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

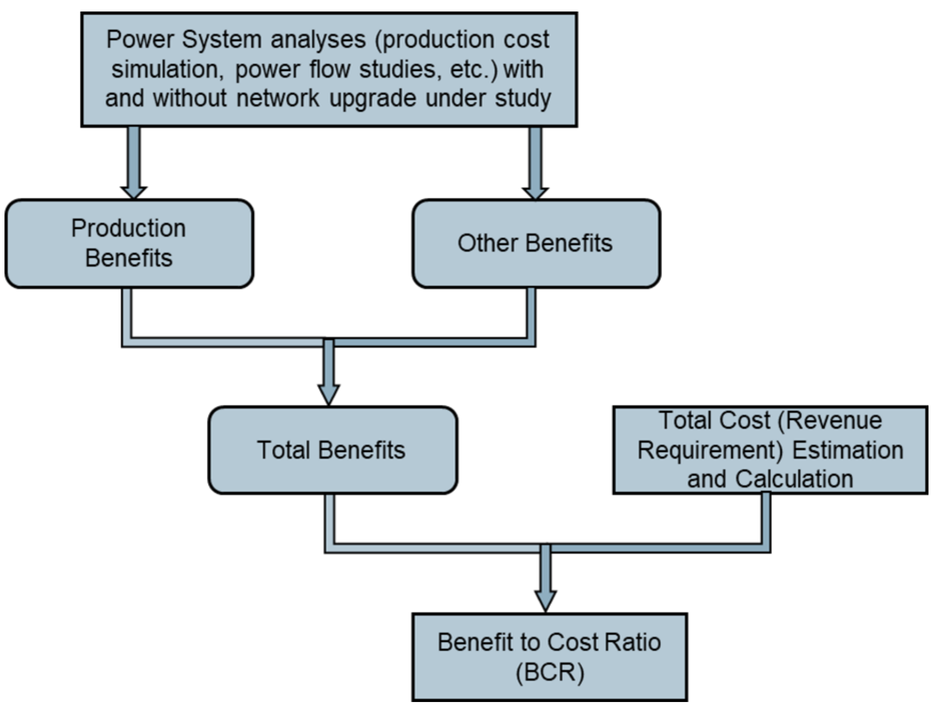
Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
	Some projects would provide local reliability benefits that otherwise would have to be purchased through LCR contracts. The Load Serving Entities (LSE) in the ISO-controlled grid 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 2022 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 12th year - in this case, the 2035-year, load forecast and resource assumption were used in the planning PCM cases.

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 2035 = 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 minus cost) has to be positive. If there are multiple alternatives, the alternative that has the

[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.

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 2021 CPUC Resource Adequacy Report[5], which is the most recently available report at the time, were used in assessing local capacity reduction benefit. The capacity costs for the southern California areas and the system capacity costs in the CPUC report are summarized in Table G.3-2. The cost converted to 2022 dollar based on the inflation rate in the CEC 2021 IEPR report[6] also included in the table.

[5] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021-ra-report---update-011624.pdf

[6] https://efiling.energy.ca.gov/GetDocument.aspx?tn=240982&DocumentContentId=74834

Table G.3-2: Capacity cost in CPUC Resource Adequacy Report

Area	Weighted average capacity cost ($/kW-month) in CPUC 2021 RA report	In 2022 dollar
System	6.24	6.40
SP26	6.52	6.69
LA Basin	6.64	6.81
Big Creek/Ventura	6.39	6.55
San Diego-IV	6.54	6.79

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:

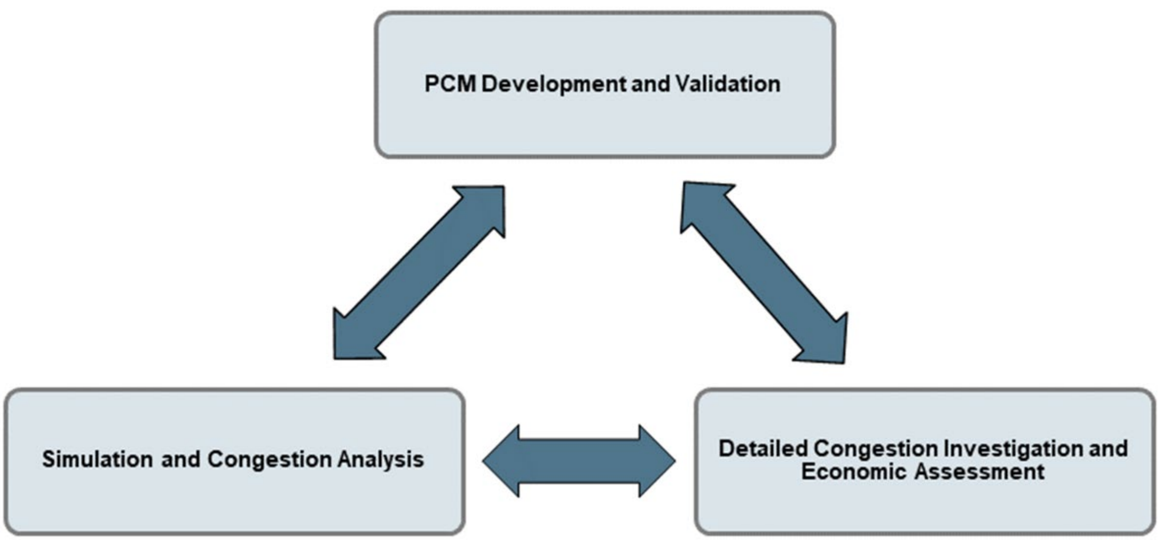
1. Network model (transmission topology, generator location, and load distribution).
2. Transmission constraint model, such as transmission contingencies, interfaces, and nomograms, etc.
3. Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, 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 and database

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™	10.3.72	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)

The ISO normally develops a database for the 10-year case as the primary case for congestion analysis and benefit calculation. The ISO may also develop an optional 5-year case for providing a data point in validating the benefit calculation of transmission upgrades by assessing a five year period of benefits before the 10-year case becomes relevant.

G.6 ISO GridView Production Cost Model Development

This section summarizes the major assumptions of system modeling used in the GridView 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 2023-2024 transmission planning process PCM development started from the ADS PCM 2032 version 2.4, which was released by WECC on May 8, 2023. Using this databases, the ISO developed the base cases for the ISO 2023-2024 transmission planning process production cost simulation. These base cases included the modeling updates and additions, which followed the ISO unified planning assumptions and are described in this section, and incremental changes in ADS PCM after the ADS PCM 2032 version 2.4 was released.

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. Different from the 2022-2023 planning cycle, both the base portfolio PCM and the sensitivity portfolio PCM used the CEC California Energy Demand Updated Forecast for 2035 with high electrification load, consistent with the demand forecast in the reliability assessment as described in Chapter 2.

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 PCM are consistent with the policy assessment power flow case for 2035, 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 base portfolio included out-of-state wind with 1500 MW of capacity identified in Wyoming areas, and 1000 MW of capacity identified in Idaho areas, which are expected to require new transmission. In the planning PCM in this planning cycle, Wyoming wind was modeled associated with the TransWest Express project. The Idaho wind was modeled associated with the SWIP North project as baseline assumption in the base portfolio PCM.

The CPUC IRP base and sensitivity portfolios also included offshore wind resources in different areas. In the base portfolio PCM, the energy only portion of Humboldt Bay offshore wind (161 MW) was modeled at Humboldt 115 kV, the incremental Humboldt Bay offshore wind (1446 MW) was modeled at Fern Road 500 kV bus. Morro Bay offshore wind (3100 MW) were modeled at the Diablo Canyon 500 kV bus. In the sensitivity portfolio PCM, the 161 MW of energy only Humboldt Bay offshore wind was still modeled at Humboldt 115 kV, and the total 5355 MW of Morro Bay offshore wind was still modeled at the Diablo Canyon 500 kV bus. However, the 7884 MW of the incremental Humboldt Bay offshore wind was modeled at a new 500 kV bus at Humboldt area with the following transmission upgrades:

- Humboldt - Fern Road 500 kV AC line
    - Also includes Fern Road – Vaca Dixon – Tesla 500 kV AC line
- Humboldt – Collinsvile HVDC
- Humboldt – Bayhub HVDC with Bayhub local 230 kV upgrades

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.

Another critical enhancement to the production simulation model is that nomograms on major transmission paths that are operated by the ISO were modeled. These nomograms were developed in the ISO's reliability assessments or identified in the operating procedures. In this planning cycle, the planning PCM continue to model critical credible contingencies in the COI corridor that were identified in the reliability assessment in lieu of COI nomograms, which is consistent with the planning PCM in the last planning cycle.

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 2032. All prices are in 2022 real dollars.

G.6.7 Renewable curtailment price model

The 2023-2024 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[7]. Based on this clarification of the cycle file definition, the battery's operation cost is calculated using the following equation:

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

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

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

$$P_{solar} + P_{battery} + REGUP_{battery} + LFUP_{solar} + LFUP_{battery} + SPIN_{battery} + FR_{battery} \leq Pmax \tag{1}$$

- P_{min} constraint (charging constraint)

$$P_{solar} + P_{battery} - REGDOWN_{battery} - LFDOWN_{solar} - LFDOWN_{battery} \geq Pmin \tag{2}$$

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 $Pmin$ 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 Fresno Henrietta 115 kV constraint

Congestion in the Fresno Henrietta 115 kV system, specifically the Leprino – Hanford and Hanford – Contadina 115 kV lines, was observed in the previous planning cycle, and in the preliminary base portfolio PCM simulation in this planning cycle as well. The congestion was observed under the N-2 contingency of the Helm-McCall 230 kV line and the Henrietta Tap2 – Mustang 230 kV #1 line. Congestion on the 115 kV lines occurred when the flow in the Henrietta 115 kV system was from the Leprino 115 kV bus to the Hanford 115 kV bus, and from the Hanford 115 kV bus to the Contadina 115 kV bus. Figure G.6-1 shows the PG&E Fresno Henrietta 115 kV system on-line diagram and Figure G.6-2 shows the N-2 contingency of the Helm – McCall and Mustang – Henrietta 230 kV lines. The congestion was mainly attributed to the loop flow between the 230 kV and 115 kV systems when the 230 kV N-2 contingency happened.

The congestion on the Henrietta 115 kV lines showed large congestion cost and significantly impacted the LMP in the PG&E areas even though it has limited impact on the overall flow pattern. The 230 kV N-2 contingency was considered as P7 contingency in the planning reliability assessment, however, it was considered as conditional P7 contingency in ISO's real time operation. Therefore, this 230 kV N-2 contingency was relaxed in the planning PCM cases in this planning cycle.

