The Value of Hydropower as a Grid-Scale Storage Resource: A Commodity Market Approach

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Abstract

Grid-scale energy storage enhances power system performance by shifting loads and supporting capacity, reliability, and transmission. However, as storage penetration increases, arbitrage opportunities—and associated profits—decline (Sioshansi et al., 2009; Li et al., 2024). In ERCOT, for example, 2024 saw reduced arbitrage due to moderate weather and expanded storage. This trend contrasts with findings that long-duration storage is essential for reliability and affordability (Blair et al., 2022), suggesting the need for new business models to capture storage's full value. Despite growing deployment in energy storage, empirical research on storage's value remains limited.

To address this gap, we develop a commodity-market-based framework and apply it to hydropower as a grid-scale storage resource. Using exogenous variation in reservoir storage volume as a proxy for energy storage, we estimate its causal effect on risk premiums—measured by the day-ahead to real-time price spread—in the Northwestern United States between May 2022 and November 2024. Employing fixed effects and lagged dependent variable models, we control for time-invariant heterogeneity across balancing authorities and account for dynamic price behavior.

We find that a 10% increase in reservoir storage volume reduces risk premiums by 5%, indicating that hydropower reservoir storage mitigates short-term supply-demand imbalances. Our results are robust to dynamic pricing effects and suggest that storage is especially valuable during grid stress events, with pronounced impacts at the upper end of the price distribution. This result indicates that reservoir storage may be more valuable during grid stress events. As most markets lack compensation mechanisms for stored energy, our findings offer empirical support for designing future models that better reflect the risk-reducing benefits of grid-scale storage.

Introduction

In this research, we empirically examine the contributions of hydropower reservoir storage volume as energy storage through the lens of commodity markets to better understand the value proposition of energy storage. Our empirical approach considers the Northwestern region of the United States due to its high percentage of storable hydroelectric power in the form of reservoirs. We examine the potential benefits (or value) of energy storage for electricity markets in the context of two theories which explain the relationship between spot and future prices in commodity markets: the theory of storage and the risk premium theory.

In the theory of storage, the relationship between the current spot price and futures price of a commodity is based on the costs and convenience of holding physical inventories in that commodity. The value of storage in this theory is based on the benefits, or convenience yield, derived from holding a physical stock of inventory over time—for example, owning inventory can allow a producer to meet sudden changes in demand or address seasonality. Historically, in electricity markets, this relationship collapses as sufficient megawatt hours of electricity cannot be "carried" from the futures to spot market to address supply and demand imbalances. Futures contracts are instead priced based on an expectation of a spot price and a risk premium, which is an additional compensation for bearing risk. These theories are not mutually exclusive, as changes in the risk premium or expected changes in the spot price can be driven by changes in the interest rate, marginal storage cost, or marginal convenience yield.

An extensive literature on the theory of storage, as summarized briefly in the next section, finds that futures prices tend to be less than spot prices (backwardation) although futures prices can exceed spot prices (contango) when storage is ample. The underlying intuition is that convenience yield is inversely related to storage levels. The risk premium literature, also discussed in the next section, finds that the risk premium represents the additional compensation to market participants for bearing supply or demand risk. In electricity markets, hedging demand-side risk (due to high demand or high price volatility) can result in excess demand for futures contracts, with futures price being greater than the expected spot price, or a negative risk premium. Hedging supply-side risk (due low demand or low price volatility) typically results in the futures price being less than the expected spot price (positive risk premium) (Bessembinder and Lemmon, 2002; Botterud et al., 2010). From these theories, we hypothesize that energy storage should have an inverse relationship with convenience yield or the risk premium, that is, we hypothesize that demand for futures contracts is likely to be higher when hydropower reservoir levels are low, due to increased hedging pressure from demand-side risk.

Our research design exploits exogenous variation in hydropower reservoir levels and inflow to those reservoirs in the Northwestern region of the United States to determine the value of energy storage. We use robust econometric methods, including fixed effects models and lagged dependent variable models to evaluate the impact of increasing levels of hydropower reservoir storage on day ahead risk premiums in the Columbia River Basin. By using fixed effects models with panel data, we can observe how controlling for time-invariant observed and unobserved heterogeneity from Northwestern balancing authorities—such as regional climate or infrastructure differences—can impact risk premiums. However, fixed effects models also have the underlying assumption that important omitted variables are time invariant. Lagged dependent variable models are instead used to account for the time-dependent nature of electricity prices on risk premiums, where previous spot price realizations can influence both risk perceptions and price expectations (Botterud et al., 2010). By including a lagged risk premium variable, we can account for this dynamic behavior and address this important potential omitted variable bias. However, including a lagged risk premium variable can cause coefficients for other explanatory variables (i.e., hydropower reservoir storage) to be biased downward in the presence of autocorrelation in the errors (Anderson and Hsiao, 1981, 1982; Angrist and Pischke, 2009). Our framework, which incorporates both fixed effects and lagged dependent variable models allows us to control for time-invariant heterogeneity across balancing authorities and account for dynamic behavior.

We acknowledge that including both a lagged risk premium variable and balancing authority-level fixed effects in some specifications of the model can induce dynamic panel bias if the lagged dependent variable is correlated with the regression error—a problem that arises when datasets are large N and small T (Nickell, 1981). However, because our dataset is small N and large T ($N = 11$, $T = 552$) in the daily average data, and an even larger time dimension in the hourly data this bias from using fixed effects with a lagged dependent variable will be small. We also report different specifications of the model (fixed effects only, lagged dependent variable only) to demonstrate the upper and lower bounds of the potential impact of hydropower reservoir storage on risk premiums.

We find that increasing levels of hydropower reservoir storage have an inverse relationship with risk premium. That is, an increase in hydropower reservoir storage volume of 10% leads to a decrease in risk premium by approximately 5%. This is in line with both the theory of storage and risk premium theory, as we would expect that increases in storage would have an inverse relationship with the convenience yield or risk premium. Further, when we examine variation in risk premiums across space (i.e., across balancing authorities), we find that an increase in hydropower reservoir storage levels of 10% decreases risk premiums by 5% to 9%.

Our research is most closely related to the work of Botterud et al. (2010) and Weron and Zator (2014) who examine the impact of hydropower reservoir storage on convenience yield and risk premiums in the NordPool, the Norwegian electricity market, which also has high penetration of hydropower reservoir storage. Using a linear regression approach, Botterud et al. (2010) found that an increase in reservoir levels negatively impacted both convenience yield and risk premiums for futures contracts that ranged from a one- to six-weeks in duration. Examining the same set of data but correcting for some noted econometric issues observed in Botterud et al. (2010), Weron and Zator came to the opposite conclusion, that an increase in reservoir levels positively impacted risk premiums.

We build on the model of Botterud et al. (2010), but address the econometric issues noted in Weron and Zator (2014) and add factors specific to the Northwestern market (natural gas storage, wind and solar production) which provide unique insights into the value of reservoir energy storage. An important contribution of our work is that we also propose a methodology which bounds the impact of including or excluding a lagged-risk premium variable to capture the impact of past market outcomes which can influence current trading decisions. Botterud et al. (2010) argue for the inclusion of the spot price variable as an important determinant of the risk premium, but Weron and Zator argue for excluding the spot price as it can induce simultaneity biases that also influence the futures price. We acknowledge that both futures and spot prices are important influences for trading decisions and instead include a lagged risk premium variable, which diminishes the role of bias resulting from the relationship between spot and current prices. In our econometric framework, we acknowledge that including a lagged risk premium variable can induce bias,[1] but argue that bias is small, and provides a lower bound for the effect of energy storage, in the form of hydropower reservoir storage, on risk premiums in a market with a high penetration of existing hydropower storage resources.

Our research reflects the reality of a hydro-rich market in the United States, which can serve as a test-case for the value of energy storage. An important limitation of our work is that energy storage in the form of hydropower reservoir storage is considered long-duration energy storage, and our findings may not apply to emerging short-duration energy storage resources. Another important limitation of our work is that there is limited publicly available data for longer-duration futures contracts in this region, so our findings are limited to the impact of energy storage on short-term risk premiums.

Last, as an extension of our work, we consider the impact that increasing hydropower reservoir storage volumes has on other aspects of price formation, including the impact of hydropower reservoir storage on real-time prices and the distribution of real time prices. We find that increases in hydropower reservoir storage volumes are more impactful at the upper end of the real-time price distribution, indicating that hydropower reservoir storage may be even more beneficial during grid stress events.

