Department of Energy
Western Area Power Administration
Colorado River Storage Project Management Center
1800 South Rio Grande Avenue
Montrose, CO 81401

March 22, 2024

SENT ELECTRONICALLY

Bureau of Reclamation
Attn: LTEMP SEIS Project Manager
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The Western Area Power Administration (WAPA) provides the following comments on the Draft Supplemental Environmental Impact Statement (SEIS) for the Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) for your consideration. WAPA appreciates the Bureau of Reclamation (Reclamation) preparing this Draft SEIS, analyzing the possible impacts, and involving various Glen Canyon Dam Adaptive Management Program stakeholders.

WAPA is a federal Power Marketing Administration within the U.S. Department of Energy responsible for marketing and delivering wholesale electricity from 57 hydropower plants across a 15-state region of the central and western United States. WAPA sells power to preference customers such as federal and state agencies, cities and towns, rural electric cooperatives, public utility districts, irrigation districts, and Native American Tribes. WAPA's preference customers, in turn, provide retail electric service to millions of consumers across the West.

The Colorado River Storage Project (CRSP) Management Center is a WAPA division responsible for marketing power from the CRSP hydroelectric plants and its participating projects, as well as from the Provo River Project and Olmstead Project in Utah, and the Falcon-Amistad Project in Texas. CRSP operates and maintains over 2,300 circuit miles of high voltage transmission lines and related facilities in Arizona, Colorado, New Mexico, Utah, and Wyoming. Glen Canyon Dam is the most significant generating asset within the CRSP system and produces approximately 80 percent of power CRSP markets as part of the Salt Lake City Integrated Projects. Reclamation and WAPA operate the CRSP hydroelectric power plants and transmission system according to the CRSP Act of 1956 and related federal reclamation law authorities.

WAPA appreciates Reclamation's efforts in preparing the public Draft SEIS and shares the goal of preventing smallmouth bass establishment in the Grand Canyon. WAPA continues to be concerned about the status of the Basin Fund and its ability to absorb impacts from experimental releases at Glen Canyon Dam as well as the availability of replacement power to offset the lost hydropower generation that may be incurred by these experiments. Based on WAPA's review of the alternatives, WAPA anticipates that any of the action alternatives will significantly impact hydropower operations and WAPA's ability to serve its customers if implemented. In some scenarios, it could compromise Basin Fund viability within 2 to 4 years.

The CRSP Act requires Reclamation to operate the hydroelectric powerplants associated with the project "so as to produce the greatest practicable amount of power and energy that can be sold at firm power and energy rates." 43 U.S.C. 620f. Also, as a Cooperating Agency, WAPA shares Reclamation's responsibility to consider the best available science and data in evaluating the impacts of proposed actions. In WAPA's view, the public Draft SEIS is inadequate in its description and methods of addressing hydropower impacts, and it proposes actions inconsistent with Reclamation's mandate to operate the project to produce the greatest practicable amount of hydropower.

WAPA, as with all commentors, is limited in its ability to adequately comment on the Draft SEIS due to the insufficient description of hydropower impacts and methodology used in the draft analysis. Department of the Interior policy states: "Scientific information considered in Departmental decision-making must be robust, of the highest quality, and the result of as rigorous a set of scientific processes as can be achieved."[1] The best available science and data to assess the impacts to the CRSP hydropower resource are produced by the PLEXOS and GTMax modeling provided by the National Renewable Energy Laboratory (NREL) and Argonne National Laboratory (Argonne). WAPA is concerned that the public Draft SEIS instead includes data from competing models that have not been peer reviewed. In WAPA's view, including competing and untested modeling data creates unnecessary confusion and undercuts efforts to accurately describe the hydropower impacts.

Given the importance of this action and magnitude of potential hydropower impacts, WAPA has provided a revised Section 3.3 incorporating PLEXOS and GTMax modeling. This revision more accurately discloses and analyzes hydropower impacts and provides a more robust treatment of the data to evaluate the risk to the hydropower resource and the potential effects of the proposed action. WAPA submits the attached revised Section 3.3 as a drop-in replacement for the corresponding section included in the public draft SEIS. WAPA also submits draft reports from WAPA's Desert Southwest Region, NREL, and Argonne on transmission and grid impact studies.

Each Action Alternative would impact power generation at Glen Canyon Dam during summer months when power is in peak demand. These changes in operations would reduce available generating capacity at Glen Canyon Dam under all four bypass alternatives. This reduction in capacity would need to be replaced by purchases and generation from other sources. The estimated financial impacts from the proposed alternatives range from a net gain of $140,000 to a cost of $222.03 million, depending on the reduction in the amount of power generated and the cost to purchase power from replacement sources. The Cool Mix alternative in particular would have an average annual impact of $60-62 million over the 4 years, if implemented.

To provide adequate protection for the Upper Colorado River Basin Fund (Basin Fund), WAPA recommends Reclamation consider the higher-end potential financial impacts that may affect the Basin Fund. At the 90th percentile for this action, for example, the impacts of the Cool Mix Alternative over the next 4 years are modeled to be $145 million for a trigger at river mile 15, and $202 million for a trigger at river mile 61. These impacts could be

[1] 305 DM 3.4 https://www.doi.gov/scientificintegrity

greater as modeling does not take into consideration real-time market dynamics that may increase prices above those used for this analysis. The Basin Fund cannot absorb those expenses and effectively fund Reclamation and WAPA's operations.

The scope of this experiment, and its potential impacts, far exceed any prior experiment executed or envisioned as part of the Glen Canyon Dam Adaptive Management Program. For example, both the 2000 Low Summer Steady Flow experiment and the potential LTEMP Low Summer Flow experiment have estimated impacts on the order of about $25 million. In addition, WAPA and Reclamation have never implemented flow experiment of the type and magnitude proposed in this SEIS. As discussed further below, WAPA is concerned that these actions may impact the electrical system in ways that cannot be quantified beforehand. WAPA is uncertain of its ability to implement the experiment without substantial risk to the project, WAPA's physical infrastructure, and the reliability of the power grid in the western United States.

Among WAPA's comments and descriptions of impacts included in the attached revised Section 3.3, WAPA has identified the following actions it believes Reclamation should address prior to executing the action:

- Develop an implementation plan in consultation with WAPA that includes flexibility to minimize hydropower impacts. This includes considering the timing and implementation in relation to power demands on the bulk electric system. Reclamation may want to consider an option that provides increased generation during the evening super peak when wind and solar are less available to offset some of the impact identified in the SEIS.
- Establish off-ramps addressing both operational and financial considerations impacting WAPA's ability to operate and maintain the CRSP system, as well as a process agreement to provide WAPA adequate notice of experimental flows with a preferred 6 weeks of lead time to allow for purchase power needs.
- Secure funding to mitigate the financial impacts of the experiment on the Basin Fund. If not mitigated, this experiment could jeopardize the solvency of CRSP and force Reclamation and WAPA to suspend funding project requirements, including operation, maintenance, and capital expenditures, which could increase the likelihood of equipment failures and other impacts to the water and power system.
- Develop and implement a robust treatment plan that simultaneously addresses the three contributing factors leading to smallmouth bass establishment: entrainment, warm-water releases, and downstream habitat availability. Addressing one contributing factor without also addressing the others will be insufficient to prevent establishment. Cold water releases via bypass only treat a symptom of the problem. The primary cause of smallmouth bass establishment below Glen Canyon Dam is entrainment resulting from low reservoir elevations, and entrainment will continue even if this action is implemented.
- Consider, under the Colorado River Post-2026 Operations process, a strategy for maintaining a reservoir elevation of at least 3,570 feet during summer months to avoid entrainment of smallmouth bass and warm water releases (see Appendix A below for one such strategy).
- Modify the -12 mile slough so it does not provide smallmouth bass nesting or nursery habitat but supports other desired ecological functions. This could be an important and relatively simple activity to disadvantage bass establishment.

Meaningfully consider all public comments, including the revised Section 3.3, and re-issue the public Draft SEIS for comment once those comments and additional technical data have been incorporated. In WAPA's view, the current draft document does not include the best available scientific and technical information, and the public should have the opportunity to review and comment on such information. This action would help ensure the Secretary of the Interior has a complete analysis and related public comment to allow informed decisions on whether to undertake these experimental releases. Improving hydrology in the spring of 2024, improvements in humpback chub populations in Grand Canyon, and the relatively high level of uncertainty that smallmouth bass might establish between the Little Colorado River and western Grand Canyon suggest Reclamation has additional time to evaluate the impacts of the action alternatives and develop related strategies. Smallmouth bass have been present in western Grand Canyon for over 2 decades, and water temperatures have been suitable for spawning every summer in that part of the canyon since temperature loggers were added to the gauges in 2008. In WAPA's view, comprehensive strategies to prevent further establishment could provide security for humpback chub populations while also allowing continued operation of hydroelectric generating facilities.

WAPA remains committed to working with Reclamation to mitigate financial and operational impacts of the action alternatives. Such financial mitigation is critical even with implementation of off-ramps. WAPA also urges Reclamation to consider additional alternatives to reduce entrainment, lower release temperatures, and reduce downstream habitat for invasive non-native fish in developing this and other actions. Combined with added measures such as keeping reservoir elevations above 3,570 feet, installing a thermal curtain in the forebay, and modifying the slough, the program could conceivably reverse the likelihood of smallmouth bass establishment in Grand Canyon. WAPA looks forward to continuing to work with Reclamation to address these comments and concerns and implement strategies to produce the greatest practicable amount of hydropower while protecting downstream resources.

Sincerely,

Rodney G. Bailey
Senior Vice President
and CRSP Manager

Enclosures
Appendix

cc:
William Stewart, WStewart@usbr.gov
(Sent electronically with enclosure)

Appendix A: Proposed New Component Common to All Alternatives

Reclamation should consider adding an option common to all alternatives in the LTEMP SEIS that includes reallocating monthly release volumes to ensure reservoir elevations at Lake Powell are above about 3570 feet during the critical summer and fall months for entrainment and release temperatures. Eppehimer et al. (In Prep[2]) identified two critical January 1 minimum reservoir elevations that would reduce entrainment (>3570 feet) and reduce warm water releases (>3550 feet) in most cases. Monitoring fish presence and water temperatures in the forebay by USU, Reclamation, and GCMRC has shown that the risk of entrainment and the likelihood of warmwater releases are greatest from June to November under most hydrological scenarios. The objective of this alternative is to reduce the likelihood of entrainment and warm water releases by increasing reservoir elevation, if needed, from June to November by adjusting monthly release volumes while staying within the prescribed annual release volume.

Under the current interim guidelines, the annual release volume is to be released by the end of the water year (i.e., September 30). This creates a number of issues that substantially increases impacts on downstream resources *and* reduces the effectiveness of this as a tool to reduce entrainment and lower release temperatures. Changing when the annual release volume must be released to a calendar year (i.e., January 1 - December 31) could markedly increase the effectiveness of this as a tool and reduce impacts to downstream resources of this proposed tool, as well as impacts associated with balancing and equalization. Potential impacts to resources and other benefits to changing the annual release requirements to a calendar year are discussed below. Further modeling and investigation should be conducted to evaluate these impacts.

Risk of entrainment and warm-water releases

As noted above, the risk of entrainment and warm water releases are greatest from June to November under most hydrological scenarios. This is because fish are generally more abundant in the forebay during the summer and fall after the reservoir stratifies and become susceptible to entrainment if reservoir elevations are low enough to where the penstocks start to draw from the warm surface waters. Warm water releases occur are most likely to occur over the summer and fall because this is the time of year the reservoir experiences the greatest warming.

Moving release volumes has the potential to increase the elevation of Lake Powell by tens of feet. This may be enough to reduce the risk of entrainment and warm water releases over the summer and fall. However, the current rule in the Interim Guidelines of having to release the annual volume by the end of the water year limits the duration that reservoir elevations can be elevated to only the first half of the entrainment and warm water release window. September 30, reservoir elevations assume the same level as if no action had been taken, while the risk of entrainment and warm water releases generally continues into November.

Figures 3-30 and 3-31 show a hypothetical example of moving 400,000-acre feet (af) from February and March 2025 to the end of 2025 water year (August and September 2025) and the impact it would have on reservoir elevations. Monthly volumes and reservoir elevations were calculated from data obtained in the February 2024 24-Month Study. Moving this amount of volume results in an increase of 5.7 feet of reservoir elevation. Releasing the moved volume to the end of the water year brings reservoir elevations back to the same level as if no action had

[2] https://www.biorxiv.org/content/10.1101/2024.01.23.576966v1

been taken by September 30 and the benefit of increased reservoir elevation is lost before the risk of entrainment and warm water releases ends in November.

Figure 3-30
Lake Powell Elevations from the February 2024 24-Month Study with and without moving 400,000 acre feet (af) from February and March 2025 to the end of the water year in August and September 2025

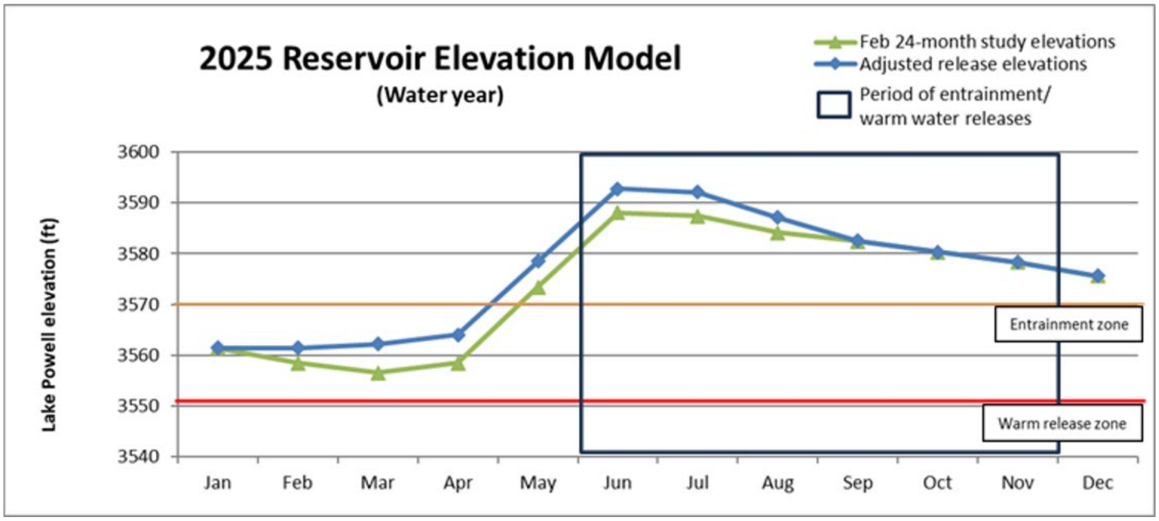
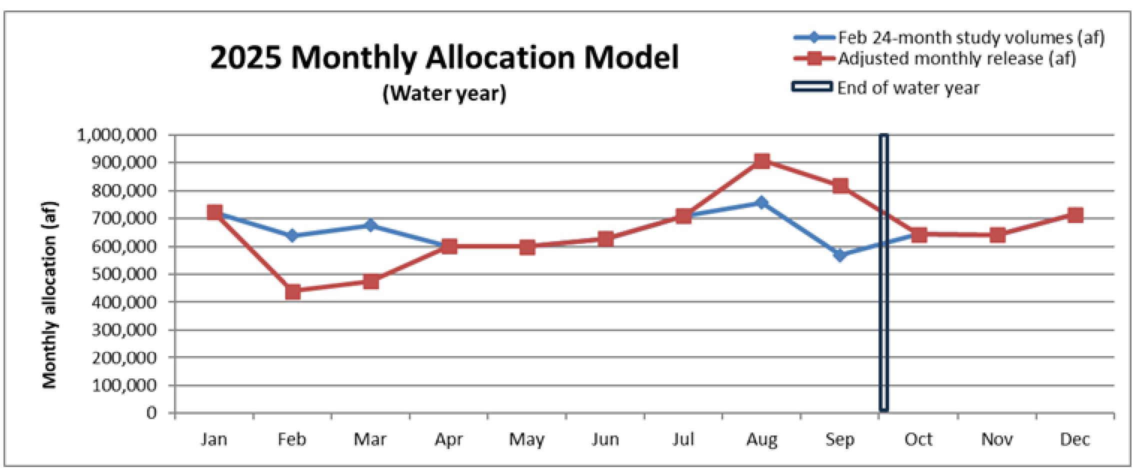


Figure 3-31
Glen Canyon Dam monthly release volumes from the February 2024 24-Month Study with and without moving 400,000 acre feet (af) from February and March 2025 to the end of the water year in August and September 2025



Moving the time of when the annual release volume has to be released to later in the winter, by either switching to a calendar year release schedule (i.e., January 1 to December 31), or through a Drought Response Operations Action, allows increased flexibility to keep reservoir elevations elevated to the end of the entrainment and warm water release window.

Figures 3-32 and 3-33 show another hypothetical example of moving 400,000 af from February and March 2025 to the end of the 2025 calendar year (November and December 2025). Monthly volumes and reservoir elevations were again calculated from data obtained in the February 2024 24-Month Study. Moving this amount of volume also results in an increase of 5.7 feet of reservoir elevation but by delaying the release of this water to November and December, the increased reservoir elevation is maintained through the summer and fall and to the end of the entrainment and warm water release window.

Figure 3-32
Lake Powell Elevations from the February 2024 24-Month Study with and without moving 400,000 acre feet (af) from February and March 2025 to the end of the calendar year in November and December 2025

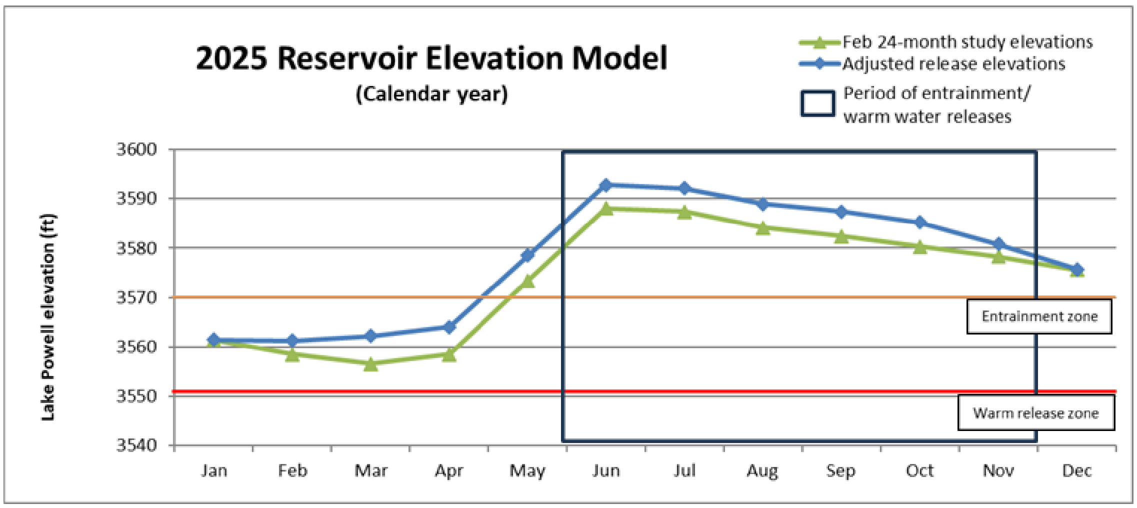
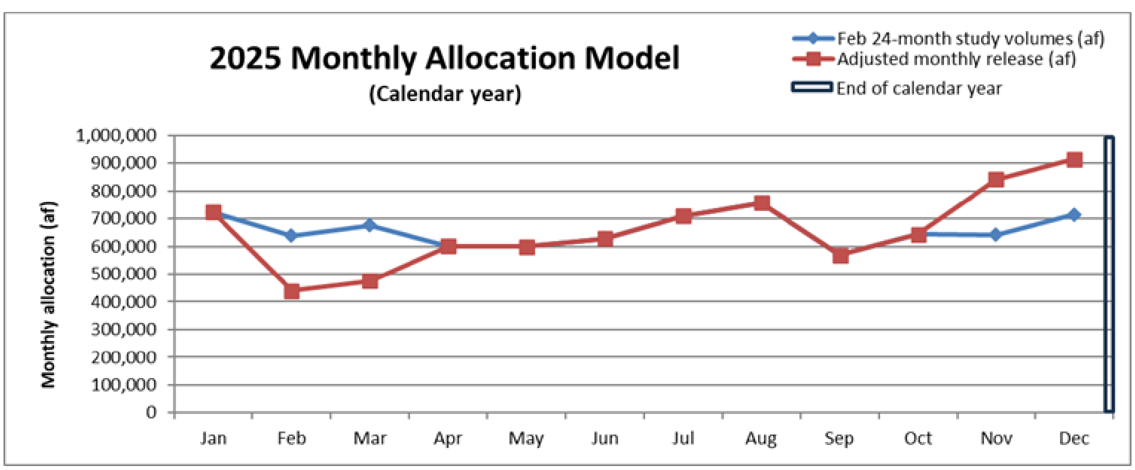


Figure 3-33
Glen Canyon Dam monthly release volumes from the February 2024 24-Month Study with and without moving 400,000 acre feet (af) from February and March 2025 to the end of the calendar year in November and December 2025



Hydropower

Moving water from shoulder months (February-May and September-November) to on-peak months (June-August and December-January) would most likely be a financial benefit to hydropower production. However, if bypass alternatives are implemented to cool release temperatures, moving volume to months where bypass is implemented could result in more bypass being needed in order to cool those higher releases. The impacts of lost hydropower generation from higher bypass volumes could substantially outweigh any benefit from moving volume into the summer. Releasing moved volumes later in a calendar year after the risk of entrainment and warm water release has past would be an improved option.

Sediment, HFEs, and beach area

Increasing release volumes in August and September would increase sediment transport during the monsoon season which could decrease the likelihood of an HFE. Sediment transport increases exponentially with increases in volume so moving water from a month that already has a lower volume to a month that already has a higher volume, results in an exponential increase in sediment transport. Higher volumes during the summer would result in greater inundation of camping beach area. Lower volumes in the spring would allow for increased aeolian sand transport and cultural resource protection. Moving volumes to shoulder months in the fall, which typically have lower initial release volumes, would be an improved option.

Recreation

Moving volume from months during the motor season (April 1 - September 15) may induce river navigation challenges for larger, motorized boats especially if minimum releases approach the minimums of 5,000 cubic feet per second (cfs) during the night and 8,000 cfs during the day. Moving release volumes from early in a calendar year to late in the calendar year could increase availability of boat ramps and other recreational activities at Lake Powell during the summer. Decreases in reservoir elevations during the summer would be of a similar, but inverted in scale, at Lake Mead. End of year reservoir elevations at Lakes Powell and Mead should be similar to a no action.

Decision making, release tiers, and shortage criteria

Neither option of moving monthly volumes within the current water year window, or moving to a calendar year window, should impact decision making, release tiers, or shortage criteria at Lakes Powell or Mead. Decisions on release tiers and shortage criteria at Lake Mead are currently made on a calendar year basis so changing Lake Powell release determinations to a calendar year window would bring the two facilities into sync with each other. Moving Lake Powell release determinations to a calendar year would also better accommodate balancing and equalization requirements between the two facilities by allowing additional time to make releases after the annual release volume is determined. WAPA considers moving Lake Powell to a calendar year would be an improved option for decision making at Lakes Powell and Mead.

3.0 METHODOLOGY

The methodology and power systems modeling developed for the LTEMP SEIS was designed to measure changes in economic, financial, and transmission metrics attributed to proposed changes in GCD Powerplant and Lake Powell Reseroir operations. Power system impacts are a function of hydropower conditions and experimental release specifications as defined by 12 LTEMP SEIS alternatives. Because future hydropower conditions are uncertain, metric values are estimated under an ensemble of forecasts as modeled by a tool that simulates the management of Colorado River Basin (CRB) water storage reserviors on a monthly timestep. The ensemble of forecasts is primarily driven by timeseries of CRB hydrologies, or traces, based on historical water inflow sequences that occurred during the past three decades.

Given monthly water releases and reservoir forebay elevations, hydropower centric models optimize temporal reservior water releases and GCD Powerplant generation at an hourly timstep. Using prices as a surrogate for marginal grid production costs, these models estimate economic and financial outcomes. Water releases through both GCD Powerplant turbines (to produce energy) and dam bypass channels (non-power release) are modeled for a 45-month period starting in January, 2024 through the end of Septemer, 2027, inclusive.

The operation of the WI power grid, where GCD resides, is also modeled. Grid modeling simulates the hourly dispatch of WI supply and demand resources, power flows on system high-voltage transmission lines/corridors, and the implications of GCD changed operations on the WI grid. This study also examines the effect of experimental releases on Colorado River Storage Project (CRSP) Office's financial transactions and on the use of contractual transmission arrangements constrained by line limits.

The geograpical scope of water and power systems analyzed for this study varies by topic/area. In general, modeling fidelity is relatively high when analyzing a small region and/or a small set of system componets. However, as the scope broadens, model fidelity tends to decrease to reduce the computational burden. Table 3.1 provides an overview of the geographical scope, time step, and relative degree of model fidelity.

Although the scope of the study is broad and interactions between GCD and larger system processes are considered to the extent possible, the study methodology "separates" GCD operations from the rest of Salt Lake City Area/Integrate Projects (SLIP) hydropower by holding generation profiles for those resources fixed among all alternatives. This method isolates the economic and financial implications of experiments conducted under an alternative to only GCD.

Measuring LTEMP SEIS alternative impacts on the timeframes and footprints shown in Table 3.1 is an extremely difficult problem. Therefore, modeling assumptions and simplifications were made to keep computer run times reasonable and within analysis time and budget constraints. Simplifying assumption regarding the representation of the CRB, WI power grid and the SLIP system are expected to affect modeling results. However, to mitigate the influences of modeling simplifications on bottom-line results, the study methodology uses a comparative approach in which action alternatives are compared to a No

Action Alternative. Any systemic inconsistencies/errors in results are assumed to occur in all alternatives. Therefore, the relative differences among alternatives are expected to be robust because errors in the No Action Alternative also tend to be present in action alternatives, thereby eliminating or reducing the modeling errors between alternatives. Using this approach to analyze GCD Powerplant changed operations on value streams is consistent with study goals to identify the relative ranking and magnitude of alternative impacts using the No Action Alternative as a benchmark.

As described in more detail in the results section, most of the economic and financial costs attributed to LTEMP SEIS experimental water releases are primarily attributed to experiment water bypass requirements. Lost GCD generation during experiments increases total grid economic costs because this lost generation must be replaced by increasing power generation at one or more other grid suppply resources to maintain a system supply and demand energy balance. Other factors such as the reallocation of monthly water release volumes during a year and associated changes in Lake Powell's forebay elevation also impact bottom-line results. This methdology directly measures those major impacts with a high degree of fidelity.

3.1 Power System Modeling Components

A LTEMP SEIS power system modeling framework was specifically designed for this study. It primarily utilized several water and power systems models and data from external sources. Table 3.2 lists key models by topic/impact area. Key external data sources include SLIP hydropower plant characteristics and operating criteria, an ensemble of future CRB inflows, energy price forecasts published by ARGUS, and historical Firm Electric Service (FES) customer requests for energy under CRSP FES contracts. It also uses a SLIP topology represented by power system nodes and links, contractual transmission constraints, and CRSP 3rd party transmission agreements. WI grid modeling is supported by a comprehensive supply, demand, and transmission system data set.

Key LTEMP SEIS modeling framework components and basic functionality are as follows:

ARGUS Price Forecasts are long-term monthly projections of on-peak and off-peak energy market prices for numerous U.S. zones and hubs. For the LTEMP SEIS, Palo Verde market hub projections were used by hydropower centric models. These data are indirectly used for both economic and financial analyses. These prices are a surrogate for the marginal value of WI energy at the Palo Verde market hub.

CRMMS is a Bureau of Reclamation (Reclamation) model that supports operational decision-making and planning for the CRB. It simulates water basin operations using a topology of inflow points, river reaches, diversions, reservoirs, canals, pipelines, and other water-resource features. CRMMS uses a monthly inflow sequence and schedules water releases from 12 Reclamation reservoirs based on prescribed operational rules to project monthly conditions. For LTEMP SEIS power system analyses, CRMMS projections of end-of-month reservoir forebay elevations and monthly total water release volumes are used as input data for the hydropower centric optimization models for each of the forementioned 30 trace forecasts. This includes CRMMS projections for Lake Powell and for all other major Federal Upper CRB hydropower resources.

The **Shaping Algorithm** is a temporal down-scaling tool developed by Argonne that generates synthetic time series based on a reference time series, or "shape", and target statistical values. For this study, the Shaping Algorithm is used to create a time series of prices of at GCD. The reference shapes are WECC hourly load profiles, and ARGUS monthly on-peak and off-peak price forecasts serve as target values.

GTMax SL Model is a hydropower centric model that simulates hourly hydropower operations over a study period and for each hydropower condition (i.e., trace). For this study, one representative week is optimized for each month. Results are then extrapolated to the rest of the days in a month. GTMax SL models all Salt Lake City Area Integrated Project (SLIP) hydropower plants and power market transactions to serve CRSP FES customer Deliverable Sales Amount (DSA) loads. Water releases comply with all physical and institutional operating criteria including environmental constraints and water delivery obligations with a primary objective for generation to follow/serve FES customer loads. In this analysis, GTMax SL is used to measure the relative economic cost of conducting experimental flows under each of the action alternatives relative to the No Action Alternative. Key outputs from GTMax SL are hourly GCD generation, power and non-power releases from Lake Powell, and economic values.

PLEXOS is a Production Cost Model (PCM). For the LTEMP SEIS analysis, it optimizes the operation of WI grid supply resources and estimates transmission system power flows to meet energy demand. Model solutions are constrained by both physical and institutional limitations. As part of its modeling process, it schedules unit commitments (i.e., when individual generating units are turned on and off) and performs a least-cost economic dispatch while simultaneously complying with all system constraints, including transmission flow limits and reserve provisions. Because the entire WI is a single intertwined system, an event or action at one grid component affects one or more other grid components. Therefore, for this study, PLEXOS measures WI component responses to alterative GCD operations. Key outputs from PLEXOS for this study include Locational Marginal Prices (LMPs) at several CRSP footprint nodes, sources of replacement energy that is lost from GCD when an experiment is conducted, and transmission congestion on key transmission system elements.

SLIP Energy Routing Model (SERM) determines optimal pathways that "*contractually*" transport SLIP energy from supply sources to sinks. In this context, supply resources include all SLIP hydropower resources and energy market power purchases at key grid points. Energy sinks include FES customer loads that are assigned to several different power grid Points of Delivery (POD) and energy market sales at market trading points. SERM also simulates Salt River Power (SRP) Exchange agreements with the CRSP Office in which generation from the SRP Craig, Hayden, and Four Corners thermal power plants serve CRSP FES customers' loads in the northern and four corners area of the SLIP footprint. In exchange, on a one-for-one MWh basis at the same time, GCD Powerplant generation is delivered to a specific SRP POD. Under another SRP agreement, energy is wheeled from SRP thermal powerplants to the SRP POD. Because of transmission constraints and transmission energy losses in the grid, LMPs vary by across the SLIP footprint. CRSP energy marketers utilize its far-reaching transmission network to strategically buy and sell energy at various locations in its footprint. Market purchase and sale prices at these locations are typically different from the LMP at GCD (i.e., a measure of GCD economic energy value). The SERM is therefore used to optimize hourly energy market purchases and sales and measure implications of action alternatives on CRSP Office finances.

3.2 Power System Modeling Framework Interactions and Dynamics

The LTEMP SEIS modeling framework, components, and information flows are shown in Figure 3.1. It was tailored to estimate the impacts of LTEMP SEIS alternatives on grid energy economics, CRSP Office finances, and the power transmission system in terms of (1) WI high voltage tranmission lines power flows and (2) the scheduling of CRSP energy on contractual pathways that link energy sources to energy sinks. Contractual energy transport is modeled in a footprint that includes SLIP hydropower supply resources, CRSP FES power customer energy sinks, and transmiswell sion lines/pathways that connect these sources and sinks.

Hydropower Ensemble Projections

Another key input into hydropower centric models are hydropower conditions as driven by basin inflows. Because the hydropower outlook is uncertain, WI economics, CRSP financial implications, and transmission impacts were estimated under an ensemble of 30 plausible hydropower futures (traces) during the study period. These outlooks were generated by CRMMS for each of the 12 alternatives and a counterfactual case. Utilized by both GTMax SL and SERM, CRMMS outputs vary by both trace and alternative/case. Key CRMMS model projections that are used by other framework components include end-of-month forebay elevation and monthly reservoir water release volumes at large SLIP hydropower plants.

Under the No Action Alternative, CRMMS assumed that High Flow Experiments (HFEs) would be periodically conducted as required by the LTEMP Record of Decision (ROD). During an HFE, a large volume of water is released requiring the shifting (reallocation) of water release volumes from one or more months of the year to the HFE month. The counterfactual CRMMS model run is identical to the No Action except it assumes that no HFEs are conducted and, therefore, it does not reallocate monthly release volumes to support HFEs. As explained in more detail in the following section, this counterfactual case provides the basis for computing CSRP Office monthly energy offers to its FES customers.

Initial Market Prices

As shown in Figure 3.1, energy prices input into GTMax SL are based on ARGUS projections for the Palo Verde market hub. Published by ARGUS on December 6, 2023, the forecasts used for this study are in terms of monthly off-peak and on-peak prices. However, both GTMax SL and SERM require hourly price inputs.

Because there is a strong correlation between historical loads/net loads and price levels, for this application, WI total hourly load shapes serve as a guide to pattern prices. The result is a profile of hourly price values during a month such that the average price during “on-peak” hours (hours 8 to 23) exactly matches the ARGUS on-peak monthly projection and the average price during “off-peak” hours (hours 24 and 1 to 7) also equals the ARGUS off-peak price projection.

This temporal down-scaling of market prices was performed by the Shaping Algorithm. It alters a reference time series, or profile, so that a specified list of statistical values of the reshaped profile equal the target values. For the LTEMP EIS power systems analysis, hourly prices were “shaped” based on a WI temporal load profile over a one-year period (reference timeseries) such that average off-peak and on-peak prices equal ARGUS projections (target values). To produce realistic time series patterns, the Shaping Algorithm identifies the optimal continuous monotonic shaping function that converts the original shape (hourly WECC loads profile) into the new shape (hourly prices) using optimization techniques. For this application, the Shaping Algorithm both maximizes the smoothness of the shaping function and minimizes the price range.

FES Customer DSA Loads

For LTEMP SEIS modeling and analysis, FES customer DSA loads are separated into two different types; namely, loads attributed to GCD Powerplant generation and loads attributed to all other SLIP hydropower plant generation. To estimate GCD FES loads, GTMax SL models GCD as an isolated power resource using CRMMS Lake Powell end-of-month reservoir elevations and monthly water release volumes for the counterfactual case. It also uses the hourly price vectors rooted in ARGUS forecasts.

GCD DSA Loads

The main objective of the CRSP Office is to use SLIP hydropower to serve FES DSA customer loads. However, at this point in the modeling process, hourly DSA loads have not yet been estimated so generic FES hourly load profiles are input into GTMax SL. This generic FES profile used both in this process and others is based on historical customer scheduling behaviors. Another modeling simplifying assumption for estimating customer DSA load offers is that market prices input into GTMax SL are static; that is, dynamics between the WI and GCD operations are not takin into account. Because the purpose of this first round of GTMax SL runs is to compute total monthly GCD generation quantities and associated DSA offers, a precise hourly GCD dispatch and power economics/financials are unnecessary. As discussed in more detail in a later section, these details are addressed in subsequent modeling steps.

GTMax SL converts hourly water releases into GCD Powerplant generation based on Lake Powell forebay elevations. Total monthly generation is then multiplied by a transmission loss factor to estimate the amount of GCD energy that the CRSP Office will offer its FES customers. Furthermore, because FES customer DSA energy offers are hydrologically driven, monthly GCD DSA offers fluctuate monthly over the study period and differ by trace.

Once total monthly GCD DSA energy is determined, hourly customer requests for DSA served by GCD generation are approximated based on a typical FES customer load shape. This profile is scaled such that the total FES customer load summed over all hours in a month equals GCD delivered energy (generation minus losses).

The CRMMS counterfactual case (No Action Alternative without HFEs) is used to compute GCD FES offers because the CRSP Office and FES customers do not pay for any costs incurred by any experiment as stipulated by LTEMP provisions. This includes shifting of monthly water volumes to support an experiment, such as HFEs. Experimental costs, referred to as a non-reimbursable expense, reduce the amount of money the CRSP Office reimburses to the U.S. Treasury for the construction of GCD dam and powerplant. In simpler terms, CRSP Office DSA energy offers assume that experimental releases are never conducted.

Because experimental costs are non-reimbursable, including HFEs and experiments required under an alternative (e.g., cold shock and cold mix), all alternatives assume the same time series of hourly FES customer energy requests as determined by CRMMS counterfactual traces. Therefore, during years that an HFE does not occur in a trace under the No-Action Alternative, GCD energy production minus transmission loss is identical to GCD DSA loads. However, whenever an experiment requires monthly water releases to be reallocated among months of the year, DSA loads during two or more months of the year do not match the amount of GCD energy that is delivered to customers. In these situations, CRSP Office energy purchases are needed to fully serve customers loads during energy short months and sales are required during energy long months.

Other SLIP DSA Loads

DSA FES loads attributed to other SLIP large hydropower resources are based on results from a recent GTMax SL simulation of the entire SLIP system (including GCD). This model run was driven by Reclamation's CRMSS results from the October 2023 24-month study most probable case. Other SLIP large hydropower plants included in this GTMax SL run include CRSP Blue Mesa, Morrow Point, Crystal, and Flaming Gorge Powerplants, and the Fontenelle Powerplant of the Seedskadee Project. The GTMax SL objective function for this run simultaneously maximizes the CRSP load following (primary) and economic value (secondary) operating objectives to simulate the operation of these five hydropower resources along with GCD. Within the bounds of all operating constraints, the output is an hourly optimal schedule of plant-level energy generation and both turbine and bypass water releases.

The GTMax SL configuration and its key operating constraints for the "other" five SLIP large hydropower plants are shown in Figure 3.2 below. It represents all the physical CRSP and Seedskadee Powerplants and downstream flows at the Jensen Gage in the Green River. GTMax SL optimizes operations during all hours of the study period, based on CRMMS data and hourly-shaped ARGUS market prices for the Palo Verde market hub. It is assumed that LTEMP SEIS alternatives and HFE releases conducted at GCD do not affect the operations of these five upstream resources. Therefore, this configuration and model results were used for all alternatives.

As shown in Figure 3.2, there are two water cascades. The first cascade, consisting of the Fontenelle and Flaming Gorge Reservoirs, is explicitly included in the CRMMS model. However, because these two reservoirs are relatively far apart and hourly reservoir elevations for these two locations are not computed in GTMax SL, this water link is not represented in GTMax SL. The Aspinall Cascade includes the Blue Mesa, Morrow Point, and Crystal reservoirs. Operationally, this cascade is very tightly coupled and therefore modeled with a high degree of fidelity in GTMax SL. CRMMS provides information about monthly water inflows into cascaded reservoirs, water release volumes, reservoir elevations, and side flows that occur between connected reservoirs, and reservoir evaporation.

Operating constraints include maximum and minimum reservoir elevation limits imposed on Aspinall Cascade reservoirs including a complex set of restrictions at the Crystal Reservoir that bound the rate of elevation changes over time. These include Crystal Reservoir elevation drawdown rates over one-day and three-day periods. To ensure that water releases do not violate reservoir operating constraints, the GTMax SL model computes hourly reservoir water mass balances and elevations using reservoir elevation-volume functions. Water balancing equations account for water inflows, side flows, evaporation, upstream reservoir water releases, and all releases from the reservoir of interest.

The forebay water elevation at Blue Mesa must always be between 7,393.0 feet (ft) and 7419.4 ft above sea level and the elevation range for Morrow Point is between 7,125.0 ft to 7,160.0 ft. When elevation at Morrow Point drops below 7,144.0 ft during the summer tour boat season, there is a daily change limit of 3.0 feet. At Crystal the elevation range is between 6,733.0 ft and 6,755.0 ft and the daily drawdown limit is 10.0 ft except during March through June when a more stringent limit of 4.0 ft is imposed. The Crystal daily drawdown limit is reduced to 0.5 ft from March through June when the reservoir elevation drops below 6,748.0 ft.

Flows at the Jensen Gage are restricted to daily stage changes of 0.1 meters/day. Because gage flows are directly affected by upstream water releases from the Flaming Gorge Reservoir, GTMax SL models gage flows that comply with the daily gage constraint. To optimize Flaming Gorge operations, water travel time distribution (WTTD) functions are used to estimate the time it takes water to flow through Green River reaches, and the attenuation of releases as water travels downstream. For this study, two reaches are defined. The first is from the Flaming Gorge Dam to the confluence of the Green and Yampa Rivers and the second is from this confluence down to the gage.

WTTD are a function of hydrological condition. Therefore, for this study monthly WTTD functions were derived from Streamflow Synthesis and Reservoir Regulation (SSARR) model outputs based on CRMMS monthly and hourly water releases from Flaming Gorge. SSARR was written by the Army Corps of Engineers. In general, it takes about 24 hr for the first fractional amount (less than 1%) of a Flaming Gorge release to reach the gage. Typically, all water passes the gage 48 hr after the release. Gage readings are computed using a function that relates the flow rate at the gage to the gage stage. Yampa River water flows into the Green River are based on historical data.

SLIP small hydropower resources are not included in the 24-month study but are modeled based on generation profiles from WAPA’s power operations and maintenance (PO&M-59) historical data reports. These small plants include Deer Creek, McPhee, Towaoc, and both upper and lower Molina Powerplants. Total GTMax SL generation for each month was then summed over all SLIP hydropower plants excluding GCD. “Other” SLIP FES monthly energy offers are set equal other SLIP generation less transmission losses. Typical hourly FES load profiles are then scaled such that monthly FES loads equal delivered other SLIP generation (generation minus transmission losses).

As a modeling simplification, DSA loads attributed to other SLIP hydropower resources are assumed to be identical under all alternatives and traces. Because LTEMP SEIS economic calculations are based solely on GCD operations, this simplification is inconsequential. However, as described in more detail in a later section, this simplification may potentially have a minor impact on the calculations of CRSP financial costs and estimates of contractual transmission schedules.

GCD Temporal Generation Patterns

The GTMax SL model runs are performed a second time to construct temporal patterns of GCD Powerplant generation. It represents GCD as an "isolated" plant; that is, without connections to the rest of the SLIP system and, except for market price signals, the WI. GTMax SL optimizes hourly water releases from Lake Powell and hourly GCD Powerplant generation. Operations are primarily driven by GCD generation patterns; namely, (1) hourly customer loads for each trace and (2) a single vector of shaped hourly energy market prices rooted in ARGUS projections for the Palo Verde market hub. This round of GTMax SL runs is more refined and comprehensive than initial runs used to estimate monthly DSA offers using counterfactual traces. In these runs, hourly GCD FES customer loads are trace-specific and runs were performed for each alternative and trace (12 X 30 = 360 multi-year simulations). The result is nearly one-million hourly generation, turbine water, and non-turbine water values for each alternative.

GCD operations comply with ROD operating criteria that includes minimum release rates that vary by the hour of day, hourly maximum release rates, limits on the change in water release rates from one hour to the next (ramp), and the maximum change in release rate over 24-hour rolling periods. The GCD maximum hourly up-ramp rate is 4,000 cubic-feet-second (cfs) and the hourly maximum down-ramp ramp rate is 2,500 cfs. The minimum release rate is 8,000 cfs beginning at 7 AM through 7 PM. The minimum is 5,000 cfs during all other hours of the day. Specified in cfs/day the daily change limit is calculated as the product of the monthly volume release volume in acre-feet (AF) and a multiplier that varies by month of the year. During June, July, and August the daily change multiplier is ten and during other months of the year it is nine. In addition, the daily change is capped at 8,000 cfs. The maximum release rate is 25,000 cfs. However, during high release months, if a 25,000 cfs rate is insufficient to release all of the target monthly release volume, then the maximum is increased, but hourly ramp rate limits are set to zero (flat flow).

All operating criteria are based on hourly average releases, not instantaneous flow rates. In addition, GTMax SL reserves GCD Powerplant capacity to fulfill spinning reserve and regulation service requirements for the Western Area Power Administration, Colorado-Missouri Region (WACM) Balancing Authority (BA) that the Western Area Power Administration (WAPA) operates.

It should be noted that, at this stage of the modeling process, GTMax SL uses the same vector of hourly prices during the 45-month study period (i.e., 32,832 hourly shaped prices) for all 12 alternatives and 30 hydropower traces. Therefore, there is an implicit assumption that GCD LMPs are static; that is, generation levels do not affect grid prices. Because the feedback between GCD operations and the WI power grid are not accounted for at this stage of the modeling process, alternative economic costs and CRSP financial implications are <u>not</u> computed.

PLEXOS Reference Point LMPs

The next stage of the modeling process uses PLEXOS to calculate LMPs at GCD and at key market nodes in the SLIP footprint. Because the representation of SLIP hydropower resources in PLEXOS is relatively coarse, the LTEMP SEIS modeling process prescribes fixed hourly SLIP generation patterns for PLEXOS. These fixed generation patterns are based on hourly average generation profiles projected by GTMax SL; that the average generation level for each of the 32,832 study hours uses 360 values (30 traces X 12 alternatives).

This approach is a modeling simplification because, ideally, SLIP operations should be represented as a set of constraints and decision variables that represent SLIP operations. Its operations should then be optimized simultaneously with all other WI supply and demand resources. However, the PLEXOS model was not designed to have a high-fidelity representation of SLIP hydropower operations. Also, the LTEMP SEIS methodology creates a chicken-and-egg problem because WI grid LMPs are a function of GCD generation whereas optimal GCD generation is influenced by market prices.

Although technically there are inconsistencies in the current approach that prescribes SLIP generation patterns, its impacts on the relative ranking, direction and magnitude of alternative outcomes are expected to be very small for several reasons. First, the primary operating objective of GCD is to serve FES customer load regardless of market prices. Secondly, when market transactions are needed to fully serve FES DSA load or sell excess generation, relative price patterns (ranking of highest price hour to lowest price hour) matter more than price magnitude when it comes to operating decisions on when to buy and sell energy. Thirdly, because GCD is a very small component of WI total resources, it has only a minor influence on grid LMPs. Therefore, in most situations, its operations are unlikely to alter the relative price patterns/ranking.

PLEXOS Grid Response to GCD Energy Production

Although static ARGUS prices were used by GTMax SL to estimate GCD generation patterns, bottom line financial and economic calculations incorporate a simple representation of WI grid responses to GCD Powerplant generation. To estimate grid responses to GCD energy production, the PLEXOS model was run under two extreme conditions. The first run considered GCD hourly generation at a very low output level during all hours of a month and the second run assumed GCD hourly generation at a very high level.

The two extreme GCD generation levels varied by month over the study period as determined by the second round of GTMax SL runs that optimized hourly GCD hydropower operations during all hours of the study period, under each of the alternatives, and for all traces. The minimum hourly generation level during a month over all alternatives and traces was then identified for each month of the study period and used for the low generation extreme in PLEXOS. Similarly, the maximum PLEXOS extreme was set equal to the GTMax SL maximum generation level over all alternatives, traces, and hours. Both runs assumed identical hourly generation levels at all other SLIP hydropower plants except GCD.

Average monthly GCD LMPs estimated by PLEXOS were then computed for these two extreme runs. In general, the PLEXOS low GCD generation run estimated slightly higher average LMPs than the high GCD generation run. This result is consistent with the basic principle of least-cost production cost models (PCM) that dispatch generating units in order from lowest to highest production cost. That is, PCMs assume that only generating units with low production costs are dispatched when electricity demand is low. However, as demand grows, units that are more expensive to operate are then dispatched. Therefore, the marginal cost to serve load increases as a function of higher demand as more expensive units are needed to serve load. Similarly, when GCD reduces its output from the high extreme level to the low extreme, GCD generation is replaced with power production from unit(s) with a higher marginal production cost.

Based on PLEXOS results for the two runs, Argonne constructed a Price Reaction Function (PRF) and computed monthly function coefficients. Basically, the PRF estimates the percent change in GCD LMP as a function of the percent changes in GCD output such that the LMP is slightly lower when GCD produces high amounts of energy relative to when it produces less energy. The PRF was then applied to prices used by the GTMax SL model to compute the economic cost of each alternative. LMPs were adjusted based on the difference between the average GCD hydropower generation pattern/level described above and the generation pattern/level for a specific alternative and trace. When generation for a specific situation is higher than the average in a specific hour (e.g., noon on July 15, 2025) applying the PRF slightly decreases the GCD LMP. On the other hand, if the generation is less than the average, applying the PRF slightly increases the GCD LMP. Using this methodology, unique price vectors are produced for each hydropower trace and alternative consistent with PLEXOS LMP grid response to changed GCD Powerplant operations.

