ONTARIO ENERGY BOARD

Webinar: Third-Party DERs as Non-Wires Solutions

Webinar Context and Background

November 22, 2023

Context for Today's Webinar

Purpose

- Respond to industry feedback that LDCs would benefit from additional guidance on the information and analysis that could be included in a proposal for third-party DER incentives.
- Present examples of incentive proposals, which are intended to provide further guidance on the information and analysis requirements set out in the OEB's Filing Guidelines for Incentives to Use Third-Party DERs (Filing Guidelines).
- Provide an opportunity to respond to participants' questions on the examples presented.

Additional Context

- Guidehouse Canada Ltd. was contracted to help develop high-level summaries of the information and analysis requirements for the example proposals.
- Examples reflect the key elements/considerations that may be included in an incentive proposal, but do not prescribe specific requirements/approaches. They are also not intended to signal which DER use-cases and incentive structures that LDCs should submit in a proposal.
- Approval of proposals is the responsibility of OEB commissioners.

Background: Framework for Energy Innovation (FEI)

OEB Report on the FEI (January 2023) established the following policies and next steps supporting DER integration:

Expectations of LDCs:

- ✓ Factor DER integration into system planning.
- ✓ Consider Non-wire Solutions (NWS) and go to market before proposing their own DER solutions.

Establish a Benefit Cost Analysis (BCA) Handbook to support consistent evaluation of DER solutions, including NWS, for meeting distribution system needs.

To provide certainty regarding cost recovery, LDCs may apply for a deferral account for material OM&A costs incurred in advance of their next rebasing application.

Invitation for LDCs to submit proposals for incentive mechanisms to use third-party DERs as NWS.

Overview of Guidance on Third-Party DER Incentives

The OEB Report on FEI invited LDCs to submit proposals for the following incentive options:

Scorecard-based Incentives

Allows LDCs to earn fees based on their performance against scorecard metrics measuring the NWS benefits.

Shared Savings Mechanisms

Calculates the savings for customers from DER solutions and allocates a formula-based portion of savings to utility shareholders.

Margin on Payments

Allows LDCs to add a margin on spending on third-party DERs.

Filing Guidelines for Incentives to Use Third-Party DERs (March 2023) provide guidance on the information that should be included in incentive proposals.

Guidehouse

ONTARIO ENERGY BOARD

Utility Incentives for Third-Party DERs used as NWSs

OEB Webinar

2023-11-22

Agenda

Example Webinar

- Example 1: Shared Savings
- Example 2: Scorecard
- Example 3: Margin on Payments

Note: The incentive examples are hypothetical and are intended to provide additional guidance on the information and analysis that could be included in an incentive proposal. OEB commissioners are responsible for determining appropriate incentive mechanisms.

Example 1:

Shared Savings Mechanism

Example 1 Summary. TS deferral, SSM incentive.

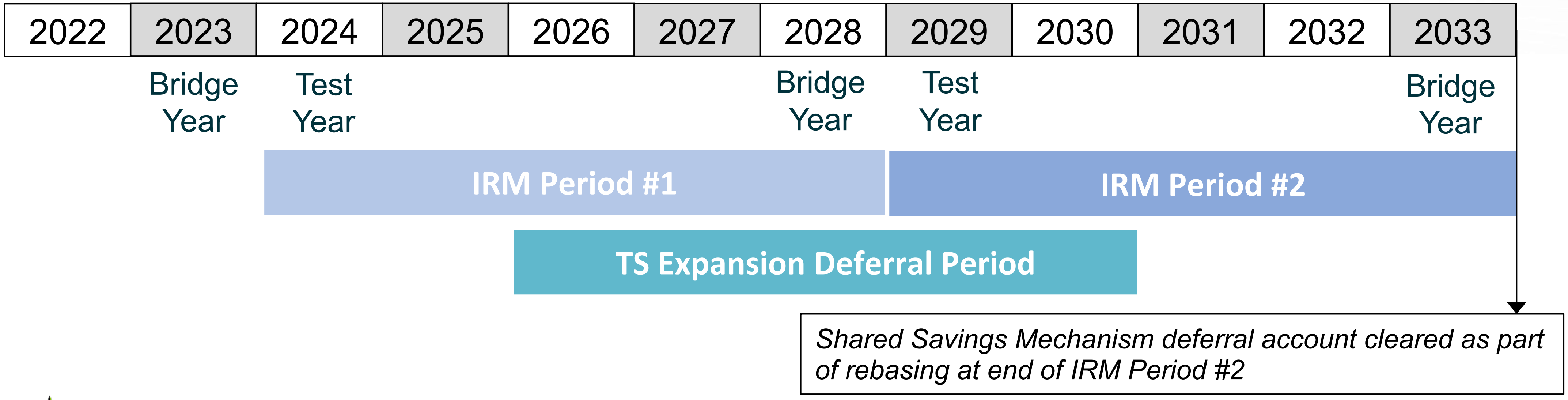
Approval Sought	**Shared Savings Mechanism**, valued at $4 million. Deferral account to be cleared on the basis of evaluated net benefits of NWA following withdrawal of NWA from service.
Driver of Need	Increasing density, hotter summers exacerbated by an urban microclimate is accelerating growth of summer peak demand at one of the LDC's transformer stations (TS).
Timing	**Submitted as part of a rebasing application.** The TS must be significantly upgraded in 2-3 years. Deployment of the DER can defer that by 4-6 years.
DER	A/C direct load control from multi-residential and commercial buildings, procured from a demand response aggregator.
Deployment Type	**Project deployment.** DER procurement is for a targeted need without expectation of recurrence beyond the deferral period.

