**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas & Electric Company for a Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot. (U39M.)	Application 20-10-011 (filed October 23, 2020)

DIRECT TESTIMONY OF PAUL L. CHERNICK AND JOHN D. WILSON ON BEHALF OF SMALL BUSINESS UTILITY ADVOCATES

Jennifer L. Weberski
Litigation Supervisor

Small Business Utility Advocates

548 Market Street, Suite 11200
San Francisco, CA 94104
Telephone: (703) 489-2924
Email: jennifer@utilityadvocates.org

April 2, 2021

SBUA
Small Business Utility Advocates

TABLE OF CONTENTS

ATTACHMENTS

I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: My name is Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, conservation program design, estimation of avoided costs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Attachment 1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. This previous testimony has included planning and ratemaking for distributed resources, distributed resource planning, the benefits of load reduction on the distribution and transmission systems, utility planning, marginal costs, and related issues.

I have filed testimony in ten California PUC proceedings since 2014.

Q: Mr. Wilson, please state your name, occupation, and business address.

A: I am John D. Wilson. I am the research director of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a BA degree from Rice University in 1990, with majors in physics and history, and an MPP degree from the Harvard Kennedy School of Government with an emphasis in energy and environmental policy, and economic and analytic methods.

I was deputy director of regulatory policy at the Southern Alliance for Clean Energy for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further summarized in Attachment 2.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two dozen times before utility regulators in California, the Southeast U.S. and Nova Scotia, and appeared numerous additional times before various regulatory and legislative bodies. I have testified before the California Public Utilities Commission in four proceedings.

II. Introduction

Q: On whose behalf are you testifying?

A: We are testifying on behalf of Small Business Utility Advocates (SBUA).

Q: What is the scope of your testimony?

A: We review the rate design, pilot structure, and marketing, education and outreach (ME&O) proposed by Pacific Gas & Electric (PG&E or the Company) in Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot (DAHRTP-CEV). PG&E's DAHRTP-CEV Pilot rate is a rate rider that would replace the TOU generation rates on Schedules BEV-1 and BEV-2 with a real time generation rate.

Q: What issues do you address?

A: We address the following aspects of PG&E's DAHRTP-CEV Pilot:

- The method for interpolating Marginal Generation Capacity Costs (MGCCs).

- The design of the Revenue Neutral Rate Adder and Subscription Charge.
- The evaluation, measurement and verification (EM&V) plan.
- The ME&O plan with respect to workplace charging and small business inclusion.

Q: What are your conclusions regarding PG&E's proposed pilot?

A: PG&E has not demonstrated that its proposed DAHRTP-CEV Pilot could generate benefits commensurate with the proposed budget of up to $6 million, even if it is successful.

We could support the DAHRTP-CEV Pilot proposal, with certain modifications, if PG&E is able to demonstrate that its proposed DAHRTP-CEV Pilot is likely to lead to a cost-effective program. Our recommendations to improve the proposed pilot are as follows.

1. The Commission should direct PG&E to conduct further study to establish the quantitative relationship of hourly ANL to reliability metrics.
2. The Commission should modify PG&E's DAHRTP-CEV Pilot proposal by replacing the flat revenue-neutral rate adder with TOU-period generation rates.
3. PG&E should propose a more comprehensive marketing, education and outreach (ME&O) plan in its rebuttal testimony. If it does not, the Commission should direct PG&E to file an Tier 3 Advice Letter with an updated ME&O plan and budget to address our four recommendations beginning on Page 25.
4. PG&E should propose a more comprehensive evaluation, measurement, and verification (EM&V) plan in its rebuttal testimony. If it does not, the Commission should direct PG&E to file

an Tier 3 Advice Letter with an updated EM&V plan and budget to address the comments in Table 4.

III. Benefits of the DAHRTP-CEV Pilot

Q: Please summarize the benefits expected from a successful DAHRTP-CEV Pilot.

A: In D.19-10-055, the Commission directed PG&E to file an application for a Commercial Electric Vehicle (CEV) dynamic rate design, finding that some CEV customers are interested in such a rate and that rate choices could help lower charging costs without shifting costs to non-participants and thus incentivize widespread transportation electrification.[1] The DAHRTP-CEV Pilot is also intended to test the hypothesis that dynamic pricing can achieve cost-effective load management, increased grid reliability, and GHG reduction. If the pilot gives evidence that dynamic pricing is a cost-effective tool, it can be applied to other customer circumstances.[2]

The Commission has not quantified the benefit of transportation electrification or increased grid reliability in a manner that can be applied in this proceeding. The benefits of GHG reduction and load management can be quantified.

Q: Is a successful DAHRTP-CEV Pilot reasonably likely to be cost-effective?

A: PG&E has not provided any estimate of the likely benefits of a successful DAHRTP-CEV tariff, so we were unable to determine whether a successful tariff is likely to be cost-effective for the system as a whole. The proposed

[1] PG&E, Testimony, Ch. 1, pp. 2-3.

[2] PG&E, Testimony, Ch. 1, pp. 3-4.

budget for the DAHRTP-CEV Pilot is $3.9–$6.0 million, an average of $120,000 per participating charging site.[3] That cost would cover development of the tools for computing, communicating and billing the real-time prices; incentives to overcome reluctance of EVSPs and drivers to incur costs required to participate in a pilot that may not continue, and various other costs, but not the bill savings to participants.

The benefits of the tariff would include reductions in energy costs, and capacity requirements for generation, transmission and perhaps distribution, as well as GHG emissions (and to a less extent, NOx and other generation emissions and effluents). Taking the benefits one at a time:

- Energy costs may be reduced by the RTP tariff shifting EV charging from high-priced hours to low-priced hours. The charging may be shifted from a high-price hour to a lower-price hour, but not to the lowest hour of the day. Much of the energy-cost savings will be passed through to the DAHRTP-CEV customers. Shifting one kWh from the highest-price hour of each day to the lowest-price hour of that day would save about $10/kW.
- The RTP tariff may also reduce load during hours with significant reliability risk, leading to lower capacity procurement to meet resource adequacy and integrated resource plan requirements. Customers who participate in the RTP tariff will likely reduce their contribution to the revenue requirement for existing generation costs, resulting in a cost shift. The benefit of reduced capacity procurements will be available to all customers. The current Avoided Cost

[3] PG&E, Testimony, Ch. 3, p. 19.

Calculator projects that avoided generation capacity will be worth about $135 per kW-year in 2023.

- Transmission capacity benefits, which the Avoided Cost Calculator assumes vary over time in proportion to generation capacity, will also benefit customers as a whole, but without any cost shift since transmission rates on Schedule BEV are not differentiated by TOU period. The Avoided Cost Calculator includes about $13/kW-year for transmission in 2023.
- Distribution capacity benefits occur in different hours than the generation and transmission benefits, and at different times in various parts of the PG&E system. While shifting load out of hours with high real-time prices will tend to reduce the contribution to distribution peaks, the shift is likely to be only a couple percent of total contribution to marginal distribution costs.
- PG&E does not propose to include GHG and other environmental costs in the real-time price formula. RTP customers who reduce use during high priced hours will generally (although not always) reduce GHG emissions. If each kW of peak load reduction results in one kWh of energy moving from the highest-RTP hour of each day to the lowest-RTP hour of that day, it would reduce GHG costs by about $8/kW-year.

While some participants may move charging load out of the peak period and reduce their non-RTP charges, most of the benefits will be distributed to customers in general.

Assuming that the total benefit from each kilowatt of load reduction from the RTP rate is the sum of the four quantified values above, that value would be $168/kW. If we arbitrarily assume that each participant site provides 5 kW of load reduction, it would take 14 years to achieve nominal benefits of $120,000 per site commensurate with the nominal cost of the pilot.

PG&E has not shown that it is reasonable to expect that 50 participants in the pilot program would generate enough benefits to non-participants to cover the costs of the pilot. If the DAHRTP-CEV Pilot is successful, it may be expanded to many more customers, and some of the implementation tools may be leveraged to serve additional customer classes and end uses with similar rate offerings. Extension of day-ahead pricing to additional participants would impose additional costs; for example, PG&E notes that broad offering of the DAHRTP-CEV rate could require use of the Customer Care Billing System.[4]

Q: What information should PG&E provide to demonstrate that the DAHRTP-CEV Pilot has the potential to provide system benefits in excess of costs?

A: In its rebuttal testimony, PG&E should provide reasonable estimates of the following:

- Benefits to participants and non-participants from the pilot, per participating site and vehicle.
- A rough estimate of the number of vehicle charging sites and participating vehicles required to achieve breakeven with the proposed program budget, taking into consideration marketing costs.
- If the required number of participants exceeds the capabilities of the Complex Billing System, a rough estimate of the additional costs to bill the rate through the Customer Care Billing System.

[4] PG&E, Testimony, Ch. 3, p. 17.

- The potential for the pilot to lead to a cost-effective suite of day-ahead tariffs.

This information should provide the Commission with an indication as to whether a successful DAHRTP-CEV Pilot might benefit PG&E's customers as a whole. Absent such a showing, we would not recommend that the Commission authorize the proposed budget.

IV. Estimating Hourly Marginal Generation Capacity Cost

Q: Please summarize PG&E's proposal for calculating MGCCs.

A: PG&E states that,

> The MGCC are forecasts of the hourly value of capacity, converted into the same units and adjusted for losses and the 15 percent planning reserve margin. MGCCs are calculated using a peak capacity allocation factor (PCAF) methodology, which assigns capacity costs only to hours in which the [Adjusted Net Load (ANL)] exceeds a threshold equal to 80 percent of the average of annual peak ANLs over the 10 weather scenarios. Hourly MGCC is then allocated proportionally to the amount each hour's ANL exceeds the threshold.[5]

Q: What is your opinion of PG&E's proposal?

A: We agree that the proposal is a generally reasonable application of California's marginal cost methods to an RTP rate design. It is reasonable for the RTP rate to collect MGCCs as determined in a General Rate Case (GRC Phase 2), adjusted for losses and the planning reserve margin.[6]

---

[5] PG&E, Testimony, Ch. 2, p. 3. PG&E defines ANL as gross, or metered, load less utility-scale wind and solar production, nuclear, hydroelectric, and other renewables. PG&E states that, "ANL is essentially the amount of load that must be met by thermal generators, imports and energy storage."

[6] In PG&E's General Rate Case (Phase 2, A.19-11-019), we testified in favor of energy-only RTP for general application to commercial classes, due to concerns with complexity and equity.

It is also reasonable to use forecast ANL as an index for assigning capacity costs to hours on a day-ahead basis. PG&E's method for calculating ANL was approved by the CPUC in D.17-01-006 for purposes of determining TOU periods and allocating marginal generation capacity costs to those periods using the Percent Capacity Allocation Factor (PCAF) method.[7] The PCAFs are hourly factors identified by the ANL whose weight depends on the amount that the hourly load is above a threshold, which has been set at 80 percent of ANL maximum load. An hour with a 90 percent ANL has a MGCC that is exactly twice that in an hour with 85 percent ANL. This linear allocation method is probably reasonable for analyses involving the aggregation of many hours, such as determining TOU periods and allocating MGCCs to those periods.

In order to determine the ANL maximum load, and hence the threshold, PG&E reasonably proposes to forecast the peak ANL using 10 weather-year scenarios.[8]

Notwithstanding the reasonableness for the existing PCAF for aggregate computations, PG&E should consider alternatives to the linear interpolation of MGCCs to individual hours for real-time pricing. Setting the real-time price

---

In this proceeding, we support including both generation capacity and energy costs, because the pilot will only enroll a limited number of charging-only customers with equipment that can respond to rapid price changes.

[7] D.17-01-006, pp. 17-18, 71-72 (Finding of Fact 15), and Appendix 1, p. 1. See also D.18-08-013, pp. 30-31, 156-157 (Finding of Fact 7). In D.17-01-006, the CPUC recognized ANL as including adjustments for nuclear and hydroelectric and in D.18.-08-013, the CPUC recognized that PG&E had added other renewable resources such as biomass and geothermal.

[8] The weather year scenarios provide hourly load and renewable energy generation that are grossed up to match overall system forecasts for the year in which the ANL peak is required. PG&E, GRC Testimony (January 15, 2021), A.19-11-019, Ch. 2, p. 14.

for a specific hour of the next day does not involve any averaging across hours; overstating the MGCC for one hour may cause customers to shift loads in ways that are not beneficial. As PG&E noted in its 2017 GRC testimony, since the PCAF-weighted load method was first adopted by the Commission in 1993, it has been refined and improved on the initiative of PG&E or in response to recommendations from interested parties.[9] As the PCAF method is being applied to real-time pricing for the first time in this proceeding, that method should be reviewed and improved.

Q: How do you recommend PG&E go about improving the PCAF method?

A: PG&E should study the relationship between ANL and reliability metrics such as loss of load probability (LOLP) and expected unserved energy (EUE). While it is reasonable to assume that ANL and reliability are related in some way, we have been unable to locate any study that verifies and quantifies the relationship.

The importance of quantifying the relationship is illustrated by analysis of data from the Demand Response ELCC study completed for CAISO.[10] That study reported average ANL, LOLP, and EUE values for each hour in each month of 2019, for a total of 288 data bins.[11] Significant LOLP and EUE

---

[9] PG&E, Direct Testimony, 2017 General Rate Case Phase II (Amended December 2, 2016), A.16-06-013, Exhibit 2, Ch. 9, p. 1.

[10] Energy and Environmental Economics, *Demand Response ELCC* (December 2020). Available at: http://www.caiso.com/InitiativeDocuments/E3DemandResponseELCCStudy-EnergyStorage-DistributedEnergyResourcesPhase4.pdf.

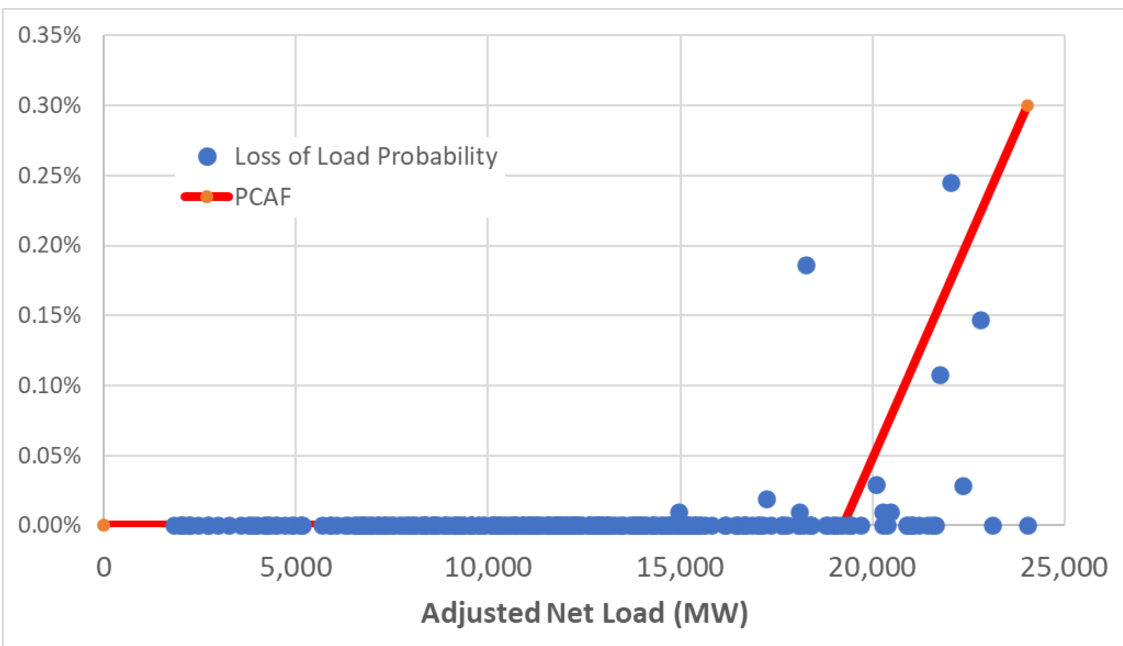
[11] We calculated "average ANL" as the average ANL for the hour and month, including all ten weather-years included in the study. The data were provided by PG&E in response to an SBUA data request as shown in Attachment 4.

occurred only in hours with ANL over about 18,000 MW, as shown in Figure 1 for LOLP.

However, out of the top 40 hour bins with the highest average ANL, only nine hours had *any* non-zero value for EUE or LOLP. Taken by itself, this analysis suggests that reliability risk is essentially constant for hourly ANL above 18,000 MW.

