Incentives for Electricity Distributors Using Third-Party Distributed Energy Resources as Non-Wires Alternatives: Margin on Payments

Consultant Report on Options for Alternative Margin on Payments Incentive Mechanisms

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Table of Contents

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Executive Summary

Early in 2025, Guidehouse Canada Ltd. ("Guidehouse") was engaged by the Ontario Energy Board (OEB) to develop quantitative criteria to clarify for electricity distributors ("distributors") the OEB's expectations for distributor proposals to retain Margin on Payment (MoP) incentives for using third-party distributed energy resources (DERs) as non-wires solutions (NWS). These criteria could be implemented by the OEB through a variety of instruments, including as a code amendment. This Consultant Report is the output of that engagement.

Introduction & Context

The MoP incentive mechanism is one of three incentive mechanisms available to distributors using third-party DERs[1] as NWS. Under this mechanism the incentive is collected by the distributor through the application of a margin on payments to third-party DER providers providing an NWS.

The OEB's goal in providing incentives to distributors is to "*evolve the current rate-setting framework to facilitate near-term progress on the use of third-party owned DERs as non-wires alternatives*" [2] Incentives are intended to assist in "leveling the playing field" such that distributors give equal consideration to NWS and traditional infrastructure solutions in meeting system needs as cost-effectively as possible.

The Filing Guidelines for this incentive mechanism are concise and provide distributors with a significant amount of flexibility. No guidance, however, is provided regarding quantitative criteria against which proposals may be evaluated, nor is a margin value specified.

To provide greater clarity regarding the incentive distributors may be eligible to receive, the Guidehouse team has proposed a single margin value and three options that combine different sets of eligibility criteria for the OEB to consider implementing. Guidehouse expects that the OEB will select one of these options, or one of its own design, for implementation through a proposed code amendment or some other mechanism.

These options and the eligibility criteria that define them have been developed to balance four Design Principles based on the OEB's legislated objectives, the Framework for Energy Innovation (FEI) consultation's Guiding Principles[3], and accepted principles of public utility regulation. The four Design Principles are: Protect the Public (Customer Value), Drive Innovation, Set Rewards to Rollow Risk, and Simplicity and Clarity.

Margin Value and Eligibility Criteria

The Guidehouse team developed its proposed margin value and its proposed eligibility criteria using the Design Principles referenced above and the findings of its jurisdictional scan, which examined NWS incentive mechanisms in seven jurisdictions. Three of the jurisdictions reviewed by Guidehouse have used a margin on payments-style incentive mechanism: California, Michigan, and Australia.

[1] "Third-party DERs" are DERs not owned by the distributor implementing the NWS. DERs owned by the distributor implementing the NWS are not eligible for an incentive.

[2] The "Filing Guidelines":

Ontario Energy Board, ***Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives***, March 2023

[3] Ontario Energy Board*,* ***Framework for Energy Innovation: Setting a Path Forward for DER Integration*****,** January 2023

California, Michigan, and Australia each allow (or have allowed) utilities to collect an incentive that is 4%, up to 15%, and 50%, respectively, of non-capital project costs. No projects were realized under the California incentive. The Michigan mechanism is tied to the utility's achievement of its regulated demand response (DR) target and does not include any explicit eligibility criteria to protect customer value. The Australian mechanism requires that the incentive must be less than the net benefit (per the cost-effectiveness assessment) of the project and that total annual incentives cannot exceed 1% of allowable revenue per year.

Eligibility Criteria

The three eligibility criteria, which may be employed in different combinations to prioritize the Design Principles in different ways, are:

- **Customer Value Criterion.**

  An incentive proposal is eligible only if the total forecast incentive payment does not exceed some share of the forecast net benefits, calculated using either the Distribution Service Test (DST) as defined in the OEB's Benefit Cost Analysis (BCA) Framework[4] or some suitable alternative.[5] The share threshold may be set high or low depending on the prioritization of the Design Principles. The value of this share differs by Option bundle (see below).

  The principles underpinning the Customer Value Criterion are that an NWS will cease to be a cost-effective alternative to infrastructure if the incentive exceeds the project's net benefits (Design Principle 2: Protect the Public – Customer Value), and that the project's net benefits should be shared between the distributor and its customers commensurate with the relative risk to which each party is exposed (Design Principle 3: Set Rewards to Follow Risk).

- **Affordability Criterion.**

  An incentive proposal is eligible only if the annual incentive payment *across all of the distributor's NWS* does not exceed some share of the distributor's approved revenue requirement. In Australia, for example, one of the eligibility criteria for the Demand Management Incentive Scheme (DMIS) is that a distributor's incentives across all projects cannot exceed 1% of its allowed revenue. For Ontario, the share should be set sufficiently high to provide distributors with a financially meaningful incentive to ensure that they give equal consideration to NWS in meeting system needs, but low enough that the incentive does not result in a material increase to customers' bills.

  Guidehouse has proposed a value of 1% for this criterion, using annual distributor revenues in Ontario to demonstrate that this provides a financially meaningful incentive, and using aggregate customer electricity costs to demonstrate that this would not materially increase total customer electricity costs.

- **Innovation Flexibility Criterion.** An incentive proposal that fails other eligibility criteria may still be approved if it delivers significant value not recognized by the other criteria,

[4] The "BCA Framework":
Ontario Energy Board, ***Benefit-Cost Analysis Framework for Addressing Electricity System Needs***, May 2024

[5] Under the BCA Framework, distributors may use some alternative method to the DST for demonstrating the cost-effectiveness of the NWS where the baseline (i.e.,. the traditional infrastructure) investment is less than $2 million. In the absence of a DST for smaller projects the Customer Value Criterion percentage value should be applied to the net benefits estimated to accrue to customers using the alternative approach.

such as building distributor capabilities to deliver customer savings in future, more routine, NWS implementations.

Margin Value

Based on the margin values used in other jurisdictions, the apparent impacts these have had on NWS implementation, and in consideration of the Design Principles, Guidehouse recommends that the OEB use a margin value higher than the 15% value used in Michigan, and less than the 50% value used in Australia. Guidehouse has proposed that the OEB use a margin value of 25%.

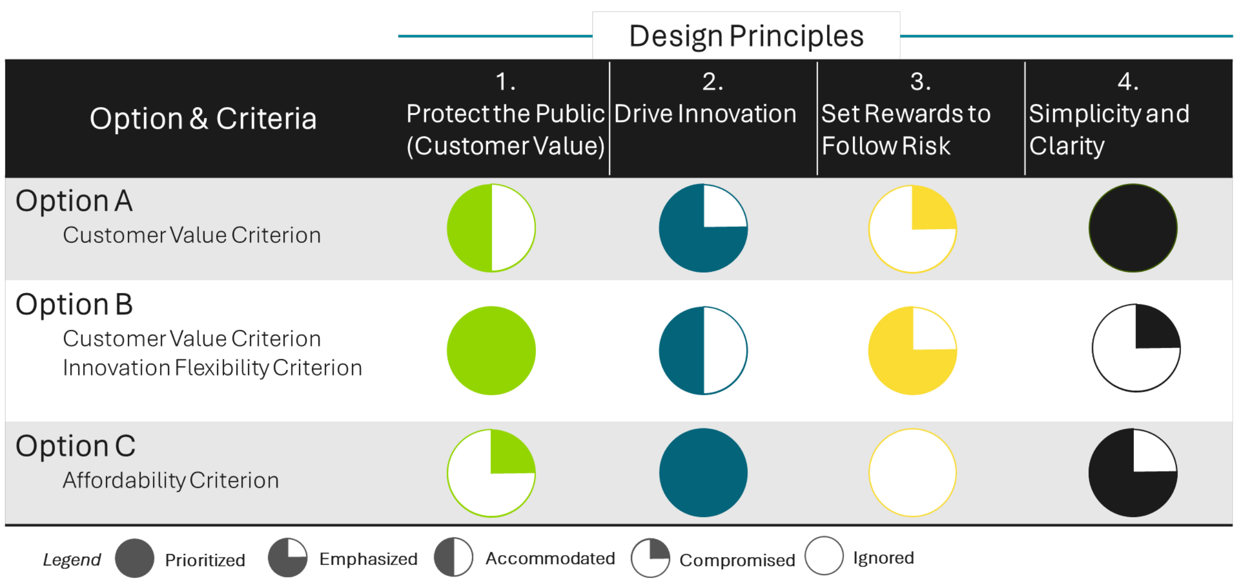
To ensure distributors can plan effectively, all eligible incentive proposals that are approved should use this margin value in implementation. To provide flexibility, however, distributors whose proposals are ineligible at the 25% margin value may, if they choose, propose a lower margin value at which their proposal does meet the relevant eligibility criteria.

Eligibility Criteria Options

Guidehouse has proposed three option bundles, each balancing the priorities of the Design Principles in a different way.

It is this relative prioritization that dictates which eligibility criteria are included in each Option, and what threshold values are applied in those criteria. Figure 1, below provides a visual summary of this prioritization.

Figure 1. Option Prioritization Summary



The three options are:

- **Option A** is subject to the Customer Value Criterion eligibility and requires that the total forecast incentive not exceed 75% of net DST benefits.
- **Option B** is subject to both the Customer Value Criterion (Stage 1) and the Innovation Flexibility Criterion (Stage 2). If, in Stage 1, the total forecast incentive is more than 30% of forecast net DST benefits, the distributor may propose a lower margin value or

proceed to Stage 2. Any NWS with a DST ratio of 1.8 or more will pass Stage 1 (calculation details provided in Section 4.2).

If a proposal proceeds to Stage 2 the distributor must demonstrate that the approval of the NWS and the associated incentive will deliver some significant value not recognized by the Customer Value Criterion in Stage 1.

- **Option C** is subject to the Affordability Criterion eligibility and requires that the total forecast incentive, summed across all of the distributor's NWS, not exceed 1% of that distributor's revenue requirement in any year.

Section 5 of this report provides a discussion of Option sensitivities. This is intended to assist OEB staff or stakeholders to develop adjustments that they may propose to apply to the options to reflect other perspectives, or to create new, alternative options.

1. Introduction

Early in 2025, Guidehouse Canada Ltd. ("Guidehouse") was engaged by the Ontario Energy Board (OEB) to develop quantitative criteria to clarify the OEB's expectations for electricity distributor ("distributor") proposals to retain Margin on Payment (MoP) incentives for using third-party distributed energy resources (DERs) as non-wires solutions (NWS). These criteria could be implemented by the OEB through a variety of instruments, including a code amendment. This Consultant Report is the output of that engagement.

This Consultant Report is divided into five sections:

1. **Introduction.** Summarizes the context for the report, defines its purpose, and lays out some key Design Principles used in Option development.
2. **Incentive Mechanisms in Other Jurisdictions.** Provides a summary of the most relevant aspects of incentive mechanisms used in other jurisdictions to encourage electricity utilities[6] to adopt DERs (including demand response) to defer or avoid infrastructure investment.
3. **Margin Value and Eligibility Criteria.** Defines the key components of the incentive mechanism: the margin value itself, as well as the different eligibility criteria considered for the three options developed in Section 4.
4. **Options for the Margin on Payments Mechanism.** Lays out three possible options that could be applied to the MoP mechanism by the OEB.
5. **Sensitivities and Developing New Options.** Describes key sensitivities that could be considered in adjusting the proposed options or developing new ones.

This report includes three appendices:

- **Appendix A Margin on Payment Examples – By Option.** Provides a worked example eligibility calculation for each of the three options.
- **Appendix B Option B DST Ratio Calculation.** Provides algebraic detail to support a value used in Section 4.2.
- **Appendix C Jurisdictional Scan.** Provides the complete output of Guidehouse's jurisdictional scan, with details of each jurisdiction presented in an "index card" format.

1.1 Context

In March 2023, the Ontario Energy Board (OEB) published its *Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives* ("Filing Guidelines")[7] to help distributors develop incentive proposals and to facilitate regulatory review. The Filing Guidelines provide distributors with significant flexibility to develop their own proposals. To

[6] Ontario's incentive mechanisms apply only to distributors. In other jurisdictions similar incentives may be applied to vertically integrated utilities that do more than just distribute electricity. When discussing other jurisdictions, Guidehouse generally uses the terminology of that jurisdiction. This means that electricity distributors in other jurisdictions may sometimes be referred to by the more generic term: "utility".

[7] The "Filing Guidelines":

Ontario Energy Board, ***Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives***, March 2023 provide additional clarity to distributors on the information that should be included in an incentive proposal the OEB presented a set of example[8] incentive proposals in a webinar.

The Filing Guidelines were one outcome of the OEB's Framework for Energy Innovation (FEI) consultation.

The FEI consultation's summary report[9] ("the FEI Report") also prescribed the development of a Benefit-Cost Analysis (BCA) Framework.[10] The BCA Framework outlines how distributors must assess the economic feasibility of using DERs as NWS to address defined electricity system needs and defines a Distribution Service Test (DST) that distributors are required to use to assess cost-effectiveness. The goal of the DST is to help distributors implement solutions that "*optimize the long-term net distribution service benefits for the electricity distributor's customers, as a group".*

This Consultant Report builds on this body of work and focuses on the Margin on Payments incentive mechanism, one of three incentive mechanisms available to distributors for using third-party DERs as NWS. It is intended to support the OEB in providing additional clarity to distributors on the MoP incentive mechanism.

The three mechanisms available to distributors are:

1. **Shared Savings Mechanism**: The incentive payment is a portion of the savings to customers associated with implementing a third-party DER solution as an NWS.
2. **Performance Target or Scorecard-Based Incentive**: The distributor earns a fixed incentive payment for achieving a single performance target or set of targets.
3. **Margin on Payments**: The incentive payment is calculated as a percentage (margin) of the distributor payments to DERs owned by customer or third parties for providing services to the distribution system as part of an NWS.

