The ISO received comments on the topics discussed at the February 14, 2019 stakeholder meeting from the following:

1. Bay Area Municipal Transmission group (BAMx)
2. Bonneville Power Administration (BPA)
3. Cal Energy Development Company LLC (CEDC)
4. California Public Utilities Commission – Staff (CPUC – Staff)
5. GridLiance
6. Hydrostor Inc
7. Imperial Irrigation District (IID)
8. LS Power (LSP)
9. North Gila Imperial Valley #2, LLC (NGIV2)
10. Nevada Hydro Company (NHC)
11. National Resource Defense Council (NRDC)
12. Pacific Gas & Electric (PG&E)
13. Public Advocates Office (PAO)
14. San Diego Gas & Electric (SDG&E)
15. Smart Wires Inc
16. Tenaska
17. University of California Office of President (UCOP)

Copies of the comments submitted are located on the 2018-2019 Transmission Planning Process page at:

http://www.caiso.com/planning/Pages/TransmissionPlanning/2018-2019TransmissionPlanningProcess.aspx

The following are the ISO's responses to the comments.

1. Bay Area Municipal Transmission Group (BAMx) Submitted by: Moisés Melgoza		
No	**Comment Submitted**	**CAISO Response**
1a	<u>Review of Previously Approved Transmission Projects</u> BAMx applauds the CAISO's work in the past four years to review previously approved transmission projects to make sure they are still needed in light of the changing energy landscape. So far, CAISO's effort resulted in over $3.25 billion of project cancellations and scope reductions. While reviewing all the transmission projects represented a significant commitment of engineering resources, the resultant savings for transmission system users was simply enormous. For instance, BAMx estimates that a reduction in $3.25 billion of capital expenditure, the majority of which is associated with the low voltage transmission facilities would reduce the PG&E-specific low voltage transmission access charge (LV TAC) by approximately $3.75-$4.25/MWh in 2025. The effort within this 2018-2019 transmission planning cycle represents a significant milestone, and BAMx encourages the CAISO to continue with this task. a) First, BAMx encourages the CAISO to establish a process whereby once transmission projects are approved, they are continuously reviewed as to their necessity and scope at least until the project starts construction. Targeted review of projects should especially be initiated for those that (i) have been delayed beyond their initially proposed on-line dates and (ii) with on-line dates during the second five-year period of the ten-year planning horizon. b) Second, there generally tends to be significant and chronic cost escalation after a transmission project is approved by the CAISO. Some examples from the Draft Plan include: (i) Cottonwood-Red Bluff 60 kV line and substation - 426% increase (ii) South of San Mateo Capacity - 900% increase (iii) Morgan Hill Reinforcement - 677% increase, (iv) West of Devers 230 kV Upgrade - 163% increase from $384 million to $1.01 billion Projects presented during this planning cycle were re-evaluated with information on their burgeoning costs. Obviously, it is critical that the CAISO	The comment has been noted. As previously indicated, the ISO will continue to review previously approved projects in the ISO transmission planning process on a case by case basis.

No	Comment Submitted	CAISO Response
	and stakeholders have the up-to-date cost information since such cost increases can materially impact the selection of the preferred alternative and overall scope of work. BAMx also recommends the CAISO monitor cost escalation and include cost information in the final transmission plan (e.g. Chapter 8 - Transmission Project List). The CAISO and stakeholders can then use this cost information to determine if any project cost increase or scope creep should trigger a detailed project review consistent with the work performed by the CAISO in the past several planning cycles. The significant increases in costs that are occurring after the CAISO approves a project makes some type of process - such as the one we suggest - extremely important.	
1b	<u>Deliverability Assessment Methodology (DAM)</u> BAMx has consistently encouraged the CAISO to regularly review the production levels of wind and solar that are assumed in deliverability studies. The resulting capacity assumptions are critical because they directly influence procurement and associated new transmission and interconnection investment decisions to meet the state's Renewable Portfolio Standards (RPS) targets. With the delay in the implementation of the revised Deliverability Assessment Methodology (DAM), it appears that the 2019-2020 TPP portfolios will continue to use the existing DAM. This appears to be a response to stakeholder comments. BAMx does not support such a delay. Many years have passed since a State law was passed to implement the Effective Load Carrying Capability (ELCC) methodology. We understand most of the delay has been due to complications of implementation at the California Public Utilities Commission (CPUC). But implementation delay in recognizing the impacts on deliverability studies at the CAISO further exacerbates the delay. We urge the CAISO not to approve any delivery network upgrades identified in the 2019-2020 Transmission Planning Process (TPP) resulting from high production levels of wind and solar for deliverability because of the delay in the revised DAM implementation.	As communicated in a recent market notice, the ISO will continue its consultation with stakeholders on this important initiative in 2019. Transition discussions can be held at that time. For clarity, policy-driven transmission is approved in the transmission planning process, and delivery network upgrades are determined in the generation interconnection and deliverability allocation process.
1c	<u>BAMx Supports Including EODS Resources in Renewable Portfolios</u> The renewable portfolios modeled in the TPP include a mix of resources with Full Capacity Deliverability Status (FCDS) and Energy Only Deliverability Status (EODS). The Draft Plan states that some stakeholders have been critical of the	The comment has been noted.

No	Comment Submitted	CAISO Response
	consideration of energy-only renewable generation to meet a portion of future RPS requirements. EODS projects are equally as effective as FCDS resources in meeting California's RPS target and are more cost effective for ratepayers. Furthermore, the resource adequacy credits associated with the renewables, primarily solar generation, is expected to drop significantly with future increased penetration. Therefore, it would be economically inefficient to build transmission upgrades to accommodate the deliverability of FCDS resources built for RPS purposes. BAMx strongly supports the CPUC, CEC and CAISO efforts in developing renewable portfolios that recognize that FCDS resources should only be selected when the capacity credit for those resources justify any increase in costs to accommodate the transmission needs for the desired deliverability.	
1d	<u>Need for Additional Coordination Between CPUC IRP and CAISO TPP</u> The CAISO 2018-2019 policy-driven assessment found the need for some major transmission upgrades and generation dropping Remedial Action Schemes (RAS), in the Eldorado-Mountain Pass-Southern NV area to mitigate large amount of congestion and transmission overloads. It was explained during the February 14th stakeholder meeting that this was a consequence of (a) modeling a large amount of solar and wind resources in these areas, (b) being mapped to transmission constrained locations, and (c) modeled at high production levels based upon the existing DAM. We appreciate the CAISO's due diligence in providing updated transmission capability amounts as well as renewable resource location selection (resource mapping), which would avoid such artificial issues in the 2019-20 TPP and also in future years. BAMx believes that the CPUC's Integrated Resource Planning (IRP) process is an appropriate forum to determine economic tradeoffs between retaining existing generation and reducing that need via new transmission or new local resources. The capacity expansion models such as RESOLVE utilized in the CPUC IRP proceeding are more suitable for performing any economic comparison of alternatives for meeting Local Capacity Requirements (LCR) than the CAISO TPP by itself. In particular, RESOLVE includes a constraint that requires that sufficient new generation capacity must be added to meet the local needs in specific LCR areas.	The comment has been noted. The ISO agrees that longer term direction from the integrated resource planning proceedings regarding overall direction on gas-fired generation resource needs is necessary for the ISO's study assumptions to shift from the conservative approach taken in this year's planning cycle for valuing local capacity requirement reduction benefits. Individual transmission planning decisions, however, remain within the ISO's transmission planning process.

No	Comment Submitted	CAISO Response
	To characterize these local capacity needs, RESOLVE relies predominantly on the CAISO's TPP. In other words, a flow of information from the CAISO's TPP to the CPUC IRP for the study of local capacity needs exists today. Similarly, the determination of the least-cost best-fit alternatives to meet LCR needs in the CAISO TPP needs to rely on the CPUC IRP process as such is better equipped in evaluating competing resource alternatives such as retaining natural gas generation, adding local renewables, energy storage, and demand response.	
1e	LCR Reduction Study BAMx appreciates the CAISO's significant efforts on the LCR Reduction study included in the draft 2018-2019 Transmission Plan. BAMx finds these informational studies to be very helpful in reviewing the options to maintain local reliability. We endorse the CAISO's comprehensive approach that not only considers (i) the reliability benefits of competing mitigation solutions including transmission and storage resources, but also assesses (ii) the production benefits and (iii) the local capacity benefits. BAMx encourages the CAISO to engage stakeholders with further discussions in the 2019-2020 TPP and through the CAISO's participation in the CPUC IRP process.	The comment has been noted. The ISO will be continuing to assess the remaining LCR areas that were not yet studied as a continuation of the 2018-2019 transmission planning process.
1f	Recommended Reliability-Driven Projects *Round Mountain and Gates 500 kV Dynamic Voltage Support Projects* There are two proposed voltage support projects in the PG&E service area: (1) Round Mountain 500 kV Dynamic Voltage Support ($160M-$190M) and (2) Gates 500 kV Dynamic Voltage Support ($210M-$250M). For the identified voltage issues at the Round Mountain and Gates 500 kV Bus facilities, the CAISO recommends a ±500 Mvar and a ±800 Mvar dynamic reactive support device at the Round Mountain and Gates 500 kV substations, respectively. BAMx believes that the choice of technology for these mitigations requires further examination and justification. The threshold questions are both the type and amount of reactive control needed. If simple switchable shunt reactors are insufficient by themselves, would a system of voltage devices, in a combined basis, be adequate? For example, a combination of Static VAR Compensators (SVC) and Static Synchronous Compensators (STATCOM) could be an effective and more cost-efficient solution rather than adding an 800MVar of	The Round Mountain 500 kV Voltage Support Project has to provide dynamic voltage support, and it can be partly made up of an SVC. Shunt reactors alone are note expected to be sufficient because of fluctuations in the COI flow and resulting fluctuations in voltage. Voltages at the Round Mountain Substation and vicinity may be unacceptably high or unacceptably low depending on the COI flow and on the generation in the area, and they may change rapidly. This is why the reactive support has to be dynamic. Gates 500 kV Dynamic Voltage Support Project is needed not only because of high voltages, but also because of the possibility of momentary cessation of the inverters in the solar PV plants with the faults in the area. Also, during summer peak conditions, a large portion of the load in the area is single-phase air conditioners that stall with faults. Due to the stalling of the induction motors, large amounts of load

No	Comment Submitted	CAISO Response
	STATCOMs at the Gates substation. Similarly, could the existing 4 x 47.7 MVar reactors be reconnected from the Round Mountain transformer to the new reactive project and reduces its size and cost? We also encourage the CAISO to open these voltage support projects, if approved by the CAISO Board, to a competitive solicitation that specify the required performance rather than technology type. BAMx urges the CAISO to provide functional specifications as part of the competitive solicitation, and not be overly prescriptive. In other words, let the market respond without being too restrictive.	may be lost. Devices such as a STATCOM will improve system performance by minimizing momentary cessation and by reducing the amount of load and distributed generation that is lost due to the induction motor load stalling. The Round Mountain and Gates 500 kV Dynamic Voltage Support Projects are eligible for competitive solicitation.
1g	*North and South of Mesa Upgrades, formerly Midway-Andrew Transmission Project* BAMx requests the CAISO to provide a cost breakdown for the South of Mesa project which is recommended for approval in the Draft Plan as well as for the North of Mesa project proposed to be on hold. Consistent with prior comments submitted in this proceeding, BAMx believes that just like the Midway-Andrew 230 kV Project, the North of Mesa project is designed to provide a level of service that may be above that required by the CAISO Planning Standards. The originally proposed Midway-Andrew 230 kV Project was estimated to cost in the range of $120M-$150M. The original scope of the Midway-Andrew 230 kV Project was greater than the combined scope of the South and North of Mesa projects that replace it. Therefore, we are questioning the higher cost of $215M associated with the newly proposed projects. While BAMx is encouraged that the CAISO is considering lower cost options that would re-purpose existing assets under the North of Mesa project, a fundamental point is not being addressed. As a reliability project, such project justifications should include a cost/benefit assessment as described in the CAISO Planning Standards (Section V.4). In response to our November 2018 comments, the CAISO has declined to calculate the benefit to cost ratios and therefore appears to not be adhering to its own planning standards. The CAISO has identified the large quantity of load being dropped and its inability to schedule outages in this area as additional justifications for this project. If this is the case, detailed justifications must be shared with the	The scope and cost estimates for the North of Mesa and the South of Mesa projects have been updated in the Revised Draft of the 2018-2019 Transmission Plan. The estimated cost of the North of Mesa Upgrade project is $114 – 144 million and is recommended to remain on hold due to uncertainties related to converting one of the 500 kV lines from Midway to Diablo to 230 kV and needing further review in future planning cycles. The scope of the South Mesa Upgrade project was modified to reflect that the rerating of the Sisquoc-Santa Ynez 115kV line has been determined to be unfeasible and will requiring reconducturing with an estimated cost of $29.6 – 59.2 million for the project. The South of Mesa Upgrade project is being recommended for approval. The total estimated cost for both projects is $143.6 to $203.2 million The ISO has provided in the September 26 and February 14 stakeholder meetings of the 2018-2019 transmission planning process the load profiles for the loads in the North of Mesa and South of Mesa

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<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td></td><td>stakeholders. Such details should include but not limited to (i) what load cannot be dropped as part of the Special Protection Scheme (SPS), and (ii) what are the load dropping scenarios and their expected frequency and impact. If the CAISO decides to proceed with the implementation of the North of Mesa Project due to the inability of obtaining clearances on equipment, further justification should be provided in regard to which clearances are not able to be scheduled under the current configuration with the knowledge that the SPS will drop load and protect the system even in an abnormal system configuration.
In summary, in addition to further assessment of the conversion of one of the 500kV lines from Midway to Diablo to 230kV as part of the North of Mesa project, we request the CAISO to address the above-mentioned issues associated with the reliability need for the North of Mesa Project in the subsequent planning cycles.</td><td>areas that identifies the amount of load that would not be able to be serviced under the N-1-1 contingencies and illustrates that there is insufficient time for maintenance to be performed where an N-1 contingency during the maintenance would result in the loss of load.</td></tr>
<tr><td>1h</td><td>Lakeville 115 kV Bus Upgrade
The Lakeville subarea project involves installing a sectionalizing breaker in order to protect against an overload on the “STHELNJ1 - PUEBLO 115 kV Line” following a P2 outage at Lakeville substation. A slide on this project presented during the February 14th stakeholder meeting states that the overload appears starting in year 2020, however, Appendix C of the draft plan does not support this claim with the overload only appearing in 2028 Summer Peak Cases. See the table below for details.
<table>
<tr><th rowspan="2">Overloaded Facility</th><th rowspan="2">Contingency (All and Worst P6)</th><th rowspan="2">Category</th><th rowspan="2">Category Description</th><th colspan="9">Loading % (Baseline Scenarios)</th></tr>
<tr><th>2020 Summer Peak</th><th>2023 Summer Peak</th><th>2028 Summer Peak</th><th>2020 Spring Off-Peak</th><th>2023 Spring Peak</th><th>2020 Winter Peak</th><th>2023 Winter Peak</th><th>2028 Winter Peak</th><th>2023 SP High CEC Forecast</th></tr>
<tr><td>31250 SONOMA 115 32564 PUEBLO 115 1 1</td><td>FULTON 230 KV BAAH BUS #1 (FAILURE OF NON-REDUNDENT RELAY)</td><td>P5</td><td>Non-Redundant Relay</td><td><100</td><td>119</td><td>130</td><td><100</td><td><100</td><td><100</td><td><100</td><td>121</td><td>110</td></tr>
<tr><td>31262 CACHE J2 115 31229 REDBUDJ2 115 1 1</td><td>CORTINA 115KV [1330] MOAS OPENED ON LUCERNJ1_LUCERNE & GEYSERS #3 115KV [1650] MOAS OPENED ON MPE TAP_MPE</td><td>P6</td><td>N-1-1</td><td><100</td><td><100</td><td>103</td><td><100</td><td><100</td><td><100</td><td><100</td><td><100</td><td><100</td></tr>
<tr><td rowspan="2">31285 STHELNJ1 115 32563 PUEBLOJT 115 1 1</td><td>LAKEVILLE 115KV - SECTION 1D & 2D</td><td>P2</td><td>Bus Breaker</td><td><100</td><td><100</td><td>119</td><td><100</td><td><100</td><td><100</td><td><100</td><td><100</td><td><100</td></tr>
<tr><td>LAKEVILLE-SONOMA #1 & LAKEVILLE-SONOMA #2 LINES</td><td>P7</td><td>DCTL</td><td><100</td><td><100</td><td>114</td><td><100</td><td><100</td><td><100</td><td><100</td><td><100</td><td><100</td></tr>
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The identified overloads are for a higher level and low probability type of contingencies and do not appear in the 2023 and 2028 cases, therefore, BAMx recommends not approving the Lakeville Bus upgrade project at this time.</td><td>In the Revised Draft of the 2018-2019 Transmission Plan the ISO is not recommending approval of the project and the ISO will be continuing to monitor the load forecast in the area that drives the need for the mitigation of the reliability constraint in future planning cycles.</td></tr>
<tr><td>1i</td><td>Cottonwood 115 kV Bus Sectionalizing Breaker
The Cottonwood 115kV Bus Sectioning Breaker project will install bus-sectionalizing breakers at the Cottonwood 115kV substation in order to protect the substation from voltage collapse resulting from a stuck bus tie breaker at</td><td>The P2-4 contingency at Cottonwood 115 kV substation resulted in the entire Humboldt area losing power under the studied scenario. The CAISO considered different alternatives including the SPS to address</td></tr>
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No	Comment Submitted	CAISO Response
	the substation. The stuck bus breaker contingency serving as a driver for the project is an extremely low probability type of contingency, hence this capital upgrade provides only very marginal risk reduction and reliability benefit. BAMx would recommend the CAISO to look into a more cost-effective solution to the P2-4 violation, such as keeping the bus tie breaker normally open and operating the substation split. Also, the CAISO should evaluate installing an SPS in order to mitigate the voltage collapse violations associated with the stuck bus breaker at the Cottonwood substation.	the issue and given the high impact of the contingency and comparable cost of the project to an SPS, the recommended solution is to add a bus sectionalizing breaker.
1j	*Gates-Gregg Transmission Project* BAMx supports the CAISO's analytic method used to evaluate the Gates-Gregg 230 kV project, whereby initial assumptions used for the transmission project were tested to assess project viability. BAMx endorses the CAISO's decision to cancel this project.	The comment has been noted.

