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Review of SaskPower Capacity Reservation Service (CRS) Rates

Report prepared for SaskPower

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1 INTRODUCTION

SaskPower has introduced, on an interim basis, a new Capacity Reservation Service (CRS) that is mandatory for Power Class customers served through customer-owned transformation (Rate Codes E22/E22/E23) that self-generate the majority of their power requirements.[1] This new service addresses an inequity that will arise under SaskPower's existing rate structure if Power Class customers[2] adopt significant self-generation.

Under SaskPower's current rate setting methodology, rates are set for each customer class at the level necessary to recover causal costs of the class as determined by SaskPower's cost allocation model. The cost allocation model identifies the customer-related costs, demand-related costs and energy-related costs attributable to each customer class. SaskPower's rates are designed with the intent that the Basic Monthly Charge recovers the customer-related costs, the Demand Charge recovers the demand-related costs and the Energy Charge recovers the energy-related cost.[3]

Rationale for the Bary Correction in SaskPower's Rate Design

An anomaly has always existed in applying this rate design methodology since the demand charge, which is intended to recover the costs associated with meeting SaskPower's coincident peak demand, is billed on the basis of the customer's non-coincident peak demand (their Billing Demand). In the absence of a corrective measure, customers with a below-average coincidence factor[4] will pay a demand charge that is greater than the demand-related costs that are attributable to them. Customers with an above average coincidence factor will pay a demand charge that is less than the demand-related costs that are attributable to them. To correct for this anomaly, SaskPower uses an adjustment to its rate design called the Bary Correction.[5]

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1 The Applicability of the CRS is included in the CRS tariff sheet.

2 The current Power Class rate codes are E22, E23 and E24. The corresponding CRS rates that have been developed are designated as rate codes N22, N23 and N24.

3 See Appendix A for a more detailed discussion of SaskPower's rate design methodology

4 A customer's coincidence factor is the ratio of their coincident peak demand to its non-coincident peak demand. Hence, a customer with peak demand that coincides with the system peak will have a 100% coincidence factor. One with coincident peak demand that is 50% of its non-coincident peak demand will have a coincidence factor of 50% and, in the absence of a correction factor, will be paying its demand charge based on a billing demand that is double its coincident peak demand. It is the coincident peak demand that causes demand-related costs.

5 The Bary Correction would not be required if the Billing Demand were the customer's coincident peak demand. Coincident peak demand is rarely used by electric utilities as a billing determinant for several reasons. Measuring the coincident peak demand requires an advanced metering technology and, more importantly is vulnerable to gaming. Customer may attempt to anticipate the timing of the coincident peak demand of the system and reduce their demand at that time. This type of gaming results in some utilities using customer demand in multiple peak hours, rather than a single coincident peak hour.

Under the Bary Correction, a portion of SaskPower's demand-related costs are recovered through the energy charge rather than the demand charge. This adjustment results in billing that approximates the amounts that customers would pay if they were billed on the basis of their coincident peak demand using a rate that corresponded to the total demand related costs divided by the total system coincident peak demand. The reasoning behind this approach is that the higher a customer's load factor, the more likely it is that its non-coincident peak demand will be close to its coincident peak demand (i.e., the customer's coincidence factor will be close to 1.0). Furthermore, the higher the customer's load factor the greater their energy consumption for a given level of peak demand. As a result, by increasing the energy charge and decreasing the demand charge, the bills of higher load factor customer will be increased and those of lower load factor customers will be decreased, which will result in closer alignment with causal costs, assuming the coincidence factor of customers corresponds to their load factor.

Rationale for the Introducing CRS Rates

SaskPower has recognized that the Bary Correction creates an inequity in the case of customers with self-generation. This inequity was not an issue in the past since self-generation has not been an economic option for customers. In the absence of self-generation, there is no problem to address. However, as the economics of distributed energy resources (DERs)[6] become more attractive, it has become necessary to address this inequity. SaskPower is responding to this emerging issue by introducing CRS rates.

The inequity is a direct consequence of the Bary Correction which results in SaskPower recovering a portion of demand-related costs in the energy charge. As a result, when a customer that adopts self generation SaskPower will no longer recover the demand related costs that are embedded in that customer's energy charge that have been avoided. This under-recovery will occur although the causal demand-related costs will not decline if the customer is relying on SaskPower for backup power in the event of a planned or unplanned outage of its self-generation. If 100% backup is assumed for system planning purposes, the causal demand-related costs will not decline when a customer self-generates. This result is inequitable because cost recovery has shifted from the customers that adopt self-generation to those without self-generation.

Backup power will be required by any customer that has self-generation that is intermittent (e.g., solar or wind generation) or will experience planned and/or unplanned outages dues to periodic maintenance requirements or unexpected equipment problems. If customers want firm backup power, SaskPower must maintain capacity that is no less than would be required if the customer had no self-generation and purchased all its power from SaskPower. An equitable CRS rate design will reflect this reality.

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6 DERs included self-generation technologies such as solar, wind, CHP (combined heat and power) and natural gas fired generation, as well as other energy resources such as storage.

When are Causal Capacity Costs Reduced by Self-Generation?

Assuming a customer with self-generation wants SaskPower to provide reliable backup power for its self-generation capacity whenever required, SaskPower must view the customer's potential coincident peak demand as being equal to its actual total demand that is being met by its self generation and SaskPower supply. Hence, the causal demand-related costs associated with firm backup power equal the causal demand-related costs associated with conventional firm power. In terms of the planning and provisioning of generation, transmission and distribution capacity, the system must be designed to accommodate the customer's peak demand whether it purchases power from SaskPower all the time or only when its self-capacity is not available.

SaskPower can only avoid capacity-related costs if customers are prepared to have backup power provided by SaskPower available only on a curtailable basis. In other words, the customer would have to accept that SaskPower will not include the demand in its system planning. If customers are not paying the costs associated with the capacity required to provide firm backup supply (CRS), other customers will be subsidizing it.

Furthermore, it would be gaming the system[7] for a customer to accept curtailable service only because it believes that SaskPower will have the capacity to serve it in any case so that curtailment would only occur in a *force majeure* situation[8].

The Implication for CRS Rates

The per MW demand-related costs that are attributable to a customer that self-generates will be equal to the per MW demand-related costs as determined by SaskPower's cost allocation study. Since under the Bary Correction SaskPower under-recovers its demand-related costs in the demand charge, a customer that self-generates will avoid paying the full amount of its causal demand-related costs if the CRS demand charge is the same as the standard demand charge for the applicable customer class. To maintain equitable rates, the CRS demand charge should therefore be equal to the per-kV.A demand-related costs for the class, as determined by SaskPower's cost allocation study, without the adjustment using the Bary Correction.

A caveat on this approach is that if, at some time in the future, the number of customers with self-generation is sufficient to result in a diversity benefit for the aggregate coincident peak demand of reserve capacity customers under CRS rates, this diversity benefit should be recognized. The diversity benefit would be recognized by revising SaskPower's

[7] For example, if a firm customer decides to self-generate and it knows that the rest of SaskPower's load will not increase to the point that the unutilized capacity will be required to serve other customers, a customer that self-generates save money by requesting far less reserve capacity than it requires. Its SaskPower bills would be reduced although it would continue to have *de facto* firm reserve capacity.

