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IESO Enduring Fee Recovery Mechanism

FTI Recommendation

A report from FTI Consulting for IESO Nova Scotia

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Table of Contents

1. Introduction	4
2. Key definitions.....	6
Core Costs	6
Market Participants.....	6
Billing determinants	8
3. Revenue requirement process and options for Nova Scotia	11
Step 1: Determination of revenue requirement.....	11
Step 2: Allocation of revenue requirement	12
Steps 3 and 4: Set ISO fees and collection and true-up	12
4. FTI's recommendation – Direct Charge to each MP	20
Ranking considerations	20
Ranking.....	20
Appendix 1: Detailed example of Direct Charge to each MP (Option 2.a.).....	23
Base allocation design	23
Allocation adjustment design.....	24
True-up design	25
Allocation adjustment and true-up working in tandem – IESO perspective	26
Allocation adjustment and true-up working in tandem – MP perspective	27
Appendix 2: Background to the Jurisdictional Scan.....	29
Appendix 3: Ranking criteria detail	31

Glossary

AEMO	Australian Energy Market Operator
AESO	Alberta Electric System Operator
CAISO	California ISO
DSM	Demand Side Management
FTI	FTI Consulting LLP
GB	Great Britain
IESO NS or the “IESO”	Nova Scotia Independent Energy System Operator
IESO Ontario	Ontario Independent Electricity System Operator
ISO	Independent System Operator
ISO-NE	ISO-New England
LSE	Load Serving Entity
MEU	Municipal Electric Utility
MP	Market Participant
MW	Megawatt
MWh	Megawatt-hour
NESO	National Energy System Operator
NSEB	Nova Scotia Energy Board
NSP	Nova Scotia Power
NSPSO	Nova Scotia Power System Operator
OATT	Open Access Transmission Tariff
PPA	Power Purchase Agreement
RtR	Renewable-to-Retail
TO	Transmission Owner
VIU	Vertically Integrated Utility

1. Introduction

Nova Scotia Independent Energy System Operator (“IESO NS” or the “IESO”) was recently established as the independent system operator (“ISO”) of Nova Scotia, taking over the system planning and procurement functions of the incumbent vertically integrated utility (“VIU”), Nova Scotia Power (“NSP”).¹ Currently, the IESO operates under a temporary mechanism to recover its ‘Core Costs’, which are the operational and capital costs incurred when running the IESO. The current mechanism recovers an approved monthly amount that is charged to NSP. However, IESO NS needs to develop an enduring mechanism for the recovery of its costs.

In this context, IESO NS has engaged FTI Consulting LLP (“FTI”) to recommend an enduring fee recovery mechanism to replace the current, temporary mechanism. This report provides a recommendation grounded in a cross-jurisdictional benchmark, our understanding of the electricity sector in Nova Scotia, and discussions with both the IESO and stakeholders.

The cross-jurisdictional benchmark and existing arrangements within Nova Scotia led us to categorise potential fee recovery mechanisms into four groups. First, introduce a new schedule in the Open Access Transmission Tariff (“OATT”) to recover Core Costs (similar to many US ISOs). Second, embed the IESO’s Core Costs in the transmission revenue requirement recovered in the OATT (similar to the ISO in Alberta). Third, introduce a Direct Charge governed outside of the OATT to the relevant Market Participants (“MPs”) (similar to the ISOs in Australia and Ontario). Fourth and last, a direct fee to NSP who passes through a proportion of the fee to the other relevant MPs (similar to the EfficiencyOne model).

In the immediate future, we propose to introduce a Direct Charge as the fee recovery mechanism where IESO NS charges the relevant MPs, i.e., the third option described above. We recommend designing the fee recovery mechanism as a fixed charge, i.e., monthly lump sum payment, that is allocated to the relevant MPs in proportion to their annual share of total electricity consumption in the province.² Such an approach would:

- Establish a clear and easy-to-follow framework with limited need for coordination with other entities and/or existing frameworks, leading to low **set-up costs** by way of a straightforward initial filing process;
- Encourage **administrative** simplicity and keep the filing process and associated costs manageable due to the low number of MPs charged;

¹ We refer to the Nova Scotia Independent Energy System Operator specifically as IESO NS or the IESO and use the more general term ISO to refer to independent system operators in the abstract.

² The IESO revenue requirement for a certain year is allocated based on the forecast share of each MP for that year. In the next year, when the actual consumption share per MP is known, the contribution per MP is adjusted accordingly.

- Allow for **flexibility to adjust for future changes** if needed to stabilise cash flows (e.g. increase true-up cadence) or adjust if the regulatory or market environment changes;
- Allow for a design that ensures **revenue stability** for the IESO while aligning with best practice cost allocation principles, as observed in other jurisdictions; and
- Align with **economic principles**, which seek to limit distortionary behaviours.

The recommendation for the fee recovery mechanism provided in this report considers the IESO not owning the OATT and not performing any system operation functions. This recommendation allows the possibility to revisit this decision when the OATT and/or the system operation function would be transferred to the IESO.

The remainder of the report is structured as follows:

- In Section 2, we define in more detail three key concepts of the costs being recovered ('Core Costs'), from whom ('Market Participants') and on what basis ('Billing Determinants');
- In Section 3, we describe the process through which ISO costs are recovered generally and how each step could be approached by the IESO; and
- In Section 4, we present our recommended cost recovery mechanism and summarise the criteria used to assess the IESO's fee recovery mechanism options.

Additionally, we have included three appendices to provide additional detail and support information.

- In Appendix 1, we provide a detailed example of the fixed, custom Direct Charge implementation;
- In Appendix 2, we provide background to the ISOs covered in the Jurisdictional Scan of how different ISOs approach recovering Core Costs; and
- In Appendix 3, we detail the relative merits of each considered approach based on proposed ranking criteria.

2. Key definitions

In this section, we outline three key concepts: (i) the costs to be recovered ('Core Costs'), (ii) from whom, the different types of relevant MPs to be charged IESO fees ('Market Participants'), and (iii) and on what basis ('Billing Determinants').

Core Costs

An ISO's Core Costs are the costs inherent to running the organisation, which include capital, operating, maintenance and administrative costs. These are all the internal costs related to ISO staff, control room operating and capital expenditures, load forecasting software, and running procurement processes, among others. Core Costs do not include the costs of procurement of capacity or ancillary services from third parties by the IESO, which can be an order of magnitude larger than the Core Costs.

We note that a significant portion of the ISO's costs are not incremental for consumers as a result of having an ISO; rather, many of these costs arise from functions that would otherwise need to be performed by the VIU (e.g., the need for having a control centre and the staff operating it).

Market Participants

The costs of running an ISO are recovered from MPs who benefit from the functions performed by the ISO. The potential MPs applicable to our analysis can be split into three key categories:³

- A Load:** Load Serving Entities ("LSEs")⁴ who serve ratepayers in Nova Scotia (e.g. NSP and municipalities);⁵
- B Intertie traders:** Traders who schedule flows on intertie lines to serve load outside of the geographical area covered by the ISO (e.g. HQ Energy Marketing and Labrador Hydro⁶); and

³ This group could be further expanded when considering the full benchmarking group, such as financial market participants - only the subset of MPs that are relevant for Nova Scotia (as listed in Nova Scotia's Accredited Market Participants list ([link](#))) are included here.

⁴ LSEs serve retail, or end-use customers. In some jurisdictions these are electric supply only entities (called retailers), while in others the distribution utility is the LSE. Some jurisdictions can have both (e.g. ISO New England ("ISO-NE")).

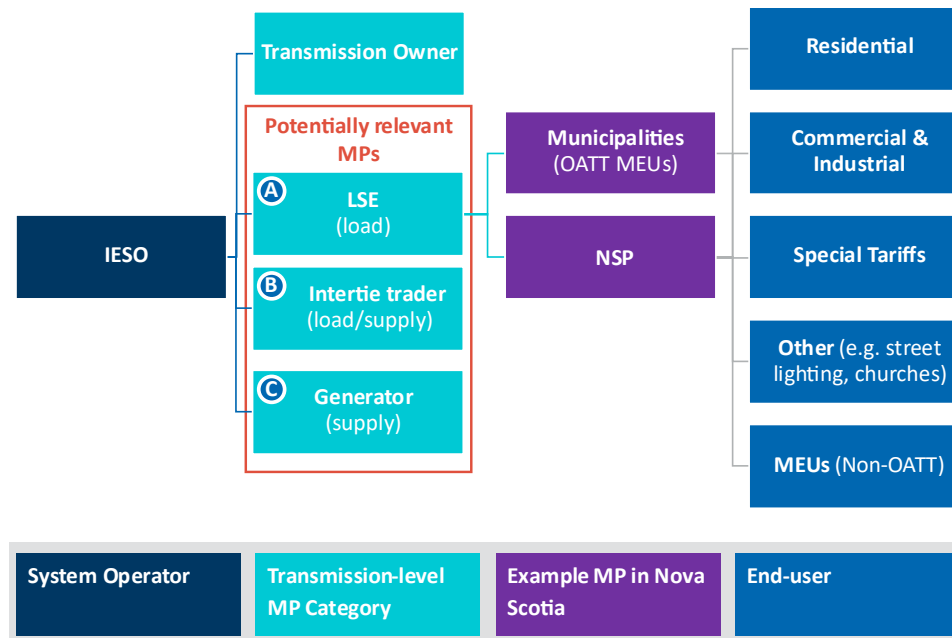
⁵ In many jurisdictions, this includes large loads directly connected to the transmission system. In some jurisdictions, such as the states operated by ISO-NE, transmission-connected load is formally served by an LSE and therefore ISO Core Costs are recovered through the same retail rate process as used for distribution-level customers. This is not true in other jurisdictions where large customers directly connected to the transmission system are not served via an LSE, e.g., oil sands or mining in Alberta.

⁶ Formerly Nalcor Energy.

c Generation: Generators or energy resources which produce electricity (e.g. NSP and independent power producers).

The potential MPs in the Nova Scotia context are shown in Figure 1 below.

Figure 1: Overview of Nova Scotia MPs and organisation



Source: FTI Analysis.

Note: MEUs = Municipal Electric Utilities

FTI prepared a report⁷ (“Jurisdictional Scan”) comparing ISO cost recovery mechanisms across a benchmarking group of ISOs. Findings from the Jurisdictional Scan provide background to the summarised information below, and throughout this report.

Generally, load (i.e., LSEs) pay the majority of ISO Core Costs. The costs of charging other MPs are likely to be passed through to load, so any fees levied on them will eventually end up in customer bills either directly or indirectly. For example, fees imposed on generators can be considered part of their operating costs, which is likely to increase the cost of electricity supply that load pays.⁸ Depending on their design and magnitude, fees on intertie

⁷ FTI Consulting LLP, *ISO Cost Recovery Mechanism: Jurisdictional Scan*, prepared for the Nova Scotia Independent Energy System Operator (IESO NS), 5 May 2026.

⁸ Some bid-based markets, such as the California ISO (“CAISO”), charge some ISO fees on generators. These generators can then increase their wholesale market bids to reflect the higher operating costs caused by ISO fees.

traders scheduling exports could lead to a reduction of the total export scheduled,⁹ potentially introducing a welfare loss.

