BEFORE THE

Alberta Utilities Commission

WRITTEN EVIDENCE OF

Dr. Kathleen Spees

Economic Assessment of Suncor's Complaint Regarding ISO Rule 203.1

SUBMITTED AT THE REQUEST OF

Alberta Electric System Operator

NOVEMBER 5, 2025

IN PROCEEDING 29009

Complaint by Suncor Energy Inc. Under Section 25 of the Electric Utilities Act Regarding Independent System Operator Rule 203.1

CONTENTS

Introduction

I, Dr. Kathleen Spees, was retained by Norton Rose Fulbright Canada, acting as outside counsel to the Alberta Electric System Operator (AESO), to review and independently assess evidence submitted by Suncor Energy Inc. in its complaint regarding the Independent System Operator (ISO) Rule 203.1 ("Suncor Complaint"), as well as the evidence submitted by Suncor's retained independent witness Dr. Jeffrey Church ("Church Evidence").[1]

I am an economic consultant at The Brattle Group, located at 1800 M St. NW, Washington DC, where I focus on bulk electricity system reliability, electricity market design, and bulk power system economics. I have supported market design reforms and modeling analysis of reliability outcomes, investment adequacy, economic efficiency, and consumer impacts in energy-only and capacity markets for ISOs, government agencies, and market participants across more than a dozen jurisdictions across Canada, the US, and internationally.[2] I earned my PhD in Engineering and Public Policy and MS in Electrical and Computer Engineering from Carnegie Mellon University, and a BS in Mechanical Engineering and Physics from Iowa State University. My curriculum vitae is included in the Appendix.

I confirm that I have a duty of independence in offering my professional opinion to the Commission. Accordingly, though I have conducted this evidence and submit this evidence at the request of the AESO, I am not an advocate for the AESO or any other party. All of the opinions set out in this submission are my own.

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1 Complaint of Suncor Energy Inc. Pursuant to Section 25 of The *Electric Utilities Act* ("Suncor Complaint"); Expert Report of Dr. Jeffery Church, "Economic Implications of the Asymmetric Treatment of Importers and Alberta Generators: An Economic Analysis of ISO Rules Section 203.1 Offers and Bids for Energy," ("Church Evidence").

2 Assignments related to resource adequacy, reliability, investment incentives and energy-only markets include: Johannes P. Pfeifenberger, Kathleen Spees. ***Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market***. Prepared for the AESO. April 2011. See also the ***2013 Update***; Johannes P. Pfeifenberger, Kathleen Spees, Kevin Carden, Nick Wintermantel. *Resource Adequacy Requirements: Reliability and Economic Implications*. Prepared for the Federal Energy Regulatory Commission (FERC). September 2013; Samuel Newell, Kathleen Spees, Johannes P. Pfeifenberger, Robert Mudge, Michael DeLucia, Robert Carlton. *ERCOT Investment Incentives and Resource Adequacy*. Prepared for ERCOT. June 2012; Samuel Newell, Kathleen Spees, Johannes P. Pfeifenberger, Ioanna Karkatsouli, Nick Wintermantel, Kevin Carden. *Estimating the Economically Optimal Reserve Margin in ERCOT*. Prepared for the Public Utility Commission of Texas. January 2014. See also the *2018 update*; Toby Brown, Neil Lessem, Roger Lueken, Kathleen Spees, Cathy Wang. *High-Impact, Low-Probability Events and the Framework for Reliability in the National Electricity Market*. Prepared for The Australian Energy Market Commission. February 2019; Testimony of Kathleen Spees before the British Columbia Utilities Commission, "Benchmark Assessment of BC Hydro's System and Locational Supply Adequacy Standards," submitted at the request of BC Hydro, 2021 Integrated Resource Plan Application #1599287.

Executive Summary

SUMMARY OF SUNCOR COMPLAINT

The Suncor Complaint submitted on April 26, 2024 to the Alberta Utilities Commission (AUC or "Commission") asserted that the Must Offer Must Comply (MOMC) obligation for internal generators included in AESO Rule 203.1 is not consistent with Alberta's Fair Efficient and Open Competition (FEOC) Regulation.[3] Suncor asserts that the MOMC constitutes a capacity commitment imposed on internal generators, and that importers enjoy discriminatory preference in the Alberta power market given that they are not subject to the MOMC.

The Suncor Complaint and Church Evidence further argue that energy prices in the Alberta market should be viewed in two components: a base component that is reflective of short-run marginal cost of supply (i.e., fuel and variable costs); and a scarcity component reflective of long-run marginal cost of supply (i.e., investment cost recovery). They assert that the second component should be considered a capacity payment and hence should be paid only to internal generators that are subject to a capacity commitment via the MOMC. By paying importers the full energy price without an MOMC obligation, they argue that AESO Rule 203.1 is non-FEOC because it "results in consumers paying Importers for a level of supply adequacy that they do not receive."[4]

To remedy their concerns with the MOMC obligation, Suncor's complaint offers two proposals:

- **Primary Relief: Non-Commitment (NC) Charge**: The primary relief requested by Suncor is to impose a new NC charge on import transactions, the size of which is: (a) zero in lower-price hours when the Alberta Pool Price is below the Reference Price that is tied to the operating cost of a high heat rate gas plant; (b) equal to the Pool Price minus the Reference Price during higher-price and scarcity conditions (other than during Energy Emergency Alert (EEA) events); and (c) zero during EEA events.[5]
- **Secondary Relief: Intertie Must Offer + NC Charge:** The secondary relief requested by Suncor is to introduce a new participation model for importers that take on an Intertie Must Offer obligation (I refer to these as "firm imports"), while maintaining the NC charge for other imports (I refer to these as "non-firm imports").[6]

[3] Suncor Complaint, ¶ 5; Alberta Utilities Commission Act Electric Utilities Act "Fair, Efficient and Open Competition Regulation."

[4] Suncor Complaint, ¶ 48.

[5] Suncor Complaint, § IV.1.

[6] Suncor Complaint, § IV.2.

Suncor requests that the implementation timing of the primary requested relief would be immediate, while the secondary relief may be implemented in several years after a consultation to develop updates to Rule 203.1.[7]

The Suncor Complaint and Church Evidence argue that the introduction of the NC Charge and/or Intertie Must Offer requirement would place importers and internal generators on a level playing field by ensuring that only resources that take on the equivalence of a capacity commitment would be eligible to earn capacity revenues (via the scarcity component of the energy price). They further assert that the outcomes under the primary and secondary relief will have no impact on customer costs (since over the long term, prices will be restored to equilibrium levels, even if they are inflated over the short term by the loss of imports), but that reliability will improve in the long term as higher prices attract more generation investments within Alberta.[8]

SCOPE OF MY ASSESSMENT

I was asked to develop this evidence to provide background information describing the nature of economic benefits created through interregional trade; to review the Suncor Complaint and supporting evidence submitted by Dr. Church; and provide independent views on:

- The grounds for Suncor's complaint, assessing whether AESO Rule 203.1 offers discriminatory preference for imports above internal generators (covered in Part I of this evidence);
- The potential reliability and economic impacts of Suncor's proposed primary relief of NC Charge, considering the differences in outcomes on a short-term vs. long-term basis (covered in Parts II and III respectively); and
- The potential impacts of Suncor's proposed secondary relief, which would include an Intertie Must Offer obligation for firm imports, combined with the NC Charge for non-firm imports (covered in Part IV).

7 Suncor states that the requested secondary relief "would require consultation and would take significant time and resources" and that "[a]ny implementation resulting from the consultation undertaken as part of the secondary relief is likely years away." Suncor Complaint, Section IV.2.

8 Throughout this evidence I use the term "reliability" as a general term, but where needed I use more precise language to distinguish between: (a) "operational reliability" when referring to operational outcomes associated with different behaviour or AESO actions in the short term (timeframes at which investment choices are fixed); and (b) "resource adequacy" or "supply adequacy" when referring to long-term investment levels and total levels and types of supply available to serve demand during tight conditions. The Suncor Complaint (footnote 6) makes a similar distinction between [operational] reliability (short term) and supply adequacy (long term).

SUMMARY OF FINDINGS

Interties are the infrastructure through which power markets can leverage regional diversity in supply and demand to gain the benefits of trade in the short term and in the long term. The benefits of trade materialize by: (a) lowering adjusted production costs, including by lowering fuel costs (when importing) and by increasing net revenues (when exporting); (b) capturing the "free" reliability benefits that can be shared between regions that experience diversity in the times of supply shortages; and (c) reducing total resource costs by building a lower-cost and more complementary fuel mix compared to neighbours. Suncor's complaint and supporting evidence fail to account for the benefits of trade and propose a solution that would eliminate many of these reliability and economic benefits.

Grounds for Complaint: The current MOMC requirement is not discriminatory. Suncor's claims are based on a flawed argument that asserts the existence of capacity commitments and capacity payments that do not exist in Alberta's energy only market. A corrected analysis demonstrates that current rules reasonably accommodate differences between importers and internal generators, with the overall result of enabling competition despite these differences. Rule 203.1 does not offer discriminatory preference for importers because:

- *The MOMC is not a capacity commitment*. Neither importers nor internal generators take on availability or other capacity-type obligations in Alberta's energy-only market. The MOMC obligation is a substantially narrower rule that requires generators to truthfully report operational status and prevents physical withholding (while allowing generators to engage in economic withholding);
- *Differences in the MOMC obligation and related rules have underlying economic and technical justifications* that accommodate differences in resource capabilities and participation mechanics. The MOMC is needed for internal generators to ensure that they can engage in economic (but not physical) withholding, and to ensure that the AESO has sufficient operational visibility and control to maintain system reliability. The MOMC rule is not relevant for imports because importers have neither the incentive nor the ability to engage in economic or physical withholding, and because other rules ensure that AESO has sufficient operational visibility and control over intertie schedules to maintain system reliability;
- *The MOMC rule does not introduce any barriers to participation or full competition*, as there is minimal or no cost to generators to align with the MOMC rules; and

- ***The effects and outcomes of Rule 203.1 demonstrate that it is not discriminatory.*** My analysis of performance during EEA events shows that importers and internal generators earn energy market revenues commensurate with their delivered reliability value. Dispatchable thermal resources earn the highest revenues per megawatt (MW) of installed capacity, intermittent renewables the lowest, and imports in between; reliability contributions follow the identical pattern, with energy revenues proportional to delivered reliability value.

Proposed Primary Relief: The proposed NC Charge on imports would introduce an inefficient barrier to trade and limit economic imports. The result would be to inflate system costs in the short term and in the long term, as follows:

- *In the short term*, the immediate effect would be to discourage imports in both normal conditions and scarcity conditions. Based on my historical analysis of prices in Alberta and external regions over the period 2019–2015, I estimate the NC Charge would result in: (a) an approximately 53% drop in imports in the hours when the NC Charge applies, due to the reduction of incentives to import compared to external market prices; and (b) an approximately 32–76% drop in imports during EEA event conditions when the NC Charge does not apply, due to importers' lack of perfect foresight of EEA events and imports' role in preventing many EEA events. The consequence would be to produce higher prices, operational inefficiencies, and lower reliability.
- *In the long term*, the inefficient exclusion of economic imports would be retained as a perpetual feature of the Alberta power market. Short-term price increases would be moderated (but not eliminated) over time as more supply is built in Alberta. A portion of price increases will remain perpetually in the long term, associated with less efficient operational and investment outcomes. Alberta will also permanently lose access to the "free" reliability benefit of non-firm imports arising from interregional diversity of supply and demand.

Proposed Secondary Relief: Combining an Intertie Must Offer obligation with the NC Charge would introduce an inefficient barrier to trade and impose obligations not applied to internal generators. Though Suncor's proposal is insufficiently specified in material ways, the intent appears to be that importers will face the choice of either: taking on a full capacity obligation (including availability and other capacity-type commitments that do not apply to internal resources under the MOMC rules); or continue to face the NC Charge. The result would be to inflate system costs in the short term and the long term, as follows:

- *Non-firm imports* would be disincentivized by the NC Charge, such that the inefficiencies and reliability challenges described above would continue to apply for imports participating on a non-firm economic basis. This barrier to non-firm imports will prevent Alberta from accessing the full reliability benefits of non-firm imports. No other energy-only or capacity market applies such an exclusion; for example, Alberta's prior capacity market proposal and all other capacity markets incorporate rules that allow the markets to capture the free reliability benefits associated with non-firm economic imports.
- *Firm imports* would be limited in participation volumes, considering the additional costs that would be associated with taking on the incremental availability commitments, resource backing, and financial risks that may be required to participate under the Intertie Must Offer rules.

Overall, the Suncor Complaint and Church Evidence respond to the fact that Alberta has a unique market design compared to its neighbours and trade partners. Alberta's energy-only market has always enabled economic competition between imports and internal generation. The advantages of enabling this competition are that a competitive market clearing price can be used to inform more efficient operating and investment choices and allow Alberta to enjoy the reliability and economic benefits of trade with neighbouring jurisdictions. The tension in interregional trade is that Alberta's historical energy-only market investment model is different from the investment model of neighbouring regions that have capacity requirements. In regions with capacity requirements, resource adequacy outcomes can be dictated in advance by the region's reliability standard. In Alberta's energy-only market, resource adequacy outcomes are determined by investors' response to energy pricing signals, and are influenced by the complex interactions amongst economic withholding; market parameters (e.g. price cap, maximum offer control share); resource mix (e.g., share of baseload, renewables, peakers, demand response); market fundamentals (e.g. fuel costs, load patterns); and the patterns of interregional trade.

Suncor's proposes to address this tension by introducing barriers to trade that would limit the role of non-firm imports in the Alberta energy market. Suncor's solution misses the mark because it focuses on the wrong problem of how to protect internal generators from the impacts of interregional trade. By interrupting the natural expression of import incentives created via the market clearing price, Suncor's proposal introduces a number of inefficiencies and transfer payments without improving the overall value proposition for customers or the Province as a whole.