The congestion on the 115 kV lines could potentially be mitigated by SPS or overcurrent relay to de-loop the Henrietta 115 kV system from the 230 kV system following the N-2 contingency. In long term, reconfiguring the 230 kV lines between Helm – McCall and between the Mustangs - Henrietta Tap2 to McCall to address the same corridor issue may be needed to completely eliminate the conditional P7 contingency in planning study.

Figure G.6-1: PG&E Fresno 115 kV system

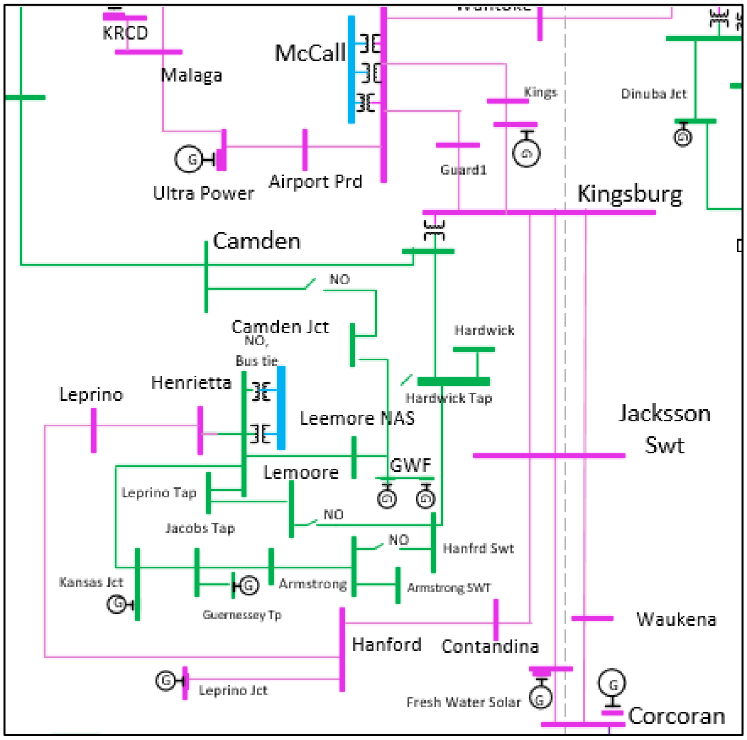
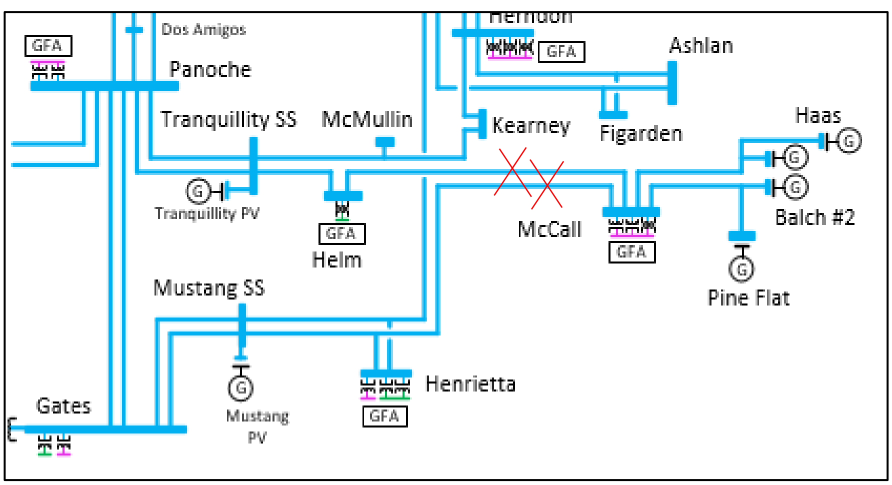


Figure G.6-2 N-2 contingency of Helm-McCall and Mustang-Henrietta 230 kV lines



G.7 Base Portfolio Production Cost Simulation Results

G.7.1 Congestion results of Base Portfolio PCM

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.

The results of the congestion assessment in the 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 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	COI Corridor	TABLE MTN-TM_VD_11 500 kV line, subject to PG&E-BANC N-1 Maxwell-Tracy 500kV	54,678	462	0	0	54,678	462
2	Path 61 (Victorville-Lugo)	LUGO-VICTORVL 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	0	0	51,400	169	51,400	169
3	COI Corridor	TABLE MTN-TM_VD_11 500 kV line #1	40,823	596	0	0	40,823	596
4	COI Corridor	P66 COI	39,404	452	0	0	39,404	452
5	Path 26 Corridor	P26 Northern-Southern California	9	11	35,606	1,753	35,615	1,764
6	PG&E Moss Landing-Las Aguilas 230 kV	MOSSLNSW-LASAGLSRCTR 230 kV line, subject to PG&E N-1 Moss Landing-Los Banos 500 kV	0	0	27,000	1,115	27,000	1,115
7	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	25,163	1,249	25,163	1,249
8	SDG&E/CFE	P45 SDG&E-CFE	3,996	638	19,878	562	23,874	1,200
9	PG&E Collinsville corridor	COLLINSVILLE-PITTSBURG-E 230 kV line, subject to PG&E N-1 Collinsvile-Pittsburg-F 230kV	22,649	1,065	0	0	22,649	1,065
10	Path 46 WOR	P46 West of Colorado River (WOR)	17,258	19	0	0	17,258	19
11	SCE North of Lugo	CALCITE-LUGO 230 kV line #1	16,633	2,177	0	0	16,633	2,177
12	COI Corridor	TM_VD_12-VACA-DIX 500 kV line #1	14,782	222	0	0	14,782	222
13	PG&E Kern 230kV	GATES F-ARCO 230 kV line #1	0	0	9,211	1,369	9,211	1,369
14	PG&E Sierra	P24 PG&E-Sierra	0	0	8,143	1,591	8,143	1,591
15	Path 15 Corridor	P15 Midway-Los Banos	8,140	351	0	0	8,140	351
16	Path 15 Corridor	MN_GT_11-GATES 500 kV line #1	0	0	8,044	274	8,044	274
17	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line #1	6,425	656	0	0	6,425	656
18	COI Corridor	RM_TM_22-TABLE MTN 500 kV line #2	5,264	122	0	0	5,264	122

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
19	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	4,953	405	4,953	405
20	SDG&E 230 kV	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	4,384	135	4,384	135
21	GridLiance/VEA	MEAD S-SLOAN CANYON 230 kV line #1	0	0	3,442	571	3,442	571
22	Path 61 (Victorville-Lugo)	P61 Lugo-Victorville 500 kV Line	0	0	3,237	1,078	3,237	1,078
23	COI Corridor	ROUND MT-RM_TM_11 500 kV line, subject to PG&E N-1 CapJack-Olinda 500 kV with Colusa SPS	2,568	18	0	0	2,568	18
24	Path 65 PDCI	P65 Pacific DC Intertie (PDCI)	1,696	9	709	144	2,405	153
25	SCE J.Hinds-Mirage	J.HINDS-MIRAGE 230 kV line #1	2,184	296	0	0	2,184	296
26	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	1,720	605	1,720	605
27	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	1,608	416	0	0	1,608	416
28	COI Corridor	ROUND MT-RM_TM_21 500 kV line #2	1,565	17	0	0	1,565	17
29	Path 49 EOR	P49 East of Colorado River (EOR)	1,448	4	0	0	1,448	4
30	PG&E Fresno Los Banos 230 kV	FINKSWSTA-WESTLEY 230 kV line, subject to PG&E N-1 Los Banos-Tesla 500kV	1,335	207	0	0	1,335	207
31	SCE North of Lugo	P60 Inyo-Control 115 kV Tie	2	4	1,322	960	1,324	964
32	PG&E POE-RIO OSO 230 kV	POE-RIO OSO 230 kV line #1	1,179	147	0	0	1,179	147
33	PG&E Panoche/Oro Loma area	LE GRAND-ADERASLRJCT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	1,153	448	1,153	448
34	GridLiance/VEA	GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV with RAS	0	0	1,137	446	1,137	446
35	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	796	734	0	0	796	734
36	Path 15 Corridor	LB_MN_11-MANNING 500 kV line #1	0	0	486	46	486	46
37	PG&E GBA	E. SHORE-SANMATEO 230 kV line, subject to PG&E N-2 Newark-Ravenswood 230kV and Tesla-Ravenswood 230kV	434	50	0	0	434	50
38	PG&E GBA	LS ESTRS 230/230 kV transformer #1	431	1,002	0	0	431	1,002
39	PG&E Kettlman Tap-Gates 70 kV	KETLMN T-GATES 70.0 kV line #1	371	1,359	0	0	371	1,359
40	PG&E Panoche/Oro Loma area	NEWHALL-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	344	453	0	0	344	453
41	SCE North of Lugo	SANDLOT-KRAMER 230 kV line #1	330	456	0	0	330	456
42	PG&E Collinsville corridor	E. SHORE-PITTSBURG-E 230 kV line, subject to PG&E N-1 Pittsburg-SanMateo 230kV	0	0	307	7	307	7

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
43	SCE Northern	MAGUNDEN-PASTORIA 230 kV line #2	281	370	0	0	281	370
44	SCE Metro	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	264	11	264	11
45	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	0	0	247	432	247	432
46	SCE Vincent-MiraLoma 500kV	VINCENT-MESA CAL 500 kV line #1	240	4	0	0	240	4
47	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line, subject to SCE N-1 RedBluff-Devers 500 kV with RAS	0	0	236	52	236	52
48	PG&E Tesla-Los Banos 500 kV	TESLA-LOS BANOS 500 kV line #1	0	0	233	9	233	9
49	COI Corridor	TABLE MTN-TM_TS_11 500 kV line #1	233	5	0	0	233	5
50	Path 26 corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	232	172	0	0	232	172
51	PG&E Fresno 230 kV	MCMULLN1-KEARNEY 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	210	56	0	0	210	56
52	COI Corridor	TABLE MTN-TM_TS_11 500 kV line, subject to PG&E-BANC N-1 Maxwell-Tracy 500kV	204	4	0	0	204	4
53	PG&E Sierra	HONEYLAK-SKEDADDLPS 60.0 kV line #1	0	0	128	90	128	90
54	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	116	55	116	55
55	SCE Eastern	DEVERS-devers i 500 kV line, subject to SCE N-1 Valley-Alberhill 500 kV with RAS	116	64	0	0	116	64
56	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	79	14	79	14
57	PG&E Humboldt 115 kV	HUMBOLDT-BRDGVLLE 115 kV line #1	79	105	0	0	79	105
58	SCE Northern	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	78	47	0	0	78	47
59	SDG&E/CFE	OTAYMESA-TJI-230 230 kV line #1	0	0	77	18	77	18
60	COI Corridor	ROUND MT-RM_TM_11 500 kV line #1	75	1	0	0	75	1
61	SWIP South	ISO iface SWIP-South	68	8	0	0	68	8
62	SDG&E 230 kV	TALEGA-S.ONOFRE 230 kV line #2	0	0	66	317	66	317
63	PG&E GBA	USWP-JRW_JCT-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	61	2	0	0	61	2
64	SCE Northern	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	60	17	60	17
65	Path 41 Sylmar transformer	P41 Sylmar to SCE	42	4	15	16	57	20

