Mountain West Joint Tariff and Regional Transmission Organization Market Study

LAP and CRSP Financial Analyses

September 5, 2017

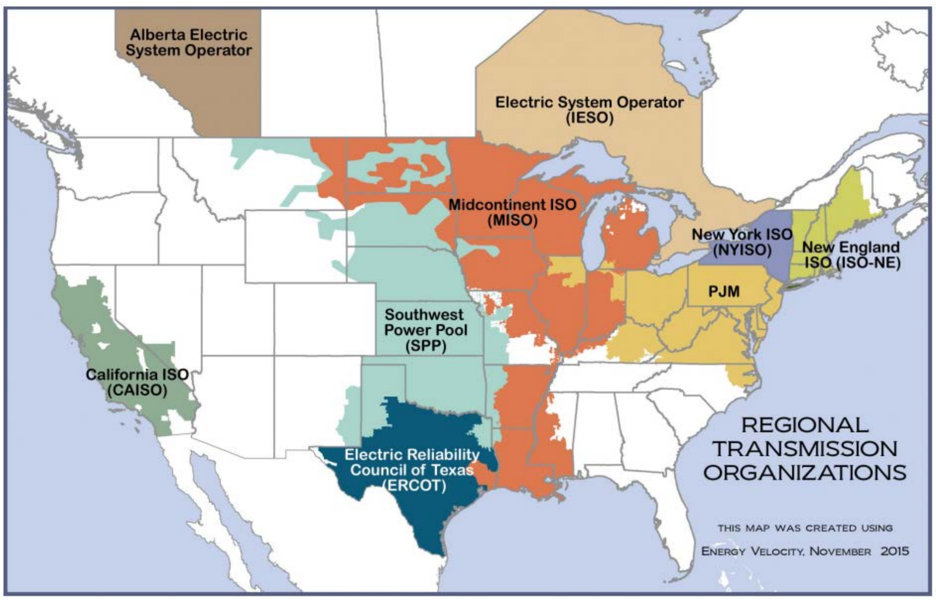
Western Area
Power Administration

Report Contents

Background and Introduction

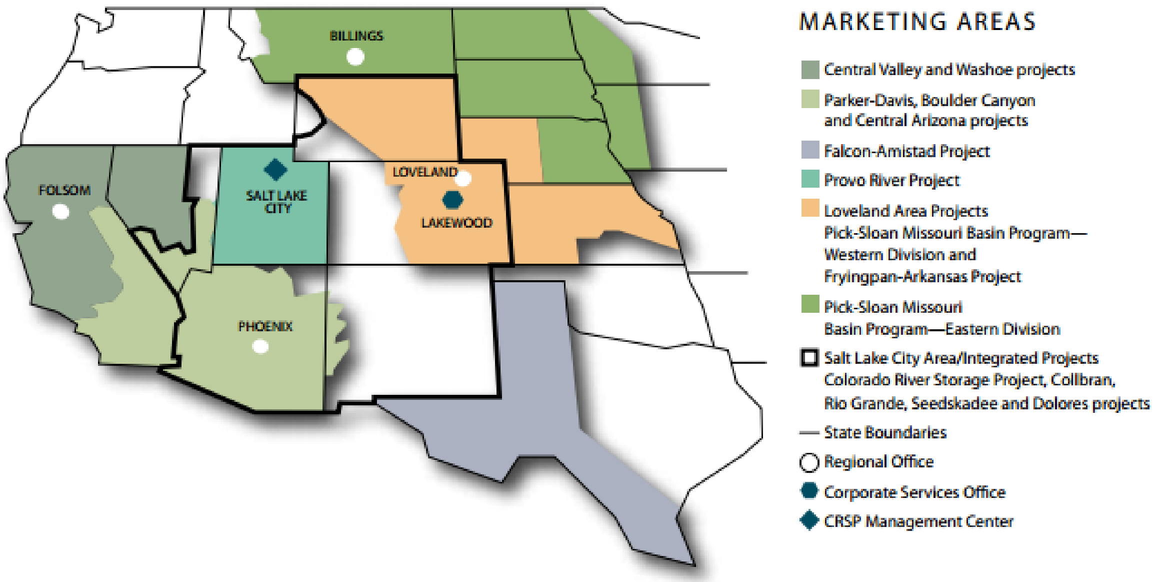
There have been numerous published reports and studies conducted over the past 20 years that describe both the costs and benefits of independent system operators (ISOs) and regional transmission organizations (RTOs), which operate the transmission system independently of wholesale market participants. To foster competition, the ISOs and RTOs use bid-based offers in an open market paradigm to determine both least-cost unit commitments and dispatch subject to grid security constraints.

After years of discussions, internal analyses, a detailed study conducted by the Brattle Group consulting firm, and public involvement, the Western Area Power Administration's (WAPA) Upper Great Plains (UGP) regional office along with Heartland Consumers Power District and a portion of Basin Electric decided to participate in the Southwest Power Pool (SPP). SPP is an independent RTO with a full day-ahead market that operates in a fourteen-state footprint in the mid-section of the U.S. including all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.



On October 1, 2015, functional control of eligible WAPA UGP transmission facilities were transferred to SPP, and UGP operations were seamlessly integrated into the SPP RTO. In addition, through its participation in the SPP, UPG submits generation offers to the centralized market for hydropower resources located in the Pick-Sloan Missouri Basin Program – Eastern Division marketing area. During its first full year of operation in the SPP, the UGP Region realized many benefits exceeding WAPA's expected savings of $11.5 million. WAPA is now exploring centralized market options for its resources located in other WAPA marketing areas.

The UGP positive outcome however does not ensure WAPA resources located in other marketing areas[1], shown in the map below, will reap similar benefits by participating in a RTO market. WAPA's marketing areas, managed by various regional offices, are unique in terms of their hydropower and transmission resources, statutory requirements, operating criteria/goals, contractual arrangements with their firm electric service (FES) customers and obligations to serve project use loads. WAPA therefore is performing detailed analyses to investigate potential outcomes if facilities in other marketing areas participate in a centralized wholesale power market.



This report discusses the potential financial benefits for WAPA's Loveland Area Projects (LAP) and Colorado River Storage Project (CRSP) participation in a joint tariff or RTO with the Mountain West Transmission Group (Mountain West).[2] This joint tariff/RTO market is referred to, in both this study and the one conducted by Brattle, as the "Regional Market." LAP resources are marketed by the WAPA Rocky Mountain Region (RMR) and CRSP is part of the Salt Lake City Area Integrated Projects (SLCA/IP) and marketed by the CRSP Management Center.

Analyses presented in this report utilize data produced by Brattle production cost modeling of the Western Interconnection (WI) grid with emphasis on Mountain West member utilities. Brattle used the Power Systems Optimizer (PSO) software developed by Polaris Systems Optimization, Inc. to simulate least-cost, security-constrained unit commitments and economic dispatch. The model determines detailed hourly grid operations, estimates system production costs, and computes locational marginal prices (LMPs). More details on Brattle study methods, processes and assumptions are documented in a

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[1] Other marketing areas within WAPA include the Loveland Area Projects, Central Valley and Washoe projects, Falcon-Amistad Project, Provo River Project, Pick-Sloan Missouri Basin Program, and the Salt Lake City Area Projects.
[2] Members include Basin Electric Power Cooperative, Black Hills Corporation, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission Cooperative, and WAPA's LAP and CRSP facilities.

report entitled "*Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint.*"[3]

Due to the very sensitive and confidential nature of model results, the Brattle report only discusses aggregate outcomes in its report without revealing the specific impacts on individual Mountain West entities. Brattle did however compute financial estimates for RMR and CRSP for a narrow set of situations. WAPA asked Argonne to broaden the investigation and estimate financial implications for LAP and CRSP under a broad set of conditions if either LAP or CRSP participated in an existing RTO along with other Mountain West participants.

Analysis Approach

Argonne estimated the financial impacts of LAP and CRSP operating in an existing RTO market via a comparative analysis, in which model runs were conducted under two different market frameworks in the year 2024. The first market framework, referred to as the "Status Quo" case, assumes that all participants continue status quo operations under which bilateral market transactions are conducted. The second market framework, referred to as the "Regional Market", assumes that a centralized wholesale RTO market structure will be adopted by Mountain West under which all participants would always offer all of their operable generating facilities to the market. This comparative analysis quantifies RMR and CRSP financial impacts as the difference between the Regional Market case and the Status Quo case.

Separate financial analyses were conducted under three different plausible futures defined by Brattle. The futures used by Argonne for financial analyses include:

1) current trends (CT): based on current most likely projections of the future based on a continuation of recent trends;
2) high gas (HG) : 2024 natural gas prices are assumed to be significantly more expensive than the CT case; and,
3) market stress (MS): includes high natural gas prices, higher Mountain West regional loads and lower WAPA hydropower generation.

For consistency with the Brattle study, Argonne utilized key hourly results produced by PSO grid simulations for the year 2024. To estimate changes in WAPA's financial positions, Argonne calculations rely on Brattle LMP results that are comprised of the following three additive components: 1) energy - referred to as the Marginal Energy Costs (MEC), 2) congestion - referred to as Marginal Congestion Costs (MCC) and 3) losses - referred to as Marginal Loss Costs (MLC). Unless a specific component is referenced, LMP in this report simply refers to the total of the three aforementioned components.

Brattle LMP calculations are dependent on numerous assumptions regarding grid costs and operations in 2024. For example, the Brattle study assumed static transaction over the WI tie to the markets in the eastern grid. Brattle used historical flows/transactions that do not allow for market

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[3] Based on information contained in a draft executive summary distributed by Brattle via email on 12/6/2016. File Name: *Mtn West Executive Summary (2016-12-01).docx*

operations in the WI to interact with markets in the eastern grid. The reader should therefore bear in mind that if key assumptions are not realized in 2024, LAP and CRSP financial results may be different from the ones presented in this report. Whereas the veracity of some of these assumptions may have little impact on the overall economics of the WI some of these key assumptions may have a large impact on specific LMPs and therefore LAP and CRSP financial results.[4] These assumptions include but are not limited to: (1) regional and bus-load growth, (2) transmission system improvements and topology changes, (3) RTO decisions regarding the opening of circuit breakers, (4) improvements and retirement schedules at existing power plants, (5) the buildout of new thermal generation technologies by type, size and location, (6) fossil fuel prices, and (7) the specific expansion locations and operation of variable energy resources (VERs). Projections for VERs are in part a function of future policies regarding state renewable energy resource portfolio standards and financial incentives such as investment tax credits.

Financial computations described and presented in this report only include generation costs and financial transactions for energy purchases and sales required to balance WAPA hydropower generation with loads plus losses. It does not include other factors that may impact WAPA's financial bottom-line. For example, the analysis does not include WAPA's foregone revenues associated with its use of transmission resources to engage in energy purchases and sales arbitrage opportunities.

Unless and until an existing RTO is selected and the market rules are known, all costs and revenues cannot be more accurately pinpointed. Presented impacts on those components that can be identified and quantified should be viewed as rough "computer model" generated projections. These should be used to identify general trends and magnitudes to help decision makers and stakeholders better understand Mountain West RTO membership advantages/disadvantages. This analysis is also used to help discover potential impacts that may not have otherwise been uncovered.

LAP Methodology

For each of the three Brattle futures, RMR financial positions for several LAP situations were analyzed including multiple hydropower conditions, operational flexibility at the Mt. Elbert pumped storage hydropower plant, reimbursement rules, transmission loss assumptions and market bidding behaviors. RMR financial analyses are based on a spreadsheet model that was specifically developed by Argonne for this study. It uses LMPs that Brattle computed for each LAP hydropower plant and load-weighted average LMPs for LAP customer deliveries. In addition, some of the model runs performed by Argonne also use the optimal hourly generation and pumping load profiles that were projected by Brattle for the Mt. Elbert pumped-storage hydropower plant.[5]

[4] The main objective of the Brattle study was to estimate the economic value of a regional market in the Mountain West footprint. As a result of grid PSO simulations that support its study, hourly LMPs and power flows are computed and output from the model. These outputs have been useful for examining WAPA financial implications, but are potentially more sensitive to specific modeling assumptions as compared to the bottom-line economic evaluations made by Brattle.

[5] "Optimal" in this context refers to a mathematical solution in which WI production costs are minimized given the information that is input into the PSO model. This does not necessarily translate into the "best" possible solution for Mt. Elbert operation from RMR's perspective, which under actual operations may consider other factors that are not fully described in PSO.

Calculations in the Argonne financial spreadsheet are based on hourly LAP net energy positions in 2014. This net position is equal to the sum of all LAP powerplant generation during a specific hour minus the sum of LAP loads times a LAP transmission loss factor. When the net position is zero, the financial position for RMR is also zero. On the other hand, in hours that LAP powerplants collectively generate more power than combined loads and losses, RMR typically has a financial benefit[6]. This benefit is equal to the LAP generation-weighted average LMP times the net excess generation. Generation-weighed LMPs were computed by Argonne. Under all situations, the total LMP is always applied when energy is a long position (i.e., energy excess). During hours that generation does not cover all of the LAP loads and losses it encounters a net financial loss. The net financial dollar amount is based on Brattle computed load-weighted LMPs times the short position (i.e., energy shortfall). Depending on the settlement rules that are assumed for WAPA, the LMPs used to compute these financial losses are either the total LMP or only the MEC component of the LMP. A more detailed description of the use of LMPs and its components are provided in the next section.

In addition to the assumptions and limitations made by Brattle for LMP calculations, the Argonne financial spreadsheet makes additional simplifying assumptions. For example, it uses static sets of hourly LAP loads and hydropower generation levels. Only one vector of chronological hourly LAP loads is used for all 2024 situations. On the supply-side of the equation, three hourly LAP generation profiles are used. These generation sets represent a range of conditions spanning dry, average, and wet hydropower situations based on historical operations. This allowed Argonne to model financial outcomes under a range of LAP net annual energy positions.

The use of these static generation patterns does not allow LAP powerplant operations to respond to market price patterns. There are a couple of important exceptions. First, under some financial model runs, Argonne used Brattle's optimized generation and pumping profiles for Mt. Elbert instead of the static 2011 historical profile. Second, Yellowtail hydropower powerplant operations were manually adjusted by WAPA scheduling experts under the Regional Market case to account for the additional flexibility that would be afforded by lower regulation and spinning reserve duties at the facility.

It was also assumed that LAP FES customers do not change hourly energy request levels or patterns in response to either hydropower conditions or evolving market price patterns under the proposed Regional Market case. The assumed lack of operational flexibility and FES customer demand variability therefore leads to a conservative estimate of LAP financial benefits (i.e., generally an under-estimate).

Argonne financial calculations use Brattle LMPs for the three futures defined above; namely, current trends, high natural gas prices, and market stress. Mathematically these prices are based on precise demand/supply equilibrium points throughout the grid. There are situations however that Argonne simulated in which LAP generation levels were modified to represent an alternative operating situation not included in any of the Brattle simulations; for example, a wet hydropower condition or a

[6] During infrequent events in which LMPs are negative, RMR would have a positive financial position when it is energy short.

historical Mt. Elbert operating pattern. Under these circumstances, Argonne did not adjust LMPs to reflect an altered LAP operating pattern. Although mathematically imprecise, this simplification was made because the LAP system is very small compared to the supply resources in the WI and therefore it was assumed that LAP operations would typically have a minimal impact on market prices.[7]

The first LAP financial model run was used to benchmark Argonne financial calculations to those made by Brattle for the current trends future under the Status Quo and Regional Market cases. Except for small rounding errors (within $10) the Argonne and Brattle amounts were in agreement – both showed a 2024 financial LAP gain of $1.48 million if LAP participated in the market. The Brattle estimate however did not compute financial implication of transmission losses using a method that is consistent with the one currently used by RMR so that result was not included in this analysis.

Benchmark model runs were also made for the high natural gas and market stress futures. For both futures, Argonne and Brattle results were within a very small rounding error.

CRSP Methodology

Argonne estimated CRSP financial impacts for three major business processes conducted by the CRSP Energy Management and Marketing Office (EMMO) located in Montrose, Colorado. These business processes include (1) SLCA/IP hydropower plant generation scheduling/operations, (2) the Salt River Project (SRP) exchange and (3) existing (a.k.a, grandfathered) transmission agreements. A more detailed explanation of each of these business processes is provided below.

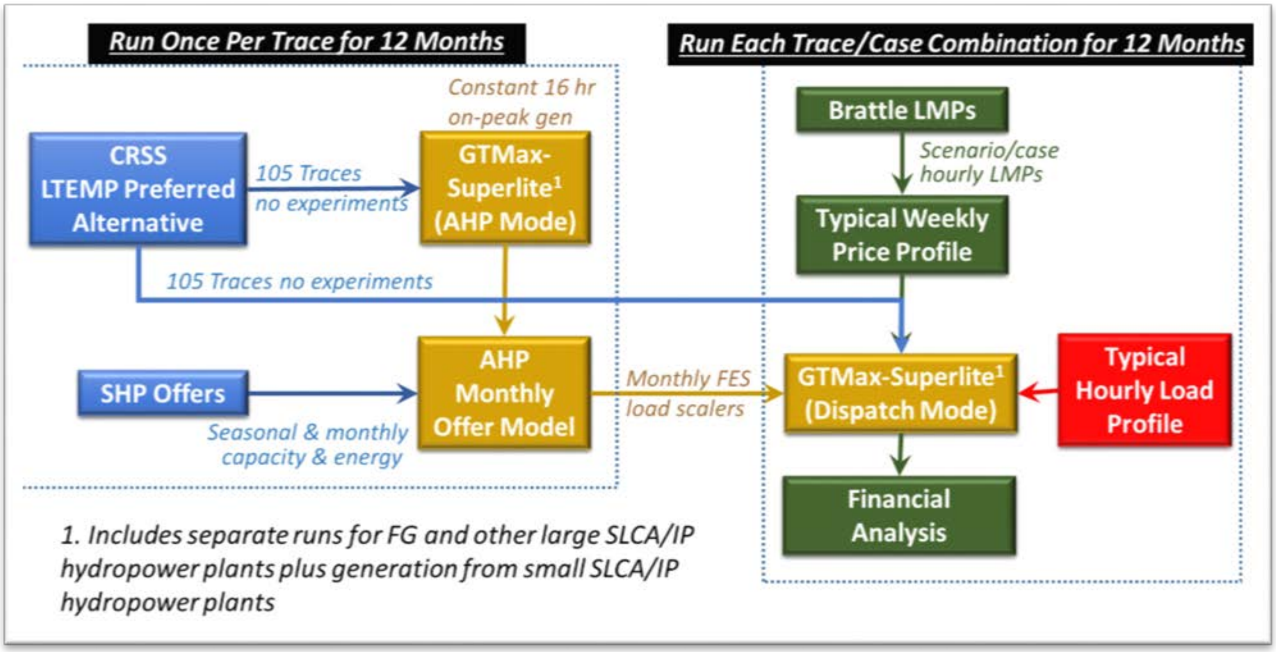
CRSP Scheduling

SLCA/IP hydropower plant generation schedules are managed by the CRSP EMMO. The methodology used for this analysis mimics the CRSP scheduling process with a set of tools that simulate the optimal operation of SLCA/IP powerplants. Constrained by environmental operating criteria, the models pattern limited water releases and associated power production such that it maximizes the financial value of SLCA/IP hydropower resources in observance with EMMO scheduling goals and guidelines. Monthly operations are primarily driven by water volume release targets that fulfill water delivery obligations in the Colorado River Basin and by hourly market forces as reflected by Brattle LMPs. Operations are subject to the physical limitations of SLCA/IP hydropower plants, dispatch guidelines/objectives, and statutory obligations to meet environmental criteria. Identical to the LAP modeling process, financial benefits associated with joining a regional market are based on a comparison of the Status Quo and Regional Market case simulation results. Financial impacts to CRSP are estimated for 105 plausible hydrology futures for each month and case/future analyzed.

The flow chart shown below displays the major model components and information flows that were used to simulate CRSP scheduling. The modeling process has two principal purposes. The first is to

[7] There are situations when system-wide power grid operating reserve margins are very tight, usually during peak demand periods, when the operation of any plant in the grid can move prices by altering its operation. Although possible, this situation however is unlikely to occur in 2024 under the futures defined by Brattle. These are also congested transmission states, for example as a result of line outages, under which suppliers may temporarily have a large influence on LMPs. RTO market monitors however do not allow supplier to take undue advantage when these situations arise.

estimate the amount of seasonal and monthly energy and capacity that the CRSP EMMO will offer to FES customers. The second purpose is to simulate SLCA/IP hydropower plant operations and to compute associated CRSP finances. The key models that are utilized in the process include the Colorado River Simulation System (CRSS), a lite version of Generation and Transmission Maximization (GTMax Superlite) model[8], the Available Hydropower (AHP) Offer routine, and a module that computes and ranks CRSP financial outcomes. A brief description of each tool used for the CRSP analysis is provided below.



Colorado River Simulation System

CRSS was developed by the Bureau of Reclamation in the early 1970s to project the monthly operations of the Colorado River in both the upper and lower basins in compliance with numerous water compacts, treaties, and laws. Projections are made under various trajectories of hydropower conditions over time using historical sequences of inflows, known as traces, and projected basin water depletions/extractions.

For this study, the CRSS model produces results for 105 hydrological traces for the year 2024. Although CRSS simulates the entire Colorado River Basin, SLCA/IP hydropower plants and associated reservoirs in the CRSS model are all in the upper basin and include Glen Canyon, Fontenelle, Flaming Gorge, Blue Mesa, Morrow Point, and Crystal. Model runs and traces used for the study are based on analyses performed in support of the CRSP post-2024 marketing study. This post-2024 marketing study CRSS formulation was updated from a previous CRSS version that was developed for the Long-Term Experimental and Management Plan (LTEMP) Environmental Impact Statement (EIS) for the Glen Canyon Dam. The LTEMP EIS record of decision (ROD) was recently issued in December 2016 and is currently being phased into Glen Canyon Dam operations.

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[8] Several versions of the GTMax model were written by Argonne for the CRSP Management Center over the past 22 years. For a static model topology, such as the one used for this analysis, the GTMax-Superlite model solves problems much faster than the full GTMax model.

GTMax Superlite Model

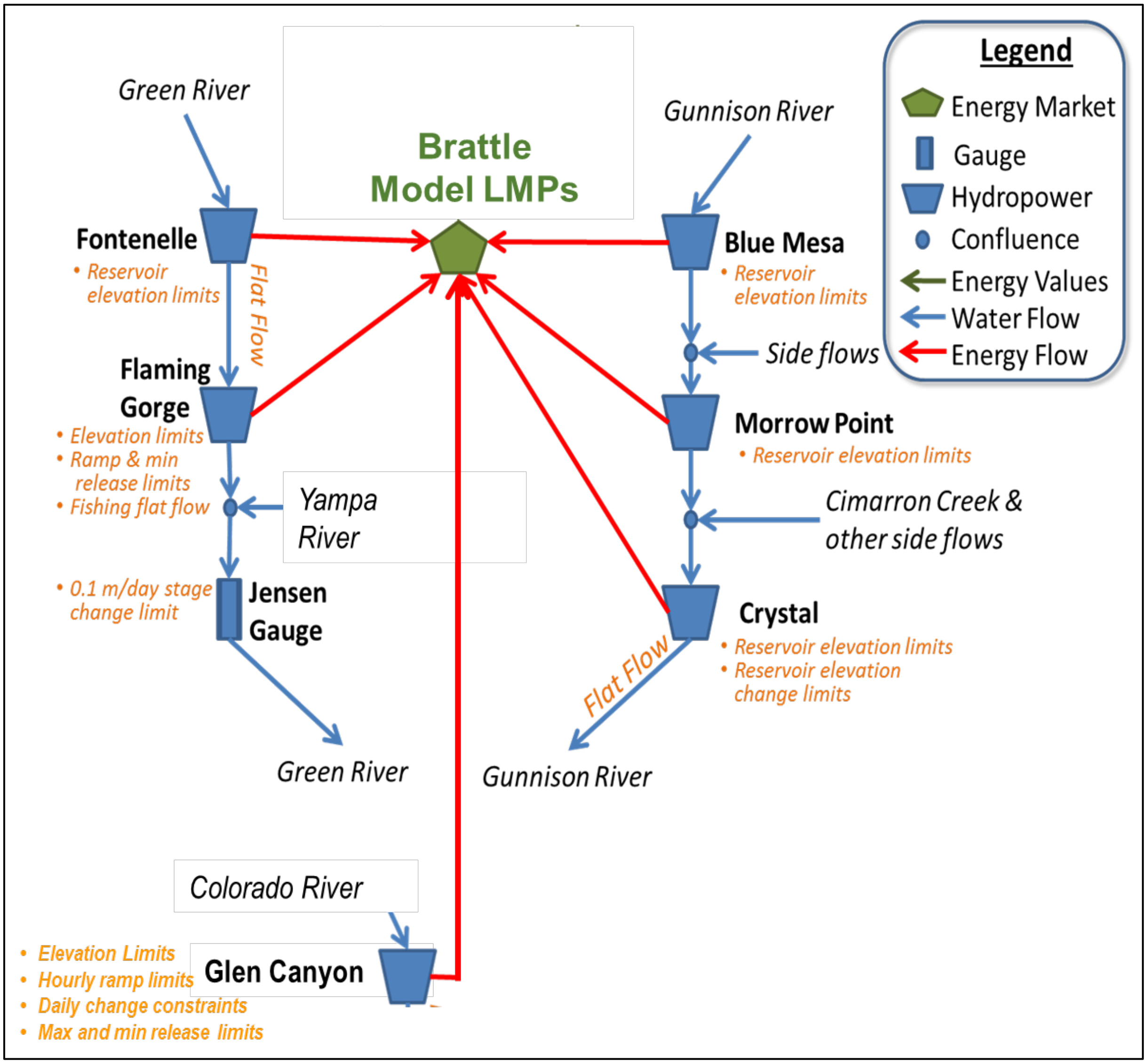
The GTMax Superlite model and supplemental spreadsheet tools simulate the scheduling and operation of SLCA/IP hydropower plants. The operation of smaller facilities are simulated using a spreadsheet tool. These smaller resources consist of the Upper and Lower Molina, McPhee, Towaoc, Dolores, and Rio Grande powerplants.

GTMax Superlite simulates the hourly operation of larger SLCA/IP hydropower plants that consist of Glen Canyon, Blue Mesa, Morrow Point, Crystal, Fontenelle and Flaming Gorge. The model is run for one typical week for each simulated month; that is; 12 simulations are performed for each of the 105 hydrological traces for a total of 1,260 situations for each case/future analyzed. Weekly capacity, energy production, and financial results are scaled up to a monthly level. This modeling process was developed by Argonne with WAPA’s guidance, funding, and support over the past 22 years. It is also utilized on an ongoing basis in support of numerous SLCA/IP hydropower business processes.

Simulated operations over a weekly time period are consistent with CRSS monthly reservoir water releases and forebay elevations. CRSS also provides information about water inflows into reservoirs, side flows that occur between connected reservoirs, and reservoir evaporation. Other inputs included operating constraints placed on the facilities, such as restrictions on water-release ramp rates and flow requirements at the Jensen Gauge downstream of Flaming Gorge. The GTMax Superlite objective is to simultaneously maximize the financial value of the hydropower resource at these large facilities over weekly time periods. The output is an hourly schedule of water releases and electric generation that maximizes the financial value of hydropower resources within the bounds of all operating constraints.

CRSP hydropower resources contain two water cascades. The first consists of the Fontenelle and Flaming Gorge Reservoirs, and the second consists of the Aspinall Cascade, which includes the Blue Mesa, Morrow Point, and Crystal reservoirs. Operationally, reservoirs in the first cascade are very loosely connected and therefore are not linked in GTMax Superlite. Reservoirs in the Aspinall Cascade are very tightly coupled and these linkages are therefore represented in GTMax Superlite.

Operating constraints include maximum and minimum limits imposed on all reservoirs and a complex set of restrictions at the Crystal Reservoir that bound the rate of elevation changes over time. In order to ensure that water releases do not violate reservoir operating constraints, GTMax-Superlite computes hourly water mass balances and reservoir 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. To ensure that operations at the end of the simulated period are in a good position for the following day, model runs used a “wrap” technique to reduce model-end effects. Conceptually the wrap technique infinitively repeats the same modeled week.



The hourly operations of large CRSP hydropower plants is simulated by two sets of GTMax Superlite model runs. First, Flaming Gorge operations are optimized in isolation with no recognition of system contributions from other CRSP facilities. This mimics current day procedures in which intra-day hourly release pattern are occasionally determined by CRSP staff for a single day. This pattern without alteration is prescribed each day until hydrological conditions appreciably change, prompting a revision of the daily release pattern. For the MWTG study, the pattern simulated by GTMax Superlite is updated monthly. The modeled release/generation pattern maximizes CRSP financial income based on Brattle LMPs and on hydrological conditions in both the Green and Yampa Rivers.

Flows at the Jensen Gauge are restricted to daily stage changes of 0.1 meters/day. Because gauge flows are directly affected by upstream water releases from the Flaming Gorge Reservoir, GTMax-Superlite determines releases that comply with the daily gauge constraint. In general, it takes about 24 hours for the first fractional amount of a Flaming Gorge release to reach the gauge. Typically, all of the water passes the gauge 48 hours after the release. Gauge readings are computed using a function that relates the water flow rate at the gauge to the gauge stage.

To ensure the modeled release/generation pattern is compliant with flow stage requirements at the Jensen Gauge, the GTMax Superlite model uses a set of **linear** equations to approximate Green River stream flows below the Flaming Gorge Dam. These linear equations require a set of input parameters/scalers to accurately compute these flows. These scalers are produced by a condensed version of the Streamflow Synthesis and Reservoir Regulation (SSARR) Model that was written by the Army Corps of Engineers. Yampa River water flows into the Green River are based on historical monthly data. For this study, a monthly 50% flow exceedance was input into both SSARR and GTMax Superlite.

SSARR uses a complex set of **non-linear** equations to estimate these scalers and downstream flows at 148 points in the Green River between the dam and the Jensen Gauge based on a given set of hourly water releases from the Flaming Gorge Dam and flow contributions from the Yampa. This given set of water releases from Flaming Gorge is estimated by GTMax Superlite. This is a classic "chicken and egg" problem because GTMax Superlite requires a set of scalers to estimate downstream water flows, and SSARR requires a set of given water releases from Flaming Gorge that is estimated by GTMax Superlite. To solve this problem, GTMax Superlite and SSARR are run iteratively in a process in which the two models share successively more refined and accurate inflammation. Jensen Gauge results produced by the models typically converge to nearly identical solutions after one to three iterations.

The second set of GTMax-Superlite model runs simultaneous optimizes the operations of all other large SLCA/IP hydropower plants. It uses Brattle LMPs, FES customer hourly loads, generation from smaller SLCA/IP hydropower plants, and Flaming Gorge prescribed/static generation patterns projected by the first set of GTMax-Superlite runs.

Small SLCA/IP Resources Spreadsheet Tool

Relatively small SLCA/IP hydropower plants including Towaoc, McPhee, Elephant Butte, Upper Molina, and Lower Molina power plants. In total, these facilities contribute a relatively small amount of capacity and all but the Molina power plants are flat flow facilities. Powerplant capacities for small powerplants are computed in a spreadsheet based on historical monthly generation data as archived in Form PO&M-59. The Molina powerplants are dispatchable and operated in unison. The spreadsheet algorithm evenly divides Form PO&M-59 monthly generation among all days in the month. The spreadsheet operates Molina at maximum output continuously until the entire daily generation is exhausted; that is, the units start and stops once per day and no power is produced in any other hours. The block of operating hours is based on market prices such that the financial value of Molina resources is maximized.

AHP Offer Routine

Under many of the hydrological futures projected by CRSS, the CRSP Office will have excess capacity and/or energy above SHP contract levels, which at the discretion of WAPA, may be offered to its FES customers. These offers, referred to as Available Hydro Power (AHP), impact SLCA/IP FES hourly firm loads input into the GTMax Superlite model and therefore computations of WAPA's energy transaction and financial positions.

The AHP Offer Routine estimates these seasonal capacity and energy offers. It was recently developed by WAPA and Argonne in support of the LTEMP EIS and subsequently modified and enhanced in support of this project. The AHP Offer Routine computes CRSP seasonal excesses and estimates AHP offers (if any) on a monthly basis for each CRSS trace. Similar to the LTEMP EIS application, for this analysis it is assumed that AHP capacity and energy offers are proportional; that is, both energy and capacity AHP offers are based on identical percentages that are applied to the SHP level. For example, AHP capacity and energy in a month are both set equal to 30% of SHP capacity and energy levels, respectively. Also, SLCA/IP total firm loads are increased by this same percentage during all hours in a month.

AHP seasonal offers are made to FES customers well in advance of a season based on anticipated future conditions. Future water releases from SLCA/IP hydropower plants and therefore the level of energy and capacity that are actually realized is subject to forecasts error and, at times, is too small to be worthwhile to prepare and make AHP offers. A minimum level of excess capacity and energy must therefore be projected before AHP is offered to FES customers.

The criteria that "triggers" an AHP offer has differed over time and has been a function of the staff and management composition at the CRSP Management Office. The AHP Offer Routine requires a consistent and concise set of rules that are applicable under a wide range of hydrological and release conditions. Criteria incorporated into the routine must also reflect realistic decisions that may be made by CRSP management in the future.

Based on the expert opinions of CRSP senior staff, criteria were developed for the LTEMP EIS. It underwent external peer reviews and was published in the final LTEMP EIS document. With minor modifications the LTEMP criteria were also used for this study. For modeling purposes the AHP "offer" protocol outlined by the CRSP Management Center is as follows:

- SLCA/IP electrical energy is modeled hourly by GTMax Superlite under projected daily operating criteria for summer and winter seasons using CRSS monthly water release volume and elevation trace data. For this purpose winter is defined as the months of October through March and summer is April through September;
- An AHP seasonal offer is triggered when hydropower energy is projected to be at least 20% greater than SHP energy during a season and there is also excess capacity available in the season to support this higher energy offer;
- For each month modeled, AHP capacity is calculated by taking the average of the daily SLCA/IP coincidental peak generation during weekdays (excluding holidays) within a month;
- Under very high hydropower conditions, the monthly AHP capacity offer is capped at the seasonal contract rate of delivery (CROD);
- AHP is offered only when SLCA/IP capacity is greater than SHP capacity for at least one of the two peak months during a season. These peak months are July and August for the summer season and December and January for the winter season;
- During on-peak months the percentage of both AHP capacity and energy over SHP levels are calculated. The lesser of the two percentages are offered to FES customers as AHP. Typical SLCA/IP SHP firm energy request profiles used by GTMax Superlite are then increased by this percentage;
- During off-peak months when seasonal AHP is offered, load scaling is based only on excess energy. Modeled AHP offers are therefore proportional to the amount of surplus energy during these lower-load months regardless of the SLCA/IP capacity level that is available to serve these offers;
- When SLCA/IP seasonal energy meets the AHP offer criteria, AHP is sold to SLCA/IP FES customers at the SLCA/IP firm energy price;
- If seasonal SLCA/IP resources are above SHP, but not enough to trigger an AHP offer, surplus seasonal energy is sold to the energy market at hourly market prices; and,

- Under all situations, financial positions associated with firming purchases and excess energy sales are based on hourly energy market prices. For this analysis, Brattle 2024 LMP projections were used to compute financial positions.

Financial Module

Using the models and process described above, Argonne estimated CRSP monthly and annual financial implications for all of the 105 CRSS traces. Estimates were made for the Status Quo case and Regional Market case under all three 2024 Brattle futures. It was assumed that Glen Canyon Dam generation patterns will be constrained by the LTEMP Hybrid Alternative operating criteria that was specified as the preferred alternative in the EIS final report. As mandated by the LTEMP ROD, Glen Canyon Dam is currently operated under these criteria.

For the purposes of this analysis, it is assumed that costs associated with conducting LTEMP experimental releases at Glen Canyon Dam, such as high flow experiments (HFEs), are non-reimbursable expenses that reduce the amount of money that WAPA is required to pay the U.S. Treasury for capital expenditure associated with the construction of CRSP dams and powerplant. In the long-run these experiments do not impact the financial position of CRSP and were therefore not modeled.[9]

Although CRSP loads are scaled upwards to account for AHP offers, financial estimates are based on an assumption that CRSP FES customers will not alter their load request patterns in response to evolving market price patterns. Also, identical to the LAP analysis, CRSP financial calculations use static Brattle LMPs; that is, it is assumed LMPs do not reflect an altered CRSP hydropower generation pattern. Although mathematically imprecise, this simplification was made because the CRSP system is very small compared to the sum of all WI supply resources and therefore its operations typically have a minimal impact on market prices.

As mentioned above, CRSP financial positions were modeled under both a Status Quo and Regional Market case. The difference between these two cases is an estimate of CRSP's financial benefit of joining a regional market. More specific modeling assumptions made under the two modeled cases are provided below.

Status Quo Modeling Assumptions

Under the Status Quo case it was assumed that current scheduling practices would continue in the future. To model this case, analysis methodologies and assumptions used in the past to simulate/optimize CRSP operations and SLCA/IP hydropower plants were also applied in the study. Key assumptions regarding Montrose EMMO scheduling practices, market price signals, ancillary services, and the treatment of transmission losses are described below.

[9] Costs to conduct experimental releases will affect CSRP short-term financial positions and the amount of money contained in the Basin Fund. The effort required to estimate this short-term financial impact would be every expensive while yielding only very modest levels of additional information. The modeling of experiment was therefore not included in this analysis.

Montrose Status Quo Scheduling Guidelines and Goals

Modeled operations mimic the general principles and goals that WAPA uses at its Montrose EMMO. These principles include:

(1) SLCA/IP hydropower plants and reservoirs are operated with within physical limits and comply with all applicable environmental criteria specified for each SLCA/IP resource including operating criteria specified for the Glen Canyon Dam under the LTEMP Preferred Alternative;
(2) During power grid emergencies, exception criteria is invoked at Glen Canyon Dam allowing operators to release water at levels that may at times be outside the bounds of the LTEMP Preferred Alternative operating criteria;
(3) In addition to letter-of-the-law operating criteria, Glen Canyon Dam generation levels are scheduled such that the lowest water release during a day is repeated each day of the week. Also, daily water release volumes do not appreciably deviate from one day to the next. Weekday total releases volumes are identical and weekend releases are no less than 85 percent of the weekday water release volume;
(4) Within user specified monetary threshold levels, incorporated into the objective function, SLCA/IP Federal hydropower resources are primarily used to serve and follow total FES hourly loads and to provide ancillary services for grid stability and security;
(5) To the extent possible, energy short positions are purchased in the day-ahead bilateral market 16-hour on-peak and 8-hour off-peak blocks;
(6) Excess energy is also sold on the day-ahead bilateral market as on-peak and off-peak blocks; and,
(7) Real-time purchase and sales transactions are made to resolve any short-term (hourly) energy imbalances;

Status Quo Energy Prices and Scheduling

Although the primary scheduling driver under the Status Quo case is to follow CRSP FES loads, bilateral markets also play a key role in the shaping of the SLCA/IP hydropower dispatch. GTMax Superlite SLCA/IP hydropower production first serves CRSP loads. Then the purchase of energy under short positions and the selling of energy under long positions is guided by bilateral market prices under the Status Quo case, hourly Palo Verde prices projected by Brattle for each future is input into the GTMax-Superlite model. This single hourly vector of hub price has long been used as the primary market signal to model the scheduling of all SLCA/IP hydropower resources under current operating practices. It was therefore also used for this analysis for hydropower plant scheduling purposes. Palo Verde hub prices are also used to compute CRSP finances. This includes costs for energy purchase, sales revenues, and net financial positions.

If loads and resources are accurately predicted in advance and are identical, no transactions are made with bilateral markets to fulfill FES demands. This condition very rarely, if ever, occurs. Under most circumstances the Montrose EMMO must therefore resolve energy imbalances by selling and buying power on the bilateral market. When simulating energy short positions, GTMax Superlite typically purchases relatively inexpensive energy on the day-ahead bilateral market in 8-hour off-peak blocks; however, when there is insufficient capacity to serve FES peak load more expensive on-peak block purchases are made by the model. When energy is long, GTMax Superlite tends to sell the excess in on-peak blocks during times of high energy prices. Because on-peak and off-peak block purchases in combination with SLCA/IP generation profiles do not always perfectly fit under the FES load curve, GTMax Superlite fills in the "gaps" with purchases and sales quantities that vary hourly. In the model these transactions represent real-time market activities. Under the Status Quo case GTMax Superlite will not engage in arbitrage that takes advantage of Palo Verde price spreads between on-peak and off-peak periods; that is, it will not buy inexpensive off-peak energy during the nighttime for the purpose of selling the "stored" energy at a higher price during high prices peak hours.

Status Quo Case Ancillary Service Assumptions

The LTEMP Preferred Alternative operating criteria for Glen Canyon Dam restricts average hourly water release rates from Lake Powell. This includes hourly minimum and maximum releases and both up and down hourly ramp rates. Because these limitations are specified on an hourly basis, instantaneous flows within an hour that are outside these bounds are allowed by the criteria. It was therefore assumed that Glen Canyon is permitted to provide regulation services while operating at the minimum and maximum allowable flow rates. Ramping is likewise not affected by regulation services. This assumption is based on actual operating data. The data show that while providing regulation services, instances of water releases above the set point (regulation up) are countered by instances of releases below the set point (regulation down). Integrated over an hourly time period the average water release rate from a regulating hydropower plant closely matches the plant's set-point release rate.

The second entry in the guidelines-and-goals list regarding exception criteria is also important because it allows Glen Canyon to provide spinning reserves while operating at the maximum water release rate. The exception criteria also allows schedulers to use the entire daily change limit that is specified by the Preferred Alternative. Dependent on hydrological conditions, this daily change criteria limits the range of Lake Powell water releases during 24-hour rolling periods.

In combination, points one and two of the goals-and-guidelines-list typically, but not always, allow CSRP operators to fulfill WAPA's ancillary service obligations without incurring financial costs. Rare exceptions occur under very high hydropower conditions and when there are several simultaneous unit outages at the Glen Canyon Dam Powerplant. This differs from the LAP system that requires a change in power plant dispatch when providing regulation services. That is, operations are altered in order to have sufficient capacity available to provide regulation. For example, Yellowtail incurs significant revenue losses when water is bypassed in the springtime/early summer in order to maintain sufficient capacity for ancillary services.

Status Quo Case Transmission Losses and FES Energy Deliveries

This analysis treats transmission losses under the Status Quo case using a methodology that has been applied to SLCA/IP analyses for at least the past 15 years. Losses for the CRSP system are modeled by applying a loss factor to generation with the option of using different factors for each generating resource. For example, a 4.5% transmission loss is represented by a loss factor of 0.9557 (i.e., 1/1.045 = 0.9557). To be consistent with recent analyses, including the one recently conducted for the LTEMP EIS, the same loss factor of 0.9557 is applied to all SLCA/IP facilities. This factor reflects recent grid conditions and current loss accounting practices.

Under energy-short positions, the above method assumes that CRSP energy purchases to fulfill energy delivery obligations to meet FES load do not include a loss quantity component. On the other hand, sales of energy to the bilateral market are reduced by the loss factor.

Montrose Scheduling Guidelines and Goals under a Regional Market

This section describes major modeling assumption differences between the Status Quo and Regional Market cases. All other assumptions and modeling methods are identical. Based on discussions with Montrose EMMO staff, its scheduling guidelines and goals may change from current practices under the Regional Market case. It is possible that under a regional market, SLCA/IP system operations would be primarily driven by LMPs at generation and load buses. Schedulers and marketers would therefore take advantage of arbitrage opportunities whereby a portion of CRSP loads would be served during relatively inexpensive periods allowing SLCA/IP generation to back down to sub-load levels. This “stored” SLCA/IP energy would then be used to produce generation above load levels during high price peak hours. The financial gain for CRSP would be a function of energy purchase/sale price spreads and the amount of energy that was shifted from load serving to market sales during one or more days. Although the EMMO may ultimately utilize a load following process in a regional market, the economic dispatch model was used in order to maintain consistency with how the other entities modeled their operations.

Generator LMPs projected by Brattle without regard for SLCA/IP FES load requests are used to guide SLCA/IP powerplant dispatch. All long and short positions are resolved by the market operator and CSRP financial positions are based on these net energy positions. Hourly short positions would be purchased primarily in the day-ahead regional market at customer delivery points and hourly excess energy would be sold in the day-ahead market at generator buses.

Energy transactions are priced at the Brattle LMPs computed at each individual load and generator bus. This differs from the Status Quo case in which all transactions are priced at the Palo Verde LMP. Also under the Regional Market case, all day-ahead purchase and sale quantities would vary hourly instead of in off-peak and on-peak blocks. As modeled for this analysis, no real-time purchases and sales transactions are made because Brattle modeled the day-ahead market deterministically and therefore no energy imbalances occur in real-time. In reality however, there may be opportunities for CRSP to gain additional financial benefits beyond those reported in this document from operating in a real-time regional market.

Under the Regional Market case, loss accounting also differs from current methods. For example, no loss factor is applied when energy is long because the excess energy is sold to the regional market at a generator. The amount of excess energy is based on SLCA/IP generation minus FES loads times a loss factor of 1.045. The LMP at generator buses reflects marginal energy value, congestion charges, and losses. Short positions are fulfilled via purchases at FES customer load buses. Financial costs associated with these purchases are based on the load-weighted LMP computed by Brattle. No additional energy is purchased to cover losses because the market delivers the energy directly to the load buses. Also imbedded in the LMP calculation are all marginal costs associated with congestion and losses.

For financial calculations, long positions are settled at the generation-weighted LMP and short positions are settled at the load-weighted LMP. As previously described in the loss paragraph above, short position is balanced at points of load (i.e., energy extraction) at the load weighted LMP. It should be noted that costs due to both transmission congestion and losses are factored into the LMP calculation thereby eliminating the need to include additional physical losses for both power purchases and excess energy sales and in financial equations.

Salt River Project Exchange and Grandfather Transmission Contracts

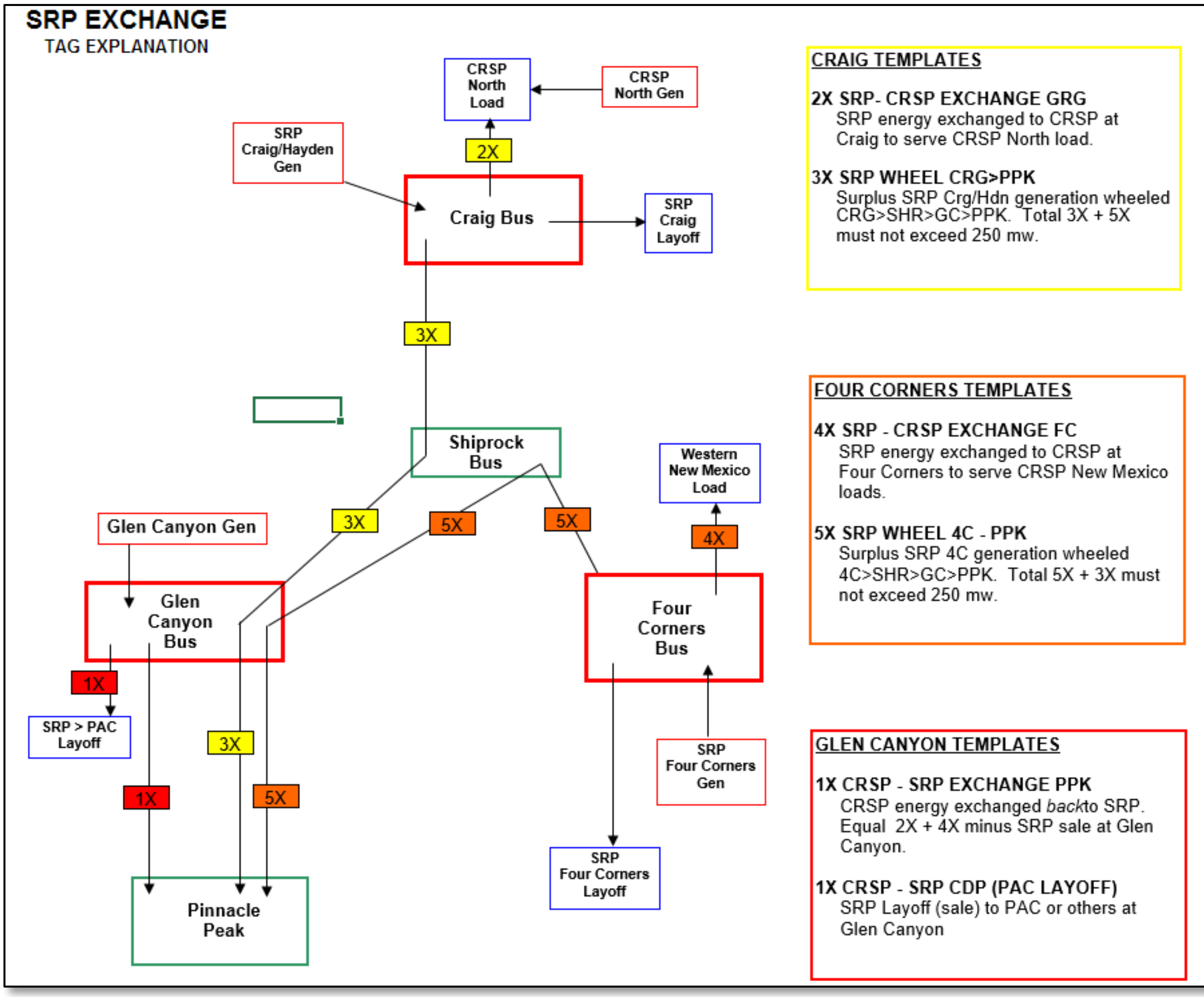
Several existing CRSP transmission contracts will remain in effect if the CRSP system becomes a member of the regional market. Two types of agreements that will have significant impacts on CRSP finances are the Salt River Project (SRP) power exchange and existing Grandfather (GFA) transmission contracts.

Salt River Project Power Exchange Agreement

The SRP power exchange agreement has two components. The first involves energy exchanges that are designed to relieve contractual transmission congestion and the second involves the use of CRSP transmission resources to wheel power for SRP. SRP owns shares in generating units in Colorado and New Mexico located far from its load centers in the Phoenix, Arizona region. Likewise, the Glen Canyon Powerplant near Page, Arizona is far from CRSP loads in Colorado and New Mexico. To reduce transmission congestion, generation from Glen Canyon Dam serves SRP loads via energy deliveries to the Pinnacle Peak substation. At the same time, on a megawatt (MWh)-for-MWh basis, SRP resources at Craig, Hayden, and Four Corners serve CRSP loads in the north and New Mexico. Under the second part of the SRP power exchange agreement, CRSP wheels power from the aforementioned SRP power plant resources to Pinnacle Peak.

To estimate the financial impacts of the SRP exchange under the Regional Market, actual CRSP energy exchanges and wheeling for the year 2015 were paired with Brattle LMP data. As illustrated in the diagram below, provided by the CRSP EMMO, the SRP power exchange transactions have TAGs of 1X through 5X. TAG 1X are transactions related to Glen Canyon Dam energy serving SRP loads in exchange for SRP generation from the Craig and Hayden power plants serving CRSP northern load (TAG 2X) and SRP generation from Four Corners that serves CRSP loads in New Mexico (TAG 4X). TAGs 3X and 5X are for wheeling transactions from the Craig power plant bus to Pinnacle Peak and from Four Corners power plant to Pinnacle Peak, respectively.

The applied methodology for computing the financial impacts of the SRP exchange agreement on CRSP finances is based on the total amount of energy, in terms of MWh, that was transacted under each TAG paired with Brattle LMP data (sum of energy, congestion and loss components) obtained from Brattle model results for the year 2024 under the Regional Market case. Status Quo case LMPs are not utilized because the SRP exchange does not incur significant costs to CRSP under the current market structure.



Because the SRP data are for the year 2015 which starts on a Thursday and LMP data are for the year 2024 which starts on a Monday the data are "out of alignment." The LMP data was therefore shifted by 3 days such that the LMP data are better aligned with the TAG data. In addition, there was a separate alignment of LMP and SRP exchange data for WECC holidays.

To compute financial implications in each hour, TAG energy quantity is multiplied by the LMP at the point of energy injection. This value is then subtracted from the TAG energy quantity times the LMP at the energy delivery point. Under the Regional Market case, CRSP benefits financially when the point of SRP exchange energy injection is more valuable (i.e., higher LMP) than the energy extraction point. On the other hand, CRSP financially losses when the injection point LMP is lower than extraction point LMP.

Grandfather Transmission Agreements

Costs for GFA contracts are computed using a similar methodology in which energy sink and source LMPs are used to compute the cost of transporting power through the WAPA system. Historical GFA contracts data in terms of the amount of MWh of energy transported by WAPA for the year 2016 was used for this analysis. These data were aligned with 2024 Brattle LMP by day type and for holidays. The GFA contracts included in financial computations are with Arizona Public Service (APS), PacifiCorp, and Deseret Electric Power Cooperative (Deseret). Energy sources and sinks used for these GFA contracts are as follows:

- APS (May-Oct) 250 MW – Glen Canyon to Pinnacle Peak (Primary Rights)
- APS (Nov-Apr) 150 MW – Glen Canyon to Pinnacle Peak (Secondary Rights)
- PacifiCorp (Nov-Apr) 250 MW – Pinnacle Peak to Glen Canyon (Primary Rights)
- PacifiCorp (May-Oct) 150 MW – Pinnacle Peak to Glen Canyon (Secondary Rights)
- Deseret (all Year) 12 MW – Flaming Gorge to Glen Canyon (note: we are using Flaming Gorge because there is not a LMP for Bonanza but there is one for Flaming Gorge)

It should be noted that for the Deseret contract, the point of energy injection is actually at the Bonanza power plant. However, Brattle data provided to CRSP did not contain LMP data for that point. LMPs at Flaming Gorge were therefore used as a surrogate energy injection point.

Identical to the SRP exchange the CRSP Office benefits financially when the point of SRP exchange energy injection has a higher LMP than the energy extraction point. The opposite occurs when the injection point LMP is less than the extraction point LMP.

Model Results

As modeled by Brattle, the economic benefits of a Mountain West RTO market are primarily driven by two factors that both lower total WI dispatch costs. Although there are some savings outside the footprint, much of the savings is gained by Mountain West members. The first economic factor is the removal of market barriers that exist in the current status quo bilateral market structure. Brattle approximates this benefit by removing transaction costs (referred to as hurdle rates) when it simulates energy flows in the Mountain West footprint. The second major economic benefit is a more efficient use of the transmission system as operated by a single RTO entity as opposed to several utilities individually managing their separate pieces of the system. Brattle represents this second economic benefit in the dispatch by allowing PSO to utilize the full rated capacities of key transmission pathways in the Mountain West footprint that, when needed, allows higher modeled energy flow rates on these pathways than is typically scheduled in current operations.

Although Brattle estimates demonstrate potential economic benefits of a Regional Market for the WI grid as a whole, economic benefits are not always equally shared by all of the entities that join and participate the regional market. Applying the methods described in previous sections, Argonne computed some of the financial implications of the Regional Market case on the LAP and CSRP Offices. These financial results are discussed below. It should be noted that the financial components discussed in this report are limited to a subset of overall impacts that feed into a larger overall financial impact study that was compiled by LAP and CRSP staff.

Loveland Area Projects Financial Results

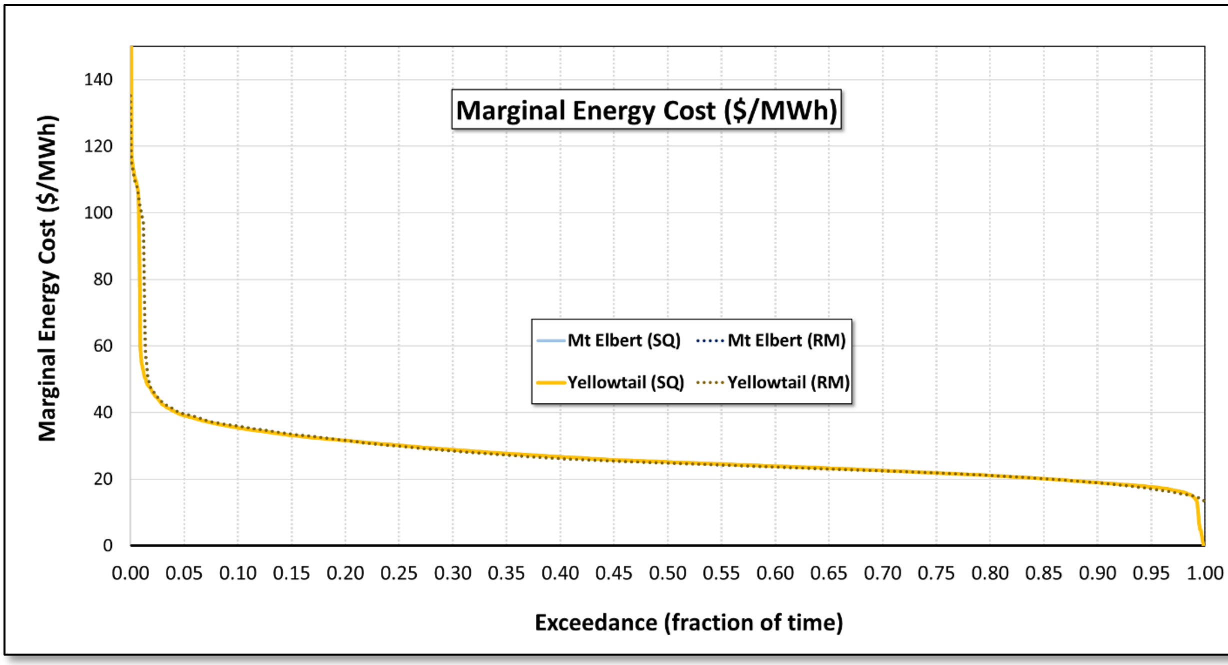
The Regional market will impact LAP finances relative to the Status Quo case primarily due to market price changes as projected by Brattle. The next section describes LAP financial calculation results under a wide-range of assumptions that have a significant impact on projected outcomes. Key assumptions that affect results include hydrology/hydropower conditions, transmission loss rates, operational flexibility at Mt Elbert, market-bidding behavior, and market settlement rules for LAP.

Changes in LMPs under the Regional Market Case

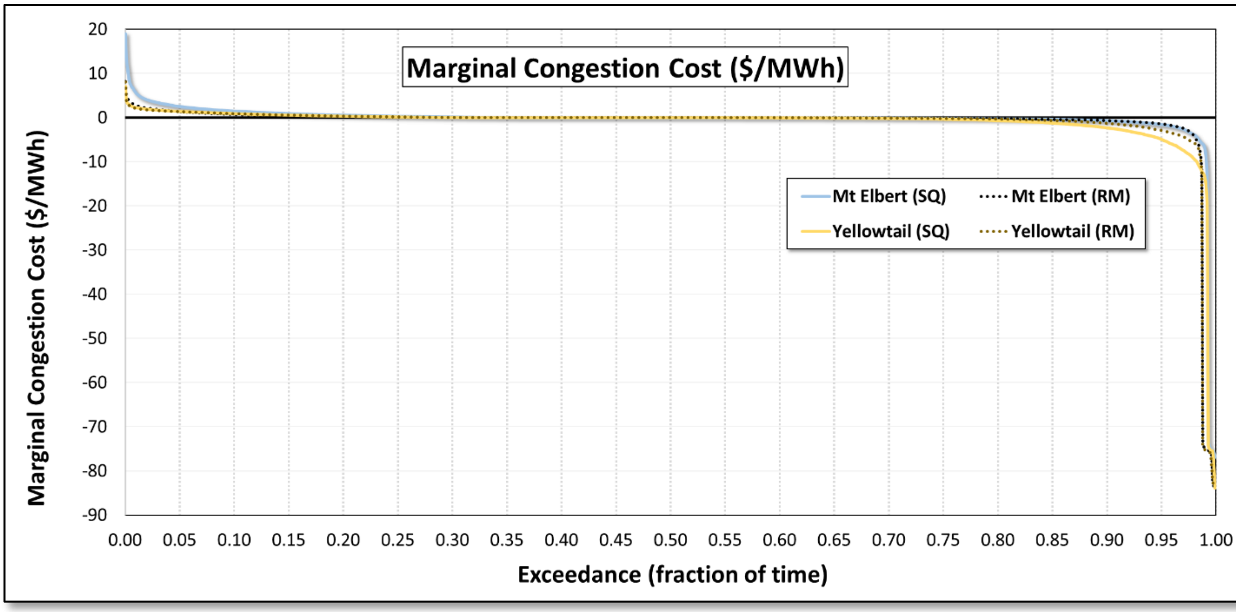
The modeling assumptions that reduce transaction costs and relax transmission constraints lowers WI total production costs under the Regional Market case. It also effects LMPs and impacts the finances of individual entities within the grid including LAP and CRSP. The table below shows average annual energy prices at two key LAP hydropower plants under the CT future for the Status Quo and Regional Market cases in 2024. On average, the total LMP is projected to decrease by $0.68/MWh at Mt Elbert and $0.12/MWh at Yellowtail. These savings are based on the summation of LMP components. As shown in the table below, the Regional Market case has slightly higher energy prices which is more than offset by lower congestion (i.e., MCC) and loss (i.e., MLC) LMP components.

