Finding Value in Local Energy Markets

An integrated software simulation of local energy markets in Belleville, Whitby, Ajax, Pickering, and Newmarket with support from the IESO Grid Innovation Fund

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NODES
NT Power
Elexicon Energy

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Final Report

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1. Executive Summary

This report summarizes an integrated software simulation of the operations of a local energy market in Belleville, Whitby, Ajax, Pickering, and Newmarket. The objective of the simulation was to model electricity and economic outcomes from a transactive model which targets peak capacity at five localities in the service area of NT Power and Elexicon Energy. The localities were selected as case studies based on a critical mass of customers and an opportunity to reduce peak demand at a station with customer sited demand response and distributed energy resources.

Hourly demand profiles were forecast for each locality for 2024-2038 and for 77 customers within the service territories. In addition to the reference case business-as-usual scenario (constructed from 2019-2022 data), the modeling considered different input values for hourly temperature due to climate change, and for electricity demand associated with electric vehicles. The impact of slowly rising temperatures was found to have a negligible effect on model outcomes. The impact of electric vehicles was found to be material and potentially represents a significant source of demand growth at each locality.

In the simulation, the distributor as buyer submits bids to the market, customers submit offers, the market transacts, and resources are activated to meet distributor needs. The distributor aggregates capacity for distribution purposes as non-wires alternatives. The market is a double auction, pay-as-bid, model. Customers participate by curtailing load, or with distributed energy resources (gas generators or battery energy storage systems).

The project enabled integration of the tools to form a process for finding value in local markets through detailed costing of customer-sited non-wires alternatives. The tools determine potential costs and value for buyer and seller, subject to detailed seller profiles including preferences and constraints. Bids and offers are automated based on participant objectives to model market participation.

Distributor bids are based on the avoided costs of system upgrades at a station. The distributor bid strategy was based on a detailed review of planning priorities identified by the distributors, Hydro One, and the IESO, and analysis of feeders and station loads to assess the potential for customer-sited demand response (with or without a distributed energy resource) to meet needs. Data provided by the distributors included interval loading information for feeders and stations and meter data for commercial and industrial customers ranging from 60-4,000 kW.

Customer offers are based on marginal costs of curtailment, production losses, and fuel costs, and subject to a range of constraints that limit availability. Customer offers were computed from meter data, and by researching individual customers for site, size, and other basic parameters. Detailed customer preferences on availability and pricing were assumed. The projected cost of customer participation varies significantly with the number of times and duration of activation events required to fulfill a need. Assumptions of customers' physical constraints were found significantly to drive the cost of capacity to the distributor.

The market clears when the bid price exceeds the offer price. The activation optimization objective is to maximize the number of trades and the amount of peak capacity traded. The quantity and duration of the distributor need was modelled based on 10 activation events per locality per year to reflect market expectations about the maximum number customers will tolerate. The modelling resulted in 5.5 to 5.8 hours in duration per curtailment during the 2024-2038 period.

Energy and economic outcomes were simulated for fifteen years, 2024-2038. Energy outcomes include maximum peak reductions, average peak reductions, and total energy reductions. Economic impacts include market outcomes by locality, and customer outcomes by month. Monthly bills were calculated for 77 participating customers from 2024 and 2038. Net bill savings from trading are significantly higher in the 2038 climate change and electric vehicle scenario compared to business as usual. The simulation highlights the growing value of local energy markets to create access to a cost-effective resource for distributors and provide efficient energy management incentives for customers.

Results and learnings from the project support ongoing sector development, specifically: distributor needs determination and planning integration, distributor functionality determination and readiness, distribution system value, and tools for customer engagement in the energy transition.

2. Introduction to local energy markets

Local energy markets, and transactive energy markets specifically, offer new models for distribution system operators to connect and serve load, and to integrate distributed energy resources (DERs) and customers with flexible demand. A local energy market enables targeted activation for distribution system capacity to support the efficient operation of the distribution system.

> *"Local energy markets have emerged as a leading approach to foster the integration of more DERs into the electricity system."*[1]

A local energy market provides access to diverse sources and types of energy services that can be transacted for capacity in lieu of more expensive capital upgrades, and to reduce demand and delivered energy cost to customers in real time. A local energy market is a way for distributors to reduce local system peaks during extreme high demand. Moments of extreme high demand set the design criterion for system upgrades and expansion, even when they occur infrequently, in a few hours in a year. During extreme hours of peak energy consumption, demand rises exponentially, prices rise exponentially, and losses on the system also rise exponentially. The top percentiles of demand hours in a year typically see the highest prices in a year. The price of energy supplied to offset marginal system losses during those high demand hours is the most expensive energy supplied during the year.