Evaluation of Storage: Two Theories

Two main theories explain price dynamics and the value of storage in commodity markets.

1. Theory of Storage.

First introduced by Working (1933), this theory links spot and futures prices to the costs and benefits of holding inventories (storage). The price difference between delivery dates is the carrying charge, which reflects storage and financing costs (storage charge), offset by the convenience yield—the benefit of holding physical stocks (Kaldor, 1939; Working, 1948; Working 1949). When convenience yield exceeds storage costs, futures prices may fall below spot prices (backwardation); when storage costs dominate, futures prices exceed spot prices

[1] With a lagged dependent variable, the coefficients for other explanatory variables may be biased downward due to residual autocorrelation as well as absorbing the explanatory power of other variables.

(contango). Convenience yield decreases as inventories rise, and is highest when stocks are scarce, helping explain observed market behaviors (Brennan, 1958; Pindyck, 1994; Pindyck 2001). Storage also shapes volatility as low inventories and high storage costs tend to increase volatility (Fama and French, 1987; Pindyck 2004a; Pindyck 2004b; Geman and Ohana, 2009).

2. Risk Premium Theory.

This framework defines futures prices as the expected future spot price plus a risk premium reflecting participants' risk aversion. If more risk-averse consumers hedge, excess demand pushes futures above expected spot prices (negative risk premium); when producers hedge, excess supply pushes futures below expected spot prices (positive risk premium) (Botterud et al., 2010; Bessembinder and Lemmon, 2002). Risk premia rise with volatility and capture the increased compensation needed for bearing supply or demand risk (Considine and Larson, 2001). Unlike the storage theory, this framework applies to both storable and non-storable commodities.

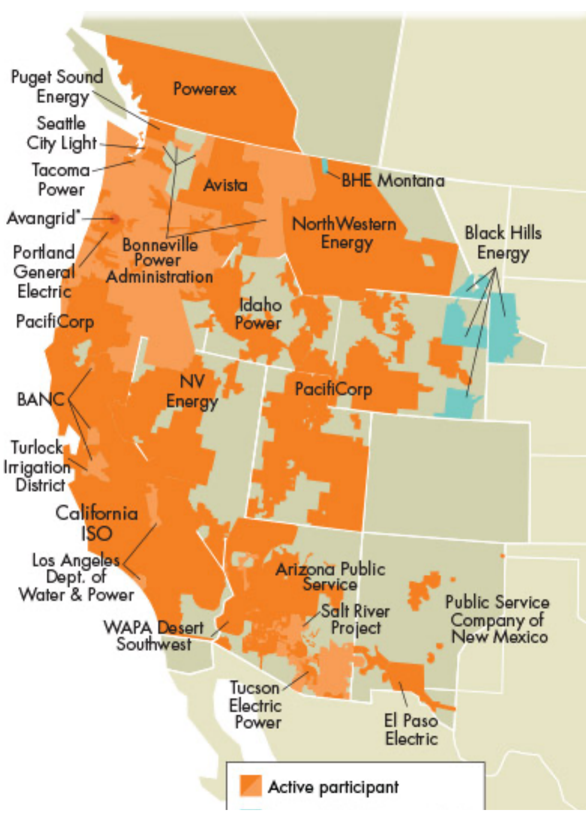

FIGURE 1: WESTERN ENERGY IMBALANCE MARKET. SOURCE: CALIFORNIA ISO

The two theories are not mutually exclusive: changes in interest rates, storage costs, or convenience yields affect both the expected spot price and risk premium (Fama and French, 1987). Together, they explain how inventories, costs, and risk preferences shape spot–futures price dynamics.

Hydropower Reservoir Storage as Energy Storage in the Pacific Northwest

Our empirical approach examines the value of hydropower reservoir storage as energy storage in the Northwestern region of the United States. This region was selected due to its high percentage of storable hydroelectric power. The Northwest is a region of vertically integrated utilities with robust bilateral trading. In this region, the mid-Columbia trading hub serves as a futures market, while the Western Energy

Imbalance market (WEIM), shown in Figure 1 allows for real-time electricity trading in a centralized spot market.

The mid-Columbia Trading Hub is a virtual trading point for hydroelectric power generated in the Columbia River basin. It comprises the control areas of Grant Public Utility District (PUD), Chelan PUD and Douglas PUD, which operate the Priest Rapids, Wanapum, Rock Island, Rocky Reach and Wells dams (S&P Global, 2024). It serves as a futures market for the Northwestern region, where participants can exchange day-ahead contracts for electricity.

The Western Energy Imbalance Market (WEIM) is a real-time wholesale power trading market operated by the California Independent System Operator (CAISO) in the western region of the United States. Although the WEIM is operated in a region of primarily bilateral power trading, it provides a centralized market for balancing real-time generation and demand. This enables more efficient allocation of power in the region, which has resulted in substantial cost savings by balancing authorities (CAISO, 2024).

Hydropower Dams

This analysis considers dams which market hydropower at the mid-Columbia trading hub (S&P Global, 2024). From furthest upstream to furthest downstream on the Columbia River, these include Wells, Rocky Reach, Rock Island, Wanapum and Priest Rapids dams, as shown in Figure 2. This sequence of dams, which begins at Wells dam, is uninterrupted by other dams. These dams are owned and operated by local public utility districts (Douglas PUD, Chelan County PUD, and Grand County PUD).

FIGURE 2: COLUMBIA RIVER BASIN DAMS

SOURCE: U.S. ARMY CORPS OF ENGINEERS

Upstream from the Wells Dam are two dams whose power is marketed by the Bonneville Power Administration (BPA): Chief Joseph Dam, owned by the United States Army Corps of Engineers (USACE), with 2,069 MW in nameplate capacity; and further upstream, the Grand Coulee Dam, owned by the United States Bureau of Reclamation (EIA, 2025). The Grand Coulee Dam is the largest power plant in the United States with a generating capacity of 6,809 MW and power distributed to eleven states. Downstream from the Priest Rapids Dam are four dams whose power is marketed by BPA.

To account for the centralized dam structure, we construct a system-level variable which represents the hydropower reservoir storage available in the Wells, Rocky Reach, Rock Island, Wanapum and Priest Rapids dams. To account for the potential impact of the upstream Grand Coulee Dam, we perform robustness tests which examine inflow impacts of this Dam on the risk premium.

Data

Futures price data

Our region of interest, the Pacific Northwest, is composed of vertically integrated utilities with a robust (but opaque) bilateral trading market. As these utilities are not part of an organized market (ISO or RTO), day-ahead price data is limited. To overcome this limitation, we utilized day-ahead price data for the mid-Columbia trading hub which is made available to the U.S. Energy Information Administration (EIA) from the Intercontinental Exchange (ICE). The ICE day-ahead data are only published when the trade date is a business day, constraining our analysis to these trade dates.

Spot price data

Robust participation in the WEIM in this region allows us to obtain 5-minute real-time price data from the California ISO's OASIS system (CAISO OASIS) which publishes locational marginal price (LMP) data for price nodes and aggregated price nodes in the WEIM.[1] Real-time price data were available at aggregate price nodes for the following balancing authorities in the Northwest which also participate in the WEIM: Bonneville Power (BPAT), Avista (AVA),

[1] Data for aggregate price nodes represents the weighted average LMP for multiple price nodes, with weights being distribution factors.

Pacificorp West (PACW), Pacificorp East (PACE), Idaho Power (IPCO), Puget Sound Energy (PSEI), Portland General Electric (PGE), Tacoma Power (TPWR), Seattle City Light (SCL), Nevada Power (NEVP)[1] and Northwestern Energy (NWMT).

Five-minute price (LMP) data were collected for each balancing authority and converted to hourly averages. As balancing authorities joined the WEIM over time, with the last balancing authority (BPA) joining on May 3, 2022, we limited our study period from May 2022 to November 2024.

To align with the daily availability of our day-ahead price data, we then aggregated our hourly average real-time pricing data to daily averages by using a load-weighted average of hourly prices for each balancing authority. We obtained load data from the EIA, which publishes hourly load data for each balancing authority.

Risk premium

Risk premium is defined as $\ln(E_t S_{t+T}/F_{t,T})$, consistent with Weron & Zator (2014), where $F_{t,T}$ is futures price at time t for a delivery time $t+T$ and $E_t S_{t+T}$ is expected time $t+T$ spot price from time t. In this paper, ex-post risk premium is used. As a result, realized spot price at time $t+T$ is used for the term $E_t S_{t+T}$ as a proxy for expected spot price from time t.

