Leveraging Energy Storage for Distribution Services

How Maximizing Revenue Streams Can Lower Costs to Electricity Customers

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A report by Power Advisory LLC. Commissioned by Energy Storage Canada

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Introduction

Ontario's electricity grid system will be significantly impacted by the drive to achieve a net zero economy. Policies of the federal, provincial, and municipal governments are underpinned by customer demand and corporate interests (e.g., Environmental, Social, and Governance (ESG) goals) in expanding renewable energy supply and achieving decarbonization goals. As a result, the electricity distribution system will experience an increase in conne12 regulations for both renewable generation and rising electricity demand resulting from the adoption of electric vehicles (EVs) and the broader electrification of industry. Moreover, as the economy electrifies, there will be added pressure to maintain high levels of reliability.

Energy storage is increasingly being considered and deployed by local distribution companies (LDCs) and their customers as a Non-Wires Alternative (NWA). Energy storage is proven technology that can be leveraged by both LDCs and their customers to meet current and future needs. LDC customers want the flexibility to manage some of their energy needs, ensuring the reliability of the energy provided, as well as the ability to help support the grid to which they are connected. Energy storage can provide the required peaking capacity for a distribution system and the operational flexibility and reliability desired (e.g., distribution services include system reliability, power quality, etc.). The deployment of energy storage is scalable to meet system needs, providing versatility in planning where demand growth is uncertain. Further, energy storage can be deployed near load centers, which allows the energy required for peak demand periods to be transported into the load center during periods of overall low system demand, ultimately providing value to both the distribution system and bulk transmission system.Ontario's LDCs and their customers should be fully enabled to deploy energy storage as an NWA, where it is cost effective to do so, and where long-term distribution needs are difficult to forecast. The Hon. Todd Smith, Minister of Energy, recognizes the need to enable NWAs. In the Minister's mandate letter to the Ontario Energy Board (OEB), he stated:

> "Developing policies that support the adoption of non-wires and non-pipeline alternatives to traditional forms of capital investment, where cost-effective, will be essential in maintaining an effective regulatory environment amidst the increasing adoption of Distributed Energy Resources."

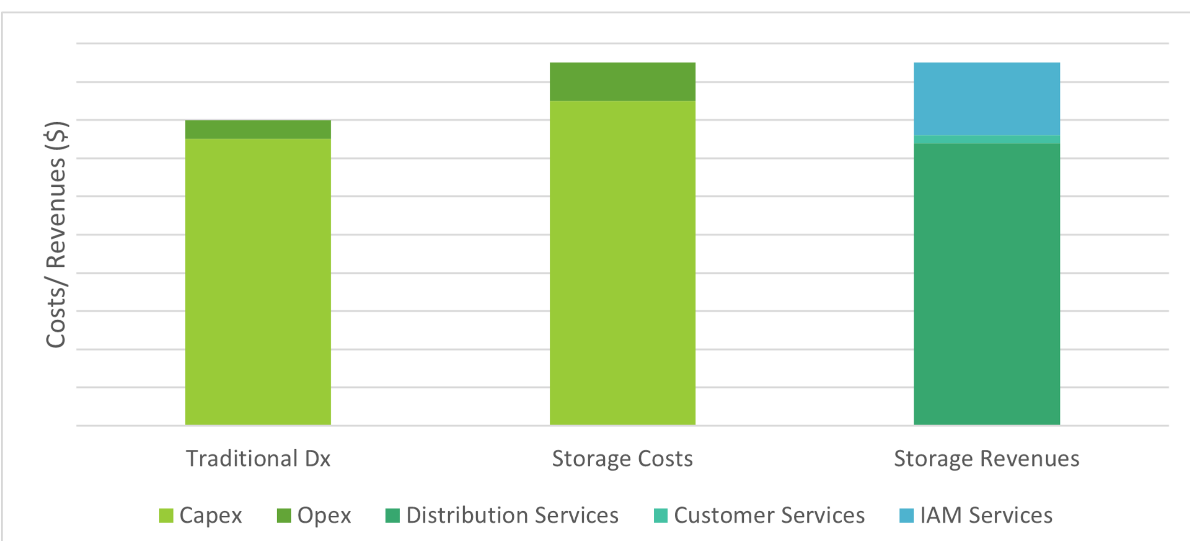
Additionally, with the release of the 2021 Conservation and Demand Management (CDM) Guidelines[1] issued by the OEB, there is a greater emphasis on the use of energy efficiency, demand response, energy storage, behind-the meter generation and innovative solutions by LDCs "to address system needs and avoid or defer investments in traditional wires infrastructure."

However, there are several legislative and regulatory barriers (e.g., government regulation and OEB codes and guidelines) related to the deployment of energy storage by LDCs and their customers, including uncertainty and the risks related to revenue offsets.

Unlike traditional distribution assets (e.g., poles and wires), energy storage can provide multiple services and generate additional revenues to offset the costs to the distribution system. Revenues earned by an LDC outside the provision of regulated distribution services serve to reduce the LDCs' revenue requirement and are considered revenue offsets. Increasing revenue offsets will decrease the cost of distribution services.[2] Therefore, ensuring that LDCs are appropriately incented to maximize revenue offsets, such as revenue sharing, would facilitate the broader adoption of cost-effective energy storage as NWAs.

Figure 1 illustrates that even if a traditional distribution investment may have lower upfront costs relative to a storage asset, the net costs, or a portion thereof, from a storage asset, included in the rate-base, could be lower than a traditional distribution investment if revenue offsets from the IESO-administered market (IAM) and other customer services are realized.

