APPENDIX G: Production Cost Simulation and Economic Assessment Detailed Results

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Appendix G

Production Cost Simulation and Economic Assessment Detailed Results

G.1 Introduction

The ISO's economic planning study is an integral part of the ISO's transmission planning process and is performed on an annual basis as part of the transmission plan. The economic planning study complements the reliability-driven and policy-driven analysis documented in this transmission plan, exploring economic-driven transmission solutions that may create opportunities to reduce ratepayer costs within the ISO.

Each cycle's study is performed after the completion of the reliability-driven and policy-driven transmission studies performed as part of this transmission plan.

G.2 Technical Study Approach and Process

Different components of ISO ratepayer benefits are assessed and quantified under the economic planning study. First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and demand by dispatching economic generation while accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the "pre-project" and "post-project" study results, production benefits can be calculated from savings of production costs or ratepayer payments.

The production benefit relied upon by the ISO includes three components of ISO ratepayer benefits: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues. Additionally, other benefits including capacity benefits are also assessed. Capacity benefits may include system and flexible resource adequacy (RA) savings and local capacity savings. The system RA benefit corresponds to a situation where a transmission solution for importing energy leads to a reduction of ISO system resource requirements, provided that out-of-state resources are less expensive to procure than in-state resources. The local capacity benefit corresponds to a situation where a transmission solution leads to a reduction of local capacity requirement in a load area or accessing an otherwise inaccessible resource.

The production cost simulation plays a major role in quantifying the production cost reductions that are often associated with congestion relief. Traditional power flow analysis is also used in quantifying other economic benefits such as system and local capacity savings.

Such an approach is consistent with the requirements of tariff Section 24.4.6.7 and TEAM principles. The calculation of these benefits is discussed in more detail below.

In the production benefit assessments, the ISO calculates ISO ratepayer's benefits[1] as follows:

- ISO ratepayers' production benefit = (ISO Net Payment of the pre-upgrade case) – (ISO Net Payment of the post-upgrade case)
- ISO Net Payment = (ISO load payment) – (ISO generator net revenue benefiting ratepayers) – (ISO transmission revenue benefiting ratepayers)

The above calculation reflects the benefits to ISO ratepayers – offsetting other ISO ratepayer costs – of transmission revenues or generation profits from certain assets whose benefits accrue to ISO ratepayers. These include:

- PTO owned transmission
- Generators owned by the utilities serving the ISO's load
- Wind and solar generation or other resources under contract with an ISO load-serving entity to meet the state renewable energy goal, and
- Other generators under contracts where information available for the public may be reviewed for consideration of the type and the length of contract.

How ISO ratepayer benefits relate to (and differ from) the ISO production cost benefits are shown in Figure G.2-1.

[1] WECC-wide societal benefits are also calculated to assess the overall reasonableness of the results and to assess the impact of the project being studied on the rest of the WECC-wide system, but not as the basis for determining whether the proejct is in the interests of the ISO ratepayer to proceed with. The WECC-wide societal benefits are assessed according to the following formula: *WECC society production benefit = (WECC Production Cost of the pre-upgrade case) – (the WECC Production Cost of the post-upgrade case)*

Figure G.2-1: Ratepayer Benefits vs. Production Cost Savings

ISO Net Ratepayer Benefits from Production Cost Simulations are the sum of:	Types of Revenues and Costs calculated in Production Cost Studies	ISO "Production Cost" Savings are the sum of:
	Load Payments at Market Prices for Energy	
Yes	Reductions in ISO Ratepayer Gross Load Payments	
	Generation Revenues and Costs	
Yes	Increases in generator profits inside ISO for generators owned by or under contract with utilities or load serving entities, being the sum of:	
	Increases in these generators' revenues	
	Decreases in these generators' costs	Yes
	Increases in merchant (benefits do not accrue to ratepayers) generator profits inside the ISO, being the sum of:	
	Increases in these generators' revenues	
	Decreases in these generators' costs	Yes
Yes	Increases in profits of dynamic scheduled resources under contract with or owned by utilities or load serving entities, being the sum of:	
	Increases in these dynamic scheduled resource revenues	
	Decreases in these dynamic scheduled resource costs	
	Transmission-related Revenues	
Yes	Increases in transmission revenues that accrue to ISO ratepayers	
	Increases in transmission revenue for merchant (e.g. non-utility owned but under ISO operational control) transmission	

In addition to the production and capacity benefits, any other benefits under TEAM — where applicable and quantifiable — can also be included. All categories of benefits identified in the TEAM document[2] and how they are addressed in the economic study process are summarized and set out in detail in Table G.2-1.

[2] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Table G.2-1: Summary of TEAM Benefit Categories

Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
Production benefits: Benefits resulting from changes in the net ratepayer payment based on production cost simulation as a consequence of the proposed transmission upgrade.	In addition to production cost benefits themselves, focusing on ISO net ratepayer benefits;	Benefits focused on ISO net ratepayer benefits through production cost modeling.
	2.5.2 Transmission loss saving benefit (AND IN CAPACITY BENEFITS FOR CAPACITY) Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.	Energy-related savings are reflected in production cost modeling results.
Capacity benefits: Benefits resulting from increased importing capability into the ISO BAA or into an LCR area. Decreased transmission losses and increased generator deliverability contribute to capacity benefits as well.	2.5.1 Resource adequacy benefit from incremental importing capability A transmission upgrade can provide RA benefit when the following four conditions are satisfied simultaneously: • The upgrade increases the import capability into the ISO's controlled grid in the study years. • There is capacity shortfall from RA perspective in ISO BAA in the study years and beyond. • The existing import capability has been fully utilized to meet RA requirement in the ISO BAA in the study years. • The capacity cost in the ISO BAA is greater than in other BAAs to which the new transmission connects.	These benefits are considered where applicable; note that local capacity reduction benefits are discussed below.
	2.5.2 Transmission loss saving benefit (AND IN PRODUCTION BENEFITS FOR ENERGY) Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.	These benefits are considered, where applicable.
	2.5.3 Deliverability benefit Transmission upgrade can potentially increase generator deliverability to the region under study through the directly increased transmission capacity or the transmission loss saving. Similarly to the resource adequacy benefit as described in Section 2.5.1 in TEAM (and in this table), such deliverability benefit can only be materialized when there will be capacity deficit in the region under study. Full assessment for assessing the deliverability benefit will be on case by case basis.	This is primarily considered if the renewables portfolios identify the need for additional deliverability (as deliverability is used in TEAM and in ISO planning and generator interconnection studies) in which case the benefits may be policy benefits that have already been addressed in the development of portfolios, and further project development for this purpose for reducing local needs at this time is considered separately below.
	2.5.4 LCR benefit	LCR benefits are assessed, and valued according to prudent assumptions at this time given the

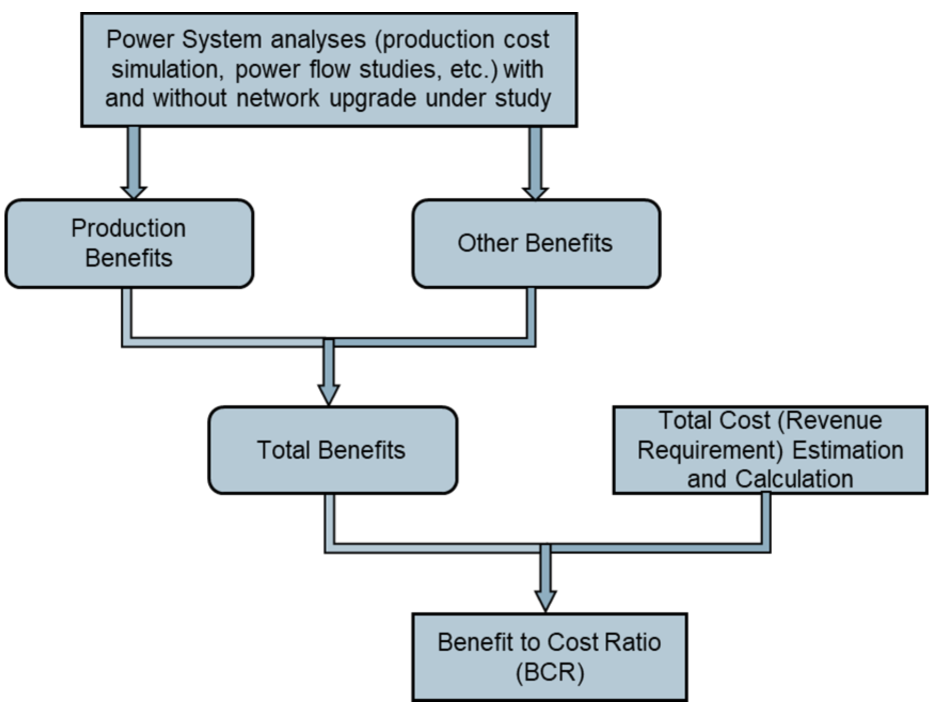
Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
	Some projects would provide local reliability benefits that otherwise would have to be purchased through LCR contracts. The Load Serving Entities (LSE) in the ISO-controlled grid pay an annual fixed payment to the unit owner in exchange for the option to call upon the unit (if it is available) to meet local reliability needs. LCR units are used for both local reliability and local market power mitigation. LCR benefit is assessed outside the production cost simulation. This assessment requires LCR studies for scenarios with and without the transmission upgrades in order to compare the LCR costs. It needs to consider the difference between the worst constraint without the upgrade and the next worst constraint with the upgrade. The benefit of the proposed transmission upgrade is the difference between the LCR requirement with and without the upgrade.	state of the IRP resource planning at the time – and supported by the CPUC.
Public-policy benefit: Transmission projects can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower-cost renewable resources located in remote areas, or by avoiding over-build.	2.5.5 Public-policy benefit If a transmission project increases the importing capability into the ISO-controlled grid, it potentially can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in remote areas. 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 the RPS goal will increase because of that. By reducing the curtailment of renewable generation, the cost of meeting the RPS goal will be reduced. This part of cost saving from avoiding over-build can be categorized as public-policy benefit.	With the current coordination of resource portfolios with the CPUC and CEC in place, these issues are addressed in the course of the portfolio development process.
Renewable integration benefit: Interregional transmission upgrades help mitigate integration challenges, such as over-supply and curtailment, by allowing sharing energy and ancillary services (A/S) among multiple BAAs.	2.5.6 Renewable integration benefit As the renewable penetration increases, it becomes challenging to integrate renewable generation. Interregional coordination would help mitigating integration problems, such as over-supply and curtailment, by allowing sharing energy and ancillary services (A/S) among multiple BAAs. A transmission upgrade that increases the importing and exporting capability of BAAs will facilitate sharing energy among BAAs, so that the potential over-supply and renewable curtailment problems within a single BAA can be relieved by exporting energy to other BAAs, whichever can or need to import energy. A transmission upgrade that creates a new tie or increases the capacity of the existing tie between two areas will also facilitate sharing A/S Sharing between the areas, if the market design allow sharing A/S. The total A/S requirement for the combined areas may reduce when it is allowed to share A/S. The lower the A/S requirement may help relieving over-supply issue and curtailment of renewable resources. It is worth noting that allowing exporting energy, sharing A/S, and reduced amount of A/S requirement will change the unit commitment and economic dispatch. The net payment of the ISO's ratepayers and the benefit because of a transmission upgrade will be changed thereafter.	This can be considered as applicable, particularly for interregional transmission projects. Re-dispatch benefits would be included in the production cost savings in any event.

Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
	However, such a type of benefit can be captured by the production cost simulation and will not be considered as a part of renewable integration benefit.	
Avoided cost of other projects: If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contributes to the benefit of the economic project.	2.5.7 Avoided cost of other projects If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contributes to the benefit of the economic project. Full assessment of the benefit from avoided costs is on a case-by-case basis.	This can be considered on a case by case basis, where applicable.

Once the total economic benefit is calculated, the benefit is weighed against the cost, which is the total revenue requirement of the project under study, as described in the TEAM. To justify a proposed transmission solution, the ISO ratepayer benefit must be considered relative to the cost of the network upgrade. If the justification is successful, the proposed transmission solution may qualify as an economic-driven transmission solution. Note that other benefits and risks are taken into account – which cannot always be quantified – in the ultimate decision to proceed with an economic-driven transmission solution.

The technical approach of the economic planning study is depicted in Figure G.2-2. The economic planning study starts from an engineering analysis with power system simulations (using production cost simulation and snapshot power flow analysis). Based on results of the engineering analysis, the study enters the economic evaluation phase with a cost-benefit analysis, which is a financial calculation that is generally conducted in spreadsheets.

Figure G.2-2: Technical approach of economic planning study



G.3 Financial Parameters Used in Cost-Benefit Analysis

A cost-benefit analysis is made for each economic planning study performed where the total costs are weighed against the total benefits of the potential transmission solutions. In these studies, all costs and benefits are expressed in 2024 U.S. dollars and discounted to the assumed operation year of the studied solution to calculate the net-present values.

G.3.1 Cost analysis

In these studies, the "total cost" is considered to be the present value of the annualized revenue requirement in the proposed operation year. The total revenue requirement includes impacts of capital cost, tax expenses, O&M expenses and other relevant costs.

In calculating the total cost of a potential economic-driven transmission solution, when necessary, the financial parameters listed in Table G.3-1 are used. The net present value of the costs (and benefits) is calculated using a social discount rate of 7% (real) with sensitivities at 5% as needed.

Table G.3-1: Parameters for Revenue Requirement Calculation

Parameter	Value in TAC model
Debt Amount	50%
Equity Amount	50%
Debt Cost	6.0%
Equity Cost	11.0%
Federal Income Tax Rate	21.00%
State Income Tax Rate	8.84%
O&M	2.0%
O&M Escalation	2.0%
Depreciation Tax Treatment	15 year MACRS
Depreciation Rate	2% and 2.5%

In the initial planning stage, detailed cash-flow information is typically not provided with the proposed network upgrade to be studied. Instead, lump-sum capital-cost estimates are provided. The ISO then uses typical financial information to convert them into annual revenue requirements, and from there to calculate the present value of the annual revenue requirements stream. As an approximation, the present value of the utility's revenue requirement is calculated as the capital cost multiplied by a "CC-to-RR multiplier". For screening purposes, the multiplier used in this assessment is 1.3, reflective of a 7% real discount rate. This is an update to the 1.45 ratio set out in the ISO's TEAM documentation[3] that was based on prior experiences of the utilities in the ISO. The update reflects changes in federal income-tax rates and more current rate of return inputs. It should be noted that this screening approximation is generally replaced

[3] The ISO expects to update the TEAM documentation dated November 2, 2017 to reflect this change.

on a case-by-case basis with more detailed modeling as needed if the screening results indicate the upgrades may be found to be needed.

As the “capital cost to revenue requirement” multiplier was developed on the basis of the long lives associated with transmission lines, the multiplier is not appropriate for shorter lifespans expected for current battery technologies. Accordingly, levelized annual revenue requirement values can be developed for battery storage capital costs and can then be compared to the annual benefits identified for those projects. This has the effect of the same comparative outcome, but adapts to both the shorter lifespans of battery storage and the varying lifespans of different major equipment within a battery storage facility that impact the levelized cost of the facility.

G.3.2 Benefit analysis

In the ISO’s benefit analysis, total benefit refers to the present value of the accumulated yearly benefits over the economic life of the transmission solution. The yearly benefits are discounted to the present value in the proposed operation year before the dollar value is accumulated towards the total economic benefit. Because of the discount, the present worth of yearly benefits diminishes very quickly in future years.[4]

In general, when detailed analysis of a high priority study area is required, production-cost simulation and subsequent benefits calculations are conducted for the 10th planning year. For years beyond the 10th planning year the benefits are estimated by extending the 10th year benefit with an assumed escalation rate. In this planning cycle, however, as indicated in section 4.5, the 10th year and the 15th year- in this case, the 2034-year and the 2039-year, load forecast and resource assumption were used in the planning PCM cases. Accordingly, the 15th year case, i.e. the 2039-year case was used as the main case for economic assessment.

The following financial parameters for calculating yearly benefits for use in determining the total benefit in this year’s transmission planning cycle are:

- Economic life of new transmission facilities = 50 years;
- Economic life of upgraded transmission facilities = 40 years;
- Benefits escalation rate beyond year 2039 = 0% (real), and
- Benefits discount rate = 7% (real) with sensitivities at 5% as needed.

G.3.3 Cost-benefit analysis

Once the total cost and benefit of a transmission solution is determined, a cost-benefit comparison is made. For a solution to qualify as an economic transmission solution under the tariff, the benefit has to be greater than the cost or the net benefit (calculated as gross benefit

[4] Discount of yearly benefit into the present worth is calculated by bi = Bi / (1 + d)i, where bi and Bi are the present and future worth respectively; d is the discount rate; and i is the number of years into the future. For example, given a yearly economic benefit of $10 million, if the benefit is in the 30th year, its present worth is $1.3 million based a discount rate of 7%. Likewise, if the benefit is in the 40th or 50th years, its present worth is $0.7 million or $0.3 million, respectively. In essence, going into future years the yearly economic benefit worth becomes very small.

minus cost) has to be positive. If there are multiple alternatives, the alternative that has the largest net benefit is considered the most economical solution. As discussed above, the traditional ISO approach is to compare the present value of annualized revenue requirements and benefits over the life of a project using standardized capital cost-to-revenue requirement ratios based on lifespans of conventional transmission. Given the relatively shorter lifespans anticipated for battery storage projects, battery storage projects can be assessed by comparing levelized annual revenue requirements to annual benefits. As indicated above, the ISO must also assess any other risks, impacts, or issues.

G.3.4 Valuing Local Capacity Requirement Reductions

As noted in Chapter 1 and earlier in this Appendix, the ISO 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. This is particularly important in considering how to assess the value to ratepayers of proposals to reduce gas-fired generation local capacity requirements in areas where, based on current planning assumptions, the gas-fired generation is sufficient to meet local capacity needs. If there are sufficient gas-fired generation resources to meet local capacity needs over the planning horizon, there is not a need for reliability-driven reinforcement; rather, the question shifts to the economic value provided by the reduction in local capacity requirement for the gas-fired generation. However, it cannot be assumed that gas-fired generation no longer required for local capacity purposes will not continue to be needed for system or flexible capacity reasons, albeit through competition with other system resources. While 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 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.

In this planning cycle, the capacity costs in the 2022 CPUC Resource Adequacy Report[5], which is the most recently available report at the time, were used in assessing local capacity reduction benefit.

[5] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2022-ra-report_05022024.pdf

G.4 Study Steps of Production Cost Simulation in Economic Planning

While the assessment of capacity benefits normally uses the results from other study processes, such as resource adequacy and local capacity assessment, production benefits are assessed through production cost simulation. The study steps and the timelines of production cost simulation in economic planning are later than the other transmission planning studies within the same planning cycle. This is because the production cost simulation needs to consider upgrades identified in the reliability and policy assessments, and the production cost model development needs coordination with the entire WECC and management of a large volume of data. In general, production cost simulation in economic planning has three components, which interact with each other: production cost simulation database (also called production cost model or PCM) development and validation, simulation and congestion analysis, and production benefit assessment for congestion mitigation.

PCM development and validation mainly include the following modeling components:

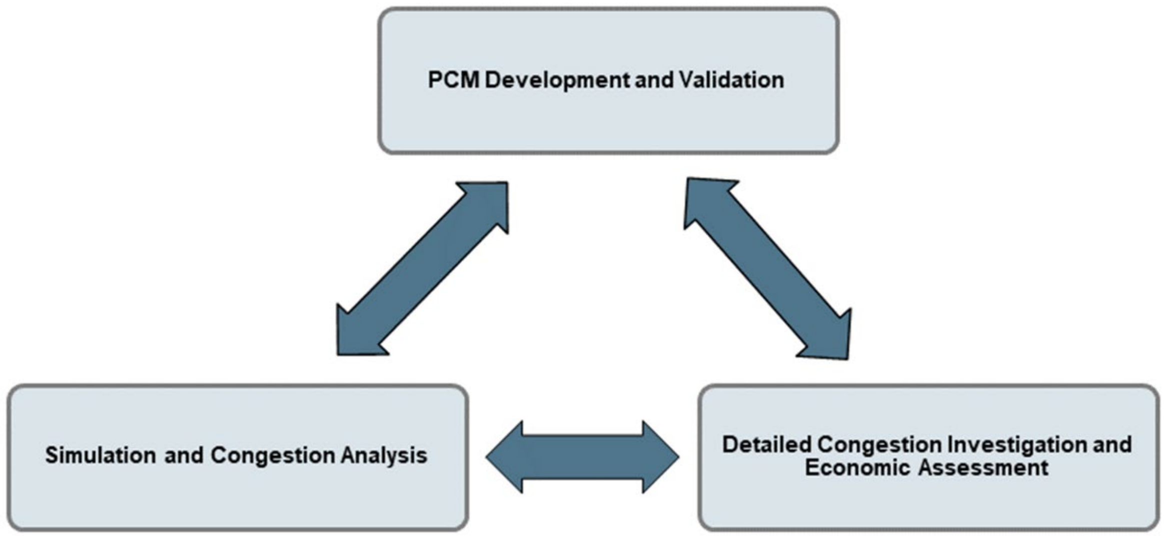
1. Network model (transmission topology, generator location, and load distribution).
2. Transmission constraint model, such as transmission contingencies, interfaces, and nomograms, etc.
3. Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, energy storage model, renewable profiles, and renewable curtailment and price model.
4. Load model, including load profiles, annual and monthly energy and peak demand, and load modifiers.
5. Market and system operation model, and other models as needed, such as ancillary service requirements, wheeling rate, emission cost and assignment, fuel price and assignment, etc.

