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November 9, 2023

VIA E-MAIL

Nancy Marconi
Registrar
Ontario Energy Board
Toronto, ON

Dear Ms. Marconi:

**Re: EB-2023-0125 – Benefit-Cost Analysis Framework for Addressing
Electricity System Needs
Draft Phase One BCA Framework Project Plan
Submission of the Vulnerable Energy Consumers Coalition (VECC)**

Please find attached VECC's submission on the above referenced matter, pursuant to the Board's letter of October 26, 2023.

Please contact me if any clarification is required (bharper.consultant@bell.net)

Yours truly,

William Harper
Consultant for VECC/PIAC

cc. J. Lawford, PIAC

**OEB BENEFIT-COST ANALYSIS FRAMEWORK FOR
ADDRESSING ELECTRICITY SYSTEM NEEDS (EB-2023-0125)
VECC'S COMMENTS RE: BCA HANDBOOK PROJECT PLAN**

INTRODUCTION

On September 20, 2023, the Ontario Energy Board (OEB) issued a letter to initiate a consultation to support the development of a Benefit-Cost Analysis (BCA) Framework for addressing electricity system needs. A stakeholder engagement session was subsequently held on October 13, 2023 at which an overview of the draft Phase One BCA Framework project plan was presented.

A copy of the draft Phase One BCA Framework project plan, prepared by Guidehouse Canada under the oversight of OEB staff, was issued on October 26, 2023 and interested parties were invited to provide comments by November 9, 2023.

Set out below are VECC's written comments.

VECC's COMMENTS

VECC's comments are organized based on the section headings for the proposed BCA Handbook. For each section VECC has considered the questions set out by Guidehouse in its October 13th presentation¹:

- i. Content: What additional information could be included in the Handbook that would help LDCs to assess the value of DERs for meeting system needs?
- ii. Impacts: For the DST and EST, are the proposed impacts and their suggested applicability correctly aligned with the purpose and intent of each test?
- iii. Examples: The BCA Handbook will include three summary worked examples of BCAs for different DER NWAs. What types of system needs, DER solutions, and practical constraints should these examples address? The more specific the detail that can be provided here, the better.
- iv. Inputs: We expect that the most significant benefits and costs of DERs will be derived from project- and program-specific information. Are you aware of any material impacts for which generic values are available and might be used?

1. INTRODUCTION

The introduction explains that the development of the BCA Handbook will take place in two-phases²:

“In this current, initial phase, the OEB is developing a BCA Handbook to provide LDCs with guidance for assessing and reporting out the net distribution service benefits of DERs employed as NWSs, with some high-level consideration of bulk electricity system impacts. A subsequent phase will expand the Framework's focus and provide an updated Handbook with more detailed guidance for assessing the net benefits of DERs to the broader electricity system, and the province as a whole.”

¹ Slide #16

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Given that the Handbook will eventually set out two “tests” (i.e., the DST and the EST) it will be important for the Handbook to clearly set out the role of each with respect to the decisions a distributor will make as between traditional wire solution and a non-wires solution to a given system need. In VECC’s view, distributors should be focusing on investments and related decisions required to meet their customers’ needs. Investments in non-wires (or for that matter traditional wires) solutions that do not benefit a distributor’s customers but are deemed to provide broader system benefits should only be pursued by a distributor if adequate compensation is provided by the system’s customers.

VECC also has concerns regarding the intent for the initial CBA Handbook to provide “some high level consideration of bulk system impacts”. Transmission system needs vary by region, both in terms of the timing of regional peaks during the day/year and the future date at which additional capacity will be required. If the EST is meant to be key component of a distributor’s decision to pursue a non-wires vs. wires based solution, then an overly simplistic approach to valuing broader system needs may lead to investment decisions that are not cost-effective.

However, at a more fundamental level, in VECC’s view there is a clear difference between: i) a Benefit Cost Analysis Framework and ii) a Cost-Effectiveness Test. Cost Effectiveness Tests deal with costs and benefits that are quantifiable such that they can be easily compared and benefit/cost ratios calculated. In contrast, a Benefit Cost Analysis Framework should include the consideration of the results of appropriate Cost Effectiveness Tests but also identify and provide a framework for considering benefits/costs that are not quantifiable or where there is a range of uncertainty such that an analysis using expected values would not be appropriate. Tables 3, 4, 5, and 6 all identify various Impact Categories and acknowledge that in some cases the impacts may only be identifiable qualitatively. In other instances the suggestion is that the impacts may be quantifiable but with great difficulty.

