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Review of SaskPower Capacity Reservation Service (CRS) Rates

Report prepared for SaskPower

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Final Version
23 April 2020

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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/E23/E24) 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

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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.

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[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 RECOMMENDATIONS AND CONCLUSIONS

4.1 RECOMMENDATIONS

Recommendation #1: CRS rates should be developed for all rate classes based on SaskPower's cost allocation model. The goal would be to provide access to backup service for all customers at rates that reflect the causal costs of the service for each class. These CSR rates are needed to facilitate economic bypass while providing appropriate price signals to discourage uneconomic bypass which benefits some customers only by shifting costs to other customers and/or other customer classes.

Recommendation #2: CRS rates should be designed on the basis that the nominated Reservation Capacity accurately reflects the actual required capacity of the customers for SaskPower system planning purposes. The Reservation Capacity should be equivalent to a 100% load factor service unless (i) the customer can demonstrate its ability and commitment to curtail its demand at any time (e.g., interrupt production rather than call on the Reservation Capacity), or (ii) the CRS class has demonstrable diversity benefits (i.e., the coincident peak demand is less than the sum of the peak demands of the individual customers in the class).

Recommendation #3: The Bary Correction should not be used in setting the CRS demand and energy charges and should be phased out of the rate design for all classes where it is currently used.

4.2 CONCLUSIONS: 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 competitive alternatives to 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 generation but limits the loss of net income to either (i) the difference between energy rates and avoidable generation costs (essentially the cost of fuel and purchased power) or (ii) the difference between energy rates and the export value of power. But over a longer term, grid defection is likely to be the greatest threat to electric utilities, including SaskPower. If there is partial or whole grid defection, assets/costs will be stranded. Changes to SaskPower's rate design alone will not solve the problem. The only effective solutions in the long run will be either (i) offering services that achieve voluntary customer retention (with new source of net revenue that replace lost revenue) or (ii) mandatory exit fees.

The theoretically ideal 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). In practice, this approach would require pricing flexibility and either the ability to price discriminate or to bundle regulated and competitive services as a means of recovering the utility's revenue requirement fully. These options raise concerns about anti-competitive practices as well as the elimination of inter- and intra-class equity as consideration in the design of rates. The solution to achieving these competing objectives is difficult; so difficult, in fact, that no widely accepted solution has been identified.

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.).

The development of customer self-generation and other competitive options 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 of 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 designs could accommodate customers that want to self-generate by offering prices below FAC but above MC, although the FAC shortfall would have to be recovered through innovate service offerings. For example, smart EV charging stations could provide value to SaskPower that would justify serving this market at attractive prices for consumers. The most cost-effective way to accommodate self-generation, however, would be to develop a collaborative system planning process that enables customer generation to be built into SaskPower’s supply plan where it is the least cost and lowest risk option for meeting the future electricity needs of the province. This would be accomplished by adopting a three-pillars approach to integrated resource planning where the three pillars are: traditional supply options (utility generation, transmission and distribution), demand side management and non-utility distributed energy resources (DERs).

The emerging disruptions of the electricity sector are forcing utilities, including SaskPower, to adapt their rate designs to accommodate the evolving market forces. Traditional rate designs embed strong incentives for customers to bypass the grid in ways that shift costs to other customers while also increasing the total costs that must be borne by all customers. If rate designs are not rationalized, uneconomic bypass through self-generation will increase cost shifting and this will become an increasingly relevant issues for all of SaskPower’s customer classes.

It will therefore be desirable to develop 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 innovative supply options. Adopting collaborative solutions to meeting the demand for electricity in the future will serve to reduce the total cost borne by customers, which is the sum of the cost incurred for self-generation plus the amounts paid by connected customers that enable the utility to recover its revenue requirement.

[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.

4.3 CONCLUSIONS: CRS RATE DESIGN CONSIDERATIONS

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 charges. The Bary Correction is only appropriate when the utility supplies all of its customers' power.[16] In the disrupted electricity sector, non-utility options allow customers to replace energy consumption from utilities with self-generation while maintaining the same demand during outages. The problem with the Bary Correction is that it increases the energy charge and as a result the revenue lost from self-generation exceeds the costs avoided by the utility. As a result, demand-related costs that are recovered in the energy charge will not be recovered from customers that self-generate.

The Bary Correction therefore 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 customers with self-generation. 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 choosing CRS rather than standard service even if they do not self-generate if the Bary Correction is not applied consistently to two services.

Given the ever-present risk that the terms and conditions for any service can provide an incentive to save money by "gaming the system", it will be important to establish terms and conditions for CRS include measures to avoid unintended cross-subsidies as a result of migration of firm service customers to CRS rates. In particular, a CRS rate design that creates 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. The implication of this consideration is that customers with effective enough management of their power requirements to consider self-generation should be able to maintain levels of Reservation Capacity that are sufficient to avoid overruns. In this circumstance, it would not be unreasonable for the penalties for overruns to be sufficient to make it uneconomic to take power in excess of the nominated Reserve Capacity rather than curtail demand.

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[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.

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)[1]
- 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[2], 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.

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

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[1] 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.

[2] 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.

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[3] 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.[4]

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.

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

4 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.[1]

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”.[2] Review of the Generation Inquiry is ongoing.

QUEBEC

Hydro Quebec offers backup service under its GD and LD rates.[3] 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 those rates, which is the maximum demand of the previous 12 months. The same rules apply for transitioning between rate LD and rate L.

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

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

[3] Hydro Quebec Electricity Rates Handbook, April 1, 2019

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.[4] 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[5] 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 rate is applicable only to customers that require service to supplement self-generation on an ongoing basis.

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4 R-3466-2001, Subsection 4.1

5 Public Utilities Regulatory Policy Act of 1978 - 18 CFR § 292.305 - Rates for sales

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%.[6] The applicable demand charge is the same demand charge faced by continuous service customers, prorated by the number of days the service is taken.

Georgia Power calculates reserved demand, or "standby power demand" by a similar methodology used in other jurisdictions. Reserved demand is maximum demand when

[6] 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.

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[7] 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.

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

7 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

sufficient load data, demand charges based on an allocation of system costs to a class of standby customers could be developed in the future."[8] 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.[9] 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 demand rates are consistent with comparable standard service customers but unscheduled demand rates are considerably higher.

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[8] 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

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

Dakota Electric[10] 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[11] 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.[12]

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

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

[12] 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.[13] 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.

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APPENDIX C: DERIVATION OF STANDARD AND CRS RATES

OVERVIEW

This appendix provides the derivation of SaskPower's current standard Power Class and proposed CRS rates[1] and a comparative analysis of those rates with the typical costs caused by Power Class customers. The analysis demonstrates that SaskPower's rate design is aligned with standard rate design practice and that revenue recovered from customers is aligned with the costs caused by those customers.

This appendix contains a brief overview of SaskPower's rates; derivation of standard Power Class rates, the Bary Method adjustment, and CRS Power Class rates; a scenario analysis; and a discussion of demand data used in SaskPower's rate design. The scenario analysis shows cost recovery with standard rates, cost recovery with CRS rates, and the costs caused by the customer under various self-generation scenarios. The resulting revenue to cost ratios under each scenario is provided in Table 1.

Table 1 – Scenario Revenue-to-Cost Ratios

Scenario	Description	E22	N22
Scenario 1	No self-generation	0.995	0.995
Scenario 2	50% self-generation – 75% ratchet in 6 months	0.782	1.009
Scenario 3	1 month generation – 75% ratchet in 11 months	0.481	1.028
Scenario 4	1 month generation – no ratchet	0.217	1.028
Scenario 5	100% self-generation - no ratchet	0.089	1.034

The revenue-to-cost ratios (R/C Ratios) above are calculated as the total bill for an average 25kV Power Class customer, under each of the E22 and N22 rates, divided by the costs SaskPower incurs to serve the customer. An R/C ratio of 1.000 indicates that the customer's total bill is equal to the costs it causes. An R/C ratio below 1.000 indicates the customer is paying less than the costs it causes. This analysis demonstrates the need for CRS rates to be implemented in order to maintain cost recovery from customers who self-generate.

SASKPOWER'S CURRENT RATES

The outcomes of SaskPower's most recent rate applications have been flat rate increases applied to its existing charges for most customer classes. It has been many years since SaskPower has rebalanced the revenue it recovers from each customer class or

[1] This analysis uses actual E22 and N22 data to illustrate the relationship between standard and CRS Power Class rates and the costs a typical customer in each class. The observations and conclusions of this analysis extend to the design and relationship between E23/N23 and E24/N24 rates.

rebalanced the charges applied to the customers within a class. Prior to the flat rate increases, SaskPower's ability to rebalance rates was limited due to rate shock concerns.

The Power Class's basic monthly, demand, and energy charges do not fully reflect SaskPower's rate design methodology because rates are not based on the utility's current cost structure. Power Class customers face significantly higher basic monthly charges than the fixed costs they cause, as determined in the cost of service model. Energy charges are similar to the output of the cost of service study with the Bary Method applied. Increased cost recovery through the basic monthly charge is somewhat offset with lower demand charges. Increased recovery of customer charges exceeds reduced recovery of demand charges so more revenue is recovered from the class than the class' fully allocated costs.[2] The discrepancies between SaskPower's actual rates and current rate design magnifies the impact of the Bary Method to further reduce demand charges below demand-related costs. Elenchus recommends that SaskPower rebalance its Power Class charges to be consistent with the results of its cost of service allocation study. This rebalancing could be phased over several years in order to mitigate excessive rate impacts on any customer classes. If that is done, however, customers should be made aware of the extend of future rate changes so that they can make investment in energy saving opportunities that more accurately recognize the longer-term financial benefits of conservation.

CRS rates are initially designed according to a standard methodology (as described in Appendix A) and are then adjusted to apply characteristics of the equivalent standard Power Class rates. The principle adjustment made to the initially designed CRS rates is to increase CRS basic monthly charges to the equivalent standard Power Class basic monthly charges. There are corresponding reductions to demand and energy charges to maintain the same level of cost recovery for a hypothetical customer with a 65% load factor that migrates to CRS rates but does not self-generate. Notably, the adjustments to energy and demand charges maintain the characteristic of over-recovery from the Power Class rates.

Standard Power Class Rates

The derivation of E22 charges under standard rate design, under SaskPower's rate design with the Bary Method adjustment, costs caused by an average E22 customer, and actual E22 charges are summarized in Table 2. Under standard rate design costs per customer are equal to total class allocated costs divided by the number of customers. There are 25 customers in this class so the average customer receives 1/25th, or 4% of each cost. SaskPower's rate design uses multiple measures of demand that causes demand charges to exceed demand-related costs so a scaling factor is applied to reduce overall revenue from the class. Standard rate design and SaskPower's rate design each

[2] Typical E23/N23 & E24/N24 customers have total charges that exceed their caused costs (see Table 13 and Table 15 of this Appendix).

result in total annual bills for average customers that equal the total costs caused by an average customer. The R/C ratio for a typical customer is 0.995.