Congestion analysis is based on production cost simulation that is conducted for each hour of the study year. Congestion can be observed on transmission lines or transformers, or on interfaces or nomograms, and can be under normal or contingency conditions. In congestion analysis, all aspects of results may need to be investigated, such as locational marginal price (LMP), unit commitment and dispatch, renewable curtailment, and the hourly power flow results under normal or contingency conditions. Through these investigations, congestion can be validated, or some data or modeling issues can be identified. In either situation, congestion analysis is used for database validation. The simulated power flow pattern is also compared with the historical data for validation purposes, although it is not necessary to have identical flow pattern between the simulation results and the historical data. There are normally many iterations between congestion analysis and PCM development.

In the detailed congestion investigation and economic assessment step, the ISO quantifies economic benefits for each identified transmission solution alternative using the production cost simulation and other means. From the economic benefit information, a cost-benefit analysis is conducted to determine if the identified transmission solution provides sufficient economic benefits to be needed. Net benefits are compared with each other where the net benefits are calculated as the gross benefits minus the costs to compare multiple alternatives that would address identified congestion issues. The most economical solution is the alternative that has the largest net benefit. In this step, the PCM and the congestion results are further validated.

Normally, there are a number of iterations among these three steps through the entire economic planning study process. Figure G.4-1 shows these components and their interaction.

Figure G.4-1: Steps of production cost simulation in Economic planning



G.5 Production cost simulation tools

The ISO primarily used the software tools listed in Table G.5-1 for this economic planning study.

Table G.5-1: Economic Planning Study Tools

Program name	Version	Functionality
Hitachi GridView™	10.3.80	The software program is a production cost simulation tool with DC power flow to simulate system operations in a continuous time period, e.g., 8,760 hours in a study year (8784 hours for leap year)

G.6 ISO Production Cost Model Development

This section summarizes the major assumptions of system modeling used in the PCM development for the economic planning study. The section also highlights the major ISO enhancements and modifications to the Western Interconnection Anchor Data Set production cost simulation model (ADS PCM) database that were incorporated into the ISO's database. It is noted that details of the modeling assumptions and the model itself are not itemized in this document, but the final PCM is posted on the ISO's market participant portal once the study is final.

G.6.1 Starting database

The 2024-2025 transmission planning process PCM development started from the ADS 2034 PCM. Using this databases, the ISO developed the base cases for the ISO 2024-2025 transmission planning process production cost simulation. These base cases included modeling updates and additions, which followed the ISO unified planning assumptions and are described in this section, and validated incremental changes in the ADS PCM.

It is worth noting that the ADS PCM is an evolving product, so the ISO's planning PCM only incorporated ADS PCM changes that were approved and validated before a cut-off date. In this planning cycle, the changes in the ADS 2034 PCM after January 15, 2025 were not included in the ISO's planning PCM. These changes will be validated and incorporated in the next cycle's planning PCM.

G.6.2 Load

As a norm for economic planning studies, the production cost simulation models 1-in-2 weather conditions load in the system to represent typical or average load conditions across the ISO system. The CEC California Energy Demand Updated Forecast for 2034 and 2039, consistent with the demand forecast in the reliability assessment as described in Chapter 2, were used to develop the 2034 and 2039 planning PCM cases.

Load modifiers, including DR, DG, AAEE, AATE, and AAFS, were modeled as generators with hourly output profiles. The locations of the load modifiers were consistent with the reliability power flow cases.

G.6.3 Generation resources

Generator locations and installed capacities in the 2034 and 2039 PCM cases are consistent with the policy assessment power flow cases for 2034 and for 2039, respectively, including both conventional and renewable generators. Chapter 3 and Appendix F provides more details about the renewables portfolios.

The CPUC IRP base and sensitivity portfolios included out-of-state wind resources in different areas. Some of the out-of-state wind resources in the CPUC IRP portfolios expected to require new transmission, while some rely on existing transmission, to deliver their wind energy to the ISO load. For the out-of-state wind resources that require new transmission, the CPUC IRP portfolio provided specified injection points to the ISO system, but did not specify particular out-of-state transmission projects to deliver the resources to the ISO boundary.

In the planning PCM in this planning cycle, New Mexico wind generation that requires new transmission was modeled at the Pinal Central 500 kV bus in Arizona, which is consistent with the last planning cycle. This is equivalent to assuming that a new transmission line would be built to deliver New Mexico wind generation to the Pinal Central 500 kV bus.

The CPUC IRP portfolios included out-of-state wind in Wyoming areas and in Idaho areas, which are expected to require new transmission. In the planning PCM in this planning cycle, the Wyoming wind was modeled associated with the TransWest Express project, and the Idaho wind was modeled associated with the SWIP North project, as baseline assumption.

G.6.4 Network modeling

The ADS PCM uses a nodal model to represent the entire WECC transmission network. However, the network model in the ADS PCM is based on a power flow case that is different from the ISO’s policy power flow cases developed in the current planning cycle. The ISO took a more comprehensive approach and modified the network model for the ISO system to exactly match the policy assessment power flow cases for the entire ISO planning area. The transmission topology, transmission line and transformer ratings, generator location, and load distribution are identical between the PCM and policy assessment power flow cases. In conjunction with modeling local transmission constraints and nomograms, unit commitment and dispatch can accurately respond to transmission limitations identified in policy assessment. This enables the production cost simulation to capture potential congestion at any voltage level and in any local area.

G.6.5 Transmission constraints

As noted earlier, the production cost database reflects a nodal network representation of the western interconnection. Transmission limits were enforced on individual transmission lines, paths (*i.e.*, flowgates) and nomograms. However, the original ADS PCM database only enforced transmission limits under normal condition for transmission lines at 230 kV and above, and for transformers at 345 kV and above.

The ISO made an important enhancement in expanding the modeling of transmission contingency constraints, which the original ADS PCM database did not model. In the updated database, the ISO modeled contingencies on multiple voltage levels (including voltage levels lower than 230 kV) in the ISO transmission grid to make sure that in the event of losing one transmission facility (and sometimes multiple transmission facilities), the remaining transmission facilities would stay within their emergency limits. The contingencies that were modeled in the ISO's database mainly are the ones that identified as critical in the ISO's reliability assessments, local capacity requirement (LCR) studies, and generation interconnection (GIP) studies. While all N-1 and N-2 (common mode) contingencies were modeled to be enforced in both unit commitment and economic dispatch stages in production cost simulation, N-1-1 contingencies that included multiple transmission facilities that were not in common mode, were normally modeled to be enforced in the unit commitment stage only. This modeling approach reflected the system reliability need identified in the other planning studies in production cost simulations, and also considered the fact that the N-1-1 contingencies normally had lower probability to happen than other contingencies and that system adjustment is allowed between the two N-1 contingencies. In addition, transmission limits for some transmission lines in the ISO transmission grid at lower voltage than 230 kV are enforced.

Scheduled maintenance of transmission lines was modeled based on historical data. Only the repeatable maintenances were considered. The corresponding derates on transmission capability were also modeled.

PDCI (Path 65) south to north rating was modeled at 1050 MW to be consistent with the operation limit of this path identified by LADWP, which is the operator of PDCI within California.

G.6.6 Fuel price and CO2 price

The forecast of Natural Gas prices, Coal prices, and CO2 prices were the same as in the ADS PCM 2034. All prices are in 2024 real dollars.

G.6.7 Renewable curtailment price model

The 2024-2025 planning PCM continued to use the multi-block renewable generator model that was first developed and used in the 2019~2020 planning cycle PCM. This model was applied to all ISO wind and solar generators. Each generator was modeled as five equal and separate generators (blocks) with identical hourly profiles, and each block's Pmax was 20% of the Pmax of the actual generator. Each block had a different curtailment price around $-25/MWh, as shown in Table G.6-1

Table G.6-1: Multi-blocks renewable model

Block	Price ($/MWh)
1	-23
2	-24
3	-25
4	-26
5	-27

G.6.8 Battery cost model and depth of discharge

The ISO also refined its modeling of battery storage through the course of the 2019-2020 planning cycle, to reflect limitations associated with the depth of discharge of battery usage cycles (DoD or cycle depth) and replacement costs associated with the cycle life (i.e. the number of cycles) and depth of discharge the battery is subjected to. In this refined battery model, the battery's operation cost was modeled as a flat average cost. Cycle life represents available cycles until remaining energy is equivalent to average DoD, as further clarified in the updated DOE report for the storage cost forecast prepared by PNNL in 2022[6]. Based on this clarification of the cycle file definition, the battery's operation cost is calculated using the following equation:

$$Average\ Cost = (1 - DoD) * \frac{Per\ unit\ replacement\ cost}{Cycle\ life * DoD * 2}$$

The baseline assumptions for battery parameters in this planning cycle were also based on the 2030 forecast in the same DOE/PNNL report:

- DoD: 80%
- Cycle life: 2640 cycles
- Per unit replacement cost: $109,450/MWh

With the above parameters, the average cost was $5.18/MWh.

G.6.9 Co-located and hybrid resource model

Starting with this planning cycle, co-located and hybrid resource were modeled in the planning PCM. A co-located or hybrid resource normally includes battery components and solar components, but can also be combination of battery and other types of resources such as wind or thermal generators. Except for where a hybrid resource has a single market ID and a co-located resource may have multiple market IDs, there are a lot of similarities between the hybrid and co-located resources from operation and modeling perspectives, although there may be differences in financial and operational requirements. As the policy and operation requirements for co-located and hybrid resources are still under development, the planning PCM in this planning cycle used the same approach to model co-located and hybrid resources.

To model co-located and hybrid resources in PCM, two constraints that are similar to the P_{max} and P_{min} constraints of the any other generators can be added:

- P_{max} constraint

$$P_{solar} + P_{battery} + REGUP_{battery} + LFUP_{solar} + LFUP_{battery} + SPIN_{battery} + FR_{battery} \leq Pmax \quad (1)$$

[6] https://www.pnnl.gov/sites/default/files/media/file/ESGC%20Cost%20Performance%20Report%202022%20PNNL-33283.pdf

- P_{min} constraint (charging constraint)

$$P_{solar} + P_{battery} - REGDOWN_{battery} - LFDOWN_{solar} - LFDOWN_{battery} \geq Pmin \qquad (2)$$

The *Pmax* is normally the allowed maximum output at the point of interconnection of the generator. The *Pmin* can be negative if the co-located or hybrid resource can charge from the grid, or equal to zero if the battery component is not expected to charge from the grid. $P_{battery}$ is positive when the battery is discharging, and negative when the battery is charging. Ancillary services and operating reserves are considered in the P_{max} and P_{min} constraints, including regulation up and down (REGUP and REGDOWN), load following up and down (LFUP and LFDOWN), spinning reserve (SPIN), and frequency response (FR).

It is noted that the P_{min} constraint was not used in this planning cycle, because there is a lack of clarity of charging requirement for co-located and hybrid resources. It will be considered in future planning cycles when there is additional clarity for the charging requirement.

G.6.10 PG&E Manning – Metcalf 500 kV upgrade

The Manning – Metcalf new 500 kV line and the associated Metcalf – Los Estores 230 kV line reconductoring have been recommended for approval as a reliability upgrade in this planning cycle. This upgrade is also effective to mitigate the congestion on the Moss Landing – Las Aguilas 230 kV line that was identified in the previous TPP cycles and in the preliminary PCM results presented in the 2024 November stakeholder meeting as well.

Two alternatives were considered for this upgrade as summarized below. The detailed scope of this upgrade can be found in Chapter 2 and Appendix B.

Alternative 1

- Build a new 500 kV line from Manning to Moss Landing looping-in to the new Loas Aguilas 500 kV substation and using the existing 230 kV line right of way.
- Reconfigure the 230 kV lines from Panoche to Las Aguilas to Coburn. Build a new Moss Landing – Metcalf 500 kV line

Alternative 2

- Build a new 500 kV line from Manning to Metcalf using new right of way.

Production cost simulations were conducted on the 2039 base portfolio PCM case with and without the Manning – Metcalf upgrade to show the effectiveness of the upgrade in terms of congestion mitigation. The results were shown in Table G.6-2. While the Moss Landing – Las Aguilas 230 kV congestion was eliminated by modeling the upgrade, it can be seen that the congestion in the Greater Bay area also reduced. In the meantime, congestion increased on the Path 15 and Path 26 corridor when the flow was from south to north. This is because that the power flow along these corridors from south to north increased after the bottleneck of the Moss Landing – Las Aguilas 230 kV line congestion was removed.

Table G.6-2: Congestion changes by modeling the Manning - Metcalf upgrade

Area or Branch Group	Congestion Cost ($M) 2039 Base Portfolio PCM	Congestion Cost ($M) 2039 Base Portfolio with Manning - Metcalf upgrade Alternative 1	Congestion Cost ($M) 2039 Base Portfolio with Manning - Metcalf upgrade Alternative 2
Path 15 Corridor	391.71	468.49	521.80
PG&E Moss Landing - Las Aguilas 230 kV	289.89	0.00	0.00
Path 26 Corridor	171.79	194.06	206.28
SWIP North	66.56	58.14	51.61
PG&E GBA	14.36	6.96	5.79
PG&E Manning - Moss Landing 500 kV	0.00	5.47	0.00
PG&E Manning - Metcalf 500 kV	0.00	0.00	3.65

Production benefit of the Manning - Metcalf upgrade was also assessed based on the CAISO's TEAM methodology. The production benefit results as shown in Table G.6-3 demonstrated that the upgrade can provide significant production benefit to the CAISO ratepayers. The annual production cost savings from these two alternatives are $83 million and $120 million, respectively, based on the production cost simulation results on the 2039 Base portfolio PCM.

Table G.6-3: Production Benefit of the Manning – Metcalf upgrade

	2039 Base Portfolio without Manning - Moss Landing - Metcalf upgrade	2039 Base Portfolio with Manning - Moss Landing - Metcalf upgrade Alternative 1		2039 Base Portfolio with Manning - Moss Landing - Metcalf upgrade Alternative 2	
	($M)	($M)	Savings ($M)	($M)	Savings ($M)
ISO load payment	19,053	18,841	212	18,823	230
ISO generator net revenue	14,174	14,241	67	14,205	30
ISO transmission revenue	1,838	1,642	-196	1,698	-140
ISO Net payment	3,040	2,957	83	2,920	120
WECC Production cost	23,942	23,872	70	23,874	68

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

These two alternatives provide similar production cost savings to the ISO's ratepayers, and both are effective to mitigate the congestion on the Moss Landing - Los Aguilas 230 kV line and the reliability constraints in the PG&E's Bay area. In the reliability assessment in this planning cycle, Alternative 2 was recommended for approval, as set out in Chapter 2. Therefore, the Alternative 2 of the Manning – Metcalf upgrade was modeled in the PCM cases for economic assessment in this planning cycle as a baseline assumption.

G.7 Production Cost Simulation Results

Based on the economic planning study methodology presented in the previous sections, a congestion simulation of the ISO transmission network was performed to identify which facilities in the ISO-controlled grid were congested. Renewable curtailment and generation utilization were also summarized based on the production cost simulation results.

G.7.1 2034 Base Portfolio PCM Congestion Results

The results of the congestion assessment in the 2034 base portfolio PCM are listed in Table G.7-1. Columns "Cost Forward" and "Duration Forward" are the cost and duration of congestion, respectively, when the flow is in forward direction as indicated in the constraint name. Columns "Cost Backward" and "Duration Backward" are the cost and duration of congestion, respectively, when flow is in backward direction. The last two columns were the total cost and total duration, respectively.

Table G.7-1: Congestion in the ISO-controlled grid in the 2034 base portfolio PCM

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
1	Path 15 Corridor	MANNING-MN_GT_11 500 kV line #1	0	0	223,948	1,910	223,948	1,910
2	Path 26 Corridor	P26 Northern-Southern California	4	6	191,487	3,320	191,491	3,326
3	SWIP North	SWIP-North (Midpoint-Robinson)	0	0	51,287	716	51,287	716
4	Path 26 Corridor	MIDWAY-MW_WRLWND_31 500 kV line #3	0	0	49,165	1,101	49,165	1,101
5	Path 15 Corridor	MN_GT_11-GATES 500 kV line #1	0	0	44,936	387	44,936	387
6	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	39,251	864	39,251	864
7	Path 65 PDCI	P65 Pacific DC Intertie (PDCI)	0	0	28,529	1,679	28,529	1,679
8	Path 15 Corridor	MN_MW_21-MN_MW_22 500 kV line #2	0	0	26,234	427	26,234	427
9	East of Pisgah	LUGO-VICTORVL 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	0	0	22,817	205	22,817	205
10	Path 15 Corridor	MANNING-MN_MW_21 500 kV line #2	0	0	22,288	711	22,288	711
11	SCE Metro	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	16,047	179	16,047	179
12	SCE Northern	WINDHUB_A 230/13.8 kV transformer #1	14,037	786	0	0	14,037	786
13	Path 42	P42 IID-SCE	11,289	495	0	0	11,289	495
14	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	9,291	830	0	0	9,291	830
15	SDG&E/CFE	P45 SDG&E-CFE	5,123	961	3,549	379	8,672	1,340

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
16	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line #2	0	0	7,880	244	7,880	244
17	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	7,555	154	7,555	154
18	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	0	0	7,534	207	7,534	207
19	PG&E North Valley 230 kV	BRNY_FST_JCT-PIT 1 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	6,763	506	6,763	506
20	PG&E Kern 230 kV	GATES D-CALFLATSSS 230 kV line #1	0	0	6,564	949	6,564	949
21	Path 41 Sylmar transformer	P41 Sylmar to SCE	4,715	298	0	0	4,715	298
22	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	4,391	298	4,391	298
23	SCE Northern	VINCNT2-WINDSTAR1 230 kV line #1	0	0	4,267	536	4,267	536
24	Path 15 Corridor	MN_MW_22-MN_MW_23 500 kV line #2	0	0	3,957	78	3,957	78
25	SDG&E Bulk	ECO 500/500 kV transformer #1	0	0	3,671	364	3,671	364
26	SCE North of Lugo	SANDLOT-KRAMER 230 kV line #1	3,577	1,482	0	0	3,577	1,482
27	COI Corridor	P66 COI	1,860	35	1,018	27	2,879	62
28	SCE Antelope 66 kV	NEENACH-TAP 85 66.0 kV line #1	2,714	1,098	0	0	2,714	1,098
29	SCE North of Lugo	CALCITE-LUGO 230 kV line #1	2,534	1,673	0	0	2,534	1,673
30	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line, subject to PG&E N-1 Pit-Cottonwood 230 kV with HR SPS	2,501	264	0	0	2,501	264
31	Path 46 WOR	P46 West of Colorado River (WOR)	2,375	45	0	0	2,375	45
32	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line #1	2,353	194	0	0	2,353	194
33	East of Pisgah	SLOAN_CYN_5-ELDORDO 500 kV line #1	1,967	200	0	0	1,967	200
34	SDG&E 230 kV	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	0	0	1,963	278	1,963	278
35	SDG&E/CFE	OTAYMESA-TJI-230 230 kV line #1	0	0	1,615	206	1,615	206
36	SDG&E 230 kV	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	1,608	142	1,608	142
37	SCE North of Lugo	P60 Inyo-Control 115 kV Tie	964	260	318	314	1,282	574
38	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line, subject to PG&E N-2 Pit-CotwdF and CotwdE-RM 230 kV with HR SPS	1,255	111	0	0	1,255	111
39	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line, subject to PG&E N-1 Delevn-Cortina 230 kV	1,154	646	0	0	1,154	646
40	East of Pisgah	P61 Lugo-Victorville 500 kV Line	915	17	15	23	930	40
41	PG&E Sierra	P24 PG&E-Sierra	0	0	927	198	927	198

