Retail Load Defection Impacts on a Major Electric Utility's Exposure to Weather Risk

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Abstract: Electric power utilities face a wide range of risks that cause financial uncertainty, with potential impacts on prices for customers. Among these, weather variability and retail load defection are perhaps two of the most studied. Whereas weather extremes expose utilities to unpredictable swings in electricity supply and demand, retail load defection, in which customers adopt distributed energy resources or switch to alternative providers, can alter utility business models fundamentally. We showed for the first time that these two phenomena can interact dynamically, with potential negative consequences for electricity ratepayers. We found that retail load defection could alter utilities' financial exposure to weather risk in a matter of years. Using open-source power system simulation software coupled with a utility financial model, we simulated outcomes for a major hydropower-producing California electric utility under stationary hydrometeorological uncertainty, and under three different load defection scenarios ranging from 0% to 90%. We found that as load defection increases, the utility's three main businesses (wholesale generation, transmission, and retail distribution) shift in relative importance. As a consequence, the impacts of interannual variability in hydropower production and demand in the utility's system (a function of streamflow and air temperatures, respectively) become significantly altered. Air temperatures (a proxy for demand) become more predictive of utility financial performance, whereas the utility's exposure to hydrology is poised to shift in complex ways. Drought will remain a major risk, but extremely wet years (which historically are beneficial to the utility's significant hydropower holdings) may become damaging due to their association with low market prices. Our results also suggest that load defection could put much more pressure on utilities to make major annual rate adjustments or quickly adapt current strategies for managing weather risk. **DOI: 10.1061/(ASCE)WR.1943-5452.0001531.**

Introduction

In the electric power sector, hydrometeorological uncertainty and extremes can negatively impact the functionality of generation resources and cause large changes in customer demand (Griffin 2020; Kern and Characklis 2017; Kern et al. 2020; Pappas et al. 2008; Stanger et al. 2019; Tobin et al. 2018; Turner et al. 2019; van Vliet et al. 2016; Zhou et al. 2018). Streamflow, which acts as a fuel for hydropower production and a critical coolant for thermal power plants, is subject to hydrologic variability. Electricity demand, which is affected strongly by heating and cooling needs, is influenced directly by deviations in air temperatures above and below the level of human comfort [around 18.3°C (65°F)], with heat waves and cold snaps typically causing spikes in demand. By affecting supply and demand (and thus wholesale prices) for electricity, variation in hydrometeorological conditions also can be a source of financial stress (fluctuations in costs and revenues) for power system participants (Deng 1999; Deng and Oren 2006; Foster et al. 2015; Kern et al. 2020; Kern and Characklis 2017; Su et al. 2017). Utilities manage their exposure in multiple ways, including passing unexpected financial losses to customers in the form of higher prices, through the use of true-up funds, and/or by purchasing hedging contracts (e.g., insurance) that pay out based on observed deviations from normal weather conditions (e.g., during a drought) (Foster et al. 2015; Kern et al. 2015). For the latter to be truly protective, utilities must be able to establish a reasonably high correlation between underlying weather conditions and financial performance.

Similar to other businesses, electric utilities also are exposed to market and regulatory risks (Deng et al. 2020; Taminiau et al. 2019). For example, in recent years the combination of policy pressure, market deregulation, and falling renewable energy costs have led to a steady transition away from fossil fuel based generation in many US power markets (Denholm et al. 2015; Su et al. 2017). This has created many new risks for some incumbent utilities, including reduced market share. Although risks for utilities from weather and the energy transition may seem independent, it is possible (perhaps likely) that these risks are interacting in complex ways, with underlying changes in one area leading to altered exposure in the other. For example, increased reliance on wind and solar power could increase a utility's exposure to uncertainties in wind speeds and solar irradiance (Collins et al. 2018). Financial distress caused by harmful weather and climate events (e.g., wildfire in California) also can result in lower credit ratings and increased cost of borrowing, potentially leading to higher costs for new renewable energy projects (Schulten et al. 2019; Woetzel et al. 2020).

A less-well-understood example is the interplay between a utility's exposure to weather risk and load defection, i.e., the gradual diminution of a utility's retail load base (demand) due to customer

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use of energy efficiency measures, self- or third-party-owned solar panels, and/or participation in community choice aggregations (CCAs). CCAs are local government entities that procure electricity on behalf of retail customers (similar to electricity retail companies) within a certain geographical area. Although participation in CCAs is voluntary, in eight US states (California, Illinois, Massachusetts, New Jersey, New York, Ohio, Rhode Island, and Virginia) they compete directly with incumbent utilities for customers (Kennedy and Rosen 2021; O'Shaughnessy et al. 2019). By sidestepping a traditional utility's generation portfolio, CCAs and their customers can (in theory) purchase their electricity from less-polluting sources, including wind and solar farms.

The potential negative effects of load defection on incumbent utilities' financial standing have been noted previously (Gunther and Bernell 2019; O'Shaughnessy et al. 2019). However, no consideration has been given yet to the effects that defections can have on an electric utility's exposure to weather risk. Utilities participating in competitive markets for electricity generally have three main revenue sources: (1) a generation business that sells electricity produced from the utility's own power plants into a wholesale market; (2) a transmission business that charges grid participants for the use of utility-owned high-voltage transmission lines; and (3) a retail distribution business that purchases electricity from the wholesale market and sells this to end users (Bryant et al. 2018). If utilities' retail electricity businesses contract due to load defection, the relative importance of other revenues sources (i.e., transmission and/or wholesale generation) may increase. For some utilities, this could alter exposure to weather risk by strengthening or weakening the correlation between certain hydrometeorological variables and financial outcomes, and/or by increasing weather-caused financial variability as a proportion of a utility's overall revenues. Given the rapid rates at which load defection is occurring now at some utilities, significant changes in financial exposure to weather risk (and reductions in the effectiveness of current mitigation strategies employed by utilities, such as insurance and other financial derivative contracts) may occur in a matter of a few years (St. John 2017; Kennedy and Rosen 2021). This is in contrast to the projected impacts of climate change, which are expected to increase utilities' physical and financial exposure to weather phenomena over decades (Bain and Acker 2018; Bartos et al. 2016; Franco and Sanstad 2006; Kraft 2018; Mazdiyasni and AghaKouchak 2015; Nierop 2014; Sautter and Twaite 2009).

We performed a series of computational modeling experiments to better understand the effects of load defection on a major utility's financial exposure to weather risk. The broader value of this work is in showing how market risk and changing utility revenue structures can impact a utility's exposure to hydrometeorological uncertainty and extremes. Our results highlight new complexities involved in helping utilities to find the most effective ways to protect themselves and their customers against financial instability caused by weather risk.

Methods

Test Bed

We focused our analysis on Pacific Gas and Electric (PG&E), the largest power and transmission utility in California. PG&E participates in the deregulated wholesale market administered by the California Independent System Operator (CAISO), technically as three separate entities, all owned by the same holding company

1. A generation business that sells electricity produced from PG&E-owned power plants and electricity procured from other sources into CAISO's competitive wholesale electricity market. Generation sold in this manner is valued at a floating price determined by the interaction between supply and demand in the wholesale market.
2. A transmission business that delivers electricity to end users.
3. A retail business, which purchases electricity from the wholesale market (also at the wholesale price) and sells it to its own retail customers (Pacific Gas and Electric Company 2019).

Since 2014, PG&E has been experiencing retail load defection from customer uptake of rooftop solar and competition from CCAs (Gunther and Bernell 2019; Kennedy and Rosen 2021; O'Shaughnessy et al. 2019) (see Supplemental Materials), and it is projected that PG&E could lose over 80% of its retail load within 3–5 years (St. John 2017).

Weather risk already is a key concern in all three of PG&E's businesses. Air temperatures strongly influence demand for electricity in PG&E's footprint (see Supplemental Materials), which also drives demand for transmission services. In PG&E's wholesale generation business, its largest source of self-owned capacity is a fleet of hydroelectric dams located in California's Sierra Nevada Mountains. These dams provide operationally flexible and low-carbon generation; however, they are highly dependent on hydrologic conditions, with high or low snowpack years leading to more or less hydropower production, respectively. As PG&E's retail business shrinks, the relative importance of its transmission and wholesale generation businesses are expected to grow. There is particular interest in understanding how the utility's overall exposure to hydrometeorological conditions (including hydrologic extremes) could change—not due to changes in air temperatures and streamflow dynamics, per se (although this is likely to occur as well due to climate change), but rather due to an evolving marketplace.

Modeling Framework and Experimental Design

We used a system-based modeling approach to simulate CAISO market operations and the financial operations of PG&E's electricity businesses (wholesale generation, transmission, and retail distribution) (Fig. 1).

CAPOW Model

To simulate the CAISO wholesale electricity market, we used the California and West Coast Power system (CAPOW) model, which is an open-source stochastic simulation framework designed specifically for evaluating the effects of hydrometeorological variables on the US West Coast bulk power system. CAPOW is Python-based, and all source code and data are available freely online; the model was validated and applied in other studies (Su et al. 2020a; Kern et al. 2020; Su et al. 2020b). The geographical scope of the CAPOW model covers two wholesale power markets: CAISO, which extends over most of California, and the informal Mid-Columbia (Mid-C) power market, which covers much of the US Pacific Northwest. CAPOW has two core components: (1) a stochastic engine; and (2) a zonal unit commitment economic dispatch (UC/ED) model (Su et al. 2020a). The stochastic engine takes historical hydrometeorological time series from multiple sites and uses these data and a range of statistical and stochastic modeling approaches to generate an expanded synthetic data set of 1,000 random, single-year realizations. Historical data are from 17 major regional airports in the NOAA Global Historical Climatological Network (air temperature and wind speed data), 7 different National Solar Resource Database sites (irradiance), and 105 streamflow gauges throughout the West Coast. The stochastic engine produces synthetic time series that capture observed statistical

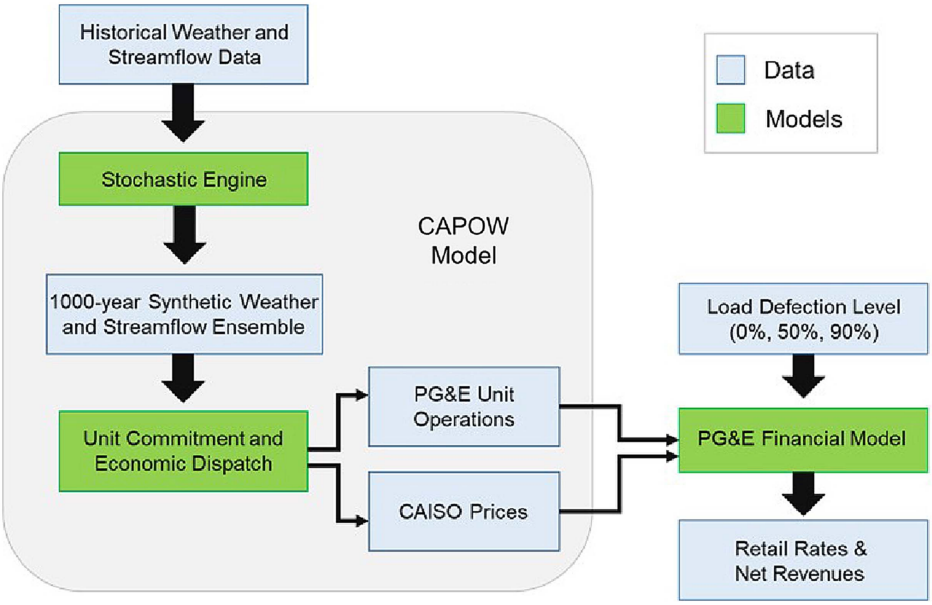

Fig. 1. Modeling framework including data inputs/outputs and models.

properties (moments, spatial, and temporal autocorrelation) across all variables, while also allowing for the occurrence of extremes outside the limited historical record.

Synthetic air temperature and wind speed data then are used to simulate daily peak and hourly electricity demand in the CAISO market (including the PG&E footprint) using multivariate regressions (see Supplemental Materials), along with a vector autoregressive model that captures spatial and temporal correlations in regression errors across demand sites. Similar methods are used to simulate wind and solar power generation on a zonal level at an hourly time step. Hydropower production is modeled using a combination of hydrologic mass balance models for dams in the Federal Columbia River Power System (Pacific Northwest); Willamette River basin (Oregon); and Sacramento, San Joaquin, and Tulare Lake basins (California). However, a large portion of the California dams do not have publicly available rule curves; thus, we used a differential evolutionary algorithm to search for best-fitting simple rule curves for those dams (Su et al. 2020a). Using these time-series inputs, CAPOW then simulates the hourly dispatch of every power plant in the system by minimizing the system-wide production cost associated with meeting hourly demand for electricity and operating reserves, subject to generator-specific and system-wide operating constraints. The UC/ED model is structured as an iterative mixed-integer linear program (MILP) with an operating (look-out) horizon of 48 h. Simulating the UC/ED component of the model generates hourly zonal electricity prices in dollars per megawatt-hour and hourly plant level generation amounts (megawatt-hours).

PG&E Financial Model

We coupled the CAPOW model with a financial operations model to simulate the PG&E's financial performance under hydrometeorological uncertainty. We ran CAPOW and then the PG&E financial model in a sequential fashion, first capturing the effects of weather and streamflow conditions on systemwide supply, demand, and wholesale prices in the CAISO market. CAPOW simulated the hourly dispatch of all generating units participating in CAISO, including those owned and contracted by PG&E. We then modeled PG&E's costs and revenues across the three core components of its business (wholesale generation, transmission, and retail distribution) using publicly available data from its annual financial reports (Pacific Gas and Electric Company 2017, 2019).

PG&E's wholesale generation business can be subdivided into (1) self-owned generation (i.e., electricity produced by power plants that PG&E owns); and (2) third-party contracts, e.g., long-term procurement of generation from assets owned by other entities, mostly in the form of power purchase agreements (PPAs) for renewable energy. Even if a majority (or all) of the generation produced by PG&E's generation assets (both self-owned and third-party contracts) ultimately is purchased by its retail distribution business, PG&E first sells generation from its power plants into the wholesale market, where it is valued at the floating market price.

PG&E's transmission revenues come from the distribution of electricity to its own retail customers as well as to CCA customers living within PG&E's geographical footprint. Each customer that receives electricity from a PG&E owned line is charged a flat rate of \$0.126/kWh for the use of PG&E's transmission infrastructure (see Supplemental Materials). PG&E's own customers pay for both electricity and transmission service, proportional to their own demand; CCA customers only pay for transmission service, also proportional to their own demand.

PG&E's retail distribution business earns revenue from the sale of electricity to customers across its four major customer classes (commercial, industrial, residential, and agricultural). Demand from each sector is disaggregated from total PG&E demand based on historical monthly demand fractions. In our model, we assume the most common seasonal rate structures for each customer class (see Supplemental Materials).

We also modeled the five main cost components of PG&E: (1) fuel costs from its generation assets; (2) payments to third-party generation contracts; (3) purchases from the wholesale market; (4) operation and maintenance costs (O&M); and (5) debt service and 10% return on equity for shareholders, assuming a depreciated asset base of \$30 billion (Pacific Gas and Electric Company 2019).

We focused on PG&E's net revenue as the primary financial performance metric. Net revenue is defined as the difference between annual revenues and costs (herein, costs included debt service and

return on equity for shareholders). Our aim was to identify how the statistical relationships between different hydrometeorological variables and PG&E's net revenues will change as their customer base declines. We focused on PG&E's exposure to uncertainty and extremes in air temperatures and streamflow, because previous research suggested that wind speeds and solar irradiance do not (yet) influence market prices on an annual scale at current installed wind and solar power levels (Su et al. 2020b). To achieve this, we simulated PG&E's operations under three different retail load scenarios: 2018 levels (assumed to be 0% load defection), 50% load defection, and 90% load defection. In our modeling, we assumed that load defection comes only from competition with CCAs, as opposed to customer-owned or -sited distributed energy resources (e.g., solar), so load defection did not reduce PG&E's transmission revenues. For each scenario, we evaluated PG&E's net revenues over 1,000 single-year hydrometeorological realizations.

Results and Discussion

Changes in Costs and Revenues

Fig. 2 breaks down PG&E's average cost and revenue structures under three different customer load levels: 2018 load levels (0% load defection), 50% load defection, and 90% load defection. The outer circles of the pie charts in Fig. 2 represent PG&E's revenue sources; the inner circles represent cost components. Figs. 2(d and e), which correspond to load defection levels of 50% and 90%, respectively, show how the contributing fraction of each revenue and cost component changes relative to the baseline. These pie charts assume that PG&E's retail rates stay the same (i.e., they are not increased by the utility to compensate for lower retail demand).

Our modeling results confirmed that load defection could cause significant changes in the composition of PG&E's cost and revenue structures. Retail revenues currently are PG&E's second largest source of revenue, after transmission revenue. When 90% of PG&E's customers leave the system, the utility's retail business becomes its smallest source of revenue. At the same time, load defection increases the relative importance of PG&E's wholesale generation and transmission businesses, even as revenues from wholesale generation and transmission stay roughly the same in an absolute sense (Fig. 3). Wholesale generation revenues are independent from load defection because the underlying generating assets owned by PG&E were assumed to remain the same (no retirements were considered). Transmission revenues, which are a function of electricity demand in the entire PG&E footprint (across all retail providers), likewise are not affected by load defection. This is tied somewhat to our assumption that competition from CCAs (and not distributed solar) is responsible for all load defection.

In terms of PG&E's cost structure, purchases from the wholesale market decrease as a function of load defection. This is true in both a relative (Fig. 2) and absolute sense (see Supplemental Materials). In fact, as PG&E's retail load decreases, the utility transitions from being (on average) a net buyer of electricity in the wholesale market to being a net seller (more frequently experiencing a surplus of wholesale generation from its self-owned and contracted resources).

As load defection increases, PG&E experiences an overall decline in revenue from about $16 billion at current load levels to $13 billion with 90% load defection (Fig. 3). In theory, PG&E aims to be net revenue neutral ($0 net revenue) after accounting for all costs and shareholder's return on equity (ROE). Losses of this

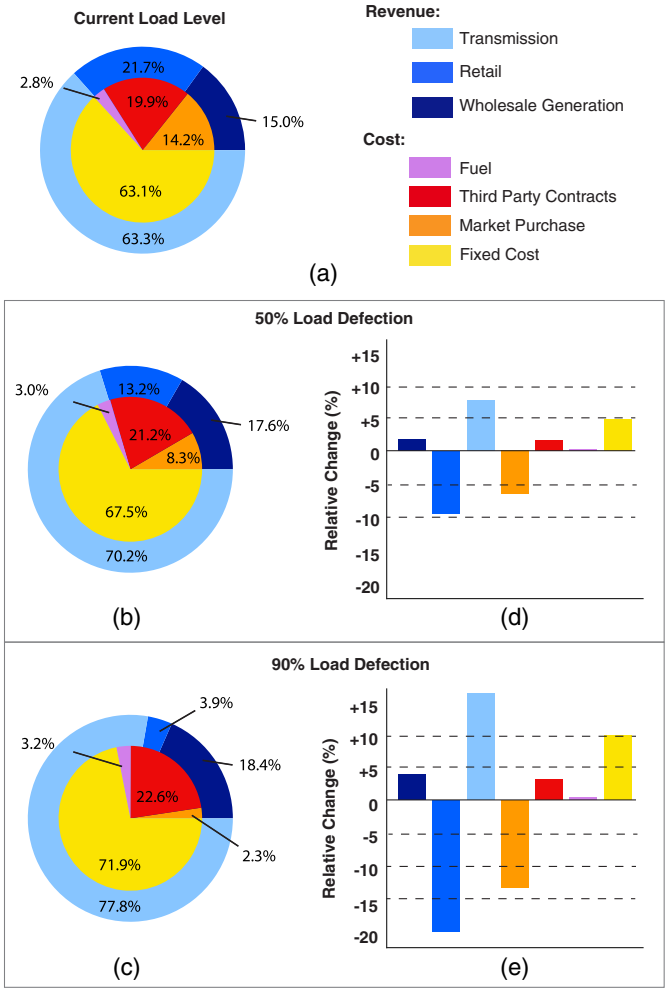

Fig. 2. (a) PG&E revenue and cost breakdown for current load levels; (b) PG&E revenue and cost breakdown for 50% load defection levels; (c) PG&E revenue and cost breakdown for 90% load defection levels; (d) relative change in PG&E revenues and costs at 50% load defection levels; and (e) relative change in PG&E revenues and costs at 90% load defection levels.

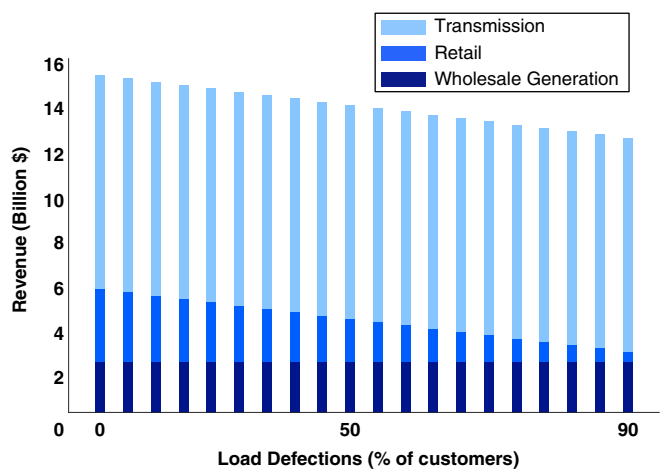

Fig. 3. Overall revenue decline experienced as load defection increases, driven primarily by falling retail revenues.

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magnitude likely would put considerable financial pressure on the utility to raise rates for customers, which is explored in the next section.

Increasing Rates and Increasing Uncertainty

Traditionally, regulated electric utilities (acting with approval from utility commissions) have been able increase electricity rates for customers to counter revenue deficits (California Public Utilities Commission 2020). However, it is not clear that this will be a viable strategy in the future if or when more and more customers defect from PG&E. At each level of load defection (and for each hydrometeorological year in the 1,000-year data set), we calculated the rate required to cover PG&E's annual operating costs, and defined this value as the net revenue neutral retail electricity rate.

The boxplots in Fig. 4 show distributions of PG&E's net revenue neutral electricity rates at increasing load defection levels across the 1,000 single-year hydrometeorological realizations. Interannual variability in the electricity rates PG&E must charge to be net revenue neutral (i.e., the range of the whiskers) is purely a function of uncertainty in weather summer air temperatures and streamflows, which directly influences CAISO market prices and PG&E's costs and revenues.

As load defection increases, PG&E's electricity rates need to increase dramatically to counter the associated decline in retail revenues. Our results indicate that at 90% load defection levels, customers remaining in PG&E's pool would need to pay average electricity rates of over \$210/MWh (i.e., \$0.21/kWh), which is 328% of the electricity rate [\$64/MWh (0.064/kWh)] under current load levels, to compensate for PG&E's reduced retail revenue. Adding associated transmission costs (\$0.127/kWh) would bring the overall retail rate for PG&E customers to about \$0.337/kWh. The increases in electricity rates in Fig. 4 can be viewed as one component of a potential utility death spiral (Castaneda et al. 2017; Laws et al. 2017), in which higher prices drive some consumers to choose cheaper options (e.g., CCAs and/or adopting distributed energy systems).

As PG&E's retail business shrinks, each remaining customer in PG&E's system needs to shoulder a greater share of the utility's operating costs. It also follows that customers remaining in PG&E's service also will absorb a greater share of year-to-year fluctuations

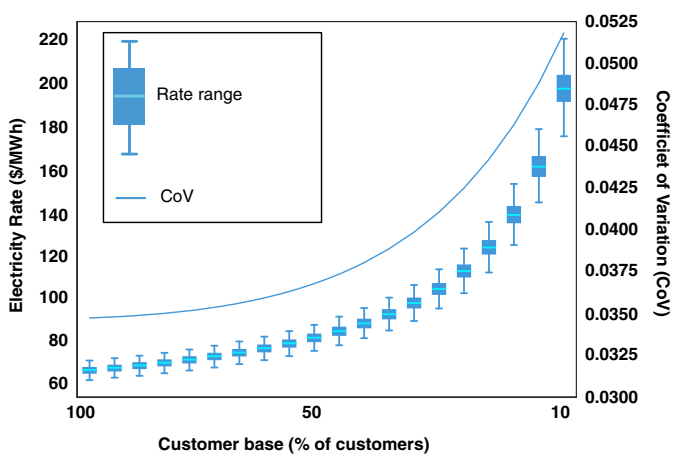

Fig. 4. Simulated rate change as customer base decreases. The rate needs to increase in an exponential way to counteract the decreased retail demand. The rate variation and coefficient of variance also will increase dramatically.

in costs caused by weather. Even without factoring in the effects of climate change, greater year-to-year swings in electricity prices caused by weather could be in store for customers that remain with PG&E (i.e., the range of the whiskers in Fig. 4 widens as load defection levels increase, and the coefficient of variation in net revenue neutral prices increases significantly). PG&E typically uses a regulatory balancing account (true-up fund) to help absorb normal fluctuations in revenues caused by weather variability. Although we did not account for this mechanism in this work, our results suggest that this fund could be under considerable pressure in the future, with larger year-to-year price fluctuations inevitable.

Net Revenue and Weather Variables

The following sections explore how load defection could alter PG&E's specific exposure to uncertainty in air temperatures and hydrologic conditions. First, in scenarios in which PG&E's retail load declines by 50% or 90%, we add a fixed fee for all retail and transmission customers to ensure that the utility's net revenue is \$0 on average across the 1,000 single-year hydrometeorological realizations. This setup approximates the exit fee that PG&E has been implementing for its departing load (Pacific Gas and Electric Company, n.d.-a). The fees we add guarantee PG&E's cost recovery in an average year (regardless of load defection level), but results in either positive or negative net revenues in all other years due to variability in weather.

Fig. 5 shows the relationship between annual average demand in the PG&E footprint (which is driven strongly by summer air temperatures) (x-axis) and annual net revenues for PG&E (y-axis) under the three different load defection levels considered [current (0%), 50%, and 90%]. Here, demand includes electricity consumed by CCA customers who are within the PG&E footprint, even though PG&E does not sell to those customers. At 0% load defection [Fig. 5(a)], net revenues are positively correlated with system demand, i.e., higher demand generally corresponds to higher net revenues, and lower demand corresponds to lower net revenues. However, as PG&E's retail customer base declines [Figs. 5(a–c)], the correlation between electricity demand and PG&E's net revenues becomes stronger (R^2 increases from 0.22 to 0.56).

Fig. 6(a) shows density plots of electricity demand under the three different load defection levels. These plots show data for the highest (95th percentile) net revenue years and the lowest (5th percentile) net revenue years from the 1,000-year ensemble. Increasing load defection causes years of extremely high or low net revenues to concentrate more in years of extremely high or low demand.

The reason for this gradual change is PG&E's shifting revenue and cost structure (Figs. 2 and 3). At higher levels of load defection, revenues from PG&E's wholesale generation and transmission businesses become more important, and transmission revenues become the utility's single largest revenue source. Both of these revenue streams benefit from higher overall demand in the CAISO system (i.e., years with hot summers), which leads to a greater volume of electricity being distributed on PG&E's transmission facilities and higher wholesale market prices for PG&E's power plants. However, despite the overall positive (and strengthening) relationship between annual demand and net revenues for PG&E, the very lowest net revenues persistently occur in years in which demand is moderate and wholesale prices are high [Figs. 5(a–c)]. These years, which are discussed next, are associated with drought and very low PG&E hydropower production.

Fig. 7 shows the relationship between PG&E hydropower production (x-axis) and modeled annual net revenue (y-axis) under the three different load levels considered (0%, 50%, and 90%). Under 0% defection, there is a strong positive correlation between

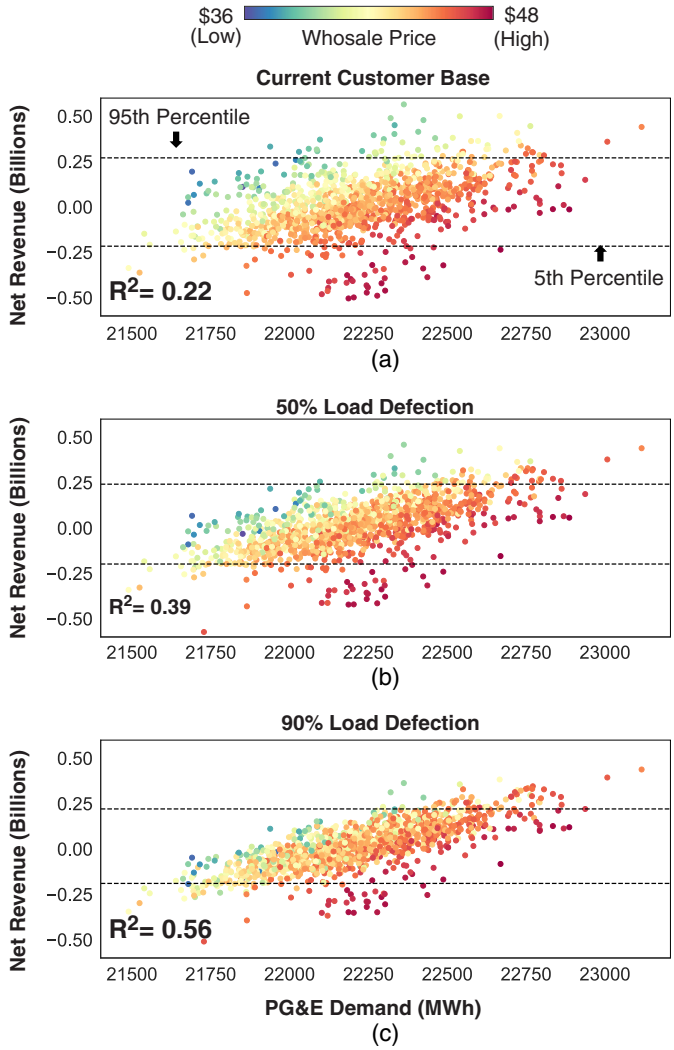

Fig. 5. PG&E net revenue versus PG&E demand and market prices at (a) current load levels; (b) 50% load defection levels; and (c) 90% load defection levels. The correlation between system demand and net revenue increases as customers leave the system.

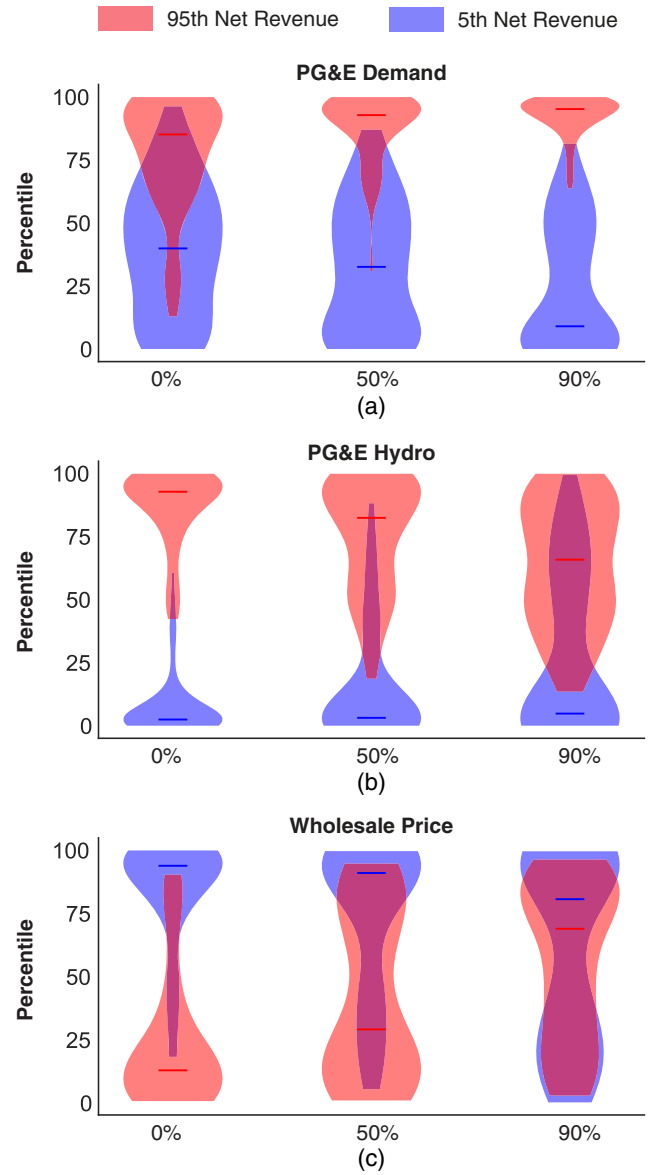

Fig. 6. Density plots of electricity demand, hydropower production and wholesale electricity prices for extreme net revenue simulations (5th and 95th percentile) under (a) current load levels; (b) 50% load defection levels; and (c) 90% load defection levels.

hydropower output at PG&E's dams and the company's net revenue, with wet years being the most profitable [a similar conclusion can be drawn from Fig. 6(b)].

There are two reasons for this relationship. First, wet years result in greater production from PG&E's hydroelectric facilities, leading to higher revenues for its wholesale generation business. Second, wet years in California tend to experience lower wholesale electricity prices, due to a greater abundance of low marginal cost hydropower in the market. With its current (2018) customer base, PG&E usually is a net buyer of electricity from the wholesale market, and lower prices during wet years make it less expensive for the utility to meet its demand, increasing net revenues.

However, the positive linear relationship between annual PG&E hydropower production and net revenues begins to break down as customers defect [Figs. 7(b and c)], with R^2 decreasing from 0.48 to 0.09. Although PG&E remains exposed financially to very dry years, extremely high and low (95th and 5th percentiles) net revenue years become associated with a much wider range of hydrologic conditions [see also Fig. 6(b)]. At higher load defection levels, the company becomes a net seller into the CAISO market, and extremely wet years (which historically were a boon to PG&E and its fleet of hydroelectric dams) actually start to appear in the lower 5th percentile of net revenue outcomes. These years generally are cooler years, as well, experiencing a combination of low demand (transmission revenues) and very low market prices that pose a liability for PG&E's wholesale generation business, which (without retail customers) is forced to sell renewable energy procured through expensive long-term PPAs into the wholesale market at a considerable loss. Related to this, as PG&E experiences more load defection and transitions to a being a net seller in CAISO, their exposure to wholesale prices changes dramatically—somewhat reversing, with low price years posing increasing risks and higher prices becoming less problematic [Fig. 6(c)].

Conclusion

Year-to-year fluctuations in streamflow and air temperatures are known to impact the operations of electricity markets like CAISO

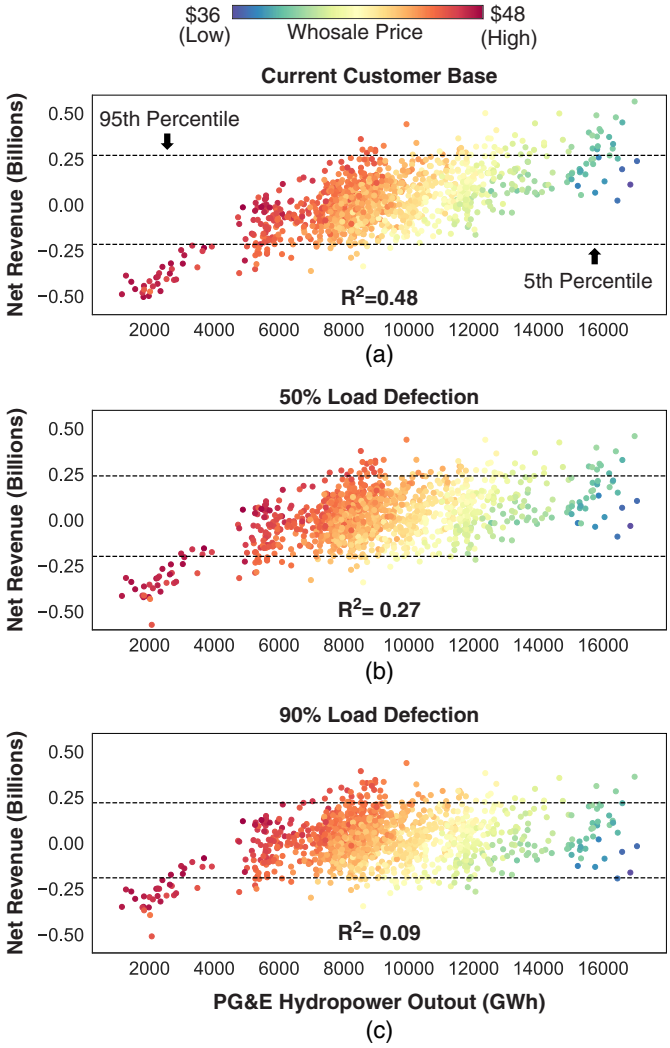

Fig. 7. PG&E net revenue versus PG&E hydropower production and market prices at (a) current load levels; (b) 50% load defection levels; and (c) 90% load defection levels. The correlation between hydropower production and net revenues weakens as customers leave the system. PG&E becomes financially exposed to extreme wet years at 90% load defection levels.

and the financial outcomes of electricity utilities participating in those markets. Here, for the first time, we demonstrated that for one major utility, exposure to weather risk and extremes may change in a matter of years—not due to the effects of climate change, but due to retail load defection. Customer losses for incumbent utilities could disrupt their traditional revenue and cost structures, altering the very nature of a utility's risk profile, including their exposure to weather.

This study used PG&E as a case study to demonstrate how its financial well-being is subject to uncertainty in two hydrometeorological variables: air temperatures, which directly influence demand for PG&E's electricity and transmission services, especially during summer; and streamflow, which controls the availability of hydropower production at PG&E dams. In addition, both variables significantly influence wholesale prices in the CAISO market. We demonstrated how PG&E's exposure to uncertainty and extremes in each variable is likely to change as a function of retail load defection. Net revenue will exhibit a stronger positive correlation with demand (air temperatures), due to the growing importance of transmission service revenues to PG&E's overall business. PG&E will remain exposed to low net revenues during dry years when its hydropower dams are less productive; however, extremely wet years, which historically have been associated with high net revenue years for PG&E, also could become financially harmful. These very wet years are associated with lower wholesale prices in the CAISO market, which begin to hurt PG&E as retail load defection causes it to switch from being a net buyer to a net seller in CAISO.

There are a number of limitations to this work, including a lack of information about the exact structure of PG&E's active PPAs. In addition, we used a simplistic representation of PG&E's financial operations, including a single rate structure for each customer class. We also assumed that PG&E's fixed costs (O&M, debt service, and so forth) are static, when in fact some year-to-year changes do occur (and may change in the future as load defection increases). Lastly, we assumed that all load defection is caused by the formation of CCAs, as opposed to customer uptake of distributed energy resources [although this assumption largely is consistent with historical data which suggests that 4/5 of PG&E's lost load in recent years was due to CCAs (see Supplemental Materials)]. However, the impacts of customers switching to distributed energy resources could be much different from load defect toward CCAs. In the latter case, CCA customers still pay for transmission services from PG&E.

Nonetheless, the results of this work strongly suggest that there is an important connection between utilities experiencing load defection and altered exposure to weather risk. This phenomenon could put additional pressure on utilities to rapidly adjust their current weather risk management strategies. For PG&E in particular, this may represent an important challenge given its recent bankruptcy and precarious financial state (Pacific Gas and Electric Company, n.d.-b). Although this work used PG&E as a case study, other utilities that face load defection in the future may experience similarly large alterations in their weather risk exposure, depending on their underlying generation portfolio, reliance on third-party contracts, and the underlying causes of load defection.

Data Availability Statement

All data, models, or code that support the findings of this study are available from the corresponding author upon reasonable request.

Supplemental Materials

Figs. S1–S5 and Tables S1 and S2 are available online in the ASCE Library (www.ascelibrary.org).

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