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Framework for Energy Innovation

Report of the Utility Incentives Subgroup

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Submitted to:
The Framework for Energy Innovation Working Group

Submitted by:
The Utility Incentives Subgroup

Contents

1. Introduction

The Framework for Energy Innovation Working Group (FEIWG) tasked the Incentives Subgroup to discuss the need and design considerations for appropriate incentives for distributors to adopt DERs for distribution uses that do not require equity investment by the utility. The members of the Subgroup are:

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This is the report of the Subgroup to the FEIWG. The views expressed in this Report are intended to reflect the discussions of the members of the Subgroup, but do not represent the views of the OEB or OEB Staff.

This Report starts with a review of important contextual issues. Then, before discussing options for utility incentives, the Report looks at recovery of DER-related costs by utilities, since lack of appropriate cost recovery can undermine any incentives implemented. The main discussion of utility incentives is then divided into two sections: first, a review of some of the principles that may be applicable to establishing an incentive framework, and second, an analysis of some of the available framework approaches, including their strengths and weaknesses. Only options that can be implemented within the current utility business model in Ontario have been discussed.

A note on consensus. The subgroup spent time discussing the scope and substance of the FEI's work, and the current and future context for the sector. This report is a collaborative effort to document that discussion, including the possible need and desirability of incentives to serve a range of purposes, and some options for consideration, with a discussion of challenges and opportunities related to those options. This report is not intended to characterize or represent an endorsement by the members of the group or their organizations either generally, or for any specific option, except where noted.

Finally, this report does not deal separately with the effects of DERs (or IRPAs) on the gas distribution sector. While the analysis in this report may assist the OEB in the future on issues related to gas distribution, as some of those issues are common between gas and electricity distribution, the subgroup is conscious that the OEB has made an initial decision on many of these issues for gas distribution in EB-2020-0091, Integrated Resource Planning, Decision with Reasons, July 22, 2021. This report assumes that Enbridge will implement DERs/IRPAs consistent with that decision, unless and until the OEB establishes new parameters for gas IRP[1].

[1] The Subgroup discussed whether OEB policy on DERs for gas and electricity should converge. While there was general agreement that consistency between the policies is something that the OEB should consider, the extent to which that would be appropriate is not clear. The members of the Subgroup agree that some of the considerations related to non-wires alternatives are dissimilar from non-pipes alternatives, and further that the evolution of the gas distribution and electricity distribution sectors can be expected to face some quite different external and internal influencing factors. Policy consistency is a goal, but policies for each sector should be tailored to that sector.

2. Context

Changes are happening in the electricity and gas distribution sectors that raise questions about the relationship between distributors, DER providers, and customers. The question we were tasked with—distributor incentives—raises a broader and perhaps longer-term question of the continuing appropriateness of the utility remuneration paradigm in use for many years. This includes treatment of costs and equity returns, and whether the business model itself is a barrier to the natural evolution of the economy and the sector's role in it.

Rate of return regulation is a capital-centred system, since so much of the costs of traditional utility solutions are capital expended on infrastructure. DERs will often, from a utility point of view, be non-capital in nature, and so a system that compensates utility shareholders based solely on capital expended may not reflect completely a DER-intensive future system[2]. It follows that there may be options available to incent utility deployment and optimization of cost-effective DER solutions that involve modifying or even replacing the rate of return paradigm with a system that is more agnostic as between traditional (capital) and non-traditional (often non-capital) alternatives.

However, a reconsideration of the utility compensation model, and/or the roles and responsibilities of distributors, is outside of the scope and mandate of both the Subgroup, and the FEI Working Group. Thus, the options considered by the Subgroup all assume that they are implemented within the current return on rate base paradigm. Some are variations on that paradigm, others are add-ons, and others just treat the current business model as a framework within which utilities will continue to operate.

[2] There has long been a debate in economics literature as to whether return on rate base is the most economically efficient approach to compensating utility shareholders. The Subgroup did not attempt to grapple with those difficult issues, nor with whether utility compensation generally should be changed. That is a major policy issue for the OEB to consider if and when it believes it is appropriate. Instead, the Subgroup recognized the extent to which the rate of return model may limit the options available to incent the deployment of cost-effective DERs, and included only those options that can work within that model.

3. Cost Recovery and Other Barriers

It is important to consider the utility's costs associated with planning for and implementing (including in some cases monitoring and evaluating) DERs[3]. While not technically incentives, cost recovery mechanisms can, if they are incomplete, or delayed, or include any component of risk, represent disincentives and thus barriers to utility support of DERs.

Removing disincentives is a natural complement to adding positive incentives. In addition, at least one enhanced cost recovery method – capitalization of operating expenditures, as discussed in the next section – can be used as a positive incentive structure. As well, it is important to recognize that design of cost recovery methods can, in some cases, narrow the scope of available or appropriate incentives.

3.1. Traditional Cost Recovery and its potential impact on DERs

Traditional utility cost recovery in an incentive ratemaking environment starts with an amount that is built into rates on rebasing for a given utility activity. The utility is then free, over the incentive rate-setting mechanism (IRM) period, to spend more or less than the allowed level, depending on each year's spending priorities.

This has two impacts. First, to the extent that spending relating to DERs must rise during the IRM period as the electricity and gas sectors evolve, the distributor risks having necessary DER-related costs lower its profits, or reduce its ability to spend on other priorities important to the utility and/or its customers,

Second, if utilities are naturally dis-incented to promote or facilitate DERs, there is a risk that utilities will prefer to spend less than their available amounts on DERs, and more on other things that are germane to the LDC's traditional objectives. In the worst case, ratepayers could end up paying in rates for DER projects that ultimately do not materialize.