[8] A *force majeure* is an unusual natural and unavoidable event that interrupts service in a manner that would interrupt service for firm service customers as well as CRS customers.

cost allocation model by adding CRS as a distinct class with demand-related costs being allocated to it based on the total coincident peak demand of the class.

The Implication of Reduced CRS Reservation Capacity Nominations

To avoid gaming, the demand of a customer that requests reserve capacity should be limited to the reserve capacity that has been contracted. Put differently, unless 100% backup is not required, it can be expected that the demand-related costs allocated to the Power Class customers will not decline[9] when self-generation is adopted. Otherwise the demand charge for other Power Class customers would have to be increased in order to recover fully the causal demand related costs of all Power Class customer classes.

Is the Need for CRS Rates Unique to SaskPower?

Regulated utilities across Canada and internationally are confronting challenges that are emerging as customers pursue opportunities to reduce their electricity bills by adopting alternatives to the traditional industry model where centralized generation supplies all customers through a single transmission/distribution grid. The basic issue is that the traditional electricity market model is being disrupted by technological innovations that are making distributed energy resources economic alternatives to utility supply at regulated rates. In its simplest terms, the challenge is that technology is transforming the electricity sector from a naturally monopolistic industry into a competitive industry.

While this transition is progressing at a pace that may not always appear to be making adaption an urgent priority, it is widely recognized that over the next decade or two it is likely that the electricity industry will transform as radically as the telecommunications industry has transformed over the past two decades.

From a public policy perspective, the most significant concern is the risk of stranded assets. Most of the assets of electric utilities are long lived assets, many with expected operating/physical lives in excess of 50 years. These assets are being amortized, with the costs being recovered in regulated rates over their expected physical life of the assets. It is highly probable that long before the cost of assets that are currently being put in place by electric utilities are fully recovered the cost of competitive alternatives such as solar, wind and gas- or hydrogen-based generation, supported by storage and small-scale backup generation, will cost less than the embedded costs of the grid-based power of the incumbent electric utilities. This scenario creates the risk of significant stranded assets.

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[9] The costs allocated to the Power Class will only decline if the annual peak demand declines. It is assumed that the Power Class customers with self generation will require backup power that will result in their peak demand being unchanged although their annual energy consumption will be reduced. If self-generation does not require backup power, the peak demand of these customers, and the Power Class, will decline. In this case, costs will be shifted to other classes in the cost allocation model and increased use of self-generation will result in costs being shifted to other classes. This cost shifting would result in higher rates for other customer classes.

The challenge is exacerbated by the conventional approach to public utility rate-setting with rates being based on the fully allocated embedded cost of the utilities. These costs are much higher than the marginal (or avoidable) costs of utilities; hence, costs do not decline to the same extent as load declines when customers self-generate. Given the cost structure of utilities, self-generation generally increases total societal costs since the cost of new self-generation typically exceeds the avoided cost of the utility due to the reduced demand for grid-based power.

When a customer self-generates, the action is referred to as bypass. When bypass results in increased total societal costs, it is referred to as uneconomic bypass. Economic bypass takes place when it results in reduced total societal cost. Demand side management (DSM) is another example of bypass, although it is not often characterized that way. As in the case of DSM, bypass is unlikely to be economic unless there are significant utility investments in traditional generation, transmission and/or distribution assets that can be avoided by adopting the supply alternative. The optimal mix of traditional utility supply assets, DSM and DERs, can be examined most comprehensively through an integrated resource planning (IRP) process.

What is the Timeframe for Designing Backup/CRS Rates for All Customer Classes?

Customers in any class that are considering an investment in self-generation will have difficulty making assessing their option meaningfully if they do not know what they will be required to pay for backup power over the lifetime of that their self-generation asset. Without that information they cannot determine the full lifetime cost of the alternatives available to them. Consequently, they risk basing their decision on SaskPower's current rate structure which could lead to making a choice that they later regret. In the view of Elenchus, customers deserve to be given as much information as possible about the future cost of backup service as soon as possible.

The electricity sector has already embarked on the transition to competition, with DERs serving as an integral supply resource. DERs will become increasingly prevalent both on a grid-connected basis and as stand-alone sources of supply, bypassing the grid. It is widely expected that as the natural monopoly of utilities such as SaskPower erodes due to the declining cost of innovative technologies, load loss will occur. This load loss may result in revenue losses that exceed the corresponding cost reductions by a wide margin since most of the costs of electric utilities are fixed. This scenario raises the spectre of either significant rate increases to offset the lost revenue or significant stranding of assets.

For electric utilities that are starting with 100% market penetration, their future sustainability is likely to rest on their ability to adopt effective strategies for customer retention, combined with the pursuit of new, profitable sources of revenue. The former telecommunications utilities that experienced a similar transition from a monopolistic to a competitive industry managed the transition very successfully.

Electric utilities have several competitive advantages that may enable them to weather the transition as successfully as the telecommunications incumbents did.

- The grid connection provides access to storage and backup without incremental investment; whereas, off-grid service will require new storage/backup assets.
- By integrating DERs into the grid at diverse downstream locations, the reliability of the grid can be improved further in the coming decades.

Nevertheless, making the transition to the utility of the future will be very disruptive in this industry which has been extraordinary stable for over a century. For example, utilities will be required to adopt new business models for their business lines that are vulnerable to competition. In particular, customer retention will require competitive pricing, which will require increased reliance on rates that are based on market considerations and marginal costs rather then relying exclusively on the traditional utility cost-based pricing methods that base rates on fully allocated historic costs.

Traditional utility rate-setting embeds significant intra-class cross-subsidies that result from treating equity as a central ratemaking principle. For example, postage stamp rates are adopted specifically to achieve equity between high-cost-to-serve and low-cost-to serve customers. Once customers have competitive options, however, customers for whom the cost of reliable self-generation options costs the least will be the first to defect from the grid. Grid defection will leave the full burden of the utility's fixed on the shoulders of the non-defecting customers.

It will be particularly important to ensure the customers that self-generate are not cross-subsidized by being undercharged of the causal costs of backup service. The comments through this report adopt cost-based CRS rates as the central principle for the design of those rates.

Elenchus has observed that self-generation is particularly attractive to commercial and industrial electricity customers because of economic, management and technology advancements. Additionally, extensive incentives for solar PV, the decreasing cost of solar panels, and increasing consumer demand for green labeling are increasing the uptake of solar PV. A large share of the technical potential for combined heat and power (CHP) resides not only for industrial customers but also in commercial buildings.

The primary existing self-generation technologies are photo-voltaic (PV) modules, aka solar panels; wind turbines; small natural gas and biomass-fuelled generators; combined heat and power (CHP) units, aka cogeneration; and ground-source heat pumps. Additional generation technologies that may become competitive with grid power before the existing assets of electric utilities such as SaskPower are fully depreciated include hydrogen fuel cells and micro modular nuclear reactors. It is generally expected that that the cost of these emerging options will decline significantly as the technologies mature and as the scale of production increases.

The customers of utilities can use these self-generation options to reduce or eliminate their demand for grid-based power. Currently, the most economic approach to adopting self-generation technologies is to use them to replace the customer's base load requirements or when self-generation is feasible or inexpensive. For example, since solar and wind power are intermittent, it can be cost effective to self-generate to replace grid power only when cost per kWh of self-generation is below the variable cost of grid power.

