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Distribution System Inquiry

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REPORT ON COMBINED MODULE 2 AND 3 TOPICS

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CONSUMERS' COALITION OF ALBERTA

Acknowledgement

This evidence was produced by the undersigned individuals, who attest that they will provide independent, unbiased, professional opinions that are fair, objective, and non-partisan.

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Table of Contents

1. Report Objective and Structure 1

1.1. Our Mandate 1

1.2. Description of Approach and Report Structure 1

1.3. Technologies and Customer Configurations to be Considered 3

2. Direct Answers to AUC Questions 4

2.1. Question 1 4

2.2. Question 2 4

2.3. Question 3 6

2.4. Question 4 7

2.5. Question 5 8

3. Regulatory Framework 9

3.1. Statement of Principles 9

3.2. Summary of Current Regulatory Framework in Alberta for DFOs 12

3.3. Key Observations Regarding Current Framework in Context of Stated Principles 14

3.4. Case Study: Performance Based Ratemaking in the UK 16

3.5. Case Study: Australian Microgrid Initiatives 20

3.6. Case Study: Hawaiian Microgrid Initiatives 23

3.7. Case Study Observations and Recommendations 26

3.8. Network Planning Considerations for Future DFO 28

3.8.1. Non-Wires Alternatives in Network Development 28

3.8.2. Stakeholder Participation in Planning Processes 30

4. Rate Design 32

4.1. Tariff Rate Design Principles 33

4.2. General Considerations in Evolving Distribution Systems 36

4.2.1. Reconsidering Rates in Light of DERs 36

4.2.2. Managing Impacts of Rate Reform 39

4.2.3. Metering and Billing Approaches for Distributed Generation 40

4.2.4. Overlaying Policy Decisions on Principled Rates 43

4.3. Applicability to Current Structures 44

4.3.1. DCG Rates – Small Micro-generation 44

4.3.2. DCG Rates – Large Micro-generation 48

4.3.3. Other DCG Connections 49

4.3.4. Demand Side Management 52
4.3.5. Storage Rates 53
4.3.6. EV Rates 54
4.4. Locational Pricing Considerations 57
4.5. Conclusions and Recommendations 59

Appendix A: DERs and Wholesale Markets – ERCOT Case Study 61
ERCOT Background 61
Market Participation Tradeoffs 61
DERs in the ERCOT Market 62
Distributed Generation 62
Energy Storage 63
Demand Response 65
Energy Efficiency 65
Key Takeaways from ERCOT 65

1. Report Objective and Structure

1.1. Our Mandate

We have been asked by the Consumers' Coalition of Alberta ("CCA") to provide expert advice for the Alberta Utilities Commission's ("AUC") Electric Distribution System Inquiry ("Inquiry"), initiated December 6, 2018, under AUC proceeding ID 24116. As stated by the AUC, the inquiry is directed at mapping "key issues related to the future of the electric distribution grid, to aid in developing the necessary regulatory framework to accommodate the evolution of the electric system."[1] This Inquiry was originally slated to be split into three modules to address (1) new technologies on the distribution system; (2) implications on distribution utility services, regulatory structures, and utility business models of these new technologies; and (3) regulatory and rate responses that may be necessary to respond to new technologies. Module One is largely complete and Modules Two and Three are to be combined into a "Combined Module."[2] Our report addresses the topics raised by the AUC to be considered in this Combined Module. We focus our input where we have experience and expertise that we believe supports the advancement of the substantive inquiry that the AUC has undertaken.

1.2. Description of Approach and Report Structure

In framing the Combined Module, the AUC presented five questions in its outline for written submissions by stakeholders in the Inquiry. We have generally structured our assessment, as described in this report, to respond to these questions. In addition, we have expanded our response to include discussion on policy aspects that support our responses. We also include relevant case studies to inform on regulatory and policy activities in other jurisdictions facing similar evolving industry issues.

The contents of the report are therefore structured as follows:

- **Section 2**: High-level responses to the AUC's five questions in its outline for written submissions in the Combined Module.
- **Section 3**: Discussion of overarching issues of regulatory structure, with a finding on the ongoing appropriateness of the "I – X" construct as the expectations for the distribution system and interconnected technologies evolve. Several related case studies are presented.
- **Section 4**: Description and assessment of issues of tariff rate design for distribution utility service. In particular, we will identify relevant rate design principles and apply them in the context of various connection schemes, like those presented in the AUC's Preliminary Information Requests.[3]

1 AUC Bulletin 2018-17, December 6, 2018

2 24116-X0106, "AUC Revised Process Schedule", December 11, 2019

3 24116-X0470, "AUC Preliminary Information Requests to All Registered Parties," November 29, 2019

- **Appendix A**: A case study of the Texas energy market ("ERCOT"). Via this case study, we identify considerations for proliferating distribution-situated generation technologies and increased demand side participation in an energy-only wholesale market, as is in place in Alberta.

The issues we address are multi-faceted and complex and although no single simple solution may present, we believe a focused, principle-based approach provides a useful framework in which to evaluate the issues that the AUC is considering in these modules. The fundamentals that we apply to our analysis and inform our findings and recommendations are as follows:

Principle-driven approach

In Sections 3 and 4, we will present a set of principles to be applied in assessing regulatory structures and rate design. In brief, these principles include, in no particular order:

- Rates support economically efficient outcomes, send correct price signals, and attempt to simulate results of competitive markets
- Rates reflect cost causation
- Rates minimize unintended consequences to the extent possible
- Rates support the utility's ability to attract capital
- Rates encourage managerial efficiency
- Regulatory frameworks should balance objectives, including affordability to customers, understandability of rates, clarity from misinterpretation, reasonable level of granularity, and avoidance of undue discrimination.[4]

Importantly, assessment of regulatory elements by a principle-driven approach is not outcome-driven. For example, the goal is not necessarily to minimize cost to consumers, nor to maximize investment or returns to utilities. Rather, the consistent application of principles should result in long term outcomes that are consistent with general regulatory objectives, including the provision of reliable service at reasonable cost. Our findings and recommendations will reflect this understanding.

Technology agnostic

Our opinion is that, from an initial position, distribution regulation and rate design should be technology agnostic, and not give undue advantage to any particular technology. This is consistent with a principle-driven approach, where regulators rely upon open markets to develop technology choices, while adopting appropriate regulatory frameworks with rates designed to incent the development of economically beneficial technology. We do not believe that any structure that assigns differing values to alternative technologies is warranted.

4 These principles are consistent with those articulated by James C Bonbright, "Principles of Public Utility Rates," New York, Columbia University Press, first edition, 1961

Policy compatible

We recognize that policy initiatives may seek to support certain technologies or otherwise drive distribution system outcomes (e.g., to achieve environmental policy goals, or to provide rate relief to lower income ratepayers or ratepayers who have less ability to adapt to, or adopt, new technologies). Such policies may be compatible with a technology-agnostic and principle-based approach; however, they should be applied deliberately and with an understanding of the outcomes resulting from any implementation of incentives.

Focus on the distribution system and distribution regulation

Given the nature of the AUC's Inquiry and our mandate from the CCA, we limit our assessment to issues that are directly related to the distribution system and distribution regulation. Although the expansion of new technologies deployed at the distribution system level can affect transmission regulation or the Alberta wholesale energy market, we purposely contain this report to distribution utility issues. Where principles may apply across distribution and transmission regulation and rate structures, we will note areas of overlap. Section 5 also comments on the relationship between wholesale market structures and technologies situated at the distribution system level.

1.3. Technologies and Customer Configurations to be Considered

As identified by the AUC in initiating this inquiry, a broad range of technological changes and deployment of new technologies may necessitate change to the future distribution network. These can include changes to the underlying regulatory framework and rate design. For our purposes, we treat those technologies identified by Dr. Richard Tabors in his Module One testimony in support of the CCA.[5] These emerging, distribution-situated technologies (we will refer to these collectively as "DERs") are:

- Distributed generation, including solar photovoltaic ("PV") and combined heat and power ("CHP") facilities
- Distributed battery storage
- Electric vehicles ("EV") and EV charging stations
- Microgrids
- Demand-side management ("DSM") measures, including demand response ("DR") and energy efficiency ("EE")

Where appropriate, we will distinguish between deployment of these technologies in front of, or behind, the customer meter. We will also identify where we think the size of a distributed resource is, or is not, relevant. Where appropriate, we will rely on the (approximately) six customer configuration examples provided in the AUC's preliminary information requests. Finally, when we refer to distribution connected generation ("DCG"), we generally are referring to both generators and storage resources. Where there is discussion specific to storage, we will identify that the distinction is being made.

5 24116-X0167, "CCA Evidence of Dr. Richard Tabors," July 17, 2019

2. Direct Answers to AUC Questions

This section provides high-level answers to the AUC's five questions in its outline for written submissions in the Combined Module. Where relevant, we reference more fulsome discussion and analysis provided in later sections of the report.

2.1. Question 1

During the technical conference for Module One, several parties recommended that the regulatory framework governing the Alberta Interconnected Electric System ("AIES") should be technology agnostic and economically efficient. Other principles that also may be applied include customer choice, fairness, efficiency and open competition. In your view, what principles should be applied to implement the regulatory framework necessary to accommodate the economic and technological forces that are transforming the market structure governing energy distribution by public utilities?

We suggest the following principles for the regulatory framework governing the AIES, and particularly for distribution networks:

- Rates support economically efficient outcomes, send correct price signals, and attempt to simulate results of competitive markets
- Rates reflect cost causation
- Rates support the utility's ability to attract capital
- Rates encourage managerial efficiency
- Rates minimize unintended consequences to the extent possible
- Regulatory frameworks should balance objectives, including affordability to customers, understandability of rates, clarity from misinterpretation, reasonable level of granularity, and avoidance of undue discrimination.

These principles are generally consistent with those laid out by James Bonbright in 1961 and have been employed broadly over the time since then. If applied thoughtfully, these same principles should remain relevant and appropriate as the landscape for distribution utilities changes in light of the various economic and technical forces referred to by the AUC. The principles are described in more detail later in this report, in section 3.1 and section 4.1.

As we note in the introduction, we support a technology agnostic approach as a starting point for a regulatory framework. However, adhering completely to a technology agnostic approach is fundamentally a policy choice. To the extent that there are policies in place that are designed to support certain preferred technologies, we urge regulators to carefully evaluate potential outcomes to avoid unintended consequences such as significant costs shifts among customers or unwarranted cost increases to the system (i.e., economically inefficient outcomes).

2.2. Question 2

When considering the various load and generation connection schemes summarized in the preliminary IRs, and potentially others, how does the current regulatory

framework governing those connection schemes apply, or not apply, to the principles put forward in part (i)? What changes might be recommended?

We suggest that several key elements comprise a regulatory framework, particularly as they relate to rate design, to achieve adherence to the principles we advance. Our recommendations apply across the various customer configuration and connection schemes detailed in the AUC's preliminary IRs. These elements include:

- Implementation of three-part rates, including for residential customers deploying DCG and/or EVs, with rates that include fixed, demand, and variable components. This is of particular concern for DCG customers (including those with storage assets) and may also be an approach to incentivizing efficient behavior for EV customers.
- To the extent that certain customer classes already face three-part rates – or similar rates with reduced emphasis on variable charges – rate structures will likely still need to be revisited to balance the relative size of fixed, demand, and variable charges to reflect costs and send effective signals to lead to efficient investment and operational decisions.
- Exceptions from three-part may generally be extended to non-adopters of DERs, as those customers are less likely to trigger the cost-shifting concerns associated with DER deployment. There may also be considerations that warrant grandfathering or transitional rate structures for certain customers who would otherwise be subject to a three-part rate.
- Additional attention should be paid to the accuracy of consumer contribution charges for new DCGs to support efficient decisions at the stage of initial deployment of capital.
- There is room for improvement in the transparency and understandability of rate structures as they apply to different customer classes with different DER and metering configurations. This is particularly true should DFOs in Alberta develop new rate classes for micro-generation customers, EV customers, etc.

These findings are described in more detail in section 4.3. If applied across customer types and configurations, we expect that the resulting customer rates would be consistent with stated principles and lead to economically efficient outcomes. We also offer the following configuration-specific observations:

- Treatment of distribution network charges for DCGs with STS contracts should be revisited. Such DCG customers should no longer contribute to reduction in DTS charges for the distributor and DTS credits should no longer be applicable. This approach ensures a level playing field between generators, thus fulfilling objectives around technology agnosticism and avoidance of undue discrimination, while also eliminating concerns over billing determinant erosion and cost shifting.
- Current rules around the recovery of the small micro-generation sell-rate should be reformed. As we understand it, there is currently no regulatory review of these rates and the entities that agree to the price bear no risk for that price. The costs incurred are ultimately borne by customers and the potential exists for significant economic efficiency losses to occur by offering above-market rates with no countervailing benefit to the system.
- If EVs become more common in Alberta, there are a range of experiences from other jurisdictions that may inform Alberta's path forward. EV-specific tariffs may work to

constrain the impact of EVs on total system requirements. There are also available approaches to limit the rate shock of EV tariff implementation and to educate consumers about EV tariff adoption.

2.3. Question 3

To what extent does the current regulatory treatment for micro-generation, distribution-connected generation, industrial systems designations, energy storage resources, and any other customers or market participants apply the principle of technology agnosticism? Should this agnosticism be applied not only to the type of technologies used within those different regulatory constructs, but also to the fuel source, connection configuration, generator size, etc.? And how should this agnosticism extend between those regulatory constructs? In other words, should it matter what type of customer is connecting to the generating unit, what the size of the generating unit is, and what the generation will be used for, so long as the generator and customer adhere to certain technical limitations of the grid and pay the appropriate tariffs?

As stated, we suggest a technologically agnostic approach to regulatory design for the distribution system, at least in establishing a foundation for the regulatory framework and rate design. We recognize that there may be a need, in some instances, to deviate from a strictly technology agnostic approach to achieve some specific outcomes. However, these policies should be applied deliberately and with an understanding of how incentives are being shifted and overall outcomes may change.

Perfectly equivalent regulatory treatment across all customer types and configurations may not be feasible or desirable. This is particularly acute across customers and/or DERs of significantly different sizes. For example, the cost of requiring more sophisticated metering equipment may be justified by the potential benefits (and costs imposed) for larger loads. In turn, this may allow increased requirements for such measures from larger customers and/or DERs. Larger entities also have a proportionally larger impact on market efficiencies and system cost and the variance in treatment may be justified.

Based on our review, the overall regulatory framework appears technology agnostic and provides Alberta DFOs the opportunity to exercise managerial discretion to make investment decisions to provide the level and types of services they perceive customers want (within prevailing regulatory and legal constraints). However, there are several ways that the current regulatory and rate structures implicitly preference certain technologies. First, to the extent rate design outcomes rely on variable rates, or do not reflect cost causation in the split between variable and demand rates, they could effectively overstate the value of DERs, particularly in energy produced or consumption avoided. By overstating this value, rates inherently promote smaller resources and technologies that are scalable to deployment as DCGs. Second, and relatedly, the particular treatment of large DCGs and associated DFO credits inappropriately favors large DCG generation over transmission connected generation based on distinctions over connection and metering configuration, which we view as insufficient to justify this result.

2.4. Question 4

If, in response to the questions posed in parts (ii) and (iii) above, changes to the existing regulatory framework have been recommended, what would need to change and why? For example, the location and configuration of the metering? Access to certain information and data? Distribution and/or transmission network planning? Who pays for the cost of connecting the site's generating unit and how it is determined? The types of tariffs applied to the site for load and generation, and their potential design? The compensation for electricity supplied to the grid? Who has control over dispatch and settlement?

Our focus in this report generally approaches the questions posed from two directions: (1) from the perspective of the overall regulatory framework and the incentives observed by utilities; and (2) from the perspective of rate design and the signals observed by consumers and other DER entities. Regarding the overall regulatory framework, we recommend shifts in the regulatory approach that better incent innovation, while ensuring utilities make the appropriate level of investments at the right cost to provide a reasonable balance and advancement from today's framework. Changes should also respond to shifts in customer needs for their utility service. Specific framework modifications could include:

- A strict set of prudence criteria with cost benefit analysis to be applied for investments in emerging technologies;
- An incentive metric in performance-based regulation ("PBR") that rewards for innovation but with a strict tie to cost-benefit and prudence;
- A PBR metric that evaluates how well utilities understand evolving customer needs;
- Continued imposition of I-X operating efficiency goals;
- A set of penalties and disincentives for uneconomic or stranded investment, especially with regards to new and emerging technologies. However, we recognize that utilities are well positioned to assume and manage risk.

Related to rate design, we have described many of our suggestions in response to (ii) and (iii) above. Our key recommendations revolve around reforms to rate design, as well as customer contribution rules for new DCGs. Thus, changes would be required to tariff design, how tariffs are applied to load and generation (including supply to grid via generation or storage), and who pays for the costs of new site connections. In some instances, implementation of three-part distribution rates will require deployment of advanced metering capabilities, though we have not recommended any changes that would necessarily require shifts in metering configuration.

We also note that we have not reviewed Alberta's regulatory framework across all of the dimensions listed above. For example, we have not addressed, in detail, issues of information and data access, distribution and transmission planning, or dispatch and settlement in the wholesale market. (On the latter, we offer a case study on the participation of DERs in the ERCOT market.) We expect other commenters in this inquiry will be better positioned to expound on these issues.

2.5. Question 5

Given your responses to part (iv) above, what would be the effect on other entities that currently operate in, or benefit from, the AIES? What are the opportunities and challenges for distribution facility owners to evolve their business models and/or value propositions?

For utilities, our recommended changes to regulatory frameworks and the I-X regulation would allow opportunities for innovation, while ensuring a balanced approach that protects against unwarranted consumer costs. Reforms would also allow utilities to respond to changing customer needs and aspirations, which may extend beyond the goal of lower rates, alone. This may lead to, among other things, opportunities to expand utility offerings and increase rate base. Improved rate design for DERs should also limit the ability for DER customers to bypass rates, which improves opportunities for cost recovery, reduces billing unit erosion, avoids cost shifting, and prevents the potential utility "death spiral."

For customers, we would expect rate reforms to limit undue cost shifts and send better signals on both operational and investment time scales. In turn, this should lead to improved static and dynamic efficiency, in which long term costs should be minimized relative to the services demanded. Furthermore, utility costs should be allocated in accordance with cost causation, along with balancing other important non-cost rate design factors, while keeping accommodations for customer populations that could be negatively affected by both rate restructuring and rate bypass by larger ratepayers. As touched on above, adjustments to the regulatory framework for DFOs have the potential to better align utility service offerings with customer preferences.

For generators, the changes to rate structure and balance across billing elements, in addition to reforms around customer contribution and large DCG credits, should level the competitive landscape across generation types, sizes, and configurations. Micro-generators should see their value proposition more accurately reflect cost causation, and overstatement of DCG energy value should be reduced. Additionally, large DCG would no longer have an inherent advantage solely on the basis of being connected at the distribution level rather than the transmission level.

3. Regulatory Framework

This section outlines the key principles that we believe should be considered in utility regulatory frameworks and provides observations as to the extent to which the current regulatory framework in Alberta reflects these principles. This section also provides case studies that explore how regulatory frameworks in the United Kingdom, Australia, and Hawaii have addressed similar issues of emerging technology adoption while balancing consumer risk and other important rate and regulatory factors. This section concludes with our observations as to potential refinements to the current Alberta regulatory framework that may help it continue to address new challenges presented by changing customer needs and preferences and emerging technologies.

3.1. Statement of Principles

A monopoly (single-provider) market is suited for public utility electric transmission and distribution ("T&D") services due to the characteristics of these public utility services and investments. T&D assets, such as substations, transformers, poles and other facilities, are usually long-lived and display a high ratio of unavoidable fixed costs to variable costs. Utility regulators typically rate regulate public utilities within this market structure to avoid the negative societal consequences of duplicative investments to service a public good or service. Because public utilities tend to deliver significant economies of scale that provide a cost advantage over the full spectrum of T&D services, including fixed costs and variable costs for respective capacity and energy needs, this single-provider structure continues to provide significant consumer and societal benefits. Conversely, a market structure that deviates from a single-provider construct for T&D services would most likely result in higher overall costs to consumers since economics of scale loss and duplicative investments would be difficult to avoid. A primary role of the regulatory framework therefore is to recognize a monopoly's societal benefits of non-duplicity and economies of scale, while ensuring efficient and reasonable consumer price outcomes.

