DEMOCRASI Demonstration Project Joint Product Solution BCA Report

Prepared for:

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Executive Summary

This report summarizes the benefit-cost assessment (BCA) of the Opus One Solutions and Kiwi Power Ltd. joint product solution (JPS) developed and demonstrated as a component of the DEMOCRASI project. It summarizes the BCA methodology, describes the project, and includes results of the BCA and the extrapolation of the BCA results to Ontario, Canada, and the UK. The JPS is used to optimize the dispatch of distributed energy resources (DER) while safely avoiding transmission and distribution (T&D) constraints on Bracebridge Generation Ltd. assets, located in Parry Sound, Ontario on the MS3 feeder.

The BCA of the JPS indicates the potential for substantial net benefits of active control of DER using the JPS, based on a utility cost test (UCT) perspective evaluated over a 10-year analysis timeframe—2021-2030—across various scenarios and extrapolation regions; these results are shown in Table 1.

Table 1. UCT BC Ratio Summary by Scenario

	Capacity Auction Benefit	Small Distribution Deferral	Large Transmission Deferral	Capacity Auction + T&D Deferral
Pilot	0.51			
Pilot w/ Low DER %	0.10			
Pilot w/ High DER %	0.55	0.83	3.99	
Extrapolation – Ontario	1.84			2.14
Extrapolation – Canada	2.49			2.72
Extrapolation – UK	3.87			4.49

Source: Guidehouse DEMOCRASI BCA Model

For the pilot project itself, the cost-effectiveness of JPS is dependent on its ability to defer large capital investments – only with a large transmission deferral opportunity is the benefit-cost (BC) ratio of the pilot project greater than 1.0. However, when extrapolating the results to a larger region, JPS is expected to be cost effective regardless of whether a T&D deferral opportunity is present. This improvement in cost effectiveness is mainly driven by economies-of-scale resulting from applying JPS on a larger number of feeders per implementation. Under full scale deployment, the value unlocked by enabling DER participation in a capacity market is sufficiently higher than the JPS implementation costs – this is demonstrated by the fact that all BC ratios for the extrapolation regions are greater than 1.0 in Table 1.

The following are key findings from the joint product solution BCA analysis.

Target Attractive Market Structure

The JPS BCA and extrapolation found that the capacity market structure and rules can dramatically influence the value of the market-based benefits. Targeting active control of DER deployment to the most attractive markets will maximize this benefit category. The minimum requirement is to target the JPS to regions that have capacity markets that allow individual and aggregated DER participation without size restrictions. Markets that pay on bid activation offer opportunities to maximize revenue via a capacity market revenue benefit stream using the JPS's optimization function by operating right up to the maximum DER capacity.

Clearly Plan Local Flexibility Management

Although there are no significant distribution or transmission constraints or violations to defer the potential for active control of DER to replace or defer transmission or distribution capacity upgrades is present given the JPS ability to safely reduce peak load on MS3. Identifying and deploying active control of DER for regions, substations, and feeders with appropriate loading, growth, and capital investment plans will enable these benefits. Extrapolation of benefits across the selected regions indicate that this can be a supplemental benefit area for the JPS. However, a key finding is that DER scheduled to be available for capacity markets will not be available for local needs, so caution is required to ensure that double counting of benefits does not occur. If you cannot count on DER being available for local needs due to bulk market participation, then you likely cannot get much LFM value.

Look for DER Penetration in the Sweet Spot

The baseline DER penetration (nameplate kW / peak load kW) is calculated on MS3 at 21%. The pilot found that as the DER penetration increases up to a hypothetical penetration of 96%, active control of DER provides benefits for peak load reduction, energy savings, and infrastructure upgrade deferral. The specifics of network types by region, as characterized in the extrapolation, will change the sweet spot of DER penetration, and additional analysis will be necessary to localize benefits. In addition, as the DER penetration rises above the safe capacity limits of the feeder, the amount of benefit hits a ceiling driven by the existence of voltage and capacity constraints. Use of the JPS would allow interconnection of more DER up to the limit because it would provide better visibility to Lakeland Distribution and ensure safe dispatch of DER assets.

Active Control of Large Batteries

The ability to operationally add multiple schedule-based and dispatched 750 kW batteries on the MS3 feeder without active control is not practical because of predicted voltage and capacity constraints. The DEMOCRASI pilot analysis found that adding multiple batteries on this feeder can be supported with the JPS enabling use cases including a virtual power plant (VPP) and LFM, but the ability to use the batteries for market participation and peak load reduction is still limited by the existence of voltage and capacity constraints. The JPS allows the utility to leverage the batteries up to the safe limits of the feeder, beyond what a schedule-based dispatch might allow, but the optimization is still constrained by the safe operation of the DER and the feeder.

Next Steps

For the pilot project, this result of a BC ratio less than 1.0 is not surprising given the nature of pilot projects that include the front-loading of costs associated with mobilization, development, and the small scale of the pilot itself. The light feeder loading, minimal DER penetration, and common reverse power flow of the MS3 pilot feeder make this a candidate feeder for a pilot but not one with substantial benefit opportunities. Important indications of potential from this pilot project BCA appear when looking closely at the BCA results calculated for the hypothetical DER and T&D deferral scenarios. In addition, when the results are extrapolated across markets and feeders throughout Ontario, other provinces of Canada, and the UK, indicators of where the JPS is likely to generate positive value appear.

The Guidehouse and DEMOCRASI team did not evaluate if applying the economies of scale at Lakeland Distribution could make the JPS cost effective if applied across a wider section of targeted circuits. However, based on the results in the extrapolation section, it looks likely that a hypothetical JPS implementation across 3 feeders w/ higher DER penetrations of the right type would be cost effective without T&D deferral.

1. Overview

The DEMOCRASI consortium received an innovation grant from the Power Forward Challenge to develop a joint product solution exploring how a combined Kiwi Power Ltd. (Kiwi Power) and Opus One Solutions optimization platform could enable distributed energy resources (DER) to provide services to system operators, local distribution companies (LDCs), and distribution network operators (DNOs). The Dispatchable Energy Market Optimized Constraint Real-time Aggregated System Interface (DEMOCRASI) project builds on assets planned and paid for during another Natural Resources Canada (NRCan) project led by Bracebridge Generation Ltd.: Project Smart, Proactive, Enabled, Energy, Distribution – Intelligently, Efficiently and Responsive, SPEEDIER.[1] Figure 1 shows the Project SPEEDIER assets being used in this project.

The innovation grant was awarded to the DEMOCRASI consortium as the project is expected to provide added social, economic, and technical value to utilities, customers, and broader stakeholders. An operational pilot was performed on the 12.47 kV MS3 feeder on the Lakeland Power Distribution Ltd. (Lakeland Power) network with these DER.

The DEMOCRASI consortium engaged Guidehouse to develop a benefit-cost assessment (BCA) that evaluates the value to the utility, its customers, and broader stakeholders of the pilot project and to provide directional statements on scenarios within which the JPS that might provide more value. The project also extrapolated the value identified during the Ontario demonstration project to a broad group of stakeholders and regions in Canada and the UK.

Figure 1. DEMOCRASI DER Resources

Resource	Capacity (MW / MWh)	Resource type options	Dispatchable*	Behind the meter	Virtual DR resource type	Revenue metered by IESO	Virtual C&I demand response type
Options:		*Demand response resource (virtual)* *Demand response resource (physical)* *Capacity generation (physical)*	*Yes* *No*	*Yes* *No*	*Commercial & Industrial* *Residential*	*Yes* *No*	*Load interruption* *Behind the meter generation*
Grid-connected battery (BESS)**	1.25 / 2.5	Demand response resource (virtual) Demand response resource (physical) Capacity generation (physical)	Yes	No	Commercial & Industrial	No	Load interruption Behind the meter generation *(if FoM on feeder or microgrid)*
Grid-connected solar	0.5 / TBC	Capacity generation (physical)	No	No	Commercial & Industrial	No	Behind the meter generation *(if FoM on feeder or microgrid)*
50x Hot Water Tanks (HWT)	0.15 / TBC	Demand response resource (virtual)	No	Yes	Residential	No	N/A
10x Residential batteries (RESS)	0.05 / 0.135	Demand response resource (virtual)	No	Yes	Residential	No	N/A
Wastewater Treatment Facility (Diesel Generator)	0.75 / TBC	Demand response resource (virtual) Demand response resource (physical) Capacity generation (physical)	No	Yes	Commercial & Industrial	No	Behind the meter generation
Sewage Pumping Station (Sewage Pumping Stn.)	0.35 / TBC	Demand response resource (virtual) Demand response resource (physical)	No	Yes	Commercial & Industrial	No	Load interruption

* Indicate whether they are capable of being a Dispatchable Load (DL)
** A BESS must be registered as load and generation, but it can't be allocated as both.

Source: DEMOCRASI Project

[1] **https://www.speedier.ca/what-is-speedier/**

1.1 Problem Statement

DER aggregators provide their service through the distribution network to the system operator at a cost to LDCs. This leads to grid instability and asset degradation, increasing the need for higher capital expenditures (CAPEX) borne by rate payers.

The DEMOCRASI solution enables LDCs and DNOs to aggregate loads and participate in future markets as they transition toward being service providers and to address increased DER penetration on distribution networks, increasing the accessibility of energy capacity and ancillary services markets.

The consortium, as listed in the following section, worked with Guidehouse to advise on and develop a BCA and extrapolation methodology, calculate the BCA and extrapolation results, and develop this report.

1.2 Stakeholders

The primary participant in the DEMOCRASI pilot is Bracebridge Generation Ltd., which received up to $3 million (£1.8 million) from NRCan and the UK Department for Business Energy & Industrial Strategy (BEIS) Power Forward Challenge to start building its smart energy systems solution. Bracebridge Generation Ltd. (under parent company Lakeland Holding Ltd.), with consortium members Opus One Solutions (Toronto, Canada) and Kiwi Power (London, UK), submitted the successful DEMOCRASI project application.

Stakeholder list:

- Opus One Solutions
- Kiwi Power Ltd.
- Lakeland Holding Ltd.
- NRCan
- UK Department for BEIS
- Western Power UK
- Ontario Independent Electricity System Operator (IESO)

1.3 Objectives and Foundational Questions

The four key objectives of NRCan and the UK Department for BEIS Power Forward Challenge are as follows:

- Demonstrate innovative technology solutions that can aggregate and manage increasingly large and complex groups of DER to support grid flexibility, stability, and reliability.
- Build on Canadian and UK strengths in smart grid technology and bring together innovators from both countries to design solutions for the grid of the future.

- Create concrete opportunities for Canadian firms looking to expand into UK (and European) markets and UK firms looking to expand into Canadian (and North American) markets.
- Support Canadian and UK leadership and competitiveness in clean technology innovation and the anticipated market opportunities for smart grid technologies in 2030 and beyond.

In addition to the previously listed objectives, the DEMOCRASI pilot is looking to address two foundational questions:

1. What are the benefits of active DER control in the pilot area to the utility? Specifically, project DEMOCRASI is targeting simulated participation in the IESO Market, Local Flexibility Management, and Islanded Microgrid use cases.
2. How do the benefits observed in the pilot scale and how to apply findings from the pilot to Ontario, Canada, and the UK?

1.4 DEMOCRASI BCA Project

The DEMOCRASI BCA project consists of two main components: calculating a BCA for the DEMOCRASI pilot project in Ontario using the JPS and extrapolating benefits across Canada and the UK. The BCA used for the DEMOCRASI project builds on standard industry BCA methodology, configured with project-specific cost, benefit, and use cases. The extrapolation methodology builds on the DEMOCRASI BCA by scaling the observations throughout the identified regions.

The basics of the approach used in the BCA is to examine the impacts of active control of DER from the DEMOCRASI JPS relative to a baseline on the MS3 feeder at Lakeland Power in Ontario. This is done using the baseline to outcome concept along with defined benefit and cost streams.

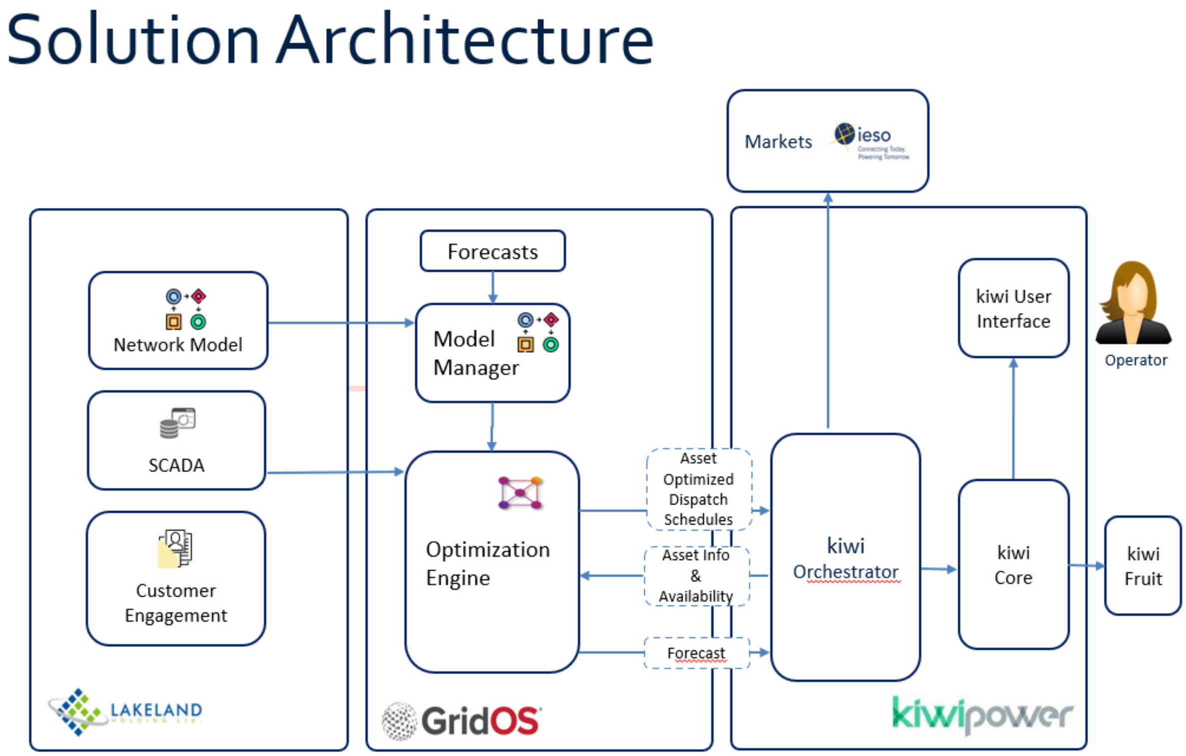
Extrapolation regions:

- Canada | Ontario
- Canada | Alberta
- UK | England
- UK | Northern Ireland
- UK | Scotland
- UK | Wales

1.5 Joint Product Solution

The JPS includes commercially available products integrated together from Opus One Solutions and Kiwi Power. These include Opus One Solutions' GridOS and Kiwi Power's Grid CORE, as Figure 2 shows.

Figure 2. JPS Context



Source: Lakeland Power

1.5.1 Opus One Solutions GridOS

Opus One's GridOS is an advanced analytics platform designed to drive the evolution of the electricity grid. It helps utilities optimize their distribution systems by creating a digital twin of the electricity distribution network. By modelling the grid in its as-operated state, utilities can analyze and optimize complex two-way power flows and use the GridOS modules to develop robust and cost-effective distribution system plans, deliver real-time energy management, and operate transactive energy markets.[2]

1.5.2 Kiwi Power Local Grid CORE

Kiwi Power's Local Grid CORE helps grid operators manage flexibility programs and incentivise market participants to support them in local grid constraint management. Kiwi CORE engages flexibility suppliers with ready-made features to register and connect monitored assets, track real-time availability of assets, dispatch assets, monitor dispatches, track discrepancies, and provide the data required for downstream settlement and billing. Kiwi Power also provides sample documentation, program incentives, and template supplier portals to jumpstart new flexibility programmes.[3]

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[2] Opus One Solutions: **https://www.opusonesolutions.com/**

[3] Kiwi Power Ltd.: **https://www.kiwipowered.com/**

1.5.3 Joint Product Solution Deployment

The JPS consists of two environments that have been deployed for the DEMOCRASI demonstration project: operational deployment and simulation deployment.

The simulation deployment can reflect any scenario as it allows the project team to vary all inputs. This is the deployment used for the pre-pilot BCA, which was used to calibrate the Ontario operational deployment.

The simulation deployment passes data into GridOS's optimization engine and outputs the results that would have been realized given the exact same datapoints being passed on as a part of the operational deployment. Three optimizations were utilized by the simulation deployment.[4]

1.5.4 Use Cases

The BCA methodology relies on creating impacts to specific uses cases that are associated with both costs and benefits. The two use cases were developed and refined by Guidehouse and the DEMOCRASI project team: virtual power plant (VPP) and local flexibility management (LFM). A third use case, islanded microgrid was discussed during the initiation of the DEMOCRASI BCA, but this use case was analyzed qualitatively—costs and benefits were not identified, monetized, and extrapolated.

- **VPP use case:** Active control of DER with the JPS to participate in the Ontario independent system operator (ISO) capacity auction.
- **LFM use case:** Active control of DER assets to reduce peak loading conditions to defer distribution capacity upgrades.
- **Islanded microgrid:** Active control of DER to ensure power flow across a virtual point of interconnection is zero. This use case was designated for qualitative treatment in the BCA and is discussed in the report but is not included in the BCA results.

The VPP and LFM use cases result in data that is used to calculate impacts across different network models and scenarios in the BCA analysis. The data is obtained through modelling, simulation, and the operational pilot. Specific data used includes feeder head loading and meter point loading throughout the network models. Meter point information is used to estimate impacts due to the VPP use case, while feeder head information is used for the LFM use case. Comparing the feeder head loading data on MS3 for each model and scenario for each use case with the baseline feeder head loading data enables calculation of impacts in kW and kWh for the LFM use case. Correspondingly, the meter point data is used for each model and scenario to assess the impacts of the VPP use case. The VPP also uses bid update information to assess impacts of the market-based interactions. The impacts associated with benefit streams are converted to benefit dollar values as part of the BCA.

1.6 DER Asset Installation

The DEMOCRASI JPS BCA is based on the installation of assets performed under another NRCan-funded project, SPEEDIER. The assets used in the BCA project are located in Parry Sound, Ontario within Lakeland Power service territory. The demonstration project included the

[4] Opus One Solutions, 2021.

installation of DER on the MS3 feeder (shown in Figure 3 and Figure 4) and included the existing CASCADE hydro generation facility.

Figure 3. Parry Sound Overview Map

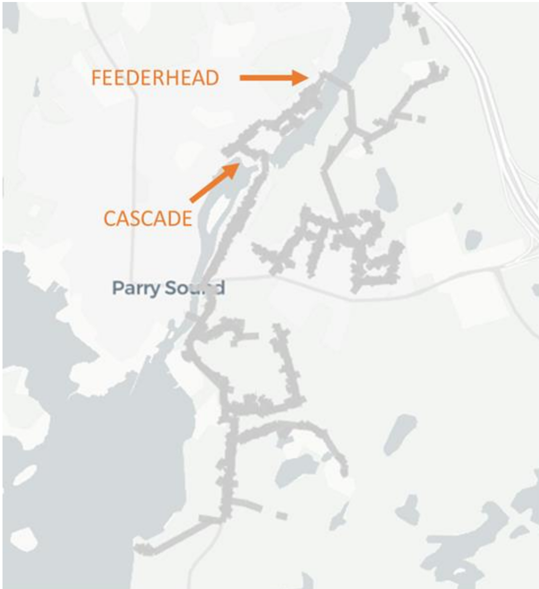
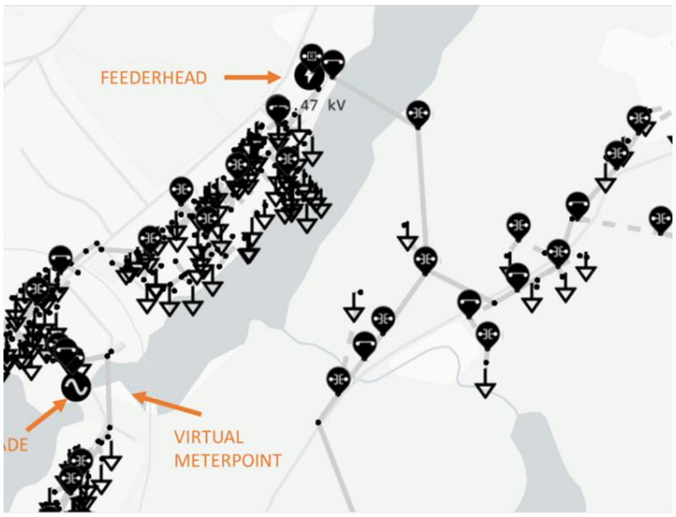


Figure 4. MS3 Feeder Map



DER deployment under the SPEEDIER project used in DEMOCRASI include the physical assets and software architecture integrations. Guidehouse and the DEMOCRASI team worked to identify a pilot timeframe that would align with equipment installation and commissioning, which resulted in a pilot timeframe of July 2021. Table 2 shows the specific DER included in the project.