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
66	PG&E Fresno Los Banos 230 kV	QUINTO_SS-LOS BANOS 230 kV line, subject to PG&E N-1 Los Banos-Tesla 500kV	0	0	51	6	51	6
67	PG&E Tesla-Los Banos 500 kV	TESLA-LOS BANOS 500 kV line, subject to PG&E N-1 Los Banos-Tracy 500kV	0	0	41	7	41	7
68	PG&E Fresno Henrietta 115 kV	GWFHANFORDSS-CONTADNA 115 kV line #1	26	19	0	0	26	19
69	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	26	6	26	6
70	GridLiance/VEA	SLOAN_CYN_5-ELDORDO 500 kV line #1	22	5	0	0	22	5
71	PG&E Sierra	MARBLE 63.0/69.0 kV transformer #1	22	5	0	0	22	5
72	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	17	18	2	5	19	23
73	PG&E Collinsville corridor	E. SHORE-PITTSBURG-E 230 kV line #1	0	0	19	3	19	3
74	Path 26 Corridor	MW_VINCNT_12-VINCENT 500 kV line #1	19	4	0	0	19	4
75	SDG&E 230 kV	SILVERGT-OLDTWNTP 230 kV line, subject to SDGE N-1 Silvergate-OldTown 230kV no RAS	18	21	0	0	18	21
76	SCE Eastern	DVRS_RB_21-DVRS_RB_22 500 kV line #2	0	0	14	3	14	3
77	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line #2	14	8	0	0	14	8
78	PG&E Cottonwood 230 kV	COTWD_F2-BRNY_FST_JCT 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	14	10	14	10
79	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	13	32	13	32
80	SCE Northern	PARDEE-VINCENT 230 kV line #2	0	0	13	24	13	24
81	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	13	2	13	2
82	PG&E Fresno 230 kV	GREGG-HENTAP1 230 kV line #1	0	0	13	3	13	3
83	SCE East of Pisgah	ELDORDO-ELD_LUGO_11 500 kV line #1	12	3	0	0	12	3
84	COI Corridor	VACA-DIX-VD_CV_11 500 kV line #1	12	4	0	0	12	4
85	SDG&E Bulk	ECO-MIGUEL 500 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	11	10	0	0	11	10
86	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	11	6	0	0	11	6
87	GridLiance/VEA	ELDORDO2-SLOAN CANYON 230 kV line #1	10	54	0	0	10	54
88	PG&E Fresno 230 kV	HENTAP1-MUSTANGSS 230 kV line #1	0	0	10	4	10	4
89	PG&E Cottonwood 230 kV	COTWD_E-ROUND MT 230 kV line, subject to PG&E N-1 RoundMtn Xfmr 500 kV	0	0	8	1	8	1

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
90	PG&E MorroBay-SolarSS 230 kV	MORROBAY-SOLARSS 230 kV line #1	0	0	8	36	8	36
91	PG&E GBA	PPASSJCT-NEWARK E 230 kV line #2	3	2	0	0	3	2
92	SCE East of Pisgah	ELDORDO-ELD_LUGO_11 500 kV line, subject to LADWP-SCE N-1 Victorville-Lugo 500kV	3	1	0	0	3	1
93	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	3	86	0	0	3	86
94	PG&E Kern 230kV	ARCO-MIDWAY-E 230 kV line #1	3	12	0	0	3	12
95	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	2	3	2	3
96	SCE Eastern	ALBERHIL-VALLEYSC 500 kV line #1	0	0	2	1	2	1
97	PG&E Cottonwood 230 kV	COTWD_E-ROUND MT 230 kV line #3	0	0	2	2	2	2
98	SCE East of Pisgah	BAKER-MTN PASS 115 kV line #1	0	0	2	19	2	19
99	SCE North of Lugo	KRAMER-TWINKLE 230 kV line #1	0	0	1	5	1	5
100	SCE North of Lugo	COLWATER-DUNNSIDE 115 kV line #1	0	0	1	11	1	11
101	SDG&E 230 kV	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-1 Silvergate-OldTown-Mission 230kV no RAS	1	2	0	0	1	2
102	SDG&E Bulk	ECO 500/500 kV transformer #1	0	0	1	5	1	5

The branch group or local-area information is provided in the first column in Table G.7-1. The branch groups are identified by aggregating congestion costs and hours of congested facilities to an associated branch or branch group for normal or contingency conditions. The congestion subject to contingencies associated with local capacity requirements were aggregated by PTO service area based on where the congestion was located. The results have been ranked based on the congestion cost. The potential congestion across specific branch groups and local areas in 2035 is summarized in Table G.7-2.

Table G.7-2: Aggregated potential congestion in the ISO-controlled grid

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	COI Corridor	159.61	1,903
2	Path 26 Corridor	61.06	3,220
3	Path 61 (Victorville-Lugo)	54.64	1,247
4	PG&E Moss Landing-Las Aguilas 230 kV	27.00	1,115
5	SDG&E/CFE	23.95	1,218
6	PG&E Collinsville corridor	22.97	1,075
7	Path 15 Corridor	21.77	1,140
8	SCE North of Lugo	18.29	3,613
9	Path 46 WOR	17.26	19
10	PG&E Panoche/Oro Loma area	9.53	1,973
11	PG&E Kern 230kV	9.21	1,381
12	PG&E Sierra	8.29	1,686
13	SDG&E 230 kV	6.19	1,080
14	GridLiance/VEA	4.61	1,076
15	Path 65 PDCI	2.41	153
16	SCE J.Hinds-Mirage	2.18	296
17	Path 49 EOR	1.45	4
18	PG&E Fresno Los Banos 230 kV	1.39	213
19	PG&E POE-RIO OSO 230 kV	1.18	147
20	PG&E GBA	0.93	1,056
21	SCE Antelope 66kV	0.80	734
22	SCE Northern	0.69	922
23	SCE Eastern	0.46	136
24	PG&E Kettlman Tap-Gates 70 kV	0.37	1,359
25	PG&E Tesla-Los Banos 500 kV	0.27	16
26	SCE Metro	0.26	11
27	SCE Vincent-MiraLoma 500kV	0.24	4
28	PG&E Fresno 230 kV	0.23	63
29	PG&E Humboldt 115 kV	0.08	105
30	SWIP South	0.07	8
31	Path 41 Sylmar transformer	0.06	20
32	PG&E Fresno Henrietta 115 kV	0.03	19
33	PG&E Cottonwood 230 kV	0.02	13
34	SCE East of Pisgah	0.02	23
35	SDG&E Bulk	0.01	15
36	Path 25 PACW-PG&E 115 kV	0.01	6
37	PG&E MorroBay-SolarSS 230 kV	0.01	36
38	SDG&E Northern 69 kV	0.00	86

G.7.2 Curtailment results of Base Portfolio PCM

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 base portfolio PCM

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
SCE Northern	42,241	2,560	44,800	5.71%
SCE Eastern	23,642	1,344	24,987	5.38%
PG&E Fresno	18,385	4,267	22,651	18.84%
NM	14,694	1,239	15,933	7.78%
SDG&E Bulk	11,693	0	11,693	0.00%
GLW/VEA	8,811	2,622	11,433	22.93%
AZ-PV	9,884	1,355	11,239	12.05%
PG&E OSW-Diablo	9,886	604	10,490	5.76%
SCE NOL	8,803	1,449	10,252	14.14%
PG&E Kern	8,357	756	9,113	8.30%
PG&E GBA	8,492	271	8,762	3.09%
SCE East of Pisgah	6,386	645	7,032	9.18%
PG&E OSW-Humboldt	6,204	71	6,276	1.14%
WY	4,921	781	5,702	13.70%
PG&E Central Coast	3,425	205	3,630	5.64%
PG&E North Valley	2,635	115	2,749	4.17%
ID	2,605	136	2,741	4.97%
NW	1,636	423	2,059	20.55%
AZ-Mead	924	51	975	5.19%
PG&E Sacramento	854	51	905	5.62%
IID	781	19	801	2.41%
SCE Metro	419	7	426	1.71%
SDG&E Eastern	156	0	156	0.00%
SDG&E Northeast	106	0	106	0.07%
PG&E Humboldt	4	1	5	10.77%
Total	**195,942**	**18,972**	**214,915**	**8.83%**

G.8 Sensitivity Portfolio Production Cost Simulation Results

G.8.1 Congestion results of Sensitivity Portfolio PCM

The results of the congestion assessment in the sensitivity portfolio PCM for the Alternative 1 case with Humboldt Bay offshore wind at Fern Road is listed in Table G.8-1. 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.8-1: Congestion in the ISO-controlled grid in the 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	PG&E Humboldt-Collinsville HVDC	HUMBOLDT-OSDC_1 500 kV line #1	118,305	1,973	0	0	118,305	1,973
2	PG&E Humboldt-FernRoad 500 kV	HUMBOLDT-HB_FR_11 500 kV line #1	96,714	1,574	136	109	96,850	1,683
3	PG&E Humboldt-BayHub HVDC	HUMBOLDT-OFSDC_1 500 kV line #1	89,294	3,505	0	0	89,294	3,505
4	PG&E DiabloCanyon 500 kV	GATES-DIABLOCNYNSS 500 kV line #1	0	0	73,518	429	73,518	429
5	COI Corridor	P66 COI	36,904	472	0	0	36,904	472
6	Path 61 (Victorville-Lugo)	LUGO-VICTORVL 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	0	0	29,830	87	29,830	87
7	PG&E Humboldt-FernRoad 500 kV	HB_FR_11-HB_FR_12 500 kV line #1	21,864	469	47	54	21,911	523
8	PG&E Collinsville corridor	COLLINSVILLE-PITTSBURG-E 230 kV line, subject to PG&E N-1 Collinsvile-Pittsburg-F 230kV	18,343	1,659	0	0	18,343	1,659
9	PG&E Humboldt-FernRoad 500 kV	HB_FR_12-FERN RD 500 kV line #1	16,832	303	39	38	16,871	341
10	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line #1	15,493	1,113	0	0	15,493	1,113
11	COI Corridor	ROUND MT-RM_TM_21 500 kV line #2	15,490	487	0	0	15,490	487
12	SDG&E/CFE	P45 SDG&E-CFE	3,910	639	11,074	501	14,984	1,140
13	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	14,022	791	0	0	14,022	791
14	Path 15 Corridor	MN_GT_11-GATES 500 kV line #1	0	0	13,379	282	13,379	282
15	Path 46 WOR	P46 West of Colorado River (WOR)	12,353	4	0	0	12,353	4
16	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	11,124	610	11,124	610
17	Path 26 Corridor	P26 Northern-Southern California	61	19	10,176	636	10,237	655
18	Path 15 Corridor	P15 Midway-Los Banos	6,221	189	523	43	6,745	232
19	SCE Antelope 66kV	NEENACH-TAP 85 66.0 kV line #1	4,307	1,558	0	0	4,307	1,558
20	PG&E Panoche/Oro Loma area	ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	4,092	563	0	0	4,092	563