Since not all impacts are quantifiable it is VECC’s view that the Cost Effectiveness Tests should focus on those costs and benefits that are readily quantifiable with a reasonable degree of accuracy and should not include Impact Categories where the values are highly speculative or uncertain. Rather these Impact Categories, along with those that can only be addressed qualitatively, should be incorporated into a broader Benefit Cost Analysis Framework. This framework should provide a comparison of the wires and non-wires solutions across all of the Impact Categories and, as such, will include quantitative measures and qualitative measures depending on the specific Impact Category. This Benefit Cost Analysis Framework will allow the distributor to identify and assess the key trade-offs between the various alternatives. While Cost Effectiveness will be a key consideration in the distributor’s decision making, ultimately the distributor’s decision should involve balancing all of the relevant Impact Considerations and will need to be explained/justified in that context.

In VECC’s view the key role/purpose of the BCA Handbook should be to identify for a distributor the Impact Categories that need to be considered, how the impacts can be measured (either quantitatively or qualitatively) and, for those that are quantifiable, how they should be incorporated into the recommended Cost Effectiveness Tests (e.g., the DST).

2. BCA DOCUMENTATION IN ONTARIO AND OTHER JURISDICTIONS

In the case of the Other Jurisdiction Sources (Table 1), it would be useful if the BCA Handbook included the actual web links so that users could readily access them if they wish to³.

3. KEY CONSIDERATIONS FOR THE BCA HANDBOOK

3.1. Direction of the FEI Consultation & Integration Into the Existing BCA Ecosystem

This section states⁴:

“A key consideration for this version of the Handbook and – especially – for Phase 2 of the framework development, is how to ensure the alignment of net benefits delivered by the EST with those that might later be provided by the IESO’s IRRP Technical Working Group. It is this group that is responsible for valuing NWS-type benefits provided by DERs to the bulk energy system, and any such values developed by the IESO will more accurately capture system level benefits than the generic benefits identified for the EST in this version of the BCA Handbook.”

It also states⁵:

“It is for this reason that the Phase 1 version of the BCA Handbook will recommend that, if possible within the LDC’s other time constraints, the LDC begin by assessing the DST, then, if it wishes to quantify any NWS benefits the DER offers the wider energy system, engage with the IESO, likely through its IRRP process. Where the timing of the IRRP process does not align with LDC constraints, LDCs may develop values for the EST according to the guidance of the Phase 1 BCA Handbook (for which the outline is presented below).”

Care needs to be taken when using the term “bulk system” in the context of benefits provided by DERs. In principle the DST focuses on the distribution utility’s system and the need to maintain its reliability and the EST then focuses on costs and benefits “upstream” of the distributor’s system (e.g., the bulk system). However, the assets upstream to a distributor utility’s system vary widely. In some cases distributors own assets, such transformer stations, that are typically considered to be part of the transmission system. In other cases, distribution utilities are embedded within another distributor’s system and the upstream assets will involve the distribution assets of the host utility as well as transmission assets. Finally, while some distributors may require the use of transmission system’s Line Connection assets, others will not. As a result there is no standard definition for the “bulk system” (i.e. the system/assets upstream of a distributor) that will be applicable to all distributors. As a consequence, there will be no standard transmission capacity cost that will be applicable to all distributors.

In VECC’s view this variation simply heightens the concern expressed above regarding the use high level estimates as to the broader system benefits of DERs and brings into

³ As part of its review of the proposed BCA Handbook-Project Plan VECC attempted to access the referenced NYSEG Benefit Cost Handbook – Version 3 in order to review the tables referenced. However, web-searches only turned up more recent versions with different table numberings.

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⁵ Page 6

question whether the use of generic system values, particularly with respect to upstream transmission costs, are appropriate.

3.2. Impacts Addressed by the Tests

There needs to be a standardization of the terminology and a clear concordance between the Impact Categories as set out in Table 3 and the DST Impact Categories in Table 4. Some examples of current inconsistencies are:

- Table 3 uses the term “Distribution Cost” which is assumed to be the same as “Distributor Cost” in Table 4.
- Table 3 uses the term “(Distribution Service) Risk” which is assumed to be the same as “Risks (Distribution System)” in Table 4
- Table 4 uses the terms “Reliability (Avoided Restoration Costs)” and “Resilience (Avoided Outage Costs)” which are assumed to be the same as “Reliability” and “Resilience” in Table 3.
- Table 3 includes “(Bulk System/Resource) Risk” as an Impact Category but there is no reference to this category in Table 4.
- Table 3 includes “(Bulk System/Resource) Ancillary Services” as a permitted Impact Category but there is no reference to this category in Table 4.
- Table 3 includes “Distribution System Losses” as a permitted Impact Category but there is no reference to this category in Table 4.

Further, either in this section or (more likely) in sections 4.5.1 and 4.5.2 there needs to be clear explanations, with examples if possible, as to the basis for and the types of costs that would be captured under each Impact Category.

