COM/MF1/ar9 **Date of Issuance 11/30/2015**

Decision 15-11-042 November 19, 2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011 (Filed September 19, 2013)

DECISION ADDRESSING THE VALUATION OF LOAD MODIFYING DEMAND RESPONSE AND DEMAND RESPONSE COST-EFFECTIVENESS PROTOCOLS

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DECISION ADDRESSING THE VALUATION OF LOAD MODIFYING DEMAND RESPONSE AND DEMAND RESPONSE COST-EFFECTIVENESS PROTOCOLS

Summary

In this Decision we solidify the Commission's commitment to the integration of demand response resources into the California Independent System Operator (CAISO) market. To support that objective, we approve several aspects of a revised version of the demand response cost-effectiveness protocols and change our treatment of certain event-based demand response programs unless and until they are integrated into the CAISO market or can be embedded or integrated into the California Energy Commission's long-term forecast.

We adopt the 2015 Cost-Effectiveness Protocols attached in Appendix A to be used to measure the cost-effectiveness of demand response programs in future demand response program applications, beginning with the 2018 demand response program year. Additional work is necessary in order to complete the revisions. Hence workshops are ordered to complete the revisions. Because of the overlap between this proceeding and the Integrated Distributed Energy Resources proceeding (Rulemaking 14-10-003) we defer the review of certain aspects of the Protocols to that proceeding.

This proceeding remains open to finalize the cost-effectiveness protocols, a Phase Two issue, and to address the remaining Phase Three issues.

1. Background

1.1. Commission Policy on Demand Response Integration

The Commission initiated a discussion of demand response integration into the California Independent System Operator (CAISO) energy market in 2008. We present a brief overview of demand response integration and bifurcation decisions to validate that the Commission overwhelmingly supports the integration of demand response into the CAISO market and has never wavered in that support.

Following the 2008 Federal Energy Regulatory Commission (FERC) requirement to allow demand response to be bid into the CAISO market,[1] the Commission began working with the CAISO to expand the role of demand response in the market and to broaden the opportunities for demand response in California. As such, a Guidance Ruling issued in Application (A.) 08-06-001 et al. required Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (jointly, The Utilities) to submit plans outlining strategies on integrating demand response retail programs with the proposed CAISO market.[2] In Decision (D.) 08-12-038, the Commission authorized four pilots to enable the utilities to take existing retail demand response resources and dispatch these resources in the market.[3] The Commission expected "much to be learned through these pilots to further shape the [U]tilities' plans to integrate their programs with the CAISO's new market."[4] In D.09-08-027, the Commission concluded that "a gradual transition of some programs from Non-Participating Load to Proxy Demand Resource and a few ultimately to Participating Load, as outlined by the [U]tilities, is reasonable."

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[1] In 2008, the FERC issued Order 719 requiring Independent System Operators such as the CAISO to revise their tariffs to create direct bid-in opportunities for retail demand response providers, including retail customers and demand response providers.

[2] A.08-06-001 et al, Guidance Ruling, February 27, 2008.

[3] D.08-12-038 authorized bridge funding for the demand response programs.

[4] D.09-08-027 at 122.

In November 2009, the Commission revised the scoping memo in Rulemaking (R.) 07-01-041 to specifically address the legal, policy, and technical issues related to the expansion of demand response bidding into the CAISO market.[5] Through R.07-01-041, the Commission adopted the initial policies governing direct bidding, authorized the Utilities to bid into the CAISO market, confirmed jurisdictional oversight over all demand response providers serving Commission-regulated utilities' bundled customers, and established policies regarding several aspects of the now-final direct participation rule.

In D.12-04-045,[6] the Commission discussed the forward-looking issue of integration with CAISO markets, noting that a deliberative approach to integration could also provide the Commission with the time to consider the different approaches. In 2013, the Commission initiated R.13-09-011 to enhance the role of demand response in meeting the state's resource planning needs and operational requirements. In the order initiating this proceeding, the Commission stated its intention to prioritize demand response as a resource competitively bid into the CAISO wholesale electricity market. One of the five purposes of the proceeding included the creation of an appropriate competitive procurement mechanism for supply-side demand response resources.

In D.14-03-026, the Commission conceptually bifurcated the demand response portfolio into load modifying and supply resources for the purposes of studying the two categories. The Commission set out to study the two resources in order to improve the efficiency of demand response. In June 2014, the

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5 R.07-01-041, Revised Scoping Memo, November 9, 2009 at 8.

6 D.12-04-45 adopted budgets and activities for the Utilities' 2012-2014 demand response portfolios.

Administrative Law Judge (ALJ) held a series of workshops to study and better understand both load modifying and supply demand response resources. These workshops led to settlement discussions and a joint party proposal.

D.14-12-024 adopted a modified proposal and established several working groups, proposed to look at 1) the integration issues of supply resources; 2) the valuation of both event and non-event load modifying resources; and 3) the operational issues of integrating load modifying resources into the CAISO operations. In D.14-12-024, the Commission clearly stated that while we acknowledge the technical complexities of demand response integration into the CAISO market, the Commission must "remain vigilant in moving forward in a reasonable pace but without unnecessary delay."[7] Hence, D.14-12-024 tightened deadlines to produce working group products on a faster pace than requested by the parties.

This abbreviated summary of nearly eight years of Commission actions supporting the integration of demand response into CAISO markets serves as the backdrop of today's decision.

1.2. Demand Response Cost-Effectiveness Protocols

In December 2010, the Commission approved D.10-12-024, which adopted protocols for estimating the cost-effectiveness of demand response activities (Protocols) and required the Utilities to use the Protocols for all future cost-effectiveness analyses of demand response activities.

A.11-03-001 et al. was the first time the Commission utilized the Protocols to determine the cost-effectiveness of demand response programs. D.12-04-045,

[7] D.14-12-024 at 15.

which approved demand response programs for 2012-2014, found three inconsistencies and omissions amongst the Utilities in using the Protocols: 1) inconsistent and speculative results in determining the five factors for adjusting a demand response program's avoided costs; 2) an inconsistent approach amongst the Utilities for allocating the budgets of supporting programs (*e.g*., marketing, education and training); and 3) the omission by the Utilities of any qualitative analysis of "optional" costs and benefits as directed by D.10-12-024. D.12-04-045 required staff to hold one or more workshops to address these issues.[8] The Ruling and Scoping Memo for R.13-09-011 included a revision of the demand response cost-effectiveness protocols to correct the inconsistencies as one of the foundational issues to be determined in Phase Two of the proceeding.

As previously stated, in August 2014, most of the parties to this proceeding filed a joint party settlement addressing many aspects of the proceeding. D.14-12-024—as modified by D.15-02-007—approved a majority of the joint party proposal and included the establishment of several working groups to develop solutions for enhancing the role of demand response in meeting California's electric resource needs. One of the working groups, the Load Modifying Resource Demand Response Valuation Working Group (Valuation Working Group) was tasked with recommending how load modifying resources should be valued after 2018. The Valuation Working Group also looked to inform quantification of demand response values for the Protocols.[9]

[8] D.12-04-045 at Ordering Paragraph (OP) 7.

[9] D.14-12-024 at Appendix 1, Attachment B, p 1.

With respect to the Protocols, the Valuation Working Group was to recommend how the load modifying resources will be valued for setting and informing demand response cost-effectiveness determination. Specifically, the working group looked at informing the quantification of demand response values for the cost-effectiveness protocols. D.14-12-024 required the Valuation Working Group to file its recommendations to the Commission on May 1, 2015.

On June 19, 2015, a Ruling was issued addressing 1) proposed changes to the Protocols and 2) the report from the Valuation Working Group. The Ruling summarized staff-proposed changes to the Protocols and the revisions from the Valuation Working Group compliance report. The Utilities were directed and parties were invited to file comments on the proposed revisions to the Protocols and to respond to specific questions on the Protocols and the Valuation Working Group report. Comments and responses were filed on July 31, 2015 and replies were filed on August 14, 2015.

2. Valuation Working Group Recommendations

On May 1, 2015, the Valuation Working Group filed its report in compliance with D.14-12-024, Ordering Paragraph 4.f.ii (Report). The Report describes recommendations that directly relate to the Protocols and others that are not related. We address both of these categories.

In summary, the recommendations to be reviewed in this decision include:

- Whether and how to establish hard triggers for the dispatch of demand response programs not integrated into the wholesale market (event-based Load Modifying Resources);
- Whether and how to establish a nomination and penalty framework through which Utilities would avoid costs through reducing effected metrics; and
- Enhancements to the demand response load impact protocols.

2.1. Working Group Hard Trigger Proposal

The Valuation Working Group set out to develop a method wherein event-based load modifying resource demand response could continue to receive system capacity value in the resource adequacy, long term procurement plan, and transmission planning processes. Event-based resources are those resources that are dispatched when a condition or trigger is met; triggers can be based on temperature, price, or an emergency, *i.e.*, capacity bidding program. Non-event-based resources do not have a trigger and occur either 24 hours a day or during a specific time of day, *i.e.* time variant pricing.

The participants of the Valuation Working Group agreed that the key requirement for load modifying demand response to be reliably valued as a system level resource is that it can be dispatched predictably in a way to reasonably avoid capacity needs. The working group also agreed that, for event-based load modifying demand response, appropriately designed hard triggers would assure the CAISO that the resource will be dispatched when pre-defined system conditions are met. The working group did not come to a consensus on how hard triggers would be set for system resource adequacy or how event-based load modifiers should be incorporated into a resource adequacy or long term procurement process. Portions of the working group recommended that the Commission continue to explore the establishment of a hard trigger through a study. Additionally, members of the working group also agreed that non-event-based load modifiers should continue to be embedded in the California Energy Commission's unmanaged/base case load forecasts.

The CAISO offered the sole distinct proposal for setting hard triggers, which became the focus of the June 19, 2015 Ruling and party comments. The CAISO hard trigger proposal recommends that in order to achieve avoided cost value, load serving entities should dispatch a pre-nominated amount of load modifying demand response when the metric that affects that particular avoided cost is forecast to reach the level that set the infrastructure investment or procurement need in the first instance. In this way, the load modifying resource would reduce the load serving entities' long term procurement and resource adequacy obligations by the nominated amount while ensuring that actual dispatch of the resource reflected the nomination. The CAISO suggests this is necessary to satisfy the loading order by demonstrably avoiding the need to build non-renewable and non-preferred resources while maintaining reliability.

The CAISO proposal provided the following example: if the resource adequacy requirement in July is set on a California Energy Commission (CEC) short-term forecast of 46,466 Megawatts (MW), the load serving entity would trigger its nominated amount of load modifying demand response during the hours when the CAISO's day-ahead load forecast is greater than or equal to 46,466 MW in July of that resource adequacy compliance year. According to the proposal, having been reliably triggered, the nominated amount of demand response would thereby reduce the need for conventional generation otherwise needed.

The CAISO proposal provided the three avoided capacity costs and the corresponding affected metric and the source of the hard trigger (*See* Table 1). Each metric reflects a distinct resource category: short term resource adequacy, long term avoided capacity, and flexible capacity. Under the CAISO proposal utilities would be allowed to pre-nominate event based demand response resources to reduce the associated procurement obligation.