2. Bonneville Power Administration (BPA) Submitted by: Ravi Aggarwal		
No	**Comment Submitted**	**CAISO Response**
2a	1. Increase the Capacity of AC and DC Interties - In Section 8, Summary and Conclusions, BPA recommends adding the following sentence at the end of the existing paragraph "BPA intends to manage the incremental 300 MW as non-firm transmission." The allocation process for addressing the additional capacity as well as an implementation procedure will require coordination among the NWACI owners and CAISO.	The comment has been noted.
2b	2. Minimum operating levels - Figures 4.3-4, 4.3-5, and 4.3-6 show minimum generation levels for main stem Federal Columbia River Power System hydro projects that violate current operating requirements. These minimum generation levels and associated operating ranges should be revised to reflect current operating requirements, such as those specified in the U.S. Army Corps of Engineers' Fish Passage Plan.	The comment has been noted.
2c	3. Increase Dynamic Transfer Capability (DTC) – In Section 8, Summary and Conclusions, BPA recommends replacing the existing paragraph and replacing it with the following: "In 2018, BPA completed its DTC study and increased the DTC limits on the NWACI from 400 MW to 600 MW. In addition, BPA has removed the DTC Voltage Stability Limit (freezing/crimping) after obtaining the WECC Remedial Action Scheme Reliability Subcommittee's approval on the BPA's Synchrophasor Remedial Action Scheme as a Wide Area Protection. An increase in DTC on the NWACI above the 600 MW was not part of the scope for the current 2018-2019 TPP informational study. Thus, a separate DTC study would be needed in the future in order to establish what would be required for an increase to the DTC limit beyond the current limit of 600 MW."	The comment has been noted.
2d	4. Implementing sub-hourly scheduling on PDCI – In Section 8, Summary and Conclusions, BPA recommends replacing the last sentence of the "Implementing sub-hourly scheduling on PDCI" sub-section with "BPA, in coordination with the LADWP and the other owners of the southern portion of the PDCI, anticipates that the project schedule from the scoping to the implementation phase will take approximately two to three years. " BPA is	The comment has been noted.

No	Comment Submitted	CAISO Response
	working closely with LADWP and the southern owners on this project and recently had an initial kickoff meeting related to this initiative.	
2e	Import RA - RA Section 7.7 states that "As per CPUC/ISO requirements, commitment of firm capacity is required 45 days ahead of the operating month in order to be counted towards RA. This might be challenging for some hydro units to forecast hydro that far in advance." Later in Section 8.0 Summary and Conclusions, it states that from the zero-carbon/GHG perspective, there seems to be little to no impact if hydro imports from the PNW have RA assigned to it or not, as hour-ahead scheduling data shows that potentially low-carbon energy is already coming into California. The barrier to increased import RA may not be due to the inability to forecast hydro, but it is more likely due to the current structure of the capacity market in California. In many months, the current market in California values capacity below the cost of carbon. This low valuation can potentially lead to system reliability problems. It is true PNW exports are currently injected into CAISO regardless of RA. This is because COB hour ahead and day-ahead prices are generally higher than Mid-Columbia prices and capturing the value of low carbon imports into CAISO in most hours is greater than the value RA provides. There is no guarantee that this will be the case going forward. Carbon legislation in Oregon and Washington, if it passes, most likely will elevate PNW prices for zero carbon generation. BPA agrees with the CAISO that RA market initiatives and regulations are outside the scope of this study. BPA sees the RA market design and pricing issues to be explained as part of a more complete response to the letters of February 2018 from the leaders of the California Public Utility Commission (CPUC) and the California Energy Commission (CEC) to which this special information study responds. BPA acknowledges the recognition in the February 4 report of these broader issues. We are attaching comments submitted to the CPUC in its current IRP proceeding that are relevant to this Appendix H.	The comment has been noted.

3. Cal Energy Development Company LLC (CEDC) Submitted by: Marty Walicki		
No	Comment Submitted	CAISO Response
3a	We are pleased the CAISO reviewed and analyzed our economic study request for the California Transmission Project (CTP) and summarized the findings at pages 285-291 of the Draft Plan. We agree with the statement on page 291 the Draft Plan: “The [CTP] project provides other benefits for which the ISO is valuing with conservative assumptions at this time, due to uncertainty regarding the future reliance on gas-fired generation for system and flexible needs” However, our independent analysis of the CTP project focusing solely on LCR benefits and reduced Path 26 congestion yielded a B/C ratio in excess of 1.0. We still believe that if the CAISO were given guidance from the CPUC on how to properly value LCR benefits in the LA Basin and with updated assumptions regarding the system benefits from relieving Path 26 congestion (reduced renewable curtailment and improved system dispatch) the CAISO would have also found the benefits to customers of our project significantly outweigh the costs.	
	The CAISO appears to have used an LCR valuation methodology which credits LCR reduction in the LA Basin of both $1.39/kw/mo. and $1.89/kw/mo. If the CAISO were to instead use LCR values which are an average of LA Basin LCR payments we have observed from public data, ($3.76/kw/mo.) the project benefits a 1000 MW HVDC connection to LA Basin alone could more than double the LA Basin LCR benefits for our project. We ask the CAISO to clarify in its final report that if CAISO were to use LCR benefits based on current LCR payments the B/C ratio for our project would have improved significantly.	As described in the draft TPP report the ISO credited $3.48 /kW-mo for the LA Basin, but then reduced that amount by either $2.09 or $1.59 /kW-mo (comparing to overall system capacity or SP 26 capacity respectively) due to the potential loss of overall system capacity the local capacity resources are also providing. Please refer to the discussion in section 4.3.4 of the draft transmission plan.
	We also observed the CAISO gave no LCR credit to our project for 1,000 MW of LCR relief provided by a HVDC connection to Big Creek/Ventura load pocket. We observe that this LCR area currently has 3511 MW of existing capacity and approximately 1733 MW is provided from gas-fired capacity. We ask the CAISO clarify in its final report that if state decarbonization policies limit the availability of those gas fired power plants in the Big Creek/Ventura load pocket the LCR values for the second CTP 1,000 MW DC Cable could qualified for LCR credit.	As noted in the comment, the ISO attributed a potential local capacity requirement reduction benefit to the termination of the HVDC cable in the Western LA Basin, and did not attribute a potential local capacity requirement reduction benefit to the termination of the HVDC cable in the Moorpark sub-area of the Big Creek-Ventura area. The attribution in the Western LA Basin was somewhat optimistic, as the Western LA Basin area was not selected for detailed study in this cycle and did not receive thorough analysis to confirm the 1000 MW LCR reduction benefit. As discussed on page 288 of the draft transmission plan, there

No	Comment Submitted	CAISO Response
		will not be a Moorpark sub-area local capacity requirement following the completion of the Pardee-Moorpark #4 230 kV circuit. While the overall Big Creek/Ventura area does have a significant local capacity requirement that can be met by resources connecting at Ormond Beach, only about 300 MW of the overall need is met with GHG-emitting resources. Attributing this amount of benefit to the HVDC project appeared overly precise given the approximation of benefits attributed in the Western LA Basin, and, when the conservative valuation assumptions are applied, the incremental benefit would not be expected to have a material impact on the results. Nonetheless, the ISO has modified the revised draft transmission plan to reflect an additional 300 MW potential local capacity requirement reduction benefit.
3b	Regarding Path 26 congestion relief, we believe that the conservative assumptions the CAISO used reduced the potential benefits of our project. It appears the conservative export limits of 2,000 MW was binding and reduced the value of Path 26 South to North flows. The result was an under valuation of the avoided solar curtailment that our project offers. Further, we understand the CAISO was compelled to use the CPUC preferred portfolio wherein the assumed operation of gas-fired generation in the default portfolio no longer complies with California state policy (60% RPS by 2030, 100% carbon free by 2045 and aggressive MMT targets). As pointed out by ISO on page 456 of its Draft 2018-2019 Transmission Plan, "all existing thermal generation resources, except the once through cooling (OTC) thermal generation plants, the Diablo Canyon nuclear plant and the plants for which mothball or retirement plans have been announced, will stay on through 2030". As a result, by using the outdated Default Portfolio, ISO's economic assessments are not accurately quantifying the true production cost benefits of CTP. We ask the CAISO mention specifically in the final report which summarizes the CPT economic analysis that the conservative export limit of 2,000 MW and the outdated assumptions regarding the gas fired generation fleet have caused a likely undervaluation of the benefits of our proposed project.	The study assumptions employed in this transmission planning cycle, and the coordination of those assumptions with the CPUC's progress in integrated resource planning considerations, have impacted the overall transmission plan and not just one set of study results. Accordingly, the ISO has made the appropriate qualifications on a comprehensive basis. For example, please refer to the first and second paragraphs of the executive summary, page 9, of the draft transmission plan.

No	Comment Submitted	CAISO Response
3c	Beyond LCR and Path 26 congestion relief benefits, there are significant additional benefits to California customers that our proposed project provides that the CAISO did not quantify. First, the unique location of CTP proposed off shore transmission line offers California an option to interconnect and deliver up to 4,000 MW of economic off shore wind energy to diversify the pool of resources available to meeting California's ambitious decarbonization goals. As the draft report states at page 289: "The ISO studied this proposal without the wind generation because that generation was not part of the renewable portfolio provided by the CPUC". We ask the CAISO amplify this statement in the final report and provide a clear signal to the CPUC that: (1) the CAISO has found benefit to the CTP without ascribing value to creating an offshore wind option and (2) The CAISO needs CPUC guidance on the value of creating an offshore wind option for California, so that this value can be taken into account when the CAISO evaluates the CPT in the next CAISO planning cycle.	In the consideration of a facility that is predominantly focused on accessing renewable generation, the ISO would expect the CPUC's integrated resource planning process to consider the net economic cost of the transmission facility as an input into its overall resource planning deliberations, and determine whether or not to include in then deciding whether to include the potential wind resources in portfolios informing the ISO's policy-driven planning processes. However, if the CPUC did in fact attribute a financial value to these provisions as suggested in the comments for purposes of ISO economic transmission planning, the ISO would consider them if and when the project is re-examined.
3d	Second, the proposed interconnection of the CTP at the Diablo Canyon Power Plant (DCPP) Switchyard allows repurposing of certain facilities, that would otherwise need to be removed at customer expense as part of the DCPP decommissioning and restoration process. We ask the CAISO reflect in its final report that if the CTP were able to reduce customer costs by reducing DCPP decommissioning costs, and if those costs could be quantified, they should be included in an economic evaluation of the CPT. The CAISO should ask the CPUC to help with the quantification of this benefit.	The facilities that may be repurposed as a part of the DCPP decommissioning will be subject to the retirement plans for the generating facility; however, they are anticipated by the ISO to only be the interconnection facilities of the two generators in Diablo substation.
3e	Third, CEDC also noted the CAISO staff is recommending a significant upgrade at Gates, the Gates 500 kV Dynamic Voltage Support project. Our analysis shows that if our proposed interconnection at DCPP Switchyard proceeds it would displace the need for this estimated $210-$250 Million voltage control project. We fully recognize there is a timing issue. The CAISO need for this reliability project at Gates is 2024 and the proposed CTP would not be in place until 2026. However, if the upgrade at Gates were accomplished using modular, redeployable equipment, that equipment could be available to relocate on the system to meet voltage requirements elsewhere. This could result in significant net saving to CAISO Grid customers. We ask the CAISO specify in Appendix I	The need for the Gates Dynamic Voltage Support Project was identified based on the assumptions in the Study Plan, and are expected to be eligible for competitive procurement. The ISO will consider in that process, according to the terms of the ISO tariff, all competitive submissions.

No	Comment Submitted	CAISO Response
	of the Transmission Plan that the preferred solution at Gates is modular redeployable equipment.	
3f	Finally, the CAISO summary of the CTP economic analysis on pages 285-91 does not mention some of the unique benefits a modern HVDC transmission cable with voltage sourced converters can provide, especially to the grid in load pockets such as the LA Basin that have historically relied on gas fired generation as a critical component of reliable service to customers. Specifically, the CTP undersea HVDC cable connection at the switchyard of a retiring coastal power plant can provide ramping capability, voltage support, frequency support, short circuit duty, etc. Essentially a HVDC connection can match or exceed the local reliability support.	It was assumed that the CTP could replace at least 1000 MW of local gas fired synchronous generation, and this implies that it could at least match the local reliability support currently provided by those existing facilities.

4. California Public Utilities Commission – Staff (CPUC – Staff)
Submitted by: Karolina Maslanka

No	Comment Submitted	CAISO Response
4a	1. CPUC staff commends the CAISO on the impressive amount of work completed in the 2018-19 TPP cycle. The multitude of projects and proposals studied as part of the reliability assessment, the economic assessment, and the interregional coordination process was undoubtedly an immense effort. CPUC Staff congratulates the CAISO on the completion of this TPP cycle. The results produced will be used to inform Integrated Resource Planning (IRP) and other CPUC programs where possible and appropriate.	The comment has been noted.
4b	2. CPUC looks forward to coordinating with the CAISO on improving the valuation of local capacity reductions when considering transmission solutions or non-wire alternatives. Staff acknowledges that in the 2018-19 TPP cycle, due to a lack of information on system-level costs and benefits, the CAISO took a conservative approach in assessing the value of a local capacity reduction benefit when considering transmission investments or non-wire solutions that could reduce the need for existing gas-fired generation providing local capacity. The differential between the local capacity price and system capacity price was applied to reductions in the need for gas-fired generation. CPUC staff supports the use of this valuation approach by CAISO in the 2018-19 TPP cycle. CPUC Staff also recognizes this valuation approach impacted the economic assessment results. Of the 25 proposals and alternatives studied by the CAISO only one economic-driven transmission solution, the Giffen Line Reconductoring Project, is being proposed as a recommendation to the Board of Governors for approval. The benefit to cost ratio of most projects was insufficient to warrant a project recommendation. Although many of the studied projects did demonstrate a substantial production cost benefit of reducing congestion, when summed with the low local capacity benefits captured under the differential approach used, the total benefits did not surpass the costs. CPUC Staff acknowledges that some of the projects may need to be restudied next year if the approach for measuring local capacity benefits is adjusted. CPUC Staff will coordinate with the CAISO to improve the information available	The comment has been noted, and the ISO agrees that some of the potential economic-driven transmission projects will need to be reconsidered in the future when additional input on valuing local capacity requirement reduction benefits is available.

No	Comment Submitted	CAISO Response
	to the CAISO on the system capacity benefits of preferred resources as they relate to reducing the cost of local capacity requirements.	
4c	3. **CPUC Staff commends the CAISO on the substantive efforts in conducting economic benefit assessments for alternatives to gas generation in local capacity areas.** CPUC Staff supports the CAISO's recommendation to restudy a number of projects in future TPP cycles. CPUC Staff supports the CAISO's recommendation for further consideration of the following projects • The S-Line Series Reactor Transmission Project due to the promising Benefit-to-Cost Ratios for both Local vs. System Capacity and Local vs. SP 26. • The Mira Loma Dynamic Reactive Support project due to the positive 1.05 benefit to cost ratio in the local vs SP 26 result. • The Pease Sub-area (Looping in of Pease-Marysville 60kV line into East Marysville 115kV substation) due to the RMR costs resulting in a benefit to cost ratio of nearly 1.0. CPUC Staff agrees that refined cost estimates and better understanding of the need for the gas-fired generation in the Hanford sub-area will be key to further study.	Regarding the specific projects; • Regarding the S-Line, the ISO has negotiated a revised scope with IID that maintains the ISO costs at approximately the same level as for the project approved in the 2017-2018 transmission planning cycle, and provides significantly higher LCR reduction benefits. This revised scope is documented in the revised draft 2018-2019 Transmission Plan. • The ISO will continue to assess this project in future planning cycles. • PG&E has provided updated cost estimates for the alternative of Looping in of the Pease-Marysville 60 kV line into East Marysville 115 kV substation in comment 12d. The ISO has updated the analysis in the revised draft of the 2018-2019 Transmission Plan. The benefit cost ratio using the updated cost estimate is now 1.62. Based on this updated benefit-to-cost ratio, the ISO is now recommending approval of the economic-driven project.
4d	4. **CPUC Staff looks forward to continuing coordination with the CAISO to ensure that the updated transmission capability estimates inform the CPUC Integrated Resource Planning process.** CPUC Staff appreciates the CAISO's use of the new deliverability assessment approach to study the 42 MMT portfolio which was transmitted to the CAISO from the CPUC's Integrated Resource Planning proceeding. CPUC Staff understands that for the 2018-19 TPP the new approach was used for information-only purposes and not to recommend transmission solutions. It will be important for the 2019-20 TPP that the CAISO establish a deliverability assessment approach vetted and sufficiently supported by stakeholders,	As communicated in a recent market notice, the ISO will continue its consultation with stakeholders on this important initiative in 2019.

No	Comment Submitted	CAISO Response
	allowing for its use in identifying economic-driven transmission solutions and recommendations. CPUC Staff requests that in 2019 the CAISO coordinate with the CPUC to do a crosswalk between the information flowing from the 18-19 deliverability assessment and used in the IRP with the expected results of the 19-20 deliverability assessment, which may use a different study approach. CPUC Staff looks forward to continuing coordination with the CAISO to ensure that the insights generated about renewable curtailment and conceptual upgrades in the Kramer-Inyokern, Eldorado, Mountain Pass and Southern NV zones are incorporated into the allocation of IRP-identified resources to substations in the future.	The ISO can work with the CPUC to include the updated policy study information from the 18-19 TPP in the IRP, but at this time it is premature to speculate on the expected results from changes to the deliverability methodology that are ultimately adopted.
4e	5. CPUC staff request additional information regarding the permitted revenue streams for the energy storage component of the Oakland Clean Energy Initiative (OCEI). CPUC Staff wants to emphasize that a timely implementation of the energy storage component of OCEI will minimize ratepayer costs associated with the running of the Oakland Power Plant which currently operates under a Reliability Must Run (RMR) contract. Has the CAISO decided whether the energy storage must function as a dedicated transmission asset, recovering capital investments only through the transmission rate case, or may the storage also access other market revenue streams?	The CAISO's original approval of the OCEI project included 10 MW/4 hour energy storage part to be a transmission asset. The CAISO is considering amending the scope to no longer explicitly require the energy storage to be a transmission asset in on order to allow for the most cost-effective combination of resources to be procured. Please refer to the comment 12(g) provided by PG&E.