Figure 1. Revenue offsets reduce cost of distribution services



1 2021 Conservation and Demand Management Guidelines for Electricity Distributors and Notice of Hearing for Cost Awards (EB-2021-0106) Retrieved: https://www.oeb.ca/sites/default/files/cvrltr-2021-CDM-Guidelines-20211220.pdf

2 Note that per incentive regulation, utilities are incented to become more efficient to benefit customers through better services and lower rate increases. Utility remuneration considers cost of service, utility performance and incentives, amongst other factors.

One of the underlying challenges for a regulator then, when developing a framework to enable energy storage deployment by LDCs, is ensuring that there are appropriate processes in place to maximize revenue offsets while minimizing risks to electricity customers.

The OEB's 2021 CDM Guidelines also recognize the ability of LDCs to earn revenues from the wholesale market which may improve the business case for ratepayer funded CDM activities. The OEB indicates that it is open alternatives approaches for cost recovery and risk allocation, and states:

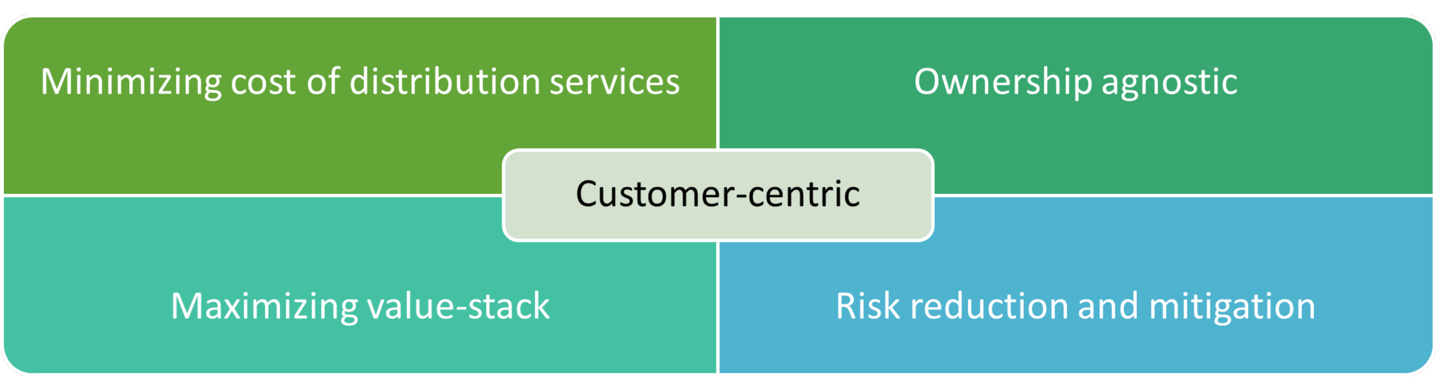
> "A distributor may also have an opportunity for its CDM activities to earn revenues through the IESO's wholesale markets, reducing the costs that need to be funded through distribution rates. If applicable, a distributor should describe its proposed approach to these revenues in its application. A distributor may request full cost recovery and indicate that any revenues earned through IESO markets will be treated as a revenue offset used to lower distribution rates, or an alternative approach that considers the allocation of risk between the distributor and its customers. Depending on circumstances, the latter approach may improve the business case for a rate-funded CDM activity."[3]

LDCs have played an important role in the deployment of DERs in Ontario, and there is now an opportunity to leverage this experience as the grid evolves. Thus, this paper explores the possible risks and benefits of different business-models for the ownership of energy storage resources providing distribution services, including:

- A fulsome description of four primary ownership frameworks
- An outline of how each framework manages risks associated with revenue offsets,
- Legislative or regulatory limitations, if any, in the Ontario context,
- Advantages and disadvantages to various ownership models,
- Jurisdictional examples of different ownership models, and
- Additional regulatory considerations pertaining to maximizing revenue offsets and decreasing costs of distribution services.

This paper does not make a recommendation in favour of one ownership model or another. Instead, this paper demonstrates the need for regulatory flexibility in consideration of the ownership of distribution NWAs, recognizing that each NWA asset may have unique characteristics. When assessing the appropriateness of an NWA ownership structure, Energy Storage Canada proposes a customer-centric approach that serves to minimize the cost of distribution services, maximize the value of other grid services (i.e., value-stack), and encourage the active participation of LDC customers while reducing and mitigating their risks.

Figure 2. Business-model considerations



3 OEB. (2021). Conservation and Demand Management Guidelines for Electricity Distributors. Retrieved: https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2021-12/CDM-Guidelines-Elec-Distributors-20211220.pdf

