Redesign of BC Hydro's transmission service rate

Information for customers and stakeholders

OCTOBER 2022

BC Hydro
Power smart

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1. Background

1.1. Overview of BC Hydro's default transmission service rate

Rate Schedule (RS) 1823, or the Stepped Rate, is the default rate for customers receiving firm electricity service at transmission voltage. It was introduced in 2006 following the Government of B.C.'s 2002 Energy Plan which included an action to encourage conservation amongst large industrial customers.[1] There are currently about 150 customer sites taking service under RS 1823. Separately, there are four exempt customers that take service under RS 1827 (Rate for Exempt Customers), three customers with sites that have biomass energy production that take service under RS 1828 (Biomass Energy Program) and FortisBC that takes service under RS 3808. Some customers on RS 1823 may also take service for a portion of their electricity consumption under one or more additional rate schedules, such as RS 1880 (Standby and Maintenance Supply) or RS 1892 (Freshet Energy).

RS 1823 consists of a flat demand charge (the price paid for power a customer draws at a given point in time, intended to recover demand-related costs on the system) as well as either a flat (RS 1823A) or tiered (RS 1823B) energy charges (the price paid per unit of energy consumed). Under the tiered rate—which is the default rate for transmission service customers—a consumption baseline is set for each customer site (or set of aggregated sites) and customers pay a lower energy charge for consumption up to and including 90% of the baseline (Tier 1) and a higher energy charge for consumption above 90% of that baseline (Tier 2). New customers or customers without an approved baseline pay a flat energy charge for a nominal 12 billing periods or other period approved by the British Columbia Utilities Commission (BCUC or the Commission).

A conservation rate

The Stepped Rate has encouraged energy efficiency and conservation from transmission service customers by providing an incentive to undertake actions that would lower their share of energy priced at the higher, Tier 2 rate. One action that customers can take is investing in customer-funded demand side management (DSM) projects which result in energy savings, lower Tier 2 energy consumption and bill savings for a specified duration.

Tariff Supplement (TS) No. 74 outlines the process for determining a customer's Customer Baseline Load (CBL), which is the basis for calculating the amount of a customer's energy priced at the Tier 1 and Tier 2 rates. As outlined in TS 74, customer-funded DSM projects are given a specific time period (duration) and may result in either:

- an adjustment (increase) to a customer's CBL, if the customer-funded DSM project is verified to be in-service during the period used to determine the initial energy CBL; or
- a treatment such that energy savings from the customer-funded DSM project do not impact whether a customer will see a reset of their CBL.

In either case, the customer-funded DSM project results in lower Tier 2 energy consumption and bill savings for a specified duration (typically, 2, 5 or 10 years based on the type of project). When the duration expires, the above TS 74 treatments no longer apply to the project.

1 Action #21 of the BC Government's Energy for Our Future: A Plan for BC ("2002 Energy Plan") stated that "New rate structures will provide better price signals to large electricity customers for conservation and energy efficiency."

1.2 Key drivers for transmission service rate redesign

Over the past 18 months, BC Hydro has been exploring options to redesign our transmission service rate in alignment with our rate design objectives of economic efficiency, decarbonization, flexibility and affordability (as described in Table 1).

Table 1: BC Hydro's Rate Design Objectives

Rate design objectives
Economic efficiency Rate design should reflect BC Hydro's short and long run marginal costs and send price signals that encourage efficient use of electricity and efficient investment decisions by customers.
Decarbonization Rate design should support greenhouse gas (GHG) reductions through electrification where economically efficient.
Flexibility Rate designs should incorporate flexibility to respond to changes in the economic and policy environment and anticipate the need for greater product and service differentiation in rate design.
Affordability Rate design bill impacts to customers should be mitigated.

In BC Hydro's view, transitioning the current transmission service rate to a rate with a higher demand charge and a lower, flat (not tiered) energy charge best meets these objectives:

- Initially, the pricing of the Tier 2 energy charge reflected BC Hydro's long run marginal cost of energy; however, the current Tier 2 price is much higher than BC Hydro's long run marginal cost of energy (i.e., ~$100/MWh vs. ~$65/MWh).
- The demand charge is intended to recover demand-related costs (i.e., costs that vary with the peak demand imposed on the system); however, the current demand charge recovers only 60% of demand-related costs.
- In July 2021, the Phase 2 Comprehensive Review of BC Hydro recommended flattening the two-tiered industrial rate to make increased consumption of clean electricity more competitive while removing a barrier to electrification and supporting the Government of B.C.'s CleanBC climate action plan.

While there are variations on the extent to which the demand charge could be increased and the energy charge could be lowered, any changes to the rate structure will necessarily increase or decrease bills for customers depending on their historical share of lower-priced Tier 1 energy and their specific energy consumption profile. Customer acceptance of a new rate design and bill mitigation (or transition) options are an important consideration with any rate design proposal. We have heard from customers that affordability, rate competitiveness, recognition of past investments in demand side management (DSM) projects, and investment certainty are top of mind in considering any potential rate design changes.

1.3 Purpose of this information booklet

This information booklet is intended to:

- Provide background on the transmission service rate redesign initiative, including stakeholder engagement activities:
  - Recap rate and bill mitigation options presented in the three public workshops held to-date.
  - Summarize feedback we received and explain how we have responded to ongoing feedback as part of the stakeholder engagement process.
- Explain key factors that have informed our thinking on current rate options since our last public workshop.
- Inform customers and interested stakeholders on our rate design proposals, including topics we will be seeking feedback on during our next public workshop.

The next public workshop on transmission service rate redesign is scheduled for October 19, 2022, which will include a more detailed discussion on the rate design and bill mitigation options presented in this booklet. Feedback from customers and interested stakeholders received during this workshop will inform our transmission service rate redesign application, which will be filed with the BCUC in early 2023 (before the end of this current fiscal year). We hope you will join us at the next workshop, and we look forward to hearing your feedback.

1.4 Structure of this information booklet

The remainder of this information booklet is structured as follows:

- Section 2 provides background on key activities and developments informing our rate design proposals, including a recap of stakeholder engagement activities, customer and stakeholder feedback and recent regulatory filings.
- Section 3 describes our proposal for the default transmission service rate, and two options to immediately offer a flat rate structure while transitioning customers to the new rate over time as well as an alternative option that would provide a more gradual transition.
- Section 4 describes our proposal for optional transmission service rates, including the adjustment, addition and/or removal of various rate schedules within the transmission service portfolio.

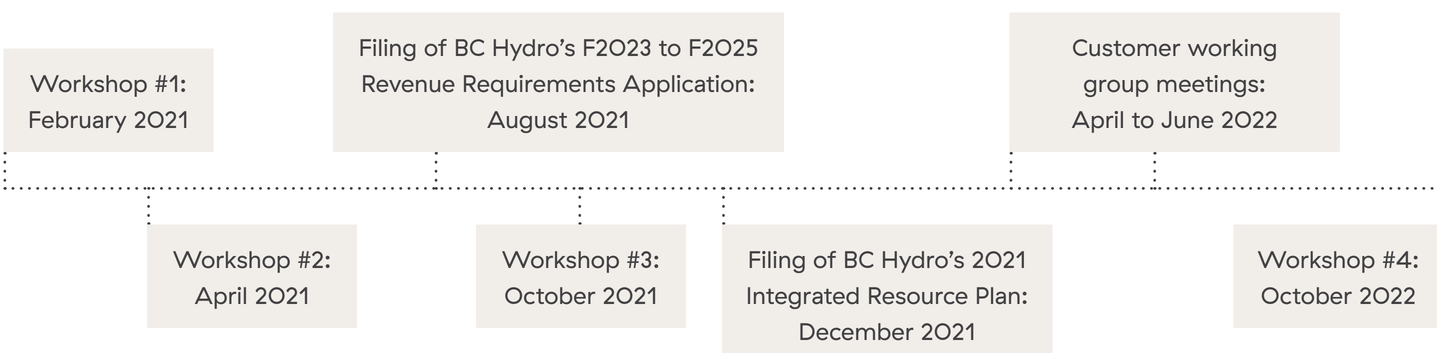
2. Key activities and developments informing our rate design proposals

This section provides a summary of key activities and developments that have informed our rate design proposals, including:

- Three public workshops that took place between February and October 2021.
- Filing of BC Hydro's F2023 to F2025 Revenue Requirements Application (RRA) in August 2021 and Integrated Resource Plan (IRP) in December 2021.
- Customer working group meetings held between April and June 2022.

A timeline of key activities and developments are outlined in the graphic below.

Figure 1: Timeline of Key Activities and Developments Informing Our Rate Design Proposal



2.1 Summary of previous public workshops

2.1.1 WORKSHOP 1: FEBRUARY 9, 2021

In the first public workshop held on February 9, 2021, we presented three revenue neutral flat rate options for feedback:

- Scenario 1—current RS 1823 demand charge and a revenue neutral energy charge.

- Scenario 2—current RS 1823 Tier 1 energy charge and a revenue neutral demand charge.
- Scenario 3—fully cost-based demand charge and a revenue neutral energy charge.

Rates were derived based on the load and revenue forecast from BC Hydro's F2022 RRA. Bill impacts ranged from −1.5% to 7.8% for an 80% load factor customer, depending on their share of Tier 1 energy.

What we heard:

- Rate options were not well supported by customers because of bill impacts and impacts on customers that have invested in DSM projects.
- Customers expressed interest in simpler rates which better incent load growth, electrification and decarbonization.
- Potential bill mitigation options were suggested by some customers.

What we concluded:

Rate design should recognize previous customer investments in DSM projects.

Rate design should manage bill increases for existing customers, including those with a high proportion of energy at the Tier 1 price.

Rate design should avoid administrative complexity.

Rate design should be consistent with rate objectives and current environment (i.e., aligned with BC Hydro's costs and encourage electrification).

2.1.2 WORKSHOP 2: APRIL 30, 2021

In the second workshop held on April 30, 2021, we presented the following:

- Jurisdictional scan for industrial default rates (Canada and U.S.):
  - Most Canadian electric utilities in regulated electricity markets offer a standard tariff with a flat energy charge and a flat demand charge for large industrial customers.[2]
  - A survey of 15 U.S. utilities for Seattle City Light identified five types of energy charges for the industrial service rate class: flat (four utilities); seasonal Time-of-Use (six utilities); seasonal flat[3] (one utility); declining block (two utilities) and Time-of-Use (two utilities).[4]
- Four rate design concepts:

1. Flat rates from Workshop 1.
2. Declining block rate—a higher, flat demand charge with a declining block energy charge (i.e., Tier 2 charge is lower than Tier 1 charge).
3. Modified Stepped Rate ('Stepped Rate 2.0')—maintain the current stepped rate design with a lower Tier 2 charge and higher Tier 1 charge, and a higher, revenue neutral demand charge.

2 The only other utility offering an inclining block energy rate is Newfoundland and Labrador Hydro through its Labrador Industrial rate. For each industrial customer receiving service on this rate, a lower energy charge is applied to consumption up to a maximum monthly threshold (referred to as the "Development Energy Block"). Past this threshold, a higher market-referenced energy rate applies. BC Hydro's Transmission Service Stepped Rate is unique since it includes customer-specific energy thresholds for determining when the higher energy charge applies through the establishment of individual Customer Baseline Loads.

3 A seasonal flat energy charge means two or more flat energy charges that vary by season.

4 Richard Cuthbert (December 2018), Industrial Service Rate Class Study for Seattle City Light.

4. Customer specific rate—rate calculated as the historical average Tier 1/Tier 2 load using F2020 as the base year.

The rate design concepts presented were priced in F2022 dollars and were derived using F2020 actual load and sales information. This reduced the forecast bill impacts relative to Workshop 1 to −5.3% to 4.3% for an 80% load factor customer, depending on their share of Tier 1 energy.

What we heard:

- Customers were generally supportive of the development of a new default rate for RS 1823.
- The Modified Stepped Rate and flat rate Scenario 3 (fully cost-based demand charge and a revenue neutral energy charge) were preferred among the rate design concepts presented. These results reflected the bifurcation of the RS 1823 customer class, with those that benefit under the existing rate structure preferring the Modified Stepped Rate, while those that benefit under a flat rate preferring flat rate Scenario 3.
- Key feedback themes included recognition of past customer investments in DSM, bill impact mitigation approaches (including moving away from revenue neutrality or separating RS 1823 customers into their own class to reduce bill impacts) and optional rate alternatives.

What we concluded:

There is a lack of customer consensus regarding the new rate structure. Customers prefer the Modified Stepped Rate or flat rate Scenario 3 depending on their individual bill impact.

Rate design should recognize customer investments in DSM.

Rate design should manage bill increases for existing customers, either through bill mitigation approaches or optional rate alternatives.

2.1.3 WORKSHOP 3: OCTOBER 22, 2021

In the third workshop held on October 22, 2021, we presented two new flat rate options that were not revenue neutral, and the top two preferred options from Workshop 2:

- Option 1—existing RS 1823 Tier 1 energy charge for all energy consumed and existing demand charge (not revenue neutral).
- Option 2—lower energy charge and moderately higher demand charge (not revenue neutral).
- Option 3 (flat rate Scenario 3 from Workshops 1 and 2)—fully cost-based demand charge, revenue neutral energy charge.
- Option 4 (Modified Stepped Rate from Workshop 2)—maintain the current stepped rate design with a lower Tier 2 charge and higher Tier 1 charge, and a higher, revenue neutral demand charge.

Options 1 and 2 had revenue shortfalls of $35 million and $20 million, respectively. BC Hydro explored whether the potential for load retention or growth could provide an economic justification for these options by offsetting the forecast revenue shortfalls.

Other bill mitigation concepts discussed during the workshop that would be revenue neutral included segmenting customers on RS 1823 into a separate rate class, delayed implementation of the new rate design and gradual implementation. Alternative bill mitigation concepts that would require funding were also considered, such as a bill credit for customers that have remaining DSM project duration (“DSM credit”), demand charge transition rates, a fixed demand credit and a high voltage credit.

Finally, we reviewed other rate schedules with pricing that is linked to the RS 1823 Tier 2 energy rate, such as RS 1880 Standby and Maintenance Supply, and optional rates such as RS 1892 Freshet Energy and RS 1893 Incremental Energy Rate, including potential changes to these optional rates that might be prompted by an update to the default rate design.

What we heard:

Following Workshop 3, we received 30 responses to our feedback form. This included responses from 22 existing customers that represent approximately 70% of customer load and revenue for the transmission class. Below is a summary of feedback received:

- There was generally strong support for TSR rate redesign. Revenue shortfall options were most popular in terms of total score. However, when weighted by overall revenue to BC Hydro, the stepped rate options (Modified Stepped Rate and status quo) were strongly preferred. There was strong opposition from non-industrial customer groups to revenue shortfall options.
- Of the three flat rate options, Option 2 had the highest score, followed by Option 1 and Option 3. However, when weighted by overall revenue to BC Hydro, Option 3 was most preferred among the flat rate options followed by Option 1 and Option 2. The high demand charge of Option 3 was a concern for some customers and other customers and interveners had concerns that Options 1 and 2 were not revenue neutral.
- The Association of Major Power Customers of British Columbia (AMPC) indicated a flat energy rate would support electrification and load attraction. While they generally supported a balanced approach of a higher demand charge and lower energy charge, they noted demand charges higher than $11/kVA "is well outside jurisdictional comparisons, especially if there are no mitigation measures."
- Responses indicated greater support for immediate implementation, followed by delayed implementation and gradual implementation. There was support for further examination of a separate rate class for RS 1823 customers to reduce bill impacts, and for the DSM credit concept. We did not receive any examples of load growth or load retention that could justify revenue shortfall options on an economic basis.

What we concluded:

There continues to be support for rate redesign of RS 1823 as well as a lack of customer consensus on the new rate structure.

While there was support for further work on segmenting RS 1823 into its own rate class (separate from RS 1827 and RS 3808) to mitigate bill increases, the reduced bill impacts achieved through segmentation are low.

Non-revenue neutral rates are not feasible. Evidence of load growth or load retention that could justify these revenue shortfalls was not identified.

Recognition of previous customer investments in DSM is an ongoing customer concern. Customers expressed interest in a DSM credit concept to address and recognize remaining energy savings.

The demand charge cannot be set too high otherwise bill increases for some customers will exceed an acceptable level.

2.2 Recent regulatory filings

2.2.1 FISCAL 2023 TO FISCAL 2025 REVENUE REQUIREMENTS APPLICATION

BC Hydro filed its Fiscal 2023 to Fiscal 2025 RRA in August 2021. The following table shows the F2024 forecast sales and revenue for RS 1823, RS 1827 (Rate for Exempt Customers) and RS 3808 (FortisBC Inc.) based on the requested 0.97% RRA increase. This information has been used in our current rate design proposal to develop a revenue neutral flat rate for F2024.