TABLE 1 Hard Trigger Metrics	
Avoided Cost Value Stream	**Affected Metric/Hard Trigger**
Short-term Avoided System Generation Capacity	Monthly System Coincident Peak Demand (Source: CEC[10] short-term Resource Adequacy Forecast)
Long-term Avoided System Generation Capacity	System Annual Coincident Peak Demand (Source: CEC IEPR CED Forecast)
Avoided Flexible Generation Capacity	Maximum Monthly 3-hour Net Load Ramp (Source: ISO Flexible Capacity Technical Analysis)

In defense of its hard trigger proposal, the CAISO states that the Commission should evaluate any hard trigger proposal based on the proposal's ability to cost-effectively fulfill the loading order and help California achieve its long term energy goals.[11] The CAISO contends that regardless of whether the demand response is a load modifying resource or a supply resource, all demand response must satisfy the loading order by demonstrably avoiding the need to build non-renewable and non-preferred resources while maintaining reliability. The CAISO cautions against adopting a proposal that spurs significant customer interest and growth in demand response but does not avoid the need to build new conventional capacity. Instead, the CAISO asserts that the Commission should adopt a proposal that demonstrably avoids the need to build new conventional capacity, even if that proposal may cause a marginal decrease in customer interest and participation.

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[10] CEC is the acronym for the California Energy Commission.

[11] CAISO Opening Comments at 2.

The CAISO claims that its hard trigger proposal meets these requirements by lowering the CEC load forecasts, which are the basis for setting resource adequacy and long-term capacity needs. The CAISO adds that its proposal improves transparency and minimizes guesswork by requiring capacity quantities be pre-nominated and dispatched under pre-defined hard triggers. Additionally, the CAISO contends that its proposal creates certainty for CAISO operators in determining when and if load modifying resources will be dispatched in such circumstances.

2.1.1. Party Positions

Most parties find problems with the CAISO hard trigger proposal to varying degrees. The main concern is that the CAISO proposal would result in no dispatches in August and few-to-zero dispatches in July when prices are high and capacity needs are most urgent possibly leading to increases in future fossil-fueled procurement.[12] The proposal also yields a significant number of dispatches in the shoulder months of February, April, May, June, September and October when the likelihood of system peak is low.[13] Furthermore, parties point out that increases in dispatches during these months could lead to a decrease in motivation to enroll in demand response if capacity values are based on moderate loads[14] and, more importantly, could further exacerbate renewable over-generation problems because some of these months are sunnier months without high peak expectations.[15] PG&E believes the CAISO proposal is

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[12] TURN Opening Comments at 7-12 and PG&E Opening Comments at 2.

[13] TURN Opening Comments at 7-12 and PG&E Opening Comments at 27.

[14] PG&E Opening Commission at 27.

[15] TURN Opening Comments at 7-12 and PG&E Opening Comments at 2.

impractical and states that the increased shoulder month dispatches could create customer confusion because dispatches would occur during times when temperatures and system loads are moderate.[16]

The Office of Ratepayer Advocates (ORA) supports the CAISO hard trigger proposal despite the increased shoulder month dispatches, stating that the increase in confidence by CAISO would result in fewer responsibilities to meet resources adequacy and long term procurement plan obligations by the Utilities. ORA contends that there is no need to increase dispatches during July and August because it would not further contribute to the avoidance of procurement. ORA argues that the intent of the CAISO proposal is to decrease the supply the utilities need to procure by decreasing the need for short term and long term avoided system generation capacity and flexible capacity.[17]

The Utility Reform Network (TURN) also supports the CAISO proposal, but with changes. TURN suggests limiting the implementation of the program to summer months and making the trigger more stringent but equal to the load minus four percent.[18] PG&E contends that with various sensitivity analyses, the results are bias to increases in shoulder month dispatches leading to economic inefficiency.[19]

In addition to the concerns regarding the number and timing of dispatches, parties also have concerns regarding the fairness of CAISO's proposed nomination and penalty framework. In the Valuation Working Group

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[16] PG&E Opening Comments at 31.

[17] ORA Opening Comments at 20-21.

[18] TURN Opening Comments at 7-12.

[19] PG&E Opening Comments at 43.

report, CAISO suggests that the load serving entity or demand response provider that nominated the load modifying resource be assessed a penalty if its performance or delivery is less than it nominated. CAISO compares this penalty to that of the penalty in aggregator managed portfolio contracts and suggests that the load serving entity would contract with the provider to provide capacity and the provider would manage the delivery risk associated with that capacity. Hence, CAISO alleges that the provider could pass the risk onto its customers, or manage the risk by the number of customers it enrolls and operates.[20] The CAISO stated that the Commission should evaluate and apply penalties similar to those applicable to similarly purposed resources.[21]

SCE contends that "imposing penalties on demand response when similar penalties are not imposed on resources lower in the Loading Order is contrary to state policy."[22] Furthermore, SCE and PG&E argue that demand response already has a mechanism in place to devalue resources performing below expectations: load impact and ex ante calculations diminish future resource adequacy value for under performance.[23] PG&E adds that "layering on new penalties is not justified and would only serve to discourage participation."[24] The Joint Demand Response Parties also argue against the CAISO proposed penalty structure stating that "the only penalties that are assessed by CAISO for under deliveries of energy is for make-up energy and the CAISO has not demonstrated

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[20] Valuation Working Group Report at 116.

[21] CAISO Opening Comments at 11.

[22] SCE Opening Comments at 17.

[23] SCE Opening Comments at 17-18 and PG&E Opening Comments at 32.

[24] PG&E Opening Comments at 32.

that under-deliveries of load modifying resources impose any more costs on the system as other resources."[25]

PG&E recommends the Commission deny adoption of the CAISO proposal and, furthermore, suggests the Commission "refrain from using any hard triggers."[26] PG&E asserts that the current soft triggers and reliability triggers provide appropriate use of resources.[27]

Lastly, SCE contends that CAISO's hard trigger proposal creates a structural imbalance where load modifying demand response is unlikely to be valued as high as an integrated resource. SCE argues this is in conflict with D.14-12-024, which, according to SCE, requires that neither load modifying or supply resources receive an unfair advantage through favorable valuation.[28] Instead, SCE argues for the adoption of a hard trigger that includes the following criteria: a) the exclusion of event-based reliability programs; b) a proposal to address the partial integration of programs; 3) limitations on dispatches; and 4) the assurance that dispatches should not conflict with the current parameters of programs.[29] SDG&E adds that hard triggers should also decrease loads in correlation with prices. If these criteria cannot be met, SDG&E joins with PG&E in recommending that the Commission forego the adoption of hard triggers for soft triggers but ensure that the triggers are not applied to the portions of demand response programs not integrated into the market.

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[25] Joint Demand Response Parties Opening Comments at 33.

[26] PG&E Opening Comments at 49.

[27] PG&E Opening Comments at 2.

[28] *Id*. at 8.

[29] SCE Opening Comments at 8-9.

2.1.2. Discussion

As described below, the Commission declines to: 1) adopt the CAISO's hard trigger proposal or any hard trigger proposal for event-based load modifying demand response resources; 2) continue the use of the soft triggers as recommended by the Utilities for these resources; and 3) approve the request to embark on a study of how to establish hard triggers for these resources. All demand response resources must be able to demonstrate their ability to avoid building non-renewable and non-preferred resources while maintaining reliability. At this time, the Commission has no such demonstration mechanism for event-based load modifying resources and therefore has no way to measure the ability of these resources to avoid building non-renewable and non-preferred resources while maintaining reliability. Therefore, as explained further below, unless and until a mechanism is developed, we conclude that event-based load modifying resources have no measureable capacity value.

The Commission finds the CAISO hard trigger proposal to be suboptimal in that it may lead to an increase in the number of dispatches during times when a) customers are not anticipating being dispatched; b) capacity needs may not be high; c) capacity values are based on moderate loads; d) over generation problems already exist; and e) energy prices are lower. All of these could culminate in the inability to cost-effectively fulfill the loading order or help the state achieve its long term energy goals. Moreover, we note that balancing these interests is in part the purpose of the CAISO markets and a fundamental reason the Commission has favored the integration of demand response resources into CAISO markets. Rather than create a parallel regulatory structure for the valuation of non-integrated demand response programs, the Commission will focus on reducing the barriers to entry for demand response to participate in the CAISO market.

The Commission also finds the CAISO proposal also lacks essential detail as to how nominations and penalties associated with the hard triggers would be implemented. Furthermore, the Commission questions whether the proposed penalty structure is fair or even necessary. These are critical elements and would require considerable time and energy to refine. Furthermore, we acknowledge that the entities to which this regime would apply, the Utilities, are fundamentally opposed to it, assuring implementation and oversight challenges. Between the suboptimal dispatch concerns and the need for additional development of nomination and penalty regulations, we find the CAISO proposal to be overly burdensome and potentially ineffective.

In consideration of the potential benefits of the CAISO proposal, the Commission finds them to be limited as the CAISO proposal, or any hard trigger proposal, would only apply to a small portion of California's demand response portfolio. Pursuant to D.10-06-034, the Utilities are obligated to integrate their reliability demand response programs. The reliability programs, which are the base interruptible, agricultural pumping, and air conditioner cycling programs, constitute the majority of the Utilities' demand response resources and are on schedule to be integrated by January 1, 2018.

Furthermore, as the Working Group recommends, non-event-based load modifying demand response should continue to be embedded in the California Energy Commission's unmanaged/base case load forecasts. The non-event-based load modifying programs, which include critical peak pricing, real time pricing, time of use rates, permanent load shifting, and peak time rebates, are already demonstrably embedded in the load forecast or on the verge of becoming so through the ongoing work of the Joint Agency Steering Committee.

As a result, any hard trigger regulations developed by the Commission would only be applicable to programs outside of these two categories. At present, these outlier programs include the aggregator managed, capacity bidding, and demand bidding programs. We underscore that a hard trigger proposal would only be applicable to these three programs if, against the stated goals for the Commission since 2008, they are not integrated into the CAISO market.

The categorization of programs delineated here serves to clarify what existing programs are currently considered supply, event based, and non-event based. In comments on this Decision parties point out that some of the non-event based resources share key characteristics with event based resources and that migration of programs from one category to another may occur. We do not seek to prejudge such outcomes with today's decisions. As programs evolve this categorization should grow stale. But these possibilities should not distract from the core conclusion of this decision: programs that can be integrated, should be.

We conclude there is no current hard trigger mechanism that meets all the criteria as suggested above by parties. In comments to the Proposed Decision, Joint Demand Response Parties contend that an alternate hard trigger proposal was included in the May 1, 2015 Valuation Working Group Report.[30] The Joint Demand Response Parties argue that this alternate approach provided several triggers for system conditions that would require the event-based, load-

[30] Joint Demand Response Parties Opening Comments to Proposed Decision at 8-9.

modifying resources to be dispatched, consistent with needs on the system, and, potentially, consistent with when supply-side resources were being dispatched.[31] In reply comments, the CAISO states that "the working group did not develop any alternative to the CAISO's proposal and the Valuation Working Group Report only contained a final recommendation by *certain* working group members to seek more time to conduct a study on possible hard triggers."[32]

The Commission also concludes that a hard trigger mechanism that would meet all the party-suggested parameters as well as an associated nomination and penalty structure would be difficult and resource intensive to create and implement, otherwise the parties would have developed a reasonable solution by now. Furthermore, the amount of time and resources needed to study, create, and implement such a hard trigger mechanism is ineffective given the limited megawatts involved.

In comments to the Proposed Decision, the Joint Demand Response Parties contend that the amount of megawatts provided by the event-based load modifying resources are not limited but, for example in August 2015, equate to 665 MW or 31 percent of demand response.[33] In reviewing the data provided by the Utilities, the number of MWs is half of what the Joint Demand Response Parties argue are present. In fact, only about 305 MW are at risk of being lost.[34]

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[31] *Id.* at 9.

