual programs might comply with or very nearly meet most of those requirements, while others comply with few if any of those requirements.*

Since the DR programs of California IOUs were designed to be used primarily either to maintain system reliability and/or to reduce demand at times when wholesale energy prices are unusually high , the programs have usually been "called" (i.e., dispatched) for events that last at least several hours. That duration is more than enough time to provide ancillary services. However, the **frequency** with which events can be called under each program would prevent them from complying with CAISO ancillary service tariffs, because events cannot be called more than once a day or more than roughly a dozen times a year under most of those DR programs. As a result, on average across the portfolio, the programs are not even "halfway" toward meeting the frequency requirements in CAISO ancillary service tariffs.

The required **notice** and **speed** of response are also difficult for most of the existing IOU DR programs to achieve, because the program responses are manually initiated (i.e., non-automated) which cannot provide ancillary services that typically are dispatched with little or no advance notice and which must respond very quickly. The maximum permissible deviation requirement is particularly limiting for most IOU DR programs, because few of those programs mandate the real-time metering and automated response that would be needed to monitor and adjust load within the narrow band required to maintain system stability.

Figure 5-1: Capability of DR Programs to Meet Ancillary Services Requirements



- ● Meets CAISO requirements
- ◐ Partially or nearly meets CAISO requirements, or some participating load may meet requirements
- ○ Does not meet CAISO requirements

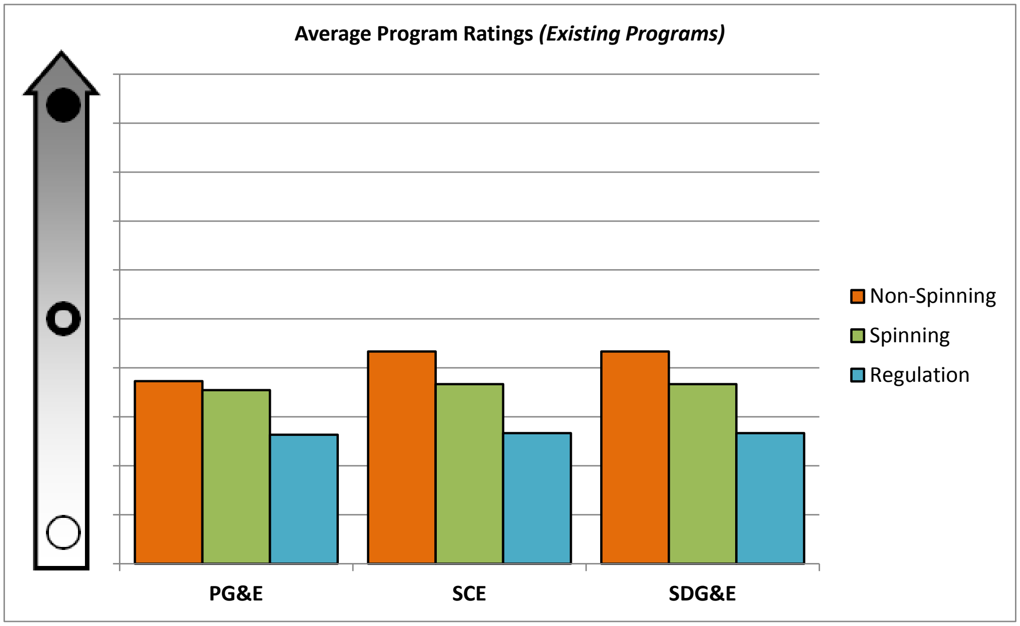
Source: Navigant analysis

The results presented by attribute in Figure 5-1 above suggest that the "average" program would rank less than halfway between "does not meet" and "meets" CAISO tariff requirements.

The ability of a program to meet all the CAISO attribute requirements for a given ancillary service product - opposed to just a few of those requirements - is an even better indication of the likelihood that a program can provide that service. Therefore, the assessment also evaluated each programs based on the average of its scores on all five ancillary services attributes. On average, the existing programs are slightly more likely to have the potential ability to provide non-spinning reserves than spinning reserves, but have little or no potential to provide regulation services. Those results are almost identical for the programs of each of the three IOUs (Figure 5-2). [121]

[121]The ratings of each IOU's version of statewide programs (e.g., the Capacity Bidding Program and the residential direct load control programs) are the same for each IOU unless there are significant differences between each IOU's rules for that program which would affect the program's ability to provide ancillary services that complied with the CAISO tariff for that service.

Figure 5-2: Average Ability of Current IOU DR Programs to Provide Non-Spinning Reserves, Spinning Reserves, and Regulation Services



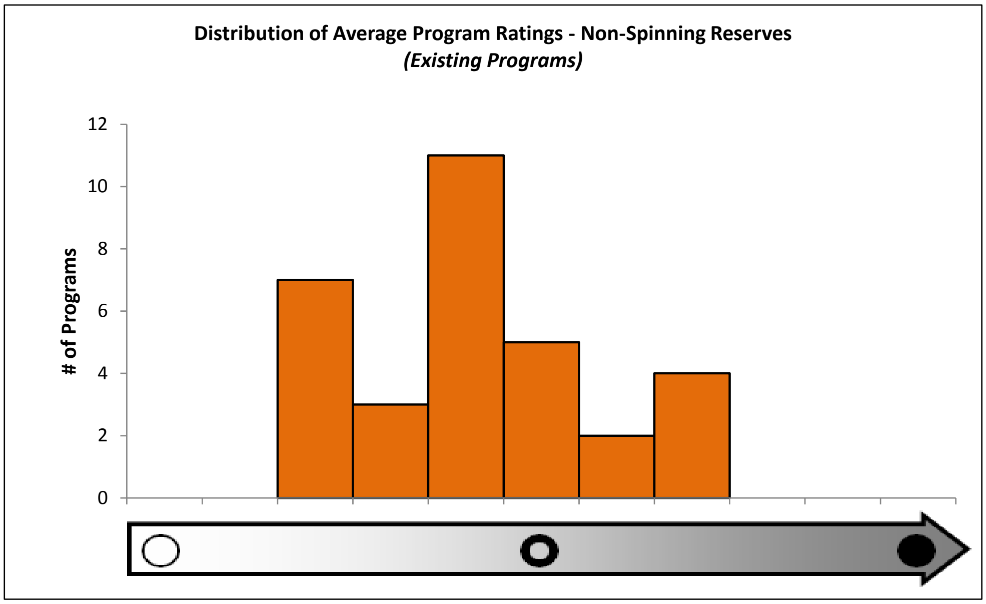
● Meets CAISO requirements
⭘ Partially or nearly meets CAISO requirements, or some participating load may meet requirements
○ Does not meet CAISO requirements

Source: Navigant analysis

The findings presented thus far treat the 33 existing IOU DR programs as a portfolio, based on the average ratings across those programs. The results reflect the significant differences between the attributes of DR programs designed for reliability and economic dispatch, and the attributes of DR programs that would potentially be designed for grid management. As a result, the ratings presented so far demonstrate the *overall inability of the current DR portfolio of each IOU to provide each of the ancillary services covered by a CAISO tariff.*

However, some DR programs might be capable of providing certain ancillary services that comply with CAISO tariff attribute requirements, if certain modifications were made to those programs. Indeed, four of the existing DR programs – IOU direct load control (DLC) programs for both residential and non-residential customers and IOU agricultural pumping load DR programs - already meet CAISO's non-spinning reserve tariff requirements for all of the key attributes except maximum allowable Deviation and, to a lesser degree, Frequency of events. These four programs are represented by the bar on the right-hand side of Figure 5-3, which summarizes the distribution of the relative ability of each of the 33 DR programs to provide non-spinning reserves, the ancillary services product that could most easily be provided by existing DR resources.

Figure 5-3: Ability of Existing DR Programs to Provide Non-Spinning Reserves



● Meets CAISO requirements
o Partially or nearly meets CAISO requirements, or some participating load may meet requirements
○ Does not meet CAISO requirements

Source: Navigant analysis

5.2 *Grid Management Capability from Modified DR Programs*

Despite the apparent inability of the existing IOU DR program portfolio to meet the attribute requirements in current CAISO tariffs for ancillary services, modified versions of some of those programs would be more likely to comply with those products as well the tariffs for new flexible capacity services that are currently being developed.[122]

The most important modifications would be:

(1) Adding a requirement for automated response;
(2) Eliminating or significantly reducing the amount of advance notice required; and,

[122] The CAISO may develop a product for frequency response because of the problems created with variable renewables and their effect on inertia. DR resources capable of responding within eight seconds could provide frequency response for contingencies. Although spinning reserves provided by quick start generating units also provide frequency response, DR with limited calls might be a better fit for frequency response for contingencies if CAISO modified its ancillary service technical attribute requirements in a way that would enable DR to provide this product However, the determination of the technical feasibility of those modifications is not within the scope of this white paper project.

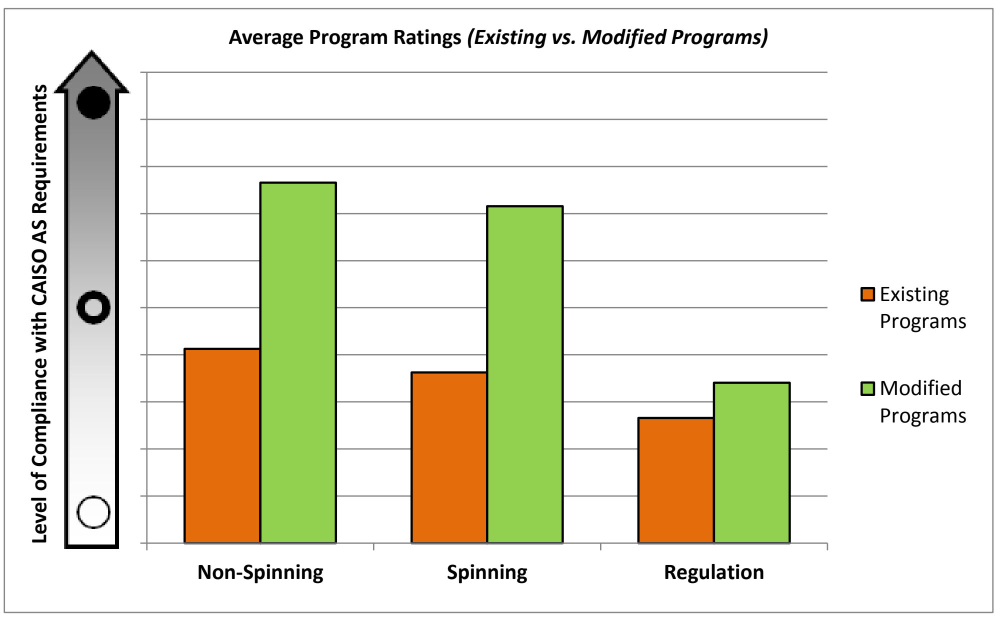
(3) Relaxing the current limits on the number and frequency of events that can be called, as well as limits on the hours and months in which events can be called.[123]

Some of these modifications might significantly reduce the number of customers and the loads willing or able to participate in those programs. Others would fundamentally alter the nature of some programs and/or significantly change certain fundamental characteristics of the program (e.g., eliminating advance notification of each impending Demand Bidding Program event).

Based on an assessment of the feasibility of making each of those modifications to each program, Navigant re-rated the programs using the same approach described above (see Appendix F) to evaluate the ability of each program, both without and with those modifications, to provide each of the ancillary services specified by CAISO tariffs.

If those modifications were made, several of the programs in the DR portfolio of the IOUs would be more likely to be able to provide some of the grid management services, particularly non-spinning and spinning reserves, needed for renewable energy integration (Figure 5-4).

Figure 5-4: Ability of Modified DR Programs to Provide Non-Spinning Reserve, Spinning Reserve, and Regulation Services



● Meets CAISO requirements
o Partially or nearly meets CAISO requirements, or some participating load may meet requirements
○ Does not meet CAISO requirements

Source: Navigant analysis

[123] Coordination between CAISO and the IOUs will become even more important if there is increased reliance on A/S provided by distribution system level DR resources. The development and use of those A/S resources also will have implications for distribution planning and operations that IOUs would need to address.

If those modifications are made, five of the current IOU DR programs might be able to meet all of the CAISO tariff attribute requirements for non-spinning reserves, while four of them would be able to comply with all of the CAISO tariff attribute requirements for spinning reserves. Of the four programs that would be capable of meeting CAISO tariff attribute requirements for spinning reserves, three also would be able to comply with all of the CAISO tariff attribute requirements for regulation services.

The three DR programs that are most likely to be able to provide regulation services if those modifications are made are the aggregator managed portfolio programs of each IOU, which by their nature probably can be customized to attract only those customers and loads that are able and willing to automate and respond in a manner that would enable them to provide regulation services that comply with CAISO tariffs. Modified versions of SCE's agricultural pumping load program and SDG&E's Peak Generation program would also be likely to be able to provide spinning and non-spinning reserves that comply with CAISO tariff requirements.

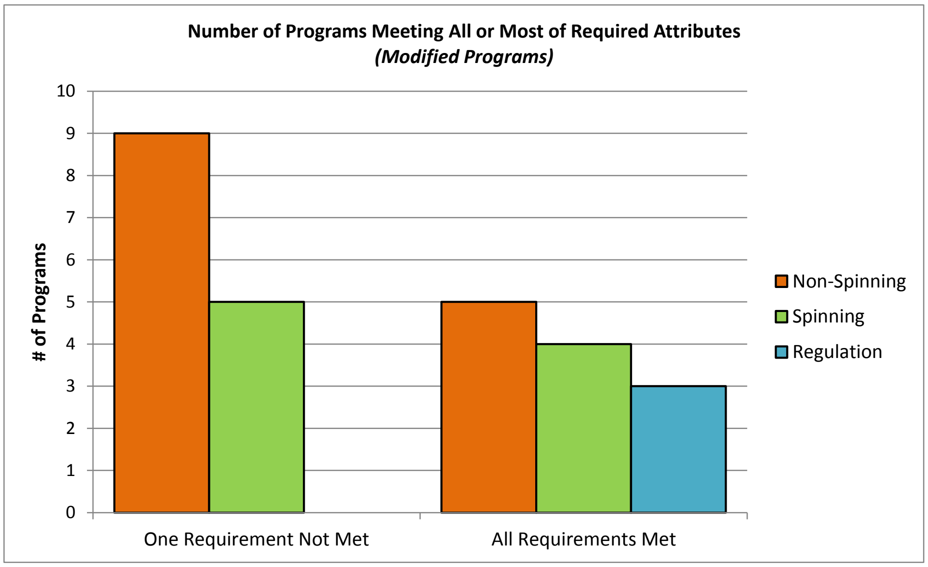
These programs are listed in Figure 5-1.

Table 5-1: IOU DR Programs that Might Be Modified to Provide Ancillary Services

IOU	Program Name (Modified)	Ancillary Service
PG&E	Aggregator Managed Portfolio	Non-Spinning Reserves
SCE	Agg. & Pump Interruptible	Non-Spinning Reserves
SCE	Demand Response Contracts	Non-Spinning Reserves
SDG&E	Aggregator Managed Program	Non-Spinning Reserves
SDG&E	Peak Generation	Non-Spinning Reserves
PG&E	Aggregator Managed Portfolio	Spinning Reserves
SCE	Agg. & Pump Interruptible	Spinning Reserves
SCE	Demand Response Contracts	Spinning Reserves
SDG&E	Aggregator Managed Program	Spinning Reserves
PG&E	Aggregator Managed Portfolio	Regulation
SCE	Demand Response Contracts	Regulation
SDG&E	Aggregator Managed Program	Regulation

The rating results for those modified programs are reflected in Figure 5-5, along with the number of modified programs that would meet the slightly less stringent requirement of complying with all but one of the technical attributes required by the CAISO tariff for each ancillary service.

Figure 5-5: Number of Current DR Programs Meeting All or All But One of the CAISO Tariff Requirements for Each Ancillary Service



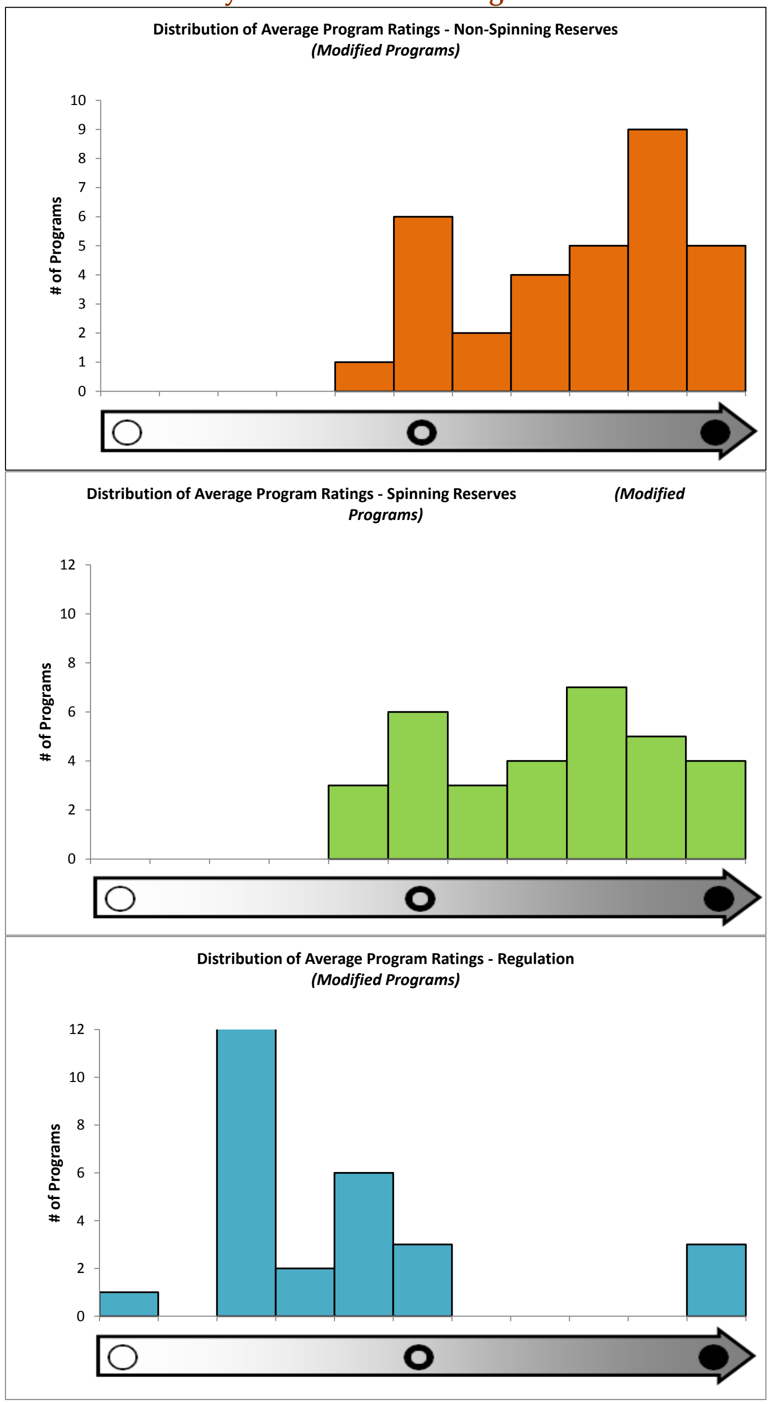
Source: Navigant analysis

Modified versions of the residential direct load control programs of each IOU and SDG&E's non-residential Summer Saver program would be most likely to be able to provide *spinning reserves if it were not for uncertainty over their ability to monitor and control loads precisely enough* in a short time interval to meet CAISO's Maximum Allowable Deviation requirements. In all, five of the IOU DR programs, once modified, could probably provide spinning reserves, and four more programs could provide *non-*spinning reserves, if they were able to comply with the maximum allowable deviation requirement or another single requirement in the CAISO tariffs for those services.

These assessments of the ability of individual DR programs to provide ancillary services that comply with CAISO tariffs are based primarily upon the methodology summarized in Appendix F. However, they also incorporate some subjective expert judgments that were needed for the reasons described at the beginning of Section 5. Consequently, another independent reviewer mighty rate the ability of those programs to provide ancillary services somewhat differently. Therefore, the assessments presented here should be treated as a broad indicator of the ability of each program to provide broadly defined grid management services, rather than as a definitive determination of the ability of each program to provide specific ancillary services. As a result, even programs with ratings below the top quartile may warrant consideration as future load following resources that could support the integration of variable renewable energy.

With that caveat in mind, Figure 5-6 summarizes the distribution of the ratings of the modified programs on a scale that ranges from *failing* to meet all CAISO tariff requirements to *meeting* all CAISO tariff attribute requirements.

Figure 5-6: Evaluation of Ability of Modified DR Programs to Provide Ancillary Services



● Meets CAISO requirements

O Partially or nearly meets CAISO requirements, or some participating load may meet requirements

○ Does not meet CAISO requirements

Source: Navigant analysis

Figure 5-6 shows that most of the modified programs would be clustered between "partially or nearly" meeting and fully "meeting" the requirements for non-spinning reserves. The two bars furthest to the right correspond to the non-spinning reserve bars in Figure 5-5 above, representing the five fully compliant modified programs and the nine modified programs that would be most likely to comply with all but one of the CAISO tariff requirements for non-spinning reserves.

The middle panel of **Figure 5-6** shows the distribution of the ratings of the modified programs in terms of their ability to comply with the CAISO tariff attribute requirements for spinning reserves. Four of the five modified programs whose attributes would comply with all of the CAISO tariff attribute requirements for non-spinning reserves would also have attributes that comply with all of the CAISO tariff requirements for spinning reserves. However, the overall distribution of program ratings for spinning reserves is slightly to the left (i.e., less compliant) than the distribution of program ratings for non-spinning reserves.

The bottom panel of Figure 6 shows the distribution of the ratings of the modified programs in terms of their ability to comply with the CAISO tariff attribute requirements for regulation services. Only the aggregator portfolio and DR contract programs would be able to meet all of the CAISO regulation services tariff attribute requirements. Furthermore the distribution of the ratings of the ability of each modified program to meet CAISO regulation services tariff requirements is much further to the left than the distribution of the ratings of the modified programs in terms of their ability to comply with the CAISO tariff attribute requirements for spinning reserves, largely because few of those programs would be able to support grid management on timescales of less than 10 seconds.

6. Possible Obstacles and Limitations to the Use of DR for Grid Management

Section 5 of this white paper summarized our assessments of the ability of each IOU DR program, both before and after feasible modifications, to provide each of the current grid management services the CAISO would use to integrate renewable energy.

Although the assessment indicates that modified versions of certain IOU DR programs could provide some of those services, there are a number of potential obstacles that might limit the ability of these programs resources to provide those services. Those obstacles can be divided into five categories: DR program attributes, technology barriers, market barriers, economic feasibility, and regulatory barriers. This section summarizes the obstacles in each of those categories.

6.1 Program-Related Limitations

Many of the barriers to DR programs' use in grid management stem from attributes of the programs themselves, including the following:

Required Technical Attributes. In order for a DR program to support grid operations, it would presumably have to meet the CAISO technical attribute requirements for ancillary services products, including any new ramping/load following products developed for purposes of integrating variable renewable energy. As discussed in an earlier section, many of the current IOU DR programs cannot provide these services because they require too much advance notice, are not sufficiently available, cannot be called often enough, and/or do not utilize the automation technology needed to provide sufficiently rapid responses to control signals. Many of the existing DR programs (e.g., price-responsive programs) also are designed in ways that would make it very difficult for them to provide ancillary services. New DR program designs, coupled with modifications to the attribute requirements in current CAISO tariffs for ancillary service and/or the introduction of CAISO tariffs for new grid management products (e.g., Flexi-Ramp) might allow more DR programs to provide ancillary services.

Size/Resource Availability. The sizes and availability of the end-use loads enrolled in DR programs can limit the ability of those programs to serve as grid management resources, particularly near real-time ancillary service products such as regulation services and spinning reserves. As illustrated in Figure 4-1, only a fraction of end-use loads are likely to be available for DR, and an even smaller portion would be capable of providing the various ancillary service products. Furthermore, the nature of the end-use loads enrolled in DR programs limits their temporal availability. That is one of the reasons why the load reduction capacities of some programs are only available in afternoons, or in the summer, or for a limited number of events or hours per year, and why the load reductions provided in some hours tend to be lower than those provided in other hours. That is also why the average load reduction capacity (MW) available from a given DR resource is likely to be either higher or lower than the ancillary services capacity that DR program could provide in any given set of hours. In other words, a DR program's capacity to provide ancillary services at any given time is likely to vary, because of differences between the temporal availability of the end-use loads enrolled in that program.

