1. EXAMPLES

The following are illustrative examples intended to provide an understanding of the use of the Benefit Cost Analysis (BCA) Framework. The examples are provided for **illustrative purposes only** and are not indicative of the level of detail expected for each application to the OEB. The level of detail that electricity distributors are expected to provide to the OEB when seeking approval for NWS funding should be commensurate with the scale and cost of the proposed NWS.

The examples provided here are not a pre-judgement or pre-approval of any NWS solution or approach. Each NWS proposal/application filed with the OEB will be decided upon through the existing adjudicative process.

1.1. Example 1: Demand Response Program

In Example 1, an electricity distributor proposes to procure DR from a mix of customers served by a transformer station (TS) approaching its capacity limit. This particular TS is located in a relatively dense service area, making upgrades very costly. The electricity distributor anticipates that it can, through the use of DR, defer the need five years into the future. Each section of the example describes what is expected and provides example content.

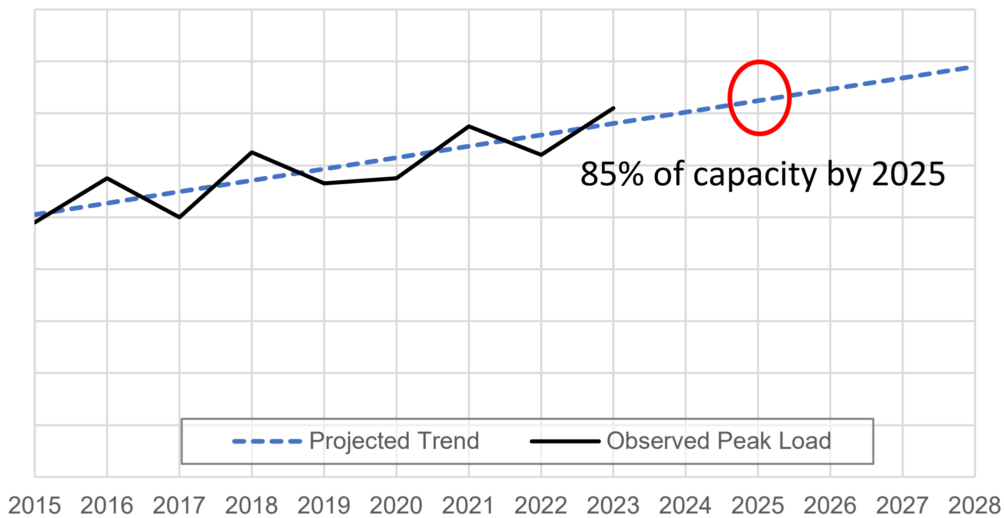
A worked-out sample of this example using the draft Microsoft Excel template has also been provided for illustrative purposes.

1.1.1. Need

The municipality in which the electricity distributor is located is projecting on-going growth in density in the region serviced by the electricity distributor's Nemo Transformer Station (Nemo TS). The distributor's service territory is summer-peaking, and the electricity distributor has used historical trends, known connection requests, and assumptions drawn from its DSP and load forecast about peak summer temperatures to project summer peak demand anticipated to be experienced by Nemo TS in the coming years.

This projection is illustrated in Figure 1, and the electricity distributor has attached the underlying data to its application, referenced its standard forecasting approach outlined in its DSP, and provided a short description of the key elements unique to the methods used for projecting the demand for this asset.

Figure 1. Nemo TS Projected Load



In developing its projection, the electricity distributor has accounted both for anticipated improvements in efficiency (from new build), as well as increasingly extreme heatwaves that drive peak loads at this TS. Peak loads are understood to be driven by cooling loads from institutional and commercial customers (including multi-residential towers).

Nemo TS is projected to reach 85% of loading by late 2025. Failure to address load growth through additional investments 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 very high loading relative to capacity puts the system at risk of violating design parameters, possibly resulting in rotating blackouts and voltage reductions. The electricity distributor has assessed that the system need must be addressed to ensure reliability and quality of service.

1.1.2. Alternatives Considered

In this section, the proponent is should describe each of the alternatives considered to meet the need. The electricity distributor should complete this section by explicitly identifying the reference scenario approach[1] (i.e., the poles and wires solution that would historically have been applied) and the preferred non-wires approach being considered in the BCA.

The electricity distributor has identified the following alternative options:

1) **Do Nothing**

   Doing nothing would result in a material number of the busses at Nemo TS being loaded at 90% or more by 2025. Doing nothing would leave the electricity distributor unable to connect some new customers requesting service without an unacceptable risk of system failure under peak conditions. The electricity distributor has assessed that doing nothing could compromise reliability, making the system need non-discretionary. Load relief is required at Nemo TS and the "do nothing" option is not further considered.