[32] CAISO Reply Comments to the Proposed Decision at 2.

[33] Joint Demand Response Parties Opening Comments at 5.

[34] CLECA Opening Comments to Proposed Decision at 2 citing October 2015 Load Impact Reports.

We address the recommendation that the Commission allow parties to continue exploring the valuation of event-based load modifying through a hard trigger study.[35] This proceeding has been exploring such valuation for nearly eighteen months.[36] At this time, the Commission concludes that a great amount of ratepayer-funded time and resources already have been expended in the exploration of the development of valuation mechanisms for event-based load modifying demand response and have resulted in no defined proposals, other than the CAISO proposal. It would not be a reasonable use of ratepayer funds to continue to study hard triggers. Therefore, the Commission declines to authorize funding and/or resources to conduct the hard trigger study.

In lieu of the use of hard triggers, PG&E argues that the current soft triggers provide an appropriate use of resources. Here too, we disagree. As the CAISO explains, in order to be valued as a capacity resource, demand response must either integrate into wholesale markets and accept requisite dispatch obligations or dependably modify load, thereby reducing a load serving entities' procurement obligation. The CAISO contends that unless demand response reduces those obligations, the resource neither fulfills the loading order nor helps California achieve its long-term energy goals. Furthermore, the CAISO contends that the cost assumed to be avoided in justifying the expense of the programs is never fully avoided, thus undermining the claim that demand response is a cost-effective resource. We agree and conclude that the existing soft triggers in place

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[35] *See* CLECA Opening Comments to Proposed Decision at 5, OPower Opening Comments at 4-5, and Joint Demand Response Parties Opening Comments at

[36] Discussions regarding valuation of load modifying demand response occurred during June 2014 workshops. See June 2014 Workshop Report.

for event-based load modifying demand response programs do not provide dependable reductions in load, procurement obligations, or avoided cost.

In comments to the proposed decision, CLECA contends that the Commission has ignored improvements to the dispatch of load modifying demand response resulting from improved soft triggers, as discussed during the April 24, 2015 workshop.[37] We return to our prior statement that appropriately designed hard triggers would assure the CAISO that the resource will be dispatched when pre-defined system conditions are met. The improvements made in the soft triggers do not address the overall level of dependability the state needs.

Having made this conclusion, the Commission faces the choice whether to maintain the existing approach to valuing demand response, through which resources receive capacity value whether or not they are integrated. Absent further action, the status quo would be preserved, allowing non-integrated dispatchable demand response to be valued as a capacity resource reinforced only by the existing soft triggers. Through its proposal the CAISO argues that to be valued as a capacity resource demand response must either integrate into wholesale markets and accept requisite dispatch obligations, or dependably modify load, thereby reducing a load serving entities' procurement obligation. They further charge that unless demand response reduces those obligations, the resource neither fulfills the loading order nor helps California achieve its long term energy goals. Further, they point out that the cost assumed to be avoided in justifying the expense of the programs is never fully avoided, undermining the

[37] CLECA Opening Comments to the Proposed Decision at 6-7.

claim that demand response is a cost effective resource. In making this argument, they fully supported by ORA and Calpine, and partially supported by TURN. We agree and we find that the existing soft triggers in place for event based demand response programs do not provide dependable reductions in load, procurement obligations, or avoided cost. The time is right to discontinue our existing valuation treatment of demand response. Going forward, effective January 1, 2018, capacity value shall be attributed only to demand response if the resource is integrated into the wholesale market or a non-event based program embedded in the CEC's unmanaged/base case load forecasts.

In response to the charge by some parties that through this action the Commission would reverse statements made in D.14-03-026 and D.14-12-024, where the Commission stated that bifurcation will allow the Commission to focus on these two distinct but equally important categories of demand response. Parties have taken out of context similar language in the OIR and in D.14-03-026 where the Commission stated that there is no intention to diminish the value of retail demand response but to take advantage of the strengths of different programs.[38] Some parties seem to have misinterpreted these statements to mean that the Commission should not make any changes to future programs. A September 14, 2015 Ruling in this proceeding noted that the intent of that language was to assure parties that the current programs and contracts would not be undercut mid-cycle such that investments made and contracts would be stranded. The Ruling underscored that "extending that logic to a new program year with discreet guidance goes beyond the original intention." We affirm this

[38] *See*, for example, PG&E Comments at 30.

statement noting that, as illustrated above, the Commission intends to integrate demand response resources into the CAISO market. Tactics to delay this process are not acceptable. The Commission has taken a deliberative approach to demand response integration since 2008. It is now time to move ahead. We conclude that the transition currently underway will benefit both the public and stakeholders through an increased ability to rely on demand response in meeting the State's resource needs. Further delay is not in the public interests. As such, our focus will now turn to a commitment to demand response integration into the CAISO market by 2018.

In comments to the Proposed Decision, SCE requested the Commission to clarify whether programs that are partially integrated but behave as if they are fully integrated should receive capacity value.[39] We clarify that the portions of a program that are integrated into the market have measureable capacity value and the portions that are not integrated into the market have no measureable capacity value.

In comments on the proposed decision, several parties asserted that not being able to measure the capacity value for all event-based load modifying resources will greatly harm the Commission's demand response programs. We disagree and provide the following overview of several Commission efforts designed to grow and improve both non-event-based load modifying and supply demand response resources to more than account for any interim loss of megawatts as a result of this decision:

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[39] SCE Opening Comments to the Proposed Decision at 3.

- **Efforts to address technical or policy barriers to integration.** In 2014, the Commission authorized a working group to identify the barriers to integration and develop recommendations. The CAISO has established the Energy Storage and Distributed Energy Resources stakeholder initiative as another forum for resolving barriers.
- **Enabling third-party demand response providers (Direct Participation)**: In 2014, the Commission approved specific policies and rules (Rule 24/32) to enable third party providers to bid into the CAISO markets. In 2015, the Commission authorized $7.4 M in Utility funding to support the implementation of Rule 24/32, which will be operational by early 2016.[40]
- **Demand Response Auction Mechanism pilots**: Authorized by the Commission in 2015, the pilot is a capacity procurement mechanism for third party providers to provide a minimum of 22 MWs of supply side resources in 2016.[41] A second auction will be performed in 2017 for a minimum of 22 MWs.
- **Demand Response Potential Study**: The Commission has authorized a $2.1 M study to estimate the amount of potential demand response in California.[42] The study will assist the Commission in setting new demand response goals and provide information on where ***new*** demand response can be captured. The study is expected to be completed in 2016.
- **Default Residential Time-of-Use Rates**: In July 2015, the Commission authorized default time-of-use rates for the residential sector across all

[40] D.15-03-042.

[41] Resolution E-4728.

[42] D.14-12-024.

three Utilities' territories beginning in 2019.[43] Time-of-use is a non-event load modifying resource and, because it will be a default rate, is anticipated to provide a substantial demand response impact, with mid-range estimates ranging from 250 MWs to 650 MWs.

- **Local Capacity Requirements (LCR) procurement activities**: In 2014, SCE and SDG&E were directed by the Commission to secure new local capacity resources (preferred resources and conventional generation) in light of the retirement of the San Onofre Nuclear Generating System and the anticipated retirement of once-through-cooling plants.[44]
- **Distribution Resources Plan (DRP) and Integrated Distributed Energy Resources (IDER) proceedings**: The purpose of the DRP rulemaking (R.14-08-013) is to move utilities toward a more full integration of distributed energy resources into their distribution system planning, operations and investment. The purpose of the IDER proceeding (R.14-10-003) is to develop a sourcing framework to enable a wide portfolio of integrated distributed energy resources. This joint effort of the two proceedings could potentially lead to more opportunities for demand response.

We continue to recognize and acknowledge the technical difficulties in integrating current programs into the CAISO market. Therefore, while we encourage the Utilities to also move forward with additional integration efforts in the 2017 demand response program year, as directed in the September 15, 2015 Assigned Commissioner and Administrative Law Judge Ruling, we consider full

[43] D.15-07-001.

[44] D.13-02-015 and D.14-03-004.

implementation in 2018 to be contingent upon the CAISO's ability to fulfill its commitments made in the Integration Working Group.[45]

3. Cost Effective Protocols

3.1. Overview of Proposed Protocols

Commission staff developed proposed revisions to the 2010 Protocols. In addition to specific recommendations described below, staff also edited the Protocols to correct minor errors and provide clarifications.

In response to the three concerns expressed in D.12-04-045, the 2015 draft Protocols recommend:

- A new model for the A factor and avoided generation capacity cost allocation, which replaces the utility calculation of the A factor;
- A new model for avoided Transmission & Distribution (T&D) costs;
- Refined definitions of the B, C, and D factors;
- Refined definitions and guidelines on the allocation of support program budgets, qualitative analysis, and the definition of the demand response portfolio; and
- A new reporting requirement.

In addition to addressing the issues discussed in D.12-04-045, the participants of an October 2012 workshop discussed other concerns with the 2010 Protocols. Hence, staff proposed additional refinements to the Protocols to address these and other policy concerns, most notably the creation of two new adjustment factors for flexibility and geographic value.

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[45] Supply Resource Demand Response Integration Working Group Compliance Report, June 30, 2015 at 6-7.

3.2. Discussion

As discussed in more depth below, we adopt the attached 2015 Demand Response Cost-Effectiveness Protocols (Appendix A) with two categories of "placeholders." We determine that the overlap with the Integrated Distributed Energy Resources proceeding (R.14-10-003) makes it more appropriate to address certain aspects of the Protocols in that proceeding, the first category of placeholders. The second category of "placeholders" includes issues that need to be technically developed in a working group or workshop setting. We also make non-substantive edits throughout the Protocols. We establish the placeholders in the Protocols and describe the steps to be taken in order to finalize the Protocols for use in review of the next demand response applications, which are to be filed by the Utilities in November 2016. As recently directed, the Utilities shall use the 2010 version of the Protocols when filing proposals for 2017 demand response program improvements.

There are three categories of issues relative to revising the Protocols in this manner: 1) the avoided cost calculator; 2) the adjustment factors; and 3) miscellaneous issues. We address each of these categories, individually, below.

3.2.1. Avoided Cost Calculator

The Commission finds that the avoided cost calculator should be updated. As described below, because the avoided cost calculator impacts all distributed energy resources, a determination on the revised avoided cost calculator should be deferred to either the Distributed Resources Plan proceeding or the Integrated Distributed Energy Resources proceeding.

In regards to the avoided cost calculator, the June 19, 2015 Ruling asked parties about the consistency of the latest version of the E3 avoided cost calculator with the proposed Protocols and also asked for a comparison of the avoided transmission and distribution cost model with the avoided cost calculator. The responses indicate that these two questions may be irrelevant. The comments instead indicate that the calculator may be "significantly limited" and requires "continually updating as market trends change." Joint Demand Response Parties call for increased transparency in cost-effectiveness methodologies and thus recommend the replacement of the avoided cost calculator with an interactive modeling framework.[46] Furthermore, SDG&E notes that the current calculator does not address changes recommended by the Valuation Working Group and suggests that the Protocols be revised to require the use of the best available cost data and not be tied to a specific version of the calculator, especially given the valuation efforts being pursued in other Commission proceedings.[47] PG&E suggests that the avoided transmission and distribution cost model, recommended by the Valuation Working Group, be reviewed as part of the Distributed Resources Plans proceeding (R.14-08-013), to ensure consistency across all distributed energy resources.[48]

Because the avoided cost calculator impacts all distributed energy resources, a decision on its revisions should not be determined in this proceeding that only considers demand response resources. Both the Distributed Resources Plans proceeding and the Integrated Distributed Energy Resources proceeding (R.14-10-003) include in each of their scopes a determination regarding cost-effectiveness methodologies for resources including demand response resources.