2 SaskPower's CRS Proposal

SaskPower has prepared a tariff sheet (page 4.0) that applies on an interim basis for Power Standard – Capacity Reservation Service. This section reproduces the text from the draft tariff sheet and provides the comments of Elenchus on the current drafting.

2.1 Applicability

The interim tariff sheet for Power Standard – Capacity Reservation Service states:

> *APPLICABILITY: To Power Class customers requiring capacity reservation who are served through customer owned transformation and attaining the majority of their power requirements through self-generation.*

Elenchus Comments

The inequities that SaskPower is seeking to address by introducing the CRS occur regardless of the level of self-generations. There is no conceptual rationale for limiting the applicability of CRS as described in the draft tariff.

With respect to limiting the applicability of CRS to Power Class customers, it should be noted that is only a matter of time until self-generation permeates all customer classes; hence, tariffs that are designed to recover the demand-related costs, as determined by SaskPower's cost allocation study, will be needed in the future. Establishing the terms and conditions for capacity reservations service (i.e., backup service) before self-generation becomes more prevalent will provide important information for customers considering an investment in self-generation in the future years.

Elenchus assumes that by specifying that the applicability of CRS is limited to Power Class customers who are served through customer owned transformation is included only because that inclusion of customer owned transformation is integral to SaskPower's definition of the class. In other circumstances this restriction would result in rates that are not equitable and would create uncertainty for Power Class customers who are not served through customer owned transformation.

Finally, Elenchus understands that limiting the applicability of CRS to Power Class customers "attaining the majority of their power requirements through self-generation" is intended to address the incentive for any Power Class customer with a high load factor to implement a small amount of self-generation in order to benefit from the lower energy rate that results from removing the Bary Correction for the CRS rate. However, unless the Bary Correction is eliminated from the rate design for the standard Power Class customers (E22/E23/E24) there will be an incentive for high load factor customers to adopt the minimum amount of self-generation necessary to qualify for CRS. This result cannot be avoided since the Bary Correction increases the energy charge applicable to this customer class. CRS rates would be attractive to a high load factor customer, to avoid the Bary Correction, so a low threshold may incent that customer to self-generate only to the threshold to avoid costs related to its contribution to the coincident peak.

To the extent that customers respond to these incentives, the level of cost recovery from different types of customers will be inequitable. Furthermore, the rate design can be expected to encourage uneconomic bypass of SaskPower. As SaskPower obtains more data of its CRS customers it will be able to delineate the costs to serve those customers from the costs to serve the related Power Classes. In the future SaskPower can include CRS customers as a separate class within its cost allocation study and apply appropriate load factors that reflect the characteristics of the customers within each class. The self-generation threshold in other jurisdictions is lower than 50%, most often it is 15%, although other jurisdictions typically do not have to consider the material differences between Power Class and CRS rates caused by the Bary Correction.

2.2 Recorded Demand

The interim tariff sheet for Power Standard – Capacity Reservation Service states:

> *Recorded Demand - Shall be the maximum kV.A demand registered during the current month's billing period.*

Elenchus Comments

This approach to measuring non-coincident peak demand is consistent with SaskPower's longstanding practice. It is also consistent with standard industry practice.

2.3 Reservation Capacity

The proposed CRS defines the Reservation Capacity as follows:

> *Reservation Capacity - The customer must nominate in writing the Reservation Capacity in kVA to be provided by SaskPower. The nomination shall provide details of how the Reservation Capacity was determined.*
>
> *In any month where the Recorded Demand exceeds the Reservation Capacity, the Reservation Capacity will increase to the level of the Recorded Demand. The Reservation Capacity will remain at this level until either the Recorded Demand*

exceeds the new Reservation Capacity or the customer nominates a new Reservation Capacity.

*The customer may submit a written request to **increase** the Reservation Capacity at any time. 12 months after the original nomination of Reservation Capacity or 12 months after any subsequent change to the Reservation Capacity, the customer may submit a written request to **reduce** the Reservation Capacity. Every request to change the Reservation Capacity should include details of how the new Reservation capacity was determined.*

ELENCHUS COMMENTS

The requirement for customers to "provide details of how the Reservation Capacity was determined" does not eliminate the incentive to nominate a Reservation Capacity that is less than the maximum demand that the customer may want to have available. The incentive for a customer to underestimate its actual requirement has at least two negative consequences.

First, an important purpose of the Reservation Capacity is to enable SaskPower to use this level of demand for the customer in its system planning, rather than the metered demand. If a Power Class customer's Reservation Capacity is understated, the peak demand value used by SaskPower will be lower than the actual capacity that it requires if the customer calls on its Reservation Capacity at a time that coincides with the system peak.

Second, since the purpose of the CRS rate design is to ensure that customers pay a share of the fixed capacity cost of the asset that are available to them, they pay the share of costs that reflects their actual requirement. Strategic nominations would result in the shifting of a portion of the costs of these assets to other customers both within the class and in other customer classes.

To illustrate the concern, a scenario can be envisioned wherein a Power Class customer has adopted a self generation technology that will have a planned outage every three years and could have an unplanned outage at any time. By justifying a minimal Reservation Capacity the customer would pay CRS charges that reflects it actual reserve requirement for only one year after each complete shutdown, while paying for less than its full requirement the rest of the time.

This incentive for customers to understate their actual reserve requirement can be easily avoided with a refinement to the proposed terms and conditions. There are at least two possible approaches.

One option would be to limit the customers demand to the Reservation Capacity. Hence, customers would not be required to justify the Reservation Capacity that they nominate. For example, they may nominate a Reservation Capacity that is less than their self-generation capacity if they are prepared to have access to only the capacity reserved in the event that their self-generation is entirely out-of-service. This would be a business decision based on the cost of having access to the lower capacity during an outage of their self-generation facilities.

Another alternative is to define any demand in excess of the Reservation Capacity as interruptible service. This approach would permit SaskPower to use the amount of the Reservation Capacity as the peak demand, while also allowing customers to have access to additional power if it is available. Since this service would not be a true interruptible service that would be an available resource to accommodate peak demand situations, the pricing of the additional power would include a premium that reflects an "overrun penalty". For example, some utilities charge 4x the demand rate for demand above the reserved capacity.[10]

In Elenchus view, relying on economic incentives to discourage gaming is far better than relying on the requirement that customers justify their nominated Reservation Capacity. Customers may have legitimate business reasons for wishing to nominate a Reservation Capacity that is significantly less than their self-generation capacity. In particular, they may be able to curtail their demand during self-generation outages at minimal cost to the business.

2.4 BILLING DEMAND

The interim tariff sheet for Power Standard – Capacity Reservation Service states:

> *Billing Demand – The monthly billing demand shall be the greater of the monthly Recorded Demand or the Reservation Capacity.*

ELENCHUS COMMENTS

Based on this description it appears that a Power Class customer that qualifies for CRS may be able to minimize its annual bill by nominating a Reserve Capacity that is significantly less than its actual maximum requirement. It would then be billed based on a billing demand that corresponds to the nominated reserve capacity until its actual demand exceeds the nominated Reserve Capacity. Its Reserve Capacity would then be increased to its higher actual demand for 12 months, after which it could again nominate a lower Reserve Capacity. This definition creates a risk that some customers could "game the system" by deliberately nominating a Reserve Capacity that is lower than its actual requirement.