Table 1 provides summary statistics for the risk premium from May 2022 to November 2024. The risk premium is, on average, negative, but there are a limited number of days with a positive risk premium (shown as the percent positive, which is the percentage of days with a positive risk premium in each balancing authority). Risk premium ranges from a minimum of -4.76 in the Nevada Power balancing authority on May 21, 2024, to a maximum of 1.2 in the Nevada Power balancing authority on May 18, 2022.

[1] Nevada Power participates in the Northwest through the Pacific Northwest-Southwest Intertie.

TABLE 1: SUMMARY STATISTICS: RISK PREMIUMS BY BALANCING AUTHORITY (5/2022 TO 11/2024)

Balancing Authority	Sample Size	Percent Positive	Mean	Standard Deviation	Skewness	Median	Maximum	Minimum
BPAT	552	6.70	-0.39	0.36	-1.31	-0.33	0.54	-2.10
AVA	552	8.15	-0.41	0.40	-1.85	-0.36	0.85	-3.40
IPCO	552	7.61	-0.40	0.37	-1.24	-0.35	0.94	-2.55
NEVP	552	11.23	-0.43	0.49	-2.16	-0.40	1.20	-4.76
NWMT	552	6.88	-0.41	0.36	-1.18	-0.37	0.80	-2.51
PACE	552	6.16	-0.47	0.41	-1.32	-0.44	0.76	-2.78
PACW	552	5.98	-0.43	0.39	-1.70	-0.36	0.54	-2.46
PGE	552	6.70	-0.41	0.38	-1.34	-0.35	0.84	-2.47
PSEI	552	7.97	-0.40	0.38	-0.90	-0.34	1.06	-2.33
SCL	552	6.52	-0.42	0.38	-1.43	-0.36	0.56	-2.49
TPWR	552	6.16	-0.42	0.37	-1.32	-0.36	0.58	-2.47

As an example of the observed trend in the risk premium variable, Figure 3 shows the risk premium in Bonneville Power Authority compared to its 20-day moving average. The risk premium in Bonneville Power is on average negative and displays negative skewness.

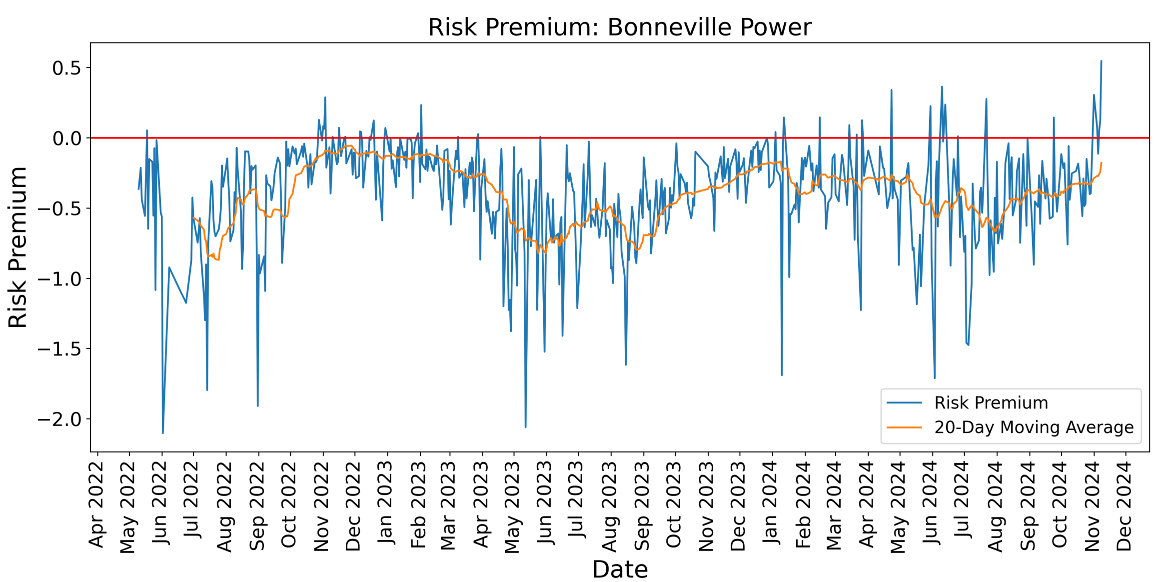

FIGURE 3: RISK PREMIUM - BONNEVILLE POWER AUTHORITY

Hydrological data

Hydrological data, including reservoir storage volume and inflow, is obtained from the Columbia Basin Water Management Division of the U.S. Army Corps of Engineers. Reservoir storage level is published as the storage volume in a particular reservoir on an hourly basis. This differs from the total reservoir volume, as legal and practical considerations preclude using much of the available reservoir volume for hydropower reservoir storage.

Rocky Reach, Rock Island, Wanapum and Priest Rapids dams operate with a centralized system dispatch coordinated by Grant PUD and Chelan PUD. The reach of the Columbia River dams is located on spawning grounds for salmon, and non-power requirements for salmon protection constrain dam operations. To address these constraints, we address seasonality at both individual variable levels, and through controls for seasonality. Examples of seasonal constraints include a mandatory reduction in flow at Wanapum and Priest Rapids dams between April and August is designed to enhance the ability of fish to pass through the turbines. To facilitate fall Chinook spawning, the daytime capacity of Priest Rapids dam is restricted in October and November. Following salmon hatching in spring, discharge throughout the day at Priest Rapids dam is regulated to prevent the stranding of fish in pools along the riverbank. Total dissolved gas restrictions can reduce allowable spill during high temperature or high flow times, increasing the required generation (Grant PUD, 2019). Chelan PUD is authorized to operate Rocky Reach dam only between 703 and 707 feet of elevation, and Rock Island Dam between 609 and 613 feet of elevation (Chelan PUD). Douglas PUD is authorized to operate Wells Dam between 771 and 781 feet of elevation.

Table 2 shows usable storage volumes for mid-Columbia dams, as reported by Chelan PUD, and total storage volumes as reported by various state and local agencies.

TABLE 2: USABLE STORAGE VOLUMES FOR MID-COLUMBIA DAMS

Dam	Usable storage (thousands of acre feet)	Total storage (thousands of acre feet)
Wells	98	331 (Douglas PUD, 2006)

Dam	Usable storage (thousands of acre feet)	Total storage (thousands of acre feet)
Rock Island	11.7	130 (Chelan PUD, 2019)
Rocky Reach	36.4	382 (USBR, 2009)
Wanapum	160	693.6 (Kittitas County, 2013)
Priest Rapids	44.5	222.6 (Washington State Department of Ecology, 2025)

To generate the variable used for hydropower reservoir storage, hydropower reservoir storage is first averaged across hours to create a daily hydropower reservoir storage value for each reservoir. Daily values are then summed across reservoirs to obtain a total hydropower reservoir storage volume for the system on a particular day. This quantity is divided by the sum of maximum hydropower reservoir storage volumes at each dam as defined by the Chelan Public Utility District (Chelan PUD). This results in a variable specification as reservoir storage volume as a percent of maximum reservoir storage capacity.[1,2] Figure 4 depicts the reservoir level as a percent of maximum capacity over the period of study. The graph shows substantial short-term variation in hydropower reservoir levels. Reservoir storage volume as a proportion of maximum reservoir storage capacity typically fluctuates between 0.6 and 0.8, with occasional outlying values above 0.8 or below 0.6.

Reservoirs also exhibit seasonality, as shown in Figure 5, where values shown for each day are the average for each occurrence of that day in the three years between November 9, 2021, and November 8, 2024 compared to a 20-day moving average. Generally, reservoir storage capacity as a percent of maximum storage capacity is higher in summer and winter, but lower in spring and fall.

[1] For Wells Dam volume, several dates (09/20/2022, 12/20/2022, 02/21/2023 and 02/28/2024) appeared to have missing data as a negative volume of –7093.2 was reported for these dates. These dates were dropped from the analysis.

[2] Reservoir storage volume (as a proportion of maximum storage capacity) is derived from a reservoir storage variable available from the U.S. Army Corps of Engineers as usable storable volume, rather than a representation of total reservoir volume.