To recognize the benefits of a single-provider market, while protecting consumers from monopolistic pricing, regulators for T&D services administratively set the price. What emerges from this construct is what is often referred to as the "regulatory compact." This compact represents the understanding that utilities, upon acquisition of an exclusive franchise, must also accept economic price regulation. The utilities also understand that linked with the exclusive franchise is an obligation to serve and that obligation carries certain performance expectations and standards. Regulatory frameworks should also encourage innovation and efficient managerial performance of the utility. The goal of the regulatory framework should be – to the extent possible – to encourage price outcomes that are consistently aligned with expected prices in a competitive market. However, it is impossible to achieve a regulated price outcome for a single-provider utility service that matches exactly to outcomes in open competition.

Regulatory frameworks for single-provider markets typically rely on cost based (cost of service) standards for rates and/or ones that incorporate a performance metric – PBR. The performance metrics can vary, but typically include cost savings and reliability targets. In some cases, mechanisms allow for utilities to retain some savings.

We emphasize that PBR or cost-based frameworks are not always perfect substitutes for competitive prices, as modelling any result of a truly competitive market outside of that construct is not possible. PBR development requires important compromises amid competing goals. We have established that competitive market structures are not well suited for T&D provision. However, open market forces lead to economically efficient outcomes and should be encouraged, when practical.

In the following paragraphs, we establish six principles for an ideal regulatory framework which, again, are in line with those espoused by James C. Bonbright in “Principles of Public Utility Rates” (1961). These principles are presented in no particular order, as each forms part of the whole. An ideal regulatory framework should:

Set utility rates to provide sufficient ability for utility to “attract capital”

Utilities are entitled to a reasonable opportunity, over a set timeframe (e.g., the life of the investment), to recover their full embedded costs, including a fair return on capital, via rates. Utilities that recover their prudently incurred embedded costs plus a return are able to maintain creditworthiness and, in turn, attract capital sources at reasonable costs. Consumers reap the benefits of lower capital costs in rates. These principles are well established through US and Canadian case law.[6] The fair rate of return earned in rates “may be regarded as a substitute, though not a close substitute, for the tendency of prices and costs to come into accord under forces of market competition.”[7] This ability to attract capital also provides utilities with the economic incentive to invest in goods and services that allow them to carry out their obligation to serve and provide the types and quantities of services requested by consumers. However, capital attraction, alone, does not necessarily incent the utility to innovate or provide safe and reliable utility service at the lowest or reasonable cost.

Set utility rates to provide “economically efficient” outcomes

Economically efficient utility rates are ones that discourage wasteful investment and encourage efficient consumption of utility services. Rates set to provide these goals help to diminish the risk of excess utility investment relative to consumer demands (leading to stranded costs) and guide investment in long term assets up to where consumers’ demand is met (with sufficient capacity reserves). For instance, rates that are set below marginal costs will only encourage wasteful investment by encouraging consumers to use services that are priced below their cost-based value. This, in turn, creates losses at the utility level that must be recovered from all consumers. Although marginal-based costs are the most efficient way to incentivize economically efficient buying behavior, setting rates entirely on a marginal cost basis will not provide a sufficient level of cost return for the utility and, in turn, will violate capital attraction need. Marginal costs, however, can be used as a guide in pricing.

Encourage “managerial efficiency”

Rates set through proper regulatory frameworks should encourage and promote efficient operation and management of the utility. For instance, costs incurred should be prudent and reasonable and incurred to provide the required level of service at reasonable cost. Inefficient operation, poor managerial actions and other actions under management control

6 E.g., Bluefield Water Works v. Public Service Commission, 262 U.S. 679 (1923); FPC v. Hope Nat. Gas Co., 320 U.S. 591 (1944).

7 James C. Bonbright, “The Role of Public Utility Rates,” New York, Columbia University, first edition, 1961 p. 53.

that result in unnecessary or excessive costs for consumers should be discouraged. From an economic signal perspective, such factors interfere with communicating the true cost and value levels of the utility service to the consumer that would otherwise be communicated freely through competitive markets. However, utilities are in the best position to evaluate consumer demands for the level and types of services needed. Frameworks must strike a balance between providing sufficient managerial control to the utility for making investment and operating decisions while ensuring economically efficient outcomes.

Set rates that send correct price signals to consumers

Consumers should be able to accurately evaluate and set their own demand for a particular service based on a correct understanding of value. In this way, consumers can weigh their purchasing decisions for utility services against their larger basket of goods and services and make an informed decision as to how to allocate their resources. Correct price signals also permit utilities to invest in their systems to provide a level and quantity of service that are in balance with consumer demand. An effective way to communicate price signals is to set rates based upon underlying costs to produce and deliver the service. Such pricing avoids overinvestment by utilities and wasteful consumption by consumers, which occurs when investments are made without accurate consideration of underlying value. Marginal costs provide the strongest price signals, since they communicate the cost of producing that next incremental unit of service. As explained earlier, rates cannot be entirely based on marginal costs, since they will not recover the full level of embedded utility costs.

Regulatory frameworks should consider affordability from the customers' perspective

This concept can compete with the goal of "capital attraction" for full cost recovery. Current regulatory frameworks acknowledge the importance of a customer's ability to pay. However, rate proceedings on this matter are generally limited to specialized rate designs or specific programs to certain eligible consumers. Rate affordability is further discussed in section 4.1.

Attempt to simulate results from a competitive market

Though regulation can never perfectly imitate competition, it should aim for an economically efficient result that would otherwise be achieved in open markets. Matching supply and demand organically resolves trade-offs. Thus, a regulatory framework must reconcile competing objectives:[8]

- **Capital attraction and managerial efficiency***.* Capital attraction, taken to an extreme, results in overinvestment in infrastructure and high rates without regard to efficiency of expenditure and operations. The regulatory framework needs to address this conflict, which would not occur in perfectly functioning competitive markets, by imposing standards for prudent investment while permitting the utility to make investments and operating decisions they believe best suit their customers' needs.
- **Capital attraction and price signals ("consumer rationing").** Utility rates are set on the basis of average embedded costs to attract capital, but using average cost rates instead of marginal cost rates obscures the true value of the next incremental service. In monopolistic markets, it is difficult to abandon the average cost rate-setting method

8 James C. Bonbright, "The Role of Public Utility Rates," New York, Columbia University, first edition, 1961 p. 38, 62.

since total rate levels must recover all embedded costs. Furthermore, since marginal costs are not additive to average costs, marginal cost pricing is not suitable for system-level rate recovery.

Competitive markets are not always perfect. To work, their prices must adjust automatically to balance supply and demand for equilibrium, offer low barriers to entry, and consist of a sufficient number of buyers and sellers to avoid market power influence. However, when working, competitive markets are best suited to foster innovation. Market forces identify winners and losers based on service quality, type, and cost as well as other factors. Therefore, regulatory frameworks seeking to address innovation should evaluate utilities based on the same factors and not be tethered to other rate setting goals that may have the effect of favoring one technology over another. That is, to foster innovation, a regulatory framework should be **technologically agnostic.**

The framework should not prescribe a certain technology. In competitive markets, this outcome would naturally evolve based on market dynamics and consumer feedback.

Set rates that minimize unintended consequences to the extent possible

Under the principles of an ideal competitive market, the following outcomes should be avoided:

- **Overcapacity from too much capital attraction**; wherein utility fixed capacity is over-built or redundant stranded costs lead to inflated price levels.
- **Under-capacity and inability to meet demand**; wherein underinvestment occurs relative to system capacity needs or other production, delivery or reliability needs, and customers face the risk of service interruption with related loss of value.
- **Products and services priced below marginal costs**; wherein customers are either unwilling to pay for a service, even at a low cost, or prices are insufficient to recover the marginal costs of providing the service.
- **Uncompetitive products and services priced above marginal costs**; wherein customers are unwilling to pay for a product or service due to its high price, such that utilities cannot recover costs. In this case, prices are higher than consumers' value of the service.

3.2. Summary of Current Regulatory Framework in Alberta for DFOs

In 2012, the AUC implemented PBR for four electric and two gas distribution utilities in the province: AltaGas, ATCO Electric and ATCO Gas, EPCOR, and Fortis. A PBR plan was also approved for the fifth electric utility, ENMAX, which commenced prior to 2012. With the exception of ENMAX's first generation PBR, the AUC has approved PBR plans in increments of five years. The first set of PBR plans were effective from January 1, 2013, to December 31, 2017. In December 2016, the AUC approved the current PBR plans, in effect from January 1, 2018, to December 31, 2022.[9] While price cap regulation applies to electric utilities, revenue cap regulation applies to the gas distribution utilities (ATCO Gas and AltaGas).

Prior to 2012, the AUC generally used cost-of-service ("COS") regulation, in some cases applying a formula-based approach. Under COS, the electric utilities ordinarily presented two-year forecasts of their revenue requirements and capital additions.[10] The AUC allowed these costs to be fully recovered via transmission and distribution charges levied on different customer classes. However, Alberta's Office of the Utilities Consumer Advocate ("UCA") found that COS regulation over-incented the addition of recoverable capital assets and discouraged non-recoverable activity such as maintenance, efficiency initiatives, and capital deferral.[11] The utilities were not permitted to keep any "profits." Any savings from predicted costs were passed onto customers in the next rate proceeding. COS regulation was also burdensome in a restructured market. The AUC needed to monitor production and retailing separately from newly competitive distribution and transmission activity. As a result, the AUC reviewed thousands of pages of test-year data and hundreds of specialized rate riders for each of the five utilities.[12]

PBR, in contrast, was designed to reduce predicted costs, discourage overinvestment in potentially superfluous capital additions, and streamline regulatory proceedings. In Alberta, the PBR mechanism is formulaic.[13] The basic formula is called "I – X" and caps a utility's prices or, in the case of gas distribution, overall revenues. I – X consists of the following components:

- **Base rate**: A utility's base starting rate, or "year zero" rate to which the I – X formula is applied in subsequent years. Base "going-in" rates are critical to the success of a PBR plan. During negotiations for the 2018-2022 PBR plans, the utilities supported a COS-regulated test year (2018) to reset going-in rates, while parties such as CCA favored eliminating all tracking of capital spending. The AUC compromised: the going-in rates reflect the actual costs, cost savings, and capital additions for 2017, the year prior to the PBR plan's implementation.
- **Adjustment percentage**: After year 1 of the PBR plan, the going-in rate is adjusted by a percentage of I – X, or an inflation rate for energy-related products less predicted

9 AUC Decision 20414-D01-2016: 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, February 6, 2017.

10 In some instances, utilities filed either single year or multi-year (e.g., 3-5 year) forecasts.

11 Application #1606029; Proceeding ID #566, Exhibit No. 299.02, December 16, 2011.

12 AUC Decision 2012-237: Distribution Performance-Based Regulation, September 12, 2012.

13 The electric and gas distribution utility ENMAX has been regulated under a two-part formulaic rate since 2009. Distribution rates, fees, and non-residential investment were calculated with an I-X mechanism. Revenue requirement and transmission were calculated with an I-X mechanism plus an additional "G factor," or the previous year's amortized transmission investment. ENMAX's going-in rates matched its approved 2006 rates. ENMAX's first formula-based regulation term was seven years to provide regulatory certainty and match the life of capital assets. (AUC Decision 2009-035) The first plan was approved for a seven-year term that ended on December 31, 2013. However, ENMAX used COS regulation to rebase its revenue requirement for the 2014 test year to establish going-in rates before filing a new two-year PBR plan for the years 2015-2017. (AUC Decision 21149-D01-2016).

efficiency improvements the utilities achieve. The X factor, (including a stretch component) is currently 0.3%[14] industry-wide, so every utility's performance is accounted for. Thus, energy-related prices adjusted by I-X reflect industry-wide conditions that would yield price changes in competitive markets and allow utilities to retain their cost savings as "profits."

Alberta's I – X formula includes some cost-based adjustments, vestiges of COS regulations. The AUC recognized that certain events might only affect the energy industry or a single utility, and these costs cannot be recovered through the I or X factors.[15] The impacts of these factors can be recovered through the following:

- **Y factor**: Predictable, non-capital costs that the utility cannot control. These include municipal fees, load balancing, weather risk, production abandonment, and income taxes. Y factor costs are directly recoverable from customers.
- **Z factor**: Unpredictable events for which the utility has no reasonable cost recovery mechanism within the I – X framework. Z factors are approved on an individual event basis and must meet a certain monetary threshold to prevent overuse.
- **K factor**: Beginning in 2018, two separate K factors, also known as "capital trackers," will be applied to two types of capital additions: Type 1 and Type 2.
  - Type 1 capital is extraordinary, not included in the utility's rate base, and required by a third party. Utilities must apply for capital tracker true-ups each year.
  - Type 2 capital is predictable and included in the utility's rate base. An initial amount of Type 2 capital, or "base K-bar", would be established for all Type 2 capital in the first year of PBR implementation. The AUC calculates Base K-bar with an accounting test. Each year, the AUC will index the 2018 base K-bar amount by I – X to incrementally increase K-bar funding.[16]

Overall, as we understand it, the AUC's second-generation approved PBR plans slowly transition from COS-based regulation to "pure" PBR, in which budget outperformance is rewarded.

3.3. Key Observations Regarding Current Framework in Context of Stated Principles

We find that the current regulatory framework in Alberta is generally in alignment with our outlined framework principles presented in this section. The framework is designed to support full embedded cost recovery for prudently incurred capital and operating expenses that provide utilities with the opportunity to earn a fair rate of return and attract capital. In addition, the framework is technology agnostic and provides the utility the opportunity to exercise

14 AUC Decision 23355-D02-2018: Rebasing for the 2018-2022 PBR Compliance Filing, October 10, 2018.

15 AUC Decision 2012-237: Distribution Performance-Based Regulation, September 12, 2012, para. 18.

16 AUC Decision 20414-D01-2016: 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, February 6, 2017, para. 242.

management discretion to make investment decisions according to the level and types of services it perceives customers want.

However, we believe that some refinements to the current framework may be warranted with regards to the treatment of new and emerging technologies. The current PBR, for instance, is designed to provide incentives for the utility to deliver operating cost efficiencies through the I-X factor. Although reasonable cost levels through operating efficiency is a valid regulatory framework goal, as we consider the opportunities and risks presented by new technologies, other incentives may be appropriate to communicate through the PBR. For instance, no specific incentive currently exists to foster innovation other than through what could be achieved via delivering a lower cost that would be rewarded through the I-X factor.

With innovation, of course, comes potential risk. In turn, risk can translate to increased costs to consumers. It is important for regulatory frameworks to sufficiently balance the need to encourage innovation while, at the same time, protect consumers from poor decision-making and management with regard to technology deployments. We believe an approach that better incents innovation, while ensuring utilities are making appropriate investments in the right amounts and the right cost, could provide a reasonable balance and advancement from today's framework. This can be achieved within PBR. We believe utilities should take the risk for innovation and that PBR should provide a reward for taking that risk. The reward may be retention of cost savings from increased margin due to efficiencies, or other specific incentives that are tied to outcomes of new technology deployment (e.g., improved reliability, deferred T&D investment). We have also already described how the potentially higher return on equity ("ROE") can be provided for successful innovation investments. However, these reward incentives should be balanced by an appropriate set of checks to ensure investments are made soundly and prudently.

In addition, it is important for the regulatory framework to respond to the fact that customer needs for utility service are changing, and these needs extend beyond the sole goal of lower rates. The current regulatory framework may benefit from providing an incentive to utilities to better understand customer evolving needs and to deliver solutions accordingly.

PBR can also provide a framework to incent utilities to make investments that promote long-term efficiency. These investments may entail immediate cost outlays but provide benefits in the future. Over a longer time horizon, these types of investments can provide a positive net present value based on the balance of costs to future benefits. For instance, advanced metering infrastructure ("AMI") programs entail significant up-front cost investments that, on a single test year basis, may entail cost increases with little to no corresponding benefit. Yet, over the life of the investment (for instance 20 years), the value of future benefits, when weighed against up-front costs, results in increased efficiency (overall lower costs) to consumers. A PBR program can potentially incentivize this type of investment by providing the utility an opportunity or incentive to make the investment and include it in rate base. However, there should also be corresponding checks in place that measure forecasted future benefits against actual benefits achieved. As one example, a PBR program could provide an incentive for the utility to retain a portion of benefits achieved that are in excess of forecasted benefits. Conversely, the program could penalize underachievement of expected benefits by forcing the utility to absorb the underachievement in follow up-reconciliations. Other potential examples could apply.

Specific framework changes could include:

- A strict set of prudence criteria with cost benefit analysis to be applied for investments in emerging technologies;
- An incentive metric in PBR that rewards for innovation, but with a strict tie to cost-benefit and prudence;
- A PBR metric that evaluates how well utilities understand evolving customer needs;
- Continued imposition of I-X operating efficiency goals;
- A set of penalties and disincentives for uneconomic or stranded investment, especially with regards to new and emerging technologies;
- A set of incentives and penalties to encourage utilities to invest in innovation that can provide future benefits. However, we recognize that utilities are well positioned to assume and manage risk (within the types of investment allowed for DFOs under prevailing statute and regulations).

The PBR framework could also be adapted, consistent with broader Alberta policies, to provide specific incentives for outcomes that have been determined to be in the public interest. This is particularly true for policies that may run counter to other incentives faced by a utility under PBR. For example, a goal of decarbonization may run counter to utility incentives to increase billing unit sales and could, therefore, be accounted for under a separate provision under PBR. Likewise, if innovation is a priority, higher returns could be provided for successful implementation of innovation projects.

3.4. Case Study: Performance Based Ratemaking in the UK

The United Kingdom ("UK") has used a mechanism similar to I – X, called RPI – X, to recover costs for various regulated industries since the 1980s.[17] The UK's gas and electric industries implemented RPI – X in 1986 and 1990 after their respective privatizations. UK regulators first set price caps to be reviewed every 5 years. The price caps were then adjusted by an RPI – X factor on an annual basis. The RPI – X factor consists of the retail price index for an industry's basket of products less expected efficiency savings across all fourteen electric distribution utilities.[18]

In 2013, Ofgem, the UK's regulator for gas and power distribution and transmission utilities, transitioned to a cost recovery mechanism called "RIIO" (Revenue = Incentives + Innovation + Outputs). RIIO aims to incent safety, reliability, carbon emission reductions, and especially customer satisfaction. One of RIIO's primary metrics is "customer satisfaction with network operators," a value out of 10 collected via a Customer Satisfaction Survey,[19] which asks customers questions such as if they experienced an outage, if the outage was swiftly handled and communicated, or they successfully connected to the grid, if applicable. The industry

17 The UK's water industry also adds a K factor for capital additions.

18 Ofgem, "Regulating Energy Networks for the Future: RPI-X@20, History of Energy Network Regulation," February 27, 2009.

19 Ofgem, "RIIO-ED1 Annual Report 2017-2018," March 8, 2019.

average score is 8.7 out of 10.[20] Utilities are also scored by Ofgem based on the number of complaints received and the degree to which they engaged with their stakeholders. The maximum reward or penalty for customer satisfaction is +/- 1.5% of annual base revenue- in 2017-2018, electricity distribution utilities received a net reward of £49.2 million.

The RIIO regulatory process allows for more reciprocity between Ofgem and transmission and distribution utilities. The utility actively assists Ofgem in setting its own performance targets by submitting a unique business plan, rather than crafting a business plan in response to a regulatory command.

RIIO terms are eight years in duration, allowing for long-term investments. Ofgem first sets a fixed revenue requirement in real dollars, or “total expenditure” (“totex”) that dictates the amount utilities may collect over the eight-year period. Totex is the sum of capital expenditures (“capex”) and operating expenditures (opex) in a pre-determined ratio. Capex and opex have separate rates of returns. Utilities maximize the rates by adhering to Ofgem’s preferred ratio of capex-opex.[21] Utilities are able to recover both capex and opex, rather than “passing through” opex benefits straight to customers without realizing them as a company. For electricity distribution entities, RIIO totex is £27.8 billion. Collectively, utilities are projected to underspend by £1,293 million (5%) by 2023; four utilities are projected to slightly exceed their revenue requirements.[22]

While RIIO retains adjustments for inflation, it is more directly performance-based than RPI - X. Utilities receive pre-set budgetary and performance targets. There are six types of performance targets: reliability, environmental impact, distribution-level connections, customer service, social obligations, and safety minima. A financial penalty is imposed if projects exceed their budgets or performance targets are not met, while utilities may keep excess revenue from projects completed under budget. The RIIO model also contains uncertainty adjustment mechanisms for unpredictable events, similar to Alberta’s Z factor. Ofgem publicizes and ranks results annually, forcing transparency and fostering productive competition amongst the utilities.

