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Post-2026 Environmental Impact Statement Rate Analysis for the Colorado River Storage Project

Energy Systems and Infrastructure Assessment Division

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Post-2026 Environmental Impact Statement Rate Analysis for the Colorado River Storage Project

by
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For
Western Area Power Administration

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Executive Summary

The Glen Canyon Dam (GCD) is a principal power-generating asset within the Colorado River Storage Project (CRSP), accounting for approximately 70–80% of CRSP power production over the past two decades. In June 2023, the U.S. Bureau of Reclamation (Reclamation) issued a Notice of Intent to prepare an Environmental Impact Statement (EIS) outlining operational guidelines and strategies for Colorado River Basin reservoirs after 2026 (Reclamation, 2023). Power generation is among CRSP's statutory purposes under the Colorado River Storage Project Act of 1956 (U.S. Congress, 1956). Assessing how alternative policy frameworks affect CRSP power production and the resulting electricity rates for U.S. customers is therefore essential to inform decision-making. This report evaluates the potential trajectories of electricity rates and the market value of electricity from the Western Area Power Administration (WAPA) CRSP GCD under multiple post-2026 policy scenarios to support Reclamation's EIS development.

The analysis covers eight policy scenarios designed by Reclamation for hypothetical implementation during the years from 2028 to 2060. Table 1.1 provides a summary of all eight policy scenarios. Five scenarios were introduced during the initial post-2026 EIS scoping phase (U.S. DOI, 2025), and the scope was expanded to eight in summer 2025. Each scenario specifies a distinct approach to CRSP water management (e.g., reservoir release schedules) consistent with goals and regulatory frameworks established in the Records of Decision (Reclamation, 2007; Reclamation, 2016). To represent uncertainty in future hydrological conditions, 1,200 distinct hydrological traces are evaluated for each scenario. The work builds on a WAPA-commissioned effort conducted by Argonne National Laboratory, which developed an advanced simulation tool to estimate future electricity production (Ploussard et al., 2025). This report focuses on the rate and market-value implications of those simulated production outcomes.

Results from advanced econometric and machine learning models indicate that the Enhanced Coordination alternative (EnhanCoor), Maximum Operational Flexibility alternative (CCA), and Supply Driven - 55 alternative (SD55) alternatives yield more favorable hydropower generation and capacity outcomes, which are objectives outlined in Reclamation's documentations (Reclamation, 2007; Reclamation, 2016). Specifically, these scenarios are associated with higher electricity production, lower projected rate trajectories, and greater economic value to the U.S. power system from CRSP generation. The remaining five scenarios generally produce lower generation, higher rate trajectories, and reduced long-term market values.

The report documents the modeling framework and key methodological choices. The research team assembled comprehensive data on WAPA CRSP plant characteristics, hydrological conditions, Argus forward prices, and WAPA power purchase and sales transactions. For the rate analysis, a stepwise rate-adjustment framework is developed, consistent with WAPA CRSP's obligation to remain financially self-sustaining and to deliver cost-based power services (U.S. DOE, 2025). For the market-value analysis, a long-term electricity price forecasting framework tailored to the CRSP system is applied (Pavičević et al., 2025).

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List of Acronyms and Abbreviations

CCA Maximum Operational Flexibility alternative. 1–4, 6, 10, 11, 16, 20, I

CCS Continued Current Strategy alternative. 1, 4, 6, 11

CDF cumulative distribution function. 13

CRiSPPy Colorado River Storage Project Python model. 4, 5, 17, 18

CRSP Colorado River Storage Project. 1, 4, 20, I

EIA U.S. Energy Information Administration. 18

EIS Environmental Impact Statement. 1, I

EnhanCoor Enhanced Coordination alternative. 1–4, 6, 10, 11, 16, 20, I

FedCont Federal Contingency alternative. 1, 4, 11

GCD Glen Canyon Dam. 1–4, 14, 17, 20, I, II

LOESS locally (weighted) estimated scatterplot smoothing. 17

LTEMP Long-Term Experimental and Management Plan. 1

NA No Action alternative. 1, 4, 6, 11, 14

NEMS National Energy Modeling System. 18

Reclamation U.S. Bureau of Reclamation. 1, 4, I

RMSE root mean squared error. 18

RR Revenue requirement. 4–6

SD55 Supply Driven - 55 alternative. 1–4, 6, 10, 11, 16, 20, I

SD65 Supply Driven - 65 alternative. 1, 4, 11

SD75 Supply Driven - 75 alternative. 1, 4, 6, 11

WAPA Western Area Power Administration. 1, 4, 10, 11, 14, 20, I

WY Water year. 4–6, 10

1 Introduction

Western Area Power Administration (WAPA) is responsible for marketing and delivering the energy products and services produced from the Colorado River Storage Project (CRSP) system. WAPA plays a vital role in delivering reliable and cost-effective hydroelectric power to millions of customers across the western United States (Reclamation, 2024; U.S. DOE, 2025). The CRSP carries out WAPA's mission in Arizona, Utah, Colorado, New Mexico, Nevada, Wyoming, and Texas. Achieving this mission requires effective resource management strategies that govern the water resources of the Colorado River system, informed by advanced analytical tools and modeling methodologies.

U.S. Bureau of Reclamation (Reclamation) manages water resources and dam operations in the Colorado River Basin. Incorporating input from Basin partners, stakeholders, and the public, Reclamation sets reservoir release schedules to meet the objectives identified in the Glen Canyon Dam (GCD) Long-Term Experimental and Management Plan (LTEMP), such as: (1) compliance with water allocation laws, regulations, and guidelines; (2) the design and scope of flow and non-flow actions; and (3) hydropower and energy objectives (Reclamation, 2016; Reclamation, 2024). Directed by the Secretary of the Interior, Reclamation initiated the preparation of an Environmental Impact Statement (EIS) for post-2026 operations, as several decisional documents and agreements that govern CRSP operations are scheduled to expire by the end of 2026 (e.g., Reclamation, 2007; IBWC, 2017; U.S. Congress, 2019). In June 2023, Reclamation issued a Notice of Intent to prepare an EIS outlining operational guidelines and strategies for post-2026 Colorado River Basin reservoirs operations as part of the National Environmental Policy Act process (Reclamation, 2023).

At the initial stage of the post-2026 EIS process, Reclamation proposed five alternative operational frameworks with detailed operating rules (U.S. DOI, 2025). Based on subsequent input from Basin partners, stakeholders, cooperating agencies, and the public, Reclamation expanded the set to eight potential post-2026 management strategies: (i) Continued Current Strategy alternative (CCS); (ii) Enhanced Coordination alternative (EnhanCoor); (iii) Maximum Operational Flexibility alternative (CCA); (iv) Federal Contingency alternative (FedCont); (v) No Action alternative (NA); (vi) Supply Driven - 55 alternative (SD55); (vii) Supply Driven - 65 alternative (SD65); and (viii) Supply Driven - 75 alternative (SD75). Each policy scenario reflects a different balance among objectives such as protecting critical infrastructure, benefiting environmental and hydropower resources, and stabilizing system storage levels (U.S. DOI, 2025). Table 1.1 presents a high-level overview of all the policy scenarios analyzed in this report. Notably, the CCS and NA scenarios are considered as the "baseline" or "reference" scenarios with which the others are compared. In particular, the NA scenario assumes that reservoir operations would follow the old operating rules used before the 2007 Interim Guidelines, with minor updates (U.S. DOI, 2025). The CCS scenario represents the current operational rules.

This report builds on Ploussard et al. (2025), which analyzed the effects of these scenarios on future power production at GCD. However, the resulting firm rate implications, long-run hydropower market values, and financial consequences for the Basin Fund and WAPA's preference customers have not been fully quantified. Here, we assess firm rate impacts and the value of electricity for the CRSP system, focusing on GCD, which accounts for 70%–80% of total WAPA CRSP power production, as a case study. The analysis covers all eight alternative management strategies for years 2028 to 2060 and is intended to inform the ongoing post-2026 EIS development, which balances multiple, sometimes competing, CRSP objectives (Reclamation, 2007;

Table 1.1: Summary of Policy Scenarios of Interests

Alternative (Abbreviation)	Key Feature(s)
No Action (NA)	This policy scenario reverts to the operating rules used before the 2007 Interim Guidelines, with minor updates (U.S. DOI, 2025).
Continued Current Strategy (CCS)	This scenario relies on existing rules largely based on the 2007 Interim Guidelines for minor shortages and fixed Lake Powell releases, with no new conservation mechanisms or Upper Basin contributions.
Federal Contingency (FedCont)	Uses Lake Mead elevation-based shortages up to 1.48 maf and flexible Lake Powell releases tied to its elevation, with no new conservation and limited Upper Basin unit releases for dam protection.
Enhanced Coordination (EnhanCoor)	This scenario determines large shortages (up to 3 maf) based on combined Powell/Mead storage, and establishes a complex new system of storage pools (up to 9 maf total) and Upper Basin conservation.
Maximum Operational Flexibility (CCA)	This most dynamic policy scenario ties releases and the largest shortages (up to 4 maf) to total system storage and recent flow conditions, establishing an 8 maf basin-wide Conservation Reserve for both basins.
Supply-Driven 75/65/55 (SD75/65/55)	This plan uses Lake Mead elevation-based shortages up to 2.1 maf and sets Lake Powell releases as a fixed percentage of the preceding 3-year flow (75%/65%/55%), while creating separate large storage pools for the Upper (3 maf) and Lower (8 maf) Basins.

