2416 Cades Way
Vista, California 92081
(760) 599–1813

David@LEAPSHydro.com

March 14, 2018

regionaltransmission@caiso.com
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630

RE: Comments on the Draft 2018-2019 Unified Planning Assumptions and Study Plan

Dear CAISO Planners,

As requested in the February 7, 2018 Market Notice from the California Independent System Operator Corporation ("CAISO") announcing the February 28, 2018 Planning Process meeting, The Nevada Hydro Company, Inc. ("Nevada Hydro") is herein submitting comments on the CAISO's Draft 2018-2019 Unified Planning Assumptions and Study Plan ("Plan").

Under the CAISO open access transmission tariff ("Tariff") §24.3.3, Nevada Hydro submitted its Lake Elsinore Advanced Pumped Storage ("LEAPS") project (FERC Project P–14227 and P–11858) to the CAISO and asked that it be considered for inclusion in the development of the Plan. In its filing, Nevada Hydro requested that LEAPS be studied and included in the Plan as a "transmission" resource that will provide reliability, public policy and economic benefits. To the extent the CAISO opted not to include LEAPS in the Plan on that basis, Nevada Hydro requested that the CAISO view LEAPS as a generation or other non-transmission alternative.

1.0. The CAISO Tariff requires that LEAPS be treated as a transmission asset

The Tariff § 24.3.3(a) provides an opportunity for stakeholder comment on the draft Plan to address three things: (1) demand response programs for inclusion in the base case, (2) generation and other non-transmission alternatives for consideration, and (3) Federal, state and local public policy requirements to be included in the plan. Tariff § 24.3.2 identify that the minimum requirements for the Plan include: (1) a description of the computer models, assumptions and criteria to be used in technical studies, (2) a list of each technical study to be performed, and (3) a description of the modifications to the planning data and assumptions to be included in the Plan. Importantly, Tariff §§ 24.3.1(g) and 24.3.2(i) identify that the Plan must address "[p]olicy requirements and directives, as appropriate, including programs initiated by state, federal, municipal and county regulatory agencies."

As explained herein, to satisfy the Federal policy compliance requirement in the Tariff, CAISO's Plan must address the Federal policy implemented through an act of Congress to treat pumped hydroelectric storage as an "advanced transmission technology" under the Energy Policy Act of 2005, and must comply with the Federal Energy Regulatory Commission's ("FERC") policy directive providing for the treatment of electric storage as wholesale transmission facilities for planning and cost recovery purposes under the Tariff. CAISO should include a sensitivity case in its Plan that treats electric storage as an "alternative" to electric transmission for non-pumped hydroelectric storage facilities and projects that do not otherwise seek to qualify as wholesale transmission under FERC's storage policy. The CAISO's planning assumptions, inputs to the Plan and quantifications of benefits should build upon the CAISO's studies and study sensitivities conducted as part of the 2016-2017 transmission planning cycle by applying a complete Transmission Economic Assessment Methodology (TEAM) analysis to electric storage included as a transmission or transmission alternative.[1] CAISO must apply all five TEAM cost-benefit categories and quantify the benefits of each. The Plan should further adapt the "CAISO Planning Standards" (as defined in the Tariff) to address the serious grid reliability and resiliency challenges that CAISO has identified in prior transmission planning studies and its recent comments to FERC in the Grid Resiliency docket (AD18-7-000) respecting the growing prevalence of non-dispatchable renewable energy resources under California's 50% renewable portfolio standard ("RPS"), coupled with retirements and curtailments of baseload nuclear generating plants and fast-ramping natural gas fired generating resources due to retirements and natural gas supply constraints. Finally, to comply with the Federal Power Act's prohibition against unduly discriminatory rates, terms and conditions, and FERC's implementation of that law through FERC Order 1000's transparency and comparability standards and the CAISO's Tariff (*e.g.*, Tariff § 24.3.3(e)), CAISO must provide a complete explanation to support the planning criteria and assumptions that it adopts in the Plan, and must provide a complete explanation of all the reasons for the selection or rejection of particular transmission solutions or transmission alternatives at the conclusion of the study process (*e.g.*, one that addresses each element of the TEAM analysis or other selection methodology such as NERC reliability criteria violations and "least regrets" planning for policy upgrades).

The CAISO has advised the CPUC through both letters and pleadings that large scale pumped storage is needed to protect California from the potential harm that could result from the existing impacts of the current 50% RPS requirement. And, the CAISO recently informed

[1] California Independent System Operator Corp., *Transmission Economic Assessment Methodology (TEAM)*, at pp. 3-4 (Nov. 2, 2017), *available at*: http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

FERC in its comments on grid resiliency that California's RPS requirement is "likely" to increase. The CAISO planning assumptions must address LEAPS ability to address the existing need for large scale pumped storage as well as the likely future need.

2.0. The LEAPS Project

LEAPS is identical in size, operating characteristics and location to the large scale pumped storage facility that CAISO has studied over the last several years. It is a proposed $2 billion pumped hydroelectric storage transmission infrastructure facility with a planned power production capacity of 500 MW and a pumping capacity of 600 MW. It will be located in Riverside County California at Lake Elsinore, which will serve as the lower reservoir for the LEAPS facility. It will include two new 500 kV interconnecting transmission lines, two new 500 kV substations, three new 500/230 kV transformers, three new phase shifting transformers, and one new 230 kV transmission line. These facilities will be located approximately midway between Los Angeles and San Diego at Lake Elsinore, California, and will link the transmission systems of San Diego Gas & Electric Company ("SDG&E") and Southern California Edison Company ("SCE"), thereby helping to relieve two of the largest transmission bottlenecks in California.[2] The total energy storage available will be approximately 6,000 MWh per day, potentially allowing for 12 hours of generation at the full plant generating capacity of 500 MW. Nevada Hydro has filed a hydroelectric license application with the Federal Energy Regulatory Commission ("FERC") for LEAPS that is currently pending in Docket No. P-14227-003.

The CAISO has recognized in its own analyses the potential benefits of adding 500 MW of pumped storage hydroelectric capability to southern California, a number of grid support services a facility identical to LEAPS can provide.[3] These services include reactive power (*i.e.*, VAR) support, load and generation balancing services (*i.e.*, regulation-up and regulation-down services), moment-to-moment load following service, spinning reserve service and black start service. LEAPS will be able to switch from providing one service to another almost instantaneously. Other grid support services that CAISO has recognized pumped storage facilities like LEAPS can provide include:

- Renewable generation integration (*i.e.*, balancing variability and over-generation)
- Frequency regulation
- Power system stability

[2] LEAPS' two 500 kV lines, however, will not connect directly with each other and, therefore, will not create free-flowing ties between SDG&E and SCE.

[3] California ISO, ISO 2016-2017 Transmission Planning Process, Supplemental Sensitivity Analysis: Benefits Analysis of Large Energy Storage (Jan. 4, 2018).

- Load following
- Contingency reserves
- Inertial response
- Cycling and ramping protection of thermal generation
- Relieving transmission congestion

These services are all becoming increasingly critical as California continues to transition to its ambitious 50% (or more) renewable energy goal while at the same time retiring fossil-fueled and nuclear generating resources historically relied upon to maintain a harmoniously functioning power grid.

LEAPS is designed to: (1) be used by the CAISO to resolve transmission and system reliability issues when the system is under over-generation conditions, (2) maintain reliability when other transmission facilities are out of service for maintenance, and (3) provide grid resiliencies as the grid is relying more and more on intermittent resources. In such situations, LEAPS would automatically come on-line and would prevent NERC reliability violations, or any interruption of electricity service to customers, and LEAPS would be able to provide reliability services throughout the requisite peak hours and during over-generation hours. LEAPS will perform transmission and reliability functions by providing the voltage control support or load reduction needed for the operation of the transmission system when called to do so. In all, LEAPS will provide ten identifiable and quantifiable transmission reliability support services:

1. voltage support,
2. thermal overload protection,
3. frequency regulation,
4. load following,
5. balancing renewable generation,
6. ramping/regulation services,
7. black start service,
8. mitigation of transmission outages/contingency reserves,
9. inertial response,
10. relief of transmission congestion between major load pockets, and cycling/ramping protection of thermal generation.

Through these services, LEAPS can be used to mitigate over-generation conditions, overloads, line trips, lines taken off line for maintenance, and voltage dips of affected transmission line segments on the CAISO transmission system.

3.0. The CAISO Unified Planning Assumptions Must Address Federal Policy to Treat Electric Storage like LEAPS as Transmission Facilities for Planning and Cost Recovery Purposes.

Sections 1223 and 1241 of the Energy Policy Act of 2005[4] identifies pumped hydroelectric storage facilities as an "advanced transmission technology" to be encouraged for transmission reliability and efficiency purposes. FERC has found that LEAPS fits the statutory definition.[5]

Moreover, FERC's Storage Policy Statement[6] issued at the outset of CAISO's last transmission planning cycle in early 2017 treats electric storage as "wholesale transmission facilities" for transmission planning and cost recovery purposes, provided certain conditions are met. LEAPS has an application pending before FERC in Docket No. EL18-131-000 requesting a finding that it satisfies the Storage Policy Statement criteria.

The Energy Policy Act of 2005 and the Storage Policy Statement establish "Federal policy" on the treatment of pumped hydroelectric storage for transmission planning and cost recovery purposes. Sections 24.3.1(g) and 24.3.2(i) of the CAISO Tariff require CAISO to account for Federal policy in its Plan, and section 24.3.3(e) requires CAISO to explain its reasons for not including any public policy requirement in its Plan. Therefore, to comply with its Tariff, CAISO's Plan must treat pumped hydroelectric storage facilities as electric transmission facilities or explain its reasons for failing to comply with Federal policy.

4.0. The Plan Should Expand Upon the Assumptions and Sensitivities Included in its Prior Studies of Large-Scale Electric Storage During the 2016-2017 Transmission Planning Cycle.

Section 24.3.2 of the Tariff specifies that the Plan must include, among other things, "potential generation capacity additions and retirements, and transmission system modifications," and "[a] description of the computer models, methodology and other criteria used in each technical study performed in the Transmission Planning Process cycle."

---

[4] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 953-54 (2005).

[5] *The Nevada Hydro Company, Inc*. 122 FERC ¶ 61,272 (2008).

[6] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,058 (2017) ("Storage Policy Statement").

The 2016-2017 transmission plan included the results of an analysis of benefits of large-scale pumped hydroelectric storage facilities.[7] That study found that "new pumped storage resources brought significant benefits to the system, including reduced renewable energy curtailment . . . lower CO2 emissions, emission costs and production costs, and the flexibility to provide ancillary services and load-following and to help follow the morning and evening ramping processes." The CAISO performed sensitivities that it published on January 4, 2018, where it confirmed the initial findings.[8] The CAISO has represented to the CPUC that its studies of large-scale storage demonstrate that:

> *additional bulk energy storage with fast-ramping capabilities is essential to balance California's rapid rise toward a 50% renewable grid. Not only would California benefit from additional bulk energy storage resources such as pumped storage, California could be harmed without them.*[9]

The CAISO uses the TEAM analysis to assess the costs and benefits of transmission projects for selection in its TPP.[10] TEAM examines five categories of benefits: (1) production cost savings, (2) capacity benefits through increased import capability into the CAISO balancing authority area, increased deliverability within CAISO, or relief of a known transmission constrained area within CAISO, (3) public policy benefits, such as the ability to lower the cost to integrate renewable energy resources, (4) the ability to relieve the over-supply and associated curtailment problems that arise from excess renewable energy production, and (5) reliability benefits and the ability to avoid other costly transmission upgrades. The analysis uses a full network computer simulation model, market prices for energy and ancillary services, an uncertainty analysis to account for the variability of input assumptions such as natural gas prices, and examines alternatives, such as adding generating facilities, to assess whether there are more economic means to achieve objectives.

CAISO identified numerous grid benefits from large-scale storage facilities even though it omitted TEAM category 5 (reliability and avoided cost benefits), performed the analysis for just

---

[7] California Independent System Operator Corp., 2016-2017 Transmission Plan, at p. 336 (Mar. 17, 2017).

[8] California Independent System Operator Corp., *ISO 2016-2017 Transmission Planning Process—Supplemental Sensitivity Analysis: Benefits Analysis of Large Energy Storage*, at pp. 7-8 (Jan. 4, 2018).

[9] *Order Instituting Rulemaking to consider policy and implementation refinements to the Energy Storage Procurement Framework and Design Program (D.13-10-040, D.14-10-045) and related Action Plan of the California Energy Storage Roadmap, Rulemaking 15-03-011*, "Comments of the California Independent System Operation Corp. on Track 2 Issues," at 4 (filed Feb. 5, 2016) (emphasis added) (Attached as Exhibit 2).

[10] California Independent System Operator Corp., *Transmission Economic Assessment Methodology (TEAM)*, at pp. 3-4 (Nov. 2, 2017), *available at*: http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf.

one year's benefits (2026) instead of a life cycle analysis, and having left out quantifications of the benefits for each category of the analysis.

The affidavit of Mr. Ziad Alaywan, the President and Chief Executive Officer of transmission consulting firm of ZGlobal Inc., identifies specific assumptions and modeling necessary to complete the analysis of large scale pumped storage.[11] In fact, Mr. Alaywan has completed the analysis himself using CAISIO software, assumptions and data inputs. Given that Mr. Alaywan has already completed most of the necessary work, the CAISO can focus on confirming Mr. Alaywan's results. The result of that exercise will demonstrate significantly greater grid benefits from large-scale storage than the CAISO has already found.

In any event, the Plan must include an analysis of the benefits LEAPS will provide to the CAISO grid using the 2016-2017 studies as a starting point, and incorporating the CAISO data inputs and assumptions that Mr. Alaywan has provided, consistent with the TEAM approach.

5.0. The Plan Should Specifically Evaluate the Grid Reliability and Resiliency Benefits of Large-Scale Pumped Storage

5.1. Reliability Benefits

In its Draft 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan ("Study Plan"), the CAISO responded to Nevada Hydro with the suggestion that:

> *the proponent considers submitting the project in the 2018 Request Window specifying the ISO-identified reliability constraints the project could mitigate. The submission will also be considered as an economic study request.*[12]

This is a useful starting point, but Nevada Hydro submits that a narrow focus on relieving a specific reliability constraint is too narrow a definition of grid reliability that excludes reliability benefits that CAISO itself has identified in its large-scale storage studies. We note that section 24.2(a) of the Tariff contemplates that the Plan must maintain grid reliability in accordance with NERC criteria and CAISO Planning Standards, which the Tariff defines as "Reliability Criteria that: (1) address specifics not covered in the NERC and WECC planning standards; (2) provide interpretations of the NERC and WECC planning standards specific to the CAISO Controlled Grid; and (3) identify whether specific criteria should be adopted that are more stringent than the NERC and WECC planning standards." Given the numerous grid management and reliability challenges posed by California's 50% RPS standard, generating plant retirements and natural gas supply constraints identified by CAISO in past planning studies and reports to FERC and the CPUC, Nevada Hydro submits that "CAISO Planning Standards" as defined in the Tariff

---

[11] The Affidavit was included with the Petition filed with FERC in Docket No. EL18-131-000.

[12] Draft 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, February 22, 2018, page 26.

encompasses the essential service flexibility that only large-scale pumped hydroelectric storage facilities can provide.

Moreover, as Mr. Alaywan's affidavit explains, LEAPS will provide other reliability benefits, including the addition of capacity to southern California's local capacity resource ("LCR") area, increased load following capability, frequency response service, black start service, inertia, and grid resiliency (discussed separately below)—meaning the ability to reduce recovery times from serious grid disturbances that otherwise might lead to blackouts such as that which occurred in September 2011 in Southern California.

As LEAPS provides significant local capacity benefits to SDG&E area (as the CAISO's special study last year pointed out) Nevada Hydro suggests that the CAISO evaluate LEAPS as a solution to the SDG&E local capacity issue. This is particularly critical, as SDG&E recently announced that it was seeking roughly 150 MW of new battery storage to help it meet the reliability challenges attributable to the loss of Aliso Canyon. Nevada Hydro believes that the CAISO should include in its analysis the costs and benefits of LEAPS providing these same services in place of SDG&E's proposed battery proposal using its TEAM methodology.

5.2. Resiliency Benefits

CAISO's recent lengthy response to FERC's questions about grid resiliency identify a number of challenges that are the subject of ongoing studies.[13] FERC has proposed to define resiliency as "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[14] As Mr. Alaywan explains, the inertia provided by large-scale pumped storage resources like LEAPS can serve a critical role in supporting grid resiliency. LEAPS will provide several attributes of resiliency because of its ability to absorb excess energy, rapidly produce energy on demand, steady grid frequency disturbances, and provide black start service to assist with the rapid recovery of the grid from an outage event.

The need for flexible fast-ramping resources like LEAPS with substantial mass has become particularly urgent in southern California where the 2,246 MW San Onofre nuclear plant with its massive 150-ton turbines has been taken out of service. Huntington Beach's 452-MVAR synchronous condenser is planned to be offline starting in 2018. Encina will lose 950 MW of gas-fired generation, Morro Bay's 650 MW gas plant was shut down in early 2014, and the Diablo Canyon 2,200 MW nuclear facility is scheduled to retire by 2026. These developments

---

[13] *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000, "Comments of the California Independent System Operator Corporation in Response to the Commission's Request for Comments About System Resiliency and Threats to Resilience" (filed March 9, 2018) ("*Grid Resiliency Comments*").

[14] *Id*. at P 23. FERC is requiring regional transmission organizations to file explanations with FERC regarding their approaches to ensuring grid resiliency, including whether they agree with FERC's definition.

all significantly and adversely affect the frequency response capability of the power grid, thereby posing a threat to grid resiliency and ultimately its reliability.

Mr. Alaywan provides several examples that illustrate how the transmission grid can benefit from resources with substantial rotating mass that can also respond quickly in the critical first few moments following a blackout such as the one that occurred in the Southwestern United States on September 8, 2011. In those critical moments the system requires large generating resources with the essential telecommunications and computer equipment coupled with a fast-reacting resource that operates under "automatic generation control" to help restore the grid to the harmony that exists when frequency is at (or very close to) 60 Hertz. Mr. Alaywan explains that "[i]f frequency deviation is not corrected in a few seconds, there is a risk for the grid to become unstable which leads to a catastrophic blackout." LEAPS will provide this essential resiliency service to southern California where the availability of rotating machines equipped with AGC is diminishing and is being replaced mainly by wind and solar (both rooftop and utility scale).

Mr. Alaywan illustrates the grid resiliency benefits that LEAPS can provide through three studies. The first study simulated frequency response for a generic 500 MW solar photovoltaic facility located at Lake Elsinore compared to LEAPS during a single large contingency—the loss of the 500 kV Southwest Power Link transmission line, which serves as the major import path for SDG&E. Southwest Power Link is considered by CAISO to be one of the greatest threat contingencies for the area.[15] The September 8, 2011 blackout in Southern California began when that transmission facility tripped off-line. Mr. Alaywan's first study shows that with LEAPS, the frequency would deviate 77% less compared to the system with a new 500 MW solar photovoltaic facility.

Mr. Alaywan's second reliability study compared the frequency response pre-and post-LEAPS upon the loss of the same 500 kV Southwest Power Link transmission line for three existing generators in the SDG&E area: (1) a 500 MW solar photovoltaic facility connected to the Drew substation, (2) the 950 MW Encina combined cycle generating facility, and (3) the 45 MW El Cajon peaking gas turbines. As summarized in his Table 12, frequency excursions caused by the transmission line outage are 12% to 18% lower with LEAPS in service than without it. Also, with LEAPS, positive frequency deviation is 3% to 26% lower than without LEAPS. Importantly, with LEAPS the frequency settles at a value closer to the initial frequency and reaches the initial steady state more quickly.

As a further illustration, Mr. Alaywan shows how LEAPS would help to stabilize the El Cajon power station from the loss of the Southwest Power Link line. His study shows the El

[15] For example, EDF Renewable Energy recently signed a long-term power sales contract with SCE to sell the output from a new 500 MW solar photovoltaic facility to be developed near Joshua Tree National Park.

Cajon gas turbine frequency dipped by 0.222 Hertz in the pre-LEAPS case, but in the post-LEAPS case its frequency dipped by just 0.192 Hertz or 14% less with LEAPS in-service, and the frequency of the natural gas generating plant stabilized in 8 seconds with LEAPS in service. Without LEAPS, El Cajon would take 20 seconds to stabilize. He found similar benefits for the Drew 500 MW photovoltaic generating station where the frequency dipped by 0.155 Hertz in the pre-LEAPS case, but just 0.136 Hz in the post-LEAPS case—a 12% improvement with 4% improved stabilization time. The frequency impact on the Ocotillo wind generation facility would also be lessened with improved stabilization time. All these examples of grid resiliency benefits underscore the critical relationship to reliability—faster recovery times equal reliability improvements that may avoid future blackouts.

6.0. CAISO's Plan Must Comply with FERC's Transparency and Comparability Principles.

As CAISO is aware, FERC's transmission planning process places a premium on comparability and transparency. California Independent System Operator Corp., 143 FERC ¶ 61,057 (2013) ("The process used to produce the regional transmission plan must satisfy the following Order No. 890 transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning") (emphasis added). These principles are incorporated in CAISO's Tariff.

Accordingly, Nevada Hydro anticipates that CAISO will fully explain its reasons for including, or not including, the Federal policy requirements, modeling methods, assumptions, and studies suggested in these comments. Likewise, CAISO must provide complete explanations giving its reasons for selecting or to declining to select LEAPS as offered into the 2018-2019 transmission planning process to address the reliability, public policy and economic transmission needs identified through that process and in this letter.

7.0. Conclusion

The panoply of services LEAPS provides could be associated with a reliability, public policy or economic transmission upgrade. With LEAPS, all these services are provided by a single asset. CAISO's unified planning assumptions should identify reliability and resiliency issues that LEAPS can solve or mitigate, "least regrets" public policy transmission needs that LEAPS can satisfy—including the ability to reduce the amount of renewable generation that California will need to meet its 50% renewables portfolio target—and measure the value of LEAPS between the SDG&E and SCE load pockets to relieve congestion and provide other benefits using the CAISO's "Transmission Economic Assessment Method," or "TEAM" approach. The CAISO should also study the "resiliency" type reliability benefits that LEAPS can provide to address the challenges that CAISO faces as described in its March 9, 2018, report to FERC in its *Grid Resiliency Comments*.

Nevada Hydro appreciates the CAISO's attention, and is available to assist with this analysis

Sincerely

David Kates
For The Nevada Hydro Company

Attachment

Attachment
Affidavit of Mr. Alaywan

Exhibit No. 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Nevada Hydro Company	)	Docket No. EL18-___-000

AFFIDAVIT OF ZIAD ALAYWAN P.E.
IN SUPPORT OF
NEVADA HYDRO COMPANY, LLC
PETITION FOR DECLARATORY ORDER

Contents

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address

A. My name is Ziad Alaywan. I am the founder, President and Chief Operating Officer of ZGlobal Inc. Located on 604 Sutter Street, suite 250, Folsom, CA 94630. I have been retained by Nevada Hydro Company, LLC ("Nevada Hydro") as a consultant on energy, operational, economic, regulatory, and technology issues in connection with its Lake Elsinore Advanced Pumped Storage ("LEAPS") project.

Q. Please describe your relevant experience.

A. I was employed by the Pacific Gas & Electric Company ("PG&E") between 1987 and 1996. From 1990 through 1996, I managed PG&E's real-time grid operations for the Northern and Central California Electric Grid. I was a member of PG&E's "7 x 24" operation staff where I served as a Transmission, Intertie Scheduler and Generation Dispatcher, as well as a Manager of Real Time Operations, of the PG&E Control Area, which during that time had a peak load of 18,000 MW.

In 1996, I joined the State of California Governor's office team focusing on implementation of California Assembly Bill 1890 that legislated the creation of the California Independent System Operator, Inc. ("CAISO"). As one of the first two interim CAISO employees, my efforts focused on the development and implementation of the First Tariff and subsequent Tariff amendments mainly regarding the CAISO's Bidding, Ancillary Services Pricing, Firm Transmission Rights, Scheduling, Pricing, Dispatch, and Settlements System. In addition, I was responsible for the Reliability Must Run, Transmission Contracts and Scheduling, Transmission Access Contract and Metered Subsystem. Subsequently, when the CAISO was formed in May 1997, I became a staff member and continued my responsibilities to oversee a $150 million budget to implement the CAISO market, settlements, and dispatch systems. My responsibilities included obtaining certification from the North American Electric Reliability Corporation ("NERC") to combine the California investor-owned utility ("IOU") systems—which in addition to PG&E, included Southern California Edison Company ("SCE") and San Diego Gas and Electric Company ("SDG&E")—into a single Balancing Authority Area. I worked with the Federal Energy Regulatory Commission ("FERC") and the California Public Utilities Commission ("CPUC") to obtain certification to start the CAISO's wholesale energy markets. I successfully led the certification of the CAISO by FERC, the three inventor-owned utilities and the State and subsequently the launch of the ISO on March 31, 1998.

From 1998 to 1999, I was the Director of CAISO Market Operations responsible for the ISO market design, implementation and operation. From 1999 through 2001, I was the CAISO Managing Director of Engineering and Operations where I was responsible for all grid operations planning, including "reliability must run" generators, and the day-to-day operation of the transmission system and the wholesale power market under CAISO control.

During the period 2002 through 2005, I was the Managing Director of Market Operations, where I was responsible for the initiation of the CAISO market re-design after the California energy crisis of 2000 and 2001. That re-design included reforms to the energy and ancillary services markets, new congestion management protocols, the treatment of reliability must run generators, scheduling of generation, and the real-time and day-ahead markets, including settlements, billing, and metering functions.

In 2005, I founded ZGlobal Inc. My company provides power engineering and energy solutions for a wide sector of clients. Among other things, ZGlobal performs economic and reliability analyses for transmission, distribution and generation assets across the western interconnection. I hold a Bachelors and a Master's degree in Electrical Engineering, graduating Summa Cum Laude with post-doctorate work in HVAC Power System Applications, Optimization, Production Model, Unit Commitment, and Power Economics from Montana State University. In 2002, I completed the Executive Management Program at the Haas School of Business, University of California at Berkeley. I am registered as Professional Engineer in the State of California and a Senior IEEE Member. Examples of my numerous publications and expert testimony are set forth in Exhibit NHC-E.

II. PURPOSE OF TESTIMONY AND CONCLUSIONS

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to support Nevada Hydro's petition for a declaratory ruling that, based on the facts present here, the proposed LEAPS project is a wholesale transmission facility consistent with the Commission's findings in its *Western Grid Development, LLC*[1] decision and is, therefore, entitled be studied as such in CAISO's annual transmission plan and included in the CAISO's cost-based system-wide transmission access charge for recovery of its annual cost of service revenue requirement. My analysis is guided by FERC's policy clarifications in its January 19, 2017, Policy Statement called "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery" ("*Storage Policy Statement*" or "*Policy Statement*").[2]

Q. What do you conclude?

A. LEAPS will be a wholesale transmission facility as FERC defined it in *Western Grid* and the *Storage Policy Statement* because:

---

[1] 130 FERC ¶ 61,056 (2010).

[2] 158 FERC ¶ 61,051 (2017).

(a) LEAPS will transport stored (not *new* energy) that is necessary to serve CAISO customers,

(b) LEAPS will provide a number of transmission and grid reliability services that are necessary for the operation of the CAISO transmission system, such as voltage support, a new transmission path to the Los Angeles basin and San Diego load centers, frequency regulation and balancing services.

(c) LEAPS will provide transmission network services by moving power flow into SCE and SDGE load pockets if CAISO deems it necessary,

(d) LEAPS will stand ready to provide these services when directed to do so by the CAISO in the same manner as a California "Participating Transmission Owner" ("PTO). In fact, Nevada Hydro intends to enter into the CAISO's standard PTO and "transmission control" agreements as set forth in its Tariff. Nevada Hydro will have full responsibility to operate and maintain LEAPS to ensure that it is ready to perform all of the transmission and grid support services that it is capable of providing; and

(e) Nevada Hydro will utilize a certified Scheduling Coordinator and will bid LEAPS at its marginal cost into the CAISO Markets to ensure *no* market distortion. Moreover, Nevada Hydro will credit any and *all* market revenues that it receives to its cost of service revenue requirement that are incidental to LEAPS transmission and grid support services. Nevada Hydro will file a cost-based revenue requirement at a future time for Commission review and acceptance.

Q. Please elaborate on why is LEAPS a transmission facility?

A. In addition to the fact that LEAPS is contemplated to operate exactly as described in the *Western Grid* decision and FERC's *Storage Policy Statement*, there are other attributes that qualify

LEAPS as a transmission asset. For example, the following elements are also transmission assets since they play a key role in facilitating transmission of energy from one location to the other while allowing for a reliable, efficient and resilient grid:

i) Capacitors and Reactors: These devices are used in series and shunt compensation techniques to regulate transmission system voltage and stability. Capacitors and reactors are used extensively on the AC transmission system, particularly in the west with its long transmission lines. When transmission voltages are low, capacitors are switched on to increase the voltage level. When transmission voltages are high, reactors are switched on to reduce the voltage level.

ii) FACTS: "Flexible AC Transmission Systems" or FACTS refers to a group of resources used to overcome certain limitations in the static and dynamic transmission capacity of electrical networks. The IEEE defines FACTS as alternating current static controllers to enhance control ability and power transfer ability. The main purpose of these systems is to supply the network as quickly as possible with stored capacitance and inductive energy to ensure transmission quality and the efficiency of the power transmission system. FACTS work like capacitors and inductive devices by storing energy from the grid and releasing the energy when it is needed for reliability. FACTS provides the grid:

- Fast voltage regulation,
- Increased power transfer over long AC lines,
- Damping of active power oscillations, and
- Controls the flow of energy in meshed systems.

FACTS thereby significantly improves the stability and performance of existing and future transmission systems. With FACTS, grid operators are able to utilize their existing transmission networks better, substantially increase the availability and reliability of their line networks and improve both dynamic and transient network stability while ensuring a better quality of supply. FACTS devices give the grid more than voltage regulation, it also allows grid operators to re-route or increase power flow by changing the power angle, damping power oscillations.

iii) <u>Phase shifting transformers</u>: Phase shifting transformers (PSTs) have similar functions as the FACTS devices and are also used to re-route or increase power transfers by changing the power angle.

LEAPS comprises a combination of transmission lines (wires), reversible pumps, phase shifting transformers, substations and other equipment. LEAPS and its associated equipment serves the same functions as the capacitors, reactors, FACTS, and PSTs, all in one and more. LEAPS increases and decreases voltages. It is able to re-route or increase power flow by changing the power angle and damp power oscillations using its PSTs. In addition, LEAPS provides frequency control, and its 37 miles of transmission lines provides a new path for delivering stored energy into the load pocket, thus moving stored energy from one location to another.

LEAPS is unlike a generator because it does not produce any *new* electrons or *new* watts to the grid. Like capacitors and reactors located at substations, it stores energy from the grid for use by the grid at a later hour as needed by grid operators to ensure reliability and improve the efficiency of the transmission network. In this way, LEAPS produces net energy of zero or less into the grid.

In addition, LEAPS serves an important role on electric power systems by improving system-wide efficiency and reliability and allowing grid operators to better balance the system in an era of increased resource intermittency and decreased capacity resources that provide grid resiliency. LEAPS will transmit stored and already purchased energy, to retail loads via two new transmission paths (wires) and will quickly react to contingencies. It will provide these reliability functions as a transmission asset without producing any new watts to the grid similar to shunt capacitors, reactors, FACTS and PSTs.

Given these characteristics, LEAPS is a transmission facility that FERC, other ISO's and utilities have considered as transmission facilities.

Q. What specific reliability benefits will LEAPS provide?

A. As demonstrated through specific analyses described in this affidavit, I found that LEAPS provides multiple benefits to support grid resiliency, including:

(a) Voltage regulation to manage high and low voltages,

(b) A new transmission path to serve retail load in the Los Angeles basin or San Diego,

(c) Ability to re-route energy flow across southern California through its PSTs,

(d) Reduced curtailments of renewable energy by storing excess energy during over-generation situations,

(e) Flexible capacity by being able to instantly dispatch stored energy to the grid. LEAPS' stored energy is not dependable on gas storage supply or weather conditions and its highly predicable,

(f) Ability to reduce the magnitude of frequency deviation and the number of frequency oscillations on the CAISO grid during an outage, and

(g) Over 200 MW of stored inertia to the CAISO grid during an outage.

Q. What economic benefits does LEAPS provide to ratepayers?

A. To quantify the LEAPS' benefits to ratepayers, I have applied the CAISO's Transmission Economic Assessment Method ("TEAM") approach to evaluate whether LEAPS' overall benefits outweigh its cost. TEAM is used by CAISO to evaluate whether a proposed transmission facility has economic benefits to costs to include in its annual transmission plan. Using the CAISO software model, data and benefit to cost assumptions where available, I have quantified the benefits of LEAPS for the five categories of service benefits that CAISO examines. I have found that LEAPS will (a) provide a life cycle expected net present value benefit-to-cost ratio (BCR) of **1.76:1** in the high solar penetration case, and (b) provide a life cycle expected net present value benefit-to-cost ratio of **1.59:1** in the more conservative high wind penetration case. The solar case shows more value because CAISO is forced to curtail generation more often during peak daylight hours and pay the generators for curtailing them. In both cases, the ratios are conservative because they do not take into account several valuable services that are difficult to quantify. In my opinion, these robust benefits ranges would justify building LEAPS as transmission assets that can both provide local capacity reliability benefits in San Diego and provide a mechanism to store renewable energy that was already paid by the ratepayers for later use while lowering the overall energy cost to ratepayers. I will describe below each benefit and cost issue that are included in my TEAM analysis.

Q. Is there any benefit that you would like to highlight?

A. Yes. One overwhelming LEAPS benefit is its ability to be an essential, predictable, flexible and dependable tool to ensure grid resiliency because it will be able to relieve over-generation by renewable energy, transmit energy to relieve major transmission constraints, provide flexibility independent of gas-fired generation, provide much needed frequency and inertia response in an era where these services are diminishing, and help maintain transmission frequency at approximately 60 Hertz ("Hz"). These benefits have led CAISO to call repeatedly for the construction of large-scale pumped storage to manage over-generation by non-controllable renewable resources, which poses a grid reliability problem.

A second major benefit is LEAPS' ability to reach the State's renewable portfolio standard ("RPS") goals at lower cost by reducing the quantity of overbuild needed to reach its 50% RPS target. Less renewable capacity is required to be built because LEAPS is able to store excess renewable energy during over-generation and dispatch the stored energy during other hours when that renewable energy may not have been produced. Thus, based on the facts present in the CAISO region, LEAPS provides dramatic benefits to ratepayers by reducing the overall cost for procurement of solar and wind capacity to achieve the State goals. This renewable capacity cost savings is quantified as one of the categories of LEAPS' benefits in my TEAM analysis.

In sum, LEAPS will operate as a transmission facility and will provide important grid support services to help maintain reliability, balance the grid, and integrate renewable generation. It will do so economically, without distorting CAISO Markets and will provide a grid management tool that the CAISO has called for on a number of occasions. LEAPS provides positive grid benefits, even when applying conservative assumptions to CAISO's TEAM analytic tool for selecting transmission projects for cost recovery through its transmission access charge. For all of these reasons FERC should find that LEAPS must be studied as a transmission facility in a manner comparable to other transmission assets that provide reliability, public policy and economic benefits and are eligible for inclusion in CAISO's transmission access charge.

III. THE LEAPS PROJECT

Q. Please describe the proposed LEAPS project.

A. The proposed LEAPS project will be comprised of a 500 / 600 MW advanced pumped storage facility, two new twenty-seven mile 500 kV interconnecting transmission lines, two new 500 kV substations, three new 500/230 kV transformers, three new phase shifting transformers, and one new 10-mile 230 kV transmission line. One 500 kV line will interconnect with the transmission network of SCE and the other will interconnect with the transmission network of SDG&E.[3] These facilities will be located approximately midway between Los Angeles and San Diego at Lake Elsinore, California. Lake Elsinore, which is the largest natural lake in southern California, will serve as the lower reservoir for the proposed facility. The Decker Canyon reservoir, which is to be constructed above the crest of the Elsinore Mountains, will serve as the upper storage reservoir of the LEAPS project. The Decker Canyon Reservoir will be approximately 9,500 feet southwest of Lake Elsinore at an elevation of approximately 2,792 feet above mean sea level.

The proposed facility will have an installed discharging capacity of approximately 500 MW and a variable charging pumping capacity of 600 MW provided by two single-stage reversible pump-turbine units operating under an average net head of approximately 1,484 feet. The total energy storage available will be approximately 6,000 MWh per day, allowing for 10 hours of discharge of the stored energy at the full discharge capacity of 500 MW. The corresponding charging / pumping requirement will be 12 hours at the full plant pumping capacity of 600 MW, with additional required pumping occurring on Saturday and/or Sunday if a weekly cycle is used.

The pump-turbine and motor-generating units and associated mechanical and electrical equipment will be located below ground, immediately adjacent to Lake Elsinore, at the foot of the Elsinore Mountains. Stored energy will be released and transformed underground to 500 kV, and transmitted to the surface by way of oil-filled cables along the side of the elevator shaft. LEAPS will be interconnected to the grid at separate interconnections with SCE and SDGE.

[3] LEAPS' two 500 kV lines, however, will not connect directly with each other and, therefore, will not create free-flowing ties between SDG&E and SCE.

The upper reservoir will have a water surface area at full capacity of approximately 100 acres; the reservoir will be fully lined and constructed so that it is isolated from surface runoff and groundwater. An intake/outlet structure located in the upper reservoir will interconnect the reservoir with the reversible pumps through a single penstock, approximately 25-feet in diameter, bored into and through the Elsinore Mountains. A single-line electrical diagram is attached at Exhibit NHC -A.

Q. Please briefly describe the services that LEAPS will be able to provide.

A. LEAPS will be an electric storage resource with the ability to both charge and discharge electricity, and provide transmission and a variety of grid support services to CAISO. These services include reactive power (*i.e.*, VAR) support, load and resource balancing services (*i.e.*, regulation-up and regulation-down services), moment-to-moment load following service, spinning reserve service, black start service, and several additional grid support services. LEAPS will be able to switch from providing one service to another almost instantaneously.

Q. What is the projected cost of the LEAPS project and its forecasted annual revenue requirement?

A. Nevada Hydro currently estimates the project's total cost to be approximately $2 billion. I have utilized the CAISO TEAM study assumptions to the extent possible: a 50-year project life, a 50%/50% debt-to-equity ratio, 5.0% debt rate, 11% nominal return on equity ("ROE"), 29.65 % state and federal taxes, 1.85% inflation[4] and 0.1% G&A.[5] The resulting levelized real revenue requirement is estimated at $177 million annually.