Figure 1 also shows the PCAF allocation for the 2019 data. The observed 18,000 MW threshold for LOLP is only about 75% of the maximum ANL, so much of the LOLP occurs in hours to which the PCAF assigns no capacity costs.

Figure 1: Adjusted Net Load, Loss of Load Probability and PCAF



This result is highly counterintuitive. Our analysis raises more questions than it answers. Further investigation is required as the Commission develops MGCC-based price signals to drive load shifting.

Q: Please summarize your findings and recommendation with respect to the method for allocating marginal generation capacity costs to hours.

A: We recommend the following findings to the Commission.

1. It is reasonable to assume there is a causal relationship between ANL and reliability and that some variant of the PCAF method would be appropriate for assigning MGCC values to high-ANL hours.
2. No recent applications of the PCAF method have demonstrated that hourly ANL is quantitatively related to reliability metrics.
3. It is reasonable for PG&E to apply the PCAF method as used in cost allocation for purposes of allocating MGCCs to hours for purposes of the DAHRTP-CEV Pilot.
4. For more widespread application of DAHRTP rates that include MGCCs, further evidence is required to demonstrate the quantitative relationship of hourly ANL to reliability metrics.

We recommend that the Commission should direct PG&E to conduct further study to establish the quantitative relationship of hourly ANL to reliability metrics. Ideally, such study would be conducted in coordination with the other IOUs and CAISO.

V. Design of the Revenue Neutral Rate Adder and Subscription Charge

Q: Please summarize PG&E's proposal for a revenue neutral rate adder.

A: PG&E proposes:

> "a rate adder that would collect other non-marginal costs collected in generation … as necessary to ensure that the rate is revenue neutral. The proposed revenue neutral rate adder would not vary by time of day. PG&E proposes to base all of its generation revenue neutral calculations on the bundled average generation rate."[12]

Based on the May 1, 2020 generation revenue requirement, PG&E proposes an adder of $0.05281/kWh.[13] PG&E's proposed treatment of the Power Charge Indifference Adjustment (PCIA) will eventually result in the PCIA being identified for bundled customers as a flat rate (not differentiated by season or TOU), but this will not affect the rate design in a meaningful way.

Q: Please summarize PG&E's proposal for a subscription charge.

A: PG&E's application does not mention the subscription charge, but PG&E states that the proposed DAHRTP-CEV rate would be identical to Schedules BEV-1 and BEV-2 with the exception of the replacement of the current TOU generation rates on those schedules.[14] We assume that PG&E intends to retain the full subscription charge from those schedules in the DAHRTP-CEV rate.

It is not entirely clear what generation costs the subscription rate is designed to collect. In its 2019 testimony proposing the initial subscription charge, PG&E gave two different explanations:

- On direct, PG&E said that "The generation subscription charge was set to the percent of non-peak PCAF fixed charges to ensure these fixed costs are collected despite usage patterns."[15]

---

[12] PG&E, Testimony, Ch. 2, p. 5.

[13] PG&E, Testimony, Ch. 2, p. 6.

[14] PG&E, Application, p. 3.

[15] PG&E, Direct Testimony, *Commercial Electric Vehicle Rate Proposal* (February 26, 2019, A.18-11-003), Ch. 2, p. 13. PG&E also stated, "The generation subscription charge was set to

- In rebuttal, PG&E said that "The subscription charge … is designed to collect fixed or Equal Percent of Marginal Cost (EPMC)-scaled costs beyond the marginal costs to produce and deliver energy to CEV customers. CEV customers, like all utility customers, incur certain fixed costs regardless of whether or how much energy they consume, and the subscription is designed to recover some of these non-variable costs."[16]

While the statement in the rebuttal testimony may be an attempt to clarify the vague explanation in the direct testimony by defining "fixed" as EPMC-scaled costs, the second statement does not explain why the original statement referred to "non-peak PCAF" costs; EPMC-scaled costs are reflected in both peak and off-peak periods.

Q: What is your opinion of PG&E's proposal?

A: We agree that non-marginal generation costs (which will not be recovered through the RTP charges) should be collected in a revenue-neutral fashion, and that other non-marginal generation costs should be differentiated by TOU period just as they are in comparable tariffs.[17]

Although SBUA and other parties presented reasonable objections to the use of a subscription charge in the 2019 Commercial Electric Vehicle Rate proceeding, the Commission approved the use of the subscription charge. We

---

the fixed charges times the proportion of PCAF in the non-peak to ensure these fixed costs are collected despite usage patterns." *Id.,* p. 10.

[16] PG&E, Rebuttal Testimony, *Commercial Electric Vehicle Rate Proposal* (May 3, 2019, A.18-11-003), p. 18.

[17] The PCIA generation cost component would be collected from both RTP and non-RTP customers as a flat rate.

therefore do not object to its use in the DAHRTP-CEV Pilot rate, and PG&E has confirmed that the subscription charge does not include generation costs.[18]

Q: How should TOU rates be used to collect the other non-marginal costs?

A: The cost components that are not recovered through real-time pricing should be recovered as they are in the current TOU generation rates on Schedules BEV-1 and BEV-2. In other words, the DAHRTP-CEV tariff should consist of the real-time pricing rates for marginal generation and the BEV rates for all other components.

To illustrate this adjustment, we have calculated the average day-ahead hourly energy and capacity costs based on the TOU periods used in Schedule BEV. Schedule BEV has three TOU periods that apply year-round. We used PG&E's historical day-ahead energy and capacity prices for January 1, 2017 – September 30, 2020, as described in Attachment 3. Marginal generation capacity costs are allocated as described in PG&E's testimony for purposes of this illustration.

The average day-ahead costs of $0.05801 shown in Table 1 are slightly higher than the value PG&E proposes for its revenue neutral $0.05281/kWh adder. This difference is at least partially attributable to the use of 2017 – 2020 data in Table 1, and the use of the May 1, 2020 total generation revenue requirement by PG&E. We have not attempted to determine if there are other meaningful differences.

---

[18] PG&E, Data Response to SBUA_001-Q03 (March 31, 2021). PG&E's initial proposed Schedule BEV rates included a generation portion in the subscription charge, but the rate design approved by D.19-10-055 did not include generation in the subscription charge.

Table 1: Average Day-Ahead RTP Rates, by TOU Period

TOU Period	DA Energy Price ($/MWh)	DA MGCC ($/MWh)	Total ($/kWh)
Peak	51.58	32.59	0.08418
Off-Peak	40.99	16.44	0.05743
Super Off-Peak	28.84	0.00	0.02884
Total	**41.05**	**16.95**	**0.05801**

We then adjusted the generation and total TOU rates for Schedule BEV by removing the average day-ahead RTP rate for each period, from Table 1.[19] As shown in Table 2, the resulting revenue neutral generation rate has very similar off-peak and super-off-peak rates, but a 16¢/kWh to 18¢/kWh differential between the peak rate and the off-peak.

Table 2: TOU Generation Rates, BEV and Differentiated RTP Residual

	Schedule BEV-1	Schedule BEV-2-S	Schedule BEV-2-P
Current Rates			
Peak	0.25786	0.27713	0.26675
Off-Peak	0.07530	0.07377	0.07077
Super Off-Peak	0.04991	0.04837	0.04657
Illustrative RTP Rate Adder with TOU Differentiation			
Peak	0.17368	0.19295	0.18257
Off-Peak	0.01787	0.01634	0.01334
Super Off-Peak	0.02107	0.01953	0.01773

Because the distribution energy rates in the BEV tariffs are very low, with only a 1 ¢/kWh differential for peak rates, the resulting differential for total energy rates shown in Table 3 is very similar to those in Table 2, at 17¢/kWh – 19¢/kWh.

[19] PG&E Schedule BEV (March 1, 2021).

Table 3: TOU Total Energy Rates, BEV and Differentiated RTP Residual

	Schedule BEV-1	Schedule BEV-2-S	Schedule BEV-2-P
Current Rates			
Peak	0.32455	0.33974	0.33195
Off-Peak	0.13254	0.12651	0.12307
Super Off-Peak	0.10588	0.10324	0.10041
Illustrative RTP Rate Adder with TOU Differentiation			
Peak	0.24037	0.25556	0.24777
Off-Peak	0.07511	0.06908	0.06564
Super Off-Peak	0.07704	0.07440	0.07157

In these examples, the residual super off-peak rates are slightly higher than the off-peak rates. Since average RTP rates will be higher in off-peak than super off-peak periods, this counter-intuitive result is not material to the overall price signals that customers will receive. However, this result suggests that the underlying Schedule BEV rate design may require some adjustment.[20]

Q: How would maintaining the TOU differential in the revenue neutral rate adder compare to PG&E's proposal for a flat adder?

A: PG&E's flat adder would result in little rate differentiation on most days. The average differentiation between super off-peak and peak rates using a flat adder would be about 5.5 ¢/kWh, as can be calculated from Table 1. Using PG&E's 2017–2020 dataset, we estimate that the average rate differential between the super off-peak and peak period would be less than 6¢/kWh on an average of 343 days annually.

In contrast, our proposal would begin with the rate differential already present in Schedule BEV, converting 5.5¢/kWh of the fixed TOU rate differential to an expected 5.5¢/kWh of real-time pricing, maintaining the BEV

[20] If that relationship occurs in the actual rate computation, and the Commission is concerned that the inverted TOU adders would confuse customers, it can require that PG&E set the off-peak and super off-peak adder components equal.

rate differential of 22¢/kWh to 24¢/kWh. On days with high ANLs—roughly 22 days per year—the rate differential would be much larger than normal under either approach. Our proposal would provide a more meaningful rate differential on average days and a slightly larger rate differential on days with high ANLs compared with PG&E's flat adder.

Q: Why is it important to provide a meaningful rate differential on average days?

A: Under our proposal, rate differentials would be virtually guaranteed to be larger than 17¢/kWh every day, giving customers the opportunity to charge at low super off-peak rates and encouraging them to shift load to that period. This would provide participants with an incentive to deploy and operate charging practices that reduce charging costs, without shifting costs to non-participants. This would help encourage widespread transportation electrification, focused on off-peak charging.

Q: Would your proposal potentially shift costs to non-participants, compared to the BEV rates or PG&E's proposal?

A: No. Because the subscription charge is relatively new, it is possible that it could incentivize customer behaviors that result in under- or over-recovery of costs, but the subscription charge would be the same under either approach.

On both the BEV rates and our proposed rates, customers would avoid charging during on-peak periods and shift demand to off-peak periods on all days. Under PG&E's flat adder approach, customers would have lower load-shifting incentives on most days compared to the BEV rates and on all days, compared to our proposal. This difference in load shape could result in different revenue recovery (and eventually different cost allocation) under the various options. Under- or over-recovery could be corrected through a true-up under the Energy Resource Recovery Account (ERRA) proceeding.

Q: Please summarize your findings with respect to the revenue neutral rate adder and subscription charge.

A: We recommend the following findings to the Commission.

1. It is feasible to maintain differentiation of the non-RTP portion of the DAHRTP-CEV Pilot rates by TOU period.
2. A significant rate differential on an average day provides customers with a meaningful opportunity to lower charging costs, which will help incentivize widespread transportation electrification.
3. Any shift of costs to or from non-participants can be mitigated by using a true-up in the ERRA proceeding. However, the limited number of participants in the DAHRTP-CEV Pilot means that the cost shift should be *de minimis* and should not require mitigation.

Q: Please summarize your recommendations with respect to the revenue neutral rate adder and subscription charge.

A: We recommend that the Commission modify PG&E's DAHRTP-CEV Pilot proposal by replacing the flat revenue-neutral rate adder with TOU-period generation rates. Those rates should be based on the generation rates in Schedule BEV, adjusted to remove the estimate of average RTP rates in each TOU period.

VI. Marketing, Education and Outreach (ME&O) Plan

Q: What is PG&E's enrollment objective?

A: PG&E intends to enroll up to 50 account holders with existing EV charging infrastructure, including five target audiences: public Direct Current Fast

Chargers, workplace, multi-unit dwellings, transit fleets and medium-duty delivery fleets.[21] PG&E intends to achieve this enrollment through one-to-one outreach and collateral/tools that may be shared directly, via technology providers, or via partner CCAs.

Q: What is your opinion regarding PG&E's interest in including at least two CCAs in its pilot?

A: We strongly support this proposal. It is our understanding that roughly half of small businesses are bundled, and that roughly half are not. We assume that very few small businesses are direct-access customers.

Q: Does PG&E mention any specific interest or intent to enroll small businesses in the pilot?

A: No. Our review of PG&E's testimony and the EPRI study did not identify any references to small businesses or to the specific concerns that small businesses may have.

Q: What was the intent of the EPRI study?

A: The EPRI study, *Commercial Electric Vehicle Rate Design: Stakeholder Interview Results*, sought to "explore the role that rate design plays in determining consumer interest in electric vehicles (EVs) for commercial applications and to assess customer understanding and acceptance of various rate design constructs."[22]

---

[21] PG&E, Direct Testimony, Ch. 3, p. 12.

[22] PG&E, Testimony, Ch. 1, Attachment A, p. 17.

Q: Does the EPRI study consider the perspective of small businesses?

A: No. None of the 23 "EV stakeholder organizations" included as study participants were small businesses or spoke to issues from a small business perspective.[23]

Q: Would an RTP rate be of interest to a small business?

A: We believe that there would be many small businesses that would be interested in an RTP rate in two categories: workplace charging and medium-duty delivery fleets.

With respect to workplace charging, small businesses that own their property (and have existing EV charging infrastructure) could be good candidates for the DAHRTP-CEV Pilot. If a small or medium-sized business (SMB) pays its own electric bill, then it is likely to be the property owner. A survey of such SMBs in the nine-county San Francisco Bay Area found that over three-quarters of them owned, managed, and occupied the entire building. Tech companies would be an obvious target market considering the likelihood that those companies and their employees would be early adopters.

Small businesses are likely to face somewhat different challenges in adopting DAHRTP-CEV than would larger businesses. For example, small businesses may lack staff with the time, authority and expertise to take the lead on EV charging (or other workplace commuting issues, for that matter). On the other hand, a small business may be able to commit more quickly than a large corporation with multiple levels of review. The actual differences between small and larger businesses should be considered in the pilot.

[23] PG&E, Testimony, Ch. 1, Attachment A, pp. 20-21.

Therefore, PG&E should aim to include at least 3 small businesses with workplace charging in the pilot.

PG&E should also explicitly consider the interests of tenants in office buildings or shopping centers. While the tenants will need to work with the property manager to benefit from NEM systems, PG&E should encourage such collaboration in its ME&O plan and address its effectiveness in the EM&V Plan, as discussed below.

With respect to medium-duty delivery fleets, a variety of small businesses (local movers, furniture or appliance retailers, grocers, caterers) are potential participants in RTP rates. While large businesses with medium-duty delivery fleets "have indicated less flexibility for charging and a preference for clear, stable rates,"[24] PG&E has not investigated whether small businesses may have more flexibility and greater interest in pursuing potential bills savings. For example, local moving companies may have longer charging windows, since their trucks would not tend to be on the road for many hours a day. Therefore, PG&E should include at least 3 small businesses with medium-duty delivery fleet charging in the pilot.

Q: Are there small businesses with existing EV charging infrastructure in PG&E's service area?

A: We believe that there are, although small businesses are likely to have fewer EV charging stations (per employee or vehicle) than larger ones. Our review of IOU transportation electrification programs suggests that none of the IOUs have focused significant outreach on small businesses.[25]

---

[24] PG&E, Testimony, Ch. 1, p. 22.

[25] SBUA, *Reply Comments on the Transportation Electrification Framework (TEF) Overview, IOU Transportation Electrification Plan Development, IOU Roles, and Near-Term*

While the proposed DAHRTP-CEV Pilot is not a transportation electrification program, we recommend that the Commission direct PG&E to conduct additional outreach to identify small businesses who may participate. If the initial outreach is unsuccessful, PG&E should direct its transportation electrification program managers to increase outreach efforts to small businesses to identify potential candidates for adding chargers and adopting the DAHRTP-CEV rate.

If PG&E is initially unable to line up sufficient small businesses for the pilot, it should proceed to recruit the necessary participants regardless of size. In that case, the Commission should authorize PG&E to add more small participants at a later date.

Q: Do you have any concerns with PG&E's marketing strategy?