SaskPower's protection against this type of gaming is that "the nomination shall provide details of how the Reservation Capacity was determined."

[10] See Appendix B.

2.5 RATES

The rates for CRS should be maintained at a level that is consistent with the customer-related, demand-related and energy-related costs per unit (customer, kV.A and kWh, respectively) as determined by SaskPower's current cost allocation model. SaskPower should create CRS classes within its cost allocation model after it has collected sufficient CRS customer load data to determine the costs caused by the class.

However, SaskPower should consider the sustainability of these rates in a market that will become increasingly vulnerable to competitive options. If SaskPower is at risk of grid defection, the issue of uneconomic bypass resulting from cost-based rates being higher than SaskPower's avoidable costs will merit consideration. From the perspective of SaskPower's customers, serving some customers at a rate that is below fully allocated costs, but above avoidable costs, will be preferable to grid defection.

3 OTHER MARKET DISRUPTION ISSUES

3.1 THE CHALLENGE OF GRID DEFECTION

SaskPower, like any other electric utility, has invested in its generation, transmission and distribution infrastructure based on long-term energy (MWh) and demand (MW) forecasts of the future requirements of its customers. Most of its assets have very long service lives and rates are designed to recover those costs over the life of the assets. Underpinning the utility model that has traditionally been used to meet the electricity needs of consumers is the expectation that the utility is a monopoly service provider; that is, all customers within the utility's service area obtain their power from the utility. Under this assumption, combined with the expectation that the aggregate demand for electricity will not decline in the long run, virtually all assets are expected to be used and useful throughout their service life. The stranding of assets will be limited to a few special circumstances, such as dedicated transmission and/or distribution assets that become stranded due to a plant closure.

A feature of the traditional "regulatory compact" is that utilities are permitted to charge rates that recover all of their prudently incurred costs. If an asset such as a power line is stranded due to a plant closure, for example, the costs associated with the stranded asset are generally included in the utility's total revenue requirement that is recovered in rates. The implication of this standard treatment of stranded assets is that the associated costs are recovered from all other customers through the utility's cost allocation and cost of service models. Similarly, the default approach to recovering the costs of assets that are stranded as a result of a customer's decision to self-generate would be to treat this loss of load in the same manner as the loss of load due to a plant closure. The utility's total costs would be allocated to customer classes using the established cost allocation model;

hence, rates for other customers would increase by the amount required to offset the net revenue loss due to the decision of a customer to self-generate.

This default approach raises unique policy questions, however, when a customer's decision to self-generate is the reason that the utility is experiencing a loss of revenue. From a policy perspective, the concern is that self-generation is a form of bypass of the utility. When a customer bypasses the service of a utility, it may constitute either economic bypass or uneconomic bypass. As noted earlier, uneconomic bypass increases the total costs of the electricity when the investment in self-generation is included.

At the present time, and for the foreseeable future, grid defection (i.e., a customer installing the facilities it needs to meet 100% of its power requirements at all times, thereby enabling it to disconnect from the grid) is unlikely to be economic for most customers and it is almost certain to constitute uneconomic bypass.

The customer perspective: Most customers require a reliable and consistent supply of power. Self-generation technologies that are intermittent (e.g., solar and wind) therefore require significant storage capacity in order to operate on a stand-alone basis. Furthermore, a stand-alone self-generation technology will typically require some form of backup power for periods of planned or unplanned outages. For these reasons, for the foreseeable future, few customers will choose to disconnect from the grid and forego the opportunity to rely on the utility for backup power to support its intermittent supply and outage periods.[11]

The utility perspective: A high proportion of the costs of utilities, such as SaskPower, are fixed costs. If there is significant grid defection, the loss of revenue for the utility (and saving to the customer) may be significant although the variable cost that can be avoided by the utility may be very small in comparison. For this reason, the cost savings for the utility will typically be small compared to the cost that will be incurred by a customer to go off-grid. This situation constitutes uneconomic bypass[12].

Uneconomic bypass occurs as a direct result of the standard approach to utility rate setting. Rates are set to recover fully allocated costs, the majority of which are the fixed costs associated with the embedded infrastructure of the utility. Furthermore, most of the utility's fixed costs are recovered through variable charges based on energy consumption (kWh) or demand (kW).

11 There are circumstances where customers will have a high tolerance for the limitations that are inherent in off-grid power solutions. In addition, it is expected that as the costs associated with self-generation and storage continue to fall, the economics of grid defection will improve for customers.

12 Economic bypass is most likely to occur in the case of a new load that may require significant incremental investment in new generation, transmission and distribution capacity to serve. This incremental investment will be avoidable if the customer bypasses the utility.

The cost allocation models used by utilities as a basis for rate design determine the average embedded cost of the utility's capacity-related costs. This unit cost is used to establish tariffs that recover the utility's total capacity-related costs from customers using kW as the billing determinant. The result is that each customer within a class pays a share of the total capacity-related costs based on its share of the utility's capacity that it requires. Since capacity is the aggregate demand that can be met by each element of the utility's generation, transmission and distribution infrastructure, this approach is an equitable way to recover the total cost of the utility, including its fixed costs.

Energy related costs are handled similarly. The total costs that are incurred to meet the total annual energy requirements of customers, which are mostly fixed, are converted into an average cost per kWh (or MWh) and customers are billed on the basis of their usage. If they reduce their annual consumption for any reason, their bill is reduced.

This equitable approach to rate setting and cost recovery has worked well in the past when aggregate energy consumption generally increased so that the average unit cost has remained relatively stable. The growing customer base and ever-expanding uses of electricity have been mitigated by conservation programs and the replacement of relatively inefficient products (e.g., incandescent lighting) with more efficient products (e.g., LED lighting), but the net result has not been significant excess capacity for most utilities. As a result, utilities have been able to continue to recover their fixed costs with variable charges that have been relatively stable. Nevertheless, it is readily apparent that any significant reduction in the billable quantities that are used to recover fixed costs will inevitably result in either significant rate increases or significant stranded costs.

The existing rate designs of most utilities uses variable rates to recover their fixed costs. This approach creates an incentive for customers to invest in self-generation technologies even when the adoption of these technologies constitutes uneconomic bypass. Self-generation is, in effect, an extreme case of a customer implementing conservation measures or of reducing its demand for any other reason, such as reducing the scale of its operations. When a customer reduces its demand and energy consumption for any reason other than self-generation, it simply pays the lower bill that results from the reduced level of demand and reduced energy charge. If it ceases operations and disconnects from the utility, the costs do not decline to the same extent as revenue lost. Under those circumstances, rates for other customers must be increased for the utility to achieve full cost recovery. Rate increases increase the incentive for more customers to bypass the utility, a result that is not sustainable in the long run. This feedback mechanism is often referred to as a "death spiral". As long as the erosion of load and revenue is small enough to reduce the rate of growth in demand, as opposed to driving a decline in total demand, the impact on the utility and other customers is not serious.

The reason that a reduction in demand as a result of the adoption of self-generation warrants different treatment is that from a public policy perspective, there is merit in the view that while self-generation that constitutes economic bypass will result in reduced total costs, self-generation that constitutes uneconomic bypass will create “winners” (i.e., customers that are saving money by adopting self-generation) and “losers” (i.e., the remaining customers who pay higher rates to offset the lost revenue that results from self-generation.