Locational Limitations. Compared to generation resources, DR resources usually have a geographic advantage in meeting local grid stability needs because their capacity tends to be located in or close to major load centers. However, that is also a limitation in that DR programs cannot be sited where loads do not exist, regardless of whether there is a need for grid management services in those locations. CAISO has defined two system geographic regions and eight sub-regions that are used to place regional constraints on the procurement of ancillary services.[124] The current set of IOU DR programs were developed independently of those geographic regions. However, if demand response resources are to provide ancillary services to help maintain the stability of a system that obtains a significant share of its energy from variable renewables, these boundaries should be considered in designing and implementing those DR resources. Newer automation technology, which can allow large numbers of individual loads to be independently addressed and controlled, can help solve this problem by allowing a program to be dispatched within pre-defined geographic boundaries. Therefore, those technologies can enable DR programs to span several ancillary services sub-regions, and still provide ancillary services.

Limited Ability to Provide Regulation Down Services. Management of the grid requires both regulation up (i.e., increased generation and/or load curtailment) and regulation down (i.e., decreased generation and/or increased loads, and/or energy storage). Although the need for regulation up is usually larger than the need for regulation down, the need for both regulation up and down is expected to increase as the proportion of load met by variable renewable energy grows.[125] While generation resources that provide ancillary services can readily ramp both up and down, virtually all existing DR resources can provide only load curtailment, which can be used only for regulation up. Thus, DR in its current form cannot provide one of the four ancillary services the CAISO needs for integrating variable renewable energy. Pilot programs in the Pacific Northwest[126] and elsewhere are testing new technologies that might hold enable DR to provide regulation-down services, but nothing that is significantly effective has been demonstrated yet, especially on a large scale.

6.2 *Technology Barriers*

Data Availability. Millions of Smart Meters have been deployed in California. Typically, processing the load data obtained through Smart Meter systems typically takes at least a day before those interval meter data can be accessed. Because of that delay, the data cannot be used to monitor the real-time (or near real-time) performance of a DR event.

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[124] See "Business Practice Manual for Market Operations, Version 25," CAISO, April 9, 2012, p.70 for discussion of AS Regions.

[125] As Figure 3-9 and Figure 3-10 show, CAISO's estimate of the need for regulation up in 2020 is much higher than its estimate of the need for regulation down.

[126] Bonneville Power Administration is currently sponsoring three pilot programs to test residential, commercial, and industrial end use storage for wind integration. Sources: Ken Nichols, EQL Energy, "End Use Energy Storage and Renewable Integration," Peak Load Management Alliance (PLMA) spring conference, May 2012; Ken Corum, Northwest Power and Conservation Council, "Wind Integration from Demand Response: Load that Moves Both Ways," PLMA fall conference, November 2010; Lee Hall, BPA, personal communication, April 26, 2012.

Aggregators that provide DR services typically obtain data from a customer meter, or separately sub-meter the controlled load, and provide their own telemetry that allows them to monitor event performance in real-time. The performance speed requirements for providing balancing or regulation services are even higher. In order to provide regulation using demand side resources, it might be necessary to provide four-second interval reads from the load, and sometimes "capture" more than only energy consumption (e.g., instantaneous power, reactive power, and other process characteristics).[127] Accomplishing that requires a high-speed communications overlay, as well as fairly direct access to load controls (i.e., working through a large building Energy Management System (EMS) may add too much delay for effective control of the resource for some uses). Without telemetry for real-time, automated response and verification of loads, DR cannot be an effective resource for ancillary services.

Because real-time meter data is needed to provide ancillary services, the discussion of DR programs in Sections 1.4 and 4 above is based on the assumption that telemetry would be available for all DR program loads. Telemetry is not necessarily needed for price-responsive DR programs or for mass-market DR programs, whose load reductions generally are not mandatory and where the aggregation of many individual small loads provides a statistically predicable range of response. However, these programs have limitations that probably would limit them to providing only non-spinning reserves, if they are capable of providing any ancillary services at all.

Need for Automation. Unless a DR resource can provide automated load response, it will not be able to respond fast enough to a control signal to provide ancillary services. However, the cost of automation can be a significant barrier to the willingness of customers to provide load curtailment through a DR program. That is due to the fact that automation usually provides only non-essential benefits to customers (e.g., improved control of building systems or remote control of isolated loads), and the revenues they obtain from providing load curtailment to ancillary services markets might not be significantly greater than those they can obtain from providing manual load reductions under "traditional" DR programs. For example, although SCE offers incentives of up to $300 per kW for the purchase and installation of qualifying DR-enabling equipment,[128] the result might still be a net cost to the customer.

6.3 Market Barriers

Customer Willingness to Participate. The combined load reduction capacity of the DR programs of the California IOUs has not exceeded 5 percent of the CAISO's system-wide peak load. Even PJM's most recent capacity reserve auction - which attracted more than 14,800 MW of DR - implied a DR penetration

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[127] Some vendors that are now implementing DR for regulation services (e.g., Embala) have concluded they need two-second interval reads to verify that their load response meets requirements.

[128] Source: SCE, *Technology Assistance and Technology Incentives* fact sheet, 2010. Also see: http://www.sce.com/b-rs/large-business/technical-assistance-technology-incentives.htm

equal to only 11 percent of PJM's peak load.[129] Compared to using DR to reduce demand in order to avoid overloading the grid, using DR to provide ancillary services needed for renewable energy integration requires greater automation, little or no advance notification, many more events, and more flexibility in changing loads from moment to moment at different times of the day. Based on all of these factors, the limited willingness of customers to participate in providing ancillary services through DR programs might significantly limit the amount of ancillary services capacity DR programs could provide.

Potential Conflicts with Other DR Programs. The same DR resources that would provide grid management services for renewable energy integration probably could, and for economic reasons likely would also provide emergency/reliability DR capacity to avoid overloading the grid. In fact, for DR resources to be economic, they also might have to provide more than just ancillary services. However, when a load is providing demand reductions in response to an actual or imminent grid emergency, it would not be available to help mitigate the impacts of variable renewables on system stability. That situation is analogous to Con Edison's Distribution Load Relief Program (DLRP), which has participants that are also enrolled in the New York Independent System Operator's (NYISO's) reliability DR programs. When the NYISO calls an event in the same hours as a DLRP event, Con Edison pays participating customers only for the amounts by which their load reductions exceeded the demand reduction commitments those customers had made under NYISO's reliability DR program.[130]

6.4 *Economic Feasibility*

Some of the modifications that would be needed to enable certain DR programs to provide ancillary services that have the technical attributes required by CAISO tariffs would require IOUs and/or the customers enrolled in those programs to incur significant costs. The extent which modified DR resources will be used to provide some of the ancillary services needed to integrate variable renewables that would otherwise be provided by generation resources will depend upon the relative costs of using each of these two types of resources to provide those services, and on supply and demand conditions in California's wholesale markets for those services.

Supply and Demand Conditions, Prices, and Costs in Wholesale Markets for Ancillary Services. The total cost of the ancillary services provided in 2011 in California was about $139 million, which was 61 percent higher than it had been in 2010. In addition to the cost of the ancillary services procured by the CAISO, that total includes the estimated $33 million value of the ancillary services that California IOUs and LSEs provided for themselves in 2011, compared to only $13 million in 2010.[131]

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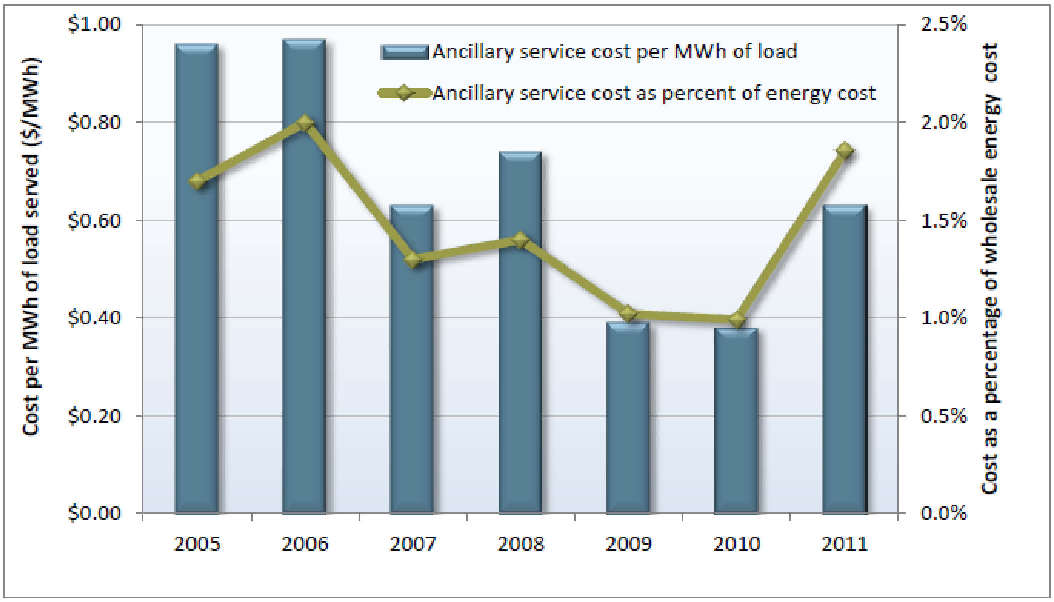
[129] PJM's 2015/2016 capacity reserve auction cleared 164,561.2 megawatts (MW) of capacity, 20.2 percent of which was reserve margin. DR represented 14,832.8 MW, or roughly 11 percent of forecasted load. Source: PJM, *2015/2016 RPM Base Residual Auction Results*, PJM Docs #699093, May 2012.

[130] Source: Con Edison Rider U tariff, Distribution Load Relief Program, issued October 22, 2010.

[131] IOUs and LSEs can reduce their ancillary service procurement requirements by self-providing ancillary services. While this is not a direct cost to the load-serving entity, self-provided ancillary services have an economic value. The CAISO estimate of the value of self-provided ancillary services that is reported here is based on the costs those IOUs

However, the total cost of the ancillary services that were procured or self-provided in 2011 only accounted for about 1.9 percent of California's total wholesale energy costs in that year, compared to just 1.0 percent in 2010 (Figure 6-1).

Figure 6-1: Ancillary Service Wholesale Market Prices and Costs in California[132]



When a resource is given an ancillary service award in the CAISO's wholesale market for an ancillary services product (i.e., the resource sells an option for the provision of that service) in either the day-ahead or real-time market, the resource receives a capacity payment that compensates the resource for the opportunity cost of not providing energy. That ancillary service capacity payment is equal to the expected profit from selling energy to the CAISO.

If the resource is actually called upon to provide energy in the real-time market as an ancillary service, the resource also is paid the real-time locational marginal price (LMP) for providing the energy, over and above that ancillary services capacity payment.

Capacity payments in the real-time market are only for incremental capacity in excess of the day-ahead procurement. Consequently, the volume of procurement in the real-time ancillary services market is very

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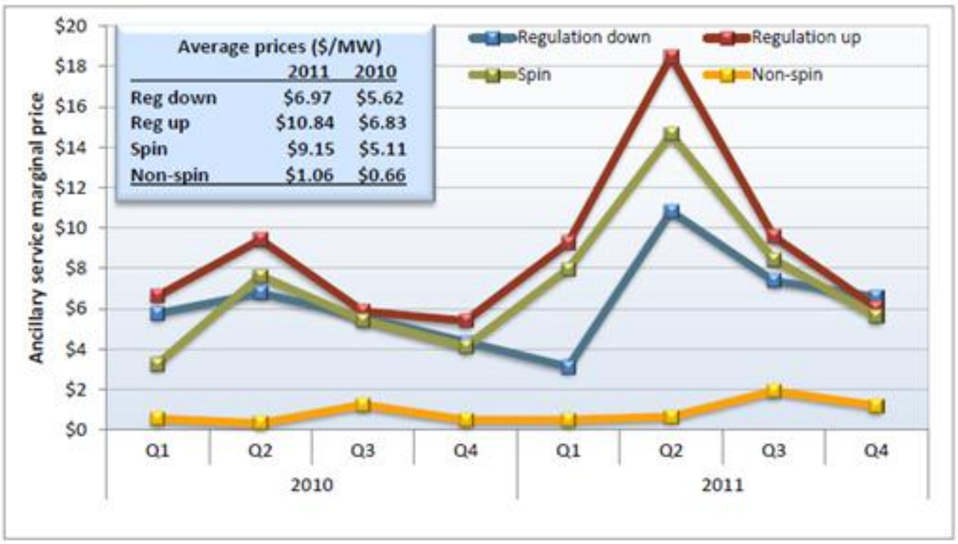
and LSEs would have incurred if they had instead purchased those ancillary services at the clearing prices in CAISO's wholesale market for ancillary services.

132 SOURCE: *CAISO's 2011 Annual Report on Market Issues & Performance*, available at http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf

limited, accounting for less than one percent of CAISO's total procurement. (Capacity payments in the real-time market for ancillary services are only for incremental capacity above the day-ahead award.)

Figure 6-2 shows the weighted average market-clearing prices for each ancillary service capacity product by quarter in the day-ahead market in 2010 and 2011.

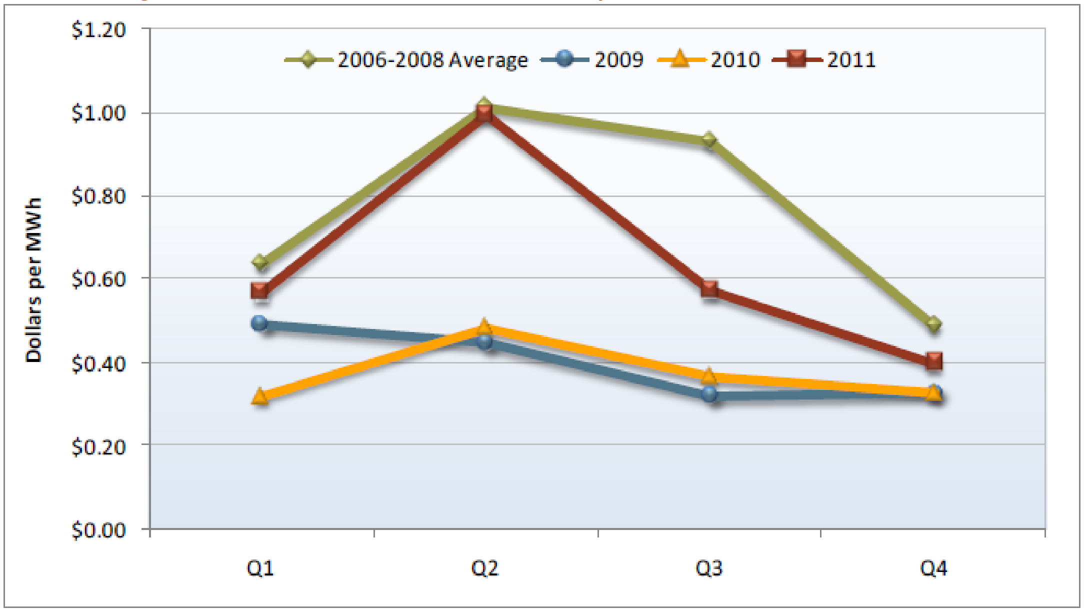
Figure 6-2: Day-Ahead Wholesale Market-Clearing Prices for Ancillary Services[133]



Although average ancillary service prices dropped somewhat after the recession began in 2008, they recovered to pre-recession levels by the last quarter end of 2011 (Figure 6-3).

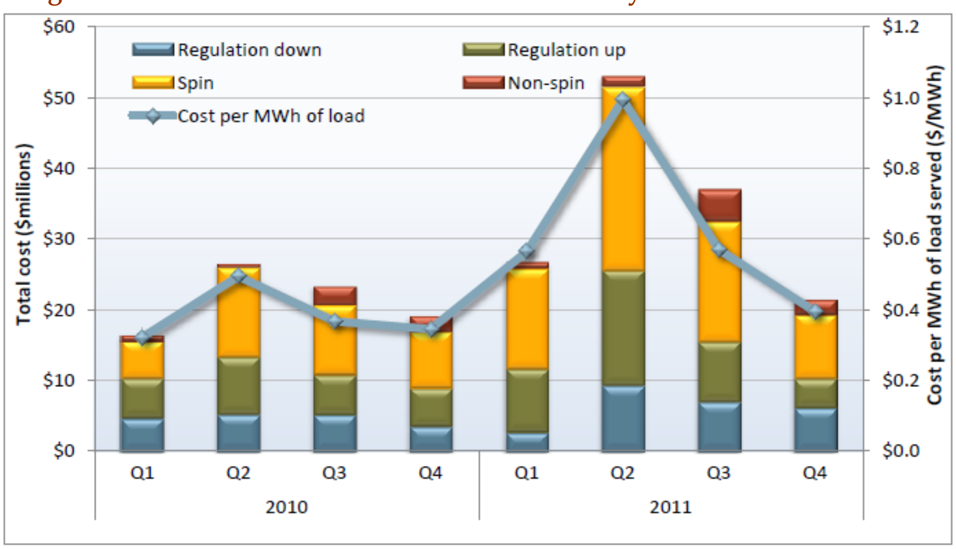
133 Ibid.

Figure 6-3: Historical Trends in Ancillary Service Prices in California[134]



Spinning reserves accounted for the largest share of the total cost of ancillary services in 2010 and 2011. Regulation up services accounted for the second largest share of that cost (Figure 6-4).

Figure 6-4: Wholesale Prices and Costs of Ancillary Services in California[135]



[134] Ibid.

[135] Ibid.

6.5 *Regulatory Barriers*

As noted above, California's "loading order preference" policy[136] requires IOUs to first procure cost-effective DR and energy efficiency resources, then renewable resources, and only then conventional generation resources. As a result, under the policies adopted by the CPUC, IOU DR programs must be cost-effective. In order to be cost effective, an IOU DR resource that has the technical ability to provide ancillary services would have to provide those services at a lower cost than the generation resource that would otherwise provide them.

In addition, third parties (e.g., DR aggregators) are likely to provide DR resources only if they expect them to be profitable.

The extent to which modified DR resources rather than generation resources will be used to provide some of the ancillary services used to integrate variable renewables will depend upon the differences between the costs and technical qualities of the ancillary services provided by those two types of resources. That is likely to become increasingly important because of the steps the CPUC has taken to introduce and promote competition between IOU DR resources, third party DR aggregators, and end-use load customers in the CAISO's wholesale markets (as described in Sections 4.2 and 4.3).

That market competition-based determination of the mix of DR and generation resources that would provide the amount of ancillary services the CAISO requires would be limited if the CPUC policies restrict the mix of DR and generation capacity that IOUs can use to comply with any flexible capacity and/or regulation services Resource Adequacy requirements the CPUC might adopt.

In addition, the CPUC already allows IOUs (and other Load Serving Entities (LSEs) in California) to use dispatchable DR resources as well as supply-side resources to comply with their respective monthly Resource Adequacy (RA) "generic" capacity requirements. IOU DR programs that have the technical ability to provide ancillary services are more likely to be cost-effective (or profitable enough in the case of DR-based ancillary services provided by aggregators) if those programs also reduce the amount of generic capacity IOUs need to comply with RA requirements.

[136] State of California Energy Action Plan (2003), page 2. http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF. Also, see State of California Energy Action Plan II, September 21, 2005, available at: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

7. Recommendations

DR can play a role in renewables integration in California, both through the use of existing programs—modified to be more suitable for providing ancillary services—and through the development of new programs specifically design to participate in CAISO's ancillary services markets.[137]

Both modified and new DR programs capable of providing ancillary services would have characteristics that are somewhat different from those the current IOU DR program portfolio used to avoid emergencies (i.e., maintain system reliability) and to lower costs by curtailing loads in periods when wholesale electricity prices are unusually high..

7.1 DR Program Designs and Products

California's existing DR resources can contribute to the integration of variable renewables through the participation of selected programs in CAISO's ancillary services markets, including yet to be defined ramping and/or load following products intended to support renewables integration. Most programs require at least modest modification in order to qualify for these markets and to provide the technical responsiveness needed for effective grid management.

In general, the most critical program improvements are:

» **Use of telemetry for real-time communications and metering**
» **Reduced notification time**
» **Automated response to control signals**
» **Increased number of allowable events**
» **Extended hours or seasons of availability**

Some programs cannot adopt these modifications while still maintaining the fundamental functioning of the program, such as real-time pricing (which does not incorporate discrete "events" and the OBMC programs (which are designed to interrupt whole circuits only on the rare occasions of an imminent rolling blackout). Many other programs could be modified to provide varying degrees of grid management services, with some capable of providing regulation services, others providing spinning or non-spinning reserves, and perhaps others able to provide only the load following/ramping services likely to be adopted in the coming years as the penetration of variable renewables continues to increase.

Although no single DR program will be capable of providing every one of the products needed to maintain grid stability by integrating variable renewable energy, the IOUs can develop a portfolio of

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[137] SCE's proposed Ancillary Services Tariff, which the CPUC did not approve, was designed to attract customers (particularly large agricultural pumping loads) who could bid into CAISO's wholesale market as Proxy Demand Response resources and respond to an AS event request within 10 minutes. Source: *Testimony in Support of Southern California Edison Company's Application for Approval of Demand Response Programs, Activities, and Budgets for 2012-2014*, Application No. A.11-03-003, Exhibit No. SCE-1, Volume 2.

programs encompassing a combination of end uses, locations, and program constraints that allow the portfolio to provide needed grid management services in many locations at all times of day and throughout the year. That portfolio would include both existing programs (most with modifications) and new programs.

7.2 *Existing Programs*

The existing IOU DR programs that are most likely to be capable of supporting renewable energy integration are the aggregator managed portfolio programs, the mass-market DLC programs, and SCE's agricultural pumping load program.

However, modified versions of the statewide Base Interruptible Program and Capacity Bidding Programs might be able to facilitate renewable energy integration by providing ancillary services products that deliver more flexible, quicker, and precisely controlled changes in load.[138]

Figure 7-1 summarizes the most important modifications that would have to be made in order for modified versions of those programs to support the integration of variable renewable energy.

Figure 7-1: Recommended Changes to Existing IOU Programs

Program	Telemetry	Reduced Notification	Automated Response	Increase in Events	Extended Hours/Seasons
Aggregator portfolios	X	X	X	varies	X
Mass-market DLC	X			X	X
Agricultural pumping	X			X	
BIP[139]	X	X	X	X	
CBP	X	X	X	X	X

Response time and precision are two of the key factors limiting the ability of using DR programs to provide the current set ancillary services. However, some of the existing programs might be able to provide load ramping and/or following services, including event-based price-responsive programs such as peak time rebates that are neither automated nor capable of providing load response that could be controlled precisely enough to comply with current CAISO tariffs for ancillary services.

[138] If the CPUC had not prohibited IOUs from counting the load reduction capacity of programs that use customer-owned fossil-fueled back up generation in complying with their Resource Adequacy requirements, this table would have indicated that extending the hours and seasons in which SDG&E's CleanGen program is available would allow that program to provide ancillary services. See: CPUC Decision 11-10-003 (October 6, 2011), pp. 22-30 available at http://docs.cpuc.ca.gov/published/Final_decision/145022.htm.

[139] The CPUC has placed a "cap" on the combined capacity of Base Interruptible Programs (BIP) and other IOU DR reliability programs. These recommendation assume the CPUC would modify that limitation , if the design of the program was changed in ways that would enable it to provide ancillary services and/or flexible capacity products.

Appendix E contains assessments of each IOU DR program's suitability for providing ancillary services, and the modifications that would enhance each program's ability to provide services that would facilitate the integration of variable renewable generation.

7.3 Potential New Programs

While existing programs can be modified to provide grid services, new programs can be designed from scratch specifically to meet the needs of a grid with a large penetration of renewables. Although these new programs might also be capable of providing emergency or economic response, renewables integration should be the primary determinant of their attributes, rather than merely an after-the-fact ancillary services benefit, as it is with existing programs designed for other purposes.