Economic Costs of LTEMP SEIS Alternatives

The economic cost of a LTEMP SEIS action alternative is calculated as the GCD economic value difference between an action alternative and the No Action alternative. To calculate GCD economic value, GCD Powerplant temporal generation patterns are multiplied by market price vectors that are adjusted for WI grid responses. Ideally, GTMax SL should be run again using the new price vectors, however, given the study time and budget limits, performing another round of GTMax SL runs was not possible. None-the-less, generation patterns produced by another round of GTMax SL runs were not expected to change the relative ranking, direction, and magnitude of alternative outcomes because the primary operating objective for GCD is to serve FES customer load regardless of market prices. Also, the timing of market energy purchases needed to fully serve FES loads or sell excess generation would not change under most conditions because grid price reactions to GCD generation are small.

Last, but not least, because the methodology measures economic outcomes on a comparative basis (e.g., action minus no-action), any errors caused by this assumption tend to cancel as the same simplifying assumption is used for all alternatives.

CRSP Office Financial Costs and Contractual Power Flows

The financial implications of a LTEMP SEIS alternative on CRSP Office energy transactions and associated financial outlays are computed with SERM. It also determines optimal pathways that "*contractually*" transport power from CRSP supply sources to energy sinks. Supply resources include all SLIP hydropower resources and energy market power purchases at designated grid points. Energy sinks include FES customer loads that are assigned to several different power grid PODs and energy market sales at market trading points.

SERM also simulates a wheeling contractual agreement with SRP that specifies WAPA's obligation to wheel/contractually transport power generation from SRP generating resources at the Craig, Hayden, and Four Corners to the SRP POD. An exchange agreement with SRP whereby generation from SRP supply resources will, under some conditions, serve CRSP FES customers' loads in the northern and four corners area of the SLIP footprint. In exchange, on a one-for-one MWh basis at the same time, GCD Powerplant generation is delivered to the SRP POD.

Because of time and budget constraints, SERM was only run for the New Window (NW), Cold Mix (CM) and Cold Shock (CS) alternatives with target locations on the Colorado River that is 15 river miles (RM15) below GCD and at the Little Colorado River confluence (RM61). Furthermore, SERM runs were only conducted during the months and traces where a LTEMP SEIS alternative triggered an experimental release.

SERM Network Given/FIXED SLIP Energy Supplies

The network of nodes and links used by SERM to represent the SLIP system is shown in Figure 3.3. SLIP hydropower plants (blue squares) are represented in the SERM network as energy supply nodes. GCD Powerplant hourly generation levels are set equal to those projected by GTMax SL runs that optimize hourly generation patterns (second round of runs) for all alternatives and traces (see the section labeled "*Glen Canyon Dam Temporal Generation Patterns*"). Hydropower generation from CRSP other large hydropower plants (Blue Mesa, Morrow Point, Crystal, Fontenelle and Flaming Gorge) are set equal to the hourly amounts optimized by the GTMax SL model run using the hydrology forecast from the October 2023 24-month study. SLIP small hydropower resources not included in the 24-month study use generation profiles based on PO&M-59 historical data. These small plants include Deer Creek, McPhee, Towaoc, and both upper and lower Molina Powerplants.

SERM Network Energy Given/Fixed Sinks

FES DSA loads (orange triangles) are represented in the model as energy sinks nodes. During each hour, the sum of the loads across all load nodes equals the load input into GTMax SL runs. Consistent with GTMax SL assumptions DSA loads are unique for each counterfactual trace.

The spatial distribution of hourly total DSA load is based on a mapping of individual customer POD for CRSP energy and historical levels of energy requests at PODs. Because there is a limit on the link from the "Vernal" junction node (VNL) to the "Utah all Federal Vernal" node, FES loads above 140 MW are shifted to the "Utah all Federal" load node that is linked to the "Glen Canyon" junction node labeled GC2.

SERM Energy Market Decision Variables

SERM simulates energy purchases and sales at market hubs (green hexagons). Whereas all generation levels are given (fixed levels of network energy injections), energy market purchases are model decision variables that represent energy supply sources. Similarly, all DSA loads are specified (fixed amounts of energy that flows out of the network) while energy market sales are model decision variables that represent energy sinks.

Because monthly DSA offers to its FES customers are based on a “no-experiment“ assumption, the CRSP system may be in either have energy-short or an energy-long position during some months of the year. The CRSP Office is therefore required to either buy or sell energy on the market to maintain a CRSP energy system balance. Even when the monthly net energy position is zero, there may be situations when CRSP needs to buy or sell on an hourly basis. For example, CRSP must buy power when the load ramps up faster than the maximum ramp of CRSP resources and must sell power when minimum generation are greater than FES loads. Under these types of circumstances when energy purchases and sales are required to maintain a SLIP energy balance, SERM minimizes net purchase costs/financial impacts.

Because of transmission constraints and transmission energy losses in the grid, prices vary by location. Therefore, CRSP energy marketers utilize its far-reaching transmission network to strategically buy and sell energy at various locations. Model decision variables not only consider transaction quantities and when to engage in energy transactions, but also where. To simulate the energy transaction decision making process, SERM purchases and sells energy at various locations to minimize net expenses and alternative financial impacts. Within contractual transmission constraints, SERM buys energy at low energy cost locations under regional and/or system-level energy short positions and sells energy at higher priced locations when energy is long.

To ensure consistency among power system models, price vectors into the SERM GCD node are the same as the prices that were used to compute GCD economic energy values. These price vectors vary by alternative and trace. At other market hubs, SERM prices are set equal to the GCD price multiplied by a locational market price multiplier (LMPM) derived from PLEXOS model LMP results. Multipliers vary monthly by market hub and were computed as the ratio of the average monthly PLEXOS LMPs at a SERM market location relative to the average monthly PLEXOS LMP at GCD. As shown in Figure 3.4, energy prices at most market hubs are less expensive than those at GCD with at Ault having the cheapest prices (multiplier less than one). On the other hand, Pinnacle Peak energy prices are more expensive than at GCD (multiplier greater than one).

SERM Network Links

All SERM link flows in the network are modeled as decision variables. This includes both links that transport energy and those that transport water (e.g., from Blue Mesa to Morrow Point). Network links include black lines that represent various segments of WAPA transmission lines and red links that represent SRP energy wheeling routes and the transport of GCD exchange energy to the SRP POD (Figure 3.3). Costs/penalties are applied to links’ contractual flows to encourage the model to find the shortest pathway from energy source to sink and/or to set preference on the use of specific links.

SERM transmission link segments have bidirectional maximum flow constraints as labeled by text adjacent to the red and black links. These limits may change over time. The model also constrains maximum contract flows across two or more aggregated line segments, called “multi-links” or TOTs.

Aggregate limits are less than the sum of individual bundled link limits. Limits on both individual links and aggregated sets of links are reduced during limited periods when the CRSP Office sells some of a line's capacity to a third party under one or more point-to-point contracts.

Water flows out of a reservoir is represented by a dashed-blue line pointing out of the hydropower plants.

SERM Network Energy Branching Nodes

Junction nodes include red and black circles and orange crosses (Figure 3.3). These nodes combine energy flows from one or more links that point into the node and energy that is distributed to one or more links that point out of a node. The net energy balance at a junction node is always zero.

SRP Exchange Network Elements

Node and link elements that represent SRP agreements with the CRSP Office are either red or light orange. SRP thermal plants (red diamonds) are represented as energy supply nodes with given/fixed energy injections into the network. The generation levels at SRP thermal power plants are identical to historical levels for calendar year 2023. This energy is either wheeled, exchanged for GCD generation, or sent to exchange layoff nodes (Figure 3.3 brown slashed circles).

SRP Energy Wheeling

The wheeling agreement limits the total amount of energy that is transported to the SRP POD (red cross). This includes energy wheeled from Craig and Hayden Powerplants (C/H Plant) and from Four Corners (FC Plant). In Figure 3.3, the Craig/Haden energy wheel, labeled "3X", is limited to 250 MW, and the Four Corners energy wheel, labeled as "5X", is limited to 154 MW. The combined 3X and 5X wheel is also limited to 250 MW (limit on the SHR2 node to the GC1 exchange junction node).

SRP Energy Exchange

The energy exchange agreement is more complicated than the wheeling agreement. It depends not only on SRP plant generation levels, but also on SLIP regional supply and energy demand balances. The maximum amount of energy exchanged in the north region of the SLIP footprint (labeled "2X") equals the lesser of the northern region energy short position or 379 MW. The short position is calculated from known/fixed variables; that is, SLIP northern loads minus SLIP northern generation (production from all SLIP resources except for GCD). Because there is no SLIP generation in the Four Corners region, it always has an energy short position. The southern energy exchange (labeled "4X") is limited to given/fixed Four Corners FES customer loads. The exchange in the Southern region (labeled "1X") is capped at GCD generation (fixed) minus total southern loads (also fixed); that is, the CRSP energy long position in the south. Because 1X is set equal to 2X plus 4X, the SRP energy exchange is curtailed or "turned off" for a variety of reasons. Such reasons include when an LTEMP SEIS flow experiment reduces GCD generation to a minimum operating level, creating a short position in the south, or when SRP thermal generation is zero.

When SRP energy exchanges are possible, it is assumed that exchanges have a higher priority than wheeling; that is, SRP energy exchanges are first computed and then any remaining SRP thermal generation up to 250 MW is wheeled. The amount of SRP thermal generation that is neither wheeled nor used for the energy exchange flows to exchange layoff nodes (Figure 3.3 brown slashed circles).

Table 3.1 Water and power modeling geographical scope and temporal/component fidelity

Study Topic/Impact Analysis	Model Geographic Scope	Time Step	Time Horizon	Power System Fidelity
Power Grid	Western Interconnection (WI)	Hourly	Daily/Weekly/Monthly	**Hydropower:** Low/Moderate **Grid:** Moderate
Water Management	Colorado River Basin	Monthly	Year to Decades	**Hydropower:** Moderate **Grid:** None
CRSP Financial Impacts and Trans Contract Schedules	SLIP with Course Grid Response	Hourly	Weekly	**Hydropower:** High (Only GCD) **Grid:** Low/Moderate
GC Power Economics	Glen Canyon with Course Grid Response	Hourly	Weekly/Monthly	**Hydropower:** High (All SLIP) **Grid:** Low/Moderate

Table 3.2 LTEMP SEIS Water and Power Models

Study Topic/Impact Analysis	Model
Power Grid	PLEXOS
Water Management	CRMM
CRSP Financial Impacts and Trans Contract Schedules	SERM
GC Power Economics	GTMax SL

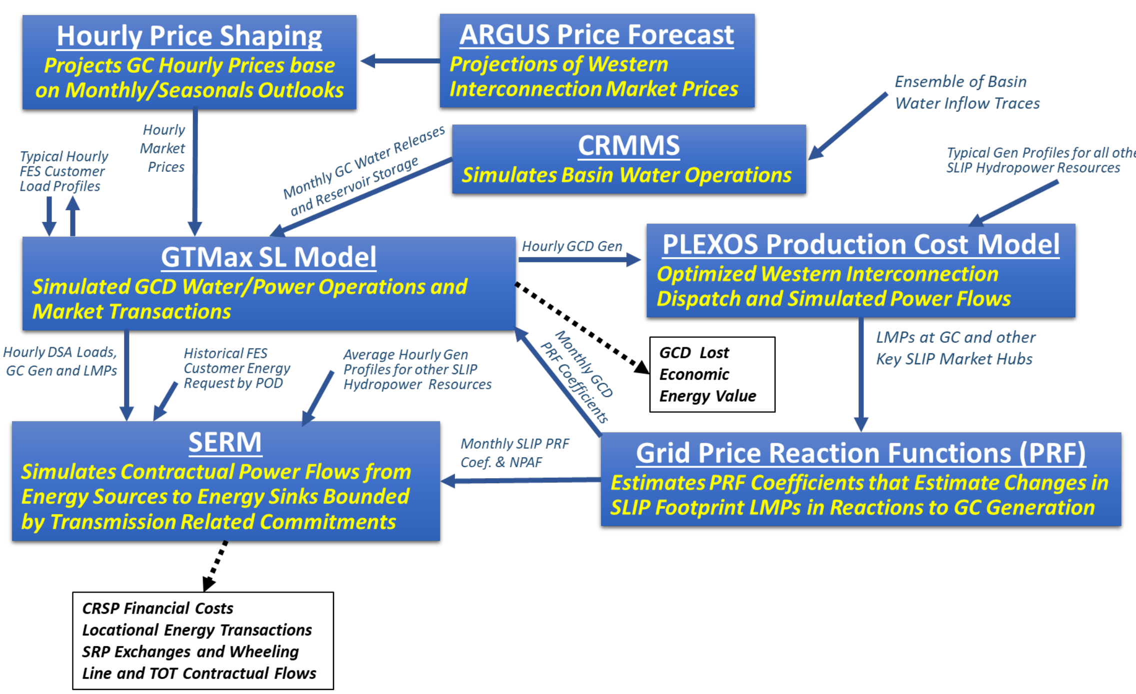


Figure 3.1 LTEMP SEIS Modeling Framework

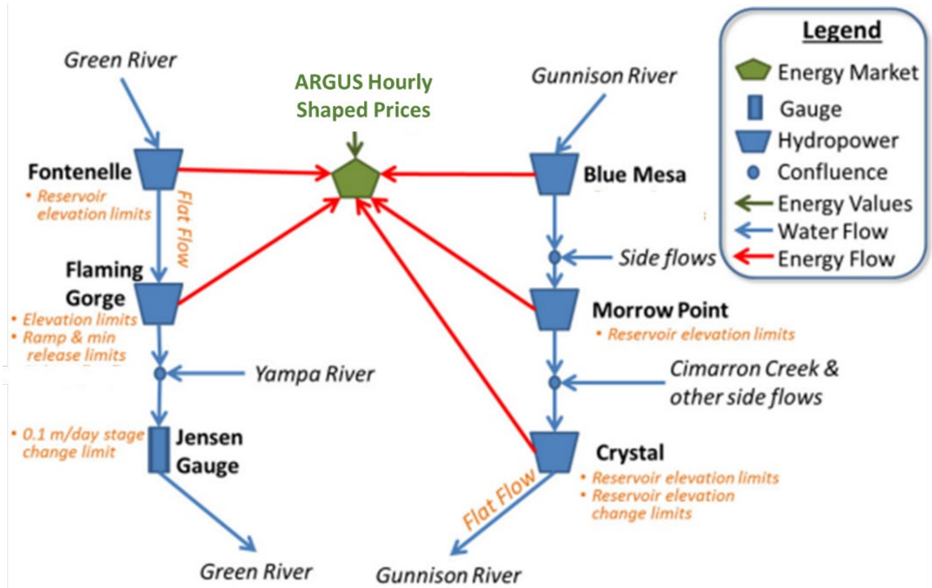


Figure 3.2 GTMax SL Network *Topology for Large* SLIP Hydropower Resources Other Than GCD

Figure 3.3 SERM Node and Network

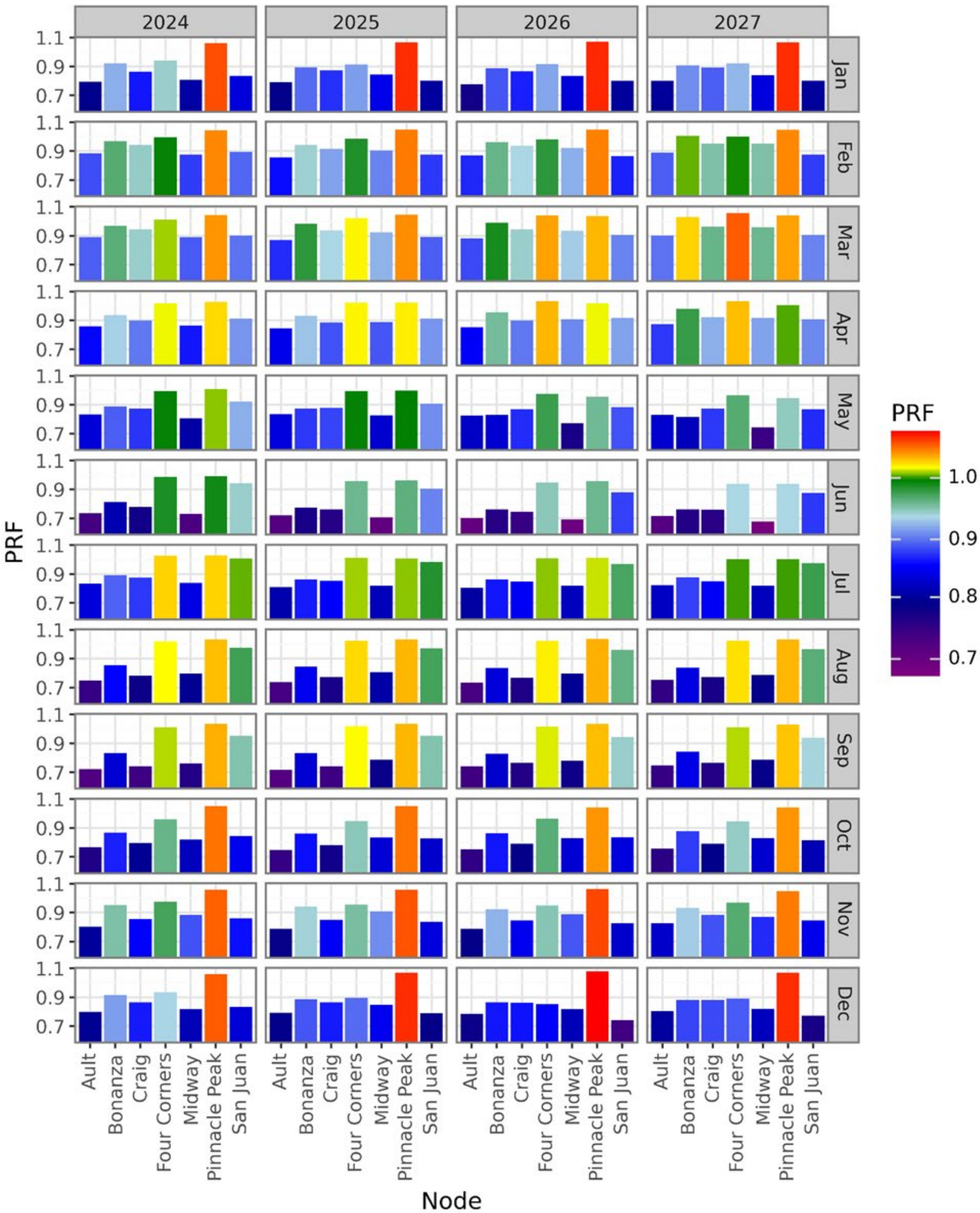


Figure 3.4 Locational Market Price Multiplication Factors by Month and Year

3. GTMax SL Transmission Model Contractual Power Flows and Financial Analysis

3.1. Introduction

The goal of this section is to analyze the financial and economic implications of the flow options recommended at GCD in the years 2024 to 2027. One of the primary cost factors associated with these releases stems from the bypass water requirements for experiments, resulting in the loss of generation at Glen Canyon Dam (GCD). This loss of generation escalates total grid costs, compelling increased power generation from other resources within the system to maintain the energy supply-demand balance. Additionally, factors such as the reallocation of monthly water release volumes and fluctuations in Lake Powell's forebay elevation further impact the economic outcomes.

This section is dedicated to examining contractual power flows and conducting financial analysis utilizing the GTMax SL Transmission model. The combination of traces and months in this analysis was selected based on the experiments that were conducted. The GTMax SL Transmission runs were performed for all the combinations traces and time periods (months) in which an experimental release was expected to be conducted. For all other months, it is assumed no significant difference from the No Action alternative.

Definition of alternatives

The alternatives under consideration, namely NW (New Window), CS (Cold Shock), CM (Cool Mix), RM15 (River Mile 15), and LCR (Little Colorado River), are defined based on their operational characteristics. A definition of alternatives is presented in Table 1.

Table 1 Definition of acronyms used in the design of action alternatives

Alternative	Description
NW (New Window)	The only difference with the No Action alternative is that the sediment accounting window for HFEs is extended throughout the year. The New Window alternative alone does not impose any bypass releases.
CS = Cold Shock	Has normal operations during the week. On weekends, all water except 2,000 cfs is bypassed.
CM = Cool Mix	Has a prescribed level of bypass for all hours of the month. The remaining volume can be shaped.
RM15 = River Mile 15	River Mile 15 Releases from alternatives are targeting temperatures at River Mile 15.
LCR = Little Colorado River (River Mile 61)	Little Colorado River Releases from alternatives are targeting temperatures at the LCR (RM61).

In this analysis, various correlations are explored to better understand the complex dynamics of experimental water releases. Firstly, the correlation between the decrease in economic value of action alternatives and the increase in water spilled gives some insights into the relationship between spill volumes and economic impacts. Additionally, a positive correlation is observed between lost generation at GCD and increased water spillage under alternative actions. The analysis delves into the potential loss of generation at GCD due to non-power releases from experiments, pinpointing critical months and traces experiencing significant losses. Furthermore, the economic cost of conducting experiments and the impact on replacement energy purchases are examined in detail. The relationship between average Locational Marginal Prices (LMPs), lost economic value, and lost generation underscores the influence of market dynamics on economic outcomes. Moreover, the reduction in generation at GCD affects energy transportation to Four Corners and Northern loads, highlighting the crucial role of TOT2 South in bridging energy deficits. Lastly, the correlation between SRP wheeling and energy exchange under alternative actions demonstrates the sensitivity of wheeling to changes in energy exchange.

3.2. Financial and Economic Analysis

3.2.1. Spillage vs Economic Value

Most of the economic and financial costs of LTEMP SEIS experimental water releases are primarily attributed to experiment bypass water requirements The loss of GCD generation during these experiments contributes to increased total grid costs, as these losses must be compensated for by increased power generation from other, more expensive, resources within the power system to maintain the balance between energy supply and demand. Additionally, other factors, such as the reallocation of monthly water release volumes and fluctuations in Lake Powell's forebay elevation, also influence the bottom-line results.

In the CM alternatives, bypass experiments are conducted during all hours of the week, whereas in the CS alternatives, bypass experiments are conducted only during the weekend. Consequently, it is expected that the CM alternatives will have a larger decrease in economic value than the CS alternatives.

Figure 1 illustrates the correlation between the decrease in economic value of action alternatives compared to the No Action alternative and the increase in water spilled. The higher the volume of spills, the greater the decrease in economic value. Intercept values, along with other regression variables, are presented in Table 2. The spill volumes and decrease in economic value are highly correlated. The cost of spillage across all traces and alternatives averages to 11.235 \$/AF. As expected, the CM alternatives have the largest decreases in economic value, which is, on average, 15.82% larger than the CS alternatives.

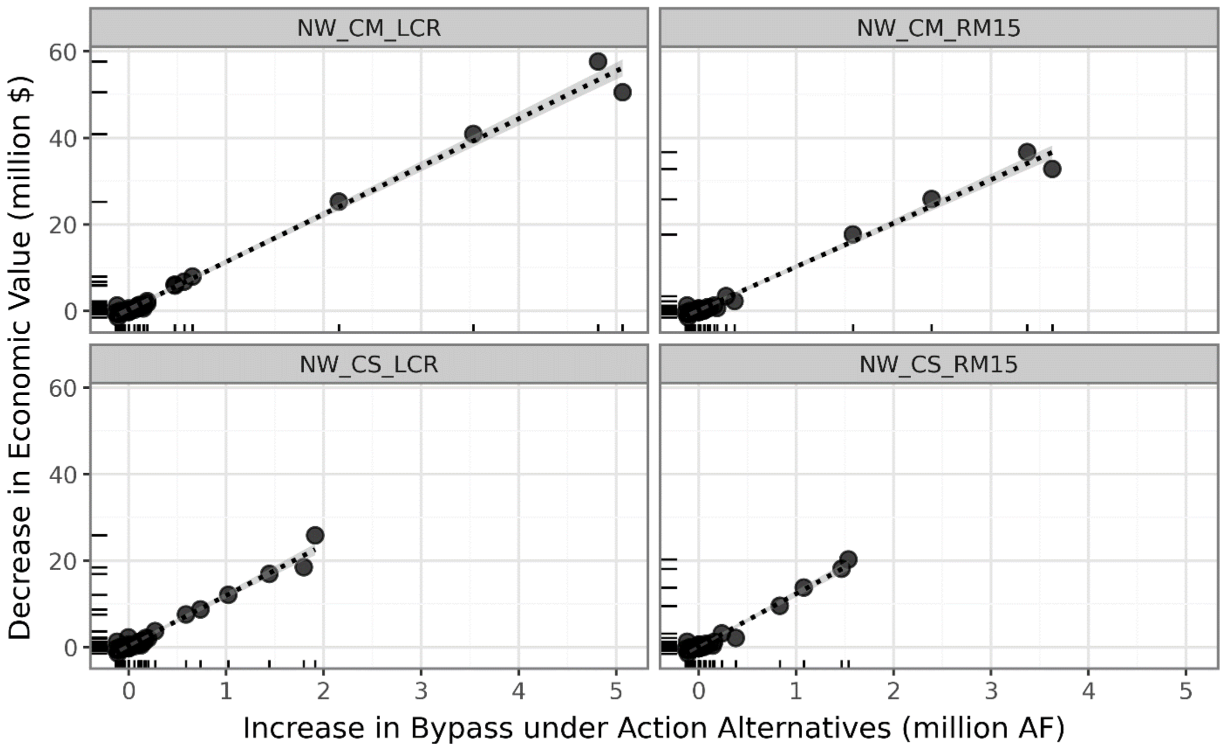


Figure 1 Correlation between the Decrease in Economic Value and Increase in Bypass Under Alternative Actions.

Table 2 Regression variables for all four alternatives

Variable	**NW_CM_LCR**	**NW_CM_RM15**	**NW_CS_LCR**	**NW_CS_RM15**
Slope ($/AF)	11.01	10.06	11.63	12.24
Intercept ($)	370,509	212,274	363,081	149,748
R value (-)	0.99525	0.99307	0.98606	0.98606
Std. err. (AF)	0.20357	0.22496	0.37091	0.39054

3.2.2. Spillage vs. Lost Generation at Glen Canyon

Figure 2 illustrates the correlation between the lost generation at GCD of action alternatives compared to the No Action alternative and the increase in water spilled. The two variables are positively correlated. The higher the volume of spills, the greater the loss of generation at GCD. Intercept values, along with other regression variables, are presented in Table 2. On average, the energy loss per volume of spillage sums to 0.364 MWh/AF.

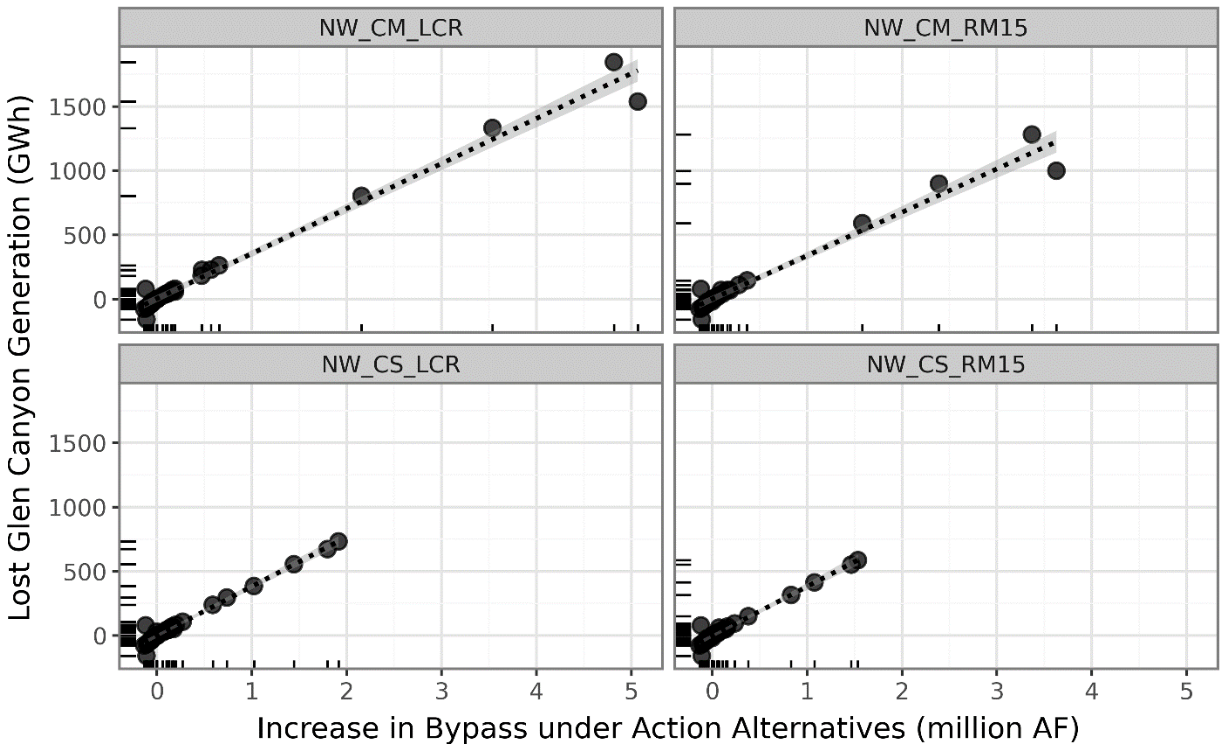


Figure 2 Relation between the Lost generation at GCD and Bypass Difference Under Alternative Actions.

Table 3 Regression variables for all four alternatives

Variable	NW_CM_LCR	NW_CM_RM15	NW_CS_LCR	NW_CS_RM15
Slope (MWh/AF)	0.350	0.338	0.384	0.385
Intercept (GWh)	4,171	899	-1,428	-2,996
R value (-)	0.9908	0.9824	0.9878	0.9814
Std. err. (AF)	0.0091	0.0121	0.0114	0.0142

The stacked bar chart displayed in Figure 3 illustrates the potential loss of generation at GCD due to non-power releases stemming from experiments across all four alternatives and all traces. The figure gives insights into the magnitude of lost generation over individual years and months.

Upon analysis, it becomes evident that the highest loss of generation occurs in traces T10, T11, and T21, consistently observed across both CM alternatives. The highest annual loss of generation is observed in the NW_CM_LCR action in Trace T21 in the year 2026 (806 GWh), where nearly 23% (184 GWh) of all lost generation occurred in August. Similarly, the highest overall loss of generation is nearly identical across traces T10 and T11. In the CS alternatives, the lost generation is significantly lower, ranging from an average of 522 GWh to 266 GWh in the LCR and from 357 GWh to 183 GWh in RM15 alternatives.

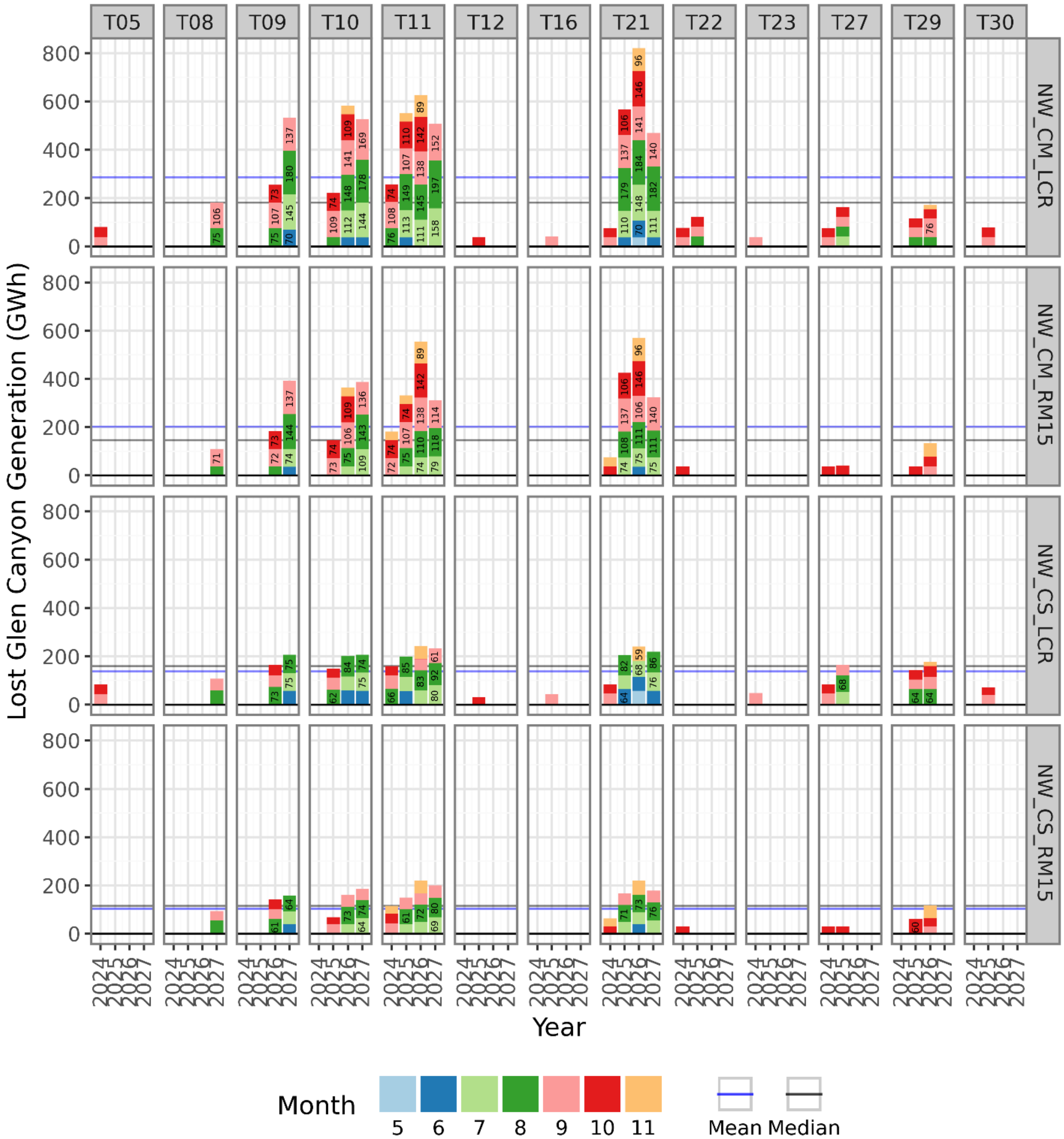


Figure 3 Lost GCD generation under alternative actions broken down by year, month, and trace (horizontal lines indicate mean and median values, calculated from the months with experiments)

On average, August (8) emerges as the month with the largest expected loss of generation across all traces and across all alternatives, followed by September (9) and October (10). These findings suggest that the highest impact on the greater regional energy system can be expected during these critical months which is directly correlated with lower water release and the highest peak demands occurring simultaneously.

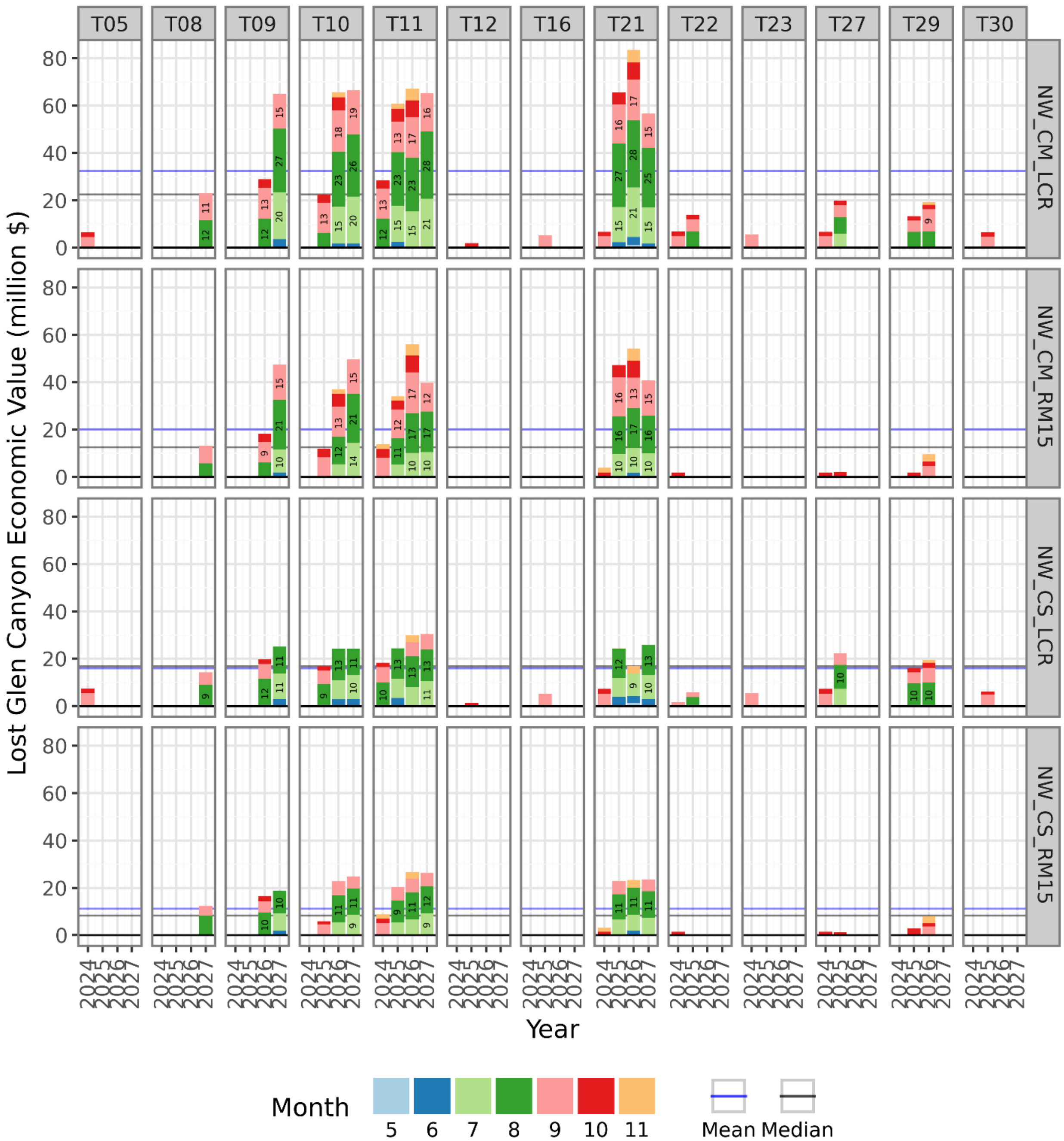


Figure 4 Lost GCD Economic Value under alternative actions over selected traces. Horizontal lines indicate mean and median values, calculated from the months with experiments.

The economic cost of conducting experiments, presented as Lost Economic Value in this chapter, is presented in Figure 4. The overall decrease in economic values is primarily attributed to the increased amount of water bypass. As mentioned earlier, the highest expected lost generation (184 GWh) occurs in August (8), resulting in the most significant impact on economic value (translated into the cost of conducting experiments), which also occurs in August ($28 million). On an annual basis, the most impacted traces are T10, T11, and T21 (those with the lowest expected water releases), while the least impacted ones are T05 and T12 (those with the highest expected water release). The largest overall lost economic value of conducting experiments is observed in traces T11 ($222 million) and T21 ($213 million) of the NW_CM_LCR alternatives, and $103 million and $73 million in NW_CS_LCR alternatives. On average, in the RM15 alternatives, the loss of economic value is lower by 40.4% for the CM and 32.1% for the CS alternatives, respectively.

Although the constraints of conducting experiments are fixed and have limited flexibility, overall, if there were more freedom to explore decisions to spill energy when prices are lower, the economic impact could potentially be minimized. However, this aspect is beyond the scope of this analysis.

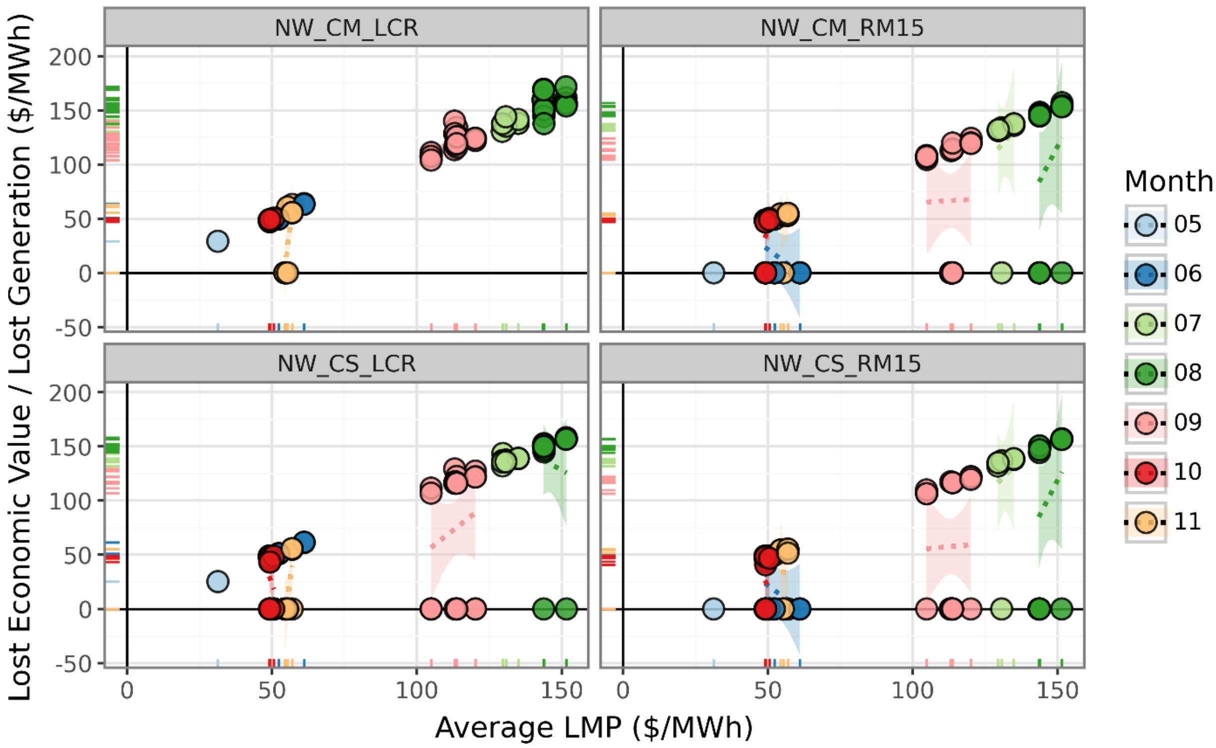


Figure 5 Correlation between average LMP and the Lost economic value over the lost generation at GCD. The color-coded lines represent regression lines indicating conditional means for individual months. They demonstrate the overall trend in the data, with the span around the lines indicating confidence intervals.

The scatter plot in Figure 5 shows individual data points representing various observations of average LMP at GCD and lost economic value over lost generation variables, with average LMP values plotted on the horizontal axis and lost economic value over lost generation values on the vertical axis. Months of the year are color-coded, while dots represent different traces. Upon analysis, it is evident that there is a clear linear relationship between the two across individual months. It's important to note that for a given month, LMPs are relatively constant among all traces and years. Additionally, owing to the correlation between the two variables, the ratio of lost economic value to lost generation is also relatively constant for most months. It is also important to note that due to large inconsistencies for relatively small values of lost generation, a cutoff of 1 GWh per month was introduced to filter out only the most relevant data points. Dots on the horizontal axis represent data points of traces where no experiments were conducted. Thus, no loss in economic value nor lost energy generation was observed. Also note the clear relationship between the driest and most energy-intensive months and the high LMP prices (mostly in July (7), August (8), and September (9). Conversely, May (5) is the month with the lowest average LMP across all traces and alternatives.

The scatter plot in Figure 6 illustrates the impact of Lost generation at GCD due to experimental bypass conducted across different action alternatives on the LMPs. Despite the relatively minor increase in LMP, there is a clear positive correlation between the two variables. As the generation at GCD decreases, the average LMP at GCD rises. The most correlated months are October (10) and November (11), a trend generally consistent across all four action alternatives, with August (8) and September (9) exhibiting the least correlation. Nevertheless, the trend remains consistently positive.

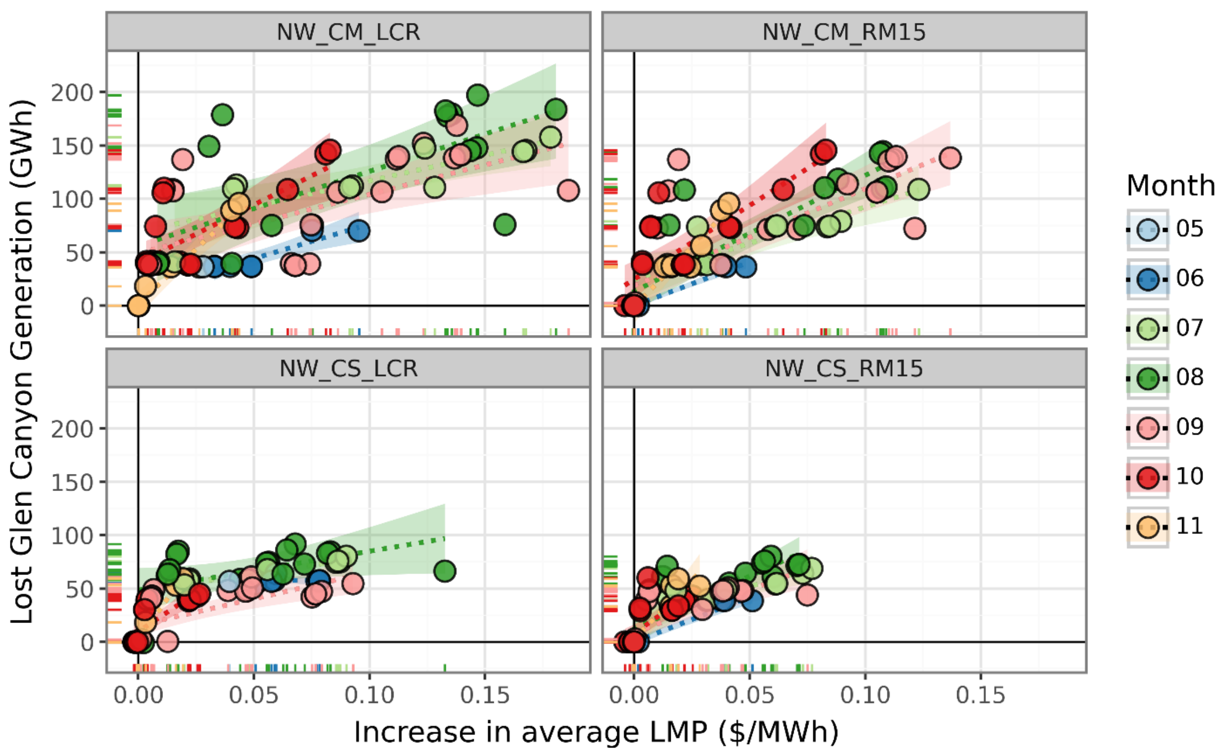


Figure 6 Impact of the increase in average LMP compared to No Action alternative on the lost generation at GCD. The color-coded lines represent regression lines indicating conditional means for individual months. They demonstrate the overall trend in the data, with the span around the lines indicating confidence intervals.

The charts in Figure 7 show the increase in replacement energy purchases under action alternatives and across all traces. Energy purchases rise under the alternatives primarily because lost generation at GCD is replaced by power purchases from other neighboring regions. When WAPA faces energy shortages, it purchases power at low LMP nodes such as Ault (located in the northeast) and transports it to serve regional loads, particularly those at Four Corners.