Table 2 – E22 Rate Derivation & Actual Charges

	Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
Standard Rate Design E22							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
Costs / Customer	3,318,528	524,714	1,577,180	511,344	43,875	27,179	
Rev. Req.[3]	230,581	538,685	109,587	524,959	3,049	27,903	
Function Subtotal	769,266		634,546		30,951		1,434,764
÷ Average BD	33,770	kVA	14,715,519	kWh	12	months	
Charges	**22.780**	**$/kVA**	**0.04312**	**$/kWh**	**2,579.28**	**$/month**	
E22 Rate with Bary Method							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
Costs / Customer	3,529,836	558,126	1,577,180	511,344	43,875	27,179	
Rev. Req.	245,263	572,986	109,587	524,959	3,049	27,903	
Function Subtotal	818,249		634,546		30,951		*1,483,747*
Bary Adjustment	(397,550)		397,550				
Subtotal/Customer	420,700		1,032,096		30,951		*1,483,747*
÷ Average BD	30,903	kVA	14,715,519	kWh	12	months	
Charges	13.614	$/kVA	0.07014	$/kWh	2,579.28	$/month	
Scaling Factor	0.967		0.967		0.967		
Scaled Charges	**13.164**	**$/kVA**	**0.06782**	**$/kWh**	**2,494.08**	**$/month**	
x Average BD	30,903	kVA	14,715,519	kWh	12	months	
Scaled Total	406,805		998,030		29,928		1,434,764
E22 Average Costs Caused							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
x Share of Costs	4.00%		4.00%		4.00%		
Costs / Customer	3,318,528	524,714	1,577,180	511,344	43,875	27,179	
Rev. Req.	230,581	538,685	109,587	524,959	3,049	27,903	
Function Subtotal	769,266		634,546		30,951		1,434,764
E22 Actual Charges for an Average Customer							
Current Charges	10.906	$/kVA	0.06902	$/kWh	6,188.90	$/month	
x Average BD	30,903	kVA	14,715,519	kWh	12	months	
Subtotal/Customer	337,026		1,015,665		74,267		1,426,958

[3] The revenue requirement figures are calculated as Rate Base times the return on rate base times the target revenue-to-revenue requirement ratio and Expenses times the target revenue-to-revenue requirement ratio. Rate Base RR = Rate Base * 0.0677 * 1.027; Expense RR = Expense * 1.027

Table 3 details the calculations for a customer with a 65% load factor with the Bary Method adjustment applied, the costs caused by a customer with average maximum demand and a 65% load factor, and the current charges for this customer. The customer with a 65% load factor is instead assigned a share of total demand costs equal to its share of the coincident peak, or 4.2% of demand costs.[4] The 65% LF customer also consumes more energy and is assigned a proportionally higher share of energy costs.

Table 3 – E22 at a 65% Load Factor

	Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
E22 Rate @ 65% LF with Bary Method							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
Costs / @ 65% LF	3,708,181	586,325	1,709,309	554,183	43,875	27,179	
Rev. Req.	257,655	601,936	118,768	568,938	3,049	27,903	
Function Subtotal	859,592		687,706		30,951		*1,578,249*
Bary Adjustment	(430,855)		430,855				
Subtotal/Customer	428,737		1,118,560		30,951		*1,578,249*
÷ BD @ 65% LF	31,493	kVA	15,948,324	kWh	12	months	
Charges	13.614	$/kVA	0.07014	$/kWh	2,579.28	$/month	
Scaling Factor	0.967		0.942		0.942		
Scaled Charges	**13.164**	**$/kVA**	**0.06782**	**$/kWh**	**2,494.03**	**$/month**	
x BD @ 65% LF	31,493	kVA	15,948,324	kWh	12	months	
Scaled Total	414,576		1,081,641		29,928		1,526,146
E22 65% LF Costs Caused							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
x Share of Costs	4.20%		4.34%		4.00%		
Costs / Customer	3,486,197	551,226	1,709,309	554,183	43,875	27,179	
Rev. Req.	242,231	565,902	118,768	568,938	3,049	27,903	
Function Subtotal	808,133		687,706		30,951		1,526,790
Actual E22 Charges for 65% LF Customer							
Current Charges	10.906	$/kVA	0.06902	$/kWh	6,188.90	$/month	
x BD @ 65% LF	31,493	kVA	15,948,324	kWh	12	months	
Subtotal/Customer	343,465		1,100,753		74,267		1,518,485

[4] A customer's coincident peak is calculated using a coincident peak regression. It is the customer's maximum demand times the total of the coincident peak slope times the load factor plus the coincident peak y-intercept.

CP kW = Customer Maximum kW * (0.717 * 0.65 + 0.283).

SaskPower's initial rate design does not necessarily result in charges that fully recover revenue so a scaling factor is applied to adjust total class revenues to equal total class costs. It is required because three different measures of demand are used at different stages of SaskPower's rate design which causes initial demand charges to exceed demand-related costs. For the purposes of this analysis the same scaling factor is applied to all charges. In practice each charge may be scaled differently to reduce material changes from existing charges.

The increase in total cost recovery between Table 1 and Table 2 is due to the increased costs caused by a customer with an assumed load factor of 65% over the class average of 59.98%. Scaled total recovery with the Bary Method adjustment is the same as the costs caused by customers with the average load factor and similar for a customer with a 65% load factor. This demonstrates the purpose of the Bary Method to align cost recovery and cost causation for customers with different load factors while imposing the same charges. Actual revenue demonstrates the same degree of slight under-recovery regardless of the load factor as the R/C ratio for a customer at a 65% load factor is also 0.995.

Bary Method Adjustment

Bary Method adjustment is derived in Table 4 for a customer with an average load factor and a customer with a 65% load factor. The Bary Method determines the $/kVA demand charge at any load factor but the exact adjustment depends on the customer's load factor. An offsetting adjustment is made to costs to be recovered through the energy charge, and there is no impact on the basic monthly charge.

Table 4 – Bary Adjustment Derivation

	Demand 59.89% LF		Demand 65% LF	
	Rate Base	Expense	Rate Base	Expense
Class Allocated Costs	82,963,194	13,117,862	82,963,194	13,117,862
Costs / @ 0% LF	1,400,995	221,521	1,400,995	221,521
Rev. Req.	97,345	227,419	97,345	227,419
Function Subtotal	324,764		324,764	
÷ Billing Demand @ 0% LF	23,856	kVA	23,856	kVA
Bary Demand Charge	13.614	$/kVA	13.614	$/kVA
x Billing Demand @ x% LF	30,903	kVA	31,493	kVA
Total Demand $	420,700		428,737	
- Alloc. Demand Costs	818,249		859,592	
Bary Adjustment	(397,550)		(430,855)	

CRS POWER CLASS RATES

The derivation of N22 charges with standard rate design, charges for a customer with a 65% load factor, cost caused by a customer with a 65% load factor, and proposed N22 charges are detailed in Table 5. The N22 customer is assumed to take power for the full year in each scenario to illustrate the total cost recovery of CRS rates relative to standard Power Class rates. Billing demand is higher for CRS classes because it is the reserved demand, the maximum demand in the previous 12 months, instead of actual demand. Billing demand is calculated with billing demand formulas that differ between standard and CRS Power Class rates to recognize the difference between actual demand and reserved demand.[5] The higher billed demand used to derive CRS rates leads to lower demand charges than standard (i.e. non-Bary) Power Class rates.

Standard rate design recovers the same demand, energy, and customer-related costs for the E22 and N22 rates. Costs recovered using both the initial and scaled rates for a customer at a 65% load factor are also between the standard and CRS Power Class rates. The proposed CRS demand and energy charges are similar to the scaled charges with an assumed 65% class load factor following standard rate design methodology. The basic monthly charge is set to the E22 rate which is significantly higher than the derived scaled charge.

The higher basic monthly charge brings the total cost recovery in line with cost recovery under the E22 rate for a customer that does not self-generate as a customer under either rate would have an R/C ratio of 0.995. The standard Power Class faces lower charges than the costs they cause as a result of ongoing flat rate increases so this characteristic is carried to CRS rates to maintain consistency between standard and CRS Power rates.

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[5] Billing Demand = Maximum kW * 12 * (Load Factor * Billing Slope + Billing y-intercept) / Power Factor. For standard Power Class customers, the formula is Billing Demand = Maximum kW * 12 * (0.65 * 0.33 + 0.67) / 0.944. For reserved demand with CRS rates the billing slope is 0% and the y-intercept is 100% so the formula is Billing Demand = Maximum kW * 12 / Power Factor.

Table 5 – N22 Rate Derivation & Proposed Charges

	Reserved Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
Standard Rate Design N22							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
Costs / Customer	3,318,528	524,714	1,577,180	511,344	43,875	27,179	
Rev. Req.[6]	230,581	538,685	109,587	524,959	3,049	27,903	
Function Subtotal	769,266		634,546		30,951		1,434,764
÷ Average BD	35,606	kVA	14,715,519	kWh	12	months	
Charges	**21.605**	**$/kVA**	**0.04312**	**$/kWh**	**2,579.28**	**$/month**	
N22 Rate @ 65% LF							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
Costs / @ 65% LF	3,708,181	586,325	1,709,309	554,183	43,875	27,179	
Rev. Req.	257,655	601,936	118,768	568,938	3,049	27,903	
Function Subtotal	859,592		687,706		30,951		*1,578,249*
÷ BD @ 65% LF	35,606	kVA	15,948,324	kWh	12	months	
Charges	24.142	$/kVA	0.04312	$/kWh	2,579.28	$/month	
Scaling Factor	0.967		0.967		0.967		
Scaled Charges	**23.355**	**$/kVA**	**0.04171**	**$/kWh**	**2,495.21**	**$/month**	
x BD @ 65% LF	35,606	kVA	15,948,324	kWh	12	months	
Scaled Total	831,572		665,276		29,942		1,526,790
N22 65% LF Costs Caused							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
x Share of Costs	4.20%		4.34%		4.00%		
Costs / Customer	3,486,197	551,226	1,709,309	554,183	43,875	27,179	
Rev. Req.	242,231	565,902	118,768	568,938	3,049	27,903	
Function Subtotal	808,133		687,706		30,951		1,526,790
Proposed N22 Charges							
Proposed Charges	22.278	$/kVA	0.04082	$/kWh	6,188.90	$/month	
x BD @ 65% LF	35,606	kVA	15,948,324	kWh	12	months	
Subtotal/Customer	793,222		651,011		74,267		1,518,499

Standard and CRS Rate Scenario Analysis

The necessity for CRS rates can be illustrated by extending the above analysis to customers that self-generate a portion of their energy requirements. In the first scenario, the customer does not self-generate. In the second scenario the customer self-generates for 6 months and takes full service from SaskPower for the remaining 6 months. It is assumed that the 75% demand ratchet will apply to the 6 self-generation months.

In the third and fourth scenarios the customer self-generates for 11 full months and takes service from SaskPower in the remaining month. The third scenario considers a customer that takes service for one month then faces 11 months of 75% ratchet demand chargers. The fourth scenario assumes a customer that has not taken service in the previous 11 months and only takes service in the last month of the year so it does not face ratchet demand charges. The fifth scenario shows cost recovery in a year that no CRS service is taken.