New programs may provide current ancillary services products, including spinning and non-spinning reserves and regulation, as well as the new products that are being developed for continuous ramping and load following. Although programs might be designed to optimize their ability to provide a specific ancillary services product, most would be capable of providing any product with less stringent requirements as well. As a general guide, programs could be designed to provide any of three types of products:

- **Spinning and non-spinning reserves.** The CAISO tariffs for these products have considerably more stringent *response* requirements than those that are likely to be contained in tariffs for ramping and load following products, and therefore would require DR programs that can provide rapid, flexible, and precisely controlled responses.
- **Regulation.** DR programs capable of providing regulation up services would have to provide even more rapid, flexible, and precisely controlled responses than those required for non-spinning and spinning reserves. In order to provide regulation-down services, DR programs would have to increase loads just as rapidly, flexibly, and precisely as DR resources that provide regulation up services.
- **Maximum continuous ramping/load following.** This category of flexible grid management products includes the two non-regulation products that the CAISO is developing to meet the grid management challenges due to increased reliance on variable renewable generation. These products would respond less rapidly and have lower ramp rates than existing ancillary services products. However, using DR resources to provide these new flexible capacity products is likely to entail considerably more operational complexity. For example, orchestrating and maintaining a multi-hour ramp using a portfolio of DR resources will require technical and load management capabilities that are outside the realm of those incorporated in typical DR program designs.

The attributes that DR programs would need to have to provide the grid management products in each of these categories are summarized in Figure 7-2.[140]

Figure 7-2: DR Program Attributes Required to Provide Products Capable of Supporting Integration of Variable Renewables

Attribute	Spinning/non-spinning reserves	Regulation	Continuous ramping/ load following
Telemetry	Required	Required	Required
Response time	Less than 10 minutes; less than 10 second to begin ramping is desirable	Less than 1 minute	Less than one hour, but some resources taking 10 hours or more could be used
Automated response	Required	Required	Required
Event limitations	Dozens to more than 100 events lasting at least one hour each	Continuous availability desired	10 hours or more duration, minimum of one hour
Daily/seasonal availability[141]	24x7 year-round	24x7 year-round	24x7 year-round, with seasonal variation
Target end uses	Agricultural and municipal pumping, electric water heat (if available)	Temperature controlled warehouses, industrial motor loads on variable frequency drives	Commercial lighting and HVAC

In addition to the attributes contained in Figure 7-2, some DR capacity should be capable of providing regulation-down services, which entails providing near-instantaneous *increase* in load. While the regulation-down requirement is not as great as regulation up, it may grow with higher penetration of renewables. . Loads with characteristics making them promising prospects for regulation down include cold storage facilities, electric domestic hot water heating,[142] and some motor loads on variable frequency

[140] **Source**: CAISO, *2013 Flexible Capacity Procurement Requirement: Supplemental Information to Proposal.* March 2, 2012.

[141] Not every resource has to provide products that are available 24 hours a day, 7 days a week in all seasons, or even be available for multiple events in a day or for the 100 or more events that could be called. A balanced portfolio of renewable integration DR programs could perform in the same way as a generation resource.

[142] A Bonneville Power Administration pilot program is evaluating the potential for adjusting domestic hot water heating loads to provide both regulation up and regulation down services. However, the size of this resource

drives. A pilot program to test the most promising resources would provide the operational data needed to assess whether such loads could provide regulation down and what changes might be necessary to CAISO rules to accommodate them.

If the amount of load capable of providing regulation up is an order of magnitude smaller than that capable of providing spinning reserves, then the capacity of DR resources capable of regulation down is likely to be more limited than the capacity of DR to provide spinning reserves.

7.4 Regulatory Policies and Tariffs

Regulatory policies and tariffs will play a key role in helping to facilitate DR taking a stronger role to support renewables integration in California. It will be important to initiate a focused initiative to reduce regulatory market barriers associated with IOU DR programs participating in the ancillary services market in California. Specifically, an effort should be undertaken to identify the key regulatory market barriers, and recommend strategies for reducing these barriers through new market mechanisms. The CPUC should explore how DR program cost-effectiveness protocols might have to be modified in order to evaluate DR programs that provide ancillary services and/or flexible capacity products, Eventually, the state should move towards automated opt-in programs that are based on more dynamic price signals and/or automated, opt-in real-time pricing tariffs. There also should be an initiative to foster improved coordination between IOUs and CAISO in developing DR programs capable of providing current ancillary service products and/or new flexible capacity products.

Policies that would facilitate DR taking a stronger role to support renewables integration in California include:

- Initiating a focused initiative aimed at reducing regulatory market barriers that limit the ability of IOU DR programs to participate in California's wholesale ancillary services markets:
  - Examine how DR program cost-effectiveness protocols might have to be modified in order to evaluate DR programs that provide ancillary services and/or flexible capacity products.
  - Explore new market mechanisms that might facilitate rather than hinder increased participation of IOU DR programs in CAISO's wholesale markets for ancillary services.
- Adopting automated, default dynamic pricing, and implementing automated, opt-in real-time pricing tariffs, for even more types of customers.
- Expanding reliance on the innovations provided by third party DR providers
- Facilitating improved coordination between IOUs and CAISO in developing DR programs capable of providing current ancillary service products and/or new flexible capacity products.

relative to overall load and need for regulation services is significantly smaller in California than in the Pacific Northwest.

8. Conclusions and Next Steps

8.1 Conclusions

Key findings of this research include:

» The difficulties in maintaining the stability of the grid are due to the variability and uncertainties created by the volatility of demand, the variability of supply, and the difficulty in accurately forecasting both supply and demand over different time intervals.

» California's existing DR resources can contribute to the integration of variable renewables through the participation of selected programs in CAISO's ancillary services markets, including yet to be defined ramping and/or load following products intended to support renewables integration. Most programs require at least modest modification in order to qualify for these markets and to provide the technical responsiveness needed for effective grid management. In general, the necessary program improvements include the following:

- Use of telemetry for real-time communications and metering
- Reduced notification time
- Automated response to control signals
- Increased number of allowable events
- Extended hours or seasons of availability

» The existing IOU DR programs with the most promise to support renewables integration are:

- Aggregator managed portfolios;
- Mass-market DLC programs; and
- Agricultural pumping load programs.

» The more lenient the response time and operational requirements for a given ancillary services product, the easier it will be for DR to provide the service to the grid. Although few programs are likely to be able to provide ancillary services covered by current CAISO tariffs unless the programs are modified, CAISO's proposed ramping and load following flexible capacity products could provide an opportunity for DR to support renewables integration. Although those products are likely to have less stringent response time requirements, it might still be necessary make operational enhancements to control and orchestrate an extended response. Two of the existing statewide DR programs are likely to be able to provide a more flexible set of ancillary services products:[143]

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[143] If the CPUC had not prohibited IOUs from counting the load reduction capacity of programs that use customer-owned fossil-fueled back up generation in complying with their Resource Adequacy requirements, this table would have indicated that extending the hours and seasons in which SDG&E's CleanGen program is available would allow

- Base Interruptible Program;[144] and,
- Capacity Bidding Program.

» Response time and precision are two of the key factors limiting DR program's use for current ancillary services. Event-based dynamic-pricing programs such as peak time rebates (which do not require a response and are neither automated now nor capable of precise load response) cannot currently provide effective grid management support. However, they could play a larger role in grid management under future CAISO tariffs for ancillary services products that have less stringent response requirements than those in current tariffs.

» New programs should be designed to have the attributes need to provide specific ancillary service product(s), with a secondary objective of providing emergency or economic response.

» Key market barriers include the effect of the cost of automation and real-time communication devices on customer willingness to participate in DR programs capable of contributing to the integration of variable renewable generation.

» Stakeholder opposition might be an obstacle, particularly with respect to DLC programmatic initiatives.

8.2 Benefits to California

Cost effective DR (along with cost effective energy efficiency) is at the top of the state's loading order policy[145] and, with appropriate modifications, has the potential ability to play a role in integrating renewable energy generation in a cost-effective and flexible manner. The CPUC and the IOUs are likely to increasingly view DR as a viable resource to help balance variable renewable energy by providing spinning, non-spinning, flexible ramping and, to a lesser extent, regulation services. The specific benefits of utilizing DR resources to provide these services include the following:

» Avoided capacity costs associated with the conventional generation, primarily natural gas-fired CTs, which might be required to provide ancillary services that can instead be provided by certain DR resources.

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that program to provide ancillary services. See: CPUC Decision 11-10-003 (October 6, 2011), pp. 22-30 available at http://docs.cpuc.ca.gov/published/Final_decision/145022.htm.

[144] The CPUC has placed a "cap" on the combined capacity of Base Interruptible Programs (BIP) and other IOU DR reliability programs. These recommendations assume the CPUC would modify that limitation, if the design of the program was changed in ways that would enable it to provide ancillary services and/or flexible capacity products.

[145] State of California Energy Action Plan (2003), page 2. http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF. Also see State of California Energy Action Plan II, September 21, 2005, available at: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

- » Reduced GHG emissions due to reduced usage of conventional fossil-fueled generation to provide ancillary services.
- » Reduced exposure to fuel price volatility due to use of ancillary services provided by DR resources rather than conventional fossil-fueled generation.
- » Reduced operations and maintenance costs for conventional fossil-fueled generation, due to a reduction in the number of starts per year.
- » Greater flexibility to meet local reliability needs, including offsetting the adverse impacts of retiring once-through-cooling generation resources.
- » Enhanced ability to capture the benefits associated with widespread deployment of advanced metering infrastructure and smart grid technologies, including initiatives funded by California ratepayers and American Recovery and Reinvestment Act of 2009 (ARRA) grants.

8.3 Next Steps

The next steps and research activities that would facilitate increased usage of DR resources in supporting the integration of variable renewable resources in California include:

- » Conducting a statewide DR Potential Study specifically focused on evaluating the technical and economic market potential for DR to provide ancillary services (i.e., identify the market potential of loads that can provide automated changes in load in response to control signals, and be available for increased number of events and extended hours and seasons).

- » Conducting an assessment of regulatory market barriers that impair widespread utilization of DR in the ancillary service market in California.

- » Developing pilot programs in each service territory that test new DR programs designs aimed at providing different ancillary services products (spinning reserves, non-spinning reserves, regulation, and emerging possible flexible capacity products).

- » Increasing coordination between IOU DR Program Administrators and CAISO to help shape the new wholesale DR products capable of facilitating the integration of variable renewable generation, taking into account the ways in which wholesale and retail markets for DR products are converging.

- » Conducting a consumer behavior study to assess the relationship between end-user costs and customer willingness to participate in new and/or modified IOU DR programs designed to meet the requirements of the ancillary services market.

- » Performing cost-effectiveness and portfolio optimization evaluations of different options for supporting renewable energy integration, including ancillary services and flexible capacity products provided by DR resources, fast-response battery storage, and conventional generation capacity.

» Assessing the market for Smart Grid technologies that could facilitate automatic DR, as well as the benefits and costs associated with deploying these technologies

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Appendix B. Interviews Conducted for this Project

- **ERCOT**
  - **Paul Wattles - 5/11/12**
- **CA ISO**
  - **John Goodin - 5/14/12**
- **ISO-NE**
  - **Laura Corcoran - 4/26/12**
- **PJM**
  - **Scott Baker – 4/24/12**
  - **Scott Baker – 4/4/12**
- **BPA**
  - **Lee Hall and Katie Pruder-Scruggs – 4/26/12**
  - **Lee Hall – 5/2/12**
  - **Ken Nichols (Ecofys, on behalf of BPA DR Programs) – 4/4/12**
  - **Tom Brim and Lee Hall – 3/12/12**
- **HECO**
  - **Angie Eide and Tim Ellis – Various dates**
- **EnerNOC**
  - **Aaron Breidenbaugh – 5/2/12**
- **PG&E**
  - **Antonio Alvarez – 1/23/12**

Appendix C. Summaries of Evaluations of IOU Demand Response Programs

Figure C-1: Pacific Gas & Electric Demand Response Programs

Pacific Gas and Electric Company FOR INTERNAL USE ONLY	LARGE COMMERCIAL, INDUSTRIAL & AGRICULTURE PeakChoice™ Program Helen Arrick 8-223-9770	LARGE COMMERCIAL, INDUSTRIAL & AGRICULTURE Peak Day Pricing (PDP) Plan Jill Faublon 8-481-2119	LARGE CI&A Demand Bidding Program (DBP) Dionne Jones-Keeton 8-223-3563	LARGE CI&A and AGGREGATOR* Base Interruptible Program (BIP) Dionne Jones-Keeton 8-223-3563	AGGREGATOR* Aggregator Managed Portfolio (AMP) Kathy Rios 8-223-4808	AGGREGATOR* Capacity Bidding Program (CBP) Jason Legner 8-222-5900
Program Description	Customers create a customized demand response program to fit their business needs. Customers can choose Committed or Best Effort participation, event notification lead time, limit on number of events in a year, duration of events, and more. Customer incentive level varies with selections.	A new CPUC-default time varying pricing plan that provides credits throughout the Summer Season in exchange for added fees (charges) during limited hours on Event Days	A voluntary bidding program that is both a system emergency and market price / day-ahead bidding program. Since participants can elect whether to participate in each event, there is no risk for non-curtailment.	BIP is a statewide, voluntary program operated throughout the year. It is intended to provide load reductions on PG&E's system on a day-of basis such as emergency conditions on the Bulk Electric System operated by the CAISO. PG&E can also dispatch the program for a localized or system-level emergency.	AMP uses third-party providers (Aggregators) to aggregate loads to achieve load reduction. AMP currently has 5 participating third-party providers (Aggregators) providing load reductions by aggregating customers in PG&E's territory to achieve load reductions	CBP participants receive a monthly capacity incentive payment and (if applicable) an energy incentive payment to reduce loadby a pre-determined amount when notified of a CBP demand response event
Curtailment Requirement	Based on selected participation option: **Committed:** Mandatory (incentive payment reduced for non-compliance) **Best Effort:** Voluntary	Voluntary	Voluntary (No penalties for missing load reduction commitment)	Mandatory	Mandatory	Participants are not required to nominate each month; however, curtailment (based on any nominations made) is mandatory
Contract Period	Customers may terminate their participation or change their program option selections annually between November and May	Customers may opt out of PDP to a TOU rate schedule up to 2 business days before their PDP default date. Once on PDP, customers may change their mind and opt out once in the first 12 months, otherwise PDP changes follow Rule 12.	This program is available until modified or canceled by the CPUC. Customers' participation will be in accordance to Electric Rule 12 and remain on the program for a minimum of 12 months. Customers may terminate their participation by giving a minimum of 30 days written notice. Modifications to the service agreement (SA) listing of an aggregated group may only occur during the March contract review period.	May be terminated during annual November Open Review Period	Five-year term, 2007-2011. PG&E is currently requesting to extend the existing term of the Agreement for one (1) additional calendar year.	Contracts between Aggregator & End-Use Customer are private (contract periods may vary). Contract between PG&E & Aggregator is commencement until terminated (Customers receiving an interval meter at no charge for CBP Participation will be required to remain in the program for one full year)
Eligibility	Bundled-Service Customers on a demand time-of-use (TOU) rate schedule are eligible. Customers on net metering, AG-R or AG-V rate schedules are not eligible.	* Bundled Large CIA customers (see Minimum Qualifying Load Criteria below) * Net metered, streetlight/traffic control, 100% standby load and Direct Access customers are not eligible for PDP. * Customers on an existing DR program will not default. Dual participation in select DR programs is permissible as of 5/1/2011.	Bundled, Direct Access, and Community Choice Aggregation Service customers. Customers must receive service on a demand TOU rate schedule (Rate schedules AG-R, AG-V, and S are not eligible), billed maximum demand of 200 kW or greater within 12 billing months and commit to reduce a minimum of 50 kW during an event.	Bundled, Direct Access, and Community Choice Aggregation Service customers. Customers must take service under on a demand TOU rate schedule (Rate schedules AG-R and AG-V are not eligible) and have at least an average monthly demand of 100 kW.	Bundled, DA and CCA customers on a commercial, industrial, partial standby, or ag rate schedule. Customers that receive electric power from WAPA, 3P (other than DA), NEM or full standby services not eligible. As of 8/1/10, customers participating in DBP are eligible to participate with AMP Day-Of, and OBMC customers are eligible to participate with AMP Day-Ahead. As of 5/1/11 PDP can participate with AMP Day-Of	Bundled, DA and CCA customers on a commercial, industrial, partial standby, or ag rate schedule. Customers that receive electric power from 3P (other than DA), NEM or full standby services not eligible. As of 8/1/10, customers participating in DBP are eligible to participate with CBP Day-Of, and OBMC customers are eligible to participate with CBP Day-Ahead. As of 5/1/11 PDP can participate with CBP Day-Of
Operating Months	Events operated from May 1 to October 31	Events operated year-round	Events operated year-round	Events operated year-round	Events operated between May 1 and October 31	Events operated between May 1 and October 31
Curtailment Window	Customer selects load reduction availability window: Weekdays excluding holidays 1:00 p.m. – 7:00 p.m. or 24 Hours/Day – 7 Days/Week	2:00 p.m. – 6:00 p.m. (7-days/week) Options for A-1, A-6, A-10 , AG4 rate schedules: *Extended Event Window: noon - 6:00 p.m. *Alternate Event Days: every other PDP event	Weekdays excluding holidays 12:00 noon – 8:00 p.m.	24 Hours/Day – 7 Days/Week	Weekdays excluding holidays 11:00 A.M. – 7:00 p.m.	Weekdays excluding holidays 11:00 A.M. – 7:00 p.m.
Minimum Qualifying Load Criteria for Program	Ability to reduce demand by at least 10 kW	**Transition Customers (default)** E-19, E-20, A-10, E-37 & AG5C rate schedules: 3 consecutive months of ≥ 200 kW, 15 minute interval meter is present, 12 months of interval data is available and interval data used for billing. **Optional voluntary enrollment:** As above, except 12 month data history not required.	≥ 200 kW Customer accounts < 200 kW may also participate as aggregated group for service accounts with same Federal Taxpayer ID Number	100 kW	No minimum demand load requirement. Customer sites must have an interval recording meter	No minimum
Event Trigger	• CAISO or PG&E forecasts CAISO system peak load will meet or exceed 43,000 MW • CAISO issues or PG&E expects CAISO to issue Stage 2 or 3 Emergency • PG&E expects to require electric generation by facilities with heat rates of 15,000 BTU/kWh or g • An actual or anticipated localized emergencies • Avg. forecasted peak temp of5 territories meets or exceeds 94°F	*Forecasted day-ahead temperature based on average of 98° weekdays and 105° on weekends and holidays in 5 territories; system reliability; high spot market power prices; or testing. *Temperature trigger can be adjusted to reach event range of 9-15 events per calendar year.	PG&E may issue a day-ahead event notification by 12:00 Noon whenthe CAISO's load forecast exceeds 43,000 MW or when the CAISO issues an Alert Notice or when PG&E forecasts that resources may not be adequate.	The CAISO may request PG&E to operate all or part of the program when (1) it has publicly issued a Warning Notice and has determined that a Stage 1 emergency is imminent consistent with its operating procedure E-508B; (2) during a Stage 2 event; (3) based on its forecasted system conditions and operating procedures; or (4) PG&E has the ability to call program for local and system emergencies.	Price-responsive program based on energy price during peak demands, when the state experiences high wholesale electrical prices, system constraints, or emergencies.	**Day-Ahead Event** When electric generation facilities with heat rates of 15,000 BTU/kWh or greater for the day-ahead market are expected to be dispatched **Day-Of Event** When electric generation facilities with heat rates of 15,000 BTU/kWh or greater
Notification Time	Customer chooses any, or combination of any, of: **Two Days** (Customers notified by noon, two days prior to event) **One Day** (Customers notified by 2:00 p.m., one day prior to event) **4.5-Hour** (Day-Of) **30-Minute** (Day-Of)	By 2:00 p.m. on a day-ahead basis	Participants notified by 12:00 noon on the day prior to the event. Bids submitted between 12:00 noon and 3:00 p.m. Bid Acceptance posted after 4:00 p.m.	30 Minutes	**Day-Ahead Event** No later than 3:00 PM on the day before the event. **Day-Of Event** No less than 30 minutes before the first hour of the event.	**Day-Ahead Event** Participant will be notified by 3:00 p.m. **Day-Of Event** Participants will be notified up to 30 minutes prior to the close of the CAISO Hour-Ahead Market (approx. 3 hours before the start of a day-of event)
Curtailment Level	**Best Effort** customers submit load reduction bids prior to event **Committed** customers pre-select load reduction level, event non-compliance incurs incentive reductions	Reduce loads to avoid higher event day total charge.	Bid Amount for each hour	Firm Service Level (FSL) ***NOTE:** The FSL must be no more than 85% of each customer's highest monthly max demand during the summer on-peak and winter partial-peak periods of the past 12 months with a min. load reduction of 100 kW.	Each Aggregator has a contractual curtailment level specified for each month. This curtailment comes from their portfolio of customers. Each Aggregator has a bilateral contract that has a committed MW amount for each year.	Nomination amount
Incentive Payment	**Committed** incentive includes monthly capacity payments as follows, based on selected notification time and committed load reduction level, event non-compliance penalty applies; plus $0.15/kWh energy payment for eligible load reduction during events **30-Minute:** $10.00/kW-mo **4.5-Hr:** $7.00/kW-mo **One Day:** $5.00/kW-mo **Two Day:** $4.00/kW-mo rate is further adjusted for other customer program selections **Best Effort** incentive is an energy payment only; no penalties **30-Minute:** $1/kWh **4.5-Hr:** $.60/kWh **One Day:** $.50/kWh **Two Day:** $.40/kWh for eligible load reduction during events	Participants receive reduced TOU demand and/or energy charges via credits. Credits vary based on rate and apply only during the Summer Season.	$0.50/kW reduction for each hour Participants must reduce at least 50 percent of their bid to qualify for any payment in any hour.	Capacity payment based on Monthly Potential Load Reduction (PLR) amount: $8.00/kW: < 500 kW $8.50/kW: 501 kW to 1,000 kW $9.00/kW: > 1,000 kW	Capacity and energy payments vary with each Aggregator. Each Aggregator has a bilateral contract that has a negotiated set Capacity and Energy payment price amount for each year.	Capacity Payments are available June - September Energy payments are available for events called May - October (for Bundled-Service only). Payment amount varies by month
Event Minimum Load Reduction Requirement	**Committed:** Customer-indicated load reduction level, incentive penalty for non-compliance **Best Effort:** No penalties for non-compliance; incentive payments start at 50% of load reduction bid	None	A minimum of 50 kW reduction per hour of the event	Must drop to Firm Service Level (FSL)	Event load reduction requirements are set MW commitments that are in each of the bilateral contracts with each Aggregator	No minimum nomination amount. Load reduction of less than the nominated amount may result in penalties (based on the reduction percentage)
Event Frequency Limits	Customer selects limits on event operations: maximum event days (from 3 to 25), event duration (2 hours to 3 hours, 3 hours to 5 hours, 4 hours to 6 hours), and maximum consecutive event days (1, 2, or 3)	**Minimum of 9 PDP event days.** **Maximum of 15 PDP event days.** Events may be called on consecutive days	None	One (1) event per day / 4-hours per event Not to exceed 10 events/month, or 120 hours/year	Maximum 50 hours per year, 4 to 6 hours per call	Maximum 24 hours per product type (product type based on advanced notification and number of event hours chosen at time of nomination)
Non-Compliance Penalties	**Committed:** Capacity payment amount adjusted for event non-compliance on an hourly basis **Best Effort:** None	None	None	$6.00/kWh over FSL	Penalties vary by amount of reduction given per event, hour by hour	Penalties vary hour by hour for an event, based on actual load reduction percentage
Meter Requirements Who Pays	Interval meter required. No interval meter cost for customers with demand above 200 kW	Interval meter required. No interval meter cost for Large customers - those with demand "200 kW or greater". No interval meter cost if a **SmartMeter™** has already been installed.	Interval meter required No interval meter cost for customers with demand above 200 kW	Interval meter PG&E (for Bundled-Service customers)	Interval data recording meter (MV90 or SmartMeter) is required for participation. Customer sites ≥ 200 kW receive a free interval data recording meter. For customer sites < 200 kW, customer or aggregator will pay for the interval data recording meter	Interval meter must be installed and communicating. PG&E covers equipment and installation cost for bundled customers with a peak load of ≥ 200 kW (for any 3 consecutive months out of the last 12 months)
Comments	Submit application via online enrollment. Partial Standby and Direct Access eligible 2010 (planned).	*Automatic option of first 12 month Bill Stabilization. *Capacity Reservation (CRL) for E-19, E-20 and AG5C rate schedules limits customer exposure to PDP rate, including the month-to-month volatility. Usage up to CRL is excluded from PDP rate (charges/credits) but subject to take-or-pay generation charges for demand shortfall. *CRL is n/a for other SMB CIA rates For their PDP options see See "Comments" under the colum labelled "Small Business" in this matrix.	Submit applications via online enrollment. **Important Note:** Prior to May 1, 2011, a customer must make a one-time designation of its election of a day-of adjustment to the baseline. Beginning May 1, 2011, a customer may elect the day-of adjustment each time it submits a bid.	Customers can submit application via online enrollment. Aggregators submit paper application to the Program Manager. UFR Program: additional credit of $0.67/kW/Month if willing to be automatically interrupted if the frequency on the PG&E system drops to 59.65 hertz for 20 cycles.	A financial adjustment will be made for DA customers. As of 8/1/10, customers participating in DBP are eligible to participate with AMP Day-Of, and OBMC customers are eligible to participate with AMP Day-Ahead. As of 5/1/11 PDP can participate with AMP Day-Of	As of 8/1/10, customers participating in DBP are eligible to participate with CBP Day-Of, and OBMC customers are eligible to participate with CBP Day-Ahead. As of 5/1/11 PDP can participate with CBP Day-Of

*(BIP, AMP, CBP) For a list of Demand Response Service Providers, please visit: www.pge.com/DRaggregators.