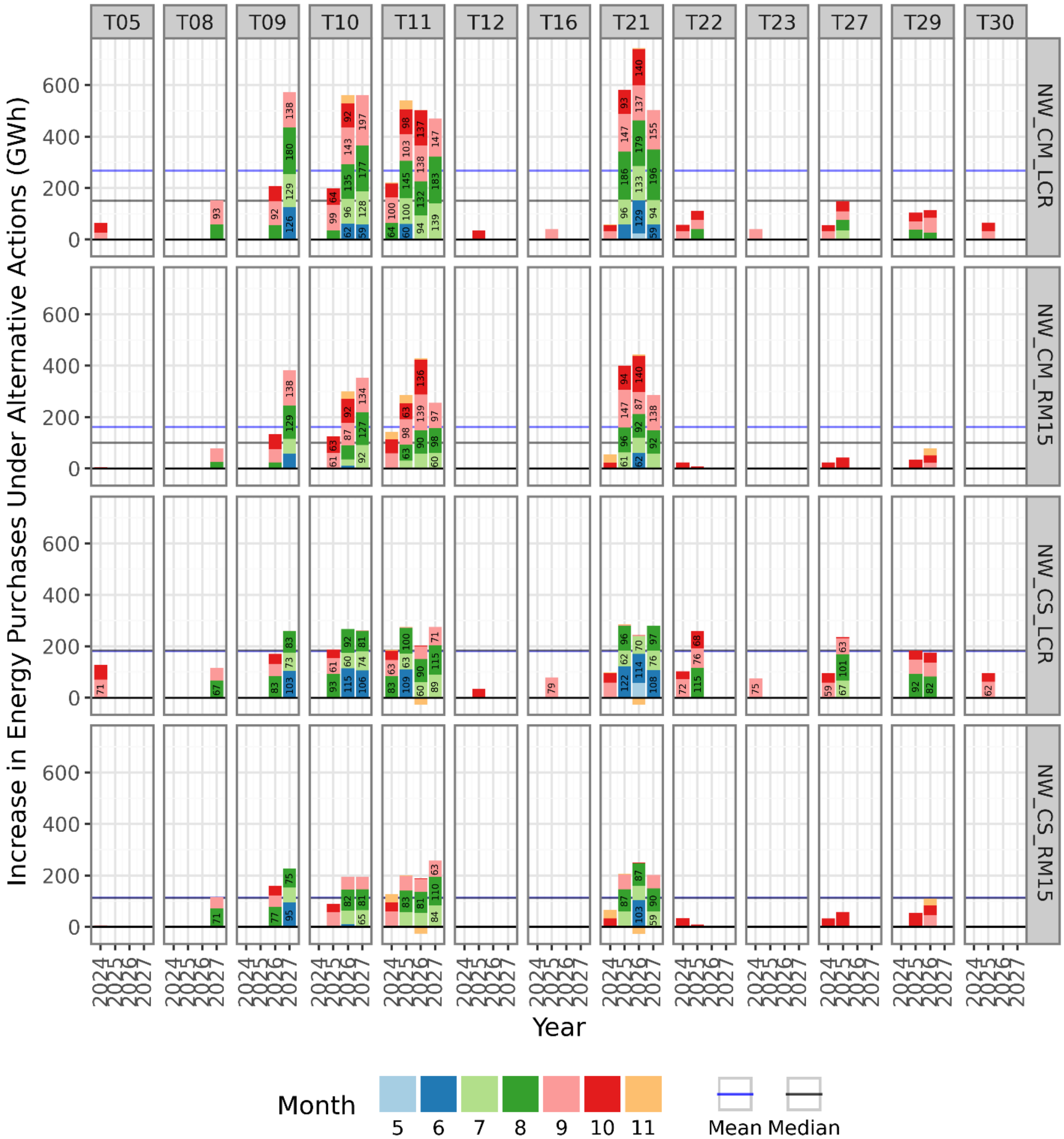


Figure 7 Increase in replacement energy purchases under alternative actions. Horizontal lines indicate mean and median values, calculated from the months with experiments.

The highest increase in replacement energy compared to the No Action alternative is observed during August (8), 2027, in trace 21. Overall, the highest annual replacement energy purchases (713 GWh) occur in Trace T21 in the year 2027 in the NW_CM_LCR alternative. CM alternatives, in general, have a more impactful effect than CS alternatives. The general seasonal patterns differ: in

CM alternatives, the most impacted months are July (7), August (8), and September (9) (with an average of more than 90% of replacement energy purchased during these months), while in CS alternatives, the most impacted months are June (6), July (7), and August (8). Overall, over the period of four years, the largest replacement energy is observed in traces T21 and T11 (ones with the driest hydrology and lowest releases), and the lowest in traces T05 and T12 (traces with the wettest hydrology and highest water releases).

Correlation between Lost GCD generation and increase in energy purchases under the alternative actions is shown in Figure 8. The most sensitive months (i.e., those where the increase in energy purchases per MWh of lost GCD generation is greater than 1, meaning that even though GCD is reducing its power output by 1 MWh, due to complex network constraints, more than 1 MWh of replacement energy needs to be purchased to supply all the loads in the network) occur in June (6), where the slope is the highest (1.59 MWh/MWh).

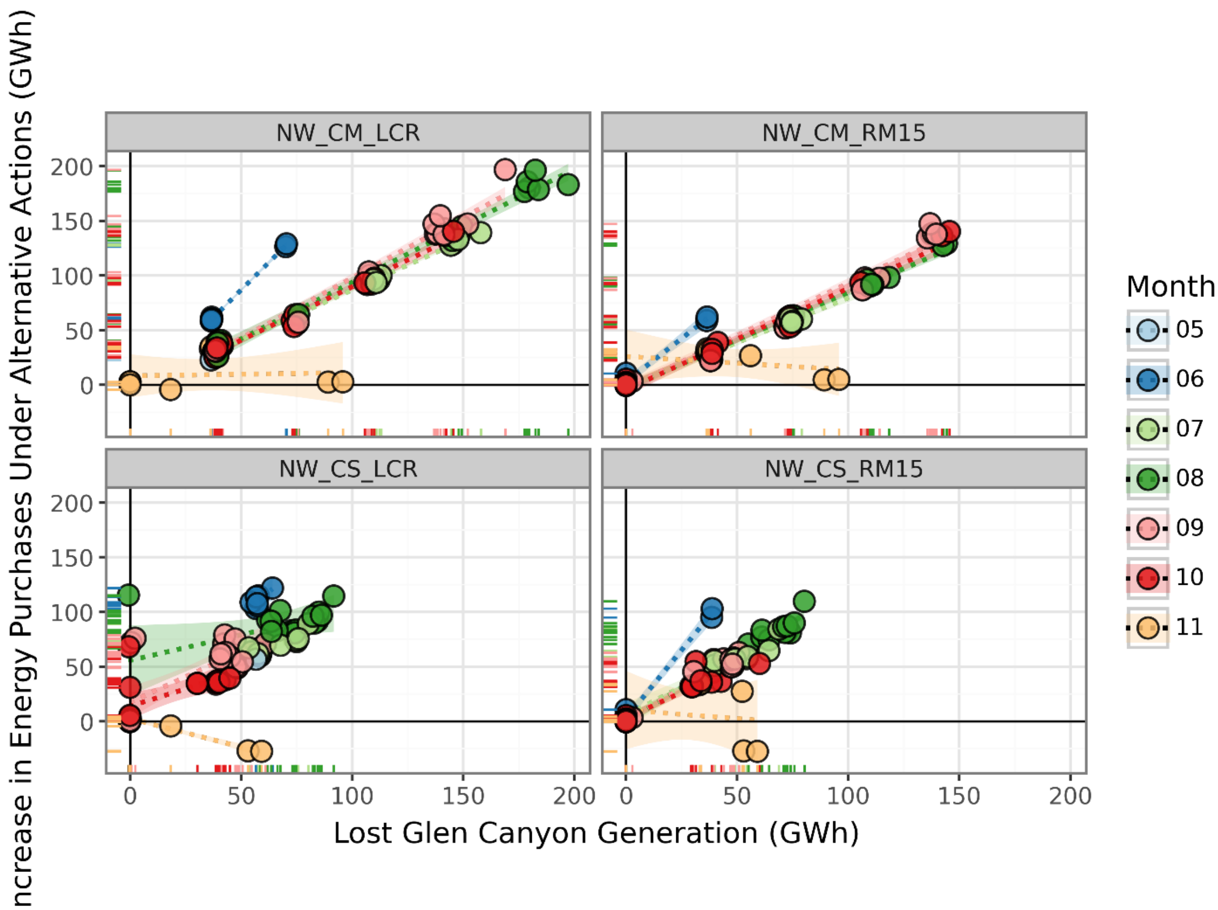


Figure 8 Correlation between lost GCD generation and increase in energy purchases under alternative actions. The color-coded lines represent regression lines indicating conditional means for individual months. They demonstrate the overall trend in the data, with the span around the lines indicating confidence intervals.

Figure 9 presents a correlation between the Decrease in Economic Value and the Increase in net financial cost of conducting experiments. There is a clear linear relationship between the two variables. The largest impact is observed in the NW_CM_LCR alternative. Both NW_CS alternatives yield nearly identical results, with LCR being slightly more pronounced (up to 5%) during the dry summer months with the largest energy demand. Typically, financial costs are less than the economic ones because WAPA has an expensive transmission network whereby it can replace lost energy at locations where the LMP is relatively low compared to the economic LMP at GCD. In average, across all months and all traces, for each dollar of lost economic value the total increase in net financial costs goes up by 0.98 dollars.

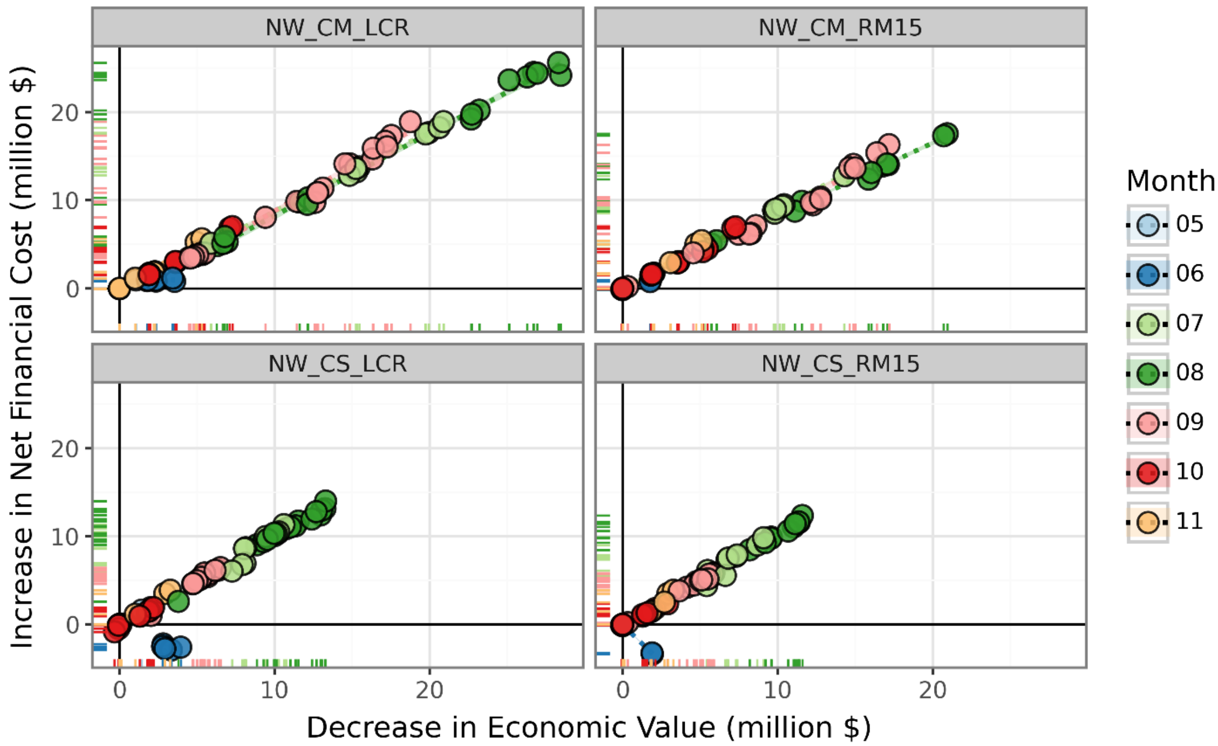


Figure 9 Correlation between Decrease in Economic value and Increase Net Financial Cost. The color-coded lines represent regression lines indicating conditional means for individual months. They demonstrate the overall trend in the data, with the span around the lines indicating confidence intervals.

The charts in Figure 10 show the net financial cost (i.e. financial loss to WAPA) of conducting experiments. This net financial loss is positively correlated with the decrease in water availability for energy use and the increase in water extraction for non-energy use (i.e., to conduct the SMB flows), which is also positively correlated with the lost generation at GCD. As more water is spilled and less water is used for generation, resulting in less water available during high LMP hours, the impact on the net financial cost of conducting experiments across all action alternatives increases, as WAPA needs to buy replacement power to serve Southern and Four Corners loads, mainly from the more expensive northern exchange. Similar to the decrease in economic value, the traces that stand out the most, with the highest overall economic cost across the analyzed four-year period, are T10 ($137.6 million), T11 ($193.0 million), and T21 ($171.8 million).

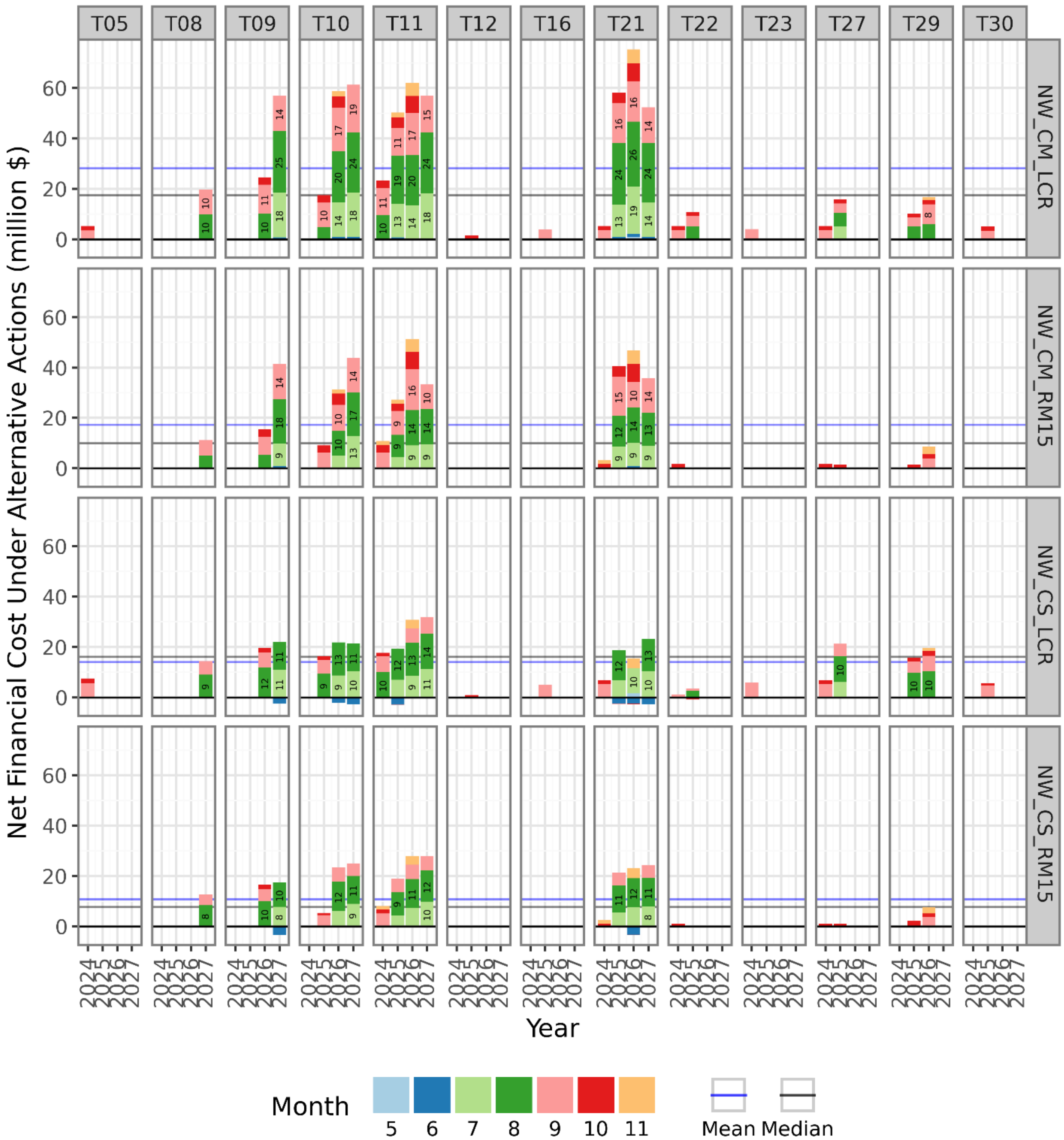


Figure 10 Net Financial Cost under Alternative Actions. Horizontal lines indicate mean and median values, calculated from the months with experiments.

3.3. Transmission system

The reduction in generation at GCD significantly affects the transportation of generated energy to both Four Corners and Northern loads. WAPA prioritizes serving GCD generation to local Southern loads before the transport of any excess generation to serve Four Corners can be considered. In fact, northern loads are rarely serviced by GCD generation due to consistently nonexistent flows on

TOT2 North. Figure 11 outlines the reductions in contractual energy schedules under alternative actions from Glen Canyon to Ship Rock.

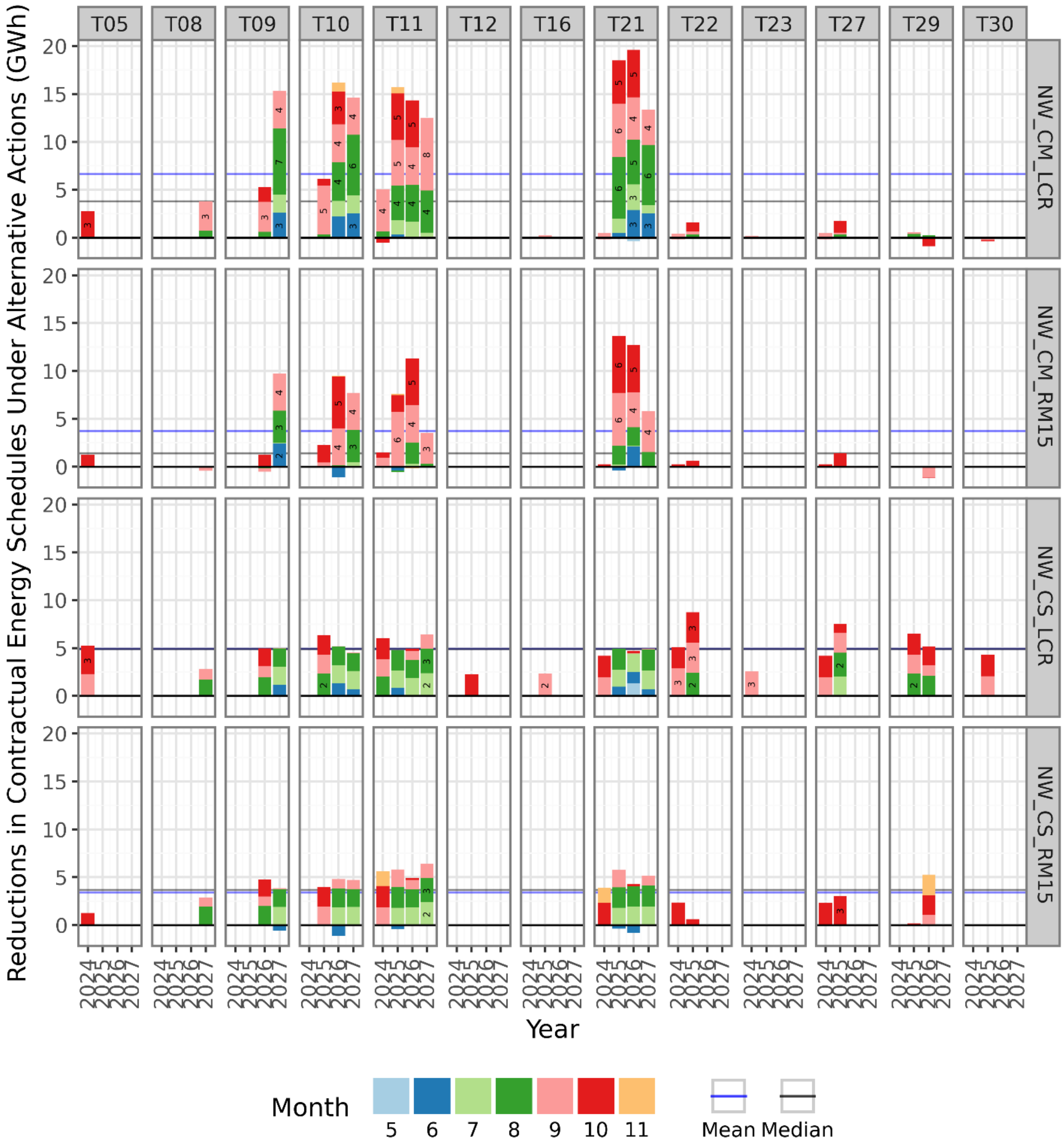


Figure 11 Reductions in contractual energy schedules under alternative actions from GCD to Ship Rock. Horizontal lines indicate mean and median values, calculated from the months with experiments.

The most affected traces, particularly T10, T11, and T21, are observed in the NW_CM_LCR alternative during the years 2025 and 2026, with August (8) experiencing the highest reductions of up to 6 GWh, followed by September (9) and October (10) with reductions of up to 5 GWh.

Conversely, in the NW_CS_LCR alternative, the overall impact remains relatively consistent across all hydrologically dry traces, indicating a uniform effect regardless of specific trace characteristics. Furthermore, as lost generation at GCD increases, Four Corners load becomes increasingly reliant on more replacement power from northern generators to compensate for the shortfall in generated energy.

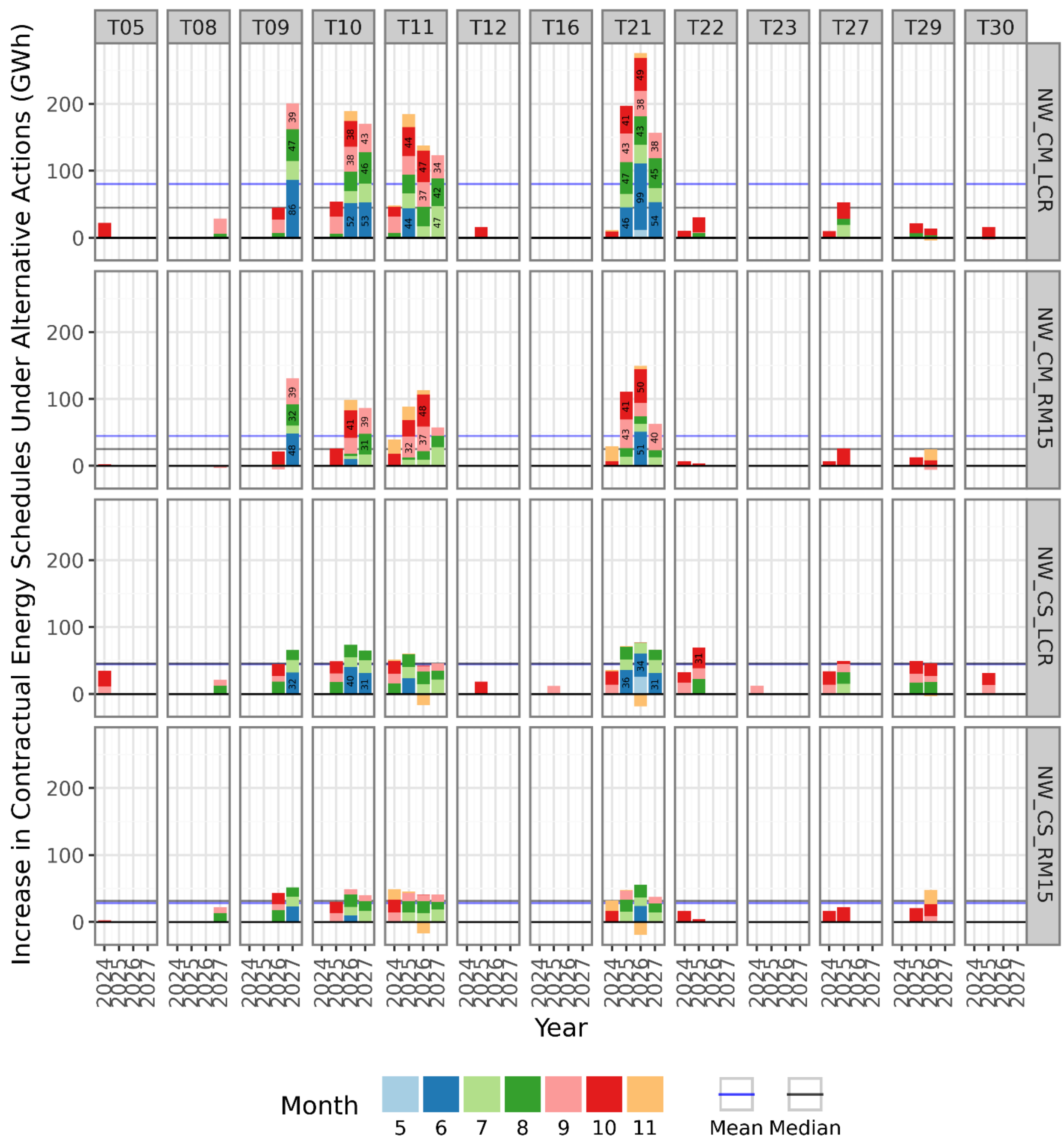


Figure 12 Increase in contractual energy schedules under alternative actions on TOT2 South (from norther region to Four Corners and South). Horizontal lines indicate mean and median values, calculated from the months with experiments.

The reduced generation at GCD results in an inability to fulfill the energy demands at Four Corners, prompting purchases of energy from the North, where prices are more favorable. To bridge the energy deficit at Four Corners, the flows over the TOT2 South needs to increase. This impact is most pronounced during the summer months, particularly in June (6), July (7), and August (8).

In the NW_CM_LCR alternative, the driest traces, T10, T11, and T21, experience the most substantial increase in contractual schedules between the North and Four Corners and the South. Notably, the largest impact on TOT2 South, totaling 99 MWh, is observed in June 2027 in trace T21. Conversely, the NW_CM_RM15 alternative exhibits a similar pattern but with a 1.8 times lower impact. Similarly, in the NW_CS alternatives, the months of June, July, and August witness significant impacts, reaching a peak of 40 GWh in Trace T10 in June 2026. The details of these impacts on TOT2 South are presented in Figure 12 , offering a comprehensive insight into the consequences of reduced generation at GCD on energy purchases and usage.

The correlation between the decrease in contractual energy sales from GCD to Pinnacle Peak is illustrated in Figure 13. A clear negative linear relationship is observed, where an increase in lost generation at GCD corresponds to a decrease in contractual energy sales to Pinnacle Peak. In NW_CS alternatives, there is a consistent trend, with each MWh of lost generation at GCD resulting in a 0.55 MWh decrease in contractual schedules to Pinnacle Peak, except for November (11), which exhibits a slight deviation. Conversely, in NW_CM alternatives, the average correlation indicates a 0.75 MWh decrease in contractual schedules for each MWh of lost generation at GCD, varying based on the month. Notably, dry summer months, such as June (6), July (7), and August (8), show a direct 1 to 1 relation, while wet months experience a lesser decrease. This pattern is attributed to the heightened demand during summer months coupled with reduced water releases.

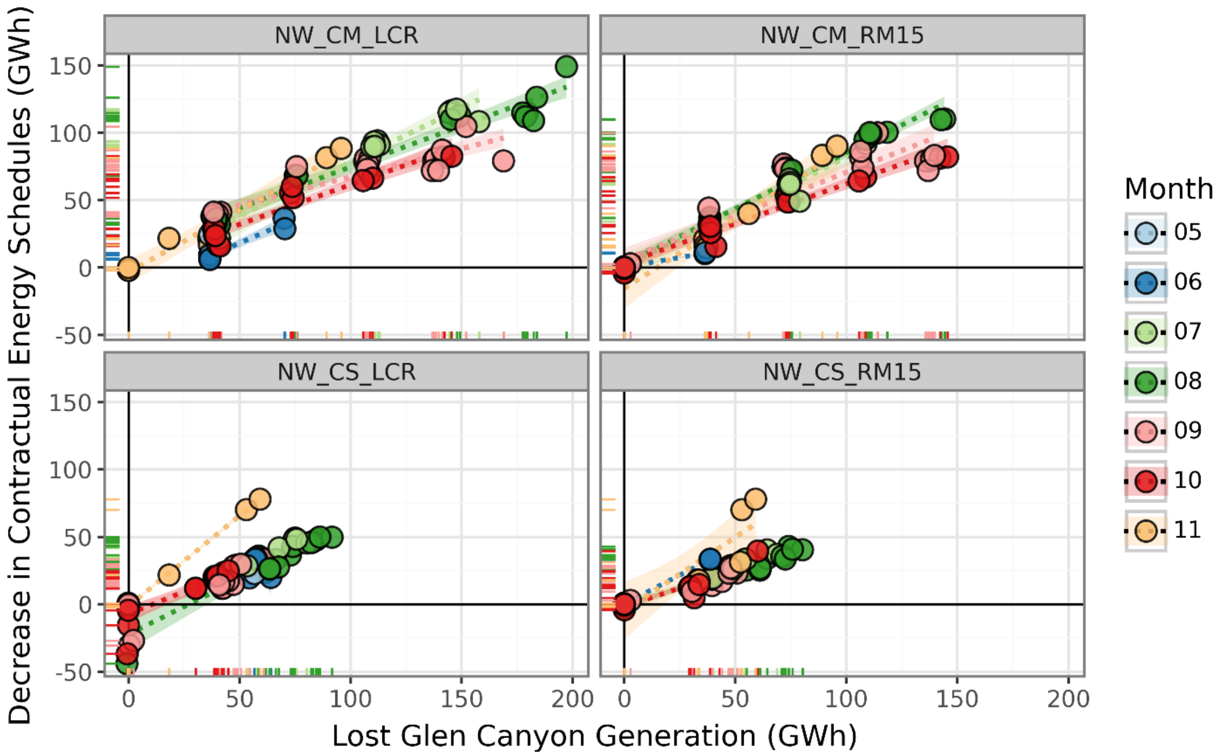


Figure 13 Decrease in contractual energy sales from GCD to Pinnacle Peak. The color-coded lines represent regression lines indicating conditional means for individual months. They demonstrate the overall trend in the data, with the span around the lines indicating confidence intervals.

The correlation between lost generation at GCD and the increase in contractual energy schedules from NTUA to GCD is presented in Figure 14. A clear positive correlation is observed between these variables on a monthly basis, although the pattern varies significantly between months. Under the NW_CS alternatives, an average of 0.3 MWh of replacement energy on the NTUA to GCD line is required for each MWh of lost generation at GCD. This correlation is particularly pronounced during June (6) and September (9) but diminishes in November (11). Conversely, in the NW_CM alternatives, while the correlation remains linear, the difference between months is more evident. For example, in June (6), 0.8 MWh of energy must be procured between NTUA and GCD for each MWh of lost generation, whereas only 0.2 MWh is required in October (10). Importantly, as generation at GCD declines, the NTUA to GCD line becomes increasingly crucial as one of the only two physical lines connecting the northern and Four Corners regions to the southern region. Despite its importance, with a total capacity of 80MW, it remains the smaller of the two lines and is mostly used without wheeling.

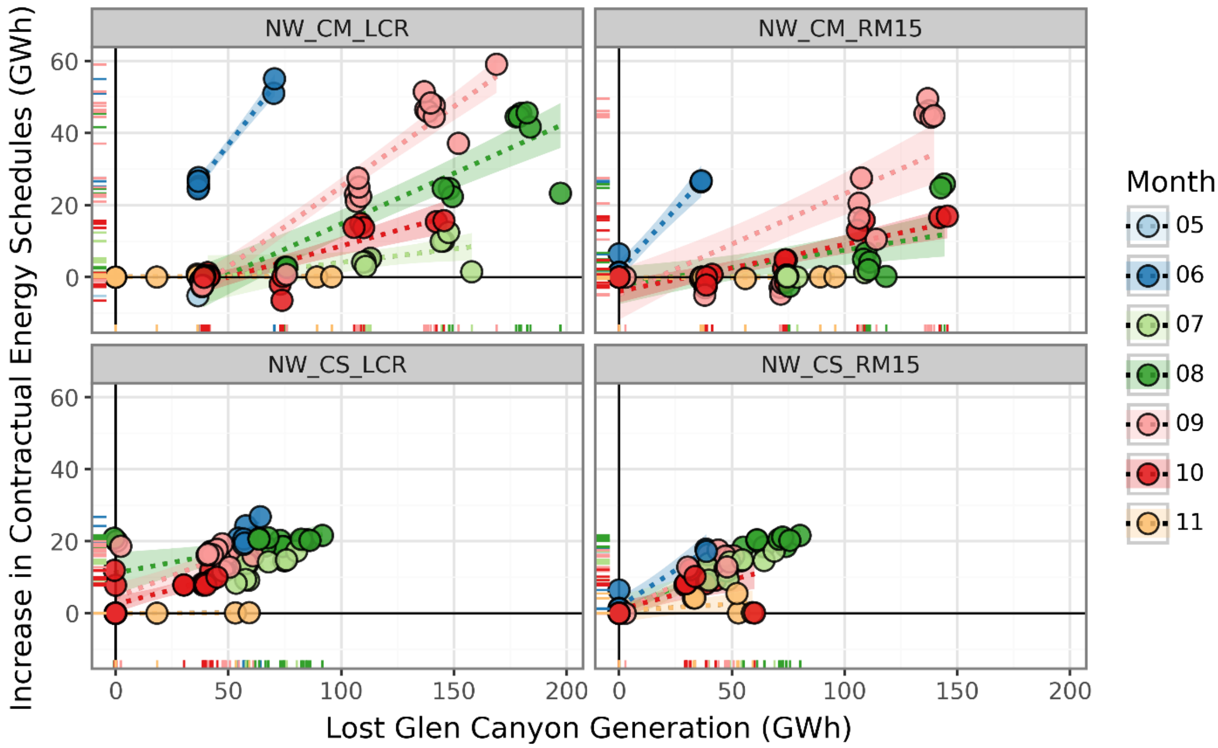


Figure 14 Correlation between Lost generation at GCD and the increase in contractual energy schedules from NTUA to GCD. The color-coded lines represent regression lines indicating conditional means for individual months. They demonstrate the overall trend in the data, with the span around the lines indicating confidence intervals.

The correlation between lost generation at GCD and the increase in southern replacement power is presented in Figure 15, showcasing a positive relationship between the two variables. As 1 MWh of generation at GCD decreases, there is an expected increase in southern replacement power. This association is evident across the data presented in the figure. In the NW_CM alternatives, June (6) exhibits the most significant impact, with each MWh of lost generation leading to a 0.9 MWh increase in southern replacement power. However, during other months, such as September (9), October (10), and November (11), these increases are notably smaller, with some months showing no increase due to sufficient water availability to cover local demand loads. Conversely, in the NW_CS alternatives, the correlation between lost generation at GCD and southern replacement power is stronger, with an average increase of 0.5 MWh in replacement power for each MWh of lost generation. Once again, June (6) stands out as the most pronounced month, while November (11) shows minimal increase in power procurement, except in specific traces. Southern replacement power encompasses both GCD generation and purchased energy directed to Pinnacle Peak, with GCD serving Pinnacle Peak through procurements from the south and Four Corners. Notably, Pinnacle Peak loads are relatively small during nighttime, allowing GCD generation to cover most of it, even under hydrologically dry traces.

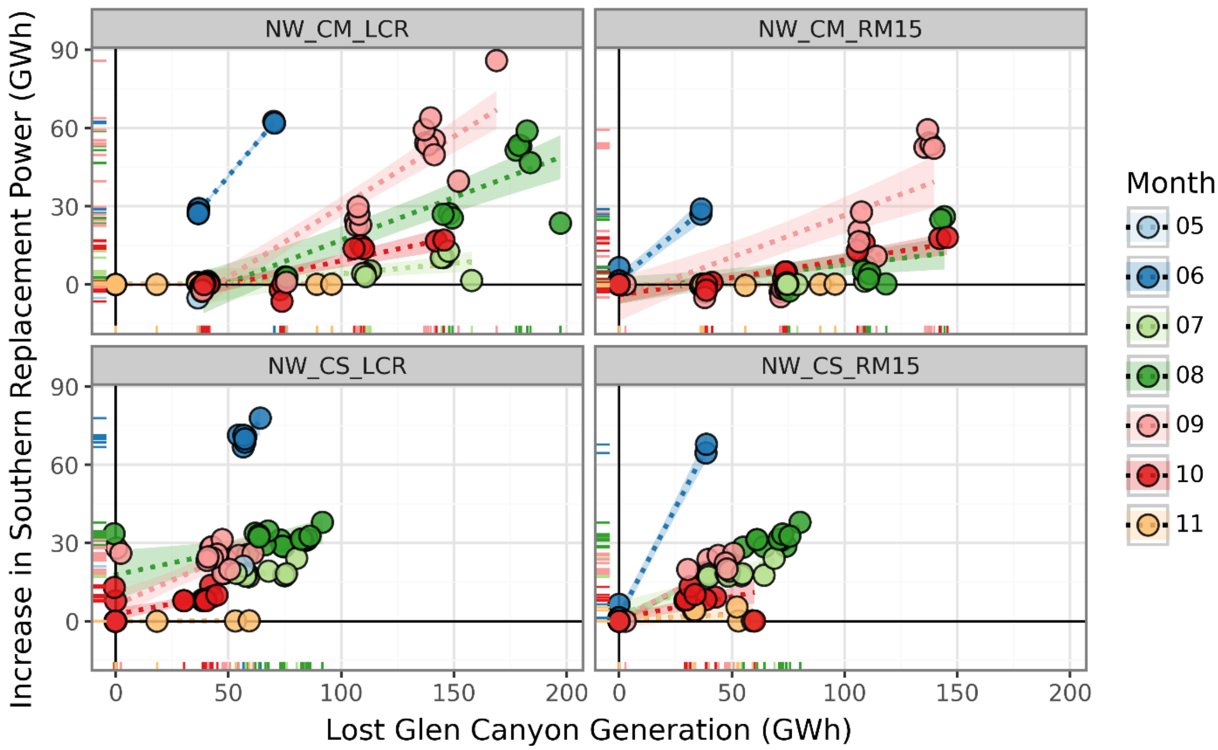


Figure 15 Correlation between the Lost generation at GCD and the increase in southern replacement power. The color-coded lines represent regression lines indicating conditional means for individual months. They demonstrate the overall trend in the data, with the span around the lines indicating confidence intervals.

The correlation between the decrease in contractual schedules from GCD to Ship Rock and the increase in contractual schedules on TOT 2 South is presented in Figure 16. There is a clear positive correlation between these two variables, with each month demonstrating a slightly nuanced correlation, yet maintaining an overall consistent trend. In the NW_CM alternatives, across all months and years, there's an average increase of 10 MWh on TOT 2 South for every 1MWh decrease in contractual schedules from GCD to Ship Rock. This pattern holds similarly in the NW_CS alternatives, with the only exception for June, where the increase in TOT 2 South is notably higher. In June, for every MWh decrease from GCD to Ship Rock, an average of 25 MWh in NW_CS alternatives and 50 MWh in NW_CM alternatives needs to be procured to meet the demand. This emphasizes the importance of TOT 2 South in redirecting energy purchases to Four Corners loads when GCD generation isn't available to serve them.

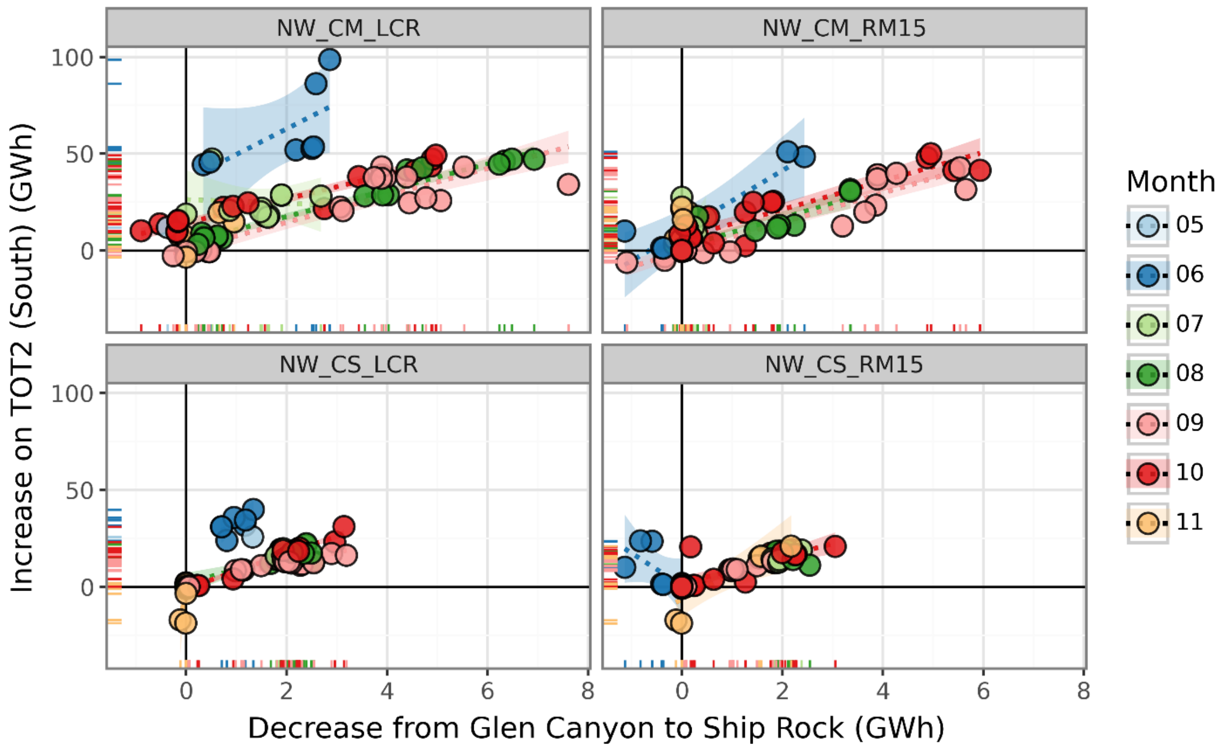


Figure 16 Correlation between the decrease of contractual schedules between GCD and Ship Rock and Increase in contractual schedules on TOT 2 South. The color-coded lines represent regression lines indicating conditional means for individual months. They demonstrate the overall trend in the data, with the span around the lines indicating confidence intervals.

5.4. SRP Exchange

This section describes the impact of the Lost generation on GCD on the SRP exchange, with a particular focus on understanding the correlation between the increase in SRP wheeling and the decrease in SRP energy exchange on the line 1X.

The increase in contractual energy under alternative actions for wheeling from SHR2 junction to GCD 1 junction is presented in Figure 17. There is a substantial disparity in the influence of NW_CM and NW_CS alternatives on the wheeling from Ship Rock 2 junction to GCD 1 junction. Specifically, the NW_CM alternatives exhibit a significantly higher impact compared to the NW_CS alternatives. In both NW_CM alternatives, the highest wheeling occurs predominantly in October and June, with July 2027 under trace T21 demonstrating the largest wheeling of 47 MWh.

The cessation of energy exchange in the event of lost generation from GCD stems from its primary role in serving southern loads. GCD generation is prioritized for southern loads before it can be allocated to Four Corners and Northern region. Consequently, when GCD experiences generation loss due to experiments, the energy exchange stops. This scenario underscores the critical role of wheeling, as it becomes the only method for transporting energy from Craig and Hayden, as well as Four Corners generation, to the SRP exchange.

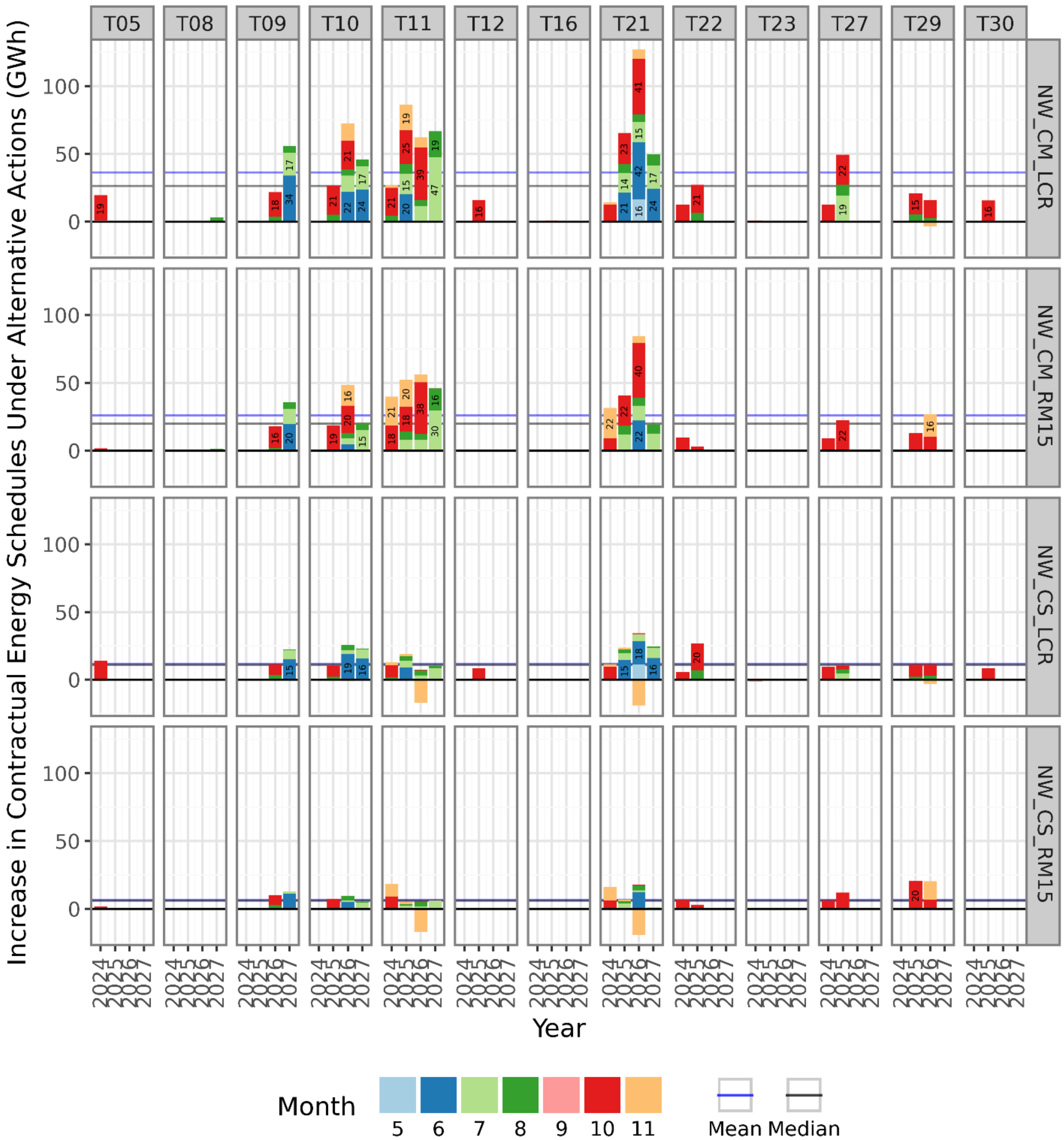


Figure 17 Increase in contractual energy under alternative actions for wheeling from SHR2 junction to GCD 1 junction. Horizontal lines indicate mean and median values, calculated from the months with experiments.

Figure 18 presents this correlation, showcasing a consistent linear pattern across months, alternatives, traces, and years. Each MWh decrease in SRP exchange, a direct consequence of lost generation at GCD, correlates with an increase in SRP wheeling.

Under the NW_CM alternatives, the relationship between the decrease in SRP exchange on 1X and the increase in SRP wheeling exhibits some variability. For each MWh decrease in SRP exchange, the increase in SRP wheeling ranges from 0.8 in June (6) to 0.1 in August (8). Interestingly, there is no change in wheeling during September (9), with only a slight change observed in November (11). This variability suggests that the NW_CM alternative is more sensitive to changes in SRP exchange compared to the NW_CS alternative.

Note that during August (8) and September (9), while the energy exchange on 1X undergoes significant changes, the wheeling remains relatively stable. This indicates that the wheeling is the least sensitive to changes in energy exchange. The heightened sensitivity observed in the NW_CM alternatives can be attributed to the continuous experiments conducted throughout the week, whereas the NW_CS alternatives restrict experiments to weekends only.