2) **Expand TS *(poles and wires – reference scenario):***

   Expand Nemo TS to provide additional local capacity. The project scope includes the installation of two 75/100/125 power transformers, four transformer breakers, one bus-tie breaker, 10 feeder breakers with five tie switchgears, and two capacitors with breakers. Expansion of this scope will necessitate the acquisition of new buildings, and would impose very high labour costs relative to a typical TS expansion because of the location of the existing TS, and the nature of the businesses and infrastructure surrounding it. Expansion will also require additional engineering analyses. The estimated cost of the reference scenario is approximately $60 million (nominal). The net present value in 2023 of the inflation-adjusted annual revenue requirement across the 40-year life of the asset (the cost to customers) is approximately $63 million.

   The electricity distributor has provided a summary of component costs in Table 1, supported by a more detailed breakdown of costs by year

[1] It is possible that as the market for NWSs evolves that in some cases the NWS may become the standard approach – the reference scenario – for addressing the system need under consideration. Should an electricity distributor believe that this is the case for the BCA under consideration it should consult with the OEB.

and sub-components, with appropriate citations and support, in an appendix.

Table 1. DR Example - Cost Breakdown of Nemo TS expansion ($Millions - Nominal)

Item	Cost
Power transformers x2	20
Transformer breakers x4	20
Bus-tie breaker x1	5
Feeder breakers x10	5
Switchgears x5	5
Capacitors x2	5
Total	**60**

3) **Deploy Demand Response (Non-Wires Solution):**

The electricity distributor has determined that the characteristics of the need are well-suited to be met with a space-cooling DR solution including both institutional and large multi-residential building customers. The electricity distributor has determined that peak demand on this asset is, because of the underlying weather-sensitive loads, consistently predictable. The magnitude of peak demand that is the driver of the system need is typically observed on fewer than three days per year.

The electricity distributor has provided a table showing a five-year history of the ten highest peak demand hours experienced by the station and the associated peak daily temperature, as well (for comparison) the average demand experienced by the asset in the same hour of the day and during the same month as each peak.

A demand response aggregator has proposed to contract with the electricity distributor and to provide 11MVA (~10MW) of DR from a combination of large institutional, medium and large commercial (including multi-residential) customers. The aggregator has provided similar services for other Ontario and North American utilities, and is willing to accept a contract with sufficiently punitive terms for failure to deliver that the electricity distributor is confident the DR capacity will be available as required. Because the asset loads are anticipated to potentially fall on days in which the Ontario energy system also peaks, the electricity distributor’s contract *forbids* the aggregator from using resources contracted to provide DR for this local system need to also be used to provide capacity to the energy system. This is to ensure the resource availability to serve the need.

The electricity distributor has identified that under the current forecast, the contracted capacity will be sufficient to defer the expansion of the TS by five years. This provides the aggregator with 2 years to prepare, and would result in it providing DR as required from 2026 through 2030.

The estimated cost of the NWS is approximately $1 million per year (nominal) for the five-year deferral period. The net present value of the inflation-adjusted annual costs over the anticipated deferral period is approximately $3.6 million.

1.1.3. Cost Effectiveness Test

The electricity distributor has submitted the required Excel output template with its BCA. The electricity distributor has added a number of additional tabs to provide: a set of global workbook assumptions and inputs values, the underlying calculations used to derive the annual value streams and net present values identified in the summary table. Output values are provided as formulas to allow reviewers to track calculations back to their source.

The electricity distributor has not provided an EST test result, indicating that the results of the DST alone are sufficient to justify DR as the preferred solution, and that there are no anticipated negative expected impacts of the DR solution for the broader electricity system that would change this conclusion. The electricity distributor has identified that because of the possibility that that DR may need to be dispatched on days in which there is also a coincident Ontario energy system peak – but at a different hour of the day – attempting to dispatch to meet both needs might result in unacceptable risks for meeting the distribution system needs. Additionally, the electricity distributor has not had the opportunity to engage with the IESO as part of the IRRP process and would have had to rely on the generic values recommended in this Framework for calculating EST benefits.

The net present values of all cost and benefit streams were calculated using the recommended 4% (real) social discount rate and assume 2% inflation per year.

1.1.3.1. DST Benefits

The quantitative benefit of the NWS comes from deferring the cost to customers of paying the annual revenue requirement associated with the poles and wires solution. Under the reference scenario, this stream of values will begin when the expansion goes into service, in 2026, and expire at the end of its life at the end of 2065. If deferred for the projected five years, this stream of values will begin in 2031 and end at the end of 2070. The deferral of the poles and wires solution associated with the NWS option results in the availability of a functioning substation from 2066 to 2070, which would have reached end-of-life in 2065 in the reference scenario. This is not captured in the NPV as it is a qualitative benefit of the NWS solution.