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
42	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	845	95	845	95
43	PG&E North Valley 230 kV	COTWD_F2-BRNY_FST_JCT 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	818	82	818	82
44	PG&E Sierra	SUMMIT 2-DRUMPH1 115 kV line #1	511	108	114	44	625	152
45	PG&E Greater Bay area	USWP-JRW_JCT-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	618	60	0	0	618	60
46	SCE Northern	PARDEE-VINCENT 230 kV line #2	0	0	590	100	590	100
47	SCE Northern	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	530	75	0	0	530	75
48	PG&E Sierra	HONEYLAK-SKEDADDLPS 60.0 kV line #1	13	4	387	120	401	124
49	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	390	20	0	0	390	20
50	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	385	66	385	66
51	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 Lugo-Mohave 500 kV	281	27	0	0	281	27
52	SDG&E Northern 69 kV	SANLUSRY-OCEAN RANCH 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	279	477	0	0	279	477
53	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	275	30	0	0	275	30
54	SCE North of Lugo	COLWATER 230/115 kV transformer #1	0	0	271	453	271	453
55	PG&E Greater Bay area	E. SHORE-SANMATEO 230 kV line, subject to PG&E N-2 Newark-Ravenswood 230kV and Tesla-Ravenswood 230kV	224	57	0	0	224	57
56	SCE North of Lugo	TAP189-CONTROL 115 kV line #1	0	0	223	26	223	26
57	East of Pisgah	HAE SVC-HAE SVCL 500 kV line #1	203	6	0	0	203	6
58	PG&E POE - RIO OSO 230 kV	POE-RIO OSO 230 kV line #1	174	72	0	0	174	72
59	PG&E North Valley 230 kV	CARIBOU-BELDENTP 230 kV line #1	163	35	0	0	163	35
60	PG&E Greater Bay area	LS ESTRS 230/230 kV transformer #1	145	53	0	0	145	53
61	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	124	14	124	14
62	Path 15 Corridor	QUINTO_SS-LOSBANOS 230 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV	0	0	114	21	114	21
63	SCE Northern	WINDHUB_A 230/13.8 kV transformer #2	109	26	0	0	109	26
64	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	108	2	108	2

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
65	Path 15 Corridor	TESLA E-WESTLEY 230 kV line #1	0	0	103	6	103	6
66	SDG&E/CFE	IV PFC1 230/230 kV transformer #1	98	16	0	0	98	16
67	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line #2	98	16	0	0	98	16
68	SCE North of Lugo	COLWATER-DUNNSIDE 115 kV line #1	97	164	0	0	97	164
69	East of Pisgah	GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	0	0	77	30	77	30
70	PG&E Greater Bay area	LS PSTAS-NEWARK D 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	74	10	0	0	74	10
71	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	74	1	74	1
72	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	71	129	71	129
73	SDG&E 230 kV	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-1 Silvergate-OldTown-Mission 230kV no RAS	69	25	0	0	69	25
74	SDG&E 230 kV	SILVERGT-OLDTWNTP 230 kV line, subject to SDGE N-1 Silvergate-OldTown 230kV no RAS	61	41	0	0	61	41
75	SCE Northern	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	60	13	60	13
76	COI Corridor	ROUND MT-RD MT 1M 500 kV line, subject to PG&E-BANC N-1 Olinda Xfmr 500 kV	0	0	55	8	55	8
77	SCE North of Lugo	KRAMER-VICTOR 230 kV line #1	47	96	0	0	47	96
78	PG&E Fresno 115 kV	HERNDON-CHLDHOSP_JCT 115 kV line #1	45	15	0	0	45	15
79	Path 26 Corridor	MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	40	15	0	0	40	15
80	SDG&E 230 kV	TALEGA-S.ONOFRE 230 kV line #1	0	0	36	148	36	148
81	East of Pisgah	IVANPAH-MTN PASS 115 kV line #1	35	36	0	0	35	36
82	PG&E Fresno 115 kV	SANGER-MC CALL 115 kV line #3	0	0	35	17	35	17
83	PG&E North Valley 230 kV	CARIBOU 230/230 kV transformer #11	0	0	33	6	33	6
84	PG&E Fresno 230 kV	GREGG-HENTAP1 230 kV line, subject to PG&E N-1 Wilson-Warnerville 230kV	0	0	29	7	29	7
85	PG&E Greater Bay area	C.COSTAPPE-BDLSWSTA 230 kV line #1	0	0	26	1	26	1
86	SDG&E/CFE	IMPRLVLY-IV PFC1 230 kV line, subject to SDGE N-2 Sycamore-Otay Mesa-Miguel and Bay Blvd-Otay Mesa-Miguel 230kV	0	0	24	12	24	12

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
87	SCE Lugo - Vincent 500 kV	LUGO-VINCENT 500 kV line #1	23	7	0	0	23	7
88	SDG&E/CFE	IV PFC1 230/230 kV transformer #2	22	3	0	0	22	3
89	PG&E Fresno 230 kV	MCMULLN1-KEARNEY 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	21	20	0	0	21	20
90	Path 26 Corridor	MIDWAY-MW_WRLWND_31 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	20	6	0	0	20	6
91	SCE Northern	PARDEE-SYLMAR220 230 kV line, subject to SCE N-1 Sylmar-Pardee 230kV	0	0	20	2	20	2
92	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line, subject to PG&E N-2 LoganCR-Delevn and Delevn-Cortina 230 kV	11	18	0	0	11	18
93	PG&E Greater Bay area	MARSHLD2-C.COSTAPPD 230 kV line #2	11	3	0	0	11	3
94	SCE Northern	PARDEE-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	8	65	0	0	8	65
95	SCE North of Lugo	KRAMER-VICTOR 230 kV line #2	8	18	0	0	8	18
96	SDG&E Northern 69 kV	ESCNDIDO-VC69_TP 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	0	0	8	90	8	90
97	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line #3	0	0	7	4	7	4
98	SCE Eastern	DVRS_RB_21-DVRS_RB_22 500 kV line #2	0	0	6	2	6	2
99	SDG&E Northern 69 kV	LILAC-PALA 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	5	71	0	0	5	71
100	Moenkope - Eldorado 500 kV	MOEN-ELD SC3-ELDORDO 500 kV line #1	4	1	0	0	4	1
101	PG&E Fresno 230 kV	HENTAP1-MUSTANGSS 230 kV line #1	0	0	4	3	4	3
102	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 Eldorado-Mohave 500 kV	4	3	0	0	4	3
103	SDG&E Bulk	ECO 230/500 kV transformer #1	3	10	0	0	3	10
104	PG&E North Valley 230 kV	BELDENTP-TABLE MTN D 230 kV line #1	3	1	0	0	3	1
105	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 Eldorado-Moenkopi 500 kV	3	1	0	0	3	1
106	PG&E Kern 230 kV	GATES D-TEMPLETN 230 kV line #1	0	0	3	18	3	18
107	PG&E Tesla 230 kV	STAGG-J2-TESLA E 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	0	0	2	1	2	1
108	SCE North of Lugo	LUGO-lugo 2i 500 kV line, subject to SCE N-1 Lugo Transformer #1 500-230 kV with RAS	0	0	2	3	2	3
109	Path 26 Corridor	MIDWAY-MW_VINCNT_11 500 kV line #1	2	1	0	0	2	1
110	PG&E Sierra	MARBLE 63.0/69.0 kV transformer #1	0	0	1	1	1	1

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
111	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	1	3	0	2	1	5
112	PG&E Kern 230 kV	ARCO-MIDWAY-E 230 kV line #1	0	0	1	30	1	30
113	SCE Northern	VINCNT2-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	1	6	0	0	1	6
114	Path 26 corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	1	3	0	0	1	3
115	SCE North of Lugo	VICTOR-LUGO 230 kV line #1	1	2	0	0	1	2
116	Path 84 Harry Allen - Eldorado 500 kV	P84 Harry Allen-Eldorado 500 kV	0	0	0	1	0	1
117	PG&E Fresno 230 kV	Q0954Q1027-GATES F 230 kV line #1	0	1	0	0	0	1
118	PG&E Greater Bay area	EIGHT MI-STAGG-J1 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	0	2	0	0	0	2
119	SCE North of Lugo	INYOKERN-KRAMER 115 kV line #1	0	1	0	0	0	1
120	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	0	1	0	1
121	PG&E Fresno 230 kV	GATES E-GATESBK11JCT 230 kV line #2	0	1	0	0	0	1

In Table G.7-1, the second column shows the branch group or local-area where the congestions locate. The aggregated congestions across specific branch groups and local areas in 2034 is summarized in Table G.7-2. The results have been ranked based on the congestion cost.

Table G.7-2: Aggregated congestion in the 2034 base portfolio PCM

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	Path 15 Corridor	389.42	5,468
2	Path 26 Corridor	241.10	4,503
3	SWIP North	51.29	716
4	East of Pisgah	35.61	1,378
5	Path 65 PDCI	28.53	1,679
6	SCE Northern	19.69	1,743
7	SCE Metro	16.05	179
8	PG&E North Valley 230 kV	15.05	1,863
9	Path 42	11.29	495
10	SDG&E/CFE	10.43	1,577
11	SCE North of Lugo	8.04	4,492
12	PG&E Kern 230kV	6.57	997
13	Path 41 Sylmar transformer	4.72	298
14	SDG&E 230 kV	3.74	634
15	SDG&E Bulk	3.67	374
16	COI Corridor	2.93	70
17	SCE Antelope 66kV	2.71	1,098
18	Path 46 WOR	2.37	45
19	PG&E Sierra	1.95	475
20	PG&E GBA	1.10	186
21	Path 25 PACW-PG&E 115 kV	0.39	20
22	SCE Eastern	0.31	19
23	SDG&E Northern 69 kV	0.29	638
24	PG&E POE - RIO OSO 230 kV	0.17	72
25	PG&E Fresno 115 kV	0.08	32
26	PG&E Fresno 230 kV	0.05	32
27	SCE Lugo - Vincent 500 kV	0.02	7
28	Moenkope - Eldorado 500 kV	0.00	1
29	PG&E Tesla 230 kV	0.00	1
30	Path 84 Harry Allen - Eldorado 500 kV	0.00	1

G.7.2 2034 Base Portfolio PCM Curtailment Results

Table G.7-3 shows the wind and solar generation curtailment in the ISO system in the base portfolio PCM. In this table, the renewable resources were aggregated by zone based on the transmission constraints to which the resources in the same zone normally contributed in the same direction, or based on geographic locations if there were not obvious transmission constraints nearby.

Table G.7-3: Wind and solar curtailment summary in the 2034 base portfolio PCM

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
SCE Northern	31,216	1,300	32,516	4.00%
SCE Eastern	20,184	277	20,461	1.36%
PG&E Fresno	16,628	1,709	18,337	9.32%
SDG&E Eastern and Bulk	14,197	427	14,624	2.92%
OSW-Diablo	13,365	769	14,134	5.44%
East of Pisgah	12,585	764	13,349	5.72%
PG&E Central Valley	11,073	416	11,488	3.62%
OOS W-WY	10,761	468	11,229	4.17%
SCE North of Lugo	10,633	411	11,044	3.72%
OOS W-SunZia	8,375	1,183	9,558	12.38%
NM	4,825	1,877	6,702	28.00%
PG&E Kern	6,053	322	6,375	5.06%
OSW-Humboldt	4,698	54	4,752	1.14%
PG&E Central Coast	4,228	144	4,372	3.30%
PG&E North Valley	3,124	147	3,271	4.50%
OOS W-ID	2,798	141	2,939	4.80%
AZ	1,920	833	2,753	30.26%
SCE Metro	2,173	68	2,241	3.04%
IID	1,408	1	1,410	0.08%
PG&E Greater Bay Area	1,193	64	1,256	5.08%
San Diego	712	4	716	0.54%
NW	554	28	582	4.77%
SMUD	379	29	408	7.07%
PG&E North Coast	387	10	397	2.42%
NV	328	49	376	12.91%
PG&E North Bay	56	4	60	6.85%
PG&E Humboldt	12	0	12	3.79%
Total	**183,865**	**11,498**	**195,364**	**5.89%**

G.7.3 2034 Base Portfolio PCM Gas-fired Generator Utilization

The utilization of gas-fired generators was assessed based on their annual capacity factors. The average capacity factors of gas-fired generators by area were summarized in Table G.7-4.

Table G.7-4: Gas-fired generator utilization in the 2034 base portfolio PCM

Areas	Sum of Capacity (MW)	Sum of Generation (MWh)	Capacity Factor
PG&E Central Coast	1,260	1,405,204	0.13
PG&E Central Valley	921	690,841	0.09
PG&E Fresno	1,213	714,106	0.07
PG&E Greater Bay Area	5,785	10,481,178	0.21
PG&E Humboldt	163	35,066	0.02
PG&E Kern	3,006	7,871,452	0.30
PG&E North Valley	1,478	1,660,388	0.13
SCE Blythe	494	518,965	0.12
SCE Eastern LA Basin	1,986	1,369,350	0.08
SCE Eldorado	495	992,991	0.23
SCE North of Lugo	922	1,170,252	0.14
SCE North of Magunden	61	19,890	0.04
SCE South of Magunden	818	649,023	0.09
SCE Tehachapi	4	492	0.01
SCE Ventura	219	197,614	0.10
SCE Western LA Basin	3,877	5,584,422	0.16
SDG&E Bulk	947	1,410,297	0.17
SDG&E San Diego	2,678	1,770,380	0.08
System Total	**26,326**	**36,541,910**	**0.16**

G.7.4 2039 Base Portfolio PCM Congestion Results

The results of the congestion assessment in the 2039 base portfolio PCM is listed in Table G.7-5. Columns “Cost Forward” and “Duration Forward” are the cost and duration of congestion, respectively, when the flow is in forward direction as indicated in the constraint name. Columns “Cost Backward” and “Duration Backward” are the cost and duration of congestion, respectively, when flow is in backward direction. The last two columns were the total cost and total duration, respectively.

Table G.7-5: Congestion in the ISO-controlled grid in the 2039 base portfolio PCM

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
1	Path 15 Corridor	MANNING-MN_GT_11 500 kV line #1	0	0	278,288	2,415	278,288	2,415
2	Path 26 Corridor	P26 Northern-Southern California	3	9	173,554	3,127	173,557	3,136
3	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	85,856	1,628	85,856	1,628
4	SCE Metro	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	67,364	667	67,364	667
5	Path 15 Corridor	MN_GT_11-GATES 500 kV line #1	0	0	54,304	475	54,304	475
6	SWIP North	SWIP-North (Midpoint-Robinson)	0	0	51,610	748	51,610	748
7	East of Pisgah	LUGO-VICTORVL 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	0	0	40,639	418	40,639	418
8	Path 15 Corridor	MN_MW_21-MN_MW_22 500 kV line #2	0	0	38,600	559	38,600	559
9	SCE Northern	WINDHUB_A 230/13.8 kV transformer #1	35,517	1,202	0	0	35,517	1,202
10	Path 26 Corridor	MIDWAY-MN_WRLWND_31 500 kV line #3	0	2	31,896	943	31,897	945
11	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	27,572	1,798	0	0	27,572	1,798
12	Path 15 Corridor	MANNING-MN_MW_21 500 kV line #2	0	0	26,691	872	26,691	872
14	SCE North of Lugo	CALCITE-LUGO 230 kV line #1	25,914	3,508	0	0	25,914	3,508
15	Path 42	P42 IID-SCE	24,129	594	0	0	24,129	594
17	Path 65 PDCI	P65 Pacific DC Intertie (PDCI)	0	0	22,989	1,380	22,989	1,380
18	SCE Northern	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	22,761	338	0	0	22,761	338
19	Path 46 WOR	P46 West of Colorado River (WOR)	19,526	308	0	0	19,526	308
20	East of Pisgah	SLOAN_CYN_5-ELDORDO 500 kV line #1	17,778	916	0	0	17,778	916
21	SDG&E/CFE	P45 SDG&E-CFE	6,355	1,080	7,785	552	14,140	1,632
22	PG&E Kern 230kV	GATES D-CALFLATSSS 230 kV line #1	0	0	11,531	1,250	11,531	1,250
23	SDG&E 230 kV	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	0	0	11,298	789	11,298	789
24	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	0	1	11,029	234	11,030	235

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
25	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line #2	0	0	10,231	339	10,231	339
26	PG&E MorroBay 230 kV	MORROBAY-DIABLOCN 230 kV line #1	0	0	9,507	1,142	9,507	1,142
27	SCE Northern	PARDEE-VINCENT 230 kV line #2	0	0	8,485	549	8,485	549
28	PG&E North Valley 230 kV	BRNY_FST_JCT-PIT 1 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	8,435	507	8,435	507
29	Path 41 Sylmar transformer	P41 Sylmar to SCE	7,934	396	0	1	7,934	397
30	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	6,925	202	6,925	202
31	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	6,756	1,613	0	0	6,756	1,613
32	SCE Northern	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	6,460	106	6,460	106
33	PG&E Sierra	P24 PG&E-Sierra	0	0	6,315	683	6,315	683
34	SCE Eastern	VALLEYSC 500/115 kV transformer #3	5,911	10	0	0	5,911	10
35	COI Corridor	P66 COI	2,462	30	2,494	20	4,956	50
40	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line, subject to PG&E N-1 Pit-Cottonwood 230 kV with HR SPS	4,481	362	0	0	4,481	362
41	SCE North of Lugo	SANDLOT-KRAMER 230 kV line #1	3,943	1,555	0	0	3,943	1,555
42	SDG&E Bulk	ECO 500/500 kV transformer #1	0	0	3,850	378	3,850	378
43	Path 15 Corridor	MN_MW_22-MN_MW_23 500 kV line #2	0	0	3,833	87	3,833	87
44	SCE Northern	VINCNT2-WINDSTAR1 230 kV line #1	0	0	3,748	453	3,748	453
45	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	3,720	254	3,720	254
46	PG&E GBA	E. SHORE-SANMATEO 230 kV line, subject to PG&E N-2 Newark-Ravenswood 230kV and Tesla-Ravenswood 230kV	2,817	318	0	0	2,817	318
47	PG&E Fresno 115 kV	SANGER-MC CALL 115 kV line #3	0	0	2,765	110	2,765	110
48	PG&E Manning - Metcalf 500 kV	MANNING-METCALF 500 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	2,735	95	0	0	2,735	95
49	SDG&E/CFE	OTAYMESA-TJI-230 230 kV line #1	0	0	2,672	280	2,672	280

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
50	PG&E GBA	LS PSTAS-NEWARK D 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	2,369	102	0	0	2,369	102
51	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	2,318	83	2,318	83
52	PG&E North Valley 230 kV	COTWD_F2-BRNY_FST_JCT 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	1,533	145	1,533	145
53	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line #1	1,435	114	0	0	1,435	114
54	PG&E Fresno 115 kV	HERNDON-CHLDHOSP_JCT 115 kV line #1	1,375	52	0	0	1,375	52
55	PG&E Sierra	HONEYLAK-SKEDADDLPS 60.0 kV line #1	0	0	1,186	213	1,186	213
56	SCE North of Lugo	P60 Inyo-Control 115 kV Tie	999	408	137	127	1,136	535
57	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	1,061	151	1,061	151
58	PG&E Manning - Metcalf 500 kV	MANNING-METCALF 500 kV line #1	914	21	0	0	914	21
59	PG&E Fresno 230 kV	GATES E-GATESBK11JCT 230 kV line #2	851	98	0	0	851	98
60	PG&E Sierra	SUMMIT 2-DRUMPH1 115 kV line #1	804	128	24	21	828	149
61	SCE North of Lugo	TAP189-CONTROL 115 kV line #1	0	0	807	69	807	69
62	SDG&E 230 kV	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	800	33	800	33
63	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	758	19	758	19
64	Path 15 Corridor	FINKSWSTA-WESTLEY 230 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV	657	21	0	0	657	21
65	SDG&E/CFE	IV PFC1 230/230 kV transformer #1	632	85	0	0	632	85
66	Moenkope - Eldorado 500 kV	MOEN-ELD SC3-ELDORDO 500 kV line #1	599	15	0	0	599	15
67	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	599	105	599	105

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
68	SCE Metro	MESACALS-LAGUBELL 230 kV line #2	526	661	0	0	526	661
69	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	523	13	523	13
70	Path 49 EOR	P49 East of Colorado River (EOR)	462	5	0	0	462	5
71	SCE Northern	PARDEE-SYLMAR220 230 kV line, subject to SCE N-1 Sylmar-Pardee 230kV	0	0	461	12	461	12
72	Path 26 Corridor	MN_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	454	55	0	0	454	55
73	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	449	236	449	236
74	SCE Northern	VINCNT2-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	440	63	0	0	440	63
75	PG&E North Valley 230 kV	CARIBOU-BELDENTP 230 kV line #1	402	62	0	0	402	62
76	SCE North of Lugo	COLWATER 230/115 kV transformer #1	0	0	370	444	370	444
77	PG&E Tesla 230 kV	STAGG-J2-TESLA E 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	0	0	355	3	355	3
78	PG&E GBA	C.COSTAPPE-BDLSWSTA 230 kV line #1	0	0	354	14	354	14
79	SDG&E/CFE	IMPRLVLY-IV PFC1 230 kV line, subject to SDGE N-2 Sycamore-Otay Mesa-Miguel and Bay Blvd-Otay Mesa-Miguel 230kV	0	0	335	66	335	66
80	PG&E Fresno 115 kV	KINGSBURGD-CONTADNA 115 kV line #1	0	0	317	41	317	41
81	East of Pisgah	P61 Lugo-Victorville 500 kV Line	281	5	25	19	306	24
82	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	294	19	0	0	294	19
83	SCE Northern	PARDEE-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	282	374	0	0	282	374
84	PG&E POE - RIO OSO 230 kV	POE-RIO OSO 230 kV line #1	281	75	0	0	281	75
85	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 Lugo-Mohave 500 kV	271	25	0	0	271	25
86	SCE North of Lugo	KRAMER-VICTOR 230 kV line #1	264	198	0	0	264	198