Reclamation, 2016; Reclamation, 2023).

Consistent with the requirement for cost-based rates (U.S. DOE, 1979; U.S. DOE, 1985), we analyze the potential rate impacts of different policy scenarios by developing a stylized, stepwise rate-adjustment framework in which GCD is assumed to remain financially self-sustaining (break-even) in the long run. On average, most policy scenarios yield sustained and substantial increases in firm electric service rates over time, with three exceptions: EnhanCoor, CCA, and SD55. Moreover, only a small share of hydrological traces under these three scenarios produce an extreme outcome in which GCD generates no electricity (below the power pool) for five consecutive years. For the remaining five scenarios, the proportion of hydrological traces leading to such an outcome is materially higher, ranging from 17% to 33%. Distributional features and uncertainty in future hydrological conditions indicate that EnhanCoor, CCA, and SD55 lead to fewer rate adjustments, smaller average increases per adjustment, and substantially lower maximum rate increases. Finally, using the long-term price projection methodology in Pavičević et al. (2025), we find that, under the vast majority of hydrological conditions, GCD's contribution to the U.S. power system's market value substantially exceeds its investment, operation, and maintenance costs. Overall, EnhanCoor, CCA, and SD55 entail less adverse financial impact on U.S. electricity consumers and provide greater protection against extreme adverse outcomes than the other five alternatives.

This report documents the modeling framework and key methodological choices. To set the stage, we first present our analysis regarding the representative case of each policy scenario. Then we proceed to incorporate uncertainties into our analysis. Section 2 specifies baseline parameters. Section 3 reports summary statistics. Section 4 analyzes temporal dynamics. Section 5 presents results for a representative hydrologic condition without uncertainty. Section 6 provides a comprehensive rate-impact analysis incorporating uncertainty. Section 7 quantifies the market value of future GCD electricity.

2 Baseline Parameters

The goal of this analysis is to assist and provide information for Reclamation in investigating the potential long-term impacts of policy scenarios governing the CRSP system's operations. The current scope of the analysis includes eight policy scenarios of interest, including (i) CCS; (ii) EnhanCoor; (iii) CCA; (iv) FedCont; (v) NA; (vi) SD55; (vii) SD65; and (viii) SD75, from 2028 to 2060 (33 Water year (WY)'s).

To assess policy scenarios' impact on WAPA CRSP's future firm electric service rate to its customers, we model the trajectory of rate changes and calculate the associated production or financial deficits, assuming that WAPA CRSP GCD must remain financially self-sustaining. In other words, revenue from GCD's energy production must equal the portion of the revenue requirement attributable to GCD's energy activities. Our model assumes that WAPA may carry a financial surplus or deficit[1] for a limited period (up to five years) and any imbalance must ultimately be reconciled through rate adjustments. To maintain analytical consistency, our rate adjustment framework simplifies the actual rate-setting process by assuming fixed five-year windows to reconcile any financial deficits or surpluses and perfect foresight regarding future hydrological conditions.

As the first step in the analysis, we establish the reference points: the Revenue requirement (RR) associated with GCD's energy production and WAPA's current customer rate. We will use the current rate $P_{curr} = \$12.36/MWh$ as the starting reference rate of the price:

$$P^* = P_{curr} = \$12.36/MWh \tag{2.1}$$

and the implied "break-even" production level Q* in MWh, given the current rate P^*:

$$Q^* = \frac{RR}{P^*} \tag{2.2}$$

At the current rate of \$12.36/MWh and an annual RR of \$45.05 million attributable to GCD's energy production, GCD must generate approximately $Q^* \approx 3.64$ million MWh per year to reach a financially break-even point. These two quantities, Q^* and P^*, serve as the central reference points for our subsequent analyses. Conceptually, focusing on adjustments in either output or price is equivalent, since equations (2.1) and (2.2) provide a direct mapping between the two parameters as long as the annual RR remains fixed.

Projected annual electricity production is simulated using Colorado River Storage Project Python model (CRiSPPy) (Ploussard et al., 2025), with 1,200 hydrological condition traces serving as inputs under each policy scenario. For each of the 33 WYs within a given hydrological trace constrained by the regulations specified in the scenario, CRiSPPy generates a simulated annual electricity production level. To mitigate the influence of extreme year-to-year production values and to align with WAPA's five-year rate planning horizon, we replace water year–specific production results with their corresponding five-year forward rolling averages. For each year, we compute the average of production in the current year and the subsequent four years and use this value in place of the original single-year production level. This forward rolling average is consistent with WAPA's rate-planning practice of setting current rates based on the expected five-year production quantities.

[1] Definition and interpretation of deficits and surpluses used in this report are elaborated in Section 3.

3 Summary Statistics

We begin with a simple calculation: for each scenario, we subtract the projected total revenue (based on the reference/current rate P^* held constant over the next 33 WYs) from the annual RR. Dividing this difference by the number of years yields the annual average financial deficit, denoted D_s^P.

$$D_s^P = \frac{1}{33} \sum R^* - (P^* \times Q_{i,s,t}) \tag{3.1}$$

Where i represents an individual trace, s is the hypothetical policy scenario, and t is the future water years. Alternatively, we can also calculate the annual average electricity production deficit D_s^Q for each scenario:

$$D_s^Q = \frac{1}{33} \sum Q_{i,s,t} - Q^* \tag{3.2}$$

We will also calculate the share of traces, Pr_s, under each scenario with at least one year of zero electricity production. We define these events as catastrophic events:[2]

$$Pr_s \;=\; \frac{1}{1200} \sum_{i=1}^{1200} \mathbb{1}\{\exists\, t \in \mathcal{T} :\; Q_{i,s,t} = 0\}, \tag{3.3}$$

Where $\mathcal{T}$ represents the set of water years t within a trace, the two deficit metrics and the share of traces with a catastrophic event will give the audience a general picture at the top level for each scenario.

Table 3.1 presents the summary statistics of each metric across different hydrological traces and WYs under each policy scenario. As formally defined in equations (3.1) and (3.2), quantity surpluses or deficits in this report refer to production levels above or below the annual reference production Q^*; likewise, financial surpluses or deficits refer to revenues exceeding or falling short of the annual RR, given the simulated production level $Q_{i,s,t}$, and the current rate P^*. Under our modeling assumptions, financial surpluses and deficits would imply rate decreases and increases, respectively. However, our model is a simplification of WAPA's actual rate-setting process. Therefore, the surplus and deficit figures presented herein should be interpreted as indicative measures of the direction and magnitude of each policy scenario's potential rate impacts, rather than as a formal rate adjustment process. Lastly, large standard deviations presented in Table 3.1 suggest substantial uncertainties in the quantities of interest. We dedicate Section 6 to discuss the uncertainties of our analysis.

Table 3.1: Summary Statistics

	NA	**CCS**	**FedCont**	**EnhanCoor**	**CCA**	**SD55**	**SD65**	**SD75**
Energy Deficit (Mil MWh/yr)	0.55	0.38	0.36	-0.13	-0.19	-0.23	0.33	0.86
	(1.44)	(1.29)	(1.28)	(0.98)	(0.95)	(0.88)	(1.21)	(1.18)
Financial Deficit (Mil $/yr)	6.79	4.68	4.50	-1.63	-2.35	-2.90	4.10	10.64
	(17.83)	(15.96)	(15.86)	(12.08)	(11.71)	(10.84)	(14.99)	(14.60)
Pr(Extreme Events)	32.25%	19.83%	21.58%	2.75%	0.33%	1.08%	17.50%	25.67%

Negative values imply financial or energy production surpluses. Standard deviations are in parentheses.