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[6] The revenue requirement figures are calculated as Rate Base times the return on rate base times the target revenue-to-revenue requirement ratio and Expenses times the target revenue-to-revenue requirement ratio. Rate Base RR = Rate Base * 0.0677 * 1.027; Expense RR = Expense * 1.027

Table 6 – Scenario Analysis

	Reserved Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
Scenario 1: No Self-Generation							
E22 Rate @ 65% LF							
Charges	10.906	$/kVA	0.06902	$/kWh	6,188.90	$/month	
x BD @ 65% LF	31,493	kVA	15,948,324	kWh	12	months	
Subtotal/Customer	343,465		1,100,753		74,267		1,518,485
N22 Rate @ 65% LF							
Proposed Charges	22.278	$/kVA	0.04082	$/kWh	6,188.90	$/month	
x BD @ 65% LF	35,606	kVA	15,948,324	kWh	12	months	
Subtotal/Customer	793,222		651,011		74,267		1,518,499
65% LF Costs Caused							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
x Share of Costs	4.20%		4.34%		4.00%		
Costs / Customer	3,486,197	551,226	1,709,309	554,183	43,875	27,179	
Rev. Req.	242,231	565,902	118,768	568,938	3,049	27,903	
Function Subtotal	808,133		687,706		30,951		1,526,790
Scenario 2: 6 Months of Self-Generation							
E22 Rate @ 65% LF							
Charges	10.906	$/kVA	0.06902	$/kWh	6,188.90	$/month	
x BD @ 65% LF	27,557	kVA	7,974,162	kWh	12	months	
Subtotal/Customer	300,531		550,377		74,267		925,175
N22 Rate @ 65% LF							
Proposed Charges	22.278	$/kVA	0.04082	$/kWh	6,188.90	$/month	
x BD @ 65% LF	35,606	kVA	7,974,162	kWh	12	months	
Subtotal/Customer	793,222		325,505		74,267		1,192,994
65% LF Costs Caused							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
x Share of Costs	4.20%		2.17%		4.00%		
Costs / Customer	3,486,197	551,226	854,655	277,091	43,875	27,179	
Rev. Req.	242,231	565,902	59,384	284,469	3,049	27,903	
Function Subtotal	808,133		343,853		30,951		1,182,938

Table 7 – Scenario Analysis – Self-Generation 11 Months

	Reserved Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
Scenario 3: 11 Months of Self-Generation (First Month)							
E22 Rate @ 65% LF							
Charges	10.906	$/kVA	0.06902	$/kWh	6,188.90	$/month	
x BD @ 65% LF	24,276	kVA	1,329,027	kWh	12	months	
Subtotal/Customer	264,754		91,729		74,267		430,750
N22 Rate @ 65% LF							
Proposed Charges	22.278	$/kVA	0.04082	$/kWh	6,188.90	$/month	
x BD @ 65% LF	35,606	kVA	1,329,027	kWh	12	months	
Subtotal/Customer	793,222		54,251		74,267		921,740
65% LF Costs Caused							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
x Share of Costs	4.20%		0.36%		4.00%		
Costs / Customer	3,486,197	551,226	142,442	46,182	43,875	27,179	
Rev. Req.	242,231	565,902	9,897	47,411	3,049	27,903	
Function Subtotal	808,133		57,309		30,951		896,394
Scenario 4: 11 Months of Self-Generation (Last Month – no ratchet demand)							
E22 Rate @ 65% LF							
Charges	10.906	$/kVA	0.06902	$/kWh	6,188.90	$/month	
x BD @ 65% LF	2,624	kVA	1,329,027	kWh	12	months	
Subtotal/Customer	28,622		91,729		74,267		194,618
N22 Rate @ 65% LF							
Proposed Charges	22.278	$/kVA	0.04082	$/kWh	6,188.90	$/month	
x BD @ 65% LF	35,606	kVA	1,329,027	kWh	12	months	
Subtotal/Customer	793,222		54,251		74,267		921,740
65% LF Costs Caused							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
x Share of Costs	4.20%		0.36%		4.00%		
Costs / Customer	3,486,197	551,226	142,442	46,182	43,875	27,179	
Rev. Req.	242,231	565,902	9,897	47,411	3,049	27,903	
Function Subtotal	808,133		57,309		30,951		896,394

Table 8 – Scenario Analysis – Full Self-Generation (No Maintenance)

	Reserved Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
Scenario 5: No Self-Generation – no ratchet							
E22 Rate @ 65% LF							
Charges	10.906	$/kVA	0.06902	$/kWh	6,188.90	$/month	
x BD @ 65% LF	0	kVA	0	kWh	12	months	
Subtotal/Customer	0		0		74,267		74,267
N22 Rate @ 65% LF							
Proposed Charges	22.278	$/kVA	0.04082	$/kWh	6,188.90	$/month	
x BD @ 65% LF	35,606	kVA	0	kWh	12	months	
Subtotal/Customer	793,222		0		74,267		867,489
65% LF Costs Caused							
Class Alloc. Costs	82,963,194	13,117,862	39,429,493	12,783,607	1,096,884	679,477	
x Share of Costs	4.20%		0.00%		4.00%		
Costs / Customer	3,486,197	551,226	0	0	43,875	27,179	
Rev. Req.	242,231	565,902	0	0	3,049	27,903	
Function Subtotal	808,133		0		30,951		839,085

As intended, the customer faces similar total bills under either the E22 rate or N22 rate in the no self-generation scenario. Under the E22 rate the customer can avoid demand charges in the months it does not take service because the E22 billed demands are 1/2 and 1/12th of full-year demand. However, SaskPower must plan for the capacity to provide backup service to the customer at any time so its demand-related costs are not avoided. The CRS rates appropriately recover demand related costs irrespective of actual demand or energy so demand costs are fully recovered regardless of the number of months service is taken. Total recovery from the average N22 customer is always close to the total costs caused by the customer.

The R/C ratios of the five scenarios are summarized in the following table. These results demonstrate that the N22 rate performs better than the E22 rate with respect to cost recovery in scenarios where there is self-generation. SaskPower is not able to fully recover costs caused by self-generating Power Class customers under current standard rates so, without CRS rates, SaskPower would be forced to increase charges for customers without self-generation to recover the recovery shortfall from customers with self-generation.

Table 9 – R/C Ratios

Scenario	Description	E22	N22
Scenario 1	No self-generation	0.995	0.995
Scenario 2	50% self-generation – 75% ratchet in 6 months	0.782	1.009
Scenario 3	1 month generation – 75% ratchet in 11 months	0.481	1.028
Scenario 4	1 month generation – no ratchet	0.217	1.028
Scenario 5	100% self-generation - no ratchet	0.089	1.034

DATA AND DEMAND DERIVATIONS

The measures of demand and energy are summarized in Table 10.

Table 10 – Class and Average Customer Data

	Load Factor	Max kW	CP kW	Billing Demand	Energy kWh	Customers
Class Total	59.98%	70,022.5	46,938.90	844,243	367,887,981	25
Average	59.98%	2,800.9	1,877.56	33,770	14,715,519	1
Average E22	59.98%	2,800.9	2,098.01	31,493	14,715,519	1
	65.00%	2,800.9	2,098.01	31,493	15,948,324	1
	0.00%	2,800.9	792.65	23,856	-	1
Average N22	59.98%	2,800.9	2,098.01	35,606	14,715,519	1
	65.00%	2,800.9	2,098.01	35,606	15,948,324	1

Average Max kW is calculated as the class total divided by the number of customers. Average CP kW and Billing Demand figures are derived from average Max kW based on the formulas below and variables provided in Table 11.

CP kW = Max kW * (CP Slope * Load Factor + CP y-intercept)

E-Rate Billing Demand = (Max kW / Power Factor) *
(Billing Slope * Load Factor + Billing y-intercept) * 12

N-Rate Billing Demand = (Max kW / Power Factor) * 12

Table 11 – Power Class Variables

Variable	Standard (E-rate)	CRS (N-rate)
Power Factor	94.4%	
Billing Demand Slope	33.0%	0.0%
Billing Demand y-intercept	67.0%	100.0%
CP Slope	71.7%	71.7%
CP y-intercept	28.3%	28.3%
Return on Rate Base	6.77%	
Target R/C Ratio	1.027	

The Billing Demand and CP kW slopes and intercepts are derived with separate regressions using actual Power Class customer data. Recognizing that customers with high load factors contribute more to coincident peak demand than customers with similar maximum demands but lower load factors, the CP slope and intercept are based on a regression of customers' CP kW divided by Max CP kW demand on load factors. Customers with higher load factors also have higher average billing determinants relative to Max kW demand than customers with similar demand and low load factors. The Billing Demand slope and intercept are based on a regression of customers' average monthly Billing Demand kVA divided by Max CP kVA demand on load factors.

The demand calculations cause average billing demand to be less than 1/25 of total billing demand and average CP kW to be greater than 1/25 of the total coincident peak. These mismatches are the cause of the discrepancy between unscaled total class revenues and total class allocated costs that necessitate the rates to be scaled. The mismatch increases demand charges because demand-related costs rely on the average customer's share of CP, which is greater than its share of maximum demand, and the cost is divided by its share billing determinants that are lower than its share of the coincident peak.

Adjusted CP figures are used for the purpose of allocating demand costs caused by the average customer. Initial coincident peak figures are scaled so that a customer with average maximum demand and an average load factor is attributed an average ($1/25^{th}$) share of demand-related costs.

Table 12 – Coincident Peak Shares

	Load Factor	Max kW	CP kW	CP Share	Adj. CP Share	Adj. CP kW
Class Total	59.98%	70,022.5	46,938.90	106.368%	100.000%	46,938.90
Average	59.98%	2,800.9	1,877.56	4.000%		
Average E22	59.98%	2,800.9	1,997.11	4.255%	4.000%	2,800.90
	65.00%	2,800.9	2,098.01	4.470%	4.202%	2,942.42
	0.00%	2,800.9	792.65	1.689%	1.588%	1,111.68
Average N22	59.98%	2,800.9	1,997.11	2.255%	4.000%	2,800.90
	65.00%	2,800.9	2,098.01	4.470%	4.202%	2,942.42

ADDITIONAL RATE DERIVATIONS & SCENARIO ANALYSIS

This section provides details for derivations of the E23/N23 and E24/N24 rates, as well as additional scenarios to illustrate the relationship between standard rates, CRS rates, and costs caused by a wider range of customers. The E23 and N23 rates are derived in tables 13 and 14. E24 and N24 rates are derived in tables 15 and 16.

Table 13 – E23 Rate Derivation & Actual Charges

	Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
Standard Rate Design E23							
Class Alloc. Costs	156,233,384	28,090,055	111,257,207	36,077,580	950,619	532,788	
Costs / Customer	8,222,810	1,478,424	5,855,642	1,898,820	50,033	28,041	
Rev. Req.	571,344	1,517,788	406,867	1,949,377	3,476	28,788	
Function Subtotal	2,089,132		2,356,244		32,265		4,477,641
÷ Average BD	111,128	kVA	55,372,851	kWh	12	months	
Charges	**18.799**	**$/kVA**	**0.04255**	**$/kWh**	**2,288.71**	**$/month**	
E23 Rate with Bary Method							
Class Alloc. Costs	156,233,384	28,090,055	111,257,207	36,077,580	950,619	532,788	
Costs / Customer	9,521,968	1,712,007	5,855,634	1,898,817	50,033	28,041	
Rev. Req.	661,614	1,757,590	406,866	1,949,374	3,476	28,788	
Function Subtotal	2,419,204		2,356,241		32,265		*4,807,709*
Bary Adjustment	(1,126,896)		1,126,896				
Subtotal/Customer	1,292,308		3,483,137		32,265		*4,807,709*
÷ Average BD	126,014	kVA	55,372,851	kWh	12	months	
Charges	10.255	$/kVA	0.06290	$/kWh	2,688.71	$/month	
Scaling Factor	0.931		0.931		0.931		
Scaled Charges	**9.551**	**$/kVA**	**0.05858**	**$/kWh**	**2,504.12**	**$/month**	
x Average BD	126,014	kVA	55,372,851	kWh	12	months	
Scaled Total	1,203,586		3,244,006		30,049		4,477,641
E23 Average Costs Caused							
Class Alloc. Costs	156,233,384	28,090,055	111,257,207	36,077,580	950,619	532,788	
x Share of Costs	5.26%		5.26%		5.26%		
Costs / Customer	8,222,810	1,478,424	5,855,634	1,898,817	50,033	28,041	
Rev. Req.	571,344	1,517,788	406,866	1,949,374	3,476	28,788	
Function Subtotal	2,089,132		2,356,241		32,265		4,477,637
E23 Actual Charges for an Average Customer							
Current Charges	8.405	$/kVA	0.06227	$/kWh	7,093.95	$/month	
x Average BD	126,014	kVA	55,372,851	kWh	12	months	
Subtotal/Customer	1,059,151		3,448,067		85,127		4,592,346