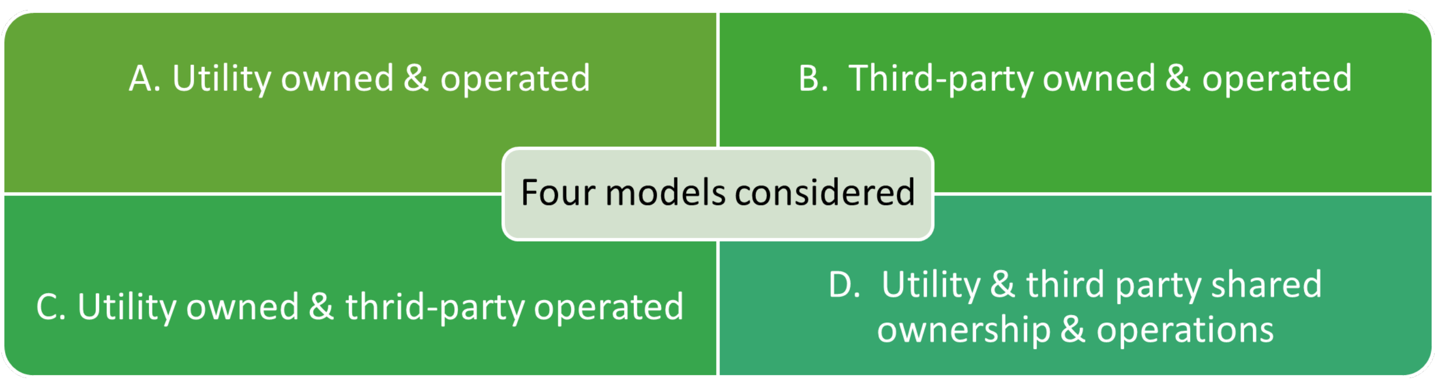
1. Business-Models for Distribution NWAs

This section reviews four possible business-models pertaining to the ownership of energy storage for the purposes of serving as a distribution NWA. These models were defined based on input from Energy Storage Canada's membership. Energy Storage Canada does not endorse one specific model, but rather explores each for potential opportunities and challenges. Each model presented is mutually exclusive and provides the perspective of a regulated LDC (i.e., licenced distributors, not LDC affiliate company) as the "utility" and competitive energy storage companies as the "third party."[4]

Each business-model recognizes that an energy storage asset may be capable of providing additional services to LDC customers (e.g., behind-the-meter services including reliability services, demand reduction, bill management, etc.) or to the regional or bulk system (e.g., transmission services, or wholesale market services.) For simplicity, this paper focuses on providing additional services to the wholesale market (i.e., IAM) and earning revenue for energy, capacity, and ancillary services (AS), as applicable. Each framework is applicable for both front-of-the-meter and behind-the meter applications.

For the purposes of this paper, the business-models below focus on capacity as the primary use case for energy storage. Other use cases may lend themselves to different framing. For example, a customer may invest in energy storage to solve a specific need such as power quality or emergency back-up. In those cases, there can be varying degrees of utility involvement.

Figure 3. Four business models are considered in this paper



A. Utility owned and operated

This approach is closest to traditional utility practices in that the utility owns the energy storage asset providing distribution, and potentially, customer specific services. The utility would also operate the energy storage asset consistent with distribution system needs (e.g., peak shifting). As both owners and operators of the energy storage asset, utilities may offer energy, capacity and/or AS to the IAM and earn additional revenues.

Utilities are also inherently incented to seek out revenue offsets because they are capital and operation and maintenance (O&M) budget constrained. Thus, additional revenues that can help to offset those costs, allow utilities to do more within the same budget.

4 Note that the "third party" may also be an LDC customer, including customers that have interest in mitigating electricity costs.

Summary of considerations:	
Utility Revenue Model	Traditional approach (e.g., capital asset included in rate-base). In addition, the regulatory framework could consider appropriate incentive mechanisms to maximize revenue offsets, such as revenue sharing.
Revenue Offsets	Utility may participate in IAM and earn additional revenues. Utilities are eligible to participate in the IAM (e.g., IESO Capacity Auction, etc.) However, the current rules do not allow for revenue offsets to be considered as part of the economic evaluation of energy storage as an NWA. Revenue offset earnings cannot be accounted for to prove that a rate-based storage asset is preferable over a traditional wires investment. Only the new CDM Guidelines would permit this approach. If a project is built to improve reliability, there are no specific rules to grant the consideration of revenue offsets.
Legislative/Regulatory	Per 71(3)(c) of the Ontario Energy Board Act, a distributor may own and operate an energy storage facility subject to criteria that may be prescribed by regulation. However, there is a need to establish guidelines and requirements detailing how an LDC could consider other revenue streams as part of the project evaluation. In addition, LDCs require clarification regarding (a) what investment amount will be reflected in the rate base, and (b) how LDCs will keep ratepayers whole if the projected revenue streams do not materialize or are underestimated.
Opportunities	Relatively straightforward for utility implementation if the NWA infrastructure is determined to be cost effective relative to traditional infrastructure. The utility will have the ability to procure assets at a favourable cost of capital. The utility will earn a rate of return on the investment like any other grid investment. Any additional revenues earned beyond projected would be returned to ratepayers.
Challenges	Increased utility operations and maintenance (O&M) expenditures due to storage operations and participation in IAMs. Complexity with respect to comparing costs of traditional infrastructure against net costs of energy storage solution (i.e., the costs of the storage solution minus expected revenue offsets). Potential for utility exposure to market risk related to revenue offsets (e.g., IAM revenues).[5] Need to ensure the utility can protect ratepayers from risks associated with uncertainty in forecasted revenue offsets. Utilities may be challenged to find appropriate sites for energy storage projects (e.g., urban utilities) Utilities may not have existing in-house experience with energy storage systems.

5 Energy Storage Canada is not suggesting that utilities would face a penalty for not achieving desired revenue offsets, but rather, an appropriate framework needs to be developed to reasonably mitigates risks associated with forecast uncertainty under a utility owned and operated approach. In addition, Model B, Model C and Model D each offer alternatives for mitigating risks to utilities and their customers.