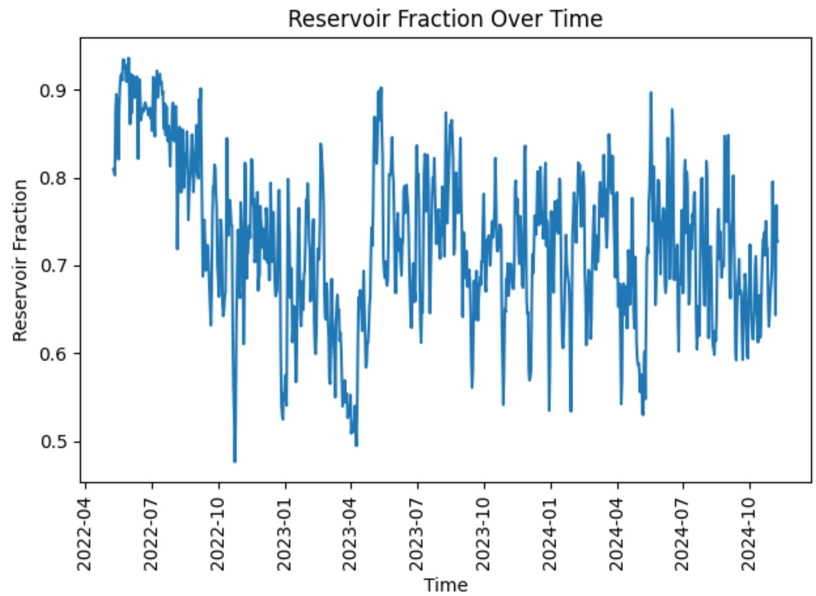

FIGURE 4: RESERVOIR STORAGE VOLUME AS A PROPORTION OF MAXIMUM RESERVOIR STORAGE CAPACITY (RESERVOIR FRACTION) FOR THE MID-COLUMBIA DAM SYSTEM

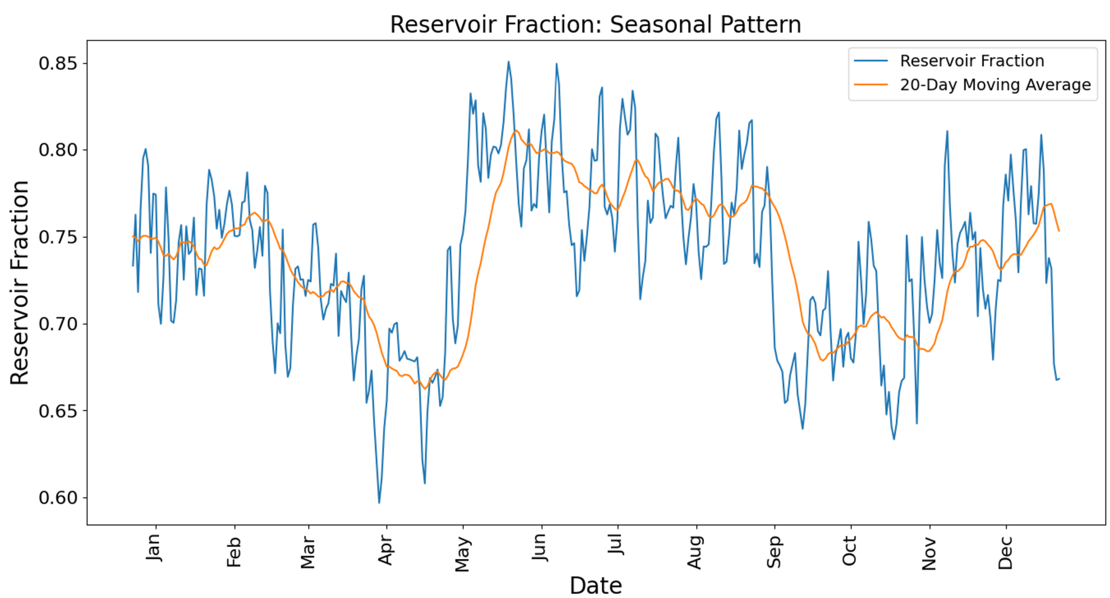

FIGURE 5: SEASONAL PATTERN OF RESERVOIR STORAGE VOLUME AS A PROPORTION OF MAXIMUM RESERVOIR STORAGE CAPACITY (RESERVOIR FRACTION) FOR THE MID-COLUMBIA DAM SYSTEM

Inflow is published as the inflow to a particular reservoir at daily granularity, measured in thousands of cubic feet per second. A single inflow variable was specified by first summing inflow across all dams. This variable was specified as a deviation from historical inflows to address for seasonality. Average total inflow to all dams for each calendar date in the year was calculated over

22 years between November 2003 and November 2024. For each date in the dataset, the inflow deviation variable took a value of the deviation of total inflow across all dams from that daily average.

Table 3 shows statistics on inflow to mid-Columbia dams with values reported in thousands of acre feet.[1]

TABLE 3: SUMMARY STATISTICS ON INFLOW TO MID-COLUMBIA DAMS

Dam	Mean	Skewness	Standard Deviation	Median	Maximum	Minimum
Priest Rapids	92.35	2.08	40.25	85.30	263.10	32.60
Rock Island	88.49	1.82	37.39	83.79	242.21	35.38
Rocky Reach	86.05	1.67	35.01	82.71	231.63	34.20
Wanapum	93.55	1.66	39.74	88.30	254.30	-16.00
Wells	87.47	1.67	35.31	82.50	223.70	37.00

The ratio of mean inflow to usable storage indicates that reservoirs can typically be filled from minimum to maximum storable volume within a day, except under conditions of particularly low inflow. This gives reservoirs operational flexibility across a variety of inflow conditions.

Data for other explanatory variables

This analysis uses historical Henry Hub natural gas prices published by the EIA, which are published at daily granularity. Henry Hub is a natural gas transaction hub located in Louisiana, which serves as a price benchmark for natural gas in the U.S. (Li et al, 2017). Natural gas inventory data is obtained from EIA's weekly natural gas storage report, which provides data at weekly granularity. The sum of natural gas inventory across the West and Mountain regions is used to

[1] We opted to provide summary data for just one year (2023) of the overall period of analysis (May 2022 to November 2024) in order to give an annual summary of data without bias toward the months with more data. Full summary statistics can be provided by the authors upon request.

create a natural gas inventory variable, as balancing authorities considered in this analysis span the West and Mountain natural gas storage regions as defined by the EIA.

Demand data is obtained from the EIA, which publishes hourly demand for balancing authorities[1]. For each balancing authority, hourly demand is summed to daily granularity for consistency with the granularity of other variables. Similarly, wind generation and solar generation data is obtained from the EIA, which publishes hourly generation data by fuel source for each balancing authority. Hourly figures are summed to daily granularity.

Data for extension to real-time price analysis

Real-time WEIM price data from CAISO OASIS enables an analysis of the impacts of reservoir level on real-time prices. Excluding day-ahead price data, the dataset used for the analysis of reservoir storage's impact on real-time prices uses the same data sources and variables as the analysis of reservoir storage's impact on risk premium, except variables are aggregated to hourly instead of daily granularity in most cases. Specifically, 5-minute real-time prices were averaged for an hourly average real-time price. Hourly reservoir storage levels and demand levels were included in the real-time price analysis. Solar and wind generation, which are available at hourly totals, were summed to daily totals to address heteroskedasticity in the data.[2] All other variables are maintained at the same level of granularity as in the risk-premium analysis (daily inflow, daily natural gas prices, and weekly natural gas volumes).

Empirical Approach

Our empirical framework exploits exogenous variation in hydropower reservoir levels and inflow to those reservoirs to determine the value of hydropower reservoir storage, as such, the hydropower reservoir storage for the dam system (as a proportion of max storage capacity) for the dam system is the independent variable of interest.

[1] For demand data from the EIA, several dates 11/04/2024 appeared to have missing data as 0 was reported as load for this date. This date was dropped from the analysis.

[2] Other data transformations for wind and solar generation, such as square root transformations, resulted in similar results.