1.2 Purpose

The purpose of this Consultant Report is to **recommend eligibility criteria and a margin value for the OEB to consider implementing in order to provide clarity to the sector.** Recommended criteria are bundled into a set of three options, each prioritizing different goals. This report is intended to provide the OEB with the rationale for these options, and the recommended eligibility criteria and margin value.

1.3 Incentive Mechanism Design Principles

To provide a formal framework against which the trade-offs of the proposed options can be considered, Guidehouse collaborated with OEB staff to develop four Design Principles. These

[8] Guidehouse, prepared for the Ontario Energy Board, ***Utility Incentives for Third-Party DERs used as NWSs***, an OEB Webinar, November 2023

Available as "*Examples of Proposals to Use Third-Party DERs (pdf)*" **here**

[9] The "FEI Report":

Ontario Energy Board***, Framework for Energy Innovation: Setting a Path Forward for DER Integration*****,** January 2023

[10] The "BCA Framework":

Ontario Energy Board, ***Benefit-Cost Analysis Framework for Addressing Electricity System Needs***, May 2024

Design Principles draw from the OEB's four legislated objectives[11], the FEI consultation's Guiding Principles, and accepted principles of public utility regulation.

The Design Principles used for assessing the three options presented in this report are:

1. **Protect the Public (Customer Value).** The purpose for requiring distributors to consider NWS in their system planning[12] is to enable positive outcomes for customers, including cost-effectiveness and demonstrable long-term value.
2. **Drive Innovation.** Enabling a "level playing field" between cost-effective innovative NWS and traditional infrastructure solutions provides value to customers. Structural disincentives are a barrier to distributors innovating and pursuing cost-effective NWS. Effective incentive design should mitigate this barrier and encourage distributors to innovate and serve their customers more cost-effectively in the long-term.
3. **Set Rewards to Follow Risk.** Incentives to innovate must be commensurate with the risk and uncertainty faced by the innovator.[13] Distributor incentives to innovate that are not tied to evaluated performance outcomes must be lower than those that are.
4. **Simplicity and Clarity.** Clear quantitative metrics will assist distributors to develop their plans and incentive proposals. The inputs for these metrics must be clearly defined and the metrics themselves simple to calculate.

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[11] "*1. To inform consumers and protect their interests… 2. To promote economic efficiency and cost-effectiveness… 3. To promote electricity conservation and demand management… 4. To facilitate innovation…*"
Ontario Energy Board Act, 1998, S.O. 1998, c.15 Sched B.

[12] Section 2.2. of the BCA Framework

[13] This is a long-standing principle for regulating public utilities. An early articulation of this may be found in the U.S. Supreme Court's 1923 Bluefield decision that a utility "*is entitled to… earn a return on the value of the property which it employs … equal to that … in other business undertakings which are attended by corresponding risks and uncertainty...*"
See **Bluefield Water Works v. Public Service Comm'n, 262 U.S. 679 (1923)**

2. Incentive Mechanisms in Other Jurisdictions

To support this engagement, Guidehouse staff conducted a scan to identify and document incentive mechanisms used in other jurisdictions. This scan informs the eligibility criteria, the proposed margin value, and how these may be combined into a cohesive mechanism.

The seven jurisdictions included in this scan were selected based on the relevance of the publicly available information that could be obtained within the project timeline. Guidehouse included jurisdictions offering non-MoP-type incentive mechanisms to develop greater insight into the trends and drivers for incentive mechanism development.

A summary of the incentive mechanisms in these jurisdictions is presented in Table 1, below. The taxonomy used in this table (e.g., “Margin on Payments” as a category of mechanism, “Eligibility” to describe some incentive requirements, etc.) reflects the terms used in Ontario and in this report, and is based on the Guidehouse team’s interpretation of each jurisdiction’s mechanism. Additional supporting detail, in the form of “index cards” and some summary analysis may be found in Appendix C.

The three most relevant findings of the jurisdictional scan are that:

1. **Five of seven jurisdictions explicitly limit total incentive payments to protect customer value.** Australia, Connecticut, Hawaii, New York, and Rhode Island limit the total incentive payments to a share of the NWS net benefits. Two jurisdictions (Australia and Hawaii) limit the total combined incentives a utility can recover across all NWS. Michigan does not set an explicit limit but has deliberately set its margin value sufficiently low to prevent incentives from exceeding net benefits.
2. **Margin on payments-style mechanisms are less common than shared savings-style mechanisms, and the value of the prescribed margin values varies widely.** Three of the jurisdictions (Australia, Michigan and California) have offered MoP-type incentives, with margin values of (respectively) 50%, 15%, and 4%.
3. **Jurisdictions with higher upper limits on total incentive payments appear to have been more successful in realizing NWS projects.** Australia and New York appear to have the most generous incentives and a clear quantitative framework for assessing them. These jurisdictions also appear to have implemented the most NWS projects of the jurisdictions reviewed (though this may be partly attributable to the relative maturity of the offerings in these jurisdictions).

Table 1 summarizes key elements of the incentive mechanisms from the jurisdictions reviewed.

Table 1 Jurisdictional Scan Summary

Jurisdiction	Corresponding Mechanism in Ontario	Incentive Structure	Eligibility
Australia	**Margin on Payments**	Distributors receive 50% of expected OM&A costs of demand management projects.	Total incentive in any year cannot exceed 1% of the distributor’s allowed revenue for that year and cannot exceed project net benefits. Eligible OM&A costs include external contracted services, customer incentives, internal labour and overhead for customer acquisition, dispatch operations and payment of customer incentives.

Jurisdiction	Corresponding Mechanism in Ontario	Incentive Structure	Eligibility
California	**Margin on Payments**	The three investor-owned utilities (IOUs) participating in an incentive pilot were permitted a return of 4% of annual 3rd party DER payments.	The total incentive plus cost paid to DER provider must be less than the cost of the deferred utility capital investment. Eligible costs are the total costs of contracted services for third-party DERs.
Connecticut	**Shared Savings**	Electric Distribution Companies can retain up to 25% of forecast net benefits from NWS.	No eligibility criterion identified.
Hawaii	**Shared Savings**	Hawaiian Electric Companies can retain 20% of actual project savings for standalone storage and grid services projects.	Total incentive payments for all projects cannot exceed $10 million per year.
Michigan	**Margin on Payments**	Utilities can retain up to 15% of annual project Operations & Maintenance (O&M) costs.	Utilities cannot recover their incentives if they achieve less than 50% of their Demand Response target. If the capacity achieved is less than 100% of the demand response (DR) target but above 50%, then the incentive is equal to 0.30% of its non-capitalized DR costs for every 1% point above the 50% DR capacity growth target achieved by the utility.
New York	**Shared Savings**	Utilities can retain an incentive of 30% of forecast net benefits plus or minus 50% of the difference between actual and forecasted costs of an NWS project.	Total incentive cannot exceed 50% of forecast net benefits. Utilities may recover their incentive once 70% of the forecasted MWs of NWS has been achieved.
Rhode Island	**Shared Savings & Scorecard (“Action-Based”)**	Utilities retain up to 20% of actual net benefits from implementing the NWS. In addition, utilities can earn performance incentives for completing specific actions identified in their System Reliability Procurement (SRP) report.	No other known eligibility criterion. The Commissions plans to approve incentives on a case-by-case basis.

3. Margin Value and Eligibility Criteria

The Filing Guidelines for the margin on payments incentive mechanism are concise and provide distributors with a significant amount of flexibility. Distributors proposing a margin on payments mechanism are required to provide a proposed margin value, the rationale for that value, a forecast of payments, and the total incentive value.

No guidance, however, is provided regarding quantitative criteria against which proposals may be evaluated.

To provide greater clarity the Guidehouse team has proposed a margin value and three eligibility criteria. These have been combined into different bundles (referred to as "Options") each of which balances of the Design Principles differently.

The value of the thresholds that Guidehouse recommends for each eligibility criterion depend on how that criterion is combined with others in a bundle. Proposed thresholds must be reviewed in the context of each bundle. Changes to these bundles may necessitate changing eligibility threshold values.

This section begins with sub-section 3.1, which specifies the different eligibility criteria. Sub-section 3.2 provides a recommended margin value.

The different bundles of criteria – the three options – are presented in Section 4. Each Option employs one or more of the eligibility criteria presented immediately below, though none employs all three. To assist readers with their review of the proposed eligibility criteria, a summary of which criteria apply to which options is provided in the Table 2 below. Section 5 provides some guidance on considerations for setting eligibility thresholds when defining additional option bundles.

Table 2. Combination of Eligibility Criteria by Option

Option A	Option B	Option C
Customer Value Criterion	Customer Value Criterion	–
–	Innovation Flexibility Criterion	–
–	–	Affordability Criterion

3.1 Eligibility Criteria

The three eligibility criteria considered as part of the options presented in Section 4 are:

- **Customer Value Criterion.** An incentive proposal is eligible only if the total forecast incentive payment does not exceed some share of the forecast net DST benefit. The share threshold may be set high or low depending on the prioritization of the Design Principles.
- **Affordability Criterion.** An incentive proposal is eligible only if the total annual incentive payments *across all of the distributor's NWS* do not exceed some share of the distributor's revenue requirement in any forecast year.
- **Innovation Flexibility Criterion.** An incentive proposal that fails other eligibility criteria may still be approved if it delivers significant value not recognized by the other criteria, such as building distributor capabilities to deliver customer savings in future, more routine, NWS implementations.

3.1.1 Customer Value Criterion

The Customer Value Criterion is intended to ensure that after accounting for the cost of the distributor incentive, the NWS will still deliver an appropriate share of savings to customers.

This criterion (or one analogous to it) is employed in the incentive mechanisms used in five of the seven jurisdictions (Australia, Connecticut, Hawaii, New York, and Rhode Island) reviewed for this report.

The proposed Customer Value Criterion is: **A distributor's margin on payments incentive proposal is eligible only when the forecast total incentive payment to the distributor is less than X% of the forecast net DST benefit of the NWS.**[14]

The value of X is set to address questions of *cost-effectiveness*, of *customer risk*, and of *balancing distributor risk and reward*. A different value of X is used for Option A and Option B (see Section 4)

Cost-Effectiveness

Under the BCA Framework, the DST is used to assess the quantifiable net benefits of an NWS. The perspective of the DST is one that optimizes "*net distribution service benefits for the electricity distributor's customers*". DST net benefits are customer savings.

Distributor incentives are a cost for customers, one incremental to the reference scenario tested as part of the DST.

An incentive that exceeds net DST benefits means that the NWS is not cost-effective and results in a net cost, rather than a savings, to customers.

For this reason, consistent with Design Principle 1, **the X value of the Customer Value Criterion cannot exceed 100%.**

Customer Risk

If a distributor retains 100% of forecast realized benefits as an incentive, then customers derive no net benefit but are also not exposed to any net cost from the NWS. Only forecast, not realized, benefits are available to test eligibility, however, so customers are exposed to risks related to forecast error.

The Guidehouse team believes it would be imprudent and unrealistic to assume that forecast error will be symmetrical. Guidehouse expects that NWS will underperform forecast net benefits more frequently than they overperform them.

This conclusion is based on the Guidehouse team's extensive experience conducting empirical impact evaluations of DERs (including managed electric vehicle charging, pricing and enabling technology mechanisms, demand response, and battery control). This conclusion is also based on the observation that the application of DERs to meet distribution system needs is a practice still in its infancy, and not a mature application. Accordingly, consistent with Design Principle 1, the X value of the Customer Value Criterion must be less than 100%.

[14] Under the BCA Framework, distributors may use some alternative method to the DST for demonstrating the cost-effectiveness of the NWS where the baseline (i.e., the traditional infrastructure) investment is less than $2 million. In the absence of a DST for smaller projects the Customer Value Criterion percentage value should be applied to the net benefits estimated to accrue to customers using the alternative approach.

Guidehouse recommends that the **X value of the Customer Value Criterion should always be less than 75%**. This protects customers from incurring a net cost from the NWS even when realized net benefits are 25% lower than forecast.

This value is lower than the analogous mechanism applied in Australia (see Section 2, above, and Section 3.2.1, below) which requires only that forecast incentives be less than net customer benefits. Guidehouse's recommendation is informed by differences in incentive design and observed outcomes, most importantly that in Australia, cost-effectiveness of an NWS project is subject to third party testing. This is a condition developed "*to verify that the Scheme is only incentivising efficient projects that deliver cost savings to retail customers.*"[15] There is no such third-party requirement in Ontario's BCA Framework or Filing Guidelines.

Distributor Risk and Reward

To define a lower bound for the range of X values, the Guidehouse team has reviewed the practices of other jurisdictions, and in particular the share of savings allocated to distributors in jurisdictions that apply shared savings-style mechanisms. This review needs to consider two important, and partially off-setting, factors.

- First, **shared savings mechanisms typically expose distributors to greater risk than margin on payments mechanisms** by tying the incentive payment to actual project outcomes. An MoP mechanism, however, insulates the distributor from risk: once a margin on payments incentive proposal is approved, the distributor may collect the prescribed margin on all eligible payments regardless of project outcomes. With this lower risk should come a lower reward, per Design Principle 3.
- Second, **the Customer Value Criterion is an eligibility threshold, not a prescribed incentive share**. That is, the shared savings specifies a final share to be allocated to the distributor, whereas the eligibility criterion specifies that no share *greater* than the specified value is permitted.

The first factor above suggests that, ideally, the Customer Value Criterion threshold should be set such that the *average* (over multiple projects and distributors) share of net benefits allocated to distributors should be lower than the share of net benefits allocated to distributors by a shared savings mechanism. Although no savings share has been prescribed by the OEB for its shared savings mechanism, Table 1 indicates that in other jurisdictions the base share varies between 20 – 30%.[16]

This suggests that a reasonable outcome would be one in which distributors *on average* retain 20% of forecast net benefits. This reflects the relatively lower risk to which the distributor is exposed under a margin on payments mechanism compared to the shared savings mechanism.