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
87	PG&E Fresno 230 kV	MCMULLN1-KEARNEY 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	260	42	0	0	260	42
88	SDG&E/CFE	IV PFC1 230/230 kV transformer #2	256	38	0	0	256	38
89	East of Pisgah	HAE SVC-HAE SVCL 500 kV line #1	233	10	0	0	233	10
90	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line, subject to PG&E N-1 Delevn-Cortina 230 kV	210	280	0	0	210	280
91	SDG&E 230 kV	TALEGA-S.ONOFRE 230 kV line #1	0	0	191	461	191	461
92	PG&E GBA	MARSHLD2-C.COSTAPPD 230 kV line #2	191	14	0	0	191	14
93	Path 26 Corridor	MN_VINCNT_22-VINCENT 500 kV line #2	161	19	0	0	161	19
94	SDG&E Bulk	ECO-MIGUEL 500 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	113	16	0	0	113	16
95	Path 26 Corridor	MN_VINCNT_11-MN_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	109	20	0	0	109	20
96	PG&E Fresno 115 kV	GWFHANFORDSS-CONTADNA 115 kV line #1	77	14	0	0	77	14
97	PG&E Fresno 230 kV	GREGG-HENTAP1 230 kV line #1	0	0	73	22	73	22
98	SCE North of Lugo	COLWATER-DUNNSIDE 115 kV line #1	59	136	0	0	59	136
99	Path 26 Corridor	MN_WRLWND_32-WIRLWIND 500 kV line #3	0	0	58	5	58	5
100	SDG&E Northern 69 kV	SANLUSRY-OCEAN RANCH 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	58	209	0	0	58	209
101	SCE Eastern	DEVERS-devers i 500 kV line, subject to SCE N-1 Valley-Alberhill 500 kV with RAS	57	36	0	0	57	36
102	PG&E Sierra	MARBLE 63.0/69.0 kV transformer #1	50	6	6	2	56	8
103	PG&E GBA	TESLA E-NEWARK D 230 kV line, subject to PG&E N-1 Tesla-Ravenswood 230kV	55	2	0	0	55	2
104	SDG&E 230 kV	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-1 Silvergate-OldTown-Mission 230kV no RAS	53	10	0	0	53	10

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
105	PG&E North Valley 230 kV	BELDENTP-TABLE MTN D 230 kV line #1	49	5	0	0	49	5
106	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line, subject to PG&E N-2 Pit-CotwdF and CotwdE-RM 230 kV with HR SPS	44	3	0	0	44	3
107	PG&E North Valley 230 kV	CARIBOU 230/230 kV transformer #11	0	0	42	6	42	6
108	East of Pisgah	IVANPAH-MTN PASS 115 kV line #1	41	38	0	0	41	38
109	PG&E Fresno 230 kV	GREGG-HENTAP1 230 kV line, subject to PG&E N-1 Gregg-Borden #1 230kV	0	0	40	10	40	10
110	SCE Eastern	DVRS_RB_21-DVRS_RB_22 500 kV line #2	0	0	37	2	37	2
111	PG&E Kern 230kV	GATES D-TEMPLETN 230 kV line #1	0	0	27	59	27	59
112	Path 84 Harry Allen - Eldorado 500 kV	P84 Harry Allen-Eldorado 500 kV	0	0	27	2	27	2
113	SDG&E Bulk	IMPRLVLY 500/500 kV transformer #1	0	0	25	49	25	49
114	SCE Vincent - MiraLoma 500kV	VINCENT-MESA CAL 500 kV line #1	25	1	0	0	25	1
115	SCE North of Lugo	LUGO-lugo 2i 500 kV line, subject to SCE N-1 Lugo Transformer #1 500-230 kV with RAS	0	0	23	27	23	27
116	East of Pisgah	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	22	12	0	0	22	12
117	SCE North of Lugo	KRAMER-VICTOR 230 kV line #2	21	48	0	0	21	48
118	SCE Lugo - Vincent 500 kV	LUGO-VINCENT 500 kV line #1	21	13	0	0	21	13
119	Path 26 Corridor	MIDWAY-MN_WRLWND_31 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	20	9	0	0	20	9
120	PG&E Kern 230kV	ARCO-MIDWAY-E 230 kV line #1	0	0	18	226	18	226
122	Path 26 Corridor	MN_WRLWND_31-MN_WRLWND_32 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	17	5	0	0	17	5
123	PG&E Tesla 230 kV	WEBER-TESLA E 230 kV line, subject to PG&E N-1 Bellota-TeslaE 230kV	0	0	15	2	15	2
125	SCE Eastern	ALBERHIL-VALLEYSC 500 kV line #1	0	0	14	5	14	5

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
126	East of Pisgah	GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	2	19	11	73	12	92
127	SCE Northern	WINDHUB_A 230/13.8 kV transformer #2	12	11	0	0	12	11
128	PG&E Fresno 115 kV	LPRNJCTSS-GWFHANFORDSS 115 kV line #1	11	6	0	0	11	6
129	SCE North of Lugo	INYOKERN-KRAMER 115 kV line #1	11	3	0	0	11	3
130	SCE Eastern	DEVERS-DVRS_RB_11 500 kV line #1	0	0	10	3	10	3
131	PG&E Fresno 230 kV	HELM-MC CALL 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	10	5	0	0	10	5
132	PG&E Fresno 115 kV	HENRETTA-LPRNJCTSS 115 kV line #1	7	4	0	0	7	4
133	PG&E GBA	NEWARK D-NRS 230 kV line #1	5	3	0	0	5	3
134	SCE North of Lugo	VICTOR-LUGO 230 kV line #1	5	7	0	0	5	7
135	PG&E Morro Bay 230 kV	TEMPLETN-MORROBAY 230 kV line #1	0	0	4	26	4	26
136	COI Corridor	ROUND MT-RM_FR_22 500 kV line #2	3	2	0	0	3	2
137	Path 26 Corridor	MN_VINCNT_12-VINCENT 500 kV line #1	2	1	0	0	2	1
138	PG&E GBA	NRS-SANJB230 230 kV line #1	0	0	1	1	1	1
139	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 Eldorado-Moenkopi 500 kV	1	1	0	0	1	1
140	PG&E GBA	DELTAPMP-SANDHLWJCT 230 kV line #1	0	0	1	2	1	2
141	Path 26 Corridor	MN_WRLWND_31-MN_WRLWND_32 500 kV line #3	0	0	1	1	1	1
142	PG&E Kern 230kV	GATES F-MIDWAY-F 230 kV line, subject to PG&E N-1 Arco-Midway 230kV	0	0	1	9	1	9
143	Path 26 Corridor	MIDWAY-MN_VINCNT_11 500 kV line #1	0	1	0	0	0	1
144	PG&E GBA	C.COSTAPPE-WINDMASTERJT 230 kV line #1	0	0	0	2	0	2
145	SDG&E Bulk	ECO 230/500 kV transformer #1	0	4	0	0	0	4
146	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	0	4	0	0	0	4

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
147	PG&E Kern 230kV	GATES F-MIDWAY-F 230 kV line, subject to PG&E N-1 Gates-Arco 230kV	0	0	0	2	0	2
148	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line, subject to PG&E N-2 LoganCR-Delevn and Delevn-Cortina 230 kV	0	1	0	0	0	1
149	PG&E Fresno 230 kV	HENTAP1-MUSTANGSS 230 kV line #1	0	0	0	3	0	3
150	PG&E Kern 230kV	GATES F-MIDWAY-F 230 kV line #1	0	0	0	1	0	1
151	PG&E Morro Bay 230 kV	MORROBAY-ESTRELLA 230 kV line #1	0	1	0	0	0	1
152	SCE Antelope 66kV	ANTELOPE-NEENACH 66.0 kV line #1	0	6	0	0	0	6
153	SCE North of Lugo	VICTOR-LUGO 230 kV line #2	0	1	0	0	0	1
154	PG&E GBA	WINDMASTERJT-DELTAPMP 230 kV line #1	0	0	0	1	0	1
155	PG&E Kern 230kV	GATES F-ARCO 230 kV line #1	0	0	0	1	0	1
156	PG&E Fresno 230 kV	HENTAP1-HENRIETTA_D 230 kV line #1	0	0	0	2	0	2

Table G.7-6 lists the aggregated congestion results across specific branch groups and local areas in the 2039 base portfolio PCM case, ranked by congestion cost.

Table G.7-6: Aggregated congestion in 2039 base portfolio PCM

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	Path 15 Corridor	521.80	7,343
2	Path 26 Corridor	206.28	4,197
3	East of Pisgah	86.87	3,334
4	SCE Northern	78.62	3,348
5	SCE Metro	67.89	1,328
6	SWIP North	51.61	748
7	SCE North of Lugo	32.55	6,531
8	Path 42	24.13	594
9	Path 65 PDCI	22.99	1,380
10	Path 46 WOR	19.53	308
11	SDG&E/CFE	18.03	2,101
12	PG&E North Valley 230 kV	16.63	1,485
13	SDG&E 230 kV	12.34	1,293
14	PG&E Kern 230kV	11.58	1,548
15	SCE Eastern	9.63	171
16	PG&E Morro Bay 230 kV	9.51	1,169
17	PG&E Sierra	8.39	1,053

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
18	Path 41 Sylmar transformer	7.93	397
19	SCE Antelope 66kV	6.76	1,619
20	PG&E GBA	5.79	459
21	COI Corridor	4.96	52
22	PG&E Fresno 115 kV	4.55	227
23	SDG&E Bulk	3.99	447
24	PG&E Manning - Metcalf 500 kV	3.65	116
25	PG&E Fresno 230 kV	1.23	182
26	Moenkope - Eldorado 500 kV	0.60	15
27	Path 49 EOR	0.46	5
28	PG&E Tesla 230 kV	0.37	5
29	Path 25 PACW-PG&E 115 kV	0.29	19
30	PG&E POE - RIO OSO 230 kV	0.28	75
31	SDG&E Northern 69 kV	0.06	209
32	Path 84 Harry Allen - Eldorado 500 kV	0.03	2
33	SCE Vincent – Mira Loma 500kV	0.02	1
34	SCE Lugo - Vincent 500 kV	0.02	13

G.7.5 2039 Base Portfolio PCM Curtailment Results

Table G.7-7 shows the wind and solar curtailment results of the 2039 base portfolio PCM.

Table G.7-7: Wind and solar curtailment summary in the 2039 base portfolio PCM

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
SCE Northern	33,455	1,373	34,828	3.94%
SCE Eastern	23,695	487	24,182	2.01%
PG&E Fresno	20,931	2,585	23,516	10.99%
East of Pisgah	16,944	952	17,896	5.32%
PG&E Central Valley	17,073	595	17,668	3.37%
OOS W-SunZia	13,268	2,592	15,860	16.34%
SDG&E Eastern and Bulk	14,953	525	15,477	3.39%
OSW-Diablo	13,319	815	14,134	5.76%
SCE North of Lugo	12,193	602	12,795	4.70%
OOS W-WY	11,087	509	11,596	4.39%
PG&E Kern	9,890	412	10,301	4.00%
OSW-Humboldt	8,140	63	8,203	0.77%
NM	4,447	2,255	6,702	33.65%
OOS W-Tesla	5,672	126	5,798	2.18%
PG&E Central Coast	4,917	281	5,198	5.40%
PG&E North Valley	4,156	192	4,348	4.42%
SCE Metro	3,008	107	3,115	3.43%
OOS W-ID	2,780	160	2,939	5.44%

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
OOS W-NW	1,819	983	2,802	35.09%
AZ	1,708	1,045	2,753	37.96%
IID	1,409	1	1,410	0.05%
PG&E Greater Bay Area	1,206	50	1,256	4.01%
San Diego	713	3	716	0.48%
NW	552	31	582	5.25%
SMUD	384	25	408	6.06%
PG&E North Coast	393	4	397	0.89%
NV	322	54	376	14.38%
PG&E North Bay	56	4	60	6.27%
PG&E Humboldt	12	0	12	2.95%
Total	**228,499**	**16,830**	**245,329**	**6.86%**

G.7.6 2039 Base Portfolio PCM Gas-fired Generator Utilization

The average capacity factors of gas-fired generators by area in the 2039 base portfolio were summarized in Table G.7-8.

Table G.7-8: Gas-fired generator utilization in the 2039 base portfolio PCM

Areas	Sum of Capacity (MW)	Sum of Generation (MWh)	Capacity Factor
PG&E Central Coast	1,221	1,768,376	0.17
PG&E Central Valley	872	779,619	0.10
PG&E Fresno	1,098	880,502	0.09
PG&E Greater Bay Area	5,538	12,717,381	0.26
PG&E Humboldt	163	65,957	0.05
PG&E Kern	2,013	6,033,211	0.34
PG&E North Valley	1,446	2,151,166	0.17
SCE Blythe	494	552,888	0.13
SCE Eastern LA Basin	1,986	1,983,297	0.11
SCE Eldorado	495	790,179	0.18
SCE North of Lugo	922	1,725,744	0.21
SCE North of Magunden	61	30,465	0.06
SCE South of Magunden	818	1,137,368	0.16
SCE Tehachapi	4	804	0.02
SCE Ventura	171	203,128	0.14
SCE Western LA Basin	3,572	5,677,020	0.18
SDG&E Bulk	947	1,523,164	0.18
SDG&E San Diego	2,678	2,598,855	0.11
System Total	**24,498**	**40,619,125**	**0.19**

G.7.7 2039 Sensitivity Portfolio PCM Congestion Results

The results of the congestion assessment in the 2039 sensitivity portfolio PCM is listed in Table G.7-9. Columns "Cost Forward" and "Duration Forward" are the cost and duration of congestion, respectively, when the flow is in forward direction as indicated in the constraint name. Columns "Cost Backward" and "Duration Backward" are the cost and duration of congestion, respectively, when flow is in backward direction. The last two columns were the total cost and total duration, respectively.

Table G.7-9: Congestion in the ISO-controlled grid in the 2039 sensitivity portfolio PCM

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
1	Path 26 Corridor	P26 Northern-Southern California	0	0	1,925,625	6,058	1,925,625	6,058
2	Path 15 Corridor	MANNING-MN_GT_11 500 kV line #1	0	0	393,428	2,008	393,428	2,008
3	Path 65 PDCI	P65 Pacific DC Intertie (PDCI)	0	0	328,793	3,808	328,793	3,808
4	Path 26 Corridor	MIDWAY-MN_WRLWND_31 500 kV line #3	0	1	267,641	2,844	267,641	2,845
5	East of Pisgah	LUGO-VICTORVL 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	0	0	250,612	672	250,612	672
6	Path 46 WOR	P46 West of Colorado River (WOR)	201,601	426	0	0	201,601	426
7	Path 41 Sylmar transformer	P41 Sylmar to SCE	101,580	643	0	0	101,580	643
8	SCE North of Lugo	CALCITE-LUGO 230 kV line #1	88,037	5,394	0	0	88,037	5,394
9	SDG&E Bulk	IMPRLVLY 500/500 kV transformer #1	0	0	84,548	1,560	84,548	1,560
10	COI Corridor	P66 COI	82,976	353	8	1	82,985	354
11	SCE Metro	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	82,696	862	82,696	862
12	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	72,042	2,213	0	0	72,042	2,213
13	PG&E Sierra	P24 PG&E-Sierra	0	0	67,848	2,262	67,848	2,262
14	SDG&E/CFE	P45 SDG&E-CFE	9,373	1,428	55,615	881	64,989	2,309
15	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	0	0	61,662	81	61,662	81
16	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	60,012	1,232	60,012	1,232
17	SWIP North	SWIP-North (Midpoint-Robinson)	0	0	50,471	591	50,471	591
18	Path 15 Corridor	MN_GT_11-GATES 500 kV line #1	0	0	25,441	195	25,441	195
19	SCE Northern	PARDEE-SYLMAR220 230 kV line, subject to SCE N-1 Sylmar-Pardee 230kV	0	0	16,740	72	16,740	72
20	PG&E MorroBay 230 kV	MORROBAY-DIABLOCN 230 kV line #1	0	0	15,122	1,267	15,122	1,267

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
21	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	13,952	98	13,952	98
22	Path 15 Corridor	MANNING-MN_MW_21 500 kV line #2	0	0	12,029	529	12,029	529
23	PG&E GBA	MARSHLD2-C.COSTAPPD 230 kV line #2	11,852	228	0	0	11,852	228
24	SCE Northern	WINDHUB_A 230/13.8 kV transformer #1	10,966	1,037	0	0	10,966	1,037
25	SCE North of Lugo	INYOKERN-KRAMER 115 kV line #1	10,263	2,141	0	0	10,263	2,141
26	PG&E GBA	LS PSTAS-NEWARK D 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	9,492	136	0	0	9,492	136
27	PG&E North Valley 230 kV	BRNY_FST_JCT-PIT 1 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	9,322	393	9,322	393
28	SDG&E/CFE	IMPRLVLY-IV PFC1 230 kV line, subject to SDGE N-2 Sycamore-Otay Mesa-Miguel and Bay Blvd-Otay Mesa-Miguel 230kV	0	0	8,132	171	8,132	171
29	East of Pisgah	SLOAN_CYN_5-ELDORDO 500 kV line #1	7,948	312	0	0	7,948	312
30	SDG&E 230 kV	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	7,054	144	7,054	144
31	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	6,856	639	6,856	639
32	PG&E Sierra	HONEYLAK-SKEDADDLPS 60.0 kV line #1	0	0	6,828	704	6,828	704
33	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	6,626	194	0	0	6,626	194
34	SCE Eastern	VALLEYSC 500/115 kV transformer #3	5,920	10	0	0	5,920	10
35	PG&E GBA	E. SHORE-SANMATEO 230 kV line, subject to PG&E N-2 Newark-Ravenswood 230kV and Tesla-Ravenswood 230kV	5,167	412	0	0	5,167	412
36	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line #1	5,030	276	0	0	5,030	276
37	Path 15 Corridor	MN_MW_23-MIDWAY 500 kV line #2	0	0	4,981	147	4,981	147
38	PG&E Manning - Metcalf 500 kV	MANNING-METCALF 500 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	4,062	185	0	0	4,062	185
39	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line, subject to PG&E N-1 Pit-Cottonwood 230 kV with HR SPS	3,492	294	0	0	3,492	294
40	Path 15 Corridor	MN_MW_21-MN_MW_22 500 kV line #2	0	0	3,412	91	3,412	91
41	SDG&E/CFE	OTAYMESA-TJI-230 230 kV line #1	98	10	3,247	334	3,345	344
42	SCE Northern	VINCNT2-WINDSTAR1 230 kV line #1	0	0	3,219	502	3,219	502

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
43	Path 15 Corridor	FINKSWSTA-WESTLEY 230 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV	3,129	121	0	0	3,129	121
44	SCE Metro	MESACALS-LAGUBELL 230 kV line #2	2,894	647	0	0	2,894	647
45	SDG&E 230 kV	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	0	0	2,868	339	2,868	339
46	SCE North of Lugo	SANDLOT-KRAMER 230 kV line #1	2,503	1,484	0	0	2,503	1,484
47	SDG&E Bulk	ECO-MIGUEL 500 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	2,307	105	0	0	2,307	105
48	PG&E Manning - Metcalf 500 kV	MANNING-METCALF 500 kV line #1	2,234	55	0	0	2,234	55
49	PG&E Sierra	SUMMIT 2-DRUMPH1 115 kV line #1	2,212	304	0	0	2,212	304
50	SCE Northern	PARDEE-VINCENT 230 kV line #2	0	0	2,142	390	2,142	390
51	PG&E Fresno 115 kV	HERNDON-CHLDHOSP_JCT 115 kV line #1	2,058	68	0	0	2,058	68
52	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	1,962	842	0	0	1,962	842
53	PG&E North Valley 230 kV	COTWD_F2-BRNY_FST_JCT 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	1,870	126	1,870	126
54	SDG&E/CFE	IV PFC1 230/230 kV transformer #1	1,470	171	398	18	1,868	189
55	East of Pisgah	HAE SVC-HAE SVCL 500 kV line #1	1,777	31	0	0	1,777	31
56	SCE North of Lugo	P60 Inyo-Control 115 kV Tie	733	327	1,015	594	1,748	921
57	SDG&E Bulk	ECO 500/500 kV transformer #1	0	0	1,713	235	1,713	235
58	SCE North of Lugo	KRAMER-VICTOR 230 kV line #1	1,548	582	0	0	1,548	582
59	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	1,408	105	1,408	105
60	SDG&E/CFE	IV PFC1 230/230 kV transformer #2	563	76	845	38	1,408	114
61	PG&E North Valley 230 kV	CARIBOU 230/230 kV transformer #11	0	0	1,355	124	1,355	124
62	SCE Northern	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	1,211	92	0	0	1,211	92
63	Path 26 Corridor	MN_WRLWND_32-WIRLWIND 500 kV line #3	0	0	1,108	32	1,108	32
64	PG&E Fresno 115 kV	SANGER-MC CALL 115 kV line #3	0	0	1,052	73	1,052	73
65	Path 42	P42 IID-SCE	956	119	0	0	956	119
66	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	881	23	881	23
67	East of Pisgah	INNOVATION-INNOVATION 230 kV line, subject to VEA N-2	858	63	0	0	858	63