In terms of the various Impact Categories attributed to the DST:

- It is not clear why either “(Bulk System/Resource) Risk” or “(Bulk System/Resource) Ancillary Services” are included as Impact Categories for the DST per Table 3 as they both seem to relate to issues/items upstream and outside a distributor’s system.
- In terms of including “Innovation and Market Transformation” as a permitted Impact Category, this would only be a benefit to the distributor if the distributor anticipates using non-wires alternative elsewhere on its system at some future point in time. However, it may have more value when considered in the context of the system and the EST.

In terms of the various Impact Categories attributed to the EST:

- Any attempt to include Market Price Effects will have to include the offsetting effect of changes in market prices will have on the Global Adjustment.

There is no recognition of the impact wires vs. non-wires alternatives may have on existing assets in terms of early retirement and write-offs. Where the discount rate being used in the economic analysis is the distributor’s weighted average cost of capital this may not be a material issue. However, the CBA Handbook proposes that the DST and EST use a standard value of 4% (real) as the discount rate. As a result, there can or will be differences in the net present value (NPV) of an asset’s costs when it’s value is written off prematurely compared to the NPV of the costs recovered from customers if that asset remained in service.

Finally, as the notes in Table 3 suggest and as discussed above, not all impacts are quantifiable. This does not mean that legitimate non-quantifiable impacts should not be considered. However, distributors should not be expected to go exceptional lengths to try and quantify impacts that are not readily quantifiable or where the value is highly uncertain.

3.3. Addressing Challenges for LDCs

VECC agrees that “the OEB’s goal is not to promote DERs for their own sake or to prefer DERs to other solutions for providing distribution service”. Rather, “its goal is to support the deployment of solutions that are optimal for customers, maximizing the value of their distribution service.”⁶

The BCA Handbook indicates⁷ “there is significantly greater operational uncertainty and risk associated with deploying DERs as NWSs than there is a traditional poles-and-wires solution”. It also indicates “there is significantly greater performance uncertainty and risk with deploying DERs as NWSs than there is a traditional poles-and-wires solution”. This is attributed to the lack of experience utilities have had with assessing, procuring and implementing DERs. In VECC’s view this increased risk cannot be ignored as it represents a real risk to customers that must be considered in choosing the optimal for customers in any benefit-cost assessment of wires vs. non-wires solutions. This is particularly the case if the BCA is to also ascribe “Innovation and Market Transformation” benefits to the non-wires solution. VECC expects that the incremental risks associated with non-wires solutions would be clearly included in the Handbook under the “(Distribution Service) Risk” Impact Category.

With respect to the three paragraphs dealing with “Regulatory Development”, it is not clear what the purpose or the intended message this section is meant to convey is. If the intent is to suggest that some of the costs distributors will incur in adopting a non-wires solution should be ignored or discounted in the analysis then VECC fundamentally disagrees as these represent real costs that the distributor’s customers will have to bear. If the intent is to suggest that some of the costs incurred by distributors who are early adopters should be borne by the overall system, then this may be appropriate provided it can be demonstrated that there is a clear system benefit which justifies the costs that customers system-wide will be expected to bear.

4. BCA HANDBOOK OUTLINE

4.1. Introduction

This section states⁸ that “the BCA Handbook is intended to provide guidance to LDCs undertaking benefit-cost analyses to assess the cost-effectiveness of meeting a distribution service need with a DER – with a non-wires solution (NWS) - in order to defer or avoid a traditional poles-and-wires solution.” As noted previously, in VECC’s view there is a clear difference between a “benefit-cost analysis” and “cost effectiveness”, particularly if the latter is based on a numerical test. To equate the two suggests that either: i) all Impact Categories can be suitably quantified or ii) only those

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⁷ Page 9

⁸ Page 10

Categories that can be quantified should be considered. In VECC's view, neither statement is correct. Rather there needs to be a step, after the Cost-Effectiveness Tests results are calculated, where those Impact Categories that are non-quantifiable are included for consideration. While the results of the Cost Effectiveness Test are a major consideration they may not always be determinative of the preferred alternative. Whether they are determinative or not, a distributor would still be expected to fully justify its decision to pursue a wires or non-wires solution based on its assessment of all the Impact Categories.

4.2. Purpose and Use

The discussion under "Criteria for Use" is somewhat inconsistent. The first sentence states that "if a local need is large a poles and wires solution will almost certainly be more cost-effective". However, the footnote states that "there is often a minimum cost threshold for project to be considered by NWS solutions", suggesting that higher cost projects are the ones that warrant consideration of non-wires solutions.