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
21	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	3,826	606	3,826	606
22	PG&E Collinsville corridor	CV_TS_11-TESLA 500 kV line #1	3,698	107	0	0	3,698	107
23	SDG&E 230 kV	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	3,566	160	3,566	160
24	PG&E Sierra	P24 PG&E-Sierra	0	0	3,418	647	3,418	647
25	PG&E Moss Landing-Las Aguilas 230 kV	MOSSLNSW-LASAGLSRCTR 230 kV line, subject to PG&E N-1 Moss Landing-Los Banos 500 kV	0	0	3,250	406	3,250	406
26	SCE North of Lugo	CALCITE-LUGO 230 kV line #1	3,247	1,176	0	0	3,247	1,176
27	Path 61 (Victorville-Lugo)	P61 Lugo-Victorville 500 kV Line	187	1	2,999	1,074	3,186	1,075
28	PG&E DiabloCanyon 500 kV	DIABLOCNYNSS-MIDWAY 500 kV line #2	2,598	60	0	0	2,598	60
29	SCE J.Hinds-Mirage	J.HINDS-MIRAGE 230 kV line #1	2,129	479	0	0	2,129	479
30	PG&E Panoche/Oro Loma area	LE GRAND-ADERASLRJCT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	2,104	657	2,104	657
31	SCE East of Pisgah	ELDORDO-ELD_LUGO_11 500 kV line, subject to LADWP-SCE N-1 Victorville-Lugo 500kV	1,491	1	0	0	1,491	1
32	SCE North of Lugo	P60 Inyo-Control 115 kV Tie	1	7	1,397	976	1,398	983
33	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	1,394	93	1,394	93
34	GridLiance/VEA	MEAD S-SLOAN CANYON 230 kV line #1	0	0	1,348	474	1,348	474
35	PG&E Tesla 230 kV	WEBER-TESLA E 230 kV line, subject to PG&E N-1 Bellota-TeslaE 230kV	0	0	1,321	76	1,321	76
36	PG&E POE-RIO OSO 230 kV	POE-RIO OSO 230 kV line #1	1,112	141	0	0	1,112	141
37	SCE Northern	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	1,089	204	0	0	1,089	204
38	SCE Northern	VINCNT2-vincen1i 230 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	0	0	1,065	79	1,065	79
39	Path 65 PDCI	P65 Pacific DC Intertie (PDCI)	588	17	310	48	898	65
40	PG&E Fresno Los Banos 230 kV	FINKSWSTA-WESTLEY 230 kV line, subject to PG&E N-1 Los Banos-Tesla 500kV	814	124	0	0	814	124
41	SCE Northern	PARDEE-VINCENT 230 kV line #2	0	0	812	85	812	85
42	PG&E Sierra	HONEYLAK-SKEDADDLPS 60.0 kV line #1	0	0	598	157	598	157

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
43	PG&E Kettlman Tap-Gates 70 kV	KETLMN T-GATES 70.0 kV line #1	596	1,296	0	0	596	1,296
44	COI Corridor	FERN RD-RM_TM_32 500 kV line #1	595	19	0	0	595	19
45	Path 49 EOR	P49 East of Colorado River (EOR)	472	3	0	0	472	3
46	SWIP South	ISO iface SWIP-South	398	38	0	0	398	38
47	PG&E Panoche/Oro Loma area	NEWHALL-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	398	219	0	0	398	219
48	COI Corridor	RM_TM_22-TABLE MTN 500 kV line #2	388	23	0	0	388	23
49	SCE Vincent-MiraLoma 500kV	VINCENT-MESA CAL 500 kV line #1	377	15	0	0	377	15
50	PG&E Tesla 230 kV	STAGG-J2-TESLA E 230 kV line, subject to PG&E N-1 EightMiles-TeslaE 230kV	0	0	363	13	363	13
51	PG&E Fresno 230 kV	MCMULLN1-KEARNEY 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	350	95	0	0	350	95
52	SCE W.LA LCIENEGA-LA FRESA 230 kV	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	331	12	331	12
53	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	298	53	0	1	298	54
54	Path 26 Corridor	MW_VINCNT_22-VINCENT 500 kV line #2	286	18	0	0	286	18
55	PG&E GBA	LS ESTRS 230/230 kV transformer #1	235	684	0	0	235	684
56	PG&E Tesla-Metcalf 500 kV	TESLA-METCALF 500 kV line #1	229	5	0	0	229	5
57	Path 26 Corridor	MIDWAY-MW_VINCNT_11 500 kV line #1	208	2	0	0	208	2
58	PG&E Kern 230kV	GATES F-ARCO 230 kV line #1	0	0	191	208	191	208
59	COI Corridor	VACA-DIX-VD_CV_11 500 kV line #1	187	12	0	0	187	12
60	COI Corridor	VD_CV_11-COLLINSVILLE 500 kV line #1	133	6	0	0	133	6
61	Path 41 Sylmar transformer	P41 Sylmar to SCE	82	4	18	16	100	20
62	SDG&E/CFE	OTAYMESA-TJI-230 230 kV line #1	0	0	84	22	84	22
63	PG&E Collinsville corridor	COLLINSVILLE-CV_TS_11 500 kV line #1	83	7	0	0	83	7
64	PG&E Fresno 230 kV	GREGG-HENTAP1 230 kV line #1	0	0	66	5	66	5
65	Path 26 Corridor	MW_VINCNT_12-VINCENT 500 kV line #1	62	9	0	0	62	9
66	PG&E Fresno Henrietta 115 kV	GWFHANFORDSS-CONTADNA 115 kV line #1	57	11	0	0	57	11

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
67	SCE North of Lugo	SANDLOT-KRAMER 230 kV line #1	50	113	0	0	50	113
68	COI Corridor	ROUND MT-RM_TM_11 500 kV line #1	47	2	1	2	48	4
69	PG&E Sierra	MARBLE 63.0/69.0 kV transformer #1	45	6	0	0	45	6
70	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	43	19	43	19
71	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	42	31	42	31
72	Path 26 Corridor	MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	40	8	0	0	40	8
73	SDG&E 230 kV	SILVERGT-OLDTWNTP 230 kV line, subject to SDGE N-1 Silvergate-OldTown 230kV no RAS	40	38	0	0	40	38
74	Path 15 Corridor	LB_MN_11-MANNING 500 kV line #1	0	0	38	5	38	5
75	PG&E Fresno 230 kV	GREGG-HENTAP1 230 kV line, subject to PG&E N-1 Wilson-Warnerville 230kV	0	0	37	10	37	10
76	SDG&E 230 kV	TALEGA-S.ONOFRE 230 kV line #2	0	0	32	221	32	221
77	PG&E Panoche/Oro Loma area	NEWHALL-DAIRYLND 115 kV line #1	32	3	0	0	32	3
78	SCE Northern	MAGUNDEN-ANTELOPE 230 kV line #1	0	0	32	64	32	64
79	PG&E Fresno Los Banos 230 kV	QUINTO_SS-LOS BANOS 230 kV line, subject to PG&E N-1 Los Banos-Tesla 500kV	0	0	23	5	23	5
80	PG&E Cottonwood 230 kV	COTWD_F2-BRNY_FST_JCT 230 kV line, subject to PG&E N-1 Carberry-RM with HR SPS	0	0	21	15	21	15
81	SDG&E 230 kV	SILVERGT-OLD TOWN 230 kV line, subject to SDGE N-1 Silvergate-OldTown-Mission 230kV no RAS	20	13	0	0	20	13
82	GridLiance/VEA	ELDORDO2-SLOAN CANYON 230 kV line #1	15	41	0	0	15	41
83	PG&E Humboldt 115 kV	HUMBOLDT-BRDGVLLE 115 kV line #1	15	18	0	0	15	18
84	SCE East of Pisgah	BAKER-MTN PASS 115 kV line #1	0	0	12	70	12	70
85	SCE Eastern	DEVERS-DVRS_RB_21 500 kV line #2	0	0	12	4	12	4
86	PG&E Cottonwood 230 kV	COTWD_E-ROUND MT 230 kV line, subject to PG&E N-1 RoundMtn Xfmr 500 kV	0	0	11	2	11	2
87	Path 25 PACW-PG&E 115 kV	P25 PacifiCorp/PG&E 115 kV Interconnection	11	4	0	0	11	4
88	SCE Northern	MAGUNDEN-PASTORIA 230 kV line #2	10	25	0	0	10	25

No.	Area	Constraints Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
89	Path 15 Corridor	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	10	11	10	11
90	SCE Northern	MAGUNDEN-VESTAL 230 kV line, subject to SCE N-1 Magunden-Vestal #1 230kV	0	0	9	12	9	12
91	PG&E Collinsville corridor	E. SHORE-PITTSBURG-E 230 kV line #1	0	0	9	4	9	4
92	PG&E Tesla-Los Banos 500 kV	TESLA-LOS BANOS 500 kV line, subject to PG&E N-1 Los Banos-Tracy 500kV	0	0	8	2	8	2
93	PG&E Fresno 230 kV	HENTAP1-MUSTANGSS 230 kV line #1	0	0	8	3	8	3
94	SCE Eastern	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	5	3	5	3
95	SDG&E Bulk	ECO-MIGUEL 500 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	4	2	0	0	4	2
96	SCE North of Lugo	COLWATER-DUNNSIDE 115 kV line #1	0	0	4	35	4	35
97	COI Corridor	TABLE MTN-TM_VD_11 500 kV line #1	3	1	0	0	3	1
98	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	2	65	0	0	2	65
99	PG&E Kern 230kV	ARCO-MIDWAY-E 230 kV line #1	2	26	0	0	2	26
100	SCE Eastern	DVRS_RB_21-DVRS_RB_22 500 kV line #2	0	0	2	3	2	3
101	COI Corridor	MALIN-MN_RM_21 500 kV line #2	2	1	0	0	2	1
102	SCE Northern	ANTELOPE-PARDEE 230 kV line #1	2	7	0	0	2	7
103	SCE Eastern	DEVERS-devers i 500 kV line, subject to SCE N-1 Valley-Alberhill 500 kV with RAS	1	4	0	0	1	4
104	SCE North of Lugo	KRAMER-TWINKLE 230 kV line #1	0	0	1	8	1	8

Table G.8-2 lists the aggregated congestion results of the sensitivity portfolio PCM case, in which the transmission upgrades were modeled for the Humboldt Bay offshore wind generators.

