Petition of Northern States Power Company for Approval of General Time-of-Use Service Tariff

MPUC Docket No. E002/M-20-86

STRATEGEN CONSULTING

Prepared for: Fresh Energy

May 29, 2020

Table of Contents

I. Introduction

Fresh Energy retained Strategen Consulting to evaluate Xcel Energy's proposed General Time-of-Use (TOU) Service tariff under Docket No. E002/M-20-86 and to design an alternative, if necessary. Strategen ultimately designed an alternate rate on behalf of Fresh Energy. This memo and the accompanying appendices provide details in support of Strategen's approach.

Strategen proposes an alternate General TOU Service tariff, or Commercial and Industrial Time-of-Use with Critical Peak Pricing (C&I TOU with CPP) rate, that emphasizes volumetrically based price signals to encourage energy shifting and peak demand reduction to more effectively achieve public policy goals. Specifically, Strategen's rate builds upon Xcel's proposal by transforming the Company's time-varying demand charges into TOU volumetric rates with a CPP component. Strategen maintains much of the rest of Xcel's proposal, while recommending future improvements.

Xcel's proposed time-varying demand charges send a less effective price signal for collecting some system capacity costs when compared to volumetric rates. Higher and more granular time-varying volumetric rates can better incentivize energy shifting and peak demand reduction to better utilize lower cost times of day with high renewable generation and create flexibility that can address system needs.

This memo first describes Strategen's proposed C&I TOU with CPP, then critiques Xcel's proposal. Section II explains Strategen's focus on volumetric revenue recovery, outlines its modeling methodology, and addresses the bill and revenue impacts of its proposed rate. Section III analyzes Xcel's proposed rate design and comments on several additional C&I rate design considerations. Finally, in Section IV, Strategen's provides its conclusions and summarizes its recommendations.

II. Strategen's C&I rate design proposal

Overview of Strategen's proposal and recommendations

Strategen proposes a Commercial and Industrial Time-of-Use with Critical Peak Pricing (C&I TOU with CPP) rate that improves upon Xcel's petition by providing more significant and granular price signals through higher volumetric TOU rates, paired with a critical peak pricing (CPP) component. Strategen proposes a C&I TOU with CPP including four rate components: a monthly customer charge, time-differentiated energy charges, a CPP charge, and a distribution demand charge.

Strategen's proposed rates and time periods are as follows:

Table 1: TOU Periods and Energy Rates

On-peak	3 p.m. to 8 p.m. on non-holiday weekdays	\$0.0780 per kWh
Off-peak	12 a.m. to 6 a.m. every day	\$0.0187 per kWh
Base	All other hours	\$0.0405 per kWh
Critical Peak Pricing	Available for 75 hours per year	\$0.5588 per kWh

Strategen's C&I TOU with CPP design shifts revenue collection from time-varying demand charges into time-varying energy charges. Specifically, Strategen eliminates all demand charges other than Xcel's "distribution demand rate" and instead collects these costs through increased on-peak, off-peak, and base TOU period rates.

Additionally, Strategen adds a CPP component to the C&I TOU structure. The CPP rate sets a predetermined number of hours for which Xcel can increase the kWh charge to well beyond any TOU period rate. The CPP would provide Xcel with 75 event hours that it could call at any point during the year. For example, if Xcel determined that the system was going to be capacity constrained and called a CPP event on a weekday from 4 p.m. to 7 p.m., the rate for C&I customers would increase by \$0.5588 per kWh. The CPP events would require Xcel to provide sufficient notice, such as 24 hours, before the kWh price could be increased.

Strategen's proposal maintains Xcel's proposed monthly customer charge, ratcheted distribution system demand charge, "rule of 100" demand limiter, and three daily pricing periods. The following sections will discuss Strategen's justification for these components and approach.

Prioritizing volumetric revenue recovery

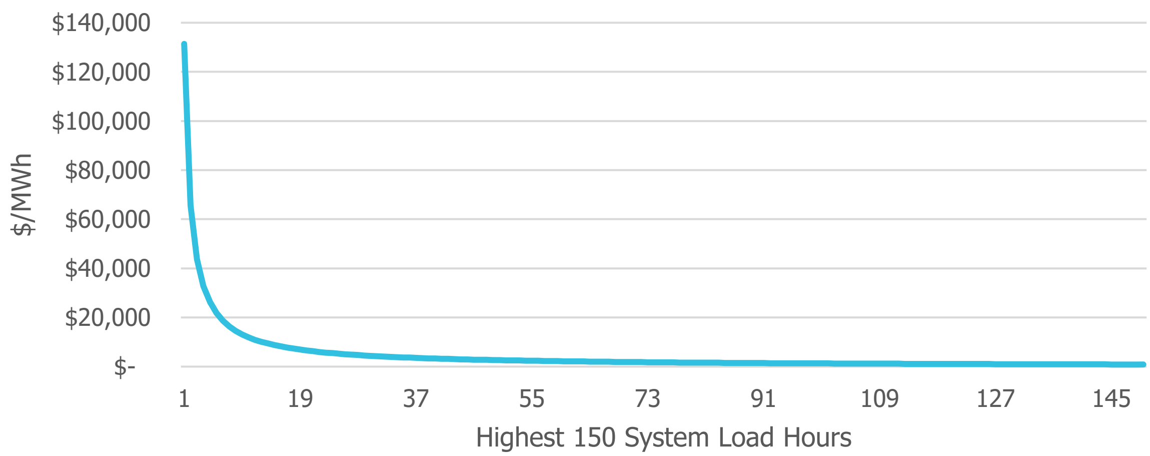
Strategen recommends that most revenue from the General TOU Service tariff be recovered through volumetric rate components. As a significant step toward this goal, Strategen recommends that most generation and all transmission costs be recovered through a volumetric TOU structure complemented by a CPP component that collects peak-related generation costs.

Strategen's proposal differs from Xcel's proposal in a few ways. However, the primary difference is that Xcel seeks to recover capacity-related generation and transmission costs through time-varying monthly demand charges as opposed to volumetric rates. There are several reasons why Strategen recommends volumetric revenue recovery over demand charges for capacity-related generation and transmission costs: (1) it more accurately reflects cost causation; (2) it better addresses the technological changes of a modernizing electric system; (3) it better rewards load flexibility and diversity; and, (4) it will better achieve Minnesota public policy goals.

Cost causation

Cost causation is the regulatory principle that says users who cause electric system costs should pay for them. In the rate design context, this means acknowledging that a large percentage of system costs are driven by a few hours within a few days per year because these hours have significantly greater demand than the rest of the year. While rates should place significant emphasis on a small number of high-demand hours, rates should also equitably allocate the cost of serving load reliably for the remaining hours in the year. Figure 1 exemplifies the high cost of serving extreme load periods: the 75 highest-load hours are significantly more costly to serve than the remainder of system hours based on Xcel's proposed analysis of system cost allocation.

Figure 1. Xcel's System Cost Duration Model from Forecasted 2025 Load Data[1]



As the power system moves to a high renewables grid environment, power system planning will be far less about "building to the peak" and much more about optimizing a diverse array of clean energy resources (including demand-side).[2] This requires a new planning paradigm as evidenced by evolving IRP and integrated distribution planning processes in Minnesota and other states.

Similarly, cost causation principles will need to evolve to reflect this broader and more nuanced electric system paradigm. Because renewable energy output is variable, it yields a more dynamic energy supply equation in a system traditionally built to serve variable demand with centralized, dispatchable supply. As the characteristics of generators have changed overtime, the nature of cost causation has necessarily evolved as well. Cost causation has historically been a function of variation in demand. On the modern and future power system, however, cost causation is a

---

[1] *See* Xcel's response to CEO information request CEO-003, Attachment A CDM2025 PUBLIC. Figure 1 demonstrates Xcel's approach to allocating costs. This represents one way of looking at system costs. There are other ways to evaluate system costs such as assessing marginal costs.