Reducing the frequency and severity of extreme demand peaks can defer and avoid the need for upgrades and expansions at distribution stations. Reducing peak demand across distribution stations with aggregated demand resources creates an opportunity to defer and avoid upgrades and expansions upstream in the transmission system and competes with new generation.

The local energy market provides value to the customer by providing an additional revenue stream from capacity (demand response) sold by customers to the distributor. Customers continue buying energy services at the bulk system price from the distributor net of services sold.

3. Market functions and tools

The project used a software platform environment developed and provided by Powerconsumer and the NODESmarket Platform to simulate transactions between distributors and customers. This was comprised of six main components:

1) Customer dashboard and registration process - Powerconsumer
2) GIS-based visualizations - NODES
3) Market trading desk - NODES
4) Automated bid and offer generation – Powerconsumer
5) Market trading[2] and optimization - Powerconsumer
6) Modelling, forecasting, simulation – Powerconsumer

The components are firewalled to ensure competition and eliminate gaming; the components can work together or independently as a technology plug-in depending on distributor or customer need. The project enabled integration of the tools to form a process for finding value in local markets through detailed costing of customer-sited non-wires alternatives. The tools determine potential costs and value for buyer and seller, subject to detailed seller profiles including preferences and constraints. Bids and offers are automated based on participant objectives to model market participation.

4. Planning context

The planning needs of NT Power and Elexicon Energy, including the communities of Belleville, Whitby, Ajax, Pickering, and Newmarket were assessed to guide the local energy market design as follows:

- Where - Five localities chosen to be distribution stations or transmission stations (data dependent) as needs are aligned across bulk, regional, and local systems
- When - All scenarios to focus on reducing peak demand at distribution and transmission stations through customer-sited demand response or DER participation
- What - In addition to a business-as-usual forward demand curves at each locality, impacts of climate change and electric vehicles to be included as a scenario

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[1] Capper, Timothy, et al. 2022. Peer-to-peer, community self-consumption, and transactive energy: a systematic literature review of local energy market models. Renewable and Sustainable Energy Review 162 (2022).

[2] For the purpose of this simulation Powerconsumer's algorithm was used to optimize transactions and match trades; NODES has trade matching functionality in use for transactional markets.

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Newmarket and Northern York Region

The IESO's Bulk Energy System plans[3,4,5] identify targeting peak electricity demand[6,7] as a near term priority (to 2024). Beyond 2024, Ontario's capacity needs are expected to emerge east of the Flow East Towards Toronto (FETT) interface. Efficient electrification is identified as a priority[8], as well as effective integration of existing resources[9].

IESO and Hydro One planning for Northern York Region[10] identifies targeting peak electricity demand[11] and deferral of Northern York Transformer Station (TS) (notionally planned for 2027)[12]. In the mid- to long-term, the regional plans project supply and demand growth, and opportunities to defer major system capacity upgrades.

Plans for 2020 to 2040 for York Region and the Town of Newmarket both have energy dimensions: reducing emissions[13], renewable energy[14], energy conservation and innovation[15,16], and smart power grids[17].

NT Power's Distribution System plan for 2020 to 2040[18] identifies utility transit cooperation and electric vehicle charging[19] as priorities as well as effective DER integration[20].

GTA East – Durham Region – Elexicon Energy

IESO[21] and Hydro One[22] plans for the Greater Toronto Area (GTA) East region (including Durham Region and the service area generally of Elexicon and the communities it serves) identify near term priorities: planning based on summer peak loads[23], conservation to defer TS upgrades (must reduce peak demand hour)[24], a new Seaton TS to be built to address growth[25], DERs considered to manage future growth[26], end of life replacement at Cherrywood TS[27], and a refurbishment of the Wilson TS[28]. Load restoration analysis was recommended[29]. In the mid- to long-term the plan sees peak residential and commercial AC demand[30].

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[3] IESO Annual Planning Outlook. December 2020. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

[4] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook

[5] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Acquisition-Report

[6] IESO APO. "Following the Pickering NGS retirement and during the nuclear refurbishment period, incremental energy needs will be met primarily by the increased utilization of the gas fleet." Page 51 of 73.

[7] "DERs can provide value by managing local peak demand and providing other services to defer, reduce or avoid capital and operating costs associated with traditional electricity infrastructure" IESO York Region Non-Wires Alternatives Demonstration Project, Webinar, July 23, 2020 p. 6

[8] IESO. Distributed Energy Resource Integration Joint Targeted Call. Application Guideline. November 2021. Page 5. https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/derr/derr-20210825-der-integration-joint-targeted-call-application-guideline.ashx

[9] IESO APO December 2020. Page 63 of 73.