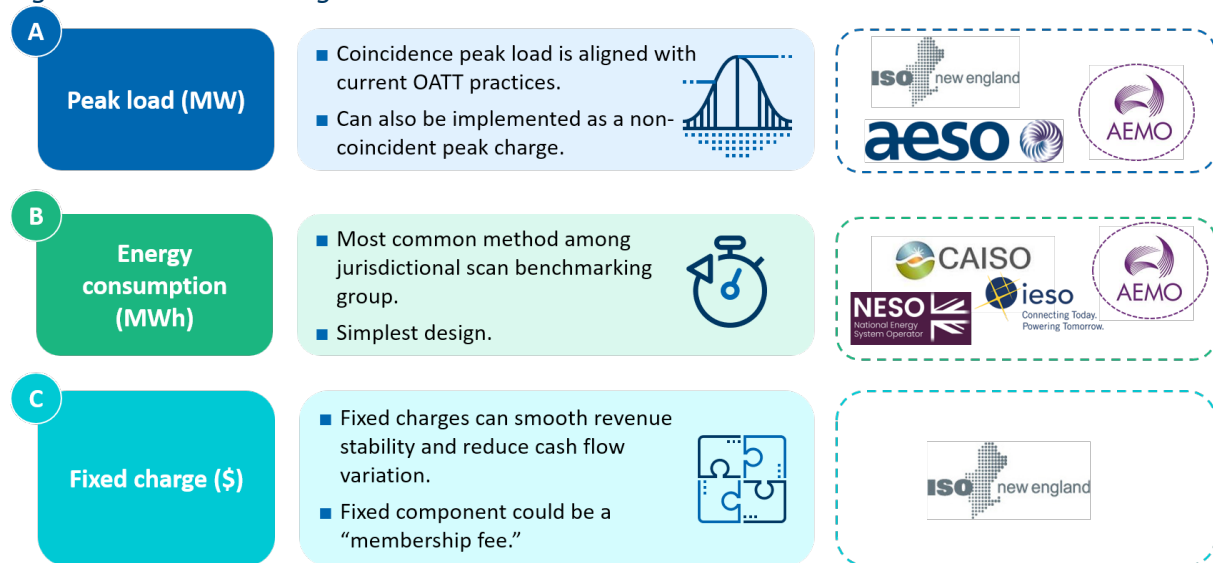
Exceptionally, the Australian Energy Market Operator (“AEMO”) also considers Transmission Owners (“TOs”) as relevant MPs for ISO fees. We do not consider the TO to be a relevant MP in the context of Nova Scotia. Fees imposed on TOs would be added to their regulated revenue requirement, which eventually would be charged to load as well.

Billing determinants

Billing determinants are the specific units of service consumption, such as megawatt-hours (“MWh”), megawatts (“MW”), or number of customers, used to calculate charges and determine how a revenue requirement is collected from customers. They are the denominators over which a revenue requirement is spread to determine rates, and later the multipliers applied to approved rates to calculate customers’ bills.

Billing determinants can be tied to usage (MW or MWh) or a fixed charge that is a flat rate for a set duration of time (often annual) independent of usage. An overview of common billing determinants for ISO fees is shown in Figure 2 below. An overview for the benchmarked jurisdictions shown in Figure 2 below can be found in Appendix 2.

Figure 2: Common billing determinants



Source: FTI Analysis, logos from ISO websites.

For regulated activities, such as the ISO planning or operating the grid, the primary economic principle guiding the choice of a billing determinant is cost reflectivity. Cost reflectivity means

⁹ A charge applied to exports increases the marginal cost of exporting electricity. As a result, some trades that would otherwise be economically efficient may no longer occur, reducing total export volumes. Because the cost of providing ISO services is fixed regardless of export volumes, any reduction in exports would simply shift recovery of the revenue requirement to other market participants, creating a potential welfare loss through a distortion of efficient trading patterns.

that the billing determinant should reflect the underlying cost driver of the activity (or asset) for which the costs are being recovered. For example, because the primary cost driver of transmission investment is generally considered to be coincident peak demand, coincident peak load (MW) charges are commonly used to recover transmission system costs (as under the OATT in Nova Scotia).¹⁰ Under such approach, customers with higher usage during coincident peak periods pay a greater share of transmission costs. At the same time, all else equal, these customers are also more responsible for the future need to expand the transmission network than customers consuming less during coincident peak periods.¹¹ In this sense, the billing determinant establishes a link between “who pays” and “who causes the cost.” Establishing this link can promote economic efficiency, as customers may have an incentive to reduce their contribution to coincident peak demand in response to the charge design, thereby potentially reducing the need for future transmission investment.¹²

However, in the case of inseparable Core Costs of an ISO, there is no clear cost driver. While some incremental Core Costs may arise as the power system increases in size, the appropriate measure of “size” is not readily identifiable. In particular, there is no clear relationship between changes in (non-)coincident peak load or volume of energy consumption, and the Core Costs incurred by an ISO.

Where costs cannot be linked to a specific cost driver, the relevant economic principle for the choice of the billing determinant becomes the minimization of pricing distortions. The textbook approaches for minimizing distortions are either to recover costs through a uniform fixed charge (\$) or to apply Ramsey pricing, whereby costs are allocated primarily to customers with the lowest price elasticity of demand. In practice, however, neither approach is typically considered feasible, as both may raise significant distributional and equity concerns.

At the same time, for inseparable ISO Core Costs, the potential efficiency losses associated with pricing distortions are likely limited under any reasonable billing determinant, as these costs represent a relatively small share of total customer charges compared with other cost

¹⁰ The extent a coincidence peak (“CP”) charge is cost reflective will be dependent on its exact design. There are many variants of CP designs such a 12CP in Nova Scotia and Alberta, i.e., a coincident peak charge levied in each month, or e.g., 5CP in Ontario, i.e., a coincident peak charge levied in the five hours with the highest load across the year.

¹¹ Perhaps the same customers with high loads during coincident peak periods were also responsible for the historical expansion of the transmission network. However, the costs associated with that historical investment are sunk. Only the future outbuild of the transmission network can be impacted by customer behaviour.

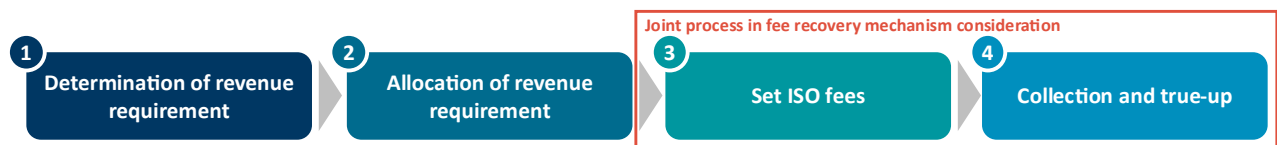
¹² Fostering economic efficiency not only depends on the billing determinant but also on the calibration of the charge. The charge should ideally signal the (short and/or long-run) marginal cost of the relevant activity. The rationale behind such calibration and how to reconcile economic efficiency with cost recovery goes beyond this filing.

categories, such as generation and transmission costs. Therefore, economic principles provide limited guidance regarding the selection of an appropriate billing determinant in this context.

3. Revenue requirement process and options for Nova Scotia

Nearly all ISOs operate on a cost recovery basis rather than for profit, that is, they aim to recover their approved costs through regulated tariffs and fees with no ability to earn a profit.^{13,14} Figure 3 below illustrates the typical process for setting tariffs and recovering these costs. Below, we discuss each step as generally observed across the benchmarking group, and how it can be implemented in Nova Scotia for the IESO. More background information regarding the benchmarking group can be found in Appendix 2.

Figure 3: Summary of typical process for setting tariffs and recovering costs¹⁵



Source: FTI Analysis.

Step 1: Determination of revenue requirement

The process begins with the ISO forecasting its revenue requirement for its Core Costs over the period of assessment, which is the revenue that it must recover through its fees to fund its operations. This is typically approved by a third-party authority.¹⁶

Step 1 Considerations for Nova Scotia

The determination process of the IESO revenue requirement, and relevant regulatory approval is already prescribed in the *More Access to Energy Act*, SNS 2024, c 2, Sch B, (the “Act”). This determines that the IESO should submit its proposed revenue requirement 90 days before the start of each fiscal year, to be approved by the Nova Scotia Energy Board (“NSEB”).¹⁷ Until NSEB has approved the revenue requirement and proposed fees, the fees approved for the previous year must remain in effect.¹⁸

¹³ All ISOs covered in our Jurisdictional Scan are non-profit organisations.

¹⁴ This differs from regulated utilities which include an approved regulated Return on Equity (“ROE”) when setting tariff rates.

¹⁵ The approaches for collection and true-up mechanism are generally a function of the choices made in step 3, hence these are considered in conjunction.

¹⁶ For example, in Ontario the IESO prepares a 3-year business plan which includes forecast costs that are then approved by the Ontario Energy Board (the regulator). See IESO Regulatory Accountability ([link](#)).

¹⁷ The current process set out in the Act states that “The IESO shall, at least 90 days before the beginning of each fiscal year, submit its proposed expenditure and revenue requirements for the fiscal year and the fees it proposes to charge during the fiscal year to the Energy Board for review.” *More Access to Energy Act*, Schedule B of Chapter 2 of the Acts of 2024, Section 29 (1), as amended by 2025, c.18, Sch., s.44.

¹⁸ “Until the Energy Board approves the proposed expenditure and revenue requirements for the fiscal year and the fees the IESO proposes to charge during the fiscal year, the fees approved for the previous fiscal year remain in effect unless the Energy Board orders otherwise.” *More Access to Energy Act*, Schedule B of Chapter 2 of the Acts of 2024, Section 29 (3), as amended by 2025, c.18, Sch., s.44.

Step 2: Allocation of revenue requirement

The revenue requirement is then allocated across the relevant services to determine the MPs that bear these costs. The revenue requirement can be split to cover

(i) ‘inseparable costs’ incurred for activities that do not have an easily identifiable beneficiary; and (ii) ‘direct costs’ attributable to an identifiable user or beneficiary (the quantum of which is expected to be low relative to inseparable costs).

This approach can be compared to the polluter pays principle, which holds that the party whose actions create a cost should bear that cost rather than transferring it to others. In regulated utility and electricity market contexts, this principle is often applied through cost causation: where a specific market participant's request, activity, or behaviour gives rise to identifiable incremental costs, those costs are allocated directly to that participant. This is especially relevant for interconnection requests where the benefiting MP may not yet be an active MP in Nova Scotia.¹⁹

As discussed in the previous section, most ISO costs, however, do not have clearly identifiable beneficiaries and therefore spread much of their costs among a broad base of MPs.

Step 2 Considerations for Nova Scotia

Inseparable costs (which include integrated resource planning, employees, and administrative costs for example) are inherent to the running of the IESO, from which the broader customer base (rather than specific beneficiaries) benefit. Therefore, most costs in the current revenue requirement are typically recovered across the Nova Scotia transmission system customer base. As discussed in the previous section, these are typically LSEs, generation and inertia traders.

Currently, the only cost that would be categorised as ‘direct costs’, i.e., costs that have an easily identifiable beneficiary, are the third-party recoveries for general interconnection study procedures.

Steps 3 and 4: Set ISO fees and collection and true-up

Once step 1, determining the revenue requirement (and associated ISO Core Costs), as well as step 2 to allocate between direct costs and inseparable costs are complete, step 3 will set rates charged to MPs to recover inseparable Core Costs. Note that the scope of the IESO fee recovery mechanism goes as far as charging the relevant MP – MP allocation to its end-use customers is outside of the control of the IESO.