Case	Total LMP ($/MWh)		Energy ($/MWh)		Congestion ($/MWh)		Losses ($/MWh)	
	Mt Elbert	Yellowtail	Mt Elbert	Yellowtail	Mt Elbert	Yellowtail	Mt Elbert	Yellowtail
Status Quo	24.50	24.01	27.00	27.00	-0.40	-1.09	-2.10	-1.90
Regional Market	23.82	23.89	27.15	27.15	-1.02	-1.15	-2.31	-2.11
Market Savings	**0.68**	**0.12**	**-0.15**	**-0.15**	**0.62**	**0.05**	**0.21**	**0.22**

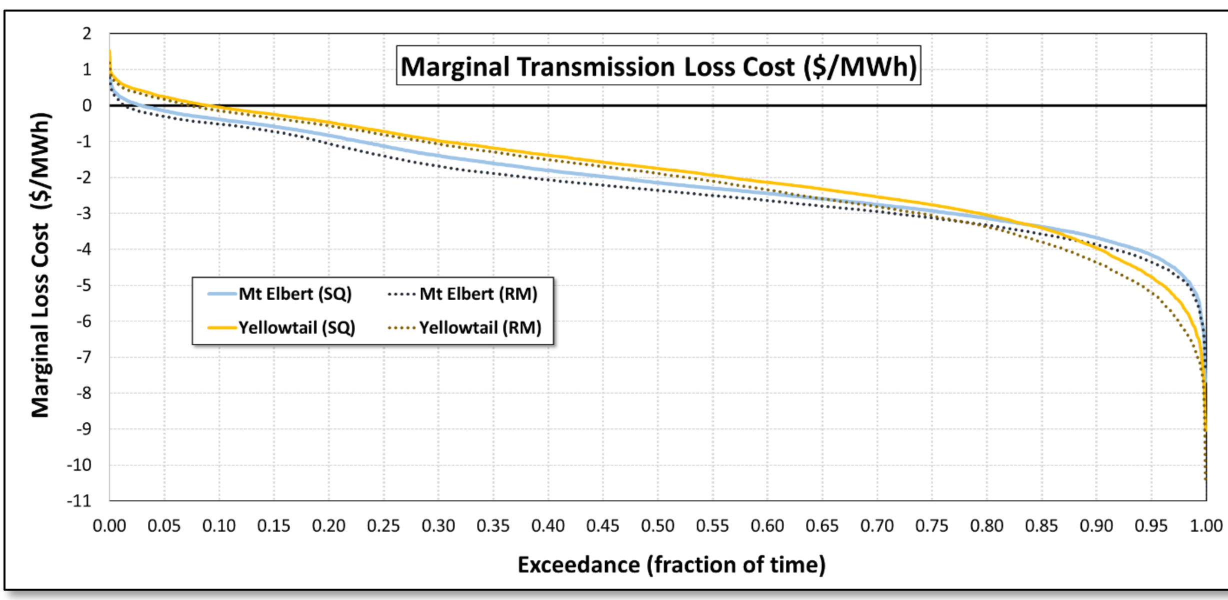
The energy component of the LMP (i.e., MEC) is projected to have a wide range of outcomes during 2024. As shown in the graph below, however, the MEC component of the LMPs for the Status Quo (SQ) and Regional Market (RM) cases are between $20/MWh to $40/MWh almost 90% of the time. Because the marginal prices at Mt. Elbert and Yellowtail are always identical under each of the cases, only Yellowtail curves are visible on the graph. From a statistical distribution perspective, prices for the two cases are within $1/MWh – larger differences between the Status Quo and Regional Market cases occur at the tail ends of the exceedance curve distribution.



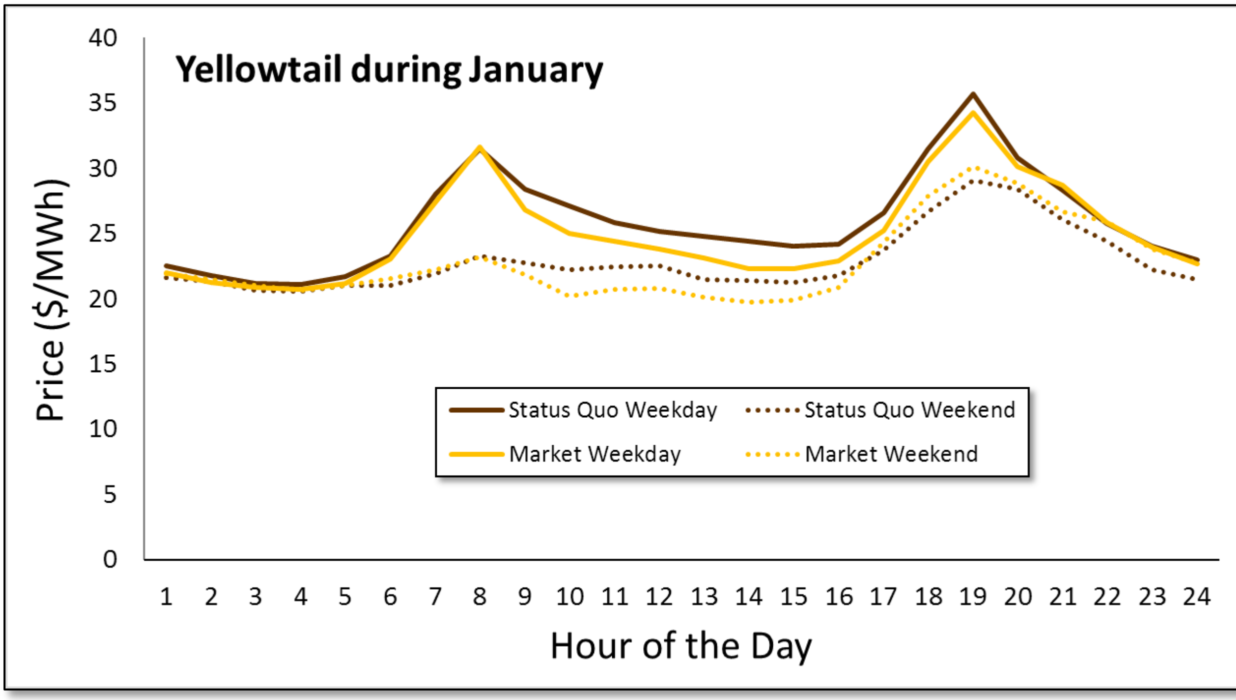
Most of the time, the MCC component of the LMP is near zero at both the Mt. Elbert and Yellowtail powerplants under both the Status Quo and Regional Market cases. The exceedance curve below shows that approximately 80 percent of the time transmission constraints do not change LMPs by more than $1/MWh at both locations under both cases. This is a strong indication that transmission congestion is usually not an issue (i.e., binding constraint) under most operating conditions. When congestion does occur, shown as larger non-zero costs at the tail ends of the curve, prices drift toward zero under the Regional Market case. Note that on both the left and right sides of the distribution the dashed lines are closer to zero than the solid lines. The MCC change (i.e., lower difference) is more pronounced at Mt. Elbert on the left side of the distribution and on right side of the distribution at Yellowtail. This result is primarily due to the relaxation of capacity limits on key transmission paths in the Mountain West footprint.



The projected range of MLC during 2024 is projected to be much narrower than the other two components. As shown in the graph below, the MLC component of the LMP is between $1/MWh to -$11/MWh -- note the change in scale relative to the previous graphs. Similar to the other LMP components, the statistical distribution of prices are within $1/MWh. Unlike the other distributions, differences do not significantly increase at the tail ends of the exceedance curve distribution.



Whereas lowering market barriers and congested pathways in the PSO WI model mathematically guarantees that the dispatch will be more economically efficient, this same dispatch solution may however result in individual entities that lose financially under a competitive market structure. Generally, this occurs because relative to the Status Quo case the market tends to increase LMPs at locations with relatively low prices and decrease LMPs in areas that are more expensive. The figure below shows an average LMP profile for weekdays and weekends at the LAP Yellowtail hydropower plant in January 2024 under the CT future. In this example, note that prices are generally lower under the Regional Market case. There are times of the day however during the weekend that the Regional Market case has prices that are more expensive. For example during the evening peak, prices under the Regional Market case are slightly more expensive than under the Status Quo case.

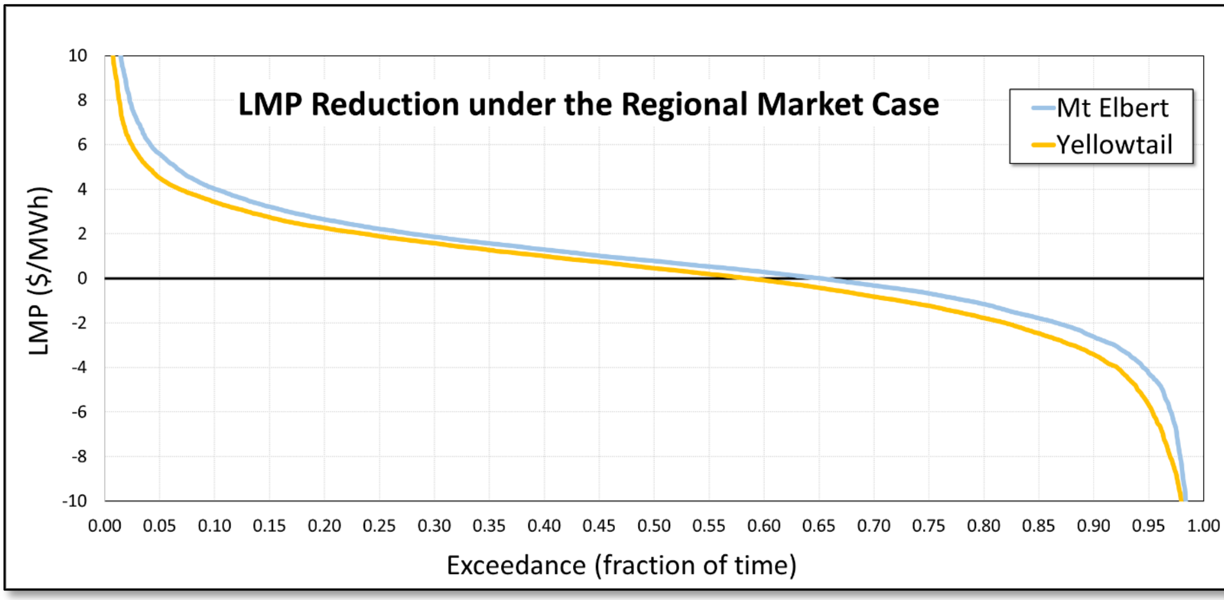


According to Brattle projections, higher LMPs under the CT future in 2024 will occur frequently. The graph below shows an annual exceedance diagram of hourly price savings under the Regional Market case at the Mt Elbert and Yellowtail powerplants[10]. Note that in order to show a higher level of detail, the range displayed in the graph is for LMP reduction between -$10.00/MWh to $10.00/MWh thus eliminating the display of higher price changes that is projected to occur about 4 percent of the time. The total range for the Mt Elbert case is from -$25.11/MWh to $75.28/MWh and for Yellowtail the range is from -$23.61/MWh to $106.05/MWh.

Note that the curve in the figure below is strikingly different from the probability distributions above that shows only very modest changes in the exceedance distribution of LMP components under the Regional Market case; that is, the difference between the solid and dashed lines. This occurs because higher occurrence of lower marginal prices are typically, but not always, offset by lower prices with

[10] The referenced graph displays hourly LMP differences (e.g., relative values) between the Status Quo and Regional Market cases. This differs from previous exceedance graphs for MEC, MCC, and MLC that show absolute values for each individual case.

approximately the same magnitude.



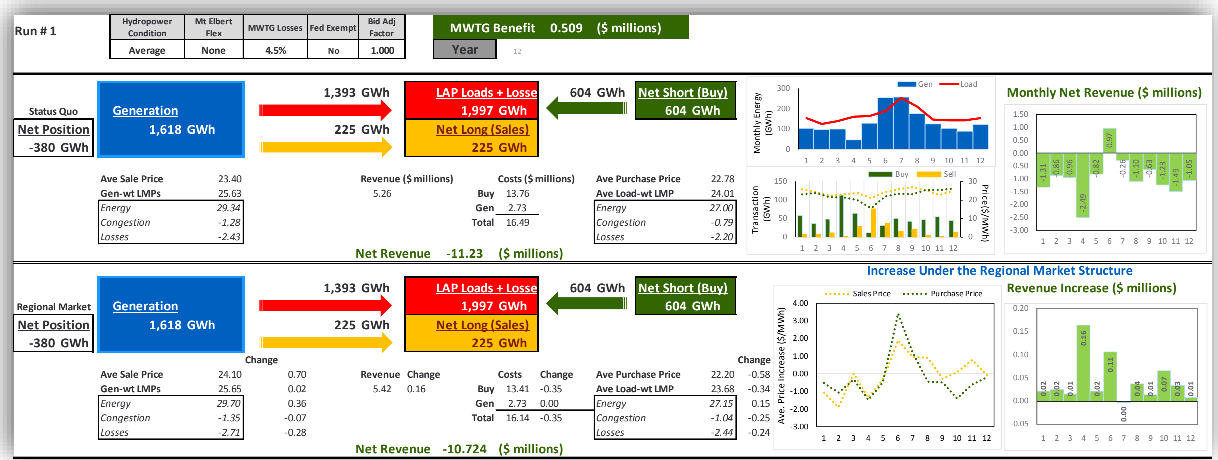
Ultimately, LMP changes such as the ones discussed above drive the projected financial outcomes for RMR and the CRSP Management office under the Regional Market case. WAPA entities experience relative financial gains under the Regional Market case when LMPs increase at its hydropower plant buses above the Status Quo case. On the other hand, WAPA entities financially lose when LMPs increase at FES customer energy delivery points. Typically, but not always, LMPs at load and generator buses tend to move in tandem; especially in situations such as the ones presented for LAP and CRSP that are projected by Brattle to very frequently have little to no transmission congestion. The level of financial gain or loss is most pronounced under wet and dry hydropower conditions when RMR and the CRSP engage in relatively large transactions to maintain supply and demand balances.

The accuracy of the Argonne financial calculations presented in this report hinge largely upon Brattle LMP estimates. As discussed previously, LMP calculations are dependent on numerous assumptions regarding grid costs, development decisions, and operations in 2024. The reader should bear in mind that if key assumptions are not realized, financial results may be different from the ones presented in this report.

Loveland Area Projects Results: Reference Future

Once a high level of confidence was gained in the Argonne financial model through testing and LAP benchmarking exercises, Argonne staff ran and performed a comparative analysis (Regional Market case relative to the Status Quo case) that is used in this report as a reference point. It is based on the CT future under an average hydropower situation in which all financial calculations were based on total LMPs. Mt Elbert operations were not able to adjust its operations in response to price signals and transmission losses were set equal to 4.5% of LAP loads. Actual Mt Elbert pumping and generation profiles during 2011 were used in this simulation to represent static/inflexible pumped-storage power plant operations. This reference point is used mainly for comparison purposes because it is simpler than many of the other futures. Other more complex situations build upon it. It is not necessary the situation with the highest probable outcome or operating criteria.

Energy flows and financial outcomes for this reference point are shown in the figure below.[11] The upper part of the figure shows information for the Status Quo case and the lower half presents results for the Regional Market case.



Under these conditions, the RMR financial benefits of joining the Mountain West market is estimated at $0.51 million (top of the figure). These results are primarily driven by the following factors:

- For both the Status Quo and Regional Market cases under the average hydropower condition, the LAP is energy short on an annual basis by approximately 380 gigawatt-hours (GWh). Due to this short positon, it purchases more energy to serve loads (~604 GWh) than it sells (~225 GWh);

- The Brattle model predicts that the average load-weighted energy price for LAP customer delivery points will drop under the Regional Market case from approximately 24.01 $/MWh (Status Quo case) to 23.68 $/MWh (Regional Market case). As a result the average purchase price is reduced by about 0.58 $/MWh resulting in lower energy purchase outlays of about $0.35 million[12]; and,

- Brattle predicts that the average generation-weighted LMP will remain nearly constant under the Regional Market case (an annual average increase of only $0.02/MWh). In those hours that LAP energy production is long, however, the average sale price of the excess generation

[11] The figure contains a screen capture of one sheet in the Argonne financial spreadsheet. Values displayed within and between blocks on the left-hand side of the figure are annual summaries. The spreadsheet user can also display monthly values. Line and bar graphs in the upper right portion of the figure are results for Case A and the graphs on the lower left are changes that are projected under Case A.

[12] Note that the load-weighted LMP price differ from the average purchase price because RMR purchase patterns differ under this situation differ from customer load patterns.

increases by $0.70/MWh from $23.4/MWh to $24.1/MWh. This price increase results in a higher annual sales revenue of $0.16 under the Regional Market case.

Under dry conditions, the LAP annual net energy short position is about 644 GWh; that is about 70% more than under the aforementioned average hydropower condition. Purchases to cover energy shortfalls therefore increase significantly. Financial benefits for RMR under the Regional Market case as a result of cheaper energy prices at load buses is estimated at $0.47 million – slightly less than under the average hydropower condition. This seemingly counterintuitive result is due to a lower energy cost for energy purchases ($0.49/MWh in the dry hydropower condition versus $0.56 MWh under the average condition) and a higher average sales price for excess generation – the average is $0.80/MWh.

A wet LAP condition based on actual 2011 generation profiles was also analyzed. This condition has an annual net long energy position of about 990 GWh with 1,151 GWh of excess energy sales and energy purchases of only 161 GWh. The financial benefits of RMR joining the centralized RTO market is estimated at $0.14 million. This is due to a slightly higher average energy sale price of $0.06/MWh under the Regional Market case relative to the Status Quo case.

The three aforementioned results show that for the CT future, LAP will benefit under wet, average, and dry hydropower conditions. This may not necessarily be true under all future hydropower conditions. A more detailed investigation of the results show that there is at least one month of the year in which the Regional Market case yields a lower financial position than the Status Quo case. It is therefore not only the annual amount of energy production from the LAP facilities that is of importance, but also the monthly and hourly production pattern in concert with LMPs that influences the outcome.

In order to provide the reader with more detailed information on the dry and wet hydropower conditions and other situations analyzed in this report, figures that contain charts and diagrams similar to the ones above are provided in Attachments A, B, and C.

Loveland Area Projects Results: Mt Elbert Operational Flexibility

The next future analyzed is identical to the one above except that Mt Elbert operations in 2024 under both the Status Quo and Regional Market cases are responsive and optimized to market prices as scheduled and operated by LAP. Under these conditions the financial benefits for LAP system is estimated at $1.35 million. That is, by enabling flexibility at Mt. Elbert the financial savings of a centralized market structure increases by about $0.84 million ($1.35 million versus $0.51 million). Because of higher Mt. Elbert operational flexibility, the following LAP changes occur relative to the reference point above:

- The LAP system net short energy position on an annual basis increases from 380 GWh to 429 GWh under the Status Quo case and to 442 GWh under the Regional Market case. Note that due to round-trip energy losses at Mt. Elbert, the net energy short position is higher than the reference point;

- Approximately twice the energy purchases are required for increased pumping load (Status Quo case purchases increase to 324 GWh and Regional Market case purchases increase to 390 MWh) at a savings of $1.10/MWh; and,
- Because of higher water pumping/release activities sales increases by roughly 50 percent to 324 GWh under the Status Quo case and 390 GWh under Regional Market case.

Centralized RTO market savings would increase to $2.71 million if it were assumed that the new market prompted operational flexibility at Mt. Elbert, but there was no such assumption made under the current market condition. That is, future operations remained inflexible under the Status Quo case using the 2011 pump/gen schedule. In addition to much higher pumping/gen activities, the average purchase price savings would increase by $2.69/MWh and the average sales price would increase by $4.64/MWh.

One note of caution regarding these results. An examination of Brattle results showed that the projected pumping and generation schedule is very aggressive (and perhaps not technically feasible) requiring at times multiple operational mode changes per day and average pumping levels in many hours that is significantly less than the full pumping rate. This type of operations may require significant upgrades at the plant and/or higher operating and maintenance costs that were not factored into the analysis.

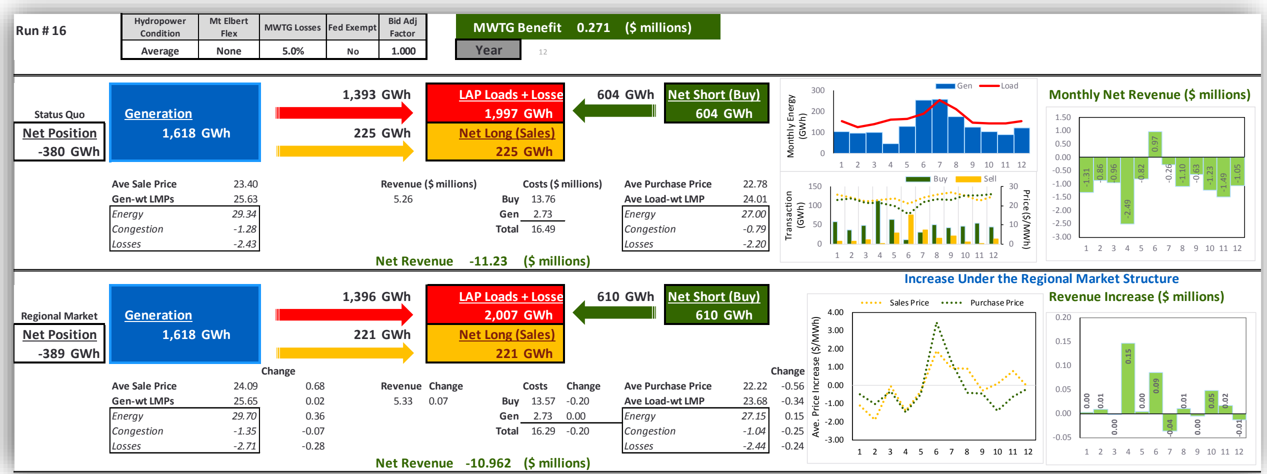
Loveland Area Projects Results: Transmission Losses

When removing transaction friction and bilateral trade barriers more energy flows on transmission line to accommodate increased power transactions in the Mountain West footprint. Power transactions with entities outside of the footprint also tends to increase. The table below shows that under the Regional Market case, the average power flow on key transmission paths are projected to increase on average by almost 10 percent. Maximum power transfer rates are also expected to increase. For example, on TOT3 the maximum simulated power flows projected by Brattle increases from 1,300 MW under the Status Quo case to 1,801 MW under the Regional Market case; that is an increase of almost 39 percent. Losses under these high flow conditions, especially when ambient temperatures are high, are expected to be higher than current levels. These potentially higher losses were not accounted for in the Brattle PSO model.

Average Path Power Flows[13] (MW)

Path	Status Quo (MW)	Regional Market (MW)	Market Flow Increase (%)
TOT 1A	302	357	18.1
TOT 2A	257	300	16.9
TOT 3	922	879	-4.6
TOT 4A	203	272	34.2
TOT 4B	432	419	-3.1
TOT 5	373	499	33.9
TOT 7	176	202	14.7
Average	**381**	**418**	**9.9**

RMR financial cost to cover higher losses, however, may be significant. For example, if LAP losses used for financial calculations increased by a half of one percent from 4.5 percent to 5.0 percent then RMR would need to supply an additional 10 GWh of energy to the grid in 2024. The figure below shows loads plus losses are about 1,997 GWh under the Status Quo case and 2007 GWh under the Regional Market case. As a result, Regional Market financial benefits would decrease by roughly a quarter of a million dollars from $0.51 million under the reference situation to about $0.27 million; that is, benefits would erode by more than 45 percent. If it were assumed that losses would further increase to 5.5 percent, RMR Regional Market case benefits would be nearly erased at only $0.03 million.



Loveland Area Projects Results: Pay Only MEC

Not all futures show a positive result under the Regional Market case. WAPA at one point was considering negotiating for a payment structure in which it only payed the MEC for energy short positions (i.e., MCC and MLC components of the LMP would not be included for firming purchases). This would be an expansion of a Federal Service Exemption that SPP granted WAPA's Upper Great Plains Region. Under

[13] Brattle power flows are computed as positive and negative values depending on the direction of the flow. The average power flow discussed in this report are based on the absolute value of the Brattle power flows.

the assumption that RMR only pays the energy portion of the LMP to satisfy its net energy short positions, the Regional Market case typically yields a lower financial position relative to the Status Quo case.

If the only parameter that changes from the reference point is only paying the MEC for firming purchases, the Regional Market case results in a higher financial cost of $1.62 million compared to the Status Quo case. This occurs because both annual load-weighted congestion and losses charges in the LMP calculation are negative for LAP FES customer deliveries. According to the Brattle simulations, the average load congestion charge is about $1.04/MWh for congestion and $2.44/MWh for losses. Because purchases made under negative net positions are much higher under dry hydropower conditions, the relative financial position, compared to the Status Quo case, is a cost of $2.22 million. On the other hand, when hydropower conditions are above average, the relative financial losses are a bit lower at $0.61 million.

Under both the reference point and “only pay MEC” for firming purchase situations, total hourly LMPs are used for both generation and loads under the Status Quo case. The comparative analysis methodology therefore cancels out these costs. Also under both situations, the generation weighted energy component of the LMP for power sales during net energy long positions at generator buses is not affected, canceling out these costs as well. The only factors therefore that are driving the results are the elimination of congestion and transmission LMP components under the Regional Market case with the “only pay MEC” assumption for energy purchases under energy short positions at load buses.

Even in those future situations in which the Regional Market case under the “only pay MEC” for firming assumption yields a positive financial position relative to the Status Quo case, the financial position of LAP would be better off (i.e., higher financial position) if RMR pays the total LMP. The main driver for these results is the location of the LAP system components. Because LAP loads are located in an area with lower LMP’s, low cost production levels within this area are partially limited (suppressed) by transmission constraints; therefore, this low cost generation cannot be transported to areas that have higher marginal production costs driving down local prices. This is indicated by the negative congestion and losses LMP components. The “only pay MEC” for firming assumption eliminates the benefits of these lower costs.

From a financial standpoint, congestion is therefore benefitting LAP when using the total LMP for firming purchases. At the same time, congestion is detrimental to overall system-wide economics. Eliminating the congestion allows lower cost generation to produce more power while units that are more expensive are dialed back. As the LMP numbers currently stand, instead of buying/selling for net short/long quantities, LAP would be better off buying all of its energy to serve load from the market and selling all of its power production to the market. Note that generation has a higher total LMP than load LMPs.

The reader should bear in mind however, that Brattle 2024 LMP projections are based on numerous assumptions that have a direct impact on LMP computed values. If one or more key assumptions do not come into fruition, LMP results could potentially be substantially different from the ones projected by Brattle. For example, if load growth in the areas where LAP customers are located is much higher than anticipated in the Brattle study while load growth in congested areas is much lower, then the load-weighted LMP congestion charge could potentially flip from negative to positive. Similarly, new transmission lines or upgrades may also elevate congestion. It should be noted that the Brattle model runs grew demands at all buses in a utility service territory by the same growth rate. Realistically, some buses are anticipated to grow faster than other buses.

Because the Brattle LMP result may not come into fruition with certainty, paying the entire LMP has some risks. If the congestion were resolved by building more lines, LMPs at LAP customer buses would be higher because a higher-priced generator that is "outside" of the low-cost area would then set the LMP. WAPA would pay more money to resolve energy short positions. In a more extreme case, if by 2024 congestion is not resolved and low cost generation were built outside of the customer's congested area (e.g., aggressive wind capacity expansion), congestion and losses may reverse congestion LMP signs from negative to positive and the Federal exemption would benefit LAP. Assumptions regarding where, when, and how much new capacity is built by technology type may also significantly affect LAP financial benefits/costs.

Loveland Area Projects Results: Bidding Behavior

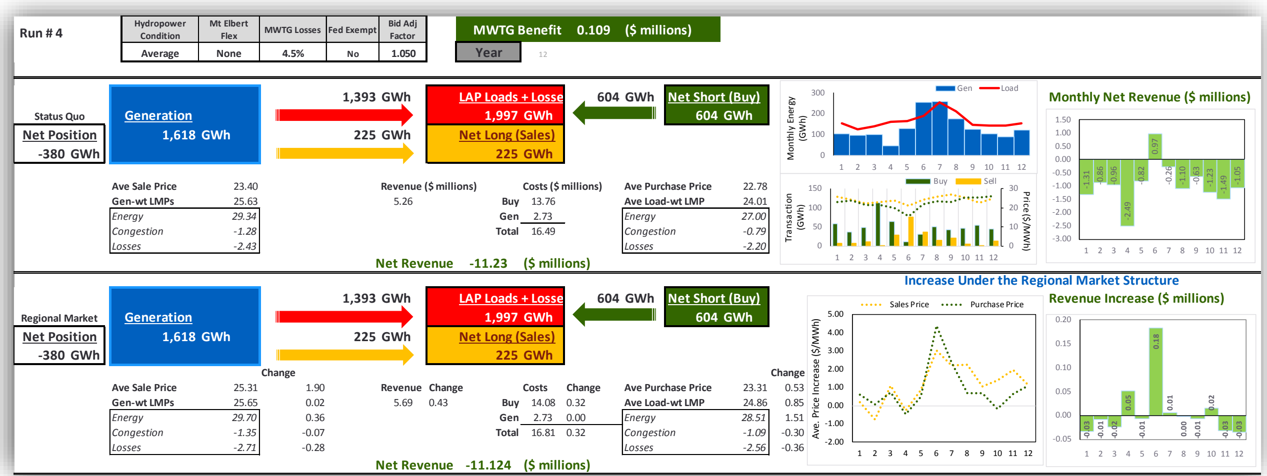
The Brattle study uses estimates of unit-level production costs for all resources in the WI as inputs into the PSO model that simulates power grid operations and computes LMPs under the Regional Market case. Hurdle rates for external power exchanges with entities outside of the footprint are also applied in the model. Brattle unit-level production cost estimates for most resources in the WI are based on generic information; however, Brattle with Mountain West Utility Group member involvement paid special attention to using more specific data for generating resources and loads within the Mountain West footprint. Although the specifics of the Mountain West market participation are not yet fully defined, the underlying principle in the Brattle study is that all utilities offer all of their resources into the market at production costs under the Regional Market case. In contrast, under the Status Quo case costs are increased with adders and hurdle rates for transactions within the Mountain West footprint to represent market bilateral barriers and the willingness to sell or buy at a minimal spread above production costs.

The production cost assumption is a good starting point for the Regional Market case because, in theory, under a perfectly competitive marketplace the seller's financial performance is maximized using a production-cost offer strategy. In reality, however, RTO markets are not perfect (as is no market) and market players do not always offer energy at production costs for all of their resources. An October 2016 Federal Energy Regulatory Commission (FERC) staff report entitled "Common Metrics Report" discusses price-cost mark-ups that compares price-based offers to cost-based offers of marginal units. Low mark-ups suggest competitive market performance. In general, over a five-year time period from 2010 to 2014, markets on average showed modest levels of price mark-ups. For example, in 2014, the annual average mark-up in the Southwest Power Pool (SPP) was just under 5 percent in its first year of operation.

During this 5-year period, the California Independent System Operator (CAISO) reported a negative annual average price mark-up in every year ranging from very close to zero in 2012 to negative 4.8 percent in 2014. This result is because the default energy bid in the CAISO market includes a 10 percent mark-up and many resources choose to bid below the default level. Adjusting for the 10 percent default adder, the CAISO mark-up from actual costs ranged from about 5.2 percent to just under 10.0 percent. Other markets show smaller mark-ups. The Midwest Independent System Operator (MISO) for example reported mark-ups that were consistently around 1% and the New York Independent System Operator (NYISO) in some years reported annual average mark-ups that were negative (approximately -1.5 percent). The FERC report also discusses the percent of time that RTOs and ISOs needed to implement mitigated price measures, presumably to counter the impact of participant strategic bidding behavior.

Based on information included in the FERC report, simplified sensitivity analyses were performed for LAP. This project does not intend to project the future behavior of Regional Market participants. Rather, the intent is to gain a general appreciation of RMR financial impacts if LMPs under the Regional Market case are either above or below the ones that Brattle computed using the cost-based offer assumption. The first sensitivity analysis assumed that total LMPs in all hours during 2024 would be 5 percent higher than the ones estimated by Brattle. All other assumptions are identical to the reference future. Proceeds from higher payments could be made to help offset fixed operation and maintenance costs (O&M) and/or capital cost payments for power plant construction.

As shown in the graph below, if LMPs were 5 percent higher as a result of bidding behavior, RMR net financial gain under the Regional Market case would drop from $0.51 million (reference future with cost-based LMPs) to about $0.11 million. Average purchase prices for RMR energy-short positions would be $24.86/MWh under the Regional Market case; that is, $0.53/MWh more expensive then Status Quo case. These higher costs would be somewhat countered by higher revenues from energy-long sales that benefit from higher LMPs.



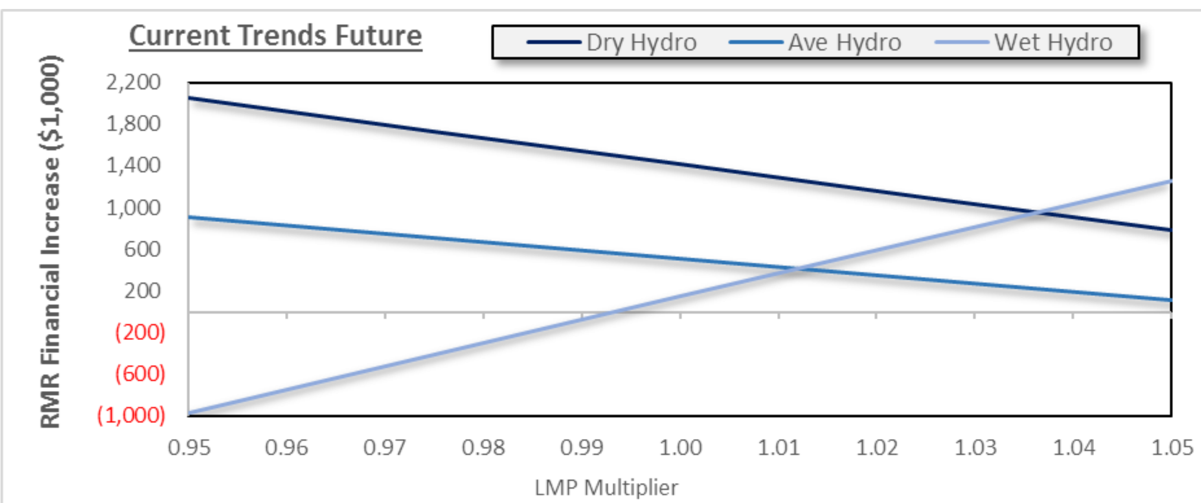
Under dry LAP conditions an increase in LAP energy purchases to cover customer delivery shortfalls increases significantly resulting in a lower net financial position of $0.25 million under the

Regional Market case relative to the Status Quo case. The opposite occurs under wet hydropower conditions during which time LAP would benefit from higher prices – net benefits are estimated to be $1.26 million higher under the Regional Market case.

A second set of sensitivity analyses were conducted that assumed total LMPs in all hours during 2024 would be 5 percent lower than the ones estimated by Brattle. This bookend is intended to represent those situations that lead to price-offers that are lower than costs such as that which occurred in the NYISO. Price-based LMPs are frequently less than cost-based LMPs in situations where power system operations are relatively inflexible and startup/shutdown costs are expensive (e.g., there is a high percentage of nuclear and baseload coal). This situation is exacerbated by high penetration rates of renewable resources, which in some regions frequently drive prices below zero.

If LMPs are lower by 5 percent, the LAP net financial gain from a centralized RTO market would almost double from $0.51 million to about $0.91 million for the CT future. Under dry LAP conditions an increase in LAP purchases to cover energy shortfalls improves LAPs net financial position by $1.19 million under the Regional Market case. The opposite occurs under wet hydropower conditions during which time LAP would collect less revenues during energy-long hours as a result of lower prices reducing LAP net revenues by an estimated $0.97 million under the Regional Market case.

A summary of the projected increase in RMR's financial position as a result of participating in a Mountain West centralized RTO market is depicted in the graph below. The graph shows that under both the dry and average hydropower conditions the net financial position of RMR trends downward as a function higher LMPs. Under both hydropower conditions RMR has a net energy short-positions; therefore, the lower the LMPs the healthier the RMR financial position. The opposite occurs under a wet hydropower condition -- the RMR's financial position improves as prices increase when operating in the Regional Market case as opposed to the Status Quo case.



Sensitivity Runs

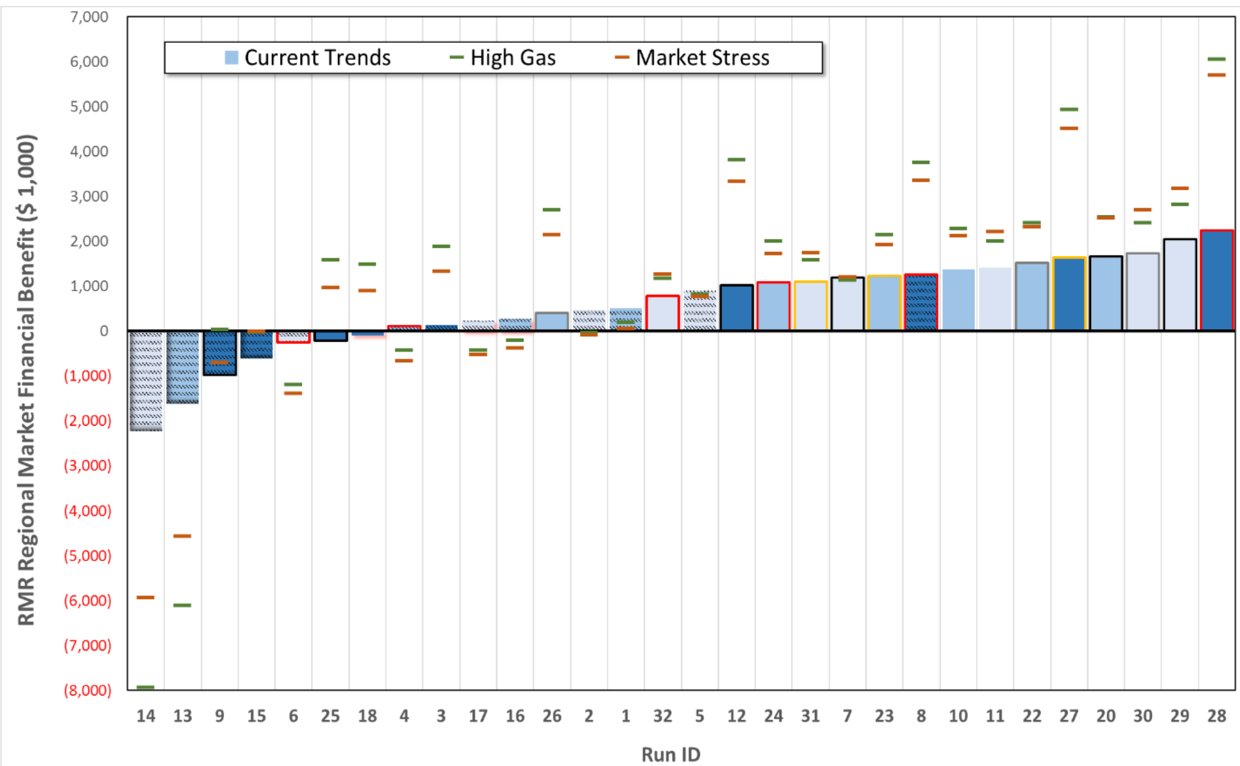
In addition to the analyses performed above many other situations were analyzed. The table below shows the bottom-line financial results of all model runs made for the LAP systems for all three futures. More financial details associated with each situation are provided in the report for the Status Quo, High Gas, and Market Stress futures in Attachments A, B, and C, respectively. Note that figures in the attachment are associated with each line in the table below via the Run ID and by future. Excluding the Brattle Benchmark (Run ID 19) that is technically incorrect but included in this analysis for benchmarking purposes, financial net benefits under the Regional Market case range from a gain of $6.06 million (Run ID 28) to a loss of $7.94 million (Run ID 14).

Regional Market Price Benefits ($1,000)

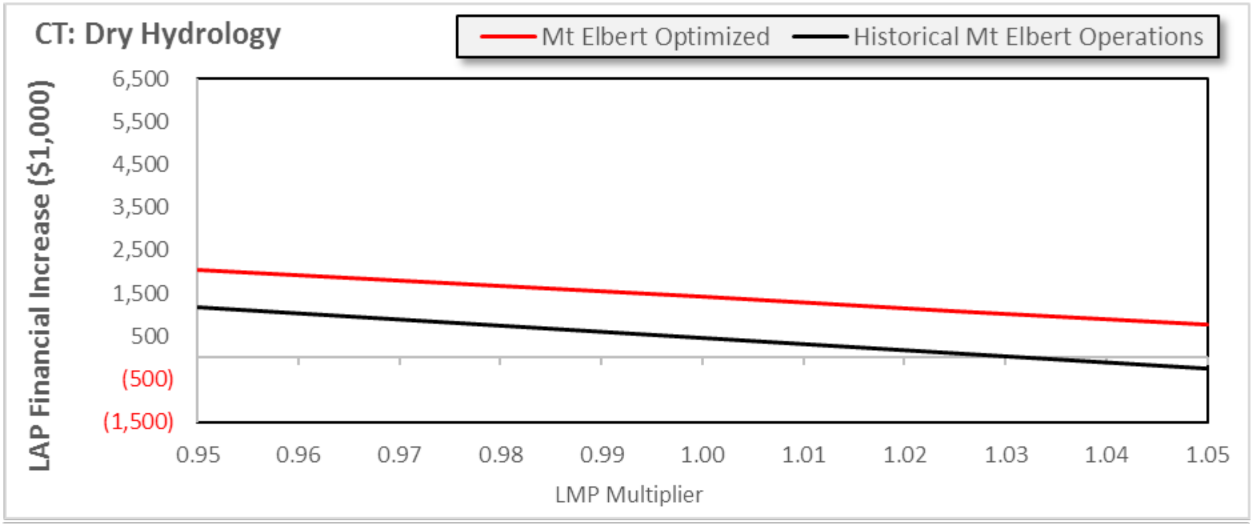
Run ID	Hydropower Condition	Mt. Elbert Flex	MWTG Losses	Only Pay MEC	Bid Adj Factor	Current Trends	High Gas Price	Market Stress		
19	**Ave/Dry for MS**	**Full**	**Brattle Loads**	**No**	**1.000**	**1,479**	**2,159**	**2,235**	**Brattle Benchmark**	
16	Average	None	5.00%	No	1.000	271	(201)	(376)	**Higher Transmission Losses**	**Static 2011 Mt Elbert Operations**
17	Dry	None	5.00%	No	1.000	232	(426)	(520)		
18	Wet	None	5.00%	No	1.000	(93)	1,501	904		
13	Average	None	4.50%	Yes	1.000	(1,618)	(6,099)	(4,571)	**Pay Only MEC**	
14	Dry	None	4.50%	Yes	1.000	(2,223)	**(7,935)**	(5,931)		
15	Wet	None	4.50%	Yes	1.000	(609)	(18)	(10)		
7	Dry	None	4.50%	No	0.950	1,189	1,135	1,206	**Offer Sensitivity: Dry Hydro**	
2	Dry	None	4.50%	No	1.000	470	(26)	(88)		
6	Dry	None	4.50%	No	1.050	(249)	(1,188)	(1,383)		
5	Average	None	4.50%	No	0.950	909	825	770	**Offer Sensitivity: Ave Hydro**	
1-Ref Pnt	Ave/Dry for MS	***None***	***4.50%***	***No***	***1.000***	***509***	***198***	***56***		
4	Average	None	4.50%	No	1.050	109	(429)	(659)		
9	Wet	None	4.50%	No	0.950	(972)	29	(702)	**Offer Sensitivity: Wet Hydro**	
3	Wet	None	4.50%	No	1.000	144	1,896	1,332		
8	Wet	None	4.50%	No	1.050	1,260	3,762	3,365		
29	Dry	Full	4.50%	No	0.950	2,046	2,828	3,178	**Offer Sensitivity: Dry Hydro**	**Fully Optimized Mt Elbert Operations**
30	Dry	Full	4.50%	No	0.975	1,730	2,416	2,701		
11	Dry	Full	4.50%	No	1.000	1,414	2,003	2,225		
31	Dry	Full	4.50%	No	1.025	1,098	1,591	1,749		
32	Dry	Full	4.50%	No	1.050	782	1,178	1,273		
20	Average	Full	4.50%	No	0.950	1,671	2,553	2,516	**Offer Sensitivity: Average Hydro**	
22	Average	Full	4.50%	No	0.975	1,526	2,418	2,320		
10	Average	Full	4.50%	No	1.000	1,381	2,283	2,124		
23	Average	Full	4.50%	No	1.025	1,237	2,147	1,928		
24	Average	Full	4.50%	No	1.050	1,092	2,012	1,732		
25	Wet	Full	4.50%	No	0.950	(209)	1,594	976	**Offer Sensitivity: Wet Hydro**	
26	Wet	Full	4.50%	No	0.975	405	2,709	2,157		
12	Wet	Full	4.50%	No	1.000	1,020	3,824	3,338		
27	Wet	Full	4.50%	No	1.025	1,634	4,940	4,519		
28	Wet	Full	4.50%	No	1.050	2,248	**6,055**	5,700		
21	Average	A Hist/C Full	4.50%	No	1.000	2,825	7,485	6,619	**High Bookend Mt Albert**	

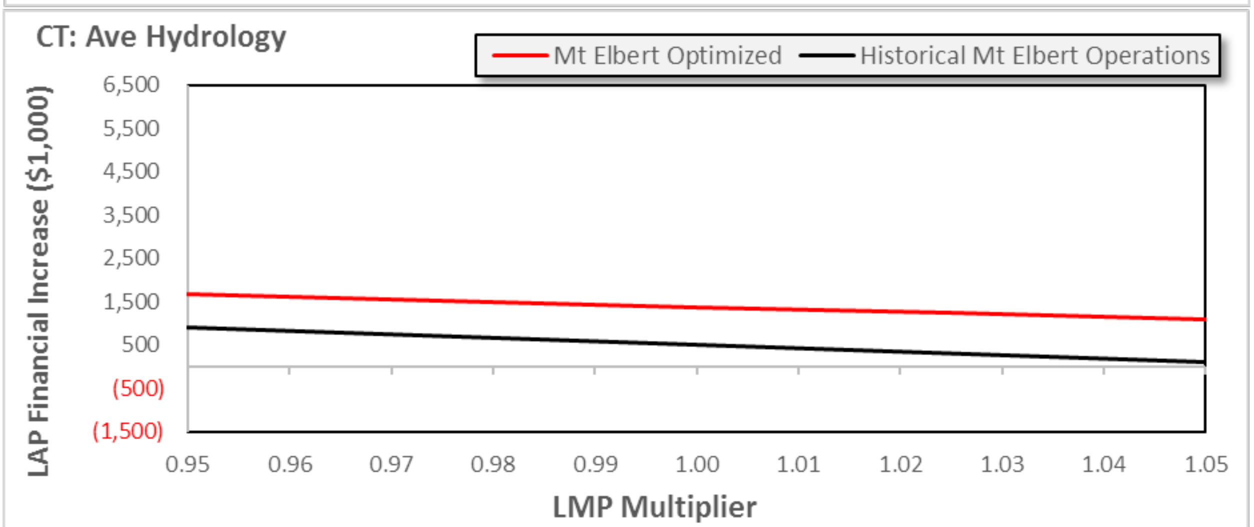
The highest benefit occurs under when LMPs are high due to the high natural gas prices and a 1.05 price multiplier in combination with wet hydropower conditions and operational flexibility at Mt. Elbert. This allows RMR to sell excess LAP energy at a high price while minimizing energy purchases to serve FES load. At the other end of the spectrum, LAP would experience a lowest financial position if it only pays the MEC for energy short positions under dry hydropower conditions and has no operational flexibility at Mt Elbert in the HG future.

These same results are also depicted in the graph below. Results shown in graph are sorted from lowest benefit to highest benefit under the CT future (bars). The color of the bars convey the hydropower condition whereby light blue is the dry hydropower condition and dark blue depict wet conditions. Bars that contain rows of hash marks are for situations that assume there is no operational flexibility at Mt. Elbert. Outlines of the bars show model results when LMP multiplier were applied in the analysis. Yellow and red outlines are for multipliers of 1.025 and 1.050, respectively, and gray and black outlines are for multipliers of 0.975 and 0.95, respectively. Bars with dark interior shading (Run IDs 13, 14, and 15) represent situations in which RMR pays only the MEC at FES load buses for energy short positions. Lastly, a red shadow (Run IDs 16, 17, and 18) represent situations that assume higher transmission losses of 5.0 percent compared to all other runs that assume a 4.5 percent transmission loss.



The figures below show the relationship between LMP multipliers and financial benefits of a centralized RTO market under a range of hydropower conditions and futures. It also shows the additional benefits that could potentially be achieved with high operational flexibility at Mt. Elbert.


CT: Dry Hydrology
Mt Elbert Optimized
Historical Mt Elbert Operations
LAP Financial Increase ($1,000)
6,500
5,500
4,500
3,500
2,500
1,500
500
(500)
(1,500)
0.95
0.96
0.97
0.98
0.99
1.00
1.01
1.02
1.03
1.04
1.05
LMP Multiplier


CT: Ave Hydrology
Mt Elbert Optimized
Historical Mt Elbert Operations
LAP Financial Increase ($1,000)
6,500
5,500
4,500
3,500
2,500
1,500
500
(500)
(1,500)
0.95
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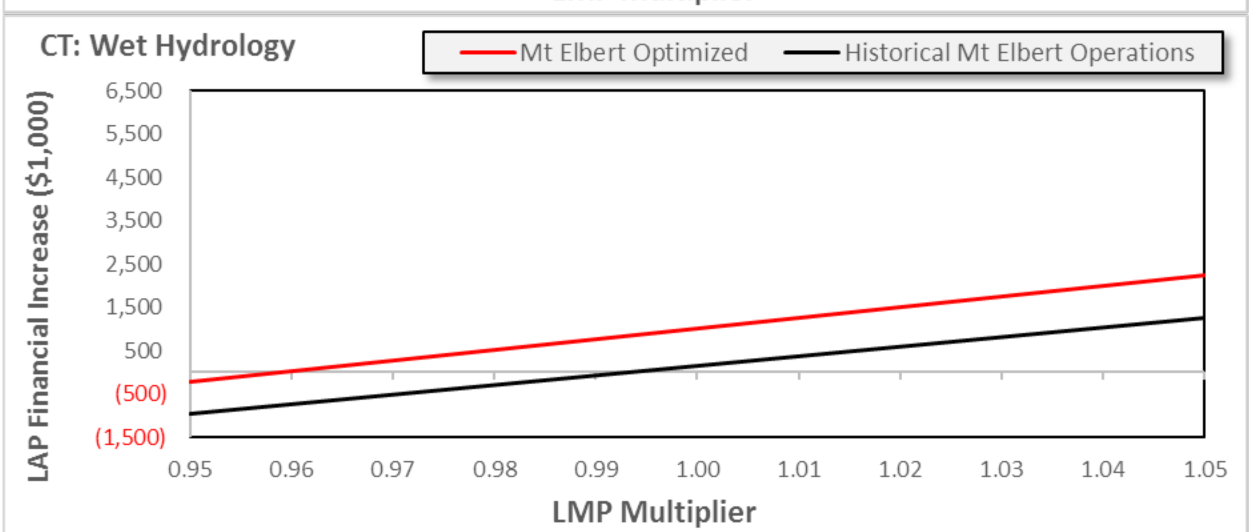
0.98
0.99
1.00
1.01
1.02
1.03
1.04
1.05
LMP Multiplier


CT: Wet Hydrology
Mt Elbert Optimized
Historical Mt Elbert Operations
LAP Financial Increase ($1,000)
6,500
5,500
4,500
3,500
2,500
1,500
500
(500)
(1,500)
0.95
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1.00
1.01
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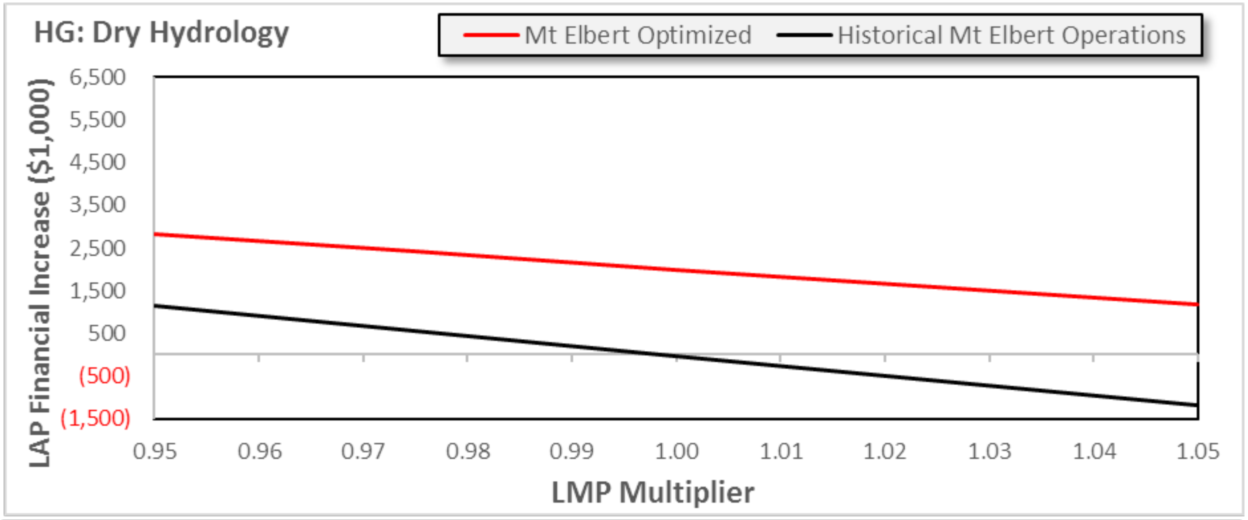
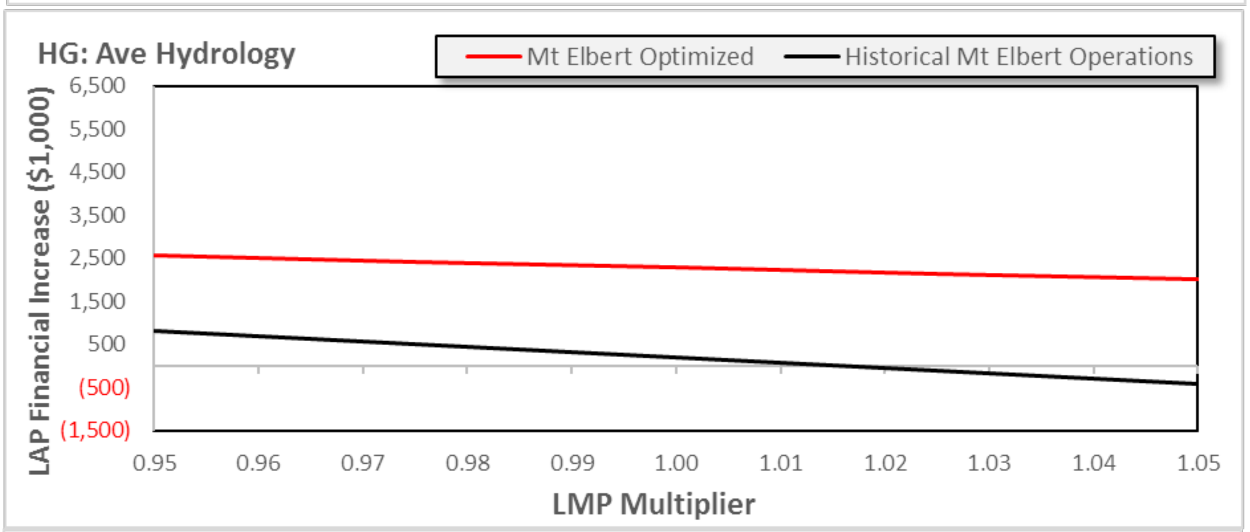
1.03
1.04
1.05
LMP Multiplier


HG: Dry Hydrology
Mt Elbert Optimized
Historical Mt Elbert Operations
6,500
5,500
4,500
3,500
2,500
1,500
500
(500)
(1,500)
LAP Financial Increase ($1,000)
0.95
0.96
0.97
0.98
0.99
1.00
1.01
1.02
1.03
1.04
1.05
LMP Multiplier


HG: Ave Hydrology
Mt Elbert Optimized
Historical Mt Elbert Operations
6,500
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4,500
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(1,500)
LAP Financial Increase ($1,000)
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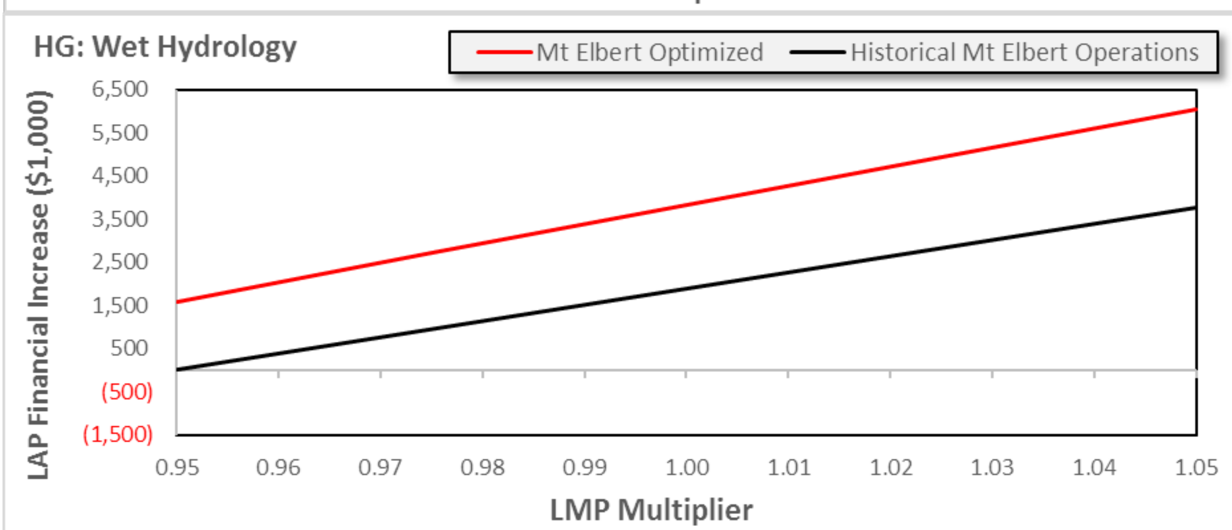
1.04
1.05
LMP Multiplier


HG: Wet Hydrology
Mt Elbert Optimized
Historical Mt Elbert Operations
6,500
5,500
4,500
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LAP Financial Increase ($1,000)
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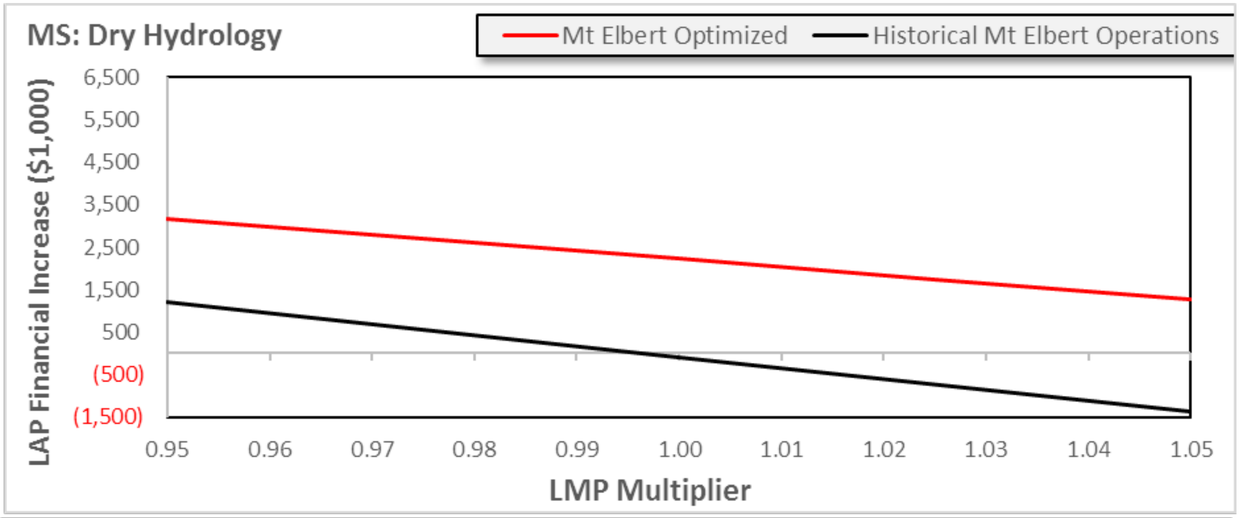
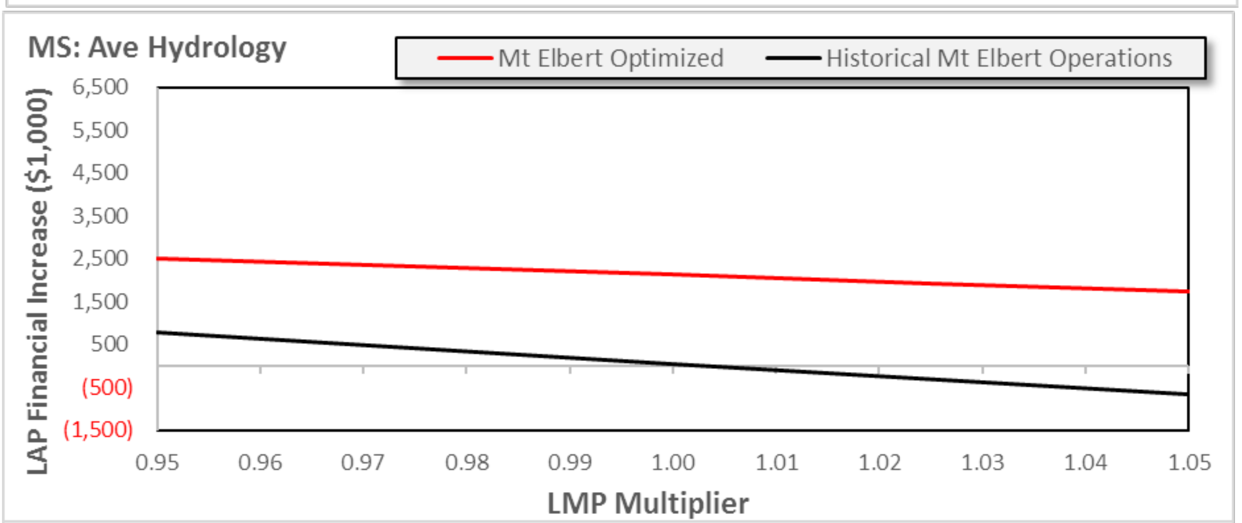
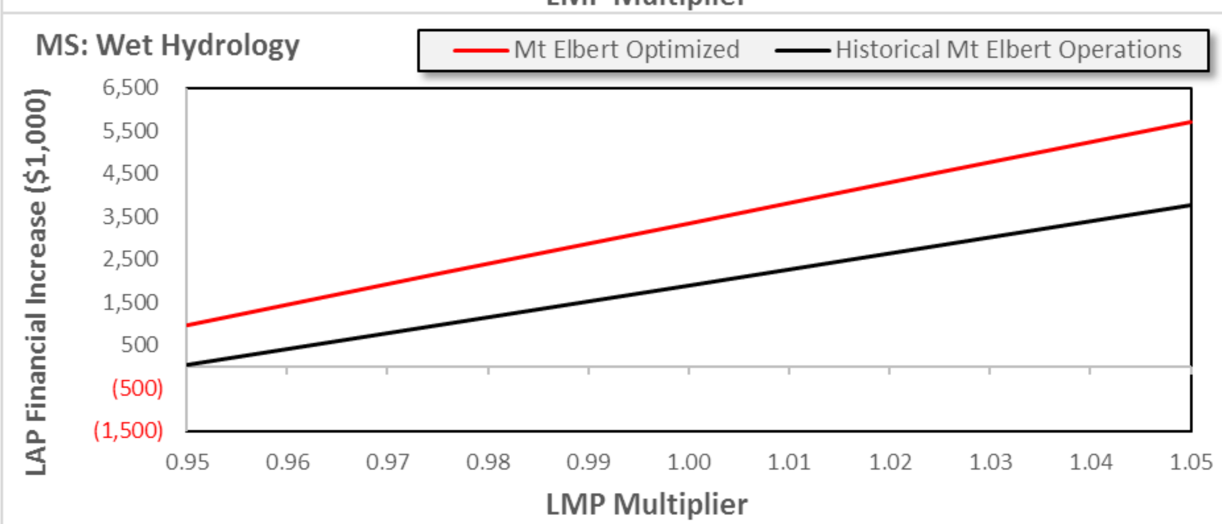
1.05
LMP Multiplier







After LAP model runs had been completed and the second draft of this report had been written, inaccuracies were discovered in the basic methodology that Brattle used and Argonne followed to compute LAP and CRSP Regional Market financial impacts. Argonne with guidance from LAP staff therefore made improvements to the LAP Financial spreadsheet in order to estimate the effect of these improvements on model results for the Current Trends future. As shown in more detail in Attachment D, general trends between the two model results and the financial benefit ranking of model runs are very similar. Based on this comparison, LAP staff concluded that differences between the revised results and those described above are not large enough to warrant a rewrite of LAP results, but were significant enough to merit mentioning and documenting with the attachment. Because CRSP model results were not yet documented when modeling improvements were identified, CRSP results presented in the main body of this report reflect the improved methodology.