Table 2. DER Assets Considered for Use by DEMOCRASI

DER asset	Asset owner	Able to contribute to IESO capacity auction?	Able to service local peak-shaving services?	Automated asset control?
Grid-Scale Battery Energy Storage System	Bracebridge Generation	Yes	Yes	Yes
Residential Battery Energy Storage System Fleet	Bracebridge Generation	Yes	Yes	Yes
Water Heater Fleet	Homeowners	No	Yes	Yes Fleet manager[5]
Electric Vehicle Charger Fleet	Bracebridge Generation	No	Yes	Yes Fleet manager[6]
Wastewater Treatment Facility Backup Generator	Town of Parry Sound	Yes	No	Yes
Sewage Pumping Facility Backup Generator	Town of Parry Sound	Yes	No	Yes
Cascade Hydroelectric Generation	Bracebridge Generation	No	No	No
Solar PV	Bracebridge Generation	No	No	Yes

The MS3 feeder is a radial distribution feeder terminating at a substation fed by the Hydro One Networks Inc. (Hydro One) transmission system. The Hydro One transmission station that serves the MS3 feeder is capacity constrained and is scheduled for upgrade in 2024.

[5] The water heaters are controlled in aggregate by the DER management system (DERMS) solution deployed on the MS3 feeder. Each residential Battery Energy Storage System cannot be controlled individually; instead a fleet manager aggregates residential water heater fleet operations. The fleet manager for this deployment is Packetized Energy. The demand response program designed will shape limitations around the use of water heater curtailment that ensure customers' water heaters are not disconnected for long periods of time.

[6] The electric vehicle chargers are controlled in aggregate by the DERMS solution deployed on the MS3 feeder. Each charger cannot be controlled individually; instead a fleet manager aggregates electric vehicle fleet operations. The fleet manager for this deployment is SWTCH.

2. BCA Methodology

This section summarizes the methodology used to calculate the BCA including the approach, benefits, and costs. The team built the BCA from a standard utility industry BCA framework, configured existing tools with DEMOCRASI specifics, and created a tailored approach to perform the extrapolation.

Baseline vs. Outcome Concept

The concept of baseline compared to an outcome is critical to the BCA methodology. The baseline captures what *would have happened* in the absence of the JPS. The outcome is a scenario that captures *what did happen* or *what was simulated to happen* using the JPS given the stated assumptions, electrical network configuration, and JPS behavior.

Each benefit is calculated from impacts created by comparing parametric values for the baseline versus outcome JPS cases. Importantly, this requires careful consideration of how the feeder head loading (for LFM) and meter point loading (for VPP) are affected by JPS relative to the baseline. Additionally, one must consider the capital costs that would have been incurred to accommodate load growth and any additional DER installed on the feeder over the analysis period and whether these costs can be avoided or deferred with a JPS implementation.

2.1 BCA Framework

Guidehouse selected the *National Standard Practice Manual (NSPM) for Benefit-Cost Analysis of Distributed Energy Resources*[7] (NSPM DER Framework) as the framework for conducting the BCA. This manual includes “a systematic approach for assessing the cost-effectiveness of investments by consistently and comprehensively comparing the benefits and costs of individual or multiple types of DERs with each other and with alternative energy resources.”

The methodology applied also aligns with IESO’s guidance for conducting cost-effectiveness (CE) analysis for conservation and demand management (CDM) resources[8] (IESO CDM EE Framework). Using the NSPM framework, the team identified the following impacts for assessment in the pilot project, as outlined in Table 3.

Table 3. Benefits Assessed

Type	Benefit Category	Impact(s) (NSPM)	Benefit Description
Utility	Capacity Auction Revenue	Capacity	The generation capacity (kW) required to meet the forecasted system peak load. For JPS, this includes capacity auction revenue.

[7] **https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf**
[8] **https://www.ieso.ca/-/media/Files/IESO/Document-Library/EMV/CDM_CE-TestGuide.ashx**

Type	Benefit Category	Impact(s) (NSPM)	Benefit Description
Utility	Distribution Capacity Costs	Distribution Capacity, Distribution Voltage, Reliability	Maintaining the availability of the distribution system to transport electricity safely and reliably. Maintaining voltage levels within an acceptable range to ensure that both real and reactive power production are matched with demand. Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components.
Utility	Transmission Capacity Costs	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably.
Utility	Energy Costs	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers.
Societal	Social Cost of Carbon	GHG Emissions	Greenhouse gas (GHG) emissions created by fossil-fueled energy resources.
Societal	NEI Adder	Non-Energy Impacts	Non-energy impacts (NEI) result in benefits not directly tied to energy. This includes a wide range of categories such as safety, public health, economic effects, etc.

In addition to the impacts listed in Table 3, the NSPM DER Framework lays out numerous additional impacts from DER programs such as market price effects, risk, reliability, NEIs, economic and jobs impacts, and more. While some of these impacts may be non-trivial from JPS, the Guidehouse and DEMOCRASI team did not perform this analysis as part of the pilot project. Therefore, these values are not quantified or monetized in this report.

Capacity Auction Revenue

This benefit captures the net revenue obtained by facilitating the participation of DER into a capacity auction. To fully capture the net effect on revenue, the Guidehouse team included any avoided non-performance penalties in the calculation. The equation used to calculate capacity auction revenue is shown as follows, with the parameters used in the benefit calculation described in Table 4.

Benefit = JPS Revenue – Baseline Revenue + Avoided Non-Performance Charges

Table 4. Capacity Benefit Parameters

Parameter	Units	Description	Source
Baseline Revenue	$	The revenue obtained from participating in the capacity auction (e.g., availability or performance payments) in the baseline case. Zero in the baseline case because the baseline consists of not participating in a capacity auction.	IESO UCAP reference price [9]
JPS Revenue	$	The revenue obtained from participating in the capacity auction in the JPS case.	IESO UCAP reference price[10]
Avoided Non-Performance Charges[11]	$	Benefit from avoiding non-performance charges due to the JPS.	IESO

This BCA assumes the revenue paid through the capacity auction is properly priced to capture the value of avoided generation capacity. The team did not include a separate value stream for avoided generation capacity to avoid double counting.

Distribution Capacity Costs

By using JPS to shave the local peak and improve grid performance (e.g., by reducing or avoiding voltage violations), utilities may be able to avoid or defer capital upgrades on the distribution system. Consistent and defensible load growth estimates, detailed criteria for distribution needs, and decision points for triggering distribution system upgrades are all key components of identifying the value of the deferred capital upgrade cost. The equation used to calculate these benefits is shown as follows, with the parameters used in the benefit calculation described in Table 5.

$$\textit{Benefit} = \textit{Baseline Capital Upgrade Cost} - \textit{JPS Capital Upgrade Cost}$$

Table 5. Distribution Capacity Benefit Parameters

Parameter	Units	Description	Source
Baseline Cost of Distribution	$	Present value of the cost of capital upgrades on the distribution system for the baseline case. This value can range from $100,000 for regulation upgrades to between $500,000 and $1 million for major feeder upgrades.	Standard industry assumption validated with Lakeland Distribution

[9] https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Capacity-Auction

[10] https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Capacity-Auction

[11] For customer-owned assets, the uncontrolled revenue may be *higher* than the controlled case; however, non-performance charges will also be higher in the uncontrolled case, so there is a tipping point to consider.

Parameter	Units	Description	Source
JPS Capital Upgrade Cost	$	Present value of the cost of capital upgrades on the distribution system for the JPS case. This value is likely to be less than the uncontrolled case because of better management of local voltage issues and peak load.	Standard industry assumption lowed by JPS

Transmission Capacity Costs

This benefit results in avoided or deferred transmission capital upgrades due to reduced peak load and improved power flow. The equation used to calculate these benefits is shown as follows, with the parameters used in the benefit calculation described in Table 6.

Benefit = Baseline Cost of Transmission – JPS Cost of Transmission

Table 6. Transmission Capacity Benefit Parameters

Parameter	Units	Description	Source
Baseline Cost of Transmission	$	The present value of the forecasted costs to maintain availability of the transmission system in the baseline case. This includes CAPEX required to alleviate capacity constraints and other grid performance issues.	Project-specific
JPS Cost of Transmission	kW	The present value of the forecasted costs to maintain availability of the transmission system in the JPS case.	Project-specific

Energy Costs

Avoided energy costs are calculated by taking the difference in hourly energy consumption (comparing JPS to the baseline), performing a true up to those impacts from the feeder level to the bulk system level using a line loss factor, and then applying an hourly wholesale energy price. The equation for calculating the avoided energy costs is shown as follows, with the parameters summarized in Table 7.

*Benefit = (Baseline Consumption – JPS Consumption) * Avoided Energy Cost * LLF*

Table 7. Energy Generation Benefit Parameters

Parameter	Units	Description	Source
Baseline Consumption	MWh	Hourly energy consumption of the DER in the baseline case.	Baseline DER load shapes (various sources)
JPS Consumption	MWh	Hourly energy consumption of the DER in the JPS case.	Power flow simulation
Avoided Energy Cost	$/MWh	Forecasted hourly energy prices over the analysis horizon. In Ontario, these are referred to as the Hourly Ontario Energy Price (HOEP).	IESO CDM CE Tool V8_2021-04-20
Line Loss Factor (LLF)	None	LLF [1/(1-%)] from the meter to the bulk system.	IESO CDM CE Tool V8_2021-04-20

Table 8 shows the avoided energy cost values by year, season, and time of use period. These are the same values as applied in the IESO CDM CE Tool.[12]

Table 8. Avoided Energy Costs by Season and Time of Use Period

Year	Winter On Peak	Winter Mid-Peak	Winter Off-Peak	Summer On Peak	Summer Mid-Peak	Summer Off-Peak	Shoulder Mid-Peak	Shoulder Off Peak
2021	$17.06	$21.76	$17.20	$24.42	$27.99	$21.39	$19.55	$16.94
2022	$23.32	$25.01	$26.97	$29.62	$28.83	$21.68	$24.45	$20.85
2023	$31.85	$30.79	$28.71	$34.08	$33.29	$27.02	$27.24	$25.25
2024	$33.49	$30.65	$32.74	$30.78	$31.97	$23.31	$26.55	$24.12
2025	$36.07	$33.90	$35.75	$37.19	$37.16	$32.16	$29.77	$26.81
2026	$37.67	$34.06	$32.05	$34.39	$34.06	$29.40	$27.82	$26.20
2027	$37.09	$33.31	$33.32	$34.43	$34.05	$27.58	$24.84	$21.37
2028	$35.14	$33.14	$28.01	$36.45	$35.60	$29.19	$27.76	$26.16
2029	$39.04	$34.81	$30.52	$34.43	$34.47	$24.25	$25.95	$24.53
2030	$36.13	$32.26	$30.27	$37.48	$36.45	$31.03	$29.78	$26.45

Social Cost of Carbon

GHG emissions reductions result in a benefit to society based on the social cost of carbon. Using the IESO CDM CE Framework, the team applied an hourly emissions value in terms of $/MWh to the energy savings resulting from the JPS relative to baseline. The equation used to calculate these benefits is shown as follows, with the parameters used in the benefit calculation described in Table 9.

[12] **https://www.ieso.ca/-/media/Files/IESO/Document-Library/EMV/IESO-CDM-CE-Tool_V8_2021-04-20.ashx**

*Benefit = (Baseline Consumption – JPS Consumption) * Social Cost Of Carbon * LLF*

Table 9. Societal Cost of Carbon Parameters

Parameter	Units	Description	Source
Baseline Consumption	MWh	Hourly energy consumption of the DER in the uncontrolled (i.e., baseline) case.	Baseline DER load shapes (various sources)
JPS Consumption	MWh	Hourly energy consumption of the DER in the JPS case.	Power flow simulation
Avoided Social Cost of Carbon	$/MWh	Forecasted social cost of carbon per MWh of wholesale energy generated. The emissions intensity (kgCO2e/MWh) is baked into this value as assumed by the IESO CDM CE Tool.	IESO CDM CE Tool V8_2021-04-20
LLF	None	LLF [1/(1-%)] from the meter to the bulk system.	IESO CDM CE Tool V8_2021-04-20

Table 10 shows the avoided social cost of carbon values per MWh generated by year, season, and time of use period. These are the same values as applied in IESO's CDM CE Tool.

Table 10. Social Cost of Carbon ($/MWh) by Season and Time of Use

Year	Winter On Peak	Winter Mid-Peak	Winter Off-Peak	Summer On Peak	Summer Mid-Peak	Summer Off-Peak	Shoulder Mid-Peak	Shoulder Off Peak
2021	$5.25	$6.71	$4.92	$5.43	$4.95	$3.26	$4.14	$2.54
2022	$5.90	$5.92	$7.31	$7.87	$5.98	$3.61	$5.69	$4.87
2023	$7.64	$7.19	$6.89	$9.32	$9.31	$9.06	$7.58	$8.07
2024	$8.06	$8.07	$9.27	$8.91	$8.95	$5.34	$7.48	$7.78
2025	$7.16	$7.43	$7.22	$6.83	$8.29	$8.18	$8.44	$8.25
2026	$6.74	$6.77	$8.01	$7.85	$8.79	$9.15	$9.00	$8.84
2027	$6.69	$7.08	$7.88	$7.21	$8.27	$7.87	$6.11	$6.41
2028	$7.82	$7.98	$8.45	$7.00	$8.29	$9.11	$8.00	$8.50
2029	$7.15	$7.35	$7.60	$8.67	$9.31	$8.70	$7.52	$7.97
2030	$8.20	$8.56	$9.05	$7.21	$8.30	$8.40	$8.07	$9.13

NEI Adder

Per the IESO CDM CE Framework, an adder for NEIs is applied on top of all total resource cost (TRC) benefits. Guidehouse included this 15% adder to all utility and customer benefits. This category is intended to estimate the collective impact of a wide range of impacts not directly related to energy, such as human health, environmental health, water resources, etc., and is shown in Table 11.

$$Benefit = Total\ TRC\ Benefits * NEI\ Adder$$

Table 11. NEI Adder Parameters

Parameter	Units	Description	Source
Total TRC Benefits	$	TRC test benefits calculated based all utility and customer benefit streams.	Calculated
NEI Adder	%	Adder to the total benefits to account for NEIs (comfort, environmental, health, water, etc.).	IESO CDM CE Tool V8_2021-04-20

2.2 Cost Test

Guidehouse assessed the value of JPS from two cost test perspectives: the societal cost test (SCT) and the utility cost test (UCT). The UCT is the primary lens through which the value of the JPS is evaluated for each model and scenario combination; the SCT is presented to provide grounding in other ways to characterize the value of active control of DER.

The **SCT** shows the value of JPS to the utility, customers, third-party DER owners, and society as a whole. Because this cost test boundary considers the collective value to these entities, incentives paid from the utility to the DER owners or customers are treated as a transfer payment and are not considered as a cost. The results of this cost test indicate whether the investment is worth considering from a government policy perspective, including potential environmental and other NEIs.

The **UCT** shows the value of JPS from a utility perspective. This perspective compares the value of active DER control relative to the supply-side and infrastructure investment necessary to meet forecasted service requirements. Contrary to the SCT, it treats DER incentives as a cost and only includes benefits that are directly attributed to the utility.

Table 12 summarizes how each value stream is treated in the context of these two cost tests.

Table 12. Cost Test Definitions

Value Stream	SCT	UCT
Capacity Auction Revenue	Benefit	Benefit
Distribution Capacity Costs	Benefit	Benefit
Transmission Capacity Costs	Benefit	Benefit
Energy Costs	Benefit	Benefit
Social Cost of Carbon	Benefit	N/A
NEI Adder	Benefit	N/A
JPS Costs	Cost	Cost

The NSPM DER Framework suggests the use of the resource value test (RVT) to assess the value of investments aligned with policy goals and objectives. Due to the geographic scope of this analysis (i.e., Canada and UK), the team did not conduct the required steps (as outlined in NSPM) to properly define the RVT for all extrapolation regions. Instead, Guidehouse determined that the SCT and UCT perspectives would be sufficient in understanding the value of JPS.

2.3 Discounting

The BCA performed for this pilot considers annual benefits and costs over a 10-year analysis horizon. To compare apples-to-apples, each annual cash flow is converted from nominal dollars into present value dollars using a discount rate before calculating key BCA outputs such as net present value and benefit-cost (BC) ratio. Stated differently, one must consider the time value of money (one dollar today is worth more than one dollar next year) when analyzing costs versus benefits. A major set of benefit streams are transmission and distribution (T&D) capital investment deferral. These benefits are driven entirely by the timing of capital investments and the value of deferring these for a number of years. Alignment of T&D planning criteria in a consistent manner with the BCA is extremely important as the magnitude of T&D investments can be large and slight changes in timing can impact the value greatly.

For societal values (i.e., social cost of carbon and NEI adder), Guidehouse applied a 5% nominal discount rate. For utility values (i.e., capacity auction revenue, T&D capacity costs, energy costs, and JPS costs), the team applied a 7% nominal discount rate.

3. JPS BCA

This section covers the JPS BCA in detail including considerations, baseline, operational pilot, simulation, impact calculation, results, and conclusions. Nuances of the DER installation, the JPS simulation capabilities, and character of the MS3 feeder all contribute to the benefit-cost calculation described in this section. The sparse data available to perform the BCA calculations resulted in the need to make simplifying assumptions, such as using representative days (e.g., peak summer, peak winter, shoulder seasons) to calculate values for the entire year rather than running 8,760 hourly simulations. Despite these simplifications, the BC ratios calculated in this directional analysis fall within expected bounds and enabled the team to identify key themes and draw conclusions.

3.1 Considerations

The JPS BCA addresses the costs and benefits to Lakeland Power (UCT) and society (SCT) to deploy the JPS on the MS3 feeder within the context of the VPP and LFM use cases under test conditions that include DER of different types and penetration levels on MS3. The following considerations were identified during the project that constrained the BCA calculation.

3.1.1 Reverse Power Flow on MS3

The MS3 feeder often exhibits reverse power flow onto the Hydro One system because of the 3.2 MW Cascade hydro generating station located on the feeder. Generation from Cascade GS for much of the year is greater than the load on the MS3 feeder, so the feeder is usually in reverse power flow through the substation transformer. This effectively reduces the net loading on the feeder, reducing the local T&D benefits of active control of DER for the LFM use case. Importantly, Cascade hydro generation is much steadier and more predictable than typical solar PV generation and does not produce the stochastic variability characteristic of PV-dominated feeders. The analysis addresses this constraint by exploring theoretical high DER penetration scenarios to place reasonable bounds around more typical feeders.

3.1.2 Hydro One Transmission Upgrades

The high voltage transmission substation on the Hydro One system that feeds MS3 is at capacity. The cost of the upgrade to the transmission substation is $27 million,[13] and this investment would occur in 2024.[14] The capacity-based investment would be initiated by Hydro One even through the cost of this upgrade will be borne by the Lakeland Power customer base. The BCA analysis does not specifically include replacing or deferring this transmission capacity upgrade due to timing and the small magnitude of the currently installed DER assets on MS3. Specifically, the transmission investment is already in the planning phase, and the potential benefits of the JPS to actively control DER for transmission deferral would need to be proven out. Also, because the transmission substation is already over capacity and the amount of currently installed DER on MS3 is small relative to the capacity constraints on the Hydro One transmission station, it does not appear that the pilot can materially address loading on an

13 https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/southgeorgianbaymuskoka/Documents/South_Georgian_Bay-Muskoka_RIP_Final.pdf

14 https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/Documents/HONI_OEB_RP_STATUS_REPORT_20201102.pdf

upstream transmission substation to facilitate a transmission investment deferral. The analysis addresses this constraint by exploring theoretical deferral scenarios to place reasonable bounds around transmission deferral. Other feeder candidates at Lakeland Distribution will have different loading profiles and potential for transmission deferral opportunities given timing, total deferral impact amount, and technical viability.