Table 2: F2024 Revenue Requirement for RS 1823, RS 1827 and RS 3808

	F2024 Forecast Energy Sales (MWh)	Interim F2024 Rates Requested RRA increase of 0.97% ($/MWh)	Baseline Revenue ($M)
Tier 1 energy	10,236,520	45.79	468.7
Tier 2 energy	258,702	102.57	26.5
RS 1823A + RS1827 + RS 3808 energy	3,918,398	51.45	201.6
Total energy	14,413,620		696.9
	F2024 Forecast Demand (kVA)	**Interim F2024 Rates Requested RRA increase of 0.97% ($/kVA)**	**Baseline Revenue ($M)**
RS 1823B demand	19,216,680	8.780	168.7
RS 1823A + RS 1827 + RS 3808 demand	8,096,621	8.780	71.1
Total demand	27,313,301		239.8
Total revenue			**936.7**

BC Hydro also filed an Electrification Plan as part of our F2023 to F2025 RRA that was released publicly in September 2021.[5] Our Electrification Plan includes actions we will be taking to encourage the use of electricity for the purpose of reducing greenhouse gas (GHG) emissions, to attract new load and to connect customers more efficiently. These actions are expected to reduce rate increases for customers, lower GHG emissions in the province and provide economic benefits to B.C.

2.2.2 INTEGRATED RESOURCE PLAN

BC Hydro's 2021 IRP was filed in December 2021. An IRP is a guidebook for what, when, and how we will meet our customers' evolving electricity needs. In the context of transmission service rate redesign, the IRP includes two important elements:

1. As part of the Base Resource Plan, actions to pursue voluntary time-varying rates for industrial customers and to advance an industrial load curtailment program. These actions will support the achievement of incremental capacity savings.
2. Information on the value of energy and capacity during times of system surplus and system deficit. These values are used by BC Hydro to develop reference prices, which are used as a cost benchmark against which the cost of potential projects, programs or initiatives are compared. Reference prices may be leveraged from a rate design perspective to set efficient price signals that align with a utility's marginal costs (that is, the change in costs resulting from a unit increase or decrease in consumption).

5 See **Chapter 10** in Exhibit B-2-3-1 of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application.

BC Hydro’s Reference Prices

The following reference prices are outlined in Appendix L of BC Hydro’s 2021 Integrated Resource Plan Application:

- An energy long-run marginal cost of $65/MWh in F2022 dollars, which represents the next cheapest generation resource to be considered once the system reaches an energy deficit.
- A capacity long-run marginal cost of $109/kW-year in F2022 dollars, which represents the next cheapest capacity resource once the system reaches a capacity deficit.

2.3 Customer working group meetings

Following the third public workshop in October 2021, AMPC suggested that BC Hydro convene a small, representative customer working group to better understand the potential impacts and opportunities from a new rate design through facilitated modelling sessions. The objectives of the working group were to: (i) better understand bill impacts from a broader and more detailed perspective, including ways to mitigate them, and (ii) consider and explore other rates/programs that could be used to help offset bill impacts for certain sectors/customers.

Four informal meetings were held with the customer working group between April and June 2022, with representation from AMPC, the Mining Association of BC (MABC) and the Canadian Association of Petroleum Producers (CAPP). The sessions were not intended to represent formal engagement on transmission service rate redesign, but were helpful in gaining more detailed feedback from customers and in developing possible rate design concepts and solutions that could be supported by customers.

Key themes discussed during the customer working group meetings included:

- Benefits of a flat rate design and options for transitioning to a flat rate.
- Recognition of the value of customer-funded DSM projects, including a request for status quo rates for customers with remaining energy savings duration.
- Implications of rate flattening on future DSM investments and programming.
- Broader and holistic view of the impact of rate redesign on other optional rates that customers take service under (e.g., RS 1880 Standby and Maintenance Supply).
- BC Hydro’s future capacity needs (as detailed in the 2021 IRP) and design considerations for a load curtailment program and industrial Time-of-Use rate.

At the customer working group meetings, BC Hydro presented a flat rate option for discussion purposes that attempted to strike an appropriate balance between reflecting BC Hydro’s costs while mitigating bill impacts for customers. Restricting the default flat rate to one option allowed for a broader discussion with customers on bill impacts, bill mitigation options and implications for the broader suite of transmission service rates. Various transition options were modelled and the list was narrowed to two leading options.[6]

What we heard:

- Customers want price stability and certainty.
- Past investments were made based on the price signals and the duration of bill savings offered by the current Stepped Rate. Recognition and/or preservation of the value of remaining energy savings is important to customers and their business.
- A higher demand charge will impact low load factor customers (such as sawmills). An alternative rate structure (such as Time-of-Use) could benefit these types of customers by providing savings if they are able to make operational changes to shift when they use electricity.

6 Further information on some of the transition options that were considered is provided in Appendix D.

- There is a desire from customers to choose from a suite of rates (i.e., optionality is preferred over a one–size fits all approach).
- There is a desire from customers for continued investments in DSM and strong interest in a load curtailment program that could provide benefits to both BC Hydro and customers.
- There is a desire to simplify the table of rates offered to transmission service customers through the redesign of RS 1823, including the removal of rates that no customers are currently taking service under or are no longer needed.
- Customers that would benefit from the rate redesign, including new high load factor customers, would prefer immediate access to the final flat rate.

What we concluded:

Customers are interested in a package of potential solutions to mitigate bill increases, such as the introduction of optional rates or programs that would provide benefits to customers and BC Hydro (e.g. a load curtailment program or optional Time–of–Use rate).

Remaining duration of energy savings from customer–funded DSM projects should be addressed as part of the rate redesign process in order to gain support from customers.

Rate redesign should be holistic and should consider the broader suite of optional rates.

Customers would like to be able to choose from more than one rate option, while simplifying the rates that are available.

Rate design should consider the timing of benefits, as some new and existing customers would benefit from immediate implementation of the final flat rate.

3. Rate design proposal for default transmission service rate

Feedback from customer and stakeholder engagement activities and other developments since our last public workshop have helped to inform our rate design proposals. By incorporating customer feedback, the proposal for the default transmission service rate aims to achieve broader customer acceptance while meeting BC Hydro's rate design objectives.

Some of the features of our proposal include:

- One revenue neutral, default flat rate design priced in F2024 dollars that incorporates feedback from customers and stakeholders and aligns with BC Hydro's cost of service and reference prices.[7]
- Two leading options to transition customers to the flat rate design in order to recognize customer investments in DSM and mitigate annual bill increases.
- Advancing optional Time–of–Use rates and a load curtailment program to provide customers with bill savings opportunities.

7 Feedback from the previous three public workshops indicated that customers differ in their preference between various rate design options, which has made it difficult to reach consensus. From subsequent customer meetings, we have found that narrowing the options to one allows for a more fulsome discussion of bill impacts and transition approaches. This booklet therefore focuses on providing the rationale for the current flat rate proposal, along with leading transition options.

Details on our proposal for the redesign of the default transmission service rate are provided in the following sections, along with areas where we will be requesting your feedback during the next public workshop.

3.1 Proposed default transmission service rate

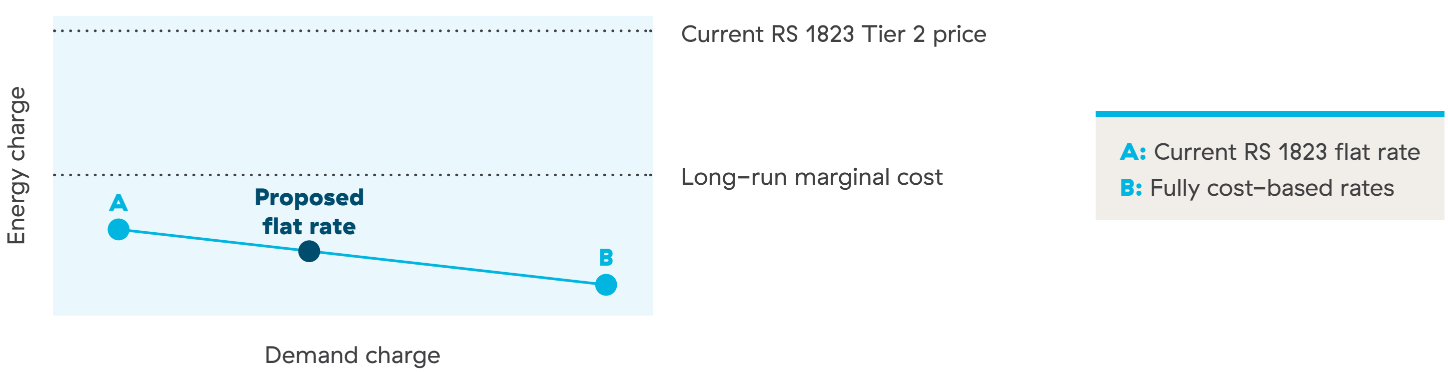
Relative to the existing stepped rate design, we believe a flat rate would:

- Improve alignment with BC Hydro's marginal cost and cost of service.
- Support government policy by encouraging electrification and decarbonization.
- Provide greater rate stability and predictability for customers.
- Provide greater flexibility to modify rates over time or add optional rates.
- Be easier to understand and administer.
- Better align with industry practice based on our jurisdictional review.

Figure 2 shows the current RS 1823 flat rate (Point A) as well as a fully cost-reflective rate (Point B). Under a flat rate design, there are variations on the extent to which the demand charge could be increased and the energy charge could be lowered. Increasing the demand charge will provide pricing that better reflects the actual cost of increased peak demand on the system. However, a fully cost-reflective demand charge would lead to significant bill increases for some customers and may result in an energy charge that is too low and becomes less reflective, over time, of the cost to BC Hydro from increased energy consumption.

BC Hydro has identified a proposed flat rate that attempts to strike an appropriate balance between increasing the demand charge and lowering the energy charge.

Figure 2: Energy Charge and Demand Charge Pricing for Default Transmission Service Rate



Revenue neutral pricing for the proposed flat rate in F2024 dollars is presented in the table below, relative to status quo. The prices include BC Hydro's expected revenue requirement increase for F2024.

Table 3: Proposed Flat Rate for Default Transmission Service Rate (F2024 dollars)

	Current RS 1823 flat rate (status quo)	Proposed flat rate
Flat energy charge ($MWh)	51.45	44.14
Tier 1 energy charge ($/MWh)	45.79	–
Tier 2 energy charge ($/MWh)	102.57	–
Demand charge ($/kVA)	8.78	11.00

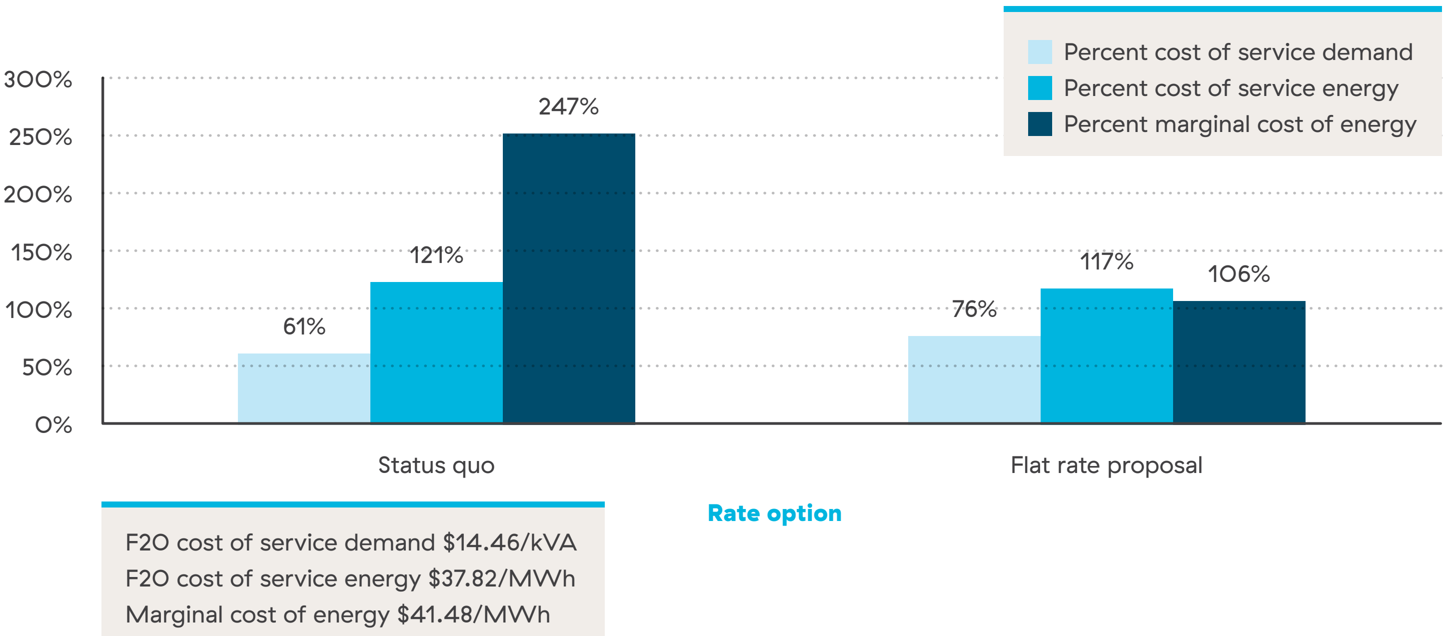
The proposed flat rate has the following key features:

- The pricing is revenue neutral for RS 1823 customers. This means that costs will not be shifted to other customer classes (i.e., residential/commercial).

- The flat energy charge of $44.14/MWh is lower than status quo ($51.45/MWh) and lies between BC Hydro's 10 year and 15 year levelized marginal cost of energy ($41.48/MWh and $48.50/MWh, respectively) in F2024 dollars.[8]
- The flat energy charge is above BC Hydro's fully allocated cost of service ($37.82/MWh in F2024 dollars, escalated from F2020 fully allocated cost of service). The demand charge of $11/kVA is higher than status quo ($8.78/kVA), but lower than BC Hydro's fully allocated cost of service ($14.46/kVA) to mitigate bill increases to customers. As discussed earlier, $11/kVA was identified through consultation as a potential upper ceiling that BC Hydro should consider in terms of how far to increase the demand charge.
- The proposed flat rate narrows the range of bill impacts for customers relative to some of the alternatives that were explored in previous workshops.

The figure below outlines how the current Stepped Rate (status quo) compares to the flat rate proposal relative to BC Hydro's cost of service and 10-year levelized marginal cost of energy. As indicated in the figure, the flat rate proposal better recovers BC Hydro's demand-related costs for transmission customers, with cost recovery increasing from 61% to 76%. The flat rate proposal also better aligns with BC Hydro's energy-related costs, with the flat rate proposal representing 117% of energy-related costs for transmission customers (compared to 121% for the current Tier 1 price) and reflecting 106% of BC Hydro's 10-year levelized marginal cost of energy (versus 247% for the current Tier 2 price). As a result, BC Hydro believes that the flat rate proposal better aligns with BC Hydro's costs and sends improved price signals to customers to encourage the efficient use of electricity.

Figure 3: Status Quo and Flat Rate Proposal relative to Cost of Service and 10-year Levelized Marginal Cost of Energy (F2024 dollars)



Note: For status quo, the Tier 1 energy rate is used for the calculation of the percent cost of service energy, and the Tier 2 energy rate is used for the calculation of the percent marginal cost of energy.

3.2 Bonbright assessment of proposed default transmission service rate

BC Hydro has assessed our rate design proposal for the default transmission service rate in accordance with generally accepted rate design criteria. The eight rate design criteria included in the following table are as outlined in Bonbright's Principles of Public Utility Rates.[9]

8 Since these levelized costs are a measure of the average present value of the marginal costs of energy over the time period, they are lower than the long run marginal cost of energy ($65/MWh).

9 James C. Bonbright, Principles of Public Utility Rates (1st Edition; Columbia University Press: New York, 1961), page 291.

Table 4: Bonbright Assessment of Proposed Flat Rate

Bonbright criteria	Remarks
Economic efficiency	
1. Price signals to encourage efficient use and discourage inefficient use	Proposed flat rate has energy charge of $44.14/MWh which improves alignment with our marginal costs, as our 10 year levelized cost of energy is $41.48/MWh.
Fairness	
2. Fair apportionment of costs among customers	Proposed flat rate has lower energy charge and higher demand charge which moves toward cost-based energy and demand relative to status quo.
3. Avoid undue discrimination	Proposed flat rate provides non-discriminatory pricing.
Practicality	
4. Customer understanding and acceptance; practical and cost effective to implement	Proposed flat rate improves ease of understanding and practicality of administration.
5. Freedom from controversies as to proper interpretation	There are customer acceptance issues with regard to the bill impacts that arise from moving from a stepped rate to a flat rate and whether a flat rate recognizes the remaining duration of energy savings from past customer-funded DSM projects. This can be addressed by transition options which help mitigate bill impacts and provide recognition of past investments in DSM.
Stability	
6. Recovery of the revenue requirement	Proposed flat rate is revenue neutral and collects the forecast revenue requirement
7. Revenue stability	Assuming no load impacts, revenue is stable and only varies each year by changes in load and change in general rate increase.
8. Rate stability	The rate is stable and only changes with general rate increases.