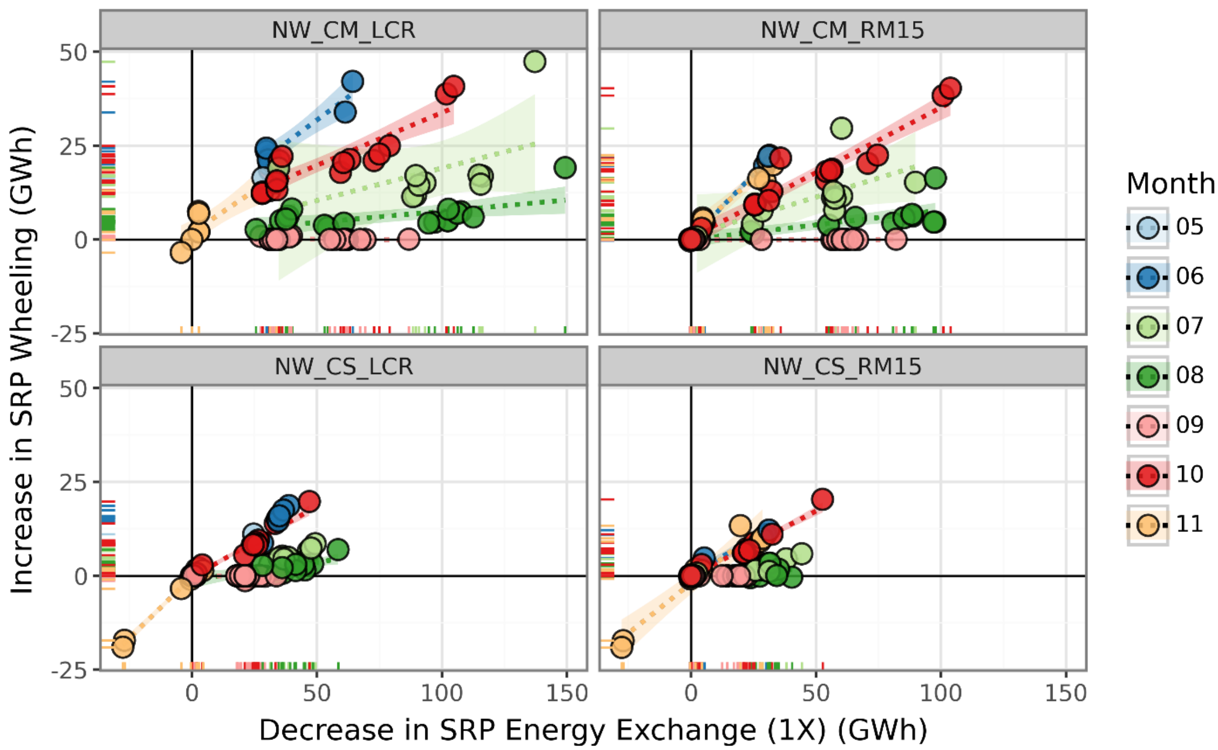


Figure 18 Increase in SRP wheeling in respect to decrease in SRP energy exchange from SHR2 junction to GCD 1 junction. The color-coded lines represent regression lines indicating conditional means for individual months. They demonstrate the overall trend in the data, with the span around the lines indicating confidence intervals.

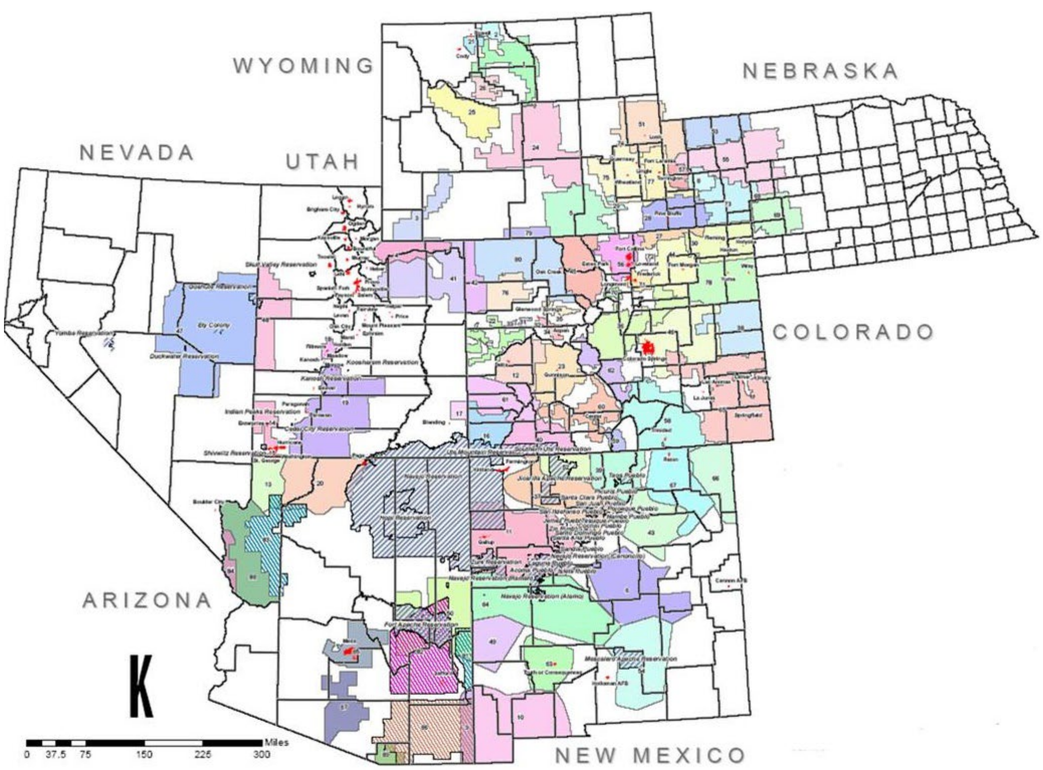
3.3 Energy and Power

3.3.1 *Affected Environment*

This section describes Glen Canyon Dam and the Glen Canyon Powerplant's power operations and power marketing. Additional information on the socioeconomic environment relating to hydropower and additional resources, including baseline economic conditions for the seven-state CRSP hydropower customer area, can be found in **Section 3.15** and **Section 3.16**, Socioeconomics and Environmental Justice, respectively.

The powerplant is connected to the Western Power Grid via a regional transmission system. Power generated at Glen Canyon Dam provides electricity for the US Department of Energy's WAPA customers. WAPA is responsible for providing electricity to a 15-state region of the western United States. Glen Canyon Dam is a major contributor to the transmission system and typically provides electricity to Wyoming, Utah, Colorado, New Mexico, Arizona, Nevada, and Nebraska (DOI 2016a, p. 3.221). Glen Canyon Dam also provided emergency power supplies to California in 2000, 2001, 2020, and again in 2022. **Figure 3-14** shows a map of CRSP hydroelectric power customers.

Figure 3-14
CRSP Hydroelectric Power Customers Map

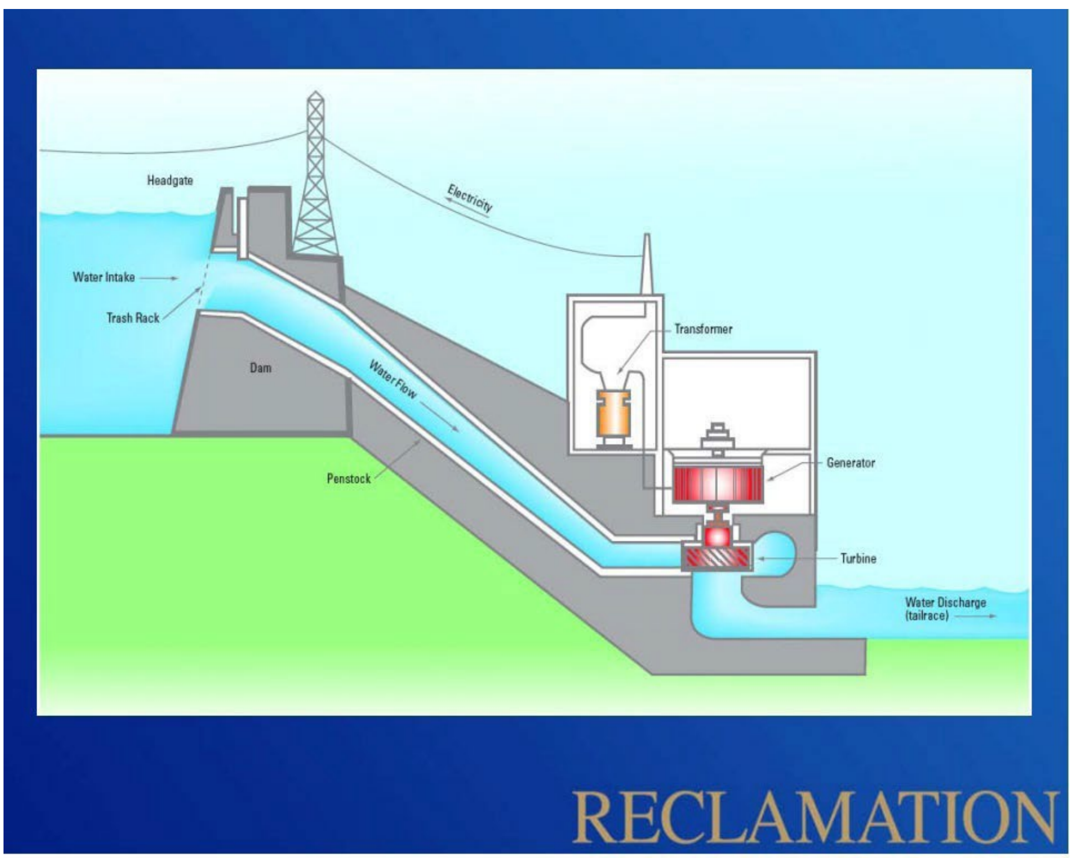


Operations at Glen Canyon Dam affect the Upper Colorado River Basin Fund (Basin Fund)[1], consumers, and government agencies. Revenues from power generation are deposited into the Basin Fund, which funds authorized activities under the CRSP Act of 1956 and other federal laws.

Power Operations

Power operations are the physical operations of an electrical power system, including hydropower generation and control, operational flexibility, scheduling, power generation load-following, regulation, reserves, transmission, and emergency operations. These are discussed in the sections below. Glen Canyon Dam operations directly impact power generation. The amount of water discharged through the generator units and the elevation of the reservoir dictate the amount of electricity generated. Typical operations at Glen Canyon Dam result in power generation at the powerplant, with electricity moving from the plant and along the transmission system to the customers. A simplified diagram of the powerplant's operations is provided in **Figure 3-15.**

Figure 3-15
Powerplant Operations Diagram



[1] https://www.usbr.gov/uc/rm/crsp/index.html

Hydropower Generation

Glen Canyon Dam has eight generators with a maximum combined capacity of 1,320 MW when the reservoir elevation is 3,700 feet (DOI 2016a). The powerplant requires a minimum Lake Powell elevation of 3,490 feet to operate. The LTEMP FEIS provides additional historical power generation data, such as annual net generation, and is incorporated by reference (DOI 2016a, pp. 3.199–3.200). Power generation varies on daily, seasonal, and yearly scales as a result of contract obligations, water release schedules, power needs, reservoir levels, and other operational requirements. Releases through the river outlet works do not generate power, and therefore, have no power system economic value (DOI 2016a).

Basin Fund

The CRSP Act of 1956 established the Basin Fund, 43 U.S.C. § 620d, which remains available until expended to carry out the project's purposes and operations. Maintaining a sufficient Basin Fund balance is critical to operating and maintaining reliability of CRSP facilities in delivering water to water users and generating and transmitting power to power customers. Reclamation and WAPA use this fund to repay the federal CRSP investment (with interest); operations and maintenance expenses of CRSP facilities; provide power for WAPA customers; provide funding under a Basin States' Memorandum of Agreement (MOA); support environmental and salinity programs; fund environmental programs like the Glen Canyon Dam Adaptive Management Program (and other related experiments) and the Upper Colorado River Recovery Implementation Program (and related experiments); and provide irrigation assistance.

WAPA provides wholesale power to preference customers including public utilities, municipalities, and American Indian Tribal Nations which fold this power into the rest of their portfolio to fulfill their load requirements and, in the case of Tribes not operating utilities, provide economic benefits of a WAPA hydropower allocation to their communities. Under WAPA's current rate structure, WAPA provides its long-term firm power customers with a set amount of power on a quarterly basis. The amount of power is based on the amount of water Reclamation forecasts to release from the CRSP units during that quarter. If CRSP units do not generate enough power to fulfill these contractual and rate obligations, WAPA and its customers purchase power and transmission on the energy market to make up the difference. WAPA uses cash from the Basin Fund to make those purchases.

Under the Grand Canyon Protection Act of 1992, Pub. L. 102-575 (GCPA), WAPA records the financial costs of environmental experiments at Glen Canyon Dam as a non-reimbursable expense by accounting for such costs as a constructive return to the U.S. Treasury, rather than an operations and maintenance expense to be recovered through WAPA's cost-based power rates. By bypassing the electrical generators at Glen Canyon Dam, the experiment will reduce hydropower generation. Accordingly, WAPA will be required to purchase replacement power to fulfill contractual delivery obligations. The experiment would markedly increase the amount of non-reimbursable costs drawn from the Basin Fund and returned to the Treasury. Other than the Basin Fund, WAPA does not have a non-reimbursable funding source that can be used to mitigate the costs of this experiment.

Operational Flexibility

The operational flexibility of hydroelectric power generation allows WAPA to quickly and efficiently increase or decrease generation in response to customer demand, generating unit or transmission line outages (contingency reserves), unscheduled customer deviation from internally scheduled contracted power usage (regulation and load/generation following) within a specific metered load area known as a Balancing Authority (BA)[2], integrated power system requirements, and requests for emergency assistance from interconnected utilities. Under the water release parameters instituted on an interim basis in 1991 and permanently under the 1996 ROD following the completion of the Glen Canyon Environmental Impact Statement (Reclamation 1995), WAPA currently restricts the scheduling of customer contract allocations to 2-day-ahead prescheduling only. Ramping restrictions, imposed under the 1996 ROD operating criteria, do not allow generation at Glen Canyon Dam to adjust sufficiently each hour to match the power customer demand schedules. These ramping restrictions result in increased use of alternate generating resources to meet power customer demand schedules. Operational conditions are complicated by the frequency, season, and time of day any of these events may occur; physical and environmental operating restrictions at other CRSP generating facilities and within the interconnected electric system; and the availability and price of alternative power resources (DOI 2016a).

Although there is considerable potential for flexibility in Glen Canyon powerplant operations, current operating criteria have placed multiple restrictions on the variability of water released from the dam, thus restricting operations at the powerplant. Prior to 1991, Reclamation operated the dam and powerplant to maintain a minimum release of 3,000 cfs in summer months and maintained a 1,000-cfs limit minimum flow for the remainder of the year. There were no restrictions on ramp rates, and daily fluctuations were occasionally as high as 28,500 cfs in the summer months and 30,500 cfs for the rest of the year (Poch et al. 2011). Beginning in August 1991, an Interim Flows decision restricted the operation of the dam for environmental reasons, and the Interim Flows decision was used as the basis for operation until February 1997, when the February 1997 operating criteria, based on the 1996 ROD, restricted dam operational flexibility with an operating regime referred to as MLFF. The operating regime was again modified with the 2016 LTEMP ROD which continued with a minimum water release rate of 8,000 cfs or greater between the hours of 7 a.m. and 7 p.m., and at least 5,000 cfs between the hours of 7 p.m. and 7 a.m., the maximum hourly increase (i.e., the up-ramp rate) is 4,000 cfs/hr, a daily fluctuation limit of 8,000 cfs per tolling 24-hr period, and a maximum release rate for power generation of 25,000 cfs. The LTEMP ROD modified the daily fluctuation limit so it is calculated as a function of the monthly volume and increased the down-ramp rate to 2,500 cfs/hr (DOI 2016a).

[2] Note that in this section of the SEIS, BA is used as the abbreviation for Balancing Authority. In other sections of the SEIS, BA refers to Biological Assessment.

Scheduling

Power scheduling occurs by matching available power generation to seasonal, daily, and hourly system energy and capacity needs. At Glen Canyon Dam, power scheduling is affected by the temporal distribution of monthly water release volumes, restrictions in water release patterns, availability of generator units (due to maintenance), availability of other CRSP hydropower units, power allocations, and peak and off-peak power demand periods. Scheduling to meet power requirements typically results in higher water releases via the powerplant in the peak power demand months of December, January, July, and August.

Load Following, Generation, and Regulation

Hydropower generation can change instantaneously in response to changes in the load (demand) or unanticipated changes in the power generation resources within the operating region. This ability to respond to rapidly changing load conditions is called load- and/or generation-following (DOI 2016a, p. 3.203).

Typically, power demand, or power load, increases during daylight hours and decreases during nighttime hours. The load is similar from Monday through Saturday, but the load drops considerably on Sunday. This type of operation (load following) creates large fluctuations in water releases, which can have negative impacts on some downstream environmental resources (DOI 2016a, p. 3.204). The 1996 ROD (Reclamation 1996) narrowed the range of operation for GCPA and CRSPA purposes, and thereby reduced the ability of power generation at Glen Canyon Dam to respond to customer load.

Changes in WAPA's scheduling guidelines typically occur slowly over a period of months, not only because of the operational constraints originally imposed by the 1996 ROD (Reclamation 1996) but also due to changing market conditions. The LTEMP FEIS also further reduced the load-following capability, despite increasing down-regulation rates, reducing operational flexibility. Operational flexibility has been affected by persistent drought and aridification, electricity market disruptions in 2000 and 2001, and extended experimental releases that reduce daily flow-rate fluctuations (DOI 2016a, p. 3.204). Operational conditions are further affected by the frequency, season, and time-of-day limitations that may be in effect; physical and environmental operating restrictions at other CRSP generating facilities and within the interconnected electric system; and the availability and price of replacement power (DOI 2016a, p. 3.201).

Capacity Reserves

WAPA operates a BA for the region and is required to maintain sufficient generating capacity to continue serving its customer load. This is to ensure reliable power availability and uninterrupted service. Total available capacity, in turn, is determined by the minimum and maximum allowable releases from other unit powerplants and is particularly important for emergency situations (DOI 2016a).

Disturbances, Emergencies, and Outage Assistance

During experimental releases, including the ones proposed in this action, Reclamation and WAPA will continue to operate Glen Canyon Dam with emergency exception criteria, as stipulated by the 2016 LTEMP ROD, the 2018 Operating Criteria for Glen Canyon Dam, and the 2021 Interagency Agreement (19-SLC-1021) between Reclamation and WAPA. Emergency operations are typically of short duration (usually less than 4 hours) and would be the result of emergencies at the dam or within the interconnected electrical system.

The emergency exception criteria specifies that operations at Glen Canyon Dam will be altered temporarily to respond to emergencies, including:

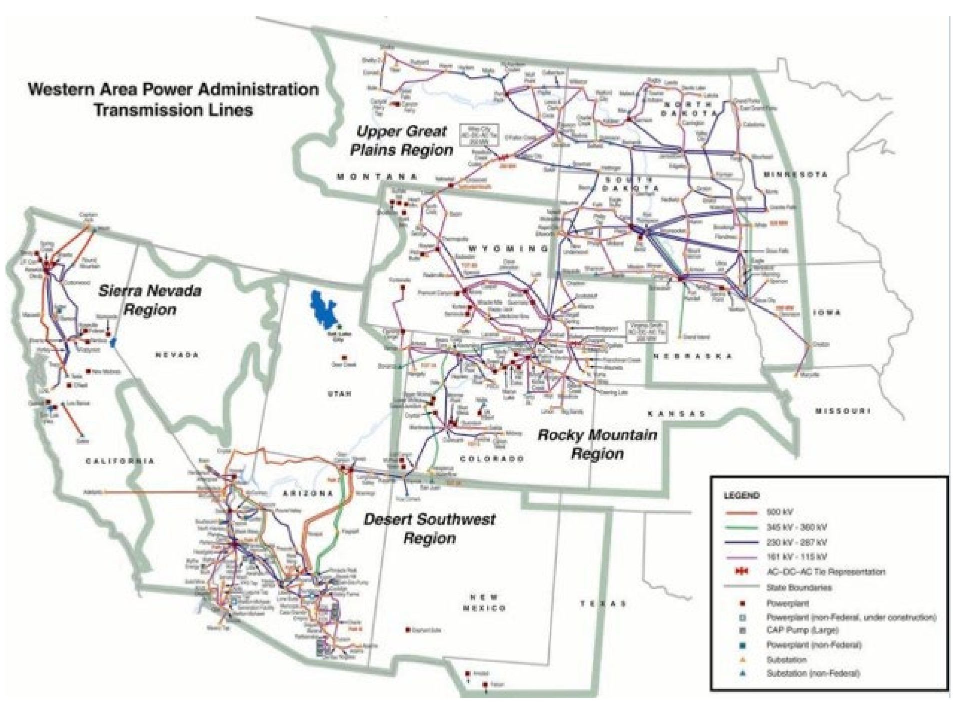
- Insufficient generating capacity
- Transmission system overload, voltage control, and frequency
- System restoration
- Humanitarian situations (search and rescue)

Transmission System

Glen Canyon Dam is connected to a transmission system that allows for power to serve users such as municipal, residential, Tribal, agricultural, and commercial consumers (**Figure 3-16**). Glen Canyon Dam's generation can affect transmission limitations when lines do not have enough capacity to transmit electricity from the point of generation to the point of demand. Actual transmission refers to the measured flow of power on the line. The North American Electric Reliability Corporation requires monitoring of the actual and scheduled power flow for system operation (DOI 2016a).

Figure 3-16

Western Area Power Administration Transmission System



Power Marketing

WAPA markets wholesale CRSP power to preference entities (WAPA, n.d.), serving approximately 5.8 million retail customers in the operating region (DOI 2016a, p. 3.206). Additional information about power marketing, including wholesale and retail rates, is included in the LTEMP FEIS. This information is incorporated by reference (DOI 2016a, pp. 3.206–3.209).

WAPA modified firm power rates for fiscal year 2022 in response to continued drought conditions and aridification, Lake Powell's reservoir level, associated reductions in power production caused by lower Glen Canyon Dam water releases and increasing market prices for firming power. Under this new rate, the burden of replacing generation not provided by the CRSP facilities was largely shifted to CRSP customers.

3.3.2 *Environmental Consequences*

This section provides an evaluation on the impacts to hydropower and CRSP by the alternatives. Evaluation should include consideration of all the following components that were analyzed in the LTEMP FEIS (2016; Page 4-322). Although the LTEMP FEIS also looked at hydropower impacts at Hoover Dam, that has not been analyzed here.

- Changes in the amount (MWh) and dollar value of hydropower generation at Glen Canyon Dam
- Impacts to the Basin Fund and CRSP Operations
- Changes in marketable capacity
- Impacts to the transmission system
- Availability of replacement power and source
- Changes in Emissions
- Effects on regional energy prices (LMPs)
- Impacts to responding to emergencies and disturbances
- Effects on the WAPA wholesale rate
- Effects on retail rates
- Non-use value

Methodology

GTMax Modeling

The GTMax SL model was developed by the U.S. Department of Energy's Argonne National Laboratory to simulate operation of the dams and powerplants in the CRSP system. The GTMax SL model is well suited for this application because it uses a systemic modeling approach to represent all system components while recognizing interactions among supply, demand, and water resources over time. GTMax SL represents other CRSP facilities in the same manner they are operated and marketed by WAPA. It optimizes the system on an hourly time step using a large set of mathematical equations that are solved using a linear programming software. All operations are within component limitations and system dispatch goals that are formulated as a set of linear constraints and bounds. The model considers reservoir information (releases and elevation), environmental constraints, electricity market prices, scheduling objectives, and operational constraints. The flow of energy between connected grid points and river flows are represented in the model by links that connect node objects. All hours are solved simultaneously, allowing the model to recognize that the dispatch of supply resources in any one hour affects the dispatch during all other times in a simulated week.

A version of the GTMax that includes the CRSP transmission topology called the SLIP Energy Routing Model (SERM) was used to estimate potential impacts to transmission of CRSP energy. and to estimate cost to replace lost Glen Canyon Dam generation. SERM determines optimal pathways that "contractually" transport CRSP energy from supply sources (generation and purchases) to sinks (FES customer loads) and energy market sales. SERM optimizes hourly energy market purchases and sales and measure implications of action alternatives on CRSP Office finances. SERM also simulates Salt River Project (SRP) Exchange agreements with the CRSP Office in which generation from the SRP Craig, Hayden, and Four Corners thermal power plants serve CRSP FES customers' loads in the northern and four corners area.

GTMax Modeling Inputs/Assumptions

Study period - Modeling from GTMax SL was conducted for the planning horizon, October 2023 through September 2027. Model results produced the energy generation (MWh) and economic value of electrical energy from operational differences at Glen Canyon Dam for each alternative. For computational efficiency, months when no experiments take place, GTMax was run for only seven-day representation each month. Hourly values from the seven-day representation are then extracted out to monthly values. In month where an experiment takes place, every hour of the month was modelled.

Energy prices – Future average peak and off-peak energy prices were from the forward mid-market power curves at the Palo Verde Hub on December 6, 2023.

Reservoir releases and elevations – Subset of 30 traces from Reclamation's CRMMS model that were used in the Interim Guidelines supplemental EIS.

Electric load – Estimated hourly generation assuming no experiments occurred was used as the estimated hourly load. Generation was with no experiments was estimated using the GTMax SL model.

PLEXOS Modeling

In order to assess the impact of varying operational patterns at the Glen Canyon Powerplant, National Renewable Energy Laboratory (NREL) used commercially available production cost modeling tool, PLEXOS (a product of Energy Exemplar (https://www.energyexemplar.com/plexos)). This tool is widely used by NREL and other organizations to simulate the operation of the electric power system on an hourly basis. PLEXOS does an optimization to determine the least-cost unit commitment and economic dispatch of every generator in the system, given the physical constraints of the system itself. These physical constraints include the hourly electricity demand, the operating parameters of individual generators, the transmission system topology, and the availability of wind, solar, and water for electricity generation. It also ensures the sufficient provision of operating reserves.

The outputs of PLEXOS include the hour-by-hour optimal dispatch of the generation fleet, locational marginal prices, and total generation cost (including fuel, variable operating and maintenance costs, and start & shutdown costs). PLEXOS can also identify transmission lines or paths which exhibit congestion and any reliability concerns, such as unserved load or reserves.

The analysis focused on the Colorado River Basin, which includes parts of several balancing authorities or load serving entities in the Southwestern United States: Western Area Lower Colorado (WALC), Western Area Colorado Missouri (WACM), Arizona Public Service (APS), Nevada Power (NEVP), parts of the PacificCorp footprint (PACE), Public Service of Colorado (PSCO), Public Service of New Mexico (PNM), Tucson Electric Power (TEP) and Salt River Project (SRP). NREL worked with study participants (WAPA, ANL, and SRP) to improve the representation of this focus area by adjusting generator retirement dates, updating of transmission line wheeling rates, and increasing the reserve requirement in the region. The largest portion of electricity generation in 2024 is still coal, but by 2027, wind and coal generation are present in roughly equal amounts driven by growth in wind generation and retirements of coal generation. Solar generation also continues to grow through the four years, and the other sources of generation (nuclear, natural gas, and hydropower) remain relatively stable. Note that the total generation in the region exceeds total annual load indicating that the region is a net exporter to other regions of the Western Interconnection.

A detailed description of methods and scenarios considered can be found in the NREL 2024 report provided as part of this comment document (dated March 10 draft report).

Alternatives

No Action Alternative

Under the No Action Alternative, no changes would be made to Glen Canyon Dam operations. Therefore, water would continue to be released primarily through the penstocks, as described in the LTEMP FEIS. Power generation would continue, similar to historical levels, with slight variations, depending on water availability and constraints outlined in the LTEMP FEIS. Economic value of electrical energy from energy sales would also continue to be generated, similar to historical levels, with slight variations, depending on consumer demands, generation levels, and constraints outlined in the LTEMP FEIS.

Action Alternatives

HFE Action Common to all Alternatives

The HFE changes to the implementation window are common to all alternatives and modify the actions in the same manner. Although an analysis of the impacts specific to the HFE window change are possible and would be informative, time constraints of this action does not allow for a robust analysis to be included in this document.

Risk, likelihood, impact, and mitigation

Risk can be defined as the combination of the probability of an event and its consequences (The Institute of Risk Management, www.theirm.org). However, Dr. Yackulic better stated that "a standard definition of risk includes the likelihood of an event, the impact of the event, and the ability to mitigate the impact if it occurs" (Yackulic, via email on 2/25/2024). To understand risk, and the probability of an event occurring, the analysis should first evaluate the likelihood of an event taking place and then evaluate the effects when those events occur. The bypass events represent a skewed distribution across the 30 hydrologic traces used in the assessment, and the data appears to be serially correlated (e.g., autocorrelation), meaning once an event is triggered it is more likely an event will be triggered in subsequent months or years (and vice versa). Because of these effects, the methodology used in the draft SEIS of describing the impacts over all 30 hydrologic traces is misleading. Of the 30 hydrologic traces, only 8 traces trigger a bypass event at the river mile 15 location, and 13 traces trigger an event at river mile 61. Therefore, in 22 traces for river mile 15 and 17 traces for river mile 61, the data contains only zeros for bypass amounts and impacts to energy value. In these cases, the probability of bypass is zero and the impact to hydropower is zero. Thus, when an average is used to describe the entire 30-trace data set (e.g., the probability), it is diluted by those zeros and produces a misleading characterization of the impact (e.g., the consequence). This conflates the two components of risk (e.g., likelihood, and effect or consequence) with each other, which then results that are misleading (and in this case an underestimate) of what may be needed to mitigate the impact of the event if it occurs.

The correct methodology to evaluate the likelihood and costs of implementing these experiments is similar to how experiments were evaluated in the LTEMP FEIS (see Page 4-346) on the "Cost of Experiments." For example, HFEs do not occur every year, but when they do occur, LTEMP describes the impact in terms of when the events are implemented, and not as an average over the years in which they could have been implemented but were not. Also, the program describes the impact of HFEs as costing about $1-3 million *per event* over the past 12 years, and not as an average of $0.59 million *per year* over the past 12 years. Describing impacts as an average over the years in which an action could have been implemented, but was not, instead of describing the impact per event will likely lead to conclusions that the impact of the experiment is smaller. Additionally, describing a multi-month experiment with impacts separated by month could also mislead decision-makers in assessing the true impacts of the experiment. For example, LTEMP describes the cost estimates for Macroinvertebrate Flows as $1.62 million *per event* even though the experiment occurs over a 4-month period of time.

WAPA's historical cost estimates have been relatively accurate to the actual cost incurred for past HFEs and Macroinvertebrate Flow experiments (**Table 3-11**). This contrasts with the large differences in the experimental cost estimate provided in the public draft SEIS and the analysis in this document (**Table 3-12**). As stated above, this analysis separates the probability of an event from the consequences of an event and does not conflate the two different components of risk. This also shows the impact of using the entire 30-trace data set to describe the impacts of an experiment that is implemented in fewer than half the traces in the data set. This illustrates that the methodology used in the public draft SEIS produced a much greater error in estimating the likely cost of an experiment when compared to WAPA's historical estimates of experimental costs. However, not all of WAPA's cost estimates err in the same direction, some estimates being higher, and others being lower than the actual cost. Contrast this with the cost estimates in the public draft SEIS which consistently underestimated the likely cost of the proposed action on hydropower on a per experiment basis. This indicates that the methodology used in the public draft SEIS underestimates the impact (i.e., consequence) to hydropower.

Table 3-11
Comparison of WAPA's Pre-experiment Cost Estimate with the Post-experiment Cost Determination for HFEs and Macroinvertebrate Flows from 2012-2023

Experiment	Estimated cost per occurrence ($M)	Actual cost per occurrence ($M)	Difference between Estimated and Actual ($M)	Difference between Estimated and Actual (%)
High Flow Experiments (HFEs)				
LTEMP EIS	1.64			
2012	--	1.918*		
2013	1.74	2.593	-0.844	-49
2014	1.749	2.1	-0.351	-20
2016	1.4	1.15	+0.25	+18
2018	0.924	1.3	-0.376	-41
2023	1.483	--**		
Macroinvertebrate Flows				
LTEMP EIS	1.62			
2018	0.336	0.166	+0.170	+51
2019	0.332	0.327	-0.005	-2
2020	0.408	0.941	-0.533	-131
2021	0.729	1.021***	-0.292	-40
2022	1.401	1.154	-0.247	+18

*Included cost of the fall steady flow

**Financial assessment has not been completed

*** Macroinvertebrate Flows were not implemented in 2021 but a cost was calculated by Argonne for discussion purposes at the time to see what the cost would have been if one had been implemented.

Table 3-12
Comparison of the Public Draft SEIS Cost Estimates (all traces) with WAPA's Cost Estimates of Experiments using only Traces that have Bypass Flows

Experiment	Average using all 30 traces ($M)	Average using only bypass traces ($M)	Difference between all traces and bypass traces ($M)	Difference between all traces and bypass traces (%)
LTEMP SEIS Experiments				
Cool Mix (RM15)	15.26	60.72	-45.46	-298
Cool Mix (RM61)	26.20	62.53	-36.33	-139
Cool Mix w-flow spike (RM15)	15.48	59.00	-43.52	-281
Cool Mix w-flow spike (RM61)	25.75	61.14	-35.39	-137
Cold Shock (RM15)	8.76	33.08	-24.32	-278
Cold Shock (RM61)	13.05	31.36	-18.31	-131
Cold Shock w-flow spike (RM15)	9.21	34.69	-25.48	-277
Cold Shock w-flow spike (RM61)	15.04	34.40	-19.36	-129
Non-Bypass (RM15)	0.97	4.00	-3.03	-312
Non-Bypass (RM61)	0.67	2.81	-2.14	-319

Impacts on Power Operations

This experiment may impact WAPA's ability to meet its customers' energy needs, and a reduction in generation could result in energy emergencies when supply is insufficient to meet demand. The proposed bypass alternatives will increase the risk that WAPA will be unable to meet its contractual obligations to provide customers with power unless it is able to procure sufficient replacement energy and associated transmission. This replacement energy and transmission may not be available without significant added expense, and WAPA has been notified by some of its trading partners that they may not have sufficient replacement power and transmission available for purchase during periods of peak power demand available at any price.

Table 3-13 shows the effect mentioned previously of including traces where the experiment is not triggered in the analysis as was provided in the public draft SEIS. In the columns showing average lost power production for all 30 traces (including when the experiment is not implemented), the potential effect to power generation is drastically reduced when compared to the average values for traces where the experiment is implemented (the 8 traces for river mile 15 and 13 traces for river mile 61). For the Cool Mix Alternative triggered at river mile 15, the average is 146.88 GWh lost over all 30 traces, while the average computed for the 8 traces where an experiment is triggered is much higher at 584.16 GWh.

Table 3-13
Potential 45-Month Flow Impacts on Power Generation, All 30 Traces versus Only Traces with Bypass

Alternative	Total Average Lost Production – RM 15		Total Average Lost Production – RM 61	
-	(GWh) 30 traces including zeros	(GWh) 8 Bypass Traces	(GWh) 30 traces including zeros	(GWh) 13 Bypass Traces
Cool Mix Alternative	146.88	584.16	234.09	552.83
Cool Mix with Flow Spike Alternative	136.73	545.60	254.56	545.51
Cold Shock Alternative	68.11	284.60	108.89	273.05
Cold Shock with Flow Spike Alternative	68.37	283.58	125.65	288.98
Non-Bypass Alternative	(9.01)	10.70	(8.43)	4.68

(GWh) 13 trac

Source: WAPA GTMax Model 2024
Model results for the operating period from January 2024 to September 2027. The figures presented are the average power generation estimates out of all 30 traces compared with just the 8 and 13 modeled traces that where an experiment was triggered.

Figures 3-17 and 3-18 show the exceedance values of lost energy production (GWh) for river mile 15 and river mile 61 respectively. This illustrates the nature of this data which includes many zeros in the time series. However, when the experiment does occur it can have substantial effects. Averaging all of these values across this series skews the impacts toward zero, or no implementation.

Figure 3-17

Exceedance Curve showing the Probability of Impact on Energy Generation (GWh) using all 30 Traces (including zeros) for all Five Proposed Alternatives if Triggered at River Mile 15.

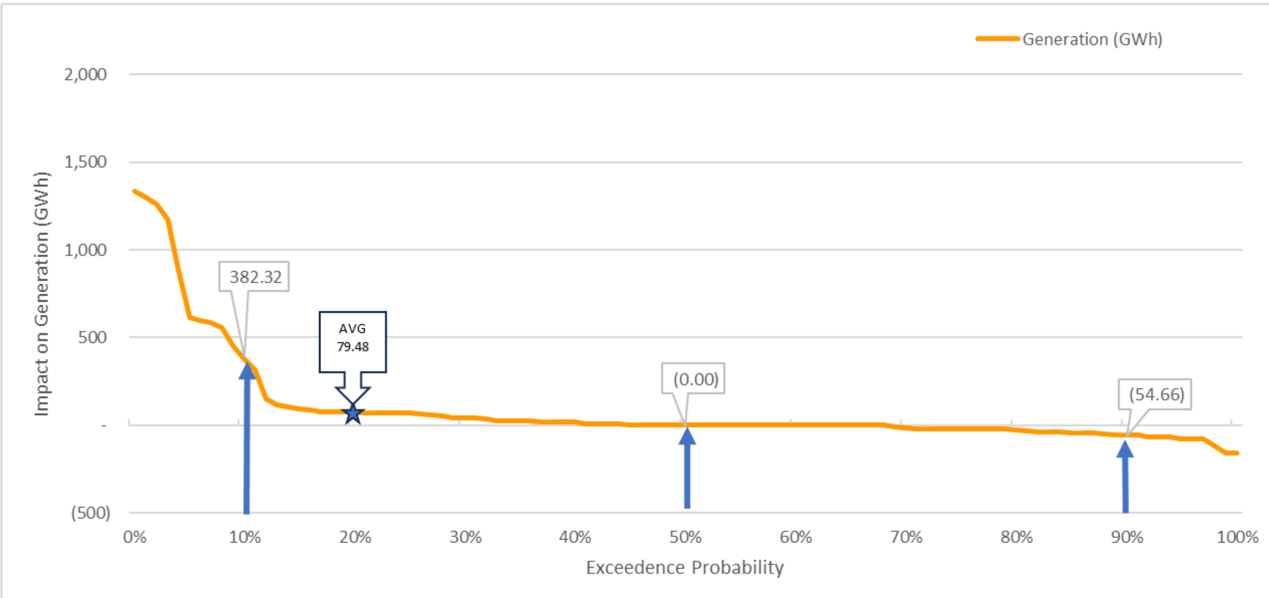
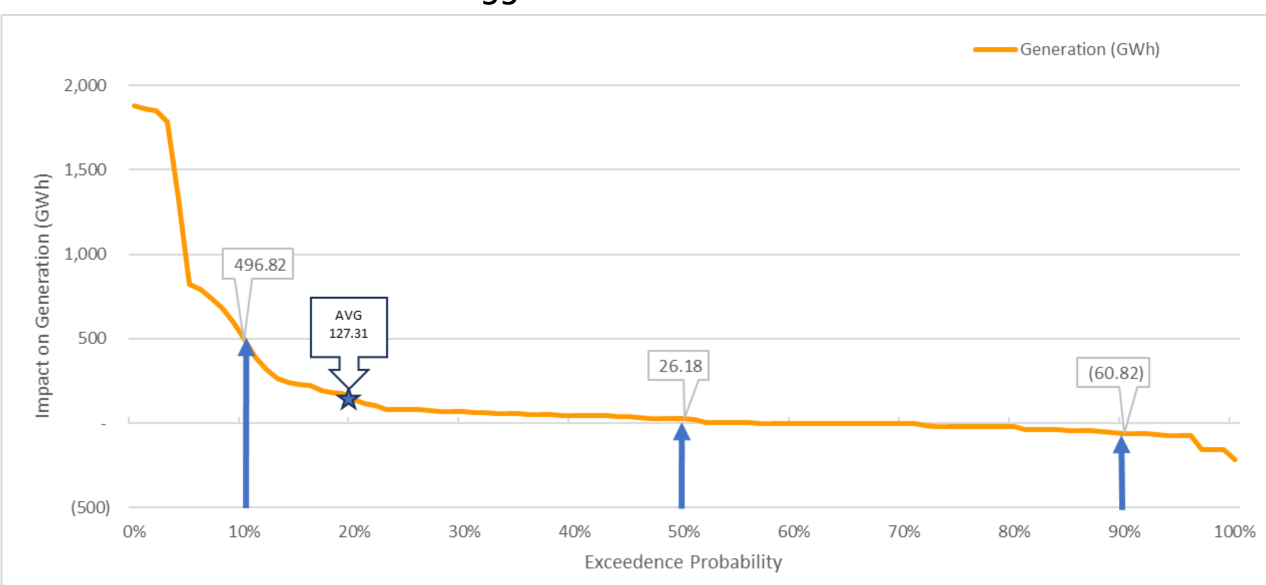


Figure 3-18

Exceedance Curve showing the Probability of Impact on Energy Generation (GWh) using all 30 Traces (including zeros) for all Five Proposed Alternatives if Triggered at River Mile 61



Another important consideration when assessing hydropower impacts is the time of year the experiment is expected to be implemented. The number of months with experiments is shown in **Figure 3-19** below. The months with the most occurrences of experimental flows are August through October. This is somewhat different from the typical release temperature data because the warmest releases typically occur in October or November. Less bypass is needed in October and November because the river stops warming as water continues downstream during this time of year (**Figure 3-20**). Thus, the peak of occurrence of experimental releases happens earlier in the year than when the warmest release temperatures are typically observed.

Peak hydropower needs and values occurs over these same months with capacity generally being limited in August (see the Impacts to Capacity section below). These data also show the serial correlation that occurs within a year. If an experiment is triggered in early season, it is much more likely to continue to be triggered in subsequent months due to factors that triggered the experiment, like low reservoir elevations which are likely to continue for the rest of the summer. Therefore, using averages will underestimate the "impact of an event" because the likelihood of having bypass in a month following a month with bypass is high, and not independent. The economic value of energy section below further describes the impacts of the various bypass traces and the impact that those events could have on hydropower value.

Figure 3-19
The Number of Times each Alternative is Triggered, by Month, for all 30 Traces

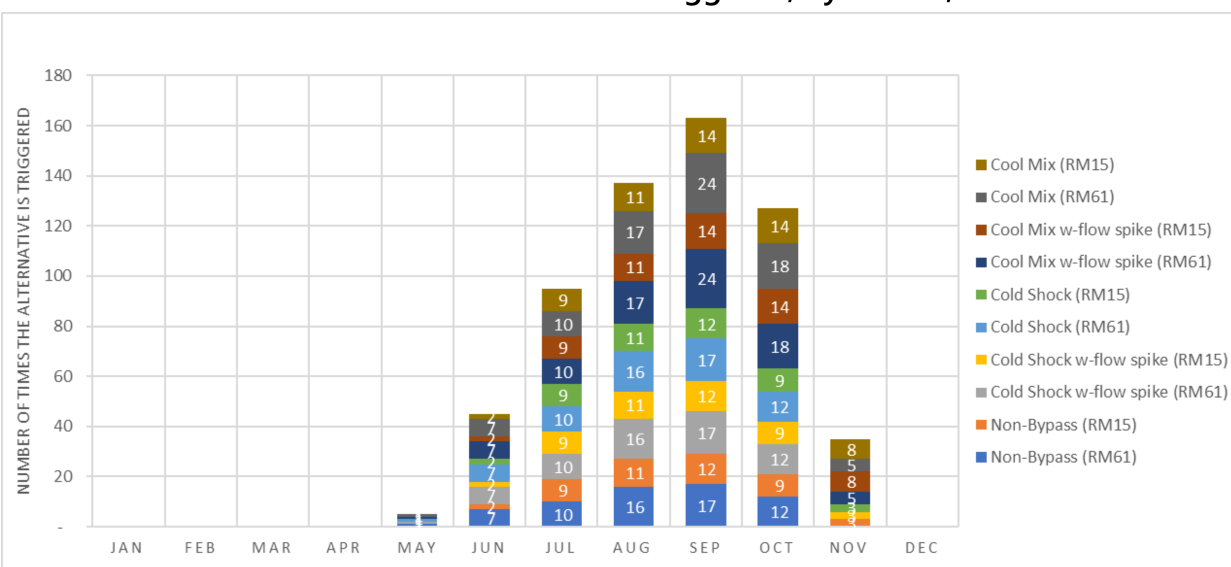
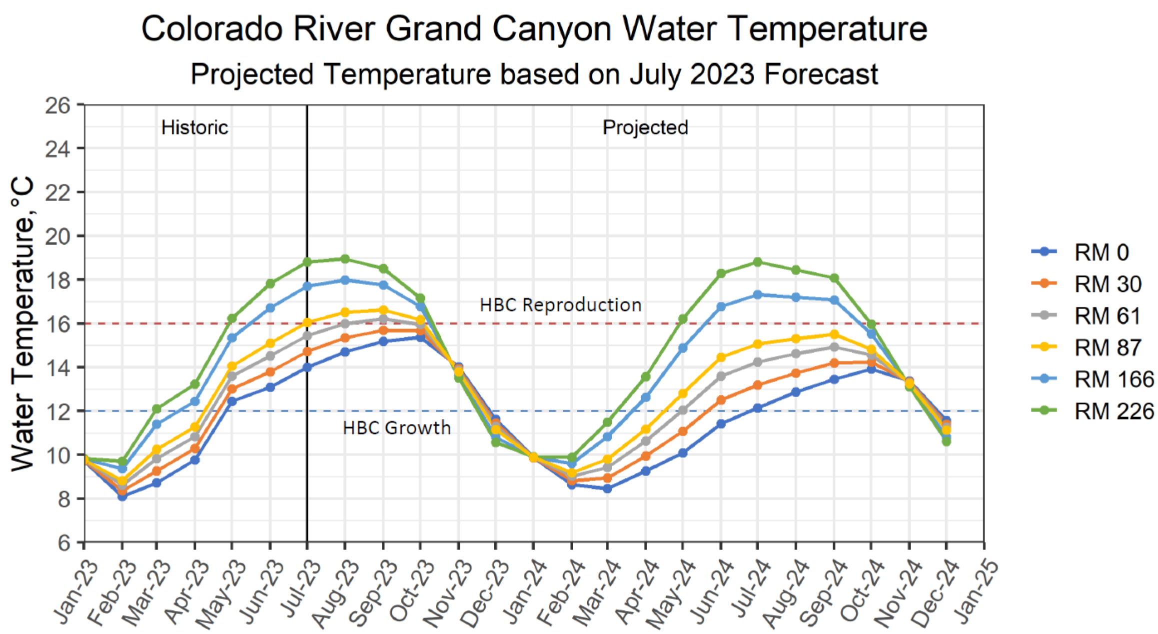


Figure 3-20
Projected Water Temperatures on the Colorado River Downstream of Lees Ferry (RM 0) in 2023 and 2024



In summary, when looking at the likelihood of implementation over the 30 traces, implementation is more likely with the river mile 61 trigger than river mile 15, and that overall implementation is less likely than not triggering a bypass experiment at all using the 30 traces. This is in part because the data is serially correlated, meaning that once the reservoir is high enough to avoid triggering a warm water release, then reservoir elevations in the months and years following are likely to be high as well, especially over a short 4 year time period like this one. Thus, the rest of the risk assessment is to determine the consequence of an event occurring and how to mitigate that event.

Therefore, from this point on in this analysis, only traces where a bypass experiment is triggered, either at river mile 15 or river mile 61, will be used in the analysis to determine the potential effect of the action on hydropower. This is similar to the how experiments were assessed in the LTEMP FEIS for HFEs and Macroinvertebrate flows. There is some ability to assess the impacts on an annual basis, however due to lack of sufficient time that analysis was not possible and results are generally provided for the sum over the 4 years by trace or traces. There would be additional value in further looking at individual years.

Impacts on Power Generation

All four bypass alternatives would include bypassing more water through the river outlet works where energy is not generated. As above, in 22 traces for river mile 15 and 17 traces for river mile 61, no incidents of bypass occur for the experiments and thus the only impacts for those traces are changes due to the new HFE window. For river mile 15, **Table 3-14** describes the impacts on generation of the 8 traces with bypass events, and for river mile 61, **Table 3-15** describes the impacts on generation of the 13 traces with bypass events.

Each bypass alternative would reduce the energy generation and increase the amount of replacement energy required to meet demand in the interconnected transmission and distribution system. The Non-Bypass Alternative would provide modest increases in energy production but is impacted by the effects of the New HFE Window at similar levels of impact.

Effects on energy generation for the bypass experiments, using the river mile 15 trigger, could range from a loss of 29.89 GWh up to a loss of 1,420.55 GWh over the 4 years of the SEIS, depending on the bypass alternative implemented (**Table 3-14**) with the Cool Mix Alternative being the most impactful. Effects on energy generation for the bypass experiments using the river mile 61 trigger could range from a loss of 30.31 GWh to a loss of 1,959.15 GWh, depending on the bypass alternative implemented (**Table 3-15**) with the Cool Mix Alternative again being the most impactful.

Table 3-14
Potential 45-Month Flow Impacts on Power Generation, River Mile 15
(Loss in GWh)

Alternative	Average	Median	Min	10th %	90th %	Max
Cool Mix Alternative	584.16	373.27	38.61	67.25	1,391.60	1,420.55
Cool Mix with Flow Spike Alternative	545.60	347.91	38.61	67.25	1,279.92	1,317.66
Cold Shock Alternative	284.60	238.29	29.89	51.79	587.56	632.60
Cold Shock with Flow Spike Alternative	283.58	210.52	29.89	51.79	593.43	641.64
Non-Bypass Alternative	10.70	13.67	(1.71)	(0.52)	19.75	22.04

Source: WAPA GTMax Model 2024
Model results for the operating period from January 2024 to September 2027. The figures presented are the power generation estimates out of 8 modeled traces where experiments are triggered at RM 15.