The better question is how to enhance reliability while lowering costs. Effective solutions will expand the role of competition by enabling a wider array of resources and market participants (including importers) to contribute to and react to competitively-determined market prices. If the current market design fails to fully measure, incentivize, or remunerate contributions to reliability, then solutions should focus on improving the definition of market products to more accurately reflect evolving system reliability needs and sharpening pricing incentives to reward the producers and customers that most meaningfully address those needs. The AESO and stakeholders are pursuing many such reforms through ongoing efforts to design the Restructured Energy Market (REM).[9] I anticipate that many of the proposed REM reforms may result in enhanced energy and ancillary service market revenues for internal Alberta resources as compared to imports, for example reforms to introduce nodal pricing, 5-minute settlements, and a 30-minute ramping product. However, under these efficiency-focused reforms, internal generators will only be in a position to earn differentially higher revenues to the extent that they deliver superior contributions to supporting system reliability needs (not because they are protected from competing with importers, as in Suncor's proposal).

9 See AESO, "Restructured Energy Market: Final Design," August 2025.

Background: How Interties Enable Benefits from Trade

Interties are the infrastructure through which mutually beneficial trade is enabled with other regions. I describe here the nature of the economic and reliability benefits created through interregional trade. As in other commodity markets, the benefits of interregional trade are largest when there is diversity in the nature of supply and demand between regions, low or no transactions costs, infrastructure enabling the trade, and no barriers to free entry and exit.

Interties enable economic and reliability benefits by leveraging interregional diversity in supply and demand. The economic benefits of economic energy trade accrue to both importing and exporting regions through: (1) adjusted production cost savings realized in the short term and that persist over the long term; (2) "free" reliability benefits from non-firm imports, available due to interregional diversity in patterns of when the supply-demand balance becomes tight; and (3) investment cost savings that arise from a lower-cost and more optimal resource mix.

I describe here the mechanics by which Alberta and its neighbours mutually benefit from economic energy trade over the interties, which provides the economic foundations to explain why this economic value is destroyed when interregional trade is inefficiently curtailed.

For completeness, I note that a comprehensive assessment of opportunities to invest in new intertie infrastructure or expand available transfer capability (ATC) would need to account for the benefits of economic energy trade that I describe here, as well as a variety of other benefits that may apply in specific instances, and compare these gross benefits the offsetting go-forward costs required to build new infrastructure or maintain/expand ATC (e.g. if additional fast frequency response service is required to enable intertie capability). For the purpose of discussions in this evidence, I focus only on the gross benefits of economic energy trade, as is relevant assessing the benefits from efficient operational use of intertie infrastructure for which the costs of building and maintaining the intertie are already sunk or otherwise fixed.

A. Adjusted Production Cost Savings

Adjusted production cost measures the variable cost of energy supply to a province or region, measured as: (a) fuel and variable operations and maintenance (VOM) costs of internal resources; plus (b) the purchase price of all imported volumes; minus (c) the sales price of all exported volumes.[10]

[10] When considering multiple regions as a whole, the sum of adjusted production costs across the multi-region footprint is equal to total system-wide production costs.

An islanded system will always reduce its adjusted production costs if it can engage in economic trade with its neighbours. For any given transaction, the benefits of trade are shared by both the importing and exporting regions, as follows:

- **Importing regions** benefit from trade by reducing fuel and VOM costs from internal resources that would have been dispatched absent the import (net benefit measured as the avoided fuel and VOM cost, minus the price of imported power); and
- **Exporting regions** benefit from trade by earning profits on exported volumes (net benefit measured as revenues realized from the export, minus incremental fuel and VOM costs incurred to serve the export).

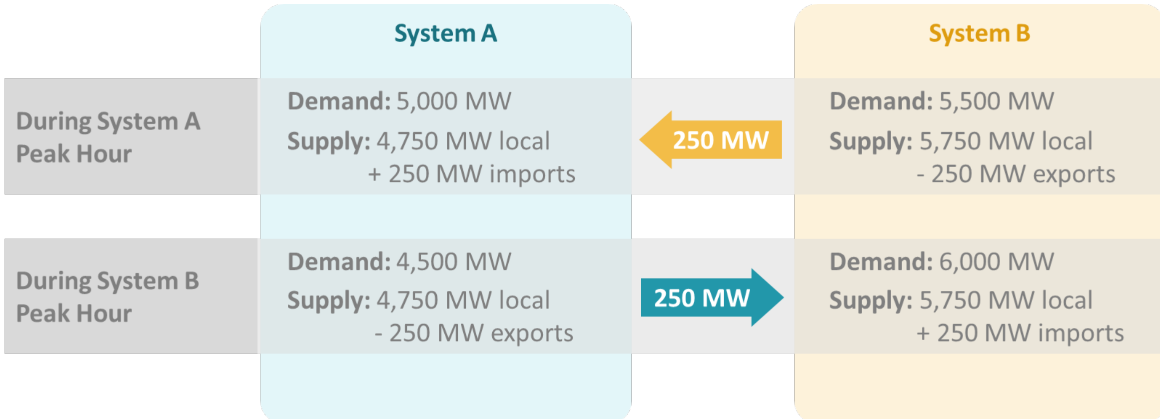
The total economic benefits from lowered adjusted production costs are the sum of benefits realized by the importing and exporting region, and accounting for the fact that Alberta (like most regions) will engage in both imports and exports across patterns of days, weeks, and years.

Regions with greater diversity in supply and demand between interconnected systems will experience higher benefits of trade. Larger differences in supply costs will create a greater economic benefit to be shared in each transaction, while large differences in supply-demand patterns will produce more frequent opportunities to benefit when one region is short while the other is long.

B. “Free” Reliability Benefits from Non-Firm Imports

Trade partners enjoy additional reliability and economic benefits by leveraging diversity in patterns of when supply and demand are tight. The following Figure 1 illustrates how example System A and System B can mutually capture reliability benefits from interregional diversity. Differences in the timing of tight supply conditions occur due to regional differences in whether and when they are most greatly affected by peak demand conditions, renewable output profiles, hydro cycles, thermal outages, or gas system constraints. In this example, if the two systems are not interconnected, System A and System B would need 11,000 MW to both meet their isolated peak demands (5,000 MW for System A plus 6,000 MW for System B). However, as long as the two systems are not identical, System A can import 250 MW of power during tight conditions (rather than building more self-supply) to meet (net) peak demand. Similarly, System B can import 250 MW of power in the reverse direction during its own (net) peak conditions at another time. Together, the total capacity needed to reliably serve demand is 10,500 MW (an investment cost savings of 500 MW) if the two interconnected systems take advantage of imports during their tightest demand hours.

FIGURE 1: EXAMPLE OF "FREE" RELIABILITY BENEFITS
SYSTEMS A AND B PROVIDE MUTUAL SUPPORT OF 250 MW DURING NEIGHBOUR'S PEAK



Sources and Notes: For simplicity, this figure excludes reference to the reserve margin of supply plus expected imports that would be required to reliably meet resource adequacy needs (a reserve margin being required to account for the possibility that imports or internal generators may be unavailable during system peak demand). A more precise description of accounting for non-firm reliability benefits would consider that the reserve margin required to meet a defined reliability standard will be lowered if one accounts for the statistically expected volume of non-firm imports. The magnitude of system benefits depends on a number of system characteristics. Systems with greater diversity will benefit more from "free" reliability benefits; smaller systems will benefit more by interconnecting with larger systems; and systems with greater intertie capability can capture a larger maximum reliability benefit.

Note that no capacity commitment is required from importers in order to capture these mutual reliability benefits. Instead, System A attracts non-firm imports from supply that has already made its primary supply commitment to its host System B, with the non-firm imports available only due to interregional diversity. For example, if System A is summer-peaking while System B is winter-peaking, both systems will have surplus capacity that can be offered for sale in the off season when the other is tight. In this way, two interconnected regions can mutually support each others' reliability at no incremental investment cost (hence the "free" reliability benefits).[11] These benefits can be enjoyed either through higher reliability, or by retaining the same level of reliability but reducing the total volume of supply that each region holds.

The MW size of non-firm reliability benefits is highly dependent on the nature of the systems in question, but the benefits tend to be greatest between systems with: (a) large interregional diversity in supply (availability, renewable profiles, hydro cycles, gas constraints); (b) large interregional diversity in demand (seasonal demand profiles, customer mix); (c) a large geographic span (which produces greater differences in temperature, wind speeds, solar

[11] Non-firm imports offer reliability with no incremental supply investment cost; the system would still incur costs to build the intertie infrastructure and pay the purchase price of imports.

insolation); and (d) small systems interconnecting with larger and more diverse regions (since the small system benefits more proportionally by importing a small share of the neighbour's supply).

The reliability benefits realized through interregional diversity and non-firm imports are widely documented in literature and industry practice. Examples of studies that describe and quantify these reliability benefits include:

- **FERC Economics of Reliability Study**:[12] In a study of the economics of reliability conducted for the US Federal Energy Regulatory Commission (FERC), reliability and total system costs were simulated across systems with different sizes and different levels of interconnection with neighbouring systems (including an islanded system case). The study demonstrated that if the same reserve margin is maintained, a system with lower interconnections will observe both poorer reliability and higher costs. Reliability can be restored by increasing internal supply and reserve margins, but at a higher total system cost.
- **WECC Study:** [13] The Western Electricity Coordinating Council (WECC) has developed the Multi-Area Variable Resource Integration Convolution (MAVRIC) model to simulate hourly demand and resource availability across regions, enabling probabilistic assessments of planning reserve margins that incorporate the contribution of imports. The analysis found that enabling subregions to import energy during tight conditions resolves most hours of potential unserved demand, demonstrating that interregional imports can substitute for in-region capacity and reduce the reserve margin needed to maintain reliability.
- **ISO New England (ISO-NE):**[14] As part of a review considering updates to its own methodology for estimating intertie reliability benefits, ISO-NE documented and compared practices across nine different ISOs and regional transmission organizations (RTOs), including the AESO. Though details differ by region, the typical approach is to conduct a probabilistic simulation that considers interregional diversity in supply-demand patterns to estimate non-firm imports that can be imported during tight intervals. Non-firm imports contribute reliability value sufficient to serve approximately 1-8% of peak load across the different systems reviewed.

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[12] See Pfeifenberger, Spees, Carden, Wintermantel, "*Resource Adequacy Requirements: Economic and Reliability Implications*," prepared for the Federal Energy Regulatory Commission, September 2013, at Section III.B.2 and Figure 19.

[13] Western Electricity Coordinating Council. *The Western Assessment of Resource Adequacy Report* 2025 at p. 3, 11-14.

[14] ISO-NE. "ISO New England Tie Benefits Methodology Evaluation," October 19, 2023.

All jurisdictions with interconnected neighbours capture the benefits of non-firm imports, though the manner in which the benefits translate to economic savings differ between regions. In energy-only markets like Alberta and the Electric Reliability Council of Texas (ERCOT), the benefit is realized by attracting imports during critical times at a lower total cost than building more internal generation. The imports can be attracted when they are not needed in the host system, thereby boosting reliability even though the purchase price of electricity only needs to be high enough to cover marginal variable and opportunity costs. By comparison, building enough internal supply to serve the same collection of scarcity events would require prices high enough to cover fuel plus investment costs. The result of utilizing non-firm imports to contribute to reliability needs is to produce some combination of improved reliability and/or lower system costs (compared to an islanded system).

In systems with reliability requirements, the reliability benefits of non-firm imports are explicitly quantified and accounted for as "tie benefits" or "capacity benefit of ties."[15] The typical process is that the system operator estimates the reserve margin above peak load that would be required to meet the 1-event-in-10-years ("1-in-10") reliability standard, with the system modeled as if it had no interties. The system is then modeled a second time, with neighbouring jurisdictions included in the model and accounting for interregional diversity in supply and demand. The reduction in MW supply needed to meet the 1-in-10 reliability standard is the quantified tie benefit and is deducted from the system-wide capacity requirement. Examples of regions that apply an explicitly quantified tie benefits deduction include: (a) Midcontinent ISO, a 3,000 MW tie benefit deduction; (b) New England, a 2,175 MW tie benefit deduction; and (c) Western Resource Adequacy Program (WRAP), a 500 MW tie benefit deduction in each sub-footprint.[16]

C. Savings from a Lower-Cost Supply Mix

Over the long term, mutually beneficial trade also allows each trading region to capture economic savings by maintaining a lower-cost resource mix (in addition to the above-described benefits of lower production costs and lower total supply needs). This is particularly true if the trade partners have naturally complementary supply resources or demand profiles.

For example, a region with abundant renewable energy can create mutually beneficial trade over the long term if trade is enabled with a region with abundant storage. If the two regions were

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15 For more detailed descriptions of how nine different ISO/RTO systems estimate tie benefits, see ISO-NE. "ISO New England Tie Benefits Methodology Evaluation," October 19, 2023.

16 See MISO Planning Year 2022–2023 Loss of Load Expectation Study Report at p. 22; ISO New England Tie Benefits Values at p.4; and Western Resource Adequacy Program December 2024 Review at p. 23.

unable to trade, the storage region would have to build more baseload or renewable supply to meet energy needs, even if they are abundant in total capacity. The renewable-heavy region would need to invest in more peaking capacity (such as combustion turbine (CT) or battery resources) in the absence of trade. By enabling trade, each region can compensate for the other's need and mutually benefit through lower total cost of supply. The storage region can avoid local renewable investments by absorbing surplus renewable supply, and by selling energy at times of scarcity. The energy-abundant region can gain revenues from renewables that would otherwise be curtailed and import at peak times at a lower price than it would cost to build more internal supply.

Another example of investment cost savings relates to the timing of supply investments. Most markets transition through long and tight supply conditions throughout investment cycles. This is particularly the case in Alberta, considering that supply investments are lumpy and relatively large compared to the total market size, demand forecasts are uncertain, and the timing of supply investments is determined by private investors (not centrally coordinated). The opportunity to sell when in surplus and buy when in deficit benefits trade partners over time, as tight conditions can be buffered by lower-cost imports and resources can sell surplus in long conditions to defray a portion of their investment costs.

Part I: Assessment of the Grounds for Suncor's Complaint

A. Summary of Responses to Suncor's Grounds for Complaint

SUNCOR'S CLAIMS: The central claim and concern presented in the Suncor Complaint is that Alberta internal generators have unfair treatment because internal generators have a "capacity commitment" while importers do not. The remainder of Suncor's complaint and Dr. Church's evidence stems from their assertion that this difference in market rules constitutes discriminatory preference for importers compared to internal generators.

MY RESPONSE: Suncor's concerns regarding Rule 203.1 are misplaced. The MOMC requirement for internal generators is not a capacity commitment and does not award discriminatory preference to importers. Instead, this difference in rules treatment is a required feature of the Alberta market that enables competitive participation across market participants with materially different technical capabilities and operational requirements.