Table G.8-2: Aggregated congestion in Sensitivty portfolio PCM

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	PG&E Humboldt-FernRoad 500 kV	135.63	2,547
2	PG&E Humboldt-Collinsville HVDC	118.30	1,973
3	PG&E Humboldt-BayHub HVDC	89.29	3,505
4	PG&E DiabloCanyon 500 kV	76.12	489
5	COI Corridor	53.75	1,025
6	Path 26 Corridor	36.28	2,147
7	Path 61 (Victorville-Lugo)	33.02	1,162
8	PG&E Collinsville corridor	22.13	1,777
9	PG&E Panoche/Oro Loma area	22.12	2,555
10	Path 15 Corridor	21.65	673
11	SDG&E/CFE	15.07	1,162
12	Path 46 WOR	12.35	4
13	SDG&E 230 kV	7.48	1,038
14	SCE North of Lugo	4.70	2,315
15	SCE Antelope 66kV	4.31	1,558
16	PG&E Sierra	4.06	810
17	PG&E Moss Landing-Las Aguilas 230 kV	3.25	406
18	SCE Northern	3.02	476
19	SCE J.Hinds-Mirage	2.13	479
20	PG&E Tesla 230 kV	1.68	89
21	SCE East of Pisgah	1.50	71
22	GridLiance/VEA	1.36	515
23	PG&E POE-RIO OSO 230 kV	1.11	141
24	Path 65 PDCI	0.90	65
25	PG&E Fresno Los Banos 230 kV	0.84	129
26	PG&E Kettlman Tap-Gates 70 kV	0.60	1,296
27	Path 49 EOR	0.47	3
28	PG&E Fresno 230 kV	0.46	113
29	SWIP South	0.40	38
30	SCE Vincent-MiraLoma 500kV	0.38	15
31	SCE W.LA LCIENEGA-LA FRESA 230 kV	0.33	12
32	PG&E GBA	0.23	684
33	PG&E Tesla-Metcalf 500 kV	0.23	5
34	PG&E Kern 230kV	0.19	234
35	Path 41 Sylmar transformer	0.10	20
36	PG&E Fresno Henrietta 115 kV	0.06	11
37	PG&E Cottonwood 230 kV	0.03	17
38	SCE Eastern	0.02	14
39	PG&E Humboldt 115 kV	0.01	18
40	Path 25 PACW-PG&E 115 kV	0.01	4
41	PG&E Tesla-Los Banos 500 kV	0.01	2
42	SDG&E Bulk	0.00	2
43	SDG&E Northern 69 kV	0.00	65

G.8.2 Curtailment results of Sensitivity Portfolio PCM

Table G.8-3 shows the wind and solar curtailment results of the sensitivity portfolio PCM.

Table G.8-3: Wind and solar curtailment summary in the Sensitivity portfolio PCM

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
SCE Northern	38,703	1,379	40,082	3.44%
PG&E OSW-Humboldt	29,961	1,455	31,417	4.63%
SCE Eastern	18,948	978	19,926	4.91%
PG&E OSW-Diablo	16,871	1,249	18,120	6.89%
PG&E Fresno	14,842	1,795	16,637	10.79%
NM	14,867	1,066	15,933	6.69%
SDG&E Bulk	10,310	0	10,310	0.00%
SCE NOL	7,403	1,112	8,515	13.06%
PG&E GBA	7,200	235	7,435	3.16%
GLW/VEA	6,218	924	7,142	12.94%
SCE East of Pisgah	6,455	576	7,032	8.20%
AZ-PV	5,738	637	6,375	9.99%
WY	5,065	637	5,702	11.16%
PG&E Kern	4,843	332	5,176	6.42%
PG&E Central Coast	2,865	189	3,054	6.19%
ID	2,617	124	2,741	4.54%
NW	1,719	341	2,059	16.54%
PG&E North Valley	1,371	35	1,406	2.49%
AZ-Mead	937	38	975	3.90%
PG&E Sacramento	728	78	807	9.69%
IID	794	7	801	0.84%
SCE Metro	414	12	426	2.93%
SDG&E Eastern	156	0	156	0.00%
SDG&E Northeast	106	0	106	0.09%
PG&E Humboldt	4	1	5	14.20%
Total	**199,136**	**13,202**	**212,338**	**6.22%**

G.9 Economic Planning Study Requests

G.9.1 Study request for SWIP-North project

Study request overview

LS Power Development, LLC submitted an economic study request to study congestion on the California-Oregon Intertie (COI), Pacific AC Intertie (PACI) and Nevada-Oregon Border (NOB). In addition, the study requests that the ISO study the Southwest Intertie Project – North (SWIP-North) project as an economic project.

LS Power requests the ISO to quantify financial congestion on the PACI, NOB, and COI paths in addition to the physical congestion that has been quantified over the last few planning cycles.

The Southwest Intertie Project - North (SWIP - North) project is comprised of a single circuit 500 kV transmission line from Midpoint substation (in Idaho) to Robinson Summit substation (in Nevada). The project will provide approximately 1050 MW of bi-directional transmission capacity between Midpoint and Harry Allen.

Evaluation

The SWIP North project was conditionally approved by the ISO in 2023. This project was modeled in the 2023-2024 planning cycle's PCM cases.

Conclusion

No future economic assessment was conducted for this study request in this planning cycle.

G.9.2 Study request for Valley Power Connect (NGIV2) project

Study request overview

The 85 mile long North Gila – Imperial Valley #2 Project is a new 500 kV line generally paralleling the existing North Gila – Imperial Valley #1 500 kV line (also known as the Southwest Power Link, or "SWPL"). The Project Sponsors propose the following project facility additions. The last three facilities to be owned and operated by the IID:

- A new 500 kV termination at the existing CAISO North Gila 500 kV Substation (operated by APS).
- A new 85-mile, 500 kV line between the North Gila 500 kV Substation to the Imperial Valley 500kV Substation. While the IID is proposing to be a 20% owner in this line, the remaining 80% is to be owned and costs recovered by a CAISO PTO.
- A new 500 kV termination at the existing CAISO Imperial Valley 500KV Substation (operated by SDGE).
- Contingent Facilities: Series compensation located at a proposed intermediate substation (known as Dunes), located approximately 56 miles west from North Gila, the location is electrically near the IID Highline 230 kV Substation. Note that the existing North Gila – Imperial Valley #1 line includes 50% series compensation, but is currently operated bypassed. The cost of these contingent facilities are included in the cost of the NGIV2 Project.
- A new 500 kV termination at the 500 kV Dunes Substation (initially only a contingent series compensation station) for the termination of a 1120 MVA 500/230 kV transformer.
- New Dunes 230 kV Switching Station.
- A new 6.6-mile, 230 kV segment from the 230 kV Dunes Switching Station terminating into IID's existing 230 kV Highline Substation. IID will Own 100% and operate the Dunes 500/230 kV transformer and the 230 kV transmission line between Dunes and Highline substations.

Evaluation

The N.Gila – Imperial Valley 500 kV #2 line was approved by the ISO in the 2022-2023 planning cycle, and was modeled in the 2023-2024 planning cycle's PCM cases. The need to connect the ISO's N.Gila-Imperial Valley 500 kV lines and the IID system was not identified in reliability and policy assessments in the 2023-2024 planning cycle. There was no congestion observed in this area in this planning cycle either.

Conclusion

No further economic assessment was conducted for this study request in this planning cycle.

G.9.3 Study request for Moss Landing – Las Aguilas 230 kV line reconductoring

Study request overview

Vistra requests the ISO review the scope of the 10 Ohms series reactor project in the 2021-2022 Transmission Plan to determine whether the scope of the approved project is sufficient to resolve the expected increase in congestion. Specifically, Vistra requests the ISO to conduct an economic study of a transmission project to reconductoring the Moss Landing – Las Aguilas 230 kV line.

Evaluation

The benefits described in the submission and the ISO's evaluation of the economic study request are summarized in Table G.9-1.

Table G.9-1: Evaluating study request – Moss Landing – Las Aguilas 230 kV line reconductoring

Study Request: Moss Landing –Las Aguilas 230 kV line congestion mitigation		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Vistra requested to study the benefit of mitigating the transmission congestion of the Moss Landing – Las Aguilas 230 kV line in the PG&E area	The interim solution of adding 10 ohm series reactor on the Moss Landing – Las Aguilas 230 kV line that was approved in the 2021-2022 TPP cycle can effectively reduce flow on the line. However, congestion on this line under the Moss Landing-Los Banos 500 kV line N-1 contingency was still observed in the Base Portfolio PCM study because the PG&E Fresno area solar generation increases and the Great Bay Area load increased, compared with the last 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	Vistra stated that mitigating the congestion would have capacity benefit in local capacity requirements 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	Vistra stated that mitigating the congestion would help to reduce renewable curtailment	The congestion was observed when the flow was from Las Aguilas to Moss Landing. PG&E Fresno area renewable and Greater Bay area load contributed to this congestion.
Other	None	No benefits identified by ISO

Conclusion

The Moss Landing – Las Aguilas 230 kV line congestion was selected to receive detailed economic assessment in this planning cycle.

G.9.4 Study request for Path 15 HVDC conversion

Study request overview

Center for Energy Efficiency and Renewable Technology (CEERT) proposed to study the potential to convert portions of Path 15 to HVDC in order to connect the potential large scale solar and battery development (30 GW+) in the PG&E South Area.

Evaluation

Path 15 corridor congestion was observed in this planning cycle, and was assessed in detail in this planning cycle.

The benefits described in the submission and the ISO's evaluation of the economic study request are summarized in Table G.9-2.