Example 1 - Driver of Need

- The LDC is projecting substantial load growth in an increasingly dense urban service area served by its Nemo Transformer Station (TS).
- Peak loads on this TS are relatively infrequent, and spiky. Peaks are closely correlated with multi-day periods of very hot week-day weather, driven by cooling loads in its institutional, commercial, and residential customers.
- Nemo TS is projected to reach 85% of loading by late 2025.
- This system need is non-discretionary
  - Failure to address it will result in reduced reliability, costly short-term load transfer projects, reduced flexibility to schedule maintenance outages, increased risk of equipment failure, and an inability to connect new loads in this rapidly growing urban environment.
  - Operating this TS at a high capacity puts the system at risk of violating design parameters, resulting in rotating blackouts and voltage reductions.
- This system need must be addressed to ensure continued power quality and reliability.
- A traditional wires solution will require acquisition of new buildings and installation of new switchgear. The cost of this solution is estimated to be approximately $60 million.

Example 1 - Timing

- Forecast peak demand growth follows a historically consistent trend, indicating that the capacity constraints facing Nemo TS must be addressed in the next 2-3 years.
- This has been determined to be sufficient lead time to allow for the acquisition of customer-based demand response (DR) capacity.
- The certainty of the forecast need, the contractual certainty of DR delivery, and timing of the need means that development of the BCA and other application materials can be accomplished as part of the drafting of the LDC’s DSP submitted as part of the LDC’s 2023 rebasing.
- Shared savings mechanism incentives will be disbursed from the project deferral account at the first rebasing following the end of the NWA benefit period (the TS expansion deferral period).



Example 1 – Distributed Energy Resource (1/2)

Proposed Non-Wires Solution

- The characteristics of the need are well-suited to be met with space-cooling DR contributed by both residential and non-residential customers.
- The system capacity need is infrequent, spiky, and highly correlated with multi-day periods of very hot weather.
- There are 2-3 years of available lead time before the need will become acute, sufficient to procure the required DR capacity.
- Urban density provides physical and logistical barriers to near-term TS expansion. The location of this TS makes it very costly to expand, substantially increasing the deferral benefit of an NWS
- A demand response aggregator has offered to contract with the LDC to provide 11 MVA (~10 MW) of DR from a combination of large institutional, medium and large commercial, and residential customers for the required deferral period.
- Nemo TS has a Limited Time Rating (LTR) capacity of approximately 200 MW. The DR would therefore expand the TS' peak capacity by approximately 5%

Example 1 – Distributed Energy Resource (2/2)

BCA Outputs from Distribution Service Test

- **NWS Cost.** The cost of this capacity is $1 million per year for 2026 through 2030.
  - This is the total NWS cost and includes incentive, administration, evaluation costs.
  - For the benefit-cost analysis (BCA) for the Distribution Service Test, this has a Net Present Value (NPV) in 2023 of ~**$4 million (2023$)**.
- **NWS Benefit.** The principal quantifiable benefit of this NWS is postponing the annual cost of service of the poles-and-wires solution with a 40-year lifetime.
  - If this asset goes into service in 2026 with a nominal book value of $60 million, the 2023 NPV of annual costs to rate-payers is ~$64 million (2023 $).
  - If this asset goes into service in 2031 with a nominal book value of $66 million, the 2023 NPV of annual costs to rate-payers is ~$52 million (2023$).
  - Annual rate-payer costs include the utility pre-tax weighted average cost of capital, depreciation and O&M costs representing 1.5% of the net book value of the asset.
  - The BCA's gross benefit is $64 - $52 = $12 million.
- **Net Benefit.** The net benefit as calculated by the BCA is $12 - $4 = $8 million

Example 1 – Deployment Type

- **Geography:** The system need and reference scenario solution is concentrated in a single location.
- **Timing of Need:** The timing of the required spending for the reference scenario solution is relatively certain with a well-defined
  - starting point (when forecast demand would result in Nemo TS being over capacity) and
  - ending point (when forecast demand can no longer be offset by DR and a TS upgrade is required).
- **Deployment Type:** The defined nature and geographic concentration of the need, and the turn-key/fully bundled package of the solution (i.e., procured from an aggregator) indicate that this DER should be considered a stand-alone, one-off **<u>project</u>** and not a longer-term program; it will not be continued past the defined deferral period or expanded to other regions within the service territory.

Example 1 – Incentive Mechanism (1/3)

Why was the selected mechanism chosen?

- As per the BCA from the Distribution Service Test perspective performed by the LDC as part of its DSP, there is an NPV net benefit of the DER of **$8 million**
- The LDC is confident in the precision/certainty of its estimate:
  - *Need:* Historical growth in TS peak load is stable, gradual, and consistent. Forecast growth is aligned with historic trends and reflects existing connection requests and municipal growth projections.
  - *Dispatch Timing / Peak Period:* Timing of DER needs is highly correlated with periods of extended high temperatures and time of day – very little operational uncertainty.
  - *Solution Performance:* The DR aggregator is well established and provides ironclad contractual guarantees of capacity delivery under peak conditions.
- Because the LDC is confident in the accuracy of its projections it is willing to accept the inherently greater risk to its incentive of allowing the determination of the incentive value to be made based mostly on actual, rather than forecast values.
- Neither Scorecard nor Margin on Payments are chosen because the LDC believes it does not need the incentive risk protection these mechanisms offer and does not want to accept the commensurately lower share of net benefits these would deliver as incentives in return for that protection.
- The LDC therefore determines to seek incentives under the **Shared Savings Mechanism**.

Example 1 – Incentive Mechanism (2/3)

What is the Total Incentive Payment on a Forecast Basis?

The LDC proposes that it is reasonable to **receive 50% of the net *actual* (evaluated) benefit.**

If the LDC's forecast inputs are accurate, this is equivalent to $4 million.