Alberta policy requires FEOC rules, with non-discriminatory access for willing buyers and sellers.[17] The concept is to build rules that minimise barriers to entry and transactions costs, so that more types of players and resources can compete to drive down prices and deliver value to customers.

The FEOC Regulation and open competition do not require market rules to be identical for all market participants, since blindly identical rules would not have sufficient flexibility to accommodate different technologies and market participants. For all potential power producers and consumers to compete in a non-discriminatory fashion requires that rules reasonably account for and accommodate differences in resources' technical capabilities, timelines, business processes, and business models. Differences in market rules therefore do not inherently signal discriminatory preference or exclusion. For example, the AUC has previously found that a difference in treatment is not inherently discriminatory; rather, other considerations that can justify differences in market rules such as "whether a reasonable distinction can be found" between the participants and whether there is "a logical link between distinctions" made among parties and the difference in treatment.[18]

[17] Alberta Utilities Commission Act: Electric Utilities Act, "Fair, Efficient And Open Competition Regulation" Alberta Regulation 159/2009.

[18] "University of Alberta, Appeal Respecting EPCOR Distribution Inc.'s Transmission Charges," Alberta Energy and Utilities Board Decision 2004-021 at ¶ 58.

In my own assessment of whether the MOMC rule creates a discriminatory preference for importers, I considered the following criteria. Differences in rules can signal discriminatory treatment if:

- Rule differences do not have a reasonable economic or technical basis;
- Rules have the effect of producing barriers to entry or excess transaction costs for a class of technologies or market participants, but not for others; and/or
- Rule differences produce outcomes that demonstrate discriminatory higher or lower compensation for a specific class of resources (or costs to a specific class of consumers), compared to what is paid to other participants that have delivered the same product or service.

Rule 203.1 MOMC does not demonstrate any of these problems. It is true that internal generators have an MOMC requirement while importers do not, but this difference in rules treatment has a clear economic and technical basis that is associated with differences in the underlying supply types and the practical realities of how they participate in the Alberta energy market. The MOMC has no discriminatory effect that harms or prevents participation from internal generators (considering that it imposes minimal or no cost to comply). Finally, realized outcomes in the market demonstrate that importers and internal generators of all types realize energy market revenues consistent with the measurable reliability value they deliver.

B. MOMC Rule is Not a Capacity Commitment

Suncor and Dr. Church incorrectly characterise the AESO Rule 203.1 MOMC requirement as a "capacity commitment."[19] They further assert that "the difference between Pool Price and the reference price, when positive, is an estimate of the payment for the Capacity Commitment."[20] Dr. Church adopts a similar description in his evidence, stating that the Pool Price "can be partitioned into compensation for short-run marginal costs and compensation (quasi-rents) for sunk capital costs. "[21]

Suncor and Dr. Church both utilize a common and helpful theoretical simplification by describing the Alberta energy price in two components: (1) a base pricing component that is associated with marginal-cost-based pricing (reflective of the marginal costs of the highest-price resource

[19] Suncor Complaint, ¶ 5.

[20] Suncor Complaint, ¶ 31.

[21] Church Evidence, ¶ 100.

dispatched); and (2) a scarcity premium that exceeds marginal variable costs and contributes to investment cost recovery.[22] It is further correct to describe the scarcity premium as being somewhat analogous to capacity payments, in that capacity payments (in capacity markets) and scarcity premiums (in energy-only markets) should both in the long run produce total market net revenues consistent with long-run marginal cost of the marginal new entrant.[23]

However, Suncor and Dr. Church are both incorrect to overstate the analogy when they assert that the MOMC is equivalent to a capacity commitment. These assertions misunderstand both the nature of the MOMC rule and how capacity commitments function in actual capacity markets. The MOMC rule does not constitute a capacity commitment. Unlike a capacity obligation, the MOMC rule does not create enforceable availability or performance requirements, nor does it penalize generators if they are unable to deliver, nor does it include an obligation to offer at or near to variable costs.

Alberta's MOMC requirement is a targeted rule that creates an obligation to truthfully offer supply when available, but there is no obligation to be available when needed for reliability. The MOMC stipulates that generators must offer their physically available capacity into the market. If their available capability is less than their maximum capability, they must provide an Acceptable Operational Reason (AOR) that explains why the resource cannot operate at its full capability.[24] This means the AESO requires that generators provide a reason for any limits to their available capability, but does *not* obligate generators to be available, to deliver during scarcity, or to maintain capacity for reliability purposes. Some examples of AORs that can limit the availability of resources include: generator forced or planned outage; physical or operational constraint of the generator; fuel non-availability; potential risk to the safety of the generator or workers; and serving behind-the-fence load (e.g., for cogeneration).[25] Generators are not penalized for forced outages or unavailability, whether during times of scarcity nor non-scarcity

[22] In the real world, this distinction between base and scarcity pricing components is not so easily made because there are many more types of resources with a wide array of different variable and fixed cost components, such that it is often infeasibly to distinguish between base and scarcity pricing in the real world compared to a simplified theoretical description that considers a small handful of resource types. Still, the simplified description is often a useful way to describe and explain short-term and long-term outcomes that should be expected in an energy-only market.

[23] At least, this is true in a well-behaved long-run equilibrium conditions, with perfect foresight of future market conditions, full competition, and minimal barriers to competitive new entry.

[24] AESO ISO Rules, Section 203.1 Offers and Bids for Energy.

[25] AESO Information Document Acceptable Operational Reasons ID #2009-003R; AESO Consolidated Authoritative Document Glossary.

conditions. Instead, the MOMC rule has the targeted effect of ensuring that offers reflect the generator's true physical state.

In contrast, a capacity commitment is separate and distinct product that introduces substantially greater obligations compared to the AESO MOMC requirement. A capacity commitment is a defined product with explicit obligations that are designed to ensure that reliability value is delivered by the producer and that imposes penalties for non-fulfillment of those obligations. Generators and importers incur costs and risk exposures in order to fulfill these obligations, the compensation for which is a capacity payment. Table 1 describes the features of a capacity commitment and illustrates why the AESO MOMC requirement does not incorporate these components. Key obligations associated with capacity market commitments include:

- **Physical Must Offer Requirement.** Resources in energy-only and capacity markets alike typically are subject to physical must offer requirements. This is the primary similarity between AESO's MOMC requirement and a capacity commitment.
- **Economic Must Offer Requirement.** Resources making a capacity commitments are additionally subject to *economic* (in addition to physical) must-offer requirements, meaning that capacity sellers with structural market power must make energy available at offer prices that are subject to cost-based offer caps that limit the potential for economic withholding.[26] The Alberta market has no such economic must offer requirement (instead, resources subject to the MOMC rule are understood to be free to engage in economic withholding).
- **Availability and Performance Requirements.** Resources with capacity commitments are subject to availability and performance requirements that ensure their availability when needed (defined based on some combination of scarcity event periods, or pre-determined availability windows). Resources that fail to offer or deliver energy or ancillaries at these times are subject to penalties (see below). The Alberta MOMC has no such availability or performance requirement.
- **Penalties for Non-Delivery and Non-Performance.** Capacity commitments can subject the seller to multiple types of penalties for resources that do not deliver or under-perform relative to their committed MW of capacity obligations. For example, ISO New England (ISO-NE) and PJM Interconnection (PJM) impose penalties for non-performance during

[26] For example, see PJM's energy market mitigation rules, capacity resource must offer requirements, and cost-based offer cap development rules in PJM Manual 11, Section 2.3.6.1 and Section 2.3.3.1; and PJM Manual 15.

shortage events of up to $9,337/megawatt hour (MWh) USD (year 2025) and $4,027/MWh USD (year 2025) respectively.[27]

In short, the Rule 203.1 MOMC requirement is not a capacity obligation. It does not introduce a set of formalized commitments that would guarantee resource availability or associated financial penalty risks on sellers. No entities in Alberta have a capacity commitment because the province operates an energy-only market (not a capacity market).

TABLE 1: COMPARISON OF OBLIGATIONS INCORPORATED INTO CAPACITY COMMITMENTS (LEFT) VERSUS AESO RULE 203.1 MOMC REQUIREMENT (RIGHT)

	Capacity Commitment (e.g. PJM, ISO-NE)	Rule 203.1 MOMC (AESO)
Physical Must Offer Requirement	Yes	Yes
Economic Must Offer	Yes. Resources with capacity obligations must offer into the energy market at or below energy offer caps to prevent economic withholding	No. Economic withholding is explicitly considered and allowed
Availability Requirements	Yes. Capacity commitments introduce obligation to maintain operational availability and produce energy/ancillary products during tight conditions (or else the resource will be subjected to penalties)	No. Resources must truthfully report availability status, but have no specific availability obligation as long as they provide an AOR
Penalties for Non-Performance	Yes. Additive penalties apply for non-delivery, non-availability, and non-performance. Example: Non-performance penalties up to $4,027/MWh in PJM (USD, 2025) and $9,337/MWh in ISO-NE (USD, 2025)	No

Sources and Notes: PJM, PJM Manual 18: PJM Capacity Market, Section 8.4A Non-Performance Assessment (see footnote 27) and ISO New England, Market Rule 1, Section III.13.7.2.5 Capacity Performance Payment Rate.

C. Technical Basis for MOMC Applies Exclusively to Internal Resources, and is Not Relevant for Importers

The need for the MOMC requirement is specifically relevant for internal supply resources, so as to allow them to engage in economic withholding (but not physical withholding) and to ensure

[27] ISO New England, Market Rule 1, Section III.13.7.2.5 Capacity Performance Payment Rate.

PJM Non-Performance Charge rate is calculated based on the Net CONE in the resource's deliverability area, as described in PJM Manual 18: PJM Capacity Market (Section 8.4A , p. 178). The maximum penalty of $4,027/MWh is based on the Net Cone in PS and PS-North divided as applied across an assumed 30 hours ($330.97/MW-Day Net CONE × 365 days ÷ 30 hours = $4,027/MWh). See 2025/2026 RPM Base Residual Auction Planning Period Parameters, Table 3 for Net CONE.

that the AESO has sufficient visibility and dispatch authority to maintain operational reliability. This rule is not relevant to apply to importers, considering: (a) the substantial differences in economic incentives, technical characteristics, and operational processes; (b) that importers do not have the incentive or ability to engage in economic withholding; and (c) other market rules ensure that the AESO has sufficient operational visibility and dispatch authority over intertie schedules.

Generators can engage in economic (but not physical) withholding in Alberta's energy-only market. Internal generators in the AESO market are permitted to engage in economic withholding (also referred to as "strategic bidding"), meaning that they can submit energy offers above their marginal cost and up to the energy market offer cap of $999.99/MWh. Alberta's energy-only market depends on economic withholding to generate scarcity prices and investment incentives for resource adequacy.[28] The concept is that large market participants will periodically find themselves in a "price maker" position with a dominant market share, when they have both the ability and the incentive to gain from economic withholding. To have the ability to exercise market power, their market control share must be large enough that they are able to increase the energy price by offering a subset of their resources at a higher offer price that exceeds their marginal costs. To have the incentive to engage in withholding, the large player must gain more profit from the increase in prices (earned as increased revenues to infra-marginal resources in their portfolio) than what is lost by the economically withheld resources (who may lose revenue if out-competed by other lower-cost offers). When the system is long with a large reserve margin, these large players will have limited times when they can profitably withhold, such that annualized average prices and returns are not high enough to attract investment in new resources. However, if the system becomes tight with a low reserve margin, large players can engage in more frequent and price-impactful withholding, thus producing higher scarcity prices and more incentive for investment. Through this dynamic, economic withholding contributes to the investment signal for attracting supply when reserve margins are low and new supply is needed from a resource adequacy perspective.

Most other entities are "price takers," that have the incentive to offer supply at their marginal variable cost because they lack the incentive and/or the ability to engage in economic withholding. Examples of price-taking entities include: small players that have insufficient market share to move the price (or profit from moving the price); demand response and other entities with a short market position (i.e., that would be harmed by higher prices); and intertie players. These entities have the incentive to offer into the AESO markets at prices reflective of their variable cost, so as to capture both infra-marginal rents and scarcity premiums. Price-taking

[28] This relationship is similarly described in both the Suncor Complaint at ¶ 22 and in Church Evidence at ¶¶ 67–69.

entities play a critical role in supporting competitive price formation and competitive discipline that puts a check on the extent of economic withholding that can be deployed by large players. If economic withholding produces prices that are anticipated to be high enough for long enough, more price-taking competitive players will be incentivized to enter the market and undercut the above-marginal-cost prices offered by large players.

I further note that while this discussion describes the role and purpose of economic withholding in Alberta's energy only market, it is a simplified treatment that focuses on only *one* of the many factors contributing to overall investment incentives.[29] The overall outcome of resource adequacy and investment incentives in the energy-only market is a complex function of underlying economic fundamentals; the size and market share of large vs. small players; resource mix; patterns of resource availability and flexibility; ancillary service needs; market settings (e.g. the price cap and maximum offer control share); and other aspects of the market design.

Allowing generators to engage in physical (as well as economic) withholding would expose the system to reliability threats. The MOMC rule is a necessary element of the AESO market design that is needed to allow internal generators to engage in the contemplated behaviours of economic withholding (described above), but without allowing them to engage in physical withholding and while still ensuring that the AESO has the information and control required to dispatch those resources as needed to maintain reliability.

Absent the MOMC requirement, internal generators would be able to engage in both economic and physical withholding. While the economic incentives and pricing outcomes are nearly identical between economic and physical withholding, physical withholding can have substantial detrimental impacts on reliability. Consider an example hour when a large price-making entity has the incentive and ability to engage in withholding. The seller chooses to withhold a 100 MW resource, only 90 MW of which is needed to meet total system energy demand. Under current rules with the MOMC requirement, the seller will economically withhold the resource by offering at the offer cap; the 100 MW marginal resource will set prices at the offer price cap of $999.99/MWh, with 90 MW clearing the energy market and the remaining 10 MW remaining

[29] Other factors that contribute to investment signals include: (a) revenues earned by infra-marginal resources (low-cost baseload that earns a profit margin even when prices are associated with marginal cost of higher-price resources with no scarcity pricing); (b) incremental revenues earned by more flexible resources that incur minimal cycling costs; (c) revenues associated with ancillary services; (d) revenues earned from environmental certificate sales; (e) revenues earned from energy arbitrage (particularly relevant for storage resources); (f) other business incentives such as cogeneration resources serving steam demand; and (g) under future REM market design, revenues earned from location-specific pricing differences, operating reserve demand curve-based scarcity price formation, and 5-minute fast redispatch.

uncleared. Under current rules, the result is to produce a high price without incurring any reliability shortfall.[30]

If the example is changed to remove the MOMC requirement, the seller may choose to engage in physical withholding instead of economic withholding. In that case, the seller will not offer the 100 MW resource at all into the energy market. The result would be an energy shortfall event, with insufficient supply to meet 90 MW of energy demand and energy prices clearing at the administratively set price cap of $1,000/MWh. While the pricing implications of withholding are nearly identical in the two situations (prices differing by only $0.01/MWh), the reliability outcome differs greatly (no shortfall with economic withholding under MOMC, versus a 90 MW shortfall with physical withholding).