How the proposed flat rate compares to the flat rate options presented in Workshop 3:

- The proposed flat rate is a revenue neutral version of Option 2 presented in Workshop 3 which had a lower energy charge of $41.60/MWh and demand charge of $11/kVA.
  - We heard concerns from non-industrial customer groups and some customers that the rates should be revenue neutral and that revenue shortfalls would otherwise need to be made up from other customers.
  - Of the flat rate options presented in Workshop 3, Option 2 had the highest score, and some customers liked the idea of a "middle ground".
- We recognize that we have yet to achieve consensus from customers among the flat rate options presented to-date and that among the flat rate options considered, there was also support for both Option 1 (Tier 1 energy charge and existing demand charge) and Option 3 (fully cost-based demand charge and energy charges) when weighted by overall revenue to BC Hydro.
  - A revenue neutral version of Option 1 would be less cost-reflective ($45.79/MWh energy charge and $10.13/MWh demand charge) compared to our proposed flat rate since it has a higher energy charge and lower demand charge.
  - We also heard from some customers that the demand charge in Option 3 is too high ($37.82/MWh energy charge and $14.46/kVA demand charge).
- On balance, we believe that our proposed flat rate best achieves our rate design objectives of economic efficiency, decarbonization, flexibility and affordability.

3.3 Bill impacts of proposed default transmission service rate

As shown in the following table, bill impacts resulting from the proposed flat rate range from −5.7% to 3.3% for an 80% load factor customer, −2.1% to 6.0% for a 50% load factor customer, and 6.6% to 12.4% for a 20% load factor customer, depending on a customer's share of Tier 1 energy.[10]

Table 5: Bill impacts of proposed flat rate by load factor and share of Tier 1 energy

	100% Tier 1 Energy Customer			95% Tier 1 energy and 5% Tier 2 energy Customer			Flat Rate RS 1823A or 90% Tier 1 energy, 10% Tier 2 energy RS 1823B		
Load factor	**Step rate avg ¢/kWh**	**Flat rate avg ¢/kWh**	**Bill impact**	**Step rate avg ¢/kWh**	**Flat rate avg ¢/kWh**	**Bill impact**	**Step rate avg ¢/kWh**	**Flat rate avg ¢/kWh**	**Bill impact**
10%	16.01	18.73	17.0%	16.29	18.73	15.0%	16.57	18.73	13.0%
20%	10.29	11.57	12.4%	10.58	11.57	9.4%	10.86	11.57	6.6%
30%	8.39	9.19	9.5%	8.67	9.19	5.9%	8.96	9.19	2.6%
40%	7.44	7.99	7.5%	7.72	7.99	3.5%	8.00	7.99	−0.1%
50%	6.86	7.28	6.0%	7.15	7.28	1.8%	7.43	7.28	−2.1%
60%	6.48	6.80	4.9%	6.77	6.80	0.5%	7.05	6.80	−3.6%
70%	6.21	6.46	4.0%	6.50	6.46	−0.6%	6.78	6.46	−4.7%
80%	6.01	6.20	3.3%	6.29	6.20	−1.4%	6.58	6.20	−5.7%
90%	5.85	6.00	2.7%	6.13	6.00	−2.1%	6.42	6.00	−6.4%
100%	5.72	5.85	2.2%	6.01	5.85	−2.7%	6.29	5.85	−7.1%

The following table shows the average bill impacts of the proposed flat rate by sector relative to status quo. In general, customers in the pulp and paper, wood manufacturing and chemicals sectors are likely to see bill increases as a result of the proposed rate design and customers in oil and gas, cement and manufacturing and other sectors are likely to see bill decreases.

Table 6: Average Bill Impacts of Proposed Flat Rate by Sector

Industry sector	Status quo unit price of electricity ($/MWh)	Unit price differential after rate redesign ($/MWh)	Average bill impact (%)
Chemicals	61	2.04	3.4%
Wood manufacturing	67	1.75	2.6%
Pulp & Paper	62	1.57	2.5%
Gas Processing	60	0.01	0.0%
Mining	63	(0.37)	−0.6%
Oil	72	(0.49)	−0.7%
Port / Terminal	76	(0.71)	−0.9%
LNG / LPG	77	(0.90)	−1.2%
Cement & Manufacturing	70	(1.39)	−2.0%
Other	67	(3.05)	−4.5%

Note: Includes RS 1823 and RS 1827 customers only.

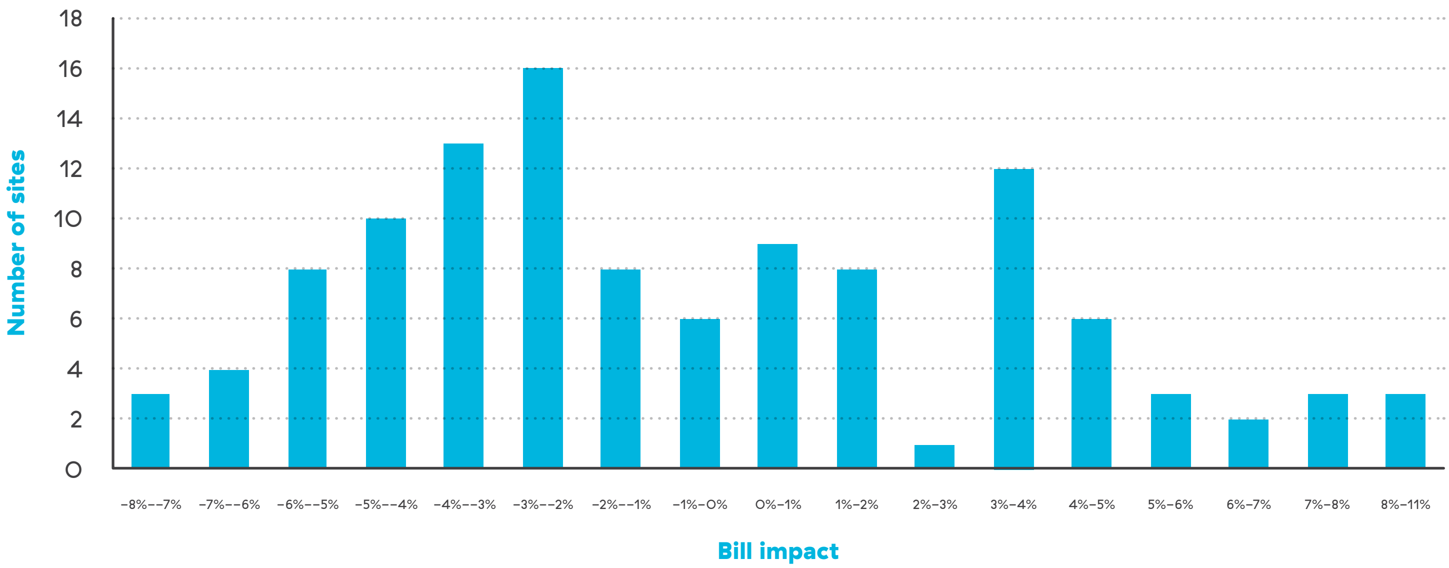
10 A complete set of bill impacts by load factor for different customers and transition options is provided in Appendix C. In Appendix C, the bill impacts resulting from the proposed flat rate are shown in the "Total" column for each transition option.

The following figure shows the distribution of bill impacts resulting from the proposed flat rate by number of customer sites (including aggregated sites under the provisions of TS 74—CBL Determination Guidelines) and based on F2024 forecast consumption. The figure shows that the annual bill impacts (assuming immediate implementation) range from −8% to 11%.

Sites with a larger share of Tier 2 energy, such as those taking service under the flat rate RS 1823A, will typically see a bill decrease, while sites with Tier 1 energy only will typically see a bill increase.

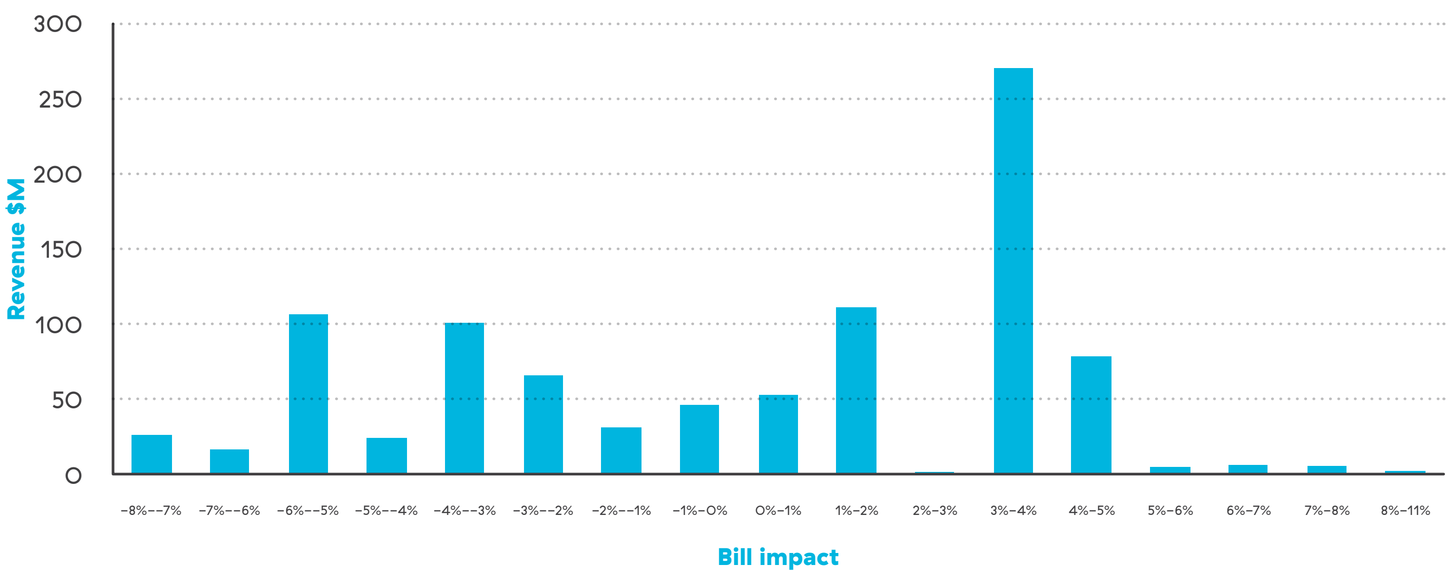
Sites with low load factors (i.e. variable consumption patterns) may also face a bill increase as a result of the higher demand charge in the proposed flat rate.

Figure 4: Bill impact distribution of proposed flat rate by number of sites



The following figure shows the distribution of bill impacts resulting from the proposed flat rate by total revenue and based on our F2024 forecast consumption.

Figure 5: Bill impact distribution of proposed flat rate by total revenue



We're looking for your feedback:

Do you understand how BC Hydro developed the proposed flat rate?

- Yes
- No

Do you agree that BC Hydro should transition away from the stepped rate design towards a flat rate design?

- Yes
- No
- Unsure

To what extent do you agree that the proposed flat rate strikes an appropriate balance between reflecting BC Hydro's costs to provide service and mitigating bill impacts resulting from a change to the status quo?

- Strongly Agree
- Somewhat Agree
- Neither Agree nor Disagree
- Somewhat Disagree
- Strongly Disagree

3.4 Transition options

BC Hydro recognizes that customers have made previous investments in DSM projects in response to the current Stepped Rate. During stakeholder consultation, some customers expressed a desire to stay on the stepped rate structure for the remaining duration of energy savings to maintain the value of these investments. However, providing optionality to customers to either continue with a stepped rate or transition to the proposed flat rate comes with a revenue shortfall, as each customer will select the least cost alternative.

In this section we present two leading options for transitioning to the proposed flat rate that incorporates customer and stakeholder feedback received to-date. These options would transition most RS 1823 customers to a flat rate as soon as possible (i.e. by F2025), while providing benefits to customers with remaining DSM and minimizing impacts to other ratepayers.

Feedback received on transition approaches during previous workshops were not in the context of a particular rate design. The two leading transition options presented in this section attempt to mitigate bill impacts and recognize past DSM investments while also immediately implementing a flat rate structure for customers. We believe that this immediate implementation of a flat rate structure coupled with transition approaches that provide bill mitigation and DSM investment recognition is responsive to previous customer feedback we received. We are seeking your feedback on which of these leading transition options your company or organization prefers. Alternatively, if you do not support these options, we are seeking your feedback on whether you would prefer a gradual implementation approach that would retain the stepped rate structure over the transition period.

We would also like your feedback on any refinements that we should consider to the two leading transition options. We expect that the final transition option that we propose in our application may have some adjustments based on this feedback.

For a summary of additional transition options that were considered, please see Appendix D.

3.4.1 OPTION 1: REVENUE NEUTRAL SEGMENTED FLAT RATES

BC Hydro recognizes that customers have different unit costs under the existing Stepped Rate depending on their share of Tier 1 and Tier 2 energy. We have also heard concerns from some customers who have invested in DSM projects which has resulted in energy savings and lower Tier 2 energy consumption with expected bill savings that will be impacted depending on how customers transition to the final flat rate.[11]

One approach to address customer concerns regarding bill increases and past DSM investment is to adjust prices over a transition period (e.g., 3 or 5 years) until they reach the new rate design. This spreads the bill impact over a longer period.[12]

Under Transition Option 1: Revenue Neutral Segmented Flat Rates, customers would be grouped based on their forecasted share of Tier 1 energy and assigned one of three different revenue neutral flat rates in F2025 that would then all transition to the same final flat rate by F2029. Below is a summary of key steps and timelines for the proposed transition:

- The Stepped Rate remains in place in F2024 to allow for regulatory process and implementation, and to provide rate stability for customers.
- Customers are grouped into three segments based on their forecasted share of Tier 1 energy for F2024, as follows:
  - **Segment 1:** Customers with a High Share of Tier 1 Energy—all forecast F2024 accounts with Tier 1 energy greater or equal to 97% of total energy consumption.
  - **Segment 2:** Customers with a Moderate Share of Tier 1 Energy—all forecast F2024 accounts with Tier 1 energy greater or equal to 93% and less than 97% of total energy consumption.
  - **Segment 3:** Customers with a Low Share of Tier 1 Energy or Currently on a Flat Rate—all forecast F2024 accounts with Tier 1 energy less than 93% of total energy and accounts on the following rate schedules: RS 1823A, RS 1827 and RS 3808.
- Each segment is assigned a revenue neutral flat rate transition schedule from F2025 to F2028, which is designed to minimize bill impacts for individual customers (positive or negative).
- All transmission service customers transition to the same final flat rate by F2029.

Proposed revenue neutral flat rates and a transition schedule for each segment are outlined in the table below.

Table 7: Revenue Neutral Segmented Flat Rates and Transition Schedule (F2024 dollars)

Year	Segment 1		Segment 2		Segment 3	
	Energy Charge $/MWh	Demand Charge $/kVA	Energy Charge $/MWh	Demand Charge $/kVA	Energy Charge $/MWh	Demand Charge $/kVA
F2024	Existing Stepped Rate					
F2025	44.14	9.88	44.99	11.00	48.73	10.13
F2026	44.14	10.16	44.78	11.00	47.58	10.35
F2027	44.14	10.44	44.57	11.00	46.44	10.57
F2028	44.14	10.72	44.35	11.00	45.29	10.78
F2029	44.14	11.00	44.14	11.00	44.14	11.00

Note: Pricing in F2024 dollars, inclusive of revenue requirement for F2024, but exclusive of Deferral Account Rate Rider (DARR)

We would like your feedback on any refinements that we should consider to this transition option and expect that if this option is chosen as the final transition option that we propose in our application, it may have some adjustments based on this feedback. In addition, if you any concerns or issues with the proposed process for grouping customers into segments, please provide us with your feedback. For more details on the approach to developing revenue neutral segmented flat rates, please see Appendix B.

11 Based on reported data for F2020, most of the remaining energy savings from customer-funded DSM projects are set to reach the end of their duration by F2029. Additional information on the value of remaining energy savings is provided in Appendix D.

12 See for example the FortisBC Residential Conservation Rate, Commission Order No. G-40-19; and BC Hydro E Plus Rate, Commission Order No. G-194-17.

3.4.2 OPTION 2: STAGGERED IMPLEMENTATION

Another approach to address customer concerns regarding bill increases and past DSM investment is to delay the implementation of a new flat rate for customers with remaining energy savings. Under Transition Option 2: Staggered Implementation, customers with remaining energy savings are provided the option to stay on the Stepped Rate until F2027 (two additional years), while all other RS 1823 customers transition to the proposed flat rate in F2025. As RS 1827 and RS 3808 customers are already on a flat rate, this would mean that most transmission service customers would be billed on a flat rate structure by F2025. Over the two-year transition period, this option is expected to have a revenue shortfall of approximately $10 million in net present value.