Table G.9-2: Evaluating study request – Path 15 HVDC Conversion Project

Study Request: Path 15 HVDC Conversion Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Not addressed in submission	Path 15 corridor congestion was observed in this planning cycle
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Connect the potential large solar and battery development in the PG&E South Area.	The HVDC conversion will significantly change the transmission topology in this area, and potentially impact how the Fresno/Kern area solar generators connect to the system. However, due to lack of clarity of detailed scope of the study request, it is not clear how it will improve deliverability of PG&E Fresno/Kern area generators.
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	No benefits identified by ISO
Other	Not addressed in submission	No benefits identified by ISO

Conclusion

The proposed Path 15 HVDC conversion was not received detailed economic assessment due to lack of clarity of detailed scope of the proposed upgrade. The study request submitter is recommended to provide detailed scope of the upgrade to the ISO in future planning cycle for further evaluation. Still, Path 15 corridor congestion was selected to receive detailed economic assessment in this planning cycles, with considering different AC alternatives of Path 15 corridor congestion mitigation, as set out in Section G.10.4.

G.9.5 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 was previously submitted as an economic study request and was resubmitted with a modified study scope to the Reliability Request Window of the ISO 2023-2024 transmission planning process. 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 La Fresa substation.

The project is 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 ISO's evaluation of the economic study request are summarized in Table G.9-3.

Table G.9-3: Evaluating study request – Pacific Transmission Expansion (PTE) HVDC Project

Study Request: Pacific Transmission Expansion HVDC Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Not addressed in submission	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.	No benefits identified by ISO
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.	LCR reduction studies for the Western LA Basin and SDG&E areas were conducted in the 2019-2020 and 2020-2021 planning cycles, which provided the same LCR reduction results in MW. The ISO used the same LCR reduction results, and updated the LCR reduction savings based the updated local and system capacity costs.
Increase in Identified Congestion	Not addressed in submission	Congestion in the Western LA Basin and Ventura areas 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	No benefits identified by ISO
Other	California Western Grid states the following benefits of the proposed project: • The faster response for AC voltage control and frequency stabilization while providing effective short circuit capacity and system damping requirements. • Project can deliver system flexibility to the locally constrained area. • Project reduces the risk of wildfire cutting off electric service to the LA coastal area.	No benefits identified by ISO

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 in this planning cycle, as set out in Section G.10.3.

G.9.6 Study request for GLW Beatty – Esmeralda Project

Study request overview

GLW requests that the CAISO conduct economic study of the Beatty - Esmeralda Project, which expands the existing GridLiance West / Valley Electric Association system from the existing Beatty substation to NV Energy's Esmeralda substation, a new station to be built as part of the Greenlink West project. GLW also requests to expand the previously approved Beatty 230 kV project to be built to 500 kV but operated as 230 kV in order to accommodate potential future renewable resources in the Beatty area.

Evaluation

The benefits described in the submission and the ISO's evaluation of the study request are summarized in Table G.9-7.

Table G.9-4: Evaluating study request – GLW Beatty - Esmeralda Project

Study Request: GLW Beatty - Esmeralda Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	GridLiance West stated that the proposed project can accommodate potential future renewable resources and substantially reduce congestion on major facilities in the GLW system.	Congestions in the Gridliance West/VEA area in this planning cycle was mainly observed on the Mead S – Sloan Canyon 230 kV line and the Gamebird 230/138 kV transformer. The Beatty – Esmeralda 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 project can facilitate the increased renewable integration in the CPUC portfolio	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) enable ISO-connected renewable generation in Southern Nevada to meet California carbon goals (2) enhance reliability by increasing access to GLW-interconnected generation and storage capacity	No benefits identified by ISO

Conclusion

The Beatty – Esmeralda 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. Therefore, this study request is not selected for detailed economic assessment. Instead, other alternatives that can directly reinforce the congested components in the GLW/VEA area were assessed in this planning cycle, as set out in Section G.10.1.

G.10 Detailed Investigation of Congestion and Economic Benefit Assessment

G.10.1 GridLiance West/VEA area Mead S – Sloan Canyon 230 kV line congestion

Congestion analysis

Congestion on the Mead S – Sloan Canyon 230 kV line in the GridLiance West/VEA area was observed in the Base portfolio PCM simulation results in this planning cycle. The congestion was observed under the normal condition. Table G.10-1 provides the congestion on the Mead S – Sloan Canyon 230 kV line.

Table G.10-1: Mead S – Sloan Canyon 230 kV line congestions

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
MEAD S-SLOAN CANYON 230 kV line #1	0	0	1,348	474	1,348	474

Congestion mitigation alternatives

The mitigation to be studied is to add the second Mead S – Sloan Canyon 230 kV line. This alternative can effectively mitigate the congestion on the existing Mead S – Sloan Canyon 230 kV line.

Production benefits

The production benefits for ISO ratepayers and the production cost savings of the second Mead S – Sloan Canyon 230 kV line are shown in Table G.10-2.

Table G.10-2: Production Benefits of adding the second Mead S – Sloan Canyon 230 kV line

	Base case	Second Mead S – Sloan Canyon 230 kV line	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,765	9,699	66
ISO generator net revenue benefiting ratepayers	5,598	5,590	-8
ISO transmission revenue benefiting ratepayers	677	654	-24
ISO Net payment	3,490	3,455	35
WECC Production cost	13,070	13,068	2

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 existing Mead S – Sloan Canyon 230 kV line was built as double circuit but strung one side, therefore, adding the second line needs only to string the other side. However, the actual cost can vary significantly as the Mead substation has limitation to add additional line position.

Conclusions

Adding the second Mead S – Sloan Canyon 230 kV line can effectively mitigate congestion on the existing Mead S – Sloan Canyon 230 kV line. However, due to the limitation within the Mead Substation for adding another line position, further assessment for the feasibility and cost of adding the second Mead S – Sloan Canyon 230 kV line will be conducted in future planning cycle in coordination with GridLiance West and the facility owners of Mead substation.

G.10.2 SCE East of Pisgah area and Path 61 corridor congestion and mitigations

Congestion analysis

Congestion in the SCE East of Pisgah area and Path 61 corridor that was observed in the base portfolio PCM in this planning cycle is mainly the congestion along the Path 61 corridor, as summarized in Table G.10-3. Minor congestion on the Eldorado – Lugo 500 kV line and the Baker – Mountain Pass 115 kV line was also observed.

Table G.10-3: SCE East of Pisgah area and Path 61 corridor congestion in the 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	51,400	169	51,400	169
P61 Lugo-Victorville 500 kV Line	0	0	3,237	1,078	3,237	1,078
ELDORDO-ELD_LUGO_11 500 kV line #1	12	3	0	0	12	3
ELDORDO-ELD_LUGO_11 500 kV line, subject to LADWP-SCE N-1 Victorville-Lugo 500kV	3	1	0	0	3	1
BAKER-MTN PASS 115 kV line #1	0	0	2	19	2	19

Congestion mitigation alternatives

Two mitigation alternatives for the SCE East of Pisgah area and Path 61 corridor congestion were assessed:

1. Adding the new Trout Canyon – Lugo 500 kV line with 70% series compensation was assessed.

2. 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.

The simulation results showed that the new Trout Canyon – Lugo 500 kV line was effective to mitigate the Lugo – Victorville 500 kV line congestion under the Eldorado-Lugo 500 kV N-1 contingency, but the Path 61 congestion due to path rating binding was still observed. The new

Trout Canyon – Lugo 500 kV line aggravated Path 26 congestion, as it increased the power flow from the Southern California areas to the Northern California areas.

The Marketplace – Adelanto HVDC conversion project can mitigate both the Path 61 congestion and the congestion on the Lugo – Victorville 500 kV line under the Eldorado-Lugo 500 kV N-1 contingency, although Path 26 congestion would be aggravated slightly.

Production benefits

The production benefit for ISO ratepayers and the production-cost savings of the Trout Canyon – Lugo 500 kV line alternative and the Marketplace – Adelanto HVDC conversion project alternative are shown in Table G.10-4, respectively.

Table G.10-4: Production Benefits of SCE East of Pisgah area and Path 61 corridor congestion mitigation alternatives

	Base case	Trout Canyon – Lugo 500 kV line		Marketplace – Adelanto project	
	($M)	Post project	Savings ($M)	Post project ($M)	Savings
ISO load payment	9,765	9,571	194	9,566	199
ISO generator net revenue benefiting	5,598	5,545	-53	5,550	-48
ISO transmission revenue benefiting	677	599	-78	585	-92
ISO Net payment	3,490	3,427	63	3,431	59
WECC Production cost	13,070	13,106	-36	13,088	-18

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 capital cost of the Trout Canyon – Lugo 500 kV line is about $2 billion based on the cost estimate in the last planning cycle. 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 Trout Canyon – Lugo 500 kV line alternative is $2,600 million.

The capital cost of the Marketplace – Adelanto HVDC conversion project was estimated based on the following assumptions:

- Two Converter stations at Marketplace and Adelanto, and 500 kV connection to the existing Marketplace and Adelanto substation, respectively: $1,231 million
- 17 miles 500 kV AC line between Adelanto and Lugo: $252 million
- 1.5 mile 500 kV AC line between Marketplace and Eldorado: $41 million
- Assuming the existing Marketplace to Adelanto 500 kV conductor and structure can be used for the HVDC conversion.

The capital cost of the Marketplace – Adelanto HVDC conversion project then was estimated at $1,525 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 Marketplace – Adelanto HVDC conversion project is $1,982 million.

Benefit-to-cost ratio

The present values of the economic benefit of the SCE East of Pisgah area and Path 61 corridor congestion mitigation alternatives are shown in Table G.10-5 along with the calculation of the benefit-to-cost ratio. The project economic life of the new Trout Canyon – Lugo 500 kV project is assumed to be 50 year, and the economic life of the Marketplace – Adelanto HVDC conversion project is assumed to be 40 year. No capacity saving was identified in this planning cycle.

Table G.10-5: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of SCE East of Pisgah area and Path 61 corridor congestion mitigation alternatives

	Trout Canyon – Lugo 500 kV line	Marketplace – Adelanto project
Production cost savings ($million/year)	63	59
Capacity saving ($million/year)	0	0
Capital cost ($million)	2,000	1,525
Discount Rate	7%	7%
PV of Production cost savings ($million)	930	842
PV of Capacity saving ($million)	0	0
Total benefit ($million)	930	842
Total cost (Revenue requirement) ($million)	2,600	1,982
Benefit-to-cost ratio (BCR)	0.358	0.425

Conclusions

Both Trout Canyon – Lugo and Marketplace – Adelanto projects have less than 1.0 benefit-to-cost ratio in this planning cycle's economic assessment, which indicated that there were not sufficient to provide economic justification for these two project in this planning cycle. The ISO will continue to monitor the congestions in the SCE East of Pisgah area and Path 61 corridor and assess transmission alternatives for mitigation in future planning cycles.