Please refer to specific Rate Schedules for details about each program.

Last Updated: 2/8/2011

Figure C-2: Pacific Gas & Electric Demand Response Programs

Pacific Gas and Electric Company FOR INTERNAL USE ONLY	RESIDENTIAL & SMALL BUSINESS SmartAC™ Wendy Brummer 8-223-0323	RESIDENTIAL SmartRate™ Program Wendy Brummer 8-223-0323	SMALL BUSINESS Peak Day Pricing (PDP) Optional Until Nov. 2011
Program Description	Direct AC load control program for residential and small to medium business customers using programmable communicating thermostats (PCTs) and direct load control devices (switches)	A voluntary rate which features increased charges during SmartDay™ events and reduced charges during non-event days the rest of the summer season	A new CPUC-default time varying pricing plan that provides credits throughout the Summer Season in exchange for added fees (charges) during limited hours on Event Days
Curtailment Requirement	Voluntary with Automatic Load Shed	Voluntary	Voluntary
Contract Period	One year commitment	None	Customers may opt out of PDP to a TOU rate schedule up to 2 business days before their PDP default date. Once on PDP, customers may change their mind and opt out once in the first 12 months, otherwise PDP changes follow Rule 12.
Eligibility	Residential, Commercial and Industrial Customers with central air conditioning and demand less than 200 kW E1, EL-1, E-8, EL-8, EM, EML, ES, ESL, ESR, ESRL, ET, ETL, TOU rate schedules, E-6, E-7, E-A7, EL-7, EL-A7, E-9 Commercial, A-1, A-10, A-6 and E-19V	**E-RSMART:** Bundled-Service Customers on a single family residential electric rate schedule **E-CSMART:** < 200 kW and on schedule A 1, A 6, A 10, E 19V No longer available to Business Customers beginning January 2010	*Bundled SMB (including Ag) Customers (see Min. Qualifying Load Criteria below) *Net metered, streetlight/traffic control, 100% standby load and Direct Access customers are not eligible for PDP. *Customers on an existing DR program will not default. Dual participation in select DR programs is permissible as of 5/1/2011.
Operating Months	Events operated from May 1 to October 31	Events operated from May 1 to October 31	Events operated year-round
Curtailment Window	24 Hours/Day – 7 Days/Week	Weekdays excluding holidays **E-RSMART:** 2:00pm – 7:00pm (Note: expires 10/31/2010) **E-CSMART:** 2:00pm – 6:00pm (Note: expires 11/01/2011)	2:00 p.m. – 6:00 p.m. (7-days/week) Options: *Extended Event Window: noon - 6:00 p.m. *Alternate Event Days: every other PDP event
Minimum Qualifying Load Criteria for Program	No minimum	No minimum	**Optional voluntary enrollment:** Rates A1, A6, A10, E19V, AG4, AG5 Bundled SMB (+ Ag) Customers with demand < 200 kW **Mandatory Transition (default)** Begins Nov 1, 2011 for SMB and Begins Feb 1, 2012 for Small Ag
Event Trigger	Emergency or Near-Emergency situations	Forecasted day-ahead temperature based on average of 98° in 5 territories, system reliability, high spot market power prices, testing. Temperature trigger can be lowered to reach total 15 events	Forecasted day-ahead temperature based on average of 98° weekdays and 105° on weekends and holidays in 5 territories; system reliability; high spot market power prices; or testing. Temperature trigger can be lowered to reach event range of 9-15 events per calendar year.
Notification Time	No notice	By 3:00 p.m. on a day-ahead basis	By 2:00 p.m. on a day-ahead basis
Curtailment Level	No more than 6 hours per event and 100 hours per year. Residential AC cycled at 50% and non-residential at 33%. No more than 4° increase for PCT customers	2-7 pm Only	Reduce loads to avoid higher event day total charge.
Incentive Payment	One time monetary thank-you. No incentive for participating in events	Participants receive a credit for usage during SmartRate™ Non-High-Price Periods and SmartRate™ Participation Credit (June 1 through September 30)	Participants receive reduced TOU demand and/or energy charges via credits. Credits vary based on rate and apply only during the Summer Season (May 1- Oct 31)
Event Minimum Load Reduction Requirement	None	None	None
Event Frequency Limits	Maximum 6 hours per event, 100 hours per season	Maximum of 15 SmartDays™ per summer season	**Minimum** of 9 PDP event days. **Maximum** of 15 PDP event days. Events may be called on consecutive days. See "Comments" below for event frequency and/or duration options.
Non-Compliance Penalties	None	None; however, participant pays SmartDay™ High-Price Period Charges during event	None; however, participant pays Peak Day Pricing Charges during event
Meter Requirements Who Pays	None	Customer must have **SmartMeter™** with read or billed status	Customer must have SmartMeterTM installed and be SmartMeterTM read or billed status for voluntary enrollment. No cost if SmartMeterTM has already been installed. Default will require 12 months of SmartMeterTM data as well.
Comments	Customer has the ability to opt-out of an event. SmartRate™/CPP participants may request their SmartA/C™ device cycle to support participation in these event days	Customer must continue service under the provisions of their otherwise-applicable schedule. Bill protection through the first full summer season	*Automatic optional first 12 month Bill Stabilization. *Customers choosing the longer event period (6 hours vs 4) pay a 1/3 lower PDP charge. *Customers choosing the every-other event option receive half of the PDP credit.

NAVIGANT

Figure C-3: Southern California Edison Demand Response Programs

	Base Interruptible Program (BIP)	Agricultural and Pumping Interruptible (API)	Summer Discount Plan (SDP) Non Residential	Summer Discount Plan (SDP) Residential
Description	Customers agree to reduce usage by at least15% of their load in exchange for credit based on the difference between monthly avg. peak period and customer's designated FSL	Eligible agricultural and pumping customers receive a credit for allowing SCE to automatically shut off total load served.	Uses a remote controlled device to turn off residential and commercial customers' air conditioners in exchange for credits	Uses a remote controlled device to turn off residential air conditioners in exchange for credits
Contract Period	12 months. Customers or Aggregators may request to adjust their Firm Service Level (FSL) and participation option or opt out of their contract once per year during the Annual Opt-Out Window (Nov. 1-Dec.1)	12 months. Customers may opt-out of their contract during the Annual Opt-Out Window (runs from November 1 through December 1).	12 Months, with automatic renewal unless customer opts-off	12 Months, with automatic renewal unless customer opts-off
Eligibility	Direct Access, SCE-Bundled Service, or Community Choice Aggregation customers on a TOU or RTP rate	Agricultural and pumping customers with a measured demand of >37kW or >50 horsepower of connected load	Not available for: DM; DMS-1,2,3; Med Baseline with AC, BIP customers	Not available for: DM; DMS1,2,3; Med Baseline with AC, BIP customers
Operating Months	Year-Round	Year-Round	June 1 – October 1	Year-Round
Curtailment Window	24 Hours/Day-7 Days/Wk, not to exceed 6 hours per event	24 Hours/Day-7 Days/Wk	24 Hours/Day-7 Days/Wk	24 Hours/Day-7 Days/Wk
Minimum Load (KW) to Qualify	200kW or <200kW if part of an aggregated group	One service account with at least 37kW	None	None
Event Trigger	CAISO Stage II, System Emergency, SCE Test	After a Warning and before the CAISO need to canvas neighboring balancing authorities and other entities for available exceptional dispatch energy/capacity.	CAISO Imminent Stage I, CAISO Stage II, Upon determination by SCE's Grid Control Center of the need to implement load reductions in SCE's service territory, SCE Test	CAISO notification to SCE that a Stage 1 is imminent, CAISO Stage II, Upon determination by SCE's grid control center of the need to implement load reductions in SCE's service territory, ES&M Wholesale Market Price, SCE Test
Notification Time	Participation Option A: 15 min Participation Option B: 30 min	None	No notice	No notice
Curtailment Level	Firm Service Level	Load Control	Load Control	Load Control
Incentive Payment	Option A: ≤2 kV: Summer On Peak: \$21.11, Mid Peak: \$6.45; Winter Mid Peak: \$1.32 ≤50 kV: Summer On Peak: \$20.74, Mid Peak: \$6.12; Winter Mid Peak: \$1.28 >50kV: Summer On Peak: \$19.56, Mid Peak: \$6.12; Winter Mid Peak: \$1.13 Option B: ≤2kV: Summer On Peak: \$19.74, Mid Peak: \$6.02; Winter Mid Peak: \$1.22 ≤50 kV: Summer On Peak: \$19.31, Mid Peak: \$5.70; Winter Mid Peak: \$1.22 >50kV: Summer On Peak: \$18.34, Mid Peak: \$5.21; Winter Mid Peak: \$1.05	\$/kW per Meter per Month: Summer Average On-Peak (\$17.22) Summer Average Mid-Peak (\$3.66) Winter Average Mid-Peak (\$1.25)	Base GS-1, TOU-GS-1: 100%-\$0.20; 50%=\$0.07; 30%=\$0.014) per ton per day (GS-2, TOU-GS-3, TOU-8: 100%=\$6.00; 50%=\$2.10; 30%=\$0.42) per ton per month Enhanced GS-1, TOU-GS-1: 100%-\$0.40; 50%=\$0.14; 30%=\$0.028) per ton per day (GS-2, TOU-GS-3, TOU-8: 100%=\$12.00; 50%=\$4.20; 30%=\$0.84) per ton per month	Base Strategy A - \$0.18 for 100% cycling Strategy B - \$0.10 for 67% cycling Strategy C - \$0.05 for 50% cycling Enhanced Strategy A - \$0.36 for 100% cycling Strategy B - \$0.20 for 67% cycling Strategy C - \$0.10 for 50% cycling
Event Minimum Load Reduction	15% of load, at least 100kW per event	None	None	None
Event Frequency Limits	One event per day up to 6 hours each, 10 events per month, 180 hours per year	One event per day up to 6 hours each, 4 events per week, 25 events per year or 150 hours per year	Base: 6 hrs per event, 15 events per summer, multiple events in one day possible Enhanced: 6 hrs per event, unlimited events during summer, multiple events in one day possible	1 or 2 hours, up to 6 hours, 20 hours minimum and 90 hours maximum, multiple events in one day possible
Non-Compliance Penalties	2kV: \$10.21 per kWh above FSL 50kV: \$10.00 per kWh above FSL >50kV: \$9.63 per kWh above FSL	None	None	None
Meter Requirements	IDR	IDR/TOU or IDR/RTEM	No Interval Meter Required	No Interval Meter Required

Figure C-4: Southern California Edison Demand Response Programs

	Capacity Bidding Program (CBP)	Demand Response Contracts (DRC)	Demand Bidding Program (DBP)	Real Time Pricing (RTP)
Description	Internet-based nomination program that offers qualified participants a monthly incentive to reduce load to a pre-determined amount during CBP events with day-of and day-ahead notification. Penalties are assessed for non-performance	Long term contracts with third party aggregators to procure demand response MWs to SCE. Customers enter into arrangements with the third party aggregators and are compensated by the aggregator under the terms of their agreement. When SCE calls an event, the aggregator is responsible for scheduling the customer load reductions according to the agreement with SCE.	The Demand Bidding Program (DBP) is a year-round Internet-based bidding program that offers qualified participants the opportunity to receive bill credits for voluntarily reducing load when a DBP event is called.	Participants are billed for the electricity they consume based on hourly prices driven by temperature. Participants may choose to make adjustments in their electricity usage based on the hourly prices within different temperature ranges (i.e. Extremely Hot, Very Hot, Hot, Moderate, Mild Summer Temperatures, and High Cost/Low Cost Winter).
Contract Period	12 Months	3 contracts expire 12/31/2012; 1 contract expires 12/31/2011	12 Months	12 months
Eligibility	Direct Access, Bundled Service, or CCA customers and aggregators of these customers	Direct Access, Bundled Service, or CCA customers on commercial or industrial TOU rates and not on any other SCE demand response program, except for DBP, OBMC, and CPP.	Bundled Service, Direct Access, or CCA business customers with adequate metering.	Bundled service customers and agricultural & pumping customers, whose maximum demand is > 75kW, or have a connected load of > 100 horsepower.
Operating Months	May 1 – October 31	3 contracts are year-round; 1 contract is May through October only	Year-round	Year-Round
Curtailment Window	Monday - Friday, 11am7pm, excluding holidays A CBP Event can be scheduled on a day-ahead and a day-of basis.	A) 3 contracts: Monday-Friday (excluding holidays), 11:00am - 5:00pm B) 2 contracts: Monday-Friday (excluding holidays), 11:00am – 7:00pm	Weekdays from 12PM-8PM, excluding holidays	24 Hours/Day- 7Days/Wk
Minimum Load (kW) to Qualify	N/A	N/A	Individual participants must commit to 30 kW minimum bids per hour. Aggregated Groups must commit to 100 kW minimum bids per hour.	N/A
Event Trigger	When SCE forecasts a thermal unit heat rate of 15,000 btu/kWh on a day-ahead or day-of basis	At SCE's discretion based on the terms of the contract	Day-Ahead load and/or price forecasts, test events	Temperature
Notification Time	A Day-Ahead event/test notice will be provided by 3 pm the day before the event. A Day-Of event/test notice will be scheduled approximately 3 hours before the event.	A Day-Ahead event/test notice will be provided by 3 pm the day before the event. A Day-Of event/test notice will be scheduled approximately 3 hours before the event.	12 Noon the day before an event (for an event occurring on Monday, notifications may be given on the previous Friday).	None. Customer must be aware of temperature, which drives prices.
Curtailment Level	Monthly Nomination	Monthly Nomination	Bid Amount for each hour	N/A
Incentive Payment	Capacity payments vary based on month, product, and participation level. Aggregators receive 100% of capacity credits and directly enrolled customers receive 80%. Energy payments based on kWh reduction and energy price/hr	SCE does not pay incentives to customers; payments are to aggregators in form of a compensation based on MWs available in non-event months and performance during an event	Bundled service participants receive a flat rate credit equal to .50 cents per kWH of load reduction. A credit will apply to any amount of actual load reduction that is 50 percent or greater and less than or equal to 200 percent of the customers Energy Bid. Direct Access and Community Choice Aggregation Service participants shall receive a flat rate credit equal to .50 cents per kWh of load reduction minus the CAISO's	Varies based on temperature (see tariff).
Event Minimum Load Reduction	None, but participants should curtail the amount of capacity nominated each month.	Varies by contract	Individual 30 kW Aggregated groups 100 kW	None
Event Frequency Limits	Max 24 hours per month, per product type	Varies by contract	None	None
Non-Compliance Penalties	Penalties apply for less than 50% of nominated load reduction	Penalties apply for less than 50% of nominated load reduction	None	No penalty, but customers pay higher energy charges the higher the temperature.
Meter Requirements	RTEM or equivalent	IDR	RTEM, or equivalent	Communicating interval meters or IDR

Figure C-5: Southern California Edison Demand Response Programs

	Critical Peak Pricing (CPP) > 200kW	Critical Peak Pricing (CPP) < 200kW	Peak Time Rebate (PTR)
Description	Large C&I bundled service customers with demands 200 kW or greater will be placed on default CPP. Customers with default CPP will receive reductions in summer on-peak time related demand charges. Bill protection will be provided for the first year of participation.	Available for Residential, Agricultural, and C&I customers with demands less than 200kW. C&I customers will be defaulted to CPP rates. Defaulted customers will have the ability to opt-out of the CPP program, but one year of bill protection applies. CPP provides reduced energy prices or demand credits during the summer months and increased energy charges for all usage during CPP events.	Event based program for Residential Customers that provides compensation in the form of monthly bill credits to customers who reduce kWh usage below their otherwise average consumption levels (CSRL) during Events.
Contract Period	None	None	None
Eligibility	Bundled General service customers whose monthly demands are 200kW and above	Bundled Service customers with demands less than 200 kW	Bundled Service Residential Customers
Operating Months	Year-Round	Year-Round	Year-Round
Curtailment Window	2-6pm on non-holiday weekdays	2-6pm on non-holiday weekdays	2-6pm on non-holiday weekdays.
Minimum Load (kW) to Qualify	200kW	None	None
Event Trigger	System conditions, price, temperature, program testing, CAISO alerts	System conditions, day-ahead load/price forecasts, temperature, program testing, CAISO alerts	System conditions, day-ahead load/price forecasts, temperature, CAISO alerts
Notification Time	Day-Ahead Basis	Day-Ahead Basis	Day Ahead
Curtailment Level	Reduce loads to avoid higher event day rates	Reduce loads to avoid higher event day rates	Reduce loads to qualify for event day incentives
Incentive Payment	Significantly reduced on-peak demand in exchange for higher capacity based energy charges during events periods. Bill protection for first 12 consecutive months. Capacity Reservation Level (CRL) for CPP customers, greater than or equal to 200 kW, can be used as a hedge against CPP event charges on a pre-determined portion of their load	Credits applied to summer month non-event kWh consumption or Demand. Higher price charged for consumption during event window for all kWh consumption. Bill protection for first 12 months enrolled relative to the customer's OAT.	$.75 for each kWh below customers CSRL. Additional $.50 if customer adopts SCE qualified enabling technology.
Event Minimum Load Reduction	N/A	N/A	Voluntary Program. No minimum load reduction required.
Event Frequency Limits	12 events per calendar year	12 events per calendar year	Unlimited number of events.
Non-Compliance Penalties	No penalty, but customers pay significantly higher than normal rate for on-peak CPP usage	No penalty, but customers pay a significantly higher than normal rate for kWh consumption during events	N/A
Meter Requirements	RTEM Meter or SmartConnect meter	Program ready SmartConnect Meter (COTO)	Program ready SmartConnect Meter (COTO)

Figure C-6: San Diego Gas & Electric Demand Response Programs

Demand Response Programs • DAY-AHEAD NOTIFICATION

	Critical Peak Pricing Default (CPP-D)	Capacity Bidding Program (CBP)
Brief Description	A time-of-use rate which features increased cost during "critical peak" periods and reduced commodity rate rest of year	Customers receive monthly capacity payments (and energy incentives during events) in return for load reduction when requested Program participants have the flexibility to choose program options (Day-Of or Day-Ahead and 2-, 4-, or 8-hour participation) Customers may participate directly through SDG&E or 3rd party aggregators
Who is eligible?	Customers that have a demand of 20 kW or greater for 12 consecutive months and appropriate electric metering.	Annual maximum demand of 20 kW on time-of-use rate
What are the incentives for participation?	Customers receive reduced commodity rate on non-CPP-D event days throughout the year	Incentives are based upon the product type selected Capacity incentive rates vary by utility Incentives will vary depending on whether participation is directly with SDG&E or with a 3rd party aggregator
What are the program months?	January 1 - December 31	May through October (6 months) (Weekends and holidays excluded)
What are the program days/hours?	Any day of the week including holidays from 11 am to 6 pm	Weekdays between the hours of 11 am to 7 pm Limit 1 event per day
Number of events	Limit of 18 annual events	Maximum of 24 hours/month
What triggers or activates the program?	Day Ahead Forecast (MCAS) / Actual System Load Tues-Fri: 84° 3,837 (MW) Sat: 86° 3,837 (MW) Mon: 86° 3,472 (MW) California Independent System Operator (CAISO) alerts or; As warranted by extreme system conditions	Statewide or local extreme system conditions or; Market price ≥ 15,000 btu/kWh heat rate
Who activates?	SDG&E monitors, triggers and initiates CPP-D using kWickview web-based tool	SDG&E triggers and initiates Capacity Bidding Program
When are the customers notified?	Day-Ahead customer notification by 3 pm	Day-Ahead option - 3 pm the day before the event Day-Of option - by 9 am but not later than 2 hrs before event
How is the customer notified?	Posted on SDG&E website Using kWickview tool, customers will be notified by e-mail and/or text message to cell phone	Posted on SDG&E website Third Party will e-mail and/or text message to cell phone or pager
How is peak load drop measured?	Customer's average consumption between the hours of 11 am - 6 pm for the three highest of the 10 most recent days, compared to program event hours	Baseline is an average consumption for the hours of 11 am to 7 pm for the ten (10) highest days from within the immediately preceding ten (10) similar non-holiday week days prior to the Event Participants may choose to have their baselines calculated using a Day-Of Adjustment
Can direct access customers participate?	No	Yes
Who can I contact regarding the programs?	Contact your Account Executive or call our Business Call Center at **1-800-336-SDGE (7343)**.	Please visit us at **www.sdge.com/business**.