Under these conditions, the NPV of the annual costs to customers under the reference scenario is approximately $63 million, and the NPV of the annual costs to customers (of the poles and wires solution) under the deferred scenario (assuming use of NWS) is approximately $52 million, a benefit of approximately $11 million.

The electricity distributor has estimated these benefits by calculating the annual revenue requirement for the asset using the cost of service approach described in Section 5.1.1.1 of the Framework, and provided the key inputs to this calculation in the BCA filing as well as in its Excel template outputs.

In developing its estimate of the annual revenue requirement the electricity distributor has made some simplifying assumptions, but has presented some qualitative sensitivity assessments to demonstrate that it is unlikely that the effects of its simplifying assumptions on the output could result in benefits failing to be substantially greater than costs.

The electricity distributor's assumptions for developing the cost of service estimates of the annual revenue requirement – and hence the deferral benefit of the NWS – are presented in Table 2 below.

Table 2. DR Example - Economic Assumptions

Economic Assumption	Value	Source
Debt/Equity Ratio	60/40	OEB cost of capital update[2]
Allowed Return on Equity (ROE)	9.21%	
Deemed Long-Term Debt Rate	4.88%	
Federal Tax Rate	15%	Government of Canada[3]
Provincial Tax Rate	11.5%	Government of Canada[4]
Pre-tax Weighted Average Cost of Capital (WACC)	8.02%	Calculated
O&M	1.5% of capital expenditure	Assumed
Asset Depreciation	Straight-line 1.5% per year for 40 years	Assumed

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 ~$63 million (2023 $).
- If this asset goes into service in 2031 with a nominal book value of $66 million[5], the 2023 NPV of annual costs to rate-payers is ~$52 million (2023$).

[2] Ontario Energy Board, 2023 Cost of Capital Parameters, October 2022
[3] Government of Canada, Corporation Tax Rates, May 2022
[4] Government of Canada, Ontario – Provincial corporation tax, August 2023
[5] The nominal book value of $66 million in the 2031 in-service scenario is greater than the nominal book value of $60 million in the 2026 in-service scenario. This $6 million increase is solely attributable to the inflationary adjustment.

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 $63 - $52 = $11 million dollars (2023$).

Electricity distributors are encouraged to add additional calculation tabs to the Excel template workbook to transparently and formulaically show how capital expenditure and the revenue requirements associated with the respective solution will evolve between the time of implementation and the end of its lifetime. An example is provided below in Table 3 and Table 4.

Table 3. DR Example - Traditional TS Expansion Capital Expenditure

	Installed at Time of Need			
			Nominal	2023 $
Calendar Year	Opening Net Book Value	Dep'n	CRF / Revenue Requirements	CRF / Revenue Requirements
2023			$0	$0
2024			$0	$0
2025			$0	$0
2026	$60.0	-$1.5	$7.2	$6.8
2027	$58.5	-$1.5	$7.0	$6.5
2028	$57.0	-$1.5	$6.9	$6.2
2061	$7.5	-$1.5	$0.9	$0.4
2062	$6.0	-$1.5	$0.7	$0.3
2063	$4.5	-$1.5	$0.5	$0.2
2064	$3.0	-$1.5	$0.4	$0.2
2065	$1.5	-$1.5	$0.2	$0.1

Without the DR program implementation, the NPV of the TS Expansion would be $64M (2023$).

Deferred to 2031 (due to the adoption of the DR program), the NPV of the same TS expansion would be $52M (2023$), as calculated in the example below.

Table 4. DR Example - Deferred Installation Capital Expenditure

	Deferred Installation			
Calendar Year	Opening Net Book Value	Dep'n	CRF / Revenue Requirements	CRF / Revenue Requirements
2023			$0	$0
2024			$0	$0
2025			$0	$0
2026			$0	$0
2027			$0	$0
2028			$0	$0
2029			$0	$0
2030			$0	$0
2031	$66.2	-$1.7	$8.0	$6.8
2066	$8.3	-$1.7	$1.0	$0.4
2067	$6.6	-$1.7	$0.8	$0.3
2068	$5.0	-$1.7	$0.6	$0.2
2069	$3.3	-$1.7	$0.4	$0.2
2070	$1.7	-$1.7	$0.2	$0.1

The electricity distributor has not quantified any other benefits for this project.

1.1.3.1. DST Costs

The quantitative cost of the NWS comes from a combination of NWS acquisition costs and OM&A costs. Most of these costs are borne directly by the DR aggregator that provides the electricity distributor with a bundled service. The costs of various components of the service provided by the aggregator are itemised in its scope of work with the electricity distributor. The electricity distributor has attached a redacted version of the scope identifying key cost items and certain contract terms that are important considerations of the BCA assessment (e.g., the punitive terms should the aggregator fail to deliver, and the definition of the metrics used to assess this). In addition to this detailed cost breakdown, the electricity distributor has provided a high-level summary within the BCA, as shown in Table 5 and Table 6, below. Costs shown in these tables include costs from all 5 years of program operation and are presented on an NPV basis, in 2023 constant dollars.