Finally, to encourage low-carbon technology buildout, two government programs offer both allowances and competition for pilot programs. The Network Innovation Allowance (“NIA”) is an annually guaranteed fund for small-scale projects such as electric vehicle charging networks, behind-the-meter battery storage, and smart meter deployment. In 2017-18, utilities registered 197 NIA projects worth £21.9m, 83% of the annual NIA allowances. The Network Innovation Competition (“NIC”) allows utilities to compete for large-scale demonstration project funds.[23] These programs allow utilities to take risks and invest in cutting-edge projects without fear of under-recovery. They also allow utilities to address their own regional needs rather than deploy a “best” technology dictated by Ofgem. Pilot program results are shared on

20 www.ofgem.gov.uk/data-portal/all-charts?search_api_views_fulltext=satisfaction

21 Steve McMahon, “Innovation and Network Price Controls: The RIIO experience,” May 2018.

22 Ofgem, “RIIO-ED1 Annual Report 2017-2018,” March 8, 2019.

23 Ofgem, “Factsheet 93: RIIO - A New Way to Regulate Energy Networks,” October 4, 2010.

a publicly accessible web portal so utilities may share information amongst themselves.[24] Ofgem remains involved throughout the NIA and NIC process. Ofgem awards grants, solicits progress reports, and decides whether to recover future costs from a utility initiative after its pilot is proven to yield financial benefits. For example, Northern Gas Networks won £8.9m in NIC funding for "demonstrat[ing] that it is safe to transport 100% hydrogen in gas distribution networks."[25] Now that the pilot is nearly complete, and the technology is demonstrably safe, Northern Gas Networks has included a gas-to-hydrogen conversion trial for 300 network customers in its latest business plan.[26] The goal of hydrogen conversion is to achieve 100% carbon-free gas networks.[27]

RIIO's second iteration, RIIO-2, will span 2021-2026 for gas distribution entities and electricity and gas transmission networks, and 2023-2028 for electricity distribution entities. Ofgem has four stated goals for RIIO-2:[28]

1. Allow consumers to dictate performance priorities;
2. Grant fair returns to utilities that properly incorporate risk and market conditions;
3. Increase efficiency incentives; and
4. Simplify price controls such that only the strongest consumer priorities are incented.

Utilities were required to submit their RIIO-2 business plans by December 2019. Amidst an increasingly decentralized energy landscape and a UK-wide net zero emissions target by 2050, Ofgem seeks business plan submissions that incorporate smart meter rollout, distributed PV solar penetration, and behind-the-meter battery storage and electric vehicle charging specific to each utility's service territory. For example, National Grid's plans for electricity transmission detail a stakeholder-recommended course of action to abate harmonic distortions. When distributed energy resources ("DERs") and offshore wind connect to the grid at uneven frequencies, customer equipment became damaged. National Grid proposed to individually respond to customer DER connection applications and build harmonic filters without third-party developer assistance, allowing for potential aggregation of harmonic filters for multiple utility-owned projects without stranding risk.[29]

Ofgem has never required specific deployment targets for these potentially disruptive distribution-level technologies. These technologies have mostly been deployed through NIA- and NIC-funded pilots. However, the planning process for electric distribution entities is still in the early stages. As consumer stakeholder working groups meet to set priorities for the 2023-2028 electric distribution RIIO-2 term, more specific targets may emerge.

24 www.smarternetworks.org/

25 Ofgem, "Network Innovation Competition 2017 Funding Decisions," November 30, 2017.

26 Northern Gas Networks, "A14-NGN RIIO-2: Our Whole Systems Strategy," December 2019.

27 Ofgem, "Network Innovation Competition 2017 Funding Decisions," November 30, 2017.

28 Ofgem, "RIIO-2 Framework Decision," 2018.

29 National Grid, "National Grid Electricity Transmission's Business Plan 2021–26," December 2019, pg. 60.

For example, Ofgem found that consumers primarily seek safe, resilient, and environmentally sustainable networks. Therefore, to satisfy the request for sustainability, electricity and gas transmission and gas distribution entities will need to meet performance targets for natural gas venting and leakage, SF_6 emission, and other environmental actions.[30]

The updated price control framework for electricity distribution networks will reflect key strategic issues to meet the main consumer priorities. Returning to the decarbonization example, Ofgem admits that performance targets will be difficult to attribute to any one utility. The price control mechanism to incent decarbonization must walk a fine line between innovation and imprudently saddling the consumer with high costs of new services and infrastructure. Similarly, resilience will be in part measured by a metric called the Network Asset Risk Metric (“NARM”) to avoid stranded costs. Instead of measuring the remaining risks in a utility’s asset portfolio, NARM will measure the reduction of risks achieved during the RIIO-2 term. NARM will also estimate present value of future benefits to further reduce expected risk. In contrast, the RIIO-1 NARM did not accurately portray true market risk, as it only measured risk reduction in one-year increments.

Future and ongoing working groups will allocate responsibilities between utilities and other entities such as the government.[31] For instance, National Grid hopes to coordinate with policymakers to share funding and infrastructure for an electric vehicle charging network in which 95% of drivers in England and Wales are located within 50 miles of a fast-charging station. National Grid estimates that 90% of necessary transmission connections can be supplied from existing substations, but to meet the 50-mile radius benchmark, outside support and investment is crucial.[32]

Price control simplification and consumer priority-setting represents a shift in Ofgem’s regulation style. The consumers’ will and understanding of RIIO-2 takes precedence. Rather than letting “expertise” drive regulatory proceedings, Ofgem is betting that an active role in designing cost recovery structure will influence customer behaviors to meet their own stated goals for their utilities.

We note that Ofgem has also made an effort to involve customers in utility matters. Ofgem’s “Consumer First” program features 1) a standing panel of 100 customers, 2) a Consumer Challenge Group of expert consumer advocates who regularly meet with Ofgem, and 3) a Price Control Review Forum in which various stakeholders and industry insiders debate key issues. Ofgem also conducts extensive consumer research about willingness to pay in order to establish desirable price controls.[33]

30 Ofgem, “RIIO-2 Sector Specific Methodology,” May 24, 2019.

31 Ofgem, “RIIO-ED2 Framework Decision,” updated January 23, 2020.

32 National Grid, “National Grid Electricity Transmission’s Business Plan 2021–26,” December 2019, pg. 61.

Maxine Frerk, “Consumer Engagement in the RIIO Price Control Process: Review,” November 25, 2016, pg. 4.

3.5. Case Study: Australian Microgrid Initiatives

Australia has quickly begun development and investment into microgrids as a way to provide reliable supply to remote communities, mitigate bushfire risks, and reduce network costs.[34] Following the growing interest in these technologies, the national government set up a Regional and Remote Communities Reliability Fund ("RRCR") in 2019 to spend up to $50M on as many as 50 feasibility studies looking at microgrid technologies to replace, upgrade, or supplement off-grid and fringe-of grid communities. With this program, Australia hopes to demonstrate commercial viability of the technology, and its associated reliability and security benefits, to attract greater investment for microgrid implementation.[35] In addition to the RRCR, there is other government funding at the federal and state levels for microgrid development and implementation. These programs' aims range from improving competitiveness and deployment of renewable energy technologies[36] to demonstrating the market potential for third-party microgrids in managing customer usage.[37]

While the funding programs for new microgrid technologies across Australia are quite extensive, the regulations and governance of these stand-alone power systems ("SAPS") continue to evolve. The Australian Energy Market Commission's ("AEMC") Consumer Action Plan 2019 includes new rules and reviews to give consumers more choices about energy products and services, while providing them with more control over energy bills and stronger protections.[38] The AEMC has identified a three-tiered framework for regulating SAPS, by size:

- Category 3, including very small microgrids with a "handful of customers" and/or those supplying large customers and individual power systems where there is a sale of energy;
- Category 2, ranging from microgrids connecting more than a "handful of customers" to those supplying smaller towns; and
- Category 1, very large microgrids with such a high potential number of customers that there is likelihood of supporting effective competition in generation and retail.[39]

The AEMC reviews also distinguish SAPS provided by distribution network service providers ("DNSP") registered with the National Energy Market ("NEM"), and those by third-party providers.[40] Recommendations regarding the two types of service providers emphasize the need to maintain access to competitive retail, ensure customers provided by SAPS retain all

34 www.minister.industry.gov.au/ministers/taylor/media-releases/more-affordable-and-reliable-energy-regional-australia

35 www.energy.gov.au/government-priorities/energy-programs/regional-and-remote-communities-reliability-fund

36 arena.gov.au/

37 solar.ovida.com.au/victorian-micro-grid-trial ; www.energy.vic.gov.au/microgrids

38 www.aemc.gov.au/sites/default/files/2019-12/Consumer%20action%20plan_1.pdf

39 AEMC, "Final Report: Review of the Regulatory Frameworks for Stand-Alone Power Systems", Priority 2.

40 The National Energy Market, which operates in the eastern half of the country, is a wholesale electricity market and physical power system supplying 200 TWh to approximately 9 million customers annually. The Australian Energy Market Operator, somewhat similar to a North American ISO/RTO, manages the electricity and gas systems and markets across both NEM and the Wholesale Electricity Market (WEM) in the western part of the country.

existing consumer protections independent of the service provider, and receive the benefits of lower network costs in rates. Recommendations additionally include changes in the distribution annual planning report to identify items specific to SAPS, as well as the introduction of new customer engagement obligations on distribution businesses. Jurisdictions are encouraged to review the legislative instruments governing reliability standards and guaranteed service levels.

Currently, National Energy Law ("NEL") only applies to the interconnected electricity grid on the east coast of the country that underpins the NEM. Stand-alone systems not connected to the grid are subject to jurisdictional regulation by the states and local governments.[41] The AEMC has chosen to defer regulation of Category 2 and 3 SAPS to the states, reasoning that smaller SAPS would generally be expected to be vertically integrated without meaningful competition. Therefore, they would not need to be governed at the federal level. AEMC has encouraged each jurisdiction to develop and adjust its own regulations for these SAPS, emphasizing the need for consumer protections, in addition to safety and metering requirements. On the other hand, for Category 1 microgrids, the AEMC believes such size and competition warrants economic regulation in a similar manner to standard supply and is supporting legislation to this end.

The AEMC has prepared several reports on the topic of microgrid regulation. The first focuses on situations in which DNSPs may recognize potential "economic efficiency" gains in moving customers to a SAPS, as compared to providing electricity from the interconnected grid. Existing NEL and National Energy Retail Rules ("NERR") apply currently only to customers supplied by the grid. Maintaining similar customer rights, if moved to SAPS by providers, is a core requirement underlying the AEMC recommendations. The report also presents recommendations regarding support for transitioning customers to SAPS supply, customer engagement, and network planning, as well as service delivery models and classifications for the purpose of network regulation.

Similar to the Community Choice Aggregation transition model in much of North America, the AEMC recommended that DSNPs not be required to obtain explicit consent from customers before moving them to SAPS supply, while requiring that they "continue to benefit from equivalent price and reliability protections."[42] Though enabling transition without explicit consent, the AEMC recommended the implementation of new SAPS customer engagement obligations, including formal SAPS consultations and announcements by DNSPs. This recommendation, however, does not apply should the customers be transitioned to a third-party SAPS provider. Further, the report recommends that DNSP-led SAPS continue to be considered part of the DNSP network, and therefore granted all rights and protections provided to grid-connected customers. In the case of new connections or reconnections of customers likely to benefit from SAPS, as opposed to existing grid-connected customers, the AEMC recommended that such supply be competitively sourced rather than automatically provided by local DNSPs.

AEMC has also concluded that service delivery model for SAPS supply would be best supported by existing wholesale energy market arrangements, such as the AEMO settlement

41 AEMC, "Final Report: Review of the Regulatory Frameworks for Stand-Alone Power Systems," Priority 1.

42 AEMC, "Priority Report 1", pg. vviii.

system. However, instead of using a market spot price for energy delivery to SAPS customers, the AEMC recommended that retailers be charged an administered settlement price. This will enable grid competition and remove retailer risk of spot market volatility while protecting customers from any wholesale price signals inconsistent with minimizing cost of a SAPS. The report also addresses classification of the services provided by a DNSP SAPS supply model and how DNSPs will be allowed to fund these services. To do so, the AEMC identifies two components of the SAPS: the stand-alone distribution system, and the generating system(s) connected to provide the electricity.[43] DNSPs would be able to recover costs of the distribution systems through usual regulated revenues. However, the generation of electricity would not be subject to the same classification by the Australian Energy Regulator ("AER") and would require competitive generation procurement.

Another report focused on the implementation and regulation of the technology. In doing so, the AEMC developed Categories 1-3, outlined above, to determine under which jurisdictions each of the SAPS would be governed. Similar to those provided by DNSRs, a third-party Category 1 SAPS would be regulated by the AER, including revenue determination and incentive schemes. Retailers would have access to Category 1 SAPS customers in the same way as grid-connected customers and would be required to provide the same security, reliability, and price protections granted to traditional customers. The AEMC encouraged COAG Energy Council to enact similar standards as the NEL and NERR to such SAPS activities. For Category 2 and 3 customers, AEMC offered recommendations but did not direct them to the Energy Council. It believed states and local jurisdictions were better suited to determine access obligations, economic regulations, reliability targets, and network operations. Their recommendations often paralleled those made for a Category 1 SAPS, as applicable, but did mandate federal action.[44]

Stakeholder engagement on SAPS-related issues is ongoing.[45] To date, we note that there has been stakeholder input from the distribution service providers, as well as the Independent Pricing and Regulatory Tribunal ("IPART"). The IPART provided feedback on changes that may be required to ensure consumers safe and reliability electricity in light of the new supply models. Furthermore, AEMC, jointly with the AER, held a SAPS workshop on January 29, 2020, where 40 stakeholders from industry, government and market bodies discussed network planning, the settlement model, and the SAPS settlement price, as well as ring-fencing and the proposed regulatory framework for distributor-led SAPS.

Australia presents a unique opportunity for wide microgrid development, given its large number of customers currently off-grid or fringe-of-grid. As described in this case study, with an array of federal and local initiatives to drive investment and implementation of SAPS, Australia has determined that it is necessary for regulations to ensure customer protections, reliability standards, and pricing structures. In its 2019 reviews, the AEMC focused its key

43 AEMC "Priority Report 1", pg. x.

44 AEMC, "Priority Report 2".

45 www.aemc.gov.au/news-centre/media-releases/workshop-recap-what-stakeholders-said-about-distributor-led-stand-alone Stakeholder comments are welcome and requested by February 13, 2020.

amendment recommendations to the NEL and NERR, as well as its prompt to states to amend their local regulations, on:

- Requirements on customer engagement and participation, specific to incumbent distributor and third-party microgrids;
- Identifying under which jurisdiction various microgrids are regulated, by customer count and grid operator type;
- Supporting microgrids with the wholesale energy markets, adjusting settlement prices as deemed necessary;
- Classifying the various components of a microgrid for the purpose of cost recovery, either through regulated revenue or other mechanisms; and,
- Ensuring reliability, security, and consumer protections regardless of how they are supplied.

3.6. Case Study: Hawaiian Microgrid Initiatives

Hawaii, an archipelago of small islands, some with peak loads under 10 MW, is a prime location for microgrid development.[46] The state is also on the forefront of renewable energy implementation, as the remote locations and strong storms encourage innovative solutions for providing reliable electricity.[47] For example, Molokai, an island with a peak demand of 5.5 MW, is working with the Hawaii Natural Energy Institute to design a stable microgrid system using local renewable energy resources.[48] Relatedly, in partnership with Hawaiian Electric Company ("HECO"), the U.S. Navy has invested in a number of microgrid projects across various Hawaiian islands, with some phases complete and others ongoing.[49] These efforts support improved grid reliability, resiliency, and renewable penetration.

In response to growing interest in microgrids and other distributed energy resources in the state, Governor Ige signed Act 200 into law in July 2018, facilitating and formalizing the development and implementation of microgrids on the islands through establishment of a standard microgrid services tariff ("MST"). In the legislation, a "microgrid project" is defined as a group of interconnected loads and DERs within clearly defined electrical boundaries, which acts as a single controllable entity but can also connect to a utility's electrical grid to operate in a grid-connected mode.[50] In response, the state Public Utilities Commission ("PUC") has opened proceedings focusing on:

- Developing a microgrid services tariff to facilitate applications for microgrid applications that improve energy resiliency;

46 What exactly constitutes a microgrid is an issue before the Hawaii PUC.

47 www.utilitydive.com/news/hawaii-microgrid-bill-aims-to-keep-the-state-a-model-for-others/525926/

48 www.hnei.hawaii.edu/projects/molokai-secure-renewable-microgrid

49 www.energy.gov/eere/femp/spiders-jctd-smart-cyber-secure-microgrids; microgridknowledge.com/military-microgrids-pearl-harbor/

50 www.capitol.hawaii.gov/session2018/bills/GM1309_.pdf

- Addressing current limitations for multi-customer applications of microgrids due to current programs, interconnection rules, and lack of utility participation in enabling grid connection or transfers between microgrids;
- Developing compensation mechanisms for resiliency services through existing programs and tariffs; and
- Standardizing the definitions and governance of microgrids and their interconnections.[51]

To address these priorities, the PUC established two working groups. The first, the Market Facilitation Working Group, was tasked with recommending draft tariff language for the MST and proposing new programs to facilitate development, including addressing compensation for grid services, and utility distribution systems in the event of an outage. The second, the Interconnection Standards Working Group, was tasked with revising rules governing distributed generation technical requirements, which would standardize interconnection and islanding/reconnection processes for existing and new microgrids. A key issue in these microgrid regulations, to be addressed by the working group, is the ability and permission of the utility to require grid connection or islanding of the microgrid at times scheduled by the utility.

The working groups submitted a combined final report in February 2020. Of note, the Market Facilitation Working Group identified two types of microgrids within the scope of the MST: customer microgrids, which use non-utility infrastructure to meet its interconnected loads, and hybrid microgrids, which use both utility and non-utility infrastructure. Both types of microgrids are interconnected to the utility grid and have an isolation breaker for islanding. In this proposed tariff, customer microgrids themselves are utility customers, paying HECO for electricity used while offsetting costs with compensation for any electricity production from the local generator. Hybrid microgrid customers are direct customers of the utility and pay HECO for electricity with similar offsetting cost compensation as the customer microgrids. In the hybrid microgrid model, however, HECO additionally compensates and charges the hybrid microgrid operator for electricity produced and consumed, respectively. The report also suggested potential tariff compensation structures for resilience and service fees, through agreements between customers and the microgrid operator, as well as by HECO pursuant to future tariffs.[52] Illustrative examples of the two microgrid models defined in the report are showing in Exhibit 1, Exhibit 2, and Exhibit 3.[53]

51 Public Utilities Commission of Hawai'i, Order No. 36481, (1) Prioritizing Items for Resolution in this Docket and (2) Making Determinations on Issues Raised by the Preliminary Questions in Order No. 35884, Docket No. 2018-0163.

52 Per PUC advice, the MST did not address compensation for microgrids while grid-connected or for retail energy sales during normal conditions, as that is to be addressed in a separate docket regarding DERs. The report also considered utility microgrids, remote microgrids, mini-grid hybrid microgrids, virtual power plants, and hybrid microgrids above 3 MW out of the scope for this MST.

53 Graphics adapted for clarity based on exhibits in the February 14, 2020 Microgrid Services Tariff Working Group Report.