3.2 OVERVIEW OF BACKUP GENERATION RATES IN OTHER JURISDICTIONS

SaskPower’s Capacity Reservation Service rates are analogous to the backup or standby service rates offered by some other utilities.[13] The rate design methodology for CRS rates is closely aligned with the standard rate design methodology used for commercial rates for continuous service. It is consistent with rates faced by standby customers in jurisdictions that do not have specific standby rates but does not include the features of a typical standby rate. In particular, demand charges for reserved capacity are usually lower than demand charges for continuous service capacity since they include terms and conditions that result in these services having lower value to the customer.[14] This is not the case for SaskPower’s CRS due to elimination of the Bary Correction from the CRS.

Backup rate schedules often consider customers that self-generate only a portion of their requirements. These customers would have a certain level of continuous service demand, when the generator is functioning normally, and additional reserved demand for power during an outage. Standby customers that also take some continuous service face the same demand charges for that service as customers that take only continuous service (i.e., published rates). The demand charge for reserved demand is typically lower but the method of determining the lower reserved demand charge differs significantly.

A common principle of standby rate-setting is that it should not be assumed that all standby customers require service at the same time during the system peak. This is a reasonable principle if there is diversity in load profiles and type of generation of self-generation customers. If it is assumed that the total demand of standby customers will always be lower than the cumulative reserved demands, then the reserved demands would also have a lower coincident factor than comparable continuous service customers. Utilities with sufficient standby customer diversity do not need to plan for or make capacity investments to meet the cumulative reserved capacity since reserved capacity is inherently a low load-factor supply service. Reserved capacity does not cause the same magnitude of costs as continuous firm capacity so reserved capacity demand charges are typically lower than continuous demand charges.

[13] Appendix B provides more detail on the experience in other jurisdictions.

[14] In some cases, rates are lower due to market conditions. The financial impact on a utility is less if customers pay a discounted price for backup service as compared to receiving no revenue if the customers chooses to forego backup or make non-utility backup arrangements.

It is not clear that SaskPower will have a sufficient number of diverse CRS customers to allow it not to plan for and make capacity investments to support the supply of full backup demand at peak times. SaskPower may not be able to avoid capacity costs if there are only one or two large standby customers.

Some utilities determine the total demand-related cost of providing standby capacity and derive reserved demand rates by dividing that cost by cumulative reserved demand. A separate allocation to only standby customers is only possible when there are data from an established standby class or the utility can reasonably forecast the load characteristics of the whole standby class. Other utilities derive reserved capacity charges by making adjustments to established continuous service rates to reflect the lower expected coincident peak of reserved capacity.

In some jurisdictions, demand-related costs are separated into “local facilities” and “shared facilities”. Local facilities are facilities that are specifically installed to serve a particular customer’s maximum load and shared facilities are facilities that serve all customers. Customers are levied two demand charges, contract demand to recover the costs of the local facilities, and daily demand charges for shared facilities on the days standby service is taken. Daily demand charges are generally only charged for on-peak demand and are often calculated as a prorated share of monthly demand. This method requires sufficient excess capacity of shared facilities and a sufficiently diverse set of standby customers such that there is no risk of standby service causing total demand to exceed system capacity. Utilities generally maintain different on-peak and off-peak demand charges for as-used demand when the utility has separate on-peak and off-peak demand rates for continuous service.

The New York Public Service Commission’s guidelines on setting standby rates acknowledges that, though there are differences in the costs caused by standby customers and continuous service customers, utilities do not initially have sufficient data to determine standby rates that reasonably reflect cost causality or full cost recovery. It determined that applying rates that were consistent with standard rate design methodology would be appropriate until the costs caused by the standby class can be more carefully considered.

The use of the Bary Correction for firm service rates and standard methodology for CRS rates creates a substantial difference between SaskPower’s continuous and backup service rates that is not present for most utilities.

The CRS rates are the same whether backup service is planned or unplanned. Many utilities have different energy rates for planned and unplanned outages because unplanned outages typically cause the utility to incur higher costs. Furthermore, planned outages can be scheduled to occur outside of peak demand times; hence, unplanned outages are more likely to occur during system peaks.

The CRS rates are proposed to be eligible for Power Class customers with customer-owned transformation that self-generate a majority of their power requirements. The threshold is typically significantly lower than 50%. SaskPower's threshold should take into account the considerable differences between Power Class rates and CRS rate structures to avoid potential "gaming" of the system.

In many jurisdictions, customers must take standby power if self-generation is greater than 15% of a customer's maximum demand. Many utilities allow standby service for any customer, even residential customers that do not have demand meters. This is possible when rates are designed to reflect appropriate price signals so that customers prefer backup rates if and only if they take backup service.

4 Summary and Conclusions

4.1 Disruption of the Electricity Sector

It is widely recognized that the electricity sector's monopoly is eroding as DERs emerge as competition for traditional grid power. As costs for the competitive options continue to decline, load loss is inevitable. But partial load-loss is a minor problem compared to loss of customers; hence, while minimizing uneconomic bypass will reduce rate increases for utility customers, the most important issue for electric utilities in response to the disruption of the sector is likely to be customer retention.

Put differently, in the short run, the challenge for SaskPower is self-generation, which strands only generation, with the loss of net income being limited to the difference between energy rates and avoidable generation costs (fuel and purchased power) or energy rates and export value. But over a longer term, grid defection is likely to be the greatest threat. If there is partial or whole grid defection, assets/costs will be stranded. Rate design will not solve the problem. The only solutions are (i) customer retention (and new source of net revenue that can replace lost revenue) or (ii) exit fees.

The "correct" price signal for customers maintaining their connection to the grid would be based on marginal costs (as in competitive markets) rather than fully allocated costs (FAC). This approach would require pricing flexibility and either the ability to price discriminate or bundle regulated and competitive services as a means of recovering the utility's revenue requirement fully. These options raise concerns about anti-competitive practices. The solution is difficult.

However, a model to consider may be the telecommunications sector where the CRTC adopted a policy of forbearance from rate regulation in markets/services that are competitive. A similar forbearance model may be the only practical solution for the electricity sector, but this would also require rules that facilitate competition (interconnection, regulated prices for access by competitors to utility services, etc.).

Self-generation can be a risk or an opportunity for utilities. Competitive firms cover their fixed costs by offering a range of products. Conceptually, electric utilities could do the same thing: some services will have high margins, others lower margins when priced in response to market factors. Hence, for example, there could be low cost basic service beside valued services with higher margins such as enhanced "prosumer" information and green power. Utilities could also finance self-generation projects using long term rental/service contracts – the low cost of capital od most utilities would give them a competitive advantage that would allow them to earn higher margins to offset power sold at prices below FAC but above marginal cost (MC). Utilities could also offer new service packages that are competitively priced and recover the full cost of all components of the "package".[15]

Finally, flexible rate design can help in managing self-generation customers by offering prices above MC, even if FAC must be recovered through innovate service offerings. For example, smart EV charging stations could provide value to SaskPower that would justify service this market at very attractive prices for consumers.

Conclusion: Self-generation will evolve and become an increasingly relevant issues for all of SaskPower's customer classes in the future. CRS rates should be developed based on the SaskPower's cost allocation model for all rate classes. It would be appropriate to develop these additional CRS rates in anticipation of customers in other classes undertaking self-generation and seeking backup capacity from SaskPower. Customers deserve timely information on the likely cost of backup services if they are considering investing in self-generation. Furthermore, an attractive strategy for SaskPower to confront the challenge of self-generation may be for it to partner with qualified firms in providing a SaskPower solution in response to market demand for more power supply options.