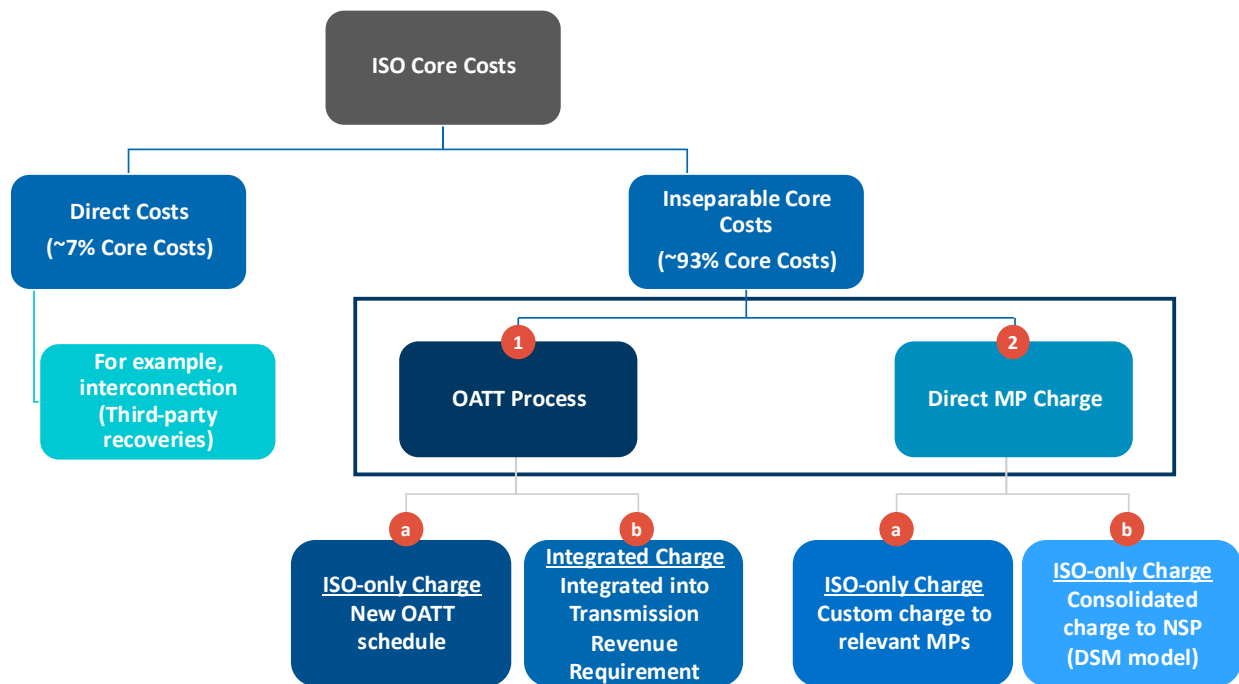
¹⁹ ISOs in the benchmarking group directly charge the relevant party for certain system impact and facilities studies, significant and non-routine information requests, non-standard contract provisions and non-standard billing arrangements. See Docket No. ER25-134 – see Section IV.A on Recovery of ISO Administrative Expenses, 17 October 2024, ([link](#)).

Finally, in step 4, collection and true-up mechanisms need to be defined.²⁰ True-up mechanisms are required because ISOs are non-profit entities; they cannot keep over-collection of the revenue requirement and should not be exposed to revenue requirement shortfalls. Over- or under-recovery can occur because of two reasons: (1) the actual IESO Core Costs will naturally vary from the forecast revenue requirement in the filing, and (2) depending on the billing determinants chosen, the revenue recovered from charges can be higher or lower than forecast when setting the fees. Because the approaches for collection and true-up mechanism are generally a function of the choices made in step 3, particularly the billing determinants, we combine the discussion of steps 3 and 4 when discussing considerations for Nova Scotia.

Steps 3 and 4 considerations for Nova Scotia

The primary decision for steps 3 and 4 is to determine the process behind fee setting. The Jurisdictional Scan has demonstrated two main processes that can be considered to recover these inseparable costs from users of the transmission system: incorporating recovery into the OATT or levying a Direct Charge to MP(s). Within each of these two processes, there are additional options for how exactly MPs will be billed, as shown in Figure 4.

Figure 4: Overview of recovery mechanism options for ISO Core Costs



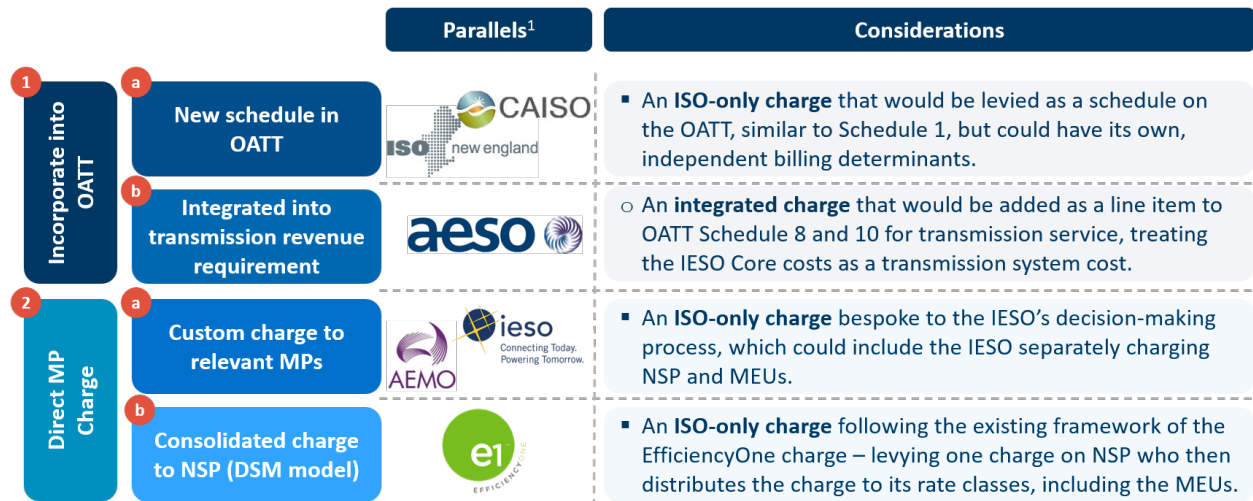
Source: FTI Analysis.

Notes: DSM = Demand Side Management.

²⁰ True-up in ratemaking terminology is a regulatory mechanism that reconciles the difference between the estimated revenue requirements (projected costs), the actually billed revenues, and actual costs over a specific period, typically one year.

Figure 5 below describes, of the two process options of OATT and directly charging, the four core options under consideration of the IESO in more detail. These are informed by FTI’s Jurisdictional Scan and tailored to the electricity system in Nova Scotia (particularly Option 2.b.). Option 1.b. is by definition an ‘integrated charge’, i.e., the ISO’s revenue requirement only represents a portion of the total charges recovered from the relevant charge(s). The other options are typically ‘ISO-only charges’ meaning the relevant charge only recovers the ISO revenue requirement.

Figure 5: Description of recovery mechanism options



Source: FTI Analysis, logos from ISO websites.

Notes: (1) Ontario IESO included under Option 2.a. as the ISO’s Core Costs are charged to the relevant MPs via a custom charge. The ISO charge is set by the regulator, who determines the exact per-kWh (volumetric) charge for end-use consumers. NESO, the GB ISO, is not included; NESO’s Core Costs are recovered together with its external costs (e.g. for ancillary services) through a separate balancing services charge using kWh as the billing determinant.

If a charge is integrated into the transmission revenue requirement (1.b.) or based on the framework used by the Demand Side Management (“DSM”) model (2.b.), then billing determinants and relevant MPs are already directly determined by the established models. If a new OATT schedule (1.a.) or newly created, standalone custom Direct Charge is chosen (2.a.), then further decisions must be made on the billing determinants and relevant MPs. These additional considerations are discussed below.

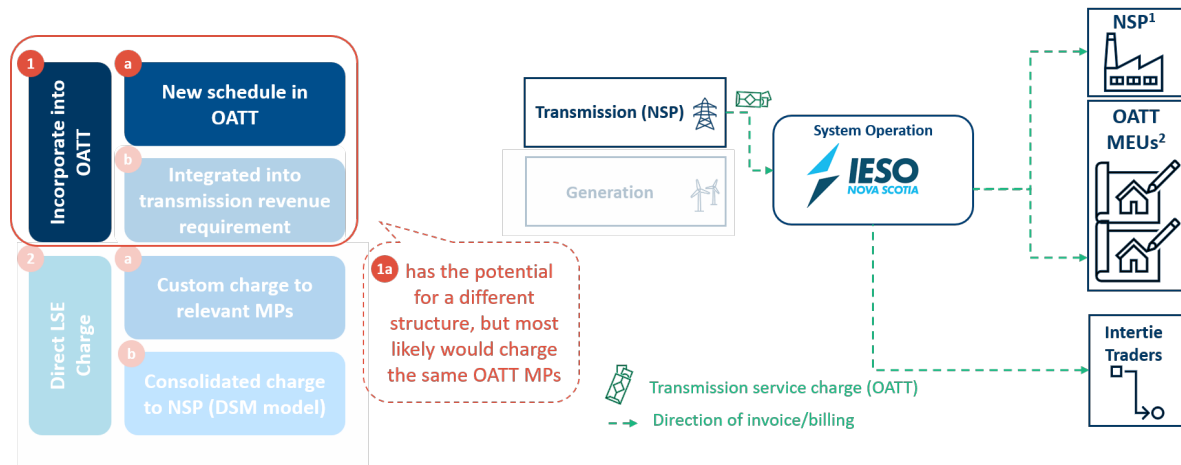
1.a. New schedule in OATT

MPs: A charge levied via the OATT would most likely charge the same MPs as the current Nova Scotia Power System Operator (“NSPSO”) ²¹ OATT, which are domestic (network

²¹ NSPSO is a department within NSP responsible for ensuring planning, dispatch and operation within the province and the application of the market rules. See *Nova Scotia Power Inc. Standards of Conduct For the Provision of Wholesale and Renewable to Retail Electric Transmission Service*, 10 June 2016 (as amended), ([link](#)).

integration) and export (point-to-point) load.²² Although a new OATT schedule has the potential for a different MP charging structure, it likely would charge the same two MP categories (domestic and export load) as the other OATT schedules. Based on the current NSPSO OATT, the specific MPs would be NSP, OATT municipal electric utilities (“MEUs”), and intertie traders.²³ This process is illustrated in Figure 6.

Figure 6: New schedule in OATT overview



Source: FTI Analysis.

Notes: (1) Non-OATT MEUs are included in NSP’s ratepayer base; and (2) Only two (of four as of June 2026) OATT MEUs shown for illustrative purposes.

Billing determinants: If a new OATT schedule is introduced, customised billing determinants can be established. Possible billing determinants, as found from our Jurisdictional Scan, are volumetric charges (per MWh), non-coincident peak charges (per MW) or fixed charges (e.g., per connection).