Exhibit 1: Hawaii concept for Simple Customer Microgrid

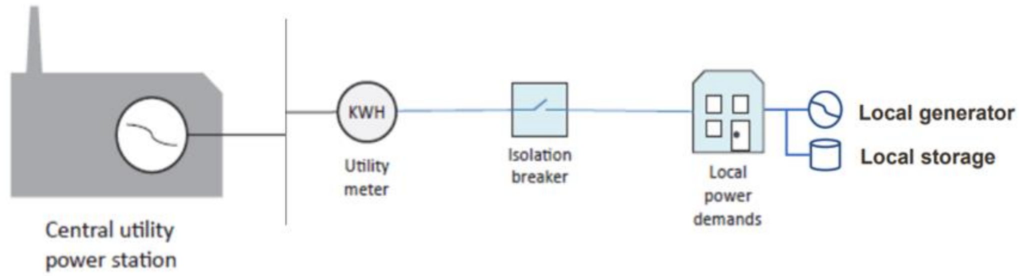


Exhibit 2: Hawaii Concept for Multiple Customer Microgrid

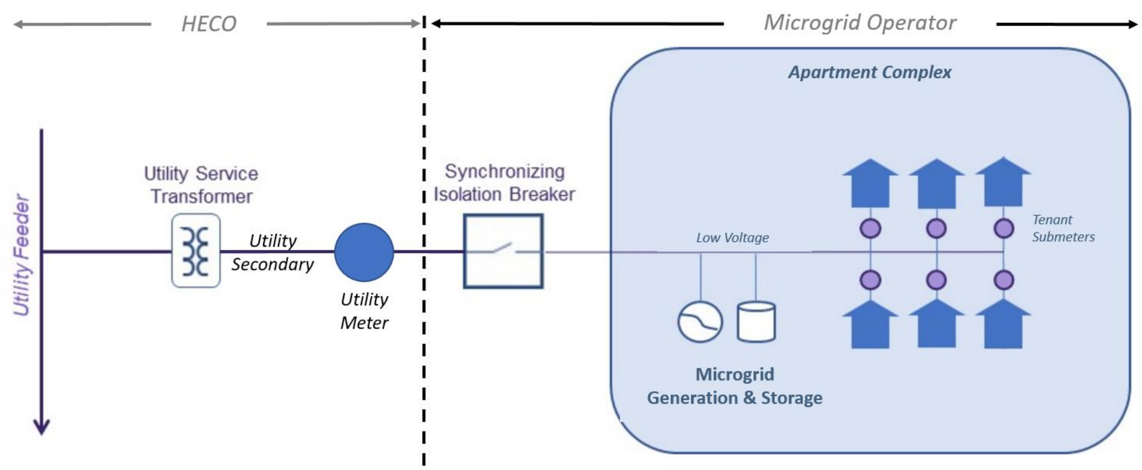
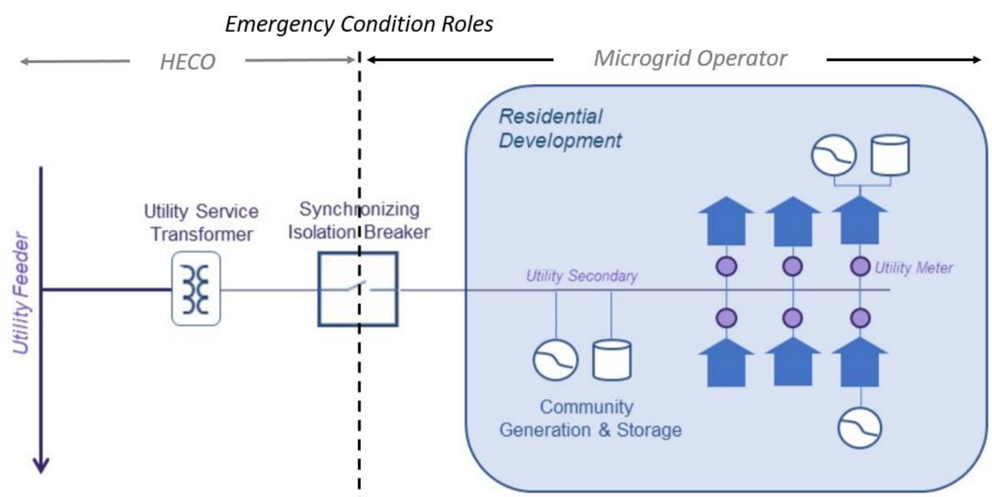


Exhibit 3: Hawaii Concept for Hybrid Microgrid



In the working group discussions, HECO proposed a hybrid microgrid tariff approach in an effort to avoid more complex issues such as retail wheeling and grid operational responsibilities in emergency conditions, as well as potential regulatory issues associated with the public utilities' participation in microgrid operations.[54] Currently, the public utilities do not allow microgrid or otherwise independent customers to transfer electricity between one another over the utility-owned transmission and distribution system. In the PUC proceedings thus far, HECO has pushed back on enabling these customers to circumvent grid charges. The proposed hybrid tariff attempts to mitigate these clashes.

The February 2020 report also included draft rules addressing a potential scheduled transition from grid-connected modes to island mode operations of a microgrid ("Island Mode"), and how it is initiated. As currently drafted, utilities may initiate Island Mode in response to abnormal conditions present on their system. The Microgrid Resources Coalition expressed its issue with such language, noting that the microgrid should not be subject to the discretion of utilities unless a service is compensated for in a contract. Given a main goal of the MST is grid resiliency, they question whether microgrids should be allowed to connect or disconnect from the grid at any time. The right to operate dispatch power needs to be addressed further in discussions.

From a stakeholder engagement standpoint, the Hawaiian microgrid initiatives have, to date, included involvement from a broad range of affected parties. A member of the Hawaii State Division of Consumer Advocacy volunteered to lead the working groups for this effort, and facilitated the meetings and development of deliverables. Many of the other working group participants were representatives of the state utilities. Other groups such as the Distributed Energy Resources Council, Renewable Energy Action Coalition of Hawaii, and Energy Freedom Coalition of America have intervened in the state PUC proceedings on the MST, which contributed to the formation of the working groups by the Commission.

Hawaii, like Australia, is a prime candidate for microgrid development. The state government is the source of the technology-specific directive to develop microgrids. However, while Australian microgrid development is largely driven by recommendations from AEMC reports, the Hawaiian PUC has given leeway to two working groups to consider the specifics of market structures and interconnection procedures. HECO, the islands' largest investor-owned utility, has proven to be a valuable member of the working groups. HECO has agreed to sacrifice some of its utility franchise, as customer microgrids are permitted to use their own infrastructure. HECO and the other stakeholders in the working group must now discuss compensation and expedited interconnection for hybrid microgrids, which use HECO's poles and wires. A key issue will be whether the working group members are able to strike a balance between fair compensation for reliability, a pressing concern on the islands, and adequate cost recovery for HECO.

3.7. Case Study Observations and Recommendations

We observe from these case studies that regulatory frameworks can differ, but they share many of the same regulatory principles we have identified as important. Differences between frameworks primarily appear in treatment of how incentives are treated for new technologies. Frameworks we reviewed continue to support the need for consumer protection, fair price setting for regulated service, and sufficient cost recovery for single-utility market providers in order for them to attract capital and maintain reliable service.

54 Microgrid Services Tariff Working Groups, "Status Update," January 9, 2020.

Relative to the current Alberta framework, UK governmental bodies appears to take a more active role in technology development and piloting, whereas it appears Alberta permits utilities to be the main decision-maker as to what technology to purchase and for what purpose. The Albertan regulatory approach is technology-agnostic which we believe best supports what would develop in an open market environment. That said, this disparity in treatments highlights the fact that additional regulatory scrutiny as well as reward for sound and innovative investment decision making may be warranted for Alberta. Since utilities are in role of decision-makers and risk takers, the framework should reward accordingly while protecting consumers from unsound investment – a delicate balance to strike. In addition, Ofgem's stated goals for RIIO-2 appear to be particularly well suited to support decisions for new technologies since they emphasize the importance of consumer needs, fair returns for sound risk taking for utilities, and emphasis on incentives that are closely tied to consumer trends. We believe these goals are also appropriate for Alberta to consider.

The Australia case study shows that even a technology choice such as a microgrid, which in some cases can almost entirely replace the need for T&D investment, can still be adequately addressed within existing regulatory frameworks. The case study reminds us that technology capabilities and deployment can happen at a faster pace than regulatory framework changes can fully accommodate. As is the case with UK, the Australian government is taking an active role in responding to consumer wishes and supporting testing and development of microgrid rollout as opposed to permitting utilities to take the primary decision-making role. Yet, AEMC's plan for consumer protection continue to acknowledge the importance of providing more options for choice for consumers while ensuring regulated rates for delivery service where needed, continue to be fair and reasonable.

The Hawaii case study highlights a policy approach in which the state government, through enactment of enabling legislation, drives a specific set of outcomes to support a specific technology (microgrids). As we have explained throughout this report, we believe there is a role for specific policy direction to support an outcome for a technology adoption choice that may be different in terms of technology or timing of adoption as compared to what open markets would deliver. The Hawaii approach also includes working group studies and pilot programs to carefully monitor results and to avoid unintended consequences. We believe this approach is also in alignment with fundamental regulatory principles. The legislative action in Hawaii is also an example where government instead of the utility or regulatory sector was the prime influencer for a specific policy direction for technology.

Throughout the cases, there exists a theme of customer protections, fair pricing, and cost-based regulated revenue streams for delivery business. Regulatory frameworks are versatile and can be adapted to emphasize and de-emphasize goals within the overall balance of recognizing obligation to serve, maintaining fair pricing, and the importance of cost recovery for single-provider distribution systems. We also observe a consistent recognition of the importance of stakeholder involvement, including utilities, regulators, advocates, and customer interests. Facilitating stakeholder involvement ensures diverse perspectives are represented and consumer protection concerns are represented.

We note there are further regulatory issues should microgrids be allowed and ultimately developed. Microgrids raise concerns over loss of traditional utility franchise and stranded network costs. If legacy network costs cannot be recovered from customers defecting to microgrids, those costs must be recovered from remaining customers (or go unrecovered). Those customers may then be more likely to develop their own microgrids, leading to what is referred to as the utility death spiral. There are available approaches to avoid this undesirable outcome and adhere to principles of cost causation and cost recovery. One measure is to introduce standby rates as a condition of allowing, and regulating, microgrids. These standby rates allow for recovery of fixed transmission and distribution investment. Such rates reflect the fact that the incumbent franchise utility is expected to back up the microgrid, and that the investments and maintenance to provide that service are not avoided. Also, for certain large facilities, regulators should consider a stranded cost recovery charge so that remaining customers do not absorb the costs of stranded assets.

3.8. Network Planning Considerations for Future DFO

An important element of economic regulation of electric utilities, including distribution utilities, is how network planning is conducted and overseen, and how proposed utility development is reviewed. In the era of centralized generation, distribution system planning was an exercise in preparing to serve a one-way supply of dispatchable generation to a set number of consumers with relatively predictable and ever-increasing consumption patterns. Now, DCG consumers may return excess electricity to the grid, all customers may have consumption metered more precisely, and sophisticated ratepayers may switch retail suppliers and control behavior in response to price or reliability events. Furthermore, expectations for consistent load growth are no longer the norm. There is also the potential to deploy declining cost technologies (e.g., battery storage) and to monitor and respond to grid conditions more precisely. In the face of new technological capabilities, including expanded DERs and vastly improved communications and information technology capabilities for system planning, it may be appropriate to revisit distribution planning and oversight. Here, we focus on two ways in which network planning may evolve: mandated consideration of non-wires alternatives and increased stakeholder participation.

3.8.1. Non-Wires Alternatives in Network Development

Under the traditional system planning paradigm, the interconnection of additional, uncontrolled load, or new generation, would generally be met by conventional “poles and wires” type network upgrades and associated costs. This need no longer be the case. With proper planning and control technologies, DERs and other non-wires technologies have the capability to add value to the distribution system and limit the need for and cost of upgrades. Such technologies may contribute via capabilities in flexible dispatch, voltage support, frequency regulation, and provision of reserves. Thus, if possible, an effective distribution planning process should 1) identify future system needs and opportunities, 2) evaluate all potential options for meeting them, and 3) determine the most valuable/least cost/least risk solutions.[55] Key to this sequence is the evaluation of options for meeting needs, and ensuring that the utility planners consider the full range of options, including both wires and non-wires solutions.

55 Carl Linville, “Distribution Planning: Why It Is Changing and What It Is Becoming,” Regulatory Assistance Project, January 28, 2020.

By way of example, we provide cases in which United States jurisdictions seek to ensure consideration of non-wires alternatives (“NWA”) as a means of exercising regulatory oversight towards ensuring that least cost options are achieved via network planning processes.

- At a federal level, in Order No. 1000, the U.S. Federal Energy Regulatory Commission (“FERC”) required regional planners “[w]hen evaluating the merits of such alternative transmission solutions, public utility transmission providers…must consider proposed non-transmission alternatives on a comparable basis.”[56] Furthermore, if selected as the efficient, cost-effective solution, the NWA planning solution would be subject to regulated recovery via regional cost allocation rules.
- In New York, the government has issued an NWA directive. Governor Andrew Cuomo’s flagship Reforming the Energy Vision (“REV”) initiative seeks to “defer or avoid conventional infrastructure investments by procuring distributed energy resources…that lower costs and emissions while maintaining or improving system reliability.”[57] The REV web portal allows developers to apply for an NWA procurement in each of New York’s six investor-owned utility territories.
- State regulators in Hawaii criticized HECO’s two-year forward grid planning document, the 2019 Integrated Grid Plan (“IGP”), for lack of NWA. For example, generation resources on the Hawai’ian island of Oahu are concentrated on the island’s western side and are flanked by mountain ranges. The IGP proposed a new substation to serve housing developments in eastern Oahu instead of “proactively working with distributed generation developers to make sure those communities are resilient and backed up.”[58]
- New Hampshire utility Eversource has proposed NWA to provide reliability and avoid distribution upgrades for the town of Westmoreland, New Hampshire. The Westmoreland Clean Innovation Project, if approved, will feature a 1.7 MW / 7.1 MWh lithium-ion battery plant. Of note, the plant will cost $7 million, while a distribution circuit upgrade would have only cost $6 million. Eversource estimates additional $2 million in long-term savings because of the battery plant’s additional ability to shave peak load.[59]

In the Canadian context, the Ontarian Independent Electricity System Operator (“IESO”) launched a small-scale electricity market pilot in York, a region with whose electricity demand is expected to outstrip its system capability within a decade. IESO intends to connect solar panels, energy storage, and other DERs to the local distribution network to reduce the need for expansion of provincial transmission capacity. These resources, once excluded from the market, will be able to compete to supply power during periods of high demand.[60]

56 FERC Order No. 1000, para. 148.

57 nyrevconnect.com/non-wires-alternatives/

58 www.utilitydive.com/news/hawaii-regulators-question-lack-of-non-wires-alternatives-in-hecos-integra/560470/

59 www.utilitydive.com/news/eversource-turns-to-non-wires-solution-in-outage-plagued-new-hampshire-town/555370/

60 www.ieso.ca/Corporate-IESO/Media/News-Releases/2019/08/IESO-Demonstration-Project-to-Test-Ontarios-First-Local-Electricity-Market

3.8.2. Stakeholder Participation in Planning Processes

In developing network plans, either at the transmission or distribution level, concerns arise if there is an insufficient amount of transparency and openness in the process. This is true both from the regulatory standpoint, as regulators should be made aware of the reasoning underlying proposed development plans, but also for other stakeholders, who may provide valuable insight and need to understand the rationale and fairness of planning processes. Transparency and openness also serve to limit the burdens of after-the-fact disputes.

In Decision 22942-D02-2019 the Commission expressed certain concerns respecting the AESO's oversight of distribution driven transmission facilities:

> *"The Commission also determined in Decision 2010-606 that although the AESO could delegate the determination of facilities in excess of GEIP to TFOs, the AESO should retain final oversight of GEIP and should review and approve any determination prepared under the delegation. As well, the Commission expected the AESO to develop distribution point of delivery interconnection process guidelines to support the determination of GEIP. However, in its response to AESO-AUC-2018NOV01-019(a), the AESO indicated that it did not carry out any work to establish distribution point of delivery process guidelines following the issuance of Decision 2010-606."*[61]

In the United States, FERC has addressed these issues in several landmark orders related to transmission planning. In 2007, FERC issued Order No. 890, which required all public utility transmission providers (both ISO/RTO transmission planners as well as non-market utilities) to adhere to a number of transmission planning principles: including coordination (e.g., hosting of meetings related to planning processes), openness (e.g., broad access to planning meetings), and transparency (e.g. sharing of methodology, criteria, and process). At the time, FERC reasoned that transmission planning was conducted with limited or no input from customers or other stakeholders, with no sharing of key assumptions or underlying data. FERC reasoned:

> *"…this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no means to determine whether the plan developed by the transmission provider in isolation is unduly discriminatory. This means that disputes over access and discrimination occur primarily after-the-fact because there is insufficient coordination and transparency between transmission providers and their customers for purposes of planning."*[62]

FERC expanded on the objectives of Order No. 890 with Order No. 1000, issued in 2010. Order No. 1000 required additional reforms to ensure that jurisdictional transmission service was provided at just and reasonable rates and in a manner that is not unduly discriminatory. As a key part of the required reforms, Order No. 1000 eliminated the right of first refusal of existing transmission providers to build all project resulting from regional transmission planning processes. As part of this change, the order continued and expanded the ability for third-party developers to submit alternative solutions in the transmission planning process. FERC required:

61 AUC, "Decision 22942-D02-2019," September 22, 2019, para. 1136.

62 FERC Order No. 890, para. 425.

> *"To ensure comparable treatment of all resources, the Commission has required public utility transmission providers to include in their OATTs language that identifies how they will evaluate and select among competing solutions and resources. This includes the identification of the criteria by which the public utility transmission provider will evaluate the relative economics and effectiveness of performance for each alternative offered for consideration."*[63]

From U.S. federal precedent, it is clear that FERC has identified stakeholder participation as a valuable element of network planning processes. The benefits of such participation accrue in terms of ensuring no undue discrimination, supporting the acceptability of the ultimate rate, and accounting for a range of possible alternative planning solutions, even if they originate through the stakeholder process. We recommend that Alberta consider this style of reform, particularly as electricity networks engage stakeholders in new way and a wider range of technologies become available to serve future needs.

63 FERC Order No. 1000, para. 315.

4. Rate Design

In this section, we introduce and discuss issues associated with distribution tariff rate design. Here, we focus on the value of proper price signals to consumers, which in turn will drive utilities to adapt, including providing appropriate services and facilitating adoption of new technologies. These signals are, in effect, what are communicated to end consumers through rates that recover allocated revenue requirements from customer classes. We first present general principles for distribution tariff rate design. We then discuss the application of those principles and whether current Alberta DFO tariff structures are consistent with the principles presented. Where they are not, we discuss what the ramifications might be, and what changes we might recommend to best align consumer price signals as the Alberta distribution system evolves.

Consistent with the regulatory principles we set forth in Section 3 associated with regulatory frameworks, particularly "opportunities for cost recovery," we work from the assumption that distribution tariff rates must generally be structured to recover the total distribution utility revenue requirement. The costs to provide distribution services are mainly fixed costs related to providing the necessary level of delivery capacity, with limited dependence on system throughput. Variable costs are primarily related to inconstant operating & maintenance ("O&M"). [64] Since rates must be designed to recover total embedded system costs, a dollar that is not collected through one customer or billing component must be recovered from another customer or billing component.

To ensure consistency and clarity, we will use the same syntax as is used elsewhere in this proceeding and in other proceedings before the AUC. In terms of customer bill components, we will focus on distribution-specific changes – though we will reference transmission or energy charges where appropriate – which include the following:

- **Fixed charges ($/period)**: A flat rate billed to a customer per billing period
- **Demand charges ($/kW)**: A rate based on a measure of peak customer consumption, typically based on contract demand, the maximum metered demand during a billing period, and/or maximum (or percentage of maximum) demand over a longer measurement period.
- **Variable charges ($/kWh):** A consumption-based rate billed on a per kWh basis

A tariff structure that includes all of the above billing components is referred to as a "three-part rate." As distribution infrastructure costs are largely fixed and have only relatively small variable costs to operate, a cost reflective three-part rate for distribution may have comparatively larger weighting of demand charges relative to variable charges.

We will also discuss several broad approaches to metering. As we refer to these approaches, we will assume the following definitions apply:

- **Net metering:** A practice in which the energy supplied to the grid is netted against, or subtracted from, the energy drawn from the grid. In effect, a single meter may be run

64 To the extent that tariff rates include energy charges and attempt to recover the cost of generation, variable charges may also include the cost of fuel.

forwards or backwards, should a customer be a net producer at any given time, and the customer is billed (or credited) for the billing period based only on the net electricity imported from the grid as measured by the meter. There is no distinction between the “buy” rate design and the “sell” rate design. Frequently, banking of injection credits is allowed across billing periods.

- **Net billing:** A metering practice in which a consumer has separate readings, but usually on the same meter, for periods of consumption from the grid and production to the grid. The customer’s bill is calculated based on all of the prevailing billing determinants for periods during which it is consuming from the grid, along with a credit, potentially set at a distinct “sell” rate, for periods when it is a net supplier to the grid. Thus, during periods when the customer is not a net supplier but is self-generating some portion of its demand, it is able to consume from on-site generation and reduce its billing volumes, and possibly reduce any peak charges. Generally, no banking is allowed across periods.
- **Buy all / Sell all (“BA/SA”)**: A practice in which there is no netting of billing permitted within the retail tariff. All consumption is metered with no adjustment for on-site generation, and that quantity is used to calculate a customer’s bill. Any and all generation is metered separately on a separate meter, the “sell” rate applies, and it is assumed to be “sold” to the grid. The consumer receives a credit for that sale at whatever the (pre-determined) rate is set to.[65] No generation is used to offset consumption billing determinants.