Table 3-15
Potential 45-Month Flow Impacts on Power Generation, River Mile 61
(Loss in GWh)

Alternative	Average	Median	Min	10th %	90th %	Max
Cool Mix Alternative	552.83	198.14	39.19	39.39	1,820.80	1,959.15
Cool Mix with Flow Spike Alternative	545.51	202.87	39.29	45.10	1,770.24	1,921.12
Cold Shock Alternative	273.05	220.82	30.31	43.53	662.38	779.33
Cold Shock with Flow Spike Alternative	288.98	140.55	30.31	58.35	677.85	829.01
Non-Bypass Alternative	4.68	0.74	(5.33)	(2.74)	16.48	23.23

Source: WAPA GTMax Model 2024
Model results for the operating period from January 2024 to September 2027. The figures presented are the power generation estimates out of 13 modeled traces where experiments are triggered at RM 61.

In addition, these releases would impact the timing of when bypass occurs during the week. For the Cool Mix Alternative and Cool Mix with Flow Spike Alternative, water would constantly be released through the river outlet works all week long. These options would result in less power generation, even during peak demand hours, which affects the Capacity evaluation below for August and must be considered in the overall economic impacts to hydropower. The Cold Shock and Cold Shock with Flow Spike Alternatives would mostly impact generation during weekends, when demand is lower and thus did not affect the Capacity analysis. The low flow portion of the Non-Bypass Alternative occurs on the weekend and at night when demand is lower and the high flow portion occurs during the day on a weekday when demand is higher but only occurs one day a week so does not affect the Capacity analysis.

Impacts on Economic Value of Electrical Energy

The bypass alternatives would have financial impacts that vary to a large extent based on market prices for energy, reservoir elevations, temperature conditions, and which river mile is targeted for cooling (i.e., RM 15 or RM 61), which will be based on the distribution of smallmouth bass being found in the river. Bypassing water around the generators results in a reduction in power generation, and in expenses to the Basin Fund because WAPA is required to purchase replacement power to cover the lost generation to firm energy contracts during experimental releases. In the next analysis, only the traces that result in bypass experiments are used and these are the same 8 traces for the RM 15 and 13 traces for the RM 61 triggers as used above. As describes earlier, adding 22 or 17 traces with all zeros in an impacts analysis only serves to underestimate the potential impact of the experiments on hydropower. When the experiment is not implemented the impact will be zero, and again this relates to risk of occurrence, not to the effect of the action. If the January 1 reservoir elevation remains above about 3570' the risk of being in one of the traces with bypass is very low (Eppehimer et. al., In Prep). Thus, if future hydrology shows it likely that the reservoir will increase in elevation then the likelihood of implementation and impacts decreases toward zero. If, however, the reservoir is declining during a bypass experiment, the risk is high of triggering an experimental bypass release the following year due to the serial correlation of the data and the nature of reservoir operations.

Effects on the value of electrical energy for the bypass experiments, using the river mile 15 trigger, could range from $1.43 million to $147.82 million over the next 4 years, depending on the bypass alternative implemented (**Table 3-16**) with the Cool Mix Alternative being the most impactful. Effects on the value of electrical energy for the bypass experiments, using the river mile 61 trigger, could range from $1.31 million to $222.03 million over the next 4 years, depending on the bypass alternative implemented (**Table 3-17**) with the Cool Mix Alternative being the most impactful.

The Cool Mix Alternative would have the most financial impacts, with an average estimated economic value of electrical energy loss of around $60.72 million for river mile 15 triggered traces, and $62.53 million for river mile 61 triggered traces over the period from January 2024 to September 2027 (**Tables 3-16 and 3-17**). The Cool Mix with Flow Spike Alternative would have the second-most financial impacts, with an estimated economic value loss of $59.0 million for river mile 15 and $61.14 million for river mile 61. The Cold Shock with Flow Spike Alternative would have the third-most financial impacts, with an estimated economic value loss of $34.69 million for river mile 15 and $34.40 for river mile 61. The Cold Shock Alternative would have an estimated economic value loss of $33.08 million for river mile 15 and $31.36 million for river mile 61. The Non-Bypass Alternative has loss of about $4.00 million at river mile 15 and $2.81 million at river mile 61.

To provide adequate protection for the Basin Fund, WAPA and Reclamation will need to consider impacts that might affect the Basin Fund at the 90th percentile and at maximum levels. Impacts to the value of energy over the next 4 years could be as much as $145-148 million for a trigger at river mile 15, and $202-222 million for a trigger at river mile 61. These scenarios would have substantial effects on the Basin Fund as described below. Typical costs for experiments historically under LTEMP have been about $1-3 million for HFEs and about $0.3-1 million for the Macroinvertebrate Flows. This is in contrast, however, to the relatively large cost of the 2000 Low Summer Steady Flow which was about $26.4 million (Ralston 2011). If the experiments are implemented, and the Cool Mix Alternative is chosen, even the average costs are estimated to be about $60 million over the 4 year time period of this SEIS with the possibility of much higher costs if poor hydrologic conditions continue. If the experiment is triggered in year 1 (e.g., summer of 2024), which remains possible based on current hydrology, then the expectation based on these traces and the serial correlation of the time series is that the costs would continue over the 4 years and tend to track the $60 million value identified above.

Table 3-16
Potential 45-Month Flow Impacts on Economic Value of Electrical Energy, River Mile 15 ($ million)

Alternative	Average	Median	Min	10th %	90th %	Max
Cool Mix Alternative	60.72	39.42	1.88	3.22	144.81	147.82
Cool Mix with Flow Spike Alternative	59.00	40.33	1.88	3.22	139.80	142.59
Cold Shock Alternative	33.08	23.78	1.43	2.32	72.51	79.11
Cold Shock with Flow Spike Alternative	34.69	25.67	1.43	2.32	76.90	85.04
Non-Bypass Alternative	4.00	2.93	(0.14)	(0.03)	9.24	9.35

Source: WAPA GTMax Model 2024
Model results for the operating period from January 2024 to September 2027. The figures presented are the average Economic Value of Electrical Energy estimates out of 8 modeled traces where experiments are triggered at RM 15. Values in parentheses represent a benefit in terms of economic value.

Table 3-17
Potential 45-Month Flow Impacts on Economic Value of Electrical Energy, River Mile 61 ($ million)

Alternative	Average	Median	Min	10th %	90th %	Max
Cool Mix Alternative	62.53	23.06	1.93	5.38	202.39	222.03
Cool Mix with Flow Spike Alternative	61.14	21.97	1.93	5.70	198.86	214.55
Cold Shock Alternative	31.36	22.87	1.31	5.26	69.85	100.01
Cold Shock with Flow Spike Alternative	34.40	18.15	1.31	6.85	71.72	109.55
Non-Bypass Alternative	2.81	1.65	0.00	0.03	7.18	10.39

Source: WAPA GTMax Model 2024
Model results for the operating period from January 2024 to September 2027. The figures presented are the average Economic Value of Electrical Energy estimates out of 13 modeled traces where experiments are triggered at RM 61.

Figures 3-21 and 3-22 show the exceedance values of lost value of energy for river mile 15 and river mile 61, respectively. This illustrates the nature of the data where there are many zeros in the time series, yet when the experiment occurs it has substantial effects, and quickly results in hundreds of millions of dollars. Averaging all of these values across this series skews the impacts toward zero, which represents no implementation. Generally, WAPA plans for the 90th percentile effect (the 10% exceedance probability in the figures below) for infrastructure impact scenarios, and those risks will be evaluated in the Basin Fund section below.

Figure 3-21
Exceedance Curve Showing the Probability of Impact on the Value of Energy ($ millions) using all 30 Traces (including zeros) for all Five Proposed Alternatives if Triggered at River Mile 15

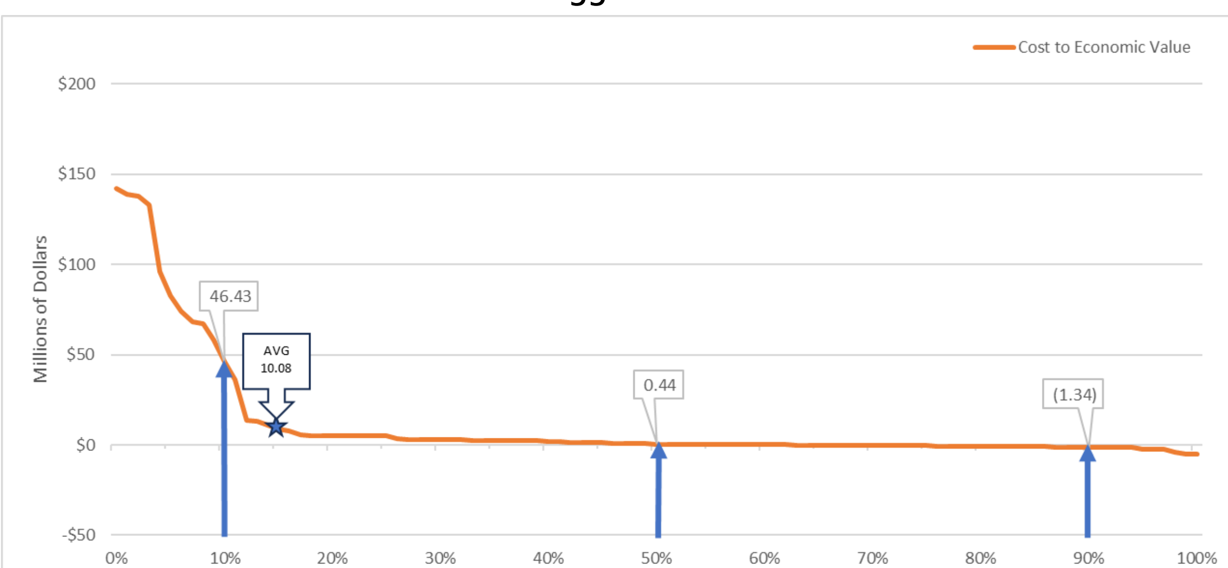
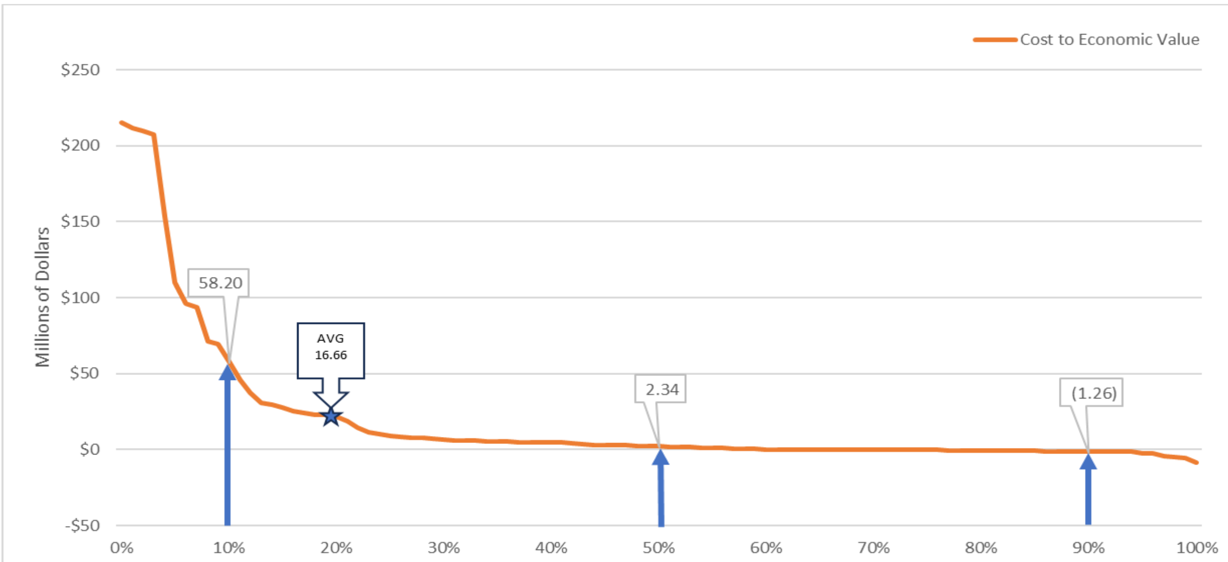


Figure 3-22

Exceedance Curve Showing the Probability of Impact on the Value of Energy ($ millions) using all 30 Traces (including zeros) for all Five Proposed Alternatives if Triggered at River Mile 61



When looking at the 8 traces in **Figure 3-23**, the impacts are concentrated in roughly 5 of the traces (trace numbers 8, 9, 10, 11, 21) and with minimal impacts from trace numbers 22, 27, and 29 using the river mile 15 trigger. For river mile 61, **Figure 3-24** shows similar effects for traces (trace numbers 8, 9, 10, 11, 21), and adds trace numbers 5, 12, 16, 23, and 30 to trace numbers 22, 27, and 29 with the smaller energy loss values. Given the relationship in the hydrologic traces to the original time series, we would expect similar levels of impact from adjacent traces because they overlap in their years of origin.

Figure 3-23

Cost to Economic Value (in millions) by Alternative, for the 8 Traces where they were Triggered at River Mile 15

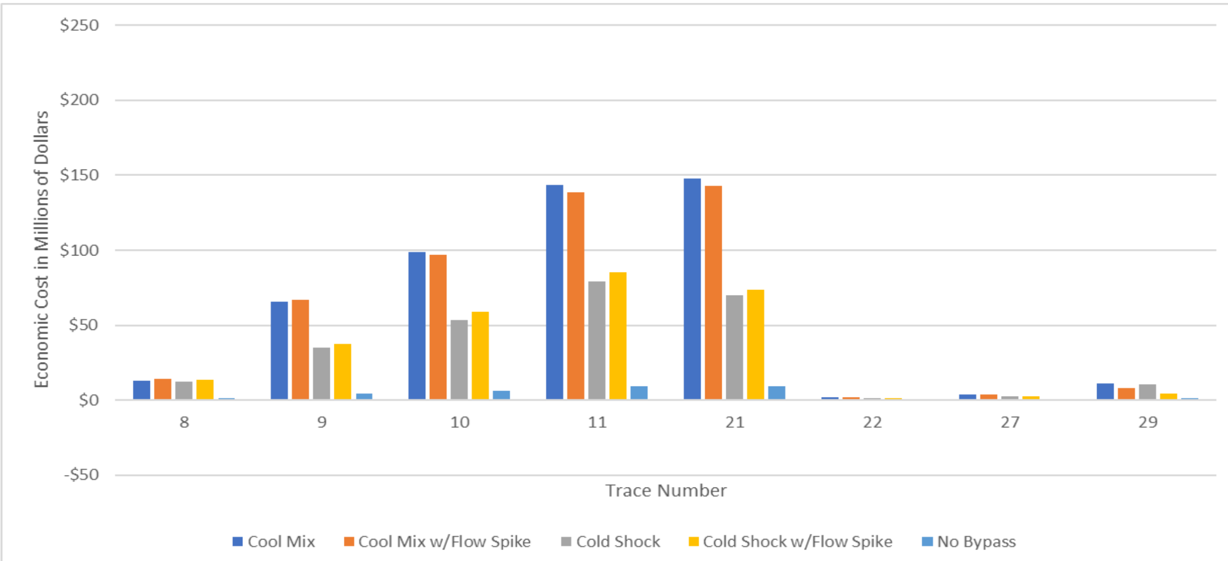
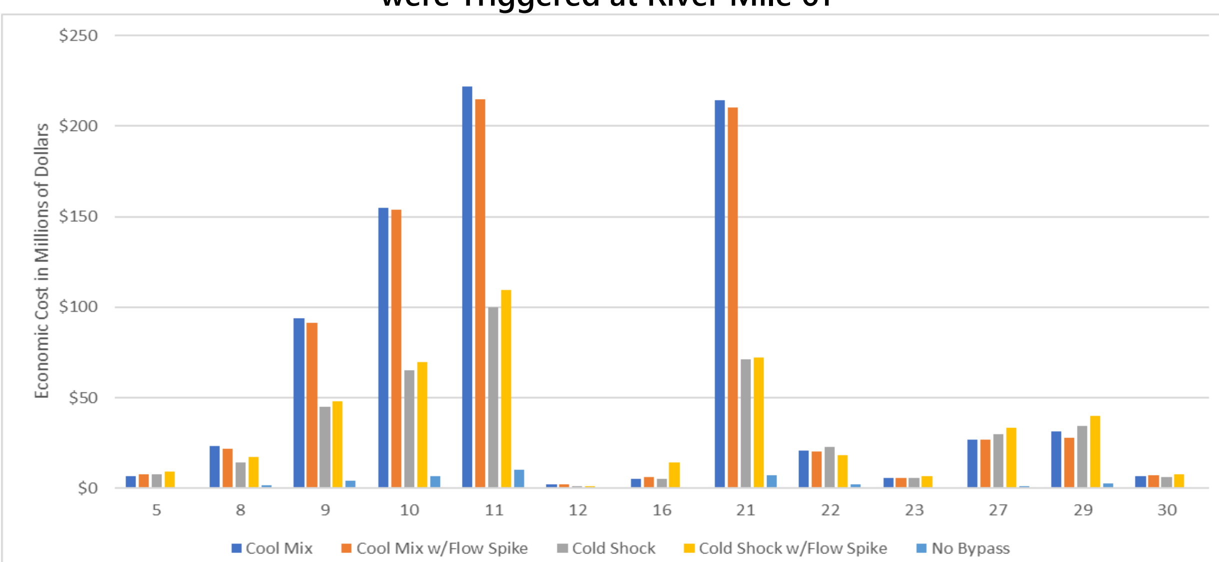


Figure 3-24

Cost to Economic Value (in millions) by Alternative, for the 13 Traces where they were Triggered at River Mile 61

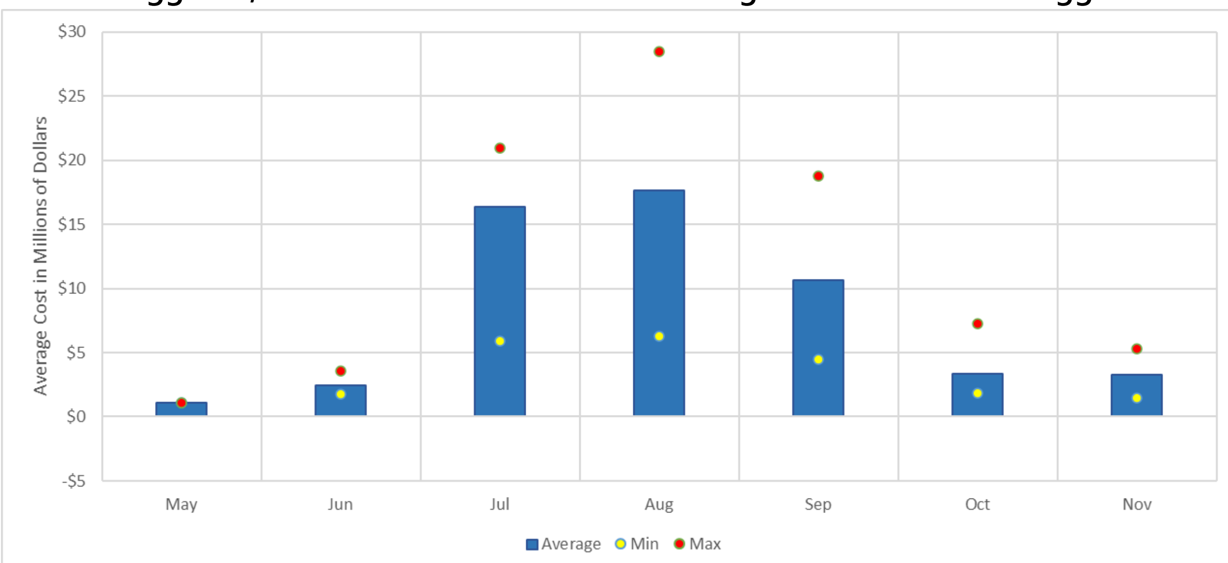


Most of the effects of the experiment occur in a few months of the year during peak demand times for power in the southwest. **Figure 3-25**, is an example for illustration purposes using one of the likely scenarios for bypass, the Cool Mix Alternative at river mile 61, and shows the average difference in hydropower value by month when the experiment is implemented. In **Figure 3-19** above, the instances of bypass events occurs most in September, then August, and

October are the highest three. However, due to energy prices, the highest energy loss occurs in August followed by July and then September (**Figures 3-25 and 3-26**). Average values for the peaks months are about $10-17 million per month for the Cool Mix, and if implemented in all of the possible months during a single year, it would equal about $62.53 million, on average for the Cool Mix Alternative using the river mile 61 trigger. The Cold Shock Alternative follows the same trend by month (**Figure 3-26**) with values ranging from about $5-11 million per month in the peak months.

Figure 3-25

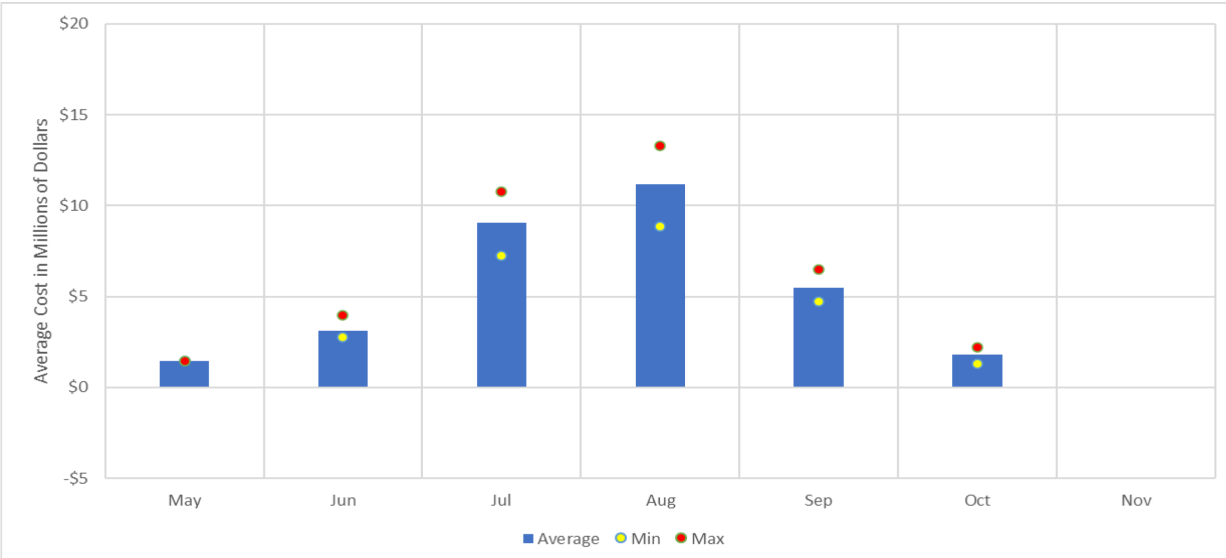
The Average Difference in Energy Value by Month for those Months when Bypass is Triggered, for the Cool Mix Alternative using the River Mile 61 Trigger



Average (blue bar), minimum (yellow dot), and maximum (red dot) values for monthly difference in energy value in months the bypass experiment occurs.

Figure 3-26

The Average Difference in Energy Value by Month for those Months when Bypass is Triggered, for the Cold Shock Alternative using the River Mile 61 Trigger



Average (blue bar), minimum (yellow dot), and maximum (red dot) values for monthly difference in energy value in months the bypass experiment occurs.

To summarize, based on the modeled generation and economic value due to electrical energy loss for each of the alternatives, the Cool Mix Alternative and the Cool Mix with Flow Spike Alternative are likely to result in the most significant loss of energy value. Relative to the No Action Alternative, the Cool Mix Alternative is modeled to have an average loss of energy value over the 4-year period of $62.53 million (for the 13 traces with bypass at river mile 61), a 90th percentile impact of $202.39 million, and a maximum modeled impact of $222.03 million (**Table 3-17**). The Cold Shock Alternatives result in the second-most modeled loss on average of $34.4 million and a maximum modeled amount of up to $109.55 million. The Non-Bypass Alternative results in the least modeled loss in energy value with some potentially modest losses of up to $10.39 million.

Impacts on the Basin Fund

The Basin Fund is Reclamation and WAPA's operating fund and is used to fund operating expenses for the CRSP. Its balance fluctuates significantly due to expenditures on operations, maintenance, and replacement costs for both Reclamation and WAPA. Reclamation and WAPA must maintain a sufficient balance in the Basin Fund to pay for project requirements despite these fluctuations. Failure to maintain a sufficient balance in the Basin Fund could result in the inability to: Adequately fund project requirements, including operations and maintenance expenses of CRSP generation and transmission facilities; repay federal project investments; meet contractual obligations to deliver electric service customers; provide the Basin States' Memorandum of Agreement (MOA) funds; support salinity control programs; and support environmental programs like the Glen Canyon Dam Adaptive Management Program (and other related experiments) and the Upper Colorado River Recovery Implementation Program (and related experiments). Section 1.3 of the LTEMP ROD, describes the implementation process for experiments which states that prior to implementation of any experiment, WAPA will provide an assessment of the Basin Fund and the effects of the experiment on the Basin Fund, which will be evaluated and considered (along with other resources).

The GCPA states that supporting studies and long-term monitoring program and activities associated with the Act shall be non-reimbursable expenses, meaning associated costs are not borne by power customers as direct project costs but by the federal government or some other funding source (Grand Canyon Protection Act of 1992, Sec. 1807). Since passage of the GCPA, WAPA has accounted for the financial impacts of experimental releases at Glen Canyon as non-reimbursable expenses and constructive returns to the Treasury.

As WAPA accounts for financial impacts of experimental releases as non-reimbursable, WAPA has not included those expenses for recovery in its power rates. Thus, without other funding sources, the cost of this experimental action will directly reduce the Basin Fund balance (see **Table 3-16** and **Table 3-17** for estimated cost). At the 90th percentile effect, used by WAPA for planning purposes, the cost estimates for this experimental action are of a magnitude that has a high likelihood of limiting WAPA and Reclamation's ability to retain system reliability of the CRSP.

The Basin Fund can experience high monthly cash fluctuations, as much as $53 million in one month, which requires a balance large enough to absorb these fluctuations along with other expenses, including unscheduled capital expenses due to unexpected requirements.

Primarily due to decreased generation because of drought, WAPA experienced significant expenditures from the Basin Fund from 2018-2022. This reduced the balance in the Basin Fund to levels that resulted in WAPA deferring approximately $45M of capital expenditures to ensure sufficient funds were available for operating requirements. WAPA has taken additional actions that substantially increased its rate and sought emergency appropriations to support operating expenses during the drought. A reimbursable appropriation of $85M was received in 2022, which has allowed firming expenditures to be made and helped to ensure sufficient funds are available for operating requirements. These funds are required to be returned to the Treasury once the risks associated with the drought subside. All these funds have been expended as of September 30, 2023.

If the proposed experiment is implemented and no mitigating funds are obtained, many of the projects and programs that are currently supported by the Basin Fund may have to be deferred or reduced to limit the risk of violating the Antideficiency Act[3]. Reclamation and WAPA will need to immediately prioritize funding for projects and programs that maintain the safety and reliability of the CRSP system. MOA revenues ($14,405,000/year) may become unavailable for use by the Basin States, and other funding sources may need to be secured to support

[3] The Antideficiency Act prohibits Federal employees from making or authorizing an expenditure from, or creating or authorizing an obligation under, any appropriation or fund in excess of the amount available in the fund unless authorized by law. Federal employees may be subject to discipline (suspension or removal), fines & imprisonment.

environmental programs like the Glen Canyon Dam Adaptive Management Program (and related experiments) and the Upper Colorado River Recovery Implementation Program (and related experiments). Capital funding may be reduced for Reclamation and WAPA, which may include deferring projects like generator rewinds, butterfly valve replacements, station service transformer replacement, selective withdrawal structure refurbishment, aging transmission line replacement, power transformer replacement, high voltage breaker replacement, and more, all of which will reduce system reliability and could lead to N-1 or N-2 system outage risks.[4]. System outages can cause major economic impacts and security risks to society.

The CRSP Act states that revenues in the Basin Fund in excess of operating needs are to be paid annually to the general fund of the Treasury. This criterion has not been met for several years, and the Basin Fund has not returned cash to the Treasury since 2012. Due to ongoing drought and increasing needs to replace infrastructure, WAPA does not project the Basin Fund having revenues in excess of operating needs for at least the next ten years.

Implementation of the proposed experimental releases in this SEIS may inhibit WAPA from fulfilling its mission mandated in the CRSP Act of maintaining and operating the CRSP hydropower system and could result in the federal government being unable to fulfill contractual obligations to its firm electrical service customers.

Impacts to Capacity

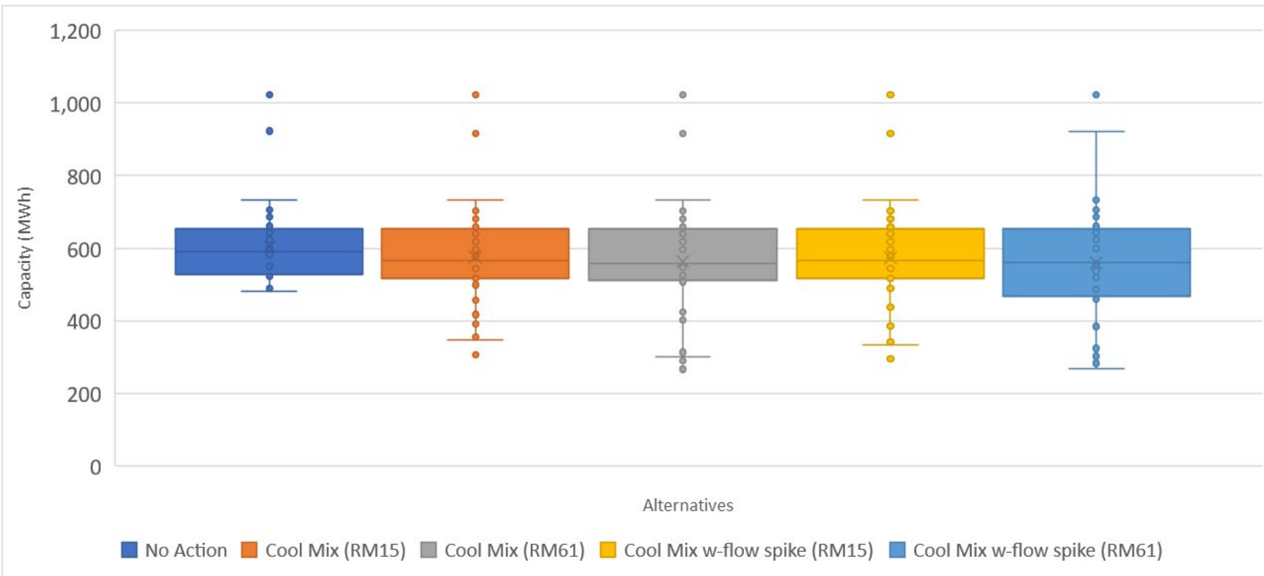
Although the Glen Canyon powerplant is rated at 1,320 MW, it has been operationally restricted since 1996 and is rarely allowed to produce power at this capacity level (Veselka et al. 2010). This is due to several factors such as the number of units that are operable, reservoir elevation, grid reliability considerations, and reservoir operating criteria. However, it can produce at rated capacity during extremely high hydropower conditions and during high peak release HFEs when the reservoir is relatively high. Under LTEMP, the firm peak capacity was reduced by about 50 MW from the previous baseline.

As shown in **Figure 3-27**, under expected conditions, the No Action alternative provides about 604 MW of firm capacity, whereas the Cool Mix with Flow Spikes Alternative at river mile 61, would reduce this to about 560 MW, or a loss of 44 MW of firm capacity in addition to what was lost under the LTEMP FEIS. The Cool Mix with Flow Spikes Alternative would reduce capacity by about 31 MW if triggered at river mile 15 and 44 MW if triggered at river mile 61. The Cool Mix Alternative would reduce capacity by about 28 MW if triggered at river mile 15 and 40 MW if triggered at river mile 61.

[4] N-1 and N-2 system outages describe a situation where power is compromised to the grid if a single component (n=1) or two components (n=2) of generation or transmission system are out of service (either planned or unplanned).

Thus, firm capacity would be reduced by an additional 4.6% to 7.2% across that range of alternatives. Other alternatives would not have an impact on capacity, with the Non-Bypass Alternative not affecting capacity as flows are not modified during weekdays in August, nor do the Cold Shock Alternatives for the same reasons by definition.

Figure 3-27
Estimates of Firm Capacity in August for the Alternatives that would Affect Capacity Calculated from those Traces with Bypass Events Triggered at River Miles 15 and 61



*This is for the 8 traces triggered at river mile 15 and the 13 traces triggered at river mile 61 that have bypass events the Cool Mix Alternative.

Impacts of Scheduling Bypass Experiments

WAPA purchases energy to “firm” to the levels established in its Firm Electric Service contracts during experimental releases at Glen Canyon Dam. To sustain this approach under each of the bypass alternatives, WAPA would be required to purchase substantial amounts of power, and possibly transmission. WAPA would need to secure these arrangements before the experimental flows are implemented to ensure the ability to meet its obligations during the experimental flows. Given the substantial amount of power the experiment could require WAPA to purchase, WAPA requires sufficient advance planning time to make these arrangements. Based on WAPA’s experience with purchasing in the wholesale energy market, WAPA will need at minimum 6 weeks to arrange the purchases necessary for implementation of any bypass alternative. This will require determining bypass volumes at least 6 weeks in advance. Power is typically purchased in weekly blocks, so changes in bypass volume will need to follow the same weekly time step. Once the 6-week purchase window has closed, WAPA may not be able to accommodate unanticipated decreases in generation, due to the difficulty of finding replacement power on the day-ahead energy market. It will be easier for WAPA to accommodate changes that reduce bypass volume (resulting in an increase generation) than to increase bypass unexpectedly and try to purchase replacement power on the day-ahead market.

Impacts to Transmission (PLEXOS)

Loss of generation from Glen Canyon Dam can also impact the transmission congestion in the surrounding region. Removing generation from Glen Canyon Dam can increase transmission congestion along certain paths and alleviate congestion in other paths. Of particular concern are the paths nearest Glen Canyon Dam. In cases with reduced generation from Glen Canyon Dam, increased congestion was observed in the Kayenta to Shiprock path and the Kayenta to Longhouse Path. In the No Action case, WAPA anticipates around 200 hours and 20 hours of congestion along each of these two paths per year, respectively. In the case with reduced Glen Canyon Dam generation, the number of hours showing congestion increases to over 2,000 hours per year along both paths as other generation flows into the area to serve the load previously met by Glen Canyon Dam. **Figure 3-28** shows the hourly flow duration (sorted high to low) and illustrates that the line exceeds its rated capacity about 600 hours of the year under reduced output from Glen Canyon Dam; exceeding the rated capacity of the line could lead to excessive thermal heating of the transmission line, damaged substation equipment, and the transmission-line breakers opening to prevent damage to the transmission lines and interconnected facilities. Other paths throughout the area see reduced congestion as flows are re-routed, but the impact is distributed among a greater number of available paths.

SRP Exchange Discussion

WAPA and Salt River Project exchange hydropower for coal-generated thermal power. This arrangement creates operational efficiencies and was agreed to when the first transmission lines were constructed under the CRSP Act of 1956. Under this agreement, hydropower generated at Glen Canyon Dam (up to about 533 MW) is delivered to Salt River Project in Phoenix; in exchange, SRP provides WAPA with the same amount of thermal energy at power generating stations at Craig and Hayden, in northwest Colorado, as well as Four Corners generation in northwest New Mexico.

The amount exchanged is dependent upon both hydropower and thermal power being available in equal quantities. Thus, a reduction in generation at Glen Canyon Dam significantly affects the transportation of generated energy to both Four Corners and Northern loads. If hydropower is not available to facilitate a full exchange, or in the case when no hydropower is available, SRP may wheel up to 250 MW of its thermal generation over WAPA's transmission lines to SRP's load centers in Phoenix. This option, at least partially, prevents stranding of SRP's 533 MW of generation when the exchange cannot be facilitated. Consequently, when Glen Canyon Dam experiences generation loss due to experiments, the energy exchange stops. This scenario underscores the critical role of wheeling, as it becomes the only method for transporting energy from Craig and Hayden, as well as Four Corners generation, to the SRP exchange.

Each MWh decrease in the SRP exchange, a direct consequence of lost generation at Glen Canyon Dam, correlates with an increase in SRP wheeling, but such wheeling may be constrained by competing power deliveries to replace the lost Glen Canyon power. As generation at Glen Canyon Dam decreases, there is an expected increase in southern replacement power purchases. Overall, the SRP Exchange is more sensitive to the cool mix alternative than the cold shock alternative, as cool mix is conducted throughout the week whereas the cold shock alternative restricts experiments to weekends only.

WAPA power flow study

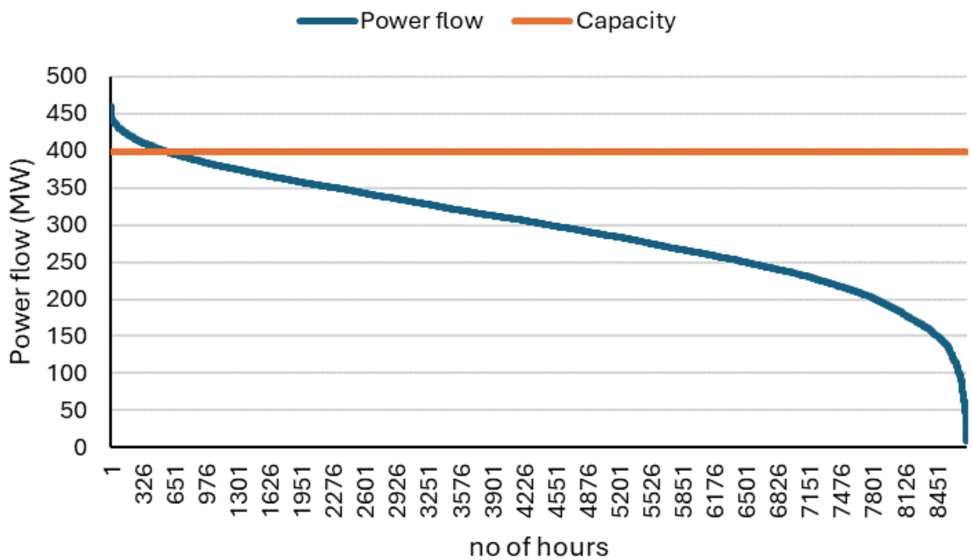
WAPA staff conducted a study to assess the impact of reduced Glen Canyon Dam hydroelectric generation on transmission reliability. The study is solely focused on the reliability of transmission system from Shiprock to Pinnacle Peak on a three-month operational horizon of summer 2024. For the purposes of this study, WAPA transmission planning engineers used two scenario cases: 2024 Heavy Summer Western Electricity Coordinating Council (WECC) base case for high loading conditions which was further coordinated by Southwest Study Area Group for operational studies; and 2024 Light Summer WECC base case for light loading conditions. The study assumed replacement power would be purchased to replace lost Glen Canyon Dam generation. There was no consideration for cost of replacement power, only an assumption that power could be purchased.

Power flow and transient stability studies were performed, and results were analyzed based on the NERC/WECC System Performance Criteria for transmission system planning.

- The reduced Glen Canyon generation in 2024 Heavy Summer case does not result in any thermal or voltage power flow violations in the study area.
- The reduced Glen Canyon generation in 2024 Heavy Summer case does not result in any WECC WR1.3-1.5 or oscillation damping dynamic stability criteria violations in the study area.
- The reduced Glen Canyon generation in 2024 Light Summer case does not result in any thermal or voltage power flow violations in the study area.
- The reduced Glen Canyon generation in 2024 Light Summer case does not result in any WECC WR1.3-1.5 or oscillation damping dynamic stability criteria violations in the study area.

With certain exceptions, the study did not find any reliability concerns for transmission system across Shiprock to Pinnacle Peak for low Glen Canyon generation. In general, none of the alternatives are likely to cause a system failure, although there may have to be purchases made at less desirable locations to maintain power flow and those could be expensive to operate. Those additional costs or effects are not analyzed here.

Figure 3-28
The Hourly Flow Duration (sorted high to low) Showing the Number of Hours showing Transmission Congestion with a Reduction of Generation at Glen Canyon Dam



Impacts to Load/Generation Following and Regulation (PLEXOS)

Overall, the PLEXOS runs do not indicate any inability to serve load (the unserved load in all cases is zero). The PLEXOS runs generally do not show any unserved reserves as well. However, in discussions with the project team, NREL assumed that current reserves provided by Glen Canyon would be able to be covered by other WAPA hydropower assets. So, any reserve shortages identified by PLEXOS would result from general scarcity conditions. In all four years of PLEXOS runs, reserve shortages were only observed in two months in the year 2027 (August and September). In a run with the "No Action" Glen Canyon generation profile, there are just two hours with a total of 42 MWh dropped reserves. In a case with Minimum Glen Canyon generation, that number increases to 600 MWh over a dozen hours. The rest of the months with unserved reserves (August 2026, August 2025, June 2027, and June 2026) have less than 100 MWh over just a few hours.

Availability of Replacement Power and Source

The National Renewable Energy Laboratory (NREL), using the PLEXOS model, projected that replacement power would generally be available for this experiment. However, the PLEXOS model assumes free exchange of power within the Western Electricity Coordinating Council (WECC) footprint. Thus, if additional generation exists in the model, and a transmission path is available, the model will dispatch the energy to meet demand without regard to generator ownership or contractual obligations. The PLEXOS model also assumes all utilities in the market have situational awareness and perfect foreknowledge. This model is an approximation, and in many ways does not reflect the reality of WAPA's transactions to secure replacement power.

WAPA purchases replacement power through bilateral contracts with trading partners, where the sellers of electrical power must recognize market uncertainties and may not be fully aware of the positions of their trading partners. Additionally, many sellers of electrical power may be less willing to sell available power in times of scarcity and uncertainty to ensure they can fulfill their own power needs. WAPA has typically purchased power from a relatively small set of utilities, in relatively small amounts, and for short durations. Typical purchases are on the order of 10s of megawatts per hour and only for a few hours at a time. It may not be possible for WAPA to find enough willing utilities to trade or purchase the amount of power needed (100's of megawatts per hour for months at a time) to offset the impact of implementing a bypass alternative. WAPA's established trading partners have indicated they may be unable or unwilling to offer excess power during projected scarcity events during the summer periods of the SEIS.

Accordingly, the experiment could impact the Federal government's ability to fulfill its contractual obligations to the customers that fund its power system if WAPA cannot secure power to firm its contractual obligations. It could also increase the likelihood of scarcity events on the power grid and contribute to power emergencies.

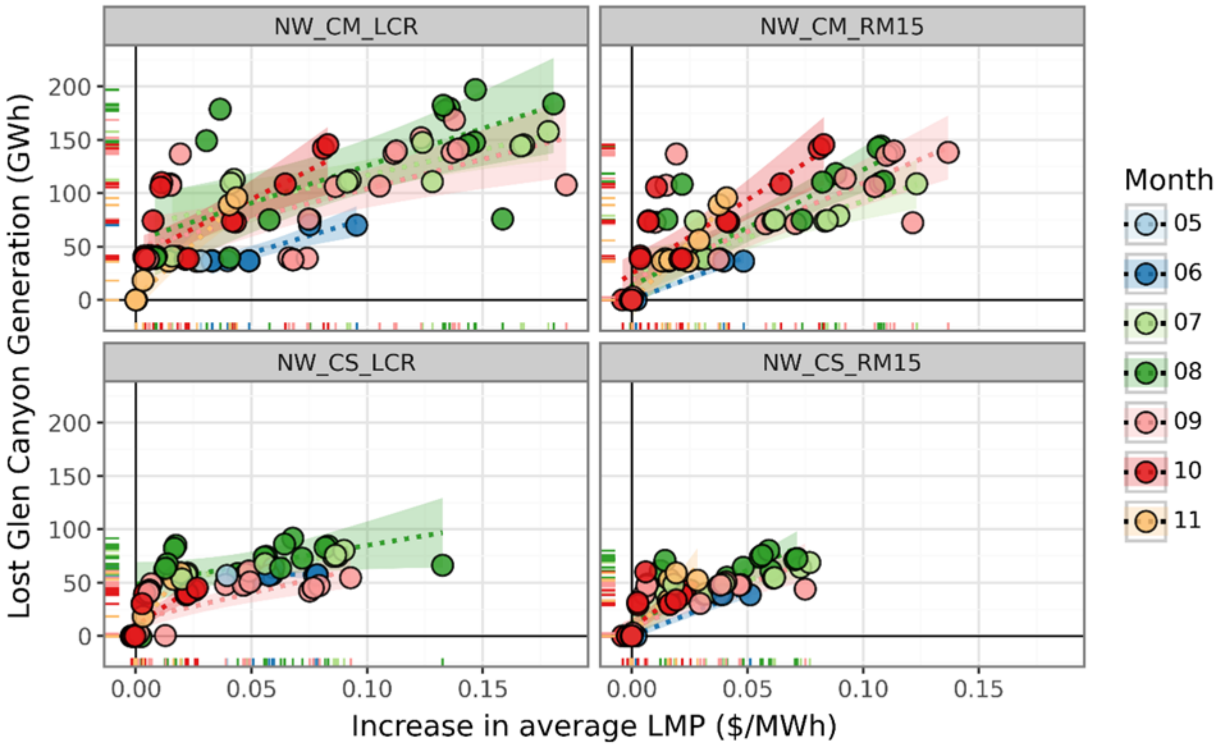
Impacts to Locational Marginal Prices (LMPs)

Using PLEXOS, the reduction of electrical power production caused by the experiment will result in a small increase in locational marginal prices in the WECC system. This means the reduction of power generated at Glen Canyon Dam is expected to make electrical power more expensive in some areas of the WECC. An increase in power prices indicates that the experiment is likely to have economic impacts to the electrical energy market. Because of the reductions in electrical generation at Glen Canyon Dam due to the experiment, utilities will be required to pay a higher price for the electrical power they purchase.

The experiment will likely also result in WAPA competing with its own customers to purchase replacement power. This competition for limited resources, with an implementation decision made weeks to months beforehand, will likely result in increased power prices (as described above with the PLEXOS modeling) and is likely the driving factor of the price increases projected at exchange nodes. Knowing this action has the potential to reduce a substantial amount of generation on the Western Grid weeks to months beforehand increases the risk of market manipulation and may increase prices far above those used for this analysis. The increased power prices at exchange nodes indicate an economic impact and suggest the experiment will have significant impacts to power users.

The scatter plot in **Figure 3-29** illustrates the impact of lost generation at Glen Canyon Dam due to experimental bypass conducted across different action alternatives on the LMPs (ANL report to WAPA). Despite the relatively minor increase in LMP, the study indicates a clear positive correlation between the two variables. As the generation at Glen Canyon Dam decreases, the average LMP at Glen Canyon Dam rises. The most correlated months are October (10) and November (11), a trend generally consistent across all four action alternatives, with August (8) and September (9) exhibiting the least correlation. Nevertheless, the trend remains consistently positive.

Figure 3-29
Impact of the Increase in Average LMP compared to the No Action Alternative on the Lost Generation at Glen Canyon Dam



The color-coded lines represent regression lines indicating conditional means for individual months. They demonstrate the overall trend in the data, with the span around the lines indicating confidence intervals.

NREL also considered a case of drought throughout the Southwest area, expecting that conditions for meeting load would be even more difficult. For this case, NREL reduced all generation from hydropower in the West by 20% and used the minimum generation profile for Glen Canyon Dam. **Table 3-18** illustrates average LMPs for WALC region for this case, relative to the case for No Action. LMPs are substantively higher for the proposed action and the proposed action with the dry hydrology scenario compared to the No Action scenario. Since hydropower is an important part of the generation mix for many parts of the Western Grid, it logically follows that losing part of the zero marginal cost resource would increase prices across the whole region.

