Case Study

Assessing the Bonneville Power Administration's Financial Vulnerability to Hydrologic Variability

Simona Denaro, Ph.D.[1]; Rosa I. Cuppari, S.M.ASCE[2]; Jordan D. Kern, Ph.D.[3]; Yufei Su, Ph.D.[4]; and Gregory W. Characklis, Ph.D., A.M.ASCE[5]

Abstract: Hydrologic variability can cause large swings in hydropower generation, inducing significant volatility in power sales. Dry years often result in low revenues that can threaten a hydropower supplier's ability to meet its fixed costs, leading to budget shortfalls, lower credit ratings, higher interest rates, and, ultimately, higher rates. This is particularly true for suppliers in hydropower-dominated regions, such as the Bonneville power administration (BPA). The BPA strategy for managing its hydrologic financial risk is multilayered, involving cash reserves, a line of credit, and tariff adjustments. Yet, compared to its long-term energy contracts and debt service, BPA's risk assessment is conducted on a short-term basis, thereby neglecting medium- and long-term temporal dynamics impacting their financial risk. This paper focuses on (1) evaluating BPA's hydrologic financial risk; and (2) testing the effectiveness of BPA's existing risk management strategy. Results suggest that BPA's financial risk will grow substantially over the next 20 years as its risk management tools become increasingly inadequate, providing cautionary lessons for organizations in similarly hydrodominated systems despite the current use of common risk management tools. **DOI: 10.1061/(ASCE)WR.1943-5452.0001590.**

Introduction

Global installed hydropower capacity reached 1,308 GW in 2020 (IHA 2020) and is responsible for 58% of all renewable electricity while contributing about 16% of global electricity production (Murdock et al. 2020). In some countries, predominantly in developing and emerging economies (e.g., Brazil, Cameroon, Tajikistan), hydropower accounts for the majority of national installed capacity (The World Bank 2015). The same happens at the regional scale in other parts of the world, such as the United States (US) Pacific Northwest, where roughly 50% of electricity is generated via hydropower (NPCC 2019). Beyond its appeal as a renewable energy source, hydropower is also attractive for its low operational costs; as with most forms of renewable energy, hydropower costs are disproportionately linked to high upfront capital expenditures and the costs of related debt (Killingtveit 2019; IRENA 2020). While in the past many hydropower facilities have been built and paid for by governments, especially in the developing world, an increasing number require at least partial financing via third parties (e.g., private lenders, World Bank), thereby making the interest rates associated with borrowing a critical factor in determining overall costs (Markannen and Braeckman 2019). This is especially true of low-income countries with fewer resources to dedicate to such projects. Competitive financing rates in this setting can often be a deciding factor in whether or not to develop a project, and any risk that could impede regular debt payments typically leads to higher interest rates.

In recent years, a growing fraction of debt associated with hydropower development has been raised in private markets. Unlike more flexible government funding, which can sometimes be deferred with less dire long-term consequences, payments on nongovernmental debt are often invariant year-to-year, regardless of how much power is generated and revenue earned (Hamilton et al. 2020; Markannen and Braeckman 2019). The predictability of these relatively constant costs is beneficial to hydropower suppliers, but it creates a misalignment with generators' variable revenues, which are dependent on environmental conditions like snowmelt and streamflow, and can present a threat to a supplier's ability to meet these fixed costs.

In fact, low-flow years (i.e., droughts) can impact hydropower-dominated utilities' financial stability in terms of reduced revenues and in terms of increased costs. Electricity producers with firm supply contracts must often compensate for supply shortfalls by buying electricity from others, typically at higher rates, to meet their customers' electricity demand (Kern and Characklis 2017; Gleick 2015). Climate change and the increasingly variable weather patterns that result are expected to compound these challenges (Gaudard et al. 2016; Zambon et al. 2016; Piman et al. 2015; Hamududu and Killingtveit 2012; Bumbaco and Mote 2010).

Failure to manage the financial risk of variable revenues and/or costs can lead to lower assessments of an organization's creditworthiness (e.g., credit rating). For a sector as capital intensive as hydropower generation, a downgrade in credit rating often leads

[1]RED–Risk, Engineering + Development, Via Frank 38, Pavia 27100, Italy; Dept. of Environmental Sciences and Engineering, Univ. of North Carolina, Chapel Hill, NC; Center on Financial Risk in Environmental Systems, Univ. of North Carolina, Chapel Hill, NC 27599-7431 (corresponding author). ORCID: https://orcid.org/0000-0003-1370-1765. Email: simona.denaro6@gmail.com; simona.denaro@polimi.it

[2]Dept. of Environmental Sciences and Engineering, Univ. of North Carolina, Chapel Hill, NC; Center on Financial Risk in Environmental Systems, Univ. of North Carolina, Chapel Hill, NC 27599-7431. ORCID: https://orcid.org/0000-0003-3530-3100

[3]Assistant Professor, Center on Financial Risk in Environmental Systems, Univ. of North Carolina, Chapel Hill, NC; Dept. of Forestry and Environmental Resources, North Carolina State Univ., Raleigh, NC 27695.

[4]Dept. of Environmental Sciences and Engineering, Univ. of North Carolina, Chapel Hill, NC; Dept. of Forestry and Environmental Resources, North Carolina State Univ., Raleigh, NC 27695; McKinsey & Company, 168 Hubin Rd., Shanghai 200020, China.

[5]William R. Kenan, Jr. Distinguished Professor, Dept. of Environmental Sciences and Engineering, Univ. of North Carolina, Chapel Hill, NC; Director, Center on Financial Risk in Environmental Systems, Univ. of North Carolina, Chapel Hill, NC.

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to an increase in interest rates and higher costs of debt service, often the largest single cost for electricity producers (IEA 2019). Indeed, credit rating agencies have recently begun to recognize variable hydrology as one of the main drivers of hydropower suppliers' financial risk and have been encouraging the adoption of integrated risk management strategies (Moody's 2019, 2020, 2021; Fitch Ratings 2021; S&P Global Ratings 2021).

Such strategies involve tools aimed at addressing different levels of financial risk, evaluated in terms of both the frequency and severity of losses. The first layer of protection typically comes in the form of risk retention strategies under which the exposed party itself takes primary responsibility for managing its financial losses through sources over which it exercises direct control, such as reserve funds. This approach is often cost-effective for high-frequency/low-severity events but becomes more expensive as potential losses become larger and less frequent due to the higher opportunity costs of maintaining large sums of highly liquid reserve funds that typically earn very little interest (Henssler Financial 2014). A line of credit is another risk retention tool, one which can be established with private lenders or governmental financial institutions such as the US Treasury or the World Bank Group. It involves prearranged borrowing terms (e.g., interest rate, maximum amount) and is a common approach employed to manage moderate losses. Another layer of protection comes in the form of risk reduction, commonly undertaken in the form of tariff adjustments wherein revenue losses are covered by increasing customers' prices. Though this approach results in risk reduction for the generator, it transfers this financial risk to customers and in so doing becomes impractical beyond a certain point either due to political pressure or customers availing themselves to less expensive, competing energy sources. Finally, the risk of severe, but infrequent, losses can also be managed via risk transfer, in which some of the potential risk is transferred to a third party (CNA Insurance 2016). Traditional risk transfer strategies include insurance, whether indemnity or index-based, or other forms of financial contracts (e.g., swaps, options). Although these types of contracts are familiar conceptually, their use in the hydropower sector has thus far been limited. This is changing, with some notable recent attempts including the "Lack of Water" contract offered by Swiss Re, which uses an index for water availability correlated with generation (Schneider and Sarkar 2017), and the bespoke $450 million index-based policy the World Bank offered the Uruguayan state-owned power company to protect against both drought and high oil prices that protects against the costs of generating alternative power to compensate for lack of hydropower (The World Bank 2013). While these tools have been evaluated individually in terms of their ability to reduce a hydropower generator's risk in isolation, little research has been done to evaluate a more integrated approach in which these tools have been implemented in a coordinated manner.