Programs may be modified or terminated without prior notice. © 2010 San Diego Gas & Electric Company. All copyright and trademark rights reserved. Printed on recycled paper with soy-based inks 1080114 0610 1M

Figure C-7: San Diego Gas & Electric Demand Response Programs

Demand Response Programs • DAY-OF NOTIFICATION

	Critical Peak Pricing-E (CPP-E)	Aggregator Managed Program (AMP)	Peak Generation (aka RBRP)	Base Interruptible Program (BIP)	Optional Binding Mandatory Curtailment (OBMC)	Summer Saver	CleanGen Program	Scheduled Load Reduction Program (SLRP)
Brief Description	A time-of-use rate which features increased costs during "critical peak" alert periods and reduced commodity rates the rest of the year	Customers receive monthly capacity payments (and energy incentives during events) in return for load reduction when requested Customers may only participate directly with EnerNoc, a Demand Response Provider (DRP)	Customers earn incentives by transferring load from the SDG&E® system to a standby generator that meets the 2008 "particulate matter" emission standard	Customers receive monthly capacity payments in turn for load reduction when requested	Customers can exempt specific circuits from rotating outages by reducing load when requested	Residential & small business customers receive an incentive for central A/C cycling during peak periods	A third-party generator load reduction program; SDG&E "remotely" dispatches customer generators	Customers can schedule load reduction, in advance, for week-day hours during summer months
Who is eligible?	Customers that have a demand of ≥ 20 kW on time-of-use rates	Average annual max demand of 100 kW on a time-of-use rate	Customers who are able to achieve ≥ 50 kW reduction	≥100 kW or 15% of monthly average peak demand, whichever is greater	Ability to reduce 15% of the total peak demand on specified circuit/s	Commercial customers ≤100 kW and all residential customers	≥250 kW	≥100 kW
What are the incentives for participation?	Customers receive reduced commodity rate on non-CPP-E event days throughout the year	Incentives are based upon participation	A $.35/kWh bill credit for actual reduction during events	Option A: 30-minute notification. $7/kW monthly capacity payment for committed pre-determined reduction level with $4.50 penalty for excess energy usage Option B: 3-hour notification. $3/kW monthly capacity payment, as above with a $1.88 penalty for excess energy usage	Exemption from rotating outages $6/kWh penalty for non-compliance	One-time payment at end of season: $25/kW for residential and small commercial customers at 50% cycling $50/kW residential at 100% cycling	Customer receives financial assistance for retrofitting standby generators to comply with new state emission regulations	$0.10/kWh of reduced load for each contracted hour Load shifting to other on-peak hours will negate incentives
What are the program months?	Year round	May through October (6 months) (weekends and holidays excluded)	Year round	Year round	Year round	May 1 - October 31 Weekend option available	Year round	June 1 - September 30
What are the program days/hours?	Any hours during the year Maximum of 6 hours per day	Weekdays between the hours of 12 pm to 6 pm Limit 1 event per day Event duration 2-5 hours	Any hours during the year	Any hours during the year	Any hours during the year	Monday through Friday Weekends optional 12 - 8 pm only	Monday through Saturday from 7 am - 10 pm	Monday through Friday Customers can select up to three time periods per week: 8 am - 12; 12 - 4 pm, or 4 pm - 8 pm on specific weekdays
Number of events	80 hours maximum per year Maximum of 40 hours per month	Maximum of 50 hours per year	75 hours per year with no event limits	Option A: Max 4 hrs/day, 10 events/month, 120 hours/year Option B: Max 3 hrs/day, 10 events/month, 90 hours/year	No limit on events	Up to 40 hours in a month and 120 hours in a year	No annual limit No more than 8 hours daily	Selection of one or more 4-hour time periods per week
What triggers or activates the program?	Utility system emergencies, extreme statewide emergency conditions, or California Independent System Operator (CAISO) alert that a Stage 3 emergency (rolling blackout) is imminent	Discretion of SDG&E	CAISO alert that a Stage 3 emergency (rolling blackout) is imminent or; CAISO declares a firm load curtailment within SDG&E service territory	CAISO initiates an interruptible period or Warning notice that a Stage 1 Emergency is imminent. Interruptible period shall start within 30 minutes for option A or 3 hrs for option B after the utility initiates communications to the customer	CAISO initiates firm load curtailment or; SDG&E initiates firm load curtailment in local geographic area	Stage 1 or 2 local emergencies at SDG&E discretion	Stage 2 emergency or a Stage 1 alert if SDG&E anticipates a Stage 2 emergency call later that day; or for high peak prices	No trigger Specific time selected by customer
Who activates?	SDG&E monitors, triggers and initiates CPP-E using the kWickview web-based tool	SDG&E triggers and initiates Bilateral Contract Program	SDG&E notifies customers via text message or e-mail prior to or at Stage 3 or when CAISO initiates firm load curtailment	SDG&E notifies customers via e-mail or text message	SDG&E notifies customers via e-mail or text message at Stage 3 or when CAISO initiates firm load curtailment	SDG&E initiates dispatch signal	SDG&E initiates dispatch signal	Not applicable
When are the customers notified?	Day-Of event with a 30-minute notification	Day-Of event with a 30-minute notification to the Demand Response Provider (DRP)	Day-Of event with a 15-minute notification	Day-Of event with either 30-minute or 3-hour notification	Day-Of event with 15-minute notification	Day-Of event	Day-Of event	No notification Customer selects weekdays and hours prior to the summer months
How is the customer notified?	Posted on SDG&E Web site Using kWickview tool, customers will be notified by e-mail and/or text message	Posted on SDG&E Web site Electronic e-mail and or text messages to pagers/cell phones	Text message to pagers/cell phones Customers respond to an SDG&E "interactive voice response" system	Using kWickview tool, customers will be notified by e-mail and/or text message	Alphanumeric pager or fax	No notification	10 minutes before start of event	No notification Customer agrees to specific time period/s and day/s on contract
How is peak load drop measured?	Customer's average consumption between the hours of 11 am and 6 pm for the three highest of the 10 most recent days, compared to program event hours	Baseline is the hourly average consumption for the three highest of the 10 similar days for the hours between 12 pm - 6 pm - excluding event days	Using kWickview, customers' hourly average consumption for the three highest of the 10 similar days for the hours 11 am - 6 pm – excluding event days	Comparing energy used to customer's committed firm reduction level	Comparing usage at the circuit level to last 10 similar days	Program specific algorithm (an estimate of load reduction taking into account A/C tonnage)	Net export meter reading from generators or; 10-day baseline calculation for load drop	Customer's recorded usage for the same hours as the SLRP event on the immediate past 10 similar days, excluding holidays and event days
Can direct access customers participate?	No	Yes	Yes	Yes	Yes	Yes	Yes	No
Who can I contact regarding the programs?	For more information, contact your Account Executive or our Business Call Center at **1-800-336-SDGE (7343)**. Please visit us at **www.sdge.com/business**.				For more information, contact your Account Executive or our Business Call Center at **1-800-336-SDGE (7343)**. Please visit us at **www.sdge.com/business**.			

Appendix D. Other ISOs/ RTOs and Non-ISO Utilities

D.1 Electric Reliability Council of Texas (ERCOT)

- Several unique features of the ERCOT grid have created a robust market for DR products:
  - Because ERCOT is effectively isolated from other U.S. power systems, it cannot import ancillary services from other systems.
  - Large industrial loads account for a significant portion of ERCOT's total system loads.
  - ERCOT has installed more wind energy capacity than any other ISO, and at times wind energy has provided as much as 22 percent of instantaneous power on ERCOT's grid.
- DR is eligible to provide spinning (responsive) reserves, non-spinning reserves, and regulation up and down services.
  - DR participates heavily in the spinning (responsive) reserves market. As of April 1st, 2012, ERCOT is required to purchase 2,800 MW of spinning reserves at all times. DR is limited to 50 percent (1,400 MW) of this, but this cap has yet to be reached.
  - DR resources are also eligible to provide regulation up and down services if the resources are controllable. Only one customer has provided this service.
  - DR resources are also eligible to provide non-spinning resources. However, ERCOT has no DR participants in this market; the staff that we interviewed indicated that the lack of participation is because of the 30 minute ramping requirement and the frequency of deployment of several times per week; loads do not have the tolerance to participate in such a demanding program.
- ERCOT has 2,400 MW of DR responsive reserves registered. DR "Load as a Resource" (or "LaaR") is allowed to participate in this market, but is capped at 1,150 MW. DR offers exceed this cap on most days. Nearly all of this participation comes from large industrial sites, electro-chemical processing, oil field equipment, cement plants, manufacturing, compression, pumping, and data centers.
  - Most capacity is from large industrial electro-chemical process loads. Ten Load Resources account for 1,030 MW of capacity.
  - Medium size industrial facilities providing 10-50 MW of capacity each provide the next largest portion of capacity. Forty Load Resources account for 820 MW of capacity.
  - The remainder of capacity is provided by small industrial and commercial facilities with 10 MW or less capacity per site. 139 Load Resources account for 550 MW of capacity.
  - These resources are deployed at all times of the day and year, but infrequently. From 2006 through October 2011, there were only 21 deployments of Load Resources. Six of these deployments were during summer peak hours; seven were during other business hours; and eight were during non-business hours.

  - The initial limit on LaaRs was set at 25 percent of ERCOT's responsive reserve requirements, due to the following perceptions and concerns:
    - Generators with governors are better able to stabilize frequency in response to small deviations in frequency than LaaRs, which have a binary (off or on) response.
    - Machines with "physical mass" are needed to maintain the stability of the network.
    - If too much interruptible load tripped-off at the same time, "over-shoot" would occur and raise frequency to an unacceptably high levels.
  - However, in 2009, the 25 percent limit on participation from LaaRs was raised as concerns about over-shoot abated and strict qualification criteria were introduced to preclude energy consumers whose load level could not be accurately predicted on a day-ahead basis from providing responsive reserves.

» ERCOT obtains additional DR resources from smaller participants:
  - Smaller resources provide emergency response services (approximately 475 MW of capacity from approximately 900 participants) and traditional summer peak DR (approximately 150 MW of capacity).
  - Economic DR (unknown amount) is provided by a variety of products including more than 11,000 interval metered loads with real-time, critical peak pricing, and time of use tariffs, and LSE direct load control programs.

» Wind energy is a significant portion of the ERCOT system:
  - On March 7, 2012, ERCOT set a new record for wind output at 7,599 MW, which represented 22 percent of the total system load. This record surpassed the record set the day before on March 6, 2012 by almost 200 MW. Prior to March 6, the record for wind output in ERCOT was 7,400 MW, recorded on Oct. 7, 2011.
  - ERCOT attributed the new wind output records in part to a new transmission analysis tool that ERCOT started using on March 6, 2012. The this transient security assessment tool allows more wind energy to be moved from the west zone by analyzing real-time conditions every 30 minutes to improve the accuracy of ERCOT's dynamic transmission limits.
  - ERCOT currently has 9,838 MW of installed wind capacity. More than 18,000 MW of wind generation projects are currently under review, according to the February system planning update.

» Barriers to DR
  - In the current market design, non-Controllable Load Resources can participate in Non-Spin and Responsive Reserve Markets. These resources are dispatched by verbal

instruction from the system operator. However, few Load Resources are willing to participate in Non-Spin since they have no control over the energy price at which they are deployed. For more traction in this program, the market design would need to be modified to let Load Resources set the price at which they would be willing to be dispatched.

- Current market activities for most part preclude participation by Residential and Small Commercial Load. However, with new advanced metering infrastructure (AMI) infrastructure, low-cost communication, and advanced control capabilities, there are opportunities for these loads to be aggregated to provide ancillary services. However, some issues that must be resolved include establishing real-time telemetry infrastructure, including these programs in forecasting models, and establishing frequency response products. ERCOT is considering a pilot program in summer 2013 to explore these issues.
- The deregulated electric industry in Texas has resulted in a decline in infrastructure investments, which could limit the pace innovation in this area.

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D.2 ISO-New England (ISO-NE)

- To date, DR has been used almost entirely (and extensively) for peak shaving capacity.
  - DR programs include load and price response programs in day-ahead and real-time markets.
  - Aggregation is allowed for most programs, with minimum loads of 100 kW.

- ISO-NE has recently completed the Demand Response Reserve Pilot Program to explore the use of manual DR for reserves.
  - The program provided 10 to 60 minute notice and events were less than one hour in duration. There were approximately 100 events over the three year span of the program.

- The actual response relative to the expected/committed response varied widely from episode to episode, and, on average, declined over the course of the pilot program. <u>The results of this pilot program emphasized that manual DR cannot provide reserve services with the responsiveness or precision necessary for load balancing.</u>

» Variability in the ISO-NE system is not expected to reach levels that would require additional balancing resources in the foreseeable future.
  - ISO-NE recognizes that wind energy has the technical potential to serve up to 24 percent of the region's load by 2020.
    - RPS targets from some New England states could actualize *some* of this potential. However, states in the region with RPS targets do not need to meet those targets through the ISO-NE.
    - Consequently, ISO-NE does not expect all of the regional RPS requirements to be met through the ISO-NE.
    - NERC research indicates that additional balancing would only be required when wind energy exceeds 20 percent of load, which suggests that balancing is not a near term need for ISO-NE.
    -

» ISO-NE staff that the Navigant team interviewed indicated that the types of customers that could provide DR for balancing are not common in New England.
  - Specifically, large industrial loads such as those at refineries and smelting facilities are much less common in New England, than in other regions such as Texas. These large industrial loads can be enrolled in autoDR programs and provide the significant, reliable, and precise load response necessary for balancing.
  - In New England, this type of autoDR would require aggregation to achieve similar levels of response, which would require additional communications and controls infrastructure while providing relatively small incentives to each individual participant.

SOURCES:

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» Personal communications with Laura Corcoran, ISO-NE. April 26, 2012.

D.3 PJM Interconnection (PJM)

- PJM has three ancillary service products that DR is eligible for: Synchronized Reserve, Regulation, and Day-ahead Scheduling Reserve.
  - Resources can be capable of providing all three reserve products.
  - At most, two products can be provided simultaneously
  - Regulation and Synchronized Reserve can never be provided simultaneously
- Most of the DR provided for ancillary services is provided by aggregators.
- PJM does not have a product similar to the CAISO proposed flexi-ramp/load following product and has not been thinking about it. PJM currently has 5 GW of wind capacity and has not seen wind cause dramatic ramps or significant impacts on reliability.
- Regulation market –
  - There is currently a limited amount of DR in PJM's Regulation Market (i.e., hundreds of kW), which all entered the market in late 2011 after FERC approved 100 kW as the minimum size for regulation. Regulation resources must receive and react (within five minutes) to a dynamic regulation control signal, and must have real-time telemetry. To date participation has been too low to effectively evaluate this resource.
  - DR Regulation resources include [#091]:
    - DR provider Enbala Power Networks uses water pumps at a wastewater treatment facility in Washington County, Pa., adjusting its water pumps up or down to match PJM's regulation signal.
    - Viridity Energy uses building load and a behind-the-meter battery in New Castle, Pa that responds to the PJM signal.
    - PJM has a 105-gallon electric water heater installed on the PJM campus that can respond to regulation signals from PJM dispatch. The device began communicating with the grid and responding to the PJM frequency signal in December.
- Synchronized Reserve Market –
  - DR has contributed as much as 18 percent (approximately 230 MW) to PJM's synchronous reserves. Although PJM has never reached the current participation limit of 25 percent, it is considered a "barrier-to-entry talking point by the industry."
  - However, Susan Covino, Manager of Demand Side Response, reports that after years of successful deployment, PJM is prepared to lift that ceiling to 35 percent.
  - PJM designates Synchronized Reserve resources as Tier 1 or Tier 2. <u>Demand response can only participate in Tier 2</u>. Tier 2 resources are only called upon to supply requirements that Tier 1 resources are not available to supply. Tier 2 resources are

notified 30 minutes before they are needed. Synchronized Reserve resources must meet the following requirements:

- Reduce load for ten minutes
- Provide one-minute interval metering
- Minimum 100 kW offer
- 24-hour availability
- Tier 2 resources must comply with mandatory reductions during PJM Synchronized Reserve events.

» Day-Ahead Scheduling Reserve Market –

- The Day-Ahead Scheduling Reserve (DASR) Market is designed to clear existing Day-Ahead Scheduling (operating) reserve requirements (i.e., 7.03 percent in 2012). DASR clears simultaneously with Day-Ahead Energy Market in a simultaneous, least-cost optimization as part of the Day-Ahead Market mechanism. Resources respond to normal PJM dispatch instructions and there is no penalty for non-performance (penalty = forgone revenue).

» Regulations specific to DR

- PJM enacted tariff and market rule changes to allow Demand Side Resources to participate in PJM's capacity, energy and ancillary service markets on June 1, 2006.
- PJM has recently proposed a number of changes to regulations and market rules to move towards load acting as supply. Several regulations and market rules changes, or pending changes, that affect DR for RI include:
  - **Minimum size requirement for ancillary services** (Approved October 2011). FERC approved rule changes that reduced the minimum required amount of resources [for all of PJM's ancillary service resource offerings] to 100 kW, from the previous minimum of 500 kW.
  - **DR compensation in energy markets** (Order 745) (Approved) – On April 1, 2012, PJM implemented new rules to pay DR resources dispatched in PJM's Energy Market the full LMP when it is cost-effective. This makes PJM the first to comply with FERC's Order 745.
  - **Tariff changes for year-round DR capacity market participation** (Approved) - The tariff changes establish two new options for demand resources seeking to participate in the capacity market – an annual resource product that would be available year-round and an extended summer product from May through October. These products are available in addition to the existing limited product, which is a summer-only, limited-duration option that can be called on only 10 times per summer.
  - **Expanded opportunity for Curtailment Service Providers (CSPs) in regulation market** (Pending FERC approval) - PJM submitted a proposal to FERC on April

2, 2012 to allow customers already contracted with CSPs for DR capacity to contract with another CSP for regulation. PJM's current rules only allow for customers to contract with one CSP.

- **Compensation for participation in multiple markets with multiple CSPs** (Pending FERC decision)– PJM has proposed to FERC to remove the restriction that if a customer uses one CSP to participate in the capacity market and a different CSP to participate in the energy and/or ancillary service markets, the customer will only receive the lesser compensation of the capacity and energy payments from an emergency event (i.e., in most cases, forfeiting the much higher capacity payments).
- **Price-Responsive Demand** (PRD; Pending FERC approval) - PJM proposed to modify both its capacity and energy market rules to allow PRD providers to submit load information that the RTO needs to optimize its dispatch, including the load's location, base consumption level and the decreasing consumption levels that correspond to increasing prices.
- **Compensation for regulation resources – Order 755** (Pending FERC approval) - Order 755 is designed to reward regulation service that can balance energy supply and demand more quickly than conventional generation resources. Order 755 found that existing compensation practices are unduly discriminatory because resources providing frequency regulation service are all being paid at the same level even though the faster-reacting resources offer greater benefits to the grid.
- **Shortage pricing – Order 719** (Pending FERC approval) - PJM's shortage pricing proposal proposes to remove the uncertainty of estimated system conditions by jointly optimizing and pricing energy, reserves, and regulation on a five-minute basis using actual system conditions. The proposal includes the creation of a new 10-minute non-synchronized reserve market and real-time joint optimization of energy and reserves. PJM would simultaneously price energy and reserves every five minutes, instead of only energy.

» Broader plans for renewables integration:
  - Although PJM's generation portfolio is only about 5 percent renewables, more than 40 percent of PJM's year-end 2010 interconnection queues relates to potential wind or solar plants. This is equal to 16 percent of the year-end 2010 installed capacity in the PJM region.
  - PJM has partnered with a number of energy storage projects to test regulation services.

» Barriers to DR deployment in PJM include:

- If an industrial facility has a 3rd party representing it (e.g., in the capacity market), another 3rd party cannot represent the same load in another market (e.g., in the ancillary services market). This is being removed in June, 2012.
- Aggregation in PJM across electric distribution companies (EDC) is not allowed. PJM staff thought that eliminating geographic barriers to aggregation is going to be key for having these more advanced programs take off.
- For smaller, distributed resources (e.g. a water heater, as opposed to centrally located, larger resources), telemetry and measurement and verification (M&V) requirements can be burdensome. PJM is participating in a test of water heaters providing frequency regulation in Summer 2012. PJM still needs to develop the M&V plan for these resources.
- Standardization of communication protocols and marketplace interfaces are needed to streamline the use of DR.
- The cost of controls must come down for smaller resources to be attracted to the market
- The retail pricing structure needs to more closely reflect what occurs at the wholesale level (regulatory barrier) to get the right pricing signals.

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D.4 New York Independent System Operator (NYISO)

- The NYISO offers two DR programs that support reliability: the Emergency Demand Response Program (EDRP) and the Installed Capacity Special Case Resource Program (ICAP/SCR).
- In addition, DR resources may participate in the NYISO's energy market through the DADRP, or the ancillary services market through the DSASP.
- NYISO is also looking into the feasibility of adding a dynamic-pricing program and other smart grid controls. NYISO identifies one of the benefits of dynamic pricing and smart grid as the integration of renewable resources.
- Ancillary Service Programs
  - To date, only NYISO and ERCOT have procured additional ancillary services to address the forecast uncertainty or supply variability of variable energy resources.
  - NYISO offers two types of ancillary service programs for DR through its DSASP: Reserves and Regulation.
  - Reserves
    - Aggregation is not allowed until direct communication market rule and software changes are complete in 2012
    - There are three types of reserves products:
      - 10-minute Synchronous/Spinning Reserve (for customer load reduction)
      - 10-Minute Non-Synchronized Reserve (for Backup/Local Generators)
      - 30-Minute Reserve (spinning and non-synchronized)
    - A local/backup generator may only provide Non-Synchronous Reserves
    - A customer load reduction resource may provide Synchronous or Non-Synchronous Reserves, but not both
    - Must achieve 10 minute or 30 minute response times, depending on registered bid
    - Minimum 1 MW reserve
    - Real-time telemetry required
    - Requirements for the three reserve products vary across NYISO's three different regions, resulting in nine different prices and requirement:
  - Regulation

- Aggregation is not allowed until direct communication market rule and software changes are complete in 2012
- Resource must be capable of Regulation response:
    - Capable of supplying Regulation Service continuously in both the up and down directions for intervals in the scheduled hour and for all hours with accepted bids
    - Capable of responding to automatic generator control signals on a 6-second basis
    - Minimum 1 MW reserve
    - To pre-qualify, the resource must provide 100 hours of regulation service
    - Non-Synchronous (i.e., local/backup generation) resources may not provide Regulation Service
    - Real-time telemetry required
- Energy Programs - NYISO has three energy programs for DR: DADRP, EDRP, Installed Capacity Special Case Resources (ICAP/SCR) (Energy Component) (see Capacity Programs section for Capacity Component)
- Capacity Programs - Only NYISO's Installed Capacity Special Case Resources (ICAP/SCR) (Capacity Component) is allowed to participate in NYISO's ICAP capacity market.
- DR in the Real-Time Energy Market - The NYISO completed an architectural design specification at the conclusion of 2011 to understand which applications may be impacted by the implementation of Demand Response in the Real-Time Energy Market.
    - The NYISO will begin work with its stakeholders in mid-2012 to complete a market design for DR in the real-time energy market by the end of 2012. As the market design and market rules are developed, the architectural design specification will be updated.
- Regulatory Activity
    - On August 19, 2011, the NYISO submitted its compliance filing to meet the requirements of Order 745. The NYISO is anticipating an order on its Order 745 compliance filing and may need to make future changes to the current implementation plan.
- Broader plans for renewables integration:
    - The NYISO has taken steps that, according to FERC, will benefit, and encourage, wind and other intermittent generators. Those steps include a centralized wind-forecasting initiative, unique market rules for wind projects, and proposals to enhance the dispatch of wind power on New York's bulk electricity grid.
    - Wind-powered generating capacity in NY grew from 48 MW in 2005 to 1,348 MW in 2011. Another 7,000 MW of wind projects proposed for interconnection to NY grid.
    - In 2012, NYISO exempted solar power from under-generation penalties to compensate solar fully for all energy production. In the future, NYISO expects the market evolution for solar resources likely to parallel wind power initiatives.
    - In 2009, NYISO implemented the first market rules in US enabling storage systems to participate in the markets as frequency regulation providers.

» Barriers to DR programs and use of DR for renewables integration:
  - NYISO is currently working on market rules to allow aggregations of small demand resources in the ancillary services market.
  - The NYISO focused its efforts in 2011 on developing the technical specifications for direct communications for DSASP.
    - Direct Communication with a DSASP Provider (“aggregator”) without a requirement for connection through the Transmission Owner is expected to streamline program participation in DSASP and make it feasible for aggregations of small demand resources to participate in the ancillary services market.
    - There will be an initial limit of 150 MW NYCA-wide for DSASP using Direct Communications. For reliability, NYISO needs to initially limit exposure of the amount of reserves that are not under Transmission Owner control during Interim Control Operations, while NYISO builds experience.
    - With the completion of the technical specifications for Direct Communications for DSASP, the NYISO has begun work on developing the proposed market rules and procedures for integrating aggregations of small demand resources into its ancillary service markets through the DSASP. Presentations to stakeholders are expected to begin in February and the NYISO anticipates filing proposed tariff changes in the spring of 2012.
    - NYISO is developing The Demand Response Information System (DRIS) to automate program processing and enhance event performance, management, and settlement.

SOURCES:

» California Independent System Operator Corporation, ISO New England, Inc., Midwest Independent Transmission Operator, Inc., New York Independent System Operator, PJM Interconnection, LLC, and Southwest Power Pool, Inc. 2011 ISO/RTO Metrics Report. Prepared for Federal Energy Regulatory Commission, 2011.

» New York Independent System Operator. NYISO 2011 Annual Report on Demand Response Programs. 17 January 2012.

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» New York Independent System Operator. DSASP Direct Communications Technical Specification. November 2011.

» Gonzales, Rick. Grid Integration of Renewables. New York Independent System Operator, 29 March 2012.

- Personal communications with Scott Baker, PJM. April 4, 2012 and April 24, 2012.