Rationale for Incentive Share

This share is consistent with regulatory policy in a comparable jurisdiction and reflective of the LDC's risks to deliver the projected savings.

Comparable Jurisdiction

- The New York PSC directs utilities to calculate a "Base Incentive" of 30% of NWS initial net benefits.
- NWA initial net benefits (for purposes of the incentive calculation) are locked in when the contract for the NWA is executed.
- If realized NWS costs are lower than projected (and so forecast benefits net of realized costs is higher than the initial net benefits), the utility receives an incremental incentive 50% of the cost reductions as additional incentive.
- The total incentive received by the utility can be up to 50% of the initial net benefit.

See embedded PDF at end of deck for citation & details.

Utility Risk

- *Performance Risk.* The LDC proposes to absorb significant risks of NWA performance (benefit) to rate-payers: net benefits will not be "locked in" at forecast values but updated on the basis of evaluated MW reduction performance.
- *Risk and Opportunity to Deliver Additional Ratepayer Benefit.*
  - In the BCA, it was identified as very uncertain as to whether the resource could deliver bulk system capacity benefits (for the Energy System Test) without compromising its distribution service value.
  - The BCA net benefits do not include these benefits.
  - The LDC proposes to take on additional risk to meeting its distribution service targets by attempting to drive further value to ratepayers through contributions to bulk energy system value (e.g., coincident peak demand capacity).

Example 1 – Incentive Mechanism (3/3)

How is the final net benefit calculated?

At the end of the deferral period, the project is evaluated, and net benefits are re-calculated.

Some parameters of the benefit calculation are held fixed at their forecast value.

Most are updated to reflect actuals.

Forecast

Need Date: Regardless of changes in load growth, the MW need specified in the BCA will be assumed to occur on the date specified in the BCA.

Peak Period: The MW need will be assumed to be required under the conditions (e.g., weather, time of day) specified in the BCA.

Poles-and-Wires Cost: Regardless of changes in the costs of equipment and labour, the rate base impact of successfully deferring the poles-and-wires solution will be as specified in the BCA

Actuals

Deferral Period: Shorter deferral periods reduce net benefits, longer ones increase them. Two of the most significant drivers of deferral period length are:

- **DER Performance:** DER performance in test events and under peak conditions may shorten the deferral benefit period (underperformance) or extend it (better than forecast performance).
- **Load Growth:** Exogenous changes in load growth may shorten or extend the deferral period.

DER Performance: The project must demonstrate, in test events and under peak conditions, the capability to deliver the total MW capacity required to defer the distribution system need.

DER Costs: Program, administrative, contract/incentive, evaluation, and all other DER costs.

Bulk System Benefits: The value of any coincident peak demand (i.e., 5CP) capacity that can be delivered.

Example 1 – Sensitivity Alternative

What is some possible variation on the above?

Alternatively, if the LDC had less appetite for risk, it might propose to “fix” contract costs (payments to customers for DR) at the forecast value, up to 30% of that value.

In exchange, it would request only **35%** of the net benefits as an incentive.

Forecast

Incentive Cost Dead-Band: Final net benefits are calculated using forecast incentive costs, providing actuals are within +/- 30% of forecast values.

And all other “Forecast” parameters as above.

Actuals

Excess Contract Costs: *Variation in incentive costs outside a range of +/- 30% of forecast value.*

DER Costs: Program, administrative, evaluation, and all other DER costs.

And all other “Actual” parameters as above.

Example 2:

Scorecard

Summary – General Information

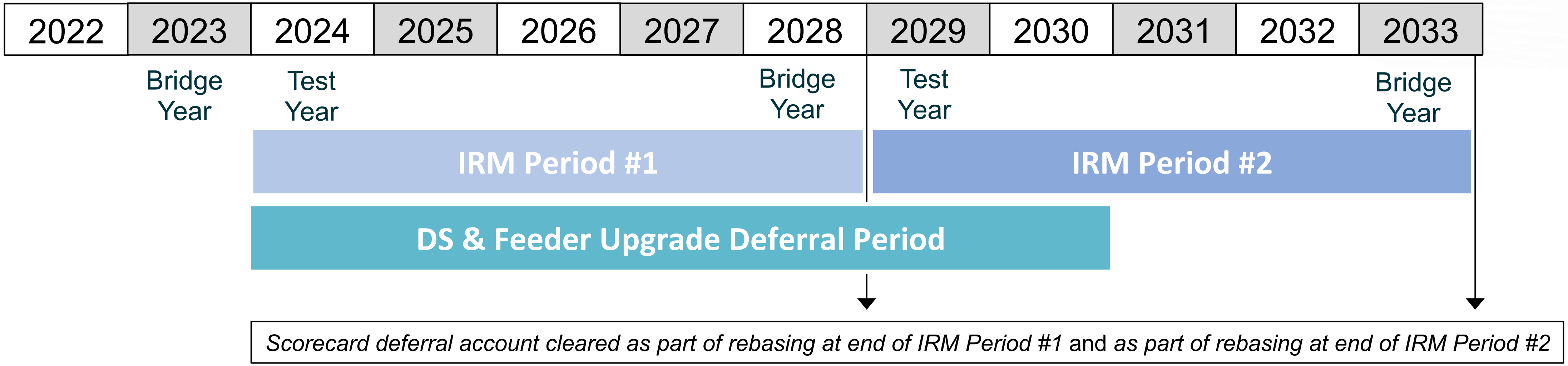
Approval Sought	**Scorecard Mechanism**, valued at approximately $1.64 million. Deferral account to be cleared on the basis of: demonstration of capability to deliver forecast capacity, controlling unit-cost of deferral, and energy system peak demand reductions.
Driver of Need	Distribution assets serving an ex-urban subdivision will be insufficient to serve capacity needs of new connections. Economic conditions have made the timing of the need less certain.
Timing	**Submitted as part of a rebasing.** The LDC sees an opportunity to establish a program that will offer value to this identified specific need and for other developments. To ensure alignment with its overall strategy, the LDC has included program planning as part of its Distribution System Plan.
DER	Behind-the-meter residential storage installed in new-build (preferred for reasons of cost) or existing homes. LDC has control of the asset for 20 days per year in exchange for a sign-up and annual payment to the owner.
Deployment Type	**Program (Pilot) deployment.** The uncertainty in the demand forecast makes the ultimate capacity need hard to predict. The LDC would like the flexibility to adjust number of batteries based on need. Successful outcomes would likely result in proposal to expand the program within the LDC territory at the next rebasing.