We recognize that the AUC has already gathered significant stakeholder input on issues of metering and rate design policy for distributed generation in the Alberta Electric Distribution System-Connected Generation Inquiry (Exhibit 22534, “DSG Inquiry”). Many of the same principles and considerations addressed in that inquiry are relevant here. We will reference the DSG inquiry as appropriate to limit duplication of material. Furthermore, as we did not participate in that Inquiry, we will note where we agree or disagree with positions taken in that proceeding.

4.1. Tariff Rate Design Principles

In regulating distribution utilities and designing distribution rates, there are a range of widely accepted principles that should be applied and balanced. Here, we focus on those signals experienced by customers. These build on principles put forth in section 3 of this report.

The crux of the following principles for distribution tariff rate design is that rates should be set to send price signals to permit consumers to accurately evaluate the demand they have for the unit of service being provided at the price offered, as compared to the value and benefit they actually receive. A principled distribution tariff rate:

- Encourages utility systems to invest to produce up to the point where consumer supply (units offered and price) and demand (units consumed) are in balance.

65 See, for example, www.nrel.gov/state-local-tribal/blog/posts/back-to-basics-unraveling-how-distributed-generation-is-compensated-and-why-its-important.html

- Avoids wasteful utility investment (excess capacity) and wasteful customer usage (units priced below marginal costs) because consumers will purchase up to levels they want at price offered, at least to the extent that customer demand is elastic.
- Facilitates consumer decisions as to how to allocate their purchasing power between utility services and other services or purchases.

Conversely, rate designs that meaningfully depart from these principles may lead to unfair, inefficient, and generally undesirable outcomes. These concerns are particularly acute in the context of the propagation of DERs, which have the potential to magnify shortcomings in existing rate design and lead to significant and unwarranted cost shifts as well as considerably inefficient short- and long-term outcomes. We present these concerns at a high level in the following section, and then in detail in section 4.3.

Cost Causation

Rate frameworks should allocate costs to consumers based on cost-causative factors to the extent possible. That is, to the degree that a particular consumer or set of consumers is responsible for imposing costs on the system (e.g., by driving the need for system upgrades), that set of consumers should be responsible for paying those costs. Cost causation supports both equity (fairness) and efficiency objectives, as aligning assignment of cost with imposition of cost on the system creates efficient incentives for consumers and protects against unwarranted costs shifts.

As applied to tariff rate design, cost causation is accounted for both in the division of cost recovery among customer classes and, more relevant here, how costs are allocated between fixed, demand, and variable charges. Fixed and demand charges should be designed to recover the largely-fixed costs of infrastructure investment and the overall capacity of the distribution system. Variable charges may then be incurred to recover the variable costs imposed on the system by use, like operation and maintenance expenditures. In the context of regulated distribution rates, it is therefore understandable that a principle-based distribution tariff design (not including energy or transmission) would be heavily weighted towards non-variable billing components given the high fixed cost and low variable cost nature of distribution infrastructure. [66]

As appropriate, the cost causation principle should be weighed against other non-cost considerations, as discussed more fully below.

Economic Efficiency

Regulatory frameworks, including tariff rate design, should set rates to that drive economically efficient outcomes. Distribution rates may affect economic efficiency both in how rates reflect the cost of infrastructure and how they impact energy generation and consumption. Proper rates will encourage economically efficient levels of consumption. Elements of economic efficiency that will be relevant for our following discussion include:

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66 The same logic applies in the case of transmission infrastructure. However, the fixed vs. variable distinction needs to be applied carefully, particularly in the context of generation. See, for example, www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf (pages 78-79).

- **Static efficiency** describes the level of efficiency of the system at a certain point in time. For electric power systems, this generally pertains to the efficiency of the system on an operational basis and has two key sub-components:
  - **Productive Efficiency**: Technically defined as being at the lowest point on the average cost curve. In the context of power markets, productive efficiency refers to whether the least cost set of resources are selected to serve load during any given operational period.
  - **Allocative Efficiency**: Whether the allocation of resources – the amount of energy consumed at any given time – reflects consumers' wants and needs. Put another way, whether the marginal price of energy (and the consumers' willingness to pay) equals the marginal cost of producing that unit of energy.[67]
- **Dynamic efficiency** describes whether the system is efficient across time and is most relevant here in the context of whether there are incentives in place that lead to appropriate levels of long-run investment to meet customer needs.

If implemented properly, distribution tariff rates may support all of these elements of economic efficiency, sending utilities signals to invest in facilities and produce up to the level of requested demand, while leading consumers purchase up to point where costs and value provided by electric service are in balance. Well-designed rates will limit the incidence of stranded costs and unneeded, wasteful investments in long-lived assets. Setting prices below marginal costs should be avoided since both these instances create wasteful use of resources that results in harmful consequences to consumers.[68]

Balance of Objectives

Cost Causation and Economic Efficiency are key goals in tariff rate design, but it is our view that they need be balanced with additional non-cost objectives. While they may entail some trade-offs that are difficult to quantify, these objectives support tariffs that are effective, practically implementable, and fair to a wide range of consumer types. These further objectives include:

- **Simplicity, ease of understanding, administration, and acceptability:** Customers should be able to understand the rates – and incentives – they face, and those rates should be publicly acceptable and feasible to apply.

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67 Bonbright elegantly states this as "the optimum-use or customer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received." (Bonbright, page 292)

68 There is a considerable literature around whether distribution rates should reflect the marginal cost of providing distribution services vs. the embedded cost of providing the service. Technically, rates based on marginal cost (not to be confused with variable rates) result in more economically efficient outcomes. However, they are likely if not certain to result in under-recovery on the part of the utility and are therefore difficult to reconcile with principles around cost recovery and capital attraction. We therefore generally assume that rate levels need to be set on an average cost basis for our purposes here. For a more fulsome discussion, see, for example, Lazar et al. "Electric Cost Allocation for a New Era: A Manual", Regulatory Assistance Project, January 2020, p. 189-195.

- **Clear of misinterpretation**: Relatedly, rates should be unambiguous and not subject to misinterpretation or controversy. This is of particular concern as the administration of distribution rates becomes more complicated with the increased prevalence of DERs.
- **Reasonably granular:** While recognizing constraints associated with precisely identifying cost causation and the value of avoiding overly-complex tariffs, rates should apportion costs among different customer types.
- **No undue discrimination**: Customers with like cost-to-serve characteristics should not be treated differently.[69]

Distribution regulatory frameworks will also generally include considerations for "ability to pay" and affordability. This concern is based on the fundamental nature of electric energy as an essential service in the modern world. A tariff rate based purely on cost causation and economic efficiency principles may result in an undue burden on certain consumer types, particularly low-income and more cost sensitive consumers. Regulatory frameworks should recognize these realities and, in a measured way, may design rates to provide concessions to certain types of consumers. Doing so should not violate principles around cost recovery and capital attraction; rather, cost shifting to other customer types may be advised.

4.2. General Considerations in Evolving Distribution Systems

4.2.1. Reconsidering Rates in Light of DERs

Particularly for residential customers, regulated distribution tariff rates have traditionally been designed to minimize fixed and demand charges and to mainly recover customer costs through the variable components of the billing structure.[70] This tended to accomplish several objectives, particularly encouraging conservation, increasing political palatability, and allowing opportunities for more cost-sensitive consumers (e.g., low income ratepayers) to reduce their bill by limiting consumption. However, two-part rates (i.e., rates without demand charges) ignore the fact that a customer's peak demand drives the level of fixed costs a utility must incur to meet delivery needs. Fixed costs cannot be reliability collected from a variable based rate component except in some limited circumstances. This problem is particularly acute when considering certain rate designs for DERs.

The trend of cost recovery via variable rates at the residential and small commercial rate tiers is evident from a review of current Albertan rates, shown in Exhibit 4. Historically, demand charges were not common for smaller customers, owing to the need for advanced metering capabilities that would allow the measurement of peak customer usage. Such metering infrastructure was limited to larger commercial and industrial customers. This need no longer be the case. For example, Fortis states that "FortisAlberta plans to exchange all current

69 James C. Bonbright, "The Role of Public Utility Rates," New York, Columbia University, first edition, 1961 p. 291.

70 To reiterate, we continue to focus here on the distribution component of customer bills, as distinguished from transmission rates, rates for energy commodity, and the several other riders that are faced by Alberta consumers. However, it is our understanding that many of these other components of the ultimate customer rate are also heavily weighted towards variable charges.

cumulative meters with new generation meters, capable of sub-hourly measurement, over the next ten years on a lifecycle replacement schedule." [71]

Exhibit 4: Current Residential Distribution Rates in Alberta

DFO / Rate	Customer Charge	Demand Charge	Variable Charge
ATCO D11 [72]	$0.9679 / day	n/a	6.86 cents / kwh
ENMAX D100 [73]	$0.5302 / day	n/a	1.08 cents / kwh
EPCOR DAS-R [74]	$0.6813 / day	n/a	0.99 cents / kwh
Fortis Rate 11 [75]	$0.8201 / day	n/a	2.31 cents / kwh

In the past, this two-part structure, while not ideal, was generally accepted for the provision of full requirements service (assuming we ignore intra-class cost shifts where two-part rates exist) since it generally was perceived to achieve a balance of cost and non-cost considerations.

Going forward, the proliferation of DERs is nearly certain to disrupt this balance. DERs will significantly shift consumption profiles – and behind-the-meter production – patterns in ways that are not well accommodated by traditionally accepted two-part rate structures with an emphasis on the variable charge. We offer two stylized examples of how a DER under a traditional rate might lead to outcomes that are inconsistent with our stated principles:

1. **Installation of rooftop solar**: A customer with PV is able to considerably reduce overall consumption of electricity, thus reducing their bill without changing their peak demand, which occurs in the evening. By cost causation logic, the customer contribution to DFO revenue should not change much. However, the traditional two-part rate will allow for "rate bypass," wherein the consumer may reduce their bill while still imposing nearly the same cost on the system. In turn, any costs avoided by the customer will need to be recovered from other customers.[76]
2. **Purchase of an EV**: A customer buys an EV and associated charging leads to an increase in overall energy demand. The customer chooses charges the vehicle outside

71 24116-X0522, "FortisAlberta Responses to AUC Preliminary IRs," February 7, 2020.

72 AUC, "Decision 24881-D01-2019: ATCO Electric 2020 PBR Annual Filing," December 16, 2019.

73 AUC, "Decision 24875-D01-2019: ENMAX Power Corporation Distribution Tariff," January 1, 2020.

74 EPCOR Distribution & Transmission, Inc., "DT Schedule 1: DAS Tariff," January 1, 2020.

75 AUC, "Decision 24876-D01-2019: FortisAlberta Inc. Rate Schedules," January 1, 2020.

76 This is frequently termed a "cost shift." DG advocates may argue that DG installations do not actually impose new costs upon the system, all things considered. However, owing to relatively fixed DFO regulatory requirements, there is still revenue that needs to be recovered. To the extent the burden of providing that revenue is shifted to other customers, some have suggested that this is better referred to as a "revenue shift." See, for example, "Rate Design for a DER Future," Advanced Energy Economy, January 22, 2018.

of peak hours. In this manner, the customer's payments for distribution service increase significantly with little, if any, increase in fixed distribution costs (the customer's increased energy load would mostly impact fuel and volumetric O&M.) Under a traditional, non-EV rate this customer may wind up paying more than their fair allocation (under cost causation logic) of the DFO's revenue requirement, especially in the near-term. Proper rate design can send signals to an EV owner to charge at times that, in aggregate, limit the need for system expansion to serve peak demand, thereby avoiding additional system costs imposed by EVs.

While more complex examples could be assembled, the conclusion remains the same: continuing under the traditional variable-rate-focused structure is likely to lead to outcomes that are inconsistent with a principled approach to rate design.[77] In the two examples above, we show one example where existing costs are bypassed, and another where there need to be appropriate signals in place to avoid imposition of additional expansion needs on the system.

The key responsive design change that we recommend, specifically for those residential and small commercial customers with on-site generation (including storage) and/or an EV, is a shift from rate structures that place an emphasis on variable rate components to rates that recover a larger portion of DFO costs through corresponding demand charges.[78] For example, the subset of residential and small commercial rate class customers with on-site generation and/or EV could be subject to rates that reflect 1) recovery of lost revenue arising from fixed and demand costs associated with on-site use, and 2) any additional demand costs associated with EV. Such rates may also be designed to provide time of use price signals. The resulting rates would better align price signals with actual costs, increase efficiency of price signals, increase uniformity of design across customer classes, and increase rate stability for utilities (and consumers) as DERs become more prevalent.[79]

Distribution tariff design for ongoing system use is not the only important price signal experienced by DER customers, and particularly those installing DCG. Consideration of ongoing tariff rate charges alone may have limited meaning, particularly in cases where investments have already been made. As pointed out by FortisAlberta, it is at least as important to consider the DFO's customer contribution policy at the time of connection when thinking about incentives for effective capital deployment.[80] We concur that customer contribution policy is key to "provision of an effective incentive for a customer (and DFO) to size the service capacity appropriately and deploy the associated capital occurs at the time of connection in response to the DFO's customer contribution (or investment) policy contained

77 Such outcomes under traditional structures can be generalized as likely to shift costs from customers with lower load factors (e.g., customer that has installed DG) to those with higher load factors (e.g., customer that operates an EV).

78 While we are focused here on distribution rates, we recommend the same change be made for transmission rates, as the same logic applies for applicable transmission fixed costs.

79 A more complete introduction to three-part rates can be found here: files.brattle.com/files/7137_curating_the_future_of_rate_design_for_residential_customers.pdf

80 24116-X0522, "FortisAlberta IR Responses," February 7, 2020, pg. 3-6.

within its Commission-approved tariff."[81] We generally agree, and would support policies that allow direct costs imposed by new DER resources to be experienced by the customers that cause those costs. This is supportive to both cost causality and dynamic efficiency goals.[82] However, we do not agree that design of monthly rates is not also important to capital deployment; a DER customer should be expected to make an investment decision in a DER capability based on *both* the up-front contribution cost and the expected ongoing costs or savings associated with the investment.

It is worth further distinguishing between incentives experienced by existing resources that represent already-deployed capital and prospective, and new resources (those discussed above). For existing resources, key decisions have already been made based on historically prevailing rate and cost allocation structures. We concur in part with Fortis that, once capital has been deployed, the rate structure may be "more about determining the appropriate means of cost recovery rather than providing any incentive(s) to deploy (or not deploy) capital."[83] We would add that rate design may also provide signals to promote desirable operational decisions. Thus, for these resources, the focus should be on fair allocation of system costs and incentives to act in a manner that facilitates economically efficient operation. This is largely achieved via ongoing incentives communicated via consumption rates, like demand and variable charges.

4.2.2. Managing Impacts of Rate Reform

Shifting emphasis in distribution rate design to three-part rates – for residential customers with DCG and/or EVs – is not without consequences. Limiting the amount of a customer bill that can be avoided reduces incentives for conservation, investments in energy efficiency, and deployment of DCG. We would argue that, strictly speaking, any reduced incentives would be consistent with a strict view of allocative economic efficiency.[84] We also recognize, though, that conservation, increased energy efficiency investments, and/or deployment of DG may be policy priorities of a given jurisdiction. Accordingly, a regulator acting in line with a policy priority may elect to limit the extent to which rates are shifted to truly reflect fixed vs. variable costs, but should do so understanding the incentives and distortions they are creating.

In addition to shifting going-forward incentives, adjustments to distribution rates to emphasize fixed and demand charges can affect customers who have made EE or DCG investments under the expectation of a certain rate structure. Particularly in the DCG case, changes in rate structure have the potential to reduce the benefit of such sunk investments, potentially prolonging or eliminating payback periods. This concern could be ameliorated by implementing gradual rate structure changes or grandfathering certain legacy rates to certain customers. Accommodations for grandfathering and transition periods should be balanced

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81 24116-X0522, "FortisAlberta IR Responses, February 7, 2020, pg. 5.

82 We discuss approaches to addressing these issue in a locational pricing context in section 4.4.

83 24116-X0522, "FortisAlberta IR Responses," February 7, 2020, pg. 4.

84 For example, variable distribution rates in excess of actual marginal cost of providing distribution service would incent energy conservation beyond levels that are efficient. Consumers would reduce energy demand in response to price signals that over-state the cost of providing the next unit of energy.

with the fact that such shifts may be warranted based on cost factors and principled rate design considerations.

The other frequent and understandable concern raised in the context of shifts away from variable rates is the impact on low use customers or those that are particularly cost sensitive. Shifts away from variable rate structures and towards rate structures focused on fixed or demand charges (that usually reflect cost imposed by the average user of a current class) make it harder to manage utility costs for low income ratepayers, as reducing consumption has a diminished effect on utility bills. Importantly, customers that do not have DCGs and/or EVs do not raise the same level concerns about rate bypass and the need for price signals that are better aligned with cost causation. For these reasons, we recommend that only the subset of residential and small commercial customers with on-site generation and/or EV be subject to the tariff reforms that we are suggesting here. This approach allows legacy rates to continue to be available to many residential and small commercial customers while also modernizing tariff structures in Alberta and improving cost accountability for customers with on-site generation and/or EVs, including those with storage installations.

4.2.3. Metering and Billing Approaches for Distributed Generation

When discussing distribution rates, it is unavoidable to discuss how DCG is metered and accounted for in bills, and therefore how they are compensated for services provided. As presented under heading 0 above, the primary suite of options includes net metering, net billing, and buy all / sell all (“BA/SA”). We recognize that the AUC has already gathered significant stakeholder input on issues of metering and rate design policy, particularly via the Alberta Electric Distribution System-Connected Generation Inquiry (“DSG Inquiry”, final report issued December 29, 2017). We further understand that a clear policy towards net billing has been stated under *Micro-generation Regulation*.[85] Thus, we will keep our comments here brief.

Based on our experience, the positions of the respective parties in the DSG Inquiry are consistent with what we would expect. DCG proponents are understandably supportive of net metering as a helpful mechanism for stimulating DCG growth.[86] On the other hand, the AUC’s final report in the proceeding succinctly lays out the arguments against net metering, presenting the DFO’s position as follows:

> *…net metering would result in DCG customers not paying for all of their share of the distribution costs that they are using. These DCG customers rely on the distribution system for the delivery of electrical energy when their DCG unit is unable to generate (for example, at night and when it is cloudy for solar DCG or when the wind is not blowing for wind DCG) and in doing so, experience the same levels of reliability enjoyed by all customers connected to the distribution system. If these DCG customers are only billed on the basis of net generation, non-DCG customers, who are often less affluent Albertans who cannot afford or have the opportunity to install DCG on their homes, are paying costs caused by the DCG customers.*[87]

85 AUC, “Alberta Electric Distribution System-Connected Generation Inquiry,” December 29, 2017, para. 221.

86 AUC, “Alberta Electric Distribution System-Connected Generation Inquiry,” December 29, 2017, para. 230.

87 AUC, “Alberta Electric Distribution System-Connected Generation Inquiry,” December 29, 2017, para. 228.

We generally agree regarding the cost shifts inherent in net metering.[88] We concur that the result is a rate structure that is inconsistent with principles, particularly cost causation and economic efficiency. Net metering threatens to allow customers who install DCG resources to avoid costs that are nonetheless incurred by the DFO to provide service on which they will rely; customers both rely on the distribution system when the DCGs are not generating, and also rely on the distribution system to facilitate export during periods when DCG production exceeds demand. Furthermore, by overstating the value of generation behind the meter, net metering threatens both static efficiency and dynamic efficiency. DCG may operate when it is inefficient to do so (for non-renewable DCG with meaningful operational costs, like fuel) and long-term investment decisions would then reflect artificially high perceived variable value of energy. [89]

We further agree that a net billing approach relieves some of the concerns raised by net metering and is therefore a reasonable approach. Net billing reduces the ability of DCG customers to bypass the cost of DFO and transmission service provided on their behalf. Furthermore, net billing limits, but does not eliminate, the ability of DCG customers to receive compensation for self-generation in excess of its value. If there are multiple variable components of a customer utility bill, the perceived value of energy generated, up to the point where the customer reaches a net grid injection, would be equal to the sum of all of the variable components. Should this include transmission, distribution, and other rider-type variable rate components, this is likely to significantly overstate the actual value of generation and lead to cost shifts.[90]

To relieve the remaining shortcomings of a net billing approach, the solution is implementation of three-part rates that better reflect and more closely track the split between fixed, demand, and variable charges on the basis of cost causation. As described throughout this report, this achieves several objectives. Establishing peak-based demand charges, that reflect the infrastructure costs to serve the consumer's peak load, can send effective and fair signals about the burden that the consumer is placing on the distribution system, and therefore should be responsible for. These costs should not be bypassable simply by reducing the total volume of energy consumed. Adjusting variable rates (downward) to reflect the limited proportion of distribution network costs that are actually a function of energy throughput is both cost reflective and eliminates the effective overstatement of value from DCG production.

