Mr. Randy Lucas, Lead Application Officer

Alberta Utilities Commission

July 17, 2019

Submitted electronically to Proceeding 24116

Dear Mr. Lucas,

Re: Distribution System Inquiry - AUC Proceeding 24116

Community Generation Working Group (CGWG) Submission for Module One

The CGWG is comprised of the Canadian Solar Industries Association ("CanSIA"), First Nations Power Authority ("FNPA") and the Alberta Community and Co-Operative Association ("ACCA"). Our submission addresses solar photovoltaic generation ("solar" or "solar PV") as well as solar paired with battery devices ("solar+storage"). Further, our submission considers both behind-the-meter supply, as well as resources directly connected to the distribution system. Solar and solar+storage are both cost-effective and accessible to communities, cooperatives and Indigenous communities, creating opportunities to reduce electricity costs and energy independence, promoting economic development and reducing green-house gas emissions.

We appreciate this opportunity to respond to Module One questions and look forward to future Modules addressing broader structural and regulatory questions related to the uptake of technologies that impact the distribution system. As emphasized in the CGWG submission to AUC Proceeding 22942, the AUC's Distribution System Inquiry provides an appropriate avenue to address any concerns about the uptake of distribution-connected generation. This submission by the CGWG outlines the benefits of solar and solar+storage to electricity consumers and grid operators, outlines potential challenges that arise as uptake increases over time, as well as cost mitigation strategies that may be considered.

Best regards,

Wes Johnston	Paul Cabaj	Guy Lonechild
President and CEO	Interim Executive Director	CEO
CanSIA	ACCA	FNPA

ALBERTA UTILITIES COMMISSION

PROCEEDING 24116

Distribution System Inquiry

MODULE ONE SUBMISSION OF THE COMMUNITY GENERATION WORKING GROUP

July 17, 2019

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Consulting support for the Community Generation Working Group

Contents

Table of Figures

List of Tables

List of Acronyms

AC	alternating current
ACCA	Alberta Community and Co-Operative Association
ADMS	advanced distribution management system
AESO	Alberta Electricity System Operator
AIES	Alberta Interconnected Electricity System
AMI	advanced metering infrastructure
ArcGIS	geographic information system software
AUC	Alberta Utilities Commission
BAA	balancing authority area
BTM	behind-the-meter
C&I	commercial and industrial
CAD	Canadian Dollars
CanSIA	Canadian Solar Industries Association
CCIR	Carbon Competitive Incentive Regulation
CGWG	Community Generation Working Group
DC	direct current
DCG	distribution-connected generators
DER	distributed energy resource
DERMS	distributed energy resources management system
DFO	distribution facility owner
DG	distributed generation (i.e., connected to the distribution system)
DSO	distribution system operator
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FNPA	First Nations Power Authority
FTM	front-of-the-meter
GW	gigawatt
GWh	gigawatt-hours
ID	AESO issued Information Document #2018-019T
ISD	In-Service Date
ISO	independent system operator
LCOE	levelized cost of energy
LDA	local distribution area
LiDAR	light detection and ranging
MW	megawatt
NWA	non-wires alternative
PG&E	Pacific Gas and Electric
PPA	power purchase agreement
PV	photovoltaic
REV	Reforming the Energy Vision
SCADA	supervisory control and data acquisition
TIER	Technology Innovation and Emissions Reduction

TOU	time-of-use
TSO	transmission system operator
U.S.	United States of America
USD	U.S. Dollars
VAR	volt-ampere

SUBMISSION OF THE COMMUNITY GENERATION WORKING GROUP

I. Introduction

1. The Community Generation Working Group (the "CGWG") is comprised of the Canadian Solar Industries Association ("CanSIA"), First Nations Power Authority ("FNPA") and the Alberta Community and Co-Operative Association ("ACCA") (collectively referred to as "we").

    a. CanSIA is a not-for-profit membership-based national trade association for the solar energy industry throughout Canada. CanSIA's mandate includes engaging in policy development and regulatory affairs activities in Alberta in order to support a growing role for solar energy in the province's electricity supply mix.[1]

    b. FNPA is a national not-for-profit membership-based organization whose mandate in Alberta includes supporting the development of Aboriginal-led business opportunities in the electricity sector. Indigenous communities can create long-term sustainable value for their members by proactively partnering in electricity generation facility development.[2]

    c. ACCA is a provincial not-for-profit membership-based co-operative whose mandate is to build a better Alberta by putting people's social and economic well-being at the forefront of their businesses and projects in sectors including (but not limited to) solar electricity generation, utilities, finance and agriculture.[3]

2. The CGWG has retained Power Advisory LLC ("Power Advisory") and Peters Energy Solutions Inc. ("Peters Energy") as consulting support. Power Advisory and Peters Energy collaborated to prepare this submission coordinating with the CGWG and are referred to in this submission as "the authors".

3. The CGWG was an intervener in the Alberta Electric System Operator (AESO) Application 2018 ISO Tariff (Proceeding 22942). As stated in paragraph 5 from the CGWG's final argument:

    "The AESO's proposed changes to feeder level totalization reflected in the ID and its Amended Application should be rejected. The AESO implemented these changes without consulting DCGs or end-use electricity ratepayers, the market participants directly affected by the changes. Further, the AESO has not provided a sound or principled rationale for implementing the changes. To the extent that the AESO's concerns with DFO-offered credits are valid, there are other more appropriate avenues to address

[1] Visit www.cansia.ca for further information.
[2] Visit www.fnpa.ca for further information.
[3] Visit www.acca.coop for further information.

these concerns, such as a DFO tariff proceeding or the AUC's Distribution Inquiry. To the extent the AESO's concerns relate to technical or reporting requirements, these should be addressed through AESO rules and not the tariff."[4]

4. The CGWG is pleased to offer this submission for the Alberta Utilities Commission's (AUC) review and consideration. As demonstrated by this submission, there are many opportunities for communities to self-supply and provide valuable grid services, particularly if enabled by solar and battery energy storage devices.

II. Module One Overview – Question 1

Question: 1 What are the technologies and innovations that have the potential to affect distribution systems, including distribution system design, operation, capital requirements and the cost of providing service? Please comment on any of the following technologies and innovations, as well as any other relevant technologies or innovations not listed:

(a) Electric vehicles
(b) Energy storage
(c) Advanced metering infrastructure
(d) Distributed energy resources and distribution-connected generation
(e) Technology that enables community generation initiatives
(f) Technology that enables demand-side elements such as energy efficiency, net-zero buildings, consumer choice aggregators, responsive load, demand responses and peak reduction
(g) Information technology advancements (for example: fifth-generation (5G) cellular technology, cloud computing, blockchain technology, the internet of things, artificial intelligence and machine learning)
(h) Advanced distribution management systems and/or distributed energy resource management systems
(i) District heating
(j) Geothermal/geo-exchange

5. The CGWG submission addresses solar photovoltaic (PV) generation ("solar") and solar paired with battery energy storage ("solar+storage"). The submission also makes reference to behind-the-meter (BTM) resources (e.g., a solar or solar+storage resource that feeds electricity directly to a distribution-connected load customer) and front-of-the-meter (FTM) resources (e.g., solar or solar+storage resource that is directly connected to a distribution system). In either case, solar and solar+storage may be referred to as distributed energy resources (DERs), although the authors note that the term "DER" encompasses a wide range of other distribution-connected technologies, such as electric vehicles, demand response, stand-alone batteries, and other generation technologies.

6. The CGWG submission focuses on solar and solar+storage; these technologies have strong potential to affect distribution system design, operation, capital requirements and the costs of providing services, and fits within the following categories[5]: (b) Energy storage, (c)

[4] Exhibit 22942_X0560
[5] As labeled by AUC scope and process letter March 29, 2019 (24116_X0106), Appendix A.

[advanced metering infrastructure (AMI)], (d) DERs and [distributed generation (DG)], (e) technology that enables community generation initiatives, and (f), specifically, technology that enables net-zero buildings, consumer choice aggregators and peak reduction.

7. Community generation projects are frequently the gateway that First Nations and Métis Communities and other Regional Governance Bodies such as Tribal Councils need in order to enter the green economy. In addition to generating much needed economic and environmental benefits, such community generation projects act as a low-risk platform for communities to gain the capacity required to participate in larger, potentially riskier, development opportunities. There are several communities in northern Alberta developing community energy plans which allow First Nations communities to understand their power consumption needs; where they can save on energy costs; and identify what type of renewable energy projects (such as solar and solar+storage), including community generation, may be viable alternatives to the existing energy supply.

8. Inverter-based technologies associated with solar and solar+storage have the potential to be transformative. Inverters are required to convert the direct current (DC) output of solar modules or batteries to the alternating current (AC) form found in the grid. In addition to this basic function, inverters are also equipped to respond to grid conditions (voltage, power factor, frequency, etc.) automatically or by external command provided by supervisory control and data acquisition (SCADA):
   a. Provide protective functions, such as anti-islanding
   b. Control power factor of the generation output, either leading or lagging
   c. Produce or absorb reactive power, even without generation (at night as well), potentially controlling distribution system voltage
   d. Control the output of the generator with a very fast response (sub-second)
   e. Control the charge input of the generator with a very fast response (sub-second)

9. Multi-point energy meters combined with internet connection and cloud storage can provide the basic functionality of a utility meter with significantly enhanced value and possibly lower cost, compared to current utility meters. These are available to consumers and can augment or potentially replace current distribution facility owner (DFO)-provided meters as measurement compliance advances.

III. Technology and Innovation Trends – Question 2 (a)

Question: 2 (a) How stable are the trends associated with a certain technology or innovation and when is it expected that [a certain technology or innovation] will be economically viable?

10. Solar is now economically viable with generally lower costs than other forms of generation. Evidence of these trends are demonstrated in Lazard's annual Levelized Cost of Energy Analysis, which shows a continued decline in the cost of generating electricity from solar

and solar+storage (Lazard, 2018). While the references from Lazard indicate prices in U.S. Dollars (USD), the trends are applicable to the Canadian and Alberta markets.

11. Figure 1 demonstrates that the levelized cost of energy (LCOE) from solar PV at rooftop and utility scales are competitive with conventional electricity supply. In particular, rooftop commercial and industrial (C&I) solar PV applications are shown to have costs that compare to peaking gas, nuclear and coal. As will be demonstrated through this submission (see for example paragraph 57 and paragraph 58), while some rooftop solar may not be competitive based on pure energy costs, its proximity to local loads provides additional value. Whether and how that value is shared with the rooftop solar owner, however, will significantly affect adoption rates.

12. Figure 2 demonstrates that utility-scale crystalline solar PV applications have decreased by 88% over the past 9 years to approximately $43/MWh (USD) in 2018. Notably, this is comparable to the contracted price resulting from Alberta's Ministry of Infrastructure's request for proposals; 50-50 partners Canadian Solar Solutions Inc. and Conklin Métis Local 193 won three solar energy supply contracts totaling 94 MW with an average power purchase agreement price of $48.5/MWh Canadian Dollars (CAD) (Canadian Solar Inc., 2019).

13. Figure 3 illustrates the LCOE for storage based on application. Of importance for the CGWG, we note that the LCOE for solar+storage is less than stand-alone storage, and while most storage applications have a higher LCOE relative to conventional energy supply, utility-scale solar+storage applications are comparable to, and in some cases competitive with, peaking gas, nuclear and coal generation.

14. As reported by BloombergNEF's New Energy Outlook, cheap renewables and batteries are fundamentally reshaping the power sector. Specifically, solar is projected to see the most growth, "rising from 2% of the world electricity generation today, to 22% in 2050" (BloombergNEF, 2019).