A: Yes. PG&E states that 70 of the 107 workplace site hosts in the Electric Vehicle Charge Network (EVCN) program have implemented their own pricing plan for drivers, rather than passing through PG&E rates.[26] PG&E acknowledges that, "Maximizing turnover and a dynamic rate may provide misaligned incentives. Yet PG&E's marketing plan for workplace charging appears to rely on "engaged customers" whose charging decisions are presumably responsive to hourly charging rates.[27]

Some workplaces may be offering free charging and others may be offering rates based on duration of the charge or hookup. Those pricing methods could be updated by the site host to utilize pricing signals from the

---

Investment Priorities (April 27, 2020), R.18-12-006; SBUA, *Opening Comments on Sections 6, 11.1 and 11.2 of the Draft TEF* (August 21, 2020), R.18-12-006.

[26] PG&E, Testimony, Ch. 1, footnotes 42, 46.

[27] PG&E, Testimony, Ch. 1, p. 21.

DAHRTP-CEV Pilot rate. Site hosts that offer free charging could notify users that charging will be unavailable (or otherwise limited) during high-priced hours. Site hosts who charge on an hourly basis could offer tiered pricing. Customers are likely to be familiar with the use of higher hourly parking charges during peak periods or special events, so a tiered hourly charging rate may be considered simpler than a RTP rate.[28] Each of these options would allow the site host to provide a rate that is generally responsive to the DAHRTP-CEV Pilot rate without requiring customers to be engaged in an hourly pricing system.

Q: Please summarize your recommendations with respect to ME&O for small businesses.

A: PG&E should reconsider its ME&O plan to address the following issues.

1. When including CCAs (and potentially DAs) in the DAHRTP-CEV Pilot, PG&E should encourage those partners to include small businesses as participating customers.
2. The DAHRTP-CEV Pilot should include participation from at least 3 small business customers in each of the workplace charging and medium-duty delivery fleet categories.
3. If neither PG&E nor its partners are able to locate a sufficient number of small businesses to participate in the DAHRTP-CEV Pilot, PG&E should conduct additional small business outreach through its transportation electrification programs to develop potential participants. Late enrollment, potentially exceeding the 50

[28] The site host might establish 3 or 4 tiers of rates, with drivers alerted to the tiers by a sign as they enter the parking facility. For example, "Today is an Green rate day, except for Orange charging rate from 4–7 PM."

participant target, should be allowed in order to obtain some level of experience with small-business participants.

4. PG&E should revise its marketing plan to engage site hosts in discussion of potential custom pricing arrangements to include methods for indirectly communicating pricing signals from the DAHRTP-CEV Pilot rate to drivers.

If PG&E does not provide an improved ME&O plan, we recommend the Commission reach the following findings.

1. PG&E's development of its DAHRTP-CEV Pilot did not specifically consider the participation of and particular interests of small businesses, who may have different challenges and capabilities than large businesses.
2. Small businesses with vehicle charging infrastructure may have a strong interest in the DAHRTP-CEV Pilot, particularly small businesses that utilize workplace charging or have medium-duty delivery fleets.
3. PG&E's vehicle electrification programs do not appear to have emphasized small business outreach in the past, and such efforts may be required to develop suitable candidates for participation in the DAHRTP-CEV Pilot.

In the absence of an improved ME&O plan, we recommend that the Commission direct PG&E to file an Tier 3 Advice Letter with an updated ME&O plan and budget to address the four recommendations we listed above.

In addition, the Commission should find that CCAs serve a large share of small businesses in PG&E's service territory, and that CCAs should be included the DAHRTP-CEV Pilot.

VII. Evaluation, Measurement and Verification Plan

Q: Please summarize PG&E's evaluation, measurement and verification (EM&V) plan.

A: PG&E's EM&V plan describes a load impact estimation. PG&E "also expects to collect and analyze qualitative data (e.g., surveys) to understand impacts and associated implications."[29] PG&E's description of pilot phases includes additional quantitative analyses such as integration of PG&E's price broadcast with price discovery tools.[30]

Q: What is your opinion of PG&E's EM&V plan?

A: The quantitative aspects of PG&E's EM&V plan are fairly vague, although there is a reference to protocols for load impact estimation that provides some assurance that the findings will be comparable to other program EM&V reports. It is unclear whether PG&E intends to conduct the EM&V activities with its own staff, or hire a consultant to provide a third-party evaluation. A third-party evaluator could bring experience with evaluating dynamic pricing rates and offer insights informed by experiences with other utilities.

Even vaguer are the qualitative aspects of PG&E's EM&V plan. Since the total enrollment is anticipated to be 50 customers or fewer, shared among five customer groups, it is unlikely that there will be statistically significant findings for each individual customer group. In its discussion of customer segmentation, PG&E presents hypotheses about each of the five groups. As shown in Table 4, the quantitative analyses in the EM&V plan may not prove or disprove these five hypotheses without further qualitative investigation.

---

[29] PG&E, Testimony, Ch. 3, p. 9.

[30] PG&E, Testimony, Ch. 3, p. 8.

Table 4: Comments on PG&E's Customer Segmentation EM&V Plan

Customer Segment	PG&E Hypothesis	Response
Public DCFC	"The dynamic rate would not provide a simple, low-cost electric fuel option for most public DCFC operators," except that those "stations that combine multiple charging ports with energy storage and photovoltaic systems" could use a dynamic rate to improve the economics of such a system.[31]	The ME&O plan does not include plans to reach out to DCFC operators with solar-plus-storage systems. The EM&V plan does not include collection of information on the operation and economics of solar-plus-storage systems.
Workplace charging	"Workplace charging on the proposed dynamic rate could produce cost savings with proactive and engaged customers."[32]	The EM&V plan to measure customer engagement only mentions "customer satisfaction surveys."[33] It lacks plans to gather information on site hosts' custom pricing decisions and methods for providing pricing updates to charger/drivers. EM&V should also gather data to measure whether customers are proactive and engaged.
Multi-unit dwellings (MUDs)	"MUD charging on the proposed dynamic rate would likely produce cost savings under the right circumstances and with the right educational resources."[34]	The EM&V plan does not include evaluation of the "circumstances" that make RTP charging beneficial (presumably resident schedules), or the effectiveness of "educational resources."
Transit operators	"A dynamic rate is unlikely to be beneficial or adopted by most transit customers, though it may be beneficial on a case-by-case basis, taking route topology, battery size and specific bus duty cycles into consideration." [35]	The EM&V plan does not include evaluation of transit system characteristics that would make a dynamic rate attractive. The plan should include both pre-participation simulation and benefit evaluation for any transit participants.

[31] PG&E, Testimony, Ch. 1, p. 20.

[32] PG&E, Testimony, Ch. 1, p. 21.

[33] PG&E, Testimony, Ch. 3, p. 8.

[34] PG&E, Testimony, Ch. 1, p. 22.

[35] PG&E, Testimony, Ch. 1, p. 22.

Customer Segment	PG&E Hypothesis	Response
Medium-duty delivery fleets	"The proposed dynamic rate may provide cost savings to MD delivery operators. MD delivery operators with fleets of vehicles that have longer charging windows are more likely to garner greater cost savings from use of a proposed dynamic rate."[36]	The EM&V plan does not include steps to gather data to measure the length of charging windows or other measures of charging flexibility. The evaluation should also determine who manages the charging schedule (driver, dispatcher, fleet manager, etc.) and what practices are followed.

Careful evaluation of each customer segment will be useful for both determining whether the DAHRTP-CEV Pilot is successful enough to continue and providing valuable data on transportation electrification practices in general and insights into the five customer segments. If the EM&V report is comprehensive, the findings could be applicable to the design of other load management or transportation electrification programs.

Q: What changes should PG&E make, or findings should the Commission reach, with respect to the proposed EM&V plan?

A: The proposed EM&V budget is $125,000 to $150,000, representing less than 1 percent of the total pilot budget.[37] The EM&V plan and its proposed budget appears insufficient to conduct an overall evaluation of the DAHRTP-CEV Pilot, including in-depth evaluation of each of the five customer segments included in the pilot. We encourage PG&E to reconsider its EM&V plan in its rebuttal testimony and propose a more comprehensive plan.

[36] PG&E, Testimony, Ch. 1, p. 23.

[37] PG&E, Testimony, Ch. 3, pp. 9-10. The plan also includes a budget for $100,000 to $200,000 for "customer experience and customer insights research." It is unclear how much of this budget may also be related to EM&V purposes. PG&E, Testimony, Ch. 3, pp. 15-16. The plan also includes a budget for $164,000 for EV driver incentives that includes a survey participation requirement. PG&E, Testimony, Ch. 3, p. 10.

If PG&E does not provide an improved EM&V plan, we recommend the Commission reach the following findings.

1. PG&E's proposed EM&V plan is insufficient to conduct an overall evaluation of the DAHRTP-CEV Pilot, including in-depth evaluation of each of the five customer segments included in the pilot.
2. A comprehensive EM&V report on the DAHRTP-CEV Pilot could be applicable to the design of other load management or transportation electrification programs.

In the absence of an improved EM&V plan, we recommend that the Commission direct PG&E to file an Tier 3 Advice Letter with an updated EM&V plan and budget to address the comments in Table 4.

Q: Does this conclude your testimony?

A: Yes.

Attachment 1

PAUL L. CHERNICK

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

"Price Effects as a Benefit of Energy-Efficiency Programs" (with John Plunkett), *2014 ACEEE Summer Study on Energy Efficiency in Buildings* (5) 57–5-69. 2014.

"Environmental Regulation in the Changing Electric-Utility Industry" (with Rachel Brailove), *International Association for Energy Economics Seventeenth Annual North American Conference* (96–105). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Jonathan Wallach), *1996 Summer Study on Energy Efficiency in Buildings,* Washington: American Council for an Energy-Efficient Economy 7(7.47–7.55). 1996.

"The Allocation of DSM Costs to Rate Classes," *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. May 1994.

"Environmental Externalities: Highways and Byways" (with Bruce Biewald and William Steinhurst), *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. May 1994.

“The Transfer Loss is All Transfer, No Loss” (with Jonathan Wallach), The *Electricity Journal* 6:6 (July 1993).

“Benefit-Cost Ratios Ignore Interclass Equity” (with others), *DSM Quarterly*, Spring 1992.

“ESCos or Utility Programs: Which Are More Likely to Succeed?” (with Sabrina Birner), *The Electricity Journal* 5:2, March 1992.

“Determining the Marginal Value of Greenhouse Gas Emissions” (with Jill Schoenberg), *Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II*, July 1991.

“Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs” (with Emily Caverhill), *Proceedings from the Demand-Side Management and the Global Environment Conference*, April 1991.

“Accounting for Externalities” (with Emily Caverhill). *Public Utilities Fortnightly* 127(5), March 1 1991.

“Methods of Valuing Environmental Externalities” (with Emily Caverhill), *The Electricity Journal* 4(2), March 1991.

“The Valuation of Environmental Externalities in Energy Conservation Planning” (with Emily Caverhill), *Energy Efficiency and the Environment: Forging the Link*. American Council for an Energy-Efficient Economy; Washington: 1991.

“The Valuation of Environmental Externalities in Utility Regulation” (with Emily Caverhill), *External Environmental Costs of Electric Power: Analysis and Internalization*. Springer-Verlag; Berlin: 1991.

“Analysis of Residential Fuel Switching as an Electric Conservation Option” (with Eric Espenhorst and Ian Goodman), *Gas Energy Review*, December 1990.

“Externalities and Your Electric Bill,” *The Electricity Journal*, October 1990, p. 64.

“Monetizing Externalities in Utility Regulations: The Role of Control Costs” (with Emily Caverhill) *Proceedings from the NARUC National Conference on Environmental Externalities*, October 1990.

“Monetizing Environmental Externalities in Utility Planning” (with Emily Caverhill), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“Analysis of Residential Fuel Switching as an Electric Conservation Option” (with Eric Espenhorst and Ian Goodman), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“A Utility Planner’s Checklist for Least-Cost Efficiency Investment” (with John Plunkett) in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

Environmental Costs of Electricity (with Richard Ottinger et al.). Oceana; Dobbs Ferry, New York: September 1990.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy" (with John Plunkett and Jonathan Wallach), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"Incorporating Environmental Externalities in Evaluation of District Heating Options" (with Emily Caverhill), *Proceedings from the International District Heating and Cooling Association 81st Annual Conference*, June 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment," (with John Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference*, June 1990.

"Incorporating Environmental Externalities in Utility Planning" (with Emily Caverhill), *Canadian Electrical Association Demand Side Management Conference*, May 1990.

"Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?" in *Proceedings of the NARUC Second Annual Conference on Least-Cost Planning*, September 10–13 1989.

"Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities," in *Least Cost Planning and Gas Utilities: Balancing Theories with Realities*, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23 1989.

"The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal" (with John Plunkett), *Summer Study on Energy Efficiency in Buildings, 1988*, American Council for an Energy Efficient Economy, 1988.

"Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels," in *Proceedings of the 1988 Annual Meeting of the American Solar Energy Society*, American Solar Energy Society, Inc., 1988, pp. 553–557.

"Capital Minimization: Salvation or Suicide?," in I. C. Bupp, ed., *The New Electric Power Business*, Cambridge Energy Research Associates, 1987, pp. 63–72.

"The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions," in *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, Albuquerque, New Mexico, April 1987, pp. 36–42.

"Power Plant Phase-In Methodologies: Alternatives to Rate Shock," in *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 547–562.

"Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System" (with A. Bachman), *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 2093–2110.

“Forensic Economics and Statistics: An Introduction to the Current State of the Art” (with Eden, P., Fairley, W., Aller, C., Vencill, C., and Meyer, M.), *The Practical Lawyer*, June 1 1985, pp. 25–36.

“Power Plant Performance Standards: Some Introductory Principles,” *Public Utilities Fortnightly*, April 18 1985, pp. 29–33.

“Opening the Utility Market to Conservation: A Competitive Approach,” *Energy Industries in Transition, 1985–2000*, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November 1984, pp. 1133–1145.

“Insurance Market Assessment of Technological Risks” (with Meyer, M., and Fairley, W) *Risk Analysis in the Private Sector*, pp. 401–416, Plenum Press, New York 1985.

“Revenue Stability Target Ratemaking,” *Public Utilities Fortnightly*, February 17 1983, pp. 35–39.

“Capacity/Energy Classifications and Allocations for Generation and Transmission Plant” (with M. Meyer), *Award Papers in Public Utility Economics and Regulation*, Institute for Public Utilities, Michigan State University 1982.

Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (with Fairley, W., Meyer, M., and Scharff, L.) (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December 1981.

Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September 1977.

REPORTS

“Review of NS Power Compliance Filing on its Proposed AMI Opt-Out Charge” (with Benjamin Griffiths). October 26, 2018. Filed by the Nova Scotia Consumer Advocate in N.S. UARB Matter No. M08349.

“Avoided Energy Supply Costs in New England: 2018 Report” (with Pat Knight, Max Chang, David White, Benjamin Griffiths, Les Deman, John Rosenkranz, Jason Gifford, and others). March 30, 2018. Cambridge, Mass.: Synapse Energy Economics.

“Review of the NS Power Application for Approval of its 2017 Annually Adjusted Rates and Load Following Setting Methodology” (with Stacia Harper). August 2017. Filed by the Nova Scotia Consumer Advocate in N.S. UARB Matter No. M08114.

“Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers” (with John T. Colgan, Rick Gilliam, Douglas Jester and Mark LeBel). Electricity Rate Design Review No. 1, July 2016.

"Implications of the Proposed Clean Power Plan for Arkansas: Review of Stakeholder Concerns and Assessment of Feasibility." 2014. Report to Arkansas Audubon, Arkansas Public Policy Panel, and Arkansas Sierra Club.

"Comments on Nova Scotia Power Inc.'s Proposed Capital Expenditure Justification Criteria." 2013. Filed by the Nova Scotia Consumer Advocate in N.S. UARB Matter No. 05355.

"Avoided Energy Supply Costs in New England: 2013 Report" (with Rick Hornby, David White, John Rosenkranz, Ron Denhardt, Elizabeth Stanton, Jason Gifford, Bob Grace, Max Chang, Patrick Luckow, Thomas Vitolo, Patrick Knight, Ben Griffiths, and Bruce Biewald). 2013. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"Affordability of Pollution Control on the Apache Coal Units: Review of Arizona Electric Power Cooperative's Comments on Behalf of the Sierra Club" (with Ben Griffiths). 2012. Filed as part of comments in Docket EPA-R09-OAR-2012-0021 by National Parks Conservation Association, Sierra Club, et al.

