Matter No. M09777

In the Matter of an Application by Nova Scotia Power Incorporated for Approval of its Time-Varying Pricing Tariff Application

EVIDENCE OF

JOHN D. WILSON AND PAUL CHERNICK

ON BEHALF OF

THE CONSUMER ADVOCATE

Resource Insight, Inc.

FEBRUARY 24, 2021

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I. Identification

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.

I have been in my current position since November of 2019. My clients have included a variety of consumer advocate, energy industry, and environmental advocacy organizations.

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 Exhibit RII-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two dozen times before utility regulators in California and the Southeast U.S. and appeared numerous additional times before various regulatory and legislative bodies.

Q: Have you previously testified in other proceedings before this Board?

A: Yes. I have filed testimony in seven proceedings. I have also assisted the Consumer Advocate in preparing comments and developing positions in numerous proceedings and stakeholder processes.

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 RII-2.

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.

Q: Have you previously testified in other proceedings before this Board?

A: Yes. I testified in over 25 Board proceedings, as listed in my resume. I have also assisted the Consumer Advocate in preparing comments and developing positions in numerous proceedings and stakeholder processes.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: Our testimony is sponsored by the Nova Scotia Consumer Advocate.

Q: How did the Time-Varying Pricing Application originate?

A: In 2017, NS Power applied for approval of its Advanced Metering Infrastructure (AMI) Project (CI #47124). It anticipated full deployment of AMI in 2019 and 2020, which has been delayed into 2021 due to COVID-19 restrictions.

Q: Please summarize the behavioral change driven benefits NS Power identified in its AMI Application.

A: In its application, NS Power projected that 21 percent of the total savings resulting from the AMI project would be driven by changes in customer behavior, including:

- Capacity savings from critical peak pricing (CPP) -- $27.0 million
- Energy conservation from bill alerts -- $13.6 million
- Third party meter reading revenues -- $2.5 million[1]

Of these three types of benefits, CPP is the primary focus of this proceeding. The bill alerts are of indirect relevance to the TVP program since they could share a common communications strategy. The third-party meter reading revenues are not relevant to this proceeding.

Respecting the capacity savings, in its application, NS Power:

> "estimated that an opt-in CPP tariff targeting peak period load reductions during the winter could produce savings of $27.0 million [net present value] … based on avoiding … 26 MW of generation capacity additions. That estimate assumed that 15 percent of residential customers would be enrolled onto the CPP tariff by 2022, and would collectively reduce their winter peak demand by 12.5%."[2]

In addition to the capacity savings from a CPP tariff, NS Power estimated 4 MW of peak capacity savings from load balancing, although the Board determined that likely overstated the effective capacity savings.[3]

Q: What concerns did the Consumer Advocate express in his closing submission?

A: The Consumer Advocate stated:

[1] Board Decision, *NS Power Advanced Metering Infrastructure Project Application (CI #47124),* Matter No. M08349 (June 11, 2018), para. 90-91. (Hereafter, "Board Decision, AMI Application")

[2] Board Decision, AMI Application, para. 93.

[3] Board Decision, AMI Application, para. 25, 35.

> NSPI appears to be reversing the accepted process of determining whether an investment is beneficial before undertaking it. In effect, NSPI proposes to spend ratepayer money on the AMI build out and then determine whether it is likely to have real value.[4]

Q: How did NS Power respond to this concern?

A: NS Power stated that, "Parties can be confident that by implementing the AMI system, the capacity benefits forecast in the Application will be realized."[5]

Q: What earnings opportunity are associated with the AMI project?

A: The Board approved the requested capital budget of $133,228,952.[6] NS Power also identified further capital expenses over the 20-year meter life, including "IT hardware refresh every three years, meter replacements at a rate of 0.5% per year, and network refreshment at a rate of 1% per year and 100% in 2030."[7] Those capital expenditures will provide NS Power with an opportunity for a return.

Q: What is the purpose of your evidence?

A: Our evidence is intended to examine the extent to which NS Power's commitment to realize the capacity benefits forecast in the Application will be realized by the TVP Application. If so, then NS Power will have demonstrated a portion of the value that it included in its Economic Analysis Model justification for the cost of the AMI project.

We have reviewed the proposed TVP tariffs, the Soft Launch plan, and the proposed Lost Revenue Adjustment Mechanism. To the extent that NS Power's proposal will not realize the capacity benefits assumed in the AMI Application, our

[4] Board Decision, AMI Application, para. 97.

[5] Board Decision, AMI Application, para. 101.

[6] Board Decision, AMI Application, para. 221.

[7] Board Decision, AMI Application, para. 125.

evidence suggests alternatives and improvements to enable the Board to address the proposal's shortcomings.

Q: Please summarize your recommendations briefly.

A: We recommend that the Board:

- Reject NS Power's proposed TVP tariffs, and instead approve our proposed CPP tariffs;
- Approve NS Power's proposed Soft Launch, with certain modifications; and
- Reject NS Power's proposed Lost Revenue Adjustment Mechanism.

We will provide a complete list of our recommendations at the close of our evidence.

III. Brief Overview of Recommended TVP Strategy

Q: Please describe the TVP strategy you recommend to the Board and NS Power.

A: We believe the focus of the TVP strategy should be to maximize capacity savings at the least cost, fulfilling the commitment NS Power made when it proposed to install AMI systems. We recommend that NS Power should introduce Critical Peak Pricing (CPP) with two voluntary participation options: CPP Basic and CPP Advanced tariffs.[8]

[8] We also propose a pilot of a General tariff with no demand charges.

Table 1: Proposed CPP Tariffs

	CPP Basic	CPP Advanced
Eligibility	Domestic Service Small General	Domestic Service Small General General
CPP Rate Periods	November to March 4 PM – 8 PM	November to March Scheduled by NS Power
Number of CPP Events	Average: 6 events Maximum: 12 events	Average: 12 events Maximum: 18 events
CPP Period Energy	$1.50 / kWh	$1.50 / kWh
Winter Energy (¢/kWh) (2nd Block for SG & GD)	Domestic Service: 15.46 Small General: 14.09	Domestic Service: 14.64 Small General: 13.41 General: 6.96

We recommend that the CPP tariffs be introduced in winter of 2021/2022 as a Soft Launch, as proposed by NS Power with certain modifications. We recommend that the Board accept NS Power's proposal to report on the impact of the offerings in the first winter period by June 30, 2022, and that its report be accompanied with proposals to address outstanding issues of this regulatory proceeding and refine the tariffs and program implementation if required.

Q: What are the principal differences between your proposal and NS Power's Application?

A: Fundamentally, our proposal incents customers to shift winter loads to maximize capacity savings, while NS Power's proposal also attempts to also reduce fuel and purchased power costs. Our proposal does not include Time of Use rates.

Q: Will your proposed TVP strategy achieve the 26 MW of capacity savings benefits that NS Power represented would be realized in its AMI Application?

A: We cannot determine whether either NS Power's proposal or our proposed TVP strategy will achieve any particular level of capacity savings benefits. NS Power's estimate of capacity savings is based on three highly questionable assumptions.

First, NS Power assumes that at full-scale deployment, it will enroll 30 percent of its customers on TVP rates. This would be among the highest rates of opt-in participation in similar rates offered in North America. We view it as improbable that such high participation rates will be realized in the next several years. We believe our proposed TVP strategy will be as attractive to customers as NS Power's, but we cannot support any particular participation forecast.

Second, NS Power assumes that winter peak load reductions will occur at roughly 50 percent of the level that are typically seen at utilities with TVP programs focused on summer peaks. Brattle acknowledges that the evidence for this assumption is scarce, due to the lack of relevant utility experience. Even among the utilities that have targeted savings at summer peaks, reported load reductions have varied widely. Thus, NS Power's estimate of load reductions could be an underestimate or an overestimate of the outcome. Given the lack of data, we do not see any way to develop reasonable participation and response assumptions; the only certainty in such estimates is their uncertainty.

Third, NS Power makes the assumption that winter peak load reductions will translate one-for-one into capacity savings. On this point, we believe that the capacity savings from NS Power's proposed TVP tariffs would be less than half of whatever load reductions occur (see page 15). We believe our proposed TVP tariff designs would deliver substantially greater the capacity savings.

IV. Effect of Proposed TVP Tariffs on Load and Capacity Savings

Q: Please explain why load reductions would not be translate directly into capacity savings.

A: There are four problems with NS Power's analysis of load reductions.

- **Focus on total system peak load**—system capacity needs are more closely tied to adjusted net load.

- **Existing peaks outside proposed TVP peak periods**—ANL peaks may occur in off-peak hours, resulting in no impact on the peak.
- **Peak shifting to off-peak hours**—Load reductions may result in the ANL peak shifting from the TVP peak period to the off-peak period, resulting in peak reduction lower than the peak-period load reduction.
- **Load shifting to off-peak hours**—Load increases resulting from load shifts may result in increased ANL peaks during off-peak hours, further reducing the resulting capacity savings.

Q: Please explain adjusted net load.

A: Reliability risks and marginal energy costs are not driven by gross system load, but by adjusted net load (ANL), which is gross load minus non-dispatchable energy.

For NS Power, non-dispatchable energy includes wind and a portion of hydroelectric generation. We estimated the non-dispatchable hydro generation in each month as the hydro system output at the minimum hourly rate for the month. This base hydro adjustment accounts for lower minimum generation levels in November and December than in January, February and March.

Q: Why is ANL a superior metric to system load?

A: ANL and other similar metrics are being adopted by utilities with substantial renewable energy penetration. We demonstrate its importance to NS Power in regression analyses comparing the correlation of hourly load and ANL with hourly system marginal energy costs in 2016 through 2019, as shown in Exhibit RII-3. We included dummy variables for each calendar year, to account for inter-annual changes in fuel costs and resources. Using load predicted 31 percent of marginal cost variation, while using ANL predicted 40 percent of marginal cost variation, an improvement of 9 points, or 29 percent.

In comparison, adding daily fuel prices and hourly hydro generation to the ANL regression only improved the prediction by 4 percentage points. This indicates that variation in marginal energy costs within a year is driven more by wind generation than gas and coal fuel prices. We would not expect the variable hydro dispatch to explain much of the price variation, since that resource is dispatched in what would otherwise be high-cost hours and reduces marginal costs in those hours.

Q: Why do you find that the proposed TVP tariffs may not reduce capacity requirements as much as expected?

A: The fundamental purpose of TVP rate design is to shift loads, and reductions in system capacity requirements only occur if customer load is shifted away from the highest ANL peak hours.[9] At full scale, Brattle's evidence estimates "that NS Power's TVP implementation can ultimately deliver a 31 MW peak demand reduction (24.3 MW from CPP and 6.2 MW from TOU)."[10] As discussed above (page 8), we view this estimate with skepticism, but for purposes of this discussion and our rate design, we use Brattle's 31 MW estimate and its underlying calculations.

To achieve 31 MW of peak demand reduction on any given day, the ANL peak must occur during the TVP period and the TVP tariffs must not increase load during the off-peak hour(s) that could become the new ANL peak.

To assess the impact of the proposed TVP rates on peak ANL, we analyzed ANL data provided by NS Power for 2016–2019 (2020 data were not available at the time we conducted our analysis). We focused on the top 0.1 percent of all hours, which is

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[9] The 31 MW estimate by Brattle differs from NS Power's rate design objective: "The TVP price differential was set at a level that, under the assumed price elasticities of demand, would produce the desired shift in system peak of 26 MW." NS Power, Exhibit N-6, response to CA IR-8

[10] Brattle, *An Assessment of Nova Scotia Power's Time Varying Pricing Proposal* (November 30, 2020), p. 9. Filed in NS Power, TVP Application, Appendix G. (Hereafter, "Brattle Evidence.")

35 hours over the four years, or roughly 9 hours per year.[11] As shown in Table 2, three of these 35 ANL peak hours occurred outside of the proposed TVP periods.

Table 2: Number of Top 0.1% of ANL hours, by Month and Hour (2016-2019)

	Hour																							
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1	-	-	-	-	-	-	1	3	5	4	-	-	-	-	-	-	-	3	2	1	1	1	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	2	3	2	-	-	-	-	-	-	-	4	1	1	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**	**-**	**1**	**5**	**8**	**6**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**7**	**4**	**2**	**1**	**1**	**-**	**-**

Source: NS Power, Hourly Gross Generation Data, provided in Matter No. M08929 (October 2020). Some source data are confidential, but NS Power has determined that this figure is not confidential.

In addition, the TVP load shifts estimated by Brattle would shift the ANL peaks on many other days to another hour, reducing the daily peak by much less than the reduction in peak-period loads. This was demonstrated in the following example.

On January 17, 2019, the ANL was highest in the period from 5 PM to 10 PM. These five hours are illustrated in shown in Table 3, with 4 PM – 8 PM highlighted as they are included in the TVP period. The ANL in the hour ending (HE) 9 PM, after the peak period, was higher than in HE 5 PM and 6 PM, but lower than the loads in HE 7 PM and 8 PM, by 22 and 14 MW, respectively. Shifting 31 MW out of the daily peak period would only have reduced the peak ANL by 22 MW, even if the load in HE 9 PM did not change.

[11] The 9 hours per year corresponds roughly with the frequency that we recommend utilizing for CPP events, as discussed elsewhere in our evidence.

Table 3: January 17, 2019 Adjusted Net Load (ANL), MWs

Hour	Load	ANL	Load Shift	Shifted ANL
3 PM – 4 PM			0	
4 PM – 5 PM	1,875	1,712	- 31	1,682
5 PM – 6 PM	2,004	1,850	- 31	1,819
6 PM – 7 PM	2,033	1,873	- 31	1,842
7 PM – 8 PM	2,026	1,865	- 31	1,834
8 PM – 9 PM	1,999	1,851	0	1,851
9 PM – 10 PM	1,939	1,786	0	1,786

Source: NS Power, Hourly Gross Generation Data, provided in Matter No. M08929 (October 2020). Some source data are confidential, but NS Power has determined that this figure is not confidential.

This example demonstrates that a 31 MW reduction in the peak period would reduce the ANL peak from 1,873 MW to—at best—1,851 MW, a reduction of only 22 MW.

After the TVP period ends at 8 PM, customers would have increased electricity use, bringing the house back to a comfortable temperature, running the dishwasher and laundry, taking a shower, and doing whatever else the household delayed in the peak period to reduce peak period load by a total of 124 MWh.[12] Beginning at 8 PM, customers are likely to use *more than usual* power, causing a "snapback" effect.[13]

If even 22 MWh (about 31%) of the shifted load ended up in HE 9 PM, the daily peak would still have been 1,873 MW (the pre-shift ANL peak); any higher shift would have increased the peak load. If the 8 PM–9 PM snapback is 31 MW, then the ANL peak would have been 1,882 MW. In that case, the ANL peak would thus have been 9 MW *higher* with the load shift than without it. If 31 MWh are shifted out of each of the four TVP peak hours, for a total of 124 MWh of deferred usage, the snapback may be much more than 31 MWh.

[12] Some of the load may have been shifted into the hours immediately prior to the peak, and some load may never be recovered.

[13] Brattle did not estimate the snapback effect in its support for the application. NS Power, Exhibit N-6, response to CA IR-9(c).

This example illustrates how the load shift effect may reduce peak load by less than the savings in the TVP peak period and may result in a counterproductive *increase* in peak ANL, and hence an *increased* capacity requirement. The high ANL in the non-peak hours is also evidence of a more fundamental problem with the proposed TVP periods. The maximum hours in Table 3 are each among the 35 highest ANL hours from 2016 to 2019. Even hours that are not the daily, weekly or annual peak can present a significant reliability risk, since many of them are very close to the maximum ANL that NS Power plans for, when any contingency—transmission loss or generation loss—may put system reliability in jeopardy.

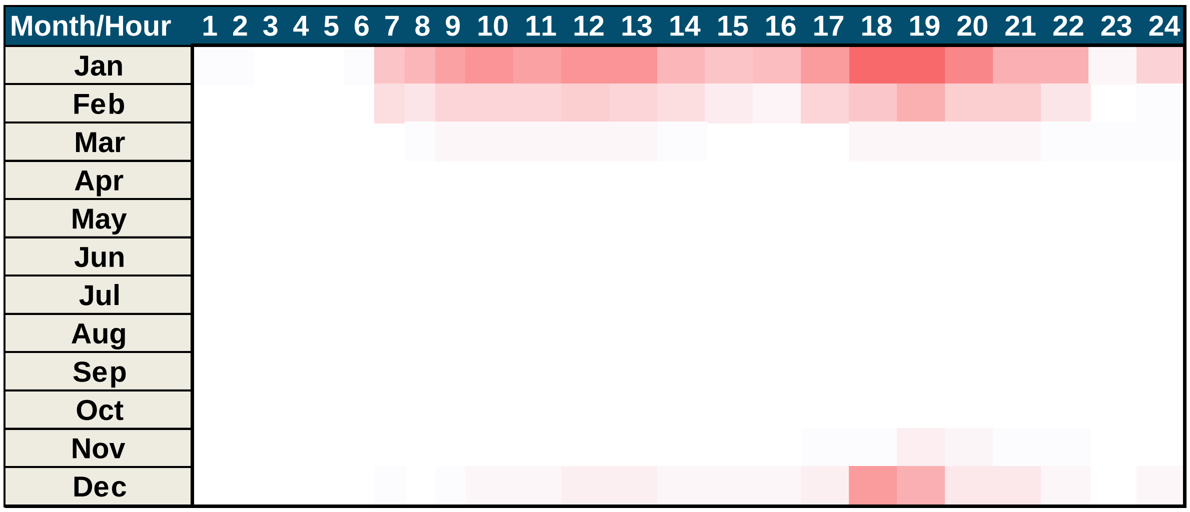
Q: How much would the proposed TVP tariffs benefit system reliability?

A: Reliability can be measured by the loss of load probability (LOLP) which is the expected probability that load plus system reserves exceeds available generating capacity. Expressed on an annual basis, loss of load expectation (LOLE) is the most common metric used to evaluate resource adequacy. Nova Scotia Power uses a 1-day-in-10-years LOLE reliability standard.

In response to an information request, NS Power provided a LOLP "heatmap," providing the probability that there would be loss of load in each hour of a month.[14] As shown in Figure 1, the heatmap confirms that system reliability risk is highest in the months of December – February, and that significant reliability risk occurs throughout the day—from 6 AM to 10 PM, especially in January.

[14] Energy and Environmental Economics, "LOLP Heatmap – Prepared for Nova Scotia Power" (February 2020). Provided by NS Power, Exhibit N-6, response to CA IR-07, Attachment 1.

Figure 1: Loss of Load Probability Heatmap



Source: Energy and Environmental Economics, "LOLP Heatmap – Prepared for Nova Scotia Power" (February 2020). Provided by NS Power, Exhibit N-6, response to CA IR-07, Attachment 1.

To determine how well the reliability risk is aligned with NS Power's proposed TVP periods, we calculated the total LOLP for those periods, compared to midday hours (between the periods) and overnight hours. We also segmented the LOLP by the core winter months (December – February) and what NS Power refers to as the shoulder months (November and March).[15] As shown in Table 4, NS Power's proposed TVP periods capture only 58 percent of the LOLP.

Table 4: Distribution of Loss of Load Probability (LOLP) by months and periods of day

Months	Proposed TVP	Midday	Overnight
Winter	53 %	23 %	17 %
Shoulder	5 %	1 %	2 %
Total	**58 %**	**24 %**	**18 %**

Source: Energy and Environmental Economics, "LOLP Heatmap – Prepared for Nova Scotia Power" (February 2020). Provided by NS Power, response to CA IR-07, Attachment 1.

In fact, NS Power's proposed TVP periods capture less than 58 percent of the LOLP since the periods exclude weekends and holidays. Other data provided by NS Power shows that peak ANL events are equally likely to occur on a weekday or a

[15] The total LOLP for April – October is exactly zero.

weekend.[16] If LOLP is also equally likely to occur on a weekday or a weekend, then NS Power's proposed TVP periods capture only 42 percent of the LOLP.

In other words, a system reliability event is more likely to occur outside of NS Power's proposed TVP periods than during those periods.

In our view, the capacity contribution of load reductions in the proposed TVP periods should be reduced significantly. If the proposed TVP tariffs were an intermittent generation technology, they would likely have an effective load carrying capability of less than 50 percent, meaning that instead of contributing 31 MW as represented by NS Power, the tariffs would contribute less than 15 MW of capacity benefit.

Q: Does NS Power provide other evidence that its proposed TVP periods are not well targeted to system peaks?

A: Yes. NS Power's proposed CPP tariff targets the 88 highest load hours of the year. In its analysis of peak and off-peak hours, NS Power found that 58 of those 88 hours occurred during on-peak hours and 30 of the highest 88 load hours of the year occurred during off-peak hours.[17] Thus, about one-third of the hours that NS Power considers critical peak hours for purposes of its filing are not included in its proposed on-peak or critical peak periods.

Q: Is there any reason to believe that the load reductions in the proposed TVP periods would perform better than the historical data suggest?

A: No, in fact the opposite. NS Power's Integrated Resource Plan anticipates acquiring significantly more wind resources during the next decade. The low wind cost

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[16] NS Power's data show that 72% of top-25 peak days occur on weekdays. Weekdays represent 71% of all days. NS Power, Exhibit N-6, response to CA IR-24(b).

[17] NS Power, Exhibit N-5, TVP Application, Appendix J, Synapse DR-03, Attachment 5, Usage Summary Tab, comparing cells S22, T22, AA22, and AB22.

sensitivity could result in as much as 631 MW of wind being added by 2026, which would roughly double NS Power's existing 595 MW of wind capacity.[18]

To evaluate the potential impact of doubling NS Power's wind capacity over the next five years, we calculated what the ANL would have been during the 2016-2019 time period with double the wind output. As shown in Table 5, over 25 percent (8 of 35) of the peak ANL hours occur outside NS Power's proposed TVP periods. While it is not certain how much wind NS Power will add to its system over the next several years, it is evident that any addition of cost-effective wind resources will make NS Power's proposed TVP periods even less well suited to enabling capacity savings.