[2] For examples, *See Generally,* Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). Electric cost allocation for a new era: A manual. Montpelier, VT: Regulatory Assistance Project.

function of variation in both demand and supply, and the overlap/imbalance between the two, also referred to as net load.

As renewable energy increases, the variability in net load will likely increase. Because of this, the ability of the demand side of the system to react, or be flexible, during severe system stress becomes increasingly important. Serving inflexible load, which does not react to temporal system conditions, becomes more expensive when compared to the traditional system. A more accurate and granular cost causation approach must therefore consider load shapes, or a customer's consumption throughout the day, season, and year. Customers, in turn, will face incentives to beneficially match their load profiles to specific needs of the power system by investing in adaptive technology.

Technological change

In a quickly evolving power system, new technology both upends the traditional supply-demand balance of the conventional grid and enables innovative consumer responses to those changes. As the falling costs of low-carbon generation contribute to higher levels of variable supply, customers can respond with their own technological investments for conserving energy or shifting consumption. A volumetric C&I TOU with CPP will provide customers an incentive to invest in technology that provides valuable system flexibility.

When compared to volumetric TOU rates with CPP, demand charges – even time-varying demand charges – do not send granular enough price signals to incent customers to invest in technology that can be used to flexibly address system needs when the system is under severe stress. Time-varying demand charges incent customers to manage monthly maximum demands. Once a customer has set a high monthly demand, that level of demand acts as a ceiling and the demand charge fails to provide an incentive to lower demand below the threshold set earlier in the month. Under Strategen's proposal, the volumetric TOU component always provides a strong incentive to manage demand throughout the month and during each TOU period. Then the CPP provides the additional flexibility of addressing infrequent, but very expensive, events where the system needs are greatest. Incenting customers to invest in technology that enables them to become grid resources when the system is under severe stress creates a significant value to both the customer and system. Strategen's proposal achieves this important objective.[3]

Consumer-side equipment for price-responsive energy management might include smart thermostats or energy storage. These technologies are sophisticated enough to manage sub-hourly load profiles; a smart thermostat can be programmed to respond autonomously to the price signals reflected in the rate structure, allowing customers to coordinate their real-time energy usage with the constraints on the grid. Likewise, energy storage can be configured to island customers from the grid, charge during off-peak hours with abundant renewables, or be used for self-consumption during high-demand periods, creating an incredibly flexible customer load. However, utilities must send customers an appropriate and granular price signal to encourage them to invest in energy management with capabilities that provide flexible benefits

[3] In Docket No. 18-643, the Commission ordered Xcel to "develop and propose a revised general service TOD rate that is more reflective of hourly system costs with a price signal designed to reduce peak demand."

to the power system. Time-differentiated price signals throughout the day paired with a dynamic critical peak pricing component will provide customers with such an incentive.

The technological investments used for energy management can have long payback periods, especially investments made by large customers. For that reason, it is important for the Commission to commit to an efficient rate structure and update it using a predictable and iterative process. Doing so will provide customers with certainty and some level of consistency. Incorporating a CPP component into the default General TOU Service tariff could lead to less frequent structural rate adjustments, given the CPP component's ability to send price signals at any time during the day and year. As TOU periods for volumetric or demand charges may require more frequent changes as temporal system needs change. The CPP component has no temporal limitation and can be called at any time in the year. Thus, customers will make long lasting technological investments to manage their use in response to the price signal they receive through the C&I TOU with CPP.

Load diversity and flexibility

Strategen's C&I TOU with CPP more strongly rewards load diversity and incentivizes customer flexibility than does Xcel's proposed design.

Load diversity is the "measurement of how different customers use power at different time of the day or year, and the extent to which those differences can enable sharing of system generation, transmission, or distribution capacity."[4] Comparing two general service customers can serve as an illustrative example of the importance of load diversity. Customer One has a flat load profile (i.e., very little load diversity) in the month of July, therefore consuming about the same amount consistently during the on-peak period throughout the month. Customer Two has a diverse load profile during on-peak periods but experienced one abnormally high hour that set its on-peak demand charge for the month.

The example demonstrates two important points. First, the probability that Customer One is going to consume during times of severe system stress is much higher than for Customer Two. Second, Customer Two could share on-peak capacity with other customers whose loads also vary throughout the month. These two issues should be reflected in rates. The C&I TOU with CPP reflects both issues in rates while time-vary demand charges do not necessarily.[5]

At a high-level, flexibility is the ability of and extent to which a customer can alter its load profile. For example, customers can demonstrate flexibility through pre-cooling before on-peak periods. Strategen's proposed C&I TOU with CPP strongly rewards this type of flexibility through large inter-period pricing ratios. Most importantly, customers can prove flexibility by responding to the CPP component of the proposed rate design. The CPP heavily rewards customers who do so, as quantified below, and therefore provides an enhanced bill control opportunity for all C&I customers.

---

[4] *See* Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era: A manual.* Montpelier, VT: Regulatory Assistance Project. At 261.

[5] *See* Jim Lazar, "Use Great Caution in the Design of Residential Demand Charges," *Natural Gas and Electricity Journal*, February 2016.

Achieving public policy goals

The price signal created through Strategen's C&I TOU with CPP proposal will aid Minnesota in achieving its ambitious clean energy goals in an equitable manner. Minnesota has many clean energy goals such as reducing peak demand, achieving high levels of variable renewable energy integration, incenting energy efficiency to the maximum reasonable extent, accelerating beneficial electrification, and efficiently integrating electric vehicles (EVs). Strategen's proposal will encourage customer-side investments in alternate energy solutions that align with the achievement of many of these goals. While this entire report focuses on why Strategen's C&I TOU with CPP will advance Minnesota's policy goals, we provide two specific examples here.

Peak Demand Reduction

The Commission has stressed that the updated General TOU Service tariff must have "price signals designed to reduce peak demand."[6] While an improved TOU volumetric rate is an important first step for aligning customer price signals with actual system costs, more granular price signals are needed to achieve significant peak reductions from the C&I class. For this reason, incorporating more targeted price signals using CPP is crucial for achieving the Commission's goal of reducing peak demand.

Strategen's proposal to include a default CPP rate component in the General TOU Service tariff may be able to contribute to Xcel's requirement 400 MW of demand response by 2023.[7] The Brattle Group recently conducted a load flexibility potential study for Xcel that found that large C&I customers had approximately 680 MW of demand response potential for an opt-out CPP program.[8] While Xcel's implementation process currently proposes that the new General TOU Service tariff begin in 2024, the Company is already rolling out AMI. For this reason, Xcel could either strategically deploy AMI meters to the General TOU Service class, given their limited numbers, or automatically enroll customers on the rate as AMI deployed.

---

[6] *See* Docket No. 18-643, Order Approving Pilots with Modifications, Authorizing Deferred Accounting, and Setting Reporting Requirements at 16-17. Filed July 17, 2019.

[7] Using the CPP component to meet the DR requirement would require a transparent evaluation, measurement, and verification process to be developed and approved by the Commission.

[8] *See* Docket No. 19-368, Appendix G2: Study: Potential for Load Flexibility at NSP (Hereinafter "Brattle Load Flexibility Study). The study found that an opt-out CPP demand response program would result in a 141.67 kW per participant "curtailment capability." Given that the General TOU Service tariff is a requirement for large customers, the 680 MW was derived by multiplying the curtailment capability by the total number of customers in the class. The study also found that the technical potential for Large C&I customers was limited to 64 MW. It is unclear in the report why the total technical potential for Large C&I customers differs from the sum of individual capabilities of a given customer type. In particular, the assumption made by Brattle that "all incremental potential estimates assume NSP's portfolio of existing programs continues to be offered as currently designed in future years, and that the 850 MW impact persists throughout the forecast horizon. Existing DR participants are excluded from the estimates of incremental potential" may be impacting the aggregate customer type technical potentials. Brattle Flexibility Study at 13, footnote 6. The reasonableness of this assumption was not supported in the report.