[2] It is worth noting that under our five-year forward rolling horizon framework, a WY with zero electricity production implies five consecutive years of zero production in the original CRiSPPy outputs—an exceptionally extreme and catastrophic event. Rate adjustments will not address such an event.

4 Summary Statistics - Temporal Dynamics

In this section, we investigate the summary statistics defined in Section 3 by WY, to provide a refined overview of how these figures evolve over time under different policy scenarios. We first compute the metrics by WY in parallel to those introduced above, including $D^P_{s,t}$, $D^Q_{s,t}$, and $Pr_{s,t}$. For each metric, we present two sets of plots (CCS *or* NA with other scenarios) to illustrate how these measures evolve over time.

A total of six plots are presented below. Each plot depicts the temporal evolution of key statistics across water years. Figures 4.1 through 4.6 provide the corresponding outputs. These results illustrate, conditional on a given level of expected water resource availability within each WY, the expected quantity deficit, financial deficit, and the share of traces with catastrophic events under each scenario.

Figures 4.1 and 4.4 illustrate that, relative to the current rate and production level, both the monetary deficit and the production deficit follow an upward trajectory over the next 33 water years. The underlying values are averaged across all potential futures for each year, so the observed trend primarily reflects declining water availability rather than policy differences. Even so, the SD75 scenario tends to produce much larger deficits over time. The SD55, CCA, and EnhanCoor scenarios will result in consistent small surpluses in electricity production and revenue relative to the reference point jointly defined by P^*, Q^*, and RR, over the period from 2028 to 2060.

Figures 4.5 and 4.6 show the fraction of traces that experience one or more catastrophic events. This share remains very low throughout the projection horizon under the SD55, CCA, and EnhanCoor scenarios. By contrast, under all five other scenarios, the share rises steadily with time, though it is projected to stay below 5% until the late 2050s.