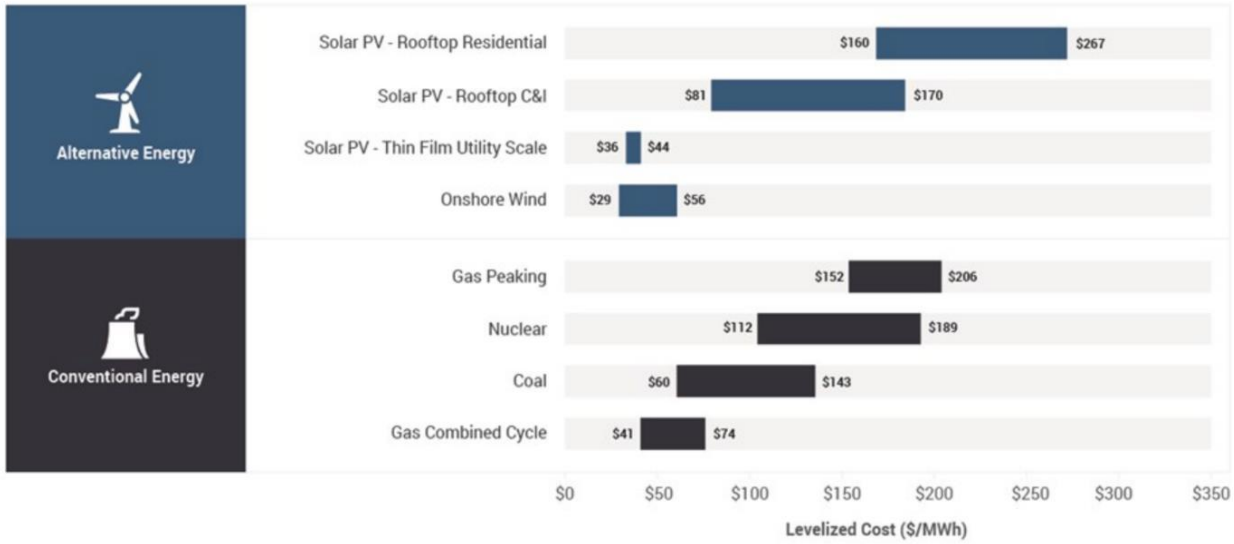

Figure 1. Levelized cost of energy by source (Lazard, 2018)

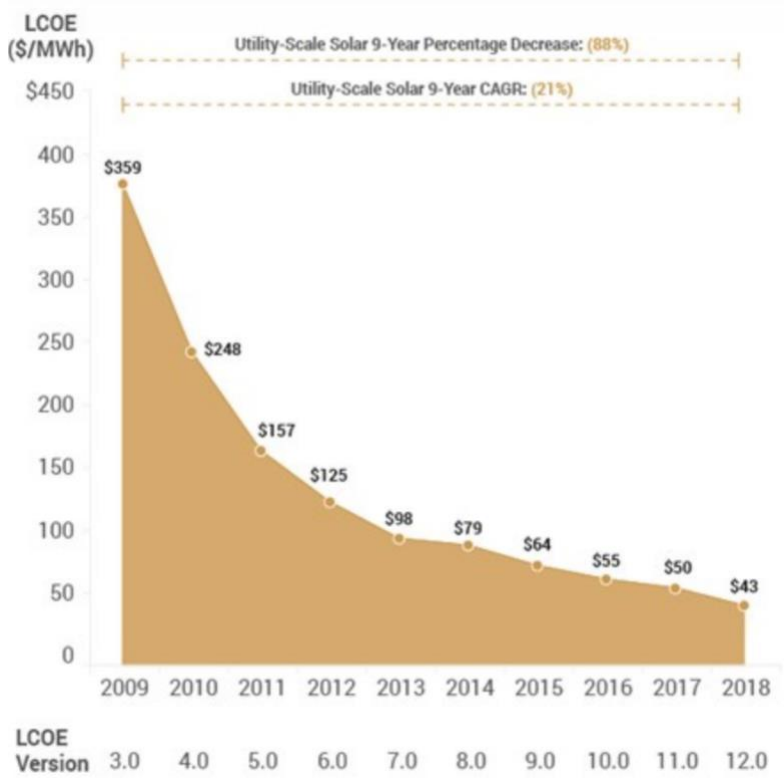

Figure 2. Unsubsidized Solar PV LCOE Mean for Crystalline Utility-Scale Solar (Lazard, 2018)

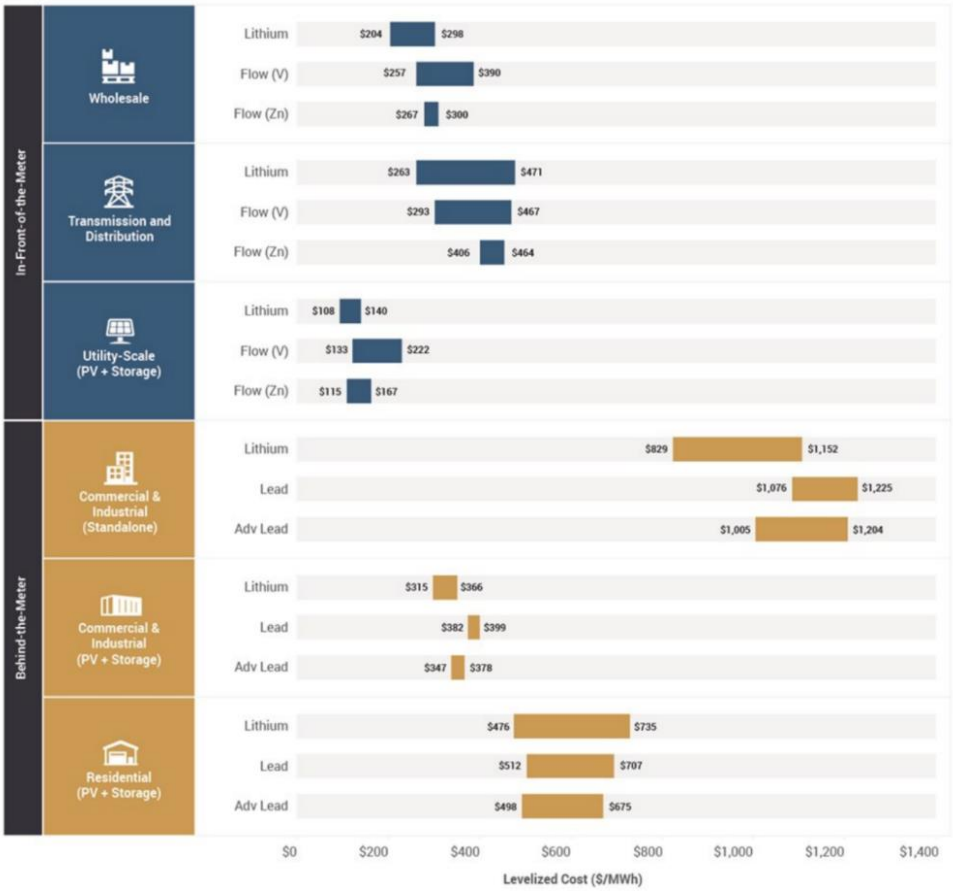

Figure 3. Levelized costs of storage by application (Lazard, 2018)

15. CanSIA and Canmet ENERGY compiled an overview of the status of solar installations throughout Canada (Poissant, Baldus-Jeursen, & Bateman, 2017). As shown in Figure 4, Ontario leads the country with solar installations. However, Alberta has become the second province in Canada to install more than 5 MW of solar in a single year (25 MWp was installed in 2017). With the connection of the Canadian Solar Inc. solar projects (per paragraph 10), Alberta is trending to secure its status as the province with the second largest solar installed capacity.

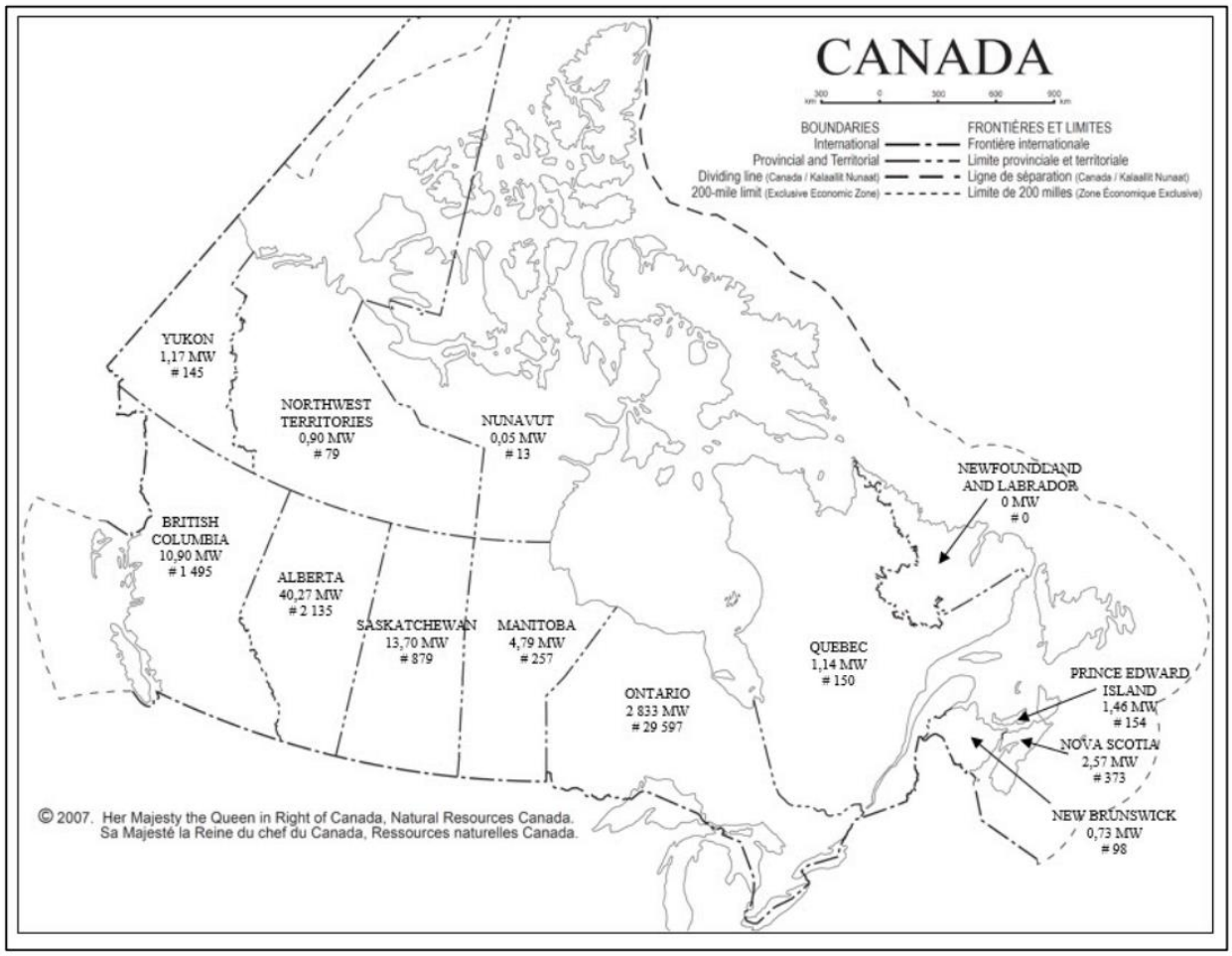

Figure 4. Map showing the Canadian provinces and territories, grid-connected PV power capacity (Poissant, Baldus-Jeursen, & Bateman, 2017)

Large-Scale Solar PV

16. Elemental Energy installed the first utility-scale solar project (15 MWp) near Brooks, Alberta in 2017. Following on its heels are projects under construction, described in Table 1. Responding to the existing competitive energy market and to the increasing interest of non-utility procurement of renewable electricity – and despite uncertainty in Alberta's regulatory and policy landscapes (per Paragraph 19) - proponents are cautiously proceeding with large, unsubsidized and competitive solar projects.

Table 1. Examples of solar farms currently undergoing construction in Alberta

Proponent	Project Name	Key Details
Solar Krafte	Vauxhall	Location: M.D. of Taber near Vauxhall on Bow River Irrigation District lands Capacity: 22 MW Capital Cost: ~$40 million GHG Offset:~23,000 tonnes Projected In-Service Date (ISD): 2020
Solar Krafte	Hull	Location: M.D. of Taber near Vauxhall Capacity: 24.5 MW Capital Cost: ~$40 million GHG Offset: ~23,000 tonnes Projected ISD: 2020
Canadian Solar	Suffield	Location: Cypress County near Suffield Capacity: 22 MWac Capital Cost: ~$50 million Grants: $15.3 million from Natural Resources Canada Under the Emerging Renewables Power Program Projected ISD: January 2020

17. Solar electricity has become a dominant option for new DG in Alberta, driven by significant technology cost decreases, availability of foreign investment, and new partnerships between developers and communities (municipalities, indigenous communities and co-operatives). There are an estimated 1,545 MW (AESO, 2019) of solar electricity generation facilities in the late stages of development in the province and even more in earlier stages of development. However, this represents a portfolio of *potential* projects and it should be understood that only a portion of these projects can be expected to go ahead, while the remaining will be eliminated by a number of reasons. For example, in large part these projects are awaiting clarity regarding regulatory issues being discussed in rate hearings or facility approval processes.

18. It is no longer a question of "if" solar projects are technically and economically viable in and of themselves. The open and competitive energy market and welcoming regulatory environment that made Alberta attractive for solar proponents, however, has shifted. Consequently, proponents are now faced with regulatory and policy uncertainty that will negatively affect the pace and quantity of solar developments in the province. The high degree of uncertainty in Alberta's regulatory and policy regime is reducing confidence among corporate, C&I entities seeking power purchase agreements (PPAs) and among project financiers – and has likewise impacted community generation. Although there is a high interest in renewable PPAs generally, there seems to be an unwillingness to commit to solar projects in Alberta as financiers and off-takers opt to wait out the uncertainty.