3.1.3 Lack of Distribution Constraints

Normal loading on MS3 combined with the 3.2 MW generation by the Cascade hydro facility results in low feeder head loading relative to the capacity of equipment and conductors on MS3. This resulted in negligible voltage and power flow violations in the baseline case. Therefore, there is limited value for deferral or avoidance of capital upgrades on the MS3 distribution system over the next 10 years. Although the specific configuration, generation, and loading of the MS3 feeder precluded this BCA from demonstrating the value of deferred capital investment, this benefit stream is commonly considered as a primary benefit of active DER control. The analysis addresses this constraint by exploring theoretical deferral scenarios to place reasonable bounds around distribution deferral.

3.1.4 Operational Pilot Timing

Timing of the operational pilot was initially targeted for the winter peak period of MS3, December 2020 and January 2021, but delays in the DEMOCRASI project due to the COVID-19 pandemic resulted in the operational pilot running from June 1 through July 15. The winter operational pilot period was selected because MS3 is a winter peaking feeder, and it was expected that the most value for the JPS would be established with the VPP and LFM use cases around the winter peak period. This situation does introduce additional uncertainty into the calculation of pilot benefits that the team mitigated by collecting data during the summer operational pilot and then simulating representative days during the winter peak to be used to estimate benefits.

3.2 Baseline

Establishing defensible baseline conditions is key to a successful BCA. The first baseline assumption is that Lakeland Power allows any number of DER onto the system and makes whatever capital upgrades are necessary to increase hosting capacity and mitigate power quality issues. This appears to be valid for connection of small DER given the current loading on MS3 but will break down for larger DER and as DER penetration on MS3 increases. This assumption sets the stage for value to be captured in the avoided distribution capital upgrades benefit through the use of the JPS.

The baseline data for the DEMOCRASI BCA consists of the most recent representative feeder loading data of MS3, addition of simulated uncontrolled DER, and application of representative load growth over the 10-year analysis timeframe, 2021-2030. Each of these concepts is described in more detail in the following sections.

3.2.1 Feeder Loading Data

The team gathered and reviewed feeder head loading and meter information for the MS3 feeder for 2010-2020. Feeder re-configuration, load growth, and equipment replacement all complicated creating a consistent feeder loading view of MS3. The initial assessment of feeder data found that loading in 2020 was significantly different from historical loading. The team attributed this to the pandemic starting in 2020 that resulted in abnormal feeder loading and discounted using 2020 feeder loading as the anchor of the baseline. 2019 exhibited significant winter and summer peak load variance from the 10-year average and was judged as not representative due to weather variability. The team found that 2018 feeder loading appeared to have a load profile that matched the prior two years, 2016 and 2017, aligned with the 10-year loading average, matched the year-over-year load growth, and was judged suitable for the base year for assembling the baseline.

3.2.2 Network Model Correction

Because of the changes to MS3 over time, network model corrections were required. The Guidehouse and DEMOCRASI team looked for anomalies including outages, large block load additions, and feeder reconfiguration and then corrected their impacts in the baseline data. Correction included ensuring that the 8,760 kW values for MS3 were continuous without jumps or disconnects. Typical practice in the industry to establish a baseline is to take nominal feeder head loading over 5 years, ensure that the data is consistent across the year, validate load growth over the time period, and address issues or disconnects observed in the data. Because of the large number of network changes, the Guidehouse and DEMOCRASI team chose to use a single year, 2018, as the basis of the baseline and to reduce the complexity of using multiple years. The team simulated losses on MS3 for 2018 and added these losses into the feeder head and meter data as a minor model correction.

3.2.3 Weather Normalization

Performing weather normalization is necessary to reduce the impact of anomalous weather and to create an average weather loading profile. Typically winter and summer temperature extremes are what drive the peak load and removing 1 out of 10-years for consistency for weather variability may be necessary. The Guidehouse and DEMOCRASI team looked at feeder loading data for 2010 through 2020 and made the assessment that 2018 was a representative weather year, eliminating the need to perform weather normalization over the study period. The team acknowledges that without performing detailed weather normalization uncertainty may be introduced into the analysis but mitigated this by choosing what appeared to be an average weather year.

3.2.4 DER Behavior

Simulating the behavior of uncontrolled DER in 2021 and beyond is done using load shapes associated with each type of DER asset, scaling to the size of each DER installed on MS3, and finally projecting DER growth over the analysis time period. These uncontrolled DER load shapes were provided by Guidehouse to Opus One and were included in the GridOS platform simulation models. Opus One then scaled each of the uncontrolled DER shapes to the installed DER assets on MS3.

3.2.5 Load Growth

Common practice in the industry for load growth assessment is to use the most granular representative load forecast available to create a defensible position that the specific load growth forecast applied to each location includes tracible links to feeder, substation, substation group, region, utility, and ISO area forecasts. Further refinement is possible to the load forecast by correcting for demographics, customer type, and other real world load impacts; these were not applied in this analysis. Load forecast is a key component of the BCA as increases in load may result in net positive benefits at a load threshold. If this occurs in the timeframe of the analysis, it can be used to identify key findings from the analysis.

Lakeland Power has historically used a load forecast of 0.5% to 1.0% for the region. Furthermore, the proposed transmission upgrade by Hydro One to the transmission substation may allow 2% load growth beyond 2023, but this has not been reflected in the distribution load forecast used by Lakeland Power. Guidehouse examined the feeder head loading on MS3 and observed that historically from 2010 to 2020, a 1% year-over-year load growth appeared to be the best fit for the data available, with the exception of 2019 and 2020.

The team chose to apply a 1% year-over-year load growth to 2019-2030 based on the base year of 2018 in alignment with observed load growth and Lakeland Power's nominal load growth.

3.3 Operational Pilot

The DEMOCRASI team ran an operational pilot on the MS3 feeder from June 1 through July 15, 2021. The JPS deployed for this project is an operational one, meaning SCADA readings and measurements are captured to support short-term forecasting and assets are dispatched in real time. The operational pilot data includes direct outputs at feeder head and meter locations used to calculate the impacts of the VPP and LFM use cases. The operational pilot conducted over six weeks in June and July 2021 was used to inform the summer peak, winter peak, and shoulder day representations of the behavior of DER on MS3 created in the simulator tool. The day representations were then used to calculate impacts for each of the benefit streams across 2021. The impacts were then scaled relative to the baseline across the 2021-2030 study period.

3.4 Simulation

The DEMOCRASI team created three different network models with different assets installed on the MS3 feeder to address the considerations described previously. These models capture a range of DER penetration possibilities that showcase varying levels of value for JPS based on the amount and type of DER. This is particularly useful when extrapolating the results of the pilot BCA to Canada and the UK.

The team took a representative day approach, identifying peak days in representative seasons for summer peak and winter peak loading along with shoulder days that represent the JPS loading on the MS3 feeder during non-peak times in alignment with the operational pilot data. Each of these representative days is scaled to the baseline during the winter peak period, summer peak period, and the remainder of the analysis year using a representative shoulder day. The baseline loading accounts for load growth and uncontrolled DER behavior, and the representative day scaled to the appropriate part of the year can then be used to model the entire load behavior.

The representative days include a winter day, a summer day, and a shoulder day for the primary network model of actual assets installed on MS3. In addition, the team modelled two hypothetical DER installations consisting of a single 250 kW battery and three 750 kW batteries. These two dimensions—temporal and DER penetration—cover the range of conditions under which the JPS is likely to generate value with active control of DER versus uncontrolled DER.

3.5 Impact Calculation

The DEMOCRASI BCA is anchored to the question outlined in the objectives and foundational questions in Section 1.3. The question focuses on the value of the JPS providing active control of DER versus uncontrolled DER for the assets installed on the MS3 feeder from 2021 through 2030. The timeframe is an important consideration for the BCA and, in this case, has been set to align with the study period of 2021 through 2030, but it is not tied to the useful life of the JPS or DER as is typical. Instead, the common timeframe is used to compare the BCA benefits across scenarios and to set up the extrapolation to other jurisdictions.

The base implementation of assets on the MS3 feeder does not capture all possible values of JPS such as distribution deferral benefits due to the nature of the local conditions on the feeder (i.e., no planned upgrades over the next 10 years). To better understand the potential value of JPS under various market and grid conditions, Guidehouse and the DEMOCRASI team assessed theoretical models and scenarios that consider varying levels of DER penetration and local constraints that could potentially be alleviated with JPS. The impacts are structured according to the model and scenario dimensions described in this section.

3.5.1 Models

The models include different sets of assets installed on MS3, including the dispatchable actual pilot assets and two hypothetical additions of DER consisting of small and large batteries. Batteries were selected because of their ability to support both the VPP and LFM use cases with maximum versatility. DER penetration is defined in this report as nameplate DER actively dispatched by the JPS divided by peak load on MS3 and is calculated as shown in Table 13.

Table 13. DER Penetration on MS3 by Model

Model	Peak Load Excluding Cascade Hydro	DER Excluding Cascade Hydro	DER %
Currently Installed Assets	2,335 kW	500 kW	21%
1 x 250 kW Battery	2,335 kW	250 kW	11%
3 x 750 kW Batteries	2,335 kW	2,250 kW	96%

The currently installed assets consist of a dispatchable 500 kW Tesla Megapack battery with a DER penetration of 21%. A single 250 kW battery was selected to represent the low DER penetration case at 11%. Three 750 kW batteries were used to represent the high DER penetration case at 96%.

3.5.1.1 Currently Installed Assets Model

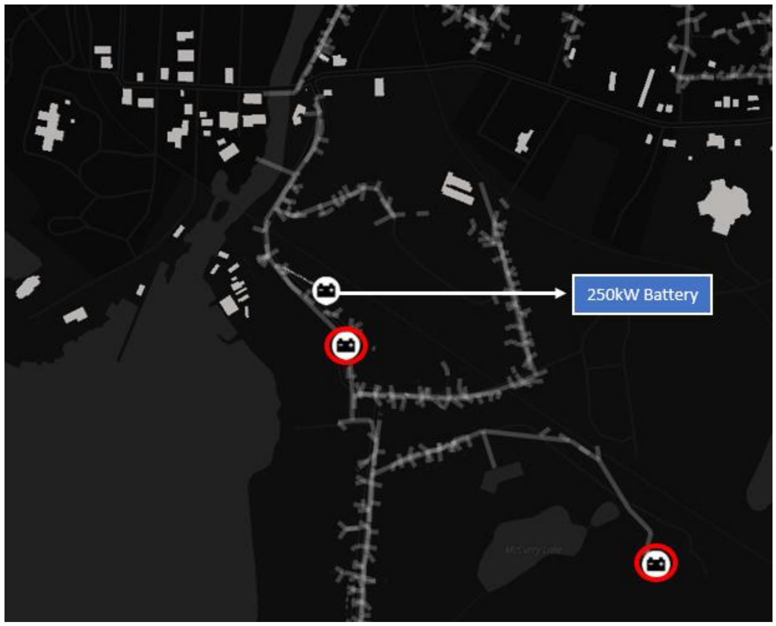
The currently installed assets on MS3 are the basis of the primary model used in the BCA. This model configuration was used for the operational pilot and is shown in Figure 5.

Figure 5. Location of Batteries on MS3

3.5.1.2 1 x 250 kW Battery Model

The 1 x 250 kW battery model takes the currently installed assets model and removes the 500 kW Tesla Megapack battery. The model replaces it with a hypothetical 250 kW battery connected at the location shown in Figure 6.

Figure 6. Location of Single 250kW Battery



The transformer that the 250 kW battery is connected to does not have available capacity for full discharge of this battery, resulting in voltage and over-current violations under different operating conditions that likely limit the ultimate value of the JPS; however, this is a realistic situation for connection of a battery of this size and type.

3.5.1.3 3 x 750 kW Batteries Model

The 3 x 750 kW battery model takes the currently installed assets model and removes the 500 kW Tesla Megapack battery. The model replaces it with three hypothetical 750 kW batteries connected at the locations shown in Figure 7.

Figure 7. Location of 3 x 750 kW Batteries

The addition of three 750 kW batteries to this feeder is at the upper limit that might be considered. Given the loading on this feeder, this many batteries on a feeder with such low loading provides the ability to use the batteries for creative market and local flexibility management purposes.

3.5.2 Scenarios

The scenarios include capacity auction benefits as the primary benefit stream with secondary benefits as a result of T&D deferral due to local capacity constraint reduction using DER and JPS on MS3 compared to the actual amounts found during the BCA project. During the BCA development, the team found that the amount of DER installed on MS3 was not large enough to affect typical T&D distribution scenarios, but because these are common and important benefit streams, the following scenarios were used in the analysis.

3.5.2.1 Capacity Auction Scenario

This is the basic scenario used to evaluate JPS benefits and includes only capacity auction revenue as the primary benefit stream with no transmission or distribution deferral. This reflects the situation found during the DEMOCRASI pilot on MS3. As described previously, the amount of DER available on the MS3 feeder that is controllable by the JPS for the VPP and LFM use cases is not enough to materially defer capacity-based distribution upgrades on MS3 or on the

Hydro One transmission station upstream. The JPS is able to actively control the DER, but the amount of net load reduction at the feeder head is limited and not enough to affect T&D deferral. In the Ontario IESO market, the market payments are based on bid update, not bid activation, even though there is a non-performance penalty if bid activation is not met.

3.5.2.2 Small Distribution Deferral Scenario

Deferring distribution system upgrades for a period of time or replacing the distribution system upgrades permanently is an important benefit stream commonly seen with the LFM use case. Because of the hydro generation on MS3 and the low loading, this is not technically viable in the capacity auction scenario but is considered hypothetically if MS3 had different loading and was due a capacity-based distribution upgrade. This scenario assumes that there is a midsized distribution deferral, $500k, where the JPS is materially able to defer the distribution upgrades for 5 years.

3.5.2.3 Large Transmission Deferral Scenario

The deferral of the Hydro One transmission station scheduled to be upgraded in 2024 is potentially a huge benefit opportunity and is considered with this scenario. The amount of capacity reduction available by using the JPS for the LFM use case is limited and will not materially affect the planned transmission upgrades at the Hydro One transmission station; however, this scenario considers the hypothetical situation that the JPS is able to generate enough capacity reduction to defer a large, $1 million, transmission upgrade for 1 year.

3.5.3 Impacts

The use cases identified earlier, VPP and LFM, result in data that is used to calculate impacts across the models and scenarios described in Sections 3.5.1 and 3.5.2. The data was obtained through modelling, simulation, and the operational pilot. Data includes feeder head loading and meter point loading throughout the network model. Meter point information is used to estimate impacts due to the VPP use case, while feeder head information is used for the LFM use case.

3.5.4 Benefits of the Joint Product Solution

The following benefit streams are associated with the VPP and LFM use cases. The mapping is shown in Table 14.

Table 14. Benefit Stream to UC Map

Benefit Stream	Type of Benefit	Description	LFM Only	VPP Only	VPP + LFM
Capacity Auction Revenue	Primary	Includes both additional revenue obtained from standby notices from the capacity auction and avoided non-performance penalties.		✓	✓
Energy Costs	Secondary	Reduced costs of generating electricity due to energy savings and shifting.	✓	✓	✓
Generation Capacity Costs	Secondary	Avoided costs for generation capacity due to a reduction in peak load coincident with the bulk system.	✓	✓	✓

Benefit Stream	Type of Benefit	Description	LFM Only	VPP Only	VPP + LFM
Transmission Capacity Costs	Primary	Avoided or deferred capital costs for transmission upgrades.	✓	✓	✓
Distribution Capacity Costs[15]	Primary	Avoided or deferred capital costs for distribution upgrades that would otherwise be incurred to avoid voltage violations, thermal violations, and capacity issues resulting from uncontrolled DER.	✓		✓
Improved Power Quality	Secondary	Avoided legal fees and reduced payments to customers for equipment damaged by power surges. This is assumed to be zero due to the baseline described in footnote 15.	✓		✓
Social Cost of Carbon	Secondary	Reduced GHG emissions (linked to avoided wholesale energy costs benefit stream)	✓	✓	✓
NEI Adder	Secondary	15% adder to the total benefits to account for the effect of NEIs (comfort, environmental, health, water, etc.)	✓	✓	✓

3.5.5 Costs of the Joint Product Solution

Establishing the cost side of the BCA is necessary to understand the value on the MS3 feeder and to enable scaling and extrapolation. The JPS is a combination of existing and newly developed software from Opus One Solutions and Kiwi Power and includes both commercially available components and new functionality created for the DEMOCRASI pilot. The creation of custom components for the DEMOCRASI pilot that are not commercially available produces challenges in creating the cost model. To create a cost profile for the entire JPS (commercially available and custom components), Guidehouse worked with Opus One Solutions and Kiwi Power to frame up the cost structure, which is shown in Table 15.

Table 15. JPS Solutions Upfront and Ongoing Fixed, Variable Costs

Parameter	Value ($CAD)	Units	Description
Fixed Upfront Cost	$101,500	Per implementation	Project implementation and engineering cost along with environment and workspace setup
Fixed Ongoing Cost	$51,250	Per-year implementation	License and platform access fees
Variable Upfront Cost	$1,000	Per feeder	Engineering cost on network model

[15] Notably, there are two different baseline viewpoints to consider for avoided distribution capital upgrades: (1) the utility will allow any number of DER onto the system but will make whatever capital upgrades are necessary to increase hosting capacity and mitigate power quality issues, or (2) the utility will curtail DER and prevent future interconnections once the baseline hosting capacity is met. For the purposes of this BCA, Guidehouse proposes using baseline perspective no. 1.

Parameter	Value ($CAD)	Units	Description
Variable Ongoing Cost	$100	Per year-feeder	Annual optimization engine license cost (including maintenance and support)
Variable Ongoing Cost	$5,190	MW-year	Scaling operating costs

3.6 Results

The viable model and scenario combinations are presented in Table 16. Model and scenario combinations with a checkmark (✓) were evaluated, while those shown with an X are not because the combination is not valid. The Small Distribution Deferral and Large Transmission Deferral scenarios do not apply to the currently installed assets model because the amount of capacity reduction available with the currently installed assets is not large enough to replace or defer either of these investments.

Table 16. Models and Scenarios Summary

	Capacity Auction	Small Distribution Deferral	Large Transmission Deferral
Currently Installed Assets	✓	X	X
1x250 kW Battery	✓	X	X
3x750 kW Battery	✓	✓	✓

Results of the analysis of models and scenario combinations are presented as follows. The costs summary is consistent in each case, as are the two cost tests applied to each model scenario combination and are described first.

Cost Summary Common to All Model and Scenario Combinations

Current cost assumptions for all model and scenario combinations are shown in Table 17. This table includes costs for the JPS components, and costs are reflected for each cost-scaling category. The total costs summarized below are high level and reflect a variety of assumptions on the amount of DER on each feeder, the maturity of the data representing the network model, and the level of effort required to implement the joint product solution. In addition, there are build in assumptions on the ability to monitor and control these DER assets centrally through the JPS. The individual implementation will need to factor in all of these factors into the actual implementation costs of the JPS in each of the regions.

Table 17. Cost Summary of JPS

Parameter	MS3	Ontario	Canada	UK	Value ($CAD)	Scaling Units
Fixed Upfront Cost	Applied	Applied	Applied	Applied	$101,500	Per implementation
Fixed Ongoing Cost	Applied	Applied	Applied	Applied	$51,250	Per year-implementation
Variable Upfront Cost	Applied	Applied	Applied	Applied	$1,000	Per Feeder
Variable Ongoing Cost	Applied	Applied	Applied	Applied	$100 $5,190	Per year-feeder Per MW-year

Summary Results

Table 18 summarizes the SCT and UCT results of the model and scenario combinations. As described previously, the UCT is the primary metric used to evaluate the overall value of each model and scenario combination.