Example 2 - Driver of Need

- The LDC has received a steady influx of requests associated with the design, construction, and connection of new subdivision homes in Mariposa, Ontario.
- One subdivision – the neighbourhood of Nusquam – is served by the F2 feeder and the Nusquam DS.
- The F2 feeder that supplies the subdivision is loaded to approximately 2 MVA, and the distribution station (DS), Nusquam DS is loaded to approximately 6 MVA. The thermal capacities of these are 4, and 7 MVA respectively.
- In the last two years, 350 new lots have been connected in this subdivision. Approximately 1,000 additional lots are planned.
- The remaining planned subdivision load is anticipated to be 4.5 MVA . This exceeds available station and feeder capacity.
- The cost of a new DS and associated feeder(s) to accommodate the excess load from Nusquam DS is approximately $7 million, of which $1.5 million has been attributed to premiums for circumventing existing supply chain constraints that would otherwise prevent its timely completion.
- The DS is old, and due for substantial refurbishment in 2031. Regardless of load growth, a DS is required by that year. Refurbishment and expansion is expected to result in a capacity to meet projected needs for the foreseeable future.

Example 2 – Timing

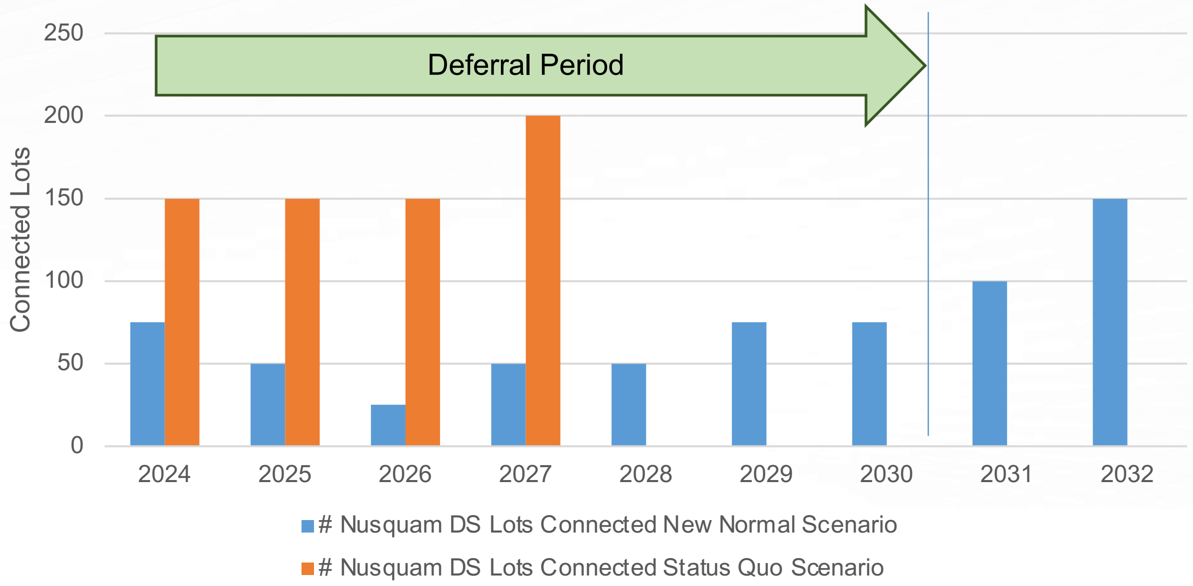
- Rising interest rates and falling real estate prices suggest that the number of required connections is likely to fall in the coming years, though considerable uncertainty exists.
- The number of confirmed connections for 2024, however, is such that by year-end either a new DS or sufficient DER capacity is required to meet the need.
- Slower than expected growth will allow for cost-effective deferral of new construction until the existing DS must be replaced in 2031. Deferring new construction is also anticipated to allow the LDC to avoid the $1.5 million supply chain premium.
- The LDC had already considered opportunities to pilot residential batteries as an NWS and so was prepared to include the BCA in its 2023 DSP as part of rebasing. For the same reason, the LDC has recently completed the IRRP process with the IESO, who have identified regional benefits that the LDC's (pilot) program could offer.



Example 1 – Distributed Energy Resource (1/4)

Proposed Non-Wires Solution

- Economic conditions make the timing of the need very uncertain. The LDC has mapped out two scenarios of lot connections:
  1. The Status Quo scenario, which assumes connections proceed as in the past
  2. The Low Growth, which assumes much slower growth (see at right).
- The LDC proposes to offer new and existing residents of the subdivision a substantial incentive to defray some battery installation and setup costs in exchange for priority to dispatch these for system needs on 20 days (LDC-chosen) per year.
- The LDC estimates that one battery is required for each new lot (historical average peak demand: 6 kW)



- The LDC will target high peak-usage customers and market the program on the basis of reliability, and potential bill savings when combined with ULO price plan. Given the value that the batteries also provide to customers, the LDC is confident to achieve its projected enrollment.
- The LDC has also coordinated with the IESO through the IRRP process and identified that it can control batteries to deliver capacity at times of regional peaks, without inhibiting its ability to deliver at times of local peak for deferral purposes. The value of this capacity has been included in its BCA.
- The LDC regards this as a pilot, and plans, if it is successful, to present a proposal for a wider-scale implementation at its next rebasing.