4.2 CAPACITY RESERVATION SERVICE RATES

Elenchus recommends that SaskPower move away from using the Bary Correction to the more standard methodology that fully recovers demand-related costs though the demand charge. The Bary Correction is only appropriate when the utility provides all of a customer's energy and demand.[16] Non-utility options allow customers to replace energy

[15] A variety of corporate and regulatory structures have been adopted by utilities that offer non-regulated services in the market. For example, some establish non-regulated affiliates to offer those services. Others tracked the costs, revenues and financial results of their non-regulated services in order to clearly demonstrate that they are not being subsidized by the regulated services. There are well-established rules for ensuring that there is no cross-subsidization.

[16] It may be noted, for example, that the Bary Correction to rates is not used in the rate setting process of Canadian utilities that have unbundled rates. To do so, would be unwieldy.

consumption from utilities with self-generation while maintaining the same capacity during outages. The Bary Correction increases the energy charge so that the revenue lost from self-generation exceeds the costs avoided by the utility. Demand-related costs that are recovered in the energy charge will not be recovered from customers that self-generate.

The Bary Correction creates a distortionary price signal that will uneconomically encourage self generation and will not permit SaskPower to fully recover the demand-related costs it incurs to serve those customers. The benefit of applying the Bary Correction to improve intra-class equity is outweighed by the distortionary price signals it creates when non-utility options are available.

Further, offering standard service at rates that use the Bary Correction and CRS rates that do not may create an incentive for high load factor service customers to take CRS in order to access the lower energy charges. Customers with load factors greater than 65% would benefit from taking CRS if the Bary Correction is not consistent.

Conclusion: Consideration should be given to setting the CRS rates on the basis that it is equivalent to a 100% load factor service since the Reservation Capacity has to be deemed to be the coincident peak demand for planning purposes until there are enough customers in the class to realize diversity benefits. Further, it would not be appropriate to use the Bary Correction in setting the CRS demand and energy charges.

Measures to avoid unintended cross-subsidies as a result of migration of firm service customers to CRS rates should be considered to avoid undue revenue loss. In particular, rate designs that provide an incentive to "game the system" by providing nominations that understate a customer's actual backup requirement should be avoided. This can be accomplished by either limiting access to power in excess of the nominated level of demand or by adopting rates that include a significant penalty for utilizing backup in excess of the nominated level of demand.

Appendix A: Overview of SaskPower's Rate Design Methodology

Consistent with standard practice, SaskPower utilizes three charge components:

- Basic Monthly Charge (Fixed, $/month)
- Demand Charge (Semi-fixed, $/kVA)[17]
- Energy Charge (Variable, $/kWh)

The share of costs to be recovered through each charge component are typically determined in a cost allocation study. Costs allocated to each rate class are identified by their cost driver: customer-related, demand-related, or energy-related. Customer-related costs are considered fixed as they do not depend on demand or energy consumption and are recovered through fixed monthly charges. Demand-related costs are costs that are incurred to meet peak capacity requirements. Demand-related costs that are incurred by utilities are fixed capital investments, but the size of the investments depend on customers' energy requirements so demand costs can be considered semi-fixed. Energy-related costs are variable because they depend only on the volume of energy consumed.

Standard practice is to recover all fixed costs through the basic monthly charge, recover all demand-related costs through the demand charge[18], and recover all energy-related costs through the variable charge.

The billing determinants of fixed and variable charges are closely aligned with the cost factors that are driving those costs to be incurred, however, there is a difference between the billing determinant of demand charges and cost driver of demand-related costs. Commercial customers are billed demand-charges according to their peak demand, but the costs incurred by the utility are caused by demand at system peak times (the coincident peak). A customer with maximum demand during the coincident peak would face the same demand charges as a customer with the same maximum demand that occurs during off-peak times. The coincident peak customer causes more demand-related costs to be incurred than the off-peak customer but pays the same demand charge.

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[17] In other jurisdictions, the demand charge for some customer classes is typically based on demand measured in kW rather than kVA. The method depends on the meter technology used. This difference will have a small impact on the rate charged since measured KW and KVA differ slightly; however, there is little impact on the resulting bills and revenue recovery.

[18] Due to the high cost of demand meters it is not practical to have demand charges for smaller volume classes, such as the residential class. Demand-related costs are instead recovered through the fixed monthly charge and/or variable energy charges.

This creates a potential intra-class rate equity problem in which the customers that are causing higher demand-related costs do not have the appropriate price signal to reflect the incremental costs they cause. High peak customers are charged less than the incremental costs they cause from incremental demand, so those costs must be recovered from other customers. Through the typical cost allocation and rate design methodologies those demand costs would be recovered from other customers within the same class that may already be paying higher demand charges than they cause.

SaskPower adjusts for this intra-class inequity with a coincident peak allocation methodology, which is also known as the Bary Correction. The Bary Correction shifts the share of costs recovered through demand charges and share of costs recovered through consumption charges by considering the relationship between customer load factors and coincidence factors.

A load factor is an indicator of the relationship between average and peak demand. It is equal to average consumption over a given time period as a share of maximum demand in that period. Given the same level of consumption, a customer with a low load factor would have a higher peak and would cause more demand-related costs than a customer with a high load factor. A coincident factor reflects the relationship between the maximum demand of a customer and the system-wide coincident peak. It is equal to demand during the coincident peak as a share of maximum demand. A customer with a high coincident factor causes more demand-related costs than a customer with a low coincident factor.

The Bary Correction reduces the share of demand-related costs recovered through demand charges and shifts the recovery of those costs to variable charges. This is based on the observation that customers with high load factors generally have high coincidence factors. Given the same maximum demand, customers with high load factors consume more energy and cause more demand-related costs so shifting cost recovery from the demand charge to variable consumption charge has the impact of recovering more costs from the customers that cause those demand-related costs.

SaskPower's commercial rates are designed by the following methodology:

1. The basic monthly charge is calculated by the standard methodology of dividing customer-related costs by the number of customers in the class and dividing that figure into 12 months.
2. The demand charge is based on a calculation of the total costs to serve a customer at a given maximum demand with no consumption and a load factor of 0%. The calculation uses the y-intercept of a regression of an average billing equation, which represents the share of demand that occurs during the coincident peak for a hypothetical customer with a 0% load factor. The total costs of this hypothetical customer, less customer-related costs, are divided by the same maximum demand used to calculate total costs per month, times the 0% load factor y-intercept, to determine the cost of demand at a 0% load factor per kVA.

3. All remaining costs are divided by forecasted kWh throughput.

The demand charge methodology effectively removes a portion of demand-related costs for which demand is correlated with coincident peak demand and leaves the portion that is independent of the coincident peak. The portion that is correlated with coincident peak demand is recovered through variable rates so more revenue is recovered from customers with higher energy consumption, which are the same customers that have higher coincident peaks and cause more demand-related costs.

SaskPower's CRS rate derivation is more closely aligned with standard practice, without using the Bary Correction. CRS rate derivations rely on the same output data of SaskPower's cost allocation study[19] as the related continuous demand classes. Fixed costs continue to be recovered with the basic monthly charge, all variable costs are recovered through the variable charge, and demand charges are calculated for a customer with a 65% load factor.