Identifying an effective strategy to mitigate hydrologic risk begins, however, with a thorough characterization of the risk, which in the case of hydropower includes evaluating the financial impacts of periods with both low supply and high demand; the probability of such conditions occurring simultaneously; and the impact of multiple years of drought, which can leave reservoirs with low water levels between years, prolonging drought impacts. The US alone has seen 13 major drought periods over the last century, and five of which lasted five years or more (Heim 2017). This suggests a need for hydropower suppliers to evaluate hydrologic risk over multiyear time horizons to ensure that risk management strategies are effective, sustainable, and capture medium- to long-term temporal dynamics—scenarios not often explored. Suppliers that evaluate hydrologic risk over short-term time horizons of less than five years may consider their risk management strategy sufficient, even if their tools would fail to cover a potential sixth year. In addition, many hydropower suppliers have long-term debt obligations spanning well beyond a five-year repayment period. Robust risk management approaches should manage financial risk impacting revenues—and therefore the suppliers' ability to repay debt—over the same period as debt is repaid. A misaligned risk evaluation may protect from total financial failure over any given year but may miss the risk of debt deferral and ensuing consequences throughout a series of sequential years.

This research focuses specifically on the Bonneville Power Administration (BPA), one of the four Power Marketing Administrations operated by the US federal government. This organization is responsible for selling and transmitting the majority of the hydropower generated in the US Pacific Northwest (PNW) as well as for paying for the construction and operation of the generation facilities, something it does by relying heavily on borrowing from both public and private sources. In addition to 31 dams in the Federal Columbia River Power System (FCRPS), BPA's generation portfolio consists of one nuclear plant (Columbia Generating Station, Hanford, WA) and several smaller hydropower and wind projects. Although BPA is a federal entity, it is self-funded and has a mandate to recover its costs through power sales revenue and thus it has a similar financial structure to most electric power utilities.

While BPA has several risk management tools at its disposal, including a reserve fund, line of credit, and the ability to adjust tariffs, many of its risk management strategies have only been evaluated over short time horizons and under a limited range of hydrologic conditions. Therefore, BPA's ability to manage hydrologic variability has been increasingly scrutinized by credit rating agencies (Fitch Ratings 2021; Moody's 2021; S&P Global Ratings 2021), with Moody's twice downgrading its credit rating between 2019 and 2020 and citing hydrologic risk as one of the primary reasons (Moody's 2019, 2020).

The specific goals of this research are to (1) perform a stochastic analysis to characterize BPA's financial risk under stationary hydrometeorological conditions; and (2) evaluate BPA's current financial risk management strategy to assess its effectiveness over a medium-term (20-year) time horizon. This analysis assesses the vulnerabilities that exist even when using what the industry considers a relatively sophisticated and integrated strategy for managing the financial risks of hydrologic variability. The challenge facing BPA is emblematic of the obstacles facing many power producers dependent on variable renewable energy to meet consumer demands for electricity, and improving their risk characterization provides an opportunity to set a benchmark for hydrologic risk management. The insights produced in this work should therefore be useful in the evaluation and management of hydrologic financial risk in other hydropower-dominated systems.

Methods

To characterize the hydrologic and energy system in which BPA resides, we couple a model of BPA's hydropower operations with an electric power system model and a newly developed financial operations model for BPA. The former simulates operations within both the Mid-Columbia (Mid-C) and California Independent System Operator (CAISO) markets, which are linked and experience some interdependencies as a result of electricity transfers between them. Model inputs are provided by a stochastic weather generator that is able to reproduce consistent time series of regional streamflow, temperature, and electricity demand as well as wind and solar power production across both markets in a manner that incorporates

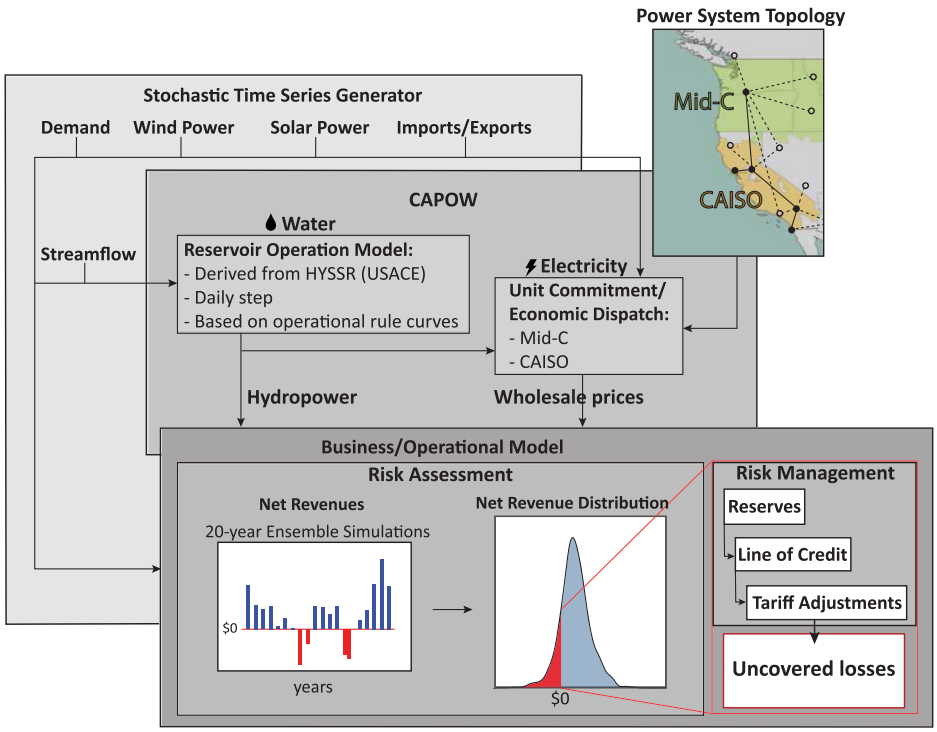

Fig. 1. Modeling methodology flowchart. Power system topology includes core nodes modeled using the unit commitment/economic dispatch model (solid dots) and connected statistically modeled nodes (unfilled dots).

consideration of spatial and temporal autocorrelation. This integrated modeling framework (Fig. 1) allows for an evaluation of BPA's financial risk and risk management strategy under a wide range of synthetic conditions that expand beyond the available historical dataset.

Bonneville Power Administration

As the PNW's primary power marketer, BPA is responsible for about 65% of the total generating capacity in the region (NPCC 2021). One notable difference between BPA and a traditional electric utility is that rather than selling power directly to retail customers, BPA sells to entities that then distribute the power to consumers, including investor-owned utilities, large industrial customers, and customer-owned cooperatives (BPA 2020c). Most of these entities contract for specified amounts of power via long-term contracts (i.e., Regional Dialogue contracts), making up a group referred to as "preference customers" (BPA 2020a).