Table 5. Example 1: NWS Acquisition Costs

Cost Category	NPV of Cost ($M 2023)	Source
Contracting Costs. Costs of procuring capacity from DR aggregators	0.14	Previous experience with DR programs [references to be provided by electricity distributor e.g. previous Distribution System Plan]
Incentive Costs. Payments to DR participants or other individual third parties providing DR.	2.01	As quoted by vendor
Equipment and Systems Costs. Costs for procuring equipment (load control equipment, metering, etc.) and the systems (software, hardware, training) necessary to effectively dispatch NWSs at times of distribution system need.	0.54	As quoted by vendor

The electricity distributor has provided an estimate of the number of electricity distributor staff FTEs required to administer and manage the project and the associated costs, and have provided a breakdown of annual operations and maintenance costs quoted by the DR aggregator. These have been attached in an appendix and summarized at a very high level in the table below.

The electricity distributor has also engaged a third-party evaluator to provide a bi-annual audit of customer settlement undertaken by the aggregator and to develop an empirical estimate of demand reductions and ongoing program capability that can assist in its planning. Key elements of the EM&V contractor’s SOW and its draft evaluation plan have been attached to the NWS report, and overall OM&A costs summarized in the table below.

Table 61. Example 1: NWS Operation, Maintenance, and Administration Costs

Cost Category	NPV of Cost ($M 2023)	Source
Operation and Maintenance Costs. Costs of operating the DR program, as indicated by the pre-selected aggregator	0.36	Previous experience with DR programs [references to be provided by electricity distributor e.g. previous Distribution System Plan]
Administrative Costs. Electricity distributor incurred programmatic costs related to customer service and contract administration	0.18	Previous experience with DR programs [references to be provided by electricity distributor e.g. previous Distribution System Plan]
Evaluation, Measurement, and Verification (EM&V). Program evaluation performed by the aggregator and processed by the electricity distributor, over the lifetime of the contract	0.36	As budgeted based on previous evaluations of DR programs.

1.1.3.2. Cost-Effectiveness Test Outcome

The total NPV benefit of deferral is approximately $11.25 million and the total NPV cost of the NWS is approximately $3.6 million, resulting in a net benefit to customers of approximately $7.7 million. The DST indicates that the NWS is the cost-effective option.

The electricity distributor provides the results of a sensitivity analysis it has undertaken to assess the impact on net benefits of a change in the deferral period as a result of observed peak demand growing faster or more slowly than predicted. This shows that even if load growth were to accelerate and peak summer temperatures were to be at their most extreme-yet observed level, only 1 – 2 years of deferral would be lost, and the project would continue to be cost-effective relative to the poles and wires solution.

The sensitivity analysis also shows that should growth slow, either due to changes in customer growth or due to efficiency improvements from provincial programs, the deferral period could be extended considerably. This would substantially improve the long-term customer net benefit of the project.

1.1.4. Other BCA Considerations

The electricity distributor has only developed a distribution service BCA, and so only the qualitative considerations related to the distribution service perspective are addressed by the electricity distributor in this section.

These considerations have been divided into qualitative benefits and qualitative cost considerations.

1.1.4.1. Qualitative Distribution Service Benefits

The electricity distributor has provided a concise discussion of other BCA considerations. The electricity distributor has not developed a detailed review of qualitative benefits because it is confident that the quantitative net benefits clearly define the value to customers of the proposed NWS. Further, the need is clear-cut and the NWS is one with a relatively mature in-market history.

The proposed program has identified benefits related to innovation and market transformation, planning value, reliability, and resilience which cannot be directly quantified at this time. These are presented in Table 7, below.

Table 7. Local DR Example - Other BCA Considerations

Consideration Category	Description
Innovation & Market Transformation	This program aligns itself with the intent to transition towards smarter, more decentralized grids. The DR program drives the electricity distributor towards achieving a more dynamic grid. This project will help, in particular with: - Learning about customer behaviour and the appetite for adjusting consumption patterns via DR programs - Modernizing the grid and preparing for future growth - Exploring new opportunities for implementing local DR programs with a particular type of customer type
Resilience	- During periods of high demand, the DR program provides greater stability to the grid and helps with grid management
Reliability	- The NWS solution is expected to deliver an equivalent level of reliance and reliability as the traditional poles and wires solution

Planning Value	- Deployment of the NWS solution allows the electricity distributor to respond to changes in load growth (e.g., should growth slow, either due to changes in customer growth or due to efficiency improvements from provincial programs). The deferral period can be adapted considering any growth uncertainty and may improve the long-term customer net benefit of the project.