[4] Inflation Rates: https://inflationdata.com/inflation/inflation_rate/currentinflation.asp http://www.usinflationcalculator.com/inflation/current-inflation-rates/

[5] This include fixed maintenance cost only. Variable maintenance cost of 3$/MWH is included in the Production cost modelling.

IV. FERC's *STORAGE POLICY STATEMENT*

Q. What does the *Storage Policy Statement* provide?

A. The *Storage Policy Statement* "provide[s] additional guidance regarding issues that arise for electric storage resources seeking to recover their costs through both cost-based and market-based rates concurrently."[6] FERC further stated that it "also believe[s] that clarification regarding our *Nevada Hydro* and *Western Grid* precedent is warranted due to potential confusion with respect to that precedent."

Q. What guidance did FERC provide on cost recovery by storage resources?

A. The *Policy Statement* provides three options for electric storage facilities to obtain cost recovery on a case-by-case basis: (1) market-based rates for the sale of electric energy, capacity and ancillary services under pre-existing policy, (2) cost-based rate recovery of the full revenue requirement for electric storage facilities, or (3) a hybrid approach whereby the cost-based revenue requirement is reduced by market revenues to assure that there is no double recovery of costs from ratepayers. Applicants must show that their storage facilities will be "wholesale transmission facilities" like the storage facility in *Western Grid*, that they will follow operating procedures like PTOs that will not inadvertently cause CAISO to become a market participant, and that there are protections against the storage operator over-recovering its cost-based revenue requirement through participation in wholesale power markets.

Q. Why did FERC issue the *Policy Statement*?

A. The *Policy Statement* reconciled conflicting precedents where FERC denied Nevada Hydro's petition to recover the costs of the LEAPS project in transmission rates,[7] whereas FERC

[6] *Storage Policy Statement* at P 9.
[7] *Storage Policy Statement*, 158 FERC ¶ 61,051 at PP 3, 9.

allowed such cost recovery in *Western Grid*.[8] FERC rejected Nevada Hydro's rate proposal over ten years ago because it would have given CAISO operational control and thereby raised potential conflicts with other market participants. In the subsequent *Western Grid* case—in which I provided a supporting affidavit—FERC ruled that battery storage used to transport stored energy for ultimate delivery to retail customers and to provide voltage support and transmission overload protection served as "wholesale transmission facilities subject to the Commission's jurisdiction if operated as described by Western Grid."[9] FERC found that Western Grid solved the CAISO's market participant dilemma by offering to operate its storage facility at CAISO's direction like the PTOs whereby Western Grid retained all operating functions, including maintenance, communication and system emergencies, and ultimate responsibility for energizing the battery array.[10] FERC stated that Western Grid, not CAISO, would be responsible for buying power to charge its battery, and for physically operating the batteries when they were being charged or discharged.[11] "Importantly," FERC added, "Western Grid will operate the Projects, at the CAISO's direction, only as transmission assets. They will be operated in a way that is similar to the operation of other transmission assets (e.g., capacitors that address voltage issues or alternate transmission circuits that address line overloads and trips)."[12] FERC also stated that "just like other transmission assets, and unlike traditional generation assets, Western Grid will not retain revenues outside of the transmission access charge, and it will credit any revenues it may accrue as a result of charging/discharging the Projects through its PTO tariff."[13]

---

[8] *Id.* at P 4.

[9] 130 FERC ¶ 61,056 at PP 43.

[10] *Id.* at P 45.

[11] *Id.*

[12] *Id.*

[13] *Id.* at P 43.

Q. Does LEAPS fit FERC's definition of a "wholesale transmission facility" as described in *Western Grid*?

A. Yes. Just like the battery storage project in *Western Grid*, LEAPS "will transport stored energy to serve retail load, similar to a transmission line, and will provide voltage support and other reliability services that are necessary for operation of the transmission system."[14] In fact, Western Grid argued that its similarity to pumped storage supported its request to be treated as a wholesale transmission facility "because they are not a net producer of electricity."[15] LEAPS will function to store energy purchased from CAISO's wholesale markets and used to pump water into its reservoir to be released later to provide energy that will be converted back to electricity as needed. As such, LEAPS will convert electrical energy to potential energy and back again to electricity with no net increase to electric production.

Moreover, LEAPS will, via its energy storage capability, be able to transmit electricity between SCE and SDG&E using LEAPS 37 miles of new transmission (wires) to relieve transmission constraints. Existing transmission choke points make SCE and SDG&E two of the biggest load pockets in California where prices can rise significantly higher than those prevailing outsides of the San Diego and Los Angeles basins. Thus, at CAISO's direction, Nevada Hydro will be able to release energy from LEAPS for delivery to either load pocket to alleviate the constraint. In addition, LEAPS will be able to provide another pathway to move electricity when network transmission facilities are out of service. As such, LEAPS will be able to serve a critical transmission function.

[14] *Id.* at P 18.

[15] *Id*. at P 20.

LEAPS will also be able to provide a variety of grid support services which the CAISO has recognized in its analyses of the potential benefits of adding 600 MW of pumped storage hydroelectric capability to southern California.[16] These services include reactive power (*i.e.*, VAR) support, load and resource balancing services (*i.e.*, regulation-up and regulation-down services), moment-to-moment load following service, spinning reserve service and black start service. LEAPS will be able to switch from providing one service to another almost instantaneously. Other grid support services that CAISO has recognized pumped storage facilities like LEAPS can provide include:

- Renewable generation integration (*i.e.*, balancing variability and over-generation)
- Frequency regulation
- Power system stability
- Load following
- Contingency reserves
- Inertial response
- Cycling and ramping protection of thermal generation
- Relieving transmission congestion

In providing transmission and transmission support services, LEAPS will differ from generators that obtain cost-based revenues as "reliability must run" units. Those units operate to provide capacity to the transmission grid primarily in circumstances when capacity shortage conditions exist. LEAPS, in contrast, will operate during all types of transmission system conditions to support grid reliability. That includes during periods of over-generation by

[16] California ISO, *ISO 2016-2017 Transmission Planning Process, Supplemental Sensitivity Analysis: Benefits Analysis of Large Energy Storage* (2018).

renewable resources when CAISO is currently forced to issue directives to curtail output and pay those generators for doing so. Importantly, LEAPS will be able to quickly switch from absorbing excess electricity in its pumping mode to producing electricity from stored energy when transmission system conditions require, such as during the evening ramp when renewable resources are providing less electricity. I will discuss these grid support services and quantify the value they provide later in my testimony when I discuss the CAISO's benefits analysis of large-scale pumped storage.

For the moment, it is important to note that the flexibility to provide the foregoing long list of grid support services contrasts with the battery storage facility in *Western Grid*, which proposed to operate to provide voltage support and to relieve thermal overloads.[17] LEAPS will be able to address those worrisome reliability conditions, and many others as well. Indeed, *no other generating resource packages all of these services and grid benefits* in the way that a large pumped storage facility like LEAPS can. Although battery storage can do some of these things, it cannot do all of them, and with the largest battery facilities being in the 15-40 MW range, those facilities simply cannot substitute for the grid resiliency benefits of a pumped storage project like LEAPS.

Q. Has FERC found LEAPS to be a transmission asset?

A. Yes. The Commission has ruled that LEAPS meets the statutory definition to be classified as an "advanced transmission asset" under sections 1223 and 1241 of the EPAct 2005.[18] In Section 1223, Congress stated that "the Commission shall encourage as appropriate the deployment of advanced transmission technology."[19] Advanced transmission technology is defined in EPAct 2005 as "a technology that increases the capacity, efficiency, or reliability of an existing or new

[17] 130 FERC ¶ 61,056 at P 47.

[18] *The Nev. Hydro Com., Inc.*, 117 FERC ¶ 61,204, at P 27 (2006).

[19] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 953-54 (2005).

transmission facility."[20] EPAct 2005 includes "energy storage devices" like pumped storage hydro facilities as advanced transmission technology.[21] LEAPS will provide classic transmission services, as I explained above, and will also enhance the capabilities of the existing transmission network as contemplated by EPAct 2005. Thus, FERC correctly found that LEAPS will be a transmission facility many years ago.

Q. Are there any other reasons why you believe LEAPS will be a transmission facility?

A. Yes. LEAPS will have physical characteristics similar to large capacitors that have historically been classified as FERC-jurisdictional transmission facilities.

As the Commission agreed in *Western Grid*,[22] it has treated facilities that operate and are physically constructed like LEAPS, such as large electrical capacitors, as FERC jurisdictional transmission facilities. For example, in *Southern Co. Services*, 80 FERC 61,318 (1997), the Commission concluded that "reactive power sources available on the Southern system include transmission equipment such as capacitors, reactors and the natural capacitance of transmission lines." (Emphasis added.) More recently, in *Transmission Relay Loadability Reliability Standard*, Notice of Proposed Rulemaking, 127 FERC ¶ 61,175, P 18 (2009) the Commission described "specific criteria to be used for certain <u>transmission system configurations</u>," stating that such criteria "account for the presence of devices such as series capacitors and address circuit and transformer thermal capability." (Emphasis added.)

Further, as explained, LEAPS is designed to: (1) be used by the CAISO to resolve transmission and system reliability issues when the system is under over-generation conditions,

[20] *Id*. at 953.

[21] *Id*. at 954.

[22] 130 FERC ¶ 61,056 at P 47 ("the Projects as Western Grid proposes to operate them do share some important characteristics with capacitors").

(2) maintain reliability when other transmission facilities are out of service for maintenance, and (3) provide grid resiliencies as the grid is relying more and more in intermittent resources. In such situations, LEAPS would automatically come on-line and would prevent any NERC reliability violations, or any interruption of electricity service to customers, and LEAPS would be able to provide reliability services throughout the requisite peak hours and during over-generation hours. LEAPS will perform transmission and reliability functions by providing the voltage control support or load reduction needed for the operation of the transmission system when called to do so. Also, LEAPS can be used to mitigate overloads, line trips, lines taken off for maintenance, and voltage dips of affected transmission line segments on the CAISO transmission system.

Q. How does Nevada Hydro propose to operate the LEAPS project?

A. Nevada Hydro will operate LEAPS consistent with the Commission's guidance in the *Policy Statement* to ensure that it does not adversely affect the CAISO's independence or any distortion to CAISO markets and non-discriminatory services. Nevada Hydro will operate LEAPS to provide transmission and reliability services such as voltage support, relief from thermal overload conditions, and grid resiliency support at CAISO's direction, just like Western Grid.

In the *Policy Statement* FERC cited to its experience with Western Grid as an example of an acceptable arrangement that would avoid drawing CAISO into a market participant role, and thereby compromise its independence. I testified on behalf of Western Grid in that proceeding. Western Grid committed to use its battery storage to provide grid support services, and promised that it would retain responsibility for energizing the battery, operating and maintaining it, and would retain responsibility for communications with the CAISO and responding to emergency conditions. Nevada Hydro plans to operate LEAPS the same way.

The roles and responsibilities among Nevada Hydro as a PTO, CAISO, and the other PTOs will be defined in a CAISO transmission control agreement as provided in the CAISO Tariff. Nevada Hydro will work with these parties to develop detailed operating procedures at the appropriate time. The more detailed operating procedures would address dispatch protocols, other transmission provider responsibilities, such as operating procedures that describe the role and responsibility under normal and emergency conditions, and also describe daily operating responsibilities that Nevada Hydro must perform. Nevada Hydro operating personnel have decades of utility experience, are NERC certified and, therefore, are able to perform these duties.

At a minimum, Nevada Hydro will perform the following tasks: (1) monitor status of the LEAPS project; (2) report to CAISO; (3) coordinate with the CAISO and other PTOs; (4) approve LEAPS maintenance schedules; (5) ensure protective relaying and automatic transfers are maintained; and (6) monitor flows and voltage levels. Nevada Hydro's TCA can provide that it will perform all duties associated with the daily 24 x 7 operations and maintenance of the LEAPS facility. These responsibilities would include: (1) ensuring the safe and reliable operations of LEAPS; (2) performing the operation and the maintenance of the protective relaying automatics; (3) performing all planned and forced outage reporting; (4) maintaining voltage level; and (5) complying with WECC and NERC reliability standards.

Moreover, Nevada Hydro, as a PTO, will perform the following operational activities: (1) operate LEAPS in accordance with Good Utility Practice and in a manner that ensures safe and reliable operation; (2) maintain appropriate voltage schedules; (3) provide voltage support when requested by CAISO; (4) operate LEAPS as required by the CAISO to alleviate thermal overload and voltage decay; (5) ensure that LEAPS can automatically connect to the grid upon pre-defined NERC N-1 and N-2 reliability contingencies; (6) respond if the CAISO notifies Nevada Hydro of changes to the status of LEAPS or limitations to automatic voltage regulators or power system stabilizers; (7) maintain or change either the LEAPS voltage schedule or its reactive power schedule as appropriate; (8) notify the ISO of system conditions and coordinate switching of voltage support or phase shifter equipment; (9) notify the CAISO of events and changes that impact voltage support equipment availability or reliability; (10) de-energize the LEAPS facility; and (11) energize LEAPS as requested by CAISO.

Q. Will LEAPS participate in CAISO's wholesale power markets?

A. Nevada Hydro will use LEAPS similar to Pacific Gas and Electric Company's ("PG&E") Helms Pumped Storage project.[23] In my experience at PG&E and CAISO, this 1,200 MW pumped storage hydroelectric facility has been used for reliability response to mitigate over-voltage and under-voltage conditions in the Fresno area, to reduce transmission overloads, and respond to over-generation conditions.[24] Nevada Hydro may receive revenues for incidental energy production delivered to CAISO in connection with its reliability and transmission support services. Nevada Hydro will credit such revenues to its cost of services rates.

Q. Will Nevada Hydro retain the revenues for incidental market-based sales of electricity from LEAPS?

A. No. Nevada Hydro proposes to recover the full revenue requirement for the LEAPS project through the CAISO's TAC and to revenue credit the proceeds of sales for any energy and ancillary electric products to TAC customers. This would include any revenue from the hourly locational marginal price of electric energy produced by LEAPS, regulation services (*i.e.*,

[23] Helms Pumped Storage participates in the ISO wholesale power market; however, the project costs are included in retail rates.

[24] California Energy Commission, 2015 Bulk Storage Workshop (Nov. 20, 2015) (PG&E presentation by Michael L. Jones), available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-MISC-05/TN206696_20151119T101527_PGE_Bulk_Storage_Presentation.pdf.

regulation up and regulation down service), and spinning reserve service. Nevada Hydro will credit market revenues received for the production and sale of electric energy incidental to its wholesale transmission and transmission support services.

Q. Is rate recovery through the TAC needed to ensure the construction of large scale pumped storage facilities?

A. Yes. Large-scale pumped storage hydroelectric projects must be licensed by the FERC and involve capital costs in the hundreds of millions of dollars to well over one billion dollars. The development lead time often is ten years or more. Nevada Hydro's efforts to develop LEAPS has already passed the decade mark. Although existing large scale pumped storage facilities provide extremely valuable services, they all were constructed before the Commission began its open access policies to promote electric competition. PG&E's Helms Project was the last pumped storage hydroelectric project placed into service in the Western Interconnection, but that was a very long time ago in 1984. The fact that no new large scale pumped storage facilities have been constructed since the FERC restructured the electric industry in the 1990's speaks for itself.

The Department of Energy's ("DOE") recent "Hydropower Vision" policy paper highlights the importance of hydroelectric pumped storage, but flagged uncertain rate recovery as the key barrier to new projects.[25] The Hydropower Vision report (which uses the acronym "PSH" for pumped storage hydro projects) observes:

> While PSH plants provide numerous services and contributions to the power system (a total of 20 PSH services and contributions were identified by Koritarov et al.), in existing U.S. electricity markets they typically can receive revenues only from energy, certain ancillary services (typically for regulation, spinning, and non-spinning reserves), and capacity markets. The provision of black start capability is typically arranged through a long-term contract. Most existing markets have no established mechanisms to provide revenues for other services and contributions of

[25] U.S. Department of Energy, "Hydropower Vision—A New Chapter for America's 1st Renewable Energy Resource," Section 2.7 (July 26, 2016) ("Hydropower Vision"), *available at*: https://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-10262016_0.pdf.

> PSH to the power grid. In contrast to competitive electricity markets, the traditional regulated utilities do not have established revenue streams for specific PSH services. The system operator typically optimizes the operation of PSH plants to minimize generation costs for the system as a whole. Therefore, in both traditional and restructured market environments, many PSH services and contributions are not explicitly monetized. Since PSH plants typically provide multiple services at the same time, it is difficult to distinguish the specific value of particular services and contributions, such as the inertial response, voltage support, transmission deferral, improved system reliability, and energy security.[26]

The Commission's *Policy Statement* is essential to removing this cost recovery barrier because of the numerous valuable services that pumped storage can provide.

Q. Can you elaborate on the need for hydroelectric pumped storage in California?

A. Hydroelectric pumped storage facilities have been the only commercially viable form of large scale electric storage. For this reason, California has an especially urgent need for hydroelectric pumped storage because of its aggressive RPS requirements. At the same time, dispatchable natural gas-fired generation is in decline, and its future is in doubt, especially in southern California where there is a question about the future operation of the Aliso Canyon natural gas storage facility[27]. Relying more on the remaining gas-fired generation for cycling and ramping will place greater stress on those generating machines, while market revenues may be inadequate to make it economic to keep them running.

Worse, California has closed all but one of its nuclear plants and the last, the 2,300 MW Diablo Canyon facility, is also set to close soon along with natural gas fired generating plants, thereby depending even more heavily on non-dispatchable renewable generation. The combined effect of more variable generation with the decline of flexible and base load generation is creating significant challenges for grid reliability. CAISO has acknowledged, hydroelectric

[26] *Id.*, at Section 2.7.7 (footnote omitted).

[27] On 2/23/2018 and until 3/3/2018, CAISO issued a Restricted Maintenance Operations due to natural gas curtailments due to Aliso Canyon.

pumped storage can play a critical role in supporting the evolving power grid.

Q. Why do the CAISO Markets not provide sufficient revenue to support pumped storage?

A. First, it is not clear that infrastructure projects the size of pumped storage projects could be financed and constructed based on market revenues alone. The CAISO market is limited to energy and ancillary services, which provide uncertain revenue streams. Capacity and other reliability based services such as voltage support and black start services are done thought bilateral contracts with prices regulated by the CPUC. This market model does not monetize all of the services that pumped storage provides, as the DOE Hydropower Vision paper recognized. For instance, the California Energy Commission in 2016 market showed that net revenues for a combined cycle unit in the CAISO ranged between $11/kW-year in northern California and $22/kW-year in southern California given day-ahead and real-time market conditions.[28] These prices were well below the CEC estimated annual revenue requirement of a natural gas plant, which it placed at 166 $/kW-year.[29]

V. ANALYSIS OF LEAPS' BENEFITS

A. CALIFORNIA'S RPS POLICY

Q. Please describe California's carbon emissions policy.

A. California's policy hopes to achieve a 40 percent reduction in CO_2 emissions from 1990 levels by 2030 and an 80 percent reduction by 2050. Air quality goals include a 90 percent

[28] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf, Page 52

[29] Annual fixed costs are derived from California Energy Commission's Estimated Cost of New Renewable and Fossil Generation in California report which is published once every couple year. The annual fixed costs in this report are the average between IOU, POU and Merchant fixed costs reported in the March 2015 final staff report, Appendix E: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf.

reduction in emissions of nitrogen oxides from 2010 levels in some of the state's most polluted areas by 2032. Meeting these ambitious clean energy and clean air goals requires, as we have witnessed thus far, fundamental changes over the next decade and beyond.

Q. Please describe the amount of renewable energy resources in California and how they impact the need for large scale pumped storage.

A. California utilities are now required to procure 50% of their electric retail sales from eligible renewable resources by the year 2030. There is, however, a push to accelerate the achievement of 50% sooner than 2030 and possibly increase the goal from 50% to 75%, or possibly even 100%. To support achieving 40% statewide GHG reductions by 2030 and 80% by 2050, California's Integrated Resource Plan and Long-Term Procurement Plan ("IRP-LTPP") recommends a 42 MMT GHG planning target for the electric sector but also considered a more aggressive 30 MMT target to assess ratepayer cost impacts.[30]

California has another challenge because the amount of dispatchable fossil- and nuclear-fueled generating capacity is decreasing, especially in Southern California and the Los Angeles basin load pocket. The natural gas-fired generating capacity that remains faces fuel supply challenges because the main natural gas distributer, Southern California Gas Company, has faced debilitating operational challenges at its Aliso Canyon natural gas storage facility. Those difficulties have contributed to the CPUC's examination of electric storage technologies, including pumped storage, as an alternative.

Electric storage can provide a number of services to supplement or even replace transmission support services otherwise provided by natural gas-fired generation. For example, a

[30] Integrated Resource Plan and Long-Term Procurement Plan proceeding, Proposed Reference System Plan, http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentA.CPUC_IRP_Proposed_Ref_System_Plan_2017_09_18.pdf.

2015 Rocky Mountain Institute study of "The Economics of Battery Energy Storage" identified 13 services provided by battery storage facilities.[31]

Q. Has the need for LEAPS changed over the years?

A. The LEAPS project has been in development for in excess of 10 years. Since the project's initial development energy policies have gone through transformational and unprecedented changes that now puts large pump storage located in the load center at more of an advantage than ever before. In 2010 the State Water Resources Control Board ("SWRCB") approved a once-through cooling ("OTC") policy that included many grid reliability recommendations made by the ISO. The Office of Administrative Law approved the policy on September 27, 2010, and it became an effective regulation on October 1, 2010. The OTC policy requires electric generators to reduce or eliminate the use of coastal or estuarine water to minimize the harmful impacts of cooling water intake structures on the environment. The OTC policy recognizes that some of these plants are critical for system and local reliability. For example, many of the plants affected by the OTC policy provide operational services needed to integrate renewable resources into the state's electric grid. Some power plant owners will repower their facilities and use dry cooling technologies to replace OTC to remain compliant with the policy, while others will retire their facilities altogether. The permanent closure of San Onofre Nuclear Generation Station in 2012 presents additional challenges to the grid especially in Southern California, which provided generating capacity and voltage support for the region.

More recently, constraints on the natural gas infrastructure in the region have limited the natural gas supply for power generation in Southern California. In the longer term, the total

---

[31] Rocky Mountain Institute, *The Economics of Battery Energy Storage: How Multi-Use, Customer-Sited Batteries Deliver the Most Services and Value to Customers and the Grid* (Oct. 2015). Available at: https://indico.hep.anl.gov/indico/getFile.py/access?resId=2&materialId=paper&confId=1129.

demand for natural gas for electric generation is expected to decline as newer more efficient natural gas plants replace older, less efficient gas plants, and more renewable resources come on-line to meet the state's RPS goals displacing natural gas generation.

Moreover, LEAPS is ideally located just a few miles from the now shuttered San Onofre plant and SDG&E's OTC plants. Its fuel source is independent of gas pipelines, it provides significant reliability benefits to two of the three largest load pockets in California and in the era of increasing intermittency, LEAPS provides flexible and fast ramping capacity which is becoming the most needed reliability tool for the CAISO operators. For these reasons, I conclude that the need for LEAPS has increased substantially.

B. CAISO'S TRANSMISSION ECONOMIC ASSESSMENT METHODOLOGY

Q. Does CAISO have a method to evaluate the benefits of electric transmission facilities for selection in its transmission planning process?

A. Yes. CAISO's Transmission Economic Assessment Methodology (TEAM) uses principles for economic planning. TEAM was first used by the CAISO in 2004,[32] and since then has become the "bedrock" for CAISO's evaluation of transmission projects and their alternatives to ensure ratepayer protection.[33]

Q. Please describe the CAISO's TEAM method.

A. TEAM relies on five key benefits categories:

1. **Production benefits:** Net ratepayer savings based on production cost simulation as a consequence of the proposed transmission upgrade, including energy and ancillary service benefits.

---

[32] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology.pdf

[33] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

2. Capacity benefits: The benefit of increased import capability into the CAISO BAA or a load pocket to meet a specific Local Capacity Requirement ("LCR") set by the CAISO. Decreased transmission losses and increased generator deliverability contribute to capacity benefits as well.

3. Public-policy benefits: Transmission projects can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in a remote area, or by avoiding over-build.

4. Renewable integration benefit: Interregional transmission upgrades help mitigate integration challenges, such as over-supply and curtailment, by increased access to energy and ancillary services.

5. Reliability benefits and avoided cost of other transmission projects: If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contributes to the benefit of the economic project.

Q. Are there other important attributes of the ISO TEAM methodology?

A. Yes, TEAM has four important components: (1) the use of a full network transmission model, (2) market-based calculation of energy and ancillary services using marginal cost, (3) an uncertainty analysis, as the economic assessment is sensitive to input assumptions such as load growth and natural gas pricing, and (4) evaluation of alternatives, including non-wire alternatives, to determine the most economic, preferred solution. In addition, CAISO conducts reliability studies to validate that alternatives do not raise reliability concerns.[34]

Q. Has CAISO applied the TEAM analysis to pumped storage projects?

34 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf, page 3 and 4

A. Yes, within the last two years CAISO performed at least four assessments or sensitivities to quantify the benefits of bulk storage. The CAISO used the 2026 study year as the basis for its analysis.

Q. Did the CAISO comply with its TEAM methodology in conducting its study, "Benefits Analysis of Large Energy Storage"? [35]

A. Partly. Over the last two years, CAISO conducted updates to previously performed studies with at least four sensitivities for a generic 500 MW hydro pump storage in Southern California noting two known potential locations in the San Diego load pocket. Although, the CAISO sensitivities are very helpful, they fell short of performing what is done under the TEAM in five important areas: [36]

(a) the analysis was conducted for only one study year (2026),

(b)the analysis did not consider the project's benefit for avoided cost of other projects,

(c) the analysis did not quantify the "reliability" benefits category of the TEAM,

(d) the analysis was not based on a life cycle cost -benefits framework per section 2.4.1 of the TEAM, and

(f) the analysis does not incorporate uncertainty or sensitivity analysis suggested in section 5 of the TEAM.

Q. What did the CAISO conclude about the benefits of bulk storage?

A. The CAISO stated that new pumped storage resources brought significant benefits to the system, including:

---

[35] http://www.caiso.com/Documents/SupplementalSensitivityAnalysis-BenefitsAnalysisofLargeEnergyStorage.pdf, (2018).

[36] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

- reducing renewable curtailment and renewable overbuild needed to meet the 50% RPS target;
- making use of the recovered renewable energy from curtailment as well as low cost out-of-state energy during hours without renewable curtailment;
- providing lower cost energy during the net peak hours in early evening and flexibility to provide ancillary services and load-following and to help follow the load in the morning and evening ramping processes; and
- lowering system production cost to serve the load.[37]

Q. What do you observe and conclude from the CAISO's analysis?

A. The CAISO has consistently found that large-scale pumped storage is needed to support the reliability, public policy and economic transmission development needs of the network under its control.

The State's energy policies of increased RPS goals and lowered emission targets, coupled with coastal gas outages, OTC, coal and nuclear plant retirements leads to less reliable operating conditions for the CAISO. The CAISO is concerned that the future resource mix will: (1) increase over-generation, (2) provide limited flexibility to respond to intermittency, and (3) have decreased capability to provide inertia and frequency response.

Q. After applying the TEAM methodology to the CAISO's study results, what are the quantified benefits for a 500 MW pump storage located between the Southern California load pockets?

A. Using the results of the CAISO's own analysis, I quantified the benefits of a 500 MW pump storage in the Southern California load pockets as shown below:

[37] http://www.caiso.com/Documents/SupplementalSensitivityAnalysis-BenefitsAnalysisofLargeEnergyStorage.pdf at , page 7.

Table 1. Summary of Benefits from CAISO's Large Energy Storage Sensitivity Analysis

Summary of Benefits from CAISO's Large Energy Storage Sensitivity Analysis for a 500 MW Pump Storage in Southern California Load Pocket	Solar Case ($Million)	Wind Case ($Million)
Sensitivity #1 - Summary of the CAISO analysis of the Updated Default Scenario (2026 Base case)	$187.8	$167.0
Basecase: Sensitivity #2 - Summary of the CAISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)	$217.0	$187.0
Sensitivity #3 - Summary of the CAISO analysis of the Updated Default Scenario with 2015 IEPR Mid - AAEE Sensitivity (2026 Base case)	$188.0	$168.0
Sensitivity #4 - Summary of the CAISO analysis of the Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)	$183.0	$175.0

CAISO's analysis for a 2026 study year showed that 500 MW pump storage in the Southern California load pockets had benefits to ratepayers that ranged from $217 million to $167 million. The benefits quantified included four of the five categories in the TEAM; however, this excluded TEAM benefit category #5, "reliability benefits and avoided cost of other projects." Applying these four TEAM benefit categories for all four sensitivities to my estimate of LEAPS' annual revenue requirement of $177 million results in a one-year benefit-to-cost range of 1.03:1 to 1.23:1 and 0.94:1 to 1.06:1 for the heavy solar and heavy wind sensitivities, respectively.

Table 2. Summary of 1-year BCR for ISO's Large Energy Storage Sensitivity Analysis

Summary of 1-year BCR from ISO's Large Energy Storage Sensitivity Analysis for a 500 MW Pump Storage in Southern California Load Pocket	Solar Case ($)	Wind Case ($M)
Sensitivity #1 - Summary of the ISO analysis of the Updated Default Scenario (2026 Base case)	1.06	0.94
Basecase: Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)	1.23	1.06
Sensitivity #3 - Summary of the ISO analysis of the Updated Default Scenario with 2015 IEPR Mid -AAEE Sensitivity (2026 Base case)	1.06	0.95
Sensitivity #4 - Summary of the ISO analysis of the Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)	1.03	0.99

Q. Can you elaborate on how you calculated the benefits summarized?

A. Yes, for instance, under Sensitivity #2, the quantified benefits from CAISO's study are presented below:

Table 3. Quantified TEAM Benefits for ISO Sensitivity #2 – Updated Default Scenario with Non-Dispatchable CHP

Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
California Production Cost Benefits	Net reduction in Energy Cost	$31.0	$37.0
	Net Reduction in Load Followings, Regulation and Spin Costs, and Energy Market Revenue for LEAPS	$55.7	$57.4
Capacity Benefits	LCR benefits	$38.0	$38.0
Public Policy Benefits	Reduction in RPS costs	$73.0	$44.0
	Reduction in Emission Costs	- $1.0	- $1.0
Renewable Integration Benefits	Over-generation cost reduction	$20.4	$11.6

Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
Reliability and Avoided Cost Benefit of other Projects	Interconnection Costs	not studied	not studied
	Avoided large transmission investments	not studied	not studied
	Reliability benefits / Grid Resiliency	not studied	not studied
Total Benefits		**$217.0**	**$187.0**
Annual Revenue Requirements		**$177.1**	**$177.1**
One Year Benefit to Cost Ratio (BCR)		**1.23**	**1.06**

As shown in **Table 3**, the benefit-to-cost ratio for 2026 ranged from 1.23:1 to 1.06:1 based on four out of the five TEAM categories that CAISO analyzed in its study. The fifth TEAM category, "reliability and avoided cost benefits of other projects," was not quantified by the CAISO. I will explain later in my testimony how I expanded the CAISO analysis to also include this benefit category, and expand the analysis over the project life cycle. I used Sensitivity #2 for my expanded analysis, which also includes an expected benefits analysis where I varied input assumptions such as natural gas prices, energy efficiencies, hydro and other important factors that can influence ratepayer benefits.

Q. Can you describe in more detail the components of each benefit category of the CAISO analysis?

A. Yes, the following is a summary of the bulk storage benefits resulting from the CAISO's study. For instance, Sensitivity # 2 found:

(a) California ISO Production Cost benefits:

i. $31 million and $37 million in reduced energy costs

ii. $55.7M and $57.4M benefit to ratepayers for revenue requirement offsets from the pump storage's net market revenue for energy, load following, regulation and spin

(b) Capacity benefits: Although no specific reliability analysis was conducted by CAISO for the 500 MW pumped storage, the CAISO noted in their study that the location of LEAPS will without any doubt qualify to provide local capacity for LCR requirements.[38] The LCR benefit is valued at $6.31 kW-month[39] which is equal to $38 million for a 500 MW pump storage.

(c) Public policy benefits:

i. RPS cost: Without pumped storage, CAISO's study indicated that an additional 1,619 MW of solar or 1,211 MW of wind will be needed in 2026 to achieve the 50% RPS goal. After adding the 500 MW pumped storage facility in Southern California, however, CAISO's study showed that this RPS requirement would be reduced from 1,619 MW to 1,296 MW in the high solar penetration case, and from 1,211 MW to 1,023 MW in the high wind penetration case. Therefore, the net reduction of RPS nameplate capacity is 323 MW of solar or 188 MW of wind respectively, which is 20% less solar generation and 15.5% less wind generation to achieve the same RPS target. The CAISO calculated an RPS annual cost reduction of $73 million and $44 million, respectively.

ii. Emission cost: CAISO calculated a $1 million cost increase for each case.

(d) Renewable integration benefits: The main benefit from this category is reduction in the cost of excess renewable generation. Without pumped storage, CAISO's calculated that

[38] 2016-2017 Board Approved ISO Transmission Plan, March 17, 2017, pages 337-338, http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf

[39] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf. Section 10.8 and the soft offer cap basis was established as the sum of mid-cost results for insurance, ad valorem, and fixed operation and maintenance costs included in the CEC's draft staff report *Estimated Cost of New Renewable and Fossil Generation in California*: available at: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf. The levelized fixed cost target presented in DMM's analysis of net market revenues for new gas-fired generation in Chapter 1 is based on the same report, but includes financing and taxes.

meeting the 50% RPS goal in 2026 would result in the need to curtail 4,615 GWh of renewable energy in the high solar generation case and 3,515 GWh in the high wind generation case. With 500 MW of pumped storage in Southern California, the curtailment would be reduced to 3,721 GWh and 2,970 GWh, respectively. The net reduction in renewable curtailment would be 894 GWh and 545 GWh respectively. CAISO used a curtailment price of -$15/MWh for the first 200 GWh of curtailment and -$25/MWh for the next 12,400 GWh of curtailment. The addition of LEAPS reduced the curtailment cost to ratepayers by $20.4 million and $11.6 million, respectively. Note that LEAPS can store approximately 2,400 GWh a year of renewable curtailment protection. The economics of additional savings are reflected in the production cost calculation. The fifth TEAM benefit category "Reliability and Avoided Cost Benefit of other Projects" was not studied by CAISO.

The following tables summarize the benefits quantified for the other three CAISO sensitivity cases that were studied for the 2026 year.

Table 4. Quantified TEAM Benefits for CAISO Sensitivity #1 – Updated Default Scenario

Sensitivity #1 - Summary of the CAISO analysis of the Updated Default Scenario (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
California Production Cost Benefits	Net reduction in Energy Costs	$48.0	$40.0
	Net Reduction in Load Followings, Regulation and Spin Costs, and Energy Market Revenue for LEAPS	$52.3	$52.8
Capacity Benefits	LCR benefits	$37.8	$38.0
Public Policy Benefits	Reduction in RPS costs	$40.0	$29.0
	Reduction in Emission Costs	-$1.0	$0.0
Renewable Integration Benefits	Over-generation cost reduction	$10.7	$7.3
Reliability and Avoided Cost Benefit of other Projects	Interconnection Costs	not studied	not studied

Sensitivity #1 - Summary of the CAISO analysis of the Updated Default Scenario (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
	Avoided large transmission investments	not studied	not studied
	Reliability benefits / Grid Resiliency	not studied	not studied
Total Benefits		**$187.8**	**$167.0**
Annual Revenue Requirements		**$177.1**	**$177.1**
One Year Benefit to Cost Ratio (BCR)		**1.06**	**0.94**

Table 5. Quantified TEAM Benefits for ISO Sensitivity #3 – Updated Default Scenario with 2015 IEPR Mid-AAEE

Sensitivity #3 - Summary of the CAISO analysis of the Updated Default Scenario with 2015 IEPR Mid -AAEE Sensitivity (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
California Production Cost Benefits	Net reduction in Energy Costs	$42.0	$45.0
	Net Reduction in Load Followings, Regulation and Spin Costs, and Energy Market Revenue for LEAPS	$54.2	$52.7
Capacity Benefits	LCR benefits	$38.0	$38.0
Public Policy Benefits	Reduction in RPS costs	$44.0	$26.0
	Reduction in Emission Costs	-$2.0	-$2.0
Renewable Integration Benefits	Over-generation cost reduction	$11.9	$8.3
Reliability and Avoided Cost Benefit of other Projects	Interconnection Costs	not studied	not studied
	Avoided large transmission investments	not studied	not studied
	Reliability benefits / Grid Resiliency	not studied	not studied
Total Benefits		**$188.0**	**$168.0**
Annual Revenue Requirements		**$177.1**	**$177.1**
One Year Benefit to Cost Ratio (BCR)		**1.06**	**0.95**

Table 6. Quantified TEAM Benefits for ISO Sensitivity #4 – Updated Default Scenario with 4-tier Curtailment Prices

Sensitivity #4 - Summary of the CAISO analysis of the Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
	Net reduction in Energy Costs	$36.0	$43.0

Sensitivity #4 - Summary of the CAISO analysis of the Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
California Production Cost Benefits	Net Reduction in Load Followings, Regulation and Spin Costs, and Energy Market Revenue for LEAPS	$67.4	$63.0
Capacity Benefits	LCR benefits	$38.0	$38.0
Public Policy Benefits	Reduction in RPS costs	$33.0	$25.0
	Reduction in Emission Costs	$0.0	$0.0
Renewable Integration Benefits	Over-generation cost reduction	$8.6	$6.0
Reliability and Avoided Cost Benefit of other Projects	Interconnection Costs	not studied	not studied
	Avoided large transmission investments	not studied	not studied
	Reliability benefits / Grid Resiliency	not studied	not studied
Total Benefits		**$183.0**	**$175.0**
Annual Revenue Requirements		**$177.1**	**$177.1**
One Year Benefit to Cost Ratio (BCR)		**1.03**	**0.99**

VI. EXPANDED ANALYSIS

Q. How does your TEAM analysis expand on the ISO's analysis?

A. My analysis augments CAISO's analysis in five areas:

1. I used CAISO Sensitivity #2 results for benefits categories 1 through 4 and I calculated benefits category #5 (reliability benefits and avoided cost of other projects). The combined results are referred to as the "2026 base case."
2. I determined benefits for 2030 for all five categories. This is referred to as the "2030 base case."
3. I used the 2026 base case and 2030 base case results to calculate the benefits over the life cycle of the LEAPS project.
4. I calculated the base net present value benefits to cost ratio which is equal to the sum of the NPV of all benefit categories divided by the present value of LEAPS' total

revenue requirement ("BPV_BCR") for the life cycle of the project. The BPV_BCR is based on the specific input assumptions used by ISO in its Sensitivity #2 study.