3.2. Enhanced Cost Recovery Mechanisms

The OEB uses three main methods to ensure that over or under-spending in a given category of non-capital costs can be flowed through to rates:

> ***Deferral and Variance Accounts.*** Annual variations from the DER budget in rates can be charged to or from a variance account, and recovered at the

[3] Cost recovery is discussed in EB-2020-0091, the Enbridge IRP Decision, starting at p. 71. The OEB in that case determined to stick to normal accounting rules for cost recovery, and limit capitalization of IRP investments to those owned by the utility. However, the decision leaves open the potential for utility cost recovery proposals in individual IRP applications.

normal time of DVA clearances, usually on rebasing. In the meantime, normal accounting rules would ensure that those variances do not increase or decrease annual utility net income levels.

Cost Pass-Through. A cost pass-through or Y factor adjusts rates annually during IRM based on variations in either actual or approved spending from the level embedded in rates. This is done today, for example with DSM costs for Enbridge Gas Inc. The advantage to the utility and the customers is that recovery of the actual amount spent is more timely. This also limits any issues of inter-generational equity.

Custom IR. Where a distributor opts for Custom IR, it can include an annual adjustment in its IR plan to reflect forecast changes in the annual DER operating budget. This can be coupled with a flow through of actual costs, or it can be limited to forecast amounts. If the latter, the problem of potential over or under-spending during each year remains but is less acute.

Each of these methods could be used to deal with annual variations in DER-related operating costs. Similarly, to the extent that DER-related costs are capital in nature, the OEB could use its existing methods (such as ICM, ACM, and Custom IR) to facilitate their timely recovery in rates.

3.3. Types of Costs[4]

The Subgroup discussed how to categorize DER-related costs that may pertain to questions about cost recovery.

Distributor Administrative Costs. For distributors to deliver on their DER responsibilities, they will have to acquire resources and expertise, either through hiring or through outsourcing. This may include planners, market analysts, program administration, specialized customer service personnel etc.[5] It is not clear that this will in all cases be incremental or material, since

[4] The Subgroup did not look at stranded assets, another category of costs. While acknowledging that the increasing penetration of DERs in the system may result in some assets being stranded, particularly at the generation and transmission levels, the subgroup determined that stranded assets are outside the scope of the current FEIWG mandate. Further, the focus here is at the distribution level, and in general while DERs may result in less poles and wires solutions being built (because of a flatter load curve, for example), the members of the Subgroup did not see a likelihood of significant stranding of existing distribution assets except in specific localized situations, at least for the near term.

[5] This may also include certain infrastructure that facilitates optimal use of DERs so as to achieve the outcomes sought by their implementation (for example, so called smart systems including metering, SCADA systems, Distribution Energy Resources Management Systems (“DERMS”). These costs, and others like them, would generally be capital in nature. The Subgroup assumed that normal methods of cost recovery would be adequate to address those capital costs, and so focused in this section on incremental operating costs.

presumably active DER implementation reduces the implementation of more traditional poles and wires options. The composition of utility skills will at least change, and may in some transitional period have to increase. These are costs that are typically managed by distributors during the IRM period, but there may be an argument that some or all of them should be flowed through to customers.

Procurement Costs*[6]*. At the other end of the spectrum, the utility may make periodic payments to third parties or customers who have contracted to provide DER services, such as demand response. These payments could be direct or indirect payments, and may be for capacity, power quality, reliability, or other reasons[7]. Where a distributor incurs procurement costs for cost-effective DERs to avoid traditional spending, it is generally agreed that, assuming the costs are not capitalized, they should in any case be recoverable from customers in rates. This could be limited to the direct third party or customer payments made, or could include some or all of the program development and administration costs.

Third Party Incentive Costs. Many DERs do not involve any contractual procurement of capacity, reliability, or other distribution services, but nevertheless result in a predictable reduction in those distribution needs. Geo-targeted conservation is an example. Distributors may provide incentives to customers or third parties to implement DERs, expecting that utility capital spending needs will thus decline and net benefits will be produced. This spending, which is typically front end loaded but does not involve the creation of capital assets, still produces benefits over a period of time. If these costs are not capitalized, there are many who believe that there should be a flow-through of some kind for recovery from customers.

3.4. Who Should Pay?

The last part of the enhanced cost recovery subject addresses the question “Recovery from whom?” There are three sources of recovery available to the OEB[8]:

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[6] The members of the Subgroup are conscious that many possible DER procurement costs that might in the future be incurred by distributors may require changes to regulatory structures, co-ordination with IESO programs, or other external factors. The York Region NWA project was cited as one such example currently being piloted.

[7] ICF, *Distribution Needs Cases /Additional Use Cases* (November 24, 2021), slides #7-9

[8] This section is not commenting on who should pay, but instead lists who could be asked to pay. The Subgroup is not making any statements on whether all or any of these groups should bear all or part of utility costs relating to DERs.

Local Distribution Customers. Normally operating costs incurred by a distributor are paid for by the customers of that distributor in rates, usually through their cost allocation process or, if from a DVA, through rate riders. Some or all of the categories of costs above can be recovered from this group.

Socialized Costs. Some distributor spending may provide benefits to the Ontario grid/system as a whole, and so these costs may be socialized more broadly. The obvious example is renewable enabling investments. The same concept could be applied to some or all of the costs in any of the above categories. In the electricity sector, this is especially true since, while the local distributor is focused on solving its own distribution issues, most DERs cause benefits that are beyond the distributor, such as reduced transmission needs, flatter or more controllable load for supply planning, and many other examples.[9] The Subgroup was unable to reach a conclusion on whether the OEB has sufficient authority currently to socialize DER-related distributor costs outside of the specific distributor's customers.