Example from another jurisdiction:

- Baltimore Gas and Electric's (BGE's) Fairhaven project is designed to solve a 2.5 MW / 4.0 MWh constraint. This is one of several projects being developed in response to the Maryland Energy Storage Pilot Project Act.
- BGE will provide PJM services (including frequency regulation services) when the system is not being used for distribution reliability

B. Third-Party owned and operated

With this approach, the utility procures distribution services from the third-party who is the owner and the operator of one or more energy storage assets. This model enables the utility to procure services from stand alone or aggregated energy storage assets. Energy storage assets could be located both in-front-of-the-meter and behind-the-meter of customers, including residential customers.

The utility would undertake competitive processes to acquire cost-effective distribution services from a third-party. An operating agreement between the utility and the third-party would be required to prescribe the operations of the energy storage asset for the purpose of providing distribution services (e.g., response requirements to utility operation instruction). The utility may lease lands to the third party for the energy storage asset. Since the third-party is the owner and the operator, they could offer excess energy, capacity and/or AS to IAM and earn additional revenues.

It is important to emphasize the importance of establishing appropriate operating agreements between utilities and third parties. Investments in distribution assets and services are directly tied to reliability and utilities need to depend on these assets to comply with instructions for grid services. Utility performance is tied to specific benchmarks, such as System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and customer satisfaction metrics. Therefore, it is expected that utilities and third parties will need to establish appropriate performance requirements and penalties if there is a reduction in utility performance benchmarks associated with the operations of NWA.[6]

A variation on this model could be a third-party owned and utility-controlled energy storage asset. In such a scenario, if the energy storage asset can resolve a distribution system need, the utility could issue a request for proposal (RFP) for existing and new energy storage capacity services to address this need. The utility would control the third-party owned storage capacity in specific instances. In exchange for this control, storage capacity providers would receive compensation, either through reduced connection costs or other compensation for service.

Summary of considerations:	
Utility Revenue Model	New utility remuneration framework required (e.g., capitalization of non-capital assets like a capital lease, energy as a service, or shared savings model) to 'level the playing field' between this type of service-based vs capital-based solution to meeting distribution system needs. With today's framework, contracting for services is problematic because costs accrue to the utility's O&M budget. There is a much higher threshold associated with O&M costs and LDCs may not be able to justify the cost even though the services would provide benefits to customers. A rule change is needed to recognize storage services procured by an LDC so they may be treated like capital costs (e.g., capital lease).

6 The importance of establishing appropriate operating agreements between utilities and third-party service providers applies to any business model that relies on third-party operations of a NWA, including Model C and Model D discussed below.

Revenue Offsets	In this model, the revenue offsets would be indirect. The third party may participate in IAM and earn additional revenues. Given sufficient competition amongst service providers, the third-party would factor additional revenue earnings expectations into its offer to the utility for the provision of distribution services, resulting in reduced costs of distribution services. In other words, those providers that can offer the lowest cost distribution services in their proposal for services are more likely to be selected by the utility to develop energy storage projects.
Legislative/Regulatory	Need to develop a utility remuneration framework that ensures utility incentive to procure services from third parties where cost-effective to do so. Utilities may need to be licensed to enable them to dispatch resources.
Opportunities	Competition amongst potential third-party storage providers to drive down costs of distribution services and maximizing IAM revenues. Ability to leverage customer-sited and existing, under-utilized, energy storage assets, including individual energy storage assets or aggregations.
Challenges	Increased utility O&M due to procured services and new protocols with the third-party operator (e.g., grid monitoring, communications, dispatch protocols with storage owner, IT integration and security, etc.). Increased operating complexity with respect to utility coordination of third-party dispatch / contract management, etc. Increased interoperability complexity for the distribution, transmission and IESO given that the third party is providing services to the LDC and participating in the IAM (i.e., communications coordination protocol will be required, and priority of dispatch signal determined).

Example from another jurisdiction:

Con Edison's Commercial Energy Storage project

- REV Demonstration Project consisting of four commercial host sites (1 MW / 1 MWh battery installation) with total project budget of $11.7 million
- Connected in front-of-the-meter. Con Edison has priority dispatch rights during critical peak system events (i.e., under contract with owner); host customer receives lease payments from owner
- During non-called events, owner participates in NYISO's wholesale markets; revenues shared between Con Edison and system owner

C. Utility owned and third-party operated

Like the first approach, the utility is the owner of the energy storage asset providing distribution services, which is reflective of the traditional asset ownership of distribution system equipment. However, this approach differs from the first approach because the utility leases the facility to a third-party operator. As in the second approach, the utility and the third party would establish an operating agreement for the purpose of providing distribution services. Additionally, the third-party operator may offer excess energy, capacity, and AS to IAM. With this approach the utility will likely include a revenue-sharing framework in the agreement with the third-party. It is also possible that an energy storage asset may be oversized, with part of the facility providing distribution services to the utility, and the remainder of the capacity dedicated to providing services to the IAM.

