

**BEFORE THE PUBLIC UTILITIES COMMISSION  
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking Pursuant to Assembly Bill  
2514 to Consider the Adoption of Procurement Targets for  
Viable and Cost-Effective Energy Storage Systems.

R.10-12-007  
Filed December 16, 2010

**REPLY COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE  
RESPONDING TO ADMINISTRATIVE LAW JUDGE'S RULING ENTERING  
INTERIM STAFF REPORT INTO RECORD AND SEEKING COMMENTS**

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February 21, 2013

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In accordance with the California Public Utilities Commission’s (“Commission’s”) Rules of Practice and Procedure, the California Energy Storage Alliance (“CESA”)<sup>1</sup> hereby submits these reply comments on the *Administrative Law Judge’s Ruling entering Staff Report Into Record and Seeking Comments*, issued by Administrative Law Judge Amy C. Yip-Kikugawa on January 18, 2013 (“ALJ’s Ruling”).

**I. INTRODUCTION.**

CESA submits these reply comments for three reasons. First, CESA corrects a number of misinterpretations and resulting mischaracterizations in Opening Comments filed by several parties concerning CESA’s presentation at the workshop held in this proceeding on January 14, 2013 (“Workshop”). CESA’s second purpose in submitting these reply comments is to register its strong agreement with Opening Comments filed by numerous parties that the Commission must promptly complete the current work in progress on cost-effectiveness that is very near

<sup>1</sup> The California Energy Storage Alliance consists of A123 Systems, Alton Energy, AU Optronics, Beacon Power, CALMAC, Chevron Energy Solutions, Christenson Electric Inc., Clean Energy Systems Inc., CODA Energy, Deeya Energy, DN Tanks, Energy Cache, EnerVault, FAFCO Thermal Storage Systems, Flextronics, Foresight Renewable Systems, Greensmith Energy Management Systems, Growing Energy Labs, Gridtential Energy, Halotechnics, Ice Energy, Innovation Core SEI, LG Chem, LightSail Energy, NextEra Energy Resources, Panasonic, Powertree, Primus Power, RedFlow Technologies, RES Americas, Saft America, Samsung SDI, Sharp Labs of America, Silent Power, SolarCity, Stem, Sovereign Energy Storage LLC, Sumitomo Corporation of America, TAS Energy, UniEnergy Technologies, and Xtreme Power. The views expressed in these Comments are those of CESA, and do not necessarily reflect the views of all of the individual CESA member companies. <http://storagealliance.org>

drawing to successful closure.<sup>2</sup> CESA agrees with Calpine,<sup>3</sup> among others, that the substantial body of soon-to-be complete collaborative work on cost-effectiveness will provide a critical element of the evidentiary foundation required by the Commission for evaluation of procurement policy options. CESA notes that the Interim Staff Report<sup>4</sup> states:

“The purpose of this Interim Staff Report is not to make specific recommendations on any of the barriers or policy options at this point in time, but rather to seek comment from stakeholders based on the work prepared in the proceeding up until this point. Staff expects stakeholder comments, future workshops, and subsequent staff proposals to all be part of the record of this proceeding.” (p. 3).

CESA also notes that informed speculation and sincere expressions of opinion by commenting parties, while appropriate at this stage of the proceeding, pale in significance when compared to the substantial evidence already in the record that can reasonably support any of the wide range of policy decisions that the Commission may make once the record is closed. Furthermore, the Commission can and should inform its policy determinations and decisions regarding procurement planning and goal setting in this proceeding with references to other related Commission decisions and proceedings. In addition to the substantial evidentiary record produced to date in this proceeding, the Commission should take official notice of (as one example) the Track 1 decision it arrived at very recently in the Long-Term Procurement Planning proceeding,<sup>5</sup> and others as appropriate.

CESA supports the timeline that was introduced by the Energy Division Staff at the Workshop, and looks forward to commenting on the final staff proposal that is expected to be produced for public comment in the coming few months. In pertinent part, the timeline proposed by the Energy Division staff specifically provides as follows :

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<sup>2</sup> The current *Draft Workplan for Cost-Effectiveness Study*, dated February 8, 2013, is subject to revision, but is attached as Appendix A to these reply comments as a point of reference.

<sup>3</sup> *Comments of Calpine*, filed February 4, 2013.

<sup>4</sup> *Energy Storage Phase 2 Interim Staff Report*, January 4, 2013.

<sup>5</sup> (D).13-02-015, issued January 13, 2013.

“1<sup>st</sup> Quarter 2013

- Glossary of Commonly Used Terms - Some parties have expressed a desire for a common set of definitions to terminology that is frequently used in this proceeding.
- Energy Storage Cost-Effectiveness Analysis – a document that outlines how cost-effectiveness for storage will be approached, complete with (1) categories of benefits to be considered (2) categories of costs to be considered and (3) a set of underlying assumptions to be used in the analysis including a ‘baseline’ of status quo solutions to compare against storage solutions
- Summary of preliminary cost-effectiveness analysis from exercising the modeling tools.
- Finalized Use Cases to incorporate cost-effectiveness analysis (recognizing that these documents may continue to evolve to fit future process needs).

2<sup>nd</sup> Quarter 2013

- Staff proposal presenting cost-effectiveness analysis, recommended procurement policies, and guidance on cost-effectiveness methodology for future procurement application.”

Third, the Commission should establish as a general policy guideline to Load Serving Entities (“LSEs”) that cost-effective and viable energy storage resources should be the *most favored* energy resource available to meet California’s system needs. This approach would be entirely consistent with the concept proposed in the comments of Pacific Gas and Electric Company (“PG&E”):<sup>6</sup>

“To the extent that any particular resource or class of resources provides the highest value, there would be a clear market signal through procurement. PG&E suggests, consistent with CESA’s recommendations, that:

- Utilities will be required to consider storage; and
- If storage projects are not found to be cost-effective, utilities will have to demonstrate to the Commission and the Procurement Review Group

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<sup>6</sup> *Pacific Gas and Electric Company Comments on the Interim Staff Report in Phase 2*, filed February 4, 2013.

(PRG) that any proposed storage projects are not cost-effective compared to other bidders. (p. 9).”

CESA asks the Commission to support PG&E’s approach in principle and the distinction CESA draws between “preferred resources” listed in the Loading Order and a “most favored resource” policy preference for the flexible operating characteristics of energy storage resources.

**II. MISCHARACTERIZATIONS OP CESA’S WORKSHOP PRESENTATION IN OPENING COMMENTS FILED BY PARTIES SHOULD BE DISREGARDED BY THE COMMISSION.**

**A. Southern California Edison.**

1. *SCE’s Comment:* Percentage-Based Procurement “Target” Lacks Any Clear Methodology or Principles.