Table 18. Model and Scenario Results

Cost Test Summary Table	SCT	UCT
Current MS3 Install Model with Capacity Auction Benefit Scenario	0.60	0.51
1x250kW Battery Model with Capacity Auction Benefit Scenario	0.12	0.10
3x750kW Battery Model with Capacity Auction Benefit Scenario	0.64	0.55
3x750kW Battery Model with Small Distribution Deferral Benefit Scenario	0.95	0.83
3x750kW Battery Model with Large Transmission Deferral Benefit Scenario	4.41	3.99

Observation 1

The capacity auction benefit scenario for the three models resulted in a UCT of 0.51 for the currently installed assets, is lower for the 1 x 250 kW battery at 0.10, but slightly higher for the 3 x 750 kW batteries model at 0.55. Because there are limited LFM benefits without the T&D deferral benefits, the benefits in these cases all flow from the VPP contribution to the Ontario market. The JPS is able to use the 500 kW Tesla Megapack battery in the currently installed assets model; however, even with the 2,250 kW in the 3 x 750 kW battery model, the JPS is not able to get much more value from the Ontario IESO market, increasing the UCT from 0.51 to 0.55. In the case of the 1 x 250 kW battery, the VPP benefits are dramatically lower even though the 250 kW battery is half the size of the 500 kW Tesla Megapack battery that it replaced. In this model, the benefits are limited by the size of the battery and the simulated voltage and overcurrent violations introduced by the limitations of the distribution transformer that the 250 kW battery is connected to.

Observation 2

The JPS can provide deferral value with high DER penetration (3 x 750 kW batteries) under the small distribution deferral benefit scenario, increasing the UCT BC ratio from 0.55 to 0.83. This is consistent with what Guidehouse expects because reducing the feeder head loading in each case reduces the capacity-constrained distribution capacity upgrades needed. In this scenario the JPS is able to meet the distribution capacity need with the batteries, allowing deferral for 5 years as outlined in the scenario.

Observation 3

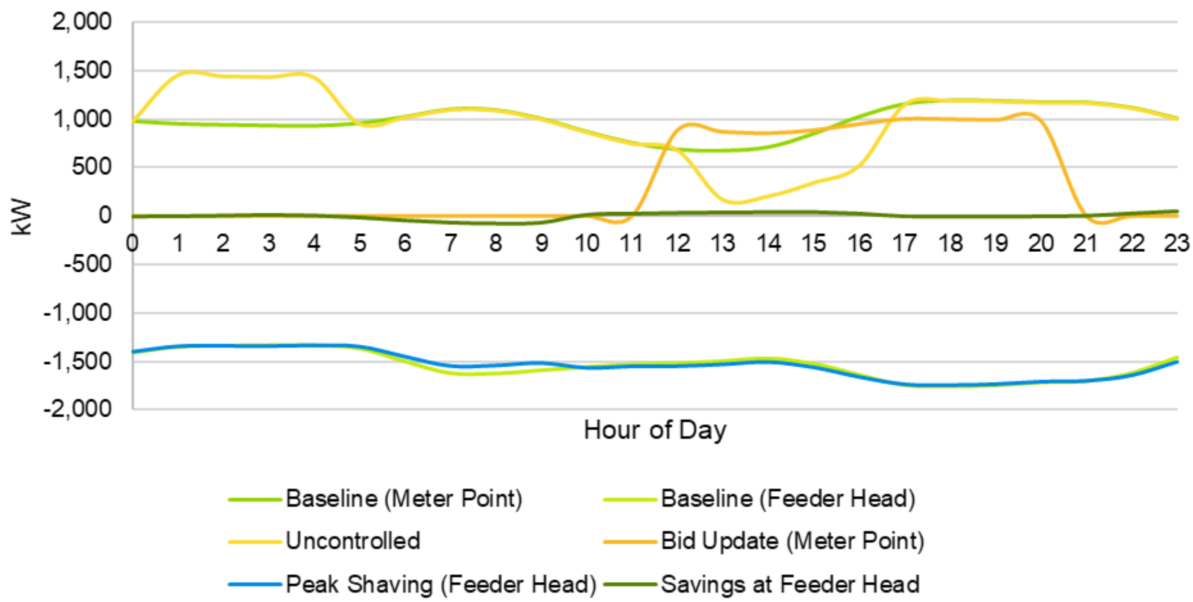
The large transmission deferral benefits scenario dramatically improves the BC ratio as shown in the UCT numbers. The 3 x 750 kW battery model moves the UCT from 0.55 to 3.99. The assumptions related to the ability of the JPS to impact deferral of a transmission capacity upgrade with active control of a single distribution feeder are specific and narrow, but the key takeaway is that the amount of benefit available here necessitates exploring the potential before other high level benefit streams.

3.6.1 Currently Installed Assets Model

The currently installed assets model is combined with the capacity auction benefits scenario to generate a set of results. This model and scenario combination reflects the actual conditions and DER penetration on MS3. The impacts are calculated using a representative day approach for the VPP and LFM use cases and includes four different daily views: winter day, shoulder day, summer day, and summer day with bid activation. The historical situation with bid activation is that it has only been called one time per year, and the assumption that it will be called one time per year is applied to the analysis period. The summer bid activation is split out from the summer representative day and will be discussed separately.

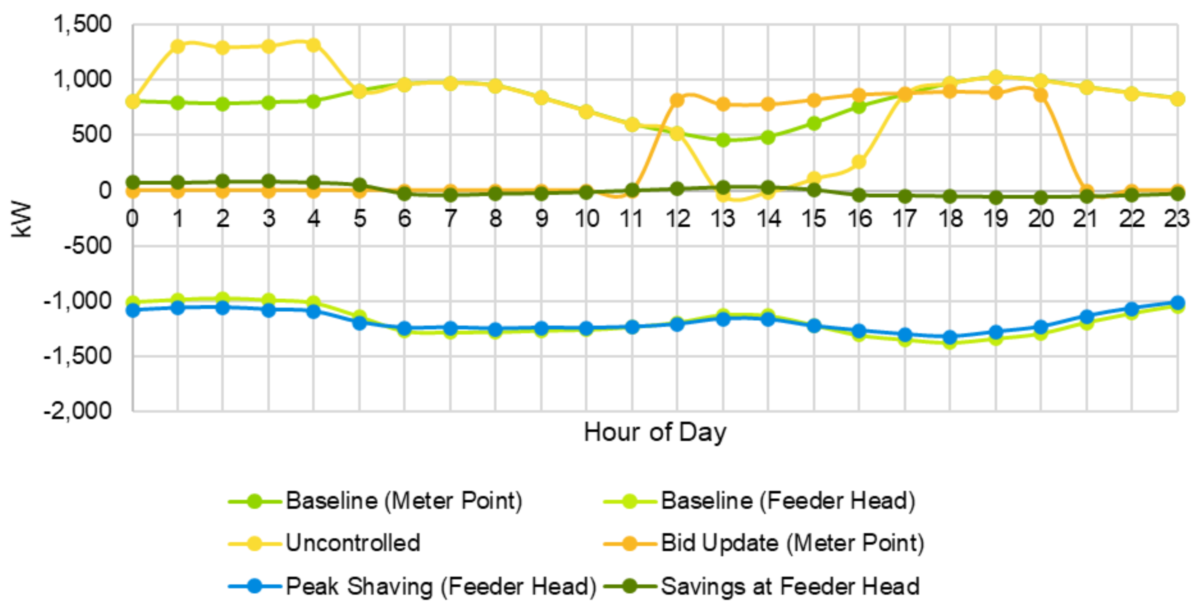
Reviewing the winter representative day, Figure 8, the bid activation meter point baseline, bid update, bid activation, and uncontrolled are shown influencing the VPP use case, and the feeder head baseline, peak shaving, and savings at the feeder head are shown supporting the LFM use case. The magnitude of peak shaving available on this winter representative day is small compared to the peak loading, resulting in small impacts and low benefit for the LFM use case. The bid update is available during the course of the day from 11:00 to 21:00 even though the bid activation is zero.

Figure 8. Current Installed Assets, Winter Day



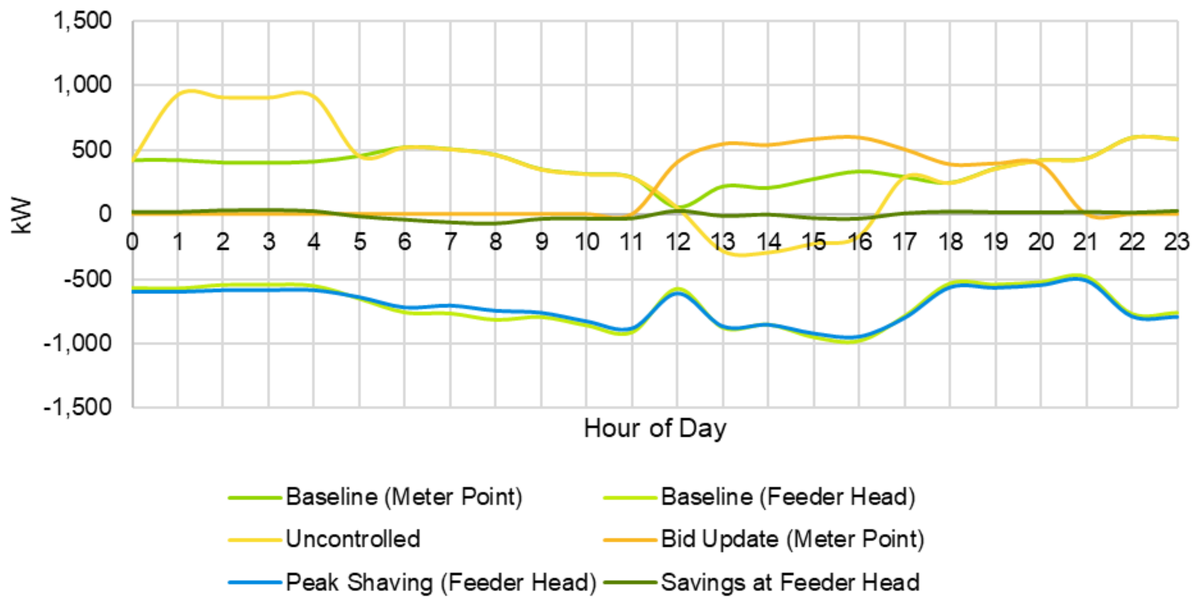
Reviewing the shoulder representative day Figure 9, there are slight differences between the winter representative and shoulder days. The biggest changes are in the peak shaving outputs as a response to the LFM use case even though the magnitude of the changes to the feeder loading are small. In a similar manner to the winter day, the bid update is available from 11:00 through 21:00, but the bid activation is zero. In the Ontario IESO market, the market payments are based on bid update, not bid activation, even though there is a non-performance penalty if bid activation is not met.

Figure 9. Current Installed Assets, Shoulder Day



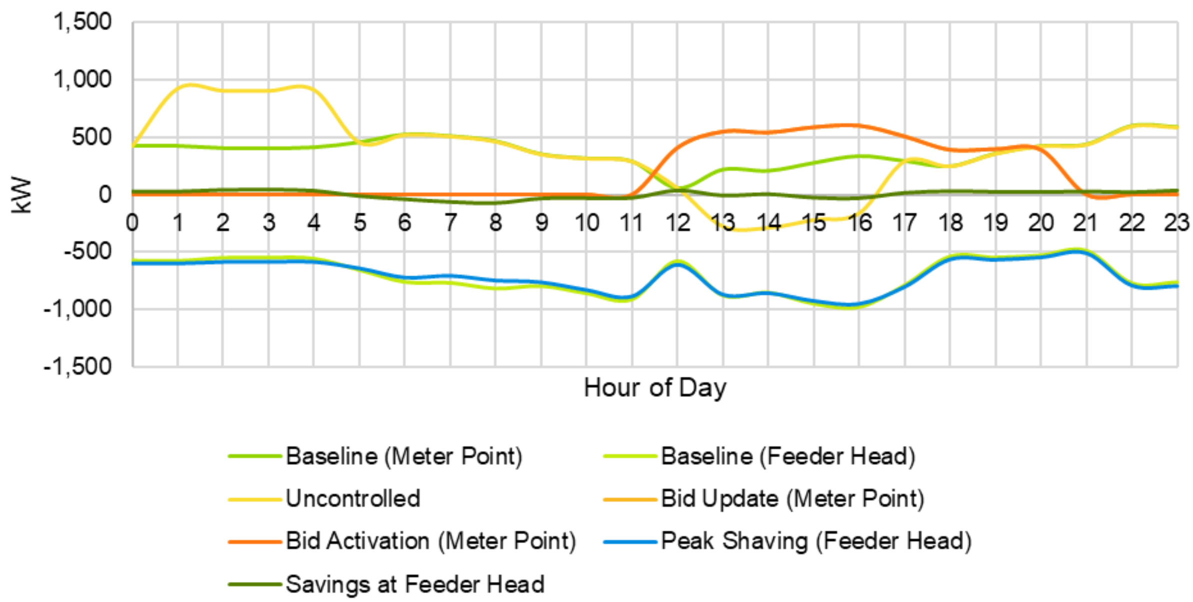
The summer day is shown in Figure 10 and highlights a feeder head loading peak from 10:00 to 16:00, along with minor changes to peak shaving throughout the day. The magnitude of the feeder head reduction is minor, similar to the winter and shoulder days, but it is measurable as a result of the JPS control of DER. The bid activation is not included in this diagram because it is not present.

Figure 10. Current Installed Assets, Summer Day



The summer day with bid activation is shown in Figure 11. The substantive difference between the summer representative day is that the bid activation, VPP use case, occurs between 11:00 and 21:00, resulting in the inability of the DER assets on MS3 to participate in the LFM or other use case.

Figure 11. Current Installed Assets, Summer Bid Activation Day



Currently Installed Assets with Capacity Auction Benefit Scenario Results

In this scenario, the primary benefit stream is from the VPP use case by enabling DER assets to participate in the IESO capacity auction. There is minimal value on the local distribution system for the LFM use case because there are not enough DER on the feeder to cause voltage or capacity issues that could be mitigated by the JPS, nor is there enough capacity available at the feeder head to materially defer distribution or transmission capacity upgrades. Also, there are no planned distribution capital upgrades that can be deferred over the next 10 years on the distribution system using the LFM use case. Similarly, there is a large transmission upgrade, Hydro One substation, that could be deferred if there was enough capacity available, but the limited amount of capacity available makes this infeasible. Other benefit streams, such as wholesale energy and avoided emissions, are minimal because JPS's optimization is not configured to maximize those values.

The previous figures show the bid update impacts of JPS relative to the baseline at the meter point for the VPP use case for the winter, shoulder, and summer representative days. Impacts are shown at the meter point because that is the interface to IESO at which capacity auction revenue is measured. Assuming the IESO capacity auction pays for availability at $200/MW-day for the 6-month summer obligation period and $200/MW-day in winter, this results in $280,307 per year in revenue that would otherwise not have been obtained.

The impacts of the JPS at the feeder head for the LFM use case for each representative day are included in the peak shaving area of each previous graph. Because the JPS is configured to dispatch assets for LFM if a bid activation is not called by IESO and it is unlikely there will be more than one bid activation in any given year, the DER assets are dispatched to the LFM use case nearly every day out of the year. These LFM impacts result in -$2,289 per year in wholesale energy benefits by multiplying the impacts and the price of electricity in each hour. This benefit is negative because the local peak at the feeder head occurs in the middle of the night, which triggers the 500 kW Tesla Megapack battery to dispatch at night when energy prices are lower and charge during the day when prices are higher.

Putting this all together, the annual cash flow of costs and benefits is calculated, converted to present value, and aligned with the UCT methodology. After discounting these cash flows back to present value dollars, the stacked benefits versus costs are shown in Figure 12.

Figure 12. Current Installed Assets, Capacity Auction Benefit Summary

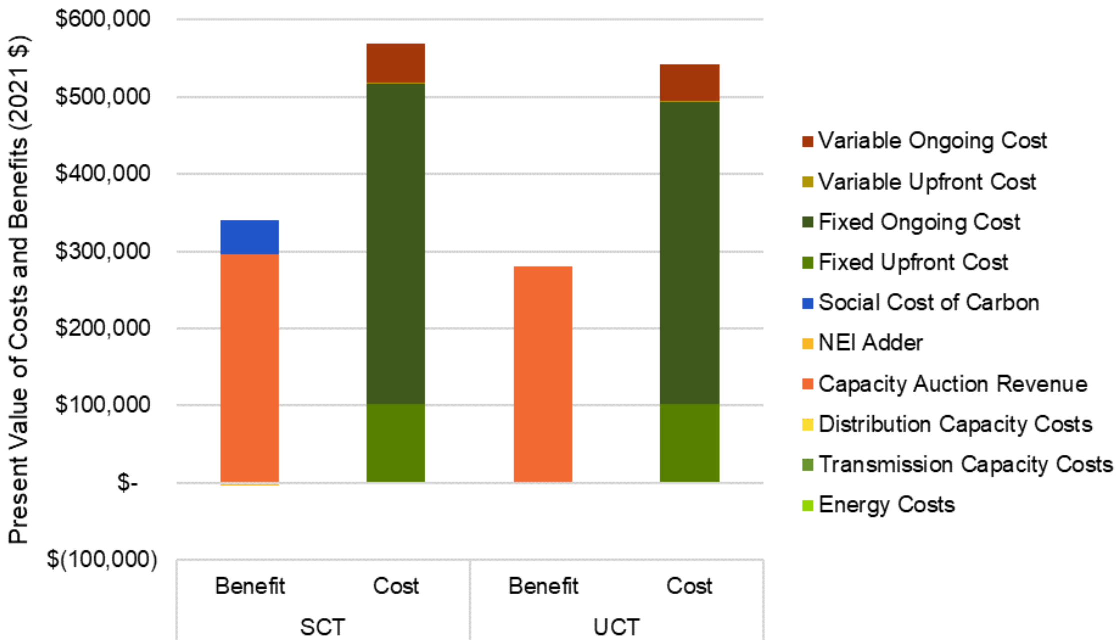


Table 19 shows the details of the UCT for the 10-year analysis timeframe.

Table 19. Current Installed Assets with Capacity Auction Benefits Results

Value Stream	Present Value Benefits ($2021)	Present Value Costs ($2021)
Energy Costs	-$2,290	N/A
Transmission Capacity Costs	$0	N/A
Distribution Capacity Costs	$0	N/A
Capacity Auction Revenue	$280,307	N/A
Fixed Upfront Cost	N/A	$101,500
Fixed Ongoing Cost	N/A	$392,375
Variable Upfront Cost	N/A	$1,000
Variable Ongoing Cost	N/A	$47,653
Total	**$278,018**	**$542,528**

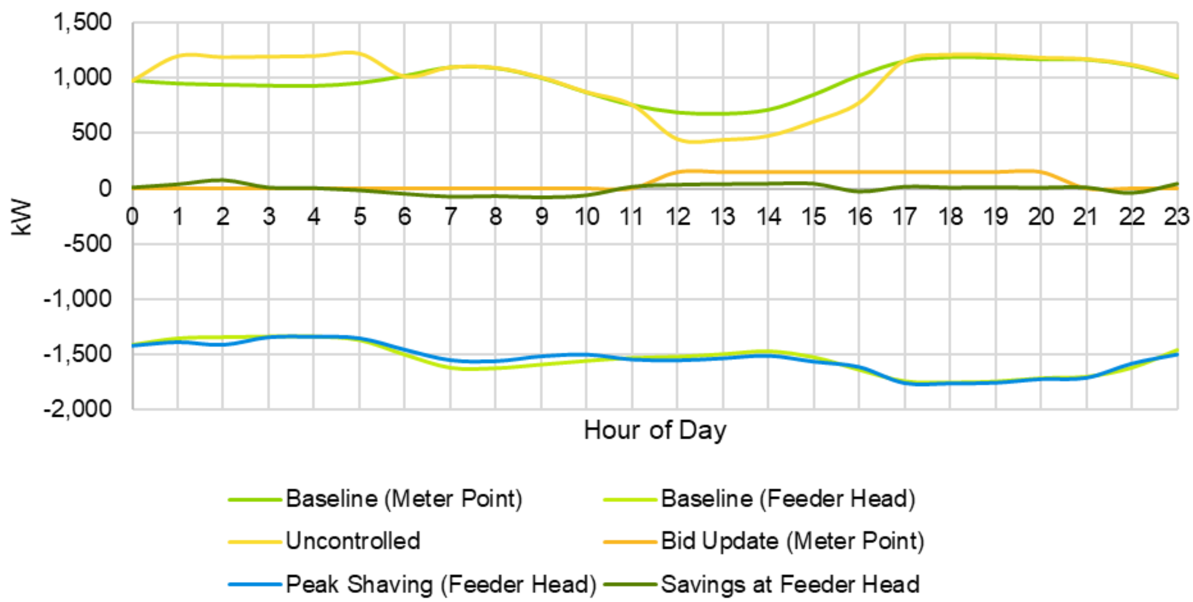
This works out to a 0.51 BC ratio. While the results of this model and scenario are not favorable from a BCA perspective, the following scenarios will demonstrate how these results could improve under various grid and market conditions.