Example 2 – Distributed Energy Resource (2/4)

BCA Outputs from Distribution Service and Energy System Test - Costs

Cost	Description	DST Cost	EST Cost
$500,000	Fixed cost for control room updates	✓	✓
$2,000	One-time per-battery admin and incentive cost	✓	✓
$300	Admin and incentive costs during deferral period	✓	✓
$200	Admin and incentive costs after deferral period		✓

- EST-only annual costs assumed to persist for the life of the battery.
- DST captures only those costs required to deliver benefits to the LDC's customers.
- EST captures costs to deliver benefits to LDC customers *and* costs required to deliver provincial benefits

NPV of NWS Costs (2023 $millions)

Scenario🡻 / Cost-Test ➔	*Scenario Probability*	Distribution Service	Energy System
Status Quo	*25%*	$2.05	$2.05 + $0.34 = $2.39
Low Growth	*75%*	$1.31	$1.31 + $0.31 = $1.62
Weighted Avg.		$1.49	$1.81

Example 2 – Distributed Energy Resource (2/4)

BCA Outputs from Distribution Service and Energy System Test - Benefits

Benefit	Description	DST Benefit	EST Benefit
$3.36 Million	Deferral benefit of postponing DS expansion	✓	✓
$144 per kW-year (2023 $)	Capacity benefit provided by IRRP Technical Working Group		✓

- The deferral benefit is fixed across scenarios; only the number of batteries required to achieve deferral will change. As battery numbers change (by scenario) so too do costs (above) and EST benefits.
- The DST considers only the benefits to the LDC's customers. The EST counts the benefits to all consumers (including the LDC's customers).

NPV of NWS Benefits (2023 $millions)

Scenario🡣 / Cost-Test 🡢	*Scenario Probability*	Distribution Service	Energy System
Status Quo	*25%*	$3.36	$3.36 + $4.15 = $7.51
Low Growth	*75%*	$3.36	$3.36 + $3.31 = $6.67
Weighted Avg.		$3.36	$6.94

Example 2 – Distributed Energy Resource (2/4)

BCA Outputs from Distribution Service and Energy System Test – Net Benefits

Because the EST benefits were developed by the IESO through the IRRP process, the LDC has a high degree of confidence in their accuracy. The scenario-weighted average net Energy System Test benefit will be used by the LDC to support its rationale for the incentive proposed.

NPV of NWS NET Benefits (2023 $millions)

Scenario↓ / Cost-Test →	***Scenario Probability***	**Distribution Service**	**Energy System**
Status Quo	*25%*	$3.36 - $2.05 = **$1.31**	$7.51 - $2.39 = **$5.12**
Low Growth	*75%*	$3.36 - $1.31 = **$2.06**	$6.67 - $1.62 = **$5.05**
Weighted Avg.		$3.36 - $1.49 = **$1.87**	$6.94 - $1.81 = **$5.07**

Net benefit to compare to incentives in evaluating rationale of proposal.

Example 2 – Deployment Type: Program (Pilot)

- **Magnitude of Need:** There is significant uncertainty regarding which scenario (Status Quo or Low Growth) will prove most likely, and the LDC requires flexibility to enroll more or fewer batteries as the situation changes.
- **Planning for the Future:** The LDC has determined that strategic deployment of residential batteries may be beneficial at a much wider scale in the future. If the pilot outcomes meet expectations, the LDC anticipates proposing – in its next rebasing – to expand the scope of the pilot.
- **Deployment Type:**
  - In order to maintain near-term flexibility to changes in customer growth and longer-term flexibility to the outcomes of the pilot, this DER should be considered a longer-term **program** and not a stand-alone project.
  - The goal is to test a program design for fulfilling a known system need. If successful, the LDC would anticipate updating its BCA and incentive application in subsequent rebasings for deployment in other areas of its service territory as needs arise.

Example 2 – Incentive Mechanism (1/4)

Why was the selected mechanism chosen?

- As per the BCA performed by the LDC as part of its DSP there is a forecast NPV net benefit of the DER of **$5.07 million** from the Energy System Test perspective (informed by IESO input)
- Although the LDC is certain of the need date, and confident that the NWS can deliver the capacity required to meet the needs (and deliver incremental system benefits), it is uncertain about the cost.
- In particular
  - If connections revert to historical patterns (requiring more batteries to continue to defer the need), costs may increase significantly
  - If the assumed contract values (i.e., customer incentives) are insufficient to entice customers to participate, costs will need to increase to ensure the need is met.
- The LDC therefore determines to seek incentives under the **Scorecard Mechanism**.
- The Shared Savings Mechanism is not selected because the utility is sufficiently uncertain about costs to want to "lock in" some incentive based on forecast benefits. Margin on Payments is not selected because the utility is sufficiently confident in the bounds of potential deployment costs to accept some risk in those costs in return for a higher incentive.