19. The following challenges pose critical uncertainties to otherwise economic and competitive business cases:

a. **Interconnection and Approval Complexity –** The application of a policy framework designed in an environment dominated by load supply (a high-majority of which are C&I customers, with increasing interest from community groups) has created a complex and overly rigid interconnection and approval process for generators. The average length of time to develop a solar project from design to interconnection is 4-5 years and is comprised of various investment and development milestones; in addition to the technical, natural environment and social context, and financial aspects of development, proponents must navigate the following complexities:
    - *AESO interconnection timelines* – inflexible and complex BTM and lengthy connection processes;
    - *Utility capacity queuing practices* – unnecessarily stringent practices (i.e., FortisAlberta restricts proponents to 52 weeks between project interconnection acceptance and construction before capacity is released). Feeder capacity queues maintained by utilities are not aligned with BTM staged requirements set forth by the AESO;
    - *Alberta Environment and Parks* – long and ambiguous review timelines that preclude AUC consideration of projects;
    - *AUC Regulatory Requirements* – Existing policy and regulation (i.e., Rule 007, Transmission Regulation) are in part not reflective of the specific characteristics of renewable DG projects. Special interest groups with exaggerated concerns can intervene and force hearings potentially costing 5% of a project capital cost.

b. **Costs Borne by Proponents** – All capital costs to interconnect to the Alberta Interconnected Electricity System (AIES) are borne by proponents and high costs to upgrade distribution and transmission infrastructure can be unfavorable for project economics. Existing policy limitations do not enable DFOs to appropriately or cost-effectively integrate renewable generation into the distribution system. For example, without the technology or devices installed to accommodate more renewable generation, TFOs and DFOs err on the side of conservative, requiring proponents to bear the costs of reconductoring, voltage control, metering and metering services (e.g., data analytics), adaptive protection and transmission upgrades. Finally, substation fraction assessments by the AESO for facility expenditures unrelated to the generation connection have the potential to make projects uneconomic or too risky for development.

c. **Independent System Operator (ISO) Tariff Changes** – The AESO Information Document ID 2018-019T (ID) and the 2018 ISO Tariff Application articulate a change to feeder level totalization versus the long-held substation level totalization (per AUC Proceeding 22942). The AESO proposed a reinterpretation of the metering point between the transmission and distribution systems from the substation to the feeder level. If implemented, this change has the potential to significantly reduce transmission credit revenues for solar DG projects and likewise, increase capital costs for transmission

facility upgrades that were originally completed to serve areas of increased load. Further, this change is proposed to apply retroactively to existing generators.

d. **Utility/ISO Tariff Structures** - Specific to residential or other small-scale battery storage, there is currently no storage specific tariff that makes the value of storage greater than the cost of installing it. For example, storage enables peak shifting (i.e., the ability to store excess electricity for later consumption) with the appropriate time-of-use (TOU) rate and tariff structures. At the utility scale, battery storage used for infrastructure deferral, ancillary grid services (i.e., frequency regulation) or firming solar outputs can be used to reduce system-wide costs. In the absence of enablement in existing tariffs, proponents do not have the appropriate market incentives and price signals to optimize battery storage deployment.

e. **Pending Capacity Market** – The continuation of the transition to a capacity market, announced by the Alberta Government in 2016, presents a significant unknown to solar proponents. In the current energy market, generators are compensated for the energy produced in hourly markets, allowing them to capture the value of higher prices that occur when demand is strong. This pure energy merchant approach provides solar proponents and investors with lower risk and relatively clear price signals. Should the capacity market move forward, the design of the capacity market and its interaction with the separate energy and ancillary markets, as yet proposed but not determined, radically changes the compensation model, scale of uncertainty, and allocation of risk for price takers such as solar projects and small scale / community generators. A detailed report by Marketing Analytics describes these market design and interaction considerations, expressly stating that no two capacity markets are alike and the design of a new capacity market must be jurisdictionally specific (Marketing Analytics, 2016).

f. **Carbon Pricing Uncertainty** – The Government of Alberta is proposing to replace the Carbon Competitive Incentive Regulation (CCIR) with a Technology Innovation and Emissions Reduction (TIER) system for Alberta's large industrial emitters, with a target effective date of January 1, 2020. The ability to generate offsets is a key value stream for solar projects and the value of carbon offsets are offered as a line item in PPA negotiations. It is anticipated that the TIER will continue to permit the use of solar energy to generate emissions offsets via the Alberta Emission Offset System[6].

g. **Uncertainty with Injection of Electricity to the Grid –** With respect to EPCOR's recent application for a 12 MW solar facility, the AUC recently released a decision stating that generation located at customer sites cannot export to the grid unless it falls under an Industrial Site Designation or Microgeneration Regulation, which is seen as a reversal of previous policy (AUC Decision 23418). The essence of the decision is that solar generation located on a customer site can only produce energy to the extent it is

[6] Quantification protocols for the Alberta Emission Offset System are available here: https://www.alberta.ca/alberta-emission-offset-system.aspx

entirely consumed onsite and raises potential need for forfeit of a generator's capabilities, affecting economics.

20. When considering the impacts of the challenges above, it is key to recognize that the costs of dealing with uncertainty, frivolous intervention, and allocation of load related facility costs are paid by the proponent. This ultimately increases required investment and undermines project economics, raising the price threshold at which projects are viable or preventing the project from proceeding and reducing the growth of generation capacity. In either case, the consumers of electricity suffer from higher costs of supplied energy due to delayed or non-existence of competitive capacity.

Small- to Medium-Scale Solar PV

21. Investment in Alberta's solar market has been facilitated by enhancements to the Micro-Generation Regulation (increasing the maximum size permissible to 5 MWac), programs for Indigenous communities and municipalities, and rebate programs for residential and commercial consumers offered through Energy Efficiency Alberta (Poissant, Baldus-Jeursen, & Bateman, 2017).

22. Although the Micro-generation Regulation enabled the growth of small-scale generation in Alberta since 2008, and following its subsequent revision in 2013, the growth is largely seen by projects less than 1 MW. The Micro-generation Regulation is restrictive in that the size of generation is dictated by the load on site and not by the generation characteristics that the site offers. For example, a project proponent that has space and connection capacity to produce energy equal to 150 percent of the on-site consumption is not permitted to fully build out under the Regulation. Further, development of small-scale generation sized greater than 1 MW under other regulation (i.e., as a DG under the Electric Utilities Act) can become cost prohibitive as it introduces the need for AUC Rule 007 approval processes, higher utility interconnection costs and reduces savings from economies of scale both for input costs and outputs generated. It is important to note that there are trade-offs for proponents to consider when developing projects and site-specifics can weigh heavily on project economics.

23. Residential, municipal and commercial customers in Alberta are increasingly interested in the prospect of independence from the grid or a source of back-up power. The recent Small-scale Generation Regulation will enable community generation for municipalities, educational institutions, remote communities, First Nations, Métis settlements and others. The Municipal Climate Change Action Centre in partnership with Alberta Innovates are investing $10 million to fund one or several projects that participate in the Municipal Community Generation Challenge. The challenge provides opportunities for municipalities to participate in access to renewable energy, generate revenue by selling electricity to the grid and realize social and environmental benefits in their communities.

24. Solas Energy Consulting presented results of an Alberta Solar Market Outlook at CanSIA's Solar West Conference in May 2017 (Solas Energy Consulting, 2017). The results indicated 6% of electricity from solar by 2030 (up to 4.3 GWdc) is reasonable in Alberta. Their findings revealed that the residential sector will continue to be important for the solar industry, that utility scale solar will be the key factor for growth and that three market segments are directly tied to the micro-generation regulations (e.g., residential, C&I and farm markets).

25. Rooftop solar has economic and technical potential particularly in urban settings. As demonstrated by a case study of the city of Lethbridge, Alberta, the achievable potential for rooftop solar electricity generation potential within the city is approximately 301 GWh annually, or 38% of its annual electricity consumption (Kouhestani, et al., 2019). As shown in Figure 5, the majority of the city's potential for solar generation comes from the residential sector, followed by the C&I sectors. Kouhestani et al. (2019) found that "about 96% of the identified suitable rooftop systems are profitable. Small systems occupying small areas are the most likely to fail to be economically justified. However, with more declined PV costs and improved efficiencies, small areas can achieve a higher packing factor, produce more energy, and become economically attractive." This case study provides a standardized methodology for assessing solar potential using light detection and ranging (LiDAR) data and geographic information system software (ArcGIS) to identify suitable rooftops and new methods of assessing the solar radiation resource available which could be applied to cities across Alberta.

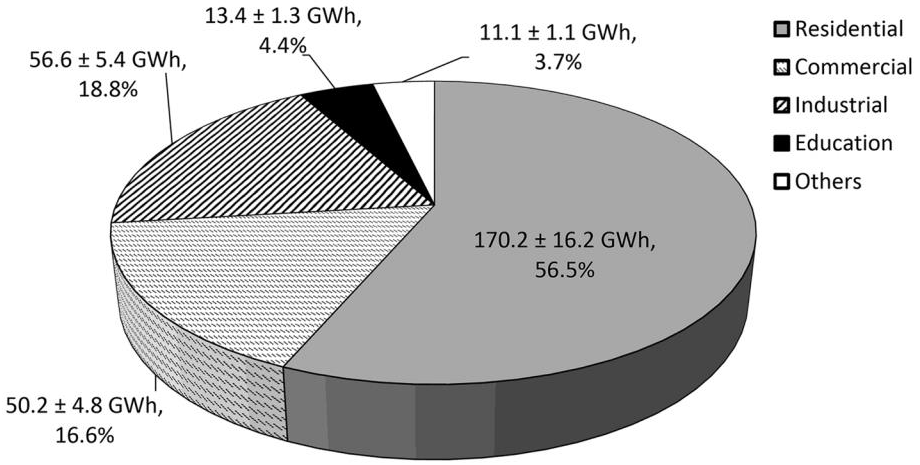

Figure 5. Rooftop solar electricity potential generation by different building sectors per Lethbridge Case Study (Kouhestani, et al., 2019)

Solar PV Plus Battery Storage

26. The value of solar to the customer can be increased by controlling and temporally shifting electricity output through the use of energy storage and other load control devices, an approach referred to as “solar plus” (O'Shaughnessya, Cutler, Ardani, & Margolis, 2018) and illustrated in Figure 6. O'Shaughnessya, Cutler, Ardani, & Margolis (2018) show that “solar plus” can increase on-site solar use and that these benefits can justify the incremental costs of “solar plus” devices for a variety of technologies (e.g., batteries, smart appliances, smart plugs, air conditioning units, hot water heating, electric vehicles), geographies, and customer load profiles. Customer benefit associated with “solar plus” is greatest when (a) electricity output is sold to the grid at a lower value than the customer’s retail rate, (b) TOU rates peak periods do not coincide with solar output, (c) demand charge rates for load peaks do not coincide with solar output, and (d) electricity delivery charge rates are significant and/or vary with consumption. While a solar plus storage home is portrayed in Figure 6, the same concepts would apply to C&I customers, as well as MUSH sector (i.e., Municipal, University, Schools, Housing), etc.

27. “Solar plus” system can either “pull” electricity use into periods of solar output or “push” solar output into later times of the day (O'Shaughnessya, Cutler, Ardani, & Margolis, 2018). As shown in Figure 7, a “solar plus” customer increases self-use during periods of solar output, reducing export to the grid and “pulling load” from the peak period. Alternatively, a “solar plus” customer can charge batteries using solar output and “push solar output” to the peak period. In either case, “solar plus” customers can respond to price signals and avoid higher-price peak periods. O'Shaughnessya, Cutler, Ardani, & Margolis (2018) note that “low-cost load control options are generally more cost-effective than higher-cost batteries, though batteries may be deployed in the near term because of co-benefits such as backup power.”

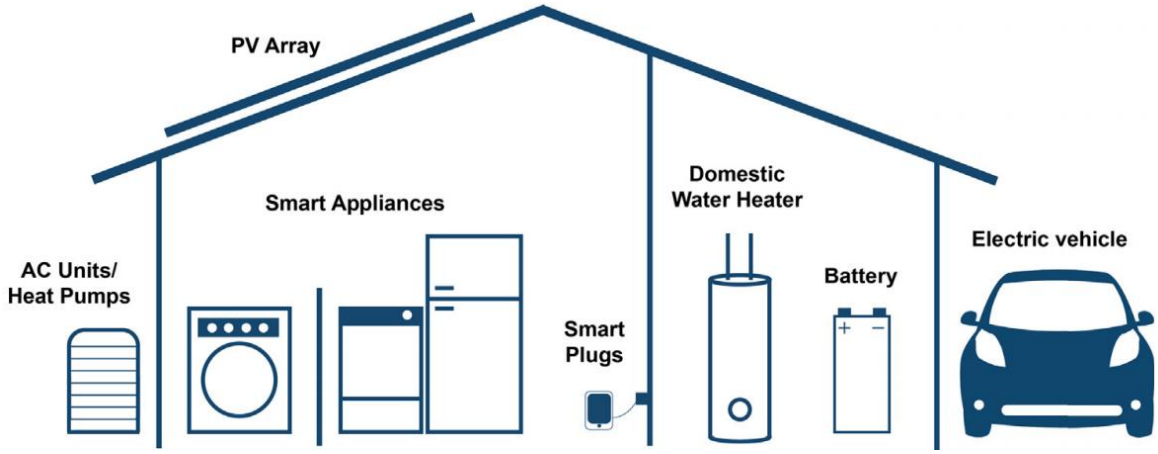

Figure 6. A "solar plus" home (O'Shaughnessya, Cutler, Ardani, & Margolis, 2018)

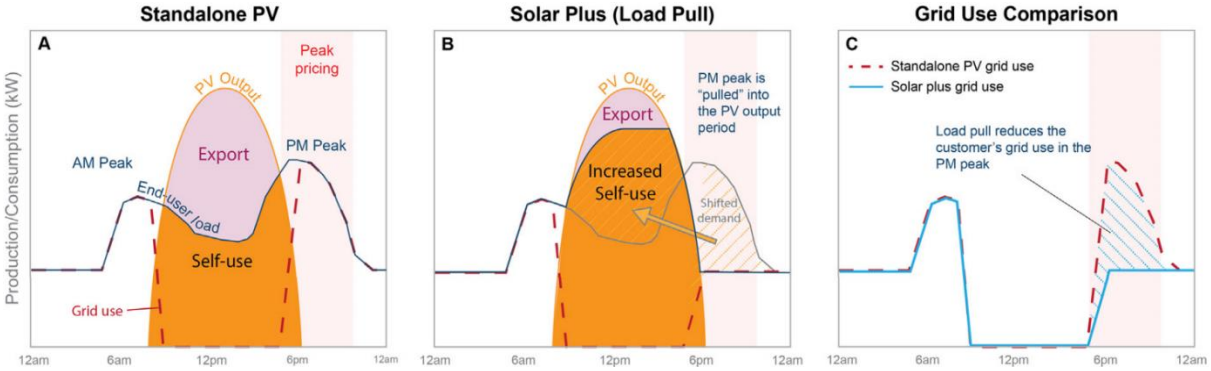

Figure 7. Grid use comparison of standalone PV and "solar plus" in load pull scenario (O'Shaughnessya, Cutler, Ardani, & Margolis, 2018)