Table 5: Number of Top 0.1% of ANL Hours, Wind Generation Doubled, by Month and Hour (2016-2019)

	Hour																							
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	2	2	3	1	1	-	-	-
2	-	-	-	-	-	-	1	1	1	1	-	-	-	-	-	-	-	-	1	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	1	1	1	-	-	1	1	4	4	2	2	-	-	-
Total	**-**	**-**	**-**	**-**	**-**	**-**	**1**	**1**	**1**	**1**	**1**	**1**	**2**			**1**	**3**	**7**	**9**	**4**	**3**	**-**	**-**	**-**

Source: NS Power, Hourly Gross Generation Data, provided in Matter No. M08929 (October 2020). Some source data are confidential, but NS Power has determined that this figure is not confidential.

Q: Can you suggest appropriate TOU periods?

A: No. Based on our analysis, there are no reasonably compact periods that provide substantial reduction in peak ANL hours or reliability risk, due to both the large number of potential peak ANL hours and the distribution of unplanned generation outages. While longer peak periods could capture a sufficient share of peak ANL

[18] NS Power, *2020 Integrated Resource Plan*, Matter No. M08929 (November 27, 2020), pp. 23, 60, 106.

hours and reliability risk, we accept Brattle's opinion that peak periods of 4 hours would not appeal to customers.[19]

We have advised regulators to adopt both voluntary and mandatory TOU rate designs in other jurisdictions. We view them as preferable to standard rates designed for purposes of cost allocation and revenue recovery. However, as a capacity-cost reduction tool, the evidence demonstrates that the NS Power system is not suited for TOU rate periods today and is likely to be even less well suited in the future.

Q: How does the current domestic time-of-day tariff compare with NS Power's proposal for the domestic TOU tariff?

A: The current domestic time-of-day tariff differs from the TOU tariff proposed by NS Power in four key respects. First, the winter is defined as December to February, which better reflects the peak-load season than NS Power's proposed November to March.

Second, the tariff's winter peak periods cover five hours in the morning and seven hours in the evening, with an intermediate "standard" rate applying during the four hours between the two peaks. Customers benefit from much lower off-peak rates from 11 PM to 7 AM. These TOU periods are not consistent with Brattle's advice to limit peak periods to four hours.

Third, while the peak rate is limited to the winter, the other months still have a time-of-day incentive, with the intermediate standard rate applying on weekdays from 7 AM to 11 PM.

Fourth, these rates are only available to customers using efficient heating technology with timing and controls approved by NS Power.

[19] NS Power, Exhibit N-5, TVP Application, Appendix J, p. 32.

While we have not analyzed this tariff in depth as part of preparing our testimony, the existing rate design appears more likely to achieve capacity savings than the proposed TVP tariffs.

V. Effect of TVP Tariffs on Energy Costs

Q: Is it likely that the proposed TVP tariffs will reduce energy costs?

A: No. There is almost no difference between marginal energy costs between peak and off-peak periods during the winter months. Wintertime marginal energy costs are forecast to be about 11 percent higher during on-peak hours in 2021.[20] NS Power has expressed its hope that the proposed TVP tariffs will shift load but does not expect energy conservation. The proposed TOU tariff is projected to shift 6.2 MW of load from all the on-peak hours to off-peak hours.[21] This shift would save only about $57,000 annually.[22]

A deeper analysis shows that load shifting will sometimes result in *higher* marginal energy costs. We compared marginal energy costs during NS Power's proposed TVP periods to costs during the eight hours that are adjacent to those periods, two hours before each peak period and two hours after, which we refer to as "shift hours." Figure 2 shows that prices are most often $0–$10 higher during on-peak hours as compared to those shift hours. More than 10 percent of the time, marginal energy costs are higher during the shift hours than in the on-peak period. This

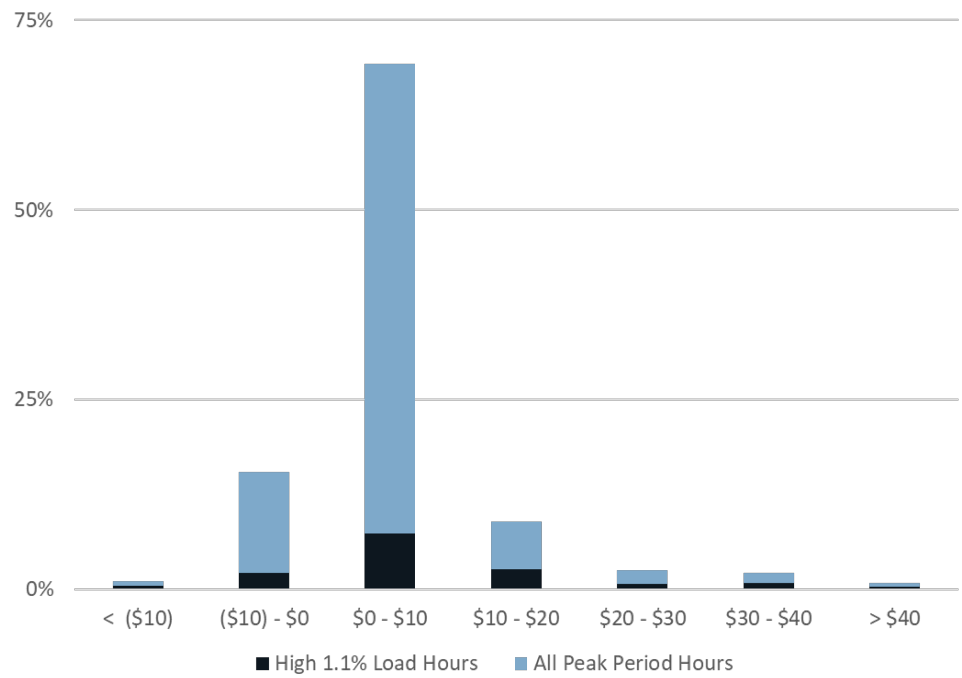
[20] NS Power, Exhibit N-6, response to CA IR-5.

[21] Brattle Evidence, p. 9.

[22] We computed the TOU shift energy savings from Synapse DR-1. Energy savings due to the CPP shift would depend on when those events are called. NS Power, Exhibit N-5, TVP Application, Appendix J, Synapse DR-1, Attachment 1.

indicates that the overall effect of any TVP tariffs on energy costs depends on how customers shift load from on-peak periods to off-peak periods.

Figure 2: Winter Difference in On-Peak vs "Shift Hours," Marginal Cost of Energy (2016-2019)



Source: NS Power, Hourly Gross Generation Data, provided in Matter No. M08929 (October 2020); TVP Application, Appendix J, response to Synapse DR-01, Attachment 1. Some source data are confidential, but NS Power has determined that this figure is not confidential.

VI. NS Power's Proposed Time-of-Use Tariff

Q: Is a time-of-use (TOU) rate design likely to reduce capacity requirements for NS Power?

A: No, a TOU tariff will not result in substantial capacity savings. As shown above (page 16), there are no TVP periods compatible with TOU design principles that result in reducing ANL or reliability risk by even half that assumed by Brattle. While Brattle projects the proposed TOU program to reduce load by about 6 MW at full scale, it is more likely to provide less than 3 MW of capacity savings (see page 15), even accepting NS Power's forecast of participation levels and load reductions in the TVP peak periods.

Nor are the proposed TVP rates likely to have a material impact on average energy costs, as shown above (page 18).

NS Power states that modifications to the TVP designs presented in its "application may be required, where a customer need has been articulated, and value can be found in doing so."[23] The evidence we have presented demonstrates that very little "value can be found" in the proposed TOU tariffs in terms of the stated objectives of reducing peak loads or energy costs.

Therefore, we recommend the Board reject the proposed TOU tariffs outright.

VII. Recommended CPP Tariffs

Q: Do the problems with the proposed TVP periods also apply to the CPP tariffs?

A: Yes, utilizing the proposed TVP periods significantly reduces the value that "can be found" from NS Power's proposed CPP tariffs. We recommend that instead of approving NS Power's proposed CPP tariffs, the Board approve alternative CPP tariffs that we have designed to increase the opportunity for capacity savings.

Q: Please describe your recommended CPP tariffs in further detail.

A: We recommend that NS Power offer two CPP tariffs during the "soft launch." Both tariffs would be applicable in the winter season (November to March), any day of the week. The CPP rate should be $1.50/kWh for both tariffs.

The CPP Basic tariff would be available to customers in the Domestic Service and Small General classes. During the Soft Launch, NS Power should target CPP Basic enrollment of 500 customers from each class. On CPP Basic Event days, the

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[23] NS Power, Exhibit N-9, response to NSAURB IR-3.

CPP rate would be in effect from 4 PM to 8 PM. NS Power's operational practices for invoking CPP Basic Event days should be designed to achieve an average of 6 events per year, and the tariff should indicate that there would be an annual maximum of 12 events. CPP Basic tariff rates are provided in Table 7, and standard rates are provided in Table 6 for comparison.

The CPP Advanced tariff would be available to customers in the Domestic Service, Small General, and General classes. During the Soft Launch, NS Power should target CPP Advanced enrollment of 500 customers from each class. On CPP Advanced Event days, NS Power would announce the event period, which should be set for a 4-hour period that most closely aligns with the expected ANL peak hours on that day. NS Power's operational practices for invoking CPP Advanced Event days should be designed to achieve an average of 12 events per year. CPP Advanced rates are provided in Table 8.

The CPP Advanced tariff should include two limitations on events. First, the annual maximum number of 4-hour events should be set at 18 events. Second, the tariff should allow for up to two "Double CPP Advanced Events." NS Power could call two 4-hour events on those days in reserves are expected to be tight in both the morning and the afternoon.

We have prepared redline edits of NS Power's proposed CPP tariffs to indicate the changes necessary to implement our recommendations. They are attached as Exhibits RII-5 through RII-9.

Table 6: Standard Rates (Cents per Kilowatt-hour)[24]

Class of Service	During a CPP Event	First 200 kWh per Month, After CPP Event Usage	All Additional kWh
Effective November 1, 2021			
Residential	n/a	n/a	16.008
Small General	n/a	16.416	14.602
General	n/a	12.545	9.266
Effective Nov 1, 2022			
Residential	n/a	n/a	16.215
Small General	n/a	16.483	14.669
General	n/a	12.820	9.541

Table 7: Proposed CPP Basic Rates (Cents per Kilowatt-hour)

Class of Service	During a CPP Event	First 200 kWh per Month, After CPP Event Usage[25]	All Additional kWh
Effective Nov 1, 2021			
Residential	150.000	n/a	15.250
Small General	150.000	16.416	14.026
Effective Nov 1, 2022			
Residential	150.000	n/a	15.456
Small General	150.000	16.483	14.092

Table 8: Proposed CPP Advanced Rates (Cents per Kilowatt-hour)

Class of Service	During a CPP Event	First 200 kWh per Month, After CPP Event Usage[25]	All Additional kWh
Effective Nov 1, 2021			
Residential	150.000	n/a	14.438
Small General	150.000	16.416	13.344
General	150.000	12.546	6.682
Effective Nov 1, 2022			
Residential	150.000	n/a	14.644
Small General	150.000	16.483	13.410
General	150.000	12.820	6.957

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[24] NS Power, Exhibit N-6, response to CA IR-1, Attachment 1, 2021 and 2022 RSP TVR Options tabs.

[25] NS Power allocated the rate reduction across both rate blocks using factors that we were not able to replicate. Due to the lack of support for those factors, our rate design assigns all rate reductions to the second block, but we would also support a more uniform rate reduction.

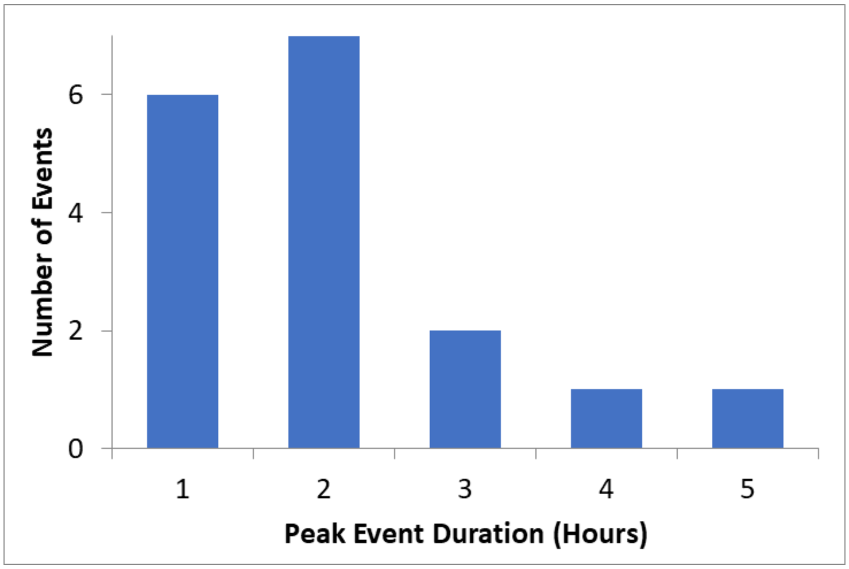
Q: Why do you recommend that the 4-hour CPP Advanced Event period not be specified in advance?

A: As discussed above, ANL peaks and system reliability events often occur outside of NS Power's proposed TVP periods (page 7). There are no reasonably compact winter-long periods that provide substantial reduction in ANL or reliability risk. We focused our design for CPP Advanced Event periods on the characteristics of the ANL peak hours, which we define as the 0.1 percent of hours with the highest ANLs—35 hours over the 4-year data period, 2016–2019. Those 35 hours occurred on 17 days.

A 4-year analysis period may not have sufficient weather diversity to present a statistically valid representation of the ANL peak events. Ideally, NS Power would conduct further modeling. Our approach was to design a CPP Advanced Event period that would capture all the events in order to maximize reduction of ANL peaks and reliability risk.

The majority of peak events (i.e., days with hours in the top 0.1% of ANL) are 1 or 2 hours in duration, as shown in Figure 3. We expect that NS Power's operators would be able forecast the ANL peak the day ahead within a 4-hour window that would bracket those 1- or 2-hour peak events. There are also a significant number of 3- to 5-hour peak events, and two such peak events extended outside NS Power's proposed TVP periods. The LOLP data presented in Table 4 indicate that there is a strong probability that ANL peaks will continue to occur outside NS Power's proposed TVP periods. Based that evidence, we recommend that the CPP Advanced Event periods should not be specified in the tariff but rather should be scheduled by NS Power when invoking each CPP Advanced Event.

Figure 3: Adjusted Net Load Peak Hours per Peak Event, 2016-2019



Source: NS Power, Hourly Gross Generation Data, provided in Matter No. M08929 (October 2020). Some source data are confidential, but NS Power has determined that this figure is not confidential.

We also recommend that the CPP Advanced tariff allow for up to two "Double CPP Advanced Events" per year. There are two analyses we conducted that support this proposal

- First, four of the 17 peak events lasted 3 to 5 hours. It may be difficult to forecast these longer peak events to within 4 hours.
- Second, we also looked at high load hours – the top 1.1% of ANLs over the 4-year period. There were 87 days with one or more high loads, including the 17 days with the peak events. Of those 87 high-load days, there were 22 events with high loads in both the morning and evening. This indicates that the NS Power system could have peak events in the morning and evening of the same day.

Based on that evidence, we recommend allowing the CPP Advanced tariff authorize NS Power to call two 4-hour events on those days in which the ANL is forecast to be near annual peak levels in both the morning and afternoon, or it may call two events back-to-back if the ANL peak period is expected to be more than four hours.

Including "Double CPP Advanced Events" in the tariff is important because it will provide NS Power with the capability to respond during the most extreme ANL peaks. As discussed above, the peak event of January 17, 2019 included five ANL peak hours, two of which were the two highest ANL hours in the 4-year dataset, and the peak event of January 18, 2019 included four ANL peak hours, one of which was the third highest hours in the dataset. While these extended events occur infrequently, they are likely to be the most consequential reliability events and we view this capability as essential to reliably reducing load on the NS Power system.

Because "Double CPP Advanced Events" will represent a significant inconvenience and potential bill impact for customers, NS Power should use this capability only after developing experience with the program. This feature of the tariff should not be used during the Soft Launch, for example.

Q: Is there much experience with a CPP tariff that does not include a scheduled event period?

A: No. Brattle states that the only CPP tariff with flexible scheduling that it is aware of is the Oklahoma Gas & Electric (OG&E) Smart Hours tariff, which is a variable-peak pricing tariff with an "over-call provision" that allows for OG&E to designate a critical peak period of 2 to 8 hours duration at any time of the year.[26] Brattle states that OG&E rarely invokes the override.[27]

It is difficult to project the effectiveness of an approach that few utilities have attempted. However, as NS Power and Brattle have discussed with stakeholders at length, there are "relatively few examples of winter-peaking utilities implementing

[26] NS Power, Exhibit N-11, response to Synapse IR-37, Attachment 1, p. 15.

[27] NS Power, Exhibit N-6, response to CA IR-3(b). Brattle also describes participation in real-time pricing, which are similar in that pricing is known only a day or an hour in advance. However, prices are not specified in real-time pricing and vary every hour, making the customer proposition substantially different from what we propose.

TVP. Most program data and designs are from summer-peaking utilities."[28] So any TVP design for NS Power is subject to additional uncertainty.

Winter peaks are typically of longer duration than summer peaks and present more challenges to load-reduction programs and storage resources. Unusual challenges call for innovative solutions. Our proposal is calibrated to meet the circumstances that NS Power's system presents.

Q: Why do you recommend that the 4-hour CPP Basic Event period be limited to a 4-hour evening period?

A: While we designed the CPP Advanced tariff for maximum impact on the ANL peak and reduction of reliability risk, we designed the CPP Basic tariff as an option that offers customers:

- Greater simplicity for ease of customer understanding;
- Less risk, so that customers are more likely to realize bill savings; and
- Similarity to the CPP Advanced tariff, so that customers can more easily upgrade as they gain experience with the CPP Basic tariff.

We also thought it appropriate to offer two CPP tariffs so that NS Power may learn from the differences what features are of interest, or concern, to potential participants.

Regarding the selection of the 4-hour evening period, we also considered recommending a 3-hour or a 5-hour evening period. We decided to adopt NS Power's proposed evening TVP period for the CPP Basic tariff after considering the following evidence.

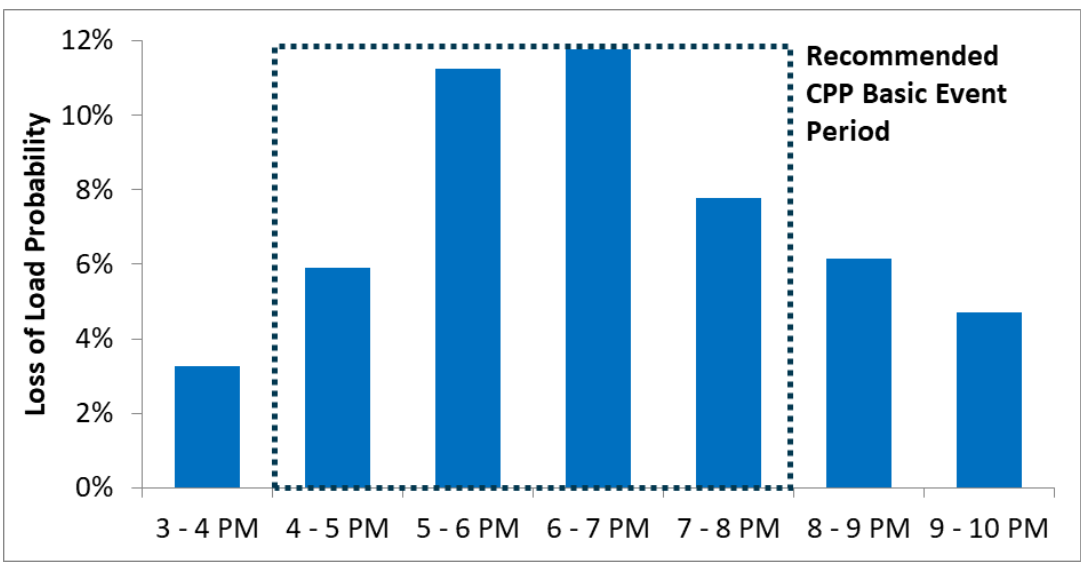
- To keep the CPP Basic tariff as simple as possible, we decided to focus on the evening period only, when load reduction could be most beneficial. NS Power's proposed TVP periods capture 37 percent of annual LOLP in the

[28] NS Power, Exhibit N-5, TVP application, pp. 27, 30-31, and Brattle Evidence, pp. 6, 18.

evening compared to only 19 percent in the morning.[29] Furthermore, comparing Table 2 with Table 5, it appears that future wind resource additions will shift more peak ANL hours into the evening period.

- As shown in Figure 4, the three hours with the highest LOLP are those ending at 6 PM to 8 PM, with the adjacent hours (ending 5 PM and 9 PM) having almost the same LOLP.
- We accepted the opinion of Brattle that peak periods longer than four hours would not appeal to customers, who might be discouraged from taking a CPP rate option if consumption would have to be curtailed for so long.[30]
- We selected a 4-hour period to minimize the number of differences between our proposal and NS Power's proposal, although using a 3-hour period would be similarly effective.

Figure 4: Share of Loss of Load Probability, November - March



Source: Energy and Environmental Economics, "LOLP Heatmap – Prepared for Nova Scotia Power" (February 2020). Provided by NS Power, Exhibit N-6, response to CA IR-07, Attachment 1.

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[29] Energy and Environmental Economics, "LOLP Heatmap – Prepared for Nova Scotia Power" (February 2020). Provided by NS Power, Exhibit N-6, response to CA IR-07, Attachment 1.

[30] NS Power, Exhibit N-6, response to CA DR-18.

Q: Why do you recommend limiting the General class eligibility to only the CPP Advanced tariff?

A: General customers have higher loads than the other two classes, and thus have greater individual opportunity to impact the ANL peak. Those customers typically have more capacity to consider and implement a more sophisticated rate design. Thus, they should be well positioned to apply and benefit from the CPP Advanced tariff.

While it might make sense to provide the CPP Basic tariff as an option for General customers, it presents rate design issues as long as the Board and NS Power wish to continue offering a demand charge, as discussed below (see Page 34). If the demand charge were removed from the CPP Basic tariff, with all demand costs recovered through energy charges, then it would be reasonable to also offer the CPP Basic tariff to General customers.

Q: Why do you recommend an enrollment target, rather than a cap?

A: NS Power's application is unclear as to whether it intends an enrollment cap or target.[31] We recommend a 500-customer enrollment target by class for each CPP tariff. Once the target is reached, NS Power could cease recruitment efforts but should accept enrollments from any customers who have already learned about the TVP program.