*CESA’s Response:* The goals included in the presentation at the Workshop were clearly labeled: “Examples.” As explained in its Opening Comments, CESA has recommended an approach to goals based upon system need.

2. *SCE’s Comment:* Contrary to CESA’s presentation, most energy storage benefits may be monetized today, or will be monetized when ongoing regulatory reforms are complete.

*CESA’s Response:* CESA disagrees with the assertion that many of these services are monetized, per our comments below. However, there is a larger issue: it is *unclear* if utility procurement processes value, or correctly evaluate, the benefits listed, due to lack of transparency on utility procurement processes to outside stakeholders. In these cases, it does not matter if an energy storage system would be able to capture the benefits if the procurement process does not recognize the benefits. If the benefits are not recognized during procurement, then energy storage systems will appear as though they are not cost-effective. They will not be procured at appropriate levels for utilities and ratepayers, and energy storage systems will have insufficient opportunity to demonstrate that they can capture those value streams. CESA expects

the cost-effectiveness work in this proceeding to show that certain applications of energy storage will, in fact, be cost-effective when all benefits are correctly accounted for.

3. ***SCE's Comment:*** "Grid Benefits," including "Reduced Fossil Fuel Use" and "Increased efficiency of installed generators," generally refers to the emissions reductions gained when energy storage displaces or abates conventional generation or enhances generation efficiency. CESA displayed a fundamental misunderstanding of the benefits captured in the daily energy markets.

***CESA's Response:*** CESA agrees that emissions reductions are gained when energy storage displaces or abates conventional generation or enhances generation efficiency. However, these benefits are not fully monetized at this time. For example, the following factors must be accounted for:

- a. Historic ancillary service market prices commonly used to evaluate generation projects do not include the price of greenhouse gasses ("GHGs"), nor do they accurately reflect the long term increases in the price of GHG offsets required to fulfill AB32 requirements.
- b. Capacity values do not currently account for expected future prices of GHG offsets. SCE assumes carbon offset prices of \$10 per ton based upon 2012 auction prices. However, evidence in the long term procurement planning proceeding shows that carbon offset prices are projected to be \$36.65 per ton by 2020.<sup>7</sup> When resources with greater than 20-year lifetimes are being considered, it is critical that long term carbon prices are taken into account when evaluating cost-effectiveness.

The developers of many generating resources are compensated through long-term power purchase agreements ("PPAs"), not through market participation. For example, generation-sited energy storage systems collocated with fossil generators can greatly increase the output of those traditional fossil generators, but established PPA rates do not change if an on-site energy storage system is able to provide more power output. Thus, the developers of generation-sited energy storage systems are unable to capture the value of the increased capacity. The result is that

<sup>7</sup> See, D.12-12-010, p. 36-37.

utility customers are deprived of resources which provide energy at lower cost than traditional assets. A proposed solution, offered at the Workshop, and in comments filed in this proceeding is to ensure these generators are able to receive a separate contract for the power produced by the generation-sited energy storage systems.

4. ***SCE's Comment:*** "Distribution Peak Capacity Support (Deferral)" and "Distribution Operation (Voltage/VAR Support)" refer to a storage device's ability to reduce peak load and the ability to provide voltage and volt-ampere reactive ("VAR") support. These benefits may allow system planners to defer system capacity upgrades or the installation of power quality equipment such as capacitors. Because a utility owns its distribution assets, the utility fully monetizes its distribution benefits by evaluating the project's impact on the distribution system to establish and estimate the abated costs.

***CESA's Response:*** CESA agrees with SCE that energy storage may "reduce peak load" and "provide volt-ampere reactive ("VAR") support. CESA also agrees that, "the utility fully monetizes its distribution benefits." However, this statement does not apply to a customer installing an energy storage system behind the meter. The customer is not able to monetize either the distribution peak capacity support or distribution operation benefits provided to the utility by the energy storage resource. Because the customer cannot monetize these benefits, it is less likely that customers will install behind the meter energy storage resources than if they were able to monetize these benefits.

5. ***SCE's Comment:*** "Locational Flexibility" and "Modularity" will be monetizable through a least-cost best-fit procurement process. Locational flexibility could reduce siting costs, resulting in a lower bid price that increases the likelihood of selection. Alternatively, locational flexibility could be incorporated on the "best fit" side: a resource that can be sited in a preferable location will be valued incrementally higher. Similarly, modularity could also be monetized through the least-cost best fit process. A modular resource could allow the developer to build precisely according to the defined need, so as to maximize needed benefits while minimizing costs.

***CESA's Response:*** There are additional benefits of locational flexibility and modularity which are not accounted for in SCE's comment. Locational flexibility and modularity are both characteristics of many energy storage systems, which can also allow them to be moved to a

different location during the course of their project life. This means that an energy storage system might be placed at one high value location, and then moved to another high value location during its lifespan. Taking advantage of the mobility of energy storage is a key benefit for certain applications such as distribution deferral. The reduced risk of achieving energy storage benefits due to their ability to be readily moved and/or modularized is not addressed by SCE's comment.

6. ***SCE's Comment:*** CESA cited benefits that are too vague to be meaningful, or are common to both conventional and storage resources. For example, it is unclear to what "Increased Integration of Renewable Resources" specifically refers; "integration" of renewable energy can mean any number of activities, including some benefits provided by conventional generation. Similarly, any resource provides some degree of "Grid Reliability," which encompasses some of the functions noted above. SCE agrees that storage provides benefits that are related to these concepts, it makes no sense to broadly claim that storage is uncompensated for them.

***CESA's Response:*** Contrary to SCE's comment, energy storage resources may provide clear benefits which are not currently compensated. The benefit of increased integration of renewable resources refers to three unique capabilities of energy storage which are critical to renewable integration. The first is the capability of energy storage systems to store renewable energy that might otherwise be wasted. The second is the capability of energy storage to balance, firm, and shape renewable energy output without producing additional emissions. Finally, by shaping and scheduling renewable energy production, energy storage has the potential to better utilize existing transmission and distribution capacity. The critical issue is that California is procuring renewables to achieve AB 32 and Renewables Portfolio Standard ("RPS") goals. If those renewables are balanced by fossil resources, then achieving high RPS goals becomes a losing battle, where increased renewables requires adding more fossil fuel generation, which requires adding additional renewables. In assisting with renewable grid integration, energy storage allows for greater penetration of renewable energy on the grid, and



increased utilization of both renewable energy assets and existing transmission and distribution assets paid for by ratepayers.

