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EXHIBIT ___

Testimony of James H. Caldwell Regarding The California Independent System Operator August 16, 2017, Moorpark Sub-Area Local Capacity Alternative Study

Summary and Recommendation

The California Independent System Operator August 16, 2017, Moorpark Sub-Area Local Capacity Alternative Study ("Study") is a good illustration of the promise and the pitfalls of using battery storage to replace a gas fired peaking plant to meet an identified Local Capacity need. It is not, however, a roadmap for using preferred resources such as energy efficiency, solar and demand response to meet that need.

The Study looked at three scenarios as alternatives to constructing a new natural gas plant (Puente) to ensure reliability in the Moorpark subarea in the event of a major multi-day transmission outage following the retirement of the obsolete beachfront, ocean cooled Ormond Beach and Mandalay gas plants. Scenario 1 relies exclusively on battery storage to mitigate the capacity shortfall. Scenario 3 relies exclusively on even more battery storage to also allow the retirement of the Ellwood plant in Goleta. Scenario 2, which is significantly more cost effective than Scenario 1 or 3, relies on a combination of stand-alone reactive power support to mitigate a condition called voltage collapse, and battery storage, which would supply the energy shortage during the transmission outage once the voltage collapse condition is mitigated.

None of the three scenarios procure any meaningful new preferred resources,[1] instead relying almost exclusively on battery storage. The only available energy to recharge those batteries to prepare for the next afternoon's peak load during an assumed multi-day transmission outage is with system power in the middle of the night when loads are low and the compromised transmission system has sufficient import capacity. As a result, the quantity of batteries required, especially when stand-alone reactive support is not also procured, is very large. Because the CAISO report relies on three-year old battery prices to estimate costs associated with these battery-heavy scenarios—particularly Scenarios 1 and 3—appear to be more expensive than the Puente plant.

Fortunately, the Study lays out enough of the analytical assumptions underlying the CAISO's determination of need to allow construction of a fourth scenario that does not require Puente or any other new natural gas plant but relies instead on procurement of preferred resources known to exist in the area lubricated by a much smaller but still

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[1] The "demand response" assumed to be procured in all three scenarios is nothing more than additional distributed, behind the meter battery storage. The small "solar/storage hybrid" assumed to be procured in all three scenarios is held as spinning reserve and the storage batteries dispatched when the daily area load rises above the reduced import limit during the assumed transmission outage. The solar component serves only to extend the battery capacity.

meaningful quantity of new battery storage to mitigate the same identified Local Capacity need.

Although the precise cost of this fourth scenario can only be determined by actually holding an RFO with firm bids to match the firm bid in hand for Puente, using literature values for the cost of the preferred resources yields a very cost effective alternative to the Puente plant.

Finally, a short-term backup plan is available to temporarily bridge the time gap, if any, between retirement of Ormond Beach and Mandalay and Ellwood and the planning, procurement, regulatory approval and construction of the preferred resource alternative. Given this set of facts, the only logical and legal course for the CEC is to reject the Puente AFC pending CPUC authorization to Southern California Edison to conduct a series of preferred resource RFOs to mitigate the Local Capacity deficit when Mandalay and Ormond Beach retire in December 2020.

Comments on the CAISO Study

The CAISO Study suffers from technical assumptions that make its assessment of the amount and cost battery storage necessary to meet the LCR need unrealistically expensive. First, the load forecast that CAISO constructed for the Study is in error due to improper use of the "peak shift" adjustment. The result is that, while the capacity shortfall for mitigation of the Local Capacity need[2] is correct, the energy shortfall is overstated by up to 10% in all of the Scenarios tested.

Second, because of the way the CAISO modeled VAR production from the inverters connecting the batteries to the grid, it missed a huge opportunity to significantly reduce the amount of batteries required. The Study models the battery/inverter voltage support capability in a way that ignores todays' "smart inverters" (including wind turbines) which are much more capable and precise in VAR production. Had the Study accounted for advances in technology, the capital cost to avoid voltage collapse would be roughly \$40M instead of the \$500+M assumed for the batteries in Scenario 1 or the \$50-100M for a stand-alone synchronous condenser assumed in Scenario 2.

Once these assumptions are corrected, the cost of all the scenarios would be substantially reduced. Appendix A to this testimony discusses these two technical details related to these assumptions and how they would affect the cost of the scenarios. The remainder of this section addresses the Study's assumptions about its preferred resource "base case" and their costs.

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[2] The LCR need here is considered N-1-1 and is defined as a prolonged outage of the Moorpark-Pardee #3 230 kv line followed by the loss of the Moorpark-Pardee #1 and #2 230 kv lines during a 1 in 10 year peak load event which causes voltage collapse. Study, p. 6.