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[46] Joint Demand Response Parties Opening Comments at 21.

[47] SDG&E Opening Comments at 18.

[48] PG&E Opening Comments at 23.

As such, we find it more efficient to defer to either of these proceedings to ensure consistency across all energy resources. However, we do not know at this time when such a determination will be made. Hence, any requirement by the Commission for the Utilities to use the E3 avoided cost calculator, prior to the adoption of a final directive in either R.14-10-003 or R.14-08-013, will include a definitive directive of the version of the calculator to use.

3.2.2. Adjustment Factors

The second category of protocol-related issues we discuss is adjustment factors. Adjustment factors are designed to reflect the program characteristics that constrain or add to the optimal use of demand response dispatching. The staff-proposed revisions to the Protocols recommend a) changes to the adjustment factors (factors) included in the Protocols and b) the creation of two new adjustment factors.

In the Protocols, the generation capacity value of a demand response program without usage or availability constraints is described as equivalent to the full combustion turbine residual capacity cost (maximum capacity value). Hence, to the extent that a demand response program has usage and availability constraints, the maximum capacity value would be adjusted downward using the following adjustment factors: A – availability factor, B – notification time factor, C – trigger factor, and D – avoided transmission and distribution costs factor. The value can also be adjusted upward using the E (energy) Factor and two newly proposed factors:F – optional flexibility factor , and G – optional geographic factor (addresses the ability to be called in a constrained area.) We address each factor individually below.

3.2.2.1. A Factor

Staff and parties agree that the probabilistic reliability modeling should be adopted by the Commission for use as a model to measure the availability of demand response resources. The resource adequacy proceeding (R.11-10-023) is currently developing such a model, which is being vetted by parties in that proceeding. In the interim, another methodology, the Renewable Energy Capacity Planning (RECAP) model, can be used as a substitute. A workshop shall be held to help parties understand this methodology, as it has not been reviewed in a demand response proceeding. Following the workshop, the Commission will consider whether to adopt the RECAP as an interim methodology until the Commission finalizes the probabilistic reliability model.

With the A Factor, referred to as the availability factor,[49] staff recommends the Commission adopt the probabilistic reliability model currently under development in the Resource Adequacy proceeding. However, until such time that the probabilistic reliability model is complete, staff proposes that load serving entities use an Effectiveness Load Carrying Capacity methodology known as the RECAP model, in the interim.[50, 51] The RECAP model, developed

[49] As described in the staff proposal, the A Factor is intended to represent the portion of capacity value that can be captured by the demand response program based on the daily and monthly availability of the program, and the frequency and duration of calls permitted.

[50] The RECAP Model, according to the developer E3's website, is an easy to use, open-source bulk system reliability model that uses established reliability planning techniques for analyzing power system reliability. RECAP calculates standard reliability metrics including loss of load probability, loss of load expectation or effective load carrying capability. See https://ethree.com/public_projects/recap.php

[51] The RECAP model was first proposed during the October 19, 2012 demand response cost-effectiveness workshop

by the consultant E3, has been used to calculate ELCC in the Renewables Portfolio Standard and the Net Energy Metering proceedings.

SDG&E states that parties are unanimous in their opinion that the current A Factor – which uses an E3 model[52] – should change.[53] Noting that the Valuation Working Group recommended that the A Factor should incorporate a loss of load probability/loss of load expectation approach, SDG&E states that the working group recommended approach is consistent with the approach used by E3 in their RECAP[54] model.[55]

While the Joint Demand Response Parties agree that the proposed RECAP model is critical to meaningful and appropriate results, Joint Demand Response Parties as well as CLECA, PG&E, and SCE contend the assumptions and approach used in the RECAP model have not been shared or fully vetted in a public process.[56] Hence, the Joint Demand Response Parties support the use of probabilistic reliability modeling to determine the A Factor, because of its transparency. However, CLECA suggests that, traditionally, avoided costs need

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[52] The current E3 model, used in the 2012-2014 demand response application process, is a fairly simple model, which spreads the residual capacity value over the 250 hours of the year with the highest demand. Staff considers this model problematic because, there was variation between the Utilities in the methodology used to allocate the residual capacity value across the 250 hours. *See* June 19, 2015 Ruling, Appendix A at 30.

[53] SDG&E Opening Comments at 12.

[54] The RECAP Model, according to the E3 website, is an easy to use, open-source bulk system reliability model that uses established reliability planning techniques for analyzing power system reliability. RECAP calculates standard reliability metrics including loss of load probability, loss of load expectation or effective load carrying capability. *See* https://ethree.com/public_projects/recap.php

[55] SCE Opening Comments at 12.

[56] Joint Demand Response Parties Opening Comments at 8, CLECA at 2, PG&E at 3-5, and SCE at 34.

to include the costs of avoiding renewable curtailment, which is currently not in any model discussed. SCE and PG&E recommend vetting the proposed RECAP Model in a stakeholder process.[57] Additionally, PG&E requests that once implemented, the assumptions for the A Factor should be provided no later than a year before the next demand response applications.[58]

ORA contends the proposal does not account for whether or not the programs triggers will actually be met and ignores the likelihood of programs being called. Hence, ORA recommends adjusting the A Factor to account for the likelihood the program is triggered and events are called.[59]

While there is agreement that a revised A Factor is needed, most parties express concern about the use of the proposed RECAP model while waiting for the probabilistic model to be developed due to lack of familiarity with the RECAP model. The Commission also finds that parties do not support a model that has not been discussed in the demand response proceeding. Hence, we do not adopt a particular model at this time but we maintain a placeholder for the A Factor. As discussed at the end of this Decision, the Commission will hold a workshop on related protocol issues. The workshop will include a discussion of the A Factor with the objective of adopting an interim until such time the Commission can develop and adopt a probabilistic model. The determination of a final interim model will be made in a future decision in 2016.

In comments to the Proposed Decision, SCE, who opposes the use of the RECAP model, requested the Commission to allow the Utilities to use the SCE

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[57] SCE at 34 and PG&E at 3.

[58] PG&E at 4-5.

[59] ORA at 9.

availability model until the probabilistic model has been developed and approved. We will include discussion of this option during the workshop.

3.2.2.2. B Factor

The B Factor values are adjusted to better reflect resource adequacy standards. As such the B Factor values, as depicted in Table 3 below are adopted.

The B Factor is an adjustment based on notification times. The purpose of this factor is to determine how often the additional information available for shorter notification times would have resulted in different decisions about event calls. Staff noted in the revised proposed Protocols that in the 2012-2014 application proceeding, the Utilities were able to only apply this factor to distinguish between day-of and day-ahead programs: day-ahead programs received a B Factor of 88 percent and day-of programs received a B Factor of 100 percent. Staff recognizes that for the B Factor, it is difficult to determine the exact, relative value of the various notification times. The proposed Protocols recommend that "until a more exact measurement can be made," load serving entities should use the values in Table 2 to determine a B Factor.

Table 2

B Factor Inputs

Notification Time	B Factor Input
5 minutes or less	100%
15 minutes	97%
30 minutes	94%
Day Of, greater than 30 minutes	91%
Day Ahead or greater	88%

Parties addressing this issue opposed the recommended change and offered varying alternate solutions. PG&E claims the B Factor changes are unnecessary, have no analytical value, and have very little connection with capacity requirements or needs.[60] Furthermore, PG&E contends that it is unnecessary for fast-response demand response to be assigned additional value via this B Factor because "any incremental value will be reflected in what the fast-response demand response is used for."[61] SCE also opposes the proposed B Factor values because they set a higher performance standard than for a combustion turbine and do not reflect that a shorter notification time does not increase the capacity value of a resource.[62]

In contrast, CLECA supports the B Factor, but contends that all day-of demand response that can be dispatched in 30 minutes or less should receive a B Factor value of 100 percent.[63] CLECA argues that the staff proposal is arbitrary in its delineation of percentages for the B Factor and notes that there are generation resources that cannot be started up in less than 30 minutes.[64] SDG&E argues that the B Factor value should be 100 percent if the resource is able to respond in 20 minutes because the CAISO gives full resources adequacy value to resources that can be dispatched in 20 minutes.[65] Both CLECA and the Joint

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60 PG&E at 6.

61 *Id*. at 7.

62 SCE at 34.

63 CLECA at 3.

64 *Ibid*.

65 SDG&E at 12,

Demand Response Parties suggest that five minute demand response receive a B Factor of more than 100 percent.

We agree that the B Factor values are arbitrary. As noted by staff, it is difficult to determine the exact, relative value of the various notification times.[66] There is consensus that resources that can be dispatched in 20-30 minutes or less have greater value. As noted by SDG&E, if the CAISO is willing to give full resource adequacy value to demand response that meets other requirements and can be dispatched in 20 minutes, the Commission should do the same. Furthermore, as previously pointed out, there are generation resources that cannot be started up in less than 30 minutes and we agree that demand response should not be required to perform at a higher standard than a combustion turbine. Hence, we adopt the B Factor values in Table 3 below on an interim basis. However, we note that Phase Three of the Resource Adequacy proceeding includes the issue of a 20 minute dispatch requirement. Hence, if the resource adequacy proceeding establishes a new associated policy, the B Factor may need to be revised to reflect the new policy.

Table 3

Adopted B Factor Inputs

Notification Time	B Factor Input
30 minutes or less	100%
Day Of, greater than 30 minutes	94%
Day Ahead or greater	88%

[66] Draft Protocols at 32.

3.2.2.3. C Factor

As described below, we decline to adopt the proposed C Factor. Two flaws in the proposed calculation: 1) the confusion of capacity and energy/ancillary market benefits and 2) the misinterpretation of the term, "availability" outweigh any benefits provided by the data in the proposed analysis.

The C Factor adjusts for triggers or conditions that permit the load serving entity to dispatch a demand response program. The proposed Protocols state that demand response programs provide insurance against catastrophic emergencies and can provide increasingly significant value by avoiding the purchase of high-priced generation. The proposed Protocols also allege that the more a program is dispatched the more valuable the program. In the proposed Protocols, programs not dispatched by the CAISO, the program begin with a C Factor value of 50 percent and add to that the result of the annual average number of event hours from 2006 to present divided by the maximum number of annual event hours. For programs dispatched by the CAISO, the proposed Protocols state that programs receive a C Factor value of 100 percent.

Most parties commenting on the C Factor oppose its adoption. Comments on the C Factor call the proposed changes arbitrary, illogical, and misguided. Two arguments are presented by parties: the confusion of capacity benefits versus energy benefits and the possible misuse of the term "available."[67]

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[67] PG&E, among others, argues that the proposed calculation reduces the value of load modifying resources and thus is contrary to Commission policy. (*See* PG&E at 9-12.) We disagree with this interpretation of Commission policy and explicitly state so in a later discussion in this decision.