5. I utilized the "uncertainty analysis" method from TEAM to calculate the net present value of expected benefits over the life cycle of LEAPS for 20 sensitivity cases that represent unique combinations of various input variables, and used to calculate the present value expected benefit to cost ratio or EPV BCR for the project.

Table 7 below summarizes the five benefit categories that I used to perform my analysis.

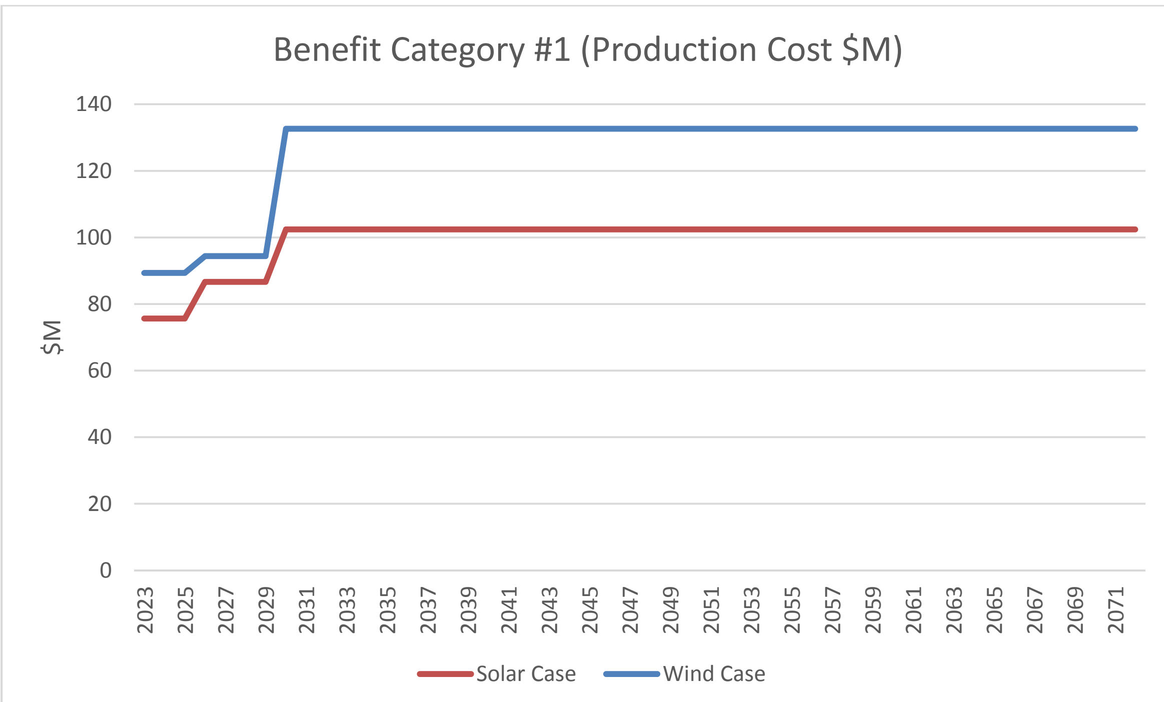
Table 7. TEAM Benefit Categories Quantified for LEAPS

Benefit Categories per TEAM	Operational Use	Value Metrics	Methodology used to Calculate Benefits
California Production Cost Benefits	**Production Cost Savings**	LEAPS is used to charge during low-cost energy hours or hours with high renewable energy dispatch and store that energy so that it may be used or sold at a later time when it is more valuable. Its presence in the supply stack has potential to lower overall cost of energy to consumers.	ISO PLEXOS software and data & PUC RESOLVE software and assumptions.
	Ancillary Services	LEAPS has the ability to ramp up and down to maintain a supply and demand balance. LEAPS can provide regulation up / regulation down to comply with Reliability Standards and ensure second by second balance of supply and demand. LEAPS can provide on-line reserve capacity to comply with Reliability Standards.	
Capacity Benefits	**Local Transmission (LCR) Savings**	Avoided cost of purchasing existing capacity to meet LCR or deferral of cost in later years to build a new combustion turbine in the local area.	CAISO assumptions of LCR capacity benefit, $6.31/Kw-month.
Public Policy Benefits	**Reduced Cost of Renewables (RPS)**	RPS capacity reduction (reduced overbuild of solar or wind) to meet 50% RPS with LEAPS.	ISO study and data / PUC RESOLVE software and assumptions.
	Emission Cost Savings	LEAPS is a hydro pump storage and is able to reduce reliance of gas-fired energy, thus reducing emissions.	ISO PLEXOS software and data & PUC RESOLVE software and assumptions.
Renewable Integration Benefits	**overgeneration cost**	reduce the amount of renewable curtailments	ISO PLEXOS software and data PUC RESOLVE software and assumptions (overgeneration Pricing was based on historical avoided energy cost to load)
Reliability and Avoided cost Benefit for other Projects	**Transmission Interconnection Cost**	LEAPS reduces the nameplate capacity of renewables needed to achieve 50% state goals, therefore, reducing transmission interconnection cost associated with lowering capacity procurement.	PUC assumptions of transmission interconnection cost of $22/kW-yr.
	Avoided Large Transmission Investment	To meet the State's 50% RPS goals and 42MMt or 30MMt emissions targets under a high wind scenario, new transmission line investments are needed.	CAISO assumptions of new transmission cost of $12 $/MWH
	Grid Resiliency (Electric Reliability Services): Frequency Response and Inertia, Flexibility, Black Start, System Reliability	LEAPS provides a large and quick response to the depleted grid from essential reliability elements such as rotating mass near the load center, immediate response in the event of power outage lasting seconds to 12 hours.	this benefits is not included in the analysis since we consider voltage support is part of the electric reliability and is part of #2 benefit. However, CES/SCE separate Voltage from Electric Service reliability benefits and estimate the voltage benefits at $40/KW-YR. Table 11, page 64.

Q. What assumptions did you use to calculate LEAPS benefit category #1?

A. The base case for my expanded TEAM analysis was based on the ISO model and results for 2026, Sensitivity #2. This base case includes all CAISO assumptions for the Updated Default Scenario with non-dispatchable CHP. The only changes for 2030 base case was to update the load forecast for the CAISO areas and the WECC. I then performed a chronological production cost analysis using the PLEXOS software and calculated the production cost savings and LEAPS' net market revenues from energy, load following, regulation and spin before and after LEAPS for 2030. **Figure 1** summarizes the production cost benefits to California ratepayers over the life of the project for the high solar penetration and high wind penetration sensitivities:

Figure 1. Production Cost Benefits to California Ratepayers due to LEAPS



Q. What assumptions did you use to calculate LEAPS benefit category #2 – Capacity Benefits?

A. LEAPS is located in the San Diego and Los Angeles load areas. For my analysis, I matched CAISO assumptions and considered LEAPS to be within the San Diego LCR area. I assumed that the capacity benefit in 2030 remained the same as 2026 base case, which is a $38 million annual benefit for both the high solar and high wind penetration sensitivities over the life of the project.

Q. Describe the local capacity requirement?

A. The CAISO's "Local Capacity Requirement" or LCR is defined as the amount of generation resource capacity that is needed within a defined area to reliably serve the load located within that area to protect against contingencies. A benefit of the LEAPS project is that it can provide local and system resource reserve capacity needed to satisfy the LCR for the San Diego-Imperial Valley area as well as be used for system wide capacity requirements.

Q. Did the CAISO agree that LEAPS qualifies to fulfill local capacity requirements?

A. Y es, CAISO's 2016-2017 Final Transmission Plan indicated that LEAPS would be inside the San Diego load pocket and qualifies as a local capacity resource.[40] In addition, the Net Qualifying Capacity ("NQC") that counts toward local capacity is 100% versus out-of-state wind's NQC of 17% or large solar's NQC of 47%. So, 100% of LEAPS can be counted towards LCR or system capacity needs, or Resource Adequacy.[41]

Q. What contingency worries the CAISO in the San Diego-Imperial Valley area?

A. The most critical contingency resulting in thermal loading concerns for the overall San Diego-Imperial Valley area is the G-1/N-1 (Category B) overlapping outage that involves the loss of the 593 MW Termoelectrica De Mexicali ("TDM") combined cycled power plant, system readjustment, followed by the loss of the Imperial Valley – North Gila 500 kV line (Category C), or vice versa. This overlapping contingency could thermally overload the Imperial Valley – El Centro 230 kV line (the "S" line). This contingency establishes a total local capacity need of 4,643 MW (includes 71 MW of deficiency) in 2022 for reliable load serving capability within the overall San Diego – Imperial Valley area.

[40] http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf, Section 6.5.6.

[41] *Id. at* Table 6.5-5 of CAISO 2016-2017 Transmission Plan.

The overload of the S line planning contingency is in the CAISO powerflow base case that I used as the starting point for my analysis. The power flow studies I performed show that adding the LEAPS project resolves the S line overload when the TDM plant and the Imperial Valley-North Gila 500 kV line are both out of service. This shows that the LEAPS project significantly benefits the system and resolves violations under the most critical conditions.

Q. How can LEAPS reduce the LCR for the San Diego-Imperial Valley area?

A. To decrease LCR for a specific area, either new major transmission projects need to be added, or a new resource needs to be placed in strategic spots to reliably serve the load under a critical outage. In this case, LEAPS project serves as both, (1) a new major transmission project that will benefit both the SDG&E and SCE systems, and (2) a new 500 MW generating facility that is within the San Diego-Imperial Valley LCR that can replace the existing conventional generation.

I ran power flow analyses to determine LEAPS' benefits for satisfying LCR needs. Per my analysis, adding LEAPS benefits both the SCE and SDG&E areas. Adding LEAPS decreases imports from the Imperial Valley substation by 377 MW compared to a no LEAPS case, and decreases imports from SCE by approximately 134 MW compared to a no LEAPS case. This means that SCE and SDG&E will be able to reduce their reliance on high cost local gas-fired generation to satisfy its LCR. Exhibit NHC - C provides further details regarding the assumptions, study approach and results of my power flow analysis.

Q. What do you conclude about the LCR benefits of LEAPS?

A. My assessment shows that the proposed LEAPS project will allow the San Diego-Imperial Valley area to serve their customers reliably during periods of unusually high energy demand, unexpected outages and abnormal conditions. LEAPS also provide flexibility in operating

California's transmission grid by adding additional import capability to San Diego County from the north, which has limited connectivity to the rest of the CAISO grid. In summary, my analysis demonstrates that LEAPS provide consumer benefits as an LCR resource and transmission reliability project. The value of the LCR capacity benefit is $6.31 kW-month based on 500 MW generation, this results in an annual benefit of $38 million.[42] I kept the capacity benefits flat over the project life cycle.

Q. What assumptions did you use to calculate LEAPS benefit category #3 – Public Policy Benefit?

A. I calculated the public policy benefits as the cost savings from reduced solar or wind overbuild to meet the 50% RPS criteria. The cost savings is based on the CAISO Sensitivity #2 results summarized below:

	Overbuild Generation Before LEAPS		Overbuild Generation with LEAPS	
Summary of RPS MW Overbuild	**Solar Case (MW)**	**Wind Case (MW)**	**Solar Case (MW)**	**Wind Case (MW)**
Basecase: Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)	1619	1211	1296	1023

Summary of RPS MW Overbuild Reduction	**Solar case (MW)**	**Wind Case (MW)**
Basecase: Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)	323	188

42 https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf. Section 10.8 and the soft offer cap basis was established as the sum of mid-cost results for insurance, ad valorem, and fixed operation and maintenance costs included in the CEC's draft staff report *Estimated Cost of New Renewable and Fossil Generation in California*: available at: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf. The levelized fixed cost target presented in DMM's analysis of net market revenues for new gas-fired generation in Chapter 1 is based on the same report, but includes financing and taxes.

The CAISO calculated that 500 MW pump storage would reduce the renewable energy needs by a net of 323 MW and 188 MW under the high solar and wind sensitivities, respectively. This reduction in renewable generation while meeting the State energy RPS objectives would save California's ratepayers $73 million and $44 million under the high solar and wind penetration sensitivities, respectively for year 2026. This translate to $226/kW-year and $234/kW-year of annual revenue requirement for the high solar and wind sensitivity cases, respectively. RPS cost savings is directly attributed to the loads. As load increases, the RPS capacity needed to maintain 50% also increases.

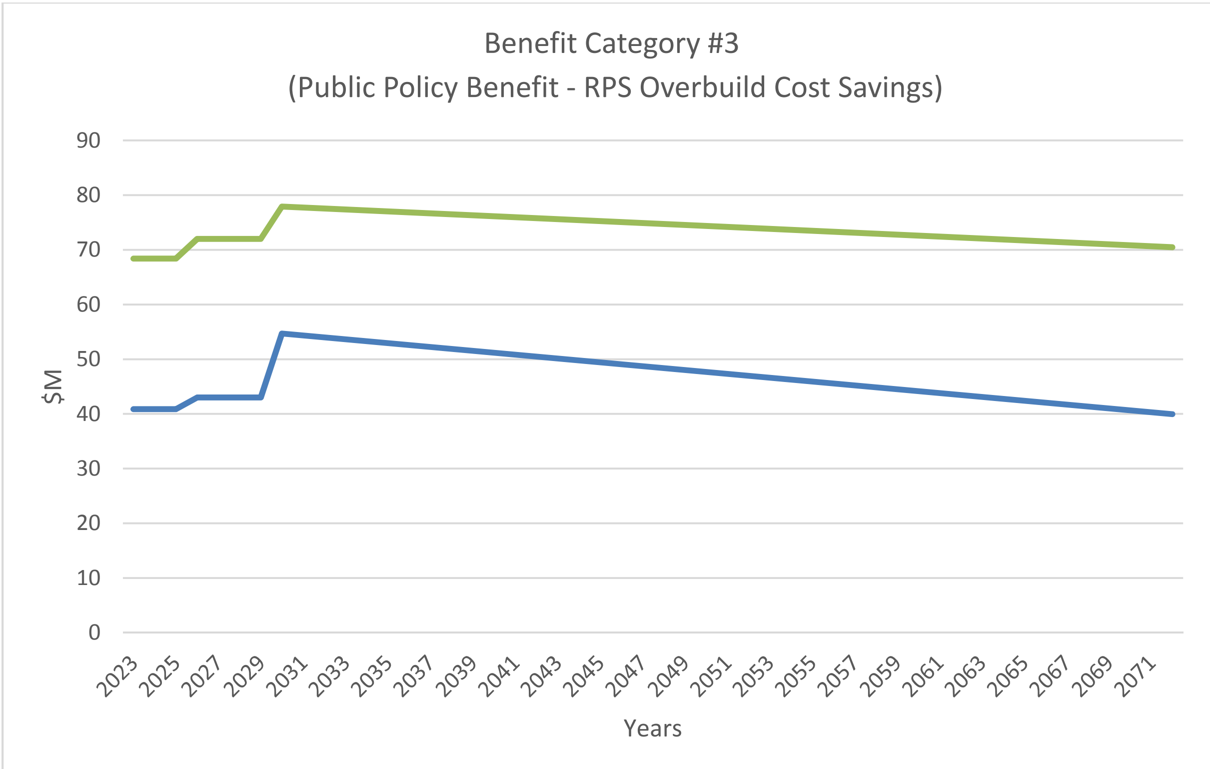
Table 8 shows the projected CAISO load in GWh for 2030. I estimated that 50% of the incremental RPS requirement from load increase in 2030 will come from solar and wind generation. I also used a 3% annual decrease in incremental renewable costs from the 2030 annual revenue requirement. Table 8 summarizes the projected load growth.

Table 8. Projected Loads for 2030

California Load for LEAPS PLEXOS Model			
Region	2026 Energy (GWh)	2030 Energy (GWh)	% Increase
PGE_Bay	52,535	54,992	4.7%
PGE_Valley	67,268	69,267	3.0%
SCE	120,825	124,049	2.7%
SDGE	24,691	25,609	3.7%
CAISO	**265,320**	**273,918**	3.2%
IID	4,709	5,009	6.4%
LADWP	31,717	32,801	3.4%
SMUD	19,639	20,464	4.2%
TID	2,975	3,084	3.7%

Figure 2 below summarizes the benefits realized from RPS overbuild cost savings with LEAPS for the life cycle of the project.

Figure 2. RPS Overbuild Cost Savings to California Ratepayers due to LEAPS



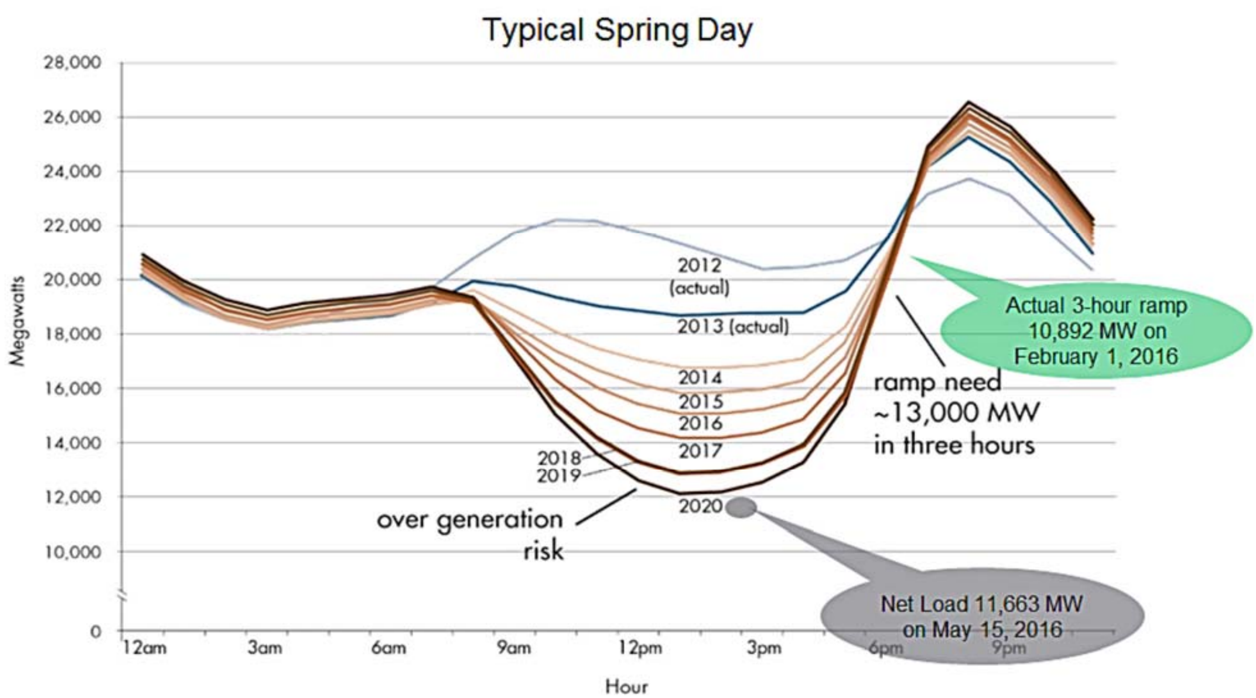
Q. Can you explain how LEAPS would provide TEAM benefit for category #4 – Renewable integration benefit?

A. The main benefit from LEAPS in this category is its ability to reduce over-generation and thus the costs of renewable generation curtailments under these conditions.

Q. Please elaborate on the problem of over-generation.

A. This problem has existed for years and is increasing as the proportion of renewable energy increases in California. Over-generation is a condition that occurs when total supply exceeds total demand in the CAISO Balancing Authority Area. The CAISO has what is sometimes called a "Day 2" wholesale power market because generator owners offer to make their generating capacity available on one day, and then must deliver it the next day when it is settled at the real-time energy price. When—as is normally the case—the amount of generating capacity accepted for sale the first day differs from the amount of capacity the CAISO actually needs to serve load the next day, it makes adjustments, which have consequences for the wholesale price of electricity in real time, as shown in **Figure 3**.

Figure 3. The Duck Chart



Net load shown in the chart is the difference between forecasted load and expected electricity production from variable generation resources. In certain times of the year, these curves produce a "belly" appearance in the mid-afternoon. Increasing demand in late afternoon requires generation to ramp up, that appears in the chart as an "arch" that resembles the neck of a duck—hence the industry moniker of "The Duck Chart".

The Duck Chart shows that over-generation conditions can occur in real-time when the quantity of supply needed to meet demand is less than the generating capacity that cleared in the Day Ahead Market. The excess day ahead cleared supply needs to be curtailed by CAISO to maintain reliable operations because currently there are extremely limited opportunities to store the extra electricity. CAISO Operating Procedures No. 2390 states "[t]his condition may affect the reliable operation of the ISO Controlled Grid, Balancing Authority Area, and the WECC interconnected Bulk Electric System. Severe Over-generation may result in critically loaded transmission facilities, significant frequency deviations, high or low voltage conditions, and unacceptable system performance."[43] The price consequences for curtailments necessitated by the Duck Chart are further illustrated at Exhibit NHC-B, which provides several examples of how generators are paid for curtailing energy in such scenarios.

Increasing renewable energy penetration will make the challenges represented by the Duck Chart worse. In an analysis published in January 2014 funded by the State's utilities with participation by the CAISO, Energy and Environmental Economics ("E3") reported that the largest integration challenge for renewable energy is over-generation, which they expect to be pervasive at RPS levels above 33 percent.[44] E3's modeling of a 40 percent RPS scenario showed over 5,000 MW of over-generation, while the modeling of a 50 percent Large Solar Portfolio scenario—relying mostly on large, utility-scale solar photo-voltaic resources in keeping with current procurement trends—indicated over 20,000 MW of over-generation. Clearly, simply building more generation will not relieve these burgeoning difficulties.

The CAISO also performed detailed analysis for every day of the year from 2012 to 2020 to understand changing grid conditions. The analysis showed how real-time electricity net demand changes in response to renewable policy goals. Several conditions emerged that will require specific resource operational capabilities. The conditions include the following:

---

[43] Operating Procedure 2390: http://www.caiso.com/Documents/2390.pdf

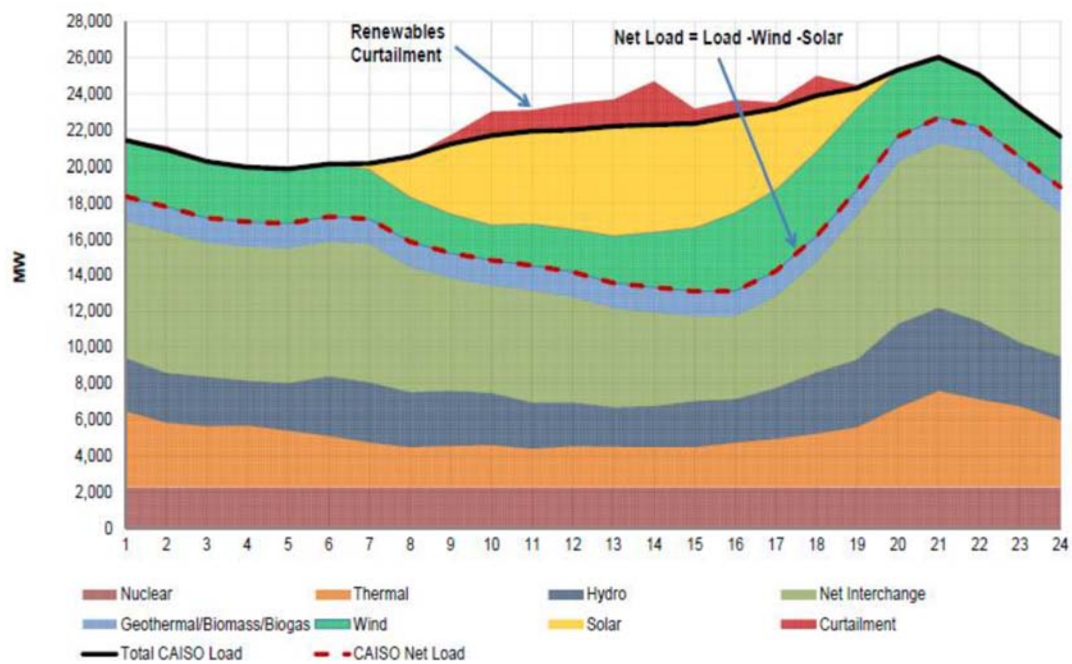
[44] Energy and Environmental Economics (E3), *Investigating a Higher Renewables Portfolio Standard in California*, pp. 25-33 , *available at*: https://www.ethree.com/wp-content/uploads/2017/01/E3_Final_RPS_Report_2014_01_06_ExecutiveSummary-1.pdf.

- Short, steep ramps – when the ISO must bring on or shut down generation resources to meet an increasing or decreasing electricity demand quickly, over a short period of time;
- Oversupply risk – when more electricity is supplied than is needed to satisfy real-time electricity requirements; and
- Decreased frequency response – when less resources are operating and available to automatically adjust electricity production to maintain grid reliability.

Maintaining reliability requires balancing supply and demand. The net load curves represent the variable portion that CAISO must meet in real time. To maintain reliability, the CAISO must continuously match the demand for electricity with supply on a second-by-second basis, which is known as frequency response. Historically, the CAISO directed conventional, controllable power plant units with automatic generation control capability to move up or down with the instantaneous or variable demand. With the growing penetration of renewable generation on the grid, there are higher levels of non-controllable, variable generation resources that lack frequency response capability.

Inadequate frequency response is not the only problem. Balancing Authority Areas must also balance supply with demand over the generation scheduling interval (historically an hour). Generation would be scheduled to meet anticipated changes in demand that is somewhat predictable. Demand typically ramps up during the morning hours and again in the early evening hours, for example. With dispatchable fossil generation, the transmission system operator is concerned only with load variability, which is accommodated through regulation service (the "Schedule 3" ancillary service in the transmission tariff). Renewable generation is variable and not controllable, which means the system operator must balance the system over the scheduling interval to account for changes to both load *and* generation. The net load curve shown for a sample day in the CAISO region in Figure 4, below, best illustrates this variability. The net load is calculated daily by taking the forecasted load and subtracting the forecasted electricity production from variable generation resources (wind and solar). The daily net load curves capture one aspect of CAISO's forecasted variability. There will also be variability intra-hour and day-to-day that must be managed.

Figure 4. ISO Net Load Curve



The foregoing explanation and the charts at **Figure 3** and **Figure 4** illustrate the challenges the CAISO faces with integrating and managing renewable resources in real time. As I will explain, the LEAPS project is a solution that can help avoid oversupply conditions, instantly resolve real-time over-generation and mitigate cost risks associated with renewable energy curtailments which, as shown later, impact California ratepayers in a significant way.

Q. Is there a solution to this problem?

A. Yes. The current solution to this problem is to curtail renewable resources. But there are other options. Electric storage, flexible load, or regional coordination solutions could reduce the cost impacts by enabling a larger portion of renewable energy output to be delivered to the grid without the adverse pricing consequences shown in the Duck Chart.[45]

Q. Can CAISO sell the over-generation to a neighboring balancing authority within WECC?

A. The State of California restricts PCC1 and PCC2 renewable energy from being exported as the renewable generator may lose its PCC1 or PCC2 renewable designation. Losing this designation will have a significant financial impact on these renewable generators, and therefore CAISO will be reluctant to sell over-generation energy resulting from excess renewable generation.

Q. How did you calculate the benefit of pumped storage from the LEAPS project to ease the over-generation problem?

A. I applied the CAISO 4-tiered renewable curtailment prices applied in its study as shown in the **Table 9** below to the curtailment reduction in each of the cases.[46]

Table 9. Curtailment Price Assumptions

	Tier 1	Tier 2	Tier 3	Tier 4
Curtailment Price ($/MWh)	-15	-25	-50	-150
Max Curtailment (GWh)	200	1,300	500	All the rest

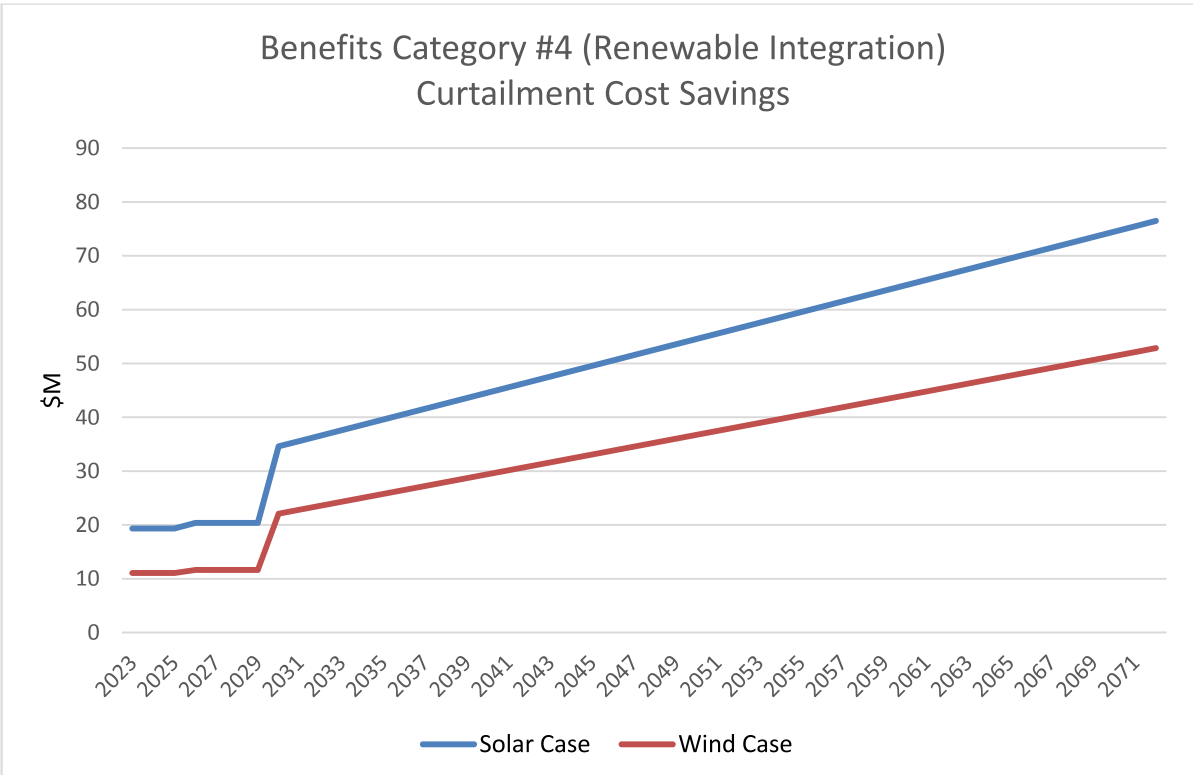
Q. Can you summarize LEAPS' renewable integration benefits?

[45] California ISO, Using Renewables to Operate Low Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant (2016), available at: https://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf .

[46] http://www.caiso.com/Documents/SupplementalSensitivityAnalysis-BenefitsAnalysisofLargeEnergyStorage.pdf, at page 6.

A. **Figure 5** below summarizes the over-generation cost savings over the life cycle of the project. As expected, the benefits increase every year as clearing prices during solar hours will continue to decrease.

Figure 5. Curtailment Cost Savings to California Ratepayers due to LEAPS



VII. RELIABILITY AND AVOIDED COST OF OTHER PROJECTS

Q. Can you explain TEAM benefit category #5?

A. Yes, for my analysis, I quantify three sub-categories for the reliability and avoided cost benefits as follows:

1. Reliability benefits due to increased flexible capacity, frequency response and inertia,
2. Avoided generation interconnection cost, and
3. Avoided cost of large transmission investments.

Q. What is flexible capacity?

A. Load following is the ability to match generation schedules to load over the course of the scheduling interval. In the days when utilities block-scheduled generators to serve load on an hourly basis, a generator might schedule 100 MW of capacity to meet an expected average load of 100 MW over the hour scheduling period. At the beginning of the hour the load might be 90 MW and at the end of the hour the load might be 110 MW. A generating resource is necessary to back down at the beginning of the hour to absorb the extra 10 MW being delivered, and then have the flexibility to make up the 10 MW shortfall at the end of the hour. Generators that can provide this "load following" have flexible ramping capability, which is essential to providing reliable service. Generation schedules in CAISO do not work exactly this way today, but the example illustrates the concept. CAISO considers load following to be a service that follows the deviations between five-minute and hourly block schedules of energy.

Q. What type of reliability services does LEAPS provide?

A. A bulk storage resource is known in the industry for its ability to quickly response to system needs outside the regulation band. The LEAPS project is designed to be highly flexible. The variable speed technology utilized by the project provide an incredible ability to move hundreds of stored MW's in minutes both in the generation and pump modes. The flexibility is a valuable reliability services and is in addition to the ancillary services such as regulation, spinning and load followings. The ability to start on a moment notice, provide voltage support, inertia and flexible capacity and energy with virtually no constraints beyond the 10 hrs. a day of full generation at full load (500 MW/hr) and 12 hour a day at full pumping of (600 MW/hr.). Furthermore, as I will discuss later in my testimony, LEAPS ability as a rotating machine can provide much needed flexibility/ramping and frequency response capabilities to the grid given the anticipated loss of more gas fired resources and Huntington beach synchronous condensers resources. As California increases its renewable energy generation supply portfolio, the need for flexible generation will compound, because the system operator will need to account for the variability of both load and generation. As the amount of variable renewable generation increases, so will the need for "flexibility resources" that can accommodate the increased variability of generation as well as ever-changing real-time load. LEAPS will be able to help keep generation schedules and load in balance because it will have fast ramping capability is more than 100 MW per minute.

Q. Why can't CAISO use conventional generation provide this flexibility?

A. The first difficulty is the amount of conventional generation available to the CAISO is in decline, as I have mentioned. Beyond this, flexibility in a world with high renewable generation using conventional generation may be problematic for several reasons.

First, the grid needs fast moving resources to accommodate a large fluctuation of wind and solar variable output that is caused by a sudden wind gust (such as a thunderstorm) or cloud covering. Conventional generation does not have the ability to provide a fast response as their ramp rates are relatively lower than a hydro pump storage.

Second, considering that renewable generation will displace a portion of conventional generation best suited to address the grid's ramping requirements, a large number of the remaining units must be kept online and partially loaded or "spinning," which adds to wear-and-tear and degrades reliability.

Third, volatile ramping on conventional gas fired generation may have undesirable side effects, such as impacts to natural gas pipeline balances and increased emissions that conflict with restrictions in environmental operating certificates.

Fourth, market revenues may not adequately compensate the generators for their operating costs, forcing retirements or additional cost-based reliability must run ("RMR") contracts.[47]

Q. What is the solution?

A. To reliably operate in these conditions, the CAISO requires flexible resources defined by their operating capabilities. These characteristics include the ability to perform the following functions:

- sustain upward or downward ramp
- respond for a defined period of time
- change ramp directions quickly, store energy or modify use
- react quickly and meet expected operating levels
- start with short notice from a zero or low-electricity operating level
- start and stop multiple times per day, and
- accurately forecast operating capability.

The CAISO needs a resource mix that can react quickly to adjust electricity production to meet the sharp changes in electricity net demand. **Figure 3** (the "Duck Chart"), above, shows a net load curve for a typical spring day for years 2012 through 2020. This curve shows the megawatt amounts the CAISO must follow on the y axis over the different hours of the day shown on the x axis. Four distinct ramp periods emerge. This means that to ensure reliability under changing grid conditions, the CAISO needs resources with ramping flexibility and the ability to start and stop multiple times per day. To ensure supply and demand matches at all times, controllable resources will need the flexibility to change output levels, and start and stop as dictated by real-time grid

[47] It is worth noting at this point that RMR contract payments are recovered through CAISO transmission rates paid by all customers.

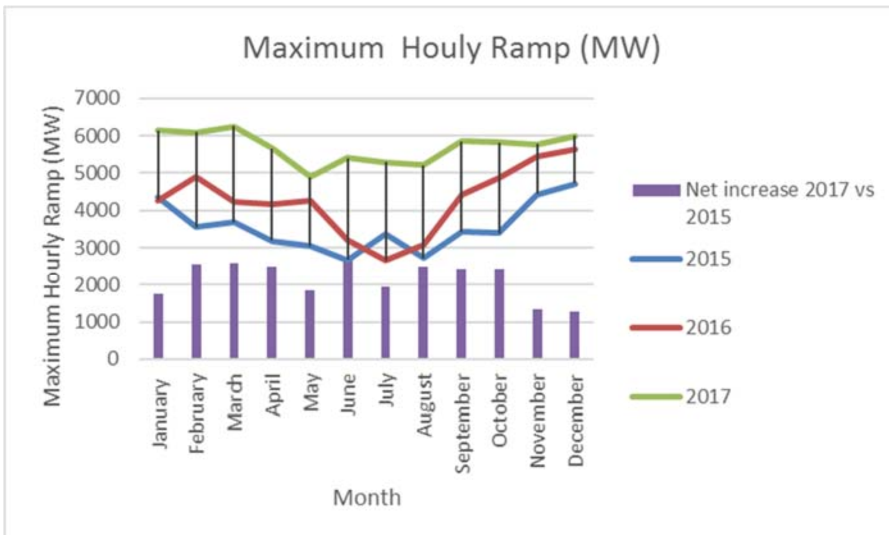
conditions. Grid ramping conditions will vary through the year. The net load curve or duck chart in **Figure 3** illustrates the steepening ramps expected during the spring. The duck chart shows the system requirement to supply an additional 13,000 MW, all within approximately three hours, to replace the electricity lost by solar power as the sun sets.

Q. How can LEAPS help?

A. LEAPS can provide the necessary quick-ramp load following for the CAISO grid. For instance, when the sun sets, California loses virtually all its solar energy in about 30 minutes.

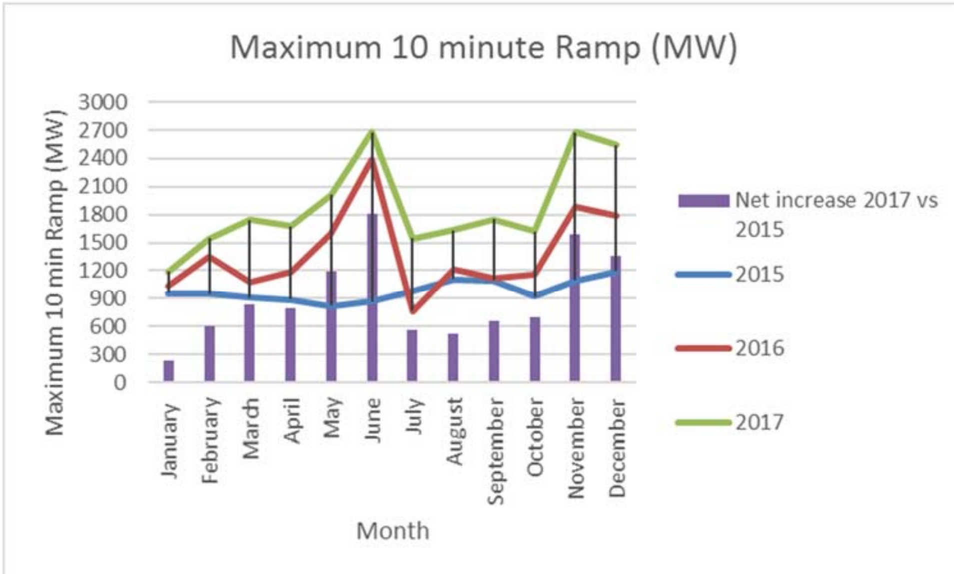
Figure **7** show the maximum hourly and 10-minute ramp requirement in megawatts by month for 2015, 2016 and 2017.[48] Both maximum and 10-minute ramp requirement steadily increase from 2015, 2016 and 2017. The net increase in ramping since 2015 is on the rise. LEAPS can be an effective, predictable and a large enough resource to deal with these multiple ramping requirements throughout the day.