1. The CAISO Study does not include procurement of any preferred resources.

The Study claims that all of the Scenarios include a "base case" of 80 MW of new "fast response" DR or "slow response" DR lubricated with short duration batteries to shorten the response time, and also 25 MW of a stand-alone PV/storage hybrid as "preferred resources." In reality, both the "demand response" and the "PV/storage hybrid" are modeled, dispatched, and priced as simply batteries, which are more expensive that true DR or PV. Specifically, the demand response is modeled and priced as much more expensive behind the meter (BTM) distributed battery storage that cannot provide voltage support to the higher voltage grid. The PV/storage hybrid is dispatched as a 25 MW block of spinning reserve for seven hours from roughly noon to 8 pm that then has its 2.5 hours of imbedded storage recharged by system power in the middle of the night.

The Study includes no new preferred resources that are actually procured and dispatched in any of the Scenarios. The CAISO did adopt the idea of enabling "slow response" DR with short duration battery storage by assuming that the existing 30 MW of slow response DR in the Moorpark area could be made to count for Local Capacity by adding 30 MW of 0.5 hour batteries. However, the Study does not include the procurement of any new DR.

As a very conservative bookend to cost/feasibility, these three "all battery" Scenarios are worth running, but hardly represent a realistic picture of a rational alternate procurement strategy. It is worth noting that, during the LCR contingency event, any PV procured would not be plagued by the low capacity value/over-generation duck curve problem typically associated with PV power. The LCR event, by definition, would occur on a hot, sunny, cloudless day, when all the desert located PV that over-saturates the system is cut off by the transmission constraint. As a result, locally generated PV is ideal to meet this LCR need, and the NQC of any local PV procured for LCR mitigation would be very high.

The cost consequence of this "all battery" policy is huge. Slow response DR is available at roughly one-tenth the cost of four hour distributed battery storage and will have a longer duration.[3] This fact alone would reduce the Scenario 2 projected cost from the $309-359M in the Study to well below the estimated $299M cost of Puente. Procuring more PV than the 25 MW "hybrid" and dispatching the PV separately from the storage would significantly reduce the cost of the "base case" for each of the scenarios. In addition, procurement of EE would reduce the cost of any of the scenarios even further. The additional PV, DR and EE would also provide the energy to mitigate the load shedding required by Scenario 2 in the absence of preferred resource procurement.

The Study's failure to even consider procurement of ANY incremental energy

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[3] See TN 217329, Demand Response Potential for California SubLAPS and Local Capacity Planning Areas an Addendum to the 2025 California Demand Response Potential Study, April 1, 2017 at 61; TN# 215438-2, A.16-11-002, Application of Southern California Edison Company for Approval of the Results of its Second Preferred Resources Pilot Request for Offers, November 4, 2016 at 2.

efficiency (AAEE) is another missed opportunity. SCE estimated that a very modest 15 MW of new targeted EE could be procured in this region. However, the Study did not include even this amount of EE, but assumed it was already included in the current CEC forecast for AAEE. However, most of the AAEE imbedded in the current CEC load forecast is baked into appliance efficiency standards and Title 24 requirements for new construction. There is absolutely no good rationale for dismissing even the very modest 15 MW of new targeted EE procurement that SCE estimated in its submittal to the CAISO for this Study. Technical potential studies conducted for the CEC[4] show that ~ 250 MW of incremental cost effective AAEE is technically available in the area and there is a legislative mandate (SB 350) to modify current utility EE programs to procure this amount. The CEC is drafting a study on the issue that is due to be released shortly. Moorpark could be the template where this mandate and proposed program modifications are tested.

2. Storage costs are too high and the system value proposition for storage is ignored.

The agreed upon study design explicitly did not include any cost estimates, yet the CAISO made an attempt anyway. There was good reason for not including costs in the study design. It was supposed to be only a technical analysis with the parties free to proffer their own cost-effectiveness and procurement feasibility analysis at the CEC. The CAISO not only ignored the agreed upon study design, but picked cost assumptions that totally misrepresent the facts. First, the storage costs from the public literature are more than two years old, which is a lifetime in today's market. The particular published reference from selected 2014-2015 projects gives a storage cost of roughly \$460/kwh while all of the current anecdotal evidence from recent publicly available PPAs (mainly from Hawaii and Arizona whereas California's restrictive confidentiality protocols keep this information confidential) say that current utility scale storage costs are roughly \$250/kwh and 2-3 year forward cost projections are on the order of \$150/kwh.[5] At a minimum, there are more recent public generic storage costs estimates available than the one cited by the CAISO.[6] The only way to settle this issue is to actually hold an RFO, procure the resources and publish the results. Under the circumstances, this would be the appropriate policy response.

Even more to the point, however, is that the initial capital cost of the various alternatives is nowhere near a complete picture of cost effectiveness. The Study notes this deficiency, but goes on to opine that a complete analysis would show even worse cost effectiveness for the all battery alternative because battery life is less than Puente.[7] Batteries indeed have a projected life of roughly 10 years in this service and would need to be replaced at least once to equal the 20 year life of the Puente PPA. However, the

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[4] TN 217328, Guidance on interpreting the forecast and production cost model for energy efficiency, Resource Consultants, LLC, August 7, 2015 at www.lowcarbongrid2030.org.