The grid reliability benefit provided by energy storage is the ability for an energy storage resource to continue to provide power to customers in a grid outage. In addition, many fast response energy storage systems may be rapidly deployed to prevent large grid outages in the first place. Compensation rules for these unique benefits of energy storage are unclear, at best.

7. ***SCE's Comment:*** CESA asserted large-scale procurement funded by ratepayers can help improve economies of scale and reduce costs. While this is true, spending enormous sums of utility customer money for the sole purpose of making something less costly in the future is a bad proposition, especially when the net benefits of storage are yet to be demonstrated. While better economies of scale is a helpful secondary benefit once a resource is found to be cost-effective, it is ultimately not the utility customers' obligation to improve the cost structure of competitive developers and manufacturers.

***CESA's Response:*** This comment implies that CESA has advocated for procurement goals for the sole purpose of improving economies of scale and reduce cost. Quite the contrary! CESA advocates for procurement goals because it is a proven way of achieving focused results by a broad set of stakeholders. The results CESA seeks are consistent with that of SCE and many other stakeholders - -a cleaner, more reliable, affordable, efficient and secure electric power system for California. Appropriate procurement goals will provide the necessary market signal to stimulate even greater investment into energy storage solutions, financing and manufacturing capacity ... which will result in greater economies of scale and even lower costs in the future, creating a virtuous cycle of enabling even more applications of energy storage to become cost effective and viable. It is important to note that procuring large amounts of conventional fossil fuel generation capacity over the next decade will have a rate payer impact as well ... and in particular, will increase the 'switching cost' of moving to a cleaner alternative. CESA is suggesting that the Commission instead support the procurement of lower-emissions,

more flexible energy storage assets that are being shown to be more cost-effective than traditional assets.

8. ***SCE's Comment:*** CESA's Presentation Distorts the Results of the CAISO's 33% RPS Studies CESA selectively quoted a slide taken out of context from a CAISO presentation to support the false claims that "Under business as usual, the 33% RPS will not reduce GHGs" and "GHG/Fuel use increases when 33% RPS happens without grid-connected storage available. CESA misrepresented the environmental benefits of moving to 33% renewables prior to inclusion of storage on the grid. SCE further states, while energy storage has some potential to decrease emissions in certain applications, CESA's implication that emissions reductions will not occur without storage is entirely false.

***CESA's Response:*** Unfortunately SCE seems to have misunderstood or taken the CESA presentation out of context by ignoring CESA's reference to "business as usual" in the slide. CESA agrees with SCE that the RPS has significant emissions benefits, and agree that energy storage does have potential to decrease emissions if effectively utilized. The recent slowdown in RPS procurement and implementation is a strong indication that under business as usual, the full and best benefits from the RPS are not being captured as best they could, and, utilizing fossil generation to balance renewable energy is a 'lost emissions reduction opportunity.' The CAISO slide in CESA's presentation identified a scenario where achieving California's 33% RPS goal did not result in reduced fuel burn in California. CESA did not mean to imply that that was the only scenario possible.

CESA is not saying that energy storage is required to get reductions, but that energy storage is essential to achieving reduction effectively. As the volatility of the grid increases (either due to increased intermittent generation or increased high demand intermittent loads such as electric vehicles), non-GHG-generating buffering is needed to reduce GHGs. Running fossil generators at minimum loads in standby mode or at high ramp rates generates a tremendous amount of GHGs. This is simply not necessary. In contrast, most energy storage resources do not require minimum load levels or wasteful minimum idling levels. Their energy output comes

from energy taken from the grid, which becomes increasingly clean as renewable penetration increases. CESA believes that a careful study of alternative emissions scenarios under AB 32 will clearly demonstrate that with use of cost-effective energy storage, the amount of emissions will likely be significantly reduced by 2020, compared to the cases without energy storage. Procurement of too much unnecessary gas now will have negative emissions consequences for many years. Cost-effective energy storage is an essential tool to lower overall cost risk, and further add value to the 33% RPS goal, and beyond.

9. ***SCE Comments:*** SCE strongly objects to implications that investor-owned utilities (“IOUs”) lack either the will or the ability to properly consider new technologies such as storage. CESA’s claim that the “inertia of business-as-usual procurement must be overcome”<sup>5</sup> ignores these ongoing efforts by utilities to transform and advance utility procurement processes as the market landscape continues to develop. SCE and other utilities are continually adapting to the changing energy landscape, changing requirements of the grid, and evolving public policy objectives. (page 6)

***CESA Response:*** CESA would like to clarify its statement from the workshop. CESA did not mean to imply that ‘IOUs’ lack the will or the ability to properly consider new resources such as energy storage. Clearly this is not the case, as SCE and other utilities have successfully implemented a broad range of pilot projects to date, and, in the case of SCE, proactively initiated in-depth study of the role of energy storage in the electric power system. What CESA intended to convey was the idea that new energy storage resources have a different risk profile, from an investor standpoint, as compared to traditional fossil based resources. In the business world, higher risk investments typically enjoy a higher return. CESA wanted to point out that under existing utility compensation mechanisms there is currently no way for utilities to be fairly compensated for the higher risk profile – both real and perceived – of future energy storage procurement. CESA recommends that this be factored in when considering energy storage policy development.

**B. Jack Ellis.**

*Jack Ellis' Comments:* CESA has also made no attempt to quantify any of the capacity and ancillary benefits that storage built for peak capacity could provide, so there's no way to compare the cost of achieving CESA's quantitative justification for the 1,500 MW of storage it suggests be targeted toward customer bill management.

*CESA's Response:* As an interested party with relatively little experience with grid-connected energy storage, Jack Ellis' comments are apparently made with insufficient context as to all of what is actually happening in this proceeding and should be regarded as such by the Commission. CESA has been working collaboratively with Energy Division staff and other stakeholders, including the utilities, on a comprehensive energy storage cost effectiveness workplan that will be used to evaluate the cost-effectiveness of each of the energy storage use cases developed in Phase 1 of this proceeding. Obviously, since this work is underway and has not been completed CESA was not able to quantify the capacity and ancillary services benefits described in its Opening Comments. This is also the primary reason why CESA has not introduced any specific procurement targets to date, as it would be premature to do so before this cost-effectiveness work has been completed.