"Audubon Arkansas Comments on Entergy's 2012 IRP." 2012. Prepared for and filed by Audubon Arkansas in Arkansas PUC Docket No. 07-016-U.

"Economic Benefits from Early Retirement of Reid Gardner" (with Jonathan Wallach). 2012. Prepared for and filed by the Sierra Club in PUC of Nevada Docket No. 11-08019.

"Analysis of Via Verde Need and Economics." 2012. Appendix V-4 of public comments of the Sierra Club et al. in response to November 30 2011 draft of U.S. Army Corps of Engineers environmental assessment in Department of the Army Environmental Assessment and Statement of Finding for Permit Application SAJ-2010-02881.

"Comments for The Alliance for Affordable Energy on Staff's 'Proposed Integrated Resource Planning Rules for Electric Utilities in Louisiana.'" 2011. Filed by the Alliance for Affordable Energy in Louisiana PSC Docket R-30021.

"Avoided Energy Supply Costs in New England: 2011 Report" (with Rick Hornby, Carl Swanson, David White, Jason Gifford, Max Chang, Nicole Hughes, Matthew Wittenstein, Rachel Wilson, and Bruce Biewald). 2011. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"State of Ohio Energy-Efficiency Technical-Reference Manual Including Predetermined Savings Values and Protocols for Determining Energy and Demand Savings" (with others). 2010. Burlington, Vt.: Vermont Energy Investment Corporation.

"Avoided Energy Supply Costs in New England: 2009 Report" (with Rick Hornby, Carl Swanson, David White, Ian Goodman, Bob Grace, Bruce Biewald, Ben Warfield, Jason Gifford, and Max Chang). 2009. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

“Green Resource Portfolios: Development, Integration, and Evaluation” (with Jonathan Wallach and Richard Mazzini). 2008. Report to the Green Energy Coalition presented as evidence in Ont. Energy Board EB 2007-0707.

“Risk Analysis of Procurement Strategies for Residential Standard Offer Service” (with Jonathan Wallach, David White, and Rick Hornby) report to Maryland Office of People’s Counsel. 2008. Baltimore: Maryland Office of People’s Counsel.

“Avoided Energy Supply Costs in New England: 2007 Final Report” (with Rick Hornby, Carl Swanson, Michael Drunsic, David White, Bruce Biewald, and Jenifer Callay). 2007. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

“Integrated Portfolio Management in a Restructured Supply Market” (with Jonathan Wallach, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers’ Counsel.

“Natural Gas Efficiency Resource Development Potential in New York” (with Phillip Mosenthal, R. Neal Elliott, Dan York, Chris Neme, and Kevin Petak). 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

“Natural Gas Efficiency Resource Development Potential in Con Edison Service Territory” (with Phillip Mosenthal, Jonathan Kleinman, R. Neal Elliott, Dan York, Chris Neme, and Kevin Petak. 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

“Evaluation and Cost Effectiveness” (principal author), Ch. 14 of “California Evaluation Framework” Prepared for California utilities as required by the California Public Utilities Commission. 2004.

“Energy Plan for the City of New York” (with Jonathan Wallach, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

“Updated Avoided Energy Supply Costs for Demand-Side Screening in New England” (with Susan Geller, Bruce Biewald, and David White). 2001. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

“Review and Critique of the Western Division Load-Pocket Study of Orange and Rockland Utilities, Inc.” (with John Plunkett, Philip Mosenthal, Robert Wichert, and Robert Rose). 1999. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

“Avoided Energy Supply Costs for Demand-Side Management in Massachusetts” (with Rachel Brailove, Susan Geller, Bruce Biewald, and David White). 1999. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

“Performance-based Regulation in a Restructured Utility Industry” (with Bruce Biewald, Tim Woolf, Peter Bradford, Susan Geller, and Jerrold Oppenheim). 1997. Washington: NARUC.

“Distributed Integrated-Resource-Planning Guidelines.” 1997. Appendix 4 of “The Power to Save: A Plan to Transform Vermont’s Energy-Efficiency Markets,” submitted to the Vt. PSB in Docket No. 5854. Montpelier: Vermont DPS.

“Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests” (with Jonathan Wallach, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People’s Counsel.

“Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire’s Electric-Utility Industry” (with Bruce Biewald and Jonathan Wallach). 1996. Concord, N.H.: NH OCA.

“Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities” (with Susan Geller, Rachel Brailove, Jonathan Wallach, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

From Here to Efficiency: Securing Demand-Management Resources (with Emily Caverhill, James Peters, John Plunkett, and Jonathan Wallach). 1993. 5 vols. Harrisburg, Penn: Pennsylvania Energy Office.

“Analysis Findings, Conclusions, and Recommendations,” vol. 1 of “Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro” (with Plunkett, John, and Jonathan Wallach), December 1992.

“Estimation of the Costs Avoided by Potential Demand-Management Activities of Ontario Hydro,” December 1992.

“Review of the Elizabethtown Gas Company’s 1992 DSM Plan and the Demand-Side Management Rules” (with Jonathan Wallach, John Plunkett, James Peters, Susan Geller, Blair. Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

Environmental Externalities Valuation and Ontario Hydro’s Resource Planning (with E. Caverhill and R. Brailove), 3 vols.; prepared for the Coalition of Environmental Groups for a Sustainable Energy Future, October 1992.

“Review of Jersey Central Power & Light’s 1992 DSM Plan and the Demand-Side Management Rules” (with Jonathan Wallach et al.); Report to the New Jersey Department of Public Advocate, June 1992.

“The AGREA Project Critique of Externality Valuation: A Brief Rebuttal,” March 1992.

“The Potential Economic Benefits of Regulatory NO_X Valuation for Clean Air Act Ozone Compliance in Massachusetts,” March 1992.

“Initial Review of Ontario Hydro’s Demand-Supply Plan Update” (with David Argue et al.), February 1992.

“Report on the Adequacy of Ontario Hydro’s Estimates of Externality Costs Associated with Electricity Exports” (with Emily Caverhill), January 1991.

“Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities,” (with John Plunkett et al.), September 1990. Filed in NY PSC Case No. 28223 in re New York utilities’ DSM plans.

“Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica’s Power Needs,” (with Conservation Law Foundation, et al.), June 1990.

“Analysis of Fuel Substitution as an Electric Conservation Option,” (with Ian Goodman and Eric Espenhorst), Boston Gas Company, December 22 1989.

“The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company” (with Eric Espenhorst), Boston Gas Company, December 22 1989.

“The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update” (with Emily Caverhill), Boston Gas Company, December 22 1989.

“Conservation Potential in the State of Minnesota,” (with Ian Goodman) Minnesota Department of Public Service, June 16 1988.

“Review of NEPOOL Performance Incentive Program,” Massachusetts Energy Facilities Siting Council, April 12 1988.

“Application of the DPU’s Used-and-Useful Standard to Pilgrim 1” (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

“Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods,” Massachusetts Energy Facilities Siting Council, June 1985.

“Final Report: Rate Design Analysis,” Pacific Northwest Electric Power and Conservation Planning Council, December 18 1981.

PRESENTATIONS

“Rethinking Utility Rate Design—Retail Demand and Energy Charges,” Solar Power PV Conference, Boston MA, February 24, 2016.

“Residential Demand Charges - Load Effects, Fairness & Rate Design Implications.” Web seminar sponsored by the NixTheFix Forum. September 2015.

“The Value of Demand Reduction Induced Price Effects.” With Chris Neme. Web seminar sponsored by the Regulatory Assistance Project. March 2015.

“Adding Transmission into New York City: Needs, Benefits, and Obstacles.” Presentation to FERC and the New York ISO on behalf of the City of New York. October 2004.

"Plugging Into a Municipal Light Plant." With Peter Enrich and Ken Barna. Panel presentation as part of the 2004 Annual Meeting of the Massachusetts Municipal Association. January 2004.

"Distributed Utility Planning." With Steve Litkovitz. Presentation to the Vermont Distributed-Utility-Planning Collaborative. November 1999.

"The Economic and Environmental Benefits of Gas IRP: FERC 636 and Beyond." Presentation as part of the Ohio Office of Energy Efficiency's seminar, "Gas Utility Integrated Resource Planning," April 1994.

"Cost Recovery and Utility Incentives." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"Cost Allocation for Utility Ratemaking." With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October 1993.

"Comparing and Integrating DSM with Supply." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"DSM Cost Recovery and Rate Impacts." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Cost-Effectiveness Analysis." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling" (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference. June 1993.

"Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making." Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

"Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels (session leader), DSM Advocacy Workshop. April 15 1992.

"Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs," Energy Planning Workshops; Columbia, S.C. October 21 1991.

"Least Cost Planning and Gas Utilities." Demand-Side Management and the Global Environment Conference; Washington, D.C. April 22 1991.

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

"Least-Cost Planning in a Multi-Fuel Context." NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

"Accounting for Externalities: Why, Which and How?" Understanding Massachusetts' New Integrated Resource Management Rules. Needham, Massachusetts, November 9 1990.

New England Gas Association Gas Utility Managers' Conference. Woodstock, Vermont, September 10 1990.

"Quantifying and Valuing Environmental Externalities." Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy's Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

"Conservation in the Future of Natural Gas Local Distribution Companies." District of Columbia Natural Gas Seminar; Washington, D.C. May 23 1989.

"Conservation and Load Management for Natural Gas Utilities," Massachusetts Natural Gas Council; Newton, Massachusetts. April 3 1989.

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop. Portsmouth, New Hampshire, January 22–23 1989.

"Assessment and Valuation of External Environmental Damages." New England Utility Rate Forum. Plymouth, Massachusetts, October 11 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

"Reviewing Utility Supply Plans." Massachusetts Energy Facilities Siting Council; Boston, Massachusetts. May 30 1985.

"Power Plant Performance.," National Association of State Utility Consumer Advocates; Williamstown, Massachusetts. August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals. August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations. March 1988 to June 1989.

Austin City Council, Austin Energy Rates, March to June 2012.

Puerto Rico Energy Commission, Puerto Rico Electric Power Authority, rate design issues, September 2015 to present.

EXPERT TESTIMONY

1. **Mass. EFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General. June 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **Mass. EFSC** 78-17, Northeast Utilities 1978 forecast; Massachusetts Attorney General. September 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **Mass. EFSC** 78-33, Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General. November 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with Susan Geller.

5. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **U.S. ASLB** NRC 50-471, Pilgrim Unit 2; Commonwealth of Massachusetts. June 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with Susan Geller.

7. **Mass. DPU** 19845, Boston Edison time-of-use-rate case; Massachusetts Attorney General. December 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with Susan Geller.

8. **Mass. DPU** 20055, petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General. January 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **Mass. DPU** 20248, petition of Massachusetts Municipal Wholesale Electric Company to purchase additional share of Seabrook Nuclear Plant; Massachusetts Attorney General. June 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **Mass. DPU** 200, Massachusetts Electric Company rate case; Massachusetts Attorney General. June 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **Mass. EFSC** 79-33, Eastern Utilities Associates 1979 forecast; Massachusetts Attorney General. July 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **Mass. DPU** 243, Eastern Edison Company rate case; Massachusetts Attorney General. August 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas PUC** 3298, Gulf States Utilities rates; East Texas Legal Services. August 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **Mass. EFSC** 79-1, Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General. November 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. **Mass. DPU** 472, recovery of residential conservation-service expenses; Massachusetts Attorney General. December 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **Mass. DPU** 535; regulations to carry out Section 210 of PURPA; Massachusetts Attorney General. January 1981 and February 1981.

    Filing requirements, certification, qualifying-facility status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of qualifying facilities in specific areas; wheeling; standardization of fees and charges.

17. **Mass. EFSC** 80-17, Northeast Utilities 1980 forecast; Massachusetts Attorney General. March 1981.

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **Mass. DPU** 558, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **Mass. DPU** 1048, Boston Edison plant performance standards; Massachusetts Attorney General. May 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **DC PSC** FC785, Potomac Electric Power rate case; DC Peoples Counsel. July 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **N.H. PSC** DE 81-312, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Mass. Division of Insurance,** hearing to fix and establish 1983 automobile insurance rates; Massachusetts Attorney General. October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Ill. CC** 82-0026, Commonwealth Edison rate case; Illinois Attorney General. October 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **N.M. PSC** 1794, Public Service of New Mexico application for certification; New Mexico Attorney General. May 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Conn. DPUC** 830301, United Illuminating rate case; Connecticut Consumers Counsel. June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **Mass. DPU** 1509, Boston Edison plant performance standards; Massachusetts Attorney General. July 15 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Mass. Division of Insurance,** hearing to fix and establish 1984 automobile-insurance rates; Massachusetts Attorney General. October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Conn. DPUC** 83-07-15, Connecticut Light and Power rate case; Alloy Foundry. October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **Mass. EFSC** 83-24, New England Electric System forecast of electric resources and requirements; Massachusetts Attorney General. November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Mich. PSC** U-7775, Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan. February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **Mass. DPU** 84-25, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. April 6 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **Mass. DPU** 84-49 and 84-50, Fitchburg Gas & Electric financing case; Massachusetts Attorney General. April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Mich. PSC** U-7785, Consumers Power fuel-cost-recovery plan; Public Interest Research Group in Michigan. April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000, Montaup Electric rate cases; Massachusetts Attorney General. April 27 1984.

    Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine PUC** 84-113, Seabrook-1 investigation; Maine Public Advocate. September 13 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **Mass. DPU** 84-145, Fitchburg Gas and Electric rate case; Massachusetts Attorney General. November 6 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Penn. PUC** R-842651, Pennsylvania Power and Light rate case; Pennsylvania Consumer Advocate. November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **N.H. PSC** 84-200, Seabrook Unit-1 investigation; New Hampshire Consumer Advocate. November 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General. November 1984.

    Profit-margin calculations, including methodology and implementation.

40. **Mass. DPU** 84-152, Seabrook Unit 1 investigation; Massachusetts Attorney General. December 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power rate case; Maine PUC Staff. December 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. Maine PUC 84-113, Seabrook 2 investigation; Maine PUC Staff. December 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. Mass. DPU 1627, Massachusetts Municipal Wholesale Electric Company financing case; Massachusetts Executive Office of Energy Resources. January 1985.

Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. Vt. PSB 4936, Millstone 3 costs and in-service date; Vermont Department of Public Service. January 1985.

Construction schedule and cost of completing Millstone Unit 3.

45. Mass. DPU 84-276, rules governing rates for utility purchases of power from qualifying facilities; Massachusetts Attorney General. March 1985 and October 1985.

Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. Mass. DPU 85-121, investigation of the Reading Municipal Light Department; Wilmington (Mass.) Chamber of Commerce. November 1985.

Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. Mass. Division of Insurance, hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. November 1985.

Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **N.M. PSC** 1833, Phase II; El Paso Electric rate case; New Mexico Attorney General. December 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Penn. PUC** R-850152, Philadelphia Electric rate case; Utility Users Committee and University of Pennsylvania. January 1986.

    Limerick-1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **Mass. DPU** 85-270;, Western Massachusetts Electric rate case; Massachusetts Attorney General. March 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Penn. PUC** R-850290, Philadelphia Electric auxiliary service rates; Albert Einstein Medical Center, University of Pennsylvania, and Amtrak. March 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **N.M. PSC** 2004, Public Service of New Mexico Palo Verde issues; New Mexico Attorney General. May 1986.

    Recommendations for power-plant performance standards for Palo Verde nuclear units 1, 2, and 3.

53. **Ill. CC** 86-0325, Iowa-Illinois Gas and Electric Co. rate investigation; Illinois Office of Public Counsel. August 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **N.M. PSC** 2009, El Paso Electric rate moderation program; New Mexico Attorney General. August 1986.

Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston Public Improvements Commission,** transfer of Boston Edison district heating steam system to Boston Thermal Corporation; Boston Housing Authority. December 1986.

History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Mass. Division of Insurance,** hearing to fix and establish 1987 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. December 1986 and January 1987.

Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **Mass. DPU** 87-19, petition for adjudication of development facilitation program; Hull (Mass.) Municipal Light Plant. January 1987.

Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **N.M. PSC** 2004, Public Service of New Mexico nuclear decommissioning fund; New Mexico Attorney General. February 1987.

Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **Mass. DPU** 86-280, Western Massachusetts Electric rate case; Massachusetts Energy Office. March 1987.

Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of Consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Mass. Division of Insurance** 87-9, 1987 Workers' Compensation rate filing; State Rating Bureau. May 1987.

    Profit-margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184, economic viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief. August 1987.

    Nuclear plant operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP-2 cost and schedule projections. Potential for conservation.

62. **Minn. PUC** ER-015/GR-87-223, Minnesota Power rate case; Minnesota Department of Public Service. August 1987.

    Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Mass. Division of Insurance** 87-27, 1988 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. September 2 1987. Rebuttal October 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **Mass. DPU** 88-19, power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric. November 1987.

    Comparison of risk from QF contract and utility avoided-cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Mass. Division of Insurance** 87-53, 1987 Workers' Compensation rate refiling; State Rating Bureau. December 1987.

    Profit-margin calculations including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Mass. Division of Insurance,** 1987 and 1988 automobile insurance remand rates; Massachusetts Attorney General and State Rating Bureau. February 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **Mass. DPU** 86-36, investigation into the pricing and ratemaking treatment to be afforded new electric generating facilities which are not qualifying facilities; Conservation Law Foundation. May 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **Mass. DPU** 88-123, petition of Riverside Steam & Electric; Riverside Steam and Electric Company. May 1988 and November 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **Mass. DPU** 88-67, Boston Gas Company; Boston Housing Authority. June 1988.

    Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **R.I. PUC** 1900, Providence Water Supply Board tariff filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island. June 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Mass. Division of Insurance** 88-22, 1989 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 1988, supplemented August 1988; Losses and Expenses, September 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vt. PSB** 5270 Module 6, investigation into least-cost investments, energy efficiency, conservation, and the management of demand for energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group. September 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vt. House of Representatives, Natural Resources Committee,** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group. February 1989.

Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **Mass. DPU** 88-67 Phase II, Boston Gas company conservation program and rate design; Boston Gas Company. March 1989.

Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vt. PSB** 5270, status conference on conservation and load management policy settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service. May 1989.

Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099, Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority. June 1989.

Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **Mass. DPU** 89-100, Boston Edison rates; Massachusetts Energy Office. June 1989.

Prudence of decision to spend $400 million from 1986–88 to return Pilgrim nuclear plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **Mass. DPU** 88-123, petition of Riverside Steam and Electric Company; Riverside Steam and Electric. July 1989. Rebuttal, October 1989.

Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **Mass. DPU** 89-72, Statewide Towing Association police-ordered towing rates; Massachusetts Automobile Rating Bureau. September 1989.

    Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vt. PSB** 5330, application of Vermont utilities for approval of a firm power and energy contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group. December 1989. Surrebuttal February 1990.

    Analysis of a proposed 20-year power purchase. Comparison to efficiency investment. Critique of conservation potential analysis. Analysis of Vermont electric energy supply. Planning risk of large supply additions. Valuation of environmental externalities. Identification of possible improvements to proposed contract.

81. **Mass. DPU** 89-239, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. Boston Gas Company. December 1989; April 1990; May 1990.

    Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California PUC,** incorporation of environmental externalities in utility planning and pricing; Coalition of Energy Efficient and Renewable Technologies. February 1990.

    Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Ill. CC** 90-0038, proceeding to adopt a least-cost electric-energy plan for Commonwealth Edison Company; City of Chicago. May 25 1990. Joint rebuttal testimony with David Birr, August 1990.

    Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Md. PSC** 8278, adequacy of Baltimore Gas & Electric's integrated resource plan; Maryland Office of People's Counsel. September 1990.

    Rationale for demand-side management. BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Ind. URC,** integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 1990.

    Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **Mass. DPU** 89-141, 90-73, 90-141, 90-194, 90-270; preliminary review of utility treatment of environmental externalities in October qualifying-facilities filings; Boston Gas Company. November 1990.

    Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **Mass. EFSC** 90-12/90-12A, adequacy of Boston Edison proposal to build combined-cycle plant; Conservation Law Foundation. December 1990.

    Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** 90-286, adequacy of conservation program of Bangor Hydro Electric; Penobscot River Coalition. February 1991.

    Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. **Va. SCC** PUE900070, commission investigation; Southern Environmental Law Center. March 1991.

    Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. **Mass. DPU** 90-261-A, economics and role of fuel-switching in the DSM program of the Massachusetts Electric Company; Boston Gas Company. April 1991.

    Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. **Private arbitration,** Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech. May 1991.

    NEPCo rates for power purchases from the New England Solid Waste Compact plant. Fuel price and avoided cost projections vs. realities.

92. **Vt. PSB** 5491, cost-effectiveness of Central Vermont's commitment to Hydro Quebec purchases; Conservation Law Foundation. July 1991.

Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **S.C. PSC** 91-216-E, cost recovery of Duke Power's DSM expenditures; South Carolina Department of Consumer Affairs. Direct, September 13 1991; Surrebuttal October 1991.

Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Md. PSC** 8241 Phase II, review of Baltimore Gas & Electric's avoided costs; Maryland Office of People's Counsel. September 1991.

Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport (Maine) Planning Board,** AES/Harriman Cove shoreland zoning application; Conservation Law Foundation and Natural Resources Council of Maine. October 1991.

New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives.

96. **Mass. DPU** 91-131, update of externalities values adopted in Docket 89-239; Boston Gas Company. October 1991. Rebuttal, December 1991.

Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Fla. PSC** 910759, petition of Florida Power Corporation for determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 1991.

Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Fla. PSC** 910833-EI, petition of Tampa Electric Company for a determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 1991.

Obligation to pursue integrated resource planning, failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Penn. PUC** I-900005, R-901880; investigation into demand-side management by electric utilities; Pennsylvania Energy Office. January 1992.

Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **S.C. PSC** 91-606-E, petition of South Carolina Electric and Gas for a certificate of public convenience and necessity for a coal-fired plant; South Carolina Department of Consumer Affairs. January 1992.

Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **Mass. DPU** 92-92, adequacy of Boston Edison's street-lighting options; Town of Lexington. June 1992.

Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **S.C. PSC** 92-208-E, integrated-resource plan of Duke Power Company; South Carolina Department of Consumer Affairs. August 1992.

Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **N.C. UC** E-100 Sub 64, integrated-resource-planning docket; Southern Environmental Law Center. September 1992.

General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ont. EAB** Ontario Hydro Demand/Supply Plan Hearings, *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); Coalition of Environmental Groups. October 1992.

Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas PUC** 110000, application of Houston Lighting and Power company for a certificate of convenience and necessity for the DuPont Project; Destec Energy, Inc. September 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine BEP,** in the matter of the Basin Mills Hydroelectric Project application; Conservation Intervenors. November 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Md. PSC** 8473, review of the power sales agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel. November 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **N.C. UC** E-100 Sub 64, analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **S.C. PSC** 92-209-E, in re Carolina Power & Light Company; South Carolina Department of Consumer Affairs. November 1992.

Demand-side-management planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Fla. DER** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation. December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Md. PSC** 8487, Baltimore Gas and Electric Company electric rate case. Direct January 1993; rebuttal February 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Md. PSC** 8179, Approval of amendment to Potomac Edison purchase agreement with AES Warrior Run; Maryland Office of People's Counsel. January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113. **Mich. PSC** U-10102, Detroit Edison rate case; Michigan United Conservation Clubs. February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

114. **Ohio PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

Demand-side-management planning, program designs, potential savings, and avoided costs.

115. **Mich. PSC** U-10335, Consumers Power rate case; Michigan United Conservation Clubs. October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

116. **Ill. CC** 92-0268, electric-energy plan for Commonwealth Edison; City of Chicago. Direct, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. **FERC** 2422 et al., application of James River–New Hampshire Electric, Public Service of New Hampshire, for licensing of hydro power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. **Vt. PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service fuel-switching and DSM program design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

119. **Fla. PSC** 930548-EG–930551-EG, conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. **Vt. PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

121. **Mass. DPU** 94-49, Boston Edison integrated-resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

122. **Mich. PSC** U-10554, Consumers Power Company DSM program and incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **Mich. PSC** U-10702, Detroit Edison Company cost recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. **N.J. BRC** EM92030359, environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. **Mich. PSC** U-10671, Detroit Edison Company DSM programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **Mich. PSC** U-10710, power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. **FERC** 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. **N.C. UC** E-100 Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. **New Orleans City Council** UD-92-2A and -2B, least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

130. **D.C. PSC** FC917 II, prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

131. **Ont. Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

Demand-side-management cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

132. **New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

133. **Mass. DPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

134. **Md. PSC** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995.

Rate design, cost-of-service study, and revenue allocation.

135. **N.C. UC** E-2 Sub 669; Carolina P&L certification of 500 MW combustion turbine; Southern Environmental Law Center. December 1995.

Need for new capacity. Purchased-power options. Energy-conservation potential and model programs.

136. **Arizona CC** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

137. **Ohio PUC** 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

138 **Vt. PSB** 5835, Central Vermont Public Service Company rates; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

139. **Md. PSC** 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

140. **Mass. DPU** 96-100, Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

141. **Mass. DPU** 96-70, Essex County Gas Company rates; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

142. **Mass. DPU** 96-60, Fall River Gas Company rates; Massachusetts Attorney General. Direct, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

143. **Md. PSC** 8725, Maryland electric-utilities merger; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

144. **N.H. PUC** DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

145. **Ont. Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and incentive mechanisms in rates for the Consumers Gas Company.

146. **New York PSC** 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

147. **Vt. PSB** 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

148. **Mass. DPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. **Vt. PSB** 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

150. **Mass. DPU** 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

151. **Mass. DTE** 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

152. **N.H. PUC** Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

153. **Md. PSC** 8774, APS-DQE merger; Maryland Office of People's Counsel. February 1998.

Proposed power-supply arrangements between APS's potential operating subsidiaries; power-supply savings; market power.

154. **Vt. PSB** 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

155. **Maine PUC** 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

156. **Mass. DTE** 98-89, purchase of Boston Edison municipal street lighting; Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

157. **Vt. PSB** 6107, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

158. **Mass. DTE** 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

159. **Md. PSC** 8794 and 8804, BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Md. PSC** 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

161. **Md. PSC** 8797, Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

162. **Conn. DPUC** 99-02-05, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

163. **Conn. DPUC** 99-03-04, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

164. **Wash. UTC** UE-981627, PacifiCorp–Scottish Power merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

165. **Utah PSC** 98-2035-04, PacifiCorp–Scottish Power merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

166. **Conn. DPUC** 99-03-35, United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

167. **Conn. DPUC** 99-03-36, Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

168. **W. Va. PSC** 98-0452-E-GI, electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

169. **Ont. Energy Board** RP-1999-0034, Ontario performance-based rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

170. **Conn. DPUC** 99-08-01, standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; supplemental, January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

171. **Conn. Superior Court** CV 99-049-7239, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the Conn. DPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

172. **Conn. Superior Court** CV 99-049-7597, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the Conn. DPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

173. **Ont. Energy Board** RP-1999-0044, Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

174. **Utah PSC** 99-2035-03, PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Conn. DPUC** 99-09-12, Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ont. Energy Board** RP-1999-0017, Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **N.Y. PSC** 99-S-1621, Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine PUC** 99-666, Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

179. **Mass. EFSB** 97-4, Massachusetts Municipal Wholesale Electric Company gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

180. **Conn. DPUC** 99-09-03; Connecticut Natural Gas Corporation merger and rate plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Conn. DPUC** 99-09-12RE01, Proposed Millstone sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **Mass. DTE** 01-25, Purchase of streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. **Conn. DPUC** 00-12-01 and 99-09-12RE03, Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. **Vt. PSB** 6460 & 6120, Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. **N.J. BPU** EM00020106, Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. **N.J. BPU** GM00080564, Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. **Conn. DPUC** 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. **N.J. BPU** EX01050303, New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. **N.Y. PSC** 00-E-1208, Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

190. **Mass. DTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

191. **N.J. BPU** EM00020106, Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

192. **Vt. PSB** 6545, Vermont Yankee proposed sale; Vermont Department of Public Service. January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. **Conn. Siting Council** 217, Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. **Vt. PSB** 6596, Citizens Utilities rates; Vermont Department of Public Service. Direct, March 2002; rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. **Conn. DPUC** 01-10-10, United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. **Conn. DPUC** 01-12-13RE01, Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

197. **Ont. Energy Board** RP-2002-0120, review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

198. **N.J. BPU** ER02080507, Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

199. **Conn. DPUC** 03-07-02, CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

200. **Conn. DPUC** 03-07-01, CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

201. **Vt. PSB** 6596, Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

202. **Ohio PUC** 03-2144-EL-ATA, Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

203. **N.Y. PSC** 03-G-1671 & 03-S-1672, Consolidated Edison company steam and gas rates; City of New York. Direct March 2004; rebuttal April 2004; settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. **N.Y. PSC** 04-E-0572, Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. **Ont. Energy Board** RP 2004-0188, cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. **Mass. DTE** 04-65, Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; supplemental, January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. **N.Y. PSC** 04-W-1221, rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. **N.Y. PSC** 05-M-0090, system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. **Md. PSC** 9036, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. **B.C. UC** 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. **Conn. DPUC** 05-07-18, financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. **Conn. DPUC** 03-07-01RE03 & 03-07-15RE02, incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005; Additional, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Conn. DPUC** Docket 05-10-03, Connecticut L&P; time-of-use, interruptible, and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ont. Energy Board** Case EB-2005-0520, Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes. New break point, cost allocation, customer charges, commodity rate blocks.

215. **Ont. Energy Board** EB-2006-0021, Natural-gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Ind. URC** 42943 and 43046, Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Penn. PUC** 00061346, Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Penn. PUC** R-00061366 et al., rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Conn. DPUC** 06-01-08, Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since September 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. **Conn. DPUC** 06-01-08, United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly August 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. **N.Y. PSC** 06-M-1017, policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Conn. DPUC** 06-01-08, procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

223. **Ohio PUC** PUCO 05-1444-GA-UNC, recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. **N.Y. PSC** 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. **Alb. EUB** 1500878, ATCo Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. May 2007.

Direct assignment of distribution costs to street lighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. **Conn. DPUC** 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **N.Y. PSC** 07-E-0524, Consolidated Edison electric rates; City of New York. September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Man. PUB** 136-07, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass. EFSB** 07-7, DPU 07-58 & -59; proposed Brockton Power Company plant; Alliance Against Power Plant Location. March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **Conn. DPUC** 08-01-01, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ont. Energy Board** 2007-0905, Ontario Power Generation payments; Green Energy Coalition. April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. **Utah** PSC 07-035-93, Rocky Mountain Power Rates; Utah Committee of Consumer Services. July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. **Ont. Energy Board** 2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **N.Y. PSC** 08-E-0596, Consolidated Edison electric rates; City of New York. September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. **Conn. DPUC** 08-07-01, Integrated resource plan; Connecticut Office of Consumer Counsel. September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. **Man. PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. **Md. PSC** 9036, Columbia Gas rates; Maryland Office of People's Counsel. January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. **Vt. PSB** 7440, extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239. **N.S. UARB** M01439, Nova Scotia Power DSM and cost recovery; Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240. **N.S. UARB** M01496, proposed biomass project; Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. **Conn. Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. July 2009. Also filed and presented in **MA EFSB** 08-02, February 2010.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242. **Mass. DPU** 09-39, NGrid rates; Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243. **Utah PSC** 09-035-23, Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009; rebuttal, November 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

244. **Utah PSC** 09-035-15, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; surrebuttal, January 2010.

Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.

245. **Penn. PUC** R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

246. **B.C. UC** 3698573, British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. February 2010.

Rate design and energy efficiency.

247. **Ark. PSC** 09-084-U, Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; surrebuttal, April 2010.

Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.

248. **Ark. PSC** 10-010-U, Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; reply, April 2010.

Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.

249. **Ark. PSC** 08-137-U, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010; supplemental, October 2010; reply, October 2010.

Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

250. **Plymouth, Mass., Superior Court** Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.), Breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

251. **N.S. UARB** M02961, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. June 2010.

Least-cost planning and renewable-energy requirements. Feasibility versus alternatives. Unknown or poorly estimated costs.

252. **Mass. DPU** 10-54, NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAs to renewable development. Effectiveness of proposed contracts as price edges.

253. **Md. PSC** 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, July 2010; rebuttal, surrebuttal, August 2010.

Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

254. **Ont. Energy Board** 2010-0008, Ontario Power Generation facilities charges; Green Energy Coalition. Evidence, August 2010.

Critique of including a return on CWIP in current rates. Setting cost of capital by business segment.