LAP Capacity Utilization and Ancillary Service at Yellowtail

The Brattle methodology assumes that operations at all LAP hydropower plants other than Mt. Elbert are assumed identical under both the Status Quo and Regional Market cases. This assumption does not allow LAP hydropower plants to utilize capacity that would no longer be needed to provide the Western Area Colorado-Missouri (WACM) balancing authority area (BAA) with ancillary services under Regional Market cases. To estimate the additional LAP financial benefits associated with this "freed-up" capacity, LAP schedulers created two hourly generation profiles under identical average hydropower conditions. The first schedule assumed that the Yellowtail Powerplant would provide all BAA ancillary services. In the second schedule, no ancillary services were required at the Yellowtail Powerplant. The assumption that all ancillary services would be provided by Yellowtail under the Status Quo case is a modeling simplification. The error associated with this simplification was judged to be small because historically most of the time all ancillary services have been carried at Yellowtail. The only other LAP powerplant that is occasionally called upon to provide ancillary services is Mt. Elbert.

Because the simulation year is 2024, it is assumed that Yellowtail rewinds/upgrades would be completed by that year increasing the powerplant capacity by about 10 MW. These plant improvements were assumed to occur under both with and without ancillary services cases. The difference in the computed revenues under the two generation schedules provides a rough approximation of LAP financial gains associated with freed-up ancillary service capacity under the Regional Market Case.

Schedules created by LAP experts were primarily driven by LMP vectors at Yellowtail as projected by Brattle for the Regional Market Case under the Current Trends future. Schedules not only included generation production but also hourly water release schedules. Under the Status Quo Case special attention was paid to not only reserving sufficient capacity for serving ancillary services, but also for ensuring that both reservoir and afterbay operational criteria would not be violated in the event that spinning reserves would need to be deployed. Water releases were identical under both cases; however, generation levels differed because scheduling points affect the operational efficiency of powerplant operations. In additional, water is sometimes spilled at Yellowtail in order to provide ancillary services.

Based on current day-ahead market scheduling practices, typically hourly Yellowtail release/generation profiles were created for a typical week each month under both cases for a total of 24 weekly profiles. Profiles were produced using current scheduling spreadsheet tools. Given these generation profiles, Argonne staff calculated financial savings for LAP using Brattle LMP projections at Yellowtail under the Current Trends future. Weekly financial results were scaled to monthly values taking into account the number of day types (i.e., Sat, Sun, Mon, etc.) that will occur in the year 2024. Holidays however were not considered in either the creation of weekly Yellowtail schedules or financial calculations because it would have resulted in inconsistent water release quantities between the two cases.

Monthly results are shown in the table below. Note that about 63% of the annual savings is projected to occur in the month of June. During this month, water releases are at a high point and the powerplant is either fully or nearly fully utilized much of the time. This leaves little available capacity to provide ancillary services if all water releases produce energy. Generation schedules must therefore be dialed back by releasing some water through the plants bypass tubes in order to have adequate generating capacity to provide regulation-up services and if needed to deploy spinning reserves. The June savings is therefore primarily due the elimination of non-power water releases under the without ancillary services (Without AS) case. Note that the lower table shows that about 41.1 GWh more energy is produced under the without ancillary services case.

Financial Value ($1,000)

	With AS	Without AS	Change
Jan	1,415	1,476	**61**
Feb	1,321	1,400	**79**
Mar	1,477	1,609	**133**
Apr	1,673	1,734	**61**
May	2,340	2,381	**41**
Jun	3,170	4,073	**904**
Jul	3,048	3,107	**59**
Aug	2,083	2,089	**6**
Sep	1,779	1,789	**10**
Oct	1,413	1,456	**42**
Nov	1,547	1,567	**20**
Dec	1,388	1,399	**11**
Annual	**22,653**	**24,080**	**1,427**

Generation (GWh)

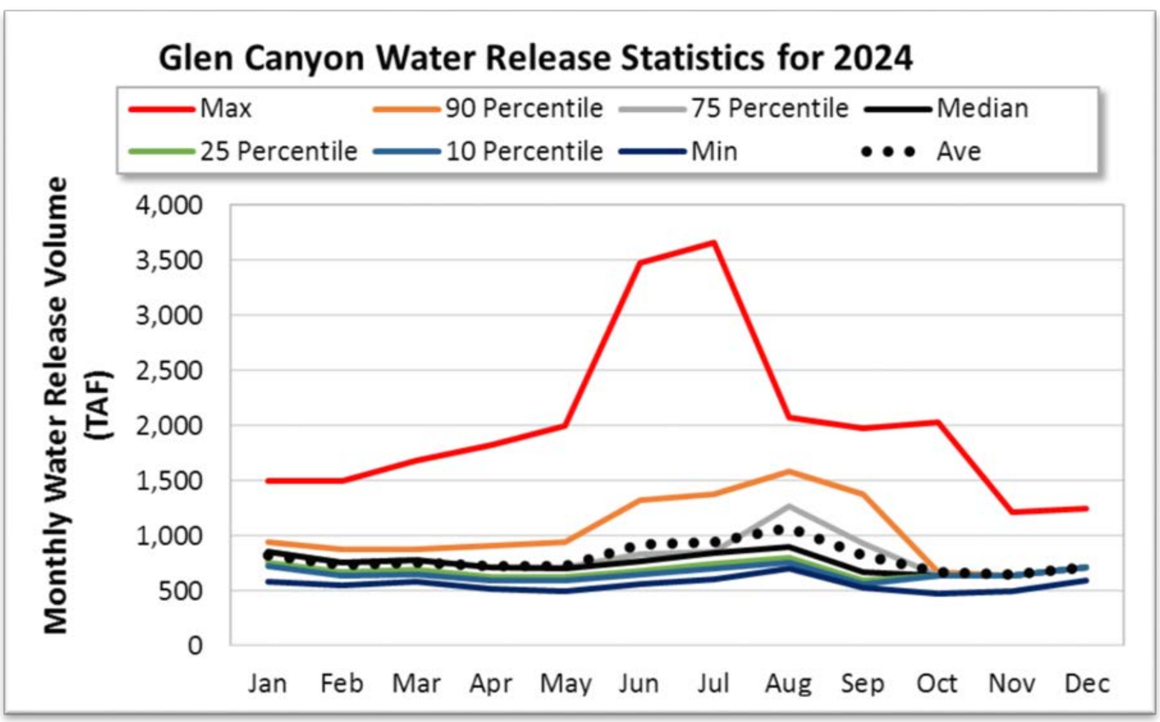
	With AS	Without AS	Change
Jan	54.2	54.4	**0.2**
Feb	50.0	50.2	**0.2**
Mar	60.9	60.6	**-0.4**
Apr	76.3	76.5	**0.1**
May	116.6	116.8	**0.2**
Jun	151.2	192.7	**41.5**
Jul	122.2	122.4	**0.2**
Aug	77.0	76.1	**-1.0**
Sep	62.5	62.5	**0.0**
Oct	53.5	53.5	**0.0**
Nov	60.7	60.6	**0.0**
Dec	48.7	48.7	**0.1**
Annual	**933.7**	**974.9**	**41.1**

Colorado River Storage Project Financial Results

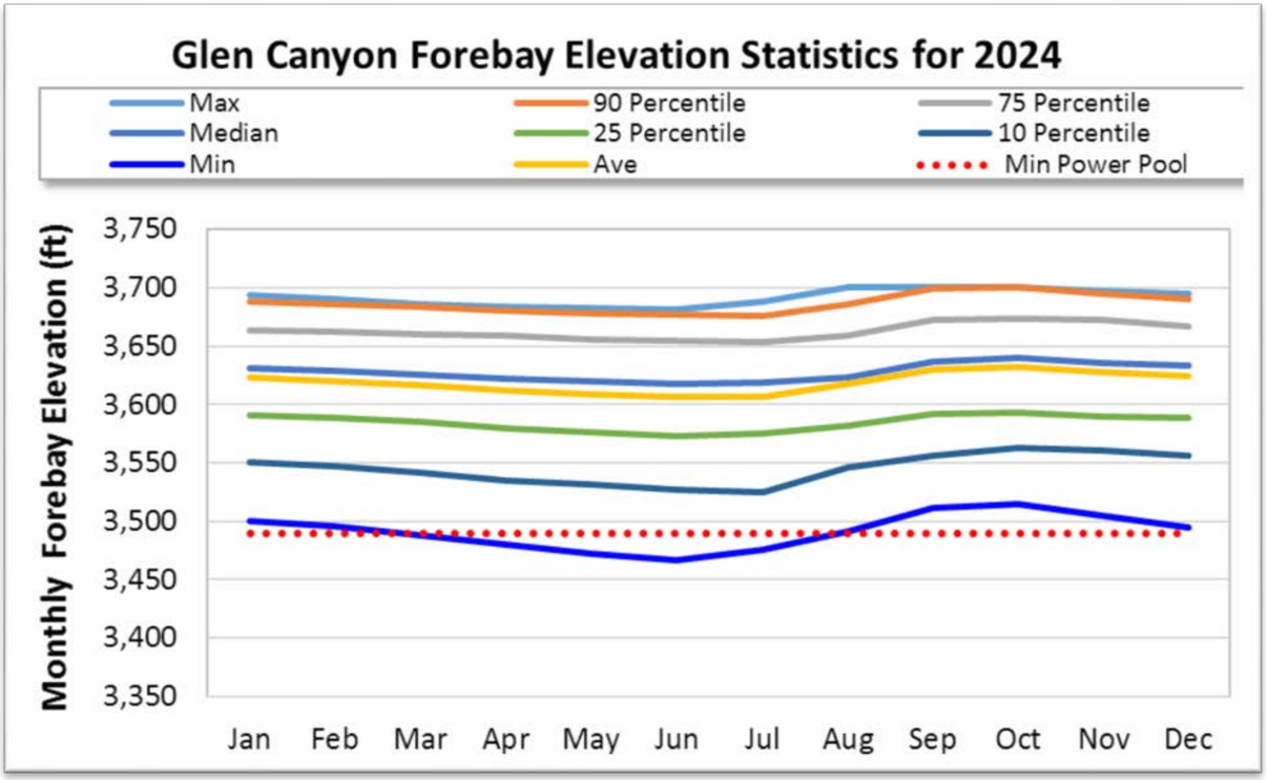
Argonne estimated CRSP financial impacts for three major business processes conducted by the CRSP EMMO located in Montrose, Colorado. These business processes include (1) SLCA/IP hydropower plant generation scheduling/operations, (2) the Salt River Project (SRP) interchange and (3) existing (a.k.a, grandfathered) transmission agreements. Results of these analyses as driven by SLCA/IP hydrological conditions and market prices are provided below.

CRSS Model Traces and AHP Offers

The financial impacts of the Regional Market case relative to the current bilateral market structure are highly influenced by hydrological conditions. CRSP financial estimates were therefore computed for all 105 hydrological traces projected by the CRSS model for the year 2024. These traces display a wide-range of potential outcome in terms of both the amount of water stored in the large SLCA/IP reservoirs as reflected in forebay elevations and dam monthly water release volumes. For example, the graph below shows CRSS monthly water release projection statistics for the Glen Canyon Dam. During the month of August, water release volumes are projected to vary by more than a factor of six. The smallest water release among all 105 traces is 603 thousand-acre-feet (TAF) and the highest release is 3,658 TAF; that is, an August water release volume range of 3,055 TAF. In contrast, the range of projected CRSS monthly water release volumes in December is 650 TAF. It ranges from a low of 600 TAF to a high of 1,250 TAF; that is, by a factor of slightly more than two. It should also be noted that on average Glen Canyon Dam monthly water releases are the highest during the peak summer months of July and August.



Reservoir forebay elevations are also projected to vary by trace and month. The figure below shows that the Glen Canyon Dam forebay elevation (a.k.a, Lake Powell water elevation) is projected to vary between 3,467 ft to 3,700 ft; that is a range about 233 ft. The forebay elevation affects the power conversion efficiency of the plant such that a higher reservoir elevation translates into more energy produced per AF of water released through powerplant turbines as compared to a lower elevation. The reservoir elevation also effects that capacity of the power plant. In a few extreme instances the CRSS water elevation in Lake Powell is projected to dip below the minimum Glen Canyon Dam power pool level. When this occurs the powerplant produces no energy and has zero capacity.



The Glen Canyon Dam accounts for about 80 percent of the total SLCA/IP hydropower resource. CRSS summary statistics for larger SLCA/IP hydropower plants that include Fontenelle, Flaming Gorge, Blue Mesa, Morrow Point, and Crystal are provided in Attachment E.

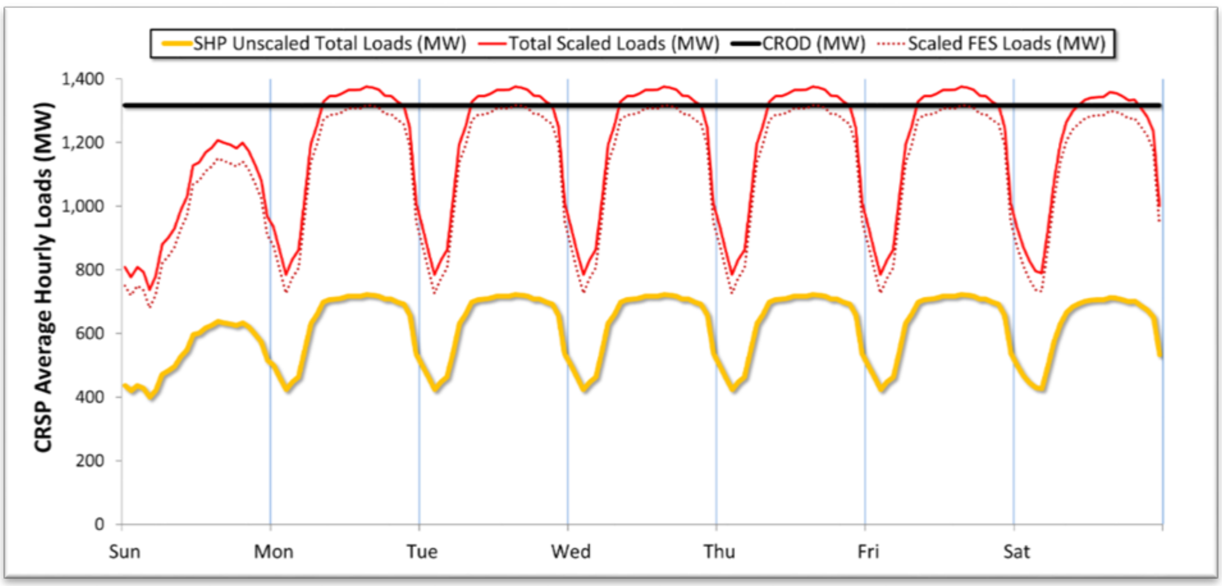
Under all hydrological traces, it is expected that the forebay elevation at all five of these powerplants will be above the minimum power pool level during calendar year 2024. Smaller SLCA/IP hydropower power plants are not included in the CRSS model. Future 2024 operations of these small hydropower plants are based on historical operations as recorded on form PO&M-59.

As explained previously in the CRSP methodology section, under many of the hydrological futures projected by CRSS, the CRSP Office will have excess SLCA/IP capacity and/or energy above SHP contract levels that, at its discretion, may be offered to its FES customers as seasonal AHP. These offers impact FES hourly firm loads that are input into the GTMax Superlite model and, therefore, computations of CRSP financial positions. The table below shows the monthly amount of AHP that will be offered to FES customers as a percentage of SHP. Note that table values are color coded such that the larger offers have a darker red shading. Note that the table spans an 18-month period over three water seasons between calendar months October 2023 and April 2025. This is 6 months longer than the analysis period (i.e., calendar year 2024). The longer analysis period is necessary because AHP is offered on a seasonal basis. It was therefore necessary to analyze all water-year seasons that affect calendar year 2024.

	Winter WY2024						Summer WY2024						Winter YR2025					
Trace	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
0	0	0	0	0	0	0	59	56	91	78	79	100	0	0	0	0	0	0
1	0	0	0	0	0	0	10	21	18	20	70	45	0	0	0	0	0	0
2	0	0	0	0	0	0	54	50	82	78	79	89	0	0	0	0	0	0
3	0	0	0	0	0	0	55	60	98	78	79	107	0	0	0	0	0	0
4	16	5	0	24	41	42	57	40	52	44	71	55	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	48	68	98	78	79	107	0	0	0	0	0	0
7	33	21	13	36	53	26	81	103	98	78	79	107	34	28	13	24	41	0
8	0	0	0	0	0	0	8	27	98	78	79	97	0	0	0	0	0	0
9	0	0	0	0	0	0	40	24	70	78	79	107	39	34	15	8	11	0
10	0	0	0	0	0	0	0	0	49	46	47	37	0	0	0	0	0	0
11	0	0	0	0	0	0	5	8	20	19	51	40	0	0	0	0	0	0
12	0	0	0	0	0	0	25	31	31	27	75	54	0	0	0	0	0	0
13	0	0	0	0	0	0	39	36	66	74	79	107	35	30	13	5	14	0
14	55	50	33	28	16	5	20	18	98	78	79	91	0	0	0	0	0	0
15	0	0	0	0	0	0	42	36	98	78	79	107	58	46	26	0	0	0
16	0	0	0	0	0	0	37	35	33	24	50	21	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	0	0	0	0	0	0	54	45	49	24	61	48	0	0	0	0	0	0
30	0	0	0	0	0	0	16	13	26	23	28	13	0	0	0	0	0	0
31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	0	0	0	0	0	0	58	56	90	78	79	94	0	0	0	0	0	0
36	0	0	0	0	0	0	10	15	32	28	30	16	0	0	0	0	0	0
37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	0	0	0	0	0	0	11	11	30	31	28	14	0	0	0	0	0	0
39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
44	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
45	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
46	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
49	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
52	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
56	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
62	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
64	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
66	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
67	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
69	0	0	0	0	0	0	15	9	18	29	37	22	0	0	0	0	0	0
70	1	0	1	63	64	83	106	111	98	78	79	107	90	31	0	30	58	50
71	90	4	0	32	35	24	51	53	98	78	79	104	0	0	0	0	0	0
72	0	0	0	0	0	0	27	77	98	78	79	107	80	79	60	4	4	2
73	77	77	58	0	21	13	33	38	98	46	74	57	0	0	0	0	0	0
74	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
76	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
80	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
83	0	0	0	0	0	0	12	12	38	33	33	19	0	0	0	0	0	0
84	0	0	0	0	0	0	23	17	45	49	79	106	0	0	0	0	0	0
85	0	0	0	0	0	0	32	23	52	44	79	65	0	0	0	0	0	0
86	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
89	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
90	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
92	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
93	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
94	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
96	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
97	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
99	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
100	0	0	0	0	0	0	60	48	98	78	79	107	0	0	0	0	0	0
101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
102	0	0	0	0	0	0	28	44	98	78	79	107	44	3	0	4	6	12
103	0	0	0	0	0	0	92	75	44	12	79	64	0	0	0	0	0	0
104	0	0	0	0	0	0	30	30	46	52	79	70	0	0	0	0	0	0

During months that have a value of zero in the table all customers are only offered SHP capacity and energy. This situation occurs most of the time. A value of 100 percent however translates into a doubling of the amount of offered energy and capacity that FES customers are offered; that is, twice the SHP level. It is assumed that all capacity and energy offered by the CRSP Office will be accepted by FES customers.

These same percentages in the table are used to scale typical FES loads. The figure below shows hourly load scaling for CRSS trace number 6 during the month of June 2024. The yellow line shows total CRSP loads under drier hydropower conditions (i.e., zero table entries for June) that include both SHP FES loads and project use loads. Using a scaler of about 85 percent, the highest scaled FES customer load is 1,217.8 MW. This level is equal to the summer CROD. The total load however is somewhat larger because it also includes project use loads.

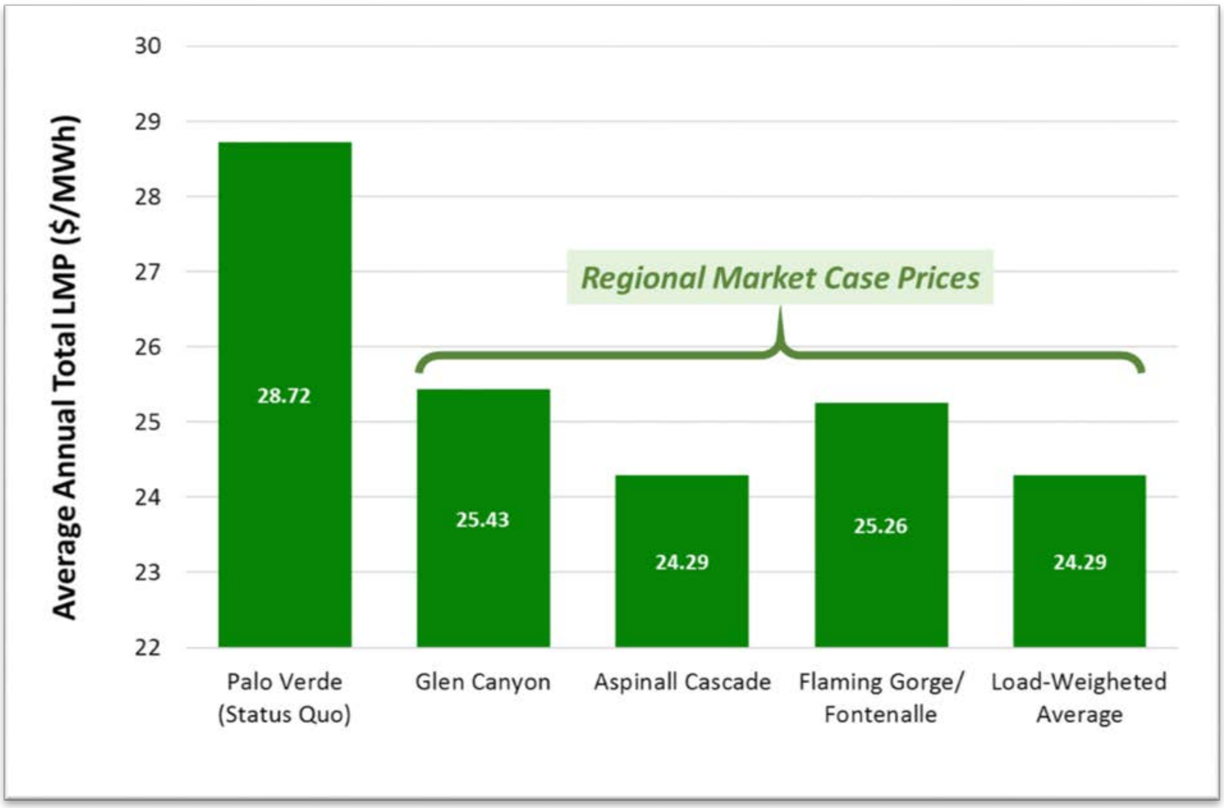


The amount of AHP energy offered to FES customers and the associated load scalers are identical under both the Status Quo and Regional Market cases. This situation arises because the AHP offer guidelines for modeling purposes only include rules related to hydrological/power conditions. Offers are therefore driven by natural hydrological conditions that do not change as a function of the market structure that CRSP operates in.

Current Trends Future: Changes in CRSP LMPs under the Regional Market case

Brattle modeling assumptions under the Regional Market case reduce energy transaction costs and relax maximum transmission flow constraints. This results in lower WI production costs, effects LMPs, and impacts CRSP finances. The graph below shows projected average annual total LMPs that the CRSP Office would be exposed to under the Current Trends future for the Status Quo and Regional Market cases in 2024. As described in the CRSP methodology section, under the Status Quo case all energy purchase and sales transactions are made at the Palo Verde LMP. On the other hand, financial calculations under the Regional Market case are based on the load-weighted average load LMP for energy purchases and on generator-weighted average LMPs for energy sales.

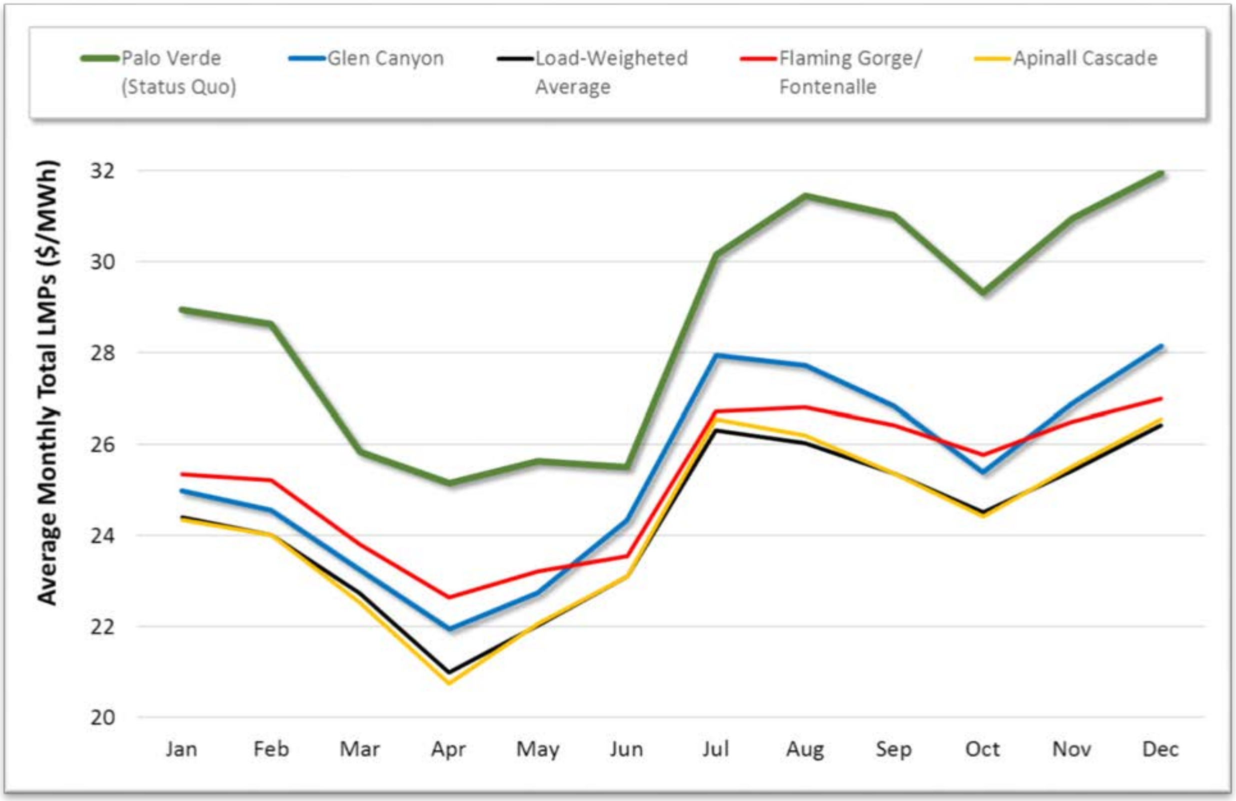
In general, when CRSP is energy long the Status Quo case yields a more favorable financial outcome because excess energy sales above loads are sold at a higher price. Note that the Status Quo Palo Verde price is $28.72/MWh as compared to Regional Market LMPs at major SLCA/IP hydropower resource that on average ranges from $24.29/MWh to $25.43/MWh[14]. The opposite occurs when CRSP is energy short because the load-weighted average LMP under the Regional Market case is $24.29/MWh compared to the Status Quo Palo Verde price of $28.72/MWh. This comparison is overly simplistic because, as modeled, purchases and sales are not made using annual prices, but are based on prices that vary hourly. A more detailed look at LMPs and LMP components is therefore necessary.



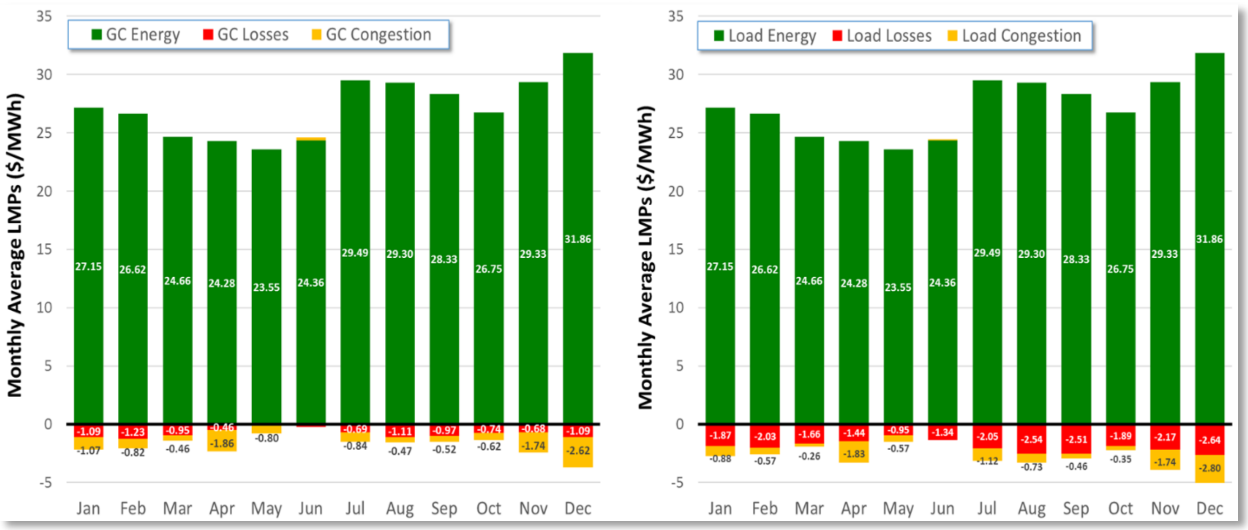
The graph below shows that average monthly LMPs for Palo Verde under the Status Quo case are always higher than both Regional Market generator-bus and load LMPs, but the price difference is not consistent. For example, the price difference between Palo Verde and the load-weighted average ranges from a low of $2.40/MWh during June to high of $5.66/MWh during September. The price difference is also relatively high during August, November, and December with differences of $5.41/MWh, $5.53/MWh, and $5.52/MWh, respectively. This is an indication that the Regional Market case may yield significantly more favorable financial outcomes in some months relative to others when CRSP is in an energy-short position. For energy sales, the LMP difference between cases indicates that higher financial gains under the Status Quo case may also vary by month. The prices spread between the Status Quo sales

[14] Brattle LMPs for Flaming Gorge and Fontenelle are identical. Monthly average LMPs at the Aspinall hydropower plants however vary within 1 to 4 cents per MWh.

price and the Regional Market LMP at Glen Canyon ranges from $1.16/MWh during June to $4.19/MWh during September.



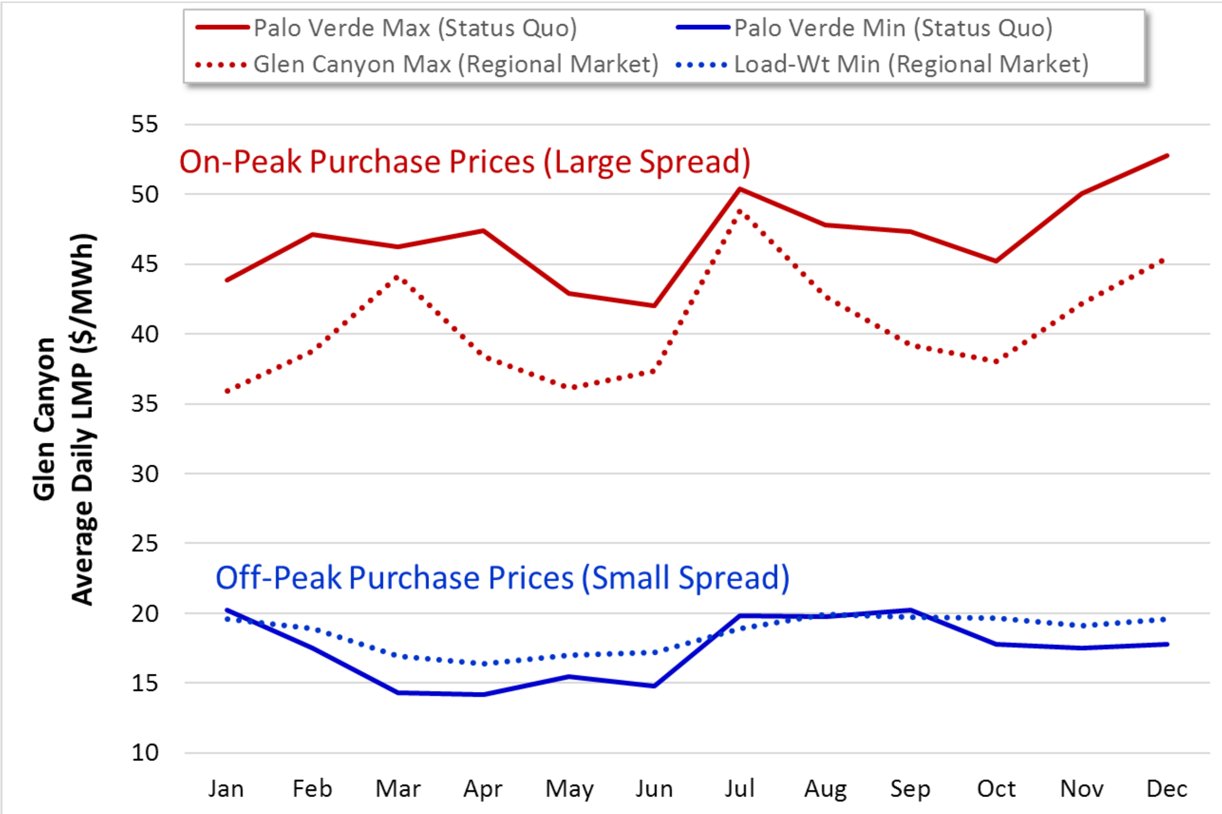
Under a Regional Market, LMPs are comprised of three components: energy, congestion, and losses. The figure below shows average monthly LMP components for Glen Canyon Dam (sales point) and for loads (purchase point). The graph shows that, on average, monthly energy prices are identical under the Regional Market case. In fact because both are located within the MWTG footprint, energy prices are identical during all hours of the 2024 study period. Only the congestion and loss components therefore vary by location. The bar chart also shows that, in general, the loss and congestion components for both are almost always negative, with larger negative values for the load-weighted average. These two components explain the difference between the blue line (Glen Canyon) and the black line (load-weighted average) in the above graph. Note that the scale in the graph above exaggerates difference relative to the bar chart.



Drilling-down deeper into LMP details provides more insights into the financial impacts of the regional market on the CRSP Office. The figure below shows monthly daily averages for Palo Verde (Status Quo purchase and sale prices), load-weighted average (Regional Market purchase price), and Glen Canyon (key Regional Market sales price). As previously mentioned, if possible, CSRP EMMO marketers sell energy during on-peak hours when prices are the highest under long energy positions and buy energy during off-peak hours when energy prices are relatively low to cover short positions.

Given the assumption that marketers "*buy low and sell high*", the red lines in the graph represent prices for on-peak energy sales under the two cases. The solid red line is the average of the daily maximum LMPs at Palo Verde over each monthly period under the Status Quo case. The red dotted line is the average daily maximum price at Glen Canyon under the Regional Market case. Based on these data, when the CRSP Office has excess on-peak energy to sell it receives a significantly higher bilateral price at Palo Verde than the Regional Market price at Glen Canyon. Note that during most months, LMPs at SLCA/IP hydropower facilities are on average lower than Glen Canyon LMPs. This further exacerbates financial losses from lower on-peak energy sales revenues under the Regional Market case.

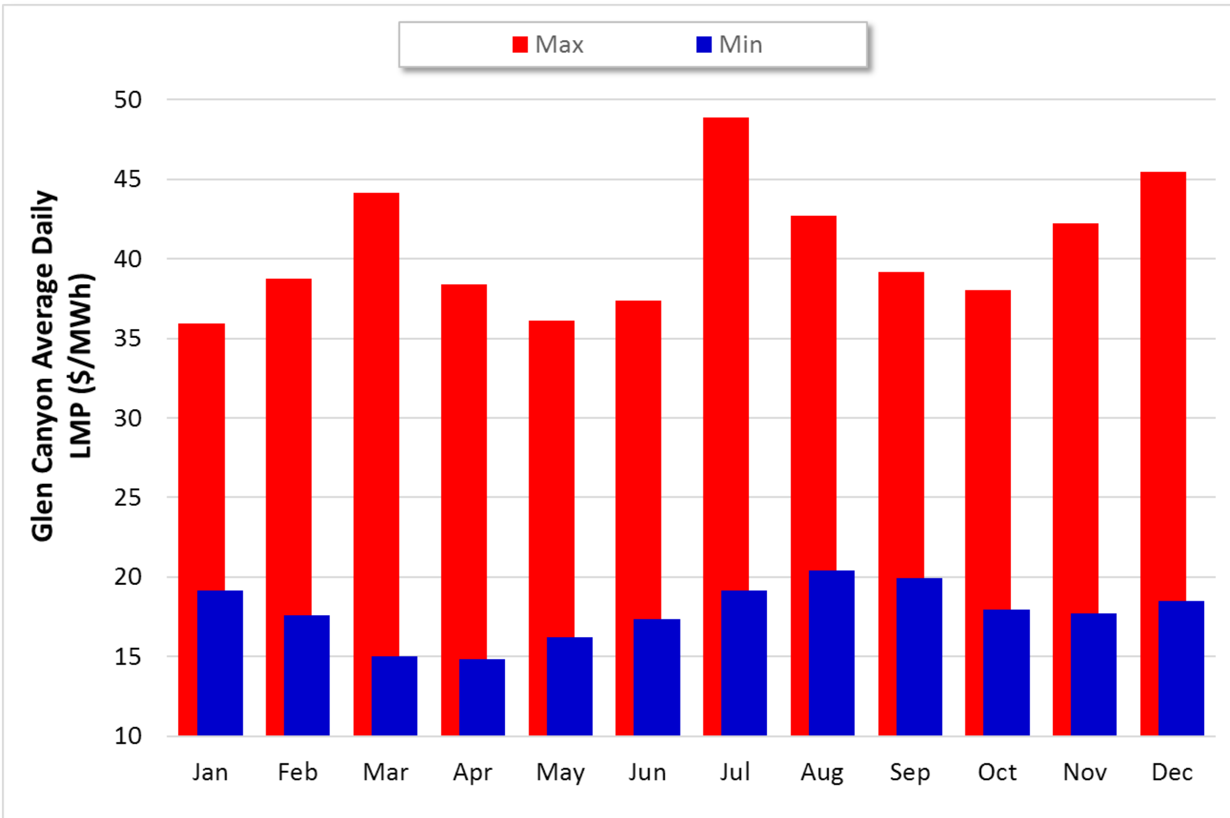
In general, LMPs under the Regional Market case are also less favorable when CRSP buys energy to cover short positions. The blue lines in the graph shows that on average LMP minimums at Palo Verde under the Regional Market case (dotted line) are either approximately the same or slightly higher (approximately $1/MWh to $2/MWh) than the Status Quo case. This in an indication that energy costs under the Regional Market case will be more expensive.



Status Quo operations place a priority on the load-following objective reducing financial gain. In this study, penalties that total $55/MWh adjust purchase and sales prices in the GTMax Superlite objective function to lower hydropower arbitrage activities; that is, purchases during one hour will not be made to increase market sales in another hour unless the objective function is increased more than $55/MWh. In contrast, SLCA/IP resources under the Regional Market case maximize revenues through price-following and hydropower arbitrage activities. These activities will help offset financial losses resulting from lower on-peak market price projections under the Regional Market case that are in general less favorable than Status Quo prices. The figure below shows wide price spreads between daily average minimum and maximum prices. This spread presents an opportunity for CRSP EMMO schedulers to reduce SLCA/IP hydropower generation to minimum allowable levels during hours with low load-weighted average LMPs and ramp up generation when generator LMPs are at a maximum. When using the price-following strategy, loads and resource imbalances would be settled by the Regional Market.

Restrictions on SLCA/IP hydropower plants operations, however, will limit hydropower shifting under the Regional Market. Except for the Upper and Lower Molina powerplants, all small SLCA/IP hydropower plants operate at a constant output level (flat-flow resources). The Fontenelle and Crystal powerplants are also flat-flow resources. Flexibility at the cascaded Molina plants is limited. These plants operate in tandem with output that is either at zero or at maximum. In addition, Molina plants only start and stop once each day. Operations at Flaming Gorge changes hourly, but as discussed previously, are restricted by Jensen gauge limits. Because it must operate with the same hourly release pattern each day, Flaming Gorge operations cannot follow evolving hourly and daily LMP patterns. Operations at the

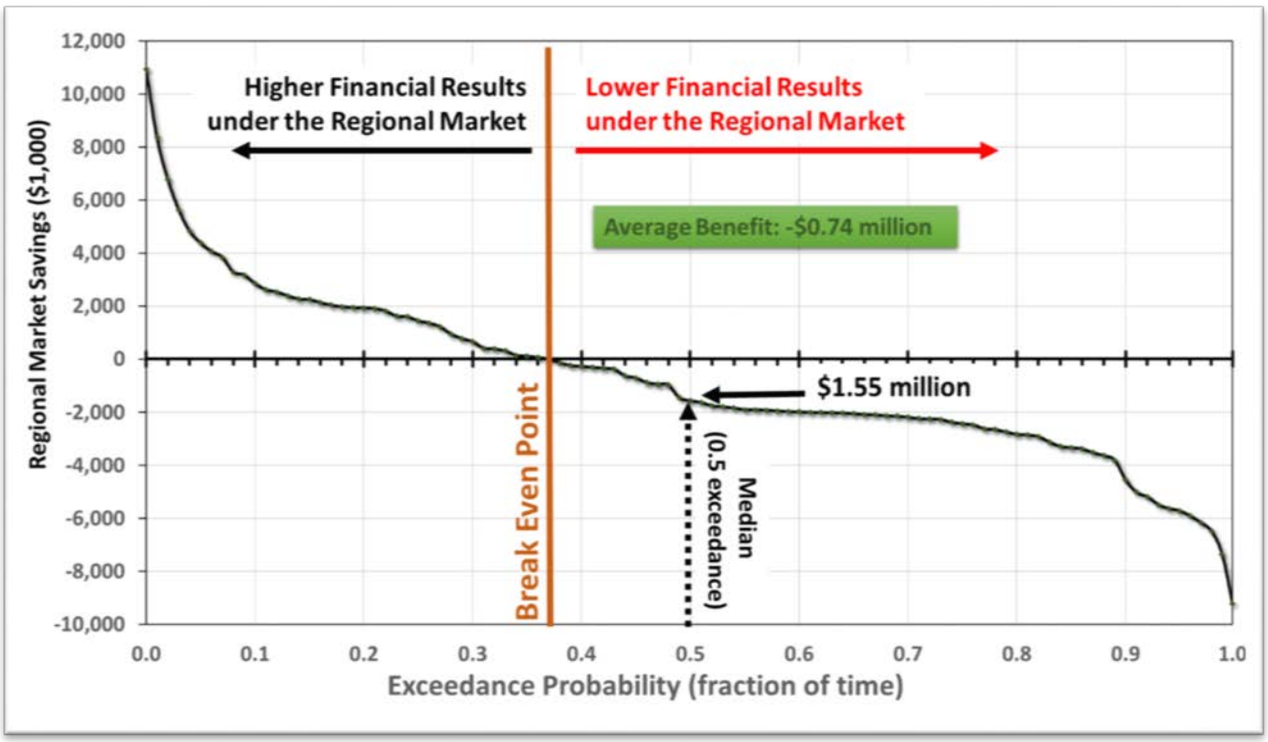
Glen Canyon are highly constrained by hourly up-ramp and down-ramp rate restrictions. It must also comply with minimum and maximum hourly flow constraints and daily change constraints. The Blue Mesa and Morrow Point powerplants have the most flexibility for taking advantage of LMP patterns. Morrow Point operations are however sometimes restricted by reservoir operating constraints in the downstream Crystal reservoir.



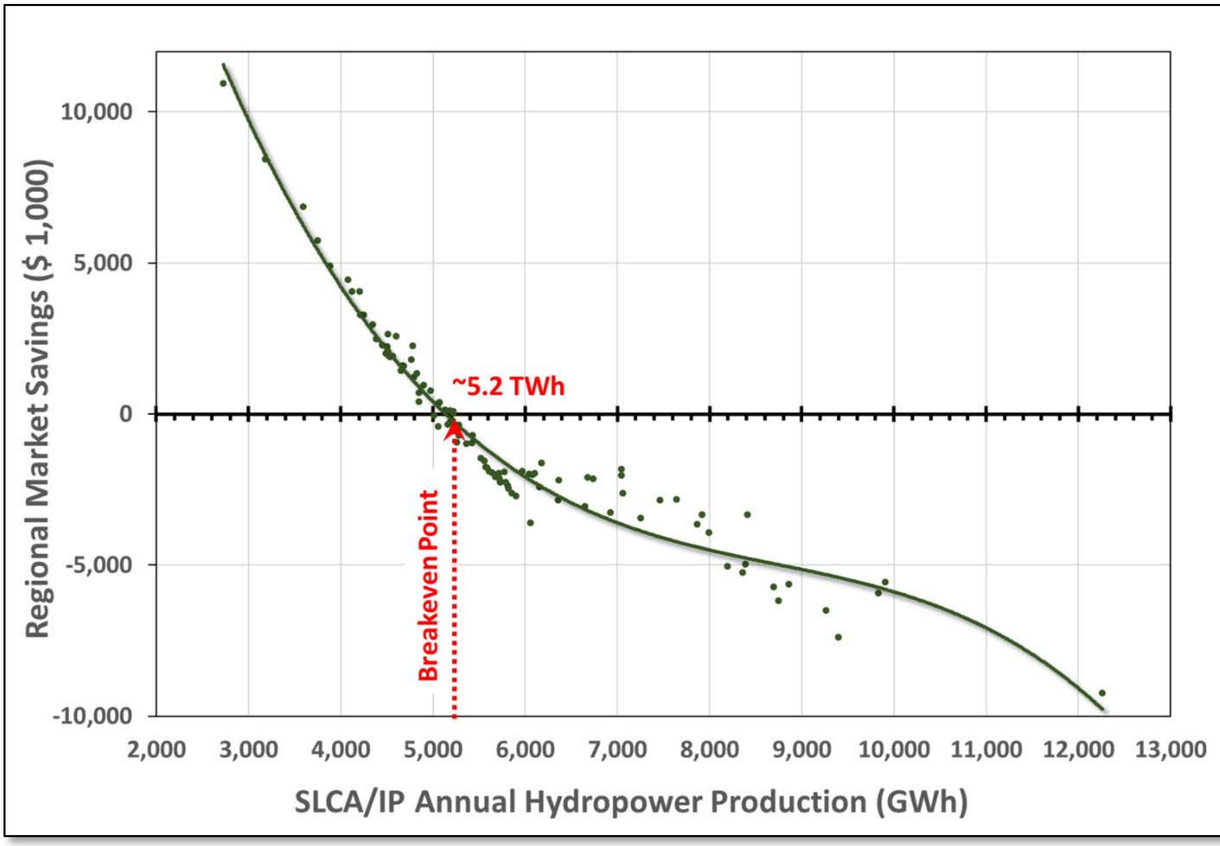
The ability for CRSP schedulers to take advantage of market opportunities under both Status Quo and Regional Market cases is dependent on many complex and intertwined factors, much of which are a function of hydrological conditions. For example, if SLCA/IP hydropower are capacity short due to low reservoir elevations, schedulers may need to purchase energy during on-peak hours when prices are high. This differs from the condition discussed above in which purchase are made when prices are relatively inexpensive. At another extreme, under high hydropower conditions, these is almost no operational flexibility under either of the market cases. The GTMax Superlite model was therefore used to optimize SLCA/IP operations throughout 2024 under 105 CRSS hydrological conditions.

Colorado River Storage Project Financial Dispatch Results for the Current Trends Case

The GTMax Superlite model was used to simulate SLCA/IP hydropower operations for all 105 CRSS hydrology projections during the 2024 study period. For the Current Trends future both market cases were optimized by GTMax Superlite. The graph below shows 2024 annual comparative results in the form of a probability exceedance curve. Comparative results are computed by subtracting Status Quo annual financial results from Regional Market financial results. The zero exceedance level shows the CRSS trace that produced the highest estimated financial benefit if the CRSP Office joined the Regional Market. This annual benefit of approximately $10.9 million is never exceeded. At the other extreme, the 1.0 exceedance level shows a negative benefit (i.e., loss) of $9.2 million. CRSP Office financial outcomes are projected to always be better than the 1.0 level. At an exceedance level of approximately 37 percent, the Regional Market and Status Quo cases yield identical results. Exceedance levels less than 37 percent result in a better CRSP financial outcome while exceedance levels greater than 37 percent show a comparative financial loss under the Regional Market case; that is, it has a worse financial outcome relative to the Status Quo case 63 percent of the time. At the 50 percent exceedance level (i.e., median value), the Regional Market case shows an annual loss of $1.55 million and on average over all 105 traces the expected loss in $0.74 million.



As previously discussed, one of the primary drivers that influences financial outcomes is the CRSP energy long or short position. This position is tightly coupled with hydrological conditions and resultant SLCA/IP energy production. The graph below shows comparative CSRP financial results under the Regional Market case as it relates to annual total SLCA/IP hydropower production. When annual generation is below approximately 5.2 terawatt (TWh) the Regional Market case has higher financial outcomes relative to the Status Quo case. Under higher hydropower conditions, it yields a lower financial outcome. The 5.2 TWh breakeven point is roughly equal to FES customer energy obligations plus project use load.

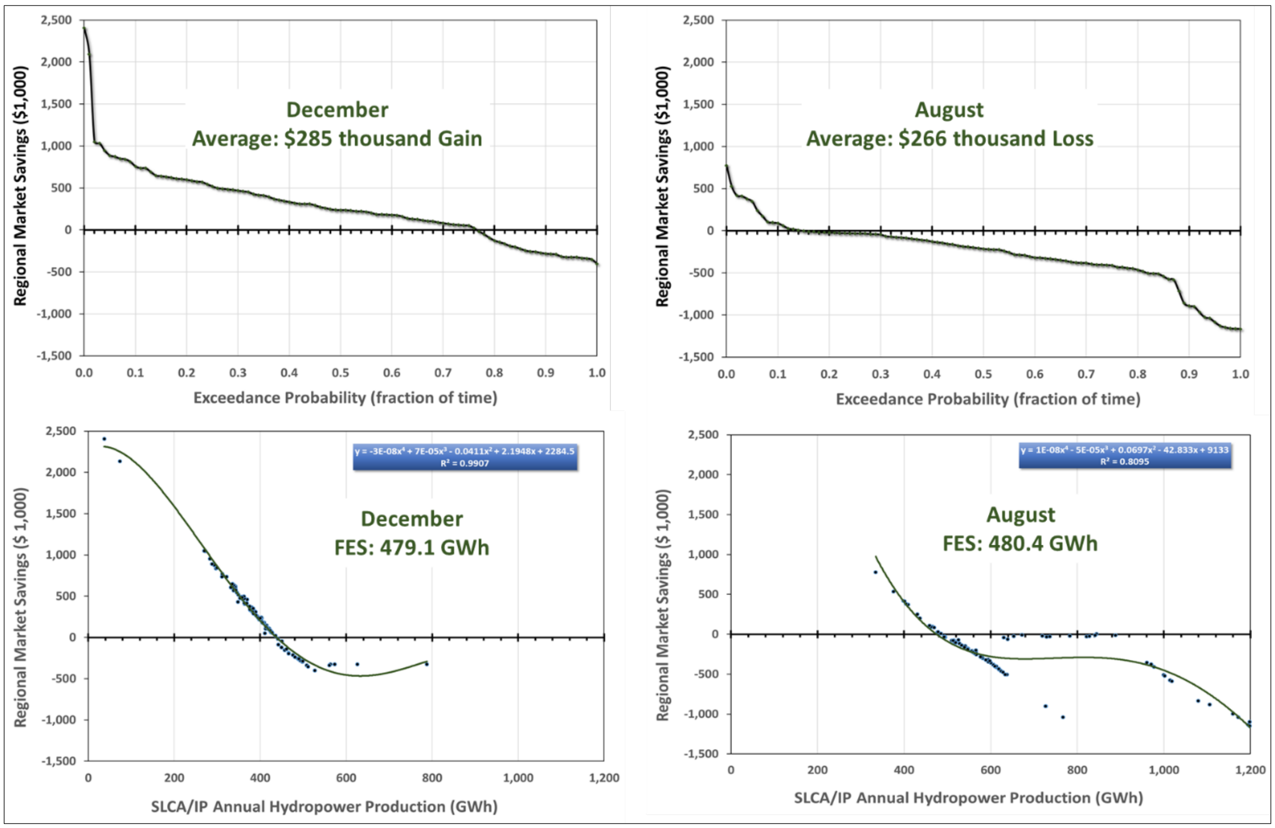


Financial exceedance curves vary significantly throughout the year. Under the Regional Market case, the winter months of November through February typically have higher financial results compared to the summer months. The graph below shows the probability exceedance curves for December and August. In December, the Regional Market case has a higher financial outcome about 77 percent of the time with an average gain of approximately $285 thousand. This gain is largely offset by losses in August which are on average $266 thousand. In August, the Regional Market case shows a positive financial benefit about 18 percent of the time.

Similar to the annual results, the impacts of Regional Market case on CRSP financial outcomes is closely correlated to SLCA/IP hydropower production. In addition, the breakeven point is roughly equal to CRSP long-term FES customer energy plus project use energy delivery obligations. In December, the two instances when SLCA/IP hydropower production is abnormally low occurs when the Lake Powell Reservoir elevation is below the minimum power pool. These two instances are also associated with highest positive financial benefits under the Regional Market case when large energy purchases are made at lower prices relative to Status Quo case prices.

During August, there are many instances when Regional Market benefits that are slightly under the zero savings line. This occurs when excess SLCA/IP hydropower energy production is offered as AHP. Note that these instances are above 568 GWh because AHP rules that require SLCA/IP seasonal energy production to be at least 20 percent higher than the SHP level before the CRSP Office makes Seasonal offers. Because energy offers are essentially capped by the summer CROD limit at very high power production levels (above 980 GWh = 1.318 GW*31 days*24 hr/day) SLCA/IP hydropower production exceeds AHP levels. Under the Regional Market case this excess is sold at a lower LMP.

There are several instances during August that do not fit the pattern resulting in a comparatively lower financial result. This occurs when there is above average energy production in August but seasonal energy does not meet the 20 percent AHP offer criteria. Excess SLCA/IP energy production during August is therefore sold at lower Regional Market case prices.

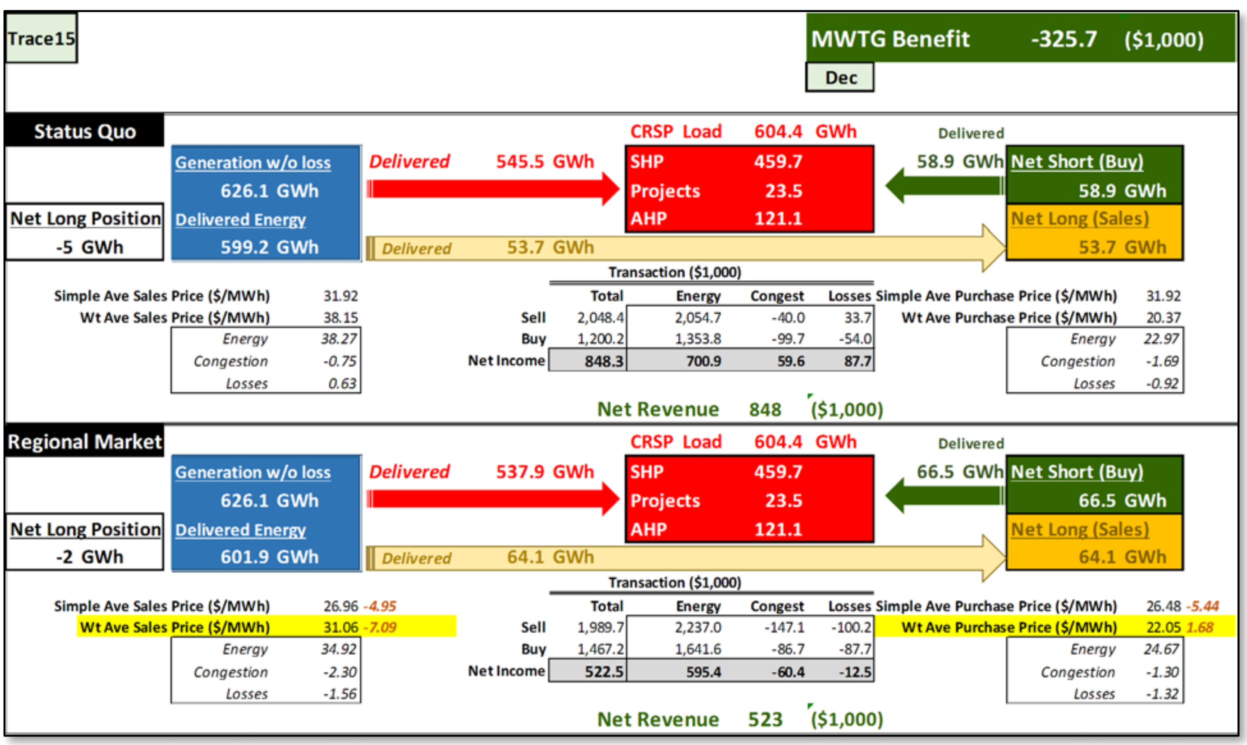


The figure below shows total monthly energy flows and average LMPs for trace 15 during December 2024. The Status Quo case is summarized in the upper half of the figure and Regional Market cases is shown in the lower half. For this CRSS trace, SLCA/IP monthly generation is 626.1 GWh under both market cases. Also under both cases, CSRP loads are identical and all of the excess SLCA/IP energy totaling 121.1 GWh is sold as AHP to CRSP FES customers. Under the Status Quo case of the 626.1 GWh of energy production only 599.2 GWh of energy was sold. This difference between these two numbers is due to transmission losses that are incurred to deliver power to CRSP load and for losses to deliver energy to the market. Although energy production is identical under both market cases note that Regional Market case energy deliveries are somewhat higher at 601.9 GWh. Under this case, energy losses are incurred for energy deliveries to the CRSP load, however, there are no losses for market sales because energy is sold at the point of production. Also note that energy deliveries to CRSP load is somewhat lower under the Regional Market case further reducing transmission losses.

Although on a monthly basis CRSP loads and SLCA/IP hydropower generation are nearly balanced, because of environmental operating criteria there are high minimum generation levels that exceed loads during the nighttime. This “forces” off-peak energy sales (long-position) when prices are typically low. It also causes energy short positions during on-peak hours because monthly production and CRSP loads are nearly identical. All of the forced off-peak energy sales must therefore be replaced by purchases during higher priced hours to balance on-peak supply and demand.