At the same time, BPA sits in the larger interconnected Western Electricity Coordinating Council (WECC), which includes the Mid-C and CAISO markets. Unique among the electricity wholesalers of the region, BPA is statutorily obligated to prioritize the electricity demand of public utilities and cooperatives in the PNW. Each year, BPA is obliged to meet its preference customers' demand (load), as set by long-term contracts, and the most recent of which was signed in 2008 and is scheduled to soon begin renegotiation ahead of its expiration in 2028. Once the regional load is met, it may then export electricity outside the region (e.g., to California).

Hydropower generation is conditioned on streamflow, which in the Columbia Basin largely depends on snowmelt that is highly variable from year to year (Hamlet et al. 2005). Given that hydropower is typically the least-cost dispatchable energy source (NPCC 2016a), during dry years when hydropower generation is low, the price of any supplemental power that BPA may need to buy on the wholesale market to meet its obligations is likely to be significantly higher than the cost of hydropower, creating a situation that involves correlated supply and price risk. Meanwhile, approximately one-third of BPA's costs are related to debt service on borrowed funds (BPA 2020c), meaning that any erosion of BPA's credit rating would likely lead to higher interest rates that could significantly increase BPA's future costs, as well as its ability to access private debt markets (BPA 2018a). This is also important because the largest portion of BPA's debt is privately held, nonfederal debt for which debt service payments cannot be easily deferred (BPA 2018c). In fact, the aforementioned 2019 and 2020 downgrades of BPA's credit rating (Moody's 2019, 2020) stressed that variable hydrology represents one of the largest drivers of BPA's financial risk and described the need for BPA to find new ways to manage it. To begin to quantify this risk, a 2016 internal report estimated that a downgrade from AA, BPA's current average credit rating, to A could result in an increase of $340 million in interest payments over ten years, as lenders relying on credit ratings identify BPA as a riskier borrower (BPA 2016). All of this is taking place at a time when the costs of maintaining and replacing aging infrastructure and investments in new environmental programs are increasing, making the risks of revenue and cost variability more pronounced.

Currently, BPA's first line of defense for managing financial risk is a cash reserve fund. It also maintains a line of credit via the US Treasury that can be used during years in which losses are too large to be covered by its reserve fund. Finally, BPA's last resort is raising tariffs for its preferred customers, an action that it does not take in consecutive years, thus leaving an occasional lag between the losses and compensatory funding. When all three measures are insufficient, BPA experiences uncovered losses, at which point it is legally obliged to defer payments on US Treasury debt first. These tools are deployed in a coordinated manner that is described in the following sections.

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Over recent history, BPA's tools for managing its financial risk have largely been adequate, but it now faces several looming challenges. First, BPA's access to its line of credit with the Treasury is declining as it continues to access this relatively low-interest source of funds to support its maintenance, replacement, and environmental investments. At BPA's current and projected rate of usage through 2028, it will deplete all of its borrowing authority on the line of credit by 2023 (BPA 2020c). Though BPA has been attempting to find other funding sources to maintain the line of credit by paying down its federal debt, this conflicts with its policy of paying off its high interest (i.e., private) debt first (BPA 2018a), and the rate at which it has been depleting its borrowing authority has remained consistent over the past decade. Moreover, BPA's ability to increase its prices via tariff adjustments is constrained given that on average its current rates have been up to 50% higher than the average in the Mid-Columbia market over the 10-year preference contract period (BPA 2019b; US EIA 2021), which is experiencing lower prices as a result of increasing penetration of inexpensive renewable energy and low natural gas prices (NPCC 2016a). This represents a major obstacle for BPA in terms of keeping its preferred customers, as additional rate increases may drive them to reconsider the renewal of their long-term contracts. Any loss of customers and their firm contracts would force BPA to sell more electricity on the competitive wholesale markets where lower prices would further reduce its revenues while increasing its exposure to market price volatility.

California and West Coast Power Systems

Hydropower generation and wholesale electricity prices in both the Mid-C and CAISO markets are simulated via the California and West Coast Power (CAPOW) systems model (Hill et al. 2021; Su et al. 2017, 2020a, b). The following provides a brief description of the primary components: the stochastic hydrometeorological generator and the unit commitment/economic dispatch model. For a more detailed discussion of the stochastic time series generator and CAPOW, please refer to Su et al. (2020a).

Stochastic Hydrometeorological Generator

The stochastic generator produces a time series of spatially and temporally autocorrelated temperature, wind, irradiance, and streamflow conditions that serve as inputs to the power system and BPA business operational models. Historical data from the period 1998–2017 from sites along the West Coast are used as the basis for a vector autoregressive model, seeded with a starting daily temperature. An error term is sampled from a multivariate distribution to incorporate cross-correlated randomness in temperature, wind, and irradiance. Simulation within this framework allows for the generation of conditions within historical, stationary trends while expanding beyond the limited available observations. This provides an opportunity to explore the impacts of extreme and compound (e.g., hot and dry) events (Su et al. 2020a).

The time series of temperature, wind, and irradiance is then translated into streamflow observations using historical relationships between annual temperature metrics (i.e., heating and cooling degree days) and streamflow (available from 1953 to 2008). The meteorological data are statistically translated to power system variables, i.e., daily demand, wind and solar power generation, and power flows across the WECC, and the entity governing electricity flows across the western US coast including both the Mid-C and CAISO markets. The stochastic generator accurately reproduces the historical statistical moments (i.e., mean, minimum, and maximum) of temperature, irradiance, and wind speed in both California and the PNW (Su et al. 2020a; Cuppari et al. 2021).

There is little to no interannual temporal autocorrelation between the hydrometeorological variables, as determined via a Box–Pierce test using historical data (see Supplemental Materials, Autocorrelation). In addition, there is very little over year storage in the major Columbia reservoirs that might suggest temporal autocorrelation in streamflow. This analysis does not include consideration of long-term, multiyear, low-frequency climate oscillations in precipitation which could affect hydropower generation, but this has been shown to be negligible for hydropower operations in other West Coast settings (Hamilton et al. 2020). Such effects may bias the results of this analysis by underestimating the probability of rare multiyear drought events. In this sense, these results may represent a somewhat conservative estimate of BPA's risk.

Unit Commitment and Economic Dispatch Model (CAPOW)

The CAPOW model (Su et al. 2020a) reproduces generation and transmission in the West Coast bulk electric power system at an hourly timestep and is composed of a unit commitment and economic dispatch (UC/ED) model that, based on available generation resources and demand, simulates hourly system operations and wholesale prices for the two main trading hubs on the West Coast: the Mid-C and CAISO markets.

Starting from the 21-zone topology used by WECC for planning purposes, five zones are defined (solid dots in Fig. 1) corresponding to the two main wholesale electricity trading hubs in the region: the Mid-C market in the PNW (zone 1) and CAISO (zones 2–5). Each zone has its portfolio of generators, whose operating characteristics (e.g., fuel type, capacity, average heat rate) are collected from publicly available datasets (USEPA 2020). Zones interact through bidirectional pathways whose transfer limits are estimated from WECC (2015).