NS Power's enrollment caps or targets are based on Brattle's "statistical power analysis" of the number of participants needed to estimate impacts of the tariffs.[32] We accept Brattle's analysis on this point and have attempted to adapt those findings to our recommendations.

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[31] NS Power, Exhibit N-5, TVP Application, p. 48; Brattle Evidence, p. 13. We have no objection to the tariff language allowing for limitation or closure of the tariff, as there may be good reasons to suspend or even terminate enrollment.

[32] Brattle Evidence, p. 13.

Our recommended enrollment targets for the residential tariffs are larger than the 250-customer enrollment target Brattle recommended for NS Power's proposed Residential CPP Tariff. We recommend a larger enrollment target for the CPP tariffs to achieve total enrollment at a similar level to the Brattle's recommendation of 1,250 residential customers in NS Power's TVP program. A residential enrollment of 1,000 is advisable to reflect diversity in the demographic and building type characteristics of Soft Launch participants.

We recommend an enrollment target, rather than a cap, for two reasons. First, we see no benefit to turning away interested customers who have learned about the program. As individual tariff targets are reached, it would be confusing to turn away customers from some tariffs while others remain open. Since NS Power seeks to ultimately enroll 30 percent of its customers in TVP rates, it should encourage rather than discourage participation.

Second, higher enrollment levels will increase confidence in the statistical analysis. This is particularly true for the non-residential classes. As Brattle observes, "these two classes are less homogenous and the impacts we are looking to detect are lower compared to the Residential class."[33] Even 500 customers are not enough to achieve the level of confidence in statistical analyses of these two classes.

In the case of the non-residential classes, NS Power should consider continuing basic customer recruitment even after the 500 customer targets are met. Social media and communications from customer account managers would be low-cost methods to further increase enrollment.

Q: Why do you recommend fewer Critical Peak Events per year than NS Power?

A: Our experience is that customer retention can be a problem for CPP programs with a large number of events per year. In California, the three large utilities call far fewer

[33] Brattle Evidence, p. 13.

than 22 Critical Peak Events per year and have recently opposed increasing the number of events even to respond to emergency conditions.

- PG&E's CPP tariffs allow it to call between nine and 15 events per year, and even during the extreme summer weather of 2020 it only called 12 residential CPP events.[34] PG&E supports removing or reducing the minimum and removing or increasing the maximum number of events allowed to ensure availability for grid management rather than using them to meet tariff requirements or withholding them due to frequency limitations. PG&E also expressed the concern that increasing the number of events could lead to bill volatility.[35]
- SCE's CPP tariffs indicate that it will call exactly 12 events per year.[36] SCE opposed changes to this standard because "it may lead to customers opting out of the program due to customer fatigue" or bill volatility.[37]
- SDG&E's CPP tariffs allow it to call up to 18 events per year with no minimum, but it only calls between zero and nine events per year. SDG&E expresses concern that, "The varying number of potential events called in a year and the resulting fluctuation in pricing causes significant bill volatility

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[34] Pacific Gas & Electric, Pro Forma Schedule B-1, Sheet 8, Advice Letter 5861-E (June 26, 2020); PG&E, Direct Testimony, California Public Utility Commission Docket No. R.20-11-003 (January 12, 2021), ch. 2, p. 6.

[35] Pacific Gas & Electric, Reply Comments, California Public Utility Commission Docket No. R.20-11-003 (December 10, 2020), p. 3.

[36] Southern California Edison, Schedule TOU-GS-1 (March 1, 2019), Sheet 12.

[37] SCE, Reply Comments, California Public Utility Commission Docket No. R.20-11-003 (December 10, 2020), pp. 4-5.

for customers who participate in the CPP rate, particularly those who are unable to shift their energy usage outside of the event hours."[38]

We did not find that NS Power or Brattle provided a clear justification for selecting 22 Critical Peak Events per year. We also do not understand why NS Power would want to require an exact number of events per year. A tariff that mandates an exact number of events creates two problems. First, as the winter season comes to a close, NS Power might need to invoke events even on days when the ANL peak is forecast to be relatively low and there are no major outages or other reasons for load reductions. Second, once NS Power has reached 22 events, it would be unable to activate the CPP tariff even if a particularly severe condition on its system emerges.

To avoid these two problems, NS Power should plan for a target number of CPP events that is significantly below each tariff's maximum limit. NS Power should only approach or reach its tariff maximum in very unusual circumstances—once in ten or twenty years. Once customers develop greater familiarity with TVP tariffs, it would be advisable to remove the firm cap on the number of events entirely to avoid any potential constraints in particularly severe conditions.

Q: Why do you recommend more CPP Advanced events than CPP Basic events?

A: Our intent is for the CPP Advanced tariff to be NS Power's primary load management tariff. By utilizing a flexible event period, NS Power will obtain the maximum impact on reliability from participating customers. Furthermore, because the event period can be called at any time of the day, there will be more opportunities to invoke a CPP Advanced Event.

In contrast, the CPP Basic tariff will be suitable for customers who require more certainty. Because CPP Basic Events will only be called when the ANL peak is

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[38] San Diego Gas & Electric, Direct Testimony, California Public Utility Commission Docket No. R.20-11-003 (January 12, 2021), p. 8.

anticipated to occur during the evening hours, there will be fewer opportunities to invoke these events.

Q: Would the CPP Basic tariff have less reliability value than the CPP Advanced tariff?

A: Yes, some high ANL hours (and in some years the annual ANL peak) may occur outside the CPP Basic Event period. Since the CPP Basic tariff will not be available during many ANL peak hours, it has less reliability value (expressed as reduced LOLE or increased load-carrying capacity) than the CPP Advanced tariff.

Even though the CPP Basic tariff will have less reliability value than the CPP Advanced tariff, it should not cause counterproductive load shifts such as those that could occur if NS Power's proposed TVP tariffs are adopted (see Page 7). In the evening peak event example described in Table 3 above, the ANL peak hours extended to 9 PM, beyond NS Power's proposed 4 PM to 8 PM peak period. In such a circumstance, NS Power could avoid shifting the ANL peak to the 8 PM to 9 PM hour by invoking a CPP Advanced Event for 5 PM to 9 PM and either (a) choosing not to invoke a CPP Basic Event or (b) invoking a CPP Basic Event if experience indicates that those customers would not shift excessive load into the 8 PM to 9 PM hour.

Q: Why do you not recommend a maximum number of CPP Events per week?

A: Neither of our proposed tariffs should include a maximum number of CPP Events per week. Increasingly, extreme weather events have led to utility systems experiencing unanticipated loads over extended periods of time. Even if the utility's general practice is to limit the number of events per week, it should not have a tariff restriction that prevents it from aligning its requests for conservation with its pricing programs. CPP Advanced customers could be confused by urgent messages to conserve energy that are not accompanied by a CPP Event declaration because a weekly limit has already been reached.[39]

Instead, NS Power could establish and publicize operational practices that indicate an intent to restrict the frequency of events per week. Most customers will rely on educational materials, and not the actual tariff, to determine if a CPP tariff is a good choice. When a particularly severe event occurs, customers are likely to understand if NS Power chooses to invoke extra events in the interest of reliability.

Q: Would the winter energy rates be lower than the standard offer energy rates?

A: Yes. However, the exact rates would be slightly different than proposed by NS Power. NS Power proposed calling exactly 22 Critical Peak Events per year, and we recommend that NS Power call, on average only 6 CPP Basic Events and 12 CPP Advanced Events per year.

Like NS Power's proposal, our proposal seeks revenue neutrality by reducing winter energy rates to match the expected revenues from the CPP rates.[40] Since there would be fewer CPP events called, there would be less additional revenue and hence less reduction in winter energy rates.

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[39] During severe events that are not aligned with the CPP Basic Event period, NS Power could communicate with those customers and urge conservation. It could take that opportunity to encourage them to switch to the CPP Advanced tariff, which will offer greater savings on the standard rate.

[40] NS Power's TOU rate is revenue neutral with respect to standard tariffs using 2022 FAM rates. NS Power's CPP rate is revenue neutral with respect to standard tariffs using 2014 FAM rates. NS Power's evidence does not explain why TOU and CPP tariff neutrality requires different FAM rate baselines. NS Power, Exhibit N-5, TVP Application, p. 45; Exhibit N-6, response to CA IR-1, Attachment 1, comparing cells BL10 from the SOR Calc 2014 Fuel, SOR Calc 2022 Fuel, CPP and TOU tabs. We elected to design CPP rates to be revenue neutral with respect to standard tariffs using 2022 FAM rates. We also recommend that NS Power discuss this discrepancy in its reply evidence and, if necessary, revise its CPP tariffs to demonstrate revenue neutrality with respect to standard tariffs using 2022 FAM rates.

VIII. Demand Charges in TVP Tariffs

Q: Please describe how demand charges are addressed in NS Power's proposed TVP tariffs.

A: The General class is the only class of the three for which TVP tariffs are proposed that has a demand charge. The General class has a year-round non-coincident peak demand charge, which is to say that the charge is the maximum demand in the month irrespective of whether total system load (or ANL) is high or low during the customer's peak demand hours. NS Power proposes that during the winter period, the demand charge should only apply during on-peak hours, while continuing to apply as the overall monthly peak for the rest of the year.

It appears that NS Power's intent is for the demand charge to apply during the on-peak period for both TOU and CPP tariffs. However, another interpretation of the CPP tariff is that the demand charge only applies when the Critical Peak Event is called.[41]

Q: What is your general opinion of non-coincident demand charges?

A: Demand charges usually do not reflect cost causation and may be counter-productive, except for recovery of costs caused by customer-specific equipment that is directly sized to the maximum load of a single customer. Costs of generation, transmission and most of the distribution system are not caused by most individual customers' maximum demand. The only costs that vary with customer maximum demand, as opposed to customer contribution to a diversified demand, are those associated with facilities dedicated to that customer (meters, service drops, sometimes transformers) and—for very large customers not included in NS Power's proposed TVP tariffs—local facilities that experience their peak loads whenever the customer peaks.

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[41] NS Power, Exhibit N-5, TVP Application, Appendix E, p. 1.

Demand charges are also inappropriate, in that they charge each customer for just one hour in each month, while the loads in many hours contribute to loss-of-load risks and shorten the life of transmission and distribution equipment. As shown in Figure 1, those hours are not evenly spread over the months, either in number or magnitude, so charging the same demand charge for one random hour in each month does not encourage the load reductions that would reduce costs. Recovery of costs related to overall system demand (or to coincident loads of many customers) through a non-coincident demand charge dampens price signals for conservation, promotes inefficient customer behavior, and undermines customers' ability to control electricity costs.

Demand charges also provide no incentive for conservation or load switching in the hours and days after the customer hits a higher load level. As NS Power acknowledges, "Applying a demand charge in a single hour of each month may not always be effective at controlling demand across all peak hours."[42]

These and other problems with demand charges are discussed at length in Exhibit RII-4, *Charge Without a Cause*, a report of the Regulatory Assistance Project.

Q: Do you agree with NS Power's proposal?

A: No. NS Power argues for applying wintertime demand charges only during its on-peak periods on the presumption that charging customers for high off-peak loads would undermine the incentives of the proposed TVP tariffs.[43] As discussed above (beginning on page 8), both the ANL peaks and the reliability risk are spread well beyond NS Power's proposed on-peak period, so neither an energy rate nor a demand charge in that period is likely to shift load in a manner that would reduce costs as NS Power intends. The value of the proposed TVP tariffs is already diminished by NS

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[42] NS Power, Exhibit N-6, response to CA IR-11(i).

[43] NS Power, Exhibit N-5, TVP Application, p. 31.

Power's limitation of them to fixed periods. Adverse load shifting—shifting load onto ANL peaks and high-risk hours—could be exacerbated by NS Power's on-peak demand charge design.

Changes to the demand charge design could also complicate the impact evaluation. Customers may find the combination of the CPP rate and the winter-only peak-period demand charge confusing. For these reasons, we find that it would be better to maintain the current demand charge structure, suboptimal as it is, than to adopt NS Power's proposal to apply winter charges during the proposed TVP periods only.

Q: How should demand charges be addressed in an efficient CPP Advanced tariff?

A: Demand charges should be drastically reduced or eliminated, as we discuss below. As long as demand charges remain in these tariffs to maintain consistency with the standard General tariff, then we recommend using a CPP-event-driven billing demand to determine all monthly demand charges for the CPP Advanced tariff.

As discussed elsewhere in our evidence, we are recommending that the CPP Advanced tariff allow for invoking CPP events during any four-hour period. (General class customers would not be eligible for CPP Basic.) NS Power's operators should schedule CPP Advanced Events to align with forecast ANL peaks (taking into account other supply conditions, such as generator outages or import restrictions). During these CPP Advanced Events, the energy rate would increase to $1.50/kWh. During any month with CPP Advanced Events, the billing demand would be the maximum customer demand in any CPP Advanced Event hour.

For months without CPP Advanced Events, the billing demand would be the average demand billed in the prior winter months with events, as illustrated in the following example.

- In winter 2021, NS Power calls CPP Advanced Events in January, February, and March. In each of those months, a customer's billing demand would be its maximum demand in any CPP Advanced Event hour for the month.
- NS Power would calculate the average of the January, February and March billing demands.
- For April 2021–March 2022, that average billing demand would be used to determine the monthly demand charge in any month for which no CPP event was called.

This proposed demand charge rate design complements the energy rates by measuring demand only during CPP Advanced Events.

The combination of the demand charge with the CPP energy rate could result in a substantial price signal for load control during a CPP Advanced Event. The customer's marginal price could be increased to over $4.00 per kWh, as illustrated in Table 9, if the CPP Event is likely to set the customer's monthly demand charge.[44]

Table 9: CPP Advanced Marginal Price, General Customer

Component	Rate	Hours	Marginal Price per kW
CPP Rate	$1.50 / kWh	4	$ 6.00
Demand Charge	$10.50 / kW	-	$10.50
Total for Average Hour[45]			**$4.12**

Using a demand charge that is aligned with the ANL Peak (via the CPP Advanced Events) will result in some complexity in the customer's perception of the marginal price. On one hand, the customer might perceive a lower marginal price if the customer is reasonably certain it will not maximize its billing demand during a

[44] The customer's incentive would be increased by the effect of the current month Event-coincident demand on subsequent months without events.

[45] $16.82 / 4 = $4.205

particular CPP Event (e.g., if it has already set a very high billing demand during a CPP event earlier in the month). On the other hand, when the customer's CPP Event load *does* set billing demand for the month, that hour's load partially determines the billing demand for all non-CPP months the following year—so the customer might perceive a *higher* marginal price.

In summary, as long as demand charges remain in NS Power's standard rate design, then the demand charge should be assessed as follows.

- Our CPP Advanced Tariff—Based on the maximum demand during CPP Advanced Events, if one occurs during the month, and otherwise on the average demand billed in the prior winter months with CPP Advanced Events.
- NS Power CPP Tariff—Based on the maximum hourly demand during the month.

Q: Does NS Power's application fully recognize the revenue impacts of its proposal on demand charges?

A: No. NS Power acknowledges that under its proposal, revenues from demand charges are likely to go down since some customers currently experience their maximum demand during off-peak hours and others may shift their load so that their maximum demand is shifted out of the peak period.[46] In spite of this effect, NS Power's demand billing determinant in Appendix H is 7.0 GW in every revenue scenario, demonstrating that its revenue calculations do not take the reduction in demand charge revenues into effect.[47]

[46] NS Power, Exhibit N-6, response to CA IR-11(b).

[47] NS Power, Exhibit N-6, response to CA IR-11(d).

NS Power explained that it did not adjust the billing demand determinant because it is "unable to provide a reliable estimate in the non-coincident demands due to the time-differentiated application of the demand charges under the TVPs."[48]

Q: Does NS Power's application demonstrate more general problems with the use of demand charges?

A: Yes. First of all, as shown in Table 4 above, 92 percent of reliability risk on the NS Power system occurs during December, January, and February, and the remaining 8 percent occurs during November and March. A demand charge based on customer's peak monthly usage throughout the year does not reflect sound economic principles.

NS Power and Brattle provide little justification for the use of demand charges. Brattle states that "capacity costs do not vary with the flow of energy. They are based on the demand the customer puts on the system. That is why a demand charge is more cost-reflective than an energy charge."[49] Other than the costs of equipment directly related to the customer's undiversified demand, demand charges to NS Power customers during the months of March through November do not reflect cost causation. An increase in a General customer's non-coincident demand during those months is very unlikely to increase ANL or LOLP, as discussed above (beginning on page 8), and it is also unlikely to contribute to the high-load hours that do the most damage to transmission and distribution equipment.[50]

The Board could somewhat improve demand charges by differentiating them seasonally and by time of use. However, NS Power stated that it did not propose such

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[48] NS Power, Exhibit N-6, response to CA IR-11(d).

[49] NS Power, Exhibit N-6, response to CA IR-11(h).

[50] In parts of Halifax, the delivery system peaks in the summer, but that probably reflects a small part of the General load.

changes "because the Company does not know hourly distribution of customer demand usage and system capacity costs."[51]

Q: Should NS Power eliminate demand charges altogether?

A: Yes. Although eliminating demand charges altogether is beyond the scope of this proceeding, the Board should direct NS Power to include a proposal to eliminate demand charges in its next General Rate Application. As discussed above, demand charges are outdated and not particularly useful at allocating costs or reducing demand in an economic manner.

Q: Could your CPP Advanced proposal be improved by removing the demand charge?

A: Yes. Our recommended rate design retains a demand charge in the interests of shifting energy charges to the CPP energy rate from the non-FAM energy rates, similar to NS Power's CPP tariff proposal and maintaining alignment in this respect with the standard tariff for General service customers. We also designed an alternative CPP rate that eliminates the demand charge and recovers its revenues via the CPP rate.

The resulting CPP Advanced Energy-Only rate for General customers is $3.56 per kWh; including the 2022 FAM charge results in a total CPP rate of $3.62 per kWh. The resulting rates are shown in Table 10. The rates for the first block are identical to those shown in Table 6, but the rates for the second block are increased slightly to account for reduction in energy use (since energy use from this block is allocated to the CPP rate).

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[51] NS Power, Exhibit N-6, response to CA IR-11(g). As discussed above, NS Power does have information on the time distribution of LOLP and hence generation costs. NS Power may not have information on the time distribution of transmission and distribution costs, because it has neglected to monitor loads on substations and feeders even as it implements hourly metering for customers.

Table 10: Proposed CPP Advanced Energy-Only Rates (Cents per Kilowatt-hour)[52]

Class of Service	During a CPP Event	First 200 kWh per Month, After CPP Event Usage	All Additional kWh
Effective November 1, 2021			
General	361.843	12.545	9.442
Effective Nov 1, 2022			
General	362.118	12.820	9.717

Q: How would your CPP Advanced Energy-Only rate design affect bills for General customers?

A: Since the rate design is revenue neutral, assuming no load shifting, there would be no bill impact for the average General customer on an annual basis.

There would be a significant shift in monthly bills from non-winter months to winter months. For months without CPP events, bills would go down due to the elimination of the demand charge. For months with one CPP event, bills would increase if the customer did not reduce demand. This is because the 4-hour CPP rate for a level kWh of customer load would increase the bill by $14.12, compared to the demand charge of $10.50, for net increase of $3.62. Each additional CPP event would increase the monthly bill impact by $14.12 for each kWh of customer load.

Actual bill impacts would be affected by the customer response to the rate changes. Customers would reduce energy use during CPP events, mitigating the impact of the higher CPP rates. Customers would increase energy use during non-event, high demand hours since there would be no demand charge.

Q: Do you recommend the Board utilize the CPP Advanced Energy-Only rate design?

A: Yes, but as a one-year pilot rather than a Soft Launch. Because NS Power will have substantial customer engagement and recruitment responsibilities, we believe that

[52] NS Power, Exhibit N-6, response to CA IR-1, Attachment 1, 2021 and 2022 RSP TVR Options tabs.

customers considering this option will require different information and customer support services. Due to the substantial effort required to implement the CPP Basic and Advanced rates, we recommend this rate design be piloted in parallel with a very limited number of customers to get feedback on the customer experience.

We recommend the Board direct NS Power to recruit 10 – 25 customers to pilot test this rate design. This rate design should be included in the impact evaluation, but the quantitative analysis will not be conclusive due to the limited sample size. The results of the impact evaluation and customer experience will inform further development of rates.

IX. Improvements to NS Power's TVP Application

Q: If the Board decides to approve aspects of NS Power's proposed TVP tariffs, what recommended improvements have you identified?

A: If the Board rejects our proposed alternative CPP tariffs and decides to approve NS Power's proposed TVP tariff designs, we have identified several changes that would improve the tariffs. We caution that these recommendations are not sufficient to address the fundamental problems we have discussed up to this point in our testimony.

- NS Power's application is unclear as to whether it intends an enrollment cap or target. (see Page 28) We recommend an enrollment target—once the target is reached, NS Power should cease recruitment efforts but should accept enrollments from any customers who have already learned about the TVP program.
- NS Power's application recommends a target or cap of 250 customers for its CPP tariff. We recommend a target of 500 customers in order to allow for attrition, as customers may react adversely to 22 CPP events.

- NS Power's application recommends exactly 22 CPP events per year, with a weekly maximum of 3 events. We recommend a target of 12 events, with a maximum of 18 events, and no weekly maximum, consistent with our CPP Advanced tariff design. (see page 20)
- To avoid the potential for the demand charge to contribute to shifting the ANL peak hour without reducing the peak, it would be better to maintain the current demand charge structure than adopt NS Power's proposal to apply the charges during the proposed TVP periods only. (see page 36)

We also recommend several additional improvements to NS Power's TVP Application that would apply to both our proposed CPP tariffs or NS Power's proposed TVP tariffs.

Q: What additional improvements to NS Power's TVP Application have you identified?

A: We address two types of improvements. First, NS Power proposes to utilize a "Soft Launch." By a Soft Launch, we understand that NS Power means limited customer participation in the first winter, the likelihood that the tariff will be significantly revised after the first winter, and the rapid development of the process for recruitment and evaluation. We recommend several process improvements.

Second, we identified further changes to rules and tariffs that should be considered, either now or after the Soft Launch.

Q: Please describe the process improvements to the proposed Soft Launch.