**C. Calpine.**

1. *Calpine's Comment:* Energy storage can increase GHG emissions depending on: (1) the extent to which it requires significantly more energy to charge than it can subsequently discharge; and (2) the mix of resources that are generating when it is charging and the resources that are displaced when it discharges. For example, if energy storage is charged using electricity that is produced from coal (or coal-based imports as the case may be in California) and displaces electricity that is produced from comparatively efficient and clean gas-fired plants when it is discharged, then energy storage has the potential to increase GHG emissions. It is important that resources, such as energy storage, are not added to the Loading Order on the basis of assumed GHG reductions until it is demonstrated that material GHG reductions will, in fact, be realized. (p. 5)

*CESA's Response:* Calpine's comments are correct in that the GHG emissions profile of energy storage is dependent on the source of the energy used to charge the energy storage

system. However, in the case of California it is highly unlikely that energy storage will increase GHG emissions for several reasons:

- a. In its comments emphasizing the importance of including carbon in the cost effectiveness calculation for energy storage,<sup>8</sup> Calpine calculated that an energy storage system needs to be at least 50% efficient to be on par with the costs and emissions reduction potential of a combined cycle gas turbine (“CCGT”), in a scenario where it displaces a high heat rate gas plant that would otherwise be needed if the energy storage was not dispatched.
- b. Fortunately, round-trip efficiencies of most energy storage resources are much more efficient than that example. Many common hydro resources, battery chemistries, and mechanical energy storage systems achieve are over 80% AC to AC round trip efficiency. In its Opening Comments, Alton Energy demonstrated a very simple methodology for quantifying the avoided CO2 emissions from higher heat rate generators. Alton points out that there are thousands of megawatts of gas combustion turbines with over a 11,000 heat rate ranging up over 15,000 heat rate generators still operating in California. Alton demonstrates that even in a scenario where the charging energy was sourced by 100% gas (for a bulk energy storage with a round-trip efficiency of 80%), specifically sourced from CCGTs at a heat rate of 7,000, that there would be substantial CO2 emissions avoided when displacing gas plants with a heat rate of 9,000 or higher.<sup>9</sup> It is clear, both through Calpine’s example and references by SCE that energy

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<sup>8</sup> *Comments of Calpine*, p. 6-7.

<sup>9</sup> *Alton Energy Comments*, filed February 4<sup>th</sup>, 2013, pp. 5-7.

storage can reduce emissions and help California reach its AB 32 goals in a timely and cost-effective manner.

- c. California is in the process of reducing its reliance on coal generation. Rather, the generation used at the margin is very efficient CCGT generation and gas peakers – not coal.
- d. California’s electricity mix is getting cleaner over time, not dirtier – especially its nighttime mix, as more and more wind generation comes on line. Energy storage can provide a useful ‘load’ for any excess wind or solar generation and so has the ability to be even cleaner than California’s baseline average electric mix.

**III. COST-EFFECTIVE AND VIABLE ENERGY STORAGE RESOURCES SHOULD BE CONSIDERED THE MOST FAVORED RESOURCE AVAILABLE TO MEET SYSTEM NEEDS.**

CESA reaffirms its consistent position that the Loading Order cannot be unilaterally altered by the Commission.<sup>10</sup> However, given energy storage’s potential to reduce GHGs and its highly flexible and modular capabilities it should be considered a “most favored resource.” This proceeding is an excellent platform to demonstrate the benefits of energy storage, to show the need and urgency for it to be included in the Loading Order, and demonstrate that energy storage does offer many of the same attributes of a preferred resources – including GHG reduction. Energy storage has not been included in Loading Order to date for the simple reason that its importance was not considered or understood when the Loading Order was originally established. In addition to its emissions reduction potential, energy storage is essential to realize and maximize the utilization and value of Preferred Resources.

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<sup>10</sup> See, e.g. *Reply Comments of the California Energy Storage Alliance on Administrative Law Judge’s Ruling Seeking Comment on Workshop Topics*, filed October 23, 2012, in R.12-03-014.

CESA agrees with the CAISO's comments in the LTPP to the effect that dispatchable resources, like demand response and energy storage, must help balance supply and demand; and non-dispatchable resources, like energy efficiency or behind the meter generation, must eliminate demand that would otherwise have to be balanced with supply. In the end, all resources, regardless of size, configuration, or type must fundamentally deliver the operating characteristics that can measurably support grid reliability by helping to balance supply and demand or by eliminating the need to do so.<sup>11</sup> CESA also agrees with the CAISO that at a minimum, dispatchable resources must provide energy when and where needed, and for how much is needed to balance the grid and maintain system stability based on ISO instructions and or submitted schedules.

The *sine qua non* of energy storage that should be considered when procuring all new dispatchable resources is its defining operating characteristic: that many energy storage technologies can be available to the grid at an operationally ideal zero PMin (minimum load).<sup>12</sup> Finally, CESA agrees with the CAISO that: "The ability to minimize PMin is highly beneficial for reliability and minimizing cost as the ISO anticipates periods of significant over-generation with increasing amounts of energy served by intermittent resources. Lower PMin will help minimize over generation and the potential for high negative prices where market participants (and ultimately consumers) pay to have excess energy consumed or exported. Minimizing minimum load as an operating characteristic is an important consideration in future procurement solicitations for dispatchable generation resources. All other benefits of energy storage aside, no other resource can cost-effectively and reliably deliver a PMin of zero."

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<sup>11</sup> See, e.g. *Comments of the California Independent System Operator*, filed October 9, 2012.

<sup>12</sup> 7 PMin is the minimum normal energy producing capability of a resource, i.e. the lowest operating level a resource can sustain and still be dispatchable.

**IV. CONCLUSION.**

CESA appreciates this opportunity to provide these reply comments, and looks forward to continuing to work with the Commission and parties to achieve the goals of this proceeding.

Respectfully submitted,



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Date: February 21, 2013



# **APPENDIX A**

**Draft Workplan for  
Energy Storage  
Cost Effectiveness Study  
in R.10-12-007**

(CPUC Staff Draft Paper for Workgroup Review on 2/12/13 – Not for General Distribution)

**Version 0.6**  
February 8, 2013

## 1 Introduction

This is a work-in-progress workplan and has been developed with the help of volunteers representing parties in the Storage rulemaking. It describes the cost-effectiveness analysis/study that Staff is conducting currently for storage use cases with the help of Storage OIR stakeholders and industry modeling tools. The intent of the study is to generate meaningful cost effectiveness (CE) data quickly in a limited time for select use cases to inform the consideration of various policy options in the Storage Rulemaking for advancing procurement of energy storage systems.