[5] http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/pr/pr2017-0110-AES%20Solar.pdf

[6] Lazard's Levelized Cost of Storage -- Version 2.0 December, 2016.

[7] Study, p. 24.

study assigns 100% of the capital cost of all alternatives to this LCR mitigation. While this is appropriate for Puente, it totally ignores the significant system value of the batteries and preferred resources during the hours that Moorpark area loads are below the voltage stability limit and they are freed to earn other revenue. A complete cost effectiveness analysis that takes these factors into account would be much more favorable to any "preferred resource" alternative rather than Puente.

In Puente's case, the project value is indeed virtually only LCR mitigation. Because there already is a large surplus of gas generating facilities even after the retirement of all of the OTC plants and Diablo Canyon, construction of Puente means some like amount of gas capacity elsewhere in the State that has no LCR value will be forced to retire or be subsidized with above market capacity payments in order to survive. Thus Puente provides no *net* system RA capacity value, no net "Flex RA" value, and exposes ratepayers to potential gas price spikes/resource availability issues such as Aliso Canyon, and rising GHG allowance prices.

On the other hand, the conditions that require potential LCR mitigation only occur, at most, some 30 days/year and any battery/preferred resources built to mitigate this contingency are freed to provide system value for the other ~330 days/year. The precise value of the non-LCR system benefits of preferred resources can be argued, but there is no denying that they are significant today and growing in the future.

The next two sections discuss these issues in more detail.

What the Study Says About Puente Operations

The Study does give granular hourly data about the operation of the Puente plant during the LCR event that is postulated to occur during a five-day, 1 in 10 year heat storm. Because the load on each of the five days is above the voltage stability limit if the LCR event were to occur, and the consequence is voltage collapse, Puente must be committed pre-contingency each and every day of the heat storm. It would run for up to 10 hours per day with a near maximum dispatch between the hours of 4-6 PM on Day 3 (the highest load day of the five day event) if the transmission outage were to occur.[8] Otherwise, if the transmission system remained intact, Puente would be committed pre-contingency and sit idling at minimum load with a poor heat rate crowding out more efficient and lower emission resources much of the time. Further, CAISO's Study for the 2013-2014 Transmission plan[9] gives historic load duration curves for the Moorpark area showing approximately 150 hours per year where the area load exceeds the voltage support limit without additional new reactive support measures. This means that Puente would be committed and on line as reliability must run for roughly 30 days per year at an average of 5 hrs/day.

LCR mitigation is the sole value for the $300M Puente project. There is a large

[8] See Study, p. 32-34 (Tables A-1a, A-2a, and A-3a; line 6.)

[9] "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process" CAISO, September 4, 2013, p. 18.

surplus of generic natural gas plants in California, and this surplus looms large well into the future. All of the identified "need" for new gas fired resources in the past 7 to 10 years arises not from system requirements for generic capacity or flexibility to integrate renewables but for local contingency related reliability considerations like the identified Moorpark LCR need.

As part of its 2016-2017 Transmission Plan, the CAISO conducted a special study titled "Risk of Early Economic Retirement Gas Fleet."[10] In this study, the CAISO looked at the need for natural gas facilities following all of the pending retirements of the Korean War era plants along the coastline that use once through ocean cooling, the retirement of Diablo Canyon, and the large investment in new renewable resources to attain the 50% RPS target. After screening out all of the gas facilities that, by location, served an LCR need, and therefore, like Puente, would receive fixed capacity payments for "reliability," the CAISO identified roughly 9000 MW of natural gas plants that are "system resources" (have no LCR capability) and are available to supply generic capacity and flexibility for renewable integration. The study found that even under a conservative view of the availability of capacity and flexibility from outside the CAISO boundaries, roughly half of that 9000 MW were not needed for either capacity or flexibility within CAISO and thus would not be eligible to receive fixed capacity payments from the CPUC's Resource Adequacy (RA) program. Instead, they would only receive the revenue they could bring as merchant facilities in the energy market in competition with other gas plants that already had their fixed costs covered outside the market. Since prices in the energy market are projected to decline as zero marginal cost renewables make up a growing share of the energy supply, the study concludes that these 4000-6000 MW of gas plants are at significant risk of early economic retirement.

These results were recently confirmed by preliminary modeling for the Integrated Resource Plan where the CPUC found no need for new natural gas plants like Puente for system capacity under a broad range of load and resource scenarios.[11]

It is worth noting that most of these at-risk plants are significantly more efficient than and at least as flexible as Puente. It is also worth noting that because a large surplus of existing plants will be chasing a limited requirement for the fixed capacity payments, capacity prices will be well below what is called cost of new entry or "CONE" that Puente is being paid under its CPUC approved PPA with Southern California Edison. Thus, the construction of the 262 MW Puente plant will only lead to higher Resource Adequacy costs, the retirement of some other plant(s) of like capacity from that list of 4000-6000 MW at-risk plants, and there will be no net incremental capacity and no incremental flexibility on the CAISO grid after Puente is operational.