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
		NWest-DesertView 230 kV with RAS						
68	PG&E Fresno 115 kV	WOODWARD-CHLDHOSP_JCT 115 kV line #1	0	0	825	5	825	5
69	SCE North of Lugo	TAP189-CONTROL 115 kV line #1	0	0	803	55	803	55
70	East of Pisgah	ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 Lugo-Mohave 500 kV	720	57	0	0	720	57
71	Path 49 EOR	P49 East of Colorado River (EOR)	663	6	0	0	663	6
72	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	633	245	633	245
73	COI Corridor	ROUND MT-RM_FR_22 500 kV line #2	620	6	0	0	620	6
74	PG&E POE - RIO OSO 230 kV	POE-RIO OSO 230 kV line #1	540	85	0	0	540	85
75	SCE Northern	MAGUNDEN-PASTORIA 230 kV line #2	531	532	0	0	531	532
76	SDG&E 230 kV	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-1 Silvergate-OldTown-Mission 230kV no RAS	513	52	0	0	513	52
77	PG&E Fresno 230 kV	MCMULLN1-KEARNEY 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	462	216	0	0	462	216
78	SCE North of Lugo	COLWATER 230/115 kV transformer #1	0	0	434	488	434	488
79	Path 15 Corridor	MN_MW_22-MN_MW_23 500 kV line #2	0	0	401	18	401	18
80	SCE Eastern	DEVERS-deversi 500 kV line, subject to SCE N-1 Valley-Alberhill 500 kV with RAS	371	113	0	0	371	113
81	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	358	144	358	144
82	Moenkope - Eldorado 500 kV	MOEN-ELD SC3-ELDORDO 500 kV line #1	344	12	0	0	344	12
83	SCE Northern	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	321	35	321	35
84	SCE Lugo - Vincent 500 kV	LUGO-VINCENT 500 kV line #1	303	23	0	0	303	23
85	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line, subject to PG&E N-1 Delevn-Cortina 230 kV	298	338	0	0	298	338
86	SCE Northern	WINDHUB_A 230/13.8 kV transformer #2	264	42	0	0	264	42
87	Path 25 PACW-PG&E 115 kV	CASCADE-DELTAP 115 kV line #1	0	0	258	14	258	14
88	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	235	8	235	8

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
89	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	88	32	144	328	232	360
90	PG&E Fresno 115 kV	KINGSBURGD-CONTADNA 115 kV line #1	0	0	223	39	223	39
91	East of Pisgah	P61 Lugo-Victorville 500 kV Line	191	1	29	12	220	13
92	PG&E GBA	C.COSTAPPE-BDLSWSTA 230 kV line #1	0	0	218	16	218	16
93	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	197	38	197	38
94	East of Pisgah	VEA_PST_2-IS TAP 138 kV line #1	0	0	169	28	169	28
95	East of Pisgah	IVANPAH-MTN PASS 115 kV line #1	123	50	0	0	123	50
96	SCE North of Lugo	KRAMER-VICTOR 230 kV line #2	122	87	0	0	122	87
97	SCE North of Lugo	COLWATER-DUNNSIDE 115 kV line #1	119	148	0	0	119	148
98	SDG&E 230 kV	TALEGA-S.ONOFRE 230 kV line #1	0	0	117	198	117	198
99	PG&E GBA	LS PSTAS-NEWARK D 230 kV line #1	117	1	0	0	117	1
100	PG&E Fresno 115 kV	LPRNJCTSS-GWFHANFORDSS 115 kV line #1	102	15	0	0	102	15
101	SDG&E Northern 69 kV	SANLUSRY-OCEAN RANCH 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	102	238	0	0	102	238
102	SCE Eastern	DEVERS-DVRS_RB_11 500 kV line #1	0	0	101	6	101	6
103	Path 26 Corridor	MN_VINCNT_22-VINCENT 500 kV line #2	28	6	72	1	101	7
104	PG&E GBA	SARATOGA-VASONA 230 kV line #1	0	0	94	3	94	3
105	PG&E Kern 230kV	ARCO-MIDWAY-E 230 kV line #1	0	0	71	325	71	325
106	PG&E Fresno 230 kV	GREGG-HENTAP1 230 kV line #1	0	0	69	11	69	11
107	PG&E Kern 230kV	GATES D-CALFLATSSS 230 kV line #1	0	0	68	326	68	326
108	SCE Eastern	ALBERHIL-VALLEYSC 500 kV line #1	0	0	46	9	46	9
109	PG&E Fresno 230 kV	GREGG-HENTAP1 230 kV line, subject to PG&E N-1 Gregg-Borden #1 230kV	0	0	41	1	41	1
110	PG&E GBA	DELTAPMP-SANDHLWJCT 230 kV line #1	0	0	39	5	39	5
111	East of Pisgah	GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	12	84	27	97	39	181
112	Path 84 Harry Allen - Eldorado 500 kV	P84 Harry Allen-Eldorado 500 kV	0	0	39	14	39	14

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
113	PG&E Tesla 230 kV	STAGG-J2-TESLA E 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	0	0	36	3	36	3
114	PG&E Sierra	MARBLE 63.0/69.0 kV transformer #1	27	9	2	1	29	10
115	PG&E Fresno 230 kV	GATES E-GATESBK11JCT 230 kV line #2	27	11	0	0	27	11
116	PG&E North Valley 230 kV	CARBERY-ROUND MT 230 kV line, subject to PG&E N-2 Pit-CotwdF and CotwdE-RM 230 kV with HR SPS	25	3	0	0	25	3
117	SCE Northern	PARDEE-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	23	91	0	0	23	91
118	SDG&E Northern 69 kV	ESCNDIDO-SANMRCOS 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	18	4	0	0	18	4
119	PG&E GBA	EIGHT MI-STAGG-J1 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	16	3	0	0	16	3
120	PG&E Fresno 115 kV	GWFHANFORDSS-CONTADNA 115 kV line #1	15	2	0	0	15	2
121	SCE Northern	MAGUNDEN-SPRINGVL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	8	2	1	4	9	6
122	PG&E Fresno 230 kV	HELM-MC CALL 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	7	3	0	0	7	3
123	SCE Eastern	DVRS_RB_21-DVRS_RB_22 500 kV line #2	0	0	7	4	7	4
124	PG&E Kern 230kV	COTWD_F2-GLENN 230 kV line #1	0	0	6	5	6	5
125	SCE North of Lugo	VICTOR-LUGO 230 kV line #1	6	12	0	0	6	12
126	SDG&E Bulk	ECO 230/500 kV transformer #1	6	14	0	0	6	14
127	East of Pisgah	ELDORDO2-SLOAN CANYON 230 kV line #1	3	20	0	0	3	20
128	East of Pisgah	AMARGOSA-SANDY 138 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	0	0	2	4	2	4
129	Path 46 WOR	DEL_CLRVR_11-DEL_CLRVR_12 500 kV line #1	2	1	0	0	2	1
130	PG&E Fresno 230 kV	HENTAP1-MUSTANGSS 230 kV line #1	0	0	2	26	2	26
131	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line #1	1	1	0	0	1	1
132	PG&E GBA	DELTAPMP-SANDHLWJCT 230 kV line #1	0	0	1	2	1	2
133	Path 26 Corridor	MN_WRLWND_31-MN_WRLWND_32 500 kV line #3	0	0	1	1	1	1
134	PG&E Kern 230kV	GATES F-MIDWAY-F 230 kV line, subject to PG&E N-1 Arco-Midway 230kV	0	0	1	9	1	9

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
135	Path 26 Corridor	MIDWAY-MN_VINCNT_11 500 kV line #1	0	1	0	0	0	1
136	PG&E GBA	C.COSTAPPE-WINDMASTERJT 230 kV line #1	0	0	0	2	0	2
137	SDG&E Bulk	ECO 230/500 kV transformer #1	0	4	0	0	0	4
138	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	0	4	0	0	0	4
139	PG&E Kern 230kV	GATES F-MIDWAY-F 230 kV line, subject to PG&E N-1 Gates-Arco 230kV	0	0	0	2	0	2
140	PG&E North Valley 230 kV	CORTINA-VACA-DIX 230 kV line, subject to PG&E N-2 LoganCR-Delev n and Delev n-Cortina 230 kV	0	1	0	0	0	1
141	PG&E Fresno 230 kV	HENTAP1-MUSTANGSS 230 kV line #1	0	0	0	3	0	3
142	PG&E Kern 230kV	GATES F-MIDWAY-F 230 kV line #1	0	0	0	1	0	1
143	PG&E MorroBay 230 kV	MORROBAY-ESTRELLA 230 kV line #1	0	1	0	0	0	1
144	SCE Antelope 66kV	ANTELOPE-NEENACH 66.0 kV line #1	0	6	0	0	0	6
145	SCE North of Lugo	VICTOR-LUGO 230 kV line #2	0	1	0	0	0	1
146	PG&E GBA	WINDMASTERJT-DELTAPMP 230 kV line #1	0	0	0	1	0	1
147	PG&E Kern 230kV	GATES F-ARCO 230 kV line #1	0	0	0	1	0	1
148	PG&E Fresno 230 kV	HENTAP1-HENRIETTA_D 230 kV line #1	0	0	0	2	0	2

Table G.7-10 lists the aggregated congestion results across specific branch groups and local areas in the 2039 base portfolio PCM case, ranked by congestion cost.

Table G.7-10: Aggregated congestion in 2039 sensitivity portfolio PCM

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	Path 26 Corridor	2,194.48	8,944
2	Path 15 Corridor	586.13	5,442
3	East of Pisgah	334.51	3,644
4	Path 65 PDCI	328.79	3,808
5	Path 46 WOR	201.60	427
6	SCE North of Lugo	105.58	11,313
7	Path 41 Sylmar transformer	101.58	643
8	SDG&E Bulk	88.57	1,918
9	SCE Metro	85.59	1,509
10	COI Corridor	83.61	360

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
11	SDG&E/CFE	79.74	3,127
12	PG&E Sierra	76.92	3,280
13	SWIP North	50.47	591
14	SCE Northern	36.02	3,307
15	PG&E GBA	27.00	809
16	PG&E North Valley 230 kV	21.39	1,556
17	PG&E MorroBay 230 kV	15.12	1,268
18	SDG&E 230 kV	10.55	733
19	SCE Eastern	8.97	278
20	Path 25 PACW-PG&E 115 kV	6.88	208
21	PG&E Manning - Metcalf 500 kV	6.30	240
22	PG&E Fresno 115 kV	4.28	202
23	SCE Antelope 66kV	1.96	848
24	Path 42	0.96	119
25	Path 49 EOR	0.66	6
26	PG&E Fresno 230 kV	0.61	273
27	PG&E POE - RIO OSO 230 kV	0.54	85
28	Moenkope - Eldorado 500 kV	0.34	12
29	SCE Lugo - Vincent 500 kV	0.30	23
30	PG&E Kern 230kV	0.15	669
31	SDG&E Northern 69 kV	0.12	242
32	Path 84 Harry Allen - Eldorado 500 kV	0.04	14
33	PG&E Tesla 230 kV	0.04	3

G.7.8 2039 Sensitivity Portfolio PCM Curtailment Results

Table G.7-11 shows the wind and solar curtailment results of the 2039 sensitivity portfolio PCM.

Table G.7-11: Wind and solar curtailment summary in the 2039 sensitivity portfolio PCM

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
AZ	1,750	1,003	2,753	36.44%
East of Pisgah	20,327	1,198	21,525	5.57%
IID	1,407	3	1,410	0.19%
NM	4,520	2,182	6,702	32.55%
NV	328	49	376	12.89%
NW	565	17	582	2.87%
OOS W-ID	2,826	113	2,939	3.84%
OOS W-SunZia	11,424	2,059	13,483	15.27%
OOS W-WY	11,050	546	11,596	4.71%
PG&E Central Coast	4,784	141	4,925	2.86%
PG&E Central Valley	13,104	90	13,194	0.68%

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
PG&E Fresno	23,849	2,069	25,917	7.98%
PG&E Greater Bay Area	1,261	8	1,270	0.67%
PG&E Humboldt	12	0	12	0.11%
PG&E Kern	10,182	243	10,425	2.33%
PG&E North Bay	60	0	60	0.25%
PG&E North Coast	396	0	397	0.09%
PG&E North Valley	5,071	37	5,108	0.72%
San Diego	711	5	716	0.71%
SCE Eastern	30,834	325	31,159	1.04%
SCE Metro	4,244	194	4,437	4.36%
SCE North of Lugo	13,768	1,845	15,612	11.81%
SCE Northern	39,771	3,272	43,043	7.60%
SDG&E Eastern and Bulk	20,883	997	21,880	4.56%
SMUD	402	6	408	1.43%
Total	**223,530**	**16,400**	**239,930**	**6.84%**

G.7.9 2039 Sensitivity Portfolio PCM Gas-fired Generator Utilization

The average capacity factors of gas-fired generators by area in the 2039 sensitivity portfolio were summarized in Table G.7-12.

Table G.7-12: Gas-fired generator utilization in the 2039 sensitivity portfolio PCM

Areas	Sum of Capacity (MW)	Sum of Generation (MWh)	Capacity Factor
PG&E Central Coast	1,161	2,954,015	0.22
PG&E Central Valley	872	2,124,324	0.23
PG&E Fresno	341	750,482	0.25
PG&E Greater Bay Area	3,928	13,483,346	0.33
PG&E Humboldt	163	362,989	0.25
PG&E Kern	947	3,470,107	0.27
PG&E North Valley	1,206	3,625,441	0.21
SCE Eastern LA Basin	964	1,066,772	0.12
SCE Eldorado	495	645,957	0.15
SCE North of Lugo	72	15,648	0.02
SCE North of Magunden	61	45,797	0.22
SCE South of Magunden	19	17,286	0.10
SCE Ventura	117	186,620	0.17
SCE Western LA Basin	2,943	5,345,622	0.13
SDG&E Bulk	947	1,380,097	0.16
SDG&E San Diego	2,678	2,862,963	0.10
SCE Tehachapi	4	1,568	0.04
System Total	16,945	38,467,416	**0.26**

G.8 Economic Planning Study Requests

G.8.1 Study request for Pacific Transmission Expansion (PTE) project

Study request overview

California Western Grid Development LLC (California Western Grid) submitted the PTE project, which consists of a 2,000 MW controllable HVDC subsea-transmission cable that connects Northern and Southern California via submarine cables to be located in the Pacific Ocean off the coast of California. The project, as proposed, will have one northern point of interconnection in the PG&E area and one interconnection in the SCE area for its southern terminal. The proposed project includes the Voltage Source Converter (VSC) stations as in the following:

- One 2,000 MW, ±525 kV HVDC bipole converter station located at the northern terminus of the project, connecting either at the Diablo Canyon 500 kV AC station or the future Morro Bay 500 kV AC station.
- One 2,000 MW, ±525 kV HVDC bipole converter station located near the El Segundo 220 kV AC substation, with underground HVDC cables from the shoreline to the converter, and the following AC connections:
    - Two 220 kV AC underground cable circuits to El Nido substation; and
    - Two 220 kV AC underground cable circuits to Redondo substation.

The project was proposed to have a total transfer capacity of 2,000 MW from the PG&E area into the southern California areas or vice versa.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-1.

Table G.8-1: Evaluating study request – Pacific Transmission Expansion (PTE) HVDC Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	The PTE project provides significant benefits in mitigating constraints on transfer capacity flows on Path 26 which continues to be identified as a congested path	The PTE project can create a path parallel to Path 26, which potentially helps to mitigate the congestion on Path 26.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	California Western Grid states that the proposed project's location off shore offers California an option to interconnect and deliver up to 2,000 MW of offshore wind energy as well as support delivery of renewable energy between northern and southern California.	The PTE project can help to deliver offshore wind to southern California.
Local Capacity Area Resource requirements	California Western Grid states that the proposed project would reduce local capacity requirements in the Western LA Basin thereby allowing 1,993 MWs of gas plant generating capacity to retire.	The PTE project can help to reduce local capacity requirement in the SCE's LA Basin area.

Benefits category	Benefits stated in submission	ISO evaluation
Increase in Identified Congestion	Not addressed in submission	Congestion in the Western LA Basin area and on the Path 26 and Path 15 corridor can be impacted by the PTE project.
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	The PTE project can help to deliver offshore wind to southern California.
Other	Not addressed in submission	Not identified by the CAISO

Conclusion

Based on the congestion analysis results and evaluation provided above, the PTE project was selected for detailed analysis as an alternative for mitigating Path 26 congestion and Western LA Basin congestion in this planning cycle, as set out in Section G.9, in which other potential benefits such as local capacity requirement reduction benefit were assessed as well.

G.8.2 Study request for Del Amo to El Nido Underground HVDC Project

Study request overview

Grid United LLC submitted the Del Amo to El Nido Underground HVDC Project to evaluate its potential to enhance deliverability, reduce congestion, and improve reliability in the Los Angeles Basin. The project proposes a new underground 1,200 MW HVDC VSC transmission line utilizing a repurposed oil and gas pipeline to provide a direct connection between Del Amo and El Nido substations.

The project, as proposed, includes the following:

- Construction of a 1,200 MW HVDC VSC transmission line from Del Amo Substation to El Nido Substation.
- Utilization of a repurposed underground oil and gas pipeline as a conduit for the transmission cable.

This project aims to improve intra-basin transmission deliverability, reduce reliance on Aliso Canyon storage, enhance voltage support in the coastal LA Basin, and provide wildfire-resistant system resilience.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-2.

Table G.8-2: Evaluating study request – Del Amo to El Nido undergrounad HVDC Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Not addressed in submission	The Del Amo to El Nido underground HVDC project can help to mitigate congestion in the SCE's Western LA Basin area.

Benefits category	Benefits stated in submission	ISO evaluation
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Grid United states that the Project would greatly expand intra-basin transmission deliverability and unlock access to new clean energy resources, primarily wind and solar from the Southern Area Reinforcement projects and other resources at Del Amo	Not identified by the CAISO.
Local Capacity Area Resource requirements	Grid United states that by facilitating the delivery of resources from the South Area Reinforcement project and other resources at Del Amo deeper to the LA Basin, the Project helps meet the LA Basin LCR requirements and decreases LA's reliance on coastal natural gas generation.	The Del Amo to El Nido underground 230 kV AC line project can help to reduce local capacity requirement in the SCE's El Nido sub-area, but cannot help to reduce local capacity requirement in the SCE's LA Basin area.
Increase in Identified Congestion	Not addressed in submission	Not identified by the CAISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	Not identified by the CAISO
Other	Grid United states that the project will: (1) provide much needed voltage support that is essential to the safe operation of a power grid with a high penetration of renewable resources. (2) wildfire resistance since it is fully underground (3) increase the system's resiliency and operational flexibility.	Not identified by the CAISO

Conclusion

Based on the congestion analysis results and evaluation provided above, the Del Amo to El Nido underground HVDC project was selected for detailed analysis as an alternative for mitigating SCE's Western LA Basin congestion in this planning cycle, as set out in Section G.9, in which other potential benefits such as local capacity requirement reduction benefit were assessed as well.

G.8.3 Study request for Del Amo to El Nido Underground 230 kV AC line Project

Study request overview

Grid United LLC submitted the Del Amo to El Nido Underground 230 kV AC Line Project to evaluate its potential to enhance transmission capacity and provide an alternative for delivering renewable energy from Del Amo deeper into the Los Angeles Basin. The project proposes a 510 MVA 230 kV AC transmission line, leveraging an existing underground right-of-way.

The project, as proposed, includes the following:

- Construction of a 230 kV AC transmission line with a capacity of up to 510 MVA from Del Amo to El Nido Substation.
- Utilization of an underground right-of-way to minimize environmental and land-use impacts.

This project aims to improve transmission reliability, enhance system flexibility, and provide an additional networked pathway for renewable energy integration in the LA Basin.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-3.

Table G.8-3: Evaluating study request – Del Amo to El Nido undergrounad 230 kV AC line Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Not addressed in submission	The Del Amo to El Nido underground HVDC project can help to mitigate congestion in the SCE's Western LA Basin area.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Grid United states that the Project would greatly expand intra-basin transmission deliverability and unlock access to new clean energy resources, primarily wind and solar from the Southern Area Reinforcement projects and other resources at Del Amo	Not identified by the CAISO.
Local Capacity Area Resource requirements	Grid United states that by facilitating the delivery of resources from the South Area Reinforcement project and other resources at Del Amo deeper to the LA Basin, the Project helps meet the LA Basin LCR requirements and decreases LA's reliance on coastal natural gas generation.	The Del Amo to El Nido underground 230 kV AC line project can help to reduce local capacity requirement in the SCE's El Nido sub-area, but cannot help to reduce local capacity requirement in the SCE's LA Basin area.
Increase in Identified Congestion	Not addressed in submission	Not identified by the CAISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	Not identified by the CAISO
Other	Grid United states that the project will: (1) provide much needed voltage support that is essential to the safe operation of a power grid with a high penetration of renewable resources. (2) wildfire resistance since it is fully underground (3) increase the system's resiliency and operational flexibility.	Not identified by the CAISO

Conclusion

Based on the congestion analysis results and evaluation provided above, the Del Amo to El Nido underground 230 kV AC line project was selected for detailed analysis as an alternative for mitigating SCE's Western LA Basin congestion in this planning cycle, as set out in Section G.9, in which other potential benefits such as local capacity requirement reduction benefit were assessed as well.