More than 85% of the hydropower resources in the Pacific Northwest are simulated mechanistically using publicly available versions of daily reservoir operation models developed by the US Army Corps of Engineers, namely the Hydro System Seasonal Regulation model (HYSSR) and the HEC-ResSIM model for the FCRPS and the linked Willamette River Basin system, respectively (USACE 2008; Jaeger et al. 2017). The remaining resources are modeled via regression or statistical scaling. Hydropower is less dominant in the CAISO region, making up less than 15% of the electricity generation in California on average (California Energy Commission 2020), though correlated drought conditions between California and the PNW can influence electricity transfers and prices, making it important for considering extreme conditions. Publicly available water balance models exist for about 12% of CAISO hydropower capacity (Cohen et al. 2020). The remaining CAISO hydropower capacity is modeled by parameterizing simple rule curves for each dam via a differential evolution algorithm. See Supplemental Materials, Streamflow Simulation, for further validation. Fig. 2 shows the primary area of focus for this analysis, along with the interties with California.

The UC/ED model is formulated as an iterative mixed-integer linear program with the objective of minimizing the cost of meeting electricity demand by dispatching (i.e., scheduling) generation resources on an hourly basis. The minimization problem is constrained by physical limits relative to individual generators as well as the capacity of the transmission pathways. The hourly price in a given zone (1–5) is estimated as the shadow price of an energy balance constraint (i.e., the change in objective function value associated with a 1 MWh increase in demand at each zone). Fig. 3 describes the validation of outputs from CAPOW with available historical data. Panel a) compares stochastically generated demand to the historical record over the period 2010–2017 ($r^2 = 0.73$ at the hourly timestep). Panel b) compares historical data on monthly

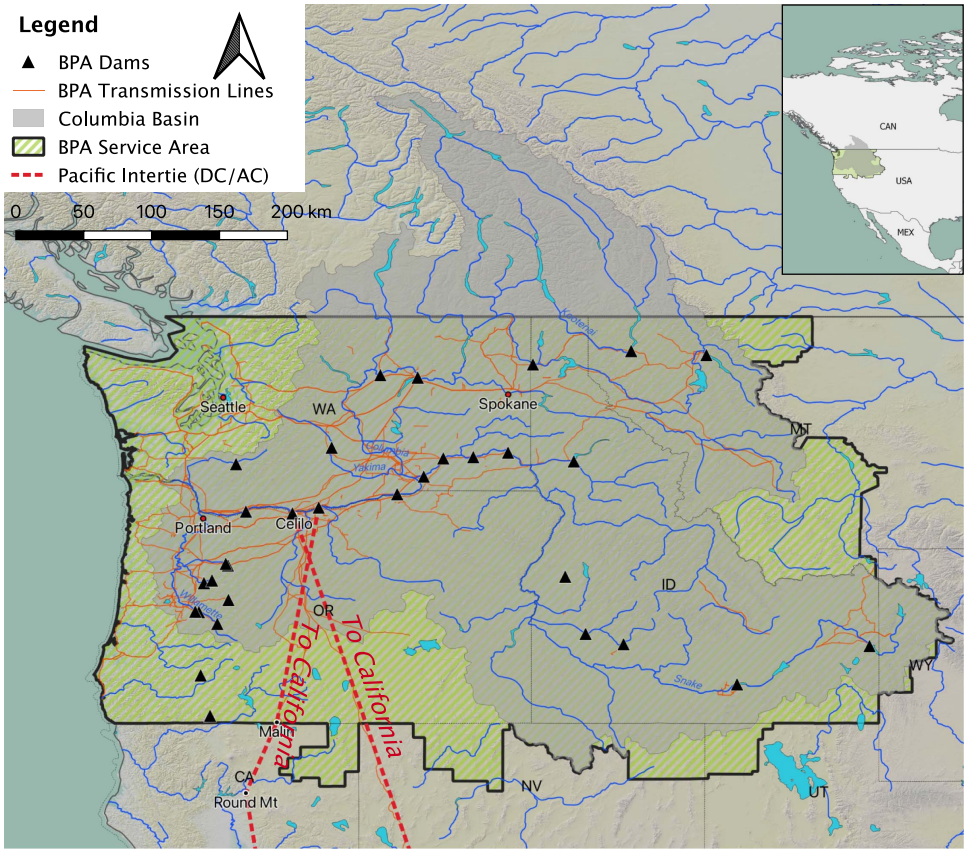

Fig. 2. BPA service area and the Columbia River Basin. BPA sells the wholesale power generated by 31 dams (triangles) in the FCRPS and manages 75% of the regional transmission lines. BPA can export surplus power to California through the Pacific interties (dashed lines). (Map by Simona Denaro.)

generation in BPA-managed dams (2010–2017) to values simulated with the FCRPS model using historical streamflow ($r^2 = 0.76$ at the monthly timestep). Panel c) plots historical and modeled 2010 daily prices produced with the UC/ED model. Validation is constrained by the availability of generation and load data, along with the change in the natural gas price regime, which occurred with the advent of hydraulic fracturing post-2009.

BPA's Business Operational Model

The aforementioned models provide inputs to BPA's financial risk assessment. This section describes the modeling of BPA's financial operations.

BPA's Net Revenue Simulation

Bonneville Power's mandate is to satisfy preference customers' load obligations, which is also referred to as firm power because it is guaranteed, and to repay its costs and debt obligations in full each year. Firm power is sold at rates that are set every two years through a public process and distinguish various categories of customers and contracts. In this work, the monthly average power rates published for the years 2018–2019 (BPA 2017) for BPA's two main customers are considered:

- Public power (Preference customers): The largest group of customers are the 125 public power utilities in the region who by law have "preference and priority" to federal power.
- Direct Select Industries (DSIs): A small group of customers, primarily aluminum companies and paper mills. The number of operating aluminum smelters has steadily declined over the years. Rates for DSIs are significantly higher than the public power rates.

Regional load is statistically simulated based on weather inputs on a daily timestep and disaggregated to the hourly level and to the two different customer classifications using historical patterns. Daily hydropower generation is simulated in the FCRPS operations model. Yearly wind and imports are simulated statistically on a daily basis, while nuclear capacity is disaggregated to daily time series based on historical data. Each day, if available generation resources are sufficient, all firm power obligations are satisfied first and revenues are calculated using each customer group's monthly rate. Any surplus electricity is sold on one of the two regional wholesale markets based on which offers the highest price. In the case of selling into the CAISO market, which occurs when prices are higher than in the Mid-C, transmission limits and additional transaction costs are also included. If the available generation does not cover BPA's firm commitments, as can happen in dry years, electricity is bought from the regional hub (i.e., Mid-C or CAISO) exhibiting the lowest price. A 3% transmission loss is also accounted for before allocating any resources (BPA 2019c). Each year, net revenues are calculated, with costs calculated as the sum of fixed operations and maintenance costs as well as debt service payments, plus the cost of buying additional electricity on the spot market to meet firm power demand.