True-up and adjustments: Independent of the chosen billing determinant, a true-up mechanism would apply to IESO budgeting. If the IESO under-forecasts its budget, it will effectively under-recover its needed revenues – likewise, if the IESO over-forecasts, it will over-recover because collections will exceed actual revenue needs. This difference in forecast and actuals would be applied to an upcoming year’s revenue requirement. Following precedent of other ISOs, and NSP’s DSM rider, this would mean an over- or under-recovery of Year 1 costs would be added to the revenue requirement of Year 3 rates – Year 3 rates being set during Year 2.²⁴ In this example, Year 3 rates would be based on Year 3 forecast ISO budget plus Year 1 under- or over-recovery.

Further, if the billing determinant were to be volumetric or peak related, a true-up mechanism would be needed to adjust future rates to resolve over- and under-recovery of

²² Nova Scotia Power OATT Schedules 1 to 10, ([link](#)).

²³ This may eventually include Renewable to Retail (“RtR”) suppliers as listed in Nova Scotia’s Accredited Market Participants list ([link](#)).

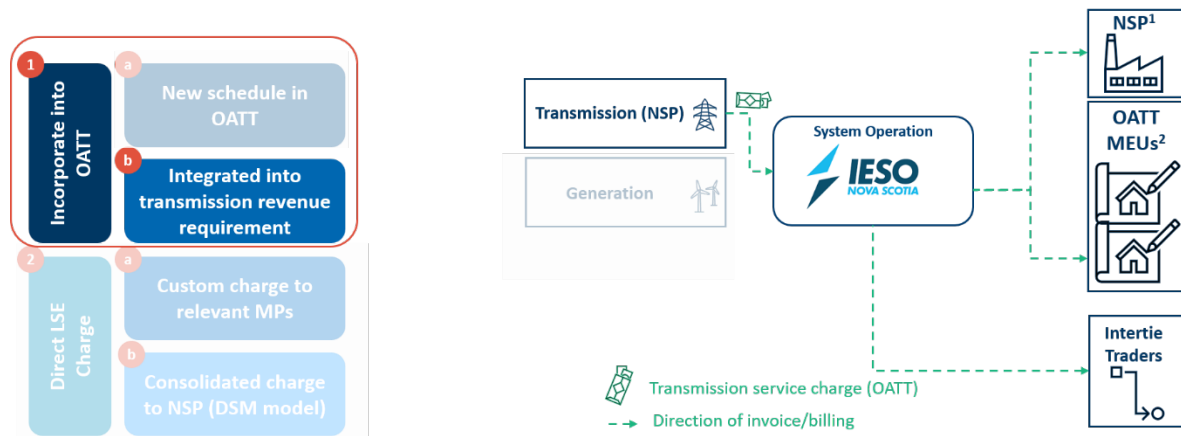
²⁴ Year 2 over- and under-recovery would be applied to Year 4, Year 3 to Year 5, etc.

prior years if consumption or (non-)coincident peaks are higher or lower than forecast. This is similar to methods used by the benchmarking group ISOs to set their rates.

1.b. Integrated into transmission revenue requirement

MPs: A charge levied via the OATT schedule for transmission service would charge the same MPs as the existing OATT schedule, which are domestic (network integration) and export (point-to-point) load.²⁵ Based on the current NSPSO OATT, the specific MPs would be NSP, OATT MEUs, and intertie traders. This process is illustrated in Figure 7.

Figure 7: Integrated into transmission revenue requirement overview



Source: FTI Analysis.

Notes: (1) Non-OATT MEUs are included in NSP's ratepayer base; and (2) Only two (of four as of June 2026) OATT MEUs shown for illustrative purposes.

Billing determinants: The OATT charges for the transmission revenue requirement are currently calibrated based on firm reservation quantity (point-to-point service) and 12-month, annual test year coincident peak load.²⁶ Fees are charged based on a MW-month basis.²⁷ This means that (i) the revenue collected from domestic and export load is not equal to the peak load billing determinant if actual flows differ from the estimated peaks, and (ii) collections by the IESO will vary with system usage over the course of the year. Hence, the IESO could over- or under-recover its revenue requirement. While the ISOs in the benchmarking group have large, diversified territories, often with numerous LSEs, the IESO

²⁵ Nova Scotia Power Open Access Transmission Tariff (OATT) Schedules 1 to 10 ([link](#)).

²⁶ 330 MW and 1,785 MW for 2027, respectively, see 2026-2027 GRA SR-01 Attachment 13, Page 4, Figure 5-10.

²⁷ Schedule 8 Non-Firm Point-to-Point Transmission Service and Schedule 10 Network Integration Transmission Service Rate.

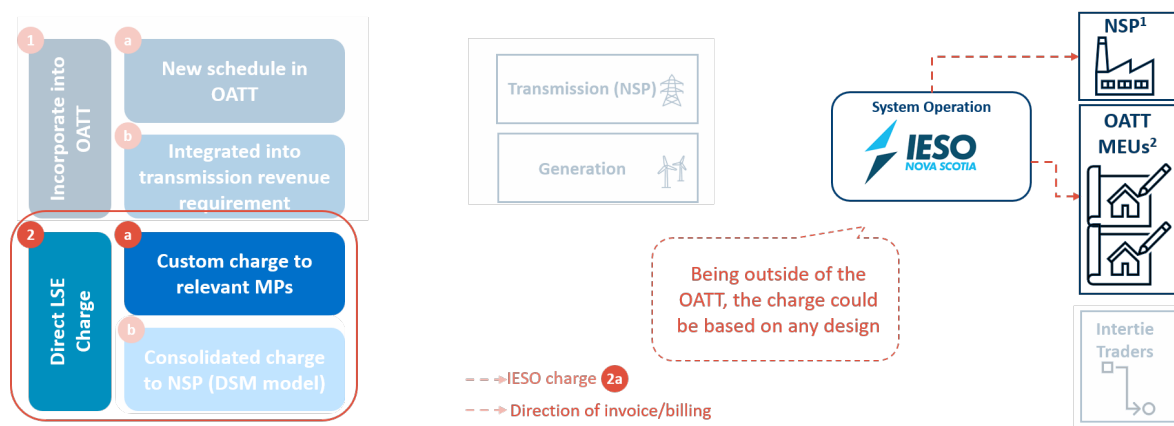
in Nova Scotia has a smaller system and correspondingly less load diversity, increasing the potential for variability in billing determinants and revenue recovery.²⁸

True-up and adjustments: considerations are the same as for Option 1.a. above.

2.a. Custom Direct Charge to each MP

MPs: A charge outside of the OATT, invoiced directly from the IESO to MPs, would allow the IESO to tailor the fee charging mechanism. While there are no restrictions with regards to what MPs to select under this option, it would seem reasonable for the charged MPs to be the LSEs who serve load in Nova Scotia and currently pay OATT costs. See Figure 8 below, and Appendix 1 for more detail on the mechanics of the charge.

Figure 8: Custom Direct Charge to MPs overview



Source: FTI Analysis.

Notes: (1) Non-OATT MEUs are included in NSP's ratepayer base; (2) Only two (of four as of June 2026) OATT MEUs shown for illustrative purposes.

Billing determinants: Similar to Option 1.a above, customised billing determinants can be introduced. Possible billing determinants, as found from our Jurisdictional Scan are volumetric charges (per MWh), non-coincident peak charges (per MW) or fixed charges (e.g., per connection).

A charge based on energy consumption (MWh), also referred to as a volumetric charge, was the most common approach identified among the jurisdictions reviewed in FTI's benchmarking scan. Such charges are generally viewed as a simple and proportional method for allocating costs that lack a clearly identifiable beneficiary or cost driver, such as inseparable ISO Core Costs. However, given the degrees of freedom in choosing the billing determinants and process under this option, we propose a hybrid billing determinant that

²⁸ Load diversity refers to the extent to which fluctuations in usage by different customers offset one another. In larger electricity systems, a greater number of customers and a larger geographic area generally produce more stable aggregate consumption and peak demand. In contrast, a smaller system with fewer market participants is more exposed to the impact of individual customer behaviour, economic activity, weather conditions, or the addition or loss of a single large load.

combines characteristics of a fixed charge and an energy consumption-based allocation. Concretely, we propose to introduce a monthly fixed charge that is proportional to the annual forecast share of consumption of each MP.^{29,30} The monthly fixed charge per MP in Year 2 would equal a twelfth³¹ of the forecast share of annual consumption of that MP for Year 2 (with the forecast being determined in Year 1) multiplied by the IESO's annual revenue requirement in Year 2.

The rationale for introducing a fixed charge based on forecast annual energy consumption (adjusted for actual energy consumption in the subsequent year) rather than a charge based directly on month-to-month metered consumption is twofold:

1. **Revenue predictability:** The IESO's forecast revenue requirement would be fully recovered through the fee, regardless of variations in system usage. This is especially valuable in a jurisdiction with variability in system load forecasts, as seen in NSP's recent 10-year System Outlooks.³²
2. **Revenue stability:** The approach provides the IESO with a predictable monthly revenue stream that is independent of seasonal fluctuations in energy consumption.

In contrast, a month-to-month volumetric charge would present several challenges. First, the charge rate (\$/MWh) would need to be determined based on forecast energy consumption, which could result in either over-recovery or under-recovery of the revenue requirement. Second, monthly consumption can vary significantly across seasons (e.g., between summer and winter), potentially requiring adjustments to the charge rate to maintain stable monthly revenues. Such adjustments would not necessarily be accurate and increase administrative complexity.

Under the proposed approach, the initial allocation of the revenue requirement would be based on forecast energy consumption (MWh) provided to IESO Nova Scotia by the LSEs. Alternatively, the fixed charge could be allocated based on forecast (non-)coincident peak demand; however, we do not recommend that approach as it would introduce additional forecasting complexity without providing a clear advantage.

True-up and adjustments: The proposed billing determinant would allow the IESO to charge its entire revenue requirement without the risk of over- or under-collecting its forecast revenue needs, because it is a fixed charge and is not directly tied to energy volumes. This charge would only need a budget variation true-up, which would account for over- or under-forecast of the IESO's budget.

²⁹ Note that in theory this billing determinant can also be introduced under Option 1.a.

³⁰ Note that in implementation, the most straightforward source of forecast load could be the prior year's actuals (potentially corrected for new entry or exit in during the prior year).

³¹ Such that the sum across each monthly invoice is equal to one-twelfth the annual revenue requirement.

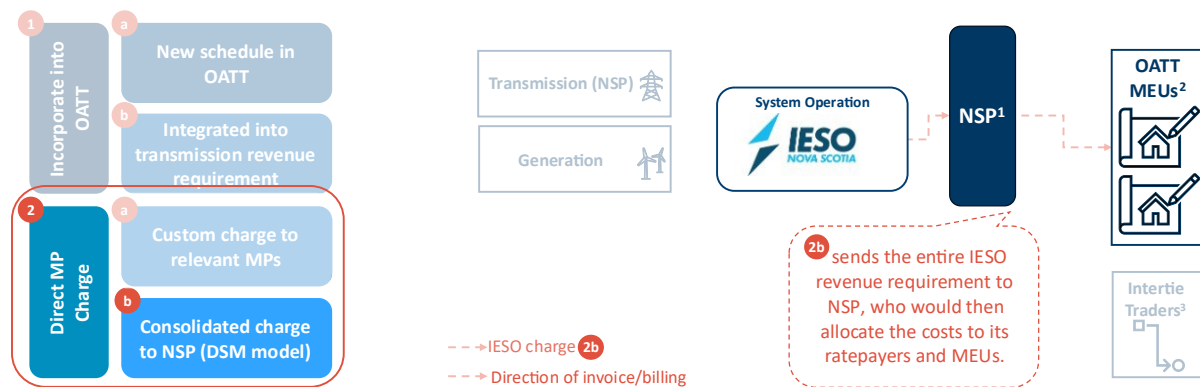
³² See Figure 1 of NSP's 2025 10-Year System Outlook showing the change in 10-year forecasts compared to the prior year's report: forecast demand for 2034 drops from ~11,700 GWh to ~11,200 GWh.