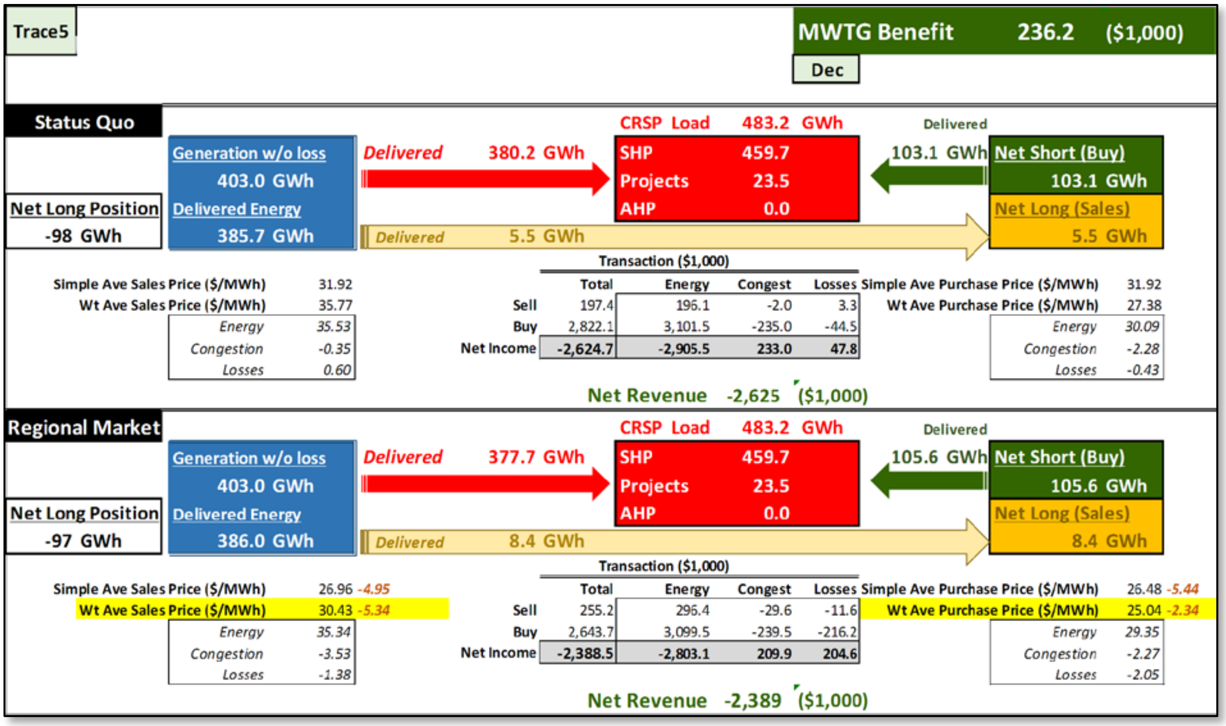
There were also a few peak price hours when CRSP energy was sold to the market under the Status Quo case. Although these on-peak energy sales could have been used to serve CRSP loads, it would have been very costly; i.e., above the load following cost threshold. The modeling of the load following objective however reduces these discretionary energy market transactions. Note that the Regional Market case, which is solely driven by prices, has significantly higher energy transactions.

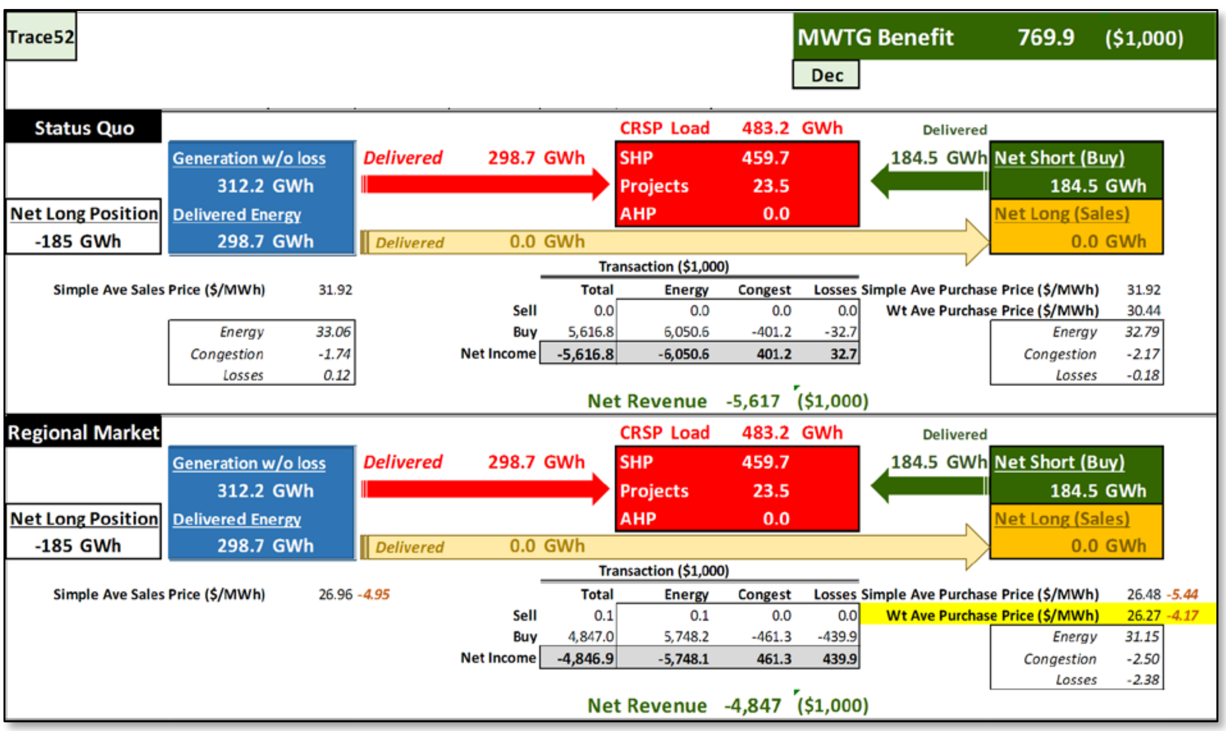
The net financial implication of the Regional Market case relative to the Status Quo case is a loss of approximately $0.326 million for CRSS trace 15 during August. This occurs because the average purchase price of $20.37/MWh under the Status Quo case is less expensive than the price of $22.05/MWh under the Regional Market case. The average energy sales price is also higher under the Status Quo case; i.e., $38.15/MWh versus $31.0/MWh. Although energy transactions under the Regional Market are higher, the larger volume is insufficient to eliminate the impacts of the price spread between purchase and sales; that is, $17.78/MWh under the Status Quo case versus $9.01/MWh under the Regional Market case. This result is also consistent with previous figures that show the Regional Market case typically has a lower CRSP financial outcome under high SLCA/IP hydropower conditions.



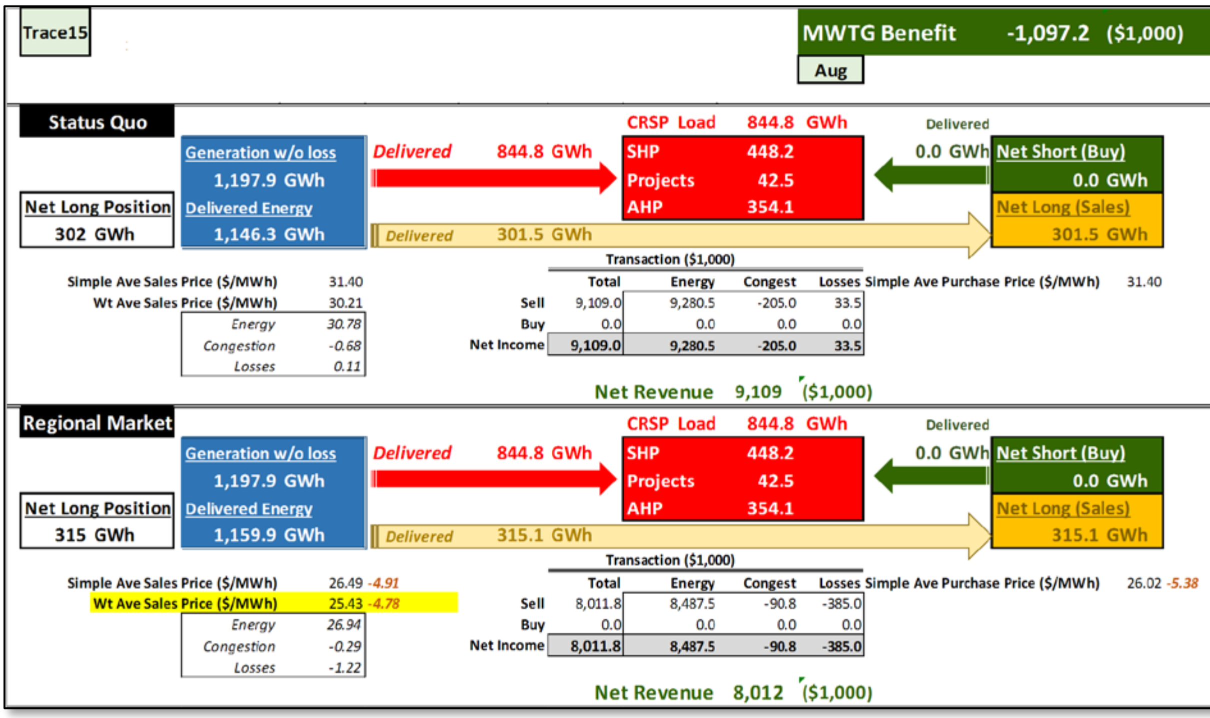
On the other hand, the Regional Market case has a higher CRSP financial outcome under low SLCA/IP hydropower conditions. The following two figures show December results for traces 5 and 52, respectively. Trace 5 has a monthly net short position of about 98 GWh and Trace 52 has a net short position of approximately 185 GWh. Because energy is short, purchases far exceed sales resulting in negative net revenue under all situations. Consistent with previous discussions, however, the lower the SLCA/IP hydropower output the higher the relative positive financial outcome of the Regional Market case; that is, net financial losses are lower under the Regional Market case. For example, under Trace 5 losses are $2.625 million under the Status Quo case but only $2.389 million under the Regional Market case; that is, a savings of $0.236 million. This savings is largely driven by a lower energy purchase price; that is, $27.38/MWh under the Status Quo case versus $25.04/MWh under the Regional Market case for a savings of $2.34/MWh. Note that although the monthly energy balance is short, there is a small amount of energy sales under both cases. Similar to the trace 15 result, this outcome is again the result of forced energy sales during the nighttime largely due to environmental operating criteria.

Under trace 52, hydropower conditions are significantly lower than trace 5. As required under CRSP long-term firm contracts, however, both the SHP and project use loads remain the same while the monthly energy short position increases to 185 GWh. Under both cases, all of the SLCA/IP energy production serves CRSP loads with no energy market sales. Note that because there are no sales to the market, transmission energy losses under both cases are identical because both assume loss rates of 4.5% for deliveries to CRSP load. The large energy-short position further increases CRSP financial losses under trace 52 relative to trace 5 while savings under the Regional Market case increase to $0.770 million. This is attributed to lower purchase costs which are $2.41/MWh cheaper under the Regional Market case compared to the Status Quo case. However, average purchase prices under trace 52 are more expensive than trace 5. For example, under the Status Quo case, it increased from $27.38/MWh under trace 5 to $30.44/MWh under trace 52; that is $3.06/MWh higher. Albeit a smaller increase, prices are $1.23/MWh higher under trace 52 under the Regional Market case. This occurs because purchase are first made during hours that have the lowest price. As purchase quantities increase, it often becomes necessary to purchase energy during hours that are more expensive.

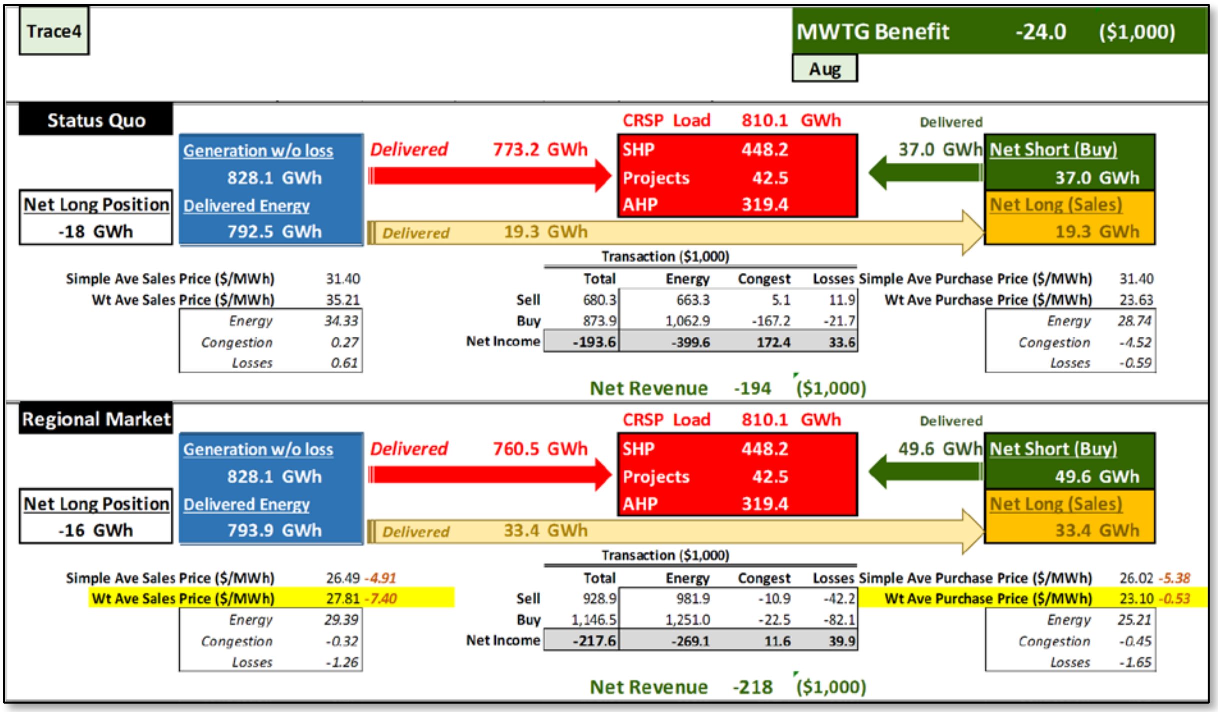




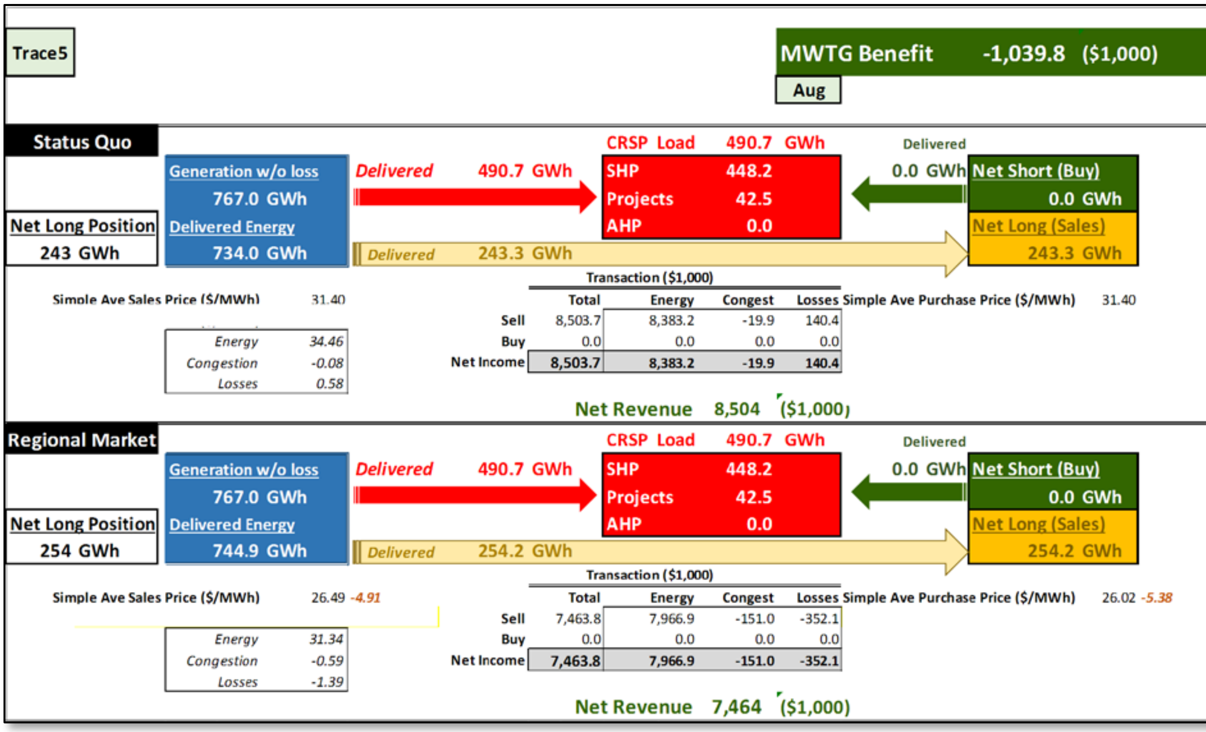
The next 4 figures illustrate Regional Market case financial impacts on the CRSP office during the peak summer month of August. The figures are ordered from highest to lowest monthly SLCA/IP hydropower production ranging from 1,197.9 GWh to 436.6 GWh. Trace 15 monthly model results shown below has very high energy production with 354.1 GWh of excess energy sold to FES customers as AHP energy. This is the highest level allowable under the AHP offer modeling process. As discussed in the methodology section AHP offers are limited by the seasonal CROD. The remaining excess energy of over 300 GWh is sold to the market. Because there are no energy purchases, the financial cost of about $1.097 million is primarily due to an average higher sales price of $30.21/MWh under the Status Quo case versus $25.43/MWh under the Regional Market case; that is on average $4.48/MWh less. One factor that slightly offsets this price difference are total market energy sales that are 13.6 GWh higher under the Regional market case. This is due to transmission losses that are incurred under the Status Quo case for deliveries of SLCA/IP energy production to a buyer. In contrast, under the Status Quo case, excess energy above FES delivery obligations is sold to the market at the point of production (i.e., generator buses).



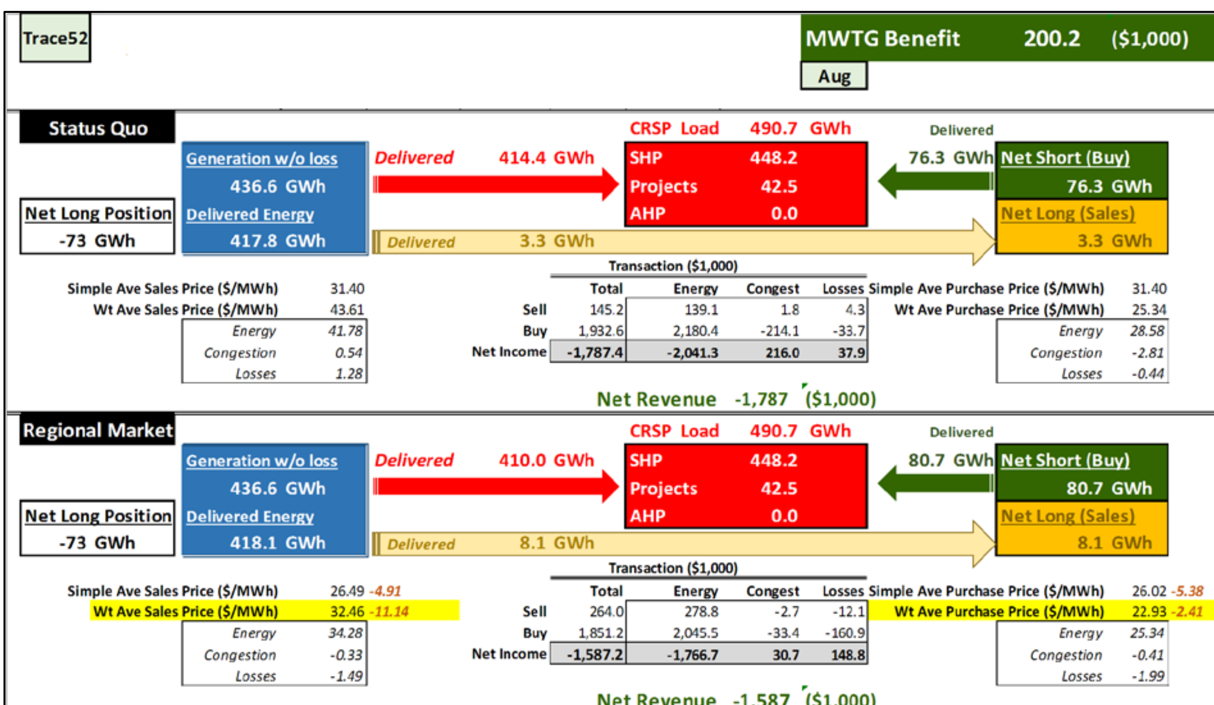
The next summertime example illustrated below is another long position, but all of the excess energy is sold to the CRSP customers as AHP energy. Under this situation, there are relatively small amounts of energy market transactions and the average purchase price differences between the two cases is only $0.53/MWh. The average sales price however is $7.40/MWh more under the Status Quo case. The result is a relative small financial cost of $0.024 million to participate in the Regional Market relative to the Status Quo case.



The graph below illustrates situations when there is excess energy, but this excess is not large enough to trigger AHP offers/sales. There are only high-price market sales under both cases. As the result of a sales price that is on average $5.60/MWh higher under the Status Quo case, net financial revenues are $1.040 million larger than under the Regional Market case. Note that energy deliveries from SLCA/IP powerplants to CRSP loads are identical, but due to transmission losses under the Status Quo case, market sales are 10.9 GWh higher under the Regional Market case.

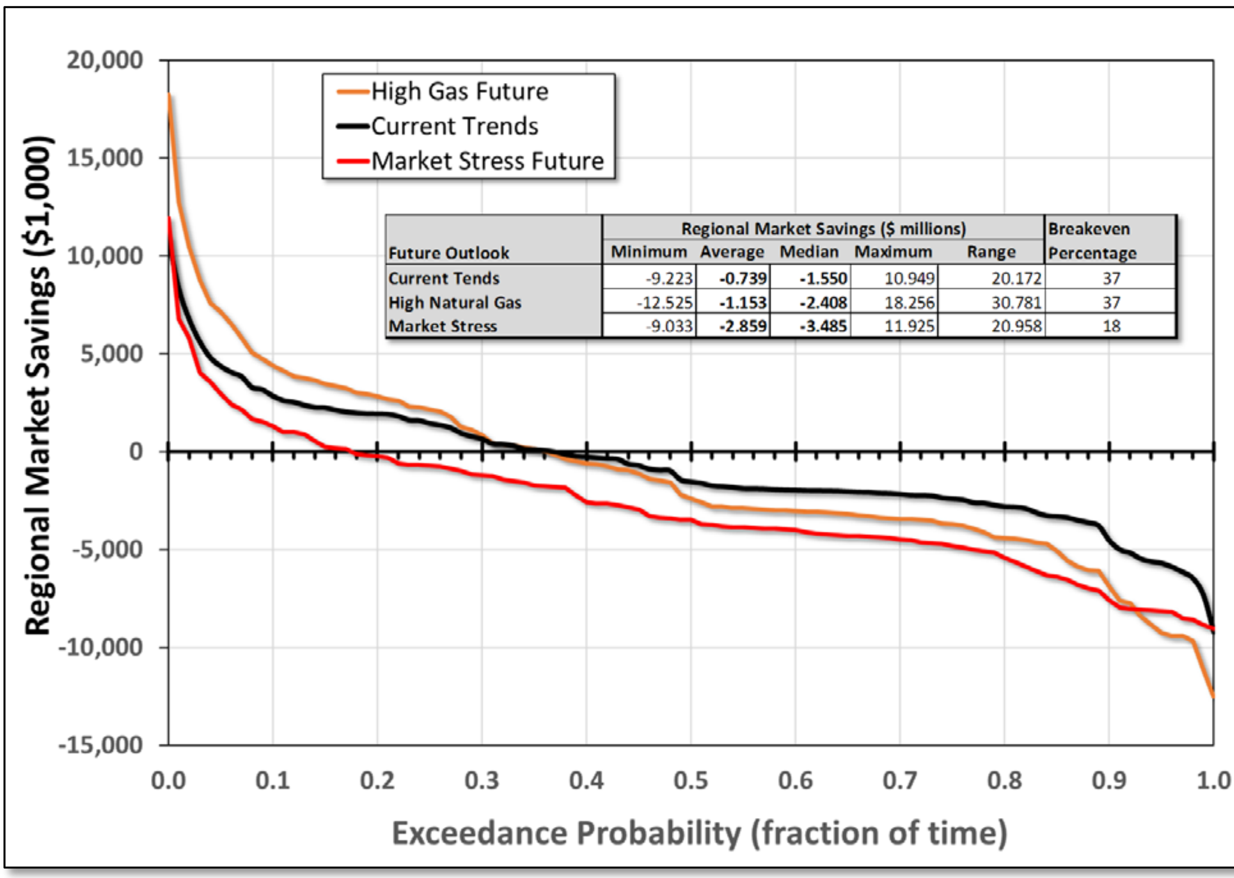


The fourth summertime figure shows that under a net energy short position of 73 GWh, the Regional Market case yields net financial revenues of about $0.2 million over the Status Quo case. This is largely attributed to an energy purchase price under a Regional Market that is $2.41/MWh lower. There are only small amounts of energy sales that are made during the highest priced hours.



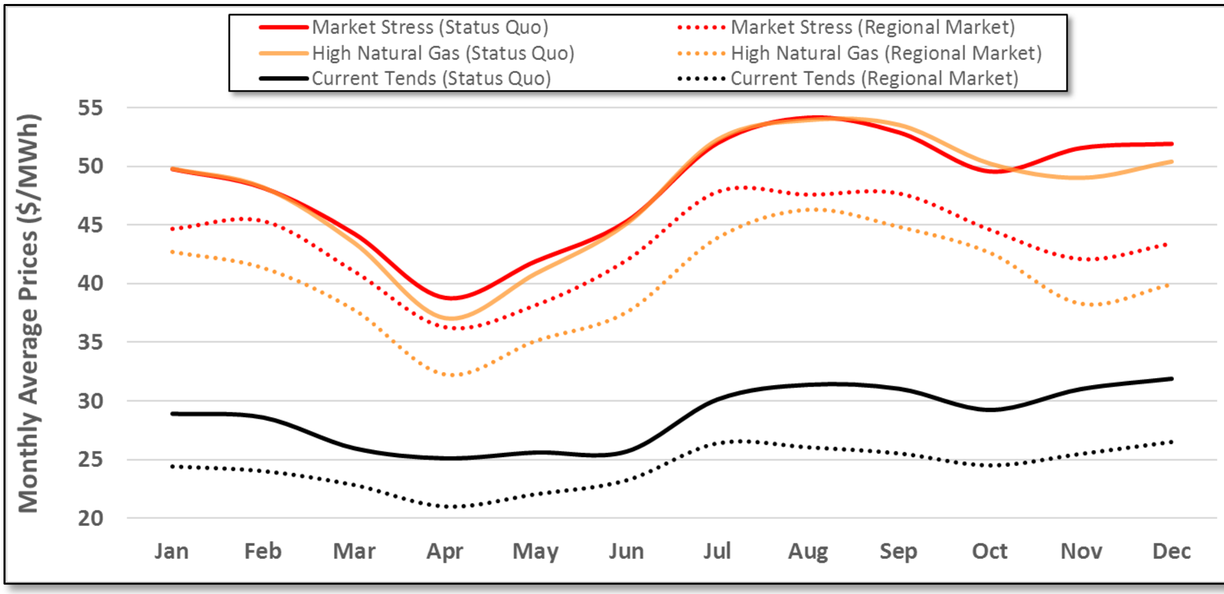
CRSP Financial Dispatch Results under the High Gas Price and Market Stress Futures

In addition to the Current Trends future, the GTMax Superlite model was also used to analyze all 105 CRSS hydrological projections for two other futures; namely, the High Gas and Market Stress outlooks. The comparative financial results (i.e., Regional Market minus Status Quo) for all three futures are shown in the figure below in probability exceedance curve. The figure also contains a table of key statistics. Note that in terms of both the average and median values all three futures indicate that the Regional Market case will result in a lower financial outcome. Also positive Regional Market outcomes occur less than half of the time. Under both the Current Trends and High Gas futures positive Regional Market outcomes are expected to occur about 37 percent of the time. This percentage drops to 18 percent of the time under the Market Stress case. The range of financial outcomes under all futures is more than $20 million.

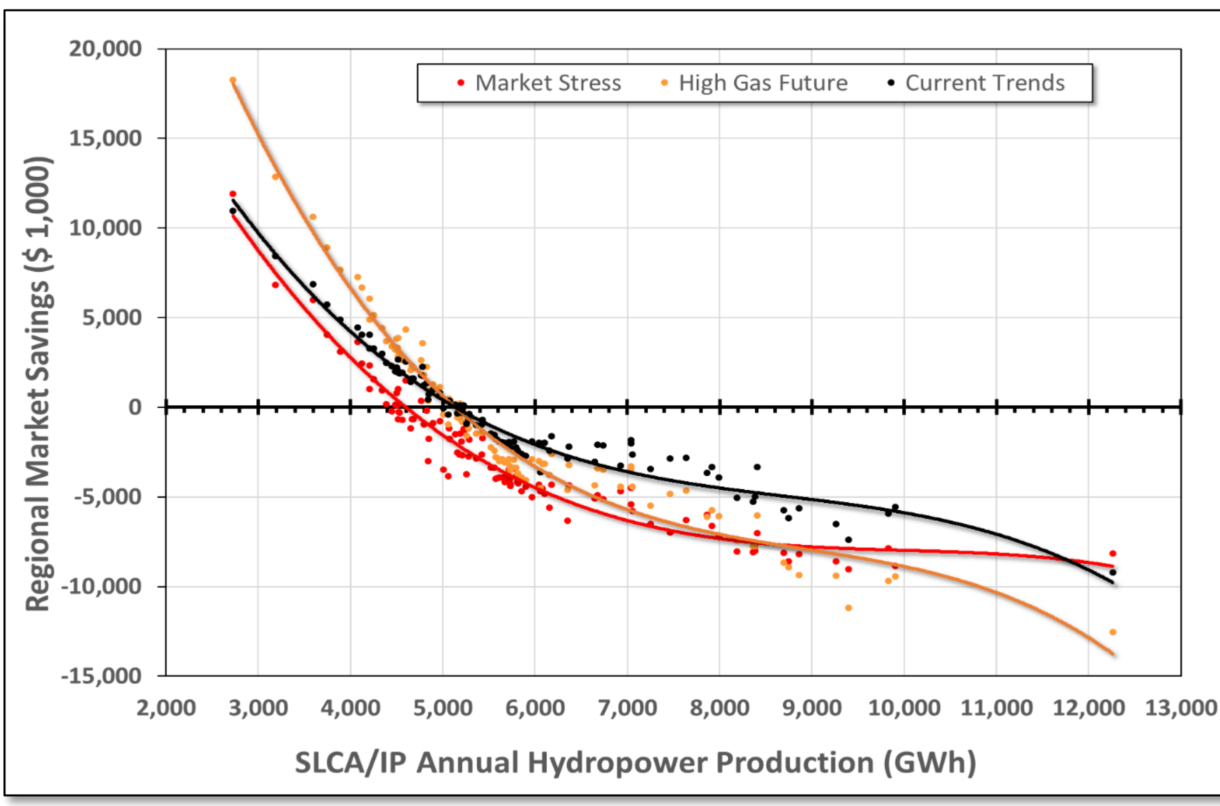


Future Outlook	Regional Market Savings ($ millions) Minimum	Average	Median	Maximum	Range	Breakeven Percentage
Current Tends	-9.223	**-0.739**	**-1.550**	10.949	20.172	37
High Natural Gas	-12.525	**-1.153**	**-2.408**	18.256	30.781	37
Market Stress	-9.033	**-2.859**	**-3.485**	11.925	20.958	18

For all CRSS traces, SLCA/IP energy production, SHP FES customer loads, AHP sales, and project use loads are identical for all three futures. The key driver that results in differences among the futures are the LMP levels and profiles projected by Brattle. The figure below shows monthly average prices for Palo Verde under the Status Quo case (solid lines) and weighted average load prices under the Regional Market case (dotted lines) for all three futures. Note that in general, prices are the most expensive for the Market stress future and the cheapest for the Current Trends future. This is consistent with the table in the figure above.



Similar to the Current, Trends future financial outcomes for the other two futures are tightly coupled with hydrological conditions and resultant SLCA/IP energy production. Note that the High Gas future is more sensitive to SLCA/IP hydropower generation level than the other two futures.



SRP Exchange Agreement and GFA Transmission Financial Benefits under the Regional Market

The financial implications of the SRP Exchange Agreement and GFA transmission contracts are based on the LMP difference between the points of energy injection and extraction multiplied by the quantity of energy exchanged/wheeled. Under the Regional Market case the CRSP Office benefits financially when the point of energy injection is more valuable (i.e., higher LMP) than the energy extraction point. On the other hand, CRSP financially losses when the injection point LMP is lower than extraction point LMP.

The SRP Exchange Agreement has two components. The first involves energy exchanges that are designed to relieve contractual transmission congestion, and the second involves the use of CRSP transmission resources to wheel power for SRP. Although the exchange terms of the SRP agreement is dependent on Glen Canyon Dam production, the total amount of energy that can be exchanged and wheeled in an hour is limited to 533 MW. For simplicity, only one financial estimate for the exchange was made based on actual data for 2015. Only one estimate is also made for GFA transmission contracts because these contracts are not dependent on SLCA/IP hydropower conditions.

The SRP Exchange and GFA transmission results presented in this below represent maximum/ near maximum financial impacts because it does not include any mitigation measures. CRSP is exploring various options that would alleviate costs associated with these agreements through various channels that are outside the scope of this analysis.

Relative to the Status Quo case, regional market financial costs associated with the SRP power exchange agreement are significantly higher than the average cost of SLCA/IP hydropower operations. Monthly financial benefits for TAGs 1X, 2X, and 4X for energy exchanges are shown in the table below. The total costs (i.e., negative benefit) for TAG 1X and 2X are \$6.15 million and \$3.00 million, respectively. Because it is assumed that CRSP New Mexico (NM) loads and SRP Four Corners (4 Corners) generation are at the same location, the financial outcomes for TAG 4X are always zero. The total financial costs of the exchange portion of the agreement is \$9.15 million. It tends to be the most costly in the summer and winter months when price spreads between energy injection and extraction points are the largest. Note that average revenue columns in the table below are quantity-weighted averages, not average price spreads.

SRP Energy Exchange Benefits under the Regional Market																	
	Net Rev ($1,000)																
	TAG 1X: GC to SRP Load					TAG 2X: Craig to CRSP North Load					TAG 4X: 4 Corners to CRSP NM Load					Total	
		Energy Price ($/MWh)					Energy Price ($/MWh)					Energy Price ($/MWh)					
		Energy In	Energy Out				Energy In	Energy Out				Energy In	Energy Out				
Month	1X SRP Exchange (GWh)	Glen Canyon LMP ($/MWh)	Pinnacle Peak LMP ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	2X SRP Exchange (GWh)	Craig	Ave WAPA Deliv Pnts	Ave Revenue ($/MWh)	Net Revenue ($1,000)	4X SRP Exchange (GWh)	Four Corners	Four Corners	Ave Revenue ($/MWh)	Net Revenue ($1,000)	Net Energy Exchange (GWh)	Net CRSP Revenue ($1,000)
Jan	237.3	24.71	27.41	-2.62	**-622.0**	192.4	23.79	25.17	-1.33	**-255.5**	57.5	25.90	25.90	0.00	**0.0**	487.2	**-877.5**
Feb	208.4	24.50	27.25	-2.46	**-513.1**	178.5	23.60	25.10	-1.34	**-239.1**	33.3	25.84	25.84	0.00	**0.0**	420.3	**-752.3**
Mar	164.2	23.28	25.73	-2.36	**-387.9**	139.8	21.88	23.52	-1.64	**-229.7**	30.9	24.13	24.13	0.00	**0.0**	334.9	**-617.6**
Apr	173.8	21.96	24.94	-2.78	**-482.5**	141.1	20.26	22.20	-1.87	**-263.4**	40.2	22.57	22.57	0.00	**0.0**	355.0	**-745.9**
May	115.1	22.69	25.56	-2.72	**-313.6**	64.1	21.56	23.20	-1.65	**-105.6**	55.0	22.92	22.92	0.00	**0.0**	234.2	**-419.2**
Jun	144.0	24.73	28.06	-3.20	**-460.7**	98.3	22.98	24.84	-1.97	**-193.1**	52.9	25.61	25.61	0.00	**0.0**	295.1	**-653.9**
Jul	192.1	28.15	31.86	-3.56	**-684.2**	127.7	26.28	28.45	-2.11	**-269.0**	72.7	29.47	29.47	0.00	**0.0**	392.5	**-953.2**
Aug	176.4	27.54	31.33	-3.79	**-668.2**	145.8	25.54	27.72	-2.17	**-315.8**	52.6	28.98	28.98	0.00	**0.0**	374.9	**-984.0**
Sep	172.6	26.78	30.14	-3.36	**-580.5**	138.8	24.93	26.92	-2.02	**-280.2**	38.4	28.11	28.11	0.00	**0.0**	349.7	**-860.7**
Oct	164.4	25.42	28.05	-2.47	**-406.2**	129.1	24.16	25.78	-1.57	**-203.1**	45.9	26.21	26.21	0.00	**0.0**	339.3	**-609.3**
Nov	182.8	26.69	29.19	-2.14	**-391.9**	165.8	24.76	26.63	-1.72	**-285.1**	21.3	27.72	27.72	0.00	**0.0**	369.9	**-677.0**
Dec	253.0	28.33	31.06	-2.53	**-639.9**	206.7	26.29	28.14	-1.75	**-360.8**	50.2	29.17	29.17	0.00	**0.0**	509.9	**-1,000.7**
Annual	**2,184.2**	**25.40**	**28.38**	**-2.83**	**-6,150.9**	**1,727.9**	**23.84**	**25.64**	**-1.76**	**-3,000.4**	**550.8**	**26.38**	**26.38**	**0.00**	**0.0**	**4,462.9**	**-9,151.3**

Costs of the wheeling part of the agreement are shown in the table below. TAG 3X for wheeling power from Craig to Pinnacle Peak is $4.04 million and TAG 5X wheeling from Four Corners to Pinnacle Peak is $0.76 million for a total of $4.80 million. These costs are the highest during the summer months.

SRP Wheeling Benefits under the Regional Market												
	TAG 3X: Craig to Pinnacle Peak					TAG 5X: 4 Corners to Pinnacle Peak					Total	
		Energy Price ($/MWh)					Energy Price ($/MWh)					
		Energy In	Energy Out				Energy In	Energy Out				
Month	3X SRP Exchange (GWh)	Craig	Pinnacle Peak	Ave Revenue ($/MWh)	Net Revenue ($1,000)	5X SRP Exchange (GWh)	Four Corners	Pinnacle Peak	Ave Revenue ($/MWh)	Net Revenue ($1,000)	Wheeled Energy (GWh)	CRSP Revenue ($1,000)
Jan	45.2	23.79	27.41	-4.05	**-182.9**	14.7	25.90	27.41	-1.42	**-20.9**	59.8	**-203.7**
Feb	49.2	23.60	27.25	-4.42	**-217.4**	35.0	25.84	27.25	-1.26	**-44.3**	84.3	**-261.7**
Mar	95.3	21.88	25.73	-3.75	**-356.9**	29.0	24.13	25.73	-1.26	**-36.6**	124.2	**-393.5**
Apr	72.3	20.26	24.94	-4.64	**-335.1**	40.3	22.57	24.94	-2.21	**-89.0**	112.5	**-424.1**
May	89.3	21.56	25.56	-3.81	**-339.7**	31.2	22.92	25.56	-2.31	**-72.0**	120.5	**-411.7**
Jun	110.9	22.98	28.06	-4.94	**-547.7**	25.8	25.61	28.06	-2.24	**-57.9**	136.7	**-605.6**
Jul	96.8	26.28	31.86	-5.84	**-565.3**	26.4	29.47	31.86	-2.18	**-57.7**	123.2	**-623.0**
Aug	104.2	25.54	31.33	-5.82	**-606.2**	24.4	28.98	31.33	-2.30	**-55.9**	128.6	**-662.1**
Sep	37.0	24.93	30.14	-4.70	**-173.7**	26.8	28.11	30.14	-1.99	**-53.3**	63.7	**-227.0**
Oct	45.5	24.16	28.05	-3.50	**-159.3**	54.8	26.21	28.05	-1.82	**-99.8**	100.3	**-259.1**
Nov	67.3	24.76	29.19	-4.50	**-302.8**	70.0	27.72	29.19	-1.48	**-103.4**	137.3	**-406.2**
Dec	48.3	26.29	31.06	-5.31	**-256.9**	34.5	29.17	31.06	-2.00	**-68.8**	82.8	**-325.8**
Annual	**861.1**	**23.84**	**28.38**	**-4.61**	**-4,043.9**	**412.7**	**26.38**	**28.38**	**-1.87**	**-759.4**	**1,273.8**	**-4,803.4**

In total SRP exchange annual costs are almost $14 million; that is, the sum of $9.15 million for exchanges and $4.80 million for wheeling.

The financial impacts of GFA contracts under the Regional Market case are much smaller. The table below shows that for all three contacts analyzed there is a total positive benefit of $1.56 million.

This is mainly attributed to the PacifiCorp (PAC) contract for transmission from Pinnacle Peak to Glen Canyon. This orientation is counter to general flow on this path. It therefore has a negative LMP congestion component. Also, benefits are limited because GFA energy quantities are significantly less than the SRP exchange.

GFA Contract Benefits under the Regional Market

APS GFA Contract					PAC GFA Contract					DGT GFA Contract					Total	
	Energy Price ($/MWh)					Energy Price ($/MWh)					Energy Price ($/MWh)					
Max 285 MW	Energy In	Energy Out			Max 250 MW	Energy In	Energy Out			Max 26 MW	Energy In	Energy Out				
APS Trans Service (GWh)	Glen Canyon ($/MWh)	Pinnacle Peak ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	PAC Trans Service (GWh)	Pinnacle Peak ($/MWh)	Glen Canyon ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	DGT Trans Service (GWh)	Flaming Gorge ($/MWh)	Glen Canyon ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	Net Energy Exchange (GWh)	Net CRSP Revenue ($1,000)
41.7	24.57	27.23	-2.52	**-105.2**	57.0	27.23	24.57	2.71	**154.3**	4.2	24.27	23.32	0.49	**2.1**	102.9	**51.2**
18.8	24.63	27.38	-3.53	**-66.5**	47.9	27.38	24.63	2.36	**112.9**	1.6	24.26	24.45	-0.71	**-1.2**	68.4	**45.3**
5.5	23.09	25.41	-1.52	**-8.4**	10.5	25.41	23.09	1.01	**10.7**	5.5	23.34	22.30	1.41	**7.8**	21.5	**10.0**
1.7	22.09	25.01	-3.49	**-5.9**	30.0	25.01	22.09	2.83	**84.8**	7.2	21.87	20.90	0.86	**6.2**	38.9	**85.1**
4.5	23.01	25.81	-1.78	**-7.9**	59.0	25.81	23.01	2.98	**176.1**	4.9	22.39	17.63	4.76	**23.4**	68.4	**191.5**
5.7	25.08	28.27	-3.11	**-17.6**	72.7	28.27	25.08	3.76	**273.5**	7.4	24.05	19.64	4.60	**33.8**	85.7	**289.7**
3.7	28.37	31.98	-3.59	**-13.2**	71.1	31.98	28.37	4.03	**286.7**	7.9	26.58	24.11	2.54	**20.1**	82.7	**293.7**
0.6	27.84	31.58	-3.54	**-2.2**	79.7	31.58	27.84	3.88	**309.2**	7.7	26.16	25.74	0.47	**3.6**	88.0	**310.6**
0.0	26.73	29.87	0.00	**0.0**	63.5	29.87	26.73	3.11	**197.4**	4.7	25.59	25.41	0.69	**3.3**	68.2	**200.7**
4.2	25.68	28.17	-2.95	**-12.4**	48.7	28.17	25.68	2.54	**123.9**	4.7	24.96	23.73	1.21	**5.7**	57.6	**117.2**
11.2	26.51	29.03	-2.69	**-30.1**	15.2	29.03	26.51	2.67	**40.7**	6.5	25.26	24.36	1.04	**6.8**	33.0	**17.5**
25.1	28.60	31.30	-2.53	**-63.5**	5.7	31.30	28.60	3.16	**18.0**	10.6	27.02	28.18	-1.06	**-11.2**	41.4	**-56.7**
122.7	**25.52**	**28.42**	**-2.60**	**-332.9**	**561.1**	**28.42**	**25.52**	**2.92**	**1,788.3**	**72.9**	**24.65**	**23.31**	**1.36**	**100.4**	**756.7**	**1,555.7**

SRP Exchange and GFA Regional Market Benefits under High Gas and Market Stress Futures

The table below summarizes the financial implications of the SRP Exchange Agreement and GFA transmission contracts under the Current Trends, High Gas, and Market Stress futures. All futures have identical exchange, wheeling, and transmission use quantities. Only LMPs at energy injection and extraction points differ among futures. Under the High Gas future, LMPs are generally higher than the Current Trends future. SRP wheeling price spreads between energy injection and extraction points also tend to be larger. Note that the TAG 5X cost for the SRP energy exchange almost doubles. On the other hand, despite higher absolute price, spreads between SRP energy exchanges and GFA contracts do not change significantly. Also, note that the congestion orientation flips for the Deseret (DGT) contract with higher prices at Glen Canyon dam relative to Flaming Gorge (surrogate point for the Bonanza plant) under the High Gas future. Under the Market Stress future, LMPs are more expensive than the other two futures, but except for SRP wheeling, price spreads are lower.

	Net Revenue ($1,000)			$/MWh Price Spread (In-Out)		
	Current Trends	High Gas	Market Stress	Current Trends	High Gas	Market Stress
SRP Energy Exchange						
TAG 1X: GC to SRP Load	-6,151	-6,238	-3,459	-2.98	-2.99	-1.74
TAG 2X: Craig to CRSP North Load	-3,000	-3,615	-2,125	-1.80	-2.23	-1.36
TAG 4X: 4 Corners to CRSP NM Load	0	0	0	0.00	0.00	0.00
Energy Exchange Total	**-9,151**	**-9,853**	**-5,583**	**n/a**	**n/a**	**n/a**
SRP Wheeling						
TAG 3X: Craig to CRSP Load North	-4,044	-5,982	-4,168	-4.55	-6.77	-4.70
TAG 5X: 4 Corners to Pinnacle Peak	-759	-1,513	-1,509	-2.00	-3.82	-3.88
Wheeling Total	**-4,803**	**-7,495**	**-5,676**	**n/a**	**n/a**	**n/a**
GFA Contracts						
APS GFA Contract	-333	-339	-174	-2.90	-2.73	-1.44
PAC GFA Contract	1,788	1,753	903	2.90	2.73	1.44
DGT GFA Contract	100	-282	-76	1.33	-3.83	-1.03
GFA Total	**1,556**	**1,133**	**653**	**n/a**	**n/a**	**n/a**
Grand Total	**-12,399**	**-16,215**	**-10,606**	**n/a**	**n/a**	**n/a**

Tables that show more detailed SRP exchange and GFA transmission contract results for the High Gas and Market Stress futures are shown in Attachment F.

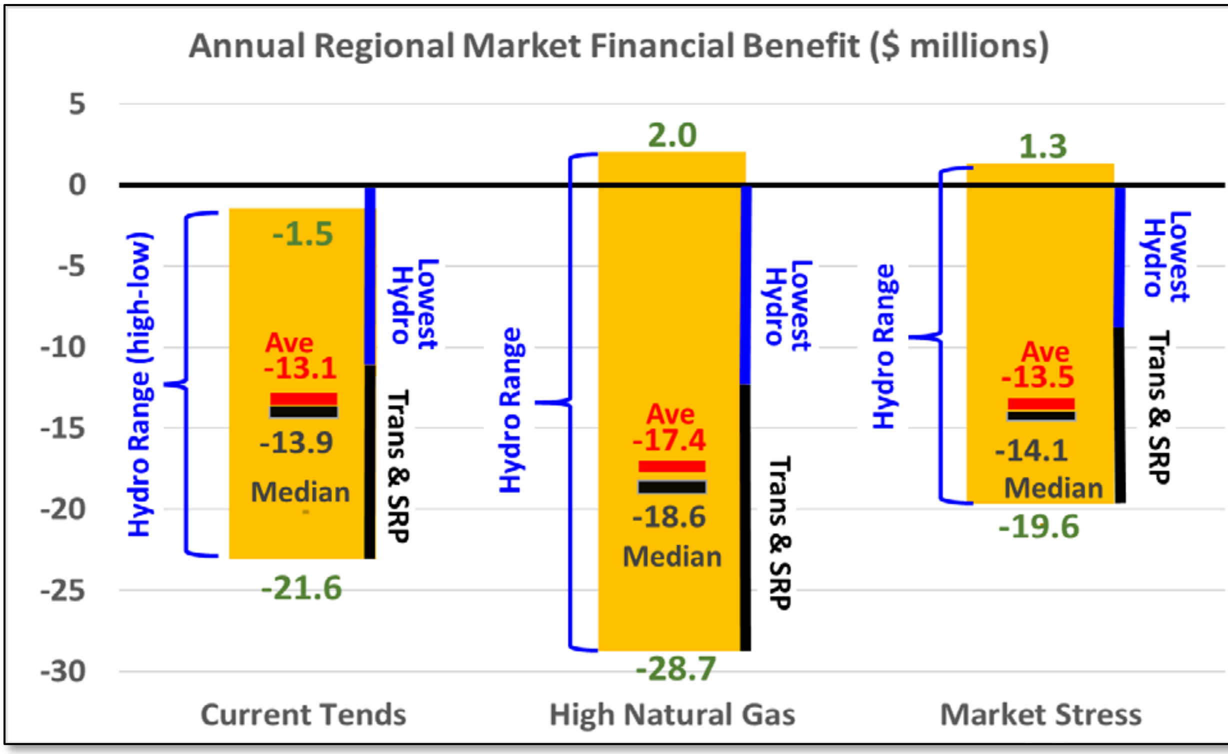
CRSP Financial Benefits Summary

Total CRSP financial benefits shown in the figure below equal the sum of transmission/SRP exchange components discussed above plus SLCA/IP hydropower energy production/operations. Transmission/exchange components, shown as thick black lines in the figure, are assumed to remain static under all CRSS hydropower traces. This is an accurate representation for GFA transmission impacts that are independent of hydrological conditions. As applied to the SRP exchange, however, the reader should realize that this portrayal is a simplification because the SRP Exchange is highly dependent on SLCA/IP hydropower generation levels (primarily Glen Canyon). The collection/construction of the necessary data and time required to quantify the economic impacts of this dependency is beyond the scope of this analysis. In addition, Western is exploring cost mitigation measures that potentially would reduce SRP exchange financial impacts.

This value combined with the worst financial result (thick blue lines) is the lowest estimated financial outcome as shown by the bottom of the gold bars. The top of each of the bars in the chart represents the best outcome under each future. For the Current Trends future all financial benefit outcomes are less than zero; that is, the highest comparative financial operating trace that has a benefit $10.9 million does not cover the combined $12.4 million financial cost of the SRP Exchange Agreement and GFA transmission contracts. The other two futures show at best a small positive net benefit under the highest financial operating trace.

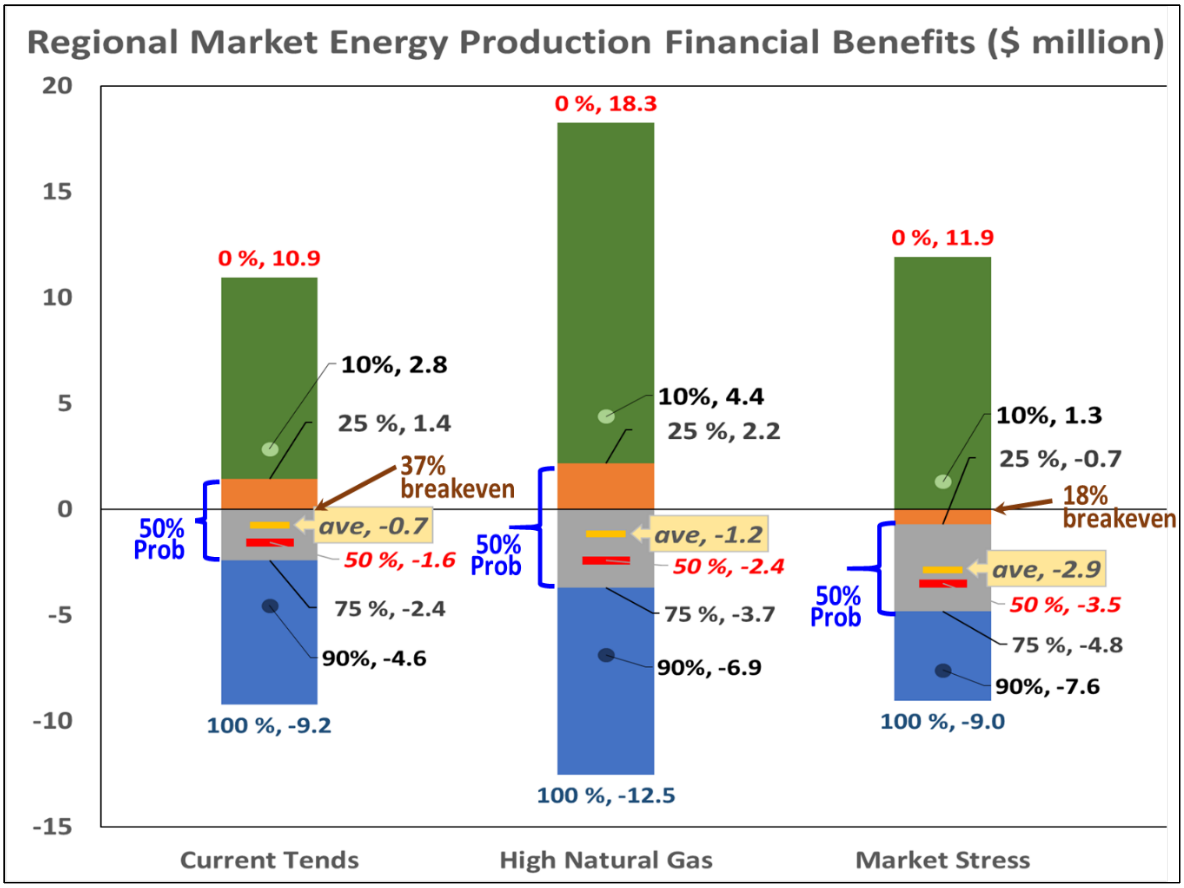
The figure below also shows that the average annual benefit ranges from a loss of $13.1 million under the Current Trends future to $17.4 million under the High Gas future. Median financial losses (i.e., 50 percent exceedance level) under all futures are higher than the average by $0.6 million to $0.8 million indicating a skewed financial distribution. The range of SLCA operating outcomes is approximately $20.2

million, $30.8 million, and $21.0 million, under the Future Trends, High Gas, and Market Stress futures, respectively.



A more detailed depiction of operational outcomes is shown in the figure below. All have negative average and median financial outcomes. In addition, the majority of outcomes result in a relative financial loss. Under the Current Trends future, half of the benefit outcomes are projected to be within a relatively narrow band ranging from a gain of $1.4 million to a loss of 1.6 million; that is, a range of $3.0 million that covers exceedances from 25 percent to 75 percent. The wider band of $7.4 million covers 80 percent of all outcomes (10 percent through 90 percent exceedance levels). The remainder of the $20.2 million range (i.e., $11.8 million) cover the tail ends of the distribution 20 percent of the time. All of these financial ranges widen under the High Gas future.

The entire $4.2 million benefit range of the 50 percent probability bracket is negative under the Market Stress future. A wider range of $8.9 million covers 80 percent of all outcomes.


Regional Market Energy Production Financial Benefits ($ million)
20
15
10
5
0
-5
-10
-15
0 %, 10.9
10%, 2.8
25 %, 1.4
37%
breakeven
50%
Prob
ave, -0.7
50 %, -1.6
75 %, -2.4
90%, -4.6
100 %, -9.2
0 %, 18.3
10%, 4.4
25 %, 2.2
50%
Prob
ave, -1.2
50 %, -2.4
75 %, -3.7
90%, -6.9
100 %, -12.5
0 %, 11.9
10%, 1.3
25 %, -0.7
18%
breakeven
ave, -2.9
50%
Prob
50 %, -3.5
75 %, -4.8
90%, -7.6
100 %, -9.0
Current Tends
High Natural Gas
Market Stress

Summary: Mountain West Regional Market Financial Analysis

This report discussed a WAPA financial analysis of RMR and CRSP Office full participation in a prospective RTO market with Mountain West. It is an extension of and consistent with the Brattle Mountain West economic study of this same market. Brattle utilized the PSO production cost model to project WI least-cost, security-constrained unit commitments and economic dispatch for two cases under three futures during calendar year 2024. PSO LMP results were used by Argonne to estimate LAP and CRSP financial impacts under a broad set of market and hydropower conditions.

Argonne financial impacts are based on a comparative analysis methodology in which Status Quo case model results are contrasted with outcomes for a Regional Market case. Impact analysis was conducted for three plausible futures created for the Brattle analysis. These futures include CT, HG, and MS.

For the RMR analyses, Argonne created and utilized a versatile spreadsheet tool to analyze financial outcomes under various assumption regarding hydrological conditions, operational flexibility at the Mt. Elbert pumped storage powerplant, market transmission losses, and market participation bid behavior. A separate RMR tool was also developed and utilized for analyzing the financial impacts of a regional market on Yellowtail ancillary services.

Financial CRSP analyses were supported by a set of modeling tools that WAPA and Argonne developed over many years. It performs SLCA/IP hydropower hourly dispatch and associated financial/economic computations for a large set of hydropower conditions. Argonne also developed and utilized two newly developed spreadsheet tools that compute CRSP financial implications for the SRP exchange and grandfathered transmission contracts.

For the RMR reference point model run the annual 2024 financial benefits of joining a regional market was \$0.51, \$0.20, and \$0.06 million for the CT, HG, and MS futures, respectively. This reference point is based on average hydropower conditions for the CT and HG futures and dry conditions for the MS future. A second estimate of CT financial benefits was also computed based on an improved pumped storage methodology and more accurate transmission loss accounting. This second estimate decreased CT reference point benefits from the aforementioned level of \$0.51 million to \$0.16 million. Because it was judged that the revised methodology did not appreciably change analysis conclusions, revised model runs for the two other futures were not performed.

In addition, it is projected that under the CT future, RMR will gain \$1.43 million in annual benefits because ancillary service duties at the Yellowtail powerplant would not be required under the regional market. Although not computed, higher energy prices at Yellowtail under the HG and MS futures would most likely result in higher benefits.

Reference point model results were based on the following assumptions: (1) RTO participants bid all its generation resources into the market at production cost, (2) there is no operational flexibility at the Mt. Elbert powerplant, (3) transmission loses are 4.5%, and (4) market energy transactions costs/benefits for short/long energy positions are based on the full LMP. Sensitivity analysis varied each of these assumptions singularly or in combination. Financial outcomes for sensitivity model runs ranged from -$2.22 to $2.83 million for the CT future, -$7.94 to $7.49 million for the HG future and -$5.93 to $6.62 million for the MS future. Using the improved computational methodology, RMR financial benefits were generally, but not always lower with a range of -$2.10 million to $1.45 million.

Financial estimates for the CRSP Office were based on 105 hydrological outcomes for calendar year 2024. The annual average financial benefits of a regional RTO market for energy production was on average -$0.74, -$1.15, and -$2.86 million for the CT, HG, and MS futures, respectively. Most hydrological conditions yielded a negative result; that is, 63% of the hydrology conditions had negative benefits for the CT and HG futures and 82% of the hydrology conditions had a negative benefit for the MS future. Financial outcomes over all hydrological conditions ranged from -$9.22 to $10.95 million for the CT future, -$12.52 to $18.26 million for the HG future and -$9.033 to $11.93 million for the MS future.

In addition to energy regional market energy benefits, there will also be financial impacts related to existing contractual arrangements. These include the SRP exchange agreement and GFA transmission contracts. The SRP exchange has two components that include energy exchanges and wheeling. Under the CT future financial benefits are projected to be -$9.15 million for the energy exchanges and -$4.80 for wheeling; that is, a total of -$13.95 million. Total SRP benefits are projected to be somewhat lower at -$17.35 million for the HG future and -$11.26 million under the MS future. Model results for GFA transmission contracts show positive financial benefits for the CRSP Office. Total GFA contracts benefits are projected to be $1.56 million, $1.13 million and $0.65 million for the CT, HG and MS cases, respectively.

WAPA staff indicated that it would be operationally difficult for only one of the two offices to join the regional market because both are in the Western Area Colorado Missouri balancing authority and both have many of the same customers. The table below summarizes financial WAPA implications if it joined the market and the CT future came into fruition. Note that this table only includes financial components that are addressed in this report. Others including financial implications associated with computer hardware/software upgrades, RTO fees, and staffing changes have been estimated by WAPA and are documented elsewhere.

WAPA Total Regional Market Energy and Ancillary Services Benefits ($million)

		Range	
RMR	**Ref/Ave[1]**	**Low**	**High**
LAP Energy	0.16	-2.10	1.45
Ancillary Services	1.43	1.43	1.43
Total	**1.59**	**-0.67**	**2.88**
CRSP			
SLCA/IP Energy	-0.74	-9.22	10.95
Ancillary Services	0.00	0.00	0.00
Total	**-0.74**	**-9.22**	**10.95**
WAPA Total	**0.85**	**-9.89**	**13.83**

[1] *Energy values are based on reference point model runs using the improved methodology for RMR and the average result for the 105 hydrological conditions modeled for CRSP*

As noted above, the net costs associated with CRSP's SRP Exchange and GFA transmission contracts represent an upper-end limit. WAPA staff continue to explore various mitigation measures that will be necessary if WAPA joins a regional market. As a result, WAPA staff have communicated to Argonne that unless some of the mitigation strategies currently being investigated are implemented, CRSP will be unable to participate in a regional market due to the significant cost associated with the SRP Exchange. Therefore, in order for CRSP to participate, it is necessary that some mitigation strategies be implemented, and the previously estimated SRP Exchange and GFA transmission costs are not ultimately realized. Although these agreements will have some impact on CRSP’s financial position, the large impacts presented in the previous section have not been included in the summary table below because, at this point in time, CRSP financial impacts, if any, are highly uncertain.