Thus, leaving aside for a moment the legitimate question of how to meet the LCR need for the Moorpark area, Puente will be one of the highest cost facilities on the grid,

[10] TN 217325, Board Approved 2016-2017 Transmission Plan, March 17, 2017 p. 203-213.

[11] Preliminary RESOLVE Modeling Results for Integrated Re
source Planning at the CPUC, CPUC Energy Division, July 19, 2017 Slide 73.

will have no system capacity value, and no net renewable integration value.

It is likely that the construction of Puente will cause the overall gas fleet dispatch efficiency to decline and more gas will be burned in the non-attainment area of California (specifically Oxnard). The 150 or so hrs/year in which Puente will be committed and online to meet LCR need are highly correlated with the hours of worst air quality and highest summer natural gas sendout in the greater Los Angeles Basin. Thus, both criteria pollutant and greenhouse gas emissions will increase. There will be more pressure to keep the natural gas storage facility at Aliso Canyon open, and more pressure to invest in the natural gas pipeline infrastructure as gas burn becomes more concentrated in the Southern California urban coastal basin.

To add insult to injury, Puente will not even be very good at performing its single remaining duty of being on standby in case of the rare but otherwise serious loss of the major electric transmission corridor into the Moorpark area. At 262 MW on one large shaft, Puente will place all of the reliability eggs in one basket. The GE Frame 7HA.01 turbine that Puente will use is designed to operate flat out at full load in so-called combined cycle mode for maximum efficiency as a "baseload" resource. It has a high "Pmin" (minimum generation) of some 85-90 MW, which risks crowding out and curtailing renewable energy with unnecessary gas during light load spring and fall months. Although capable of relatively quick starts and of being "ramped" (accelerated and/or braked at less than full output), the long heavy shaft with tight blade clearances simply does not tolerate well the high thermal and mechanical stresses associated with the emergency starts, jamming on the accelerator and stomping on the brakes that this duty implies. The result will be higher "forced outage rates", i.e., failure to answer the bell when called—potentially leading to the very catastrophe the plant was designed to prevent.

Puente will see approximately 30 "emergency starts" per year as the area load increases above the voltage stability limit on hot days. Meeting the LCR needs depends on Puente being operable on all 30 of these days. Puente will also incur higher operating and maintenance costs and/or the plant will be treated conservatively when called upon such as slower starts in advance of the actual increase in load above the voltage stability limit "just in case."

At only slight risk of hyperbole, Puente could be compared to using a sledgehammer to crack a walnut.

A True Preferred Resource Scenario

Although the CAISO study does not include a true preferred resource scenario, a variation of Scenario 2, that includes true DR and PV, would meet the technical specifications identified by CAISO for the LCR need. This Scenario 4 would include reinstating and expanding the Goleta RFO to procure—at a minimum—the 135 MW that CAISO assumes are available in the Moorpark subarea in addition to the resources initially sought in that RFO. Coupled with that would be two RFOs to procure dynamic reactive power and incremental AAEE to enable the ultimate retirement of not only

Mandalay 1 and 2, but also Mandalay 3 and Ellwood. Appendix B sets forth recent developments in preferred resource procurement demonstrating why these resources are feasible.

Last year, Southern California Edison initiated a preferred resource RFO[12] in the Goleta sub-area of the Moorpark region.[13] The objective was to procure approximately 55 MW of LCR qualified preferred resources to mitigate SCE's identification of another reliability need in the area. Goleta comprises approximately 15% of the total load in the larger Moorpark region. That RFO was suspended due to uncertainty surrounding the continued operation and an expensive refurbishment of the 54 MW Ellwood peaker located at the end of the 230 kv transmission system north of Santa Barbara.

Given the results of this CAISO Study, and the obvious limitations of the Puente project to meet either the State's long term resource goals or to provide a resilient, lasting solution to the Moorpark LCR need, the appropriate response to the uncertainty should be to expand the RFO to include the entire Moorpark region. This RFO should expand the procurement objective to at least 250 MW, which would include the initial procurement, include the 135 MW CAISO assumes in its "base case," and potentially allow for the retirement of Ellwood. Minor modifications to the existing RFO, mostly in the way of clarifications are warranted in addition to the geographic and quantity expansions:

- Clarify that "slow" demand response is indeed eligible for this LCR procurement if paired with a minimum of 0.5 hr of dedicated battery storage to allow effectively calling the entire demand response quantity within 20 minutes.