The discussions under "Development & Submission Process" and under "Regulatory Context" both suggest that BCAs would be submitted prior to the project being implemented. However, there is also a possibility that subsequent to the filing of a rebasing cost of service application and associated DSP, the distributor might identify an opportunity to use a non-wires solution in lieu of a wires solution included in its DSP. In such cases, funding will have already been covered by the DSP and the rebased rates such that an ICM application would not be justified. In such cases, it would be necessary for the OEB to clarify whether the utility is expected to:

- i. File an application for approval of spending on the non-wires solution, as it would for a utility-funded CDM program, or
- ii. Prepare the necessary documentation (including BCA) in order to defend the inclusion of the associated costs in its rate base/ongoing O&M expense at its next rebasing.

The discussion under "Interpreting BCA Outcomes and Handbook Requirements" states⁹:

"LDCs must be provided with an indication of what is considered an acceptable outcome (or pass) of their BCA – e.g., a DST result of 1 or more for any LDC-proposed NWS, consistent with the OEB's policy priorities and the guidance of the Renewed Regulatory Framework. Some indication should also be provided of the OEB's expectations with respect to the prescriptiveness of the Handbook."

In VECC's view, any such guidance will need to reflect the fact that (as discussed above) a benefit cost analysis is more than a cost-effectiveness test and that, recognizing the need to consider qualitative as well as quantitative measures expectations should not be overly prescriptive.

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4.3. General Methodological Considerations

This section states¹⁰:

“Any LDC proposing to use a DER as an NWS must, where material investment is required, complete a BCA. The primary, and compulsory, output of this analysis is benefit-cost ratio or set of net benefit values (benefits less costs) for competing alternatives calculated according to the requirements of the Distribution Service Test (DST).”

The OEB will need to clearly define what is considered a “material investment” and in doing indicate how capital costs and on-going O&M costs arising from the investment are to be treated when assessing materiality.

The section also states¹¹:

“Utilities may also, but are not required to, develop a benefit-cost ratio calculated according to the requirements of the Energy System Test (EST). Both testing approaches are described in the Handbook, though it is expected that the EST will continue to evolve as the OEB proceeds with Phase 2 of the development of its BCA Framework.”

It is not clear what role, if any, the EST will play in determining whether the outcome of the BCA is favourable or unfavourable with respect to a distribution utility undertaking a non-wires solution. The OEB should provide clarification.

4.3.1. What to Include

4.3.1.1. Description of Grid Need Being Served

With respect to the illustrative list of grid needs¹²:

- Reliability, Resilience and (Distribution Service) Risk Impact are three Impact Categories that distributors may have difficulty understanding and determining whether there are additional benefits or costs assignable to the non-wires solution. As result it would be useful if, under Sources of Value, some examples were provided.
- When discussing Sources of Value the BCA Handbook should be clear as to whether any example cited is applicable to the DST as well as the EST.

4.3.1.2. Comprehensive Evaluation of Benefit Streams Not Required

This section notes¹³ that “LDCs must, however, document and include in the BCA all relevant and material DER costs, as defined in Section 4.5 below.” The BCA Handbook should be clear that this includes not only direct costs but also any indirect costs as well as any loss of potential benefits associated with the wires solution. For example, under the Forecast Overload Under Blue-Sky Conditions described on the previous page, if a traditional upgrade would have involved improving the reliability of the line then this lost benefit needs to identified as part of the cost of the non-wires solution.

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¹¹ Page 12

¹² Page 13

¹³ Page 14

4.3.1.3. Forward-Looking Uncertainty

This section advocates¹⁴ the use of expected-value calculations where “loss functions are asymmetric” in order to “help LDCs more accurately capture the long-term benefits of DERs in aggregate and so provide a better estimate of the value of a given NWS.” The section then goes on to state¹⁵:

“Expected-value calculations or proposed de-rating factors may be based on sensitivity analyses or scenario reviews conducted as part of the BCA, on historical data, or documented outcomes from similar or analogous projects. Supporting evidence must be provided for any probability estimates used in expected-value calculations.”

It is VECC’s understanding that scenario analyses often do not involve the assignment of probabilities but rather the simply the creation of futures that are reasonably plausible given the uncertainty regarding future economic conditions and government policy. For many distributors the forecasting techniques used may not readily provide the probability distributions required to undertake expected value calculations. As a result, the Handbook should characterize the use of scenario analysis as an alternative to expected-value calculations.

4.3.1.4. Difficult to Quantify Impacts / Qualitative Impacts

With respect to the value to be ascribed to lessons learned, VECC notes that there is wide experience with DERs and non-wires solutions in jurisdictions outside of Ontario and that any value ascribed to “lessons learned” must truly be new information and not readily obvious. Indeed, the example cited is one where it is obvious that permitting participants to opt-out of a control event will reduce the expected demand savings. VECC also suspects that there is evidence from other jurisdictions indicating the extent to which participants “opt-out”.

4.3.1.5. Symmetrical Treatment

In order to ensure that distributors fully understand this point, it would be useful if, for the example cited, the Handbook explained more fully what symmetrical treatment would entail.