G.10.3 Path 26 corridor 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.10-6. 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 identified in the CPUC portfolio.

Table G.10-6: Path 26 corridor congestion

Constraint Name	Cost Forward	Duration Forward	Cost Backward	Duration Backward	Costs Total ($K)	Duration Total (Hrs)
P26 Northern-Southern California	9	11	35,606	1,753	35,615	1,764
MW_WRLWND_31-MW_WRLWND_32 500 kV line	0	0	25,163	1,249	25,163	1,249
MW_WRLWND_31-MW_WRLWND_32 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	232	172	0	0	232	172
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	17	18	2	5	19	23
MW_VINCNT_12-VINCENT 500 kV line #1	19	4	0	0	19	4
MW_VINCNT_22-VINCENT 500 kV line #2	14	8	0	0	14	8

Congestion mitigation alternatives

The mitigation alternative for the Path 26 corridor congestion considered in this planning cycle is the Pacific Transmission Expansion (PTE) project, which is an economic study request with offshore HVDC lines between the Northern and Southern California systems.

Table G.10-7 shows the changes of congestions that were impacted most by the PTE project. It was observed that the PTE project partially mitigated Path 26 corridor congestion. The PTE project increased Path 15 corridors congestion slightly however. This is because the Path 26 corridor congestion occurred mainly when the flow was from south to north, and the Path 15 corridor is at the downstream of Path 26 when power flow is in this direction. COI corridor congestion decreased slightly mainly due to the flow along the Path 15 corridor from south to north increased, which pushed COI north to south flow back.

Table G.10-7: Congestion changes with PTE project modeled

Area or Branch Group	Congestion Cost ($M) Base case	Congestion Cost ($M) PTE-New	Change in Congestion Cost $M
Path 15 Corridor	21.77	26.59	4.83
COI Corridor	159.61	153.64	-5.97
Path 26 Corridor	61.06	32.59	-28.47

Production benefits

The production benefits of the two alternatives for the ISO's ratepayers and the production cost savings are shown in Table G.10-8.

Table G.10-8: Production benefits of the PTE project

	Base case	PTE case	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,765	9,778	-13
ISO generator net revenue benefiting	5,598	5,636	38
ISO transmission revenue benefiting	677	656	-21
ISO Net payment	3,490	3,486	3
WECC Production cost	13,070	13,034	36

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.

LCR reduction benefit

The PTE project can potentially reduce LCR requirements in local areas in southern California, as indicated in the 2019-2020 and 2020-2021 planning cycles TPP reports. In the 2023-2024 planning cycle, long term LCR was not assessed due to lack of clarity of gas-fired generator retirement assumption. The LCR reduction attributed to the PTE project as assessed in the 2019-2020 and 2020-2021 planning cycles was used in the LCR reduction benefit assessment. In this planning cycle, the PTE economic study request suggested that the PTE project has only one terminal in southern California, which is at El Segundo in the Western LA Basin area. This configuration is different from the one used in the 2019-2020 and 2020-2021 planning cycles, which had multiple terminus in southern California. Therefore, only the Western LA Basin's LCR reduction result in the previous planning cycles was used in the LCR reduction saving calculation in this planning cylce's assessment. The impact of the PTE project on other local areas was assumed to be small and not considered in this assessment. It should be noted that other factors can also impact the LCR reduction results, such as transmission upgrades approved since the 2020-2021 planning cycle, changes in load forecast, and changes in the CPUC IRP resource assumption.

The local and system capacity costs also changed from year to year. In this planning cycle, the capacity costs in the CPUC 2021 Resource Adequacy Report were used to recalculate the LCR reduction savings of the PTE project. The CPUC's capacity costs shown in Table G.10-9, which is the same table as Table G.3-2 and represent in this section. The LCR reduction benefit results assessed based on this approach are summarized in Table G.10-10.

Table G.10-9: Capacity cost in CPUC Resource Adequacy Report

Area	Weighted average capacity cost ($/kW-month) in CPUC 2021 RA report	In 2022 dollar
System	6.24	6.40
SP26	6.52	6.69
LA Basin	6.64	6.81

Table G.10-10: LCR reduction savings of the PTE project based on the capacity costs in the CPUC 2021 Resource Adequacy Report

	Pacific Transmission Expansion HVDC Project	
	Local vs System RA cost	Local vs SP 26 RA cost
LCR reduction benefit (Western LA Basin) (MW)	1,889	
Capacity value ($/MW-year)	4,922	1,476
LCR Reduction Benefit ($million)	9.30	2.79

For comparison, sensitivity assessment for LCR reduction savings of the PTE project 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. Note that the economic study request only provided system capacity cost and the LA Basin's local capacity cost. In this sensitivity assessment, the SP26 capacity cost was assumed to be the same as the system capacity cost, as the PTE economic study request did not provide SP26 capacity cost. The capacity cost assumption for this sensitivity assessment is summarized in Table G.10-11.

Table G.10-11: Capacity cost proposed in the PTE project economic study request

Area	Weighted average capacity cost ($/kW-month)	Note
System	Low: 2.21, High: 2.58	The PTE economic study request assumed the system capacity marginal cost would be set by battery storage
SP26	Low: 2.21, High: 2.58	The PTE economic study request did not provide the SP26 capacity cost. Assumed same as the system capacity cost in this assessment
LA Basin	Low: 4.86, High: 7.45	The PTE economic study request provided the LA Basin capacity cost

Comparing Table G.10-9 and Table G.10-11, it was observed that the system capacity costs in the CPUC report are higher than in the PTE economic study request, while the local capacity costs in the CPUC report are higher than the low end numbers and lower than the high end numbers of the local capacity costs in the PTE economic study request. Among these capacity cost assumptions between these two data sources there can be different combinations of the local and system capacity costs for calculating the LCR reduction savings. Two scenarios that provides estimate for the upper bounds of the LCR reduction savings were selected to conduct sensitivity assessments:

- Sensitivity 1: the local capacity cost in the CPUC report and the low system capacity cost ($2.21/kW-month) in the PTE economic study request were used
- Sensitivity 2: the high local capacity cost and the low system capacity cost ($2.21/kW-month) in the PTE economic study request were used

The LCR reduction savings results of these two sensitivity assessments are summarized in Table G.10-12.

Table G.10-12: LCR reduction savings of the PTE project in Sensitivity Assessments

	Pacific Transmission Expansion HVDC Project	
	Sensitivity 1 **Local cost in CPUC report vs System cost (low) in PTE study request**	**Sensitivity 2** **Local cost (high) in PTE study request vs System cost (low) in PTE study request**
LCR reduction benefit (Western LA Basin) (MW)	1,889	1,889
Capacity value ($/MW-year)	55,177	62,900
LCR Reduction Benefit ($million)	104.23	118.82

Cost Estimate

Based on the cost of $1850 million originally provided in the economic study request to the 2019-2020 transmission planning cycle, the capital cost of the PTE project was about $1950 million in 2022 dollar. 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 PTE project is about $2,535 million in 2022 dollar.

Benefit-to-cost ratio

The present values of the economic benefit of the PTE project are shown in Table G.10-13 along with the calculation of the benefit-to-cost ratio. The project economic life is assumed to be 50 year.

Table G.10-13: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of PTE project congestion mitigation alternatives

	Baseline study (all capacity costs are based on CPUC 2021 Resource Adequacy Report)		Sensitivity studies	
	Local vs System RA cost	**Local vs SP 26 RA cost**	**Sensitivity 1** **Local cost in CPUC report vs System cost (low) in PTE study request**	**Sensitivity 2** **Local cost (high) in PTE study request vs System cost (low) in PTE study request**
Production cost savings ($million/year)	3.32	3.32	3.32	3.32
Capacity saving ($million/year)	9.30	2.79	104.23	118.82
Capital cost ($million)	1,950	1,950	1,950	1,950
Discount Rate	7%	7%	7%	7%
PV of Production cost savings ($million)	48.99	48.99	48.99	48.99
PV of Capacity saving ($million)	137.28	41.18	1,539.14	1,754.56
Total benefit ($million)	186.27	90.18	1,588.13	1,803.55
Total cost (Revenue requirement) ($million)	2,535	2,535	2,535	2,535
Benefit-to-cost ratio (BCR)	0.073	0.036	0.626	0.711

Conclusion

The benefit-to-cost ratio result showed that there was not sufficient economic justification for recommending the PTE project as an economic-driven project in this planning cycle.

It should be noted that the assumptions around the value of reducing capacity requirements directly affect the value of the project. The PTE project's 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.10.4 PG&E Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion and mitigations

Congestion analysis

Path 15 corridor congestion and Moss Landing – Las Aguilas 230 kV line 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 portfolio. 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 these two constraints are summarized in Table G.10-14.

Table G.10-14: PG&E Path 15 corridor and Mosslandng – Las Aguilas 230 kV line congestions

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
MOSSLNSW-LASAGLSRCTR 230 kV line, subject to PG&E N-1 Moss Landing-Los Banos 500 kV	0	0	27,000	1,115	27,000	1,115
P15 Midway-Los Banos	8,140	351	0	0	8,140	351
MN_GT_11-GATES 500 kV line #1	0	0	8,044	274	8,044	274
GATES-GT_MW_11 500 kV line #1	0	0	4,953	405	4,953	405
LB_MN_11-MANNING 500 kV line #1	0	0	486	46	486	46
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	116	55	116	55
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	26	6	26	6
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	2	3	2	3

Congestion mitigation alternatives

Several alternatives for mitigating the Path 15 corridor congestion and/or the Moss Landing – Las Aguilas 230 kV line congestion, including combinations of alternatives, were assessed in this planning cycle. Table G.10-15 shows the congestion costs on Path 15 corridor, Path 26 corridor, and the Moss Landing – Las Aguilas 230 kV line, 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.