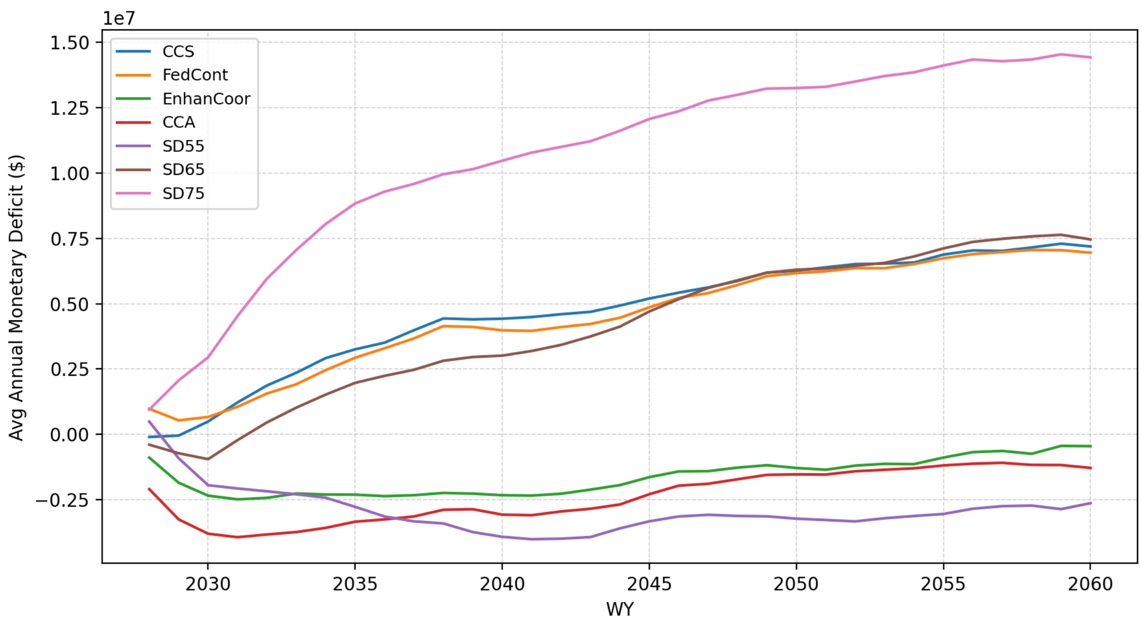

Figure 4.1: Monetary Deficit by WY - CCS and Other Scenarios

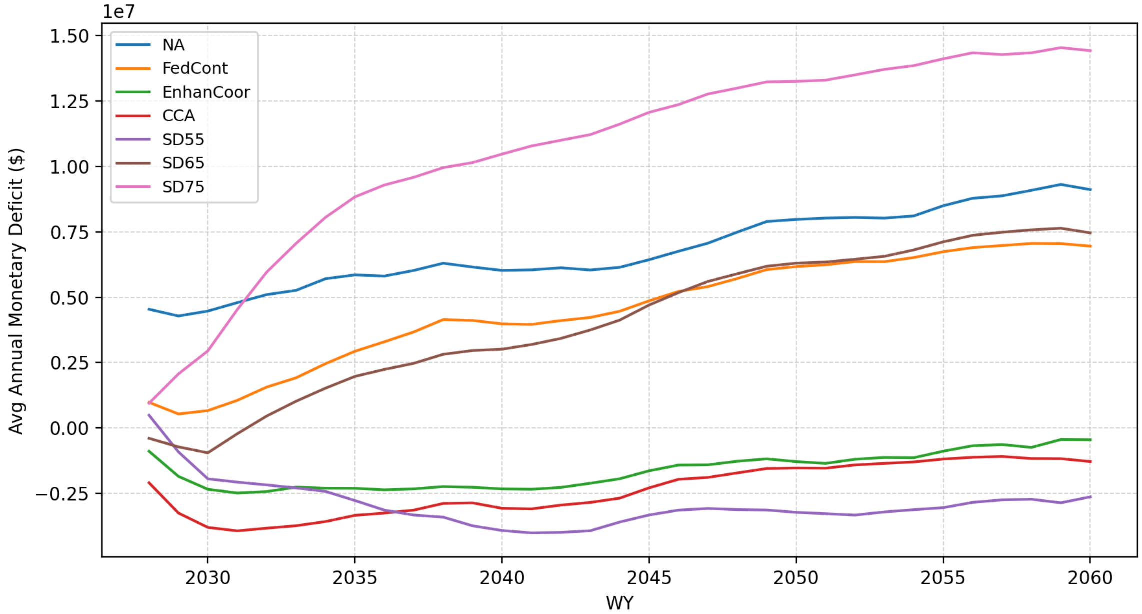

Figure 4.2: Monetary Deficit by WY - NA and Other Scenarios

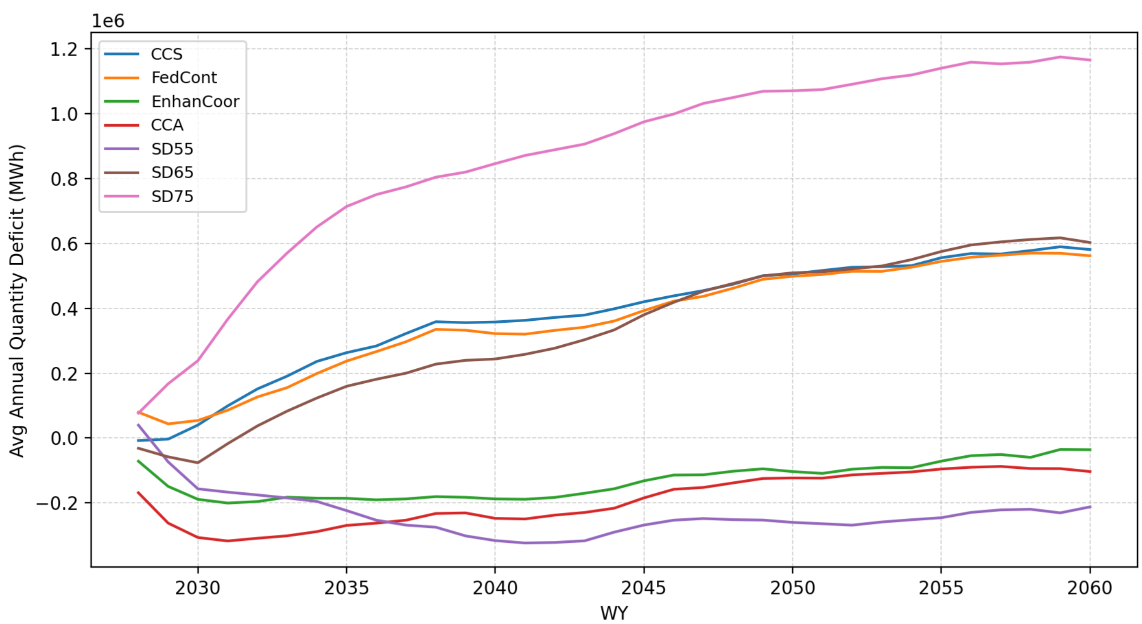

Figure 4.3: Electricity Quantity Deficit by WY - CCS and Other Scenarios

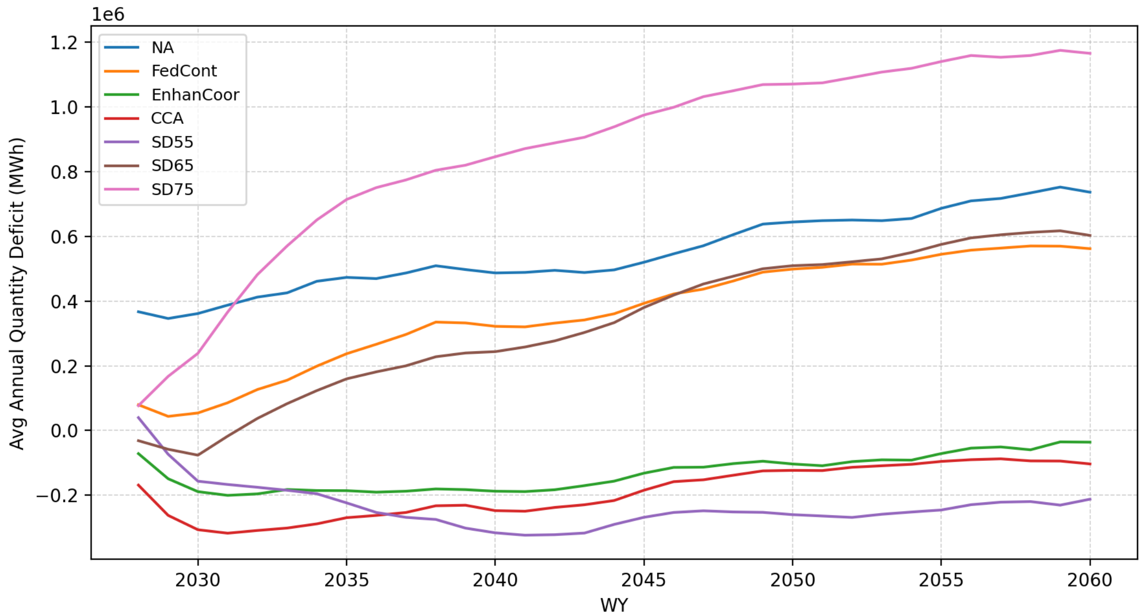

Figure 4.4: Electricity Quantity Deficit by WY - NA and Other Scenarios

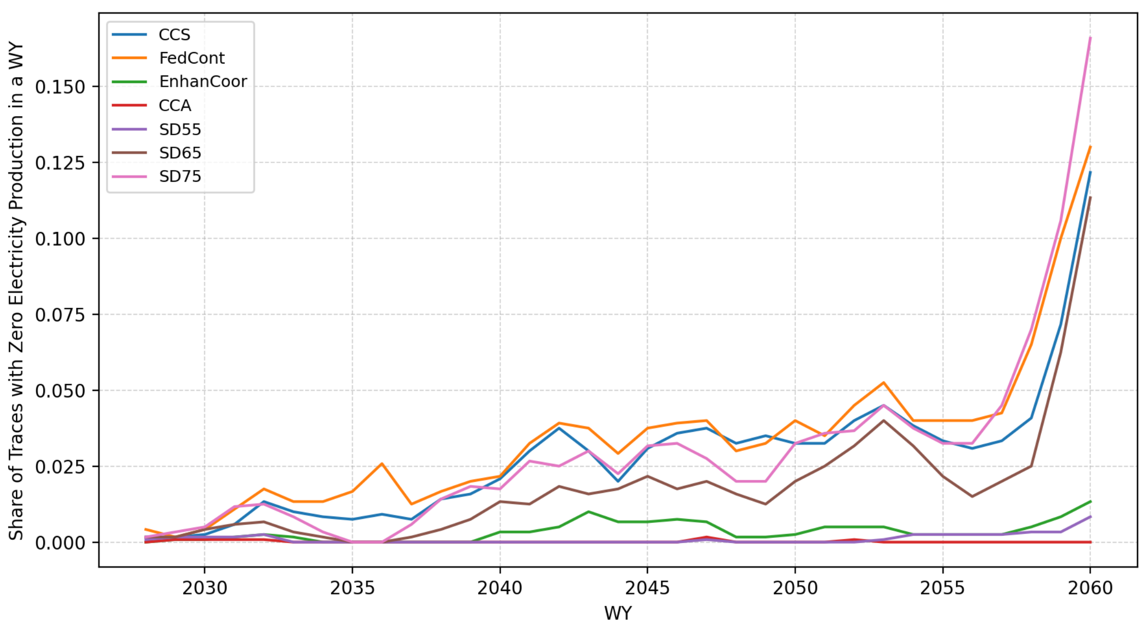

Figure 4.5: Share of Traces with Catastrophic Events by WY - CCS and Other Scenarios

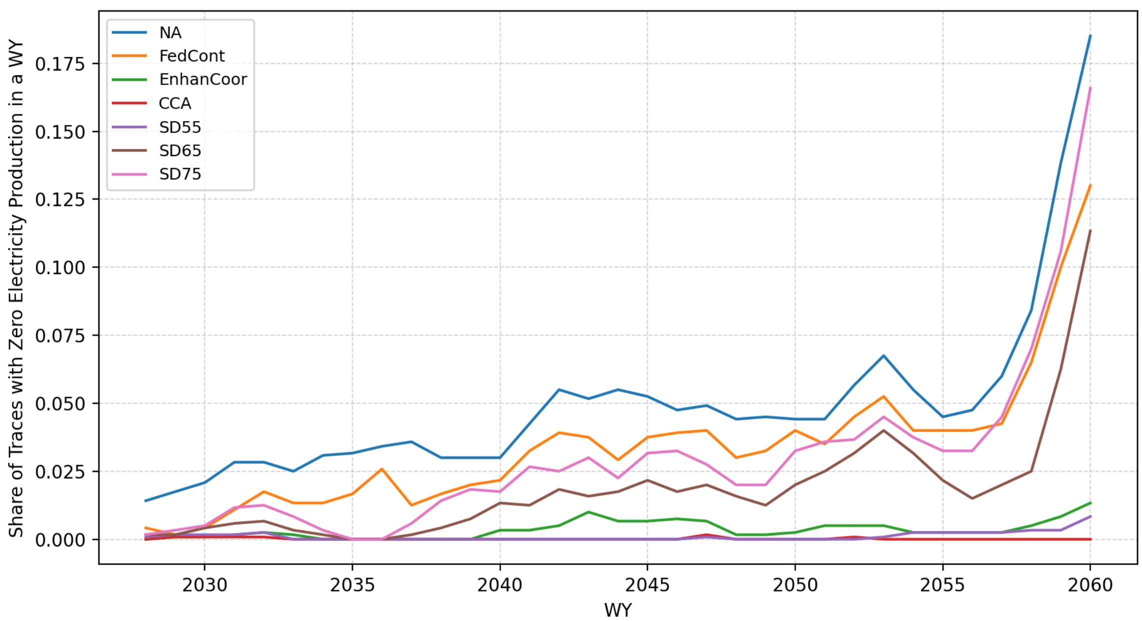

Figure 4.6: Share of Traces with Catastrophic Events by WY - NA and Other Scenarios

5 Rate Trajectory of the Representative Trace

Building on the preceding sections, we translate the deficit measures into discrete rate actions to approximate cost-based rate adjustments over time. This section focuses on rate trajectories for representative production traces under each policy scenario, abstracting from the uncertainty associated with future hydrological conditions. The objective is to illustrate the general relative direction and relative magnitude of theoretical rate changes over time for each alternative. The results presented herein should not be interpreted as definitive forecasts of rate actions, but rather as indicative representations of the relative rate impacts arising from different Glen Canyon Dam release policy alternatives.