Table 3-18
WALC Average Prices ($/MWh) from 2024-2027 for Glen Canyon No Action, Proposed Action, and Minimum Generation with Dry Hydrology

Month	No Action ($/MWh)	Proposed Action ($/MWh)	Proposed Action with Dry Hydrology ($/MWh)
May	22.29	22.80	24.22
June	28.18	29.42	30.17
July	32.75	34.15	34.92
August	35.16	36.53	36.80
September	30.82	31.88	32.06
October	23.95	24.75	25.40
November	24.65	25.33	25.80
Total	28.26	29.26	29.91

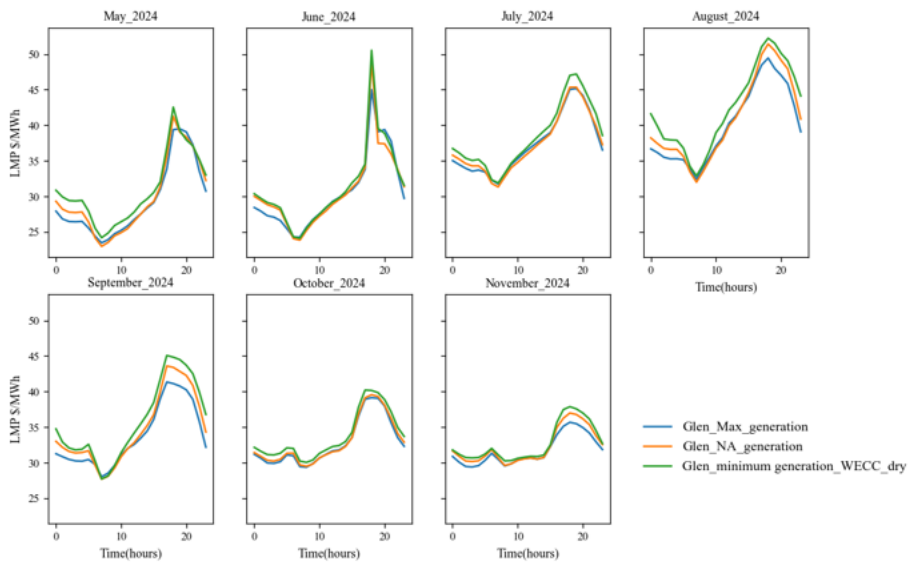
Table 3-19 shows how prices increase over the focus regions for Glen Canyon Dam generation loss with dry hydrology. The highest price increase is noticeable in WALC region with prices increased by 3.2%. In addition, NREL noted that evening peak prices have increased more than 7%-20% for all the regions.

Table 3-19
Average Prices ($/MWh) of Focus Regions from 2024-2027 for No Action and Minimum Generation Scenarios

Region	No Action with Normal Hydrology ($/MWh)	Proposed Action with Normal Hydrology ($/MWh)	Percent Change in Price with Normal Hydrology	No Action with Dry Hydrology ($/MWh)	Proposed Action with Dry Hydrology ($/MWh)	Percent Change in Price with Dry Hydrology
PAUT	24.65	24.67	0.09%	$25.10	25.16	2.05%
PAWY	23.54	23.62	0.35%	$24.10	24.13	2.52%
PSCO	34.10	34.41	0.90%	$34.63	34.70	1.76%
WACM	25.76	26.06	1.17%	$26.58	26.63	3.40%
AZPS	31.92	32.24	1.02%	$32.66	32.77	2.66%
PNM	36.79	37.27	1.31%	$37.37	37.56	2.09%
SRP	31.44	31.85	1.30%	$32.18	32.40	3.06%
TEPC	31.12	31.60	1.52%	$31.74	31.86	2.36%
WALC	30.27	30.87	1.98%	$30.90	31.35	3.56%

The next question is whether these increases in prices would affect the total economic value. That analysis is possible, however timing restraints prevented the ability to re-model these scenarios with higher prices. Generally, it is reasonable to assume the lost value would increase across alternatives, but it isn't necessarily a one-to-one effect because much of the increases in prices occurred during peak hours of the day, especially in the evening (see NREL report, their Figure 5 and inserted below as **Figure 3-30**). Because GTMax can optimize operations, there would be offsetting actions to avoid purchases during those peak times and avoid the high costs. Thus, although lost value would be higher, it would likely be less than expected based on the increase in percentage in **Table 3-19** above. This provides an opportunity for implementation of the action to avoid bypass during the few hours of the evening during this peak and have bypass during the day when solar energy is readily available and reducing prices. Given the high costs of purchase power during those evening peaks, this provides a great opportunity for WAPA and Reclamation to partner on implementation and reduce the costs of the experiment.

Figure 3-30
WALC region average diurnal LMPs for 2024 maximum, no action with normal hydro conditions and minimum Glen Canyon generation profiles for dry hydro conditions in the Western Interconnection.



Impacts to Responding to Disturbances, Emergencies, and Outages

None of the Action Alternatives would impinge on WAPA's ability to respond to electrical disturbances, emergencies, or outages. These experimental releases would follow LTEMP requirements for emergency situations, which requires the experimental releases to be adjusted or suspended in the event of an electrical disturbance, emergency, or outage. In the event of an electrical emergency, Reclamation will terminate the experiment for the duration of the emergency.

Displaced Generation and Emissions

Using the "warm start" methodology, PLEXOS can identify which of the generation sources may be called upon to provide additional generation. The "warm start" method starts with one base case run of the full Western Interconnection, with the No Action or base case Glen Canyon Dam generation profile. This base case run determines the generation levels of all generating units outside of the focus area. In this case, the annual replacement generation is from mostly Gas Combined Cycle (Gas CC) generation, with a large portion also coming from coal-fired generation. In the spring months, when load is low and hydropower, solar, and wind are all available, more of the replacement generation comes from coal generators which have turned down to accommodate the influx of available low-marginal-cost generation from those resources. In some cases, curtailed solar is also to a small degree being used to replace the generation from Glen Canyon Dam, but only in small amounts during spring months. During the late summer months, the generation fleet is more constrained, with even more expensive units being called upon to provide replacement power, such as the most expensive marginal source of generation, gas combustion turbines (Gas CT). Some winter months actually exhibit less wind generation due to the loss of Glen Canyon Dam generation. These results are likely due to requiring more inflexible coal generation, which often has low ramp rates and high minimum generation levels, leading to slightly more economic wind curtailment as the increased rates of coal are accommodated by the system.

It is important to note that hydropower is a zero-marginal source of electricity, and a zero-marginal emissions source as well. Therefore, most of the power being used to replace Glen Canyon Dam will have both higher costs and higher emissions on a marginal basis. So, corresponding to the increase in generation from the coal and natural gas fleet, bypass alternatives are likely to result in a increases to both total generation costs (in terms of fuel and start & shutdown costs) as well as emissions.

Applying the Energy Information Administration (EIA's) average emissions factors (https://www.eia.gov/tools/faqs/faq.php?id=74&t=11), NREL computed the additional carbon dioxide emission from the increase in generation. For the reduced Glan Canyon generation case with the dry scenario, using an emissions rate of coal of 2.3 lbs. carbon dioxide per kWh, and an emissions rate of natural gas of 0.97 lbs. dioxide per kWh, yields an increase of 0.64 million tons of carbon dioxide for 2024, 0.94 million tons for 2025, 1.2 million tons for 2026 and 0.8 million tons for 2027.

Summary of Hydropower Effects

The Action Alternatives would result in impacts on power generation at Glen Canyon Dam during the peak summer power months. Changes in operations at Glen Canyon Dam would reduce available generating capacity at Glen Canyon Dam under all four bypass alternatives. This reduction in capacity would need to be replaced by purchases and generation from other sources. The estimated financial impacts from the proposed alternatives range from a net gain of $140,000 to a cost of $222.03 million, depending on the reduction in the amount of power generated and the cost to purchase power from replacement sources.

Power consumers would experience additional impacts throughout the Western Electrical Grid. The generation from Glen Canyon Dam is both zero marginal cost and zero marginal emissions, meaning that replacement generation will certainly increase both total generation costs as well as total emission from the power sector, as the makeup generation comes from mostly Natural Gas plants and from coal as well. The model simulations show that loss of Glen Canyon Dam also has impacts to locational marginal prices in the region, by generally increasing prices since the replacement power is more costly. This is particularly true in a drought scenario in which the hydropower from the rest of the Western Interconnection is already reduced.

Impacts on power generation and the need to purchase replacement power, the potential impacts on the Basin Fund and consumers, and the potential impacts on the transmission system would be greatest under the Cool Mix Alternative and the Cool Mix with Flow Spike Alternative. The Cold Shock with Flow Spike Alternative would have the third-most impacts. The Cold Shock Alternative would have the second-least impacts, and the Non-Bypass Alternative would have the least impacts.

If funding is not secured prior to implementing this experiment to mitigate the financial impacts on the Basin Fund, this experiment could;

- Jeopardize the solvency of the Colorado River Storage Project,
- Force Reclamation and WAPA to suspend funding project requirements, including operations and maintenance activities for both power and multi-purpose facilities of the CRSP,
- Reduce power being provided to WAPA customers,
- Postpone the delivery of the Upper Basin States' Memorandum of Agreement (MOA) funds,
- Reduce support of environmental and salinity programs,
- Reduce further experimentation with releases at Glen Canyon Dam, and/or
- Require deferring critical projects and reducing system reliability potentially leading to N-1 or N-2 system outage risks.

4.1 SERM Detailed Hourly Results

SERM determines optimal contractual pathways flows (not physical flows) that transports SLIP energy from supply sources to sinks and minimizes the net cost of CRSP Office energy transactions (financial expenses). It also simulates SRP wheeling and energy exchange agreements.

As discussed in the methodology section, SERM disaggregates the CRSP footprint into three regions: namely, north, four corners, and south. Within each of these regions, there tends to be little contractual congestion in the transport of energy within each of these regions. That is, under most circumstances, contractual energy flows on transmission lines are lower than the limits. However, between these regions flows are more frequently constrained by contractual flow line limits resulting in flows that are bound by, or at, the contractual line capacity limit.

Hourly Flows Among Regions

To gain an appreciation for SERM functionality and the effects of LTEM SEIS alternatives on contractual power flows and CRSP Office agreements with SRP, this section presents detailed SERM results for a few situations. This includes both an off-peak summer hour (Sunday, August 3, 2025, at 5 AM) and an on-peak summer hour (Friday, August 15, 2025, at 7 PM) under the No Action Alternative and four action alternatives for hydropower trace 21.

Because intraregional congestion is atypical, a visualization tool that distills detailed SERM results from a relative complex network (Figure 3.3) into a simple three-region diagram was created for this study.

Off-peak No-Action Results

Figure 4.1 shows SERM results for a summer off-peak hour under the No Action Alternative. GCD generation during this hour is relatively low at 251.5 MWh (*GC Gen*). Approximately, half of this generation, 125.8 MWh is used to serve SLIP loads in the south. Because the GCD generation in the south region is greater than southern loads of 115.1 MWh, it is a long energy state (*Net South 136.4*). Because conditions in the north and four corners region can support an SRP energy exchange of 125.7 MW (*CG 1X Exchange*); that is, 51.5 MWh short in the north and the four corners is short by 74.2 MWh for a total of 251 MWh. If the energy short position had been larger in either the north or four corners region or both regions, then all 136.4 MWh of the south region excess would have gone to the exchange. Instead, the exchange was cut short by 10.3 MWh (see north "L*ayoff*").

Crag and Hayden generation (*C/H Gen*) during this hour was 246.0 MWh. Because the SLIP energy position was short by 51.5 MWh, that same amount of energy was sent to the SRP energy exchange (*2X exchange*). Similarly, 74.2 MWh of generation from SRP's Four Corners Plant (*4C Gen*) was sent to the SRP Exchange (*4X exchange*) to cover the SLIP short position in the four corners region. Under the wheeling agreement with the CSRP Office a limited amount of generation produced by the three SRP plants is wheeled to a SRP POD. Under the off-peak conditions illustrated in Figure 4.1, 184.2 MWh is wheeled from Craig and Hayen (*3X wheel)* and an additional 65.8 MWh is wheeled from the SRP Four Corners Powerplant (*5X wheel*) for a total of 250.0 MWh (*total wheel 3X + 5X*); that is, the SRP wheeling limit specified by the CRSP Office contract. If the agreement allowed for unlimited wheeling, then there would be no Craig/Hayen layoffs in the north. Note that SRP contact flows as depicted as red-dashed lines in Figure 4.1.

Over the entire SLIP region, the SLIP generation was 384.2 MWh and FES customer DSA load was slightly lower at 384.2 MWh for a system-wide energy long position of 10.7 MWh. That amount of energy was sold in the south region where there is a surplus and energy market prices are also the highest (70.18 $/MWh). This transaction resulted in a CRSP Office financial outcome of $752 dollars (note that the dark green highlighted area the "*SLIP Net Energy Cost ($)*" is negative). Also shown in the dark green highlighted area is the estimated GCD economic value of energy (*GCD Eon Value ($)*). At $17,051 dollars it is set equal to GCD generation times the energy market price at GCD. Note that energy prices vary by region and sales prices in a region are higher than purchase prices. SERM has more than one energy market location in each region, therefore prices shown in the figure are the highest cost in the region for a CRSP Office sales transaction and the lowest regional price for a purchase transaction. As described in the methods document, these geographical differences in prices are based on PLEXOS LMP results for key points in the SLIP footprint.

Figure 4.1 also shows contractual energy flows between two regions as black lines with black text indicating flow quantity and direction. Note in this situation that there are no flows on these lines because each region maintains an energy balance via the SRP energy exchange agreement and the sale of long south energy to a south energy transaction location.

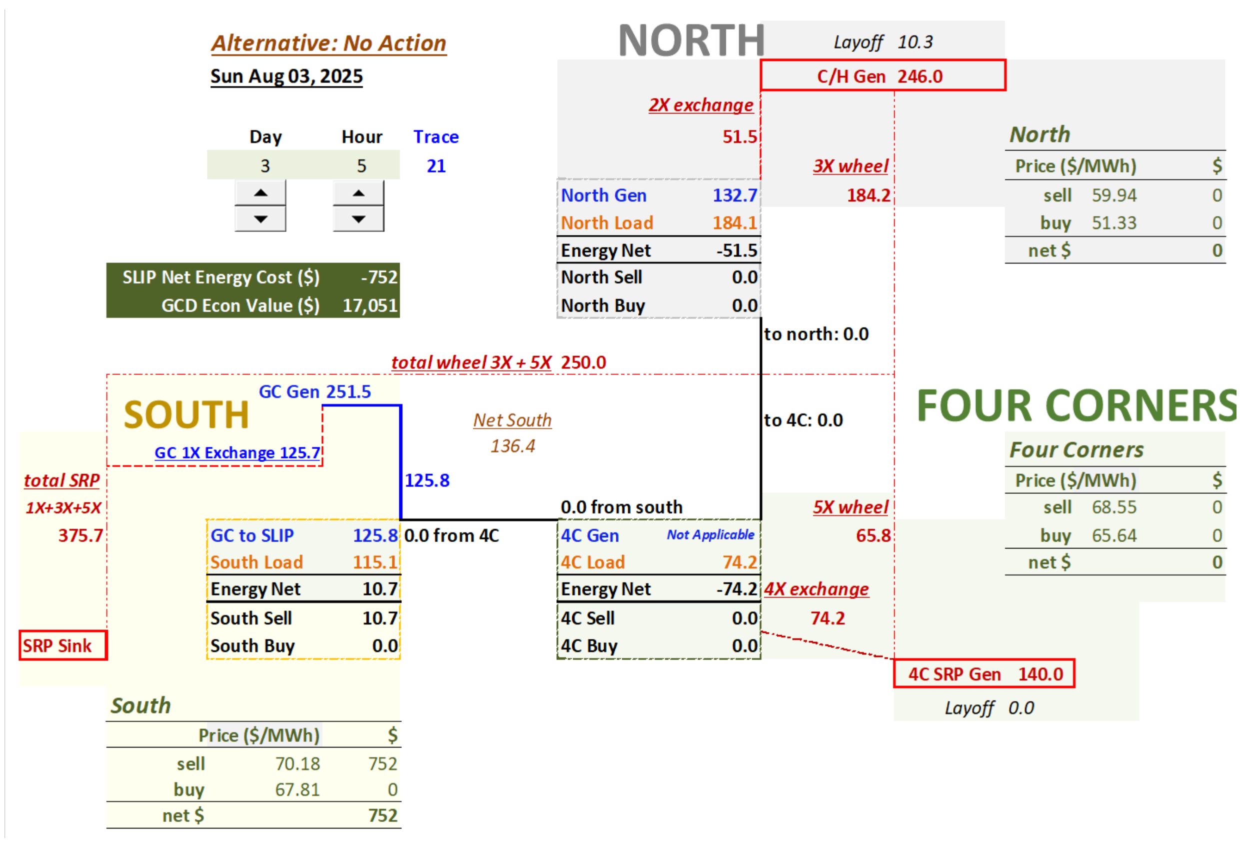


Figure 4.1 SERM Results for a Summer Off-peak Hour under the No Action Alternative.

Off-peak NW_CM-RM15 Results

Figure 4.2 shows SERM results for the same time and trace discussed above, except it is assumes operations under the New Window, Cold Mix, River Mile 15 (NW_CM_RM15) Alternative. GCD generation is only 76.5 MWh, all of which is used to serve SLIP loads in the south. This generation level results in a south region energy deficit of 38.6 MWh, essentially turning off SRP energy exchanges. Note that *1X*, *2X*, and *4X* are all zero. This south energy deficit plus a 51.5 MWh short position in the north and a four corners short position of 74.2 MWh are all resolved (to balance to SLIP system) by energy purchases.

Because energy exchanges are turned off, SPR can only utilize its wheeling arrangement with the CRSP Office to contractually transport generation from its powerplants down to its service territory. Craig and Hayen wheeling (*3X)* is 110 MWh with an additional 140 MWh wheeled from the SRP Four Corners Powerplant (*5X*) for a total of 250.0 MWh (*3X + 5X*). That is the same amount wheeled under the No Action Alternative. However, because the energy exchange has been turned off, the energy layoff from Craig and Hayen increased from about 10 MWh under the No Action Alternative 136 MWh under the NW_CM-RM15 Alternative.

The SLIP system total generation was 209.2 MWh while FES customer DSA load remains at 384.2 MWh; that is, unchanged demand from the No Action Alternative. As described in more detail in the methods experimental costs are non-reimbursable, therefore, experiments do not impact CRSP Office monthly DSA offers to its FES customers.

The system-wide SLIP energy deficit of 164.2 MWh is resolved by northern energy market purchases at a location with the lowest price in the SLIP footprint. Because action alternative water bypass requirements cause an energy short position in all SLIP regions, 112.8 MWh (164.2 MWh minus a 51.5 MWh north deficit) is contractually sent to the four corners region (*to 4C: 112.8*) to serve four corners load of 74.2 MWh. The remaining 38.6 MWh resolves the energy deficit in the south (*38.6 from 4C*).

Note that both buy and sell prices in all regions under the NW_CM-RM15 Alternative are higher (pennies) than prices under the Action Alternative. That is consistent with PLEXOS LMP results produced by PLEXOS that show LMPs decrease as a function of higher energy production at the GCD Powerplant. As described in more detail in the results section, for GTMax SL and SERM applications a PRF is applied to GCD generation to adjust prices. Based on the adjusted prices and energy purchases, the SLIP economic value of the NW_CM-RM15 Alternative is $5,191 dollars compared to a No Action Alternative value of $17,051 dollars. The SLIP CRSP Office financial outcome changed from a net positive revenue of $752 dollars (No Action) to a $8,433 dollar cost.

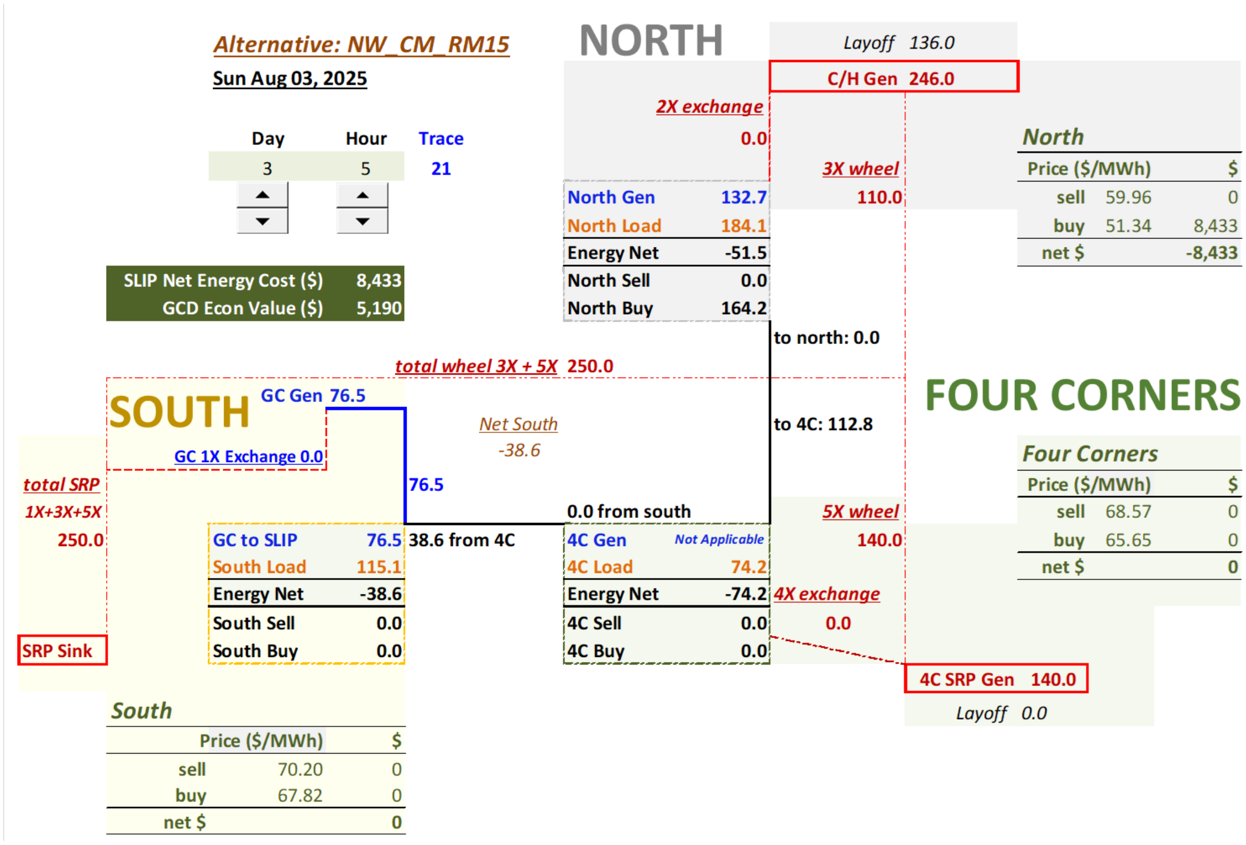


Figure 4.2 SERM Results for a Summer Off-peak Hour under the Cold Mix, River Mile 15 Alternative.

Off-peak NW_CM-LCR Results

Results for the New Window, Cold Mix, Little Colorado River (NW_CM_LCR) Alternative are shown in Figure 4.3. Additional changes relative to the NW_CM_RM15 alternative are small. The SRP energy exchange continues to be turned off and SRP wheeling is unchanged. However, GCD generation is further reduced to 40 MWh from 76.5 MWh (NW_CM-LCR) resulting in a lower economic outcome and both higher purchase quantities and associated outlays. Another notable difference is that there is a tiny purchase of 0.3 MWh in the four corners region even though energy purchase prices in that region are more expensive than in the north. This occurs because a combination of purchase power transfers, SRP wheeling and the sale of transmission capacity through 3rd party contracts is creating congestion on pathways from the north to four corners.

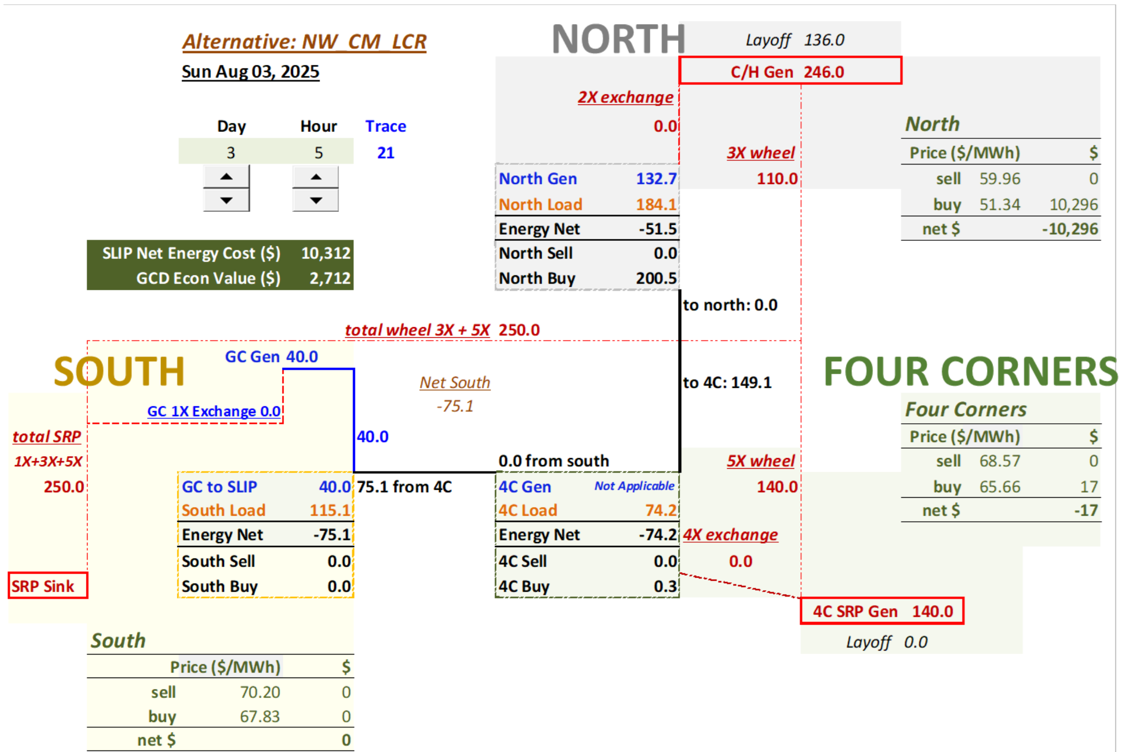


Figure 4.3 SERM Results for a Summer Off-peak Hour under the Cold Mix, Little Colorado River Alternative.

Off-peak Cold Shock Results

Results from both cold shock SERM, RM and LCR variations, for the August, 2025, summer day at 5 AM are nearly identical except for very small (inconsequential) differences in economic value and financial cost outcomes (about $1 dollar). Principally driven by GCD generation levels, Economic and financial outcomes for these two cold shock alternatives are situated between the cold mix alternatives, NW_CM_RM15 and NW_CM_LCR.

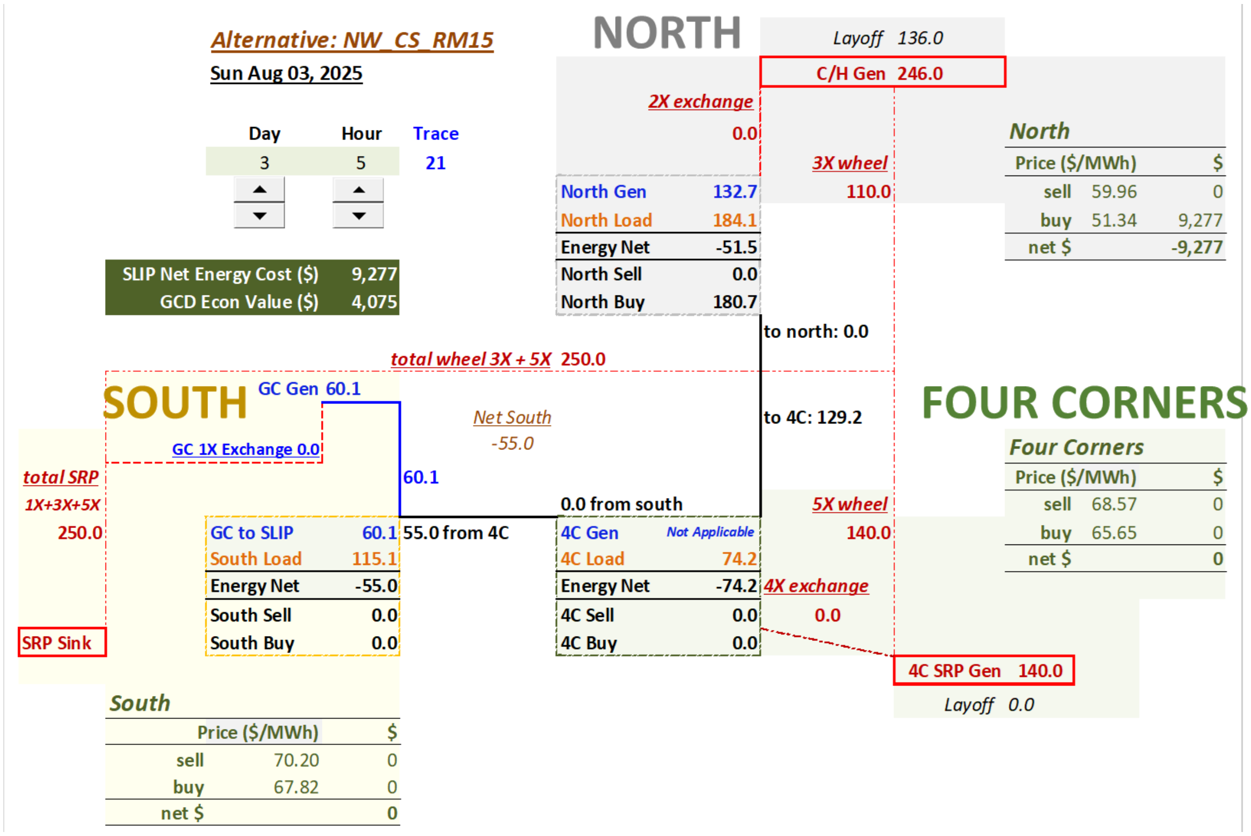


Figure 4.4 SERM Results for a Summer Off-peak Hour under the Cold Shock, RM15 Alternative.

Off-peak Hour Summary

A summary of metric outcomes by alternative for Sunday, August 3, at 5 AM is provided in Table 4.1. It shows that the No Action Alternative has the highest GCD generation level and best outcomes from a power systems perspective. More specifically, the No Action Alternative has the highest economic value, a positive net financial value, a long-energy position, and CRSP operations engage in an SRP energy exchange.

Under all action alternatives, the SRP exchange is turned off because the south region has an energy deficit. However, SRP wheeling is unaffected by experimental releases prescribed by the action alternatives. The worst alternative from a power perspective is the NW_CM-LCR Alternative primarily because GCD generation is the lowest among all alternatives, that is 20 MWh. The economic value under this alternative is only 12.5 percent of the No Action Alternative and financial costs are over ten thousand dollars for this single off-peak hour.

Table 4.1 SERM Model Results for Sunday, August 3, 2025, at 5 AM (Off-Peak Hour)

	LTEMP SEIS Alternatives				
Metric	No Action	NW_CM-RM15	NW_CM-LCR	NW_CS-RM15	NW_CS-LCR

GCD Generation (MWh)	252	77	40	60	60
FES Customer DSA Load (MWh)	373	373	373	373	373
Net Energy Purchases (MW)	-11	146	201	181	181
GCD Economic Energy Value ($)	17,051	5,190	2,714	4,075	4,074
CSRP Office Net Financial Costs ($)	-752	8,433	10,312	9,277	9,277
SRP Powerplant Generation (MWh)	386	386	386	386	386
SRP Energy Exchange 1X (MW)	126	0	0	0	0
SRP Energy Wheeling 3X + 5X (MW)	250	250	250	250	250
SRP Agreement Layoff (MW)	10	136	136	136	136

Metrics for action alternatives relative to the No-Action case are shown in Table 4.2. Negative change in generation is interpreted as lost generation due to an action alternative changed operations (primarily bypass releases) and negative economic values are a measure the increase in WI power grid production cost. Relative to the No Action case, CRSP Office power market operator will need to purchase more energy on the market lowering the CRSP Office net financial position. Lastly, because the SRP energy exchange is shut down, there will be an increase in SRP generation layoffs.

Table 4.2 Action Alternative Changes from the No-Action Alternative for Sunday, August 3, 2025, at 5 AM (Off-Peak Hour)

	Action Alternative minus No Action Alternative			
Metric	**NW_CM-RM15**	**NW_CM-LCR**	**NW_CS-RM15**	**NW_CS-LCR**
GCD Generation (MWh)	-175	-212	-191	-191
FES Customer DSA Load (MWh)	0	0	0	0
Net Energy Purchases (MW)	157	212	191	191
GCD Economic Energy Value ($)	-11,861	-14,337	-12,976	-12,977
CSRP Office Net Financial Costs ($)	9,185	11,064	10,029	10,029
SRP Powerplant Generation (MWh)	0	0	0	0
SRP Energy Exchange 1X (MW)	-126	-126	-126	-126
SRP Energy Wheeling 3X + 5X (MW)	0	0	0	0
SRP Agreement Layoff (MW)	126	126	126	126

On-peak No-Action Results

Figure 4.5 shows SERM results for a summer on-peak hour (Friday, August 15, 2025, at 7 PM) under the No Action Alternative. GCD generation during this hour is higher at 481.5 MWh compared to the off-peak hour generation level of 251.5 MWh. Of that total amount 285.8 MWh is used to serve all the SLIP loads in the south and the remaining GCD energy is used for the SRP 1X energy exchange (*Net South 195.6*). The GCD 1X energy is exchanged for 102.7 MWh of Craig and Hayen generation to cover the entire SLIP short position (*2X*) in the north and 92.9 MWh of generation from SRP Four Corner

Powerplant covers 92.9 MWh of the 108.3 MWh of the short position in the four corners region. The remainder of the four corners region short position is balanced by a 15.4 MWh purchase in the north SLIP region. If the energy short position had been larger in either the north or four corners region or both regions, then all 136.4 MWh of the south region excess would have gone to the exchange. This situation differs from the No Action Alternative off-peak position, during which time, the SLIP system was in an energy long position and there was an energy balance in each region, that is, there were no regional energy transfers.

The total amount of on-peak energy wheeled (*3X + 5X* = 250 MWh) was the same as the off-peak hour. However, the amount wheeled from Craig and Hayen (*3X wheel)* increased 202.9 MWh to partially accommodate the increased output from those two powerplants. Energy wheeled from the SRP Four Corners Powerplant (*5X wheel*) at 47.1 MWh was lower than the off-peak hour because more Four Corners energy production was used to cover the higher on peak loads in the SLIP four corners region. Although the on-peak hour 1X exchange increased from the off-peak 1X exchange level, it was not enough to accommodate the 120 MWh increase in SRP north generation resulting in a on-peak 60.4 MWh layoff compared to a layoff of 10.3 MWh during the off-peak hour.

This 15.4 MWh energy purchase in the north at a price of 154.51 $/MWh resulted in a CRSP Office financial expenditure of $2,379 dollars compared to a financial net gain of $752 dollars during the off-peak hour. The estimated GCD $98,269 dollars economic value of energy was much higher during the on-peak hour than the off-peak economic value at $17,051 dollars. This is the result of both higher on-peak hour GCD generation and more expensive energy prices.

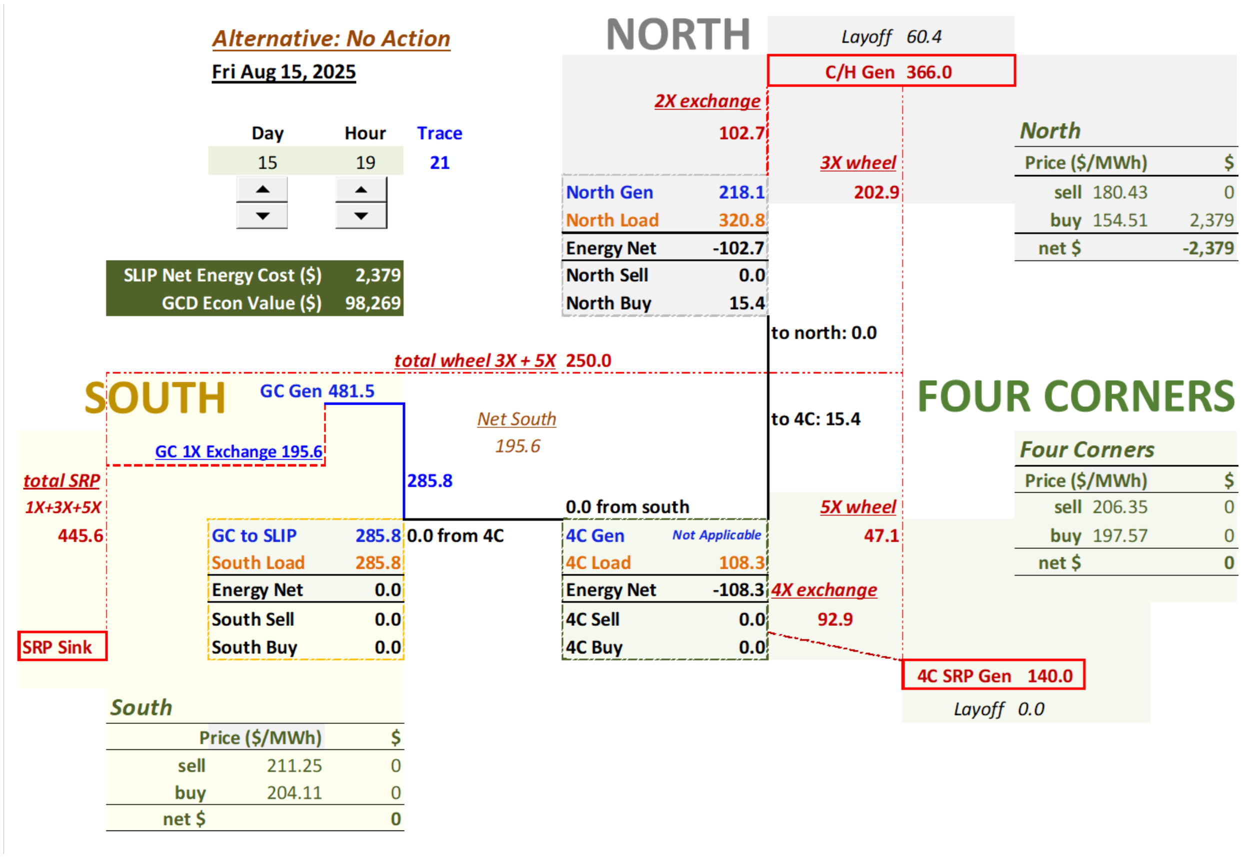


Figure 4.5 SERM Results for a Summer On-peak Hour under the No Action Alternative.

On-peak NW_CM-RM15 Results

Figure 4.6 shows SERM results the NW_CM_RM15 Alternative during the on-peak hour. GCD generation is 346.9 MW of 285.8 MWh is used to serve SLIP all the south load. The remaining 61.0 MWh is used for the SRP exchange (*1X*) all of which is exchanged from SRP generation in the SLIP north region (*2X)*. In contrast, there was zero energy exchanged under this alternative during the off-peak hour.

Identical to the NW_CM_RM15 Alternative during the off-peak hour, Craig and Hayen energy wheeling (*3X)* remains at 110 MWh with an additional 140 MWh wheeled from the SRP Four Corners Powerplant (*5X*) for a total of 250.0 MWh (*3X + 5X*). However, 195.0 MWh layoff energy in the north is higher during the on-peak hour because the 61.0 MWh increase in north energy exchange (*2X*) is less than the 120 MWh increase in Craig and Haden generation.

The SLIP energy short position of 150 MWh is balanced with a north region purchase at a CRSP Office financial cost of $23,179 dollars. This purchase is used to serve the entire four corners load and the remaining short position, after the energy exchange, in the north. Economic value under this alternative is $70,806 dollars which is a value reduction of more than 27 thousand dollars relative to the No Action on-peak result.

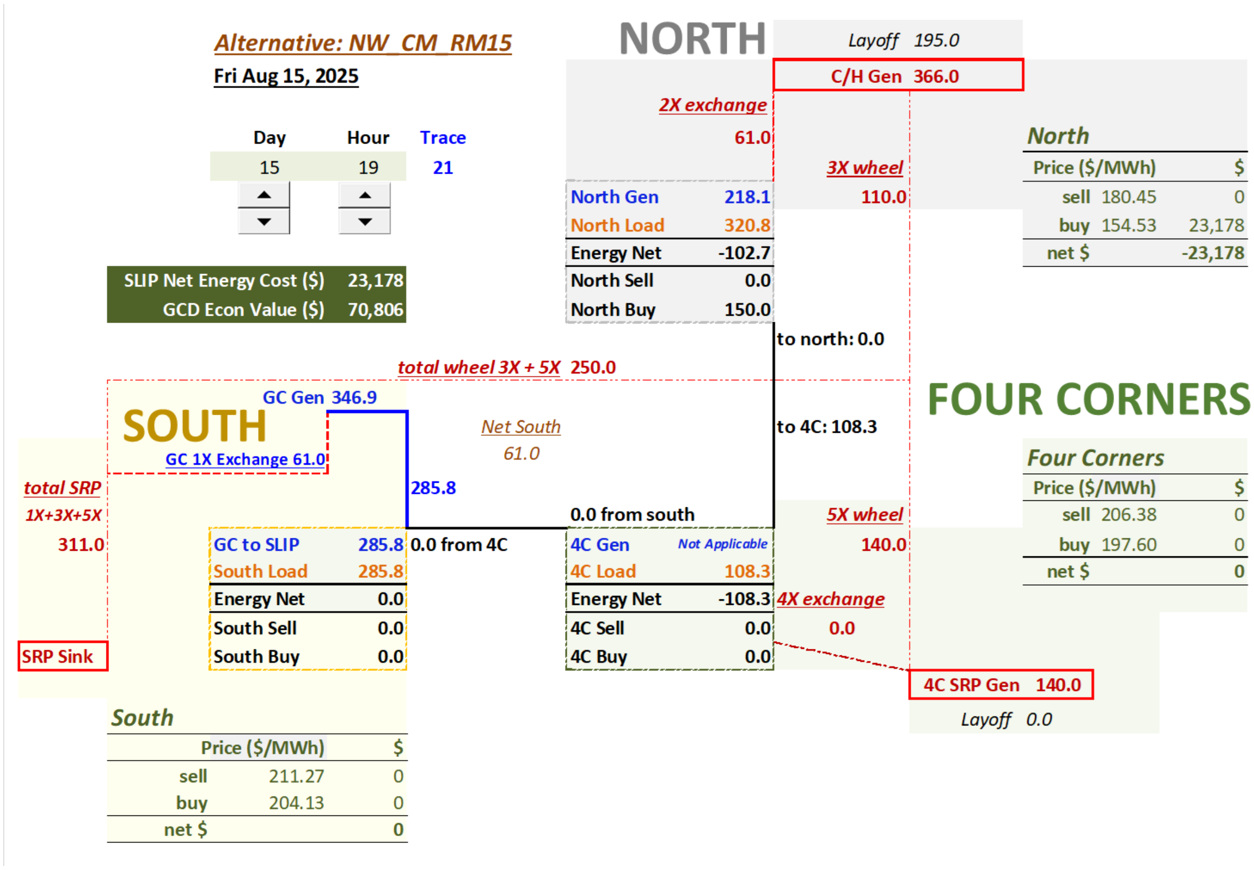


Figure 4.6 SERM Results for a Summer On-peak Hour under the NW_CM_RM15 Alternative.

On-peak NW_CM-LCR Results

Results for the NW_CM_LCR Alternative for the on-peak hour are shown in Figure 4.7. Although changes relative to the NW_CM_RM15 Alternative are small for the off-peak hour, difference between NW_CM_RM15 and the NW_CM_LCR Alternative during the on-peak hour are substantial. This is caused by a large GCD generation difference between the two alternatives: specifically, 346.9 MWh for NW_CM_RM15 and 266.3 MWh for NW_CM_LCR (a reduction of 80.6 MWh).

The generation reduction causes a south energy short position of 19.5 MWh, thereby turning off SRP energy exchanges. Other impacts relative to NM_CM_LCR are increases in (1) CRSP Office energy market purchases, (2) energy purchase costs, (3) contractual power flows from the north region to the four corners region, and (4) SRP powerplant layoffs. On the other hand, the economic value under the NW_CM_LCR Alternative ($54,365 dollars) is significantly lower than under the NW_CM_RM15 Alternative.

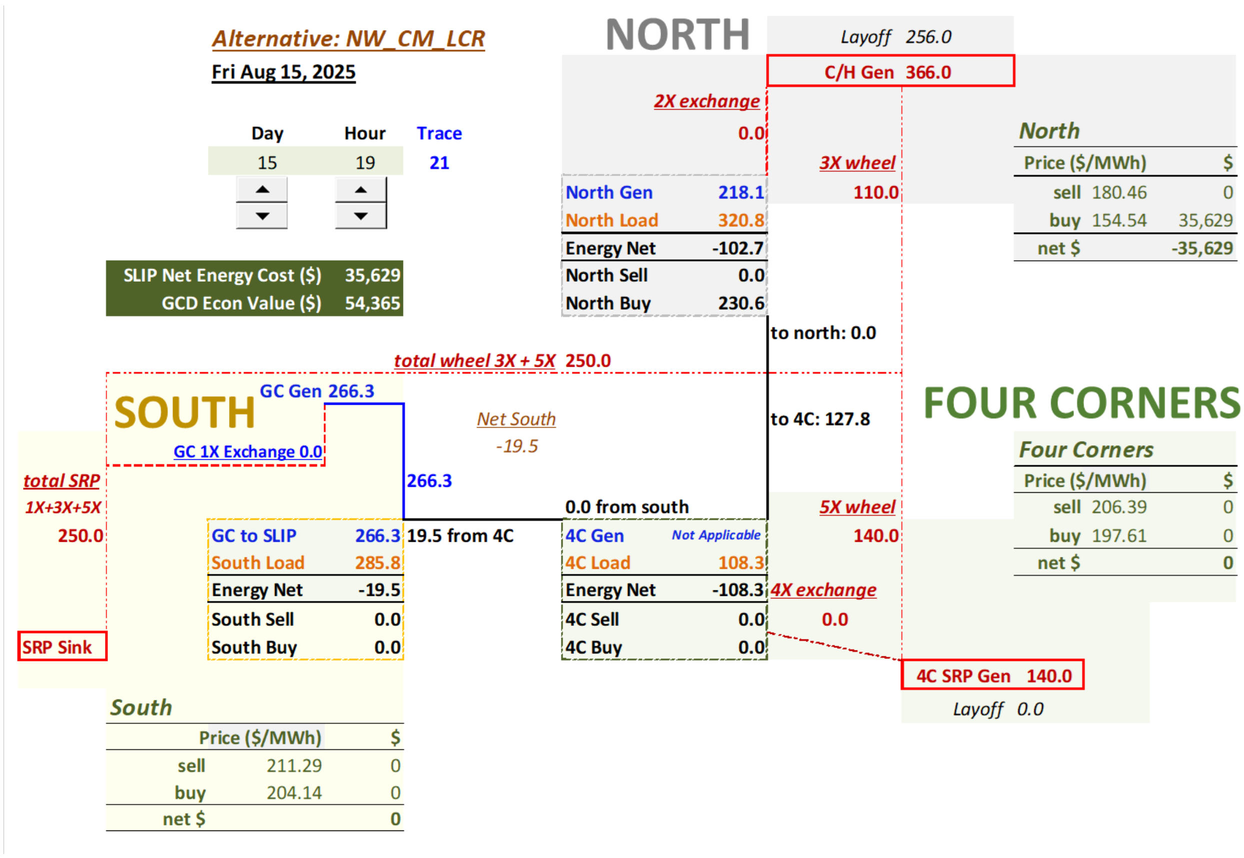


Figure 4.7 SERM Results for a Summer On-peak Hour under the NW_CM_CLR Alternative.

On-peak Cold Shock Results

Because cold shock experiments, under the NW_CS_RM15 and NW_CS_CLR Alternatives are only conducted on weekends, SLIP and SRP impacts during a weekday are much smaller than during the off-peak Sunday hour. Figures 4.8 and 4.9 show that SERM results for cold shock alternatives have a relatively small impact on power economics and SLIP operations relative to the No Action Alternative. GCD generation under the NW_CM_RM15 Alternative is only 1.8 MWh lower and for the NW_CM_CLR Alternative it is 21.5 MWh lower.