5. GridLiance Submitted by: Jody Holland		
No	**Comment Submitted**	**CAISO Response**
5a	1. Request for Clarification of Generation Siting GLW would appreciate if CAISO clarified some of what was presented regarding the 2018-2019 TPP Policy-Driven Assessment. Specifically, slide 8 of Mr. Barave's presentation describes a "modeling change" in production cost modeling simulations for Kramer – Inyokern and Southern Nevada resources. The CPUC's Reference System Plan identified Southern Nevada renewable resources as low cost. CAISO's presentation seems to say that it placed all of these resources at the Lugo 500 kV and Eldorado 500 kV stations when performing its production cost modeling. The California Energy Commission (CEC) developed a specific siting of the Southern Nevada resources identified by the CPUC. Subsequently, it seems CAISO decided to move all these resources to the Eldorado 500 kV station. GLW would like clarification as to why CAISO did not perform production cost modeling using the CEC's siting. During the February 14 presentation, CAISO indicated that local constraints will need further evaluation. With this being the case, GLW would like to understand if CAISO will perform a full production cost modeling study with resources mapped to GLW's system in accordance with the CPUC portfolio and CEC siting. If so, will this study include potential transmission upgrades? If not, how does CAISO anticipate defining the additional RESOLVE transmission limitations, or "nested constraints," to which it refers in the presentation (page 103 of the PDF). Further, GLW would expect CAISO would not only reflect the cost of needed transmission upgrades (those costs for which GLW believes are significantly overstated in CAISO's initial estimates (pages 86-87 of the PDF)) but also the related benefits of any transmission upgrades.	The ISO did perform studies with the mapping suggested by the CEC staff and presented the results during the November stakeholder meeting. It was evident that local constraints caused significant amount of curtailment of these resources. As the next step, the ISO wanted to test if this curtailment had masked any issues on the rest of the transmission system. Therefore, in order to capture this impact and avoid masking of any other transmission issues due to curtailment of these resources triggered by local constraints, the ISO tested the cases by modeling the resources at Lugo 500 kV and Eldorado 500 kV substations. Slide 8 also clarified that this was not an indication of a preferred point of resource interconnection on the ISO's part The ISO does not plan to re-run the sensitivity portfolio production cost modeling simulations as part of the 2018-2019 TPP. The ISO reiterated the feedback regarding nested constraints to the CPUC that was provided in the previous IRP cycle and was confirmed by the latest information from GIDAP studies. Also, in the draft TPP report and during the February 14, 2019 stakeholder meeting, the ISO provided new insights about how the local upgrades in GLW could potentially increase the transmission capability estimates along with respective conceptual cost estimates. However, due to the timing of the information being available, the CPUC could not incorporate this new information in the renewable portfolio creation for 2019-2020 TPP. The ISO expects the CPUC to incorporate this information during the creation of renewable portfolios for the next TPP cycle (2020-2021 TPP). The ISO will perform the production cost modeling simulations with resources mapped in accordance with the CPUC portfolios and the mapping suggested by the CEC staff as part of the 2019-2020 TPP.
5b	2. Request for Clarification Regarding CAISO's Decision to Reduce S. Nevada Capacity	The ISO did not decide to reduce Southern NV capacity. The lower MW amount (2,000 MW) in this zone was tested in order to inform the

No	Comment Submitted	CAISO Response
	GLW seeks additional clarification on slides 14-25 of Mr. Barave's presentation, "Southern CA snapshot assessment – Resource and dispatch assumptions in Eldorado, Mountain Pass, and Southern NV" (pages 77-88 of the PDF). In each mitigation option that CAISO studied for the CPUC's Reference System Plan, CAISO indicates a preference to reducing the Southern Nevada renewable capacity to 2,000 MW. Because CAISO indicated that a production cost modeling simulation was not conducted on this scenario, GLW seeks to understand the benefit in reducing the capacity vs. upgrading the network to accommodate the 3,006 MW capacity. GLW requests that CAISO provide further information about these trade-offs.	CPUC and the stakeholders about the incremental capability that the upgrades could possibly add to this zone and the respective conceptual costs of upgrade options. The ISO has no specific preference for reducing or increasing Southern NV resource selection. The intention was to inform the CPUC and the stakeholders so that the IRP process can account for appropriate trade-offs between reducing resource selection versus upgrading the network to accommodate the 3,006 MW capacity. As was communicated previously, the steps described in 5(a) above were due to the ISO's identification that a certain nested transmission constraint was not recognized in the RESOLVE modeling and resource mapping that produced the renewable generation portfolios to be used for transmission planning purposes.
5c	3. Request for Information on Stakeholder Input Process Regarding CAISO's further collaboration with the CPUC on "nested constraints" and the CEC regarding mapping (page 103 of the PDF), GLW seeks further information about opportunities for stakeholders to be privy to those considerations or to offer any stakeholder feedback on the recommended approaches and outcomes. For example, GLW is aware of certain limited transmission system upgrades that produce meaningful production cost savings—in fact, far more in savings than the cost of the upgrades. With respect to the mapping with the CEC, GLW wishes to understand the process that ensures that transmission buildout tradeoffs are considered in conjunction with renewable buildout choices such that the solution is optimal, as opposed to, for example, strictly and artificially limiting resource development in certain areas by not "mapping" resources to such areas without consideration to other IRP-related buildout attributes.	The ISO did not provide new information to the CPUC that led to the change of concern to GridLiance – rather, the ISO noted that the material already provided regarding the nested constraint did not seem to be reflected the initial mapping provided to the ISO. Regarding other considerations that GridLiance believes should be taken into account in planning the renewable generation portfolios, to the extent that the considerations relate to production cost savings outside of specifically alleviating curtailment of the renewable generation in the portfolio for which the upgrades are being proposed to deliver, the ISO notes that this would be a significant departure from the current process that the CPUC is utilizing for incorporating transmission information into the portfolio development process. Such an approach would need to be applied across the entire system rather than just in the VEA/Gridliance area. Nevertheless, the CAISO encourages GridLiance to reach out to the CPUC directly regarding Gridliance's proposal to incorporate this major change into the CPUC's process.
5d	4. Request for Information Regarding Additional Production Cost Modeling	

No	Comment Submitted	CAISO Response
	CAISO's production cost simulation results captured in the slides (pages 121-128 of the PDF) reflect significant levels of congestion in the GLW/VEA system even when the portfolio resources are mapped to Eldorado and Lugo. Does CAISO plan to perform additional PCM studies to address this congestion? Assessing the costs and benefits of siting, or "mapping," IRP portfolio resources within GLW/VEA's system should be determined based on the congestion incremental to that which occurs in the GLW/VEA system when resources are not mapped to GLW/VEA. Does CAISO plan to perform such incremental analysis? If not, can CAISO please clarify how it will be able to conclude that siting within GLW/VEA's service would result in a higher cost IRP solution than siting in Southern Nevada but outside of GLW/VEA's service area?	The ISO will continue to investigate the congestion in VEA system in the 2019~2020 planning cycle, based on the new CPUC renewable portfolios.
5e	5. Encouragement to Consider Land Constraints and Physical Congestion at Eldorado 500 kV CAISO staff has indicated that mapping projects to the Eldorado 500 kV station instead of the GLW/VEA system will not only result in less congestion but will also result in less transmission being needed. GLW believes that further research and study by CAISO is needed before this assumption can be made. The fact is that there are significant land availability limitations and physical constraints that severely limit how much generation can be sited in that area and, therefore, economically interconnected to the Eldorado 500 kV substation. For one, much of the BLM land outside Boulder City has been designated by the BLM as either solar exclusion or solar variance by the BLM pursuant to the Solar PEIS. This land is either unavailable for solar development or, if available, would only be so following a lengthy, costly and uncertain permitting process. Within Boulder City, lands remaining for solar development are extremely limited, owing in large part to the Clark County administered Boulder City Conservation Easement, a vast swath of land set aside for the preservation of desert tortoise. Only one 1,100 acre parcel of Boulder City-owned land has been identified for near term future solar development, and that project area lies approximately one mile from the Sloan Canyon Switchyard, significantly closer than the project area is to any of the other interconnection point in the Eldorado Valley. Further, there are constructability problems for new transmission (including generation interconnection facilities). There are many high voltage transmission	Regarding the siting of new generation and the associated permitting challenges, the ISO refers GridLiance to the CPUC and CEC.

No	Comment Submitted	CAISO Response
	lines running across the Eldorado Valley. Any new construction would require potentially dozens of line crossings—this increases costs and raises other concerns that should be considered. Constructing long transmission lines in the corridors to reach the Eldorado 500 kV station from areas where land is available will significantly increase the cost of generation and ultimately the cost of renewable resources to serve California ratepayers. Unless CAISO considers this, GLW fears California will lose a clear opportunity to access the low-cost renewable resources available in the other parts of Southern Nevada.	

6. Hydrostor Inc (Hydrostor) Submitted by: Stewart Jensen		
No	**Comment Submitted**	**CAISO Response**
6a	Recommended Projects in the Central Coast and Los Padres Areas Hydrostor proposed a 175 MW – 200 MW Advanced-CAES system to the CAISO through a request window submission as a means of meeting reliability needs in the Los Padres region. This project was referred to as the "Los Padres ACAES Project" in the Draft 2018-2019 Transmission Plan (the "Project"). The CAISO's Draft 2018-2019 Transmission Plan did not recommend the Project citing that "the project would not address all of the reliability needs in the area such as the P6 contingency of the 230/115 kV transformers at the Mesa substation."	
	As proposed, the Project may not have addressed the P6 contingency identified by the CAISO. However, Hydrostor notes that the Project did provide significant reliability benefit to the region and addressed a number of the CAISO's identified needs. This includes resolving voltage collapse and overload issues on the 115 kV Morro Bay to Mesa/Santa Maria circuit in the event of a simultaneous loss of two 230 kV transmission connections between the Morro Bay and Mesa substations. The power flow modeling prepared in association with this application demonstrates energy storage's ability to act as a transmission asset and supports increased consideration of storage as a transmission asset in the CAISO balancing area.	The North of Mesa project addresses the reliability requirements in the area and at a lower capital cost.
	Hydrostor would appreciate the CAISO providing additional details regarding the P6 contingency which the Project was unable to address at the Mesa substation. This will enable Hydrostor to refine the Project's design to address this additional reliability concern, enhancing a potential future request window resubmission of this Project or similar projects thereby potentially benefitting the system.	The P6 contingency is the loss of one 230/115 kV transformers at Mesa substation followed by the loss of the second 230/115 kV transformers at Mesa substation.
6b	Valuation of Energy Storage as a Transmission Asset Energy storage's ability to benefit the electricity system has been widely documented in the industry. Similar to the Federal Energy Regulatory Commission, Hydrostor believes that energy storage offers a range of transmission system benefits and encourages the CAISO to place a greater	The ISO does not take exception to the bulk of the comments set out below. However, these are generally parameters that are best considered in resource procurement processes, and the ISO believes these should be reiterated in those processes led by the CPUC. Inertia, frequency response and short circuit capabilities are

No	Comment Submitted	CAISO Response
	value on the technical characteristics of energy storage generally and long-duration energy storage specifically when assessing future projects. In addition to the specific reliability benefits of the Project noted in our request window submission, the general transmission system benefits of long-duration storage include: • ▪ Long Duration Potential: The loss of a transmission line can result in the loss of electric service to customers for extended durations. In the context of recent natural disasters, long-duration energy storage is highly valuable to help ensure reliability. • ▪ Maintenance Reliability: Routine maintenance of transmission assets typically requires taking these assets offline temporarily. Long-duration energy storage could allow for more frequent system maintenance by providing 12-24+ hours of local backup generation and increase the life of existing transmission assets in the region. • ▪ Technology Diversity: The grid would benefit from technology which has capabilities distinct from what has already been deployed. The inclusion of such technology would minimize the long-term performance risks of the electricity system. Given the prevalence of lithium-ion storage (typically in 4-hour duration configurations), inclusion of long-duration storage technologies would significantly improve diversity. • ▪ Environmental Benefits: The carbon reduction benefits of renewable generation are well recognized, and further reinforced by the adoption of Senate Bill 100 and the State’s 100% renewable energy goal. Not only is energy storage an important enabling technology for continued renewable energy deployments, emissions-free generation capacity is unquestionably required to achieve a significantly decarbonized grid. • ▪ Synchronous Generation and Rotational Inertia: The modern power system relies on rotating generators. Inertia from spinning generators, provides critical support maintaining the system stability. The impact of generator retirement has already been seen in South Australia which recently experienced a number of large blackouts. Advanced-CAES uses turbine generators (similar to current fossil-based generators, but which operate on air and result in no direct emissions) that create synchronous generation and can provide rotational inertia to support grid stability and resiliency.	parameters that the ISO is either directly, or, in the case of short circuit levels working with the local transmission owners, to monitor and study. The ISO agrees that the SATA initiative would be helpful, but notes that in considering the economic benefits of storage projects, the ISO considered the benefits both to the grid as well as the potential revenue from providing market services, recognizing that the storage could also be procured as a market-participating resource under an appropriately structured power purchase agreement by load serving entities.

No	Comment Submitted	CAISO Response
	• ▪ Longevity: Many long-duration energy storage technologies can operate for 30+ years to minimize long-run marginal costs of grid operation. Further, long-duration energy storage can benefit the grid by providing a reliable and ongoing backbone of long-duration storage capacity for the electricity system. • ▪ Performance Reliability: Advanced-CAES operates with little-to-no performance degradation over time, offering reliable and predictable service to the grid for 30+ years (and much longer with adequate maintenance and minor overhaul, similar to fossil facilities). • ▪ All-Season Performance Certainty: Electricity demand peaks are often seasonably dependent and frequently occur during temperature extremes. Advanced-CAES can deliver power regardless of weather conditions, with limited-to-no performance degradation and is not limited by state-of-charge. Energy storage is a proven, reliable solution that can provide significant benefits to transmission systems. This is evidenced by the actions of regulators in other regions who are already allowing energy storage assets to provide both regulated and unregulated services1. Hydrostor believes that if CAISO put a greater emphasis on quantifying these system benefits, a number of economically viable energy storage projects will be identified. As the deployment of such projects would clearly benefit the system, Hydrostor recommends the CAISO place further quantitative values on these attributes when conducting project-specific economic analysis. Beginning in 2018, the CAISO's Storage as a Transmission Asset ("SATA") process has sought to enable transmission connected storage assets providing regulated cost-of-service-based transmission service to also access other market revenue streams. However, at the January 2019 stakeholder meeting, the CAISO temporarily suspended SATA initiatives to address certain issues through the ESDER 4 process. Hydrostor supports the CAISO's SATA process and encourages the CAISO to restart the SATA process expeditiously so that storage can play a greater role as a transmission asset. The dual treatment of storage assets as generation and transmission assets is in the best interests of California ratepayers, as it will help ensure that the most cost-effective outcomes are possible by ensuring appropriate value recognition for all benefits	

No	Comment Submitted	CAISO Response
	of an asset on the grid. Leveling the playing field for storage assets that play both a generation and transmission role will only ensure more competitive outcomes for the grid.	
6c	Finally, we believe it would be beneficial to better integrate the CAISO TPP with the California Public Utilities Commission's ("CPUC") Integrated Resource Planning ("IRP") process, implicitly recognizing the dual-value of long duration storage assets to both transmission and longer-term generation needs. This is inherently an important principle to provide true least-cost planning to the system. Currently, the TPP and IRP are not well-integrated in that solutions are identified independently through each process, while storage, and long duration bulk scale storage in particular, clearly has a role to play in both processes and, as a result, their proposed procurement outcomes. Hydrostor has filed comments to this effect with the CPUC as part of their Rulemaking 16-02-0074 and would be happy to further discuss with the CAISO how such a process could be designed.	The comment has been noted. The ISO is continuing to work to effectively coordinate between the transmission planning process and the ISO's participation in the CPUC's IRP process. Concrete suggestions to improve coordination will be considered.

7. Imperial Irrigation District (IID) Submitted by:		
No	**Comment Submitted**	**CAISO Response**
7a	With regard to the S-Line Series Reactor Project, the CAISO's Draft 2018-2019 Transmission Plan issued on February 4, 2019 concludes: "The benefit to cost ratio of this project is encouraging notwithstanding the conservative value assigned to local capacity requirement reductions. The project will be considered in future planning cycles, once the design and configuration of the IID-owned S-Line upgrade is finalized." Draft Plan at 325. The CAISO's November 16, 2018 response to IID's prior comments lists a number of alternative Local Capacity Requirements ("LCR") reduction options, which are discussed in the February 14 presentation and Draft 2018-2019 Transmission Plan. IID urges the CAISO to continue considering the other identified alternatives, and to share with stakeholders additional details regarding its analyses. IID would like to propose the further analyses of additional dynamic solutions, such as phase shifting, which would offer greater operational flexibility than a static solution such as the proposed series reactor. As the series reactor analysis is focused on benefits to the CAISO ratepayer, IID would need to assess the project for potential impacts to its area. IID looks forward to working with the CAISO in the further analysis of this proposal as well as the development and evaluation of potential of alternatives. Is the 600MW reduction in the SD-IV area LCR attributed to the reactor project itself or does it include the 213MW LCR reduction previously identified in the 2017-2018 Transmission Plan attributed to the S-line upgrade? In other words, is the S-line upgrade plus the series reactor project reducing the SD-IV LCR by ~800MW? In the 2017-2018 Transmission Plan it was noted that the S-line upgrade plus additional 230:92kV transformation could potentially reduce the LCR in the SD-IV area by 500MW. In that assessment, was an increase in the LA Basin area LCR also identified?	Since the draft transmission plan was posted, the ISO has coordinated amendments to the configuration of the S-Line upgrade; the modified scope and benefits will be described in the revised draft 2018-2019 Transmission Plan.
7b	It is noted in section 7.2.1 that Table 7.2-1 reflects a diminution of geothermal resources by 1,197MW going from the Reference System Plan (RSP) to the Hybrid Conforming Plan (HCP). Please inform on potential impacts to the Salton Sea Geothermal region towards both existing and future geothermal resources in the change from RSP to HCP. IID notes the increase HCP	The comment has been noted and the CAISO encourages IID to provide this comment directly to the CPUC.

No	Comment Submitted	CAISO Response
	renewable capacity to 714MW but the reduction of 5,649GWh less is directly correlated to the reduction of base load geothermal as compared to the RSP. It is further noted that the CAISO has indicated its support of the utilization of geothermal resources located in the Salton Sea Geothermal region.	

8. LS Power Submitted by: Sandeep Arora and Mark Milburn		
No	Comment Submitted	CAISO Response
8a	<u>Economic Studies:</u> <u>PACI/NOB congestion:</u> CAISO has not demonstrated any progress on steps it intends to take to resolve this recurring issue that is costing ratepayers $50mm to $148mm annually. In previous stakeholder meetings CAISO indicated that it was going to investigate whether PACI/NOB Day Ahead congestion could be alleviated through market enhancements. If not, CAISO indicated that it would look to address this congestion through the Transmission Planning Process. Yet the Draft Plan does not directly address how it plans to alleviate this Day Ahead congestion, nor does it provide steps CAISO intends to take or the timeline for addressing this high cost problem. In the Draft Plan, CAISO concludes that "the greatest opportunity is for the ISO market to gain access to the additional physical capacity that cannot currently be utilized in the ISO market. The ISO is accordingly investigating with its neighbors the possibility of accessing this capacity". LS Power first brought this issue to CAISO's attention four years ago. It appears that another year has elapsed with no material progress on addressing the congestion. We recommend CAISO establish a deadline to conclude its investigation and create a timeline for resolving this issue and execute on it. Consistent with our previous TPP comments, LS Power reiterates the importance of correctly modelling PACI/NOB congestion. The congestion on this path has been one of the top congestion issues in CAISO's Day Ahead Markets for the last several years, resulting in CAISO ratepayers overpaying $50 to $100 million in each of the past 3 years. Similarly in 2011-2014 the congestion reported by DMM ranged from $62mm to $148mm. This signals the need for additional transmission capacity that should pay for itself by allowing more economic transfers from the Pacific NW into California. Since this congestion doesn't get correctly quantified in the current planning models, CAISO's Transmission Planning Process does not properly identify the need for additional transmission capacity to relieve the reported congestion and reduce ratepayer costs. While CAISO should make efforts in correcting its economic study model, however, even if the model cannot fully replicate the historical	The ISO's transmission planning process focuses on relieving physical limitation on transmission. Market related issues regarding the day-ahead congestion need to be resolved through market design and may need market stakeholder processes. The ISO appreciates the concerns expressed by LS Power, particularly as the discussions with other parties controlling a portion of the transmission rights that may provide additional capacity through the ISO tariff are not yet public. The ISO notes that the excess capacity is available capacity available on the owners' OASIS sites in accordance with their respective OATTs. The ISO is optimistic that progress will be made through 2019 and will keep stakeholders informed when developments occur. In the stakeholder meeting on November 16, 2018, the ISO presented the investigation on the day-ahead scheduling congestion related to COI. The draft transmission plan includes the investigation results. The ISO's transmission planning study reflected the physical constraints of the transmission system along COI corridor. The study results were directionally consistent with the real-time utilization of COI with consideration of the unified planning assumptions for future years.