To begin, we calculate the representative trace for each scenario, defined as the average production trace across all 1,200 simulations. This produces a 33-by-1 electricity production array per scenario, denoted as $Q_{s,t}$. We then divide the time series into six 5-year intervals and one 3-year interval, covering the full 33-year horizon. For the first window (WY 1–5), we apply the current rate $P^* = P_0$ with production given by the representative trace, and calculate the cumulative deficit $D_{s,1}$ for scenario s (or more generally, D_{sw} for any window $w \in \{1, 2, 3, 4, 5, 6\}$ and any scenario $s \in \{NA,\ CCS,\ CCA,\ FedCont,\ EnhanCoor,$
$SD55,\ SD65,\ SD75\}$):[3]

$$D_{s,w} = 5R^* - \sum Q_{s,t} P_{w-1} \tag{5.1}$$

We calculate a new rate starting from year 6 for the entire next 5-year window such that:

$$\delta_w = \frac{D_{s,w}}{\sum_{t=5w+1}^{t=5w+5} Q_{s,t}} \tag{5.2}$$

And the new price becomes:

$$P_w = P_{w-1} + \delta_w \tag{5.3}$$

Ultimately, this procedure yields one rate trajectory per scenario over the 33 WYs. The underlying assumption is that WAPA must recover exactly the amount of revenue required to meet its annual obligation. Financial surpluses or deficits are permitted only within each time window, but any imbalance must be resolved by the end of that window. Complement to the representative price trajectory, we also calculate the share of traces under each scenario that lead to a major rate increase ($\delta_w \geq \$1.5/MWh$) at the end of each time window, as depicted in Figure 5.1.

The serial correlation of hydrologic conditions across years warrants caution in interpreting Figure 5.1 and all time-dependent results in this report. Dry periods tend to persist; thus, a trace with reduced water availability in earlier years is more likely to exhibit reduced availability later. Moreover, the step-wise rate adjustment mechanism is path dependent and can interact with this autocorrelation to produce different rate trajectories under otherwise identical later-year hydrology.[4] The EnhanCoor, CCA, and SD55 scenarios result in lower shares of traces

[3]For the last 3-year window, equation (5.1), (5.2), and (5.3) are adapted into a 3-year revenue requirement version, by which we will only seek to make the rate adjustment at the end of trace to balance any financial surplus/defict.

[4]Consider two traces, A and B. If A experiences dry conditions in 2028–2033 that trigger a major rate increase in 2033, its rates from 2033 onward will be higher than B's if B had no increase. Consequently, even if A and B face identical hydrologic conditions in 2038–2043, A may not require another increase in 2038, whereas B may.

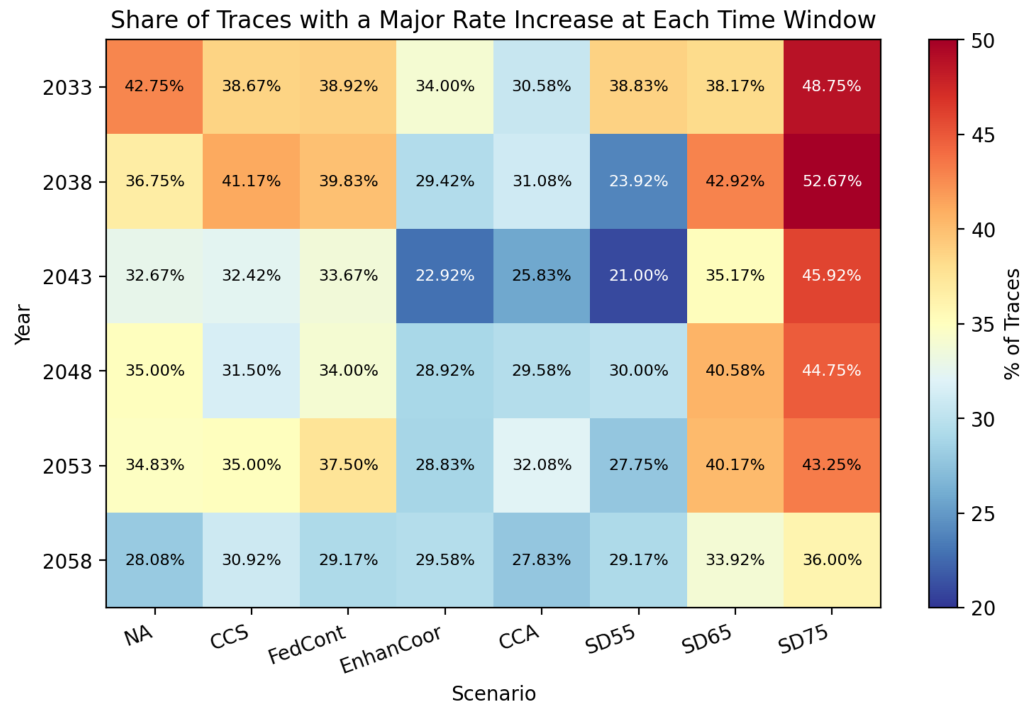

Figure 5.1: Each cell shows the share of traces with a major rate increase ($\delta \geq 1.5$) in the time window.

with major rate increases at all time windows, and the SD75 scenario leads to higher shares of traces with major rate increases for all time windows.

Given our assumptions of balanced financial positions and a fixed schedule of rate adjustments, Figures 5.2 and 5.3 illustrate the evolution of rates under the representative trace. Consistent with our findings from Figure 4.1 to 4.6, the EnhanCoor, CCA, and SD55 scenarios will lead to lower rates than the current rate due to the production/financial surpluses. Rates under other scenarios rise over time to meet WAPA's revenue requirement due to energy production and financial deficits. Moreover, the NA, CCS, FedCont, SD65, and SD75 scenarios consistently generate much steeper rate trajectories and higher probabilities of major rate increases compared with the EnhanCoor, CCA, and SD55 scenarios.

Identical later hydrology need not imply identical rate outcomes because prior adjustments alter the starting price level.

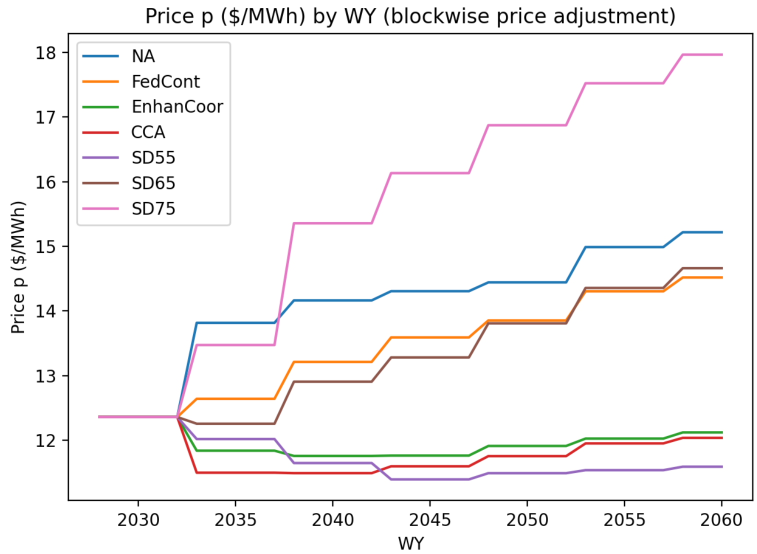

Figure 5.2: Rate Evolution for the Representative Trace - NA and others

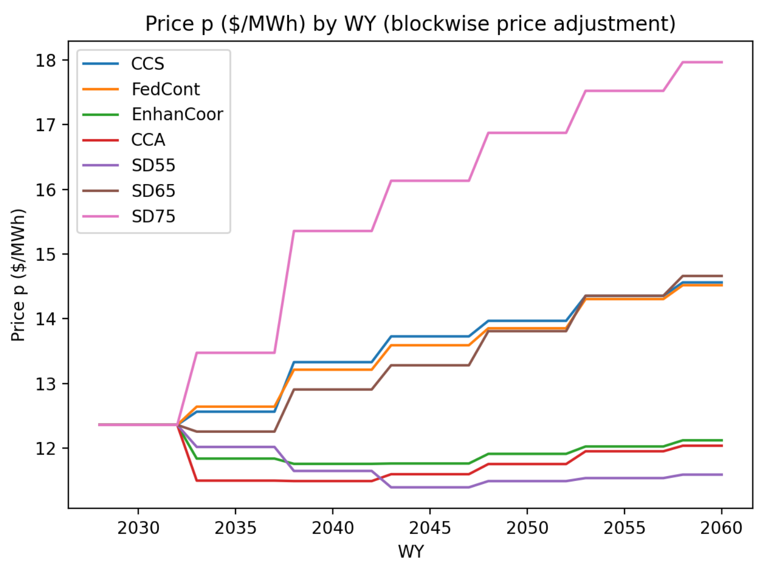

Figure 5.3: Rate Evolution for the Representative Trace - CCS and others

6 Uncertainties in the Future

Next, rather than focusing on a single representative trace, we examine the financial and production outcomes of individual future traces under each policy scenario. This approach provides a clearer picture of the distributions of both electricity production and rate increases. Consider all traces under scenario s with k rate increases. Among these, we identify the trace(s) with the smallest electricity production deficit, denoted as $\underline{D_{i,s}}(k)$. In general, except in degenerate cases, most traces with $D_{i,s} < \underline{D_{i,s}}(k)$ are expected to require fewer than k rate increases. We formally define $D_{i,s}$ as:

$$D_{i,s} = \frac{1}{33} \sum_{t=1}^{33} D_{i,s,t} \tag{6.1}$$

Combining with the framework laid out in Section 1 and the benchmark quantity Q^*, we can translate D_{is} into an actual production level cutoff point $\underline{Q_{i,s}}(k)$:

$$\underline{Q_{i,s}}(k) = \underline{D_{i,s}}(k) + Q^* \tag{6.2}$$

The empirical cumulative distribution function (CDF) of $D_{i,s}$, denoted $F(D_{is})$, can be directly calculated from the data. By applying the transformation defined in equation (6.2), we can also construct the empirical CDF of Q_{is}, denoted $F(Q_{i,s})$. Examining the values of $F(Q_{i,s})$ (ranging from 0 to 1) provides an intuitive interpretation of the distribution of future rate increases and production outcomes.

For example, suppose $F(\underline{Q_{i,s}}(1)) = 0.05$, $\underline{Q_{i,s}}(1) = 5M$ MWh/year, and this trace corresponds to an average major rate increase of \$2/MWh. This implies that 5% of traces under scenario s would result in fewer than one rate increase; the minimum annual production level consistent with one or fewer rate increases is 5 million MWh/year; and the average magnitude of a major rate increase would be less than \$2/MWh. We can apply the same procedure for traces with 2, 3, 4, 5, and 6 rate increases (or decreases). The results are summarized in Figures 6.1 to 6.3.

However, the non-monotonic and non-linear mapping between financial/quantity deficits and rate action counts introduces empirical challenges in our analysis. In particular, there is no theoretical guarantee that the following monotonicity condition holds:

$$\underline{D_{i,s}}(k) > \max D_{i,s}(k'), \ \forall k > k' \tag{6.3}$$

where $\underline{D_{i,s}}(k)$ denotes the minimum deficit among traces with k rate increases, and $\max D_{i,s}(k')$ denotes the maximum deficit among traces with k' rate increases.

Empirically, our data suggest that a weaker condition holds:

$$\max D_{i,s}(k) > \max D_{i,s}(k'), \ \forall k > k' \tag{6.4}$$

Although $\max D_{i,s}(k)$ might appear to serve as a reasonable cutoff, it is uninformative in practice, since many traces with lower production levels can yield the same number and magnitude of rate increases. To address this, we adopt a k-bin approach: for each k, we define the cutoff as the x^*th percentile of $D_{i,s}$ among traces with k rate increases (or decreases). Formally, the cutoff is given by

$$D^*(k) = \text{Quantile}_{x^*}\{D_{i,s} \mid \text{trace } i \text{ has } k \text{ rate increases}\}. \tag{6.5}$$

We then evaluate the empirical frequency of violations of Equation (6.3). In the present analysis, we set $x^* = 90$, which ensures that the share of traces exhibiting such violations remains below 5%.[5]

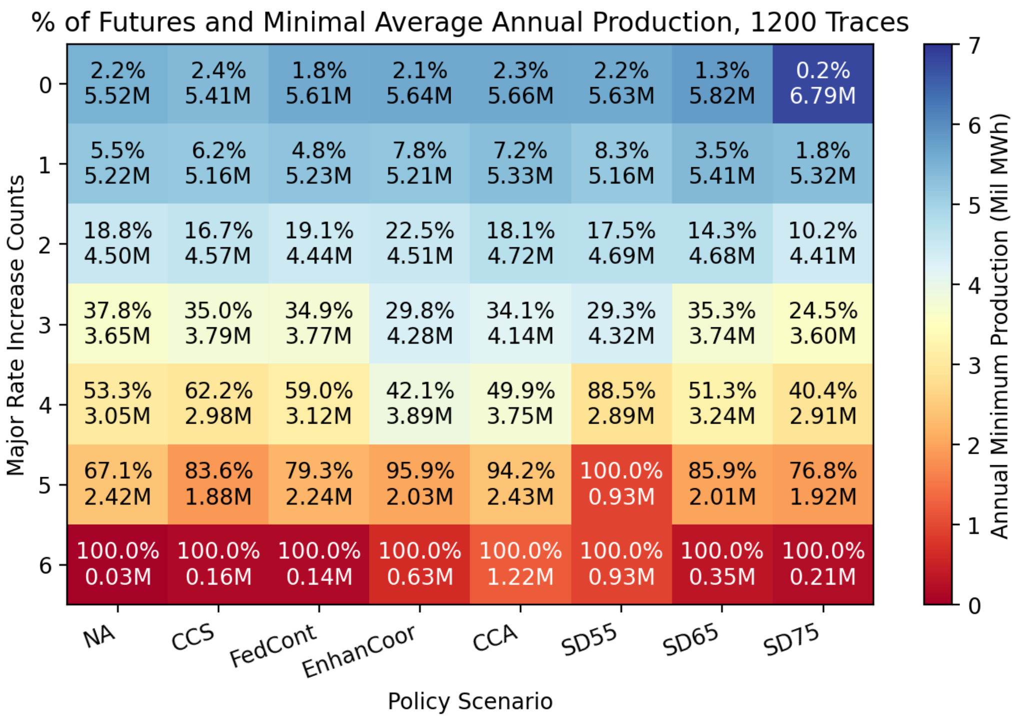

Figure 6.1: Each cell displays the minimum average annual production quantity, in MWh.

The interpretation of Figures 6.1 to 6.3 follows the same logic. For instance, consider the top-left cell in Figure 6.1 (2.2% / 5.52M MWh). This indicates that 2.2% of traces in the NA scenario result in zero major rate increases; for those traces, the average annual generation is at least 5.52 million MWh. In the last row of Figure 6.1, since all hydrological future traces produce at most six rate increases, the percentage is 100%. Accordingly, we report the minimal annual average production level under each policy scenario.

A similar interpretation applies to Figure 6.2. For the top-left cell (2.2% / \$0.00/MWh), 1.8% of traces in the NA scenario result in zero major rate increases; for those traces, the average rate increase magnitude is zero, consistent with the first row representing no major rate increases. In the last row of Figure 6.2, since all hydrological future traces produce at most six rate increases, the percentage is 100%. Here, we report the maximal rate increase magnitude per rate increase under each policy scenario, thereby capturing the worst-case outcome.

It is important to note that Figure 6.2 includes futures in which GCD produces zero electricity. Such an extraordinary and unprecedented event is unlikely to be addressed through rate actions by WAPA. For this reason, we exclude all futures that contain at least one year of

[5] For example, under the NA scenario, we observe 11 violations in the case where $D^*(1) > D_{is}(2)$. Since there are 237 traces associated with $k = 2$, this corresponds to a violation rate of 4.6%. Aggregating across all values of k, the overall violation rate is approximately 2.9%. Choosing $x^* = 75$ would increase the violation rate to 8%.