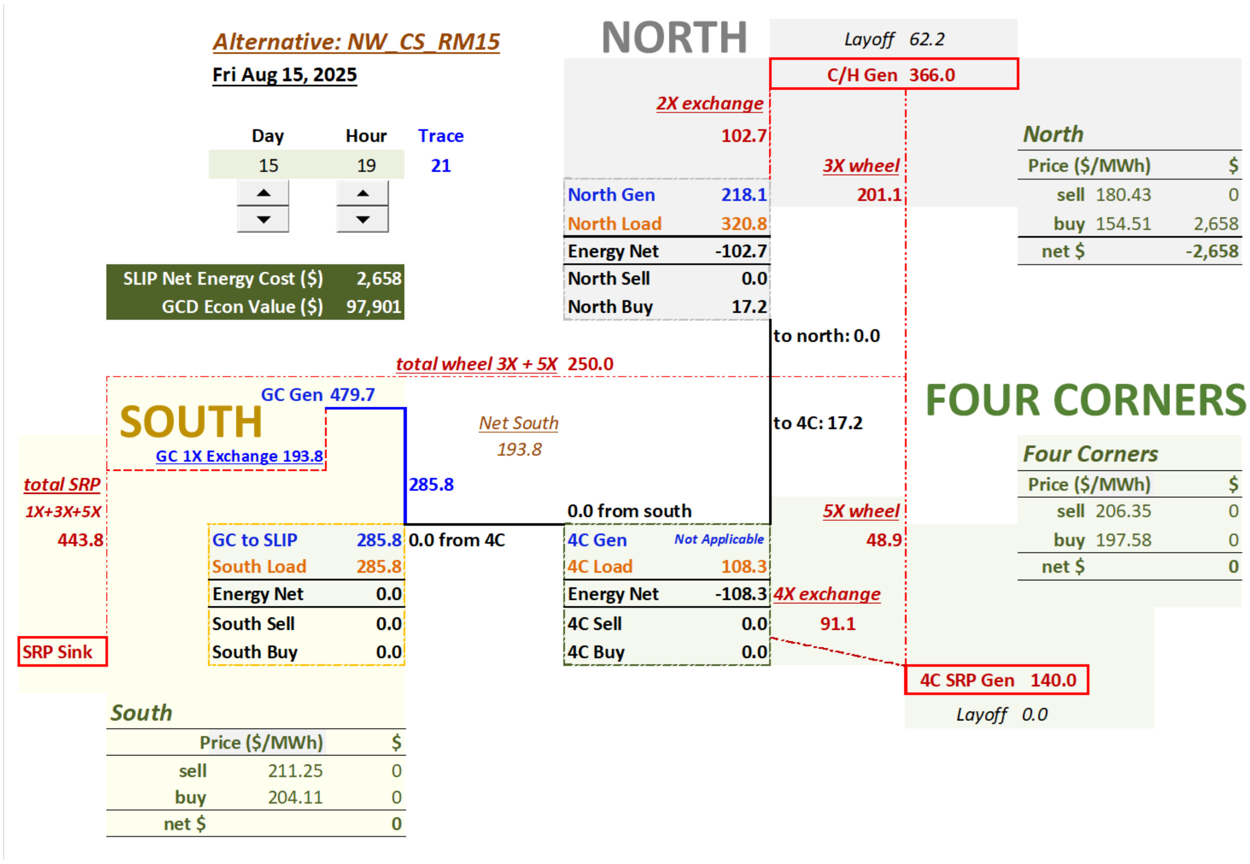


Figure 4.8 SERM Results for a Summer On-peak Hour under the NW_CS_RM15 Alternative.

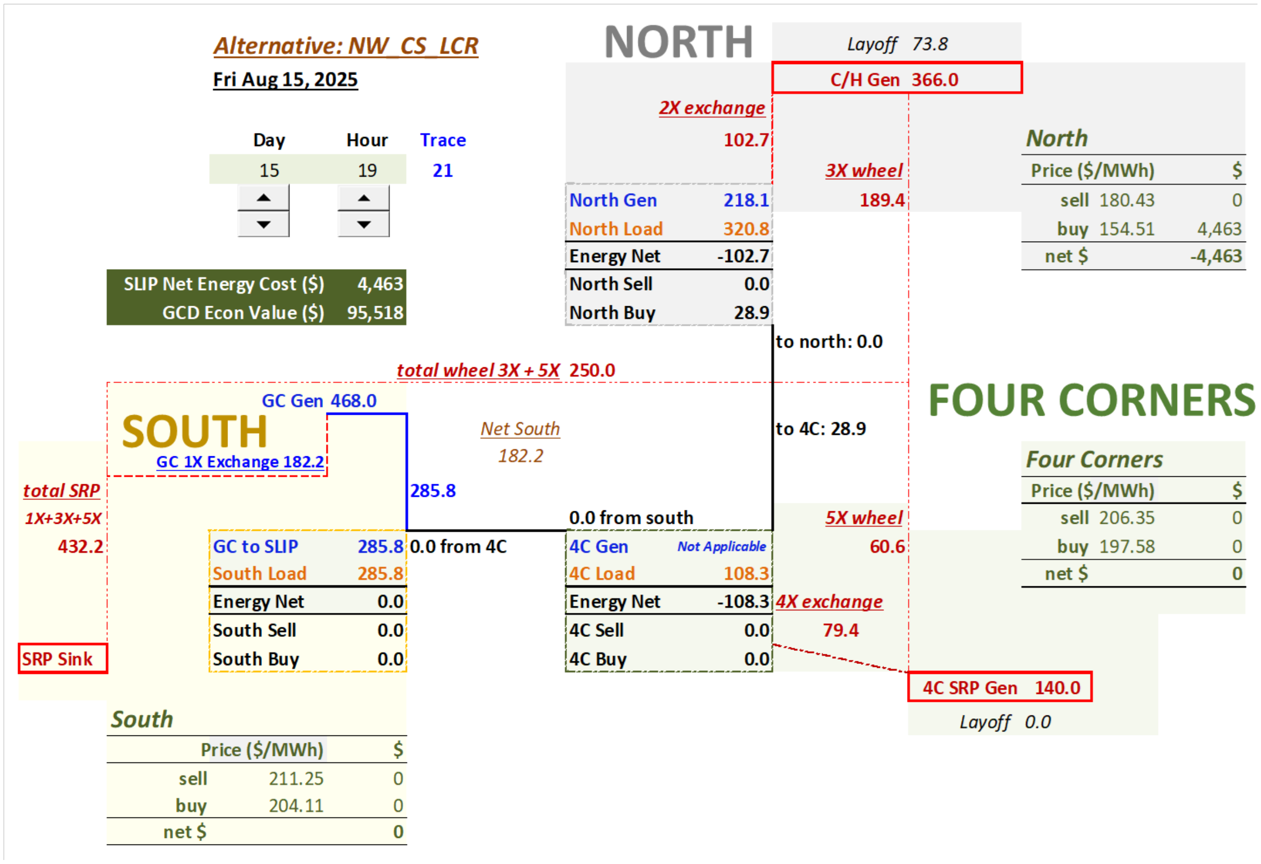


Figure 4.9 SERM Results for a Summer On-peak Hour under the NW_CS_LCR Alternative.

On-peak Hour Summary

A summary of metric outcomes by alternative for Friday, August 15, 2025, at 7 PM is provided in Tables 4.3 and 4.4. Like off-peak hour results, during an on-peak hour the No Action Alternative has the highest GCD generation level and best outcomes from a power systems perspective. As previously discussed, however, cold shock impacts are much smaller than cold mix impacts. Also, cold mix alternative impacts are much higher during the on-peak hour. For example, relative to the No Action Alternative, economic costs of the NW_CM_RM15 increases from $11,861 dollars for the off-peak hour to $27,463 dollars for the on-peak hour.

Table 4.3 SERM Model Results for Friday, August 15, 2025, at 7 PM (On-Peak Hour)

	LTEMP SEIS Alternatives				
Metric	No Action	NW_CM-RM15	NW_CM-LCR	NW_CS-RM15	NW_CS-LCR
GCD Generation (MWh)	482	347	266	480	460
FES Customer DSA Load (MWh)	715	715	715	715	715
Net Energy Purchases (MW)	15	150	231	17	29
GCD Economic Energy Value ($)	98,269	70,806	54,365	97,901	95,518

CSRP Office Net Financial Costs ($)	2,379	23,178	35,629	2,658	4,463
SRP Powerplant Generation (MWh)	506	506	506	506	506
SRP Energy Exchange 1X (MW)	196	61	0	194	182
SRP Energy Wheeling 3X + 5X (MW)	250	250	250	250	250
SRP Agreement Layoff (MW)	60	195	256	62	74

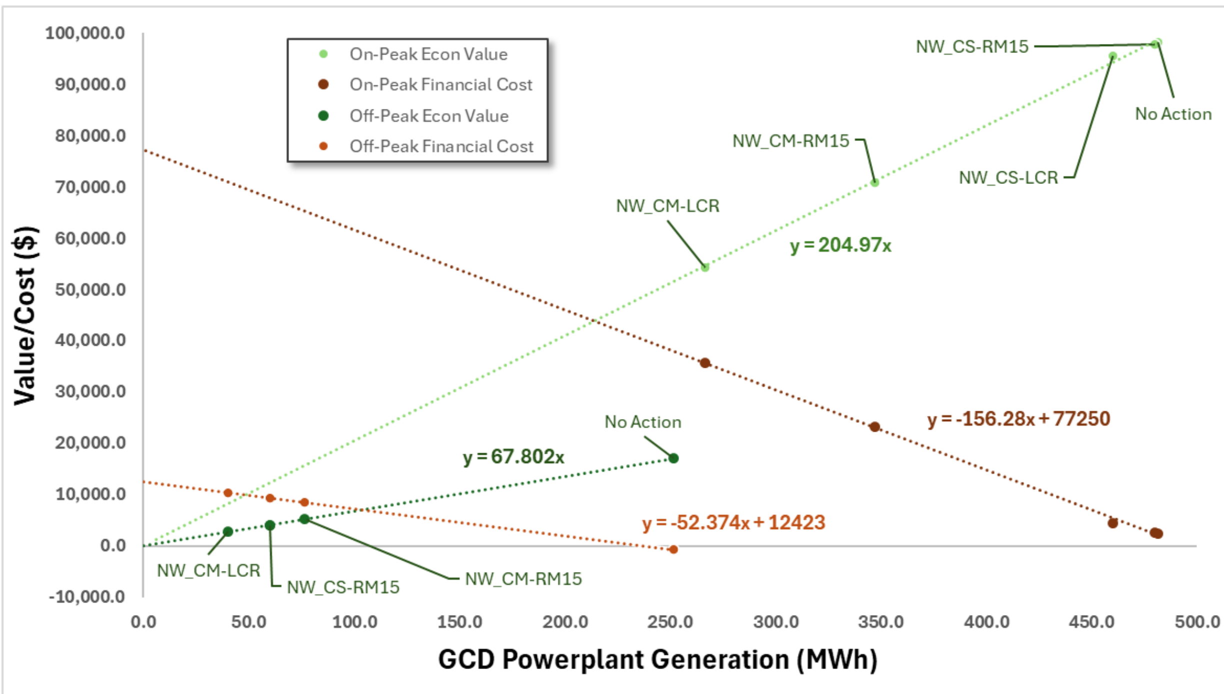
Table 4.4 Action Alternative Changes from the No-Action Alternative for Friday, August 15, 2025, at 7 PM (On-Peak Hour)

	Action Alternative minus No Action Alternative			
Metric	**NW_CM-RM15**	**NW_CM-LCR**	**NW_CS-RM15**	**NW_CS-LCR**
GCD Generation (MWh)	-135	-215	-2	-22
FES Customer DSA Load (MWh)	0	0	0	0
Net Energy Purchases (MW)	135	215	2	14
GCD Economic Energy Value ($)	-27,463	-43,904	-368	-2,751
CSRP Office Net Financial Costs ($)	20,799	33,250	279	2,084
SRP Powerplant Generation (MWh)	0	0	0	0
SRP Energy Exchange 1X (MW)	-135	-196	-2	-13
SRP Energy Wheeling 3X + 5X (MW)	0	0	0	0
SRP Agreement Layoff (MW)	135	196	2	13

Figure 4.10 Relationships between GDC Powerplant Generation, Economic Value, and Financial Cost of the On-peak hour and Off-peak hour.

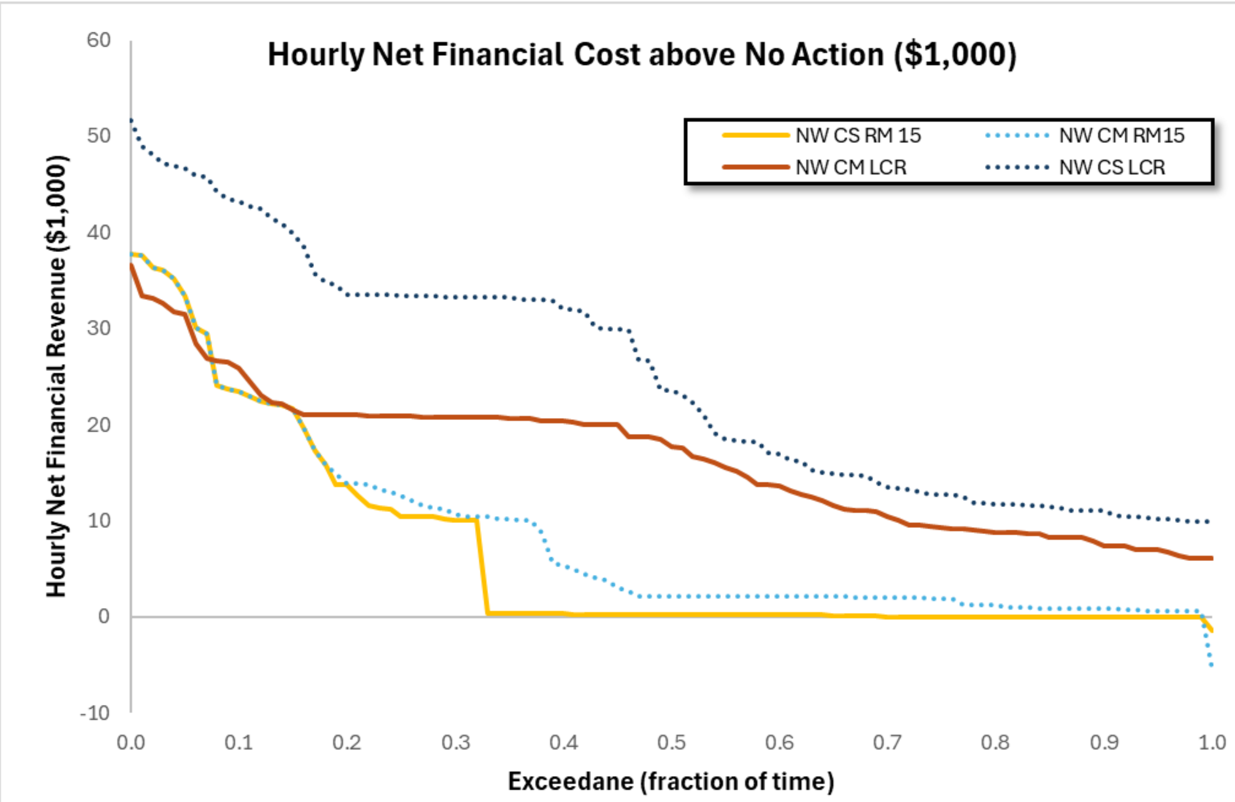
GCD Generation Impacts of SERM Results

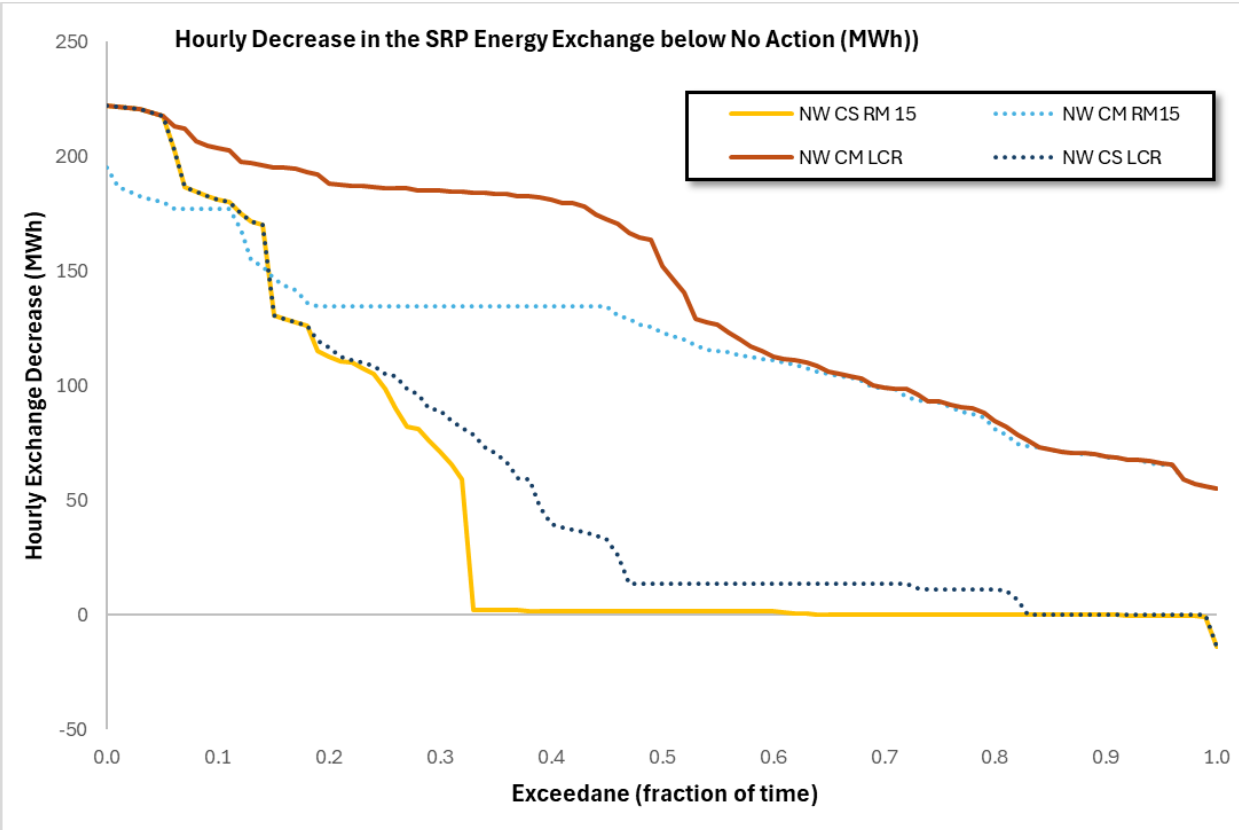
Using the data contained in Tables 4.1 and 4.3, Figure 4.10 shows the relationship between GCD hydropower generation and economic/financial outcomes. It shows a very strong linear relationship between generations and both economic/financial outcomes during the off-peak and on-peak hours. The slope of those economic lines is directly tied to the cost of energy purchases and sales. Note that the slope for the off-peak is 67.80 $/MWh and for the on-peak hour it is 204.8 $/MWh; that is, nearly identical to the energy prices at GCD.   The negative slopes for financial show that as GCD generation Increase, the CRSP financial cost decrease. For the off-peak hour, the slope is -52.37 $/MWh or approximately the market energy purchase price in the north during the off-peak hour. Similarly, the on-peak slope is -156.28 $/MWh; that is, close to the market energy price in the north during the on-peak hour to buy energy.

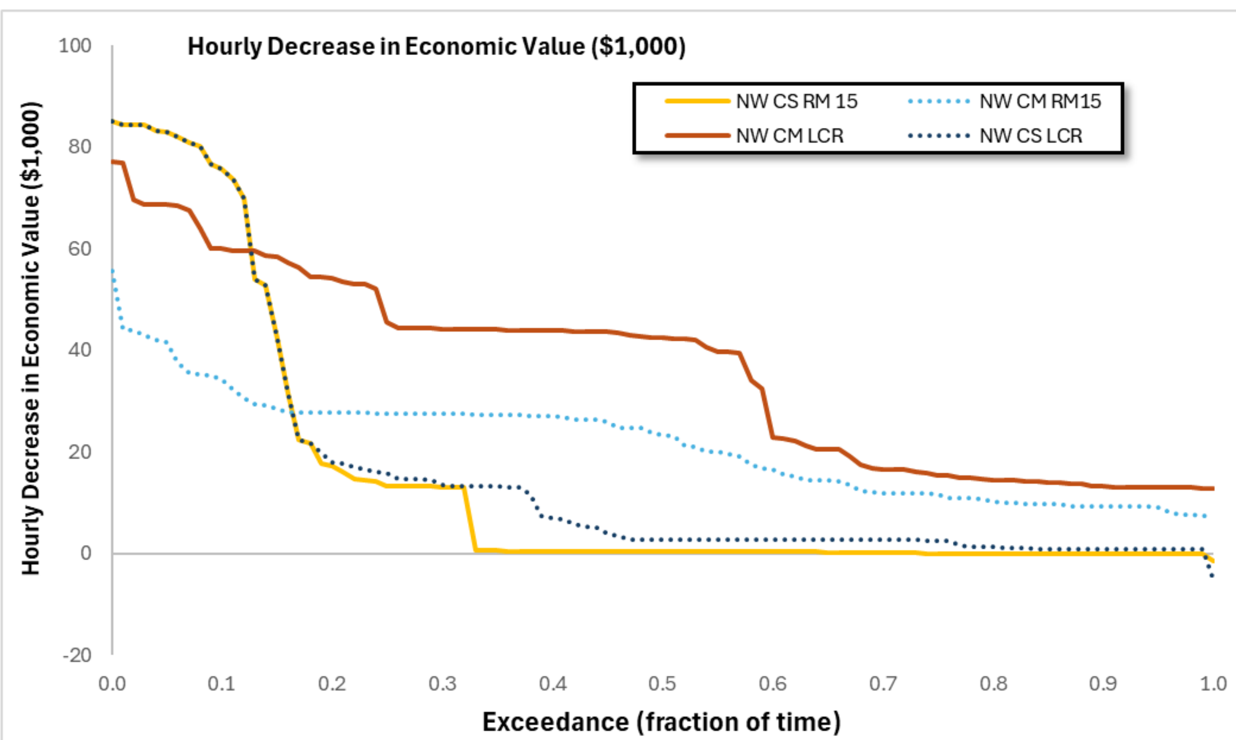


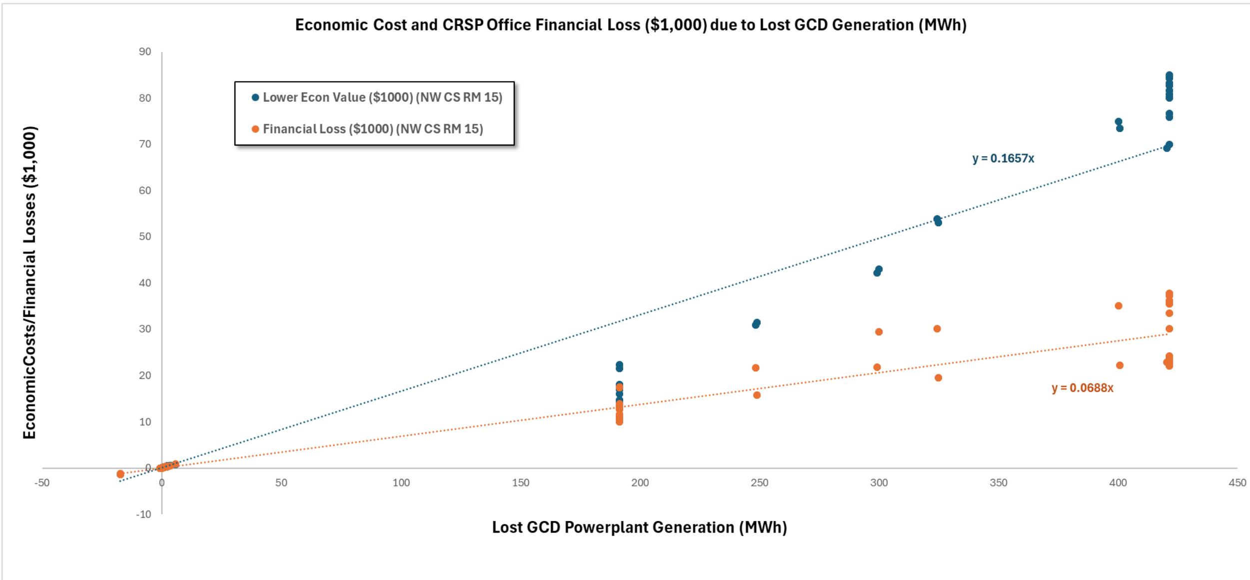
Analysis of all hours during August 2025 for Trace 21

Metric	No Action	NW CS RM 15	NW CM RM15	NW CM LCR	NW CS LCR	NW CS RM 15	NW CM RM15	NW CM LCR	NW CS LCR
	August 2025, Trace 21					**Change for No Action**			
Net Financial Costs ($1,000)	593	5,448	12,877	19,178	6,811	4,856	12,285	18,585	6,218
GCD Economic Value ($1,000)	44,327	33,653	28,473	17,386	31,924	10,674	15,854	26,941	12,403
SRP Energy Exchange -1X (GWh)	105	71	18	0	61	35	88	105	44
GCD Generation (GWh)	278	207	170	100	196	71	108	179	82
Craig to San Juan Line Flow (GWh)	17	45	70	103	53	28	53	86	36




Hourly Decrease in the SRP Energy Exchange below No Action (MWh))
NW CS RM 15
NW CM RM15
NW CM LCR
NW CS LCR
Hourly Exchange Decrease (MWh)
250
200
150
100
50
0
-50
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Exceedane (fraction of time)


Hourly Decrease in Economic Value ($1,000)
NW CS RM 15
NW CM RM15
NW CM LCR
NW CS LCR
Hourly Decrease in Economic Value ($1,000)
100
80
60
40
20
0
-20
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Exceedance (fraction of time)



Economic Cost and CRSP Office Financial Loss ($1,000) due to Lost GCD Generation (MWh)
Lower Econ Value ($1000) (NW CS RM 15)
Financial Loss ($1000) (NW CS RM 15)
y = 0.1657x
y = 0.0688x
EconomicCosts/Financial Losses ($1,000)
Lost GCD Powerplant Generation (MWh)
90
80
70
60
50
40
30
20
10
0
-10
-50
0
50
100
150
200
250
300
350
400
450

Methodology – Description of System

In order to assess the impact of varying operational patterns of Glen Canyon Powerplant, NREL used commercially-available production cost modeling tool, PLEXOS[1]. This tool is widely used by NREL and other organizations to simulate the operation of the electric power system on an hourly basis. PLEXOS does an optimization to determine the least-cost unit commitment and economic dispatch of every generator in the system, given the physical constraints of the system itself. These physical constraints include the hourly electricity demand, the operating parameters of individual generators, the transmission system topology, and the availability of wind, solar, and water for electricity generation. It also ensures the sufficient provision of operating reserves.

The outputs of PLEXOS include the hour-by-hour optimal dispatch of the generation fleet, locational marginal prices, and total generation cost (including fuel, variable operating and maintenance costs, and start & shutdown costs). PLEXOS can also identify transmission lines or paths which exhibit congestion and any reliability concerns, such as unserved load or reserves.

NREL has developed a dataset that represents a possible evolution of the Western Interconnection that spans the western portions of the United States and Canada. This dataset contains detailed information about thousands of generation units along with nodes and transmission lines that connect them to load. We represent the chronological years of 2024 – 2027 but use historical 2012 weather data for determining load, wind, and solar profiles. For some cases we also use historical 2012 hydrology to determine hydropower generation, but based on discussions with the project team, we also show a scenario which attempts to capture the current status of drought in the Southwestern U.S. In this case, we derate all hydropower generation to a level of 80% of normal (determined by historical hydrology).

The analysis focused on the Colorado River Basin, which includes parts of several balancing authorities or load serving entities in the Southwestern United States: Western Area Lower Colorado (WALC), Western Area Colorado Missouri (WACM), Arizona Public Service (APS), Nevada Power (NEVP), parts of the PacificCorp footprint (PACE), Public Service of Colorado (PSCO), Public Service of New Mexico (PNM), Tucson Electric Power (TEP) and Salt River Project (SRP). We worked with study participants (WAPA, ANL, SRP) to improve the representation of this focus area by adjusting generator retirement dates, updating of transmission line wheeling rates, and increasing the reserve requirement in the region. Figure 1 shows the annual generation mix in the footprint (approximately the states of Arizona, New Mexico, Colorado, Nevada, Wyoming, and Utah) for each of the four chronological years. It indicates that the largest portion of electricity generation in 2024 is still coal, but by 2027, wind and coal generation are present in roughly equal amounts driven by growth in wind generation and retirements of coal generation. Solar generation also continues to grow through the four years, and the other sources of generation (nuclear, natural gas, and hydropower) remain relatively stable. Note that the total generation in the region exceeds total annual load (the horizontal black line) indicating that the region is a net exporter to other regions of the Western Interconnection, likely California in this case.

[1] PLEXOS is a product of Energy Exemplar (https://www.energyexemplar.com/plexos)

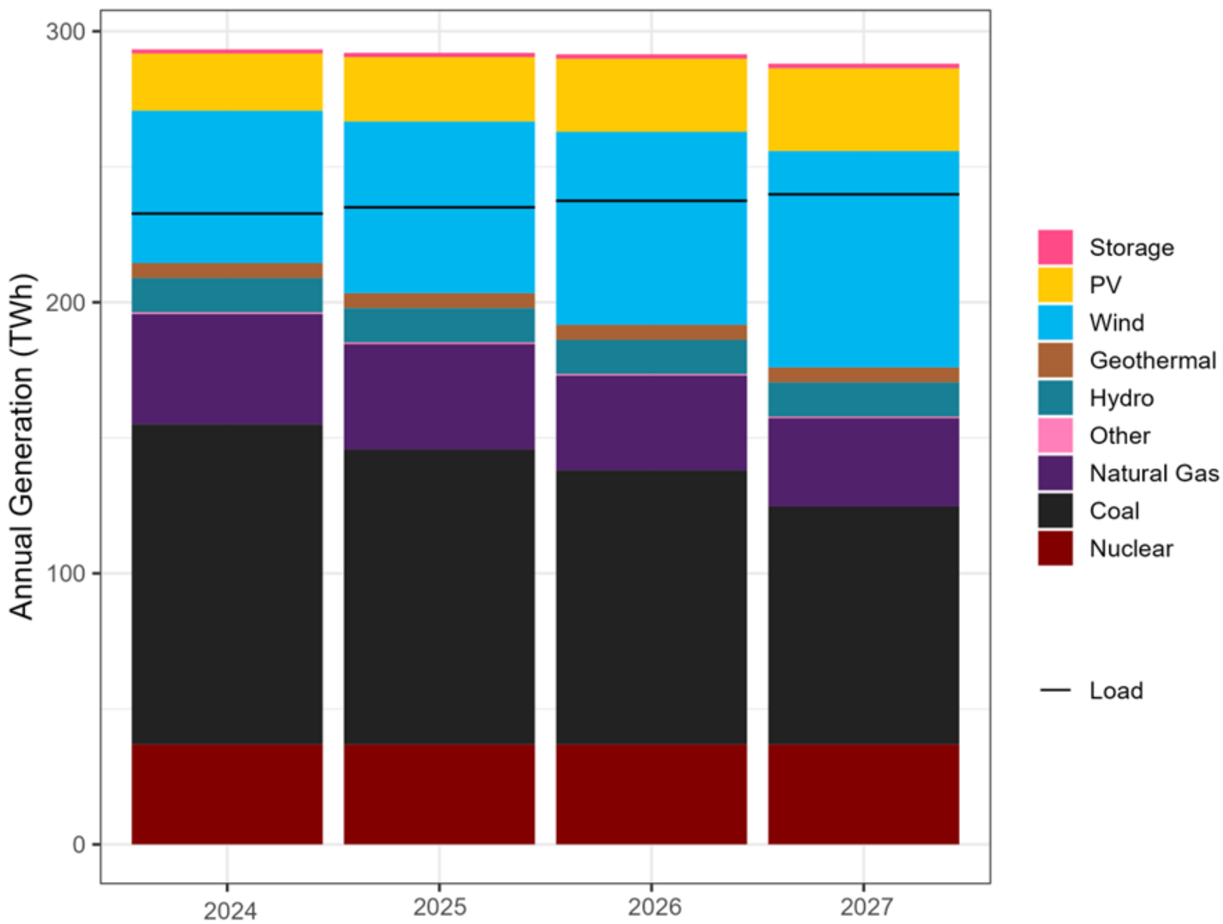


Figure 1. Annual generation mix in the study focus area for each of four chronological years (2024-2027).

Figure 2 shows the average daily net load curve for the study region, which is defined as the total demand for electricity minus contributions from wind and solar generation. It shows that even in 2024, the "duck curve" net load shape is on display, where solar generation decreases the net load in the middle of the day. The peak net load occurs in the summer months, since the peak electricity demand in this region of the country is largely driven by cooling needs during the warm summer months, with more moderate consumption of electricity during the cooler months of the year.

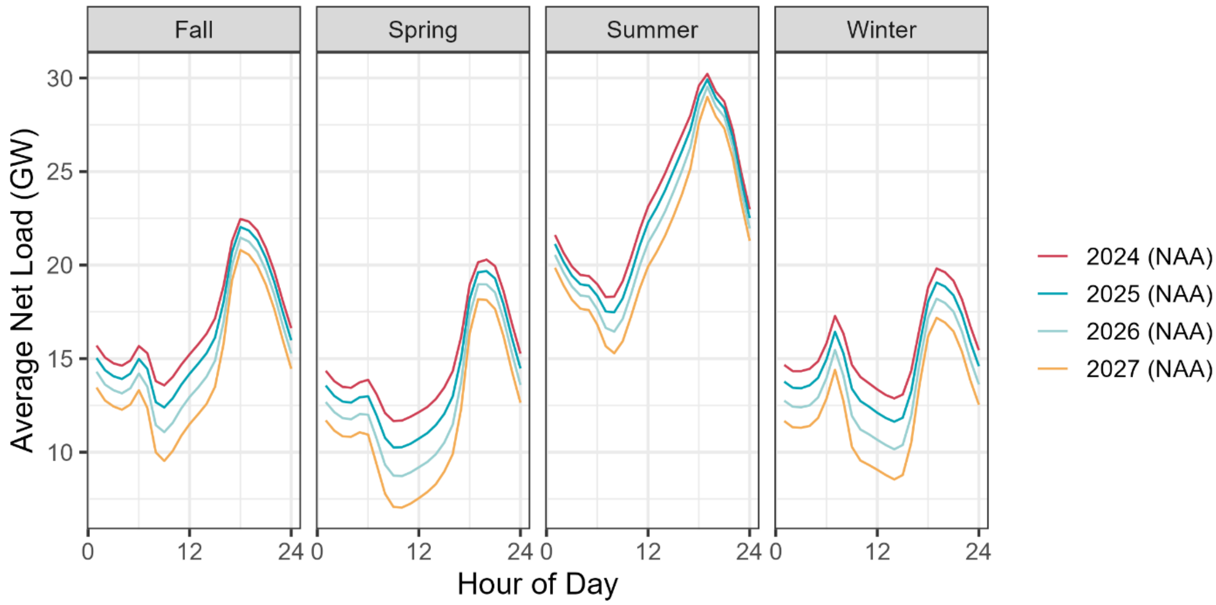


Figure 2. Average daily net load (electricity demand minus contributions from wind and solar) for the study footprint in each of the four study years.

Methodology – Model Reduction

In this study, we are looking at the impact of changing Glen Canyon Dam (GCD) generation schedules on the rest of the electricity system in the Western Interconnection. Although GCD is a large generating station (rated capacity of around 1300 MW with an annual generation of close to 4 TWh), it's relatively small compared to the rest of the Western Interconnection, which has an estimated installed capacity of 286,000 MW. So, we reduce the focus of our model in an attempt to carve out the impacts of the small change. We have tested and utilized numerous approaches for this study, and have employed the help of the software developers of PLEXOS for their assistance as well. The approaches are:

1) Kron reduction: The Kron reduction method is a setting in PLEXOS in which regions outside of the focus area can be collapsed to a single point (with some simplified knowledge about generation and load) so that imports and exports with the outside regions can be approximated. This method reduces the run time and allows for more precise modeling, but the algorithm is a bit of a "black box" within PLEXOS itself, and the NREL team worked closely with Energy Exemplar to understand the correct use of this method.
2) "Warm Start" approach: This method starts with one base case run of the full Western Interconnection, with the "No Action" or base case GCD generation profile. This base case run determines the generation levels of all generating units outside of the focus area. Since most of the variables are "fixed", we can employ a reduced MIP tolerance (solve gap) while still maintaining a tractable run time. We re-run the model again (with a different GCD generation profile), and only a select subset of generating units within the focus area are allowed to redispatch to meet change in generation from GCD. The candidate list of

generators that are allowed to redispatch were agreed upon by the project team and stakeholders (NREL, Argonne, WAPA, SRP, etc). This method allows us to determine which generating assets would be able to make up the difference in a case with less GCD generation and identify any issues faced with transmission congestion or unserved load.

Scenarios

For examining the impact of future generation profiles from GCD, we studied three central scenarios. These scenarios were determined through work done by our partners at WAPA and Argonne National Lab. They were created using thousands of possible GCD generation traces using past hydrology year data from Bureau of Reclamation. Given limited time and resources, we selected three hourly generation profiles which bound possible future generation profiles:

1) No Action Alternative (NAA). In this case, GCD continues to operate similarly to today's patterns. The values are calculated as an average of hydrological traces for the Environmental Impact Statement (EIS) test.
2) Maximum generation (Max). This case was created with the maximum amount of generation observed from the flow modeling traces and represents the highest GCD generation case.
3) Minimum generation (Min). This case was created with the lowest amount of generation observed from the flow modeling and simulates very low generation patterns from GCD.

Figure 3 shows the differences between the three scenarios. As the name suggests, the Max generation case has the highest generation, especially observed in the late summer/fall months. In contrast, the Min generation case has extremely low generation during those same months, which in some cases (such as August and September) correspond to high levels of demand on the system. So not only does flow vary the most in those months across scenarios, but the impact to the power system might be most important as resources across the West are stretched to meet peak net demand (Figure 2). Figure 4 shows the corresponding hourly generation for the three scenarios based on the flow modeling (Min, NoAction, and Max).

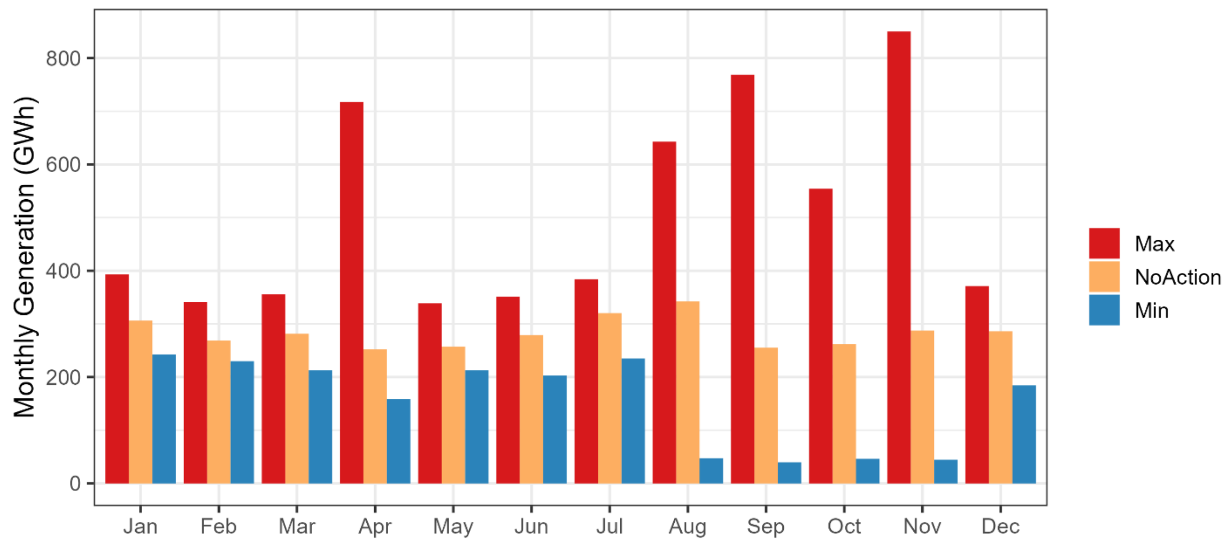


Figure 3. This figure shows the monthly generation (for year 2024) for each of the three GCD generation scenarios considered here.

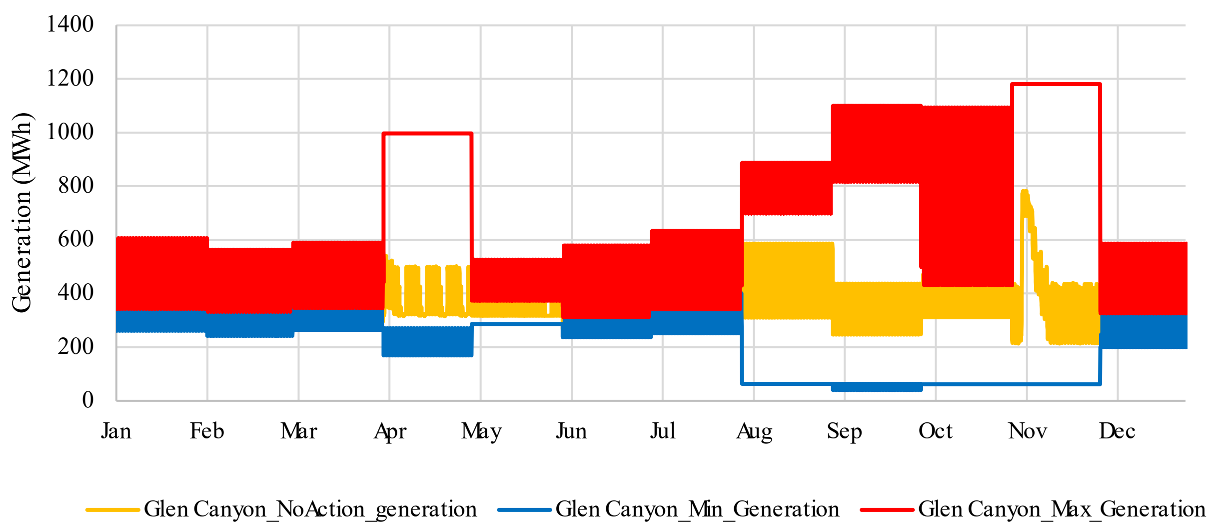


Figure 4. Hourly generation from GCD for three of the generation profiles identified through the flow modeling (Min, Max and No Action).

Results – Impact on Reliability

Overall, the PLEXOS runs do not indicate any inability to serve load (the unserved load in all cases is zero). This is the case for both methodologies discussed above (Kron reduction and Warm Start). The PLEXOS runs do show some hours of unserved reserves in the focus area in the Warm Start configuration (with a smaller, more negligible amount in the Kron reduction methodology). In all four years of PLEXOS runs, reserve shortages mostly occur in August (years 2025, 2026, and 2027), and in June (years 2026 and 2027). and September). In a run with the “No Action” GCD generation profile, we see just two hours with a total of 42 MW-h dropped reserves. In a case with Minimum

GCD generation which has the most unserved reserves (August 2027), that number increases to 600 MW-h over a dozen hours. The rest of the months with unserved reserves (August 2026, August 2025, June 2027, and June 2026) have less than 100 MW-h over just a few hours.

Results – Impact on Prices

Electricity prices (locational marginal prices) are derived from the PLEXOS model runs using the Kron reduction method for the following regions and nodes:

Regions: PAUT, PAWY, PSCO, WACM, AZPS, PNM, SRP, TEPC, WALC

Nodes: CRAIG, AULT, MIDWAY, SAN_JUAN, FOURCORN, PINNPK, GLENCANY, BONANZA. These nodes represent the hubs for trading or large generators in the region.

Figure 5 illustrates average daily local marginal prices (LMPs) profiles for the WALC region for the year 2024 for minimum, maximum and no action generation patterns derived from the Environmental Impact Statement (EIS) test's Glen Canyon generation traces. The maximum and no action generation profiles are simulated with the normal hydropower conditions of Western power grid. The minimum Glen generation is simulated with dry hydropower condition, 20% less from normal, of the grid. LMPs are higher for the minimum generation profile, especially during evening peak. This is because GCD is a source of zero-marginal cost electricity, and the reduction in generation from GCD must come from other, presumably more expensive generation options. Further, prices are higher during the summer months compared to other months, although the impact of GCD profiles is less obvious. We noticed similar LMP patterns for other regions. In August, one might expect a larger observable impact of the loss of GCD generation on the daily price profile. However, generation and load levels are much higher and the loss of GCD is smaller as a percentage of total demand.

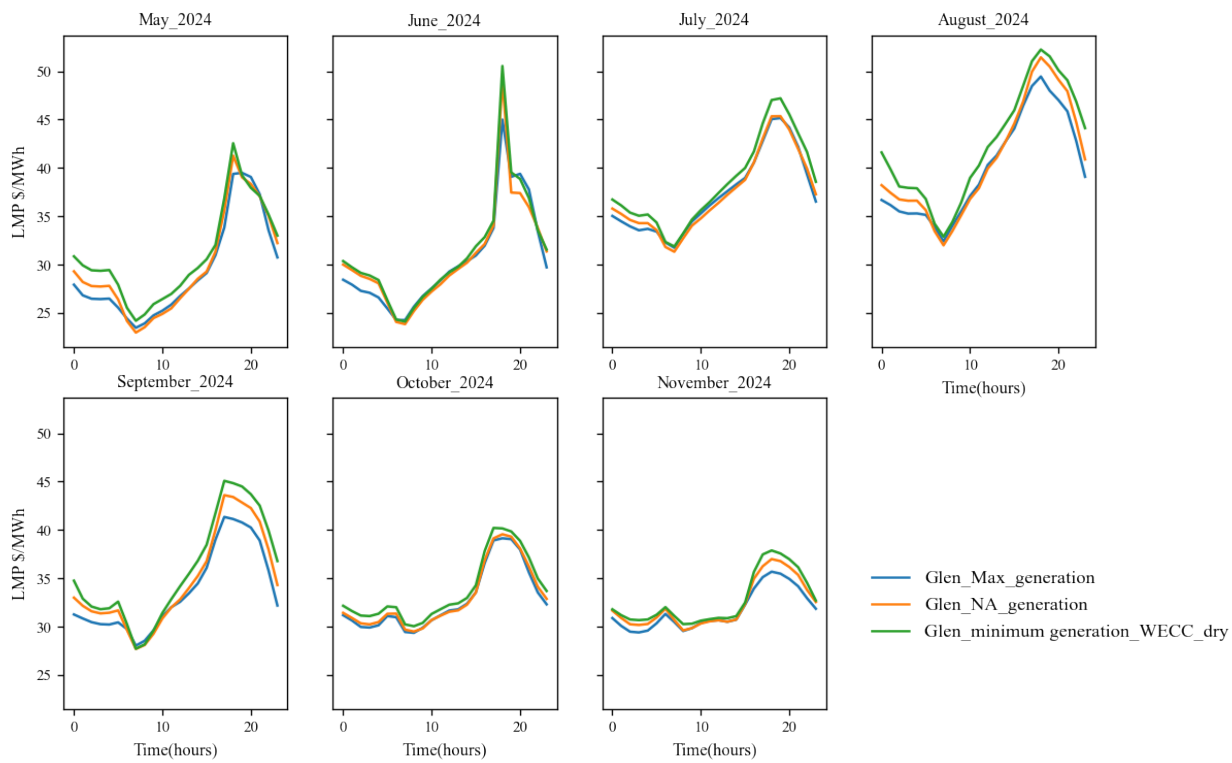


Figure 5 WALC region average diurnal LMPs for 2024 maximum, no action with normal hydro conditions and minimum Glen Canyon generation profiles for dry hydro conditions in the Western Interconnection.

As discussed above, WALC LMPs are higher under drought conditions with 20% less hydropower availability than under average conditions, which is similar to recent drought observations throughout the region (Figure 5, Figure 6). Table 1 and Table 2 show the monthly average LMPs for comparison, and we note that WALC prices are increased by 4% under the drought scenario.

Table 3 shows how prices increase over the focus regions for Glen Canyon generation loss and dry hydropower condition. The highest price increase is noticeable in PAUT region, and WALC prices increased by 3.1%. In addition, we have noted that evening peak prices have increased more than 20%-7% range for all the regions.

Table 1WALC average prices 2024 for Glen Canyon (1) maximum generation, (2)no action and (3)minimum generation with 20% low WECC hydropower conditions

Month	Max_Gen	NA_Gen	Min_Gen_dry
May	30.64	30.95	32.04
June	32.76	35.88	36.39
July	37.26	37.32	38.4
August	40.62	40.81	42.44
September	34.18	34.69	35.82
October	32.79	32.99	33.73
November	31.8	32.24	32.72
Total	34.29	34.98	35.93

Table 2 Average prices of focus regions for year 2024 no action and minimum generation scenarios

Region	No Action ($/MWh)	Minimum generation dry ($/MWh)	price increase
PAUT	[illegible]	[illegible]	8.3%
PAWY	[illegible]	[illegible]	7.5%
PSCO	[illegible]	[illegible]	1.0%
WACM	[illegible]	[illegible]	2.6%
AZPS	[illegible]	[illegible]	2.1%
PNM	[illegible]	[illegible]	2.6%
SRP	[illegible]	[illegible]	3.3%
TEPC	[illegible]	[illegible]	2.5%
WALC	[illegible]	[illegible]	3.1%

As discussed above, we also study the impact on 2025 through 2027. Figure 7, Figure 9 and Figure 11 illustrate year 2025, 2026 and 2027 WALC average LMP profiles for the maximum and minimum generation with average hydropower conditions, while Figure 8, Figure 10, and Figure 12 illustrate year 2025, 2026 and 2027 WALC average LMP profiles for the minimum generation GCD profile and with drought hydropower conditions.