Beyond the reliability risks that can be introduced by physical withholding, the MOMC rule is required to ensure that the AESO has accurate information with which to manage a wide range of other operational reliability needs. The AESO must have accurate and timely information about resources' operational availability, status, and physical parameters in order to monitor and manage intra-hour balancing needs, voltage levels, congestion, and other operating conditions.

The technical and economic reasons for applying a MOMC to internal generators are not relevant for importers. The above discussion explains why the MOMC rule is needed and relevant for internal generation resources; but these same considerations do not apply to imports considering the substantial differences in economic incentives, technical characteristics, and operational processes.

One critical difference is that, unlike internal generators, importers have neither the incentive nor the ability to engage in economic or physical withholding; instead, they have the incentive to participate as price-takers that import on an economic basis whenever prices are high enough to cover their supply costs. The reasons that importers do not have the incentive or ability to gain from withholding include that: (a) individual intertie players are small compared to Alberta's market size; (b) unless an internal fleet of infra-marginal resources, the intertie player would not be in a position to benefit from any price increases caused by withholding; (c) economic withholding is not feasible under current market rules, considering that all imports are at zero-dollar price, making them price takers by definition;[31] and (d) physical withholding is infeasible,

[30] AESO, ISO Rules, Rule 203.1.3(3)(a)(i) Offers and Bids for Energy and Rules 203.6.6(2) and 6(3) Market Requirements for the Energy Market.

[31] Note that even if importers were able to offer at an above-zero price, they would be price takers in that they have the incentive to offer at marginal cost (including the marginal opportunity cost of not selling energy to other neighbouring markets.) See AESO, ISO Rules, ISO Rule 203.1.3(3)(a)(ii) and 203.1(7)(2)(a)(ii) Offers and Bids for Energy.

since if an individual importer opts against making an import schedule, the import volume would be replaced by a different competitive player using the available intertie capacity to execute the import transaction, as long as the import is economically attractive.

Further, imports and internal generation have numerous differences in technical capabilities and scheduling processes, that necessitate different treatment for enabling market participation while ensuring that the AESO has sufficient visibility and control over import schedules to ensure operational reliability. These obligations reflect the unique information, coordination, and processes necessary to maintain reliability and implement intertie schedules within the current market framework. Processes and obligations that apply to importers that do not apply to generators include:

- **Available Transfer Capability (ATC)**: The volume of energy that can be imported over each intertie is determined by AESO on an ongoing basis, and is dependent on many factors, including FFR availability, internal transmission limitations, and the simultaneous feasibility across multiple interties;[32]
- **$0 Offer Prices**: Unlike internal generators, importers are required to offer all imports at $0/MWh price, making them price takers;[33]
- **T-2 Offers, with T-20 Scheduling:** importers must submit offers to Alberta 2 hours ahead of the scheduled time of import, with selected offers limited by ATC. If selected, the importer must finalize import schedules 20 minutes prior to delivery; [34]
- **Priority Curtailment**: During times of surplus supply when more generation is offered at $0/MWh than is needed to meet demand, imports are curtailed before internal generators.[35]

These different rules and processes for importers are driven by technical differences compared to internal generators, which require different rules to enable these players to participate in the energy market. The T-2 ahead offer submission and T-20 scheduling, along with the $0 offer price structure, is set up to accommodate the current complexity and necessary lead time for coordinating import offers with transmission scheduling between Alberta and other jurisdictions. In other words, though no equivalent to the MOMC rule applies to imports, these transactions

[32] AESO, Information Document Available Transfer Capability and Transfer Path Management ID #2011-001R, October 3, 2023.

[33] AESO, ISO Rules, ISO Rule 203.1.3(3)(a)(ii) Offers and Bids for Energy.

[34] AESO, "ISO Rules Part 200 Markets Division 203 Energy Markets Section 203.6 Available Transfer Capability and Transfer Path Management," section 6(2).

[35] ISO Rules Part 200 Markets Division 202 Dispatching the Markets Section 202.5 Supply Surplus, section 2.

are subject to other rules that ensure AESO has sufficient visibility and control to ensure operational reliability throughout the T-2 and T-20 scheduling processes.[36]

Overall, the MOMC requirement for generators is specifically relevant for internal generators to support reliability by enabling them to engage in economic (but not physical) withholding while ensuring that AESO has accurate operational information and dispatch authority with which to reliably manage the grid. Importers are not subject to the equivalent of the MOMC because they have neither the incentive nor the ability to engage in economic or physical withholding, and other rules are used to ensure that AESO has sufficient visibility and dispatch authorities over scheduling processes to maintain reliability.

D. MOMC Imposes Minimal or No Cost on Internal Generators

The purpose and effect of the MOMC is to ensure that internal generators truthfully report their physical status and offer that supply into the AESO market if and when it is available. This requirement introduces minimal or no cost to generators to comply, considering that the resource's physical operational status and economic participation in the market is not affected.

Suncor's complaint asserts that the MOMC requirement "comes at a cost" but provides no explanation or evidence describing the nature of any associated costs on generators.[37] When asked to expand in the Information Request, Suncor did not point to any source of additional costs associated with the MOMC rule (other than the total cost of resource investments required to participate in the market).[38]

Considering the MOMC does not impose material transaction costs or other barrier to market participation on internal generators compared to imports, the MOMC is not discriminatory based on this specific criterion.

E. Importers and Generators Earn Revenues Commensurate with Delivered Reliability

Suncor asserts that importers have discriminatory preference because they are paid for reliability that is not delivered, stating that consumers paid imports "through the electricity market for a

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[36] AESO, "ISO Rules Section 203.6 - Available Transfer Capability and Transfer Path Management," §§10 and 11.

[37] Suncor Complaint, ¶ 27.

[38] Suncor Information Request Response to Alberta Electric System Operator ("AESO"): Information Requests Round 1, August 5, 2025, p. 5.

contribution to supply adequacy that was not provided."[39] Their evidentiary support provided for the claim that importers do not contribute to reliability is twofold: (1) that importers do not have a MOMC requirement; and (2) the reliability events on January 13, 2024 when EEA events coincided with low volumes of imports.

To assess Suncor's and Dr. Church's claims that importers are paid for reliability that is not delivered, I reviewed the energy market payments versus energy deliveries across all EEA events from 2019 to June 2025. This assessment illustrates reliability value of resources, as it allows for the comparison of the *measurable contribution* made to preventing shortfalls during emergency conditions alongside the market revenues earned via this contribution. Figure 2 shows the average volume of energy supply delivered from each intertie and produced by each internal generation resource type during EEA events. Figure 3 shows the average annual energy market revenue received for energy delivered during these events.[40] Both figures are normalized by total maximum resource capacity on a monthly basis.

FIGURE 2: AVERAGE SUPPLY DURING EEA EVENTS

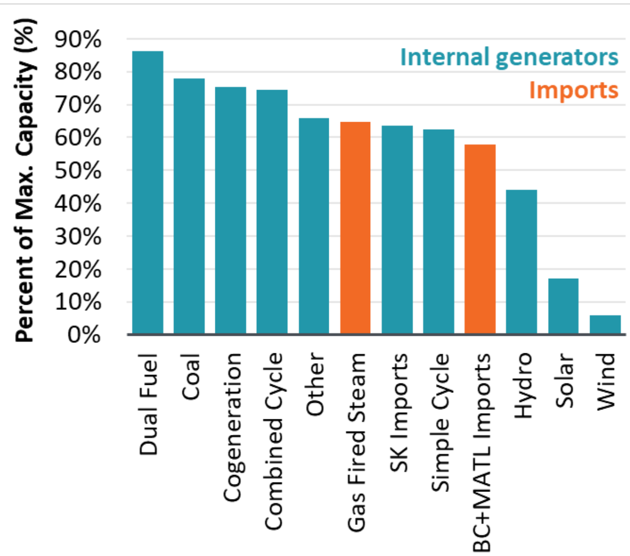
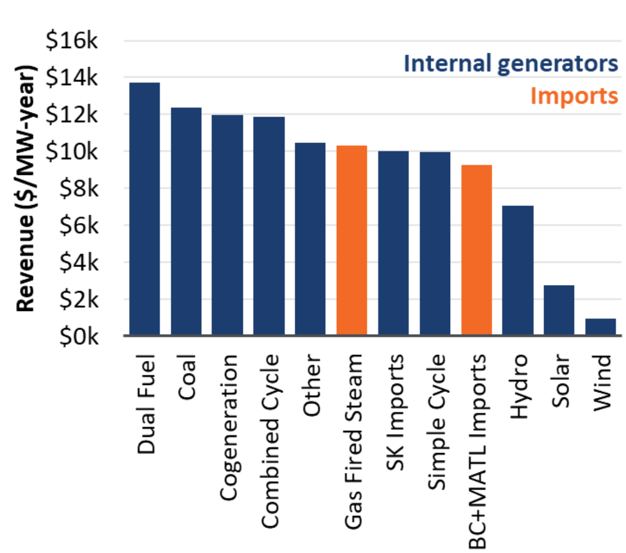


FIGURE 3: REVENUE EARNED DURING EEA EVENTS



Sources and Notes: Pool Price, net import volume, import ATC, and generation and capacity data for each fuel type are from AESO Annual Market Statistics Report. 90th percentile monthly ATC is used as the measure of intertie capacity, and hourly intertie Flows are used as the measure of intertie supply. Hourly reported Maximum Capacity is used as the measure of installed generation capacity, and hourly Total Generation is used as the measure of supply. As of July 2024, there is no remaining coal or dual fuel generation in AESO.

These two figures summarize the reliability value of different resource types (left) compared to the energy market compensation earned by these resources (right). Together, the figures

39 Suncor Complaint, ¶ 14.

40 By using the median monthly ATC for each intertie, the supply percentages are reduced due to outages on the intertie and de-rating of the import capability by the AESO.

demonstrate that the energy-only market is compensating importers and internal generators in proportion to the reliability value they contribute during EEA events.

The figures show that reliability contributions differ across resource types. The resources that historically have provided the highest reliability contribution during EEA events are dispatchable thermal resources (e.g., gas CCs), with lower reliability contributions provided by intermittent renewables, and imports in between. Energy market compensation during EEA events follows the same pattern, such that energy market revenues earned by each resource type is proportional to delivered energy volumes delivered. This result is as expected in an energy-only market where the energy price is intended to compensate for delivered reliability value and contradicts Suncor's claim that imports are paid for reliability that is not delivered.[41]

Figure 2 also illustrates a substantial range in reliability value across internal generation resource types, despite all internal generators being subject to the same MOMC rule. For example, wind generators are subject to the same MOMC requirements as gas CCs yet offer much lower energy supply during EEA events. The reason for this discrepancy in delivered reliability value is tied to the underlying characteristics of the resource types, which makes some resources more available than others due to patterns of wind, sun, hydro, outages, fuel supply, steam host requirements, and other characteristics. As already discussed above, these data illustrate that the MOMC rule does not require resources to perform at a certain level of availability or even that they have substantial reliability value, only that they truthfully report their operational status and make an energy market offer when available.

I further reviewed Suncor's claim that importers deliver less reliability than internal generators, considering their discussion of low import volumes during EEA events that occurred on January 13, 2024. Reviewing outcomes from that date, Suncor stated:

> "An example of how the effect of the reduced supply adequacy is evident, are the circumstances surrounding the January 13, 2024, emergency alert issued by the AESO (January 2024 Emergency Alert). As a result of that emergency alert, Alberta electricity users responded with a 200 MW demand reduction. Over the period in which the emergency alert was operating, and as currently permitted under Rule 203.1, Importers elected to limit their participation in the Alberta electricity

[41] Delivered energy during EEA events is admittedly an imprecise and blunt measure of reliability value, though it is still the definition of reliability utilized in Alberta's current energy-only market. Going forward under the Restructured Energy Market, the AESO market rules will incorporate more granular energy and ancillary service market products and prices to enhance the definition of delivered reliability and incentivize resources to maximize their reliability contributions to the AESO system. See AESO, "Restructured Energy Market: Final Design," August 2025.

market despite more than 250 MW of excess import capacity being available. Simple math suggests that had Importers been subject to the Must Offer Obligation that all Generators are subject to, it is likely that the January 2024 Emergency Alert would have been avoided." (footnotes omitted)[42]

Suncor correctly states that imports had relatively low delivered volumes during the January 13, 2024 EEA events, and further correctly states that there was additional unutilized ATC that could have supported additional imports. However, Suncor's brief description did not provide the primary explanation for the lack of imports, which was that neighbouring jurisdictions were experiencing a simultaneous shortage event. January 13, 2025 was an extraordinary weather event, with cold temperatures and high demand occurring across the US Northwest and Western Canadian provinces leading to emergency events declared in four balancing areas. As a result, non-firm imports to Alberta were either not available or discouraged from importing by the $1,000/MWh Alberta market price cap (prices in Mid-Columbia exceeded $1,000/MWh for most of the day).[43] Despite the extreme conditions, importers were still able to provide emergency supply, as the Market Surveillance Administrator (MSA) stated: "Although there were limited market-based imports, Alberta received emergency imports from British Columbia (BC) and Saskatchewan in addition to imports though the Northwest Power Pool Reserve Sharing Program."[44]

This January 13, 2024 EEA event illustrates several factors that affect the role of imports as contributing to reliability. The first is that imports are not always available when needed, and that a primary factor that can cause non-availability of imports is if neighbouring jurisdictions are experiencing simultaneous tight supply events. This is a different reason for non-availability compared to internal generators, whose non-availability in an EEA event is usually caused by other factors such as plant outages or lack of fuel supply. For both internal generators and imports however, supply that is not physically available cannot be offered into the market.