Below is a summary of key steps and timelines for the proposed transition:

- The Stepped Rate remains in place in F2024 to allow for regulatory process and implementation, and to provide rate stability for customers.
- RS 1823 customers with remaining customer-funded DSM project duration can choose to stay on the existing Stepped Rate for two additional years (F2025 and F2026) or move directly to the proposed flat rate starting in F2025.
- The pricing of RS 1827 is maintained for three years (F2024–F2026). In F2027, customers previously taking service under RS 1827 will take service under the proposed flat rate.
- The RS 3808 Tranche 1 energy and demand charge is maintained for three years (F2024–F2026). In F2027, the RS 3808 Tranche 1 energy and demand charge will be updated to reflect that of the proposed flat rate.
- All other RS 1823 customers move to the proposed flat rate starting in F2025.

Proposed rates and a transition schedule for customers are summarized in the table below.

Table 8: Staggered Implementation Rates and Transition Schedule (F2024 dollars)

Year	RS 1823 Customers with Remaining DSM		RS 1823 Customers without Remaining DSM		RS 1827 Customers and RS 3808 Tranche 1 energy and demand charge	
	Energy Charge $/MWh	Demand Charge $/kVA	Energy Charge $/MWh	Demand Charge $/kVA	Energy Charge $/MWh	Demand Charge $/kVA
F2024	Existing rates					
F2025	Existing Stepped Rate (by election)		44.14	11.00	Existing rates	
F2026	Existing Stepped Rate (by election)		44.14	11.00	Existing rates	
F2027	44.14	11.00	44.14	11.00	44.14	11.00

Note: Pricing in F2024 dollars, inclusive of revenue requirement for F2024, but exclusive of Deferral Account Rate Rider (DARR)

3.4.3 ALTERNATIVE TRANSITION: GRADUAL IMPLEMENTATION

Based on feedback from Workshop 3, we heard that most customers and stakeholders would support the recognition of past investments in customer-funded DSM and would prefer immediate implementation of a new rate design. The two leading transition options were developed based on this feedback.

Alternatively, if you do not support these options, we are seeking your feedback on whether you would prefer a gradual implementation approach that would retain the stepped rate structure over a five-year transition period.

Proposed rates and a transition schedule for this alternative is provided below.

Table 9: Gradual Implementation Rates and Transition Schedule (F2024 dollars)

Year	RS 1823 Customers				RS 1827 and RS 3808 Customers	
	Flat Energy Charge $/MWh	Tier 1 Energy Charge	Tier 2 Energy Charge	Demand Charge $/kVA	Energy Charge $/MWh	Demand Charge $/kVA
F2024	Existing rates					
F2025	49.99	45.46	90.88	9.22	49.99	9.22
F2026	48.53	45.13	79.2	9.67	48.53	9.67
F2027	47.06	44.80	67.51	10.11	47.06	10.11
F2028	45.60	44.47	55.83	10.56	45.60	10.56
F2029	44.14	n/a	n/a	11.00	44.14	11.00

Note: Pricing in F2024 dollars, inclusive of revenue requirement for F2024, but exclusive of Deferral Account Rate Rider (DARR)

3.4.4 ASSESSMENT OF TRANSITION OPTIONS

Detailed bill impacts for customers from each transition option are included in Appendix C, with and without the impact of general rate increases (based on forecast revenue requirements). An overview of other transition options that were considered, as well as calculations of the value of each transition option to customers with remaining DSM project duration, is provided in Appendix D.

The table below shows the alignment of each transition option with key issues that were identified through our stakeholder engagement. Areas highlighted in green indicate where, in BC Hydro's view, one option has an advantage over the alternatives.

Table 10: Alignment of Each Transition Option with Key Issues Identified through Stakeholder Engagement

	Transition option 1: Segmented flat rates	Transition option 2: Staggered implementation	Alternative transition: Gradual implementation
Consistent with rate design objectives and current environment	All customers on a flat rate by F2025.	Stepped Rate maintained for two additional years.	Stepped Rate maintained for four additional years.
Revenue neutral	Revenue neutral.	Revenue shortfall of $10 million over two-year transition period.	Revenue neutral.
Recognition of customer investments in DSM (expressed as overall value to customers with remaining DSM from F2025 to F2032)	Net present value of approx. $42 million.	Net present value of approx. $44 million.	Net present value of approx. $37 million.
Manage bill increases	Annual bill increases phased in over longer time frame and allows for immediate introduction of optional rates.	Full bill impacts in F2025 for customers without DSM and allows for immediate introduction of optional rates.	Minimizes range of bill impacts and provides gradual transition.
Avoid administrative complexity	Will need to administer different flat rates for different customers from F2025 to F2028.	Maintains customer baseline loads (CBLs) for two additional years, but transition is simpler.	Maintains customer baseline loads for four additional years, however all customers on same rate schedule.
Timing of benefits for new and some existing high load factor customers	Full benefits delayed until F2029 for new and some existing high load factor customers that would benefit from immediate implementation of the proposed flat rate.	Full benefits from the proposed flat rate starting in F2025.	Delayed benefits of the final flat rate until F2029.

How the proposed transition options reflect feedback from Workshop 3:

- During Workshop 3, we gathered feedback from customers and stakeholders about various transition options in general terms (i.e., not in relation to a specific rate change). The feedback is summarized below:
  - 80% of respondents to our feedback form supported the concept of a DSM credit to help customers with remaining energy savings duration from past customer-funded DSM projects.
  - Customers and stakeholders supported immediate, delayed and gradual implementation by differing degrees: 55% of respondents supported immediate implementation, 42% supported delayed implementation and 35% supported gradual implementation.
  - If a delayed implementation was proposed, 24% of respondents felt that a one-year delay was reasonable, 24% felt that a two-year delay was reasonable, and 24% felt that a three-year delay was reasonable.
  - If a gradual implementation was proposed, 17% of respondents supported a one-year transition, 42% supported a three-year transition, and 17% supported a five-year transition.
- The leading transition options incorporate this feedback as follows:
  - The DSM credit was estimated to result in a $23 million revenue shortfall, as outlined in Appendix D. Based on feedback we heard during Workshop 3, revenue shortfalls in the range of $20 million to $35 million were strongly opposed from other customer groups. This prompted us to consider other transition options that would provide comparable benefits to customers with remaining DSM relative to the DSM credit approach, but that eliminate or significantly reduce the revenue shortfall.
  - Transition Option 1 results in immediate implementation of the flat rate design. It has a five-year transition schedule which provides customers with remaining DSM energy savings comparable value relative to the DSM credit approach, but without a revenue shortfall, as explained further in Appendix D. A five-year transition period allows greater recognition of remaining energy savings duration relative to a three-year transition. We have chosen the longer transition period as we have heard that recognition of remaining customer-funded DSM is a significant customer concern.
  - Transition Option 2 is more responsive to RS 1823 customers that would prefer immediate implementation of the new rate, since all RS 1823 customers without remaining DSM (and some with remaining DSM) would be on the proposed flat rate starting in F2025. For customers with remaining energy savings duration, this transition would provide similar benefits to the DSM credit by providing these customers with a choice of staying on the current Stepped Rate for an additional two years (F2025 and F2026). Because of the optionality provided to customers, this transition would result in a smaller and time-limited revenue shortfall of $10 million over the two-year transition period.
  - A five-year gradual implementation is being presented in the context of our proposed flat rate as an alternative to immediate flat rate implementation in the event there is not support for the two leading transition options.

We're looking for your feedback:

Which statement best represents the viewpoint of your company/organization:

- All customers should immediately transition to the proposed flat rate in F2025
- BC Hydro should have a transition mechanism in place to ease bill impacts for customers impacted by the rate change

Of the two leading transition options presented, which does your company/organization prefer?

- Option 1: Revenue neutral segmented flat rates (all customers on proposed flat rate by F2029)
- Option 2: Staggered Implementation (all customers on proposed flat rate by F2027)

Please indicate your level of support for the following transition approaches:

	Strongly oppose	Somewhat oppose	Indifferent	Somewhat support	Strongly support
Transition option 1: Revenue-neutral segmented flat rates					
Transition option 2: Staggered implementation					
Transition Alternative: Gradual implementation					

Do you have any suggested modifications to one or more of the transition approaches that would increase your level of support? If so, please describe.

4. Rate design proposal for optional transmission service rates

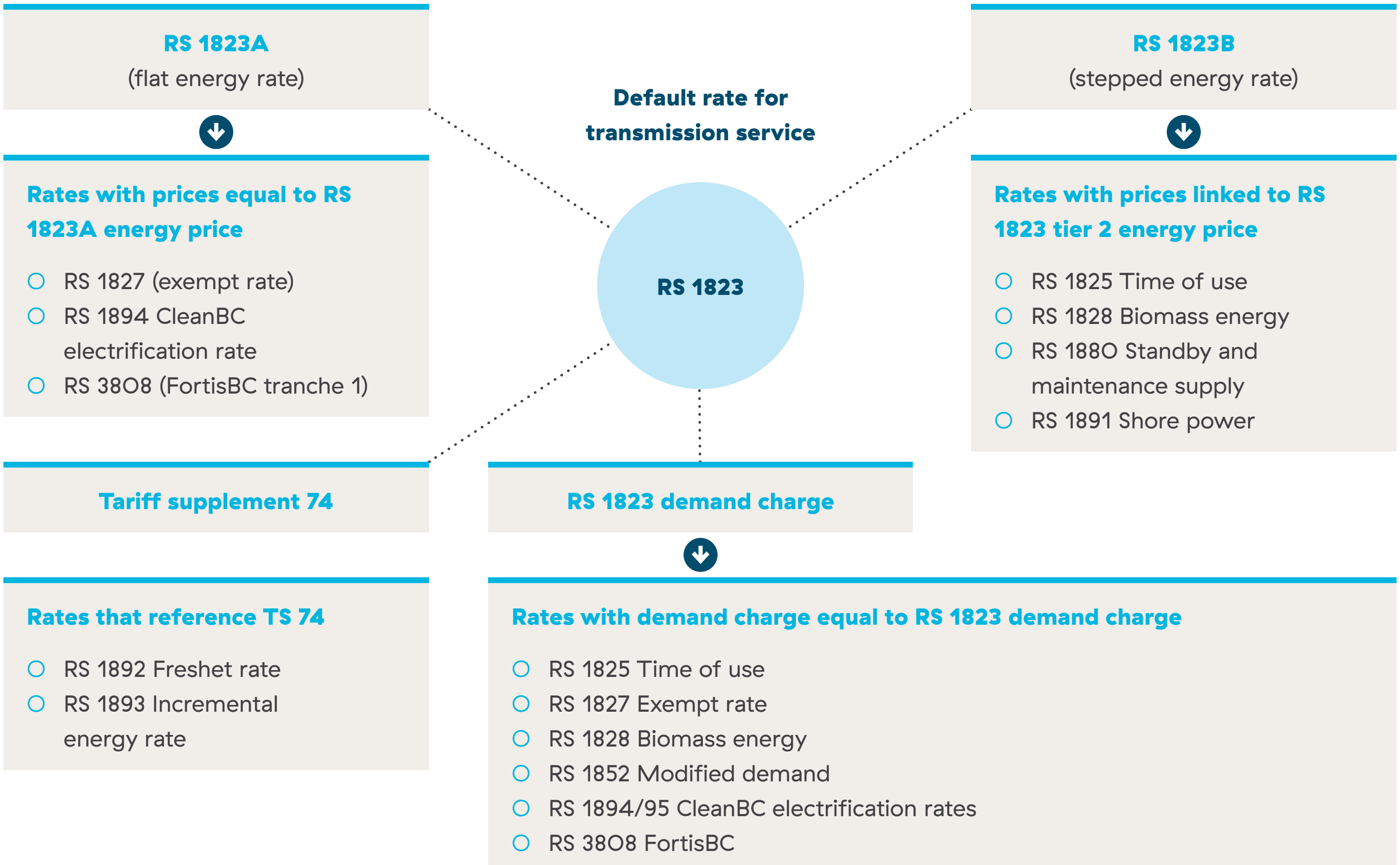
Section 4 of this booklet provides information on proposed adjustments and revisions to the broader suite of rates within the transmission service portfolio. At a high-level, some of the proposed changes include:

- Merging customers on RS 1827 (Rate for Exempt Customers) with those currently on RS 1823.
- Repricing RS 1880 Standby and Maintenance Supply and RS 1891 Shore Power Service.
- Introducing a new optional Time-of-Use rate.
- Introducing a load curtailment program.

4.1. Interconnectedness of transmission service rate schedules

Part of the complexity with redesigning the default transmission service rate is that there are a number of other rate schedules within the transmission service portfolio that are linked to RS 1823 pricing and/or baseline concepts. Similarly, transmission service customers may be billed on multiple rate schedules, and accordingly, customers are seeking a comprehensive view of the implications of RS 1823 rate redesign on the broader suite of rates. The figure below illustrates the interconnectedness of BC Hydro's transmission service rates.

Figure 6: Other Transmission Service Rate Schedules Linked to RS 1823[13, 14]



4.1.1 RS 1827 (EXEMPT CUSTOMERS) AND RS 3808 (FORTISBC INC.)

In the absence of a default stepped rate for transmission service customers, there is no longer a need for RS 1827 customers to be exempt from the stepped rate structure. As these customers already receive service with a flat energy charge, BC Hydro proposes that RS 1827 customers will take service under the new rate schedule for the proposed flat rate and RS 1827 would be eliminated. While RS 3808 (Transmission Service Rate for FortisBC. Inc) would remain a separate rate schedule, the pricing of Tranche 1 energy and demand, which is currently tied to RS 1827, would be revised so that it is tied to the proposed flat rate.

13 RS 1828 and RS 1894/95 were directed by the B.C. Government. (See Order in Council No. 158 issued April 1, 2019, BC Reg. 71/2019 and Order in Council No. 657 issued December 21, 2020, BC Reg. 295/2020.) Any amendments to these rate schedules may be directed by government.

14 There are currently no customers taking service on RS 1825 Time of Use or RS 1852 Modified Demand.

The timing of these proposed changes would differ under each transition option:

- For Transition Option 1, the pricing of RS 1827 and RS 3808 Tranche 1 energy and demand would follow that of Segment 3. In F2029, RS 1827 customers would take service on the new default rate schedule for transmission customers and the pricing of RS 3808 Tranche 1 energy and demand would be revised so that it is tied to the proposed flat rate.
- For Transition Option 2, the pricing of RS 1827 and RS 3808 would be maintained until F2026. In F2027, RS 1827 would take service on the new default rate schedule and the pricing of RS 3808 Tranche 1 energy and demand would be revised so that it is tied to the proposed flat rate.
- For the Alternative Transition, the pricing of RS 1827 and RS 3808 Tranche 1 would follow the gradual implementation rate schedule. In F2029, RS 1827 customers would take service on the new default rate schedule and the pricing of RS 3808 Tranche 1 energy and demand would be revised so that it is tied to the proposed flat rate.

Treatment of RS 1827 (exempt customers)

BC Hydro has taken the following considerations into account in its proposals for RS 1827 customers:

- These customers have been paying flat rates under a separate rate schedule since the introduction of the RS 1823 Stepped Rate in 2006.
- In order for RS 1827 customers to take service on the new rate schedule, we must first flatten the Stepped Rate. Under Transition Option 1, all transmission service customers would be on a flat rate structure by F2025 and under Transition Option 2, most RS 1823 customers would transition to a flat rate in F2025. The next step would be to align the pricing for customers within the transmission rate class (including RS 1827). In Transition Option 1, this occurs by F2029, and in Transition Option 2, this occurs by F2027.

4.1.2 RS 1880 STANDBY AND MAINTENANCE SUPPLY AND RS 1891 SHORE POWER SERVICE

The pricing of RS 1880 Standby and Maintenance Supply and RS 1891 Shore Power Service are currently tied to the Tier 2 rate of RS 1823. With the removal of the stepped rate structure, BC Hydro will need to re-price these rate schedules. BC Hydro is considering the following options for re-pricing:

- Set the energy charge equal to the new flat energy charge (i.e., the energy charge of the proposed flat rate presented in Section 3).
- Tie the energy charge to a market-referenced price (as is currently the case with RS 1892 and RS 1893). A market-referenced price would be more reflective of BC Hydro's shorter-term marginal costs, and would be updated on a set schedule (e.g., daily, weekly, quarterly or annually).

Both options would better reflect BC Hydro's marginal costs of energy relative to the current Tier 2 price, thereby sending a more efficient and cost-reflective price signal to RS 1880 and RS 1891 customers.[15]

BC Hydro proposes that this change would take effect in F2025 under Transition Option 1 or 2, and would take effect in F2029 under the Alternative Transition approach.

15 As indicated in Section 3, the flat energy charge of $44.14/MWh lies between BC Hydro's 10 year levelized and 15 year levelized marginal cost of energy ($41.48/MWh and $48.50/MWh, respectively) in F2024 dollars.

We're looking for your feedback:

How should RS 1880 Standby and Maintenance Supply be re-priced?

- ○ Same energy charge as that of the proposed flat rate
- ○ Market-referenced price (e.g., Mid-C)
- ○ Other

How should RS 1891 Shore Power Service be re-priced?