CPP achieves peak demand reductions by significantly raising electricity prices during specific hours of very high anticipated demand.[9] CPP provides granular, equitable price signals by relying on the utility to identify times of severe system stress and providing customers with sufficient notice that a CPP event will occur. Often, the general time period is predictable, for example between 3p.m. and 8p.m. on summer weekdays, but a utility will identify only a small number of critical events within that window per year. The utility will notify customers approximately 24 hours in advance of a predicted critical peak and it will be the customers' responsibility to lower their consumption. The C&I TOU with CPP provides reduced volumetric energy prices during non-CPP hours, which counterbalances the higher-priced CPP events. These CPP events have been piloted numerous times and have led to peak demand reductions of between 7 and 55 percent.[10]

Efficiently Integrating EVs

Under Xcel's proposed rate design, qualifying EV charging would be administered through the C&I TOU tariff. Xcel noted that, in some instances, EV chargers may trigger the "demand limiter provision" in the tariff.[11]

The demand limiter provision reads:

> *"a demand limiter that reduces the billed kW demand quantity as a protection for customers with very low load factors, which occur when a customer has very low total kWh energy usage relative to the level of their peak kW demand during a billing month. This is accomplished by limiting the billed kW demand quantity to the result of total kWh energy usage divided by 100-hour use, which represents a customer load factor under 14 percent. This process efficiently caps the billed average price per kWh, which is a reasonable and useful provision for EV charging and other applications that may operate at very low load factors".*[12]

The demand limiter prevents some specific EV charging facilities from incurring exceptionally high demand charges. However, while the demand limiter protects extremely low load factor customers, it may not be applicable to number of situations with EV chargers. For example, any customer with its own substantial load, such as a box store or other employer looking to offer charging, will not likely qualify for the demand limiter. For this reason, Xcel's proposal may limit EV chargers being added at customer sites that already have substantial load. This would not be the case under Strategen's proposal because the demand charges would be significantly lower.

---

[9] Like CPP, a Peak-Time Rebate (PTR) can also achieve peak savings during specific hours of very high anticipated demand. Instead of raising rates dramatically during that period, a utility will instead pay customers for reducing their consumption during the pre-specified time. This proposal recommends CPP over PTR because PTR is more administratively burdensome and complex, as it requires estimating what the customer's load would have been if not for the tariff. In Strategen's opinion, PTR is a more reasonable option for residential rate design, while CPP is a more reasonable for medium and large C&I customers due to the higher level of sophistication.

[10] *See* Faruqui, et. al., Time-Varying and Dynamic Rate Design.

[11] *See* Petition, Attachment C at 2.

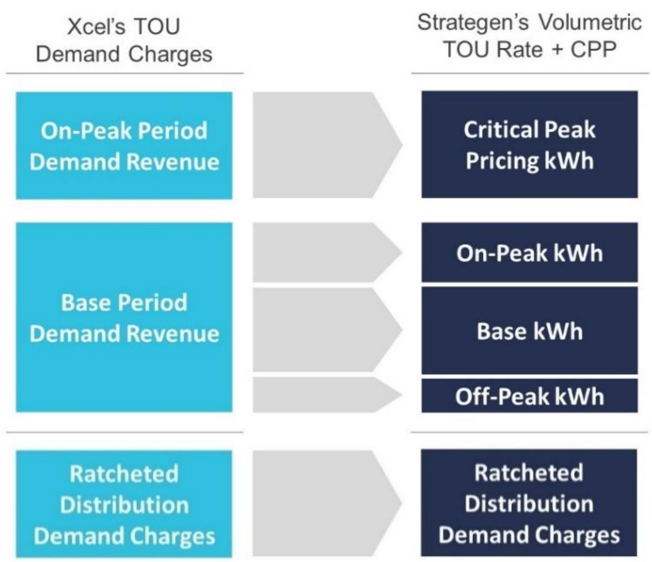
[12] *See* Petition at 13.

Methodology

Strategen was involved in designing Xcel's three-period residential TOU pilot in 2017 and produced a model that Xcel repurposed to develop its rate design proposal in this docket. Thus, Strategen's proposal contains many of the same methodological steps as that approved approach. In many aspects, Strategen and Xcel's C&I proposals share similar methodological underpinnings and approaches. Specifically, Strategen preserved the three TOU periods that Xcel proposed, along with the Company's ratcheted distribution demand charge and fuel cost allocation.

As depicted in Figure 2, the primary methodological difference between Strategen's and Xcel's proposals is how capacity-related generation and transmission costs are recovered through rates. While Xcel proposes to recover capacity-related generation and transmission costs through time-varying demand charges, Strategen recommends these costs be recovered through volumetric TOU rates and the CPP rate component.

Figure 2. Strategen's Methodology for Adapting Xcel's Proposed General TOU Service Rate



Collecting capacity-related generation and transmission costs through volumetric TOU rates and a CPP component for C&I customers was recently recommended by the Regulatory Assistance Project (RAP). The RAP report, Smart Non-Residential Rate Design, develops guiding principles for C&I rate design, discusses the underlying support for relying heavily on volumetric revenue collection, and ultimately recommends a similar C&I rate design to that proposed by Strategen in this docket.

Allocation of capacity-related generation and transmission costs

Strategen's approach recovers all capacity-related generation and transmission costs through volumetric rate components as opposed to demand charges.[13] Specifically, Strategen assigns all

[13] For the purpose of Strategen's proposal, the definition of capacity-related generation and transmission costs are those proposed to be collected through Xcel's proposed on-peak and base demand charges.

revenue that Xcel proposes to collect through its base period demand charges to the three volumetric TOU periods. This increases the magnitude of the TOU price differentials. The allocation of base demand charge costs to the volumetric periods was informed by the cost duration curve, Xcel's proposed TOU period ratios, and general rate design principles. The CPP component was created by allocating on-peak demand costs to the highest 75 hours of system stress.[14] Along with the volumetric TOU rates, Strategen recognizes that the CPP component may need to be calibrated in order to represent the appropriate number of critical peak hours and result in reasonable customer bill impacts.

Data limitations

Strategen's approach made use of the limited information provided by Xcel and that which was otherwise readily available. There are numerous potential approaches for allocating capacity-related generation and transmission to volumetric rate components. For example, RAP discusses allocating generation capacity costs using the baseload, intermediate, and peaking designations to low, mid, and peak TOU periods as a cost allocation approach.[15] This approach would require additional analysis and the associated data inputs, likely within a detail cost of service analysis, which Xcel declined to provide in this docket.[16] While additional data would have been nice to have, any alternative approaches would have been evaluated against the factors that Strategen took into account in this proposal and may not have had a significant impact on the proposed rate.

Additionally, Xcel's proposed rate is calibrated on a limited sample of C&I customers; only 80 customers were in the sample. Xcel's sample of 80 customers represents a small portion of the total customers on the General TOU Service tariff. While Strategen's rate was designed to be revenue neutral, the data limitations will require the rate to be interpreted as a structural recommendation. Furthermore, Strategen is open to considering modifications to their proposal, such as the number of hours available for CPP events and the noticed provided to customers. As with Xcel's own proposal, Strategen's proposed rate design will require calibration during the implementation process. An important consequence of the limited data is the effect it may have on both Xcel and Strategen's bill impact estimates. Given the need to calibrate both Strategen's and Xcel's rates, the bill impacts from these two rate proposals should be considered as best estimates that could vary. Further efforts to calibrate rates could be used to offset significant bill impacts.