3.6.2 Single 250 kW Battery Model

The single 250 kW battery model assesses a constrained situation that builds on actual conditions and DER penetration on MS3. It removes the 500 kW Tesla Megapack battery and replaces it with a single 250 kW battery placed in the middle of the MS3 feeder on a distribution transformer that has limited capacity. This reduces the ability of the JPS to safely dispatch the battery for the VPP and LFM use cases. Dispatching the battery fully results in voltage and overcurrent violations in the model and restricts the power available from the battery for operational objectives. The 500 kW Tesla Megapack is not included in this model and is not included in the BCA calculation for this model and scenario setup.

The winter representative day for this model, Figure 13, shows the meter point and feeder head baseline, bid update, and peak shaving that support the VPP and LFM use cases. A key observation from the winter day is that the magnitude of bid update and peak shaving available is smaller compared to the currently installed assets model.

Figure 13. 1x250 kW Battery, Winter Day



Similar to the winter day shown previously, Figure 14 shows the smaller magnitude of bid update, VPP use case, and peak shaving, LFM use case, than in the currently installed assets model.

Figure 14. 1x250 kW Battery, Shoulder Day

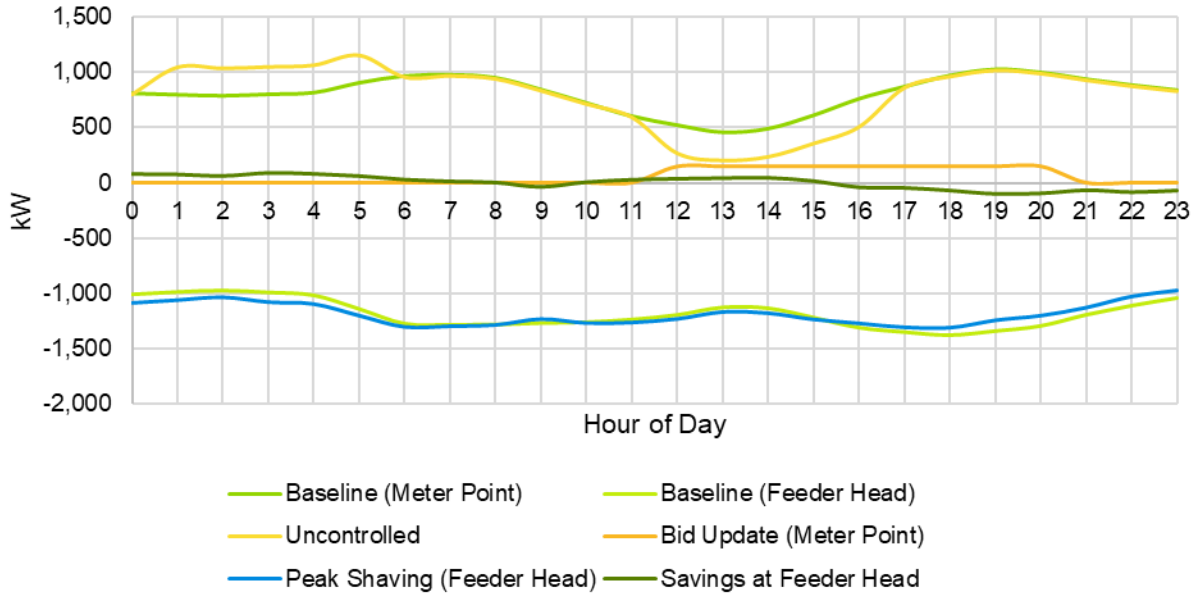
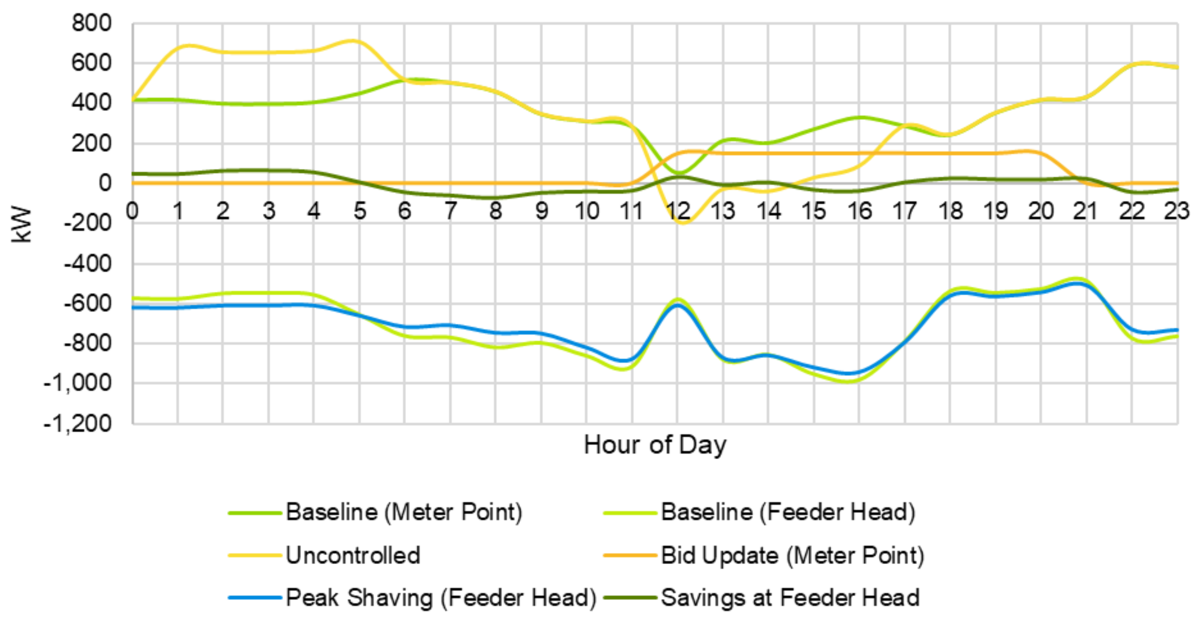


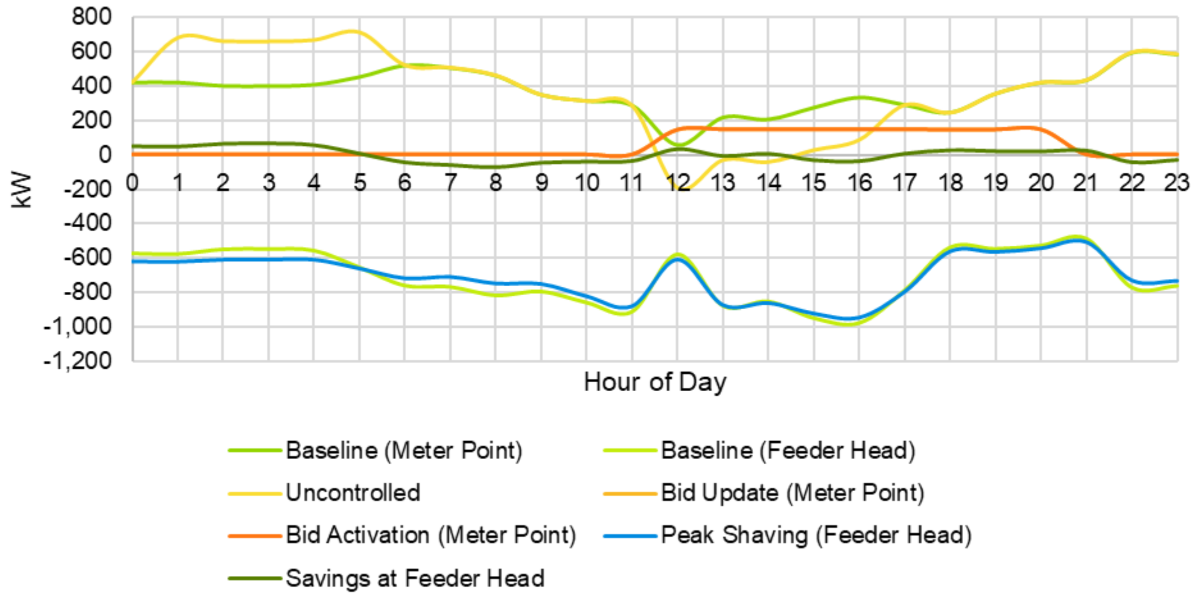
Figure 15 shows a reduced magnitude of bid update and peak shaving available compared to the currently installed assets on a representative summer day.

Figure 15. 1x250 kW Battery, Summer Day



The final representative day highlights the bid activation assumed to happen one time during the year during a peak summer day and is shown in Figure 16. Similar to the currently installed assets model, bid activation occurs at 11:00 and runs through 21:00, causing the DER assets, primarily the 250 kW battery, to be used to support the bid update commitment, VPP use case, not the peak shaving, LFM use case.

Figure 16. 1x250 kW Battery, Summer Bid Activation Day



In the modelled scenarios for the single 250 kW battery model, the primary benefit stream is the VPP use case by enabling DER assets to participate in the Ontario capacity auction. Because of the reduced size (250 kW of battery compared to the 500 kW Megapack) and the voltage and current constraints on the connected battery, the potential benefits are reduced compared to the currently installed assets. In addition, the small size of the battery and constrained transformer capacity are likely to result in small deferral benefits for T&D deferral and will be analyzed against the three scenarios identified.

Single 250 kW Battery with Capacity Auction Benefit Scenario Results

As described previously in the winter, shoulder, summer, and bid activation day descriptions, this model and scenario align with the currently installed assets model with the replacement of the 500 kW Tesla Megapack battery with a 250 kW battery located on a constrained transformer. This ultimately results in lower benefits for the capacity auction revenue, VPP use case, as shown in Figure 17.

Because there are no planned distribution capital upgrades that can be deferred over the next 10 years, the distribution deferral is zero. The magnitude of the peak shaving, LFM use case, is small, so there is no opportunity for deferral of the Hydro One transmission station, resulting in zero transmission capacity upgrades. Other benefit streams, such as wholesale energy and avoided emissions, are minor because JPS's optimization is not configured to maximize those values. Energy avoided costs are small and negative based on this simulation, indicating that energy costs increase based on daily load shifting through JPS. Capacity auction revenue provides the largest benefit. Transmission capacity deferrals are set to zero in this scenario but may provide significant benefits in other scenarios. Distribution capacity deferrals are set to zero in this scenario but may provide significant benefits in other scenarios.

Figure 17. 1x250 kW Battery with Capacity Auction Benefit Summary

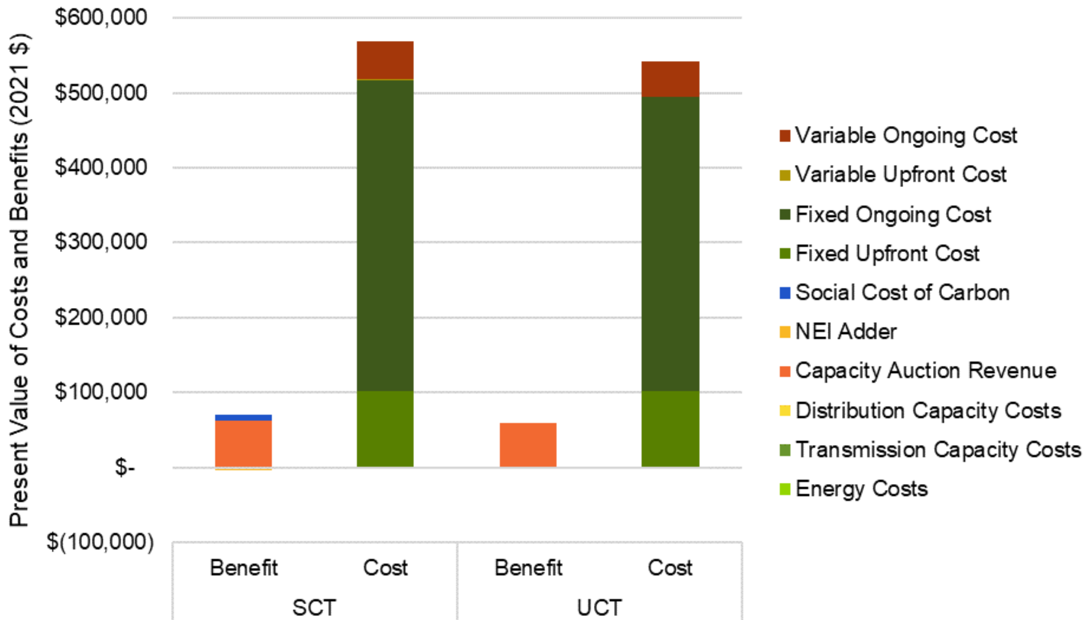


Table 20 shows the details of the UCT for the 10-year analysis timeframe.

Table 20. 1x250 kW Battery with Capacity Auction Benefit Details

Value Stream	Present Value Benefits ($2021)	Present Value Costs ($2021)
Energy Costs	-$2,393	N/A
Transmission Capacity Costs	$0	N/A
Distribution Capacity Costs	$0	N/A
Capacity Auction Revenue	$58,610	N/A
Fixed Upfront Cost	N/A	$101,500
Fixed Ongoing Cost	N/A	$392,375
Variable Upfront Cost	N/A	$1,000
Variable Ongoing Cost	N/A	$47,653
Total	**$56,217**	**$542,528**

This results in a .10 BC ratio and sets the lower range for the benefits of the JPS on the MS3 feeder under constrained conditions in the absence of T&D deferral benefits.

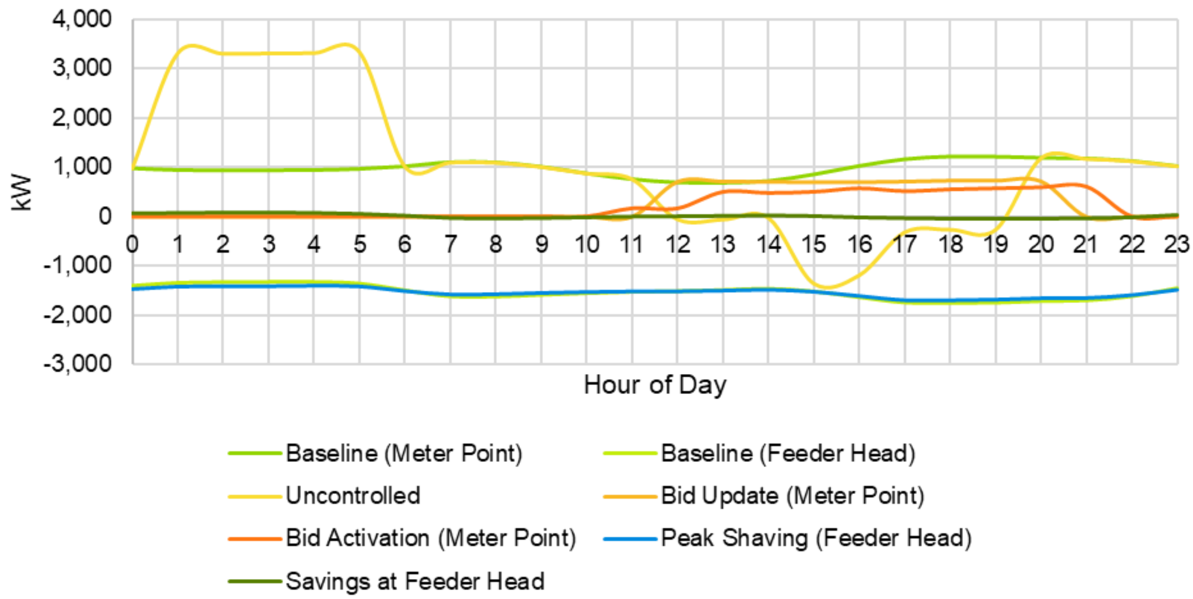
3.6.3 Three 750 kW Batteries Model

This model assesses a situation that builds on MS3 with the addition of three 750 kW batteries as described in Section 3.3. The 500 kW Tesla Megapack is not included in this model and is not included in the BCA calculation for this model and scenario setup.

In this scenario, the primary benefit stream is from the VPP use case by enabling DER assets to participate in the IESO capacity auction—specifically, the three 750 kW batteries and excluding the 500 kW Tesla Megapack battery that is not included in the model calculation.

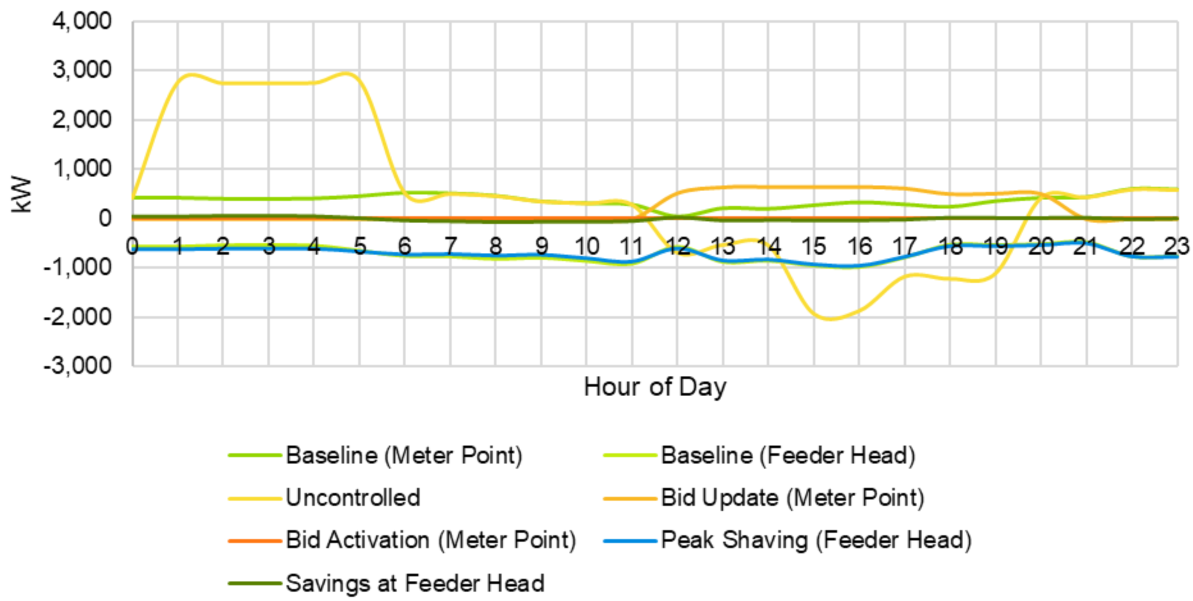
The winter representative day is shown in Figure 18 with charging of the three 750 kW batteries occurring from 00:00 to 06:00.

Figure 18. 3x750 kW Batteries, Winter Day



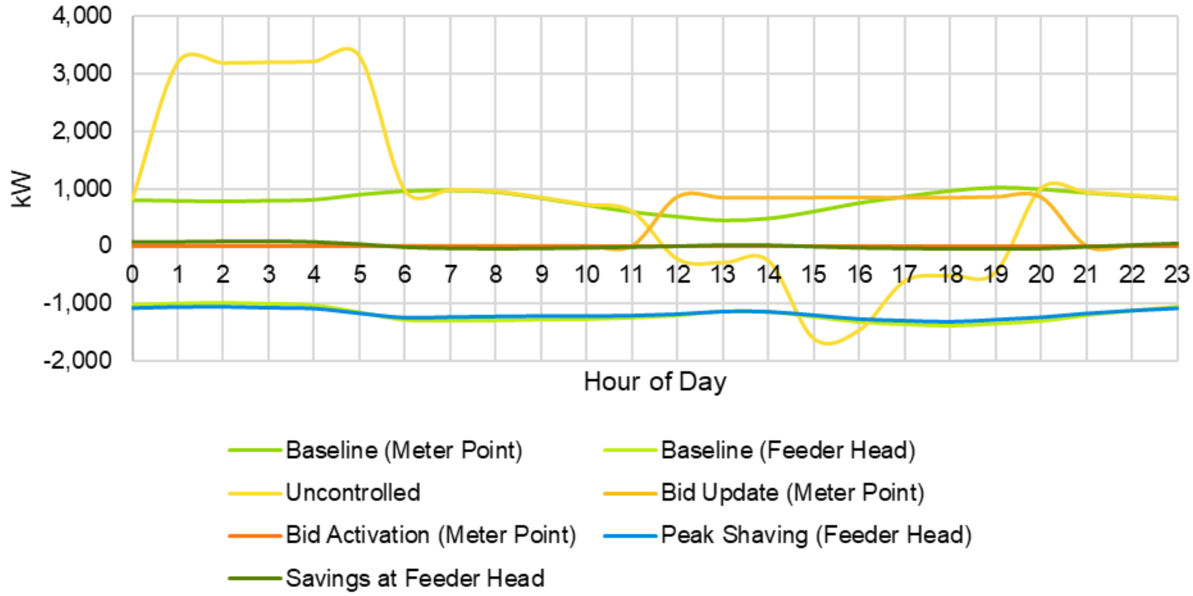
The shoulder representative day is shown in Figure 19 with charging of the three 750 kW batteries occurring from 00:00 to 06:00.