Example 2 – Incentive Mechanism (2/4)

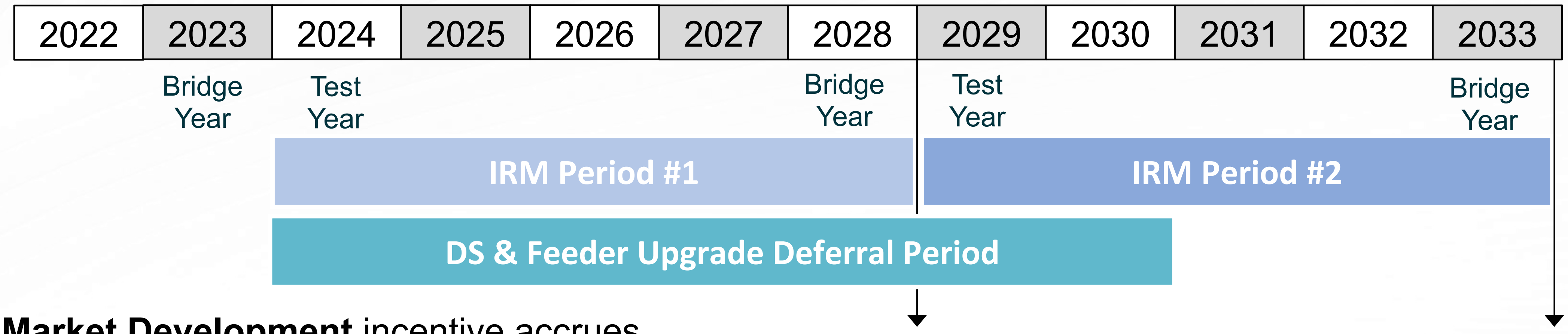
What are the scorecard metrics, and how do they impact incentives

- The LDC has proposed three scorecard metrics. These moderate the LDC's exposure to risk on costs without eliminating
- The scorecard metrics are structured to support the acquisition of operational capabilities supporting DER market development.

Metric	Description
Market Development	Fulfilled upon the demonstration of the capability to deliver the forecast capacity required to fulfill the forecast 2024 need. A lump-sum equivalent to 35% of the forecast control-room update cost.
Cost Control	Metric assessed when deferral account cleared. Payment is 75% of forecast NWS cost, *minus* 75% of the difference between forecast and actual NWS costs, to a minimum incentive payment of $0. The LDC is rewarded for reducing costs below forecast values.
System Benefit	Metric assessed annually. Payment is 3% of forecast energy system capacity value per kW of coincident peak capacity delivered.

Example 2 – Incentive Mechanism (3/4)

Incentive payment timing varies by Scorecard Metric



- **Market Development** incentive accrues when capability is demonstrated and is cleared from the deferral account at the next subsequent rebasing.
- **Cost Control** incentive accrues at the end of the deferral period and is cleared at the subsequent rebasing.
- **System Benefit** incentive accrues annually and is cleared from the deferral account at each rebasing.

Example 2 – Incentive Mechanism (3/3)

What does the total utility incentive look like?

The Scorecard mechanism is less risky for the utility than the Shared Savings Mechanism, and scorecard metrics have been selected accordingly. The total incentive under three different scenarios is shown below.

	Forecast Scenario	Status Quo Scenario	Low Growth Scenario
Market Development	$175,000	$175,000	$175,000
Cost Control	$1,359,000	$926,000	$1,503,000
System Benefit	$106,000	$125,000	$99,000
Scenario Net Benefit (MILLIONS 2023$)	$5.07	$5.12	$5.05
Scenario Incentive as % of Scenario Net Benefit	32%	24%	35%

Example 3:

Margin on Payments

Summary – General Information

Approval Sought	**Margin on Payments Mechanism**, valued at 10% of program costs, to be paid out as 30% of incurred costs. Deferral account to be cleared on the basis of audited program costs.
Driver of Need	EV adoption is accelerating in LDC territory but not uniformly – clustered by neighbourhood. Depending on electricity rate and policy changes, EV adoption is likely to materially increase distribution capacity needs over the long term.
Timing	**Submitted as a stand-alone application.** Incipient system need and staff resource constraint concerns mean this will not be part of a rebasing. The LDC would expect to begin exercising DER capacity from this program in 2027.
DER	Vendor software allows LDC to throttle EVSE* of participating customers. LDC proposes to offer ULO** subscribers with EVs a modest annual payment to permit them to throttle delivery capacity to 1.5 kW as needed for a limited number of overnight periods.
Deployment Type	**Program deployment.** The uncertainty in EV growth (policy, other exogenous factors), locational clustering, and charging patterns (dependent on rates and customer price responsiveness) require nimble deployment over many years.