Table 14 – N23 Rate Derivation & Proposed Charges

	Reserved Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
Standard Rate Design N23							
Class Alloc. Costs	156,233,384	28,090,055	111,257,207	36,077,580	950,619	532,788	
Costs / Customer	8,222,810	1,478,424	5,855,642	1,898,820	50,033	28,041	
Rev. Req.	571,344	1,517,788	406,867	1,949,377	3,476	28,788	
Function Subtotal	2,089,132		2,356,244		32,265		4,477,641
÷ Average BD	148,503	kVA	55,372,851	kWh	12	months	
Charges	**14.068**	**$/kVA**	**0.04255**	**$/kWh**	**2,688.71**	**$/month**	
N23 Rate @ 65% LF							
Class Alloc. Costs	156,233,384	28,090,055	111,257,207	36,077,580	950,619	532,788	
Costs / @ 65% LF	10,630,049	1,911,235	7,034,119	2,280,967	50,033	28,041	
Rev. Req.	738,606	1,962,122	488,751	2,341,699	3,476	28,788	
Function Subtotal	2,700,729		2,830,450		32,265		*5,563,443*
÷ BD @ 65% LF	148,503	kVA	66,517,008	kWh	12	months	
Charges	18.186	$/kVA	0.04255	$/kWh	2,688.71	$/month	
Scaling Factor	0.934		0.934		0.934		
Scaled Charges	**16.982**	**$/kVA**	**0.03973**	**$/kWh**	**2,510.72**	**$/month**	
x BD @ 65% LF	148,503	kVA	66,517,008	kWh	12	months	
Scaled Total	2,521,898		2,642,934		30,129		5,194,961
N23 65% LF Costs Caused							
Class Alloc. Costs	156,233,384	28,090,055	111,257,207	36,077,580	950,619	532,788	
x Share of Costs	5.88%		6.32%		5.26%		
Costs / Customer	9,179,706	1,650,470	7,034,119	2,280,967	50,033	28,041	
Rev. Req.	637,832	1,694,414	488,751	2,341,699	3,476	28,788	
Function Subtotal	2,332,247		2,830,450		32,265		5,194,961
Proposed N23 Charges							
Proposed Charges	17.409	$/kVA	0.04028	$/kWh	7.093.95	$/month	
x BD @ 65% LF	148,503	kVA	66,517,008	kWh	12	months	
Subtotal/Customer	2,585,295		2,679,305		85,127		5,349,727

Table 15 – E24 Rate Derivation & Actual Charges

	Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
Standard Rate Design E24							
Class Alloc. Costs	598,796,485	95,431,740	402,399,121	130,536,874	1,887,017	1,021,516	
Costs / Customer	16,633,236	2,650,882	11,177,753	3,626,024	52,417	28,375	
Rev. Req.	1,155,725	2,721,463	776,662	3,722,569	3,642	29,131	
Function Subtotal	3,877,188		108,755,705		32,773		8,409,193
÷ Average BD	217,270	kVA	108,755,705	kWh	12	months	
Charges	**17.845**	**$/kVA**	**0.04137**	**$/kWh**	**2,731.09**	**$/month**	
E24 Rate with Bary Method							
Class Alloc. Costs	598,796,485	95,431,740	402,399,121	130,536,874	1,887,017	1,021,516	
Costs / Customer	18,430,437	2,937,306	11,177,753	3,626,024	52,417	28,375	
Rev. Req.	1,280,600	3,015,514	776,662	3,722,569	3,642	29,131	
Function Subtotal	4,296,114		4,499,232		32,773		*8,828,118*
Bary Adjustment	(2,205,330)		2,205,330				
Subtotal/Customer	2,090,783		6,704,562		32,773		*8,828,118*
÷ Average BD	204,611	kVA	108,755,705	kWh	12	months	
Charges	10.218	$/kVA	0.06165	$/kWh	2,731.09	$/month	
Scaling Factor	0.953		0.953		0.953		
Scaled Charges	**9.733**	**$/kVA**	**0.05872**	**$/kWh**	**2,601.49**	**$/month**	
x Average BD	204,611	kVA	108,755,705	kWh	12	months	
Scaled Total	1,991,568		6,386,407		31,218		8,409,193
E24 Average Costs Caused							
Class Alloc. Costs	598,796,485	95,431,740	402,399,121	130,536,874	1,887,017	1,021,516	
x Share of Costs	2.78%		2.78%		2.78%		
Costs / Customer	16,633,236	2,650,882	11,177,753	3,626,024	52,417	28,375	
Rev. Req.	1,155,725	2,721,463	776,662	3,722,569	3,642	29,131	
Function Subtotal	3,877,188		4,499,232		32,773		8,409,193
E24 Actual Charges for an Average Customer							
Current Charges	8.284	$/kVA	0.06109	$/kWh	7,615.80	$/month	
x Average BD	204,611	kVA	108,755,705	kWh	12	months	
Subtotal/Customer	1,694,997		6,643,886		91,390		8,430,272

Note that the E24 rate class has an average load factor greater than 65% so the CRS rates are lower than standard rate design.

Table 16 – N24 Rate Derivation & Proposed Charges

	Reserved Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
Standard Rate Design N24							
Class Alloc. Costs	598,796,485	95,431,740	402,399,121	130,536,874	1,887,017	1,021,516	
Costs / Customer	16,633,236	2,650,882	11,177,753	3,626,024	52,417	28,375	
Rev. Req.	1,155,725	2,721,463	776,662	3,722,569	3,642	29,131	
Function Subtotal	3,877,188		4,499,232		32,773		8,409,193
÷ Average BD	227,656	kVA	108,755,705	kWh	12	months	
Charges	**17.031**	**$/kVA**	**0.04137**	**$/kWh**	**2,731.09**	**$/month**	
N24 Rate @ 65% LF							
Class Alloc. Costs	598,796,485	95,431,740	402,399,121	130,536,874	1,887,017	1,021,516	
Costs / @ 65% LF	17,697,757	2,820,537	10,480,401	3,399,806	52,417	28,375	
Rev. Req.	1,229,691	2,895,636	728,208	3,490,327	3,642	29,131	
Function Subtotal	4,125,327		4,218,536		32,773		*8,376,635*
÷ BD @ 65% LF	227,656	kVA	108,755,705	kWh	12	months	
Charges	18.121	$/kVA	0.04137	$/kWh	2,731.09	$/month	
Scaling Factor	0.952		0.952		0.952		
Scaled Charges	**17.251**	**$/kVA**	**0.03938**	**$/kWh**	**2,559.93**	**$/month**	
x BD @ 65% LF	227,656	kVA	108,755,705	kWh	12	months	
Scaled Total	3,927,232		4,015,933		31,199		7,974,364
N24 65% LF Costs Caused							
Class Alloc. Costs	598,796,485	95,431,740	402,399,121	130,536,874	1,887,017	1,021,516	
x Share of Costs	2.67%		2.60%		2.78%		
Costs / Customer	15,972,001	2,545,499	10,480,401	3,399,806	52,417	28,375	
Rev. Req.	1,109,781	2,613,274	728,208	3,490,327	3,642	29,131	
Function Subtotal	3,723,055		4,218,536		32,773		7,974,364
Proposed N24 Charges							
Proposed Charges	17.152	$/kVA	0.03916	$/kWh	7.615.80	$/month	
x BD @ 65% LF	227,656	kVA	101,970,705	kWh	12	months	
Subtotal/Customer	3,904,754		3,993,173		91,390		7,989,317

Table 17 provides a comparison of E23 and N23 rates under two 50% generation scenarios: one in which the customer buys energy from SaskPower for 6 months then self-generates for 6 months (with a 75% demand ratchet) and one in which the customer self-generates half its energy requirements in all months. There is no difference in the costs incurred by SaskPower in each scenario but the customer faces different total bills.

Table 17 – 50% Self-Generation Scenarios – E23/N23

	Reserved Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
6 Months of Self-Generation							
E23 Rate @ 65% LF							
Current Charges	8.405	$/kVA	0.06227	$/kWh	7,093.95	$/month	
x Average BD	114,932	kVA	33,258,504	kWh	12	months	
Subtotal/Customer	966,006		2,071,007		85,127		3,122,140
N23 Rate @ 65% LF							
Proposed Charges	17.409	$/kVA	0.04028	$/kWh	7.093.95	$/month	
x BD @ 65% LF	148,503	kVA	33,258,504	kWh	12	months	
Subtotal/Customer	2,585,295		1,339,653		85,127		4,010,075
65% LF Costs Caused							
Class Alloc. Costs	156,233,384	28,090,055	111,257,207	36,077,580	950,619	532,788	
x Share of Costs	5.88%		3.16%		5.26%		
Costs / Customer	9,179,706	1,650,470	3,517,060	1,140,483	50,033	28,041	
Rev. Req.	637,832	1,694,414	244,375	1,170,849	3,476	28,788	
Function Subtotal	2,332,247		1,415,225		32,265		3,779,736
50% Self-Generation in Each Month							
E23 Rate @ 92.4% LF							
Current Charges	8.405	$/kVA	0.06227	$/kWh	7,093.95	$/month	
x Average BD	131,351	kVA	33,258,504	kWh	12	months	
Subtotal/Customer	1,104,009		2,071,007		85,127		3,260,141
N23 Rate @ 92.4% LF							
Proposed Charges	17.409	$/kVA	0.04028	$/kWh	7.093.95	$/month	
x BD @ 65% LF	148,503	kVA	33,258,504	kWh	12	months	
Subtotal/Customer	2,585,295		1,339,653		85,127		4,010,075
65% LF Costs Caused							
Class Alloc. Costs	156,233,384	28,090,055	111,257,207	36,077,580	950,619	532,788	
x Share of Costs	5.88%		3.16%		5.26%		
Costs / Customer	9,179,706	1,650,470	3,517,060	1,140,483	50,033	28,041	
Rev. Req.	637,832	1,694,414	244,375	1,170,849	3,476	28,788	
Function Subtotal	2,332,247		1,415,225		32,265		3,779,736

Table 18 provides details for a scenario for the hypothetical customer E24 provided by Paper Excellence. This customer has a maximum demand of 45MW, a 92.4% load factor, and pays E24 rates. A hypothetical customer with a maximum demand of 45MW and default 65% load factor, as used in the derivation of the CRS rates, is also provided as a reference.