BPA's Risk Management Strategy

This research characterizes BPA's financial risk over the same time horizon as current preference customers' contracts 20 years. This acts as a consistent time window over which BPA's net revenues are evaluated, simulating 60 × 20-year ensembles (a total of 1200 synthetic years). Compared to BPA's existing risk assessments, which are only conducted during biennial rate proceedings or for strategic

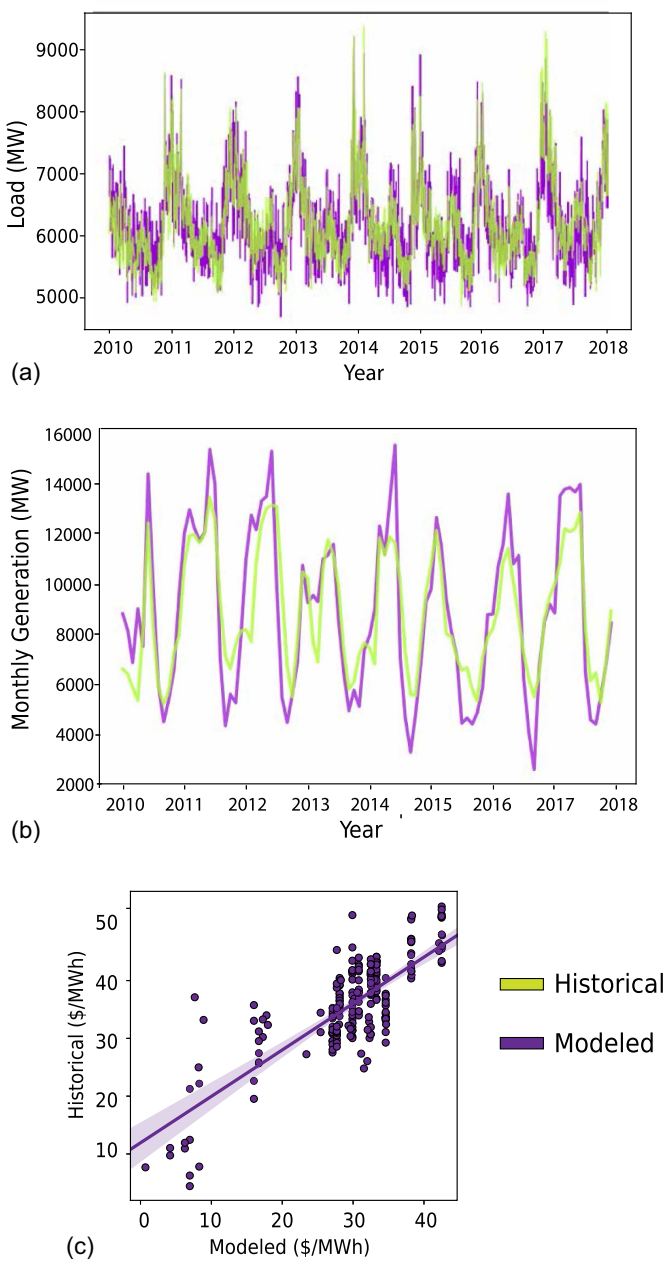

Fig. 3. Validation of the CAPOW model components: (a) electricity demand; (b) hydropower generation; and (c) mid-C electricity market price.

plans published every five years, this analysis allows evaluation of medium-term in addition to short-term risk.

The existing three-tier BPA financial risk management strategy including reserves, line of credit, and tariff adjustments are simulated using the modeling framework presented in Fig. 1. When available, cash reserves are BPA's first tool for mitigating financial risk and are able to cover smaller losses that occur as a result of more common but less severe hydrometeorological events. At the beginning of each 20-year simulation, reserves are set to those available in September 2018 ($158 million), with the intent to consider each ensemble as 2018–2038 given stationary conditions (e.g., without considering the financial impact of the pandemic, or climate change). In years with positive net revenues, BPA contributes 10% of net revenues to its reserves, up to a cumulative cap defined as 120 days of cash on hand, approximately $610 million

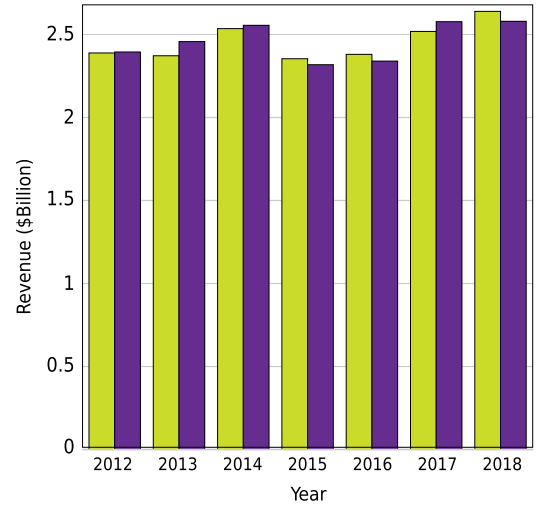

Fig. 4. 4 Historic versus modeled BPA net revenues.

(Fitch Ratings 2020; BPA 2018b). Once the contribution to reserves reaches its cap, BPA dedicates 32% of its positive net revenues from its power system to capital costs including debt service (BPA 2018a, d).

In years in which reserves are insufficient to make up for negative net revenues, BPA turns to the line of credit made available by the US Treasury. Through this low-interest line, BPA can access up to $750 million in immediately liquid funds (the Treasury Facility). However, the available financing from the US Treasury's line of credit for BPA is capped, long-term, at $7.7 billion, also known as the borrowing authority. The Treasury Facility is the component of the borrowing authority that is immediately available. For many years, BPA has also used the borrowing authority to finance expenses in both the power and the aging transmission sector. While BPA has access to the full remaining line of credit ($2.1 billion remaining as of 2020), Bonneville's goal is to maintain a minimum level of $1.5 billion. Nevertheless, based on the 2018 financial plan, BPA anticipates using roughly $490 million per year for the next decade for various expenses including capital financing. At this rate, it projects to exhaust the borrowing authority (i.e., line of credit) by 2023 (BPA 2018c). Finally, if losses exceed the capacity of both reserves and the Treasury Facility, BPA can impose tariff adjustments on its preferred customers. This follows a rate increase approval process invoking the cost recovery adjustment clause (CRAC) under the condition that at least half of its $750 million lines of credit was used in the previous year and that CRAC was not invoked in the year prior (modeled as being feasible on a biannual basis). Adjustments are calculated based on revenue shortfalls and capped at an amount equivalent to about $5/MWh based on BPA's current average annual load (BPA 2019a).

Fig. 4 shows validation of the BPA financial operations model, with BPA's revenue from regional and surplus sales. Historical net revenue data has only been reported in a consistent manner since 2012, preventing validation using earlier data.

Results

The model is run over 60 20-year ensembles for a total of 1,200 years using historical weather trends. We assess both BPA's yearly net revenue distribution over 1,200 years and the performance of BPA's financial risk management strategy, including

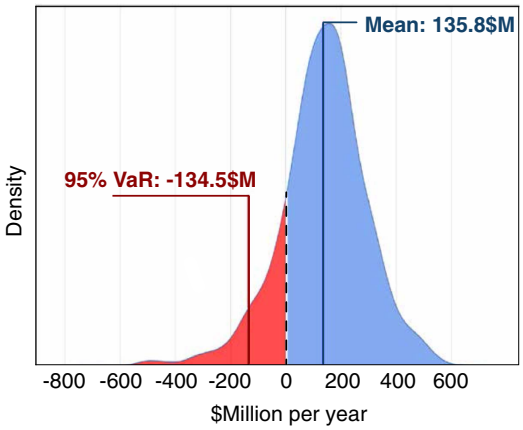

Fig. 5. BPA's yearly net revenue distribution, under historical conditions.

consideration of all three risk management tools currently at BPA's disposal: cash reserves, the line of credit, and tariff adjustments.