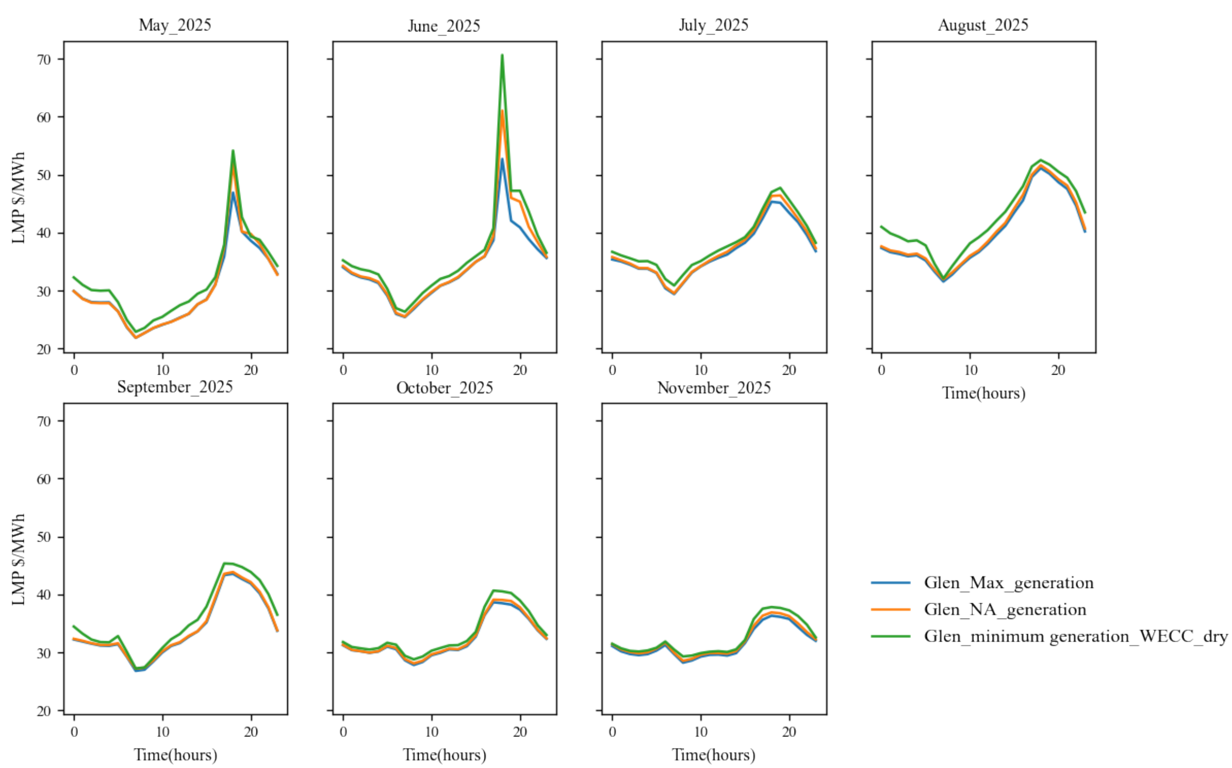


Figure 6 WALC region average diurnal LMPs for 2025 maximum and minimum Glen Canyon generation profiles for average hydropower conditions. Note the difference in y-axis scales.

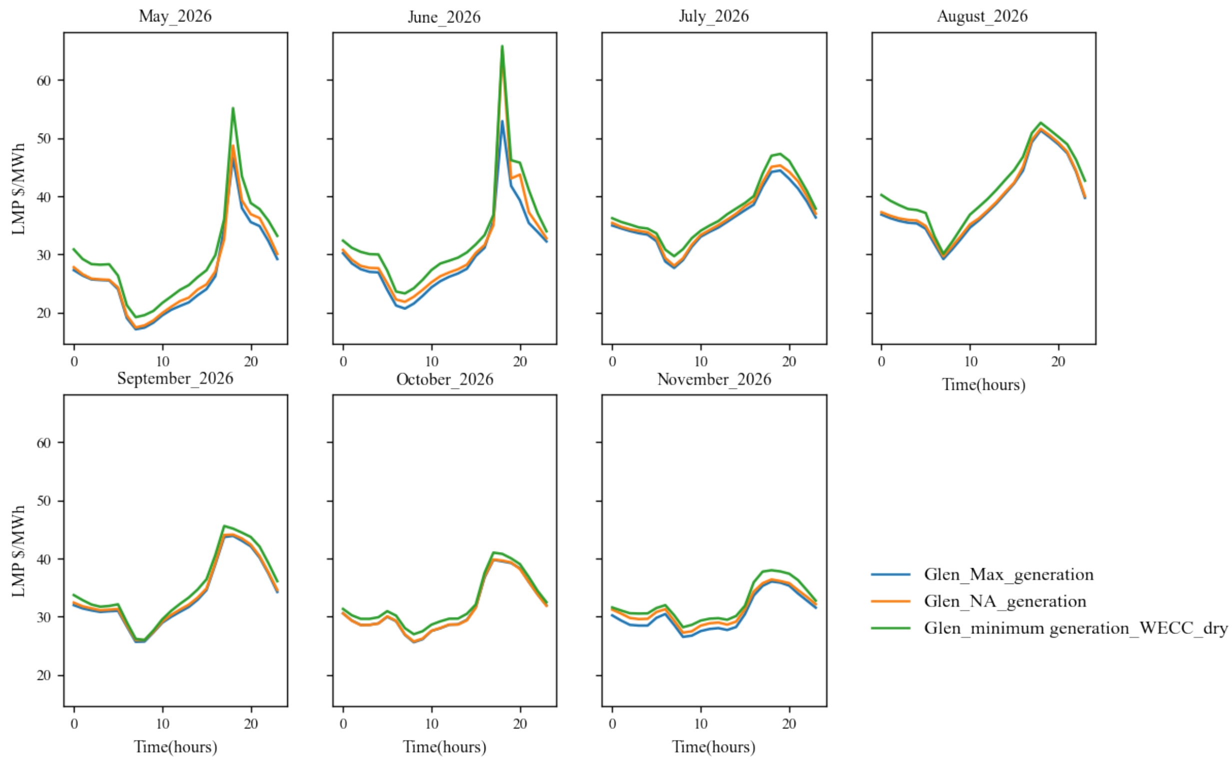


Figure 7 WALC region average diurnal LMPs for 2026 maximum and minimum Glen Canyon generation profiles for average hydropower conditions. Note the difference in y-axis scales.

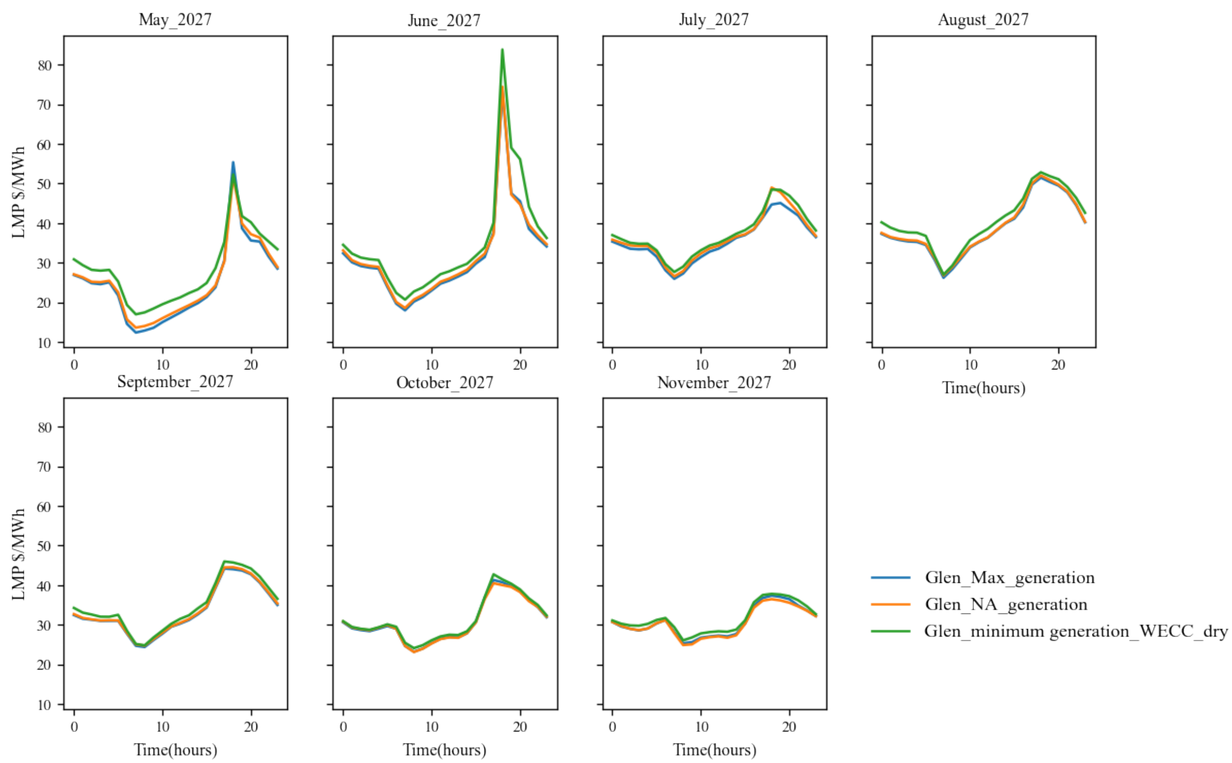


Figure 8 WALC region average diurnal LMPs for 2027 maximum and minimum Glen Canyon generation profiles for average hydropower conditions. Note the difference in y-axis scales. Further note that the EIS test is not conducted for 2027 October to December.

Results – Displaced Generation

In order to determine the sources of generation to make up the deficit when generation is lost at GCD, we use the "Warm Start" approach as discussed in the Methodology section. Using this methodology, we can identify which of the generation sources may be called upon to provide additional generation. In this case, we compare the "Minimum GCD" scenario compared to the "No Action Alternative" scenario. For this scenario, we identified candidate generators with the project team. We determined individual generators in the following balancing authority regions that can dispatch to meet the loss of GCD generation: WACM, PSC, WALC, PNM, and TEP. We allow some replacement generation from APS and SRP, but only in non-summer months. In discussions with the project team, it was unlikely that APS and SRP would have replacement energy to sell during the constrained months of the year in order to prioritize meeting their own load.

For basis of comparison we only examine May through November in which the flow experiments are taking place. Figure 13 illustrates the change in generation sources for each of these years. The negative y-axis direction shows the reduction in hydro generation, and the positive y-axis direction shows the generation sources which make up the deficit. In this case, the replacement generation from mostly Natural Gas Fired generation (Gas Combined Cycle (Gas CC) generation and Gas Combustion Turbine (Gas CT)), with a small portion also coming from coal-fired generation. Figure 14 shows the monthly change in generation across May through November. The graph illustrates how the available generation mix changes month-by-month during the year. In the summer months, when load is high and generation becomes more constrained, replacement generation is more expensive, using a majority of peakers (Gas CTs) which are generally the most expensive marginal source of generation. During other months, a majority of generation comes from Gas CCs.

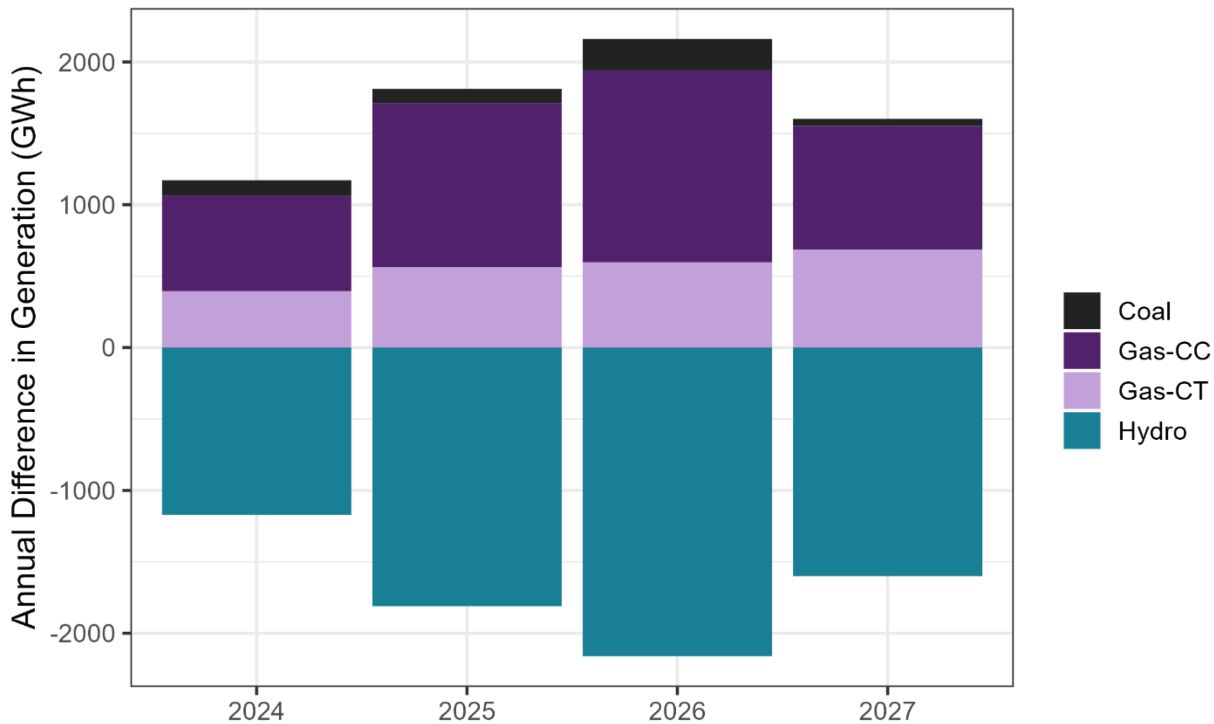


Figure 9. Annual change in dispatch in a comparing the "No Action Alternative" to the "Minimum Generation" from GCD for four years.

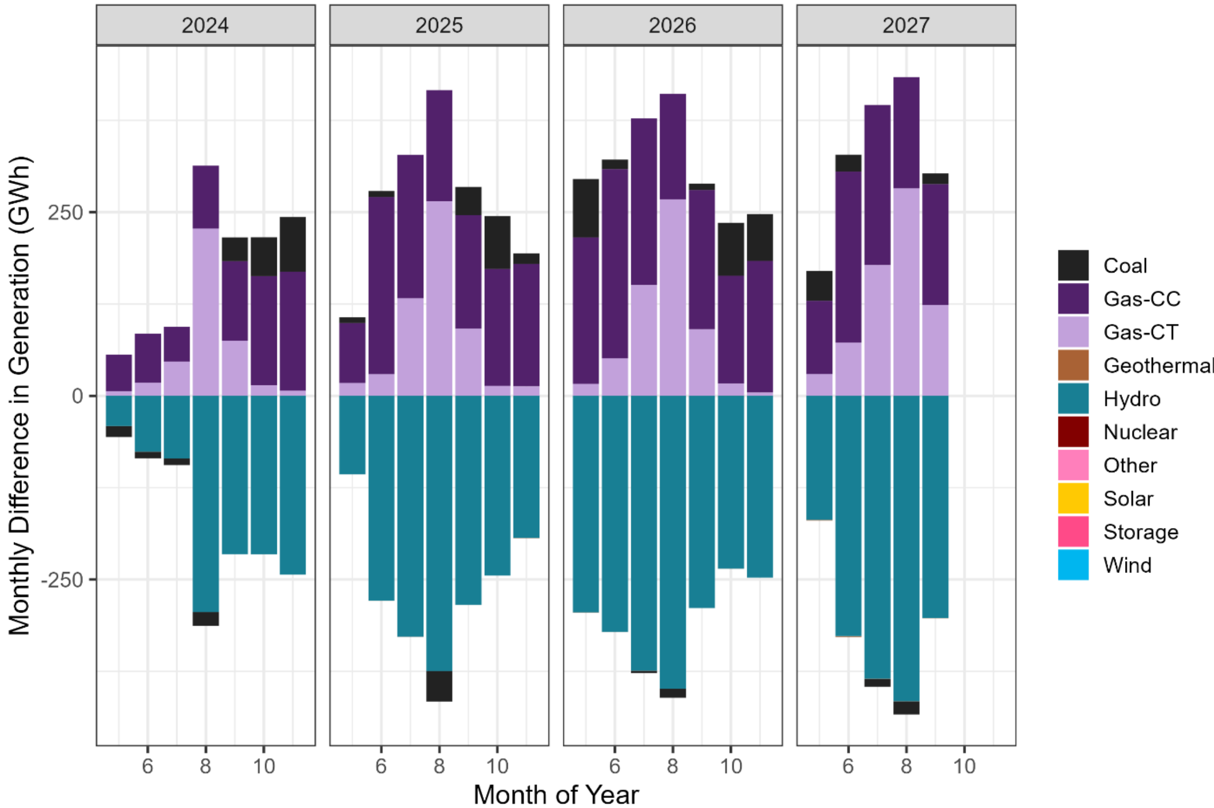


Figure 10. Monthly change in generation with the loss of generation from GCD for 2024 through 2027. Note that the experiments only occur in May through November of 2024-2026, and May through September of 2027.

We can also identify individual generators which provide peak pour during the most constrained days of the year. For example, Table 3 shows the replacement generation utilized during peak days in 2024 for June, July, and August. Generally, various sources of generation throughout Colorado, New Mexico, and Wyoming are used in this example. The result implies that there is sufficient transmission capacity to use generation from these units to meet existing load on the system that had previously been served by GCD.

Table 3. Replacement Generation utilized during peak days in 2024 for June, July, and August.

June PeakDay 2024		
BrushCC1-Total_WI	CC_WI	PSCO_WI
Dry_Fork_Sta_WI	Coal_ST_WI	WACM_WI
July Peak Day2024		
PNM_Generic_CT5_WI	CT_WI	PNM_WI
August Peak Day2024		
FountainValley2_WI	CT_WI	PSCO_WI
FountainValley3_WI	CT_WI	PSCO_WI
FountainValley4_WI	CT_WI	PSCO_WI
FountainValley5_WI	CT_WI	PSCO_WI
PNM_Generic_CT2_WI	CT_WI	PNM_WI

PNM_Generic_CT3_WI	CT_WI	PNM_WI
Reeves_3_WI	CT_WI	PNM_WI
BrushCC2-Total_WI	CC_WI	PSCO_WI
BrushCC3-Total_WI	CC_WI	PSCO_WI
Valencia1_WI	CT_WI	PNM_WI

It is important to note that hydropower is a zero-marginal source of electricity, and a zero-marginal emissions source as well. Therefore, *most* of the power being used to replace GCD will have both higher costs and higher emissions on a marginal basis. So, corresponding to the increase in generation from the coal and natural gas fleet, we would also expect to see an increase in both total generation costs (in terms of fuel and start & shutdown costs) as well as emissions.

For the focus area, the total cost of generation in each chronological year (with reduction in GCD generation) is shown in Table 4. The table shows the annual generation cost across the full Western Interconnection differences in a case with normal GCD generation and a case with reduced generation. This comparison uses the Warm Start method to compute the total generation cost. The cost of replacement energy at GCD is around 80 million dollars each year, with the average cost of replacement energy (in terms of marginal fuel, variable operating and maintenance, and start costs) is between $37-72/MWh, depending on the year. Note that this is just the average marginal cost of replacement energy, accounting only for fuel, start ups, and variable operating and maintenance costs. As such, it does not account for financial transactions, transmission wheeling rates, and other mechanisms that could serve to increase the price of electricity to meet the load.

Table 4. Annual total generation cost statistics for each of the four chronological years under normal GCD generation and comparison between the "No Action Alternative" case and the "Min Gen" GCD case.

	NAA Total Generation Cost ($B)	Min GCD Generation Cost ($B)	Cost of Loss of GCD ($M)	Cost of Avg Replacement Energy ($/MWh)
2024	10.37	10.29	84.7	72.1
2025	10.07	10.00	72.7	40.1
2026	97.17	96.36	81.0	37.5
2027	68.06	67.19	87.8	54.9

If we apply the Energy Information Administration (EIA's) average emissions factors (https://www.eia.gov/tools/faqs/faq.php?id=74&t=11) we can compute the additional carbon dioxide emission from the increase in generation. If we assume the emissions rate of coal is 2.3 lbs carbon dioxide per kWh, and the emissions rate of natural gas is 0.97 lbs dioxide per kWh, we compute an increase of 0.64 million tons of carbon dioxide for 2024, 0.94 million tons for 2025, 1.2 million tons for 2026 and 0.8 million tons for 2027.

Results – Impact on Transmission

We also note that loss of generation from GCD can also impact the transmission congestion in the surrounding region. To analyze these results, we use the Kron reduction method. Generally, we notice that removing generation from GCD can increase transmission congestion along certain paths and alleviate congestion in other paths. Of particular interest are the paths nearest GDC (see Figure 15). In cases with reduced generation from GCD, we note increased congestion in the Kayenta to Shiprock path and the Kayenta to Longhouse Path. In the No Action case, we see around 200 hours and 20 of congestion along each of these two paths per year, respectively. In the case with reduced GCD generation, the hours of congestion increases to over 2000 hours per year along both paths as other generation flows into the area to serve the load previously met by GCD. Figure 16 show the hourly flow along Kayenta to Longhouse and Figure 17 shows the hourly flow duration (sorted high to low) and illustrates that the line exceeds its rated capacity about 600 hours of the year under reduced GCD output. We do note that other paths throughout the area do see reduced congestion as flows are re-routed but the impact is distributed among much more paths.

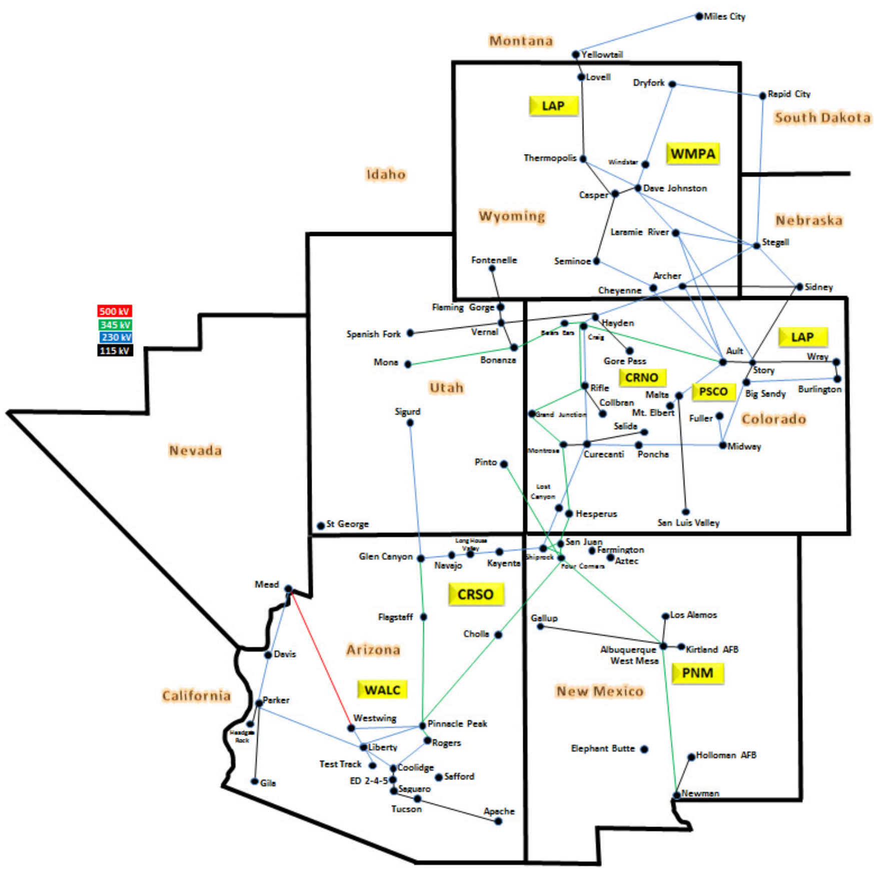


Figure 11. Transmission topology of the region surrounding Glen Canyon.

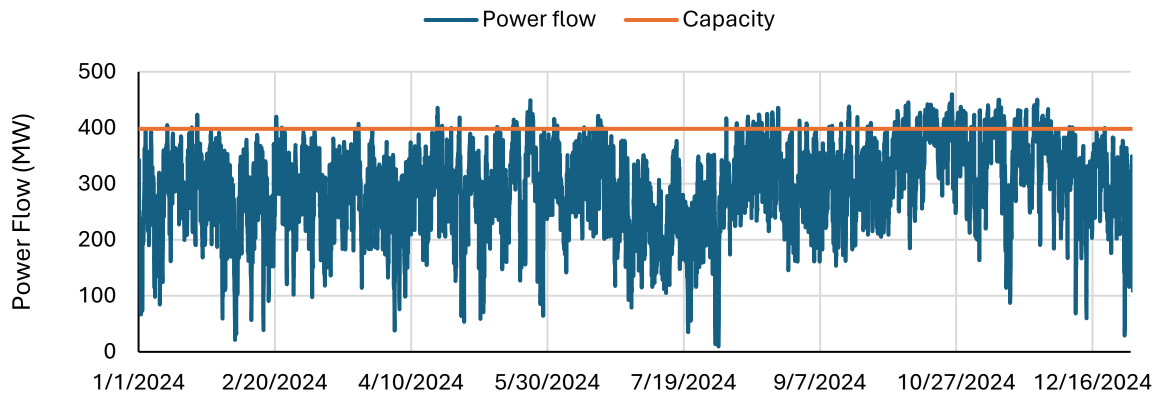


Figure 12 Hourly power flow of line Kayenta to Longhouse in WALC

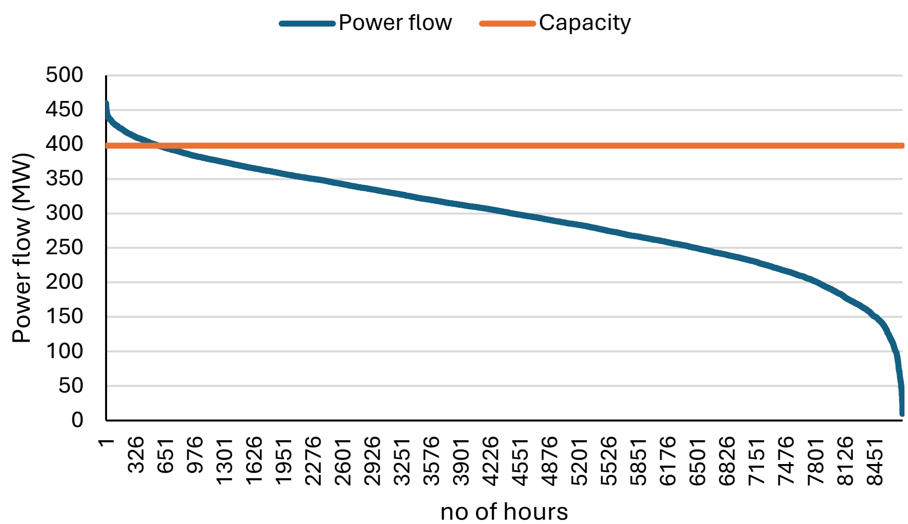


Figure 13 Power flow duration curve of Kayenta to Longhouse in WALC

Conclusions

The loss of generation at GCD will have impacts on the entire electricity system, as it currently has a rated capacity of over 1 GW and generates between 3-4 TWh of electricity on an annual basis. Although it is a small part of the larger power system, the loss of electricity from this source will need to be provided by other sources. Our modeling of four years (2024-2027) chronologically using PLEXOS, a commercial production cost model, begins to examine the impacts to the wider system. The generation from GCD is both zero marginal cost and zero marginal emissions, meaning that replacement generation will certainly increase both total generation costs as well as total emission from the power sector, as the makeup generation comes from mostly Natural Gas plants and from coal as well. The simulations show that loss of GCD also has impacts to locational marginal prices in the region, by generally increasing prices since the replacement power is more costly. This is particularly true in a drought scenario in which the hydropower from the rest of the Western Interconnection is already reduced.

IMPACT OF REDUCED GLEN CANYON HYDROELECTRIC GENERATION ON TRANSMISSION RELIABILITY

SUMMER 2024

Western Area Power Administration

Desert Southwest Region

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LIST OF APPENDICES

1 EXECUTIVE SUMMARY

Western Area Power Administration (WAPA) Desert Southwest Region (DSW) conducted this study to assess the impact of reduced Glen Canyon (GC) hydroelectric generation on transmission reliability. The study is solely focused on the reliability of transmission system from Shiprock to Pinnacle Peak on a three-month operational horizon of summer 2024.

For the purposes of this study, WAPA-DSW Transmission Planning utilized two scenario cases:

- 2024 Heavy Summer Western Electricity Coordinating Council (WECC) base case for high loading conditions which was further coordinated by SASG group for operational studies.
- 2024 Light Summer WECC base case for light loading conditions.

In both scenario cases, the Glen Canyon generation was set to 100 MW. The study assumed maximum 1635 MW generation from Four Corners. The reduced generation at Glen Canyon was compensated by net interchange from other nearby areas. For 2024 Heavy Summer, the 935 MW net-interchange was assumed as, 300 MW from CRAIG in WAPA Rocky Mountain (RM), 400 MW from Southern California Edison (SCE) and Los Angeles Department of Water and Power (LADWP) in CAISO, and 235 MW from Arizona utilities. For 2024 Light Summer, the 700 MW net-interchange was assumed as, 300 MW from CRAIG in WAPA RM, 250 MW from LADWP in CAISO, and 150 MW from WAPA-DSW/Arizona utilities. The study does not reflect any actual planned interchange schedule from Power Marketing, nor it guarantees any wheeling of power across any lines.

The Glen Canyon Unit Dropping Scheme is in place to prevent thermal equipment overloads on the WAPA DSW transmission system; however, it will not be activated because the generation from Glen Canyon will already be at a level lower than level 3 set point required to trigger the RAS scheme.

Power flow and transient stability studies were performed, and results were analyzed based on the NERC/WECC System Performance Criteria for transmission system planning.

- The reduced Glen Canyon generation in 2024 Heavy Summer case *does not* result in any thermal or voltage power flow violations in the study area.
- The reduced Glen Canyon generation in 2024 Heavy Summer case *does not* result in any WECC WR1.3-1.5 or oscillation damping dynamic stability criteria violations in the study area.
- The reduced Glen Canyon generation in 2024 Light Summer case *does not* result in any thermal or voltage power flow violations in the study area.
- The reduced Glen Canyon generation in 2024 Light Summer case *does not* result in any WECC WR1.3-1.5 or oscillation damping dynamic stability criteria violations in the study area.

The study does not address the internal protection of GC generators for out of step tripping. However, if a single in-service GC generator potentially trips for any contingency due to angular stability of the generator itself, it does not impact the reliability of transmission system. *Overall, the study did not find any reliability concerns for transmission system across Shiprock to Pinnacle Peak for low GC generation.*

2 INTRODUCTION

The Glen Canyon (GC) Power Plant was constructed in 1964, and today it has an installed capacity of about 1,200 MW. This large amount of generation lies on the Colorado River, near the border of Arizona and Utah, distant from any major load center. The plant consists of eight generators, which feed into the Western Area Power Administration Desert Southwest Region (WAPA DSW) transmission system. Two of the Glen Canyon units are connected at the WAPA DSW 230 kV bus, and six of the units are connected at the WAPA DSW 345 kV bus. The 230 kV bus is connected to two long transmission lines, one traveling to the Sigurd (SIG) station in central Utah (159 miles) and one traveling to Shiprock (SHR) in northeastern New Mexico (about 190 miles). The 345 kV station is also connected to two long parallel 345 kV lines that travel through Flagstaff (FLG) to Pinnacle Peak (PPK) in the Phoenix area (about 240 miles). The two 345 kV lines toward Phoenix provide the lowest impedance path for generation power transfer out of the GC Area to PPK.

Figure 1 below shows a rough relation of Glen Canyon station to other major high voltage lines in Arizona.

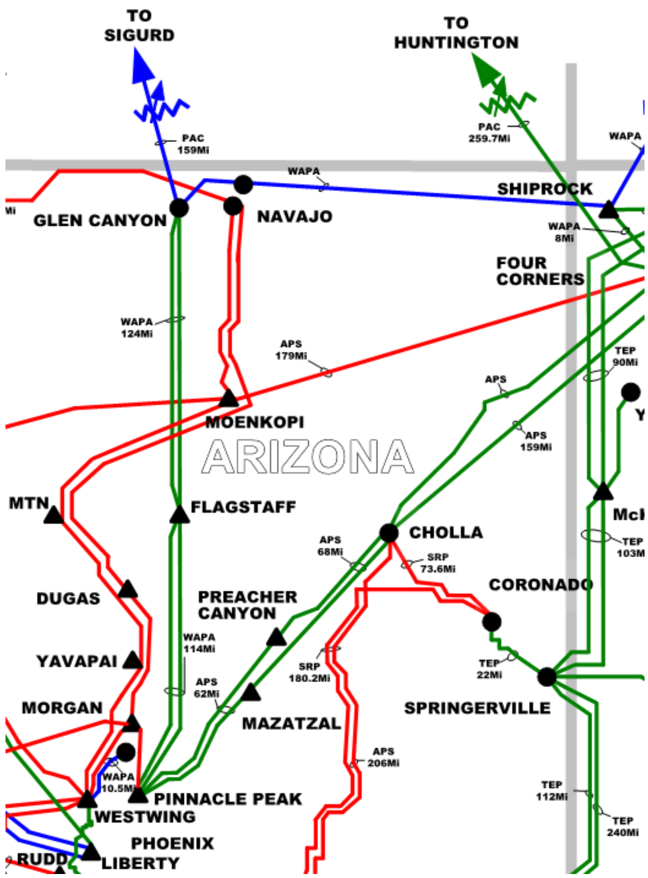

Figure 1

Figure 2 shows a layout of the Pinnacle Peak to Shiprock facilities.

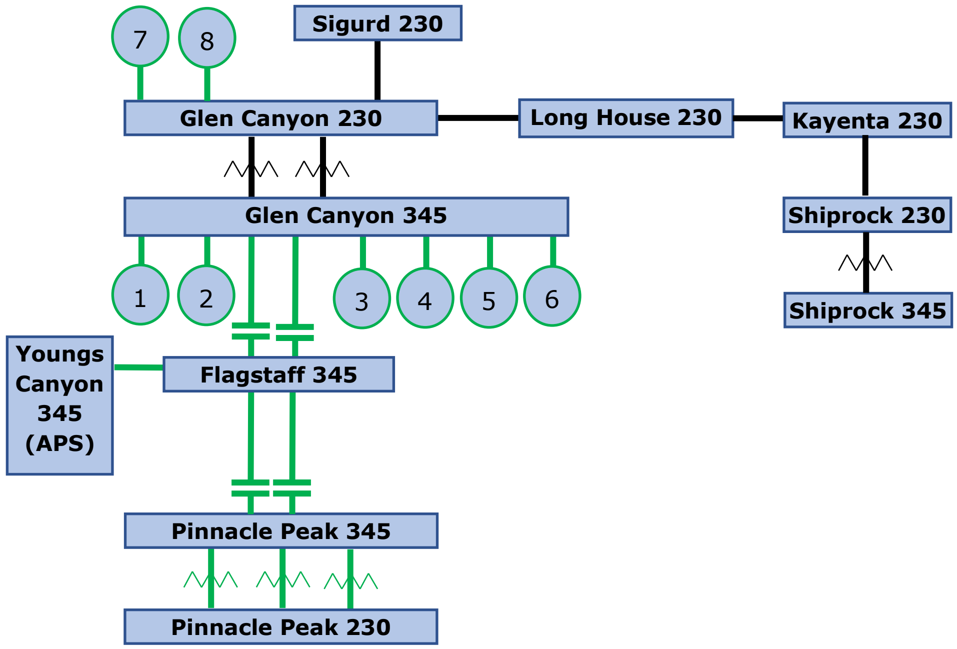

Figure 2

3 STUDY CASES AND ASSUMPTIONS

The General Electric (GE) Positive Sequence Load Flow (PSLF) version 23.0.6 software was used to analyze the study cases with respect to North American Electric Reliability Corporation (NERC) Transmission System Planning Performance Requirements standard (TPL-001-5) P1 through P7 Planning Events and their corresponding WECC system performance criteria (TPL-001-WECC-CRT-3.1).

3.1 Cases Studied

For the purposes of this study, WAPA DSW developed two scenario cases to assess the impact of reduced Glen Canyon hydroelectric generation on transmission reliability.

The reduced generation at Glen Canyon was compensated in the cases by net interchange from other nearby areas. Glen Canyon generation is placed in WAPA L.C. (Area 19) in the base cases referred to as WAPA-DSW in the report.

These scenario cases were studied for power flow analysis and transient stability analysis.

3.1.1 2024 Heavy Summer

A '2024 Heavy Summer' WECC base case which was further coordinates by SASG group for operational studies was studied to analyze system under high loading conditions. Total generation in the 2024 heavy summer for WAPA-DSW (Area 19) was 4480.7 MW, while total generation for WAPA RM (Area 73) was 6687.6 MW. Total load in the 2024 heavy summer for WAPA-DSW (Area 19) was 1299.3 MW, while total load for WAPA RM (Area 73) was 5412.4 MW.

Glen Canyon generation in the case was reduced by 935 MW, from 1035 MW to 100 MW to analyze the impact of low GC hydro generation. The study assumed 100 MW from GC generator #1.

The study assumed maximum 1635 MW generation from Four Corners. The reduced 935 MW generation at Glen Canyon was compensated by net interchange from other nearby areas. Following net-interchange assumptions were utilized for the study:

- 300 MW from CRAIG generation in WAPA R.M. (Area 73).
- 300 MW from LADWP (Area 26) as net-interchange from CAISO.
- 100 MW from SCE (Area 24) as net-interchange from CAISO.
- 135 MW from SRP (Area 15) as net-interchange from Arizona utilities.
- 100 MW from APS (Area 14) as net-interchange from Arizona utilities.

3.1.2 2024 Light Summer

A '2024 Light Summer' WECC base case was studied to analyze system under light loading conditions. Total generation in the 2024 light summer for WAPA-DSW (Area 19) was 3369.7 MW, while total generation for WAPA R.M. (Area 73) was 5237.8 MW. Total load in the 2024 light summer for WAPA-DSW (Area 19) was 1070 MW, while total load for WAPA R.M. (Area 73) was 3721.6 MW.

Glen Canyon generation in the case was reduced by 700 MW, from 800 MW to 100 MW to analyze the impact of low GC hydro generation. The study assumed 100 MW from GC generator #1.

The study assumed maximum 1635 MW generation from Four Corners. The reduced 800 MW generation at Glen Canyon was compensated by net interchange from other nearby areas. Following net-interchange assumptions were utilized for the study:

- 300 MW from CRAIG generation in WAPA R.M. (Area 73).
- 250 MW from LADWP (Area 26) as net-interchange from CAISO.
- 150 MW from within WAPA-DSW from South Point (Area 19).

3.2 Transient Stability Modeling

The transient stability modeling used for 2024 Heavy Summer case in the study came from the WECC Master Dynamics File and updated by SASG group. The transient stability modeling used for 2024 Light Summer case in the study came from the WECC Master Dynamics File.

4 STUDY METHODOLOGY

The study methodology defines performance criteria for power flow and transient stability analysis and provides a framework for analyzing the impact of the low GC generation on the system.

4.1 Power Flow Analysis

The cases were used to simulate the impact of the low GC hydro generation during normal and contingency event conditions. All power flow study work was conducted with version 23.0.6 of GE's PSLF software. Power flow results were monitored and recorded using GE PSLF's Steady State Analysis Tool (SSTOOLS) software package.

4.1.1 Power Flow System Performance Criteria

Reported thermal overloads were limited to the condition where a modeled transmission component was loaded over 100% of its applicable normal or emergency rating (as entered in the power flow database).

As described immediately below, violations of steady state voltage criteria were based on minimum acceptable voltages, maximum acceptable voltages, and maximum acceptable post-transient voltage deviations.

Consistent with industry practice, for NERC P0 (no contingency) conditions, voltage criteria violations were defined as per unit voltages less than 0.95 or greater than 1.05 on all buses less than 500 kV; and, as per unit voltages less than 1.00 or greater than 1.10 for 500-kV buses. For NERC P1 – P2 (single contingency) and NERC P3 – P7 (multiple contingency) conditions, voltage criteria violations were defined as per unit voltages less than 0.90 or greater than 1.10 on all buses less than 500 kV; and, as per unit voltages less than 0.95 or greater than 1.10 for 500 kV.

In addition to steady state minimum and maximum voltage criteria, per the WECC post-transient voltage deviation criteria, voltage deviations at load serving buses between the pre-contingency and post-contingency conditions were reported whenever greater than 8% for NERC P1 events.

4.1.2 Power Flow Analysis Process

The system was simulated with switchable VAr devices active, load tap changing in service, phase shifter controls active, and area interchange applied for pre-contingency conditions. For contingency conditions, the system was simulated with the expected automatic operation of devices designed to provide steady state control of electrical system quantities. Therefore, the switchable VAr device, load tap changer, and phase shifter settings were set to active, and the area interchange setting was fixed at the pre-contingency setting. For contingencies that resulted in generation or load losses of 20 MW or more, generation in Arizona, California and Colorado participated in a redispatch to account for the lost generation, load, or increased system power losses.

The contingencies simulated included:

- All single transmission circuit, transformer, generator, and shunt device outages within the study area (NERC P1).
- All single contingency events of bus section faults, internal breaker faults, and open ending a line section without a fault (NERC P2).
- Multiple contingency type events (NERC P3 – P7).

The contingency lists were initially generated using various WAPA created tools. These lists were then modified with changes such as modeling breaker-to-breaker outages and modeling contingency events that involve multiple elements. The list of contingencies used for the study can be found in **Appendix A**.

4.2 Transient Stability

Transient stability studies were performed to ensure system stability following a fault or other event on the system. Transient stability analysis, based on WECC Transmission System Planning Performance criteria, was performed for selected system contingencies. Initial transient stability contingency simulations were performed out to 10 seconds. If system performance was not assessed with confidence, simulation times up to 30 seconds was used to evaluate system damping. Under normal fault clearing times for dynamic stability contingencies, all 345-kV and 500-kV contingency faults simulated a 4-cycle fault clearing time; and all lower voltage contingency faults simulated a 5-cycle fault clearing time. Under delayed fault clearing times for NERC Planning Event contingencies, a 15-cycle fault clearing time was simulated. The list of contingencies used for the study can be found in **Appendix A**.

All transient stability simulations were conducted using version 23.0.6 of GE's PSLF software and the GE PSLF "DYTOOLS" software program was used to model operations specific to transient stability analysis.

A WAPA developed post-processing tool for analyzing the transient stability results was used. The tool iterates over all the channel file data to detect when any WECC WR1.3-1.5 criteria is exceeded. The output results from the WAPA tool were used to report any NERC/WECC Performance Criteria violations.

System damping was assessed visually with the aid of stability plots obtained through the GE PSLF PLOT software. This criterion states that the oscillations should show positive damping within thirty seconds following the fault. The transient stability plots are included in **Appendix B**.

Figure 3 is an excerpt from the WECC Transmission System Planning Performance criteria and was used to evaluate dynamic stability contingencies that were simulated in this study.

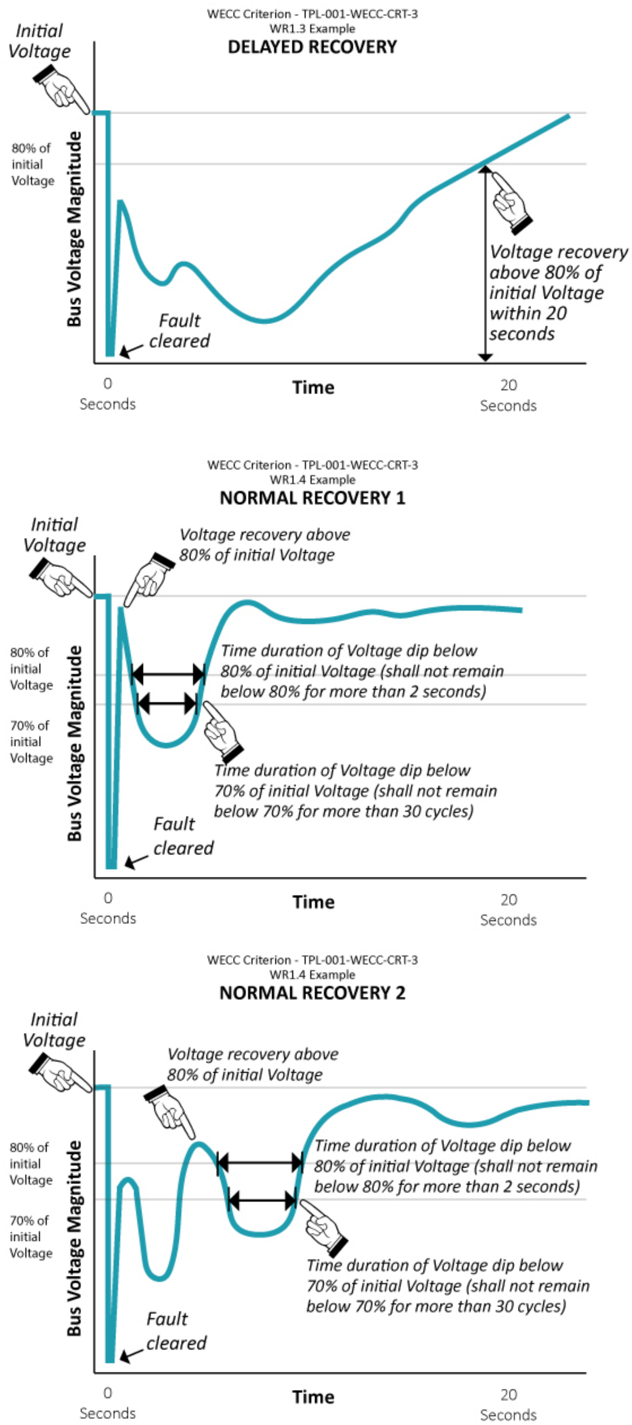

Figure 3: Graphical Representation of Stability Analysis Evaluation Criteria

5 RESULTS

The power flow and transient stability results are described below.

5.1 Power Flow Results

5.1.1 2024 Heavy Summer

Based on the criteria described in section 4, the reduced Glen Canyon generation in 2024 Heavy Summer case does not result in any overload, voltage, or delta voltage violations in the study area.

5.1.2 2024 Light Summer

Based on the criteria described in section 4, the reduced Glen Canyon generation in 2024 Light Summer case does not result in any overload, voltage, or delta voltage violations in the study area.

5.2 Transient Stability Analysis Results

5.2.1 2024 Heavy Summer

Based on the criteria described in section 4, the reduced Glen Canyon generation in 2024 Heavy Summer case does not result in any WECC WR1.3-1.5 or oscillation damping dynamic stability criteria violations.

5.2.2 2024 Light Summer

Based on the criteria described in section 4, the reduced Glen Canyon generation in 2024 Light Summer case does not result in any WECC WR1.3-1.5 or oscillation damping dynamic stability criteria violations.

6 CONCLUSIONS

Power flow and transient stability studies were performed for reduced generation at Glen Canyon in the 2024 Heavy Summer case for high loading conditions and 2024 Light Summer case for low loading conditions.

The study solely focused on reliability of transmission system from Shiprock to Pinnacle Peak lines.

The study assumed net-interchange with other areas to make-up for reduced Glen Canyon generation based on the available information at the time and engineering judgement. The study does not reflect any actual planned interchange schedule by Power Marketing in case Glen Canyon generation drops significantly.

The study does not guarantee any wheeling of power across any lines. Wheeling of power is normally done across BA to BA through transmission tie-lines based on available capacity. This study addresses transmission reliability which is based on net-interchange across planning areas in the base cases.

The study did not address the internal protection of GC generators for out of step tripping. If a GC generator potentially trips for any contingency due to angular stability issue of the generator itself, it does not impact the reliability of transmission system in this study.

The study did not find any reliability concerns for transmission system across Shiprock to Pinnacle Peak for reduced Glen Canyon generation to 100 MW for the various NERC TPL-001-5 P1 through P7 Planning Events.