Further, while the design of the billing determinant ensures the charges recovered equal the IESO revenue requirement, there can be an over-or under-charging of the relevant MPs. This would be the case when an MP's metered percentage share of total system usage (MWh) differs from its forecast percentage share. In that case, the MP would either pay or receive an allocation adjustment to or from the IESO. The IESO would be revenue neutral of these allocation adjustments, as they would net out under a "zero sum" reconciliation process.

2.b. Consolidated Direct Charge

MPs: A charge outside of the OATT that follows the existing framework established by EfficiencyOne³³ would instead have a simpler billing structure than Option 2.a. The entire IESO revenue requirement is billed to NSP, who then allocates these costs to the relevant MPs. Historically, MEUs have been the only MP to which NSP allocates DSM costs.³⁴ This process is illustrated in Figure 9.

Figure 9: Consolidated Direct Charge overview



Source: FTI Analysis.

Notes: (1) Non-OATT MEUs are included in NSP's ratepayer base; (2) Only two (of four as of June 2026) OATT MEUs shown for illustrative purposes; and (3) There is no precedent for charging intertie traders following the EfficiencyOne model, as DSM costs are in-province.

Billing determinants: The entire revenue requirement would be charged to NSP as a fixed charge (as opposed to a MW or MWh charge). However, this option requires further decisions about how NSP would allocate the charge among other relevant MPs.

True-up and adjustments: This charge would only need a budget variation true-up, which would account for over- or under-forecast of the IESO's budget.

³³ EfficiencyOne is an independent, federally-incorporated, non-profit organisation that holds the exclusive franchise for energy efficiency and conservation services in Nova Scotia, whose costs are recovered through charges billed to NSP.

³⁴ However, RtR suppliers will additionally be charged DSM fees when operational. As stated in the 2022 GRA Decision, "For customers taking service in the Wholesale or Renewable to Retail markets, recovery of DSM costs will be through direct billing by NS Power to such customers." See Decision in 2023 NSUARB 12, Matter No. M10431, pg. 30 ([link](#)).

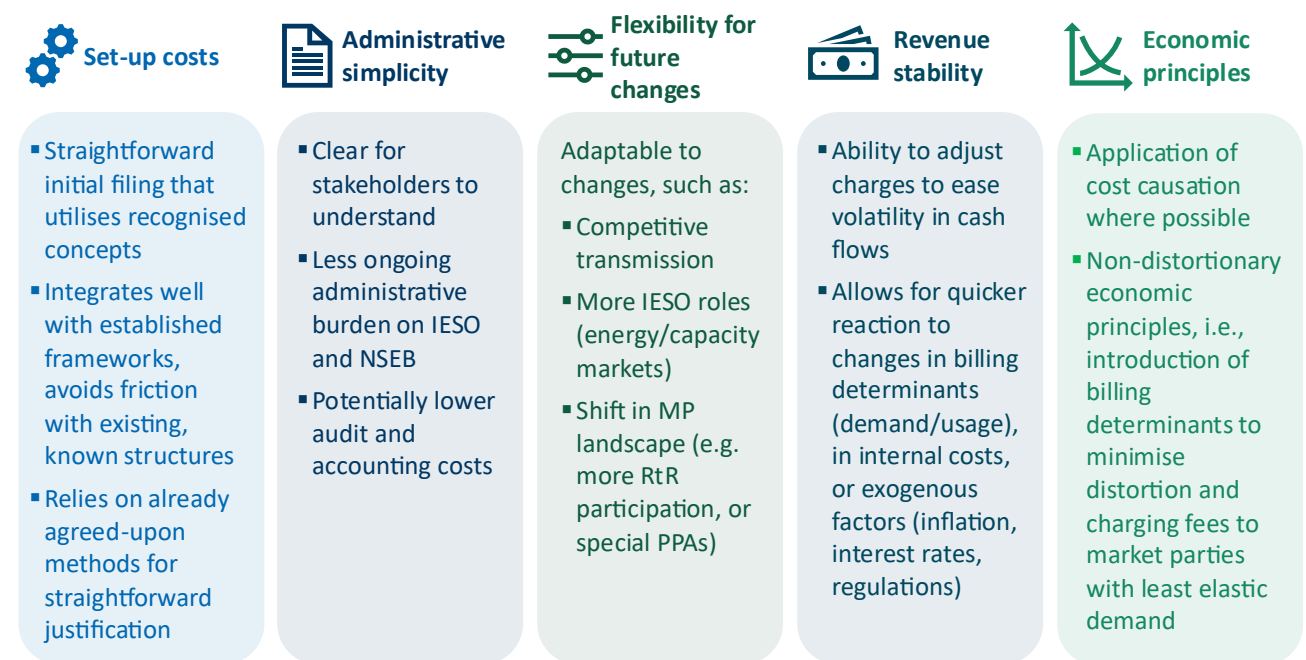
4. FTI's recommendation – Direct Charge to each MP

FTI performed a qualitative review of the four key options under consideration as described in the previous section. Based on five criteria explained below, we believe Option 2.a., a custom Direct Charge to each MP, is the most suitable option for the IESO. This review evaluated the exact design choices described in Section 3 above, such as the specific fixed charge approach for Option 2.a..

Ranking considerations

FTI developed five criteria to illustrate the key concerns of the IESO. This is not a comprehensive list of all potential concerns of the IESO, but provides a high-level suite of considerations. The factors here are not necessarily of equal weight – and there are inherent trade-offs between certain categories, especially relating to flexibility, accuracy, and simplicity. Each of the five considerations is described in Figure 10. These serve as a description of factors which were considered in our recommendation.

Figure 10: Overview of evaluation criteria for recovery mechanisms



Source: FTI Analysis.

Note: PPA = Power Purchase Agreement, RtR = Renewable to Retail.

Ranking

Ranking of each of the four options based on the five criteria indicates that a custom Direct Charge to MPs would most effectively recover IESO fees from users of the system, as shown in Figure 11.

Figure 11: Ranking of recovery mechanisms against established criteria

		 Set-up costs	 Administrative simplicity	 Flexibility for future changes	 Revenue stability	 Economic principles
1	Incorporate into OATT	 OATT ownership				
		a New schedule in OATT	NSP Changes established framework	Additional schedule(s) to administer	Tied to existing OATT framework and cadence	Update cadence tied to OATT framework
	Integrated into transmission revenue requirement	IESO Changes established framework	Additional schedule(s) to administer	Tied to existing OATT framework and cadence	Update cadence tied to OATT framework	Amount too small to distort
		b	Coordination costs to file, but allocation pre-determined	Tied to existing OATT framework and cadence	Update cadence tied to OATT framework	Amount too small to distort
2	Direct MP Charge	a Custom Direct Charge to relevant MPs	Assumed low set-up costs (simple, yet new, design)	Simple process due to only few parties billed	Full flexibility to update recovery timing and method	Fully flexible
		b Consolidated charge to (DSM model)	Existing DSM structure to act as roadmap	Coordination costs	Full flexibility to update recovery timing and method	Fully flexible

Source: FTI Analysis.

Further detail on this ranking is provided in Appendix 3. The high-level rationale for the criteria is described below:

- **Set-up costs:** Options 1.a. and 1.b. present potentially high set-up costs to establish the mechanism, as they would either require extensive collaboration with NSP when NSP owns the OATT or require rework of the already established OATT. The custom Direct Charge to MPs, however, should be straightforward to set up given the simple design. A fixed charge directly, and only to NSP (Option 2.b.), could be equally simple to set up depending on the degree of collaboration needed from NSP.
- **Administrative simplicity:** An OATT-based charge (Options 1.a. and 1.b.) would be moderately simple going forward as it would conform to an existing process but would still require collaboration with NSP while NSP still owns the OATT. The simple design of Option 2.a., however, should facilitate straightforward annual filings outside of the more-complex OATT proceedings. A fixed charge directly, and only to NSP, in Option 2.b. could lead to ongoing administrative coordination with NSP each year during the filing and cost allocation process.
- **Flexibility for future changes:** OATT-based charges (Options 1.a. and 1.b.) could take an extended period of time for changes to flow through into rates, and would be subject to the timing of OATT proceedings. A custom Direct Charge to MPs under Option 2.a., however, leaves the ability to adjust the framework if needed to accommodate changes in the Nova Scotia electricity sector. For example, a sudden change in MP makeup due to load migration, defection, or uptake in RtR participation could be resolved within a year with the use of the allocation adjustment. A consolidated charge fully invoiced to NSP (Option 2.b.) could potentially become more challenging in a future state with measurably large changes in the number and size of MPs if there is uncertainty regarding allocation methods.

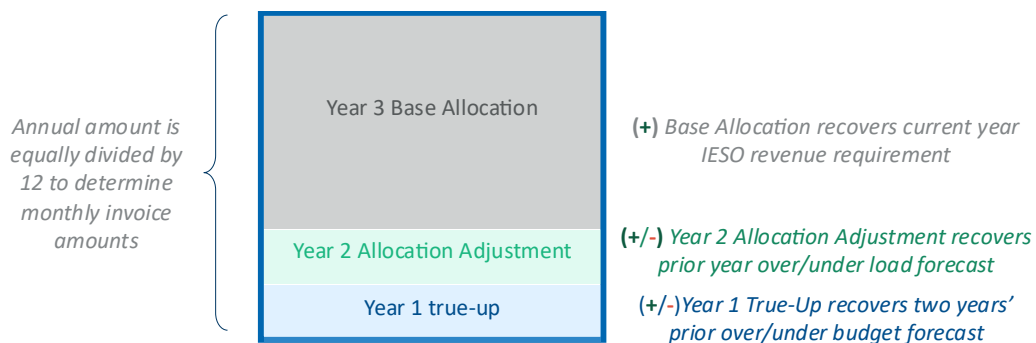
- **Revenue stability:** OATT-based charges (Options 1.a. and 1.b.), as the OATT is currently approved, are tied to actual system conditions (peak MW-month) and may vary by month. This exposes the IESO to under- or over-recovery. A fixed charge (Options 2.a. and 2.b.), however, provides significant revenue stability by ensuring the IESO receives its exact forecast revenue requirement in predictable monthly payments. A Direct Charge to relevant MPs allows for more flexibility to make as-needed adjustments if necessary to match variance in the IESO's revenue needs.
- **Economic principles:** There is no clear beneficiary of inseparable ISO Core Costs, rather, it is a system-wide cost, hence designing a cost-reflective charge is not possible. Instead, the key economic principle to follow in the charge design is to limit distortions, i.e., the way that the charge is levied should minimise the impact on consumption/production/trading behaviour as they do not impact the magnitude of the total revenue requirement (i.e., such behavioural changes to avoid paying the charge would merely lead to cost shifting among MPs without any economic gain). Because the revenue requirement is relatively small per unit when spread over a large usage base, distortions are unlikely to arise from the charge design, particularly when charges are levied primarily on load and most load is relatively inelastic. Overall, a fixed charge can be expected to balance practicality by allocating costs according to forecast usage while minimising behavioural distortions.