Summary of considerations:	
Utility Revenue Model	Capital asset included in rate-base.
Revenue Offsets	The third-party may participate in IAM and earn additional revenues. The utility and the third-party may also enter into a revenue-sharing arrangement related to additional revenues earned.
Legislative / Regulatory	Need to confirm applicability of 71(3)(c) of Ontario Energy Board Act (e.g., confirm distributor can own but not operate an energy storage facility.) Utilities may need to be licensed to enable them to dispatch resources.
Opportunities	Reduces utility O&M expenditure related to operations of the energy storage asset which is performed by the third-party. Leverages third-party experience and their existing protocols for market participation (e.g., dispatch workstation, market monitoring, etc.) Provides clear incentives for the third-party to maximize revenues from IAM and increase revenue offsets.
Challenges	Need to establish operating protocols with third-party (e.g., grid monitoring, communications, dispatch protocols with storage owner, IT integration and security, etc.) Increased operating complexity with respect to utility coordination of third-party dispatch / contract management, etc. Magnitude of revenue offsets are based on third-party performance (can be managed contractually) Increased interoperability complexity for the distribution, transmission and IESO given that the utility-owned asset is being operated by a third party who is also participating in the IAM (i.e., communications coordination protocol will be required, and priority of dispatch signal determined).

Example from another jurisdiction:

Pepco's National Harbor Storage Pilot Project

- One of several projects being developed in response to the Maryland Energy Storage Pilot Project Act.
- Existing substation expected to have a 1% overload in 2027 and 2% overload in 2028 (1 MW / 3 MWh)
- Located on utility property
- BESS will provide 3 hours of peak shaving capability to Pepco, and will derive additional revenue through PJM market

D. Utility and Third-Party shared ownership and operations

This approach would enable co-ownership of an energy storage asset by both a third party and the LDC. The asset would provide both distribution and other LDC customer specific services along with participating in IAM opportunities. The third party is responsible for the operation of the energy storage asset. The utility and the third party would establish an agreement related to shared responsibilities with respect to ownership related issues such as operational costs and dispatch decisions. Note that in this scenario, there is also the possibility that the third party is the utility customer with an energy storage asset located behind-the-meter.

Summary of consideration:	
Utility Revenue Model	Capital asset included in rate-base for portion owned by regulated distributor. May need to establish appropriate remuneration framework for portion of asset owned by the third-party.
Revenue Offsets	The operator of the energy storage facility may participate in the IAM and earn additional revenues. The utility and the third-party may establish a revenue sharing agreement.
Legislative/Regulatory	Need to confirm applicability of 71(3)(c) of Ontario Energy Board Act (e.g., confirm that a distributor may co-own and co-operate an energy storage facility.) Utilities may need to be licensed to enable them to dispatch resources.
Opportunities	Potential to reduce utility O&M expenditure related to operations of the energy storage asset. Leverages third-party experience and their existing protocols for market participation (e.g., dispatch workstation, market monitoring, etc.) Provides incentives to maximize revenues from the IAM and increase revenue offsets. Provides options for third-party capital investment. A utility can scale up or down to any percentage of the required need in any area, while a third party can leverage the utility to lower their market risk and exposure. Gives the utility full visibility into all aspects of energy storage deployment and operation. Ensures utility has opportunity to easily facilitate full system purchase from the third-party should it be in its best interest to do so.
Challenges	Some increased utility O&M due to dispatch protocols with third-party operator (e.g., grid monitoring, communications, dispatch protocols with storage owner, IT integration and security, etc.). Increased operating complexity with respect to utility coordination of third-party dispatch / contract management, etc. For example, there are complexities related to establishing priorities of dispatch of energy storage for utility purposes and IAM participation. Other challenges result form physical limitations on feeders. The utility could be evaluating the option of a large storage facility for distribution purposes against enabling behind-the-meter storage for customers who want to mitigate electricity costs. Increased regulatory complexity due to the nature of the shared ownership of the asset. Increased interoperability complexity for the distribution, transmission and IESO given that the third party is providing services to the LDC and participating in the IAM (i.e., communications coordination protocol will be required, and priority of dispatch signal determined). Need to ensure the utility can protect ratepayers from risks associated uncertainty in forecasted revenue offsets.

Example:

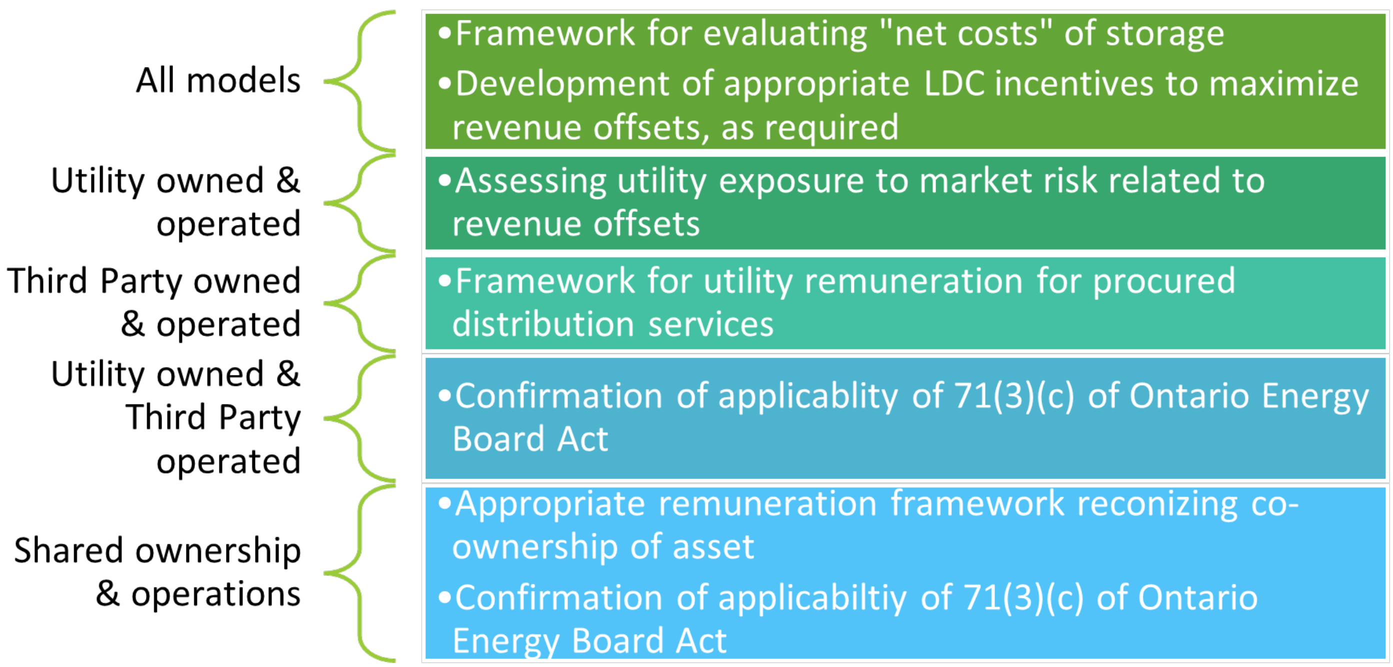
- Some Energy Storage Canada members are currently negotiating with Ontario LDCs on this model structure.