SDG&E contends that the proposed changes confuse capacity and energy/ancillary market benefits. SDG&E argues that a demand response program dispatched less often than its maximum number of dispatches should be interpreted as meaning the energy benefits were less than they could have been and has nothing to do with the value of the capacity provided. SDG&E suggests that the C Factor be unchanged from the 2010 Protocols or be applied to estimate energy benefits and not capacity benefits.[68] SCE agrees, highlighting that capacity value is based on a resource being available and the proposed C Factor reduces the capacity value based on a resource being dispatched. SCE argues that no evidence has been presented to show that resources dispatched with less frequency are less likely to be available when called upon.[69] PG&E adds that there is no evidence to support reducing the value of load modifying resources by 50 percent.[70]

SCE also argues that the term "available" is misinterpreted in the proposed calculation. SCE explains that while a program may be available for 180 hours, there is no expectation that the program will be dispatched for 180 hours. If this were the case, SCE states, a perverse incentive would be created where reducing available hours would actually result in higher program value.[71] CLECA agrees, noting that in the CAISO market a must-offer obligation (must be available) does not mean a must-dispatch obligation.[72]

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[68] SDG&E at 13.

[69] SCE at 35.

[70] PG&E at 9.

[71] SCE at 36.

[72] CLECA at 3.

We agree that what the C Factor actually calculates is not what it is meant to calculate, i.e. capacity versus energy benefits. We are also concerned about the use of the term "available" in this calculation and its potential impact on program design. Hence, we do not find it reasonable to adopt the C Factor analysis, as currently proposed by staff.

3.2.2.4. D Factor: Transmission and Distribution Avoided Costs

Once a finalized locational net benefits methodology is adopted in R.14-08-013, the Protocols will be updated to reflect the use of this methodology to adjust for transmission and distribution avoided costs. As discussed below, until such time as the locational net benefits methodology is adopted, the Utilities shall include in future cost-effectiveness analysis results, work papers justifying estimates for transmission and distribution avoided costs.

The purpose of the D Factor is to adjust for transmission and distribution avoided costs. The draft Protocols propose two models, one for the Utilities and one for other load serving entities.

The draft Protocols propose that the Utilities each use the new E3 model developed in the California Net Energy Metering Ratepayer Impacts Evaluation (NEM Model), which separately calculates a transmission avoided cost for subtransmission downstream of the CAISO and distribution system avoided costs. The Protocols note that the NEM model requires the use of confidential data in the distribution-level avoided costs calculation, a rare occurrence for the Commission in that it normally prefers public data. All other load serving entities would continue to use the method used in the 2010 Protocols.

The Valuation Working Group report recommended a process where each of the Utilities would calculate a locational avoided cost for each project where a load modifying resource may contribute to project mitigation either as a stand-alone solution or a portfolio of solutions. The working group also proposed that the amount of locational avoided cost would be determined by calculating the load carrying capacity (needs) of the load modifying resource or its equivalent in the local area.

PG&E recommends that the Commission defer to the Distribution Resources Plans proceeding for transmission and distribution benefits. PG&E explained that its proposed locational net transmission and distribution benefits methodology was recently filed in that proceeding and contends that it is in the scope of R.14-08-013 and not in this proceeding.[73] PG&E alleges the use of this the locational net benefits methodology will create consistency across all distributed energy resources, instead of having a "one-off" methodology in demand response. Furthermore, PG&E argues this will allow for flexibility, consistency and transparency.[74] In the interim, PG&E recommends that the Commission authorize the Utilities to include as part of its cost-effectiveness analysis results, work papers supporting T&D costs.[75]

Joint Demand Response Parties[76] and SCE[77] recommend that the D Factor be based on the Valuation Working Group proposal and not the NEM model. SCE claims that the Valuation Working Group proposal fits squarely with the revised draft Protocols and, furthermore, contends there are no conflicts between

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[73] PG&E Opening Comments at 5.

[74] PG&E Opening Comments at 6.

[75] PG&E Opening Comments at 12.

[76] Joint Demand Response Parties Opening Comments at 16.

[77] SCE Opening Comments at 31-32 and 38-39.

the recommendations SCE set forth in the Valuation Working Group report and its proposal filed in R.14-08-013.[78] SCE further explains that the Valuation Working Group proposal is explicitly targeted to defer transmission and distribution spending and reflects the requirements of "Right Time, Right Place, Right Certainty, and Right Availability."[79]

While it supports the use of the Valuation Working Group proposal versus the NEM model, the Joint Demand Response Parties recommend using confidential data in the Present Worth method, as proposed in the revised Protocols.[80] However, SCE argues that there is ambiguity regarding the application of the present worth method in the staff proposal; as such the Commission should allow the Utilities to estimate transmission and distribution deferral benefits and support its estimates with work papers accompanying the analysis results.[81]

We find overwhelming support for the use of the locational net benefits methodology versus the NEM methodology to adjust for transmission and distribution avoided costs. We agree that the use of the locational net benefits methodology will create consistency across all distributed energy resources. As the development of this methodology is in the scope of R.14-08-13, we find it reasonable to defer to this issue to R.14-08-013. As further detailed below, the Protocols will be updated to reflect the outcome of R.14-08-013.

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[78] *Ibid.*

[79] SCE Opening Comments at 38-39.

[80] Joint Demand Response Parties Opening Comments at 16.

[81] SCE Opening Comments at 31-32 and 38-39.

However, we need an interim methodology to use until the locational net benefits methodology is finalized. We agree that it is more efficient to utilize work papers in the interim, rather than adopt a potentially inconsistent "one-off" transmission and distribution avoided cost methodology in this proceeding on an interim basis. Hence, until the locational net benefits methodology is finalized, load serving entities and the Utilities shall include in their cost-effectiveness analysis results, work papers justifying estimates for transmission and distribution avoided costs.

3.2.2.5. E Factor

The E Factor has not been revised and few parties presented comments on it. We confirm its inclusion here solely to provide a complete picture of the factors. As further described below, we adopt the E Factor as proposed in the revised Protocols.

The E Factor is an adder in the cost-effectiveness analysis, to adjust for energy to reflect the correlation between electricity prices and the times when demand response program events are expected to occur, based on the time in which the program will be available, constraints on the use of the program, and the probability distribution of and correlations between the trigger conditions under which events can be called for that program.

Few parties commented on the E Factor. Joint Demand Response Parties state that the E Factor should include energy price, because excluding the value of energy price would be discriminatory.[82] California Energy Storage Alliance (CESA) contends that the E Factor should be mandatory for load serving entities

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[82] Joint Demand Response Parties at 16.

because it is the only factor that incorporates real time congestion and grid conditions.[83] SCE argues that the E Factor should be strictly optional for use to better capture the value of a specific program.[84]

Because SCE provided no justification showing how an optional E Factor improves program value, we adopt the mandatory E Factor as proposed.

3.2.2.6. F Factor

As further described below, we conclude that it is reasonable to approve a placeholder for an F Factor in the 2015 Protocols; however, further workshops are required to craft a methodology.

The revised Protocols propose the addition of an F Factor, which adjusts for flexibility. The F Factor is an adder like the E Factor above; hence the minimum value is 100 percent. Created to provide additional value for resources that are very flexible and useful for responding to intermittent generation, a load serving entity must include justification in its work papers when using the F Factor. The proposed Protocols did not offer a methodology to determine the F Factor.

While no party opposes the F Factor, several expressed concern about the lack of a methodology. SDG&E states that the Protocols should specify the methodology to calculate the F Factor, since the purpose of the Protocols is to provide guidance. SDG&E suggests that the Commission use the resource balance concept to calculate the premium for local or flexible capacity.[85] ORA recommends that the Commission require that in order to claim an F Factor, an

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[83] CESA Opening Comments at 5.

[84] SCE Opening Comments at 39.

[85] SDG&E at 13.

entity must meet all the qualifications for being such a resource as identified in D.14-06-050.[86]

CLECA cautions that quantifying the F Factor may be difficult since informal discussions in the resource adequacy proceeding suggest that there is not much of a flexibility premium in the resource adequacy market to date.[87] CLECA, as well as PG&E and the Joint Demand Response Parties, suggests that the protocols address increasing load to deal with over-generation thereby rewarding providers for reducing ramping requirements and avoided renewable curtailment.[88] PG&E suggests that the Commission hold a workshop to vet all ideas on this issue.

Given that the purpose of the F Factor is to reward flexibility, it is consistent with the Commission's desire to address intermittent generation, i.e., wind and solar. Therefore, we find value in the concept of an F Factor. We conclude that it is reasonable to approve a placeholder for an F Factor in the 2015 Protocols. However, we agree that a methodology to calculate the E Factor is needed. The most expeditious approach to developing a methodology is a technical workshop. We direct the Utilities to organize a working group to develop and then present a draft proposal to interested parties, in a technical workshop no later than 90 days from the issuance of this decision. No more than 30 days after the workshop, the Utilities shall file a Tier Three advice letter proposing a methodology for the F Factor to be adopted by the Commission via Resolution. The proposed methodology should represent a consensus proposal

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[86] ORA at 11.

[87] CLECA at 5.

[88] CLECA at 5, PG&E at 16, and Joint demand response parties at 17.

by the working group. In finalizing the proposed F Factor methodology, the Utilities shall collaborate with the Energy Division and all interested parties to consider the ideas discussed in this Decision and during the technical workshop.

3.2.2.7. G Factor

We previously determined that to adjust for transmission and distribution avoided costs, the Commission would defer to R.14-08-013, where a locational net benefit methodology would be developed. The adoption of this methodology would make moot the need for a G Factor. As described below, we adopt, on an interim basis, the use of written justification for a G Factor or its default values to accompany the cost-effectiveness analysis results for each demand response program.

Staff proposes the addition of a G Factor, which adds value for those demand response resources that can be called locally in regions that are resource-constrained. Here again, the G Factor is an adder and its minimum value is 100 percent. Load serving entities may propose this adder for any demand response program which can be dispatched locally in a region which is facing constraints at a higher than normal risk of experiencing generation capacity shortages. Justification for using the G Factor shall be included in the work papers accompanying the cost-effectiveness analysis for a program. The staff proposal included default G factors ranging from 100 percent to 110 percent, but did not propose an overall methodology.

Again, parties support the concept of a G Factor but argue that the default G Factors seem arbitrary.[89] PG&E suggests that the proposed default G Factors

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[89] *See* CLECA at 5, and SDG&E at 14.

may be related to the Commission's finding in the Long Term Procurement Plan (LTPP) proceeding that there are incremental resource needs in San Diego, Los Angeles Basin, and Big Creek-Ventura caused by the retirement of the San Onofre Nuclear Generating System. PG&E requests that "if the Commission plans to make it an ongoing practice to allow those local values to be captured as they change with time, the G Factor should be reviewed and updated following each LTPP, and based on evidence in that proceeding.[90]

We previously determined that to adjust for transmission and distribution avoided costs, the Commission would defer to R.14-08-013, where a locational net benefit methodology would be developed. Once this methodology is created, there will no longer be a need for a G Factor. However, we need an interim methodology in the meantime.

We agree that the default G Factors are rooted in the LTPP evidentiary record. Hence, because it is on an interim basis, the Commission adopts the default G Factors, as defined in the proposed Protocols, until the locational net benefit methodology is finalized and adopted by the Commission. Furthermore, the Commission finds it reasonable to adopt the use of written justification for the G Factor to accompany the cost-effectiveness analysis results for each program.