- Clarify that the need to dedicate the preferred resources procured to LCR mitigation and incur the tariffed obligations this entails is limited to days of the year when area load is forecasted a day ahead to exceed the voltage support limit of the Moorpark region as calculated in Scenario 2 of this Study and/or the analogous import limit of the Goleta sub-area. Energy limited resources such as battery storage are required to remain fully charged and on standby reserve during these defined periods, but are free to be utilized for other uses in other days of the year. As available energy resources are required to dedicate 100% of their output to serve the LCR need during these defined high load days. Respondents are to bid the required fixed payment to dedicate the resource to LCR duty when required and a variable energy payment if actually called to produce energy to mitigate an LCR need. Value streams earned in days of the year outside the defined LCR periods are not considered or payable to SCE under the terms of this RFO.

- Clarify that the NQC of solar resources for the purpose of meeting the LCR need will be calculated by an ELCC methodology that considers the particular circumstances of import restrictions and weather conditions during the defined

[12] TN 217331, Goleta Area Request for Offers https://scegarfo.accionpower.com.
[13] Goleta is the northwestern sliver of the Moorpark region and includes the city of Santa Barbara.

LCR event.

Two other RFOs should be conducted in parallel with this preferred resource procurement. First, procurement of dynamic reactive power support totaling 250 MVAR in the Moorpark area with an appropriate portion of that capability located in the Goleta sub-area. Consideration is to be given to devices that provide inertia and short circuit current duty as well as MVARs as appropriate. Co-location with preferred resources from the first RFO is encouraged. Second, conduct an AAEE procurement for the Moorpark region intended to be additional to existing and currently planned energy efficiency procurements and targeted at reducing demand during peak load hours. This procurement would take notice of the pending CEC report on SB 350 AAEE procurement. In concept, it would be similar to PG&E's proposed AAEE procurement in the Diablo Canyon proceeding.[14]

It will clearly take time to plan, award, permit, give regulatory approval for cost recovery, and construct resources under these RFOs. Based on the response to the Aliso Canyon closure and the procurement and installation of battery operations within 8 months, it is reasonable to expect that much of the 135 MW identified by the CAISO Study are available and can be brought on line by December 2020, when Ormond Beach and Mandalay 1 & 2 are slated to retire. Any remaining LCR need can be addressed by short term contracting with Ellwood, Mandalay 3 and, potentially, temporary conversion of Mandalay 1 or 2 to synchronous condenser operation to supply reactive support until the permanent reactive support facilities are in operation.[15]

What The Study Says About Operation of the Preferred Resource Alternative

In stark contrast to mitigation with Puente, mitigation with a Preferred Resource Alternative Scenario 4—that is, the variation of Scenario 2 detailed above will operate significantly differently than Puente or the CAISO Scenario 1 and be much more resilient. The first key is the provision of enough dynamic voltage support to mitigate voltage collapse. The Study models this procurement in Scenario 2 as a single large synchronous condenser at Mandalay. However, as explained Appendix A, sufficient VARS could be provided in a variety of ways.

As shown in Figure 3-3,[16] the provision of 250 MVAR of voltage support pre-

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[14] PG&E EE Procurement Plan for Diablo: A.16-08-006 Revised PG&E Testimony 2/27/17 Chapter 4 pp. 4-1, 4-11.

[15] Although not included in the Study parameters, even if Mandalay 3 and Ellwood were not available for short-term contracting, there is precedent for extending the OTC deadline to ensure local reliability needs are met. *See* 2017 Report of the Statewide Advisory Committee on Cooling Water Intake Structures; SACCWIS Encina Power Station 2018 Reliability Study Report; Appendix A, Proposed Amendment to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plan Cooling, adopted August 15, 2017.

[16] Study, p. 15.

contingency raises the voltage stability import limit from 1473 MW to 1582 MW and reduces the amount of real power that must be supplied by the preferred resources on the peak day from 1491.5 MW-H to 530 MW-H or a reduction of almost two-thirds.[17] In addition, this provision of reactive support reduces the duration of the "event" from nine hours to seven hours if the peak shift error is not corrected and from eight hours to five hours if the peak shift correction is made. Finally, Scenario 4 reduces the number of hours per year where load is above the voltage stability limit and some action must be taken, even if only pre-planning for spinning reserves, from approximately 150 hours with Puente or the battery only Scenario 1 to approximately 40 hours per year—a reduction of almost three- quarters.

Second, because voltage collapse has been avoided, the threat of immediate blackout when the transmission line trips no longer exists, and there is time to redispatch the system to call on spinning reserves before the remaining in service transmission lines exceed their thermal limit rating. In this case, because any energy efficiency or solar energy will already have been dispatched to reduce the "remaining load to be served," spinning reserves would come from the new battery storage backed up with demand response that would be called up post contingency. However, in contrast to Scenario 1, where the only energy available to recharge the battery storage is system power in the middle of the night, under Scenario 4, the local availability of energy efficiency, demand response, and solar energy during the event itself means that the amount of energy that must be stored in the batteries is significantly less and the duration of that supply significantly shorter. Finally, the largest difference is that real power only needs to be actually supplied if the transmission outage actually occurs rather than being dispatched pre-contingency in Scenarios 1 and 3.