When interpreting the results presented in this study it is important that the reader be aware of the limitations of the models used for this analysis. For example, Brattle computed LMPs that are key for financial calculations are dependent on numerous grid assumptions. For example, the Brattle study assumed static transaction over tie lines that connect the WI to eastern grid markets. The reader should therefore bear in mind that if key assumptions are not realized in 2024, results may be different from the ones presented in this report. Whereas the veracity of some of these assumptions may have little impact on the overall economics of the WI some of these key assumptions may have a significant impact on specific LMPs. These assumptions include but are not limited to: (1) regional and bus-load growth, (2) transmission system improvements and topology changes, (3) RTO decisions regarding the opening of circuit breakers, (4) improvements and retirement schedules at existing power plants, (5) the buildout of new thermal generation technologies by type, size and location, (6) fossil fuel prices, and (7) the specific expansion locations and operation of VERs. In addition, until an existing RTO is selected and the market rules are known, all costs and revenues cannot be more accurately pinpointed.

Because of modeling challenges and simplifications, the financial impacts presented in this report should be viewed as rough “computer model” generated projections. It is not intended to provide “exact” levels of impacts for individual situations. Rather, recognizing the implications of the above caveats, the intent of this study is to learn about general trends and relative impact magnitudes over a large set of situations to help decision makers and stakeholders better understand Mountain West RTO membership advantages/disadvantages.