Risk Premium Analysis

To estimate the short-term impacts of hydropower reservoir storage on risk premiums in the Northwestern U.S. bilateral electricity system, our approach incorporates several variables that control for factors other than hydropower reservoir storage that can impact risk premiums. These explanatory variables are plausibly exogenous, to allow us to establish causality of reservoir storage impacts. We include electricity demand as it has been shown to have a negative and statistically significant impact on risk premium in power markets (Jacobs et al, 2022). Electricity demand is largely insensitive to wholesale prices, making it plausibly exogenous. We include natural gas volume in the West and Mountain regions as natural gas volume has been shown to have a negative impact on forward premium in the PJM interconnection (Douglas & Popova, 2008). Natural gas volume is plausibly exogenous as supply and demand decisions for natural gas storage are determined through other markets. Inflow deviation is included as a control, as increases in reservoir inflow could theoretically increase power supply and reduce power prices (Botterud et al., 2010). This could result in reduced demand for futures contracts and impact risk premiums. As discussed in the preceding section, reservoir inflow is a deviation from historical average inflow, allowing us to identify off of within daily variation in reservoir inflow. To account for increasing uncertainty from renewable resource production and its impact on day-ahead and real-time price spreads, solar and wind generation are also included as controls. Solar and wind generation are dependent on the sun shining or wind blowing and are plausibly exogenous. To control for differences in prices and risk premiums that may vary due to demand variation by weekday we include day-of-week fixed effects. Long-run trends, such as changes in the generation resource portfolio or seasonality are controlled for with month-by-year fixed effects. Because of the time-dependent nature of electricity prices where past realizations of prices can influence futures and expected spot prices (and thus, the risk premium), we also included a lagged risk premium variable in some specifications of our model.

The time-dependent nature of electricity market variables also raises the potential for non-stationarity in our variables. Non-stationarity can cause spurious regression results if, for example, there is an underlying trend in an exogenous variable that drives results. To address this concern, we use an Augmented Dickey-Fuller (ADF) test to check the stationarity of each independent variable. In instances where the ADF failed to reject the presence of a unit root in any balancing authority, we transformed the data to ensure stationarity.

Solar generation and demand were found to be non-stationary across most balancing authorities. We first-differenced these variables to achieve stationarity. Natural gas price and natural gas volume were also found to be non-stationary. Given the seasonal patterns of these variables, we deseasonalized the data by removing the seasonal component[1], including only the stochastic portion which can't be explained by seasonality as our identifying variation. All other independent variables were found to be stationary.

For our first model, we propose a fixed effects model to determine the short-term impact of reservoir energy storage on risk premiums. This model establishes the upper bound for the impact of reservoir level on risk premium as it assumes any important omitted variables are time invariant:

$$\begin{aligned} RP_{t,T,i} \ &= \alpha_0 + \alpha_1\, RESF_t + \alpha_2 INFD_t + \alpha_3 D_{t,i} + \alpha_4 GV_t + \alpha_5 GP_t + \alpha_6 S_{t,i} + \alpha_7 W_{t,i} \\ &\quad + \alpha_8 X_t + \alpha_9 BA_i + \epsilon \end{aligned} \tag{1}$$

Where $RP_{t,T,i}$ is the risk premium between time t and $t + T$ in balancing authority i. $RESF_t$ is the reservoir storage volume as a proportion of maximum reservoir storage capacity on day t in Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids dams, expressed as a percent of total capacity. $INFD_t$ is the deviation from the daily historical average inflow, $D_{t,i}$ is the first-differenced electricity demand for each balancing authority, GV_t is the deseasonlized weekly gas volume, GP_t is the deseasonalized daily Henry Hub natural gas price, $S_{t,i}$ is first-differenced solar generation for each balancing authority, $W_{t,i}$ is wind generation for each balancing authority, and X_t is a set of time fixed effects which include day-of-week fixed effects and month-by-year fixed effects. In our first model, we also include a balancing-authority fixed effect, BA_i, to account for observed and unobserved differences in balancing authorities such as differences in infrastructure that may influence supply and demand. We estimate our model with Driscoll-Kraay standard errors to account for both heteroskedasticity and AR1 autocorrelation in the errors.

[1] To deseasonalize the natural gas price and natural gas volume variables, we regressed gas price and gas volume on month and year controls and retained the residuals as the transformed values.

As past hourly prices have been shown to be an important explanatory variable for current prices[1], and could influence futures and expected spot prices, in some specifications of the regression, we include a lagged risk premium variable (RP), as shown in model 2:

$$RP_{t,T,i} = \alpha_0 + \alpha_1\ RESF_t + \beta_1 RP_{t-1} + \alpha_2 INFD_t + \alpha_3 D_{t,i} + \alpha_4 GV_t + \alpha_5 GP_t + \alpha_6 S_{t,i} \\ +\alpha_7 W_{t,i} + \alpha_8 X_t + \alpha_9 BA_i + \epsilon \tag{2}$$

We acknowledge that including a lagged risk premium variable with our balancing-authority level fixed effects can induce dynamic panel bias but demonstrate the potential impact of that bias by providing the upper and lower bounds of reservoir storage impacts on risk premiums in models 1 and 3, respectively. The lower bound is provided by including the lagged risk premium variable but excluding the balancing authority level fixed effects as shown in model 3:

$$RP_{t,T,i} = \alpha_0 + \alpha_1\ RESF_t + \beta_1 RP_{t-1} + \alpha_2 INFD_t + \alpha_3 D_{t,i} + \alpha_4 GV_t + \alpha_5 GP_t + \alpha_6 S_{t,i} \\ +\alpha_7 W_{t,i} + \alpha_8 X_t + \epsilon \tag{3}$$

As reservoir levels may have differential price impacts on balancing authorities, we then assess the short-term impact of reservoir storage on risk premiums over space by using a Prais-Winsten regression in each balancing authority.[2] For this analysis, we assess the models in equation 1 and equation 3 separately for each balancing authority. In this specification of the model, we exclude balancing authority level fixed effects from these equations.

Real-time price analysis

As an extension of our work, we examine how increasing hydropower reservoir storage affects price formation, including impacts on real-time prices and their distribution. To estimate the short-term impacts of hydropower reservoir storage on real-time prices in the WEIM, our approach leverages our econometric framework formulated for the risk premium analysis but adds an important control needed for the more granular hourly data: hour fixed effects to control for hourly price variation within a day. Because of the time-dependent nature of electricity prices where past

[1] See Nicholson et al., 2010; Woo et al., 2016; and a survey of the literature in Tarufelli et al., 2022 for reference.

[2] We use Prais-Winsten regressions to account for AR1 autocorrelation in the errors (Prais and Winsten, 1954).

realizations of prices can influence future prices, we also included a lagged real-time price variable in some specifications of our model.

The time-dependent nature of electricity market variables also raises the potential for non-stationarity in our real-time price analysis. We found that only natural gas volume was non-stationary, and deseasonalized that variable by removing the seasonal component[1], including only the stochastic portion which can't be explained by seasonality as our identifying variation.

To account for the large number of hours with zero variable renewable generation, we used daily sums of sun and wind generation. We also made several adjustments to address outliers in the data. Due to some high, outlying values during a January 2024 polar vortex in the Pacific Northwest, we log transformed gas prices. We also log transformed demand due to a few extreme outlier values. The dependent variable of real-time prices is also log transformed to enable consistency in interpretation with the risk premium analysis.

For our first real-time price model, we propose a fixed effects model to determine an upper bound of the short-term impact of reservoir energy storage on real-time price:

$$\begin{aligned} &LMP_{t,i} \\ &= \alpha_0 + \alpha_1\ RESF_t + \alpha_2 INFD_t + \alpha_3 D_{t,i} + \alpha_4 GV_t + \alpha_5 GP_t + \alpha_6 S_{t,i} + \alpha_7 W_{t,i} + \alpha_8 X_t + \alpha_9 BA_i + \epsilon \end{aligned} \tag{4}$$

$LMP_{t,i}$ is the logged locational marginal price at time t in balancing authority i. $RESF_t$ is the reservoir storage volume as a proportion of maximum reservoir storage capacity at time t in Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids dams, expressed as a percent of total capacity. $INFD_t$ is the deviation from the daily historical average inflow, $D_{t,i}$ is the logged electricity demand for each balancing authority, GV_t is the deseasonalized weekly gas volume, GP_t is the logged daily Henry Hub natural gas price, $S_{t,i}$ is daily solar generation for each balancing authority, $W_{t,i}$ is daily wind generation for each balancing authority, and X_t is a set of time fixed effects which include hour fixed effects, day-of-week fixed effects and month-by-year fixed effects. In our first model, we also include a balancing-authority fixed effect, BA_i, to account for observed and unobserved differences in balancing authorities such as differences in infrastructure that may influence supply and demand. We estimate our model with Driscoll-Kraay standard errors to account for both heteroskedasticity and AR1 autocorrelation in the errors.

[1] To deseasonalize the natural gas price and natural gas volume variables, we regressed gas price and gas volume on month and year controls and retained the residuals as the transformed values.