255. **N.S. UARB** 03454, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

Cost allocation. Cost of capital. Effect on rates of growth in sales.

256. **Man. PUB** 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. December 2010.

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** M03665, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

258. **New Orleans City Council** UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. December 2010.

Integrated resource planning: Purpose, screening, cost recovery, and generation planning.

259. **N.S. UARB** M03665, depreciation rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.

Steam-plant retirement dates, post-retirement use, timing of decommissioning and removal costs.

260. **N.S. UARB M**03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.

Adjustments to estimate of cost-based feed-in tariffs. Rate effects of feed-in tariffs.

261. **Mass. EFSB** 10-2/**DPU** 10-131, 10-132; NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.

Need for new transmission; errors in load forecasting; probability of power outages.

262. **Utah PSC** 10-035-124, Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011.

Load data, allocation of generation plants, scrubbers, power purchases, and service drops. Marginal cost study: inclusion of all load-related transmission projects, critique of minimum- and zero-intercept methods for distribution. Residential rate design.

263. **N.S. UARB** M04104; Nova Scotia Power general rate application; Nova Scotia Consumer Advocate. August 2011.

Cost allocation: allocation of costs of wind power and substations. Rate design: marginal-cost-based rates, demand charges, time-of-use rates.

264. **N.S. UARB** M04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.

Marginal cost of serving very large industrial electric loads; risk, incentives and rate design.

265. **Ark. PSC** 10-101-R, Rulemaking re self-directed energy efficiency for large customers; National Audubon Society and Audubon Arkansas. July 2011.

Structuring energy-efficiency programs for large customers.

266. **Okla. CC** PUD 201100077, current and pending federal regulations and legislation affecting Oklahoma utilities; Sierra Club. Comments July, October 2011; presentation July 2011.

Challenges facing Oklahoma coal plants; efficiency, renewable and conventional resources available to replace existing coal plants; integrated environmental compliance planning.

267. **Nevada PUC** 11-08019, integrated analysis of resource acquisition, Sierra Club. Comments, September 2011; hearing, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

268. **La. PSC** R-30021, Louisiana integrated-resource-planning rules; Alliance for Affordable Energy. Comments, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

269. **Okla. CC** PUD 201100087, Oklahoma Gas and Electric Company electric rates; Sierra Club. November 2011.

Resource monitoring and acquisition. Benefits to ratepayers of energy conservation and renewables. Supply planning

270. **Ky. PSC** 2011-00375, Kentucky utilities' purchase and construction of power plants; Sierra Club and National Resources Defense Council. December 2011.

Assessment of resources, especially renewables. Treatment of risk. Treatment of future environmental costs.

271. **N.S. UARB** M04819, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.

Avoided costs. Allocation of costs. Reporting of bill effects.

272. **Kansas CC** 12-GIMX-337-GIV, utility energy-efficiency programs; The Climate and Energy Project. June 2012.

Cost-benefit tests for energy-efficiency programs. Collaborative program design.

273. **N.S. UARB** M04862, Port Hawksbury load-retention mechanism; Nova Scotia Consumer Advocate. June 2012.

Effect on ratepayers of proposed load-retention tariff. Incremental capital costs, renewable-energy costs, and costs of operating biomass cogeneration plant.

274. **Utah PSC** 11-035-200, Rocky Mountain Power Rates; Utah Office of Consumer Council. June 2012.

Cost allocation. Estimation of marginal customer costs.

275. **Ark. PSC** 12-008-U, environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012; rebuttal, August 2012; further, March 2013.

Costs and benefits of environmental retrofit to permit continued operation of coal plant, versus other options including purchased gas generation, efficiency, and wind. Fuel-price projections. Need for transmission upgrades.

276. **U.S. EPA** EPA-R09-OAR-2012-0021, air-quality implementation plan; Sierra Club. September 2012.

Costs, financing, and rate effects of Apache coal-plant scrubbers. Relative incomes in service territories of Arizona Coop and other utilities.

277. **Arkansas PSC** Docket No. 07-016-U; Entergy Arkansas' integrated resource plan; Audubon Arkansas. Comments, September 2012.

Estimation of future gas prices. Estimation of energy-efficiency potential. Screening of resource decisions. Wind costs.

278. **Vt. PSB** 7862, Entergy Nuclear Vermont and Entergy Nuclear Operations petition to operate Vermont Yankee; Conservation Law Foundation. October 2012.

Effect of continued operation on market prices. Value of revenue-sharing agreement. Risks of underfunding decommissioning fund.

279. **Man. PUB** 2012–13 GRA, Manitoba Hydro rates; Green Action Centre. November 2012.

Estimation of marginal costs. Fuel switching.

280. **N.S. UARB** M05339, Capital Plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

281. **N.S. UARB** M05416, South Canoe wind project of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

282. **N.S. UARB** 05419; Maritime Link transmission project and related contracts, Nova Scotia Consumer Advocate and Small Business Advocate. Direct, April 2013; supplemental (with Seth Parker), November 2013.

Load forecast, including treatment of economy energy sales. Wind power cost forecasts. Cost effectiveness and risk of proposed project. Opportunities for improving economics of project.

283. **Ont. Energy Board** 2012-0451/0433/0074, Enbridge Gas Greater Toronto Area project; Green Energy Coalition. June 2013, revised August 2013.

Estimating gas pipeline and distribution costs avoidable through gas DSM and curtailment of electric generation. Integrating DSM and pipeline planning.

284. **N.S. UARB** 05092, tidal-energy feed-in-tariff rate; Nova Scotia Consumer Advocate. August 2013.

Purchase rate for test and demonstration projects. Maximizing benefits under rate-impact caps. Pricing to maximize provincial advantage as a hub for emerging tidal-power industry.

285. **N.S. UARB** 05473, Nova Scotia Power 2013 cost-of-service study; Nova Scotia Consumer Advocate. October 2013.

Cost-allocation and rate design.

286. **B.C. UC** 3698715 & 3698719; performance-based ratemaking plan for FortisBC companies; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct (with John Plunkett), December 2013.

Rationale for enhanced gas and electric DSM portfolios. Correction of utility estimates of electric avoided costs. Errors in program screening. Program potential. Recommended program ramp-up rates.

287. **Conn. PURA** Docket No. 14-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. July and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

288. **Conn. PURA** Docket No. 14-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. January, April, July, and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

289. **Man. PUB** 2014, need for and alternatives to proposed hydro-electric facilities; Green Action Centre. Evidence (with Wesley Stevens) February 2014.

Potential for fuel switching, DSM, and wind to meet future demand.

290. **Utah PSC** 13-035-184, Rocky Mountain Power Rates; Utah Office of Consumer Services. May 2014.

Class cost allocation. Classification and allocation of generation plant and purchased power. Principles of cost-causation. Design of backup rates.

291. **Minn. PSC** E002/GR-13-868, Northern States Power rates; Clean Energy Intervenors. Direct, June 2014; rebuttal, July 2014; surrebuttal, August 2014.

Inclining-block residential rate design. Rationale for minimizing customer charges.

292. **Cal. PUC** Rulemaking 12-06-013, electric rates and rate structures; Natural Resources Defense Council. September 2014.

Redesigning residential rates to simplify tier structure while maintaining efficiency and conservation incentives. Effect of marginal price on energy consumption. Realistic modeling of consumer price response. Benefits of minimizing customer charges.

293. **Md. PSC** 9361, proposed merger of PEPCo Holdings into Exelon; Sierra Club and Chesapeake Climate Action Network. Direct, December 2014; surrebuttal, January 2015.

Effect of proposed merger on Consumer bills, renewable energy, energy efficiency, and climate goals.

294. **N.S. UARB** M06514, 2015 capital-expenditure plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Economic evaluation of proposed projects. Treatment of AFUDC, overheads, and replacement costs of lost generation. Computation of rate effects of spending plan.

295. **Md. PSC** 9153 et al., Maryland energy-efficiency programs; Maryland Office of People's Counsel. January 2015.

Costs avoided by demand-side management. Demand-reduction-induced price effects.

296. **Québec Régie de L'énergie** R-3867-2013 phase 1, Gaz Métro cost allocation and rate structure; ROEÉ. February 2015

Classification of the area-spanning system; minimum system and more realistic approaches. Allocation of overhead, energy-efficiency, gas-supply, engineering-and-planning, and billing costs.

297. **Conn. PURA** Docket No. 15-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. February and July 2015.

Proxy for review of bids. Oversight of procurement and selection process.

298. **Conn. PURA** Docket No. 15-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. February, July, and October 2015.

Proxy for review of bids. Oversight of procurement and selection process.

299. **Ky. PSC** 2014-00371, Kentucky Utilities electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

300. **Ky. PSC** 2014-00372, Louisville Gas and Electric electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

301. **Mich. PSC** U-17767, DTE Electric Company rates; Michigan Environmental Council, Sierra Club, and Natural Resource Defense Council. May 2015.

Cost effectiveness of pollution-control retrofits versus retirements. Market prices. Costs of alternatives.

302. **N.S. UARB** M06733, supply agreement between Efficiency One and Nova Scotia Power; Nova Scotia Consumer Advocate. June 2015.

Avoided costs. Cost-effectiveness screening of DSM. Portfolio design. Affordability and bill effects.

303. **Penn. PUC** P-2014-2459362, Philadelphia Gas Works DSM, universal-service, and energy-conservation plans; Philadelphia Gas Works. Direct, May 2015; Rebuttal, July 2015.

Avoided costs. Recovery of lost margin.

304. **Ont. Energy Board** EB-2015-0029/0049, 2015–2020 DSM Plans Of Enbridge Gas Distribution and Union Gas, Green Energy Coalition. Evidence July 31, 2015, Corrected August 12, 2015.

Avoided costs: price mitigation, carbon prices, marginal gas supply costs, avoidable distribution costs, avoidable upstream costs (including utility-owned pipeline facilities).

305. **PUC Ohio** 14-1693-EL-RDR, AEP Ohio Affiliate purchased-power agreement, Sierra Club. September 2015.

Economics of proposed PPA, market energy and capacity projections. Risk shifting. Lack of price stability and reliability benefits. Market viability of PPA units.

306. **N.S. UARB** M06214, NS Power Renewable-to-Retail rate, Nova Scotia Consumer Advocate. November 2015.

Review of proposed design of rate for third-party sales of renewable energy to retail customers. Distribution, transmission and generation charges.

307. **PUC Texas** Docket No. 44941, El Paso Electric rates; Energy Freedom Coalition of America. December 2015.

Cost allocation and rate design. Effect of proposed DG rate on solar customers. Load shapes of residential customers with and without solar. Problems with demand charges.

308. N.S. UARB M07176, NS Power 2016 Capital Expenditures Plan, Nova Scotia Consumer Advocate. February 2016.

Economic evaluation of proposed projects, including replacement energy costs and modeling of equipment failures. Treatment of capitalized overheads and depreciation cash flow in computation of rate effects of spending plan.

309. Md. PSC 9406, BGE Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct February 2016, Rebuttal March 2016, Surrebuttal March 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; capacity load reductions and price mitigation; free riders and load shifting in peak-time rebate (PTR) program; cost of PTR participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

310. City of Austin TX, Austin Energy 2016 Rate Review, Sierra Club and Public Citizen. May 2016

Allocation of generation costs. Residential rate design. Geographical rate differentials. Recognition of coal-plant retirement costs.

311. Manitoba PUB, Manitoba Hydro Cost of Service Methodology Review, Green Action Centre. June 2016, reply August 2016.

Allocation of generation costs. Identifying generation-related transmission assets. Treatment of subtransmission. Classification of distribution lines. Allocation of distribution substations and lines. Customer allocators. Shared service drops.

312. Md. PSC 9418, PEPCo Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct July 2016, Rebuttal August 2016, Surrebuttal September 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; load reductions in dynamic-pricing (DP) program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

313. Md. PSC 9424, Delmarva P&L Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct September 2016, Rebuttal October 2016, Surrebuttal October 2016.

Estimation of effects of Smart Meter programs—dynamic pricing (DP), conservation voltage reduction and an informational program—on wholesale revenues, wholesale prices and avoided costs; estimating load reductions from the DP program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

314. N.H. PUC Docket No. DE 16-576, Alternative Net Metering Tariffs, Conservation Law Foundation. Direct October 2016, Reply December 2016.

Framework for evaluating rates for distributed generation. Costs avoided and imposed by distributed solar. Rate design for distributed generation.

315. Puerto Rico Energy Commission CEPR-AP-2015-0001, Puerto Rico Electric Power Authority rate proceeding, PR Energy Commission. Report December 2016.

Comprehensive review of structure of electric utility, cost causation, load data, cost allocation, revenue allocation, marginal costs, retail rate designs, identification and treatment of customer subsidies, structuring rate riders, and rates for distributed generation and net metering.

316. N.S. UARB M07745, NS Power 2017 Capital Expenditures Plan, Nova Scotia Consumer Advocate. January 2017.

Computation and presentation of rate effects. Consistency of assumed plant operation and replacement power costs. Control of total cost of small projects. Coordination of information-technology investments. Investments in biomass plant with uncertain future.

317. N.S. UARB M07746, NS Power Enterprise Resource Planning project, Nova Scotia Consumer Advocate. February 2017.

Estimated software project costs. Costs of internal and contractor labor. Affiliate cost allocation.

318. N.S. UARB M07767, NS Power Advanced Metering Infrastructure projects, Nova Scotia Consumer Advocate. February 2017.

Design and goals of the AMI pilot program. Procurement. Coordination with information-technology and software projects.

319. Québec Régie de l'énergie R-3867-2013 phase 3A; Gaz Métro estimates of marginal O&M costs; ROEÉ. March 2017.

Estimation of one-time, continuing and periodic customer-related operating and maintenance cost. Costs related to loads and revenues. Dealing with lumpy costs.

320. N.S. UARB M07718, NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. April 2017.

Usefulness of transmission interconnection prior to operation of the associated power plant.

321. **Mass. DPU** 17-05, Eversource Rate Case, Cape Light Compact. Direct April 2017, Rebuttal May 2017.

Critique of proposed performance-based ratemaking mechanism. Proposal for improvements.

322. **PUCO** 16-1852, AEP Ohio Electric Security Plan, Natural Resources Defense Council. May 2017.

Residential customer charge. Cost causation. Effect of rate design on consumption.

323. **Iowa Utilities Board** RPU-2017-0001, Interstate Power and Light rate case, Natural Resources Defense Council. Direct August 2017, Reply September 2017.

Critique of proposed demand-charge pilot rates for residential and small commercial customers. Defects of demand rates and shortcomings of IPL experimental proposal design.

324. **N.S. UARB** M08087, NS Power 2017 Load Forecast, Nova Scotia Consumer Advocate. Direct August 2017.

Review of forecast methodology, including extrapolation of drivers of commercial load from US national data; treatment of non-firm and competitive loads; behind-the-meter generation and controlling peak-load growth.

325. **Québec Régie de l'énergie** R-3867-2013 phase 3B; Gaz Métro line-extension policy; ROEÉ. September 2017.

The costs of adding new load. Estimating the durability of revenues from line extensions.

326. **Mass. EFSB** 17-02; Eversource proposed Hudson-Sudbury transmission line; Town of Sudbury. Direct October 2017, Supplemental January 2018..

Accuracy of ISO New England regional load forecasts. Potential for distributed solar, storage and demand response.

327. **Manitoba PUB**, Manitoba 2017/18 & 2018/19 General Rate Application; Green Action Coalition. October 2017.

Marginal costs. Rate design. Affordability rate design for low-income and electric-heating customers. Design of residential inclining blocks. Problems with demand charges and demand ratchets. Cost-of-service study improvements.

328. **N.S. UARB** M08383, NS Power 2018 Annually Adjusted Rates; Consumer Advocate. January 2018.

Projection of incremental dispatch cost. Computing administrative charges. Methodological issues.

329. **N.S. UARB** M08349, NS Power's Advanced Metering Infrastructure Proposal; Consumer Advocate. January 2018.

Estimation of AMI benefits: load balancing among feeders, critical peak pricing, avoided costs of meters for distributed generation. NS Power's claims of benefits from accounting credits (AFUDC, overheads, and converting write-offs to reduced revenue) and shifting costs to customers (earlier billing, higher recorded usage). Realistic AMI meter life. Excessive charge for customers who opt out of AMI.

330. **N.S. UARB** M08350, NS Power 2018 Annual Capital Expenditures Plan; Consumer Advocate. February 2018.