** EVSE: electric vehicle service equipment – EV chargers.*

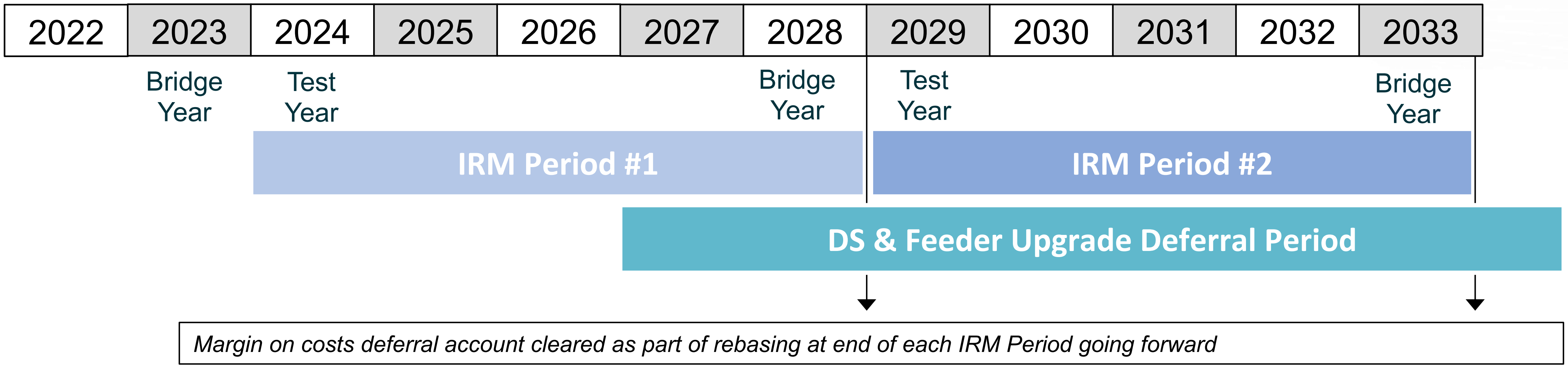
*** Ultra Low Overnight RPP price plan*

Example 3 - Driver of Need

- The LDC has observed accelerating adoption of electric vehicles (EVs) in its service territory.
- EV adoption appears to be clustered around localized “hot spots”.
- Of most concern are residential hot spots where EV adoption and alignment of charging behaviours across households an is resulting in some feeders approaching or exceeding capacity.
- The LDC procured a spatial forecast of EV adoption in its service territory to identify key areas of future growth.
- The LDC also procured a study to assess the long-term impact on capital investment needs and volumes similar to Elmallah et al 2022 (Environ. Res.: Infrastruct Sustain).
- This study estimated that without the application of smart managed charging, the total cost of incremental capital investment over the 25 years from 2027 through 2050 could be (cumulatively) as much as 2 – 3 times the value of its current annual capital budget. This is approximately equivalent to an average annual increase in capital costs of 4 – 8%, relative to status quo projections.

Example 3 – Timing

- The LDC believes that if it can develop the capability to deploy managed charging to customer EVSE on an as-needed basis it could, over the long-term, reduce EV-driven capital investment by as much as 50%.
- Extensive and careful planning and testing will be required before the LDC expects that it could have its first cohort of EVSE subject to full “production environment” charge management.
- Accordingly, to ensure that sufficient LDC resources were available to support the BCA work and program planning, the LDC submitted its proposal as a stand-alone application in early 2025.
- The LDC anticipates that it would request renewal of approval for program activities at each rebasing following its implementation.



Example 3 – Distributed Energy Resource (1/3)

Proposed Non-Wires Solution

- The LDC is working with a vendor that can provide the LDC with the ability to remotely throttle EVSE from most major Level 2 EVSE manufacturers.
- Throttling works by limiting EVSE delivery capacity to 1.5 kW, reducing demand from charging vehicles by an average of 5.5 kW.
- The vendor control system allows the LDC to define groups/clusters of EVSE on the basis of the distribution assets that serve them.
- The LDC dispatches charge management by cluster. When dispatched, the vendor algorithm randomly throttles one or more in-use EVSE (defined by the LDC) to achieve greater diversity in overnight charging.
- The LDC is confident that it can enroll participants for only a relatively modest incentive payment since:
    - It will target for recruitment customers already enrolled in the Ultra-Low Overnight (ULO) price plan (i.e., already charging overnight) so unlikely to object to further charge management within the Overnight price window.
    - It will dispatch control events fewer than 25 days in a year
    - Even if the EV is fully throttled over the entire ULO period (11pm – 7am) the charge provided in that time should be sufficient for at least 60 km.
    - It will provide 12 hours' notice prior to curtailment events.

Example 3 – Distributed Energy Resource (2/3)

BCA Outputs from Distribution Service Test

- **NWS Costs:**
  - Although variable costs (per EVSE) for implementation are low, fixed (set-up) costs for this NWS are quite high.
  - Fixed costs include
    - The annual costs of licensing the vendor EVSE control system
    - The costs of developing the control room capabilities and resource capacity to monitor distribution asset demands and identify charge management dispatch conditions with 12 hours' advance notice.
  - Variable costs include the administrative and incentive costs to enroll participants.
- **NWS Benefits:**
  - Projected benefits are very sensitive to analysis input assumptions, including: the accuracy of the EV spatial adoption forecast, the assumed rate of enrollment in the ULO, and the associated typical charging profiles.
  - Assuming a program in-place and operating as projected through to 2050, the LDC has estimated it could reduce the incremental capital investment needed to serve new EV loads over that time by up to 50%.
  - The utility anticipates that the program benefits would be re-evaluated formally as part of each rebasing and accompanying DSP.

Example 3 – Distributed Energy Resource (3/3)

Distribution Service Test Net Benefits

- Considering the control room upgrade, the vendor licensing and equipment costs, administrative and incentive costs, the total deferral benefit of the NWS, through the end of 2050, is currently estimated to be 4x the cost.
- The current best estimate of the net benefit is, accordingly 3x the estimated cost.
- The LDC proposes to re-estimate the net benefits of the program with the latest information available at each rebasing.

Example 3 – Deployment Type: Program (Pilot)

- **Certainty of Aggregate Need:** The studies performed by the LDC and its consultants align with the professional literature: large-scale EV adoption is very likely and clustering adoption is very likely, if unchecked, to require substantial incremental capital investment.
- **Uncertainty of Timing and Location of Need:** Considerable uncertainty exists as to where and when this need will arise.
- **Deployment Type:** The LDC will proceed with developing managed charging capabilities on a pilot basis. As these are proved out, the LDC will revisit its BCA and proposed incentive amounts in subsequent rebasings, but, given the anticipated long-term continuity required, proposes this as a **program**.

Example 3 – Incentive Mechanism (1/2)

Why was the selected mechanism chosen?

- Although the net benefit of the proposed program is significant over its lifetime, it is unevenly distributed: a high proportion of costs are fixed, while benefits are proportional to participation.
- Although the LDC is confident of its analysis in aggregate, specific parameters are highly uncertain (and must be updated at subsequent rebasings).
- Accordingly, the LDC is proposing to seek incentives under the **Margin on Payments** mechanism.