DER Providers. The role of the distributor in facilitating DERs also benefits private sector companies that sell or manage DER solutions. While in some cases this may be outside the jurisdiction of the OEB, it is possible that DER providers could cover some part of the utility costs to deliver their important role in the DER rollout. This could include, by way of example only, a) application and other fees as part of their interactions with utilities, b) amendments to the Distribution System Code to require contributions in aid of construction if DER providers request system expansion spending, or c) approval of incremental distributor system spending to facilitate DERs conditional on DER providers or their customers contributing some part of the cost.[10] The Subgroup did not do a complete review of this possibility, and did not conclude that any cost allocation to DER providers is appropriate, but included it to ensure that the list of possible sources of cost recovery is complete.

[9] In the gas sector, these benefits are quantified and considered as part of the EBO 134 cost-effectiveness test.

[10] One example that was used was the application in EB-2011-0123 by Guelph Hydro to include Zigbee chips in its smart meters, in order to facilitate future behind the meter functionalities to be marketed by third parties. In theory instead of disallowing the cost, the OEB could have approved it, conditional on the utility obtaining some percentage as a contribution from the third parties that would be marketing the in-home equipment.

3.5. Non-Financial Barriers

Just as limitations on cost recovery of DER-related costs can be a barrier or disincentive to utility implementation of these options, so too there are non-financial barriers that operate as a similar disincentive, such as operational limitations, provisions in the Distribution System Code, and others[11]. There is a consensus in the Subgroup that removing these barriers should be a priority for the OEB as it manages the evolution of the electricity system.

[11] Some of these have been discussed by the DER Connections Working Group (EB-2019-0207), including some that have been reflected in draft changes to the DSC (EB-2021-0117).

4. Principles Applicable to Developing an Incentive Framework

The Subgroup has discussed three categories of issues that the OEB should consider in choosing an appropriate DER incentive policy for distributors.

4.1. Division of DER Benefits

Whenever a DER is implemented, it is implicit in its selection that there are net benefits produced by the DER relative to traditional solutions, and that the costs associated with the DER are incurred to achieve those net benefits. The OEB's role in developing a policy is necessarily about how the net value of those benefits will be divided between different groups, since any allocation of costs, including incentives, is an adjustment in the share of net benefits. Some of that division will be market driven, and some will be policy driven, but all must be considered by the OEB in the development of its DERs policies.

There are four categories of stakeholders who may have a claim on some or all of the benefits from the DER:

> ***Third Party DER Providers.*** While perhaps obvious, it is important to be clear that some portion of the benefit of a DER is enjoyed by the business entity that supplies or manages the DER. The portion they keep – their profit margin – is established by market forces. One of the benefits of DERs is that competitive markets for their supply will tend to drive down costs and profit margins for the DER providers over time. However, it may also be true that allocation of costs to DER providers may be offset by changes to DER pricing in order to achieve the profit level that the market requires. This may impact the cost-effectiveness of some DERs.
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> ***Participating Customers.*** Those customers who implement a DER must receive some benefits from that DER, or they will not see it as in their economic interest to implement it. For example, a customer who agrees to participate in a demand response program will receive an incentive because of that agreement. Without a sufficient incentive they will not participate, and the benefits of the DER will not be realized. This is essentially a market-driven share of the benefits.
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> ***Non-Participating Customers.*** In most cases cost-effective DERs are expected to provide net system benefits, resulting in customer bills that are

lower with DER implementation than with traditional solutions[12]. When this happens, non-participating customers also benefit. Similarly, many non-financial benefits of DERs, such as increased system resiliency, or reduced environmental impacts of generation and transmission, or regional economic development, etc., are shared by all customers. It should be noted that typically participating customers enjoy the same financial and non-financial benefits as non-participating customers, plus additional benefits as a result of their participation.

Distributors. The incentives that are the main subject of this Report are the final part of the division of DER benefits. If a distributor receives a financial incentive (accruing to benefit of their shareholders) for their involvement in the expansion of DERs, that will come from the other stakeholders (in almost every case the non-participating customers, since the market sets the allocation to the first two categories) and will reduce the benefits enjoyed by those stakeholders.

The Subgroup discussed that, once the optimal DER solution is chosen and implemented, the total financial benefit to be divided is fixed, and dividing it between the stakeholders through allocation of cost responsibility and payment of incentives is a zero-sum activity. That does not mean that the only test of that division is fairness between the stakeholders. Getting the incentives for each of the stakeholders right is the key to ensuring that the optimal DER solution is in fact implemented, and therefore ensuring that the total benefit is also maximized.

4.2. Structure of OEB Policy

The group discussed advantages of a framework[13] for DER implementation, and utility incentives applicable to all distributors. This would provide clarity on the "rules of the game" for DERs, since for any given DER the incentive available would be known in advance.

[12] The members of the Subgroup acknowledge that the benefits of DERs will not always translate into immediate or even long-term reductions in distribution or total bills. Some of those benefits will not be distribution-related, and some will not even be bill-related (such as environmental or reliability benefits). However, in the context of this working group the Subgroup focused on the distribution component, and thus the assumption of system benefits.
[13] The Subgroup uses the term "framework" to describe a Board policy that stipulates what incentives, if any, are available in each situation, and how those incentives will be calculated, paid, and recovered. This is in contrast to a menu of options available for distributors to fashion their own customized DER incentive approach. The list in this report is not intended to be a menu, but alternatives available to the OEB in developing a common policy applicable to all distributors.

A framework approach would create a level playing field for smaller utilities as well, and DER providers would be dealing with a common DER framework throughout the province, which should make it easier for them to implement DER offerings broadly.

Finally, the regulator, utilities and customers would benefit from a common understanding of the rules, processes, and practices that arise from a universal regulatory framework.

4.3. Design of Utility DER Incentives

A utility DER incentive framework should consider both the overall amount of incentives, and the mechanism to deliver them, all in the context of how much of the DER benefit is going to the utility, and when.