D.5 *Midwest ISO (MISO)*

- MISO uses DR for energy, capacity and ancillary services.
    - Energy - Reduction in short term energy use in Real-Time or Day-Ahead markets. Results in lower short term prices for all users
    - Emergency Energy (Capacity) - Also called reliability or planning reserves. Reduces demand when demand threatens to exceed supply. Used to avoid rolling blackouts.
        - MISO has not experienced the need to deploy Load Modifying Resources (LMR) in an emergency (such as via Emergency Operating Procedures [EOP-002]) and thus does not have a record of LMR performance since the launch of the new Resource Adequacy construct in 2009.
    - Ancillary Services – procured by the grid operator to help control and stabilize the grid
        - Regulation: Ability decrease or increase Demand (or supply) within seconds. Full range capability within 20 minutes.
        - Spinning Reserves: Ability to decrease demand (or increase supply) within 10 minutes and hold for a specified period.
- MISO has significant DR capacity.
    - DR capacity as a percentage of total capacity rose from 2.6 percent in 2006 to 3.2 percent in 2010 (12,500 MW)
- MISO seeks to integrate DR into existing MISO markets instead of creating new markets.
    - Unlike other RTOs, MISO does not create "programs" for DR. Instead MISO seeks to create opportunities to integrate DR into existing MISO markets.
    - MISO model could result in underuse of DR due to failure to integrate the differing characteristics of DR.
    - For comparison, PJM allows "voluntary" response to energy prices without penalty, allowing for the inherent uncertainty in the quantity of reduction.
- Regulations
    - Through Order 719, FERC directed operators of organized markets such as MISO to address barriers to DR and address jurisdictional issues at the retail/wholesale interface. The jurisdictional issues are as follows:
        - Some utilities and Retail regulators (states, munis, coops) have asserted that RTO based DR programs may conflict with local regulated DR programs.
        - RTOs may not unduly discriminate among market participants.
        - FERC has provided guidelines for RTOs that are intended to provide clarity.
        - Many utilities, including public power, view RTO DR as a threat to customer control.

            - Eligibility for RTO programs varies by utility size
                - Retail customers of Large Utilities are eligible for RTO programs unless the regulator says otherwise. (Opt out)
                    - Opt out states include MI, IN, KY, WI, IA and MN
                - Retail customers of Small Utilities are not eligible for RTO programs unless the regulator permits participation. (Opt in)
                    - Small utilities sell less than 4 million MWh/yr – about 900 MW peak capacity.
                    - Many self-regulating public power entities have declined to "opt in".

» Aggregators of Retail Customers (ARCs)
    - While some large retail customers can participate directly in markets, ARCs can facilitate participation of smaller customers. The sole business of many ARCs is to enable DR activity by managing RTO interfaces and providing metering.
    - While utilities are often conflicted by the impact of revenue reductions from foregone sales, ARCs are not conflicted.
    - Responding to Order 719, MISO has proposed rule changes to FERC that are intended to remove barriers to ARC participation. The changes include:
    - Elimination of requirement to be an LSE
    - Reformed (but perhaps still large) market credit requirements
    - Modifications to technical requirements

» Broader plans for renewables integration:
    - The most prominent renewables integration issue in the MISO region is wind curtailment.

» MISO's renewable energy produced as a percentage of total energy rose from 0.65 percent in 2006 to 3.8 percent in 2010. In 2010, there were 2,117 curtailments of wind that were backed down due to local congestion issues. This included the curtailment of an estimated 824,000 MWh of energy and spanned over 19,951 duration hours.

» MISO's regional planning enables more economic placement of wind resources in the region. The economic placement of wind resources defers new capacity construction. The quantitative benefit of MISO's regional planning has been estimated to be $34 million to $42 million in annual savings.

» Barriers to DR programs and use of DR for renewables integration
    - Barriers related to ARCs were identified in multiple sources.
        - ARCs currently do not participate in any of its markets, and thus MISO has not seen the growth in new DR that ARCs have generated in other markets.

    - There are several major barriers that have excluded ARCs, including real-time metering requirements that raise the cost of participation and the lack of a settlement mechanism to compensate ARCs. These barriers, in combination with relatively low market prices, have resulted in limited direct DR participation in the energy and ancillary services markets.
  - In addition, there are more general barriers to DR in the MISO service territory.
    - Incomparable treatment of LMRs and Demand Response Resources (DRRs) relative to generation in terms of disqualification from resource adequacy and revenue sufficiency guarantee (RSG) payments
    - Lack of capacity price transparency, which is especially important for ARCs
    - Undetermined rules regarding LMR deliverability
    - Some bidding and modeling issues such as the lack of PRD bidding in the real-time energy market, the inability of DRR-Type I resources to set real-time prices, and insufficient bid parameters in regulation offers to fully accommodate the special characteristics of DR.

SOURCES:

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D.6 Hawaiian Electric Company (HECO)

- HECO currently has two DLC programs.
  - HECO's Residential Direct Load Control ("RDLC") Program: Docket No. 2009-0073

        - HECO's Residential Direct Load Control ("RDLC") Program offers eligible residential customers the opportunity to participate in an interruptible program for electric water heaters and central air-conditioning systems. Customers receive a monthly electric bill credit of $3.00 for electric water heaters and $5.00 for central air-conditioning systems as an incentive for participating in the program.
    - HECO's Commercial Direct Load Control ("CIDLC") Program: Docket No. 2009-0097
        - HECO's Commercial and Industrial Direct Load Control ("CIDLC") Program offers eligible commercial and industrial electric customers the opportunity to designate a portion of their electrical load as directly controllable or interruptible by HECO under certain circumstances. Participants receive a monthly and per event incentive in exchange for agreeing to reduce their electrical usage to a designated contract level during a load control event.
    - Data from the first year (2009) of these DLC programs is available.
    - The PUC has approved 3-year extensions of the residential and commercial and industrial (C&I) direct load control programs.

- Residential sector assessment:
    - HECO currently has plans filed with the PUC to develop a water heater load control program. The technical assessment calculated that this program could lead to 43 percent savings during peak periods.
    - Technical assessment of air conditioners suggests 32 percent savings during peak periods would be possible.
- Interruptible program assessment:
    - The analysis of technical potential for interruptible was based largely on estimates developed by HECO from its July 2003 site survey efforts for large commercial and industrial customers to address standby generation and interruptible loads. That analysis revealed a technical potential of roughly 114.5 MW for standby generation and 53.7 MW of interruptible load, coming from a variety of building types and manufacturing entities.

- In February 2012, Honeywell announced a two-year pilot program with Hawaiian Electric Co. in Honolulu to demonstrate how DR technology can help integrate more intermittent renewable energy to the electric grid.
    - The pilot will validate the technical design and tariffs for a full-scale DR program to support Hawaii's renewable energy goals. It will also contribute to a broader statewide effort to increase energy independence, security and sustainability. Currently, Hawaiian Electric has to rely on fossil fuel generation to manage the inherent intermittency

associated with certain types of renewable energy and other interruptions in grid stability. Fast DR has the potential to reduce the use of fossil fuels to balance the increased integration of renewable energy in Hawaii.

- The pilot will help Hawaiian Electric create direct connections to loads at commercial and industrial facilities. For the first phase, Honeywell will work with Hawaiian Electric to enroll and connect customers to a ROC. If demand outpaces supply, Hawaiian Electric will trigger a notice for customers to reduce demand within 10 minutes, providing more than 6 MW of semi-automated load control when the program is fully subscribed.
- A second phase will feature the use of Auto DR tools from Honeywell, including Akuacom and Tridium technologies. Hawaiian Electric will use the Demand Response Automation Server (DRAS) software from Akuacom to manage its resources and events. At each customer facility, a Tridium smart grid controller will poll the DRAS for event signals. When the utility triggers an event, the controller will receive the signal and communicate with the site's building management system to automatically execute load-shed measures the customer sets in advance, such as cycling air conditioners, and turning off non-essential lights, pumps and motors. The smart grid controller also sends data from the facility's electricity meter back to the DRAS every 5 minutes so the utility has immediate feedback on the decrease in demand. The Akuacom and Tridium technologies are based on open, industry-accepted standards so they can interact with virtually any building system to enable highly reliable machine-to-machine communication and rapid load reductions.

» Maximum achievable potential from DR measures.

Figure D-1: Aggregate Program-Level Expected Savings from DR

	2009	2014	2019	2024	2029
Demand Savings (MW)	44	82	84	86	88

» Broader plans for renewables integration:

- The Hawaii Electric Light Company (HELCO) faces many challenges to integrating large amounts of variable renewable energy in its system. It has no interconnections to other grids, a large percentage of its generation that provides no frequency regulation, a small number of large wind power plants with few diversity benefits, and a large renewable generation penetration with excess energy in the off-peak period.

- The Maui Electric Company's (MECO's) electric system on the island of Maui is similar in load size to the HELCO system, with a peak load of approximately 190 MW and a minimum load of approximately 85 MW. The majority of MECO's firm energy is provided by a combination of oil- and biomass-fired steam, combustion turbine, and internal combustion engine generation. A single 30-MW wind plant on its system at times providing nearly 15 percent of the system's energy. The Maui wind plant has similar ramp-rate limits to those of HELCO: 2 MW/min upward and 2 MW/min downward, when operationally feasible. It also has undervoltage and underfrequency ridethrough requirements.

- HECO, which serves the island of Oahu, the most populated of the Hawaiian islands, does not currently have wind generation on its system. It is served by a mix of oil- and coal-fit i steam and oil-fired combustion turbine generation. A medium size waste-to-energy-fueled steam generator serves the system as well. The HECO system peak is approximately 1,200 MW, and the minimum is approximately 600 MW. HECO's largest unit is a 180-MW coal-fi A steam generator operated by an independent power producer.
  - HECO currently carries spinning reserves large enough to cover the loss of the capacity of the largest unit on the system.

» Lessons learned
- BluePoint's D-RAAP ™ solution has been favorably received in California and Hawaii programs.
  - As of June 30, 2008, BluePoint Energy's recent concentrated efforts in HECO's territory have yielded four megawatts under customer agreements or acknowledgements.
  - It is expected that most, if not all, of these acknowledgements will become executed contracts within the next 60 days. In connection with these executed agreements, BluePoint has commenced installing its proprietary GenView(TM) controls comprised of pre-assembled and pre-tested systems manufactured by the Company.
  - Implemented with a very limited "beta" sales effort, these initial marketing and selling initiatives in connection with BluePoint's Demand Response Asset Aggregation Program have yielded very positive customer responses to its D-RAAP(TM) solution in an extremely short period of time. These end-use customers clearly value both the added protection of their standby generation assets afforded by the BluePoint D-RAAP(TM) solution as well as the opportunity to provide green solutions to the ever increasing challenges of meeting the needs of the California and Hawaii energy markets.

SOURCES:

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- Matsuura, Marc. "Island Breezes: Renewable Energy Integration from a Hawaiian Perspective." IEEE Power & Energy Magazine, 2009.
- Personal discussion with Angie Eide and Tim Ellis, HECO. Various dates in Spring 2012.
- Public Utilities Commission, State of Hawaii. Annual Report: Fiscal Year 2009-10. November 2010.

D.7 Bonneville Power Administration (BPA)

- BPA's pilot projects[146] looking at DR specifically for renewables integration include:
    - **Ecofys US, Inc.** is testing energy storage opportunities with both residential and commercial customers in a project called the "Smart End-use Energy Storage and Integration of Renewable Energy".
        - The residential pilots are in the service territories of Lower Valley Energy, Eugene Water and Electric Board, and Cowlitz public utility district (PUD). The residential pilot includes thermal storage furnaces and space and water heater control devices from Steffes Corporation. As of September 2011, a portion of the installations were complete with the remaining installations to be completed prior to early 2012.
        - The commercial pilot is being developed by EnerNOC and is targeting commercial cold storage facilities at various locations in the Pacific Northwest. As of September 2011, five sites had been selected for total controllable resource of ~1MW (approx. 20 percent of load per site). All five end users have been successfully enrolled and enabled with preliminary testing completed. Final results from the pilot are expected in 2012.
        - The Ecofys project will continue through 2012 and will test many of the assumptions in the business case, review commercial terms for the sale of balancing services, propose and test dispatch methods and optimization schemes, survey program satisfaction and acceptance, and evaluate distribution system impacts (positive and negative) of large-scale DR deployment.

[146] Additional DR programs within Bonneville's territory include a handful of existing utility-sponsored DR programs, the DR pilots occurring through the Pacific Northwest Smart Grid Demonstration Project, and several DR pilots that BPA is deploying to evaluate a diverse group of technologies and determine the feasibility of DR in its service territory. [See #068 for more information.]

- The DR resource (comprised primarily of refrigerated warehouse loads) in BPA's Ecofys C&I load following DR pilot meets "stringent resource parameters" including:
  - Direct load control, although customer will have manual override capability, as well as the ability to set specific temperature boundaries
  - Loads controlled both up and down
  - 24/7/365 resource availability
  - Dispatch upon 10 minutes' notice
  - Maximum 30 minutes per dispatch and two dispatches per day
  - Minimum 3 hours between dispatches
- Preliminary results from BPA's Ecofys residential load following DR pilot include and asymmetrical response to BPA need for increase and decrease (INCs/DECs)
  - ETS water heaters have more capacity to provide DECs than INCs
  - Control strategy needs to evaluate energy balance over time, so not to "over-charge" the tanks
- The aggregate water heater load shape was split into its component value streams:
  - Peak Shaving was about ½ the value received
  - Load shaping (taking advantage of Time-Of-Use (TOU) rates, if any)
  - Balancing Reserves (i.e., Incremental and Decremental reserves) were about ¼ to ½ the value, with more contributed by providing DEC reserves
- This tool needs further development, including sensitivity analysis to price ranges for providing INCs and DECs

- **Mason County PUD #3 ("MCP3")** includes water heater controls activated by renewable energy signal. MCP3 will demonstrate use of automated DR to manage demand in correlation with renewable resources, identify the optimal control and shedding strategies for intermittent renewable events, power outages and control system peaking events, and evaluate the economic and socio-economic factors that influence customer participation. Control technology provided by Allyn Technology Group.

  - **City of Port Angeles** is working with EnerNOC to develop bi-directional load ramping/load following capabilities for a large industrial customer of up to 41 MWs in response to load intermittency due to BPA's significant renewable resources.
    - 15 MW of this project went live in April 2012, although it was not yet at a commercial stage.

» Broader plans for renewables integration
  - The pace of wind power development in the Pacific Northwest is exceeding BPA's expectations: BPA has more than 3,000 MW of wind interconnected today, with 6,000 MW of requests "in-process" and another 15,000 MW of requests "in-discussion."
  - Wind Integration Pilot with Iberdrola - Iberdrola manages about 1,300 megawatts of wind energy in eastern Oregon and Washington. Until last September, BPA used reserves of federal hydropower to balance unscheduled variations in this wind power. Since then, Iberdrola has provided its own reserves in a pilot project, freeing about 300 megawatts of balancing reserves from federal power for other uses. Iberdrola and BPA have agreed to continue the Customer Supplied Generation Imbalance Pilot through BPA's 2012-2013 rate period.
  - During this second phase, BPA will continue to test the pilot's effectiveness and ultimately determine whether the agency can expand the initiative.

» **Barriers to DR programs and use of DR for renewables integration:**
  - There are also complexities with contracting methods for DR due to unknown performance limitations of DR, dispatch process, and aggregation requirements to package the DR service for sale to wholesale market participants. For instance, a distribution utility may deploy DR to gain the benefits of peak clipping, and find that selling balancing services to BPA or other third party as an additional revenue source.
  - From discussions with BPA, whether a resource can be used for both peak reduction and balancing is a key uncertainty, since it can change the cost-effectiveness equation significantly, but the mechanisms for having a resource do both are not yet clear.
  - Key questions include who pays for what, who gets the payment, how they get the payment, etc. This capability will also be different for each load type, which BPA has made the point "shows the importance of a portfolio approach."
  - Finally, due to limited availability of BPA-provided generator imbalance service, BPA gives variable resources the option to 1) purchase a limited amount of imbalance service at a base rate from BPA and risk more frequent curtailment, or 2) purchase additional imbalance service (i.e., "Supplemental Service") at BPA's actual cost for the capacity plus an administrative fee.

- BPA has recognized the need for streamlined, automated infrastructure to scale pilot programs in the region up to regional resources.

SOURCES:

- Bonneville Power Administration. Bonneville Power Administration Petition for Declaratory Order Granting Reciprocity Approval and for Exemption from Filing Fee. Proposed Tariff to Federal Electric Regulatory Commission. 30 March 2012.
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- Personal communications with Ken Nichols, BPA. April 4, 2012.
- Personal communications with Lee Hall and Katie Pruder-Scruggs, BPA April 26, 2012.
- Personal communications with Lee Hall, BPA. May 2, 2012.
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Appendix E. Detailed Evaluations of Each IOU DR Programs

E.1 Pacific Gas & Electric DR Program Evaluations

The methodology presented in Appendix F is used below to evaluate individual DR programs for potential to help integrate renewable energy. The following PG&E DR programs are included in this subsection:

- » PeakChoice Program
- » PDP-Peak Day Pricing
- » DBP: Demand Bidding Program
- » BIP: Base Interruptable Program
- » AMP: Aggregator Managed Portfolio
- » CBP: Capacity Bidding Program
- » SmartAC
- » SmartRate
- » PDP-Peak Day Pricing (Small-Medium Business)
- » OBMP: Optional Binding Manditory Curtailment
- » SLRP: Scheduled Load Reduction Program

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
⭘	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***PG&E***

Program Name ***PeakChoice Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	●	< 1 min	●	**●**	< 10 min.	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	⭘	**⭘**	1-10 min	⭘	⭘	10-30 min	⭘	⭘	10-30 min	**⭘**	**⭘**	20-200	⭘	**⭘**	Likely can meet CAISO reqts
	○	○	>10 min	**○**	○	>30 min	○	○	< 10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	⭘	**⭘**	1-5 min.	⭘	**⭘**	<10 min	⭘	⭘	10-30 min	**⭘**	**⭘**	20-200	⭘	**⭘**	Likely can meet CAISO reqts
	○	○	>5 min.	**○**	○	>10 min	○	○	<10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	⭘	⭘	n/a	⭘	⭘	n/a	⭘	⭘	30-60 min	⭘	⭘	Continuous	⭘	⭘	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Fastest notification time is 30 minute. Program could be modified sub-10 minute notice for some of participating load. Would require technology assistance/automation.
SR-Notice	Fastest notification time is 30 minute. Program could be modified for sub-5 minute notice for some of participating load. Would require technology assistance/automation.
NR-Speed	Program could be modified for faster startup,and response to signal in less than 10 minutes (for some participating load). Would require technology /automation
SR-Speed	Program could be modified for faster startup,and response to signal in less than 10 minutes (for some participating load), but not sub-minute. Would require technology /automation
NR-Frequency	# event days ranges from 3 to 25. Program modifications to increase frequency of use are possible, but would be major program changes, and probably could not reach 200 times/year.
SR-Frequency	"
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR), but still difficult to get to 3%.
SR-Deviation	"

Summary:

PeakChoice provides a range of options for notification time and frequency of participation. This range could potentially be expanded to include faster notification and more frequent use of the resource. It would also have to include some form of automation and ability to accept a control signal to allow some participating load to provide Non-Spinning Reserve capabilities, and perhaps even Spinning Reserves (both for some fraction of the contracted load). However these are significant program modifictions including the use of networked technology to send control signals.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***PG&E***

Program Name ***PDP-Peak Day Pricing***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	**●**	< 1 min	●	●	< 10 min.	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-10 min	◎	**◎**	10-30 min	◎	◎	10-30 min	◎	**◎**	20-200	◎	**◎**	Likely can meet CAISO reqts
	○	○	>10 min	**○**	○	>30 min	○	○	< 10 min	**○**	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	**●**	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-5 min.	◎	**◎**	<10 min	◎	◎	10-30 min	◎	**◎**	20-200	◎	**◎**	Likely can meet CAISO reqts
	○	○	>5 min.	**○**	○	>10 min	○	○	<10 min	**○**	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program uses 2pm day-ahead notice. Might be automated to provide sub-minute notice, which would likely be acceptable to only a portion of program customers
SR-Notice	Program uses 2pm day-ahead notice. Might be automated to provide sub-minute notice, which would likely be acceptable to only a portion of program customers
NR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide 10 to 30 minute response (for some participating load).
SR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load).
NR-Frequency	Program current max. of 15 event days could be modifed to larger # (e.g. >20 times/year, or even more).
SR-Frequency	Program current max. of 15 event days could be modifed to larger # (e.g. >20 times/year, or even more).
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance and automation, but still difficult to get to 3%.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance and automation, but still difficult to get to 3%.

Summary:

PDP is fundamentally a day-ahead notice program. Program could be modified to provide a much quicker response, but would need to leverage automation, and customers (at least some % of them) would need to accept much quicker notice of deployment, which might fundamentally change the nature of the program from customer perspective.

NAVIGANT

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
o	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***PG&E***

Program Name ***DBP: Demand Bidding Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	●	< 1 min	●	●	< 10 min.	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	o	o	1-10 min	**o**	**o**	10-30 min	o	o	10-30 min	**o**	**o**	20-200	o	**o**	Likely can meet CAISO reqts
	○	**○**	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	o	o	1-5 min.	o	o	<10 min	o	o	10-30 min	**o**	**o**	20-200	o	**o**	Likely can meet CAISO reqts
	○	**○**	>5 min.	**○**	**○**	>10 min	○	○	<10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	o	o	n/a	o	o	n/a	o	o	30-60 min	o	o	Continuous	o	o	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program could be modified so that day-ahead or day-of notice was used to put facility/load on notice that more granular control will be required during the event. This is a slight re-definition of "notice."
NR-Speed	Program might be modified for faster startup and more granular control, possibly using technology assistance (e.g., AutoDR) to control specific loads. Aggregator approach could be used for better, more granular control.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.

Summary:

The nature of a day-ahead Demand Bidding Program is difficult to modify to meet the requirements of reserve or regulation products. The program and load controls would have to be automated to the degree that bidding would occur essentially real-time, which would be a fundamental change to the program, making it essentially a real-time bidding program.

NAVIGANT

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◉	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***PG&E***

Program Name ***BIP: Base Interruptable Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	**●**	< 1 min	●	**●**	< 10 min.	**●**	**●**	>30	●	**●**	>200	●	●	As reliable as CT
	◉	◉	1-10 min	**◉**	◉	10-30 min	◉	◉	10-30 min	**◉**	◉	20-200	◉	**◉**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	**●**	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	**●**	>200	●	●	As reliable as CT
	◉	◉	1-5 min.	◉	**◉**	<10 min	◉	◉	10-30 min	**◉**	◉	20-200	◉	**◉**	Likely can meet CAISO reqts
	○	○	>5 min.	**○**	○	>10 min	○	○	<10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◉	◉	n/a	◉	◉	n/a	◉	◉	30-60 min	◉	◉	Continuous	◉	◉	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
SR-Notice	Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
NR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load).
SR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load), but it's not clear that a signficant portion of the load could respond w/in 8 seconds.
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >10 events/month, >120 hours/year), but could be a significant program change.
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >10 events/month, >120 hours/year), but could be a significant program change.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation

Summary:

Program could potentially be modified provide some Non-Spinning Reserve capabilities, and even Spinning Reserve capabilities (perhaps for some fraction of the contracted load, focusing on those customers using 30 minute notification). However modifictions would be significant and would need to include the use of networked technology to send pricing and control signals, as well as changes to allow more freqent use and perhaps expand the seasonal availability. Details would have to be worked through bi-lateral contract negotiations with Aggregators.

Note: Navigant recognizes that the CPUC has placed a "cap" on the combined capacity of BIP and other IOU DR reliability programs. The evaluation of the DR programs presented here assumes that any such a limitation would be removed, at the CPUC's discretion, if the program design changes that would be required for those programs to provide ancillary services were adopted.

NAVIGANT

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
o	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***PG&E***

Program Name ***AMP: Aggregator Managed Portfolio***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	**●**	< 1 min	●	**●**	< 10 min.	**●**	**●**	>30	●	**●**	>200	●	**●**	As reliable as CT
	o	o	1-10 min	**o**	o	10-30 min	o	o	10-30 min	**o**	o	20-200	**o**	o	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	**●**	<1 min.	●	**●**	< 8 sec (10% load)	**●**	**●**	>30	●	**●**	>200	●	**●**	As reliable as CT
	o	o	1-5 min.	o	o	<10 min	o	o	10-30 min	**o**	o	20-200	**o**	o	Likely can meet CAISO reqts
	○	○	>5 min.	**○**	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	**●**	None	●	**●**	4-sec (AGC)	**●**	**●**	60 min. or greater	●	**●**	Continuous	●	**●**	can meet w/ certainty
	o	o	n/a	o	o	n/a	o	o	30-60 min	o	o	Continuous	o	o	can meet most of time
	○	○	Any adv. notice	**○**	○	Non-AGC capable	○	○	<30 min	**○**	○	Continuous	**○**	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Requirements could be modified to provide <1 minute notice, and aggregator would adjust appropriately to meet these requirements. New terms might be acceptable to only a portion of current program customers (customers on 30 minute notice), Modifications would have to work through Aggregators with different bi-lateral contract
SR-Notice	Requirements could be modified to provide <1 minute notice, and aggregator would adjust appropriately to meet these requirements. New terms might be acceptable to only a portion of current program customers (customers on 30 minute notice), Modifications would have to work through Aggregators with different bi-lateral contract
NR-Speed	Requirements could be modified to provide the necessary response time and service levels.
SR-Speed	Requirements could be modified to provide the necessary response time and service levels.
R-Speed	Requirements could be modified to provide the necessary response time and service levels.
NR-Frequency	Requirements could be modified to provide the necessary response time and service levels.
SR-Frequency	Requirements could be modified to provide the necessary response time and service levels.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.
R-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance. Something more advanced than AutoDR might be required in the short term. Aggregator approach could help balance diverse loads.