The workpaper is divided into six sections, corresponding to the following topics:

1. Introduction
2. Prioritized list of selected use cases to analyze
3. Overall “framework” and approach to be used for CE analysis of use cases
4. Summary of benefit streams and cost factors applicable to the use case analysis
5. Limitations or other caveats related to modeling tools (EPRI’s ESVT, DNV KEMA)
6. Input templates for driving modeling tools to generate CE results, populated with:
  - a. Direct cost & benefit inputs (source citations for inputs will be included where possible)
  - b. “Global” parameters affecting costs/benefits (discount rates, inflation, etc.)
  - c. Suggested modeling scenarios (base case, low case, high case)
  - d. Suggested sensitivity analysis

It is also important to note what this CE study does NOT do. It does not:

- establish a CPUC endorsed storage CE “methodology”
- make any factual findings regarding storage CE (such factual findings are appropriately made in other CPUC proceedings involving IOU applications seeking approval of a proposed real-world project or program with specific benefits and cost estimates)
- attempt to pursue an exhaustive, comprehensive, analytically precise and rigorous study; by necessity and to expedite, the study effort will use shortcuts and reasonable compromises and rely on available tools as is

The CE framework utilized in this study and the stakeholder learning from this process could inform the development of application-specific CE methodologies used to evaluate energy storage procurement by IOUs.

It is expected that results based on EPRI’s tool will be available by March, followed by results based on KEMA’s tools. Staff expects to hold a workshop in March-April to review the CE study results, followed by a Staff report in April.

## 2 Prioritized Use Cases

Given the limitation of time and resources, based on stakeholder feedback, complexity of the use case, potential for new insights, availability of data, and understanding of model capabilities, Staff has prioritized the use cases in the order in which they should be analyzed to efficiently use the limited time available in the proceeding to complete the CE study (basically, during 2013Q1: see timeline details noted in Section 5.3 of the CPUC Staff Phase 2 Interim Report). Using a prioritized approach, the goal is to learn from the analysis of the initial priority use cases and apply that learning to subsequent use cases

to the extent time permits.

Below is a proposed prioritized list of select use cases to be analyzed in the CE study (and the suggested technology alternatives to be compared for the respective use cases):

		Priority	Use Case Prioritization	Primary Benefit	Conventional Technology Priority #1	Storage Technology Priority #1	Storage Technology Priority #2	Storage Technology Priority #3
Phase 1	T-Connected Bulk Storage	1	Peaker Plant	Capacity, Energy, A/S	CT	Battery	Flow Battery	
		2	Ancillary Services Only	A/S	CT	Flywheel	Battery	
		3	Base Load Plant	Capacity, Energy	CCGT	Pumped Hydro	CAES	Flow Battery
	Distribution Energy Storage	4	Distributed Peaker	Upgrade deferral & Market \$	Circuit Upgrade & CT	Battery	Flow Battery	
		5	Substation-Sited Storage	Voltage Reg	Circuit Upgrade	Battery		
		6	Community Energy Storage	Voltage Reg	Circuit Upgrade	Battery		
Phase 2	Behind-the-Meter Energy Storage	7	Behind the Meter	Bill Mgt/ Avoid Cost, Market \$	Circuit Upgrade & CT	Battery	Flow Battery	
		8	Behind the Meter Utility Controlled	Bill Mgt/ Avoid Cost, Market \$, Grid Rel	Circuit Upgrade & CT	Battery	Flow Battery	
		9	Permanent Load Shifting	Bill Mgt/ Avoid Cost, Grid Rel	CT	Thermal	Battery	
Deferred		10	EV Charging		Circuit Upgrade	Battery		
		11	VER-Sited Storage		CT	Battery	Flow Battery	Thermal
		12	GasTurbine-Sited Storage		CT	Thermal	Battery	

The last three cases have been deferred as it is felt that they appear to be too complex requiring high effort relative to the limited modeling capabilities available.

### 3 Cost Effectiveness Framework

This section describes the proposed CE “framework” to be used for assessing the CE of selected use cases. The framework is based on assessing costs and benefits of a proposed use case solution from a “Total Resource Cost (TRC)” perspective using the following approach:

- 1) Assume there is an unmet system need that requires incremental investment in a new resource to address the need. The resource addition could be a conventional technology or a storage alternative.
- 2) Determine and compare lifecycle net benefit on a CDCF<sup>1</sup> basis of two “comparable” solutions for a “use case” (one based on conventional technology and the other based on storage technology) using an available modeling tool, subject to model limitations (such as any benefit or cost factors not considered by the model).<sup>2</sup>
- 3) Make adjustments to modeling input values, if/where possible, for benefits or costs not considered by the model, or qualitatively note the potential impact of these factors.
- 4) Separately consider, via stakeholder comments, other potential benefits or costs associated with attributes not already considered above.

A glossary of some terms used above follows.

**Net Benefits Comparison:** means *comparing* net benefits (NB) of two “comparable” solutions for a “use case”, with one solution based on conventional technology and the other solution based on storage technology, where  $NB_A$  of solution A =  $TB_A$  (total lifecycle benefits of solution A) –  $TC_A$  (total lifecycle costs of solution A). This is further illustrated below:

Net Benefit Framework	← Time →		
	Yr1	Yr2	YrN
<b>Benefits</b>			
<b>Capacity</b> Revenues for RA contributions			
<b>Energy</b> Market Revenues (includes arbitrage)			
<b>Ancillary Service</b> Market Revenues (regulation, spin, non-spin, ramping, black start)			
<b>Other</b>			
<b>Costs</b>			
<b>Fixed Costs</b> (capital costs, labor, financing, ROE, etc.)			
<b>Fixed O&amp;M</b> (staff, etc.)			
<b>Variable O&amp;M</b> (charging fuel, efficiency losses, emissions, wear & tear, start-up, operations, maintenance, etc.)			
<b>Net Benefit = Benefits – Costs</b>			

<sup>1</sup> CDCF = cumulative discounted cash flow

<sup>2</sup> In other words, an incremental storage solution is to be compared with an incremental conventional solution, not with already existing resources.

Note the following observations regarding NB (net benefits):

- If NB of a solution equals or exceeds zero, the solution is considered cost-effective.
- If  $NB_A \geq NB_B$  (even if negative), solution A is considered superior to solution B in terms of CE. However, it should be noted that procurement decisions often involve additional considerations beyond CE in determining the best solution.
- In cases where the cost of storage solution is difficult to establish, it may be of interest to look at “breakeven cost analysis.”