The distribution of BPA's yearly net revenue can be seen in Fig. 5. In 84% of the simulated years, BPA collects positive net revenues that are used to replenish its cash reserves, support capital investment, and provide early debt payment. However, in dry years, BPA often experiences negative net revenues (losses) as large as $750 million per year. The risk of losses is commonly evaluated as the 95% value at risk (VaR), defined as the value of losses that have a 5% probability of being exceeded. In this case, the 95% VaR for BPA's power system net revenues is -$134.6 million in any given year. In the 16% of years with negative net revenues (area left to zero in Fig. 5), BPA's financial risk management strategy is activated to cover these losses. A successful strategy would allow BPA to cover its debt service payments in time and in full at the end of the year, independently of hydrologic conditions. For this to occur, BPA can experience losses but should have capacity via its reserves, line of credit, or other tools to cover its losses.

To compensate for years with negative net revenues, BPA's reserves, line of credit, and tariff adjustments vary over the 20-year planning horizon, as can be seen in Fig. 6. This current combined strategy is largely effective for protecting against less severe events, particularly in the early parts of the 20-year period: as seen in the top panel, the ensemble net revenues (solid line) are positive over the entire 20-year period, and 90% of the ensembles maintain positive cash reserves over this period. That said, in 5% of ensembles, there is a reserve deficit (shown as "negative" or below zero reserve availability in the top panel) wherein reserves required to cover losses are far greater than reserves available.

Given BPA's current rate of drawdown on the borrowing authority, our analysis finds that it exhausts the tool at the end of the 8th year in 90% of ensembles (as shown in the lower panel in Fig. 6), which is consistent with BPA's own internal projections (BPA 2020c). This essentially makes the line of credit unusable to cover losses much beyond this point later in the 20-year planning horizon, apart from ensembles with particularly wet periods in early years. Though BPA does have a mechanism for early repayment in years with positive net revenues which can contribute to the line of credit, this fails to prolong the availability of the line of credit available much beyond year seven given the rate of drawdown to support new infrastructure and rehabilitation projects. Without the line of credit, the cash reserves are depleted more often and tariff adjustments are more commonly triggered starting in year 8. In 5% of ensembles, tariffs are increased by 15% (+$5/MWh), which is the maximum allowed under CRAC. This is a significant increase given the $36/MWh average tariff for preference customers in fiscal year 2021 (BPA 2020b) and the range of average annual market prices on the Mid-C market, which have remained below $30/MWh since 2010, hitting lows of $23/MWh (US EIA 2021).

A failure event with respect to BPA's multilayer risk management approach is defined as a year in which reserves are depleted, the line of credit has been exhausted, and the tariff adjustment cap has been reached, a condition that results in uncovered losses. Such a condition occurs in roughly 5% of 60 20-year ensembles. This is an uncomfortably high level of risk given that BPA would likely have no recourse beyond deferring debt service payments and that this risk violates BPA's stated goal of maintaining a 97.5% probability of meeting treasury payments (BPA 2020c). Though deferral of federal debt alone may not trigger a credit downgrade as compared to missed payments on nonfederal debt, barring external intervention, it would likely be accompanied by both exhausted reserves and sustained declines in the line of credit, which both are identified as factors potentially leading to a credit downgrade (Moody's 2021; S&P Global Ratings 2021). It also likely represents a conservative estimate of the risk as climate change models suggest the region will experience greater hydrologic variability in the future even if most of this change is predicted to come after 2050 (Hill et al. 2021; River Management Joint Operating Committee 2018).

In the most extreme years, those in which losses are greater than or equal to the 90% VaR, the three financial tools are deployed to varying degrees to cover negative net revenues (Fig. 7). It is also clear from Fig. 7 that the utilization of BPA's three financial tools changes over the 20-year planning horizon (upper panels): the short-term (years 1–5), the near-term (years 6–10), and the medium-term (years 11–20).

Over the short-term, cash reserves are typically available, though often insufficient to cover more extreme losses alone. In 5% of simulations within the short-term, reserves are able to cover less than $150 million of total losses, though these losses can reach over $500 million (99th percentile of losses in years 1–5). In these cases, the line of credit provides a relatively inexpensive and easily deployed tool when available; as a result, in the first five years of the 20-year period, BPA can largely avoid tariff adjustments and still cover its losses. Only 1% of the short-term realizations require tariff adjustments to cover losses. Similarly, there are very few uncovered losses in these initial years, and when they do occur, they are modest (less than $50 million).

In the "near-term" (years 6–10), however, BPA's current risk management instruments begin to fall short. Reserves, which are often relied on during years 1–5 of each ensemble, have often been drawn down at this point; less than $100 million of reserves are available to cover losses over the near term. Typically, BPA uses its line of credit once reserves are depleted. Alas, this line of credit is exhausted between the 6th and the 8th year in all ensembles, leaving tariff adjustments as the last available tool. In the worst 1% of near-term realizations, tariff adjustments cover losses of up to $180 million, leaving over $156 million of losses uncovered - far greater uncovered losses than in the short-term. When tariff adjustments are insufficient, BPA experiences uncovered losses, which must result in deferring an equivalent portion of BPA's debt payments. Uncovered losses over the near-term are far larger than in the years 1–5, as BPA depletes its reserves and line of credit, while also approaching the cap on its tariff adjustments (Fig. 6). In this near-term period, very wet and very dry years have an outsize impact because tariff adjustments are not invoked on sequential years; two successive dry years can provoke uncovered losses in years in which the tariff adjustments have not yet been adequately