Recovering demand and/or customer related costs by an energy charge was generally viewed as sustainable given the monopoly environment that prevailed for utilities in the past. With the increasing availability and declining cost of alternatives to grid-based supply, however, many jurisdictions either have implemented, or are considering, rate design changes that better align rates with costs. Rate designs that align more closely with allocated costs facilitate consumer behaviour that better aligns with industry economics in the contemporary electricity marketplace that includes an expanding array of non-utility options. The desirable goal is to facilitate economic bypass of utility services while discouraging uneconomic bypass.[20]

SaskPower's rate model calculates the CRS demand rate using an assumed 65% load factor, which corresponds to the average coincidence factor of Power Class (E22, E23 and E24) customers. The load factor has an impact because consumption influences the allocation of demand-related costs. Instead of taking the class revenue requirement, allocating the costs by category and dividing the allocated costs by the class billing determinants, this model calculates everything on a per customer basis. It uses average figures, except for the load factor, which somewhat distorts the results. Customers with a load factor greater than 65% would have lower total bills by switching to CRS rates and reserving their full demand.

19 Elenchus relied on the cost allocation and rate design model titled "2018Test-Original-Flat3"

20 Uneconomic bypass can occur when the incremental cost of non-utility services exceeds the incremental cost of utility service, while pricing anomalies result in the non-utility services costing the consumer less than utility service. This situation arises due to the traditional approach to utility rate setting such as basing rates on fully allocated costs and embedding intra-class cross-subsidies.

Appendix B: Survey of Other Jurisdictions

Alberta

The Alberta Utilities Commission (AUC) held an Electric Distribution System-Connected Generation Inquiry on matters related to distributed generation, including rate design issues. The inquiry was requested by the provincial government to aid the development of policies to support clean generation. The AUC summarized the public hearings and submissions related to the inquiry in a 2017 report.[21]

The Inquiry report discusses the positions of utilities and distribution-connected generation (DCG) proponents. The report describes how rate design can act as an enabler or barrier to the development of DCG. DCG proponents made submissions that tariff design should encourage the use of DCG. Utilities discussed ways to improve rate design but emphasized that rates should be set on the basis of cost causality to avoid cross-subsidization between customers with self-generation and customers without self-generation.

The utilities explained that their costs structure is overwhelmingly fixed costs that do not differ depending on whether a customer owns DCG. Therefore, its costs should be recovered primarily though fixed and semi-fixed charges. DCG proponents generally preferred variable charges as that would provide a higher net benefit from self-generation. The AUC noted a “gap in DCG proponents’ understanding” of utility cost drivers and participants suggested the AUC engage stakeholders to “address the complexity of tariff design”.[22] Review of the Generation Inquiry is ongoing.

Quebec

Hydro Quebec offers backup service under its GD and LD rates.[23] The GD rate is available to medium-power customers, which are customers with maximum demand below 5 MW, and the LD rate is available to customers with maximum loads greater than 5 MW. The utility does not have different charges for reserved demand and actual demand; customers are charged each month based on reserved demand. However, the backup service customers face high energy charges, particularly in winter months.

When a customer migrates to or from the continuous service classes (rates G and M) to Rate GD, the minimum billed demand cannot be less than the demand established under

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21 AUC – Alberta Electric Distribution System-Connect Generation Inquiry Final Report, December 29, 2017

22 AUC – Alberta Electric Distribution System-Connect Generation Inquiry Final Report, December 29, 2017, page 60

23 Hydro Quebec Electricity Rates Handbook, April 1, 2019

those rates, which is the maximum demand of the previous 12 months. The same rules apply for transitioning between rate LD and rate L.

The design of rate LD is based on the design of rate H for large-power customers with utilization mainly outside of peak winter days.[24] The GD rate is similar to its G9 rate for customers with high demand but low load factors. Demand charges are much lower than continuous service because they are based on demand during off-peak times. The energy charge is significantly greater, particularly during peak winter days. This design effectively assumes that backup service is taken during off peak times and recovers peak demand-related costs through high on-peak consumption charges. The Régie notes that the rates are not cost-based as they rely on the rate design of customers similar, but not identical, loads. In other words, the GD and LD rates were not specifically designed as backup rates.

UNITED STATES - GENERAL

Many US utilities created standby or backup rates for customers with Combined Heat and Power (CHP) generation. CHP generation has increased in recent years as low natural gas prices have increased the cost efficiency of this option. The rates are designed for backup supply during planned and unplanned outages of CHP equipment but can apply more broadly to any type of self-generation.

The US Public Utilities Regulatory Policy Act of 1978[25] requires rates for backup power:

(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and
(2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

Oregon

Pacific Power has “Partial Requirements Supply Service” rates for customers with self-generation.

A customer’s demand charge is based on its peak demand during on-peak hours, which are 6:00 am to 10:00 pm from Mondays to Saturdays.

Recovery of transmission and ancillary services costs are calculated based on actual monthly demand. Recovery of local distribution costs are based on a customer’s “baseline demand”, which is demand when the customer’s generator is operating normally. This

[24] R-3466-2001, Subsection 4.1

[25] Public Utilities Regulatory Policy Act of 1978 - 18 CFR § 292.305 - Rates for sales

rate is applicable only to customers that require service to supplement self-generation on an ongoing basis.

Baseline demand is determined as the peak in the previous 12 months at times that the generator is operating normally. When a firm customer installs a generator the baseline is calculated as peak demand in the previous 12 months less the demand replaced by the generator. Baseline demand charges for partial requirement customers are equivalent to demand charges for firm demand customers.

Customers served within the Partial Requirements classes also pay Reserve Charges based on their Facility Capacity. Facility Capacity is calculated as the average of a customer's two highest non-zero monthly demands. Facility Capacity can be reduced with curtailment plans and other self-generation. The monthly charge for facility capacity is approximately one quarter of the demand charge for baseline demand.

Energy consumed by partial requirement customers are subject to three separate charges. The energy charge for consumption within baseline demand is equal to the energy charge for firm customers. Energy consumed during scheduled maintenance in which the utility was notified at least 30 days before delivery the customer can take cost-based supply service or standard offer supply service. Customers may take scheduled maintenance service for only two events in a calendar year and may not exceed 31 cumulative days. Unscheduled energy charges are market-based prices plus 0.14¢/kWh.

Georgia

Georgia Power's rate design is uncommon in that all variable and demand costs are recovered through tiered variable rates, even for large use commercial customers. A separate minimum monthly bill, based on a high demand rate, is also calculated and used if it exceeds variable charges.

Georgia Power has separate standby charges depending on whether the service is firm or interruptible and whether the service is maintenance (with notice to the utility) or backup. Firm standby capacity rates only charged in cases that the customer takes standby service for more than two days in a billing period. Demand for maintenance service in which the customer provided 14-days notice to the utility is scaled down so the customer pays for only 60% of the incremental demand. Interruptible standby service, whether it is maintenance or backup service, is also scaled down to 60% of actual demand. Firm back-up demand is scaled up by 50%.[26] The applicable demand charge is the same demand charge faced by continuous service customers, prorated by the number of days the service is taken.

[26] Elenchus notes that the adjustments to the quantity of demand is equivalent to adjustments to the associated rate at actual demand. In other words, scaling demand to 60% of actual demand and charging the continuous rate results in the same total demand charge as reducing the continuous demand charge to 60% and applying actual demand.