The same event also illustrates the role that market rules and emergency reserve sharing agreements can have in affecting the reliability value of imports. A higher energy market price cap in AESO may help to attract more non-firm imports during scarcity conditions (as is proposed

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[42] Suncor Testimony at ¶ 15.

[43] MSA, "Alberta Electricity System Events On January 13 And April 5, 2024: MSA Review And Recommendations," p. 29.

[44] MSA, "Alberta Electricity System Events On January 13 And April 5, 2024: MSA Review And Recommendations," p. 29.

in the Redesigned Energy Market),[45] while effective coordination with neighbouring jurisdictions can improve the capability to provide mutual support during emergency conditions.

These events do not, however, provide any indication that the MOMC rule equivalent to what is placed on internal generators would offer any improvement to the volume of realized imports during EEA events. As discussed above, the MOMC rule is not a capacity commitment, does not include any obligation for resource availability, and does not impose any financial consequences for non-availability. A similar rule if applied to importers would acknowledge the non-availability of imports whenever neighbouring jurisdictions are tight and non-firm market purchases are not feasible. The only way to increase the volume of imports during these events would be to impose additional requirements, such as financially binding availability requirements, on importers (i.e., by introducing new requirements that are not included in MOMC rule and not applied to internal generators).

Finally, the relevance of the EEA events from January 13, 2024 should be interpreted as a single event, and one that is not broadly representative of imports' performance during scarcity conditions. The following Figure 4 shows the realized imports across all EEA event hours from 2019–2025, with the hours from the January 13, 2024 event discussed by Suncor (highlighted in red in Figure 4). Though imports were lower during the EEA events highlighted by Suncor, these outcomes should not be over-emphasized compared to other EEA events during which imports are typically higher. One could as easily cherry pick a day when imports were much higher during EEA events, such as the more recent event that on April 5, 2024 (highlighted in green in Figure 4). During this event, about 4,350 MW of internal generation was on outage or offline, which was the primary cause of the EEA according to the MSA. Imports, on the other hand, supplied power up to the full hourly ATC capability for the duration of the event.[46]

Though each individual EEA event can offer instructive lessons, none should be reviewed in isolation to inform the overall reliability value of imports or generation. Instead, the more relevant way to review resource adequacy contributions by resource type is on a statistical basis considering performance across all EEA events and system conditions (as in Figure 2 and Figure 3 above).

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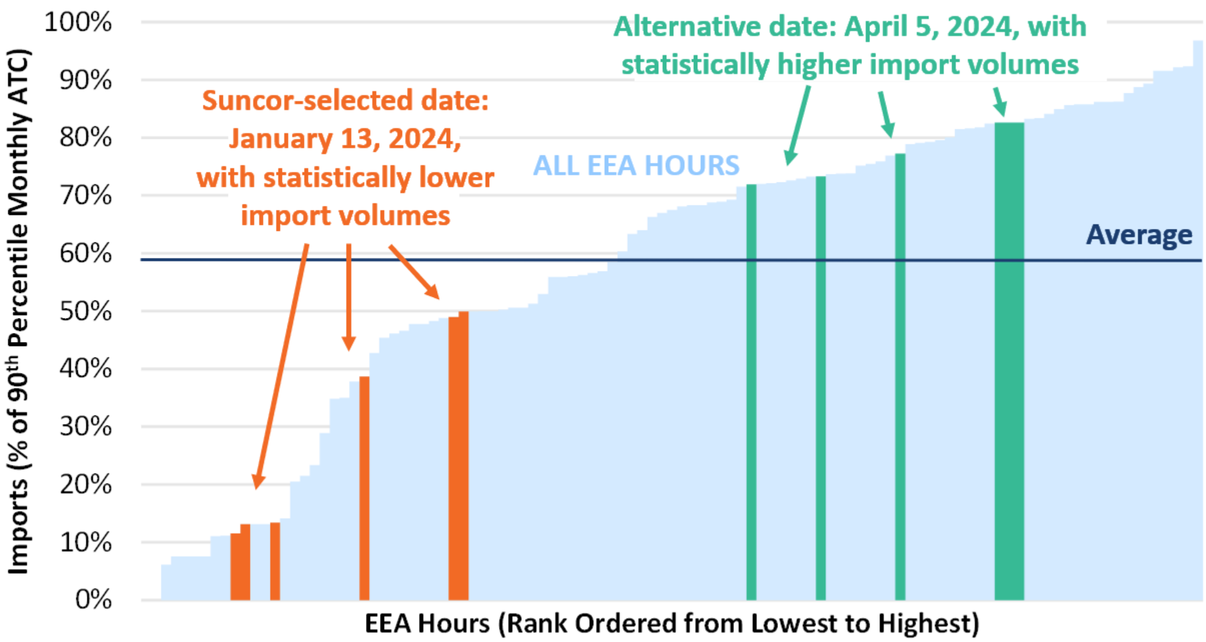
45 AESO, "Restructured Energy Market: Final Design," August 2025, p. 6.

46 MSA, "Alberta Electricity System Events On January 13 And April 5, 2024: MSA Review And Recommendations," p. 52.

FIGURE 4: RANK-ORDERED HOURLY IMPORT SUPPLY DURING EEA EVENTS
107 HOURS WITH EEA EVENTS OCCURING OVER DATE RANGE: 2019–2025



Sources and Notes: Considers all hours from 2019 to June 2025 with 107 total EEA event hours. Every hour with an event is shown as 1 entry (multi-hour events show as multiple entries). The import volume is normalized by the 90th percentile monthly ATC.

Overall, Suncor's claim that imports are paid for reliability value not delivered is not supported by evidence. My analysis shows that imports do contribute substantial reliability value, and that the energy market revenues are commensurate with the reliability value delivered when compared to internal generators. I further demonstrate that resources with MOMC requirements do not inherently deliver higher reliability. Instead, the differential reliability value and availability of both imports and internal generation is primarily associated with the characteristics of the underlying technology and resource type.

F. Rule 203.1 and Related Market Rules Reasonably Accommodate Competition Amongst Differently Situated Resources and Market Participants

Rule 203.1's MOMC requirement fills an important role for ensuring reliability in two ways: (1) the MOMC ensures that internal generators can engage in economic withholding to produce scarcity pricing in Alberta's energy only market, without exposing the market to reliability threats that may otherwise be caused by physical withholding; and (2) by ensuring that the AESO has sufficient information and dispatch authority over internal resources to maintain operational reliability. The MOMC requirement applies to internal generators, but not to importers, and is one of many market rules that incorporates differences in treatment for differently situated resources. Importers similarly face unique rules associated with their different bidding processes and scheduling timeframes that do not apply to generators.

A difference in applicable rules, by itself, does not constitute discriminatory preference or exclusion from the market. Instead, many market rules require differences in treatment as the means by which more players and resource types can be enabled to participate and compete in the market.

In conducting my own assessment of the MOMC requirement and related market rules, I find that the current rule is aligned with supporting non-discriminatory competition between internal generators and importers despite these differences because:

- **The technical and economic need for the MOMC requirement is specifically relevant to internal generators**. The rule is not relevant nor feasible to apply to importers, because: (1) importers have neither the incentive nor the ability to engage in physical withholding; and (2) other rules apply to importers to ensure that AESO has sufficient operational visibility and dispatch authority. The differences in the technical, operational, and economic realities between internal generators and importers mean that different rules must apply to these different classes of market participants, if both are to be enabled to participate and compete in the Alberta energy market;
- **The MOMC rule imposes minimal or no identifiable costs on internal generators**, and so does not introduce barrier or cost to full market participation relative to importers; and
- **Outcomes from the energy-only market demonstrate that importers and internal generators are being compensated proportionally to the reliability value they contribute**.

Overall, the MOMC requirement incorporates a reasonable distinction between internal generators and importers based on their economic and technical characteristics, and introduces no outcomes of discriminatory preference or exclusion from market participation.

Part II: Assessment of Short-Term Impacts from Suncor's Primary Requested Relief: Applying a Non-Commitment Recovery Charge to Importers

A. Summary of Anticipated Short-Term Impacts from Suncor's Proposed NC Charge

SUNCOR'S PROPOSAL: As the primary relief requested to correct the claimed discriminatory nature of the Rule 203.1 MOMC rule, Suncor proposes creating a Non-Commitment (NC) Charge. As summarized in Table 2, the three distinct pricing conditions would be: (1) low-price hours (prices up to the Reference Price) with no NC charge; (2) high-price hours (prices above the Reference Price, but below the price cap) when the NC charge would apply; and (3) EEA events (prices at or above the $999.99/MWh offer cap), when the NC charge would not apply. The relevant Reference Price in Suncor's proposal is the value defined in AESO Rule 201.6, which is a proxy value approximating the marginal variable cost of a gas turbine with a high heat rate.[47]

The NC charge would be equal to the difference between the Pool Price and the Reference Price, thus effectively capping the price paid to importers at the monthly Reference Price, except during an EEA event.

TABLE 2: FORMULATION OF SUNCOR'S PROPOSED NON-COMMITMENT CHARGE

Pool Price Condition	NC Charge	Effective Price to Importers
Condition 1: **Pool Price ≤ Reference Price** **No EEA**	$0	Pool Price
Condition 2: **Pool Price > Reference Price** **No EEA**	Pool Price – Reference Price	Reference Price
Condition 3: **At Price Cap (≥ $999.99/MWh)** **EEA Declared**	$0	Pool Price

Sources and Notes: Suncor Complaint, ¶ 55.

47 Suncor's analysis of the proposed NC charge also incorporates an assumption that the Reference Price would be increased through a separate rule change, see Suncor Complaint, footnote 23: "To be conservative, Suncor updated the reference price to be based on a 15 HR unit, to include carbon costs, and to include a $5/MWh variable O&M charge as the reference price has not been updated recently." I do not assess the validity of an adjustment to the Reference Price in this testimony, as I understand that such a change would need to be pursued and considered in a process outside the present docket. However, I review the NC charge using Suncor's updated Reference Price, so as to assess the impact of the NC charge as proposed by Suncor in their complaint.

SUNCOR COMPLAINT AND CHURCH EVIDENCE: The Suncor Complaint and Church Evidence do not meaningfully assess the short-term implications of the NC charge. Their submissions suffer from two key omissions that, if left unaddressed, create an incomplete and misleading understanding of the proposal's likely effects.

First, both Suncor and Dr. Church adopt a framing that suggests import volumes could be unaffected by the application of the NC charge.[48] When interpreted without sufficient scrutiny, this framing could create the false impression that this is a plausible outcome. A more accurate analysis must start by acknowledging that the obvious and immediate effect of the NC charge will be to reduce imports. The application of the NC charge will reduce economic incentives for importers by eliminating importers' incentives to offer into Alberta whenever their opportunity cost or cost of supply exceeds the Reference Price.

Second, both testimonies focus only on long-term market dynamics and do not provide a meaningful assessment of the short-term consequences. This omission could leave the impression that near-term impacts are negligible or irrelevant, when in fact they are likely to be both substantial and immediate.

MY ASSESSMENT: In my assessment, I address these analytical gaps and evaluate the short-term outcomes that would result if Suncor's proposal were implemented. Specifically, I find that there would be detrimental impacts on:

- **Import Participation:** Imports would be immediately discouraged from participating in the Alberta market, with substantial reductions to the volume of imports realized. Imports would drop not only during the non-scarcity hours directly targeted by the NC Charge (because market revenues would no longer justify the imports), but also during EEA events when the NC Charge would not apply (because importers cannot predict with perfect foresight the timing of EEA events, and because import volumes are often large enough to tip the balance of whether an EEA event occurs or not).
- **Market Reliability:** The reliability of Alberta's electricity market would deteriorate in the near term as the market is less able to attract imports during tight conditions.

[48] Dr. Church Testimony, ¶ 104: "The level of supply adequacy, assuming import volumes are unchanged, is not affected by the non-commitment recovery charge, but the cost of maintaining that level of supply adequacy in Alberta is reduced."

Suncor Response to IRs, p. 12: "Suncor has not conducted modeling to predict the extent to which the proposed N-C Recovery Charge would reduce import volumes…Suncor would not expect a significant reduction in import activity."

- **Economic Efficiency:** The combined effect of these changes would introduce operational inefficiencies and erode the benefits of trade that would otherwise be created by market participation of economic imports.

The economic inefficiencies and erosion of reliability introduced by the NC charge would come at the expense of Alberta consumers (through higher prices and poorer reliability) and importers (who would no longer gain a portion of the benefits of trade). The only beneficiaries of the NC Charge would be incumbent internal generation resources, who would capture higher revenues and profit margins. The net result of these effects is to reduce the total economic surplus created by the market (when considering the sum of producer and consumer surplus), since the inefficiencies from the NC Charge are deadweight losses that benefit neither producers nor consumers.

B. NC Charge would Reduce Imports during both Scarcity and Non-Scarcity Conditions

The NC Charge proposed by Suncor would discourage importers from selling into Alberta during both scarcity and non-scarcity conditions. The economic effects of Suncor's proposed NC Charge across the three distinct pricing conditions described in Table 2 are as follows:

- **Condition 1: Pool Prices are less than the Reference Price (no NC Charge):** The NC Charge does not apply in these hours, and so the NC Charge should not affect the volume of realized imports (except to the extent that imperfect foresight of the NC Charge and Alberta prices influence realized volumes). These lower-price hours make up the largest share of hours and imports, but also represent the times when imports have more moderate economic value. These low-price hours tend to be at times when Alberta demand is lower, and wind and solar generation is higher, such that imported power is less valuable (and in many cases, Alberta would tend to be exporting rather than importing). Overall, the NC Charge should not substantially affect imports in these non-scarcity hours.
- **Condition 2: Pool Prices are greater than the Reference Price, but no EEA declared (NC Charge applies)**: When the NC Charge is applied, it caps the revenue that importers can receive at the Reference Price, which will reduce incentives to import. As a comparison of the economic incentives to import with or without the NC Charge, consider a scenario in which the AESO Pool Price is $200/MWh, the price at Mid-Columbia is $100/MWh, the Reference Price is $50/MWh, and importers must pay $10/MWh in losses and wheeling charges to complete an import schedule. The economic incentives to import are:

- *Without the NC Charge:* $200 Alberta price, minus $100/MWh Mid-Columbia price, minus $10/MWh in wheeling costs = $90/MWh in net revenues. Without the NC charge, imports are incentivized to be scheduled.
- *With the NC Charge:* $200 Alberta price, minus $100/MWh Mid-Columbia price, minus $10/MWh in wheeling costs, minus $150/MWh in NC Charges = −$60/MWh in net revenues (i.e., a $60/MWh net cost of the transaction). With the NC charge, imports will not be scheduled.