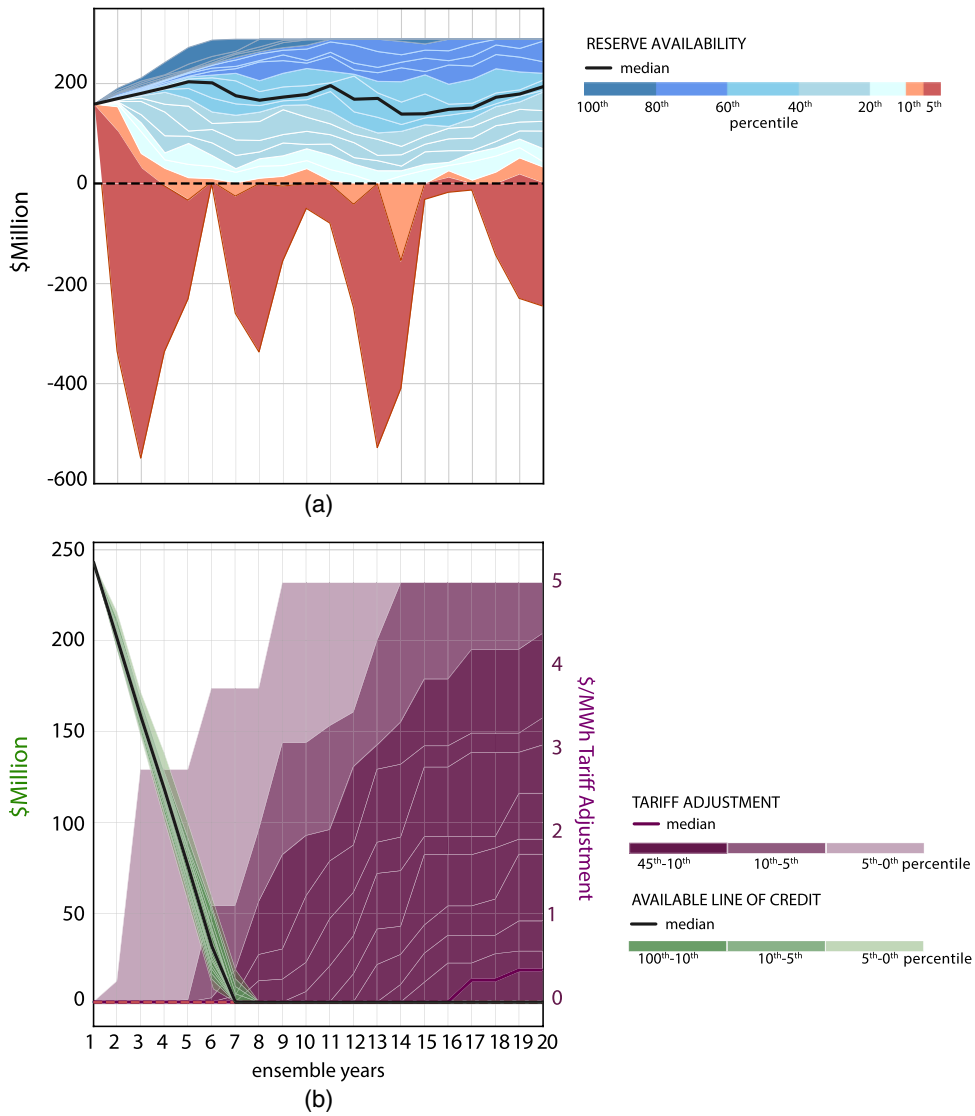

Fig. 6. Analysis of BPA's current financial risk management tools as percentile distribution of the stochastic 20-year ensembles: (a) percentiles of available financial reserves over the 20-year ensembles. Negative values indicate that reserves were insufficient to cover losses; and (b) the percentiles of the available line of credit, which is depleted within the 8th year across all ensembles, along with the value of the tariff adjustments (CRAC) that are used to compensate for both falling reserves and depletion of the borrowing authority.

triggered, while very wet years with tariff adjustments already in place allow reserves to recover.

Indeed, reserves tend to recover in the "medium-term" (years 11–20) as tariff adjustments in earlier years lead to higher rates. Though a mechanism to redistribute surplus revenue from surcharges is available, it has not been historically applied to rates. In the years following a tariff adjustment, BPA's revenues increase and it is able to pay down its debt and add to its cash reserves more often, increasing the reserves available in the most extreme realizations of the medium-term. In fact, while only 5% of ensembles in the short term result in tariff adjustments, 25% of ensembles in the near term and 53% in the medium term do, with average tariff adjustments in the near- and medium-terms averaging \$0.33/MWh and \$1.06/MWh, respectively. This suggests that while the CRAC may not be effective for protecting against losses in individual years, it is a powerful mechanism for adapting rates to prevent losses in the future.

Though reserves are less effective over the medium-term when compared to the short-term, the tariff adjustments in these medium-term years thus help replenish reserves more than they would have in earlier wet (profitable) years. As such, reserves are available in larger sums than in years 6–10, although they are still unable to cover large losses once the line of credit has been exhausted. In the medium-term, BPA experiences its largest uncovered losses: approximately \$200 million. These uncovered losses can only be managed by deferring an equivalent amount of debt repayment to the Treasury—an event likely to trigger external consequences, such as a credit downgrade and interest rate increases that would have long-term financial consequences for BPA.

Discussion

The results describe how a hydrodominated system may be vulnerable to extreme hydrological conditions even when a multitool, integrated financial risk management strategy is in place. It is evident that tools such as cash reserves are efficient for managing smaller, more frequent losses, but there is a threshold level of reserves above which the opportunity cost of maintaining them becomes expensive

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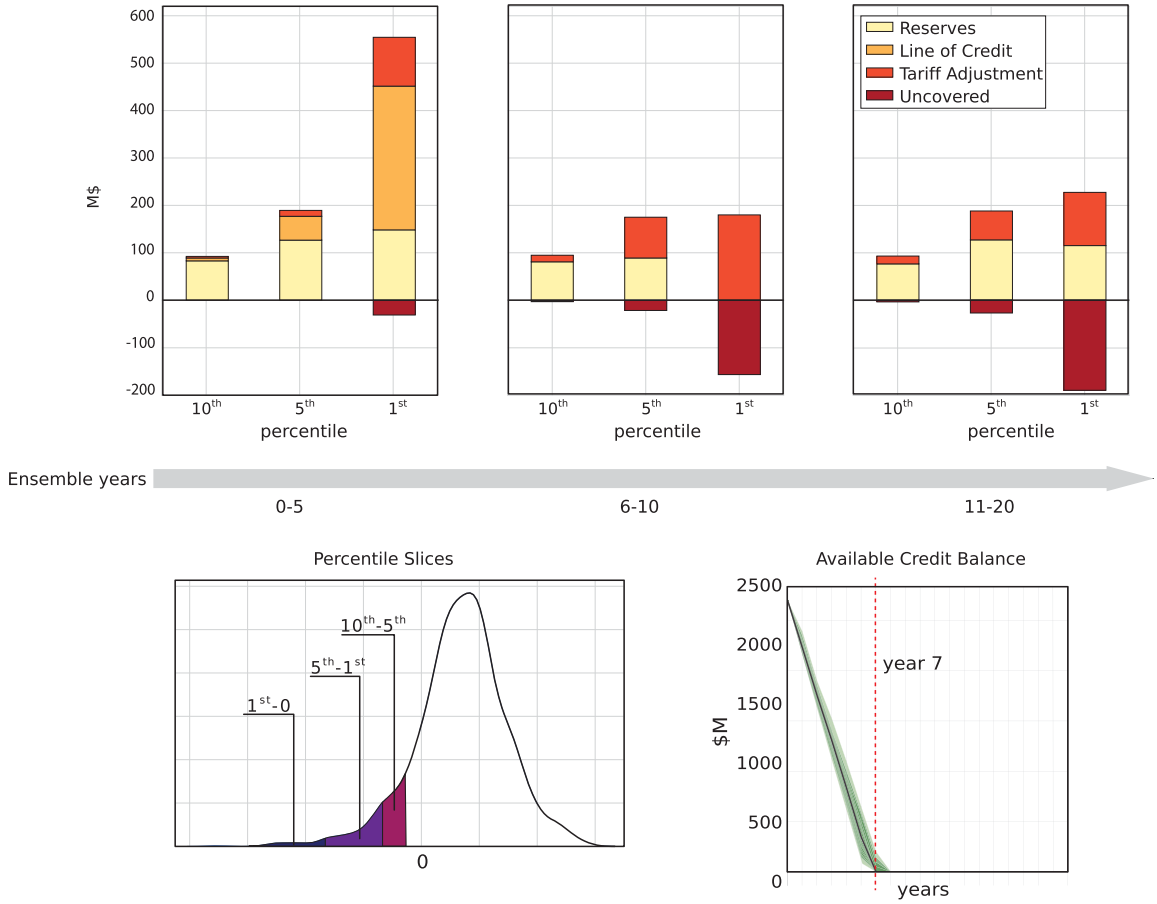

Fig. 7. BPA's financial strategy under the most extreme conditions (losses higher than the 90th percentile). Results are split in time to show how BPA's strategy changes when the line of credit is exhausted.

and indicates that some alternative risk management tools should be employed. As an additional layer of protection, BPA's line of credit from the US Treasury is well suited for managing more extreme risks, but it is rapidly being depleted. Though the 2021 Bipartisan Infrastructure Law includes a temporary enlargement of the borrowing authority to $10 billion, a recognition of the financial challenges BPA faces, available funding will be reduced to less than $6 billion as of 2028 (House 2022). As this line of credit is exhausted, perhaps a nongovernmental line of credit can be established with private-sector lenders, albeit at a higher interest rate, otherwise losses will be increasingly transferred to customers via tariff adjustments, and this can have unintended consequences.