88 These cost shifts and the inherent subsidy in net metering were also pointed out by Dr. Tabors in his Module One Evidence (24116-X0167, "CCA Evidence of Dr. Richard Tabors," July 17, 2019, para. 16)

89 It is noteworthy that AltaLink pointed out that the same considerations apply for net metering in the context of transmission charges, which seek to recover largely fixed cost assets primarily through variable rates. (DSG Inquiry Report at P 229) We agree with this point and add that transmission tariff rate structure, as reflected in customer bills, may warrant reforms that use the same logic as that applied for DFO rates.

90 This is only true to the extent that transmission and distribution rate design has not been modified to a cost-reflective three-part tariff rate.

Exhibit 5: Example of Impact of Illustrative Three-part Rate on Perceived Value of DCG Production and Cost Shifting under Net Billing (1000 kWh/month customer, 4 kW peak)[91]

	Actual on % Basis	Variable Focused Rate	Three-part Rate (inaccurate)	Three-Part Rate (accurate)
Retail Energy Rate		$0.07 / kWh	$0.07 / kWh	$0.07 / kWh
Customer Charge	5%	$5	$5	$5
Variable Charge	10%	$0.10 / kWh	$0.05 / kWh	$0.01 / kWh
Demand Charge	85%	$0	$12.5 / kW-mo	$22.5 /kW-mo
Perceived Value of DCG Energy or Load Reduction		$170 / MWh	$120 / MWh	$80 / MWh
Monthly DFO Charges (excl. energy)		$105	$105	$105
Results of addition of 1kw of DCG generation capability (adjusted peak = 3kW), 400 kWh total generation, no net generation to grid				
Monthly DFO Charges with DCG		$65.00	$72.50	$78.50
Embedded Costs to Serve[92]		$78.50	$78.50	$78.50
All Fixed Costs Recovered		No	No	Yes
Unintended Cost Shifting		Yes	Yes	No

Exhibit 5 illustrates two of these dynamics in a stylized example. First, by over-weighting distribution cost recovery into a variable rate, the cost signal received by the customer significantly overstates the value of reductions in consumption, or from behind-the-meter DCG production. Second, assuming a fixed cost to serve the customer (on a $ per kW basis),

91 This stylized example assumes away transmission rates and other riders (which would exacerbate the issues identified) and also assumes that the monthly annual cost/revenue responsibility of this customer is accurately $105 to the DFO. This example is also not designed to be representative of an Albertan customer or Albertan DFO rates. Rather, numbers are selected for ease of computation and illustration.

92 This is a generalization for the purposes of this example. There are nuances that are not captured here. For example, at significant penetrations of DCGs, the total number of billing units on a kW basis could decline, thus increasing the demand charge necessary to recover the embedded cost of service.

installation of a DCG asset is likely to lead to under-recovery of costs to serve the customer, and those costs are then likely to be shifted and recovered from other customers, leading to inequities.

Having discussed net metering and net billing, a third option is BA/SA, in which there is no need to manage netting of consumption or production. Rather, all consumption is metered and billed based on a gross basis, and all generation is metered and assumed to be sold at the prevailing sell rate, which may be fixed or variable. BA/SA requires a separate production meter to be associated with the generator (which may be a considerable expense). BA/SA has the benefit of being transparent and simple, potentially more so than a net billing approach, while minimizing cross-subsidization issues. Sell rate billing components associated with energy sales may also be adjusted outside of a rate case to reflect changing market conditions over time. BA/SA still requires assessment of the costs (or credits) associated with using the distribution system, and is still vulnerable to over- or under-stating the value of generation if these costs are not cost reflective. We could also support a BA/SA approach to metering, though most of the benefits can be achieved via a well-structured net billing approach, which is already the Alberta standard.

4.2.4. Overlaying Policy Decisions on Principled Rates

Distribution tariff design should achieve goals that are constrained to the principled regulation of distribution infrastructure and associated cost recovery, as we have described. Though rates may, by coincidence, be structured such that they have the consequence of promoting certain outcomes, we advise a more purposeful approach. For example, a policy of net metering is likely to promote development of distributed generation by overstating the value of that generation to the end user, thereby improving the economics of self-generation and DG installation. While such outcomes may be consistent with broader policy goals (e.g., deployment of rooftop PV solar, or clean energy generation more generally), they may also have unintended consequences, like also promoting behind-the-meter backup diesel generators. To the extent that end-use customer electricity rates are to be used as tools to achieve policy objectives, there are appropriate, targeted mechanisms available.

Separate mechanisms designed to promote certain policy outcomes can be more precise, more transparent, and less likely to produce unintended costs shifts. A common example is a feed-in-tariff (“FIT”), wherein a volumetric adder for certain distributed generation technologies is provided for every kWh generated or injected to the grid, depending on policy design and whether a net metering or BA/SA structure is in place. Such a policy has a range of advantages, including:

- The rate may be adjusted over time in response to policy decisions or other determinations, and such changes may be made outside a rate case;
- The incentive may be targeted at certain types of generation. For example, distributed clean energy technologies may be allowed to participate, while emitting technologies may be excluded;
- The particular incentive is transparent and not bundled in with broader rate design determinations;
- Costs may be allocated transparently and in a manner reflecting the benefits achieved by the policy. For example, policies to reduce emissions and improve environmental

quality may be allocated broadly to all ratepayers (via a surcharge) or even to taxpayers, if credits are funded outside of utility rates. This also avoids unintended costs shifts, like those inherent in a net metering approach.

FIT structures are not the only mechanisms available to drive certain outcomes, nor is clean energy development the only type of outcome that may be promoted. To support certain types of DERs, regulators and policymakers may consider mechanisms like direct financial incentives (rebates and tax credits), low-interest financing programs, and streamlined interconnection processes.[93] Certain types of utility initiatives (e.g., microgrids or EV charging network development) may be supported through funding of pilot programs, guaranteed cost recovery, or revenue decoupling. At a higher level, certain outcomes may be achieved through clean electricity standards or emissions pricing schemes.

4.3. Applicability to Current Structures

This section aims to apply our stated principles in the context of the DERs under consideration in the AUC's Distribution System Inquiry. We will assess where, in our view, principles are being applied properly, and where there is room for improvement. As a guide, we will reference the resource configurations laid out in the AUC's information requests of November 29, 2019. We will also provide examples from current, publicly-available Alberta DFO tariff sheets, though we will not attempt to critique every tariff schedule.

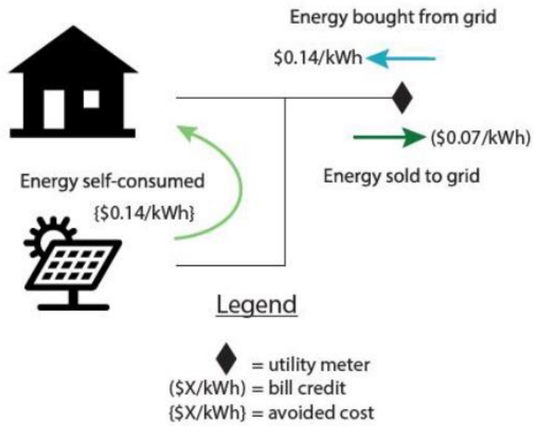
4.3.1. DCG Rates – Small Micro-generation

In its preliminary IRs to all parties, the AUC describes the rate treatment of a small micro-generation (<150 kW) subject to the *Micro-generation Regulation*. For small micro-generators, we understand that a net billing structure is in place and there must be, at least, separate registers for recording consumption from the grid and generation to the grid. There is no metering required for energy consumed on site, and there is no requirement for interval metering such that the timing of generation or consumption is a factor in billing. This metering arrangement is necessary and sufficient to facilitate a basic net billing approach. In the example provided, there is a symmetric credit available for any net generation equivalent to the energy charge. Generally, there are no customer-specific contributions required by the DCG customer to fund metering, settlement, or interconnection costs.[94]

93 www.usaid.gov/sites/default/files/documents/1865/68469.pdf

94 24116-X0470, "AUC Preliminary IRs to All Parties," November 29, 2019, pg. 4-6.

Exhibit 6: Excerpt from Figure 2 of AUC Preliminary IRs[95]



This example illustrates several of the issues we have raised with respect to rate design and associated principles. While we recognize that the scenario is fictional, it nonetheless shows how a rate that is made up primarily of variable charges can overstate the value of self-generated energy. The overstated value can negatively impact efficient system operation and investment in a number of ways:

- **Dynamic efficiency loss**: Offering value to micro-generators in excess of the marginal value they bring to the system will incentivize investment beyond efficient levels, and lead to an inefficient supply mix in the long-term.
- **Productive efficiency loss**: Many micro-generators may be renewable units, like rooftop PV, with zero operating cost. However, we are not aware that this is a constraint on qualifying as a micro-generator. Some customers could then install micro-generators, like a diesel backup generator. If the cost of operating the generator is $100/MWh, the actual value of self-generation is (for the sake of argument) $80/MWh, and the perceived value is $140/MWh, there would be the incentive to operate the generator at periods when the cost of doing so exceeds the actual value to the system and the prevailing energy price, thereby displacing more efficient generation.[96] This leads to productive efficiency loss.
- **Allocative efficiency loss**: While not directly related to the micro-generator, the overstatement of the value of reducing demand (along with self-generation) may lead to conservation efforts when the actual marginal cost of supply is not more than the marginal benefit of consumption. This issue is less acute at the residential level where consumers are less sophisticated and may exhibit less price elasticity, but it is a concern nonetheless.

Generally, all of these issues reinforce the importance of accurate price signals, like those provided by cost-reflective three-part rates. To transition to three-part rates would require a

95 24116-X0470, "AUC Preliminary IRs to All Parties," November 29, 2019, pg. 4.

96 To some extent, this is a function of smaller customers not being exposed to real-time market prices. However, the issue is exacerbated by a distribution tariff that overstates the variable cost of consumption.

rate study. The primary results would be that a meaningful fraction of variable charges would be repriced into a demand billing component.

When considering expanding and updating network service demand charges, it is important to carefully design how demand billing units are measured. Broadly speaking, demand charge may be measured based on customer demand at the system coincident peak (“CP”) or some other measure, usually a variation of non-coincident peak (“NCP”). Our observation is that applying demand charges based on system CP[97] is an arrangement susceptible to gaming; sophisticated customers (with the help of energy service providers) may be able to manage measurement of demand during CP. Furthermore, customer usage during system coincident peak may not coincide with the level of investment deployed with the DFO to support customer needs.[98] We recommend assessing peak demand on a NCP basis, or on a hybrid basis.[99] A hybrid can reflect the notion that networks are generally planned for high use periods, while also considering that specific network loading during those periods is unpredictable and gaming should be discouraged. A hybrid example would be if customer demand were measured based on the highest monthly demand between 4pm and 8pm on weekdays.

Another consideration is the particulars of the sell-rate for net generation. A buy-rate for a standard residential customer may reflect the weighted average of the cost to deliver energy across all hours of a period (though such structures can vary across competitive suppliers). A sell-rate, to provide more accurate price signals to generators, may be structured more granularly as rate structures evolve. For example, if the expectation is that most DCG customers will be installing solar generation, sell-rates could be calculated to reflect the historical or expected market price during daytime hours. Depending on metering available, like for large micro-generators, sell-rates could be made even more dynamic. Taking into account such factors in sell rate formulation has the potential to overcome some of the inefficiencies associated with DCGs, particularly given that they do not actively participate in the wholesale market and are not subject to the time-varying wholesale price. However, improving sell-rate formulation needs to be balanced against the distortions associated with asymmetric buy- and sell-rates, as described below.

As both buy- and sell-rates evolve, particularly if more temporal (or locational) precision may be introduced on both sides, there is value in eventually converging to a symmetric rate. The virtue in conveying symmetric signals between buying and selling also ties back to the need

97 The 12 CP method is presently used to allocate transmission bulk system costs to DTS customers and, DFO’s include bulk system costs as a component of distribution tariffs.

98 When a customer avoids usage on CP, embedded costs for facilities to serve CP must be recovered from remaining customers; over the longer term however, if the customer consistently is able to avoid causing demand on CP and does not in effect, simply shift CP to create another system peak at a different time, it is possible future system CP related investment may be deferred.

99 This is already practice in some Alberta customer rates. For example, for Small General Service (Rate 41) FortisAlberta defines demand for distribution capacity based on the greatest of: (1) the highest Metered kW Demand in the billing period; (2) 85% of the highest Metered Demand in the past 12 months including and ending with the billing period, less 50 kW; (3) the Contract Minimum Demand as specified by the Terms and Conditions; or (4) the Rate Minimum of 3 kW.

to accurately convey the cost of consumption, and value of production or curtailment, to consumers via tariff rates. Experts from MIT express this concept well:

> *"If these prices and charges are not symmetrical, incentives can be significantly distorted. For example, if exports of power are compensated at a lower rate than withdrawals or consumption of power at the same location and time, then a generator that is individually metered and exporting power will earn less than a behind-the-meter generator at the same location, despite having the exact same value to the power system. Similarly, a megawatt-hour of demand reduction behind the meter would see greater economic value than a megawatt-hour of injection from a generator at the same location. These kinds of distortions should be minimized in order to put all resources on a level playing field and avoid inefficient regulatory arbitrage opportunities."*[100]

More concerning than the current small micro-generation sell-rate itself is how the costs associated with those rates are recovered. As described by the AUC in its preliminary IRs, credits for the sell-rate for small DCG customers are set by each customer's energy service provider. Revenues from those rates are then flowed through to the Alberta Electric System Operator ("AESO"), which collects sufficient revenue to compensate the energy service providers via the transmission tariff. There is no regulatory review of these rates, the AESO has no influence over the agreed-to rate, and the energy service providers bear no risk for the agreed-to sale price. [101] Indeed, the energy service provider may benefit from selling electricity at an above-market rate during periods when micro-generators are not offering, while passing the cost of what is effectively an above-market incentive on to other (transmission) ratepayers. These outcomes are significantly concerning for a range of reasons, not least because there is insufficient oversight of a utility cost ultimately borne by customers, and potential exists for significant economic efficiency losses by offering above-market rates with no countervailing benefit to the system.

We note that there are limited provisions for passing metering, settlement, or interconnection costs to customers that install DCG. This may be an explicit policy choice to support micro-generation. This approach, however, may mask the true cost to consumers of installing DCG, threatening both the principles of cost causation and economic efficiency, while also potentially leading to cost shifting from those customers that install DCG to those who do not.

We also have concerns about the treatment of micro-generators – and DERs more generally – in the context of principles that support tariffs that are easy to understand and clear of misinterpretation. While the AUC's description of the treatment of micro-generators and other customer configurations is quite clear, we struggled to derive the same understanding from the various applicable DFO tariffs and regulations. There is no separate tariff for such resources, and we were unable to easily identify the net billing sell rate.[102] This should be remedied. We would suggest, at least, specific DCG tariffs for residential and commercial customers with DCG resources installed that clearly lay out the metering, billing, and settlement rules for such resources. As described above, we also recommend that the

100 Pérez-Arriaga and Knittel, "Utility of the Future Full Report," Massachusetts Institute of Technology, pg. 77, 2016.

101 24116-X0470, "AUC Preliminary IRs to All Parties," November 29, 2019, pg. 13.

102 This problem is evident to us due to the fact there were instances in which the descriptions in the IRs needed to be clarified by intervening DFOs.

development of such tariffs is done with a corresponding shift towards cost reflective three-part rates for those customers with onsite generation and/or EV.

All of the discussion in this sub-section, with the exception of issues related to the sell rate, applies equally if the DCG customer has installed generation solely for its own use, that is, the customer installs a DCG but never expects self-generated supply to exceed demand. This scenario is put forth by the AUC in question 5 of its IRs.

4.3.2. DCG Rates – Large Micro-generation

As described by the AUC, large micro-generation (greater than 150 kW and less than 5 MW) has both important similarities and differences with small micro-generation. The metering configuration is similar and net billing applies. The meters used for large micro-generators are interval meters, which facilitate the requirement that the net generation sell-rate to be tied to the prevailing wholesale market price on a dynamic basis. Customers with large micro-generators also tend to be in commercial or industrial rate classes, which in Alberta generally have three-part rate structures (or at least structures with demand charges).[103]

Exhibit 7: Current Example C&I Distribution Rates in Alberta

DER / Rate	Customer Charge	Demand Charge[104]	Variable Charge
ATCO D31 [105]	$0.4923 / day	28.39 cents / kW-day (first 500 kW) 18.72 cents / kW-day (over 500 kW)	n/a
ENMAX D300 [106]	$6.87 / day	4.66 cents / kVA-day	0.48 cents / kwh
EPCOR DAS-MC [107]	$0.95 / day	17.47 cents / kVA-day	0.51 cents / kwh
Fortis Rate 61 [108]	n/a	26.88 cents / kw-day (first tier)	n/a

The structure of DCG billing and rates appears generally consistent with our stated principles. Without performing any specific cost of service analysis, the prevailing three-part rates shown in Exhibit 7 are more consistent with what we would expect to see in a rate that appropriately differentiates between the fixed and variable costs of providing distribution service. Combined

103 24116-X0470, “AUC Preliminary IRs to All Parties,” November 29, 2019, pg. 8-11.

104 Measurement of peak demand, against which the demand charge is levied, is subject to variation by DFO.

105 AUC, “Decision 24881-D01-2019: ATCO Electric 2020 PBR Annual Filing,” December 16, 2019.

106 AUC, “Decision 24875-D01-2019: ENMAX Power Corporation Distribution Tariff,” January 1, 2020.

107 EPCOR Distribution & Transmission, Inc., “DT Schedule 1: DAS Tariff,” January 1, 2020.

108 AUC, “Decision 24876-D01-2019: FortisAlberta Inc. Rate Schedules,” January 1, 2020.

with the required approach to interval metering and time-varying sell rates, the overall incentives faced by large micro-generators are likely be more consistent with the principles of cost causality and economic efficiency. We would nonetheless reiterate our comments about the need to improve clarity in the tariff sheets around the treatment of DCGs in billing and settlement.

4.3.3. Other DCG Connections

Other DCG connections may include small scale generation and other DCG that are neither covered under *Micro Generation Regulation* nor the *Small Scale Generation Regulation*, and may also include DCG with associated load or without. This set of generators, with STS contracts and generation capability typically greater than 5 MW[109], is what we focus on in this section.[110]

The AUC describes a class of DCGs connected directly to the distribution system with no associated load, as shown in Exhibit 8. The purpose of these generators is chiefly to supply energy to the grid. They may be connected under either the *Electric Utilities Act* ("EUA") or *Small Scale Generation Regulation*. In the former case, costs of metering, meter data management, and interconnection are generally borne by the DFO. The exception is a case in which the generation unit exceeds typical interconnection costs, in which case a portion of costs will be borne by the DCG. If the DCG is subject to the *Small Scale Generation Regulation*, all such costs are borne by the owner of the DCG. All DCGs with no load sell through an interval meter and are settled at the Alberta pool price.

In responding to the AUC's IRs, the DFOs clarify that in both cases, costs of metering, meter data management, and interconnection are generally borne by the DCG owner.[111] It is also worth noting here that there is potential for confusion about rates introduced by the current arrangements given that it is not immediately clear to us in which case the EUA rules should apply and when the *Small Scale Generation Regulation* should apply.[112] Furthermore, Fortis

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109 Substation fraction means the share of a substation's capacity attributable to a market participant under Rate DTS or Rate STS, calculated by dividing the contract capacity of the individual system access service by the sum of all contract capacities of all system access services provided at the same substation under Rate DTS and Rate STS. Therefore, an STS contract is required for the substation fraction calculation. Whether a DCG is over or below 5 MW an STS contract may be required depending on the minimum loading levels at the substation as determined by the DFO.

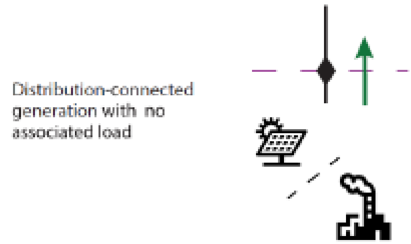
110 DCG eligible under the *Small Scale Generation Regulation* are suppliers of renewable energy with or without load, and we understand that regulatory treatment is tied to community benefits. DCGs under this regulation are required to exchange energy through the balancing pool and their nameplate capacity cannot exceed the hosting capacity of the distribution system at the interconnection point.