Because the preferred resources are distributed throughout the region and come from diverse technologies as opposed to one single large shaft using one technology and one fuel source, the preferred resource mitigation package is much more resilient. The cost differential is stark. The Study estimates the cost of Scenario 1 at $805 M and Scenario 2 at $305-359M. The Preferred Resource alternative is cheaper than both Scenario 2 and Puente at $299M because the capital cost of energy efficiency, demand response, shorter duration battery storage, and solar net of other system revenue streams is less than the dedicated long-duration battery storage that underlies all of the CAISO scenarios. Precise cost estimates would require the actual results of the RFO(s) and be subject to confirmation by the CAISO that enough preferred resources were procured to mitigate the identified LCR need[18] A Preferred Resource variant of Scenario 3 would indeed add some expense, but the expense of refurbishing the 45-year old Ellwood facility would be avoided as well as the fuel expense, and GHG emissions and criteria pollutant emissions associated with Ellwood operation.

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[17] [Table A-1a Sum of Load to Serve (line 6) for hours 12-21] vs. [Table A-4 Sum of Load to Serve (line 6) for hours 13-20].

[18] This confirmation would be similar to the "Step 3" process used in the Study.

Declaration of Jim Caldwell

1. I am a consultant with V. John White & Associates and the Center for Energy Efficiency and Renewable Technology. A copy of my qualifications was previously docketed as TN 215438-1.

2. I am personally familiar with the facts and conclusions related in the testimony attached to this declaration, and if called as a witness could testify competently thereto. It is my professional opinion that my testimony is valid and accurate with respect to the issues presented therein.

I declare under the penalty of perjury that the foregoing is true and correct.

Executed August 30, 2017 at Sonoma, California.

Jim Caldwell

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Appendix A

This appendix addresses two of the technical shortcomings in the CAISO study that result in an overestimate of the amount of batteries needed in all of the alternative scenarios.

1. The Study Relies on an improper use of the "peak shift" in the load forecast

The load forecast that CAISO constructed for the Study is in error due to improper use of the "peak shift" adjustment. The result is that, while the capacity shortfall for mitigation of the Local Capacity need[1] is correct, the energy shortfall is overstated by up to 10% in all of the Scenarios tested.

The "peak shift" adjustment to CEC load forecasts is a temporary adjustment while CEC updates their forecasting methodology to a true hourly model.. The current CEC forecasting methodology starts with recent loads and load shapes and forecasts the impact of variables, such as future behind the meter PV that impact future load but retains the current load shape. This methodology misses the change in load shape and the uptick in net load as the sun goes down and output from rooftop PV declines sharply. To mitigate this weakness in the forecasting model, the CEC has temporarily adjusted its forecasts by adding an exogenously calculated "peak shift" to the early evening hour to arrive at a better peak load estimate. There is currently no announced schedule for when the model will be "fixed" permanently, but the quantity of the calculated "peak shift" to be added to the calculated future peak load is well documented and adequate for most uses. For this Study, however, the CAISO needs not simply the instantaneous peak load, but the duration of loads above the voltage stability import limit to calculate the energy shortfall to be met at the margin by new storage located in the Moorpark sub-area.

CAISO calculated the 2022 peak load based on scaling the 2014, 2015 and 2016 load shapes but improperly added the late afternoon energy from the "peak shift" before scaling the historic load shapes without subtracting the energy that would be produced earlier in the day by the incremental PV that causes the peak shift. As a result, the load forecasts used for all the alternative analyses adds 53 MWH to the peak load[2] to be mitigated by the Local Capacity resources when it should have subtracted ~ 53 MWH of energy *net* (lower midday load and higher early evening load). This means that ~106 MWH of extra battery storage is required.[3]

This is simply a methodological error that artificially inflates the energy and thus the amount of battery storage required. Another way of looking at it is that the actual load shape will be "peakier" than the modeled load shape, so although the MW quantity of batteries is not wrong, the MWH is too high. Procuring the additional MWH drives up the duration and cost of the

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[1] The LCR need here is considered N-1-1 and is defined as a prolonged outage of the Moorpark-Pardee #3 230 kv line followed by the loss of the Moorpark-Pardee #1 and #2 230 kv lines during a 1 in 10 year peak load event which causes voltage collapse. Study, p. 6.
[2] Study, p. 10.
[3] The precise number is a little more complicated because not all of the energy from the new behind the meter solar PV occurs when the area load is above the voltage stability limit and intervention is required, plus efficiency losses need to be considered.

storage required.