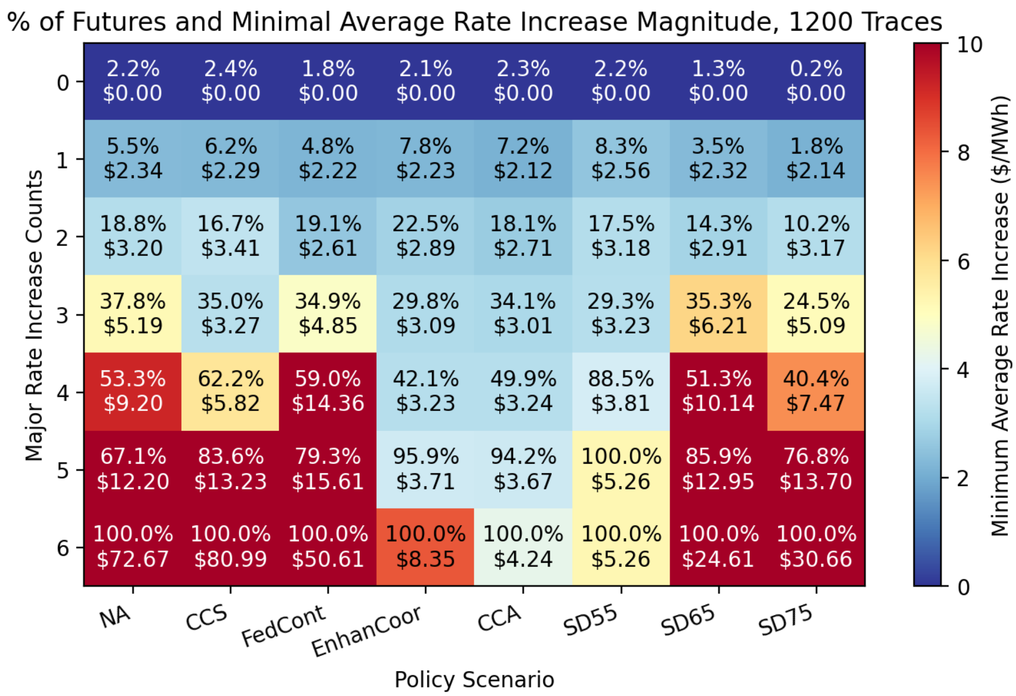

Figure 6.2: Each cell displays the minimum average rate increase amount per major rate increase, in $/MWh.

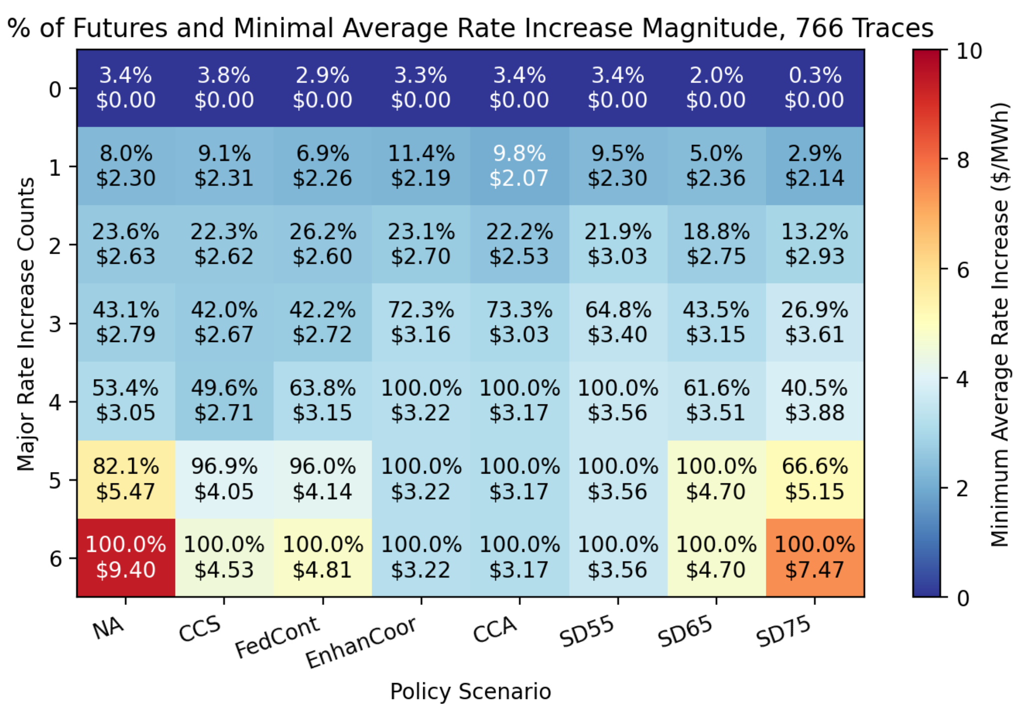

Figure 6.3: Each cell displays the minimum average rate increase amount per major rate increase, in $/MWh.

zero production under any scenario and present the adjusted results in Figure 6.3. This data exclusion effectively removes the driest hydrological futures from the analysis and, therefore, warrants careful interpretation. Certain policy scenarios are designed to better preserve hydropower generation at GCD under conditions of limited water availability. Excluding these drier hydrological traces implicitly downplays the relative resilience of policy alternatives to future scenarios characterized by constrained water resources.

The overall qualitative interpretation of Figures 6.2 and 6.3 remains unchanged: under wet or average hydrological conditions, the EnhanCoor, CCA, and SD55 scenarios lead to rate outcomes that are similar to, or slightly better than, those under other scenarios. In contrast, under dry hydrological conditions, EnhanCoor, CCA, and SD55 scenarios result in substantially smaller rate increases and less frequent rate adjustments.

7 Market Value of Future Electricity at GCD

In this section, we set forth the methodology for estimating the future market value of electricity generated at GCD under alternative policy scenarios. In contrast to the preceding rate analyses, which are anchored in satisfying the revenue requirement, the market value of GCD's future electricity deliveries is determined by projections of long-term electricity prices. As outlined in Section 1, our approach integrates simulated electricity production levels from CRiSPPy with modeled annual electricity price trajectories for the period 2028–2060 to derive estimates of the average annual market value of electricity from GCD.

$$V_{i,s} = \frac{1}{33} \sum_{t=2028}^{2060} Q_{i,s,t} \times P_t \tag{7.1}$$

Let the average annual market value of electricity for hydrological trace i under policy scenario s be denoted as $V_{i,s}$, where $Q_{i,s,t}$ represents the simulated annual production in year t, and P_t denotes the modeled long-term electricity price levels. We adopt the simplifying assumption that P_t is independent of GCD's production level and hydrological conditions.[6] For each policy scenario, this framework yields 1,200 distinct $V_{i,s}$ values, which collectively form the distribution of average annual electricity values at GCD across hydrological conditions.

To project the long-term electricity price trajectory, we employ a machine learning–based approach. Directly specifying the structural dynamics of future electricity markets, a method involving the detailed integration of a capacity expansion model and a production cost model, would necessitate strong, often highly uncertain, assumptions about distant policy, technological, and climate scenarios. While such integrated structural analyses can provide high-fidelity, structure-oriented future system dynamics, the requisite complexity falls beyond the scope and resources of this study. Instead, our model is trained on decomposed historical monthly average Palo Verde Hub electricity prices spanning 2020 to 2025. The parameters estimated during this training process are then used to generate long-term electricity price projections applicable to GCD.

First, we decompose the historical Palo Verde hub electricity prices into three components: (1) a long-term temporal trend, (2) seasonality, and (3) idiosyncratic errors. For the long-term price projection, we focus on modeling the trend and the seasonality component, abstracting away from idiosyncratic errors. This decomposition serves to achieve stationarity, a property in which the mean, variance, and autocorrelation structure of the series remain stable over time. Working with a stationary representation of the data allows us to isolate short-run fluctuations around equilibrium while separately modeling the structural trend. This stability ensures that historical patterns are informative for future projections. By contrast, a non-stationary process (e.g., one exhibiting a unit root or random walk) can drift indefinitely, producing unreliable long-term projections. Such unbounded divergence would be inconsistent with electricity markets, which are fundamentally constrained by supply, demand, and regulatory structures. We implement the decomposition through the *STL* module based on locally (weighted) estimated scatterplot smoothing (LOESS) originally developed by Cleveland et al. (1990).

[6] Given GCD's size, price at the local grid is likely to be endogenous to GCD's production level. The current analysis seeks to proxy GCD's economic contribution to the broader U.S. electricity market. Consequently, we use data from one of the largest electricity trading hubs in the Western Interconnection, the Palo Verde hub, to approximate the long-term price.

Second, we employ *XGBoost* (Chen et al., 2023) to model the seasonality component of the data. Special care is taken to address the price spikes observed during the winter of 2022, which were driven by extreme weather conditions and represent idiosyncratic outliers. Model training is performed using a grid search over the standard hyperparameters of *XGBoost*, as well as weights applied to monthly price observations. We evaluate the optimal set of hyperparameters using time-series cross-validation: from 60 months of data, we begin with a 10-month training window and predict the subsequent 10 months, iteratively expanding the training set until the full dataset is utilized. The optimal hyperparameters are selected based on minimizing the root mean squared error (RMSE). Predictor variables include month, quarter, day of the month, the number of holidays, the number of Sundays, and counts of on- and off-peak hours per month. The trained model is then used to project future seasonality.