1.1.4.2. Qualitative Distribution Service Costs

The electricity distributor is required to provide a qualitative review of BCA considerations that impact questions of cost in the benefit-cost analysis. Because the electricity distributor is only conducting a distribution service BCA and not also the (voluntary) energy system BCA, only those qualitative cost considerations required for the distribution service BCA are required.

Distribution System Ancillary Services
The electricity distributor affirms that the anticipated NWS should not in any meaningful way impact distribution system ancillary costs. Though the electricity distributor notes that some studies have shown some positive impacts of customer demand response on system voltage, the electricity distributor does not believe that any impacts on this or any other system characteristic associated with distribution ancillary services would impact mean annual ancillary service costs in any statistically distinguishable way.

Risks
The electricity distributor has identified the key risks and divided them into two categories; risks affecting customer benefits, and risks affecting customer costs.

The principal risks affecting customer benefits are:

- *Deferral Period.* If growth (number of customers) accelerates, or the highest summer temperatures become more extreme (increasing peak demand per customer) the contracted DR may be insufficient to defer construction for the full five years, shortening the deferral period. The electricity distributor has quantified the sensitivity of benefits to the length of the deferral period (see above).

- *Infrastructure Cost.* If real (i.e., corrected for inflation) costs of the poles and wires costs increase over time, the time-value of deferral could be eroded or limited. Particular risks here include the cost of real estate, the cost of labour, and the costs of access to the TS (in and around other urban infrastructure).

  To illustrate this risk, the electricity distributor has identified historical trends in the price per square foot of commercial real estate in the city (contrasted with CPI) and the average cost per FTE of contract construction labour (also contrasted with CPI) over time. Although labour costs have historically lagged CPI commercial real estate costs are a real risk.

  To illustrate the risk for the costs of access (e.g., the costs of engaging paid duty officers to direct traffic, the additional time for getting materials to and from site, etc.) the electricity distributor has provided a time series showing the average annual O&M costs per GWh of throughput per year for transformer stations in urban regions illustrating the correlation between the growth of these costs and the number of customers served (as a proxy for growth in density).

- *Performance Risk*. If the DR resource fails to perform as contracted the deferral period is shortened and project benefits fall.

The principal risks affecting customer costs are:

- *Customer Incentives.* The DR aggregator is sharing some risk related to customer incentives with the electricity distributor. There is a possibility that if incentives are insufficient to acquire the necessary DR capacity that they will need to be increased. This will increase project costs and erode net benefits.
- *Other Implementation Costs.* Administrative costs, costs related to control room dispatch systems, and other project technology costs could be higher than projected.

Mitigation strategies for all risks are provided in the relevant section of the BCA.

1.1.5. Outcome

The electricity distributor has provided a short statement formally identifying the outcome of the BCA and the alternative with which the electricity distributor proposes to proceed.

For example: “*Based on the finding that deferring investment in Nemo TS for 5 years through the implementation of DR program Y yields a net benefit of $7.7M, with a benefit to cost ratio of 2, electricity distributor ABC plans to proceed with the procurement of a DR program meeting the specifications described in Section 7.1.2.*”

1.1.6. Risk Mitigation

In identifying risk mitigation, the electricity distributor has provided a summary assessment of the level of risk and the mitigation strategy it intends to pursue. These are noted in Table 8.

Table 82. DR Example - Risks and Mitigation

Risk Category	Assessment	Mitigation
Deferral Period (Benefit Risk)	Low downside risk from customer growth, moderate downside risk from climate change related extreme weather events. Moderate upside risk – CDM or other changes in natural efficiency could extend deferral period.	Monitor leading indicators of customer growth and changes in weather sensitivity of loads at high temperatures. Review distribution of temperature peaks over time to ensure trends are within tolerances.
Infrastructure Cost (Benefit Risk)	Moderate risk from growth in real estate values, low risk from growth in labour costs, and low risk from increasing costs of access	Use time granted by deferral period to monitor available sites and make opportunistic acquisitions to minimize costs of required land/buildings at end of deferral period.
Performance Risk (Benefit Risk)	Low risk of performance shortfall.	DR aggregator has accepted potentially very punitive contract terms to ensure delivery of capacity to meet needs. Additional mitigation includes annual testing of capabilities and engagement of third-party evaluator for ongoing audits and EM&V or performance.

Customer Incentive Risk (Cost Risk)	Low risk; the electricity distributor and its DR aggregator partner have generated sufficient leads based on an early offer to be confident of achieving needed capacity without increasing incentives.	Electricity distributor and DR aggregator are collaborating using electricity distributor data to identify customers with weather sensitive loads that previously engaged with the electricity distributor for programs or have systems deemed likely to be suitable for the types of control measures envisioned by the project.