The Customer Value Criterion, however, defines the *maximum* share of net benefits that can be allocated to the distributor, not the average. The average share of net forecast benefits that will be realized by distributors is unknown. However, if the Customer Value Criterion takes any value lower than 20%, the average share of net

[15] See Section 5, Table 1 of
Australia Energy Regulator, ***Explanatory Statement – Demand Management Incentive Scheme***, Ref: 58882, December 14th 2017

[16] In New York, actual project outcomes can cause this base value to be revised as high as 50% or as low as 0%.

savings allocated to distributors is *guaranteed* to be less than the reasonable average specified above.

Accordingly, Guidehouse recommends that the **X value of the Customer Value Criterion should be 20% or higher**.

A different value of X is proposed for the two options (A and B) to which this eligibility criterion is applied, varying by Option to reflect the differences in the way the Design Principles are prioritized for each Option and based on the bundle of eligibility criteria included in each Option.

The net benefit to which the X% Customer Value Criterion is applied should be the output of the DST in an approved BCA or (if no BCA was undertaken) the net benefit quantified as part of any alternative cost-effectiveness assessment used by the distributor to support its use of an NWS.[17] The DST is evaluated only on quantitative benefits and costs. Qualitative BCA considerations (e.g., benefits that cannot be robustly quantified) may be considered under the Innovation Flexibility Criterion (see below).

3.1.2 Affordability Criterion

The Affordability Criterion is intended to ensure that the sum of annual incentives paid to the distributor across all NWS implemented by that distributor does not materially increase customers' bills.

This criterion (or one analogous to it) is employed in the incentive mechanisms of Australia and Hawaii.

The proposed Affordability Criterion is: **A distributor's margin on payments incentive proposal is eligible only if the total forecast annual incentive payments for all of that distributor's NWS sum to less than Q% of the distributor's approved revenue requirement for each year.**[18]

This Criterion is applied only in one bundle (Option C). Guidehouse recommends, consistent with the example of Australia, to use a value of Q of 1%. Were this criterion to be combined in an Option with the Customer Value Criterion (as in Australia), a higher value of Q might be reasonable, depending on what value was set for the Customer Value Criterion.

The value of Q is set to balance the need to allow distributors to capture an incentive that is *sufficient to support the OEB's goal of "leveling the playing field"* (to promote innovation, Design Principle 2) and the need to *limit the impacts of such incentives on customer bills* (Design Principle 1).

Incentive Sufficient to "Level the Playing Field"

To help assess the impact of the maximum eligible incentive on distributor financial performance, Guidehouse has drawn on data from OEB Open Data[19],[20] to compare the impact of the maximum possible annual incentive value under the cap relative to other financial metrics commonly monitored by distributors. The purpose of this analysis is illustrative and intended to provide reviewers with the context to assess whether the

[17] Distributors may, for proposed investments with projected capital costs less than $2 million use existing, alternative, cost-effectiveness or decision-making protocols, at their discretion.

[18] A distributor's "revenue requirement" refers to distribution revenue approved in the last cost-based application for the given year, including any appropriate escalation from the test year.

[19] Ontario Energy Board, ***Electricity Reporting & Record Keeping Requirements (RRR): Section 2.1.7 Trial Balance**, **Table 2 Income Statement Analysis***, Accessed February 2025

[20] Ontario Energy Board, ***Electricity Reporting & Record Keeping Requirements (RRR): Section 2.1.5.6 Regulated Return on Equity (ROE)***, Accessed February 2025

proposed cap is sufficient to incent distributors consider the use of NWS where it is more cost-effective than the infrastructure solution.

For convenience, Guidehouse has used historical actual distributor revenue, rather than the approved revenue requirement (escalated where appropriate), to identify the incentive cap for this analysis.

Using 2023[21] reported revenue, Guidehouse has calculated the dollar value of the 1% Affordability Criterion. Using 2023 revenue, the average annual incentive cap across Ontario's 54 distributors would be approximately $830 thousand.[22]

This value is equivalent to approximately 5.2% of the average equity return[23] earned by this group of distributors in 2023 (approximately $16 million, on average).[24] Guidehouse examined the data of 14 Australian electricity distributors and determined that the application of the 1% incentive cap in 2023 would result in a 5.6% increase to those distributors' annual return, a value very similar to that derived for Ontario.

This incentive cap for 2023 is also equivalent to approximately 2% of Ontario distributors' 2023 operations, maintenance and administration (OM&A) costs – so achieving the incentive cap would deliver a benefit to the average distributor approximately equivalent to a reduction of OM&A costs of 2%.

It is the judgement of the Guidehouse team that this incentive cap, **represents an incentive that is sufficient to support a more "level playing field", motivate distributor proposals for cost-effective NWS**, and is consistent with Design Principle 2.

Customer Bill Impact

The Affordability Criterion implicitly recognizes that building distributors' capability to routinely deliver NWS that drive customer value may require that in the near term, incentives must sometimes be larger than customer savings. The focus of the Affordability Criterion is on limiting the net cost to customers to avoid any *material* increase in monthly bills.

To better assess the materiality of the Affordability Criterion incentive cap, Guidehouse compared annual distributor revenues with the estimated average supply and transmission costs paid by the distributors' customers. This provides a directional estimate of the materiality of the incremental cost of the incentive to customers as a whole.[25]

Distributor revenue accounts, on average, for approximately a quarter of distribution customers' total electricity costs.

[21] Guidehouse repeated this analysis for years 2016 through 2022 to test the sensitivity of the outputs to the year selected. Although the key output values of interest do change when different years are used, the range of variation is relatively narrow, and the 2023 output lies within that range.

[22] For the 13 distributors with an average 2023 revenue in excess of $30 million, the average incentive cap was $3.1 million. For the 41 distributors with an average 2023 revenue of less than $30 million, the average incentive cap was approximately $110 thousand.

[23] This is also equivalent to approximately a 0.5-point increase to these distributors' return on equity percentage (often approximately 9%).

[24] For the top 13 distributors, the average 2023 equity return was approximately $60 million. For the remaining 41 distributors, the average 2023 equity return was approximately $1.7 million.

[25] The Guidehouse team recognizes that bills include other (e.g., regulatory) charges, that costs are not collected evenly across customer classes, etc.

> This suggests that the bill impact of an incentive that attains the proposed Affordability Criterion cap will, on average, increase customer bills by no more than approximately 0.25%. Recognizing that although any bill increase may be meaningful to customers in precarity, a 0.25% increase in electricity bills cannot be described as a material increase to most distribution customers.

The Affordability Criterion is compared to the sum of *all* incentives for NWS that the distributor forecasts collecting across the incentive period of the project for which an incentive has been proposed. So, for example, if the distributor's incentive cap is $2.5 million, and the distributor expects to collect $1 million per year from other, existing and approved, NWS incentives, the same distributor can only propose an additional NWS incentive on a new project of up to $1.5 million per year (since that, in addition to the already approved incentive, will attain the cap of $2.5 million).

The requirement that the cap apply to the sum of all incentives is related to the question of the materiality of the bill impacts noted above. What matters to a customer examining their bill is not the increase per project, but the *total bill increase* due to incentives. This is why the Criterion must apply to the total incentive amount for the distributor and not just for each project.

3.1.3 Innovation Flexibility Criterion

The Innovation Flexibility Criterion is only intended to be combined with other criteria in Option bundles as an alternative path to eligibility and is not intended to be the sole criterion included in an Option. This criterion is intended to provide distributors with the flexibility to innovate by providing a path to approval for proposals that deliver significant value not recognized by other criteria.

For example, an NWS BCA that fails the DST would not be eligible for an incentive under the Customer Value Criterion but could attain an incentive via the Innovation Flexibility Criterion if it were available.[26] Alternatively, if a small distributor's proposal for a cost-effective NWS is ineligible under the Affordability Criterion because its revenue requirement is relatively small (limiting the size of its incentive cap), the Innovation Flexibility Criterion provides another path to approval.

Pairing this criterion with either (or both) the Customer Value and Affordability criteria in an incentive design can allow for a higher level of customer protection (e.g., via a more stringent value for the Customer Value Criterion) without shutting out innovative NWS designs. This is addressed in greater detail in Section 4.2, below.

Although this criterion is not formally a part of any of the incentive mechanisms reviewed by the Guidehouse team in its jurisdictional scan, it is consistent with the flexibility provided by the BCA Framework. In the BCA Framework, an NWS that does not demonstrate a net benefit through the DST test may still be approved "*when there are compelling qualitative impacts that support the deployment of the specific NWS*".

3.2 Margin on Payments Value

The margin on payments value is the percentage value that is applied to all payments made by distributors to third-party DERs providing services to the distribution system as part of an NWS.

[26] As per the BCA Framework, an NWS BCA may be approved despite a DST that does not pass: "*A passing score on the DST is necessary unless other qualitative benefits warrant proceeding with the NWS.*"

3.2.1 Jurisdictional Precedent & Observed Experience

Three of the jurisdictions reviewed use a margin on payments-style incentive mechanism: California (4%), Michigan (15%), and Australia (50%).

- The **California** value applies to all non-capitalized project costs. This was offered in an incentive pilot, but none of California's three participating investor-owned utilities completed any projects under the pilot. The initial value proposed by California Public Utilities Commission (CPUC) staff was 3.5%.[27] This is derived as the average point difference between the investor-owned utilities' (IOUs') Return on Equity and Cost of Capital[28]. A subsequent Rulemaking decision by a commissioner noted an error in the original proposal related to the application of this percentage, identifying the correct value as 3%.[29] Based on feedback provided to the CPUC that third-party DER payments are likely to be considerably lower than infrastructure investments (with the implication that this would be insufficient to incentivize the use of non-wires solutions), the commissioner proposed a higher value: 4%.
- The **Michigan** value is applied to all operations and maintenance expenses[30] (O&M) incurred by utilities to develop and maintain the demand response (DR) capacity required of them by regulation. An incentive of 20% on capital *and* expenses was first proposed by a utility to encourage the development of DR resources to act as a virtual power plant (VPP).[31] The rationale provided for the magnitude of this value is that because the costs associated with DR are much less than traditional infrastructure, the percentage incentive must be higher than the traditional return to incent the utility.[32]

  Michigan Public Service Commission (MPSC) staff advised[33] "*the Commission to reject the Company's proposal… Staff believes the Company's proposed mechanism is far too generous…"* and recommended the adoption of a 15% incentive payment on non-capitalized

[27] California Public Utilities Commission, *Assigned Commissioner's Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment,* Rulemaking 14-10-003, April 4th 2016, **https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K702/159702148.PDF**

[28] The derivation of this value is deliberately approximate: "*Since in recent years r* [Return on Equity] *has consistently exceeded k* [Cost of Capital] *by roughly 2.5 to 3.5 percentage points in California as well as nationally…"* See PDF page 6 of 16 of Rulemaking 14-10-003 (above).

[29] See PDF page 18 of 24 of

California Public Utilities Commission, *Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge,* Rulemaking 14-10-003, September 1st 2016, **https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M166/K474/166474892.PDF**

[30] O&M expenses are all the non-capitalized expenses related to the development and maintenance of the targeted DR capacity.

[31] See PDF page 301 of 320

Michigan Public Service Commission, *Consumers Energy Company Application for 2017 Demand Response Program Costs,* Case U-20164, May 31st 2018, **https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t00000022p1bAAA**

[32] "*… a 20% return on $10 million is much less attractive to shareholders than a 10% return on $500 million…"*

See PDF page 313 of 320, MPSC Case U-20164 cited immediately above.

Importantly, however, for the OEB's goal of "leveling the playing field", the utility application also states (PDF page 310 of 320): "*While this* [20% incentive] ***will not necessarily put DR on an equal footing with supply-side resources****, it will encourage the Company to increase investments in DR opportunities…"* (Emphasis added)

[33] See PDF pages 84 and 85 of 113 in:

Michigan Public Service Commission, *Metro Court Reporters Transcript,* Case U-20164, March 11th 2019 **https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000004HTWnAAO** spending, conditional on the utility's achievement of its DR capacity.[34] A key driver of the 15% value, applied only to non-capitalized DR spending was Commission staff's desire to ensure that the incentive did not result in an attainment of DR capacity that was not cost-effective: "*Staff does not want costs to exceed benefits however and would prefer to start out with a more conservative mechanism that will allow both the Company and Staff to assess the appropriate level of outcomes for these programs*."[35] Guidehouse has not conducted a comprehensive assessment of the attainment of DR targets by Michigan's utilities, but notes that in recent years the two largest utilities (Consumers and DTE) appear to have attained their DR capacity targets. In 2022, DTE achieved 786 MW of peak demand DR capacity, exceeding its target of 757 MW[36]. In 2023, Consumers achieved 644 MW of peak demand DR capacity, exceeding its target of 618 MW[37].

- The **Australia** value is characterized as a cost-multiplier, and is applied to demand management OM&A costs.[38] The Australian Energy Regulator (AER) selected this value primarily based on its being within the range identified by modeling conducted by the Institute of Sustainable Futures and the fact that "*a cost multiplier of 50 per cent broadly aligns with stakeholder submissions".[39]* The AER illustrates that this incentive is equivalent to a distributor receiving "*an allowed rate of return of 6.3 percent compounded semi-annually over approximately 6.5 years."* though this is clearly an illustrative example intended to contextualize the value, and not the method by which the incentive magnitude was derived.