**“Comparable” solutions:** means two solutions (based on different technology alternatives) “sized” to deliver the same value in terms of some primary benefit(s) [however, TB of the solution still includes values of both primary and other secondary benefits realized by the solution]. This is illustrated via two different examples below:

- a) Example of peak capacity as the “normalized” primary benefit: Compare the net benefits of a gas CT peaker plant vs. an energy storage project, both sized to provide 100MW of usable peak capacity under specified conditions. Note that the nameplate capacities of the two resources required to deliver 100MW usable peak capacity will be different: specifically, the CT nameplate must be greater than 100MW to allow for temperature-based capacity deration in order to effectively deliver 100MW under high temperature conditions.
- b) Example of flexible capacity such as the “normalized” primary benefit: Compare a 100MW CT peaker with a minimum operating level of 20MW (providing 80MW of dynamic range) to 40 MW of energy storage (which can deliver the same 80MW of flexible range due to its ability to charge 40MW “down” and discharge 40MW “up”).

**BreakEven Cost Analysis** (CESA suggested option): In the case where TC of a storage solution may be difficult to establish (due to lack of data or consensus, for example), an alternative approach is to determine what the “break even cost” would be for a given use case based on the maximum  $TC_S$  satisfying the inequality:  $TC_S \leq TB_S - NB_C$ . Here,  $TC_S$  and  $TB_S$  are total costs and benefits associated with the storage solution and  $NB_C$  is the net benefit of the conventional solution.

## 4 Summary of Benefits and Costs Applicable to Use Cases

The list of all benefits applicable to a use case is based on the analysis already completed by stakeholders and summarized in the corresponding Use Case Document (see Staff Interim Report):

TBD: Complete/Correct the table below

	End Use / Benefit Stream	T-Connected Bulk Storage			Distributed Energy Storage			Behind the Meter Energy Storage			Gen-sited	
		Peaker Plant	Ancillary Services Only	Base Load Plant	Distributed Peaker	Substation-Sited Storage	Community Energy Storage	Behind the Meter Storage	Behind the Meter Utility Controlled	Permanent Load Shifting	EV Charging	VER-Sited Storage
Generation/Wholesale Markets	Electric Energy Time-Shift (Arbitrage)	P		P	S							
	Frequency Response (Inertia)	S	P	S	S							
	Frequency Regulation Up	P	P	S	S							
	Frequency Regulation Down	P	P	S	S							
	Ramping	S	P	S	S							
	Real-Time Energy Balancing	S	P	S	S							
	Synchronous Reserve (Spin)	S	S	S	S							
	Non-Synchronous Reserve (Non-Spin)	S	S	S	S							
	Black Start	S		S	S							
	System Electric Supply Capacity	P		P	S							
	Local Electric Supply Capacity	P		P	S							
Resource Adequacy	P		P	S								
VER	Intermittent Resource Integration (Ramp/Voltage Support)											
	VER/PV Shifting, Voltage Sag, Rapid Demand Support											
	Supply Firming											
	Peak Shaving: Load Shift											
Transmission	Transmission Peak Capacity Support (Deferral)											
	Transmission Operation											
	Transmission Congestion Relief											
Distribution	Distribution Peak Capacity Support (Deferral)				P	S	S					
	Distribution Operation (Voltage/VAR Support)				S	P	P					
Behind Meter	Outage Mitigation (Microgrid)											
	TOU Electric Bill Management											
	Power Quality											
	Backup Power											

Other benefits may be applicable to the selected cost effectiveness framework, such as those listed below. Note that the value of some of these attributes may actually be captured through adjustments to benefit or cost components already listed above.

TBD: Add comments applicable to KEMA modeling to the table below as needed

<i>Benefit</i>	<i>Relevant Portion of NB Framework</i>	<i>How the benefit is currently captured in real-life implementation?</i>	<i>How the benefit is treated in the cost-effectiveness models and framework?</i>
Flexibility (Dynamic Operations)	Variable Costs  Energy Market Revenues  AS Market Revenues	Flexible capacity is provided by energy storage resources to the CAISO energy and ancillary services markets. This benefit is captured by bidding into the CAISO markets and being selected to provide regulation, operating reserves, and flexible ramping.  To the extent that a resource is capable of multiple start/stops and have short startup times, these benefits will be taken into account by having lower variable costs, which in turn will result in lower bid costs and increase net value. A lower bid cost will increase utilization of resource.	ESVT: Included in model at the hour level of granularity to capture $P_{min}$ and start/stop variable costs.  Ramping rates, response times, other flexibility attributes at the sub-hour level of granularity are <i>excluded</i> from the model's capabilities.  Without adjustments to inputs, benefits and costs associated with sub-hour performance factors such as FERC 755 pay-for-performance regulation market values are <i>not captured</i> in the model.
Over generation management  Increased use of renewables to meet RPS goals	Revenues – Energy Market	At times of over generation, energy storage can help to avoid uneconomic curtailment of RPS and conventional resources. During periods of excess energy, the CAISO energy market prices will become negative and a storage resource that can absorb excess energy can receive compensation for charging. The CAISO currently has a bid floor (the maximum energy unit price for absorbing energy) of - \$30 and will lower the bid floor to - \$150/MWh in Fall 2013. Even lower bid floors will be introduced in future years.	ESVT: Since most over generation effects on negative pricing occurs in the real time market, and the ESVT does not allow for participation in the real time market, this value is <i>not fully captured</i> in the ESVT model.  Adjustments to inputs of day ahead market pricing can potentially mitigate ESVT's deficiencies in this area.
Full use of assets already invested in by ratepayers	Revenues – Energy, Ancillary Services, or Capacity  Fixed and Variable Costs	Storage could be used to enhance an existing generation resource by allowing it to offer more capacity, energy, or ancillary services and increasing its revenues. On-site to conventional generator only.	ESVT: As a resource-specific dispatch model, the portfolio impacts are <i>not accounted</i> for in the results. To account for portfolio impacts, one would need a production cost model.  Because portfolio effects are not accounted for, the following limitations have been identified: (1) impacts to overall portfolio fuel requirements are <i>not accounted</i> for in the ESVT model, (2) emission impacts are <i>not accounted</i> for in the ESVT model, and (3) unit commitment impacts are <i>not accounted</i> for in the ESVT model.  No workarounds within the ESVT model for these portfolio effect issues have been identified at present. Emissions are a significant factor to consider in overall cost effectiveness analysis. Any ESVT results should be carefully qualified with this deficiency.
Reduced System Costs	AS Market Revenues	Some technologies can respond faster and provide a higher amount of benefit to the system for frequency regulation. This could also reduce the amount of frequency	ESVT: See comment above for "Full use of assets already invested in by ratepayers"