A: We are generally supportive of the Soft Launch concept, as opposed to a pilot or a full-scale launch. NS Power's application primarily relies on Brattle's evidence with respect to describing the Soft Launch. Brattle's evidence discusses the customer engagement and recruitment strategy, the metrics and data collection methods, and evaluation, measurement and verification plan. We have recommendations in each of these areas.

Q: Please describe NS Power's customer engagement and recruitment strategy.

A: Brattle indicates that "customer education plans and marketing materials for a full-scale launch would have to be developed based on generic best practices and experiences of other jurisdictions."[53] NS Power described the components of that plan as follows.

- Customer education timeline
- Determination of key considerations and challenges
- Market research consisting of surveys, focus groups and interviews
- Identification of target audience
- Identification of key education and recruitment channels
- Detailed education and recruitment tactics, by phase
- Key messages for each phase
- Development of various marketing materials including direct mail, web site content, text messaging, phone messaging, advertising, and social media postings
- Marketing metrics and evaluation of communication tactics[54]

NS Power believes that such a plan can be developed in four to six weeks, primarily relying on internal resources, with implementation taking three to six months.[55] NS Power also expressed a commitment to work with stakeholders to develop this plan.[56]

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[53] Brattle Evidence, p. 8.

[54] NS Power, Exhibit N-11, response to Synapse IR-54(a).

[55] NS Power, Exhibit N-11, response to Synapse IR-54(c); Exhibit N-6, response to CA IR-22.

[56] NS Power, Exhibit N-5, TVP Application, pp. 38, 50.

Brattle's evidence emphasizes the importance of focus groups. Brattle also expresses a preference for telemarketing, e-marketing, social media, and local media over direct mail for recruitment.[57] Brattle notes that direct mail can take several months in order to achieve maximum enrollment.

Q: Do you believe a customer engagement and recruitment plan can be created in 4-6 weeks?

A: No. We are skeptical that a robust plan for customer engagement and strategy can be created in 4-6 weeks, including meaningful engagement with participants in this proceeding. The success of the TVP program will depend on the quality of this plan. As NS Power states,

> "… near-term bill savings are only one of the drivers of participation; customers may also be motivated by other reasons such as concerns regarding the environment and helping to reduce future rate increases. For these reasons, marketing and education are essential in the success of a time-varying rate offering."[58]

In our view, after completing a first draft of the plan, there will be areas of further research, especially the focus group research discussed by Brattle. Then there will be a need to significantly refine the first draft based on those investigations.

Based on our experience in this proceeding and in the IRP, developing a robust plan will take at least 3-4 months, and perhaps longer.[59] In addition to the focus groups described by Brattle, we recommend that NS Power consult with experts on low-income engagement and behavioral messaging. Stakeholders are likely to have

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[57] Brattle Evidence, p. 8.

[58] NS Power, Exhibit N-5, TVP Application, Appendix J, p. 39.

[59] We note that CA IR-22 requested Brattle's best estimate for the time to engage a consulting firm and complete well-designed focus group research, but that information was not provided. NS Power, Exhibit N-6, response to CA IR-22.

substantive feedback and, to NS Power's credit, its staff consider feedback seriously and take the necessary time to make appropriate changes.

Considering also the further steps described in NS Power's proposed market research approach, it will then take several more months before recruitment can be launched in earnest.[60] It is evident that it will be challenging to complete recruitment by November 1, but it may not be necessary to have all participants enrolled until early December since it is unlikely that there will be any CPP events in November.

Q: Why should NS Power consult with experts on low-income engagement?

A: In order to reach its long-term goal of 30 percent customer participation, NS Power should pay extra attention to outreach to low-income customers. NS Power stated that, "In recent customer surveys, interest in TVP appears to be generally consistent across customer interest levels,"[61] but NS Power did not identify any specific plans for considering low-income participation in the initial rollouts.[62]

To improve outreach to low-income customers, NS Power should engage appropriate expertise prior to conducting the initial focus groups. Low-income participation in the focus group process is essential to ensuring that proposed engagement and recruiting strategies consider their opinions in developing the final plan. As Brattle notes, some marketing techniques can exclude "certain fractions of the eligible population, such as elderly or non-tech savvy customers."[63] Since NS Power's long-term goal is to achieve 30 percent customer participation, it needs to

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[60] NS Power, Exhibit N-11, response to Synapse IR-54, Attachment 4. NS Power's proposed market research approach envisions a 6-month timeline, which we view as optimistic.

[61] NS Power, Exhibit N-11, response to Synapse DR-5(b). It is not clear what surveys were conducted regarding customer interest in TVP as the application does not include any survey results.

[62] NS Power, Exhibit N-6, response to CA IR-17.

[63] Brattle Evidence, p. 12.

begin with a comprehensive view of its customers in the engagement and recruitment plan.

Q: Why should NS Power consult with experts on behavioral messaging?

A: A behavioral messaging strategy, often referred to as a Behavioral Demand Response program, is a complementary approach to addressing peak demand periods with messaging, social norming, and other encouragement. Such programs can complement TVP tariffs as well as reducing load from customers who remain on standard tariffs.

Behavioral Demand response is also relevant to the AMI project because NS Power has committed to achieving energy conservation from bill alerts. We are unsure whether NS Power has taken any steps towards implementing its commitment to achieve energy conservation from bill alerts.

In its 2021 ACE Plan, NS Power described a "Customer Energy Insights" project which appeared to be in fulfillment of the bill alert commitment. However, in response to an information request, NS Power indicated that both the Customer Energy Insights project and the Time Varying Pricing Solutions projects are required to enable the TVP rates.[64] NS Power indicated that the combined project (CI C0021839) will have a total budget of over $1 million and will require formal submission for review and approval.

We strongly urge NS Power to consider close coordination between its bill alerts program and its TVP strategy. NS Power can use behavioral messaging techniques to communicate with all its customers—including those on standard rates—with customer-specific data obtained from AMI indicating whether and how much the customer reduced demand during an ANL peak event compared to neighbors or customers as a whole. This "social norming" has been shown to achieve measurable

[64] NS Power, Exhibit N-3, Matter No. M09920, response to CA IR-7(a).

impacts on demand. NS Power acknowledged the validity of this approach in a response to an information request.[65]

Accordingly, we recommend that the Board direct NS Power to submit further details regarding its plans to fulfill its bill alerts commitment. We recommend that NS Power's proposal include a strategy to achieve both energy conservation as well as load reduction during ANL peaks from its broader customer base, as well as Behavioral Demand strategies to enhance the TVP tariffs. In order to support the Soft Launch, the program should be initiated at the same time (or before) and should also be included in the post-Soft Launch evaluation. It may be appropriate for NS Power to hire a consultant with expertise in designing or supporting a Behavioral Demand Response program. It is possible that E1 has the necessary expertise,[66] which could complement its other areas of customer communications.

Furthermore, we request that NS Power provide an update on the scope and estimated budget for its forthcoming submission of CI C0032502 in its reply evidence to provide the Board with a full understanding of the implementation costs for the TVP Application. If the scope and budget for that project might be affected by a Board decision to adopt any of our recommendations, we request that NS Power provide that information as well.

Q: Are there any other major omissions from NS Power's discussion of customer engagement and recruitment?

A: Yes. NS Power does not explicitly discuss the importance of customer incentives in its application. As demonstrated in the examples of marketing practices from other jurisdictions provided by NS Power, customers are often offered small financial

[65] NS Power, Exhibit N-6, response to CA IR-21.

[66] NS Power indicates that it is not in communication with E1 regarding the capital project. NS Power, Exhibit N-3, Matter No. M09920, response to CA IR-7(b).

incentives to participate in surveys and focus groups, and potentially to enroll in TVP tariffs.[67]

One common enrollment incentive is enabling technology, such as a free or discounted thermostat.[68] NS Power notes that only 37 percent of its customers with electric heat as their primary source have a smart or programmable thermostat. NS Power currently intends to leave it "to the customer to determine, likely based on economics of adding the equipment and convenience provided, whether to install such equipment."[69]

Currently, Efficiency Nova Scotia offers customers a $100 rebate towards a smart thermostat or the option to rent a smart thermostat for $6.95 per month.[70]

We view the lack of a strategy to incentivize or require enabling technologies as a significant oversight. NS Power included the following observation in its June submission, "When paired with enabling technologies (e.g. smart thermostats) the effect of TVP on capacity reduction is amplified."[71] Brattle states that for every 10% increase in the peak-to-off-peak price ratio, residential customers without enabling

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[67] BGE and PEPCO Maryland offer $25 bill credits for each pilot survey completed. NS Power, Exhibit N-11, response to Synapse IR-37, Attachment 1, p. 4 and Attachment 2, p. 7. SMUD offers prizes such as discounts and gifts. Attachment 3, p. 26.

[68] NS Power, Exhibit N-5, TVP Application, Appendix J, p. 37. SMUD offers a countertop electricity use display. NS Power, Exhibit N-11, response to Synapse IR-37, Attachment 3, p. 1. SDG&E offers smart thermostat incentives that are linked to participation in TOU rates. See https://www.sdge.com/residential/savings-center/energy-saving-programs/reduce-your-use/reduce-your-use-thermostat. DTE offers a free smart thermostat, including installation, for customers on its TOU/CPP rate. https://newlook.dteenergy.com/wps/wcm/connect/dte-web/home/service-request/residential/pricing/rate-options.

[69] NS Power, Exhibit N-6, response to CA IR-20.

[70] See https://www.efficiencyns.ca/residential/products-rebates/smart-thermostats/

[71] NS Power, Exhibit N-5, TVP Application, p. 17.

technology reduce peak usage by 6.5 percent and those with enabling technology reduce peak usage by 11 percent.[72] By offering enabling technologies, NS Power will recruit the equivalent of two customers at a modest additional cost.

In addition to greater impact, providing enabling technologies drives up recruitment. Brattle justified the potential to reach 30 percent opt-in rates by referencing three utilities that provide "bill guarantees, *smart thermostats,* or in some cases, less attractive standard offer rates."[73] (emphasis added)

Smart thermostats provision will also enhance the flexibility of scheduling CPP events, especially the CPP Advanced tariff. Brattle notes that when "CPP prices are paired with a smart thermostat, they can be offered on the day of the event."[74]

We recommend that NS Power coordinate with the Efficiency Nova Scotia offer and offer an additional $100 thermostat incentive (for a total of $200) for TVP Soft Launch participants whose primary heating source is electric.[75] This incentive could also be conditional on completion of a pre-participation survey.

Q: Please describe NS Power's metrics and data collection methods.

A: NS Power intends to develop an evaluation, measurement and verification (EM&V) plan in Q1-Q2 2021 in consultation with stakeholders, which will include identification of metrics and data collection methods. Once participants are enrolled, NS Power hopes to collect a few months of AMI data before activating the TVP rate.

[72] NS Power, Exhibit N-5, TVP Application, Appendix I, p. 25.

[73] NS Power, Exhibit N-5, TVP Application, Appendix J, p. 38.

[74] Brattle Evidence, p. 1.

[75] Currently, Best Buy Canada is offering the ecobee3 Lite Smart Thermostat for $196. This thermostat is incentivized by other North American TVP programs.

NS Power intends to conduct both an impact evaluation and a process evaluation.[76] While NS Power discusses its plans for impact evaluation at a high level, its application does not refer to the discussion of process evaluation in Brattle's evidence.

With respect to impact evaluation, NS Power provided a high-level summary discussing the process for the necessary econometric analysis, which adopts Brattle's advice to select a control group of customers for each class for panel data analysis.[77] NS Power did not provide further details regarding the metrics that will be required,[78] but Brattle's evidence and prior work provides a good indication of the metrics required for a successful impact evaluation. For example, Brattle discusses the importance of not just measuring the load impacts, but also estimating the "substitution price elasticities representing customers' sensitivities to prices."[79] These elasticities are necessary to identify adjustments to TVP rates as well as the impact of rate changes that occur over time.

While most of the metrics that Brattle recommends for impact evaluation can be made available using NS Power's own resources, Brattle also recommends collecting "data on customer characteristics (such as building envelope) during the prelaunch period."[80] This will require surveying both tariff participants and the control group.

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[76] NS Power, Exhibit N-9, response to NSUARB IR-11.

[77] NS Power, Exhibit N-6, response to CA IR-31; NS Power, Exhibit N-5, TVP Application, Appendix G, p. 18.

[78] NS Power did commit to include evaluation of the snapback effect in the impact evaluation. NS Power, Exhibit N-11, response to Synapse IR-63.

[79] Brattle Evidence, p. 14.

[80] Brattle Evidence, p. 13.

Q: What is your opinion of Brattle's approach to impact evaluation?

A: Overall, Brattle appears well-qualified to advise on metrics and data collection methods, and to conduct the impact evaluation. (Other firms may be equally well-qualified.) For example, Brattle recently conducted an evaluation of Maryland's time-of-use pilots.[81] Notably, that evaluation measured both summer and winter peak reduction impacts.

Q: Are you concerned that the schedule will not allow for ample data collection in advance of activating the TVP rates?

A: No. As discussed above, we anticipate that implementation schedule may result in enrollment continuing through November, which would make collecting a few months of AMI data on customers and control panel members impractical.

While the schedule might impede effective analysis of NS Power's proposed TOU tariffs, the schedule is not as great of a concern for our recommended CPP-only tariffs. Brattle notes that data collection in advance of activating CPP rates is not as critical because CPP tariff analysis will compare the event days to non-event days.[82]

Q: After developing the metrics and data collection methods, what additional EM&V activities does NS Power intend to complete?

A: NS Power intends to report on the outcome of the first winter implementation of the TVP tariffs by June 30, 2022 and propose refinements to the tariffs if required.[83] Brattle recommends that the EM&V report include a:

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[81] NS Power, Exhibit N-5, TVP Application, Appendix J, p. 56.

[82] NS Power, Exhibit N-6, response to CA IR-31.

[83] NS Power, Exhibit N-5, TVP Application, p. 5.

> "well-rounded evaluation of aspects of program implementation, which can in turn be used to identify and describe program strengths and weaknesses. Ultimately, this type of evaluation can highlight the successes of the program as well as identifying possible improvements to program processes and designs. It may also provide guidance as to the scalability of the impacts."[84]

Q: Will addressing Brattle's advice on process evaluation require additional data?

A: Yes. Brattle recommends process evaluation and identifies eleven "dimensions" for data collection. Data collection for process evaluation will require surveys of participants and control group members as well as internal data collection.

Surveys of customers and perhaps leveraging of other external data resources are needed to evaluate the effectiveness of engagement/recruitment initiatives, customer participation responses, and customer behavior while on the TVP tariffs. To analyze those topics, data will need to be collected on customer characteristics (business markets, residential demographics).

NS Power's internal operations should also be evaluated, including its policies and practices for invoking (or *not* invoking) CPP events. Requirements for operator logs regarding CPP event decision-making will need to be developed in advance. Those requirements should consider existing and emerging practices regarding generation dispatch, and dispatch practices may need to be modified to ensure appropriate scheduling of CPP events. Brattle also identifies quality control practices, management, and implementation challenges among its "dimensions" for which data will need to be collected.

Q: What further changes to rules and tariffs that should be considered, either now or in the future?

A: We have identified three related changes that the Board should consider.

[84] Brattle Evidence, p. 15.

First, the Board should update Net Metering Service Regulation 3.6.4(g). Currently the regulation refers to "domestic time-of-day service." NS Power anticipates applying the Net Metering Service to its TVP tariffs using the same practices. The regulation should be updated to replace "domestic time-of-day service" with any "time differentiated tariff."

Second, the Board should consider applying whatever TVP tariff design is approved as an alternative to NS Power's domestic service rate for charitable organizations. It would be appropriate for NS Power to include this in its update after the Soft Launch.

Third, in response to testimony filed by Mr. Wilson,[85] the Board has directed NS Power to "include some discussion in its next [AAR] application regarding the incorporation of time varying rates into the design of AARs."[86] Because the AARs are primarily concerned with fuel costs, the level of price differentiation in these rates would be much less than in the tariffs proposed in this proceeding. Furthermore, our recommendations with respect to rate design would be mainly focused on aligning fuel cost recovery with customer use, with less attention to reducing ANL peaks. Thus, while a CPP rate could be applied, it may make more sense to use a simple TOU rate design for time-varying AARs similar to the existing Domestic Time-of-Day tariff. No action on this item is required as it has already been addressed in the AAR proceeding; it is included for information purposes only.

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[85] John D. Wilson, Exhibit N-7, Evidence on behalf of the Consumer Advocate, *NS Power 2021 Annually Adjusted Rates,* Matter No. M09898 (January 7, 2021), p. 8.

[86] Board Decision, *NS Power 2021 Annually Adjusted Rates,* Matter No. M09898 (February 2, 2021), p. 7.

X. Lost Revenue Adjustment Mechanism

Q: Please summarize NS Power's Lost Revenue Adjustment Mechanism (LRAM).

A: NS Power seeks to have an amount that it characterizes as lost revenues accumulated in a deferral account until considered in a General Rate Application, at which time it would request an amortization period so that it and subsequent lost revenues could be incorporated within future rates.

Q: On what basis does NS Power justify the LRAM request?

A: NS Power's consultant Brattle states that:

> The Company is requesting the institution of an LRAM in its application to recover the lost revenues associated with the implementation of TVPs. We are supportive of the request. **The Company should be given the necessary economic incentives** by enabling the recovery of its fixed costs, as its pursuit of these programs are expected to provide both near and long-term benefits for customers. It is essential to establish the appropriate incentive mechanism at the onset of the TVP implementation, instead of delaying the implementation in which case it will not help mitigate the revenue uncertainty for the Company and **may slow down the pace of innovation**.[87] (emphasis added)

Q: Is the LRAM proposal consistent with the Board's approval of the AMI project?

A: No. NS Power does not require any economic incentive to provide customers with the benefits of customer-funded capital investments, and it should fulfill its commitment at the pace to which it committed in its AMI project application. In requesting approval for the AMI project, NS Power stated that, "Parties can be confident that by implementing the AMI system, the capacity benefits forecast in the Application will be realized."[88]The Board should not give serious consideration to its request for further incentives to deliver customer the benefits NS Power has promised.

[87] NS Power, Exhibit N-5, TVP Application, p. 46.

[88] Board Decision, AMI Application, para. 101.

NS Power promised the capital savings benefit of a CPP tariff as justification for the $133 million cost of the AMI project. The benefit was measured as the avoided capital cost of generation in 2022 plus future operating cost savings. An LRAM would increase customer bills until the next General Rate Application, at which time the capacity savings from the TVP program would be reflected in lower rates. These impacts to customers were not considered in NS Power's economic analysis of the AMI project.

A further concern is that the 26 MW capacity reduction benefits estimated in the AMI Application are unlikely to occur as quickly as estimated in the AMI project application. While we are supportive of the Soft Launch approach, it is certain that the participation levels required to achieve 26 MW capacity reduction will not occur until *at least* the second winter—likely longer. If the delay extends beyond the test year for the next General Rate Application, then the capacity savings would not be reflected in lower rates.

Notwithstanding our opinion on the merit of the request for an LRAM, we will address some further points raised by NS Power and Brattle below.

Q: Can the data required to support the calculation of an LRAM be relied upon?

A: That is yet to be seen. NS Power notes that the ability to compute the lost revenues will depend on the impact evaluation study.[89] NS Power will need to quantify the energy shifted from the peak to the off-peak period and changes in overall energy consumption, and distinguish the effect of TVP rates from any other conditions that may affect customer behavior. The impact evaluation plan has not been developed,[90] and the Board should not approve a cost recovery mechanism without confidence that the costs to be recovered will be based on reliable data.

[89] NS Power, Exhibit N-11, response to Synapse IR-7(c).

[90] NS Power, Exhibit N-11, response to Synapse IR-61(a).

Until the impact evaluation is designed, there is no clarity regarding how well NS Power will be able to establish baseline revenues. In its numerical example of calculating lost revenues, NS Power relies on a "pre-shift calculation" of energy sales.[91] Furthermore, NS Power intends to compute the LRAM for each rate class.[92] To accomplish this, NS Power will require class-specific load data relevant to the peak and off-peak periods for TOU tariffs and to the specific CPP event days for CPP tariffs. NS Power does not explain how it will establish those baselines, but elsewhere in the TVP Application the 2014 Cost of Service Study is relied upon for class-specific load data.[93]

The calculation of the baseline is further complicated by the snapback effect, changes in the demand charge for General customers, and the difference between participant load shapes and class-wide average load shapes. Participant load shapes will differ from the class due to both load shifts in response to TVP price signals and the tendency of customers with favorable load shapes volunteering for the new rate.

While we do not know NS Power's plan for setting the LRAM baseline, it is definitely not reasonable to rely on the 2014 Cost of Service Study for essential load-related inputs to a new cost recovery mechanism relating to customer load in 2022. There has been a material shift in load shapes over the past eight years.

Q: Have other utilities addressed the problems you describe in LRAMs?

A: No. As NS Power acknowledges, nearly every instance of an LRAM has been in the context of a ratepayer funded energy efficiency or demand response program, where the connection between the utility activity (a rebate, or a load-management incentive)

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[91] NS Power, Exhibit N-11, response to Synapse IR-8.

[92] NS Power, Exhibit N-6, response to CA IR-11(e).

[93] See, for example, NS Power, Exhibit N-6, response to CA IR-1.

is much clearer. The only example of an LRAM that addresses a TVP tariff cited by NS Power or Brattle is the OG&E variable pricing tariff.

Q: How should a revenue deficiency be addressed?

A: Any purported revenue deficiency should be addressed through a General Rate Application. For example, NS Power states that it is likely to "examine broader revenue decoupling opportunities as part of a General Rate Application."[94]

XI. Summary of Recommendations

Q: Please summarize your recommendations with respect to NS Power's proposed tariffs and LRAM.

A: We recommend that:

- NS Power's proposed TOU tariffs should not be approved because they will achieve less than 50 percent of the purported capacity savings—the NS Power system is not suited for TOU rate periods today and is likely to be even less well suited in the future (page 20);
- NS Power's proposed CPP tariffs should not be approved because they rely on the same rate periods which reduce capacity savings (page 20); and
- NS Power's proposed LRAM should not be approved.

If the Board decides to approve either of NS Power's proposed TVP tariffs, we recommended changes related to enrollment, the number of events, and demand charge design. (page 42)

Q: Please summarize your recommended alternative TVP tariffs.

A: We recommend that the Board:

[94] NS Power, Exhibit N-11, response to Synapse IR-9.