2. The Study relies on inadequate and expensive voltage support in Scenario 1 and 3.

Because of the way the CAISO modeled VAR production from the inverters connecting the batteries to the grid, it missed a huge opportunity to significantly reduce the amount of batteries required. The battery/inverter voltage support capability is modeled in the Study as +/- 0.95 power factor with VAR production proportional to real power output like a synchronous generator. This is the current CAISO interconnection standard for non-synchronous generation and is derived from FERC Order 661 circa 2005.[4]

Today, "smart inverters" (including wind turbines) are very different and much more capable and precise in VAR production. Today's inverters are "full 4 quadrant" machines that can be electronically controlled precisely to produce MW and MVAR independently up to the MVA rating of the inverter. Thus, the so-called "P-Q Curve" of MW and MVAR is a full circle with a radius of the MVA rating of the inverter. This feature is very useful during the shoulder hours of the load increase/decrease when the LCR mitigation can be VARs only thus saving the energy stored in the batteries for the highest peak load hours. As the CAISO points out, during the higher peak hours, you need both MW and MVAR simultaneously, so the limit of the inverter MVA rating limits the usefulness of this capability. The Study alludes to the possibility of "oversizing the inverter" to remove this restriction.[5] A better way is to simply add a conventional static var compensator (SVC) to the battery installation(s).[6] An SVC is a widely used source of combustion free reactive support that is effectively nothing more than a stripped down inverter but roughly 20% cheaper.

Even more to the point, in this case, inexpensive SVCs can partially substitute for long duration batteries that are roughly 7-10 times more costly. It is difficult to precisely calculate the impact of taking this route without rerunning the power flow models to recalculate the new voltage stability limit for each case, but a rough approximation can be seen by comparing Scenario 2 with Scenario 1. In Scenario 2 the CAISO added a large stand-alone synchronous condenser to supply VARS, inertia, and short circuit current to the grid that has very little synchronous generation. The addition of that 250 MVAR synchronous condenser reduced the battery requirement by 1125 MWH from Scenario 1[7]costing over $500M at the "inflated" battery cost used in the study as compared to an expenditure of $50-100M for the stand-alone synchronous condenser. Larger reductions in required battery duration would be achieved in Scenario 3 as well.

If, instead of one large synchronous condenser, one were to use multiple SVCs to supply VARS (or a smaller synchronous condenser plus some SVCs if there is a need for inertia and/or short

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[4] This reasonably represented the capability of wind technology 12-14 years ago -- solar was not a factor at that time.

[5] Study, p. 9.

[6] The installation could be stand alone, but it is cheaper and the control logic is simpler if the SVCs are co-located with the batteries/inverters.

[7] 125 MW of 9 hour batteries. See Study p. 21.

circuit current), the capital cost to avoid voltage collapse would be roughly $40M instead of the $500+M from the long duration batteries.

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Appendix B

(Compendium of Preferred Resource Advancements Since 2014)

- The CPUC commissioned a study of the technical potential for Demand Response in California by Lawrence Berkeley National Laboratory. The study concludes that there is sufficient technical and economic potential for LCR qualified demand response in the Moorpark sub-area at less than one-tenth the cost of Puente.[1]

- Southern California Edison conducted an LCR RFO in Orange County called the "Preferred Resource Pilot 2." The RFO led to contracts totaling 125 MW of preferred resources that satisfy LCR criteria. These contracts are now before the Commission for approval.[2] The Orange County area covered by the RFO is similar in size to the Moorpark sub-area.

- Investments in energy efficiency (AAEE) acquired under existing utility programs plus customer sited "rooftop solar" installations have combined to reduce the Moorpark area 10-yr ahead peak electric load forecast by 20% over the past three years[3] in the face of population expansion and economic growth. It should be noted that the quantity of installed and forecast rooftop solar installations is significant enough to move the peak load hours to later in the day as the sun is setting. Thus, additional solar installations from now on will have little additional effect on peak load for purposes of setting LCR need. However, new programs to implement the SB 350 mandate to cumulatively double energy efficiency savings are not yet in place. Technical potential studies conducted as an addendum to current CEC forecasts confirm that enough technical potential exists at acquisition costs below forecasted marginal electricity prices to achieve this doubling with current technology.[4]

- The CAISO conducted field trials to verify the ability of "smart inverters" to supply a range of essential reliability services relevant to the Moorpark LCR need.[5] Several of

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[1] TN 217329, Demand Response Potential for California SubLAPS and Local Capacity Planning Areas an Addendum to the 2025 California Demand Response Potential Study, April 1, 2017 at 61.

[2] TN 215438-2, A.16-11-002, Application of Southern California Edison Company for Approval of the Results of its Second Preferred Resources Pilot Request for Offers, November 4, 2016 at 2.

[3] CEC forecasts and CAISO forecasts derived from the CEC forecasts for the Moorpark region encompass slightly different geographic boundaries. Data presentation changes over the past four years as well as changes in how AAEE is accounted for make precise direct year-to-year comparisons difficult. The 20% number is an interpolation based on data presented in the 2014 CAISO TPP vs. the 2016 CAISO TPP.