<i>Benefit</i>	<i>Relevant Portion of NB Framework</i>	<i>How the benefit is currently captured in real-life implementation?</i>	<i>How the benefit is treated in the cost-effectiveness models and framework?</i>
		<p>regulation that is ultimately procured by the CAISO.</p> <p>Implementation of Order 755 will implement pay for performance regulation. In this case, resources that can respond faster to regulation signals may receive a higher compensation – whether this occurs and its value is highly dependent on the amount of storage deployed, bidder behavior, resultant market prices, and the reduced lifetime of storage that may rise from faster dispatch.</p>	
Reduced Emissions	<p>Variable Costs</p> <p>Energy Market Revenues</p> <p>AS Market Revenues</p>	<p>Starting 2013, California’s energy price will reflect the cost of GHG emissions as part of the cap-and-trade rules.</p> <p>A storage facility itself does not have emissions, it benefits when selling energy and ancillary services to the wholesale market. A resource can charge on the hours when generation resources have no emissions or low emissions and compete to discharge at hours when generation resources have higher emissions.</p>	ESVT: See comment above for “Full use of assets already invested in by ratepayers”
Reduced Fossil Fuel Use	(same as above)	Storage could allow fossil units to operate at a more efficient level. Reduction in fossil use is most directly linked with reduction in GHG emissions.	ESVT: See comment above for “Full use of assets already invested in by ratepayers”
Increased Transmission Utilization	Excluded	<p>This benefit is very similar to transmission investment deferral.</p> <p>Bulk storage devices connected to the transmission system could increase utilization of transmission assets or defer upgrades. Current FERC accounting rules prevent a resource classified as a transmission asset from earning wholesale market revenues simultaneously. Additional clarity from FERC is necessary. Refer to “transmission peak capacity support” in section 3.2.</p> <p>This benefit is very locational dependent and providing such a benefit will constrain operations for charging, discharging, and providing market functions. A transmission benefit could be included provided that energy, A/S, and capacity revenue streams are adjusted to reflect the additional operational constraints due to providing a transmission function.</p>	Not considered due the FERC limitation.
Power Factor Correction		Same as conventional generators (this service essentially provided for free by conventional generators).	ESVT: Power factor is <i>not accounted</i> for in the model

<i>Benefit</i>	<i>Relevant Portion of NB Framework</i>	<i>How the benefit is currently captured in real-life implementation?</i>	<i>How the benefit is treated in the cost-effectiveness models and framework?</i>
		Generators can inject reactive power to help with correction of power factor.	
Faster build time	Fixed Costs	<p>If certain technologies are faster to build then that benefit would be reflected in the offer price.</p> <p>On the cost side, delayed capital deployment for a certain quantity of capacity will result in lower development cost due to time value of money, leading to a reduced offer price, thus increasing likelihood of selection</p>	ESVT: <i>Accounted for</i> by calculating overnight CAPEX as the input to ESVT. The overnight CAPEX is defined as the initial capital expenditure of a project as a net present value calculation that accounts for the cost of capital during the full length of the planning, design, and construction time. For example, if two projects have the same initial capital expenditure, but one project takes twice as long to build, the project with the longer build time will have a higher overnight CAPEX due to the time value of money and the cost of capital.
Modularity/Incremental build	Fixed Costs	Same analysis as "faster build time." Key Benefit here is delayed deployment of capital resulting in lower offer price	Not considered in the analysis.
Locational flexibility	Fixed Costs Capacity Revenues	This benefit could be monetized in two forms, depending on the nature of the locational advantage. Either (a) Reduced offer price, by being able to site at a more economical location, or (b) located in a capacity constrained region to contribute local reliability requirements, which would lead to increased local RA revenues.	Not considered in the analysis.
Mobility	Fixed Costs	Some types of storage can be relocated, including containerized storage and other types (e.g. NGK's NAS.)	Not considered in the analysis.
Multi-site aggregation	Fixed Costs	This is highly situation dependent. It could show in the revenues and costs when comparing different alternatives of single site vs. multi-site installations.	Not considered in the analysis.
Optionality		<p>Resources that are quickly deployable can provide viable alternatives to long lead time assets. Such resources could have an value for optionality, where there is reduced risk by deploying a resource closer to the time that it is need.</p> <p>The optionality value comes from flexibility of deployment date and size.</p> <p>The value arises from multiple effects:</p> <ul style="list-style-type: none"> <li>• Some storage technologies can be deployed when needed, as opposed to far in advance of need.</li> <li>• The storage is only deployed if needed and the deployment can be timed and sized to match</li> </ul>	Not considered in the analysis.

<i>Benefit</i>	<i>Relevant Portion of NB Framework</i>	<i>How the benefit is currently captured in real-life implementation?</i>	<i>How the benefit is treated in the cost-effectiveness models and framework?</i>
		economic and demographic shifts, eliminating the risk of short term overbuilding.	
Gas Fuel Price Risk Analysis/Adjustments	Variable Costs	The cost of emissions (both GHG and other pollutants) may not be accurately estimated in gas price projections, and the uncertainty of these costs over time involves the potential for substantial risk. Political and regulatory changes to what economic values are included in the assessed cost of emissions can have significant cost effectiveness implications. Considering this risk adjustment when comparing one technology over another should be analyzed, potentially in a manner similar to how option value is used above to account for shorter lead times.	ESVT: See comment above for "Full use of assets already invested in by ratepayers"
System-Wide Reliability Economic Impact	Revenues—Reliability	Example: blackout events and the economic impact such as Hurricane Sandy	Not considered in the analysis.

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## 5A Modeling Issues Specific to EPRI's ESVT

Based on discussions with EPRI and E3 staff, below is a summary of some key issues and limitations of EPRI's modeling tool known as ESVT; the list is not meant to be exhaustive or critical of EPRI's tool (all models have limitations) but should be kept in mind as important caveats when evaluating any modeling results:

1. ESVT is strictly an hourly dispatch model and not a production simulation model
  - a. It can't model unit commitments
  - b. It can't consider reductions in total portfolio MW requirements
  - c. It doesn't consider ramp rates of technologies
2. ESVT evaluates bids in the day ahead markets only. In reality, real time market participation would also be an option, and in some time periods during the year, such as real time negative energy pricing due to over-generation, real time markets may be the optimal participation strategy.

While exploring workarounds, discussion with E3 suggests that while the real time markets may be where most of the negative values occur now, in 2020 the introduction of a ramping product may cannibalize the negative price events and "transfer" the lost value into the day ahead A/S market. By making negative pricing part of the day ahead energy market in the ESVT model, one may attempt to use this approach as a workaround for capturing some of the value that may be associated with the new ramping product. However, it appears to be too difficult to adjust pricing for one product without adversely affecting the other market prices.