As of today, imports will be attracted to sell into Alberta only if the revenues they can collect are higher than the costs of supply, including the cost of purchasing power (or opportunity cost of not selling power) into neighbouring jurisdictions at the available market price. Since the Reference Price is relatively low compared to the price levels that can be realized when other markets begin to approach scarcity conditions, the NC Charge will often make it more profitable for importers to sell power outside of Alberta. This effect of the NC Charge to discourage imports is obvious but is not accounted for in Suncor's or Dr. Church's analysis. Instead, Dr. Church claims that "the portion of the pool price [above the Reference Price] collected by importers is not required to elicit efficient imports."[49] This is incorrect. Since importers always have the option to sell into neighbouring markets instead of Alberta, the portion of the Pool Price above the Reference Price is critical to attract imports. In my own analysis, I account for the effect of the price of power in other jurisdictions to change realized import volumes whenever the NC Charge would be applied.

- **Condition 3: During EEA events:** The proposed NC Charge does not apply during EEA events. By excluding NC Charges from applying during EEA events, Suncor's proposal intends to ensure that import incentives are fully restored and therefore ensure that imports needed during reliability events could be maintained. In reality however, imports would be discouraged during EEA events *even if no NC Charge applies*, for two reasons:
  - *Imperfect Foresight of EEA Events*: Importers do not have perfect foresight of when EEA events will occur, so they must apply an uncertainty factor of whether the NC Charge is likely to occur when they make import offer decisions two hours in advance of delivery.[50] Consider an example of tight conditions, when the Alberta price is predicted to be $1,000/MWh (EEA event), Mid-Columbia prices are at $600/MWh, the Reference Price is $50/MWh, and wheeling+losses charges are at $10/MWh. If the

[49] Church Testimony, ¶ 102.

[50] AESO, ISO Rules Part 200 Markets Division 203 Energy Markets Section 203.6 Available Transfer Capability and Transfer Path Management, March 31, 2023 at p. 2.

importer can accurately predict the EEA event with certainty, they will proceed with an import ($1,000/MWh Alberta price, minus $600/MWh Mid-Columbia purchase price, minus $10/MWh wheeling charges = $390/MWh net revenues.) However, the importer would face a large loss if the EEA event is narrowly avoided and the AESO Pool Price lands at $950/MWh ($950/MWh Alberta price, minus $600/MWh Mid-Columbia purchase price, minus $10/MWh wheeling charges, minus $900/MWh NC Charges, results in $560 in net costs for the transaction). Facing the risk of large potential losses, importers will prefer to sell into other markets at a guaranteed price rather than absorb the risk of large potential losses from selling into Alberta even if an EEA event is predicted.

– *Imports Can Prevent EEA Events from Occurring:* Import volumes realized in tight conditions can be large enough to tip the balance of whether an EEA event occurs, which creates a Catch-22 situation for importers (even if they have perfect foresight). The two outcomes the importer would consider are: (a) *not scheduling imports*, in which case an EEA event will occur, no NC Charge would apply, and a hypothetical import would have appeared profitable; versus (b) *scheduling imports*, in which case no EEA event will occur, the NC Charge would apply, and the importer would absorb the net losses of an unprofitable transaction. Faced with this choice, a rational participant will not schedule the import and instead sell the energy to another marketplace. The result is that Alberta will incur additional EEA events with prices at the cap, even if neighbouring markets have ample supply that could be utilized to meet reliability needs (see Section II.C for an estimate of the additional EEA events that may be experienced).

To assess the scale of uncertainties that importers have in predicting EEA events (and hence to accurately predict whether an NC Charge will apply in near scarcity conditions), I conducted an analysis of the accuracy of two-hour ahead (T-2) price forecasts available at the time when import offers must be made. As shown in Table 3, importers will be faced with substantial uncertainty and generally be unable to predict whether an EEA event will occur, considering that:

- **T-2 forecasts have a 52% false positive rate for predicting EEA events**: Over the past 6.5 years, in hours when the T-2 forecasted price was above $999/MWh, indicating that an EEA was expected, 52% of time no EEA event was declared in real time. The T-2 prediction only correctly predicted the EEA event 48% of the time. Rational importers will account for the high probability that the EEA event may not occur and the NC Charge will be applied. This effect will discourage imports from being scheduled even when reliability is threatened and an EEA is anticipated by the market.

- **T-2 forecasts have a <u>42% false negative rate</u> predicting EEA events**: Over the same time period, only 42% of hours that experienced an EEA event had a T-2 forecast of that hour that was above $999/MWh, failing to accurately forecast the occurrence of the EEA event. This false negative rate will similarly discourage imports during scarcity conditions when prices are high and reliability is threatened, but under which EEA events are not possible to predict with perfect foresight.

Absent the NC charge, imports would be attracted by high Alberta prices and help to prevent or mitigate the scale of these events (whether or not scarcity materializes into an EEA event). However, the introduction of the NC charge will undermine incentives for imports during scarcity events. Importers will not be able to confidently predict EEA events in the two-hour ahead timeframe by which they must submit offers. Therefore, importers will likely need to assume that no EEA event will occur in order to avoid the risk of paying a high price to source power but be unable to earn the prevailing AESO market price in case an EEA event does not occur.

TABLE 3: TWO-HOUR AHEAD (T-2) FORECAST ERROR FOR PREDICTING EEA EVENTS

False Positive *EEA was forecasted, but did not occur*		**False Negative** *EEA was not forecasted, but did occur*	
Total Hours with T-2 > $999/MWh	128	Total Hours with EEA event	107
T-2 > $999/MWh but no EEA event	66	T-2 < $999/MWh but EEA declared	45
False Positive Rate	52%	False Negative Rate	42%

Sources and Notes: Calculated for 2019-June 2025. Comparison the T-2 price forecast the realized hours emergency conditions. We take a T-2 price forecast of > $999/MWh to indicate a forecasted EEA event.

To assess the overall scale of impacts that the NC charge may have in discouraging imports in both non-scarcity and scarcity conditions, I conducted a historical analysis of market prices and import incentives in Alberta over the period 2019 through mid-2025, with the results summarized in the following Table 4. For each hour, I use the Pool Price, Reference Price, historical net import volume, external market prices, and an assumed $10/MWh transaction cost to estimate when imports would be lost due to the NC Charge causing imports to be uneconomical. If the Reference Price minus the transaction costs is less than the external price, imports become uneconomic and cease to flow in the presence of the NC Charge. In conducting this analysis, I only consider imports from the British Columbia (BC) and Montana Alberta Tie Line (MATL) interties, considering the transparency with which external market prices are available.

TABLE 4: IMPACT OF NC CHARGE ON BC+MATL IMPORT VOLUME IN HOURS WHEN THE POOL PRICE IS ABOVE THE REFERENCE PRICE AND NO EEA IS DECLARED

	2019	2020	2021	2022	2023	2024	2025 Q1-2	Average
Average Price ($/MWh)								
Pool Price	$55	$47	$102	$162	$134	$63	$40	$90
Reference Price	$29	$48	$71	$104	$69	$55	$71	$63
Percent of Hours								
Condition 1: Non-Scarcity, No NC Charge	22%	92%	69%	66%	63%	79%	92%	67%
Condition 2: Pool Price > Reference Price, With NC Charge	78%	8%	31%	34%	37%	20%	8%	33%
Condition 3: EEA Event	0.06%	0.10%	0.21%	0.27%	0.19%	0.39%	0.00%	0%
Import Volume (GWh)								
Condition 1: Non-Scarcity, No NC Charge	278	3,193	2,312	2,426	667	405	172	1,443
Condition 2: Pool Price > Reference Price, With NC Charge	1,534	344	1,102	1,164	741	335	68	809
Condition 3: EEA Event	3.3	7.3	8.1	10.5	5.4	10.6	*	7.0
Import Volume Lost with NC Charge (GWh)								
Condition 1: Non-Scarcity, No NC Charge	0	0	0	0	0	0	0	0
Condition 2: Pool Price > Reference Price, With NC Charge	1,361	92	221	325	515	252	29	428
Condition 3: EEA Event (Low Estimate)	1.9	3.5	0.1	3.7	3.1	1.9	*	2.2
Condition 3: EEA Event (High Estimate)	3.3	4.3	1.8	10.5	4.0	10.4	*	5.3
Percent of Imports Lost with NC Charge								
Condition 1: Non-Scarcity, No NC Charge	0%	0%	0%	0%	0%	0%	0%	0%
Condition 2: Pool Price > Reference Price, With NC Charge	89%	27%	20%	28%	69%	75%	42%	53%
Condition 3: EEA Event (Low Estimate)	59%	48%	2%	36%	56%	18%	*	32%
Condition 3: EEA Event (High Estimate)	100%	59%	23%	100%	73%	98%	*	76%

Sources and Notes: Import volume calculated as the sum of positive values of net intertie flow, ignoring the hours with net exports. 2025 includes data covering the first 6 months. AESO has had no EEA events so far in 2025. The analysis covers imports over the BC and MATL ties, SK imports are not considered in this analysis. In assessing lost imports during EEA event hours, the "Low" estimate assumes offers are made based on T-2 price forecast of predicted EEA events (T-2 Price > $999/MWh); the "High" estimate assumes that importers will behave as if they believe the NC charge always applies during EEA events.

Table 4 summarizes over the historical period from 2019 through mid-2025, the percent of hours and import volumes under each of the three distinct conditions when NC charges would or would not apply, as well as reporting the volume of imports affected by the charge. Suncor presents a similar analysis in the Suncor Testimony, Appendix E, and has broadly similar conclusions regarding the frequency with which the NC charge would apply.[51]

I conduct an additional analysis to determine the share of imports that would be rendered uneconomic and lost with the introduction of the NC Charge (neither Suncor nor Dr. Church conducted a similar analysis to estimate the scale of lost imports). I find that the NC Charge would cause a substantial reduction in imports during hours where the NC Charge is in effect, losing 20-89% of imports across hours when the NC Charge applies. The volume and percentage of imports

[51] Though I conduct my analysis assuming Suncor's updated Reference Price formula is in place, I note that using the current AESO Reference Price would significantly increase the number of affected hours and lose a higher share of the imports, both during the lower-price hours when the NC charge would not have been in effect with the Suncor's Reference Price and during higher price hours since the NC charge applied to importers would be even greater. Suncor Testimony, Appendix E, Summary tab.

lost are greater when the Reference Price is lower, the Pool Price is higher, and/or external market prices are higher.

Focusing specifically on the hours when EEA events have occurred in the past, I conduct two estimates to evaluate the potential loss of imports during EEA events. In an optimistic "Low" estimate, I assume that importers will assume that the T-2 price can accurately predict EEA events, and will schedule imports accordingly; in a more pessimistic "High" estimate I assume that importers will behave in a risk-averse fashion and make import scheduling choices as if they believe the NC charge will apply in all EEA event hours.[52] I estimate that imports during EEA events would drop by 32% (yearly range 2–59%) in the Low estimate or 76% (yearly range 23–100%) in the High estimate.

Overall, the effect of the NC charge will be to substantially reduce economic imports attracted into Alberta in non-scarcity conditions when the NC charge applies; in scarcity conditions when supply is tight but no NC charge applies because there is no EEA event; and even during EEA events when the NC charge does not apply.

C. NC Charge would Harm Reliability by Reducing Imports During Scarcity Conditions

Imposing the NC Charge on importers would harm system reliability by discouraging imports precisely when they are most needed, during tight supply conditions. When Alberta has ample surplus generation (typically during low-price hours), any reduction in imports could be offset by internal generation with some incremental cost but without affecting reliability. However, during periods of limited internal supply, there may not be enough generation available to replace lost imports, resulting in a thinner supply cushion and an elevated risk to system reliability. The NC Charge structure is particularly problematic from a reliability perspective because it imposes the greatest disincentive against imports during high-price, tight-supply hours when imports are most valuable for maintaining reliability (and may be able to do so at moderate costs, especially if other jurisdictions are not facing coincident tight supply conditions).

Despite Suncor's proposal to limit the size of reliability harm by removing the NC Charge during EEA events, imports' contribution to reliability will still be eroded both in hours when the NC

52 Both the "Low" and "High" cases similarly determine whether the import would be offered based on whether the profit for the importer is higher than selling externally. The "Low" case makes an offer decision assuming the NC charge will not be in effect when the T-2 price forecast exceeds $999/MWh (assuming an EEA event would be in place). The "High" case assumes the offer decision is made with the assumption that the NC charge will always be in effect if the pool price exceeds the Reference Price, given the uncertainty of forecasting EEA events.

Charge applies and during scarcity conditions when the NC Charge does not apply (during EEA events), as explained in Section II.B. In the following Table 5, I summarize my analysis estimating the erosion to reliability that would be introduced by the NC charge, under the assumption that each 1 MWh of lost imports during an EEA event must be addressed by triggering 1 MWh of emergency actions to address the resulting energy shortfall (e.g., via involuntary load shedding).[53] I estimate the reliability impact of the NC charge derived from two effects:

- **Effect 1: Reliability Shortfalls Due to Loss of Imports During Pre-Existing EEA Events.** Since 2019, imports have supplied approximately 500 MW, on average, during EEA events. I estimate that the NC Charge would reduce imports by approximately 35–75% during EEA events (as discussed in Part II.B above), due to forecast uncertainty of whether the EEA will actually occur and therefore whether the NC Charge will be applied. Reduced imports during EEA events would directly harm reliability by exacerbating the depth of supply shortfalls during reliability events. The loss of imports during these events would need to be made up through other reliability actions up to and including additional involuntary load shedding. Using the same analysis of lost imports described in Part II.B above, I estimate that the loss of imports during EEA events would introduce approximately 5,326 MWh per year of load shedding or other reliability actions to address the shortfall.
- **Effect 2: Reliability Shortfalls During Additional EEA Events Caused by Loss of Imports.** In addition, the reduction of supply in tight supply cushion hours when the NC Charge is in effect will also harm reliability. There are many hours in which the AESO has avoided an EEA event in part due to imports being motivated to sell into AESO to capture the high Pool Price. If imports are lost during these tight supply hours, more EEA events will be triggered. Again, using the same analysis of lost imports described in Part II.B above, I estimate that the NC Charge would increase the number of EEA event hours from 18 hours/year (historical average) up to 87 hours/year (with the NC charge), or an increase of 69 EEA event hours per year. I account for the portion of the imports lost in these hours that could be replaced by internal generation from the remaining supply cushion, and estimate the remaining portion that would need to be addressed by reliability actions including additional involuntary load shedding. I estimate the increase in load shedding

[53] The value I estimate is a total quantity of supply shortfall that can be addressed by some combination of involuntary load shedding and other reliability actions (e.g. shallow and short-duration EEA events can partially managed by tolerating operating reserve shortfalls). I do not attempt to estimate what portion of supply shortfalls would need to be addressed through load shedding versus other emergency actions, or whether other behavioural changes may be possible inside Alberta (e.g. incremental demand response curtailments) to address a portion of this estimated shortfall.

associated with additional EEA events under the NC Charge to be approximately 13,636 MWh per year.