No	Comment Submitted	CAISO Response
	congestion reported by CAISO's DMM, CAISO has enough consistent historical congestion data to support evaluation of transmission solutions in the TPP.	
8b	CAISO's Economic Study Model: LS Power submitted modelling recommendations to CAISO to capture PACI/NOB congestion in the 2017/18 TPP through work that the Brattle Group conducted on behalf of LS Power. CAISO must correct the Economic Study models to accurately capture the historical Day Ahead congestion on these paths. CAISO should investigate in particular whether the software it uses currently to perform production cost simulation work can be enhanced to capture transmission capacity rights and allow CAISO to alter wheeling rates to accurately represent transmission capacity arrangements. CAISO should look into using different software for performing this work if the software it currently uses cannot be used for this purpose. LS Power stands prepared to have detailed discussion with CAISO team on this, as needed.	The comment has been noted. Please refer to the response to Comment 8a regarding the day-ahead congestion versus physical transmission limitation. The ISO appreciates the LS power's comments on the wheeling rate and transmission right model. The potential impact of transmission rights has been considered in the ISO's assessment. The wheeling rate and transmission right model in the production cost model (PCM) is currently under review through the WECC-wide ADS PCM process. Stakeholders are welcomed to participate into the discussion. The ISO will also keep stakeholders informed when the modeling approach is updated.
8c	SWIP North Economic Study: CAISO staff conducted study to analyze economic benefits of the SWIP North project. The study compared WECC-wide production costs with and without SWIP North. LS Power has several comments on this study: 1) It is not clear whether CAISO was able to accurately model SWIP North as a 1000 MW wheel-free path from Midpoint (Idaho Power) to Eldorado (CAISO) as specified in LS Power's regional economic study request and interregional study request. If any hurdle rate was assumed in CAISO's production cost analysis for energy to wheel from Idaho Power to NV Energy to CAISO, this should be removed and study results revised. If the software CAISO uses cannot support this analysis accurately then CAISO should look into other tools that can do this.	The ISO's study identified that the primary factors that affected the benefit assessment for SWIP North project were the resource and transmission assumptions. Transmission rights were considered, but did not create material changes in the results.
8d	2) It is not clear if CAISO's economic analysis accounted for several additional benefits that SWIP North, an out of state transmission project, can provide. Our understanding is that CAISO's TEAM methodology does not account	(a) GHG emissions and prices have been modeled in the ISO's planning PCM. (b) The ISO's study used the CPUC's renewable portfolio as the input for renewable generator model. The renewable capacity cost as

No	Comment Submitted	CAISO Response
	for these benefits and these need to be accounted for to get a complete picture of overall benefits of a transmission project such as SWIP North. (a) Green House Gas (GHG) reduction benefits: SWIP North will enable an incremental 1000 MW of transmission capacity that can be used to import/export generation resources into/from CAISO. CAISO's analysis shows that "SWIP - North may allow more exports from California to other regions when there are renewable energy surplus within California". This will certainly help reduce GHG emissions in California by allowing more renewable generators to remain online and displacing fossil fuel generation. CAISO should quantify GHG reductions and renewable curtailment reductions from SWIP North. An approach CAISO can take in quantifying these benefits would be similar to how CAISO calculates similar benefits for its Quarterly EIM benefits analysis. As per CAISO's Q4 2018 EIM report total avoided renewable curtailment volume in MWh for Q4 2018 was calculated to be 23,425 MWh. The environmental benefits of avoided renewable curtailment were noted to be significant and CAISO used an assumption that avoided renewable curtailments displace production from other resources at a default emission rate of 0.428 metric tons CO2/MWh. We recommend similar approach be used in quantifying these benefits for projects like SWIP North. CPUC's study for 2017-18 IRP6 also noted significant benefits of out of state transmission in terms of GHG reduction, renewable curtailment reduction and lower renewable integration costs. CAISO should capture these benefits as it works on finalizing the Transmission Plan. (b) Renewable capacity capital cost savings: In CAISO's studies, SWIP North has shown to helps reduce renewable curtailments in CAISO footprint by providing a conduit to export surplus renewable energy from California. As renewable curtailments are reduced, there will be capital cost savings as CAISO Load Serving Entities will not need to build incremental renewables to meet same RPS goals. These capital cost savings should be captured. (c) Load Diversity/Reserve Capacity reduction benefits:	the stakeholder commented should be considered in the CPUC's renewable portfolio development process. (c) Load diversity has been considered in the load model of the PCM. Reserve sharing from remote areas requires knowing specific remote resources with contracts to provide this service, which were modeled as ISO remote generators in the ISO's planning PCM. In the study PCM case for SWIP North, no additional remote resources were modeled as ISO resources beyond those already under contract. Any further assumptions for remote resources must be consistent with the CPUC's resource plan and available contract information.

No	Comment Submitted	CAISO Response
	Enabling 1000 MW of transmission capacity from CAISO to neighboring Regions will allow the flexible ramping requirement for CAISO and the Regions to be reduced as they will be able to take advantage of the diversity of resources and shape of the load. These diversity saving benefits should be accounted for. CAISO's Quarterly EIM reports capture these benefits and this is an approach that CAISO Transmission Planning can use as well for this study.	
8e	3) CAISO's analysis concluded that "The SWIP - North line may not provide incremental import from Northwest regions during some hours when there is no energy surplus in those regions depending on resource and transmission assumptions in Northwest regions in the model". The $50mm to $148mm of recorded historic congestion on the PACI/NOB paths that CAISO experiences every year demonstrates the contrary, i.e. there is enough economic energy available in PNW but there isn't sufficient transmission capacity for this economic energy to be scheduled into CAISO. In light of this, an incremental 1000 MW transmission capacity from SWIP North should allow CAISO to access this economic energy and lower the cost for its ratepayers.	The presentation in the stakeholder meeting on November 16, 2018 and the draft transmission plan discussed the investigation results for the day-ahead congestion related to COI corridor. The physical limitation of transmission capacity only contributed to a part of the day-ahead congestion. The ISO's planning study focused on the physical limitation, and study results were directionally consistent with the investigation.
8f	4) CAISO's analysis concluded that "lower priced imports can result in increased profits to out-of-state generation and reduced profits to ISO owned generation in the ISO footprint whose profits accrue to ISO ratepayers." LS Power recommends that CAISO revisit this conclusion. If a project like SWIP North enables 1000 MW of new transmission capacity between the PNW and CAISO, will that enable some of the existing PNW resources that may be contracted to serve CAISO to schedule into California? If so, should the profits for those out-of-state generation resources be treated the same as profit for internal CAISO resources?	Remote generators under contract with the ISO's LSEs were modeled in the PCM base case (i.e. without SWIP North), and considered as ISO's resources. In the study PCM case for SWIP North, no additional remote resources were modeled as ISO resources. Any further assumption for remote resources must be consistent with the CPUC's resource plan and available contract information.
8g	5) Based on CAISO's analysis of historical PACI/NOB congestion, it is quite evident that congestion is caused because not enough transmission capacity gets offered into the Day Ahead market for economic PNW resources to be able to schedule into CAISO. CAISO's economic analysis for SWIP North should quantify benefits of a new 1000 MW transmission capacity that can serve as a diverse transmission path and allow part or all	The presentation in the stakeholder meeting on November 16, 2018 and the draft transmission plan discussed the investigation results for the day-ahead congestion related to COI corridor. The physical limitation of transmission capacity only contributed to a part of the day-ahead congestion. The ISO's planning study focused on the physical

No	Comment Submitted	CAISO Response
	of the economic PNW resources to schedule into CAISO through SWIP North. Further, this new transmission path would also reduce friction in scheduling, as is typically experienced in the West.	limitation, and study results were directionally consistent with the investigation.
8h	<u>Reactive Support Projects at Round Mountain & Gates:</u> CAISO's reliability project proposals should be further refined as follows: 1) CAISO should test the effectiveness of looping the reactive support projects into two existing transmission lines between Round Mountain and Table Mountain substations, rather than limiting the proposals to connect to Round Mountain. Based on studies conducted by LS Power, looping into the two existing lines provides a more effective solution for addressing voltage issues at not just Round Mountain substation but also substations in the vicinity: Table Mountain and Maxwell. In addition, looping in provides the following incremental benefits as opposed to connecting directly into existing substation: a) Saves costs by avoiding expansion of existing Round Mountain substation and conversion of existing Ring bus to Breaker and a Half configuration as contemplated by PG&E b) Maximizes the scope of the project that will be subject to competitive solicitation, thereby allowing CAISO and its ratepayers an opportunity to select competitive proposals which will lead to potential cost savings c) Minimizes capital expenditures required from Pacific Gas & Electric Company (PG&E), which may be prudent for CAISO ratepayers and for ensuring that this reliability project gets completed in time, in light of recent financial events at PG&E.	Since the Round Mountain 500 kV Voltage Support project and Gates 500 kV Voltage Support Project are open for competitive solicitation, alternatives other than connecting the reactive device to the substations may be considered. However, connection of the device to the substation in several blocks appears to be more reliable, because with the looping of the transmission lines into a new substation, adequate electrical separate of the blocks of reactive support may be more difficult and the whole reactive support capability may be more at risk of being lost for single or double contingencies.
8i	2) In the Functional specifications released for Gates voltage support project, CAISO indicated that it will allow the use of SVC, STATCOM, Synchronous Condenser or Battery Storage as acceptable solutions. This somewhat contradicts with the discussion in Draft Plan where CAISO states that it prefers STATCOM as a solution at Gates. We recommend CAISO clarify in Final Transmission Plan.	The comment has been noted. For the Gates Voltage Support Project, different technologies may be considered as long as the solution satisfies the need. The preference expressed in the draft transmission plan simply reflected the additional challenges anticipated for the other devices to meet the needs. The project is eligible for competitive solicitation.
8j	<u>CAISO-PNW Increased Transfers Study</u> CAISO's conclusion on this study is that there is no capital upgrade required to increase COI N-S rating by 300 MW. While NERC TPL-001-04 standard treats the double line outage that drives COI Path Rating as Extreme Contingency (P7), but the WECC Path Rating Catalog still considers this as a NERC P6	With no capital upgrades required, there would be value in increasing the rating of the Path Rating to allow for operational flexibility of the system when the conditions allow for the contingency to be considered as conditionally credible. The increased capacity would not be

No	Comment Submitted	CAISO Response
	contingency. Further, CAISO Operations is now treating this double line outage as conditionally credible and as referenced in the Market notice provided by CAISO Operations system conditions in Operations may trigger the need for CAISO to not treat these contingencies as credible events. Given this, relying on the less stringent criteria for planning purposes can pose reliability risk. We recommend CAISO reconsider its proposal to increase path rating of the existing COI path. Planning ratings should not be changed if these cannot be used at all time in Operations.	considered available when conditions do not warrant it, and are not depended upon for meeting reliability criteria.
8k	Bulk Storage Study CAISO studied the economics of two large pump storage projects and concluded that the projects provided benefits; however a large portion of the benefits were from Net Market Revenues. We recommend that for any future similar analysis, CAISO should also consider long duration battery storage projects and OOS transmission projects. Both these alternatives can provide competing benefits with respect to GHG reduction, renewable curtailment reduction and production cost savings. This should allow CAISO to arrive at a more comprehensive and robust conclusion in this area.	The comment has been noted. The ISO notes that while the PLEXOS analysis conducted as a special study update in this planning cycle focused on pumped hydro storage, the ISO studied as part of its economic-driven transmission analysis battery storage and out of state transmission projects.

9. North Gila Imperial Valley #2, LLC (NGIV2)
Submitted by:

No	Comment Submitted	CAISO Response
9a	<u>Adjustments Are Needed to the Reliability and Economic Analysis for NGIV2</u> The proposed NGIV2 Project would become an additional component of the Western Electricity Coordinating Council's (WECC) West of Colorado River Transmission Path (WOR or Path 46), and it is expected to raise the Path 46 non-simultaneous "Accepted Rating" from 11,200 MW to 12,450 MW (an increase of 1,250 MW), while satisfying NERC Reliability Standard and WECC System Performance Criteria. We understand that the analysis performed by the CAISO for the draft Transmission Plan did not include this incremental limit capacity addition on Path 46 and its additional benefits for relieving constraints. Therefore, we request that the CAISO modify the binding constraint for Path 46 and set it to 12,450MW for the post-NGIV2 project economic case. We also request that the CAISO run a sensitivity to eliminate the 2000 MW net export limit from California, and re-evaluate the NGIV2 project's impact on net load payments and renewable curtailments. We believe that the net export limit in the production cost models artificially reduces the benefits of the NGIV2 project, and that the project can only be appropriately considered with the net export limit lifted. The CAISO's own analysis shows that eliminating the net export limit reduces renewable curtailment across the CAISO footprint, and may also reduce congestion, revealing NGIV2 project benefits that the CAISO's economic analysis is not otherwise measuring. Furthermore, since no net export limit is applied in market operations, its application in the economic studies creates unrealistic dispatch scenarios in the production cost models, which calls the validity of such modeling assumptions into question. Our review of the economic analysis in the draft Transmission Plan indicates that the production cost models may not be dispatching existing and proposed HVDC lines economically. Coupled with the net export limit, we suggest that uneconomic dispatch of the Pacific DC Intertie and Inter-mountain HVDC lines is creating some of the regional congestion and LCR increases identified in the pre- and post-project study results for the NGIV2 project. The separate analysis of SDG&E's proposed HVDC conversion of the existing North Gila – Imperial Valley 500 kV line, shows similar impacts on congestion and LCR, despite	The CAISO has approved projects that are also in the process of increasing the Path 46 non-simultaneous "Accepted Rating". We can consider the benefits of increasing the Path 46 rating due to the NGIV2 project after the benefits of increasing the Path 46 rating from projects already approved by the ISO have been considered. The 2000 MW net export limit is not based on transmission constraints, so it is not expected that the addition of the NGIV2 project would alleviate limitations on neighboring systems to take surplus renewable power from California. The HVDC model and dispatch in production cost simulation is software dependent. The ISO uses ABB GridView software to do production cost simulations for planning studies, which is attempting to economically operate the HVDC to minimize the system total production cost. If the stakeholder suggested a different HVDC model

No	Comment Submitted	CAISO Response
	proposing to convert the existing ties into Miguel and Suncrest into completely controllable bi-directional DC interfaces. Intuitively, the post-SDG&E project production cost models should hold hourly flows on these lines to the same amount as pre-project flows to avoid creating more costly congestion – and the SDG&E project should, at worst, show zero congestion relief benefits. The increases in congestion and LCR resulting from the SDG&E project, which are similar to those shown by the CAISO for the NGIV2 project, are further evidence of anomalies in the production cost model dispatch. We respectfully request that the CAISO restudy the NGIV2 project operating the HVDC lines economically, rather than assuming that controllable elements will be operated uneconomically	in the PCM, please coordinate with ABB to make sure the software implementation is as expected. The ISO can review and consider incorporating the stakeholder's model into the PCM.
9b	<u>Local Capacity Requirement (LCR) Reductions for NGIV2 Are Understated</u> The CAISO has indicated (in response to a question at the 2/14/19 stakeholder meeting) that its determination that the NGIV2 project has the potential to reduce LCR for the San Diego/Imperial Valley area by 865 MW was based on an N-1-1 analysis of the existing North Gila – Imperial Valley line and one of the segments of the NGIV2 project; specifically, the Highline to Imperial Valley segment. The permitting of the NGIV2 project will include a separation from the existing North Gila – Imperial Valley line of a minimum 250 feet, and we expect that the modeled outage would be considered an Extreme Event, rather than a P6. We request that the CAISO clarify whether this provides flexibility for further actions and reductions of the LCR. In addition, we request that the CAISO provide the value of LCR reduction associated with the relief of the El Centro 230/92kV transformer limitation (the next binding constraint).	The NERC definition of a P6 contingency includes the loss of one transmission circuit followed by system adjustments and then the loss of another transmission circuit. The two transmission circuits do not need to be adjacent to be considered a P6 contingency.
	The determination of the 100MW incremental impact on the LA Basin LCR, and subsequent impact on the overall net benefits of the NGIV2 project, is limited by a 1% overload on the Mesa – Laguna Bell 230kV line under the N-1-1 of Mesa-Redondo and Mesa-Lighthipe 230kV circuits. We propose making other system adjustments, including potential operational solutions referenced in the draft Transmission Plan that "are often selected in lieu of transmission upgrades," following the N-1 to reduce the 1% overload following the subsequent N-1. By doing so, the economic and LCR reduction benefits of the NGIV2 project further increase by 11%. This increase, coupled with the economic benefits provided by enabling the delivery of additional renewable resource output from the	The ISO would need specific operational solutions to be provided for this comment to be evaluated.

No	Comment Submitted	CAISO Response
	Imperial Valley, would push the Benefit/Cost ratio for the NGIV2 project above 1.0. The CAISO draft Transmission Plan notes the benefit cost ratio of NGIV2 would go down if "potential negative impacts" were included in the calculation. We respectfully note that the "potential negative impacts" criterion/phrase does not appear anywhere else in the draft Transmission Plan, and further, that other projects would likely also see a reduction of Benefit Cost ratios if "potential negative impacts" were evaluated as CAISO appears to do only with NGIV2. Thus, one wonders whether the NGIV2 project is being held to a standard not imposed on other projects. Moreover, the statements about the "potential negative impacts" are based on exceeding criteria that are assumed elsewhere in the document that study the San Diego Import as operating between 2400 and 3500 MW. Our analysis shows that with adherence to the 3,500 MW San Diego Import Limit, there are no negative reliability impacts due to the NGIV2 project. We request the CAISO to limit its evaluation to the criteria for study as stated in Section 2.3, reiterated in Section 2.9.2. We note that NGIV2 would help provide flexibility and strengthened connection to the San Diego area that could potentially help avoid operational issues such as those experienced in 2011. CAISO's own analysis demonstrates that NGIV2's economic and LCR reduction benefits are over $20M per year, that the project enables additional renewable resources to be delivered to regional load, including resources directly connected to the Imperial Irrigation District (IID), and that it adds capacity and reliability for Path 42 and the CAISO system in the form of improved ties between California and neighboring states. By enabling more renewable generation to be delivered from the Imperial Valley, the NGIV2 project also has the potential to spark new development in that area, creating economic growth and jobs for a disadvantaged community.	First, contrary to the comment, the ISO has made observations where relevant about other projects having potential for negative impacts that were noteworthy but that it was not necessary to explore in detail at this time. Please refer to section 4.9.3.2 of the draft transmission plan for an example. Second, the base cases used for this analysis were used to perform our NERC TPL-001 compliance analysis documented in Chapter 2 of the report and are posted on the ISO's market participant portal. Third, regarding potential for additional renewable generation development, this is a consideration to be raised with the CPUC in the development of renewable generation portfolios for policy-driven transmission planning purposes.
9c	<u>NGIV2 Compliments and Expands Benefits Provided By the S-Line Upgrade</u>	

No	Comment Submitted	CAISO Response
	We would also like to take this opportunity to comment on the S-Line Upgrade Project approved in the 2017-2018 Transmission Plan. We support the continued need for this upgrade for reliability reasons, and for delivery of energy from renewable resources from the IID system. However, as the CAISO has noted, the need to mitigate for the loss of the existing North Gila – Imperial Valley line is still warranted following completion of the S-Line upgrade. We maintain that the NGIV2 project compliments and rounds out the benefits provided by the S-Line Upgrade. The combination of the S-Line Upgrade and NGIV2 projects would provide long-term reliability improvement, further increase the LCR reduction benefits, and offer more complete congestion relief for the southern region. Additionally, this combination offers a least-regrets solution that provides bi-directional outlet from the Palo Verde hub, which will be critical as the Energy Imbalance Market continues its expansion eastward from California. In summary, we respectfully request that the CAISO make the following adjustments to the analysis informing its draft recommendations and the calculation of the Benefit/Cost ratio for the NGIV2 project: • Set the binding constraint for WECC Path 46 to 12,450MW for the post-NGIV2 project economic case; • Re-evaluate the NGIV2 project's impact on net load payments and renewable curtailments in a sensitivity case eliminating the 2000 MW net export limit; • Restudy the controllable HVDC lines in the production cost model dispatch operating them economically; • Address the potential for further LCR reduction benefits to be attributed to the NGIV2 project with the clarifications and adjustments discussed above; and • Clarify or remove statements attributing potential negative impacts arising from the project that are based on criteria that go beyond the assumptions used elsewhere in the document.	Please see responses above.