  The AER places several important eligibility restrictions on the application of the incentive:

  - it can be applied only to "*projects that have the highest net benefit, having undergone a transparent assessment process subjected to **third party testing** "* (emphasis added),
  - "*a project's incentive cannot exceed that project's expected net benefits*"[40],

[34] Although the initial order required utilities to complete an assessment of the use of their DR capacity to act as an NWS for five potential projects, this requirement was withdrawn in 2021, see:

Michigan Public Service Commission, *Order Approving Settlement Agreement,* Case U-21080, March 3rd 2022 **https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002DAXuAAO**

[35] See PDF page 85 of 113 in Case U-20164 transcript cited immediately above.

[36] Michigan Public Service Commission, **DTE Electric Company application for 2022 demand response program costs***,* Case U-21403, June 29th 2023

[37] Michigan Public Service Commission, **Consumers Energy Company application for 2023 demand response program costs***,* Case U-21647, November 20th 2024

[38] The AER specifies that the cost multiplier project incentive is 50% of expected "demand management costs".

See of Section 7.5

Australia Energy Regulator, ***Explanatory Statement – Demand Management Incentive Scheme****,* Ref: 58882, December 14th 2017

Subsequently, Ausgrid's 2020 – 2021 DMIS report identified its "demand management costs" to include external contracted services, customer incentives, internal labour and overhead for: customer acquisition, dispatch operations and payment of incentives. See Section 3.1.2 of

Ausgrid, ***DMIS Annual Report 2020 – 2021*** – *Public Version*, September 2021

[39] See PDF page 31 of 81 of AER *Explanatory Statement* cited immediately above.

[40] See PDF pages 28 and 29 of 81 of AER *Explanatory Statement* cited immediately above.

- The total financial incentive a distributor can receive in any regulatory year cannot exceed 1% of that distributor's Allowed Revenue for that regulatory year.[41]

As of May 2023, the AER has reported that this scheme has delivered $50 million in benefits to consumers at a cost of $3.2 million[42], suggesting that this magnitude of incentive has been successful at motivating distributors to pursue innovative DER solutions, and indicating that the solutions implemented are all highly cost-effective.

A review of the evolution of the incentives in these three jurisdictions (and the rationales used to support their specification) makes it clear that **the prescribed margin value is, in each case, a negotiated value**. That is, in each case the value is selected according to the judgement of regulatory authorities on the basis of a variety of inputs, including considerations of stakeholder input, protecting customer value, and motivating distributors to pursue NWS. Although allowed returns on equity are referenced in each discussion as a point of comparison, in none of the three cases is the margin value derived directly from that allowed return.

In each case, the three jurisdictions recognize the challenge of motivating utilities to implement non-capitalized solutions that do not earn a rate of return while still protecting the value that such solutions are intended to deliver to the utility's customers. California and Michigan attempt to balance these concerns by constraining the value of the cost multiplier (the margin) itself. Australia does so differently; allowing a generous margin value (to motivate distributors) but imposing strict eligibility constraints (to protect the distributors' customers).

3.2.2 Recommended Margin Value

Guidehouse recommends the use of a 25% margin value. The rationale for this recommendation is provided below.

Guidehouse has identified three jurisdictions that employ a mechanism for incenting the use of NWS analogous to Ontario's margin on payments mechanism. California, Michigan, and Australia each allow (or have allowed) utilities to collect an incentive that is 4%, up to 15%, and 50%, respectively, of non-capital project costs.

In the California example, none of the three IOUs completed any projects under that pilot, strongly suggesting (in the context of the values used by the other jurisdictions) that this value is too low to motivate innovation. *The margin value in Ontario should be higher than this 4%.*

In the Michigan example, the incentive is tied to a defined goal, a targeted volume of DR capacity that the utilities are required to acquire by their regulator. This differs from the more open-ended Ontario goal of "leveling the playing field" such that NWS are considered by distributors on an equal footing with traditional infrastructure capital investments.

A key consideration in setting the Michigan margin value was to ensure that costs of DR (inclusive of the incentive) did not exceed its benefits. The Michigan mechanism, however, does not include eligibility criteria, such as those proposed above (i.e., the Customer Value and Affordability criteria) designed to protect distributors' customers. For this reason, and because of

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[41] The selection of this magnitude was based on the AER's judgement that the value is: "*Substantial enough to incentivise distributors to actively explore demand management opportunities, where efficient to do so… Modest enough to protect retail customers from bearing costs under the Scheme that are unexpectedly high…* [and] *Unlikely to be too restrictive or conservative…"*

See section 9.1 of AER *Explanatory Statement* cited immediately above

[42] Australian Energy Regulator, ***Decision – Demand Management Incentive Scheme payments for 2020-21 and 2021-22***, Ref: 14866586.2, May 18th 2023

Ontario's more open-ended goal of "leveling the playing field", *the margin value in Ontario should be higher than 15%.*

In the Australia example, although the incentive margin value is itself very generous, it is accompanied by strict eligibility criteria: total incentive payments must be less than 1% of allowed revenue, incentive payments for a project must be less than the net benefit the project offers consumers, and the cost-effectiveness of the proposed solution (which itself determines the net benefits) must be tested by a third party.

Versions of the first two of these eligibility criteria have been proposed above for Ontario but have not been applied together in any single Option bundle. The BCA Framework likewise does not include a requirement that cost-effectiveness be tested by a third party. Given Australia's more stringent eligibility conditions and customer protections, *the margin value in Ontario should be lower than 50%.*

The above indicates that Ontario should use a margin value of between 15% and 50%.

The MPSC has revisited[43] the 15% value in subsequent filings and has not changed this total value suggesting that it is satisfied with the impact this incentive has had in supporting Michigan's utilities in attaining their DR capacity targets. Noting this, and the stringency of Australia's customer protections, Guidehouse believes that an initial margin value for Ontario should be closer to that of Michigan than Australia.

Accordingly, **Guidehouse recommends a margin value of 25%.**

Guidehouse recommends however, that the OEB ensure that, as the AER has done in Australia, it preserves flexibility to adjust this value:

> "*Downwards, but also possibly upwards in response to regulatory changes that affect distributors' incentives to undertake efficient demand management…*
>
> *Downwards, but also upwards in response to market changes that affect the likelihood of distributors undertaking efficient demand management…*
>
> *Upwards if distributors face a greater imbalance of incentives against demand management than was initially considered when setting the cost multiplier."*[44]

3.2.3 Fixed Value

To ensure distributors can plan effectively, all eligible incentive proposals that are approved should use this margin value in implementation.

To provide flexibility, however, distributors whose proposals are ineligible at the 25% margin value may, if they choose, propose a lower custom margin value at which their proposal *does* meet the relevant eligibility criteria. Providing this flexibility increases the pool of potential projects (since it provides a path to eligibility for projects that otherwise would fail the criteria) without jeopardizing the customer protections (since it is the margin value that changes, and not the eligibility criteria, which exist to provide that protection).

Any changes to the margin value should be proposed by a distributor, however, and not imposed on it.

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[43] See Appendix C.5 for more context.

[44] See Section 4.3 of
Australia Energy Regulator, ***Explanatory Statement – Demand Management Incentive Scheme***, Ref: 58882, December 14th 2017

4. Options for the Margin on Payments Mechanism

The Guidehouse team has developed three options for the OEB to consider implementing. These options are mutually exclusive; Guidehouse would not expect (for example) the OEB to implement Option A as well as Option B. Some guidance for developing additional options is presented in Section 5, below.

Each of the three options apply a different set of eligibility criteria and balance the priorities of the Design Principles differently. All of the options use the same margin value of 25%.

4.1 Option A

Eligibility Criteria Applied:	Customer Value Criterion
Eligibility Details:	A distributor is eligible to claim the 25% margin on payments incentive only if the total forecast incentive payment is less than 75% of the forecast net DST benefit.[45]

Option A *prioritizes* simplicity (Design Principle 4), *emphasizes* innovation (Design Principle 2), *accommodates* customer value (Design Principle 1), but *compromises* on an appropriate balance of risk and reward (Design Principle 3).

- **Simplicity** is *prioritized* by applying only a single criterion, and the one that is simplest to assess. Use of DERs as an NWS requires either an approved BCA or some other demonstration of cost-effectiveness (for NWS addressing system needs requiring an investment of less than $2 million). Distributors should be able to easily assess their proposal's eligibility without undertaking any incremental analysis beyond that required for the BCA.
- **Innovation** is *emphasized* by maximizing the share of the net DST benefit that the distributor can retain as an incentive. The Guidehouse team believes that 75% is the maximum value that can be prudently applied without the risk of NWS implementation resulting in a net cost to customers (see Section 3.1.1).
- **Customer Value** is *accommodated* by applying the Customer Value Criterion, intended to ensure that, at minimum, the NWS does not impose a net cost on customers.
- **Risk and Reward** is *compromised* because the maximum share of the net benefit that may be retained by the distributor is set to its highest prudent level, despite there being no performance risk to the distributor associated with incentive collection.

4.2 Option B

Eligibility Criteria Applied:	Customer Value Criterion Innovation Flexibility Criterion
Eligibility Details:	<u>Stage 1:</u> A distributor is eligible to claim the 25% margin on payments incentive only if the total forecast incentive payment is less than 30% of the forecast net DST benefit.

[45] Under Option A, if the OEB approves an NWS BCA with a DST that does not pass cost-effectiveness (i.e., the net benefits are negative), that NWS would not be eligible for the Margin on Payments incentive mechanism, unless Option A were expanded to include the Innovation Flexibility Criterion. Alternatively in such cases (and perhaps more appropriately), the distributor could propose a Scorecard-Based incentive incentive.

Stage 2 (Optional): If the proposed incentive fails the Customer Value Criterion in Stage 1, the distributor can request that the OEB consider its proposal's eligibility under the Stage 2 Innovation Flexibility Criterion.

Option B *prioritizes* customer value (Design Principle 1), *emphasizes* a reasonable allocation of risk (Design Principle 3), but still *accommodates* the possibility of innovative projects (Design Principle 2). Option B, however, *compromises* on simplicity (Design Principle 4) for projects that only deliver modest amounts of net DST benefits and so must pass to Stage 2.

- **Customer Value** is *prioritized* by combining the Innovation Flexibility Criterion with the Customer Value Criterion.

  The inclusion of the Innovation Flexibility Criterion in the Option design means that near-term customer value can be more stringently protected through a lower Customer Value Criterion value without significantly jeopardizing longer-term (perhaps more difficult to quantify) customer benefits that can be captured through the Innovation Flexibility Criterion.

  The inclusion of the Innovation Flexibility Criterion means that room exists to incent innovative NWS that are only modestly cost-effective while still motivating distributors (via the 30% Customer Value Criterion) to focus on the most cost-effective NWS implementations.

- **Reward and Risk** is *emphasized* through a Customer Value Criterion that is lower than Option A and so better reflects the relative distribution of risk to customer and distributor value.

  The Guidehouse team selected the 30% value that defines the maximum share of forecast net benefits that can be retained by the distributor in large part on basis of its use in New York's shared savings incentive mechanism, the most mature of the North American incentive mechanisms reviewed for this report. In New York distributors may retain 30% of forecast net benefits, to be collected once 70% of the DERs are operational, conditional on avoiding cost over-runs.[46]

  The New York Public Service Commission (NY PSC), in its Order approving the incentive noted that: "… *incentive opportunities should be financially meaningful and structured such that they encourage enterprise-wide attention at the utility and spur strategic, portfolio-level approaches beyond narrow programs. Further, incentive opportunities should be commensurate with the level of financial risk borne by utility shareholders.*"[47]

  Guidehouse has therefore assessed for Option B that 30% balances the rewards of NWS net benefits commensurate with the risk to which distributors are exposed, relative to customers.

- **Innovation** is *accommodated* for, as noted in the discussion above, through the inclusion in the Option of the Innovation Flexibility Criterion, which provides a path to approval for incentives applied to projects whose greatest benefits may not be captured

[46] The New York incentive is adjusted by 50% of the difference between forecast and realized costs, to a minimum of 0% and a maximum of 50% of the forecast net benefits.

[47] See PDF page 3 of 15 of

New York State Public Commission, **Order Approving Shareholder Incentives**, Docket 15-00844, January 25th 2017 by the DST (or other alternative cost-effectiveness assessments used for smaller projects).

- **Simplicity** is *compromised*, however, by the two-stage nature of the design, which is more complex than Option A or Option C.

  This additional complexity, however, *applies only to distributors bringing forward incentive proposals for projects with relatively modest cost-effectiveness.*

  Even assuming that <u>all</u> of a project's costs are DER payments to which the margin applies, any project with a DST benefit-cost ratio of 1.8 or more will be eligible under the 30% Customer Value Criterion.

  If DER payments to which the margin applies are only half of the project's costs (a more realistic estimate), then any project with a DST benefit-cost ratio of 1.4 or more will be eligible under Option A without needing the additional complexity imposed by the Innovation Flexibility Criterion.

  Option B is, in fact, just as simple as Option A when the NWS project is more than modestly cost-effective. The derivation of the DST ratio thresholds noted above may be found in Appendix B.

4.3 Option C

Eligibility Criteria Applied:	Affordability Criterion
Eligibility Details:	A distributor is eligible to claim the 25% margin on payments incentive only if the sum of annual forecast incentive payments for all the distributor's NWS is less than 1% of the distributor's approved revenue requirement in each year.

Option C *prioritizes* driving innovation (Design Principle 2), *emphasizes* simplicity in application (Design Principle 4), while *accommodating* some customer protection (Design Principle 1). Option C, however, *ignores* the appropriate allocation of risk and reward (Design Principle 3).