1.2. Example 2: EV Managed Charging Program

In Example 2, an electricity distributor proposes a much longer-term program. In this example the electricity distributor has identified a long-term need: to be able to proactively engage with individual customers that are purchasing EVs and the level 2 electric vehicle service equipment (EVSEs) to manage charging on assets serving clusters of EV driving customers. The BCA takes a very long view (i.e., considering ongoing cost and benefit streams out through 2050) and is forthright about the significant uncertainties at every level, proposing to develop a comprehensive update to the BCA as part of each subsequent DSP submittal at future rebasings.

1.2.1. Need

The electricity distributor service territory includes a wide range of customer demographics. Five years ago, as part of its strategic planning, the electricity distributor began to actively monitor EV adoption in its region. It has done this through a combination of subscriptions to proprietary data, incented customer surveys, publicly available EV tracking data[6], and, most recently through customer subscriptions to the new Ultra-Low Overnight (ULO) RPP price plan.

Two years ago, the electricity distributor procured a spatial EV adoption forecast to assist it with long-term planning. The outputs of this study were then used by the electricity distributor's planning team, supported by a specialized consultant, to develop a long-term assessment of the potential impacts of unmitigated EV adoption on the electricity distributor's distribution infrastructure requirements and capital spend. This was a study similar in

[6] Government of Ontario Data Catalogue, *Electric Vehicles in Ontario – By Forward Sortation Area*, accessed October 2023
https://data.ontario.ca/dataset/electric-vehicles-in-ontario-by-forward-sortation-area

nature (though substantially different in specifics) to a 2022 study of the impact of EV adoption on distribution system costs in northern California.[7]

This study provided a set of different cost outcomes tied to different sets of underlying growth scenarios and mitigation strategies. The main reference cost projection assumed no active mitigation strategies, widespread adoption of the ULO rate, and projected EV adoption associated with the “Accelerated Pathway” identified in the EV adoption forecast. This adoption pathway was selected as the reference scenario based on the observation that observed EV adoption in the electricity distributor’s service territory since the study’s completion was more closely aligned with that then the “Steady Adoption” pathway.

The electricity distributor has attached to its BCA:

- The final report associated with its EV adoption forecast
- The final report from the cost study.
- The numerical appendices for the cost study.

The electricity distributor has also provided a five-page survey of the most current professional literature (published within the last 2 years) providing forecasts or projections of EV adoption, as a share of the market. This survey document includes a brief summary of legislation in Canada and the U.S. that will continue to support EV adoption. The survey concludes that “Accelerated Pathway” adoption scenario remains the most prudent utility planning scenario.

The electricity distributor’s cost study estimates that, absent the application of smart charging, even with the impacts of the ULO price plan, the total incremental capital investment required by the utility over the 25-year period from 2027 through 2050 could be in total as much as 2-3 times its annual budget.

Electricity distributor staff, working with these values have estimated that this is approximately equivalent to an annualized incremental cost to the electricity distributor’s customers of 4 – 8% per year.

The electricity distributor has noted that the need is long-term, not tied to any

[7] Salma Elmallah et al 2022 Environ. Res.: Infrastruct. Sustain. 2 045005 https://haas.berkeley.edu/wp-content/uploads/WP327.pdf

specific assets, and discretionary.

1.2.2. Alternatives Considered

In this section, the proponent is should describe each of the alternatives considered to meet the need. The electricity distributor should complete this section by explicitly identifying the reference scenario approach and the preferred non-wires approach being considered in the BCA.

The electricity distributor has identified the following alternative options:

1) **Do Nothing *(reference scenario)***

   Doing nothing is reference scenario; although the electricity distributor's strategic plan has identified undertaking actions to help support an orderly and cost-effective energy transition, absent the proposed actions in the BCA (which is embedded in the electricity distributor's DSP submitted as part of a current rebasing), no actions would be undertaken.

2) **Develop Managed Charging Program *(Non-Wires Solution)***

   To address the long-term need and deliver value to its customers, the electricity distributor is proposing to put in place the control room upgrades and procure the software and equipment necessary to implement a voluntary managed charging program. It proposes to begin by procuring the services of a vendor that will allow it to throttle the delivery capacity of enrolled EVSEs from most of the major manufacturers.

   The electricity distributor has developed a long-form program plan, a document of approximately 80 pages (accompanied by a set of workbook appendices) that provides a detailed review of the value proposition to customers, the specifications of the equipment and software it plans to use in the initial years of its program development as well as the longer-term technologies it plans to leverage.

   The long-term plan also provides a review of the electricity distributor's strategy to monitor EV adoption and asset capacities and conditions to enable it to deploy offers to customers opportunistically as the value to distribution service warrants it.