In considering an incentive, the OEB may want to ask these questions:

> ***Effectiveness of Incentive.*** The purpose of the incentive is to influence the distributor to facilitate DERs in its service territory. The incentive is, at its root, intended to assist in the creation of outcomes that are different from those which prevail in the existing rate of return paradigm. This transition is important, as it will naturally require utilities to approach planning and operations differently than they do in today's regulatory construct. Also, distributors are, in some cases, being asked to assist third party businesses that will supply energy services that compete with those provided by the distributors. As system owners, providing monopoly distribution grid/system services, distributors have an important role in the facilitation of DER solutions. The size and structure of the incentives must be tested against their ability to influence utility behaviour, which is already influenced by existing regulatory structures. Of critical concern for the OEB is that, on the one hand, optimizing the incentive framework is necessary in order to maximize the overall benefits from DERs, but, on the other hand, greater utility incentives reduce the benefits available to other stakeholders.
>
> ***Cost to Customers.*** Assuming that the market will establish the share of DER benefits that goes to third party service providers, utility incentives come out of the pockets of customers. Since participating customers have to be given a sufficient share of the DER benefits to make a conscious decision to participate (so the size of that share is also largely market driven), that means that the OEB's concern needs to focus on the cost incurred by non-participating customers (or customers at large). In effect, the utility incentive is "paid" by the non-participating customers in reduced net value of the DER solutions available to them. It should also be noted that the timing of customer costs is important. DER-related costs may be investments for

future benefits, meaning that customers today will pay more, so that down the line their bills are lower than they might otherwise have been without the DER solution.

Intended and Unintended Consequences. In developing an incentive framework, the OEB should consider whether it will produce any unintended consequences. For example, an incentive based on achievement of targets could incent lower targets rather than high performance. An incentive based on a share of calculated savings could be controversial and onerous to administer. The OEB has a long history with DSM programs, in which many of these issues have arisen in the past, so there may be methods of limiting undesirable outcomes. As a result, the OEB needs to be crystal clear on the objectives and the outcomes sought, and then consider what, if any, other consequences may arise in order to avoid (or minimize) unintended consequences.

Regulatory Simplicity. Different incentives have different regulatory implications. For example, some require extensive calculations and valuations in order to establish either the entitlement to, or amount of, incentives. Others raise controversial issues that can cause the claiming of incentives to have high regulatory costs or long delays. Generally, increased precision of the incentive in targeting the best possible result for both customers and utilities will be reflected in greater regulatory costs and/or complexity. Striking a balance that doesn't oversimplify the incentive (and potentially limit its connection to the actions it is incenting), while still minimizing the regulatory burden it generates, should be a key criterion for the OEB in selecting which incentive(s) should be included in the final policy framework.

5. Incentives Considered

There are a range of options available to incent distributors to include non-utility owned DERs in their planning, and to ensure through utility programs and actions that they are implemented whenever they are cost effective and in the public interest. The Subgroup has not attempted to reach consensus on the best incentive or package of incentives to implement but has instead chosen to list the options which it discussed, with some analysis of advantages and disadvantages of each.

5.1. Capitalization of DER Spending

The option that is closest to the current business model is to allow distributors to capitalize their spending related to DER implementations, and thus earn a return on those capital "assets" over the life of the DER, or some other period.

There are two main variations on this option:

> ***Rate Base.*** Add capitalized DER spending to rate base and allow normal cost of capital (debt, equity, and taxes) to apply over an appropriate amortization period.
>
> ***Separate Capital Pool.*** Create a separate capital pool for this spending and allow a different cost of capital (whether more or less than traditional levels) to be recovered in rates.

Each of these approaches can be applied to certain categories of DER-related costs (see "Types of Costs", above), or all costs. Justifications for capitalization may differ between different categories of costs.

In each case, there could be issues associated with capitalizing spending that, for accounting and or tax purposes, may be required to be treated as a current expenditure. There are techniques for dealing with this difference, such as maintaining two sets of books, but the divergence of financial results from regulatory results may become substantial over time, and costly to maintain.[14]

The capital added by DER spending may not be the same as the capital that would otherwise be included in rate base if traditional wires or pipes alternatives were implemented. If some of the capital cost is borne by the private sector, and/or the overall cost of the non-wires/non-pipe option is lower, necessarily the utility cost

[14] The treatment of actions approved by a regulator could vary materially whether financial accounting is being performed under US General Accepted Accounting Principles (GAAP) or International Financial Accounting Standards (IFRS). The new proposal for an IFRS rate regulated accounting (Regulatory Assets and Regulatory Liabilities) standard may potentially address or partially address this issue, however the standard is not yet final.

capitalized must be much lower. The result is that, even though this is the option closest to the current business model, it could still involve reduced opportunities for distributors to grow their rate base and net income. It should be noted that this may be offset in part by system enhancements needed to accommodate more DERs.

Capitalization of what are otherwise current operating expenditures for accounting purposes has a number of potential downsides:

> ***Cost to Customers.*** The lifetime cost associated with capitalized spending can be significantly greater than expensing it immediately. It is not just the basic financing cost, but also the return on equity and the income taxes associated with it. Operating expenses of utilities have not traditionally included any profit component or income taxes. They are limited to cost recovery.
>
> ***Financial Statements.*** As a utility transitions from being primarily a provider of infrastructure services to a provider of energy services, its regulatory books could increasingly diverge from its accounting books. This could have implications for financing, credit rating, and other aspects of a utility's financial health.
>
> ***Assets.*** Current utility capital is for the most part backed by physical assets that can be valued in the market. Intangible assets representing capitalized operating costs represent only a right to recover amounts in future rates. The value of these assets may not be as strong or reliable, from the point of view of the markets, as physical assets. In addition, if assets cease to provide value, intangible assets may become stranded more quickly or more completely than physical assets. Even if such a stranded asset differential does not ultimately arise, the utility's credit in the meantime may be impacted by substantial regulatory assets that are not backed by physical assets (i.e., a market perception of increased stranded asset risk).
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> ***Intergenerational Equity.*** Capitalization depends on a reliable forecast of the benefits of DER spending. While forecasting is a common utility risk, some believe that DERs increase forecasting uncertainty. To the extent that the capitalization period is too long or too short, the customers who pay are not the customers who benefit. In addition, as customers change their use of the system, the share of the cost that they bear also changes. For example, a customer who adds behind the meter generation may see a substantial reduction in their contribution for past DERs, even though they may still benefit from a more DER-friendly system.