Summary:

The assumption here is that the AMP program is fundamenally set up as an aggregation program to meet whatever requirements PG&E decides are important (in contrast to the BIP and CBP programs, which are set up for specific purposes but use aggregators simply to deliver those purposes. This assumption implies that terms can be modified provide any of the services defined above. However modifictions would be significant and would need to include the use of networked technology to send pricing and control signals, as well as changes to allow more freqent use and perhaps expand the seasonal availability. Details would have to be worked through bi-lateral contract negotiations with Aggregators.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***PG&E***

Program Name ***CBP: Capacity Bidding Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-10 min	◎	◎	10-30 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-5 min.	◎	◎	<10 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Might be automated to provide <1 minute notice. Would probably be acceptable to only a portion of program customers that are currently on 30 minute notice, and would have to work through Aggregators with different bi-lateral contrad terms.
SR-Notice	Might be automated to provide <1 minute notice. Would probably be acceptable to only a portion of program customers that are currently on 30 minute notice, and would have to work through Aggregators with different bi-lateral contrad terms.
NR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide a <10 minute response (for some participating load). Would have to work through Aggregators with different bi-lateral contrad terms.
SR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load). Would have to work through Aggregators with different bi-lateral contrad terms.
NR-Frequency	Program modifications would be necessary to allow for more than one event per day; and desirable to make this a year-round program..
SR-Frequency	Program modifications would be necessary to allow for more than one event per day; and desirable to make this a year-round program..
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.

Summary:

Program could potentially be modified provide some Non-Spinning Reserve capabilities, and even Spinning Reserve capabilities (perhaps for some fraction of the contracted load, focusing on those customers using 30 minute notification). However modifictions would be significant and would need to include the use of networked technology to send pricing and control signals, as well as changes to allow more freqent use and perhaps expand the seasonal availability. Details would have to be worked through bi-lateral contract negotiations with Aggregators.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
O	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

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Program Name ***SmartAC***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	O	**O**	1-10 min	**O**	**O**	10-30 min	**O**	**O**	10-30 min	**O**	**O**	20-200	**O**	**O**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	O	**O**	1-5 min.	**O**	**O**	<10 min	**O**	**O**	10-30 min	**O**	**O**	20-200	**O**	**O**	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	O	**O**	n/a	**O**	**O**	n/a	**O**	**O**	30-60 min	**O**	**O**	Continuous	**O**	**O**	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
SR-Speed	Program might be modified for faster startup and more granular control to have a 10 % of load participating within 8 seconds. This would require technology enhancements (e.g.,broadband internet connectivity) to control individual loads.
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >100 hours/year), but could be a significant program change.
SR-Frequency	Program modifications to increase frequency of use are possible (e.g. >100 hours/year), but could be a significant program change.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., SEP 2.0 and head-end algorithms).
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., SEP 2.0 and head-end algorithms).

Summary:

Program could be modified provide some Non-Spinning and potentially Spinning Reserve capabilities (perhaps for some fraction of the contracted load). Current automation and network technology would likely need to be upgraded, possibly significantly, to participate in AS products.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
○	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

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Program Name ***SmartRate***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	○	**○**	1-10 min	**○**	**○**	10-30 min	**○**	**○**	10-30 min	**○**	**○**	20-200	**○**	**○**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	○	**○**	1-5 min.	**○**	**○**	<10 min	**○**	**○**	10-30 min	**○**	**○**	20-200	**○**	**○**	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	○	**○**	n/a	**○**	**○**	n/a	**○**	**○**	30-60 min	**○**	**○**	Continuous	**○**	**○**	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Speed	Program might be modified to respond to control signal within 10 minutes. This would require technology enhancements (e.g., SEP 2.0? And internet connectivity) to control individual loads. This would be a fundamental modification to the program by requiring technology.
SR-Speed	Program might be modified to respond to control signal within 10 minutes. This would require technology enhancements (e.g., SEP 2.0? And internet connectivity) to control individual loads. This would be a fundamental modification to the program by requiring technology.
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >15 events/year), but could be a significant program change.
SR-Frequency	Program modifications to increase frequency of use are possible (e.g. >15 events/year), but could be a significant program change.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., SEP 2.0 and head-end algorithms).
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., SEP 2.0 and head-end algorithms).

Summary:

Program is fundamentally a pricing program without automation requirements. Significant automation would be required to provide any of the ancillary services. Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
⭘	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

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Program Name ***PDP-Peak Day Pricing (Small-Medium Business)***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves	● ⭘ ○	● ⭘ ○	< 1 min 1-10 min >10 min	● ⭘ ○	● ⭘ ○	< 10 min. 10-30 min >30 min	● ⭘ ○	2 ● ⭘ ○	>30 10-30 min < 10 min	● ⭘ ○	● ⭘ ○	>200 20-200 <20	● ⭘ ○	● ⭘ ○	As reliable as CT Likely can meet CAISO reqts Cannot meet CAISO reqts
Spinning Reserves	● ⭘ ○	● ⭘ ○	<1 min. 1-5 min. >5 min.	● ⭘ ○	● ⭘ ○	< 8 sec (10% load) <10 min >10 min	● ⭘ ○	● ⭘ ○	>30 10-30 min <10 min	● ⭘ ○	● ⭘ ○	>200 20-200 <20	● ⭘ ○	● ⭘ ○	As reliable as CT Likely can meet CAISO reqts Cannot meet CAISO reqts
Regulation	● ⭘ ○	● ⭘ ○	None n/a Any adv. notice	● ⭘ ○	● ⭘ ○	4-sec (AGC) n/a Non-AGC capable	● ⭘ ○	● ⭘ ○	60 min. or greater 30-60 min <30 min	● ⭘ ○	● ⭘ ○	Continuous Continuous Continuous	● ⭘ ○	● ⭘ ○	can meet w/ certainty can meet most of time can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program uses 2pm day-ahead notice. Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
NR-Notice	Program uses 2pm day-ahead notice. Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
NR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide 10 to 30 minute response (for some participating load).
NR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load).
NR-Frequency	Program current max. of 15 event days could be modifed to larger # (e.g. >20 times/year, or even more).
SR-Frequency	Program current max. of 15 event days could be modifed to larger # (e.g. >20 times/year, or even more).
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance and automation, but still difficult to get to 3%.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance and automation, but still difficult to get to 3%.

Summary:

PDP is fundamentally a day-ahead notice program. Program could be modified to provide a much quicker response, but would need to leverage automation, and customers (at least some % of them) would need to accept much quicker notice of deployment, which might fundamentally change the nature of the program from customer perspective.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***PG&E***

Program Name ***OBMP: Optional Binding Manditory Curtailment***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-10 min	◎	◎	10-30 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	<8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-5 min.	◎	◎	<10 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program could be modified to provide sub minute notice. This would require some form of automation.
SR-Notice	Program could be modified to provide very fast notice. This would require automation.
NR-Speed	Program might be modified for faster startup and more granular control, possibly using technology assistance (e.g., AutoDR) to control specific loads.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.

Summary:

Program could be modified provide some Non-Spinning and potentially Spinning Reserve capabilities (perhaps for some fraction of the contracted load). However modifictions would be significant and would need to include the use of networked technology to send control signals, as well as changes to allow more freqent use.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
O	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***PG&E***

Program Name ***SLRP: Scheduled Load Reduction Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	●	< 1 min	●	●	< 10 min.	**●**	**●**	>30	**●**	**●**	>200	●	●	As reliable as CT
	O	O	1-10 min	O	O	10-30 min	O	O	10-30 min	O	O	20-200	O	**O**	Likely can meet CAISO reqts
	○	**○**	>10 min	**○**	**○**	>30 min	○	○	< 10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	**●**	**●**	>200	●	●	As reliable as CT
	O	O	1-5 min.	O	O	<10 min	O	O	10-30 min	O	O	20-200	O	**O**	Likely can meet CAISO reqts
	○	**○**	>5 min.	**○**	**○**	>10 min	○	○	<10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	**●**	**●**	Continuous	●	●	can meet w/ certainty
	O	O	n/a	O	O	n/a	O	O	30-60 min	O	O	Continuous	O	O	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	○	○	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:

NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR), but still difficult to get to 3%.
NS-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR), but still difficult to get to 3%.

Summary:

Pre-scheduling would make it very difficult/ impossible for this program to be used for reserves or regulation.

E.2 Southern California Edison DR Program Evaluations

The methodology presented in Appendix F is used below to evaluate individual DR programs for potential to help integrate renewable energy. The following SCE DR programs are included in this subsection:

» Summer Discount Program - Residential
» Summer Discount Program - Non-Residential
» Base Interruptible Program (BIP)
» Optional Binding Mandatory Curtailment Program
» Agricultural and Pumping Interruptible Program
» Capacity Bidding Program
» Demand Bidding Program
» Demand Response Contracts
» Real-Time Pricing
» Peak Time Rebate >200kW
» Peak Time Rebate <200kW
» Peak Time Rebate

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DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◉	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Summer Discount Program - Residential***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	**●**	< 1 min	**●**	**●**	< 10 min.	**●**	**●**	>30	●	**●**	>200	●	●	As reliable as CT
	◉	◉	1-10 min	◉	◉	10-30 min	◉	◉	10-30 min	**◉**	◉	20-200	◉	**◉**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	**●**	**●**	<1 min.	●	**●**	< 8 sec (10% load)	**●**	**●**	>30	●	**●**	>200	●	●	As reliable as CT
	◉	◉	1-5 min.	**◉**	◉	<10 min	◉	◉	10-30 min	**◉**	◉	20-200	◉	**◉**	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	**●**	**●**	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◉	◉	n/a	◉	◉	n/a	◉	◉	30-60 min	**◉**	**◉**	Continuous	◉	◉	can meet most of time
	○	○	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	○	○	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
SR-Speed	Head-end and communications technology is capable of providing 10 minute response, with some load reacting within 8 seconds; existing equipment and comminications configurations may not be set up to achieve this.
NR-Frequency	Current program has limits on event hours that could preclude its use for non-spinning reserves over a long period of time; program could extend limits to eliminate this obstacle. May need to allow other end-uses, such as pool pumps, in order to provide year-round curtailment, albeit at a lower level of MW.
SR-Frequency	Current program has limits on event hours that could preclude its use for non-spinning reserves over a long period of time; program could extend limits to eliminate this obstacle. May need to allow other end-uses, such as pool pumps, in order to provide year-round curtailment, albeit at a lower level of MW.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., SEP 2.0 and head-end algorithms), but speed of two-way communication (eg, AMI or broadband) could be a limitation.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., SEP 2.0 and head-end algorithms), but speed of two-way communication (eg, AMI or broadband) could be a limitation.

Summary:

SDP and other residential direct load control programs are among the more promising DR programs for supporting integration of renewables due to the lack of required advanced notification, the unlimited number of events that can be called year-round (limited only to 90 hours per year and 6 hours per event), and DLC's relatively fast speed of response to curtailment signals. Still unproven, however, is the ability of DLC to provide adequately precise curtailment (within the limits of permissa deviation from bid amount). There is potential to provide regulation up services, but the requirements for speed and frequency of response may limit its use for regulation.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
⭘	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Summer Discount Program - Non-Residential***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	⭘	⭘	1-10 min	⭘	⭘	10-30 min	⭘	⭘	10-30 min	⭘	⭘	20-200	⭘	⭘	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	⭘	⭘	1-5 min.	⭘	⭘	<10 min	⭘	⭘	10-30 min	⭘	⭘	20-200	⭘	⭘	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	⭘	⭘	n/a	⭘	⭘	n/a	⭘	⭘	30-60 min	⭘	⭘	Continuous	⭘	⭘	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
SR-Speed	Head-end and communications technology is capable of providing 10 minute response, with some load reacting within 8 seconds; existing equipment and comminications configurations may not be set up to achieve this.
R-Speed	Technology and communications is likely capable of meeting speed of response requirements for regulation, but it is uncertain whether it can do so consistency or for all participating loads.
NR-Frequency	Current program is summer-only and has an option that limits the number of events (15), which could preclude its use for non-spinning reserves during the summer season; program could extend limits to eliminate this obstacle.
SR-Frequency	Current program is summer-only and has an option that limits the number of events (15), which could preclude its use for spinning reserves during the summer season; program could extend limits to eliminate this obstacle.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., SEP 2.0 and head-end algorithms), but speed of two-way communication (eg, AMI or broadband) could be a limitation.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., SEP 2.0 and head-end algorithms), but speed of two-way communication (eg, AMI or broadband) could be a limitation.

Summary:

SDP and other residential direct load control programs are among the more promising DR programs for supporting integration of renewables due to the lack of required advanced notification, the unlimited number of events that can be called year-round (limited only to 90 hours per year and 6 hours per event), and DLC's relatively fast speed of response to curtailment signals. Still unproven, however, is the ability of DLC to provide adequately precise curtailment (within the limits of permissa deviation from bid amount). There is potential to provide regulation up services, but the requirements for speed and frequency of response may limit its use for regulation.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Base Interruptible Program (BIP)***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves	● ◎ ○	● ◎ ○	< 1 min 1-10 min >10 min	● ◎ ○	● ◎ ○	< 10 min. 10-30 min >30 min	● ◎ ○	2 ● ◎ ○	>30 10-30 min < 10 min	● ◎ ○	● ◎ ○	>200 20-200 <20	● ◎ ○	● ◎ ○	As reliable as CT Likely can meet CAISO reqts Cannot meet CAISO reqts
Spinning Reserves	● ◎ ○	● ◎ ○	<1 min. 1-5 min. >5 min.	● ◎ ○	● ◎ ○	< 8 sec (10% load) <10 min >10 min	● ◎ ○	● ◎ ○	>30 10-30 min <10 min	● ◎ ○	● ◎ ○	>200 20-200 <20	● ◎ ○	● ◎ ○	As reliable as CT Likely can meet CAISO reqts Cannot meet CAISO reqts
Regulation	● ◎ ○	● ◎ ○	None n/a Any adv. notice	● ◎ ○	● ◎ ○	4-sec (AGC) n/a Non-AGC capable	● ◎ ○	● ◎ ○	60 min. or greater 30-60 min <30 min	● ◎ ○	● ◎ ○	Continuous Continuous Continuous	● ◎ ○	● ◎ ○	can meet w/ certainty can meet most of time can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
SR-Notice	Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
NR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load).
SR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load), but it is not clear whether a significant portion of load can respond within 8 seconds.
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >10 events/month, >180 hours/year), but would be a significant program change that could limit recruitment.
SR-Frequency	Program modifications to increase frequency of use are possible (e.g. >10 events/month, >180 hours/year), but would be a significant program change that could limit recruitment.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation; however, reaching the deviation limits within 10 minute windows could prove difficult to achieve.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation; however, reaching the deviation limits within 10 minute windows could prove difficult to achieve.

Summary:

Program could be adapated to provide ancillary services, but would require automation and a reduction in notification time (from the current 15 or 30 minutes). Speed of response may still be insufficient to provide spinning reserves, especially within the permissable range of deviation from schedule.

Note: Navigant recognizes that the CPUC has placed a "cap" on the combined capacity of BIP and other IOU DR reliability programs. The evaluation of the DR programs presented here assumes that any such a limitation would be removed, at the CPUC's discretion, if the program design changes that would be required for those programs to provide ancillary services were adopted.

NAVIGANT

DR Program Evaluation Criteria		
Symbol	Value	***Is program capable of exhibiting required attributes for a product?***
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Optional Binding Mandatory Curtailment Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves	●	**●**	< 1 min	●	**●**	< 10 min.	**●**	**●**	>30	●	●	>200	●	**●**	As reliable as CT
	◎	◎	1-10 min	**◎**	◎	10-30 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	**○**	**○**	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	**●**	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	●	>200	●	**●**	As reliable as CT
	◎	◎	1-5 min.	◎	**◎**	<10 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>5 min.	**○**	○	>10 min	○	○	<10 min	**○**	**○**	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
SR-Notice	Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
NR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load).
SR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load), but it is not clear whether a significant portion of load can respond within 8 seconds.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation; however, reaching the deviation limits within 10 minute windows could prove difficult to achieve.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation; however, reaching the deviation limits within 10 minute windows could prove difficult to achieve.

Summary:

Program is designed to be employed during rotating outages which occur on rare occasions. Increasing the requirements regarding advanced notice, speed of response, and frequency would render this program similar to a BIP program that was modified to provide AS. Given the nature of OBMC and the expectations of customers participating in it, the program is not a good candidate for modification.

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DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
o	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Agricultural and Pumping Interruptible Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	o	**o**	1-10 min	**o**	**o**	10-30 min	**o**	**o**	10-30 min	**o**	**o**	20-200	**o**	**o**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	o	**o**	1-5 min.	**o**	**o**	<10 min	**o**	**o**	10-30 min	**o**	**o**	20-200	**o**	**o**	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	o	**o**	n/a	**o**	**o**	n/a	**o**	**o**	30-60 min	**o**	**o**	Continuous	**o**	**o**	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
SR-Speed	Automated response to control signal already part of program; partial load response would be required within 8 seconds.
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >25 events/month, >150 hours/year), but would be a significant program change that could limit recruitment.
SR-Frequency	Program modifications to increase frequency of use are possible (e.g. >25 events/month, >150 hours/year), but would be a significant program change that could limit recruitment.

Summary:

Agricultural pumping loads are relatively well-suited to provide ancillary services since they are derived from a single end use--pump motors. The program requires no advanced notification, and curtailments are automated--thus, two of the more common obstacles for DR supporting renewables integration are already addressed under current program rules. Modifications likely would be required in communications, monitoring, and control technologies in order to ensure adqueate response time for spinning reserves and to maintain response MW within a permissable range. The program already allows for year-round curtailment 10 times per month and 180 times per year, but these elements may need to be expanded to fully accomodate grid management requirements.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◉	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Capacity Bidding Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	**●**	< 1 min	●	**●**	< 10 min.	**●**	**●**	>30	●	**●**	>200	●	●	As reliable as CT
	◉	◉	1-10 min	**◉**	◉	10-30 min	◉	◉	10-30 min	**◉**	◉	20-200	◉	**◉**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	**●**	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	**●**	>200	●	●	As reliable as CT
	◉	◉	1-5 min.	◉	**◉**	<10 min	◉	◉	10-30 min	**◉**	◉	20-200	◉	**◉**	Likely can meet CAISO reqts
	○	○	>5 min.	**○**	○	>10 min	○	○	<10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◉	◉	n/a	◉	◉	n/a	◉	◉	30-60 min	◉	◉	Continuous	◉	◉	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
SR-Notice	Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
NR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load).
SR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load), but it is not clear whether a significant portion of load can respond within 8 seconds.
NR-Frequency	Program modifications would be necessary to allow for more than one event per day; and desirable to make this a year-round program..
SR-Frequency	Program modifications would be necessary to allow for more than one event per day; and desirable to make this a year-round program..
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation; however, reaching the deviation limits within 10 minute windows could prove difficult to achieve.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation; however, reaching the deviation limits within 10 minute windows could prove difficult to achieve.

Summary:

Program could be adapated to provide ancillary services, but would require automation and a reduction in notification time (from the current 3 hours or day-ahead). Speed of response may still be insufficient to provide spinning reserves (especially within the permissable range of deviation from schedule), and the current limit of one event per day would need to be increased. Under present rules, capacity nominations can change each month, making the effective availability of the resource (in MW) uncertain for planning purposes.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
⭘	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Demand Bidding Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	⭘	⭘	1-10 min	⭘	⭘	10-30 min	⭘	⭘	10-30 min	⭘	⭘	20-200	⭘	⭘	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	⭘	⭘	1-5 min.	⭘	⭘	<10 min	⭘	⭘	10-30 min	⭘	⭘	20-200	⭘	⭘	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	⭘	⭘	n/a	⭘	⭘	n/a	⭘	⭘	30-60 min	⭘	⭘	Continuous	⭘	⭘	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation; however, reaching the deviation limits within 10 minute windows could prove difficult to achieve.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation; however, reaching the deviation limits within 10 minute windows could prove difficult to achieve.

Summary:

As a program where curtailments are voluntary, even for participants, and payments are for energy, not capacity, the DBP is not a good candidate for providing ancillary services. Program modifications could address specific areas where the program rules do not meet AS requirements; however, introducing these changes would fundamentally alter the nature of the program to the point that it would better resemble one of the other, existing programs, such as CBP or BIP.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Demand Response Contracts***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-10 min	◎	◎	10-30 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-5 min.	◎	◎	<10 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
All-Notice	Through use of automated response, demand response contracts could allow for notification of less than one minute, or even zero notification required for regulation services.
All-Speed	Through use of automated response, aggregators could construct a portfolio of customers that can provide near-instantaneous response and respond to AGC signals.
All-Frequency	Contract terms vary by aggregator and some terms are confidential; however, it is likely that contracts allow for sufficient frequency to provide some spinning and non-spinning reserves. For the right price, aggregators could construct a portofolio that can accommodate a sufficient number of events to provide ancillary services.
All-Frequency	Contract terms vary by aggregator and some terms are confidential; however, it is likely that contracts require aggregators to meet MW targets, subject to penalties. For the right price, aggregators could construct a portofolio that can be monitored and balanced to meet deviation requirements. Requirements for regulation would significantly limit the number and types of customers and loads that could particate.

Summary:

Contract terms vary by aggregator and some terms are confidential; however, it is likely that aggregator portfolios include a mix of customers and end uses such that a portion of them could meet some or all of the requirements for ancillary services. Auto-DR would be required, and contract terms would to be modified to specify minimum performance with regard to advanced notification, speed of response, frequency of response, and deviation. Demand response contracts, as a DR program category, is among the most flexible programs in terms of its ability to be modified to provide ancillary services. The open questions are cost and the amount of MW that can be provided for each AS product.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
○	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Real-Time Pricing***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								0							
	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	○	**○**	1-10 min	**○**	**○**	10-30 min	**○**	**○**	10-30 min	**○**	**○**	20-200	**○**	**○**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	○	**○**	1-5 min.	**○**	**○**	<10 min	**○**	**○**	10-30 min	**○**	**○**	20-200	**○**	**○**	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	○	**○**	n/a	**○**	**○**	n/a	**○**	**○**	30-60 min	**○**	**○**	Continuous	**○**	**○**	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program could be modified to provide active notification of prices when AS are needed. Response would require automation tied to pre-set price-response strategies. It is not clear whether pricing information could be provided with less than one minute notice.
SR-Notice	Program could be modified to provide active notification of prices when AS are needed. Response would require automation tied to pre-set price-response strategies. It is not clear whether pricing information could be provided with less than one minute notice.

Summary:

As a program where curtailments are voluntary, even for participants, and financial incentives are based on reductions in energy, not capacity, RTP is not a good candidate for providing ancillary services. Additionally, the nature of the program cannot accommodate "events" which are needed to provide AS for period specified by the CAISO. Modifications could also address specific areas where the program rules do not meet AS requirements; however, introducing these changes would fundamentally alter the nature of the program (namely the mandatory, rather than voluntary nature of the program) to the point that it would better resemble one of the other, existing programs, such as CBP or BIP.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
○	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Peak Time Rebate >200kW***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	○	**○**	1-10 min	**○**	**○**	10-30 min	**○**	**○**	10-30 min	**○**	**○**	20-200	**○**	**○**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	○	**○**	1-5 min.	**○**	**○**	<10 min	**○**	**○**	10-30 min	**○**	**○**	20-200	**○**	**○**	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	○	**○**	n/a	**○**	**○**	n/a	**○**	**○**	30-60 min	**○**	**○**	Continuous	**○**	**○**	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program could be modified to provide notice of a CPP event within one minute of the event start. However, to be effective in terms of the speed of response, this would require automated response from customers.
SR-Notice	Program could be modified to provide notice of a CPP event within one minute of the event start. However, to be effective in terms of the speed of response, this would require automated response from customers.
NR-Frequency	Current limit of 12 events per year could be increased, but likely not sufficiently to meet CAISO requirements.
SR-Frequency	Current limit of 12 events per year could be increased, but likely not sufficiently to meet CAISO requirements.