Figure 6. ISO's Maximum Hourly Ramp Requirement by Month for 2015 - 2017



[48] http://www.ISO.com/Documents/MonthlyRenewablesPerformanceReport-Nov2017.html.

Figure 7. CAISO's Maximum 10-minute Ramp Requirement by Month for 2015 - 2017



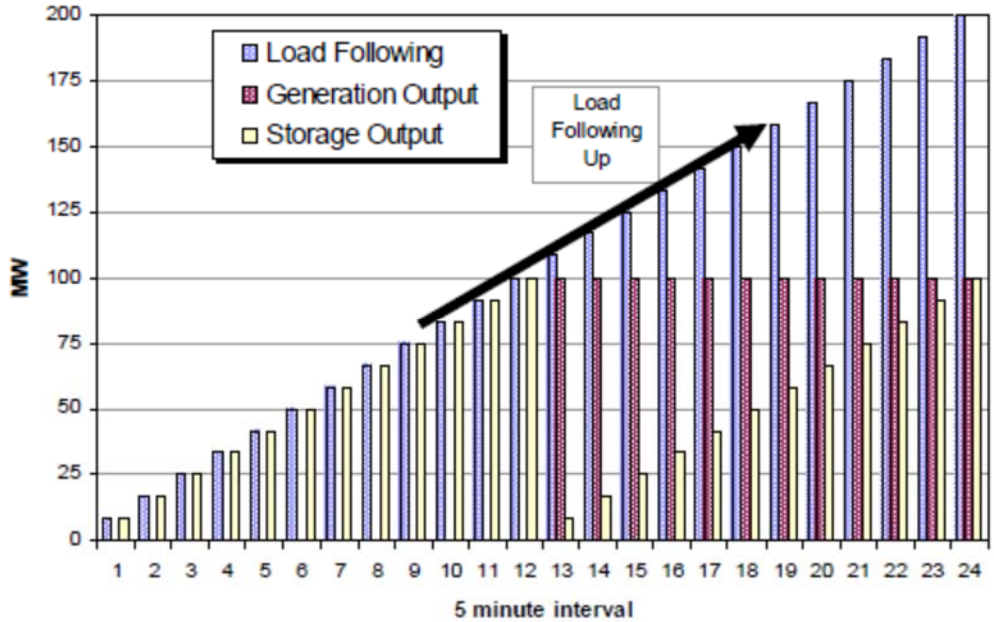
Q. Please explain.

A. The maximum hourly ramp in a given month is the amount of energy the CAISO would need from one hour to the next. Similarly, the maximum 10-minute ramp is the maximum amount of energy in a 10-minute period for a given month that CAISO needs to balance the system and maintain reliability. Energy for CAISO's steep ramping requirement means that it can only come from fast moving resources that are dispatchable. Solar and wind are intermittent resources and are non-dispatchable. Hydro and battery storage are considered the best, most responsive resources that can quickly be available. For instance, LEAPS can supply 500 MW in a few minutes, and turn around and shut down and act as a load in just four minutes. LEAPS can provide the flexibility and load following that the grid is increasingly needing.

Figure 8, below, illustrates this. The load following capacity is indicated by the blue bars labeled "Load Following." The rate of LEAPS' generation output increases as load increases (shown by the yellow bars labeled "Storage Output"). After the first hour of load following with LEAPS, a full 100-MW block of other ISO generation is dispatched (shown by the red bars) while

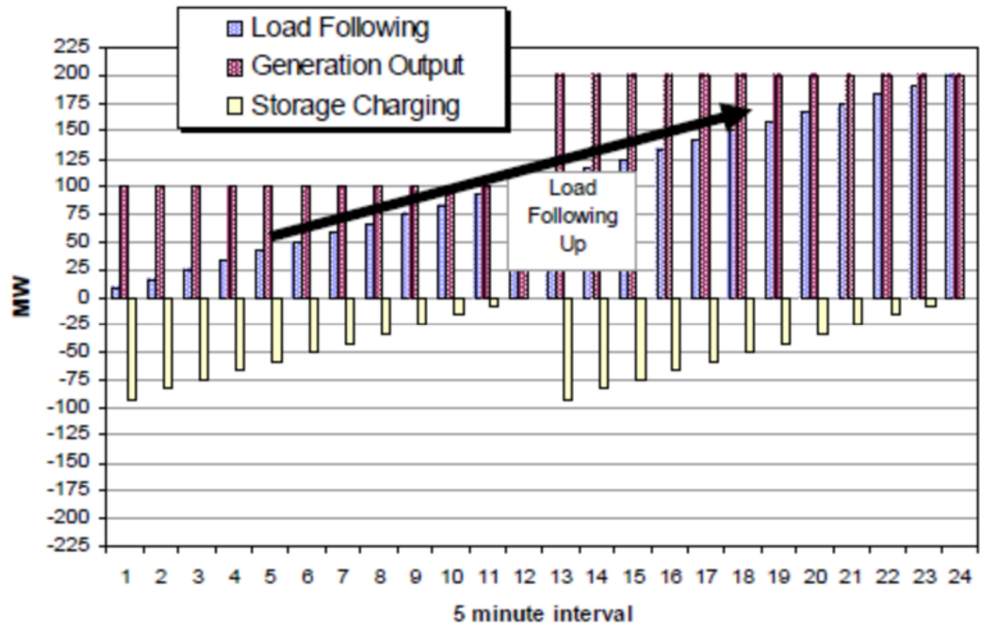
LEAPS generation is curtailed (at interval #13) when generation output such as wind (Red) becomes available. Throughout the second hour of load following, LEAPS' output can be increased every five minutes (as it was during the first hour) as load increases.

Figure 8. Illustration of How LEAPS Provides Load Following Up



LEAPS pumping can also be used to provide load following up by reducing the pumping load throughout an hour, commensurate with increasing load. Consider the illustration shown in , below. At the beginning of the first hour of load following, a 100-MW wind generator becomes available (see the red bars labeled "Generation Output"). At the same time, LEAPS begins pumping at a rate of 100 MW, which is equal to the wind generation. Every five minutes, the pumping load is reduced to the extent that load has increased (note the yellow bars labeled "Storage Charging"). The resulting load following up is shown by the blue bars. At the beginning of the second hour of load following, an additional 100 MW of wind generation becomes available, and LEAPS pumping commences again at 100 MW equal to the output of the second wind generator.

Figure 9. Illustration of How LEAPS Provides flexibility Up in Pump Mode



Q. How does LEAPS work when renewable generation decreases?

A. LEAPS provide load following down by decreasing its generation output and/or by increasing its pumping load as illustrated in **Figure 10** and , below. **Figure 10** shows how LEAPS generation can be used for load following down. LEAPS generation is dispatched from full output to very low (or no) output twice in a two-hour period. The example assumes that at the end of the previous hour (not shown), a 200 MW wind generator is reduced to 100 MW. Then LEAPS comes online (as shown by the yellow bars labeled "Storage Output"). Another 100 MW of wind generation is still online (shown by the red bars labeled "Generation Output"). The generation output is reduced every five minutes during the first hour as load drops. The resulting load following capacity is shown by the blue bars labeled "Load Following." At the beginning of the next hour, the 100 MW wind generator is reduced to zero and LEAPS begins generating again at 100 MW. Energy output from LEAPS decreases throughout the second hour as load decreases until output is zero at the end of the second hour.

Figure 10. Illustration of How LEAPS Provides Load Following Down

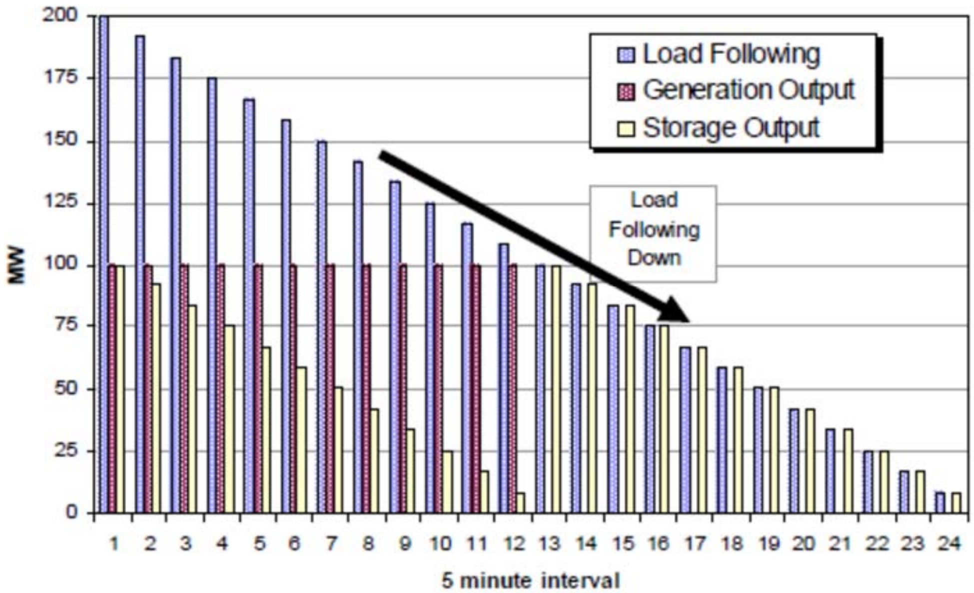
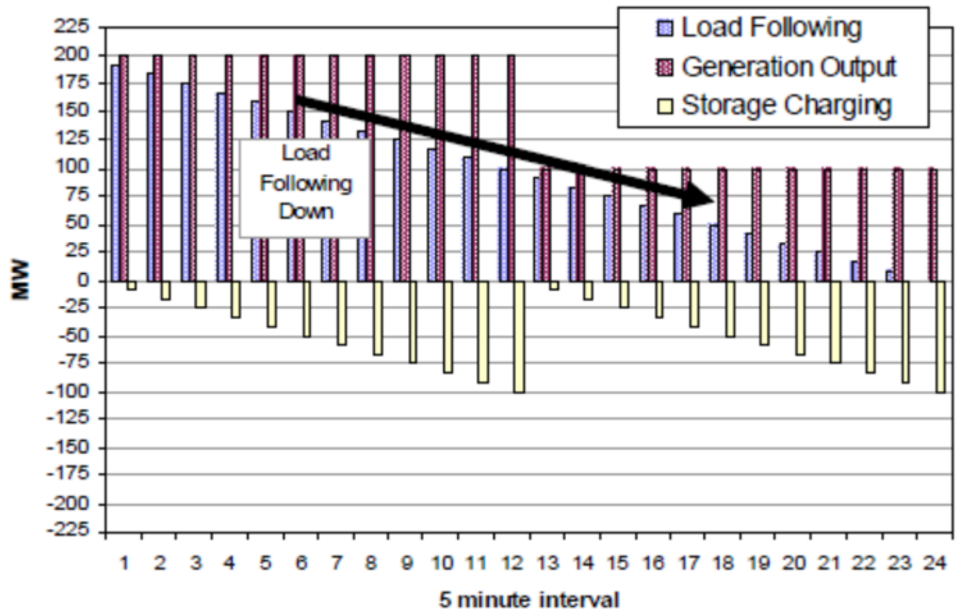


Figure 11 shows how LEAPS can be used to provide load following down while pumping. At the beginning of the hour, two 100 MW wind generators are on-line for a total of 200 MW (shown by the red bars labeled "Generation Output"). As load decreases, there is a commensurate increase of LEAPS pumping (shown by the yellow bars labeled "Storage Charging"). The resulting load following capacity is shown by the blue bars labeled "Load Following." At the beginning of the second hour, 100 MW of wind generation is not available, LEAPS begins pumping again with a low pump load. As load continues to diminish, LEAPS' pumping is increased until the beginning of the next hour (not shown) when LEAPS' pumping and wind generation both decrease to zero.

Figure 11. Illustration of How LEAPS Provides Load Following Down in Pump Mode



Q. What other critical reliability services does LEAPS provide?

A. LEAPS has the capability to provide the grid with more resiliency.

Q. What is grid resiliency?

A. Grid resiliency is a concept that encompasses traditional reliability through compliance the NERC rules concerning the operation of the bulk electric system in compliance with Section 215 of the Federal Power Act,[49] but also includes attributes that contribute to the robustness of the bulk electric system to respond to service disruptions, as the Commission recently explained an order on a proposed rule to address grid resiliency and pricing issues.[50] As FERC explained in its grid resiliency order, there is no common industry definition of "resilience," but commenters in the proceeding generally used the term to mean "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to,

[49] 16 U.S.C. § 824o (2016).

[50] Order Terminating Rulemaking Proceeding, Initiating Proceeding, and Establishing Additional Procedures Proceeding reGrid Reliability and Resilience Pricing, 162 FERC ¶ 61,012 (2018).

and/or rapidly recover from such an event."[51] Among the questions FERC has posed for industry comment is to identify generation and transmission services that support grid resilience.[52]

I agree with FERC's definition. Resiliency has many attributes, but fundamentally it is obtained from a robust transmission system coupled with generating facilities with rotating mass or turbines (such as hydro, nuclear, coal, geothermal, biomass and gas-fired generation). One aspect is the ability of the grid to use generation and transmission assets to respond to any imbalance.

Q. Can you give an example?

A. Yes. A critical threat that lies at the root of most major blackouts is what happens in the first few seconds on the grid following an outage. These first few seconds is what determines whether the grid can absorb and recover from an outage, which lies at the core of FERC's proposed resiliency definition. For instance, one of the most common measures of reliability is system frequency which measures the extent to which supply and demand are in balance. To ensure reliability, system frequency must be managed in a very tight band around 60 hertz. When an unexpected event occurs that disrupts the supply-demand balance, such as a loss of a generator or transmission line, frequency is impacted. These events do not allow time for manual response and balance is maintained through generating facilities equipped with automatic generation control ("AGC") telecommunications and computer facilities that allow the generator to fluctuate in response to moment-to-moment frequency changes on the grid. Conventional and rotating generation resources include frequency-sensing equipment, or governors, that automatically adjust electricity output within seconds in response to frequency to correct out-of-balance conditions. If

[51] *Id*. at P 23. FERC required regional transmission organizations to file explanations with FERC regarding their approaches to ensuring grid resiliency, including whether they agree with FERC's definition.

[52] *Id*. at P 27(c).

frequency deviation is not corrected in a few seconds, there is a risk for the grid to become unstable which leads to a catastrophic blackout. Transmission providers are required to make frequency response service available to transmission customers under Schedule 2 of their open access transmission tariffs.

Q. Have generation trends in California impacted the frequency response capability of the transmission network?

A. Yes. In California, the availability of rotating machines equipped with AGC is diminishing and is being replaced mainly by wind and solar (both rooftop and utility scale).[53] Figure 12, below, shows the increase in renewable fueled generation. In addition, and in the vicinity of the LEAPS project, the 2,246 MW San Onofre nuclear plant with its massive 150-ton turbines has been taken out of service. Huntington Beach's 452-MVAR synchronous condensers is planned to be offline starting in 2018.[54] Encina will lose 950 MW of gas-fired generation, Morro Bay's 650 MW gas plant was shut down in early 2014, and the Diablo Canyon 2,200 MW nuclear facility is scheduled to retire by 2026. These developments all significantly and adversely affect the frequency response capability of the power grid.

Furthermore, section 2.3.4.2 of the ISO 2016-2017 transmission plan points out that the renewable generation dependability as a percentage of name plate under stress summer peak conditions varies between 100% for biomass, geothermal and biogas to 36 % for solar and 0% for wind.[55]

Q. Do transmission facilities contribute to resiliency?

---

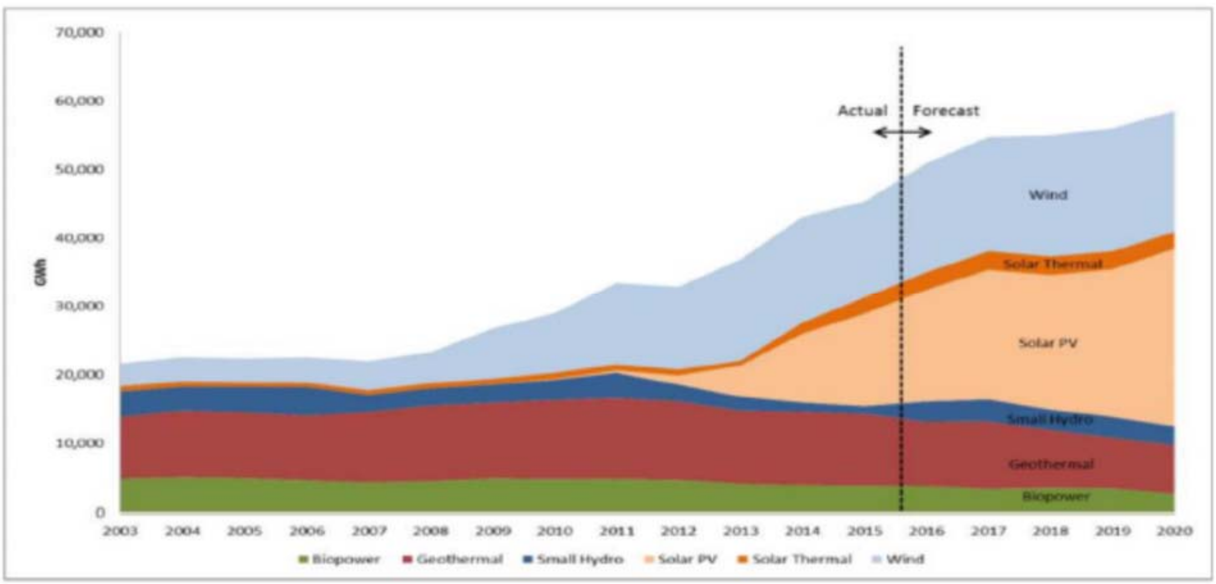
[53] CPUC Report to the Legislature in Compliance with Public Utilities Code Section 910, May 2015

[54] http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf, Table 2.3-7, page 43.

[55] *Id.* at Table 2.3.6, page 41.

A. Yes, when the facilities are adequate to reach all economic supply. That is not always the case, however, which is why there are load pockets that require local generation to serve peak demand. For example, San Diego's load cannot be served exclusively from electric imports because there is not enough transmission capacity. Therefore, local generating capacity is required to serve peak demand.

Figure 12. Generation mix (Actual and Forecast)



Q. Has CAISO studied frequency response resiliency?

A. Yes. Part of the renewable integration analysis conducted by the CAISO uncovered concerns about frequency response capabilities due to the displacement of conventional generators on the system. The CAISO's 2020 33% renewable penetration studies show that in times of low load and high renewable generation, as much as 60% of the energy production would come from renewable generators that displace conventional generation, thereby depressing frequency response capability.[56] Under these operating conditions, the grid may not be able to prevent frequency decline following the loss of a large conventional generator or transmission asset (*i.e.*, a NERC "N-1" reliability contingency). This situation would arise because renewable generators are not currently required to include AGC equipment and are operated at full output. Without this automated capability, the system becomes increasingly exposed to blackouts when generation or transmission outages occur.

Q. Have there been any other studies?

A. Yes. A recent study by the US Department of Energy's ("DOE") National Renewable Energy Laboratory found that about 65% of a typical rooftop solar energy customer's electricity demand is non-coincidental with the electricity generated from their own rooftop solar photovoltaic generating equipment.[57] Therefore, a 100% solar PV power supply portfolio would neither be capable of meeting peak demands nor be capable of supplying consumers connected to the grid with the electricity that they want, whenever they want it. That is clearly a problem.

Q. Has FERC done anything about this?

A. Yes. On January 16, 2014, FERC approved NERC Reliability Standard BAL-003-1, which placed a new frequency response requirement on BAAs (including the ISO). BAL-003-1 requires balancing authorities to demonstrate sufficient primary frequency response to disturbances in system frequency.[58] Primary frequency response is a service that provides an actual response to a

---

[56] http://www.caiso.com/documents/FlexibleResourcesHelpRenewables_FastFacts.pdf and http://www.ISO.com/Documents/IssuePaper_FrequencyResponsePhase2.pdf.

[57] Lori Bird, *et al.*, *Impact of Rate Design Alternatives on Residential Solar Customer Bills: Increased Fixed Charges, Minimum Bills and Demand-Based Rates*, https://www.nrel.gov/docs/fy15osti/64850.pdf.

[58] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014) ("Order 794") ("the purpose of this section is to present the reliability need underpinning frequency response service. The reliability need is to control frequency to stable levels to support a well-functioning grid. An interconnection needs to have a system frequency that is on average near the scheduled frequency value at 60 Hz. If frequency increases far above the scheduled value due to over-generation relative to demand it can lead to grid instability. If frequency decreases well below the scheduled value due to insufficient generation

frequency change when additional power is provided to the grid to arrest and stabilize frequency within 52 seconds by automatic, autonomous response either through control devices or system operator signals based on an algorithm that matches product specifications.

CAISO's analysis showed that it could at times be short of its required share of frequency response.[59] CAISO, therefore, filed tariff revisions to ensure interim compliance with BAL-003-1 for 2017 by procuring "transferred frequency response" and strengthening requirements for conventional resources.[60] Transferred frequency response is an annual contract to allow a transfer of frequency response performance between BAAs. FERC approved the filing September 16, 2016.[61] CAISO committed to evaluate whether a market mechanism should be designed to encourage frequency response capabilities of all participating resources, enable the diverse mix of resources to provide services, and ensures CAISO meets applicable reliability criteria.

Q. Are there other aspects of frequency response that are important?

A. Yes. Frequency response ride through and frequency inertia are two important concepts to understand, particularly when it comes to seeing how the LEAPS project can help the system.

Q. What is frequency response ride through?

A. This concept takes a bit of technical explanation. The frequency of the system will vary as load and generation change. Increasing the mechanical input power to a synchronous generator will not greatly affect the system frequency, but will produce more electric power from that unit. During a severe overload caused by tripping or failure of generators or transmission lines, the power system frequency will decline due to an imbalance of load versus generation. Loss of an

relative to demand it can lead to grid instability. The under-frequency events introduce a high grid reliability risk since if an under-frequency event persists it could cause cascading black outs.").

[59] *Id*. at 4

[60] *Cal. Indep. Sys Operator Corp*., Tariff Revisions (Apr. 21, 2016).

[61] *Cal. Indep. Sys Operator Corp*., 156 FERC ¶ 61,182 (2016).

interconnection, while exporting power (relative to system total generation) will cause system frequency to rise. AGC is used to maintain scheduled frequency and interchange power flows. Control systems in power stations detect changes in the network-wide frequency and adjust mechanical power input to generators back to their target frequency. This counteraction usually takes a tens of seconds due to the large rotating masses involved. Temporary frequency changes are an unavoidable consequence of changing demand.

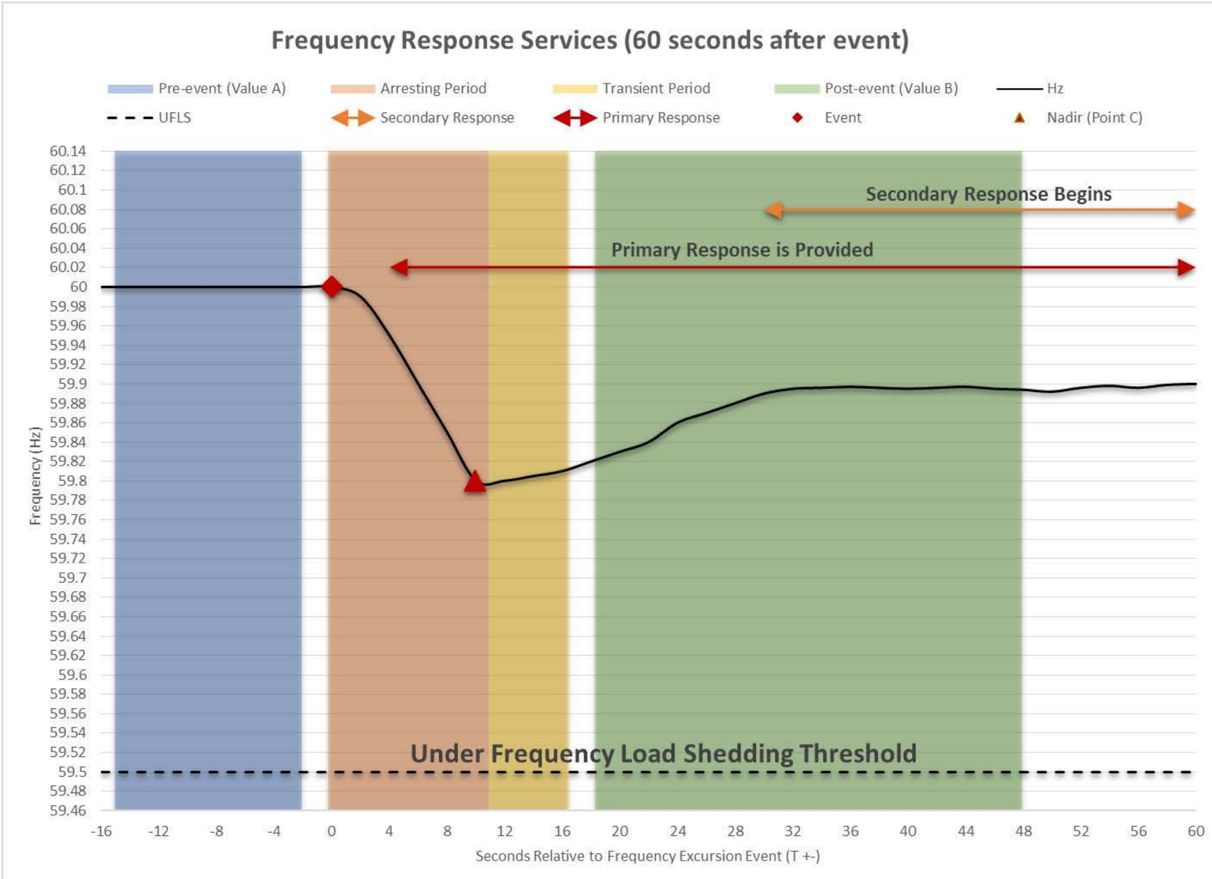
The operating frequency of the US grid is 60 Hz. Typically, a decreased frequency indicates that the load demand is greater than generation and vice versa. The frequency response of the system is a measure of its stability. For CAISO the frequency response required is around 258 MW for each 0.1 Hz (*i.e.*, capability to provide 258 MW in response to a drop in frequency by 0.1 Hz).[62] The resiliency of the system to frequency deviations improves with an increase in this value.

Frequency deviations occur during contingencies like loss of generation, loss of a transmission line followed by a remedial action scheme, etc. When such deviations occur, there are three types of actions taken to remediate the deviation: primary, secondary, and tertiary response.

Primary frequency response is the first line of defense against frequency deviations after an event, the frequency change is arrested and stabilized through automatic generator response, load response and other devices. The primary response starts within a few seconds of an event that leads to frequency deviation as shown in **Figure 13**, below. During these few seconds the frequency drops rapidly, and the drop is proportional to the amount of generation MW lost. This excursion will have to be arrested to prevent generators from tripping and to avoid load shedding.

[62] http://www.ISO.com/Documents/IssuePaper_FrequencyResponsePhase2.pdf, Table 1

Figure 13. Frequency Response Services after an Event[63]



Note that frequency during the "arresting period" needs to recover to 60 Hz in a couple of seconds. The longer the "arresting period," the less the grid is reliable. Arrest generators are protected by relays that read the frequency of the grid and isolate the generators from the grid when required. If the relays trip the generators for small up or down frequency deviations, they add to the instability in the system. So, NERC and WECC have mandated that a generator should operate within specific frequency limits even during a contingency event for a set period, this feature is called frequency ride through. These settings are given in **Table 10**, below. Beyond these limits, the generators are free to trip.

[63] *Id.*

Table 10. WECC Frequency Ride-Through Setting.

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

Q. What is generator inertia?

A. Inertial response of the system plays an important role in arresting the frequency excursion. The slope of the frequency excursion after the drop is inversely proportional to the inertia of the system. The inertial response with load damping provide stability to the system before frequency response can take place.

Hydro generators have massive prime movers which have a lot of inertia, especially 500 MW hydro generators as in the LEAPS project. Hence, when a contingency occurs, and the frequency varies, they do not speed up or slow down rapidly like other generators. They continue to provide stability to the system. This gives primary response time to act and stabilize the frequency. Even after the excursions, during the transient period hydro generators provide better stability than inverter based photovoltaic solar generation of similar size.

Q. How can LEAPS help frequency response?

A. To quantify the benefits that LEAPS can provide, I performed two frequency response studies and one inertia assessment for the SDG&E system using CAISO's transmission planning base case for 2022. I chose the 2022 base because that is when the project is expected to be in service.

Q. Please explain your first study.

A. The first study simulated frequency response for a generic 500 MW solar photovoltaic facility located at Lake Elsinore versus LEAPS upon the loss of the 500 kV Southwest Power Link transmission line, which serves as the major import path for SDG&E. Southwest Power Link is considered by ISO to be one of the greatest threat contingencies for the area.[64] The September 8, 2011 blackout in Southern California began when that transmission facility tripped off-line. The frequency response of each generator was monitored under both scenarios and the results are shown in **Table 11**.

Table 11. Frequency Response comparison for the loss of the 500 kV Southwest Power Link.

Frequency Response Comparison	Generic PV or LEAPS (Hz.)
Generic PV Case	-0.096
LEAPS Case	-0.022
% change in - ΔF	-77%

Q. What did your first study show?

A. My study shows that in the LEAPS case, the negative frequency deviation is less following the outage. The frequency deviates 77% less with LEAPS compared with 500 MW of Solar PV.

Q. Please describe your second study.

A. The second study compares the frequency response pre-and post-LEAPS upon the loss of the same 500 kV Southwest Power Link transmission line for three existing generators in the SDG&E area: (a) Solar PV connected to the Drew substation, (b) the 950 MW Encina combined

[64] For example, EDF Renewable Energy recently signed a long-term power sales contract with SCE to sell the output from a new 500 MW solar photovoltaic facility to be developed near Joshua Tree National Park.

cycle gas-fired generating facility, and (3) the 45 MW El Cajon gas turbines. **Table 12** summarizes the results pre-LEAPS and post-LEAPS simulations.[65]

Table 12. Summary of Frequency response Pre-LEAPS and Post-LEAPS.

Plot Number-Generator	PRE - LEAPS				POST - LEAPS					
	Min Frequency Hz	-ΔF Hz	Max Frequency Hz	+ ΔF Hz	Min Frequency Hz	-ΔF Hz	% change in - ΔF	Max Frequency Hz	+ΔF Hz	% change in +ΔF
El Cajon Gas Turbine Gen	59.778	-0.222	60.140	0.140	59.808	-0.192	-14%	60.107	0.107	-24%
Drew solar PV Gen	59.845	-0.155	60.188	0.188	59.864	-0.136	-12%	60.183	0.183	-3%
Ocotillo Wind Gen	59.598	-0.402	60.133	0.133	59.670	-0.330	-18%	60.098	0.098	-26%

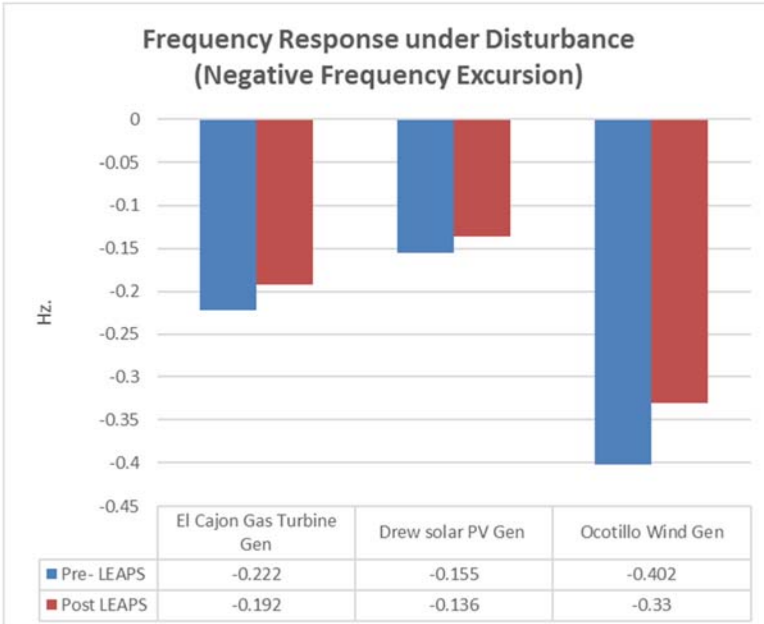
Q. What do you conclude from your second study?

A. The primary frequency response of different generators in the SDGE Area is monitored pre-LEAPS and post-LEAPS. When comparing the pre-LEAPS and post-LEAPS frequency values in **Table 12**, it is apparent that LEAPS reduces the magnitude of frequency excursions. The percentage change in frequency excursions (*i.e.*, ΔF presented in **Table 12** are negative indicating that the deviation in frequency is a lot less when LEAPS is present in the system). This is illustrated in **Figure 14**.

---

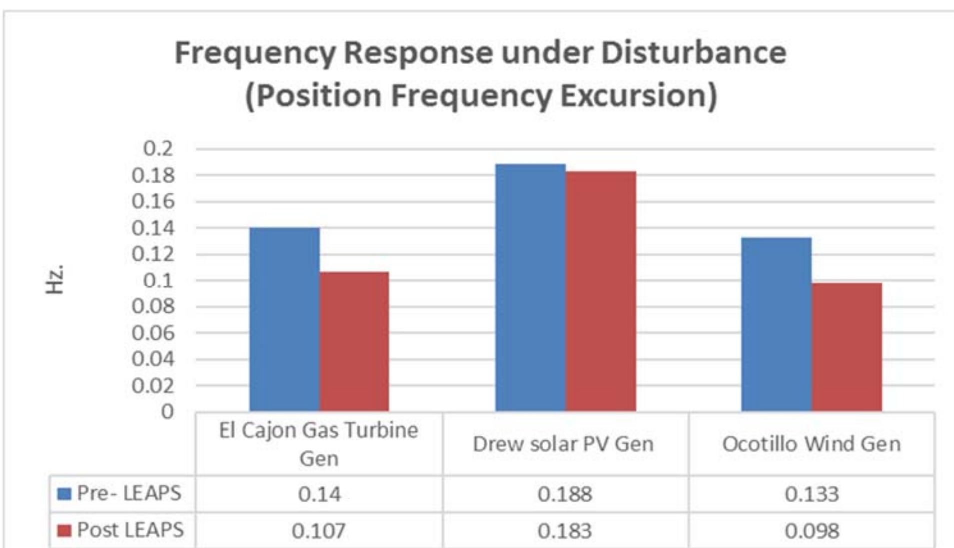
[65] Min Frequency is the lowest frequency, Max Frequency is the highest frequency. +ΔF represents change in frequency from the steady state value (60 Hz.). Small increase in frequency is consider more resilient grid. -ΔF represents decrease in frequency below the steady state value i.e. 60 Hz. Small decrease in frequency is considered as a more resilient grid scenario.

Figure 14. Graphical comparison of Negative Frequency Excursions Pre-LEAPS and Post-LEAPS



As shown in **Table 12** and **Figure 14**, with LEAPS, negative frequency deviation is 12% to 18% lower than without LEAPS. This means that under the outage, frequency "dips" less with LEAPS, as illustrated in **Figure 15**.

Figure 15. Graphical comparison of Positive Frequency Excursions Pre-LEAPS and Post-LEAPS



As shown in **Table 12** and **Figure 15**, with LEAPS, positive frequency deviation is 3% to 26% lower than without LEAPS. This means that under the outage, frequency "overshoot" is less with LEAPS. Also, note that with LEAPS the frequency settles at a value closer to the initial frequency and reaches the initial steady state quicker. In the plots shown in **Figure 16** through*, my study results show there are oscillations in the pre-LEAPS plots (Green) around the 13th second and the 18th second, which are not present in the plots obtained with LEAPS (Red).*

A general observation is that the oscillations in the plots are a lot less pronounced with LEAPS. **Figure 16**, below, also shows the response from the existing El Cajon Plant for a given loss of the same line under both a pre-LEAPS and a post-LEAPS scenario. The El Cajon gas turbine frequency dipped by 0.222 Hz in the pre-LEAPS case. In the post-LEAPS case, its frequency dipped by 0.192 Hz. El Cajon's frequency dipped 14% less with LEAPS in-service. **Figure 16** also shows that the frequency "over shoot" under the LEAPS scenario was 24% lower than without LEAPS. Finally, the gas turbine frequency stabilized in 8 seconds with LEAPS compared to without LEAPS, whereas the frequency for the gas turbine took 20 second to stabilize.