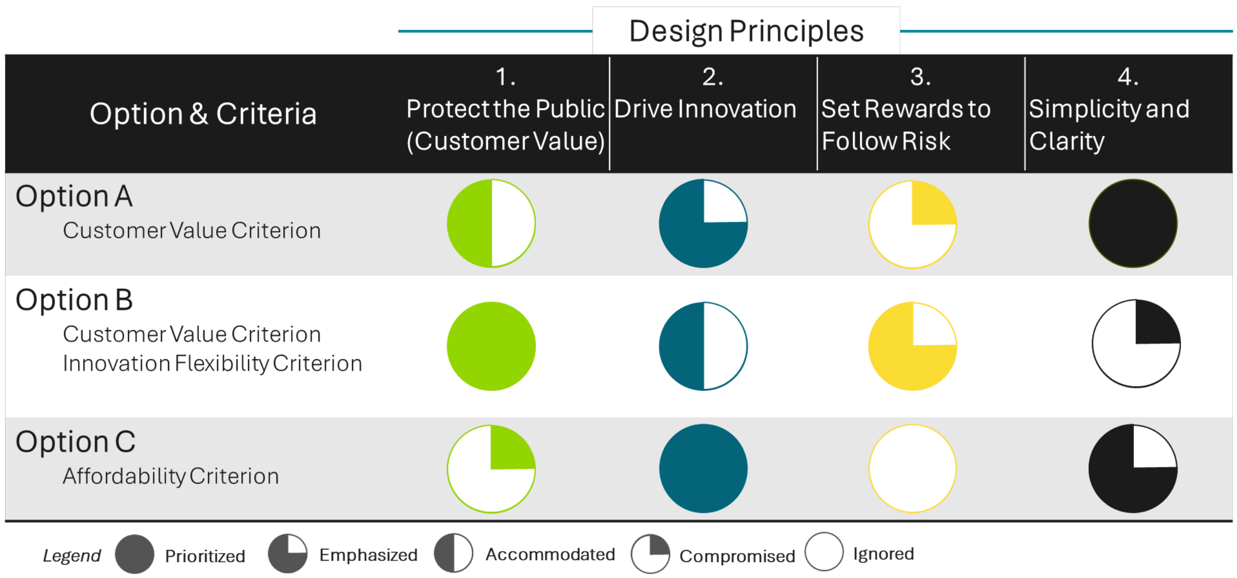
- **Innovation** is *prioritized* by disregarding considerations of the cost-effectiveness of the incentive (no Customer Value Criterion is applied). This Option implicitly assumes that part of "leveling the playing field" is accelerating infant industries with incentive support that may not appear cost-effective in the near term (e.g., for the first cohort of projects), but is necessary to enable more cost-effective NWS in the future. This Option allows distributors to earn incentives for innovative NWS that may be only modestly cost-effective, perhaps because of the use of emerging technologies that are not yet produced at scale and so are relatively more costly in the near term.
- **Simplicity** is *emphasized* by the application of the Affordability Criterion. All that is required for the distributor to assess their eligibility is their revenue requirement in the years in which the incentive will be collected, the forecast value of the NWS incentive in each year for which the incentive is being proposed, and the total amount of all other proposed or approved NWS incentives.
- **Customer Value** is *compromised* because the Option includes no mechanism to protect customers from being exposed to a net cost resulting from the NWS. Some protection, however, is provided by the application of the Affordability Criterion, intended to ensure that any short-term net cost impact is not too onerous.

- **Risk and Reward** is *ignored*. This Option allows the distributor to potentially retain an incentive in excess of the project's net benefits, despite customers bearing the higher share of risk.

4.4 Option Summary

The rationale for the design of each of the three options above is expressed through the relative prioritization of the four Design Principles. It is this relative prioritization that dictates which eligibility criteria are included in each Option, and what threshold values are applied in those criteria. Figure 2, below provides a visual summary of this prioritization.

Figure 2. Option Prioritization Summary



Design Principle 1 (Customer Value) is

- *prioritized* in Option B due to the share used in the Customer Value Criterion and the application of the Innovation Flexibility Criterion to provide a path to approval for proposals that provide long-term customer value that may not be captured in the DST
- *accommodated* in Option A through the Customer Value Criterion, set with the goal of ensuring that NWS do not impose any net cost on customers
- *compromised* in Option C through the Affordability Criterion, set with the goal of ensuring that even if an incentive imposes a net cost on customers, it is not a meaningful net cost.

Design Principle 2 (Drive Innovation) is

- *prioritized* in Option C by avoiding constraining eligibility with considerations of the cost-effectiveness of the incentive.
- *emphasized* in Option A by setting the Customer Value Criterion threshold to its prudent maximum, ensuring as wide a pool as possible of eligible cost-effective incentive proposals
- *accommodated* in Option B through the inclusion of the Innovation Flexibility Criterion to provide a path to approval for projects whose greatest benefits may not be captured by the DST.

Design Principle 3 (Risk and Reward) is

- *emphasized* in Option B, which limits eligibility to incentive proposals in a way that attempts to balance rewards allocated to distributors and customers relative to the risk to which they are exposed
- *compromised* in Option A, because it permits distributors to retain as much as 75% of the net benefits, despite customers bearing the greater share of risk.
- *ignored* in Option C, which allows incentives to exceed the value of the NWS net DST benefits

Design Principle 4 (Simplicity and Clarity) is

- *prioritized* in Option A, which allows distributors to assess their eligibility using only a BCA output already in hand
- *emphasized* in Option C, which requires distributors consider total incentives across all NWS (not just that proposed) when assessing eligibility
- *compromised* in Option B for distributors proposing incentives for NWS that are only modestly cost-effective NWS, as they are required to provide an alternative rationale to justify their proposal's eligibility under the Innovation Flexibility Criterion

5. Sensitivities and Developing New Options

The structure of this report and of Guidehouse's recommendations is deliberately modular. The purpose of this modularity is to allow OEB staff and stakeholders to better understand the characteristics of the individual Option components. This is intended to assist OEB staff or stakeholders to develop adjustments that they may propose to apply to the options to reflect other perspectives, or to create new, alternative options.

In this section four types of sensitivity are briefly discussed: the sensitivity of the options' eligibility criteria to the margin value, the sensitivity of Customer Value Criterion eligibility threshold values to OEB priorities, alternative combinations of the eligibility criteria (and how such combinations might impact recommended eligibility thresholds), and potential adjustments that could be applied to accommodate smaller utilities.

5.1 Option Eligibility Threshold Sensitivity to Margin Value

Absent other information, Guidehouse would not recommend adjusting the proposed Option A, B, and C eligibility criteria thresholds in response to a change in the margin value. The purpose of the Customer Value and Affordability criteria is to protect customers. Their effectiveness in doing so should not be impacted by a change in the margin value.

If the margin value is increased substantially, and some credible evidence exists to suggest that this could result in either the Customer Value or the Affordability Criterion restricting cost-effective innovation, some adjustments to these criteria threshold values may be reasonable.

Should some alternative Option be developed (e.g., one that combines both the Customer Value and the Affordability Criterion – see below) that uses an alternative margin value then eligibility criteria thresholds specific to that Option should be developed on the basis of the considerations and analysis presented above.

5.2 Customer Value Criterion Sensitivity

In Section 3.1.1 Guidehouse recommended that the Customer Value Criterion threshold range should fall between 20% and 75%, with the goal that on average (across many projects and distributors) the average total incentive recovered by distributors should be approximately 20% of NWS project net benefits to customers. Guidehouse has, on this basis, and in consideration of each Option's Design Principle prioritization, recommended threshold values for the two options to which the Customer Value Criterion has been applied.

If the OEB wishes to develop an alternative Option that includes the Customer Value Criterion, the Guidehouse team would recommend setting the threshold according to the following heuristics:

- **Higher thresholds are riskier to customers.** Setting a lower threshold will only render ineligible for incentives NWS projects with low cost-effectiveness ratios. Projects with low forecast cost-effectiveness ratios are less likely than projects with high forecast cost-effectiveness ratios to be cost-effective when realized. Setting a lower threshold protects customer value from riskier projects.
- **Lower thresholds may discourage more innovative, but riskier, projects.** Highly innovative projects are more likely to have low cost-effectiveness ratios. Many forms of DERs, and techniques for using them as NWS, are emerging technologies, and, as such, are likely to be relatively costly in a maturing market. Setting a higher threshold

"levels the playing field" for highly innovative solutions that carry more short-term risk for customers.

5.3 Alternative Eligibility Criteria Combinations

None of the options presented combine both the Customer Value Criterion and the Affordability Criterion. In developing the options, Guidehouse deliberately sought to create bundles that were maximally different from one another, to better illustrate alternative prioritizations.

If the Customer Value Criterion were added to Option C it would allow for the possibility of increasing the threshold value of the Affordability Criterion. The reason for this is that if an NWS is cost-effective, and a substantial proportion of the net benefit is allocated to customers (as in Option B), then customer bills should decrease in the longer term, which would mitigate the impact of relaxing the Affordability Criterion.

In this example combination, the primary purpose of the Affordability Criterion is to protect customers against the risk that the forecast net benefits are not realized.

5.4 Adjusting Options to Accommodate Small Distributors

Guidehouse understands that undertaking to include NWS in distribution system planning will be a significant change from distributors' business-as-usual. The process of "leveling the playing field" will impose some fixed costs on distributors, requiring adjustments to staffing and resourcing.

Guidehouse expects larger distributors whose scale makes them better able to bear these fixed costs (without requiring significant rate increases) will lead innovation into this space, breaking a trail for others to follow. Guidehouse does, however, also recognize the importance of accommodating smaller distributors to ensure that they too are provided with opportunities to drive value to their customers through cost-saving innovation.

Guidehouse anticipates that Option C might be the most challenging for smaller utilities – the magnitude of their revenue requirement could impose on them a relatively small incentive cap, making it difficult for these distributors to make a compelling internal business case to pursue NWS. As noted in Section 3.1.2, the average incentive cap of the 41 smallest Ontario distributors would be approximately $110 thousand per year.

Three ways this issue with Option C could be addressed are:

- A Customer Value Criterion could be added to Option C. If there is a requirement that the incentive be cost-effective (and so deliver a net savings to customers), then it would be reasonable to raise the Affordability Criterion.
- An Innovation Flexibility Criterion could be added to this Option. This would provide smaller distributors with a path to approval for projects with proposed incentives that exceeded the Affordability Criterion threshold.
- An alternative threshold value for the Affordability Criterion could be applied for smaller distributors.

Of these three possibilities, Guidehouse would recommend the first. This would be the simplest option and the one that doesn't require making any arbitrary or ad hoc exceptions or adjustments.

6. Conclusion

The purpose of this report is to help the OEB clarify to the Ontario electricity sector its expectations of applications by distributors to receive margin-on-payments incentives for implementing DERs as NWS. To provide greater clarity, Guidehouse has developed a specific set of quantitative criteria that distributors may use to assist them in their planning.

Guidehouse has developed these criteria with an understanding that the core purpose of providing distributors with incentives to implement cost-effective NWS is to drive customer value. Incentives are intended to accomplish this by “leveling the playing field” between traditional infrastructure and non-wires solutions in distribution planning decision-making, such that distributors implement the solution that is most cost-effective to its customers.

This “leveling of the playing field” is necessary because the use of DERs as NWS to defer distribution infrastructure capital investments is a relatively new phenomenon. Legacy regulatory frameworks in Ontario and abroad have had to be adapted to address the issues DERs and NWS raise.

The relative novelty of this phenomenon will also mean that market conditions may change quickly. Guidehouse recommends that the OEB, as identified in the FEI Report, continue to carefully monitor developments in Ontario and elsewhere, and, like the AER in Australia, remain flexible to evolving its incentive criteria as lessons are learned by the OEB, Ontario distributors, and other stakeholders.

Appendix A. Margin on Payment Examples – By Option

This Appendix provides a hypothetical example to demonstrate the magnitude of incentives and effect of eligibility criteria across three options.

Example: A distributor is planning to deliver a program to address localized distribution asset peak capacity issues through targeted procurement of demand response (i.e. peak shaving) services from owners of DERs and flexible loads. The program can help defer or avoid capital expenditures of $10 million, at a cost of $6 million for third-party DERs. This is the only program for which the distributor is requesting NWS incentive payments.

The only incremental costs for this program are the costs of paying the DERs for their capacity.

Forecast Year	*Third-Party DER Forecast Costs*	*Forecast Incentive (25% x Third-Party DER Costs)*
Year 1	*$0.20 million*	*$0.05 million*
Year 2	*$0.75 million*	*$0.19 million*
Year 3	*$1.25 million*	*$0.31 million*
Year 4	*$1.80 million*	*$0.45 million*
Year 5	*$2.0 million*	*$0.5 million*
TOTAL	***$6.0 million***	***$1.5 million***

$$Net\ DST\ benefit = Avoided\ Distribution\ Capital - Costs = \$10\ million - \$6\ million = \$4\ million$$

Option A

The distributor is eligible to claim the 25% margin on payments incentive only if the total forecast incentive payment is less than 75% of the forecast net DST benefit.

$$Incentive\ Cap = 75\% \times \$4\ million = \$3\ million$$

Since the calculated incentive of $1.5 million is less than the incentive cap of $3 million, the distributor is eligible and may apply the 25% margin value for collecting its incentive.

Option B

The distributor is eligible to claim the 25% margin on payments incentive only if the total forecast incentive payment is less than 30% of the forecast net DST benefit (Stage 1 Customer Value Criterion).

$$Incentive\ Cap = 30\% \times \$4\ million = \$1.2\ million$$

Since the calculated incentive of $1.5 million is more than the incentive cap of $1.2 million, the distributor is not eligible for the full incentive under the Stage 1 criterion.

The distributor can choose either to propose a lower margin value or to proceed to Stage 2 Innovation Flexibility Criterion. If the distributor elects to propose a lower margin value of 20%, the total forecast incentive would be $1.2 million, which is eligible under the Stage 1 criterion.