10. Nevada Hydro Company (NHC) Submitted by:		
No	**Comment Submitted**	**CAISO Response**
10a	1. The Plan does not appear recognize FERC's finding that LEAPS qualifies under federal law as an "advanced transmission technology." If studied as a transmission asset, please identify each reliability need for which CAISO studied LEAPS as a potential solution and the results of the analysis explaining why CAISO did not select LEAPS as a reliability solution. Please confirm that CAISO also studied LEAPS in the Plan as an "economic transmission" project.	The ISO's tariff calls for the ISO to identify reliability needs, and then consider potential solutions to meet those needs. As there were no identified transmission reliability needs that LEAPS could address, there was no further study as a potential reliability solution. Please refer to chapter 2. The ISO also studied LEAPS as an economic transmission project.
10b	2. The Plan also does not explain how the conclusions regarding LEAPS are consistent with the Federal Energy Regulatory Commission's ("FERC") Policy Statement governing the treatment of electric storage as wholesale transmission facilities for planning and cost recovery purposes under the Federal Power Act. Please explain how the CAISO applied the FERC Storage Policy Statement to its assessment of LEAPS in the Plan.	Regarding reliability needs, please refer to the response to 10(a) above. Regarding economic-driven transmission needs, please refer to section 4.9.11.5. Regarding the referenced policy statement, the ISO notes that FERC clarified in its order dismissing the Nevada Hydro Company's petition for a declaratory order, issued September 20, 2018, that the policy statement "*does not provide guidance for determining whether a particular electric storage resource is a transmission facility eligible for cost recovery through transmission rates. Rather, the Storage Policy Statement provides guidance only with respect to issues that must be addressed if an electric storage resource seeks to receive cost-based rate recovery for certain services, whether through transmission rates or any other cost-based rate, while also receiving market-based revenues for providing separate market-based services*." The ISO's analysis, without needing to delve into the cost recovery mechanisms involved, considered potential market revenues in the assessment of the economic benefits of LEAPS and in ascertaining that the economic benefits did not support the costs.
10c	3. The CAISO told FERC that it "has committed to studying LEAPS as a transmission proposal, both as a means to address reliability needs . . . and as an economic planning study request." Nevada Hydro Co., Inc., 164 FERC ¶ 61,197, at P 23 (2018). FERC cautioned that "We expect CAISO will adhere to this commitment." Id. This commitment entailed evaluating whether LEAPS will (1) solve identified reliability violations within the CAISO's transmission planning horizon, and (2) meet the criteria for an economic transmission project by evaluating system benefits under the	Regarding reliability needs, please refer to 10(a) above. The ISO does not agree with the characterization of the transmission plan. The ISO does consider its analysis to address the appropriate range of TEAM benefits, and again notes that a reliability or policy requirement needs to be identified in order for a reliability or policy benefit to be assessed.

No	Comment Submitted	CAISO Response
	five-part Transmission Economic Assessment Method ("TEAM") that CAISO has long applied to its evaluation of transmission proposals. The Plan does not appear to meet this goal, and thus falls short of the CAISO's promise to FERC.	
10d	4. The Plan does not appear to quantify benefits provided by LEAPS that CAISO has counted for other transmission projects offered into the Plan. As one example, the CAISO identifies for "informational" purposes significant PCM cost reduction benefits to the entire WECC region resulting from the LEAPS project (as it typically does for economic transmission projects), but limits the quantification of benefits from LEAPS to only those estimated for the CAISO sub-region of WECC. Please explain why CAISO did not count benefits accruing to the entire WECC region for LEAPS when it does so for other transmission projects and whether the CAISO is no willing to correct this disparate treatment.	The ISO's treatment of LEAPS is consistent with the assessment of other projects. Given the level of documentation available in the draft transmission plan, NHC's references to unspecified "other projects" make the comment somewhat unclear. Regarding the quantification of WECC-wide production cost savings, these values were provided for the LEAPS project in Tables 4.9-40 and 4.9-45. Regarding the consideration of WECC-wide production cost savings in decision-making, the ISO's updated TEAM documentation dated November 2, 2017 and available on the ISO website states on page 4, section ES.5, that "*The CAISO will primarily rely on ISO ratepayer perspective when evaluating the economic viability of a potential transmission upgrade since cost covering of transmission upgrades is collected from the ratepayers by the TAC. Additionally, the societal perspective is applied as a test for the benefit of the whole WECC region. This second perspective is especially considered for upgrades with interregional impacts.*" This document is available at: http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf A reference for "other transmission projects" would have been helpful. The ISO is not aware of any instance where it counted the benefits to the entire WECC region in determining that a project was economic. The costs of ISO regional projects are borne by ISO ratepayers, not the entirety of WECC.
10e	5. The CAISO's calculation of LCR benefits for LEAPS is inconsistent with the CAISO's study quantifying locational capacity resource ("LCR") needs in	As noted on the 64th page of the ISO's November 16, 2018 stakeholder meeting presentation "*In considering economic benefits to reduce local capacity reductions in this cycle: Conservative assumptions will be*

No	Comment Submitted	CAISO Response
	other transmission studies and the recent CAISO contracts entered into for LCR capacity needs. (See attached ZGlobal analysis.)	*employed at this time for potential transmission project approvals, while awaiting clearer direction in future CPUC IRP cycles on SB 100-related gas-fired generation reduction plans*". This was clarified in section 4.3.4 of the draft transmission plan, and the approach was used consistently in the 2018-2019 transmission planning cycle to assess local capacity requirement reduction benefits. It was also noted that the ISO expects to revisit this in future planning cycles when clearer direction on SB-100 related gas fired generation reduction plans is available.
10f	6. The CAISO has completed two recent Special Studies of pumped storage hydro ("PSH") in Southern California in order to advise the CPUC on the value of PSH to California customers and concluding that PSH provides indispensable benefits to California ratepayers in light of California's increasing renewable portfolio standard ("RPS"), including LCR benefits. The CAISO described the assumptions in those studies as overly conservative. Since CAISO's earlier studies, California has in Senate Bill 100 ("SB 100") increased the RPS requirement from 30% to 60% by 2030 and 100% by 2045. Please indicate what assumptions are driving the dramatically different results in the TPP study.	The comment has comingled several issues. First, the "special studies" conducted for informational purposes and to inform the ISO's participation in the CPUC's Integrated Resource Planning proceedings found significant benefits to pumped storage, but the benefits were not found to be "indispensable", and did not provide a benefit to cost ratio exceeding 1. No reference was provided regarding the comment describing the CAISO's description of its assumptions as overly conservative. On the assumption that this is reference to an ISO statement on page The reference to the statement on page 323 of the 2016-2017 Transmission Plan: "*There are uncertainties in some of these assumptions and the assumptions generally lead to conservative curtailment results understating the benefits of the pumped storage.*" The paragraph continued on, however, to note: "*The ISO will conduct additional sensitivity analyses on the various assumptions to frame the range of potential results, including…*" These supplemental sensitivity studies were conducted over the next year, and posted to the ISO website as supplemental 2016-2017 planning process analysis. Regarding production cost analysis, the assumptions are set out in each of the transmission plans. Regarding capacity benefits, please refer to the response to 10(e) above.

No	Comment Submitted	CAISO Response
10g	7. We also request that the CAISO reconcile the benefit calculations in the two recent Special Studies performed for the CPUC with the current benefit calculations pertaining to LEAPS in the Plan. The Plan does not seem to make clear the rationale supporting the use of these different assumptions that have produced the different results.	Please refer to the response to 10(e) above.
10h	As CAISO is aware, FERC's transmission planning process places a premium on comparability and transparency and these principles are incorporated in CAISO's Tariff. The answers to questions provided above are necessary for Nevada Hydro to properly assess whether the Plan has adequately complied with these tariff requirements.	Please refer to the above responses.
10i	<u>Issues with Using CPUC Default Portfolio in Production Cost Modeling for the Economic Assessments</u> • The assumed operation of gas-fired generation in the default portfolio no longer complies with California state policy (60% RPS by 2030, 100% carbon free by 2045 and aggressive MMT targets). Further this portfolio does not reflect LSE procurement expected in the planning horizon as now observed in the Hybrid Conforming Portfolio being recommended by CPUC as the Preferred System Plan in the 2017-2018 IRP. Moreover, as pointed out by ISO on page 456 of its Draft 2018-2019 Transmission Plan, "the CPUC not only made changes to the selection of new resources, it also retired all gas-fired thermal generation resources that are 40 year or older." As a result, by using the outdated Default Portfolio, ISO's economic assessments are not adequately quantifying the true production cost benefits of LEAPS. • Default Portfolio: The ISO's study reflect that the transmission benefits for ISO ratepayers produce a negative Production Cost results for LEAPS. Table 4.9-40 – Option 1b and Option 2 show negative production cost benefits of negative (-) $31 million and (-) $34 million respectively. This results in ISO concluding that LEAPS has no economic value as a transmission service. The ISO offers in a note under table 4.9-40 that it excluded $73 million of production cost benefits that are from market revenues from LEAPS. When included, the net production cost benefits for	As NHC is aware, the study assumptions are developed early in the study cycle, with modeling and analysis then developed through the planning cycle. New requirements developing through the planning cycle or late in the planning cycle are incorporated into the next planning cycle – with the study plan development overlapping the final stages of the current year's transmission plan development. The ISO expects future portfolios provided by the CPUC will reflect emerging issues. The comment misconstrues the ISO documentation and is fundamentally incorrect. For tracking purposes, the ISO ratepayer production cost benefits without LEAPS' market revenues and the LEAPS market revenues were reported separately in Table 4.9-40. However, as set out in Table 4.9.44 and Table 4.9-45, the ISO ratepayer PCM benefits without LEAPS market revenues <u>and</u> the LEAPS market revenues were summed to provide a Total PCM Benefits value, and the ISO used that total value in calculating the benefit to cost ratios for the various LEAPS options. Thus all benefits were counted while remaining indifferent to whether the asset was

No	Comment Submitted	CAISO Response
	LEAPS is positive $42 million and $39 million for Option 1b and Option 2 respectively (Table 4.9-44). Please explain why it is appropriate to reduce the production cost benefits of LEAPS in this way. • Hybrid Conforming Portfolio: However, in their special study (Chapter 7) using the HCP and different software (PLEXOS), they conclude that 500 MW pumped storage results in ISO production cost benefits of $51 million. The HCP appears to increase the production cost benefits of LEAPS between $9 and $12 million. Is this correct? Can ISO explain the drivers for the increase?	receiving cost of service based revenue and market revenues, or if it was under a PPA. The results discussed above demonstrated that the benefits did not outweigh the costs given the study assumptions used in this planning cycle. The statement in the NHC comments that "This results in ISO concluding that LEAPS has no economic value as a transmission service" is incorrect, as the ISO found some benefits but they did not outweigh the costs. The assumptions used in the special study are set in section 7.2.1 and the development of the PLEXOS model are set out in section 7.2.2 of the draft transmission plan. These differ from the assumptions developed for the transmission planning process. Further, the PLEXOS model is a zonal model and a nodal model is used in the GridView analysis.
10j	<u>Retirement of Gas-fired plants:</u> • As mentioned above, the Default Portfolio used in ISO TPP has gas fired plants running and hides the value that LEAPS has to support reliability, system and flexible capacity needs. Would ISO be willing to consider in its economic assessment additional sensitivity scenarios that assess the value LEAPS to eliminate, a) The need to rely on local gas-fired generation used in operational procedures to mitigate local reliability issues, b) Reliance of gas-fired resources to provide system and flexible capacity. This seems consistent with ISO statement that it "…recognizes that additional coordination on the long-term resource requirements for gas-fired generation for system capacity and flexibility requirements will need to take place with the CPUC through future integrated resource planning processes." However, we feel that ISO can do more to advance long-lead time solutions such as LEAPS in its TPP studies done in this cycle to quantify this value in its TEAM and recommend value-added transmission solutions that will support future reliability needs for the state's policy	These issues are best addressed in the CPUC's Integrated Resource Planning proceedings, and the ISO intends to continue to actively participate in those proceedings.

No	Comment Submitted	CAISO Response
	directives. It seems that ISO is in the best position to identify this value now in order to assure long lead time solutions such as LEAPS are constructed and ready for operation when gas-fired plants are retired or are no longer viable to run because of state policy objectives and laws (SB100).	
10k	No Quantification of RPS Overbuild Cost Savings: • ISO's TEAM analysis does not capture LEAPS benefits to reduce overbuild. TPP is the appropriate study to assess the transmission solution benefits of enabling the selection of a more efficient capacity procurement mix that reduces overbuild. This was demonstrated by CAISO in its Special Studies conducted in their 2017-2018 and 2016-2017 cycles where between $29 and $73 million dollars of RPS overbuild savings can be realized with 500 MW of Pumped Storage. This is a TEAM benefit that was ignored by ISO but allowed under TEAM principles per its methodology document, page 22 Section 2.5.5, "When there is a lot of curtailment of renewable generation, extra renewable generators would be built or procured to meet the goal of renewable portfolio standards (RPS). The cost of meeting RPS goal will increase because of that."	For clarity, section 2.5.5 refers to a transmission project that "increases the importing capability into the CAISO controlled grid". Further, referring to the comments submitted by CPUC Staff on October 5, 2018, following the ISO's September 20-12 stakeholder meeting: "*CPUC Staff believes that energy storage, when used for resource substitution, is under CPUC's purview for approval and should not be approved as part of the CAISO's Transmission Planning Process (TPP).*" Regarding the special studies, the following explanation was provided on page 465 of the draft transmission plan regarding the change in approach in the special studies: "*In the previous cycles of transmission planning cycles, the bulk energy storage studies calculated the benefits of storage reducing the amount of renewable "overbuild" necessary to achieve the 50% RPS target. In the 2017-2018 IRP proceeding, sufficient renewable resources were selected that exceeded the RPS 50% target of the 2017-2018 IRP cycle even after considering curtailment. In addition, there are also some "banked" renewable energy certificates (RECs) available to be used in 2030 taking the achieved level even higher. Therefore, the benefits of storage reducing the "overbuild" of wind and solar capacity were not calculated, and instead the GHG pricing addresses those benefits.*"
10l	LCR Price ISO's study undervalues LEAPS benefit to provide LCR capacity to San Diego area. The ISO acknowledges that it uses conservative assumptions and has changed its perspective compared to last year's studies. The LCR price used in this year's TPP is a reduction of between $56,640/MW-Year (High) and $24,780/MW-Year (Low).	The CPUC-provided actual capacity procurement costs are a more reasonable estimate of capacity costs than the CPM soft offer cap, especially given other uncertainties regarding the future reliance on gas-fired generation. While the ISO acknowledged that the assumptions used in this planning cycle are conservative, they may

No	Comment Submitted	CAISO Response
	Last year's study San Diego Area LCR benefit price range: $75,720/MW-Year (High) and $37,860/MW-Year (Low) (or $6.31/kW-month and $3.155/kW-month respectively) This year's study San Diego Area LCR benefit price range: $19,080/MW-Year (High) and $13,080/MW-Year (Low) (or $1.59/kW-month and $1.09/kW-month respectively) This is a reduction of $56,640/MW-Year and $24,780/MW-Year respectively. From page 253, 2017-2018 Board Approved Transmission Plan: The price of San Diego area generation capacity in 2018 based on the Capacity Procurement Mechanism (CPM) price set out in the ISO tariff is the applicable monthly soft offer cap of $6.31/kw-month. This results in a $75,720/MW-Year price for this capacity. The full value can be used as an estimate of the high end of the range of benefit provided by a reduction in local capacity requirement. Recognizing that local capacity in the San Diego-Imperial Valley area could also provide other benefits such as flexible generation, a reasonable low end of the benefit is half of the local capacity price, or about $37,860/MW-Year.	prove to be more accurate depending on future direction from the CPUC's IRP proceedings.

11. Natural Resources Defense Council (NRDC) Submitted by: Julia Prochnik		
No	Comment Submitted	CAISO Response
11a	NRDC would like the CAISO to explore the 2000 MW net export limit. At the recent FERC Order 1000 Interregional meeting in Salt Lake City, there was discussion among stakeholders on how the CAISO and other FERC 1000 regions modeled export limits. CAISO has a 2000 MW restriction, while the other regions did not place this limit and discovered different findings. NRDC would like to see the CAISO dig into the data and model limitations. This limitation could be reducing benefits and driving up renewable curtailment in the region. Eliminating the export limit can result in a reduction in renewable resource curtailment and possible decreases in congestion in the CAISO footprint, which will create economic, reliability and public policy benefits to California. NRDC looks forward to working with CAISO and CPUC to re-evaluate the export limitations.	The comment has been noted. The ISO notes that the 2000 MW export is not a physical transmission capability limit, but rather an estimate of the practical ability of systems outside of the ISO footprint to manage and accommodate higher levels of import from the ISO. This issue has been a topic of discussion in CPUC IRP processes, and the ISO intends to continue to participate in that forum. The ISO expects to incorporate in the transmission planning process any change in this assumption resulting from consideration in the IRP process.
11b	NRDC supports the work to ensure the dynamic stability simulations models demonstrate adequate dynamic stability performance and appreciate the importance to share the updates with WECC to help improve coordinated regional planning.	The comment has been noted.
11c	Lastly, NRDC looks forward to updates from the public policy slide 40 regarding next steps: • Provide the updated transmission capability estimates to the CPUC and assist with incorporating these into the RESOLVE model • The ISO is currently working with the CPUC to ensure that nested constraints are considered • Inform the IRP proceeding with insights regarding renewable curtailment and conceptual upgrades tested in 2018-2019 policy driven assessment • Incorporate key findings from this study in coordinating with the CEC staff for mapping portfolio resources in zones with high likelihood of severe local transmission constraints • Develop framework based on CPUC-provided objectives for siting generic storage selected in CPUC IRP process	The comment has been noted. The ISO notes that updates based on information available at the time was provided to the CPUC in January, 2019 for input into the CPUC's development of planning assumptions for the 2019-2010 planning cycle, but that the CPUC's schedule did not accommodate waiting for the ISO's 2018-2019 transmission planning analysis to be completed at a later date.