Table G.10-15: Alternatives for mitigating the Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion

	Path 15 corridor congestion		Path 26 corridor congestion		PG&E Moss Landing-Las Aguilas 230 kV congestion		
	Congestion Cost ($M)		Congestion Cost ($M)		Congestion Cost ($M)		
Base portfolio PCM case	21.77		61.06		27.00		
Alternatives	**Congestion Cost ($M)**	**Congestion Cost Change from Base ($M)**	**Congestion Cost ($M)**	**Congestion Cost Change from Base ($M)**	**Congestion Cost ($M)**	**Congestion Cost Change from Base ($M)**	**Note**
Alternative 1: Manning – Moss Landing 500 kV line and Moss Landing – Metcalf 500 kV line reconductoring, removing the existing Moss Landing – Las Aguilas 230 kV line	40.65	18.88	74.77	13.71	0	-27.00	Assuming that the new Manning – Moss Landing 500 kV line will use the right of way of the existing Moss Landing – Las Aguilas 230 kV line. Congestion on the Gates-Manning 500 kV line increased, which contributed to the Path 15 corridor congestion increased
Alternative 2: Moss Landing – Las Aguilas 230 kV reconductoring, keep the series reactor approved in the 2021-2022 plannign cycle	26.89	5.13	63.04	1.98	0	-27.00	The Moss Landing-Las Aguilas 230 kV congestion was mitigated. Congestion on the Gates – Manning 500 kV line and the Path 26 corridor increased slightly. Minor congestion on the Moslanding-Los Banos 500 KV line was observed
Alternative 3: Moss Landing – Las Aguilas 230 kV reconductoring, not keep the series reactor	26.24	4.47	61.05	-0.01	0	-27.00	The Moss Landing-Las Aguilas 230 kV congestion was mitigated. Congestion on the Gates – Manning 500 kV line increased slightly. Minor congestion on the Moslanding-Los Banos 500 KV line was observed
Alternative 4: Midway – Gates – Manning new 500 kV line	11.4	-10.37	67.65	6.59	24.76	-2.24	Congestion on the Manning – Los Banos 500 kV line increased, although the overall Path1 15 corridor congestion reduced
Alternative 5: Manning-Los Banos-Tracy new 500 kV line	32.89	11.12	64.01	2.95	8.32	-18.68	Congestion on the Gates – Manning 500 kV line increased, which contributed to the Path 15 corridor congestion increased

	Path 15 corridor congestion		Path 26 corridor congestion		PG&E Moss Landing-Las Aguilas 230 kV congestion		
	Congestion Cost ($M)		Congestion Cost ($M)		Congestion Cost ($M)		
Base portfolio PCM case	21.77		61.06		27.00		
Alternatives	**Congestion Cost ($M)**	**Congestion Cost Change from Base ($M)**	**Congestion Cost ($M)**	**Congestion Cost Change from Base ($M)**	**Congestion Cost ($M)**	**Congestion Cost Change from Base ($M)**	**Note**
Alternative 6: Manning – Moss Landing 500 kV line and Mosslaning – Metcalf 500 kV line reconductoring plus Midway – Gates – Manning new 500 kV line (alt 1 plus alt 4)	1.9	-19.87	90.27	29.21	0	-27.00	This is a combination of Alternative 1 and Alternative 4. Both path 15 corridor congestion and the Moss Landing-Las Aguilas 230 kV congestion can be mitigated, but the Path 26 corridor congestion increased.
Alternative 7: Moss Landing – Las Aguilas 230 kV reconductoring plus Midway – Gates – Mainning new 500 kV line (alt3 plus alt 4)	16.57	-5.20	68.37	7.31	0	-27.00	This is a combination of Alternative 3 and Alternative 4. Congestion on the Moss Landing – Las Aguilas, 230 kV line was mitigated, which is similar to Alternative 3. Path 15 corridor congestion was only partially mitigated and Path 20 corridor congestion increased, which are similar to Alternative 4.
Alternative 8: Manning-Los Banos-Tracy new 500 kV line, plus Midway-Gates-Manning new 500 kV line (alt 4 plus alt 5)	0.44	-21.33	79.7	18.64	13.55	-13.45	This is a combination of Alternative 4 and Alternative 5. Both path 15 corridor congestino and the Moss Landing-Las Aguila 230 kV congestion can be mitigated or partilly mitigated, but Path 26 corridor congestion increased.

Production benefits

The production benefits for ISO ratepayers and the production cost savings of all alternatives discussed above are summarized in Table G.10-16 .

Table G.10-16: Production Benefits of mitigation alternatives for Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion

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		9,765	5,598	677	3,490	13,070
Alternative 1: Manning – Moss Landing 500 kV line and Moss Landing – Metcalf 500 kV line reconductoring, removing the existing Moss Landing – Las Aguilas 230 kV line	**Post project**	9,765	5,612	685	3,467	13,065
	Savings	0	15	8	23	5
Alternative 2: Moss Landing – Las Aguilas 230 kV reconductoring, keep the series reactor approved in the 2021-2022 plannign cycle	**Post project**	9,672	5,571	659	3,442	13,072
	Savings	93	-27	-18	48	-2
Alternative 3: Moss Landing – Las Aguilas 230 kV reconductoring, not keep the series reactor	**Post project**	9,739	5,616	649	3,475	13,067
	Savings	26	18	-28	15	3
Alternative 4: Midway – Gates – Manning new 500 kV line	**Post project**	9,739	5,610	654	3,475	13,058
	Savings	26	12	-23	15	12
Alternative 5: Manning-Los Banos-Tracy new 500 kV line	**Post project**	9,680	5,597	643	3,439	13,064
	Savings	86	-1	-35	50	6
Alternative 6: Manning – Moss Landing 500 kV line and Mosslaning – Metcalf 500 kV line reconductoring plus Midway – Gates – Manning new 500 kV line (alt 1 plus alt 4)	**Post project**	9,869	5,699	660	3,511	13,056
	Savings	-104	101	-18	-21	14
Alternative 7: Moss Landing – Las Aguilas 230 kV reconductoring plus Midway – Gates – Mainning new 500 kV line (alt3 plus alt 4)	**Post project**	9,731	5,614	635	3,482	13,070
	Savings	34	16	-42	8	0
Alternative 8: Manning-Los Banos-Tracy new 500 kV line, plus Midway-Gates-Manning new 500 kV line (alt 4 plus alt 5)	**Post project**	9,877	5,685	671	3,521	13,065
	Savings	-112	88	-6	-31	5

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 all alternatives assessed for mitigating the Path 15 corridor and the Moss Landing – Las Aguilas 230 kV 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.10-17. Note that the cost estimate for Alternative 3 considered the avoided cost for not installing the series reactor that was previously approved by the ISO in the 2021-2022 planning cycle, which resulted in that the cost of Alternative 3 is less than the cost of Alternative 2.

Table G.10-17: Cost estimate of mitigation alternatives for Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion

Alternative	Capital Cost Estimate ($M)	Total Cost Estimate ($M)
Alternative 1: Manning – Moss Landing 500 kV line and Moss Landing – Metcalf 500 kV line reconductoring, removing the existing Moss Landing – Las Aguilas 230 kV line	631	820
Alternative 2: Moss Landing – Las Aguilas 230 kV reconductoring, keep the series reactor approved in the 2021-2022 plannign cycle	182	237
Alternative 3: Moss Landing – Las Aguilas 230 kV reconductoring, not keep the series reactor	161	209
Alternative 4: Midway – Gates – Manning new 500 kV line	741	963
Alternative 5: Manning-Los Banos-Tracy new 500 kV line	720	936
Alternative 6: Manning – Moss Landing 500 kV line and Mosslaning – Metcalf 500 kV line reconductoring plus Midway – Gates – Manning new 500 kV line (alt 1 plus alt 4)	1,372	1,784
Alternative 7: Moss Landing – Las Aguilas 230 kV reconductoring plus Midway – Gates – Mainning new 500 kV line (alt3 plus alt 4)	923	1,200
Alternative 8: Manning-Los Banos-Tracy new 500 kV line, plus Midway-Gates-Manning new 500 kV line (alt 4 plus alt 5)	1,461	1,899

Benefit-to-cost ratio

The present values of the economic benefit of the Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion mitigation alternatives are shown in Table G.10-18 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 not assessed in this planning cycle, as further clarity for gas-fired generator retirement in CPUC IRP is required to conduct such assessment.

Table G.10-18: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion mitigation alternatives

	Alt 1: Manning-Moss Landing 500 kV line and Moss-Metcalf reconductor	Alt2: Moss Landing-Las Aguilas reconductor, and keep reactor always in	Alt3: Moss Landing- Las Aguilas reconductor, and remove reactor	Alt4: Midway-Gates-Manning new 500 kV line	Alt5: Manning-Tracy	Alt6: Midway-Manning-Moss Landing-Metcalf (Alt1 plus Alt4)	Alt7: Midway-Manning and Reconductor Moss Landing - Las Aguilas (Alt3 plus Alt4)	Alt8: Midway-Gates-Manning-Los Banos-Tracy 500 kV line (Alt4 plus Alt5)
Production cost savings ($million/year)	23	48	15	15	50	-21	8	-31
Capacity saving ($million/year)	0	0	0	0	0	0	0	0
Capital cost ($million)	631	182	161	741	720	1,372	876	1,461
Cost to Revenue Ratio	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Discount Rate	7%	7%	7%	7%	7%	7%	7%	7%
Economic Life (year)	50	40	40	50	50	50	50	50
PV of Production cost savings ($million)	340	685	214	222	738	-310	118	-458
PV of Capacity saving ($million)	0	0	0	0	0	0	0	0
Total benefit ($million)	340	685	214	222	738	-310	118	-458
Total cost (Revenue requirement) ($million)	820	237	209	963	936	1,784	1,139	1,899
Benefit-to-cost ratio (BCR)	0.414	2.894	1.022	0.230	0.789	-0.174	0.104	-0.241

Conclusions

Multiple alternatives for mitigating the congestion on the Path 15 corridor and the Moss Landing – Las Aguilas 230 kV line were assessed.

Moss Landing – Las Aguilas 230 kV line reconductoring showed benefit to cost ratio greater than 1.0. Some of the 500 kV alternatives assessed in this planning cycle also showed meaningful production cost saving. Considering the potential changes in resource assumption in future CPUC IRP for the PG&E areas, including the assumptions for the Fresno/Kern area solar, Greater Bay area gas-fired generator retirement, and offshore wind, it is expected that the flow and congestion pattern on Path 15 corridor and the Moss Landing – Las Aguilas 230 kV line will have large variation from this planning cycle's results. Production cost saving of these transmission alternatives will be impacted as well. Also, the potential LCR reduction benefit was not considered in this planning cycle, which requires further clarity of gas-fired generator retirement assumption in CPUC IRP. Therefore, the ISO recommended to not approve any of these transmission alternatives for Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion mitigation in this planning cycle. Instead, the ISO will continue to investigate different transmission alternatives and their combinations for Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion mitigation in the next planning cycle using the new CPUC IRP resource assumption.