Figure 16. Frequency Response for an Existing Gas Turbine in San Diego Pre-LEAPS and Post-LEAPS

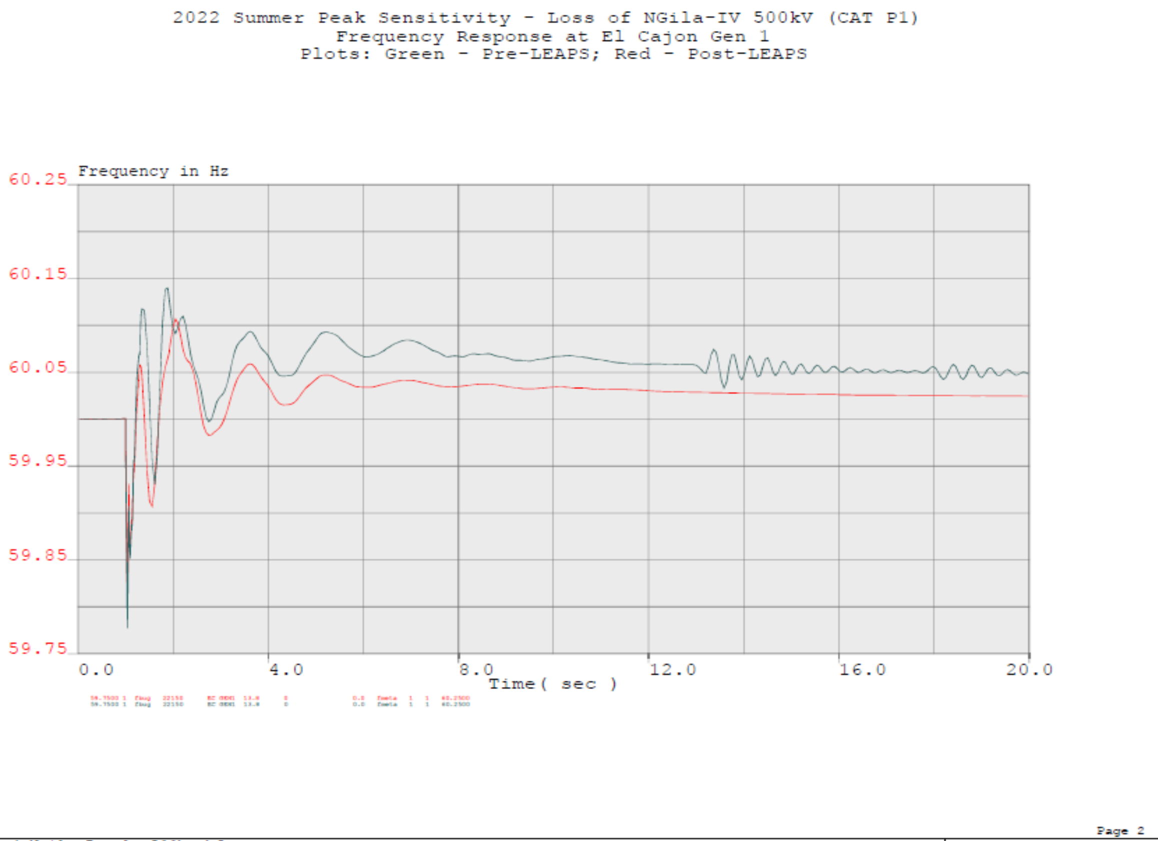


Figure 17, below, shows the response for the existing Drew PV plant pre-LEAPS and post-LEAPS for the loss of a single 500 kV line. The PV frequency dipped by 0.155 Hz in the pre-LEAPS case whereas it dipped by 0.136 Hz in the post-LEAPS case. This result is a 12% improvement with LEAPS. The frequency overshoot for Drew PV improved by 3% from +0.188 to +0.183 Hz and the stabilization time improved by approximately 4 seconds.

Figure 17. Frequency Response for an Existing Solar PV in San Diego Pre-LEAPS and Post-LEAPS

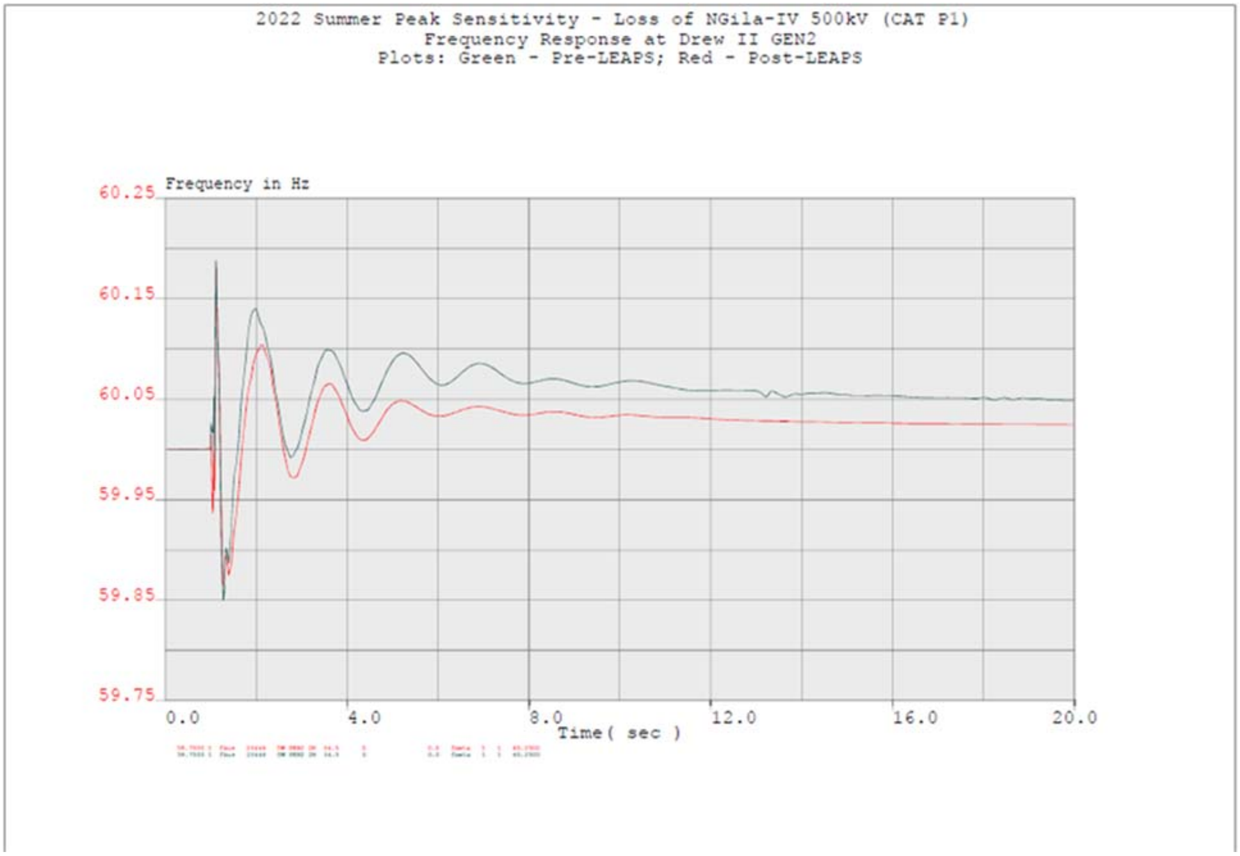
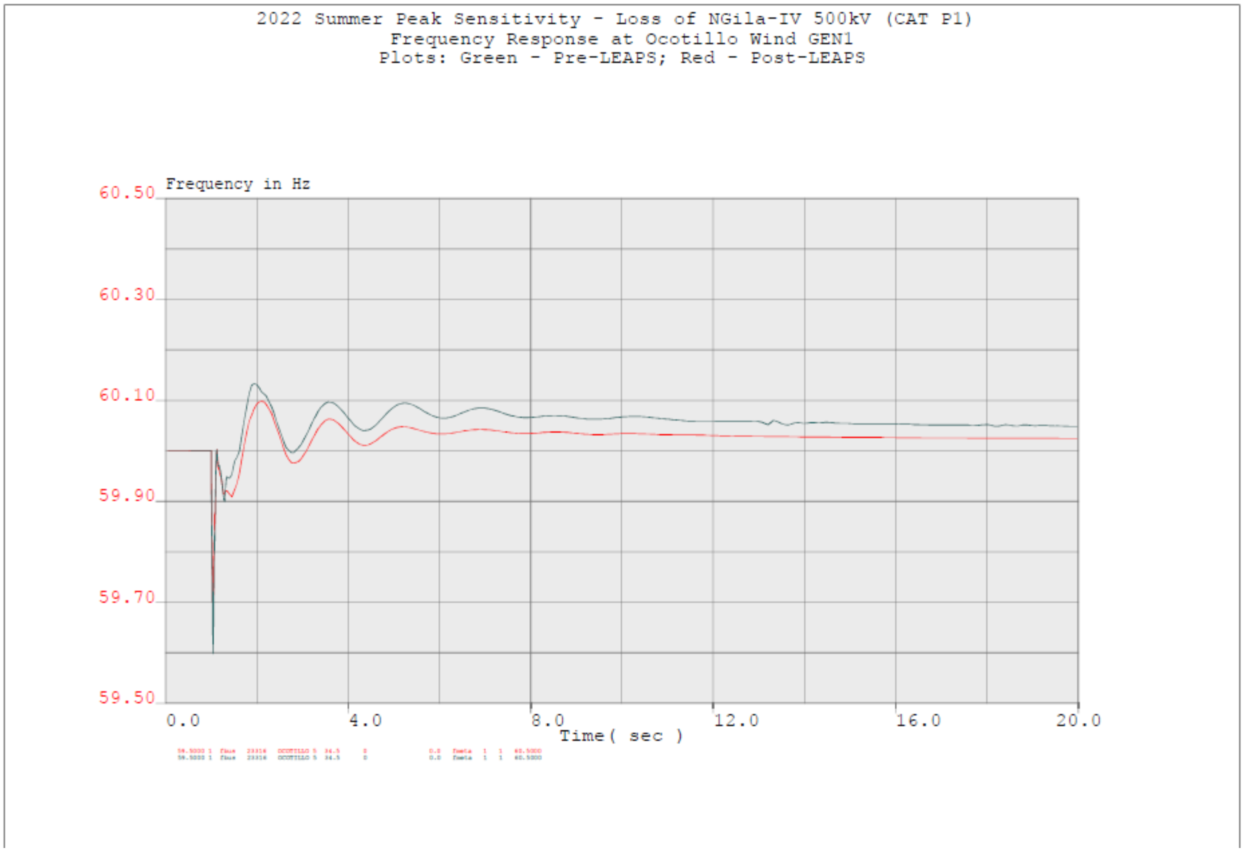


Figure 18, below, shows the response for the Ocotillo wind generation facility pre-LEAPS and post-LEAPS for the loss of the same 500 kV line. The PV plant frequency dipped by 0.402 Hz in the pre-LEAPS case whereas it dipped by 0.33 Hz in the post-LEAPS case. This results in an 18% improvement with LEAPS. The frequency overshoot for Drew PV improved by 26% from +0.133 to +0.098 Hz and the stabilization time improved by approximately 2 seconds.

Figure 18. Frequency Response for an Existing Wind Generator in San Diego Pre-LEAPS and Post-LEAPS



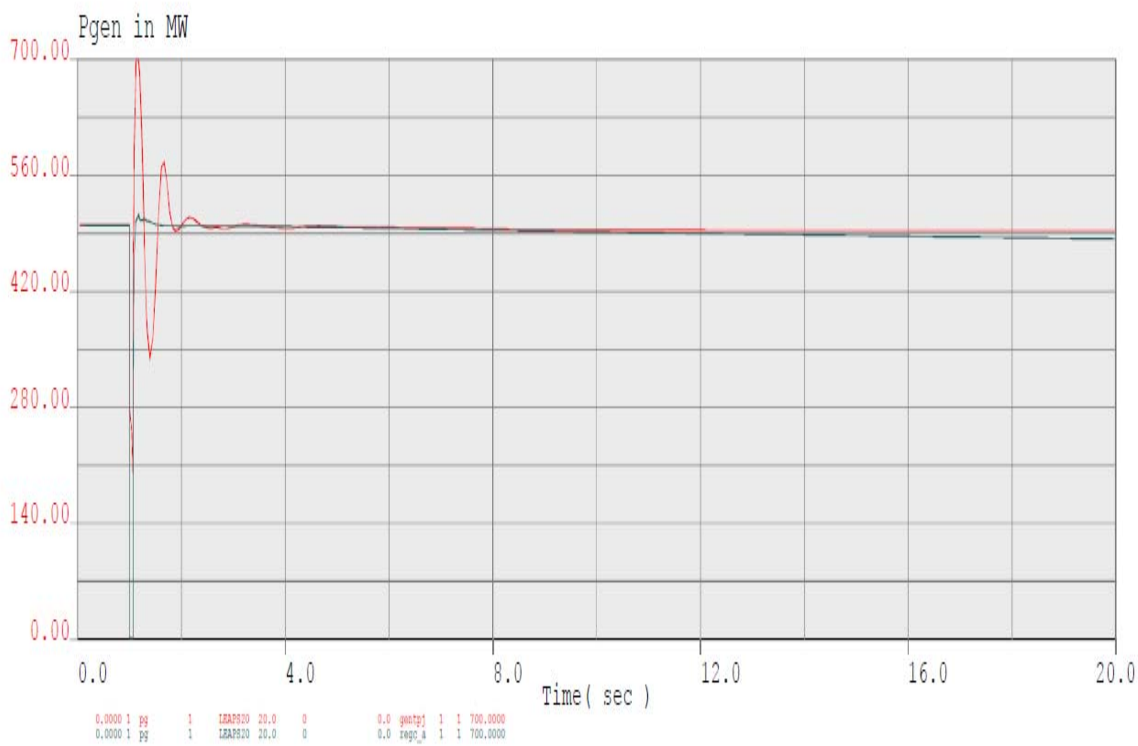
Q. Please describe your third study.

A. My third study is an analysis to assess LEAPS' ability to provide inertia response for system disturbances similar to the September 8, 2011 Southern California blackout. I simulated the generation response from an existing Solar PV and the proposed LEAPS project. **Figure 19** shows both plants generating 500 MW. Upon the loss of the 500-kV line, all 500 MW of PV generation dropped and recovered back to 500 MW. However, LEAPS generation dropped from 500 MW to 300 MW but also produced 700 MW which was 200 MW above its initial generation level (RED). This 200 MW is called "inertia" response. LEAPS help the system by (1) not losing all its generation and (2) producing 200 MW more energy before returning to its 500 MW level.

Q. What do you conclude?

A. My conclusion is that a hydroelectric generator performs better during contingencies and reduces the frequency deviations much better than a similar sized solar photovoltaic generator. This is due to the inherent inertial response contributed from the hydro generator whereas the inverter-based generators do not have mechanical inertia. The PV inverter control system must detect the fault and react to it, which constitutes a delay of few cycles. This can be seen in **Figure 19**, below, where the black plot is a PV generator and the red plot is hydroelectric generator. As mentioned, the real power output of the PV generator drops to zero while that of the hydro generator does not. So, when the event occurs, the hydro generator adds to the inertial response of the system, arresting the frequency drop and thereby improving the stability of the transmission grid. Also with the hydro generator the frequency returns to a level closer to the initial frequency.

Figure 19. Generation Response for an existing Solar PV and LEAPS in San Diego



Q. How would you sum this up?

A. The LEAPS project helps improve the stability of the system by:

1. Reducing both negative and positive frequency excursions,
2. Providing quicker frequency recovery to levels closer to pre-contingency, and
3. Reducing the time to reach stable operating levels.

By keeping a check on the frequency swings, the LEAPS project reduces the chances of instantaneous tripping of other generators, thereby reducing the risk of a cascading failure and potential blackouts.

Q. What other electric support services can LEAPS provide?

A. Frequency response, inertia, voltage support, phase shifting, reactive and black start capabilities are sometimes lumped together into “electric reliability services.” LEAPS provides reactive power (VAR) support by providing and absorbing reactive power. It will be capable of moving up or down by 500 MVAR, similar to a synchronous condenser, like a gas-fired power plant, or shunt capacitors and reactors that are typically used as transmission devices to control the voltage on the grid. LEAPS also provides black start capability and is able to quickly utilize its three large phase shifters to automatically re-route power when needed, based on the angular separation between the main substations similar to the phased angle technologies. Operating efficiency of electric transmission system can be improved by using appropriate FACTS devices. Phase shifting transformer is one of the devices in the FACTS family which can be used for power control in a network.[66]

[66] As renewable energy continues to expand, the transmission grids are reaching their limits in many areas. One way of avoiding bottlenecks is to distribute load on parallel sections. To distribute load, the phase shifter transformer changes the phase angle between the transformer's primary and secondary side as required. The tap-changer used must have a large number of switching steps and operate at very high-power levels. The more finely the active power

Q. What is the avoided generation interconnection cost?

A. As shown by the ISO, TEAM Public Policy Benefits #3 shows that LEAPS is able to reduce the amount of nameplate renewables generating capacity to achieve California's 50% RPS goal. The avoided renewable generation capital cost also has an avoided transmission interconnection cost because generators that are not built do not trigger the need for transmission upgrades that must, ultimately, otherwise be paid for by consumers. The avoided transmission interconnection cost is based on the reduced renewable capacity to meet the state's 50% RPS goal with LEAPS in service multiplied by a price of $22/kW-year.[67] The resulting levelized annual benefits based on 511 MW

Table 13 below summarizes the amount of solar or wind needed under each of the ISO four sensitivities before and after LEAPS. LEAPS eliminates the need for 148 MW to 323 MW and from 108 MW to 188 MW of solar and wind overbuild respectively. The avoided interconnection cost is calculated by the avoided renewable generation name place capacity by a price of $22/kW-year.[68] This results in savings that ranges from $2.4 million to $7.1 million per year. This annual revenue requirement for the avoided interconnection cost is held constant throughout the life cycle of the project.

---

is graduated, the more tap-change operations are possible. The tap-changer for the phase shifter transformer is frequently adapted to the specific requirements.

[67] http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf at page 17.

[68] http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf at page 17.

Table 13. Avoided Interconnection Cost Summary

	Net Renewable Generation decreased and annual avoided cost			
Summary of Avoided Interconnection Costs	Solar case (MW)	Wind Case (MW)	Solar Case ($M)	Wind Case ($M)
Sensitivity #1 - Summary of the ISO analysis of the Updated Default Scen	163	112	$3.6	$2.5
Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)	323	188	$7.1	$4.1
Sensitivity #3 - Summary of the ISO analysis of the Updated Default Scenario with 2015 IEPR Mid -AAEE Sensitivity (2026 Base case)	194	115	$4.3	$2.5
Sensitivity #4 - Summary of the ISO analysis of the Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)	148	108	$3.3	$2.4

Q. How can LEAPS help to avoid transmission expansion costs?

A. As mentioned before, the reliability benefits and avoided cost category includes three benefit sub-categories. The second sub-category is the avoided large transmission investments related to the reduction of RPS costs associated with the 323 MW solar and 188 MW wind. It was not clear from CAISO's analysis whether any transmission will be needed to achieve this 50% RPS goal, so I have only included the avoided transmission cost of RPS due to LEAPS which is (323 MW + 188 MW) * solar capacity factor * CAISO TAC (15 $/MWH) = $35 million.

Q. Did you calculate the LEAPS reliability service benefits?

A. Reliability services, such as frequency control, black start, and the avoidance of Reliability Must Run contract was not included in the CAISO study, however I have calculated the benefits of this sub-category for this testimony. LEAPS provide much needed grid resiliency and its electric reliability service benefit is estimated to be $50/kW-year[69] and so the annual benefit for this category due to LEAPS is $30 million/year based on a capacity of 600 MW.

Q. What other avoided cost did you consider?

A. Reduced costs for RMR contracts is a likely benefit. There are, however, several things that point to the kinds of savings consumers could see.

[69] http://www.energy.ca.gov/2013publications/CEC-500-2013-044/CEC-500-2013-044.pdf. Prepared by CED, SCE and Quanta Technology, March 2012, Table 12, page 66. .

For example, the CAISO estimated that the annualized fixed costs for a hypothetical combined cycle unit are $166/kW-year.[70] Their analysis showed that net revenues for the same combined cycle unit in the CAISO may have ranged between $11/kW-year in northern California and $22/kW-year in southern California given day-ahead and real-time market conditions that existed in the ISO in 2016.[71] Similarly, the California Energy Commission estimated that the annualized fixed costs for a combustion turbine is $177/kW-year.[72] Their analysis showed that net revenues for a similar combustion turbine in the CAISO may have ranged between $5/kW-year and $17/kW-year for real-time market conditions that existed in the CAISO in 2016.[73] In both cases net revenues earned through the market fell significantly below expected fixed costs. This underscores the need for new reliability resources to recover additional costs from longterm bilateral contracts.[74]

More recently, on October 30, 2017, the CAISO Board granted Calpine's Metcalf Energy Center Power Plant an RMR contract following Calpine's request to remove and declare the plant unavailable citing concern that CAISO's capacity procurement mechanismprovided insufficient return on their capital investment.[75] The plant is a 564 MW combined cycle commisioned in 2005

---

[70] Annual fixed costs are derived from California Energy Commission's Estimated Cost of New Renewable and Fossil Generation in California report which is published once every couple year. The annual fixed costs in this report are the average between IOU, POU and Merchant fixed costs reported in the March 2015 final staff report, Appendix E: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf.

[71] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf, page 52

[72] Annual fixed costs are derived from California Energy Commission's Estimated Cost of New Renewable and Fossil Generation in California report which is published once every couple year. The annual fixed costs in this report are the average between IOU, POU and Merchant fixed costs reported in the March 2015 final staff report, Appendix E: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf.

[73] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf, Page 52

[74] *Id*.

[75] http://www.ISO.com/Documents/Decision_ReliabilityMust-RunDesignation_MetcalfEnergyCenter-UpdatedMemo-Nov2017.pdf.

and is considered one of the most efficient units in California. FERC recenty accepted this contract for filing, but set it for hearing to decide whether the amount of the payment is just and reasonable.[76]

It is likely that gas fired resources in the San Diego area will require RMR contracts to provide local reliability services given the low expected energy prices. Since some of the local reliability services include local capacity as I have discussed, I elected to ignore the avoided cost of RMR contracts because LEAPS could provide both local capacity and similar reliability services required under an RMR contract.

Q. Can you summarize the TEAM Category #5 benefits – Reliability and avoided cost of other projects?

A. For the high solar penetration case, I calculated an avoided interconnection cost benefits of $7.1 million per year. The avoided transmission expansion cost is $28.2 million per year. The avoided reliability service cost is $30 million per year. Adding the three sub-categories results in a total reliability benefits and avoided cost benefit of $65 million per year for the high solar penetration case which I kept constant over the life of the project.

For the high wind penetration case, I calculated an avoided interconnection cost benefits of $3.1 million per year. The avoided transmission expansion cost is $18.8 million per year. The avoided reliability service cost is $30 million per year. Adding the three sub-categories results in a total reliability benefits and avoided cost benefit of $52 million per year for the high wind penetration case, which I kept constant over the life of the project.

[76] *Metcalf Energy Center, LLC*, 161 FERC ¶ 61,310 (2017)

VIII. SUMMARY OF THE LIFE CYCLE BENEFITS OF LEAPS

Q. Can you summarize your analysis of the total life cycle benefits realized from all five TEAM benefits categories?

A. The total life cycle benefits realized from the five TEAM categories are shown below for the solar and wind cases respectively.

Figure 20. LEAPS' Life Cycle TEAM Benefits – Solar Case

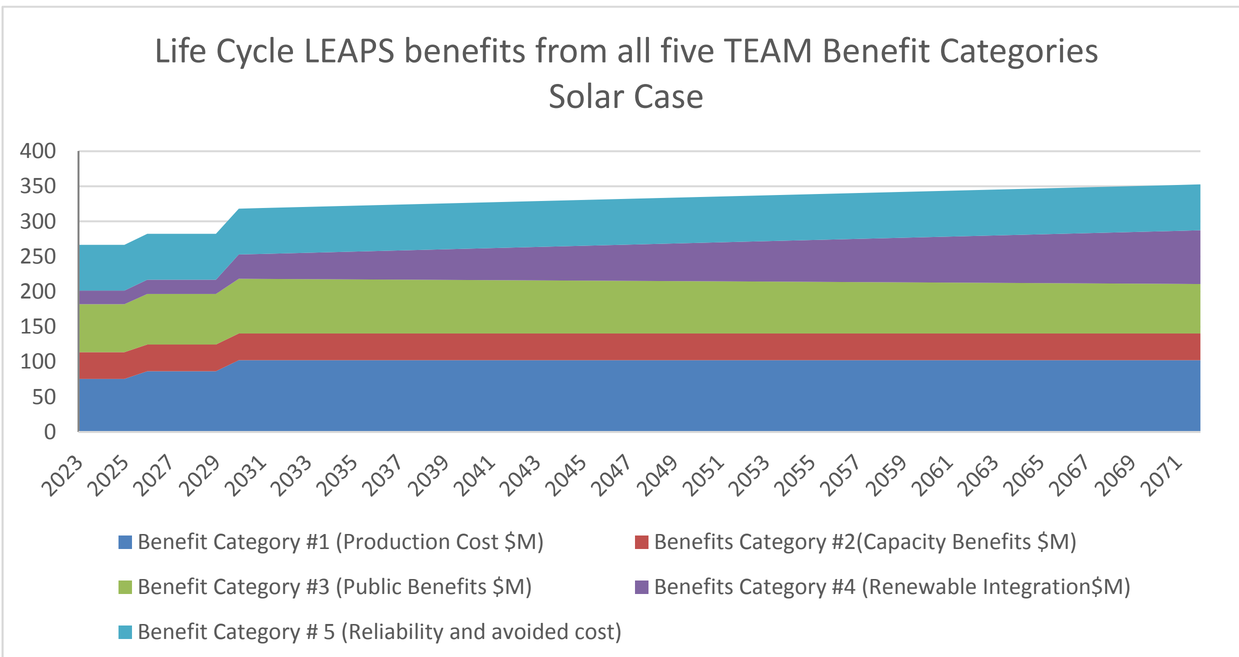
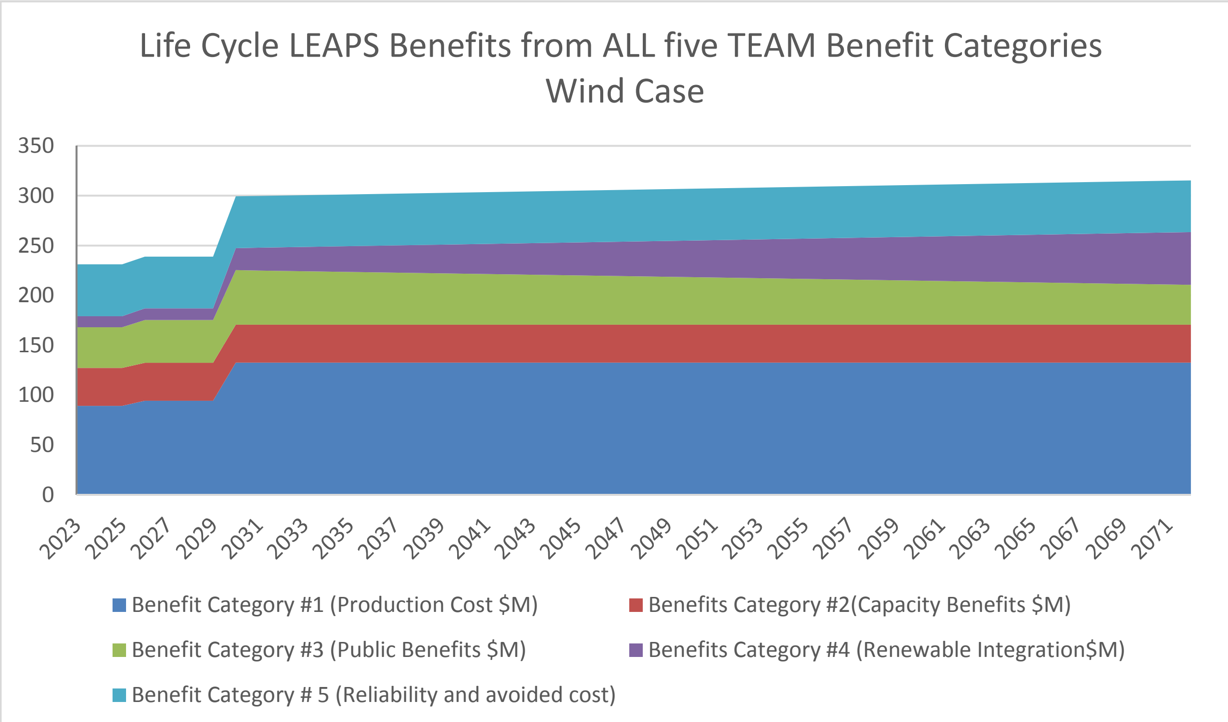


Figure 21. LEAPS' Life Cycle TEAM Benefits – Wind Case



Q. What is the total net present value benefits and cost of LEAPS?

A. The net present value benefit of LEAPS for the high penetration solar case is $5.424 billion. The LEAPS net present value cost is $3.083 billion. The BPV_BCR is 1.76:1.

Table 14. LEAPS Present Value Benefit to Cost Ratio – Solar Case

Benefits	NPV ($M)
Benefit Category #1 (Production Cost $M)	$1,663.20
Benefits Category #2 (Capacity Benefits $M)	$661.73
Benefit Category #3 (Public Benefits $M)	$1,284.85
Benefits Category #4 (Renewable Integration $M)	$676.97
Benefit Category # 5 (Reliability and avoided cost)	$1,137.15
Total Present Value Benefits	$5,423.89
Present Value Cost ($M)	$3,083.40
Total BPV_BCR	1.76

The net present value benefit of LEAPS for the high wind penetration case is $4.906 billion. The LEAPS net present value cost is $3.083 billion. The BPV_BCR is 1.59:1.

Table 15. LEAPS Present Value Benefit to Cost Ratio – Wind Case

Benefits	NPV ($M)
Benefit Category #1 (Production Cost $M)	$2,076.98
Benefits Category #2(Capacity Benefits $M)	$661.73
Benefit Category #3 (Public Benefits $M)	$823.88
Benefits Category #4 (Renewable Integration $M)	$439.82
Benefit Category # 5 (Reliability and avoided cost)	$903.79
Total Present Value Benefits	$4,906.20
Present Value Cost ($M)	$3,083.40
Total BPV_BCR	1.59

IX. LEAPS "UNCERTAINTY ANALYSIS

Q. Can you elaborate on the value of incorporating "Uncertainty Analysis"?

A. Decisions on whether to build new infrastructure tend to be challenging since decisions that are made today will be dealt with for 50 years. When in fact, there are risks and uncertainties about the future that could alter the projected value of a project. Future load growth, fuel costs, State energy policies, additions and retirements of generation capacities and the location of those generators, and availability of hydro resources are among some of the many factors impacting decision making. Some of these risks and uncertainties can be easily measured and quantified, and some cannot. There are two fundamental reasons why the TEAM considers risk and uncertainty in transmission evaluation.

First, changes in future system conditions can affect benefits from transmission expansion significantly. Historically the relationship between transmission benefits and underlying system conditions was found many times to be nonlinear. Thus, evaluating a transmission project based only on assumptions of average future system conditions might greatly underestimate or overestimate the true benefit of the project and may lead to less than optimal decision making. To make sure we fully capture all impacts the project may have, we must examine a wide range of possible system conditions.

Second, historical evidence suggests that transmission upgrades have been particularly valuable during extreme conditions.[77]

Q. Did you apply all TEAM principles?

A. Yes, this section addresses the last TEAM principle called "Uncertainty Analysis" which completes the application of all TEAM principles in my analysis.

Q. Please explain how you applied uncertainty analysis to the benefit to cost results.

A. I utilized the CAISO's results for the 2026 year and supplemented with my own production cost modelling for the 2030 year using on CAISO's data and model, and applied the TEAM methodology to calculate the benefits for each category. The benefits derived from the two study years, "2026 Base" and "2030 Base" form the deterministic values of total benefits for LEAPS. I then used linear interpolation to calculate LEAPS' life cycle benefits and the present value benefits at the WACC rate. These two deterministic values are based on specific set on input assumptions. However, it does not measure the impact of risk and uncertainty. To measure the impact of risk and uncertainty, I used stochastic analysis to model the uncertainty associated with different input parameters that drive the magnitudes of the benefits for the LEAPS project. Stochastic analysis uses probabilistic representations of the future loads, natural gas prices, RPS targets, hydro and other generation availability. The combination of the deterministic and stochastic analysis results

[77] Professor Frank Wolak, chair of the CAISO's Market Surveillance Committee, estimated that a large inter-connection between WSCC and the eastern United States during the period June 2000 to June 2001 would have been worth on the order of $30 billion. http://www.caiso.com/Documents/MSCOpiniononTransmissionExpansionAssessmentMethodology.pdf at page 10.9

in calculating a range of benefit outcomes given the uncertainties in the input parameters so that I can then calculate the Present Value Expected Benefits (PVEB) for the project.

Q. Can you elaborate on the input variables used to perform the Uncertainty Analysis for LEAPS?

A. Yes, Table 5.1 from the CAISO TEAM methodology[78] provide guidance on the types of input variables that are typically used to evaluate uncertainty:

Table 5-1: Typical sensitivity analyses

Sensitivity analyses	Note and typical variation
Load - High	+6% above forecast
Load - Low	-6% below forecast
Hydro - High	if applicable and data available
Hydro - Low	if applicable and data available
Natural gas prices - High	+50%
Natural gas prices - Low	-25%
CO2 price	If data available
CA RPS portfolios	If data available
Other sensitivities per requested	

I selected to perform sensitivity analysis for the load, hydro, natural gas, Mid-level Energy Efficiency and CA RPS consistent with the table above.

Q. How is the sensitivity analysis performed?

A. To assess the sensitivity of these input variables to the resulting benefits, I first calculated the probabilities of occurrences for 20 combinations (cases) of the five input variables. In other

[78] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf, Table 5-1, page 26

words, the probability of occurrence is a factor that represents the variation from the deterministic base case (CAISO Sensitivity #2) assumptions as follows:

- High Load (HL) = +6% above base case load
- Low Load (LL) = -6% below base case load
- High Hydro (HH) = wet hydro year
- Low Hydro (LH) = dry hydro year
- High Natural Gas Prices (HG) = +50% of base case natural gas assumption
- Low Natural Gas Prices (LG) = -25% of base case natural gas assumption
- High RPS (HRPS) = Increasing RPS capacity to achieve GHG emission target of 30 MMT, and
- High Energy Efficiency (HEE) = 2015 IEPR High-AAEE instead of the Mid-AAEE in the base case

Next and consistent with the fourth TEAM principle ("explicit uncertainty analysis"), the benefits of LEAPS are considered in the context of uncertainties that will unfold over the life of the project. I quantified the impact of this uncertainty by developing cases with different levels of input assumptions for load, hydro conditions, gas prices, RPS capacity and energy efficiency. I believe that these cases cover a reasonable range of possibilities. I then calculated expected benefits across these cases considering their probabilities. In addition, we consider LEAPS' "insurance benefit" by calculating benefits under various possible contingencies. In the expected benefit calculation, I focused on the five key variables just mentioned, defining 20 combinations in each year. For the cases where I varied load and gas prices, I examined three levels: high (H), base (B), and low (L). For the hydro generation, I also examined three levels: wet (W), base (B), or dry (D) year. I determined the values of the demand and gas price cases by analyzing the historical accuracy of predictions of those variables, comparing CEC forecasts of loads and prices over the past 20 years and historical hydro production to their realized levels. Load distributions are characterized using normal distributions fitted to the historical forecast errors, while gas prices follow a log-normal distribution. The "L" and "H" levels used in the load, hydro and gas sensitivity cases are based on 90% confidence intervals from their distributions. For loads, those levels vary only slightly from the base case, while for natural gas and hydro the differences are large. I also examined the impact of two more variables, RPS capacity and energy efficiency. I included high RPS sensitivity since most likely the State will continue to move toward higher RPS to meet lower emission standards. Likewise, I included a sensitivity for higher energy efficiency standards.

There are 3x3x3x3x3 =243 possible combinations or cases that could be assessed for the five uncertain variables. This is too many to simulate. Therefore, I considered a smaller but representative subset of 20 cases in the expected benefits calculations for the high solar penetration case as follows:

1. Base values for all five variables (1 case),
2. Base values for four of the five variables, and the low value for the fifth variable (3 cases, case 2, 3 and 4). I did not consider the "low RPS" and "low EE" as a valid scenario.
3. Base values for three of the five variables, and the high value for the remaining variables (4 cases, case 5,6,7, and 8), and
4. Additional cases representing plausible combinations of extreme scenarios such as a high stress condition (high load, high gas price, dry hydro, high RPS), economic boom (high load and gas prices), or recession induced by high fuel prices (low load, high gas price).

5. Another consideration in selecting these cases was to make it possible for probabilities to be chosen so that the means and standard deviations of each of the individual variables matched the assumptions, and for correlations to be reasonable (for instance, I expect a positive correlation between dry conditions and high demand due to warm temperatures) (12 cases).

Table 16 shows the selected 20 cases for 2026 and 2030 cases.

Table 16. Sensitivity Cases for the Uncertainty Analysis

Cases	Loads	Hydro	Gas	RPS	EE
1	B	B	B	B	B
2	B	B	L	B	B
3	B	L	B	B	B
4	L	B	B	B	B
5	B	B	B	H	H
6	B	B	H	H	B
7	B	H	H	B	B
8	H	B	B	B	H
9	H	L	H	H	B
10	H	H	L	B	B
11	H	H	H	B	H
12	H	B	B	H	H
13	H	H	L	H	H
14	L	L	L	B	B
15	L	B	L	H	H
16	L	L	L	B	H
17	L	B	L	B	B
18	L	L	B	H	H
19	L	L	H	H	B
20	L	L	H	B	B

I calculated the Expected LEAPS Benefits following the methodology outlined by CAISO TEAM.[79] Next, after selecting representative cases, it is necessary to determine the probability that each of the selected case could occur in the future. Each case is a realization of the various dimensions of uncertainty in future system conditions. However, the input data described above only provides an estimate of the marginal distribution of each of these dimensions. For example, I used information on the marginal distributions of future hydro conditions and gas prices, but not their joint density. Consequently, I pick values for the joint probability of each set of future system conditions. I calculated these probabilities using a non-linear program that maximizes the logarithm of likelihood (the sum of the logarithm of the joint probabilities) of observing the 20 cases subject to the constraint that the joint probabilities replicate the first two moments of the marginal distribution of each variable. Mathematically, I chose the Pi for cases i = 1, 2,..,20 to maximize the sum of Ln (Pi) subject to the constraints: Σ Pi = 1, and the mean and standard deviation for each variable implied by these joint probabilities match the assumed values for the marginal distribution of each variable. The Pi for each case is added in **Table 17**.

Table 17. Probability (Pi) for Sensitivity Cases

Cases	Loads	Hydro	Gas	RPS	EE	Pi
1	B	B	B	B	B	13.50%
2	B	B	L	B	B	3.00%
3	B	L	B	B	B	6.60%
4	L	B	B	B	B	7.50%
5	B	B	B	H	H	11.00%
6	B	B	H	H	B	7.70%
7	B	H	H	B	B	3.50%
8	H	B	B	B	H	2.90%
9	H	L	H	H	B	1.60%

[79] https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Using%20Market%20Simulations%20for%20Economic%20Assessment%20of%20Transmission%20Upgrades_Applications%20of%20the%20California%20ISO%20Approach.pdf.

Cases	Loads	Hydro	Gas	RPS	EE	Pi
10	H	H	L	B	B	4.40%
11	H	H	H	B	H	1.20%
12	H	B	B	H	H	2.70%
13	H	H	L	H	H	5.50%
14	L	L	L	B	B	3.80%
15	L	B	L	H	H	10.50%
16	L	L	L	B	H	2.00%
17	L	B	L	B	B	3.10%
18	L	L	B	H	H	3.55%
19	L	L	H	H	B	1.54%
20	L	L	H	B	B	4.50%

Q. How did you calculate the Benefit Categories for these 20 cases?

A. I calculated each of the five benefit categories under each case by multiplying the results of the two base cases by its correspondent probability of occurrence to get the total annual benefits. The results are then expanded over the life cycle of the project.