4.3.1.6. Incremental Analysis

This section states¹⁶:

“Reference scenarios should align with business-as-usual LDC practices. For example, where load growth means that demand on an asset will exceed its capacity, the reference scenario should be the historically standard response of the LDC to addressing such growth i.e., the development of a poles-and-wires solution.”

The Handbook needs to be clear that “business-as-usual” is not the same as “like-for-like”. For example, in the case of upgrades to an existing distribution feeder the business-as-usual option would likely involve incorporating new standards/construction

¹⁴ Page 14

¹⁵ Page 15

¹⁶ Page 17

approaches that improve reliability and/or reduce losses. In such cases, these business-as-usual innovations should be the basis for the reference scenario.

4.3.2. How to Apply What is Included

One aspect with respect to the overall approach that is missing is the need to use a common reference system reference point when describing changes in need (e.g., kW of capacity) and cost/benefit impacts of various solutions. Potential points of reference would include the point of delivery to the utility (e.g., interface point with the upstream system), the utility's primary distribution system or the point of delivery to its retail customers. Depending upon the point of reference chosen adjustments will need to be made for coincidence with peak demand at that point and losses.

4.3.2.1. Net Present Value/Discounted Cash Flow Analysis

This section states¹⁷:

"All value streams included in the BCA must be evaluated on a net present value basis, in constant dollars. Consistent with the IESO's guidance for the economic analysis of NWSs, LDCs should use a social discount rate of 4% for discounting cash flows to present value, and an assumed inflation rate of 2% for conversions between nominal and constant dollars."

VECC understands why a social discount rate is used by the IESO in the assessing of non-wires alternatives for regional resource plans. It is also understandable why this would be an appropriate discount rate to use on the EST. However, for the DST, which is meant to look at the decision from the perspective of the distributor and the impact on its customers the use of a social discount rate, as opposed to the distributor's own weighted average cost of capital becomes questionable. The Handbook should explain more fully why the use of a 4% (real) social discount rate is appropriate. Also, if the social discount rate is to be used for purposes of the DST then a similar test where the PV is based on the distributor's own weighted average cost of capital should be included as another consideration in the overall benefit cost framework¹⁸.

4.3.2.2. Discretionary vs. Non-Discretionary System Needs

Throughout this section reference is made to "investments" to meet either a discretionary or non-discretionary need. The Handbook should be clear that references to "investments" include additional incremental O&M expenditures as well as capital spending.

4.3.2.3. Study Period

The key principle regarding the appropriate study period is currently set out in the last paragraph of this section, namely that the study period should capture the timeframe during which the benefits and costs of the traditional wires vs. a non-wires solution differ. This point should be moved up and introduced at the start of the section. The discussion around discretionary vs. non-discretionary investments are then examples of how this principle results in different study periods depending upon the circumstances.

¹⁷ Page 17

¹⁸ See the earlier discussion for the distinction VECC makes between cost effectiveness tests and a benefit cost framework.

Indeed, for the example provided regarding the application of the DST to a situation where the DER defers the need for additional distribution assets by five years, the assumption that only the payment period needs to be considered is predicated on the assumption that deferral does not impact the annual expenditures required in the subsequent years. This may not be the case if the deferral of the distribution asset's in-service date also defers the date for any subsequent sustaining capital spending.

4.3.2.4. Transparency and Validation

This section states¹⁹:

“As with other aspects of rate applications, including capital funding requests for traditional poles-and-wires investments, the BCA information filed in support of proposed distributor spending may be tested during a hearing. LDCs should ensure that their analysis is transparent, based on robust data and reputable sources, and replicable by a third party provided with the same inputs.”

As discussed above, the Handbook should note that BCA information may also be required to substantiate the inclusion of actual distributor spending in rate base in subsequent hearings.

4.3.2.5. Projects and Programs

This section states²⁰:

“LDCs may therefore develop BCAs for proposed programs of DER adoption as NWSSs, that may be used to address multiple (but similar) needs, at different locations within the distribution system.”

The Handbook should be clear that the program approach only works if the cost of the traditional wires alternative is similar in the different locations and, equally, the cost of the non-wires solution is similar in the different locations within the distribution system. In the case of Example 1 provided in this section, a program approach would only be appropriate if the various feeders under consideration had similar upgrade costs and the cost of deploying EV managed charging controls was similar in all cases.

4.3.2.6. Resource Procurement Approach

This section notes that²¹:

“For example, if an LDC deploys a utility-scale storage solution to defer a distribution system need, that LDC can with reasonable certainty quantify the energy system value that storage solution might deliver to the bulk energy system following the end of the deferral period.”

With respect to any energy system values that a storage solution might deliver following the deferral period, it would be useful to note that any incentive payments or other ongoing costs would also need to be included.