3.2.3. Miscellaneous Protocol Issues

The third aspect of the Protocols we address here is the category of Miscellaneous Issues. Issues in this category range from administrative costs to

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90 PG&E at 17.

the development of a separate protocol for the Permanent Load Shifting program. Below is a summary of the issues we address in this decision:

- Other than pilots, if a Utility requests funding for a program in a demand response portfolio application, a cost-effectiveness analysis pursuant to the Protocols is required. Furthermore, all costs associated with a program shall be included in the cost-effectiveness analysis even if that cost was previously adopted in a prior decision or in a separate proceeding.
- A demand response portfolio shall include all programs requested for that particular demand response program funding cycle and all associated costs with those programs, including, as previously stated, costs funded by prior decisions in other proceedings.
- The allocation of support program budgets is adopted as recommended in the proposed Protocol.
- The use of confidential data is discouraged in cost-effectiveness analyses, as previously determined by the Commission in D.10-12-024. As described in the proposed revisions, load serving entities are required to request, in writing, to use confidential data prior to the filing of their analyses.
- To address the cost-effectiveness of programs which allow dual participation, we adopt the requirement to provide an additional analysis of both the capacity and energy program combined.
- A working group is established to develop a cost-effectiveness protocol for the Permanent Load Shifting program.
- Qualitative analyses are required. The language in the proposed Protocols requires editing to improve clarity and provide better explanation of the expectations.
- No changes shall be made to the 2010 Protocols regarding non-energy benefits. This issue is in the scope of and will be addressed in R.14-10-003.
- The drop out discount may be included in the capital cost calculation.
- An ex-post demand response cost-effectiveness analysis is not a requirement of the Protocols. However, this issue will be re-considered during the upcoming discussion of the demand response evaluative process. The proposed calculation for participant costs is approved.

- The cost-effectiveness reporting tool requires updating; the update will be included as one of tasks to be addressed in the working group addressed discussed below.

3.2.3.1. Intended Use of Protocols

We begin with a discussion of the intended use of the Protocols. Here we identify those programs requiring a cost-effectiveness analysis. We also identify the activities and programs that belong in the demand response portfolio analysis.

In the proposed Protocols, load serving entities are required to file cost-effectiveness analyses for all demand response activities that have measureable load impacts for which the load serving entity is requesting budget approval. The proposed Protocols recommend omitting pilot programs, technical assistance, educational, or marketing and outreach activities from this requirement and suggests that the Protocols may not be applicable to permanent load shifting programs. The proposed Protocols also recommend a separate cost-effectiveness analysis on the entire portfolio including any program or activity previously funded in another proceeding. Finally, the proposed Protocols state that the Protocols are to be applied to supply resources on a partial-basis, including those resources bid into the CAISO market as part of the demand response auction mechanism pilot project.

SDG&E contends that only programs where funding is being requested should be included in the cost-effectiveness analysis because it would otherwise create complications in valuation.[91] SCE argues that dynamic pricing programs

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[91] SDG&E Opening Comments at 5.

should not be included in the portfolio pursuant to D.12-04-045 and therefore should not require a cost-effectiveness analysis. SCE also contends that the Protocols are not appropriate for the permanent load shifting program and recommends that the Commission establish a working group to develop a protocol specific to the permanent load shifting program.[92] ORA argues that all costs attributable to a program where funding is being requested should be included in the cost-effectiveness analysis.[93]

We agree that dynamic pricing programs are not required to be in the demand response portfolio, pursuant to D.12-04-045, and hence, do not require a cost-effectiveness analyses. However, the Utilities shall include all non-dynamic pricing demand response activities in their routine demand response program applications. If a utility does not include this information, the utility's application shall explain the reason for this omission. Hence, all requests for activities to be funded in the application shall require a cost-effectiveness analysis with the exception of pilot programs, technical assistance, educational, or marketing and outreach activities. As explained in the proposed Protocols, the Protocols are not designed to measure these types of activities. However, we agree that all costs associated with programs, including the costs for the activities not analyzed for cost-effectiveness and costs funded through other proceedings, shall be included in an otherwise applicable cost-effectiveness analysis. This enables the Commission to account for a complete review of the cost-effectiveness of demand response programs as well as the demand response portfolio.

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[92] SCE Opening Comments at 19.

[93] ORA Opening Comments at 6.

In regards to a separate cost-effectiveness analysis on the portfolio as a whole, we agree with ORA that a portfolio analysis should include all costs attributable to a program including costs approved in other proceedings. We underscore the difference between funding for programs and activities and funding for costs associated with programs and activities. Hence, we do not agree that whole programs or activities approved in other proceedings should be included in the portfolio analysis. We previously stated that the Commission encourages the Utilities, to the best of their ability, to request funding for all demand response related activities and programs in the routine budget application. In turn, we also discourage the Utilities from a) including demand response program or activity requests in general rate cases or b) filing applications for demand response programs or activities outside of the routine budget application cycle. Furthermore, we agree that including programs and activities previously funded in other proceedings could skew the portfolio analysis. As previously pointed out, the purpose of the portfolio analysis is to avoid double-counting.[94]

Regarding the issue of supply side resources, we agree that these resources should be subject to the Protocols, with the exception of the resources bid into the demand response auction mechanism pilot. Funding for these programs, at this time, continues to be generated through ratepayer funds. Hence, these programs should be subject to cost-effectiveness analysis. However, as we previously stated, pilot programs, including the demand response auction mechanism are not subject to a cost-effectiveness analysis. Therefore, we revise

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[94] SCE Opening Comments at 27.

the Protocols to clarify that supply side resources are subject to a cost-effectiveness analysis.

Lastly, we agree with that the protocols, as revised, are not a good tool to measure the cost-effectiveness of the permanent load shifting program. We, therefore, establish a working group to develop an appropriate methodology to evaluate the cost-effectiveness of the permanent load shifting program. We direct Commission Energy Division staff to facilitate the working group meetings. Within 60 days from the issuance of this decision, staff shall notice an initial meeting to begin this work. The utility representatives shall participate in this working group and work with other parties to develop a proposal. Within 180 days from the issuance of this decision, the Utilities shall file a report, in this proceeding, providing the findings of the working group and requesting Commission review and approval.

In order to ensure clarity on this discussion, we provide the following figure below.

FIGURE 1

DEMAND RESPONSE PORTFOLIO CONTENTS

Demand Response Portfolio Contents	Cost-Effectiveness Analysis Required using Adopted Protocols	Costs to be Included in the Cost-Effectiveness Analysis
↓	↓	↓
All Demand Response Programs and Activities for which the Load Serving Entity is Requesting	All Demand Response Programs and Activities EXCEPT for Pilots, Technical Assistance, Educational Activities, Marketing & Outreach Activities, Permanent Load Shifting Programs.	All Costs attributable to the program or activity requesting funding including all supporting programs such as marketing & outreach, etc. and including costs previously funded

Funding in the Current Application.		through other proceedings.

Also included in this section of the Protocols is a discussion regarding a requirement for an ex post analysis. As described below, we find that an ex-post demand response cost-effectiveness analysis should not be a requirement of the Protocols. However, the information attained from this type of analysis could be useful to the Commission; thus this issue will be re-considered during a future discussion of the demand response evaluative process.

Parties commenting on the requirement for an ex-post cost-effectiveness analysis considered the requirement inappropriate and counterproductive.[95] PG&E argues that the requirement is currently being performed through at least six other reporting requirements.[96] Furthermore, both SDG&E and SCE contend that the purpose of a cost-effectiveness analysis is to determine expected avoided costs and expected load impacts. An ex-post analysis should look at actual load impacts. Joint Demand Response Parties argue that requiring such an analysis is discriminatory to demand response programs since no other resource requires an ex-post cost-effectiveness analysis.

We find the ex-post cost-effectiveness analysis requirement to be unnecessary given the wealth of information available regarding actual performance. As noted by PG&E, demand response performance is currently measured by six other tests. However, the information attained in such an

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[95] *See*, for example, PG&E Opening Comments at 21 and Joint Demand Response Parties Opening Comments at 10.

[96] PG&E Opening Comments at 21.

analysis may be useful in other respects. Hence, we will revisit this type of analysis in a future discussion on demand response evaluation.

3.2.3.2. Confidentiality

We next address the issue of confidentiality. The requirement in the Protocols has not been changed since the Commission adopted the 2010 Protocols in D.10-12-024: the Protocols "discourage" the use of confidential or proprietary data and require the load serving entity to obtain prior written Commission approval if such data is used in any cost-effectiveness analysis. SCE argues that this "goes against longstanding Commission practice, serves no public purpose, and violates due process rights."

We reiterate that this requirement is not new. Hence, SCE has already had an opportunity to argue these points. We take this opportunity to highlight the purpose behind this requirement. As stated in the 2010 Protocols and the proposed Protocols, the methods presented in the Protocols should promote transparency by using clear and publicly available data and data sources. The Commission has already determined that transparency is a critical component of establishing results in which all parties can have confidence.[97] Thus, we make no changes to the confidentiality section of the Protocols.

3.2.3.3. Qualitative Analysis

We turn to a discussion on qualitative analysis and confirm that it is required as part of the cost-effectiveness analysis. The proposed Protocols recommend that the Commission adopt a requirement to include qualitative analyses, as described in Section 1.G. The proposed Protocols note that the

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[97] Proposed Protocols at Section 1.C: Confidentiality.

2010 Protocols also included this requirement but none of the Utilities provided a qualitative analysis as part of the 2012-2014 demand response application filing.

Only SDG&E commented on this issue. SDG&E contends that the 2010 Protocols were "optional" but SDG&E submitted a qualitative analysis that was deemed insufficient. SDG&E requests the Commission to define what constitutes sufficient, provide more direction as to what is required by this section, and remove the words "optional" and "not required to" from the discussion.[98]

SDG&E's comments on this subject are compelling. We confirm that the qualitative analysis was required in 2010 and we continue to require this analysis. In reviewing the language in this section of the proposed Protocols, however, we agree that there needs to be clarification on the expectations of this analysis. Equally important, the language should be improved to clarify that the qualitative analysis is required. At this time, we adopt a placeholder for this section. Below, we establish a process for addressing the need to finalize language in the Protocols.

3.2.3.4. Dual Participation

Dual participation allows demand response participants to enroll in more than one demand response program. The 2010 Protocols required load serving entities to attribute the load impacts of dually-participating customers only to the capacity programs. This resulted in underestimates of the cost-effectiveness of the energy programs. Hence, the proposed Protocols provide three options to determine the cost-effectiveness of programs that allow

[98] SDG&E Opening Comments at 5.

dual participation: 1) requiring an additional analysis of both the capacity and the energy program combined; 2) including the dually participating customers in the separate analysis of each program, taking care not to double-count when calculating the portfolio analysis; or 3) requiring an additional analysis of only the dually-enrolled customers in both the capacity and energy programs. The proposed Protocols recognize that it would be administratively burdensome to perform all three options but do not recommend any one option.

In comments, SCE advises against performing individual analyses of dual participation programs and instead recommends performing additional analysis of both programs combined to avoid double counting.[99] ORA, PG&E, and CLECA also recommend a combined analysis of both programs. PG&E contends this will eliminate double counting load impacts.[100]

There is evidence that the current methodology for analyzing the cost-effectiveness of dual participation programs is not appropriate. In determining which of the three recommended options to pursue, there is little evidence to make a determination. However, there is consensus that option 1, requiring an additional analysis of both the capacity and the energy program combined, is the preferred option. We find option 1 to be a reasonable option, given the limited data available. Hence, we adopt the methodology requiring an additional cost-effectiveness analysis of both dual participation programs combined to avoid double counting.

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[99] SCE Opening Comments at 28.

[100] PG&E Opening Comments at 19.

3.2.3.5. Costs: Participant and Capital Costs

We now address several specific issues regarding both participant and capital costs.