Table 5 summarizes my estimates of the number of new EEA events and reliability actions that would have occurred each year due to the NC charge, with a combined effect of causing approximately 69 additional EEA event hours and approximately 18,962 MWh of additional load shed or other reliability actions. Further, many more hours would have had an even tighter supply cushion, increasing the system's vulnerability to unexpected fluctuations and lower-level scarcity events.

TABLE 5: ADDITIONAL EEA EVENTS AND SHORTFALLS THAT MAY BE CAUSED BY LOSING IMPORTS DUE TO THE NC CHARGE

	EEA Event Hours Impacts of NC Charge			**Shortfall Impacts of NC Charge**		
Year	**Historical EEA Event Hours** *(hours)*	**Additional EEA Event Hours Due to Loss of Imports** *(hours)*	**Total Resulting EEA Event Hours** *(hours)*	**Effect 1: Added Shortfalls During Historical EEA Events Due to Loss of Imports** *(MWh)*	**Effect 2: Shortfalls During Additional EEA Event Hours Due to Loss of Imports** *(MWh)*	**Total Additional Shortfall Due to Loss of Imports** *(MWh)*
2019	5	176	181	2,921	33,736	36,657
2020	9	28	37	4,279	11,599	15,878
2021	18	12	30	1,683	1,631	3,314
2022	24	93	117	10,195	19,074	29,269
2023	17	49	66	3,375	7,106	10,481
2024	34	57	91	9,505	8,670	18,175
Average	18	69	87	5,326	13,636	18,962
Total	107	415	522	31,959	81,816	113,774

Sources and Notes: In Effect 1, every MWh of lost imports is assumed to contribute toward a 1 MWh increase in required load shedding to compensate for the lost supply. In Effect 2, an hour is assumed to be pushed into an EEA event whenever the lost import volume due to the NC charge exceeds the available supply cushion. A new "event hour" is any hour there is a supply cushion at or below 0; the depth of the shortfall in such an hour is tabulated in MWh toward the total increase in load shedding events caused by Effect 2.

When Alberta faces high demand and internal generation shortfalls, it depends on imports from neighbouring regions to maintain reliability. By imposing the NC Charge, the Alberta market would discourage imports exactly when they are most needed, undermining the price signals needed to attract supply during scarcity. This creates a perverse incentive structure: rather than encouraging importers to respond to high prices and support reliability, the NC Charge penalises them for doing so (while also flipping incentives back again to reward imports only once the system is pushed into an EEA event). The result may lead to erratic, less predictable importer offer behaviour that leaves the system with a thinner and more volatile supply cushion that is disconnected from economic incentives in neighbouring markets. Or (potentially more likely) importers will apply a more cautious approach that assumes the NC Charge is always in place, cease any efforts to track Alberta Pool Prices, and prioritize exports to other markets in times of scarcity.

D. NC Charge would Introduce Operational Inefficiencies and Erode the Benefits of Trade

Imports play a critical role in supporting efficient price formation in the Alberta market, working together with other categories of price-taking market participants (alongside smaller generators and demand response) to contribute to efficient market outcomes and efficient price formation during tight supply conditions.[54] Introducing the NC charge would disincentivize imports and remove supply from the Alberta market, particularly during high-demand hours when prices are already high (above the Reference Price). The NC Charge would distort economic incentives and break the economic link that has historically attracted imports when Alberta prices are high and allowed the province to compete for power when regional conditions are tight. The NC Charge would cap incentives for Importers as if the Alberta market price could rise no higher than the Reference Price, eliminating their incentive to provide power when the system needs it most. As Pool Prices rise, the charge imposed on imports increases, even though the benefit of imports to mitigate reliability events, high-cost demand curtailments, and other costly supply response is greater. This dynamic discourages imports precisely when they are most valuable. Consequently, importers would lose the incentive to respond when prices are high and power is most needed.

Inefficiencies will be introduced by the NC Charge whenever lower-cost imports are replaced by higher-cost internal supply. Suncor's proposal aims to mitigate the scale of these operational efficiencies by applying the NC Charge only to incentives above the Reference Price, under the theory that any pricing accomplished above the Reference Price should be considered to be the realm of "scarcity pricing" that only plays a role in driving long-term internal generation investments and plays no role in guiding operational efficiencies. I disagree with Suncor's and Dr. Church's assessment of the role of scarcity pricing on both timeframes. I respond here by describing operational inefficiencies that would be introduced by the loss of imports during NC Charge hours and discussing the long-term inefficiencies in Part III below.

As explained in Background Section A above, the benefits of trade over the interties arise from economic diversity between regions, benefits that materialize as short-term operational or

[54] Though importers technically offer into the market at a zero price under current rules, their price-taker role is more nuanced in that they influence prices by offering or not offering volumes depending on their predictions of Alberta price relative to the prices of surrounding jurisdictions. When Alberta prices are predicted to be high, scheduled imports increase and importers moderate the extent to which prices will rise as the system approaches scarcity conditions.

production cost savings, reliability benefits from non-firm economic imports, and (over time) investment efficiencies associated with a lower-cost resource mix.

Imports create value to Alberta when prevailing market conditions mean that purchasing and delivering energy into Alberta has a lower total cost of supply than the next cheapest alternative for producing it locally. The benefits of trade are measured on the margin as the internal marginal cost of supply in Alberta, minus the marginal cost of purchasing imports from another region. These are the true economic efficiency benefits of trade measured as a reduction in total production costs (across both the importing and exporting regions) or the reduction in adjusted production costs (if measuring the impact for Alberta on a stand-alone basis).[55]

The introduction of the NC Charge would interrupt the economic signals incentivizing economic imports, introducing inefficiencies at the times when supply conditions are relatively tight and the NC Charge would apply. In fact, because the NC Charge is calculated as a function of the Alberta Pool Price, the size of the NC Charge and associated distortion to import incentives grows as the system becomes tight.

Inefficiencies will be introduced by the NC Charge whenever lower-cost imports are replaced by higher-cost internal supply. Below are a series of examples illustrating the nature of operational inefficiencies that can be introduced by this displacement. In each case, I use an example where the AESO Pool Price is $200/MWh, the external market price (plus any wheeling costs) is $100/MWh to supply imports, and the Reference Price is $90/MWh (i.e., low enough that applying it causes imports to become uneconomic). The examples illustrate scenarios in which the economic inefficiencies are zero from the NC Charge (this case being the closest to what Suncor and Dr. Church describe in their evidence), to situations where economic inefficiencies are larger but arising from different sources. Consider:

- **Example 1: Internal Supply Cost is Equal to External Supply Cost.** In this first example, I make the most optimistic assumption that the true marginal cost of supply inside Alberta and in the external market are identical at $100/MWh. The Alberta Pool Price is $200/MWh only because internal resources are engaging in economic withholding. In this scenario, there is no operational efficiency loss due to the exclusion of imports under the NC Charge (external supply at $100/MWh is simply replaced by internal generation at $100/MWh, so no change in true costs). If prices remain the same at $200/MWh, then the result is a transfer payment where internal generators (rather than importers) capture

[55] Note that, in the short term, customer cost impacts from the loss of imports would be larger than this measure of adjusted production cost savings or true efficiency benefits, considering that customer costs are measured as a delta in price multiplied by total demand volume.

the profit from trade when the NC charge is introduced. If prices increase due to the reduction in supply cushion, then there is an additional transfer payment from consumer load to internal generators. These transfer payments work against customers and importers and in favor of internal generators, but no operational inefficiencies are introduced.

- **Example 2: Higher-Cost Internal Generation is Marginal.** Revising the above example, assume that the next highest-cost resource that is dispatched in Alberta is a higher cost generation resource, whose startup and variable costs must be incurred to make up for the lost import supply (for a total variable cost of \$200/MWh). In this case, an inefficiency has been introduced because Alberta has forgone \$100/MWh of lower-cost imports and instead has incurred the commitment and dispatch costs of a higher-cost internal resource.
- **Example 3: Internal Prices Rise Enough to Induce Demand Curtailments.** Extending the example, assume that loss of imports increases internal prices to \$300/MWh, the price at which internal demand resources will shut down industrial manufacturing activities. In this example, an inefficiency is introduced because Alberta has forgone \$100/MWh of lower-cost imports, and instead pursued a \$300/MWh demand curtailment.
- **Example 4: Energy-Limited Hydro Resources are Inefficiently Deployed.** Further extending the example, assume that the marginal action that must be taken to make up for lost imports is to dispatch energy-limited hydro earlier than would otherwise be necessary. By exhausting hydro supply early in the day, an opportunity cost is incurred and the hydro will be unable to provide operating reserves over the balance of the day and following days, at a net cost of \$500/MWh for the deployed energy. The inefficiency created is the difference between the \$100/MWh of forgone low-cost imports and the \$500/MWh value of deploying energy-limited hydro.
- **Example 5: Batteries are Inefficiently Deployed**. Similar to the hydro example, assume that batteries would prefer to sell operating reserves throughout the day, but will sell energy for a limited period only if the energy price rises above \$700/MWh (enough to cover the cost of charging, round-trip losses, incurred transmission charges, and lost revenues from not selling operating reserves over the remainder of the day). Again, the inefficiency introduced is the difference between the \$100/MWh low-cost imports and the \$700/MWh cost of battery discharge.

This series of examples illustrates in a handful of situations why paying imports the prevailing market price produces the most efficient operating incentives. By reacting to a common market price, imports and internal resources (generation, batteries, and demand response) all react to and contribute to efficient prices and thereby gain operational efficiencies individually and on a market-wide basis.

The examples further illustrate the error that both Suncor and Dr. Church make by relying too heavily on the simplified treatment of scarcity pricing as a separate and distinct component of the energy price that only relates to long-term investment signals and that has no role in supporting efficient operational choices. While it is helpful to separately examine the role of scarcity pricing in many cases, the simplification is not appropriate in this context when the primary economic implication of the charge in question is to introduce large changes to operational outcomes. The NC Charge would cause approximately 436 gigawatt hours (GWh) per year of imports to cease flowing, and each GWh of those imports would need to be replaced by internal supply or demand curtailments. These transactions will come at a higher system cost than the imports that would otherwise have been delivered.

The result of these inefficiencies will be to introduce deadweight losses that increase prices in ways that benefit neither customers nor generators (both in the short term and the long term).

Part III: Assessment of Long-Term Impacts from Suncor's Primary Requested Relief: Applying a Non-Commitment Recovery Charge to Importers

SUMMARY OF THE SUNCOR COMPLAINT AND CHURCH EVIDENCE: Though the Suncor Complaint and Church Evidence do not meaningfully assess the immediate and short-term implications of the proposed NC Charge, both provide an analysis describing the predicted implications for prices, investments, and reliability over the long term.

In both cases, they acknowledge that the NC Charge has the potential to increase prices over the short term, but that the resulting price increases would be temporary. Over the longer term, the higher Alberta Pool Prices would attract more internal generation resources, which would then compete prices back down such that the prices faced by customers would be the same over the long term, since they would eventually be set by the long-run marginal cost of supply (with or without the NC Charge). They further assert that the resulting increase in internal generation investments will improve reliability.[56]

Based on this analysis, Suncor and Dr. Church argue that the proposed NC Charge will benefit Alberta consumers by increasing reliability while maintaining prices at the same level as would prevail absent the charge.

MY RESPONSE, AREAS OF AGREEMENT: I agree with many of the foundational discussions presented by both Suncor and Dr. Church, including the description of how investments are attracted in energy-only markets (some of which I have also repeated in my own evidence).

I further agree with Suncor and Dr. Church that the short-term price impacts from losing imports from the proposed NC Charge would be largest in the short term (immediately after implementation), but that over time these higher prices would attract supply-side investment response that would mitigate the scale of short-term price increases.

MY RESPONSE, AREAS OF DISAGREEMENT: I disagree with Suncor and Dr. Church in several ways however, regarding the long-term outcomes that should be expected if the NC Charge is made a permanent feature of the Alberta energy-only market. A more complete assessment of the NC Charge should consider the perpetual inefficiencies and loss of reliability benefits from economically discouraging a large volume of non-firm imports. Supply-side response to high

[56] Church Evidence, ¶ 86: "Reducing imports will lead to short-run increases in prices, but the long-run response is an increase in generating capacity in Alberta, that reduces prices back to their long-run level and enhances supply adequacy by increasing incentives for, and investment in, generating capacity in Alberta."

prices will partly (but never fully) mitigate the price impacts associated with the NC Charge and would not address the inefficiencies created. Finally, though I agree that additional internal generation investments would be indirectly attracted by higher Pool Prices if an NC Charge is implemented, the ultimate impact on reliability is inconclusive due to the offsetting factor of lost reliability value from imports.