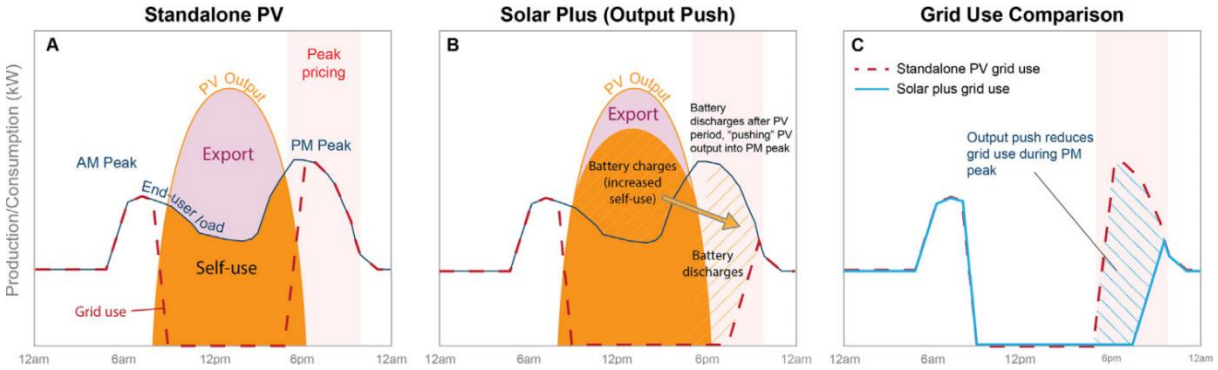

Figure 8. Grid use comparison of standalone PV and "solar plus" in output push scenario (O'Shaughnessya, Cutler, Ardani, & Margolis, 2018)

28. In Alberta, solar output aligns well with high summer electricity demands, including air conditioning and C&I cooling. There is a high degree of correlation between daytime solar outputs with consumption activities which makes solar a viable option on its own. Further, solar is highly predictable, and its outputs can be reasonably forecasted to incorporate solar into a system-wide dispatch strategy.[7] Large-scale deployments of battery storage provide a beneficial addition for solar to provide a firmer capacity product. For example, Electric Reliability Council of Texas (ERCOT) projects solar "will be the biggest contributor to raising the grid's reserve margin to 11.6% by 2021, significantly reducing the likelihood of shortages.[8]"

Summary

29. Solar is an economically viable source of electricity supply. It is a particularly accessible source of energy for community projects given its scalability and ability to be connected directly to a host consumer or directly to the electricity grid. In certain circumstances,

[7] Exhibit 22942-X0331, Appendix B Peters Energy Evidence. PDF Pages 24-25.
[8] Reference: https://www.utilitydive.com/news/ercots-reliability-anxiety-energy-groups-square-off-on-whats-to-blame/553608/

solar+storage applications are becoming increasingly more cost effective as well. Solar as part of a "solar plus" system can be responsive to price signals and incentives to shift consumption or output. Whether an individual consumer, community or corporation, uncertainties may impact the business case for the adoption of solar or solar+storage, including: interconnection and approval; costs borne by proponents; ISO tariff charges; utility/ISO tariff structures; pending capacity market decisions; carbon pricing; and uncertainty with respect to injection of electricity to the grid.

IV. Impacts on Distribution System – Question 2 (b)

Question: 2 (b) How might distribution facility owners need to respond at a technical level to the adoption of a certain technology or innovation? What modifications to their existing distribution systems may be required, and what are the expected costs?

30. Contemplation of the costs for technology to interconnect and integrate DERs onto the distribution system (and AIES) is heavily dependent on the utility industry's ability to shift from a traditional to an integrated utility model. This shift represents an ideological change from a long-standing industry to one where innovative and customer-valued services become a key part of the business model. A walk, jog, run approach is recommended to ensure contemplation of these changes and their effects on costs. Generally, costs can be lower if policy evolution and the business model transitions of DFOs, AESO and the AUC:
    - Incorporate greater reliance on non-wires alternatives (NWAs);
    - Integrate the reactive power capabilities of inverter-based generators;
    - Embrace bi-directional flows on the distribution system; and
    - Integrate information and controls to address unlikely conditions and "edge cases" rather than responding to capacity or reliability issues with capital investment solutions.

31. Lawrence Berkeley National Laboratory have proposed a three-staged evolutionary framework for the distribution system driven by the growth of DERs (De Martini, Kristov, & Schwartz, 2015). As illustrated in Figure 9, Stage 1 considers grid modernization with low level of DER adoption, Stage 2 considers DER integration, optimization and distribution platform development with moderate to high levels of customer adoption, and Stage 3 considers distributed markets operations and multi-party transactions. In practice, this means that distribution functions (i.e., planning, operations, and market) should evolve as greater customer adoption of DERs occurs, as listed in Figure 10.

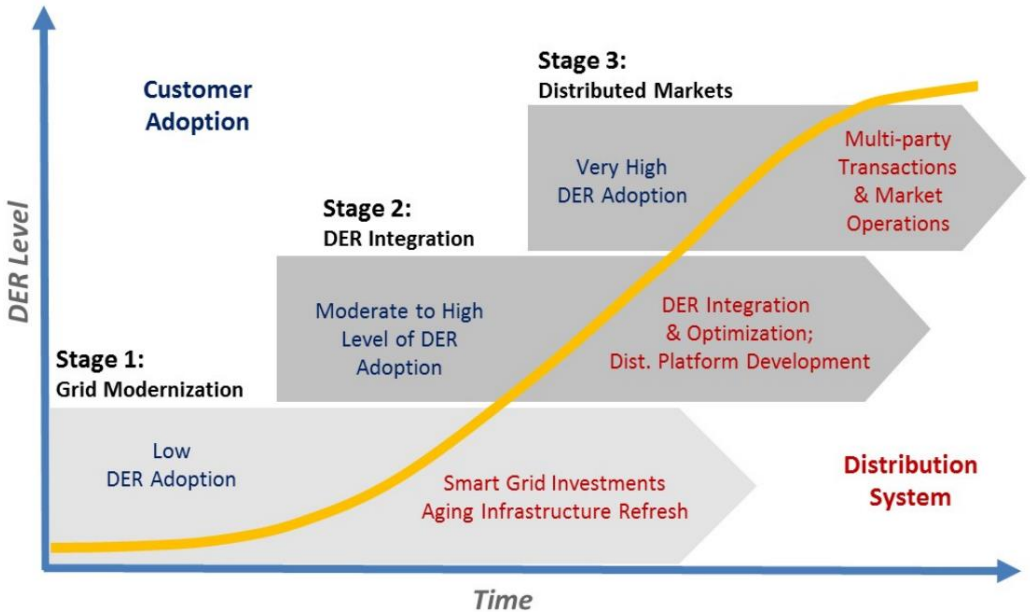

Figure 9. Distribution System Evolution (De Martini, Kristov, & Schwartz, 2015)

Distribution Functions	Stage 1	Stage 2	Stage 3
1. Planning			
A. Scenario based, probabilistic distribution engineering analysis	✓	✓	✓
B. DER Interconnection studies and procedures	✓	✓	✓
C. DER Hosting capacity analysis	✓	✓	✓
D. DER Locational value analysis		✓	✓
E. Integrated T&D planning		✓	✓
2. Operations			
A. Design-build and ownership of distribution grid	✓	✓	✓
B. Switching, outage restoration & distribution maintenance	✓	✓	✓
C. Physical coordination of DER schedules		✓	✓
D. Coordination with ISO at T-D interface		✓	✓
3. Market			
A. Sourcing distribution grid services		✓	✓
B. Optimally dispatch DER provided distribution grid services		✓	✓
C. Aggregation of DER for wholesale market participation		✓	✓
D. Creation & operation of distribution level energy markets; transactions among DER			✓
E. Clearing and settlements for inter-DER transactions			✓
F. Market facilitation services			✓

Figure 10. Distribution Functions by Evolutionary Stage (De Martini, Kristov, & Schwartz, 2015)

32. The response of DFOs to greater uptake of DERs is not hypothetical along the three stages described in paragraph 23, as evidenced by ConEdison's distribution system implementation plans (Consolidated Edison , 2018). ConEdison has developed a 20-year grid modernization plan that details initiatives and upgrades the company will undertake, as illustrated in Figure 11. Over the next 5 years, ConEdison is anticipating investments in a range of activities, including grid visibility, planning tools, DER hosting capacity tools, two-way power flows, cyber threat detection, etc. ConEdison has also outlined long-term goals for the development of its distribution system platform, including market services (e.g., procurement, market coordination, wholesale tariff, billing/settlement), DER Integration (e.g., integrated DER planning, DER interconnection, DER management), and information sharing (e.g., information management, customer engagement), shown in Figure 12.

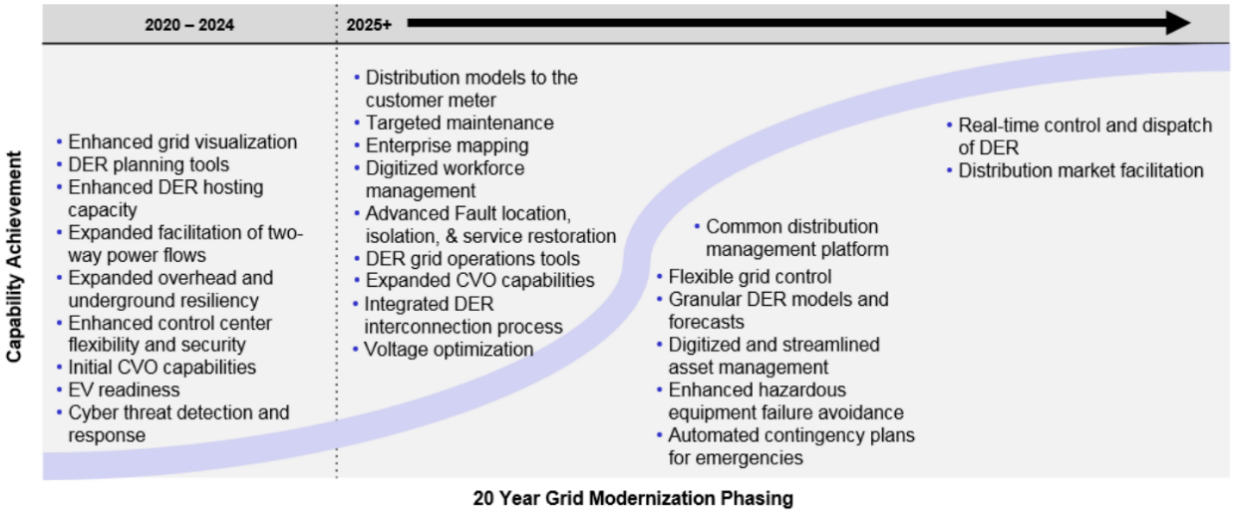

Figure 11. Overview of ConEdison's grid modernization plan (Consolidated Edison , 2018)

Figure 12. Overview of ConEdison's Long-Term Goals for Distribution System Platform Functions (Consolidated Edison , 2018)

33. More broadly, the results of a survey of multiple U.S. states summarizing new approaches adopted with respect to distribution system planning in context of grid modernization and higher levels of DERs is shown in Figure 13.

Planning Approaches	States With Advanced Practices					Other States' Approaches										
	California	Hawaii	Massachusetts	Minnesota	New York	D.C.	Florida	Illinois	Indiana	Maryland	Michigan	Ohio	Oregon	Pennsylvania	Rhode Island	Washington
Distribution system plan requirement[1]	√	√	√	*	√					√	√					
Grid modernization plan requirement	√	√	√	√	√											
Incentives reflecting locational value	√				√											
Hosting capacity analysis requirement	√	√		√	√											
Non-wires alternatives requirements	√				√										√	
Standardized calculations / processes	√				√											
Storm hardening requirements							√			√						
No planning requirement but proceeding underway[2]						√		√				√	√		√	√
Requirement to summarize current practice				√	√					√						
Voluntary distribution or grid modernization plans supporting surcharge/rider cost recovery								√	√			√		√		
Improved alignment / linking processes	√			*											*	*
Required reporting on poor-performing circuits and improvement plans							√	√				√		√	√	

√ is used to indicate the planning approach is applicable under the present regulatory or statutory requirements.
* is used to indicate that the planning approach would apply under pending proposals or proposed decisions.
[1] Requirements for one or more utilities.
[2] States noted in this row have processes underway which may result in adoption of one or multiple planning approaches listed in this table.