As past hourly prices have been shown to be an important explanatory variable for current prices[1], and could influence futures and expected spot prices, in some specifications of the regression, we include a lagged real-time locational marginal price variable (LMP) with the same log transformation as the dependent variable, as shown in real-time price model 2:

$$LMP_{t,i} = \alpha_0 + \alpha_1\, RESF_t + \beta_1 LMP_{t-1} + \alpha_2 INFD_t + \alpha_3 D_{t,i} + \alpha_4 GV_t + \alpha_5 GP_t + \alpha_6 S_{t,i} + \alpha_7 W_{t,i} + \alpha_8 X_t + \alpha_9 BA_i + \epsilon \tag{5}$$

We acknowledge that including a lagged real-time price variable with our balancing-authority level fixed effects can induce dynamic panel bias but mitigate the potential impact of that bias by providing the upper and lower bounds of reservoir storage impacts on real-time price in model 1 and model 3, respectively. The lower bound is provided by including the lagged real-time price variable but excluding the balancing authority level fixed effects as shown in real-time price model 3:

$$LMP_{t,i} = \alpha_0 + \alpha_1\, RESF_t + \beta_1 LMP_{t-1} + \alpha_2 INFD_t + \alpha_3 D_{t,i} + \alpha_4 GV_t + \alpha_5 GP_t + \alpha_6 S_{t,i} + \alpha_7 W_{t,i} + \alpha_8 X_t + \epsilon \tag{6}$$

Last, as we are also interested in the distributional impact of hydropower reservoir storage volume on real-time prices, we use a quantile regression framework to examine the impact of hydropower on the 50th ($Q_{LMP_{t,i}}(0.5|\omega_{t,i})$ and 95th ($Q_{LMP_{t,i}}(0.95|\omega_{t,i})$ percentiles of the real-time price distribution. This approach allows us to move beyond the mean effects captured by our previous regression analyses to assess how reservoir storage volume influences median and upper quantiles of the real-time price distribution.

$$\begin{aligned} &Q_{LMP_{t,i}}(\tau|\omega_{t,i}) \\ &= \alpha_0(\tau) + \alpha_1(\tau) RESF_t + \beta_1(\tau) LMP_{t-1} + \alpha_2(\tau) INFD_t + \alpha_3(\tau) D_{t,i} + \alpha_4(\tau) GV_t + \alpha_5(\tau) GP_t \\ &+ \alpha_6(\tau) S_{t,i} + \alpha_7(\tau) W_{t,i} + \alpha_8(\tau) X_t + \alpha_9(\tau) BA_i + \epsilon \end{aligned} \tag{7}$$

To account for the non-standard distribution of the quantile regression estimator, we compute standard errors using bootstrapping, which provides consistent inference under heteroskedasticity and serial correlation within panels.

[1] See Nicholson et al., 2010; Woo et al., 2016; and a survey of the literature in Tarufelli et al., 2022 for reference.

Results

Average Hydropower Reservoir Storage Impacts on Risk Premium

In our first analysis, we estimate how hydropower reservoir storage volume (as a proportion of maximum storage capacity) impacts the daily average risk premium across all Northwestern balancing authorities in a pooled regression.

For model (1) we exclude our lagged risk premium variable but include the balancing authority level fixed effect. This establishes the upper bound of the hydropower reservoir storage impact on risk premiums as this model can tend to estimate coefficients that are too large (Nickell, 1981). For model (2) we include both balancing authority-level fixed effects, time-fixed effects, and the lagged risk premium variable. With this model, we address time-variant and time-invariant observed and unobserved heterogeneity at the balancing authority-level by including both a lagged dependent variable and fixed effects. We acknowledge that this regression can be slightly biased but note that any bias should be small due to the large time dimension of our data (Nickell, 1981). For model (3) we include the lagged risk premium variable but exclude the balancing authority-level fixed effects (and include time fixed effects). With this model we establish the lower bound of the hydropower reservoir storage impact on risk premiums, as this model produces coefficient estimates that will tend to be the most conservative (Anderson and Hsiao, 1981, 1982; Keele & Kelly, 2006; Angrist and Pischke, 2009).

We find that an increase in hydropower reservoir storage volume significantly reduces risk premiums across all balancing authorities. As shown in Table 4, Model 1, which includes balancing authority level fixed effects but does not include the lagged risk premium variable results in an upper-bound estimate for the impact of hydropower reservoir storage volume (as a proportion of maximum storage capacity) on risk premium. The impact is significant and negative, with a coefficient of -0.66, meaning that increasing hydropower reservoir storage volume by 10% of its total storable value results in an estimated decrease in risk premium by approximately 7%. Model 2, which includes both a balancing authority level fixed effect and a lagged risk premium variable results in a negative and statistically significant coefficient of -0.462, indicating a 5% decrease in risk premium for a 10% increase in hydropower reservoir storage. Model 3, which excludes the balancing authority level fixed effect but includes a lagged risk premium variable establish the lower bound estimate of on coefficient at -0.459, meaning that an increase in reservoir storage volume of 10% decreases risk premiums by about 5%. Deviation from average inflow is positively correlated with risk premium, consistent with the results of Botterud et al (2010). Wind generation has a small but significantly negative impact on risk premium. Other control variables have positive but statistically insignificant impacts on risk premium.

TABLE 4: POOLED IMPACT OF HYDROPOWER RESERVOIR STORAGE VOLUME ON RISK PREMIUM ACROSS BALANCING AUTHORITIES

	Model (1)	Model (2)	Model (3)
	BA-level Fixed Effects	Fixed Effects & Lagged Risk Premium	Lagged Risk Premium
Hydropower Reservoir Storage Volume (as a proportion of maximum capacity)	-0.6608 (0.2679) **	-0.4622 (0.2313) **	-0.4589 (0.2217) **
Inflow Deviation (cubic feet per second * 1000)	0.0005 (0.0002) **	0.0003 (0.0002) **	0.0003 (0.0002) **
Demand (MWh)	0.0004 (0.0020)	0.0004 (0.0018)	0.0004 (0.0020)
Gas Volume (billions of cubic feet)	0.0008 (0.0009)	0.0003 (0.0007)	0.0003 (0.0007)
Gas Price ($ / million btu)	0.0041 (0.0169)	0.0036 (0.0133)	0.0040 (0.0132)
Daily Solar Generation (MWh)	0.0013 (0.0045)	0.0033 (0.0048)	0.0034 (0.0048)
Daily Wind Generation (MWh)	-0.0030 (0.0008) ***	-0.0023 (0.0008) ***	-0.0014 (0.0004) ***
Lagged Risk Premium		0.2751 (0.0423) ***	0.2781 (0.0419) ***
Balancing Authority Fixed Effects	Y	Y	N
Time Fixed Effects	Y	Y	Y
Constant			0.2580 (0.2217)
Observations	552	552	6072
R-squared	0.266	0.320	0.321

Notes: This table reports impacts of hydropower reservoir storage volume (as a proportion of maximum storage volume) across all Balancing Authorities. Model (1) includes the full set of time fixed effects (day of week, month by year), and BA-level fixed effects. Model (2) includes a lagged risk premium variable, the full set of time fixed effects and BA-level fixed effects. Model (3) includes the lagged risk premium variable and the full set of time fixed effects. Standard errors reported in columns (1) – (3) have been transformed to remove AR(1) serial correlation and heteroskedasticity. Standard errors are in parentheses. * p < 0.10, ** p < 0.05, *** p < 0.01.

Balancing authority-level impacts of energy storage on risk premiums

We then consider the effect of hydropower reservoir storage over space, by examining the impact of reservoir storage volume on each individual Balancing Authority's risk premium. For most balancing authorities, reservoir storage volume had a negative and statistically significant impact on day-ahead risk premium. This is consistent with the findings of Botterud et al. (2010), who found a negative impact of reservoir storage volume on risk premium in the NordPool market. The impact was statistically significant at the 10% level in 8 out of 11 balancing authorities. The smallest impact of reservoir storage volume (as a proportion of maximum storage capacity) on risk premium was seen in Nevada Power, which participates in the Northwest through the Pacific Northwest – Southwest Intertie but is geographically remote from the dam system. The coefficient of -0.24 indicates that a 10% increase in reservoir storage volume results in approximately a 2% decrease in risk premium. The greatest impact of reservoir storage volume on risk premium was seen in Portland General Electric. The coefficient of -0.84 indicates that a 10% increase in reservoir storage volume results in approximately an 8% decrease in risk premium.