Summary

As outlined above, there are multiple prospective business-models for energy storage deployment as a NWA in Ontario, each with potential advantages and disadvantages.

Importantly, all the models reviewed require additional regulatory clarity for efficient implementation, as summarized in the figure below.

Figure 4. Summary of core regulatory considerations for each business-model



2. Regulatory Considerations

As outlined in Section 2, there are several constraints within Ontario's regulatory framework that create challenges for the efficient deployment of energy storage as an NWA. This section of the paper provides additional insights with respect to these challenges and the factors that should be considered by policymakers and regulators.

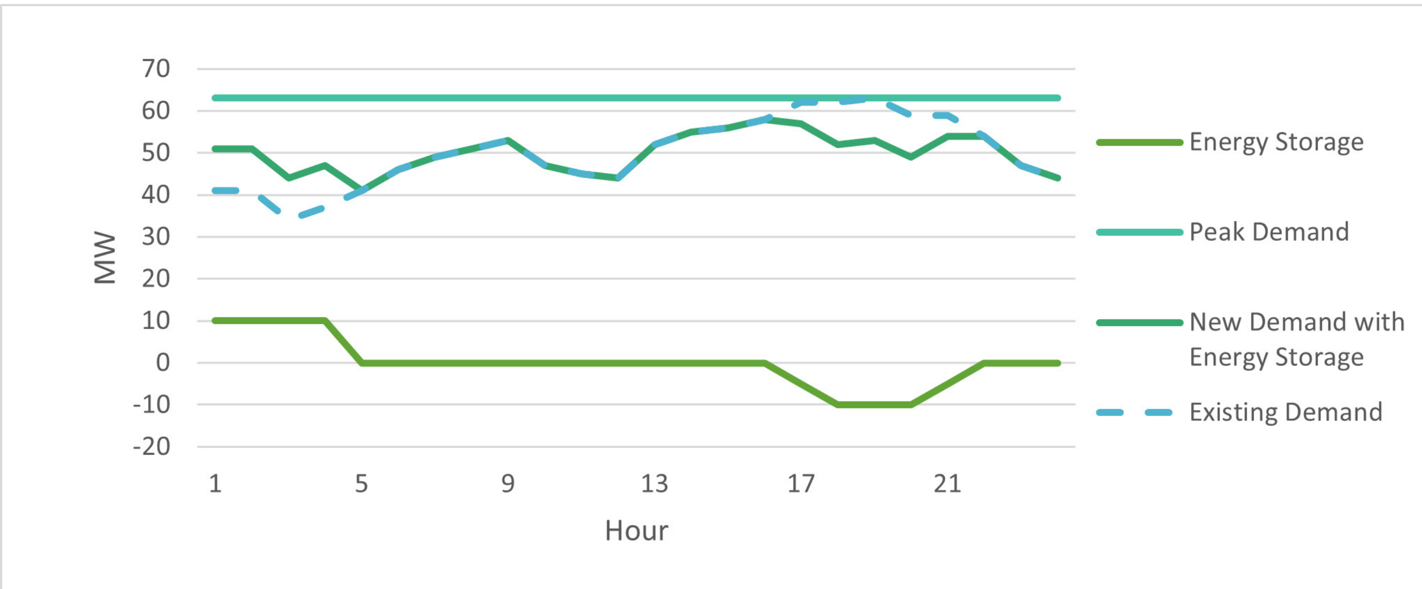
Rate Design

Ontario's rate design may serve as a disadvantage for third-party owned and operated energy storage. Currently, Ontario's rate design for delivery charges (i.e., transmission and distribution charges) are based on non-coincident peak (NCP) demand. This rate design does not reflect the efficient operating characteristics of front-of-the-meter energy storage, which would result in off-peak charging and on-peak injection of energy to the distribution system, as illustrated in the figure below.

Therefore, as currently structured, NCP demand charges are not efficient price signals for front-of-the-meter energy storage, because it does not reflect usage of the system, provide economic incentive for efficient operations, or offer benefits for customers related to system peak reduction.