Seasonal differentiation of volumetric TOU rates

It would further reflect cost causation to incorporate seasonal differentiation in the volumetric TOU rates. Xcel recognized that consumption during the summer and winter account for a greater portion of system capacity costs by differentiating its proposed time-varying demand charges by

---

[14] According to the Company's cost duration model, about 25% of system costs are caused by the top 75 hours of the year. The Brattle Group also selected the top 75 hours for C&I CPP program design in its study of load flexibility for Xcel in Docket No. E002/RP-19-368.

[15] *See* Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era: A manual.* Montpelier, VT: Regulatory Assistance Project.

[16] *See* Xcel's response to CEO information request CEO-004.

season. The Company also proposed to collect no peak demand charges during the fall and spring months.

Strategen implicitly proposes seasonal differentiation for on-peak costs, through its CPP rate. CPP charges collect on-peak costs during the top 75 hours of system needs. Because these hours can occur at any point during the year, the CPP is seasonal in nature. Although Strategen effectively collects the on-peak costs seasonally, there remain generation and transmission capacity costs that are distributed evenly throughout the year through the proposed volumetric rates. Therefore, seasonally differentiating Strategen's proposed TOU rates could be a reasonable step to further increase granularity and align rates with cost causation.

However, data limitations made it difficult to propose a revenue-neutral, seasonally differentiated volumetric TOU rate. More granular cost data would have been useful for the purpose of seasonally differentiating to a greater degree. For example, data on utilization of generation assets during different seasons would be useful.

Lastly, Xcel did not provide justification for its own seasonal differentiation or any significant discussion of its approach. Therefore, a better understanding of Xcel's approach to seasonal differentiation would also be helpful before modifications are proposed.

Bill and revenue impacts

Bill impacts

Strategen's proposed C&I TOU with CPP sends a stronger price signal compared to Xcel's proposed time-varying demand charges. Therefore, the bill impacts – at least for the 80-customer C&I sample for which Xcel provided data – reflect more variability than Xcel's proposal.[17] The histogram in Figure 3 presents annual rate change percentages under the two proposed rate designs compared to the current C&I rate.

[17] Strategen calculated bill impacts using a similar methodology to Xcel. Importantly, bill impacts assume no change to consumption patterns or behavior response to price signals.

Figure 3. Count of Bill Impact Magnitude by Rate Structure

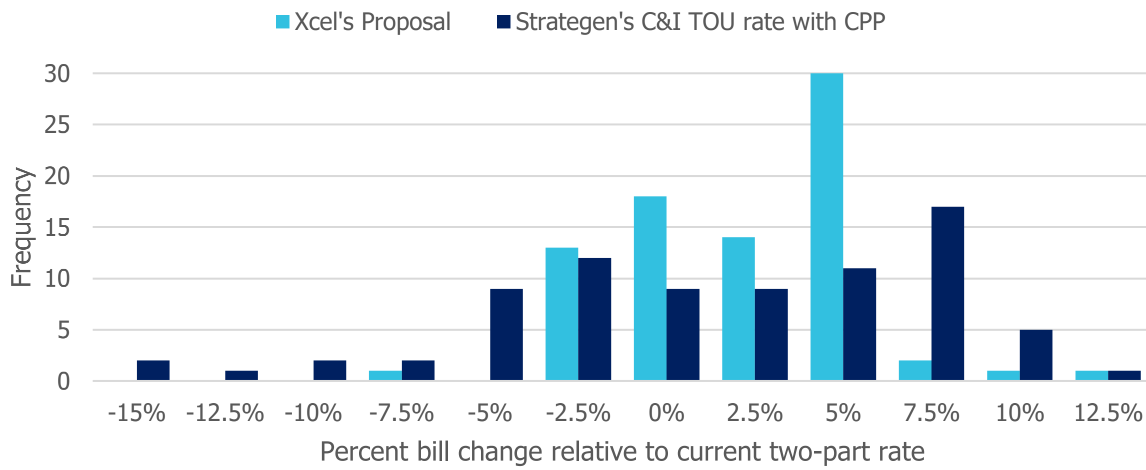
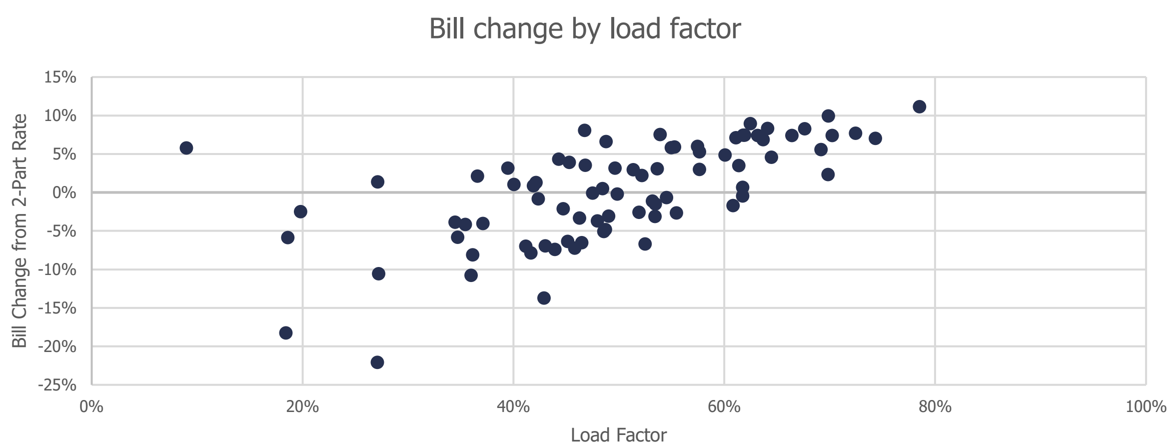


Figure 3 demonstrates that there is a broader spread of rate impacts under Strategen's proposal compared to Xcel's. Although both proposals are revenue neutral, both bill impact distributions are right-skewed because the rate changes impact some types of customers differently than others.

Figure 4 reveals another way that Strategen's proposal impacts customer types differently, juxtaposing bill change and load factor.[18]

Figure 4. Bill Impact by Load Factor



The figure shows that high load factor customers generally experience greater bill increases than low load factor customers. This result recognizes that load diversity is rewarded through the C&I TOU with CPP more than under the current rate structure.

High load factor customers

Under the traditional electric system structure, customers with steady, constant demand were once desirable. They were desirable because traditional generation operated in a way that made

[18] Xcel's proposal has similar bill impacts related to customer load factors and average load.

serving this type of load more cost-effective than highly variable load. An important metric for electric system efficiency was customer load factor, or the ratio of total energy used in a billing period to the total possible energy consumption if usage remained constant at peak demand. A high load factor signified efficient electrical usage, while a load factor below 0.5 meant periods of higher demand with a low overall utilization rate. Under this paradigm, consistent usage was better for the grid than spiky demand. However, with the increase in variable generation, load shape has become a more important metric than load factor. A customer's ability to alter its load profile makes it flexible and therefore more valuable to the electric grid than those with inflexible load.[19] Indeed, the Minnesota Public Utilities Commission has recently acknowledged the importance of focusing on net load factor – i.e., load factor for load net of variable generation – over load factor in the performance metrics docket.[20]

Strategen's proposal could have a significant initial impact on customers with high and consistent energy usage because it relies on higher proportions of volumetric revenue recovery relative to demand charge-based revenue recovery. Some high load factor customers may be able to shift their energy consumption to the off-peak period or flex during times of severe system stress. Others may not be able to significantly lower their energy consumption during peak and shoulder hours of the day and may not have a flexible load that enables them to respond to CPP signals. The differences in these customers' load profiles and individual flexibility should be accurately reflected through rates because otherwise these costs are shifted to other customers.