TABLE 5: IMPACT OF RESERVOIR STORAGE VOLUME ON RISK PREMIUM BY BALANCING AUTHORITY

Balancing Authority	Model 1: Prais-Winsten	Model 2: Prais-Winsten with Lagged Risk Premium
AVA	-0.76 (0.288) ***	-0.69 (0.265) ***
BPAT	-0.62 (0.250) **	-0.61 (0.245) **
IPCO	-0.44 (0.302)	-0.43 (0.281)
NEVP	-0.24 (0.410)	-0.27 (0.372)
NWMT	-0.55 (0.267) **	-0.55 (0.245) **
PACE	-0.33 (0.318)	-0.34 (0.285)
PACW	-0.74 (0.293) **	-0.71 (0.276) **
PGE	-0.84 (0.292) ***	-0.77 (0.271) ***
PSEI	-0.48 (0.283) *	-0.49 (0.277) *
SCL	-0.57 (0.272) **	-0.54 (0.258) **
TPWR	-0.65 (0.265) **	-0.62 (0.250) **

Notes: This table reports impacts of reservoir storage volume (as a proportion of maximum storage capacity) for each Balancing Authority. Model (1) includes the full set of time fixed effects (day of week, month by year). Model (2) includes a lagged risk premium variable and the full set of time fixed effects. Standard errors reported in columns (1) – (2) have been transformed to remove AR(1) serial correlation and heteroskedasticity. Standard errors are in parentheses. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Robustness of risk premium results

Although our pooled and individual balancing authority level results indicate that increases in hydropower reservoir storage volumes decrease risk premiums, a key endogeneity concern arises due to the geographic location of the dams. The Grand Coulee Dam is located upstream from the mid-Columbia dams. Its power is marketed by Bonneville Power Administration, which is a participant in the WEIM considered for this analysis. If the Grand Coulee Dam operators are changing hydropower reservoir storage volumes in response to market conditions, their actions may impact downstream reservoir levels through changing their inflow, resulting in potential endogeneity between risk premium and mid-Columbia inflow variable. To account for this potential endogeneity, we respecified our econometric models (1 through 3) to include a variable representing deviation from average inflow into Grand Coulee, instead of deviation from average inflow into the mid-Columbia reservoirs characterized in the previous section. Inflow to Grand Coulee is plausibly exogenous, as inflow is primarily determined by upstream hydrological conditions (such as snowpack, precipitation, runoff) and upstream dams (in both Canada and the U.S.) have regulated releases under pre-established operational rules (such as the Columbia River Treaty), indicating that upstream water release decisions are not in response to short-term electricity market prices in the WEIM. Like the variable for inflow deviation into mid-Columbia reservoirs, this variable was specified as the deviation from mean inflow between November 2003 and November 2024 for any given date. Data were also obtained from the Columbia Basin Water Management Division of the U.S. Army Corps of Engineers.

With the Grand Coulee inflow variable, we find similar results, although coefficients are smaller in magnitude and estimates have more noise. In Model 1, the estimated coefficient for hydropower reservoir storage volume (as a proportion of maximum capacity) remains negative with a 10% increase in reservoir storage volume reducing risk premium between 4-5%. Models 2 and 3 have a negative, though statistically insignificant coefficient. Overall, the similarity of results to our main specification provides assurance that upstream Grand Coulee dam operations are not significantly affecting downstream reservoir storage volume impacts on risk premiums.

TABLE 6: POOLED IMPACT OF RESERVOIR STORAGE VOLUME ON RISK PREMIUM ACROSS BALANCING AUTHORITIES WITH GRAND COULEE INFLOW

	Model (1) BA-level Fixed Effects	Model (2) Fixed Effects & Lagged Risk Premium	Model (3) Lagged Risk Premium
Hydropower Reservoir Storage Volume (as a proportion of Maximum Storage Capacity)	-0.5175 (0.2619) **	-0.3626 (0.2222)	-0.3580 (0.2224)

	Model (1) BA-level Fixed Effects	Model (2) Fixed Effects & Lagged Risk Premium	Model (3) Lagged Risk Premium
Inflow Deviation upstream from Grand Coulee Dam (cubic feet per second * 1000)	0.0006 (0.0012)	0.0006 (0.0011)	0.0006 (0.0011)
Demand (MWh)	0.0002 (0.0021)	0.0002 (0.0020)	0.0002 (0.0020)
Gas Volume (billions of cubic feet)	0.0009 (0.0009)	0.0004 (0.0007)	0.0004 (0.0008)
Gas Price ($ / million btu)	0.0003 (0.0173)	0.0014 (0.0133)	0.0018 (0.0132)
Daily Solar Generation (MWh)	0.0007 (0.0045)	0.0030 (0.0048)	0.0030 (0.0048)
Daily Wind Generation (MWh)	-0.0032 (0.0009) ***	-0.0025 (0.0009) ***	-0.0015 (0.0004) ***
Lagged Risk Premium		0.2818 (0.0418) ***	0.2848 (0.0415) ***
Balancing Authority Fixed Effects	Y	Y	N
Time Fixed Effects	Y	Y	Y
Constant			0.1479 (0.2118)
Observations	552	552	6072
R-squared	0.260	0.317	0.318

Notes: This table reports impacts of reservoir storage volume (as a proportion of maximum storage capacity) across all Balancing Authorities. Model (1) includes the full set of time fixed effects (day of week, month by year), and BA-level fixed effects. Model (2) includes a lagged risk premium variable, the full set of time fixed effects and BA-level fixed effects. Model (3) includes the lagged risk premium variable and the full set of time fixed effects. Standard errors reported in columns (1) – (3) have been transformed to remove AR(1) serial correlation and heteroskedasticity. Standard errors are in parentheses. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

We also respecify the regressions for each individual Balancing Authority as Prais-Winsten regressions to analyze the impact of hydropower reservoir storage volume on risk premium with the average inflow into Grand Coulee variable, instead of deviation from average inflow into the mid-Columbia reservoirs. Results of these regressions are shown in Table 7. Similar to the pooled regressions, we find that regression results are slightly smaller in magnitude with more noise but support the conclusion that the impact of reservoir storage volume on risk premium is robust to this particular endogeneity concern of upstream dam operator actions influencing downstream inflow (and reservoir) levels.

TABLE 7: IMPACT OF RESERVOIR STORAGE VOLUME ON RISK PREMIUM FOR INDIVIDUAL BALANCING AUTHORITIES WITH GRAND COULEE INFLOW

Balancing Authority	Model 1: Prais-Winsten, Grand Coulee Inflow	Model 2: Prais-Winsten with Lagged Risk Premium, Grand Coulee Inflow
AVA	-0.61 (0.273) **	-0.59 (0.248) **
BPAT	-0.54 (0.237) **	-0.53 (0.228) **
IPCO	-0.25 (0.292)	0.25 (0.267)
NEVP	-0.18 (0.422)	-0.20 (0.386)
NWMT	-0.39 (0.254)	-0.39 (0.228) *
PACE	-0.22 (0.323)	-0.22 (0.282)
PACW	-0.63 (0.278) **	-0.62 (0.264) **
PGE	-0.67 (0.281) ***	-0.61 (0.257) **
PSEI	-0.40 (0.272)	-0.41 (0.264)
SCL	-0.46 (0.266) *	-0.44 (0.248) *
TPWR	-0.53 (0.259) **	-0.50 (0.242) **

Notes: This table reports impacts of reservoir storage volume (as a proportion of maximum storage capacity) for each individual Balancing Authority. Model (1) includes the full set of time fixed effects (day of week, month by year). Model (2) includes a lagged risk premium variable and the full set of time fixed effects. Standard errors reported in columns (1) – (2) have been transformed to remove AR(1) serial correlation and heteroskedasticity. Standard errors are in parentheses. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Average Hydropower Reservoir Storage Impacts on Real-Time Prices

We then estimate how hydropower reservoir storage volume (as a proportion of maximum storage capacity) impacts the real-time price across all Northwestern balancing authorities in a pooled regression.

For real-time price model (1) (Eq. 4) we exclude our lagged real-time price variable but include the balancing authority level fixed effect, this establishes the upper bound of the hydropower reservoir storage impact on real-time prices as this model can tend to estimate coefficients that are too large. For real-time price model (2) (Eq. 5) we include both balancing authority-level fixed effects, time-fixed effects, and the lagged real-time price variable. With this model, we address time-variant and time-invariant observed and unobserved heterogeneity at the balancing authority-level by including both a lagged dependent variable and fixed effects. We acknowledge that this regression can be slightly biased but note that any bias should be small due to the large time dimension of our data. For real-time price model (3) (Eq. 6) we include the lagged real-time price variable but exclude the balancing authority-level fixed effects (and include time fixed effects). With this model we establish the lower bound of the hydropower reservoir storage impact on real-time price, as this model produces coefficient estimates that will tend to be the most conservative.