[10] York Region Integrated Regional Resource Plan. February 28, 2020. IESO. https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Completed/Integrated-Regional-Resource-Plan-York-Region

[11] "As part of ongoing engagement with municipalities and stakeholders, the IESO will actively seek new opportunities to target peak electricity demand. … opportunities to align local municipal and stakeholder activities that may help defer the medium-term need for stepdown station capacity and long-term need for major system capacity upgrades will be explored and evaluated to determine feasibility and cost-effectiveness. The purpose of this information York Region IRRP gathering is to inform the assessment of possible solutions and decisions required in the next IRRP (currently anticipated to be completed in 2025)." York Region IRRP page 3 of 77.

[12] "The first anticipated need is for a Markham #5 MTS in 2025, followed by a Northern York TS (notionally 2027) and Vaughan #5 MTS (notionally 2030). The need dates for all three step-down stations could be deferred by NWAs that target peak demand electricity use, with the longer-term need dates more candidates for deferral…. In order to defer a new Northern York TS, measures targeting the higher-growth northern municipalities of Newmarket, East Gwillimbury and Aurora would likely be the most effective." York IRRP Page 6 0f 77

[13] "Residents want our communities to reduce emissions and are aware of the impacts of climate change in York Region" Region of York Municipal Comprehensive Review 2020.

[14] Town of Newmarket 2006 Official Plan as amended through 2019. Section 12.3 Sustainability in design. https://www.newmarket.ca/LivingHere/Documents/Planning%20Department/Official%20Plan/2006%20Official%20Plan%20-%20December%202016%20Consolidation%20FINAL.pdf

[15] York Region Official Plan 2010.

[16] "The practical application of energy conservation will be encouraged throughout the Town through site planning, building design, renewable energy sources, alternative energy sources, and efficient equipment and operations." Town of Newmarket Official Plan 2006. Section 14.7 Energy conservation.

[17] "To encourage utility networks that can adapt to emerging technologies, such as smart power grids, smart metering, and advanced telecommunications." York Region Official Plan 2020 policy 7.5.1.

[18] Newmarket-Tay Power Distribution Ltd. 2024-2040 Distribution System Plan. October 2020.

[19] NT Power Distribution System Plan 2020. Page 112. https://www.rds.oeb.ca/CMWebDrawer/Record/699952/File/document

[20] NT Power DSP. 2020. Page 35.

[21] Pickering-Ajax-Whitby sub-region Integrated Regional Resource Plan (IRRP). June 2016. IESO. https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/Pickering-Ajax-Whitby

[22] GTA East Regional Infrastructure Plan (RIP), 2019-2024. February 2020. Hydro One. https://www.hydroone.com/about/corporate-information/regional-plans/gta-east

[23] GTA East Regional Infrastructure Plan (RIP), 2019-2024. February 2020. Hydro One, p.22. https://www.hydroone.com/about/corporate-information/regional-plans/gta-east

[24] Pickering-Ajax-Whitby sub-region Integrated Regional Resource Plan (IRRP). June 2016. IESO, p.36. https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/Pickering-Ajax-Whitby

[25] GTA East Regional Infrastructure Plan (RIP), 2019-2024. February 2020. Hydro One p. 8 and p. 28. https://www.hydroone.com/about/corporate-information/regional-plans/gta-east

[26] Pickering-Ajax-Whitby sub-region Integrated Regional Resource Plan (IRRP). June 2016. IESO, p.37 https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/Pickering-Ajax-Whitby

[27] GTA East Regional Infrastructure Plan (RIP), 2019-2024. February 2020. Hydro One. https://www.hydroone.com/about/corporate-information/regional-plans/gta-east p.8 and p.29

[28] Ibid, p. 30

[29] Pickering-Ajax-Whitby sub-region Integrated Regional Resource Plan (IRRP). June 2016. IESO. https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/Pickering-Ajax-Whitby p.44 "undertake further restoration analysis and recommend next steps as part of the RIP for the GTA East Region"

[30] Ibid, p.16, "Regional and sub-regional peak driven by the air conditioning loads of residential and commercial customers (80% of load in area)"

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Residential and commercial growth near the lakeshore may require new TS[31]. DERs are considered impractical to address regional restoration needs[32].

In Durham Region[33] the plan for 2016-2050 includes reducing emissions[34], renewable energy[35], community energy/self sufficiency[36], EVs[37] and coordination of EV infrastructure and policy[38] and population doubling between 2018-2050[39].