Rate designs that reflect the coincident peak impact of energy storage would lead to more efficient outcomes for customers, including reduced operating costs for energy storage assets (i.e., lower energy bid price, lower cost to provide distribution services, etc.), and the realization of the operating benefits of storage. In addition, the current rate design does not consider the locational value of energy storage, nor does it factor in potential risk of energy storage located in an area of the grid where the asset may be underutilized.

Figure 5. Impact of energy storage on load profile



Overall, the current rate design is a significant hinderance for the deployment of energy storage, including situations where energy storage may provide value to the distribution system. The current approach cannot be considered just or reasonable since energy storage is being charged for contributing to peak demand of the system when energy storage should be operating to reduce a system constraint or peak. Some LDCs monthly demand charges are based on customer peak demands set between 7:00 am and 7:00 pm,[7] which more appropriately reflects costs.

In addition to changes to NCP demand charges, the OEB should also consider incentivizing the siting and connection of energy storage on the system where it can be deployed to provide maximum benefits. This could be done by reducing connection costs paid by energy storage resources that connect where the capacity is needed.

Current regulations around Gross Load Billing are also a deterrent for behind-the-meter systems, as peak load displacement is penalized with the installation of energy storage. A customer may operate its behind-the-meter storage asset every hour to reduce their peak demands on the distribution and transmission systems, however, the monthly peak demand level is grossed up by the size of the installed energy storage facility for delivery charges.

7 Elexicon's Transmission Network Change is billed on peak kW demand registered between 7 a.m. and 7 p.m. during each billing period

Energy Storage Canada recognizes that rate design is a complex and challenging topic, and that care needs to be taken while implementing new approaches. However, the "postage stamp" approach which does not consider locational value on the distribution system is problematic. Moreover, it is necessary to consider a cost recovery scenario if generation connection results in less use of existing assets or drives the need for more assets only used by the generator.

Recommendation

- The OEB should evaluate new rate designs that incentivize efficient operations of energy storage

Market Revenues

The regulatory framework needs to ensure that potential revenues from the IAM (or other revenue streams) are considered by LDCs for all energy storage applications when comparing traditional distribution system upgrades versus energy storage solutions. If it does not compromise the provision of the intended distribution services, LDCs should be permitted to maximize revenue offsets, where feasible, when economically evaluating a potential energy storage solution. However, the decision to allow LDCs to account for potential market revenues in their economic evaluation of a storage project must be weighed carefully by the regulator due to potential uncertainty in prices for wholesale market services. While the IESO has a market for capacity (i.e., Capacity Auction), energy and operating reserve, there is little transparency with respect to procurement of other ancillary services, such as regulation capacity.

As a result, a new risk management framework and protocols are required related to the assessment of these revenue streams to ensure ratepayers are protected from utility investments in energy storage facilities. Specifically, if market revenues are greater then projected, how are the benefits to be shared with customers? Or, alternatively, if market revenues are less than projected, what will the impact be to the LDC's revenue requirement or return on equity?

Many de-regulated electricity markets in North America restrict utility participation and ownership of generation due to concerns related to market power and the possibility of supressing market price signals. For example, in Texas, distributors are permitted to procure distribution services from energy storage assets but are not permitted to own energy storage. In New York, distributors are enabled to procure services from energy storage and are only permitted to own energy storage if the energy storage asset is located on a utility property, if markets are not adequately serving needs of low-income community, or if the project is a demonstration project. Meanwhile, in California, the public utility commission established a mandate for the deployment of energy storage and encouraged utilities to consider all forms of ownership, including third-party, customer, and joint ownership.

The unique attributes of Ontario's electricity market must be considered when the framework for enabling utility ownership of energy storage is developed. This includes recognition of historical precedent established in the Ontario Energy Board Act, which currently enables distributors to own and operate energy storage resources. Furthermore, the OEB staff bulletin issued on August 6, 2020, expressed the staff's view that behind-the-meter energy storage assets may be considered a distribution activity provided the main purpose of the asset is to improve reliability of service. Given Ontario's current statutory framework, it is reasonable to continue to allow for LDC-ownership of energy storage devices, while enabling alternative business models allowing third-party operations of energy storage and shared ownership of energy storage assets. These new tools should be available to LDCs as options to reduce the costs of providing distribution services and to mitigate the risk associated with other revenue streams.

Recommendation

- Guidance from the OEB is required with respect to treatment of market revenues and associated market risks

Dual Participation

All the business models discussed in this paper predicated the potential for an energy storage asset providing services to both the IAM and the distribution system. If this is to be achieved, the IESO, Ontario's LDCs and other third-party service providers need to develop protocols for dual participation of resources. The IESO's Market Vision and Design Project is considering the potential for dual participation of resources, including coordination protocols, which are being discussed at the IESO's Transmission Distribution Coordination Working Group.[8]

The potential for "nested benefits" of distributed energy resources (DERs) is both a challenge and an opportunity. Nested benefits arise when the DER has an opportunity to alleviate both a distribution constraint and a transmission constraint. Ideally, an NWA procurement program would attempt to capture nested benefits (e.g., target development of DERs that have high distribution benefits and high transmission benefits). However, timing is an issue for many potential projects. If the distribution system needs do not align with the bulk transmission system needs, DERs dispatched for one time-period may be prevented from operating in another period when they are required. Therefore, decisions about "dispatch priority" need to be optimally coordinated between the IESO and LDCs to ensure that DERs are operated efficiently.