12. Pacific Gas & Electric (PG&E)
Submitted by: Matt Lecar

No	Comment Submitted	CAISO Response
12a	Assessment of Previously Approved Projects PG&E appreciates and supports the CAISO's efforts to re-evaluate previously approved projects in the PG&E service territory. PG&E offers the following commentary on projects with "on-hold" status in the 2017/2018 TPP Re-Assessment: Diablo Canyon Voltage Support Project The CAISO recommends cancelling the Diablo SVC project which was originally proposed to meet Nuclear Power Interface Requirements (NPIR) at Diablo Canyon Power Plant (DCPP), and instead to rely on local Under Voltage Load Shedding (UVLS) schemes such as Divide UVLS and Mesa UVLS to meet NPIR until DCPP retires in 2025. PG&E agrees to cancel this project but is concerned about the local UVLS's capability to meet NPIR at DCPP without any modifications. For example, these existing local UVLSs are not designed to monitor the voltage at the Diablo 230kV bus so that they may not be triggered when the voltage is below NIPR requirements at the Diablo 230kV bus. In addition, the total amount of armed load for these UVLSs are not designed to meet NPIR, so they may not be able to trip enough load to mitigate the low voltage issues at the Diablo 230kV. As such, PG&E recommends to further evaluate the need for any necessary upgrades or modifications for the local UVLSs to ensure the NPIR could be met.	The comment has been noted. The ISO will continue to work with PG&E on the UVLS requirements in the area. The ISO will review the upgrades as PG&E conducts its additional assessments and, if in agreement, will concur with PG&E proceeding with the potential upgrades as the ISO has done with other protection upgrades such as RAS or UVLS schemes required for reliability.
12b	South of Mesa Upgrade Project Part of the CAISO recommended scope is to rerate the winter emergency rating for the Sisquoc – Santa Ynez 115 kV line. However, pursuant to PG&E's Conductor Rerate Process for Overhead Transmission Circuits procedure manual, TD-1004P-04, PG&E cannot rerate the transmission line to 4fps on the winter emergency ratings. Given this, PG&E recommends the CAISO approve the alternative scope of reconductoring roughly 23 miles of the Sisquoc – Santa Ynez 115 kV line using at least 715 AAC. PG&E's initial total AACE Class 5 Cost estimate for the entire South of Mesa Project will be increased to $59.2M accordingly.	The ISO has modified the scope for the South of Mesa Upgrade recommended for approval in the Revised Draft of the 2018-2019 Transmission Plan to reconductor the Sisquoc – Santa Ynez 115 kV line as indicated.

No	Comment Submitted	CAISO Response
12c	PG&E offers the following clarifying comments on a previously approved project that was not "on-hold" in the 2017/2018 TPP Re-Assessment: Cottonwood 115 kV substation shunt reactor project The Cottonwood 115 kV substation shunt reactor project (approved in the 2015-16 TPP cycle) has been re-scoped to include the replacement of Cottonwood 230/115 kV transformer banks 1 and 4 with 420/462 MVA transformers and LTC, but the CAISO TPP project name has not been revised to align with the scope. For clarity and ease of tracking, PG&E recommends officially renaming the project to "Cottonwood 230/115 kV Transformers 1 and 4 Replacement" in the CAISO Plan.	The project name has been updated in the Revised Draft of the 2018-2019 transmission Plan.
12d	<u>Assessment of Newly Proposed Projects</u> PG&E offers the following commentary on newly proposed projects presented in the CAISO's 2018-2019 draft Transmission Plan. Pease Economic Project The CAISO's analysis of the Pease sub-area suggests a BCR of 0.99 for looping in of Pease-Marysville 60kV line into East Marysville 115kV substation, installing a 115/60kV transformer at East Marysville substation and adding 25MVAR of voltage support. Since the date of PG&E's original project submittal in September 2018, which included an AACE Class 5 cost estimate of $26M to $52M, inclusive of 100% contingency, PG&E has further refined the project cost estimate range to be $26M - 32M. As of the date of these comments, this $26M – 32M is the "expected" cost estimate. CAISO's analysis suggesting a BCR of 0.99 utilizes the now dated, high-end estimate presented in the original project submittal of $52M. Given this newly revised, and relatively lower cost estimate, the updated BCR is projected to be greater than one. PG&E recommends the CAISO approve this project in 2018-19 TPP cycle.	The ISO has updated the analysis in the Revised Draft of the 2018-2019 Transmission Plan to reflect the revised cost estimate for the project. The ISO has recommended the approval of the East Marysville 115/60 kV project in the Revised Draft of the 2018-2019 transmission Plan..
12e	500kV Voltage Control Projects PG&E supports the CAISO's conclusion that 500kV voltage control projects are needed at both the Round Mountain and Gates substations. Based on previous experiences with competitive solicitations, PG&E recommends the competitive solicitation materials be clear and explicit about the scope delineation between the competitive and non-competitive scope elements for each of the two 500kV voltage control projects.	The comment has been noted.

No	Comment Submitted	CAISO Response
12f	Kingsburg-Lemoore Reconductoring The reconductoring of the Lemoore to Hanford section of the Kingsburg-Lemoore 70 KV Line addresses two major business risks - reliability and safety. In addition to increasing emergency load serving capability for Lemoore Substation customers (as explained in the project submittal document), reconductoring the section will address aging and obsolescent infrastructure. PG&E plans to further assess its assets in this section of the line and implement necessary mitigations	The comment has been noted.
12g	Oakland Clean Energy Initiative (OCEI) During the 2017-18 TPP, PG&E proposed and the CAISO approved an innovative project to resolve reliability issues that would otherwise occur in the absence of the aging Dynegy/Vistra Oakland Power Plant, which is currently designated as a Reliability Must Run (RMR) facility. In its Board Approved Plan1, the CAISO stated: The ISO review found that the OCEI project address [sic] all reliability issues identified in the Oakland area without local generation. The ISO is recommending the approval of the transmission regulated assets of the Oakland Clean Energy Initiative project for the substation upgrades at Moraga and Oakland X, rerating of Moraga-Claremont 115 kV Lines #1 and #2 and the installation of the battery storage at the Oakland C and Oakland L 115 kV substations that are estimated to cost $56 to $73 million with an in-service date of 2022. The ISO is recommending PG&E to seek approval through the CPUC procurement process [for] the additional identified preferred resources for the Oakland Clean Energy Initiative. Based on the last year of additional study and after consultation with CAISO Staff, PG&E requests that CAISO amend its approval language for the OCEI in the following ways: 1) Under contingency, there is an additional subarea constraint at Oakland L requiring a minimum of 7 MW/28 MWh. PG&E should modify its plan to include the most cost-effective combination of either additional transmission solutions and/or dedicated resource procurement at Oakland L. The new language would	The CAISO concurs with the modifications proposed for the OCEI project and has included in the Revised Draft of the 2018-2019 transmission Plan.

No	Comment Submitted	CAISO Response
	state that, of the total resource mix (20 MW/120 MWh) to be sited within the Oakland C and Oakland L 115 kV substation pocket, no less than 7 MW/28 MWh should be either located at the Oakland L substation or interconnected via the PG&E distribution system to the CAISO-controlled grid at Oakland L. 2) CAISO should no longer explicitly require a utility-owned storage battery as part of the OCEI solution. Instead, CAISO should encourage PG&E to seek the most cost-effective combination of resources, with no minimum prescribed amount of utility ownership. PG&E may competitively solicit (and seek CPUC approval to procure) market-participating preferred resources to meet any amount up to the total 20 MW/120 MWh need within the Oakland C and Oakland L 115 kV substation pocket.	

13. Public Advocate Office Submitted by: Kanya Dorland		
No	**Comment Submitted**	**CAISO Response**
13a	A. RECOMMENDATIONS ON PROPOSED 2018-2019 RELIABILITY PROJECTS 1. Pacific Gas and Electric Company's (PG&E) Gold Hill 230/115 kilovolt (kV)Transformer Addition Project The proposed Gold Hill 230/115 (kV) Transformer Addition project is in the PG&E service area and has an estimated cost of $22 million. 1 The Gold Hill substation has two existing 230/115kV transformers that serve the entire load on the 115-kV system from Drum to Gold Hill to El Dorado Power House substations. This project would add a third 230/115 kV transformer to the Gold Hill substation.2 The CAISO proposes constructing a third 230/115 kV transformer at the Gold Hill substation instead of the proposed Atlantic Placer 115 kV project, which was approved in the 2012-2013 CAISO Transmission Plan. The 2018-2019 TPP reliability assessment demonstrated that reliability issues occur when one of the Gold Hill transformers are taken out for maintenance and a third transformer would address this reliability issue. The Public Advocates Office recommends that the CAISO consider installing a special protection system (SPS) to allow for maintenance on the existing two Gold Hill transformers as an alternative solution to address the identified reliability issues instead of constructing a new transformer. The CAISO should also provide a cost estimate for this proposed alternative solution to enable stakeholders to make costs comparisons with the proposed project. The Public Advocates Office, however, recommends that a SPS that would drop load not be used as a long-term solution.	Based on the ISO's planning standards, an N-1 contingency should not result in load shedding during maintenance activities. Since the ISO's analysis indicated that there is no such window available for maintenance of the Gold Hill 230/115 kV transformers, the addition of a 3rd transformer is recommended to meet the planning standards.
13b	2. PG&E 115 kV Line Reconductor Projects There are two proposed line reconductoring projects in the PG&E service area which are: (1) the Christie-Sobrante 115 kV Line Reconductor project with a cost estimate of $10.5 million and (2) the Moraga-Sobrante 115 kV Line Reconductoring project with a cost estimate of $12 to $18 million. To confirm this project is the lowest costs solution to address the identified overloads in the service area, the Public Advocates Office requests that the CAISO evaluate an alternative solution that would involve the addition of circuit breakers to improve	For the Christie-Sobrante 115 kV line reconductor project, the ISO considered low cost alternatives like rerating the line, which was found to be insufficient due to the amount of the overload. The circuit breaker addition solution is not sufficient as it doesn't address all contingencies that result in overloads on this line.

No	Comment Submitted	CAISO Response
	the operation of the Sobrante bus. The CAISO should also provide a cost estimate for this proposed alternative solution to enable stakeholders to make costs comparisons with the proposed project.	For the Moraga-Sobrante 115 kV line reconductor project, the ISO considered low cost alternatives like rerating the line, which was found to be infeasible due to the composition of the line that includes sections of different conductors. The circuit breaker addition solution was also considered and was found to be more costly as it triggered significant upgrades to the Moraga and Sobrante 230 kV buses.
13c	3. PG&E Voltage Support Projects There are two proposed voltage support projects in the PG&E service area which are: (1) Round Mountain 500 kV Dynamic Voltage Support with a cost estimate of $160 to $190 million and (2) Gates 500 kV Dynamic Voltage Support with a cost estimate of $210 to $250 million. For the identified voltage issues at the Round Mountain and Gates 500 kV bus facilities, the CAISO recommends reactive support projects in the form of Static Volt-Amp Reactive (VAR) Compensator (SVC), Static Synchronous Compensator (STATCOM), or synchronous condenser. In order to address these identified voltage issues, the Public Advocates Office recommends that the CAISO not overly prescribe the required technology for the competitive solicitations for these projects. Instead, the Public Advocates Office recommends the CAISO provide functional specifications for the proposed two voltage support projects as part of the competitive solicitation in order to allow lower costs solutions to be proposed. The Public Advocates Office notes that the costs associated with the mitigation solutions proposed to address the voltage support issues at Round Mountain and Gates by some project proponents were significantly lower than others. For example, capacitors, other reactors and storage technology could be part of a lower cost solution. As stated in the Public Advocates Office's comments on 2018-2019 TPP Preliminary Results, "competitive solicitations without proscribed solutions have the potential to result in identifying lower cost solutions than those proscribed, which would reduce costs for ratepayers."	The comment has been noted. For the Round Mountain and Gates Voltage Support Projects, different technologies may be considered as long as the solution satisfies the need. The voltage support has to be dynamic, and for the Gates project, it has to be fast-acting to minimize momentary cessation of the inverters and the loss of load due to stalling of single-phase air conditioners. Please refer to the response to 8(i). These projects are eligible for competitive solicitation.
13d	4. PG&E North and South of Mesa Upgrades The CAISO proposed two projects in PG&E's Central Coast/Los Padres service area which are the North Mesa and South Mesa Upgrades. These projects would address thermal overloads in the 115-kV system from the Mesa substation and allow for planned facility maintenance. The North Mesa Upgrade	The ISO has updated the project scopes for the North of Mesa and South of Mesa Upgrade projects in the Revised Draft of the 2018-2019 Transmission Plan.

No	Comment Submitted	CAISO Response
	project would build a new substation, energize a line and create new connections and line loops into the new substation. Its estimated cost is $170 million. The South Mesa Upgrade would increase the winter emergency rating of an area line, install a 20 mega volt amps reactive (Mvar) capacitor bank, and install a SPS to shed load if a P6 situation occurs under peak load. Its estimated cost is $45 million. These projects would be in place of the previously proposed Midway-Andrew project. The current cost estimate for the Midway-Andrew project is $215 million which is equal to the cost estimates of the North and South Mesa upgrades combined and it involves a similar scope as the proposed alternative projects. Thus, the proposed Midway-Andrew project alternatives are not more cost efficient than the Midway-Andrew project.	
	Since there are uncertainties associated with the retirement of the Diablo Canyon Power Plant and the proposed Midway-Andrew project alternatives are not lower in costs then the previously proposed solution, the Public Advocates Office requests two additional alternatives be considered to address the reliability needs in the Central Coast/Los Padres area: (1) As recommended in comments on the 2017-2018 CAISO TPP and the Midway-Andrew project, consider existing transmission lines in the project area and their ability to solve any reliability issues remaining after the retirement of the Diablo Canyon Power Plant as lower costs solutions to address the area reliability needs. There are a number of 500 kV lines and 230 kV lines in the Diablo Canyon-Midway-Andrew project area that may be under-utilized or experience lower demand after the retirement of the Diablo Canyon Power Plant. (2) Revisit the Lopez to Divide 500/230 kV Transmission System Project in the 2019-2020 TPP cycle as an additional alternative to the Midway-Andrew project. This project would address the same reliability issues as the North Mesa Upgrade project and at potentially lower costs than the North and South of Mesa Upgrades. The Public Advocates Office requests that the CAISO provide the costs associated with these proposed alternative solutions along with the costs for the components of the North Mesa and South Mesa Upgrade projects so that stakeholders can make costs comparisons and determine the most cost-efficient solution.	The estimated cost of the North of Mesa Upgrade project is $114 – 144 million and is recommended to be on hold due to uncertainties related to converting one of the 500 kV lines from Midway to Diablio to 230 kV and needing further review in future planning cycles. The scope of the South Mesa Upgrade project was modified to reflect that the rerating of the Sisquoc-Santa Ynez 115kV line has been determined to be unfeasible and will requiring with an estimated cost of $29.6 – 59.2 million for the project. The South of Mesa Upgrade project is being recommended for approval. The Divide – Lopez project has been reviewed as an alternative and while it would address the reliability needs similar to the North of Mesa Upgrade project. However the costs provided in the project submitted in the request window only reflect the cost of the project scope identified and does not include the cost of additional work required by the incumbent PTO which would be significant due to the substation and transmission line work not included in the estimate that would result in similar or higher costs than the North of Mesa cost estimate.

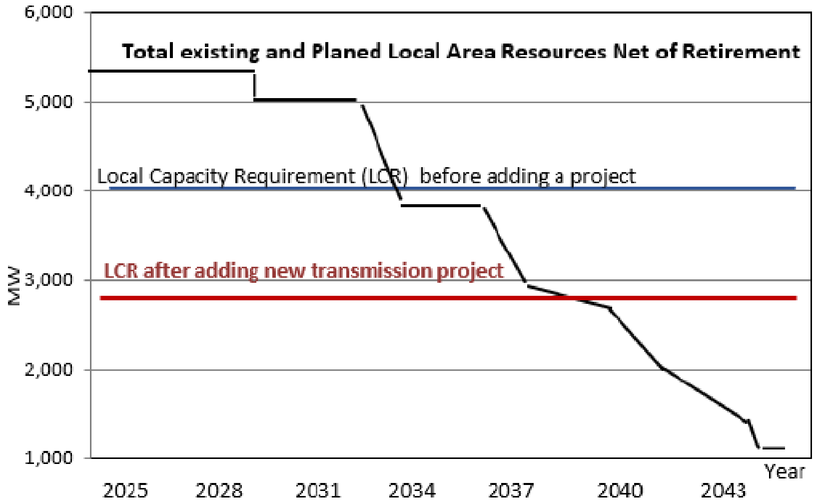
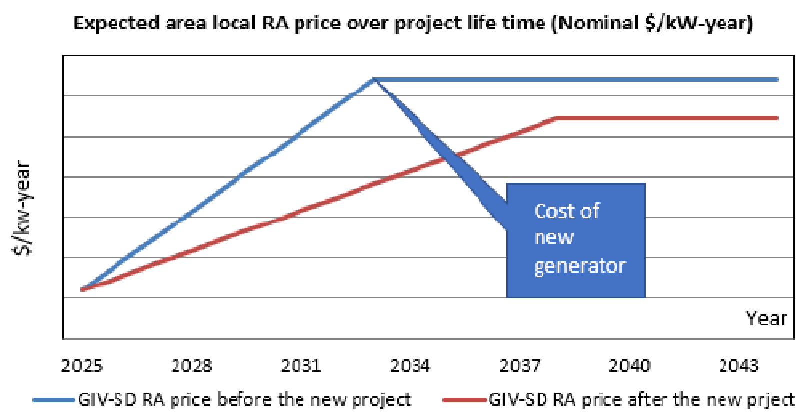
No	Comment Submitted	CAISO Response
13e	5. Projects outside of the CAISO's TPP Approval Process The CAISO received and reviewed three projects during the request window submission timeframe in Southern California Edison Company's service area. These projects are: (1) Control-Silver Peak 55 kV Line rebuild; (2) Ivanpah to Control Segment 3 Rebuild and capacity derate; and (3) Ivanpah to Control Segment 4 Baker Ring Bus and capacity derate. Each of these projects has a cost estimate of $50 million or less with the exception of the Control-Silver Peak 55 kV rebuild, which has a cost estimate of $60 to $70 million. The CAISO stated that CAISO Board approval is not required for these projects. The Public Advocates Office requests more information on the need for these projects for project evaluation and to determine if lower cost solutions can be considered. The Public Advocates Office recommends that projects received during the request window timeframe be reviewed in the September CAISO TPP public meetings and that project presentations include information on the project need. At this time, the Public Advocates Office reserves the right to comment on these projects further once the requested information has been provided in a public TPP meeting. The Public Advocates Office also requests confirmation that the proposed Control-Silver Peak 55 kV rebuild project does not require CAISO Board approval since the estimated costs of this project is greater than $50 million. It is our understanding that CAISO Board Approval is required for projects with costs greater than $50 million.	The complete request window submittal application and supporting information provided by SCE was posted on the ISO Market Participant Portal in early January 2019. None of these projects, including the Control-Silver Peak 55 kV rebuild are being planned for the purpose of expanding the capability of the transmission system. Asset maintenance activities do not require ISO approval and the cost of the project does not differentiate between expansion planning and asset maintenance activities. The purpose of the projects are to mitigate electrical clearance issues on the SCE system in support of NERC reliability and in compliance with CPUC's General Order 95. For the Control-Silver Peak 55 kV rebuild, SCE intends to file the application for Certificate of Public Convenience and Necessity (CPCN) or Permit to Construct (PTC) with the CPUC for licensing mitigation measures with the goal to complete the engineering design and construction activities by year 2025 per SCE's NERC Mitigation Plan.
13f	B. RECOMMENDATIONS ON METHODS, POLICIES, AND PROCESSES 1. Assumptions on Storage The draft 2018-2019 Transmission Plan states that alternative storage solutions for reliability and Local Capacity Reliability (LCR) reduction projects were considered, but storage costs, analysis and other storage assumptions were not included. To better understand the CAISO's storage solution analysis for replacing gas-fired generation and for mitigating reliability needs, the Public Advocates Office requests that the CAISO provide the assumptions used to evaluate storage as a preferred alternative in each TPP cycle. These storage assumptions should include assumptions on capital and maintenance costs, discharging capacity, charging speed, applicable storage technologies, anticipated charging source(s) and lifecycle timeframe. Going forward, the CAISO should present its storage assumptions during the beginning of the TPP	Regarding the storage projects studied in the 2018-2019 transmission planning cycle, please refer to sections 4.8 and 4.9.11 in particular. The comment also appears to be requesting development of generic planning information for consideration in a future planning cycles. This comment should be submitted into the development of the study plan for future planning cycles. The ISO's preferred approach has been to provide information regarding the characteristics of the needs that were identified, inform stakeholders when possible about particular opportunities for preferred