Overlap between ACE projects and AMI project. Hydro project planning and valuation of lost hydro energy output.

331. **Conn. PURA** Docket No. 08-01-01RE05, Proposed Amendment to Peaker Contracts; Connecticut Consumers Counsel. May 2018.

Dividing increased revenues from ISO-NE's Pay-for-Performance mechanism between contract generators and ratepayers.

332. **Kansas CC** Docket No. 18-WSEE-328-RTS, Westar Rate Case; Sierra Club. Direct June 2018. Rebuttal June 2018. Supplement July 2018.

Costs and benefits of running Westar coal plants. Costs of renewables and other alternatives. Recommendation regarding planning, coal retirement schedule, and acquisition of leased capacity.

333. **Cal. PUC** Application 17-09-006; Pacific Gas and Electric Gas Cost Allocation Proceeding; Small Business Utility Advocates. Direct June 2018.

Allocation of gas distribution system costs. Allocation of costs of energy-efficiency programs.

334. **N.S. UARB** M08670, NS Power 2018 Load Forecast, Nova Scotia Consumer Advocate. Direct July 2018.

Review of forecast methodology, including treatment of future energy-efficiency programs, treatment of third-party supply and behind-the-meter generation.

335. **Iowa Utilities Board** RPU-2018-0003, MidAmerican Energy Request for Approval of Ratemaking Principles for Wind XII; Sierra Club. Direct August 2018.

Cost and benefits of continued operation of six MidAmerican coal-fired units.

336. **Cal. PUC** A.18-02-016, 03-001, 03-002; 2018 Energy Storage Plans; Small Business Utility Advocates. Direct, Rebuttal and Supplement, August 2018.

Reliance on substation-sited storage. Need for increased emphasis on customer-sited and shared storage. Maximizing benefits, total and for small business. Oversized SDG&E proposed projects. Cost recovery. Storage technology diversity.

337. **La. PSC** U-34794; Cleco Corp Purchase of NRG Assets and Contracts; Sierra Club. Direct, September 2018.

Economics of NRG generation resources, Cleco Power coal plants and wholesale sales contracts. Risks of the proposed transaction.

338. **Cal. PUC** A.18-11-005; Southern California Gas Demand-Response Proposal; Small Business Utility Advocates. Direct March 2019, Rebuttal April 2019.

Potential benefits of gas demand response and SoCalGas failure to identify potential benefits from its programs. Program design. Cost allocation.

339. **Cal. PUC** A.18-11-003; Pacific Gas & Electric Electric Vehicle Rate; Small Business Utility Advocates. Direct April 2019, Rebuttal May 2019.

Critique of subscription demand charge. Time-of-use periods. Outreach to small business. Time-of-use price differentials.

340. **Cal. PUC** A.18-07-024; Southern California Gas and San Diego Gas & Electric Triennial Cost Allocation Proceeding; Small Business Utility Advocates. Direct April 2019.

Core commercial declining blocks. Computation of customer charges. Embedded versus marginal cost allocation. Marginal cost computation. Allocation of self-generation incentives.

341. **Vt. PUC** 19-0397-PET; Screening Values for Energy-Efficiency Measures; Conservation Law Foundation. Direct May 2019.

Conceptual basis for including price-suppression benefits to consumers. Avoided T&D costs. Avoided externalities with a renewable energy standard. Risk mitigation.

342. **N.S. UARB** M09096; EfficiencyOne Application for 2020–2022 DSM Plan; Consumer Advocate. May 2019

Evaluate NS Power critique of EfficiencyOne proposal. Comparability of efficiency budgets. Affordability. Energy-efficiency programs and resource planning.

343. **N.S. UARB** M09191; NS Power 2019 Load Forecast Report; Consumer Advocate. July 2019.

Review load-forecast treatment of energy efficiency, fuel switching, electric vehicles, behind-the-meter solar, AMI-enabled programs, and the changing trend in lighting efficiency.

344. **Iowa Utilities Board** RPU-2019-001; Interstate Power and Light Rate Case; Sierra Club. Direct August 2019; Rebuttal September 2019.

Economics of continued operation of five coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of all units.

345. **Maine PUC** 2019-00101; Unitil Precedent Agreement for Westbrook Xpress, Conservation Law Foundation. August 2019.

The role of fuel convserions in Unitil's load forecast. Mandates for reducing greenhouse gas emissions. Efficient electric end uses as alternatives to gas system expansion. Risks of and alternatives to new pipeline supply.

346. **Maine PUC** 2019-00105; Bangor Natural Gas Precedent Agreement for Westbrook Xpress, Conservation Law Foundation. August 2019.

Mandates for reducing greenhouse gas emissions. Efficient electric end uses as alternatives to gas system expansion. Risks of and alternatives to new pipeline supply.

347. **Wisconsin PSC 6690-UR-126**; Wisconsin Public Service Corporation 2020 Rate Case, Sierra Club. Direct August 2019, Surrebuttal October 2019.

Economics of continued operation of four coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of uneconomic units.

348. **Wisconsin PSC 05-UR-109**; Wisconsin Electric Power Company2020 Rate Case; Sierra Club. Direct August 2019, Surrebuttal October 2019

Economics of continued operation of six coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of uneconomic units.

349 **N.S. UARB M09277**; NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. August 2019.

Benefits of the Maritime Link transmission line prior to operation of associated power supply and connecting transmission facilties.

350. **N.H. PUC** DG 17-198; Liberty Utilities Petition to Approve Firm Supply, Transportation Agreements, and the Granite Bridge Project; Conservation Law Foundation. September 2019.

Need for transportation contracts and new pipeline. Alternative of switching oil and propane to efficient electric end uses. Limited life of gas infrastructure and effect on ratepayer costs.

351. **Colorado PUC** 19AL-0268E; Public Service of Colorado Rate Case; Sierra Club. September 2019.

Prudence of management of superheater tube failures. Unfavorable economics of coal plants nationally. Need for continuing review of coal-plant economics and benefits of retirement.

352. **N.H. PUC** DG 17-152; Liberty Utilities Least Cost Integrated Resource Plan; Conservation Law Foundation. September 2019.
Integrated planning for gas utilities in an era of carbon constraints. Heat pump electrification versus gas conversion of oil-fired space and water heating.

353. **N.S. UARB** M09420; NS Power Application for an Extra-Large Industrial Active Demand Control Tariff; Nova Scotia Consumer Advocate. December 2019.

Estimating incremental costs, including lost wheeling revenues, variable O&M, and variable capital cost; updating and reconciliation of incremental costs.

354. **Cal. PUC** A.19-07-006; San Diego Gas & Electric Fast-Charging and Heavy-Duty Electric Vehicle Proposal; Small Business Utility Advocates. Direct January 2020, Rebuttal February 2020.

Interim rate proposal. Critique of subscription and demand charges. Time-of-use periods. Recovery of lost revenues.

355. **N.S. UARB** M09519; NS Power Smart Grid Application; Nova Scotia Consumer Advocate. February 2020. Joint testimony with John D. Wilson.

Differentiating capital costs from expenses. Inclusion of decommissioning costs in project plan. Selection of the Distributed Energy Resources Management System.

356. **N.S. UARB** M09499; NS Power 2020 Annual Capital Expenditure Plan; Nova Scotia Consumer Advocate. February 2020. Joint testimony with John D. Wilson.

Planning for hydro life extension or retirement. Appropriate levels of contingency in project budgets. Aggregation of multi-year capital programs. Cost-control efforts.

357. **Cal. PUC** A.19-03-002; San Diego Gas & Electric General Rate Application, Phase 2; Small Business Utility Advocates. Direct March 2020; Rebuttal May 2020.

Problems with proposed increases in the Monthly Service Fees and reliance on demand charges in for medium non-residential customers. Improving hours for the TOU periods.

358. **N.S. UARB** M09609; NS Power Authorization to Overspend on Gaspereau Dam Works; Nova Scotia Consumer Advocate. May 2020. Joint testimony with John D. Wilson.

Alternatives to the proposed project, including decommissioning the affected hydro system. Choice of project contingency factor. Estimation of archaeological costs. Replacement energy cost assumptions.

359. **N.S. UARB** M09609; NS Power Advanced Distribution Management System Upgrade; Nova Scotia Consumer Advocate. May 2020. Joint testimony with John D. Wilson.

Need for the ADMS. Integration with the Distributed Energy Resources Management System.

360. **Cal. PUC** A.19-10-012; San Diego Gas & Electric Power Your Drive Electric Vehicle Charging Program; Small Business Utility Advocates. Direct May 2020; Rebuttal June 2020. Joint testimony with John D. Wilson.

Ensuring that utility-installed chargers advance California goal for electric vehicles. Budget controls. Reporting requirements. Evaluation, monitoring and verification processes. Outreach to small business customers.

361. **N.S. UARB** M09499; Authorization to Overspend for Various Distribution Routines; Nova Scotia Consumer Advocate. June 2020.

Guidelines for reporting cost overruns due to extreme weather. Documentation of drivers of equipment deterioration and replacement. Tracking costs of connecting new customers.

362. **N.S. UARB** M09499; NS Power 2020 Load Forecast Report; Nova Scotia Consumer Advocate. July 2020. Joint testimony with John D. Wilson.

Impacts of the COVID-19 recession on load. Additional appropriate end-use studies. Improvements to modelling of electrification and factors. Effects of AMI and time-varying pricing on data availability and load.

363. **Cal. PUC** A.20-03-002, et al; Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric 2020 Energy Storage Procurement and Investment Plans; Small Business Utility Advocates. Direct and Rebuttal September 2020.

Adequacy of transmission, distribution and customer-side storage acquisition. Extending residential smart water-heater and new-home storage programs to small commercial customers.

364. **Penn. PUC** P-2014-2459362; Philadelphia Gas Works DSM Plan; Philadelphia Gas Works. October 2020.

Avoided costs of commodity and delivery. Water heater load shape. DRIPE.

365. **Cal. PUC** A.19-11-019; Pacific G&E Marginal Costs, Revenue Allocation, and Rate Design; Small Business Utility Advocates. November 2020. Joint testimony with John D. Wilson. Direct November 2020.

Marginal capacity costs for distribution, generation, transmission and customer access. Customer charges, demand charges, TOU differentials and periods, and real-time pricing.

366.

ACRONYMS AND INITIALISMS

APS	Alleghany Power System
ASLB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
CC	Corporation Commission
CMP	Central Maine Power
DER	Department of Environmental Regulation
DPS	Department of Public Service
DQE	Duquesne Light
DPUC	Department of Public Utilities Control
DSM	Demand-Side Management
DTE	Department of Telecommunications and Energy
EAB	Environmental Assessment Board
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EUB	Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LRAM	Lost-Revenue-Adjustment Mechanism
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NRC	Nuclear Regulatory Commission
OCA	Office of Consumer Advocate
PSB	Public Service Board
PBR	Performance-based Regulation
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURA	Public Utility Regulatory Authority
PURPA	Public Utility Regulatory Policy Act
ROEÉ	Regroupement des organismes environnementaux en énergie
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UC	Utilities Commission
URC	Utility Regulatory Commission
UTC	Utilities and Transportation Commission

John D. Wilson

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

2019–Present **Research Director, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, and regulation. Reviews electric-utility rate design. Designs and evaluates conservation programs for electric utilities, including conservation cost recovery mechanisms and performance incentives. Evaluates performance of renewable resources and designs performance evaluation systems for procurement. Designs and assesses resource planning and procurement strategies for regulated and competitive markets.

2007-19 **Deputy Director for Regulatory Policy, Southern Alliance for Clean Energy.** Managed regulatory policy, including supervision of experts in areas of energy efficiency, renewable energy, and market data. Provided expert witness testimony on topics of resource planning, renewable energy, energy efficiency to utility regulators. Directed litigation activities, including support of expert witnesses in the areas of rate design, resource planning, renewable energy, energy efficiency, and resource procurement. Conducted supporting research and policy development. Represented SACE on numerous legislative, utility, and private committees across a wide range of climate and energy related topics.

2001–06 **Executive Director, Galveston-Houston Association for Smog Prevention.** Directed advocacy and regulatory policy related to air pollution reduction, including ozone, air toxics, and other related pollutants in the industrial, utility, and transportation sectors. Served on the Regional Air Quality Planning Committee, Transportation Policy Technical Advisory Committee, and Steering Committee of the TCEQ Interim Science Committee.

2000–01 **Senior Associate, The Goodman Corporation.** Provided transportation and urban planning consultant services to cities and business districts across Texas.

1997–99 **Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Florida Legislature.** Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures. Edited statewide government accountability newsletter and coordinated online and internal technical projects.

1997 **Environmental Management Consultant, Florida State University.** Project staff for Florida Assessment of Coastal Trends.

1992-96 **Research Associate, Center for Global Studies, Houston Advanced Research Center.** Coordinated and led research for projects assessing environmental and resource issues in the Rio Grande / Rio Bravo river basin and across the Greater Houston region. Coordinated task force and edited book on climate change in Texas.

EDUCATION

BA, Physics (with honors) and history, Rice University, 1990.

MPP, John F. Kennedy School of Government, Harvard University, 1992. Concentration areas: Environment, negotiation, economic and analytic methods.

PUBLICATIONS

"Urban Areas," with Judith Clarkson and Wolfgang Roeseler, in Gerald R. North, Jurgen Schmandt and Judith Clarkson, *The Impact of Global Warming on Texas: A Report of the Task Force on Climate Change in Texas*, 1995.

"Quality of Life and Comparative Risk in Houston," with Janet E. Kohlhase and Sabrina Strawn, *Urban Ecosystems*, Vol. 3, Issue 2, July 1999.

"Seeking Consistency in Performance Incentives for Utility Energy Efficiency Programs," with Tom Franks and J. Richard Hornby, *2010 American Council for an Energy-Efficient Economy Summer Study on Energy Efficiency in Buildings*, August 2010.

"Monopsony Behavior in the Power Generation Market," with Mike O'Boyle and Ron Lehr, *Electricity Journal*, August-September 2020.

REPORTS

"Policy Options: Responding to Climate Change in Texas," Houston Advanced Research Center, US EPA and Texas Water Commission, October 1993.

Houston Environmental Foresight Science Panel, *Houston Environment 1995*, Houston Advanced Research Center, 1996.

Houston Environmental Foresight Committee, *Seeking Environmental Improvement*, Houston Advanced Research Center, January 1996.

Florida Coastal Management Program, *Florida Assessment of Coastal Trends*, June 1997.

Office of Program Policy Analysis and Government Accountability, *Best Financial Management Practices for Florida School Districts*, Report No. 97-08, October 1997.

Office of Program Policy Analysis and Government Accountability, *Review of the Community Development Corporation Support and Assistance Program*, Report No. 97-45, February 1998.

Office of Program Policy Analysis and Government Accountability, *Review of the Expedited Permitting Process Coordinated by the Governor's Office of Tourism, Trade, and Economic Development,* Report No. 98-17, October 1998.

Office of Program Policy Analysis and Government Accountability, *Florida Water Policy: Discouraging Competing Applications for Water Permits; Encouraging Cost-Effective Water Development,* Report No. 99-06, August 1999.

"Smoke in the Water: Air Pollution Hidden in the Water Vapor from Cooling Towers – Agencies Fail to Enforce Against Polluters," Galveston Houston Association for Smog Prevention, February 2004.

"Reducing Air Pollution from Houston-Area School Buses," Galveston Houston Association for Smog Prevention, March 2004.

"Who's Counting: The Systematic Underreporting of Toxic Air Emissions," Environmental Integrity Project and Galveston Houston Association for Smog Prevention, June 2004.

"Mercury in Galveston and Houston Fish: Contamination by Neurotoxin Places Children at Risk," Galveston Houston Association for Smog Prevention, October 2004.

"Exceeding the Limit: Industry Violations of New Rule Almost Slid Under State's Radar," Galveston Houston Association for Smog Prevention, January 2006.

"Whiners Matter! Citizen Complaints Lead to Improved Regional Air Quality Control," Galveston Houston Association for Smog Prevention, June 2006.

"Bringing Clean Energy to the Southeastern United States: Achieving the Federal Renewable Energy Standard," Southern Alliance for Clean Energy, February 2008.

"Cornerstones: Building a Secure Foundation for North Carolina's Energy Future," Southern Alliance for Clean Energy, May 2008.

"Yes We Can: Southern Solutions for a National Renewable Energy Standard," Southern Alliance for Clean Energy, February 2009.