On the other side, capitalization can also have significant benefits:

Utility Compensation. Utilities may prefer capitalizing DER expenditures because that generates profits consistent with their existing business model. It is possible that the barrier to DERs is lower in this situation, since the utility comparison is between competing capital costs, and the only difference is that one could be cheaper than the other. In other words, this fits within the traditional perspective for system planning.

Initial Cost. While the overall lifetime cost to customers of capitalized operating costs is higher, the initial cost is lower, sometimes even negative. Those who would prefer higher spending on DERs today may prefer capitalization, since that lower initial cost gives more room for current spending on DERs. This is a one-time benefit, however, since after about nine years of capitalizing a fixed amount of costs, the annual cost in rates is the same as if the costs were expensed[15]. That annual cost then continues to rise, as long as that amount of annual spending is continued.

Intergenerational Equity. Many DER options provide a long-term benefit to ratepayers. If they are expensed, current ratepayers bear the cost, but future ratepayers benefit. Depending on the persistence (useful life) of the DER option, this could be a twenty-year shift, or longer. Capitalizing the costs seeks to match the rate impact of those costs each year to the annual benefits to customers. Most utility operating costs do not have this kind of longer-term impact, although there are some exceptions (training programs, for example, or adoption of better planning techniques).

The idea of capitalization of some costs that have long term benefits is not new. For example, the current Enbridge DSM Plan proceeding (EB-2021-0002) is considering whether some DSM costs should be capitalized, and many of the same issues discussed above will arise. Other jurisdictions have also looked at whether some DSM or CDM costs should be capitalized[16]. In some places, such as Maryland[17], this has been implemented and then subsequently challenged and debated because of the high lifetime cost customers ultimately bear.

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[15] Two recent studies filed in EB-2021-0002 describe this impact in some detail, with full calculations. See "Review and Assessment of Cost Recovery and Performance Incentive Options for Natural Gas Demand Side Management Programs." Optimal Energy. (December 1, 2021) pp., 6-12, and "Amortization and Performance Incentives as Business Models for Utility Demand-Side Management Portfolios: Recommendations for Enbridge Gas", First Tracks Consulting Inc. (January 31, 2022, figures 3-6, updated in I.7.EGI.SEC.3, then further updated March 21, 2022.

[16] US states using amortization for cost recovery include Maryland, Illinois, New Jersey, New York, Utah, Delaware and Missouri. See Optimal Energy (December 1, 2021), pp., 13-14

[17] See Optimal Energy (December 1, 2021), pp., 7

The Subgroup has not been able to identify any other jurisdictions that use capitalization of DER-related spending as an incentive for distributors. However, the totex concept in the UK may in some cases provide this kind of incentive indirectly.[18]

5.2. Fixed Incentives

A step removed from the current business model is providing for distributors to earn fixed fees or similar compensation for their DER activities. Those amounts could be:

> ***Predetermined Amounts,*** for example, built into rates at the time of rebasing and set based on a DER implementation plan (perhaps as part of the distributor's DSP).
>
> ***Performance-Based Amounts,*** which could be similar to the Shared Savings or Scorecard approaches set out below.
>
> ***An ROE Premium,*** which is a number of basis points added to allowed ROE based on forecast activity, actual performance, or achieving a target threshold[19].

The Subgroup notes that the different types of fixed payments to utilities reflect widely different levels of incentive. A predetermined amount to compensate for implementing a specific plan, for example, provides no actual incentive for performance, i.e., outcomes beneficial to customers and/or the system as a whole. It may in fact incent poor performance, since once the payment has been determined, it is in the utility's financial interest to reduce DER-related spending and so improve its bottom line.

On the other hand, annual incentive payments that are variable based on performance or results tie the activities of the utility directly to the benefits to be achieved. There remains, however, the question of how the performance or results are measured, and how the incentive varies with that calculation. The two main methods of measuring performance and results are shared savings and scorecards, both discussed below.

It is also possible to calculate the annual incentive payment based on spending rather than results. This avoids the risk of underspending, but still ties utility compensation to

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[18] The totex approach aims to incent utilities to deliver outputs at the lowest total cost, without preferring either operating expenditure (opex) or capital expenditure (capex) solutions. Historically, companies have preferred capex solutions since the addition to rate base generated a return. Under the totex approach, when companies spend money on a solution, the same percentage is capitalised irrespective of whether that solution involves opex or capex. Utilities are therefore theoretically more likely to adopt the overall cost-effective solution (e.g., encourage utilities to use DSM to avoid installing new capacity). See "Guide to the RIIO-ED1 Electricity Distribution Price Control" OFGEM (June 18, 2017), pp., 14-15.

[19] This is different from, and unrelated to, the ROE available when DER expenditures are capitalized. In this case, the basis points of additional ROE are not related to financing any spending, but are related to either the level of DER activity by the utility, or the performance-related results of the utility DER program.

the public benefit only indirectly. This method is discussed under Margin on Payments, below.

The use of variable ROE as a mechanism to deliver this type of incentive has the advantage that utilities are familiar with ROE as a measure of management success. Utilities that are public companies can also have share price and credit rating impacts associated with higher or lower ROE, so the incentive value of an ROE adder could be higher for those companies[20].

One disadvantage to ROE adders is that they do not bear any intuitive relationship to DER market penetration or enhancement of the public interest. They are simply utility-friendly methods of payment[21].