- ○ Same energy charge as that of the proposed flat rate
- ○ Market-referenced price (e.g., Mid-C)
- ○ Other

4.1.3 RS 1892 FRESHET ENERGY AND RS 1893 INCREMENTAL ENERGY RATE

RS 1892 Freshet Energy was initially offered on a four-year pilot basis, commencing in February 2016, and was made permanent in May 2020. It encourages incremental energy use (over and above a baseline) during the May to July freshet period. Customers pay a market-referenced energy charge (Mid-C) plus $3/MWh adder for incremental consumption, with no demand charge.

RS 1893 Incremental Energy Rate is currently offered on a 51-month pilot basis (January 1, 2020 to March 31, 2024). It encourages incremental energy use all year round. Customers pay a market-referenced energy charge (Mid-C) plus $3/MWh adder in freshet months and $7/MWh adder in all other months for incremental consumption, with no demand charge. An evaluation report for the Incremental Energy Rate pilot is anticipated to be filed with BCUC by September 15, 2023.

The market-referenced price applies to consumption above a customer's baseline. The baselines for RS 1892 and RS 1893 were established consistent with the principles and criteria of TS 74—CBL Determination Guidelines.

There are a number of customers that currently receive service on both RS 1823 and RS 1892/93. However, with the implementation of a flat default rate for RS 1823, customers may operate differently on a flat rate relative to how they have historically operated on a stepped rate. Accordingly, the ability to discern "normal use" of a customer will likely be impacted. BC Hydro is therefore seeking feedback on whether these rates should continue with a default flat rate and, if they were to continue, what an appropriate baseline would be for assessing incremental consumption on a default flat rate.

A few of the options currently under consideration, and for which we would like to receive feedback, include:

1. Continue to offer RS 1892 but allow RS 1893 to expire at the end of the pilot period on March 31, 2024.
2. Continue to offer RS 1892 and RS 1893 (subject to evaluation), but require a period of consumption on a default flat rate prior to customers re-initiating service on RS 1892 or RS 1893.
3. Continue to offer RS 1892 or RS 1893 (subject to evaluation) using current baselines, with a mechanism to reset/adjust a customer's baseline based on changes in consumption on a default flat rate.

We're looking for your feedback:

Should RS 1892 Freshet Energy continue to be offered if a flat default rate is implemented?

- Yes
- No
- Uncertain

Should RS 1893 Incremental Energy Rate continue to be offered if a flat default rate is implemented?

- Yes
- No
- Uncertain

If RS 1892 or RS 1893 are continued, should a new baseline (CBL) be established based on one-year of consumption on a flat rate?

- Yes
- No
- Uncertain

Should a new simplified TS 74 – CBL Determination Guidelines be developed for optional rates? If so, please suggest areas for simplification and improvement.

- Yes
- No
- Uncertain

For RS 1892 and RS 1893, what CBL reset/adjustment mechanism would your company or organization prefer?

- Reset triggered by +10%/-10% change based on prior year's consumption
- Adjust CBL by a growth adjustment factor (i.e., increase or decrease CBL over time based on prior year's actual consumption)
- Other

4.1.4 TIME-OF-USE RATE

The Base Resource Plan of the 2021 IRP includes both an industrial load curtailment program and voluntary time-varying rates.

While BC Hydro currently offers an optional Time-of-Use (TOU) rate for transmission service customers (RS 1825), the price ratio between peak and off-peak periods is close to 1 (approximately 1.24:1), and only applies to Tier 2 energy consumption. No transmission service customers have taken service on this rate schedule since it was introduced in April 2006.

Modelling carried out as part of the 2021 IRP included an industrial TOU rate with a 3:1 peak to off-peak price ratio. A TOU rate with a more significant peak to off-peak price ratio would send a stronger price signal to encourage customers to shift load away from BC Hydro's peak periods.

BC Hydro is seeking to introduce a new, optional TOU rate for transmission service customers.

At this time, BC Hydro is exploring the development of a two-part structure for the TOU rate, as follows:

- Part 1: Fixed Charge: Designed to collect the customer's historic contribution to embedded cost, calculated based on a CBL priced at the default transmission service rates for energy and demand.
- Part 2: Time-of-Use (TOU) Energy Charge: Fixed TOU prices for marginal consumption, with customers paying a charge for incremental consumption and receiving a credit for decremental consumption based on the applicable TOU price. Incremental energy is proposed to be firm (e.g., up to contract demand) and would have no demand charge.

Under this structure, the fixed TOU energy charge would vary by season and by time-of-day and would apply to any increases or decreases in consumption relative to the customer's baseline (CBL). A 3:1 price ratio would mean that the TOU price in the peak period would be three times higher than the TOU price in the off-peak period. This would mean that customers who are able to shift consumption from the peak period to the off-peak period (without changing their overall load) would receive a bill credit based on the difference between these two prices.

The table below shows three options for an industrial TOU rate.

Table 11: Options for an Industrial Time-of-Use Rate

Option A: Winter only, two time periods	**Option B: Three seasons, two time periods**	**Option C: Three seasons, three time periods**
Overview		

TOU prices for the following seasons and time periods:
• Winter (November to February)
    ◦ Peak (4 to 8 pm weekdays)
    ◦ Off-peak (remainder)
Marginal consumption during all other times of the year would be charged at the default rate.
	TOU prices for the following seasons and time periods:
	• Winter (November to February)
	    ◦ Peak (4 to 8 pm weekdays)
	    ◦ Off-peak (remainder)
	• Spring (May to June)—all time periods
	• Remainder—all time periods
		TOU prices for the following seasons and time periods:
		• Winter (November to February)
		    ◦ Peak (4 to 8 pm weekdays)
		    ◦ Shoulder (6 am to 4 pm, 8 to 10 pm)
		    ◦ Off-peak (remainder)
		• Spring (May to June)—all time periods
		• Remainder—all time periods

Advantages		
• With only one season and two time periods, this design would be simple to understand and administer. • Would target load shifting to when it is most needed by BC Hydro (i.e., shifts load away from winter peak).	• Maintains simplicity but provides year-round benefits to participants. • Provides greater flexibility to customers to shift load across time periods and seasons.	• Most aligned with BC Hydro's cost of service with prices that vary across time periods and seasons. • Greatest flexibility to customers to encourage load shifting.
Disadvantages		
• Provides potential bill savings to customers in winter period only, which may discourage participation. • Does not reflect seasonal variations in energy costs at other times of the year.	• Less targeted offering and greater complexity.	• Less targeted offering and greater complexity.

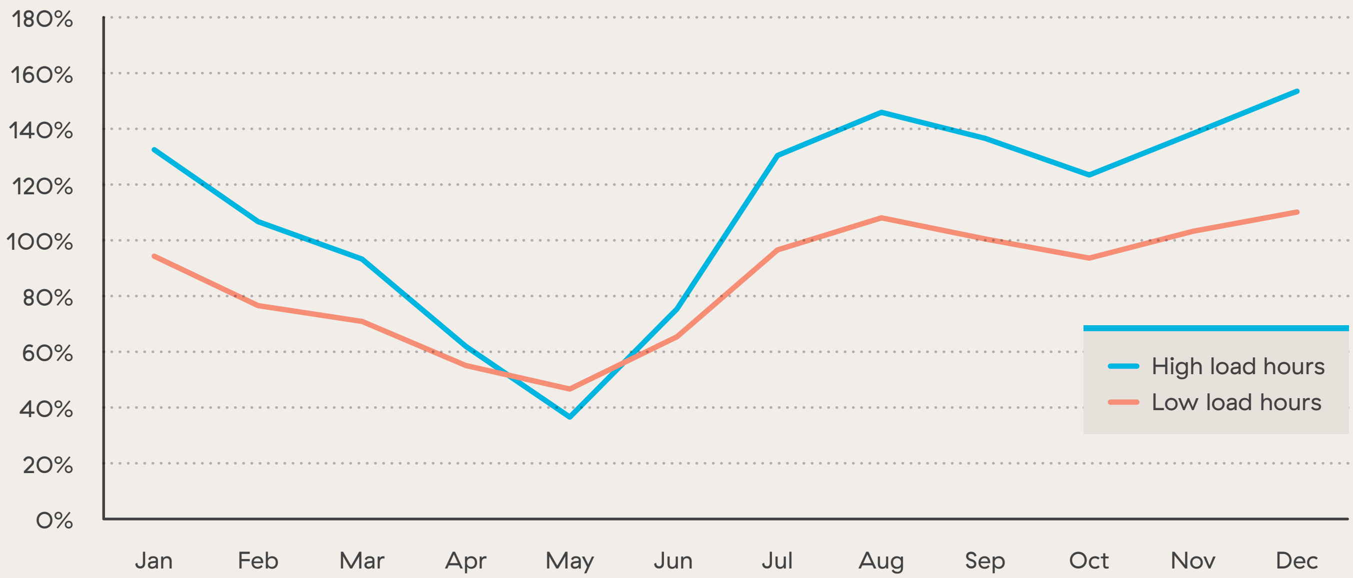
BC Hydro will be carrying out additional analysis and consultation activities on an industrial TOU rate with the objective of applying for an optional TOU rate as part of the same regulatory proceeding to review the proposed new default rate. Analysis and consultation activities will include further development of the rate structure and pricing concepts presented in this booklet, as well as details related to the process for establishing and adjusting customer baselines.

At this time, we are seeking initial feedback from customers and stakeholders to help frame next steps. The textbox below presents illustrative pricing to help customers better understand the proposed rate structure.

Illustrative pricing for a time of use rate

One option for developing fixed TOU prices that vary by season and by time-of-day is to shape BC Hydro's embedded energy cost by the forecast Mid-C price shape. The graph below provides an example of how market prices vary by month (season) and by time-of-day (high load hours versus low load hours). Shaping our embedded energy cost in this manner would result in prices that vary by season and by time-of-day according to these market fluctuations.

Sample Mid-C 2x12 factors



Illustrative pricing based on a 3:1 peak to off-peak price ratio is provided in the table below.

		Option A	Option B	Option C
Winter (November to February)	Peak (4 to 8 p.m. weekdays)	$127.74	$127.74	$127.74
	Shoulder (6 a.m. to 4 p.m. and 8 to 10 p.m. weekdays)	n/a	n/a	$49.50
	Off-peak (remaining hours)	$42.58	$42.58	$35.75
Spring (May to June)	All time periods	n/a	$21.30	$21.30
Remaining months	All time periods	n/a	$38.42	$38.42

We're looking for your feedback:

Would your company or organization likely be interested in participating in a Time-of-Use (TOU) rate?

- Yes
- No
- Unsure

Which rate design would your company or organization likely prefer?

- Option A: Winter only, two time periods
- Option B: Three seasons, two time periods
- Option C: Three seasons, three time periods
- Unsure/Other

Please rank which winter peak to off-peak TOU price ratio your company would likely prefer (with 1 being the highest and 3 the lowest):

- 4:1 _____
- 3:1 _____
- 2:1 _____

Please rank which TOU peak winter period your company would likely prefer (with 1 being the highest and 4 the lowest):

- 4 p.m. to 9 p.m. _____
- 4 p.m. to 8 p.m. _____
- 3 p.m. to 7 p.m. _____
- 5 p.m. to 9 p.m. _____

What actions or measures would your company or organization likely undertake in response to a TOU rate?

- Schedule equipment maintenance/downtime during peak periods
- Shift operations from peak periods to off-peak periods
- Shift timing of self-generation
- Invest in battery storage technology
- Other

Would your company or organization likely be interested in a TOU option with more frequent updating of TOU prices (e.g., annually or quarterly) and tied to shorter term market prices?

- Yes
- No
- Unsure

4.1.5 INDUSTRIAL LOAD CURTAILMENT

The industrial load curtailment resource option that is included in the Base Resource Plan of the 2021 IRP is intended for transmission service rate customers and is based on industrial load curtailment pilots that BC Hydro carried out from 2015 to 2018. BC Hydro modelled this resource option in the 2021 IRP based on the following specifications:

- 16 hours of load curtailment per event with 36 events during the winter and shoulder season.[16]
- One event called per day.
- Total availability of 576 hours.

The incentive assumed for the modelling of load curtailment was $75/kW-yr.

Based on learnings from our industrial load curtailment pilots, BC Hydro would plan to begin design of the load curtailment program two years prior to implementation. Program design details would be discussed with representatives from the industrial sector and would include the following elements at a minimum:

- Term of load curtailment contracts;
- Notification timing and communication protocols;
- Baselines;
- Payment structure and value;
- Decision on bid-process or bi-lateral negotiations;
- Non-performance consequences;
- Confirmation of MW target; and
- Hours of curtailment blocks.

A minimum of 5 MW of load that could be curtailed is expected to be required of participants in any future program design.

5. Ways to provide feedback

BC Hydro is convening a workshop on October 19, 2022 with customers and stakeholders to review and discuss the information contained in this booklet. After this meeting, we will be providing a feedback form to seek more detailed feedback in key areas that have been highlighted throughout this document. Additional comments and questions can be shared with your Key Account Manager or **bchydroregulatorygroup@bchydro.com**.

16 The 36-day specification was derived from the potential for three two-week periods (excluding Sundays) where curtailment would be required.

Appendix A: Glossary and abbreviations

Word or abbreviation	Definition
AMPC	Association of Major Power Consumers of British Columbia
Base Resource Plan	BC Hydro's plan for meeting its current and future customers' expected electricity needs.
British Columbia Utilities Commission (BCUC or the Commission)	An independent regulatory agency of the provincial government operating under the Utilities Commission Act. The BCUC regulates BC Hydro's domestic supply and rates, as well as the safety and reliability of the services BC Hydro provides. The BCUC also assesses concerns from ratepayers regarding BC Hydro's service.
CAPP	Canadian Association of Petroleum Producers
CBL	Customer Baseline Load—represents the customer's normal annual energy consumption in kWh in the absence of the Stepped Rate, as approved by the British Columbia Utilities Commission.
Cost of Service	A study that functionalizes, classifies, and allocates BC Hydro's costs to rate classes.
Default rate	The rate that customers pay unless they have the option for another rate and have chosen that option.
Demand charge	The price per kilovolt ampere (kVA) or per kilowatt (kW) of electricity, calculated to reflect the costs of Transmission and/or Distribution facilities to meet customers' maximum power demands.
Duration	In the context of this booklet, duration means the period of time, commencing from the project in-service date, over which a customer-funded Demand Side Management (DSM) project will be recognized. The duration of customer-funded DSM projects is detailed in Attachment A of Tariff Supplement No. 74—Customer Baseline Load Determination Guidelines.
DSM project	Demand Side Management project—in the context of this booklet, a Demand Side Management project means a customer-funded project relating to energy efficiency or conservation, as detailed in Tariff Supplement No. 74—Customer Baseline Load Determination Guidelines.
Energy	The amount of electricity produced or used over a period of time, usually measured in kilowatt hours (kWh), megawatt hours (MWh) and gigawatt hours (GWh).
Energy charge	The price per kilowatt-hour or megawatt-hour of electricity consumed (¢ per kWh or $ per MWh).
F	Fiscal Year—BC Hydro's fiscal year starting April 1 of the previous calendar year and ending March 31 of the year given. Dates marked with an F refer to the year ending March 31 in the year given.
Flat energy rate	A rate with a constant ¢ per kWh charge for all kWh consumed.
GHG	Greenhouse gas—any of the atmospheric gases that contribute to climate change such as water vapour, methane, or carbon dioxide.
IRP	Integrated Resource Plan—BC Hydro's long-term resource plan to meet customers' electricity needs using existing, committed, and planned demand-side and supply-side resources.
kWh	Kilowatt-hour—The amount of energy delivered in one hour, when delivery is at a constant rate of one kilowatt.
Load	The amount of electricity required by a customer or group of customers.

Word or abbreviation	Definition
Load curtailment	A measure that reduces electrical use for a period of time. Load curtailment programs provide customers with an incentive in exchange for agreeing to curtail energy use during specific periods requested by the utility.
Load factor	The ratio of energy consumed during a given period of time, to that which would have been consumed if the load had operated at peak 100 percent of that time. A high load factor indicates steady usage. A low load factor indicates the recorded demand was not present for very long.
Load forecast	The load requirements that an electricity system is expected to have to meet in future years.
LRMC	Long-Run Marginal Cost—refers to the cost of the next cheapest group (or block) of generation resources to be considered during system deficit. System deficit occurs when our customer's electricity needs exceed supply.
MABC	Mining Association of British Columbia
Marginal Costs	Marginal cost refers to the incremental costs incurred when producing additional units of a good or service. In the electric utility context, there are several types of marginal costs—energy, generation capacity, transmission capacity and distribution capacity
Mid-C	Mid-Columbia—wholesale electricity trading hub located in the U.S. Pacific Northwest.
Off-peak	Time period when the electric system does not usually face high demand (peak).
Optional rate	A rate that customers can voluntarily choose to receive service under.
Peak demand	The highest electric requirement occurring in a given period (e.g., an hour, a day, month, season or year).
Rate	A utility's unit price for electricity service provided (usually defined in cents per kilowatt-hours) or per unit of demand (usually defined in dollars per Kilowatt (kW) or per kilovolt ampere (kVA)).
RS	Rate Schedule
Revenue neutrality	Rate is designed to collect the revenue requirement for a customer class, which is the forecast load multiplied by the previous year's rates and any general rate increase or decrease so that the revenue requirement for a class of customers continues to be collected on a forecast basis and other ratepayers are not harmed.
RRA	Revenue Requirements Application—BC Hydro's application to the British Columbia Utilities Commission to determine the rates BC Hydro will need to recover sufficient revenues for its operations to ensure a safe and reliable supply of electricity to its customers.
Stepped Rate	Refers to Rate Schedule 1823 Energy Charge B which includes tiered energy charges for transmission service customers with a Customer Baseline Load.
Tier 1	The energy charge that is applied under the Stepped Rate to a customer's consumption up to and including 90% of its Customer Baseline Load in each billing year.
Tier 2	The energy charge that is applied under the Stepped Rate to a customer's consumption above 90% of its Customer Baseline Load in each billing year.
TOU	Time-of-Use—a type of time-varying rate which generally includes two or more predetermined daily price periods to encourage customers to shift their use of electricity from the system peak period to off-peak periods.
Transmission service	Service for commercial, industrial and institutional customers, provided at 60 kilovolts (kV) or more.
TS	Tariff Supplement
TSR	Transmission Service Rate—the suite of approved rate schedules that are included in BC Hydro's Electric Tariff and are offered to transmission service customers.