The high load factor bill impacts highlight two issues related to cost causation. First, high load factor customers cannot share generation and transmission capacity with other customers due to their lack of load diversity. Strategen's rate addresses this by having high load factor customers always pay for generation and transmission capacity, including off-peak. Second, as noted above, a significant amount of system costs are caused in only a few hours of severe system stress throughout a year. Only very granular price signals, such as our CPP component, can accurately align this cost causation with rates. If high load factor customers consume during times of severe system stress, they should pay more. If not, they should pay less. Strategen's proposal addresses both cost causative issues, while Xcel's does not.

Finally, high load factor customers may have access to capital that they can invest in more efficient appliances and equipment. Providing granular and robust price signals will incent these customers to make investments that benefit the system and minimize their bills. To maximize this effect, a C&I rate design should be coupled with a strong C&I DSM portfolio that focuses on modern industrial efficiency programs (e.g., continuous improvement and strategic energy management with customized solutions over prescriptive measures and focus on automation and controls).

Customer bill control

[19] *See* Linvill, et. al. Smart Non-Residential Rate Design Optimizing Rates for Equity, Integration, and DER Deployment at 11.

[20] *See* Order Establishing Methodologies and Reporting Schedules. April 16, 2020. MN Public Utilities Commission. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b003B8471-0000-C210-BAEF-1348A8CCCEF3%7d&documentTitle=20204-162148-01.

Strategen's C&I TOU with CPP provides customers a high degree of control over their bills.

Figure 5 shows the bill savings that four of Xcel's high load factor customers – selected from the 80 total customer profiles that Xcel provided – can achieve through energy management.[21] This analysis simulates the results if each customer shifted 5% or 15% of its on-peak consumption to off-peak hours, or if each customer shaved 15% or 30% of its load during the 75 higher-priced CPP hours.[22] The results of the scenarios are presented as reductions in the bill increases resulting from Strategen's proposal.

Figure 5. Potential Bill Savings from Energy Management for Different Load Factor (LF) Customers

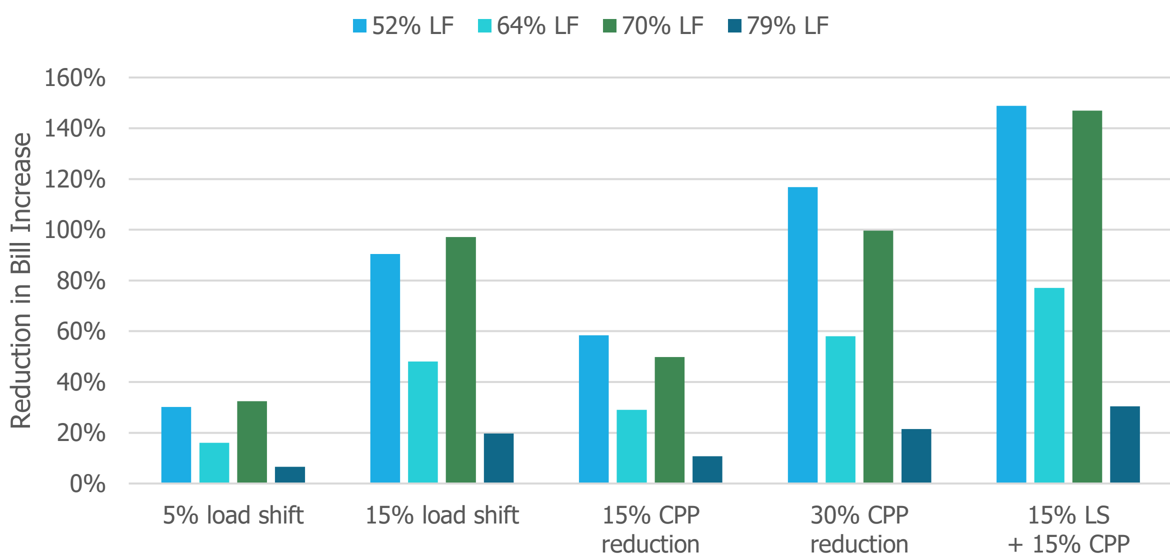


Figure 5 demonstrates that high load factor customers can modify their behavior and reduce, or eliminate, the bill impact created from Strategen's proposal. For example, the customer with the 52% load factor had a $1,683, or 2.22%, annual bill increase from Strategen's proposal. If that customer were to shift 15% of its on-peak consumption to the off-peak period, it would reduce that initial bill impact by 90%, or $1,522. If that customer were to reduce its peak demand by 30% during the highest 75 system load hours of the year, it would not only negate its entire original bill impact; it would also yield additional savings compared to the current General TOU Service tariff. The customer could save even more if it manages enough demand during peak periods to combine load shifting and CPP approaches for an additive effect.

Revenue recovery

Volumetric revenue recovery sometime raises concerns regarding the utility's ability to collect its authorized revenue. RAP has challenged this notion, noting that demand charges are not inherently better than energy charges for revenue recovery.[23] Demand charges are more sensitive

[21] The bill impact results for Xcel's sample are provided in Appendix A
[22] Sensitivities for the analysis were informed by: Faruqui, et. al. Time-Varying and Dynamic Rate Design.
[23] *See* Linvill, et. al. Smart Non-Residential Rate Design Optimizing Rates for Equity, Integration, and DER Deployment at 19.

to external factors such as weather variation[24] that could dramatically affect the singular monthly peak. Demand charges are also susceptible to some of the same impacts as volumetric rates, such as economic downturn. In fact, C&I customers in North Carolina have recently requested a demand charge holiday in light of the novel coronavirus pandemic – a waiver that Duke Energy estimated would cost it $28 million over three months.[25] If the North Carolina Utilities Commission approves the petition, demand reduction would contribute to revenue shortfall alongside energy reduction.

Additionally, Xcel's C&I class was recently granted full revenue decoupling by the Commission.[26] Revenue decoupling will help to ensure that Xcel continues to collect its authorized revenue amount from the C&I class.[27]

---

[24] *See* Linvill, et. al. Smart Non-Residential Rate Design Optimizing Rates for Equity, Integration, and DER Deployment at 19.

[25] *See* "N.C. factories ask Duke Energy to waive charges during pandemic," Tribune News Service. May 1, 2020. https://www.greensboro.com/business/n-c-factories-ask-duke-energy-to-waive-charges-during-pandemic/article_1baaf184-04fa-5d04-9f06-2c5f3ff594fa.html.

[26] *See* Docket No. 19-688, In the Matter of Northern States Power Company d/b/a Xcel Energy for Approval of True-Up Mechanisms, Order Approving True-Ups and Requiring Xcel to Withdraw Its Notice of Change in Rates and Interim Rate Petition. Filed March 13, 2020.

[27] *See* Petition, Attachment B at 25 stating, "decoupling is essential to maintaining fixed cost recovery in the interim years between rate cases."

III. Xcel's C&I rate design proposal

Overview of the Company's proposal

Xcel proposes a General TOU Service tariff with four rate components: a monthly customer charge, time-differentiated energy charges, time-differentiated system demand charges, and a distribution demand charge. The energy and demand rates follow three daily pricing periods: peak, base, and off-peak. Demand rates also differ seasonally. The distribution demand rates are differentiated by voltage but not by time.