Option C

The distributor is eligible to claim the 25% margin on payments incentive only if the total annual incentive payments *across all of the distributor’s NWS incentive proposals* sum to less than 1% of the distributor’s most recently available audited annual distribution revenue in any forecast year.

$$Annual\ Distribution\ Revenue = \$800\ million$$

$$Annual\ Incentive\ Cap = 1\% \ \times \$800\ million = \$8\ million$$

Since the distributor has no other NWS incentive proposals and forecast incentives do not exceed $8 million for any forecast year, then they are eligible for the full $1.5 million incentive.

Appendix B. Option B DST Ratio Calculation

Section 4.2 notes that the Option B Stage 2 Innovation Flexibility Criterion will only really be required by distributors bringing forward incentive proposals for projects with relatively modest cost-effectiveness.

Even assuming that all of a project's costs are DER payments to which the margin applies, any project with a DST ratio of 1.8 or more will be eligible under the 30% Customer Value Criterion.

If DER payments to which the margin applies are only half of the project's costs (a more realistic estimate), then any project with a DST ratio of 1.4 or more will be eligible without needing the additional complexity imposed by the Innovation Flexibility Criterion.

Option B is, in fact, just as simple as Option A when the NWS project is more than modestly cost-effective.

The logic supporting the statements above related to DST ratios is presented below.

Under the Option B Stage 1 criterion, an incentive proposal is eligible where:

(Benefits – Costs) * 30% ≥ DERPaymentShare * Costs * 25%

Where "DERPaymentShare" refers to the percent of all project costs that are DER payments (and so to which the margin may be applied), and 25% is the margin value.

This can be simplified first to:

Benefits * 30% ≥ DERPaymentShare * Costs * 25% + Costs * 30%

And then to:

Benefits * 30% ≥ (DERPaymentShare * 25% + 30%) * Costs

And finally, to:

(Benefits * 30%) / (DERPaymentShare * 25% + 30%) ≥ Costs

So, even if DER Payments constitute 100% of NWS costs, then the 30% Customer Value Criterion will only rule incentives as ineligible for projects where the costs are more than 54.5% (30%/55%) of the benefits, or, put another way when the DST ratio of project cost-effectiveness is less than approximately 1.8.

In most cases, of course, DER payments will be a much smaller fraction of the total costs. If DER payments are (for example) 50% of NWS costs then the 30% Customer Value Criterion will only rule incentives as ineligible for projects where costs are more than (30% / (50% * 25% + 30%)) = (30%/ 42.5%) = 71% of the benefits, or, put another way when the DST ratio of project cost-effectiveness is less than approximately 1.4.

Appendix C. Jurisdictional Scan

To support this engagement, Guidehouse staff conducted a scan to identify and document incentive mechanisms used in other jurisdictions. This scan informs the eligibility criteria, the proposed margin value, and how these may be combined into a cohesive mechanism.

The seven jurisdictions included in this scan were selected based on the relevance of the publicly available information that could be obtained within the project timeline. Guidehouse included jurisdictions offering non-MoP-type incentive mechanisms to develop greater insight into the trends and drivers for incentive mechanism development.

A summary of the incentive mechanisms in these jurisdictions is presented in Table 3, below. The taxonomy used in this table (e.g., “Margin on Payments” as a category of mechanism, “Eligibility” to describe some incentive requirements, etc.) reflects the terms used in Ontario and in this report, and is based on the Guidehouse team’s interpretation of each jurisdiction’s mechanism.

This table is followed by text that identifies three of the most relevant insights provided by the jurisdictional scan, supported by references to individual jurisdictions. Finally, the seven subsequent sub-sections of this appendix provide a set of “index card” style jurisdictional summaries and the relevant citations.

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Table 3 Jurisdictional Scan Summary

Jurisdiction	Mechanism	Incentive Structure	Eligibility	Recent Developments
Australia	**Margin on Payments**	Distributors receive 50% of expected OM&A costs of demand management projects.	Total incentive in any year cannot exceed 1% of the distributor's allowed revenue for that year and cannot exceed project net benefits. Eligible OM&A costs include external contracted services, customer incentives, internal labour and overhead for customer acquisition, dispatch operations and payment of customer incentives.	The same incentive mechanism continues to be used by distributors. In May 2023, the Australian Energy Regulator estimated that the incentive has delivered a total of $50 million in benefits to customers at a cost of $3.2 million.
California	**Margin on Payments**	The three investor-owned utilities (IOUs)participating in an incentive pilot were permitted a return of 4% of annual 3rd party DER payments	The total incentive plus cost paid to DER provider must be less than the cost of the deferred utility capital investment. Eligible costs are the total costs of contracted services for 3rd party DERs.	None of the IOUs received cost-competitive bids under the pilot in 2017. No further progress was made on MoPs once the pilot was terminated.
Connecticut	**Shared Savings**	Electric Distribution Companies can retain up to 25% of forecast net benefits from NWS.	No eligibility criterion identified.	The incentive mechanism has not been implemented yet, the first process filings were scheduled to begin February 2025.
Hawaii	**Shared Savings**	Hawaiian Electric Companies can retain 20% of actual project savings for standalone storage and grid services projects.	Total incentive payments for all projects cannot exceed $10 million per year.	In December 2023, Hawaiian Electric announced its final award group for Stage 3 RFP totaling over 1,170 MW of capacity and 2,144 MWh of battery storage.
Michigan	**Margin on Payments**	Utilities can retain up to 15% of annual project O&M costs.	Utilities cannot recover their incentives if they achieve less than 50% of their Demand Response target. If the capacity achieved is less than 100% of the demand response (DR) target but above 50%, then the incentive	In 2023, Consumer's Energy achieved 644.4 MW of peak

Jurisdiction	Mechanism	Incentive Structure	Eligibility	Recent Developments
			is equal to 0.30% of its non-capitalized DR costs for every 1% point above the 50% DR capacity growth target achieved by the utility.	demand reduction, exceeding their target of 618 MW. In 2022, DTE achieved 786 MW of peak demand reduction, exceeding their target of 757 MW. In 2023, DTE achieved 831 MW of peak demand reduction, 24 MW short of their 855 MW target and leading to an 8% MoP incentive,
New York	**Shared Savings & Scorecard**	Utilities can retain an initial incentive of 30% of forecast net benefits plus or minus 50% of the difference between actual and forecasted costs of a NWS project.	Total incentive cannot exceed 50% of forecast net benefits. Utilities may recover their incentive once 70% of the forecasted MWs of NWS has been achieved.	In 2024, there were four open RFPs for NWS projects with load sizes ranging from 2 MW to 5 MW.
Rhode Island	**Shared Savings & Scorecard**	Utilities retain up to 20% of actual net benefits from implementing the NWS. In addition, utilities can earn performance incentives for completing specific actions identified in their System Reliability Procurement (SRP) report.	. No other known eligibility criterion. The Commissions plans to approve incentives on a case-by-case basis.	In Rhode Island Energy's 2024-2026 SRP they requested minimum performance incentives for successful implementation of their NWS. A shared incentive was also requested to continue their Demand Response program "ConnectedSolutions." The Commission has yet to finalize a decision on this.

Five of seven jurisdictions explicitly limit total incentive payments to protect customer value.

- *New York* allows utilities to retain an initial 30% of net benefits and may potentially earn up to 50% if they can lower NWS project costs. To ensure that customers are benefiting from actual project outcomes, New York only allows utilities to recover their incentive once 70% of the forecasted MWs of NWS has been achieved and adjusts the incentive payment by 50% of the difference between forecast and realized project costs.
- *Hawaii* uses a 20% shared savings mechanism coupled with a cap of $10 million for all incentives annually.
- *Australia* uses a 50% MoP style approach, requires the total incentive to be less than project net benefits *and* requires that the distributor's total annual incentive to be less than 1% of its allowed revenue in each year.
- *Rhode Island* nominally uses a 20% shared savings mechanism.
- *Michigan* applies a 15% adder to non-capital project costs only the utility ahieves at least 50% of their Demand Response target.

Margin on payments-style mechanisms are less common than shared savings-style mechanisms, and the value of the prescribed margins varies widely.

The jurisdictional scan revealed a wide range of margin values from 4% to 50%. A review of the evolution of the incentives in Australia, Michigan and California, and the rationales used to support their specification make it clear that the prescribed margin value is, in each case, a negotiated value. Although allowed returns on equity are referenced in each discussion as a point of comparison, in none of the three cases is the margin value derived directly from that allowed return.

Jurisdictions with higher upper limits on total incentive payments appear to have been more successful in realizing NWS projects.

- *New York* utilities each release Request for Proposals for NWS opportunities on an ongoing basis at the same shared savings value of 30% with a cap of 50%. Service-area-defined eligibility requirements provide utilities with flexibility to procure more projects by varying the level of effort applied to opportunity assessment according to project size and cost. This flexibility in addition to the incentive payments and likely the offerings maturity appears to have resulted in a relatively higher uptake in New York compared to other jurisdictions.

  In 2019, Con Edison had two deployed NWS projects which would provide a combined 95 MW by 2021, with 52 MW completed in 2018. Con Edison also, at this time, had two NWS projects in planning stages, projects projected to provide 66 MW of load relief over 10 years. In 2024, NY State Electric and Gas procured a 1 MW battery energy storage system to defer the implementation of a traditional solution for 10 years. Four RFPs for NWS projects with load sizes ranging from 2 MW to 5 MW were released in 2024 in New York.
- *Michigan* utilities' incentives are tied to a targeted volume of DR capacity that the utilities are required to acquire by their regulator. Guidehouse has not conducted a comprehensive assessment of the attainment of DR targets by Michigan's utilities, but notes that in recent years the two largest utilities (Consumers and DTE) appear to have attained their DR capacity targets and so achieved the incentive payments of 15% of O&M costs. In 2019 and 2020, Consumer's Energy conducted the five NWS assessments to receive the additional 2% incentive provided for doing so. In 2023, Consumer's Energy achieved 644.4 MW of peak demand reduction, exceeding their target of 618 MW.

- *California*'s pilot, with a 4% margin of payments, did not result in any projects. Two of the three large utilities participating did not receive any cost-competitive bids for DER projects. No NWS projects were implemented, and the incentive was not extended past the pilot period.
- *Australia*'s Energy Regulator (AER) estimated in May of 2023 that its incentive structure (50%) has delivered $50 million in benefits to customers at a cost of $3.2 million. AER launched their Demand Management Incentive Scheme in 2017 with an accompanying document outlining requirements for project eligibility; methodology for determining maximum incentives a project may accrue; detailed worked examples; compliance reporting and data requirements; outlines the incentive recovery process and how AER have considered stakeholder submissions. Providing clarity around process and requirements may also have contributed to Australia's success. The AER expects to be able to decrease the margin value in the future as the market transforms, and other indirect incentives encourage their deployment.

C.1 Australia

Jurisdiction	**Australia**
Incentive Structure	Margin on Payments
Incentive Value Calculation	• Utilities can receive an incentive up to 50% of expected costs on demand management (DM) projects. The final incentive value is calculated by taking the expected present value of the of the project's DM costs minus the subsidies the utility will receive for the DM component of the project and multiplying it by 50%.
Incentive Limits and Eligibility Criteria	• The incentive value cannot be less than $0 and cannot be greater than the expected relevant net benefits of the project. The eligible costs are any OM&A development and implementation costs of the project. This includes external contracted services, customer incentives, internal labour and overhead for customer acquisition, dispatch operations and payment of customer incentives. • The total incentive in any year cannot exceed 1% of the utility's allowed revenue for that year. • The utility must identify if the project is an efficient non-network option by completing the Australian Energy Regulator's regulatory investment test (RIT-D) for large projects or using a simpler cost-benefit analysis for small projects prescribed by the minimum project evaluation requirements.
Implementation History & Rationale	• In 2009, a Demand Management Incentive Scheme (DMIS) was developed where utilities had a fixed annual allowance to use for non-network demand management projects.[1] • In 2012, the Australian Energy Market Commission determined the scheme did not provide enough incentives to encourage utilities to apply for DM projects. As part of this, Ausgrid (electricity distribution

	company) raised the idea of a shared savings mechanism where utilities retain 30% of net market benefits and 70% is retained by customers [2]
	• In 2017, the Australian Energy Regulator (AER) held a proceeding to update the DMIS[3] and to allow utilities collect an incentive up to 50% of the project's cost with the annual cap limiting total incentives received to 1% of the utilities' allowed revenue for that year.
	• The AER opted for a margin on payments mechanism as their "*assessment took into account stakeholder views that indicated that the Scheme should include financial incentives, impose a small administrative burden, and not contribute to uncertainty. We consider that the cost multiplier* [MoP] *is the better option to address these concerns compared with net benefit sharing* [shared savings mechanism]"[4]
	• AER selected a 50% MoP value primarily based on its being within the range identified by modeling conducted by the Institute of Sustainable Futures[48] and the fact that "*a cost multiplier of 50 per cent broadly aligns with stakeholder submissions".* [4]
	• The AER illustrated that the 50% MoP incentive is equivalent to a distributor receiving "*an allowed rate of return of 6.3 percent compounded semi-annually over approximately 6.5 years."*
	• AER chose a cap of 1% on utilities' allowed revenue because it "*is similar to the cap used under the annual network capability incentive allowance. This cannot be greater than 1.5 percent of the average annual maximum allowed revenue of a transmission network service provider over the regulatory control period*".[4]
	• AER also found that the 1% cap still allowed utilities to receive large financial incentives and did not limit the amount a utility can spend on DR.[4]
	• AER states that they believe the 50% cost multiplier will likely change in the future due to the following reasons[4]:
	    o A decrease in the value if there are compliance breaches
	    o A decrease or possible increase in response to regulatory changes that affect the utilities' reasons to undertake demand management.