G.8.4 Study request for K-SEL Midway to El Nido HVDC Project

Study request overview

Kern-Southland Energy Link LLC submitted the K-SEL Midway to El Nido HVDC Project to evaluate its potential to enhance transmission capacity, alleviate congestion on Path 26, and improve deliverability for renewable resources in Kern County and the Los Angeles Basin. The project proposes a new underground HVDC transmission link utilizing a repurposed oil and gas pipeline to provide a direct connection between Midway and El Nido substations.

The project, as proposed, includes the following:

- Construction of a 2,000 MW HVDC VSC transmission line from Midway 500 kV Substation to El Nido 230 kV Substation.
- Potential expansion to Del Amo 500 kV Substation, integrating with the South Area Reinforcement projects.

This project aims to expand deliverability for Kern County renewables, reduce congestion and curtailment on Path 26, lower reliance on Aliso Canyon storage, and improve system resilience through an underground, wildfire-resistant design.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-4.

Table G.8-4: Evaluating study request – K-SEL Midway to El Nido Underground HVDC Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Grid United states that by providing a controllable DC tie at Midway, K-SEL would provide CAISO operational flexibility to take control actions required to reduce congestion on Path 26.	The Midway to El Nido underground HVDC project can help to mitigate congestion in the SCE's Western LA Basin area, and to reduce congestion in the Path 26 corridor
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Grid United states that K-SEL would greatly expand intra-basin transmission deliverability and unlock access to new, in-state energy resources, primarily wind and solar in Kern County. C	Not identified by the CAISO.
Local Capacity Area Resource requirements	Grid United states that By delivering resources deep into the LA Basin, K-SEL helps meet the LA Basin LCR requirements.	The Midway to El Nido underground HVDC project can help to reduce local capacity requirement in the SCE's LA Basin area.
Increase in Identified Congestion	Not addressed in submission	Not identified by the CAISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	Not identified by the CAISO
Other	Grid United states that the project will: (1) provide voltage support that is essential to the safe operation of a power grid with a high penetration of renewable resources. (2) wildfire resistance since it is fully underground (3) increase the system's resiliency and operational flexibility.	Not identified by the CAISO

Conclusion

Based on the congestion analysis results and evaluation provided above, the Midway to El Nido underground HVDC project was selected for detailed analysis as an alternative for mitigating SCE's Western LA Basin and Path 26 congestions in this planning cycle, as set out in Section G.9, in which other potential benefits such as local capacity requirement reduction benefit were assessed as well.

G.8.5 Study request for Sloan Canyon - Mead Project

Study request overview

GridLiance West (GLW) submitted the Sloan Canyon - Mead Project, proposing a second 230 kV connection from Sloan Canyon to Mead. The project aims to enhance transmission capacity, alleviate congestion in the Mead area, and improve deliverability for renewable resources in Southern Nevada.

The project, as proposed, includes the following:

- Addition of a circuit breaker to the existing 230 kV bay in Sloan Canyon substation.
- Construction of a new 14-mile circuit on the vacant position of the existing double circuit ready Sloan Canyon to Mead 230 kV line.
- Expansion of the 230 kV bay at WAPA's Mead substation or creation of a new bay if necessary.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the study request were summarized in Table G.8-5.

Table G.8-5: Evaluating study request – Sloan Canyon - Mead Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	GridLiance West stated that the proposed project is expected to provide economic benefits by alleviating congestion in the Mead area and reducing generation curtailment.	Congestions in the Gridliance West/VEA area in this planning cycle was mainly observed on the Sloan Canyon – Eldorado 500 kV line and the VEA 138 kV system. The Sloan Canyon – Mead Project was not identified effective to mitigate any reliability, policy, or congestion issues in this area based on the resource assumption in the CPUC renewable portfolio.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	The Sloan Canyon - Mead Project will provide enhanced delivery for current proposed levels of renewable generation identified in the latest 2024-2025 CPUC Generation Resource mapping in the Mead area. The Sloan Canyon - Mead Project provides an additional interconnection path for the delivery of the combined expected FCDS and EODS generation and will enable around 890 MW of additional transmission capacity from Mead area to CAISO.	No benefits identified by ISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	See "Delivery of Location Constrained Resource Interconnection" above
Other	GridLiance West states that the proposed upgrades will: (1) Project may provide reliability benefits to the system including potential contingency relief on existing Sloan Canyon-Mead 230kV circuit 1.	No benefits identified by ISO

	(2) Providing resilience enhancements within the CAISO grid (3) A new GLW Sloan Canyon—Mead connection will reduce LSE's cost (4) A new GLW Sloan Canyon—Mead connection would provide benefit to meeting 3 the CAISO's resource adequacy (RA) needs	

Conclusion

Sloan Canyon – Mead 230 kV line congestion was not observed in this planning cycle due to the renewable generator assumption change in the GridLiance/VEA area compared with the previous planning cycle. No detailed production cost simulation was conducted for this study request.

G.8.6 Study request for GLW Upsize to Sagebrush Project

Study request overview

GridLiance West (GLW) submitted the GLW Upsize to Sagebrush Project, which proposes to upgrade segments of the existing GridLiance West/Valley Electric Association (GLW/VEA) system from 230 kV to 500 kV-capable towers while establishing a new interconnection with NV Energy's Sagebrush Substation, part of the Greenlink West project.

The project, as proposed, includes the following:

- Conversion of the Trout Canyon – Johnnie Corner segment from double-circuit 230 kV to double-circuit 500 kV, operating one circuit at 230 kV initially.
- Expansion of the Johnnie Corner Substation to accommodate 500/230 kV capabilities.
- Conversion of the Johnnie Corner – Lathrop Wells segment from double-circuit 230 kV to double-circuit 500 kV, operating one circuit at 230 kV.
- Conversion of the Lathrop Wells – Beatty segment from single-circuit 230 kV to double-circuit 500 kV-capable towers, maintaining the approved 230 kV circuit.
- Addition of a new 3000 MVA, 500 kV line from Lathrop Wells to Sagebrush, utilizing an available position on the planned Lathrop – Beatty double-circuit 500 kV towers.

The project is proposed to enhance transfer capability between CAISO and NV Energy (NVE), increase deliverability for renewable generation, and alleviate congestion in the GLW/VEA area. Additionally, it leverages existing right-of-way (ROW) and permitting efforts to expedite development, with an expected capacity increase of approximately 2.5-4.5 GW.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the study request were summarized in Table G.8-6.

Table G.8-6: Evaluating study request – GLW Upsize to Sagebrush Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	GridLiance West stated that the proposed project is expected to provide economic benefits by alleviating congestion in the Mead area and reducing generation curtailment.	Congestions in the Gridliance West/VEA area in this planning cycle was mainly observed on the Sloan Canyon – Eldorado 500 kV line and the VEA 138 kV system. The Sloan Canyon – Mead Project was not identified effective to mitigate any reliability, policy, or congestion issues in this area based on the resource assumption in the CPUC renewable portfolio.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	The double circuit upgrade to 500 kV and the new interconnection from Beatty to Sagebrush can enable other interconnections of new or existing facilities and improve the utilization of existing infrastructure, helping California achieve its renewable portfolio targets.	No benefits identified by ISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	See "Delivery of Location Constrained Resource Interconnection" above
Other	GridLiance West states that the proposed upgrades will: (1) The connection allows greater operational flexibility by managing the supply-demand fluctuations across a larger geographical area. This increases the grid's responsiveness to changing operational conditions like variable weather or sudden equipment failures (2) Providing resilience enhancements within the CAISO grid (3) Increased capacity and connectivity to neighboring systems may improve Remedial Action Schemes since it provides a new path to load for Beatty generation. (4) The project provides another tie-line to NVE system that can enhance Resource Adequacy and transfer capabilities from neighboring systems. (5) The project provides a more robust networked delivery of generation resources in this area of the CAISO bulk system.	No benefits identified by ISO

Conclusion

No significant congestion was observed in the GridLiance/VEA area. The GLW Upsize to Sagebrush Project was not identified effective to mitigate the congestion in the GridLiance/VEA area observed in this planning cycle. No detailed production cost simulation was conducted for this study request.

G.8.7 Study request for Mead - Mohave Project

Study request overview

GridLiance West (GLW) submitted the Mead - Mohave Project, which proposes to upgrade the existing Mead to Davis 230 kV line to 500 kV and extend a new 500 kV single circuit from Davis to Mohave. The project aims to enhance transmission capacity, alleviate congestion in the Mead area, and improve deliverability for renewable resources in Southern Nevada.

The project, as proposed, includes the following:

- Upgrade of the existing Mead – Davis transmission line from 230 kV to 500 kV
- Construction of a new 5-mile 500 kV transmission line from Davis to Mohave
- Development of a new 500 kV BAAH substation with 500/230 kV transformation at WAPA Davis
- Necessary bus work at Mead and Mohave to accommodate the upgraded transmission infrastructure.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the study request were summarized in Table G.8-7.

Table G.8-7: Evaluating study request – Mead-Mohave Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	GridLiance West stated that the proposed project is expected to provide economic benefits by alleviating congestion in the Mead area and reducing generation curtailment.	Congestions in the Gridliance West/VEA area in this planning cycle was mainly observed on the Sloan Canyon – Eldorado 500 kV line and the VEA 138 kV system. The Mead-Mohave Project was not identified effective to mitigate any reliability, policy, or congestion issues in this area based on the resource assumption in the CPUC renewable portfolio.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	The Sloan Canyon - Mead Project will provide enhanced delivery for current proposed levels of renewable generation identified in the latest 2024-2025 CPUC Generation Resource mapping in the Mead area. The Sloan Canyon - Mead Project provides an additional interconnection path for the delivery of the combined expected FCDS and EODS generation and will enable around 890 MW of additional transmission capacity from Mead area to CAISO.	No benefits identified by ISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	See "Delivery of Location Constrained Resource Interconnection" above
Other	GridLiance West states that the proposed upgrades will: (1) Project may provide reliability benefits to the system including potential contingency relief on existing Sloan Canyon-Mead 230kV circuit 1.	No benefits identified by ISO

Benefits category	Benefits stated in submission	ISO evaluation
	(2) Providing resilience enhancements within the CAISO grid (3) A new GLW Sloan Canyon—Mead connection will reduce LSE's cost (4) A new GLW Sloan Canyon—Mead connection would provide benefit to meeting 3 the CAISO's resource adequacy (RA) needs	

Conclusion

Sloan Canyon – Mead 230 kV line congestion was not observed in this planning cycle due to the renewable generator assumption change in the GridLiance/VEA area compared with the previous planning cycle. No detailed production cost simulation was conducted for this study request.

G.8.8 Study request for GLW Upsize to Esmeralda Project

Study request overview

GridLiance West (GLW) submitted the GLW Upsize to Esmeralda Project, which proposes to upgrade the existing GridLiance West/Valley Electric Association (GLW/VEA) system from 230 kV to 500 kV-capable towers while adding a new interconnection with NV Energy's Esmeralda Substation, part of the Greenlink West project.

The project, as proposed, includes the following:

The Phase 1 GLW Upsize would consist of:

- Convert Trout Canyon – Johnnie Corner from double circuit 230kV to double circuit 500 kV (operate one circuit at 230 kV).
- Expand Johnnie Corner Substation to 500/230 kV
- Convert Johnnie Corner – Lathrop from double circuit 230kV to double circuit 500 kV (operate one circuit at 230 kV)
- Convert Lathrop Wells to Beatty from single circuit 230kV to double circuit capable 500 kV.
    - The approved single circuit Lathrop Wells to Beatty is to remain intact and operated at 230 kV.
    - Add a new 3000 MVA Lathrop Wells to Beatty 500 kV line using the proposed empty position on the double circuit 500 kV
    - Loop in the 500kV Lathrop Wells to Beatty into NVE's Sagebrush station
- Expand Beatty Substation to 500/230 kV

The Phase 2 Esmeralda extension would consist of:

- Add new Beatty – Esmeralda 108 mi, approximately 3000 MVA, Single Circuit 500 kV.

- Bus work to interconnect at NVE's Esmeralda.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the study request were summarized in Table G.8-8.

Table G.8-8: Evaluating study request – GLW Upsize to Esmeralda Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	GridLiance West stated that the proposed project is expected to provide economic benefits by alleviating congestion in the GLW/VEA area and reducing generation curtailment.	Congestions in the Gridliance West/VEA area in this planning cycle was mainly observed on the Sloan Canyon – Eldorado 500 kV line and the VEA 138 kV system. The Mead-Mohave Project was not identified effective to mitigate any reliability, policy, or congestion issues in this area based on the resource assumption in the CPUC renewable portfolio.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	GridLiance West stated the 500kV upsizing from Trout Canyon to Beatty transmission path provides a higher capacity alternative and optionality to maximize future renewable generation on the previously studied GLW upgrades. The GLW transmission capability expansion could support an increased volume of renewable resources – such as solar, wind, geothermal, and battery storage.	The resources identified in the GLW economic study request was not included in the CPUC IPR portfolio in this planning cycle.
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	See "Delivery of Location Constrained Resource Interconnection" above
Other	GridLiance West states that the proposed upgrades will: (1) provide reliability benefits to the system while providing resilience enhancements within the CAISO grid. (2) will provide a more robust networked delivery of generation resources in this area of the CAISO bulk system. (3) improve Remedial Action Schemes since it provides a new path to load for Beatty generation.	No benefits identified by ISO

Conclusion

No significant congestion was observed in the GridLiance/VEA area. The GLW Upsize to Esmeralda Project was not identified effective to mitigate the congestion in the GridLiance/VEA area observed in this planning cycle. No detailed production cost simulation was conducted for this study request.

G.8.9 Study request for New 500 kV line from Colorado River - Red Bluff - Devers - Mira Loma Project

Study request overview

EDF Renewables (EDFR) submitted a request to evaluate the addition of a 3rd 500 kV transmission line from Colorado River to Red Bluff, Devers, and Mira Loma to address severe congestion and support growing renewable integration, including New Mexico wind imports.

The project, as proposed, includes the following:

- Construction of a 3rd 500 kV circuit from Colorado River to Red Bluff to Devers to Mira Loma.
- Line rating of 3291/3880 MVA, matching existing circuits.

This upgrade aims to relieve congestion, reduce renewable curtailment, improve system reliability, and potentially increase Maximum Import Capability (MIC) for new out-of-state wind resources entering CAISO through the Palo Verde Interface.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-9.

Table G.8-9: Evaluating study request – New 500 kV line Colorado River - Red Bluff - Devers - Mira Loma Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	EDF states that this project would relieve congestion, reduce curtailment of renewable resources, limit impacts of outages on the existing 500kV sys	No significant congestion was identified in the SCE Eastern area. However, a new 500 kV line to Mira Loma can help to mitigate congestion on the Victorville to Lugo 500 kV line.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	EDF states that this project would provide potential increases in Maximum Import Capability (MIC) for new out of state wind resources that want to enter CAISO through the Palo Verde Interface	Not identified by the CAISO.
Local Capacity Area Resource requirements	Not addressed in submission	Not identified by the CAISO
Increase in Identified Congestion	Not addressed in submission	This project potentially increase congestion on Path 46.
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	Not identified by the CAISO.
Other	Not addressed in submission	Not identified by the CAISO.

Conclusion

Based on the congestion analysis results and evaluation provided above, the new 500 kV line from Colorado River - Red Bluff - Devers - Mira Loma project was selected for detailed analysis as an alternative for mitigating Victorville – Lugo 500 kV line congestion in this planning cycle, as set out in Section G.9.

G.8.10 Study request for Third Red Bluff Transformer Project

Study request overview

EDF Renewables (EDFR) submitted a request to evaluate the installation of a third transformer at Red Bluff Substation to address increasing congestion and curtailment caused by transformer limitations.

The project, as proposed, includes the following:

- Installation of a 3rd 230/500 kV AA transformer at Red Bluff.

This upgrade aims to improve deliverability for solar and storage resources in the Red Bluff area, enhance reliability, and prevent resources from being trapped under N-1 outages or transformer failures.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-10.

Table G.8-10: Evaluating study request – Third Red Bluff Transformer Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	EDF states that this project would relieve congestion, reduce curtailment of renewable resources	Red Bluff transformer was not congested in this planning cycle's production cost simulation
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	EDF states that this upgrade would increase deliverability in the Red Bluff area by providing adequate transformer capacity to reach the grid	Not identified by the CAISO.
Local Capacity Area Resource requirements	Not addressed in submission	Not identified by the CAISO.
Increase in Identified Congestion	Not addressed in submission	Not identified by the CAISO.
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	Not identified by the CAISO.
Other	Not addressed in submission	Not identified by the CAISO.

Conclusion

Based on the congestion analysis results and evaluation provided above, the third Red Bluff transformer project was not selected for detailed analysis in this planning cycle.

G.8.11 Study request for 230 kV Red Bluff tap to Buck Blvd - J. Hinds Project

Study request overview

EDF Renewables (EDFR) submitted a request to study the addition of a 230 kV transmission tap at Red Bluff to address transformer-related congestion and provide an additional outlet for generation during outages.

The project, as proposed, includes the following:

- Construction of a 230 kV line from Red Bluff to a new 230 kV switchyard tapping the Buck Blvd – J. Hinds 230 kV line.
- Alternative option: Loop the Buck Blvd – J. Hinds line into Red Bluff 230 kV.

This upgrade is expected to improve deliverability, increase transmission capacity, and reduce congestion and curtailments at Red Bluff.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-11.

Table G.8-11: Evaluating study request – 230 kV Red Bluff tap to Buck Blvd - J. Hinds Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	EDF states that this project increase transmission outlet at the Red Bluff Substation by providing additional network connections to reach the grid, thereby increasing reliability, deliverability and reducing congestion and curtailments	Minor congestion was identified on the J.Hinds to Mirage 230 kV line, which can be mitigated by the reliability upgrade of recondutoring the congested line.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	EDF states that this project increase transmission outlet at the Red Bluff Substation by providing additional network connections to reach the grid, thereby increasing reliability, deliverability and reducing congestion and curtailments	Not identified by the CAISO.
Local Capacity Area Resource requirements	Not addressed in submission	Not identified by the CAISO.
Increase in Identified Congestion	Not addressed in submission	Not identified by the CAISO.
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	Not identified by the CAISO.
Other	Not addressed in submission	Not identified by the CAISO.

Conclusion

Based on the congestion analysis results and evaluation provided above, the 230 kV Red Bluff tap to Buck Blvd - J. Hinds project was not selected for detailed analysis in this planning cycle.

G.8.12 Study request for Third Devers Transformer Project

Study request overview

EDF Renewables (EDFR) submitted a request to evaluate the installation of a 3rd transformer at Devers Substation to mitigate congestion and curtailment caused by operational outages on the existing transformer banks.

The project, as proposed, includes the following:

- Installation of a 3rd 230/500 kV AA transformer at Devers.

This upgrade is expected to improve system reliability, ensure deliverability for renewable resources in Riverside County, and provide long-term grid stability.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-12.

Table G.8-12: Evaluating study request – Third Devers Transformer Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	EDF states that this upgrade would relieve congestion on the Devers 500/230 transformers	Minor congestion on Devers transformers was identified in this planning cycle.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	EDF states that this upgrade would ensure that renewable resources located in the Riverside County remain deliverable to load.	Not identified by the CAISO.
Local Capacity Area Resource requirements	Not addressed in submission	Not identified by the CAISO.
Increase in Identified Congestion	Not addressed in submission	Not identified by the CAISO.
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	Not identified by the CAISO.
Other	Not addressed in submission	Not identified by the CAISO.

Conclusion

Based on the congestion analysis results and evaluation provided above, the third Devers transformer project was not selected for detailed analysis in this planning cycle as the Devers transformer congestion is minor.

G.8.13 Study request for Temporary Reconfiguration Solutions to Relieve Devers 500/230 kV Transformer Congestion

Study request overview

EDF Renewables (EDFR) submitted a request to explore temporary transmission reconfiguration solutions to reduce congestion and curtailment while minimizing costs to ratepayers.

The project, as proposed, includes the following:

- Development of a methodology to study and implement reconfigurations and grid-enhancing technologies such as Dynamic Line Ratings.
- Evaluation of reconfiguration strategies similar to those implemented in other ISOs, such as MISO, to improve congestion management.

These solutions are expected to enhance grid flexibility, improve reliability, and optimize renewable energy integration while long-term transmission upgrades are being developed.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-13.