- Approve our proposed alternative CPP Basic and CPP Advanced tariffs (as described beginning on page 20 and in Exhibits RII-4 through RII-9); and
- Establish a pilot of a CPP Advanced Energy-Only tariff for General service customers. (page 41)

Q: Please summarize your recommendations that relate to the Soft Launch and other matters that apply to both NS Power's proposed TVP tariffs and to your recommended alternative CPP tariffs.

A: We recommend approval of the Soft Launch, with several modifications as follows.

- The Board should direct NS Power to revise the plan for customer engagement and strategy to reflect a realistic timeline for accomplishing essential tasks and allowing for recruitment to extend into early December if necessary. (page 45)
- The Board should direct NS Power to consult with experts on low-income engagement. (page 46)
- The Board should direct NS Power to consult with experts on behavioral messaging and submit further details regarding its plans to fulfill its bill alerts commitment. The proposal should include a strategy to achieve both energy conservation as well as load reduction during ANL peaks from its broader customer base, as well as Behavioral Demand strategies to enhance the TVP tariffs. (page 47)
- The Board should direct NS Power to coordinate with the Efficiency Nova Scotia offer and offer an additional $100 thermostat incentive (for a total of $200) for TVP Soft Launch participants whose primary heating source is electric. (page 49)

We also recommend the following modifications to regulations and tariffs.

- The Board should update Net Metering Service Regulation 3.6.4(g) to replace “domestic time-of-day service” with any “time differentiated tariff.” (page 54)
- The Board should consider applying whatever TVP tariff design is approved as an alternative to NS Power’s domestic service rate for charitable organizations. (page 54)

Q: Please summarize your recommendations for NS Power’s reply evidence.

A: NS Power should:

- discuss a discrepancy in application of revenue neutrality to its rate design (footnote 40);
- provide an update on the scope and estimated budget for its forthcoming submission of CI C0032502 in its reply evidence to provide the Board with a full understanding of the implementation costs for the TVP Application, and if the scope and budget for that project might be affected by a Board decision to adopt any of our recommendations, we request that NS Power provide that information as well (page 48);

Q: Please summarize your recommendations to the Board for issues that may be resolved in other proceedings.

A: The Board should direct NS Power to include a proposal to eliminate demand charges in its next General Rate Application. (page 40) We also suggest that if NS Power wishes to address lost revenue issues, a General Rate Application is a more appropriate proceeding. (page 58)

Q: Does this conclude your testimony?

A: Yes.

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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.

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REPORTS

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"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.

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"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.

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"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.

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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.

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"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.

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

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"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.

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"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.

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

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"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.

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"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.

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"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.

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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

Exhibit RII-3: Adjusted Net Load Regression Model

The regression analysis RII used to compare system load to net system load (adjusted for non-dispatchable power) is described here.

Two versions of each model were created, one including just load and marginal cost data, the other also including fuel price and dispatchable hydro availability.

Variable	Rationale	Load Model	Net Load Model
Marginal Cost	Dependent Variable	Yes	Yes
System Load	NS Power assumes system load drives capacity and energy costs	Yes	Yes
Net System Load	Adjustment to load to reflect non-dispatchable power		Yes
Wind	Part of adjustment		Yes
Base hydro	Part of adjustment: Monthly minimum hourly generation		Yes
Variable hydro	Average additional hourly generation above base hydro (by month and year)		Alternative
Natural gas	Hourly prices – Algonquin, intended to improve model prediction by accounting for fuel prices	Alternative	Alternative
Coal	Monthly prices (FAM), intended to improve model prediction by accounting for fuel prices	Alternative	Alternative
Year	Individual variables reflecting load year (June-May)	Yes	Yes

Sources: NS Power, Hourly Gross Generation Data, provided in Matter No. M08929 (October 2020). Algonquin natural gas price data are public source. Monthly coal prices are from Fuel Adjustment Mechanism monthly reports. Some source data are confidential, but NS Power has determined that this analysis is not confidential.

a. System Load with dummy variables

```
                            OLS Regression Results
==============================================================================
Dep. Variable:           MarginalCost   R-squared:                       0.308
Model:                            OLS   Adj. R-squared:                  0.308
Method:                 Least Squares   F-statistic:                     2606.
Date:                Tue, 06 Oct 2020   Prob (F-statistic):               0.00
Time:                        11:15:48   Log-Likelihood:            -1.5078e+05
No. Observations:               35063   AIC:                         3.016e+05
Df Residuals:                   35056   BIC:                         3.016e+05
Df Model:                           6
Covariance Type:            nonrobust
================================================================================
                 coef    std err          t      P>|t|      [0.025      0.975]
--------------------------------------------------------------------------------
Intercept     49.8523      2.260     22.055      0.000      45.422      54.283
SystemLoad    -0.0527      0.003    -15.343      0.000      -0.059      -0.046
SystemLoadSq 3.379e-05    1.3e-06    25.939      0.000    3.12e-05    3.63e-05
Y2016          9.5667      0.348     27.452      0.000       8.884      10.250
Y2017         21.0202      0.349     60.252      0.000      20.336      21.704
Y2018         22.1382      0.348     63.644      0.000      21.456      22.820
Y2019         12.0273      0.390     30.833      0.000      11.263      12.792
==============================================================================
Omnibus:                    31554.388   Durbin-Watson:                   0.391
Prob(Omnibus):                  0.000   Jarque-Bera (JB):          1576723.746
Skew:                           4.220   Prob(JB):                         0.00
Kurtosis:                      34.749   Cond. No.                     4.23e+07
==============================================================================

Warnings:
[1] Standard Errors assume that the covariance matrix of the errors is correctly specified.
[2] The condition number is large, 4.23e+07. This might indicate that there are
strong multicollinearity or other numerical problems.
```

b. Regress load net wind and base hydro with dummy variables

```
                            OLS Regression Results
==============================================================================
Dep. Variable:           MarginalCost   R-squared:                       0.395
Model:                            OLS   Adj. R-squared:                  0.395
Method:                 Least Squares   F-statistic:                     3809.
Date:                Tue, 06 Oct 2020   Prob (F-statistic):               0.00
Time:                        11:16:03   Log-Likelihood:            -1.4845e+05
No. Observations:               35063   AIC:                         2.969e+05
Df Residuals:                   35056   BIC:                         2.970e+05
Df Model:                           6
Covariance Type:            nonrobust
===========================================================================================
                              coef    std err          t      P>|t|      [0.025      0.975]
-------------------------------------------------------------------------------------------
Intercept                  48.0602      1.552     30.970      0.000      45.018      51.102
LoadNetWindBaseHydro       -0.0615      0.003    -22.250      0.000      -0.067      -0.056
LoadNetWindBaseHydroSq   4.789e-05   1.23e-06     38.937      0.000    4.55e-05    5.03e-05
Y2016                       8.5641      0.325     26.388      0.000       7.928       9.200
Y2017                      20.4072      0.325     62.811      0.000      19.770      21.044
Y2018                      20.8894      0.325     64.372      0.000      20.253      21.525
Y2019                      10.9072      0.360     30.331      0.000      10.202      11.612
==============================================================================
Omnibus:                    32950.281   Durbin-Watson:                   0.446
Prob(Omnibus):                  0.000   Jarque-Bera (JB):          2140573.327
Skew:                           4.425   Prob(JB):                         0.00
Kurtosis:                      40.241   Cond. No.                     2.32e+07
==============================================================================

Warnings:
[1] Standard Errors assume that the covariance matrix of the errors is correctly specified.
[2] The condition number is large, 2.32e+07. This might indicate that there are
strong multicollinearity or other numerical problems.
```

c. Regress load net wind and base hydro with dummy variables, variable hydro, NG price, and coal price

```
                            OLS Regression Results
==============================================================================
Dep. Variable:           MarginalCost   R-squared:                       0.440
Model:                            OLS   Adj. R-squared:                  0.440
Method:                 Least Squares   F-statistic:                     3057.
Date:                Tue, 06 Oct 2020   Prob (F-statistic):               0.00
Time:                        11:16:09   Log-Likelihood:            -1.4709e+05
No. Observations:               35063   AIC:                         2.942e+05
Df Residuals:                   35053   BIC:                         2.943e+05
Df Model:                           9
Covariance Type:            nonrobust
===============================================================================================
                                  coef    std err          t      P>|t|      [0.025      0.975]
-----------------------------------------------------------------------------------------------
Intercept                      55.2479      1.805     30.609      0.000      51.710      58.786
LoadNetWindBaseHydro           -0.0474      0.003    -17.598      0.000      -0.053      -0.042
LoadNetWindBaseHydroSq        3.86e-05   1.21e-06     31.903      0.000    3.62e-05     4.1e-05
VariableHydro                  -0.0480      0.004    -13.619      0.000      -0.055      -0.041
AlgNGPriceNetWindBaseHydro      1.4352      0.028     51.855      0.000       1.381       1.489
CoalPrice                      -0.3096      0.027    -11.274      0.000      -0.363      -0.256
Y2016                           6.2615      0.325     19.263      0.000       5.624       6.899
Y2017                          14.6964      0.372     39.545      0.000      13.968      15.425
Y2018                          17.4051      0.354     49.228      0.000      16.712      18.098
Y2019                           9.4959      0.362     26.215      0.000       8.786      10.206
==============================================================================
Omnibus:                    30635.904   Durbin-Watson:                   0.479
Prob(Omnibus):                  0.000   Jarque-Bera (JB):          1632669.493
Skew:                           3.990   Prob(JB):                         0.00
Kurtosis:                      35.463   Cond. No.                     2.83e+07
==============================================================================

Warnings:
[1] Standard Errors assume that the covariance matrix of the errors is correctly specified.
[2] The condition number is large, 2.83e+07. This might indicate that there are
strong multicollinearity or other numerical problems.
```