Q. How did you arrive to the Expected Benefits of LEAPS?

A. Using this uncertainty analysis, I was able to calculate the expected benefits of the LEAPS under each TEAM benefit category. I then calculated the Present Value Expected Benefits for each category at the Real WACC. I calculated the Expected PV BCR by dividing the Present Value Expected benefits by the Present Value project cost. The Expected PV BCR was calculated to equal to 1.72:1 for the high solar penetration case and 1.54:1 for the high wind penetration case.

The Expected PV BCR of 1.72:1 is slightly lower than the Base PV BCR of 1.76:1. The base case PV BCR of 1.76:1 has a present value life cycle total benefits of $5.42 billion while the Expected PV BCR has a present value life cycle benefits of $5.3 billion. The Expected Benefits calculation revealed that LEAPS has a net $120 million loss to the ratepayers when considering the uncertainty of the input variables that drive the project benefits. **Table 18** provides a summary of how the EPV_BCR varies with the uncertainty of input variables where the range is from 1.15:1 to 2.12:1.

Table 18. EPV_BCR for the Sensitivity Cases

Cases	Loads	Hydro	Gas	RPS	EE	Pi	EPV_BCR
1	B	B	B	B	B	13.50%	1.76
2	B	B	L	B	B	3.00%	1.32
3	B	L	B	B	B	6.60%	1.79
4	L	B	B	B	B	7.50%	1.5
5	B	B	B	H	H	11.00%	1.81
6	B	B	H	H	B	7.70%	1.98
7	B	H	H	B	B	3.50%	2.12
8	H	B	B	B	H	2.90%	1.65
9	H	L	H	H	B	1.60%	2.1
10	H	H	L	B	B	4.40%	1.76
11	H	H	H	B	H	1.20%	1.88
12	H	B	B	H	H	2.70%	1.76
13	H	H	L	H	H	5.50%	1.84
14	L	L	L	B	B	3.80%	1.32
15	L	B	L	H	H	10.50%	1.93
16	L	L	L	B	H	2.00%	1.15
17	L	B	L	B	B	3.10%	1.33
18	L	L	B	H	H	3.55%	1.28
19	L	L	H	H	B	1.54%	1.8
20	L	L	H	B	B	4.50%	1.45

Q. What other observations do you have?

A. I note that 8 out of 20 sensitivity cases resulted in equal or lower Expected PV BCR compared to the Base Expected PV BCR and 11 out of 20 cases resulted in higher or equivalent Expected PV BCR compared to the Base Expected PV BCR. In my opinion, this shows a robustness in the project's Expected benefit. Also, all cases show an Expected PV BCR greater than 1.15:1.

X. OTHER BENEFITS THAT ARE NOT QUANTIFIED

Q. Will LEAPS provide other benefits in addition to the ones that you have already discussed?

A. Yes. LEAPS will provide additional operational benefits that I identify in ***Table 19***. Although these eight operational uses are not quantified in this testimony, it is my experience that LEAPS can provide these benefits to consumers which from a total benefits-to-cost perspective, will provide an upside to ratepayers.

Table 19. LEAPS' Operational Uses without Quantifiable Benefits

Operational Use	Value Metrics	Methodology used to Calculate Benefits
Power Quality	LEAPS can protect the loads downstream against short-duration Event that Affect the Quality of power Delivered to loads. These short duration events include low power factor, harmonics and interruptions of services.	the Power Quality benefits are not included in this analysis since LEAPS is HV transmission and not directly connected to distribution. Value of 50 $/KW-YR. Table 11, page 64
Intermittency Capacity Firming	The benefit for firming output from renewable energy generation is related to the cost that can be avoided for other electric supply capacity. If renewable energy generation output is constant during times when demand is high, then less conventional generation capacity is needed, otherwise, additional capacity is needed on standby	the Intermittency capacity Firming Benefits that LEAPS can provide are not included in this analysis. Its estimated to be 12 $/KW-YR. Table 11, page 64
Intermittent Grid Integration	When wind and solar experience sudden reduction in output, the grid need energy on standby to response to the volatility and variability of these intermittent resource.	the Intermittency Grid Integration or energy firming benefits that LEAPS can provide are not included in this analysis. the benefits are estimated to be 50 $/KW-YR. Table 11, page 64. Its extremely difficult to separate load followings from grid integration and as a conservative measure, we did not include these benefits
Demand response	LEAPS variable pump technology and the ability to ramp up and own very quickly without restriction on the number on stops and starts and without any minimum start time and minimum down time qualify for demand response services	leaps can provide an instand demand response by creating a 600 MW load or shave off 600 MW of load

Q. What other method did you use to quantify the LEAPS benefits?

A. I have supplemented the TEAM based method with the CPUC's Integrated Resource Planning assumptions and RESOLVE software. The range of benefit-to-costs for LEAPS is from 1.53 to 3.8.

Exhibit NHC-D shows the analysis and calculation of the project benefits using the CPUC's method and software.

Q. Does this conclude your testimony?

A. Yes.

Q. Thank you.

STATE OF CALIFORNIA)
) ss
COUNTY OF Sacramento)

I, Ziad Alaywan, being duly sworn, depose and say as follows:

The foregoing "Affidavit of Ziad Alaywan P.E. in Support of Nevada Hydro Company, LLC Petition for Declaratory Order" was prepared by me, or under my direction and supervision, and the factual statements contained in such Affidavit are true and correct to the best of my knowledge, information and belief.

Further affiant saith not.

Ziad Alaywan P.E.

REGISTERED PROFESSIONAL ENGINEER
ZIAD ALAYWAN
13880
ELECTRICAL
STATE OF CALIFORNIA

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

On this 8 day of March, 2018, before me, the undersigned notary public, personally appeared Ziad Alaywan and acknowledged to me that he signed the foregoing document voluntarily for the purposes stated therein. I identified Ziad Alaywan to be the person whose name is signed on the foregoing document by the following satisfactory evidence of identity (check one):

___ Identification based on my personal knowledge of his identity, or

✓ Current government-issued identification bearing his photographic image and signature.

See Attached Notary Acknowledgment Certificate

Notary Public

My commission expires: Dec 30, 2020
(SEAL)

J. NAGEL
Notary Public - California
Sacramento County
Commission # 2177570
My Comm. Expires Dec 30, 2020

CALIFORNIA ALL-PURPOSE ACKNOWLEDGEMENT **CIVIL CODE § 1189**

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

STATE OF CALIFORNIA }
} ss.
COUNTY OF SACRAMENTO }

On March 8, 2018, before me, J. Nagel, a notary public in and for the State of California, personally appeared Ziad Alaywan, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

J. NAGEL
Notary Public - California
Sacramento County
Commission # 2177570
My Comm. Expires Dec 30, 2020

NOTARY SIGNATURE

NOTARY SEAL

OPTIONAL

Though the information below is not required by law, it may prove valuable to persons relying on the document and could prevent fraudulent removal and reattachment of this form to another document.

Description of attached document

Title or Type of Document: Affidavit of Ziad Alaywan P.E. in Support of Nevada Hydro Company, LLC Petition for Declaratory Order
Document Date: March 8, 2018 Number of Pages: 1
Signer(s) Other Than Named Above: Not Applicable

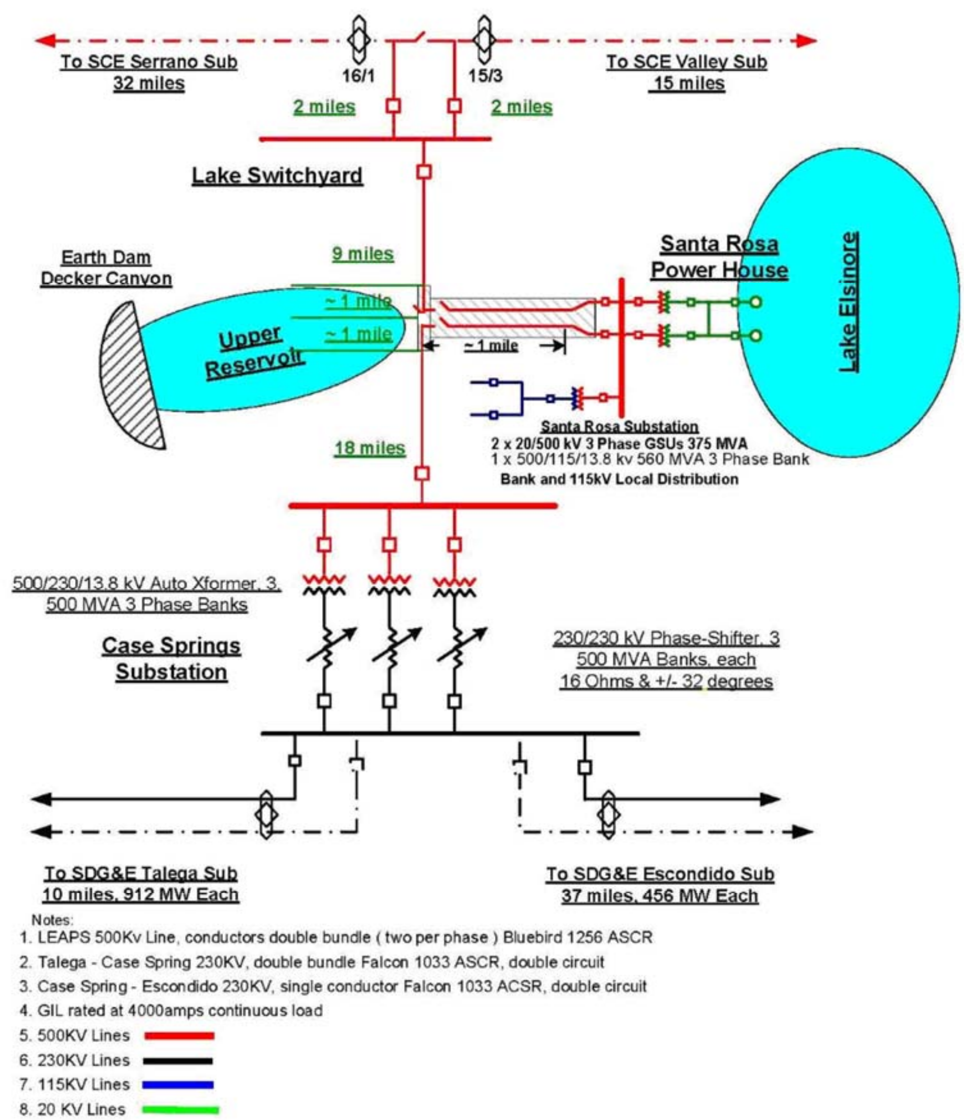
Capacity(ies) Claimed by Signer(s)

Signer's Name: Ziad Alaywan
☐ Corporate Officer – Title(s) ____
☐ Partner - ☐ Limited ☐ General
☒ Individual ☐ Attorney in Fact
☐ Trustee ☐ Guardian or Conservator
☐ Other: ____
Signer Is Representing: Ziad Alaywan, P.E.

Signer's Name: ____
☐ Corporate Officer – Title(s) ____
☐ Partner - ☐ Limited ☐ General
☐ Individual ☐ Attorney in Fact
☐ Trustee ☐ Guardian or Conservator
☐ Other: ____
Signer Is Representing: ____

EXHIBIT NHC - A

LEAPS PROJECT CONCEPTUAL SINGLE LINE DIAGRAM



4.

EXHIBIT NHC – B

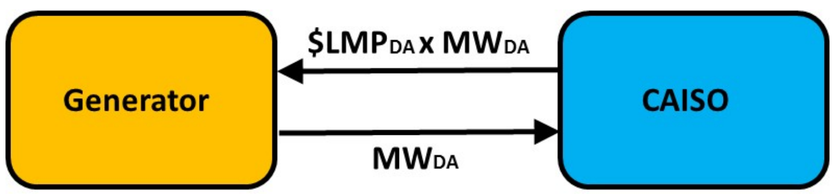
OVER-GENERATION EXAMPLES

The examples below describe how generators can be compensated when over-generation conditions occur.

<u>Example 1 – Economic Curtailment (Real-Time Schedule Reduction from Day-Ahead Market Awards)</u>

When a generator is awarded an hourly MW schedule in the California Independent System Operator's (ISO) Day-Ahead market, the generator is then paid for energy that the ISO expects it to produce at the Day-Ahead Locational Marginal Price (LMP) node where the generator interconnects to the ISO grid.

Figure 22. Generation Schedule and Payment because of Day-Ahead Market Awards

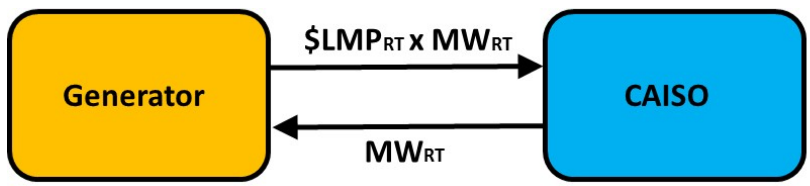


If the generator's schedule in an hour is 10 MW, and the ISO's Day-Ahead market clearing price as represented by the LMP is $25/MWh, then the payment by the ISO to the generator is $250 (10 MW x $25/MWh). This payment by the ISO to the generator is independent of how much energy the generator produces.

On the flow day, the ISO operates its ISO Real-Time market. The ISO runs its Real-Time market intra-hour, but for simplicity, assume that the intra-hour Real-Time market results average to a single hourly price that can be compared to the ISO's Day-Ahead hourly price.

Over-generation (a condition when supply exceeds demand within the ISO's balancing area) occurs when ISO Day-Ahead market supply and demand MW awards from the Day Ahead market run differ from the supply or demand produced in real-time resulting in additional energy supply that outstrips demand. When over-generation occurs, market prices fall, even to a negative value. When Real-Time prices fall far enough, generators are incented to not produce energy thereby reducing the over generation. The generator buys back the energy it scheduled to the ISO in the Day-Ahead market at Real-Time prices.

Figure 23. Generation Schedule Reduction and Payment because of Real-Time Market Awards

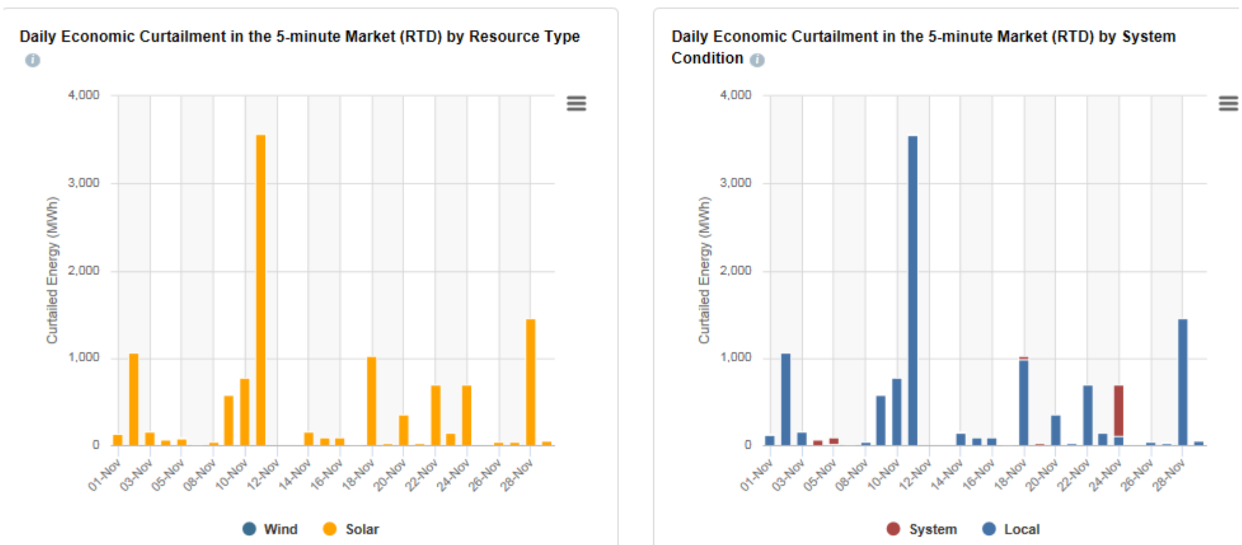


If the ISO Real-Time LMP clears at negative $30/MWh, and the generator has a bid in the ISO's Real-Time market to reduce its schedule if the LMP clears below a bid price of negative $10/MWh, then the generator's bid to buy energy from the ISO's Real-Time market will be accepted. The generator's schedule is 10 MW purchase at the LMP clearing price of negative $30/MWh. The payment from the generator to the ISO is negative $300. Because the payment amount from the ISO to the generator is negative, it is $300 received by the generator.

The total proceeds to the generator from the Day-Ahead and Real-Time markets is $550 ($250 from the ISO Day-Ahead market, and $300 from the ISO Real-Time market). Note that the generator produced no energy but was paid $550.

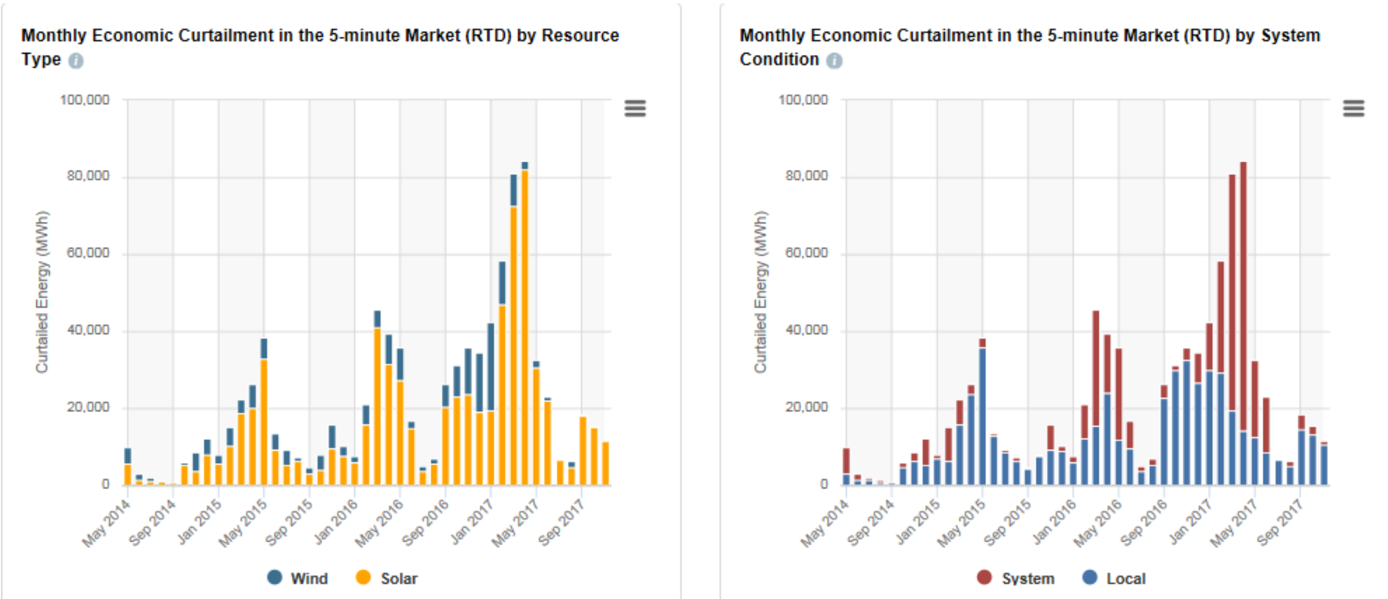
The reduction in output compared to schedule is called "Economic Curtailment" because the generator was curtailed based on economics (its bid into the ISO's markets) and resultant schedule based on ISO LMP market clearing prices. The ISO has produced a renewable energy report that tracks Economic Curtailment shown in the graphs below[80]. In November 2017, the ISO Economically Curtailed nearly 11,000 MWh of renewable resources, primarily solar. From May 2014 through November 2017, over 900,000 MWh of renewable energy has been Economically Curtailed.

Figure 24. Economic Curtailment MWh by Day for November 2017



[80] California ISO Monthly Renewables Performance Report, VER Curtailment tab, Economic Curtailment Dropdown at: [http://www.ISO.com/Documents/MonthlyRenewablesPerformanceReport-Nov2017.html.](http://www.ISO.com/Documents/MonthlyRenewablesPerformanceReport-Nov2017.html)

Figure 25. Economic Curtailment MWh by Month for 2017



<u>Example 2 – Economic Curtailment (Real-Time Schedule Reduction from Fifteen-Minute Market Awards)</u>

A generator can also receive benefits when reducing output with only a Real-Time energy bid. It works the same way as described in Example 1, but there is no Day-Ahead schedule for the generator. Rather the generator is awarded a MW schedule in the 15-minute market, and offers a bid in the ISO's Real-Time market to reduce its output for a price.

Similar to the ISO Day-Ahead market, when a generator is awarded an hourly MW schedule in the ISO's Fifteen-Minute market, the generator is paid for energy that the ISO expects it to produce at the Fifteen-Minute LMP node where the generator interconnects to the ISO grid.

If the generator's schedule in an hour is 10 MW, and the ISO's Fifteen-Minute market clearing price as represented by the LMP is $25/MWh, then the payment by the ISO to the generator is

$250 (10 MW x $25/MWh). Similar to the Day-Ahead market, this payment by the ISO to the generator is independent of how much energy the generator produces.

Again, if the ISO Real-Time LMP clears at negative $30/MWh, and the generator has a bid in the ISO's Real-Time market to reduce its schedule if the LMP clears below a bid price of negative $10/MWh, then the generator's bid to buy energy from the ISO's Real-Time market will be accepted. The generator's schedule is 10 MW purchase at the LMP clearing price of negative $30/MWh. The payment from the generator to the ISO is negative $300, and $300 received by the generator.

The total proceeds to the generator from the Fifteen-Minute and Real-Time markets is $550 ($250 from the ISO Fifteen-Minute market, and $300 from the ISO Real-Time market). Note that the generator produced no energy but was paid $550.

<u>Example 3 – Exceptional and Self-Schedule Curtailment</u>

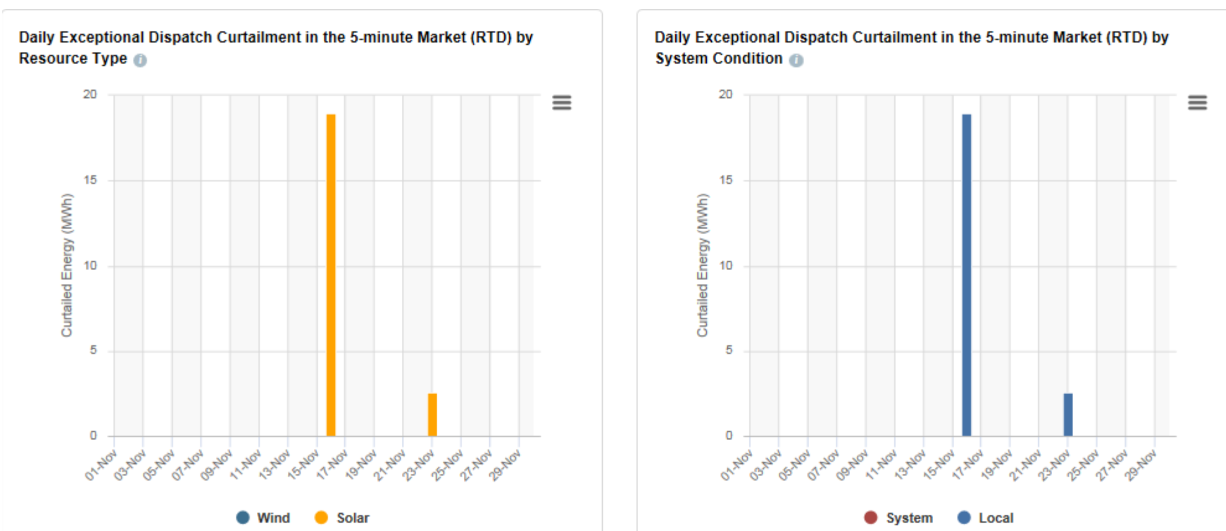
If the ISO's Real-Time market does not have enough decremental energy bids (generators' bids to buy back energy that they scheduled in the ISO market), the ISO may have to resort to ordering generators to reduce output. At that point, the ISO is ensuring reliability by acting outside the market. The LMP clearing price should reflect the over-generation condition and be negative.

If the ISO Real-Time LMP clears at negative $30/MWh, the generator has a schedule of 10 MW from the ISO's Fifteen-Minute market, with a Fifteen-Minute market LMP of $25/MWh, and the generator produces 0 MWh because of following the ISO's order to reduce output, then the generator would be paid $300 by the ISO (10 MW x negative $30/MWh). That amount is in addition to the $250 that it was paid in the Fifteen-Minute market for its 10 MW schedule at the

Fifteen-Minute market LMP of $25/MWh. Again, the generator is paid $550 total for not producing energy.

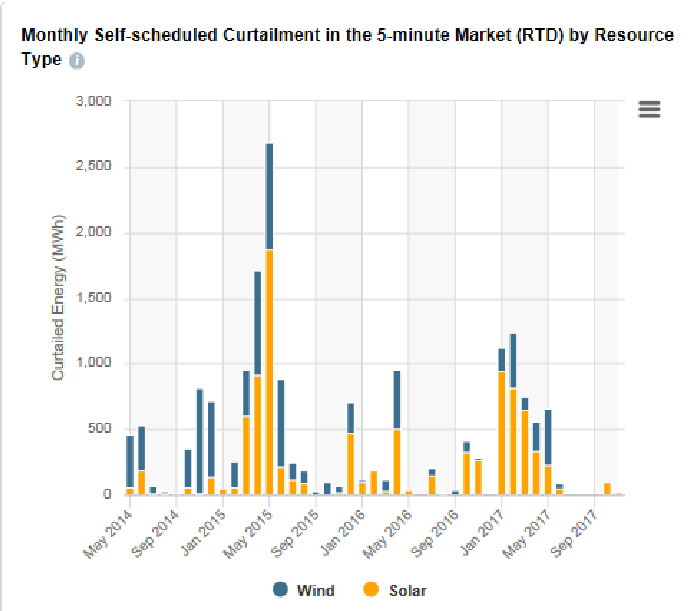
The reduction in output compared to schedule is called "Exceptional Dispatch", or "Self-Schedule Curtailment" because the generator was curtailed based on direction from the ISO outside the market. The ISO has produced a renewable energy report that tracks Exceptional and Self-Schedule Curtailment shown in the graphs below[81]. In November 2017, the ISO's Exceptional and Self-Schedule Curtailment was only 20 MWh. From May 2014 through November 2017, approximately 15,500 MWh of renewable energy has been reduced through Exceptional and Self-Schedule Curtailment.

Figure 26. Exceptional and Self-Schedule Curtailment MWh by Day for November 2017



[81] California ISO Monthly Renewables Performance Report, VER Curtailment tab, Exceptional and Self Schedule Curtailment Dropdown at: http://www.ISO.com/Documents/MonthlyRenewablesPerformanceReport-Nov2017.html.

Figure 27. Exceptional and Self-Schedule Curtailment MWh by Month for 2017



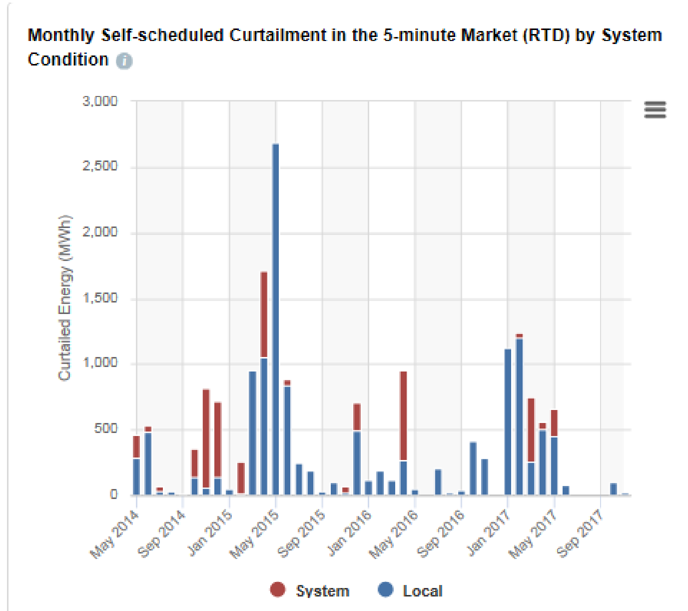


EXHIBIT NHC – C

POWER FLOW ANALYSIS DEMONSTRATING LCR, TRANSMISSION UTILIZATION AND RELIABILITY BENEFITS FOR THE SCE/SDGE AREAS

LEAPS is expected to be in service in 2022 timeframe. The base case that was picked for the analysis is ISO board approved 2017/2018 transmission planning case for the year of 2022 focused on San Diego area (case name B2_22P_SDGE_V1.sav). The projected load extracted from the base case for the year of 2022 in SDGE is 4,551 MW.

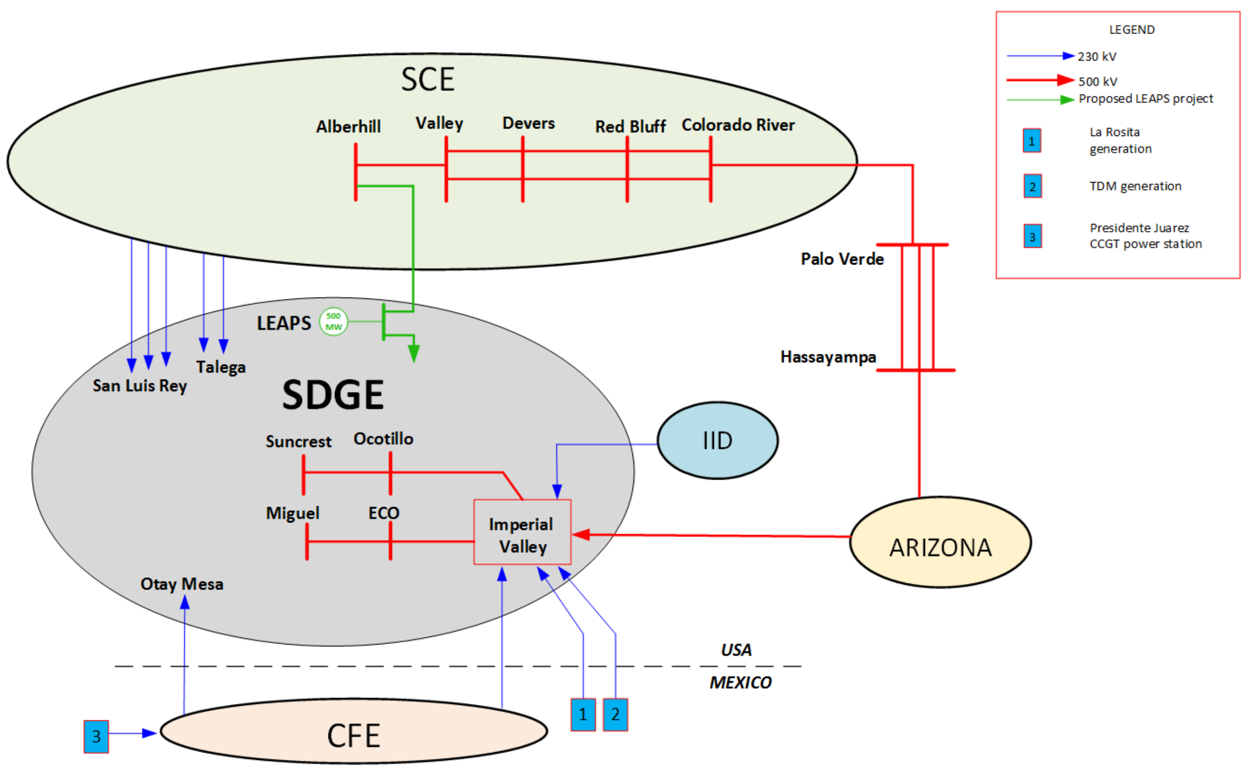
San Diego Gas and Electric (SDGE) is an investor owned utility that provides energy and gas to San Diego and southern Orange Counties, located in Southern California. The SDGE system depends on imports and internal generation to serve its area load. The energy imports are transmitted over 230 kV and 500 kV lines through the following ties:

1. SCE's San Onofre (SONGS) substation:
   - A. SONGS-San Luis Rey #1 230 kV line.
   - B. SONGS-San Luis Rey #2 230 kV line.
   - C. SONGS-San Luis Rey #3 230 kV line.
   - D. SONGS-Talega #1 230 kV line.
   - E. SONGS-Talega #2 230 kV line.
2. The Southwest Powerlink (SWPL) and Sunrise Powerlink via Imperial Valley substation:
   - A. SWPL: North Gila-Imperial Valley-Miguel 500 kV line.
   - B. Sunrise Power link: Imperial Valley-Ocotillo-Suncrest 500 kV line.
3. Otay Mesa-Tijuana 230 kV line (from CFE)

Transmission Line Utilization Study

The focus of this power flow analysis is to assess SDGE's major tie-line utilization and to determine how the LEAPS project affects its usage. As shown in the simplified diagram in , SDGE peak load of 4,548 MW is served primarily from a single substation located east of San Diego County at Imperial Valley Substation. The remaining supply is within SDGE loads from gas-fired resources. Since the retirement of SONGS, SDGE imports from SCE has been less than 10%. LEAPS creates a strong (500 kV) connection between two of the three largest load centers in California.[82]

Figure 28. Simplified Diagram of LEAPS Connections to SCE and SDGE Transmission



[82] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf, page 29, LA Basin, Bay Area and San Diego represent 41%, 20% and 11% of ISO system peak, respectively.

Case 1- Pre-LEAPS: Prior to adding LEAPS project, the analysis shows that under normal operating conditions (No outages), SDGE is importing 2,911 MW (64% of total SDGE load) from Imperial Valley substation, 379 MW (8% of total load) from SCE, and the rest of the load (28%) is being served by internal SDGE gas fired generation. SDGE is depending on a single substation, Imperial Valley Substation, to serve 64% of its total load, which can cause major reliability issues under severe emergency conditions, like the September 8, 2011 blackout where one of the 500kv line tripped initiating major Blackout[83].

Case 2- LEAPS Transmission Only: After modeling LEAPS transmission project-without LEAPS generation (500 kV connection to SCE and 230 kV connection to SDGE), the topology of the system changed, and it created an additional low impedance path to serve SDGE load. It was shown under normal conditions, Imperial Valley Substation is now serving 60% of SDGE load, SCE is serving 12%, and the remaining 28% is being served by internal SDGE generation. The LEAPS transmission creates a new link between SCE and SDGE that increases the SCE imports by 4% and decreases imports from Imperial Valley Substation by 4%, or approximately 200 MW.

Under normal operating conditions, LEAPS transmission benefits SDGE system by:

- Adding an additional major 500KV tie- line with SCE, and

[83] The outage impacted approximately 2.7 million customers without power. The outages affected parts of Arizona, southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly 1.5 million customers losing power, some for up to 12 hours. The disturbance occurred near rush hour, on a business day, snarling traffic for hours. Schools and businesses closed, some flights and public transportation were disrupted, water and sewage pumping stations lost power, and beaches were closed due to sewage spills. Millions went without air conditioning on a hot day. *See*: http://www.nerc.com/pa/rrm/ea/Pages/September-2011-Southwest-Blackout-Event.aspx.

- Decreasing the percentage of load being served from a single source (Imperial Valley substation) by approximately 200 MW.

Also, under emergency conditions:

The loss of SDGE's ECO-Miguel 500 kV line with LEAPS transmission only (No generation):

- SDGE load served from Imperial Valley substation is 54% with no LEAPS, compared to 50% with LEAPS transmission.
- SDGE load served from SCE is 22% with no LEAPS, compared to 26% with LEAPS transmission.

The loss of SCE's Valley-Alberhill 500 kV line with LEAPS transmission only (No generation):

- SDGE load served from Imperial Valley substation is 67% with no LEAPS, compared to 64% with LEAPS transmission.
- SDGE load served from SCE is 6% with no LEAPS, compared to 8% with LEAPS transmission.

Case 3- LEAPS Transmission and Generation: The following case contains LEAPS transmission and generation project (500 MW of LEAPS hydro generation was modeled, and 500 MW of SDG&E Gas-fired generation was switched offline to maintain generation-load balance.) The results show that under normal operating conditions, Imperial Valley substation is now serving 56% of total SDGE load, SCE is serving 5% of total SDGE load, the remaining 39% is being served by internal SDGE generation including LEAPS generation.

LEAPS 500 MW generation is serving 11% of total SDGE load under normal operating conditions. In summary, LEAPS transmission and generation benefits:

a. SDGE decrease its imports from Imperial Valley substation by 377 MW compared to the no LEAPS case. This means that LEAPS reduce SDGE reliance on 377 MW of local gas fired resources and could import equal number of renewables using existing transmission capacity that was vacated by LEAPS.

b. SCE decreases exports to SDGE by approximately 134 MW compared to the no LEAPS case. This means that SCE can use the 134 MW to reduce their reliance on local gas-fired generation and import 234 MW of renewables using existing transmission system.

Also, under emergency conditions:

The loss of SDGE's ECO-Miguel 500 kV line with LEAPS transmission and generation:

- SDGE load served from Imperial Valley substation is 54% with no LEAPS, compared to 47% with LEAPS transmission and generation.
- SDGE load served from SCE is 22% with no LEAPS, compared to 18% with LEAPS transmission and generation.

The loss of SCE's Valley-Alberhill 500 kV line with LEAPS transmission and generation:

- SDGE load served from Imperial Valley substation is 67% with no LEAPS, compared to 59% with LEAPS transmission and generation.
- SDGE load served from SCE is 6% with no LEAPS, compared to 2% with LEAPS transmission and generation.

This demonstrates that even under emergency conditions, the LEAPS project benefits both SCE and SDGE systems.

Reliability Analysis

To assess the reliability benefits of LEAPS transmission and generation project, 700 system outages were evaluated to see how the system will react under emergency/severe conditions.

Several contingency files were used to assess the impacts of outages or contingencies associated with the selected base cases. The contingency files, listed below, were run for each of the 3 different case scenarios. The files were adjusted as necessary to accommodate the topology changes for each of the project scenarios (No Project, Proposed LEAPS transmission, Proposed LEAPS transmission and generation).

1. **SDGE-MAIN_P1~P7** (NERC TPL-001-4 based)

   Contains Category P1 (N-1) 500 kV and 230 kV line and transformer outages; adjacent system (SCE – IID) contingencies; selected generator outages; Category C (N-2) stuck breaker, bus, and common structure outages, Sub-System Multiple Terminal line, transformer and generator outages, Orange County outages, N-3 for 69 kV and 138 kV bus outages.

2. **SCE combined outage file (SCE Bulk, SCE East of Lugo, SCE Metro)**

   Contains single and multiple SCE outages for transmission and sub transmission systems. Contains outages for neighboring systems, also major 500/230 kV lines that feed LA Basin load.