Attachment A

Current Trends Future: RMR Financial Model Result Synopsis

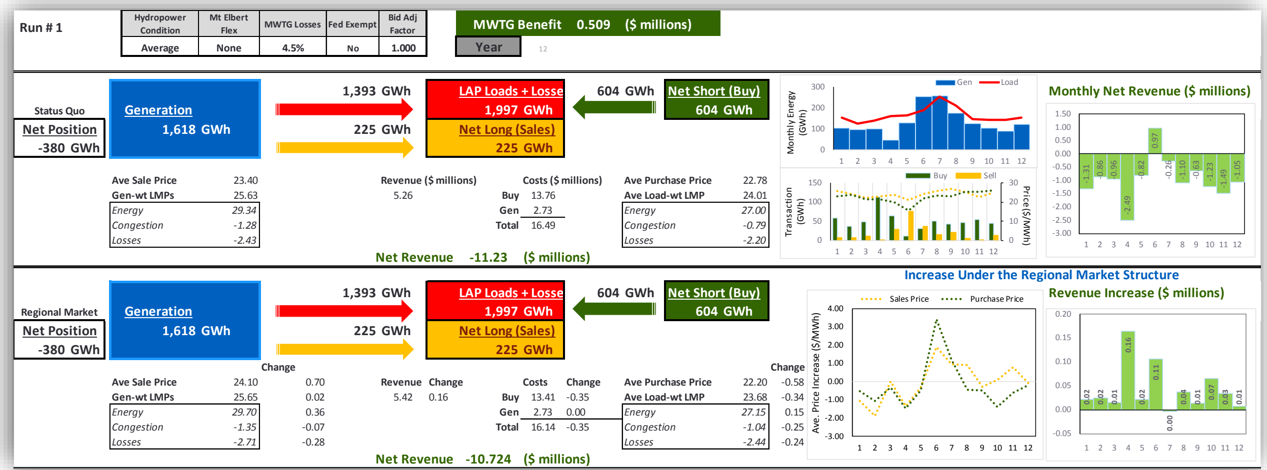


Figure A.1 RMR Current Trends: Run 1 Energy and Financial Flow Results

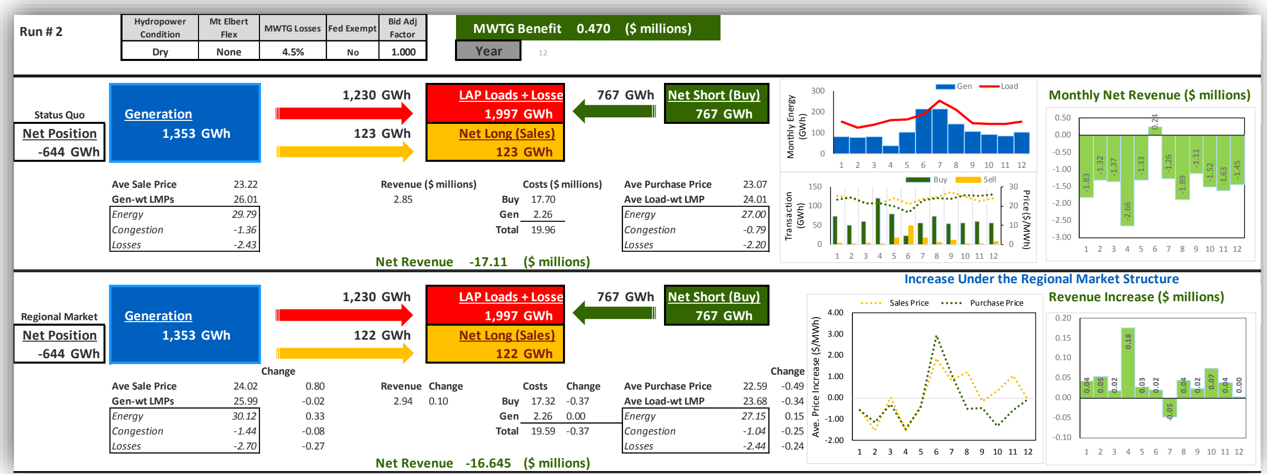


Figure A.2 RMR Current Trends: Run 2 Energy and Financial Flow Results

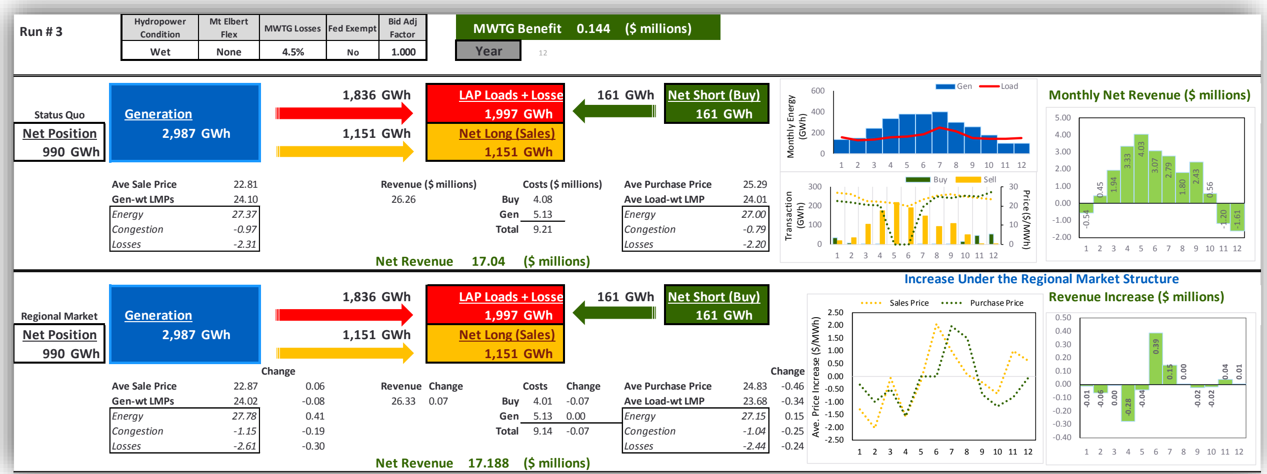


Figure A.3 RMR Current Trends: Run 3 Energy and Financial Flow Results

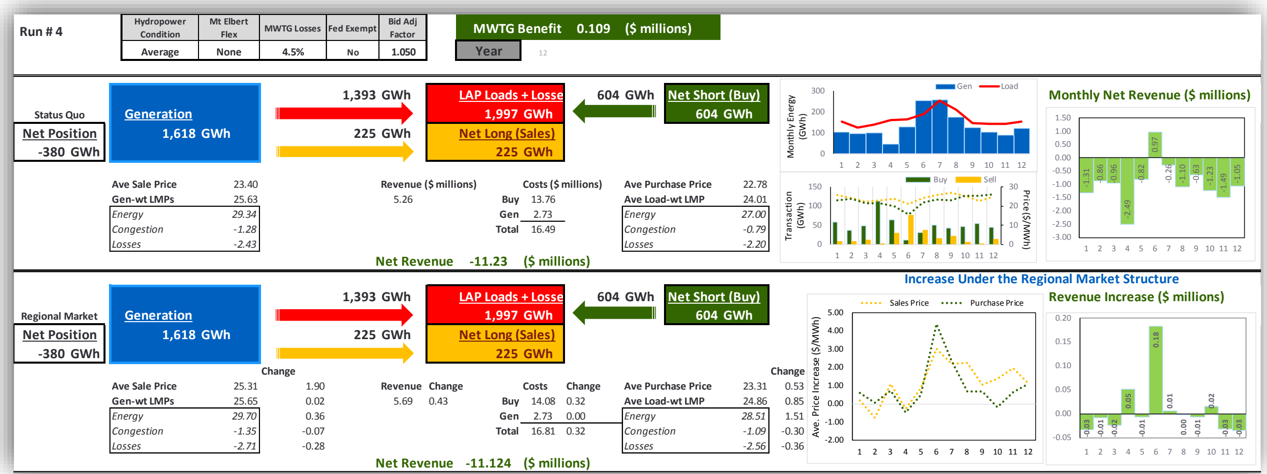


Figure A.4 RMR Current Trends: Run 4 Energy and Financial Flow Results

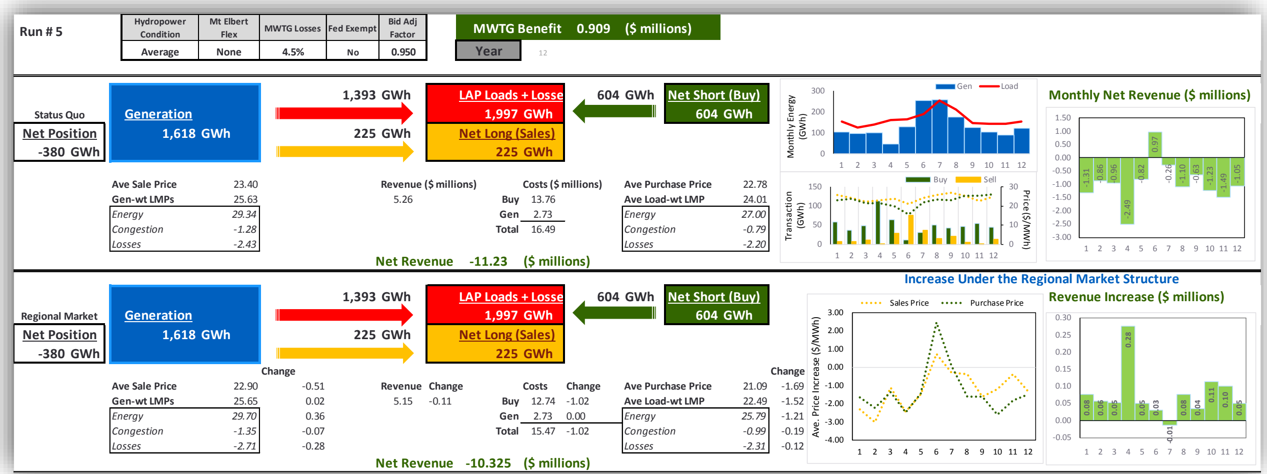


Figure A.5 RMR Current Trends: Run 5 Energy and Financial Flow Results

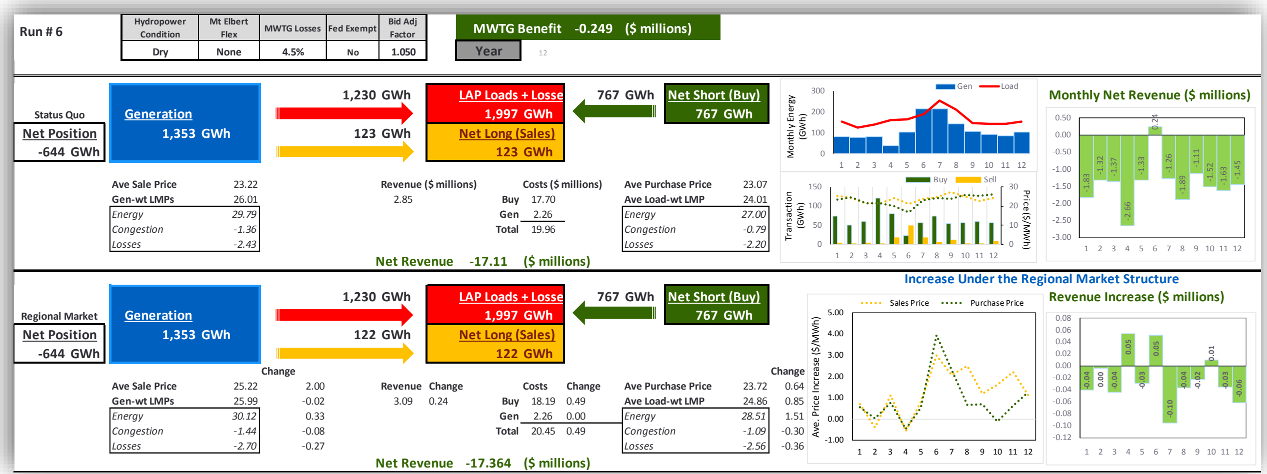


Figure A.6 RMR Current Trends: Run 6 Energy and Financial Flow Results

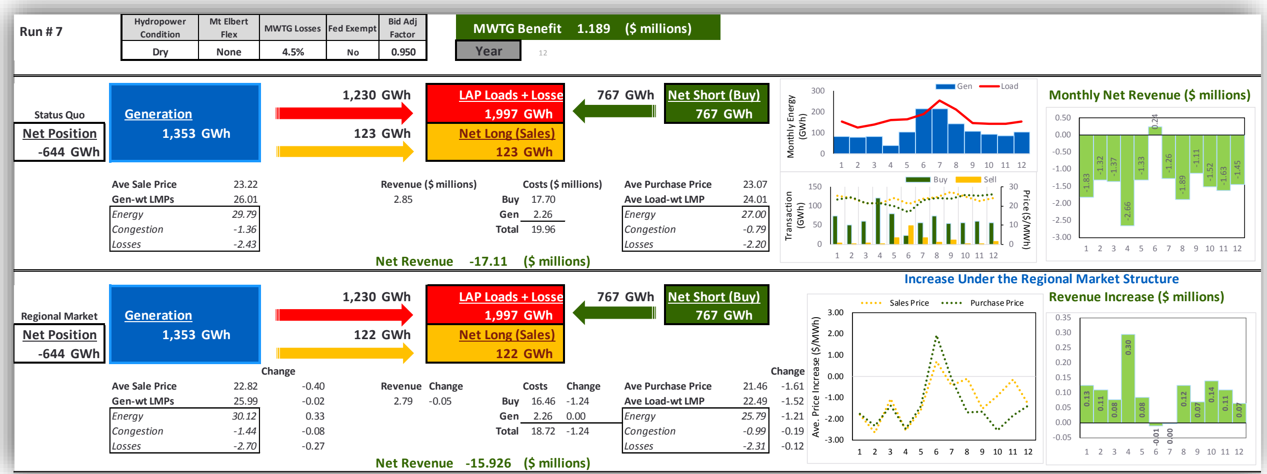


Figure A.7 RMR Current Trends: Run 7 Energy and Financial Flow Results

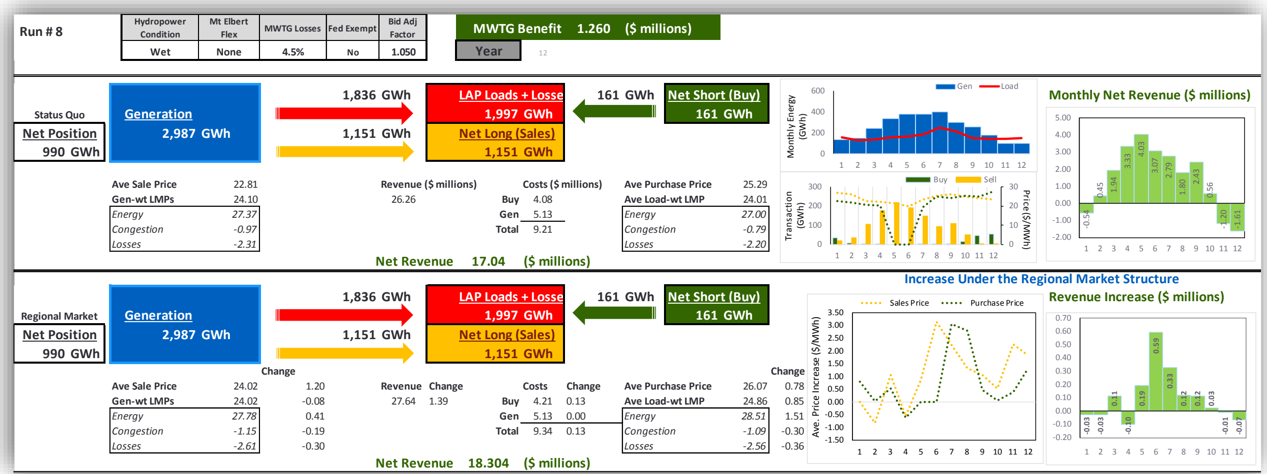


Figure A.8 RMR Current Trends: Run 8 Energy and Financial Flow Results

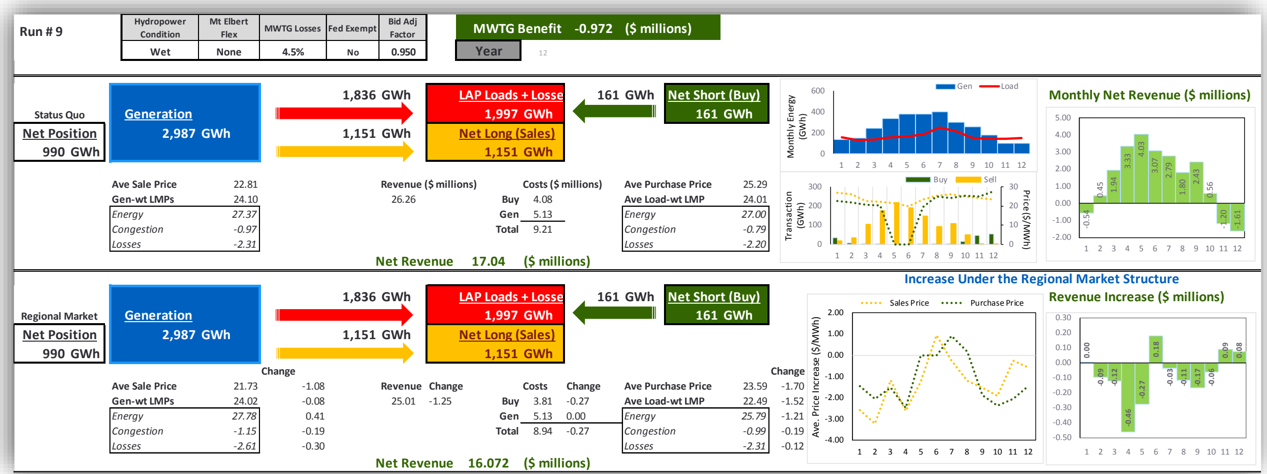


Figure A.9 RMR Current Trends: Run 9 Energy and Financial Flow Results

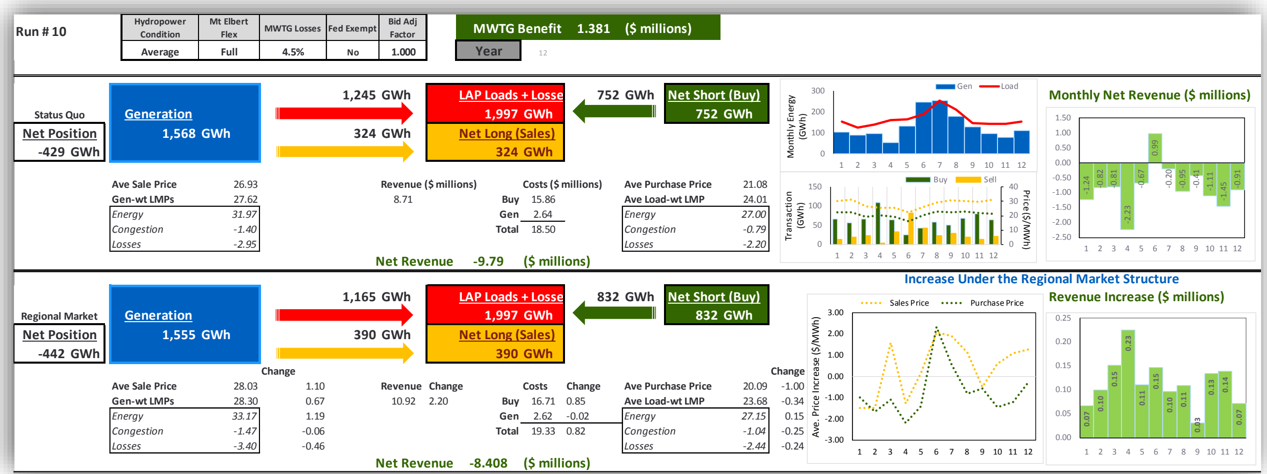


Figure A.10 RMR Current Trends: Run 10 Energy and Financial Flow Results

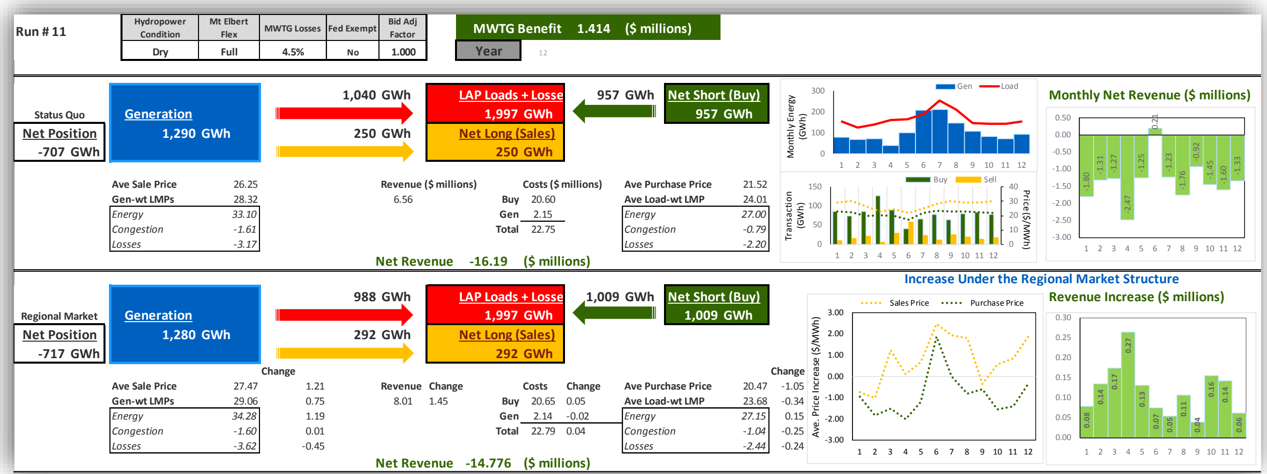


Figure A.11 RMR Current Trends: Run 11 Energy and Financial Flow Results

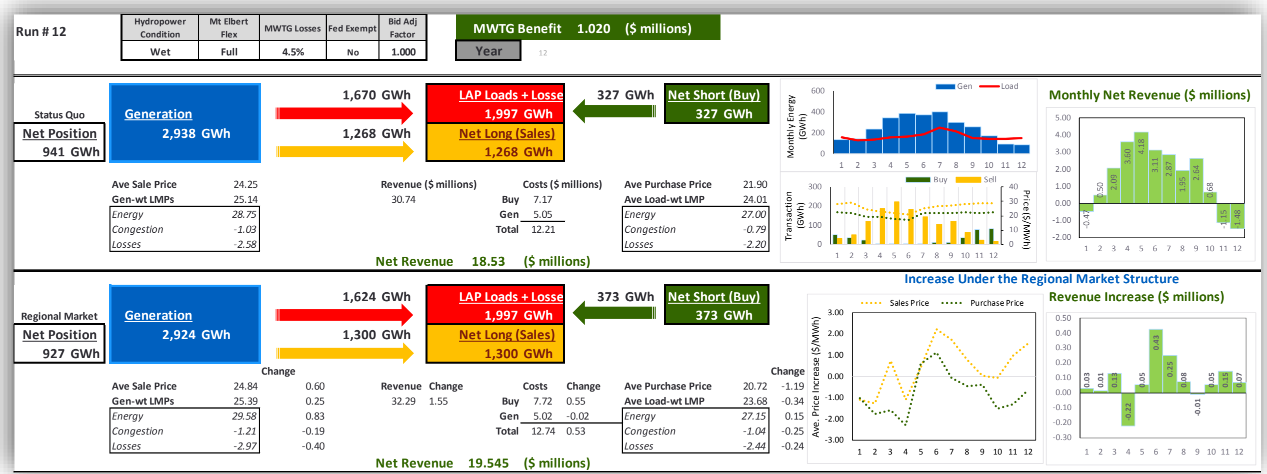


Figure A.12 RMR Current Trends: Run 12 Energy and Financial Flow Results

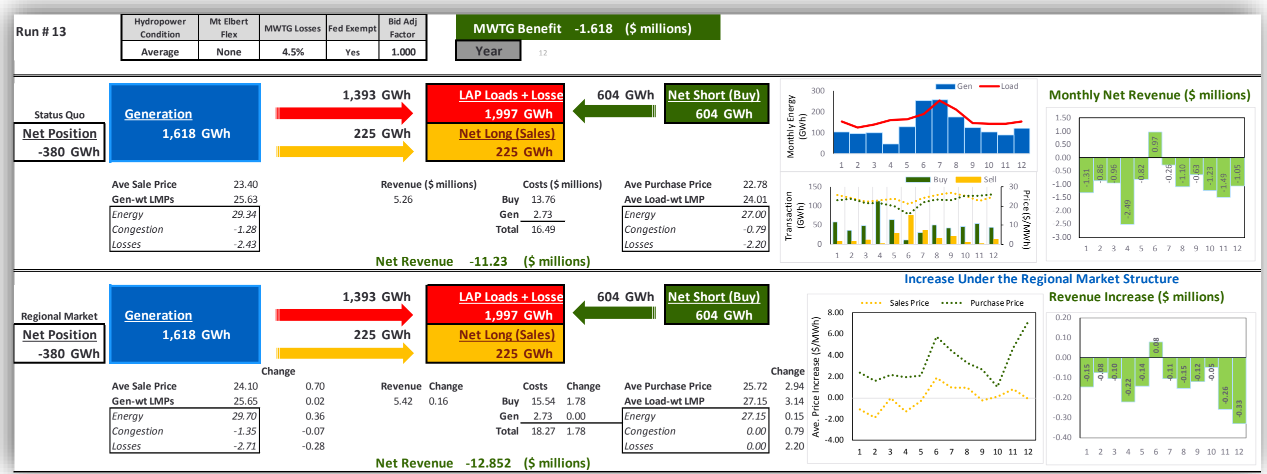


Figure A.13 RMR Current Trends: Run 13 Energy and Financial Flow Results

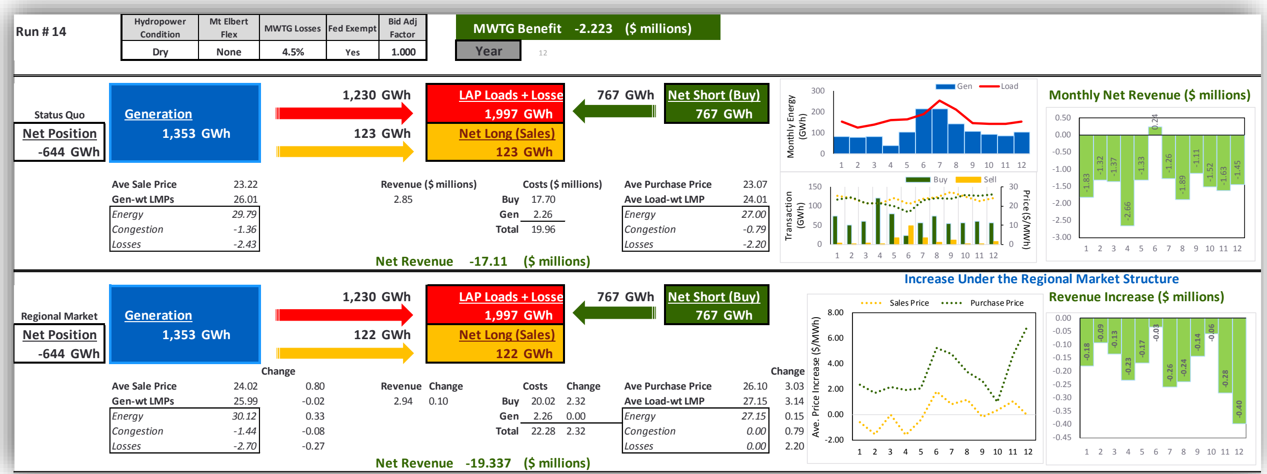


Figure A.14 RMR Current Trends: Run 14 Energy and Financial Flow Results

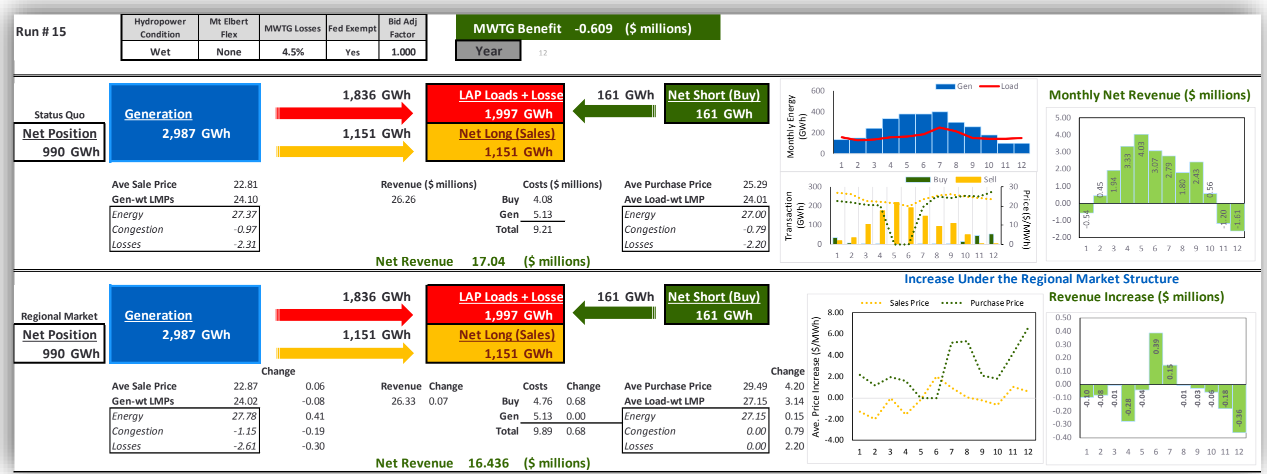


Figure A.15 RMR Current Trends: Run 15 Energy and Financial Flow Results

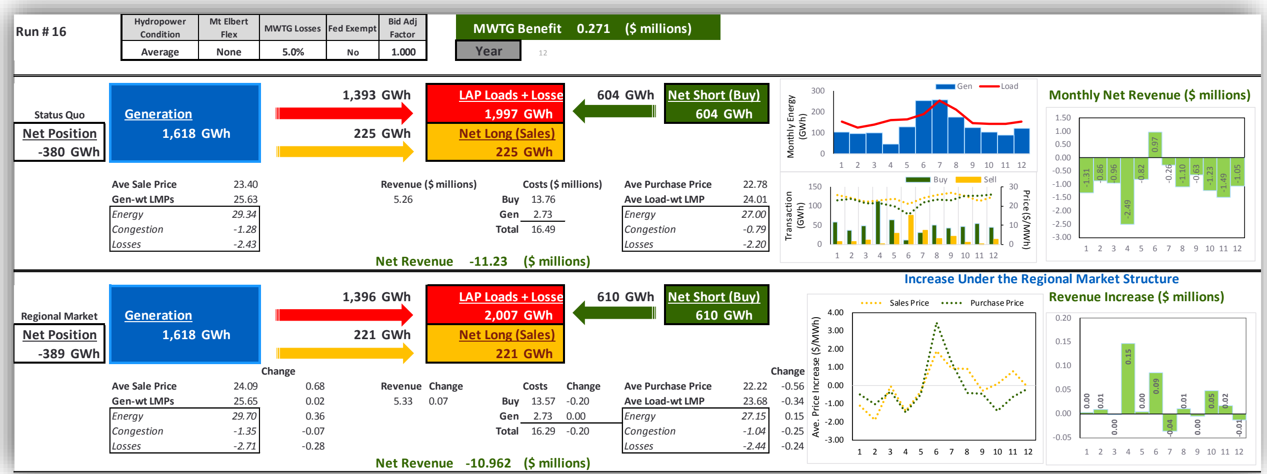


Figure A.16 RMR Current Trends: Run 16 Energy and Financial Flow Results

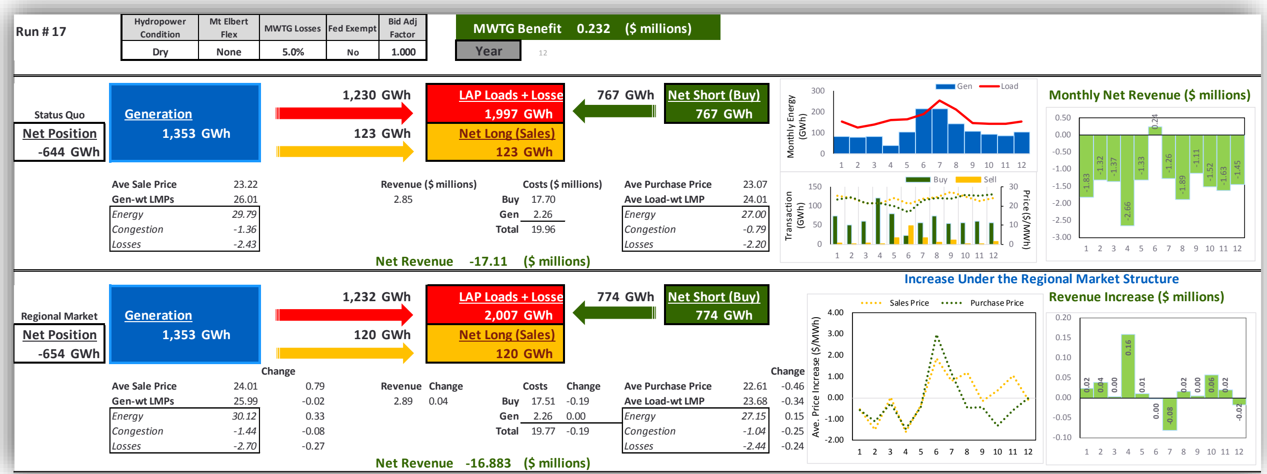


Figure A.17 RMR Current Trends: Run 17 Energy and Financial Flow Results

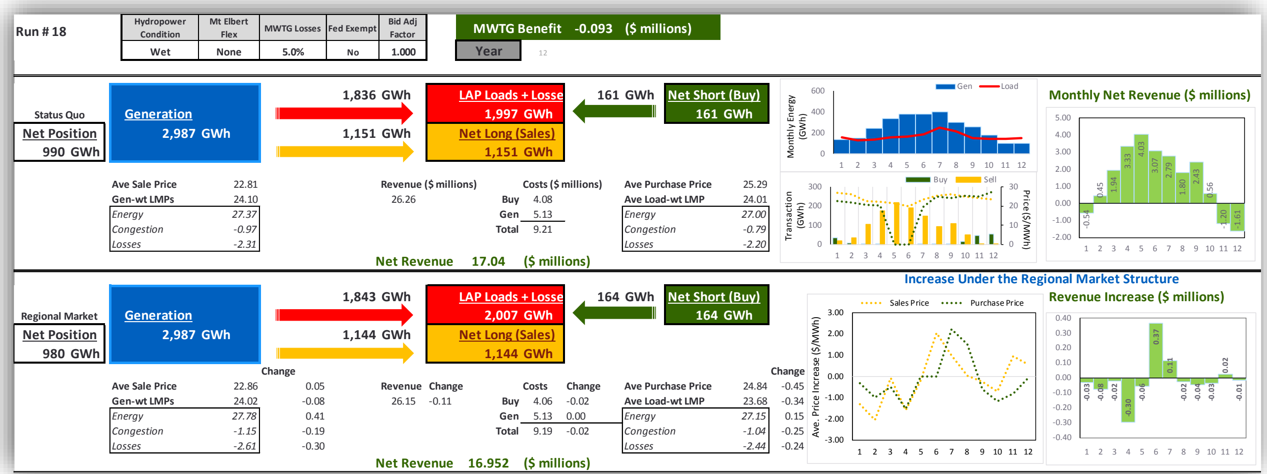


Figure A.18 RMR Current Trends: Run 18 Energy and Financial Flow Results

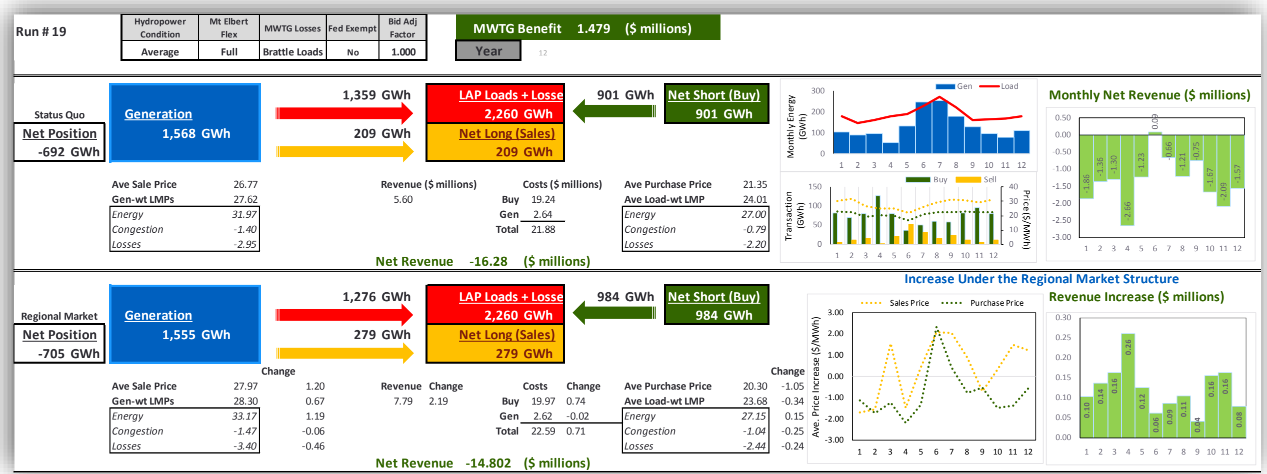


Figure A.19 RMR Current Trends: Run 19 Energy and Financial Flow Results

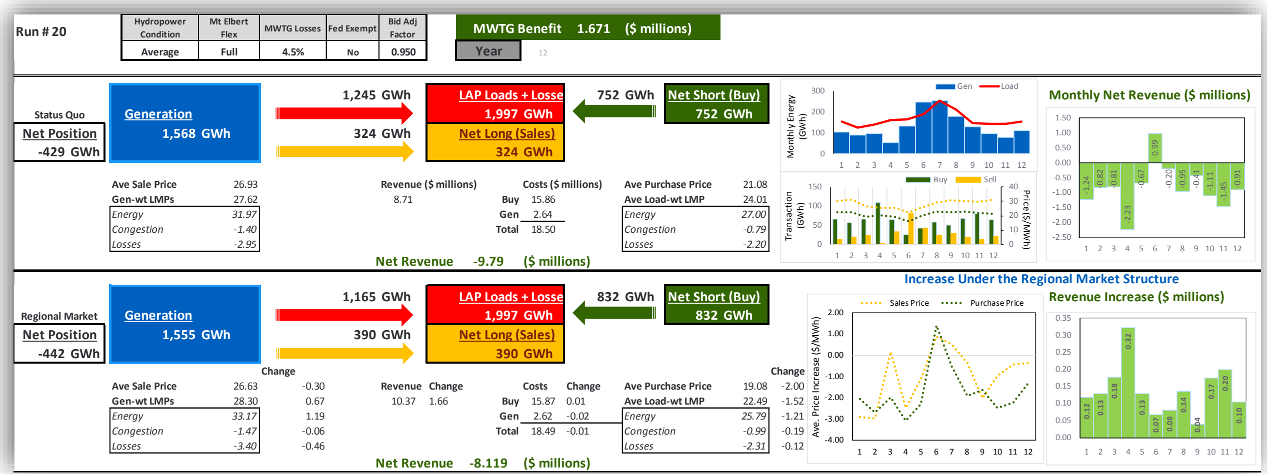


Figure A.20 RMR Current Trends: Run 20 Energy and Financial Flow Results

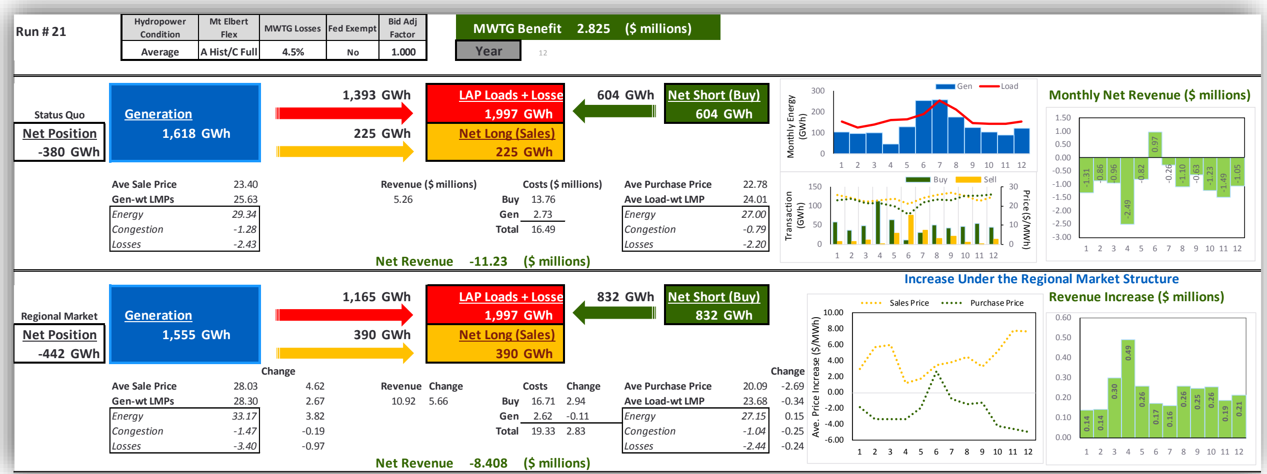


Figure A.21 RMR Current Trends: Run 21 Energy and Financial Flow Results

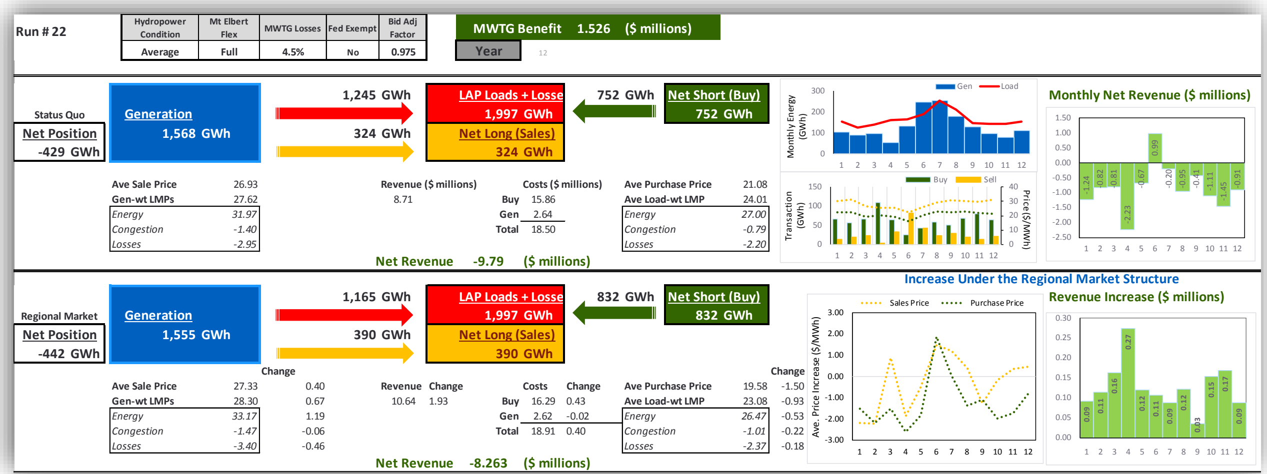


Figure A.22 RMR Current Trends: Run 22 Energy and Financial Flow Results

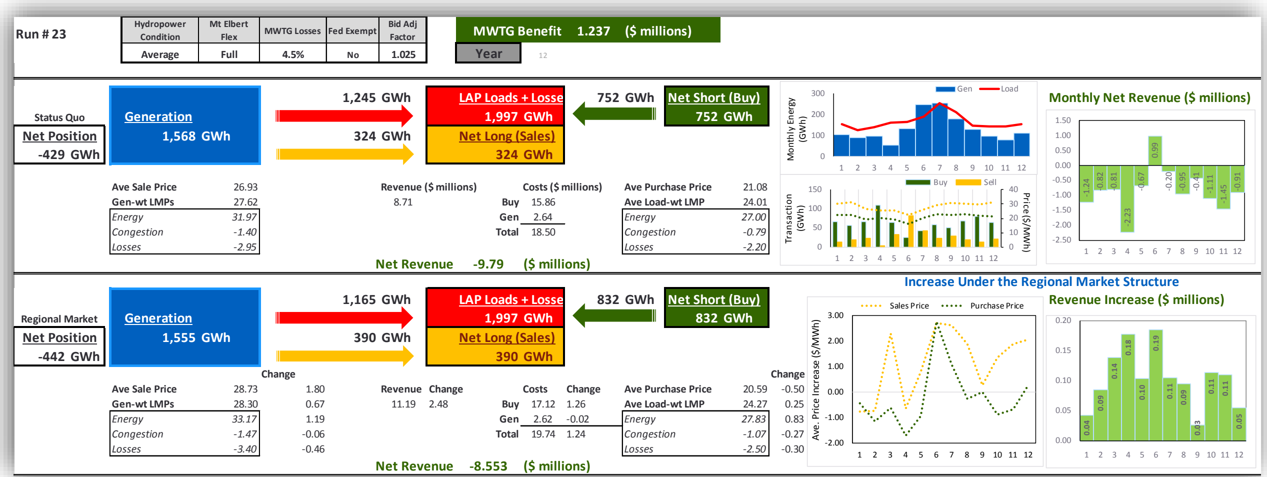


Figure A.23 RMR Current Trends: Run 23 Energy and Financial Flow Results

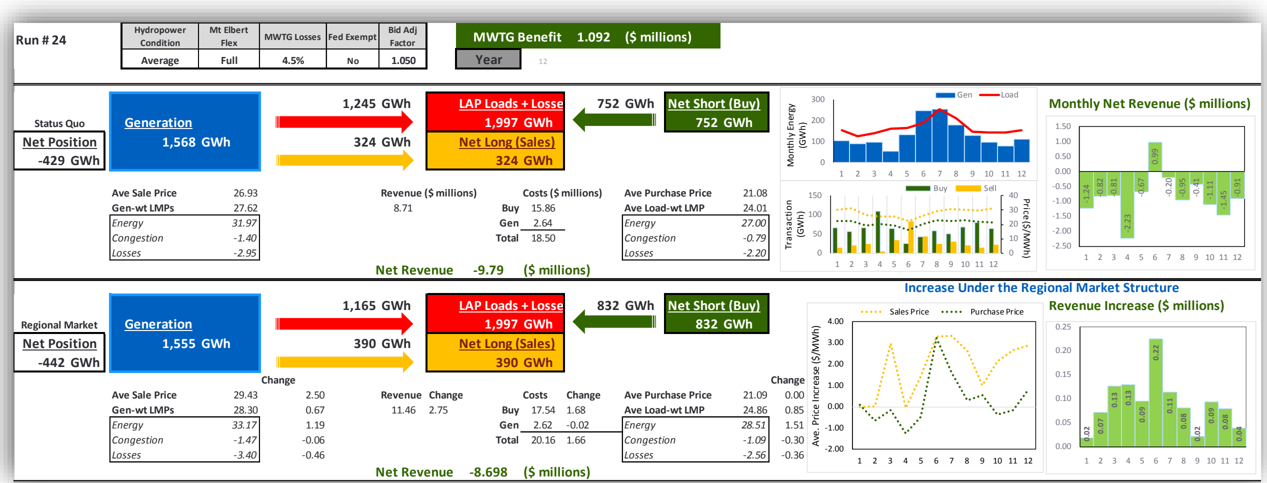


Figure A.24 RMR Current Trends: Run 24 Energy and Financial Flow Results

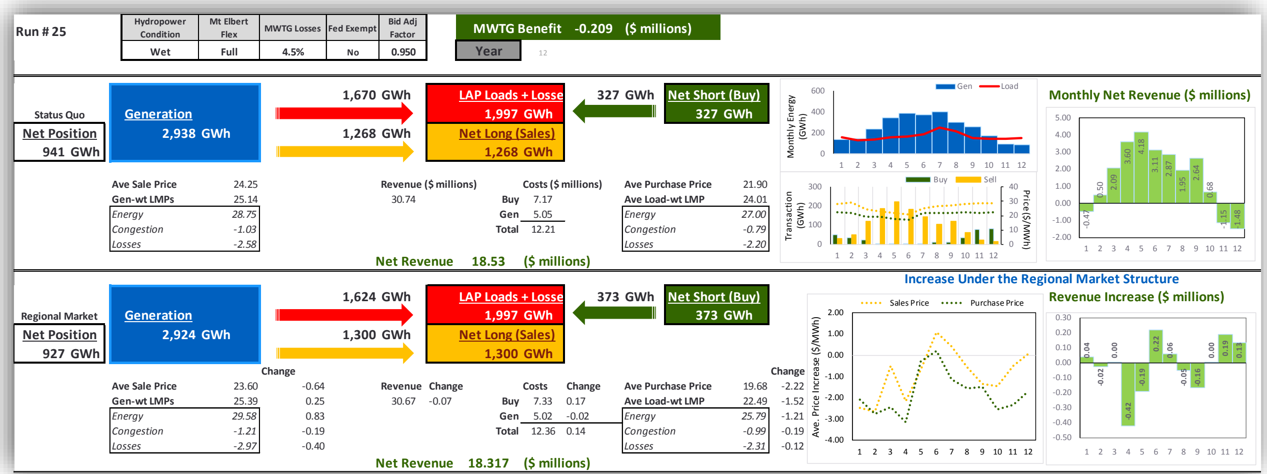


Figure A.25 RMR Current Trends: Run 25 Energy and Financial Flow Results

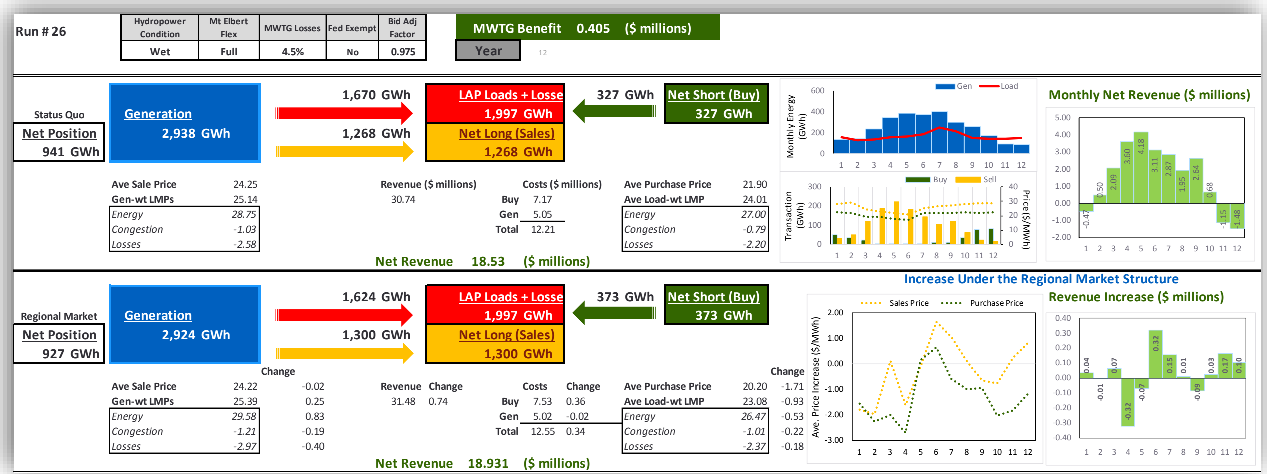


Figure A.26 RMR Current Trends: Run 26 Energy and Financial Flow Results

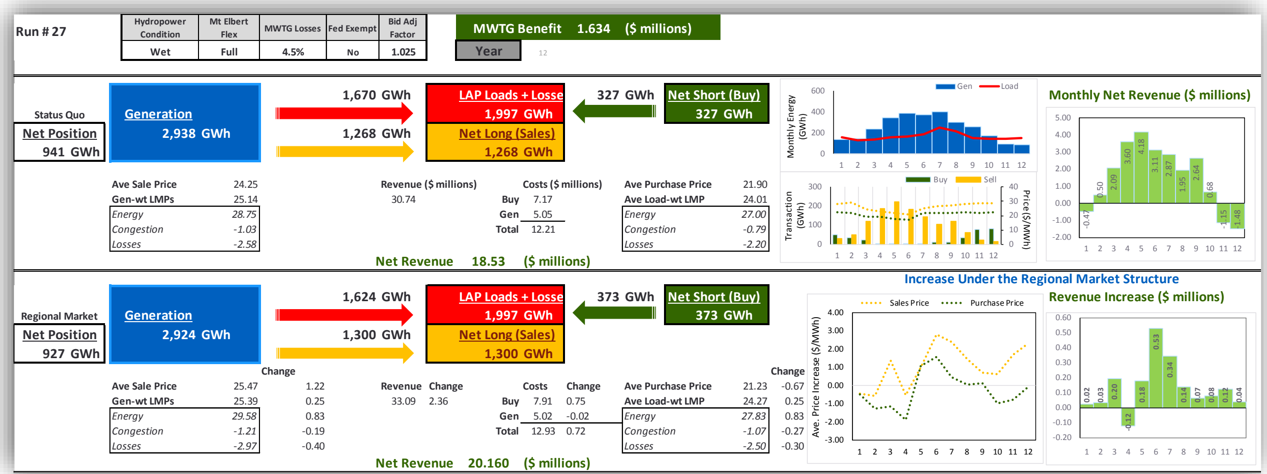


Figure A.27 RMR Current Trends: Run 27 Energy and Financial Flow Results

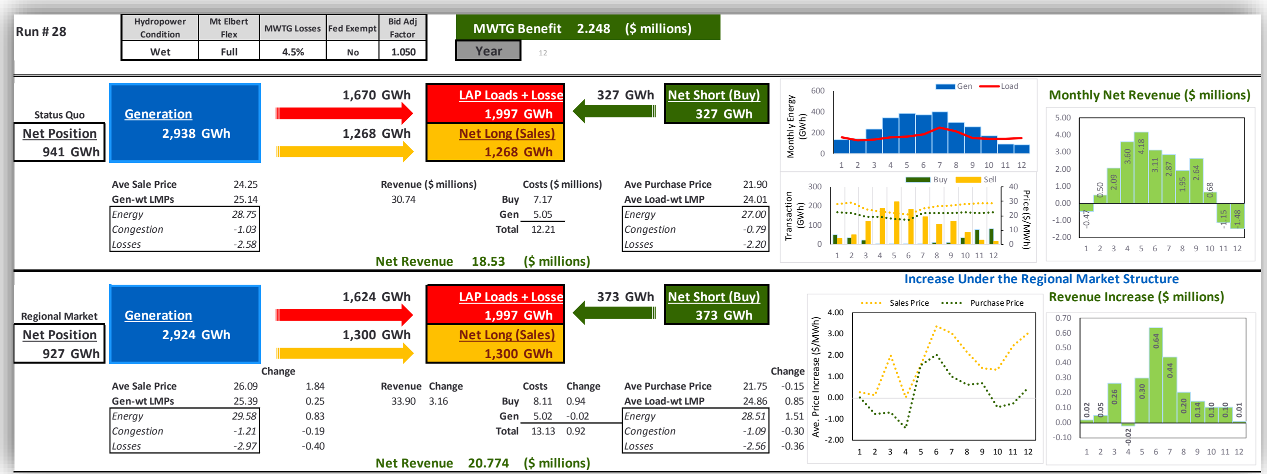


Figure A.28 RMR Current Trends: Run 28 Energy and Financial Flow Results

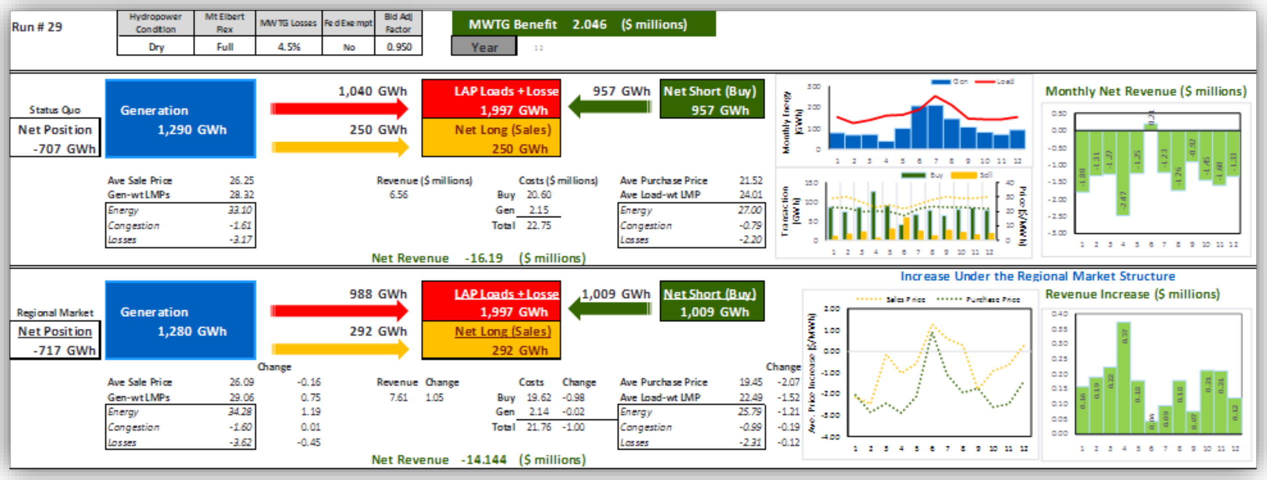


Figure A.29 RMR Current Trends: Run 29 Energy and Financial Flow Results

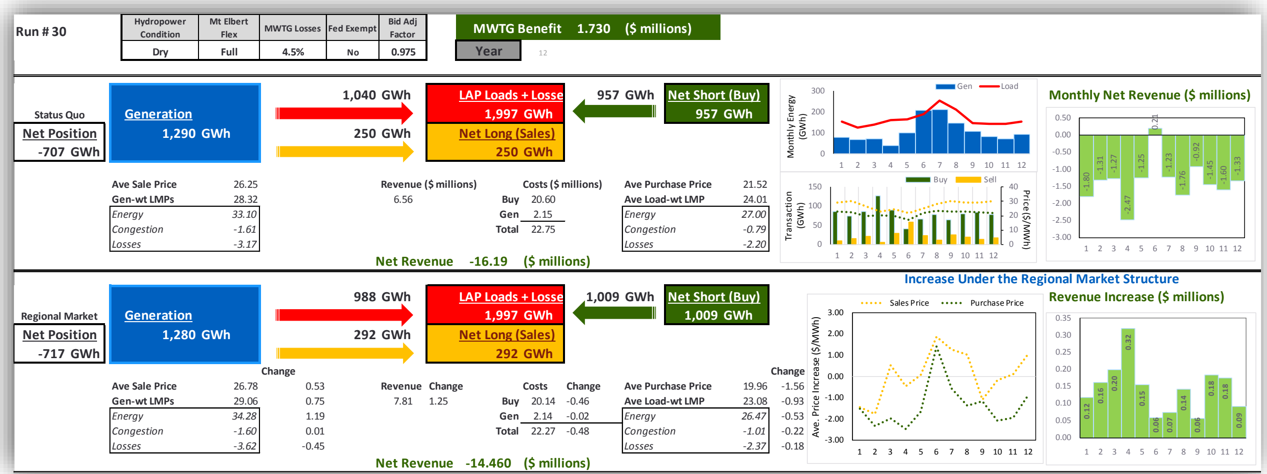


Figure A.30 RMR Current Trends: Run 30 Energy and Financial Flow Results

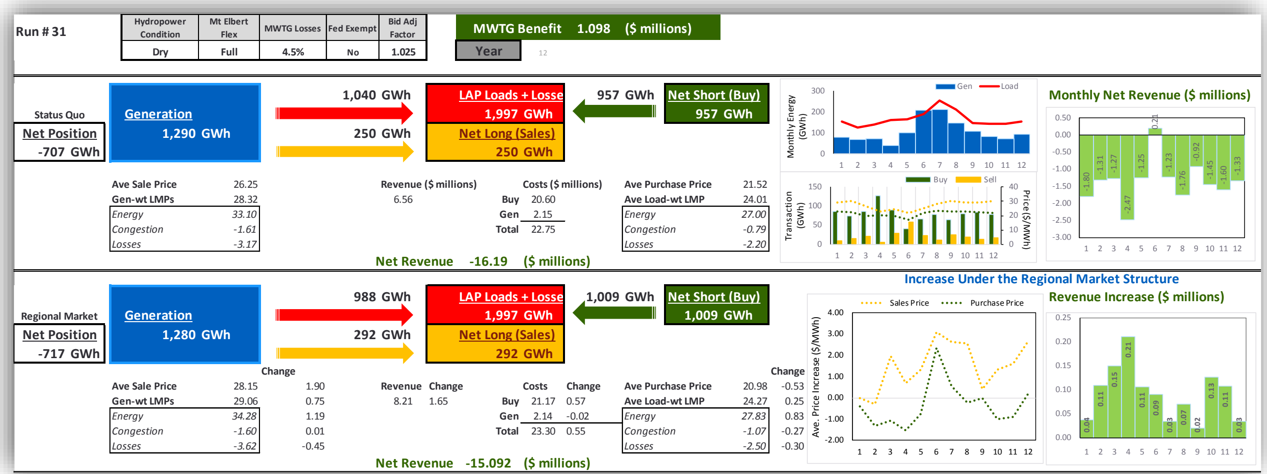


Figure A.31 RMR Current Trends: Run 31 Energy and Financial Flow Results

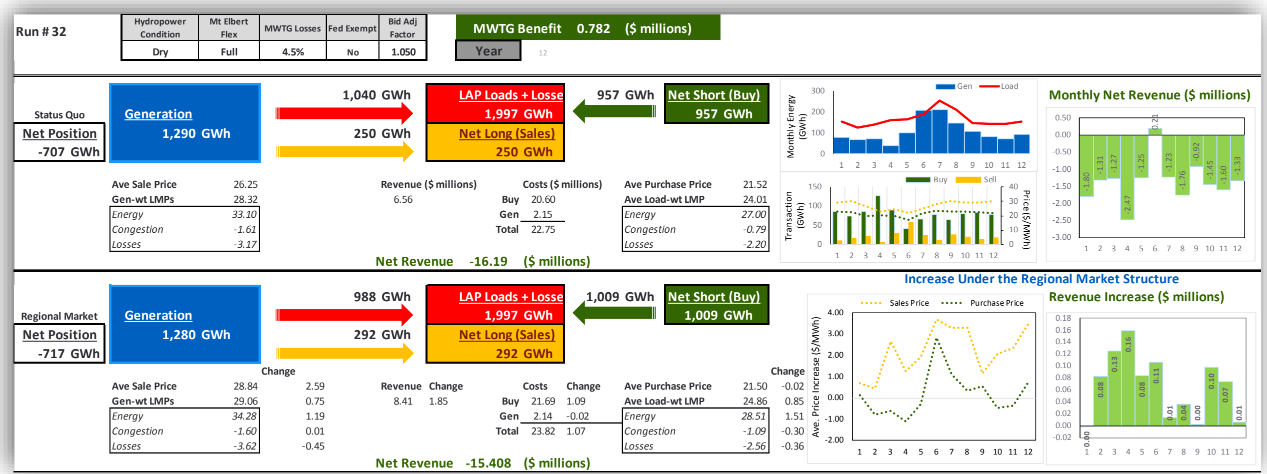


Figure A.32 RMR Current Trends: Run 32 Energy and Financial Flow Results

Attachment B

High Gas Price Future: RMR Financial Model Result Synopsis

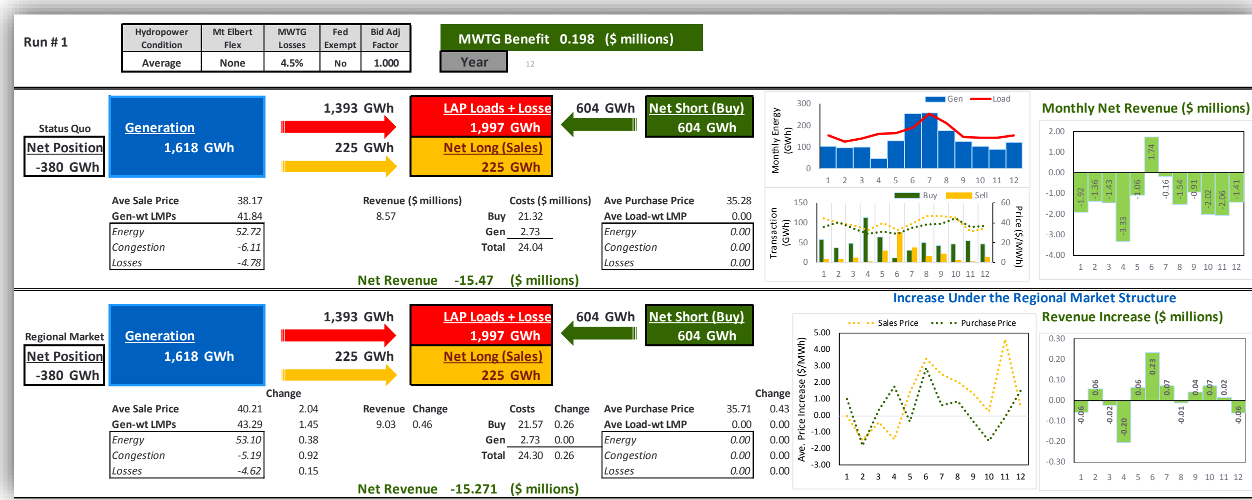


Figure B.1 RMR High Gas Price Future: Run 1 Energy and Financial Flow Results

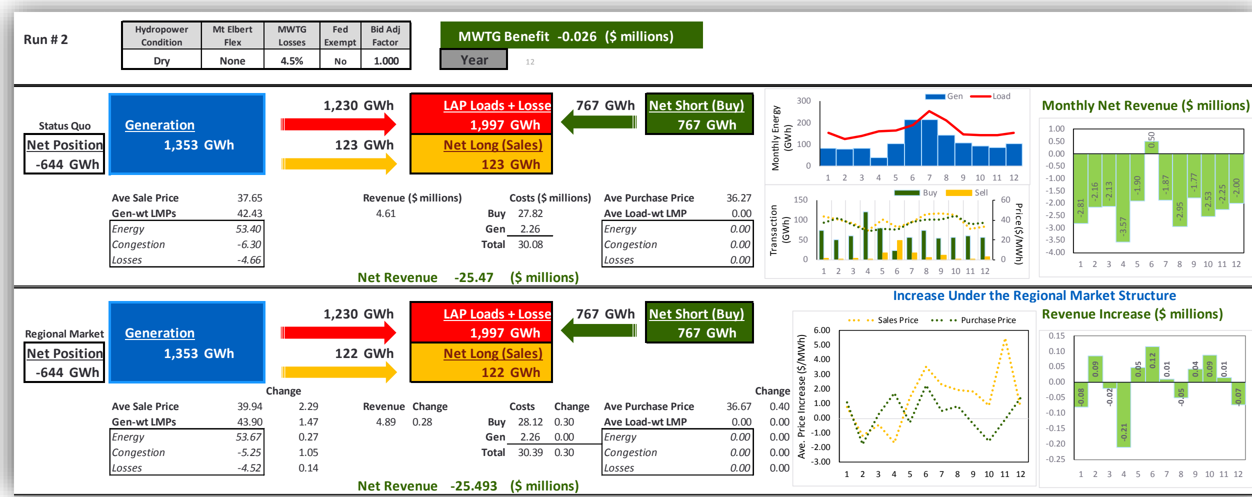


Figure B.2 RMR High Gas Price Future: Run 2 Energy and Financial Flow Results

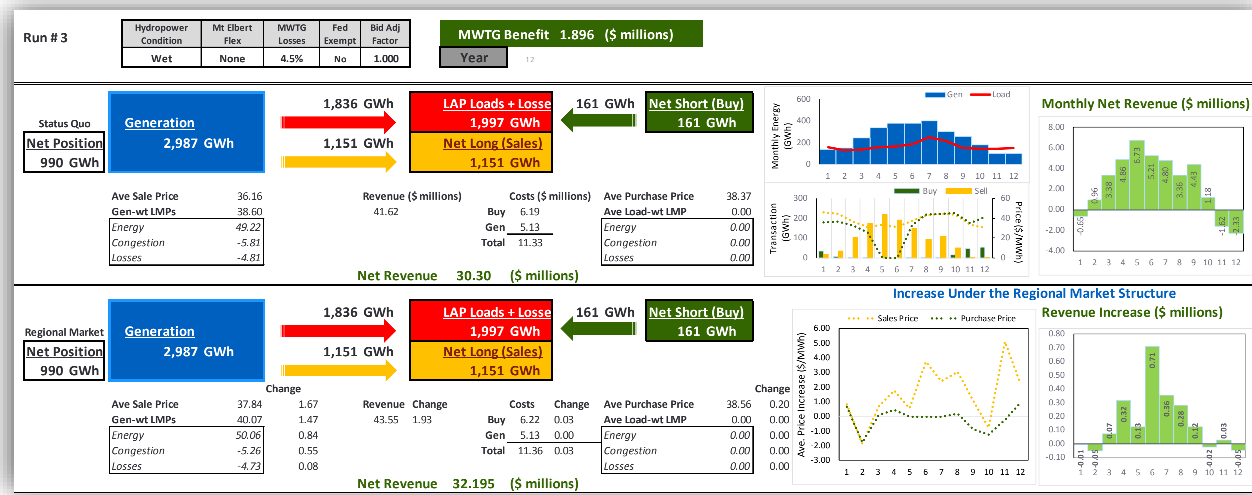


Figure B.3 RMR High Gas Price Future: Run 3 Energy and Financial Flow Results

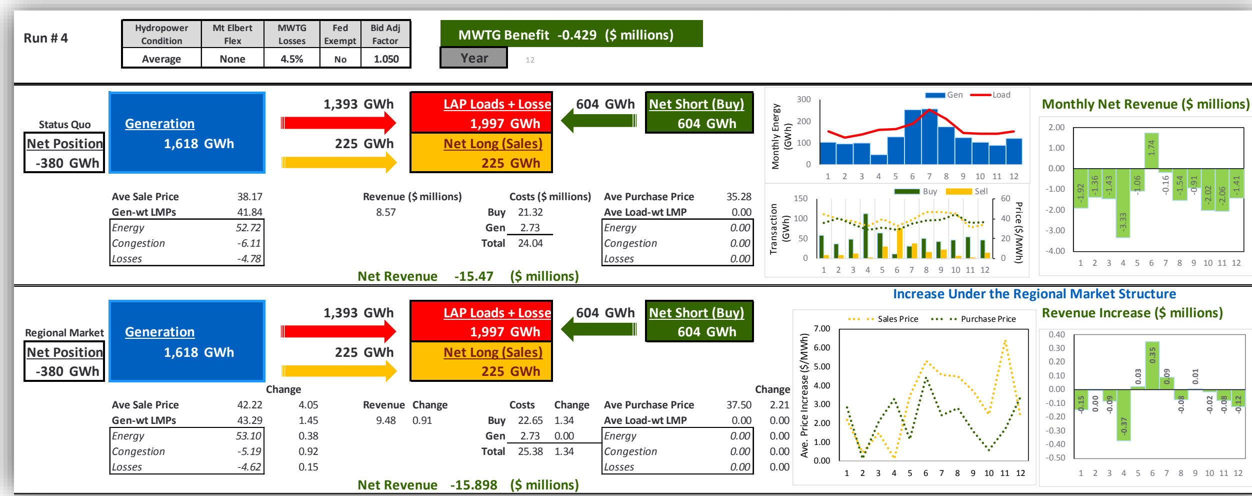


Figure B.4 RMR High Gas Price Future: Run 4 Energy and Financial Flow Results

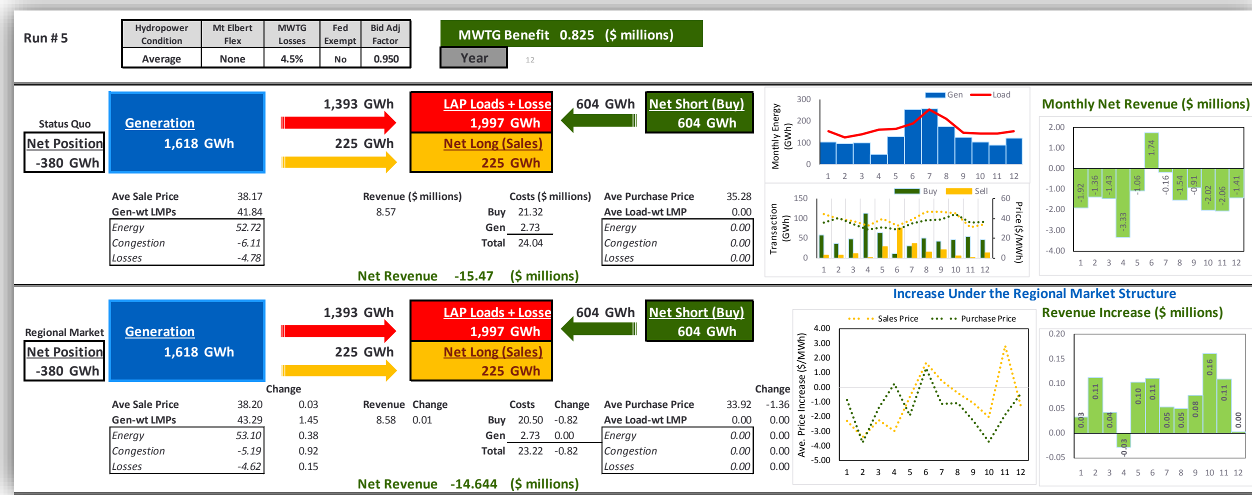


Figure B.5 RMR High Gas Price Future: Run 5 Energy and Financial Flow Results

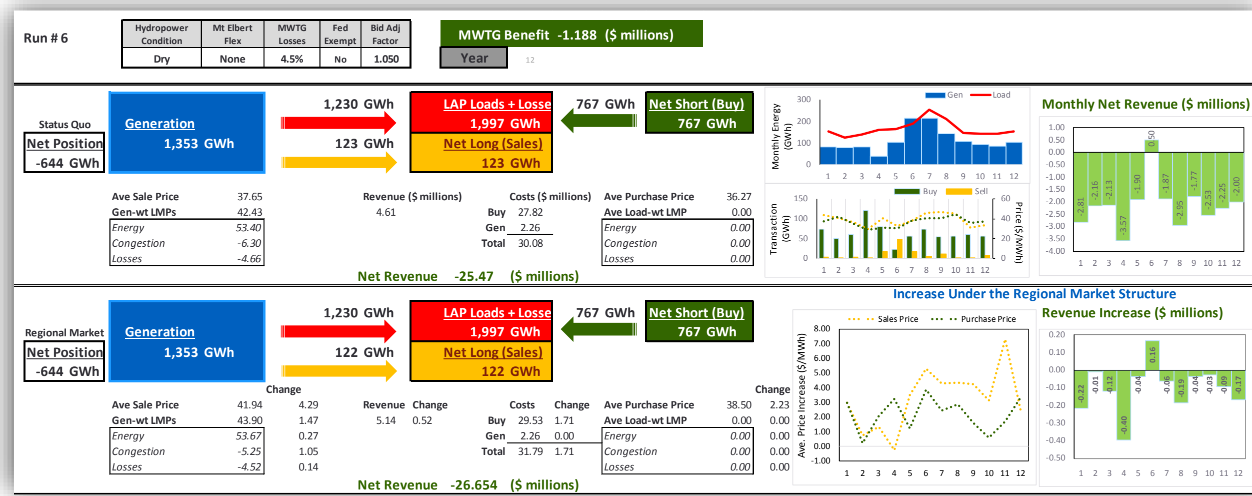


Figure B.6 RMR High Gas Price Future: Run 6 Energy and Financial Flow Results

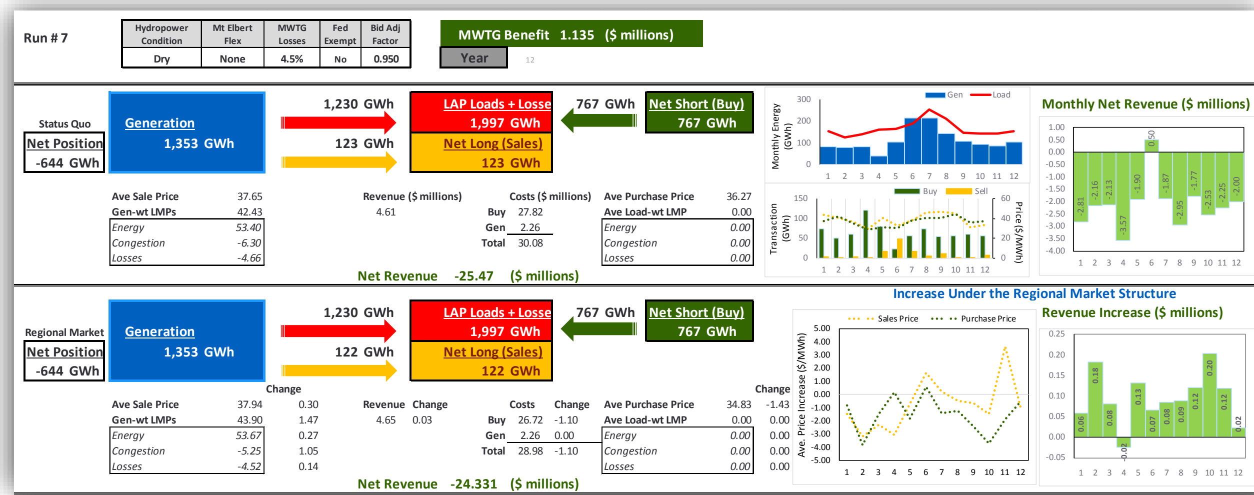


Figure B.7 RMR High Gas Price Future: Run 7 Energy and Financial Flow Results

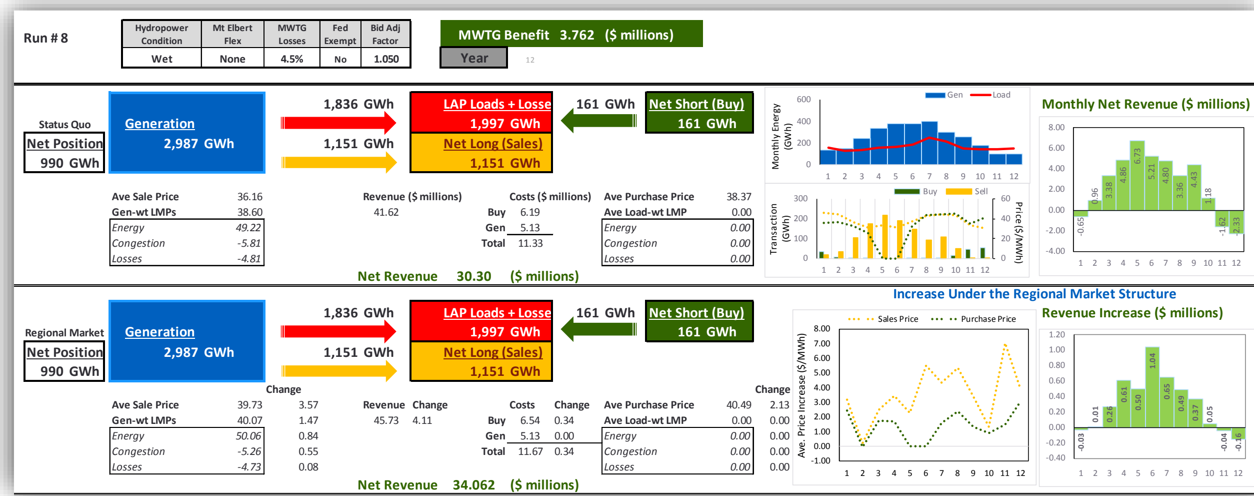


Figure B.8 RMR High Gas Price Future: Run 8 Energy and Financial Flow Results

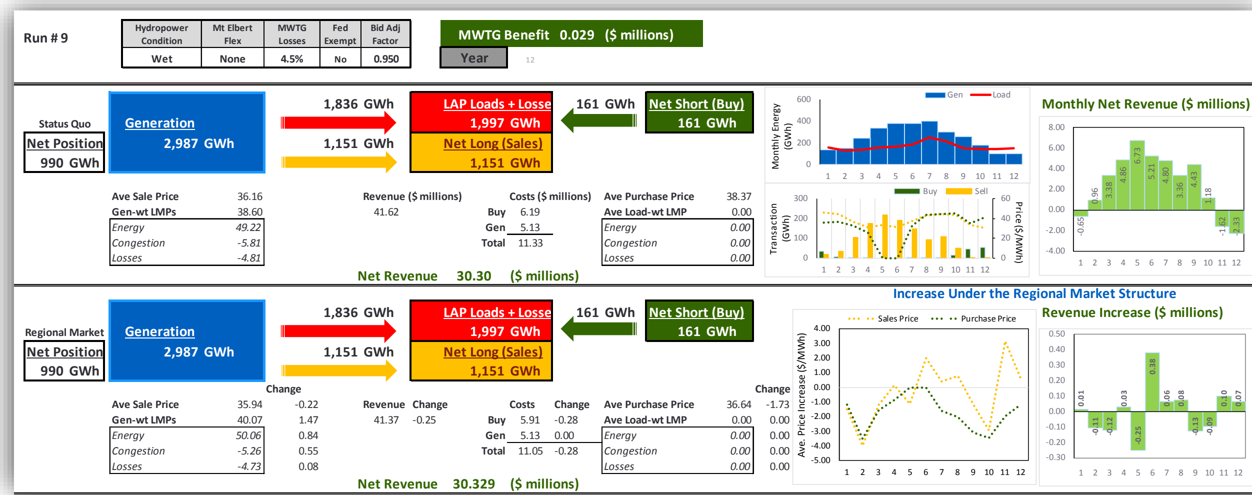


Figure B.9 RMR High Gas Price Future: Run 9 Energy and Financial Flow Results

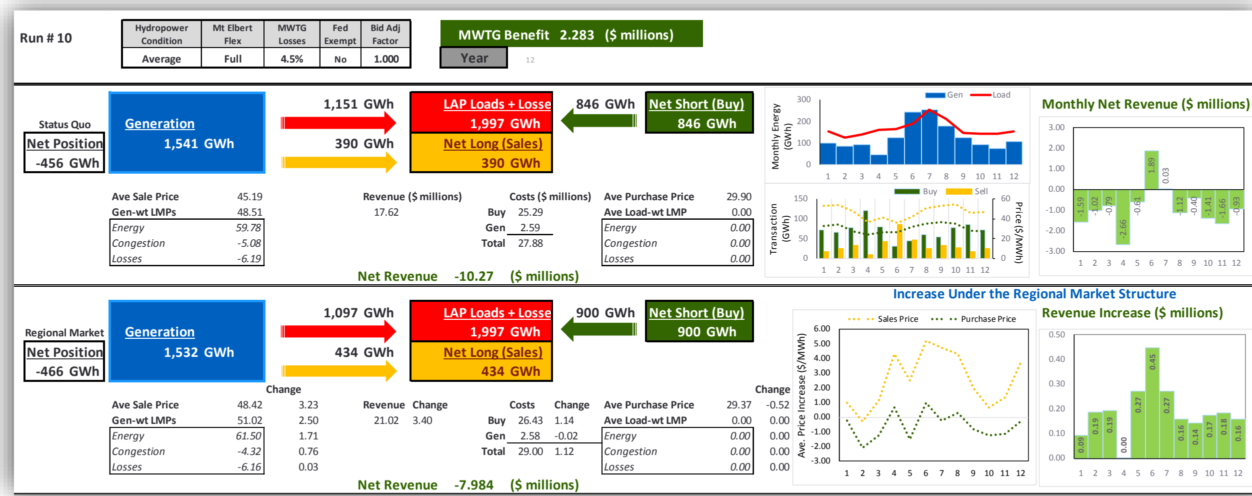


Figure B.10 RMR High Gas Price Future: Run 10 Energy and Financial Flow Results

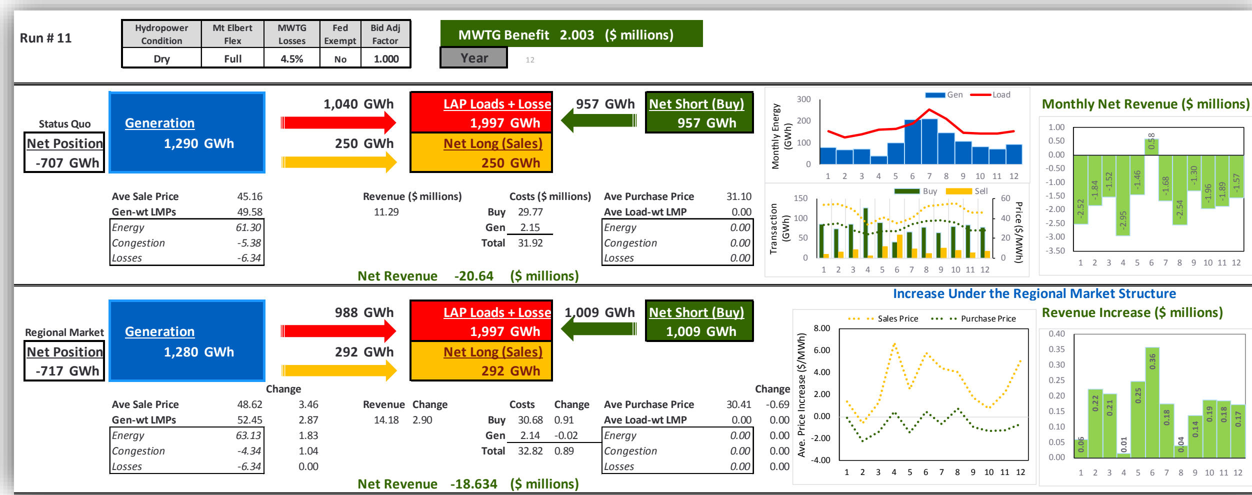


Figure B.11 RMR High Gas Price Future: Run 11 Energy and Financial Flow Results

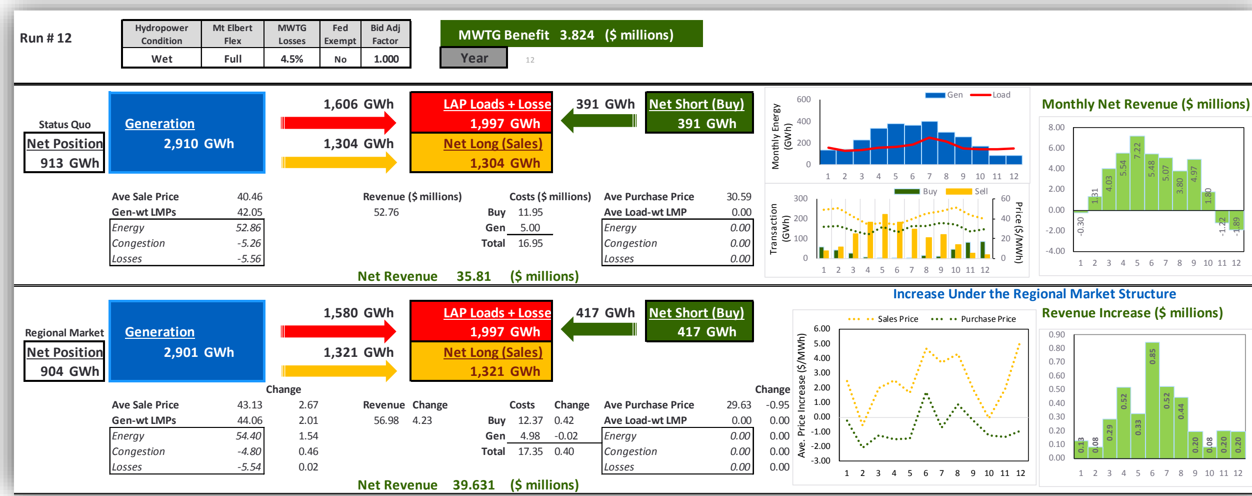


Figure B.12 RMR High Gas Price Future: Run 12 Energy and Financial Flow Results

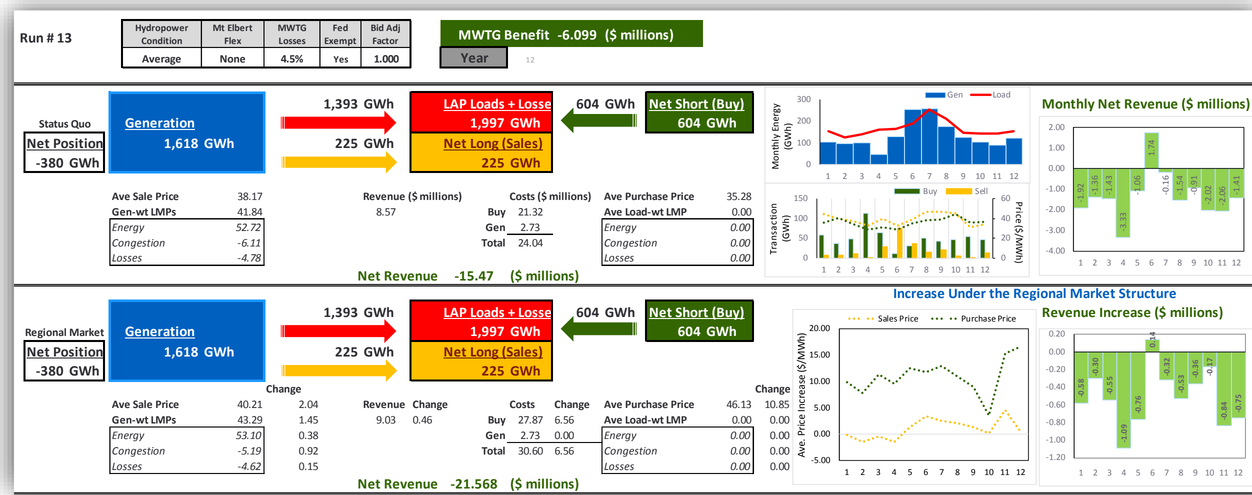


Figure B.13 RMR High Gas Price Future: Run 13 Energy and Financial Flow Results

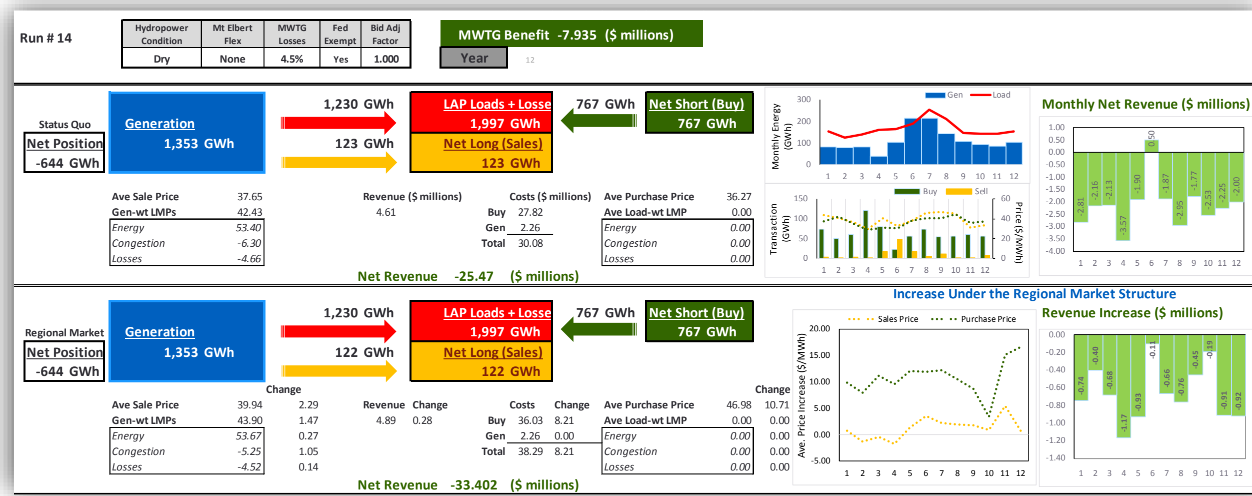


Figure B.14 RMR High Gas Price Future: Run 14 Energy and Financial Flow Results

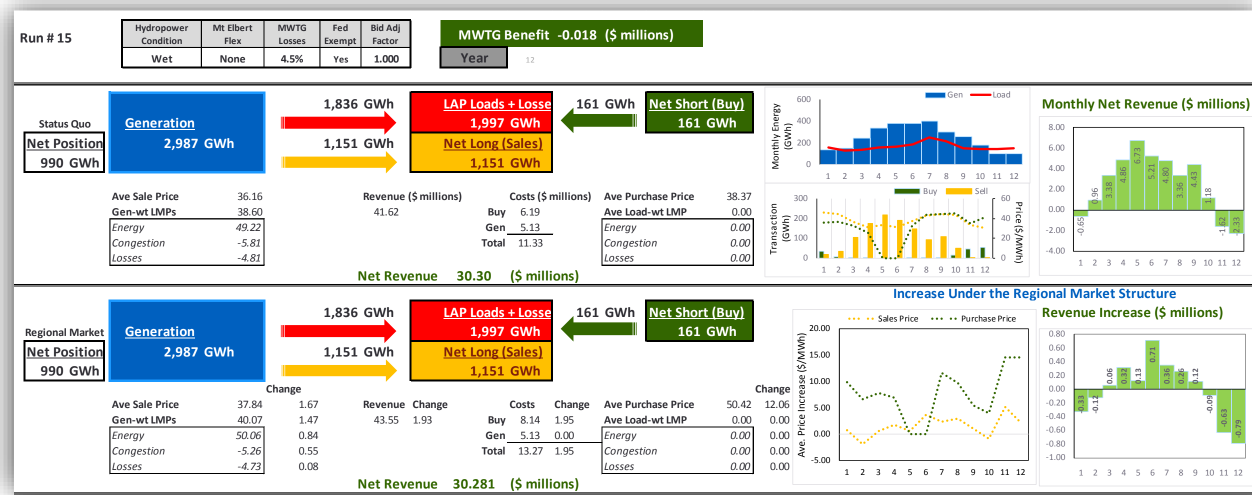


Figure B.15 RMR High Gas Price Future: Run 15 Energy and Financial Flow Results

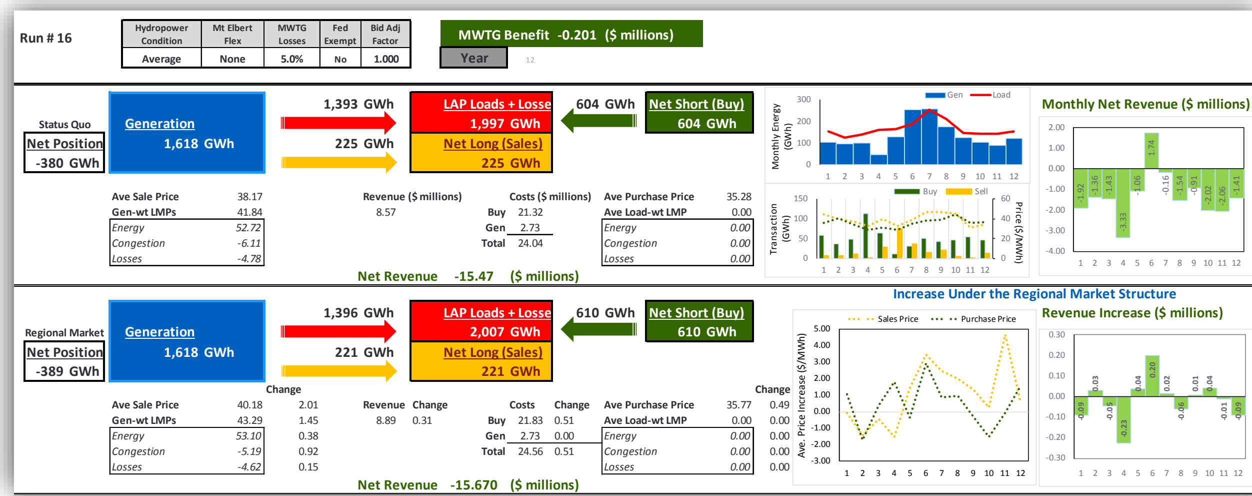


Figure B.16 RMR High Gas Price Future: Run 16 Energy and Financial Flow Results

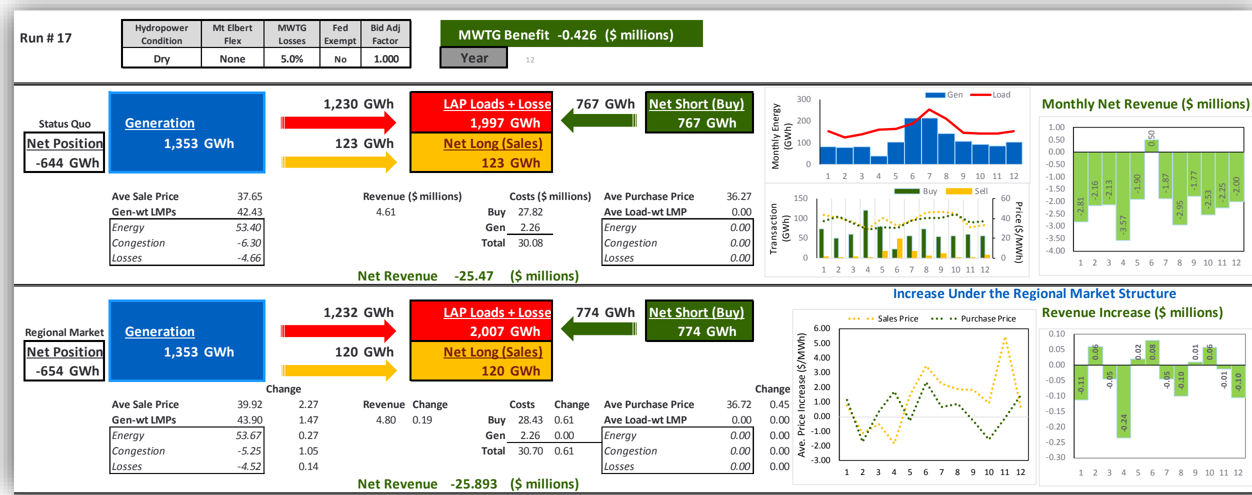


Figure B.17 RMR High Gas Price Future: Run 17 Energy and Financial Flow Results

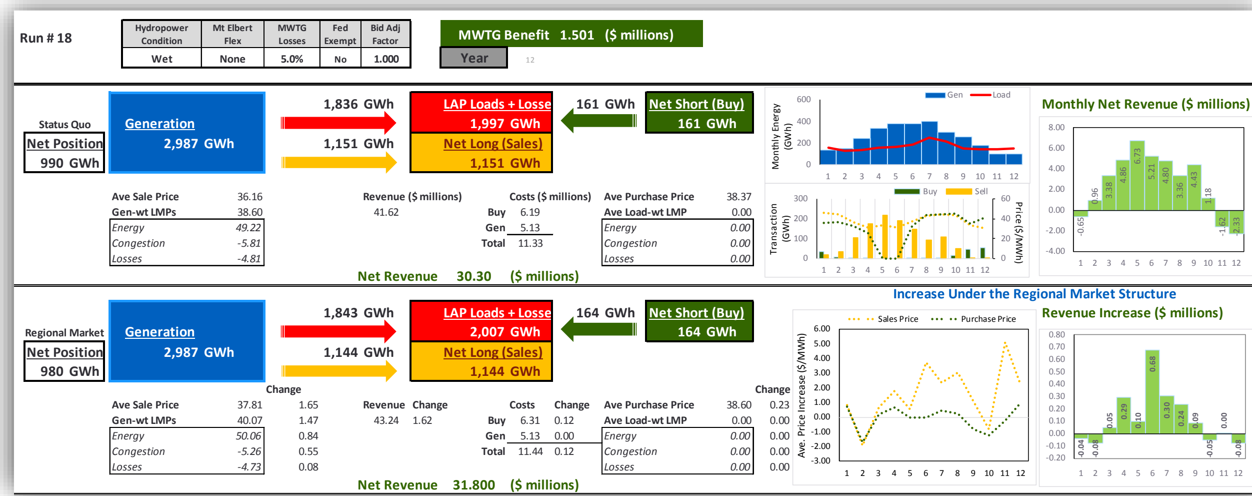


Figure B.18 RMR High Gas Price Future: Run 18 Energy and Financial Flow Results

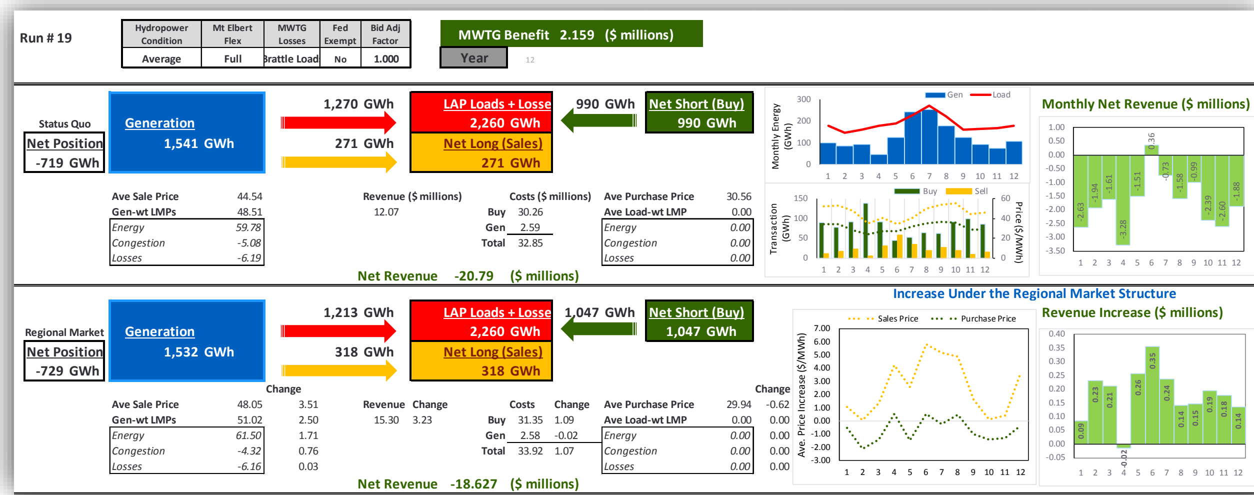


Figure B.19 RMR High Gas Price Future: Run 19 Energy and Financial Flow Results

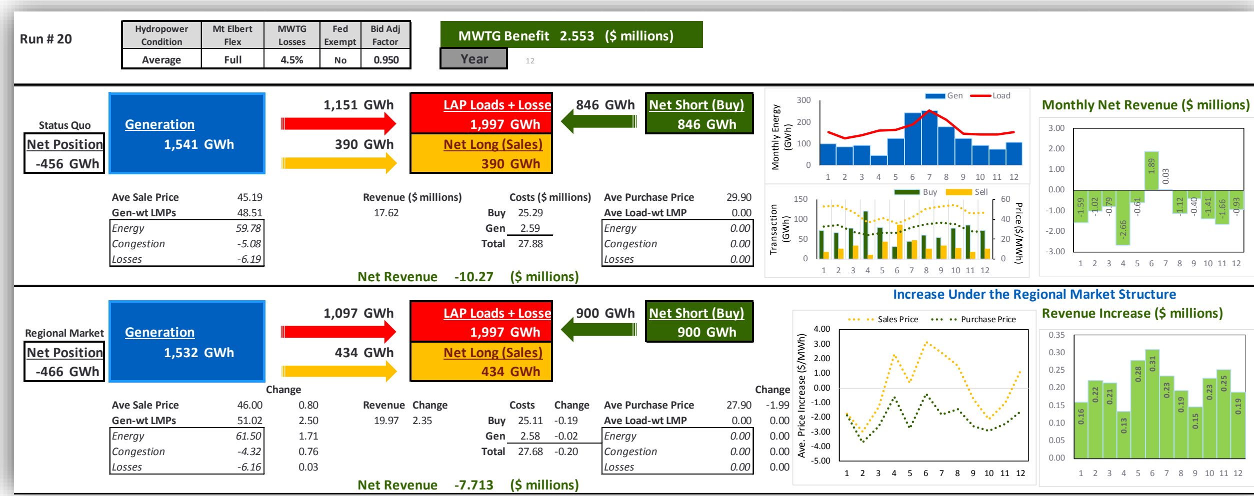


Figure B.20 RMR High Gas Price Future: Run 20 Energy and Financial Flow Results

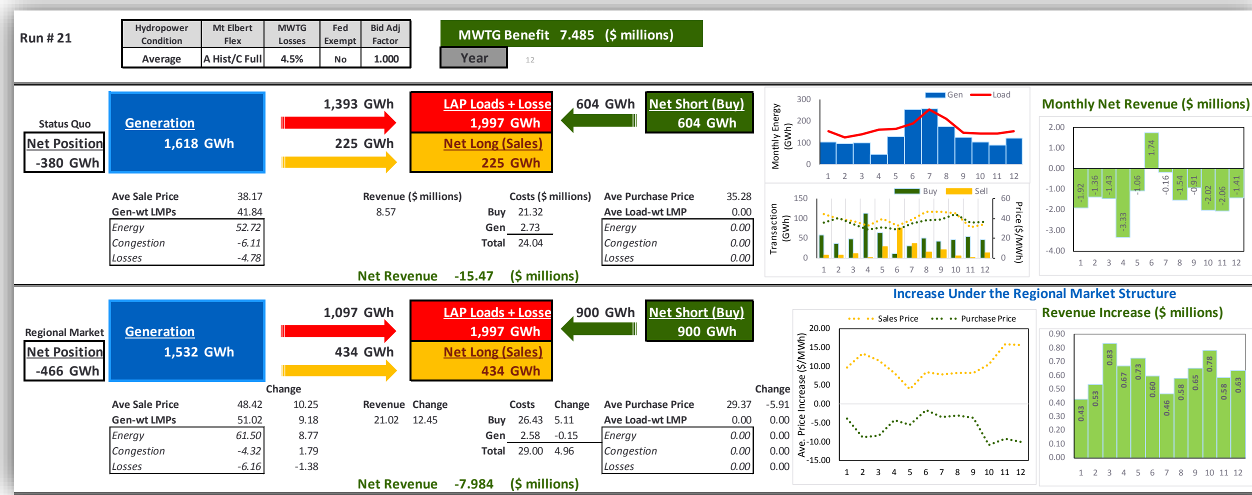


Figure B.21 RMR High Gas Price Future: Run 21 Energy and Financial Flow Results

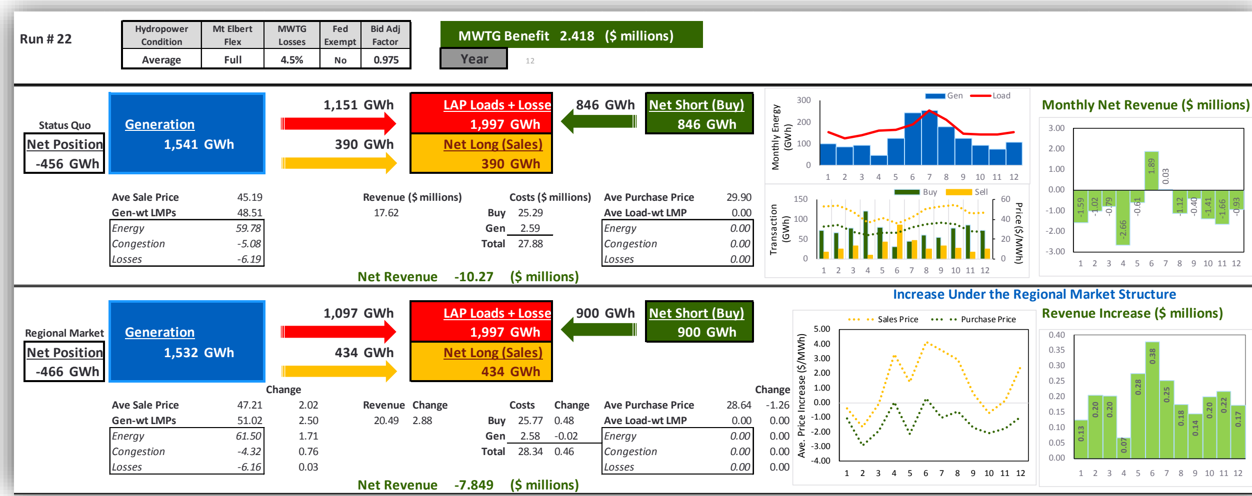


Figure B.22 RMR High Gas Price Future: Run 22 Energy and Financial Flow Results

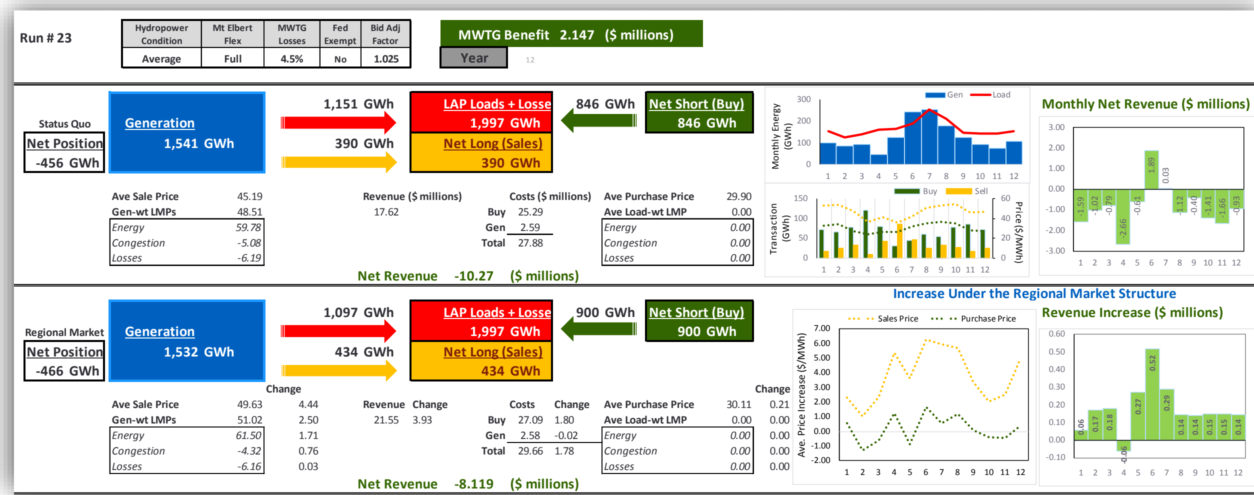


Figure B.23 RMR High Gas Price Future: Run 23 Energy and Financial Flow Results

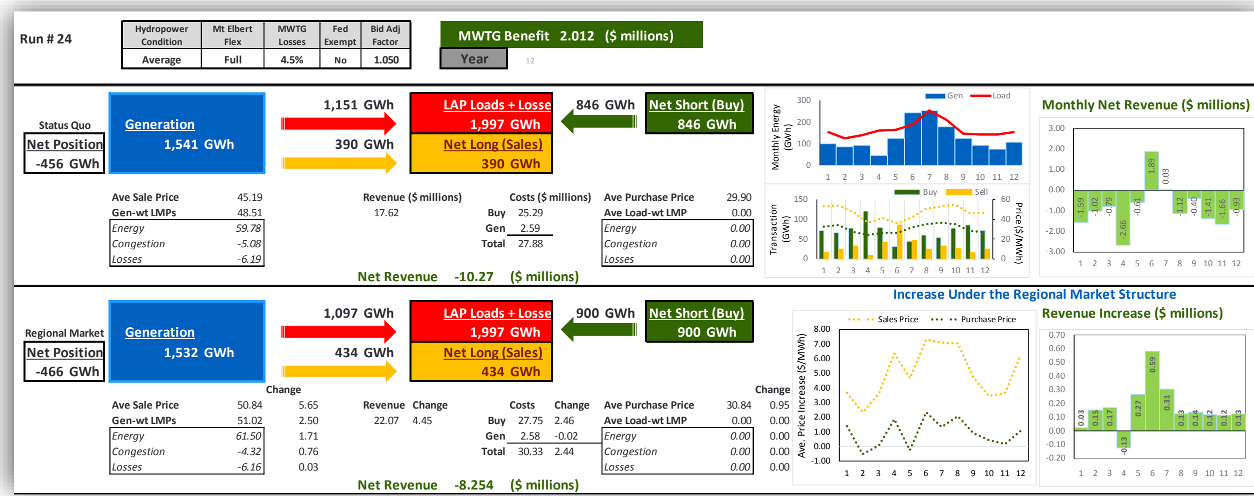


Figure B.24 RMR High Gas Price Future: Run 24 Energy and Financial Flow Results

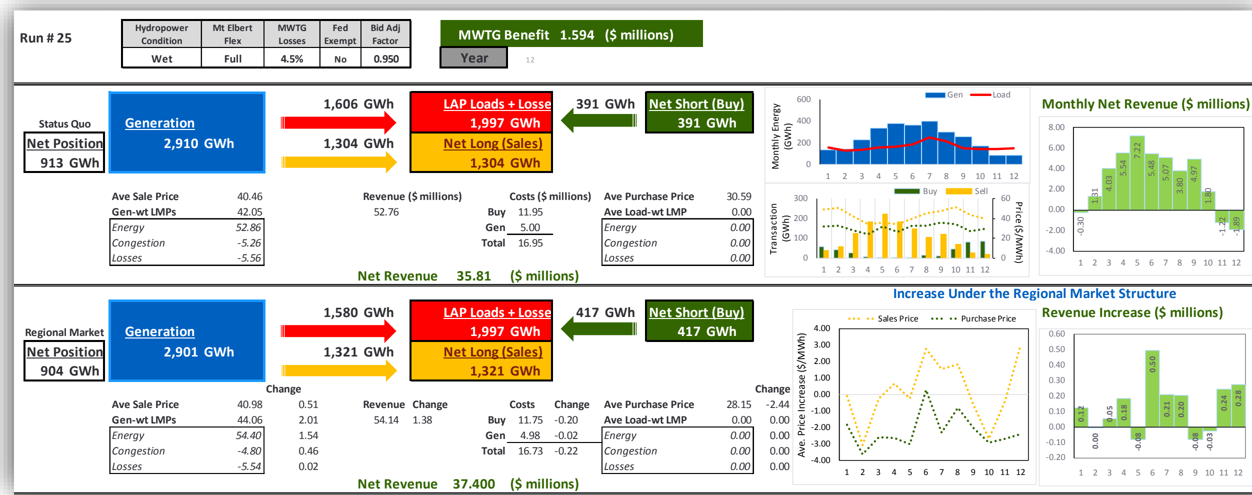


Figure B.25 RMR High Gas Price Future: Run 25 Energy and Financial Flow Results

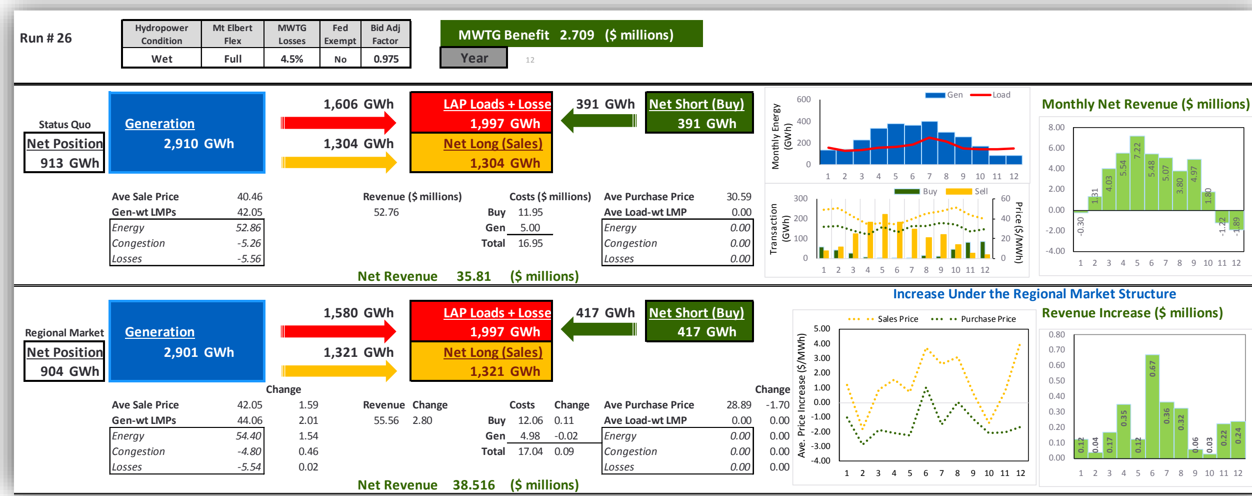


Figure B.26 RMR High Gas Price Future: Run 26 Energy and Financial Flow Results

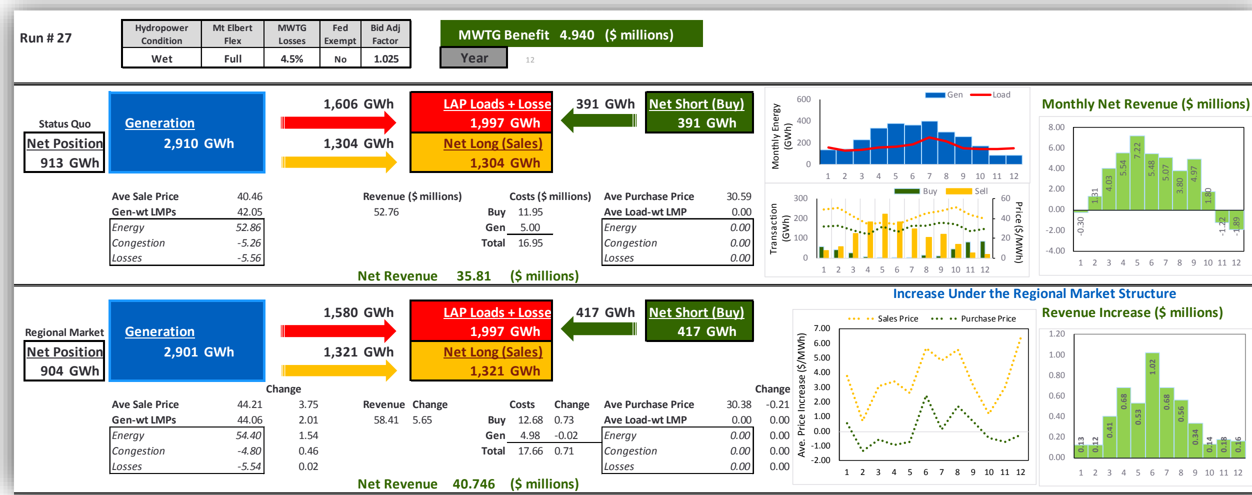


Figure B.27 RMR High Gas Price Future: Run 27 Energy and Financial Flow Results

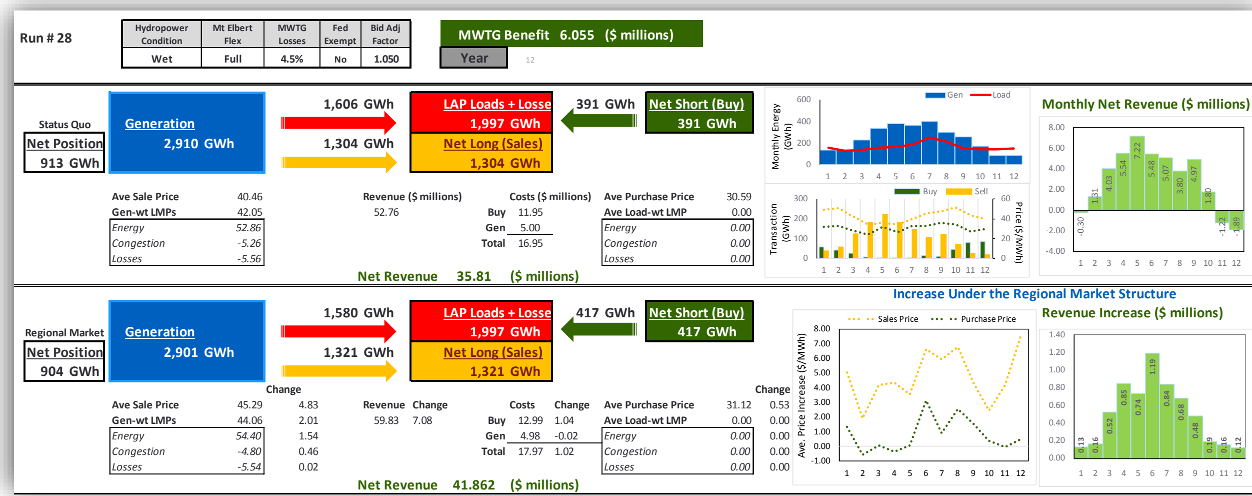


Figure B.28 RMR High Gas Price Future: Run 28 Energy and Financial Flow Results

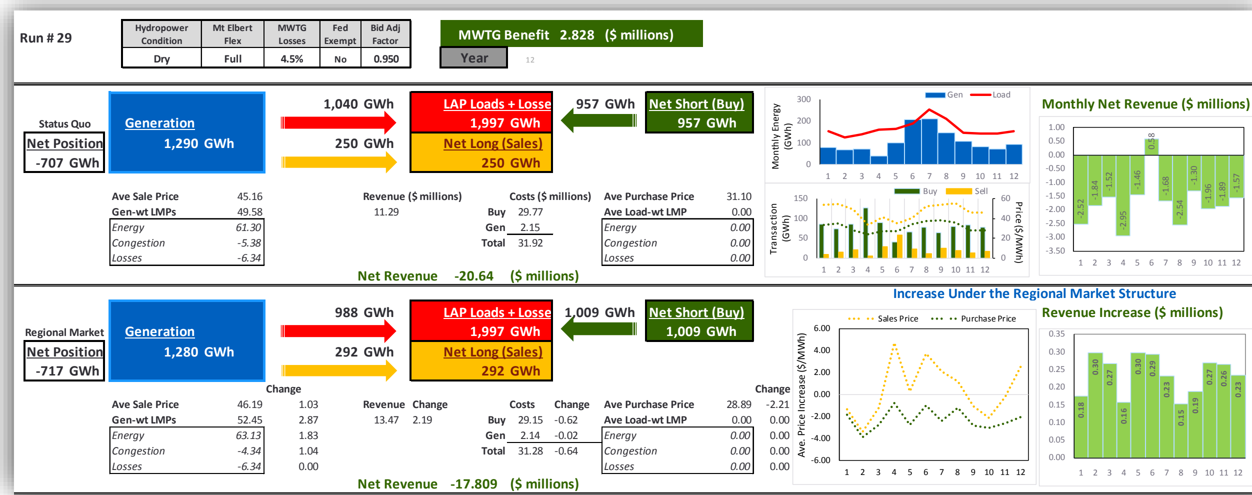


Figure B.29 RMR High Gas Price Future: Run 29 Energy and Financial Flow Results

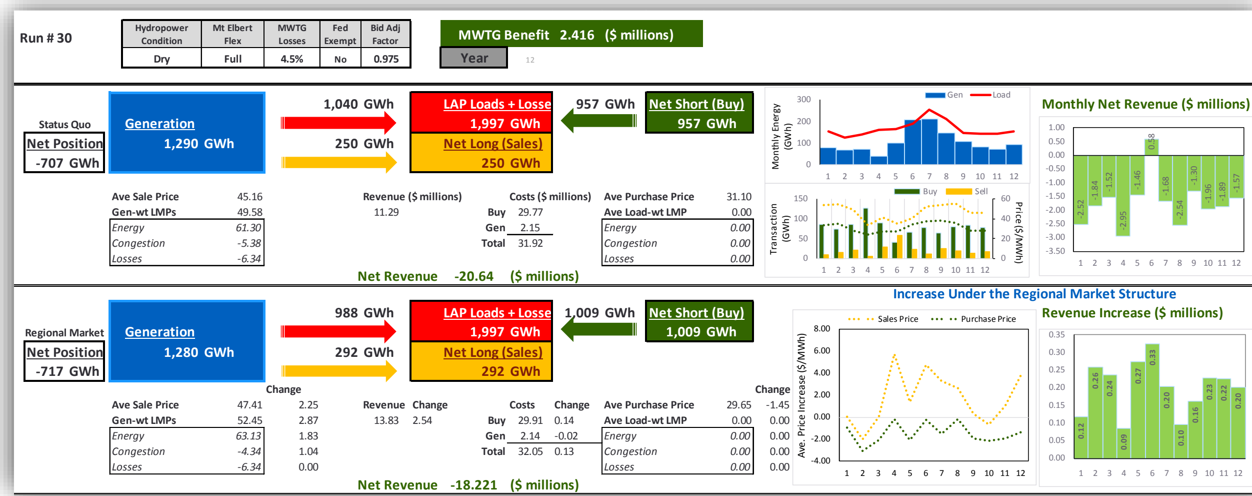


Figure B.30 RMR High Gas Price Future: Run 30 Energy and Financial Flow Results

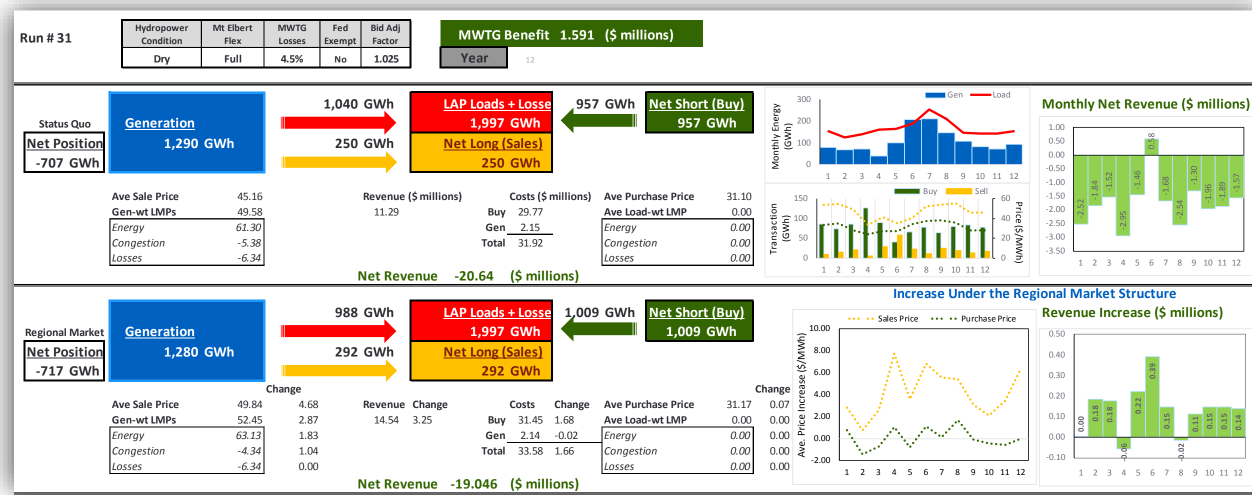


Figure B.31 RMR High Gas Price Future: Run 31 Energy and Financial Flow Results

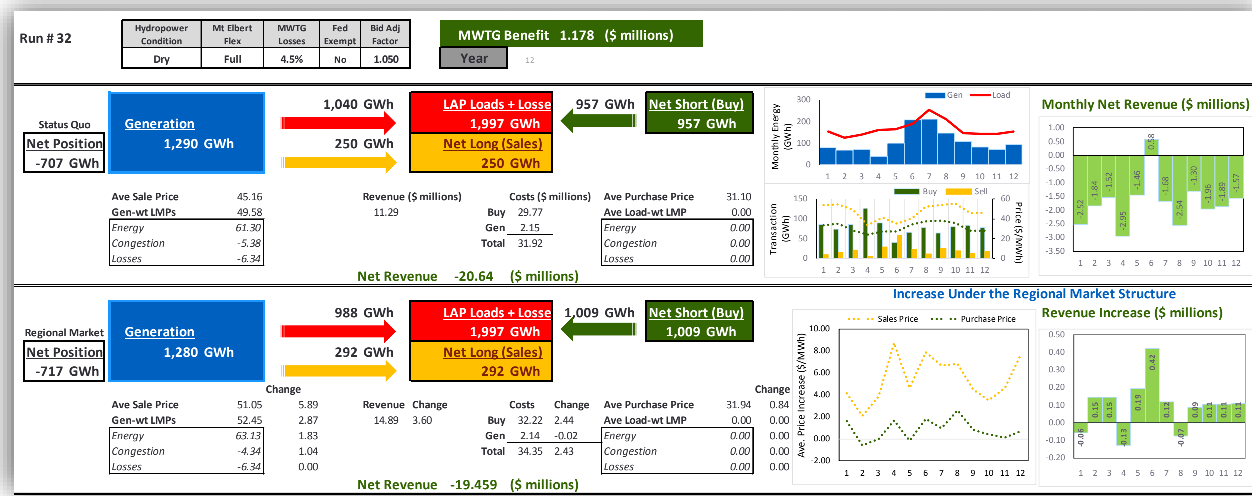


Figure B.32 RMR High Gas Price Future: Run 32 Energy and Financial Flow Results

Attachment C

Market Stress Future: RMR Financial Model Result Synopsis

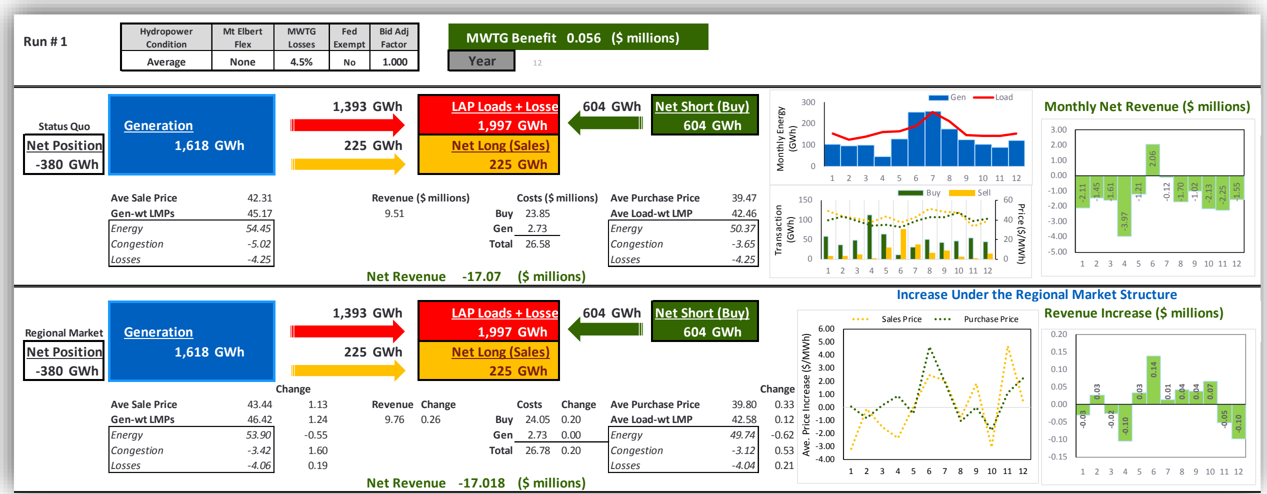


Figure C.1 RMR Market Stress Future: Run 1 Energy and Financial Flow Results

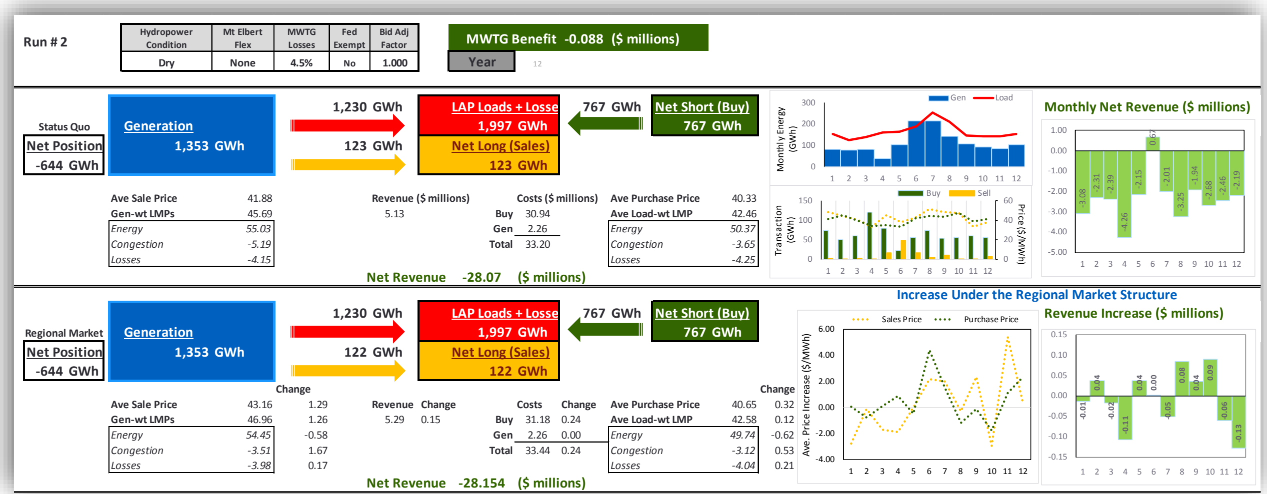


Figure C.2 RMR Market Stress Future: Run 2 Energy and Financial Flow Results

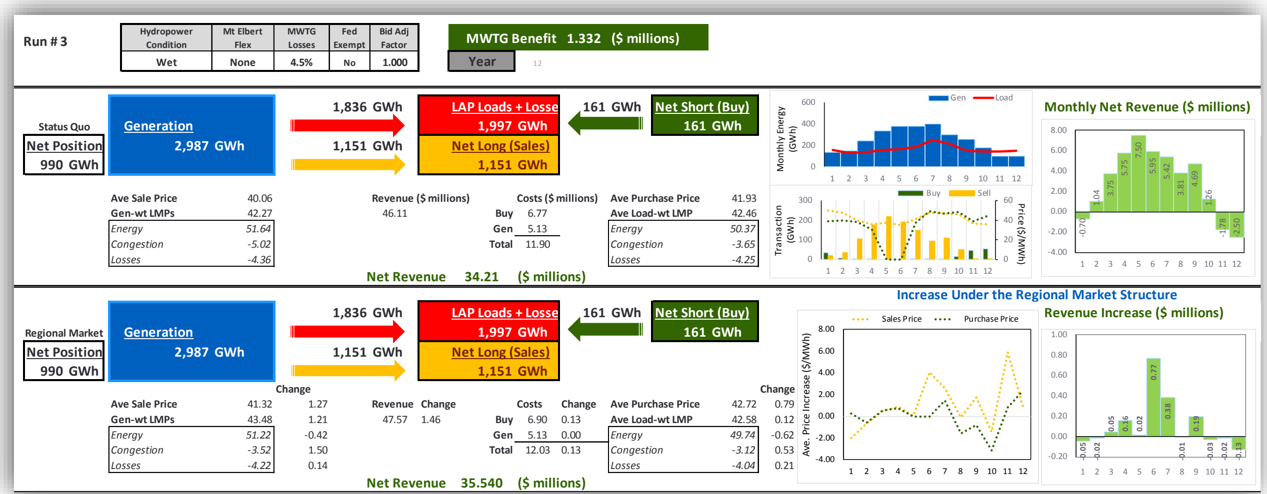


Figure C.3 RMR Market Stress Future: Run 3 Energy and Financial Flow Results

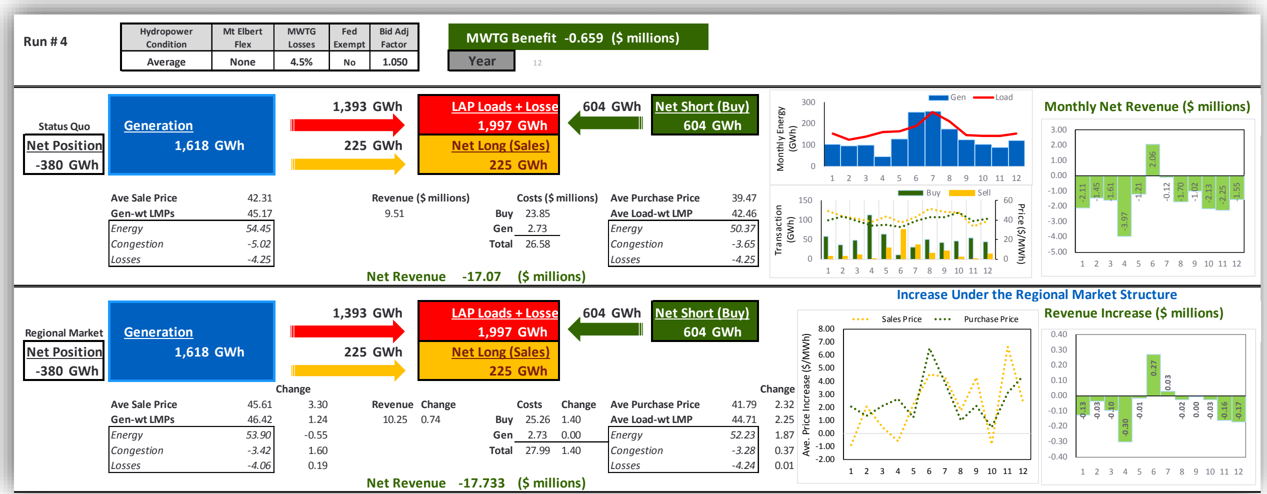


Figure C.4 RMR Market Stress Future: Run 4 Energy and Financial Flow Results

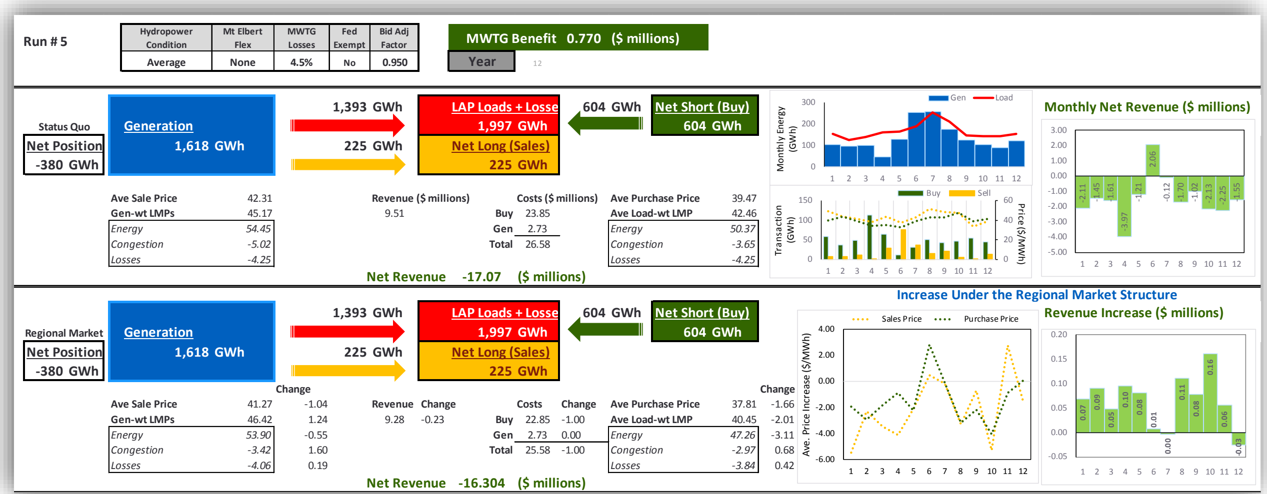


Figure C.5 RMR Market Stress Future: Run 5 Energy and Financial Flow Results

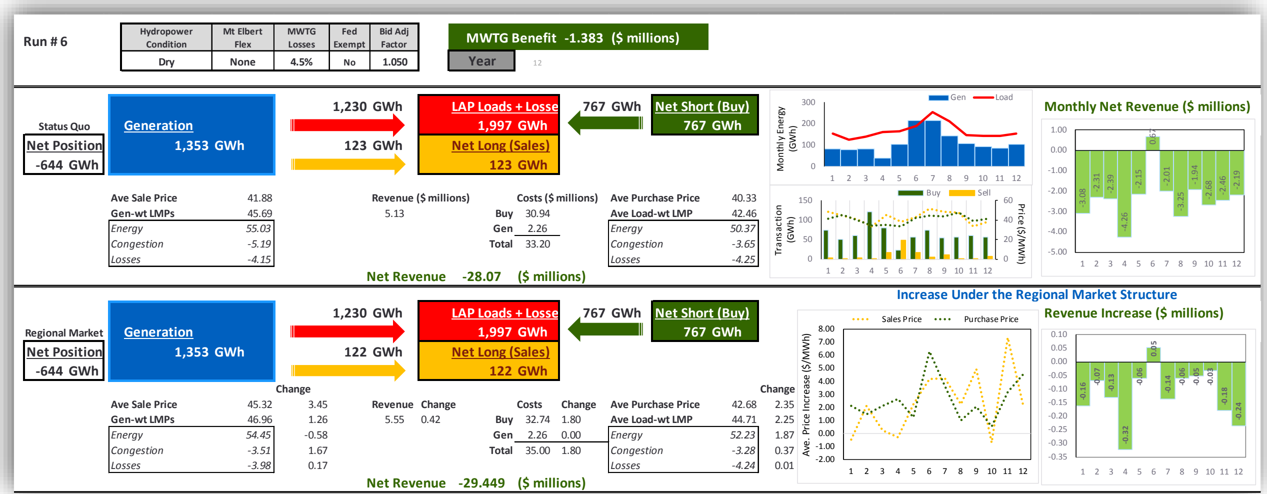


Figure C.6 RMR Market Stress Future: Run 6 Energy and Financial Flow Results

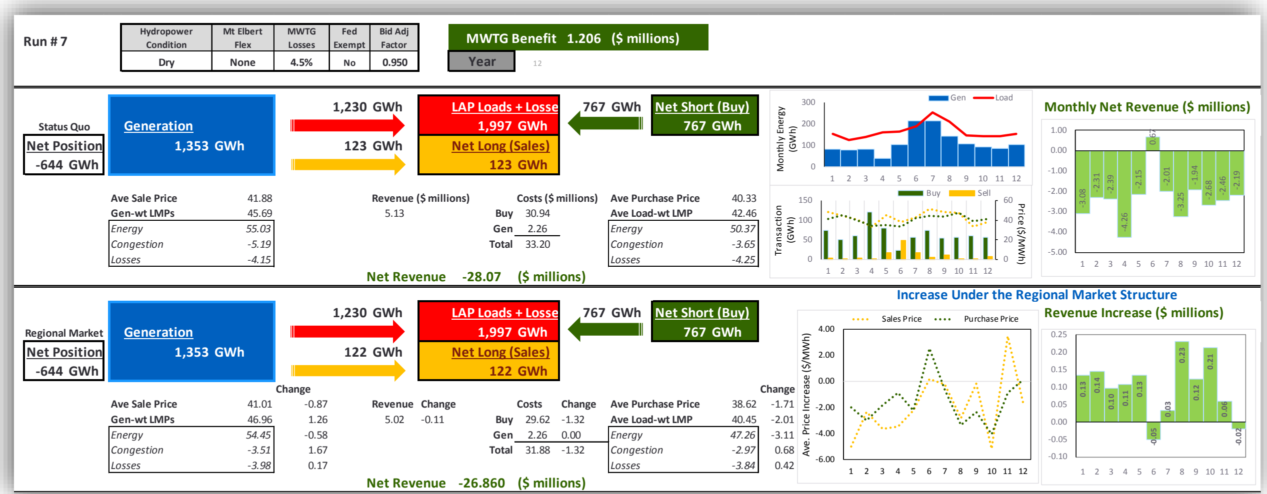


Figure C.7 RMR Market Stress Future: Run 7 Energy and Financial Flow Results

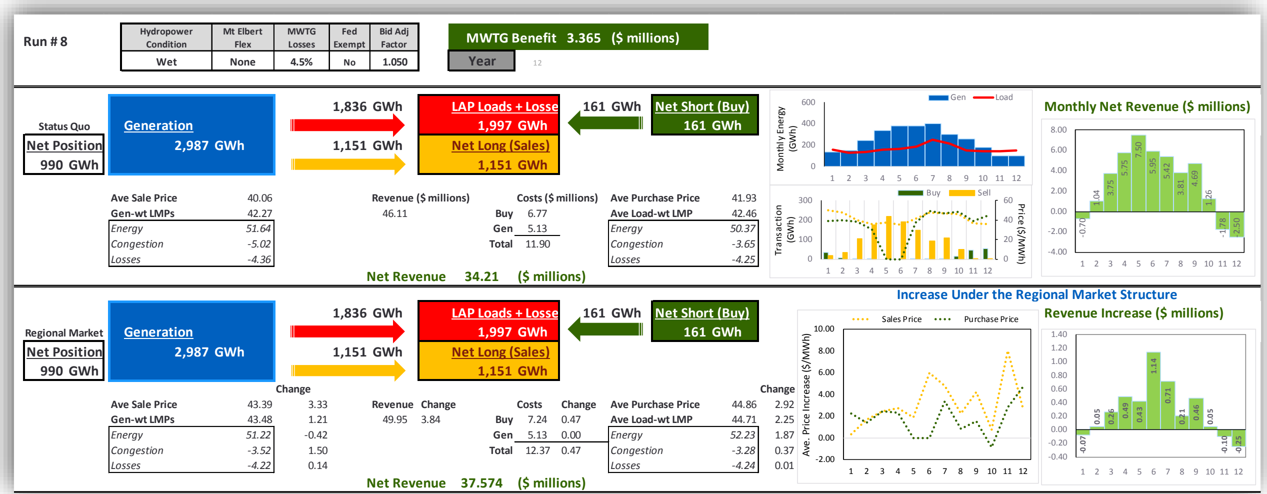


Figure C.8 RMR Market Stress Future: Run 8 Energy and Financial Flow Results

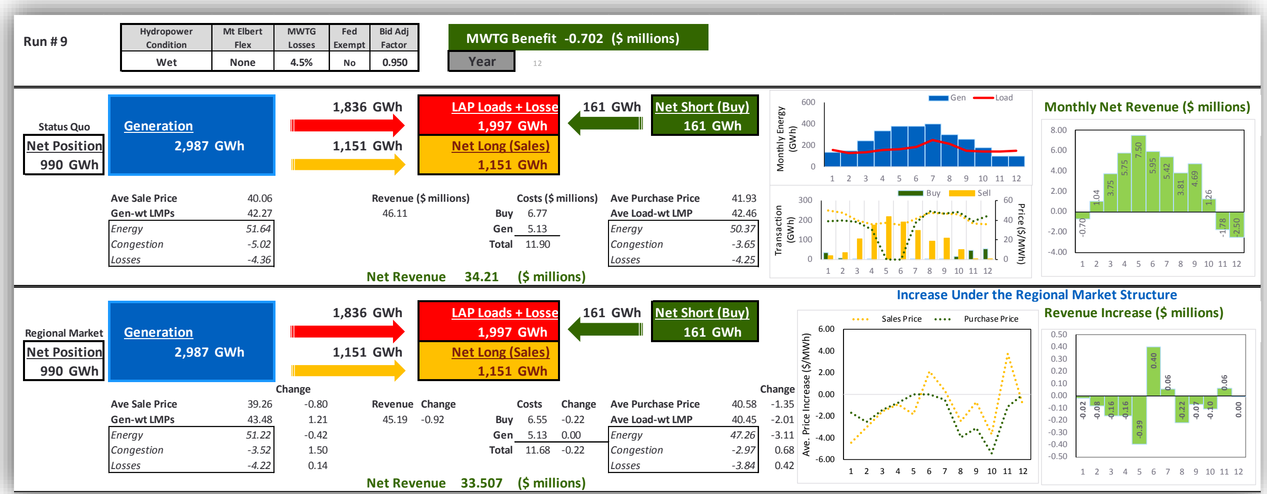


Figure C.9 RMR Market Stress Future: Run 9 Energy and Financial Flow Results

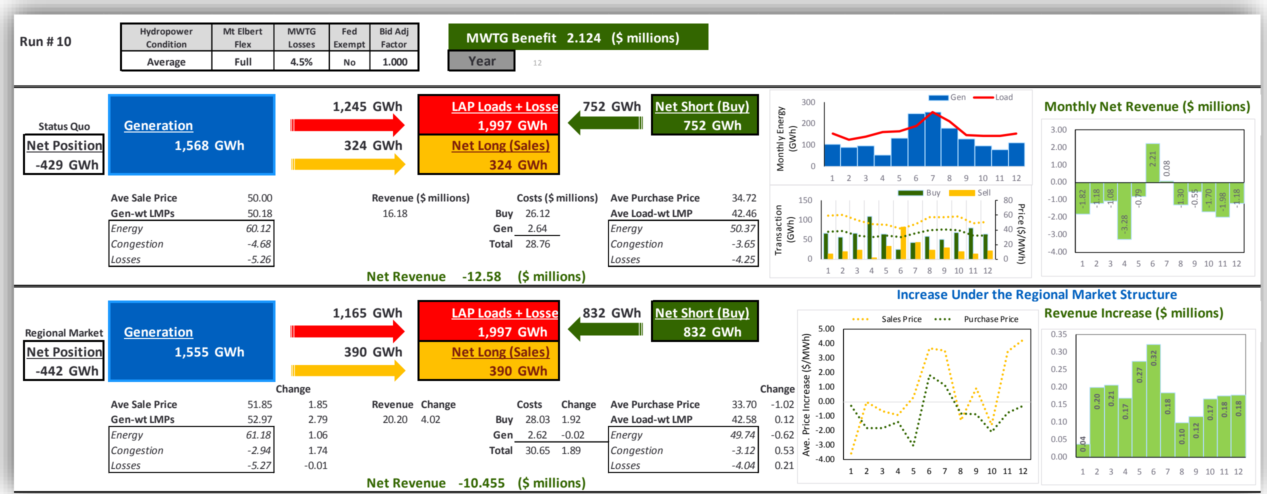


Figure C.10 RMR Market Stress Future: Run 10 Energy and Financial Flow Results

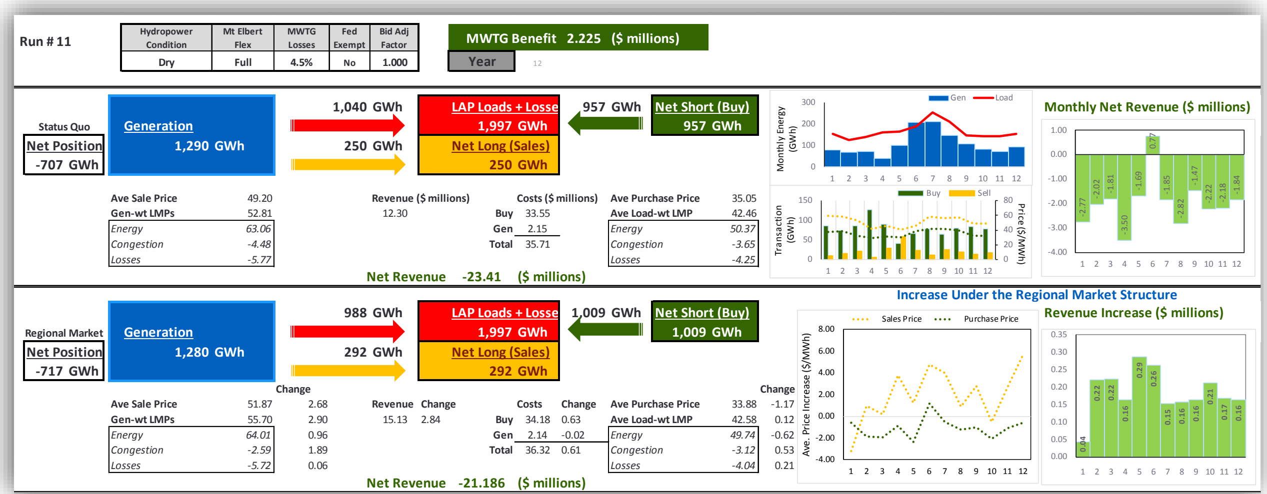


Figure C.11 RMR Market Stress Future: Run 11 Energy and Financial Flow Results

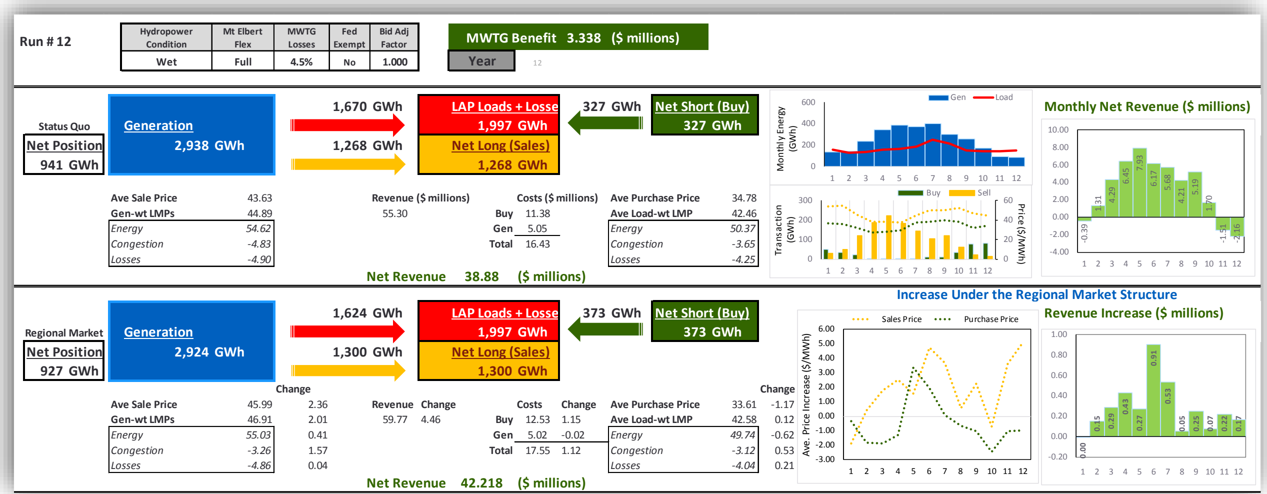


Figure C.12 RMR Market Stress Future: Run 12 Energy and Financial Flow Results

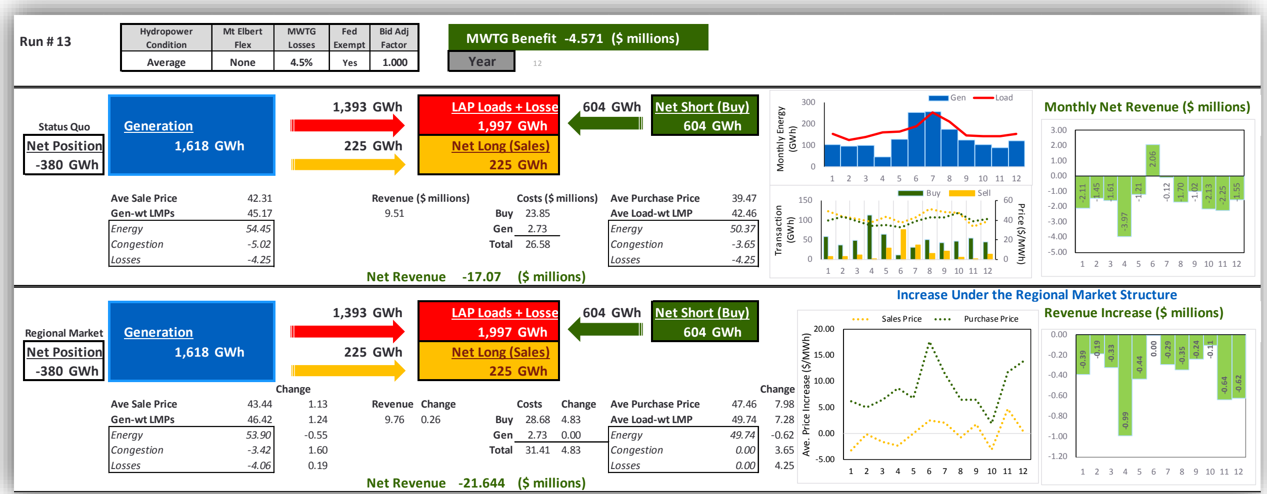


Figure C.13 RMR Market Stress Future: Run 13 Energy and Financial Flow Results

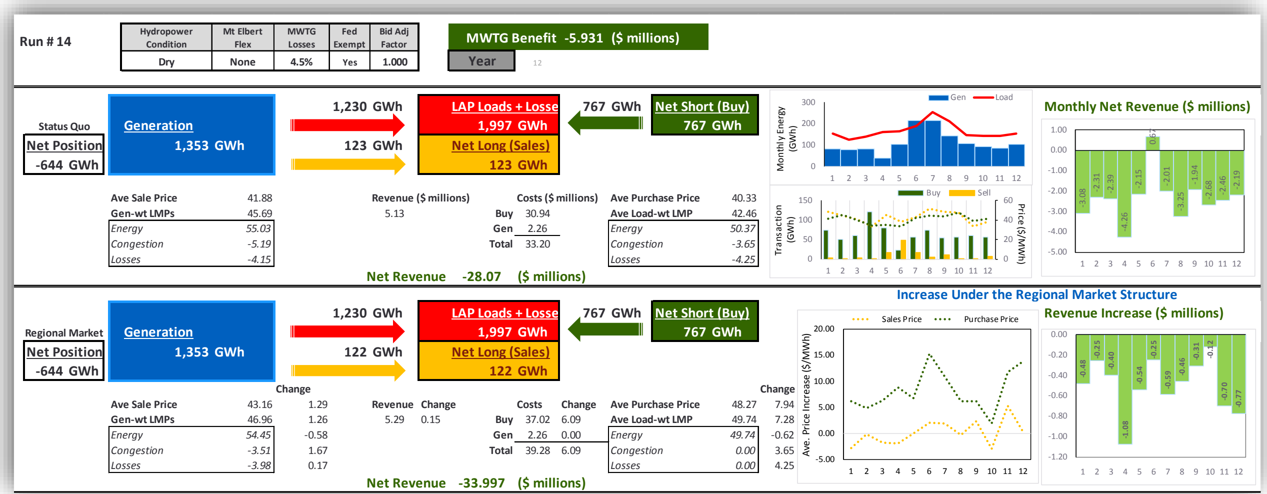


Figure C.14 RMR Market Stress Future: Run 14 Energy and Financial Flow Results

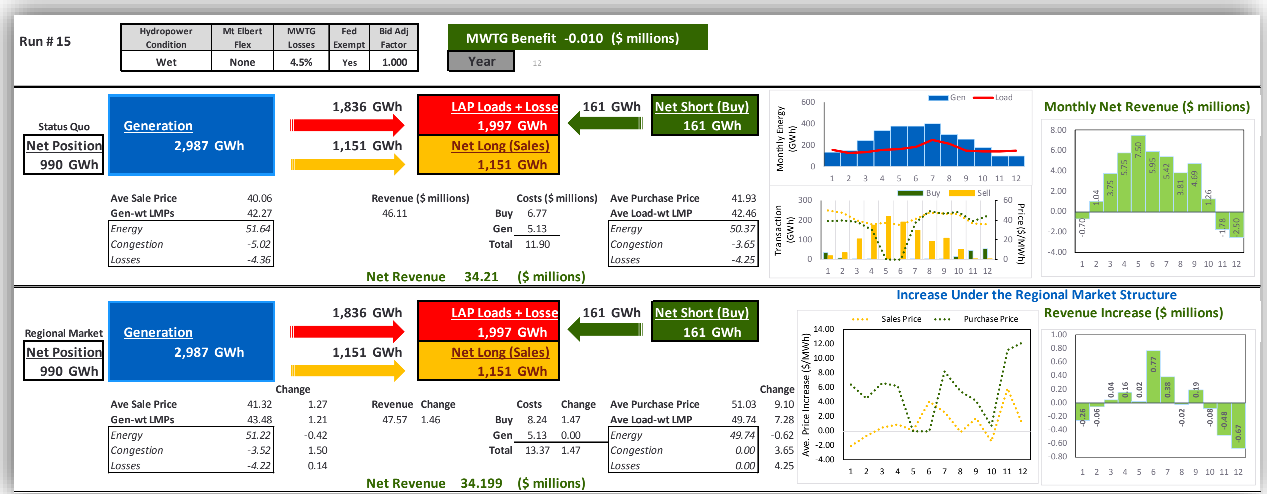


Figure C.15 RMR Market Stress Future: Run 15 Energy and Financial Flow Results

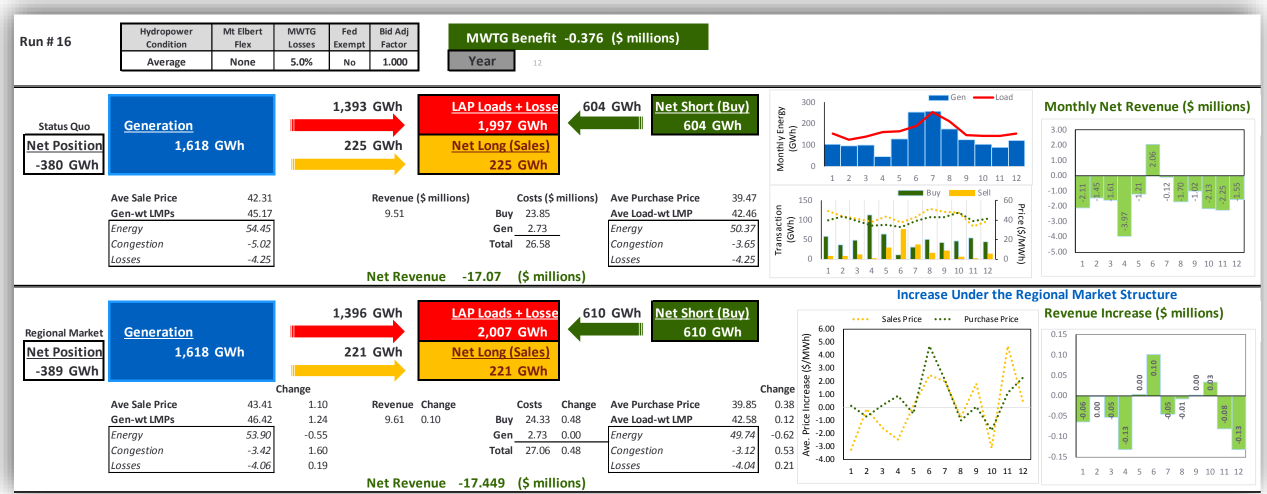


Figure C.16 RMR Market Stress Future: Run 16 Energy and Financial Flow Results

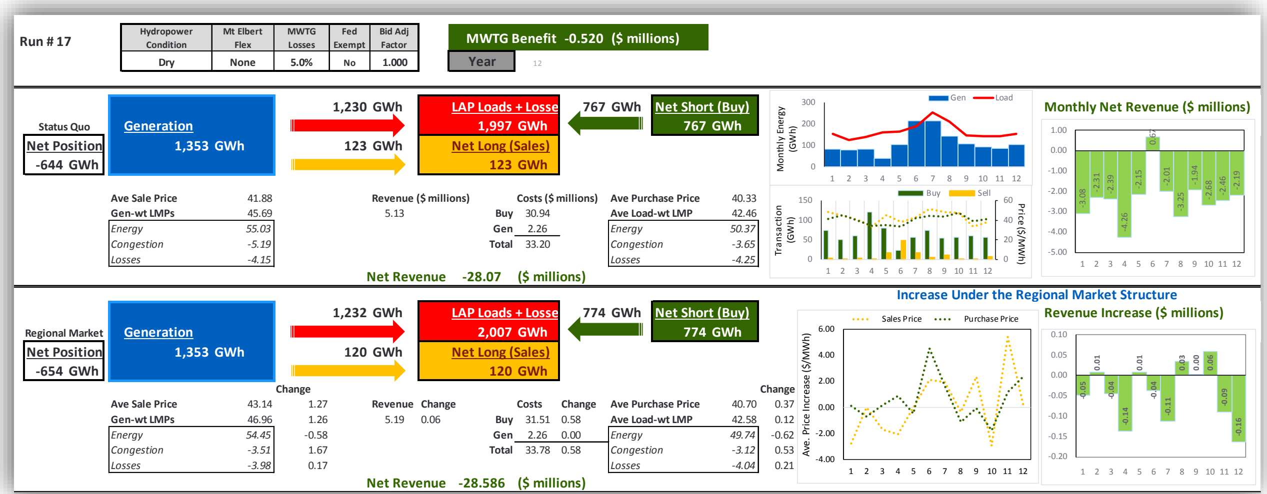


Figure C.17 RMR Market Stress Future: Run 17 Energy and Financial Flow Results

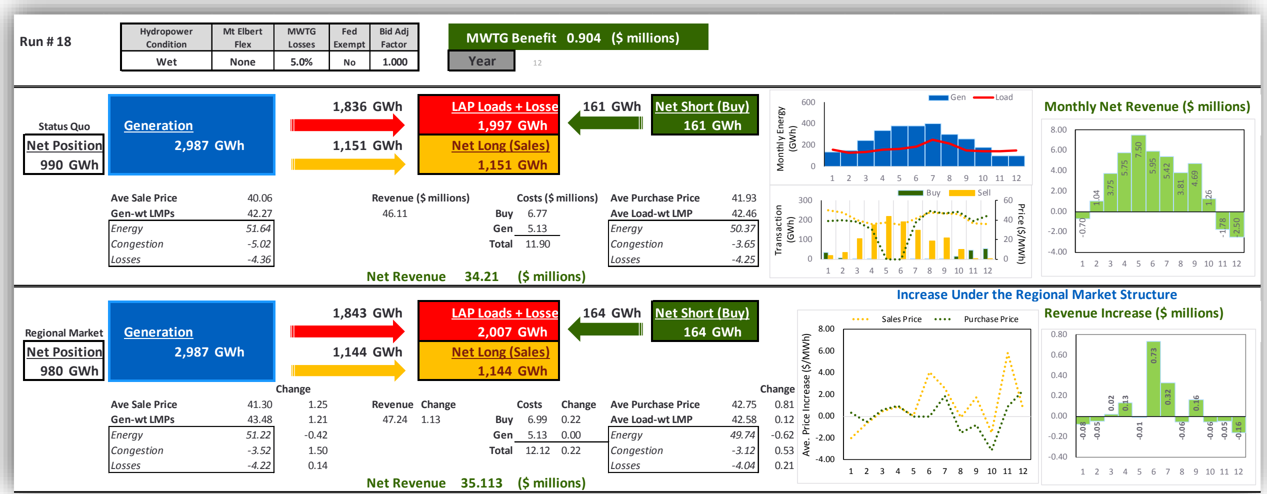


Figure C.18 RMR Market Stress Future: Run 18 Energy and Financial Flow Results

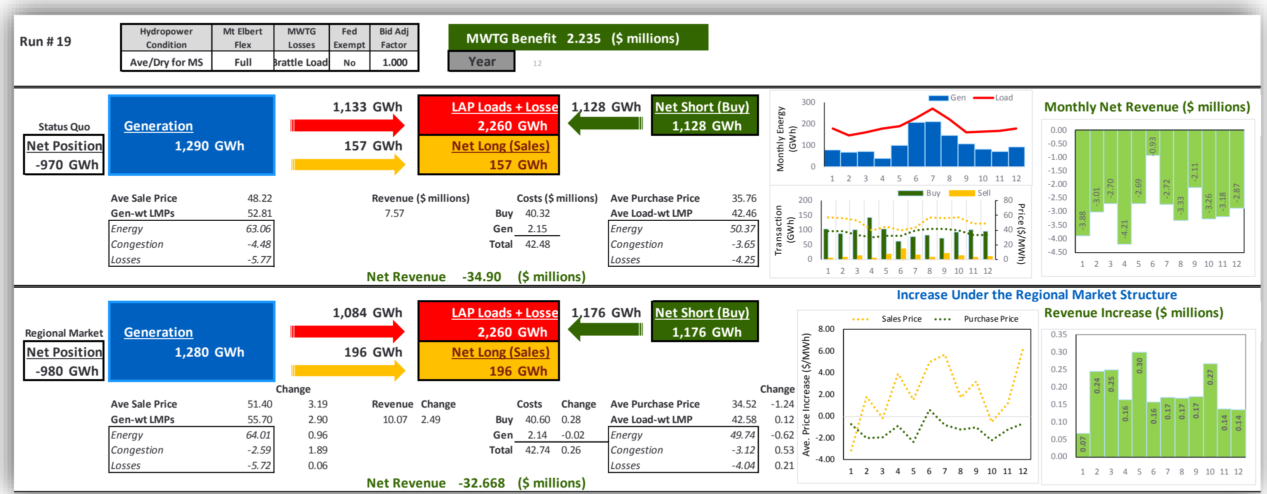


Figure C.19 RMR Market Stress Future: Run 19 Energy and Financial Flow Results

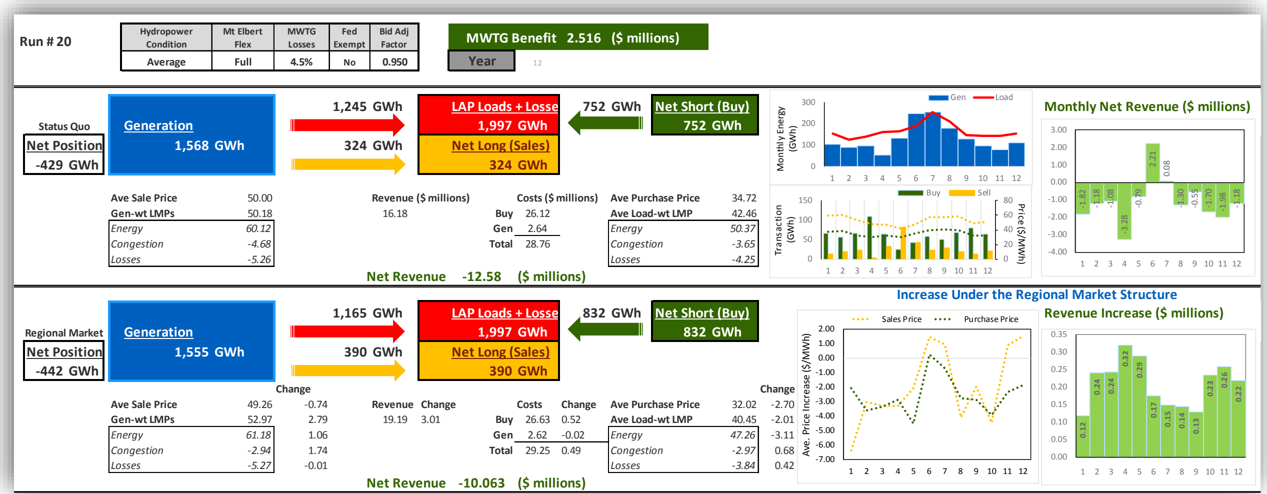


Figure C.20 RMR Market Stress Future: Run 20 Energy and Financial Flow Results

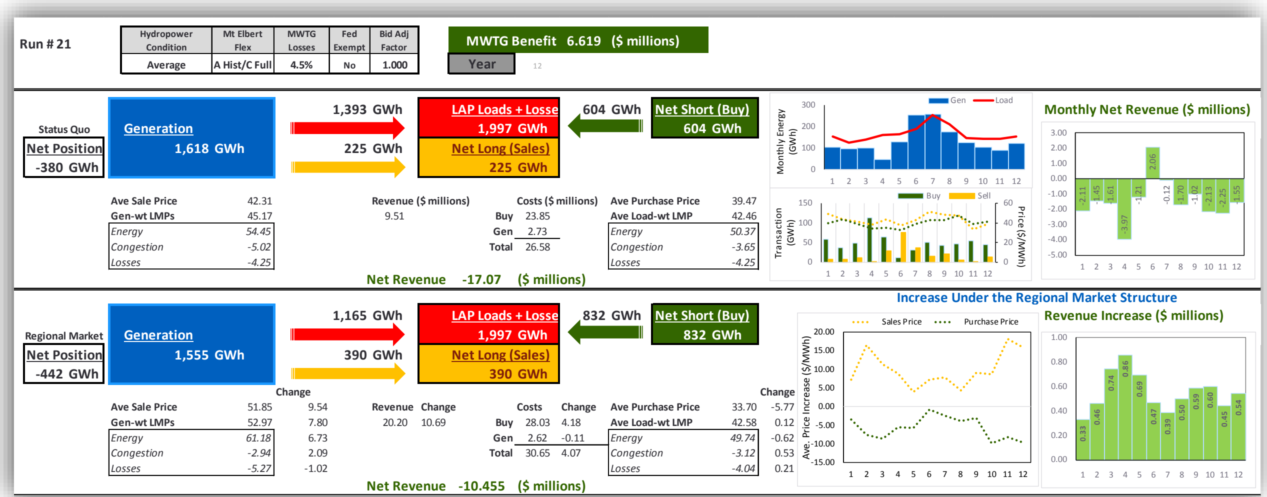


Figure C.21 RMR Market Stress Future: Run 21 Energy and Financial Flow Results

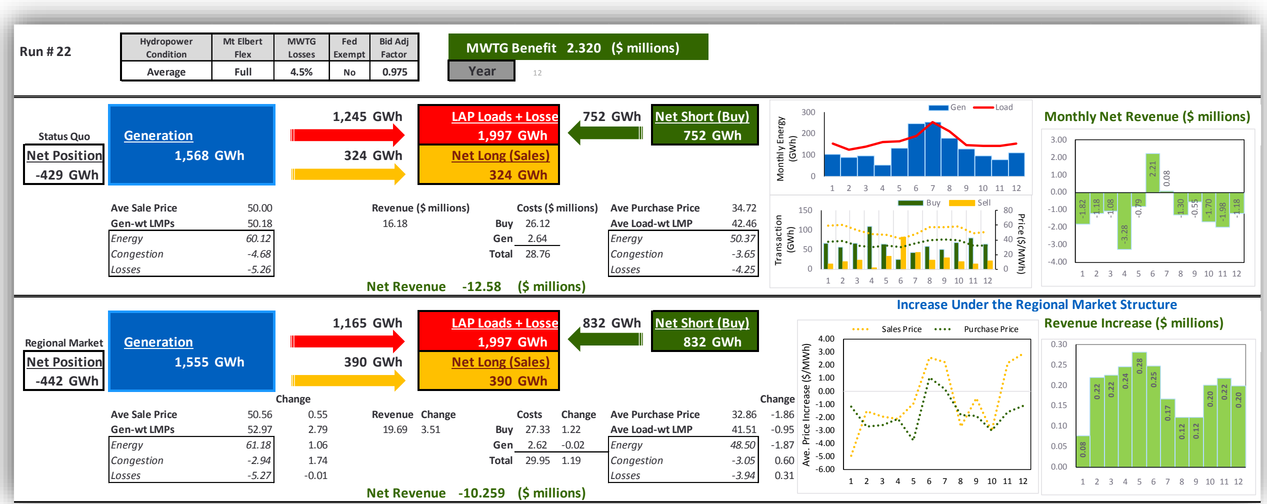


Figure C.22 RMR Market Stress Future: Run 22 Energy and Financial Flow Results