[48] The AER cites this range as being between 40 and 90 per cent. These values effectively capture the difference between customer net benefits under the demand management solution and the distributor profits under the capital infrastructure solution. The authors of this paper refer to this as a pattern of "*what is good for the distribution network is bad for customers".*

See PDF page 19 of 58 in

Australia Renewable Energy Agency, ***Demand Management Incentives Review – Creating a level playing field for network Demand Management in the National Electricity Market***, June 2017

	○ A decrease or possible increase in response to market changes that affect the utilities' reasons to undertake demand management. ○ An increase if utilities encounter greater costs and difficulties when applying demand management than initially considered. . • In May 2023, AER estimated that DMIS has delivered $50 million in benefits to consumers at a cost of $3.2 million by encouraging utilities to defer their capital expenditures with demand management activities.[5]
Sources	[1]Australia Energy Regulator, ***Demand Management Incentive Scheme***, 2011-15, April 23rd 2009 [2]Australian Energy Market Commission, ***Power of choice review – giving consumers options in the way they use electricity***, Ref: EPR0022, November 30th 2012Error! Hyperlink reference not valid. [3]Australia Energy Regulator, ***Demand Management Incentive Scheme***, Ref: 58882, December 14th 2017, [4]Australia Energy Regulator, ***Explanatory statement – Demand Management Incentive Scheme***, Ref: 58882, December 14th 2017 [5]Australian Energy Regulator, ***Decision – Demand Management Incentive Scheme payments for 2020-21 and 2021-22***, Ref: 14866586.2, May 18th 2023,

C.2 California

Jurisdiction	**California**
Incentive Structure	Margin on Payments
Incentive Value Calculation	The pilot incentive program allowed investor-owned utilities (IOUs) to receive an incentive of 4% pre-tax of the actual total annual cost of contracted services for DER projects.
Incentive Limits and Eligibility Criteria	• The total incentive plus cost paid to DER provider must be less than the cost of the avoided or deferred utility capital investment. • Eligible costs are the total costs of contracted services for 3rd party DERs. • IOUs could propose up to four projects for this pilot program.
Implementation History & Rationale	• In 2016, an initial proposal named *Assigned Commissioner's Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment* [1] was released by the California Public Utilities Commission

	(CPUC). It proposed a margin on payments incentive of 3.5% for DER procurement. This incentive magnitude was proposed based on how much the return on equity typically exceeds the cost of capital for most of California's traditional utility investments (how much actual profit the utility typically makes on a project). • The 2016 initial proposal states "*the utility's incentive to invest is determined by r* [Return on Equity] *minus k* [Cost of Capital]. *Since in recent years r* [Return on Equity] *has consistently exceeded k* [Cost of Capital] *by roughly 2.5 to 3.5 percentage points in California as well as nationally, the incentive to invest additional capital in the utility business has been strong. If this Commission desires to incent the IOUs* [Invested Owned Utilities] *to displace some of that investment by procuring DERs, it should offer utility shareholders the opportunity to achieve equal or greater value by so doing*."[1] • Stakeholders voiced concerns on the approach for arriving at the 3.5% proposal and some suggested it needed to be higher to address the investment scale problem – which is when DERs are a lot cheaper than the traditional investment, the utility might still be better off financially if they chose the traditional investment. • On September 1st, 2016, CPUC submitted a revised proposal[2], *Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge.* The proposal revised the methodology and stated that pre-tax actual profit is 6% and the typical equity portion is half of that, thus a 3% incentive minimum is a reasonable starting point. CPUC proposed a higher MoP value of 4% to address stakeholder concerns to address the investment scale problem.[2] • On December 15th, 2016, the CPUC approved the incentive pilot proposed as a consensus was reached among parties. The pilot was set for three utilities: Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) who were encouraged to each select up to three additional projects to test the incentive mechanism. The pilot program covered a timeline of 17 months [3] • Neither PG&E or SDG&E received any cost-competitive bids during the incentive pilot program solicitation and therefore did not complete a project. SCE did pursue a project but "*unknowingly implemented the pilot on a distribution system that did not need voltage regulation support and was unable to complete the analysis*."[4] • PG&E reported that a major lesson from the program was the uncertainty in load forecasts and the importance of direct and indirect impacts of changes to loads for assessing the validity of DERs.[4] • Prior to the pilot, IOUs expressed that it is not the lack of shareholder financial incentives that have limited DER deployment but the lack of foundational frameworks such as: distribution system planning

	integrating DERs; how to define DER services utilities can rely on for operations; cost comparison methodology for traditional vs third-party DER; and contracting process for acquiring DERs.[5]
Sources	[1] California Public Utilities Commission, ***Assigned Commissioner's Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment***, Rulemaking 14-10-003, April 4th 2016, [2] California Public Utilities Commission, ***Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge***, Rulemaking 14-10-003, September 1st 2016, [3]California Public Utilities Commission, ***Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Program***, Rulemaking 14-10-003, December 15th 2016, [4]Lawrence Berkeley National Laboratory, ***Locational Value of Distributed Energy Resources***, February 2021, [5]Smart Electric Power Alliance, ***California pilot programs to test if shareholder incentives can boost DER deployment***, September 29th 2016,

C.3 Connecticut

Jurisdiction	**Connecticut**
Incentive Structure	Shared Savings
Incentive Value Calculation	• Utilities can retain an incentive up to 25% of estimated forecast net benefits from the NWS based on the Total Resource Cost test (TRC). • The exact incentive percentage value is decided by the Connecticut Public Utilities Regulatory Authority (PURA) during the bid selection process.
Incentive Limits and Eligibility Criteria	The total incentive is capped at 25% of estimated forecast net benefits based on the Total Resource Cost test (TRC).

Implementation History & Rationale	• In 2021, a Straw Proposal[1] was issued by Connecticut Public Utilities Regulatory Authority (PURA) to establish a process for comparing potential NWS against traditional distribution system upgrades. PURA recommends a shared savings incentive of up to 25% of the projected net savings in comparison to the traditional solution. • PURA states that a 25% incentive is reasonable as customer savings should be prioritized, it provides utilities with a strong signal to consider NWSs and is more conservative than other jurisdictions. On the last point, they state "*New York allows a 30% sharing of net benefits (as distinct from net consumer savings). In this regard, the Authority* [PURA] *suggests a more conservative test because either the consumer savings incentive or the customer benefit incentive would both be capped at 25% of customer savings. This structure hems the Authority's approach closely to pursuing customer savings at the same time it advances Connecticut's grid modernization through NWA and other initiatives.*"[1] • The Straw proposal[1] also suggested an additional incentive based on the achievement of superior grid benefits, the performance incentive would be up to half of the calculated value of additional/superior grid benefits provided that "*the total grid and customer benefit incentives shall not exceed the customer savings incentives* [the 25% incentive described above]". • In 2022, the Final Decision[2] by PURA was ordered which included the 25% customer savings incentive, however there was no mention of the performance incentive discussed in the Straw Proposal. • The selection process[3] for NWS involves the utility issuing an RFP for grid needs, then NWS bidders respond to it. The utility will evaluate each solution based on the TRC test and recommend the option that maximizes net benefits (based on the test) to PURA. Recommendations can be a mix of several bids; PURA will then decide (PURA selection decision) where they will quantify the precise shared savings incentive. • In a 2025 Staff Concept Paper by PURA, the incentive is encouraged by the commission and states the need for NWSs to be considered in utilities' integrated distribution system planning.[4] • The incentive mechanism has not been implemented yet, the first process filings will begin in February 2025.
Sources	[1]State of Connecticut Public Utilities Regulatory Authority, ***Non-Wires-Alternatives Straw Proposal***, Docket 17-12-03RE07, July 30th 2021 [2]State of Connecticut Public Utilities Regulatory Authority, ***PURA Investigation into Distribution System Planning of the Electric***

	Distribution Companies – Non-Wires Alternatives Final Decision, Docket 17-12-03RE07, November 9th 2022 [3]State of Connecticut Public Utilities Regulatory Authority, ***Appendix A Non-Wires Solutions Process Design Document***, Docket 17-12-03RE07, November 9th 2022 [4]State of Connecticut Public Utilities Regulatory Authority, ***Revised Staff Concept Paper No. 1***, Docket 21-05-15RE03, January 6th 2025

C.4 Hawaii

Jurisdiction	**Hawaii**
Incentive Structure	Shared Savings & Performance Targets
Incentive Value Calculation	• Hawaiian Electric Companies can retain a shared savings incentive of 20% of the actual project savings for standalone storage and grid services projects. • The savings are calculated by comparing the actual project costs to the Commission set thresholds. The thresholds are set at a reasonable percentage (i.e. 20%) below the applicable value of service to encourage competition from potential bidders. • The initial allocation of the incentive is 20% share of the savings, multiplied by the forecasted first-year energy production.

Incentive Limits and Eligibility Criteria	• The cap for combined incentives is $10 million (after taxes) annually, through 2025.
	• For standalone storage projects, the utility must prove the following:
	  o Delivered cost of electricity from a standalone storage project must be 20% below the average avoided cost of electricity for that calendar year.
	  o GHG emissions related to the delivered electricity from standalone storage must be at least 25% below GHG emissions of the capacity resource being replaced.

Implementation History & Rationale	• In 2018, Hawaii Public Commission established an Order[1] for Performance Incentive Mechanisms (PIM) for Hawaiian electric companies to receive incentives for procuring low-cost renewable energy power purchase agreements. • The Order[1] established a shared savings incentive with a split of 80% to customers and 20% to utilities with a cap of $3,500,000 (which later got set to $6,500,000 to address impacts of the volcanic eruption on Hawaii Island due to lost renewable generation) which was approximately equal to 3% of the Hawaiian Electric Companies net income in 2017.

	• In 2019, Phase 2[2] of the PIMs incentive was established with a proposal from the Hawaiian Electric Companies. The Commission set an Order which expanded the incentives to include standalone storage and ancillary services from aggregated DERs (grid services). • From the results of the Phase 1 incentive in 2018, the Commission believed that the incentives significantly contributed to the success of the overall bidding process. • The Commission set an overall cap of $10 million on combined PIMs based on their consideration of opportunities to bring on renewable energy and grid services and the value to customers that could be delivered as a result of procurements.
Sources	[1]State of Hawaii Public Utilities Commission, ***Establishing a Performance Incentive Mechanism for Procurement in Phase 1 of Hawaiian Electric Companies' Final Variable Requests for Proposal***, Order 35405, Docket 2017-0352, April 6th 2018 Available as "*Order No. 35405*" (**PDF**) [2]State of Hawaii Public Utilities Commission, ***Establishing Performance Incentive Mechanisms for the Hawaiian Electric Companies' Phase 2 Requests for Proposal***, Order 36604, Docket 2017-0352, October 9th 2019 Available as "*Order No. 36604*" (**PDF**) [3]State of Hawaii Public Utilities Commission, ***Addressing the Hawaiian Electric Companies' Motion for Clarification and/or Reconsideration of Order 36604***, Order 37123, Docket 2017-0352, May 1st 2020 Available as "*Order No. 37123*" (**PDF**)

C.5 Michigan

Jurisdiction	**Michigan**
Incentive Structure	Margin on Payments
Incentive Value Calculation	• Utilities earn up to an annual 15% on Operations & Maintenance (O&M) costs • If the capacity growth result is less than 100% of their DR target but above 50%, then the incentive is equal to 0.30% of its non-capitalized DR costs for every 1% above the 50% DR capacity growth target.
Incentive Limits and Eligibility Criteria	• The total incentive is capped at 15% of O&M costs (non-capitalized costs which refer to customer acquisition costs and customer incentive payments). • The 15% incentive is paid conditional on utilities attaining 100% of their Demand Response (DR) capacity growth target.