Appendix 1: Detailed example of Direct Charge to each MP (Option 2.a.)

To provide more detail and explanation on how the monthly charges for a Direct Charge to MPs would work, the figures below provide additional illustration of the recommended charge design. Because the design includes allocation adjustments and true-ups that may take up to two years to go into effect, throughout this section, we focus on Year 3 as the example year to explain the proposed mechanism.

Ultimately, the monthly charge to MPs will be composed of three parts: a base allocation for that year's revenue requirement, an allocation adjustment for the difference between forecast and actual load share for that MP, and a true-up for the difference between the forecast and actual IESO revenue requirement. This is illustrated in Figure 12.

Figure 12: Illustrative Year 3 monthly charge for an MP



Source: FTI Analysis.

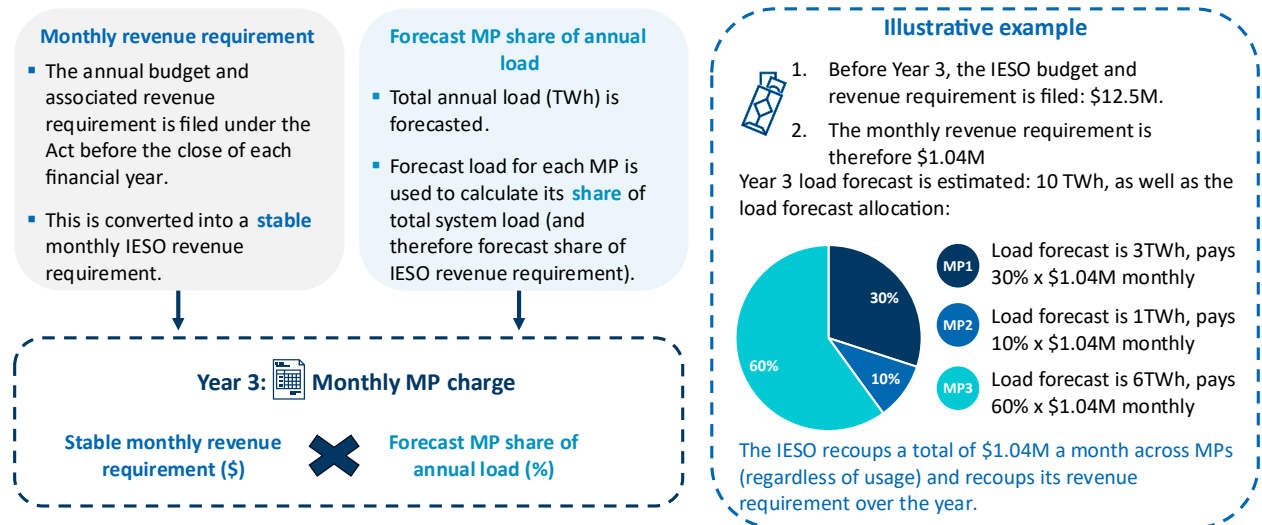
Notes: Base allocation will always be positive, while allocation adjustment and true-up components can be negative if the IESO over-forecasts the MP load share or the IESO revenue requirement, respectively.

The total monthly revenues collected by the IESO will be based on two parts: the sum of base allocations and the sum of true-up amounts; the sum of allocation adjustments will net out to zero because they resolve allocation among MPs.

Base allocation design

The base allocation to recover the IESO's revenue requirement for the current year will be derived from two key inputs: the IESO's forecast budget for the year, and the forecast load of each MP. This is further illustrated in Figure 13 below, which illustrates Year 3 to continue our example from previous figures.

Figure 13: Base allocation process



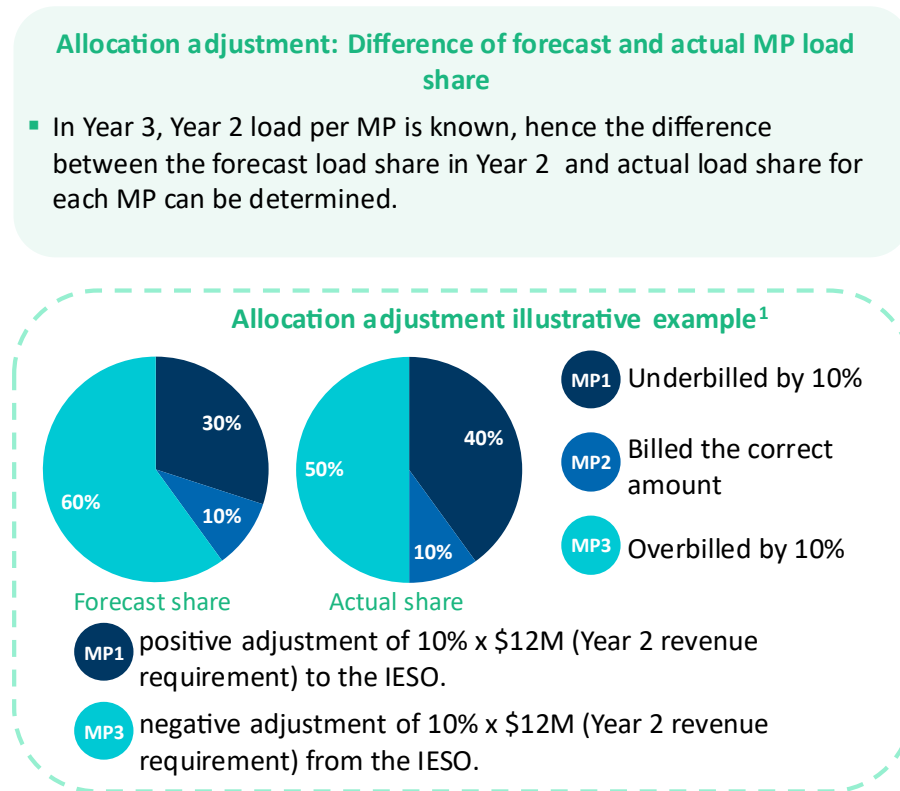
Source: FTI Analysis.

Each MP is charged the same amount each month, therefore the IESO collects the same monthly revenue.

Allocation adjustment design

The allocation adjustment will resolve any over/under-forecast of MP load share. This provides a similar allocation to a usage-based charge, but without the risk of the IESO over/under-recovering due to unexpectedly high or low system usage. As shown in Figure 14 below, if an MP's relative share of energy consumption is higher than forecast, its charge due to the IESO will increase with a positive adjustment over the course of the following year. If an MP's relative share of energy consumption is lower than forecast, it will receive a negative adjustment (in the form of a reduction in billed amount) from the IESO over the course of the following year.

Figure 14: Allocation adjustment example



Source: FTI Analysis.

Notes: (1) MPs exiting during the year could cause revenue instability for the IESO and could be remedied by: a) a collateral requirement, or b) an in-year adjustment of the monthly fixed charges charged to the remaining MPs. MPs entering during the year would lead to a potentially inflated ISO charge for the other MPs, this would be resolved via the allocation adjustment.

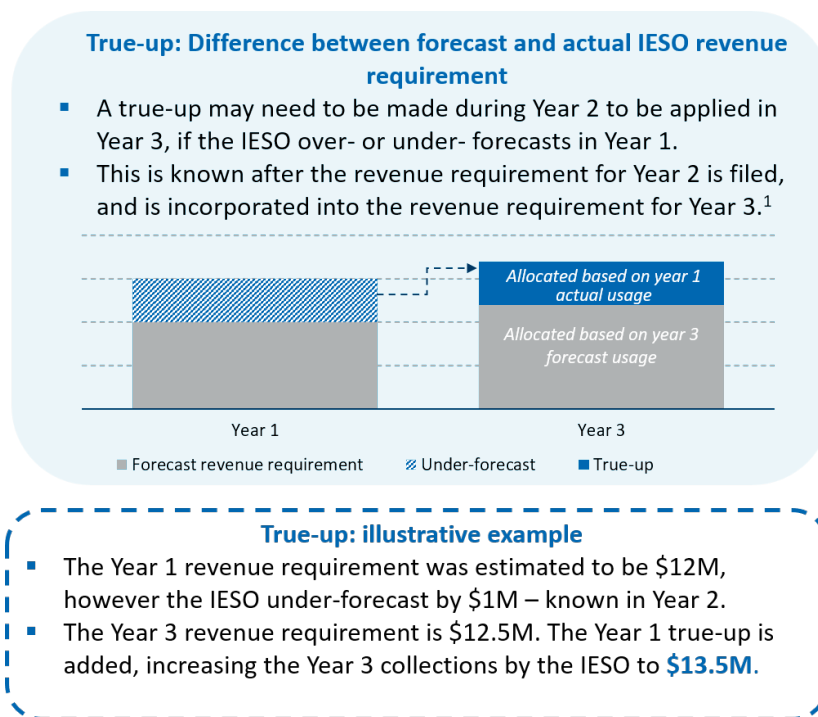
As described in Figure 14 above, each month, MP1 will pay the IESO an additional \$0.10M per month³⁵ on top of the base allocation component of its bill. MP3, however, will have \$0.10M reduced from its charge each month to account for its relative overpayment in the prior year. Across all MPs, the sum of allocation adjustments will sum to zero as they are reconciling charges among MPs.

True-up design

The true-up will resolve any over/under-forecast of IESO revenue requirement. As shown in Figure 15 below, if the IESO's revenue needs are higher than forecast when setting the charge, it will increase the total amount to be collected in a future year because the IESO would not have collected enough revenues to cover its costs (subject to prudence review as established by the NSEB) in that year. If the IESO's revenue needs are lower than forecast, then it will decrease the total amount to be collected in a future year because it would have collected revenues above its approved costs.

³⁵ $(10\% \times \$12M) / 12 = \$0.10M$ per month.

Figure 15: True-up example



Source: FTI Analysis.

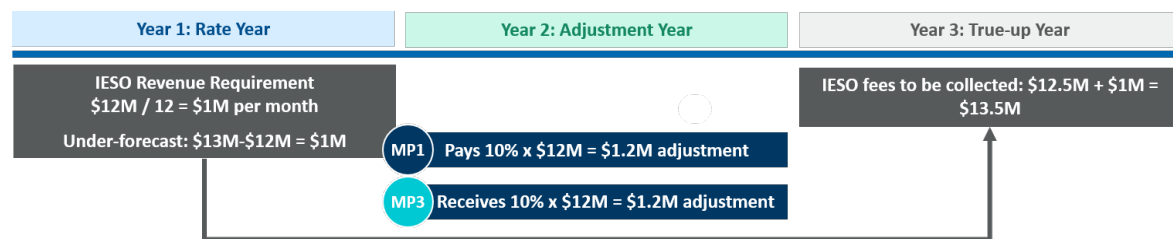
Notes: (1) Year 2 is not shown as it is not relevant to the Year 1 true-up.

The true-up amount charged to each MP will be relative to its actual load share for the year being true-up (as in Year 3 the actual load share in Year 1 will be known). In our example, this means that a true-up for the Year 1 revenue requirement will be allocated based on the actual Year 1 load share (as noted in Figure 15 above).