d. Regress system load with dummy variables, NG price, and coal price

```
                            OLS Regression Results
==============================================================================
Dep. Variable:           MarginalCost   R-squared:                       0.363
Model:                            OLS   Adj. R-squared:                  0.363
Method:                 Least Squares   F-statistic:                     2495.
Date:                Tue, 06 Oct 2020   Prob (F-statistic):               0.00
Time:                        11:16:15   Log-Likelihood:            -1.4935e+05
No. Observations:               35063   AIC:                         2.987e+05
Df Residuals:                   35054   BIC:                         2.988e+05
Df Model:                           8
Covariance Type:            nonrobust
===============================================================================================
                                  coef    std err          t      P>|t|      [0.025      0.975]
-----------------------------------------------------------------------------------------------
Intercept                      44.8300      2.363     18.969      0.000      40.198      49.462
SystemLoad                     -0.0299      0.003     -8.967      0.000      -0.036      -0.023
SystemLoadSq                 2.139e-05   1.27e-06     16.801      0.000    1.89e-05    2.39e-05
AlgNGPriceNetWindBaseHydro      1.6344      0.030     54.615      0.000       1.576       1.693
CoalPrice                      -0.2009      0.029     -6.856      0.000      -0.258      -0.143
Y2016                           8.0101      0.336     23.844      0.000       7.352       8.669
Y2017                          16.3302      0.389     41.959      0.000      15.567      17.093
Y2018                          19.4266      0.374     51.889      0.000      18.693      20.160
Y2019                          10.3830      0.391     26.545      0.000       9.616      11.150
==============================================================================
Omnibus:                    28939.661   Durbin-Watson:                   0.423
Prob(Omnibus):                  0.000   Jarque-Bera (JB):          1250107.219
Skew:                           3.714   Prob(JB):                         0.00
Kurtosis:                      31.293   Cond. No.                     4.62e+07
==============================================================================

Warnings:
[1] Standard Errors assume that the covariance matrix of the errors is correctly specified.
[2] The condition number is large, 4.62e+07. This might indicate that there are
strong multicollinearity or other numerical problems.
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Exhibit RII-4

Charge Without a Cause?

Assessing Electric Utility Demand Charges on Small Consumers

Electricity Rate Design Review Paper No. 1

July 18, 2016

Paul Chernick
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Douglas Jester
Mark LeBel

Charge Without a Cause?

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Introduction & Overview

There has been significant recent attention to the possibility of including demand charges in the electricity rates charged to residents and small businesses. Electric utilities have historically served these ‘small customers’ under a two-part rate structure comprised of a fixed monthly customer charge that recovers the cost of connecting to the grid and an energy charge (or charges) that recover all other costs. Much of this attention to the issue of demand charges for small customers has been initiated by electric utilities reacting to actual or potential reductions in sales, revenue and cost recovery.

Demand charges are widely familiar to large, commercial and industrial customers, where they are used to base some portion of these customers’ bills on their maximum rate of consumption. While a customer charge imposes the same monthly cost for every customer in a rate class, and an energy charge usually imposes the same cost per unit of energy used over a long period of time (e.g. the entire year, a month, or all weekday summer afternoons), most demand charges impose a cost based on usage in a very short period of time, such as 15 minutes or one hour per month. The timing of the specific single maximum demand event in a month that will result in demand charges is generally not known in advance.

The goal of this document is to unpack the key elements of demand charges and explore their effect on fairness, efficiency, customer acceptability and the certainty of utility cost recovery. As will be evident, most applications of demand charges for small customers perform poorly in all categories. Following are five key takeaways:

- Residents and small businesses are very diverse in their use of electricity across the day, month and year — most small consumers’ individual peak usage does not actually occur during peak system usage overall. This means that traditional demand charges tend to overcharge the individual small consumer.
- Apartment residents are particularly disadvantaged by demand charges because a particular apartment resident’s peak usage isn’t actually served by the utility. Utilities only serve the combined diverse demand of multiple apartments in a building or complex rather than the individual apartment unit.
- Demand charges are complex, difficult for small consumers to understand, and not likely to be widely accepted by the small customer groups.
- Very little of utility capacity costs are associated with the demands of individual small consumers. Nearly all capacity is sized to the combined and diverse demand of the entire system, the costs of which are not captured by traditional demand charges. If consumers actually were able to respond to a demand charge by levelizing their electricity usage across broader peak periods, then utilities would incur revenue shortages without any corresponding reduction in system costs.
- Demand charges do not offer actionable price signals to small consumers without investment in demand control technologies or very challenging household routine changes. This results in effectively adding another mandatory fixed fee to residential and small consumer electric bills.

About the Authors

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The authors thank the many colleagues from organizations around the country who offered their technical, legal and policy insights and perspectives on this paper.

Legacy Demand Charges

While there are a large number of variants on the basic theme, the standard demand charge is a fee in dollars per kW times the customer's highest usage in a short (e.g. one-hour) period during the billing month. These charges are nearly universal for industrial and larger commercial customers.

This rate design is a legacy of the 19th century, when utilities imposed demand charges to differentiate between customers with fairly stable loads over the month (mostly industrial loads) from those who used lots of energy in a few hours, but much less the rest of the month. Utilities recognized that the latter customers with peaky loads were more expensive to serve per kWh, and monthly maximum demand was the only other measurement available given existing meter technology at the time.

Beyond the standard design, variants include:

- Billing demand computed as the highest load over 15 or 30 minutes, rather than an hour;
- Charges per kVA rather than per kW, thereby incorporating power factor;
- Charges that are higher in some months and/or some daily periods than in others;
- Ratchets, in which the demand charge can be set by the highest load in the preceding year or peak season, as well as the current month; and
- Hours-use or load-factor rates, where the price per kWh declines as monthly kWh/kW increases, thereby incorporating an effective demand charge within an energy charge framework. For example:

First 200 kWh/kW	$0.15
Next 200 kWh/kW	$0.12
Over 400 kWh/kW	$0.10

For a high load factor customer (e.g. over 400 kWh/kW, or 60%), this works out to a $14/kW demand charge. But, for a low load factor customer with high peak demand at some times but otherwise low usage, like a school stadium lighting system with only 20 hours/month of usage, this rate design example works out to $1/kW (20 hours x .05/kWh built into the first 200 kWh/kW).

Demand-Charge Design Elements

As noted above, the standard demand charge uses the billing demand at the time of the customer's greatest consumption, integrated over a short period such as one hour, measured monthly. Thus, the charge is based on a single hour out of the 720 hours of a 30-day month, with each customer charged for load in whichever hour their maximum demand occurs, regardless of coincidence with the peak demand of the system. Because a customer's individual peak demand can occur at any time of day and not necessarily during the hour when system costs are greatest, the standard demand charge does not generally reflect cost causation. There are three categories of design options for demand charges: the time at which demand is measured, the period over which demand is averaged, and the frequency of its measurement.

Timing of billing demand measurement

The term "peak demand" is used in many different ways in utility jargon. These peaks include the following:

- **Customer peak:** Each customer experiences a non-coincident[1] maximum demand (NCP) at some point in the month. That value is typically used in legacy demand charges. Each customer also experiences a maximum non-coincident demand for the year (i.e. the highest of 12 monthly maximum non-coincident demands). This value is used for demand charges with ratchets.[2]
- **Equipment peak:** Each piece of utility transmission and distribution equipment experiences a maximum load each month and each year. Utilities often have detailed data on the timing of loads on substations, transmission lines, and distribution feeders. They use those data for system planning, but usually not in setting rates. The capacity of equipment varies with weather; when temperatures are cooler, equipment dissipates heat better and has more capacity.
- **Class peak:** Utilities generally estimate a class peak load for each customer class (e.g. residential, small commercial, large commercial), which may occur at different hours, months and seasons. Aggregated class peaks are often used in allocating some distribution costs to classes.
- **System peak:** The entire system experiences a maximum peak in each month, one of which will be the annual maximum peak. Loads of customers or customer classes measured at the time of the maximum monthly or annual system peak are said to be coincident demands for that month or year.
- **Designated or seasonal peak:** Utilities often designate a "peak period" for one or more months, when there is a high probability that the system's highest peak demands will occur, such as 3-7 p.m. from June through September. However, these designated peak times are based on expectations and do not necessarily coincide with actual system peak. Demand charges may measure each customer's highest one-hour demand during these periods. This is sometimes incorrectly referred to as a 'coincident peak demand charge,' or a 'demand time of use rate.'

Because of their diversity in energy usage, customers' individual non-coincident maximum loads usually do not occur at the same time as the peaks on the system as a whole — or even at the same time as peaks on the local distribution system. Thus, in addition to not reflecting the customer's contribution to utility costs, billing on the customer maximum demand does not effectively encourage customers to reduce their contribution to costs, and may actually encourage customers to move load from the times of their individual maximum demands to times of high system loads and costs. Unlike attempting to capture customer coincident demands, billing parameters for customer non-coincident load is relatively easy to measure. However, these loads are difficult to control, and a single brief unusual event (e.g. simultaneous operation of multiple end uses or equipment failure) can set the billing demand for the month and year.

With modern utility metering, utilities have the option of charging for customer loads at times that more closely correspond to cost causation — times when the system (or its various parts) is experiencing its maximum demand. A range of approaches are available:

- **Actual coincident peaks**. Because many cost allocation systems assign at least a portion of generation and transmission costs to customer classes on the basis of customer class contributions to the system peak(s) — the coincident peak or "CP" method — there is some logic behind billing on the basis of the individual customer's contribution to the system peak. A significant challenge with CP billing is there is no way to know that a particular hour will be the system peak, even as it is occurring, since a higher load may occur later in the day, month, season or year. The utility could provide customers with information on current and forecast loads, and each customer could try to respond to the *possibility* of a system peak, spreading out their response across many high load hours,

[1] The term "non-coincident" means not *intentionally* coincident with, i.e. at the same time as, the systempeak. Coincidence with the systempeak would only be by happenstance.
[2] The sum over customers by class of maximum non-coincident annual peak demands is used by some utilities in allocating some distribution costs.

only one of which will actually be used in computing billing demand. Like Russian Roulette, it is likely to be difficult for many residential and small commercial customers to understand and respond to this type of system.

- **Designated peak hours**. Rather than computing the billing demand for the actual system peak hours, the utility could, on relatively short notice, designate particular hours as potential peak (or potentially critical) hours and compute the billing demand as the average of the customer's load in those hours. This approach is similar to the designation of critical peak periods in some time-of-use rates or peak-time rebates in some load-management programs. Provided that the potential peak hour information can be effectively communicated to all customers subject to the structure, the ability to respond should be somewhat improved over the NCP and CP approaches.
- **Forecast peak periods**. Rather than designating individual hours for computation of billing demand, a utility could designate a peak window, such as noon to 4 p.m., when the system is likely to experience a peak or other critical condition, and set the billing demand as the customer's average consumption during that window. The hours around the system peak hour also tend to experience loads close to the actual peak load and contribute to reliability risk. Shifting load from the peak hour to one hour earlier or later may create a worse situation in that new hour. Here too, customers may be better able to respond to forecast peak periods than to individual hours, even if the period is only designated the day before or a few hours before the event.
- **Standard peak-exposure periods**. In the above examples, customers may only learn about peak periods after-the-fact or just a day or hours before they are set, but utilities could set time periods farther in advance, for instance in a rate case as part of the tariff itself. Especially for small customers, establishing a fixed period in which peaks and resource insufficiency are most likely, such as July and August weekdays or even more narrowly non-holiday summer weekday periods between noon and 4 p.m., may be more acceptable and effective than declaring the demand-charge hours on short notice. This approach trades improved predictability for customers for a diminished relationship to system costs. Customer response, such as limiting their maximum energy demands during the known peak periods, would be similar to the response to time of use rates, but with the consequences of not responding potentially more dire.

Period of billing demand measurement

Measurement of the customer's billing demand can occur over a wide variety of time frames. An instantaneous or short-duration measure of billing demand is possible but would penalize customers with overlapping loads of standard behind the meter technologies. Many residential customers have limited choice or control over when they use appliances. For example, electric furnaces and water heaters can consume significant levels of electricity, with common models drawing 10.5 kW and 4.5 kW, respectively. Air conditioners draw from 2 kW for a one-ton capacity model to 9 kW for a five-ton model. In addition, common hair dryers typically draw 1 kW and often more; the average microwave or toaster oven can draw 1 kW; and an electric kettle can draw 1 kW.

It is easy to see how the typical morning routine for a family would result in an instantaneous peak demand of as much as 18 kW and demand over a one-hour period in excess of 10 kW. A billed demand of 10 kW or more would result in high and hard-to-avoid charges, in addition to a fixed monthly charge, meaning that this household would have little to no control over the bulk of its monthly bill.

While families may be able to understand how this peak demand occurs, school schedules and work schedules may allow little flexibility to do anything about it. Further, many of these devices are designed to be automatically controlled by thermostats that would be difficult to override on a short-term basis to avoid demand charges. Moreover, these overlapping appliance demands do not drive costs on the system.

This example shows the electric demand of a morning schedule, while peak system demands are often later in the day. In addition, customer diversity can spread these demands out, diluting any effect on peak system demand.

At the other extreme, the billing demand measure could be 720 hours, for a 30-day month. This billing period would capture all the loads imposed by the customer to the utility system and requires no new metering. In fact, this billing approach is in common practice today and is known as the two-part rate, which charges customers for demand during each hour of each day of the billing period (a.k.a. energy) on top of the basic flat monthly customer charge.

Within this spectrum, the most common billing demand periods in practice today for commercial and industrial customers (outside of the two-part rate) range from 15 minutes to 60 minutes.[3] Short periods of measured billing demand are more difficult for customers to manage. For example, an apartment dweller who takes a shower and dries their hair while something is in the oven can run up demand of 10 kW or more, even though the average contribution to the system peak across units in the same apartment building is typically no more than 2 or 3 kW. Longer periods of measurement, such as 60 minutes or the average demand over several hours, tend to dilute the impacts of very short-term events.

There is great diversity in maximum loads among residential consumers. As mentioned above, demand charges have historically only been applied to large commercial and industrial customers, with a multitude of loads served through a single meter, and generally a dedicated transformer or transformer bank. For very large industrial customers, there is typically a dedicated distribution circuit or even distribution substation. So for these customers, diversity occurs on the customer's side of the meter, such as when copiers, fans, compressors, and other equipment cycles on and off in a large office building.

For residential consumers, there is also diversity — but it occurs on the utility's side of the meter as customers in different homes and apartments connected to the same transformers and circuits use power at different moments in time. The point is that the type of rate design that is appropriate for industrial customers, who may have a dedicated substation or circuit, is not necessarily appropriate for residential customers who share distribution components down to and including the final line transformer.

Indeed, in the example in the previous section regarding measurement of peak demand during a window designed to capture higher-cost hours (i.e. standard peak-exposure periods), one can envision a peak demand period that covers the entire window. Such an approach may be more closely tied to cost causation, but it would be difficult for the customer to respond unless measurement occurred each day and was averaged for the full billing period.

Frequency of billing demand measurement

By far the most common frequency of measurement is once per month. However, this is not the result of careful study and analysis, but is rather a matter of convenience related to the selection of billing periods approximating one month. Months and billing periods are arbitrary creations, whereas cost variation tends to be more seasonal in nature at the macro-scale, weekly at a mid-scale (workdays vs. weekends and holidays), and daily at a micro-scale.

However, actual generation capacity requirements are driven by many high-load hours, which collectively account for most of the risk of insufficient capacity following a major generation or transmission outage,

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[3] A related decision point is specifying whether the billing demand period to be measured is random or clock-based. For example, can a 60-minute billing demand period begin at any time, or should it be restricted to clock hours?

so any single peak customer load is unlikely to provide optimal price signals. Pragmatically, loads of very short duration — the highest 50 hours per year or so — are best served with demand response measures that require no investment whatsoever in generation, transmission, or distribution capacity.

Some commercial and industrial customers are subject to what are called "demand ratchets" which set the minimum billing demand for each month based on a percentage (typically 50% to 100%) of the maximum billing demand for any month in the previous peak season (summer or winter) or previous 11 or 12 months. While ratchets smooth revenue recovery for the utility, they are the antithesis of cost causation in a utility system with diversified loads, and can severely penalize seasonal loads. The resulting unavoidable fixed charges impair the energy conservation price signal to customers. Therefore, billing demands could reflect cost causation more closely by having seasonal elements, and also weekly and daily elements, but this increases the complexity. Alternatively, demands could be measured and averaged over the 100 hours each month that contribute most to system peak loads.[4]