Summary:

As a program where curtailments are voluntary, even for participants, and financial incentives are based on reductions in energy, not capacity, CPP is not a good candidate for providing ancillary services. Program modifications could provide for automated response to CPP events, but this would convert the program into something resembling the DBP, but with variable incentives according to the number and duration of events. Additional modifications could also address specific areas where the program rules do not meet AS requirements; however, introducing these changes would fundamentally alter the nature of the program (namely the mandatory, rather than voluntary nature of the program) to the point that it would better resemble one of the other, existing programs, such as CBP or BIP.

NAVIGANT

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
o	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Peak Time Rebate <200kW***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	**●**	< 1 min	●	●	< 10 min.	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	o	o	1-10 min	o	o	10-30 min	o	o	10-30 min	o	**o**	20-200	o	o	Likely can meet CAISO reqts
	○	○	>10 min	**○**	**○**	>30 min	○	○	< 10 min	**○**	○	<20	**○**	**○**	Cannot meet CAISO reqts
Spinning Reserves	●	**●**	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	o	o	1-5 min.	o	o	<10 min	o	o	10-30 min	o	**o**	20-200	o	o	Likely can meet CAISO reqts
	○	○	>5 min.	**○**	**○**	>10 min	○	○	<10 min	**○**	○	<20	**○**	**○**	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	o	o	n/a	o	o	n/a	o	o	30-60 min	o	o	Continuous	o	o	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program could be modified to provide notice of a CPP event within one minute of the event start. However, to be effective in terms of the speed of response, this would require automated response from customers.
SR-Notice	Program could be modified to provide notice of a CPP event within one minute of the event start. However, to be effective in terms of the speed of response, this would require automated response from customers.
NR-Frequency	Current limit of 12 events per year could be increased, but likely not sufficiently to meet CAISO requirements.
SR-Frequency	Current limit of 12 events per year could be increased, but likely not sufficiently to meet CAISO requirements.

Summary:

As a program where curtailments are voluntary, even for participants, and financial incentives are based on reductions in energy, not capacity, RTP is not a good candidate for providing ancillary services. Program modifications could provide for automated response to RTP events, but this would convert the program into something resembling the SDP, but with variable incentives according to the number and duration of events. Additional modifications could also address specific areas where the program rules do not meet AS requirements; however, introducing these changes would fundamentally alter the nature of the program (namely the mandatory, rather than voluntary nature of the program).

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
○	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SCE***

Program Name ***Peak Time Rebate***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	○	**○**	1-10 min	**○**	**○**	10-30 min	**○**	**○**	10-30 min	**○**	**○**	20-200	**○**	**○**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	○	**○**	1-5 min.	**○**	**○**	<10 min	**○**	**○**	10-30 min	**○**	**○**	20-200	**○**	**○**	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	○	**○**	n/a	**○**	**○**	n/a	**○**	**○**	30-60 min	**○**	**○**	Continuous	**○**	**○**	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program could be modified to provide notice of a PTR event within one minute of the CPP pricing going into effect. However, to be effective in terms of the speed of response, this would require automated response from customers.
SR-Notice	Program could be modified to provide notice of a PTR event within one minute of the CPP pricing going into effect. However, to be effective in terms of the speed of response, this would require automated response from customers.

Summary:

As a program where curtailments are voluntary, even for participants, and financial incentives are based on reductions in energy, not capacity, PTR is not a good candidate for providing ancillary services. Program modifications could provide for automated response to PTR events, but this would convert the program into something resembling the SDP, but with variable incentives according to the number and duration of events. Additional modifications could also address specific areas where the program rules do not meet AS requirements; however, introducing these changes would fundamentally alter the nature of the program (namely the mandatory, rather than voluntary nature of the program).

E.3 San Diego Gas & Electric DR Program Evaluations

The methodology presented in Appendix F is used below to evaluate individual DR programs for potential to help integrate renewable energy. The following SDG&E DR programs are included in this subsection:

- CPP-E: Critical Peak Pricing-E
- CPP-D: Critical Peak Pricing-Default
- CBP: Capacity Bidding Program
- AMP: Aggregator Managed Program
- RBRP: Peak Generation
- BIP: Base Interruptable Program
- OBMP: Optional Binding Manditory Curtailment
- Summer Saver
- SLRP: Scheduled Load Reduction Program

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
o	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SDG&E***

Program Name ***CPP-E: Critical Peak Pricing-E***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	o	o	1-10 min	o	o	10-30 min	o	o	10-30 min	o	o	20-200	o	o	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	o	o	1-5 min.	o	o	<10 min	o	o	10-30 min	o	o	20-200	o	o	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	o	o	n/a	o	o	n/a	o	o	30-60 min	o	o	Continuous	o	o	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program could be modified for faster notice, possibly using technology assistance (e.g., AutoDR)
SR-Notice	Program could be modified for faster notice, possibly using technology assistance (e.g., AutoDR)
NR-Speed	Program could be modified for faster startup, possibly using technology assistance (e.g., AutoDR)
NR-Frequency	Program modifications to increase frequency of use are possible, but would be major program changes.
SR-Frequency	Program modifications to increase frequency of use are possible, but would be major program changes.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR), but still difficult to get to 3%.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR), but still difficult to get to 3%.

Summary:

Program could potentially be modified provide some Non-Spinning Reserve capabilities, and perhaps even Spinning Reserves (both for some fraction of the contracted load). However the program would need significant modifictions including the use of networked technology to send pricing and control signals, as well as changes to allow more freqent use and perhaps expand the seasonal availability.

NAVIGANT

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SDG&E***

Program Name ***CPP-D: Critical Peak Pricing-Default***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	**●**	< 1 min	●	●	< 10 min.	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-10 min	◎	**◎**	10-30 min	◎	◎	10-30 min	◎	**◎**	20-200	◎	**◎**	Likely can meet CAISO reqts
	○	○	>10 min	**○**	○	>30 min	○	○	< 10 min	**○**	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	**●**	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-5 min.	◎	◎	<10 min	◎	◎	10-30 min	◎	◎	20-200	◎	**◎**	Likely can meet CAISO reqts
	○	○	>5 min.	**○**	**○**	>10 min	○	○	<10 min	**○**	**○**	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Fast notice could be provided via automation
NR-Speed	Fast notice could be provided via automation
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >20 times/year), but would be major program change.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR), but still difficult to get to 3%.

Summary:

Program could potentially be modified provide some Non-Spinning Reserve capabilities, (perhaps for some fraction of the contracted load). However modifictions would be significant and would need to include the use of networked technology to send pricing and control signals, as well as changes to allow more freqent use and perhaps expand the seasonal availability.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
o	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SDG&E***

Program Name ***CBP: Capacity Bidding Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	o	**o**	1-10 min	**o**	**o**	10-30 min	**o**	**o**	10-30 min	**o**	**o**	20-200	**o**	**o**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	o	**o**	1-5 min.	**o**	**o**	<10 min	**o**	**o**	10-30 min	**o**	**o**	20-200	**o**	**o**	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	o	**o**	n/a	**o**	**o**	n/a	**o**	**o**	30-60 min	**o**	**o**	Continuous	**o**	**o**	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program could be modified so that day-ahead or day-of notice was used to put facility/load on notice that more granular control will be required during the event. This is a slight re-definition of "notice."
NR-Speed	Program might be modified for faster startup and more granular control, possibly using technology assistance (e.g., AutoDR) to control specific loads. Aggregator approach could be used for better, more granular control.
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >20 times/year), but could be a significant program change.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.

Summary:

Program could potentially be modified provide some Non-Spinning Reserve capabilities, (perhaps for some fraction of the contracted load). However modifictions would be significant and would need to include the use of networked technology to send pricing and control signals, as well as changes to allow more freqent use and perhaps expand the seasonal availability.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SDG&E***

Program Name ***AMP: Aggregator Managed Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-10 min	◎	◎	10-30 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-5 min.	◎	◎	<10 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Requirements could be modified to provide <1 minute notice, and aggregator would adjust appropriately to meet these requirements. New terms might be acceptable to only a portion of current program customers (customers on 30 minute notice), Modifications would have to work through Aggregators with different bi-lateral contract
SR-Notice	Requirements could be modified to provide <1 minute notice, and aggregator would adjust appropriately to meet these requirements. New terms might be acceptable to only a portion of current program customers (customers on 30 minute notice), Modifications would have to work through Aggregators with different bi-lateral contract
NR-Speed	Requirements could be modified to provide the necessary response time and service levels.
SR-Speed	Requirements could be modified to provide the necessary response time and service levels.
R-Speed	Requirements could be modified to provide the necessary response time and service levels.
NR-Frequency	Requirements could be modified to provide the necessary response time and service levels.
SR-Frequency	Requirements could be modified to provide the necessary response time and service levels.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.
R-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance. Something more advanced than AutoDR might be required in the short term. Aggregator approach could help balance diverse loads.

Summary:

The assumption here is that the AMP program is fundamenally set up as an aggregation program to meet whatever requirements SDG&E decides are important. This assumption implies that terms can be modified provide any of the services defined above. However modifictions would be significant and would need to include the use of networked technology to send pricing and control signals, as well as changes to allow more freqent use and perhaps expand the seasonal availability. Details would have to be worked through bi-lateral contract negotiations with Aggregators.

NAVIGANT

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SDG&E***

Program Name ***RBRP: Peak Generation***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
Non-Spinning Reserves								2							
	●	●	< 1 min	●	●	< 10 min.	●	●	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-10 min	◎	◎	10-30 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	●	●	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-5 min.	◎	◎	<10 min	◎	◎	10-30 min	◎	◎	20-200	◎	◎	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	○	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	●	●	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	○	Any adv. notice	○	○	Non-AGC capable	○	○	<30 min	○	○	Continuous	○	○	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:

NR-Notice	Program could be modified to provide very fast notice. This would likely require some form of automation.
SR-Notice	Program could be modified to provide sub 15 minute notice. This would likely require some form of automation.
NR-Speed	Program might be modified for faster startup and more granular control, possibly using technology assistance (e.g., AutoDR) to control specific loads.
SR-Speed	Program might be modified for faster startup and more granular control, possibly using technology assistance (e.g., AutoDR) to control specific loads.
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >75 hours/year), but could be a significant program change.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.

Summary:

Program could potentially be modified provide some Non-Spinning and potentially Spinning Reserve capabilities (perhaps for some fraction of the contracted load). However modifictions would be significant and would need to include the use of networked technology to send control signals, as well as changes to allow more freqent use.

NAVIGANT

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SDG&E***

Program Name ***BIP: Base Interruptable Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	**●**	< 1 min	●	**●**	< 10 min.	**●**	**●**	>30	●	**●**	>200	●	●	As reliable as CT
	◎	◎	1-10 min	**◎**	◎	10-30 min	◎	◎	10-30 min	**◎**	◎	20-200	◎	**◎**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	**●**	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	**●**	>200	●	●	As reliable as CT
	◎	◎	1-5 min.	◎	**◎**	<10 min	◎	◎	10-30 min	**◎**	◎	20-200	◎	**◎**	Likely can meet CAISO reqts
	○	○	>5 min.	**○**	○	>10 min	○	○	<10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Program could be modified to provide sub 1 minute notice. This would likely require some form of automation.
SR-Notice	Program could be modified to provide sub 1 minute notice. This would likely require some form of automation.
NR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load).
SR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load), but it's not clear that a signficant portion of the load could respond w/in 8 seconds.
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >120 hours/year), but could be a significant program change.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.

Summary:

Program could be modified provide some Non-Spinning and potentially Spinning Reserve capabilities (perhaps for some fraction of the contracted load). However modifictions would be significant and would need to include the use of networked technology to send control signals, as well as changes to allow more freqent use.

Note: Navigant recognizes that the CPUC has placed a "cap" on the combined capacity of BIP and other IOU DR reliability programs. The evaluation of the DR programs presented here assumes that any such a limitation would be removed, at the CPUC's discretion, if the program design changes that would be required for those programs to provide ancillary services were adopted.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SDG&E***

Program Name ***OBMP: Optional Binding Manditory Curtailment***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	**●**	< 1 min	●	**●**	< 10 min.	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-10 min	**◎**	◎	10-30 min	◎	◎	10-30 min	◎	**◎**	20-200	◎	**◎**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	**○**	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	**●**	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	●	>200	●	●	As reliable as CT
	◎	◎	1-5 min.	◎	**◎**	<10 min	◎	◎	10-30 min	◎	**◎**	20-200	◎	**◎**	Likely can meet CAISO reqts
	○	○	>5 min.	**○**	○	>10 min	○	○	<10 min	**○**	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Notice	Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
SR-Notice	Might be modified to provide <1 minute notice, but this would require automation, and would probably be acceptable to only a portion of program customers
NR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load).
SR-Speed	Program would have to be modifed with automation to accept a control signal. It might then provide <10 minute response (for some participating load), but it is not clear whether a significant portion of load can respond within 8 seconds.
NR-Frequency	Program modifications to increase frequency of use are possible but since the program is designed to be used only for rotating outages, this would fundamentally alter the program.
SR-Frequency	Program modifications to increase frequency of use are possible but since the program is designed to be used only for rotating outages, this would fundamentally alter the program.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation; however, reaching the deviation limits within 10 minute windows could prove difficult to achieve.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance /automation; however, reaching the deviation limits within 10 minute windows could prove difficult to achieve.

Summary:

Program is designed to be employed during rotating outages which occur on rare occasions. Increasing the requirements regarding advanced notice, speed of response, and frequency would render this program similar to a BIP program that was modified to provide AS. Given the nature of OBMC and the expectations of customers participating in it, the program is not a good candidate for modification.

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◎	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility ***SDG&E***

Program Name ***Summer Saver***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	**●**	**●**	< 1 min	●	**●**	< 10 min.	**●**	**●**	>30	●	**●**	>200	●	●	As reliable as CT
	◎	◎	1-10 min	**◎**	◎	10-30 min	◎	◎	10-30 min	**◎**	◎	20-200	◎	**◎**	Likely can meet CAISO reqts
	○	○	>10 min	○	○	>30 min	○	○	< 10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	**●**	**●**	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	●	**●**	>200	●	●	As reliable as CT
	◎	◎	1-5 min.	**◎**	**◎**	<10 min	◎	◎	10-30 min	**◎**	◎	20-200	◎	**◎**	Likely can meet CAISO reqts
	○	○	>5 min.	○	○	>10 min	○	○	<10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	**●**	**●**	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	●	●	Continuous	●	●	can meet w/ certainty
	◎	◎	n/a	◎	◎	n/a	◎	◎	30-60 min	◎	◎	Continuous	◎	◎	can meet most of time
	○	○	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	**○**	**○**	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:	
NR-Speed	Program might be modified for faster startup and more granular control, possibly using technology assistance (e.g., SEP 2.0?) to control individual loads.
NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.
NR-Frequency	Program modifications to increase frequency of use are possible (e.g. >120 hours/year), but could be a significant program change.
SR-Frequency	Program modifications to increase frequency of use are possible (e.g. >120 hours/year), but could be a significant program change.
SR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR and head-end algorithms). Aggregator approach could help balance diverse loads.

Summary:

Program could be modified provide some Non-Spinning and potentially Spinning Reserve capabilities (perhaps for some fraction of the contracted load). However modifictions would be significant and would need to include the use of networked technology to send control signals, as well as changes to allow more freqent use.

NAVIGANT

DR Program Evaluation Criteria		
Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◉	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

Utility **SDG&E**

Program Name ***SLRP: Scheduled Load Reduction Program***

	Notice			Speed			Duration			Frequency			Deviation		
	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria	As-Is	Mod	Criteria
								2							
Non-Spinning Reserves	●	●	< 1 min	●	●	< 10 min.	**●**	**●**	>30	**●**	**●**	>200	●	●	As reliable as CT
	◉	◉	1-10 min	◉	◉	10-30 min	◉	◉	10-30 min	◉	◉	20-200	◉	**◉**	Likely can meet CAISO reqts
	○	**○**	>10 min	**○**	**○**	>30 min	○	○	< 10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Spinning Reserves	●	●	<1 min.	●	●	< 8 sec (10% load)	**●**	**●**	>30	**●**	**●**	>200	●	●	As reliable as CT
	◉	◉	1-5 min.	◉	◉	<10 min	◉	◉	10-30 min	◉	◉	20-200	◉	**◉**	Likely can meet CAISO reqts
	○	**○**	>5 min.	**○**	**○**	>10 min	○	○	<10 min	○	○	<20	**○**	○	Cannot meet CAISO reqts
Regulation	●	●	None	●	●	4-sec (AGC)	**●**	**●**	60 min. or greater	**●**	**●**	Continuous	●	●	can meet w/ certainty
	◉	◉	n/a	◉	◉	n/a	◉	◉	30-60 min	◉	◉	Continuous	◉	◉	can meet most of time
	○	**○**	Any adv. notice	**○**	**○**	Non-AGC capable	○	○	<30 min	○	○	Continuous	**○**	**○**	can meet some of time

Deviation Requirement: The requirement for permissible deviation from schedule is 5 MW or 3% of maximum output, whichever is higher (See Table F 2 for more detail).

This assessment assumes that existing DR programs cannot provide regulation down services. Chapter 6 discusses in more detail.

Notes:

NR-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR), but still difficult to get to 3%.
NS-Deviation	Deviation could be controlled more accurately and with greater time precision with use of technology assistance (e.g., AutoDR), but still difficult to get to 3%.

Summary:

Pre-scheduling would make it very difficult/ impossible for this program to be used for reserves or regulation.

Appendix F. Demand Response Program Assessment Methodology

This Appendix summarizes the methodology that was used to assess the potential for using California IOU DR programs for renewable energy integration. The results of that analysis are summarized in Section 5 of this white paper.

As previously noted, Navigant evaluated each program for how compatible its rules and attributes are with the requirements of the CAISO's existing ancillary services products that support grid management — in particular non-spinning reserves, spinning reserves, and regulation up services.[147]

While there may be additional requirements beyond the five technical categories presented here (e.g., the need for telemetry to enable near-instantaneous two-way communications), this evaluation broadly identifies those programs most likely to be capable of supporting renewables integration. The assessment borrows from the findings presented in the overarching issues described above, which characterize program attributes that either enable or limit DR's use as non-spinning and spinning reserves and as a regulation resource. It then matches program-specific rules and attributes with the CAISO requirements to assess whether, with regard to a single criterion, a program currently meets the requirement or could reasonably be modified to meet the requirement.

Navigant began with the full portfolio of programs from the three IOUs (Section 4.4.1, Section 0, and Section 4.4.3), and compared program rules and attributes to the CAISO requirements for the three ancillary services products used for the integration of variable renewable energy. For each product, the comparison assigned a rating to each of five attributes:

- **Advanced notice of deployment (Notice) –** the amount of time between when a customer is informed of an event and when they are required to begin curtailing load (no advanced notice for ancillary services)
- **Speed of response to control signal (Speed) –** the amount of time between when a load curtailment or ancillary service request signal is sent and when the MW must be delivered
- **Duration of response (Duration) –** the amount of time that that MW must be provided for each event
- **Frequency of response (Frequency) –** the number of times per day or per year that the MW must be provided
- **Permissible deviation (Deviation) –** the maximum variation from scheduled MW that is acceptable under CAISO rules

[147] These requirements are presented in Figure 3-18. One additional criterion used in the assessment of spinning reserves is the CAISO's requirement that a resource be capable of providing 10 percent of it spinning capacity within 8 seconds. Source: CAISO. *California Independent System Operator Corporation Fifth Replacement FERC Electric Tariff.* April 1, 2011, http://www.caiso.com/Documents/CombinedPDFDocument-FifthReplacementCAISOTariff.pdf.

The ratings were on a 3-point scale representing whether a DR resource 1) *meets CAISO requirements* for the ancillary services product in question, denoted symbolically by a filled-in circle, 2) partially or nearly meets CAISO requirements (or some load in the program likely meets the requirements), denoted by a partially filled-in circle, or 3) does not meet CAISO requirements. Ordinal scores were also assigned to facilitate quantification of ratings across the portfolio, with a "2" representing "meets requirements", a "1" indicating partially meeting requirements, and a "0" indicating failure to meet requirements (Figure F-1).

Figure F-1: DR Program Evaluation Criteria for Meeting Ancillary Services Requirements

Symbol	Value	*Is program capable of exhibiting required attributes for a product?*
●	2	Program criteria meet CAISO product requirements.
◉	1	Program criteria partially or nearly meet CAISO product requirements, but may be able to provide some service (e.g., some participating load may meet requirements).
○	0	Program criteria do NOT meet CAISO product requirements.

The required characteristics for each of the three ancillary services products and each of the five program/product attributes are presented in Figure F-2. For example, if a DR program provides for a 30 minute advanced notification of an event, then it would be scored as a zero (○) for the Notice attribute for non-spinning reserves, since advanced notification must be less than one minute (see top-left set of criteria in the table). Similarly, if a program requires automated response, such as residential DLC programs, then it would be scored as a "2" (●) for the Speed attribute for non-spinning reserves, since the program can provide response in less than 10 minutes (see criteria in the Non-Spinning Reserves row under Speed of Response to Control Signal).

Figure F-2: Program Attribute Values for Rating Compliance with CAISO Requirements

	Advance Notice of Deployment (Notice)		Speed of Response to Control Signal (Speed)		Duration of Response (Duration)		Frequency of Response (Frequency)		Permissable Deviation* (Deviation)	
Non-Spinning Reserves	●	< 1 min	●	< 10 min.	●	>30	●	>200	●	Expected to meet criteria
	◉	1-10 min	◉	10-30 min	◉	10-30 min	◉	20-200	◉	Likely could meet criteria
	○	>10 min	○	>30 min	○	< 10 min	○	<20	○	Unlikely to meet criteria
Spinning Reserves	●	<1 min.	●	< 8 sec (10% load)	●	>30	●	>200	●	Expected to meet criteria
	◉	1-5 min.	◉	<10 min	◉	10-30 min	◉	20-200	◉	Likely could meet criteria
	○	>5 min.	○	>10 min	○	<10 min	○	<20	○	Unlikely to meet criteria
Regulation Up**	●	None	●	4-sec (AGC)	●	greater	●	continuous	●	Expected to meet criteria
	◉	n/a	◉	n/a	◉	30-60 min	◉	continuous	◉	Likely could meet criteria
	○	Any advanced notice	○	Non-AGC capable	○	<30 min	○	continuous	○	Unlikely to meet criteria

* The requirement for permissible deviation from schedule is 5 MW or 3 percent of maximum output, whichever is higher. DR programs do not specify permissible deviation and there is little data available to definitively conclude whether a given program would be able to achieve the requirements for maximum permissible deviation. In assessing the likelihood that a program can meet the requirements of this attribute, this white paper considers the required speed of response and the technologies deployed.

** This assessment assumes that existing DR programs cannot provide regulation-down services. The discussion of new and modified programs in Chapter 6 discusses the potential for DR to provide both types of regulation services.

Source: Navigant and CAISO

In some cases, the assignment of a rating required some subjectivity, such as for the Frequency attribute. A program that can only provide 10 events per month, or only for summer months, can still support renewables integration. However, it will have to be part of a portfolio that can meet CAISO needs continuously and throughout the year. In these cases, a program was typically assigned a rating of "2" (●).

Programs were also assessed for the degree to which they could reasonably be modified without changing the fundamental nature of the programs. For example, the Capacity Bidding Programs could not be changed to a notification time of just a few minutes, since this would not be compatible with the idea of advanced bidding. Automated response was a common program modification considered in the analysis. Based on the programs as modified, Navigant re-rated the programs as described above.

The assessment aggregated ratings by ancillary services product type, program attribute, and utility — both for programs as they currently exist and as modified through the assessment. The results of this analysis are presented Section 5, with program-specific details in Appendix E.