Example 3 – Incentive Mechanism (2/2)

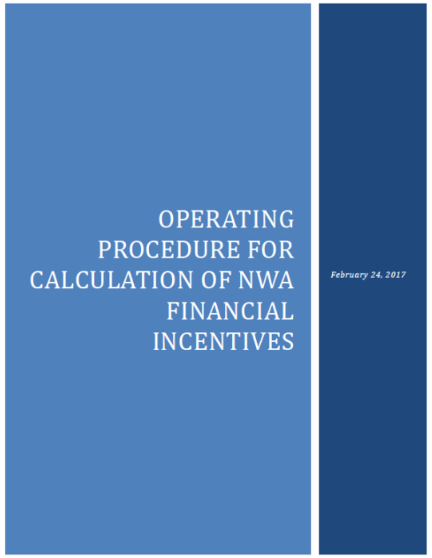
What incentive margin should be applied to program costs?

- The current best estimate of the program's benefit through 2050 is that it will be 4x costs, and therefore the net benefit will be 3x costs.
- Because there is very limited risk to the utility in pursuing this incentive mechanism, the LDC has proposed that total incentive payments should be equal to 10% of estimated net benefits, on a forecast basis (in comparison to ~30% for the example Scorecard mechanism and to 50% for the example Shared Savings Mechanism).
- An incentive valued at 10% of net benefits is equal to 30% of costs. The LDC therefore will receive an annual incentive (to be cleared from the deferral account at each rebasing) of 30% of all program costs incurred *that were included in the BCA*.
- At each rebasing, the LDC will submit an updated BCA as part of its DSP. Updated estimates of net benefits reflecting observed performance will impact incentive-setting in subsequent periods.
- The incentive-cost margin for the subsequent IRM periods will be determined such that – if held constant for the remainder of the projection period (i.e., through 2050) – it would provide a total incentive equivalent to approximately 10% of the (updated, actual) net benefit.
- The LDC has identified that in a future rebasing it may propose an alternative incentive mechanism as it attains greater certainty regarding the performance of the DER.

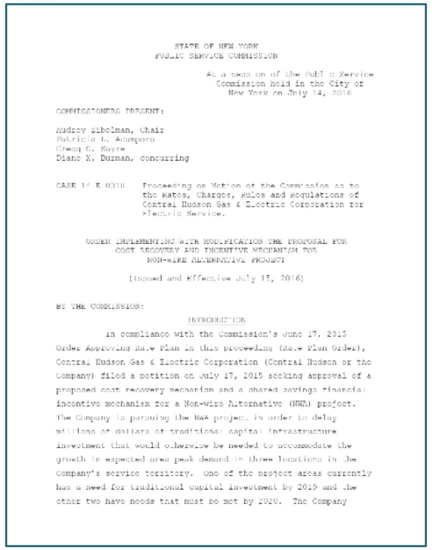
Supporting Documents

Supporting Documents

New York Public Service Commission, *Operating Procedure for Calculation of NWA Financial Incentives*



New York Public Service Commission, *Case 14-E-0318 Order Implmenting With Modification the Proposal for Cost Recovery and Incentive Mechanism for Non-Wire Alternative Project,* July 2016



STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of New York on July 14, 2016

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Gregg C. Sayre
Diane X. Burman, concurring

CASE 14-E-0318 Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service.

ORDER IMPLEMENTING WITH MODIFICATION THE PROPOSAL FOR COST RECOVERY AND INCENTIVE MECHANISM FOR NON-WIRE ALTERNATIVE PROJECT

(Issued and Effective July 15, 2016)

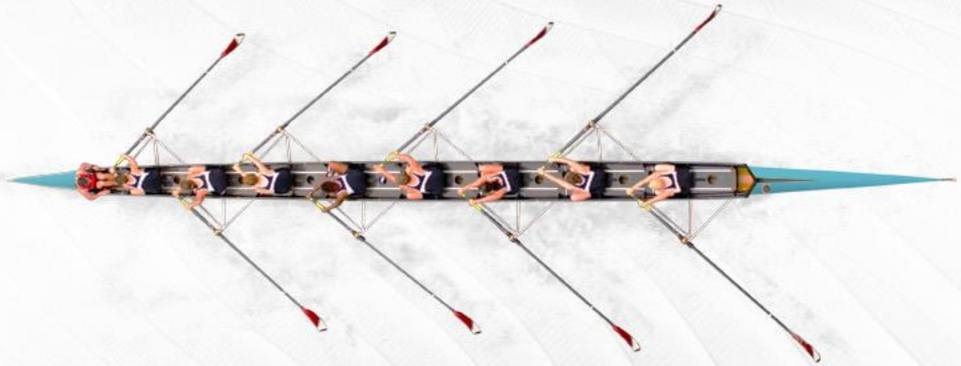
BY THE COMMISSION:

INTRODUCTION

In compliance with the Commission's June 17, 2015 Order Approving Rate Plan in this proceeding (Rate Plan Order), Central Hudson Gas & Electric Corporation (Central Hudson or the Company) filed a petition on July 17, 2015 seeking approval of a proposed cost recovery mechanism and a shared savings financial incentive mechanism for a Non-wire Alternative (NWA) project. The Company is pursuing the NWA project in order to delay millions of dollars of traditional capital infrastructure investment that would otherwise be needed to accommodate the growth in expected area peak demand in three locations in the Company's service territory. One of the project areas currently has a need for traditional capital investment by 2019 and the other two have needs that must be met by 2020. The Company

Peter Steele-Mosey
Director
peter.steele-mosey@guidehouse.com
(416) 956-5050

Todd Williams
Director
twilliams@guidehouse.com
(646) 227-4480



Guidehouse
Outwit *Complexity*