No	Comment Submitted	CAISO Response
	cycle and include its assumptions in an appendix to the Transmission Plan. The storage assumption presentation and appendix should include information from actual projects and or verified technological advances and the resources consulted to develop storage evaluation assumptions. The Public Advocates Office requests this information in order to confirm that the lowest cost solutions are approved and to assist with revisiting prior storage proposals once the Storage as a Transmission Asset initiative concludes and once the CPUC provides long-term direction on the gas-fired generation fleet.	resources and storage to play a role, and perform more detailed assessments based on alternatives and proposals brought forward by proponents, but will consider the suggestion.
13g	2. Resource Mapping and Transmission Planning Process-Integrated Resource Plan Feedback Loop The Public Advocates Office requests that the CAISO share its updated California Energy Commission (CEC) resource maps in a public stakeholder meeting and identify areas with good resource potential and transmission capacity. The CAISO should specifically identify areas where the CAISO made necessary modifications to the CEC's resource maps to address interconnection challenges such as in the noted Southern Nevada zone. The Public Advocates Office is making this request because the Transmission Plan assessment of the Integrated Resource Plan (IRP) 42 million metric tons (MMT) scenario portfolio revealed that the identified areas for new renewable procurement in the Kramer- Inyokern, Southern Nevada, Riverside East and Palm Springs and Tehachapi areas will experience significant congestion and or reliability issues that would require mitigation. The CAISO's recommended mitigations included dropping generation, using SPSs and constructing major capital projects. The draft resource portfolios recommended for the 2019-2020 TPP cycle as part of the CPUC's IRP proceeding, correct some of these issues observed in the CAISO 2018-2019 TPP 42 MMT scenario portfolio assessment. The Public Advocates Office also requests that CAISO provide additional and more frequent technical information to the CPUC and advise on possible alternative locations and renewable resources, such as wind and or solar paired with storage to achieve lower impacts on existing congestion and renewable curtailment. The Public Advocates Office requests the updated resource maps and mentioned additional guidance be provided as soon as possible to inform the CPUC IRP process which is underway. As stated in the Public Advocates	The comment has been noted. Because the CEC staff develops the proposed resource mapping, the ISO refers PAO to the CEC and the CPUC. During 2018-2019 TPP, the CEC staff provided the ISO with a proposed substation-level mapping for portfolio resources. The ISO presented the details of this mapping and any modifications during the stakeholder meeting held on September 20-21, 2018. (page 13 of "2018-2019 TPP Policy-driven Assessment" presentation)

No	Comment Submitted	CAISO Response
	Office's comments on the 2018-2019 CAISO TPP preliminary policy and economic assessment, to achieve a reasonable resource portfolio recommendation, a feedback loop between the proposed CPUC's IRP procurement determinations and the CAISO TPP transmission capacity determination is essential. This feedback loop should also involve public presentations to stakeholders that explain the preliminary determinations that led to the recommended renewable generation locations and should seek stakeholder input before finalizing them.	
13h	3. Interconnection Queue Projects and New Deliverability Methodology The Public Advocates Office appreciates that the CAISO convened a separate stakeholder meeting to review the revised Generator Deliverability Assessment Methodology (GDAM) on December 18, 2018 as requested. The Public Advocates Office requests confirmation on the following: (1) the revised deliverability methodology will be used to evaluate the current CAISO interconnection cluster to ensure that any proposed reliability network upgrades to interconnect new renewable generators are necessary and consistent with expected capacity, and (2) the CAISO will evaluate renewables paired with storage further to determine their capacity to meet the highest system need hours starting at 6 pm. In the past, the Public Advocates Office encouraged the CAISO to periodically revisit the production levels of wind and solar for deliverability because the resulting capacity assumptions directly influence procurement decisions as well as new transmission and interconnection investments that may be needed to meet the State's renewable portfolio standards (RPS) targets. It appears that the 2019-2020 CAISO TPP resource portfolios will continue to use the existing GDAM. We encourage the CAISO to take into consideration that this methodology is subject to change in case any delivery network upgrades are identified in the 2019-2020 CAISO TPP.	As noted in the comment, the ISO held a stakeholder call on December 18, 2018 to offer a more in-depth review of the proposed revisions to the generation deliverability assessment methodology originally discussed in the 2018-2019 transmission planning process meeting on November 16, 2018. Stakeholders' written comments were generally supportive of the proposed changes, but raised various concerns regarding impacts to other processes and existing generation, recommended that the ISO take more time to address these concerns. The ISO has considered those comments and decided to delay implementation of the revised methodology and instead continue to apply the current methodology in studies required by the Generation Interconnection and Deliverability Allocation Procedures for Cluster 11 phase 2 and Cluster 12 phase 1 efforts. Further stakeholder engagement on this topic is planned for the second quarter of 2019.
13i	4. Support for Energy-Only Contracts As the Public Advocates Office stated in its August 11, 2017 comments on the 2017 Expedited Generator Interconnection and Deliverability Allocation Procedures Enhancements Straw Proposal, Energy Only Delivery Status (EODS) contracts are a reasonable outcome since EODS projects are	The comment has been noted.

No	Comment Submitted	CAISO Response
	considered equally as effective as Full Capacity Deliverability Status (FCDS) resources in meeting California's RPS target and are more cost effective for ratepayers. The Public Advocates Office continues to support the CPUC's and CAISO's efforts to develop renewable portfolios that are a combination of FCDS and EODS resources.	

14. San Diego Gas & Electric (SDG&E) Submitted by:		
No	**Comment Submitted**	**CAISO Response**
14a	1. Develop long-term Resource Adequacy (RA) prices that correspond with long asset lives when evaluating the cost-effectiveness of reducing Local Capacity Requirements (LCR) with transmission infrastructure additions. SDG&E notes that in the 2018-2019 planning cycle, the CAISO used the difference between near-term local capacity prices and near-term system capacity prices to assess the economic benefits of transmission projects that are proposed to reduce LCRs. The near-term capacity prices used by the CAISO were based on the CPUC's most recent 2017 Resource Adequacy Report. SDG&E has some concerns regarding the CAISO's new RA price forecasting approach. The CPUC's 2017 Resource Adequacy Report reflects only near-term (less than 5 years) system and local RA capacity prices. Near-term price forecasts are not an accurate representation of capacity prices for time periods in the future when a potential transmission project could be placed in-service and operational. Longterm price forecasts which account for forecast LCR, projections of existing and committed amounts of RA capacity within the LCR area, and estimates for the Cost of New Entry (CONE) when projections of existing and committed amounts of RA capacity are less than the forecast LCR, are needed to evaluate the cost-effectiveness of potential transmission projects. By doing so, consideration of project construction timeframes, which may take as long as seven years, and appropriate asset economic life can be accounted for. Specifically, SDG&E's proposed approach is to forecast longer term (corresponding to asset lives of 50 or more years) capacity prices by considering resource scarcities over time, the cost of building new generators that will comply with California's policies (e.g. SB100) including the replacement of such generation when their useful economic lives end, and the impact of future technology improvements on zero-carbon resources' costs (e.g. storage). The graph below illustrates such a methodology:	As stated in the draft transmission plan, future IRP efforts are expected to provide more guidance and direction regarding expectations for the gas-fired generation fleet at a policy level. Without that broader system perspective being available at this time, the ISO has taken a conservative approach in assessing the value of a local capacity reduction benefit when considering a transmission reinforcement or other alternatives that could reduce the need for existing gas-fired generation providing local capacity.

No	Comment Submitted	CAISO Response
	SDG&E's Approach of evaluating capacity benefits   SDG&E notes that important studies by the CAISO have been previously conducted using the approach proposed by SDG&E in these comments. SDG&E is unclear why, in the current transmission planning cycle, the CAISO has chosen to use a different approach for forecasting long-term RA capacity prices. Frequent changes to the LCR reduction benefit methodology creates	

No	Comment Submitted	CAISO Response
	uncertainties and difficulties for stakeholders working on potential LCR reduction projects. SDG&E encourages the CAISO to consider launching a stakeholder initiative that would enable stakeholders to collaboratively develop a more robust and more permanent LCR reduction benefit methodology. Because the short-term RA prices used by the CAISO to evaluate long-lived transmission projects are significantly lower than the Cost of New Entry (CONE), SDG&E believes the 2018-2019 transmission plan presented to the CAISO Board for approval, should include the following caveat: *"Long-term RA prices were derived from near-term local RA price data, and from near-term system-wide RA price data. This use of near-term RA prices to determine cost-effectiveness for projects with long asset lives (e.g., more than 50 years for transmission projects that would reduce LCR) creates a temporal disconnect. Further study and refinement is necessary before the Plan reaches determinative findings on cost-effectiveness."*	
14b	2. <u>Anomalies in production cost results need to be addressed before reaching definitive conclusions on the cost-effectiveness of proposed transmission projects.</u> The CAISO's economic assessment of most transmission projects show negative WECC-wide production cost savings. While the application of the Transmission Economic Assessment Methodology (TEAM) could result in negative energy cost savings for consumers within the CAISO Balancing Authority Area, it is difficult to understand how the addition of transmission capacity (which reduces overall grid impedance) could result in higher production costs for the WECC as a whole. If the production cost model objective function is to minimize total system wide production cost in order to meet system load plus losses, an improved/expanded transmission system should allow more efficient use of more economic generation resources in the system through the economic dispatch. These anomalous results (Tables 4.9-2, 4.9-5,4.9-7,4.9-8,4.9-11, 4.9-26, etc.) suggest that refinements of input data and/or changes to modeling techniques may be needed.	As is discussed in the draft transmission plan in several locations, the ISO did identify a handful of cases where interactions between the renewable curtailment model and other parameters resulted in material anomalies. In those cases, sensitivities were performed with a fixed renewable curtailment price, which addressed the anomalies and provided reasonable results for assessing the projects being studied. The ISO notes, however, that enhancements to this model are being explored for the 2019-2020 planning cycle. The requested caveat is unnecessary, as the ISO's transmission planning process results in recommendations based on each plan's findings, which can be re-visited in future cycles if circumstances change.

No	Comment Submitted	CAISO Response
	For instance, the Plan stated that the proposed 230 kV transmission project intended to mitigate congestion for high San Onofre north-bound flow resulted in increased thermal and renewable generation in the San Diego and Imperial Valley area, reduced thermal and renewable generation in the SCE area, and increased Path 26 north-bound congestion. If the optimization model is correct, the generation in the SCE area prior to the addition of the 230 kV transmission project should be more expensive than generation in the SCE area after the addition of the 230 kV transmission project. Similarly, prior to the addition of the 230 kV transmission project, generation north of Path 26 should be more expensive than the generation south of Path 26 and this price difference should be eliminated or moderated subsequent to adding the new 230 kV transmission project. Overall, the new generation pattern effectuated by the economic dispatch model with the addition of the new 230 kV transmission project, will reduce or eliminate north-bound congestion and necessarily result in a lower WECC wide production cost. We note that since the rest of the WECC often acts as a "sink" for a significant amount of California's renewable energy, a schedulable HVDC can further improve the efficiency of this "sink," resulting in reduced WECC wide production costs. Unless CAISO can demonstrate the negative WECC production cost savings are reasonable, SDG&E believes the 2018-2019 transmission plan presented to the CAISO Board for approval, should include the following caveat: *"Further study and refinement is necessary before the Plan reaches determinative findings on project cost-effectiveness in the cases where WECC production cost savings are negative."*	
14c	3. <u>Improve the production cost modeling for HVDC and Phase Shifters to better reflect these devices' capabilities.</u> It is SDG&E's opinion that the current economic results in many cases do not reflect the full economic benefits of projects that have power flow control capabilities such as HVDC or phase shifting transformer projects. It is SDG&E's recommendation, because of current model limitations in the tools used by the CAISO, that the CAISO should consider not including these results in the	Please refer to the response to Comment 9a regarding the HVDC modeling in PCM. The HVDC project is modeled in the ISO's planning PCM, based on SDG&E proposed topology and parameters. The IV PFCs are modeled as phase shifters in the PCM using the parameters in the reliability

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current iteration of the Plan, or at a minimum indicate they are preliminary in nature and subject to future refinement when the tools are improved.
In real-time systems, generation and transmission flexibilities are fully deployed to achieve the least cost dispatch to serve the load while meeting transmission security and generation ramping and regulation requirements. The same is expected for the models used in system planning. If there are modeling limitations, the planners should try to work with the model vendors to improve the tools. If engineering judgement is selected instead, the CAISO should ensure that all stakeholders agree with the workarounds used to overcome limitations in the models. Further detailed comments and recommendations are also listed below:
<table>
<tr><th>No.</th><th>Document Reference</th><th>Issues & Comments</th></tr>
<tr><td>1</td><td>P.327 of the Plan – The SWPL HVDC project “increased congestion along the IV to San Diego corridor, mainly on the Suncrest to Sycamore corridor, and on Path 26, although SDG&E Bay Blvd-Silvergate and San Luis Rey to S. Onofre congestions were reduced, as shown in Figure 4.9-18. Renewable curtailment was reduced in the IV area, but increased in most of the other areas in Southern California, as shown in Figure 4.9-19.”</td><td>
<u>Need for an improved HVDC model to fully access the economic benefits of the SWPL HVDC project:</u>
Most production cost simulation models greatly simplify the capability and flexibility of an HVDC. For example, the GridView software models a two-terminal HVDC link with an open circuit and a pair of a generator-load for respective ends of the two-terminal HVDC. When the CAISO system needs emergency generation injection into a certain area under contingency conditions, the model is unable to schedule that power movement during the simulations. The model causes the controllable HVDC to appear no different than a plain AC line. The current production cost simulation software should be enhanced to properly model the operation of the three-terminal HVDC.
Additionally, the SWPL HVDC has many other features or flexibilities that are clearly beyond the capability of currently available production cost models. Namely:
1) The SWPL HVDC has a metallic return coupled with VSC technology-based terminals, making it a truly bipolar HVDC system. This technology and configuration enable the HVDC to operate with one pole if the other pole is out or faulted (an N-1 contingency per NERC/WECC standards). It is important to note the technology differences between the SWPL HVDC and the other two existing HVDC links in CAISO - PDCI and IPPDC. PDCI and IPPDC both use earth return and are LCC technology
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</td><td>assessment. Stakeholders can review these models in the ISO’s planning PCM, which has been posted to the ISO MPP.</td></tr>
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2) The production cost model's solution routine should be enhanced with a "balance equation" to ensure the proper optimization of internal DC flows in three-terminal DC lines. In the meantime, the model should allow the three terminals to participate in the minimization of the system wide production cost.
3) An HVDC project can transfer 50% higher than the rated power over an extended period of time following an N-1 contingency. For example, if one pole is lost, the other pole can carry 2250 MW. That is, an N-1 contingency of the SWPL HVDC would only reduce the power transfer capability from 3000 MW to 2250 MW. If the pre-contingency loading is at 2250 MW or lower, the post contingency flow can be maintained at the same or even higher level depending on the system needs. The Plan should be enhanced to fully capture this favorable feature for grid operations.</td></tr>
<tr><td>2</td><td>P.327 of the Plan – "It was observed in the simulation results that modeling the HVDC Conversion project increased congestion along the IV to San Diego corridor, mainly on the Suncrest to Sycamore corridor, and on Path 26, although SDG&E Bay Blvd-Silvergate and San Luis Rey to S. Onofre congestions were reduced, as shown in Figure 4.9-18. Renewable curtailment was reduced in the IV area, but increased in most of the other areas in Southern California, as shown in Figure 4.9-19."</td><td><u>Unaccounted for HVDC operational and reliability benefits:</u>
It is conceivable that with the SWPL still an AC line and not controllable, the described congestion can happen. However, it is not clear in the Plan if the controllability feature of the SWPL HVDC was activated to alleviate any post contingency overloads, which should thereby reduce congestion.

Since the SWPL HVDC can be controlled by the grid operators, it offers flexibility under different system conditions and provides various forms of relief. For instance, during a fire event, grid operators can adjust loading on critical facilities in rapid and granular increments to avoid more significant subsequent interruptions in flow or can reduce the HVDC voltage to prevent arcing or force outages due to heavy smoke. Additionally, an HVDC's ability to ramp up and down flow almost instantaneously further helps to mitigate overloads or meet system frequency regulation requirements.

These operational and reliability benefits should be captured by the TEAM method as "Benefits from Increased Operational Flexibility" (see page 2-20 of the TEAM Process document).

Additionally, the HVDC will become part of the WOR Path and it is expected to provide a significant increase in transmission capacity on Path 46 between Arizona and southern California. This potential Path rating increase should also be considered in the Plan.</td></tr>
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</td><td>The congestion on Suncrest to Sycamore corridor increased mainly due to the topology change associated with the HVDC project. Specifically, ECO substation and the generators connected to it were relocated from SWPL 500 kV line to Sunrise 500 kV line, which contributed to the flow increase on the Suncrest to Sycamore corridor.

Path rating change should be assessed through the path rating study process. It is also noted that disconnecting the NG-IV 500 kV AC line potentially reduce the path rating, while adding the new DC line may increase the rating.</td></tr>
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<tr><td>3</td><td>P.241 and 247 of the Plan – Table 4.7-1, 4.7-3, and “Path 26 south to north congestion increased from previous planning cycles, and was mostly caused by the large amount of renewable generation in Southern CA identified in the CPUC portfolio.”</td><td><u>Path 26 congestion and the need to coordinate the operation of all HVDC lines in the CAISO system to ensure optimal results:</u>
In addition to the large amount of renewable generation in Southern California, it seems that a high northwest hydro flow (into CA through COI and PDCI) looping through Southern California was one of the possible reasons why Path 26 has over 1000 hours of northbound congestion. Path 26 congestion is the second highest in the Plan, only lower than the COI in the production cost simulations.