Appendix B: Methodology for developing revenue neutral segmented flat rates

Under the revenue neutral segmented flat rates approach, the rates would gradually be adjusted over time so that all customers pay the same final flat rate after a five-year transition period. In Appendix D, we outline how customers with remaining energy savings duration from past customer-funded DSM projects would benefit under this transition option. Customers that are expected to see bill savings from the proposed flat rate would have their bill savings smoothed over the transition period.

The following outlines the steps undertaken to develop revenue neutral segmented flat rates:

STEP 1: DETERMINE SEGMENTS

We reviewed F2024 forecast Tier 1 and Tier 2 energy by customer site and noticed that there is a cut-off point at 95% Tier 1 energy at 70% load factor where a flat rate becomes cheaper, all else equal. However, preliminary analysis of two segments with 95% Tier 1 as the threshold indicated that three segments would reduce the number of customers with windfall gains and losses. Accordingly, the following three segments are proposed:

Segment 1: All forecast F2024 accounts with Tier 1 energy greater or equal to 97% of total energy consumption.

Segment 2: All forecast F2024 accounts with Tier 1 energy greater or equal to 93% and less than 97% of total energy consumption.

Segment 3: All forecast F2024 accounts with Tier 1 energy less than 93% of total energy and accounts on RS 1823A, RS 1827 and RS 3808.

We compared the F2024 allocation of customers to segments with the allocation based on average F2017–F2019 Tier 1 energy share. We found that large, aggregated accounts in Segment 1 have been quite stable as have RS 1823A customers.

If you have any concerns or issues with the proposed process for grouping customers into segments, please provide us with your feedback so that we can refine this approach.

STEP 2: DETERMINE REVENUE NEUTRAL RATES FOR EACH SEGMENT

We calculated revenue neutral rates for each segment using the final flat rate of $44.14/MWh for energy and $11/kVA as the starting point. For Segment 1, we chose the $44.14/MWh for the energy charge and calculated $9.88/kVA as the revenue neutral demand charge for the first year of the transition. For Segment 2, we chose the $11/kVA demand charge and calculated $44.99/MWh as the revenue neutral energy charge. For Segment 3, we initially chose the $11/kVA demand charge and revenue neutral $46.88/MWh energy charge, which we presented at a customer working group meeting. However, we have since revised Segment 3 rates to have a lower demand charge of $10.13/kVA and energy charge of $48.73/MWh which mitigates bill impacts to customers with the lowest load factors. The segmented rates have been chosen to minimize annual bill impacts (positive or negative) within each segment.

The segmented flat rates recover the same revenue as under RS 1823, RS 1827 and RS 3808 based on the F2024 forecast load for each segment. The following table shows the resulting rates for the first year of the transition.

F2024 Pricing	Energy Charge $/MWh	Demand Charge $/kVA
Segment 1 Tier 1 energy greater or equal to 97%	44.14	9.88
Segment 2 Tier 1 energy greater or equal to 93% and less than 97%	44.99	11.00
Segment 3 Tier 1 energy less than 93%, RS 1823A, RS 1827, RS 3808	48.73	10.13

We would like your feedback on any refinements that we should consider to this transition option and expect that if this option is chosen as the final transition option that we propose in our application, it may have some adjustments based on this feedback.

STEP 3: DETERMINE REVENUE NEUTRAL RATES FOR TRANSITION PERIOD

We adjusted the segmented flat rates so that they reach the final flat rate over a five-year period. These rates recover the F2024 forecast revenue in each year (i.e., they have not been adjusted to take into account future revenue requirements).

Year	Segment 1		Segment 2		Segment 3	
	Energy charge $/MWh	Demand charge $/kVA	Energy charge $/MWh	Demand charge $/kVA	Energy charge $/MWh	Demand charge $/kVA
F2024	Existing Stepped Rate					
F2025	44.14	9.88	44.99	11.00	48.73	10.13
F2026	44.14	10.16	44.78	11.00	47.58	10.35
F2027	44.14	10.44	44.57	11.00	46.44	10.57
F2028	44.14	10.72	44.35	11.00	45.29	10.78
F2029	44.14	11.00	44.14	11.00	44.14	11.00

Note: Pricing in F2024 dollars, inclusive of revenue requirement for F2024, but exclusive of Deferral Account Rate Rider (DARR)

Appendix C: Bill Impacts of Rate Transition Options

Bill impacts of rate redesign only

TRANSITION OPTION 1: REVENUE NEUTRAL SEGMENTED FLAT RATES

Year	Segment 1		Segment 2		Segment 3	
	Energy Charge $/MWh	Demand Charge $/kVA	Energy Charge $/MWh	Demand Charge $/kVA	Energy Charge $/MWh	Demand Charge $/kVA
F2024	Existing Stepped Rate					
F2025	44.14	9.88	44.99	11.00	48.73	10.13
F2026	44.14	10.16	44.78	11.00	47.58	10.35
F2027	44.14	10.44	44.57	11.00	46.44	10.57
F2028	44.14	10.72	44.35	11.00	45.29	10.78
F2029	44.14	11.00	44.14	11.00	44.14	11.00

Note: Pricing in F2024 dollars, inclusive of revenue requirement for F2024, but exclusive of Deferral Account Rate Rider (DARR)

Segment 1 Bill Impacts (assumes 100% Tier 1 energy)

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Seg 1 Rate Avg ¢/kWh	Bill Impact	Seg 1 Rate Avg ¢/kWh	Bill Impact	Seg 1 Rate Avg ¢/kWh	Bill Impact	Seg 1 Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.01	17.27	7.9%	17.64	2.1%	18.00	2.1%	18.36	2.0%	18.73	2.0%	17.0%
20%	10.29	10.84	5.4%	11.02	1.7%	11.21	1.7%	11.39	1.6%	11.57	1.6%	12.4%
30%	8.39	8.70	3.7%	8.82	1.4%	8.94	1.4%	9.06	1.4%	9.19	1.3%	9.5%
40%	7.44	7.63	2.6%	7.72	1.2%	7.81	1.2%	7.90	1.2%	7.99	1.2%	7.5%
50%	6.86	6.99	1.8%	7.06	1.0%	7.13	1.0%	7.20	1.0%	7.28	1.0%	6.0%
60%	6.48	6.56	1.1%	6.62	0.9%	6.68	0.9%	6.74	0.9%	6.80	0.9%	4.9%
70%	6.21	6.25	0.6%	6.30	0.8%	6.35	0.8%	6.41	0.8%	6.46	0.8%	4.0%
80%	6.01	6.02	0.2%	6.07	0.8%	6.11	0.8%	6.16	0.7%	6.20	0.7%	3.3%
90%	5.85	5.84	−0.1%	5.88	0.7%	5.92	0.7%	5.96	0.7%	6.00	0.7%	2.7%
100%	5.72	5.70	−0.4%	5.74	0.6%	5.77	0.6%	5.81	0.6%	5.85	0.6%	2.2%

Segment 2 Bill Impacts (assumes 95% Tier 1 and 5% Tier 2)

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Seg 2 Rate Avg ¢/kWh	Bill Impact	Seg 2 Rate Avg ¢/kWh	Bill Impact	Seg 2 Rate Avg ¢/kWh	Bill Impact	Seg 2 Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.29	18.81	15.5%	18.79	−0.1%	18.77	−0.1%	18.75	−0.1%	18.73	−0.1%	15.0%
20%	10.58	11.66	10.2%	11.64	−0.2%	11.61	−0.2%	11.59	−0.2%	11.57	−0.2%	9.4%
30%	8.67	9.27	6.9%	9.25	−0.2%	9.23	−0.2%	9.21	−0.2%	9.19	−0.2%	5.9%
40%	7.72	8.08	4.6%	8.06	−0.3%	8.04	−0.3%	8.01	−0.3%	7.99	−0.3%	3.5%
50%	7.15	7.36	3.0%	7.34	−0.3%	7.32	−0.3%	7.30	−0.3%	7.28	−0.3%	1.8%
60%	6.77	6.88	1.7%	6.86	−0.3%	6.84	−0.3%	6.82	−0.3%	6.80	−0.3%	0.5%
70%	6.50	6.54	0.8%	6.52	−0.3%	6.50	−0.3%	6.48	−0.3%	6.46	−0.3%	−0.6%
80%	6.29	6.29	0.0%	6.27	−0.3%	6.25	−0.3%	6.22	−0.4%	6.20	−0.3%	−1.4%
90%	6.13	6.09	−0.7%	6.07	−0.3%	6.05	−0.3%	6.03	−0.4%	6.00	−0.3%	−2.1%
100%	6.01	5.93	−1.3%	5.91	−0.4%	5.89	−0.4%	5.87	−0.4%	5.85	−0.4%	−2.7%

Segment 3 Bill Impacts (assumes 90% Tier 1 energy and 10% Tier 2 energy)

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Seg 3 Rate Avg ¢/kWh	Bill Impact	Seg 3 Rate Avg ¢/kWh	Bill Impact	Seg 3 Rate Avg ¢/kWh	Bill Impact	Seg 3 Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.57	18.06	8.9%	18.23	0.9%	18.40	0.9%	18.56	0.9%	18.73	0.9%	13.0%
20%	10.86	11.46	5.6%	11.49	0.2%	11.52	0.3%	11.54	0.2%	11.57	0.2%	6.6%
30%	8.96	9.27	3.5%	9.25	-0.2%	9.23	-0.2%	9.21	-0.3%	9.19	-0.2%	2.6%
40%	8.00	8.17	2.1%	8.13	-0.5%	8.08	-0.5%	8.04	-0.6%	7.99	-0.5%	-0.1%
50%	7.43	7.51	1.0%	7.45	-0.8%	7.40	-0.8%	7.33	-0.8%	7.28	-0.8%	-2.1%
60%	7.05	7.07	0.3%	7.00	-1.0%	6.94	-0.9%	6.87	-1.0%	6.80	-1.0%	-3.6%
70%	6.78	6.76	-0.3%	6.68	-1.1%	6.61	-1.1%	6.53	-1.1%	6.46	-1.1%	-4.7%
80%	6.58	6.52	-0.8%	6.44	-1.2%	6.36	-1.2%	6.28	-1.3%	6.20	-1.3%	-5.7%
90%	6.42	6.34	-1.2%	6.25	-1.3%	6.17	-1.3%	6.09	-1.4%	6.00	-1.4%	-6.4%
100%	6.29	6.19	-1.6%	6.10	-1.4%	6.02	-1.4%	5.93	-1.5%	5.85	-1.5%	-7.1%

TRANSITION OPTION 2: STAGGERED IMPLEMENTATION

Bill impacts for 100% Tier 1 Energy Customer with DSM

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.01	16.01	0.0%	16.01	0.0%	18.73	17.0%	18.73	0.0%	18.73	0.0%	17.0%
20%	10.29	10.29	0.0%	10.29	0.0%	11.57	12.4%	11.57	0.0%	11.57	0.0%	12.4%
30%	8.39	8.39	0.0%	8.39	0.0%	9.19	9.5%	9.19	0.0%	9.19	0.0%	9.5%
40%	7.44	7.44	0.0%	7.44	0.0%	7.99	7.5%	7.99	0.0%	7.99	0.0%	7.5%
50%	6.86	6.86	0.0%	6.86	0.0%	7.28	6.0%	7.28	0.0%	7.28	0.0%	6.0%
60%	6.48	6.48	0.0%	6.48	0.0%	6.80	4.9%	6.80	0.0%	6.80	0.0%	4.9%
70%	6.21	6.21	0.0%	6.21	0.0%	6.46	4.0%	6.46	0.0%	6.46	0.0%	4.0%
80%	6.01	6.01	0.0%	6.01	0.0%	6.20	3.3%	6.20	0.0%	6.20	0.0%	3.3%
90%	5.85	5.85	0.0%	5.85	0.0%	6.00	2.7%	6.00	0.0%	6.00	0.0%	2.7%
100%	5.72	5.72	0.0%	5.72	0.0%	5.85	2.2%	5.85	0.0%	5.85	0.0%	2.2%

Bill impacts for 100% Tier 1 Energy Customer without DSM

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.01	18.73	17.0%	18.73	0.0%	18.73	0.0%	18.73	0.0%	18.73	0.0%	17.0%
20%	10.29	11.57	12.4%	11.57	0.0%	11.57	0.0%	11.57	0.0%	11.57	0.0%	12.4%
30%	8.39	9.19	9.5%	9.19	0.0%	9.19	0.0%	9.19	0.0%	9.19	0.0%	9.5%
40%	7.44	7.99	7.5%	7.99	0.0%	7.99	0.0%	7.99	0.0%	7.99	0.0%	7.5%
50%	6.86	7.28	6.0%	7.28	0.0%	7.28	0.0%	7.28	0.0%	7.28	0.0%	6.0%
60%	6.48	6.80	4.9%	6.80	0.0%	6.80	0.0%	6.80	0.0%	6.80	0.0%	4.9%
70%	6.21	6.46	4.0%	6.46	0.0%	6.46	0.0%	6.46	0.0%	6.46	0.0%	4.0%
80%	6.01	6.20	3.3%	6.20	0.0%	6.20	0.0%	6.20	0.0%	6.20	0.0%	3.3%
90%	5.85	6.00	2.7%	6.00	0.0%	6.00	0.0%	6.00	0.0%	6.00	0.0%	2.7%
100%	5.72	5.85	2.2%	5.85	0.0%	5.85	0.0%	5.85	0.0%	5.85	0.0%	2.2%

Bill impacts for 95% Tier 1 energy and 5% Tier 2 energy Customer without DSM

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.29	18.73	15.0%	18.73	0.0%	18.73	0.0%	18.73	0.0%	18.73	0.0%	15.0%
20%	10.58	11.57	9.4%	11.57	0.0%	11.57	0.0%	11.57	0.0%	11.57	0.0%	9.4%
30%	8.67	9.19	5.9%	9.19	0.0%	9.19	0.0%	9.19	0.0%	9.19	0.0%	5.9%
40%	7.72	7.99	3.5%	7.99	0.0%	7.99	0.0%	7.99	0.0%	7.99	0.0%	3.5%
50%	7.15	7.28	1.8%	7.28	0.0%	7.28	0.0%	7.28	0.0%	7.28	0.0%	1.8%
60%	6.77	6.80	0.5%	6.80	0.0%	6.80	0.0%	6.80	0.0%	6.80	0.0%	0.5%
70%	6.50	6.46	−0.6%	6.46	0.0%	6.46	0.0%	6.46	0.0%	6.46	0.0%	−0.6%
80%	6.29	6.20	−1.4%	6.20	0.0%	6.20	0.0%	6.20	0.0%	6.20	0.0%	−1.4%
90%	6.13	6.00	−2.1%	6.00	0.0%	6.00	0.0%	6.00	0.0%	6.00	0.0%	−2.1%
100%	6.01	5.85	−2.7%	5.85	0.0%	5.85	0.0%	5.85	0.0%	5.85	0.0%	−2.7%

Bill impacts for Flat Rate RS 1823A or 90% Tier 1 energy, 10% Tier 2 energy RS 1823B Customer without DSM

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.57	18.73	13.0%	18.73	0.0%	18.73	0.0%	18.73	0.0%	18.73	0.0%	13.0%
20%	10.86	11.57	6.6%	11.57	0.0%	11.57	0.0%	11.57	0.0%	11.57	0.0%	6.6%
30%	8.96	9.19	2.6%	9.19	0.0%	9.19	0.0%	9.19	0.0%	9.19	0.0%	2.6%
40%	8.00	7.99	−0.1%	7.99	0.0%	7.99	0.0%	7.99	0.0%	7.99	0.0%	−0.1%
50%	7.43	7.28	−2.1%	7.28	0.0%	7.28	0.0%	7.28	0.0%	7.28	0.0%	−2.1%
60%	7.05	6.80	−3.6%	6.80	0.0%	6.80	0.0%	6.80	0.0%	6.80	0.0%	−3.6%
70%	6.78	6.46	−4.7%	6.46	0.0%	6.46	0.0%	6.46	0.0%	6.46	0.0%	−4.7%
80%	6.58	6.20	−5.7%	6.20	0.0%	6.20	0.0%	6.20	0.0%	6.20	0.0%	−5.7%
90%	6.42	6.00	−6.4%	6.00	0.0%	6.00	0.0%	6.00	0.0%	6.00	0.0%	−6.4%
100%	6.29	5.85	−7.1%	5.85	0.0%	5.85	0.0%	5.85	0.0%	5.85	0.0%	−7.1%

Note: For RS 1827 and RS 3808 (tranche 1) customers, the stated bill impacts would occur in Fiscal 2027 instead of Fiscal 2025.