Georgia Power calculates reserved demand, or "standby power demand" by a similar methodology used in other jurisdictions. Reserved demand is maximum demand when standby power is taken less maximum power when it is not, which is equivalent to the normal operating generating capacity of a customer's self-generation. Georgia Power also applies a "standby demand adjustment factor" that transitions customers to continuous rates if they use too much standby service. Once a customer uses standby service for more than 876 hours, or 36.5 full days, the utility starts shifting demand considered reserved capacity to demand considered as firm continuous demand, which has a materially higher charge. The customer pays fully continuous rates when it reaches 1,752 hours, or 73 full days, of standby service in a 12-month period.

New York

New York state has six utilities with standby service rates that follow rate-setting guidelines provided by the New York Public Service Commission. The Guidelines[27] relate only to distribution service as standby customers are expected to arrange their own energy supply in the competitive market.

The Commission acknowledged that there was insufficient data related to the operation and cost causation of standby customers to justify the creation of a separate standby service rate when the Guidelines were created in 2001. However, the Commission also concluded that standby service is sufficiently different from continuous service to warrant difference in treatment.

The Guidelines proposed that demand-related costs should be separated into "local facilities" and "shared facilities". Local facilities are facilities that are specifically installed to serve a particular customer's maximum load and shared facilities are facilities that serve all customers. Customers are levied two demand charges, contract demand to recover the costs of the local facilities, and "as-used daily" demand charges for shared facilities on the days standby service is taken. Contract demand charges are calculated as the monthly cost to operate local facilities divided by maximum contract demand. The charges change when the contract demand changes to ensure full cost recovery of local facilities. Functionally, it is no different from billing the monthly cost of local facilities as part of the basic monthly charge.

As-used daily demand charges are prorated monthly demand charges faced by continuous service customers. There are different demand charges for on-peak and off-peak demand in New York and standby customers are generally only charged for on-peak demand. As-used demand includes transmission charges, but no capacity costs related to generation.

[27] CASE 99-E-1470 – Proceeding on Motion of the Commission as to the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service

The coincidence factor of standby customers is assumed by be the same as continuous service customers when first deriving standby rates. The commission notes that "with sufficient load data, demand charges based on an allocation of system costs to a class of standby customers could be developed in the future."[28] The Commission emphasized that principles of cost causality and full cost recovery should be the basis for setting standby rates but acknowledged that fully adhering to these principles is not achievable when introductory standby rates are established.

The Commission noted that the established rate design at the time, as with SaskPower's current rate design, a share of demand related costs is recovered with the variable charges. Customers could avoid demand-related costs by producing their own electricity so they would elect to continue on the same rates if given a choice between existing rates and standby rates. Customers with maximum demand above 50 kW who self-generate more than 15% of its energy requirements must take standby service, and customers with self-generation or demand lower than those thresholds, including residential customers, can elect to take standby service.

Minnesota

Standby charges differ significantly across utilities in Minnesota. All standby rates are designed based on the principles of cost causality and full cost recovery but rates can differ significantly depending on whether the outage was planned or unplanned and whether the outage occurs off-peak. Utilities generally bill for standby service through a rate rider instead of separate rate or rate class.

Minnesota Power's rate design disproportionately recovers costs for demand during unscheduled outages. The utility has low demand charges for reserved capacity that are based on the typical outage rate of the generator used for self-generation. The utility also tracks actual demand unscheduled and scheduled demand of backup services and charges the greater of the reservation demand and actual standby demand. Standby demand charges for scheduled outages are lower than the reservation fee, and the charge is pro-rated by number of demand days, so the reservation charge is usually lower unless the customer had a prolonged outage or if demand was unscheduled. To illustrate the difference between unplanned and planned outages, Minnesota Power provides standby billing examples in its tariff schedule.[29] For a hypothetical customer with 2,000 kW of reserved demand, a 10% generator outage rate, and 5 outage days, standby demand charges would not exceed the reservation charge of $3,780. For the same customer with an unplanned outage, demand charges are $38,990. The scheduled

[28] NYPSC Case 99-E-1470, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, Opinion No. 01-4, page 8, footnote 7

[29] Minnesota Power Electric Rate Book – Volume 1. Section V, Page 61.8, Revision 8

demand rates are consistent with comparable standard service customers but unscheduled demand rates are considerably higher.

Dakota Electric[30] customers with self-generation reserve capacity at a reservation fee that is applied as a rate rider to bills in months that backup service is not taken. When backup service is taken the customer pays the standard continuous service demand rate for that month. If backup energy is consumed during the generation peak[31] the customer is billed for incremental energy costs.

These two utilities show the potential intra-class divergences of standby rate designs that adhere to the same basic principles. Minnesota Power considers unscheduled outages to contribute more to the peak and levies high demand charges for unscheduled outages and low charges for scheduled maintenance. Standby costs are predominantly recovered from customers that actually contribute to the peak instead of customers that could potentially contribute to the peak but to not. Dakota Electric, on the other hand, does not levy substantially different charges depending on the circumstances of outage so costs are recovered in line with each customer's potential contribution to the peak. Both rates are designed such that self-generating customers will prefer standby service to avoid demand charges in months standby service is not taken.

Michigan

Standby service charges differ greatly by utility in Michigan. Some utilities have standby rates that do not significantly differ based on whether backup service is actually taken and two utilities, Upper Michigan Energy Resources Corp (UMERC) and Upper Peninsula Power Company (UPPCo), that only charge when standby service is taken. The significant differences are highlighted in the following table produced by Michigan's Public Service Commission.[32]

[30] Dakota Electric Association, Commercial and Industrial Electric Rate, Section V, Sheet 31.2, Schedule 60

[31] This is the peak for the utility's wholesale power supplier

[32] Michigan Public Service Commission Staff – Standby Rate Working Group Supplemental Report, page 21

Table 1: Comparison of Standby Service Tariff Rates for Four Michigan Utilities[19,20]

Scenario Description	Consumers	DTE	UMERC	UPPCO
No Outage	8,300	10,535	0	0
Scheduled Outage 16 Hours Off-Peak	9,246	11,657	2,218	2,911
Scheduled Outage 16 Hours On-Peak	11,645	18,653	3,098	3,883
Scheduled Outage 8 Hours On-Peak, 8 Hours Off-Peak	11,191	13,405	2,658	3,397
Scheduled Generator Outage 32 Hours On-Peak	14,833	30,272	6,196	7,766
Unscheduled Outage 8 Hours On-Peak, 8 Hours Off-Peak	11,191	17,545	30,536	31,631

DTE's generation reservation fee is 12% of the on-peak demand charge for continuous service customers.[33] Customers pay an additional demand charge that is approximately one third of the continuous demand charge for each day it requires backup service. After three days of service the demand charge is capped at the continuous service rate for that month.

UMERC and UPPCo have the same rate design in which standby rates apply only in months that backup service is taken. Similar to utilities in Minnesota, customers pay pro-rated daily demand charges for service that was planned or pay the full monthly continuous service demand charge when service is unplanned. Customers do not pay any reservation charge so the costs caused by the class are recovered primarily from customers that have unplanned outages.

[33] Michigan Public Service Commission Staff – Standby Rate Working Group Supplemental Report, page 11