"Green in the Grid: Renewable Electricity Opportunities in the Southeast United States," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Local Clean Power," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Energy Efficiency Program Impacts and Policies in the Southeast," Southern Alliance for Clean Energy, May 2009.

"Recommendations for Feed-In-Tariff Program Implementation In The Southeast Region To Accelerate Renewable Energy Development," Southern Alliance for Clean Energy, March 2011.

"Renewable Energy Standard Offer: A Tennessee Valley Authority Case Study," Southern Alliance for Clean Energy, November 2012.

"Increased Levels of Renewable Energy Will Be Compatible with Reliable Electric Service in the Southeast," Southern Alliance for Clean Energy, November 2014.

"Cleaner Energy for Southern Company: Finding a Low Cost Path to Clean Power Plan Compliance," Southern Alliance for Clean Energy, July 2015.

"Analysis of Solar Capacity Equivalent Values for Duke Energy Carolinas and Duke Energy Progress Systems," prepared for and filed by Southern Alliance for Clean Energy, Natural Resources Defense Council, and Sierra Club in North Carolina NCUC Docket No. E-100, Sub 147, February 17, 2017.

"Seasonal Electric Demand in the Southeastern United States," Southern Alliance for Clean Energy, March 2017.

"Analysis of Solar Capacity Equivalent Values for the South Carolina Electric and Gas System," Southern Alliance for Clean Energy, March 2017.

"Solar in the Southeast, 2017 Annual Report," with Bryan Jacob, Southern Alliance for Clean Energy, February 2018.

"Energy Efficiency in the Southeast, 2018 Annual Report," with Forest Bradley-Wright, Southern Alliance for Clean Energy, December 2018.

"Solar in the Southeast, 2018 Annual Report," with Bryan Jacob, Southern Alliance for Clean Energy, April 2018.

"Tracking Decarbonization in the Southeast, 2019 Generation and CO_2 Emissions Report," with Heather Pohnan and Maggie Shober, Southern Alliance for Clean Energy, August 2019.

"Seasonal Electric Demand in the Southeastern United States," with Maggie Shober, Southern Alliance for Clean Energy, April 2020.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," with Mike O'Boyle, Ron Lehr, and Mark Detsky, Energy Innovation Policy & Technology LLC and Southern Alliance for Clean Energy, April 2020.

"Monopsony Behavior in the Power Generation Market," *The Electricity Journal* 33, with Mike O'Boyle and Ron Lehr (2020).

"Review of Nova Scotia Power's 2020 Integrated Resource Plan," prepared for the Nova Scotia Consumer Advocate, NSUARB Matter No. M08059, with Paul Chernick (January 2021).

PRESENTATIONS

"Clean Energy Solutions for Western North Carolina," presentation to Progress Energy Carolinas WNC Community Energy Advisory Council, February 7, 2008.

"Energy Efficiency: Regulating Cost-Effectiveness," Florida Public Service Commission undocketed workshop, April 25, 2008.

"Utility-Scale Renewable Energy," presentation on behalf of Southern Alliance for Clean Energy to the Board of the Tennessee Valley Authority, March 5, 2008.

"An Advocates Perspective on the Duke Save-a-Watt Approach," ACEEE 5th National Conference on Energy Efficiency as a Resource, September 2009.

"Building the Energy Efficiency Resource for the TVA Region," presentation on behalf of Southern Alliance for Clean Energy to the Tennessee Valley Authority Integrated Resource Planning Stakeholder Review Group, December 10, 2009.

"Florida Energy Policy Discussion," testimony before Energy & Utilities Policy Committee, Florida House of Representatives, January 2010.

"The Changing Face of Energy Supply in Florida (and the Southeast)," 37th Annual PURC Conference, February 2010.

"Bringing Energy Efficiency to Southerners," Environmental and Energy Study Institute panel on "Energy Efficiency in the South," April 10, 2010.

"Energy Efficiency: The Southeast Considers its Options," NAESCO Southeast Regional Workshop, September 2010.

"Energy Efficiency Delivers Growth and Savings for Florida," testimony before Energy & Utilities Subcommittee, Florida House of Representatives, February 2011.

"Rates vs. Energy Efficiency," 2013 ACEEE National Conference on Energy Efficiency as a Resource, September 2013.

"TVA IRP Update," TenneSEIA Annual Meeting, November 19, 2014.

"Views on TVA EE Modeling Approach," presentation with Natalie Mims to Tennessee Valley Authority's Evaluating Energy Efficiency in Utility Resource Planning Meeting, February 10, 2015.

"The Clean Power Plan Can Be Implemented While Maintaining Reliable Electric Service in the Southeast," FERC Eastern Region Technical Conference on EPA's Clean Power Plan Proposed Rule, March 11, 2015.

"Renewable Energy & Reliability," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Challenges to a Southeast Carbon Market," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Solar Capacity Value: Preview of Analysis to Date," Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) meeting, Orlando, FL, November 2017.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Southeast Energy and Environmental Leadership Forum, Nicholas Institute for Environmental Policy Solutions, August 2020.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Indiana State Bar Association, Utility Law Section, Virtual Fall Seminar, September 2020.

EXPERT TESTIMONY

2008 **South Carolina PSC** Docket No. 2007-358-E, surrebuttal testimony on behalf of Environmental Defense, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2009 **North Carolina NCUC** Docket No. E-7, Sub 831, direct testimony on behalf of Environmental Defense Fund, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

Florida PSC Docket Nos. 080407-EG through 080413-EG, direct testimony on behalf of Southern Alliance for Clean Energy and the Natural Resources Defense Council. Energy efficiency potential and utility program goals.

South Carolina PSC Docket No. 2009-226-E, direct testimony in general rate case on behalf of Environmental Defense, the Natural Resources Defense Council, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2010 **North Carolina NCUC** Docket No. E-100, Sub 124, direct testimony on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Adequacy of consideration of energy efficiency in Duke Energy Carolinas and Progress Energy Carolinas' 2009 integrated resource plans.

Georgia PSC Docket No. 31081, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues.

Georgia PSC Docket No. 31082, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 demand side management plan, including program revisions, planning process, stakeholder engagement, and shareholder incentive mechanism.

2011 **South Carolina PSC** Docket No. 2011-09-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of South Carolina Electric & Gas's 2011 integrated resource plan, including resource mix, sensitivity analysis, alternative supply and demand side options, and load growth scenarios.

South Carolina PSC Docket Nos. 2011-08-E and 2011-10-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of Progress Energy Carolinas and Duke Energy Carolinas' 2011 integrated resource plans, including resource mix, sensitivity analysis, alternative supply and demand side options, cost escalation, uncertainty of nuclear and economic impact modeling.

2013 **Georgia PSC** Docket No. 36498, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2013 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues, economics of fuel switching and renewable resources.

South Carolina PSC Docket No. 2013-392-E, direct testimony with Hamilton Davis in Duke Energy Carolinas need certification case on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Need for capacity, adequacy of energy efficiency and renewable energy alternatives, and use of solar power as an energy resource.

2014 **South Carolina PSC** Docket No. 2014-246-E, direct testimony generic proceeding on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Methods for calculating dependable capacity credit for renewable resources and application to determination of avoided cost.

2015 **Florida PSC** Docket No. 150196-EI, direct testimony in Florida Power & Light need certification case on behalf of Southern Alliance for Clean Energy. Appropriate reserve margin and system reliability need.

2016 **Georgia PSC** Docket No. 40161, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in Georgia Power's 2016 integrated resource plan, including portfolio diversity, operational and implementation risk, analysis of project-specific costs and benefits (including location and technology considerations), and methods for calculating dependable capacity credit for renewable resources.

2019 **Georgia PSC** Docket Nos. 42310 and 42311, direct testimony with Bryan A. Jacob in Georgia Power's 2019 integrated resource plan and demand side management plan on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in IRP, retirement of uneconomic plants, and use of all-source procurement process. Shareholder incentive mechanism for both renewable energy and DSM plan.

2020 **Nova Scotia UARB** Matter No. M09519, direct testimony with Paul Chernick in Nova Scotia Power's application for approval of the Smart Grid Nova Scotia Project on behalf of the Nova Scotia Consumer Advocate. Cost classification, decommissioning costs, justification for software vendor selection, and suggested changes to project scope.

Nova Scotia UARB Matter No. M09499, direct testimony with Paul Chernick in Nova Scotia Power's 2020 annual capital expenditure plan on behalf of the Nova Scotia Consumer Advocate. Potential to decommission hydroelectric systems, review of annually recurring capital projects, use of project contingencies, and cost minimization practices.

Nova Scotia UARB Matter No. M09579, direct testimony with Paul Chernick in Nova Scotia Power's application for the Gaspereau Dam Safety Remedial Works on behalf of the Nova Scotia Consumer Advocate. Alternatives to proposed project, project contingency factor, estimation of archaeological costs, and replacement energy cost calculation.

Nova Scotia UARB Matter No. M09707, direct testimony with Paul Chernick on Nova Scotia Power's 2020 Load Forecast on behalf of the Nova Scotia Consumer Advocate. Impacts of recession, application of end-use studies, improvements to forecast components, and impact of time-varying pricing.

California PUC Docket A.19-10-012, direct and rebuttal testimony with Paul Chernick in San Diego Gas & Electric's application for the Power Your Drive Electric Vehicle Charging Program on behalf of the Small Business Utility Advocates. Ensuring that utility-installed chargers advance California goal for electric vehicles. Budget controls. Reporting requirements. Evaluation, monitoring and verification processes. Outreach to small business customers.

California PUC Docket A.19-08-013, direct testimony in Southern California Edison's 2021 general rate case (track 2) on behalf of the Small Business Utility Advocates. Reasonableness of remedial software costs to be included in authorized revenue requirement.

Georgia PSC Docket Nos. 4822, 16573 and 19279, direct, rebuttal and surrebuttal testimony in Georgia Power Company's PURPA avoided cost review on behalf of the Georgia Large Scale Solar Association. Reviewing compliance with prior Commission orders. Application of capacity need forecast in projection of avoided capacity cost. Calculation of cost of new capacity. Proposal of standard offer contract.

California PUC Docket A.19-11-019, direct testimony with Paul Chernick in Pacific Gas & Electric's 2021 general rate case (phase 2) on behalf of the Small Business Utility Advocates. Cost of service methods. Rate design, including customer charges, demand charges, real time pricing tariffs, TOU differentials and periods.

Nova Scotia UARB Matter No. M09548, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Reasonableness of fuel contract costs. Scope of study on dispatch practices. Impact of greenhouse gas shadow pricing. Compliance issues related to resource planning.

2021 **California PUC** Docket R.20-11-003, direct and reply testimony on rulemaking to ensure reliable electric service in the event of an extreme weather event on behalf of the Small Business Utility Advocates. Modifications to Critical Peak Pricing programs and Time of Use periods. Modifications to load management programs.

Nova Scotia UARB Matter No. M09898, direct testimony on Nova Scotia Power's Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Effect of delays in power contract. Unit modeling assumptions. Variable capital costs. Application of Time-Varying Pricing.

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase II
Application 19-11-019
Data Response

PG&E Data Request No.:	SBUA_005-Q01		
PG&E File Name:	GRC-2020-PhII_DR_SBUA_005-Q01		
Request Date:	March 23, 2021	Requester DR No.:	005
Date Sent:	March 25, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Jan Grygier	Requester:	Jennifer Weberski

QUESTION 01

Pursuant to the March 23, 2021 email of Jan Grygier, please provide the following:

a. Calculations of historical hourly DA and RT MGCCs.
b. A comparison of DA and RT energy and capacity rates, including consideration of variability and forecastability.

ANSWER 01

a. Please see attachment “GRC-2020-PhII_DR_SBUA_005-Q01Atch01.xlsb”
b. Please see attachment “GRC-2020-PhII_DR_SBUA_005-Q01Atch02.xlsb”

Note that due to the size of the attachments…

PG&E reserves the right to make modifications to the above-referenced files prior to their release as workpapers for PG&E’s March 29, 2021 filings.

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase II
Application 19-11-019
Data Response

PG&E Data Request No.:	SBUA_004-Q01		
PG&E File Name:	GRC-2020-PhII_DR_SBUA_004-Q01Supp01		
Request Date:	March 2, 2021	Requester DR No.:	004
Date Sent:	March 30, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Jan Grygier	Requester:	Jennifer Weberski

QUESTION 01

Please provide PG&E's most recent resource adequacy study and the following supporting data, all for the same modeling years:

1. Hourly adjusted net load, or the relevant load and generation components, corresponding to the entire CAISO footprint;
2. Hourly LOLE or equivalent metric, corresponding to the PG&E service territory; and
3. Hourly LOLE or equivalent metric, corresponding to any local resource adequacy areas that PG&E models separately

ANSWER 01

As ordered in D.19-09-043, the three investor owned utilities (IOUs) performed a joint study to assess the ELCC values used in Renewables Portfolio Standard (RPS) bid evaluations. That study (the Joint IOUs ELCC Study) is the most recent resource adequacy study that includes PG&E's service territory, and is provided as attachment "GRC-2020-PhII_DR_SBUA_03-Q01-Atch01_Joint IOU ELCC Study Wind Solar Hybrid July 2020.pdf."

The Joint IOUs ELCC Study modeled 2022, 2026 and 2030.

1. The Joint IOUs ELCC Study did not calculate or report adjusted net load (ANL). However, PG&E calculated hourly ANL for ten scenarios (corresponding to weather years of 2005 through 2014) for forecast years 2022, 2026 and 2030 as part of its modeling of Marginal Energy Costs (MEC) for the GRC Phase II. The hourly ANL for all ten scenarios for the indicated forecast years (as well as 2021) are provided as attachment "GRC-2020-PhII_DR_SBUA_03-Q01-Atch02_ANL_2021_2022_2026_2030.xlsb."
2. The requested data was not generated as part of the Joint IOUs ELCC Study.
3. The requested data was not generated as part of the Joint IOUs ELCC Study.

QUESTION 01 – SUPPLEMENTAL 01

a. Please provide the requested information or any similar information in PG&E's possession, regardless of whether it was produced for the Joint IOUs ELCC Study. To be clear, the request would cover modeling for 365 days for a current or future year, or typical days by month, or any other analysis that indicates the relative reliability risk by hour (and if available, day time) and season or month.

b. If PG&E has no information on the hourly LOLE for its service territory, please explain why PG&E decided that information would be not worth modelling.

c. If PG&E has estimates of hourly LOLE or equivalent metric for the CAISO system, please provide those estimates.

ANSWER 01 – SUPPLEMENTAL 01

a. PG&E does not have its own LOLE study, i.e. providing relative reliability risk by hour, day time, and season or month. If SBUA wishes to use information from another source, please see supplemental response to Q 01-c below.

b. PG&E objects to this question as assuming that hourly LOLE for its service territory would be worth modeling for this case.

c. Two relative reliability metrics for the CAISO system - Loss of Load Probability (LOLP) and Expected Unserved Energy (EUE) – are available on a month-hour basis (i.e., as a 12x24 matrix) from another source (e.g. Energy and Environmental Economics, Inc., or E3), as contained in the e-mail sent to you on March 26 on a preliminary basis, and as attached to this data response as file "GRC-2020-PhII_DR_SBUA_004-Q01Supp01.xlsx."

   The data in the attached file are outputs corresponding to historical conditions in 2019 and forecasted conditions in 2030 from a study E3 conducted for the CAISO looking at the effective load carrying capability of demand response. The study and data are public, available at http://www.caiso.com/InitiativeDocuments/E3DemandResponseELCCStudy-EnergyStorage-DistributedEnergyResourcesPhase4.pdf.

   While PG&E has already provided both historical and forecasted ANL data as part of its confidential workpapers for this proceeding, PG&E is also attaching its *public* calculated ANL values for 2019 and 2030 as file "GRC-2020-PhII_DR_SBUA_004-Q01Supp02.xlsx," for convenience.

   If SBUA is interested in using more granular data than appears in the E3 study, PG&E suggests asking Donald Brooks at the CPUC for a "debug report" from SERVM runs that were presented as part of the November 23rd Track 3.B Workshop in the RA proceeding, or alternatively from SERVM runs performed for the 2019-2020 Reference System Plan. PG&E understands that a SERVM debug report provides detailed information regarding load, renewables and other generation, as well as unserved energy and reserves shortfalls, that could prove useful to SBUA.

However, PG&E has not seen such a report and can make no guarantee as to its usefulness for SBUA’s purposes.