Figure 19. 3x750 kW Batteries, Shoulder Day



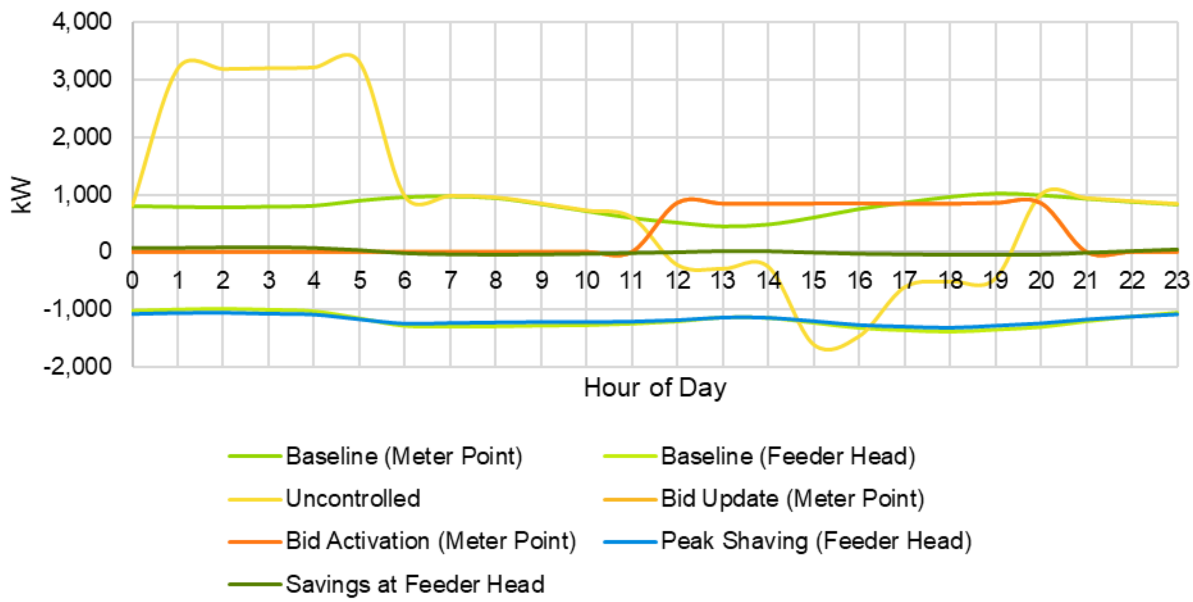
The summer representative day is shown in Figure 20 with the same battery charging behavior as described previously.

Figure 20. 3x750 kW Batteries, Summer Day



The summer bid activation day is shown in Figure 21 and highlights the bid activation occurring between 11:00 and 21:00.

Figure 21. 3x750 kW Batteries Summer Bid Activation Day



Three 750 kW Batteries with Capacity Auction Benefit Scenario Results

As described previously in the winter, shoulder, summer, and bid activation day descriptions, this high DER model and scenario align with the currently installed assets model with the replacement of the 500 kW Tesla Megapack battery with three 750 kW batteries. This ultimately results in higher benefits for the capacity auction revenue, VPP use case, as shown in Figure 22.

Because there are no planned distribution capital upgrades that can be deferred over the next 10 years, the distribution deferral is zero. The magnitude of the peak shaving, LFM use case, is small, so there is no opportunity for deferral of the Hydro One transmission station, resulting in zero transmission capacity upgrades. Other benefit streams, such as wholesale energy and avoided emissions, are trivial because JPS's optimization is not configured to maximize those values. The high DER model produces energy avoided costs that are small and negative based on this simulation, indicating that energy costs increase based on daily load shifting through JPS. The capacity auction revenue provides the largest benefit. The T&D capacity deferrals are set to zero in this scenario but may provide significant benefits in other scenarios.

Figure 22. 3x750 kW Batteries with Capacity Auction Benefits Summary

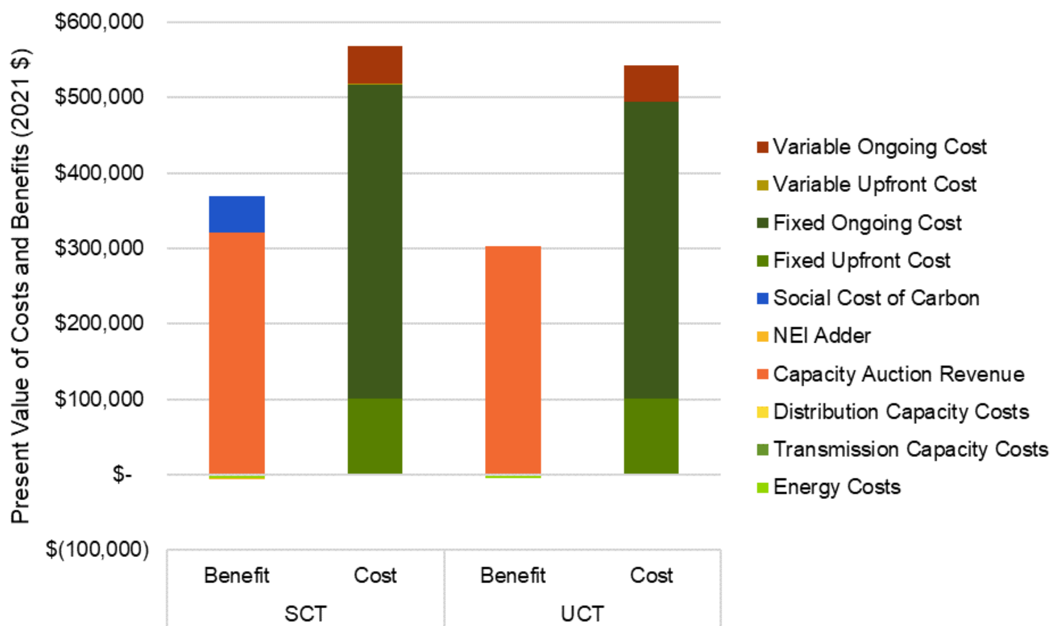


Table 21 shows the details of the UCT for the 10-year analysis timeframe.

Table 21. 3x750 kW Batteries with Capacity Auction Benefits Details

Value Stream	Present Value Benefits ($2021)	Present Value Costs ($2021)
Energy Costs	-$4,534	N/A
Transmission Capacity Costs	$0	N/A
Distribution Capacity Costs	$0	N/A
Capacity Auction Revenue	$303,253	N/A
Fixed Upfront Cost	N/A	$101,500
Fixed Ongoing Cost	N/A	$392,375
Variable Upfront Cost	N/A	$1,000

Value Stream	Present Value Benefits ($2021)	Present Value Costs ($2021)
Variable Ongoing Cost	N/A	$47,653
Total	**$298,719**	**$542,528**

This results in a low point 0.55 BC ratio and reflects the benefits of the JPS on the MS3 feeder under high DER penetration conditions in the absence of T&D deferral benefits.

Three 750 kW Batteries with Small Distribution Deferral Scenario Results

This high DER scenario assumes small distribution deferral benefits are available in addition to the capacity auction revenue. These are shown in Figure 23.

Assuming a small distribution capital upgrade deferral does change the calculated benefits positively. In this scenario, no opportunity for deferral of the Hydro One transmission station is assumed, resulting in zero transmission capacity upgrades. Energy avoided costs are small and negative based on this simulation, indicating that energy costs increase based on daily load shifting through JPS. Capacity auction revenue provides the largest benefit. Transmission capacity deferrals are set to zero in this scenario but may provide significant benefits in other scenarios. Distribution capacity deferrals are calculated assuming a $500,000 investment planned for 2024 is deferred by 5 years.

Figure 23. 3x750 kW Batteries with Small Distribution Deferral Summary

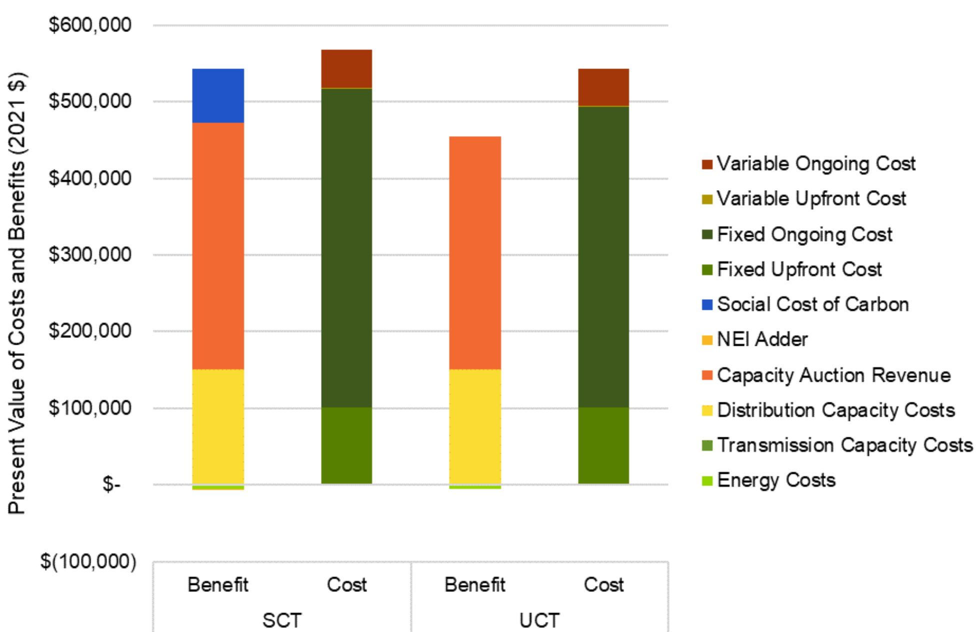


Table 22 shows the details of the UCT for the 10-year analysis timeframe.

Table 22. 3x750 kW Batteries with Small Distribution Deferral Summary

Value Stream	Present Value Benefits ($2021)	Present Value Costs ($2021)
Energy Costs	-$4,534	N/A
Transmission Capacity Costs	$0	N/A
Distribution Capacity Costs	$151,249	N/A
Capacity Auction Revenue	$303,253	N/A
Fixed Upfront Cost	N/A	$101,500
Fixed Ongoing Cost	N/A	$392,375
Variable Upfront Cost	N/A	$1,000
Variable Ongoing Cost	N/A	$47,653
Total	**$449,968**	**$542,528**

This results in a 0.83 BC ratio and sets a midpoint for the benefits of the JPS on the MS3 feeder under high DER penetration conditions in the presence of small distribution deferral benefits and the absence of transmission deferral benefits.

Three 750 kW Batteries with Large Transmission Deferral Scenario Results

This high DER scenario assumes no distribution deferral benefits are available but large transmission deferral benefits are available. Due to the large amounts of DER on MS3 and three 750 kW batteries, high benefits for the capacity auction revenue are calculated, which is shown in Figure 24.

Assuming a large transmission capital upgrade deferral does change the calculated benefits dramatically. In this scenario, an opportunity for deferral of the Hydro One transmission station is assumed, resulting in transmission capacity upgrade benefits even through no distribution deferral benefits are available. Other benefit streams, such as wholesale energy and avoided emissions, are trivial because JPS's optimization is not configured to maximize those values. Energy avoided costs are small and negative based on this simulation, indicating that energy costs increase based on daily load shifting through JPS. Capacity auction revenue provides the second largest benefit. Transmission capacity deferrals are calculated assuming a $27 million investment planned for 2024 is deferred by 1 year. Distribution capacity deferrals are set to zero in this scenario but may provide significant benefits in other scenarios.

Figure 24. 3x750 kW Batteries with Large Transmission Deferral Summary

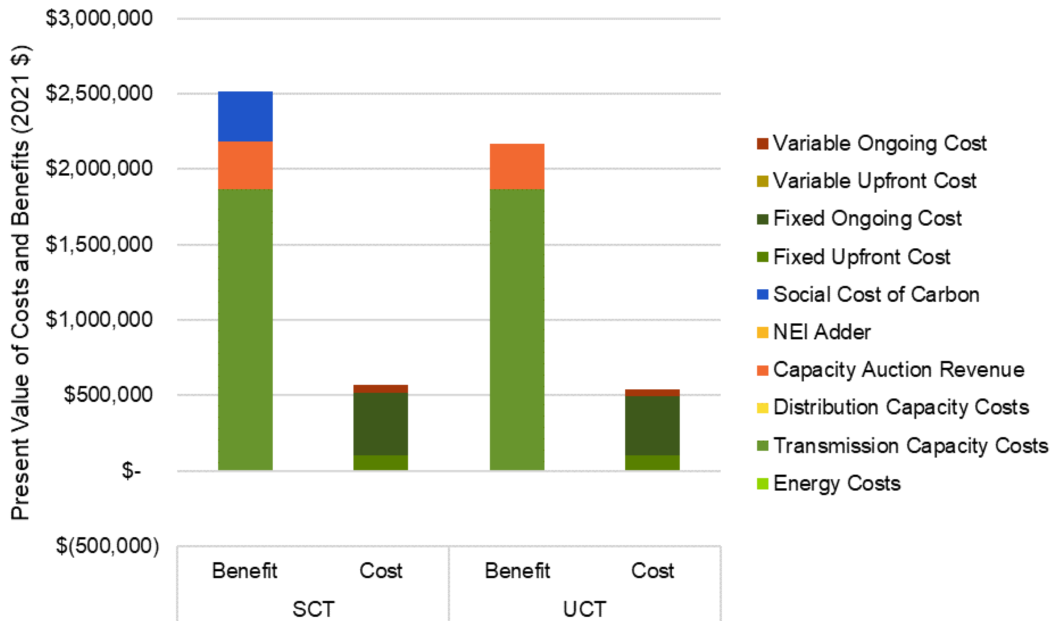


Table 23 shows the details of the UCT for the 10-year analysis timeframe.

Table 23. 3x750 kW Batteries with Large Transmission Deferral Details

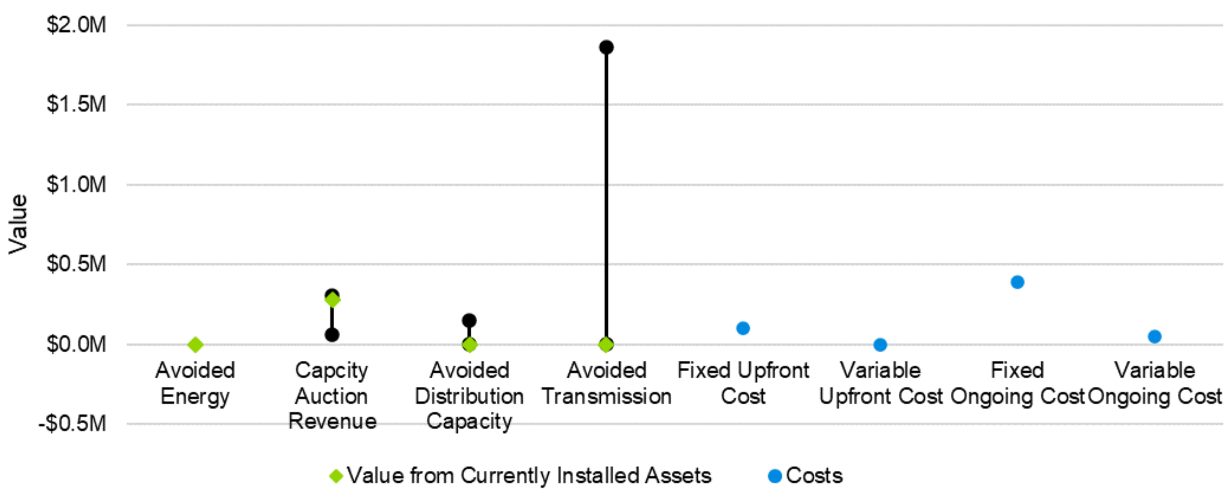
Value Stream	Present Value Benefits ($2021)	Present Value Costs ($2021)
Energy Costs	-$4,534	N/A
Transmission Capacity Costs	$1,864,098	N/A
Distribution Capacity Costs	$0	N/A
Capacity Auction Revenue	$303,253	N/A
Fixed Upfront Cost	N/A	$101,500
Fixed Ongoing Cost	N/A	$392,375
Variable Upfront Cost	N/A	$1,000
Variable Ongoing Cost	N/A	$47,653
Total	**$2,162,817**	**$542,528**

This results in a 3.99 BC ratio and sets a high point for the benefits of the JPS on the MS3 feeder under high DER penetration conditions in the presence of large transmission deferral benefits and the absence of distribution deferral benefits.

3.7 Conclusions

Figure 25 shows the ranges of benefits obtained in the BCA of the combinations of models and scenarios. The benefits associated with the base model of current installed assets on MS3 along with the scenario of capacity auction benefits are at the bottom of the range, as expected. This chart highlights the potential benefits of the JPS to address types of feeders with loading profiles, distribution deferral opportunities, and transmission deferral opportunities in the sweet spot of the projected benefits. In general, high DER feeders with capacity-based deferral opportunities in regions with capacity auctions are the best target for JPS deployment.

Figure 25. MS3 Benefit Ranges and Costs



Guidehouse arrived at the following conclusions as a result of the DEMOCRASI JPS BCA:

- As expected, the JPS in this pilot project is not cost effective on the single MS3 feeder. This result is due to the local conditions on MS3 and the cost of the pilot not making use of economies-of-scale.
- If we assume there is a very large amount of DER (3x750kW batteries) and the transmission investment can be deferred, then the pilot would have been cost effective. Different individual feeders at Lakeland Distribution that may be on a tipping point of deferring a T&D deferral could exhibit a BC ratio above 1.0.
- The Guidehouse and DEMOCRASI team did not evaluate if applying JPS across a larger number of targeted circuits at Lakeland Distribution could make the implementation cost effective. However, based on the results in the extrapolation section below, it looks likely that a hypothetical JPS implementation across multiple feeders w/ higher DER penetrations of the right type would be cost effective.
- Market structure can dramatically influence the value of benefits and impact where JPS can provide value for the VPP use case. For example, the MS3 feeder is located in Ontario where there is over $200/MW-day of value to be obtained from participating in a capacity auction. If this revenue stream was unavailable, then the BC ratio would be less than 0.1 for the currently installed assets model. The minimum requirement to extract value from the JPS is regions that have capacity auctions that allow individual and aggregated DER participation without size restrictions. Markets that pay on bid activation offer opportunities to maximize revenue via a capacity auction revenue benefit stream using the JPS's optimization function beyond bid update by operating right up to the maximum safe capacity of the feeder.
- Mature LFM opportunities are not observed in this pilot project data and the MS3 feeder. The JPS has the capability to coordinate DER to produce peak load reduction, but the planning of distribution upgrades is not present in this case. Lack of distribution planning

for LFM, peak reduction, and deferral of distribution upgrades reduces this benefit stream opportunity. As DER increases on MS3, there is a tipping point at which the uncontrolled behavior of DER creates voltage and thermal violations on MS3 that would force Lakeland Power to upgrade the feeder, potentially creating opportunities for distribution deferral. Lakeland Power does individual spot checks for power quality when observations of local voltage problems are reported, but it does not have a broad distribution upgrade plan that could be removed or deferred by the JPS applied for LFM. Feeders with identified future capacity constraints, high penetration of DER, and with enough time to implement, test, and scale JPS are more viable high benefit opportunities.