Table 18 – Scenario Analysis – 45MW @ 92.4% Load Factor E24/N24

	Reserved Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
50% Self-Generation in Each Month							
E24 Rate @ 65% LF – 45MW Max Demand							
Charges	8.284	$/kVA	0.06109	$/kWh	7,615.80	$/month	
x BD @ 65% LF	505,978	kVA	128,115,000	kWh	12	months	
Subtotal/Customer	4,191,519		7,826,545		91,390		12,109,454
N24 Rate @ 65% LF – 45MW Max Demand							
Proposed Charges	17.152	$/kVA	0.03916	$/kWh	7.615.80	$/month	
x BD @ 65% LF	572,049	kVA	128,115,000	kWh	12	months	
Subtotal/Customer	9,811,790		5,016,983		91,390		14,920,163
65% LF Costs Caused – 45MW Max Demand							
Class Alloc. Costs	598,796,485	95,431,740	402,399,121	130,536,874	1,887,017	1,021,516	
x Share of Costs	6.70%		3.27%		2.78%		
Costs / Customer	40,134,133	6,396,280	13,167,474	4,271,483	52,417	28,375	
Rev. Req.	2,788,635	6,566,585	914,914	4,385,213	3,642	29,131	
Function Subtotal	9,355,220		5,300,127		32,773		14,688,120
50% Self-Generation in Each Month							
E24 Rate @ 92.4% LF – 45MW Max Demand							
Charges	8.284	$/kVA	0.06109	$/kWh	6,188.90	$/month	
x BD @ 92.4% LF	557,697	kVA	182,115,000	kWh	12	months	
Subtotal/Customer	4,619,963		11,125,405		91,390		15,836,758
N24 Rate @ 92.4% LF – 45MW Max Demand							
Proposed Charges	17.152	$/kVA	0.03916	$/kWh	6,188.90	$/month	
x BD @ 92.4% LF	572,049	kVA	182,115,000	kWh	12	months	
Subtotal/Customer	9,811,790		7,131,623		91,390		17,034,803
92.4% LF Costs Caused – 45MW Max Demand							
Class Alloc. Costs	598,796,485	95,431,740	402,399,121	130,536,874	1,096,884	679,477	
x Share of Costs	8.46%		4.65%		2.78%		
Costs / Customer	50,659,321	8,073,707	18,717,515	6,071,897	52,417	28,375	
Rev. Req.	3,519,955	8,288,673	1,300,547	6,233,564	3,642	29,131	
Function Subtotal	11,808,629		7,534,111		32,773		19,375,513

The details for a scenario in which a customer moves from 49% self-generation under the E24 rate to 50% self-generation under the N24 rate are provided in Table 19.

Table 19 – Scenario Analysis – 49% Self-Generation E24/N24

	Reserved Demand		Energy		Customer		
	Rate Base	Expense	Rate Base	Expense	Rate Base	Expense	Total Recovery
49% Self-Generation in Each Month							
E24 Rate @ 65% LF							
Charges	8.284	$/kVA	0.06109	$/kWh	7,615.80	$/month	
x BD @ 65% LF	201,362	kVA	52,005,060	kWh	12	months	
Subtotal/Customer	1,668,080		3,176,989		91,390		4,936,459
N24 Rate @ 65% LF							
Proposed Charges	17.152	$/kVA	0.03916	$/kWh	7.615.80	$/month	
x BD @ 65% LF	227,656	kVA	52,005,060	kWh	12	months	
Subtotal/Customer	3,904,754		2,036,518		91,390		6,032,662
65% LF Costs Caused							
Class Alloc. Costs	598,796,485	95,431,740	402,399,121	130,536,874	1,887,017	1,021,516	
x Share of Costs	2.67%		1.33%		2.78%		
Costs / Customer	15,972,001	2,545,499	5,345,004	1,733,901	52,417	28,375	
Rev. Req.	1,109,781	2,613,274	371,386	1,780,067	3,642	29,131	
Function Subtotal	3,723,055		2,151,453		32,773		5,907,281
50% Self-Generation in Each Month							
E24 Rate @ 65% LF							
Charges	8.284	$/kVA	0.06109	$/kWh	6,188.90	$/month	
x BD @ 65% LF	201,362	kVA	50,985,353	kWh	12	months	
Subtotal/Customer	1,668,080		3,114,695		91,390		4,874,165
N24 Rate @ 65% LF							
Proposed Charges	17.152	$/kVA	0.03916	$/kWh	6,188.90	$/month	
x BD @ 65% LF	227,656	kVA	50,985,353	kWh	12	months	
Subtotal/Customer	3,904,754		1,996,586		91,390		5,992,730
65% LF Costs Caused							
Class Alloc. Costs	598,796,485	95,431,740	402,399,121	130,536,874	1,096,884	679,477	
x Share of Costs	2.67%		1.30%		2.78%		
Costs / Customer	15,972,001	2,545,499	5,240,200	1,699,903	52,417	28,375	
Rev. Req.	1,109,781	2,613,274	364,104	1,745,164	3,642	29,131	
Function Subtotal	3,723,055		2,109,268		32,773		5,865,096

The costs this customer causes declines by 0.17% as it increases self-generation from 49% to 50%. The customer's total bill would increase by 21.74% as it moves from the E24 rate to the N24 rate. This creates a disincentive to increase self-generation that is unrelated to cost causality. Note, however, that the customer self-generating 49% of its energy requirements is paying materially lower total bill than the costs it causes, as it avoids demand-related costs recovered through the energy charge.

Appendix D: Comments of Paper Excellence and Response of Elenchus and SaskPower

Paper Excellence ("PE") submitted a letter providing its comments on the proposed CRS rate. The letter contained a number of requests for comments of the consultant (Elenchus). The requests for comment are listed below. Responses are provided in this appendix.

1. *Can the consultant provide some comments on generation costs relative to the industrial rate?*
2. *Can the consultant comment on the proposed rate design relative to some of the other Bonbright principles, namely:*

   1. Price signals that encourage efficient use – how is the installation of generation different from reducing purchases through the implementation of other demand side management (DSM) initiatives?

   2. Rate stability – does the rate as proposed represent rate shock relative to the present industrial rates? [we have attached a spreadsheet to analyze some scenarios, please review and confirm that our interpretation and analysis represents the intent of the rate]

   3. Avoidance of undue discrimination – does the rate as proposed create discrimination within the customer class based on the definition of self-generation and the threshold to trigger the rate.

   4. Practical and cost effective to manage –

   a. how is the threshold ratio determined, generation capacity relative to historical purchases? Actual generation vs actual purchases?

   b. What happens when a customer drops below the threshold?

   c. Will the threshold calculation be adjusted to reflect one time impacts (e.g., major maintenance, market curtailments, force majeure events, etc.)
3. *Can the consultant comment on the number of jurisdictions in Canada where industrials are selling energy back to the utility/grid?*
4. *Can the consultant comment on the determination of peak demand in other jurisdictions?*
5. *Can the consultant review our analysis to confirm our interpretation of the rate schedule?*

6. *Can the consultant comment on the application of a similar [to BC] energy only product for SaskPower?*

1. *Can the consultant provide some comments on generation costs relative to the industrial rate?*

Please refer to Appendix C of the Elenchus Report, Table 9. Scenario 1 in Table 1 shows the revenue-to-cost ratio for the E22 class is 0.995 for a customer with no self-generation. The revenue-to-cost ratio for the E23 is 1.026 and E24 ratio is 1.003 for customers with no self-generation. The revenue-cost-ratio is based on the most recent update of SaskPower's costs allocation model. The costs include transmission as well as generation costs. The revenue, costs caused, and R/C Ratio of an average customer in each class are provided below.

Rate Code	Revenue	Costs Caused	R/C Ratio
E22	$1,426,958	$1,434,764	0.995
E23	$4,592,346	$4,477,637	1.026
E24	$8,430,272	$8,409,193	1.003

As described in Elenchus' CRS Report, SaskPower uses a Bary Method adjustment that shifts a portion of demand-related costs to be recovered through energy charges. This adjustment is detailed in Appendix C of the Elenchus Report (see table 15). The current energy charge for an E24 customer is $61.09/MWh and SaskPower's generation costs are $41.37/MWh.

2. *Can the consultant comment on the proposed rate design relative to some of the other Bonbright principles, namely:*

   (1) *Price signals that encourage efficient use – how is the installation of generation different from reducing purchases through the implementation of other demand side management (DSM) initiatives?*

   (2) *Rate stability – does the rate as proposed represent rate shock relative to the present industrial rates? [we have attached a spreadsheet to analyze some scenarios, please review and confirm that our interpretation and analysis represents the intent of the rate]*

   (3) *Avoidance of undue discrimination – does the rate as proposed create discrimination within the customer class based on the definition of self-generation and the threshold to trigger the rate.*

   (4) *Practical and cost effective to manage –*

      a. *how is the threshold ratio determined, generation capacity relative to historical purchases? Actual generation vs actual purchases?*

      b. *What happens when a customer drops below the threshold?*

      c. *Will the threshold calculation be adjusted to reflect one time impacts (e.g., major maintenance, market curtailments, force majeure events, etc.)*

RESPONSE

Elenchus interprets PE's comment as referring to the ten "attributes of a sound rate structure" that are identified at page 383-384 of Bonbright, James C., Albert L Danielsen and David R Kamerschen, Principles of Public Utility Rates, Second Edition (1988), Public Utilities Reports, Inc. ("Bonbright") rather than the eight principles listed at page 291 in the first edition of that seminal work.

PE's comments state that "[T]he report focusses on the principles of cost recovery and the fair apportionment of costs." Elenchus does not agree with this characterization. Elenchus' analysis considered all ten of the Bonbright principles, although this report was not structured to explicitly address each principle in a systematic way. Elenchus notes below how the assessment of the CRS rates took into account each of the four principles identified in the EM comments.

Price signals that encourage efficient use: Elenchus interprets this point to encompass Bonbright's attributes #4, static efficiency, and #8, dynamic efficiency. As Bonbright's full discussion of the issues, particularly in Part Four, The Rate Structure, makes clear, static and dynamic efficiency would most effectively be achieved by adopting rates that correspond to short-term and long-term marginal costs, respectively. Since a public utility such as SaskPower would either over-recover or under-recovery (generally the latter) if tariffs were based on marginal costs, regulators across Canada and elsewhere have adopted fully allocated (or distributed) costs as the basis for rate setting. See Bonbright, chapter 19 for a discussion of this approach. In the Elenchus report, this point is made in section 4.1, page 16, where it states:

> *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.*

The approach taken by Elenchus in the report is consistent with accepted regulatory practice in Canada and internationally. Elenchus has attempted to point out that further rate evolution will become necessary in the coming years and decades as the traditional practice of basing rates on fully allocated costs becomes more difficult to sustain.

Rate stability; This issue is typically addressed by SaskPower and other electric utilities by phasing in significant rate changes. Elenchus takes it for granted that SaskPower will not implement a rate change that results in unacceptable rate shock. The Bonbright principles do not imply that rate shock should be avoided by maintaining a rate that is misaligned with costs any longer than is necessary to mitigate rate shock.

Avoidance of undue discrimination: The refinements to the CRS rates as proposed by SaskPower contained in the Elenchus report are intended to address both the unintended incentive for customers to "game the system" and to ensure that the rates for all customer classes are designed to ensure that there is no undue discrimination (as defined by Bonbright attributes #6 and #7). Elenchus notes that this concern would be most effectively addressed by billing using coincident peak demand, rather than non-coincident peak demand, as the billing determinant for demand-related costs. Given the practical difficulties of billing on the basis of coincident peak demand, Elenchus notes that various "next best alternatives" have been adopted by utilities. For example, the Bary correction has been used by SaskPower; however, that has resulted in the unintended incentives discussed in the Elenchus report. An alternative used in some other jurisdictions is to bill based on multiple coincident peaks (for example, the "high five" approach used for large industrial customers in Ontario).

Practical and cost effective to manage: The Bonbright attributes include two "Practical-related Attributes: "9. The related practical attributes of simplicity, certainty, convenience of payment, economy of collection, understandability, public acceptability, and feasibility of application" and "10: Freedom form controversy as to proper interpretation." It is in recognition of the types of questions raised by PE that Elenchus commented in section

2.1 on Applicability that “[T]he self-generation threshold in other jurisdictions is lower than 50%, most often it is 15%.” In retrospect, the view of Elenchus on this point lacked clarity.