The Subgroup has not identified any jurisdictions that use a fixed payment, unconnected from spending or results, to incent utility DER activities (or to incent CDM/DSM activities). There are jurisdictions that have used formula-based payments for these purposes, and those are discussed under the sections dealing with those methods.

5.3. Margin on Payments

Similarly, the distributor could be allowed to add a margin on top of any spending it incurs to implement or compensate DERs owned by customers or third parties. There are a number of variations on this option, including:

> ***Spending Margin.*** In this simplest approach, the distributor adds a percentage to all spending related to DERs, regardless of the nature of the spending.
>
> ***Third Party Payments.*** A more results-oriented approach is to add a distributor compensation component to payments the distributor makes to third parties/customers that provide services through DERs. If the distributor pays demand response standby fees to battery owners, for example, the distributor might add X% to those amounts in rates as its own compensation for that program.

[20] A variable interest rate is used in Illinois: see Optimal Energy, op. cit, p. 13.

[21] The Subgroup notes that the ROE of Ontario distributors has not undergone a comprehensive review in many years. This may complicate the use of ROE adders, since it may implicitly open up the issue of what is the appropriate level of ROE in any given situation.

An example of this latter kind of incentive exists in California, in which the CPUC allows utilities to recover their annual costs for certain DER procurements, plus a 4% adder to reflect the involvement of the utility in the process[22].
Customers sometimes oppose spending adders, because they add a utility profit for spending funds collected from ratepayers. Further, they continue some of the perceived problems of rate of return regulation, including equating more spending with higher profits. Customers may oppose structures that incent utilities to spend more money.

A second disadvantage to this approach is that the incentive is not tied to results, and therefore any benefits to customers depend on the assumption that there is a connection between spending and benefits. Effectiveness of the spending is not measured.

On the other side, fixed adders have the advantage of simplicity. Utilities have a known and immediate financial impact when they spend on desirable DER-related procurement or activities.

Fixed adders have a second advantage in that they mimic how service companies in the competitive markets are compensated. Competitive companies that provide services usually add a margin to their costs to generate profits. That margin can be greater or lesser, depending on whether it has to cover some categories of indirect costs along with generating profits. In the California example, and most other possible structures of this spending adder, no costs are covered by the adder. The amount is just profit, with the costs associated with DERs recovered in rates through normal or enhanced cost recovery mechanisms (see earlier discussion).

5.4. Shared Savings Mechanisms

DSM and CDM programs have in the past compensated utilities by calculating the savings for customers from those programs, and then allocating a formula-based portion of those savings to the utility shareholders. The main benefit of this approach is that, if it is implemented right, it is on its face a win-win for customers and utilities alike.

The calculation of the savings is often much debated, using methods such as the Total Resource Cost test, with or without adders[23], or the Societal Cost Test. Calculation issues have resulted in substantial regulatory costs and delays, and many regulators

[22] In 2016, the CPUC adopted an Integrated Distributed Energy Resource (IDER) incentive pilot that required the three largest utilities (PG&E, Southern California Edison, an SDG&E) to select at least one project and up to three additional projects to test a 4% pre-tax incentive on DER procurements in lieu of traditional investments. See Naseem Golestani et all. “Distributed Energy Resources Deferral Tariff and Request for Offer Streamlining” (October 5, 2020), pp., 13-14
[23] Ontario uses TRC+, for example, where the + is an environmental adder.

(including the OEB[24]) have in DSM plans moved wholly or partly away from pure shared savings mechanisms for that reason. On the other hand, even scorecard systems (see below) are often based on savings calculations that can become controversial.

The key to any shared savings approach is that the utility is paid an incentive calculated on the basis of the benefits generated by the DERs. In the simplest case, a utility avoids a capital expenditure that would have been recovered in rates. If the rate recovery would have been $10 million per year, and the cost of the DER solution included in rates is $6 million per year, the utility gets some percentage of the $4 million difference as a reward for making it happen.

This raises two problems.

First, the $10 million per year cost of the traditional solution might typically have included $2 million or more of ROE, which the utility records as profit (although it is considered a cost of capital for regulatory purposes). Unless the utility is entitled to 50% of the $4 million of savings, it will still have a lower profitability using DERs than with the traditional solution. This is partially illusory, because the traditional solution requires the deployment of utility capital, and the DER solution does not. However, lower profit remains a potential disincentive to utilities, while shared savings that keep the utility whole from the point of view of profit may require a very substantial share of savings going to the shareholders[25].

Second, the benefits of the DER solution are not just the financial savings associated with a cheaper option than traditional wires. Many of the benefits of DERs come in other forms, unrelated to the distributor's direct spending. They include commodity savings, resiliency, customer comfort, better environmental attributes, and the like. Shared savings mechanisms, to be thorough, should value and include some or all of those additional benefits, even though the compensation of the customers for these benefits may be through separate means.

Calculation methods like the Total Resource Cost test (now in Ontario TRC+, with environmental adders), and the loosely related Societal Cost Test, attempt to capture some of those net benefits that do not directly impact the distributor. They face four main difficulties:

[24] In June 2011, the OEB updated its DSM Guidelines for natural gas distributors (EB-2008-0346) and discontinued the use of a shared savings mechanism in favour of a scorecard approach. DSM multi-year plans for 2012-2014 were filed in response to changes to the guidelines. See section 5.5 for greater detail on scorecard-based financial incentives.

[25] This is a common problem with utility DSM programs, since the personnel and other resources allocated to DSM activities are disproportionate to the percentage of the utility's profit available from those activities.

Design. In many jurisdictions there have been intense debates about what should be included in the benefits attributed to conservation activities. This is particularly acute with respect to benefits that are externalities, such as cleaner air or water, and so are not a direct financial cost to utilities or to their customers. No jurisdiction has designed a benefit calculation method that resolves these debates. The same issue can be expected to arise with respect to DERs, and may perhaps be more difficult because the benefits are mostly at levels other than the distribution level.