	• No incentive is recovered if the company achieves less than 50% of its target.
Implementation History & Rationale	• In 2018, Consumers Energy Company filed an application[1] to reconcile its 2017 demand response costs and revenue in accordance with a 2017 order. In the application, they request approval of a DR financial incentive mechanism which would encourage the building, usage, and application of the DR virtual power plant in Michigan. • Their proposed incentive would allow them to earn an incentive of 20% on all expenses to implement, manage and enroll customers in the DR programs and earn an incentive of 20% on payments to use DR resources.[1] • The Michigan Public Service Commission believed that the proposed mechanism is "*far too generous and it does not promote aggressive, positive and balanced actions by the Company* [Consumers Energy Company] *to appropriately harness the benefits of DR.*"[2] The Commission determined an incentive based on annual incentive payments to customers may result in the utility maximizing the customer incentives to be higher than necessary. • To counter Consumer Energy's proposal, the Commission proposed a less generous incentive which they believe is more reasonable. Their proposed mechanism would allow the utility to earn its normal return on DR capital costs (10%). Regarding non-capitalized costs, utilities would receive up to a 10% incentive on non-capitalized costs for reaching up to 100% of their DR target. In addition, the utility can earn an additional incentive equal to 10% of cost savings **or** 3% of non-capitalized costs (whichever is lesser). Finally, the incentive comes along with a bonus 2% incentive for demonstrated assessment of DR as part of NWSs for at least five T&D projects. The incentive cap would be 15% of non-capitalized spending = (10% non-capitalized costs) + lesser of (10% cost savings or 3% non-capitalized) + (2% for NWA assessments).[2] • The Commission states "*Thoughtful DR programs are beneficial to the Company* [Consumers Energy Company]*, their customers, and the stability of the electric grid. Staff does not want costs to exceed benefits however and would prefer to start out with a more conservative mechanism that will allow both the Company* [Consumers Energy Company] *and Staff to assess the appropriate level of outcomes for these programs*."[2] • The Natural Resources Defense Council (NRDC) raised concerns about the magnitude of the incentive saying that a DR incentive should be less than an energy efficiency incentive since DR does not produce a loss of revenue as energy efficiency does due to reduced energy sales. Consumer Energy Company's proposal would allow them to

	earn five times what it can earn on annual energy efficiency program spending.[2] • Currently, Michigan has an energy efficiency incentive which allows utilities to recover 20% of their actual energy waste reduction program expenditures for the year.[3] • NRDC proposed the incentive mechanism that is applied today consisting of up to 13% annual payment of non-capitalized DR costs for achieving DR capacity growth targets and an additional 2% for NWS assessments. They suggested that the "*magnitude of shareholder incentives in distributed energy resources be at least equal per dollar of investment (not absolute dollars) as supply alternatives.*"[2] • In 2019, the Commission approved the Order[4] with the financial incentive mechanism proposed by NRDC. • In 2021, Consumers Energy requested that the additional incentive for 2% of NWS assessment was removed as several alternative forums are beginning to address NWS such as the development of five-year distribution plans. They suggested to "*to end the NWA requirement as part of the DR incentive and include any potential NWA incentives as part of a different forum.*"[5] • In 2021, Consumers Energy also requested for the incentive to increase from 15% to 20% as they felt that the current 15% did not provide a compelling reason to invest in DR. They state that "*While there is a significant gap in earnings opportunity between a supply-side resource and DR investment, the Company is not implying that it should earn the same profit as it would by investing in a supply-side option; simply that any DR financial incentive should consider the divergence in profitability between investing in supply-side and demand-side options.*"[5] • The Commission denied the request to increase the incentive magnitude but agreed to remove the additional incentive for 2% for NWS assessments in 2021. Utilities are now allowed to earn a total of 15% on O&M costs without conducting NWS assessments.[6] • In 2019 and 2020, Consumer's Energy conducted the five NWS assessments to receive the additional 2% incentive.[6] • In 2023, Consumer's Energy achieved 644.4 MW of peak demand reduction, exceeding their target of 618 MW.[7] However, their 2024 Electric Distribution Infrastructure Investment Plan did not explicitly consider NWS as an alternative to traditional investment. [8] • In 2022, Detroit Edison (DTE) achieved 786 MW of peak demand reduction, exceeding their target of 757 MW[9]. In 2023, DTE achieved 831 MW of peak demand reduction, not exceeding their target of 855 MW.[10]

Sources	[1]Michigan Public Service Commission, ***Consumers Energy Company Application for 2017 Demand Response Program Costs***, Case U-20164, May 31st 2018 [2]Michigan Public Service Commission, ***Metro Court Reporters Transcript***, Case U-20164, March 11th 2019 [3]State of Michigan, ***Clean and Renewable Energy and Energy Waste Reduction Act***, Act No. 342, Section 75 (b), April 20th 2017, [4]Michigan Public Service Commission, ***Order Approving Financial Incentive Mechanism***, Case U-20164, July 18th 2019 [5]Michigan Public Service Commission, ***Application for Reconciliation of its 2020 Demand Response Program Costs***, Case U-21080, June 1st 2021 [6]Michigan Public Service Commission, ***Order Approving Settlement Agreement***, Case U-21080, March 3rd 2022 [7]Michigan Public Service Commission, **Consumers Energy Company application for 2023 demand response program costs**, Case U-21647, November 20th 2024 [8]Consumers Energy Company, **Electric Distribution Investment Plan (2024-2028)**, September 27th 2023 [9]Michigan Public Service Commission, **DTE Electric Company application for 2022 demand response program costs**, Case U-21403, June 29th 2023 [10]Michigan Public Service Commission, **DTE Electric Company application for 2023 demand response program costs**, Case U-21658, June 28th 2024

C.6 New York

Jurisdiction	**New York**
Incentive Structure	Shared Savings & Scorecard
Incentive Value Calculation	Utilities can retain an initial incentive of 30% of estimated forecast net benefits, *plus or minus* 50% of the difference between actual and forecasted costs of a NWS project.
Incentive Limits and	• The final incentive is capped at 50% of the estimated forecast net benefits, based upon the Societal Cost Test (SCT).

Eligibility Criteria	• If additional MWs are needed, a utility may recover expenses incurred in obtaining the additional MWs, including ongoing expenses. *However, the final incentive will not include these costs.* • If the utility needs less than 70% of the initially forecasted MWs then it can calculate an Initial Unit Incentive which is 30% of its calculated share divided by the initially forecasted number of MWs.
Implementation History & Rationale	• In a 2015 proposal[1], Central Hudson proposed a NWS incentive mechanism where they would retain 50% of the estimated forecast of net benefits. • This was in relation to Central Hudson's need for a demand reduction of 16 MW in three targeted areas. Central Hudson proposed that 50% of the incentive would be triggered at the achievement of 7 MW of demand response and the remaining 50% be triggered at the achievement of the total 16 MW of demand response. • In a 2016 order[2], The New York Public Commission accepted the proposal with the modification that utilities would retain 30% and ratepayers would retain 70%. The commission states "*We arrived at the sharing percentage by considering the magnitude of the alternative investments, the deferred investment period of the traditional T&D projects, and the likelihood of achieving the savings for consumers.*"[2] • Specifically, the Commission noted that an incentive opportunity should be financially meaningful to the utility and produce significant net benefits to customers. A 30% incentive would aid residential customers to save approximately $5 million on a net present value basis over the deferred investment period for the proposed project (16 MW of demand response mentioned above)[2]. • In a 2016 ConEdison proposal[3], ConEdison requested an incentive mechanism for demand management projects including NWS where the initial incentive is a 50-50 sharing of the net benefits plus 50% of cost overruns or underrun, as long as the total final incentive is a maximum of 75% of net benefits. ConEdison states that since the incentive is based on a pre-tax basis, ConEdison's real share of the net benefits would be 25-30%. Therefore, it is a reasonable distribution of the benefits as customers receive the majority of benefits. • In a 2017 Order[4], the Commission accepted the proposal with modifications. The Commission believes that a 30% share for utilities is acceptable, they state "*the 30% sharing adopted here represents a financially meaningful incentive opportunity that should encourage Con Edison to pursue the innovative portfolio-level approach to implementing NWA projects, while producing significant net benefits to customers and reflecting the financial risk required of Con Edison shareholders*."

	• The Commission also adopted a final incentive cap of 50% rather than the proposed 75%. The rationale for the modifications were based on the level of investment risk that is taken by the utility for this incentive: 1) With an incentive floor of $0, the mechanism is a reward-only incentive. 2) The utility is also able to recover its NWS project costs even if the traditional project is not deferred for the full period envisioned.[4] • Service-area-defined eligibility requirements provided utilities with flexibility to procure more projects by varying the level of effort applied to opportunity assessment according to project size and cost. This flexibility in addition to the incentive payments resulted in a relatively higher uptake in New York compared to other jurisdictions. • The shared savings incentive mechanism remained the same once the order was placed with some changes in NWS suitability for one utility. The incentive mechanism was applied to all utility rate orders moving forward. The most recent rate plan (2023-2026) for New York State Electric and Gas (NYSEG) contains the incentive mechanism in Appendix HH[5]. • New York utilities continue to submit applications for NWS projects with the shared-savings incentive - in 2024 the NYSEG submitted a proposal[6] to defer the costs of a planned substation with an estimated cost of $13.70 million. • The incentive showed success in utilities procuring NWS, in 2019 ConEdison had two ongoing NWS projects providing a combined 95 MW by 2021, with 52 MW already having been completed in 2018. Two NWS projects were in development which would provide a total of 66 MW of load relief over 10 years.[7] • In 2024, there were four open RFPs for NWS projects with load sizes ranging from 2 MW to 5 MW[8]. One project was in progress in 2024 which would install a 1 MW battery energy storage system to defer the implementation of a traditional solution for 10 years[6].
Sources	[1]New York State Public Commission, ***Central Hudson NWA Project Cost Recover and Incentive Proposal***, Docket 14-01483, July 17th 2015 [2]New York State Public Commission, ***Order Implementing With Modification the Proposal for Cost Recovery and Incentive Mechanism for Non-Wire Alternative Project***, Docket 14-01483, July 15th 2016 [3]New York State Public Commission, ***ConEdison TDM Incentive Mechanism Proposal***, Docket 15-00844, March 4th 2016 [4]New York State Public Commission, ***Order Approving Shareholder Incentives***, Docket 15-00844, January 25th 2017

	[5]New York State Public Commission, ***NYSEG Order Adopting Joint Proposal***, Docket 22-E-0317, October 12th 2023 [6]New York State Public Commission, ***NYSEG Stillwater Implementation Plan***, Docket 22-E-0317, January 25th 2024 [7] ConEdison, ***Non-Wires Solutions Spring 2019 Program Update***, April 17th 2019 [8] Joint Utilities of New York, ***Non-Wires Alternatives Opportunities***,

C.7 Rhode Island

Jurisdiction	**Rhode Island**
Incentive Structure	Shared Savings & Scorecard ("Action-Based")

Incentive Value Calculation	• Utilities can retain a shared savings incentive up to 20% of the actual net benefits from implementing NWS.
	  o The utility will submit their incentive proposal as part of their annual System Reliability Procurement (SRP) plan following the year-end evaluation, measurement and validation of the project's performance.
	  o The incentive will be calculated using the Utility Cost Test
	• Utilities can also earn an action-based incentive equal to a portion of their initial annual SRP budget for completing certain actions which they state in their SRP report. The utility states associated percentages with the actions in their SRP proposal.
	  o The incentive value is based on the initial annual budget calculated in the submitted SRP report.
	  o For example, a utility could earn a 2% incentive if they issue RFPs for NWS resources.

Incentive Limits and Eligibility Criteria	The shared savings incentive is set at 20% of the achieved net benefits.
Implementation History & Rationale	• In 2017, the Least Cost Procurement Standards[1] were published by Rhode Island Public Utilities which states that a "*distribution company shall have an opportunity to earn a shareholder incentive that is dependent on its performance in implementing the approved SRP Plan*". • In their 2018 SRP[2], Rhode Island Energy proposed an incentive mechanism comprised of action-based and savings-based incentives. • The Rhode Island Public Utilities approved the 2018 SRP, stating that the incentive mechanisms "*encourages completion of short-term planning milestones and the sharing of long-term cost savings between the Company and customers*"[3].

	• The shared savings incentive was applied to Rhode Island's Little Compton Battery Storage project, which delivered $ USD 566k of net benefits, resulting in an incentive of $USD 113k for National Grid.[4].
	• The action-based SRP incentives for the 2018 SRP included five actions with a maximum incentive of 6% of the 2018 SRP budget[2]. The utility proposed these action-based incentives designed to "*promote the availability of distribution grid information for distribution energy resource solution providers, customers and other stakeholders*"[2].
	• The Commission stated that the action-based incentives, seem reasonable when compared to Rhode Island Energy's original energy efficiency plans since they also contained similar action-based and savings incentives. The Commission predicts that the SRP incentives will evolve similarly to energy efficiency incentives, stating that "*As the Company and stakeholders gain an understanding of SRP, the uncertainty will be diminished and there will be more opportunities to adopt shared-savings incentives.*"[3]
	• The actions and their associated incentive percentages are:
	  o Distribution System Loading Map (1%)
	  o Distributed Generation (DG) Focused Map (1%)
	  o Avoided Cost Stakeholder Review Process (1%)
	  o Marketing & Engagement Plan (1%)
	  o Issue RFPs for NWA Resources (2%)
	
	Rhode Island Energy will also be able to earn the savings-based incentive of 20% of its actual net benefits for the DERs installed as a result of the SRP initiatives stated above.[2]
	
	• The Commission approved Rhode Island Energy's 2021/2023 SRP which included the action-based performance incentives mentioned above. In their 2024-2026 SRP plan, Rhode Island Energy proposed a shared savings incentive of 80/20 as well as an additional minimum performance incentive for successful implementation of each SRP solution. This minimum performance incentive was intended to make Rhode Island Energy whole (equivalent to return for traditional investment) for selecting the NWS solution[5]
	• In 2024, the Commission commented on the Rhode Island Energy's SRP, stating that the 80/20 shared savings split is appropriate for most investments but recommends a case-by-case evaluation of each proposal. They also state that a minimum performance incentive appears contrary to its desire to decrease utility spending. They regard the plan as a guiding framework that will allow for reasonable methods of evaluating SRP proposals, but did not approve it.[6]
	• In Rhode Island Energy's 2024-2026 SRP they requested a shared incentive to continue their Demand Response program

	"ConnectedSolutions." The Commission has yet to finalize a decision on this. [7]
Sources	[1]Rhode Island Public Utilities Commission, ***Least Cost Procurement Standards***, Docket No. 4684, July 28th 2017 [2]Rhode Island Public Utilities Commission, ***National Grid 2018 System Reliability Procurement Report***, Docket No. 4756, November 1st 2017, [3]Rhode Island Public Utilities Commission, ***Order for the 2018 System Reliability Procurement Report***, Docket No. 4756, December 20th 2017 [4] Rhode Island Public Utilities Commission, ***National Grid 2019 System Reliability Procurement Plan Report***, September 2018 [4]Rhode Island Public Utilities Commission, ***2021-2023 System Reliability Procurement Three-Year Plan***, Docket No. 5070, November 20th 2020 [5]Rhode Island Public Utilities Commission, ***2024-2026 System Reliability Procurement Three-Year Plan***, Docket No. 23-47-EE, November 17th 2023 [6]Rhode Island Public Utilities Commission, ***2024-2026 SRP Review***, Docket No. 23-47-EE, April 26th 2024 [7]Rhode Island Public Utilities Commission, ***2024-2026 SRP Three-Year Plan***, Docket No. 23-47-EE, November 17th 2023