Elenchus recommends that the threshold should be eliminated, provided that the rules related to nomination of Reservation Capacity (see the discussion on page 9-10 of the Elenchus report) are modified to address the identified concerns related to the incentive to game the system by nominating less capacity than is actually required in order to avoid paying for rates that reflect actual causal costs.

3. *Can the consultant comment on the number of jurisdictions in Canada where industrials are selling energy back to the utility/grid?*

It is a standard practice in all jurisdictions for industrial customers with generation assets to sell energy to a utility or into the grid. Power sold to the utility is generally contracted as a power purchase agreement ("PPA") that is entered into by the utility as an integral part of its supply planning.

Elenchus notes that Ontario and Alberta have very different electricity systems than other provinces. These provinces operate a real-time wholesale electricity market in which all participants including industrial customers with generation assets, competitively sell output at their marginal cost on a short-term (5-minute) basis. The other provinces are served primarily by vertically integrated utilities.

Province	Industrial load sells power to grid
British Columbia	✓
Alberta	✓
Saskatchewan	✓
Manitoba	✓
Ontario	✓
Quebec	✓
New Brunswick	✓
Nova Scotia	✓
Newfoundland and Labrador	✓

British Columbia: BC Hydro has signed more than 100 power purchase agreements (PPAs) with a range of generators. A number of these generators, predominantly cogeneration and biomass facilities, are located within industrial load customers.

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/ipp-supply-list-in-operation.pdf

Alberta: Many large industrial customers, particularly in the oil sands and mining sectors, have installed cogeneration generators. These assets often sell excess energy into the real-time wholesale energy market.

http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet

Saskatchewan: SaskPower has a number of Power Purchase Agreements (PPAs) with Independent Power Producers (IPPs), made up largely of natural gas and wind generation.

https://www.saskpower.com/Our-Power-Future/Powering-2030/Creating-A-Cleaner-Power-Future

Manitoba: Manitoba Hydro allows alternative energy technologies to sell excess energy back to the utility at a pre-established non-utility generation price.

https://www.hydro.mb.ca/accounts_and_services/generating_your_own_electricity/

Ontario: Ontario has undertaken multiple procurements for combined heat and power (CHP) plants. These assets are often located at industrial facilities. Nearly all these power purchase agreements (PPAs) are for terms of 20 years. Many industrial facilities also participate in the Industrial Conservation Initiative (ICI) – a peak shaving program offered to large loads. As a result of the ICI, many industrial loads have installed some form of behind-the-meter generation. The Market Surveillance Panel recently completed a comprehensive and critical analysis of this program.

https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

http://www.ieso.ca/en/Sector-Participants/Energy-Procurement-Programs-and-Contracts/Combined-Heat-and-Power

And as an example:

https://www.power-technology.com/projects/thorald/

Quebec: Hydro Quebec has signed a number of long-term PPAs with cogeneration facilities, many of which are located within industrial facilities. A list is available at:

http://www.hydroquebec.com/electricity-purchases-quebec/electricity-contracts.html

Also see:

https://renewablesnow.com/news/innovente-buys-5-mw-cogeneration-plant-in-canada-14608/

New Brunswick: NB Power has a few PPAs with industrial facilities with installed cogeneration plants. Two examples are:

https://www.twinriverspaper.com/operations/edmundston-pulp-mill/, and https://www.tcenergy.com/siteassets/pdfs/power/grandview-cogeneration-plant/tc-power-grandview-fact-sheet.pdf

Nova Scotia: Nova Scotia signed several long-term PPAs with generators – wind and biomass, among others – at industrial facilities.

https://energy.novascotia.ca/sites/default/files/files/Copy%20of%20DRAFT%20Comfit%20Status%20as%20of%20May%202019.pdf

Newfoundland and Labrador: Nalcor energy has signed a limited number of long-term PPAs, with a portion of these assets located within industrial facilities. See page 52 at:

https://www.gov.nl.ca/nr/files/publications-energy-review-of-nl-electricty-system.pdf

4. *Can the consultant comment on the determination of peak demand in other jurisdictions?*

Recorded demand for customers in rate classes analogous to the Power Class within other jurisdictions are typically determined by actual measured non-coincident peak demand. Many jurisdictions measure and bill based on kW instead of kVA. The use of demand ratchets varies by jurisdiction. As is the case with SaskPower, for purposes of allocating costs to customer classes, typically the coincident peak demand of the classes is used as the allocator of demand-related costs.

With respect to capacity reservation service, most utilities surveyed by Elenchus in other jurisdictions use a similar “reservation capacity” measure for backup/standby service rate designs. The same reservation capacity is used in each month until a customer can demonstrate that it can reduce demand during backup/standby service periods. Reservation capacity is used by utility planners to maintain the customer’s identified backup/standby capacity so some utilities impose punitive charges for exceeding reservation capacity in order to incentivize customers to provide the appropriate level of reservation capacity commiserate with its maximum demand. Reservation capacity is usually provided by the customer; however, in some cases it is determined by the utility. Some utilities use a customer’s recorded demand before generation is installed as the reservation capacity. An increase to reservation capacity when actual demand exceeds the current reservation capacity is a common feature of backup/standby service rate designs.

5. *Can the consultant review our analysis to confirm our interpretation of the rate schedule?*

Paper Excellence's interpretation of the CRS rate schedule (N24) is correct.

The CRS on-peak energy charge is listed as $36.16/MW but should be $39.16/MW within the spreadsheet. The all-in CRS charge is described as $93.14/MWh in the preamble to the question but the all-in charge, including carbon tax, is $95.13/MWh. The calculation is revised to $96.47/MWh with the on-peak charge correction. Elenchus considers these to be typos rather than misinterpretations of the schedule.

The spreadsheet calculations for the standard Power Service (E84 & E24) rates are correct assuming the customer does not self-generate or take capacity reservation service during "planned maintenance" days and the customer reaches its maximum demand in each month, including the "100% Self Generation" scenario (which could more accurately be labelled "95% Self Generation"). A customer's average monthly billing demand is typically lower than its annual maximum demand and it can be expected to be even lower for self-generating customers. A typical standard Power Class customer with the characteristics of the hypothetical customer within the spreadsheet would have lower average monthly demand, and therefore lower total demand charges and total bills, than what is calculated in the spreadsheet. Please see Table 18 of Appendix C for Elenchus' derivation of rates and costs caused by the hypothetical customer provided in the spreadsheet.

6. *Can the consultant comment on the application of a similar [to BC] energy only product for SaskPower?*

For background, this rate was first introduced in 1991 and has been in place since.

The main difference between the RS 1880 referenced in this IR and what SaskPower is proposing is that RS 1880 is an interruptible service and, as such, has no associated demand charge. There is a small administrative charge ($150) per incident, but the customer is charged only for energy consumed due to it being an interruptible service. As it's an interruptible service, BC Hydro does not need to consider it in its capacity forecasts or requirements.

- See page 402: https://sitecstatement.files.wordpress.com/2016/05/bc-hydro-2015-2015-rate-design-application-appendix-c-5a-p-107.pdf
- See page 29: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/tsr/0-2019-04-15-bchydro-order-request-rs1828.pdf
- See page 65: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-03-13-bch-rda-wksp5-tsr1-pfb.pdf

Elenchus does not consider a rate similar to BC Hydro's RS 1880 to be applicable to the current SaskPower circumstances. In particular, interruptible rates such as BC Hydro's RS 1880 are general introduced at a time when the utility is faced with expensive capacity upgrades to meet expected peak demand requirements. The interruptible rate is economically justified when the lost revenue resulting from the introduction of the interruptible rate is less than the avoided cost that result from the reduction in peak demand when the peak is shaved by replacing firm service with interruptible service.

Appendix E: Questions of Mosaic and Response of Elenchus and SaskPower

Mosaic submitted the document that included the following seven questions related to the Elenchus report. Elenchus and SaskPower have provided the responses contained in this appendix.

1. *When was the Bary correction first implemented, and what was the original intent?*
   - *Elenchus report states it was to improve intra-class equity; was there ever a case of inter-class subsidization?*
   - *Would SaskPower consider removing Bary correction for entire Power Class?*
2. *Please provide an example of the CRS structure if a 100% load factor were utilized as per the recommendation from Elenchus on page 18.*
3. *Please provide SaskPower's winter/summer coincident peak and non-coincident peak profiles. How does the nature of the Power Class customer base compare to other jurisdictions? Would you consider the Power Class load profile diverse or does it put excessive stress on the SaskPower system?*
   - *Power Class Information Request:*
     - *Customer count*
     - *Total Revenue*
     - *Total Energy*
     - *Total Demand Peak (by non-coincident and coincident peak)*
4. *How would the utility manage the CRS reservation capacity when comparing a new customer versus an existing customer?*
   - *New Customer – would SaskPower build capacity to that site based on reservation capacity provided by customer or by aggregate site consumption? Would SaskPower build excess capacity to allow for potential interruptible service?*
   - *Existing Customer – known excess capacity to customer's facility when self-generation installed, would SaskPower require installation of automatic load shed or transfer trips from utility to customer in the event capacity is no longer available above the Reservation Capacity?*
5. *Is the SaskPower Power Class considered diverse enough to accept that it should be not be assumed all standby customers will require service at the same time during the system peak?*

- *Has an opportunity presented itself to gather the Power Class customers and solicit the potential generation capability which could be funded by the utility as proposed on page 17 of the Elenchus report? This would allow the utility to retain customers and facilitate economic bypass.*
- *Consideration should be made to account for the difference in federal and provincial carbon programs as well.*
- *What would be required within the Power Class to achieve the adequate diversity benefit for the aggregate coincident peak demand as per page 3 in the Elenchus report?*

6. *Backup Power*
   - *Will you consider the statement in the Elenchus report regarding other jurisdictions differentiating between rates for planned and unplanned events?*
     - *If consumer could procure 10% of site requirement from utility to maintain grid interconnectivity and self-generate the rest*
       - *Backup Power (Interruptible) – required during unplanned outage*
       - *Supplemental Power (Firm) – 10% mentioned earlier; site would be configured to maintain essential operations during an unplanned outage*
       - *Maintenance Power (Firm) – scheduled maintenance periods that would be pre-arranged with the utility to ensure the system had available capacity to serve the site*
7. *We support the availability of interruptible service in the event site demand exceeds the Reservation Capacity provided to the utility.*
   - *We do not support the proposed 4x existing demand charge for the interruptible service.*
   - *IT rates could be based on current economic conditions; if excess capacity is available this would facilitate additional revenue for the utility.*

1. *When was the Bary correction first implemented, and what was the original intent?*
   - *Elenchus report states it was to improve intra-class equity; was there ever a case of inter-class subsidization?*
   - *Would SaskPower consider removing Bary correction for entire Power Class?*

SASKPOWER'S RESPONSE:

The Bary Correction was first implemented into SaskPower's rates in 2001 with the oversight and support of the Saskatchewan Rate Review Panel (SRRP). It was done to address the relationship between a customer's load factor and coincident peak that is not recognized in standard rate designs. Demand related costs are allocated to customer classes based on the total coincident peak demand of the class, yet most utilities invoice customers based on each customer's non-coincident peak (billing demand). This approach implicitly assumes that all customers in the class have the same (i.e., the average) coincident factor. As a result, individual customers in a class with below average coincident factors will pay a larger demand charge than the capacity-related costs that they cause individually. Conversely, an above average coincident factor customer will pay less demand charges relative to the capacity related costs they cause. The Bary Correction was inserted into the rates to address this anomaly. Elenchus provides a detailed explanation of the Bary Correction and the rationale for its implementation on pages 1 & 2 of its report.