Even when tariffs are feasible—legally, politically, and otherwise—they can have the unexpected effect of decreasing loads, either because customers reduce their electricity use (e.g., via efficiency) or because other sources of electricity are available at lower rates (e.g., wind)—both of which can translate to lower revenues for electricity suppliers. In the case of BPA, this is a serious threat, considering that their long-term contracts with preference customers will expire in 2028 and that growth in wind generation paired with low natural gas prices are expected to keep Mid-C prices low in the future, as they have in the last decade (NPCC 2016b; S&P Global Ratings 2021). Loss of preference customers could force BPA to sell more of its electricity into the wholesale markets where it would garner lower average prices and subject BPA to more volatility. Though one may argue that BPA could benefit from higher prices during low-flow periods, the lower average market price of the Mid-C market means that any potential short-term upside is likely outweighed by the long-term decreases in revenue by selling to the wholesale market. This is pronounced because BPA's preference customer prices have been up to 50% higher than average wholesale prices in the last 10 years (BPA 2019b; US EIA 2021). Furthermore, it would be challenging for BPA to delay electricity generation substantially in order to avoid selling to the market during low-price periods because BPA is also beholden to maintaining minimum levels of streamflow and maximum reservoir levels. Finally, BPA benefits from a stable income that can match its rather constant long-term costs.

A scenario in which long-term customers defect could also potentially lead to a "death spiral" wherein BPA would need to continue raising prices on an ever-smaller number of more vulnerable preference customers, providing them with greater incentives to terminate their long-term contracts. That said, utilities may maintain their contracts with BPA even if it raises prices, given that the long-term contracts offer greater price stability than purchasing electricity exclusively on the wholesale market. This may be especially true in light of the recent extreme weather conditions causing short-term record wholesale electricity prices across the country, notably in the Pacific Northwest as in Texas (Hersher 2021; Chediak et al. 2021); a utility's willingness to abandon its contract with BPA signifies accepting the risk of price shocks that BPA currently absorbs for its customers.

It should also be noted that although BPA's goal is to provide inexpensive power as a means of encouraging regional economic development, it has several well-established mechanisms in place for raising rates. Many other utilities that depend on hydropower generation, particularly in emerging economies such as Brazil,

Albania, and Ethiopia, may be less willing or able to raise tariffs to the same degree, leaving them even more exposed to the types of financial risk that will lead to less favorable borrowing arrangements with international lenders (e.g., World Bank).

This work suggests that BPA's risk management would benefit from a longer-term planning horizon, as it has often limited this planning cycle to two years. Without considering how well its risk management strategy operates beyond a 5–10 year window, BPA diminishes its ability to understand the impact of factors such as the rise and fall of its reserves in a complete manner. Another example is evaluating the long-term effects of depleting its line of credit, as BPA currently does not plan its tariff adjustments or reserve size targets accounting for this. For BPA's preference customers, which have long-term contracts, but are due to begin negotiating their next round of agreements in 2025, a short-term evaluation will likely lead to more and larger tariff increases than they would expect if they were to focus beyond the short-term planning cycle.

These results also suggest that BPA's current set of risk management tools is likely to prove insufficient to mitigate its hydrology-based financial risk within the next 5–10 years. As such, it should begin to develop alternative risk management strategies, perhaps including additional tools such as index insurance, which have been considered in the literature (Hamilton et al. 2020; Meyer et al. 2016; Foster et al. 2015; Kern et al. 2015), but only implemented in a few cases (The World Bank 2013; Schneider and Sarkar 2017). The study methods are further enriched by the use of stochastically generated weather conditions in evaluating financial outcomes over longer time horizons—a crucial component for characterizing the efficacy of a risk management strategy. The importance of time horizons in such an analysis is demonstrated in the comparison between the capacity of reserves to manage losses in years 1–5 versus 11–20, and the impact of tariff adjustments. In the former, dry years cause high losses because BPA rates are lower but cause low uncovered losses because other risk management tools are available (i.e., line of credit, reserves). In contrast, dry years in the medium-term may produce lower losses thanks to higher rates but higher uncovered losses during extreme events as other risk management tools are unavailable. Implementing a more robust hydrologic financial risk analysis and pairing it with appropriate financial instruments could increase BPA's available resources in extreme events economically.

Managing BPA's financial risk may become even more important over the long term (20+ years). The River Management Joint Operating Committee (RMJOC), comprised of BPA, the US Army Corps of Engineers, and the US Bureau of Reclamation, has recently published a report on projected climate change impacts in the Columbia River Basin (River Management Joint Operating Committee 2018, 2020). With respect to hydropower, the study finds limited seasonal changes in generation before 2060, in agreement with other projections that significant changes in the FCRPS will not take place until after 2050 and that the most severe changes will not take place until the late 21st century (Rupp et al. 2017). These include potential increases in variability of streamflow and hydropower generation, especially during the summer months.

From BPA's standpoint, any variability in streamflow timing will impact revenues by changing the alignment between hydropower supply and demand, which currently yield the inverse relationship between hydropower and Mid-C prices (Su et al. 2020b). Periods during which BPA produces surplus electricity—which can only partially be transferred to California due to limited transmission capacity (Su et al. 2017)—coincide with periods of lower electricity prices. On the other hand, higher price periods tend to occur when hydropower is scarce and BPA needs to buy additional power to satisfy its obligations to its preferred customers. As climate change is expected to exacerbate these extremes, particularly regional supply shortfalls that drive higher summer electricity prices (Hill et al. 2021), it is likely that BPA's financial risk will increase, making the need to develop improved methods of managing financial risk all the more pressing.

Conclusion

In this work, we assess the performance of a multitool financial risk management strategy for BPA, a larger hydropower supplier in a hydrodominated system. Results show that even a relatively sophisticated strategy fails to cover BPA's losses under extreme conditions, while also demonstrating that a short-term planning horizon is insufficient to fully evaluate its financial risk. Over the next 5–10 years, BPA is likely to become even more vulnerable to extreme drought and face uncovered losses that must often be transferred to customers through higher rates, a situation that could lead these customers to purchase their electricity elsewhere, further exacerbating BPA's financial risk.

Energy generators or suppliers with significant portions of their portfolio dedicated to hydropower are coming under increasing pressure from lenders, credit ratings agencies, and customers to find new and more cost-effective strategies for managing financial risk arising from hydrometeorological variability. New tools and improved methods of evaluating this risk will be required, perhaps in the form of novel insurance or hedging contracts, particularly as the impacts of climate change take on greater significance.

Data Availability Statement

Some or all data, models, or code generated or used during the study are available in a repository or online in accordance with funder data retention policies. The data that support the findings of this study were derived from resources available in the public domain at www.bpa.gov. All code and data required to run the CAPOW model, as well as some documentation of the model, are available at https://github.com/romulus97/CAPOW_PY36 under the MIT free software license. All code and data required to run the BPA business operational model are available at https://github.com/S-Denaro/BPA_Busi_Op under the MIT free software license.

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Supplemental Materials

Figs. S1, S2, and additional text are available online in the ASCE Library (www.ascelibrary.org).

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