Figure 13. Approaches to distribution system planning by U.S. state (Cooke, Schwartx, & Homer, 2018)

34. With respect to costs, it is important to acknowledge that at low penetration levels (e.g., up to the hosting capacity), the costs of integrated distributed solar is zero or near zero. While each utility will be case specific, one framework proposed breaks down the cost of integrating solar into three domains, as illustrated in Figure 14 (Horowitz, Palmintier, Mather, & Denholm, 2018). Beyond the (near) zero cost domain (i.e., existing hosting capacity), the quantifiable cost domain consists of incremental costs of increasing solar penetration; however, costs will be dependent on the mitigation strategy selected by the utility and the specifics of the existing network (e.g., feeders, loads, solar resource, etc.). For example, transmission protection and control mitigations recommend substation protection equipment for “side-case” or unlikely conditions.

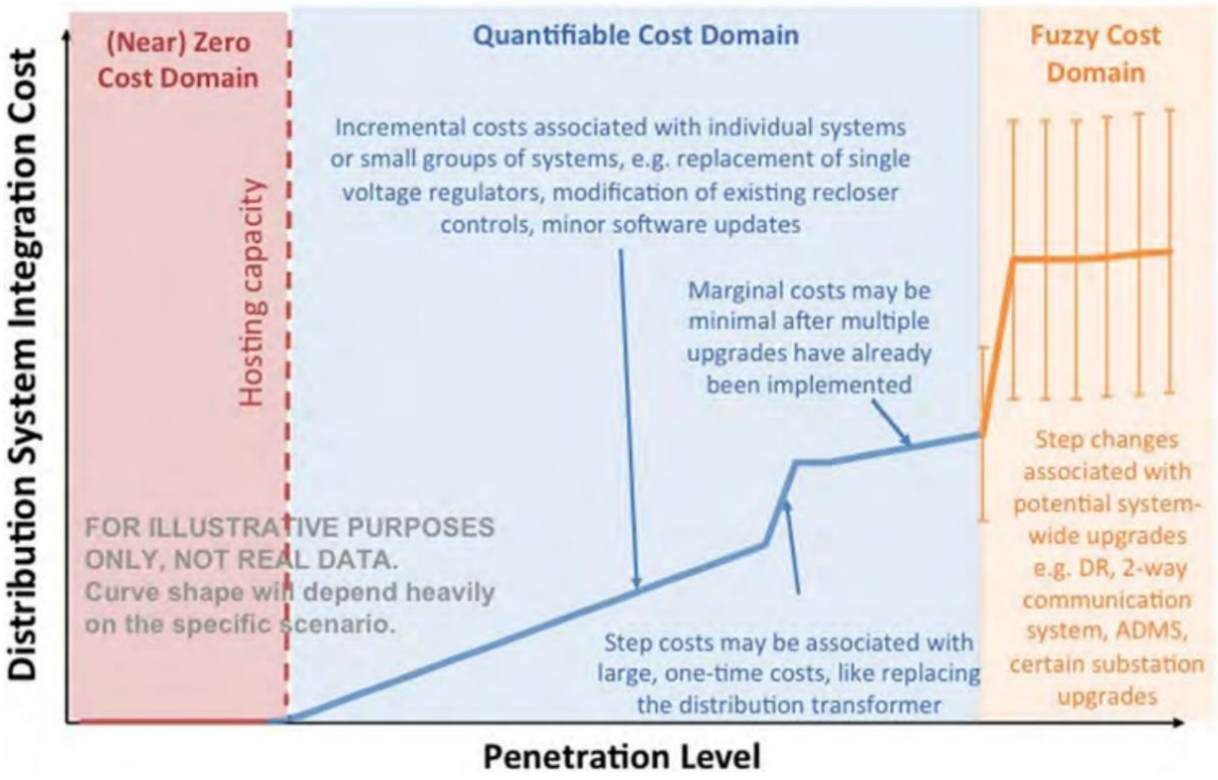

Figure 14. Three domains of solar distribution system integration costs (Horowitz, Palmintier, Mather, & Denholm, 2018)

35. In cases where a proponent proposes to connect new generation to a feeder, protection equipment is required in the event that the feeder load drops off and reverse power flow to the substation is a risk. In the "fuzzy cost domain", solar integration costs are not only difficult to quantify, but they may also be difficult to attribute to solar uptake (Horowitz, Palmintier, Mather, & Denholm, 2018). In other words, many upgrades, such as communications, or SCADA software, may be implemented to support overall grid modernization. Note that while these upgrades are shown in the high solar penetration levels, certain upgrades may be justified by utilities at lower penetration levels (e.g., forward planning, broader efforts to reduce outages, etc.)

36. A list of distribution system upgrade costs associated with solar is provided in Figure 15. Note that the list of costs includes components that have multiple motivations and are not solely attributed to solar uptake (Horowitz, Palmintier, Mather, & Denholm, 2018).

37. When considering increased penetration of solar on the grid, there are a variety of solutions that, if optimally deployed, could affordably transform variable solar output into a firm resource and enable very high solar penetration (Perez, et al., 2016). As shown in Figure 16, solutions to firm electricity production to meet electrical demand with operational guarantees include energy storage, smart curtailment, load shaping and geographic dispersion.

Communication networks (wireless, fiber-optic, power line)*
Communication modules*
Communication bridges for field and substation devices*
Line sensors (voltage, current)
Recloser
Recloser controller
Relay
Relay controller
Fuses
Capacitor banks
Capacitor bank controller
Static VAR compensator
Modifications to or replacement of existing electronic controllers (for relays, reclosers, capacitors, etc.)
Load tap changer/Voltage regulator
Modify settings on load tap changer
Substation transformer
Distribution transformer
Grounding transformer
Smart meters and advanced metering infrastructure (AMI)*
Distribution supervisory control and data acquisition (SCADA) software or upgrade*
Conductor (for the distribution network)
Cost to integrate new systems with existing infrastructure*
Software for demand response*
Smart breaker panel*
Li-ion battery systems (including smart control system)*
Software and hardware for dynamic PV curtailment
Any additional software required for system re-optimization and protection
Applications for Volt/VAR optimization*
Solar resource and output modeling and forecasting software
PV monitoring and fleet management applications: Other
Distributed energy resources management system (DERMS) software or upgrade*
Distribution management system (DMS) software upgrade*
Data management solutions*
Phasor measurement units and accompanying software
Advanced substation controller*

Figure 15. List of distributions system upgrade costs related to distributed solar (Horowitz, Palmintier, Mather, & Denholm, 2018)

Starred (*) components in above list have multiple motivations for adoption (e.g., may be adopted in absence of solar uptake)

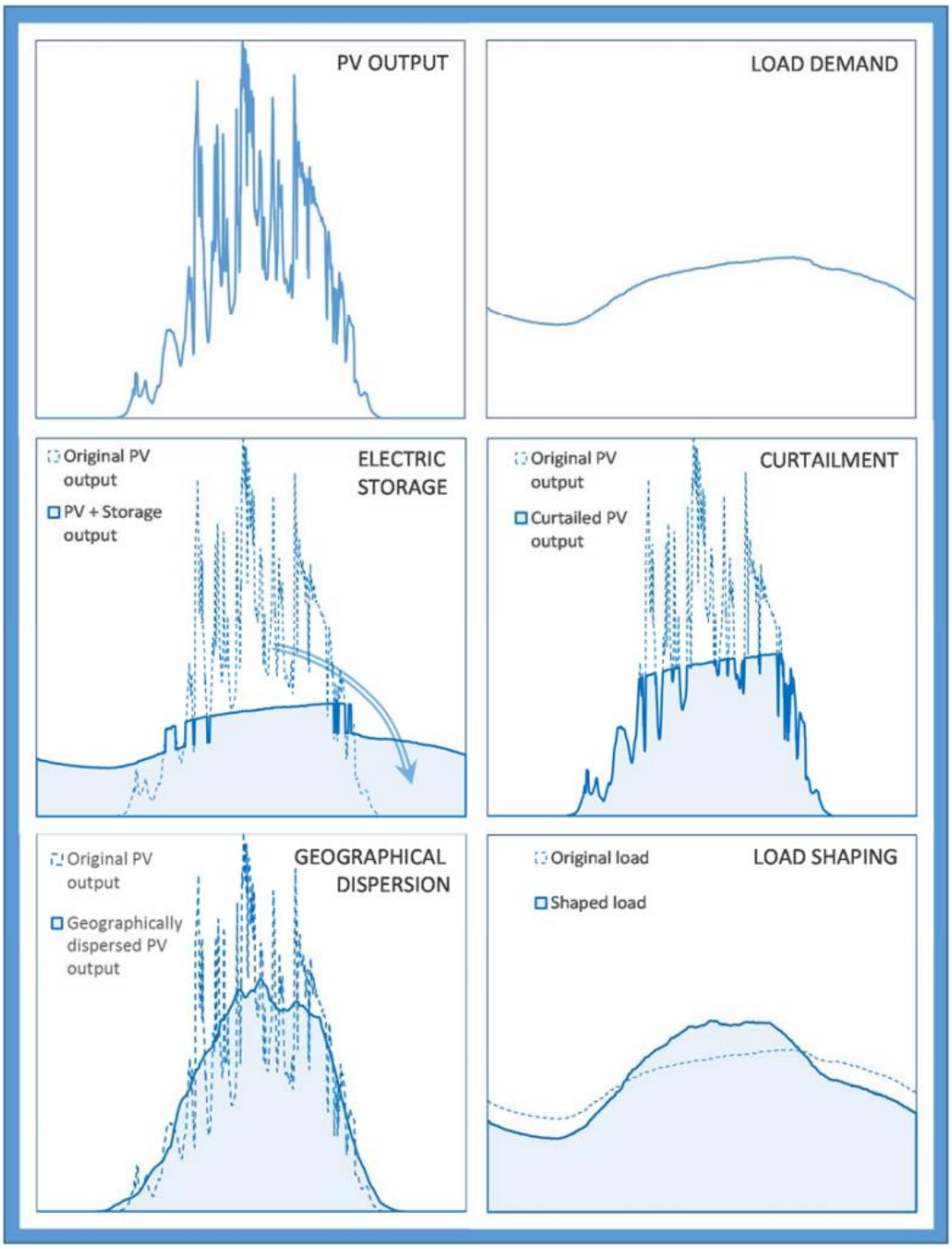

Figure 16. Solutions for firming solar generation at very high penetration (Perez, et al., 2016)

38. Although solar has variability due to impacts of the location of the sun and cloud cover, intermittency is something that all generation experiences. Almost daily, large fossil fuel or other generators are off-line due to planned or unplanned outages of the equipment. To compensate, the AESO is required to plan for and mitigate intermittency of the existing generation fleet. In comparison, solar equipment is extremely reliable and robust. Modules,

inverters and collection systems have very few moving parts. Reliability is further enhanced by the fact that a typical solar farm is really a collection of power plants up to a maximum of 2.5 MW in size, so a failure in any one of those plants has a very minor system impact. The position of the sun is wholly predictable; only cloud cover creates uncertainty in the output of solar generation, and loads related to cooling are highly correlated with solar output.

Summary

39. With DERs increasing within distribution systems based on demand from individual customers, corporations and communities, as well as their ability to be leveraged as NWAs, DFOs will need to adapt to changing conditions and expectations. As we see in other jurisdictions, this includes taking immediate steps in advance of significant DER uptake, including scenario-based probabilistic distribution engineering analysis, reviewing DER interconnection procedures, and DER hosting capacity analysis. Each utility should understand the current hosting capacity of DERs on the system (e.g., "(near) zero cost domain" per Figure 14) and be prepared to identify "quantifiable costs" as DER uptake increases. For community generation and Indigenous projects in particular, assessing available hosting capacity is a critical early step for business case development.

V. Impacts on broader Alberta Interconnected Electric System – Question 2 (c)

Question: 2 (c) Are there any expected effects on other entities that operate on the Alberta Interconnected Electric System, including the transmission system, the Independent System Operator, transmission-connected generators and/or retailers, as a result of the adoption of a certain technology or innovation? If so, how might these entities need to respond?

40. In a recent staff report, the Federal Energy Regulatory Commission (FERC) reviewed the technical considerations for the bulk power system with increasing uptake of DERs (Federal Energy Regulatory Commission, 2018). At a high-level, FERC staff identified the following:
    - Challenges associated with grid visibility associated with "netting off" DERs with load (i.e., lack of telemetry associated with BTM resources) masking operational effects of DERs;
    - DER capabilities for voltage and frequency ride through during contingencies;
    - The potential for improved customer-level voltages due to the unloading of the bulk power system associated with the location of DERs at or near customer loads;
    - The potential effects on system-wide transmission line flows and generation dispatch due to changing load patterns; and
    - The sensitivity of voltage or power needs to different types of DER applications (i.e., the provision of energy, capacity, or ancillary services).

41. With the potential increase of DERs over time, the bulk grid shifts "to a complementary role as a residual supplier and a network for economic transactions" (Kristov, 2019). As shown in Figure 20, an integrated-decentralized power system model envisions that transmission system operators (TSOs) or ISO would continue to be responsible for their balancing

authority area (BAA) while interacting more closely with connected local distribution areas (LDA). The distribution system operator (DSO) would take on increased responsibilities with respect to the activity of DERs within the LDA, communicating in real-time effects of the DER operations in aggregate to the TSO/ISO and potentially taking on a greater role with respect to the dispatch/operations of DERs. As DER connections increase, greater coordination between ISO/TSOs and DSOs is required to mitigate operational challenges, including volatility, new peaks and peak shifts, real-time balancing, fast ramps and flexibility.