For clarity, SaskPower defines intra-class as between customers within the same class and inter-class as between customer classes. SaskPower does include some levels of inter-class subsidization within its rates, a standard industry practice. The level of cross subsidization is reflected in a utility's revenue to revenue requirement ratios (R/RR), which is the ratio of the revenues received from a customer class to the revenues required to serve them. A R/RR below 1.00 indicates that a customer class is paying less than the cost to serve while an R/RR above 1.00 indicates that a customer class is paying more than the cost to serve. On a system-wide basis, the ratio must equal 1.00. A range of acceptable R/RR ratios of 0.95 to 1.05 is used in many jurisdictions as being acceptable for rate design and is considered to reflect that a customer is paying their fair share of costs. SaskPower attempts to set its ratios between 0.98-1.02 during rate applications, with residential and farm customers being set to 0.98, Resellers to 1.00 and all other customers classes at 1.02.

SaskPower is currently examining its entire rate design strategies and all options, including the removal of the Bary correction, are being examined. A final decision will be announced during the next scheduled rate application.

2. *Please provide an example of the CRS structure if a 100% load factor were utilized as per the recommendation from Elenchus on page 18.*

SaskPower's Response:

Please see the table below showing the CRS rate structures at a 100% load factor:

	N22@100%	N23@100%	N24@100%
Basic Monthly	$6,188.90	$7,093.95	$7,615.80
Energy ($/kWh)	$0.04082	$0.04028	$0.03916
Demand ($/kVa)	$30.339	$23.559	$23.396

3. *Please provide SaskPower's winter/summer coincident peak and non-coincident peak profiles. How does the nature of the Power Class customer base compare to other jurisdictions? Would you consider the Power Class load profile diverse or does it put excessive stress on the SaskPower system?*

- *Power Class Information Request:*
    - *Customer count*
    - *Total Revenue*
    - Total Energy
    - Total Demand Peak (by non-coincident and coincident peak)

ELENCHUS' RESPONSE:

Electric utilities across Canada define their industrial and commercial classes in different ways that reflect the types of demands that their customers have. Most utilities attempt to define their large volume classes in a way that groups customers with similar demands into distinct rate classes. As a result, it is not unusual for there to be limited diversity within each industrial and commercial class. When that is done, most customers within the class have load factors and coincidence factors that are close to the average, making adjustments such as the Bary correction less necessary.

When a rate class is fairly homogeneous there is relatively little intra-class diversity. The diversity benefits relate more to intra-class diversity which is captured in the cost allocation study since cost allocation of demand-related generation and transmission costs is based on the coincident peak demands of the customer classes.

Given the inconsistency of both the definition and the make-up of large volume classes across utilities undertaking a comparison would require significant effort and resources.

SASKPOWER'S RESPONSE:

Saskatchewan Power Class customers are usually base loaded due to their processes, meaning that they typically do not vary their load hour by hour, day by day, or even season by season. There may exist some diversity from customer to customer; however, the overall class is viewed as a base loaded entity, and are consistently drawing load at the time of system peak, as indicated by their high coincident peak load factors in the table below:

						2CP		WINTER		SUMMER	
	Customers	Revenue	GWH	NCP KW	NCP LF %	2CP KW	2CP LF%	CP-W KW	Winter LF%	CP-S KW	Summer LF%
Power Class	137	$ 808,842,258	10,149.7	1,784,953	64.9%	1,223,327	94.7%	1,248,575	92.8%	1,198,079	96.7%

It should be noted that although the Power Class' summer peak is lower than their winter, summer deliverability capability is de-rated relative to winter due to higher ambient temperatures. Air cooled equipment (breakers, switches, conductors, etc.) has a reduced capability the higher the ambient temperature. Based on information from SaskPower staff, the capacity of network equipment in the summer can be reduced by as much as 20% to 30% of the winter capacity due to the higher summer temperatures. As a result, even though SaskPower is a winter peaking utility, it is the summer capacity that determines the required installed capacity of certain facilities.

4. *How would the utility manage the CRS reservation capacity when comparing a new customer versus an existing customer?*
   - *New Customer – would SaskPower build capacity to that site based on reservation capacity provided by customer or by aggregate site consumption? Would SaskPower build excess capacity to allow for potential interruptible service?*
   - *Existing Customer – known excess capacity to customer's facility when self-generation installed, would SaskPower require installation of automatic load shed or transfer trips from utility to customer in the event capacity is no longer available above the Reservation Capacity?*

SASKPOWER'S RESPONSE:

For new and existing customers, SaskPower assesses system impacts based on what is requested by the customer. Facilities are installed to service the requested capacity. Transmission facilities provide a step change to installed capacity. As an example, one of SaskPower's standard 138/72-25 kV transformers are 25 MVA. If a customer requests 10 MVA of 25 kV service and the existing 25 kV network in the area can not support it, a step change in transformer capacity would be required. Similarly, the line built to the customer site would be a step change (not just exactly for 10 MVA).

ELENCHUS' RESPONSE:

Non-firm/interruptible service is typically provided on the basis that offering interruptible service is the least cost option for meeting peak demand. For example, in a capacity constrained system expensive system upgrades can be avoided if some customers can be interrupted in high demand periods. Interruptible service has no value to a utility if investment in capacity upgrades cannot be avoided.

Utilities that maintain interruptible service as an on-going option typically do so for one of two reasons.

- The interruptible (or curtailable) rate may be made available to customers that use it to displace alternate types of energy when the interruptible supply is available and lower cost. For example, Manitoba Hydro offers curtailable service at a rate that is based on the value of its power in the export market. Manitoba Hydro reduces it exports when it can sell power to a domestic customer at a rate that is as profitable as exporting the power.
- Interruptible power is more commonly used as a supply tool with industry and the utility engaging in joint planning to minimize the total cost of meeting the needs of customers.

5. *Is the SaskPower Power Class considered diverse enough to accept that it should be not be assumed all standby customers will require service at the same time during the system peak?*
    - *Has an opportunity presented itself to gather the Power Class customers and solicit the potential generation capability which could be funded by the utility as proposed on page 17 of the Elenchus report? This would allow the utility to retain customers and facilitate economic bypass.*
    - *Consideration should be made to account for the difference in federal and provincial carbon programs as well.*
    - *What would be required within the Power Class to achieve the adequate diversity benefit for the aggregate coincident peak demand as per page 3 in the Elenchus report?*

SASKPOWER'S RESPONSE:

Historically, SaskPower has worked with customers to contract for large scale power when an opportunity has existed. Some customers have also installed self-generation for back-up purposes. From a production cost of electricity perspective, small scale thermal electricity generation installed by customers is not cost effective relative to SaskPower building larger thermal generation facilities. New small thermal generation facilities also emit greenhouse gas emissions at a higher rate than larger thermal generation facilities that SaskPower builds. No economic or environmental advantage for Saskatchewan is gained by encouraging smaller scale thermal generation since it is higher cost and has higher emissions.

As far as the Saskatchewan wholesale electricity sector is concerned, there is only the Federal regulator. Federal regulation imposes a cost which SaskPower seeks to mitigate as it can economically, but the cost is primarily unavoidable and is passed along to rate payers. Discriminating between rate payers in applying this cost burden is not desirable; it is inefficient and unfair. The potential advantage of self-generation to avoid paying this cost is a problem but it is better resolved by changes to Federal and Provincial regulation to provide a similar treatment between wholesale generation and self-generation.

As detailed in Question 3, Power Class customers consistently draw load at the time of system peak during the winter and summer seasons, indicating there is little diversity within the class. From the system planning perspective, firm backup requires the same capacity to be available at the peak whether or not the CRS customer has self-generation. Furthermore, since the self-generation is either available or not available, the diversity benefit that is realized with a firm customer is lost. The firm classes (E22/E23/E24) will have less diversity and the CRS classes will have no diversity until there are multiple customers in the class.

Furthermore, the CRS rates were derived based on existing Power Class' profiles, as there is no other historical load data to base their designs from. Since there are no customers currently residing on the CRS rates, determining the actual diversity benefit whenever the number of customers is too low requires an extensive analysis of the maximum coincident peak demands of the class over many years. Therefore, SaskPower currently does not have enough information to assume all standby customers will not require service at the same time during system peak. SaskPower would require at least 3 to 5 years of load data of multiple customers within the class to verify its diversity. Caution should be exercised, however, as diversity does not necessarily correlate with benefit. Costs are allocated to customer classes based on cost causality principles. It is possible that the maximum coincident peak demand of the newly defined class may result in higher demand charges, depending on their consumption at the time of SaskPower's system peaks.

6. *Backup Power*

   - *Will you consider the statement in the Elenchus report regarding other jurisdictions differentiating between rates for planned and unplanned events?*

     - *If consumer could procure 10% of site requirement from utility to maintain grid interconnectivity and self-generate the rest*

       - *Backup Power (Interruptible) – required during unplanned outage*
       - *Supplemental Power (Firm) – 10% mentioned earlier; site would be configured to maintain essential operations during an unplanned outage*
       - *Maintenance Power (Firm) – scheduled maintenance periods that would be pre-arranged with the utility to ensure the system had available capacity to serve the site*

ELENCHUS' RESPONSE:

The Elenchus report implicitly addresses each of these possible service options by observing that the primary rate design principle is that customers should pay a share of the utility's costs that corresponds to the cost they cause. The "cost causality principle".

It follows that if, from a planning perspective, any portion of a customer's load that must be included in the utility's forecast demand for system planning purposes "causes" the related energy and capacity costs that will be required to serve the customer's load. Causal costs should be recovered from the "causing customer" whether the required energy and capacity is required 100% of the time or only during planned or unplanned outages.

Required backup, supplemental and maintenance power as defined in the question will each cause the utility to maintain available capacity and energy unless the customer is technically and economically able to forgo grid-based electricity in the relevant circumstances. The terms and conditions for any of the services need to be designed to send an economic signal to customers that is consistent with the system planning assumptions and is an effective deterrent against gaming the system (e.g., paying a rate for interruptible service only because the customer believes the utility has the capacity to serve it; hence, interruption is not a practical consideration).

SASKPOWER'S RESPONSE:

SaskPower agrees with Elenchus' statement above. The scenarios above entail customers securing minimum interconnectivity to the grid while requiring SaskPower to maintain facilities that have the potential to provide full stand-by services for their self-generated loads at reduced rates. Any rates designed for services must be reflective of the utility's costs (the majority of which are fixed), be recovered based on cost-causality principles and consistent with the system planning assumptions (currently the maximum peak demand the customer has reached over the previous rolling 2-year period).

7. *We support the availability of interruptible service in the event site demand exceeds the Reservation Capacity provided to the utility.*
    - *We do not support the proposed 4x existing demand charge for the interruptible service.*
    - *IT rates could be based on current economic conditions; if excess capacity is available this would facilitate additional revenue for the utility.*

ELENCHUS' RESPONSE:

Elenchus interprets this question as seeking comment on the merit of SaskPower introducing an interruptible service that could be utilized if demand exceeds the Reservation Capacity provided to the utility.

Elenchus notes that interruptible service is normally introduced by a utility as a means of shaving peak demand. This is done to avoid incurring significant capital costs to increase its generation and/or transmission capacity as would otherwise be required to meet forecast peak firm demand. In that circumstance, interruptible service is the least cost option of meeting future customer demand.

In a circumstance where capacity expansion is not required, enabling customers to replace firm demand with interruptible demand will have the effect of shifting the recovery of causal costs from the customers that switch to the lower interruptible rates to the remaining firm customers.

Also refer to the response to PE #6 at page 11 of Appendix D.