111 See, for example, 24116-X0529, "EDTI-AUC-2019NOV29-001-013," February 7, 2020, pg. 5 and 24116-X0522, "FortisAlberta IR Responses, February 7, 2020.

112 Based on discussions with our local expert, Raj Retnanandan, we understand that the Small Scale Generation Regulation is applicable to renewable or alternative energy provided to the AIES and the EUA applies to suppliers from sources other than renewable and alternative energy.

points out that, in practice, no maximum investment level ("MIL") charges for distributed generation interconnection costs are applied to DCGs.[113]

Exhibit 8: Excerpt from Figure 6 of AUC Preliminary IRs[114]



From an energy transaction standpoint, treatment of DCGs with no load is consistent with what we would expect would drive economically efficient outcomes. Direct settlement at levels tied to the pool price should send appropriate price signals to DCGs for operation and investment, and should avoid distortions caused by passing energy costs through a third party, like a DFO or retailer. Likewise, our view is that, based on the DFO's corrected interpretation of cost allocation for metering and interconnection costs, costs are appropriately borne by the cost causer.

The other major issue here, which is raised by the AUC in item 009 of its preliminary IRs, is the appropriate applicability of distribution and transmission network charges for DCGs with no load. We recognize that Alberta has already grappled with this issue in the context of transmission service in a proceeding that ended with AUC Decision 22942-D02-2019. The AUC found that energy export to the transmission system should be subject to the applicable generation access tariff, including payment for substation fraction. The specific arrangements eliminate totalization at the substation level, which effectively establishes an even playing field between distribution and transmission connected generators, at least as related to transmission charges.[115] This approach appears consistent with technological neutrality as well as elimination of potential for undue discrimination as a result of transmission service charges.

With respect to *distribution* network charges for DCGs with no load, the situation appears more problematic. As we understand it, the current situation in Alberta allows for transmission credits (or charges) within distribution tariffs for DCGs, based on the demand transmission service ("DTS") transmission tariff avoided by the distributor at the point of delivery. The DFO may still collect the DTS revenue from consumers as if the DCG was not in place and collect those costs in order to fund the DCG credits. The resulting circumstances are concerning for the following reasons, many of which have already been substantially acknowledged by the AUC, though we frame them in the language of this report and offer further observations:[116]

113 24116-X0522, "FortisAlberta IR Responses, February 7, 2020.

114 24116-X0470, "AUC Preliminary IRs to All Parties," November 29, 2019, pg. 14.

115 AUC, "Decision 22942-D02-2019," Section 7.3.

116 For example, AUC, "Decision 22942-D02-2019," September 22, 2019, para. 638-645.

- Allowing a credit to DCGs that is not available to transmission-connected generators constitutes *undue discrimination* by offering what amounts to a subsidy.[117] There is no meaningful economic or technical differentiation between distribution- and transmission-connected generators, except for what amounts to a coincidence of meter location. Both types of units rely on both distribution and transmission systems to deliver electricity to consumers and benefit from services the transmission system provides.[118] This undue discrimination also would lead to an implicit *technology preference* by offering an additional, unwarranted revenue stream to DCGs (with no load).[119]

- The result of establishing an uneven playing field for DCGs as compared to transmission-connected generation would be *inefficient long-term outcomes*. By providing an additional revenue stream to DCGs, we would expect a shift towards DCG development *ceteris paribus*. This shift would be inconsistent with a generation buildout with competitive and non-discriminatory price signals relying on competitive forces and would therefore likely be *economically inefficient*.

- Offering DTS credits to DCGs based on reduction in point of delivery ("POD") billing determinants effectively results in a cost shift from DCGs to consumers without justification. DCGs do nothing to reduce near term transmission revenue requirements; those amounts are based on already-deployed capital. Yet, allowing them to reduce POD determinants will lead to erosion of overall transmission billing determinants, which will eventually lead to increased transmission costs for all customers. In aggregate, customers also face duplicative charges, they pay for the credits for avoided DTS paid to DCGs, and then must provide additional funding to compensate for the billing determinant erosion. This result is *inequitable* and *inconsistent with cost causation*.

While the issue of how to implement the changes arising from Decision 22942 is currently being discussed, we suggest the following principle-based approach to addressing the charges and credits in question. That is, DCG customers who are required to enter into STS contracts should no longer receive any credits for reduction in DTS charges for the distributor. Such DCGs would pay for their use of the transmission system through the substation fraction charge. Since DCG customers with STS contracts would no longer contribute to reduction in POD charges, the premise of DTS credits and concerns would no longer be applicable. This should apply regardless of whether such DCGs are associated with load.[120] This approach ensures a level playing field between generation types, thus fulfilling objectives around technology agnosticism and avoidance of undue discrimination, while also eliminating concerns over billing determinant erosion and cost shifting. This approach should also be

117 Similar points are recognized by several respondents to the AUC's preliminary IRs. See, for example, 24116-X0517, "Capital Power Responses to AUC Information Requests," February 7, 2020; 24116-X0518, "AESO-AUC-2019NOV29-001 to 013," February 7, 2020.

118 AUC, "Decision 22942-D02-2019," September 22, 2019, para. 741.

119 We also understand that DCGs may avoid Generator Unit Operator Contribution ("GUOC") charges.

120 To the extent feasible, the same principles should be extended to DCG customers with production capability less than the minimum loading level at the substation in order to place all non-micro generation DCG on an equal footing.

applied uniformly across DFOs; this would ensure adherence to principles and increase certainty in the marketplace.[121]

Here, we also raise the issue of the changing nature of distribution grid usage (and charges), for customers with DCG. Traditionally, distribution systems (and many transmission systems) have been characterized by one-way electricity flow and clear differentiation between suppliers and consumers. With DCG, this clear distinction fades. DCG customers may be both consumers and producers and drive bi-directional flows on the distribution system. Resulting cost impacts on the distribution system may include:

- Dependence on the grid for backup, maintenance, or black start services;
- Initial network investments to accommodate power injected by DCG, including substation or switchboard replacement or upgrades;
- Changes in network O&M costs, including changing loss factors, and need for more sophisticated voltage control schemes and protective devices;
- New processes for long-term network planning.[122]

Thus, it may be appropriate to revise network charges to account for this shift, which could be done by implementing a separate rate for dual use customers (i.e., DCG customers). The resulting rate could reflect the nature of the DCG customer as a supplier. As suppliers, DCGs can impose demands on the grid, which may drive needs for upgrades. This should be recognized in rates. This could be achieved through a wholly separate rate category, or by calibration of the sell rate under a net billing or a BA/SA structure. Various approaches have been suggested for how such charges could be structured.[123] In the Albertan context, it would be important to ensure that DCG network use and upgrade charges are structured similarly to supply transmission service (“STS”) and other charges experienced by wholesale generators selling into the AESO market. This avoids undue discrimination and ensures a level playing field across generator types. To the extent wholesale generators are not currently responsible for the above noted non wires costs, the issue may need to be revisited in the context of STS rates.

4.3.4. Demand Side Management

Demand side management efforts, including energy efficiency and demand response, are not new. As Dr. Tabors described in his Module One testimony, consumer acceptance of such activities has been limited, owing to factors like the low overall cost of electricity, limits on supportive technology, and price inelasticity of demand (i.e., limited value to effectuating energy price response).[124] However, new technologies like programmable charging in EVs, smart thermostats, and other capabilities sometimes referred to as “the internet of things”

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121 This eliminates what AltaLink refers to as “tariff shopping”, wherein different tariff structures provide different price signals; with no corresponding difference in the services received or provided by/to the grid.” (AML-AUC-2019NOV29-001)

122 www.iit.comillas.edu/docs/IIT-14-076A.pdf

123 For example, www.iit.comillas.edu/docs/IIT-14-076A.pdf and ceepr.mit.edu/files/papers/2014-006.pdf

124 24116-X0167, “CCA Evidence of Dr. Richard Tabors,” July 17, 2019, para. 47-56.

have the potential to shift this dynamic and increase price responsiveness. In particular, digital aggregation and remote control of loads by entities like Curtailment Service Providers ("CSPs") has the potential to drive demand side management, while not requiring major investments of time or capital by individual consumers.

As load becomes more participatory in its approach to consumption of electric services, via DSM measures, it is important that it also receives the right price signals such that it is able to participate in a manner that fosters economic efficiency. Historically, especially for residential and small commercial customers, there was limited price-driven variation in electricity consumption, and therefore variable-based rates only provided incentives for consumer to limit overall energy consumption. However, with the expectation of increased DSM comes heightened concern over developing rates that reflect cost and send signals for economically efficient behavior. As described in the context of DCGs as well, the chief concern with allocative efficiency loss, should consumers limit consumption based rate structures that overstate the actual marginal cost of supply. The same principles apply; it is important not to over- or under-value each increment of consumption.

Furthermore, as described in the context of demand charges, it is important to carefully design tariff rates to recover fixed infrastructure costs. In this instance, distribution systems are planned for and allocated based on non-coincident demand, and demand billing determinants should therefore be on the same basis.

4.3.5. Storage Rates

In its IRs, the AUC comments that there are no current enactments or market rules that govern energy storage resources in Alberta. Instead, the AUC introduces several hypothetical arrangements for storage resources connected to the distribution and transmission systems. These include a behind-the-meter storage system, a distribution-connected storage system, and a transmission-connected storage system.

Given the current regulatory circumstances in Alberta, there is little to comment on here in terms of specifics. Thus, we provide general thoughts about storage and rely on our principle-based approach to setting distribution tariff rates. As an initial matter, storage is an important and versatile technology that we expect to see play a larger role in future power systems owing to falling costs of certain types of energy storage assets (e.g., electrochemical batteries) and synergies between storage and expanded deployment of variable energy resources. In other jurisdictions, the expectation of an expanded role for energy storage has driven regulatory reforms to level the playing field for storage. For example, FERC Order No. 841 requires U.S. RTOs to revise their rules to allow storage resources to participate in their markets on an equivalent basis to other resource types.

We recommend that the AUC and other Alberta utility stakeholders work towards implementing rules to facilitate the deployment of energy storage as appropriate and consistent with the principle of technology agnosticism. Particular areas of regulation where storage participation should be considered include:

- Treatment of merchant storage connected to the distribution system;
- Storage as a regulated asset on distribution or transmission systems;
- Merchant storage participating in the wholesale market.

In the distribution-connected merchant context, we contend that a distribution tariff rate that sends well-designed cost signals to distribution customers and DCGs should also serve well to send cost signals to electric storage resources.[125] To first order, a distribution situated storage resource may be viewed at times as a load, and at times as a generator. If appropriate signals are in place for both roles of a non-storage resource, appropriate signals should also be in place for each role of an energy storage resource.

Treatment of storage as a competitive asset acting under distribution tariff rates and price signals to consumers is only one element of how storage may be considered in the regulation of distribution utilities. Storage also holds the potential to play a role not as a competitive asset, but as a regulated, rate-based asset. In the context of distribution planning and operation (and transmission planning and operation), storage may be considered as cost-effective non-wires alternative for deferring or avoiding certain system upgrades or providing ancillary services.[126] These other potential uses of storage technology should also be considered in distribution utility regulation. When storage performs non-merchant services, the applicable storage tariffs should attempt to recognize the relevant context from a cost and value perspective.

There are different, complex considerations for larger resources participating in a wholesale market environment. In wholesale markets, the flexible nature of storage resources may be more fully and dynamically leveraged. For example, with more sophisticated operational strategies in play, there may be a need to represent the capabilities and constraints of storage more thoroughly in market offers and market optimization software. To treat batteries in this manner would require market software that optimizes across operational time periods, which in our understanding is not currently a feature of the AESO market.

4.3.6. EV Rates

According to the AUC, there are no tariff rates specific to EV charging infrastructure, whether in-home, at a commercial site, or as part of a direct charging network. Noting that vehicle-to-grid charging is still in early development stages, the AUC focuses its IRs on EVs as load in four scenarios with successively higher demands on the system and variation between whether sites are private or public, and at residential or commercial sites.[127]

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125 However, this is not to argue that storage resources should do not deserve specific treatment. To eliminate concerns over misunderstandings, particularly given the expanded role that storage resources are expected to play in the future power system, we would suggest that storage receive explicit treatment in tariff rates and applicable regulations.

126 We agree with entities like IPCAA that point out that the deployment of ESRs by DFOs or TFOs requires careful management and oversight. Regulated ESR investments need to be well-justified as a cost effective solution. Resulting ESR development would probably also benefit from competitive sourcing. See, IPCAA-AUC-2019NOV29-013. As Capital Power points out, it would also be important to make sure that a regulated ESR investment is not able to over-recover costs based on both merchant sales and regulated rates. See, CPC-AUC-2019NOV29-013.

127 24116-X0470, “AUC Preliminary IRs to All Parties,” November 29, 2019, para. 31-34.

In our view, EVs can be treated as potentially large new loads from a distribution tariff design standpoint and, for Level 1 chargers, cost impact considerations may be minimal.[128] However, as pointed out by Dr. Tabors, network issues may arise if EV adoption happens quickly and is clustered in certain neighborhoods.[129] EDTI also notes that Level 2 chargers do present unusually large, sustained demands on the system.[130] In our view, the impact can be significantly mitigated if EV adoption is planned for and EV owners are incentivized to act in an efficient manner.[131] If this is done effectively, the introduction of EVs may increase load factor and utilization of existing infrastructure; if done poorly, EVs may increase load factor, drive need for system reinforcements, and increase overall distribution system costs.

This again points to a rate design that effectively communicates to the customer, and EV owner, a reasonably accurate signal about the costs being imposed on the system by charging, and the cost to charge the vehicle at any given time. Again, rates reflective of cost causation by on-site generation and/or EV achieves this objective and helps to achieve desirable outcomes like maximizing use of existing infrastructure while limiting the need for new development and additional system cost. This can be accomplished via three-part rates or via other structures, like time-of-use tariffs for energy or a ratepayer impact model, as described further below.[132] Here, the key issue is representing the time-differentiated impact of charging decisions both on the burden imposed on the distribution (and transmission) networks and the cost of energy.

EV owners should be incentivized to charge at times that they are not going to increase their peak demand – and thereby limit system expansion needs – or to limit how much their peak demand increases. Rates that adhere to the cost causation principle will also limit the ability of EV customers to shift costs of associated system expansion onto EV non-adopters. We acknowledge again that many C&I customer tariffs in Alberta already have multi-part rates that provide the types of signals being suggested.

A novel feature of EV-type loads is that most EVs come with the ability to control when charging occurs via a programmable charge controller. This increased sophistication, paired with the potential for increased load on the system, suggests that alternative customer classes may be appropriate. For example, all four of Maryland's investor-owned utilities must develop a time-of-use rate specific to residential EV customers. Additionally, public stations

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128 Should Vehicle to Grid ("V2G") technologies become more prevalent, it is likely that the nature of EVs could change considerably in their ability to act more like a bulk storage resource than a distributed load. However, as pointed out by Dr. Tabors, this technology is not yet mature for commercial applications (Dr. Tabors Module One Evidence, para. 29).

129 24116-X0167, "CCA Evidence of Dr. Richard Tabors," July 17, 2019, para. 26.

130 24116-X0529, EDTI-AUC-2019NOV29-012.

131 www.raponline.org/blog/electric-cars-are-a-lot-like-water-heaters/

132 It is conceivable that charges in a distribution tariff could be differentiated by time, as is common for energy TOU rates. This would provide further incentives to shift consumption to outside of peak periods.

owned by the utility will use a separate electricity rate so EV drivers pay for infrastructure and electricity use without spreading the cost across all electricity consumers.[133]

While not specific to the DFO rates, new EV tariff classes could have more time-sensitive rate structures for the energy component of customer charges.[134] Time-of-use energy rates could also be imposed on EV charging customers if there is concern that they are failing to receive appropriate signals about the cost of energy being consumed at any given time, which would lead to potential allocative efficiency loss. In a jurisdiction like Alberta, with retail competition, the imposition of time-of-use ("TOU") energy rates cannot necessarily be required for all customers as they are in some jurisdictions.[135] However, one change would be for the non-switching customer rate to be set as a TOU-type rate for all customers with an EV.

EV rate classes are a prime example of the interplay between rate design and public policy, particularly for public charging infrastructure. There is criticism that demand charges, which historically have been in place for C&I customers, are not well suited to public fast chargers, particularly if the peaky nature of public fast charging winds up shifting costs to charging installations beyond what would reflect cost causation. Furthermore, high monthly fixed costs, even if warranted, are challenging for new, not-yet-mature businesses like public fast charging providers. If there is policy interest in supporting EV infrastructure and deployment of zero-emitting EVs in general, then these hurdles to deploying charging infrastructure may be lowered via rate design decisions. With these challenges and societal policy goals in mind, RMI recommends EV tariffs for public chargers that limit fixed charges, instead focusing on cost recovery via variable rates that vary by time and location.[136]

If Alberta's DFOs were to develop EV-specific rate classes, there are approaches used elsewhere that may provide a guide for how to limit rate shock and bill impacts on existing EV customers. Before implementing a new distribution-level EV tariff, many jurisdictions have conducted pilot programs with both EV and non-EV owners participating. Then, using ratepayer impact models ("RIM"), utilities calculated the net present values of the tariff's costs and benefits by category. For instance, the New York Power Authority assessed the "Ratepayer Impact of EV Adoption by Region" by assigning electricity supply and residential charger installation into a cost category and utility bill savings to a benefit category and calculating the net benefit.[137] Portland General Electric used a modified RIM analysis called TEAM, which includes 17 cost-benefit categories such as tax credits, administrative costs,

133 Maryland Public Service Commission, "Maryland PSC Approves Modified Utility Electric Vehicle Portfolio," January 14, 2019.

134 Some examples of EV tariff rates are provided here: www.swenergy.org/data/sites/1/media/documents/publications/documents/How_Leading_Utilities_Are_Embracing_EVs_Feb-2016.pdf and files.brattle.com/files/14717_the_state_of_residential_ev_electric_rates_10-15-2018.pdf

135 Jim Lazar, Paul Chernick, and William Marcus, "Electric Cost Allocation for a New Era," Regulatory Assistance Project, January 2020, pg. 87.

136 rmi.org/rate-design-best-practices-public-electric-vehicle-chargers/

137 NYSERDA, "Benefit-Cost Analysis of Electric Vehicle Deployment in New York State," February 2019, pg. S-6.

and environmental benefits.[138] In Maryland, some proposed tariff offerings will not place all charging infrastructure costs on ratepayers. Some upfront costs will be borne under utility rate base or a government subsidy.[139]

Transitions to EV tariffs may also be facilitated by education programs. According to a study by New York State, even with high levels of EV infrastructure in place, the benefits of EV tariffs do not outweigh the costs unless customers follow the price signals built into the tariff.[140] First, customers must be incented to visit an education portal. The utility Salt River Project in Arizona rewards EV customers with a $50 gift card for signing up for alerts from the utility's EV mailing list.[141] Then, the education program itself must be memorable and clear. Pacific Gas and Electric developed a low-budget, consumer-friendly web platform where consumers can search for regional incentives, compare tariffs, and locate charging stations, all in one centralized hub.[142]

4.4. Locational Pricing Considerations

As load and generation patterns shift over time, not all spots on distribution networks will be affected equally. Some infrastructure may be sufficient or over-built to serve the needs of customers and DERs, while some parts of the grid may be stressed and require upgrades. This dynamic has long been recognized in transmission pricing and planning. Bulk locational marginal prices ("LMPs") in most electric markets[143] send time- and location-varying indications to generators and loads about where electric energy (and new transmission) is most valuable, and planning processes have sought to reduce transmission congestion where justified. Similar opportunities may be available for sending locational price signals at the distribution level. Locational signals for distribution could be developed to apply at operational time scales, which should incent shifts to both short- and long-term behavior, or to send signals more focused on long-term siting of DERs or load. Put another way, locational price signals can communicate to customers and market participants both *where* to develop new resources and *how* to operate both new and existing resources.

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138 Portland General Electric Company, "UM 1811 Transportation Electrification Compliance Filing," February 15, 2019, pg. 22.

139 Maryland Public Service Commission, "Maryland PSC Approves Modified Utility Electric Vehicle Portfolio," January 14, 2019.

140 NYSERDA, "Benefit-Cost Analysis of Electric Vehicle Deployment in New York State," February 2019, pg. 83-84.

141 Melissa Whited, Avi Allison, and Rachel Wilson, "Driving Transportation Electrification Forward in New York," Synapse Energy Economics June 25, 2018.