The rates and time periods are as follows:[28]

Table 2: TOU Periods and Energy Rates

Peak	3 p.m. to 8 p.m. on non-holiday weekdays	$0.05054 per kWh
Off-peak	12 a.m. to 6 a.m. every day	$0.00810 per kWh
Base	All other hours	$0.02686 per kWh

Table 3: System Demand Rates

	Summer (Jun-Sept)	Winter (Dec-Mar)	Shoulder (other months)
Peak	$6.25 per kW	$4.25 per kW	$0.00 per kW
Base	$8.75 per kW	$6.00 per kW	$6.00 per kW

Table 4: Distribution Demand Rates

Secondary Voltage	$2.00 per kW
Primary Voltage	$1.52 per kW
Transmission Transformed Voltage	$0.64 per kW

The energy rates collect variable generation costs, reflecting changes in wholesale locational marginal price at different times of day. The system demand rates collect generation and transmission capacity costs based on periods of high forecasted system load. Customers must pay the peak period rate per kW of demand during their highest monthly load occurring in the peak period; they pay the base rate per kW of demand during their maximum monthly load occurring in either the peak or base time periods. The Company provided the following example to illustrate the system demand billing:

[28] *See* Petition at 11.

Table 5: System Demand Billing Example[29]

	Customer 1	Customer 2
Monthly Max Demand Time	Wednesday, Jan. 15 4 p.m.	Wednesday, Jan. 15 11 a.m.
Monthly Max Demand	1,000 kW	1,000 kW
Peak Billing Units	1,000 kW	876 kW (1/7 @ 5 p.m.)
Base Billing Units	1,000 kW	1,000 kW
Peak Billing Charge	$4,250	$3,723
Base Billing Charge	$6,000	$6,000
Total System Demand Charge	**$10,250**	**$9,723**

In the above example, Customer One hits its monthly maximum demand during the on-peak period, meaning that its 1000 kW maximum applies to both the on-peak and base period rates. Customer Two, however, hits its monthly maximum demand during the base period, meaning that its 1000 kW maximum applies only to the base period rate, while its on-peak period maximum, of 876 kW, applies to its on-peak period rate.

The distribution demand rates collect distribution-related costs at all levels of the distribution system. Xcel proposes to bill the distribution demand rate based on ratcheted non-coincident peak, i.e. based on an individual customer's highest kW demand over 12 months.

Xcel proposes to establish a revenue true-up mechanism and customer bill protection provisions as ways to mitigate significant rate changes. The Company suggests establishing these features through a separate process once the Commission approves the General TOU Service tariff. Xcel also proposes allowing EV customers to access the new rate structure sooner than other demand customers.

Xcel's theoretical premise

Rate design goals

The Company's petition notes that the "primary goal of the new tariff is to more precisely align rates with the fixed and variable costs of providing electricity."[30] Categorizing electric system costs as "fixed" and "variable" does not contemplate many characteristics of the modern and future power system and leads to a gross oversimplification of cost classification. This oversimplification often treats fuel and other short-term marginal costs as variable (to be collected through kWh charges) and other investments as fixed (to be collected based on demand).[31] The application of the fixed and variable premise over-emphasizes short-term costs, and therefore revenue collection, and de-emphasizes long-term asset avoidance and overall system efficiency.[32]

[29] *See* Petition at 12.
[30] *See* Petition at 7.
[31] Xcel does not provide a definition of what it considers fixed versus variable, nor did the Company clearly distinguish the types of costs that are collected through each rate component.
[32] *See* Linvill, et. al. Smart Non-Residential Rate Design Optimizing Rates for Equity, Integration, and DER Deployment at 20.

In the modern power system, traditional fixed and variable costs no longer serve these set purposes and will not reflect cost causation if categorized as such for rate design. For example, wind and solar facilities would traditionally be considered fixed investments with very little variable cost. Informing rate design through the fixed and variable paradigm may lead to recovering wind and solar resources completely through system demand charges. However, utilities often invest in wind and solar to avoid fuel costs, which are traditionally considered variable. Xcel's "Steel for Fuel" campaign clearly acknowledges this substitution. By furthering the legacy concept of fixed and variable cost categorization, Xcel allows itself to carry over historic rate design structures that less effectively serve the modern power grid.

Xcel's proposed time-varying demand and energy charges

Xcel's proposal to refine its time-varying demand charges helps to align the class's rate with cost causation, as does its proposed volumetric TOU rate. An important question is about the extent to which Xcel's proposal will achieve policy goals and align customers' incentives with cost causation. Two of the primary goals of the updated C&I TOU rate are (1) reducing peak demand and (2) shifting load to off-peak hours. Xcel's proposal will not achieve these objectives to the same extent as Strategen's C&I TOU with CPP will.

By collecting more capacity related costs through the volumetric on-peak and shoulder TOU periods, Strategen's proposal provides a stronger incentive to consume during off-peak periods. While Xcel proposes a low off-peak energy rate, the demand-charge component dampens the incentive for off-peak consumption.

The time-varying demand charges will not incentivize customers to the extent of the CPP component to invest in technology that provides system flexibility. The time-varying demand charges incent a less granular type of energy management that provides less benefit to the power system.

Additional issues

Xcel's limited customer engagement process

Xcel supports its rate design petition with the results of a customer engagement process comprising two customer engagement sessions and an informal survey. The Company cites customer concerns regarding shifting load to off-peak hours, price impacts for high load factor customers, and customers' desire for bill protection against transitional bill increases.

These claims about customer preference and behavioral change are based on a survey of just **eight** large customers.[33] Relying on this source of customer input would project the priorities of only eight, very large customers onto the entire TOU C&I Demand tariff, which serves roughly 4,800 customers. The results of these customer engagement sessions and surveys do not appear representative of Xcel's TOU C&I Demand class and should not be the only customer feedback relied upon to inform rates.

[33] *See* Xcel's response to CEO information request CEO-007, Att A-TOU Survey Results 091719

Fuel cost allocation

Xcel's current fuel cost allocation is based off the current structure of the General TOU Service tariff. The current tariff has only two time periods; on and off peak. Instead of creating new fuel cost estimates that are divided into three periods, Xcel subjectively created a proportion split from the two-period design to create a three-period design. This approach is likely inaccurate and does not reflect cost causation. There should be additional analysis conducted on Xcel's fuel clause allocation, and it should be reconstructed to provide better price signals, reflect the underlying fuel cost variations, and align with the three TOU periods for C&I customers.

Distribution demand charges

Xcel's distribution demand charge collects most the Company's distribution system costs, including distribution substations and primary distribution system.[34] In future iterations of the class's rate design, only local, customer-specific distribution system facilities should be collected through the distribution demand charge: those facilities include service line, transformer, and secondary distribution facilities. Primary distribution and substation costs should not be collected through the distribution demand charge unless they are customer specific.

[34] *See* Xcel's response to CEO information request CEO-019.

IV. Conclusion and recommendations

Power system's needs are changing rapidly due to the high levels of clean renewable energy being brought onto Xcel's and the regional grid. This transition creates a need to send clear and strong price signals to sophisticated customers to promote demand reduction and load shifting.

Strategen's C&I TOU with CPP improves upon the Company's General TOU Service proposal by establishing more granular and cost-reflective rates that will produce electric system benefits and achieve policy goals. Strategen improves price signals to large customers by recovering on-peak capacity costs through a critical peak pricing component and the remaining generation and transmission capacity costs through increased TOU volumetric rates. Table 1 displays Strategen's recommended rate design structure by component.

Strategen also recommends that the Commission adopt the following:

- Require the Company to modify the approach to fuel cost allocation to conform to the newly approved General TOU Service tariff in its next rate case;
- Require the Company to file testimony on the costs that it recovers through its distribution demand charge in its next rate case; and
    - As part of the testimony, require the Company to file a distribution demand charge that collects only local and customer-specific distribution system facilities.

Strategen appreciates the opportunity to file its proposed C&I TOU with CPP rate and looks forward to further collaborating with stakeholders on this important rate design.