Table G.8-13: Evaluating study request – Temporary Reconfiguration Solutions to Relieve Devers 500/230 kV Transformer Congestion

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	EDF states that this upgrade would relieve congestion on the Devers 500/230 transformers	Minor congestion on Devers transformers was identified in this planning cycle.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	Not identified by the CAISO.
Local Capacity Area Resource requirements	Not addressed in submission	Not identified by the CAISO.
Increase in Identified Congestion	Not addressed in submission	Not identified by the CAISO.
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	Not identified by the CAISO.
Other	Not addressed in submission	Not identified by the CAISO.

Conclusion

Based on the congestion analysis results and evaluation provided above, the temporary reconfiguration solutions to relieve Devers 500/230 kV transformer congestion was not selected for detailed analysis in this planning cycle as the Devers transformer congestion is minor.

G.8.14 Study request for Fourth Whirlwind Transformer Project

Study request overview

EDF Renewables (EDFR) submitted a request to evaluate the installation of a 4th transformer at Whirlwind Substation to address congestion and curtailment issues caused by operational derates and outages on the existing transformer banks.

The project, as proposed, includes the following:

- Installation of a 4th 230/500 kV AA transformer at Whirlwind Substation.

This upgrade aims to ensure adequate transformer capacity for renewable resources at Whirlwind, improve reliability, and support future energy growth in the area.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request are summarized in Table G.8-14.

Table G.8-14: Evaluating study request – Fourth Whirlwind Transformer Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Not addressed in submission	Congestion on the Whirlwind transformer was not identified by the CAISO.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	EDF states that this upgrade would ensure that the resources located at the Whirlwind substation have adequate transformer capacity to reach the grid.	Not identified by the CAISO.
Local Capacity Area Resource requirements	Not addressed in submission	Not identified by the CAISO.
Increase in Identified Congestion	Not addressed in submission	Not identified by the CAISO.
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	Not identified by the CAISO.
Other	Not addressed in submission	Not identified by the CAISO.

Conclusion

Based on the congestion analysis results and evaluation provided above, the fourth Whirlwind transformer project was not selected for detailed analysis in this planning cycle.

G.8.15 Study request for Upgrades on PG&E 500 kV Lines

Study request overview

EDF Renewables (EDFR) submitted a request to study upgrades on PG&E's 500 kV transmission network to address increasing congestion on Paths 15 and 26 and improve North-South transfer capacity.

The project, as proposed, includes the following:

- Construction of a 3rd 500 kV line on the following segments:
  - Los Banos – Gates
  - Gates – Midway
  - Tesla – Los Banos
  - Gates – Diablo

These upgrades aim to enhance reliability, reduce curtailments, and improve resiliency in Northern California's transmission system.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-15.

Table G.8-15: Evaluating study request – Upgrades on PG&E 500 kV Lines

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	EDF states that this upgrade would relieve congestion on Path 15	Path 15 corridor congestion was observed in this planning cycle
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	No benefits identified by ISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by ISO
Other	EDF states that this upgrade would improve the North -South transfer capacity, improve reliability in the region, and provide resiliency to the Northern California.	No benefits identified by ISO

Conclusion

Path 15 corridor congestion was selected to receive detailed economic assessment in this planning cycles, with considering different alternatives including some segments of this study request, as set out in Section G.9.

G.8.16 Study request for New 500kV line From Midpoint to Gregg and Gregg to Table Mountain

Study request overview

EDF Renewables (EDFR) submitted a request to evaluate the construction of a new 500 kV transmission line to address congestion on Paths 15 and 26 and support North toSouth energy transfers.

The project, as proposed, includes the following:

- Construction of a new 500 kV transmission line from Midway to Gregg.
- Extension of the 500 kV line from Gregg to Table Mountain.

This upgrade is expected to reduce congestion, minimize solar curtailments, improve system reliability, and enhance CAISO's ability to transfer resources efficiently across Northern and Southern California.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-16.

Table G.8-16: Evaluating study request – New 500kV line From Midpoint to Gregg and Gregg to Table Mountain

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	EDF states that this upgrade would relieve congestion on Path 15	Path 15 corridor congestion was observed in this planning cycle
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	No benefits identified by ISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by ISO
Other	EDF states that this upgrade would increase reliability, and provide CAISO more resiliency to move the diverse resources between Northern and Southern regions more effectively	No benefits identified by ISO

Conclusion

Path 15 corridor congestion was selected to receive detailed economic assessment in this planning cycles, with considering different alternatives including some segments of this study request, as set out in Section G.9.

G.8.17 Study request for Monarch Project

Study request overview

Golden State Clean Energy, LLC (GSCE) submitted the Monarch 500 kV Transmission Project to evaluate its potential to mitigate congestion on Path 15 and other key transmission corridors while facilitating renewable energy integration in the Greater Bay Area and San Joaquin Valley.

The project, as proposed, includes the following:

- Construction of a new 500 kV transmission line to improve north-south flows.
- Integration with existing infrastructure to enhance access to cost-effective renewables.
- Potential collaboration between CAISO and the Balancing Authority of Northern California to optimize capacity and reduce costs.

The Monarch project aims to alleviate increasing congestion in the PG&E Fresno area and improve overall system efficiency while supporting California's long-term clean energy goals.

Evaluation

The benefits described in the submission and the CAISO's evaluation of the economic study request were summarized in Table G.8-17.

Table G.8-17: Evaluating study request – Monarch Project

Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Golden State Clean Energy states that this upgrade would relieve congestion on Path 15 north of Los Banos and Moss Landing – Las Aguilas lines	Path 15 corridor congestion was observed in this planning cycle. This project can help to relieve congestion on the segments of north of Los Banos.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	No benefits identified by ISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by ISO
Other	Golden State Clean Energy states that this upgrade would provide policy benefits to California and the CAISO controlled grid	No benefits identified by ISO

Conclusion

Path 15 corridor congestion was selected to receive detailed economic assessment in this planning cycles, with considering different alternatives including the Monarch project, as set out in Section G.9.

G.9 Detailed Investigation of Congestion and Economic Benefit Assessment

G.9.1 Selection of Detailed Studies

The ISO selected the high priority study areas listed in Table G.9-1 for further detailed assessment.

Table G.9-1: Areas receiving detailed economic assessment

Detailed investigation	Alternative	Reason for receiving detailed assessment
East of Pisgah and Path 46 congestion	The Trout Canyon to Lugo project to build a new Trout Canyon – Lugo 500 kV line with 70% compensation	Recurring congestion on the Path 61 corridor under both contingency and normal condition when the flow was from Victorville to Lugo was observed. Large congestions on the Eldorado – McCullough 500 kV line and the Sloan Canyon – Eldorado 500 kV line, and the Path 46, were also observed. The congestion in this area is mainly attributed to renewable generation in the SCE's East of Pisgah area, GridLiance West/VEA area, and the out of state wind generation delivered to the Harry Allen and Eldorado area. Solar generation in Arizona and New Mexico wind generation in the CPUC portfolios also contributed to the Path 46 congestion.
	The Marketplace to Adelanto project to convert the Marketplace-Adelanto 500 kV line to HVDC, and build a 500 kV line from Adelanto to Lugo and a 500 kV line from Marketplace to Eldorado	
	Build the second Sloan Canyon – Eldorado 500 kV line	
	Build a new Adelanto – Lugo 500 kV line	
	Build the third Colorado River – Red Bluff 500 kV line and a new Red Bluff – Mira Loma 500 kV line	
LA Basin and Path 26 corridor congestion	The PTE project	Path 26 congestion is a recurring congestion with large congestion cost. La Fresa – La Cienega 230 kV congestion was also observed. The mitigation alternatives are expected to help to mitigate the congestion, and to reduce local capacity requirements.
	The K-SEL project (Midway – El Nido 2000 MW HVDC)	
	The Del Amo – El Nido underground HVDC project	
	The Del Amo – El Nido underground 230 kV AC line project	
	Build the third Midway – Vincent 500 kV line	
Path 15 corridor congestion	Alternative 1: Build a new Manning – Los Banos – Tesla 500 kV line	Path 15 corridor congestion showed significant increase in this planning cycle compared with the results in previous planning cycles, as the resource assumption changed in the CPUC IRP portfolio.
	Alternative 2: A1 plus a new Midway – Gates – Manning 500 kV line	
	Alternative 3: Monarch Option 1 Gates – Los Banos #3 500 kV line loops in new New Point 500 kV substation and build a new New Point to Tracy 500 kV line	
	Alternative 4: A3 plus New Point – Tracy looping in Tesla	
	Alternative 5: A4 plus build a new Midway – New Point 500 kV line	
	Alternative 6: Monarch Option 2 Build a new Manning – New Point – Tracy 500 kV line	
	Alternative 7: A6 plus New Point – Tracy looping in Tesla	
	Alternative 8: A7 plus build a new Midway – New Point 500 kV line	
	Alternative 9: Build a new 500 kV line from Midway to the new Gregg 500 kV substation to Tesla	
	Alternative 10: Install a 10 ohm series reactor on each of the two Panoche – Gates 230 kV lines	

In this planning cycle, the 2039 base portfolio PCM case was used as the main case for the detailed economic assessment.

G.9.2 East of Pisgah area and Path 46 congestion mitigations

Congestion analysis

Congestion in the East of Pisgah (EOP) area and on the Path 46 corridor was summarized in Table G.9-2.

Table G.9-2: Major East of Pisgah and Path 46 congestions in the 2039 Base portfolio PCM

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
LUGO-VICTORVL 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	0	0	40,639	418	40,639	418
ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	27,572	1,798	0	0	27,572	1,798
P46 West of Colorado River (WOR)	19,526	308	0	0	19,526	308
SLOAN_CYN_5-ELDORDO 500 kV line #1	17,778	916	0	0	17,778	916
P61 Lugo-Victorville 500 kV Line	281	5	25	19	306	24
GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	2	19	11	73	12	92

Congestion mitigation alternatives

Five mitigation alternatives for the East of Pisgah area and Path 46 congestion were assessed:

Alternative 1: The Trout Canyon to Lugo project to build a new Trout Canyon – Lugo 500 kV line with 70% series compensation.

Alternative 2: The Marketplace – Adelanto HVDC conversion project, including to convert the Marketplace to Adelanto 500 kV line to HVDC with 3,500 MW capacity, and to build a 17 miles 500 kV line from Adelanto to Vincent – Lugo 500 kV line and a new 1.5 miles 500 kV line from Marketplace to Eldorado.

Alternative 3: Build the second Sloan Canyon – Eldorado 500 kV line.

Alternative 4: Build a new Adelanto – Lugo 500 kV line.

Alternative 5: Build the third Colorado River – Red Bluff 500 kV line and a new Red Bluff – Mira Loma 500 kV line.

Table G.9-3 shows how these transmission alternatives impact East of Pisgah and Path 46 congestions.

Table G.9-3: Impact of transmission upgrade alternatives on EOP and Path 46 congestions

	Congestion Costs ($K)					
	Base	A1: Trout Canyon - Lugo	A2: Marketplace -Adelanto HVDC	A3: Sloan Canyon - Eldorado	A4: Adelanto-Lugo	A5: Colorado River – Red Bluff – Mira Loma
LUGO-VICTORVL 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	40,639	13	0	42,019	0	21,288
ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	27,572	473	36,067	39,945	49,620	27,097
P46 West of Colorado River (WOR)	19,526	5,575	3,020	21,768	22,933	35,157
SLOAN_CYN_5-ELDORDO 500 kV line #1	17,778	79	22,453	0	11,789	17,436
P61 Lugo-Victorville 500 kV Line	306	1,883	2	616	0	794
GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	12	19,237	13	16	14	11

The Trout Canyon to Lugo 500 kV line upgrade can significantly reduce some congestions in the East of Pisgah area, such as Lugo – Victorville 500 kV line congestion when flow is from Victorville to Lugo, Eldorado – McCullough 500 kV congestion, Sloan Canyon – Eldorado 500 kV congestion. It can also reduce congestion on Path 46. On the other hand, the Trout Canyon to Lugo 500 kV line can aggravate flow from Lugo to Victorville in some hours, which may cause additional congestion on Path 61 in that direction.

The Marketplace to Adelanto HVDC project can help to reduce the Path 61 and Path 46 congestions. However, it aggravated congestions on Sloan Canyon – Eldorado 500 kV line and Eldorado – McCullough 500 kV line, because this project essentially increased flow from Sloan Canyon to Eldorado and from Eldorado to McCullough.

The second Sloan Canyon – Eldorado 500 kV line and the Adelanto – Lugo 500 kV line are effective to mitigate congestions on the Sloan Canyon – Eldorado 500 kV line and congestions on the Path 61 corridor. Both alternatives aggravate congestion on the Eldorado – McCullough 500 kV line, as the Sloan Canyon – Eldorado 500 kV line can push more flow to Eldorado, and the Adelanto – Lugo 500 kV line can attract more flow from Eldorado to McCullough.

The Colorado River to Red Bluff to Mira Loma 500 kV line can partially mitigate the congestions on Path 61 and Eldorado – McCullough 500 kV line, but it aggravated Path 46 (West of River) congestion. This is because the new 500 kV line provides a new path from Colorado River to the LA Basin load center and can potentially increase flow on the 500 kV lines from Palo Verde or Delany to Colorado River, which are part of Path 46.

Production benefits

The production benefits of the mitigation alternatives in the East of Pisgah area and Path 46 for ISO ratepayers were summarized in Table G.9-4.

Table G.9-4: Production Benefits of EOP and Path 46 congestion mitigation alternatives

	Base case	A1: Trout Canyon – Lugo 500 kV line		A2: Marketplace-Adelanto HVDC		A3: the second Sloan Canyon – Eldorado 500 kV line		A4: Adelanto-Lugo 500 kV line		A5: Colorado River – Red Bluff – Mira Loma 500 kV line	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	18,823	19,021	-198	18,913	-90	18,822	1	18,864	-41	18,773	50
ISO generator net revenue benefiting ratepayers	14,205	14,335	130	14,272	68	14,199	-6	14,233	29	14,188	-16
ISO transmission revenue benefiting ratepayers	1,698	1,696	-2	1,644	-54	1,684	-13	1,652	-46	1,721	23
ISO Net payment	2,920	2,990	-70	2,997	-76	2,939	-18	2,978	-58	2,863	57
WECC Production cost	23,874	23,886	-12	23,816	58	23,869	5	23,848	26	23,841	33

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative savings is an incremental cost or loss.

Among the five mitigation alternatives for the East of Pisgah and Path 46 congestion, only Alternative 5, building a new 500 kV line from Colorado River to Red Bluff to Mira Loma, showed positive benefit to the CAISO's ratepayer. The annual production cost saving from this alternative is $57 million. Other alternatives showed negative production cost saving for the CAISO's ratepayer.

Cost estimate and benefit to cost ratio

Cost estimate and benefit to cost ratio were calculated only for the alterative with positive production cost saving. CAISO's transmission per unit cost was used to estimate the capital cost of the upgrade. The capital cost estimate of the Colorado – Red Bluff – Mira Loma 500 kV line is $2,644 million. Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the total cost of the Colorado – Red Bluff – Mira Loma 500 kV line upgrade is about $3,437 million in 2024 dollar.

The total benefit of the Colorado – Red Bluff – Mira Loma 500 kV line is the present value of the production cost savings plus other benefit. As no other benefit from this upgrade was identified in this planning cycle, only the present value of the production cost saving was calculated. Based on the assumptions of 7% real discount rate and 50-year economic life, the present value of the $57 million annual production cost saving is $842 million in 2024 dollar. The benefit to cost ratio is 0.245.

Conclusions

Five transmission upgrades were study as alternatives for mitigating the East of Pisgah and Path 46 congestions in this planning cycle. The economic assessment results showed that four out of five alternatives have negative benefit to the CAISO's ratepayers. Only the Colorado River to Red Bluff to Mira Loma 500 kV line upgrade has positive benefit but its benefit to cost ratio was less than 1.0. Therefore, there was no sufficient economic justification for recommending these five transmission upgrades as economic-driven projects in this planning cycle.

G.9.3 Path 26 corridor and LA Basin congestion

Congestion analysis

The production cost simulation results demonstrated congestion occurring on the Path 26 corridor mainly when the flow was from south to north. Renewable generators in the Southern California area in the CPUC IRP portfolio were the main driver of the Path 26 corridor congestion, which is consistent with the results in the previous planning cycles. Congestion on the Path 26 corridor when the flow was from north to south was also observed, attributed to the increase of renewable generation in the PG&E area in the CPUC portfolio, including offshore wind generators. The congestion cost and hours of the Path 26 corridor congestion are shown in Table G.9-5.

Table G.9-5: Major Path 26 corridor and LA Basin congestions in the 2039 Base portfolio PCM

Constraint Name	Cost Forward	Duration Forward	Cost Backward	Duration Backward	Costs Total ($K)	Duration Total (Hrs)
P26 Northern-Southern California	3	9	173,554	3,127	173,557	3,136
LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	67,364	667	67,364	667
MIDWAY-MN_WRLWND_31 500 kV line #3	0	2	31,896	943	31,897	945

It was observed that the majority of the Path 26 corridor congestion was as a result of the Path 26 path rating binding and the Midway to Whirlwind 500 kV line congestion under normal condition. The 1503 MVA normal rating was applied for this 500 kV line in order to achieve higher emergency rating. This is one of the reasons that this line is congested under normal condition in more hours than the other Path 26 lines. Another reason is that there is a large volume of renewable and battery generators modeled at Whirlwind and Windhub 500 kV buses as suggested by the CPUC portfolios.

LA Basin congestion was mainly observed on the La Fresa to La Cienega 230 kV line under the N-2 contingency of the La Fresa – El Nido 230 kV lines. This congestion was aggravated from the previous planning cycle due to both the renewable generation increase in the SCE areas and the gas-fired generator retirement in the Western LA Basin area.

Congestion mitigation alternatives

Five mitigation alternatives for the Path 26 corridor and the LA Basin area congestion were assessed:

Alternative 1: The PTE project

Alternative 2: The K-SEL project building a 2000 MW HVDC line from Midway to El Nido

Alternative 3: The Del Amo – El Nido underground HVDC project

Alternative 4: The Del Amo – El Nido underground 230 kV AC project

Alternative 5: Build the third Midway – Vincent 500 kV line

Table G.9-6 shows the impact of these transmission alternatives on the congestions of the Path 26 corridor and the La Fresa – La Cienega 230 kV line.

Table G.9-6: Impact of Path 26 and LA Basin transmission alternatives on Path 26 and LA Basin congestions

	Congestion Costs ($K)					
	Base	**A1: PTE**	**A2: K-SEL**	**A3: Del Amo – El Nido HVDC**	**A4: Del Amo – El Nido 230 kV AC**	**A5: the third Midway-Vincent line**
P26 Northern-Southern California	173,557	62,850	138,873	174,109	173,500	69,092
LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	67,364	0	0	0	0	65,736
MIDWAY-MN_WRLWND_31 500 kV line #3	31,897	20,048	39,060	30,335	29,847	25,994

The PTE project and the third Midway – Vincent 500 kV line can help to reduce Path 26 congestion significantly. The K-SEL project can also reduce Path 26 congestion, but is not as effective as the above two alternatives. The PTE project, the K-SEL project, and the Del Amo – El Nido HVDC or 230 kV AC projects are all sufficient to mitigate the La Fresa to La Cienega 230 kV line congestion. The transmission alternatives assessed in this section are not very effective to mitigate the congestion on the Midway – Whirlwind 500 kV line.

Production benefits

The production benefits of the transmission upgrades in the Path 26 corridor and LA Basin area for ISO's ratepayers were shown in Table G.9-7.

Table G.9-7: Production Benefits of Path 26 corridor and LA Basin area congestion mitigation alternatives

	Base case	A1: PTE		A2: K-SEL		A3: Del Amo – El Nido HVDC		A4: Del Amo – El Nido 230 kV AC		A5: the third Midway-Vincent line	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	18,823	18,725	98	18,808	15	18,828	-5	18,804	19	18,788	35
ISO generator net revenue benefiting ratepayers	14,205	14,303	99	14,286	82	14,271	67	14,257	52	14,178	-27
ISO transmission revenue benefiting ratepayers	1,698	1,459	-239	1,588	-110	1,633	-64	1,626	-72	1,677	-21
ISO Net payment	2,920	2,963	-42	2,933	-13	2,923	-3	2,921	-1	2,933	-12
WECC Production cost	23,874	23,785	89	23,843	31	23,867	7	23,859	15	23,824	50

Note that ISO ratepayer "savings" are a <u>decrease</u> in load payment, but an <u>increase</u> in ISO generator net revenue benefiting ratepayers and an <u>increase</u> in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a <u>decrease</u> in overall production cost. A negative savings is an incremental cost or loss.