3. Only a single global escalation rate is available as an input for adjusting future market prices. A separate escalation rate for prices of different market services cannot be specified in the current version of ESVT.

TBD: A possible workaround is to construct different market scenarios.

4. For frequency regulation, the model uses a historic ISO dispatch signal to simulate plant utilization. Any assumption changes to the frequency regulation benefit stream (e.g. Pay-for-Performance tariffs) should include an adjustment to this ISO dispatch signal input.
5. To determine the system capacity value, ESVT uses CONE (Cost of New Entry) based on residual capacity value methodology. In the simplest terms, the equation is the following:
  - a.  $CONE = \text{residual capacity value } \$/kW = [\text{CAPEX of CT} - (\text{energy market benefits} + \text{ancillary service market benefits})] / \text{temperature-derated effective capacity of CT}$
  - b. To normalize the capacity value into a  $\$/kW\text{-yr}$  payment for a specific generator, the nameplate capacity is adjusted for the temperature dependency of the generator being modeled. For example, a CT with a nameplate capacity of 100MW and temperature derate of 85%, the capacity payment would be made on 85MW. E3's DER avoided cost model contains information on these temperature-derated capacity values for CTs.<sup>3</sup>

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<sup>3</sup> Sensitivities on both the temperature capacity derate and heat rate impacts can be performed on the CT Performance Tab of this Avoided Cost Model: [http://www.ethree.com/documents/DERAvoidedCostModel\\_v3\\_9\\_2011\\_v4d.xlsx](http://www.ethree.com/documents/DERAvoidedCostModel_v3_9_2011_v4d.xlsx)

- c. EPRI/E3 suggest allowing the ESVT to calculate the CONE in the model rather than specifying a CONE based on the output of an external model
6. ESVT does not model temperature derate of output capacity. However, To determine the capacity value of a CT, ESVT counts the temperature derated “effective” capacity under peak conditions. In contrast, for the energy and A/S services, the full nameplate capacity of the CT is bid into the market at all times by ESVT.
7. ESVT allows for partial load CT heat rate deration at discrete points. However, it does not currently consider other impacts on CT heat rate such as temperature or ramping.

Per E3, because the CT usually runs at a low capacity factor, Heat Rate impacts are quite small in the overall costs. For example, raising the heat rate from 9,300 to 10,000 Btu/kWh for all generation increases the cost by \$6/kW-yr.<sup>4</sup>

8. Emissions costs are not modeled by ESVT. Some analytical approaches to “reverse engineer” the available output data to account for emissions are being explored.
9. There is no way in the ESVT model to turn depreciation off for non-equipment components of CAPEX (e.g. land costs or environmental permitting). The impact to this with MACRS is minimal and will be ignored in the analysis.
10. Scheduled and forced outage rates are not modeled. They could be applied manually to the ESVT model output cash flows if outage rates are to be considered.
11. For customer side of the meter ancillary service market participation, certain modeling issues with regard to REM and energy charging prices need to be discussed in more detail with EPRI/E3.
12. For distribution storage use cases, the voltage support benefit is not specifically modeled in ESVT, since voltage profiles are not an input to the model. However, it may be possible to do a workaround by adjusting the inputs associated with the upgrade deferral benefit to account for voltage support. TBD: This needs to be confirmed with EPRI/E3.

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<sup>4</sup> Email from Eric Cutter of E3 dated 1/25/13.

## 5B Modeling Issues Specific to KEMA's Tools

TBD

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## 6 Input Templates

A separate Excel spreadsheet summarizes all global assumptions and cost and benefit inputs applicable to each use case selected for CE analysis and is divided into the following tabs.

- Global Modeling Assumptions
- CT Cost Assumptions
- Storage Cost Assumptions
- Benefit Assumptions
- Use Case Scenarios

The first **three Assumptions Tabs** show all inputs affecting financing and fixed and variable costs. For each parameter listed in the tab, the ESVT default value where applicable is shown, along with recommended inputs to replace the defaults in the Staff-led CE study. Sources are cited where possible for the recommended inputs. A red field in the ESVT default column indicates that the corresponding parameter is not considered by the model.

Some input values are listed currently as placeholder subject to additional research or stakeholder feedback before being finalized.

It is not clear how best to account for future cost of emissions in the analysis. Feedback from PG&E indicates that forecasted gas prices do not price in GHG costs.

The ESVT model uses overnight CAPEX (see definition of overnight CAPEX in section 4).

The **Benefit Assumptions Tab** shows the future market prices to be applied to the modeling run.

For hourly market prices as input to the model, it is expected the model will utilize 2011 price file from CAISO. Presently, it is not clear how best to represent future hourly market prices with 33% renewable penetration (including overgen conditions and negative price ceilings, pay-for-performance frequency regulation, and new markets such as ramping).

To model the CAISO market benefits for project start years of 2015 and 2020, scenarios were generated to escalate historic 2011 CAISO market prices to construct potential combinations of future gas, energy, and ancillary services prices. The table below summarizes these potential combinations:

Project Start Year	Scenario	Price Escalation to Project Start Year		
		Gas	Energy	A/S
2015	Base Case	Real: 2% Inflation: 2% Total: 4%	Real: 1% Inflation: 2% Total: 3%	Real: 1% Inflation: 2% Total: 3%
	High gas prices, renewables lower energy market price but increase A/S costs	Real: 3% Inflation: 2% Total: 5%	Real: 0% Inflation: 2% Total: 2%	Real: 3% Inflation: 2% Total: 5%
	Low gas price, low energy price, A/S has base case escalation	Real: 1% Inflation: 2% Total: 3%	Real: 0% Inflation: 2% Total: 2%	Real: 1% Inflation: 2% Total: 3%
2020	Base Case	Real: 2% Inflation: 2% Total: 4%	Real: 1% Inflation: 2% Total: 3%	Real: 1% Inflation: 2% Total: 3%
	High gas prices, renewables lower energy market price but increase A/S costs	Real: 3% Inflation: 2% Total: 5%	Real: 0% Inflation: 2% Total: 2%	Real: 3% Inflation: 2% Total: 5%
	Low gas price, low energy price, A/S has base case escalation	Real: 1% Inflation: 2% Total: 3%	Real: 0% Inflation: 2% Total: 2%	Real: 1% Inflation: 2% Total: 3%

The **Use Case Tab** describes proposed modeling exercises involving specified use cases, along with technology combinations and proposed sensitivities on selected inputs.