Third, we apply Prophet (Taylor and Letham, 2018; Prophet Developers, 2025), a machine learning framework developed by Meta, to model the temporal trend component of historical prices. Prophet is specified with a logistic growth function, subject to an upper cap of \$158/MWh in 2060, consistent with long-term projections reported by U.S. EIA (2023). Specifically, the U.S. Energy Information Administration (EIA) anticipates wholesale industrial electricity prices to reach approximately \$130/MWh by 2050, increasing at an average annual rate of 2 percent, which implies a price of about \$158/MWh in 2060.[7] It is worth noting that for both the EIA and our long-term projections are on a monthly average price scale, which abstracts away from hourly fluctuations. However, unlike a production cost model, our machine-learning-based model was trained on real market data, thereby better capturing the month-to-month price fluctuations embedded in the empirical market process.

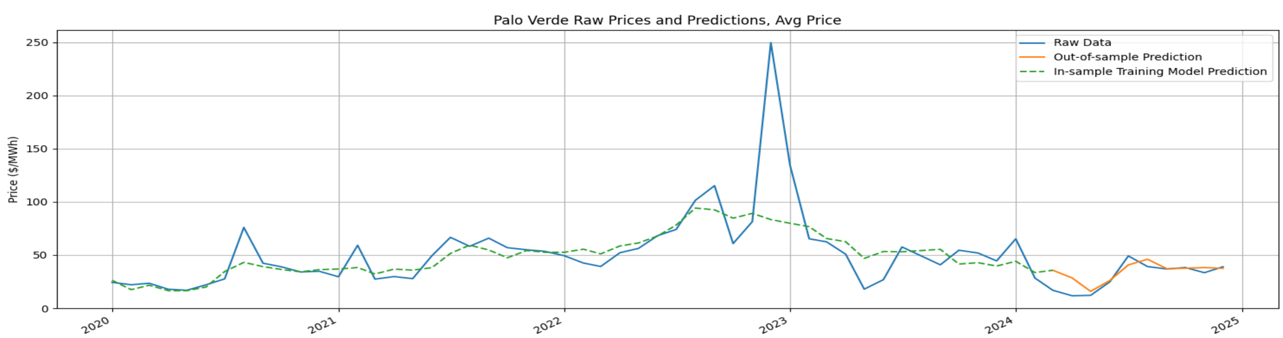

Figure 7.1: Comparison with Historical Data

Finally, our long-term price projection at each point in time is obtained as the sum of the seasonality component estimated via *XGBoost* and the trend component estimated via *Prophet*. This produces a forward projection of 432 monthly prices spanning 2025–2060. We then compute annual prices as the arithmetic average of the 12 monthly forecasts within each year, and use the years 2028–2060 for consistency with the CRiSPPy production simulations.

Figure 7.1 illustrates the last expanding window of our time series cross-validation. The orange line segments are out-of-sample predictions of the parameters trained based on the sample of data from 2020 to early 2024. As shown in the figure, our model provides good in-sample (green dashed line) and out-of-sample predictions (orange solid line) empirically.

[7]The EIA uses National Energy Modeling System (NEMS), an integrated assessment model, to derive their estimates. NEMS considers multiple market equilibrium processes, such as capacity expansion, fuel sup-

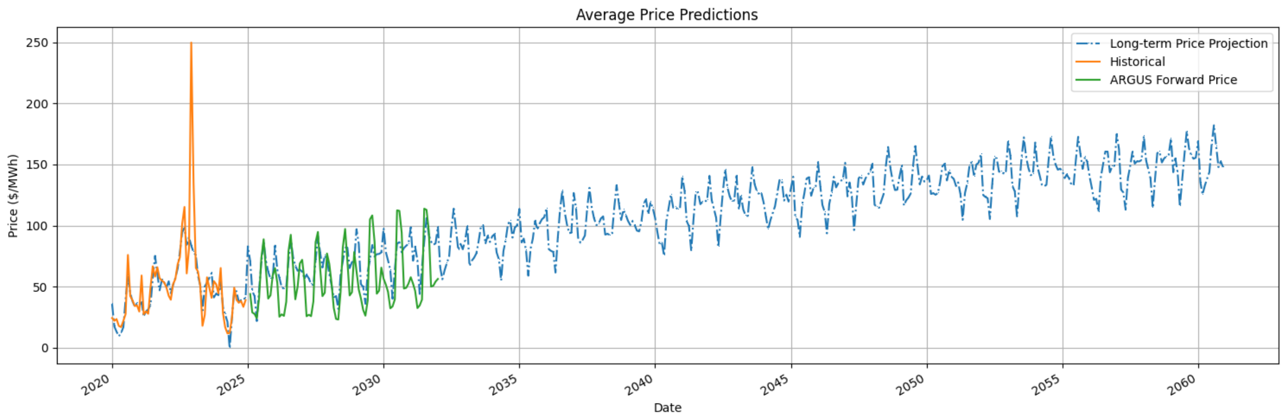

Figure 7.2: Comparison with Historical and Argus Long-term Forward Prices

In Figure 7.2, we present a visual representation of our long-term price projections in comparison with historical Palo Verde price data and Argus forward prices. For the time period between 2020 and 2032, in which we have either historical prices or Argus estimates as reference points, our model produces price projections that are in a reasonable range relative to these reference points.

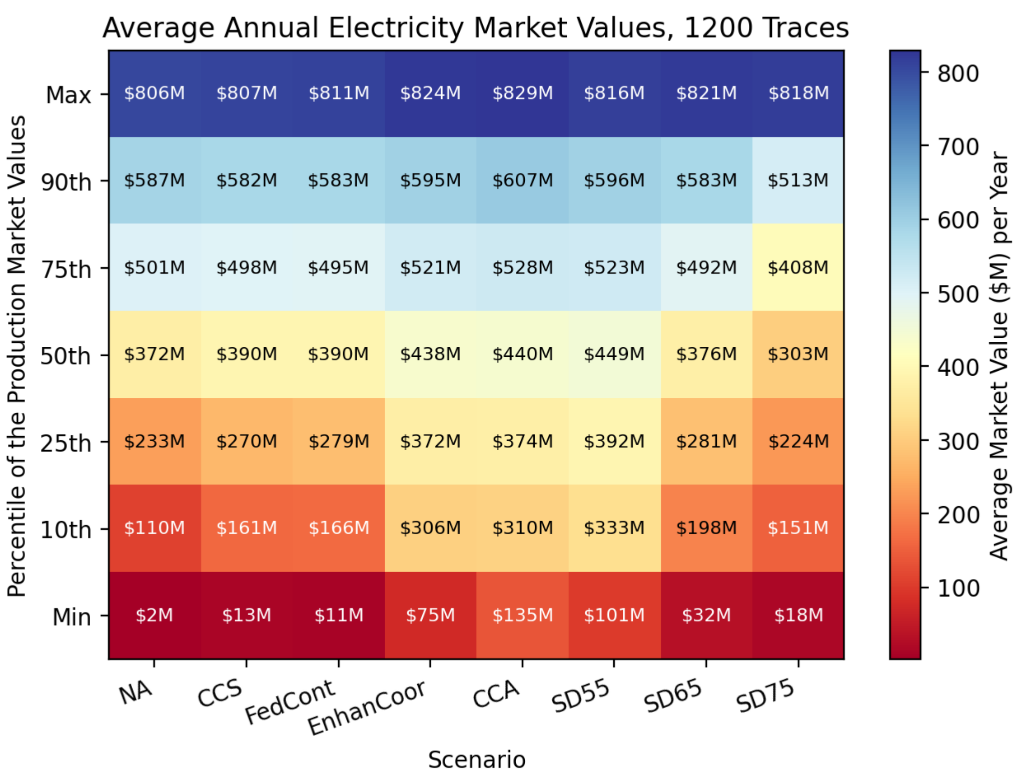

Figure 7.3: Each cell displays the average annual market value of electricity, in million $

As the final step, we compute the percentiles of the annual average market value of electricity

ply/demand, and transmission.

produced at GCD for the projection period and present the results in Figure 7.3. Several conclusions emerge from this analysis. First, under favorable hydrological conditions (i.e., the top four rows of Figure 7.3), the different policy scenarios yield broadly similar market values. Because the per-unit market price remains the same across scenarios in this section, variations in total market value arise solely from differences in electricity production, which is determined by water availability. Second, under conditions of water scarcity (i.e., the bottom three rows of Figure 7.3), certain policy scenarios, specifically EnhanCoor, CCA, and SD55, result in substantially higher values of electricity generated at GCD. Finally, the market value estimates presented in this section should be interpreted as approximate measures of the value of electricity to participants in the U.S. wholesale market. They reflect the contribution of WAPA CRSP GCD to the broader power system rather than revenues received by WAPA. Under WAPA's current rate-design framework, the rates charged to preferred customers are decoupled from the market value of power.

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