First, we discuss the issue of participant costs, specifically as it relates to air conditioning cycling. Participant costs for demand response programs consist of the value of service lost, which participants incur when they respond to events, and the participant transaction costs, which are associated with enrolling, etc. Because the value of service lost and transaction costs are difficult to calculate, the proposed Protocols use a percentage of customer incentives as a proxy value for measuring participant costs. The proposed Protocols continue the use of the proxy measurement, but propose to change the percentage used for air conditioning cycling programs due to program evaluations indicating that both transaction costs and value of service lost are particularly low for these programs. The proposed Protocols provide a reduction in the participant cost value for the air conditioner cycling programs from 75 percent of customer incentives to 35 percent of customer incentives For all other demand response programs, the participant cost value remains at 75 percent of customer incentives. participant cost value for the air conditioning cycling program.

Both SCE and SDG&E oppose the adoption of this calculation. SCE contends that it will make it difficult to compare the demand response programs in its portfolio if one program's participant costs are different that the others. SDG&E argues that if the value of service lost is lower for a particular program, then the incentive value would be lower.

However, neither SCE nor SDG&E address the results of the evaluations from air conditioning cycling programs, which shows that the value of service lost and the transaction costs of air conditioner cycling programs (which involve mostly residential customers) is considerably lower than the value of service lost and the transaction costs of other demand response programs (which involve mostly non-residential customers). The Commission concludes it is reasonable to adopt the calculation as defined in the proposed Protocols.

Next, we discuss the issue of capital costs. The proposed Protocols recommend a formula for determining the base value of each capital investment.

Base value = low value + ½ * (high value – low value)[101]

Parties commenting on this issue found it discriminatory, unreflective of the reality of cost recovery, and harsh.[102] SDG&E and SCE claim that amortizing the capital costs over just the three year cycle (the high case) does not accurately reflect the reality of cost recovery and over penalizes the measures.[103] Furthermore, both entities maintain that averaging this estimate with the ten year amortization case results in an exaggerated amortization cost and inappropriately low cost-effectiveness ratio. SDG&E contends that neither the high nor the low values are currently considered in the evaluation of programs and, thus, the most likely value–the lifetime amortization case–should be the

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101 The "high value" for capital costs represents the maximum possible value of these costs, which would occur if equipment were used only for the duration of the reporting period (usually three years) and then discarded. The "low value" for capital costs represents the minimum possible value of those costs, which would occur if equipment were used by both the load-serving entities and all the participants for the entire lifetime of the equipment (generally a minimum of five years). Because it is difficult to determine the extent to which either the utilities or the participants will continue to use the equipment or participate in the program, the proposed Protocols recommend a base value that is halfway between the low and high values.

102 *See* SDG&E Opening Comments at 16, Joint Demand Response Parties Opening Comments at 11, and PG&E at 19.

103 SDG&E Opening Comments at 15-16 and SCE Opening Comments at 40.

base value.[104] PG&E states that such an adjustment should be based on data and analytics specific to each type of equipment and each program.[105]

SDG&E believes that it is appropriate to fully amortize the equipment over a minimum of ten years. Similarly, SCE recommends the costs be amortized over the "useful life" and adds that only the first three years of the amortization costs should be included.[106] Referencing the term "used and useful" from an earlier section of the proposed Protocols, the Joint Demand Response Parties also request the Commission to use the "useful life" of the equipment as the time period for the evaluation.[107]

In the discussion regarding costs and benefits, the proposed Protocols state that program reporting will be limited to the length of time in the proceeding in which the cost-effectiveness analysis is being filed, which routinely has been three years. However, the proposed Protocols also suggest that load serving entities may amortize capital costs over a longer period. We find it reasonable to take this same approach in the Protocols section regarding load serving entities' capital costs. While we adopt the proposed Protocol calculation for base values, we also permit load serving entities to develop base values for capital costs over the used and useful life, such as the method recommended by SCE. However, we underscore that load serving entities will be expected to document that the installed capital equipment will actually be "used and useful" in providing load reductions over the assumed useful life.

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104 SDG&E Opening Comments at 15-16.

105 PG&E Opening Comments at 19.

106 SCE Opening Comments at 40.

107 Joint Demand Response Parties Opening Comments at 11 citing the Protocols at 12.

3.2.3.6. Non-energy and Nonmonetary Benefits

The proposed Protocols present a detailed discussion of the non-energy and non-monetary benefits. Parties were clear that non-energy and non-monetary benefits are best applied to a societal test. As further discussed below, no changes will be made to the application of these benefits. However, as we previously determined, a qualitative analysis of these benefits is required but further work on the expectations of the analysis is need. Furthermore, issues related to the societal test are being contemplated in R.14-10-003. We defer to that rulemaking for any policy determinations.

The proposed Protocols separate these benefits into three categories: social, utility and participant non-energy benefits, explaining each section in more detail than was provided in the 2010 Protocols. Pointing out that the load serving entities are not required to include these benefits in the cost-effectiveness analysis, the proposed Protocols[108] underscore that a qualitative analysis of these benefits is required. Furthermore, the proposed Protocols recommend adding some of these benefits to the analysis for each of the four Standard Practice Manual tests.[109]

PG&E protests the "attempted reworking of the Standard Practice Manual" by the unilaterally addition of non-energy benefits to each of the four tests thus altering "current Commission policy on how programs are valued via their cost-effectiveness. Furthermore, PG&E and SCE contend that this would

[108] SDG&E at 5, CLECA at 6, and Joint Demand Response Parties at 17.

[109] The four Standard Practice Manual tests are: Total Resource Cost (TRC), Ratepayer Impact Measure (RIM), Program Administrators Test (PAC) and Participant Test.

convert the Total Resource Cost (TRC) test into the Societal Cost Test.[110] SCE however, notes that the addition of a Societal test is more appropriate.[111] Other parties also express support that non-energy benefits belong in a societal test.

We agree that each of the four cost-effectiveness tests represent a different perspective and is valuable to inform a policy outcome. We also note that the four tests used in the Standard Practice Manual are used in other proceedings. As recognized by PG&E, changing these tests would have far-ranging effects in these other proceedings. Hence, we decline to adopt the changes recommended in the proposed Protocols. However, the Commission should consider the idea of a societal test, as supported by most parties in this proceeding. Given the breadth of the use of the Standard Practice Manual and the four tests, the creation of a new test should be developed by a wider audience than demand response stakeholders. The scope of R.14-10-003, the integration of distributed energy resources, includes the valuation of all distributed energy resources i.e., cost-effectiveness methodologies. As such we defer the issue of the development of a societal test for the purposes of cost-effectiveness evaluation to R.14-10-003 for a discussion by an appropriately wider audience.

3.2.4. Finalizing the Adopted Protocols

Throughout this Decision, we make reference to necessary clarifications in the proposed Protocols. In comments, several parties recommended the use of a working group or workshop to address ambiguities in the proposed Protocols. We agree that the proposed Protocols are not complete and work remains to be done.

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[110] PG&E at 17-18 and SCE at 25.

[111] SCE at 25.

Within 60 days from the issuance of this Decision, the Utilities shall facilitate a working group, to include the Commission's Energy Division Staff, to make the necessary amendments and clarifications to the draft Proposal as follows:

- Provide an improved understanding of the interim A Factor, the RECAP model;
- Provide guidelines and expectation for the D Factor work papers;
- Improve language in the Protocols to address the expectations of the qualitative analysis and make clear that the qualitative analysis is required; and
- Revise the cost-effectiveness reporting tool to be in compliance with this Decision.

Once a final draft Protocol is developed, the Utilities shall host a workshop discussing the draft Protocol. The Utilities shall be responsible for filing the final Protocol, as agreed to in the workshop, via a tier three advice letter. The advice letter shall be filed no later than 120 days from the issuance of this Decision. A resolution addressing the advice letter and final Protocols shall be developed by Energy Division for Commission consideration.

4. Comments on Proposed Decision

The alternate proposed decision of Commissioner Florio in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on November 5, 2015 by the following parties: CAISO, Calpine Corporation, CLECA, Environmental Defense Fund (EDF), Joint Demand Response Parties, ORA, OPWER, PG&E, SDG&E, and SCEReply comments were filed on November 10, 2015 by CAISO, CLECA, Clean

Coalition, Joint Demand Response Parties, ORA, PG&E, SDG&E and SCE. . In response to comments to the Proposed Decision, corrections and clarifications have been made throughout this decision.

We make particular note of three comments here. First, EDF requests the Commission to establish incentives for the adoption of load modifying demand response, such as time of use rates.[112] There is nothing in the record of this proceeding to help us create pilots or demonstrations projects. However, we note that the appropriate place to create such a record would be in the next set of demand response applications.

Second, the Joint Demand Response Parties contend that the Proposed Decision intended to diminish load modifying demand response resources.[113] We disagree. The Commission is strengthening both the non-event-based load modifying demand response and the supply side demand response by ensuring all demand response is reliable. As we listed above, the Commission is currently engaged in several efforts to improve and expand reliable and measureable demand response resources throughout California.

Third, in their comments on the Proposed Decision, the IOUs, CLECA, and the Joint DR Parties argue the effective date of the capacity value determinations adopted herein should be January 1, 2018. PG&E and SDG&E each make a commitment to complete the integration of effected programs by 2018, while asserting 2017 would introduce new costs and hardship. CLECA and the Joint DR Parties reason that setting the deadline to 2018 increases the likelihood that enrolled customers successfully transition to integrated programs. CLECA

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[112] EDF Opening comments to the Proposed Decision at 4.

[113] Joint Demand Response Parties Opening comments to the Proposed Decision at 8.

further points out the need to prove enough time to complete and test CAISO system improvements. We find these reasons compelling and have modified the proposal to make the effective date January 1, 2018. This change in no way diminishes our sense of urgency in completing the integration of IOU programs.

5. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and Kelly A. Hymes is the assigned ALJ in this proceeding.

Findings of Fact

1. The Commission has expressed its support of the integration of demand response into the CAISO market since 2008 and has not waived from that support.

2. The Order Instituting Rulemaking 13-09-011 and D.14-03-026 provided assurance that the current demand response programs and contracts would not be undercut mid-cycle such that investments made and contracts entered into would be stranded.

3. Extending that logic to a new program year with discreet guidance goes beyond the original intention.

4. The Commission has taken a deliberative approach to demand response integration since 2008.

5. The transition currently underway will benefit both the public and stakeholders through an increased ability to rely on demand response in meeting California's resource needs.

6. The CAISO hard trigger proposal is suboptimal in that it may lead to an increase in the number of dispatches during times when a) customers are not anticipating being dispatched; b) capacity needs may not be high; c) capacity

values are based on moderate loads; d) over-generation problems already exist; and e) energy prices are lower.

7. Implementation of the CAISO hard trigger proposal could culminate in the inability to cost-effectively fulfill the loading order or help the state achieve its long term energy goals.

8. The reliability demand response programs are scheduled to be integrated into the CAISO market by January 1, 2018.

9. Non-event-based load modifying demand response are and should continue to be embedded into the California Energy Commission's unmanaged/base case load forecasts.

10. Once reliability demand response programs are integrated into the CAISO market, as required by D.10-06-034, the number of programs remaining in the event-based load modifying category and the associated megawatts are minimal.

11. The Commission has already spent a considerable amount of time and resources, including ratepayer funded resources to attempt to create a hard trigger mechanism and has been unsuccessful.

12. It is not reasonable to continue to expend ratepayer funded time and resources to study hard triggers.

13. The potential benefits of the CAISO hard trigger proposal are limited given the proposal would only apply to a small amount of megawatts.

14. A hard trigger meeting all the party-suggested parameters as well as the associated nomination and penalty structure would be difficult to create and adopt.

15. Existing soft triggers for event-based load modifying demand response programs do not provide dependable reductions in load, procurement obligations, or avoided cost.