42. DERs such as solar and solar+storage can be "passive" - not integrated into the wholesale electricity market, or "active" - integrated into the wholesale electricity market. Depending on whether DERs are active or passive, DERs can have varying impacts on ISOs. For example, increased passive DERs can lead to challenges with respect to load and generation forecasting, as DERs are not necessarily visible to the ISO, are not necessarily responsive to wholesale market price signals and are not in dispatch control of the ISO. Some ISOs are taking steps to enable more active DER participation, either by lowering the threshold for participation in the wholesale market (e.g., Alberta's threshold for participation is 5 MW), or designing more permissive aggregation frameworks for resource participation.

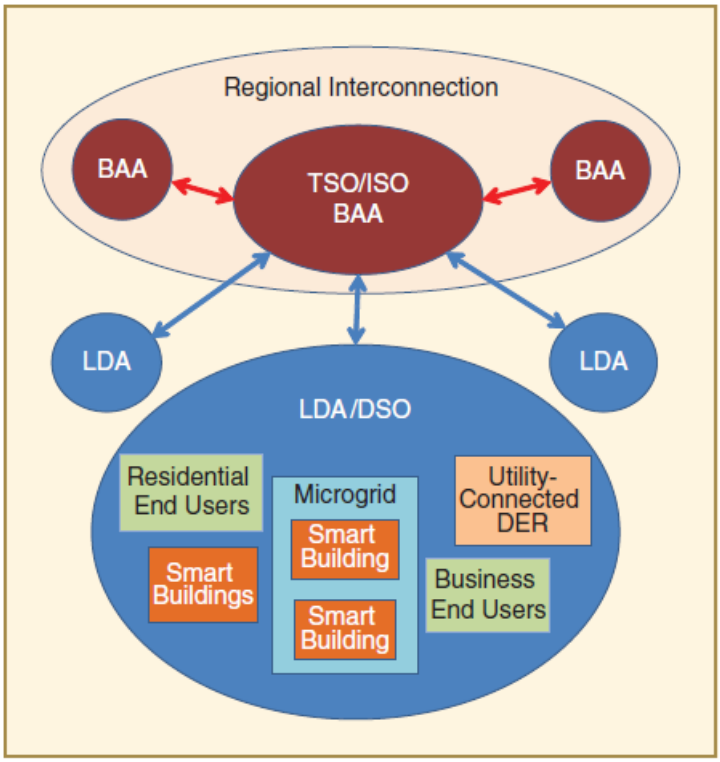

Figure 17. The integrated-decentralized power system (Kristov, 2019)

43. In the distribution system, solar and solar+storage can provide active assistance to distribution operations. Storage can be dispatched to provide energy to feeders during

times of outage or peaks, providing significant capital savings as construction of additional facilities to used only during times of outage or peak load can be avoided.

44. Solar and solar+storage systems can also provide active power factor support, 24 hours per day to the distribution system. Inverters at solar farms are able to produce or absorb volt-amperes (VARs), whether there is sun on the solar farm or not. The inverters can be readily controlled to setpoints on the distribution system or taking a system from the DFO, enabling the system to be optimized for performance, to reduce losses, etc. There can also be a capital cost saving for DFOs since by contracting with solar or solar+storage operators, installation of capacitors can be avoided. The performance of the power factor control can also be improved since capacitors are generally passive devices optimized to an assumed singular design condition.

45. In addition to the wholesale electricity markets, DERs can provide assistance to the grid as a whole in the form of ancillary services. Current AESO programs for ancillary services have performance requirements that match typical performance of fossil fuel generators. However solar generators and batteries, relying on inverters that react at a very high speed, can outperform fossil fuel generators. By moving to an hourly market rather than a 16 hour market executed up to three days ahead, solar generators and batteries can participate fully in the Alberta ancillary services market, enhancing competition and significantly reducing cost.

46. Most utilities in Alberta have transitioned to automated smart meters, which use powerline communication to send usage data from the meter to utilities and on to the energy retailer. Smart meters are a first step in AMI deployments. Further integration of AMI with outage management systems, distribution management systems, and other distribution automation systems increases visibility and control for utilities. AMI will also enable customer devices and systems that operate using smart meter load data and price signals from the utility to facilitate customer participation in electricity markets and encourage peak demand reduction. The ability to communicate electricity prices and consumption levels frequently is enabled with data provided at 1, 5, 15 or greater time intervals. This visibility enables time of use pricing and other customer incentives to manage (peak) demand resulting in the potential for:
    - BTM demand side management that can defer distribution or generation infrastructure upgrades or builds;
    - Increased customer engagement through reduced electricity bills and reduced peak demand;
    - Increased customer uptake and integration of solar, battery storage and other DERs such electric vehicles;
    - Aggregation of customer load and generation data to provide grid-level demand response to the ISO.

Summary

47. As more DERs, including solar and solar+storage, connect to the distribution system, there will be a growing need for coordination between ISOs, TFOs, and DFOs, particularly as more demand is served by local supply and the grid is available to provide residual supply and provides a network for economic transactions between parties. The need for greater coordination means that DFOs could take on greater roles to coordinate DERs connected to their networks. Resources that are not registered within the AESO market (i.e., passive DERs) are not visible to the AESO which may lead to challenges with respect to forecasting, planning and operations of the bulk system over time.

VI. Managing and Reducing Future Costs – Question 2 (d)

Question (d) How might a certain technology or innovation aid distribution utilities in managing and/or reducing future capital costs, including creating opportunities for non-wire alternatives and non-traditional utility planning approaches?

48. Traditional utility planning involves building more generation and expanding transmission and distribution infrastructure to accommodate it. Increased penetration of customer-sited solar generation, utility-scale solar, and battery storage – distributed across the AIES - have the potential to create an environment where traditional planning approaches will no longer be viable.

49. Escalating distribution and transmission wires charges in Alberta and the adversely declining costs of solar generation and battery storage are prompting greater customer interest and growth in DER investments. Growth in DERs can be an upside for distribution utilities whose business models rely on distribution infrastructure. With the appropriate enabling regulatory and policy structures in place, distribution utilities can better facilitate the interconnection and integration of DERs, thereby finding new financial opportunities and passing savings on to customers.

50. During the Alberta Electric Distribution System-Connected Generation Inquiry (Proceeding 22534), DFOs noted that:

    *"…as [*distribution-connected generators*] DCG penetration levels increase, they will need to invest in monitoring, control, communication and protection devices and systems to maintain system reliability, power quality and the safe operation of their distribution systems. Real-time knowledge of each systems' capacity could allow for the more efficient use of the existing infrastructure. Although these technological investments could enable the development of alternative and renewable DCG, the necessary investment costs would be a barrier."*

51. DFOs went on to list several technological upgrades including reinforced protection systems and infrastructure, grid-scale battery storage, advanced distribution management system

(ADMS),distributed energy resources management system (DERMS), and AMI metering. These technologies, while necessary for grid modernization that will facilitate increased penetration of DERs on the grid, have the potential to add significant capital costs without certainty of who will be responsible for these costs. Further, these technologies do not themselves address a fundamental need for utilities to adopt new planning approaches that consider cost-effective and dynamic methods to both plan for and better integrate DERs.

52. With forecasted growth in solar and battery storage interconnections, there is an increasing need for utilities to include DERs into planning forecasts to better understand their impacts, costs and benefits. This would guide cost-effective utility investments (and avoided investments) including the consideration of NWAs to replace or augment aging infrastructure and provide required system upgrades to address insufficient capacity (Figure 18)

53. Most utility load forecasting employs a top down approach that is based on historical trends and projected growth in peak loads, which is then extrapolated to certain locations on the grid. Relatively slow penetration of BTM DER adoption in Alberta to date has perhaps not yet warranted its inclusion in load forecasts. In the future, load forecasting should be adjusted for the effects of solar installations and battery storage on the observed peak loads to ensure that distribution and transmission system upgrades that can be deferred by customer adoption of solar and/or battery storage are, in fact, deferred.

54. Further, forecasts should also be completed for solar (Mills, Barbose, & Seel, 2016). Solar and battery deployments are highly variable and dependent on several factors affecting customer adoption, including the upfront cost of solar or solar+storage systems, availability and level of incentives, and tariff and rate designs that affect the bill savings/credits and macro factors such as load growth, oil and gas prices and the cost of battery storage. Utilities in the United States are testing several approaches to forecasting DER deployments. The use of customer adoption modelling is designed to account for customer-based decision making in projecting installed capacity of solar (Mills, Barbose, & Seel, 2016). For example, Pacific Gas & Electric (PG&E) was able to forecast DER adoption down to the substation level up to 2030 using Navigant's customer adoption modelling.

55. With the uptake of solar and solar+storage, it is commonly accepted that distribution system planning practices will require modernization. One framework for distribution system planning is illustrated in Figure 18. In their report, the Advanced Energy Economy States that:

    > "Although by no means the only objective of distribution system planning, one key outcome is to encourage DER to be sited in areas where it can be most beneficial to the grid. By making hosting capacity and non-wires solicitation information available to stakeholders, and building appropriate transparency into the planning process, utilities can help DER customers and providers to catalyze innovation and support private capital investment that complements utility investment. In turn, owners/operators of non-utility DER that provide grid services should provide appropriate information that allows

the utility to optimize their value for the benefit of all customers." (Advanced Energy Economy, 2018)

56. Inputs to the distribution system planning process include load modeling & forecasting, DER interconnection queues, customer and municipal project needs analysis (new loads), maintenance & report schedules and DER forecasts and scenario modelling. Outputs from the planning process including hosting capacity information (i.e., tables, maps, etc.), locational net-benefits analysis, which each serve as inputs with respect to sourcing of DER-provided services (i.e., NWAs); this in turn provides inputs into distribution system planning investment plans and the utility rate case.

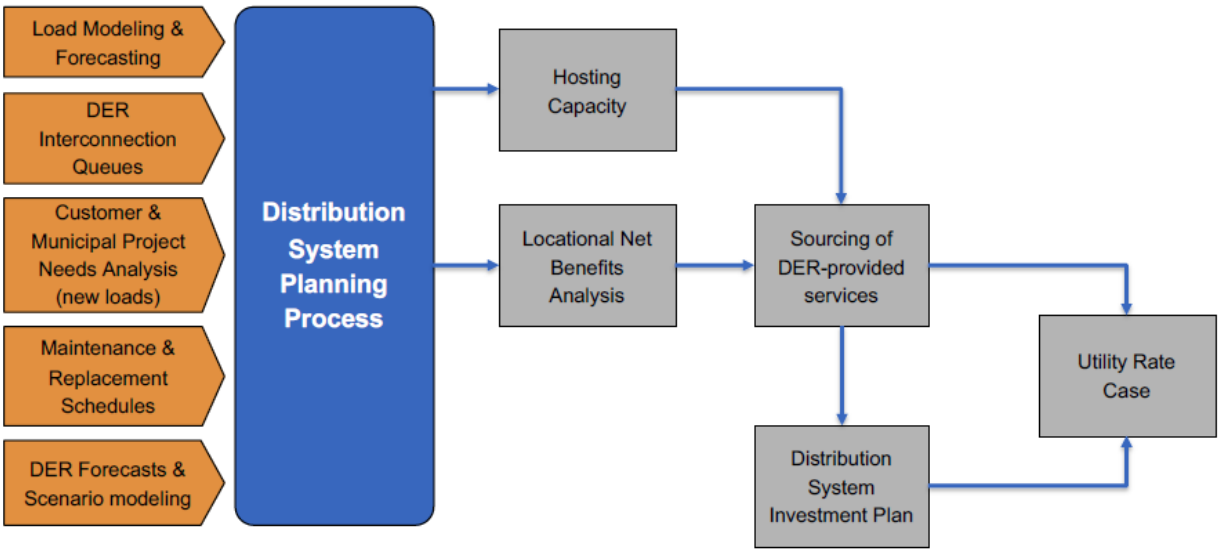

Figure 18. Modern distribution system planning process (Advanced Energy Economy, 2018)

57. Solar, particularly "solar plus" solutions (refer to paragraph 26), can provide a range of potential benefits and challenges to distribution utilities (O'Shaughnessya, Cutler, Ardani, & Margolis, 2018), as described in Figure 20. For example, benefits include distribution grid relief, transmission grid relief and grid infrastructure deferral. The potential challenges are driven by customer uptake (i.e., not necessarily within the distribution utilities control), change in peak load profiles, and grid operability issues.