It is not clear from the Plan that these northwest flows that are causing additional congestion on Path 26 are a result of predefined inputs such as “fixed schedules” over COI and PDCI, or optimal economic behavior computed by the production cost software. If these flows are caused by predefined inputs, they should be fine-tuned to more realistic schedules to reduce some of the congestion seen on Path 26.

Furthermore, A true controllable SWPL HVDC can help direct low-cost northwest energy into the thermally-dominated southwest WECC region. Absent such control, the production cost model may be pushing the energy northward across Path 26 and increasing transmission losses. Therefore, it is recommended that the flow patterns of all DC lines should be modeled flexibly, in amount and direction, and are a result of an economic optimization.</td></tr>
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</td><td>In production cost simulation, the economic dispatch tends to use PDCI to mitigate Path 26 congestion. PDCI south to north flow was observed when there was Path 26 congestion from south to north.

There is no pre-defined fixed schedules over COI or PDCI in the ISO’s planning PCM.</td></tr>
<tr><td>14d</td><td>4. <u>Planning standards and methodologies should be applied clearly and consistently</u>
It appears that the CAISO may not be consistently applying the standard limiting generation tripping for a single SPS. It has become a good industry practice to reduce the impact of special protection scheme (“SPS”) in light of NERC standard compliance. For example, major transmission projects and SPS retirements have been planned and implemented for this purpose in the NPCC region. CAISO has a planning policy for this as well, but it appears the CAISO may not be implementing this policy consistently.

The CAISO mentioned in response to stakeholder questions that one of the criteria to evaluate the need for a reliability project is the need to limit generation tripping by existing or planned SPS’s to within the limits imposed by the CAISO planning standards. Currently, the standard ISO SPS3 limits the</td><td>The ISO consistently limits the amount of generation tripping to 1150 MW and 1400 MW in its planning studies for single and multiple contingency events, respectively. However, as described specifically in interconnection study reports, all generation is required to participate in RAS if it impacts a constraint that is protected by RAS. This approach simplifies the modeling of the RAS in the ISO market because it avoids the need to check which generators can be tripped and which cannot. It could be that only the gas generators are producing power or that only the solar is producing and it is at 50% output. Either of these conditions could be less than 1150 MW, and ISO planning studies consistently apply this generation tripping limit in simulations of RAS activation. Also, generation curtailment after the first contingency of a</td></tr>
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No	Comment Submitted	CAISO Response
	amount of generation tripping under a single contingency to 1100 MW and 1400 MW under double contingencies. It is worth noting that the current SPS in service at the Imperial Valley substation near El Centro would trip generation in excess of these limits, on the order of 2900 MW depending on system conditions. This raises concerns in both planning and operations, and control area balancing and consequential load shedding. SDG&E has long held that SPS are operational tools, not appropriate as long-term planning solutions. A similar view is shared by the industry. For example, major transmission projects and SPS retirements have been planned and implemented for this purpose in the NPCC region. An SPS, such as the Imperial Valley SPS, that trips large amounts of generation is especially concerning, as it indicates the network may not be capable of handling the amount of connected generation in some circumstances. Projects have been proposed that would effectively reduce the amount of generation tripping to the limits of the CAISO standard. To date, the CAISO has not approved any of these projects. In light of the increasing dependence on SPS, SDG&E recommends the CAISO reconsider projects which would allow this dependence to be reduced.	P6 outage can be utilized to ensure that the RAS is sufficient for the second contingency, or pre-contingency congestion management can be utilized.
14e	5. <u>Improve LCR studies</u> Specific comments and recommendations are listed below:	In response to the SDG&E comments and recommendations: • Southern California Region LCR Reduction Project: this project was submitted to the ISO to evaluate for potential LCR reduction in the Orange County with northbound flow direction on the phase shifters and was evaluated accordingly. With this new recommendation from SDG&E to utilize the Mission phase shifters (part of the submitted project) for southbound flow to help reduce local capacity need in the overall San Diego-Imperial Valley area, the ISO did a preliminary assessment and found that although the Mission phase shifters may help reduce about 244 MW of LCR need in the San Diego-Imperial Valley area, this also could cause an adverse impact to the Western LA Basin by about 100 MW in local capacity need. This still would not help offset the adverse

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<td>P.184 of the Plan – "The 30-minute emergency ratings..., and adjusting the phase shifting transformers at Imperial Valley substation."

P.319 of the Plan "It was determined that a southbound flow schedule of 40 MW on the Mission phase shifters would be sufficient to mitigate the potential overloading concern on the El Centro 230/92 kV transformer. Therefore, there is no impact to the local capacity requirement for the San Diego –Imperial Valley LCR area".

P.329 of the Plan – "The HVDC Conversion project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 690 MW".</td>
<td><u>Limited use of the flow control capabilities of phase shifters and HVDC lines when evaluating LCRs:</u>
It seems that the Plan has taken into consideration the flow control capability of the Imperial Valley phase shifter. However, in calculating the benefits of a phase shifter that would reduce LCR for the San Diego – Greater Imperial Valley area, the plan appears to not fully utilize the Mission phase shifter flow control capabilities, such as bidirectional and multiple control mode. The LCR benefits were only evaluated assuming the Mission phase shifter was set to push a fixed flow from San Diego into the western LA basin sub-area. In other words, the study could have shown different benefits if the full capability and flexibility of the proposed Mission phase shifter was modeled in the study.

The SWPL HVDC project may provide the same, if not more, capability as the Imperial Valley phase shifting transformer. This capability can be used to control power flows in a way that would mitigate potential overload concerns such as the overloads on the El Centro 230/92 kV transformer which drives the San Diego-Imperial Valley LCR needs. However, because the SWPL HVDC was fixed pre-contingency at a 1650 MW flow, due to potential constraints caused by the Miguel-Mission 230 N-2 contingency without considering the post contingency flexibility of the HVDC project, the LCR benefit of the project might have been underestimated to only 690 MW.

SDG&E recommends that LCR studies considers the full capabilities of the HVDC project and phase shifters.</td>
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<td>P. 188 of the Plan - Border Sub-Area LCR Reduction
P. 191 of the Plan – Otay-Otay Lake Tap 69 kV Reconductor Project</td>
<td><u>Cost and duration of generator contracts should be used to evaluate LCR reduction projects:</u>
Neither of these proposed projects in the San Ysidro area were approved by the CAISO. The main mitigation stated for both is to redispatch available generation in the area. The CAISO in its analysis should consider the cost and duration of generator contracts to evaluate LCR reduction projects in sub-areas.</td>
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<td>impact of negative production cost savings. The benefit-to-cost ratio would still be negative 0.3 for the proposed project.

HVDC Conversion Project: for the post project scenario, the constraint that drives the need for local capacity in the San Diego-Imperial Valley LCR area is not the El Centro 230/92 kV transformer but rather the thermal loading constraint on the Bay Blvd.-Silvergate 230kV line under an N-2 contingency of the Miguel-Mission 230kV line. This information was reported in the Draft Transmission Plan on page 329.
Border Subarea LCR Reduction and the Otay-Otay Lake Tap 69kV Reconductor Project: the ISO evaluated the Border Subarea LCR Reduction Project and included the study results on page 395 of the Draft Transmission Plan. Although the proposed project could potentially reduce the local LCR need, it is not economic to proceed unilaterally on the proposed project without a broader strategy to reduce local capacity requirements in the overall San Diego-Imperial Valley area.
Regarding the proposed Otay-Otay Lake Tap 69kV Reconductor Project, the ISO determined that this project is not needed because the identified reliability concern can be mitigated by generation re-dispatch or curtailment (Draft Transmission Plan, page 191). With generation curtailment, it has the opposite effect of needing local capacity for maintaining reliability for this subarea.

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<td>6. <u>Storage as a transmission asset determination</u>
Several proposed storage projects in this cycle were studied at different locations with the production cost modeling software to assess whether they were providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff. If a specific project showed the same benefits at two different locations (e.g. SDG&E vs. SCE), the CAISO concluded the project was mainly providing a system benefit instead of a local benefit needed to consider the project as a transmission asset. It is however unclear from the Plan, the required difference in benefits between locations that could</td>
<td>The comment does not correctly characterize the ISO's consideration of the issue set out in the draft transmission plan.

In considering if a storage project was providing a transmission function, the first objective is to ascertain what service being provided was in fact a transmission function. In this regard, the ISO did not find a function being provided by the storage projects that could not also be provided by a similarly situated generation resource or other preferred</td>
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No	Comment Submitted	CAISO Response
	have made storage projects qualify as transmission assets. SDG&E would appreciate if the CAISO could provide more information on how much benefit difference (e.g. percentage or amount) is needed between two locations, for the same storage project, to qualify as providing a transmission function.	resource. (Note that the ISO has generally used a more expansive definition of preferred resources to also include storage than the more narrowly defined definition used by the CPUC.) Further, the ISO noted that the needs being met by the storage were currently being met by gas-fired generation that the storage would replace. This lack of identification of a needed function provided by storage that could not also be provided by other market resources was the primary indicator that a transmission function was not being provided in response to the ISO needs. However, given this is a nascent issue, the ISO examined the issue further by conducting the sensitivities described in the comments to see if some aspect of the market revenues and PCM benefits could be attributed to providing a transmission function that would be unique to the transmission constrained local capacity area the storage was located in. As discussed in the draft transmission plan, the results were not materially different, so the sensitivities alone did not suggest the original conclusion needed to be questioned further. Accordingly, the ISO does not have a measure that qualify (or not) a storage project as providing a transmission function, and this would not be the key or sole metric in any event.

15. Smart Wires Inc
Submitted by: Chris Ariante

No	Comment Submitted	CAISO Response
15a	Moraga-Sobrante 115 kV Line Reconductor Project This project is to resolve overloads due to P2 and P6 contingencies, with a proposed in-service date of 2023 at an estimated cost of $12 million to $18 million. Smart Wires respectfully requests the CAISO to investigate using Smart Wires technology as an alternative to reconductoring this line. Smart Wires has done some preliminary investigation, and would like to share its results and data with the CAISO.	The CAISO has reviewed the alternative submitted by Smart Wires and found that it creates new overloads in other parts of the East Bay 115 kV system. Therefore, the Smart Wires alternative is not recommended to address overloads identified on the Moraga-Sobrante 115 kV line. As this alternative was submitted late in the process, evaluation of this alternative is not documented as a Request Window submission in the Transmission Plan.

16. Tenaska
Submitted by: Tim Hemig

No	Comment Submitted	CAISO Response
16a	DELTA RELIABILITY ENERGY STORAGE (DRES) COMMENTS The CAISO response to the DRES project in the Draft Plan is delineated below: “Tenaska, Inc. proposed the Delta Reliability Energy Storage targeting thermal overload on the Tesla-Delta Switch Yard 230 kV Line identified as a constraint for Contra Costa LCR Sub-area. In the 2018-2019 transmission planning process the Contra Costa LCR Sub-area was not selected to assess alternatives to reduce or eliminate the requirement for gas-fired generation to address the LCR requirement. As such, the ISO will not evaluate the proposed Delta Reliability.” Tenaska requests that the CAISO reconsider its recommendation based on the following: 1. DRES was proposed primarily to address a current reliability problem which is the loss of Telsa-Kelso 230kV Line overloading the Tesla-Delta Switch Yard 230kV Line (not just as an LCR alternative as described in the CAISO recommendation); 2. Tenaska’s Request Window Submission for DRES indicated the project was a “Reliability Transmission Project,” and should have been evaluated accordingly; 3. DRES is significantly more effective than any existing generation option in the CAISO Control Area at addressing the reliability problem delineated in justification point 1 above; 4. DRES qualifies as a Preferred Resource. Right now, the CAISO is relying on and supporting gas fired generation to mitigate overloads on the Tesla-Delta Switch Yard 230kV Line in lieu of Preferred Resources. For these reasons, Tenaska requests the CAISO to reconsider and to perform a full evaluation of DRES in the Draft Plan.	The CAISO has not identified reliability issue on the Tesla-Delta Switch Yard 230 kV line. As indicated in CAISO’s response, this is a constraint for Contra Costa LCR sub-area and relying on existing thermal generation versus the proposed DRES is an economic issue as opposed to a reliability issue. The sub-area was not selected as one of the areas or sub-areas to be assessed for alternatives to reduce or eliminate the requirement in this TPP cycle. The CAISO will be performing an assessment for this sub-area in 2019 and will consider this alternative within that assessment.
16b	SYCAMORE RELIABILITY ENERGY STORAGE (SRES) COMMENTS The CAISO reliability related response to the DRES project in the Draft Plan is delineated below: “Tenaska, Inc. proposed this project as a reliability need to eliminate the P6 thermal overload concerns on the Suncrest-Sycamore 230 kV lines, Suncrest	

No	Comment Submitted	CAISO Response
	500/230 kV transformers. The Project is also proposed as an economic-driven project to reduce the LCR requirement for the San Diego sub-area. The proposed scope is to build a 350 MW/175~350 MWh battery energy storage system (BESS) and interconnect it to the SDG&E Sycamore substation. The project has an estimated cost of $108-178 million and an expected in-service date of December 2021. The ISO has not identified a reliability need for this project. As discussed above, the P6 thermal overloads identified in SWPL and SRPL can be eliminated by the operational measures. For this reasons, the project was not found to be needed for reliability." The CAISO comment above references additional justifications in "Suncrest-Sycamore 230 kV Transmission project" section of the Draft Plan as provide below: "The P6 thermal overloads identified on the Suncrest–Sycamore 230 kV corridor can be eliminated by the existing RASs including newly implemented TL23054/TL23055 RAS and along with operation actions, such as adjustment of the IV phase shifting transformers, system reconfiguration, and generation redispatch in the baseline scenarios. Further assessment concluded that the preferred resources and the operation actions are adequate to mitigate the overload concerns identified in the sensitivity scenarios." The 2018-2019 TPP Reliability Assessment results recognized the P6 outage of the ECO-Miguel 500 kV line plus a Sycamore–Suncrest 230 kV line as a reliability issue. For a P6 outage, NERC allows for a system adjustment between the first and second outage. Based on the CAISO statement above, operators will make tap setting changes on the IV phase shifters, system reconfiguration and generation dispatch changes. All these adjustment will likely need to be made very quickly.	
	Unfortunately, this is appearing analogous to the 2011 Southwest blackout on September 8th, 2011. If Tenaska recalls correctly, SDG&E and the CAISO didn't have very many options available to use as a system adjustment following the first outage. As a result, IID's transformers started overloading and tripping. The outage of the second element can happen in a couple minutes as it did on September 8th.	ISO planning standards assume that the system is being operated in a secure state to withstand a single contingency outage without cascading outages, and then adjustments are made to prepare the next potential worst-contingency. Facility overloads following a P1 contingency have not been identified in the 2018-2019 TPP Reliability Assessment on the Sycamore–Suncrest 230 kV lines.

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<tr><td></td><td>Tenaska believes the CAISO's solution to the ECO-Miguel 500 kV line plus a Sycamore–Suncrest 230 kV line outage is overly optimistic and that a project like SRES should be considered as a more robust path to reliability. Based on the large number of projects proposed in the current TPP, there is substantial agreement by market participants and the transmission owner that real projects are the right course of action to address this reliability constraint.

If CAISO maintains that no projects are needed, then Tenaska believes a next step should be for CAISO to perform a transparent reliability study that quantifies in greater detail CAISO's proposed solution for this key outage. The study should include the following:
1. Identification of the generation tripped with the existing RAS (including aggregate maximum generation capacity);
2. Identification of the generation and/or load tripped by the new TL23054/TL23055 RAS;
3. Coordination with the multiple existing CFE RAS schemes that protect their system from large power diversions from Imperial Valley into Mexico;
4. Delineation of the generation dispatch changes required (automatic versus manual operator changes) and how long they take;
5. Description of the IV phase shifter phase angle changes and final angle (automatic versus manual operator changes);
6. Definition of the other system reconfiguration changes (automatic versus manual operator changes) and how long they take; and
7. A capacity accounting of how much generation is tripped offline by all Remedial Action Schemes and operator actions in the ISO Control Area and in CFE.

In addition, Tenaska requests the results of the study above be contrasted against the reliability study of the SRES project, IV phase shifter phase angle changes and the existing RAS. In addition to address the reliability benefits and impacts, each study should attempt to quantify the likelihood of a successful outcome given all the automatic and manual moving parts.</td><td>The ISO agrees that the operational requirements to ensure the reliability of this portion of the system are considerable. However, relying on an energy limited storage device as proposed by Tenaska would not necessarily simplify the operation of the system, and, based on the ISO's analysis, is not needed at this time.

The models and assumptions used to perform the analysis have all been provided to stakeholders, and the study has been comprehensively documented in the report and in multiple stakeholder meetings and presentations.

1. The contingency files have been posted and include this information.
2. The contingency files have been posted and include this information.
3. The ISO works closely with CFE and recently installed a phase shifter to control loop flow through their system.
4. An IROL has been identified in this area so typically post-contingency generation dispatch changes are required to be completed within 30 minutes.
5. The phase shifter is typically operated manually during contingency conditions.
6. Necessary system reconfiguration changes, if any, have been documented in the report.
7. Please see response to 14d.</td></tr>
</table>

17. University of California Office of the President
Submitted by: Mark Byron

No	Comment Submitted	CAISO Response
17a	An earlier CAISO presentation titled “Economic Planning - Preliminary Production Cost Simulation Results” indicated that the GFFNJCT-GIFFEN 70.0 kV line #1 constraint resulted in 1912 hours of congestion. CAISO noted that the production cost model (PCM) default 50% RPS scenario modeled 55 MW of existing and future solar generation in the Giffen area which are radially connected to the system over this congested line. The congested line is only 5 miles long and the congestion is serious; UCOP previously strongly encouraged CAISO to prioritize exploring low cost opportunities for an economic upgrade to the line. CAISO’s economic planning study highlights that this congestion is not temporary. Unless and until an upgrade or re-rating of the line is implemented, CAISO’s study indicates that this congestion will persist indefinitely. In the Draft 2018-2019 Transmission Planning report the CAISO studied reconductoring the radial line to the Giffen area to mitigate the curtailment. The CAISO calculated the present value of the reconductoring benefit “to be $49 million…” Further, the CAISO states in the draft report that “the benefit to cost ratio then is about 7.5, which provides sufficient economic justification for recommending approval for this project.” A cost benefit ratio of 7.5 is an enormously high value. This ratio makes it self-evident that the PG&E Fresno Giffen area reconductoring project is highly economic and beneficial to CAISO ratepayers. UCOP believes that the PG&E Fresno Giffen area reconductoring should remain in the final TPP report and that the CAISO and PG&E should subsequently take appropriate steps to ensure project completion by no later than start of summer 2019 to mitigate the known curtailment issue in the area.	The ISO is working with PG&E to assess the implementation schedule for the upgrade for the earliest in-service date achievable.