ALTERNATIVE TRANSITION: GRADUAL IMPLEMENTATION

Year	Flat Energy Charge $/MWh	Tier 1 Energy Charge $/MWh	Tier 2 Energy Charge$/MWh	Demand Charge $/kVA
F2024	Existing Stepped Rate			
F2025	49.99	45.46	90.88	9.22
F2026	48.53	45.13	79.2	9.67
F2027	47.06	44.80	67.51	10.11
F2028	45.60	44.47	55.83	10.56
F2029	44.14	n/a	n/a	11.00

Note: Pricing in F2024 dollars, inclusive of revenue requirement for F2024, but exclusive of Deferral Account Rate Rider (DARR)

Bill Impacts for 100% Tier 1 Energy Customer

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.01	16.54	3.4%	17.10	3.3%	17.64	3.2%	18.19	3.1%	18.73	3.0%	17.0%
20%	10.29	10.55	2.5%	10.81	2.5%	11.06	2.3%	11.32	2.3%	11.57	2.2%	12.4%
30%	8.39	8.55	1.9%	8.71	1.9%	8.87	1.8%	9.03	1.8%	9.19	1.7%	9.5%
40%	7.44	7.55	1.5%	7.66	1.5%	7.77	1.4%	7.88	1.5%	7.99	1.4%	7.5%
50%	6.86	6.95	1.2%	7.03	1.2%	7.11	1.2%	7.20	1.2%	7.28	1.1%	6.0%
60%	6.48	6.55	1.0%	6.61	1.0%	6.67	0.9%	6.74	1.0%	6.80	0.9%	4.9%
70%	6.21	6.26	0.8%	6.31	0.8%	6.36	0.8%	6.41	0.8%	6.46	0.8%	4.0%
80%	6.01	6.05	0.6%	6.09	0.7%	6.12	0.6%	6.16	0.7%	6.20	0.6%	3.3%
90%	5.85	5.88	0.5%	5.91	0.5%	5.94	0.5%	5.97	0.5%	6.00	0.5%	2.7%
100%	5.72	5.75	0.4%	5.77	0.4%	5.80	0.4%	5.82	0.4%	5.85	0.4%	2.2%

Bill impacts for 95% Tier 1 energy and 5% Tier 2 energy Customer

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.29	16.77	3.0%	17.27	3.0%	17.75	2.8%	18.25	2.8%	18.73	2.6%	15.0%
20%	10.58	10.77	1.9%	10.98	1.9%	11.17	1.8%	11.38	1.8%	11.57	1.7%	9.4%
30%	8.67	8.77	1.2%	8.88	1.2%	8.98	1.1%	9.08	1.2%	9.19	1.1%	5.9%
40%	7.72	7.77	0.7%	7.83	0.7%	7.88	0.7%	7.94	0.7%	7.99	0.7%	3.5%
50%	7.15	7.17	0.3%	7.20	0.4%	7.23	0.4%	7.25	0.4%	7.28	0.3%	1.8%
60%	6.77	6.77	0.1%	6.78	0.1%	6.79	0.1%	6.79	0.1%	6.80	0.1%	0.5%
70%	6.50	6.49	−0.1%	6.48	−0.1%	6.47	−0.1%	6.47	−0.1%	6.46	−0.1%	−0.6%
80%	6.29	6.27	−0.3%	6.26	−0.3%	6.24	−0.3%	6.22	−0.3%	6.20	−0.3%	−1.4%
90%	6.13	6.11	−0.4%	6.08	−0.4%	6.06	−0.4%	6.03	−0.4%	6.00	−0.4%	−2.1%
100%	6.01	5.97	−0.5%	5.94	−0.5%	5.91	−0.5%	5.88	−0.5%	5.85	−0.6%	−2.7%

Bill impacts for Flat Rate RS 1823A or 90% Tier 1 energy, 10% Tier 2 energy RS 1823B Customer

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.57	17.00	2.6%	17.43	2.6%	17.75	1.8%	18.30	3.1%	18.73	2.3%	13.0%
20%	10.86	11.00	1.3%	11.14	1.3%	11.17	0.3%	11.43	2.3%	11.57	1.2%	6.6%
30%	8.96	9.00	0.5%	9.04	0.5%	8.98	−0.7%	9.14	1.8%	9.19	0.5%	2.6%
40%	8.00	8.00	0.0%	8.00	0.0%	7.88	−1.4%	8.00	1.4%	7.99	0.0%	−0.1%
50%	7.43	7.40	−0.4%	7.37	−0.4%	7.23	−1.9%	7.31	1.2%	7.28	−0.4%	−2.1%
60%	7.05	7.00	−0.7%	6.95	−0.7%	6.79	−2.3%	6.85	1.0%	6.80	−0.8%	−3.6%
70%	6.78	6.71	−1.0%	6.65	−1.0%	6.47	−2.6%	6.52	0.8%	6.46	−1.0%	−4.7%
80%	6.58	6.50	−1.1%	6.42	−1.2%	6.24	−2.9%	6.28	0.6%	6.20	−1.2%	−5.7%
90%	6.42	6.33	−1.3%	6.25	−1.3%	6.06	−3.1%	6.09	0.5%	6.00	−1.4%	−6.4%
100%	6.29	6.20	−1.4%	6.11	−1.5%	5.91	−3.3%	5.94	0.4%	5.85	−1.5%	−7.1%

Bill Impacts from Rate Redesign and Forecast RRA increases Combined

TRANSITION OPTION 1: REVENUE NEUTRAL SEGMENTED FLAT RATES

Year	Segment 1		Segment 2		Segment 3	
	Energy Charge $/MWh	Demand Charge $/kVA	Energy Charge $/MWh	Demand Charge $/kVA	Energy Charge $/MWh	Demand Charge $/kVA
F2024	Existing Stepped Rate					
F2025	45.10	10.10	45.97	11.24	49.79	10.35
F2026	47.31	10.89	48.00	11.79	51.00	11.09
F2027	47.36	11.20	47.82	11.80	49.82	11.34
F2028	47.98	11.65	48.21	11.96	49.22	11.72
F2029	48.02	11.97	48.02	11.97	48.02	11.97

Note: Pricing inclusive of revenue requirement increases, but exclusive of Deferral Account Rate Rider (DARR)

Assumed RRA increases: F25 2.18%, F26 4.9%, F27 0.1%, F28 1.3%, F29 0.1% (see response to BCUC 1.1.1 F23-F25 RRA Proceeding)

Segment 1 Bill Impacts (assumes 100% Tier 1)

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Seg 1 Rate Avg ¢/kWh	Bill Impact	Seg 1 Rate Avg ¢/kWh	Bill Impact	Seg 1 Rate Avg ¢/kWh	Bill Impact	Seg 1 Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.01	17.65	10.31%	18.90	7.1%	19.31	2.2%	19.96	3.4%	20.38	2.1%	27.3%
20%	10.29	11.08	7.7%	11.82	6.6%	12.02	1.7%	12.38	3.0%	12.59	1.7%	22.3%
30%	8.39	8.89	6.0%	9.45	6.3%	9.59	1.5%	9.85	2.7%	9.99	1.4%	19.2%
40%	7.44	7.80	4.8%	8.27	6.1%	8.38	1.3%	8.59	2.5%	8.70	1.3%	17.0%
50%	6.86	7.14	4.0%	7.57	6.0%	7.65	1.1%	7.83	2.3%	7.92	1.1%	15.3%
60%	6.48	6.70	3.4%	7.09	5.9%	7.17	1.0%	7.32	2.2%	7.40	1.0%	14.1%
70%	6.21	6.39	2.8%	6.76	5.8%	6.82	0.9%	6.96	2.1%	7.03	0.9%	13.1%
80%	6.01	6.15	2.4%	6.50	5.7%	6.56	0.9%	6.69	2.1%	6.75	0.8%	12.4%
90%	5.85	5.97	2.1%	6.31	5.6%	6.36	0.8%	6.48	2.0%	6.53	0.8%	11.7%
100%	5.72	5.82	1.8%	6.15	5.6%	6.19	0.7%	6.31	1.9%	6.36	0.7%	11.2%

Segment 2 Bill Impacts (assumes 95% Tier 1 energy and 5% Tier 2 energy)

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Seg 2 Rate Avg ¢/kWh	Bill Impact	Seg 2 Rate Avg ¢/kWh	Bill Impact	Seg 2 Rate Avg ¢/kWh	Bill Impact	Seg 2 Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.29	19.22	18.0%	20.14	4.8%	20.14	0.0%	20.39	1.2%	20.38	0.0%	25.1%
20%	10.58	11.91	12.6%	12.47	4.7%	12.46	-0.1%	12.60	1.1%	12.59	-0.1%	19.0%
30%	8.67	9.47	9.2%	9.91	4.7%	9.90	-0.1%	10.01	1.1%	9.99	-0.1%	15.3%
40%	7.72	8.25	6.9%	8.64	4.6%	8.62	-0.2%	8.71	1.1%	8.70	-0.2%	12.7%
50%	7.15	7.52	5.2%	7.87	4.6%	7.85	-0.2%	7.93	1.0%	7.92	-0.2%	10.8%
60%	6.77	7.03	4.0%	7.36	4.6%	7.34	-0.2%	7.42	1.0%	7.40	-0.2%	9.3%
70%	6.50	6.69	2.9%	6.99	4.6%	6.98	-0.2%	7.04	1.0%	7.03	-0.2%	8.2%
80%	6.29	6.43	2.1%	6.72	4.6%	6.70	-0.2%	6.77	1.0%	6.75	-0.3%	7.3%
90%	6.13	6.22	1.5%	6.50	4.5%	6.49	-0.3%	6.55	1.0%	6.53	-0.3%	6.5%
100%	6.01	6.06	0.9%	6.33	4.5%	6.32	-0.3%	6.38	0.9%	6.36	-0.3%	5.9%

Segment 3 Bill Impacts (assumes 90% Tier 1 energy and 10% Tier 2 energy)

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Seg 3 Rate Avg ¢/kWh	Bill Impact	Seg 3 Rate Avg ¢/kWh	Bill Impact	Seg 3 Rate Avg ¢/kWh	Bill Impact	Seg 3 Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.57	18.45	11.3%	19.53	5.9%	19.74	1.1%	20.17	2.2%	20.38	1.0%	23.0%
20%	10.86	11.71	7.9%	12.32	5.1%	12.36	0.4%	12.55	1.5%	12.59	0.3%	15.9%
30%	8.96	9.47	5.7%	9.91	4.7%	9.90	-0.1%	10.01	1.1%	9.99	-0.1%	11.6%
40%	8.00	8.35	4.3%	8.71	4.3%	8.67	-0.4%	8.74	0.7%	8.70	-0.4%	8.7%
50%	7.43	7.67	3.2%	7.99	4.1%	7.93	-0.7%	7.97	0.5%	7.92	-0.7%	6.5%
60%	7.05	7.22	2.4%	7.51	3.9%	7.44	-0.8%	7.46	0.3%	7.40	-0.9%	4.9%
70%	6.78	6.90	1.8%	7.16	3.7%	7.09	-1.0%	7.10	0.2%	7.03	-1.0%	3.7%
80%	6.58	6.66	1.3%	6.90	3.6%	6.83	-1.1%	6.83	0.0%	6.75	-1.2%	2.6%
90%	6.42	6.48	0.9%	6.70	3.5%	6.62	-1.2%	6.62	-0.1%	6.53	-1.3%	1.8%
100%	6.29	6.33	0.6%	6.54	3.4%	6.46	-1.3%	6.45	-0.2%	6.36	-1.4%	1.1%

TRANSITION OPTION 2: STAGGERED IMPLEMENTATION

Bill impacts for 100% Tier 1 Energy Customer with DSM

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.01	16.35	2.2%	17.15	4.9%	20.09	17.1%	20.36	1.3%	20.38	0.1%	27.3%
20%	10.29	10.52	2.2%	11.03	4.9%	12.41	12.5%	12.58	1.3%	12.59	0.1%	22.3%
30%	8.39	8.57	2.2%	8.99	4.9%	9.85	9.6%	9.99	1.3%	9.99	0.1%	19.2%
40%	7.44	7.60	2.2%	7.97	4.9%	8.58	7.6%	8.69	1.3%	8.70	0.1%	17.0%
50%	6.86	7.01	2.2%	7.36	4.9%	7.81	6.1%	7.91	1.3%	7.92	0.1%	15.3%
60%	6.48	6.62	2.2%	6.95	4.9%	7.30	5.0%	7.39	1.3%	7.40	0.1%	14.1%
70%	6.21	6.35	2.2%	6.66	4.9%	6.93	4.1%	7.02	1.3%	7.03	0.1%	13.1%
80%	6.01	6.14	2.2%	6.44	4.9%	6.66	3.4%	6.74	1.3%	6.75	0.1%	12.4%
90%	5.85	5.98	2.2%	6.27	4.9%	6.44	2.8%	6.53	1.3%	6.53	0.1%	11.7%
100%	5.72	5.85	2.2%	6.13	4.9%	6.27	2.3%	6.35	1.3%	6.36	0.1%	11.2%

Bill impacts for 100% Tier 1 Energy Customer without DSM

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.01	19.14	19.6%	20.07	4.9%	20.09	0.1%	20.36	1.3%	20.38	0.1%	27.3%
20%	10.29	11.82	14.9%	12.40	4.9%	12.41	0.1%	12.58	1.3%	12.59	0.1%	22.3%
30%	8.39	9.39	11.9%	9.85	4.9%	9.85	0.1%	9.99	1.3%	9.99	0.1%	19.2%
40%	7.44	8.17	9.8%	8.57	4.9%	8.58	0.1%	8.69	1.3%	8.70	0.1%	17.0%
50%	6.86	7.44	8.3%	7.80	4.9%	7.81	0.1%	7.91	1.3%	7.92	0.1%	15.3%
60%	6.48	6.95	7.2%	7.29	4.9%	7.30	0.1%	7.39	1.3%	7.40	0.1%	14.1%
70%	6.21	6.60	6.3%	6.92	4.9%	6.93	0.1%	7.02	1.3%	7.03	0.1%	13.1%
80%	6.01	6.34	5.5%	6.65	4.9%	6.66	0.1%	6.74	1.3%	6.75	0.1%	12.4%
90%	5.85	6.14	4.9%	6.44	4.9%	6.44	0.1%	6.53	1.3%	6.53	0.1%	11.7%
100%	5.72	5.97	4.4%	6.27	4.9%	6.27	0.1%	6.35	1.3%	6.36	0.1%	11.2%

Bill impacts for 95% Tier 1 energy and 5% Tier 2 energy Customer without DSM

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.29	19.14	17.5%	20.07	4.9%	20.09	0.1%	20.36	1.3%	20.38	0.1%	25.1%
20%	10.58	11.82	11.8%	12.40	4.9%	12.41	0.1%	12.58	1.3%	12.59	0.1%	19.0%
30%	8.67	9.39	8.2%	9.85	4.9%	9.85	0.1%	9.99	1.3%	9.99	0.1%	15.3%
40%	7.72	8.17	5.8%	8.57	4.9%	8.58	0.1%	8.69	1.3%	8.70	0.1%	12.7%
50%	7.15	7.44	4.0%	7.80	4.9%	7.81	0.1%	7.91	1.3%	7.92	0.1%	10.8%
60%	6.77	6.95	2.7%	7.29	4.9%	7.30	0.1%	7.39	1.3%	7.40	0.1%	9.3%
70%	6.50	6.60	1.6%	6.92	4.9%	6.93	0.1%	7.02	1.3%	7.03	0.1%	8.2%
80%	6.29	6.34	0.7%	6.65	4.9%	6.66	0.1%	6.74	1.3%	6.75	0.1%	7.3%
90%	6.13	6.14	0.0%	6.44	4.9%	6.44	0.1%	6.53	1.3%	6.53	0.1%	6.5%
100%	6.01	5.97	-0.5%	6.27	4.9%	6.27	0.1%	6.35	1.3%	6.36	0.1%	5.9%

Bill impacts for Flat Rate RS 1823A Customer or 90% Tier 1 energy, 10% Tier 2 energy RS 1823B Customer without DSM