Complexity. Most of the benefits of conservation (and of DERs) require assumptions about the real-world impacts of the measures implemented. Issues such as persistence, behavioural adjustments, the reasonableness of the counterfactual (what would have happened without the beneficial conservation or DER solution), attribution, free ridership, and spillover, to name just a few, have bedevilled utilities and their regulators and customers for decades. The process of calculating the benefits from conservation programs, and hence from DERs, has regularly been time consuming and expensive.

Diversity of Actors. The benefits of conservation and DERs are promoted (and sometimes incented) by different stakeholders, including governments at multiple levels, regulators, utilities, and the private sector. The benefits from the conservation and DERs are also enjoyed by different actors (see discussion of principles), so reducing the "savings" to a single number, of which some percentage is allocated to the utility as an incentive, is difficult.

The Straw Man Problem. Almost all shared savings mechanisms are based on a bottom-up calculation of the savings, and there appear to be no examples in which an empirical measure of actual savings (i.e. top-down) has been the basis of utility incentives. This creates a situation in which utility costs and rate base (and rates) can continue to increase, while at the same time the calculation method is showing that savings are being enjoyed by customers. In effect, the savings are relative to a straw man that cannot be verified in any empirical way.

The shared savings approach has been a commonly used method of incenting utilities that deliver conservation and energy efficiency programs for at least two decades in Ontario and other jurisdictions. It therefore has the advantage that the OEB is familiar with it, and may be able to implement it more easily by applying existing knowledge of its intricacies.

5.5. Scorecard-Based Financial Incentives

Distributors can also be compensated by earning fees based on their performance against scorecard metrics. In this scenario, a scorecard is developed in advance that includes either fixed or variable performance targets for outcomes that have value to customers and/or the system as a whole. Each year, the utility's performance is measured against those targets, a score is developed, and a shareholder incentive amount is calculated based on a formula.

This is now done with DSM, although still with a heavy emphasis on volumes of gas saved (i.e., shared savings). In the case of electricity distributors, scorecards could be developed with metrics for reliability, controlling rate base growth, resilience, and many other goals assisted by DERs[26]. Scorecards could also directly measure DER penetration within the service territory, although that may be more difficult to target given the large disparities of DER potential between geographic areas.

The theoretical basis of scorecards is the assumption that the benefits of DERs cannot be measured by a single metric, like cost reduction or units of energy saved. Because DERs provide a diverse range of benefits, there should be metrics that capture each of those benefits.

In determining what should be measured, many of the same issues arise as in shared savings, but the use of separate metrics means that combining them into a single test is less complex. Prioritization is arguably more straightforward.

However, determining what to include in a scorecard is still challenging, for a number of reasons:

> ***Results-Related Metrics.*** Scorecard items that directly measure results suffer not only from the problem of determining what results to measure (for example, reliability, or reduced rate base growth), but also what calculation method produces an appropriate measure of "success". In DSM, for example, customers and utilities have debated whether lifetime cubic meters or annual cubic meters saved are a better metric of success. In DERs, the reliability, capacity, or other impacts of a diverse set of non-traditional options are not easily measured.

[26] In essence, any of the benefits of DERs, as discussed in the Report of the BCA Subgroup.

Activity-Related Metrics. Some scorecards include results that reflect utility activities, rather than actual benefits to customers. As discussed earlier, activity-based incentives assume, without any measurement, that there is a relationship between the activity and customer benefits. Many customers object to paying utility incentives based on effort rather than results.

Target-Setting. Scorecards can only form the basis for utility incentives if they include targets, since in a scorecard system the incentive is only paid by reference to performance against target. This is similar to targets given to employees, upon which bonuses, stock options, or other compensation components are based. Establishing targets can be difficult.

Prioritization. Scorecards generally calculate a series of performance measures, and then produce an aggregate score on which the incentive is based. The calculation of the aggregate score involves prioritization of the various objectives, and the metrics to measure them. This can also be challenging.

The most immediate example of a scorecard system is the Enbridge DSM programs in Ontario[27]. The Enbridge incentive for delivery of the programs is based on a multi-page scorecard that includes mostly bottom-up results targets (lifetime cubic meters saved), but also some indirect results (homes built to above-Code efficiency) and some activity-based metrics (builders trained on energy efficiency topics). The Enbridge scorecard approach is currently being examined by the Board in their 2023-2027 DSM Plan proceeding, EB-2021-0002.

5.6. Non-Financial Tools

Distributors can also be incented to include DERs in their planning and to promote DER implementation in their service territories through non-financial means. There are two main types of non-financial approaches:

Obligation. Distributors can simply be required by the regulator to maximize DER use within their service territory, and the approval of their DSP and capital spending can be conditional on successfully meeting that requirement. This is similar to many other requirements currently imposed on distributors in Ontario, which do not have incentives attached to them. This is often implemented by licence condition.

[27] In a Decision and Order filed under EB-2021-0002 on August 26, 2021, the OEB approved the continuation of Enbridge Gas' 2021 DSM scorecards for 2022. The scorecards are defined in Appendix A to the decision.

Scorecards. Scorecards can also be used without any associated financial consequences, as they are today for reliability, customer care, and other metrics applicable to electricity distributors. Because scorecards are published and are reviewed by the public and by shareholders, management may be influenced to maximize scorecard achievements as a measure of their own performance.

The Subgroup discussed the possibility that non-financial tools could be included in any set of OEB policies promoting/facilitating DERs, and those non-financial tools could include both licence requirements imposed on distributors, and measurement (with public disclosure) of utility performance.

There is a range of views on the extent to which non-financial tools should be used. Utilities for the most part see non-financial tools as the "stick" in the proverbial 'carrot and stick'. While there is general agreement that utilities respond favourably to directives from the regulator requiring them to do things, for example, most utilities believe that directives are less effective if they do not include positive incentives as well.