I arrive at my conclusions based on the following:

- **Inefficiencies**: The introduction of the NC charge would introduce economic inefficiencies in the short term (as described in Part I above), and these inefficiencies would become a permanent feature of the Alberta energy market over the long term. The effect of the NC Charge is to discourage imports by breaking the link between import incentives and marginal prices, which will permanently erode the benefits that are otherwise created by allowing imports and internal resources to make operational decisions relative to a common market price. The result will be to continue to exclude economic imports over the long term and eliminate many of the benefits of trade that would be created by imports absent the NC Charge. Benefits of trade that will be permanently eroded include each of the categories of benefits described in the Background section above, including:
  - *Adjusted production costs* will be permanently inflated, considering that the NC Charge will always prioritize the activation of higher-cost internal resources over lower-cost imports whenever the charge is active (as described in Part II.D above);
  - *"Free" reliability benefits from non-firm imports* will be permanently eroded, considering that the NC Charge will discourage imports in both near-scarcity conditions and EEA event hours (for the same reasons described in Part II.C above). The result will be to limit Alberta's access to cost-effective support for meeting reliability needs, including imports that can be accomplished at medium or low costs because neighbours are not experiencing reliability events at the same time; and
  - *Savings from a lower-cost supply mix* will not be fully incentivized, considering that the natural patterns of low-cost import supply availability will not be reflected in Alberta Pool Prices, and so cannot be used to inform a more optimal and complementary internal supply mix.
- **Equilibrium Conditions and Long-Run Prices:** Both Dr. Church and Suncor incorrectly assert that prices will be identical in the long run with or without the NC charge. Dr. Church states "That is, generation capacity will adjust in response to those shocks such that the long-run equilibrium price level (the average hourly price) is unchanged. The

time-weighted average price in the long run is equal to the long-run marginal cost of baseload generation."[57]

Dr. Church's description of long-run equilibrium conditions is not precisely true. A corrected version of the statement should assert that long-term prices will be moderated until operating margins are just sufficient to recover the investment costs of at least one marginal technology (i.e., until supply investment can be attracted).[58] The equilibrium condition that prices are high enough for at least one type of resource to recover investment with and without the NC Charge does not equate to the statement that customer costs are identical in both cases. Instead, long-run prices will be higher if the NC Charge is implemented because:

- The NC Charge introduces a number of operational efficiencies (as described in the Part II.D above) that result in higher operating and production costs on a system-wide basis than would exist without the NC Charge. These costs are economic inefficiencies that must be recovered through the market price and that do not contribute to investment cost recovery (i.e., they are deadweight losses that benefit neither customers nor producers, but yet must be recovered via higher energy prices);
- Similarly, less efficient prices, price patterns, and operational patterns with the NC Charge will alter investment incentives so as to deviate from the least cost resource mix; and
- The marginal supply resource that will be attracted in the coming years is likely to be a higher-cost resource than supply investments that have been made in the past, particularly considering global tight supply conditions, which will accelerate the timeframe over which these new entry pricing levels would have been faced absent the NC Charge.

- **Reliability**: The long-term reliability outcomes under the NC Charge are inconclusive when compared to the status quo, because there will be two offsetting effects: (a) higher prices will attract more supply investments (improving reliability); but this effect is offset by (b) the loss of reliability value caused by a reduction in non-firm imports as described in Sections II.B-C above. Which effect is larger will depend on the scale of imports lost (particularly during tight conditions and EEA events), and whether the resulting loss of

[57] Church Evidence, p. 24.

[58] Additionally, there are a number of caveats and assumptions that have to be true in order for this statement to be accurate. These include that supply can enter freely without excess barriers to entry, that market conditions have to be reasonably predictable and stable (else the market will simply shift from one disequilibrium to another), and that multiple technologies can be marginal at once (e.g., since batteries and wind, CCs and CTs can naturally complement one another in a competitive equilibrium).

imports is greater or less than the incremental reliability value of new investments attracted by prices inflated by the NC charge.

Overall, the effect of the NC charge will be to permanently disincentivize economic imports to below the economically efficient level and introduce ongoing inefficiencies to the market.

Part IV: Assessment of Suncor's Secondary Requested Relief: Applying a Must Offer Obligation for Imports

A. Summary of Responses to Suncor's Proposed Secondary Relief

SUNCOR'S PROPOSAL: As secondary relief, Suncor proposes to introduce an Intertie Must Offer requirement, in addition to maintaining the NC Charge for any importer not taking on the Intertie Must Offer requirement.[59] Importers would then have two options for how they would participate in the Alberta electricity market, they could either participate as (introducing my own terms): (a) non-firm economic imports that are subject to the NC Charge; or (b) firm imports that accept an Intertie Must Offer obligation and that are not subject to the NC Charge.

Suncor and Dr. Church argue that the proposed Intertie Must Offer requirement is equivalent to the Rule 203.1 MOMC obligation already in place for internal generation and therefore would ensure that resources offer commensurate contributions to resource adequacy value in order to earn payments associated with the "scarcity" portion of the energy price above the Reference Price.

MY RESPONSE: Suncor's proposed Intertie Must Offer obligation is insufficiently specified, but overall appears intended to impose the equivalence of a capacity or availability commitment to any importer that wishes to avoid being subject to the NC Charge. As explained in Part I.B above, the MOMC is not a capacity commitment and does not impose any obligation for availability commensurate with what Suncor proposes to be included in the Intertie Must Offer obligation. Applying any such availability or related capacity obligations to importers would introduce a substantial cost and barrier to market participation that is not similar to the MOMC or other rules applicable for internal generation resources.

Because Suncor's secondary relief proposes to maintain the NC Charge for any non-firm economic imports, the proposal will maintain most or all of the harms to economic efficiency, reliability, and customer cost over the short and long terms that I have described in Part II and Part III above. If a portion of importers opt to take on an Intertie Must Offer Requirement, then the scale of inefficiencies and reliability harms will depend on the extent of availability or other capacity-type commitments imposed on importers. If the Intertie Must Offer obligation is similar

[59] Suncor Complaint ¶ 55: "Suncor submits that in the longer term, equal treatment between Generators and some Importers can be established by imposing the same obligations on those Importers that is imposed on Generators through a future update to Rule 203.1 (Updated Rule 203.1). The remaining, non-committed Imports would remain subject to the N-C Recovery Charge."

to a capacity commitment, then Suncor's proposal would result in short- and long-term inefficiencies, inflated costs, and the loss of the "free" reliability benefits associated with non-firm imports.

B. Suncor's Intertie Must Offer Proposal Would Introduce Obligations and Participation Barriers for Importers

Before assessing the implications of the Intertie Must Offer obligation, I note that the proposal is incomplete and insufficiently specified to implement or accurately assess. In reviewing Suncor's proposal, I was unable to determine several important aspects of how the Intertie Must Offer obligation would work. The answers to each of the following questions would have a material impact on the economic and reliability implications of the Intertie Must Offer obligation and so should be clarified before further considering the merits of the proposal.

Features of the Intertie Must Offer Obligation that are not clear in Suncor's proposal include:

- What entity would be subject to the Intertie Must Offer Obligation? Is it an individual market participant engaging in import transactions, the intertie owner itself, the owner of firm/non-firm transmission rights on the intertie, or an external generation resource in another market?
- Would the importer with an Intertie Must Offer Obligation be required to conform to an availability requirement, similar to what is required in a capacity commitment? Would there be penalties or other financial consequences for non-availability? How would availability and performance relative to the Intertie Must Offer Obligation be measured?
- Would importers be required to secure firm transmission rights externally and from the AESO system in order to qualify to participate under the Must Offer Obligation? Would firm importers be granted first rights or first access to importing to the Alberta market (above non-firm economic imports)? If the importer is physically unable or economically not incentivized to flow power, could other importers be enabled to utilize the available intertie capacity (and if so, can that be utilized without applying the NC charge)? What changes would need to be made to intertie energy market participation to enable these mechanics?
- Would importers be forgiven with no financial penalty if they fail to make an offer, similar to the AORs that can be submitted by internal generators that are physically unavailable? If so, which of the following AORs would be considered as acceptable reasons for failing to make an offer: ATC derates, external generation resource on outage, host system in

shortage (such that non-firm exports may be curtailed)? Would importers be required to schedule uneconomic imports (i.e. importing even if Alberta prices are below external market prices) in order to fulfill the Intertie Must Offer Obligations?

It would not be possible to fully assess or implement the Intertie Must Offer proposal without specifying the answers to these questions. However, for the purposes of responding to Suncor's proposal, I fill in these gaps by assuming that that the answer is generally: Yes, capacity-type availability obligations, qualification requirements, performance measurements, firm transmission rights, and financial penalties would be imposed on importers in order to qualify under the Intertie Must Offer participation category. I understand this to be Suncor's intent based on their reference to the AESO rules that would have been relevant for firm capacity imports under the prior capacity market proceeding.[60]

However, Suncor's reference to capacity market proceedings also highlights inefficiencies and inconsistencies with how firm imports, non-firm imports, and internal generation resources would be treated under Suncor's Intertie Must Offer proposal. These problems include:

- **Firm importers would be subject to capacity commitment type obligations that are not presently imposed on internal generators under the Rule 203.1 MOMC obligations.** The capacity market proposal referenced by Suncor would have imposed capacity obligations on *both* firm imports and internal generators as a means to secure availability commitments under a standardized measurement schemes and under-performance penalties that aimed to ensure that capacity commitments secured from all resource types would deliver a uniform resource adequacy and reliability value.[61] To place firm imports and internal generators on an equal footing, Suncor's proposal would need to be amended such that internal generators would also be subject to these capacity-type obligations that substantially exceed the MOMC obligations under Rule 203.1 (as described in Part I.B above).

[60] Suncor Complaint ¶ 55: "Draft language for an Updated Rule 203.1 could be drawn from the submissions made by the AESO in Proceeding 23757 as part of the Capacity Market Proposal, which included a Must Offer Obligation for capacity committed imports"; AESO. "Alberta Electric System Operator Application for Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market," submitted to the AUC in Proceeding 23757. January 31, 2019.

[61] See AESO. "Alberta Electric System Operator Application for Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market," submitted to the AUC in Proceeding 23757. January 31, 2019. In particular, see "Section 11: Performance Obligations and Incentives" that laid out a comprehensive framework for applying availability obligations and performance incentives/penalties that would have applied equally to both internal resources and firm imports.

- **Maintaining an NC Charge for non-firm imports would harm reliability and economic efficiency**. The prior Alberta capacity market proposal contemplated full economic access to non-firm imports, and never included the application of an NC Charge or similar charge that might discourage non-firm imports. Instead, that capacity market proposal explicitly incorporated rules to ensure that non-firm imports would be dispatched relative to marginal pricing incentives (with no priority for firm over non-firm imports).[62] As explained in Background Section B above, non-firm economic imports offer free reliability value by leveraging diversity in supply and demand (without the need to build additional external capacity resource to back the commitment). By applying the NC Charge to non-firm imports, Suncor's proposal would eliminate the associated "free" reliability benefits.

The result of the Intertie Must Offer proposal would be to introduce a substantial capacity-type availability obligation on firm importers, with no similar obligations imposed on internal generators providing the same product (which is energy, not capacity).

C. Suncor's Proposed Secondary Relief Would Limit Imports, Harm Reliability and Create Inefficiencies in the Short- and Long-Term

The implications of adopting Suncor's proposed secondary relief depend on whether importers would primarily participate as non-firm resources subject to the NC Charge, or firm imports subject to the Intertie Must Offer obligation. If imports only or primarily participate on a non-firm basis, then the consequences of the proposed secondary relief would be to erode market efficiencies, harm reliability, and inflate customer costs in the short term and in the long term (as discussed in Part II and Part III above).

If a portion of importers opt to participate under the Intertie Must Offer Obligation, then the operational inefficiencies from the NC Charge would be reduced (namely operational efficiencies would be reduced for the portion of importers that take on the Must Offer Obligation, as long as we assume that the importer would have reasonable flexibility to source imports from multiple

[62] The proposal stated: "10.4.11 The AESO must dispatch imports based on the respective energy market merit orders, independent of any capacity obligations (an import asset with a capacity commitment will not have priority dispatch). If available transfer capability is available and the import asset with a capacity commitment is in merit, it is dispatched. If available transfer capability is not available for all in merit offers, offers are dispatched in order and a volume may not be dispatched." See AESO, "Appendix A: Comprehensive Market Design Final Proposal and Rationale," submitted to the AUC in Proceeding 23757.

resources or markets). However, several short- and long-term inefficiencies would persist with the Intertie Must Offer option because:

- Importers will face substantial costs to qualify, ensure availability, and manage penalty risks associated with the Intertie Must Offer rule requirements. These incremental costs will limit participation (meaning that many or most importers are likely to continue participating on a non-firm basis, despite the NC Charge).
- Intertie Must Offer participants are likely to require firm capacity backing and firm transmission arrangements, which will further increase costs and limit participation.
- Non-firm imports will continue to be subject to the NC Charge, such that the operational inefficiencies associated with the NC Charge will be maintained (as described in Part II.D above).
- The “free” reliability benefits associated with economic non-firm imports will be lost, since: (a) firm imports not subject to the NC charge would likely need to be backed by dedicated capacity resources, which would require the full cost of capacity to be incurred to support the commitment (this is not the case for non-firm imports, whose reliability value stems from interregional diversity even though there is no dedicated supply resource, see Background Section B); and (b) the NC charge will discourage non-firm imports from delivering surplus supply to Alberta, even when interregional diversity would otherwise make this reliability available at low cost.

The overall result of Suncor’s proposal would be to introduce inefficiencies, which would translate to higher system and customer costs in the short term and in the long term. As under Suncor’s primary proposed relief, reliability outcomes are inconclusive (and for largely similar reasons). Reliability would be harmed by the loss of reliability value from non-firm imports subject to the NC Charge, but reliability would be boosted by the offsetting effect of incremental internal generation investments and incremental availability commitments guaranteed by the importers participating under the Intertie Must Offer option.

Appendix: Curriculum Vitae of Dr. Kathleen Spees

Dr. Spees is a Principal at The Brattle Group with expertise in wholesale electricity and environmental policy design and analysis. Her work for market operators, regulators, regulated utilities, and market participants focuses on: energy, capacity, and ancillary service market design; the design of carbon and environmental policies; valuation and integration of both traditional and emerging technology assets; and power market modeling. Dr. Spees has worked in more than a dozen international jurisdictions supporting the design and enhancement of environmental policies and wholesale power markets in decarbonizing electricity systems. Dr. Spees earned her PhD in Engineering and Public Policy within the Carnegie Mellon Electricity Industry Center in 2008 and her MS in Electrical and Computer Engineering from Carnegie Mellon University in 2007. She earned her BS in Physics and Mechanical Engineering from Iowa State University in 2005.

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