Allocation adjustment and true-up working in tandem – IESO perspective

Both allocation adjustment and true-up will be recovered in future years, however, they will be collected during different periods. The reason for this difference in collection is due to the timing of data collection and accounting. System and MP-level load is collected and published regularly and should be available soon after the close of the year. In contrast, financial accounting, relevant for the true-up, often takes several months to complete and will not be available until far into the following year (Year 2 in our example). As shown in Figure 16, the allocation adjustment is reconciled in Year 2, while the true-up values are not applied until Year 3.

Figure 16: Allocation adjustment and true-up implementation over time



Source: FTI Analysis.

The amount to be collected by the IESO in Year 3 shown in Figure 16 above is composed of the Year 3 revenue requirement, and the Year 1 true-up. This is similar to the amounts shown in Figure 15 above. The Year 2 allocation adjustments purposefully summed to zero at the IESO-level, effectively reconciling under/over-payment by MPs relative to each other.

Allocation adjustment and true-up working in tandem – MP perspective

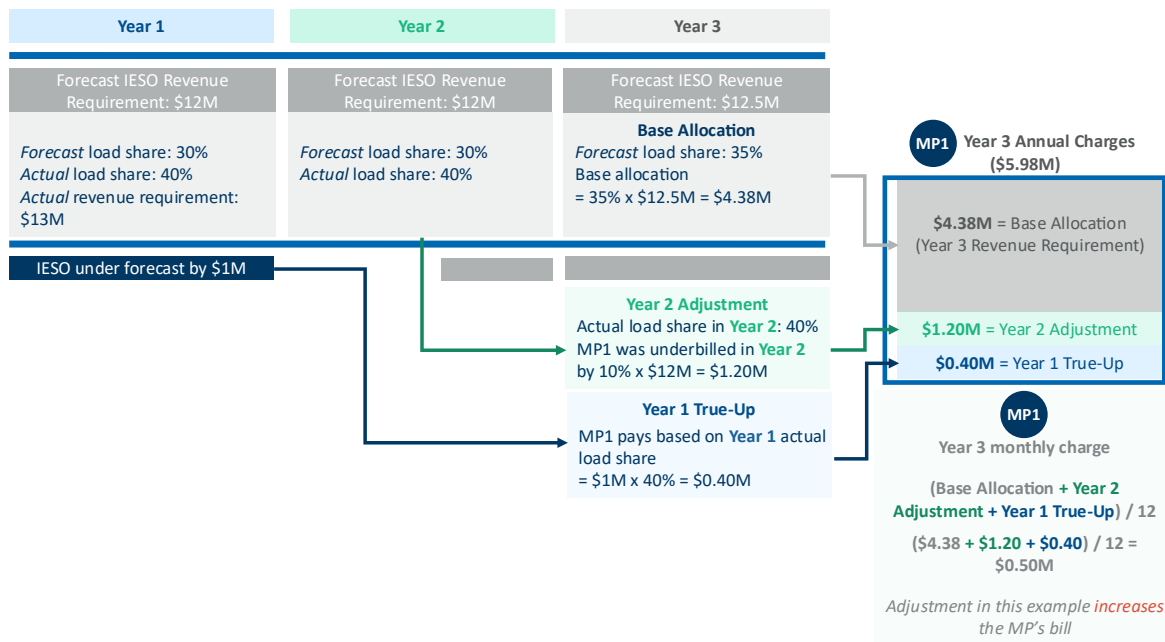
From an individual MP perspective, its bill in a given year is made up of three components: its share of that year's IESO revenue requirement, its adjustment for the prior year's load forecast share, and its share of the two years' prior revenue requirement.

Below are two examples of how an individual MP's bill could be calculated. In the examples, we focus on the charges paid by the MPs in Year 3. We assume the forecast revenue requirement in Year 2 to be \$12M, and the forecast revenue requirement for Year 3 to be \$12.5M. We also assume that the revenue requirement for Year 1 was under-forecast by \$1M, i.e., a true-up of \$1M is added to the total IESO fees in Year 3.

Actual load above forecast (undercharged)

Figure 17 below illustrates an example Year 3 charge for MP1. MP1 was undercharged in Year 2 because its forecast load share was lower than its actual load, so its monthly bill is higher than the sum of the current year's base allocation and the two years' prior true-up.

Figure 17: MP1 example charge for Year 3

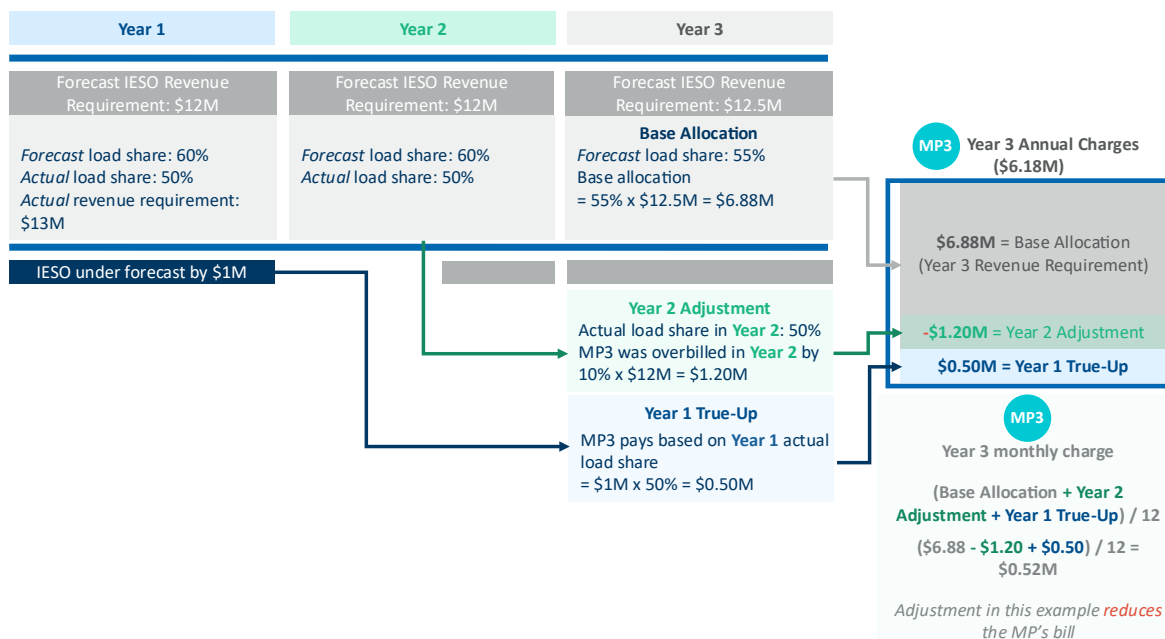


Source: FTI Analysis.

Actual load below forecast (overcharged)

Figure 18 below illustrates an example Year 3 charge for MP3. MP3 was overcharged in Year 2 because its forecast load was higher than its actual load, relative to other MPs, so its monthly bill is lower than the sum of the current year's base allocation and the two years' prior true-up.

Figure 18: MP3 example charge for Year 3



Source: FTI Analysis.

Appendix 2: Background to the Jurisdictional Scan

IESO NS engaged FTI to conduct an international benchmarking exercise on ISO approaches to cost recovery.³⁶ This scan has provided background and understanding of how other ISOs recover their fees. Overall, we found that the determination of charges to recover the cost to run an ISO varies by jurisdiction, but has similar, underlying fundamentals.

While a primary, underlying purpose of an ISO is to independently operate the bulk electricity system as a non-profit entity, the roles and responsibilities of an ISO are not rigidly defined, and the range of functions an ISO typically executes varies (and can vary over time).

No existing ISO is entirely comparable with IESO NS in its current form; however, several ISOs share certain characteristics. We reviewed the following ISOs in our Jurisdictional Scan, which were chosen to represent a variety of relevant peers:

- **Canadian ISOs:** Alberta Electric System Operator (“AESO”) and the Ontario Independent Electricity System Operator (“IESO Ontario”);
- **US ISOs:** ISO-New England (“ISO-NE”) and the California ISO (“CAISO”); and
- **ISOs outside of North America:** National Energy System Operator (“NESCO”) in Great Britain (“GB”) and AEMO.

As shown in Figure 19, we have considered four characteristics of IESO NS (utility structure, jurisdictional footprint, age, and resource mix of the jurisdiction) and, for each characteristic, mapped a selection of ISO(s) that share it.

Figure 19: Overview of the characteristics of IESO NS shared by the benchmarking group

CHARACTERISTIC	STRUCTURE	JURISDICTION	AGE	RESOURCE MIX
	Large Incumbent(s)	Single Province within a Nation	Newly Restructured	High Renewables ¹
	  	  		 

Source: FTI Analysis, logos from ISO websites.

Note: (1) High renewables criteria based on Nova Scotia’s goal for 80% clean electricity by 2030 as described in the Clean Power Plan ([link](#)).

³⁶ FTI Consulting LLP, *ISO Cost Recovery Mechanism: Jurisdictional Scan*, prepared for the Nova Scotia Independent Energy System Operator (IESO NS), 5 May 2026.

The Jurisdictional Scan concluded that most ISOs in the benchmarking group charge an ISO-only charge primarily to load-serving MPs (LSEs and intertie traders). Charges to generation tend to be smaller or less frequent, and only in bid-based markets where generators can adjust bids to reflect increases in costs (i.e., ISO fees). The billing determinants are often energy consumption (MWh), although some (especially ISO-NE) charge based on peak usage.

Table 1: Number of Core Costs charges by ISO and format by market participant

ISO	Number of charges ¹	Load (LSE and Tx-connected load) ²	Generation	Intertie traders	Charge type
General	Varies	Energy consumption (sometimes includes fixed fees)	Per unit or load obligation basis	Energy or capacity basis	ISO-only
ISO-NE	3	MW	Per-unit fee	MW	ISO-only
CAISO	2	MWh	MWh	MWh	ISO-only
IESO Ontario	2	MWh	N/A	MWh	ISO-only
AESO ³	2	MW/MWh	MWh (market operation)	MWh/per-transaction	Integrated
NESO ⁴	2	MWh	N/A	N/A	Integrated
AEMO ⁵	3	MWh/per-unit fee	MWh/MW	N/A	ISO-only

Note: (1) The number of charges refers to the number of separate tariffs used to recover costs applicable to IESO Nova Scotia – there are always at least two as at least one will recover direct costs and at least one will recover inseparable costs; (2) In some grids, such as ISO-NE, transmission-connected (“Tx-connected”) load is formally served by an LSE and therefore ISO Core Costs are recovered through the same retail rate process as used for distribution-level customers; (3) The AESO also has specific service charges, charged on a per service basis and do not vary by market participant/TO; (4) NESO’s charge is integrated into a system balancing charge that recovers both ISO Core Costs and the ISO’s external costs for balancing services; (5) The AEMO is unusual in that it charges TOs based on metered outflow (MWh); because no other grid charges TOs for Core Costs, TOs are not listed in this table.³⁷

³⁷ A 2022 determination by the Australian Energy Regulator (“AER”) concluded that “Transmission Network Service Providers (“TNSPs”) will be subject to incentive-based regulation over AEMO’s participant fees (excluding network transmission planner function fees), so TNSPs will have an incentive to assist AEMO to minimise AEMO’s costs that eventually flow through to consumers.” See Australian Energy Market Commission, Rule Determination ERC0335, 20 October 2022 ([link](#)).