Similarly, public disclosure of performance can be seen as a kind of "naming and shaming" for poor performers, with much less incentive value for good performers.

Further, whether a utility performs poorly or well on publicly available performance metrics, there is skepticism as to whether most members of the public can fairly be expected to understand the public reporting.

In addition, there may be a risk that increased obligations on utilities for which they are not compensated may have an impact on credit ratings or business risk assessments.

At the other end of that spectrum, some customers believe that facilitation of DERs should be treated as a fundamental obligation of distributors, part of their existing obligation to implement only the most cost-effective solutions to customer needs (i.e., the principle of prudence).

In this regard, there is a concern that utilities may not need to be incented for following OEB directives. If facilitating DERs requires incentives, how is this distinguished from other utility obligations? This argument may be particularly relevant for groups of customers who are most vulnerable to utility performance, such as low-income residential customers.

Non-financial tools are, nevertheless, by far the method most commonly used by regulators and legislatures to incent utility compliance with public interest goals.

Distributors have many licence conditions that require performance to certain standards, and they also have statutory compliance obligations in numerous functional areas.

Utility performance is also routinely measured and reported publicly. LDCs have a Scorecard that is posted to their website, and includes more than a dozen measures of utility performance. The OEB Yearbook of Electricity Distributors presents side by side comparisons of utility financial and operating data. The continued push by the OEB to standardize reporting of that data has improved the value of that comparative information, which informs the regulator in utility applications, the shareholders, and the public. The OEB also provides a bill calculator that allows customers to compare their own bills across different distributors.

In both licence conditions and scorecards, non-financial incentives have generally been effective tools where they have been used in Ontario.

Non-financial tools are a necessary part of DER policies, but views diverge on the extent to which the OEB can or should rely on them, as compared to reliance on financial incentives.

6. Next Steps

The Subgroup was conscious throughout its discussions that the issue of incenting distributors to incorporate DERs, or to be more DER-positive, raises many issues outside of the scope of the Subgroup. As noted earlier, the Subgroup kept a narrow focus on what can be done within the existing Rate of Return business model, for example. In addition, given its mandate and the time available, the Subgroup decided not to attempt significant tasks that, while important, require a more detailed review of some aspects of the subject.

This led the group to identify three general areas of next steps that the OEB may wish to consider, whether as additional phases to the work of FEIWG, or as separate initiatives. Those areas are the following (not in order of priority):

1. **Testing Incentives Against Use Cases.** It is likely that determining which incentives to apply, if any, in which situation, would benefit from a more detailed review of the consequences of doing so. DERs are not one size fits all, but are instead a range of different solutions, which in turn solve different issues in different ways. Further, a common issue for DERs is that the costs and benefits are spread amongst the distribution system, the transmission system, generation, the private sector, and elsewhere. Each of the areas in which there are costs or benefits may also have utility, government, or other programs that include recovery, sharing of benefits, or incentives to various parties. The Report of the BCA Subgroup is addressing that set of issues in the context of some sample use cases.

   Testing possible incentives to see how they would affect the parties to individual types of DERs is a complicated task, but it may be beneficial as a way of establishing the appropriate incentives. The OEB may wish to take this step, either through work by OEB Staff, external consultants, or a working group looking at sample use cases and seeing how different incentives affect the positions of different parties affected. Alternatively, the OEB may prefer to test incentives through some pilot projects, to see how they interact with costs and benefits in real life.

2. **Identifying Existing Expectations.** The Subgroup believes it would be worthwhile for the OEB to identify what utility actions that can affect DER implementation are currently:

   a) Required
   b) Allowed, or
   c) Prohibited

   in the various regulatory rules that govern the actions of utilities[28]. A thorough breakdown of utility expectations into these categories will assist in identifying what changes are needed to unshackle utilities and allow them to meet the needs of customers using more DERs.

3. **Fundamental Change.** Whether fundamental change, for example to the rate of return paradigm, is necessary or desirable is the subject of considerable debate, and the Subgroup did not reach any consensus on this. What is clear, however, is that there are important basic issues that are affecting now, and will affect in the future, the evolution of the electricity and gas sectors. They may include at least four important (and likely interrelated) elements:

   a) A compensation model that only allows utilities to grow their profits through capital spending.
   b) Obligations (such as reliability, or the obligation to serve) that force utilities to seek solutions they can control completely, and devalue market-based solutions that are less controllable.
   c) An approach to planning that focuses on building and managing the utility distribution system, as opposed to starting with the needs of the customers and working backwards to the available solutions.
   d) A sector which has, for decades, emphasized utility-owned solutions and therefore has (quite rightly) populated its engineering, operational, and planning staffs with individuals who are good at designing, building and operating utility-owned solutions.

   The Subgroup generally agrees that the sector will evolve substantially over the next 10-20 years, although there is no consensus as to the extent of that change. There is consensus that it would be valuable for the OEB to identify some of the above issues, and take initial steps to assess what changes to those elements, if any,

[28] This could include the Distribution System Code and other relevant Rules or Codes, Rate and other handbooks, Licences, Filing Requirements, Regulations, etc.

should be considered over the medium and longer terms. This is not, it should be noted, about driving the change, but rather about being prepared for it as it happens.

4. **<u>Co-ordination of Initiatives.</u>** The Subgroup notes that there are a multiplicity of working groups, studies, proceedings, consultations, and committees, whether at the OEB, the IESO, the government, or otherwise, dealing with the evolution of the sector, including the issues being dealt with by this Subgroup and the FEI Working Group. The work of this working group, and those other initiatives, would benefit from the OEB taking the lead in co-ordinating those activities. While some work is already being done, including in particular co-ordination between the OEB and the IESO, the Subgroup believes that an increased effort to integrate those activities would be beneficial to the sector.