3. **CFE and other significant 500 kV lines that connects California to neighboring states.**

The results of the contingency analysis shown below:

Figure 29. Comparison of Results for Single Contingency of Miguel 500/230 kV #1 Pre-LEAPS and Post-LEAPS

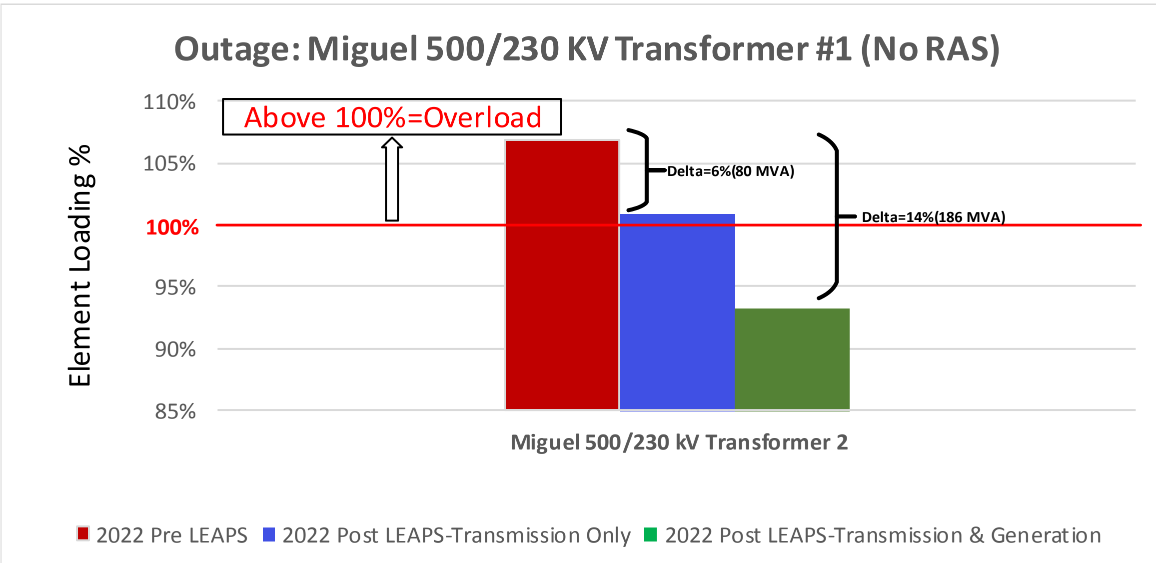


Table 20. Miguel 230/500 kV Transformer #2 Loading following Single Contingency

Transmission Element	Case A- Pre-LEAPS loading (%)	Case B- LEAPS transmission loading (%)	Case C- LEAPS transmission and generation loading (%)	Delta (Case C-A) % / MVA
Miguel 230/500 kV Transformer	107%	101%	93%	14% / 186 MVA

Figure 30. Comparison of Results for Single Contingency of ECO-Miguel 500 kV Line Pre-LEAPS and Post-LEAPS

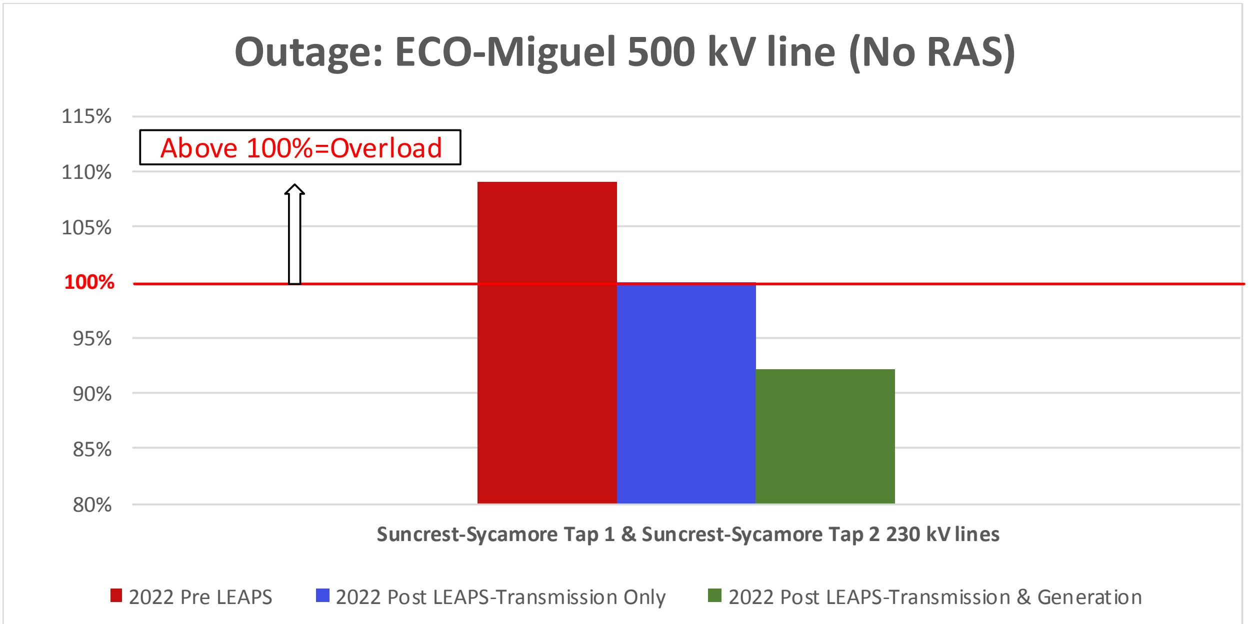


Table 21. Suncrest-Sycamore Tap 230 kV Line Loading following Single Contingency

Transmission Element	Case A- Pre-LEAPS loading (%)	Case B- LEAPS transmission loading (%)	Case C- LEAPS transmission and generation loading (%)	Delta (Case C-A) %/MVA
Suncrest-Sycamore Tap 230 kV	109%	100%	92%	17% / 78 MVA

Figure 31. Comparison of Results for Double Contingency of ECO-Miguel & Suncrest 500 kV line Pre-LEAPS and Post-LEAPS

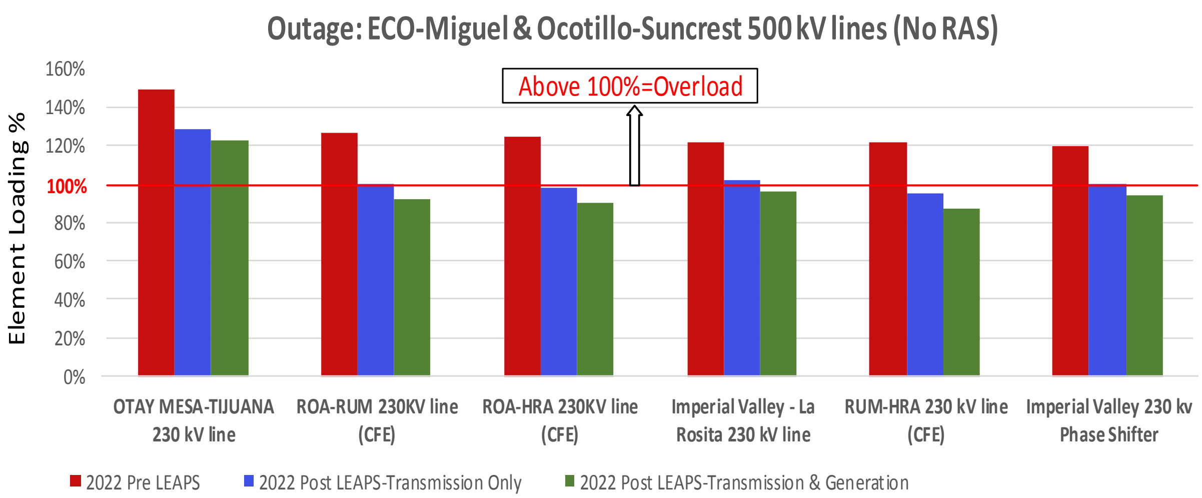


Table 22. Loading of Multiple Elements following Double Contingency of ECO-Miguel & Suncrest 500 kV line

Transmission Element	Case A-Pre-LEAPS loading (%)	Case B-LEAPS transmission loading (%)	Case C- LEAPS transmission and generation loading (%)	Delta (Case C-A) %/MVA
Otay Mesa-Tijuana Tap 230 kV	149%	129%	123%	26% / 221 MVA
Imperial Valley-La Rosita 230 kV	122%	102%	96%	26% / 296 MVA
Imperial Valley 230 kV Phase Shifter	119%	100%	94%	25% / 125 MVA

Figure 32. Comparison of Results for Double Contingency of Ocotillo-Suncrest 500 kV and Imperial Valley-La Rosita 230 kV line Pre-LEAPS and Post-LEAPS

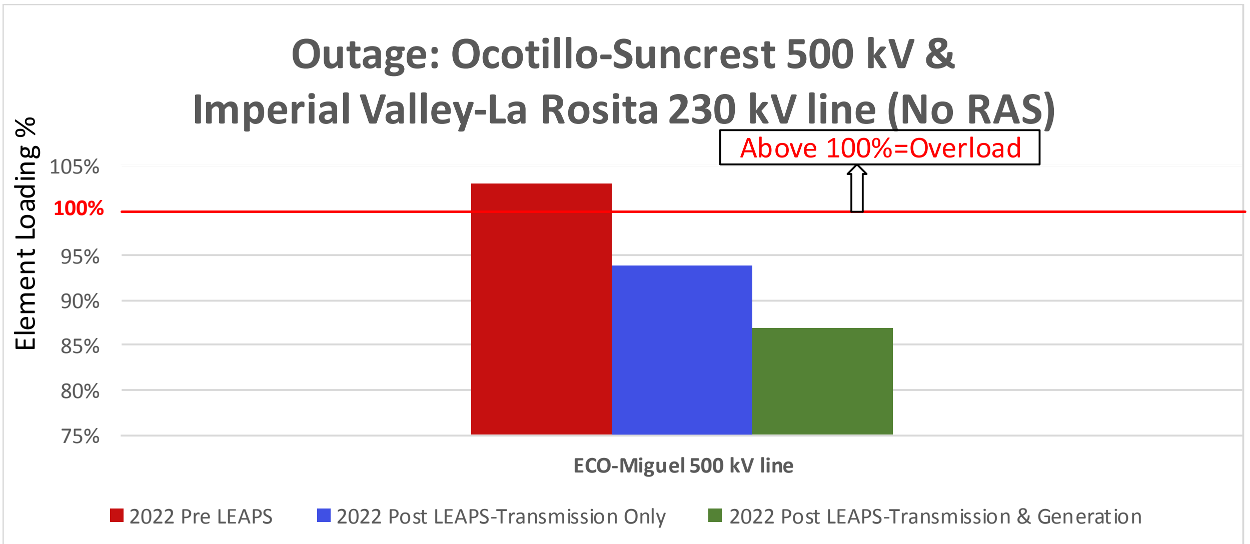


Table 23. Loading of Multiple Elements following Double Contingency of Ocotillo-Suncrest 500 kV and Imperial Valley-La Rosita 230 kV line

Transmission Element	Case A- Pre-LEAPS loading (%)	Case B- LEAPS transmission loading (%)	Case C- LEAPS transmission and generation loading (%)	Delta (Case C-A) %/MVA
ECO-Miguel 500 kV line	103%	94%	87%	16%/416MVA

For all the single and multiple contingencies that were evaluated, LEAPS project did not cause any new thermal or voltage violations on the system. LEAPS project helped decrease and relieve overloads that existed prior to adding LEAPS project.

Although RAS schemes are associated with a lot of the major contingencies that were studied, with modeling the LEAPS project, a RAS scheme to drop generation would not be necessary since the LEAPS project is providing the necessary mitigation to the system under those outages. The reliability assessment that was conducted shows decrease in San Diego and LA Basin Area local capacity requirements that are required to meet the ISO's adverse weather reliability requirement. The assessment shows that the proposed LEAPS project will allow San Diego area to reliably serve their customers during periods of unusually high energy demand, unexpected outages and abnormal conditions. LEAPS also provide flexibility in operating California's transmission grid, by adding additional import capability to San Diego County from the north, which has limited connectivity to the rest of the ISO grid.

5. EXHIBIT NHC – D

6. LEAPS BENEFITS USING THE CPUC IRP RESOLVE METHODOLOGY

I performed an analysis to quantify the following benefits that LEAPS provides to California consumers:

- Curtailment Risk from Over-generation Benefit
- Production Cost Savings
- Emissions Reduction
- Regulation and Spinning Reserve Cost Savings
- Load Following Benefits
- Local Capacity Requirement Benefits
- Avoided Large Transmission Investments
- Avoided Interconnection Costs
- RPS Cost Savings

7. The LEAPS project will provide benefits in all of the critical areas identified by the CPUC through enhanced reliability and grid resiliency while lowering overall costs to consumers by reducing transmission and generation costs. I have been extremely careful not to duplicate benefits across categories. Based on my calculation of the benefits, I derived a present value estimate of total benefits for LEAPS and compared to its present value cost and find it provides a benefit to cost ratio range of 1.3 to 2.74.

A. Curtailment Risk

I performed an analysis to quantify the curtailment risk benefits that LEAPS provides to California consumers. My analysis utilized production cost modeling, using the CPUC's RESOLVE production cost platform and assumptions to assess the quantity (in MWh) of curtailment risk associated with a 50% RPS generation portfolio sufficient to meet an electric sector emissions target of 42 MMT and 30 MMT respectively for scenarios with and without the LEAPS project.[84] I developed the following four cases to quantify the potential range of curtailment risk benefits:

- CPUC Reference Case 1 ("Case 1") - 42 MMT GHG emissions target, high solar build to meet 50% RPS by 2030,
- CPUC Reference Case 2 ("Case 2") - 42 MMT GHG emissions target, high wind build to meet 50% RPS by 2030,
- CPUC Reference Case 3 ("Case 3") - 30 MMT GHG emissions target, high solar build to meet 50% RPS by 2030, and
- CPUC Reference Case 4 ("Case 4") - 30 MMT GHG emissions target, high wind build to meet 50% RPS by 2030.

8. For each scenario, I ran a "base" production cost simulation run without LEAPS capacity to determine a least-cost renewable portfolio that met or exceeded the GHG and RPS goals. I used this approach to determine an optimal renewable resource procurement plan for three

[84] The RESOLVE model was used to prepare CPUC Staff's recommended Reference System Plan for the 2017-2018 IRP-LTPP. RESOLVE is a capacity expansion model that co-optimizes consumer costs for infrastructure investment and energy dispatch to select optimal resource portfolios that meet the state's GHG targets and other policy objectives such as 50% RPS. A description of the model's input assumptions and other related documentation is located at: http://cpuc.ca.gov/irp/proposedrsp/.

simulation years: 2022, 2026 and 2030. I chose 2022 as the first year because that is when Nevada Hydro anticipates that the LEAPS project will be on-line. I chose 2026 as the second year because that is when the 2200 MW Diablo Canyon nuclear facility is planned for retirement. Finally, I chose 2030 because that is when the State's emissions and RPS policies are to be fully implemented. I developed scenarios for each of the GHG planning targets that optimized for both a high solar (Cases 1 and 3) and high wind (Cases 2 and 4) renewable procurement plan which resulted in the expected curtailment energy shown in **Table 24**.

9. Table 24. Renewable Curtailment Summary without LEAPS

42mmt - Base				
Renewable Curtailment Summary	**Unit**	**2022**	**2026**	**2030**
Case 1	*GWh*	4,678	4,060	7,266
Case 2	*GWh*	3,884	3,516	6,119
30mmt - Base				
Renewable Curtailment Summary	**Unit**	**2022**	**2026**	**2030**
Case 3	*GWh*	6,019	5,055	37,441
Case 4	*GWh*	3,853	3,599	10,292

The level of expected curtailment is notably higher in Cases 1 and 3 compared with Cases 2 and 4 dues to the quantity of solar capacity overbuild needed to satisfy the 50% RPS criteria. Solar capacity output is highest during mid-day and drives a lower net load resulting in higher curtailment energy.

Next, we ran a second set of RESOLVE production cost runs with LEAPS to quantify its benefit for lowering the curtailment energy. With LEAPS, there is lower solar or wind procurement as shown in **Table 25**. For instance, in Case 1, the base case shows a need of 1,141 MW of wind starting 2022 and 9740 MW of new solar starting 2022 and an additional 615 MW in 2030, the Case 1 with LEAPS shows the need for 1,141 MW of wind starting 2022 but 9,467 MW of solar starting in 2022. LEAPS reduce solar procurement is reduced by 273 MW for years 2022 and 2026, and by 888 MW in 2030 to meet 50% RPS.

Table 25. Lower Procurement Capacity to meet 50% RPS with LEAPS

Case 1		Base			w/LEAPS			Change		
Wind/Solar Capacity	**Unit**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Wind	*MW*	1,141	1,141	1,141	1,141	1,141	1,141	-	-	-
Solar	*MW*	9,740	9,740	10,355	9,467	9,467	9,467	(273)	(273)	(888)
Case 2		**Base**			**w/LEAPS**			**Change**		
Wind/Solar Capacity	**Unit**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Wind	*MW*	1,145	1,145	1,904	1,145	1,145	1,328	-	-	(575)
Solar	*MW*	8,841	8,841	8,842	8,841	8,841	8,848	-	-	6
Case 3		**Base**			**w/LEAPS**			**Change**		
Wind/Solar Capacity	**Unit**	2022	2026	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Wind	*MW*	1,141	1,141	4,772	1,141	1,141	4,772	-	-	-
Solar	*MW*	10,977	10,977	23,738	11,229	11,229	19,348	252	252	(4,390)
Case 4		**Base**			**w/LEAPS**			**Change**		
Wind/Solar Capacity	**Unit**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Wind	*MW*	4,512	4,512	9,585	4,350	4,350	8,901	(162)	(162)	(684)
Solar	*MW*	7,761	7,761	7,761	7,771	7,771	7,771	11	11	11

The lower procurement combined with LEAPS' pump storage availability during mid-day hours to absorb excess variable energy reduces total curtailment energy across all years for all cases. Curtailment reductions for each of the 4 cases are summarized in **Table 26**.[85]

Table 26. Curtailment Reduction Summary with LEAPS

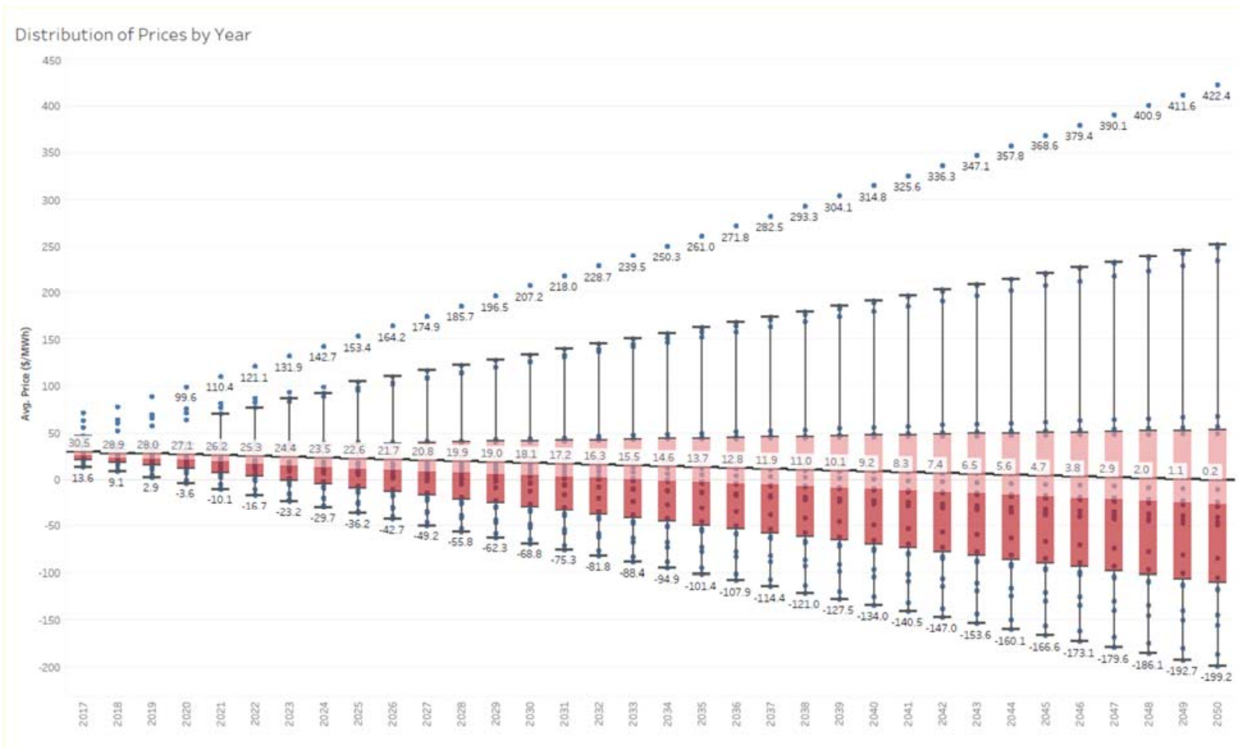
42mmt				
Curtailment Reduction with LEAPS	**Unit**	**2022**	**2026**	**2030**
Case 1	*GWh*	(768)	(573)	(1,651)
Case 2	*GWh*	(497)	(342)	(957)
30mmt				
Curtailment Reduction with LEAPS	**Unit**	**2022**	**2026**	**2030**
Case 3	*GWh*	(410)	(412)	(11,254)
Case 4	*GWh*	(480)	(326)	(1,373)

LEAPS is able to pump 600 MW for 12 hours 360 days/yr. with a round trip efficiency of 83%. This translate to a total pumping capability of 2,152 GWH annually.

[85] Case 3 resulted in curtailment benefit in excess of maximum annual LEAPS pumping energy. For the benefit calculation, we have capped the annual GWh benefit at 2500 GWh.

The potential \$/MWh cost of curtailment energy to consumers is based on a projection of the average hourly real-time 5-minute marginal cost of energy (MCE) expected over the life of the project. Using historic average hourly real-time MCEs obtained from CAISO from 2015, 2016 and 2017, I projected out average hourly prices for 2018 through 2050 based on the linear price trend obtained from the historic data. The distribution of these hourly projected prices is shown in **Figure 33** which shows the range of hourly forecasted CAISO MCE price in \$/MWh along with the maximum, minimum, and average price.

10. Figure 33. Distribution of Projected Hourly MCEs



In the CAISO markets, negative MCEs are indicative of over-generation or oversupply conditions. To calculate the annual curtailment benefit over the life of the project, I computed the hourly pumping revenue by distributing the curtailment reduction energy over the hours with expected negative MCEs, considering LEAPS's maximum pumping capability. The annual benefits are provided graphically in **Figure 34** and the resulting annual levelized benefits for each of the Cases are provided in **Table 27**.

Figure 34. Annual Curtailment Benefit

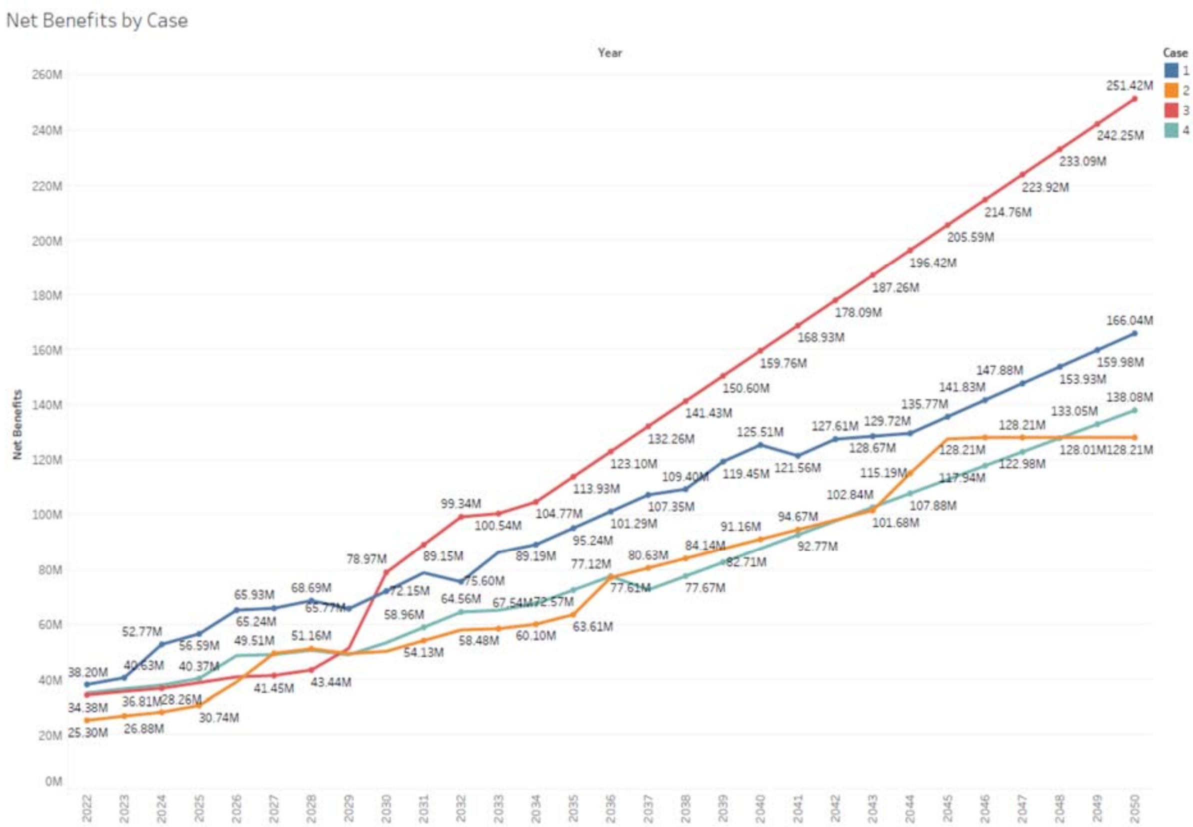


Table 27. Levelized Annual Curtailment Benefit with LEAPS.

Levelized Annual Benefits ($)	**42mmt**		**30mmt**	
	Case 1	Case 2	Case 3	Case 4
Curtailment Benefit	$128,280,745	$98,729,512	$179,965,951	$103,639,516

LEAPS is able to save the ratepayers $98.7 million to $179.9 million in costs that otherwise will be paid to generators for over-generation.

B. Production Cost Benefits

The LEAPS project provides energy cost benefits to consumers with its ability to displace or facilitate redispatch ISO generation more economically. I utilized the production cost analysis described in the previous sections to quantify the energy cost savings with LEAPS. The energy cost is calculated as the sum of the variable operating costs, fuel costs, start-up and shutdown costs of the dispatched resources in the cases. The cost difference between the without and with LEAPS case is the energy cost savings to consumers where a positive dollar amount is a benefit and a negative dollar amount is the incremental cost to consumers with LEAPS. My analysis shown in Table 28, below, that LEAPS would result in annual benefits to consumers ranging from -$17 million in Case 2 in 2030 to $143 million in Case 3 in 2026. The energy cost savings is primarily due to savings in fuel and variable operating costs of natural gas-fired resources. LEAPS contributes to the redispatch of those resources as shown in Table 29. Gas-fired resource production is reduced as high as 15,459 GWh in 2030 for Case 1. In Case 3, the main driver is lower marginal pricing as the energy output increased by 182 GWh yet the system still realized a benefit of $21 million in 2030.

Table 28. Production Cost Savings due to LEAPS.

		Base			w/LEAPS			Benefit		
Production Cost	**Unit**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Case 1	*$MM*	$3,285	$4,118	$5,146	$3,233	$4,048	$5,033	$52	$70	$113
Case 2	*$MM*	$3,361	$4,203	$5,175	$3,280	$4,102	$5,192	$80	$101	$(17)
Case 3	*$MM*	$3,191	$4,257	$4,304	$3,089	$4,115	$4,283	$102	$143	$21
Case 4	*$MM*	$3,041	$3,993	$4,045	$2,970	$3,927	$4,015	$71	$66	$31

11.

Table 29. Energy Output of Natural Gas Fired Units

		Base			w/LEAPS			Change		
Natural Gas Energy	Unit	2022	2026	2030	2022	2026	2030	2022	2026	2030
Case 1	GWh	40,171	55,817	65,285	36,292	55,096	49,826	(3,880)	(721)	(15,459)
Case 2	GWh	42,048	57,838	65,908	40,990	56,473	66,541	(1,058)	(1,365)	633
Case 3	GWh	37,840	57,083	49,644	36,292	55,096	49,826	(1,549)	(1,987)	182
Case 4	GWh	36,261	54,042	46,872	35,309	53,322	46,773	(953)	(720)	(99)

The production cost benefits for the three study years are used to calculate annual levelized production cost benefits over the life of the project. I estimate those savings to range between $200,000 and $104.7 million. (**Table 30**)

Table 30. Levelized Annual Avoided RPS Fixed Cost Benefit due to LEAPS

Levelized Annual Benefits ($)	42mmt		30mmt	
	Case 1	Case 2	Case 3	Case 4
Production Cost Savings	$104,680,000	$200,000	$37,240,000	$37,000,000

C. Emissions Benefits

The production cost scenarios optimized the portfolios to ensure meeting either a 42mmt or 30mmt carbon emission target for the electric utility sectors. A comparison of the emissions output shows LEAPS can help meet those targets with lower overall emissions as shown in Table 31.

Table 31. Emissions Benefits due to LEAPS

		Base			w/LEAPS			Change		
Emissions Summary	Unit	022	026	030	022	026	030	022	026	030
Case 1	*MMtCO2*	1	7	0	1	6	9	0.2)	0.3)	0.6)
Case 2	*MMtCO2*	2	7	0	1	7	0	0.4)	0.5)	.2
Case 3	*MMtCO2*	0	7	4	9	6	4	0.6)	0.7)	.0
Case 4	*MMtCO2*	0	6	3	9	6	3	0.4)	0.3)	0.1)

Based on $23.27/m-ton price,[86] the emissions benefits due to LEAPS are shown in Table 32.

Table 32. Emissions Cost Savings due to LEAPS

Levelized Annual Benefits ($)	42mmt		30mmt	
	Case 1	Case 2	Case 3	Case 4
Emission Cost Savings	$12,658,880	-$2,233,920	$2,420,080	$3,257,800

D. Regulation and Spinning Reserve Benefits

The production cost study results, using the CPUC RESOLVE model, also optimized LEAPS' capabilities to provide regulation and spinning reserve capacity to the ISO. My study shows that LEAPS can provide between 266 GW and 386 GW of regulation capacity annually, and between 442 GW and 565 GW of spinning reserve capacity annually as summarized in *and , respectively. The three-year average historic regulation and* spinning reserve clearing prices from ISO were $10.20/MWh and $6.81/MWh, respectively. Using these prices, I calculate the levelized annual benefits for regulation service to be between $2.85 million and $3.38 million, and for spinning reserves to be between $3.3 million and $3.8 million (Table 35.)

[86] http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf at page 25.

Table 33. Annual Regulation for LEAPS

Annual		LEAPS		
Regulation	Unit	2022	2026	2030
Case 1	MW	374,947	304,441	329,253
	#hours	5,742	4,805	5,288
Case 2	MW	386,187	321,123	314,151
	#hours	5,776	5,041	4,617
Case 3	MW	356,368	312,377	277,468
	#hours	5,532	4,699	4,546
Case 4	MW	362,165	332,678	266,574
	#hours	5,542	4,970	4,262

Table 34. Annual Spin Capacity for LEAPS

Annual		LEAPS		
Spin	Unit	2022	2026	2030
Case 1	MW	555,296	539,458	491,905
	#hours	4,406	4,264	3,912
Case 2	MW	538,876	486,409	561,544
	#hours	4,269	3,825	4,373
Case 3	MW	442,752	477,546	489,416
	#hours	3,720	3,885	3,660
Case 4	MW	511,095	497,099	565,036
	#hours	4,005	3,971	4,199

Table 35. Levelized Annual Regulation and Spin Reserve Benefit for LEAPS

Levelized Annual Benefits ($)	42mmt		30mmt	
	Case 1	Case 2	Case 3	Case 4
Regulation	$3,375,425	$3,268,808	$2,923,042	$2,851,000
Spinning Reserve	$3,410,317	$3,770,832	$3,301,036	$3,781,497

E. Load Following Benefits

LEAPS has tremendous flexibility to provide load following to the grid in an era of increased intermittent resources and less reliance on gas plants. A fast-moving resource such as LEAPS is critical from an operation and reliability perspectives. I used the results of the production cost scenarios described in Section A to quantify the hourly load following capacity (MW) provided by LEAPS in each study year. LEAPS capacity is used for both load following up and down for over 7000 hours annually in most of cases. **Table 36**is a summary of the capacity used. The load following benefit from LEAPS is valued at the net avoided cost to use LEAPS instead of other more expensive units for load following. I have calculated an avoided cost of the three-year historic average (RT 5-min) LMP at ISO pricing node SP15 of $30.16/MWh. This translates to a range of $58.7 million to $65.4 million levelized annual benefit for load following (**Table 37**.)

Table 36. Annual Load Following Capacity for LEAPS

Annual		LEAPS		
Load Following	Unit	2022	2026	2030
Case 1	*MW*	1,646,175	1,734,944	2,259,051
	#hours	7,332	7,079	7,437
Case 2	*MW*	1,587,572	1,760,389	2,200,403
	#hours	7,300	7,385	7,394
Case 3	*MW*	1,756,906	1,874,607	2,047,482
	#hours	7,478	7,096	6,915
Case 4	*MW*	1,557,893	1,752,731	2,000,720
	#hours	7,077	7,162	7,023

Table 37. Levelized Annual Load Following Benefit

Levelized Annual Benefits ($)	42mmt		30mmt	
	Case 1	Case 2	Case 3	Case 4
Load Following Benefit	$65,389,674	$63,823,854	$60,633,833	$58,674,927

F. Local Capacity Requirement Benefits

I ran power flow analyses to determine LEAPS benefits for satisfying LCR needs. Per my analysis, adding LEAPS benefits both SCE and SDGE areas. Adding LEAPS decreases import flow from Imperial Valley substation by 377 MW compared to a no LEAPS case, and decreases import flow from SCE by approximately 134 MW compared to a no LEAPS case. This means that SCE and SDGE will be able to reduce their reliance on high cost local gas-fired generation to satisfy its LCR. Exhibit NHC-C provides further details regarding the assumptions, study approach and results of my power flow analysis.

A. My assessment shows that the proposed LEAPS project will allow San Diego area to reliably serve their customers during periods of unusually high energy demand, unexpected outages and abnormal conditions. LEAPS also provide flexibility in operating California's transmission grid, by adding additional import capability to San Diego County from the north, which has limited connectivity to the rest of the CAISO grid. In summary, my analysis demonstrates that LEAPS provides consumer benefits as an LCR resource and transmission reliability project. The value of the LCR capacity benefit is $75.68 kw-yr.[87] based on 500 MW generation, this results in an annual benefit of $38 million.

[87] https://www.CAISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf. Section 10.8 and the soft offer cap basis was established as the sum of mid-cost results for insurance, ad valorem, and fixed operation and maintenance costs included in the CEC's draft staff report *Estimated Cost of New Renewable and Fossil Generation in California*: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf. The levelized fixed cost target presented in DMM's analysis of net market revenues for new gas-fired generation in Chapter 1 is based on the same report, but includes financing and taxes.

G. Avoided Interconnection Costs

As shown in Section I, LEAPS reduces the renewable capacity needed to achieve the 50% RPS goal. For instance, under Case 1, using the PUC RESOLVE model, LEAPS can avoid capital investment of 273 MW to 888 MW of solar capacity from 2022 to 2030. The avoided renewable capital cost also has an avoided transmission interconnection cost. The avoided transmission interconnection cost is based on the reduced renewable capacity to meet the state's 50% RPS goal with LEAPS in service multiplied by a price of $22/kW-yr.[88]. The reduced capacity for each of the production cost scenarios reference cases is provided in **Table 40**. The resulting levelized annual benefits are shown in **Table 38** for each of the scenarios. I estimate the avoided transmission interconnection cost to range between $13 million and $80 million annually.

Table 38. Levelized Annual Avoided Interconnection Cost Benefit due to LEAPS

Levelized Annual Benefits ($)	**42mmt**		**30mmt**	
	Case 1	Case 2	Case 3	Case 4
Avoided Interconnection Cost	$17,371,200	$10,515,120	$80,240,160	$12,987,040

H. Avoided Large Transmission Investments

Under Cases 2 and 4, with high wind penetration, new transmission projects will need to be built to interconnect new wind capacity to meet California's RPS and emissions goals. The analysis shows that under Case 2 and 4, LEAPS could reduce procurement of wind by 569 MW and 684 MW respectively (**Table 40**), thus the fixed costs for new transmission lines in the relevant areas will be avoided. Based on the utilized PUC RESOLVE assumptions, the avoided transmission

[88] http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf at page 17.

costs occurred in the Greater Carrizo and in the Northern California transmission zones for Case 2 and Case 4 at a cost of $89/kW-yr. and $52/kW-yr. respectively in year 2030. The resulting annual levelized benefit for LEAPS ranges between $29.9 and $43 million as shown in **Table 39**.

Table 39. Levelized Annual Avoided Large Transmission Cost Benefit due to LEAPS

Levelized Annual Benefits ($)	**42mmt**		**30mmt**	
	Case 1	Case 2	Case 3	Case 4
Avoided Large Transmission Investment	$0	$42,987,000	$0	$29,877,120

I. RPS Cost Savings

LEAPS will reduce the quantity of additional renewable capacity needed to achieve the state's 50% RPS goal. This benefits California consumers by reducing the cost of reaching renewable energy targets because the LEAPS project facilitates the integration of lower cost renewable resources located in remote areas, or reduces solar and wind over-build as shown in **Table 40**. Using the results of the same production cost scenarios described in Section A above, I quantified the consumer savings realized by LEAPS based on the avoided fixed cost of new renewable generation that would not be needed to meet the 50% RPS target when LEAPS is on-line. The change of renewable portfolio capacity due to LEAPS is shown in **Table 40**, below. The renewable generating capacity reduction in year 2030 ranges from 569 MW to 4,390 MW, given the assumptions of the 4 cases. I used the CPUC RESOLVE model to develop optimized portfolios both with and without LEAPS for each of the three study years: 2022, 2026, and 2030. Additional ("new") renewable capacity is selected by the RESOLVE optimization to achieve 50% RPS and California's emissions target by 2030. The selected generating resources include new in-state or out-of-state geothermal, biomass, solar or wind resources beyond the model's baseline resource assumptions. The baseline resources include ISO's existing resources, adjusted for planned retirements, renewable resources likely to be constructed based on prior CPUC approval, 1,325 MW of mandated energy storage capacity as well as achievement of demand-side energy efficiency programs.