Appendix 3: Ranking criteria detail

This appendix presents the relative merits of each approach based on the proposed criteria.

Set-up costs

The set-up costs are the initial implementation costs associated with establishing the new recovery mechanism under each framework. The criterion is defined according to i) whether the initial filing process is straightforward and uses recognised concepts; ii) the mechanism integrates well with established frameworks and avoids friction with existing and known structures; iii) the mechanism relies on already agreed-upon methods for allowing for a straightforward justification.

Set-up costs to establish the recovery mechanism, especially if not fully permanent, are important to bear in mind as a lengthy filing process could cost additional staffing resources.

Figure 20: Set-up costs ratings by recovery mechanism

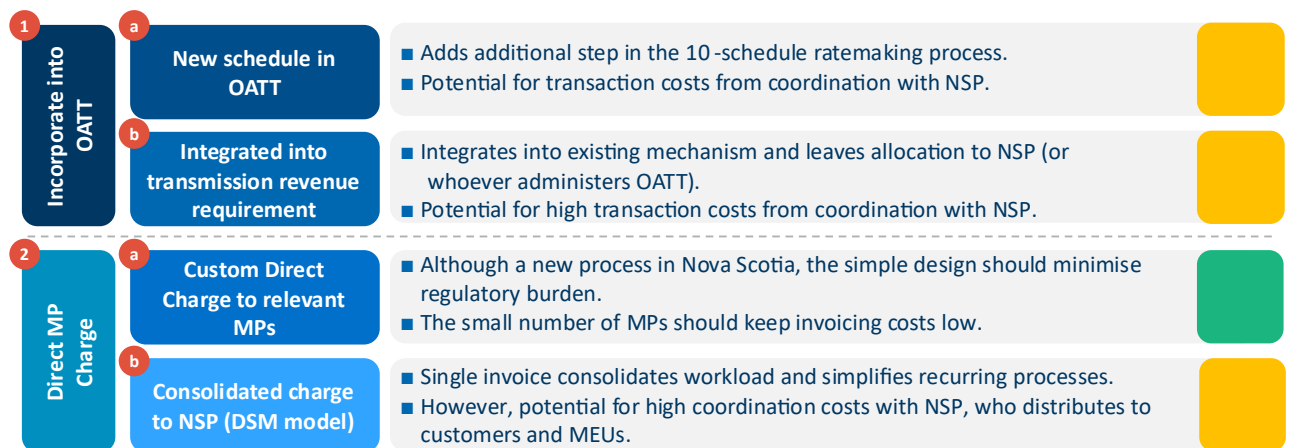
1	Incorporate into OATT	a	New schedule in OATT	■ Changes scope of the OATT by including Phase 1 IESO roles.	NSP owns OATT
		b	Integrated into transmission revenue requirement	■ Requires addition to definition of certain schedules. For example, adding IESO costs to Schedule 1 and keeping control centre assets in Schedules 8 & 10. However, it may be difficult if NSP maintains the OATT.	IESO owns OATT
2	Direct MP Charge	a	Custom Direct Charge to relevant MPs	■ A straightforward design would have a streamlined regulatory process. ■ Limited coordination costs in the setup with other entities such as NSP.	NSP owns OATT
		b	Consolidated charge to NSP (DSM model)	■ Uses existing DSM cost recovery framework as a roadmap, integrating IESO - specific requirements where necessary (such as cadence of filings).	IESO owns OATT

Administrative simplicity

The administrative simplicity criterion reflects i) the ease with which the new recovery mechanism can be integrated into existing operations; ii) the limited administrative burden on the IESO and NSEB; and iii) the potential reduction in audit costs resulting from the implementation of the mechanism.

The ease of recurring filings is a primary concern as time spent in front of the regulator could become a costly process.

Figure 21: Administrative simplicity ratings by recovery mechanism

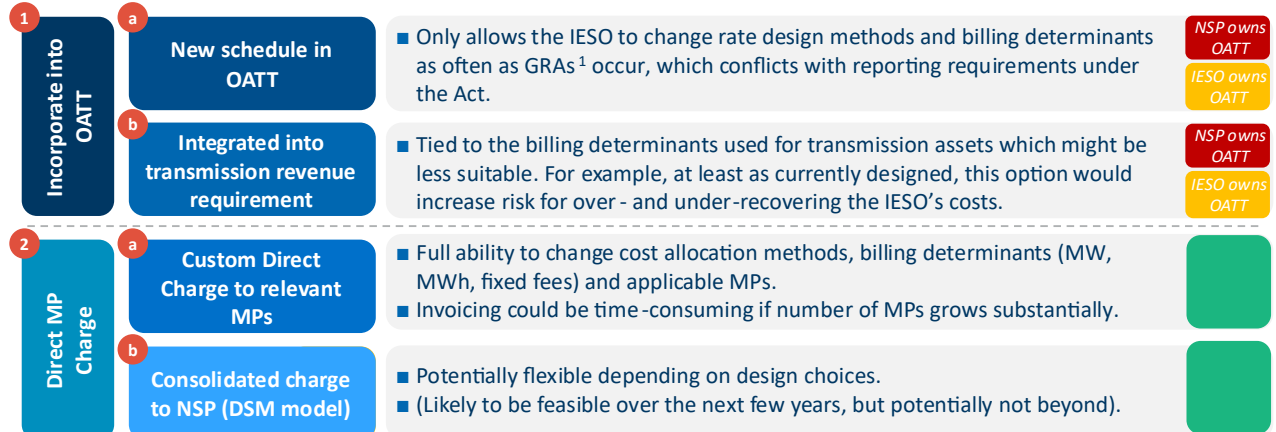


Flexibility for future changes

The flexibility for future changes criterion illustrates how the recovery mechanism is adaptable to changes such as i) an increase in transmission service competition; ii) an increasing IESO role (future energy and capacity markets); and iii) shifts in the MP landscape (greater RtR participation, emergence of special power purchase agreements (“PPAs”)).

Flexibility for future changes is important to bear in mind, considering potential changes in future fee requirements if the IESO’s role evolves over time.

Figure 22: Flexibility for future changes ratings by recovery mechanism



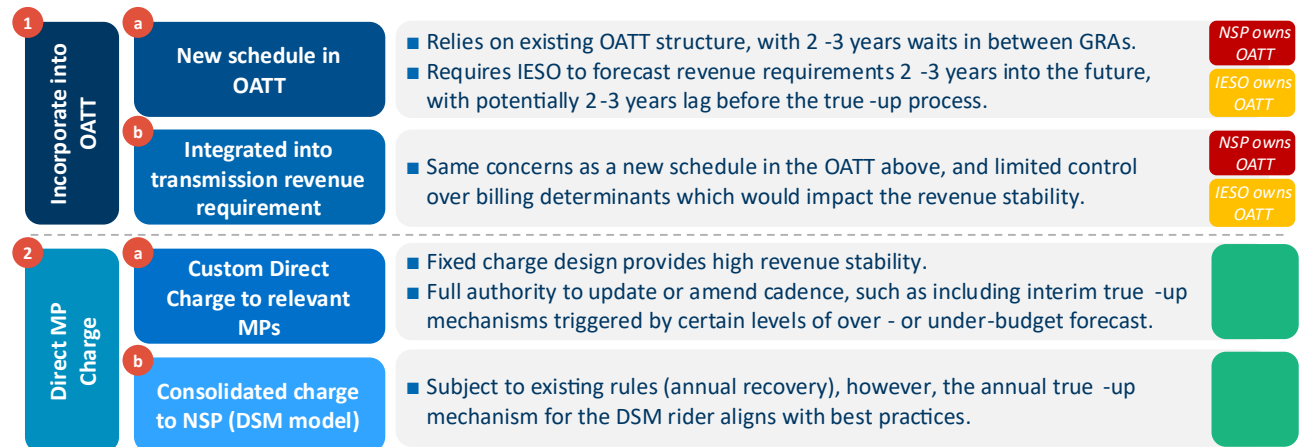
Note: (1) GRA = General Rate Application

Revenue stability

The revenue stability criterion shows i) how the recovery mechanism can adjust charges to reduce cash flow variability, and ii) whether it enables a quicker response to changes in billing determinants (demand/usage), internal costs, and exogenous factors (inflation, interest rates, regulatory changes etc.).

Revenue stability is an additional feature to consider for the cost recovery mechanism, as the IESO may want to ensure it can meet upcoming cash flow needs for potentially large investments.

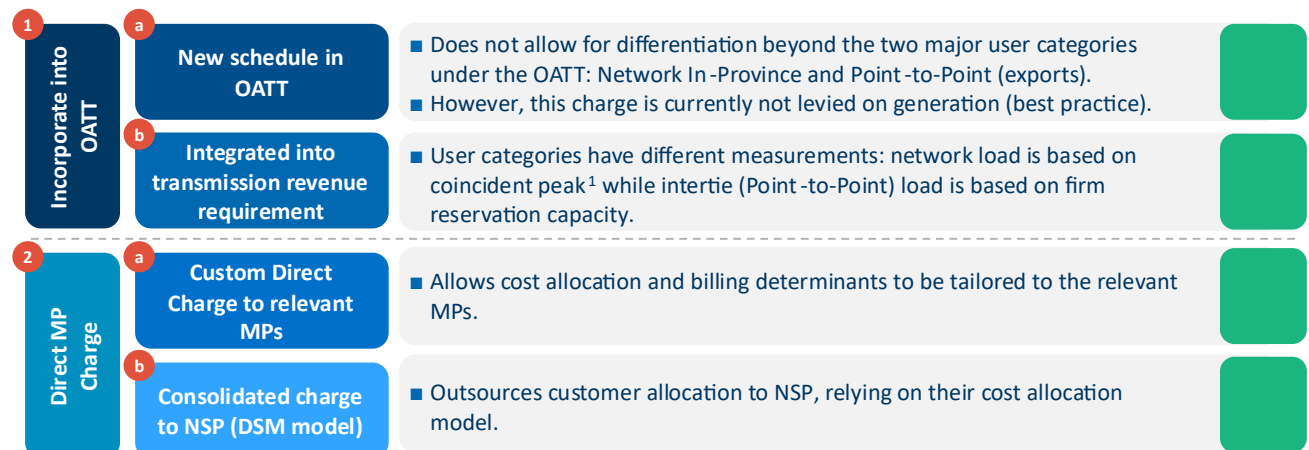
Figure 23: Revenue stability ratings by recovery mechanism



Economic principles

The economic principles criterion assesses i) the extent to which the recovery mechanism applies cost causation effectively, and ii) whether it encompasses non-distortionary economic principles, such as the introduction of billing determinants to minimise distortion and charging market participants with the least elastic demand.

The economic principles dictate that charges should avoid being levied on MPs that will change behaviour to avoid the charge, and align desired incentives (non-distortionary). We assess this criterion to be positive ('green') for all options due to the limited magnitude of the IESO fee relative to charges for the other components of the electricity system, particularly generation and transmission.



Note: (1) NSP continues to use and refine Statistically Adjusted End-Use ("SAE") models to forecast load for the residential and commercial rate classes. End-use energy forecasts derived from the residential and commercial SAE models are combined with an econometric and customer-specific forecasts for NSP's large customers to develop an energy forecast for the province, also referred to as the Net System Requirement ("NSR"). See 2026-2027 GRA SR-02 Attachment 1 Page 52 of 175.