V. Appendix

Appendix A. Bill Impact Calculations

Customer	Load Factor	Current 2-Part Bill (Annual)	$/MWh	Proposed 3-Part Bill (Annual)	$/MWh	Percent Change
1	37.1%	$ 15,058.96	$ 92.17	$ 14,450.48	$ 88.44	-4.0%
2	41.7%	$ 326,584.70	$ 96.26	$ 300,930.65	$ 88.70	-7.9%
3	55.3%	$ 285,862.53	$ 77.06	$ 302,712.58	$ 81.61	5.9%
4	42.4%	$ 642,474.47	$ 88.50	$ 637,028.38	$ 87.75	-0.8%
5	60.8%	$ 581,148.79	$ 86.86	$ 571,283.26	$ 85.39	-1.7%
6	36.0%	$ 201,509.50	$ 99.62	$ 179,845.96	$ 88.91	-10.8%
7	63.7%	$ 22,327.87	$ 74.93	$ 23,863.59	$ 80.08	6.9%
8	27.1%	$ 164,708.17	$ 104.43	$ 128,372.14	$ 81.39	-22.1%
9	64.5%	$ 239,617.18	$ 77.99	$ 250,575.70	$ 81.56	4.6%
10	53.6%	$ 12,001.14	$ 82.93	$ 12,373.00	$ 85.50	3.1%
11	54.5%	$ 37,806.21	$ 84.21	$ 37,549.23	$ 83.64	-0.7%
12	46.3%	$ 281,489.65	$ 91.11	$ 272,115.08	$ 88.08	-3.3%
13	69.2%	$ 21,300.30	$ 75.30	$ 22,489.96	$ 79.51	5.6%
14	61.9%	$ 192,019.56	$ 74.24	$ 206,324.65	$ 79.77	7.4%
15	42.1%	$ 137,423.38	$ 86.42	$ 139,180.96	$ 87.53	1.3%
16	39.5%	$ 160,438.69	$ 86.28	$ 165,512.68	$ 89.00	3.2%
17	48.0%	$ 331,421.44	$ 91.81	$ 319,170.91	$ 88.42	-3.7%
18	52.2%	$ 75,639.28	$ 81.58	$ 77,322.15	$ 83.39	2.2%
19	27.1%	$ 1,810.89	$ 105.12	$ 1,835.72	$ 106.57	1.4%
20	45.8%	$ 360,617.55	$ 90.15	$ 334,487.08	$ 83.62	-7.2%
21	61.7%	$ 635,564.17	$ 81.60	$ 639,725.36	$ 82.13	0.7%
22	41.9%	$ 118,516.23	$ 88.47	$ 119,545.64	$ 89.24	0.9%
23	34.5%	$ 24,601.36	$ 94.05	$ 23,655.52	$ 90.44	-3.8%
24	67.6%	$ 329,416.41	$ 75.12	$ 356,691.17	$ 81.34	8.3%
25	51.4%	$ 293,035.28	$ 80.29	$ 301,711.53	$ 82.66	3.0%
26	48.8%	$ 341,648.99	$ 78.65	$ 364,192.87	$ 83.84	6.6%
27	60.1%	$ 272,837.98	$ 76.12	$ 286,159.94	$ 79.84	4.9%
28	49.8%	$ 263,029.26	$ 85.24	$ 262,518.66	$ 85.07	-0.2%
29	27.2%	$ 252,998.10	$ 105.42	$ 226,266.39	$ 94.28	-10.6%
30	74.4%	$ 119,623.67	$ 74.92	$ 128,030.46	$ 80.19	7.0%
31	43.9%	$ 340,162.58	$ 95.02	$ 315,009.75	$ 87.99	-7.4%
32	55.0%	$ 443,561.60	$ 76.80	$ 469,379.66	$ 81.27	5.8%
33	55.5%	$ 388,147.03	$ 84.78	$ 377,826.61	$ 82.53	-2.7%
34	18.4%	$ 12,213.36	$ 111.63	$ 9,983.40	$ 91.25	-18.3%
35	61.4%	$ 40,762.17	$ 79.61	$ 42,195.86	$ 82.41	3.5%
36	78.5%	$ 297,154.89	$ 70.94	$ 330,233.74	$ 78.83	11.1%
37	36.6%	$ 70,587.01	$ 84.13	$ 72,089.58	$ 85.92	2.1%
38	44.7%	$ 56,994.26	$ 79.82	$ 55,789.83	$ 78.13	-2.1%

39	46.8%	$ 191,789.08	$ 77.34	$ 207,289.46	$ 83.59	8.1%
40	62.5%	$ 245,756.39	$ 73.93	$ 267,747.53	$ 80.54	8.9%
41	42.9%	$ 313,177.98	$ 96.92	$ 270,224.18	$ 83.62	-13.7%
42	45.2%	$ 75,104.79	$ 92.34	$ 70,317.55	$ 86.45	-6.4%
43	52.5%	$ 385,451.31	$ 90.93	$ 359,688.28	$ 84.86	-6.7%
44	43.0%	$ 331,333.48	$ 94.47	$ 308,318.40	$ 87.91	-6.9%
45	53.2%	$ 68,034.51	$ 86.91	$ 67,284.16	$ 85.95	-1.1%
46	49.0%	$ 661,426.43	$ 89.06	$ 641,159.91	$ 86.33	-3.1%
47	66.4%	$ 152,449.82	$ 75.61	$ 163,757.43	$ 81.22	7.4%
48	9.0%	$ 107,520.27	$ 109.73	$ 113,726.84	$ 116.06	5.8%
49	48.6%	$ 526,518.28	$ 91.35	$ 499,775.96	$ 86.71	-5.1%
50	61.8%	$ 260,879.08	$ 75.97	$ 280,304.29	$ 81.62	7.4%
51	18.6%	$ 2,555.85	$ 101.76	$ 2,406.38	$ 95.81	-5.8%
52	57.7%	$ 274,228.22	$ 78.71	$ 288,682.05	$ 82.86	5.3%
53	34.7%	$ 676,691.73	$ 89.47	$ 637,368.31	$ 84.27	-5.8%
54	63.2%	$ 362,375.36	$ 73.37	$ 389,201.27	$ 78.80	7.4%
55	49.6%	$ 63,556.59	$ 81.38	$ 65,568.11	$ 83.95	3.2%
56	69.9%	$ 254,540.17	$ 72.76	$ 279,798.31	$ 79.98	9.9%
57	53.4%	$ 504,300.21	$ 88.11	$ 488,511.27	$ 85.35	-3.1%
58	57.6%	$ 636,367.02	$ 80.88	$ 655,507.77	$ 83.32	3.0%
59	51.9%	$ 87,416.21	$ 87.59	$ 85,183.91	$ 85.35	-2.6%
60	19.8%	$ 169,666.13	$ 104.81	$ 165,459.35	$ 102.21	-2.5%
61	35.4%	$ 255,648.50	$ 93.89	$ 245,011.78	$ 89.98	-4.2%
62	46.8%	$ 197,601.15	$ 85.56	$ 204,575.71	$ 88.58	3.5%
63	48.7%	$ 642,362.18	$ 88.71	$ 611,332.52	$ 84.42	-4.8%
64	64.1%	$ 265,002.34	$ 75.13	$ 287,040.43	$ 81.38	8.3%
65	46.5%	$ 411,300.33	$ 92.97	$ 384,396.12	$ 86.89	-6.5%
66	53.9%	$ 450,028.11	$ 75.85	$ 483,963.98	$ 81.56	7.5%
67	36.2%	$ 14,928.37	$ 92.37	$ 13,719.28	$ 84.88	-8.1%
68	72.5%	$ 340,355.50	$ 74.34	$ 366,503.16	$ 80.05	7.7%
69	70.3%	$ 58,443.05	$ 74.42	$ 62,776.61	$ 79.94	7.4%
70	48.5%	$ 22,558.24	$ 84.32	$ 22,671.19	$ 84.75	0.5%
71	61.1%	$ 298,316.31	$ 76.76	$ 319,567.84	$ 82.23	7.1%
72	69.9%	$ 1,320,433.26	$ 79.06	$ 1,351,037.49	$ 80.89	2.3%
73	41.2%	$ 418,306.87	$ 96.59	$ 389,154.44	$ 89.86	-7.0%
74	57.5%	$ 180,970.95	$ 78.31	$ 191,809.03	$ 83.00	6.0%
75	45.3%	$ 11,967.16	$ 79.74	$ 12,433.46	$ 82.85	3.9%
76	44.3%	$ 165,255.19	$ 84.16	$ 172,409.64	$ 87.80	4.3%
77	40.1%	$ 47,196.50	$ 82.50	$ 47,681.07	$ 83.35	1.0%
78	47.5%	$ 555,928.73	$ 86.12	$ 555,468.42	$ 86.05	-0.1%
79	61.8%	$ 315,481.79	$ 83.08	$ 314,073.67	$ 82.71	-0.4%
80	53.5%	$ 196,534.69	$ 82.48	$ 193,619.46	$ 81.26	-1.5%