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.57	19.14	15.5%	20.07	4.9%	20.09	0.1%	20.36	1.3%	20.38	0.1%	23.0%
20%	10.86	11.82	8.9%	12.40	4.9%	12.41	0.1%	12.58	1.3%	12.59	0.1%	15.9%
30%	8.96	9.39	4.8%	9.85	4.9%	9.85	0.1%	9.99	1.3%	9.99	0.1%	11.6%
40%	8.00	8.17	2.1%	8.57	4.9%	8.58	0.1%	8.69	1.3%	8.70	0.1%	8.7%
50%	7.43	7.44	0.1%	7.80	4.9%	7.81	0.1%	7.91	1.3%	7.92	0.1%	6.5%
60%	7.05	6.95	-1.4%	7.29	4.9%	7.30	0.1%	7.39	1.3%	7.40	0.1%	4.9%
70%	6.78	6.60	-2.6%	6.92	4.9%	6.93	0.1%	7.02	1.3%	7.03	0.1%	3.7%
80%	6.58	6.34	-3.6%	6.65	4.9%	6.66	0.1%	6.74	1.3%	6.75	0.1%	2.6%
90%	6.42	6.14	-4.4%	6.44	4.9%	6.44	0.1%	6.53	1.3%	6.53	0.1%	1.8%
100%	6.29	5.97	-5.0%	6.27	4.9%	6.27	0.1%	6.35	1.3%	6.36	0.1%	1.1%

ALTERNATIVE TRANSITION: GRADUAL IMPLEMENTATION

Year	Flat Energy Charge $/MWh	Tier 1 Energy Charge $/MWh	Tier 2 Energy Charge $/MWh	Demand Charge $/kVA
F2024	Existing Stepped Rate			
F2025	51.09	46.45	92.86	9.42
F2026	52.03	48.37	84.89	10.36
F2027	50.50	48.07	72.43	10.85
F2028	49.57	48.33	60.68	11.48
F2029	48.02	n/a	n/a	11.97

Bill Impacts for 100% Tier 1 Energy Customer

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.01	16.91	5.6%	18.33	8.4%	18.92	3.3%	19.77	4.5%	20.38	3.1%	27.3%
20%	10.29	10.78	4.7%	11.58	7.4%	11.87	2.5%	12.30	3.7%	12.59	2.4%	22.3%
30%	8.39	8.74	4.2%	9.33	6.8%	9.51	1.9%	9.81	3.1%	9.99	1.9%	19.2%
40%	7.44	7.71	3.8%	8.21	6.4%	8.34	1.5%	8.57	2.8%	8.70	1.5%	17.0%
50%	6.86	7.10	3.5%	7.53	6.1%	7.63	1.3%	7.82	2.5%	7.92	1.2%	15.3%
60%	6.48	6.69	3.2%	7.09	5.9%	7.16	1.1%	7.32	2.3%	7.40	1.0%	14.1%
70%	6.21	6.40	3.1%	6.76	5.7%	6.82	0.9%	6.97	2.1%	7.03	0.9%	13.1%
80%	6.01	6.18	2.9%	6.52	5.5%	6.57	0.7%	6.70	2.0%	6.75	0.7%	12.4%
90%	5.85	6.01	2.8%	6.34	5.4%	6.38	0.6%	6.49	1.8%	6.53	0.6%	11.7%
100%	5.72	5.88	2.7%	6.19	5.3%	6.22	0.5%	6.33	1.7%	6.36	0.5%	11.2%

Bill impacts for 95% Tier 1 energy and 5% Tier 2 energy Customer

	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.29	17.14	5.2%	18.51	8.0%	19.05	2.9%	19.83	4.1%	20.38	2.8%	25.1%
20%	10.58	11.01	4.1%	11.76	6.9%	11.99	1.9%	12.36	3.1%	12.59	1.8%	19.1%
30%	8.67	8.96	3.4%	9.52	6.2%	9.63	1.2%	9.87	2.5%	9.99	1.2%	15.3%
40%	7.72	7.94	2.9%	8.39	5.7%	8.46	0.8%	8.63	2.0%	8.70	0.8%	12.7%
50%	7.15	7.33	2.5%	7.72	5.3%	7.75	0.4%	7.88	1.7%	7.92	0.4%	10.8%
60%	6.77	6.92	2.3%	7.27	5.0%	7.28	0.2%	7.38	1.4%	7.40	0.2%	9.3%
70%	6.50	6.63	2.0%	6.95	4.8%	6.95	0.0%	7.03	1.2%	7.03	0.0%	8.2%
80%	6.29	6.41	1.9%	6.71	4.6%	6.69	−0.2%	6.76	1.0%	6.75	−0.2%	7.3%
90%	6.13	6.24	1.7%	6.52	4.5%	6.50	−0.3%	6.55	0.9%	6.53	−0.3%	6.5%
100%	6.01	6.10	1.6%	6.37	4.4%	6.34	−0.4%	6.39	0.8%	6.36	−0.5%	5.9%

Bill impacts for Flat Rate RS 1823A or 90% Tier 1 energy, 10% Tier 2 energy RS 1823B Customer

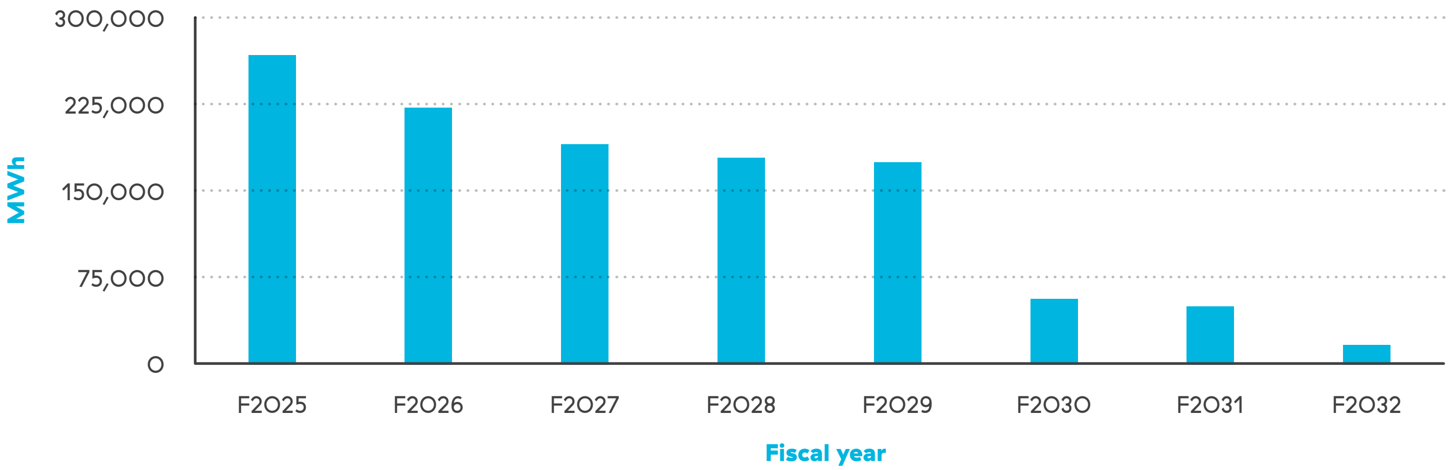
	Fiscal 2024	Fiscal 2025		Fiscal 2026		Fiscal 2027		Fiscal 2028		Fiscal 2029		Total
Load Factor	Step Rate Avg ¢/kWh	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Step Rate Avg ¢/kWh	Bill Impact	Flat Rate Avg ¢/kWh	Bill Impact	Bill Impact
10%	16.57	17.37	4.8%	18.69	7.6%	19.17	2.5%	19.89	3.8%	20.38	2.4%	23.0%
20%	10.86	11.24	3.5%	11.95	6.3%	12.11	1.3%	12.43	2.6%	12.59	1.3%	15.9%
30%	8.96	9.20	2.7%	9.70	5.5%	9.76	0.6%	9.94	1.8%	9.99	0.6%	11.6%
40%	8.00	8.17	2.1%	8.58	4.9%	8.58	0.0%	8.69	1.3%	8.70	0.1%	8.7%
50%	7.43	7.56	1.7%	7.90	4.5%	7.87	−0.3%	7.94	0.9%	7.92	−0.3%	6.5%
60%	7.05	7.15	1.4%	7.45	4.2%	7.40	−0.6%	7.45	0.6%	7.40	−0.6%	4.9%
70%	6.78	6.86	1.2%	7.13	3.9%	7.07	−0.9%	7.09	0.3%	7.03	−0.9%	3.7%
80%	6.58	6.64	1.0%	6.89	3.7%	6.81	−1.1%	6.82	0.1%	6.75	−1.1%	2.6%
90%	6.42	6.47	0.9%	6.70	3.6%	6.62	−1.2%	6.62	0.0%	6.53	−1.3%	1.8%
100%	6.29	6.33	0.7%	6.55	3.4%	6.46	−1.4%	6.45	−0.2%	6.36	−1.4%	1.1%

Appendix D: Recognition of remaining duration of DSM energy savings

Background

The figure below shows the remaining energy savings from customer-funded Demand Side Management (DSM) projects from F2025 to end of duration based on reported data for F2020, adjusted to account for the maximum amount of energy savings that would be priced at the Tier 2 rate (i.e., based on a maximum of 10% of F2020 energy consumption for an individual site). Most of the remaining energy savings are set to reach the end of their duration prior to F2030.

Figure D-1: Adjusted Remaining Energy Savings from Customer-Funded DSM Projects (MWh)



The value of these remaining energy savings varies depending on what avoided cost of energy is assumed in the calculation. While the Tier 2 energy rate was initially intended to reflect BC Hydro's long-run marginal costs, the current Tier 2 rate exceeds BC Hydro's long-run marginal costs.

Rate scenarios

BC Hydro modelled several transition and bill mitigation scenarios that would provide benefits to customers with remaining DSM. As part of this analysis, we assessed the potential revenue shortfall of each scenario and the overall value to customers with remaining DSM. Initial results were shared with a subset of customers during a customer working group meeting held in June 2022. While the number of scenarios considered was extensive, the following six scenarios are shown here for comparison purposes:

1. Customers with remaining DSM stay on the current Stepped Rate for the duration of remaining energy savings, all other customers move to the proposed flat rate in F2025.
2. Customers with remaining DSM move to a Modified Stepped Rate (Tier 1 rate = $42.99/MWh, Tier 2 rate = $70.95) in F2025, all other customers move to the proposed flat rate in F2025.
3. All customers move to the proposed flat rate in F2025 and customers with remaining DSM receive a bill credit valued at $22.65/MWh of remaining energy savings ("DSM credit").
4. Customers transition to the proposed flat rate over a five-year transition period by gradually flattening the stepped rate over time.
5. Customers are grouped into three segments and each segment is assigned a revenue-neutral flat rate transition schedule to transition to the proposed flat rate over a five-year period ('Transition Option 1').
6. Some customers with remaining DSM and RS 1827 and RS 3808 customers stay on their current rates until F2027, all others transition to the proposed flat rate in F2025 ('Transition Option 2').

Scenario 1 was brought forward during the customer working group meetings and would recognize the remaining energy savings from F2025 to end of duration at the existing Tier 2 rate. The existing Tier 2 rate is $102.57/MWh, while the existing Tier 1 rate is $45.79/MWh. This results in the energy savings being valued at $56.78/MWh (the additional benefit of the Tier 2 rate over and above the Tier 1 rate).

Scenario 2 assumes that the Tier 2 rate is $70.95/MWh, which is close to BC Hydro's long-run marginal cost of energy ($65/MWh in F2022 dollars). In this scenario, the energy savings would be valued at $27.96/MWh (the additional benefit of the Tier 2 rate over and above the Tier 1 rate of $42.99/MWh).

Scenario 3 is based on BC Hydro's existing capital incentive for industrial DSM projects and assumes a DSM credit valued at $22.65/MWh of the remaining energy savings.

Scenario 4 would gradually transition customers to the proposed flat rate by reducing the price differential between Tier 1 and Tier 2. In this scenario, customers with remaining DSM would be treated the same as customers without remaining DSM.

Scenarios 5 and 6 are the leading transition options. We believe these transition options provide reasonable value to customers with remaining energy savings from customer-funded DSM, while minimizing impacts to other ratepayers.

Assumptions

- In Scenarios 1, 2 and 6, customers with remaining energy savings duration from customer-funded DSM would have a one-time nomination to remain on existing Stepped Rate or take service under the proposed flat rate.
  - A customer with an aggregated CBL could choose to stay on the current Stepped Rate if any individual site has remaining DSM.
  - Customers with remaining DSM could choose whichever rate is cheaper. There are some customers with remaining DSM that are better off under the flat rate proposal.
  - At the end of the transition period or once the duration of remaining DSM ends (whichever comes first), customers will take service under the proposed flat rate.
- In Scenario 3, the DSM credit is reduced for customers that would receive a bill decrease from moving to the proposed flat rate, such that the sum of the bill decrease and the DSM credit equal the calculated value of the remaining DSM. This assumption is made to reduce the overall cost of the DSM credit and to avoid double counting of benefits.
- The analysis does not include any new customer-funded DSM projects reported after F2020 and assumes there would be a sunset clause restricting eligibility for any new DSM after a certain date.

Results

The method for calculating the benefit of each transition and bill mitigation scenario to customers with remaining DSM is outlined in the table below.[17]

Table D-1: Calculation of Benefits for Customers with Remaining Energy Savings

Customer group	Calculation of benefits for customers with remaining energy savings from customer-funded DSM
RS 1823 customers with remaining energy savings from customer-funded DSM that would see a bill increase under the final flat rate	Avoided cost of the proposed flat rate by paying the transition/staggered implementation rates instead of the proposed flat rate, plus value of the DSM credit
RS 1823 customers with remaining energy savings from customer-funded DSM that would see a bill decrease under the final flat rate	Bill savings from the transition rates or proposed flat rate relative to the current Stepped Rate, plus adjusted value of DSM credit (adjusted to take into account bill savings)

17 Please note that the methodology for calculating the benefit to customers with remaining DSM differs from that presented in the June 2022 customer meeting slides.

The following table shows the revenue shortfall in each year and in net present value for each of the above scenarios. Scenario 1 has the largest revenue shortfall of $50 million since all remaining energy savings are priced at the existing Tier 2 rate. Scenario 2 has a stepped rate with a lower Tier 2 energy charge and therefore has a lower revenue shortfall of $29 million. Scenario 3 includes a DSM credit of $22.65/MWh which results in a slightly lower revenue shortfall of $23 million. Scenarios 4 and 5 do not have a revenue shortfall and Scenario 6 has a revenue shortfall of $10 million.

Scenario 1 has the highest avoided cost benefit for the customers with remaining DSM ($51 million) as the energy savings are valued at the current Tier 2 rate for the entire remaining duration. Scenario 4, which gradually flattens the stepped rate over time, has the lowest avoided cost benefit ($19 million).

Scenario 3 has the highest bill savings benefit for customers with remaining DSM of $27 million, as all customers would transition to the proposed flat rate in F2025. Scenario 5 (segmented flat rate transition) has the lowest bill savings benefit of $16 million, as the transition to the proposed flat rate occurs over a longer period of time.

Our leading transition options (Scenarios 5 and 6) provide a total benefit to customers with remaining DSM of between $42 million to $44 million in net present value over the transition period. These options provide comparable benefits to customers relative to the DSM credit approach (Scenario 3), while reducing or eliminating the revenue shortfall.

Table D-2: Value of Transition Scenarios to Customers with Remaining Energy Savings from Customer-Funded DSM ($M)

	Scenario 1 DSM Customer on Step Rate Final Flat Rate for Other	Scenario 2 DSM Customer on Step Rate (Tier 2 =$70.95/MWh) Final Flat Rate for Other	Scenario 3 DSM credit of $22.65/MWh and Final Flat Rate	Scenario 4 Stepped Rate Transition for All Customers	Scenario 5 Revenue neutral segmented flat rates	Scenario 6 Staggered Implementation
F2024						
F2025	(9.97)	(5.99)	(5.94)			(5.38)
F2026	(9.93)	(5.98)	(4.89)			(5.35)
F2027	(8.84)	(5.33)	(4.18)			
F2028	(8.28)	(4.91)	(3.91)			
F2029	(8.17)	(4.87)	(3.82)			
F2030	(4.43)	(2.39)	(1.15)			
F2031	(4.01)	(2.12)	(1.01)			
F2032	(1.77)	(0.94)	(0.24)			
NPV Revenue Shortfall (F2024 to F2032)	**(50.00)**	**(29.41)**	**(22.98)**	**0**	**0**	**(10.28)**
NPV DSM Customer Avoided Cost Benefit (F2024 to F2032)	50.77	30.12	21.21	19.02	25.71	19.26
NPV DSM Customer Bill Savings Benefit (F2024 to F2032)	24.54	24.60	27.07	17.96	16.43	24.54
NPV Total DSM Customer Benefit (F2024 to F2032)	**75.30**	**54.71**	**48.28**	**36.98**	**42.15**	**43.80**

We are proposing our leading transition options for feedback (Scenarios 5 and 6) as we believe these transition options provide reasonable value to customers with remaining energy savings from customer-funded DSM, while minimizing impacts to other ratepayers.

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