- The DER penetration (nameplate / peak load) is 21% on MS3. If the loading on MS3 was higher, the ability to actively control the DER to provide increased LFM benefits for peak load reduction, energy savings, and deferral of upgrades would be expected. The ability to realize T&D deferral is complicated and depends on how much deferral potential is present. This model simplified T&D deferral, but the details of the amount available impact the T&D aspects of the BCA. If the deferral value has been realized, this potential value stream may be overstated. In addition, just because there is potential for T&D deferral, the deferral depends on a designated amount of peak load reduction. The amount of DER asset peak load reduction in the LFM use case depends directly on the number of and type of DER on the individual feeder. If the DER exists and can be marshalled with limited cost, this analysis holds, but if DER must be built, procured, aggregated, or incentivized over a period of time, this can influence the ability to realize the T&D deferral benefits.
- The ability to add 250 kW or larger batteries on the MS3 feeder without active control is not practical because of the voltage violations that would likely occur on the distribution system. This means that, without JPS, significant CAPEX would be necessary to upgrade the feeder to alleviate the resulting voltage issues. Adding multiple large batteries on this feeder can be supported with the LFM use case enabled by JPS.
- The use of the JPS to support an islanded microgrid was discussed and considered during the project. The team identified an individual islanded microgrid use case that was not tested during the operational pilot, but the potential for segmenting a portion of the MS3 feeder and testing the operation of that feeder segment as an islanded microgrid is an area for future study. Guidehouse and the DEMOCRASI team observes that there is great potential to use the JPS to establish virtual meter points that can improve reliability and resilience on the network and allow advanced market participation by aggregating multiple DER resources.

The joint product solution is able to safely and effectively unlock value present in Ontario capacity auctions. The Ontario capacity auction pays on bid update and penalizes if a bid activation is not met when called. Historically, there has been one bid activation annually. The potential for double counting value from the VPP and LFM use cases is present in this market, even though it is small, because if DER assets are reserved in the bid update for the VPP use case, they cannot be used for LFM. The timing of the Ontario market reduces this risk, but other markets may not allow as much value to be realized.

4. Extrapolation

Building on the results of the models and scenarios used in the DEMOCRASI BCA, Guidehouse extrapolated the results of the pilot to Ontario, Canada, and the UK using a feeder-based extrapolation model. This model takes the results observed in the BCA conducted on the MS3 feeder and applies it to these locations.

4.1 Methodology

Extrapolation of the benefits is done using the BC ratio ranges identified in the DEMOCRASI BCA developed on MS3. These benefits are normalized to an individual feeder and then scaled to the appropriate regions using the methodology described below.

The BC ratio ranges identified during the DEMOCRASI pilot BCA work capture multiple models of the primary dimension, DER penetration. This includes typical DER penetration, low DER penetration, and high DER penetration. The pilot BCA explored capacity auction benefits as observed on MS3, small distribution deferral, and large transmission deferral. The extrapolation simplifies this to look at the capacity auction benefits scenario and scales the results of the BCA to Ontario, Canada, and the UK. Scaling the BC ratio ranges in this manner is designed to capture the high-level ranges of benefits available in the designated regions.

Methodology Description

The extrapolation starts with a count of population and utility customers in each region; the inputs are shown in Table 24. The team converted the population of each subregion into to an estimate of utility customers by applying a scaling factor based on a customer to population scaling factor where obtaining subregion-specific information was not possible. Using industry averages of customer per feeder, the extrapolation estimated the number of feeders in each subregion and summed them into the view shown in the following section. A binary yes/no factor to account for benefits based on existence of capacity auctions was applied by subregion. Scaling factors for the number of feeders with distribution deferral opportunities and transmission upgrade deferral opportunities was applied to the average and high DER penetration models across the three scenarios used in the BCA. This analysis is anchored by the existence of regional capacity auctions in each subregion to support the VPP use case and includes the existing T&D deferral benefits aligned with the LFM use case.

4.2 Extrapolation Data

Data used to extrapolate benefits to the selected regions includes the items shown in the following sections.

Population and Utility Customers

The following subregional and regional values were used in the extrapolation. The specific subregion numbers are included in the model and are summed in Table 24. Feeders are calculated based on utility customers by subregion. The team used 800 [16]customers per feeder for all of Canada and 1,600 [17]customers per feeder for the UK.

Table 24. Population, Customers, and Feeders by Region

Region	Population	Utility Customers	Feeders (Calculated)	Average MW
Ontario	14.8 million	5.4 million	6,731	18,209
Canada	38.1 million	17.7 million	22,065	52,026
UK	66.7 million	37.5 million	23,434	40,120

Guidehouse determined that only feeders in a region with a capacity auction would be applicable for JPS. Therefore, 56% of feeders in the Canadian extrapolation region were considered, including feeders in Ontario, New Brunswick, and Quebec. All feeders in the Ontario and UK extrapolation regions are applicable. Of these feeders, Guidehouse assumed that 10% of the feeders are suitable for JPS. This high-level assumption considers factors such as sufficient DER penetration and local conditions conducive to unlocking value with JPS. Therefore, the benefits and costs assessed in this section assume that JPS is implemented on 10% of the feeders within each extrapolation region.

T&D Deferral Opportunities

The extrapolation assumes that of the distribution feeders in the study area suitable for JPS, 5% of these feeders have the opportunity for a distribution deferral in the 10-year analysis time period using the same assumptions as applied in the DEMOCRASI pilot BCA analysis. Additionally, 2% of these feeders could be involved in a material deferral of a transmission upgrade.

Capacity Markets by Region

A key component of value extrapolation is capacity market revenue. Guidehouse researched the regions and sub-regions to identify where capacity markets exist. The extrapolation regions where the team found existing capacity auctions include the following:

Canada Regional Capacity Markets

- New Brunswick
- Ontario
- Quebec

UK National Capacity Market

- UK wholesale capacity market

UK Regional Capacity Markets

- SSE Energy Networks
- Northern Ireland Electricity

[16] EAI Data, 2020 used to calculate customers / feeder for US and aligned with Canadian distribution utilities.

[17] UK distribution utility metrics used to calculate average customers / feeder.

- Western Power UK[18] [19] [20]

The team researched each of the regions and subregions included in the extrapolation and looked for the existence of capacity markets in each subregion, as Table 25 shows.

Table 25. Capacity Markets in Subregion

Subregion	Capacity Market
Canada | Alberta	None identified
Canada | British Columbia	None identified
Canada | Manitoba	None identified
Canada | New Brunswick	Yes – ISO New England (ISO-NE)
Canada | Newfoundland and Labrador	None identified
Canada | Northwest Territories	None identified
Canada | Nova Scotia	None identified
Canada | Nunavut	None identified
Canada | Ontario	Yes – IESO
Canada | Prince Edward Island	None identified
Canada | Quebec	Yes – ISO-NE
Canada | Saskatchewan	None identified
Canada | Yukon	None identified
UK | SSE Power Distribution	Yes – National Grid ESO
UK | SP Energy Networks	None identified for 2021; in 2020, participated in National Grid ESO CM
UK | Northern Powergrid	None identified
UK | Electricity North West	None identified
UK | Western Power Distribution	None identified
UK | UK Power Networks	None identified
UK | Northern Ireland Electricity	Yes – Integrated-Single Electricity Market (I-SEM)

The specifics of the capacity markets constrain the benefits of participation in the market. Regions in Canada with capacity markets have the potential in the extrapolation to provide capacity auction revenue benefits. The UK market is more mature and complicated with layered national level capacity markets and regional capacity markets as well. For the extrapolation Guidehouse used the national level capacity market to identify what circuits were candidates for capacity auction benefits. The normative values for market participation observed in the DEMOCRASI pilot in Ontario were used as a first order approximation of the value potentially realizable in each market.

[18] Western Power Distribution. **Distribution Future Energy Scenarios: A Generation And Demand Study.**
[19] Proffitt, E. 2021. **Balancing The Electricity System With Demand Side Flexibility And Storage.** 2021.
[20]Grid Beyond. **The many questions about National Grid's acquisition of WPD.** March 2021. **The many questions about National Grid's acquisition of WPD**

4.3 Results

Guidehouse found that targeting attractive market structures in Ontario, Canada, and the UK will maximize the capacity auction revenue of the JPS as the primary benefit stream. Markets that pay on bid activation offer opportunities to use the JPS's optimization function by operating right up to the market's maximum capacity. Opportunities for distribution deferral and transmission deferral provide secondary benefits, as Table 26 shows.

Table 26. Extrapolation Results (UCT)

	Capacity Auction Benefit	Small Distribution Deferral	Large Transmission Deferral	Capacity Auction + T&D Deferral
Pilot	0.51			
Pilot w/ Low DER %	0.10			
Pilot w/ High DER %	0.55	0.83	3.99	
Extrapolation – Ontario	1.84			2.14
Extrapolation – Canada	2.49			2.72
Extrapolation – UK	3.87			4.49

For the extrapolation, Guidehouse scaled the benefits of the currently installed MS3 assets model with (21% DER penetration) to each region. The 3x750kW model was not scaled as this was an illustrative case that is not realistic. As stated above, Guidehouse assumed that 10% of the feeders within each region are suitable for JPS, and of those circuits, 5% and 2% of feeders have investment deferral opportunities on the distribution and transmission systems, respectively.

The BC ratios in the full-scale extrapolation are significantly higher than the pilot project because there are a larger number of feeders per implementation. Similarly, the UK is more cost effective than Canada because distribution companies are much larger, enabling JPS to better take advantage of its economies of scale. These BC ratios would be reduced with more conservative assumptions on the % of feeders in Canada and the UK that are candidates for T&D deferral, lower DER penetration, type of DER penetration, etc.

The extrapolation considers six different cases across the three regions: Ontario, Canada, and the UK with both capacity auction benefits only and capacity auction benefits with added T&D deferral benefits. DER penetration is not varied in this extrapolation analysis and is based upon the 21% DER penetration observed on the MS3 feeder in the JPS pilot project.

Results from each individual region and scenario are discussed in the following sections.

4.3.1 Ontario

Ontario with Capacity Auction Benefits

Figure 26 summarizes the costs and benefits in Ontario.

Figure 26. Ontario with Capacity Auction Benefits Summary

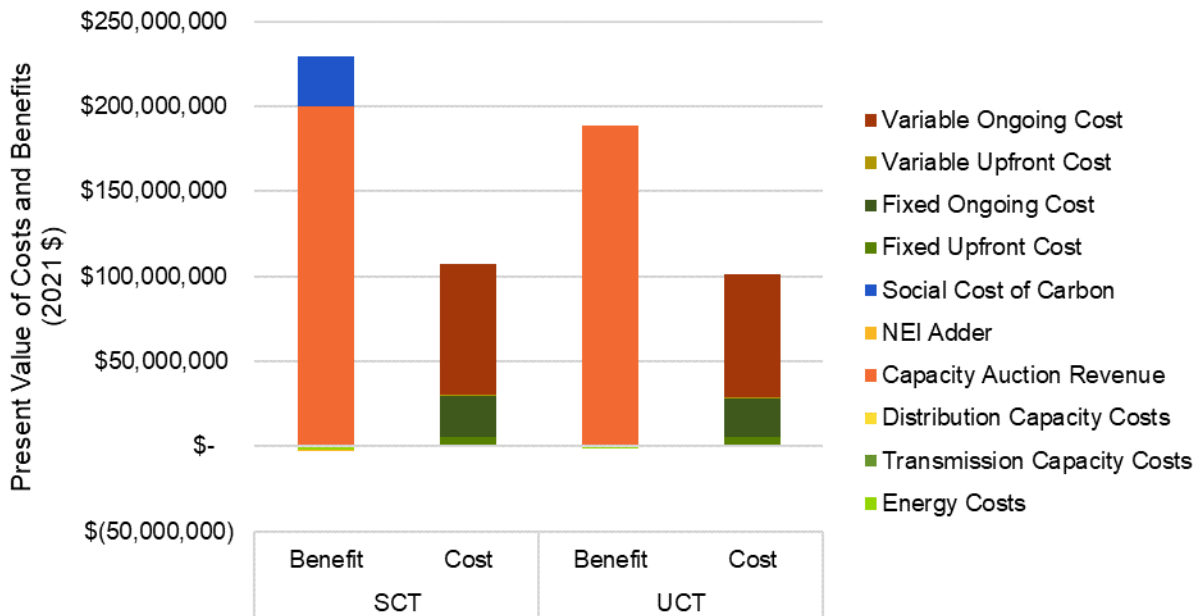


Table 27 shows that the detailed benefits of the deployment of the JPS are much higher than the projected costs in Ontario.

Table 27. Ontario with Capacity Auction Benefits Details UCT

Value Stream	PV UCT Benefits ($2021)	PV UCT Costs ($2021)
Energy Costs	-$1,541,059	N/A
Transmission Capacity Costs	$0	N/A
Distribution Capacity Costs	$0	N/A
Capacity Auction Revenue	$188,668,258	N/A
Fixed Upfront Cost	N/A	$5,785,500
Fixed Ongoing Cost	N/A	$22,365,394
Variable Upfront Cost	N/A	$673,077
Variable Ongoing Cost	N/A	$72,869,446
Total	**$187,127,199**	**$101,693,417**

Ontario with Capacity Auction and T&D Deferral Benefits

Figure 27 summarizes the costs and benefits in Ontario.

Figure 27. Ontario with Capacity Auction and T&D Deferral Benefits Summary

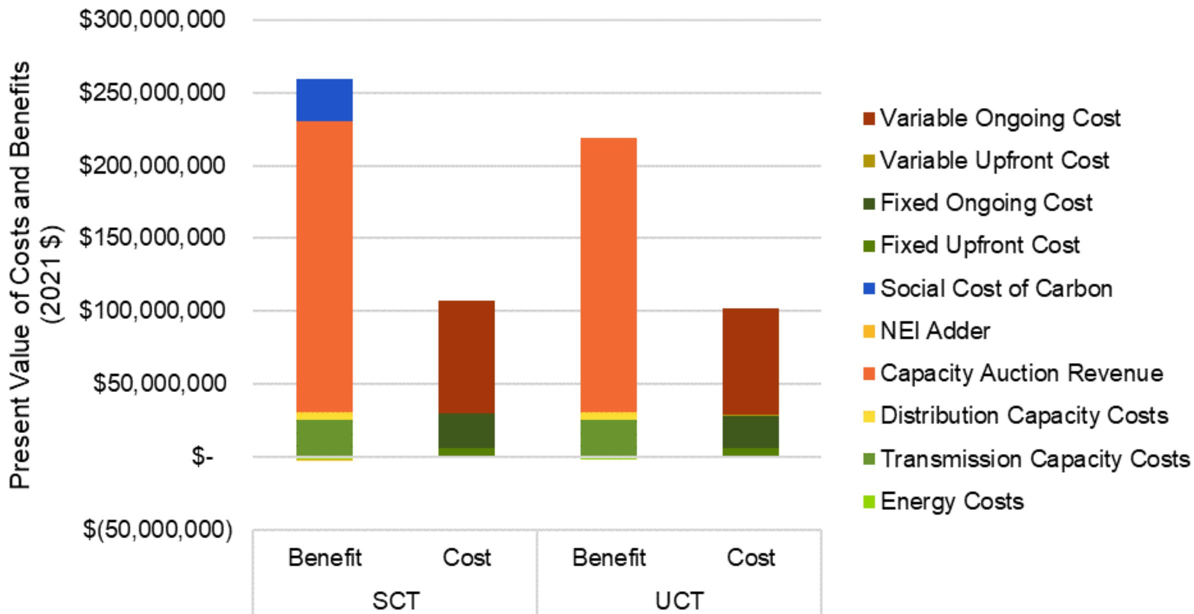


Table 28 shows that the detailed benefits of the deployment of the JPS are much higher than the projected costs in Ontario.

Table 28. Ontario with Capacity Auction and T&D Deferral Benefits Details UCT

Value Stream	PV UCT Benefits ($2021)	PV UCT Costs ($2021)
Energy Costs	-$1,541,059	N/A
Transmission Capacity Costs	$25,093,623	N/A
Distribution Capacity Costs	$5,090,096	N/A
Capacity Auction Revenue	$188,668,258	N/A
Fixed Upfront Cost	N/A	$5,785,500
Fixed Ongoing Cost	N/A	$22,365,394
Variable Upfront Cost	N/A	$673,077
Variable Ongoing Cost	N/A	$72,869,446
Total	**$217,310,918**	**$101,693,417**

4.3.2 Canada

Canada with Capacity Auction Benefit

Figure 28 summarizes the costs and benefits in Canada.

Figure 28. Canada with Capacity Auction Benefit Summary

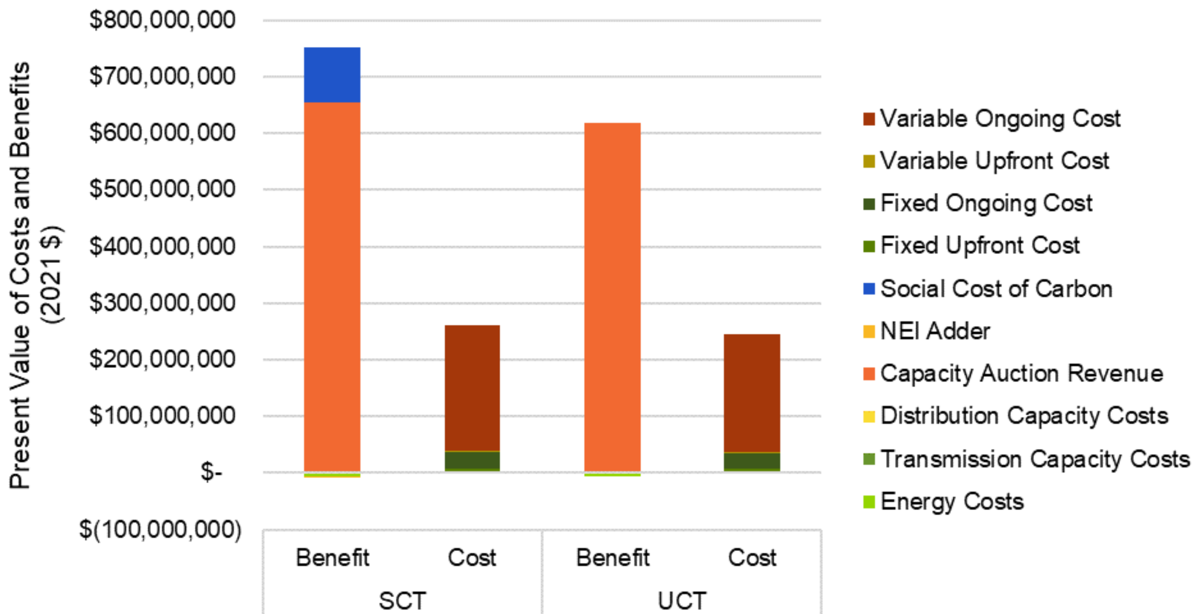


Table 29 shows that the detailed benefits of the deployment of the JPS are significantly higher than the projected costs in Canada.

Table 29. Canada with Capacity Auction Benefit Details UCT

Value Stream	PV UCT Benefits ($2021)	PV UCT Costs ($2021)
Energy Costs	-$5,051,947	N/A
Transmission Capacity Costs	$0	N/A
Distribution Capacity Costs	$0	N/A
Capacity Auction Revenue	$618,498,244	N/A
Fixed Upfront Cost	N/A	$7,308,000
Fixed Ongoing Cost	N/A	$28,251,024
Variable Upfront Cost	N/A	$2,206,502
Variable Ongoing Cost	N/A	$208,415,572
Total	**$613,446,297**	**$246,181,098**

Canada with Capacity Auction and T&D Deferral Benefits

Figure 29 summarizes the costs and benefits in Canada.