> The electricity distributor notes that a significant challenge from the perspective of the program economics, and for the development of a BCA, is the fact that benefits and costs are not contemporaneous. Significant up-front investment in control room equipment and training, and in fixed-cost program development spend is more than compensated for by long-term deferral benefits, but that those deferral benefits, by virtue of being realized four or more years in the future, are somewhat uncertain.

This BCA is to fulfil a *discretionary* system need. Although the electricity distributor believes (and has argued) that long-term planning for the effects of the energy transition is a prudent use of its resources to ensure the reliability and continuity of its distribution service, it also acknowledges that – at present – not developing a managed charging program would not put it out of compliance with regulation or legislation.

The electricity distributor has noted, however, that because the cost of the do-nothing option can be understood only in the context of the benefit of the NWS, that for the purposes of the BCA it will consider the avoided costs of the “do-nothing” option as the benefits. The electricity distributor argues that the costs of the do-nothing option are fully quantified in its long-term cost study (attached to the BCA), and that assessing the value of the proposed program is therefore most appropriate as a comparison of avoided costs (benefits) and program costs.

1.2.3. Cost-Effectiveness Test

The electricity distributor has submitted the required Excel output template with its BCA. Two versions of the Excel output template have been provided. One version (Near-Term Analysis – NTA) covers the period between 2025 and 2030 and one (the Long-Term Analysis, LTA), covers the entirety of the BCA period (out to 2050).

The purpose for the provision of the two outputs is to provide greater transparency. The LTA demonstrates the cost-effectiveness of the program from a distribution service perspective, but the NTA provides a much more detailed assessment of the flows of benefits and costs in the near-term, where there is much greater certainty. The LTA is derived almost entirely from the outputs of the cost-study that has motivated the application, whereas the NTA reflects the more detailed program planning included in the program plan document attached to the BCA.

The electricity distributor has not provided an EST test result. It has not had the opportunity to fully engage with the IESO as part of the IRRP process.

The electricity distributor wants to minimize planning and regulatory delays and has submitted its application mid-stream, with the commitment to provide updates to inputs and assumptions when it submits its new DSP as part of its rebasing application in 2028. The electricity distributor plans to continue to engage with the IESO in parallel to the BCA review process.

1.2.3.1. DST Benefits

The electricity distributor has submitted an estimate of the NPV of DST benefits in both the NTA (which covers only the first five years of the program) and the LTA (which covers the program period out through 2050).

The DST benefits in both the NTA and the LTA have been calculated using an adaptation of the marginal capacity value approach described in Section 5.1.1.1.

In the case of the NTA, the electricity distributor has identified all distribution assets likely to be impacted by clustered adoption projected by the EV adoption forecast. These have been assigned risk categories on the basis of the estimated uncertainty included in the EV adoption forecast and the existing (and business-as-usual) forecast available capacity of the assets.

The electricity distributor has also assigned a second categorical variable, corresponding to the estimated cost of addressing the need for the given asset. These costs are, for the most part, averages based on historical upgrade and construction costs, but in some cases have been subject to ad hoc adjustment given the individual characteristics of the asset and its location.

The electricity distributor has used these two dimensions to identify the regions in which enrollment would be targeted, and has, on the basis of the incremental capacity of upgraded equipment and the costs of upgrading or replacing the equipment assessed a marginal cost of distribution equipment – a $/kW-year value applicable within each region.

The electricity distributor has made certain assumptions about the charging profiles of vehicles in this region (assuming that nearly all will subscribe to the ULO), the forecast distribution of vehicle and EVSE types, and has developed an estimate of the average kW reduction (of the local asset peak) it believes it is likely to achieve from each enrolment.

The electricity distributor has then identified a ceiling number of enrolments per region (i.e., beyond which there is no incremental distribution service benefit) on the basis of the DR capability per enrollment and compared this with the forecast EVs in the region. The electricity distributor has targeted enrolling 115% of the ceiling value. The electricity distributor argues in its BCA (and in its program plan) that although this reduces the average value of each participant (since the marginal value beyond the ceiling is zero), it provides contingency and compensates for the asymmetric consequences of uncertainty.[8]

The electricity distributor has assumed that it can meet its enrollment targets and presented the NPV of the NTA.

For calculating the benefits of the LTA, the electricity distributor has calibrated some of its longer-term avoided cost assumptions (outputs of its cost-study) to the findings of the NTA to ensure a smooth transition from one to the other. The LTA, however, takes a much higher-level perspective than the NTA, an approach that the electricity distributor argues is appropriate given the much greater uncertainty. In the LTA, the electricity distributor assumes improvements in the efficiency of the program (i.e., that it can achieve more avoided kW for each enrollment).

The NPV of benefits from the LTA is quite considerably larger than the benefits estimated by the LTA, reflecting both the longer timeline, substantially increased volume of EV adoption, and improved efficiency of benefit delivery in the future.