Appendix B. RAP Non-Residential Rate Design Principles[35]

1. The service drop, metering, and billing costs should be recovered in a customer fixed charge, but the cost of the proximate transformer most directly affected by the non-coincident usage of the customer, along with any dedicated facilities installed specifically to accommodate the customer, should be recovered in a non-coincident peak (NCP) demand charge.

2.1 De-emphasize NCP demand charges except as noted in NR Principle 1. All shared generation and transmission capacity costs should be reflected in system-wide time-varying rates so that diversity benefits are equitably rewarded.

2.2 Shift shared distribution network revenue requirements into regional or nodal time-varying rates. This recognizes that some costs are required to provide service at all hours, and that higher costs are incurred to size the system for peak demands.

2.3 Consider short-run marginal cost pricing signals and long-run marginal cost pricing signals together in establishing time-varying rates for system resources.

2.4 Time-varying rates should provide pricing signals that are helpful in aligning controllable load, customer generation, and storage dispatch with electric system needs.

2.5 Non-residential rate design options should exist that provide all customers with an easy-to-understand default tariff that does not require sophisticated energy management, along with more complex optional tariffs that present more refined price signals but require active management by the customer or the customer's aggregator.

2.6 Optimal non-residential rate design will evolve as technology and system operations matures, so opportunities to revisit rate design should occur regularly.

[35] *See* Linvill, et. al. "Smart Non-Residential Rate Design Optimizing Rates for Equity, Integration, and DER Deployment". Regulatory Assistance Project (RAP). At 3.

About Strategen

Strategen is an internationally recognized, mission-driven, professional services firm focused on energy sector market transformation for a low carbon grid. Our multidisciplinary team specializes in work with policymakers and regulators, utilities, and unregulated market participants on issues related to zero carbon grid technologies such as energy storage, solar, wind, electric vehicles, demand response and energy efficiency. Our functional expertise includes technical analysis, economic analysis, regulatory thought leadership, and corporate strategy, as well as ability to leverage our thought leadership platform in ways that motivate and empower local leadership and change.

Ron Nelson
Director

+1 (510) 679-1976 | rnelson@strategen.com

STRATEGEN
strategen.com

Ron is a Director in the Government and Utility Practice at Strategen. He works with clients to improve regulatory structures in order to more efficiently achieve public policy goals. Additionally, Ron provides expert testimony on numerous topics including multi-year rate plans, performance incentive mechanisms, cost of service modeling, residential and commercial rate design, renewable energy program design, and electric vehicle policy.

Education

BA, Environmental Economics, Western Washington University, 2011

MS, Agricultural and Resource Economics, Colorado State University, 2013

Domain Expertise

Regulatory Strategy

Rate Design

Performance-Based Regulation

Performance Incentive Mechanisms

Cost of Service Analysis

DER Compensation

Rate Case Support

Electric Vehicles

Renewable Energy Program Design

Expert Testimony

Pennsylvania Power and Light, DER Management Plan, P-2018-3010128

Public Service of New Hampshire d/b/a Eversource, Petition for Permanent Rate Increase, Docket No. DE 19-057

Oklahoma Gas & Electric, Formula Rates and Rate Design, Docket No. 201800140

Experience

Director
Strategen – Portland, OR
January 2018 – Present

Designing policies and programs to advance deployment of distributed energy resources, demand-side management programs, energy storage and grid integration.

Economist
Minnesota Attorney General's Office – St. Paul, MN
July 2013 – December 2017

Provided expert testimony on cost of service modeling, rate design, grid modernization and utility business models. Analyzed issues related to conservation incentive programs, value of solar, grid modernization, performance-based regulation, renewable energy program design, and MISO.

Economic Research Associate
U.S. Geological Survey (USGS) – Fort Collins, CO
February 2012 – August 2013

Analyzed the ongoing impact of the 2011 drought in Colorado. Wrote and obtained grants, set and managed their budgets, and delivered final research projects.

Graduate Research Associate
Colorado State University – Fort Collins, CO
August 2011 – July 2013

Analyzed the ongoing impact of the 2011 drought in Colorado. Wrote and obtained grants, set and managed their budgets, and delivered final research projects.

Economic Research Assistant
Washington State University – Mount Vernon, WA
August 2011 – July 2013

Developed a payment for ecosystem services program for The Nature Conservancy. Responsible for establishing ecological metrics that could be monetized into economic benefits and estimating the benefits and costs to farmers.

Caroline Palmer
Regulatory Consultant

+1 (510) 369-5932 | cpalmer@strategen.com

STRATEGEN
strategen.com

As Regulatory Consultant at Strategen, Caroline supports clients in regulatory proceedings, including electric utility cost of service and rate design, avoided cost methodology, and distributed generation interconnection and planning. Caroline has expertise in energy and environmental economics, electric power systems, consumer advocacy, and policy analysis.

Education

MPP, Energy Policy, University of CA, Berkeley, 2019

BSFS, Science, Tech., & Int'l Affairs, Georgetown University, 2013

Domain Expertise

Regulatory Strategy

Energy Economics

Policy Analysis

Utility Cost of Service

Wholesale Market Design

Transportation Electrification & Infrastructure

Renewable Energy Policy Design

Publications & Speaking

Using Low Carbon Fuel Standard Proceeds from EV Adoption to Improve the Efficiency of Electricity Rates". *Berkeley Public Policy Journal*. September 2019.

Integration of renewable energy in Greek energy markets: A case study". 2nd HAEE International Conference. May 2017

Experience

Regulatory Consultant
Strategen – Berkeley, CA
July 2019 – Present

Fostering the market ecosystems necessary to scale clean energy technologies for the benefit of all electric consumers.

Clean Energy Fellow
Metropolitan Area Planning Council – Boston, MA
February 2017 – July 2017

Provided technical assistance to Massachusetts local governments on renewable energy technology and energy planning. Authored white paper on clean heating and cooling technologies, policies, and opportunities for municipalities.

Fulbright Research Fellow
Fulbright Foundation – Athens, Greece
August 2015 – June 2016

Designed and conducted original, independent research on renewable energy policy-making and implementation in the context of Greece's severe economic crisis.

Analyst
Meister Consultants Group (now Cadmus) – Boston, MA
January 2014 – June 2015

Performed research and writing for renewable energy policy design, analysis, and implementation.