We find that an increase in hydropower reservoir storage volume also significantly reduces real-time prices. Real-time price model 1, which includes balancing authority level fixed effects but does not include the lagged real-time price variable, results in an upper-bound estimate for the impact of hydropower reservoir storage volume on real-time prices. The impact is significant and negative, with a coefficient of -1.5265, meaning that increasing hydropower reservoir storage volume by 10% of its total storable value results in an estimated decrease in real-time price by approximately 15%). Real-time price model 2, which includes both a balancing authority level fixed effect and a lagged real-time price variable results in a negative and statistically significant coefficient of -0.515, indicating a 10% increase in hydropower reservoir storage decreases real-time price by approximately 5.2%. Real-time price model 3, which excludes the balancing authority level fixed effect but includes a lagged real-time price variable establish the lower bound estimate of on coefficient at -0.503, meaning that an increase in reservoir storage volume of 10% decreases real-time prices by about 5%. Results for other controls are consistent with their theoretical impacts. Increased wind and solar generation reduce real-time price. Increases in demand increase real-time price. Increases in natural gas volume reduce real-time price, and increases in natural gas prices increase real-time electricity prices. Inflow deviation has a positive correlation with real-time price in real-time price models 2 and 3, and an insignificant result in real-time price model 1.

TABLE 8: POOLED IMPACT OF HYDROPOWER RESERVOIR STORAGE VOLUME ON REAL-TIME PRICES ACROSS BALANCING AUTHORITIES

	Model (1) BA-level Fixed Effects	Model (2) Fixed Effects & Lagged Real-time Price	Model (3) Lagged Real-time Price
Hydropower Reservoir Storage Volume (as a proportion of Maximum Storage Capacity)	-1.5265 (0.1456) ***	-0.5148 (0.0523) ***	-0.5033 (0.0523) ***
Inflow Deviation (cubic feet per second * 1000)	0.00001 (0.0002)	0.00004 (0.00004)	0.00008 (0.00005) *
Log Demand (MWh)	1.2251 (0.0470) ***	-0.2740 (0.0218) ***	0.0094 (0.0014) ***
Gas Volume (billions of cubic feet)	-0.0016 (-0.0006) ***	-0.0004 (0.0002) **	0.0005 (0.0002) ***

	Model (1) BA-level Fixed Effects	Model (2) Fixed Effects & Lagged Real-time Price	Model (3) Lagged Real-time Price
Log Gas Price ($ / million btu)	0.9703 (0.0748) ***	0.3021 (0.0274) ***	0.3127 (0.0280) ***
Daily Solar Generation (MWh)	-0.000006 (0.000002) ***	-0.000002 (0.0000004) ***	-0.000002 (0.000004) ***
Daily Wind Generation (MWh)	-0.000005 (-0.000002) ***	-0.000002 (0.0000001) ***	0.0000001 (0.0000001) ***
Log Lagged Real-time Price		0.7010 (0.0147) ***	0.7162 (0.0141) ***
Balancing Authority Fixed Effects	Y	Y	N
Time Fixed Effects	Y	Y	Y
Constant			0.9132 (0.0826) ***
Observations	229505	226807	226807
R-squared	0.533	0.775	0.775

Notes: This table reports impacts of reservoir storage volume (as a proportion of maximum storage capacity) across all Balancing Authorities. Model (1) includes the full set of time fixed effects (day of week, month by year), and BA-level fixed effects. Model (2) includes a lagged real-time price variable, the full set of time fixed effects and BA-level fixed effects. Model (3) includes the lagged real-time price variable and the full set of time fixed effects. Standard errors reported in columns (1) – (3) have been transformed to remove AR(1) serial correlation and heteroskedasticity. Standard errors are in parentheses. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Average Hydropower Reservoir Storage Impacts on Distribution of Real-Time Prices

With our previous real-time price regressions, we examined the average effect of reservoir storage volume on real-time prices. As the impact of reservoir storage volume may impact price differently across the distribution of prices, our next analysis utilizes a quantile regression approach to assess the impact of reservoir storage volumes on median (50th) percentile of the real-time price distribution and the 95th percentile of the real-time price distribution.

As shown in Table 9, a 10% increase in reservoir storage volume decreases risk premiums by approximately 5% at the median of the distribution. This result is in line with our previous real-time price regression results which estimate the conditional mean, indicating that our previous regression results are not being driven by skewness or outliers. However, we do find that a 10% increase in reservoir storage volume at the 95th percentile is more impactful, decreasing risk premiums by approximately 6%. This result indicates that reservoir storage may be more valuable during grid stress events. Also worth noting is that increases in gas prices are more impactful at the upper end of the real-time price distribution and lagged real-time prices (previous realizations of real time prices) are less impactful. All other signs on coefficients are in line with expectations from the literature.

TABLE 9: QUANTILE REGRESSION OF THE REAL-TIME PRICE DISTRIBUTION

	50th Percentile	95th Percentile
Hydropower Reservoir Storage Volume (as a proportion of Maximum Storage Capacity)	-0.5176 (0.0074)***	-0.6174 (0.0392)***
Inflow Deviation (cubic feet per second * 1000)	0.00005 (0.00002) ***	0.0005 (0.00005)***
Log Demand (MWh)	0.2864 (.0096) ***	0.6837 (0.0219)***
Gas Volume (billions of cubic feet)	-0.0005 (.00007)***	-0.0021 (0.0002)***
Log Gas Price ($ / million btu)	0.3224 (.0098)***	0.9617 (0.0247)***
Daily Solar Generation (MWh)	-0.00000196 (0.0000002)***	-0.00000308 (0.0000004)***
Daily Wind Generation (MWh)	-0.00000152 (0.00000004)***	-0.00000147 (0.00000008)***
Log Lagged Real-time Price	0.6812 (0.0074)***	0.0577 (0.0193)***
Balancing Authority Fixed Effects	Y	Y
Time Fixed Effects	Y	Y
Observations	226,796	226,796

Notes: This table reports impacts of reservoir storage volume (as a proportion of maximum storage capacity) using a quantile regression approach Model (1) estimates the 50th percentile of the real-time price distribution and Model (2) estimates the 95th percentile of the real-time price distribution. To account for the non-standard distribution of the quantile regression estimator, standard errors are computed using bootstrapping to provide consistent inference under heteroskedasticity and serial correlation within panels. Standard errors are in parentheses. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Discussion

We find that, on average, a 10% increase in hydropower reservoir storage volumes reduces risk premiums by 5%. Our regressions are robust to inclusion of a lagged risk premium variable to account for the potential that previous market outcomes can influence both risk perceptions and price expectations, as well as robust to specifications controlling for inflow to Grand Coulee. Our results are consistent with Botterud et al (2010), who examined the relationship between reservoir level and risk premium in Nord Pool between 1996 and 2006. Intuitively, our findings indicate that higher reservoir storage volumes lower the compensation required by power purchasers for holding electricity futures contracts. In short, storage reduces market participants' risk. We posit that reservoir storage serves as a mechanism for managing short-term imbalances of supply and demand in electricity markets, leading to that reduced risk. As an extension, we then consider the impact of reservoir storage on real-time prices and the distribution of real time prices. We find similar results, a 10% increase in reservoir storage reduces real-time price by 5% on average. At the upper-end of the real-time price distribution—reflecting grid stress events—a 10% increase in reservoir storage is even more impactful, reducing real-time prices by 6%. In future work, we will continue to examine the value of hydropower reservoir storage through assessing the impact of reservoir storage during meteorologically driven grid stress events as well as examine the impact of reservoir storage on other price dynamics such as price spikes and volatility.

Our current findings provide evidence that hydropower reservoir storage has an important risk reducing effect on electricity markets, pointing to the value of stored energy. While most electricity markets do not currently provide a compensation mechanism for stored energy, new compensation models are emerging, such as the winter reserve mechanism in Switzerland, which contracts and pays hydro operators in Switzerland to hold back water in reservoirs—rather than generating electricity in early winter—so that withheld energy can be dispatched during supply shortages. The need for new business and compensation models, as well as what those models may value remains an important area of research for hydropower and other energy storage resources.

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