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²⁰ Page 20

²¹ Page 22

4.4. Cost Effectiveness Tests

This section states²²:

“LDCs wishing to recover costs associated with DERs or DER services as an NWS must calculate (and present to the OEB) the benefits and costs prescribed by the Distribution Service Test. LDCs may also elect to calculate the benefits and costs prescribed for the Energy Service Test.”

This wording suggests that in order to recover the costs associated with DER LDCs must provide the results of the DST. The OEB should clarify whether this is the intent. It would also be useful to clarify whether presentation to the OEB must occur before the DER is implemented and cost recovery commences and also whether inclusion requires formal OEB approval. To this last point, VECC notes that while a DSP is submitted as part of each rebasing application, beyond its implications for the test year rate calculation the DSP is not currently approved by the OEB.

4.4.1. Distribution Service Test (DST)

This section states²³:

“The DST will be the main test used to test the cost-effectiveness of the NWS considered by an LDC.” (emphasis added)

Further clarification is required as to the role of the DST in determining: i) the cost effectiveness of a NWS and ii) whether from LDC perspective a non-wires solution is prudent expenditure (in lieu of a traditional wires solution). More specifically the OEB needs to clarify:

- If the DST is the main test, are there other tests for cost-effectiveness and, if so, what are they and how is the LDC to proceed if the results of these tests differ as to what is the more cost-effective solution.
- Given that cost and benefits cannot be quantified for all Impact Categories and incorporated in the DST, what role does the qualitative assessment undertaken for these categories play in the final decision (e.g., is it conceivable that based on these considerations an LDC could justify as prudent an investment that did not satisfy the DST?).

4.5. Benefits and Costs

This section notes that²⁴:

“Considerable range exists in the degree to which BCA Handbooks in other jurisdictions prescribe the methods for estimating the impacts required for the various cost-effectiveness tests. The New York utilities – whose BCA Handbooks all spring from a common template first developed in 2016 – provide detailed formulae for each impact, including for distribution capacity benefits (see Table 1 for the New York utilities BCA Handbooks noted here).”

It is important to clarify that what is being discussed here is not the types of impacts (i.e., the Impact Categories) that are to be included in DST but rather how the actual

²² Page 22

²³ Page 23

²⁴ Page 26

impacts for each Impact Category are to be determined. Given the large number of distribution utilities in Ontario and the variation in service areas and types of facilities used VECC's view is that the use of generic values for distribution level impacts would be inappropriate. Also, as the costing and reliability data available for each utility will differ²⁵, prescribing detailed formulae and specific input requirements as to how the impacts are to be calculated is likely to prove unworkable.

Overall VECC agrees with Guidehouse's expectation that "in most cases impacts will be estimated as "custom" values, drawn from the utility's available costing data"²⁶. Even then, not all distributors may have the necessary data to derive the required impacts. If the OEB determines that such circumstances necessitate the use of generic values for the benefit/cost analysis then the distributor should be required to: i) comment on the reasonableness of the generic value and ii) assess the sensitivity of results to using the generic value.

4.5.1. Distribution Service Tests Benefits and Costs

4.5.1.1. Avoided Distribution Capacity Infrastructure

The "Change in NPV" approach considers the change in the NPV of the traditional wire solution based on the assumption that it is either deferred or avoided as a result of the adoption of the NWS. The Handbook should note that this NPV calculation needs to account for not only the initial cost of the traditional wires solution but also any sustaining investments that would be required over its lifetime.

With respect to the "Carrying Cost" approach, the incremental annual revenue requirement associated with a traditional investment is not a constant value that can be determined based on a percentage of a project's costs. The incremental revenue requirement will typically decline over time in both real and nominal terms as the initial investment costs are depreciated and the net book value used to determine the annual equity and debt costs associated with the investment declines.

With respect to the "Marginal Capacity Value" approach, VECC has the following comments:

- In Table 8, the Note with respect to MarginalDistCost states: "It is assumed that the marginal cost of service is based on the bulk system ("b")". VECC presumes this statement is meant to say that the marginal cost is based on demand changes at the bulk delivery level and, if so, should be re-worded to clearly state this.
- No guidance is provided as to how an LDC is to calculate the "Marginal cost of the distribution equipment from which the load is being relieved" other than to state it would be based on utility-specific or project-specific data.
- It is not at all clear why an allowance for transmission losses is being included unless the point of reference for the load change and the marginal cost of distribution is at the energy system level.

²⁵ Apart from that reported to the OEB in RRR filings.