Finally, as discussed relative to the period of measurement, if kW of demand were to be measured in every hour of the month and summed, the result would be the current two part rate with no additional more expensive metering required.

Evaluation of Demand Charges

Loads, load management and load diversity

The costs that utilities typically recover in existing demand charges applied to large customers include those that are usually assigned to customer classes on the basis of a demand allocator.[5] These costs tend to be fixed for a period of more than one year, and usually include one or more of the following:

- Generation capacity costs (cost of peaking generators and all or a portion of the cost of baseload[6] units)
- Transmission costs (all or a portion)
- Distribution costs (all or a portion of distribution circuits and transformer costs)

Some utilities utilize separate demand charges for each major function, or sometimes group functions together, such as generation and transmission, that are allocated to customer classes on similar bases.

Because billing demand is a function of the total load of a customer's on-site electrical equipment operating simultaneously for a relatively short period of time, the demand charge may act as an incentive to levelize demand across the day. The types of large commercial and industrial customers that are currently subject to demand charges are usually sophisticated enough to understand the sources and timing of their electrical equipment and its consequent energy consumption.[7] Many, i.e. over half,[8] have

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[4] Such a system would be more likely to capture high loads and peak demands on the system sub-functions, e.g. transformers, feeders, substations, transmission, and generation.

[5] It should be noted that some jurisdictions allocate a portion of fixed costs on average demand, or energy.

[6] Because baseload units serve all hours, many regulators have used the Peak Credit or Equivalent Peaker method to classify baseload plant costs between Demand and Energy. For example, in Washington, it's about 25% demand, 75% energy. In marginal cost studies, only the cost of a peaker is typically considered demand-related.

[7] Most utilities do not apply demand charges to small commercial customers under 20-50 kW demand.

energy managers whose job in part is to manage that energy consumption in light of the rates and rate structure of their local utility. Monitoring and load management equipment can be employed to maximize profitable industrial processes while avoiding new, higher peak demand charges. In other words, sophisticated large commercial and industrial customers may use energy management systems to restrain demand by scheduling or controlling when different pieces of equipment are used like fans, compressors, electrolytic processes, and other major equipment, in order to levelize the load over the day. Because these large customers have a diversity of uses on their premises, they may be able to manage that diversity to present a relatively stable load to the utility.[9] However, because individual customer demand often does not coincide with system demand, much of the demand management activity by the more sophisticated large customers is essentially pointless and wasteful from a system cost perspective.

Moreover, while it appears utilities believe demand-charge revenues are more stable than energy revenues, the stability of demand charge revenue even for large customers is highly dependent on the size, load factor and weather sensitivity of the large customers.

The sophistication of large customer energy management does not currently exist for most small commercial and residential customers. These customers have a great deal of load diversity, but that diversity is not within a single customer but between different customers using power at different times (see Appendix B). In these classes, because each customer is served through a separate meter, it is unlikely that individual constituents will have much ability to reduce the overall system demand or their own maximum billing demand in any significant way without acquisition and effective use of advanced load monitoring and management technologies. Residential demand controllers are marketed to all-electric customers (e.g. at some rural utilities with limited circuit capacity) that have implemented demand charges. These do enable customers with electric cooking, water heating, clothes dryers, space conditioning, and swimming pools to levelize their demand. But for urban apartment dwellers and other low-usage customers, the natural diversity between customers is much greater than the potential control over the diversity of uses within a household.

Technologies to manage and control this diversity of small customer usage are best deployed as demand response measures, targeted at hours that are key to the system, not to the individual consumer usage pattern. As a result of the small customers' lack of ability to control individual peak demands, a demand charge on small customers acts effectively as a fixed charge and generally provides a more stable and consistent revenue collection vehicle for the utility than volumetric energy charges.

Cost drivers and load alignment

Evidence shows that small residential customers are less likely to have their individual high usage occur at the time of the system peak demand, whereas large residential users are more likely. This is simply because large residential users are more likely to have significant air conditioning and other peak-oriented loads. Large residential users' loads tend to be more coincident with system peak periods and thus more expensive to serve. As a result of these load patterns, on an individual customer basis large residential users have higher individual load factors, meaning they will pay lower average rates if a non-coincident demand charge is imposed.

The figure below shows this relationship, in the context of residential customers:

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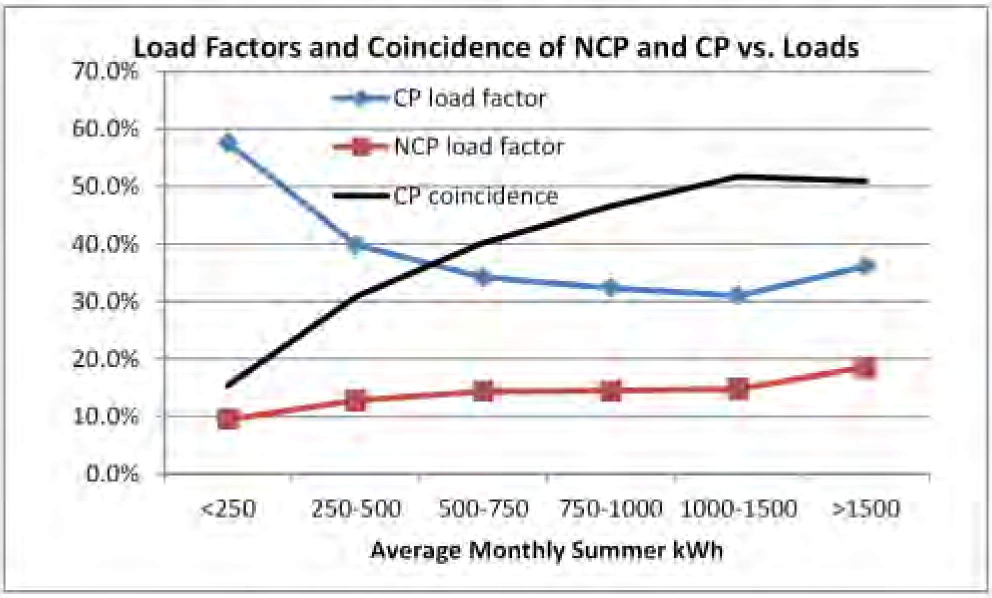
[8] A Review Of Alternative Rate Designs Industry Experience With Time-Based And Demand Charge Rates For Mass-Market Customers; Rocky Mountain Institute, p. 76, May 2016 download at: www.rmi.org/alternative_rate_designs

[9] That stable load may not be less expensive to serve than the customer's most efficient load.

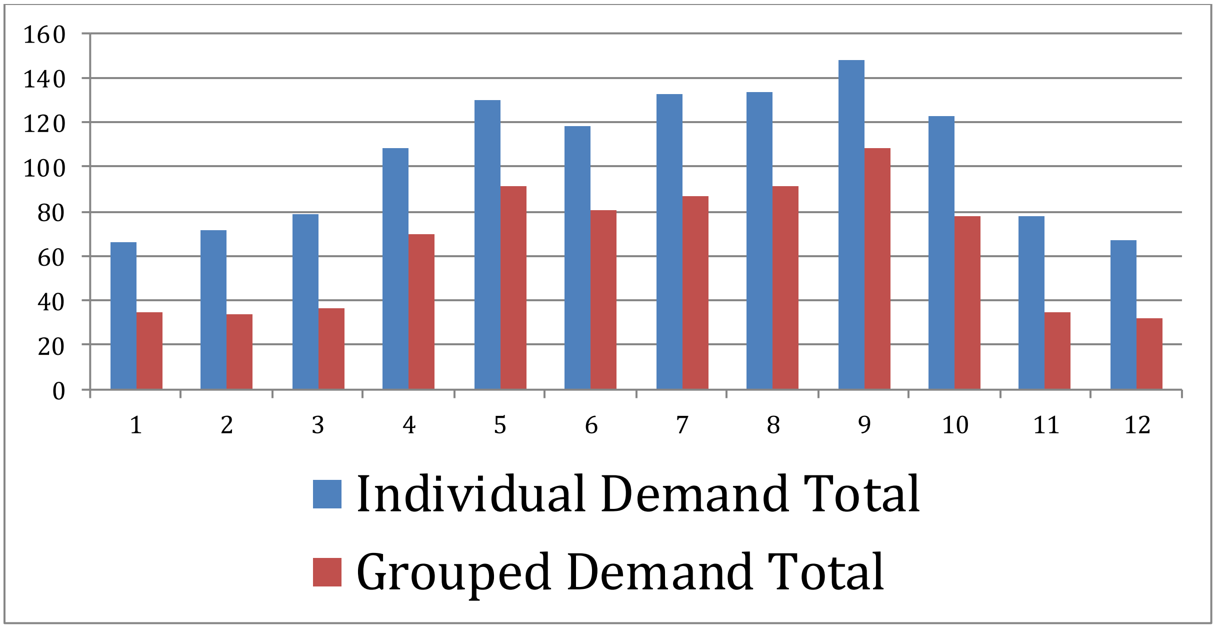


Source: Marcus Presentation to WCPSC, June 2015

The black line shows customers whose individual peak demand coincides with system peak tend to have both higher monthly energy use (kWh) and higher metered individual load factors. The red line shows that larger-use customers have higher individual metered non-coincident load factors. The blue line shows that smaller-use customers have higher "group" collective load factors, measured relative to the system coincident peak.

As described above, the breadth of equipment on a large commercial or industrial customer's site results in load diversity behind the meter allowing for a fairly smooth load pattern for these larger customers. Smaller customers without the same degree of behind the meter load diversity have many small appliances that often operate for short periods of time. It takes but a few operating simultaneously to establish a peak demand. For a large group of 100,000 to one million customers or so, there is a general pattern for the class load and in many cases it tends to drive the utility's peak demand towards later in the day, but on an individual customer basis, peak loads can occur at any time during the month depending on the lifestyle, ages of family members, work situation, and other factors.

Apartments are particularly affected. About three-quarters of apartments in the US have electric water heaters. An electric water heater draws 4.4 kW when charging, but only operates about two hours per day, for a total of about 9 kWh of consumption per day. But each apartment has its own water-heating unit. Combined with hair dryer, range, clothes dryer, and other appliances, an apartment unit may draw 10-15 kW for short periods, but only about 0.5 to 1.0 kW on average (360-720 kWh per apartment per month). Because many apartments are served through a single transformer and meter bank, what actually matters to system design is not the individual demands of apartments, but the combined (diverse) demand of the building or complex. The illustration below shows how the sum of individual apartments' maximum hourly demands in one apartment building (in the Los Angeles area) compares to the combined maximum hourly demand for the complex:



Source: RAP Demand Charge Webinar, December 2015

The equity of rates and bills for apartment residents, where each household has few residents, but the entire building is connected to the utility through a single transformer bank, must also be addressed because the utility does not actually serve the consumption of individual customers, but only their collective needs. Finally, if customers do respond and levelize their consumption across the day or across the peak hours to minimize their demand charges, then the rates designed will not produce the revenue expected but any impacts on system costs (e.g. avoided upgrades or expansions) would likely not occur for years.

Appendix B contains residential load curves for customers in New Mexico and Colorado covering the four summer peak days for the utility providing service. It is clear from these charts that individual residential customer load is volatile, and not subject to consistent patterns that the customer would be in a position to manage. Each customer experienced its individual peak at a unique time. The collective group peak was not at the time of each individual customer's peak in any of the months. The bottom line is no discernible cost causation relationship with individual customers' peak demand.

Metering costs and allocation

Finally, demand charges also require more complex, and expensive, metering technologies than conventional two-part tariffs. The cost-effectiveness of these upgrades should be analyzed on their own merits, and where the costs are justified by energy savings or peak load reduction, they should be treated in the same fashion as the costs that are avoided, with only the portion justified by customer-related benefits (e.g. reduced meter reading expense) treated as customer-related. The remainder would be attributed to such drivers as energy costs and coincident peaks. For more information, see Smart Rate Design for a Smart Future for a discussion of how Smart Grid costs should be classified and allocated in the rate design process.[10]

[10] Regulatory Assistance Project, Smart Rate Design for a Smart Future, 2015.

Demand charges as a price signal

Imposition of demand charges runs counter to the ratemaking principles of simplicity, understandability, public acceptability, and feasibility of application. It's a formidable task to try to train millions of customers in the meaning of billing demand, the factors driving it, and how to control and manage it. Indeed, RMI (2016, p. 76) notes "[w]hile it's possible that, if customers are sufficiently educated about a demand charge rate, they will reduce peak demand in response, no reliable studies have evaluated the potential for peak reduction as a result of demand charges." The same RMI report indicates that time-varying energy charges are more effective at reducing peak demands than are demand charges.[11] Additionally, the Brattle Group reported a peak load reduction of less than **2%** for residential demand charges, compared with reductions as great as **40%** for critical peak pricing energy rates.[12]

The examples given in Appendix B show no pattern that a customer might be able to manage in advance — which is the knowledge required in order to control a peak demand occurrence. In part this is due to a mix of appliances that are set to turn on and off automatically as needed (e.g. air conditioning, hot water heaters, refrigerator) and others that are under the control of the home or small business owner (e.g. lighting, hair dryers, kitchen appliances, television). Without sophisticated load control and automation devices, it is unclear how small customers could manage peak loads. Without installation of such load control technology, a demand charge is not an effective price signal. Importantly, a charge like a demand charge is only a price signal if the customer can respond to it. If not, it becomes an unmanageable fixed charge with a substantially random character.

Indeed, large residential customers with many appliances (e.g. swimming pool heaters and pumps) that have higher load factors may benefit from demand charges as cost recovery is shifted to a charge based on a single peak demand from demand-related costs being applied against every kWh. This has been true with the larger commercial and industrial class as well. Conversely, low usage customers — including low-income customers — would likely pay more on average.

The Bonbright Criteria

Professor Bonbright's famous 1961 work, Principles of Public Utility Rates, outlined eight criteria of a sound rate structure. It is useful to consider how demand charges fare under these criteria and the following summary addresses each criteria.

1. **The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.**

   Simplicity: While the demand rate itself can be viewed as simple — a single charge applied to a single parameter — the concept of demand integrated over a short time frame (e.g. 15 minutes or one hour) is not simple and requires customer education.

   Understandability: The application and management of demand rates is likely to be difficult because customers cannot easily manage the demand in the short time intervals typically applied to demand charge rate design.

[11] A Review Of Alternative Rate Designs Industry Experience With Time-Based And Demand Charge Rates For Mass-Market Customers; Rocky Mountain Institute, May 2016 download at: www.rmi.org/alternative_rate_designs
[12] Presentations of Ahmad Faruqui and Ryan Hledik, EUCI Residential Demand Charge Summit, 2015.

Public acceptability: Demand charges are not likely to be readily accepted by small customers for the reasons outlined above. Indeed, for most consumers they will just seem like another fixed charge. (See Arizona Public Service Company case study below.)

Feasibility of application: While technically feasible, new metering is required. The likely metering technology is smart meters that can also be used for more appropriate time-varying rates (although some claim the smart meter only estimates the peak demand). As noted above, it is not clear that customers can respond to demand charges; for many utilities, the attraction of demand charges for small customers may be that customers will not be able to avoid them.

2. Freedom from controversies as to proper interpretation.

Proper interpretation of demand charges will be difficult for customers who don't have the behavioral or technological ability to understand, prepare for and manage peak demands in advance. This may result in misunderstandings, frustration and increasing complaints. A utility should be able to demonstrate that the smallest customers currently on demand rates understand their bills, before applying demand charges to still smaller customers.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

Rate structures that establish an effective relationship between billing parameters and cost causation are reasonably likely to yield total revenue requirements following implementation. However, it is clear that individual maximum demands for small customers are very diverse and rarely occur at the time of maximum system demand. To the extent small customers are able to respond to the demand price signal, they may move their peak load from a less costly time of day to a more costly time of day, and their measured demand (and the associated revenue) may vary sharply from month to month as different appliances happen to be used simultaneously generating the measured demand upon which the charge is based. Thus the link with cost causation is weak, and achieving total revenue requirements is more at risk.

4. Revenue stability from year to year.

Similarly, the weak cost causation link can cause instability as a significant portion (often 60% or more) of a small customer's revenue is dependent on the relative stability of a single 15 minute or one hour period during the entire month. Customer peak demand, particularly for air conditioning customers, is highly temperature sensitive, so mild summers may result in severe undercollection of revenues.

5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")

Here, too, it is unclear whether demand charges for small customers will be stable over time, but given the volatility of small customer loads, bills may lack stability. If small customers are unable to respond to the demand charge price signal, then the demand charge will act as a fixed charge and the *rate* would likely be stable. If over time small customers are able to use technologies or behavioral changes to reduce maximum demands, utility revenue may drop significantly and the rate will need to be increased to recover allowed revenues, and thus will be less stable. This paradoxical situation results in the shifting of costs from those able to manage peak loads to those who are unable.

6. Fairness of the specific rates in the apportionment of total costs of service among the different customers.

As pointed out above in comparing customers of different sizes (see for example the apartment dwellers discussion), small customers tend to have lower individual load factors, i.e. higher peak demands relative to their energy consumption, but higher collective group load factors (which drive utility capacity needs). In fact, lower use customers tend to have less coincidence of their individual peak demands with the system peak demand. As a result, demand charges paid by these customers would be associated with a time period that is not correlated with cost causation. This would place an unfair burden on small customers.

7. **Avoidance of "undue discrimination" in rate relationships.**

   As above, the lower coincidence of individual peak demands of lower use customers with system peak loads should lead to lower charges or bills, but applying the same demand charges to the customer's peak demand whenever it occurs would generate high charges and bills, thus discriminating against low use customers.

8. **Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:**

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service (on peak versus off peak electricity, Pullman travel versus coach travel, single party telephone service versus service from a multi party line, etc.).

As noted in the body of this paper, in addition to a lack of coincidence with cost-causing system peak loads, demand charges (particularly NCP demand charges) are generally not actionable for small customers. Thus the small customer cannot respond to this "signal" in any meaningful way that might result in lower utility costs.

More importantly, there is evidence that small customers can and do respond to price signals based on energy charges that vary by time or usage. Shifting cost recovery from energy charges to demand charges reduces the customer's incentive to reduce consumption, and results in an inefficient use of resources.

Finally, the authors of this paper support the concept of **customer agency.** In other words, the customer should have choice, control, and the right of energy self-determination. Demand charges without associated technology to control demand tend to act as fixed and unavoidable charges, and will have the effect of reducing the variable energy rate. These rate changes can significantly diminish the incentive for customers to reduce energy consumption through behavioral changes, energy efficiency technologies, or distributed generation resources and result in increased fossil fuel emissions.

Arizona Case Study

While no regulatory Commission has approved mandatory demand charges for residential customers in recent memory, this has not always been the case. A real world example is Arizona Public Service Company's (APS) residential demand rate. APS has an optional demand charge residential rate, which has been in effect since the 1980s and currently has about 10% enrollment. The customers who self-select onto this rate design are those whose usage patterns benefit from this rate option; others choose a TOU rate or an inclining block rate. The Company assists customers in identifying the lowest cost rate option for their individual usage patterns.

In a 2015 case study performed by APS, the utility explains that its optional residential demand rate "helps customers select the best rate at time of new service through [its] website rate comparison tool."[13] An examination of the relative size of residential customers that have self-selected onto the demand rate reveals that they have an average monthly consumption nearly three times the average monthly consumption of customers on the default rate.[14]

There is important history here. In the late 1980's, as the Palo Verde nuclear plants came into service and APS rates increased sharply, the ACC implemented inclining block default rates. The company opposed this at the time, but found a work-around for large-use customers, the demand and TOU rates. The demand and TOU rates have no inclining blocks (there are no barriers to implementing both together, but Arizona has not done so), so it is a way for large-use customers to avoid the higher per-unit price for higher unit that the Arizona Corporation Commission (ACC) created in with the inclining block rate design. The Company markets the demand rate only to large-use customers who they think will benefit. Many of these customers have diverse loads behind the meter, and can benefit from a demand charge if they have (or can shape) load to take advantage of the rate design, and evade the inclining block rate. Some install demand controllers to ensure their water heaters or swimming pool pumps turn off when the air conditioning turns on.[15] So it is a self-selected subclass of customers with above-average usage, and above-average diversity. Results from this subset should not be presumed to reflect behavior or experience of other subclasses.