142 ev.pge.com/

143 Alberta's current system-wide marginal price does not account for small-scale local variances in the temporal and locational marginal costs of electricity generation, transmission, and distribution. (www.aeso.ca/aeso/training/guide-to-understanding-albertas-electricity-market)

The most basic long-term price signal for distribution system locational pricing is a varying interconnection fee based on capacity and reliability needs.[144] Depending on the maximum capacity for a regional substation and expected consumption and production patterns, more DCG on the system could either overload or provide relief to the system. The interconnection fee for any particular location would vary depending on the costs that would be imposed by the DCG. The initial interconnection fee for DCG can be conceptualized as a price signal regarding the parts of the system that can best accommodate further DCG capability. We note the importance of ensuring that charges to new DERs are sufficiently "deep" to appropriately disincentivize investment where it is likely to lead to significant upgrade costs. Also, adding transparency to such costs is a worthwhile goal, which may ease locational decisions for developers of DERs. For example, National Grid's electricity transmission entity hosts a real-time "network capacity map" of every substation in its United Kingdom service territory, color-coded by amount of available capacity.[145] An alternative or complement to locational charges is "hot spot" credits, an option suggested by the Rocky Mountain Institute, to provide incentives for resources that would relieve current system constraints.[146]

The above fee structure aims to avoid new asset development leading to uneconomic buildout of distribution infrastructure such as substations, transformers, and elevated utility poles and cables, because once installed, infrastructure is a sunk cost. Similar signals can also be provided to existing resources via location-varying demand charges, which may indicate to the consumer the value of changing operational behavior to delay or avoid an upcoming network upgrade. Locational demand charges like this can be thought of as indicating the marginal cost of using the network and, by location, could be layered on top of existing demand charges to recover embedded costs. Experts at MIT point out that, "the strength of the economic signals sent to network users through their network charges should be modulated to account for the capacity margin of the network under consideration."[147] That is, the lower the capacity margin of the network, the larger the distribution price signal would be to consume the remaining margin. The considerations to achieve this are complex and depend on a number of factors, and need to be structured to avoid penalizing customers who have little ability to change their contribution to network costs.

An even more complex approach to sending short-term price signals for consumers at the distribution level is a distribution locational marginal price ("DLMP").[148] Like LMPs at the bulk power system (i.e., transmission) level, DLMPs convey to the consumer the marginal cost of

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144 We note that location price signals from Generating Unit Owner Contributions ("GUOC") are in place for transmission connected wholesale power generation pursuant to Section 29(1) of the Transmission Regulation. Concurrent with review of locational pricing for DCG, there may be merit in reviewing GUOC in the interest of improving the effectiveness of price signals as well as to achieve harmonization between DCG and wholesale generation.

145 www.nationalgridet.com/get-connected/network-capacity-map

146 Devi Glick, Matt Lehrman, and Owen Smith, "Rate Design For The Distribution Edge," Rocky Mountain Institute, August 2014.

147 Pérez-Arriaga and Knittel, "Utility of the Future Full Report," Massachusetts Institute of Technology, pg. 111 (Box 4.5), and 290, 2016.

148 In the context of locational price signals and DLMP, it can be challenging to differentiate between the locational price for wires service and energy, so we will discuss them together.

supplying an additional unit of demand at a certain location, accounting for the time varying cost of energy, congestion, and losses.[149] Depending on how it is structured, DLMP may incorporate:

- Local generation availability via bids and offers for both reactive and real power, resulting in price curves down to the substation level;[150]
- Line congestion and losses;[151] and
- Feeder load.[152]

If calculating LMPs is a complex task, calculating DLMPs is even more so. Nonetheless, it has been suggested as an approach to managing locational issues arising from increased prevalence of DERs. There are also formulations of DLMP that attempt to simplify the construct somewhat. While less precise, an alternative approach to providing a distribution level price signal is to use the so-called “LMP+D” method for distributed generators: LMP+D is an average, administrative estimate of the total avoided cost of the full process of electricity delivery. This would sum the wholesale locational marginal price plus a utility-provided estimate of the average avoided distribution system costs.[153]

A system like DLMP or LMP is likely a long way off in Alberta. As it stands, Alberta does not yet use locational marginal pricing in its wholesale markets. If network congestion and the need for better locational price signals become pressing concerns, implementing an LMP is likely a more cost effective first step towards improving price signals and market efficiency. DLMPs will remain an option for the long term, but have yet to be implemented at scale in any jurisdiction. We expect the level of associated complexity will deter near-term adoption, and this would not be a recommended path for Alberta at this time.

4.5. Conclusions and Recommendations

In this section, we address tariff rate design issues in general and assess whether current distribution rate structures in Alberta adhere to principles we set forth. The principles we put forward include:

- Rates should drive towards economically efficient outcomes;
- Rates should reflect cost causation;

149 Edmunds, Galloway, and Gill, “Distributed Electricity Markets and Distribution Locational Marginal Prices: A Review,” 2017.

150 Richard D. Tabors, “Valuing Distributed Energy Resources (DER) via Distribution Locational Marginal Prices (DLMP),” June 1, 2016.

151 Edmunds, Galloway, and Gill, “Distributed Electricity Markets and Distribution Locational Marginal Prices: A Review,” 2017.

152 Reno et al., “Using Distribution LMP and Time-of-Delivery Pricing to Promote Optimal Placement and Increased Profitability of Residential PV Systems,” 2014.

153 Richard D. Tabors, “Valuing Distributed Energy Resources (DER) via Distribution Locational Marginal Prices (DLMP),” June 1, 2016.

- Rates should balance non-cost objectives, including 1) simplicity, east of understanding, administration and acceptability; 2) clear of misinterpretation; 3) reasonably granular; and 4) no undue discrimination.

As an initial matter, we describe why the expanded deployment of DERs is likely to result in a shift in distribution customer behavior that is concerning in the context of historical approaches to rate design, particularly for residential customers. If rate design is not better aligned with fundamental principles, we expect that inefficient and unequitable outcomes are likely to result. We then review current rate design structures in Alberta, using the AUCs IRs as the primary guide. We identify certain concerns, and suggest the following reforms to avoid outcomes that would not be in line with principled rate design:

- Implementation of three-part rates reflective of cost causation for those customers with on-site generation (including storage) and/or electric vehicles. Further attention should also be paid to the accuracy of consumer contribution charges for new DCGs.
- To the extent that certain customer classes already face three-part rates – or rates with significantly less emphasis on variable charges – rate structures may still need to be revisited to balance the relative size of fixed, demand, and variable charges to be reflective of cost and send effective signals to lead to efficient operational decisions.
- Customers that do not have DCGs and/or EVs do not raise the same level of concerns about rate bypass and cost shifting, imposition of additional system needs and costs, and the general need for price signals that are better aligned with cost causation. Such customers should be allowed access to legacy rates. Customers that made investment decisions based on price signals embedded in previously-available rates may be accommodated via grandfathering or transition periods.
- Treatment of distribution network charges for DCGs with STS contracts should be revisited. Such DCG customers should no longer contribute to reduction in DTS charges for the distributor and DTS credits should no longer be applicable. This approach ensures a level playing field between generation types, thus fulfilling objectives around technology agnosticism and avoidance of undue discrimination, while also eliminating concerns over billing determinant erosion and cost shifting.
- Current rules around the recovery of the small micro-generation sell-rate should be reformed. As we understand it, there is currently no regulatory review of these rates and the entities that agree to the price bear no risk for that price. The costs incurred are ultimately borne by customers, and potential exists for significant economic efficiency losses by offering above-market rates with not countervailing benefit to the system.
- As these changes are deployed in Alberta, it is also important to improve the transparency and understandability of rate structures, particularly as they apply to different customer classes with different DER and metering configurations. This issue will be particularly relevant should the AUC and the Alberta DFOs develop further rate classes for DCG and EV customers, as recommended.

Appendix A: DERs and Wholesale Markets – ERCOT Case Study

In considering the role of DERs in a liberalized jurisdiction, one important element of the overall industry and regulatory structure is the interplay between the wholesale markets and resources that have not traditionally been active participants in those markets. While this is not squarely within our focus, which is the regulatory and rates treatment of distributed resources, we have been asked to provide a case study for how such issues are treated in other markets.

ERCOT Background

The Texas electricity market ("ERCOT") presents a good analog for Alberta and is a good case study because it is farther along in some issues related to market design and participation of distributed resources. Like Alberta, ERCOT runs an "energy-only market" where the price signals from the energy and ancillary services markets incent producers (and consumers) to ensure long-term resource adequacy. Neither market has a capacity market. Furthermore, both markets have successful programs associated with retail competition and choice, both markets have limited interconnections with neighboring systems, and both markets have considerable industrial load related to extractives industries.

ERCOT and the Alberta market also have some significant differences. While ERCOT uses administrative shortage pricing to supplement energy market price signals when the system is strained, the AESO market relies on permissive market power monitoring and mitigation procedures, including the unilateral exercise of market power (via economic withholding), to simulate shortages and assist generators in recovering long run marginal costs. ERCOT and Alberta's markets are also different. ERCOT co-optimizes the procurement of energy and ancillary services, and relies on locational pricing to send locational signals for both short term operational purposes and as a mechanism to stimulate generation development at parts of the system where it is most needed. ERCOT is also significantly larger than Alberta, with more than 26 million customers served and a peak demand in excess of 74 GW.

Market Participation Tradeoffs

Allowing and accounting for participation of DERs in wholesale energy markets is frequently a tradeoff between measures that improve efficiency and considerations around administrative and technical burden for market participants and the market operator. In a perfect world, a market operator would optimize the utilization of all resources on the system and balance them with a robust representation of load, including any price elasticity of demand. In practice, this is not feasible.

On the supply side, active participation by smaller generating resources may be burdensome for resource owners (e.g., formulation and submission of offers on a daily basis) and, owing to the small size of the resources, have a small impact on overall market efficiency. Including a larger number of supply resources also adds complexity to the already-complex task of optimizing unit commitment and dispatch. Thus, a balanced market design might relegate smaller generators to "settlement only" status so that price signals are communicated without including smaller resources in operational decisions like larger ones.

On the demand side, customers may be shielded from time- (and location-) varying wholesale price signals by rate design either on purpose or by nature of the arrangements with competitive suppliers. As discussed, they may not have the interest, capability, or sensitivity to respond to price signals, at least not without facilitation by a third party (e.g., an aggregator). It is infeasible to ask customers, or even groups of customers, to indicate their consumption preferences to a market operator on a regular basis.

Taken together, the practical realities of running a power market do not allow all resources to be treated on an equivalent basis, and decisions need to be made about which resources can and should participate actively, and which resources may participate in a less active manner. Here, we observe how some of these tradeoffs have been made in the ERCOT market.

DERs in the ERCOT Market

The below sections describe how ERCOT rules treat various DERs, as well as how they are being updated to reflect evolving system needs.

Distributed Generation

ERCOT defines Distributed Generation ("DG") as a generating facility located at the point of customer delivery, 10 MW or less in capacity, and connected to a voltage less than or equal to 60 kV. All Distributed Generation Resources ("DGR") greater than 1 MW are required to register with ERCOT as a Settlement Only Distribution Generator. Electricity exports to the distribution system are accounted for in ERCOT market settlements. DGR with installed capacity of less than or equal to 1 MW, or with capacity greater than 1 MW that does not export, is registered as a Self-Generator with the PUC and does not need to register with ERCOT. Metering and reporting of meter data is the responsibility of the host transmission or distribution service provider.[154] While DGRs are a subset of Generation Resources (GR) and therefore subject to all ERCOT Protocols and rules that apply to GRs, DGRs are designated as settlement-only assets and do not impact market clearing prices.

ERCOT has expressed that DGRs present certain operational concerns that could create reliability risks for the system. As noted in a September 2019 Market Notice, these risks are due to regulatory gaps in governance of outage coordination and modelling of distribution facilities, as well as accommodation of DGR impacts during load shedding events.[155] To address these issues, ERCOT has proposed revisions to the Protocols governing DGR participation and is actively hosting workshops to engage with stakeholders. These workshops began in November 2019 and are currently scheduled monthly through February 2020.[156] As indicated in the agenda from the initial November DGR workshop, these discussions will result in a formal Nodal Protocol Revision Request ("NPRR") as well as other

154 www.ercot.com/services/rq/re/dgresource

155 www.ercot.com/services/comm/mkt_notices/archives/4288

156 www.ercot.com/committees/workshops

rule changes to the DGR participation models.[157] Key items to be addressed in such changes are DGR definitions and size requirements, outage scheduling requirements, and modelling of such resources. In the interim, all new DGR connections to the grid have been suspended, though existing resources may continue to operate.

Previously, in 2015, ERCOT developed the Distributed Resource Energy and Ancillaries Market Task Force ("DREAM TF") to review the regulatory and market frameworks for distributed resource participation in the markets and propose enhancements to the existing model. Among issues reviewed were the potential for a DGR to be associated with a Resource Node and be included in zonal pricing or Congestion Revenue Rights markets, as well as allowances for the resources to take economic outages and/or be aggregated on a zonal and system-wide basis. DREAM TF also reviewed opportunities for enhancements to the existing ERCOT registration and compliance requirements, settlement data submission processes, and the ERCOT dispatch and control for such assets.

While the Task Force's February 2016 report did not state recommendations to be implemented regarding these assets, it identified the current regulatory challenges or barriers to entry that would need to be addressed should ERCOT choose to grant DGRs participation outside of the existing mechanisms, in which DGRs are settlement-only resources. These include the lack of guidance in existing ERCOT Protocols on representing DGRs in association with Resource Nodes, requirements for Aggregated Load Resources to all be located within the same Zone, and the cost of metering that these assets would have to absorb in the absence of cost recovery mechanisms.[158] Some of these and similar issues are being addressed again in the DGR workshops.

Additionally**,** while there have been a few utility-launched pilot programs for demonstrating electric vehicles as distributed energy resources on the grid, ERCOT has not yet released its own research or pilot programs of adopting such resources onto the grid.[159]

Energy Storage

ERCOT has also recently addressed how energy storage resources ("ESR") are treated in the markets, forming the Battery Energy Storage Task Force ("BESTF") to review the participation models. ESRs in ERCOT have been historically modeled as a combination of a Generation Resource and a Controllable Load Resource ("CLR"). The initial set of ERCOT market rule revisions, which codifies consensus reached at the BESTF and TAC, was approved by the ERCOT Board in February 2020. This included changes to ESR market participation and compensation:

157 The ERCOT Protocols are intended to implement ERCOT's functions as the Independent Organization for the ERCOT Region as certified by the Public Utility Commission of Texas (PUCT). Market Participants, the Independent Market Monitor, and ERCOT are all subject to the Protocols. Formal revisions to such Protocols are done through Nodal Protocol Revision Requests (NPRR), which are subject to stakeholder comments and impact analysis reviews before being addressed by the Technical Advisory Committee and Board. Revisions are ultimately filed to the PUCT.

158 ERCOT, "Distributed Resource Energy and Ancillaries Market Task Force (DREAM TF) TAC Report," February 2016.

159 www.greentechmedia.com/articles/read/vehicle-to-grid-testing-austin-energy-pecan-street

- Settlement Points for ESRs set to the Resource Node of the existing modeled generator resource associated with the ESR, providing symmetrical dispatch and settlement for charging and discharging at the real-time price;
- Setting the offer cap for ESRs at the system-wide offer cap, the maximum allowed energy market offer as set by the Public Utilities Commission of Texas (“PUCT”);
- Applying startup offers and minimum-energy offers of $0 per start and $0/MWh, respectively; and,
- Allowing ESRs to update energy offer curves and real-time energy market bids any time prior to the security constrained economic dispatch (“SCED”) execution, enabling enhanced flexibility for these resources. [160]

The BESTF operational and market policy review is ongoing, with monthly meetings scheduled throughout 2020 that will likely lead to additional NPRRs. Key discussion topics and revisions not yet approved by the Board include removal of duration limitations on such resources, as well as eliminating the designation of ESRs as dual DG and CLRs, instead to be registered as an Energy Storage Resource to participate in economic dispatch and ancillary services. While the recent U.S. Federal Energy Regulatory Commission (“FERC”) Order No. 841 required ISOs and RTOs to provide more opportunities for ESRs to participate in the wholesale markets, ERCOT is not under FERC jurisdiction and has chosen not to comply with the ruling, instead revising treatment of such resources through the Task Force.[161]

The ownership of ESRs has been contested in Texas, as the previously existing model enabled transmission and distribution companies to own these assets. In attempts to alleviate confusion as to whether this is permitted under state law, several responsive pieces of legislation have been proposed. Ultimately, Senate Bill 1012 was recommended by the PUC and signed into law effective September 1, 2019. This succeeded in clarifying that municipally-owned utilities and electric cooperatives may own and operate batteries without registering as power generation companies. Whether transmission and distribution utilities may legally own battery storage has yet to be decided by the state. Generating companies in the state, such as Vistra and NextEra, have argued that utilities cannot do so – while storage developer Tesla and investor-owned utility Oncor Electric believe ownership is permitted through the Public Utility Regulatory Act, which governs the ERCOT grid. The debate between the utilities and non-utilities focuses on whether utility-owned storage devices would be considered generation, in which case the wholesale power markets and power prices would be affected, and merchant operators would be required to compete with assets that are able to recover cost under regulated rates. Utilities argue that such effects would be insignificant, and indistinguishable from other potential actions they may take.[162]

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160 ERCOT, “BESTF-2 Energy Storage Resource Energy Offer Curves, Pricing, Dispatch, and Mitigation Board Report,” approved February 11, 2020.

161 www.ercot.com/content/wcm/lists/164134/Storage_One_Pager_FINAL.pdf

162 www.utilitydive.com/news/texas-utilities-poised-to-get-new-ability-to-own-energy-storage-assets/560797/

Demand Response

A number of DR programs and participation models exist in Texas, some directly administered by ERCOT and others by service providers in the region. DR resources participate in ERCOT's real-time energy and ancillary service markets. DR opportunities in the wholesale market include emergency response services and ancillary service products, while opportunities facilitated by utilities include peak reduction, contracted load response, commercial load management, and self-initiated price response. Resources may qualify for various market and program participation based on resource type, size, and response times.[163] For example, energy storage resources currently participate primarily in the Fast Responding Regulation Services, in which they are registered like a generating resource when injecting onto the grid, and a CLR when withdrawing.[164] Distributed generation with advanced metering systems may participate in price response activity. In 2018, no resources on the system qualified to provide non-spinning reserve services, as none qualified to do so.[165] Various response time requirements also determine which resources can participate in the programs, as the Emergency Response Service allows a maximum of 30-minute ramp time. [166]

Texas load management programs are implemented by the transmission and distribution service providers, under which end-use customers receive payment from the providers in exchange for reducing peak demand upon request. In the event of larger system emergencies, ERCOT can request the service providers to deploy the program.[166]

Energy Efficiency

Energy Efficiency ("EE") measures do not have any active role in the ERCOT wholesale markets. Instead, EE is governed through the state Energy Efficiency Rule, passed in 2011, which calls for IOUs to achieve 30% reduction of its annual growth in demand of residential and commercial customers. Once a 30% reduction in annual growth in demand is achieved, the standard reverts to 0.4% of total peak demand thereafter. Required reduction levels cannot fall below previous year's levels.[167]

Key Takeaways from ERCOT

While Texas has a number of protocols and mechanisms in place for distributed generation, energy storage, and demand response resources to participate in the ERCOT markets, much of these participation models are currently being revisited or debated in a range of venues

163 ERCOT, "Load Participation in the ERCOT Nodal Market", Draft Version 3.01 www.ercot.com/content/services/programs/load/Load%20Participation%20in%20the%20ERCOT%20Nodal%20Market_3.01.doc

164 This model is likely to change given revisions to the Protocols being prepared by the Battery Energy Storage Task Force.

165 Security-Constrained Economic Dispatch Qualification is required for Load Resources to provide Non-Spinning Reserve Services.

166 ERCOT, "2018 Annual Report of Demand Response in the ERCOT Region," March 2019.

167 programs.dsireusa.org/system/program/detail/4622

(e.g., PUCT, Texas legislature, ERCOT) in response to expectations for increased penetration of renewables and demand side resources. Distributed generators currently participate as settlement-only assets, though after the ERCOT workshops, their definitions, requirements, and participation model may change. ERCOT is also reviewing how energy storage resources participate and are compensated, while the allowable ownership structures of such resources have been contested at the PUCT and state legislature. Demand response in ERCOT has more established mechanisms that are not currently as challenged or reviewed, but DR resources' role as active participants is also limited. Permissible DR participation varies based on the market involved, resource type, size, and achievable response times.