1.2.3.2. DST Costs

The DST costs estimated by the electricity distributor are a combination of very substantial fixed costs in the first four years of the period of analysis, and an annual series of operations, maintenance, administration, and

[8] If insufficient EVs are enrolled, the distribution system costs are incurred, potentially wiping out the value (from a distribution service perspective) of those that were enrolled. The risk here is between spending a little too much to save a lot, or spending quite a bit, but saving nothing.

incentive costs. The up-front fixed costs account for nearly half of the approximately 30-year lifetime costs of the program.

This disparity in fixed and variables costs is due, as noted above, to the need for the electricity distributor to invest significant amounts of funds and resources into developing the necessary capabilities to connect Level 2 EVSEs for control, monitor distribution system resources in near-real-time (including EVSEs), and dispatch controlled EVSEs efficiently as required to both trim distribution asset peaks and avoid creating new peaks due to peak migration.

Incentive costs are relatively low; the electricity distributor argues that market research and the observable trend that EV drivers are extremely price-sensitive (and their demand extremely fungible) means that, provided the electricity distributor is careful not to throttle EVSE too aggressively, enrolment goals can be achieved at relatively little cost.

The electricity distributor has provided, as an additional Excel workbook, a more detailed breakdown of the fixed costs. The electricity distributor has argued that many of these costs are for items that deliver other incremental benefits to distribution customers, and others are for items (e.g., equipment monitoring gear) the acquisition of which would be necessitated by other energy transition activities anyway.

The electricity distributor has categorized the fixed costs according to three criteria: costs that are attributable only to the program, costs that are for investments that deliver significant long-term customer benefits outside of the program, and costs that would have to be incurred anyway in the medium- to long-term and are only advanced by the program.

The three groups of costs are presented separately both in the LTA and in the NTA.

1.2.3.3. Cost-Effectiveness Test Outcome

In the LTA, benefits are more than four times higher than costs, with a net benefits slightly greater than three times higher than costs. The LTA net benefits cover the period from program inception through to the end of 2050.

In the NTA, benefits do *not* exceed costs, and the DST fails. Benefits in the first five years of the program amount to less than 60% of the costs incurred in the first five years of the program.

1.2.4. Other BCA Considerations

The electricity distributor has a brief summary discussion of the each of the considerations, but also includes a detailed section that focuses primarily on the planning value benefits and overall project risks[9].

The content of this section is a synthesis of key points included in the EV adoption forecast reporting, the cost study, and in its own program planning documentation. The key thrust of the argument made is this:

- The most significant risk to customers of proceeding is that EV adoption stagnates.
- The cost to customers in this case is not small, but of the costs that will have been incurred by the time that it becomes clear that EV adoption has ceased to grow, most will be costs related to equipment or other assets that deliver value in other areas, or costs that were otherwise inevitable and drawn forward.
- Conversely, if EV adoption proceeds as forecast by a near consensus of thought leaders (as identified in the survey study developed by the electricity distributor and referenced above) there's a near certainty of an increase in customer distribution service costs many times higher than the costs being risked to set up and prepare systems for early mitigation.

The risk to customers of EV adoption stagnating is low, and the cost of that consequence is moderate. The risk to customers of EV adoption growing quickly is high, and the cost of that consequence is high.

From an expected value perspective, the answer is clear: the short-term expense of investing in the capability to dynamically control EV charging on congested circuits is more than justified by the long-term value it will drive to customers in the form of reduced electricity distributor costs.

1.2.5. Outcome

The electricity distributor has provided a short statement formally identifying

[9] For illustrative purposes only, one such risk that may be considered in this example is technology-based. Considering the 30-year asset lifecycle, the NWS infrastructure may age faster than originally contemplated and/or the selected infrastructure may not adequately control EV loads over the longer-term. This may lead to the need for replacement or upgrades prior to the end of the expected 30-year asset lifecycle.

the outcome of the BCA and the alternative with which the electricity distributor proposes to proceed.

For example: "*Based on the long-term value that managed charging provides to customers, despite the short-term risks, the electricity distributor proposes to proceed with the investment in the necessary tools and resources to implement the managed charging pilot laid out in its program planning document.*"

1.2.6. Risk Mitigation

The electricity distributor recognizes that the program's risks, though moderate to low relative to the benefits of the program are significant in absolute terms. The electricity distributor, as a risk mitigation measure has committed to a regular reporting process with OEB and IESO staff, in addition to providing a formal update to all BCA assumptions and inputs at each subsequent rebasing. The electricity distributor will provide OEB and IESO staff a semi-annual status report on progress. This will include a written report that will address a series of key performance indicators defined by the electricity distributor in the risk mitigation section of its BCA, as well as a set of Excel workbooks tracking program costs, enrollments and other key quantitative performance metrics.