LCR reduction benefit

The PTE project, which is to build a HVDC line from Diablo Canyon to El Segundo, can potentially reduce LCR requirement in the LA Basin area, as indicated in the previous planning cycles TPP reports. The K-SEL project, which is to build a HVDC line from Midway to El Nido, is similar the PTE project in term of reducing LCR requirement in the LA Basin area. According to the previous TPP, the LCR requirement reduction for the LA Basin area by the PTE project was approximately equal to the capacity of the HVDC line coming into the LA Basin. In the meantime, the capacity requirements reduced in the local area will still be needed for system RA. Using the same assumption in this planning cycle, LCR reduction for the LA Basin area by the PTE and K-SEL projects is assumed to be approximately equal to the transmission capacity of the projects. According to the economic study request overview in section 8, the transmission capacity of these two projects are:

- PTE project – 2000 MW
- K-SEL project – 2000 MW

The Del Amo – El Nido HVDC project and the Del Amo – El Nido 230 kV AC project can mitigate congestion on the La Fresa – La Cienega 230 kV line, which is a binding constraint of the El Nido sub-area; hence these two project can help to reduce LCR requirement of the El Nido sub-area. However, as both the Del Amo and El Nido substations are within the LA Basin area, these two projects cannot help to reduce the overall LCR requirement of the LA Basin area.

It is worth noting that the assumptions for LCR reduction in this study were used only for screening purpose. Detailed LCR study will be needed if the screening results show that a project may provide economic benefit to CAISO's ratepayers sufficient or close to compensate the cost of the project, i.e. have benefit to cost ratio greater than or close to 1.0.

The local and system capacity costs changed from year to year. In this planning cycle, the capacity costs in the latest CPUC 2022 Resource Adequacy Report were used to calculate the LCR reduction savings. The capacity costs for the southern California areas and the system capacity costs in the CPUC report were summarized in Table G.9-8. The costs converted to 2024 dollar based on the inflation rate in the CEC 2023 IEPR report[7] were also included in the table.

Table G.9-8: Capacity cost in CPUC Resource Adequacy Report

Area	Weighted average capacity cost ($/kW-month) in CPUC 2022 RA report	In 2024 dollar
System	7.62	8.08
SP26	7.22	7.66
LA Basin	7.54	8.00

The LCR reduction benefit results assessed based the CPUC's capacity cost were summarized in Table G.9-9.

Table G.9-9: LCR reduction savings based on the capacity costs in the CPUC 2022 Resource Adequacy Report

	PTE		K-SEL	
	Local vs System RA cost	Local vs SP 26 RA cost	Local vs System RA cost	Local vs SP 26 RA cost
LCR reduction benefit (Western LA Basin) (MW)	2,000		2,000	
Capacity value($/MW-year)	-1,018	4,073	-1,018	4,073
LCR Reduction Benefit ($million/year)	-2.04	8.15	-2.04	8.15

For comparison, sensitivity assessment for LCR reduction savings was conducted using different capacity cost assumptions. Specifically, the capacity costs proposed in the PTE economic study request submitted by California Western Grid LLC were used in the sensitivity assessment for both of the PTE project and the K-SEL project. Note that the PTE economic study request did not provide SP26 capacity cost, so the capacity value was only evaluated

[7] https://efiling.energy.ca.gov/GetDocument.aspx?tn=254569&DocumentContentId=89994

using the LA Basin and the system capacity cost in this sensitivity study. The capacity costs in 2024 dollar for this sensitivity assessment were summarized in Table G.9-10.

Table G.9-10: Capacity cost proposed in the PTE project economic study request

Area	Weighted average capacity cost ($/kW-month) in 2024 dollar	Note
System	Low: 2.34, High: 2.74	The PTE economic study request assumed the system capacity marginal cost would be set by battery storage
LA Basin	Low: 5.15, High: 7.79	The PTE economic study request provided the LA Basin capacity cost

Comparing Table G.9-8 and Table G.9-10, it was observed that both of the system capacity cost and the LA Basin cost in the CPUC report are higher than in the PTE economic study request. In this sensitivity study, the CPUC LA Basin cost and the low system capacity cost in the PTE economic study request were used to evaluate the capacity value.

The LCR reduction savings results of the sensitivity assessments are summarized in Table G.9-11.

Table G.9-11: LCR reduction savings of LA Basin congestion mitigation alternatives in Sensitivity Assessments

	PTE	K-SEL
	Local vs System RA cost	Local vs System RA cost
LCR reduction benefit (Western LA Basin) (MW)	2,000	2,000
Capacity value($/MW-year)	67,870	67,870
LCR Reduction Benefit ($million/year)	135.74	135.74

Cost Estimate

The capital cost of the PTE project was based on the cost provided in the economic study request to the 2024-2025 transmission planning cycle, which is $2,200 million. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the total cost of the PTE project is about $2,860 million.

The capital cost of the K-SEL project was estimated based on the ISO's transmission per unit cost with assuming each HVDC convertor station cost is about $600 million based on industry practice. This gave the K-SEL project estimated capital cost at $2,424 million. Applying the ISO's screening factor of 1.3, the total cost of the K-SEL project is about $3,152 million.

The other three transmission alternatives had negative production cost savings and did not have LCR reduction benefit, which results in net negative benefit to the CAISO ratepayers, hence there is no need to further evaluate benefit to cost ratio for them.

Benefit-to-cost ratio

The present values of the economic benefit of the PTE project and the K-SEL project were shown in Table G.9-12 along with the calculation of the benefit-to-cost ratio. The economic life of the projects is assumed to be 50 years. Benefit to cost ratio was not assessed for the other three alternatives for Path 26 and LA Basin congestion mitigation as these alternatives did not show positive benefit to the CAISO's ratepayers.

Table G.9-12: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of PTE project and K-SEL project

	PTE			K-SEL		
	Baseline study (CPUC capacity cost)		Sensitivity assessment	Baseline study (CPUC capacity cost)		Sensitivity assessment
	Local vs System RA cost	Local vs SP 26 RA cost	Local cost in CPUC report vs System cost (low) in PTE study request	Local vs System RA cost	Local vs SP 26 RA cost	Local cost in CPUC report vs System cost (low) in PTE study request
Production cost savings ($million/year)	-42	-42	-42	-13	-13	-13
Capacity saving ($million/year)	-2.04	8.15	135.74	-2.04	8.15	135.74
Capital cost ($million)	2,200	2,200	2,200	2,424	2,424	2,424
Cost to Revenue Ratio	1.3	1.3	1.3	1.3	1.3	1.3
Discount Rate	7%	7%	7%	7%	7%	7%
Economic life (year)	50	50	50	50	50	50
PV of Production cost savings ($million)	-620	-620	-620	-192	-192	-192
PV of Capacity saving ($million)	-30	120	2,004	-30	120	2,004
Total benefit ($million)	-650	-500	1,384	-222	-72	1,812
Total cost (Revenue requirement) ($million)	2,860	2,860	2,860	3,152	3,152	3,152
Benefit-to-cost ratio (BCR)	-0.23	-0.17	0.48	-0.07	-0.02	0.58

Conclusion

Five transmission upgrades were assessed in this section as mitigation alternatives for the Path 26 corridor and LA Basin congestions. All five alternatives had negative production cost savings for the CAISO's ratepayers. LCR reduction benefit was assessed for the PTE project and the K-SEL project, based on different capacity cost assumptions. The benefit-to-cost ratio results showed that there was no sufficient economic justification for recommending the PTE project and the K-SEL project as an economic-driven project in this planning cycle. The other three alternatives were not recommended either because the benefit to the CAISO's ratepayers were negative.

It should be noted that the assumptions around the value of reducing capacity requirements directly affect the value of the projects that can potentially reduce LCR requirements. The potential benefit of reducing capacity requirements needs to be reassessed in future planning cycles as the assumptions change, particularly if the need to retain the existing gas-fired fleet for system-wide resource reliability purposes is relaxed, or if capacity cost is updated to show meaningful difference between the local capacity cost and the system capacity cost.

G.9.4 PG&E Path 15 corridor congestion and mitigations

Congestion analysis

Path 15 corridor and Path 26 corridor congestion showed significant increase in this planning cycle compared with the results in previous planning cycles. This change was expected since the resource assumption changed in the CPUC IRP portfolios for the 2024-2025 TPP cycle. Congestion on these two corridors correlated to each other in multiple ways. First of all, renewable resources in the PG&E's Fresno/Kern areas and the Path 26 flow from south to north contribute to the flows and congestion on both corridors. On the other hand, mitigations for one constraint may impact the flow and even aggravate the congestion on the other constraints because of the topology connection between these two constraints. Congestions on Path 15 corridor were summarized in Table G.9-13, while the Path 26 corridor congestions were discussed in section G.9.3.

Table G.9-13: PG&E Path 15 corridor congestions in the 2039 Base portfolio PCM

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
MANNING-MN_GT_11 500 kV line #1	0	0	278,288	2,415	278,288	2,415
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	85,856	1,628	85,856	1,628
MN_GT_11-GATES 500 kV line #1	0	0	54,304	475	54,304	475
MN_MW_21-MN_MW_22 500 kV line #2	0	0	38,600	559	38,600	559
MANNING-MN_MW_21 500 kV line #2	0	0	26,691	872	26,691	872
GT_MW_11-MIDWAY 500 kV line #1	0	1	11,029	234	11,030	235
MN_MW_23-MIDWAY 500 kV line #2	0	0	10,231	339	10,231	339
GATES-GT_MW_11 500 kV line #1	0	0	6,925	202	6,925	202
MN_MW_22-MN_MW_23 500 kV line #2	0	0	3,833	87	3,833	87
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	3,720	254	3,720	254
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	1,061	151	1,061	151
FINKSWSTA-WESTLEY 230 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV	657	21	0	0	657	21
PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	599	105	599	105

Congestion mitigation alternatives

Several transmission alternatives for mitigating the Path 15 corridor congestion, including combinations of alternatives, were assessed in this planning cycle. Table G.9-14 shows the congestion costs on Path 15 corridor and Path 26 corridor, in the base portfolio PCM case and the PCM cases with mitigation alternative modeled. The columns "Congestion Cost Change ($M) show the congestion cost change from the base portfolio PCM case when mitigation alternatives are modeled. The last column in the table provided further discussion about how the alternatives affects congestions.

Table G.9-14: Impact of transmission alternatives on Path 15 corridor and Path 26 corridor congestion

	Path 15 corridor congestion		Path 26 corridor congestion		
	Congestion Cost ($M)		Congestion Cost ($M)		
2039 Base portfolio PCM case	521.80		206.28		
Alternatives	**Congestion Cost ($M)**	**Congestion Cost Change from Base ($M)**	**Congestion Cost ($M)**	**Congestion Cost Change from Base ($M)**	**Note**
Alternative 1: Build a new Manning – Los Banos – Tesla 500 kV line	574.52	52.72	212.03	5.75	Congestion on the Path 15 south of Manning segments increased, which contributed to the Path 15 corridor congestion increased
Alternative 2: A1 plus a new Midway – Gates – Manning 500 kV line	70.42	-451.37	289.95	83.67	Path 15 south of Manning congestion was significantly reduced. The remaining Path 15 congestion was mainly observed on the Panoche - Gates 230 kV lines. Path 26 congestion increased.
Alternative 3: Monarch Option 1 Gates – Los Banos #3 500 kV line loops in new New Point 500 kV substation and build a new New Point to Tracy 500 kV line	497.54	-24.26	215.59	9.31	The Gates - Los Banos #3 line looping-in to the New Point substation helps to reduce the flow and congestion on Gates - Manning 500 kV lines.
Alternative 4: A3 plus New Point – Tracy looping in Tesla	479.10	-42.70	220.51	14.23	Flow and congestion impact is similar to Alternative 3.
Alternative 5: A4 plus build a new Midway – New Point 500 kV line	211.25	-310.54	311.96	105.68	Adding the Midway - New Point 500 kV line can help to reduce Path 15 south of Manning congestion but the Path 26 congestion increased significantly.
Alternative 6: Monarch Option 2 Build a new Manning – New Point – Tracy 500 kV line	594.39	72.60	212.22	5.95	Congestion on the Gates - Manning 500 kV lines significantly increased after modeling the Manning - New Point - Tracy 500 kV line.
Alternative 7: A6 plus New Point – Tracy looping in Tesla	607.81	86.01	215.70	9.42	Flow and congestion impact is similar to Alternative 6.
Alternative 8: A7 plus build a new Midway – NewPoint 500 kV line	217.84	-303.96	313.95	107.68	Adding the Midway - New Point 500 kV line can help to reduce Path 15 south of Manning congestion but the Path 26 congestion increased significantly.

	Path 15 corridor congestion		Path 26 corridor congestion		
	Congestion Cost ($M)		Congestion Cost ($M)		
2039 Base portfolio PCM case	521.80		206.28		
Alternatives	**Congestion Cost ($M)**	**Congestion Cost Change from Base ($M)**	**Congestion Cost ($M)**	**Congestion Cost Change from Base ($M)**	**Note**
Alternative 9: Build a new 500 kV line from Midway to new Gregg 500 kV substation to Tesla	137.77	-384.02	300.28	94.00	This alternative help to reduce the Path 15 congestion on both south of Manning segments and Panoche - Gates 230 kV lines, but increase the Path 26 congestion.
Alternative 10: Install a 10 ohm series reactor on each of the two Panoche – Gates 230 kV lines	516.87	-4.93	200.97	-5.31	Adding series reactors on the Panoche - Gates 230 kV lines helped to mitigate the congestion on the lines, but it aggravated the congestion on the Gates - Manning 500 kV lines.

Production benefits

The production cost savings of all transmission alternatives discussed above were summarized in Table G.9-15 .

Table G.9-15: Production Benefits of Path 15 corridor congestion mitigation tranmsission alternatives

Scenarios		ISO load payment ($M)	ISO generator net revenue benefiting ratepayers ($M)	ISO transmission revenue benefiting ratepayers ($M)	ISO Net payment ($M)	WECC Production cost ($M)
Base case		18,823	14,205	1,698	2,920	23,874
Alternative 1: Build a new Manning – Los Banos – Tesla 500 kV line	Post project	18,831	14,182	1,759	2,890	23,874
	Savings	-8	-22	61	31	0
Alternative 2: A1 plus a new Midway – Gates – Manning 500 kV line	Post project	18,783	14,452	1,319	3,012	23,761
	Savings	40	247	-379	-91	113
Alternative 3: Monarch Option 1 Gates – Los Banos #3 500 kV line loops in new New Point 500 kV substation and build a new New Point to Tracy 500 kV line	Post project	18,804	14,230	1,671	2,903	23,851
	Savings	19	25	-27	18	23
Alternative 4: A3 plus New Point – Tracy looping in Tesla	Post project	18,827	14,265	1,660	2,901	23,849
	Savings	-4	61	-37	19	24
Alternative 5: A4 plus build a new Midway – New Point 500 kV line	Post project	18,776	14,404	1,470	2,902	23,776
	Savings	47	199	-228	18	98
Alternative 6: Monarch Option 2 Build a new Manning – New Point – Tracy 500 kV line	Post project	18,855	14,191	1,779	2,885	23,878
	Savings	-32	-14	82	36	-4
Alternative 7: A6 plus New Point – Tracy looping in Tesla	Post project	18,861	14,186	1,800	2,876	23,885

Scenarios		ISO load payment ($M)	ISO generator net revenue benefiting ratepayers ($M)	ISO transmission revenue benefiting ratepayers ($M)	ISO Net payment ($M)	WECC Production cost ($M)
Base case		18,823	14,205	1,698	2,920	23,874
	Savings	-38	-19	102	45	-12
Alternative 8: A7 plus Midway – New Point	Post project	18,782	14,402	1,482	2,898	23,761
	Savings	41	198	-215	23	113
Alternative 9: Build a new 500 kV line from Midway to new Gregg 500 kV substation to Tesla	Post project	18,777	14,449	1,385	2,943	23,769
	Savings	46	244	-312	-23	105
Alternative 10: Install a 10 ohm series reactor on each of the two Panoche – Gates 230 kV lines	Post project	18,843	14,223	1,699	2,922	23,873
	Savings	-20	18	1	-1	1

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative savings is an incremental cost or loss.

Cost Estimate

The ISO per unit cost was used to estimate the capital cost of the transmission alternatives assessed for mitigating the Path 15 corridor congestion. The ISO's screening factor of 1.3 then was applied to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost". The cost estimate was summarized in Table G.9-16.

Table G.9-16: Cost estimate of Path 15 corridor congestion mitigation transmission alternatives

Alternative	Capital Cost Estimate ($M)	Total Cost Estimate ($M)
Alternative 1: Build a new Manning – Los Banos – Tesla 500 kV line	888	1,155
Alternative 2: A1 plus a new Midway – Gates – Manning 500 kV line	2,018	2,624
Alternative 3: Monarch Option 1	950	1,235
Alternative 4: A3 plus New Point – Tracy looping in Tesla	1,164	1,513
Alternative 5: A4 plus build a new Midway – New Point 500 kV line	2,068	2,688
Alternative 6: Monarch Option 2	851	1,107
Alternative 7: A6 plus New Point – Tracy looping in Tesla	1,065	1,385
Alternative 8: A7 plus build a new Midway – New Point 500 kV line	1,933	2,513
Alternative 9: Build a new 500 kV line from Midway to new Gregg 500 kV substation to Tesla	1,781	2,315
Alternative 10: Install a 10 ohm series reactor on each of the two Panoche – Gates 230 kV lines	109	142

Benefit-to-cost ratio

The present values of the economic benefit of the Path 15 corridor congestion mitigation alternatives are shown in Table G.9-17 along with the calculation of the benefit-to-cost ratio. The economic life of transmission upgrade is 50 years for adding new transmission line or 40 years for reconductoring. Capacity saving was assumed to be zero for all these transmission alternatives since none of them has direct impact on the PG&E's local capacity areas or on the CAISO import capability.

Table G.9-17: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of Path 15 corridor congestion mitigation transmission alternatives

	A1: new Manning – Los Banos – Tesla 500 kV line	A2: A1 plus a new Midway – Gates – Manning 500 kV line	A3: Monarch Option 1	A4: A3 plus NewPoint – Tracy looping in Tesla	A5: A4 plus new Midway – New Point 500 kV line	A6: Monarch Option 2	A7: A6 plus NewPoint – Tracy looping in Tesla	A8: A7 plus build a new Midway – NewPoint 500 kV line	A9: new 500 kV line from Midway to Tesla	A10: series reactor on Panoche – Gates 230 kV lines
Production cost savings ($million/year)	31	-91	18	19	18	36	45	23	-23	-1
Capacity saving ($million/year)	0	0	0	0	0	0	0	0	0	0
Capital cost ($million)	888	2,018	950	1,164	2,068	851	1,065	1,933	1,781	109
Cost to Revenue Ratio	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Discount Rate	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Economic Life (year)	50	50	50	50	50	50	50	50	50	50
PV of Production cost savings ($million)	452	-1,348	259	282	267	525	661	337	-335	-20
PV of Capacity saving ($million)	0	0	0	0	0	0	0	0	0	0
Total benefit ($million)	452	-1,348	259	282	267	525	661	337	-335	-20
Total cost (Revenue requirement) ($million)	1,155	2,624	1,235	1,513	2,688	1,107	1,385	2,513	2,315	142
Benefit-to-cost ratio (BCR)	0.39	-0.51	0.21	0.19	0.10	0.47	0.48	0.13	-0.14	-0.14

Conclusions

Multiple transmission alternatives for mitigating the congestion on the Path 15 corridor were assessed in this section. Transmission alternatives to increase transmission capacity at north of Manning in the Path 15 corridor showed positive benefit to the CAISO's ratepayers, but none of these alternatives have benefit to cost ratio greater than 1.0. These north of Manning alternatives normally aggravated congestions on the south of Manning segments of the Path 15 corridor and congestions on the Path 26 corridor, when flow is from south to north. This is because such upgrades at north of Manning helped to attract more flow to the north along the Path 26 and Path 15 corridors. The increase in Path 15 and Path 26 congestion caused by some north of manning transmission upgrade alternatives can be significant, and may aggravate renewable curtailment and raise reliability concern in future system.

Transmission alternatives that combine transmission upgrades at north of Manning and south of Manning were assessed as well. While the congestion on the south of Manning segments of the Path 15 corridor was mitigated or reduced, the economic benefit of such transmission alternatives also reduced or even became negative. This happened when the congestion cost, which is considered as transmission revenue in TEAM methodology, reduced significantly as the south of Manning congestion in the Path 15 corridor was mitigated. These transmission alternatives may increase load payment savings and generation profit savings, but the increase was not large enough to compensate the transmission revenue reduction.

The benefit to cost ratio calculation in this section was based on the assumption that all transmission upgrade alternatives are fully rate-based projects, and the capital costs of the projects were estimated based on the CAISO transmission per unit cost. If these cost assumptions change, the benefit to cost ratios need to be recalculated, although the production cost simulation results may not change. It is worth noting that total capacity of renewable and battery resources in the Fresno/Kern area and in the southern California areas may continue increase in future CPUC IRP portfolios, which will aggravate congestions on the Path 15 and Path 26 corridors. Transmission upgrade alternatives for mitigating Path 15 and Path 26 corridors assessed in this planning cycle need to be reassessed in future planning cycles with consideration of the resource capacity changes in the Fresno/Kern area and in the southern California areas.