Table 40. Comparison of Renewable Procurement Plan to Meet State RPS Goals with and without LEAPS

		Base			w/LEAPS			Change		
Renewable Procurement	**Unit**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Case 1	*MW*	10,881	10,881	11,748	10,608	10,608	10,860	(273)	(273)	(888)
Case 2	*MW*	9,985	9,985	10,998	9,985	9,985	10,429	-	-	(569)
Case 3	*MW*	12,118	12,118	30,889	12,370	12,370	26,499	252	252	(4,390)
Case 4	*MW*	12,272	12,272	19,724	12,121	12,121	19,050	(151)	(151)	(674)

The difference between the RPS portfolio's fixed procurement cost without and with LEAPS quantifies the net benefit where a positive dollar amount represents a benefit to consumers and a negative dollar amount means consumers do not benefit from LEAPS. My analysis shows that the reduced capacity procurement due to LEAPS results in an annual RPS benefit that ranges from $111 to $637 million dollars in 2030 (**Table 41**).[89]

Table 41. Annual RPS Benefit due to LEAPS

		Base			w/LEAPS			Benefit (Excluding TX costs))		
New Renewables Fixed Cost	**Unit**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Case 1	*$MM*	$1,472	$1,472	$1,735	$1,435	$1,435	$1,592	$ 31	$ 31	$ 123
Case 2	*$MM*	$1,351	$1,351	$1,673	$1,351	$1,351	$1,549	$ -	$ -	$ 111
Case 3	*$MM*	$1,639	$1,639	$6,334	$1,673	$1,673	$5,599	$(28)	$(28)	$637
Case 4	*$MM*	$1,777	$1,777	$4,628	$1,751	$1,751	$4,455	$ 22	$ 22	$ 158

[89] All costs expressed in 2016 dollars.

Table 42 and **Table 43** show the locational RPS portfolio mix for Case 1 with and without LEAPS and the difference in fixed costs for the two RPS portfolios. The LEAPS project reduces the need to procure solar capacity in the Riverside East area by 273 MW in years 2022 and 2026, and by 888 MW in 2030 resulting in an annual cost savings of $31 million in years 2022 and 2026, and $123 million in year 2030.

Table 42. Comparison of RPS Procurement without and with LEAPS for Case 1.

Renewable Resource Build by Location (MW)		Base			w/LEAPS			Change		
RESOLVE Resource	Tx Zone	022	026	030	022	026	030	022	026	030
Northern California_ Solar	Northern California									
Solano_Solar										
Central_Valley_North _Los_Banos_Solar										
Westlands_Solar										
Greater_Carrizo_Solar										
Tehachapi_Solar	*Tehachapi*	,013	,013	,013	,013	,013	,013			
Kramer_Inyokern_ Solar	*Kramer_Inyokern*	,981	,981	,981	,981	,981	,981			
Mountain_Pass_El_ Dorado_Solar										
Southern_California_ Desert_Solar										
Riverside_East_Palm_ Springs_Solar	*Riverside_East_ Palm_Springs*	,740	,740	,355	,467	,467	,467	273)	273)	888)
Greater_Imperial_ Solar										
Distributed_Solar										
Baja_California_Solar										
Utah_Solar										
Southern_Nevada_ Solar	*Mountain_Pass_El_ Dorado*	,006	,006	,006	,006	,006	,006			
Arizona_Solar										
New_Mexico_Solar										
Northern_California_ Wind										
Solano_Wind	*Solano*	43	43	43	43	43	43			
Central_Valley_North _Los_Banos_Wind	*Central_Valley_ North_Los_Banos*	46	46	46	46	46	46			
Greater_Carrizo_ Wind	*Greater Carrizo*	60	60	60	60	60	60			

Renewable Resource Build by Location (MW)		Base			w/LEAPS			Change		
RESOLVE Resource	**Tx Zone**	**022**	**026**	**030**	**022**	**026**	**030**	**022**	**026**	**030**
Tehachapi_Wind	*Tehachapi*	49	49	49	49	49	49			
Kramer_Inyokern_ Wind										
Southern_California_ Desert_Wind										
Riverside_East_Palm_ Springs_Wind	*Riverside East_ Palm_Springs*	2	2	2	2	2	2			
Greater_Imperial_ Wind										
Distributed_Wind										
Baja_California_Wind										
Pacific_Northwest_ Wind										
NW_Ext_Tx_Wind										
Idaho Wind										
Utah_Wind										
Wyoming_Wind										
Southern Nevada_ Wind										
Arizona_Wind										
New_Mexico_Wind										
SW_Ext_Tx_Wind										
InState_Biomass										
Greater_Imperial_ Geothermal										
Northern California_ Geothermal	*Northern California*			53			53			
Pacific Northwest_ Geothermal										
Southern Nevada_ Geothermal										
In-State		,875	,875	,742	,602	,602	,854	273)	273)	888)
Out-Of-State		,006	,006	,006	,006	,006	,006			

Table 43. RPS Fixed Cost Benefit for Case 1.

CA RPS Fixed Costs by Technology		Base			w/LEAPS			Change		
Technology	**Unit**	**022**	**026**	**030**	**022**	**026**	**030**	**022**	**026**	**030**
Geothermal	*$MM*	-	-	157	-	-	157	-	-	-
Biomass	*$MM*	-	-	-	-	-	-	-	-	-

CA RPS Fixed Costs by Technology		Base			w/LEAPS			Change		
Technology	Unit	022	026	030	022	026	030	022	026	030
Wind	*$MM*	183	183	183	183	183	183	-	-	-
Solar	*$MM*	1,289	1,289	1,395	1,252	1,252	1,252	37	37	143
Total	*$MM*	1,472	1,472	1,735	1,435	1,435	1,592	37	37	143

The avoided renewable fixed costs include the associated interconnection costs discussed in Section G. Thus, for purposes of quantifying the net RPS Fixed Cost benefit due to LEAPS I have subtracted out the interconnection avoided costs from the RPS Fixed Cost totals shown in **Table 41**. The resulting levelized annual RPS fixed cost benefit ranges between $93.6 million and $530.8 million as shown in **Table 44**.

Table 44. Levelized Annual Avoided RPS Fixed Cost Benefit due to LEAPS (excluding transmission costs)

Levelized Annual Benefits ($)	**42mmt**		**30mmt**	
	Case 1	Case 2	Case 3	Case 4
Reduced Cost of Renewables (RPS)	$108,668,800	$93,644,880	$530,879,840	$136,492,960

J. Summary of Benefits

For each of the quantifiable benefits, I calculated a hypothetical levelized annual benefit over the estimated [50-year life] of the project and divided this amount by the levelized annual cost of the project for each of the four reference cases used for my analysis. I used the depreciation assumption in the CPUC RESOLVE model for purposes of this analysis. It is important to note that the actual revenue requirement for the LEAPS project will likely differ based on FERC's determination of the just and reasonable rate, including the award of incentives that are appropriate for the LEAPS project. Table 45 summarizes the benefits of each of the categories and provides the resulting benefit-to-cost ratio for LEAPS under the four cases. The range of benefit-to-costs for LEAPS is from 1.53 to 3.8:

Table 45. LEAPS Benefits to Cost Ratio for the 4 Reference Cases Analyzed

	Scenarios	**42 mmt Scenario**		**30 mmt Scenario**	
Benefit #	Levelized Annual Benefits	CPUC Reference Case 1	CPUC Reference Case 2	CPUC Reference Case 3	CPUC Reference Case 4
1	*Over-generation/ Curtailment Benefit*	$128,280,745	$98,729,512	$179,965,951	$103,639,516
2	*Grid Resiliency (Electric Reliability Services)*	$30,000,000	$30,000,000	$30,000,000	$30,000,000
3	*Load Following Savings*	$65,389,674	$63,823,854	$60,633,833	$58,674,927
4	*Regulation*	$3,375,425	$3,268,808	$2,923,042	$2,851,000
5	*Spinning Reserve*	$3,410,317	$3,770,832	$3,301,036	$3,781,497
6	*Transmission Interconnection Cost*	$17,371,200	$10,515,120	$80,240,160	$12,987,040
7	*Local Transmission (LCR) Savings*	$37,840,000	$37,840,000	$37,840,000	$37,840,000
8	*Avoided Large Transmission Investment*	$0	$42,987,000	$0	$29,877,120
9	*Reduced Cost of Renewables (RPS)*	$108,668,800	$93,644,880	$530,879,840	$136,492,960
10	*Production Cost Savings*	$104,680,000	$200,000	$37,240,000	$37,000,000
11	*Emission Cost Savings*	$12,658,880	$2,233,920	$2,420,080	$3,257,800
Levelized Annual Benefits		$511,675,040	$382,546,086	$965,443,942	$456,401,859
Levelized Annual Costs		$249,852,456	$249,852,456	$249,852,456	$249,852,456
Benefits to Cost Ratio (BCR)		2.05	1.53	3.864	1.827

Figure 35. Levelized Project Benefits Per Benefit Category

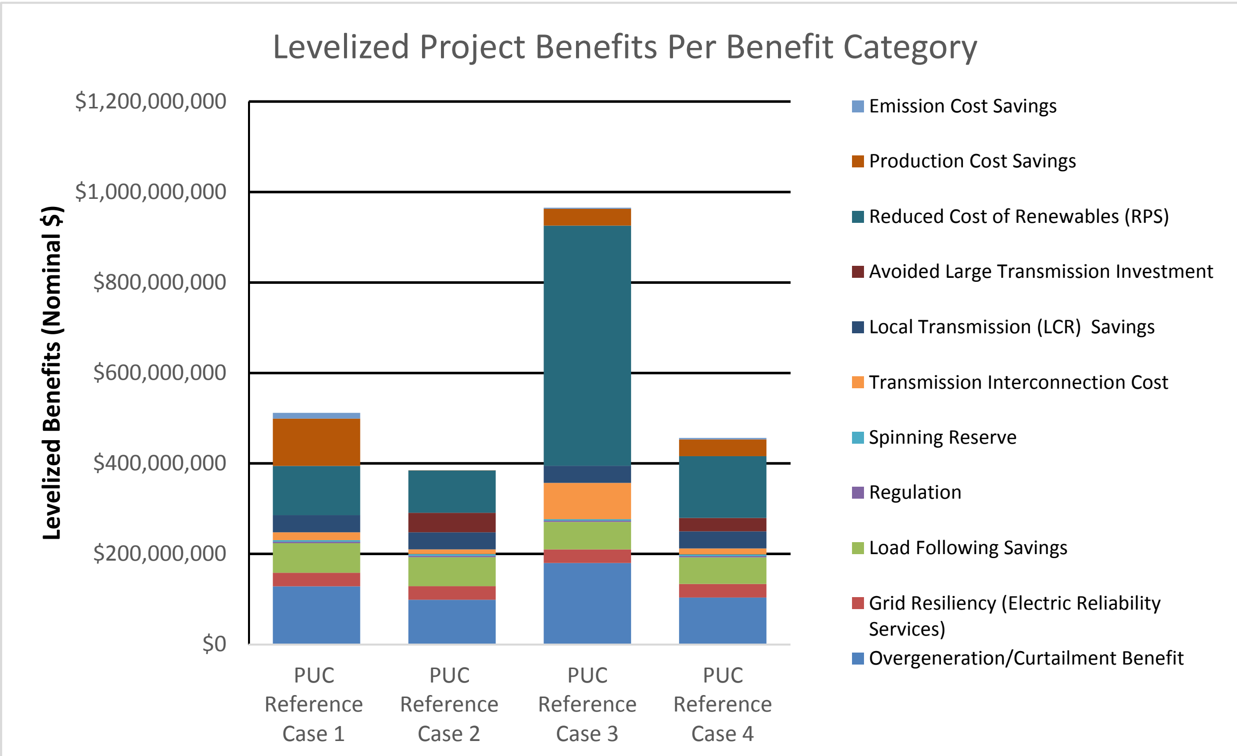
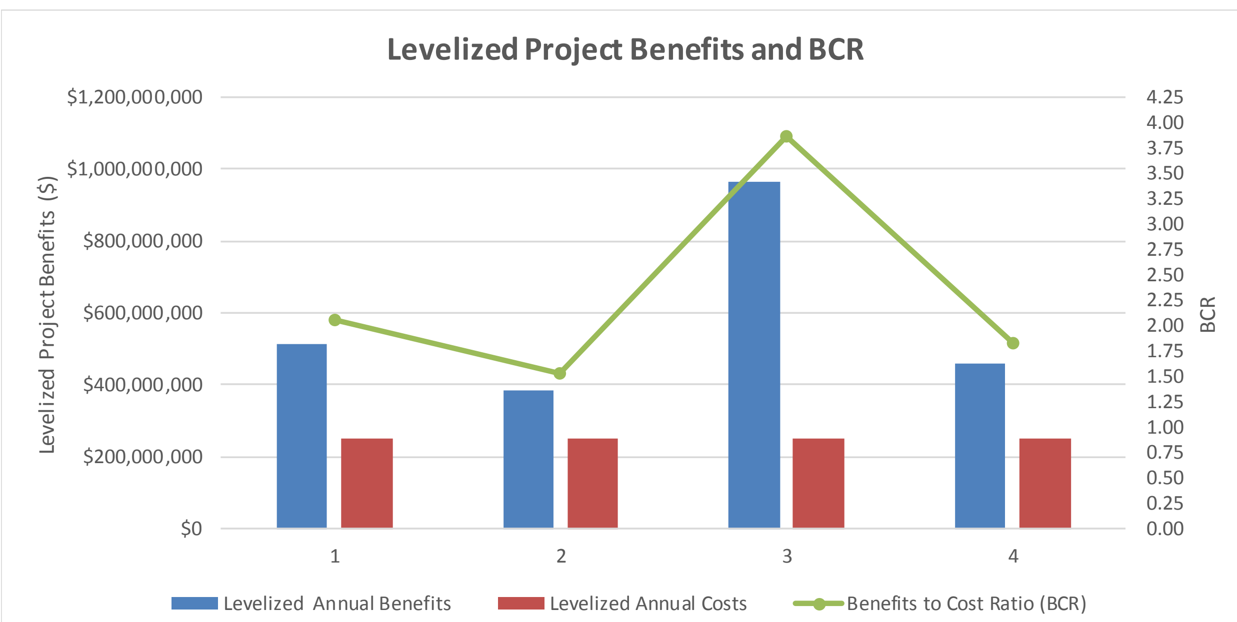


Figure 36. Levelized Project Benefits and BCR



As a final step I calculated the present value benefits and benefit to cost ratio. I have provided a summary in Table 46 below.

Table 46. NPV and Benefits-to-Cost Ratio for LEAPS for the 4 Reference Cases

Scenarios	42 mmt Scenario		30 mmt Scenario	
Present Value	PUC Reference Case 1	PUC Reference Case 2	PUC Reference Case 3	PUC Reference Case 4
NPV of all Benefits at WACC	$5,126,458,788	$4,034,307,077	$8,480,725,326	$4,647,764,023
Project Costs at WACC	$3,092,957,029	$3,092,957,029	$3,092,957,029	$3,092,957,029
Benefits to Cost Ratio (BCR)	1.66	1.30	2.74	1.50

Figure 37. Levelized Project Benefits Per Benefit Category

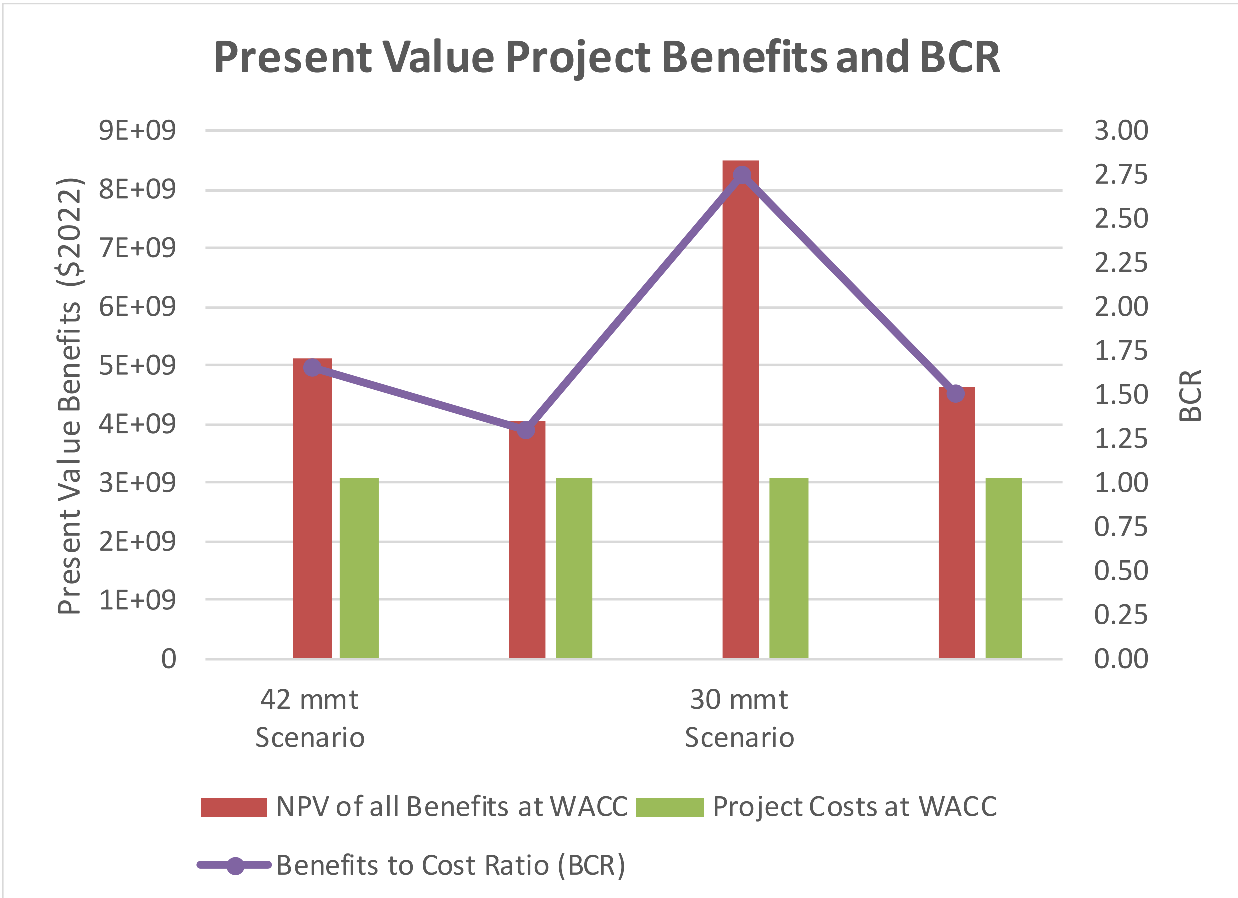


EXHIBIT NHC- E

ZIAD ALAYWAN P.E. TESTIMONY AND PUBLICATIONS

FEDERAL ENERGY REGULATORY COMMISSION AND FEDERAL COURTS

1. Design of California Real-Time Energy and Ancillary Services Markets, Testimony by Alaywan, Z.; Docket No. ER98-2843-009, November 16, 1998.

2. Introducing the Firm Transmission Rights Market under Amendment No. 9 of the CAISO Tariff; Testimony by Alaywan, Z.; Docket No. ER 98-3594-001. 1998.

3. Introducing the Downward Regulation Bids design under Amendment No. 11 of the CAISO Tariff, Testimony by Alaywan, Z.; Dockets No EC96-19-039; ER96-1663-040.1999.

4. Modification of Ancillary Service Market design, Amendment No. 14 of the CAISO Tariff; CAISO, Testimony by Alaywan, Z.; Docket No ER99-1971. 1999.

5. Introducing the Intra Zonal Congestion Management under Amendment No.18 of the CAISO Tariff, Testimony by Alaywan, Z.; Docket No. ER99-3301-000, 1999.

6. Introducing the Rational Buyer changes to the ancillary Service Auction under Amendment No. 20 of the CAISO Tariff; Testimony by Alaywan, Z.; Docket No ER99-3879-000, 1999.

7. Reliability Must Run Tariff, Docket No ER98-441, Testimony by Alaywan, Z.; ER98-1019-000 and El Segundo Power, Docket No. ER98-2550-000, 2000.

8. Instituting a New Congestion Zone (ZP26) in the California Market, Testimony by Alaywan, Z.; Docket No. ER-03-683, 2000.

9. Reliability Must Run Tariff, Testimony by Alaywan, Z.; Docket No ER98-495- 000, ER98-1614, ER98-2145; Duke Energy Moss Landing ER98-2668 and ER98-4300; ER98-2669-000 and ER98-4296-000, 2001.

10. Reliability Must Run contracts between CAISO and generators, Testimony by Alaywan, Z.; FERC Docket No. ER 03-683-003, August 2003.

11. Instituting a Transmission Revenue Requirement for Transmission outside California, Testimony by Alaywan, Z.; Docket No. El-03-15-000, December 2004.

12. Instituting a Decremental Reference Price in CAISO Markets, Testimony by Alaywan, Z.; Docket No. ER-04-938-001, September 2004.

13. Generation Payment under CAISO Market, Attachment Outlining the proposed payments for generators under CAISO markets, Testimony by Alaywan, Z.; Docket No. ER04-938-September 16, 2004.

14. Scheduling Protocols of the Cities of Anaheim and Riverside, Testimony by Alaywan, Z.; Docket No. EL03-15-000 and EL03-20-000, April 8, 2004.

15. On Behalf of SMUD regarding Seams between CAISO and adjacent Balancing Authorities Market Redesign and Technology Upgrade Proposal (MRTU); testimony by Alaywan, Z.; Docket Nos. ER06-615-001; ER06-615-002; ER02-1656-027; ER02-1656-029; ER02-1656-031; 2004.

16. On Behalf of SMUD, Agreements Governing the Transmission Operation and Rates, Terms and Conditions of Service over the 3,200 MW the Pacific-AC Intertie ("PACI")", Declaration submitted to FERC. Testimony by Alaywan, Z.; Docket Nos. ER07-882-000, ER07-967-000, July 30, 2007.

17. On Behalf of Western Grid Development; Western Grid Requests Commission finding that its proposed energy storage device projects are wholesale transmission facilities, as well as Commission approval of certain incentive rate treatments for the Projects under Federal Power Act (FPA). Testimony by Alaywan, Z.; Harris, P and Perez, A.; 'Docket, No EL10-19-000, 2008

18. On Behalf of Opti Solar LLC, Opti solar generation interconnection, Testimony by Alaywan, Z; Docket No. ER08-1317-000 000, October 27, 2008.

19. On Behalf of Transbay Cable, An Economic Benefit Evaluation of the TransBay Cable", comprehensive economic and reliability evaluation of the TransBay Cable, a 230 kV cable across the San Francisco Bay, Trans Bay Cable LLC, Cost of Service Rate Filing, FERC Docket No. ER10-116-000, TBC3, October 23, 2009. The project is currently on line.

20. On Behalf of Desert Southwest Power LLC, Petition for Declaratory Order Allowing Incentive Rate Treatment of Desert Southwest Power LLC", ZGlobal performed a cost benefit analysis for a planned 500 kV transmission line in Southern California, March 30, 2010.

THE STATE OF CALIFORNIA

21. On behalf of the State of California Governor's office, testified in front of a panels of FERC, CPUC, SCE, PG&E, SDGE and California Large customers that CAISO systems and Market are ready to open on 3/31/1998. Three weeks Testimony by Alaywan, Z. Certification from the panels was unanimously obtained and CAISO went into operation on 3/31/1998.

22. On Behalf of the CAISO, Testimony in Front of the California State Senate Sub-Committee on Energy" provided insight on electric operation during the energy crisis, October 2000. On behalf of the CAISO, filed the "Facilitating the congestion Management Market in California", Testimony by Alaywan, Z. Docket ER98-3760.

23. State Senate Select Committee Investigations and reposts regarding California Energy Crisis –This is the first hearing held on April 18, 2001 in Sacramento, CA by the Senate Select Committee to Investigate Price Manipulation of the Wholesale Energy Market. Testimony by Alaywan, Z.

24. State Senator Dunn hearing on 1/21/03. Issues include C66 protocol discussion, the fictitious load, and the MD02 update. (Stock #1207-S; $9.16 - includes tax s/h) (2/03), How to finance these price increases. (Stock #1082-S; $5.93 –includes tax s/h) (4/01). Testimony by Alaywan, Z.

25. Actual Operating Conditions during the Energy Crisis; Several Testimony by Alaywan, Z to State Senators Committee on Energy and Senate Staff, November 2002.

26. The State of California and The Public Utility commission on the case of the City of Roseville, Silicon Valley Power, and the Northern California Power Agency participate with the ISO through the metered subsystem program. Testimony by Alaywan, Z; 2003

27. On Behalf of the CAISO, Scenario Analysis (Planning Criteria), CPUC AB -970 Data Request, Southern California Long-Term Transmission Study…to provide a means to improve current management of Intra-Zonal Congestion and mitigate local market power; and (2) to make data-sharing changes to the ISO Tariff to Allow the ISO to share Generator Outage information with entities operating Transmission and distribution systems affected by the Outage", Testimony by Alaywan, Z.; Docket No. ER03-683-003, August 5, 2003

28. In the Matter of the Application of Southern California Edison Company (U338-E) for a Certificate of Public Convenience and Necessity Concerning the Antelope-Pardee 500 kV (Segment 1) Transmission Project as Required by Decision 04-06-010", Testimony by Alaywan, Z; California PUC Application 04-12-007.

29. On behalf of the State of California and the California Attorney general office, in the matter if widespread market manipulation that occurred in the California wholesale markets between May 1, 2000 and June 20, 2001; San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Respondents. Testimony by Alaywan, Z. and McIntosh, J.; Docket Nos. EL00-95-000; EL00-95-045; EL00-95-075; EL00-98-000; EL00-98-042; EL00-98-063. Docket No. EL01-10-085. Specifically, testified in federal court that led to the settlements of the

dispute between the State of California and Powerex. The State of California Receive a settlement of 750 million.

30. On Behalf of SMUD, United States Court of Appeals, District of Columbia Circuit Nos. 07-1208, 07-1216; 07-1217; 07-1513; 08-1298, 08-1311. Regarding charges of marginal loss charges in Locational Marginal Pricing on non-jurisdictional utilities, July 23, 2010. Testimony by Alaywan, Z.

PUBLICATIONS

POWER SYSTEM OPERATIONS

1. "Increasing of Ground Resistance of Human Foot in Substations Yards" by Alaywan, Z. et al., Power Engineering Review, IEEE, Vol. 9, No.7, pp.53-54, July 1989, doi: 10.1109/MPER.1989.4310806.
2. "Increasing of Ground Resistance of Human Foot in Substations' Yards" by Alaywan, Z. et al., Power Delivery, IEEE Transactions, Vol. 4, No. 3, pp.1695-1700, July 1989, doi: 10.1109/61.32661. "Steady State Voltage Instability – Operations Perspective" presented and published at the IEEE-PES Conference (90 WM 037-2 PWRS), Atlanta, Georgia, 1990.
3. "Steady State Voltage Instability Operations Perspective" by Alaywan, Z. et al., Power Systems, IEEE Transactions, Vol. 5, No. 4, pp.1345-1354, November 1990, doi: 10.1109/59.99386.
4. "Voltage Collapse: Operating Philosophy at PG&E" presented at the IEEE – PES, Summer 1990.
5. "Cost/Benefits Analysis of an Optimal Power Flow: The PG&E Experience" by Alaywan, Z. et al., Power Industry Computer Application Conference, 1993, Conference Proceedings, pp. 82-88, 4-7 May 1993, doi: 10.1109/PICA.1993.291032.
6. "External Network Modeling – Recent Practical Experience" IEEE Transmission and Power Systems, Volume 9, pp. 216-228, February 1994
7. "Marginal Unit Average Costs Based Clearing Prices" Final Report, PG&E/PUC, August 1996.

8. "Data Validation of Market Based Electric Operation" FERC Technical Conference, 1997.

9. “California Electric Restructuring; a Broad Description of the Development of the California ISO" (PE-926-PWRS-0-12-1997) published at the IEEE-PES, 1997.

10. "California Electric Restructuring; a Broad Description of the Development of the California ISO" by Alaywan, Z. et al., Power Systems, IEEE Transactions, Vol.13, No.4, pp. 1445-1452, November 1998, doi: 10.1109/59.736288.

11. RTO / ISO; Market Design, scheduling and Operations:

12. "Ancillary Service Design, Implementation and Operation" Stanford University Business School, Palo Alto, CA, January 26, 1999.

13. "Implementation of the California Independent System Operator" by Alaywan, Z. et al., Power Industry Computer Applications, 1999, PICA '99, Proceedings of the 21st 1999 IEEE International Conference, pp. 233-238, July 1999, doi: 10.1109/PICA.1999.779408.

14. “Facilitating the Congestion Management Market in California” by Alaywan, Z., IEEE PES Conference Proceeding Paper, Edmonton, Canada, published IEEE-PES, Summer 1999.

15. “California ISO Formation and Implementation” by Alaywan, Z. et al., Computer Applications in Power, IEEE, Vol. 12, No. 4, pp. 30-34, October 1999, doi: 10.1109/67.795135.

16. “California ISO Announces Sale of Approximately $41 Million in the First Ever Firm Transmission Rights Auction in California” by Alaywan, Z., November 19, 1999.

17. "Practical Aspects of Running Netscape Server in Deregulated Market Operations" by Alaywan, Z., et al., Power Engineering Society Winter Meeting, 2000. IEEE, Vol. 3, No., pp. 1662-1667 Vol. 3, 23-27 January 2000, doi: 10.1109/PESW.2000.847594.

18. "Evolution of the California Independent System Operator Markets" by Alaywan, Z., The Electricity Journal, July 2000 Evolution of the California Independent System Operator Markets The Electricity Journal, Volume 13, Number 6, 3 July 2000, pp. 69-83 (15).

19. "Adjustable Inter-SC Trade Modeling in Congestion Management" by Alaywan, Z. et al., Power Engineering Society Summer Meeting, 2001, Vol. 2, No., pp. 1063-1069 Vol. 2, 2001, doi: 10.1109/PESS.2001.970206.

20. "Flexible Adjustable Inter-SC Trades Modeling in Congestion Management" presented and published at the IEEE-PES, February 2001.

21. "Fundamentals of Electrical Power Markets" presented at the PICA Conference, Sydney, Australia, May 20-24, 2001.

22. "Declaring Emergencies in California: The Realities of ISO Operation" Fortnightly Magazine, Volume 139, No 19, October 15, 2001.

23. "Best Operating Practices under Strict Environmental Initiatives" International Conference on Renewable Energy", London 2002.

24. "Real-Time Energy Market: Design and Operating Principle" presented to the European Delegation on Restructuring, University Of Toulouse, France, May 2002.

25. "A Rational Buyer Algorithm Used for Ancillary Services" an Ancillary Service Auction used by CAISO Market, Alaywan, Z. et al.., published at the IEEE- PES, October 03, 2004.

26. "California's Electricity Restructuring: The Challenge to Providing Service and Grid Reliability" Final Report, December 2002.

27. "Transmission Pricing and Auction" by Alaywan, Z., presented to the European Delegation on Restructuring, University Of Toulouse, France, 2003.

28. "The California Firm Transmission Rights" by Alaywan, Z., published at the Energy and Power Risk Management, U.K., March 2003.

29. "Capacity Payment for Local Reliability Resources" ECUI Conference, May 9, 2003.

30. "Impact of De-regulation on System Operation in California" by Alaywan, Z., Power Engineering Society General Meeting, 2003, IEEE , Vol. 4, No., pp. 4 Vol. 2666, 13-17 July 2003, doi: 10.1109/PES.2003.1270970.

31. "Effects of Firm Transmission Rights on Transmission Revenue Allocation" by Alaywan, Z., et al., presented and published at the IEEE – PES, October 22, 2003.

32. "Managing Regional Transmission Bottleneck across California and the Southwest Region" by Alaywan, Z., presented to FERC, CPUC and Southwestern Region, December 2003.

33. "Pricing Energy and Ancillary Services in Integrated Market Systems by an Optimal Power Flow" by Alaywan, Z. et al., Power Systems, IEEE Transactions, Vol. 19, No. 1, pp. 339- 347, February 2004, doi: 10.1109/TPWRS.2003.820701.

TRANSMISSION PLANNING, SCHEDULING AND OPERATIONS:

34. “Scheduling Restriction of the Cities of Anaheim and Riverside” by Alaywan, Z., testimony submitted to FERC, Docket No. EL03-15-000 and EL03-20-000, April 8, 2004.]

35. “Transmission Economic Assessment Methodology (TEAM)” CAISO, June 2004.

36. "Economic Assessment for Path 15 Upgrades; Cost Analysis Studies” CAISO, September 7, 2004. Project is online.

37. "Transitioning the California Market from a Zonal to a Nodal Framework: An Operational Perspective" by Alaywan, Z. et al., Power Systems Conference and Exposition, 2004, IEEE PES, pp. 862- 867 Vol. 2, 10-13 October 2004, doi: 10.1109/PSCE.2004.1397468.

38. "Regional Ancillary Services Procurement in Simultaneous Energy/Reserve Markets" by Alaywan, Z., et al., Power Systems Conference and Exposition, 2004, IEEE PES , pp. 1788- 1793 Vol. 3, 10-13 October 2004, doi: 10.1109/PSCE.2004.1397467.

39. "A View from The Operating Room" by Alaywan, Z., McIntosh, J., Power Systems Conference and Exposition, 2004, IEEE PES, pp. 1709- 1727 Vol. 3, 10-13 October 2004, doi:10.1109/PSCE.2004.1397673.

40. "Transmission Modeling of Southern California Municipal Utilities" by Alaywan, Z., report to FERC, December 15, 2004.

41. “Economic Evaluation of the Palo Verde-Devers 500kV Line No. 2” February 24, 2005.

42. "A Perspective on Renewable Energy Development in the Western U.S." presented at the International Renewable Conference in Cairo, March 2005.

43. "Locational Marginal Price Calculations Using the Distributed-slack Power-Flow Formulation" by Alaywan, Z. et al., Power Systems, IEEE Transactions, Vol. 20, No. 2, pp. 1188- 1190, May 2005, doi: 10.1109/TPWRS.2005.846156.

44. "Early Experience in Centralized Real Time Energy Market" presented at the European Engineering Conference in Spain, EURPES, June 2005.

45. "Effect of Market Structure and Design on Grid Reliability" by Alaywan, Z., Power Engineering Society General Meeting, 2005, IEEE , pp. 945- 946 Vol. 1, 12-16 June 2005, doi: 10.1109/PES.2005.1489466.

46. "Why California is Moving Toward Locational Marginal Pricing – The Real Story" presented at the 2nd CIGRE/IEEE Power Engineering Society in New Orleans, October 2005.

47. "Impact of De-regulation on System Operation in California" by Alaywan, Z., CIGRE/IEEE PES, 2005, International Symposium, pp. 24-30, 7-7 October 2005, doi: 10.1109/ CIGRE.2005.1532722.

48. "San Francisco Peninsula Phase 2 Long - Term Electric Transmission Planning Technical Study" Cal-ISO Stakeholder Process Joint Study, November 14, 2005.

49. "Financial Transmission Market in California - Seven Year Assessment" by Alaywan, Z. et al., presented at the IEEE-Power Tech 2007, July 1-5, 2007, Lausanne, Switzerland.

50. "Building a New Path that Benefits the Imperial Valley and Region" presented to the CPUC staff by Jesse Montano and Ziad Alaywan, February 22, 2008.

51. "Experiences with Joint Transmission-Project Development in the West" prepared by ZGlobal on behalf of California Municipal Utilities Association, Imperial Irrigation District, Los Angeles Department of Water and Power and the Sacramento Municipal

Utility District, filed to the California Energy Commission on August 1, 2008, Docket No. 08-IEP-IB.

52. "Renewable Generation Boom" presented at the Imperial Valley Economic Development Conference, November 13, 2008

53. Delivery Challenges for Geothermal and Remotely Located Generation" presented at Platts Geothermal Power Development, June 16, 2009.

54. "The Tres Amigas Superstation: Linking Renewable Energy and the Nation's Grid (July 2010)" by Alaywan, Z. et al., Power and Energy Society General Meeting, 2010 IEEE , pp. 1-5, 25-29 July 2010,doi: 10.1109/PES.2010.5590084.

55. "The Tres Amigas Project: Project Development, Business Case and Benefits" presented at ERCOT, January 2010.

56. "Benefit of Tres Amigas Initial Findings" presented to PNM staff by Ziad Alaywan, June 2010.

57. "The Tres Amigas Superstation: Linking Renewable Energy and the Nation's Grid (July 2010)" by Alaywan, Z. et al., Power and Energy Society General Meeting, 2010 IEEE , pp. 1-5, 25-29 July 2010, doi: 10.1109/PES.2010.5590084.

58. "Solutions to Transmission Capacity Limitations" Alaywan, Z., AWEA Fall Symposium 2011.

59. "Deliverability of Resource Adequacy Capacity on Interties" submitted to CAISO on March 15, 2011 by Kevin Coffee.

60. "Interconnecting North America: The Tres Amigas Superstation" by Alaywan, Z., Coffee, K., Bergman, D., Vangelatos, C. Presented and published at the 2011 CIGRE

International Symposium Integrating Supergrids and Microgrids, Bologna, Italy, September 13-15, 2011

61. "The Tres Amigas Superstation – Interconnecting the Nation" by Alaywan, Z., Transmission Summit West, September 19-21, 2011.

62. "The Golden Spike: Advanced Power Electronics Enables Renewable Development Across NERC Regions" by Alaywan, Z. et al., Power and Energy Magazine, IEEE , Vol. 10, No. 2, pp. 71-78, March 2012, doi: 10.1109/MPE.2011.2178299.

63. "Comparative Economic and Reliability Study Final Report" by ZGlobal Inc. for the Proposed Antelope Valley ClearView ("AV Clearview") Transmission Project in Southern California, February 5, 2013.

64. "Dynamic Transfers for Renewable Energy in the Western Interconnection" presented at Committee on Regional Electric Power Cooperation (CREPC) State-Provincial Steering Committee (SPSC) under the Western Governors Association, April 10, 2013.

65. "Network New Mexico - A Vision for an Integrated Transmission System to Provide for Transmission of Energy from Production Areas to Load Centers and Electricity Market Hubs" presented by ZGlobal at the NM Finance Authority Board of the NM Legislation, August 27, 2013.

66. "Where is Californian Energy Market Headed" by Ziad Alaywan, James McIntosh and Kevin Coffee, Public Generating Pool, Seattle, WA, December 2013.

67. "Locational Marginal Price Calculations Using the Distributed- Slack Power-Flow Formulation" a Locational Marginal Pricing decomposition methodology used by CAISO Market, Alaywan, Z.

68. “Strategic plan for the State's electric transmission” Alaywan testimony on IEPR Committee Workshop on Transmission Needed to Meet State Renewable Policy Mandates and Goals, California Energy Commission, Docket No. 11-IEP-1E, 11-IEP-1G.