APPENDIX F: COMMENTS OF NUTRIEN AND RESPONSES OF ELENCHUS

Nutrien submitted comments on April 13 that addressed several statements contained in the Elenchus report. A number of the comments stated that Nutrien agreed with the quoted statement. The areas of agreement are not addressed in this appendix.

For each of the 12 comments that expressed disagreement or agreement with a caveat, the quoted text from the Elenchus report, the Nutrien comment and Elenchus' response are provided in this appendix.

1. Elenchus Report: 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 to the causal demand-related costs associated with conventional firm power."*

Nutrien disagrees;

There is a considerable difference between customers self-generating with solar and wind driven generation (which require back-up power on a regular, consistent basis) and those utilizing natural gas fired generation (which require back-up power only when generation equipment fails, fuel delivery is interrupted or during planned maintenance).

The probability that a self-generating industrial customer utilizing natural gas fired generation would have a generation failure on the system coincident peak hour is significantly less than the likelihood that a sales customer without self-generation will consume its maximum contract demand on that same hour.

Also, different options are available to industrial self-generation customers should an interruption occur. Unlike residential or commercial customers which must have power to function, industrial customers may have load shedding options which limit power requirements well below historical usage.

The assignment of cost responsibility to an industrial CRS Service should consider these facts.

ELENCHUS RESPONSE

Elenchus does not disagree with the comments of Nutrien; however, the circumstances that are implicit in the comments of Nutrien are not the same as the circumstances referred to in the quote from the Elenchus report.

The Elenchus report states: “Assuming a customer with self-generation wants SaskPower to provide reliable backup power for its self-generation capacity whenever required …” The context is a service which always makes firm capacity available to a customer, including at the time of system peak. This capacity on the system must be available whether it is utilized by the customer or not; hence there is no difference in terms of capacity-related costs between the CRS and firm service. Energy-related costs, of course, will depend on actual utilization of this capacity.

Nutrien’s comment states that “industrial customers may have load shedding options which limit power requirements well below historical usage.” This statement implies a context in which the customer’s reservation capacity considers load shedding options that allow it to nominate a capacity that is less than its historical usage. Hence, capacity in excess of the nominated Reservation Capacity will not be utilized.

The definition of the Reservation Capacity in SaskPower’s CRS takes this consideration into account since the capacity nominated by the customer is not necessarily based on historical usage. It is intended to be based on the customer’s actual reservation capacity requirement. This requirement would be net of load shedding ability.

Elenchus agrees that customers should not be required to nominate a CRS reserve capacity in excess of its actual requirement, on the basis of historical usage. At the same time, the rules related to the nomination of reservation capacity should not be open to gaming – that is, the opportunity to nominate and pay for less capacity than is actually required once an outage occurs. As suggested by Elenchus, the simplest way to achieve this result would be to limit the CRS customer’s right to access capacity under the CRS to the nominated capacity.

See also the quote from the Elenchus report included for comment #5.

2. *Elenchus Report: The Implication for CRS Rates*

> *“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.”*

Nutrien agrees.

However, we disagree that the number of customers is the only appropriate measure of when the diversity benefit is recognized.

Elenchus Response

For the sake of clarity, it should be noted that the intent of Elenchus' comment is that any diversity benefit would be determined by assessing the load profile of the class. The reference to the number of customers is not intended to suggest that the load profile of the customers and the class would not be relevant, only that there would have to be more than one customer before load profile diversity would be relevant. Furthermore, consistent with the law of large numbers, the confidence interval for diversity benefit decreases as the number of customers increases.

Elenchus therefore agrees that other factors may be relevant in assessing any diversity benefits. At the present time, and under the present circumstances, however, Elenchus is not aware of any additional factors that would be relevant in assessing the diversity benefit for allocating demand-related costs to the CRS class.

3. Elenchus Report: 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."*

Nutrien agrees.

However, the CRS customer should be allowed to determine the amount of reserved capacity.

Elenchus Response

See the response to comment #1 above.

4. Elenchus Report: The Implication of Reduced CRS Reservation Capacity Nominations

> *"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 when self-generation is adopted." (emphasis added)*

Nutrien agrees.

However, it should not be assumed that all CRS customers will require 100% backup.

Elenchus Response

See the response to comment #1 above.

5. Elenchus Report: SASKPOWER'S CRS PROPOSAL -2.3 RESERVATION CAPACITY

"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. For instance, they may be able to curtail their demand during self-generation outages at minimal cost to the business."

Nutrien agrees.

A CRS customer should be able to nominate its reservation capacity based solely on its willingness to accept the risk that the nomination is sufficient and not require details as to how the reservation amount was determined. However, this favorable provision is somewhat undone by SaskPower's proposed 12- month billing demand ratchet.

Also, it seems reasonable that any difference between CRS customer reservation demand and their prior full-service sales demand be recognized as capacity available to meet system requirements, thereby reducing the need and expense for future capacity expansion. This benefit should be reflected in the determination of CRS rates.

ELENCHUS RESPONSE

The demand ratchet is one possible way to address the risk of gaming. It reduces the ability of a customer to avoid paying its share of demand-related costs while retaining its ability to rely on SaskPower to provide 100% backup for its actual requirement as demonstrated during an outage.

In the view of Elenchus, the demand rachet is not the preferred method for addressing this concern. For example, a demand rachet would not be required if the customer has no ability to exceed its nominated capacity. If a CRS customer is able to exceed its nominated capacity, however, there would have to be either sufficient risk that the additional capacity would not be available, or a sufficient penalty charge, to address the incentive to game the system.

6. Elenchus Report: SASKPOWER'S CRS PROPOSAL -2.3 RESERVATION CAPACITY

"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."

Nutrien comment;

Elenchus offers two possible terms and conditions to accommodate a CRS customer nominated reservation capacity amount.

The second of these options is preferable because it allows the utility to receive an incremental revenue contribution to recover excess capacity cost. However, while some penalty may be necessary to avoid gaming, the 4X the demand rate example provided seems arbitrary and excessive.

ELENCHUS RESPONSE

At the core of the concern with gaming is the reality that unless customer self-generation is serving as an alternative to SaskPower investing in increased system capacity, the customer's investment in self-generation will not result in any capacity-related costs being avoided by SaskPower (only energy-related costs will be avoided). In the absence of avoided costs, the primary effect of self-generation is that costs will be shifted from the customer that is self-generating to other customers.

Elenchus notes that further analysis would be required to determine the penalty that would be sufficient to remove the incentive to game the system.

In the view of Elenchus, the ideal approach to ensuring that self-generation does not constitute uneconomic bypass would be to include customer plans to self-generate in SaskPower's system planning so that self-generation is only adopted when it is the least cost solution to meeting the total electricity requirements of all customers.

See the response to comment #10 below.

7. Elenchus Report: SASKPOWER'S CRS PROPOSAL - 2.4 BILLING DEMAND

Nutrien comment;

Elenchus mentions but does not fully discuss SaskPower's proposed 12-month billing demand adjusted ratchet. Given the low probability of repeated generation failure, it *is unreasonable to assume that a single excess demand incident is indicative of the next 12 months capacity reservation requirement. SaskPower's proposed billing demand ratchet is punitive and unjustified if excess capacity is available to satisfy the single incident excess demand.*

Furthermore, the imposition of an unrealistically high monthly demand cost which cannot be avoided for 12 months, coupled with the significantly lower CRS energy charge could provide a disincentive for continued on-site generation operation. Alternative mechanisms to encourage setting appropriate reservation amounts such as overrun penalties should be considered.

ELENCHUS RESPONSE

Elenchus agrees that options should be considered for addressing the concern about gaming. Any option that is adopted should be effective in ensuring that the bill reductions for a customer that self-generates reflects savings on the total cost of generating and transmitting power within the province, and not just a shifting of costs to other customers.

8. Elenchus Report: SASKPOWER'S CRS PROPOSAL - 2.5 RATES

"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."

Nutrien agrees.

It is important to remember that a decremental customer is just as valuable as an incremental customer. Utilities will often offer discounted rates to obtain incremental load based on marginal economics. That rationale also applies to decremental load.

ELENCHUS RESPONSE

Elenchus agrees with the comment subject to the caveat that any discounted rate for either incremental or decremental load is not a *de facto* form of price discrimination. It would be inequitable for selected customers to receive rate discounts unless doing so is beneficial to the remaining utility customers. This win-win outcomes would only be achieved in the event that the utility is recovering more than its incremental costs and the demand to which the discount applies would be lost at a higher rate.

It is important to recognize that the value of backup service can be significant compared to the charge for backup service (e.g., the value of lost production due to backup service not being available may be a large multiple of the backup charge). It would be inequitable for a customer to be able to avoid its normal contribution to maintaining reliable service by relying on discounted backup service that it is relying on only because it expects to have *de facto* firm backup despite paying the discounted rate.

9. *Elenchus Report: OTHER MARKET DISRUPTION ISSUES*

> *"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."*

Nutrien comment;

SaskPower does not, but should, include a planned service (Maintenance Power) option in its CRS service. Likewise, many utilities offer an Economic Replacement Power option which allows the utility to sell short term power to a CRS customer at market prices if the terms of the sale are mutually beneficial.

Adding such an option to SaskPower's CRS service costs nothing but provides an opportunity to generate incremental revenue.

ELENCHUS RESPONSE

Elenchus agrees that SaskPower could consider additional service options in the future.

Elenchus reiterates, however, that the justification for new services should be that all customers benefit because any lost revenue would be offset by avoided costs. It would not be consistent with generally accepted ratemaking principles to introduce new rate designs that are discriminatory in that they facilitate bill reductions for some customers by shifting the recovery of appropriately allocated system costs to other customer in their class or to other customer classes.

10. *Elenchus Report: SUMMARY AND CONCLUSIONS - DISRUPTION OF THE ELECTRICITY SECTOR*

> *"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."*
>
> *"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."*

Nutrien agrees.

SaskPower should consider the opportunity industrial on-site power presents and resist the temptation to erect barriers designed to perpetuate a traditional utility business model.

ELENCHUS RESPONSE

Elenchus is of the view that Nutrien's comment would be addressed through the adoption of a planning process that involves collaboration between SaskPower and customers that are interested in self-generation. A constructive collaborative process would be built on joint acceptance that the evolution of the provincial system should be based on the principles of integrated resource planning with the goal of minimizing the total cost (utility and customer costs) of the electrical system in Saskatchewan.

11. Elenchus Report: SUMMARY AND CONCLUSIONS - CAPACITY RESERVATION SERVICE RATES

> *"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."*

Nutrien Disagrees.

As discussed above, the probability that a CRS customer will require 100% of its load on the system peak hour is significantly less than 100%. Furthermore, Elenchus does not explain how diversity benefits are measured, what level of diversity benefits would be enough, or why the number of customers is an appropriate metric.

ELENCHUS RESPONSE

The quoted comment relates to the specific context where the CRS is being used to back up self-generation that has not resulted in any avoided costs for the utility. Furthermore, it assumes that the customer is choosing CRS either because it is a firm service (hence, the customer's demand is included in the utility's system peak demand for system planning purposes) or the CRS capacity is being relied on by the customer as a *de facto* firm service (since the unutilized capacity when self-generation is available will become excess in the system for the foreseeable future).

Also see the response to comment #2.

12. Appendix C – Rates

Nutrien comment:

Elenchus offers a detailed calculation and justification of CRS proposed rates based on the assumption that CRS customer cost causation will be no different than the corresponding sales customer. As stated above Nutrien disagrees with that assumption.

ELENCHUS RESPONSE

See the response to comment #1 above.