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4.5.1.2. Reliability (Net Avoided Restoration Costs)

It should be noted that restoration costs could be higher or lower as a result of the implementation of a non-wires solution. In the case where the non-wires solution simply defers the upgrade of an existing line (or substation) and existing facilities remain in-service as is, restoration costs could actually be higher under the non-wires solution if the upgrade would have improved the reliability of the line/substation and, thereby, reduced the occurrence of outages. Indeed, there are likely to only be net avoided restoration costs if the non-wires solution totally replaces a line/substation.

Also, equal treatment requires that for those non-wires solution that are subject to failure, the anticipated annual restoration costs will need to be accounted for in the analysis. Presumably this would be captured as an incremental O&M cost of the non-wires solution (section 4.5.1.8 of the Handbook).

4.5.1.3. Resilience (Avoided Outage Costs)

VECC notes that this section requires further development including an explanation of the equation provided for Net Avoided Outage Costs and the sources to be used for its inputs. At this stage, VECC offers the following initial observations:

- The same reasoning used in the preceding section to suggest restoration costs could be higher or lower as a result of implementing a non-wires solution also applies to outage costs.
- It is not evident how Equation 5 would yield the net avoided outage costs as it appears to use the LDC's current value for SAIDI.
- Even if the equation was meant to incorporate the change in SAIDI, distribution utilities have frequently expressed the view that it difficult (if not impossible) to establish a relationship between capital spending and reliability performance.
- The value of service is highly subjective and proxies such as a customer's retail rates are poor measures of the value of avoiding what is likely to be a short service outage.

4.5.1.4. Innovation and Market Transformation

This section states²⁷:

“Certain pilot costs may be excluded or adjusted within the BCA if they are not reflective of unit costs at scale. Alternatively, the benefit of learning value may be quantified. Only one approach may be used – LDCs may not both exclude pilot costs and add quantified future benefits within the BCA.”

The assessment of pilots warrants a more fulsome and separate discussion. In VECC's view to call a project a “pilot” and seek to justify it on that basis suggests that the project has a totally different purpose than simply choosing the most prudent investment to meet a particular system need and it should be evaluated accordingly.

4.5.1.5. Planning Value (and 4.5.1.7 – Risks)

The section notes²⁸ that “these benefits may be difficult to quantify and may often be tied to asymmetric outcomes for relatively symmetric probabilities”. Regardless of

²⁷ Page 34

²⁸ Page 34

whether the intent is that “Planning Value” be considered quantitatively as an input the DST or just qualitatively, a more detailed explanation is required as to the nature of the benefits and how they could arise. This should be supplemented by one or more specific examples.

4.5.1.6. DER Capacity Acquisition Costs/Program Costs (and 4.5.1.8 – Distribution O&M Costs & 4.5.1.9 – Distribution Ancillary Services)

The draft BCA Handbook-Project Plan includes a number of sections dealing with the incremental cost of the DER solution (i.e., sections 4.5.1.6, 4.5.1.8 and 4.5.1.9). The key point that needs to be made is that collectively these three categories of costs need to identify all of the incremental costs associated with the DER and the application of the different categories does not result in any cost being either ignored or counted twice. Indeed, this is more important than determining a specific cost has been included in the “right” category.

4.5.2. Energy System Test Benefits and Costs

This section states²⁹:

“There is overlap between the impact categories included in the DST and the EST. Therefore, the section below focuses on incremental impacts relative to the DST. It is expected that LDCs will conduct DSTs ahead of performing an EST, and they should therefore leverage DST results for impacts common to both tests, within the EST.”

“LDCs are encouraged to engage with the IESO IRRP process as soon as possible in the BCA development process to identify any additional bulk system benefits or refine the values used for initial development of the EST. Generally, LDCs may use the IESO’s published CDM avoided costs for the purposes of valuing any bulk system energy benefits that the DERs deliver as preliminary values to use as part of IRRP process discussions.”

“Proponents may not have a detailed understanding of the energy system impacts of the NWS they are considering. Proponents are encouraged to complete the EST with placeholders and generic values (e.g. \$144/MW-yr for the system capacity value from the NWA guide).”

While much of this section is subject to further development, VECC offers the following initial observations:

- Any determination of capacity benefits from a transmission or generation perspective will have to account for differences between the timing of the distribution utility’s peak demand and the timing of peak demand from a transmission or generation perspective. This may require the use of different coincidence factors than were used in the DST.
- Any assumption that the DER will also be used to offset transmission or generation capacity requirement will need to consider the extent to which this could impact the role/ability of the DER in managing distribution system peaks.
- As well as energy benefits certain DERs (e.g. storage) may also give rise to an increase in energy costs.

²⁹ Page 37

- It is unclear how a DER installed to defer/replace a traditional distribution wires solution could impact either restoration costs or outage costs related to transmission and generation-related facilities.

4.6. Reporting Requirements

4.6.1. Reporting Format/Template

This section states³⁰:

“LDCs are required to report on their proposed DER as NWSs using a similar format to that used by the distributor for justifying capital expenditures within the DSP. LDCs must specify: the need, the alternatives considered, the quantitative results of the BCA, any qualitative considerations or supporting evidence for the BCA, the alternative selected, the risks of that selection and the mitigation to be applied. This will also apply in cases where a BCA was undertaken but a traditional poles-and-wires solution was determined to be the preferred solution.”

VECC’s earlier comments with respect to Section 4.2 are equally applicable here and are copied below as the above wording also suggests that distributors will report their proposed DERs:

However, there is also a possibility that subsequent to the filing of a rebasing cost of service application and associated DSP, the distributor might identify an opportunity to use a non-wires solution in lieu of a wires solution included in its DSP. In such cases, funding will have already been covered by the DSP and the rebased rates such that an ICM application would not be justified. In such cases, it would be necessary for the OEB to clarify whether the utility is expected to:

- File an application for approval of spending on the non-wires solution, as it would for a utility-funded CDM program, or*
- Prepare the necessary documentation (including BCA) in order to defend the inclusion of the associated costs in its rate base/ongoing O&M expense at its next rebasing.*

Furthermore, in those cases where the LDC has included the implementation of a DER in the DSP in a year beyond the rebasing test year, the OEB should clarify whether the “reporting” is just for information purposes or is the expectation that the OEB will approve the spending.

Finally, the last sentence in the above reference indicates that similar reporting is required where a BCA was undertaken but a traditional poles-and-wires solution was determined to be the preferred solution. This highlights the need for the OEB to clearly set out when a BCA is required (i.e., when non-wires solutions must be considered).

4.7. Examples

To be useful the examples will need to illustrate the level of detail distributors will be expected to provide as opposed to just the types of information that should be provided. In the case of the BCA results (section 4.7.1.3), for those values that would be calculated by the distributor the example should outline not only the sources for the data required but also illustrate how the data would be used to calculate the value.

³⁰ Page 39

As discussed earlier, it is unlikely that the results for all of the Impact Categories will be quantifiable such that they can be incorporated into the DST. As a result the Outcome section (4.7.1.5) should consist of more than a short statement as to which solution produced the highest benefit cost ratio. This section should indicate what the preferred solution chosen is based on a consideration of both the DST results (section 4.7.1.3) and the other qualitative considerations described in section 4.7.1.4 and why.

The examples presented should represent a variety of potential circumstances (e.g. discretionary vs. non-discretionary investments, situations where new facilities are deferred vs. totally avoided, etc.).

5. OVERALL

Key points from the preceding comments include:

- The role/purpose of the BCA Handbook should be to identify for a distributor the Impact Categories that need to be considered, how the impacts can be measured (either quantitatively or qualitatively) and, for those that are quantifiable, how they should be incorporated into the recommended Cost Effectiveness Tests (e.g., the DST).
- The Handbook will need to clearly set out when a BCA is required and, in particular, how any materiality thresholds are to be applied.
- There is a clear difference between: i) a Benefit Cost Analysis Framework and ii) a Cost-Effectiveness Test. Cost Effectiveness Tests deal with costs and benefits that are quantifiable such that they can be easily compared and benefit/cost ratios calculated. In contrast, a Benefit Cost Analysis Framework should include the consideration of the results of appropriate Cost Effectiveness Tests but also identify and provide a framework for considering benefits/costs that are not quantifiable or where there is a range of uncertainty such that an analysis using expected values would not be appropriate.
- The Cost Effectiveness Tests should focus on those costs and benefits that are readily quantifiable with a reasonable degree of accuracy and should not include Impact Categories where the values are highly speculative or uncertain.
- It will be important for the Handbook to clearly set out the role of the DST versus the EST with respect to the decisions a distributor will make as between a traditional wire solution and a non-wires solution to a given system need. In VECC's view, distributors should be focusing on investments and related decisions required to meet their customers' needs. Investments in non-wires (or for that matter traditional wires) solutions that do not benefit a distributor's customers but are deemed to provide broader system benefits should only be pursued by a distributor if adequate compensation is provided by the system's customers.
- There needs to be a step, after the Cost-Effectiveness Tests results are calculated, where those Impact Categories that are non-quantifiable are included for consideration. While the results of the Cost Effectiveness Test are a major consideration they may not always be determinative of the preferred alternative. Whether they are determinative or not, a distributor should still be expected to fully justify its decision to pursue a wires or non-wires solution based on its assessment of all the Impact Categories.
- The draft Handbook suggests that in order to recover the costs associated with DER LDCs must provide the OEB with the results of the BCA (including the DST) before

the project is implemented. The OEB should clarify whether this is the intent. It would also be useful for the OEB to clarify whether this means OEB approval is required before cost recovery commences and, if so, how this would work for investment opportunities identified during a distributor's IRM period.