FERC Order 2222 enables participation of DERs, including aggregated distributed energy resources. As part of their implementation plan, utilities must specify which grid services can be provided simultaneously by a DER and outline restrictions including situations where the DER-operator must choose between the provision of competing services. These participation frameworks are still being developed by ISO/RTOs in their filing compliance in response to FERC Order 2222.

Recommendation

- Continue to develop dual participation protocols as part of the IESO's TDWG.

Utility Remuneration

Currently, LDCs have performance regulation to support the identification of least-cost alternatives, while utility revenues are traditionally based on a return on equity model focusing on capital expenditures. Although the current remuneration model is suitable for utility owned and operated energy storage (e.g., capital asset investment), the regulatory framework needs to ensure that LDCs are agnostic to the least-cost option to provide distribution services, including the procurement of services from a third-party provider. The OEB's Framework for Energy Innovation (FEI) working group is considering utility incentives for using third-party owned DERs at

8 IESO TDWG. https://ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Transmission-Distribution-Coordination-Working-Group

this time, however, staff have indicated utility remuneration would be part of future phases of the FEI work.[9]

There are several novel approaches to remuneration Ontario could further explore. One approach may be to adopt a share-of-savings incentive, whereby the LDC would earn a percentage of the total savings achieved by the NWA relative to a traditional asset (i.e., to service as an incremental incentive to the utility). This approach was piloted in Central Hudson's Peak Perks project, a demand response program in New York. The New York State Department of Public Service authorized Central Hudson to earn 30% of the savings, with 70% of savings being passed through to the ratepayers.

Another approach adopted in New York is an earnings adjustment mechanism (EAM), in recognition of utility transition to a platform services provider. EAMs are incremental to performance incentives received by a utility, in recognition of achieving certain targets or metrics established by the regulator.

Furthermore, the OEB commissioned a report as part of its former Utility Remuneration (EB-2018-0287) consultation by London Economics on possible mechanisms and regulatory reforms utilized in other jurisdictions, including the UK's Totex model, which endeavours to further remove utility incentive towards capital expenditures. The OEB continues to engage with stakeholders with the Framework for Energy Innovation consultation.

Recommendation

- During the next phase of the FEI the OEB should undertake a holistic review of utility remuneration.

Grid Connection

Finally, grid connection of storage to the distribution system should be agnostic to the storage business model and ownership of the storage asset (i.e., connection should not be prioritized or rejected based on asset ownership or use-case). The connection process should ensure transparency and fairness related to connection access and prioritization, recognizing that storage may be developed for different primary purposes, such as IESO's Capacity Auction or RFPs, customer needs, or distribution system needs.

Energy Storage Canada recognizes that significant progress has been made recently by the OEB with respect to improvements to the DER connection process, with new code amendments coming into force in October 2022 to streamline the connection process.[10] The new changes will, amongst other things, categorize DERs as either exporting or non-exporting, standardize the preliminary consultation stage for DER connection requests, establish the classification of cost responsibility rules that apply to DER connections and determine a new DER connection procedure (DERCP) document to outline detailed process steps for DER connection.

9 OEB. Framework for Energy Innovation: Distributed Resources and Utility Incentives. https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/framework-energy-innovation

10 See OEB's DER Connection Review Process: https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/distributed-energy-resources-der

Summary and Conclusions

This paper reviewed four business-models related to utility deployment of energy storage for the purpose of providing distribution services. While each business-model has potential opportunities and challenges, Energy Storage Canada recommends that each option be made available to LDCs and their customers. Like the process for planning for traditional capital assets, an LDC should make its business case and present it as part of the rate application based on current materiality rules. LDCs should evaluate different ownership options within their distribution system plans and should outline plans to maximize the value and increase the utilization of energy storage to reduce costs to customers. Additionally, the OEB should provide further clarity regarding the circumstances in which certain business models should be used and how third parties should be engaged for potential joint-ownership arrangements.

Furthermore, to achieve the benefits of energy storage as an NWA, Ontario's LDCs require a new remuneration framework to ensure the alignment of incentives towards the least cost option. Yet, as this paper demonstrates, the least cost option may only be achievable if additional revenues are considered. Notably, possible revenues earned from the IAM should be considered by LDC planners, along with appropriate risk allocation frameworks. This concept is now established within the OEB's 2021 CDM guidelines and the business models presented in this paper are a demonstration of possible risk sharing approaches.

Energy Storage Canada also recommends considering a review of the impacts of distribution rates on energy storage and encourages LDCs to establish an appropriate rate design for front-of-the-meter and behind-the-meter energy storage. The rate design should reflect the storage asset's actual contribution to peak periods, as well as its value to the distribution system to support peak and valley reduction, facilitating better overall usage of the transmission and distribution grids, and allowing for increased electrification to occur at the most efficient cost to ratepayers.

Overall, Energy Storage Canada is encouraged by activities underway at the OEB and the IESO, including the establishment of the OEB's FEI and the IESO's TDWG. It is our hope that this paper supports further analysis and consideration by OEB and government policy makers. If the recommendations in this paper were adopted, customers would benefit from reduced costs of distribution services, as well as the potential for reduced costs for other wholesale market services, such as capacity and energy. Energy Storage Canada urges the OEB and the IESO to support a balance between utility solutions and competitive solutions, which enables greater system optimization and while providing cost-effective and reliable distribution services.

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