Use of the rate comparison tool for self-selection infers that those APS residential customers who have chosen to take service on the demand rate did so because it would lower their bills without any modification in consumption patterns. Current enrollment in APS's optional demand rate does not imply that customers in APS's territory have the ability to respond to the price signal set by demand charges. Indeed, since the customer has no way of knowing when they have hit their peak demand, it is unclear if there is even a price signal being sent. To the contrary, the fact that APS has marketed its optional demand charge rates for upwards of three decades with only 10% current enrollment demonstrates that 90% of APS's customers have either not gained an understanding of how the demand charge rate would impact them, or they have decided that the demand charge rate is not the best option for them.

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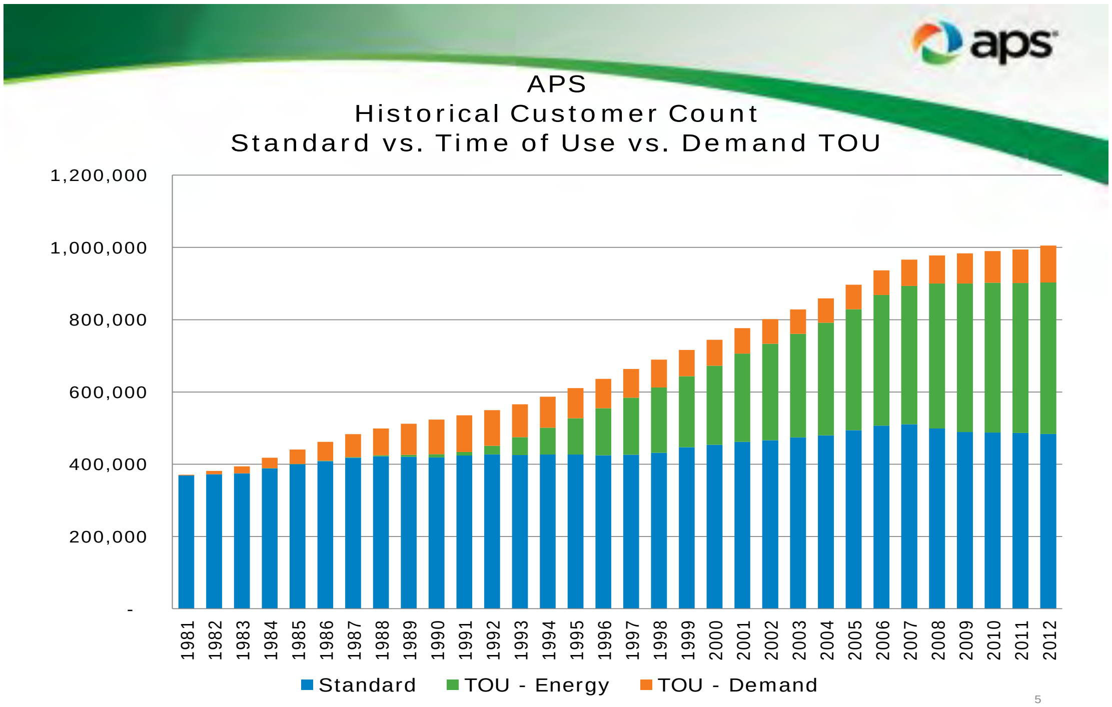
[13] Meghan Grabel, APS, *Residential Demand Rates: APS Case Study* 3 (June 25, 2015), *available at* http://www.ksg.harvard.edu/hepg/Papers/2015/June%202015/Grabel%20Panel%201.pdf.
[14] *Id.* at 7.
[15] See, for example, http://www.apsloadcontroller.com/ or www.energysentry.com for examples of devices that cost



In a recent rate proceeding, APS revealed that as many as 40% of its customers that recently switched from a two part rate to the optional demand charge rate actually increased their maximum on-peak demand. This means that even among the customers that self-selected onto the demand charge rate (mostly to save money relative to the inclining block standard rate), 40% did not respond to the demand charge price signal in their optional tariff.

It should be noted that APS's current optional residential demand charge tariff was originally approved by the ACC in October 1980 as a mandatory tariff for new residential customers with refrigerated air-conditioning. However, the Commission removed the mandatory requirement less than three years later, noting the change was "in response to complaints that the mandatory nature of the EC-l rate produced unfair results for low volume users." In addition, the Commission stated that removal of the mandatory demand charge would "alleviate the necessity for investment by low consumption customers in load control devices to mitigate what would otherwise be significant rate impacts under the EC-l rate."

Appendix A: Additional References

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Moving Towards Demand-based Residential Rates, Scott Rubin, Nov 2015
Legal Case against Standby Rates, Casten & Karegianes, Nov 2007

E source survey: *Net Metering Wars: What Do Customers Think?*:
http://b.3cdn.net/solarchoice/27dbacad2a21535d4c_78m6ber2o.pdf

Natural Gas and Electricity Magazine: *Residential Demand Charges*, February 2016:
https://www.researchgate.net/journal/1545-7907_Natural_Gas_Electricity

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Rethinking Standby and Fixed Cost Charges: Regulatory and Rate Design Pathways to Deeper Solar Cost Reductions, August 2014: https://nccleantech.ncsu.edu/wp-content/uploads/Rethinking-Standby-and-Fixed-Cost-Charges_V2.pdf

Regulatory Assistance Project
- Smart Rate Design for a Smart Future: https://www.raponline.org/document/download/id/7680
- Designing DG Tariffs Well: http://www.raponline.org/document/download/id/6898
- Use Great Caution in the Design of Residential Demand Charges: http://www.raponline.org/document/download/id/7844
- *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs: http://www.raponline.org/document/download/id/7361*
- *Time-Varying and Dynamic Rate Design: http://www.raponline.org/document/download/id/5131*

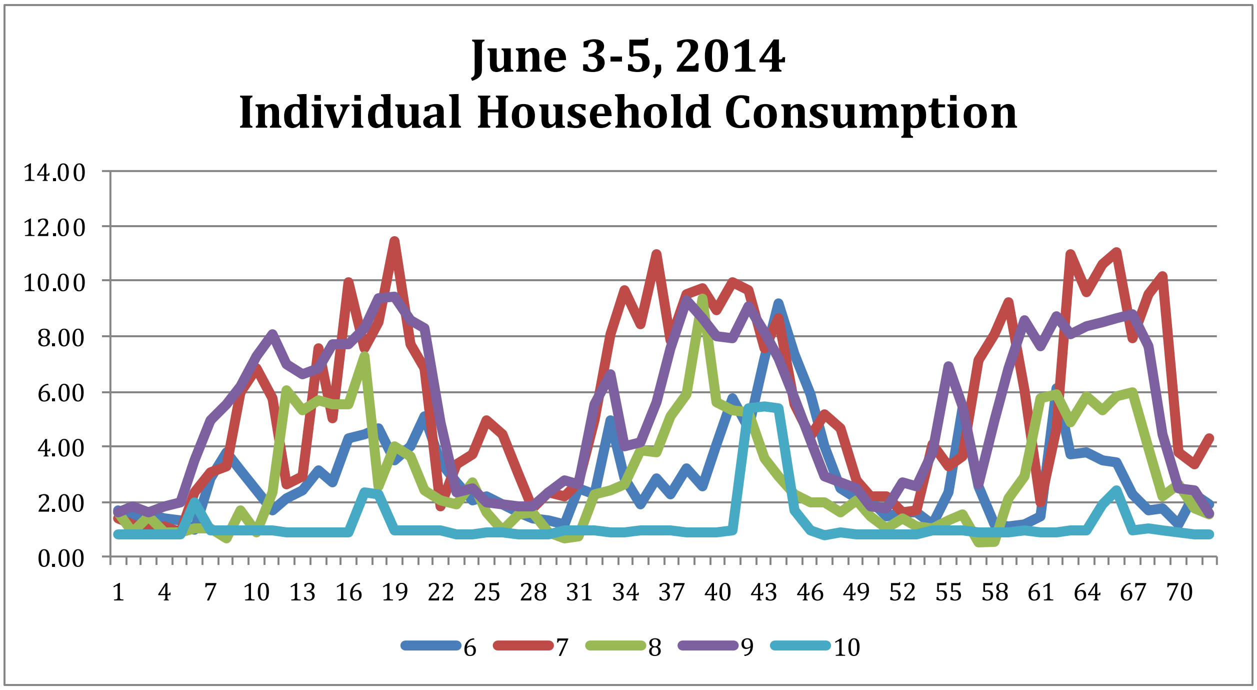
Rocky Mountain Institute
- A Review of Rate Design Alternatives: http://www.rmi.org/alternative_rate_designs

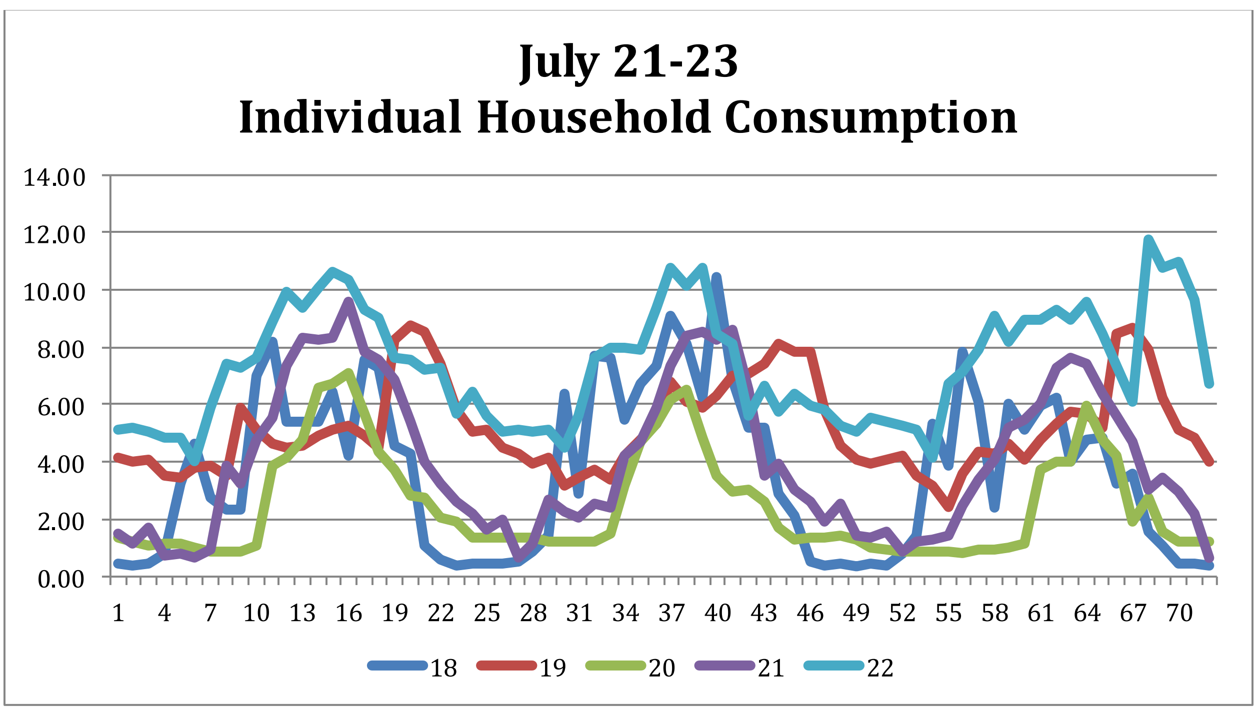
Appendix B: Sample Individual Residential Customer Loads

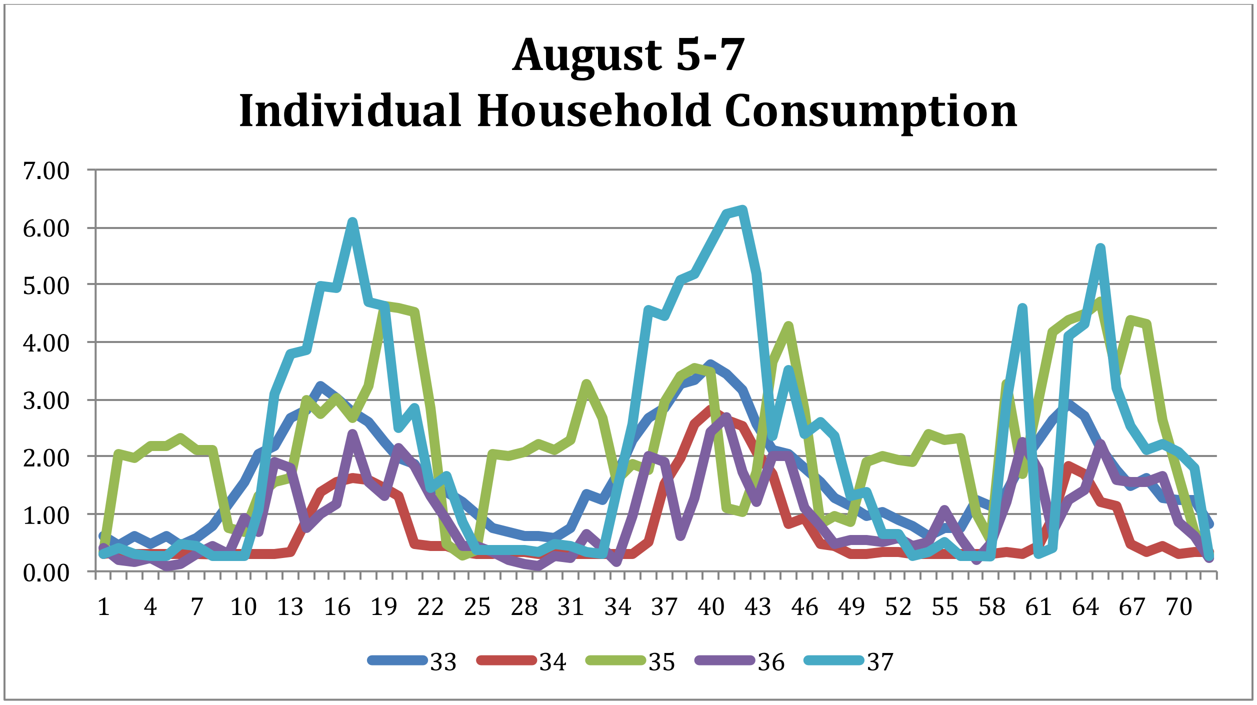
<u>New Mexico</u>

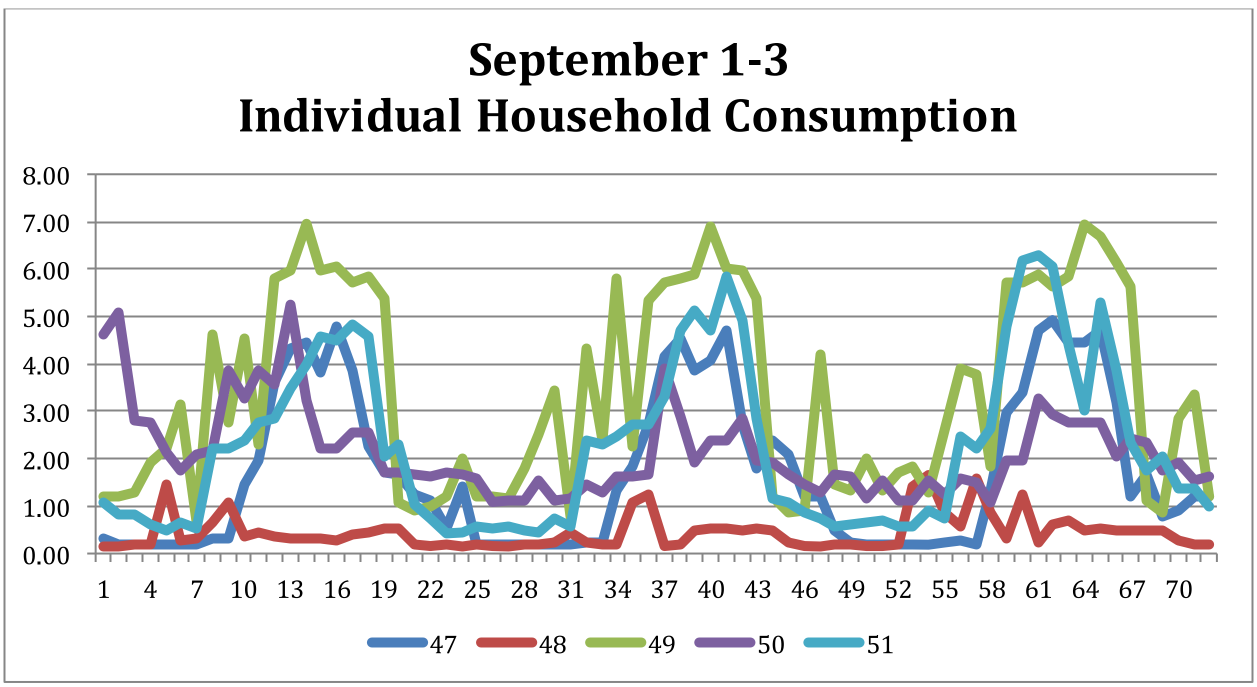
Four summer peak periods; three days and five customers per chart

(middle day is system peak day)





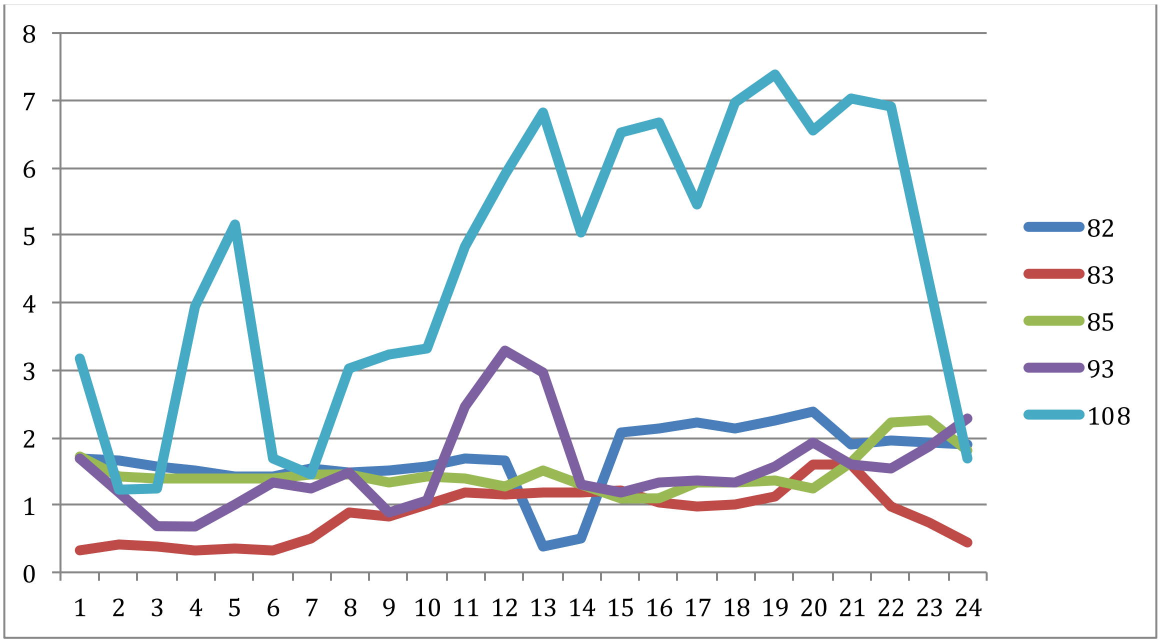

August 5-7
Individual Household Consumption
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70
33 34 35 36 37


September 1-3
Individual Household Consumption
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70
47 48 49 50 51

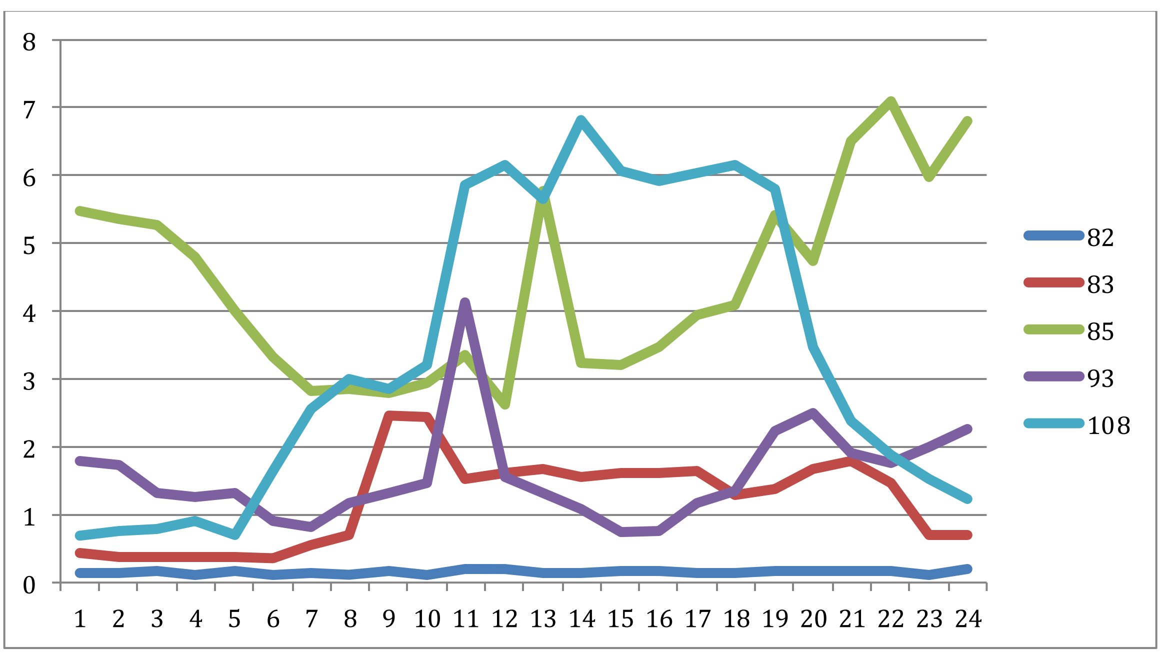
Colorado

Four summer peak days; five customers per chart

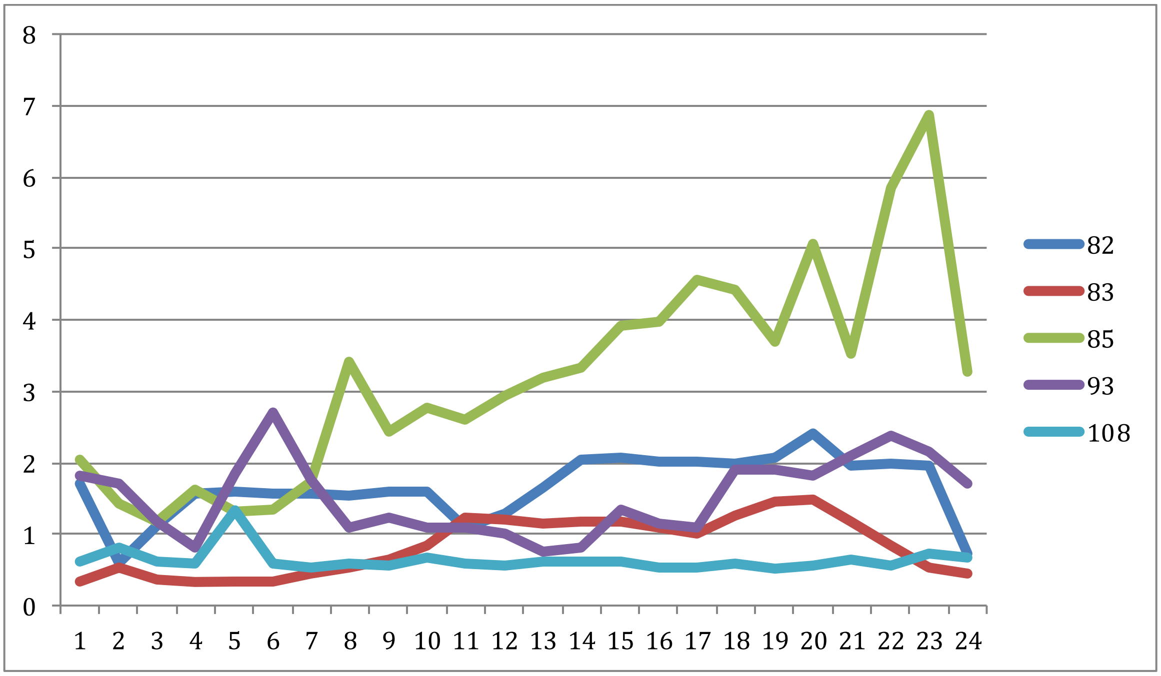
June 27, 2013



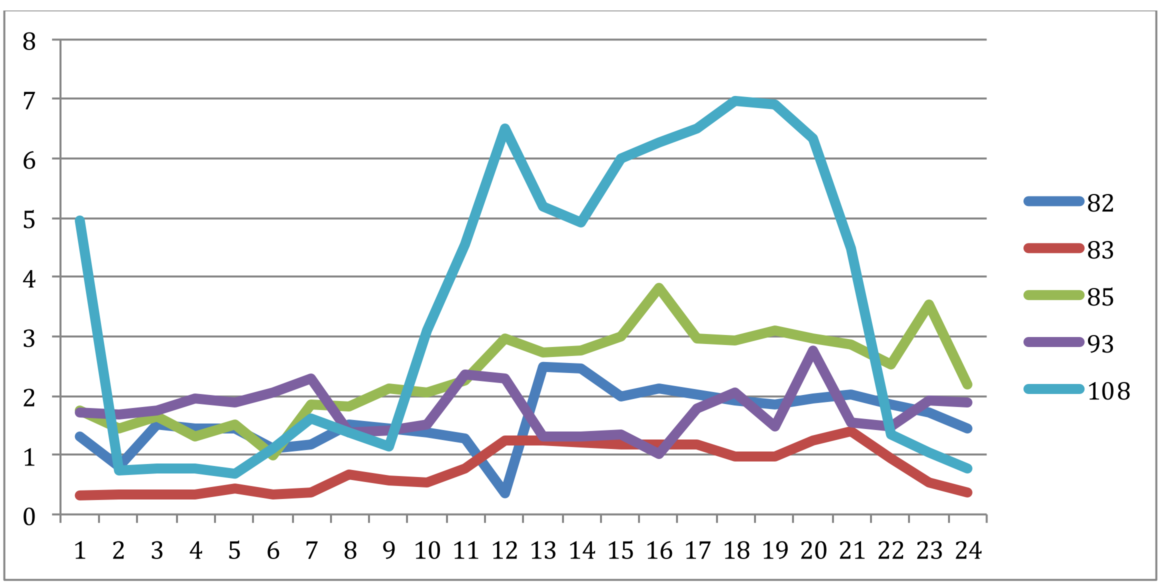
July 11, 2013



August 20, 2013



September 6, 2013



PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the Domestic Service Tariff.

CUSTOMER CHARGE

$10.83 per month.

ENERGY CHARGE

	Cents per kilowatt-hour	
	Effective November 1, 2021	**Effective January 1, 2022**
Non-Critical Peak Hours	~~13.189~~15.250	~~13.395~~ 15.456
During a Critical Peak Event	150.000	150.000

~~Winter Period November 1 through March 31~~	
~~Peak Periods - Weekdays~~	~~Critical Peak Event Hours~~
~~On-peak (morning)~~	~~7:00 am to 11:00 am~~
~~On-peak (evening)~~	~~4:00 pm to 8:00 pm~~

The Critical Peak Event Hours will be 4: 00 pm to 8:00 pm. A Critical Peak Event may be called during the Winter Period: November 1 to March 31.

The Critical Peak Event pricing applies when a Critical Peak Event is called. In all other hours in the Winter Period, and for all hours in the Non-Winter Period, the rate shall be the Non-Critical Peak Hours Rate in the table above.

CRITICAL PEAK EVENT PROCEDURE

~~1. In the Winter Period, Critical Peak Event Hours exclude all hours on Saturdays, Sundays, and the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, Victoria Day, July 1, Natal Day, Labour Day, Thanksgiving, November 11, December 25 and December 26. If January 1, July 1, November 11, December 25 or 26 fall on a weekend, the Critical Peak Event Hours also exclude the weekday the holiday is observed.~~

~~2.~~ 1. The duration of a Critical Peak Event is defined as the Critical Peak Event Hours ~~in either the~~

~~On-peak (morning) or On-peak (evening)~~. Critical Peak Events will be scheduled during the Critical Peak Event Hours, at the sole discretion of NSPI, when NSPI is expecting conditions including, but not limited to, high energy (kWh) usage, high market energy costs, or generation or transmission outages.

~~3.~~2. When a Critical Peak Event is scheduled, subscribers to this tariff will be notified in advance and the Critical Peak Event Energy Charge (higher rate) will be in effect for all kWh consumed by the customer during the period. The notification is a signal to the customer to reduce the amount of electricity they are using.

~~4.~~3. Critical Peak Events will only be scheduled to occur during the Winter Period during the Critical Peak Event Hours.

4. NSPI expects to call an average of 6 Critical Peak Events per year for this Tariff.

5. No more than ~~2~~12 Critical Peak Events may be scheduled per Winter season (November through March inclusive) for this Tariff.

6. Customers will be notified of a Critical Peak Event in advance. By 4:00 pm the day prior to the event, the Customer will receive a notification message. The Customer is responsible to watch for this message, and to notify NSPI in advance if their contact information changes.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $10.83.

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) The customer must be on electronic billing and have a MyAccount profile.
d) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
e) The customer cannot be taking seasonal service from NSPI under Regulation 3.3.

Optional Green Power Rider

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing "blocks" of Green Power. For every block purchased, NSPI will provide 125 kWh per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer's normal bill for service taken under the Domestic ~~Service~~ Critical Peak Pricing — Basic Tariff.

Special Terms and Provisions

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the Domestic Service Tariff.

CUSTOMER CHARGE

$10.83 per month.

ENERGY CHARGE

	Cents per kilowatt-hour	
	Effective November 1, 2021	Effective January 1, 2022
Non-Critical Peak Hours	~~13.189~~ 14.438	~~13.395~~ 14.644
During a Critical Peak Event	150.000	150.000

~~Winter Period November 1 through March 31~~	
~~Peak Periods - Weekdays~~	~~Critical Peak Event Hours~~
~~On-peak (morning)~~	~~7:00 am to 11:00 am~~
~~On-peak (evening)~~	~~4:00 pm to 8:00 pm~~

A Critical Peak Event may be called during the Winter Period: November 1 to March 31.

The Critical Peak Event pricing applies when a Critical Peak Event is called and will last 4 hours. In all other hours in the Winter Period, and for all hours in the Non-Winter Period, the rate shall be the Non-Critical Peak Hours Rate in the table above.

CRITICAL PEAK EVENT PROCEDURE

~~1. In the Winter Period, Critical Peak Event Hours exclude all hours on Saturdays, Sundays, and the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, Victoria Day, July 1, Natal Day, Labour Day, Thanksgiving, November 11, December 25 and December 26. If January 1, July 1, November 11, December 25 or 26 fall on a weekend, the Critical Peak Event Hours also exclude the weekday the holiday is observed.~~

~~2.~~ 1. The duration of a Critical Peak Event is 4 ~~defined as the Critical Peak Event H~~hours ~~in either the On-peak (morning) or On-peak (evening)~~. Critical Peak Events will be scheduled ~~during the~~

~~Critical Peak Event Hours,~~ at the sole discretion of NSPI, when NSPI is expecting conditions including, but not limited to, high energy (kWh) usage, high market energy costs, or generation or transmission outages.

~~3.~~2. When a Critical Peak Event is scheduled, subscribers to this tariff will be notified in advance and the Critical Peak Event Energy Charge (higher rate) will be in effect for all kWh consumed by the customer during the period, as identified by NSPI in the notification. The notification is a signal to the customer to reduce the amount of electricity they are using.

~~4.~~3. Critical Peak Events will only be scheduled to occur during the Winter Period ~~during the Critical Peak Event Hours~~.

4. NSPI expects to call an average of 12 Critical Peak Events per year for this Tariff.

5. No more than ~~22~~18 Critical Peak Events may be scheduled per Winter season (November through March inclusive) for this Tariff.

~~5.~~6. NSPI may schedule two Critical Peak Events for the same day when NSPI is expecting unusually severe conditions. The events may be scheduled back-to-back, or at different times of the day. No more than 2 such Double Critical Peak Events may scheduled per Winter seasion (November through March inclusive) for this Tariff.

~~6.~~7. Customers will be notified of a Critical Peak Event in advance. By 4:00 pm the day prior to the event, the Customer will receive a notification message. The Customer is responsible to watch for this message, and to notify NSPI in advance if their contact information changes.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $10.83.

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) The customer must be on electronic billing and have a MyAccount profile.
d) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
e) The customer cannot be taking seasonal service from NSPI under Regulation 3.3.

Optional Green Power Rider

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing "blocks" of Green Power. For every block purchased, NSPI will provide 125 kWh per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer's normal bill for service taken under the Domestic ~~Service~~ Critical Peak Pricing—Advanced Tariff.

Special Terms and Provisions

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the Small General Tariff.

CUSTOMER CHARGE

$12.65 per month

ENERGY CHARGE

	Cents per kilowatt-hour		
	During a Critical Peak Event	For the first 200 kilowatt hours per month after Critical Peak Event usage	For all additional kilowatt hours
Effective November 1, 2021	150.000	~~14.228~~16.416	~~12.815~~14.026
Effective January 1, 2022	150.000	~~14.295~~16.483	~~12.882~~14.092

~~**Winter Period November 1 through March 31**~~	
~~**Peak Periods - Weekdays**~~	~~**Critical Peak Event Hours**~~
~~On-peak (morning)~~	~~7:00 am to 11:00 am~~
~~On-peak (evening)~~	~~4:00 pm to 8:00 pm~~

The Critical Peak Event hours will be 4: 00 pm to 8:00 pm. A Critical Peak Event may be called during the Winter Period: November 1 to March 31.

The Critical Peak Event pricing applies when a Critical Peak Event is called. In all other hours in the Winter Period, and for all hours in the Non-Winter Period, the rate shall be the Non-Critical Peak Hours Rate in the table above.

CRITICAL PEAK EVENT PROCEDURE

1. ~~In the Winter Period, Critical Peak Event Hours exclude all hours on Saturdays, Sundays, and the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, Victoria Day, July 1, Natal Day, Labour Day, Thanksgiving, November 11, December 25 and~~

~~December 26. If January 1, July 1, November 11, December 25 or 26 fall on a weekend, the Critical Peak Event Hours also exclude the weekday the holiday is observed.~~

~~2.~~1. The duration of a Critical Peak Event is defined as the Critical Peak Event Hours ~~in either the On-peak (morning) or On-peak (evening)~~. Critical Peak Events will be scheduled during the Critical Peak Event Hours, at the sole discretion of NSPI, when NSPI is expecting conditions including, but not limited to, high energy (kWh) usage, high market energy costs, or generation or transmission outages.
~~3.~~2. When a Critical Peak Event is scheduled, subscribers to this tariff will be notified in advance and the Critical Peak Event Energy Charge (higher rate) will be in effect for all kWh consumed by the customer during the period. The notification is a signal to the customer to reduce the amount of electricity they are using.
3. Critical Peak Events will only be scheduled to occur during the Winter Period during the Critical Peak Event Hours.
4. NSPI expects to call an average of 6 Critical Peak Events per year for this Tariff.
5. No more than ~~22~~12 Critical Peak Events may be scheduled per Winter season (November through March inclusive) for this Tariff.
6. Customers will be notified of a Critical Peak Event in advance. By 4:00 pm the day prior to the event, the Customer will receive a notification message. The Customer is responsible to watch for this message, and to notify NS Power in advance if their contact information changes.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) The customer must be on electronic billing and have a MyAccount profile.
d) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
e) The customer cannot be taking seasonal service from NSPI under Regulation 3.3.

SMALL GENERAL CRITICAL PEAK PRICING—ADVANCED TARIFF

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the Small General Tariff.

CUSTOMER CHARGE

$12.65 per month

ENERGY CHARGE

	Cents per kilowatt-hour		
	During a Critical Peak Event	For the first 200 kilowatt hours per month after Critical Peak Event usage	For all additional kilowatt hours
Effective November 1, 2021	150.000	~~14.228~~16.416	~~12.815~~13.344
Effective January 1, 2022	150.000	~~14.295~~16.483	~~12.882~~13.410

~~**Winter Period November 1 through March 31**~~	
~~**Peak Periods - Weekdays**~~	~~**Critical Peak Event Hours**~~
~~On-peak (morning)~~	~~7:00 am to 11:00 am~~
~~On-peak (evening)~~	~~4:00 pm to 8:00 pm~~

A Critical Peak Event may be called during the Winter Period: November 1 to March 31.

The Critical Peak Event pricing applies when a Critical Peak Event is called. In all other hours in the Winter Period, and for all hours in the Non-Winter Period, the rate shall be the Non-Critical Peak Hours Rate in the table above.

CRITICAL PEAK EVENT PROCEDURE

1. ~~In the Winter Period, Critical Peak Event Hours exclude all hours on Saturdays, Sundays, and the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, Victoria Day, July 1, Natal Day, Labour Day, Thanksgiving, November 11, December 25 and December 26. If January 1, July 1, November 11, December 25 or 26 fall on a weekend, the~~

~~Critical Peak Event Hours also exclude the weekday the holiday is observed.~~

~~2.~~1. The duration of a Critical Peak Event is ~~defined as the Critical Peak Event H~~4 hours ~~in either the On-peak (morning) or On-peak (evening)~~. Critical Peak Events will be scheduled ~~during the Critical Peak Event Hours,~~ at the sole discretion of NSPI, when NSPI is expecting conditions including, but not limited to, high energy (kWh) usage, high market energy costs, or generation or transmission outages.

~~3.~~2. When a Critical Peak Event is scheduled, subscribers to this tariff will be notified in advance and the Critical Peak Event Energy Charge (higher rate) will be in effect for all kWh consumed by the customer during the period, as identified by NSPI in the notification. The notification is a signal to the customer to reduce the amount of electricity they are using.

~~4.~~3. Critical Peak Events will only be scheduled to occur during the Winter Period ~~during the Critical Peak Event Hours~~.

4. NSPI expects to call an average of 12 Critical Peak Events per year for this Tariff.

5. No more than ~~22~~18 Critical Peak Events may be scheduled per Winter season (November through March inclusive) for this Tariff.

6. NSPI may schedule two Critical Peak Events for the same day when NSPI is expecting unusually severe conditions. The events may be scheduled back-to-back, or at different times of the day. No more than 2 such Double Critical Peak Events may scheduled per Winter seasion (November through March inclusive) for this Tariff.

~~6.~~7. Customers will be notified of a Critical Peak Event in advance. By 4:00 pm the day prior to the event, the Customer will receive a notification message. The Customer is responsible to watch for this message, and to notify NS Power in advance if their contact information changes.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) The customer must be on electronic billing and have a MyAccount profile.
d) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
e) The customer cannot be taking seasonal service from NSPI under Regulation 3.3.

GENERAL CRITICAL PEAK PRICING—ADVANCED TARIFF

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the General Tariff.

DEMAND CHARGE

~~For April to October inclusive, $10.497 per month per kilowatt of maximum demand.~~

For ~~November to March inclusive~~any month during which a Critical Peak Event is called, $10.497 per month per kilowatt of maximum demand measured only during ~~Peak Periods~~Critical Peak Event Hours as described below.

For all other month, $10.497 per month per kilowatt of Average Winter Event Month Demand as described below.

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

The Average Winter Event Month Demand is calculated as the average of the billing demand for winter months in which a Critical Peak Event was called. The Average Winter Event Month Demand shall be updated after the Winter Period and shall be applied for any months in which a Critical Peak Event is not called until it is updated after the subsequent Winter Period.

ENERGY CHARGE

	Cents per kilowatt-hour		
	During a Critical Peak Event	**For the first 200 kilowatt hours per month per kilowatt of maximum demand after Critical Peak Event usage**	**For all additional kilowatt hours**
Effective November 1, 2021	150.000	~~9.792~~12.546	~~7.962~~6.682
Effective January 1, 2022	150.000	~~10.067~~12.820	~~8.237~~6.957

~~**Winter Period**~~
~~**November 1 through March 31**~~

~~Peak Periods - Weekdays~~	~~Critical Peak Event Hours~~
~~On-peak (morning)~~	~~7:00 am to 11:00 am~~
~~On-peak (evening)~~	~~4:00 pm to 8:00 pm~~

A Critical Peak Event may be called during the Winter Period: November 1 to March 31.

The Critical Peak Event pricing applies when a Critical Peak Event is called. In all other hours in the Winter Period, and for all hours in the Non-Winter Period, the rate shall be the Non-Critical Peak Hours Rate in the table above.

CRITICAL PEAK EVENT PROCEDURE

~~1. In the Winter Period, Critical Peak Event Hours exclude all hours on Saturdays, Sundays, and the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, Victoria Day, July 1, Natal Day, Labour Day, Thanksgiving, November 11, December 25 and December 26. If January 1, July 1, November 11, December 25 or 26 fall on a weekend, the Critical Peak Event Hours also exclude the weekday the holiday is observed.~~

~~2.~~1. The duration of a Critical Peak Event is ~~defined as the Critical Peak Event H~~4 hours ~~in either the On-peak (morning) or On-peak (evening)~~. Critical Peak Events will be scheduled ~~during the Critical Peak Event Hours,~~ at the sole discretion of NSPI, when NSPI is expecting conditions including, but not limited to, high energy (kWh) usage, high market energy costs, or generation or transmission outages.

~~3.~~2. When a Critical Peak Event is scheduled, subscribers to this tariff will be notified in advance and the Critical Peak Event Energy Charge (higher rate) will be in effect for all kWh consumed by the customer during the period, as identified by NSPI in the notification. The notification is a signal to the customer to reduce the amount of electricity they are using.

~~4.~~3. Critical Peak Events will only be scheduled to occur during the Winter Period ~~during the Critical Peak Event Hours~~.

4. NSPI expects to call an average of 12 Critical Peak Events per year for this Tariff.

5. No more than ~~22~~18 Critical Peak Events may be scheduled per Winter season (November through March inclusive).

6. NSPI may schedule two Critical Peak Events for the same day when NSPI is expecting unusually severe conditions. The events may be scheduled back-to-back, or at different times of the day. No more than 2 such Double Critical Peak Events may scheduled per Winter seasion (November through March inclusive) for this Tariff.

~~6.~~7. Customers will be notified of a Critical Peak Event in advance. By 4:00 pm the day prior to the event, the Customer will receive a notification message. The Customer is responsible to watch for this message, and to notify NS Power in advance if their contact information changes.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh, applying to that portion of the bill which is not concerned with determination of the cost of the Critical Peak Events, will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) The customer must be on electronic billing and have a MyAccount profile.
d) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.