16. The Commission directive, "to demonstrate that neither load modifying nor supply resources receive an unfair advantage," was established in D.14-12-024 to ensure that load modifying resources were not augmented to further disadvantage supply resources.

17. The existing soft triggers in place for event based demand response programs do not provide dependable reductions in load, procurement obligations, or avoided cost.

18. In D.14-12-024, the Commission wanted to ensure that supply resources become more prevalent in demand response.

19. Resource value is not the only value for demand response resources.

20. Demand response could meet distribution needs.

21. The Commission is exploring other values for demand response resources in R.14-08-013.

22. The CAISO Hard Trigger proposal lacks essential detail on how nominations and penalties associated with the hard triggers would be implemented.

23. At this time, there is no viable methodology for valuing and accounting for event-based load modifying demand response in the CAISO market.

24. The Commission has embarked on several efforts to grow and improve non-event-based load modifying and supply side resources.

25. The avoided cost calculator impacts all distributed energy resources.

26. The Distributed Resources Plans proceeding and the Integrated Distributed Energy Resources proceeding include in each of their scopes a

determination regarding cost-effectiveness methodologies for resources including demand response resources.

27. It is efficient to defer a determination regarding cost-effectiveness methodologies to either the Distributed Resources Plans proceeding or the Integrated Distributed Energy Resources proceeding.

28. Parties agree that a revised A Factor is needed.

29. Parties are concerned with the use of the proposed RECAP model.

30. Parties do not support a model that has not been vetted in the demand response proceeding.

31. The RECAP model has not been vetted in the demand response proceeding.

32. The B Factor values are arbitrary.

33. Resources that can be dispatched in 20 to 30 minutes or less have greater value than those dispatched in more time.

34. There are generation resources that cannot be started up in less than 30 minutes.

35. Demand response, a clean resource, should not be required to perform at a higher standard than a fossil-fueled combustion turbine.

36. If the resource adequacy proceeding establishes a new associated policy regarding the dispatch time requirement, the B Factor adopted here may need to be revised.

37. What the C Factor actually calculates is not what it is meant to calculate, i.e., capacity versus energy benefits.

38. The use of the term “available” in the proposed C Factor may negatively impact program design.

39. There may be relevant data in the C Factor analysis in regards to a resource's ability to be dispatched.

40. A demand response program that is dispatched increases its value by avoiding the purchase of high-priced generation.

41. There is support for the use of the locational net benefits methodology versus the Net Energy Metering methodology to adjust for transmission and distribution avoided costs.

42. The use of the locational net benefits methodology will create consistency across all distributed energy resources.

43. The development of the locational net benefits methodology is in the scope of R.14-08-013.

44. SCE provided no justification for making the E Factor optional.

45. The purpose of the F Factor is to reward flexibility.

46. There is a need to address intermittent generation, i.e., wind and solar.

47. There is value in the concept of an F Factor.

48. The most expeditious approach to developing a methodology for the F Factor is a technical workshop.

49. R.14-08-013 is developing a locational net benefit methodology.

50. The creation of a locational net benefit methodology will negate the need for a G Factor.

51. The default G Factors proposed are rooted in the long term procurement planning proceeding evidentiary record.

52. Dynamic pricing programs are not required to be in the demand response portfolio pursuant to D.12-04-045.

53. The protocols are not designed to measure the cost-effectiveness of pilot programs, technical assistance, educational, or marketing and outreach activities.

54. The Commission must account for a complete review of the cost-effectiveness of individual demand response programs as well as the demand response portfolio.

55. Including all costs associated with a demand response program, including those costs approved in prior decisions, allows the Commission to account for a complete review of the cost effectiveness of individual demand response programs and the entire demand response portfolio.

56. There is a difference between funding for entire demand response programs and activities and funding for costs associated with those programs and activities.

57. Including programs and activities previously funded in other proceedings could skew the portfolio analysis.

58. The purpose of the portfolio analysis is to avoid double-counting.

59. The protocols are not a good tool to measure the cost-effectiveness of the permanent load shifting program.

60. There are currently at least six tests measuring demand response performance.

61. The information attained in the proposed ex-post cost-effectiveness analysis may be useful in other respects.

62. The requirement to obtain prior written Commission approval if confidential data is used in any cost-effectiveness analysis is not a new requirement.

63. Parties had a prior opportunity to argue the merits of allowing the use of confidential data.

64. The methods presented in the Protocols should present transparency by using clear and publicly available data and data sources.

65. Transparency is a critical component of establishing results in which all parties can have confidence.

66. The 2010 adopted Protocols required a qualitative analysis, as described in Section 1.G.

67. The language in Section 1.G of the Protocols needs to be improved to clarify that the qualitative analysis is required.

68. Clarification is needed on the expectations of the qualitative analysis.

69. The current methodology for analyzing the cost-effectiveness of dual participation programs is not appropriate.

70. There is little evidence to determine which of the three options for measuring cost-effectiveness of dual participation programs to approve.

71. There is consensus that option 1, requiring an additional analysis of both the capacity and the energy program combined, is the preferred option.

72. Option 1 should avoid double counting.

73. The proposed calculation for determining bill increases and reductions is complex due to customer churn.

74. The calculation for determining bill increases and reductions only impacts default programs and customer without bill protection.

75. The proposed Protocol offers a default option for approximating the values for determining bill increases and reductions.

76. The proposed Protocol limits program reporting to the length of time of the proceeding in which the cost-effectiveness analysis is being filed, which routinely has been three years.

77. The proposed Protocol allows load serving entities to amortize capital costs over a longer period of time.

78. Each of the four cost-effectiveness tests represent a different perspective.

79. Each of the four cost-effectiveness tests are valuable to inform a policy outcome.

80. The four tests used in the Standard Practice Manual are used in other proceedings.

81. Changing these tests in this demand response proceeding would have far-ranging effects in other proceedings.

82. The creation of a societal test should be developed by a wider audience than demand response stakeholders.

83. The scope of R.14-10-003 includes the valuation of all distributed energy resources, i.e., cost-effectiveness methodologies.

84. The proposed Protocols are not complete; work remains to be done.

Conclusions of Law

1. It is reasonable to conclude that the Commission intends to integrate demand response resources into the CAISO market.

2. The amount of time and resources needed to develop and implement a hard trigger is unreasonable given the limited megawatts involved.

3. It is not reasonable to continue to expend ratepayer funds to study hard triggers.

4. It is reasonable to conclude that without a valid and substantive methodology, event-based load modifying demand response has no capacity value.

5. It is not reasonable to determine the use of the avoided cost calculator in a demand response centric proceeding.

6. It is reasonable to adopt a placeholder for the A Factor until parties have an opportunity to vet the RECAP model.

7. It is reasonable to adopt the revised values for the B Factor.

8. It is reasonable to adopt the C Factor solely as a sensitivity analysis.

9. It is reasonable to defer the development of the locational net benefits methodology to R.14-08-013.

10. It is reasonable to consider the lack of comments on the E Factor to indicate no opposition to the adoption of the E Factor, as proposed.

11. It is reasonable to approve a placeholder for an F Factor until a methodology is adopted.

12. It is reasonable to adopt the default G factors on an interim basis until a locational net benefit methodology is finalized.

13. It is reasonable to require all costs associated with a demand response program or activity to be included in a cost-effectiveness analysis, including costs approved in prior proceedings.

14. It is reasonable to revisit the ex post cost-effectiveness analysis in a future discussion on demand response evaluation.

15. It is reasonable to continue the requirement that load serving entities shall obtain prior written Commission approval if confidential data is used in any cost-effectiveness analysis.

16. It is reasonable to adopt a placeholder for the language in Section 1.G. until the language is finalized through a workshop.

17. It is reasonable to adopt option 1, requiring an additional analysis of both the capacity and the energy program combined, to measure the cost-effectiveness of dual participation programs.

18. It is reasonable to adopt the proposed calculation for determining bill increases and reductions.

19. It is reasonable to allow load serving entities to amortize capital costs over a period longer than three years.

20. The Commission should consider the idea of a societal test as part of the cost-effectiveness analysis.

21. It is reasonable to defer the issue of the development of a societal test for the purposes of cost-effectiveness evaluation to R.14-10-003.

O R D E R

IT IS ORDERED that:

1. Effective January 1, 2018 Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall only attribute capacity value to demand response programs that are integrated into the California Independent System Operators wholesale market or embedded in the California Energy Commission's unmanaged/base case load forecast.

2. The 2015 Demand Response Cost-Effectiveness Protocols, attached as Appendix A, are adopted.

3. A placeholder for the A Factor is created, in the 2015 Demand Response Cost-Effectiveness Protocols, attached as Appendix A, until an interim methodology is developed through a workshop. A final interim methodology will be adopted in a future decision. Once a probabilistic model is adopted in Rulemaking 11-10-023, it will replace the interim methodology.

4. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall use the following B Factor values as adopted in the demand response cost-effectiveness protocols: 100 percent for those programs with a notification time of 30 minutes or less, 94 percent for those

programs with a notification greater than 30 minutes the day of, and 88 percent for those programs with a notification time the day ahead or greater.

5. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall include, in their cost benefits analysis results, work papers justifying estimates for the D Factor.

6. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall use the E Factor as described in the 2015 Demand Response Cost-Effectiveness Protocols, attached as Appendix A.

7. The Commission's Energy Division shall organize a working group to develop a draft proposal for an F Factor methodology. No later than 90 days from the issuance of this decision, the Energy Division shall present the draft proposal for the F Factor methodology in a workshop in this proceeding.

8. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall file a Tier Three advice letter requesting the Commission to adopt a final methodology for the F Factor resulting from the workshop required by Ordering Paragraph 6. In finalizing the F Factor methodology, the Utilities shall collaborate with the Commission's Energy Division Staff and all interested parties to consider the ideas discussed in this decision and during the technical workshop.

9. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) may use the default G Factors in the proposed protocol on an interim basis until a locational benefit methodology is finalized in Rulemaking 14-08-013. The Utilities shall include justification for using the default G Factors in the work papers accompanying the cost-effectiveness analysis for a program.

10. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall include all costs associated with a demand response activity or program, including costs previously approved in a prior decision, i performing a cost-effectiveness analysis on a demand response activity or program.

11. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall request funding for all demand response related activities and programs in their routine budget application. The Utilities are discouraged from including demand response program or activity budget requests in general rate cases or applications outside of the routine demand response budget application.

12. The Commission's Energy Division shall organize a working group to develop a draft proposal for a methodology to measure the cost-effectiveness of a permanent load shifting program. No later than 60 days from the issuance of this decision, the Energy Division shall notice the first meeting for this work.

13. No later than 180 days from the issuance of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall file a report in this proceeding requesting Commission review and approval on the findings of the permanent load shifting methodology working group.

14. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall perform an additional analysis of both the capacity and the energy program combined in order to measure the cost-effectiveness of dual participation demand response programs.

15. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall comply with the 2015 Demand

Response Cost-Effectiveness Protocols for determining bill increases and reductions in participant costs.

16. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall comply with the 2015 Demand Response Cost-Effectiveness Protocols for determining the cost of capital equipment. The Utilities shall document that the installed capital equipment will be used and useful in providing load reductions over the assumed useful life.

17. No later than 60 days from the issuance of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall facilitate a working group to work with parties to create a final Protocol that completes the work as described in this decision.

18. No later than 120 days from the issuance of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file the final Protocol via a tier 3 advice letter.

19. Phase II of Rulemaking 13-09-011 remains open to finalize the cost-effectiveness protocols and to address the remaining issues of Phase Three.

This order is effective today.

Dated November 19, 2015, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners