BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES IN IDAHO AND APPROVAL OF PROPOSED ELECTRIC SERVICE SCHEDULES AND REGULATIONS	)))))))	CASE NO. PAC-E-24-04 DIRECT TESTIMONY OF FRANK GRAVES

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-24-04

May 2024

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is Frank Graves. I am a Principal at The Brattle Group, located in our headquarters office at One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this direct testimony before the Idaho Public Utilities Commission ("Commission") on behalf of PacifiCorp d/b/a/ Rocky Mountain Power (the "Company").

Q. Please describe your education and professional experience.

A. For most of my career spanning over 30 years as a consultant, I have worked in regulatory and financial economics, especially regarding long-range planning for electric and gas utilities, and in litigation matters related to securities litigation and risk management. My education includes an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

In regard to forecasting and mitigating utility risks, which are central matters in this case, I have extensive experience in all aspects of utility system planning, regulatory policy and market modeling, financial and ratemaking practices, and formal risk management techniques. Recently, I have focused on evaluating pathways to deep decarbonization of the energy sector, including the impacts of much greater reliance on renewable generation and distributed energy resources. I have developed, evaluated, or used many power system production and resource planning models as well as utility financial projections for revenue requirements and alternative rate design purposes, and I have evaluated financial risk and cost of capital in a wide variety of settings for energy infrastructure and utility investments. I have given expert testimony on financial and regulatory issues before the Federal Energy Regulatory Commission ("FERC"), many state regulatory commissions, and state and federal courts. My background and qualifications are described in greater detail in the résumé attached as Exhibit No. 18.

I am also sponsoring the following exhibits:

Exhibit No. 18—Résumé of Frank Graves

Exhibit No. 19—Area Burned from Human Caused Wildfires in the West

Exhibit No. 20—Costs of +$1 Billion Wildfires in the United States

Exhibit No. 21—Recent Costs of Wildfire Insurance Faced by Regional Utilities

Exhibit No. 22—Recent Wildfire Insurance Cost Recovery Settlements Achieved by Regional Utilities

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified many times before other public utility commissions in approximately 35 states as well as before the FERC. Though not in Idaho, on several occasions I have previously testified on behalf of Rocky Mountain Power regarding fuel forecasting, procurement and hedging, incentives, and cost recovery mechanisms.[1] More generally, I have participated in many rate cases, prudence hearings, regulatory policy forums and sometimes litigation on industry transitions and new issues on such matters as power industry restructuring via vertical unbundling, retail competition and Provider of Last Resort service design, natural gas hedging practices, extreme (cold) weather preparedness, and the associated utility investment and business practices.

II. PURPOSE OF TESTIMONY AND SUMMARY CONCLUSIONS

Q. What is the purpose of your direct testimony in this case?

A. The purpose of my testimony is to provide context for the need and appropriateness of current PacifiCorp initiatives to manage the growing risk of financial exposure to wildfire-related liabilities as described in

[1] *See* e.g., Docket No. 11-035-200 in Utah, Docket No. 20000-405-ER-11 in Wyoming.

the testimony of Company witness Joelle R. Steward. These initiatives include the following regulatory approaches:

- An Insurance Cost Adjustment that will recover the volatile and rapidly increasing annual costs of insurance for excess liability (from wildfire damages to third party properties and well-being), and
- A new Insurance Mechanism allowing PacifiCorp to insure against non-catastrophic levels of third-party wildfire liabilities using the most economical combination of commercial insurance and self-insurance, to the extent commercial insurance is available.
- A Catastrophic Fire Fund that will involve creation of a multi-state risk pool for rare but potentially catastrophic fire events where third-party liabilities could be well in excess of the Company's coverages for more ordinary levels of risk. This "tail risk" coverage is necessary to preempt extreme financial distress that could otherwise threaten the viability or quality of ongoing utility service.

Toward this objective, I review metrics indicating the scope of increased wildfire risk affecting the Western United States ("U.S."), the resulting financial exposure faced by regional electric utilities, the experience of those utilities in managing that financial exposure, and related implications for PacifiCorp's proposed remedies.

Q. Please summarize the principal conclusions of your direct testimony.

A. I find that the structure and evolving terms of PacifiCorp's proposed remedies to growing wildfire exposure are reasonable based on strong and readily observable growing trends and threats of wildfires and the resulting financial exposure. This risk coincides with increasing limitations (high cost, limited availability) of traditional risk management tools to address such large exposures, and the resulting development of new precedents for coping with this problem that have been established in other jurisdictions, particularly California.

More specifically, this conclusion is premised on the following:

- PacifiCorp is facing an exogenous, largely climate-induced fire-risk phenomenon. Growing wildfire risk is similarly afflicting many other electric utilities and society at large.
- With wildfire risks mounting, the demand for wildfire insurance has been expanding at the same time as the supply of insurers willing or able to bear wildfire risk (and catastrophic climate-event

risk generally) is contracting or being exhausted. Unsurprisingly, the current supply/demand imbalance is resulting in much higher costs per dollar of coverage. Company witness Mariya V. Coleman discusses the challenges of procuring excess liability insurance for the 2024-2025 policy year.

- Electric utilities in the western U.S. have both (i) faced dramatic increases in the levels and unpredictability of wildfire insurance costs, and (ii) crafted workable solutions for those costs in recent rate-case proceedings. These solutions appropriately recognize wildfire insurance as a legitimate cost of service and form useful precedents for PacifiCorp's recovery of such costs.
- As a separate matter, to the degree commercial insurance markets may become dysfunctional—e.g., if insurance premia offered to PacifiCorp rise to levels in excess of statistically expected losses, or if the availability of such insurance should simply dry up to where it is not possible to obtain sufficient incremental coverage—it may make sense to replace or supplement commercial insurance with self-insurance (which formed the basis for recent settlements in California). PacifiCorp is thus

developing a proposal for contingent authorization to substitute self-insurance for commercial insurance.

- Importantly, even with any level of available commercial insurance (or self-insurance in substitution thereof), PacifiCorp still faces the risk of rare but catastrophic exposure to unprecedented levels of extreme wildfire loss claims that I understand may be uninsurable at any cost in commercial markets. Such worst-case events could be crippling to PacifiCorp’s financial stability and potentially disruptive to normal utility operations. PacifiCorp is therefore additionally proposing a Catastrophic Fire Fund—above and beyond customary coverage—to absorb such extreme losses. (The precise boundary of where to begin such coverage, and how far to extend it into the highest-cost conceivable outcomes, has not been determined, but is a topic in ongoing workshops. Here the purpose is to gain recognition of this need and to create a structure for eventually dealing with it.) Like all insurance, this extreme-event protection is desirable because it provides liquidity for responding to such events, and because it distributes the costs of their possible occurrence more smoothly and broadly over time and geography, i.e. diversifying risk.

- Subject to compliance with reasonable mitigation standards, extreme wildfire loss claims (if they occur) should be viewed as costs of utility service recoverable from customers (just as insurance premia normally are). This is because such losses are an unavoidable residual risk that cannot be fully eliminated under any rational level of prior insurance and any associated utility management practices for mitigating such risks over time, for several reasons: It is unrealistic to expect that PacifiCorp (or any other utility) could fully avoid extreme wildfire losses through physical mitigation alone, which is limited by the extreme difficulties of anticipating extreme weather, vast geography, the time required to develop mitigation systems, finite capital resources (and related concerns about customer bill impacts from extreme mitigation efforts), and diminishing marginal returns to wildfire mitigation investment. Put another way, mitigation can reduce but not eliminate the likelihood of fire events, while external circumstances largely determine the resulting damage from them.

- Customers and regulators themselves will also recognize these factors in resisting large upfront costs for wildfire mitigation or very extreme contingency insurance. Wildfire insurance and prevention efforts must be integrated and balanced with all the other objectives and constraints of providing reliable utility services at reasonable rates. Thus, some form of agreed, socialized cost recovery for these adverse possible situations should be developed before they arise.

Importantly at this time, PacifiCorp is working with fire liability risk assessment and insurance professionals to update and extend its understanding of the magnitude of possible wildfire liability risk that could affect its service territories.

III. REGIONAL WILDFIRE RISK AND COST ARE GROWING

Q. Please describe the landscape of wildfire occurrence in the West and beyond in recent years.

A. Wildfire risk is a growing and menacing global phenomenon, which has had a material adverse impact on diverse businesses and individuals far beyond Idaho in recent years and months. Major wildfire risk zones have been identified in geographies as diverse as Europe, Australia, Canada, South America, and the Western U.S.[2] In North America, wildfire risk has become a chronic issue, i.e., more frequent, larger, and more consequential (similar to other climate-driven natural disasters in the rest of the U.S. and around the world). For example, recent analysis of human-caused wildfires in the West by the National Interagency Fire Center shows an approximately four-fold increase from 2001 to 2023 in acres burned annually (see also Exhibit No. 19).[3] Across the western states experiencing this trend, most major events have been centered around California, but large human-caused fires have also occurred in the Pacific Northwest and Idaho (i.e. the 2022 Moose Fire outside Salmon).

In response to the increase of wildfire events in the West and other climate change related events throughout the country, utilities have experienced credit rating consequences. Specifically, investor-owned utilities and publicly owned utilities in California and Hawaii have experienced actual downgrades due to wildfire risk, while utilities that operate in

[2] https://www.marshmclennan.com/insights/publications/2019/oct/wildfire-paper--oct--2019-.html.

[3] National Interagency Fire Center, "Wildfires and Acres," May 24, 2024, https://www.nifc.gov/fire-information/statistics/human-caused. The west includes the Northwest, California, Northern Rockies, Great Basin, and Southwest regions.

Colorado, Idaho, Oregon, Washington, and Utah have been issued negative rating outlooks.[4]

Q. How has this increase been correlated with the growth in other extreme weather events?

A. The increasing frequency and severity of wildfires has occurred in parallel with climate change generally, as well as other climate-related natural disasters such as floods, hurricanes, and severe cold-weather storms. It is intuitive that wildfire risk can be both widespread and increasingly severe and damaging, since it is largely a function of the effects of climate change interacting with residential and commercial growth in locations already prone to ignition (the so-called wildland-urban interface, or WUI). Conditions such as high temperatures and low precipitation have been linked to extended fire seasons, exacerbating weather conditions such as high winds, and near inability to predict the behavior of individual fires.[5] The growth in the overall burden of extreme weather events makes insuring any of them more difficult.

Q. What about the cost impact of wildfires?

A. The cost impact of wildfires has grown with the frequency

[4] S&P Global Ratings, *A Storm is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality* (Nov. 9, 2023).

[5] Next-Generation Fire and Vegetation Modeling for a Hot and Dry Future, Federation of American Scientists, June 20, 2023.

and scope of physical impacts. Globally, the reported annual economic losses from wildfires have more than doubled since 2015 relative to the prior 15 years.[6] This step-change is even more pronounced for the U.S., where, comparing the same time period, economic losses have increased five-fold, and in some years amounted to many tens of billions of dollars (see Exhibit No. 20).[7]

Q. How have affected utilities insured against this risk?

A. Utilities have customarily obtained commercial insurance to cover multiple types of extreme event liabilities that can cause third-party damages and injury, including wildfires, on a bundled basis. In limited instances, utilities have augmented commercial insurance with capital market instruments to cover highly specified risks such as wildfires in the form of so-called "Catastrophe Bonds." More recently, as further described below, utilities in California have turned to self-insurance specifically for wildfires.

Q. How has the growth in extreme events affected the availability of commercial insurance?

A. Risks stemming from both climate change generally and wildfires specifically have contributed to a tightening

[6] Aon, 2023 Weather, Climate and Catastrophe Insight.
[7] National Oceanic and Atmospheric Administration - National Centers for Environmental Information U.S. Billion-Dollar Weather and Climate Disasters (2023), https://www.ncei.noaa.gov/access/billions/state-summary/US.

of coverage availability provided by the commercial insurance industry. The industry has noted that "many risk buyers [seeking insurance coverage] are challenged to find adequate coverage for their natural catastrophe-prone exposures."[8] In response to significant and severe losses and "limitations" in effectively modeling future catastrophes (which are statistically difficult to characterize, because they are both rare and extreme), many insurance providers have chosen to "de-risk or withdraw" from offering certain coverages.[9] Others are hitting financial limits on their ability to diversify or fund their own coverage offerings, so prices can skyrocket. The problem appears to be anxiety over the rising frequency and costs of fire events and the correlated problems with other climate-related risks.[10]

[8] Aon, *Climate and Catastrophe Insight,* at 29 (2024).

[9] Howden, *The Great Realignment* at 14 (2023), accessed at https://www.howdengroup.com/sites/g/files/mwfley566/files/2023-01/the-great-realignment-report-2023.pdf. *See also*, p. 11: "Persistent and elevated catastrophe losses, along with the attendant issue of catastrophe model efficacy, continued to drive sentiment in property lines amidst concerns that changing weather patterns are increasing both the frequency and severity of climate-sensitive perils. Higher retentions, tighter terms and reduced frequency coverage (i.e. aggregates, lower excess-of-loss layers, quota shares) reflected reinsurers' resolve to focus more on capital protection after six consecutive years of above-average catastrophe losses."

[10] *See*, Claire Wilkinson, *Utilities contractors challenged in finding wildfire coverage,* Business Insurance, accessed at https://www.businessinsurance.com/article/20210525/NEWS06/912342050/Utilities-contractors-challenged-in-finding-wildfire-coverage: "The lack of interest from the marketplace to cover wildfire risks, in general, has 'spread like a wildfire' beyond California and throughout the country…".

Q. Have these climate change and wildfire risks affected the availability of commercial insurance for electric utilities, including for PacifiCorp?

A. Yes. PacifiCorp has encountered recent difficulty in obtaining wildfire liability insurance. As explained by Company witness Coleman, insurers who historically would consider selling wildfire liability will no longer do so.

This experience is hardly unique to PacifiCorp or other Berkshire Hathaway Energy entities. In the course of its 2023 general rate case ("GRC") process, Pacific Gas & Electric Company ("PG&E") reported that "there has been a significant decrease in the number of insurers offering wildfire coverage to California [investor owned utilities ("IOUs")]."[11] This situation has led to PG&E receiving anemic insurance company responses to recent wildfire insurance solicitations, reporting only 16 offers to 73 inquiries in 2021.[12] The trend was observed as early as 2017, when Southern California Edison ("SCE") was already noting a "diminishing general liability and wildfire insurance market in California

[11] *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service on January 1, 2023*, Application (A.) 21-06-021, Exhibit 9, Chapter 3 at 3-23.

[12] *Id.*, p. 3-26.

for investor-owned utilities, to the extent even available."[13]

Q. How has increased wildfire risk affected the cost of commercial insurance?

A. Increased wildfire risk has led to sharp increases in the cost of wildfire liability insurance for utilities. Company witnesses Coleman and Steward address the cost increases experienced by PacifiCorp. This reflects both the increasing burden on the insurance industry from rising claims and the much more difficult risk estimation that has accompanied the global warming aspects of the problem. For instance, the current wildfire operational models are deemed "incapable" of simulating and accounting for the "substantial ecosystem changes that are occurring from climate change."[14] This is occurring because there are too many factors changing rapidly (e.g. soil dryness, number of extremely high temperature days, unusually concentrated rainfall, disease or pest infestation in plants and trees, etc.)

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[13] Letter from Russell G. Worden to Timothy J. Sullivan, "Letter of notification establishing a Z-Factor for costs associated with incremental wildfire-related liability insurance," at 2-3 (Dec. 29, 2017).

[14] Matthew Hurteau, *Next-Generation Fire and Vegetation Modeling for a Hot and Dry Future*, Federation of American Scientists (June 20, 2023), accessed at https://fas.org/publication/next-generation-fire-and-vegetation-modeling-for-a-hot-and-dry-future/.

for which history does not provide sufficient evidence of their consequences or interactions.[15]

While frequently not made public, some wildfire insurance costs and coverage levels have been made available in financial and regulatory filings by the California IOUs. More limited insurance data has been provided by other utilities in the west, such as Avista Corporation ("Avista") and Idaho Power Company ("Idaho Power") in the course of their regulatory filings. Such insurance cost data is summarized in Exhibit No. 21[16] and placed in context relative to insurance coverage levels (where available) and operating and maintenance ("O&M") expense.[17]

- *PG&E* – PG&E has experienced the sharpest cost increases, with wildfire liability insurance costs growing by approximately a factor of ten since 2017 in both absolute terms and costs per dollar of coverage.[18] For the period 2022-2023, PG&E's wildfire liability insurance expense stood at $745 million, for coverage of $940 million.[19] Thus, for that period, PG&E was paying an effective wildfire

[15] *Id.*
[16] Note that regulatory orders approving the recovery of self-insurance costs are summarized below in Section V(A).
[17] Specifically, O&M costs omitting fuel and purchased power.
[18] A. 21-06-021, California Public Utilities Commission ("CPUC") Decision ("D.") 23-01-005 at Table 2 (Jan. 17, 2023) (the "PG&E Decision").
[19] *Id.*

liability insurance premium of 79 percent of the coverage! PG&E’s wildfire liability insurance expense for 2022-2023 comprised approximately eight percent of its total O&M expense for calendar 2022, versus approximately only 1 percent in 2017.[20] (This highlights not just the need for new insurance mechanisms, but the need for their costs to be efficiently recovered in cost of service rates.)

PG&E noted in its 2023 GRC application that “the difficulty of managing the company’s risks through the commercial insurance market alone continues to be extremely challenging as does the prospect of accurately forecasting the costs to do so.”[21] Among other things, the new market conditions mean that “PG&E now procures most of its wildfire coverage separately from coverage for other perils, essentially creating two different insurance towers—one for wildfire and one for non-wildfire.”[22]

- *SCE* — SCE has experienced similar, if less extreme, increases in wildfire insurance costs, with costs per dollar of coverage doubling since 2018, to

[20] By comparison, PG&E’s wildfire liability insurance expense for 2022-2023 formed a significantly larger share—approximately 30%--of the company’s authorized return on equity.
[21] A.21-06-021, Application, Exhibit 9, Chapter 3 at 3-24.
[22] *Id.*, at 3-23.

43 percent for the 2022-2023 period.[23] SCE's wildfire liability insurance expense stepped up from nine percent of O&M in 2018 to nearly 13 percent on average for 2019-2021.

In SCE's 2021 GRC request, SCE recognized that its wildfire liability insurance expense forecast of $624 million was "significantly higher than previous years, but that is not unexpected given the dramatically increased risks faced by electric utilities from wildfires, and the insurance industry's willingness to insure against those risks."[24] SCE observed further that these wildfire insurance market conditions were "well known to and [had] been frequently and explicitly recognized by the Commission."[25] SCE additionally noted that "in the current insurance environment, it is impossible to forecast wildfire liability insurance premiums precisely."[26]

- *San Diego Gas & Electric ("SDG&E")* – SDG&E's wildfire liability insurance costs nearly tripled in absolute terms from the 2016-2017 period to

[23] Edison International Form 10-K.
[24] *Application of Southern California Edison Company for Authority to Increase its Authorized Revenues for Electric Service in 2021, Among Other Things, and to Reflect that Increase in Rates*, A.19-08-013, Opening Brief of Southern California Edison Company at 238 (Sept. 11, 2020).
[25] *Id.*
[26] *Id.*, at 247.

2022-2023, when they stood at $221 million.[27] Assuming that (as reported in SDG&E's 2020 cost of capital proceeding[28]) SDG&E has maintained coverage levels of approximately $1.5 billion, this represents an effective average wildfire insurance premium of 15 percent ($221mm/$1.5b) for 2022-2023. As a percentage of O&M costs, SDG&E's wildfire liability insurance costs grew from approximately eight percent in 2016 to 14 percent on average for 2019-2022.[29]

In its 2024 GRC application, SDG&E noted that "[i]nsurance market uncertainty continues because of wildfire risk, inverse condemnation, and global catastrophe losses. Because of this uncertainty and continued volatility in the cost of liability insurance, SoCalGas and SDG&E request that the

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[27] *Application of San Diego Gas & Electric Company for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2024,* A.22-05-016, SDG&E Prepared Direct Testimony of Dennis J. Gaughan (Corporate Center - Insurance), Table DG-18 (years 2021 and 2022 are forecasts) (May 2022).

[28] *Application of San Diego Gas & Electric Company,* A.19-04-017, Exhibit No. SDG&E-05, Prepared Direct Testimony of John J. Reed and James M. Coyne at 34 (Apr. 2019).

[29] Importantly, the cost of insurance per dollar of coverage depends critically on where the insurance is positioned in the stack of claims to cover liabilities. The first layers to be drawn upon have a much higher unit cost because they are statistically more exposed to the risks than residual claims after these funds have been exhausted. Thus SDGE's average could be well below its costs to specific risk tranches on the margin.

Commission reauthorize their [balancing accounts] for liability insurance premiums."[30]

- *Avista* — Avista reported a doubling in general liability insurance expense between 2020 and 2022, when costs reached $14 million.[31] This represented a near doubling in insurance expense as a percentage of O&M —from 1.8 percent to 3.3 percent— over the same period. Avista identified these cost increases as "largely related to wildfire exposure in the industry at large, and especially in the West."[32] Avista further characterized the costs as "undoubtedly 'extraordinary' and volatile" relative to past years, and "beyond the Company's control, notwithstanding our best efforts under the Wildfire Resiliency Plan."[33]

- *Idaho Power* — Idaho Power reported a 64 percent increase in Excess Liability insurance expense between 2020 and 2022, when costs exceeded $14 million.[34] This represented a 46 percent

[30] A.22-05-016, SDG&E Prepared Direct Testimony of Dennis J. Gaughan (Corporate Center - Insurance) at DJG-24 (May 2022).
[31] *Avista Corporation v. WUTC,* Washington Utilities and Transportation Commission ("WUTC"), Docket Nos. UE-220053, UG-220054, UE-210854, Rebuttal Testimony of Elizabeth M. Andrews, Table 7 (August 19, 2022).
[32] *Avista Corporation v. WUTC,* WUTC Docket Nos. UE-220053, UG-220054, UE-210854, Direct Testimony of Elizabeth M. Andrews, p. 70 (Jan. 25, 2022).
[33] *Id.,* p. 68.
[34] *In the Matter of the Application of Idaho Power for an Accounting Order Authorizing the Deferral of Incremental Wildfire Mitigation and Insurance Costs,* Case No. IPC-E-21-02, filed Jan. 22, 2021; *In the Matter of the*

increase in insurance expense as a percentage of O&M expense—from 2.3 percent to 3.3 percent—over the same period. Idaho Power has attributed these costs "to the frequency and magnitude of Western-state wildfires in recent years, as well as Idaho Power's specific wildfire risk."[35] Like other utilities, Idaho Power is a "price taker" when it comes to buying insurance. The Company notes that "[i]n that regard, despite annual assessment of its insurance portfolio to identify the best value and the retention of an experienced insurance broker, the Company is subject to price increases as insurers raise premiums due to losses, either pertaining to Idaho Power or to insurers' overall insured base."[36]

Q. How have increased wildfire risks otherwise affected electric utilities?

A. Perhaps inevitably, the interactions of wildfires and utility equipment have led to claims and court rulings against utilities. This has been exacerbated in

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Application of Idaho Power for Authority to Increase its Rates and Charges for Electric Service in the State of Idaho and for Associated Regulatory Account Treatment, Case No. IPC-E-23-11, Motion for Approval of Stipulation and Settlement, October 2023.

[35] *Application of Idaho Power for an Accounting Order Authorizing the Deferral of Incremental Wildfire Mitigation and Insurance Costs Before the Idaho Public Utilities Commission,* Case No. IPC-E-21-02, Application at 26 (Jan. 2021).

[36] Case No. IPC-E-23-1, Direct Testimony of Brian R. Buckham at 34 (June 2023).

California by the doctrine of “inverse condemnation”—under which I understand utilities automatically bear responsibility for wildfire damage claims involving their equipment or operations as a legal matter, regardless of negligence, mitigation practices, or foreseeability. This policy does not apply in other states, but legal decisions upholding wildfire liability claims against utilities in other states with only modest linkages to utility practices may have a similar effect.

Wildfire claims have aggregated in the tens of billions of dollars for the California IOUs (PG&E, SCE, and SDG&E), and, more recently, as much as $2.4 billion in probable losses accrued by PacifiCorp as of September 30, 2023.[37] Famously, the problems facing PG&E culminated in it declaring bankruptcy to restructure its liabilities and financing.

Q. Have there been adverse reactions from the credit rating agencies?

A. Yes. Credit rating agencies have been concerned with the risks of wildfires on utility credit profiles. As specifically discussed by Company witness Steward, the risk of wildfire liabilities was a cause for Standard & Poor’s (“S&P”) and Moody’s Investor Service (“Moody’s”)

[37] PacifiCorp Form 10-Q for period ending September 30, 2023, at 23.

to downgrade PacifiCorp's senior unsecured issuer rating during 2023. S&P downgraded PacifiCorp to BBB+ in June 2023, stating their belief that "the operating risks for PacifiCorp have significantly increased."[38] Moody's downgraded PacifiCorp to Baa1 in November 2023 and stated that "wildfire risk, a form of physical climate risk, was a key driver of the downgrade."[39]

These risks have affected credit profiles for electric utilities across the industry. As recently noted by S&P, "[d]amages and related costs from physical risks are escalating in North America as regions designated as high-fire risk expand."[40] Furthermore, S&P "has downgraded more [Investor-Owned Utilities] due to physical events (e.g. hurricanes, storms, and wildfires) over the past six years by nearly 10 times compared with the previous 13 years."[41]

IV. WILDFIRE MITIGATION CANNOT FEASIBLY ELIMINATE ALL RISK

Q. What are utilities currently doing to mitigate wildfire risk?

A. Some utilities in the West are re-evaluating their fire mitigation, risk management funding and protocols, and

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[38] S&P Global, *PacifiCorp Downgraded to 'BBB+', Outlook Revised to Negative; Berkshire Hathaway Energy Co. Outlook Also Negative* (June 20, 2023). S&P assessed PacifiCorp's "stand-alone credit profile" at BB+.
[39] Moody's Investor Service, *Rating Action: Moody's downgrades PacifiCorp to Baa1, outlook stable* (Nov. 21, 2023).
[40] S&P Global, *A Storm Is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality* (Nov. 9, 2023).
[41] *Id.*

cost recovery mechanisms to be more proactive for this kind of problem, including:

- Compiling better statistics on apparent risk over long periods of time (even if very difficult to do with any precision), which allows them to at least evaluate what the price of risk is in offered insurance compared to their estimated loss exposure.[42]
- Formulating *ex ante* risk mitigation plans subject to agreement with regulators and intervenors that those plans are aggressive enough (spend enough but not too much money) and are prioritized for most likely effectiveness—with the intent that compliance with these plans will inoculate the utility against findings of imprudence and loss of cost recovery if/when disasters occur despite mitigation efforts.[43]

[42] For example, California utilities must submit public risk studies as part of the CPUC's periodic Risk Assessment and Mitigation Phase ("RAMP") proceedings. These studies are probabilistic in nature and address wildfire risk along with a variety of other risks. *See* https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/risk-assessment-mitigation-phase.

[43] Note, for example, protocols relating to accessing the California Wildfire Fund described below, which evaluate utility prudency "based on actions taken by a utility, not the outcome of those actions." *See* Safety Certification FAQ | Office of Energy Infrastructure Safety, https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/safety-certifications/safety-certification-faqs/.

Q. Are these plans focused narrowly on wildfires or do they encompass multiple risks?

A. It varies. In many cases, insurance covers a suite of possible catastrophic problems of which wildfire is just one. Also for sizing of effort and priority among such risks, it is preferable that a utility's extreme risk management system not be designed piecemeal, one type of risk at a time (though this is not uncommon, as some hazards tend to occur rarely) but instead reflects some attempt to achieve equal benefits per dollar of effort put into mitigation across all major types of risks (such as cybersecurity, system safety, wildfires, earthquake recovery, extreme storm hardening and recovery). This is difficult because the types of damages across risk types are quite distinct, but to some extent they can be monetized or at least ranked in terms of dimensions like energy delivery disruption likelihood, frequency of occurrence, personnel and customer safety or survival risk, interaction with other critical systems, tendency to include property damage etc., and their mitigations can be ranked in terms of extent of the system and time frame of improved protection achieved by each. This allows an elementary comparison across risks for some degree of equivalent response planning. An integrated approach of this type lends further credibility to the plans for whatever are the strongest concerns.

Q. Why can't these efforts be relied upon to eliminate wildfire risk?

A. Even with the best of utility-sponsored fire mitigation plans, it is impossible (and would be too expensive even if it were possible in principle) to fully eliminate the wildfire risks in a large region. This is true for several reasons:

- *Extreme weather poses an unpredictable threat* — Extreme weather behaves differently than past statistical evidence on temperatures, precipitations, wind speed and the like, making it extremely difficult to model rigorously. In the parlance of statistics, catastrophic conditions are "black swan" events, arising only in the "tails" of the probability distributions otherwise describing the range of typical experience. In addition to the occurrence of extreme fires being very hard to predict, this dramatically amplifies the uncertainty range of possible economic damage consequences of a given wildfire, even as mitigation plans reduce the risk of a wildfire outbreak occurrence. This means that the challenges are a moving target, and factors outside the control of the utility will significantly determine the extent of the outcome of consequences and damages of wildfires. As noted above, it has also made modeling of fire risk quite difficult and inconsistent with recently observed disasters.

- *Wildfire mitigation comprises a massive geographic challenge* — It is not possible to pinpoint exactly where wildfires will start in the future, hence one cannot eliminate the wildfire events by preemptive measures assured of taking place at the "right" location among many possible locations where a fire could start in a very large area encompassing multiple states. Indeed, there is a paradoxical situation that if/where mitigation works, it will help avoid fires at those locations -- but then the fires will happen somewhere else that was not yet at the head of the line for earlier intervention, making it look like those spots were somehow neglected. But there will always be some such areas, no matter what order is used for the mitigation! All possible areas need to be targeted, ideally in order of declining risk, which itself is a diagnostic that takes time to develop and implement.

- *Other responsible entities* — Responsibility to mitigate wildfire risks is not uniquely a utility responsibility, in terms of detection, prevention, response or recovery. These needs are typically distributed across multiple agencies and many individuals, with utility mitigation plans forming just one of many relevant factors.
- *Competing priorities of maintaining service quality* — The expected benefits of additional expenditures on wildfire mitigation plans need to be weighed against customer benefits from spending that money on other useful utility programs or service features (reliability, resiliency, service efficiency, customer services, relative risk priority, etc.), or from simply not increasing rates enough to cover all the feasible mitigation activities. To date, utility expenditures approved by regulators for wildfire mitigation plans typically represent a small portion of total revenue requirements. While that may well increase, it will inevitably face budgetary caps.
- *Law of diminishing marginal returns to mitigation efforts* — Another consideration that limits the cost effectiveness of additional expenditures to be spent on wildfire mitigation plans by utilities is

the economics "law" of diminishing marginal returns. That is the tendency of economic activities to see declining value per unit of benefit as the scale of effort increases. This arises for at least two reasons: First, early economic efforts are usually directed at the "low hanging fruit" where there are quicker paybacks; higher hanging fruit is more difficult and expensive to reach. Second, expanding some capabilities on any system initially reduces constraints in those direct service attributes, but eventually constraints in other parts of the system or operations start to bind. Since the types of activities in the fire mitigation plans for a given total budget will (or should) be selected based on the greatest possible cost-effective impact in mitigating the wildfire risks, expansion or continuation of the total budget will gradually start facing activities that tend to have smaller and smaller incremental benefits. These declining marginal benefits ultimately justify putting a limit on how much improvement to pursue. In general, all forms of risk reduction become dramatically more expensive as the remaining expected risks decline. This is similar to why electric utilities in the U.S. have typically implemented a 1-in-10 years Loss of Load Expectation threshold (or variations thereof) for determining planning reserve margins to maintain resource adequacy, instead of trying to eliminate all risk for reliability outage events.

Thus, residual risk is inevitable and even efficient under even the most aggressive mitigation plan, so it is more than likely that associated damage claims will continue to occur. But wildfire mitigation plan effectiveness will gradually reduce the amount and cost of insurance otherwise needed.

Q. How should appropriate mitigation efforts be determined?

A. In a regulatory setting, while the utility has the greatest expertise and best vantage point for assessing costs and likely efficacy of any particular mitigation program, the process of determining appropriate mitigation efforts and protocols is as much negotiation as analysis, involving all stakeholders. Again, given the infeasibility of eliminating the risk, there must be a balance of interest among stakeholders about how far and fast to go, relative to using funds and resources for other important utility services. Similarly, the right amount and layering of insurance (commercial or self-provided) also needs this joint resolution, as insurance does not eliminate risk, it simply spreads out how the expected risk is paid for, and it improves liquidity if/when the risk occurs. *There is no per se right level of such smoothing*, as this depends on risk preferences and interacts (like mitigation) with other budgetary tradeoffs for the utility and its customers. The stakeholder workshops that PacifiCorp has been implementing are a good venue for such discussions.

V. POTENTIAL REGULATORY RELIEF

Q. Are a utility's wildfire risks and costs already compensated by its allowed return on equity ("ROE") making regulatory mechanisms unnecessary?

A. No, wildfire risks and costs are not typically compensated by a utility's allowed ROE, nor would such compensation via an enhanced ROE allowance be very effective in covering the problem. This is recognized by regulators in the normal practice of providing for recovery of insurance costs separately from allowed ROE risk premiums, and it applies all the more to increased insurance premia and/ or costs associated with extreme wildfire events. Exogenous risks like wildfire liability are not well captured in utility ROEs for several reasons, mostly springing off the fact that they are asymmetric risks, with the only possible outcomes being either no losses or some losses, but no outcomes with gains. Such insurance costs are intuitively one-sided. The possible losses from insurance risks reduce the expected cash flows from an asset, but that reduction is not accompanied by any prospect of compensatory upside returns.

Q. Please elaborate with some examples.

A. For example, when a public company faces an economic loss from a third-party liability claim, or simply the possibility of a future uninsured loss occurring, its stock price will fall by the present value of the expected loss, all else equal. That stock will not be expected thereafter to appreciate more than similar companies that do not have that problem, and so shareholders will not have the opportunity to cover the unexpected loss.[44] Net of the expected loss, the earnings of the affected company will not tend to be higher because of that adverse starting condition. Instead, its business risks will be comparable to other companies that do not have that problem. So the measured cost of capital will not reflect this problem. (This would be true even if all companies in the industry faced the same kind of insurance risks. They all lose value and

[44] Importantly, insurance losses can be diversified but they cannot be diversified *away*, which is unlike other business risk that involves a blend of uncorrelated economic outcomes, some positive and some negative.

none gain offsetting growth opportunities because of it.)

The asymmetry problem is more severe for regulated utilities than for unregulated companies, which have the opportunity to choose when, where, how, and how much to invest, and therefore are able to pick market participation sectors where they have expectations of earning returns in excess of their cost of capital. In particular, they can try to stay away from market sectors where they are exposed to asymmetric, downside risks. Regulated utilities, by contrast, do not have this discretion, as they operate under an obligation to serve and then must sell services with cost-based pricing that provides very limited or no upside opportunities relative to allowed ROEs. Because they cannot pick and choose where to serve, the costs of insurance problems must be treated like a legitimate cost of service item, not as a risk the utility investors can or should just internalize.

Q. What about allowing a premium ROE to cover asymmetric risk?

A. An allowed ROE could be augmented, in principle, by a premium to the customarily measured cost of capital to reflect asymmetric risk. However, there are multiple challenges to applying this ROE approach, not least that there are considerable estimation difficulties of the appropriate amount (given the recent growth in frequency and severity of wildfires) which make it possible that even a large premium only partly addresses the problem. That is, they would have to be awarded the expected cost of the excess risks remaining after any of their conventional insurance mechanisms were exhausted – which is the "black swan" part of the distribution that is not well understood. That could be a huge number, bigger than is likely to be acceptable. At the same time, any such allowance may create the incorrect impression in the eyes of the public and regulators that the utilities have been fully compensated for damage costs, no matter how large they might turn out to be, from all potential wildfire catastrophes. Any events dramatically exceeding the allowed premiums could be financially destructive to the utility, hence to its service to customers.

Absent a meaningful opportunity to offset risk via returns on investment, it is essential that utilities have a variety of *ex ante* and *ex post* equitable cost recovery mechanisms such as recovering higher commercial insurance costs (possibly through self-insurance) and those discussed below.

A. Recovering Higher Commercial Insurance Costs

Q. How have increased wildfire liability insurance costs been handled by other utilities and their regulators?

A. The large increases in wildfire insurance costs described above have presented urgent challenges in cost recovery for affected utilities and their regulators. In particular, the cost recovery settlements achieved by the California IOUs ("California Precedents"), Avista and Idaho Power (together, the "Regional Precedents") provide useful context for PacifiCorp's filing. The Regional Precedents directly inform PacifiCorp's filing in the following ways:

- Regulatory acknowledgement of higher and more uncertain wildfire insurance costs,
- Regulatory recognition of exogenous drivers, and
- Self-insurance mechanisms similar to those currently being considered by PacifiCorp.

Importantly, the California Precedents further underscore the recognition of current uncertainty in wildfire liability insurance markets by authorizing the recovery of wildfire insurance costs on a contingent (i.e. formulaic) basis, as discussed further below.

Q. Please describe the California Precedents.

A. Given that the costs of commercial wildfire insurance have reached such high levels, the California IOUs have each recently been authorized or have settlements pending that would authorize recovery of very substantial wildfire self-insurance costs over multi-year periods.

The California Settlements are summarized below and in Exhibit No. 22.

- *PG&E* – In CPUC D.23-01-005, issued in January 2023[45], PG&E was authorized to self-insure by setting aside funds potentially approaching recent commercial cost levels toward covering wildfire liability up to $1 billion annually for the "2023 GRC Period": 2023–2026.

  In a "worst case" scenario assuming wildfire liability claims of $1 billion in each year of the 2023 GRC Period, the PG&E Settlement provided that 72 percent of realized costs would be recovered via PG&E's Risk Transfer Balancing Account ("RTBA")[46] not subject to reimbursement "tied to the outcomes

[45] *See* CPUC A.21-06-021, PG&E Decision (approving settlement between PG&E, the Utility Reform Network, and the Public Advocates Office at the CPUC ("PGE Settlement").

[46] The RTBA had been previously established in CPUC D.20-12-005 (Dec. 3, 2020) to "record the difference between the amounts authorized in this GRC and actual costs of insurance premiums for coverage up to $1.4 billion" (D.20-12-005 at 249). D.20-12-005 further noted that "[r]egarding the establishment of the RTBA, we agree that insurance costs for General Liability coverage has been difficult to predict in recent times because of market conditions and the recent wildfires in California. A two-way balancing account will also allow PG&E to address uncertainty in a timely manner and at the same time ensure that there is adequate insurance coverage" (D.20-12-005 at 254).

of reasonableness reviews."[47] In such a "worst case" scenario, most of the 28 percent portion remaining uncollected at the end of the 2023 GRC Period could be subsequently recovered from customers via a Tier 2 Advice Letter Filing,[48] with 5 percent paid by a shareholder deductible.[49]

Importantly, per the agreed Settlement formulas illustrated in Appendix B of the PG&E Settlement, the portion of claims recoverable not subject to a reasonableness review could be increased significantly under a less adverse loss scenario. For example, were realized losses over the 2023 GRC Period limited to the level actually experienced for 2019-2021 ($458 million per year), such recoveries would grow to 93 percent.[50]

In support of the PG&E Settlement, the PG&E Decision acknowledged the insurance market realities affecting PG&E:

> "Due to a number of factors including PG&E's increased claims, the general liability insurance market continued to increase insurance premiums and reduce the availability of insurance to cover wildfire risk. As Table 2

[47] *See* PG&E Decision, at 13, and PG&E Settlement Section 3.4 and Appendix B: "Illustrative Calculation Reflecting the Worst Case Scenario—Cost Recovery for Undercollections at the End of the 2023 GRC Period", the latter reflected in Exhibit 5.
[48] PG&E Settlement Section 3.7 and Appendix B. Note that a Tier 2 Advice Letter could be subject to challenge.
[49] PG&E Settlement Section 3.2.3.
[50] See Exhibit RMP Exhibit No. 22.

illustrates, PG&E's wildfire liability insurance cost per limit of coverage grew until the costs reached 81.6 percent of the coverage amount for the 2020-21 insurance policy"[51]

As to self-insurance, the CPUC reasoned that "[s]ince 2017, wildfire liability insurance for third-party claims has risen to the point that self-insurance is likely to achieve sufficient insurance coverage at a lower overall cost to PG&E's customers than commercial insurance."[52] The PG&E Decision went on to say that "[n]ow that the cost of commercial insurance is up to 80 percent of the coverage it would provide, the Commission finds the Settlement recommending PG&E to use self-insurance for wildfire claims to be a reasonable alternative."[53]

- *SCE* — Similar to PG&E, in CPUC D.23-05-013,[54] SCE was authorized to self-insure toward covering wildfire liability up to $1 billion annually for the "Program Period": July 2023–December 2028,[55]

[51] PG&E Decision, at 6. The PG&E Decision additionally recognized that "[g]iven the significant difference in price for wildfire and non-wildfire liability insurance, PG&E now purchases liability coverage for wildfire claims separate from non-wildfire liability insurance" (PG&E Decision at page 4).
[52] PG&E Decision, at 2.
[53] *Id.*, at 15.
[54] *See* A.19-08-013, D.23-05-013 (May 19, 2023) (the "SCE Decision"), approving the Settlement between SCE, The Utility Reform Network, and the Public Advocates Office at the CPUC (the "SCE Settlement").
[55] Note that 2025 – 2028 would remain subject to revision in the 2025 GRC; *see* SCE Decision page 6.

again by setting aside funds potentially approaching recent levels of commercial wildfire insurance costs.

In a "worst case" scenario assuming wildfire liability claims of $1 billion in each year of the Program Period, 74 percent of realized costs would be recovered via SCE's Risk Management Balancing Account ("RMBA")[56] not subject to reimbursement tied to the outcomes of "reasonableness reviews".[57] In such a "worst case" scenario, most of the 26 percent portion remaining uncollected the end of the 2023 GRC Period could be recovered via a Tier 2 Advice Letter Filing[58], with 1.25 percent paid by a shareholder deductible (2.5 percent on amounts above the $500 million of annual claims). Importantly, per the agreed Settlement formulas, the portion of claims recoverable via the RMBA could be increased significantly under a less adverse scenario. For example, were realized losses over the Program Period limited to $400 million per year—per Appendix B, Example 2 of the SCE

[56] As further described below, the RMBA was established as part of SCE's 2021 GRC.
[57] SCE Decision, page 8; and SCE Settlement Section 3.4 and Appendix B: "Illustrative Calculation Reflecting the Worst Case Scenario—Cost Recovery for Undercollections at the End of the Program Period".
[58] *See* SCE Settlement Sections 3.3.2, 3.7 and Appendix B. Note that a Tier 2 Advice Letter could be subject to challenge.

Settlement—claims recoverable via the RMBA would grow to 85 percent.

In support of the settlement, the CPUC noted the following:

> "SCE's wildfire insurance costs have increased significantly in recent years. In the 2018 GRC, the Commission authorized $92.4 million for total liability insurance expense (combined wildfire and non-wildfire) for the 2018 test year. In the Track 1 decision, the Commission authorized a 2021 test year forecast of $460.0 million for wildfire liability insurance costs to obtain $1 billion of coverage based on SCE's recorded 2020 costs. Due to the volatility and uncertainty of these costs, the Commission authorized SCE to establish the one way RMBA to ensure any overcollection is returned to ratepayers and also authorized SCE to continue to seek rate recovery of any costs in excess of the forecast through its WEMA."[59]

The CPUC articulated further the same reasoning it had used in the PG&E Decisions:

> "Although not guaranteed, we find it likely that customers will receive more cost savings and benefits from self-insurance in 2023 and 2024 compared to commercial insurance. The proposed self-insurance program for SCE is substantially similar to the multi-year 100 percent self-insurance program for wildfire liability approved for Pacific Gas and Electric Company (PG&E) in its 2023 GRC."[60]

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[59] SCE Decision, at 9-10. WEMA refers to the Wildfire Expense Memorandum Accounts under which California utilities can record wildfire-related costs pending authority to reflect those costs in rates. *See also, Decision Approving Southern California Edison Company's Application for Authorization to Recovery Costs Related to Wildfire Insurance Premiums Recorded in its Wildfire Expense Memorandum Account*, D. 20-09-024 (Sept. 24, 2020).

[60] SCE Decision, at 13.

- *SDG&E* — In a joint motion filed in October 2023, SDG&E and key stakeholders proposed a settlement embedding a wildfire liability self-insurance option within an authorized test year forecast of $173 million for up to $1 billion in commercial wildfire liability coverage.[61] The self-insurance option would allow SDG&E (with SoCalGas) to set aside $14 million per year toward the first $50 million of potential losses.[62] The SDG&E Settlement remains under consideration by the CPUC.

Q. Please describe the other Regional Precedents.

A. Other noteworthy precedents include wildfire insurance settlements recently achieved by Avista Corporation and Idaho Power.

- *Avista* - In Final Order 10/04,[63] the Washington Utilities and Transportation Commission ("WUTC") approved a settlement authorizing Avista to establish an Insurance Expense Balancing Account for 2023 and 2024 with a step-up in baseline authority of approximately $5.3 million.

[61] *See* CPUC A.22-05-016, Joint Motion of Southern California Gas Company (U 904 G), SGD&E, The Public Advocates Office at the CPUC, The Utility Reform Network, The Utility Consumer's Action Network, and Community Legal Services for Adoption of a Settlement Agreement Resolving All Insurance Issues, filed Oct. 24, 2023, (the "SDG&E Settlement").
[62] SDG&E Settlement, at 11.
[63] WUTC Docket Nos. UE-220053, UG-220054, UE-210854 (cons.), Final Order 10/04 (Dec. 12, 2022).

The WUTC noted the following:

> "[W]e find that Avista has demonstrated unprecedented increases and volatility in its insurance costs. We agree that Avista has shown the insurance expense increases in recent years are "extraordinary" and "volatile" and caused an under-recovery of approximately $5.3 million in 2022. We also find that Avista has demonstrated that it has taken and is taking appropriate steps to try to control these costs, but has shown unprecedented recent increases in insurance that are largely out of its control."[64]

- *Idaho Power* — The Commission has allowed Idaho Power to defer incremental costs associated with its insurance premiums. The Commission approved this deferred treatment in 2021, stating the following:

> "We agree with the Company that customers should benefit from adequate insurance coverage. Insurance protects the Company and its customers from unforeseen wildfire-related costs which have caused utility bankruptcy in recent years. While the increased insurance premiums, including the "wildfire load," represent additional costs, the alternative is not prudent or wise. We believe the Company's proactive investment will provide benefits to customers should the Company ever face significant wildfire liability. We find it reasonable to allow the Company to defer its Idaho jurisdictional share of incremental wildfire insurance costs above 2019 levels."[65]

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[64] *Id.*, at 50.
[65] Case No. IPC-E-21-02, Order No. 35077 at 8 (June 17, 2021).

Idaho Power and interveners proposed a settlement in Idaho Power's 2023 GRC to continue this deferred treatment. The Commission approved the settlement.[66]

Q. What are the implications of these precedents for PacifiCorp's filing?

A. The Regional Precedents have the following implications for PacifiCorp's filing:

- Perhaps most importantly, they demonstrate strongly that PacifiCorp is not unique in facing the dramatic and pressing challenge of increasing and more volatile wildfire risk, insurance, and potential damage costs.
- PacifiCorp's utility peers and their regulators recognize wildfire risk—and hence associated insurance costs—as an exogenous risks – not controllable but requiring cost of service acceptance, somewhat like volatile fuel costs require adaptive (tracking) cost recovery in order for a utility to be financially stable power provider.
- Regulatory cost recovery mechanisms need to evolve to deal with the pace and scale of this problem. In

[66] Case No. IPC-E-23-11, Order No. 36042 at 10 (Dec. 28, 2023).

this regard, regulators have recently entered into settlements with the California IOUs, Avista, and Idaho Power that both defer increased insurance costs, but in some cases pre-authorize the contingent commitment of funds for self-insurance (based on claims actually realized).

- Even if recent wildfire liability conditions and regulatory treatments can be described as a "new normal," it is not clear that this state of affairs can be considered stable or predictable. The uncertainty is underscored by the recognition in approved settlements that current conditions are "volatile" and the contingent nature of the California settlements, which are designed to accommodate a wide range of potential wildfire liability outcomes. Thus, at this time, there is no allowance that could be given with confidence that over time it will most likely cover whatever happens, with some ups and downs along the way. Instead, mechanisms that adjust with realized circumstances are needed.
- To the degree that PacifiCorp encounters dysfunctional commercial insurance markets similar to what the California IOUs have faced in recent years, there is no reason that PacifiCorp should

not similarly avail itself the benefits of self-insurance in some form.

B. Protection From Extreme Events

Q. What are potential consequences of utility exposure to extreme wildfire claims exceeding normal coverage?

A. As noted above, the "new normal" has included not just uncertainty about increased insurance costs but also the increased likelihood that wildfire liability costs may rarely but very significantly exceed available levels of coverage at any price, possibly reaching several billion dollars. Only a very small number of fires grow to such levels of conflagration, but climate change and more residences and other properties being in the WUI zone of high risk have made the possibility of worst-case scenarios very grim indeed. Claims to date have materially eroded the affected utilities' financial resiliency, and in the case of PG&E, led to its bankruptcy in 2019. I understand these huge risks are virtually uninsurable in commercial markets, or at least not at any reasonable price, so they need creative utility-based mechanisms for solutions.

Q. Beyond just recovering the costs of insurance, how has the risk of extreme wildfire claims been handled in other jurisdictions?

A. Responding to the urgent threat posed by major wildfires in 2017, 2018, and after, the State of California has established mechanisms to protect utilities from associated financial claims. The goals include maintaining financial stability for utilities in support of their obligation to reliably serve customers.

In August 2018, the California state legislature passed a bill to address the cost allocation relating to the 2017 wildfires.[67] While I am not an attorney, my understanding is that Senate Bill 901 expanded various fire prevention and mitigation efforts by several state agencies, and it clarified the CPUC's reasonableness review of utility activities and costs regarding fire mitigation. Importantly, the bill created a framework for socializing wildfire-related costs in 2017 and in future years through a securitized utility financing mechanism. For 2017 specifically, the bill mandated that the CPUC take into account "the electrical corporation's financial status" by determining "the maximum amount the corporation can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service."[68] The bill thus established a mechanism for PG&E to recover costs for 2017 wildfires that would

[67] California Senate Bill 901 (Wildfires), Legislative Counsel's Digest, published September 8, 2018, https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB901.
[68] Section 27 of Senate Bill 901.

otherwise be disallowed, at least beyond the point to where the disallowance would threaten the utility's financial viability or its ability to provide utility service.[69]

Following PG&E's bankruptcy filing in 2019, the California state legislature passed Assembly Bill ("AB") 1054 to further address utility wildfire risk by, among other things, establishing an insurance-like Wildfire Fund (the "California Wildfire Fund"). The legislative language in AB 1054 observed that "[t]he establishment of a wildfire fund supports the credit worthiness of electrical corporations, and provides a mechanism to attract capital for investment in safe, clean, and reliable power for California at a reasonable cost to ratepayers."[70]

The California Wildfire Fund provided $21 billion of claim-paying coverage to California IOUs in the event of wildfire damages exceeding $1 billion (assumed to approximate the level of commercial insurance available to each of the California IOUs). Utility shareholders and customers both contributed to the fund in equal measure.

[69] This concept was further developed by the CPUC in its Order Instituting Rulemaking to Implement Public Utilities Code Section 451.2 Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901 (2018), July 8, 2019.
[70] AB 1054, Section 1(a)(5).

It is my understanding that AB 1054 established standards by which the CPUC could determine whether a utility had acted prudently and was therefore eligible to recover wildfire costs through the Fund (or, if the Fund had been exhausted, potentially through electric rates). Prudent conduct in connection with a wildfire event was broadly defined as that consistent with actions that a reasonable utility would have undertaken under similar circumstances, at the relevant point in time, and based on the information available at that time. In due course prudent utility conduct was more specifically codified in the form of specific wildfire mitigation programs and protocols needed to obtain a "safety certification" which formed the main criterion for access to the Fund. Importantly, as part of qualifying for a safety certification, a utility's implementation of its wildfire mitigation plan "is evaluated based on actions taken by a utility, not the outcome of those actions."[71]

[71] *See* Safety Certification FAQ | Office of Energy Infrastructure Safety, https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/safety-certifications/safety-certification-faqs/.

Q. Does Rocky Mountain Power benefit by any similar mechanisms?

A. Yes. It is my understanding that Utah Senate Bill 224 ("SB 224"), enacted in March 2024, authorizes large-scale electric utilities in that state to establish a "Utah fire fund" for the purpose of offsetting exclusively Utah-specific third-party wildfire liabilities that are beyond the utility's insurance (or self-insurance) coverage limits, up to 50 percent of the utility's revenue requirement. Subject to approval by the Commission, the Utah fire fund is intended to support "the financial health of the large-scale electric utility"[72] and maintain or improve "the large-scale electric utility's ability to deliver safe reliable services."[73] In support of the fund, a large-scale electric utility may collect a customer surcharge over a 10-year period, subject to limits on annual rate increases (or cumulative amounts over 50 percent of the utility's revenue requirement).

Separately, SB 224 limits utility liability for third-party wildfire claims (including specified dollar caps for certain non-economic damages) subject to

[72] Utah S.B. 224, Part 3 § 54-24-301 (4)(a).
[73] *Id.*

Commission determination of utility compliance with a wildfire mitigation plan.[74]

The above features of SB 224 are unambiguously favorable for the financial health of Rocky Mountain Power. Details of how to integrate such state-specific features into PacifiCorp's overall insurance portfolio are to be determined, but these features do not alter the need for the mechanisms PacifiCorp is introducing here.

Q. To what extent should extreme event wildfire risk be the responsibility of utility customers?

A. Ultimately, all reasonable costs of the utility, whether preemptive (insurance, mitigation) or reactive (uncovered claims), must be reasonably expected to be recoverable in order for it to maintain financial integrity sufficient to provide reliable, cost-effective service and to attract capital. Wildfire costs are no exception, despite the complex ways in which they may arise or the abnormal size they could reach. As long as they are not a product of gross negligence or incompetence, they should be fully recoverable, either spread out broadly and over time via pre-paid commercial or self-insurance, or amortized after the fact for amounts not covered by such reserves. As noted above in

[74] *Id.* § 54-24-303, (3), (4) and (6).

Section IV, wildfire mitigation cannot reasonably be expected to eliminate all risks. That is both infeasible in principle and it becomes uneconomical at extremes. Additionally, for regulated utilities, the necessary judgment-calls relating to system hardening and/or operating protocols do not fall solely within the discretion of management. Mitigation expenditures and operating protocols must be approved by regulators on behalf of customers. This is a judgment based not so much on fire prevention by itself but on what fire prevention efforts could crowd out, assuming there is a practical cap on what level of rates is acceptable. This feature of the regulatory compact amounts, at minimum, to an implicit recognition by regulators that agreed mitigation efforts are optimized from a customer spending and cost/benefit balancing perspective, and therefore such costs (both direct and their residual fire damage outcomes, if any) are prudent.

Q. How should customer responsibility for wildfire damage claims be considered in cost recovery protocols?

A. It is certainly possible that legal reviews of fire liability and damages may deem utilities responsible for fires and their third-party harms. However, liability or negligence standards brought to bear in wildfire damage claims against utilities may not be aligned with the guidelines or trade-offs necessarily embedded in efficient and prudent wildfire mitigation plans and overall utility management. The clearest example of this is the doctrine of "inverse condemnation" applicable in California, which imposes strict liability on the utility without reference to regulatory standards of prudent management. Negligence standards in other jurisdictions may be interpreted to effectively embed inverse condemnation, or for different reasons do not reflect or proxy for feasible wildfire mitigation plans.[75] Neither judges nor juries can be expected to evaluate the technical intricacies of such plans, nor to identify what tradeoffs were made or would have resulted from a different course of action than what damaged the plaintiffs.

In contrast, those considerations are central to utility regulation and compensation for utility operations. In essence, the analysis brought to bear in assigning legal liability may not be similar to what is appropriate and conventional for setting regulatory responsibility standards, so adverse opinions from the

[75] Notably, the California Wildfire Fund is intended as financial relief from findings of liability, based on prudent utility management. *See* Safety Certification FAQ | Office of Energy Infrastructure Safety, https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/safety-certifications/safety-certification-faqs/.

former should not automatically bleed over to governing disallowance actions of the latter.

Instead, it logically falls to utilities, to choose, in conjunction with customers and regulators, a level of mitigation that is balanced and acceptable. The process is one of negotiation as well as analysis. Key trade-offs must be evaluated between factors including fire mitigation, service quality and reliability, rate increases, and potential future exposure. As noted above, the consensus solution is likely to stop well short of attempting to solve the whole problem rapidly or even fully.

As a natural consequence of these processes, there will be residual risk —elected jointly by the stakeholders. In this circumstance, one in which near-term wildfire mitigation spending and associated rate increases are balanced with competing imperatives, there must be provision for recovering residual exposure should it be incurred.

Q. What is the responsibility of the utility?

A. The *quid pro quo* for such contingent cost recovery, of course, is that utility managers diligently pursue a well-defined wildfire mitigation plan accepted by customers and regulators. In the parlance of schools, they should be graded on effort not on outcomes, as the former are controllable while here the latter are not so much. This principle was established in forming the California Wildfire Fund, with the following key components:

- Utility access to the insurance function of the California Wildfire Fund is contingent on maintaining a safety certification giving evidence of compliance with an approved wildfire mitigation plan.
- Such compliance is to be evaluated based on agreed mitigation efforts—not wildfire outcomes—in recognition of the challenges facing wildfire mitigation and the regulatory process in forming a consensus wildfire mitigation plan.
- Adherence to mitigation plan should be deemed proof of prudence hence cost recovery. That is, absent negligence, regulators should evaluate utilities on the quality of their inputs to the fire prevention problem, not on the outputs of how many fires happen, how much they cost, or even whether a piece of utility equipment was involved (except insofar as that is a basis for revising future mitigation).

Q. How does PacifiCorp's proposal to address extreme risk meet these criteria?

A. PacifiCorp's proposal to establish a Catastrophic Fire Fund remains in development via the stakeholder workshop process. It is being proposed in conjunction with a material slate of mitigation activities that should help reduce the risks of fires occurring, but as noted earlier, the ultimate scale of any fires that do occur is largely beyond control, if those coincide with adverse weather conditions. Thus, a Catastrophic Fund remains essential. I understand that the details of the Catastrophic Fire Fund proposal are intended to reflect the principles enumerated above as they take further shape.

VI. CONCLUSIONS

Q. Please summarize your principal conclusions.

A. My principal conclusions can be summarized as follows:

- PacifiCorp is facing an exogenous, largely climate-induced phenomenon in increased wildfire risk.
- With wildfire risks mounting, the cost of wildfire liability insurance is increasing dramatically. Those costs should be recoverable even if not perfectly foreseen in prior rate cases, akin to the way fuel costs adjust.

- Similarly positioned utilities have crafted workable solutions for those costs that recognize wildfire insurance as a legitimate cost of service in recent rate-case proceedings.
- To the degree that PacifiCorp encounters dysfunctional commercial insurance markets similar to what the California IOUs have faced in recent years PacifiCorp should avail itself of the benefits of self-insurance in some form.
- To the degree that PacifiCorp faces material and increasing likelihood of catastrophic exposure to unprecedented levels of extreme wildfire loss claims, as ongoing analysis indicates is a credible concern, PacifiCorp is proposing a Catastrophic Fire Fund to provide liquidity and maintain longer term financial stability. The design (size, positioning and funding) of this Fund need to be specified after better analytic information is available about the risk magnitudes.
- Subject to compliance with reasonable mitigation standards, uninsured extreme wildfire loss claims (if they occur) should be viewed as costs of utility service recoverable from customers (just as insurance premia normally are). This is true regardless of legal decisions attributing utility

liability for fires, unless those findings are based on gross negligence.

- Thus, some form of agreed, socialized cost recovery for these adverse possible situations should be developed before they arise.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-24-04
Exhibit No. 18
Witness: Frank Graves

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Frank Graves

Resume of Frank Graves

May 2024

FRANK C. GRAVES

Principal

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Mr. Frank C. Graves is a Principal of The Brattle Group who specializes in regulatory and financial economics, especially for electric and gas utilities, and in litigation matters related to securities litigation, damages from breached energy contracts, and risk management.

He has over 40 years of experience assisting utilities in forecasting, valuation, financial planning, and risk management for many kinds of long range investment and service design decisions, such as generation and network capacity expansion, fuel and gas supply procurement and hedging, pricing and cost recovery mechanisms, cost and performance benchmarking, renewable asset selection and contracting, and new business models for distributed energy technologies. He has testified before many state regulatory commissions and the FERC as well as in state and federal courts and arbitration proceedings on such matters as the prudence of investment and contracting decisions, risk management, cost of capital, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions.

In the area of financial economics, he has assisted and testified in civil cases in regard to contract damages estimation, securities litigation suits, special purpose audits of non-standard business transactions and their accounting, tax disputes, risk management, and cost of capital estimation, and he has testified in criminal cases regarding corporate executives' culpability for securities fraud.

He received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

Mr. Graves is also a professional violinist and chairperson of the Dean's Advisory Council to the Jacobs School of Music at Indiana University

AREAS OF EXPERTISE

- Utility Planning and Operations
- Financial Analysis and Commercial Litigation
- Regulated Industry Policy and Restructuring
- Energy Market Competition

PROFESSIONAL AFFILIATIONS

- IEEE Power Engineering Society
- Mathematical Association of America
- American Finance Association

Recent Activities

Testimony

For Public Service Company of New Mexico, Case No. 22-00270-UT before the New Mexico Public Service Commission, Mr. Graves provided testimonies on whether the Four Corners Power Plant had been prudently evaluated, environmentally upgraded, and contracted for fuel in decisions made over the prior decade. Direct testimony December 2022, rebuttal July 2023.

For Peoples' Gas Light Co. and North Shore Gas of Chicago, he testified in their general rate cases regarding whether various cost recovery or capital expenditure constraints should be place on the companies because of expected decarbonization policies in Illinois that could cause natural gas to be displaced by electrification. He argued that this is an important issue requiring more analysis and more stakeholders than a GRC setting includes, so those issues should be set for a series of Future of Gas workshops. Docket Nos. 23-0068 and 23-0069 before the Illinois Commerce Commission, June 2023.

For the Alberta Utilities Commission, Mr. Graves provided written direct and rebuttal testimony on cost of capital risk-positioning in regard to decarbonization policies, and on the financial impacts of service bypass by Rural Electrification Associations on FortisAlberta Company, Proceeding 27084, February and April 2023.

For Holtec International, Mr. Graves provided testimony regarding feasibility of completing disposal of spent nuclear fuel from decommissioning of Palisades nuclear plant ISFSI by 2040, before the Nuclear Regulatory Commission, Docket No(s). 50-255-LT-2, 50-155-LT-2, 72-007-LT, 72-043-LT-2, February 2023.

For Commonwealth Edison Company, testimony on the cost of equity capital for ComEd's four-year rate plan, before the Illinois Commerce Commission. Docket No. 23-0055, January 17, 2023.

For members of the Wisconsin Utilities Association, testimony on how to regulate rooftop solar development when it is contracted under long term power purchase agreements, Case No 9300-DR-105, November 1 and 2, 2022, Wisconsin Public Service Commission.

For Peoples Gas Light and Coke, Inc. in Chicago, Illinois he testified on how to establish prudence for recurring annual expenditures to replace aged and corroded iron pipe gas distribution infrastructure, before the Illinois Commerce Commission, Docket 17-0137, October 2022.

For Northstar Vermont Yankee Co., he testified in the Court of Federal Claims (October 31, 2022) regarding the company's position in a market for exchanging positions in the queue of spent nuclear fuel removal rights, had DOE not breached its obligations to create a permanent repository. Oral direct and rebuttal testimonies were presented. Docket 18-1209C.

For WE Energies, Mr. Graves provided testimony on the importance of maintaining or growing fixed charges in electric rates as more and more customers adopt self-supply (rooftop solar) and smart energy management technologies. Case Nos. 5-UR-110 and 6690-UR-127, October 4, 2022.

On behalf of Entergy's System Energy Resources, Inc., Mr. Graves testified (September 28, 2022) before the FERC about whether various costs of structuring and periodically refinancing a capital lease for a portion of the Grand Gulf Nuclear Station had been recorded properly for accounting and ratemaking purposes under formula rates. FERC Docket EL20-72-000.

For Calpine Corp. Mr Graves testified in Bankruptcy Court in regard to why extraordinarily high power prices that arose during the February 2021 extreme freeze causing nearly half of Texas to lose power for several days should not be waived as ongoing liabilities for Brazos Municipal Power Cooperative, which had incurred a $1.5billion liability to ERCOT from its inabilities to cover (or hedge) its power needs during that situation. Docket No. 21-03863-ADV, March 2, 2022

For Public Service Company of New Mexico, Mr. Graves presented rebuttal and sur-rebuttal (March 15, 2021) testimonies before the NMPSC (Case No. 21-00017-UT) on whether ownership of a share of the Four Corners power plant had been imprudently sustained in the past decade. He presented analyses that supplemented past resource planning and that compared the realized costs of the Four Corners plant to the alternative gas plant that critics felt should have been chosen, showing that even if imprudent, little or no damages had ensued.

For Alta Windpower, testimony in regard to whether locations of adjacent wind farms was causing interference and if so, how much harm to output was occurring (JAMS Case No.1220065657, January 16, 2021). He showed that plaintiff's alleged damages were highly speculative and overstated because based on only a single scenario for complex future decarbonization economics, and that the plaintiff's projection was out of line compared to many other forecasts.

For PacifiCorp before the Oregon Public Utility Commission (Docket UE-374, February 2020), Mr. Graves prepared testimony on the difficulties in forecasting short-term power system balancing and trading transactions and the resulting tendency for these to be underestimated in projected operating costs, hence under-collected in rates. Based on a comparison to other states practices, he proposed that such costs be fully recovered on a flow-through basis without risk-sharing, subject to prudence.

Client Engagements

- Electric resource planning is a much harder and different problem under deep decarbonization goals than it was for the past few decades. Finding an economic mix of enough clean energy to serve annual energy requirements, and electrifying then fitting/shifting load to the times when that clean energy will be most available, have become much more important than efficient choices for capacity adequacy. Mr. Graves is involved in IRP studies and in technology assessments of what emerging clean energy mechanisms will be most likely to succeed, or what it would take for them to do so.

- Mr. Graves has lead a study of how ambitious economy-wide decarbonization policies in New York are creating a possible "death spiral" risk for natural gas distribution companies, due to potential demand contraction from electrifying end-uses traditionally served by natural gas at the same time as the industry requires capital investments in safety upgrades to aging infrastructure. He has developed cost-benefit models of alternative pricing mechanisms for serving electric power generators, as well as systems dynamics models of the feedbacks and tipping points in gas distribution that may ensue unless significant regulatory innovations are allowed.
- Economic recovery from the stresses of the Covid pandemic involves significant opportunities for infrastructure improvements. For the Coalition for Green Capital, Mr. Graves lead a Brattle team collaborating with The Analysis Group to develop a proposal for a $100 billion "green accelerator" package that would be provide funding and risk-sharing to debottleneck energy industry improvements that would reduce GHG emissions, provide quick economic stimulus, and improve equity to disadvantaged communities and customer segments. It is a portion of the infrastructure bills being considered by Congress. Relatedly, he prepared an assessment of expected economic harm from low income rental evictions from ending the Covid moratorium on rent liabilities, on behalf of the National Low Income Housing Coalition.
- Liability for wildfire damages drove PG&E to bankruptcy in 2020. Mr. Graves was part of an advisory team that helped appraise and explain the financial benefits to alternative means of compensating victims as part of the debtor's Plan of Reorganization, including securitized debt or contingent payments tied to future financial stability of the company.
- With improvements in performance and cost of microgeneration, as well as low cost natural gas, many hospitals, universities, and similar campuses are considering combined heat and power supply as an alternative to utility energy services. Mr. Graves has helped several such entities evaluate potential benefits of CHP, including choosing the preferred size and mix of technology and design of risk sharing terms in financial and operating contracts for the CHP systems.

Publications

"The Emerging Economics of Hydrogen Production", a Brattle presentation prepared in collaboration with Environmental Defense Fund, reviewing hydrogen costs foreseeable through 2030 with recent IRA tax incentives and improving technologies. Prepared with Josh Figueroa, Ragini Sreenath, Lorenzo Sala, Jadon Grove, and Steven Thumb, March, 2024.

"The Role of Nuclear Power in US Electricity Markets" prepared with Carless Traviss for MIT and CATF's Nuclear Power in a Low Carbon World conference, August 2023,

"Future of Gas Series: Transitioning Gas Utilities to a Decarbonized Future," three Brattle presentations (Assessing Risks, Aug 2021; Evaluating Strategies, Sept 2021; Setting Regulations, Nov 2021) with Long Lam, Kasparas Spokas, Josh Figueroa, Tess Counts, and Shreeansh Agarwal

"Brattle Issue Brief on ERCOT's Power Outage", March 2021, with Sam Newell, Jesse Cohen, and Sophie Leamon.

"2020 CAISO Blackouts and Beyond: The Future of California Resource Planning" with John Tsoukalis and Sophie Leamon for LSI's Electric Power in the West Conference, January 2021.

"Clean Energy and Sustainability Accelerator – Opportunities for Long Term Deployment" on recommended targets and mechanisms for use of a $100 billion economic recovery and decarbonization stimulus package for the Biden administration. With Bob Mudge, Roger Lueken, and Tess Counts. Prepared for the Coalition for Green Capital, January 14, 2021.

"Emerging Value of Carbon Capture for Utilities" with Kasparas Spokas and Katie Mansur, Public Utilities Fortnightly, October 2020, p. 36-41

"Impacts and Implications of COVID-19 for the Energy Industry" for Energy Bar Association's Virtual Fall Conference, October 13, 2020. (Also several presentations with co-authors Bob Mudge, Tess Counts, Josh Figueroa, Lily Mwalenga, and Shivangi Panon the same topic at earlier dates, for public release and other conferences.)

"System Dynamics Modeling: An Approach to Planning and Developing Strategy in the Changing Electricity Industry" (with Toshiki Bruce Tsuchida, Philip Q Hanser, and Nicole Irwin), Brattle White Paper, April 2019.

"California Megafires: Approaches for Risk Compensation and Financial Resiliency Against Extreme Events" (with Robert S. Mudge and Mariko Geronimo Aydin), Brattle White Paper, October 1, 2018.

"Retail Choice: Ripe for Reform?" (with Augustin Ros, Sanem Sergici, Rebecca Carroll and Kathryn Haderlein), Brattle White Paper, July 2018.

"Resetting FERC RoE Policy; a Window of Opportunity" (with Robert Mudge and Akarsh Sheilendranath), Brattle White Paper, May 2018

Full C.V.

Financial Analysis and Commercial Litigation

- Mr. Graves assisted a nuclear genco considering transfer of its responsibilities for spent fuel management and site remediation to a third party aspiring to consolidate waste management at a national repository. Analyses and financial projections of the costs, risks, and regulatory hurdles for both approaches were developed to find the range of conditions under which the transfer would be beneficial for the genco and financially viable for the new management company.

- Liability for wildfire damages drove PG&E to bankruptcy in 2020. Mr. Graves was part of an advisory team that helped appraise and explain the financial benefits to alternative means of compensating victims as part of the debtor's Plan of Reorganization, including securitized debt or contingent payments tied to future financial stability of the company.
- A public power utility faced viability-threatening financial distress after a major baseload power plant project proved uneconomic when only partly completed. Mr. Graves led a team that reassessed the decision path that resulted in this outcome, in order to identify what expenditures or contract commitments might be deemed imprudent. He developed system and financial models of the company under alternative resource plans, which also informed how much financial burden would ensue from different kinds of penalties.
- Wildfires in California have become catastrophic in the past 5 years, creating both financial turmoil for the utilities and controversy over how to insure and manage this problem. Mr. Graves has been extensively involved in estimating the expected, growing cost of this problem and the design of mechanisms to insure it and compensate investors for the likelihood of uncompensated costs from fire damages.
- Despite well settled financial economics, there is great regulatory controversy surrounding how or whether to make adjustments in cost of capital measurements for differences in leverage between the proxy firms used to estimate the rate and the capital structure of the target utility. Mr. Graves has lead analyses of how to demonstrate the need for this adjustment, with testimony given to explain the foundations.
- For the government of Colombia, Mr. Graves testified in arbitration about misrepresentations that occurred in the negotiation of royalties over coal mining production. Those negotiations resulted in a royalty scheme that was much more favorable to the coal company than would have been acceptable to Colombia had more realistic representations occurred. He showed that the mining companies own studies projected much higher value and more favorable operating conditions for the facility, and that alternative schedules for running the mine would have produced more value than was asserted possible by its owners.

- For the co-owners of the SONGS nuclear power plant that had become inoperable due to failed and irreparable steam generators, Mr. Graves provided written and oral testimony in arbitration over what damages had been incurred by the utilities from having to replace the nuclear plant with new generation, purchased power, and transmission upgrades, as well as accelerated decommissioning liabilities. His report evaluated the impacts of the lost plant on the entire western power market, including how it would change the needs and costs for emission allowances in the California GHG market. He estimated that damages were nearly $7 billion dollars.

- For an international energy company seeking to expand its operations in the US, Mr. Graves lead an assessment of the market performance risks facing a possible acquisition target, in order to determine what contingencies or market shifts were critical to it being an attractive target. Uncertain long run wholesale energy conditions, tightening environmental regulations, and disruptive technology development prospects were considered.

- For an international technology firm that had experienced a recent bankruptcy, Mr. Graves assisted in the design of a study of how the remaining valuable assets could be deemed assignable to disparate country-specific claims. Company operating practices for research and development risk and profit sharing were evaluated to identify an equitable approach.

- For a merchant power company with a prematurely terminated development contract, Mr. Graves co-lead a team to value the lost contract. The contract included several different kinds of revenue streams of different risks, for which Brattle developed different discount rates and debt carrying-capacity assessments. The case was settled with a very large award consistent with the Brattle valuations.

- Holding company utilities with many subsidiaries in different states face differing kinds of regulatory allowances, balancing accounts with differing lags and allowed returns for cost recovery, possibly different capital structures, as well as different (and varying) operating conditions. Given such heterogeneity, it can be difficult to determine which subsidiaries are performing well vs. poorly relative to their regulatory and operational challenges. Mr. Graves developed a set of financial reporting normalization adjustments to isolate how much of each subsidiary's profitability was due to financial, vs. managerial, vs. non-recurring operational conditions, so that meaningful performance appraisal was possible.

- Many banks, insurance firms and capital management subsidiaries of large multinational corporations have entered into long term, cross border leases of properties under sale and leaseback or lease in, lease out terms. These have been deemed to be unacceptable tax shelters by the IRS, but that is an appealable claim. Mr. Graves has assisted several companies in evaluating whether their cross border leases had legitimate business purpose and economic substance, above and beyond their tax benefits, due to likelihood of potentially facing a role as equity holder with ownership risks and rewards. He has shown that this is a case-specific matter, not per se determined by the general character of these transactions.

- For a private energy hedge fund providing risk management contracts to industrial energy users, a breach of contract from one industrial customer was disputed as supposedly involving little or no loss because the fund had not been forced to liquidate positions at a loss that corresponded precisely to the abruptly terminated contract. Mr. Graves provided analysis demonstrating how the portfolio loss was borne, but other fund management metrics used to control positions, and other unrelated hedging positions, also changed roughly concurrently in a manner that disguised the way the economic damage was realized over time. The case was settled on favorable terms for Mr. Graves' client.

- Many utilities have regulated and unregulated subsidiaries, which face different types and degrees of risk. Mr. Graves lead a study of the appropriate adjustments to corporate hurdle rates for the various lines of business of a utility with many types of operations.
- A company that incurred Windfall Tax liabilities in the U.K. regarded those taxes as creditable against U.S. income taxes, but this was disputed by the IRS. Mr. Graves lead a team that prepared reports and testimony on why the Windfall Tax had the character of a typical excess profits tax, and so should be deemed creditable in the U.S. The tax courts concurred with this opinion and allowed the claimed tax deductions in full.
- For a defendant in a sentencing hearing for securities' fraud, Mr. Graves prepared an analysis of how the defendant's role in the corporate crisis was confounded by other concurrent events and disclosures that made loss calculations unreliable. At trial, the Government stipulated that it agreed with Mr. Graves' analysis.
- For the U.S. Department of Justice, Mr. Graves prepared an event study quantifying bounds on the economic harm to shareholders that had likely ensued from revelations that Dynegy Corporation's "Project Alpha" had been improperly represented as a source of operating income rather than as a financing. The event study was presented in the re-sentencing hearing of Mr. Jamie Olis, the primary architect of Project Alpha.
- For a utility facing significant financial losses from likely future costs of its Provider of Last Resort (POLR) obligations, Mr. Graves prepared an analysis of how optimal hindsight coverage of the liability would have compared in costs to a proposed restructuring of theobligation. He also reviewed the prudence of prior, actual coverage of the obligation in light of conventional risk management practices and prevailing market conditions of credit constraints and low long-term liquidity.
- Several banks were accused of aiding and abetting Enron's fraudulent schemes and were sued for damages. Mr. Graves analyzed how the stock market had reacted to one bank's equity analyst's reports endorsing Enron as a "buy," to determine if those reports induced statistically significant positive abnormal returns. He showed that individually and collectively they did not have such an effect.
- Mr. Graves lead an analysis of whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil" of limited liability. The analysis investigated the presence of untenable debt capitalization in the subsidiary, overlapping management staff, the adherence to normal corporate governance protocols, and other kinds of evidence of excessive parental control.

- As a tax-revenue enhancement measure, the IRS was considering a plan to recapture deferred taxes associated with generation assets that were divested or reorganized during state restructurings for retail access. Mr. Graves prepared a white paper demonstrating the unfairness and adverse consequences of such a plan, which was instrumental in eliminating the proposal.
- For a major electronics and semiconductor firm, Mr. Graves critiqued and refined a proposed procedure for ranking the attractiveness of research and development projects. Aspects of risk peculiar to research projects were emphasized over the standards used for budgeting an already proven commercial venture.
- In a dispute over damages from a prematurely terminated long-term power tolling contract, Mr. Graves presented evidence for the plaintiff power plant on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. The amount of damages was dramatically larger under a two-discount rate calculation, which was the position adopted by the court.
- The energy and telecom industries, especially in the late 1990s and early 2000s, were plagued by allegations regarding trading and accounting misrepresentations, such as wash trades, manipulations of mark-to-market valuations, premature recognition of revenues, and improper use of off-balance sheet entities. In many cases, this conduct has preceded financial collapse and subsequent shareholder suits. Mr. Graves lead research on accounting and financial evidence, including event studies of the stock price movements around the time of the contested practices, and reconstruction of accounting and economic justifications for the way asset values and revenues were recorded.
- Dramatic natural gas price increases in the U.S. often put natural gas and electric utilities in the position of having to counter claims that they should have hedged more of their fuel supplies at times in the past. For several companies, Mr. Graves developed testimony to rebut this hindsight criticism and risk management techniques for fuel (and power) procurement for utilities to apply in the future to avoid prudence challenges.
- As a means of calculating its stranded costs, a utility used a partial spin-off of its generation assets to a company that had a minority ownership from public shareholders. A dispute arose as to whether this minority ownership might be depressing the stock price, if a “control premium” was being implicitly deducted from its value. Using event studies and structural analyses, Mr. Graves identified the key drivers of value for this partially spun-off subsidiary, and he showed that value was not being impaired by the operating, financial and strategic restrictions on the company. He also reviewed the financial economics literature on empirical evidence for control premiums, which he showed reinforced the view that no control premium de-valuation was likely to be affecting the stock.
- A large public power agency was concerned about its debt capacity in light of increasing competitive pressures to allow its resale customers to use alternative suppliers. Mr. Graves lead

a team that developed an Economic Balance Sheet representation of the agency's electric assets and liabilities in market value terms, which was analyzed across several scenarios to determine safe levels of debt financing. In addition, new service pricing and upstream supply contracting arrangements were identified to help reduce risks.

- Wholesale generating companies intuitively realize that there are considerable differences in the financial risk of different kinds of power plant projects, depending on fuel type, length and duration of power purchase agreements, and tightness of local markets. However, they often are unaware of how if at all to adjust the hurdle rates applied to valuation and development decisions. Mr. Graves lead a Brattle analysis of risk-adjusted discount rates for generation; very substantial adjustments were found to be necessary.
- A major telecommunications firm was concerned about when and how to reenter the Pacific Rim for wireless ventures following the economic collapse of that region in 1997-99. Mr. Graves lead an engagement to identify prospective local partners with a governance structure that made it unlikely for them to divert capital from the venture if markets went soft. He also helped specify contracting and financing structures that create incentives for the venture to remain together should it face financial distress, while offering strong returns under good performance.
- There are many risks associated with operations in a foreign country, related to the stability of its currency, its macro economy, its foreign investment policies, and even its political system. Mr. Graves has assisted firms facing these new dimensions to assess the risks, identify strategic advantages, and choose an appropriate, risk-adjusted hurdle rate for the market conditions and contracting terms they will face.
- The glut of generation capacity that helped usher in electric industry restructuring in the US led to asset devaluations in many places, even where no retail access was allowed. In some cases, this has led to bankruptcy, especially of a few large rural electric cooperatives. Mr. Graves assisted one such coop with its long term financial modeling and rate design under its plan of reorganization, which was approved. Testimony was provided on cost-of-service justifications for the new generation and transmission prices, as well as on risks to the plan from potential environmental liabilities.
- Power plants often provide a significant contribution to the property tax revenues of the townships where they are located. A common valuation policy for such assets has been that they are worth at least their book value, because that is the foundation for their cost recovery under cost-of-service utility ratemaking. However, restructuring throws away that guarantee, requiring reappraisal of these assets. Traditional valuation methods, e.g., based on the replacement costs of comparable assets, can be misleading because they do not consider market conditions. Mr. Graves testified on such matters on behalf of the owners of a small, out-of-market coal unit in Massachusetts.
- Stranded costs and out-of-market contracts from restructuring can affect municipalities and cooperatives as well as investor-owned utilities. Mr. Graves assisted one debt-financed utility in an evaluation of its possibilities for reorganization, refinancing, and re-engineering to

improve financial health and to lower rates. Sale and leaseback of generation, fuel contract renegotiation, targeted downsizing, spin-off of transmission, and new marketing programs were among the many components of the proposed new business plan.

- As a means of reducing supply commitment risk, some utilities have solicited offers for power contracts that grant the right but not the obligation to take power at some future date at a predetermined price, in exchange for an initial option premium payment. Mr. Graves assisted several of these utilities in the development of valuation models for comparing the asking prices to fair market values for option contracts. In addition, he has helped these clients develop estimates of the critical option valuation parameters, such as trend, volatility, and correlations of the future prices of electric power and the various fuel indexes proposed for pricing the optional power.
- For the World Bank and several investor-owned electric utilities, Mr. Graves presented tutorial seminars on applying methods of financial economics to the evaluation of power production investments. Techniques for using option pricing to appraise the value of flexibility (such as arises from fuel switching capability or small plant size) were emphasized. He has applied these methods in estimating the value of contingent contract terms in fuel contracts (such as price caps and floors) for natural gas pipelines.
- Mr. Graves prepared a review of empirical evidence regarding the stock market's reaction to alternative dividend, stock repurchase, and stock dividend policies for a major electric utility. Tax effects, clientele shifting, signaling, and ability to sustain any new policies into the future were evaluated. A one-time stock repurchase, with careful announcement wording, was recommended.
- For a division of a large telecommunications firm, Mr. Graves assisted in a cost benchmarking study, in which the costs and management processes for billing, service order and inventory, and software development were compared to the practices of other affiliates and competitors. Unit costs were developed at a level far more detailed than the company normally tracked, and numerical measures of drivers that explained the structural and efficiency causes of variation in cost performance were identified. Potential costs savings of 10-50 percent were estimated, and procedures for better identification of inefficiencies were suggested.
- For an electric utility seeking to improve its plant maintenance program, Mr. Graves directed a study on the incremental value of a percentage point decrease in the expected forced outage rate at each plant owned and operated by the company. This defined an economic priority ladder for efforts to reduce outage that could be used in lieu of engineering standards for each plant's availability. The potential savings were compared to the costs of alternative schedules and contracting policies for preventive and reactive maintenance, in order to specify a cost reduction program.
- Mr. Graves conducted a study on the risk-adjusted discount rate appropriate to a publicly-owned electric utility's capacity planning. Since revenue requirements (the amounts being discounted) include operating costs in addition to capital recovery costs, the weighted average cost of capital for a comparable utility with traded securities may not be the correct rate for

every alternative or scenario. The risks implicit in the utility's expansion alternatives were broken into component sources and phases, weighted, and compared to the risks of bondsand stocks to estimate project-specific discount rates and their probable bounds.

Utility Planning and Operations

- Uncertainty over the pace and extent of potential distributed energy resources (DERs) adoption by customers makes load forecasting and system planning much more complex, possibly involving future “tipping points” when DER use could accelerate rapidly. However, statistical histories on these improving technologies are not yet very informative as to when or why such a shift might occur. Mr. Graves has assisted several distribution utilities with a new, behavior-based modeling technique for long range system planning that simulates possible paths to DER adoption, utilizing system dynamics methods that recognize feedbacks between electricity prices, customers’ propensities to use DERs, declining technology costs, cost shifting to non-users, load shapes, and financial performance.
- Many large high-tech firms are seeking power supply services relying entirely on renewable resources. This can only be done for average or cumulative power needs, but the resulting green energy production will not match the time pattern of those firms’ demand. Mr. Graves lead a team evaluating how much risk is borne by a utility from offering such service over many years, when it will have to balance a significant green supply (such as rooftop and utility- scale solar) against its own load and the regional market.
- With improvements in performance and cost of microgeneration, many hospitals, universities, and similar campuses are considering combined heat and power supply as an alternative to utility energy services. Mr. Graves has helped several such entities evaluate potential benefits of CHP, including choosing the preferred size and mix of technology and risk analysis of terms in financial and operating contracts for the CHP systems.
- Many utilities are facing a concern through the expected useful lives of their coal plants are being shortened by low gas prices and increased use of renewables. Mr. Graves helped a utility justify early retirement of a coal plant with full recovery of its stranded costs, when that plan could be replaced more economically with new wind plants while the tax incentives for their development were still in effect.
- Mr. Graves developed a valuation and risk analysis model showing that a utility’s RFP for new generation could be better served by deferring new plant construction for a few years via a less costly and less risky transitional market-based power supply contract with price and quantity terms shaped to match the shifting needs over time until supply shortfalls were large enough to justify the investment in a new power plant at efficient scale. The parties negotiated a multi-year contract along these lines in lieu of pursuing the construction alternative that initially came out of the RFP selection.
- In Maryland the electric distribution companies administer SOS (Standard Offer Service) supply procurement and accounting to backup customers who do not use a competitive retail power supplier. The utilities are authorized to recover both the direct and financing costs of

that service plus a return on equity. Mr. Graves developed a method for sizing an appropriate equity return for the SOS risks and administrative services based on analogies to various intermediation businesses on the internet, such as EBay, PayPal, and others—in which, like SOS intermediation, the businesses do not take ownership for the products conveyed. Testimony was provided.

- Mr. Graves co-lead a team of Brattle analysts to assess the relative influence of different factors that were affected by the "Polar Vortex" cold snap of early 2014 that caused dramatic spikes in local power and gas prices in parts of the mid-Atlantic and northeastern US. The risks of similar recurring events were assessed in light of pending expansions of the electric and gas transmission grids, as well as likely coal plant retirements.
- For the Board of Directors or executive management teams of several utilities, Mr. Graves has lead strategic retreats on disruptive issues facing the electric industry in the future and how a utility should choose which risks and opportunities to embrace vs. avoid.
- Air quality and other power plant environmental regulations were tightened considerably in the period from about 2014-2018. Mr. Graves has co-developed a market and financial model for determining what power plants are most likely to retire vs. retrofit with new environmental controls, and how much this may alter their profitability. This has been used to help several power market participants assess future capacity needs, as well as to adjust their price forecasts for the coming decade.
- Successful merchant power plant development and financing depends in part on obtaining a long term power purchase agreement. Mr. Graves directed a study of what pricing points and risk-sharing terms should be attractive to potential buyers of long-term power supply contracts from a large baseload facility.
- Many utilities are pursuing smart meters and time-of-use pricing to increase customer ability to consume electricity economically. Mr. Graves has led a study of the costs and benefits of different scales and timing of installation of such meters, to determine the appropriate pace. He has also evaluated how various customer incentives to increase conservation and demand response might be provided over the internet, and how much they might increase the participation rates in smart meter programs.
- Wind resources are a critical part of the generation expansion plans and contracting interests of many utilities, in order to satisfy renewable portfolio standards and to reduce long run exposure to carbon prices and fuel cost uncertainty. Mr. Graves has applied Brattle's risk modeling capabilities to simulate the impacts of on- and off-shore wind resources on the potential range of costs for portfolios of wholesale power contracts designed to serve retail electricity loads. These impacts were compared to gas CCs and CTs and to simply buying more from the wholesale market to identify the most economical supply strategy.
- For a municipal utility with an opportunity to invest in a nuclear power plant expansion, Mr. Graves lead an analysis of how the proposed plant fit the needs of the company, what market and regulatory (environmental) conditions would be required for the plant to be more economical than conventional fossil-fired generation, and how the development risks could be

shared among co-owners to better match their needs and risk tolerances. He also assessed the market for potential off-take contracts to recover some of the costs and capacity that would be available for a few years, ahead of the needs of the municipal utility.

- The potential introduction of environmental restrictions or fees for CO2 emissions has made generation expansion decisions much more complex and risky. He helped one utility assess these risks in regard to a planned baseload coal plant, finding that the value of flexibility in other technologies was high enough to prefer not building a conventional coalplant.
- Mr. Graves helped design, implement, and gain regulatory approvals for a natural gas procurement hedging program for a western U.S. gas and electric utility. A model of how gas forward prices evolve over time was estimated and combined with a statistical model of the term structure of gas volatility to simulate the uncertainty in the annual cost of gas at various times during its procurement, and the resulting impact on the range of potential customer costs.
- Generation planning for utilities has become very complex and risky due to high natural gas prices and potential CO2 restrictions of emission allowances. Some of the scenarios that must be considered would radically alter system operations relative to current patterns of use. Mr. Graves has assisted utilities with long range planning for how to measure and cope with these risks, including how to build and value contingency plans in their resource selection criteria, and what kinds of regulatory communications to pursue to manage expectations in this difficult environment.
- For a Midwestern utility proposing to divest a nuclear plant, Mr. Graves analyzed the reasonableness of the proposed power buyback agreement and the effects on risks to utility customers from continued ownership vs. divestiture. The decommissioning funds were also assessed as to whether their transfer altered the appropriate purchase price.
- Several utilities with coal-fired power plants have faced allegations from the U.S. EPA that they have conducted past maintenance on these plants which should be deemed "major modifications", thereby triggering New Source Review standards for air quality controls. Mr. Graves has helped one such utility assess limitations on the way in which GADS data can be used retrospectively to quantify comparisons between past actual and projected future emissions. For another utility, Mr. Graves developed retrospective estimates of changes in emissions before and after repairs using production costing simulations. In a third, he reviewed contemporaneous corporate planning documents to show that no increase in emissions would have been expected from the repairs, due to projected reductions in future use of the plant as well as higher efficiency. In all three cases, testimony was presented.
- The U.S. Government is contractually obligated to dispose of spent nuclear fuel at commercial reactors after January 1998, but it has not fulfilled this duty. As a result, nuclear facilities that are shutdown or facing full spent fuel pools are facing burdensome costs and risks. Mr. Graves prepared developed an economic model of the performance that could have reasonably been expected of the government, had it not breached its contract to remove the spentfuel.

- Capturing the full value of hydroelectric generation assets in a competitive power market is heavily dependent on operating practices that astutely shift between real power and ancillary services markets, while still observing a host of non-electric hydrological constraints. Mr. Graves led studies for several major hydro generation owners in regard to forecasting of market conditions and corresponding hydro schedule optimization. He has also designed transfer pricing procedures that create an internal market for diverting hydro assets from real power to system support services firms that do not yet have explicit, observable marketprices.
- Mr. Graves led a gas distribution company in the development of an incentive ratemaking system to replace all aspects of its traditional cost of service regulation. The base rates (for non-fuel operating and capital costs) were indexed on a price-cap basis (RPI-X), while the gas and upstream transportation costs allowances were tied to optimal average annual usage of a reference portfolio of supply and transportation contracts. The gas program also included numerous adjustments to the gas company's rate design, such as designing new standby rates so that customer choice will not be distorted by pricing inefficiencies.
- An electric utility with several out-of-market independent power contracts wanted to determine the value of making those plants dispatchable and to devise a negotiating strategy for restructuring the IPP agreements. Mr. Graves developed a range of forecasts for the delivered price of natural gas to this area of the country. Alternative ways of sharing the potential dispatch savings were proposed as incentives for the IPPs to renegotiate their utility contracts.
- For an electric utility considering the conversion of some large oil-fired units to natural gas, Mr. Graves conducted a study of the advantages of alternative means of obtaining gas supplies and gas transportation services. A combination of monthly and daily spot gas supplies, interruptible pipeline transportation over several routes, gas storage services, and "swing" (contingent) supply contracts with gas marketers was shown to be attractive. Testimony was presented on why the additional services of a local distribution company would be unneeded and uneconomic.
- A power engineering firm entered into a contract to provide operations and maintenance services for a cogenerator, with incentives fees tied to the unit's availability and operating cost. When the fees increased due to changes in the electric utility tariff to which they were tied, a dispute arose. Mr. Graves provided analysis and testimony on the avoided costs associated with improved cogeneration performance under a variety of economic scenarios and under several alternative utility tariffs.
- Mr. Graves has helped several pipelines design incentive pricing mechanisms for recovering their expected costs and reducing their regulatory burdens. Among these have been Automatic Rate Adjustment Mechanisms (ARAMs) for indexation of operations and maintenance expenses, construction-cost variance-sharing for routine capital expenditures that included a procedure for eliciting unbiased estimates of future costs, and market-based prices capped at replacement costs when near-term future expansion was an uncertain but probableneed.

- For a major industrial gas user, he prepared a critique of the transportation balancing charges proposed by the local gas distribution company. Those charges were shown to be arbitrarily sensitive to the measurement period as well as to inconsistent attribution of storage versus replacement supply costs to imbalance volumes. Alternative balancing valuation and accounting methods were shown to be cheaper, more efficient, and simpler to administer. This analysis helped the parties reach a settlement based on a cash-in/cash-out design.
- The Clean Air Act Amendments authorized electric utilities to trade emission allowances (EAs) as part of their approach to complying with SO2 emissions reductions targets. For the Electric Power Research Institute (EPRI), Mr. Graves developed multi-stage planning models to illustrate how the considerable uncertainty surrounding future EA prices justifies waiting to invest in irreversible control technologies, such as scrubbers or SCRs, until the present value cost of such investments is significantly below that projected from relying on EAs.
- For an electric utility with a troubled nuclear plant, Mr. Graves presented testimony on the economic benefits likely to ensue from a major reorganization. The plant was to be spun off to a jointly-owned subsidiary that would sell available energy back to the original owner under a contract indexed to industry unit cost experience. This proposal afforded a considerable reduction of risk to ratepayers in exchange for a reasonable, but highly uncertain prospect of profits for new investors. Testimony compared the incentive benefits and potential conflicts under this arrangement to the outcomes foreseeable from more conventional incentive ratemaking arrangements.
- Mr. Graves helped design Gas Inventory Charge (GIC) tariffs for interstate pipelines seeking to reduce their risks of not recovering the full costs of multi-year gas supply contracts. The costs of holding supplies in anticipation of future, uncertain demand were evaluated with models of the pipeline's supply portfolio that reveal how many non-production costs (demand charges, take-or-pay penalties, reservation fees, or remarketing costs for released gas) would accrue under a range of demand scenarios. The expected present value of these costs provided a basis for the GIC tariff.
- Mr. Graves performed a review and critique of a state energy commission's assessment of regional natural gas and electric power markets in order to determine what kinds of pipeline expansion into the area was economic. A proposed facility under review for regulatory approval was found to depend strongly on uneconomic bypass of existing pipelines and LDCs. In testimony, modular expansion of existing pipelines was shown to have significantly lower costs and risks.
- For several electric utilities with generation capacity in excess of target reserve margins, Mr. Graves designed and supervised market analyses to identify resale opportunities by comparing the marginal operating costs of all this company's power plants not needed to meet target reserves to the marginal costs for almost 100 neighboring utilities. These cost curves were then overlaid on the corresponding curve for the client utility to identify which neighbors were competitors and which were potential customers. The strength of their relative threat or

attractiveness could be quantified by the present value of the product of the amount, duration, and differential cost of capacity that was displaceable by the client utility.

- Mr. Graves specified algorithms for the enhancement of the EPRI EGEAS generation expansion optimization model, to capture the first-order effects of financial and regulatory constraints on the preferred generation mix.
- For a major electric power wholesaler, Mr. Graves developed a framework for estimating how pricing policies affect the relative attractiveness of capacity expansion alternatives. Traditional cost-recovery pricing rules can significantly distort the choice between two otherwise equivalent capacity plans, if one includes a severe "front end load" while the other does not. Price-demand feedback loops in simulation models and quantification of consumer satisfaction measures were used to appraise the problem. This "value of service" framework was generalized for the Electric Power Research Institute.
- For a large gas and electric utility, Mr. Graves participated in coordinating and evaluating the design of a strategic and operational planning system. This included computer models of all aspects of utility operations, from demand forecasting through generation planning to financing and rate design. Efforts were split between technical contributions to model design and attention to organizational priorities and behavioral norms with which the system had to be compatible.
- For an oil and gas exploration and production firm, Mr. Graves developed a framework for identifying what industry groups were most likely to be interested in natural gas supply contracts featuring atypical risk-sharing provisions. These provisions, such as price indexing or performance requirements contingent on market conditions, are a form of product differentiation for the producer, allowing it to obtain a price premium for the insurance-like services.
- For a natural gas distribution company, Mr. Graves established procedures for redefining customer classes and for repricing gas services according to customers' similarities in load shape, access to alternative gas supplies, expected growth, and need for reliability. In this manner, natural gas service was effectively differentiated into several products, each with price and risk appropriate to a specific market. Planning tools were developed for balancing gas portfolios to customer group demands.
- For a Midwestern electric utility, Mr. Graves extended a regulatory pro forma financialmodel to capture the contractual and tax implications of canceling and writing off a nuclear power plant in mid-construction. This possibility was then appraised relative to completion or substitution alternatives from the viewpoints of shareholders (market value of common equity) and ratepayers (present value of revenue requirements).
- For a corporate venture capital group, Mr. Graves conducted a market-risk assessment of investing in a gas exploration and production company with contracts to an interstate pipeline. The pipeline's market growth, competitive strength, alternative suppliers, and regulatory exposure were appraised to determine whether its future would support the purchase volumes needed to make the venture attractive.

- For a natural gas production and distribution company, he developed a strategic plan to integrate the company's functional policies and to reposition its operations for the next five years. Decision analysis concepts were combined with marginal cost estimation and financial pro forma simulation to identify attractive and resilient alternatives. Recommendations included target markets, supply sources, capital budget constraints, rate design, and a planning system. A two-day planning conference was conducted with the client's executives to refine and internalize the strategy.
- For the New Mexico Public Service Commission, he analyzed the merits of a corporate reorganization of the major New Mexico gas production and distribution company. State ownership of the company as a large public utility was considered but rejected on concerns over efficiency and the burdening of performance risks onto state and localtaxpayers.

Regulated Industry Policy and Restructuring

- There has been a proliferation of customer-based renewable energy sources, smart appliances, and storage. For a developer of energy management equipment and software to optimize the use of such technologies, Mr. Graves and a Brattle team evaluated what types of services could be economically attractive to customers and/or utility partners, and what the market potential might be.
- Several states and cities have set goals of deep decarbonization of their local economies, often dubbed "80 by 50" if they aspire to 80% reductions in GHG emissions by 2050. Achieving this will involve radical change in the economy of those regions, potentially with dramatic load growth due to electrification and massive investment in new infrastructure for end-use and power supply and delivery. Mr. Graves has built models that show what types and degree of change could arise, and what they might cost depending on how such transformations are incentivized or enforced.
- As wholesale power and natural gas prices have fallen, interest in "retail choice" for energy supply has increased. At the same time, some state regulatory agencies have become concerned that misleading marketing and non-competitive pricing are too common in the mass market, especially afflicting low income and senior residential customers. Mr. Graves lead a review of such concerns that compared practices and market performance in several states to identify what could be done to improve such services.
- For a group of utilities responding to a state mandate to consider means of encouraging distributed technologies to be assessed and incentivized in parity with central station generation, Mr. Graves and others at Brattle prepared alternative means of incorporating marginal cost and externality value considerations into new cost/benefit assessment tools, procurement mechanisms, and supply contracting.
- For a mid-Atlantic gas distribution utility, Mr. Graves assessed mark to market losses that had occurred from gas supply hedges entered before spot prices declined precipitously. Concerns were voice that this outcome indicated the company's hedging practices were no longer attune to market conditions, so Mr. Graves developed and lead workshop between the company,

intervener groups, and state commission staff to define new appropriate goals, mechanisms and review standards for revised risk management approach.

- For a major participant in the Japanese power industry contemplating reorganization of that country's electric sector following Fukushima, Mr. Graves lead a research project on the performance of alternative market designs around the US and around the world for vertical unbundling, RTO design, and retail choice.
- For several utilities facing the end of transitional "provider of last resort" (or POLR) prices, Mr. Graves developed forecasts and risk analyses of alternative procurement mechanisms for follow-on POLR contracts. He compared portfolio risk management approaches to full requirements outsourcing under various terms and conditions.
- For a large municipal electric and gas company considering whether to opt-in to state retail access programs, Mr. Graves lead an analysis of what changes in the level and volatility of customer rates would likely occur, what transition mechanisms would be required, and what impacts this would have on city revenues earned as a portion of local electric and gas service charges.
- Many utilities experienced significant "rate shock" when they ended "rate freeze" transition periods that had been implemented with earlier retail restructuring. The adverse customer and political reactions have led to proposals to annual procurement auctions and to return to utility-owned or managed supply portfolios. Mr. Graves has assisted utilities and wholesale gencos with analyses of whether alternative supply procurement arrangements could be beneficial.
- The impacts of transmission open access and wholesale competition on electric generators risks and financial health are well documented. In addition, there are substantial impacts on fuel suppliers, due to revised dispatch, repowerings and retirements, changes in expansion mix, altered load shapes and load growth under more competitive pricing. For EPRI, Mr. Graves co-authored a study that projected changes in fuel use within and between ten large power market regions spanning the country under different scenarios for the pace and success of restructuring.
- As a result of vertical unbundling, many utilities must procure a substantial portion of their power from resources they do not own or operate. Market prices for such supplies are quite volatile. In addition, utilities may face future customer switching to or from their supply service, especially if they are acting as provider of last resort (POLR). This problem is a blending of risk management with the traditional least-cost Integrated Resource Planning (IRP). Regulatory standards for findings of prudence in such a hybrid environment are often not well understood or articulated, leaving utilities at risk for cost disallowances that can jeopardize their credit-worthiness. Mr. Graves has assisted several utilities in devising updated procurement mechanisms, hedging strategies, and associated regulatory guidelines thatclarify the conditions for approval and cost recovery of resource plans, in order to make possible the expedited procurement of power from wholesale market suppliers.
- Public power authorities and cooperatives face risks from wholesale restructuring if their sales-for-resale customers are free to switch to or from supply contracting with other wholesale suppliers. Such switching can create difficulties in servicing the significant debt capitalization

of these public power entities, as well as equitable problems with respect to non-switching customers. Mr. Graves has lead analyses of this problem, and has designed alternative product pricing, switching terms and conditions, and debt capitalization policies to cope with the risks.

- As a means of unbundling to retain ownership but not control of generation, some utilities turned to divesting output contracts. Mr. Graves was involved in the design and approval of such agreements for a utility's fleet of generation. The work entailed estimating and projecting cost functions that were likely to track the future marginal and total costs of the units and analysis of the financial risks the plant operator would bear from the output pricing formula. Testimony on risks under this form of restructuring was presented.
- Mr. Graves contributed to the design and pricing of unbundled services on several natural gas pipelines. To identify attractive alternatives, the marginal costs of possible changes in a pipeline's service mix were quantified by simulating the least-cost operating practices subject to the network's physical and contractual constraints. Such analysis helped one pipeline to justify a zone-based rate design for its firm transportation service. Another pipeline used this technique to demonstrate that unintended degradations of system performance and increased costs could ensue from certain proposed unbundling designs that were insensitive to system operations.
- For several natural gas pipeline companies, Mr. Graves evaluated the cost of equity capital in light of the requirements of FERC Order 636 to unbundle and reprice pipeline services. In addition to traditional DCF and risk positioning studies, the risk implications of different degrees of financial leverage (debt capitalization) were modeled and quantified. Aspects of rate design and cost allocation between services that also affect pipeline risk were considered.
- Mr. Graves assisted several utilities in forecasting market prices, revenues, and risks for generation assets being shifted from regulated cost recovery to competitive, deregulated wholesale power markets. Such studies have facilitated planning decisions, such as whether to divest generation or retain it, and they have been used as the basis for quantifying stranded costs associated with restructuring in regulatory hearings. Mr. Graves has assisted a leasing company with analyses of the tax-legitimacy of complex leasing transactions by reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent of defeasance, and compliance with prevailing guidelines for true-lease status.

Market Competition

- Mr. Graves assisted a nuclear plant owner with an assessment of whether a proposed merger of a company in whom it had a partial investment interest would alter the co-owner's incentives to manage the plant for maximum stand-alone value of the asset. Structural and behavioral models of the relevant market were developed to determine that there would be no material changes in incentive or ability to affect the value of the asset.

- Mr. Graves has testified on the quality of retail competition in Pennsylvania and on whether various proposals for altering Default Service might create more robust competition.
- Regulatory and legal approvals of utility mergers require evidence that the combined entity will not have undue market power. Mr. Graves assisted several utilities in evaluating the competitive impacts of potential mergers and acquisitions. He has identified ways in which transmission constraints reduce the number and type of suppliers, along with mechanisms for incorporating physical flow limits in FERC's Delivered Price Test (DPT) for mergers. He has also assessed the adequacy of mitigation measures (divestitures and conduct restrictions) under the DPT, Market-Based Rates, and other tests of potential market power arising from proposed mergers.
- A major concern associated with electric utility industry restructuring is whether or not generation markets are adequately competitive. Because of the state-dependent nature of transmission transfer capability between regions, itself a function of generation use, the quality of competition in the wholesale generation markets can vary significantly and may be susceptible to market power abuse by dominant suppliers. Mr. Graves helped one of the largest ISOs in the U.S. develop market monitoring procedures to detect and discourage market manipulations that would impair competition.
- Vertical market power arises when sufficient control of an upstream market creates a competitive advantage in a downstream market. It is possible for this problem to arise in power supply, in settings where the likely marginal generation is dependent on very few fuel suppliers who also have economic interests in the local generation market. Mr. Graves analyzed this problem in the context of the California gas and electric markets and filed testimony to explain the magnitude and manifestations of the problem.
- The increased use of transmission congestion pricing has created interest in merchant transmission facilities. Mr. Graves assisted a developer with testimony on the potential impacts of a proposed line on market competition for transmission services and adjacent generation markets. He also assisted in the design of the process for soliciting and ranking bids to buy tranches of capacity over the line.
- Many regions have misgivings about whether the preconditions for retail electric access are truly in place. In one such region, Mr. Graves assisted a group of industrial customers with a critique of retail restructuring proposals to demonstrate that the locally weak transmission grid made adequate competition among numerous generation suppliers very implausible.
- Mr. Graves assisted one of the early ISOs with its initial market performance assessment and its design of market monitoring tests for diagnosing the quality of prevailing competition.

Electric and Gas Transmission

- Substantial fleets of wind-based generation can impose significant integration costs on power systems. Mr. Graves assisted in assessing what additional amounts and costs for ancillary services would be needed for a Western utility with a large renewable fleet. The approach included a statistical analysis of how wind output was correlated with demand, and how much forecasting error in wind output was likely to be faced over different scheduling horizons. Benefits of geographic diversity of the wind fleet were also assessed.

- For a utility seeking FERC approval for the purchase of an affiliate's generating facility, Mr. Graves analyzed how transmission constraints affecting alternative supply resources altered their usefulness to the buyer, in comparison to the benefits from the affiliated plant.
- As part of a generation capacity planning study, he lead an analysis of how congestion premiums and discounts relative to locational marginal prices (LMPs) at load centers affected the attractiveness of different potential locations for new generation. At issue was whether the prevailing LMP differences would be stable over time, as new transmission facilities were completed, and whether new plants could exacerbate existing differentials and lead to degraded market value at other plants.
- Mr. Graves assisted a genco with its involvement in the negotiation and settlement of "regional through and out rates" (RTOR) that were to be abolished when MISO joined PJM. His team analyzed the distribution of cost impacts from several competing proposals, and they commented on administrative difficulties or advantages associated with each.
- For the electric utility regulatory commission of Colombia, S.A., Mr. Graves led a study to assess the inadequacies in the physical capabilities and economic incentives to manage voltages at adequate levels. The Brattle team developed minimum reactive power support obligations and supplement reactive power acquisition mechanisms for generators, transmission companies, and distribution companies.
- Mr. Graves conducted a cost-of-service analysis for the pricing of ancillary services provided by the New York Power Authority.
- On behalf of the Electric Power Research Institute (EPRI), Mr. Graves wrote a primer on how to define and measure the cost of electric utility transmission services for better planning, pricing, and regulatory policies. The text covers the basic electrical engineering of power circuits, utility practices to exploit transmission economies of scale, means of assuring system stability, economic dispatch subject to transmission constraints, and the estimation of marginal costs of transmission. The implications for a variety of policy issues are alsodiscussed.
- The natural gas pipeline industry is wedged between competitive gas production and competitive resale of gas delivered to end users. In principle, the resulting basis differentials between locations around the pipeline ought to provide efficient usage and expansion signals, but traditional pricing rules prevent the pipeline companies from participating in the marginal value of their own services. Mr. Graves worked to develop alternative pricing mechanisms and

service mixes for pipelines that would provide more dynamically efficient signals and incentives.

- Mr. Graves analyzed the spatial and temporal patterns of marginal costs on gas and electric utility transmission networks using optimization models of production costs and network flows. These results were used by one natural gas transmission company to design receipt-point-based transmission service tariffs, and by another to demonstrate the incremental costs and uneven distribution of impacts on customers that would result from a proposed unbundling of services.

TESTIMONY

For Public Service Company of New Mexico, Case No. 22-00270-UT before the New Mexico Public Service Commission, Mr. Graves provided testimonies on whether the Four Corners Power Plant had been prudently evaluated, environmentally upgraded, and contracted for fuel in decisions made over the prior decade. Direct testimony December 2022, rebuttal July 2023.

For Peoples' Gas Light Co. and North Shore Gas of Chicago, he testified in their general rate cases regarding whether various cost recovery or capital expenditure constraints should be place on the companies because of expected decarbonization policies in Illinois that could cause natural gas to be displaced by electrification. He argued that this is an important issue requiring more analysis and more stakeholders than a GRC setting includes, so those issues should be set for a series of Future of Gas workshops. Docket Nos. 23-0068 and 23-0069 before the Illinois Commerce Commission, June 2023.

For the Alberta Utilities Commission, Mr. Graves provided written direct and rebuttal testimony on cost of capital risk-positioning in regard to decarbonization policies, and on the financial impacts of service bypass by Rural Electrification Associations on FortisAlberta Company, Proceeding 27084, February and April 2023.

For Holtec International, Mr. Graves provided testimony regarding feasibility of decommissioning of Palisades nuclear plant ISFSI by 2040, before the Nuclear Regulatory Commission, Docket No(s). 50-255-LT-2, 50-155-LT-2, 72-007-LT, 72-043-LT-2, February 2023.

For Commonwealth Edison Company, testimony on the cost of equity capital for ComEd's four-year rate plan, before the Illinois Commerce Commission. Docket No. 23-0055, January 17, 2023.

For members of the Wisconsin Utilities Association, testimony on how to regulate rooftop solar development when it is contracted under long term power purchase agreements, Case No 9300-DR-105, November 1 and 2, 2022, Wisconsin Public Service Commission.

For WE Energies, Mr. Graves provided testimony on the importance of maintaining or growing fixed charges in electric rates as more and more customers adopt self-supply (rooftop solar) and smart energy management technologies. Case Nos. 5-UR-110 and 6690-UR-127, October 4, 2022.

For Northstar Vermont Yankee Co., he testified in the Court of Federal Claims (October 31, 2022) regarding the company's position in a market for exchanging positions in the queue of spent nuclear fuel removal rights, had DOE not breached its obligations to create a permanent repository. Oral direct and rebuttal testimonies were presented. Docket 18-1209C.

On behalf of Entergy's System Energy Resources, Inc., Mr. Graves testified (September 28, 2022) before the FERC about whether various costs of structuring and periodically refinancing a capital lease for a portion of the Grand Gulf Nuclear Station had been recorded properly for accounting and ratemaking purposes under formula rates. FERC Docket EL20-72-000.

For Calpine Corp. Mr Graves testified in Bankruptcy Court in regard to why extraordinarily high power prices that arose during the February 2021 extreme freeze, causing nearly half of Texas to lose power for several days, should not be waived as ongoing liabilities for Brazos Municipal Power Cooperative, which had incurred a $1.5billion liability to ERCOT from its inabilities to cover (or hedge) its power needs during that situation. Docket No. 21-03863-ADV, March 2, 2022

For Public Service Company of New Mexico, Mr. Graves presented rebuttal and sur-rebuttal (March 15, 2021) testimonies before the NMPSC (Case No. 21-00017-UT) on whether ownership of a share of the Four Corners power plant had been imprudently sustained in the past decade. He presented analyses that supplemented past resource planning and that compared the realized costs of the Four Corners plant to the alternative gas plant that interveners felt should have been chosen instead, showing that even if prior decisions had been imprudent, little or no damages had ensued.

For Alta Windpower, testimony in regard to whether locations of adjacent wind farms was causing interference and if so, how much harm to output was occurring (JAMS Case No.1220065657, January 16, 2021). He showed that plaintiff's alleged damages were highly speculative and overstated because based on only a single scenario for complex future decarbonization economics, and that the plaintiff's projection was out of line compared to many other forecasts.

For PacifiCorp before the Oregon Public Utility Commission (Docket UE-374, February 2020), Mr. Graves prepared testimony on the difficulties in forecasting short-term power system balancing and trading transactions and the resulting tendency for these to be underestimated in projected operating costs, hence under-collected in rates. Based on a comparison to other states practices, he proposed that such costs be fully recovered on a flow-through basis without risk-sharing, subject to prudence.

On behalf of Public Service Company of New Mexico, presented testimony before the New Mexico Public Regulation Commission on the merits of replacing the San Juan Generating Station coal units with a fleet of renewables, storage and gas-fired peakers, and on the reasons for allowing full recovery of the coal plant's sunk costs despite early retirement. Case No. 19-00018-UT, November 15, 2019.

On behalf of both Southern California Edison and Pacific Gas & Electric Company, presented direct and rebuttal testimony co-authored with Robert Mudge in regard to cost of wildfire risk under AB 1054, a state policy to create a fire insurance mechanism. Applications 19-04-014 and 19-04-015, September 4, 2019.

For Dominion Energy Kewaunee, Mr. Graves filed expert testimony in the U.S. Court of Federal Claims (Case No. 18-808 C, July 25, 2019) in regard to the ability of the plaintiff (Kewaunee Nuclear) to have had all its spent nuclear fuel removed by the U.S. DoE, had the government met its obligations to perform under the Standard Contract with the nuclear industry. Modeling shows why the government ought to be liable for damages from otherwise unnecessary storage costs at the site. Similar testimonies were filed on behalf of NorthStar for Vermont Yankee (Aug. 2019) and on behalf of Duke Power in regard to the Crystal River nuclear plant (Sept. 2019).

For Nicor Gas, a natural gas distribution company, Mr. Graves co-authored testimony on the cost of equity capital utilizing a broad spectrum of risk-pricing methods and explaining how financial leverage affects it. Testimony was filed with the Illinois Commerce Commission, Docket 18-xxxx, November 9, 2018.

For the electric transmission division of Pacific Gas & Electric, Mr. Graves presented testimony and co-authored an accompanying report on the cost of capital impacts from the extreme risks arising from potential liability for damages caused by large wildfires in California. Testimony before the FERC, Docket ER19-_- 000, Exhibit PGE-0019, October 1, 2018.

For the Government of Colombia, written and oral testimony in regard to apparent misrepresentationsof coal mine development costs and expected profitability by Glencore Corporation that adversely affected royalty payments for Colombia to Glencore. Heard in the International Court of Arbitration, ICSID Case No ARB/16/6, Washington DC, June 2018

Before the Pennsylvania Public Utility Commission, written direct testimony for Philadelphia Gas Works, Docket No. R-2017-2586783, June 2017, regarding financial benchmarking of the company vs. investor owned and public agency peers, and the need for a rate increase to maintain financial metrics and cover future costs.

Direct testimony in regard to a claim for a share of lime consumption reduction costs obtained by Plum Point as one of SMEPA's power plant operator/suppliers, on behalf of SMEPA, before the American Arbitration Association in the matter of Southwest Mississippi Electric Power Association vs. Plum Point Energy Associates, Case No. 01-15-0002-6062, September 2016.

Direct, Rebuttal and Supplementary Rebuttal reports regarding damages from loss of a nuclear generation facility, on behalf of Southern California Edison Company, Edison Material Supply LLC., San Diego Gas and Electric Company and City of Riverside before the International Chamber of Commerce in the matter of Southern California Edison v. Mitsubishi Nuclear Energy Systems, Inc. and Mitsubishi Heavy Industries, Ltd., Case No. 19784/AGF/RD, July 27, 2015 (direct), January 19, 2016 (rebuttal) and March 14, 2016 (supplemental).

Direct report re determination of an appropriate level of return needed for Standard Offer Service (SOS), on behalf of Delmarva Power & Light Company and Potomac Electric Power Company before the Maryland Public Service, Case Nos. 9226 and 9232, July 24, 2015.

Direct testimony in regard to the prudence of its gas hedging, on behalf of Hope Gas, Inc., before the West Virginia Public Service Commission, Case No. 12-1070-G-30C, June 24, 2013.

Direct testimony on behalf of Public Service Company of New Mexico before the NM Public Regulation Commission re appropriate profit incentives for energy conservation activities, Case No. 12-00317-UT, October 5, 2012.

Rebuttal testimony on behalf of Rocky Mountain Power Company before the Public Service Commission of Utah in regard to hedging practices for natural gas supply, Docket 11-035-200, July2012.

Rebuttal testimony on behalf of Rocky Mountain Power Company before the Public Service Commission of Wyoming in regard to gas supply hedging and loss-sharing, Docket No. 20000-405-ER-11, June2012.

Direct testimony on behalf of Ohio Power Company before the PUC of Ohio in regard to performance of PJM capacity markets, in Ohio Power's application for its ESP service charges, Case No. 10-2929-EL-UNC, March 30, 2012.

Expert report and oral testimony on behalf of Pepco Holdings, Inc. before the Maryland Public Service Commission in regard to inadequacies in the MD PSC's RFP for new combined cycle generation development in SWMAAC, Case No. 9214, January 31, 2012.

Direct testimony on behalf of Columbus Southern Power Company and Ohio Power Company before the Public Utilities Commission of Ohio in the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, Case No. 10-2929 -EL-UNC, August 31, 2011.

Rebuttal report on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 07-876C, No. 07-875C, No. 07-877C, August 5, 2011.

Direct Testimony on rehearing regarding the allowance of swaps in Rocky Mountain Power's fuel adjustment cost recovery mechanism, on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, July 2011.

Comments and Reply Comments on capacity procurement and transmission planning on behalf of New Jersey Electric Distribution Companies before the State of New Jersey Board of Public Utilities in the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning, NJ BPU Docket No. EO11050309, June 17, 2011; July 12, 2011.

Rebuttal testimony regarding Rocky Mountain Power's hedging practices on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, Docket No. 10-035-124, June 2011.

Expert and Rebuttal reports regarding contract termination damages, on behalf of Hess Corporation before the United States District Court for the Northern District of New York, Case No. 5:10-cv-587 (NPM/GHL), April 29, 2011, May 13, 2011.

Expert and Rebuttal reports on spent fuel removal at Rancho Seco nuclear power plant, on behalf of Sacramento Municipal Utility District before the U.S. Court of Federal Claims, No. 09-587C, October 2010, July 1, 2011.

Rebuttal testimony on the Impacts of the Merger with First Energy on retail electric competition in Pennsylvania, on behalf of Allegheny Power before the Pennsylvania Public Utility Commission, Docket Nos. A-2010-2176520 and A-2010-2176732, September 13, 2010.

Expert and Rebuttal reports on the interpretation of pricing terms in a long term power purchase agreement, on behalf of Chambers Cogeneration Limited Partnership before the Superior Court of New Jersey, Docket No. L-329-08, August 23, 2010, September 21, 2010.

Expert and Rebuttal reports on spent fuel removal at Trojan nuclear facility, on behalf of Portland General Electric Company, The City of Eugene, Oregon, and PacifiCorp before the United States Court of Federal Claims No. 04-0009C, August 2010, June 29, 2011.

Rebuttal and Rejoinder testimonies on the approval of its Smart Meter Technology Procurement and Installation Plan before the Pennsylvania Public Utility Commission on behalf of West Penn Power Company d/b/a Allegheny Power, Docket No. M-2009-2123951, October 27, 2009, November 6, 2009.

Supplemental Direct testimony on the need for an energy cost adjustment mechanism in Utah to recover the costs of fuel and purchased power, on behalf of Rocky Mountain Power before the Public Service Commission of Utah, Docket No. 09-035-15, August 2009.

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Case No. PAC-E-24-04
Exhibit No. 19
Witness: Frank Graves

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

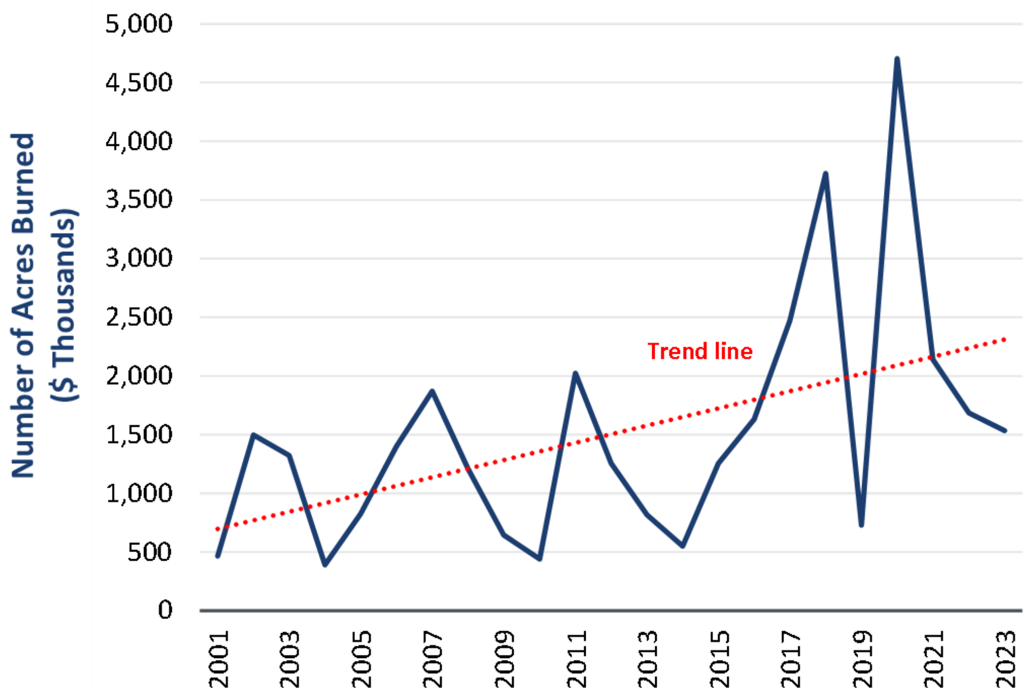
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Frank Graves

Area Burned from Human Caused Wildfires in the West

May 2024

AREA BURNED FROM HUMAN CAUSED WILDFIRES IN THE WEST



Source: National Interagency Coordination Center, https://www.nifc.gov/fire-information/statistics/human-caused. The West includes the Northwest, California, Northern Rockies, Great Basin, and Southwest regions.

Case No. PAC-E-24-04
Exhibit No. 20
Witness: Frank Graves

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

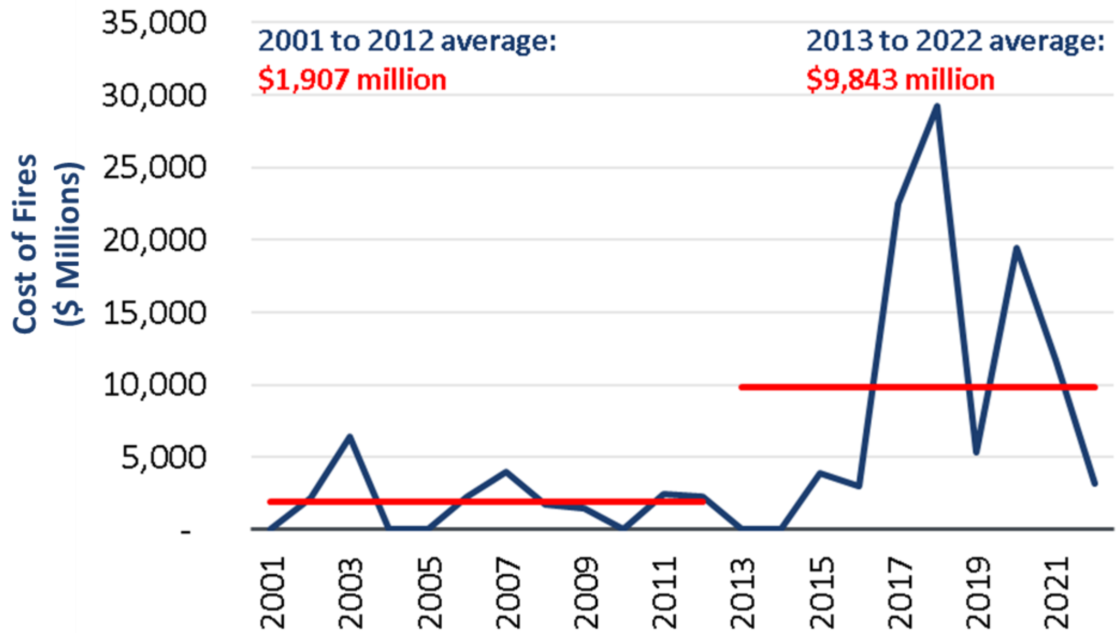
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Frank Graves

Costs of +$1 Billion Wildfires in the United States

May 2024

COSTS OF $1 BILLION+ WILDFIRES IN THE UNITED STATES



Source: National Oceanic and Atmosphere Administration – National Centers for Environmental Information U.S. Billion-Dollar Weather and Climate Disasters (2023), https://www.ncei.noaa.gov/access/billions/state-summary/US.

Case No. PAC-E-24-04
Exhibit No. 21
Witness: Frank Graves

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Frank Graves

Recent Costs of Wildfire Insurance Faced by Regional Utilities

May 2024

RECENT COSTS OF WILDFIRE INSURANCE FACED BY REGIONAL UTILITIES

			Period							
		Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
PG&E (Wildfire Liability)	[a]									
Costs		$M	43	72	120	385	159	708	707	745
Coverage Limits		$M	931	869	843	1,400	430	868	900	940
Costs/ Coverage		%	5%	8%	14%	28%	37%	82%	79%	79%
Cal. Year O&M Expense (excl. fuel and purchased power)		$M	6,949	7,327	6,383	7,153	8,750	8,707	10,194	9,725
Insurance Cost/ O&M Expense		%	0.6%	1.0%	1.9%	5.4%	1.8%	8.1%	6.9%	7.7%
SCE (Wildfire)	[b]									
Costs		$M				237	400	450	413	357
Coverage Limits		$M				990	1000	870	875	835
Costs/ Coverage		%				24%	40%	52%	47%	43%
Cal. Year O&M Expense (excl. fuel and purchased power)		$M				2,702	2,936	3,523	3,588	4,659
Insurance Cost/ O&M Expense		%				8.8%	13.6%	12.8%	11.5%	7.7%
SDG&E (Wildfire Liability)	[c]									
Costs		$M		80	110	129	183	202	215	221
Coverage Limits		$M		1,500	1,500	1,500	1,500	1,500	1,500	1,500
Costs/ Coverage		%		5%	7%	9%	12%	13%	14%	15%
Cal. Year O&M Expense (excl. fuel and purchased power)		$M		1,048	1,020	1,058	1,181	1,455	1,587	1,677
Insurance Cost/ O&M Expense		%		7.6%	10.8%	12.2%	15.5%	13.9%	13.6%	13.2%
Avista (General Liability)	[d]									
Costs		$M						7	9	14
Coverage Limits		$M						na	na	na
Costs/ Coverage		%						na	na	na
Cal. Year O&M Expense (excl. fuel and purchased power)		$M						360	372	417
Insurance Cost/ O&M Expense		%						1.8%	2.5%	3.3%
Idaho Power (Excess Liability)	[e]									
Costs		$M				7	8	9	11	14
Coverage Limits		$M				na	na	na	na	na
Costs/ Coverage		%				na	na	na	na	na
Cal. Year O&M Expense (excl. fuel and purchased power)		$M				401	392	388	396	437
Insurance Cost/ O&M Expense		%				1.8%	1.9%	2.3%	2.8%	3.3%

[a] A. 21-06-021, CPUC Decision (D.) 23-01-005 at Table 2 (Jan. 17, 2023) , Table 2; PG&E 10K; S&P Capital IQ.

[b] EIX Form 10-K; S&P Capital IQ.

[c] Application of San Diego Gas & Electric Company for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2024, A.22-05-016, SDG&E Prepared Direct Testimony of Dennis J. Gaughan (Corporate Center - Insurance), Table DG-18 (years 2021 and 2022 are forecasts) (May 2022).. Application of San Diego Gas & Electric Company, A.19-04-017, Exhibit No. SDG&E-05, Prepared Direct Testimony of John J. Reed and James M. Coyne at 34 (Apr. 2019); S&P Capital IQ.

[d] Avista Corporation v. WUTC, Washington Utilities and Transportation Commission (WUTC), Docket Nos. UE-220053, UG-220054, UE-210854, Rebuttal Testimony of Elizabeth M. Andrews, Table 7 (August 19, 2022); S&P Capital IQ.

[e] In the Matter of the Application of Idaho Power for an Accounting Order Authorizing the Deferral of Incremental Wildfire Mitigation and Insurance Costs, Idaho Public Utilities Commission Case No. IPC-E-21-02, filed Jan. 22, 2021; In the Matter of the Application of Idaho Power for Authority to Increase its Rates and Charges for Electric Service in the State of Idaho and for Associated Regulatory Account Treatment, Idaho Public Utilities Commission (IPUC) Case No. IPC-E-23-11, Motion for Approval of Stipulation and Settlement, October 2023; S&P Capital IQ.

Brattle

Case No. PAC-E-24-04
Exhibit No. 22
Witness: Frank Graves

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Frank Graves

Recent Wildfire Insurance Cost Recovery Settlements
Achieved by Regional Utilities

May 2024

Recent Wildfire Insurance Cost Recovery Settlements Achieved by Regional Utilities

	PG&E		SCE		SDG&E		Avista	Idaho Power
Jurisdiction	CPUC		CPUC		CPUC		WUTC	IPUC
Decision/ Settlement	Application 21-06-021: DECISION APPROVING SETTLEMENT REGARDING WILDFIRE LIABILITY INSURANCE COVERAGE		Application 19-08-013: DECISION MODIFYING DECISION 21-08-036 AND ADOPTING AGREEMENT REGARDING WILDFIRE LIABILITY INSURANCE		Application No. 22-05-016: JOINT MOTION FOR ADOPTION OF A SETTLEMENT AGREEMENT RESOLVING ALL INSURANCE ISSUES		Dockets UE-220053, UG-220054, UE-210, Final Order 10/04 Rejecting Tariff Sheets; Granting Petition; Approving and Adopting Full Multiparty Settlement Stipulation Subject to Conditions; Authorizing and Requiring Compliance Filing	Case No. IPC-E-23-11, Motion for Approval of Stipulation and Settlement
Date	Jan-23		May-23		Oct-23		Dec-22	Oct-23
Status	Settlement Approved		Settlement Approved		Settlement Filed		Settlement Approved	Settlement Filed
Applicable Period	2023-2026		2023-2028		2024-2027		2023-2024	2024
Insurance Type	Self		Self		Self Option**	Commercial	Commercial	Commercial
Average Annual Losses ($M):	Worst Case	Recent Exp.	Worst Case	App. B, Ex. 2	Worst Case			
	1,000.0	458.0	1,000.0	400.0	50.0			
Average Annual Loss Allocations ($M):								
Preauthorized Recovery*	718.8	424.8	741.4	338.3	33.5	173.0	8.3	14.5
Shareholder Deductible	50.0	22.9	12.5	0.0				
Undercollection/ (Overcollection)	231.3	10.3	246.1	61.7				
Average Annual Loss Allocations (%):								
Preauthorized Recovery*	71.9%	92.8%	74.1%	84.6%	67.0%			
Shareholder Deductible	5.0%	5.0%	1.3%	0.0%				
Undercollection/ (Overcollection)	23.1%	2.2%	24.6%	15.4%				
Preauthorized Cost/ Target Coverage (%):						17.3%	NA	NA
Preauthorized Cost/ O&M (%)***:	7.4%	4.4%	15.9%	7.3%	2.0%	10.3%	3.3%	3.3%
Cost Deferral Mechanisms	Balancing Account		Balancing Account		Balancing Account		Balancing Account	TBD

*Varies with actual losses for self-insurance

**Embedded within commercial authorization @ $14m per year up to $50m.

*** WA portion for Avista

Brattle