Figure 29. Canada with Capacity Auction and T&D Deferral Benefits Summary

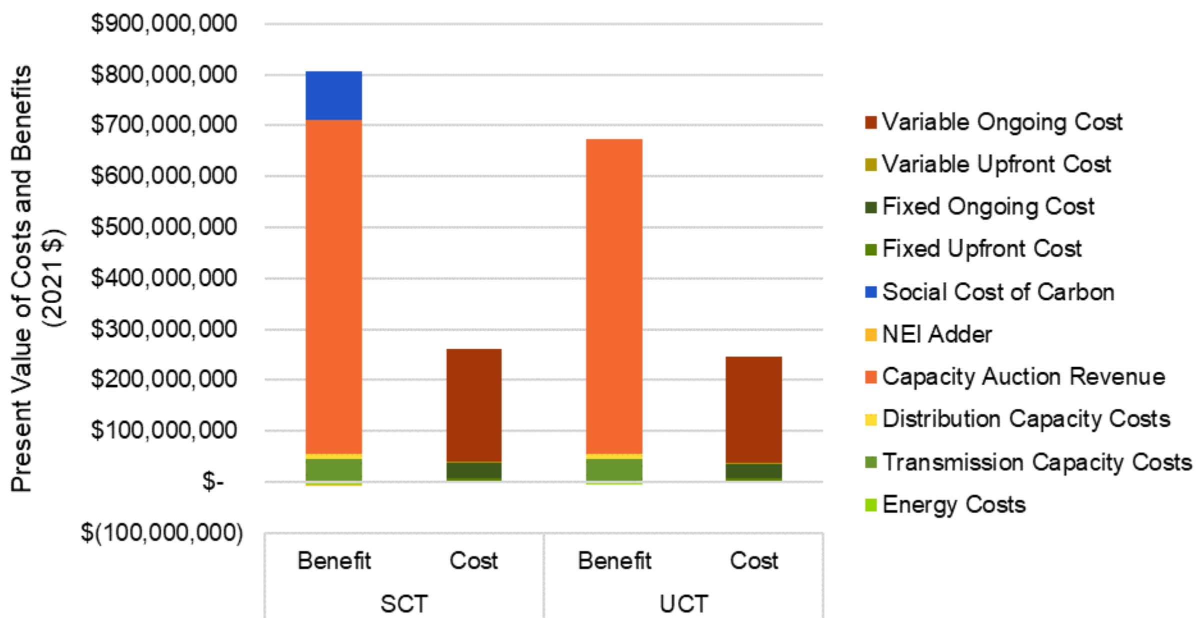


Table 30 shows that the detailed benefits of the deployment of the JPS are significantly higher than the projected costs in Canada.

Table 30. Canada with Capacity Auction and T&D Deferral Benefits Details UCT

Value Stream	PV UCT Benefits ($2021)	PV UCT Costs ($2021)
Energy Costs	-$5,051,947	N/A
Transmission Capacity Costs	$45,766,468	N/A
Distribution Capacity Costs	$9,283,463	N/A
Capacity Auction Revenue	$618,498,244	N/A
Fixed Upfront Cost	N/A	$7,308,000
Fixed Ongoing Cost	N/A	$28,251,024
Variable Upfront Cost	N/A	$2,206,502
Variable Ongoing Cost	N/A	$208,415,572
Total	**$668,496,228**	**$246,181,098**

4.3.3 UK

UK with Capacity Auction Benefit

Figure 30 summarizes the costs and benefits in the UK.

Figure 30. UK with Capacity Auction Benefit

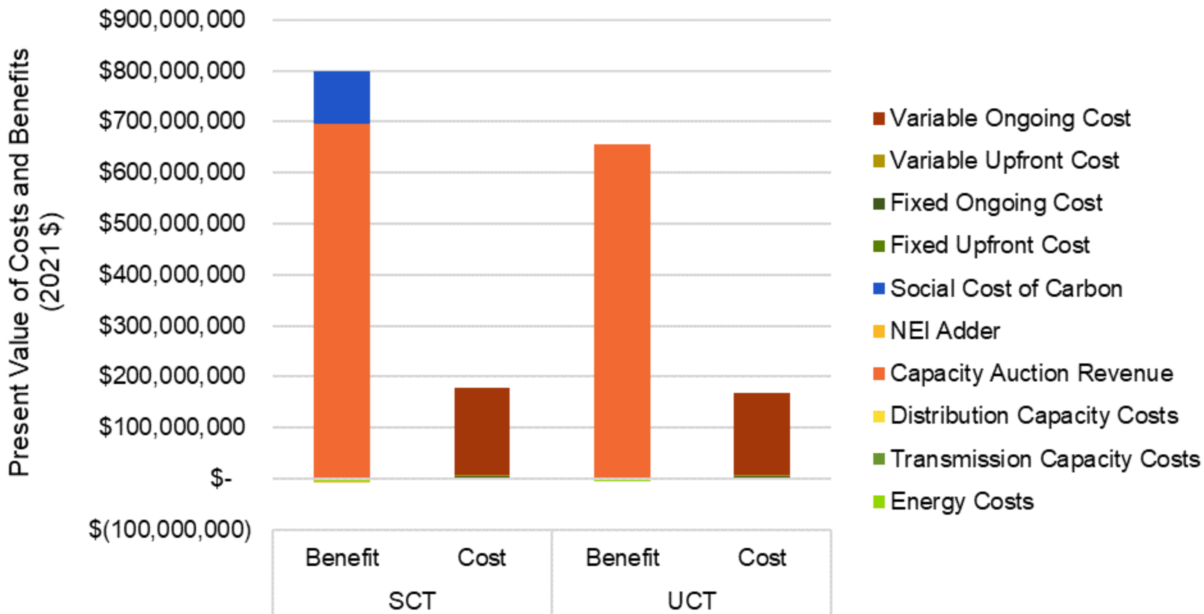


Table 31 shows that the detailed benefits of the deployment of the JPS are significantly higher than the projected costs in the UK.

Table 31. UK with Capacity Auction Benefit Details UCT

Value Stream	PV UCT Benefits ($2021)	PV UCT Costs ($2021)
Energy Costs	-$5,365,471	N/A
Transmission Capacity Costs	$0	N/A
Distribution Capacity Costs	$0	N/A
Capacity Auction Revenue	$656,882,278	N/A
Fixed Upfront Cost	N/A	$1,015,000
Fixed Ongoing Cost	N/A	$3,923,753
Variable Upfront Cost	N/A	$2,343,438
Variable Ongoing Cost	N/A	$161,211,705
Total	**$651,516,807**	**$168,493,896**

UK Capacity Auction and T&D Deferral Benefits

Figure 31 summarizes the costs and benefits in the UK.

Figure 31. UK with Capacity Auction and T&D Deferral Benefits

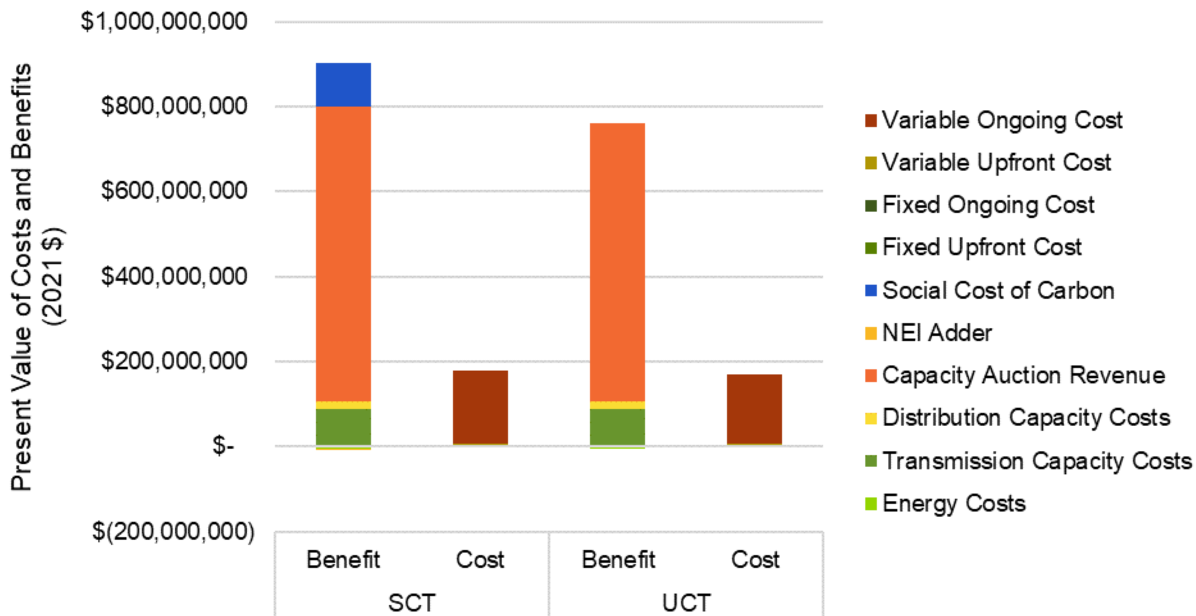


Table 32 shows that the detailed benefits of the deployment of the JPS are significantly higher than the projected costs in the UK.

Table 32. UK with Capacity Auction and T&D Deferral Benefits Details UCT

Value Stream	PV UCT Benefits ($2021)	PV UCT Costs ($2021)
Energy Costs	-$5,365,471	N/A
Transmission Capacity Costs	$87,367,935	N/A
Distribution Capacity Costs	$17,722,080	N/A
Capacity Auction Revenue	$656,882,278	N/A
Fixed Upfront Cost	N/A	$1,015,000
Fixed Ongoing Cost	N/A	$3,923,753
Variable Upfront Cost	N/A	$2,343,438
Variable Ongoing Cost	N/A	$161,211,705
Total	**$756,606,822**	**$168,493,896**

4.4 Conclusions

Guidehouse arrived at conclusions as an outcome of the extrapolation to Ontario, Canada, and the UK as shown below:

- Benefits of the JPS are driven primarily on capacity auctions in each region. If there is no capacity market in a region, then JPS would likely not be cost effective when depending solely on the benefits from T&D investment deferral.

- Distribution deferral benefits are assumed to be the smallest of the primary benefit streams, approximately 40-60 times less than the capacity auction benefits. This is driven by Guidehouse's assumptions that only 5% of feeders have opportunities to defer distribution investments through active management of DERs. Challenges finding and targeting these specific opportunities are significant and depend on the maturity of the individual distribution utility's planning capabilities.
- Transmission deferral benefits are approximately 8-10 times less than the potential capacity auction benefits, driven by Guidehouse's assumption that only 2% of feeders have opportunities to defer transmission investments through active management of DERs. The long-term nature of transmission projects introduces significant challenges in targeting and supporting these benefits.
- The BC ratio depends on the costs of large-scale deployments of the JPS across Ontario, Canada, and the UK. Because there is a fixed cost component (i.e., cost per implementation) and a variable cost component (i.e., cost per MW or feeder) of JPS, the BC ratio is heavily driven by the average size (i.e., feeders per implementation) of the implementation. This is the main reason why the BC ratios are higher in the UK compared to Canada. It is important to note that the pricing model for the JPS components from Opus One Solutions and Kiwi Power is not fully developed for large-scale deployment, which introduces significant uncertainty into the BCA ratios for the extrapolation.

Extrapolation of the JPS BCA to Ontario, Canada, and the UK results in key takeaways for identifying value of active control of DER. It appears that the JPS can be cost effective on feeder groups with modest controllable DER penetration between 20% and 30% as long as the economies of scale are in play and the JPS is deployed upon a number of adjacent feeders. Deeper analysis on the optimal number of feeders and amount of DER penetration to maximize value of JPS was not performed as part of this report. As summarised in the extrapolation BCA, JPS can be cost effective even without T&D deferral opportunities. When deploying JPS for additional value from T&D deferral, one must consider the "sweet spot" where a local area on the grid has sufficient DER penetration and a readily available T&D deferral opportunity, which may limit the number of suitable feeders. Targeting specific feeders and feeder groups with existing T&D deferral opportunity is another opportunity to the JPS.

Looking at the differences between Canada and the UK, the higher density of feeders per distribution utility combined with the nationwide capacity market make the UK a more viable JPS target based upon the extrapolation. This can be extended to Ontario and Canada so that if higher participation in DER markets is desired using active control of DER, then creating more markets throughout Canada and increasing the payments for market participation are levers that can be used to incentivize additional active control of DER.

Appendix A. Capacity Market Details

A.1 Ontario Capacity Market

Details of the Ontario IESO market are shown as follows based on Guidehouse's research. The following limitations exist on the type of asset allowed to bid into the market:

- Each resource participating in the forward capacity auction must be 1 MW (in units of UCAP[21]). Resources can fall to the following categories:
  - New or existing generating capacity resource
    - Dispatchable (thermal or hydro)
    - Self-generating
    - Storage
      - Dispatchable and self-generating
  - New or existing import capacity
    - System-backed importation
  - New or existing demand capacity
    - Capacity dispatchable load resources
    - Hourly demand response resources

Unforced capacity (UCAP): The maximum generation or load reduction capability of a resource reduced by either the forced outage rates or energy limitations and reflects the maximum capacity that can be offered into the capacity auction.[22] The calculation methodology was developed by IESO.

DER aggregation is possible but may be unclear and complex. Under current market rules, there are three types of aggregations are permitted:[23]

- Aggregations of dispatchable generation within a single transmission-distribution node *(must be of the same type).*
- Aggregations of dispatchable load within a single transmission-distribution node *(must be same type).*
- Aggregation of non-dispatchable load (e.g., hourly demand response) within an IESO transmission zone.

Aggregation can be the same resource type or a combination of separate resources separately metered. Although aggregation of dispatchable DER and load is permissible, the process for evaluating the aggregation bid can be time- and resource-intensive.

[21] **Capacity Auction # 2 March 2021 Draft Design**

[22] Ibid.

[23] **Exploring Expanded DER Participation in the IESO-Administered Markets. Part II: Options To Enhance Der Participation**

No participation models are in place for the aggregation of non-dispatchable DER.[24] Identified barriers for aggregating DER in the capacity auction include the following:

- Restriction for creating and operating DER.
- Cost of meeting IESO's telemetry requirement.
- Lack of available information on upstream bulk system ghosting capacity for resources.
- Lack of available information regarding T&D nodes that would be high or low risk.
- Lack of clear language or information regarding the considerations evaluated for a proposed aggregation.
- Lack of clear information regarding characteristics of aggregations that could impact reliability, which may decrease the chances of being approved).

Availability payment vs. payment when the assets are dispatched: The IESO market is currently structured to provide monthly availability payments. Participants receive payments for each month they have a capacity obligation.[25]

A.2 Canada Capacity Market

Details of the New Brunswick and Quebec (ISO-NE) capacity markets are shown as follows based on Guidehouse's research.

The following limitations exist on the **type** of asset allowed to bid into the market:

- Resources must be capable of providing at least 100 kW of capacity[26] and can fall into one of the following categories: imports, demand resource, or generating resource.
    - Imports:[27]
        - Backed by a single external new (non-commercial) generating resource
        - Backed by an external existing (commercial) generating resource
        - Backed by an external control area
        - Backed by imports crossing intervening control areas
        - Imports may be either of the following:
            - Delivered over existing AC or DC transmission lines that interconnect the New England Control Area with adjacent control areas
            - Bundled with a new transmission facility (elective transmission upgrade, or ETU)
    - Demand resources:

[24] Ibid.

[25] **Capacity Auction # 2 March 2021 Draft Design**

[26] **ISO New England Inc./ISO New England Inc. Transmission, Markets and Services Tariff. Section III.13. Forward Capacity Market.**

[27] ISO-New England. **Qualification Process for New Imports**. ISO-New England

        - On-peak demand capacity resources *(non-dispatchable)*
        - Seasonal peak demand capacity resources *(non-dispatchable)*
        - Active demand capacity resources such as load management and distributed generation *(dispatchable)*
        - A demand resource show of interest can be submitted for the following:[28]
            - New passive demand capacity resource not in service before the forward capacity market applicable existing capacity qualification deadline.
            - Distributed generation operated only to address power outages or local emergencies
            - New increment to an existing demand capacity resource
    - Generating resources: Can be an intermittent or non-intermittent resource.
        - If 115 kV and or 5 MW or greater, must be registered as a *generator.*[29]
        - Otherwise, generating facilities may register as a settlement-only resource/generator (SOR) or alternative technology regulation resources.
        - If a facility is between 1 MW and 5 MW, the facility may also be registered as a generator.[30]

DER aggregation:

- Existing participation models do not allow DER aggregations that inject energy into the system with DER that withdraws energy from the system.
- Demand response resource model for demand response aggregations per Federal Energy Regulatory Commission (FERC) Order No. 745.
- Alternative technology regulation resources model[31] for an aggregation of one or more resources providing regulation.
- According to a recent study, resources with seasonal capacities can be aggregated to meet the year-round availability requirement.[32]
- For small generators and storage, the capacity market does not use aggregation. Instead, the minimum size requirement is waived, and the generator can register as a SOR. As an SOR, the generator must be less than 5 MW but more that the capacity auction requirement of 100 kW.[33]

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[28] ISO-New England. **Qualification Process for New Demand Capacity Resources**. ISO-New England

[29] **ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources**

[30] Ibid.

[31] See Chapter III: Technical Requirements For Alternative Technology Regulation Resources in **ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources**

[32] **Reinventing the Utility for DERs: A Proposal for a DSO-Centric Retail Electricity Market**

[33] **ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources**

- ISO-NE is working with stakeholders to design a framework and model for DER participation in future auctions.[34,35]

Availability payment vs. payment when the assets are dispatched:

- ISO-NE is structured to provide monthly capacity payments including a resource capacity base payment for the obligation month and resource capacity performance payment for all 5-minute intervals in the obligation month.[36]
- Base payments are reflective of cleared capacity and the capacity clearing price in the capacity zone and, if applicable, clearing prices to account for appropriate reconfiguration auction, capacity supply obligation bilateral, or the substitution auction.
- Performance payments are essentially credits (or charges) from capacity performance based on performance scores during any capacity scarcity conditions and the associated capacity performance rate within the obligation month.[37]

A.3 UK Capacity Market

Details of the National Grid ESO capacity market are shown as follows based on Guidehouse's research.

The following limitations exist on the **type** of asset allowed to bid into the market:

- Types of resources that can participate in capacity market:[38]
    - New and existing generators
    - Embedded generators (organizations with onsite generators)
    - Combined heat and power (CHP)
    - Demand-side responders (DSR) (organizations that can reduce their demand when requested to provide additional capacity on the grid)
    - Storage
    - Interconnectors
- The minimum capacity to participate is 2 MW;[39] however, the UK Government has committed to improve capacity market requirements by reducing the minimum capacity to 1 MW.[40]

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[34] **Draft high-level market design approach to comply with Order No. 2222**. Order No. 2222: Participation of Distributed Energy Resource Aggregations in Wholesale Markets

[35] **Revised market design approach to comply with Order No. 2222 (cont.)** Order No. 2222: Participation of Distributed Energy Resource Aggregations in Wholesale Markets

[36] See Section III.13.7 in **Market Rules 1: Section 13**

[37] **Forward Capacity Market (FCM) Credit**

[38] National Grid ESO. July 2021. **Capacity Market Auction Guidelines.** July 2021.

[39] Department for Business Energy, and Industrial Strategy. March 2020. **Capacity Market Consultation on Future Improvements**.

[40] Ibid

DER aggregation: Resource aggregation is allowed. Many of the DSR contracts awarded have been through aggregators.[41] Furthermore, there is no participation model set for DER participation.

- Most renewable energy technologies are ineligible; bids with generation resources receiving support from renewables obligation, the contracts for difference, or feed-in tariffs schemes cannot participate in the market.[42]
- Technologies not listed as a generation technology are not permitted for capacity market payments[43, 44] (e.g., aggregations of electric vehicle load[45]).

Availability payment vs. payment when the assets are dispatched: During the delivery year, participants providing capacity receive monthly payments for their obligation at the clearing price.[46,47] Failure to deliver will result in a charge.

However, several changes are planned over the next 10 years:

*From **Capacity Market Consultation on Future Improvements**

- Lowering the minimum capacity threshold for participating in the auctions.
- Direct participation of cross-border capacity.
- Participation rules for new types of capacity.
- Access to long-term agreements.
- Volume of capacity to be secured in the year-ahead auction.
- Compliance with the new Electricity Regulation (EU 2019/943)4, in particular the implementation of carbon emissions limits.

[41] Bray, R. 2018. **Policy and Regulatory Barriers to Local Energy Markets in Great Britain**

[42] National Grid ESO. May 2021. **Electricity Capacity Report**

[43] Department for Business Energy, and Industrial Strategy. March 2020. **Capacity Market Consultation on Future Improvements**.

[44] **Capacity Market Auction Guidelines** for generation resource classes and their de-rating factors

[45] T Pownall, et al. 2021. **Re-Designing GB's Electricity Market Design: A Conceptual Framework Which Recognizes the Value of Distribute Energy Resources**

[46] Engie. July 2016. **Understanding the Capacity Market**

[47] Nationwide Utilities. **Capacity Market**