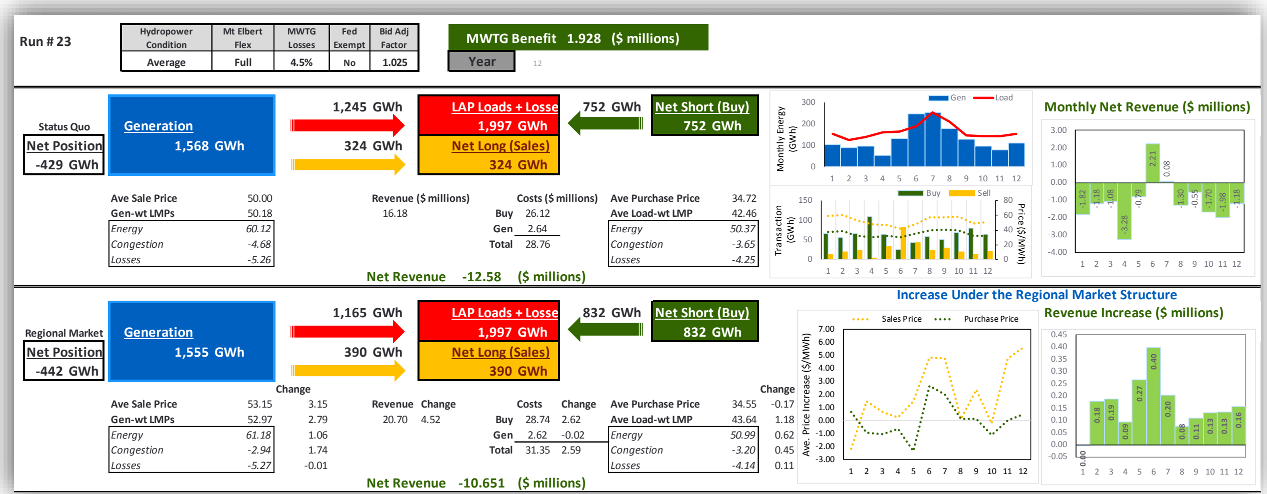


Figure C.23 RMR Market Stress Future: Run 23 Energy and Financial Flow Results

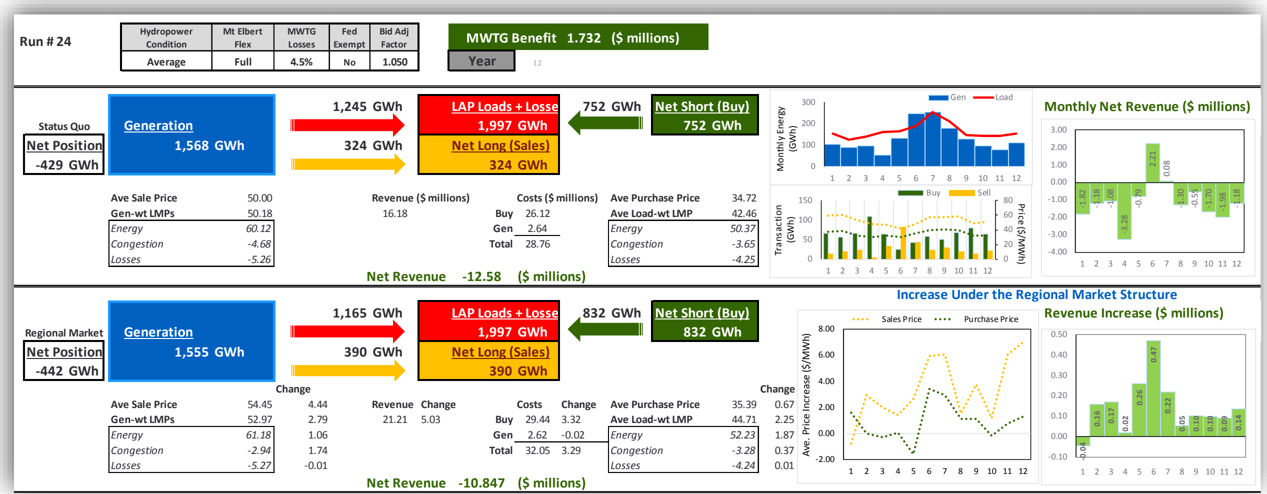


Figure C.24 RMR Market Stress Future: Run 24 Energy and Financial Flow Results

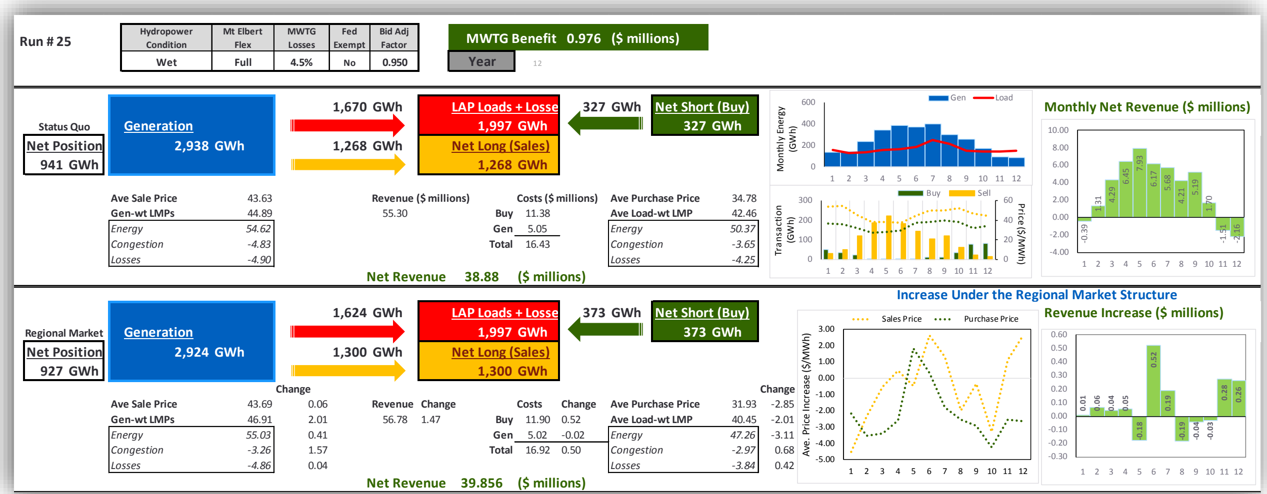


Figure C.25 RMR Market Stress Future: Run 25 Energy and Financial Flow Results

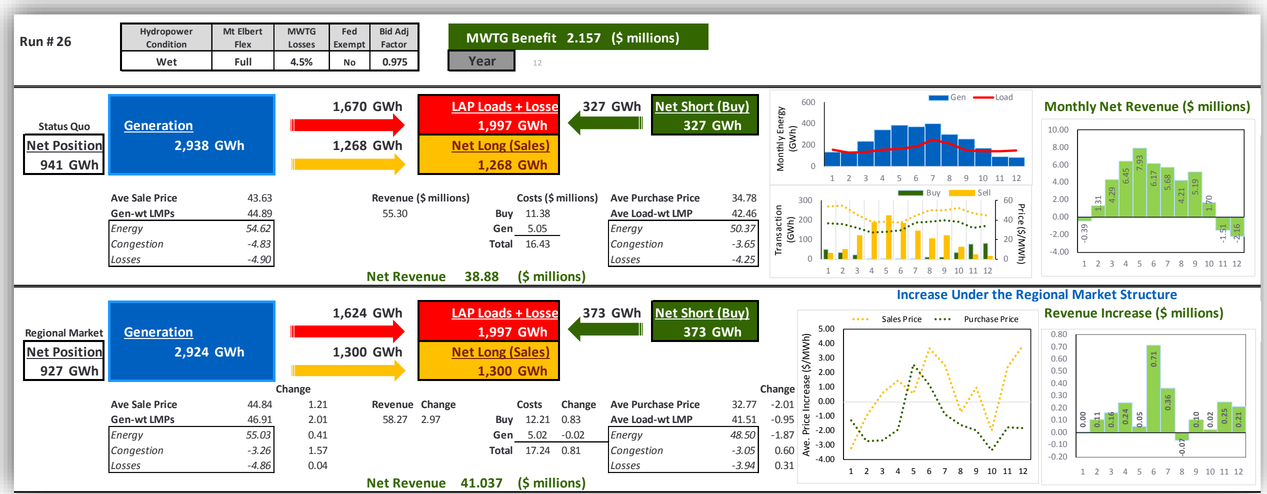


Figure C.26 RMR Market Stress Future: Run 26 Energy and Financial Flow Results

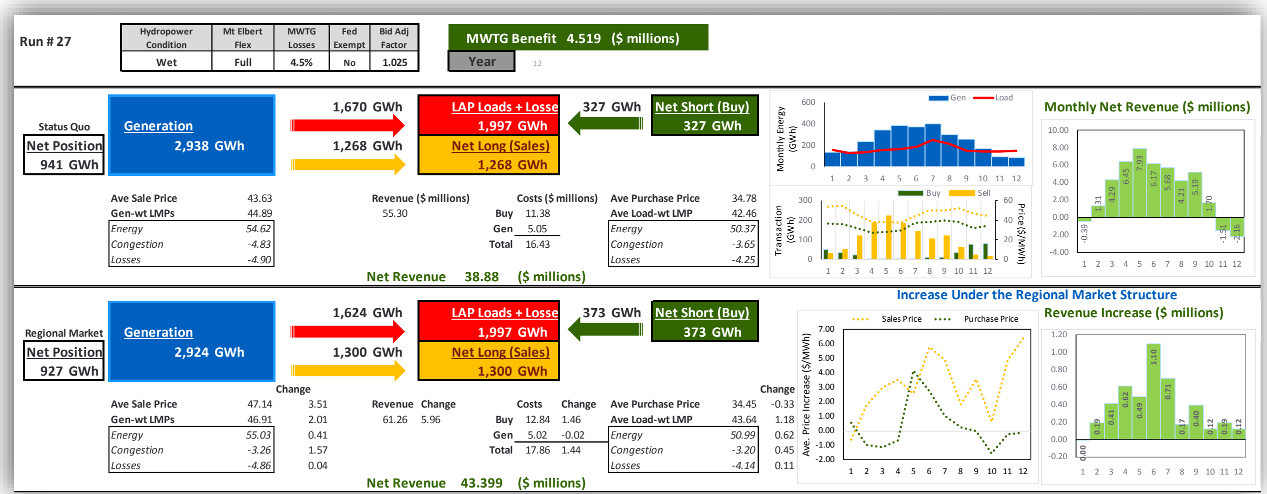


Figure C.27 RMR Market Stress Future: Run 27 Energy and Financial Flow Results

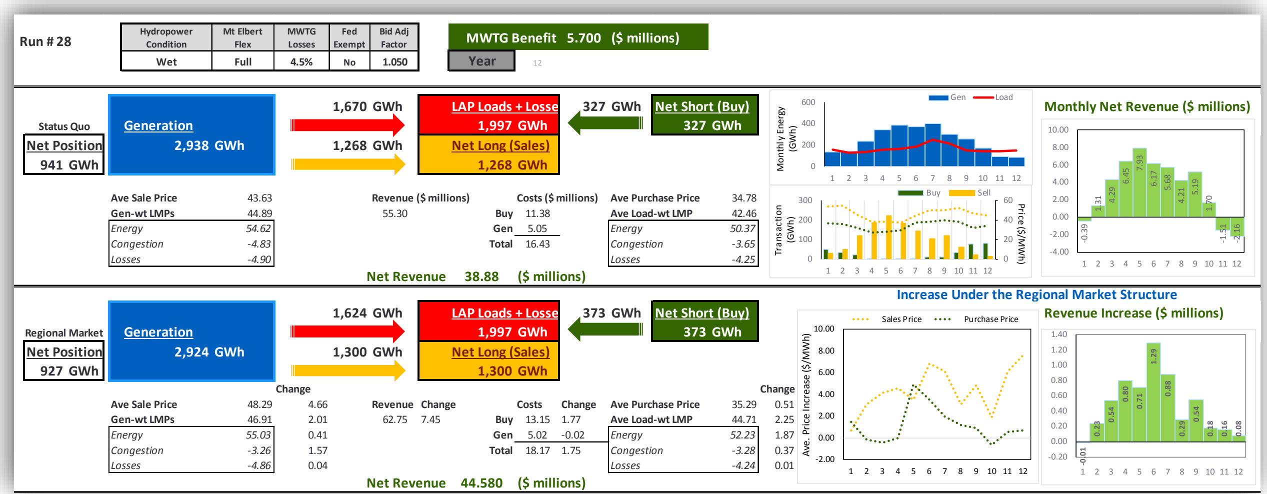


Figure C.28 RMR Market Stress Future: Run 28 Energy and Financial Flow Results

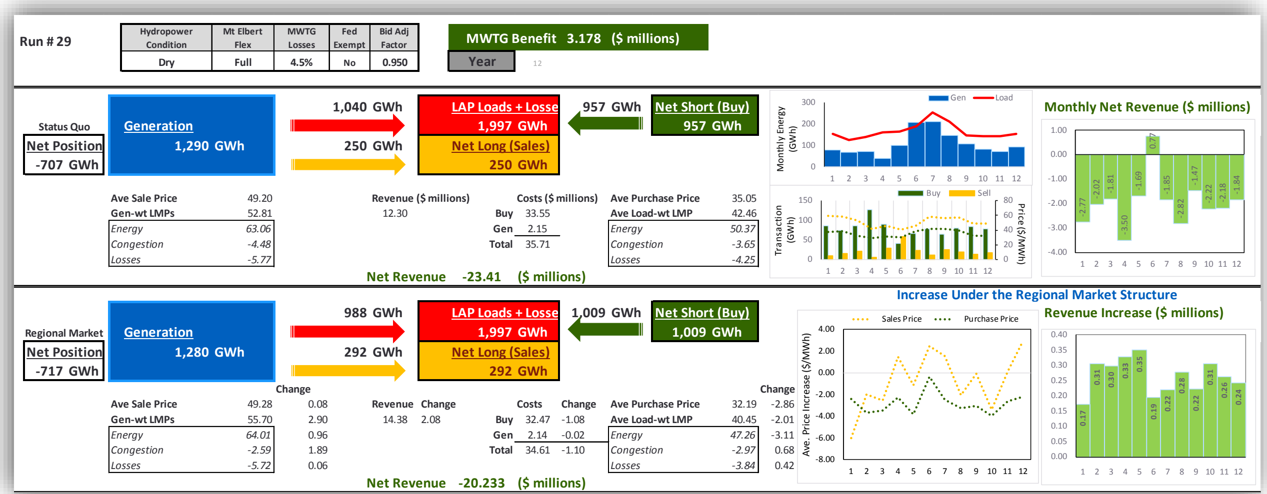


Figure C.29 RMR Market Stress Future: Run 29 Energy and Financial Flow Results

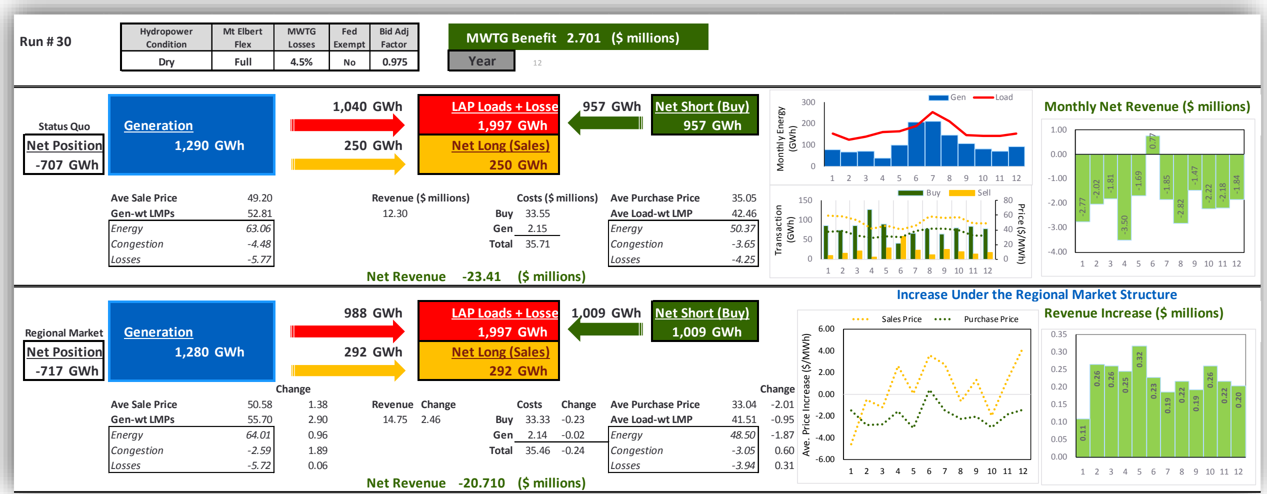


Figure C.30 RMR Market Stress Future: Run 30 Energy and Financial Flow Results

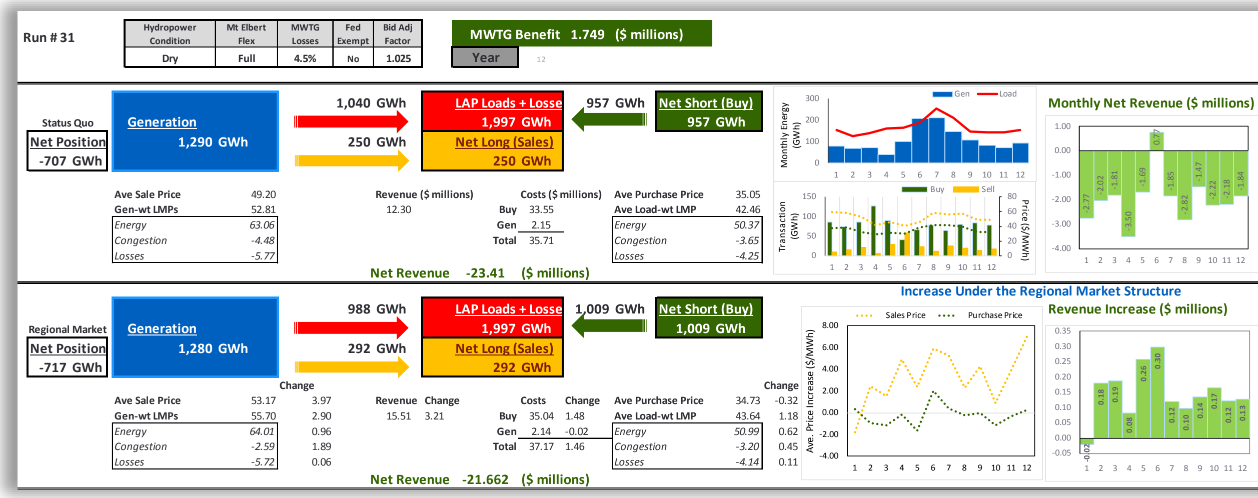


Figure C.31 RMR Market Stress Future: Run 31 Energy and Financial Flow Results

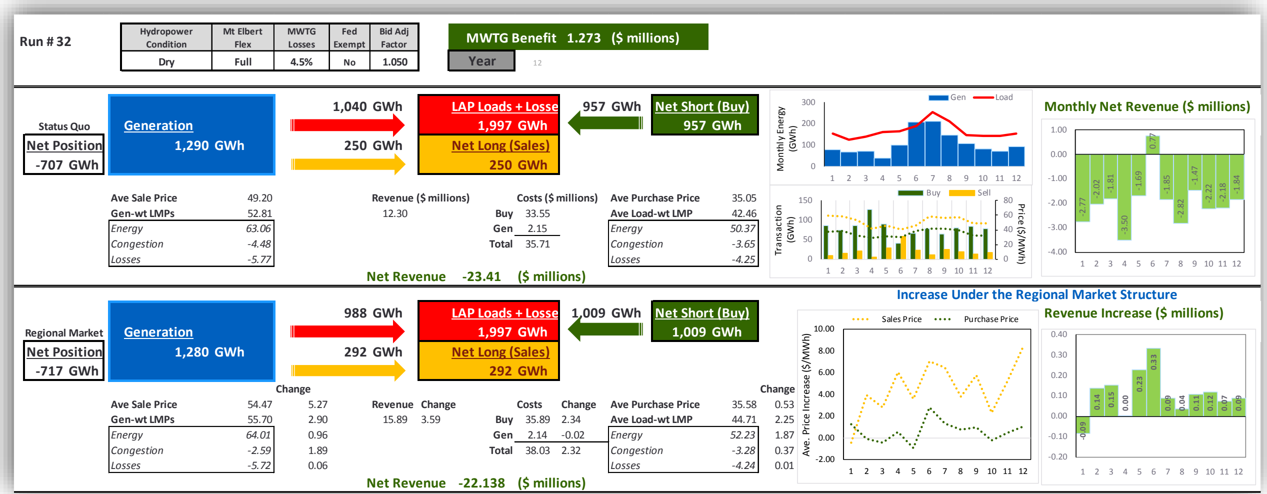


Figure C.32 RMR Market Stress Future: Run 32 Energy and Financial Flow Results

Attachment D

Adjustments to the Pump Storage Methodology and Transmission Loss Accounting

After LAP model runs had been completed and the second draft of this report had been written, inaccuracies were discovered in the basic methodology that Brattle used and Argonne followed to compute LAP and CRSP Regional Market financial impacts. Argonne with guidance from LAP staff therefore made improvements to the LAP Financial spreadsheet in order to estimate the effect of these improvements on LAP modeling results. Because the CRSP modeling process was not yet complete at the time modeling inaccuracies were discovered, Argonne modified the modeling process it used for the CRSP system such that it more closely mimicked current-day operations under the Status Quo Case. These modeling improvements are reflected in the CRSP results presented earlier in this report.

The LAP Financial Spreadsheet was improved to more accurately compute the following situations:

Energy short positions: For short positions, LAP losses are backed out from FES load bus calculations, thus removing double counting of losses.

Pump Storage: Pumped storage production was treated as negative generation in the Brattle methodology. Under some situations, this incurred pumping purchase costs that were based on the weighted-average load LMP instead of at the Mt. Elbert LMP. Also pumping treated as negative generation was multiplied by the powerplant production cost resulting in a positive revenue associated with pumping water to the Mt. Elbert upper reservoir. This was corrected such that pumping now incurs an operating cost in addition to energy purchase that are required to pump water. Lastly, because pumping energy was treated as an additional load it was also subject to load-based rules regarding exemptions from marginal congestion and loss LMP components. This inconsistency was resolved by treating pumped mode power consumption as a load at the Mt. Elbert bus. The revised methodology assumes that LAP generating resources serves as much Mt. Elbert pumping load as possible. Any remaining load is then served by the market at the Mt. Elbert bus at the plant's LMP. When purchasing power from the grid there are no energy transmission losses, however, the loss and congestion components of the LMP remain. In addition, when pumping, the load is also excluded from the generation-weighted LMP calculation.

Revised LAP financial results for the Current Trends Future is shown below along with a comparison of previous results (i.e., prior model enhancements). It should be noted that under reference point assumptions (Run 1) the estimated Regional Market financial benefits are about $345,000 lower under the revised methodology. General trends among model results and the financial benefit ranking of model runs are very similar. Based on this comparison LAP staff concluded that the differences between the results shown below and those described in the main body of this report were not large enough to warrant the rewrite of this report, but were significant enough to warrant mentioning and documenting with this attachment.

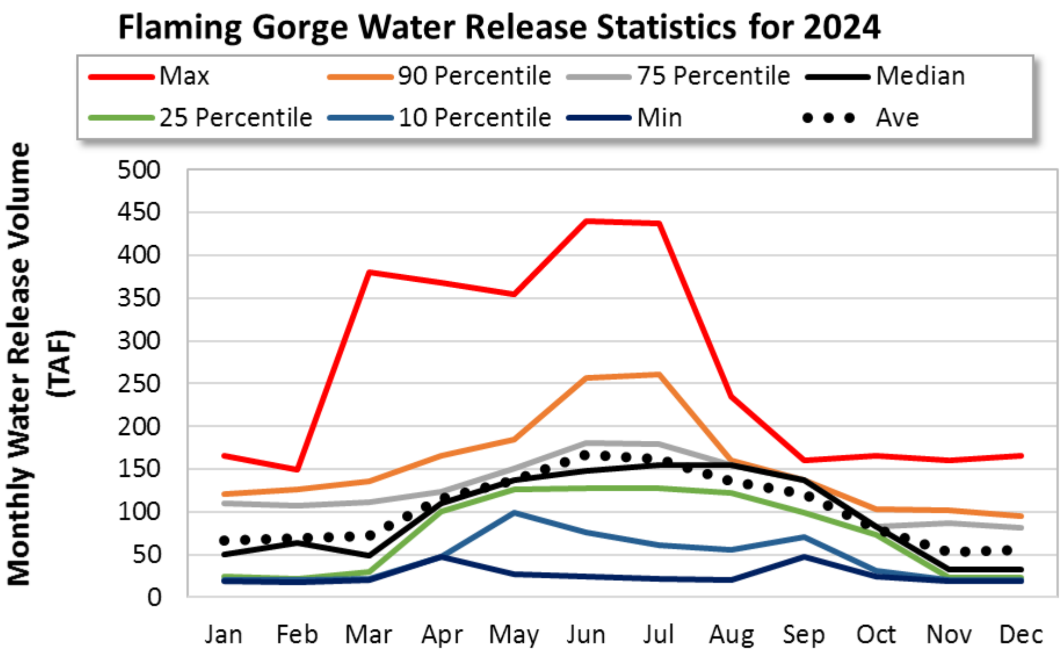
Current Trends

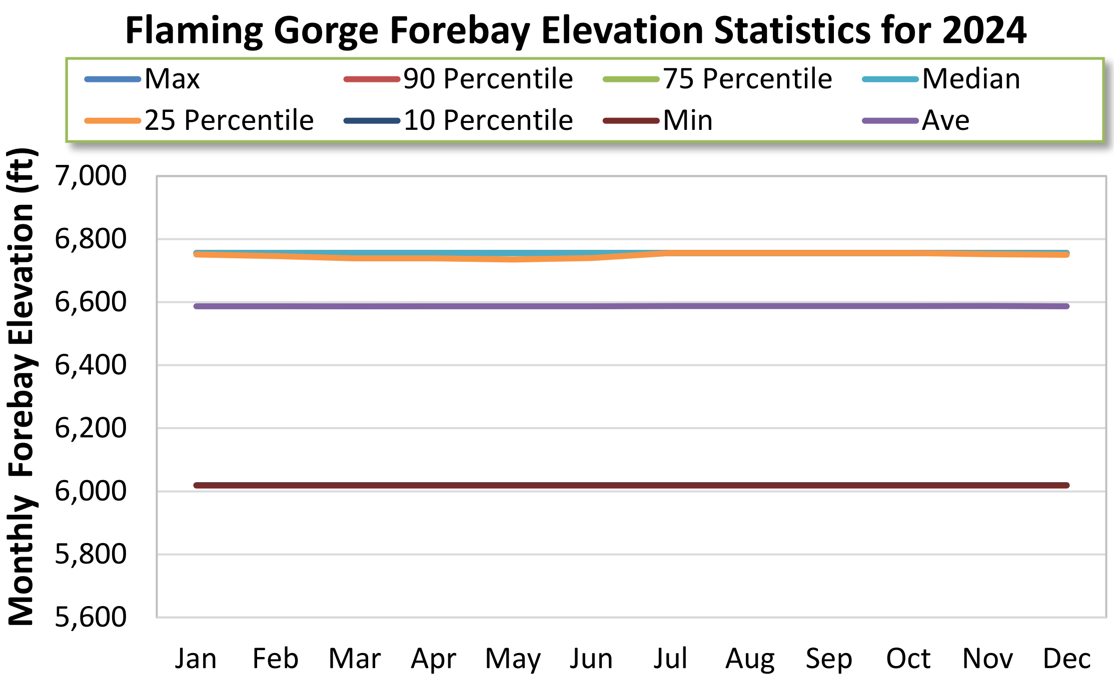
Regional Market Price Benefits ($1,000)

Run ID	Hydropower Condition	Mt. Albert Flex	MWTG Losses	Only Pay MEC	Bid Adj Factor	Revised Values	Previous Values	Change ($1,000)	% Change from Previous Values
19- Brattle Bench	**Ave/Dry for MS**	**Full**	**Brattle Loa**	**No**	**1.000**	**323**	**1,479**	**(1,156)**	**(78)**
16	Average	None	5.00%	No	1.000	11	271	(260)	(96)
17	Dry	None	5.00%	No	1.000	(42)	232	(274)	(118)
18	Wet	None	5.00%	No	1.000	(218)	(93)	(125)	135
13	Average	None	4.50%	Yes	1.000	(1,915)	(1,618)	(297)	18
14	Dry	None	4.50%	Yes	1.000	(2,102)	(2,223)	121	(5)
15	Wet	None	4.50%	Yes	1.000	(1,439)	(609)	(830)	136
7	Dry	None	4.50%	No	0.950	255	1,189	(934)	(79)
2	Dry	None	4.50%	No	1.000	71	470	(399)	(85)
6	Dry	None	4.50%	No	1.050	(112)	(249)	137	(55)
5	Average	None	4.50%	No	0.950	191	909	(718)	(79)
1-Ref Pnt	Ave/Dry for MS	***None***	***4.50%***	***No***	***1.000***	***164***	***509***	***(344)***	***(68)***
4	Average	None	4.50%	No	1.050	138	109	29	27
9	Wet	None	4.50%	No	0.950	(1,174)	(972)	(202)	21
3	Wet	None	4.50%	No	1.000	55	144	(89)	(62)
8	Wet	None	4.50%	No	1.050	1,285	1,260	25	2
29	Dry	Full	4.50%	No	0.950	1,091	2,046	(955)	(47)
30	Dry	Full	4.50%	No	0.975	1,040	1,730	(690)	(40)
11	Dry	Full	4.50%	No	1.000	988	1,414	(426)	(30)
31	Dry	Full	4.50%	No	1.025	937	1,098	(161)	(15)
32	Dry	Full	4.50%	No	1.050	886	782	104	0
20	Average	Full	4.50%	No	0.950	361	1,671	(1,310)	(78)
22	Average	Full	4.50%	No	0.975	413	1,526	(1,113)	(73)
10	Average	Full	4.50%	No	1.000	465	1,381	(917)	(66)
23	Average	Full	4.50%	No	1.025	517	1,237	(720)	(58)
24	Average	Full	4.50%	No	1.050	569	1,092	(523)	(48)
25	Wet	Full	4.50%	No	0.950	(1,293)	(209)	(1,084)	519
26	Wet	Full	4.50%	No	0.975	(607)	405	(1,012)	(250)
12	Wet	Full	4.50%	No	1.000	79	1,020	(940)	(92)
27	Wet	Full	4.50%	No	1.025	765	1,634	(869)	(53)
28	Wet	Full	4.50%	No	1.050	1,451	2,248	(797)	(35)
21	Average	، Hist/C Fu	4.50%	No	1.000	(698)	2,825	(3,523)	(125)

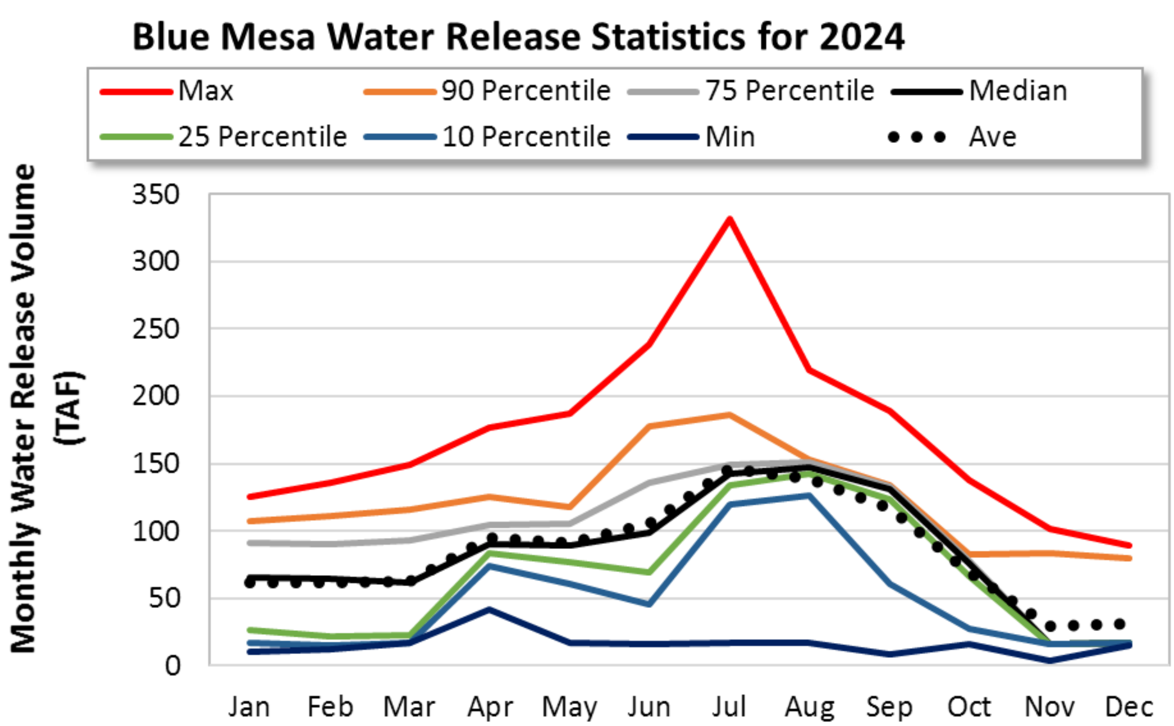
Attachment E

CRSP Monthly Model Result Statistics

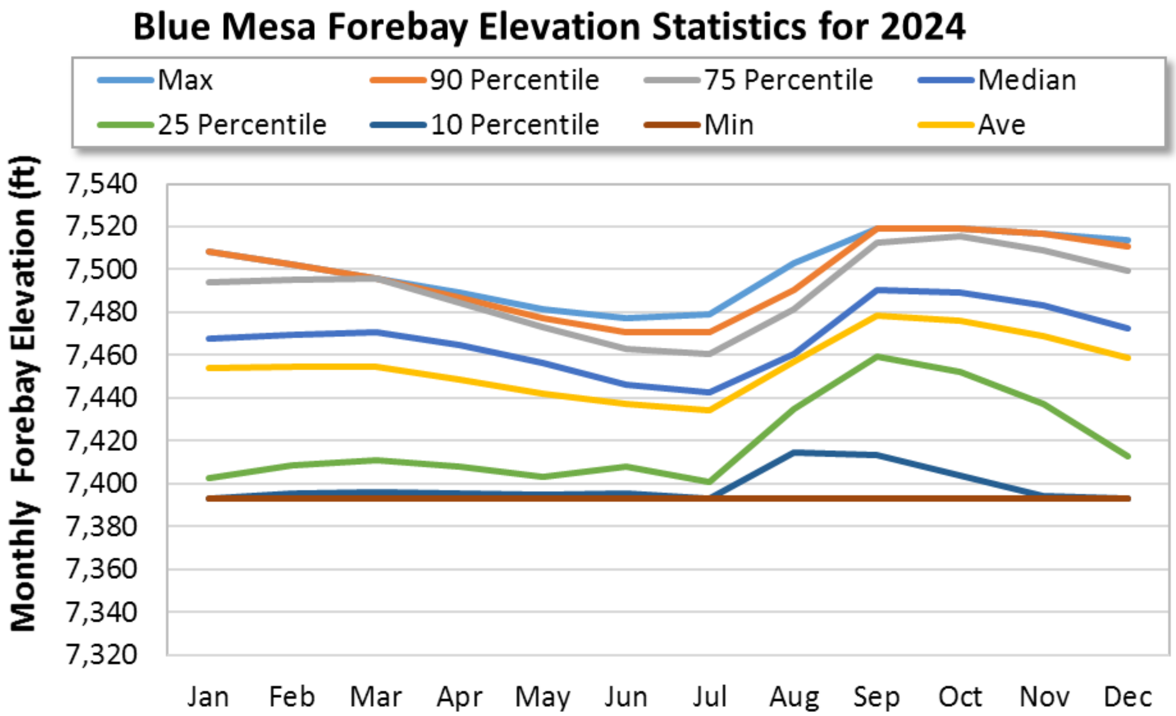




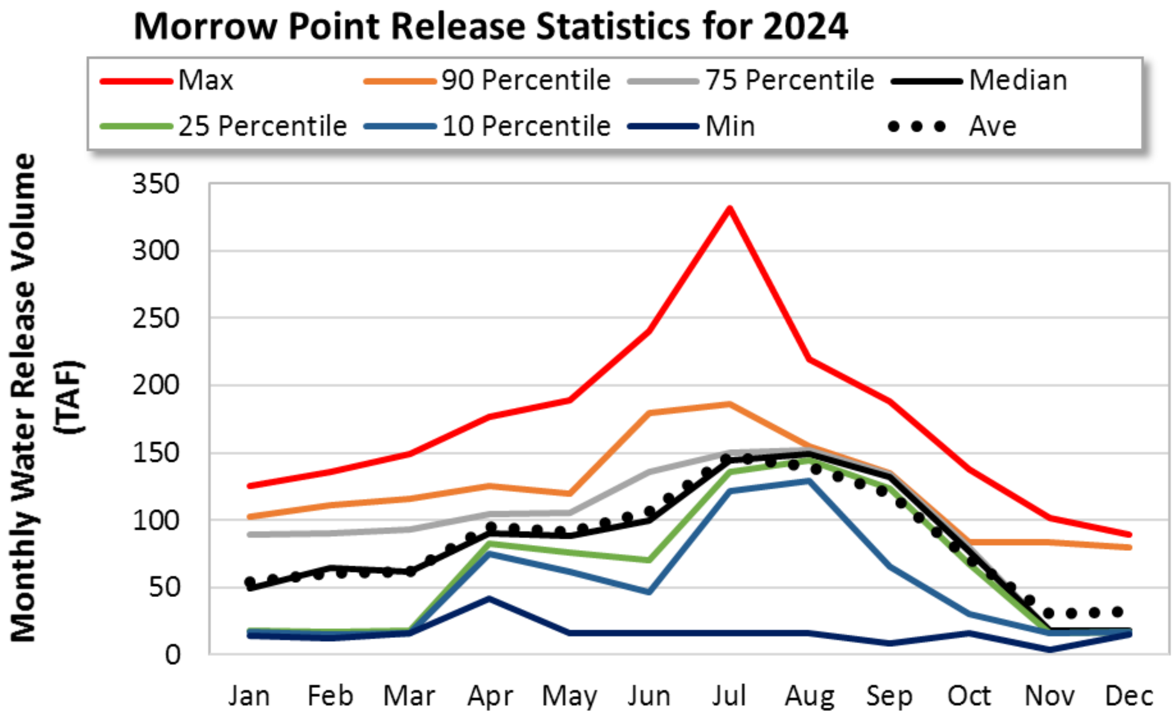
Flaming Gorge Forebay Elevation Statistics for 2024
Max
90 Percentile
75 Percentile
Median
25 Percentile
10 Percentile
Min
Ave
Monthly Forebay Elevation (ft)
7,000
6,800
6,600
6,400
6,200
6,000
5,800
5,600
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

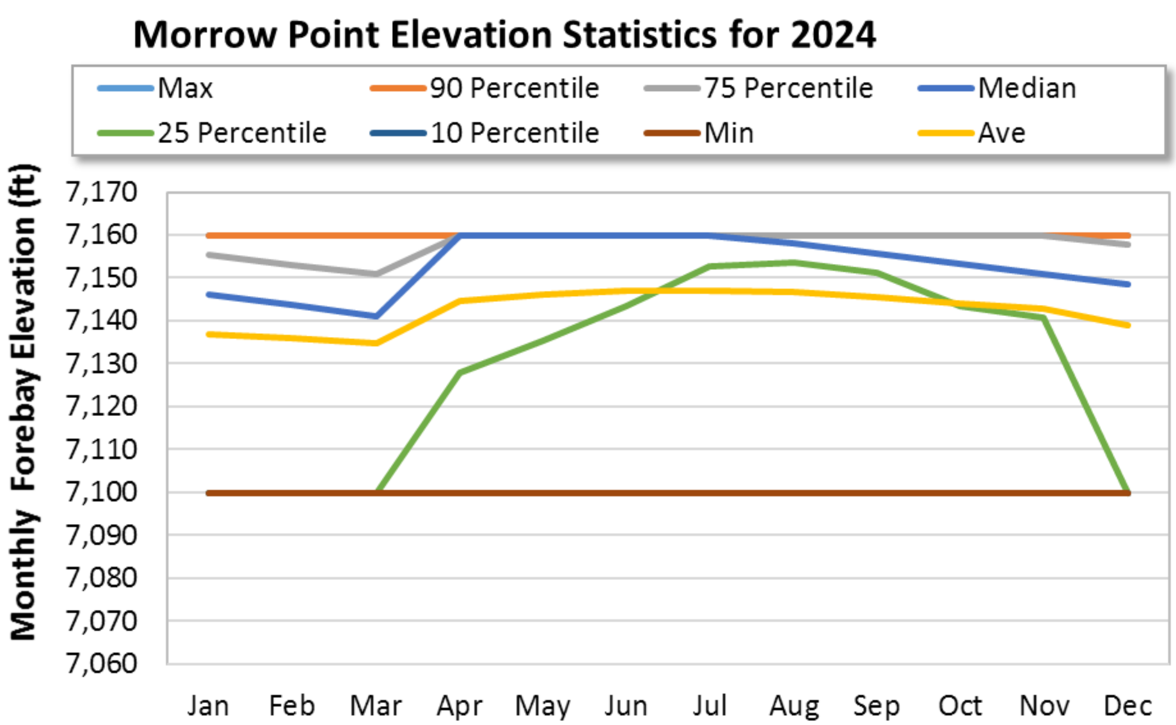


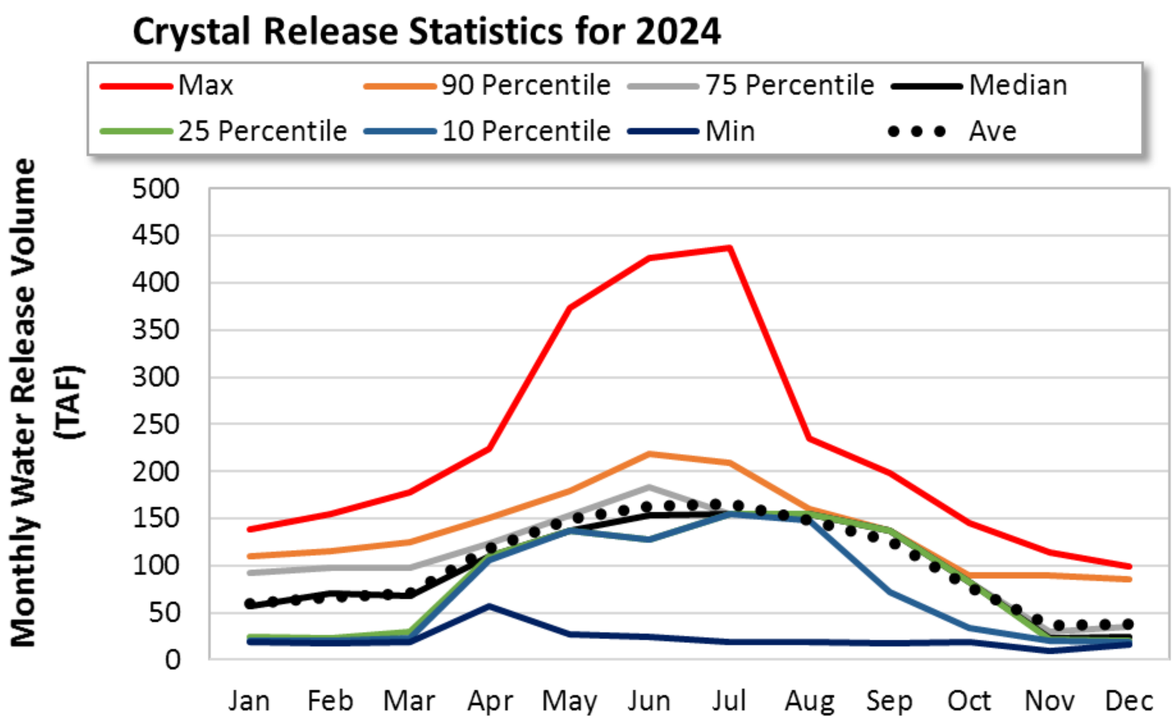
Blue Mesa Water Release Statistics for 2024
Max
90 Percentile
75 Percentile
Median
25 Percentile
10 Percentile
Min
Ave
Monthly Water Release Volume (TAF)
350
300
250
200
150
100
50
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

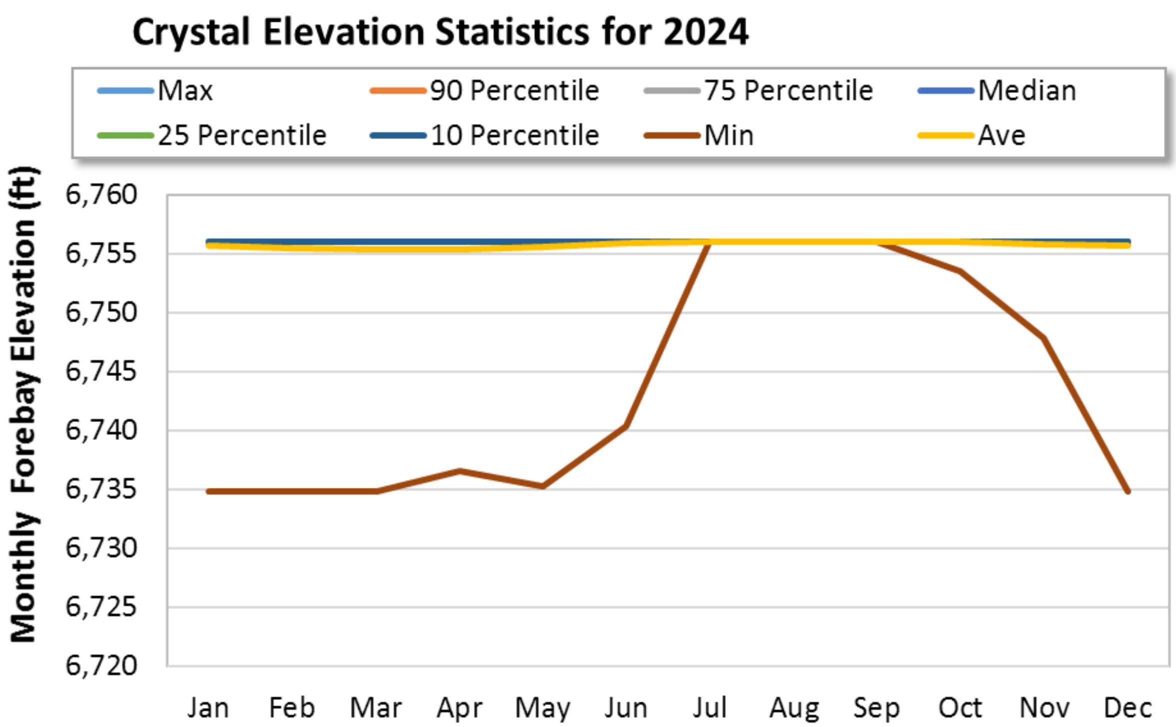


Blue Mesa Forebay Elevation Statistics for 2024
Max
90 Percentile
75 Percentile
Median
25 Percentile
10 Percentile
Min
Ave
Monthly Forebay Elevation (ft)
7,540
7,520
7,500
7,480
7,460
7,440
7,420
7,400
7,380
7,360
7,340
7,320
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

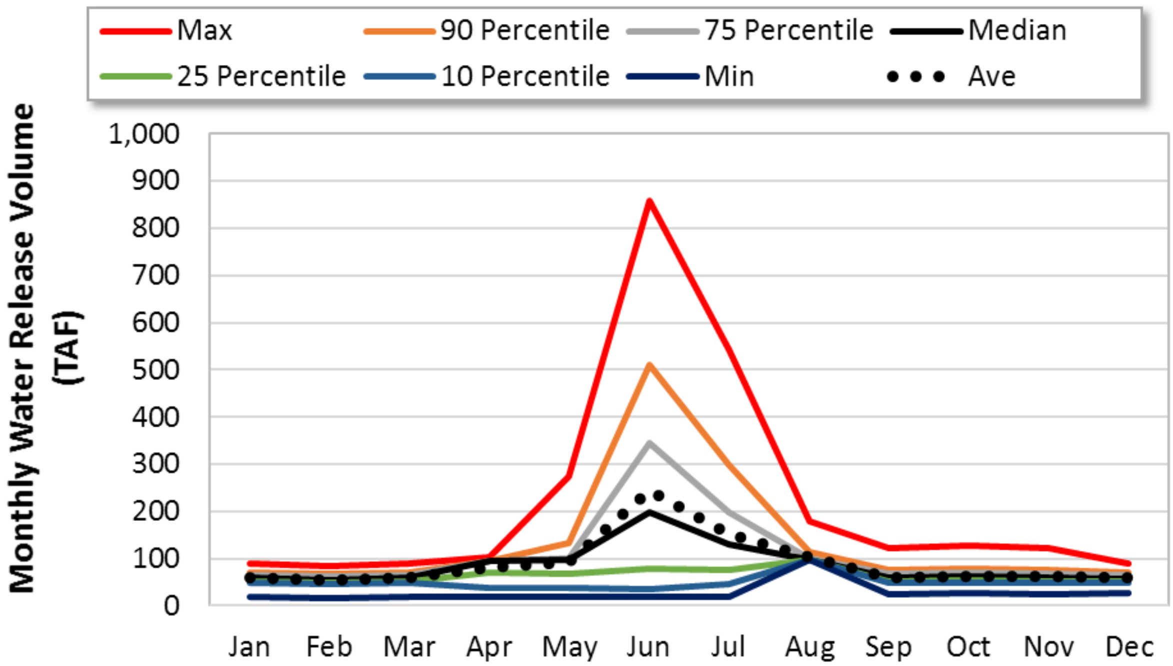

Morrow Point Release Statistics for 2024
Max
90 Percentile
75 Percentile
Median
25 Percentile
10 Percentile
Min
Ave
Monthly Water Release Volume (TAF)
350
300
250
200
150
100
50
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec


Morrow Point Elevation Statistics for 2024
Max
90 Percentile
75 Percentile
Median
25 Percentile
10 Percentile
Min
Ave
Monthly Forebay Elevation (ft)
7,170
7,160
7,150
7,140
7,130
7,120
7,110
7,100
7,090
7,080
7,070
7,060
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

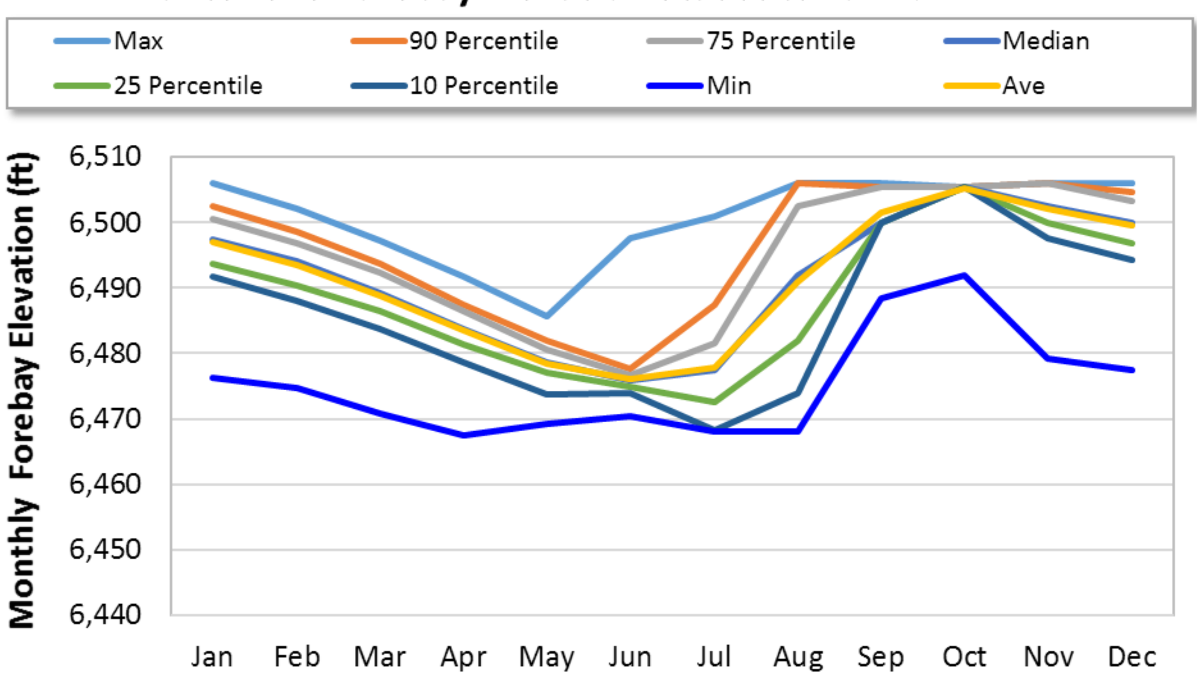

Crystal Release Statistics for 2024
Max
90 Percentile
75 Percentile
Median
25 Percentile
10 Percentile
Min
Ave
Monthly Water Release Volume (TAF)
500
450
400
350
300
250
200
150
100
50
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec


Crystal Elevation Statistics for 2024
Max
90 Percentile
75 Percentile
Median
25 Percentile
10 Percentile
Min
Ave
Monthly Forebay Elevation (ft)
6,760
6,755
6,750
6,745
6,740
6,735
6,730
6,725
6,720
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

Fontenelle Water Release Statistics for 2024



Fontenelle Forebay Elevation Statistics for 2024



Attachment F

Detailed SRP Exchange and GFA Contracts Result under High Gas and Market Stress Futures

Results for the High Gas Future

SRP Energy Exchange Benefits under the Regional Market

Net Rev ($1,000)

	TAG 1X: GC to SRP Load					TAG 2X: Craig to CRSP North Load					TAG 4X: 4 Corners to CRSP NM Load					Total	
		Energy Price ($/MWh)					Energy Price ($/MWh)					Energy Price ($/MWh)					
		Energy In	Energy Out				Energy In	Energy Out				Energy In	Energy Out				
Month	1X SRP Exchange (GWh)	Glen Canyon LMP ($/MWh)	Pinnacle Peak LMP ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	2X SRP Exchange (GWh)	Craig	Ave WAPA Deliv Pnts	Ave Revenue ($/MWh)	Net Revenue ($1,000)	4X SRP Exchange (GWh)	Four Corners	Four Corners	Ave Revenue ($/MWh)	Net Revenue ($1,000)	Net Energy Exchange (GWh)	Net CRSP Revenue ($1,000)
Jan	237.3	45.40	48.37	-2.92	**-693.6**	192.4	42.01	44.07	-1.95	**-375.4**	57.5	44.94	44.94	0.00	**0.0**	487.2	**-1,068.9**
Feb	208.4	43.82	45.55	-1.58	**-329.1**	178.5	41.48	42.73	-1.07	**-190.2**	33.3	42.37	42.37	0.00	**0.0**	420.3	**-519.3**
Mar	164.2	38.80	40.69	-1.80	**-294.8**	139.8	36.31	37.67	-1.23	**-172.1**	30.9	37.56	37.56	0.00	**0.0**	334.9	**-466.9**
Apr	173.8	35.65	38.21	-2.29	**-397.2**	141.1	32.22	34.23	-1.78	**-251.7**	40.2	34.82	34.82	0.00	**0.0**	355.0	**-648.9**
May	115.1	38.14	40.32	-2.06	**-236.9**	64.1	34.87	36.76	-1.77	**-113.7**	55.0	36.55	36.55	0.00	**0.0**	234.2	**-350.6**
Jun	144.0	41.92	45.48	-3.49	**-502.6**	98.3	37.39	39.83	-2.44	**-239.8**	52.9	40.51	40.51	0.00	**0.0**	295.1	**-742.5**
Jul	192.1	49.58	53.50	-3.71	**-713.5**	127.7	45.23	47.96	-2.41	**-308.2**	72.7	48.87	48.87	0.00	**0.0**	392.5	**-1,021.7**
Aug	176.4	49.97	54.44	-4.55	**-802.3**	145.8	45.85	48.56	-2.64	**-385.1**	52.6	49.67	49.67	0.00	**0.0**	374.9	**-1,187.4**
Sep	172.6	47.87	51.37	-3.43	**-591.4**	138.8	43.86	46.36	-2.42	**-336.4**	38.4	47.22	47.22	0.00	**0.0**	349.7	**-927.7**