[4] TN 217328, Guidance on interpreting the forecast and production cost model for energy efficiency, Tierra Resource Consultants, LLC, August 7, 2015 at www.lowcarbongrid2030.org.

[5] TN 217327, Using Renewables To Operate a Low-Carbon Grid, CAISO, First Solar, NREL, Jan 11, 2017 at www.caiso.com/about/Pages/News/Default.aspx.

these inverters capable of supplying at least dynamic voltage support to mitigate voltage collapse have already been installed in the Moorpark region.

- On March 3, 2017, Southern California Edison issued an LCR RFO[6] for up to 55 MW of distributed resources in the "Goleta" sub-area to mitigate an N-2 contingency for the transmission corridor into Santa Barbara that is similar to the N-1-1 Moorpark contingency at issue here. Any resources acquired through this RFO would count against the Moorpark LCR need as well as the Goleta LCR need. Goleta represents roughly 15% of the Moorpark region customer load. Preliminary results will be available early this summer.

- As part of its 2014 Energy Storage RFO, Southern California Edison signed contracts for 15 MW/60 MWH of LCR capacity with a 20 MW/80 MWH battery storage facility at the Wakefield substation in Santa Paula.[7] 5 MW of this installation has already been energized and cost recovery approved under the Aliso Canyon Resolution to mitigate that gas reliability need.[8] This installation not only counts towards filling the Moorpark LCR need, but also supplies 20 MVAR of dynamic voltage support to the region that raises the reactive margin and additionally reduces the LCR need.

- Southern California Edison retrofitted two of its six new peaking plants (Center and Grapeland) with General Electric Enhanced Gas Turbine or "EGT" technology.[9] The EGT package is a modestly priced relatively small battery pack and a software/firmware package that not only increases the peaking plant's effective capacity to mitigate an LCR need, but, very importantly, increases the unit's flexibility and enables treating the entire facility as "spinning reserve" and adds significant dynamic voltage support *without* combustion. Each of these features contributes toward reducing an LCR need such as Moorpark and provides greenhouse gas-free essential reliability services consistent with the long-term State goal to decarbonize the electric grid. The McGrath peaker adjacent to the Puente site is an identical model gas turbine of the same vintage as the gas turbines at Center and Grapeland and could be retrofitted in the same manner. SCE has already approached the City of Oxnard regarding this upgrade.

- There are 45 MW of so called "slow response" DR in the Moorpark region.[10] This existing resource currently does not count towards mitigation of the LCR need because it takes longer than 20 minutes to activate. This activation time, along with the 10 minutes

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[6] TN 217331, Goleta Area Request for Offers https://scegarfo.accionpower.com. The addendum to this report explains why SCE's recent suspension of the RFO does not affect the viability of the Preferred Resources Alternative outlined here.

[7] D.16-09-004.

[8] TN 217333, SCE Advice Letter 3454-E, August 15, 2016.

[9] TN 217326, A.17-03-XXX, March 30, 2017. Testimony in Support of Application of Southern California Edison Company for Recovery of Aliso Canyon Utility Owned Energy Storage Costs, Section B, at 46-51.

[10] TN 217330, CPUC, A.14-11-016, Exhibit No. ORA 7 Data Request Responses from Southern California Edison Company, Nov 1, 2016 at 34.

required to dispatch the resource following the contingency event, means that the resource is not available in time to meet the NERC/WECC/CAISO reliability standard of returning the system to a secure state within 30 minutes of the N-1 event. Therefore, it cannot be counted as mitigation of the LCR need. However, the EGT package retrofitted to the McGrath peaker has sufficient battery storage to be used to bridge that 10-30 minutes of time to activate the slow start demand response. Together the EGT package and the slow response DR add 45 MW of LCR mitigation that neither alone can provide. Alternatively, this 45 MW of existing DR could be paired with other new short duration battery storage, which together would mitigate the LCR need.

- On April 10, 2017, bids were due for Southern California Edison's so called "DRAM III" (Demand Response Auction Mechanism III) RFO to procure demand response resources in its service territory. Based on results of its DRAM II RFO last year and the dramatic year-to-year increases in quantity and reductions in price for preferred resources across all similar RFOs, it is highly likely that significant preferred resources capable of mitigating the Moorpark area LCR need will be swept up in this RFO. Preliminary results will be available this summer.

- The CAISO and the CPUC are conducting a joint initiative designed to develop clear tariff rules and practices to allow a significantly larger fraction of current Demand Response resources to count for LCR capacity under CPUC procurement rules. In addition, the objective is to significantly lower the cost of actually bidding DR resources into CAISO markets and expanding the availability of new customers for participation in new programs for mitigating an LCR need such as Moorpark. Two workshops have been conducted in this process and a third Workshop scheduled for mid-May will discuss preliminary results of studies designed to quantify the impact of this initiative for next year's RA procurement. Thus, results relevant to this AFC alternative will be available this summer.

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