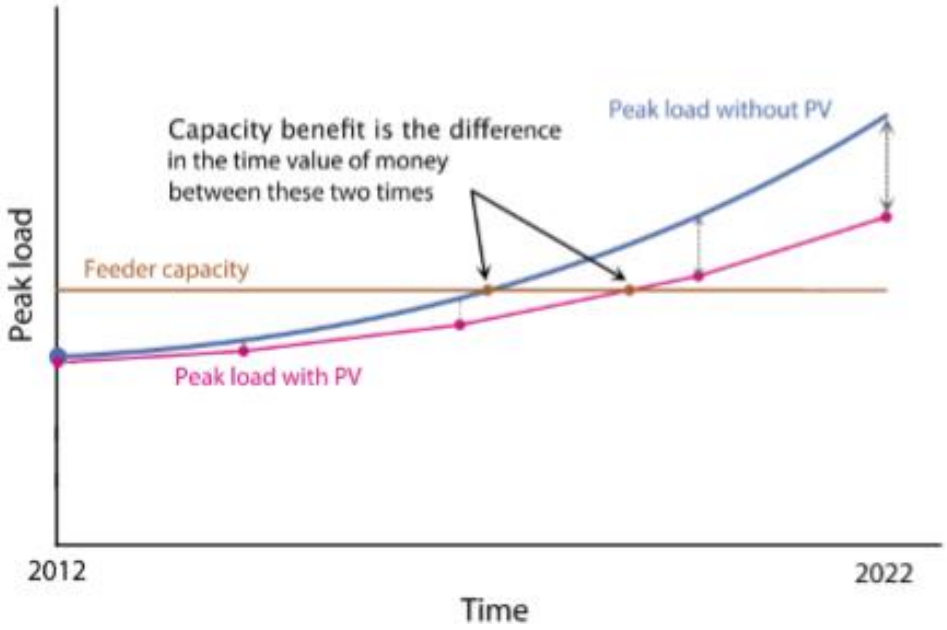

Figure 19. Example of distribution capacity deferral value of Solar (Mills, Barbose, & Seel, 2016)

Note: The deferral value would be greatest where the current peak load is near the capacity of the distribution feeder and where the Solar is coincident with the peak load on the feeder.

Potential benefits	Potential costs/challenges
• Increased value of PV output • Load smoothing • Improved system flexibility, provision of ancillary services (e.g., frequency regulation) • Distribution grid relief • Transmission grid relief • Grid infrastructure investment deferral • Black start capabilities	• More pronounced peaks in load profiles • System siting determined by end-users rather than grid operator • Irresponsive, decentralized capacity • Grid operability issues • Supply saturation • Equity impacts: disproportional benefits to high-income consumers • Effects on non-adopters • More complex grid/policy planning

Figure 20. System-level benefits and costs of "solar plus" (O'Shaughnessya, Cutler, Ardani, & Margolis, 2018)

58. Benefits to taxpayers and ratepayers can be quantified with respect to increased solar adoption relative to system costs (Perez, et al., 2016). An example of the range and magnitude of these impacts and benefits is provided in Figure 21, including energy value, transmission capacity value, loss savings, distribution capacity value, fuel price risk mitigation, market price suppression, security, environment, societal, economic development and local resiliency.

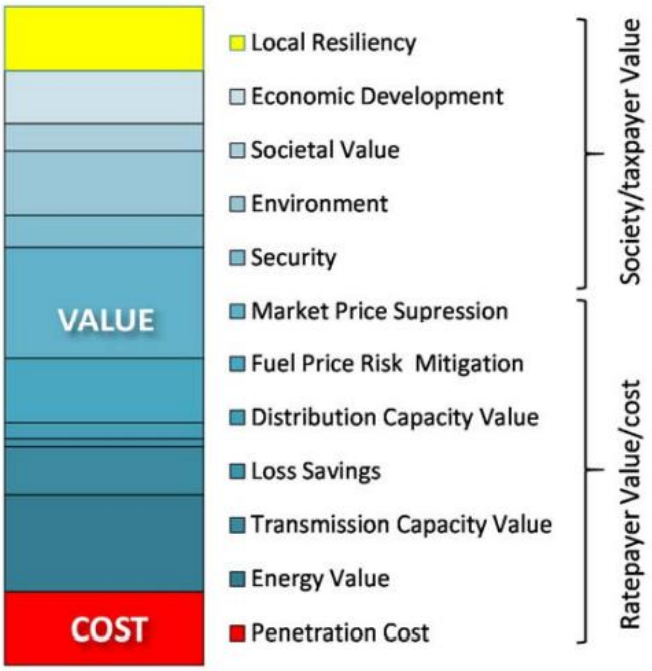

Figure 21. Example of composite taxpayer/ratepayer value and cost of solar (Perez, et al., 2016)

59. In 2018, the Smart Electric Power Alliance, Peak Load Management Alliance and E4TheFuture published cased studies from leading U.S.-based NWA projects (Chew B. , Myers, Adolf, & Thomas, 2018). References from their report refer to 10 NWA case studies and share insights from those projects, including:
    - Flexibility – NWAs can be implemented in phases as load grows;
    - Reliability – NWAs can provide comparable reliability at lower costs compared to transmission construction projects;
    - Cost savings – NWAs can reduce stranded costs that may result from unnecessary infrastructure upgrades if forecasted load growth does not materialize; and
    - New approaches to revenue and incentives are needed – a major hurdle for NWA projects is the traditional utility model of compensation (e.g., fixed rate of return on traditional capital investments).

60. A clear demonstration of how distribution facility operators are responding to NWA opportunities is illustrated by Reforming the Energy Vision (REV) Connect (NY REV Connect,

2019). Their website clearly lists all NWA procurements by utilities. Instead of prescribing a solution, the NWA procurement defines the problem and lists the technical requirements of the solution. In this way, the procurement is technology agnostic, and enables bidders to propose the most cost-effective solution to meet specific system needs.

61. The case studies in New York State are representative of the use of solar and solar+storage as non-traditional planning approaches, including: (i) aggregated BTM energy storage; (ii) technology to increase hosting capacity on a circuit; (iii) innovative battery storage business model; (iv) flexible interconnection capacity solution to interconnect large DERs more efficiently; and, (v) clean virtual power plant that bundles solar and storage (New York Public Service Commission, 2019).

62. Traditional planning and interconnection practices limit the amount of DERs that can be interconnected before the costs of distribution or transmission system upgrades borne by the project proponents become economically non-viable and detrimental impacts to the grid are introduced. These effects are especially applicable for large-scale (5-20 MW) DG projects that have more complex technical requirements and greater export capacity. With the ongoing need to accommodate a growing number of DERs, the availability of cost-effective hosting capacity is a priority among proponents.

63. To accommodate customers in the future, utilities may also consider expanding their hosting capacity by evaluating the costs of using advanced inverter functionality and advanced inverters and storage. Navigant's 2015 Virginia Solar Pathways Project concluded that customer-located inverter control and battery storage are effective means to increase solar hosting capacity and mitigate voltage impacts, but are highly location-specific and potentially costly compared to traditional utility upgrades such as reconductoring (Navigant Consulting Inc., 2016). While customer-centric and collaborative, these approaches represent a new paradigm of control and access to the grid by customers that utilities may not be prepared for financially, technologically and ideologically.

64. However, utilities are looking to engage customers differently, and public concerns related to rising electricity delivery costs and the environment are increasing. In response, utilities are exploring creative solutions to address infrastructure needs at a lower cost with greater customer and environmental benefits using NWAs. Navigant Research forecasts that global spending on NWAs will grow from $63 million in 2017 to $580 million by 2026 (Chew B. , Myers, Adolf, & Thomas, 2018).

65. In the U.S., some utilities are opting to pursue NWAs voluntarily. However, most projects are the result of state-level regulatory processes, particularly in California and New York. The challenges and opportunities offered by NWAs are presented in a report of leading U.S. NWA case studies (Chew B. , Myers, Adolf, & Thomas, 2018). The report concluded that NWAs projects generally met their objectives, but further enablement is needed in the form of incentives, regulatory construct and changes to utility business models.

66. While the current regulatory and policy frameworks in Alberta do not enable the deployment and integration of NWAs, provincial funding has incentivized utilities to undertake NWA and utility-led energy projects as described in Table 2 below.

Table 2. Proposed utility-scale solar and/or solar and battery storage projects in Alberta

Proponent	Project	Technology	Benefits
AltaLink Management Ltd.	Whitecourt Transmission Deferral Battery	Construct 20MW/20MWh battery energy storage system at the existing Whitecourt substation	Transmission line deferral
ATCO	Kneehill 1 and 2 Michichi	Construct two 25MW solar PV systems near Three Hills, AB Construct a 25MW solar PV system near Drumheller, AB	Prove commercial and technical viability as a generation portfolio option for Alberta
Enmax Generation Portfolio Inc.	Enmax Midstream Industrial Solar and Storage Project	Solar PV and lithium ion battery storage at Keyera Corporation's Rimbey, AB gas plant	Energy savings through reduced consumption Peak shaving
Epcor	E.L. Smith Solar Project	Solar PV system	Sustainability - E.L. Smith Water Treatment Plant will be powered with renewable electricity
FortisAlberta	Waterton Battery Energy Storage Project	Solar PV and lithium ion battery storage in Waterton National Park/Waterton Townsite	Distribution line deferral
TransCanada Energy	Saddlebrook Solar and Storage	Utility scale solar PV and flow battery energy storage system near Aldersyde, AB	Prove commercial and technical viability as a generation portfolio option for Alberta

VII. Opportunity for Market Entry and Competition within Distribution System – Question 2 (e)

Question (e) How does a certain technology or innovation create the opportunity for market entry within a monopoly franchise? How might a certain technology or innovation introduce and/or increase competition within the distribution system?

67. The most fundamental competition issue raised by solar and solar+storage is its potential to facilitate market entry and to supplant the need for traditional centralized generation and future transmission and, to some extent, distribution infrastructure builds. The unknown factor is the degree to which dispersed, renewable generation is going to displace the centralized generation and distribution model in Alberta. This is largely dependent on fair and indiscriminatory rules and practices for the interconnection and operation of solar and storage.

68. Thus, competition can generally be characterized to occur in two streams:

a) Market Opportunities – creation or expansion of new business opportunities in nascent or undeveloped markets, including electric vehicles, storage, customer data analytics.
b) Grid Services and Products – necessary and traditional means to deliver energy to customers, including system reliability, energy delivery, customer marketing.

Both streams of competition are potentially exacerbated by customers' desire and need for energy self-sufficiency, whether that be to pursue generation/storage as a back-up to grid reliability and resiliency or as a means to reduce electricity costs through electricity self supply. The risk of grid defection should be considered a competitive force in the context of traditional revenue erosion but also in the opportunities its consideration provides to customers and third parties. An example of the above is the future need to measure energy at multiple points in the home, business or industry.

Market Opportunities

69. Utilities, if enabled with an appropriate regulatory environment, have an opportunity to offer the value of a macro distribution grid connection to micro-grids by way of providing tangible value for the provision of grid services including reactive power, opportunities for price arbitrage, avoiding redundant capacity and other ancillary grid services.

70. The addition of solar, solar+storage, electric vehicles and other technologies in the residential, and C&I sectors show both a need and opportunity for additional measurement within a site, rather than merely at the edge of a site. The following paragraphs describe the needs, opportunities and potential solutions. The discussion is presented in a residential context, but applies similarly to C&I and other sectors.

71. In a residential or commercial context, rooftop solar additions need a low-cost solution to verify solar generation so that the carbon offset credits can be sold. Currently, DFO's provide measurement and reporting of energy flows as measured at the edge of the site. Combined with this responsibility, the DFOs may also provide a service to measure and report the solar production. An efficient information flow to an entity that purchases or aggregates carbon offset credits will enable the sale of carbon offset credits from residential or commercial rooftop generation.

72. In addition to expanding measurement responsibility to include on-site solar generation, measurement of a number of electricity consuming, producing or storage devices will enable visibility, business transactions, as well as policy support/discouragement of a variety of behaviours. These include:
    a. Contribution of solar or other renewable generation
    b. Storage (charge or discharge)
    c. Battery electric vehicles, charge or discharge
    d. Air conditioning or other differentiated uses.

73. These measurement services can be provided competitively. A number of devices already exist, marketed to consumers who wish to monitor total site consumption, generation, or specific consuming devices. These devices could be modified and certified to be acceptable by Measurement Canada standards within 2-3 years so that they perform the same tasks as existing DFO meters, as well as a number of additional information streams.

74. Examples of the existing consumer-marketed measurement devices are made by the following manufacturers. Examples are also found at https://www.postscapes.com/wifi-home-energy-monitor-neurio/ .
    a. Honeywell
    b. Neurio
    c. CURB
    d. Sense Home Energy
    e. Eyedro
    f. Smappee

75. These existing devices already move their data to a cloud location and process them for viewing and analysis on almost any device. Any of these service providers could provide the software upgrades required to deliver meter data to the DFOs for load settlement as well as verification of carbon offset credits.

76. An opportunity for competitive service provision includes transmission of meter data from meters to DFOs. Already, most homes and businesses have some of the following services, that could with some hardware and software development, transmit meter data to DFOs or other entities. These include:
    a. Alarm monitoring providers
    b. Telephone providers
    c. Home energy monitors
    d. Eldercare monitoring providers
    e. Internet service providers
    f. Cable TV providers

69. Similar separation of measurement of different loads or generation sources can be achieved for C&I scenarios. Regardless of the end-use application, the proliferation of BTM solar, storage and solar+storage will create future areas of competition in the metering and customer data analytics space. Metering of electricity is a service that can be provided by any number of service providers, not only the DFOs – and competition will generally reduce cost and improve service.

70. Customers can also access solar energy through virtual PPAs, as illustrated in Figure 22. Hastings-Simon, Kaddoura, Klonick, Leitch, & Porter (2018) provide an overview of non-utility buyers, which can include corporations, municipalities, communities or co-operatives.

The renewable energy project owner delivers electricity to the electricity grid and recieves the market price for electricity, and environmental attribute (EAs), such as carbon offsets credits, are transferred to the buyer. The renewable energy project owner maybe able to offer a fixed contract price to the buyer, and therefore a price differential be paid to true-up the difference between the contract price and the market price. The buyer could retire the EAs that are transferred, or the buyer could, if eligible, use the EAs as offsets towards emissions targets or trade the EA to other interested buyers. In the case of a co-operative, the benefits would be distributed to members of the co-operatives.