Oct	164.4	44.70	47.45	-2.52	**-414.6**	129.1	42.01	43.87	-1.73	**-223.5**	45.9	44.05	44.05	0.00	**0.0**	339.3	**-638.2**
Nov	182.8	42.80	45.92	-2.76	**-504.0**	165.8	37.44	40.47	-2.78	**-460.4**	21.3	42.83	42.83	0.00	**0.0**	369.9	**-964.4**
Dec	253.0	46.59	49.82	-3.00	**-758.1**	206.7	41.13	44.05	-2.70	**-558.2**	50.2	45.88	45.88	0.00	**0.0**	509.9	**-1,316.2**
Annual	**2,184.2**	**43.77**	**46.76**	**-2.84**	**-6,238.1**	**1,727.9**	**39.98**	**42.21**	**-2.08**	**-3,614.6**	**550.8**	**42.94**	**42.94**	**0.00**	**0.0**	**4,462.9**	**-9,852.7**

SRP Wheeling Benefits under the Regional Market

TAG 3X: Craig to Pinnacle Peak					TAG 5X: 4 Corners to Pinnacle Peak					Total	
	Energy Price ($/MWh)					Energy Price ($/MWh)					
	Energy In	Energy Out				Energy In	Energy Out				
3X SRP Exchange (GWh)	Craig	Pinnacle Peak	Ave Revenue ($/MWh)	Net Revenue ($1,000)	5X SRP Exchange (GWh)	Four Corners	Pinnacle Peak	Ave Revenue ($/MWh)	Net Revenue ($1,000)	Wheeled Energy (GWh)	CRSP Revenue ($1,000)
45.2	42.01	48.37	-7.72	**-348.5**	14.7	44.94	48.37	-2.93	**-43.0**	59.8	-391.4
49.2	41.48	45.55	-5.00	**-246.0**	35.0	42.37	45.55	-2.86	**-100.2**	84.3	-346.2
95.3	36.31	40.69	-4.42	**-420.8**	29.0	37.56	40.69	-2.73	**-79.0**	124.2	-499.8
72.3	32.22	38.21	-5.79	**-418.3**	40.3	34.82	38.21	-3.50	**-141.0**	112.5	-559.3
89.3	34.87	40.32	-5.11	**-455.9**	31.2	36.55	40.32	-4.01	**-125.2**	120.5	-581.1
110.9	37.39	45.48	-7.53	**-834.5**	25.8	40.51	45.48	-5.06	**-130.8**	136.7	-965.3
96.8	45.23	53.50	-8.85	**-856.3**	26.4	48.87	53.50	-4.51	**-119.1**	123.2	-975.4
104.2	45.85	54.44	-8.59	**-895.3**	24.4	49.67	54.44	-4.87	**-118.7**	128.6	-1,014.0
37.0	43.86	51.37	-6.71	**-248.1**	26.8	47.22	51.37	-4.12	**-110.3**	63.7	-358.4
45.5	42.01	47.45	-4.80	**-218.5**	54.8	44.05	47.45	-3.41	**-186.8**	100.3	-405.3
67.3	37.44	45.92	-8.40	**-565.4**	70.0	42.83	45.92	-3.10	**-216.7**	137.3	-782.1
48.3	41.13	49.82	-9.81	**-474.3**	34.5	45.88	49.82	-4.13	**-142.3**	82.8	-616.6
861.1	**39.98**	**46.76**	**-6.89**	**-5,982.0**	**412.7**	**42.94**	**46.76**	**-3.77**	**-1,513.0**	**1,273.8**	**-7,495.0**

GFA Contract Benefits under the Regional Market

	APS GFA Contract					PAC GFA Contract					DGT GFA Contract					Total	
	Hr Max 285 MW	Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out			Hr Max 250 MW	Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out			Hr Max 26 MW	Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out				
Month	APS Trans Service (GWh)	Glen Canyon ($/MWh)	Pinnacle Peak ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	PAC Trans Service (GWh)	Pinnacle Peak ($/MWh)	Glen Canyon ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	DGT Trans Service (GWh)	Flaming Gorge ($/MWh)	Glen Canyon ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	Total Trans Service (GWh)	Net CRSP Revenue ($1,000)
Jan	41.7	45.34	48.06	-2.81	**-117.2**	57.0	48.06	45.34	2.66	**151.8**	4.2	41.72	45.43	-4.56	**-19.2**	102.9	**15.4**
Feb	18.8	44.05	45.55	-2.82	**-53.0**	47.9	45.55	44.05	1.30	**62.2**	1.6	41.38	46.19	-4.38	**-7.1**	68.4	**2.0**
Mar	5.5	38.36	40.06	-1.15	**-6.3**	10.5	40.06	38.36	0.70	**7.3**	5.5	36.03	42.31	-6.26	**-34.4**	21.5	**-33.4**
Apr	1.7	36.22	38.47	-1.38	**-2.3**	30.0	38.47	36.22	2.29	**68.7**	7.2	33.26	39.55	-6.47	**-46.7**	38.9	**19.7**
May	4.5	39.15	41.08	-0.57	**-2.5**	59.0	41.08	39.15	2.01	**118.9**	4.9	35.35	34.43	1.28	**6.3**	68.4	**122.6**
Jun	5.7	42.97	46.20	-2.77	**-15.7**	72.7	46.20	42.97	3.86	**280.3**	7.4	37.98	38.21	0.34	**2.5**	85.7	**267.1**
Jul	3.7	49.76	53.40	-3.98	**-14.6**	71.1	53.40	49.76	4.01	**284.9**	7.9	44.68	45.73	-0.76	**-6.0**	82.7	**264.2**
Aug	0.6	50.62	54.88	-2.38	**-1.5**	79.7	54.88	50.62	4.83	**384.9**	7.7	45.94	49.95	-3.83	**-29.4**	88.0	**354.0**
Sep	0.0	47.56	50.76	0.00	**0.0**	63.5	50.76	47.56	3.30	**209.6**	4.7	44.18	48.77	-4.27	**-20.1**	68.2	**189.6**
Oct	4.2	44.89	47.27	-1.89	**-8.0**	48.7	47.27	44.89	2.38	**116.1**	4.7	42.35	44.69	-3.10	**-14.5**	57.6	**93.6**
Nov	11.2	43.04	45.94	-3.48	**-38.9**	15.2	45.94	43.04	3.25	**49.6**	6.5	36.58	43.15	-6.03	**-39.4**	33.0	**-28.8**
Dec	25.1	47.23	50.22	-3.15	**-79.1**	5.7	50.22	47.23	3.38	**19.2**	10.6	41.32	48.37	-6.97	**-73.7**	41.4	**-133.5**
Annual	122.7	44.10	46.82	-2.20	-339.2	561.1	46.82	44.10	2.83	1,753.4	72.9	40.07	43.90	-3.75	-281.7	756.7	1,132.6

Results for the Market Stress Future Results

SRP Energy Exchange Benefits under the Regional Market

	Net Rev ($1,000)																
	TAG 1X: GC to SRP Load					TAG 2X: Craig to CRSP North Load					TAG 4X: 4 Corners to CRSP NM Load					Total	
		Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out				Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out				Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out				
Month	1X SRP Exchange (GWh)	Glen Canyon LMP ($/MWh)	Pinnacle Peak LMP ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	2X SRP Exchange (GWh)	Craig	Ave WAPA Deliv Pnts	Ave Revenue ($/MWh)	Net Revenue ($1,000)	4X SRP Exchange (GWh)	Four Corners	Four Corners	Ave Revenue ($/MWh)	Net Revenue ($1,000)	Net Energy Exchange (GWh)	Net CRSP Revenue ($1,000)
Jan	237.3	47.07	48.56	-1.40	**-333.2**	192.4	44.08	45.41	-1.25	**-239.7**	57.5	45.22	45.22	0.00	**0.0**	487.2	**-572.9**
Feb	208.4	47.11	47.69	-0.49	**-101.3**	178.5	45.25	45.79	-0.34	**-61.1**	33.3	44.40	44.40	0.00	**0.0**	420.3	**-162.4**
Mar	164.2	41.56	42.53	-0.86	**-141.4**	139.8	39.76	40.35	-0.45	**-62.6**	30.9	38.82	38.82	0.00	**0.0**	334.9	**-204.0**
Apr	173.8	39.19	40.51	-1.03	**-179.5**	141.1	36.48	37.58	-0.89	**-125.6**	40.2	36.70	36.70	0.00	**0.0**	355.0	**-305.1**
May	115.1	40.72	41.59	-0.71	**-81.4**	64.1	37.93	39.00	-0.92	**-59.2**	55.0	37.09	37.09	0.00	**0.0**	234.2	**-140.6**
Jun	144.0	45.34	47.60	-2.08	**-299.9**	98.3	41.76	43.23	-1.42	**-139.5**	52.9	42.36	42.36	0.00	**0.0**	295.1	**-439.4**
Jul	192.1	52.34	54.88	-2.33	**-446.8**	127.7	48.79	50.65	-1.57	**-200.4**	72.7	50.24	50.24	0.00	**0.0**	392.5	**-647.2**
Aug	176.4	51.35	53.88	-2.49	**-439.4**	145.8	47.91	49.65	-1.67	**-243.0**	52.6	49.58	49.58	0.00	**0.0**	374.9	**-682.5**
Sep	172.6	49.89	52.08	-2.10	**-362.1**	138.8	46.79	48.32	-1.49	**-207.5**	38.4	48.19	48.19	0.00	**0.0**	349.7	**-569.6**
Oct	164.4	46.15	48.11	-1.78	**-292.5**	129.1	44.29	45.44	-1.07	**-138.2**	45.9	44.67	44.67	0.00	**0.0**	339.3	**-430.7**
Nov	182.8	45.71	47.77	-1.69	**-309.8**	165.8	41.67	43.76	-1.88	**-311.0**	21.3	44.91	44.91	0.00	**0.0**	369.9	**-620.8**
Dec	253.0	47.85	49.93	-1.86	**-471.5**	206.7	44.08	45.90	-1.63	**-336.7**	50.2	46.43	46.43	0.00	**0.0**	509.9	**-808.2**
Annual	2,184.2	46.19	47.93	-1.57	-3,458.8	1,727.9	43.23	44.59	-1.21	-2,124.5	550.8	44.05	44.05	0.00	0.0	4,462.9	-5,583.3

SRP Wheeling Benefits under the Regional Market

Month	TAG 3X: Craig to Pinnacle Peak					TAG 5X: 4 Corners to Pinnacle Peak					Total	
		Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out				Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out				
Month	3X SRP Exchange (GWh)	Craig	Pinnacle Peak	Ave Revenue ($/MWh)	Net Revenue ($1,000)	5X SRP Exchange (GWh)	Four Corners	Pinnacle Peak	Ave Revenue ($/MWh)	Net Revenue ($1,000)	Wheeled Energy (GWh)	CRSP Revenue ($1,000)
Jan	45.2	44.08	48.56	-5.51	**-248.9**	14.7	45.22	48.56	-2.90	**-42.5**	59.8	**-291.5**
Feb	49.2	45.25	47.69	-3.42	**-168.2**	35.0	44.40	47.69	-2.96	**-103.8**	84.3	**-272.0**
Mar	95.3	39.76	42.53	-2.77	**-263.6**	29.0	38.82	42.53	-3.34	**-96.8**	124.2	**-360.5**
Apr	72.3	36.48	40.51	-3.95	**-285.0**	40.3	36.70	40.51	-3.91	**-157.7**	112.5	**-442.8**
May	89.3	37.93	41.59	-3.35	**-299.1**	31.2	37.09	41.59	-4.52	**-140.9**	120.5	**-440.0**
Jun	110.9	41.76	47.60	-5.36	**-593.8**	25.8	42.36	47.60	-4.88	**-126.1**	136.7	**-719.9**
Jul	96.8	48.79	54.88	-6.53	**-631.8**	26.4	50.24	54.88	-4.41	**-116.4**	123.2	**-748.2**
Aug	104.2	47.91	53.88	-6.05	**-630.9**	24.4	49.58	53.88	-4.45	**-108.5**	128.6	**-739.3**
Sep	37.0	46.79	52.08	-4.52	**-166.9**	26.8	48.19	52.08	-3.86	**-103.4**	63.7	**-270.3**
Oct	45.5	44.29	48.11	-3.03	**-137.9**	54.8	44.67	48.11	-3.47	**-190.0**	100.3	**-327.9**
Nov	67.3	41.67	47.77	-6.14	**-413.7**	70.0	44.91	47.77	-2.86	**-200.2**	137.3	**-613.9**
Dec	48.3	44.08	49.93	-6.78	**-327.6**	34.5	46.43	49.93	-3.55	**-122.2**	82.8	**-449.9**
Annual	**861.1**	**43.23**	**47.93**	**-4.78**	**-4,167.6**	**412.7**	**44.05**	**47.93**	**-3.76**	**-1,508.6**	**1,273.8**	**-5,676.2**

GFA Contract Benefits under the Regional Market

Month	APS GFA Contract					PAC GFA Contract					DGT GFA Contract					Total	
	Hr Max 285 MW	Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out			Hr Max 250 MW	Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out			Hr Max 26 MW	Energy Price ($/MWh) Energy In	Energy Price ($/MWh) Energy Out				
Month	APS Trans Service (GWh)	Glen Canyon ($/MWh)	Pinnacle Peak ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	PAC Trans Service (GWh)	Pinnacle Peak ($/MWh)	Glen Canyon ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	DGT Trans Service (GWh)	Flaming Gorge ($/MWh)	Glen Canyon ($/MWh)	Ave Revenue ($/MWh)	Net Revenue ($1,000)	Net Energy Exchange (GWh)	Net CRSP Revenue ($1,000)
Jan	41.7	46.89	48.08	-1.33	**-55.5**	57.0	48.08	46.89	1.20	**68.2**	4.2	43.72	44.87	-2.19	**-9.2**	102.9	**3.5**
Feb	18.8	47.39	47.68	-1.21	**-22.8**	47.9	47.68	47.39	0.15	**7.0**	1.6	45.13	46.81	-1.42	**-2.3**	68.4	**-18.1**
Mar	5.5	41.11	41.89	-0.42	**-2.3**	10.5	41.89	41.11	-0.18	**-1.9**	5.5	39.36	42.95	-3.28	**-18.0**	21.5	**-22.2**
Apr	1.7	39.83	40.78	0.33	**0.6**	30.0	40.78	39.83	1.17	**35.1**	7.2	37.14	40.60	-3.64	**-26.2**	38.9	**9.4**
May	4.5	41.60	42.09	1.40	**6.3**	59.0	42.09	41.60	0.29	**17.1**	4.9	38.07	34.98	3.38	**16.6**	68.4	**40.0**
Jun	5.7	46.56	48.42	-1.78	**-10.1**	72.7	48.42	46.56	2.22	**161.3**	7.4	42.47	39.68	3.29	**24.2**	85.7	**175.4**
Jul	3.7	52.39	54.59	-2.46	**-9.1**	71.1	54.59	52.39	2.40	**170.3**	7.9	48.03	46.43	1.86	**14.7**	82.7	**176.0**
Aug	0.6	51.91	54.24	-1.16	**-0.7**	79.7	54.24	51.91	2.59	**206.6**	7.7	47.85	49.11	-1.11	**-8.5**	88.0	**197.4**
Sep	0.0	49.97	51.87	0.00	**0.0**	63.5	51.87	49.97	1.76	**111.4**	4.7	46.97	48.93	-1.51	**-7.1**	68.2	**104.3**
Oct	4.2	46.28	47.87	-1.13	**-4.8**	48.7	47.87	46.28	1.61	**78.2**	4.7	44.57	44.48	-0.26	**-1.2**	57.6	**72.3**
Nov	11.2	45.49	47.47	-2.72	**-30.4**	15.2	47.47	45.49	2.33	**35.5**	6.5	40.88	43.88	-2.66	**-17.4**	33.0	**-12.3**
Dec	25.1	48.89	50.61	-1.81	**-45.4**	5.7	50.61	48.89	2.50	**14.2**	10.6	44.84	48.72	-3.89	**-41.1**	41.4	**-72.3**
Annual	**122.7**	**46.53**	**47.97**	**-1.02**	**-174.2**	**561.1**	**47.97**	**46.53**	**1.50**	**903.2**	**72.9**	**43.25**	**44.29**	**-0.95**	**-75.5**	**756.7**	**653.4**