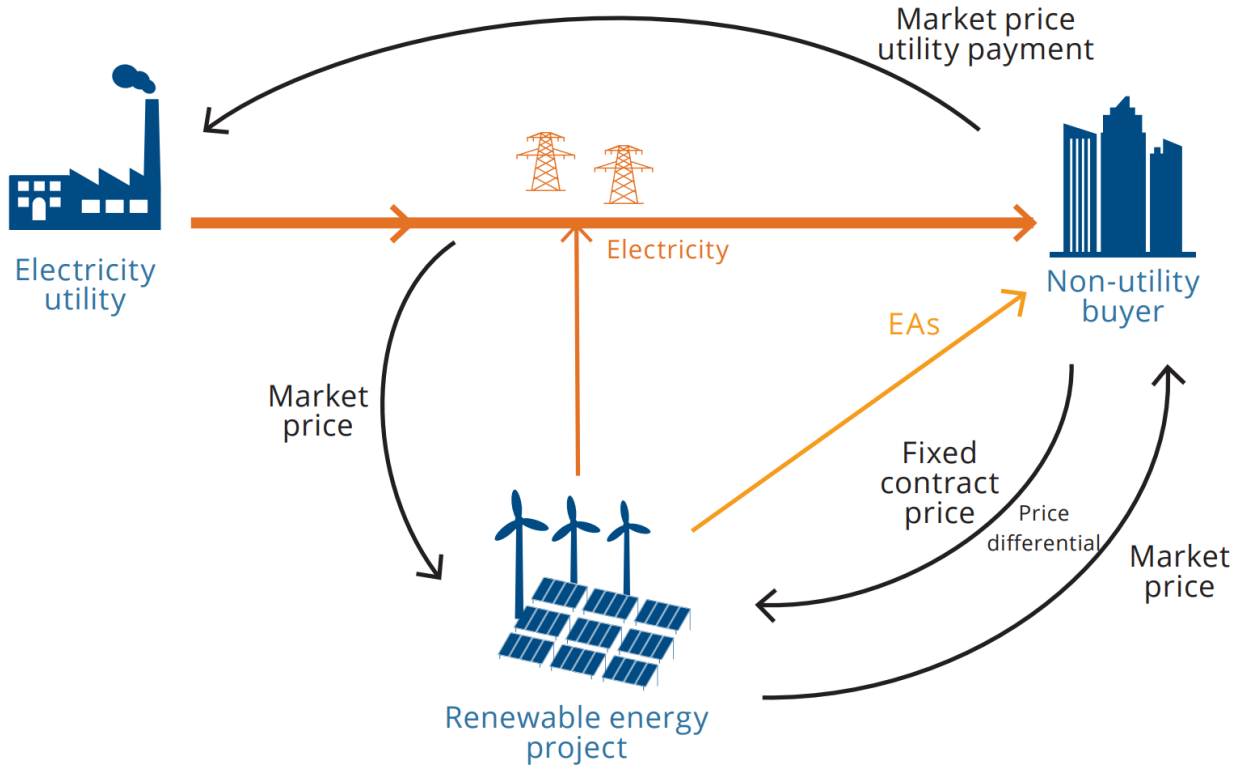

Figure 22. Structure of virtual power purchase agreement (Hastings-Simon, Kaddoura, Klonick, Leitch, & Porter, 2018)

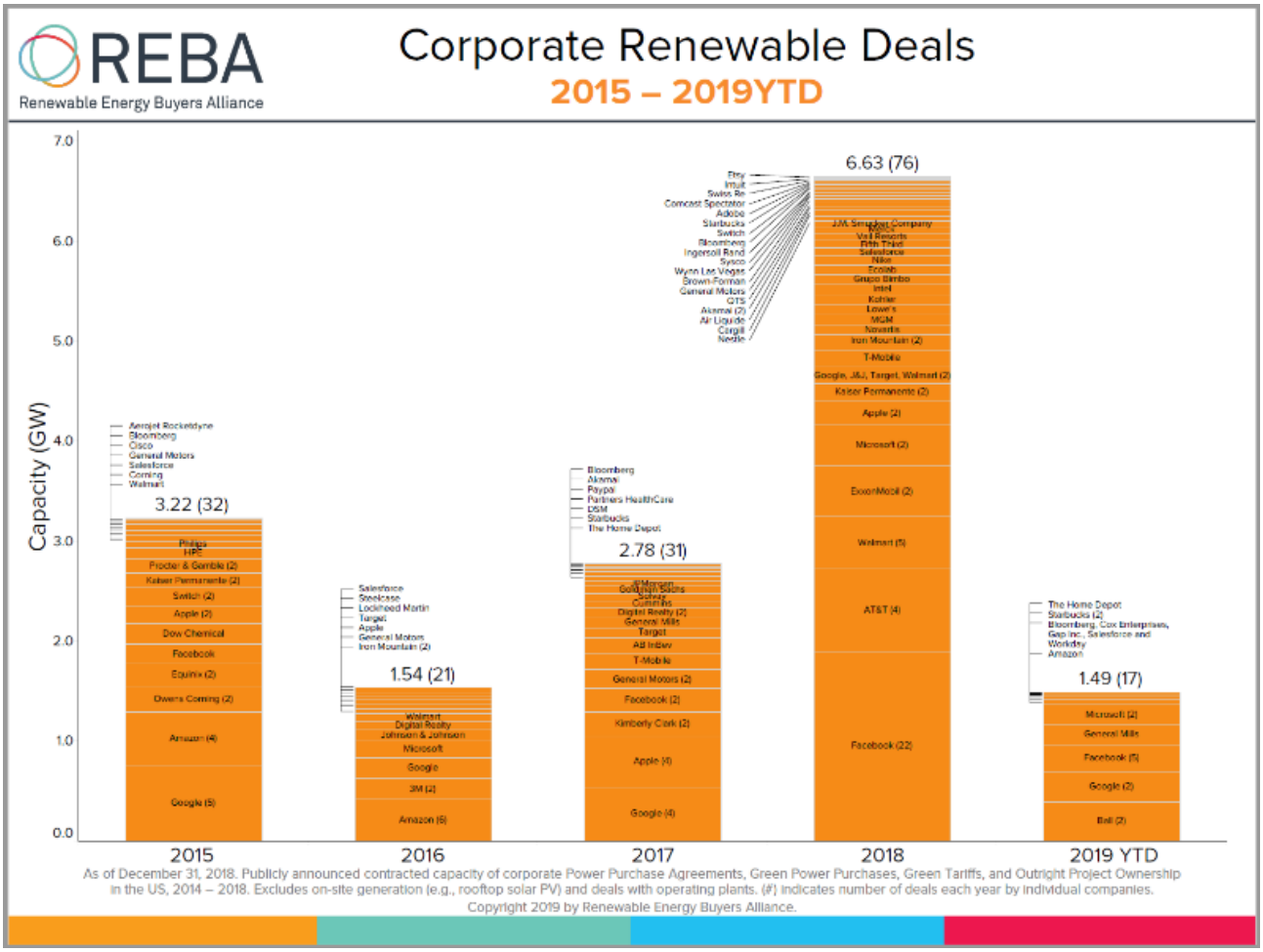

Figure 23. Corporate renewable energy deals reported in the US as of July 2019 (Renewable Energy Buyers Alliance, 2019)

71. Corporate renewable energy agreements are becoming increasingly popular. As reported by the Renewable Energy Buyers Alliance, corporate adoption had a major up-tick in the U.S. in 2018 with mainstream adopters such as Facebook, AT&T, Walmart, ExxonMobil, Microsoft and Apple.

Grid Services and Products

72. Many large industrial customers in Alberta have or are seeking to connect co-generation, opting to make use of waste heat, steam or gas to self-generate electricity. Extractive industries, including oil and gas, oilsands, metal and mineral mining have energy intensive operations and often electricity represents one of the largest operational expenses. A report commissioned by the Oil Sands Community Alliance in 2014 reported that 52 out of 126 oil sands projects have developed or are expecting to develop co-generation (Desiderata Energy Consulting Inc., 2014). The top three influential factors contributing to co-generation

decisions are indicated as the need for increased reliability, the delivered price of power versus the cost of generating, and transmission charges.

73. The report went on to describe that the continued growth of co-generation is proportional to the growth of on-site power demand of oil sands projects (Figure 22) (Desiderata Energy Consulting Inc., 2014). In instances where co-generation is sized to meet the steam loads versus the electricity demand loads, excess electricity is created for potential export to the grid. It is notable that oil sands projects largely maintain a grid connection for power supply and reliability reasons, presenting technical opportunities to export excess power to the grid. The difference between co-generation capacity and on-site power demands outlined in Figure 22 presents an opportunity for battery storage systems to leverage this excess energy and create valuable return on investment

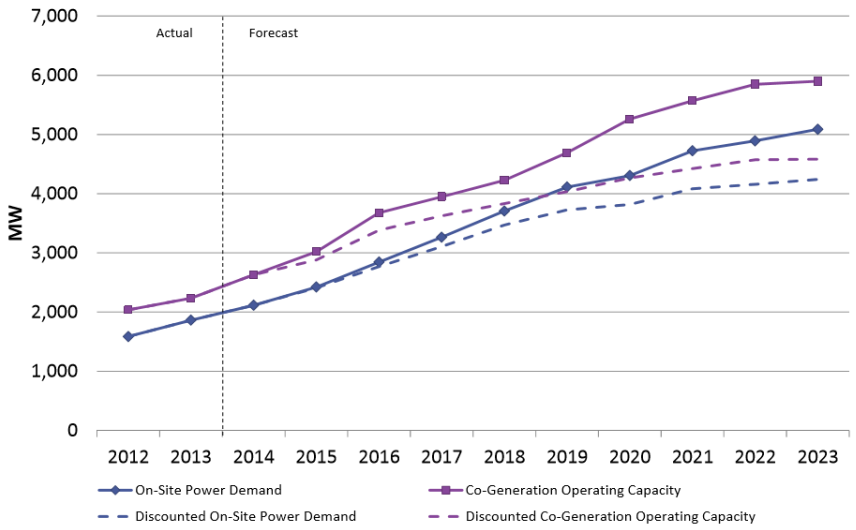

Figure 24. 2014 Anticipated On-Site Demand & Installed Co-Generation Forecast (Medium Range) (Desiderata Energy Consulting Inc., 2014)

74. The use of battery energy storage among Alberta customers is nascent due to market barriers including uncertain interconnection policy and regulation for battery storage systems. However, the Midstream Industrial Solar and Storage and the Drumheller Solar and Battery Storage projects proposed by Enmax and Longspur Developments, respectively, demonstrate growing customer interest in pairing battery storage with solar and to lower costs and optimize on-site generation.

75. Installation of storage within load-serving entities such as those enabled by the Small-scale Generation Regulation, municipal distribution networks, and in support of transmission-connected C&I customers, allow these entities to leverage excess energy or variable renewable energy into dispatchable loads, further enabling micro-grid scenarios. This would

enable generators to take advantage of energy arbitrage and potentially engage in "behind the meter" bi-lateral contracts with other customers.

VIII. Conclusions

76. In summary, the CGWG submits that:

    a. Viable economics of solar and solar+storage is here; it is a matter of customers taking action for off-grid or grid-supported energy solutions. Incentives for solar have been a "pull in" to engage the public, proponents and investors and overcome vestigial regulatory and utility procedure barriers. There is now a push from citizens and proponents for government, policy-makers, and utilities to find unsubsidized ways to enable, approve, simplify, facilitate, and lower the cost and complexity for solar and solar+storage energy development.

    b. Solar, solar+storage and other DERs and consumers have an opportunity to play a role, have ownership, and take action irrespective of government drivers. Going forward, policy-makers, regulators and utilities must ask the question: if solar can help reduce consumer utility bills, how can and should rates, regulations and DFOs encourage consumer-based solar?

    c. The declining costs of solar and solar+storage have created significant opportunities for Community Generation, Co-operative owned and, and Indigenous power projects, if enabled by tariffs and regulation. Greater public interest is prompting industry collaborations and partnerships to develop and further projects.

    d. Utilities, while engaging through non-regulated parts of their businesses, may be seeking to engage customers through their regulated businesses. Though the need for change and innovation is generally understood, it is not sufficiently enabled in the current regulatory and policy regime. As an NWA, solar and solar+storage can offer cost savings through avoided infrastructure to the distribution system, that is by displacing loads or by offering automated power factor and other support. Further, growth in DERs can be an upside for distribution utilities whose business models rely on distribution infrastructure

    e. The move to a grid with more distributed resources will require significant changes over time including:
        - rate structure and tariff reform
        - technology deployment and enablement across the grid
        - changes to utility planning practices
        - clarification of AESO rules
        - consideration of new revenue streams and services for utilities or third parties
        - enablement of NWAs via legislative, policy, and regulatory modernization

f. Smaller renewable generation, up to 5 MW, requires support of low-cost verification of GHG credits so that smaller projects can benefit from sale of the credits. This is a service that should be mandated to be provided by the provider of metering.

g. Opportunity exists for metering services to be made a customer choice enabling lower cost or enhanced value services to be provided. Infrastructure to provide an additional data stream (meter data) from a residence or business is redundant when other providers already provide these streams for other purposes.

77. We thank you for the opportunity to submit these comments and look forward to the next steps of this proceeding.

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