Elexicon's Distribution System plan (2022-2026) identifies investment drivers of environmental impact, innovative technology as non-wires alternatives and customer engagement[40] and a need to enhance Information and Operational Technology (IT/OT) to support DERs and EVs[41]. The DSP sees over-utilization of feeders and stations from commercial and residential growth[42], future reliability performance more granular[43], upstream transmission issues as a barrier to renewable energy connections[44], and customers wanting grid improvement to protect from future climate-related service disruptions.[45]

Planning for reliability and resilience

The initial project design anticipated being able to quantify outcomes of a range of electricity services and outcomes to customers, including reliability and resilience outcomes, considering how those are measured in the system, and how those kinds of measures are accounted for in plans. The customer's experience of reliability is largely related to incidents of short duration. Information on momentary outages is not captured or reported by distributors. Reportable incidents over one hour duration are reported as part of SAIFI/SAIDI[46] indices for reliability for distribution companies. The IESO uses different and multiple measures in its role as Reliability Coordinator for the Ontario electricity system. Targeting flexibility during peak energy demand hours makes positive contributions to customer outcomes, even where it has no effect on contingency-related outages and momentary interruptions at the level of the actual customer's experience.

Project research with NT Power highlighted a commissioned climate change impact analysis specific to the Newmarket service territory. The analysis documented an approach to determining resilience requirements similar to the IESO's emergency and restoration planning in that it takes a bottom-up approach to assessing minimal operational requirements, the impact of contingencies, and the process/time to restoration of normal operations. Further work would be required with customers and the distributors to establish workable baselines to assess the potential for customer-sited flexibility to support operations during contingencies and restoration.

5. Local energy market rules

All markets are comprised of exchanges between buyers and sellers. In Ontario, energy at the bulk system level is dispatched through the IESO market. For distributors and most energy customers in Ontario, the status quo involves passive exchanges of energy. A distributor, in fulfilling its obligations to sell[47,48] electricity to every customer connected to its system, buys all energy from the

[31] Ibid, p. 45
[32] Ibid, p.42, see also Appendix C, p. 6 of Value of Line Loss (VOLL)
[33] Durham Community Energy Plan. 2018. Region of Durham. https://www.durham.ca/en/living-here/low-carbon-pathway.aspx
[34] Elexicon Energy Inc. Distribution System Plan (2022-2026). April 2021. https://elexiconenergy.com/wp-content/uploads/2021/05/Elexicon_DSP_20210401.PDF p. 16
[35] Ibid
[36] Ibid
[37] Durham Community Energy Plan. 2018. Region of Durham. https://www.durham.ca/en/living-here/low-carbon-pathway.aspx p. 11, 19 and 60 "modelling suggests that electrifying personal vehicles can reduce GHGs 11% of Durham Region's targets
[38] Ibid, p.91
[39] Ibid, p.10
[40] Elexicon Energy Inc. Distribution System Plan (2022-2026). April 2021. https://elexiconenergy.com/wp-content/uploads/2021/05/Elexicon_DSP_20210401.PDF p. 16, p. 91
[41] Ibid, p. 172 – noted in Table to capture Elexicon's interest and spending in for future EV/DER integration
[42] Ibid, p. 213
[43] Ibid, p. 17, p.81
[44] Ibid, p.165
[45] Ibid, p.25
[46] System-wide reliability indices: the system average interruption frequency index ("SAIFI") and the system average interruption duration index ("SAIDI")
[47] s.29 Electricity Act 1998
Distributor's obligation to sell electricity
29 (1) A distributor shall sell electricity to every person connected to the distributor's distribution system, except a person who advises the distributor in writing that the person does not wish to purchase electricity from the distributor. 1998, c. 15, Sched. A, s. 29 (1).
[48] Standard Service Supply Code
This Code establishes the manner in which a distributor must provide standard supply service to meet its obligation to sell electricity under section 29 of the Electricity Act or to give effect to rates determined by the Board under section 79.16 of the Act.
1.1.2 This Code provides for three regimes applicable to the commodity price for electricity provided as standard supply service: (a) spot market-based pricing for non-RPP consumers and electing spot consumers (section 3.2); (b) the Board's regulated price plan contemplated in section 79.16 of the Act for RPP consumers with conventional meters (section 3.3); and (c) the Board's regulated price plan contemplated in section 79.16 of the Act for RPP consumers with eligible time-of-use meters (section 3.4).

IESO[49]. The distributor does this through its licence[50,51] to own and operate a distribution system by means of conveyance[52] (i.e., capacity via poles, wires, transformers, distribution stations etc.). Customers of a distributor buy energy from their distributor.

In this simulation of the local energy market, the buyer is a distributor (Elexicon Energy or NT Power), the customers at a locality are sellers. The distributor buys capacity through the local energy market at a locality as an alternative to wires. Customers continue to be passive buyers of energy and are enabled to actively participate in a local energy market as sellers of capacity to the distributor. Customers participate with behind-the-meter DERs or curtailment. The project constructs a local energy market to simulate transactions of active exchange of capacity within the distribution system.

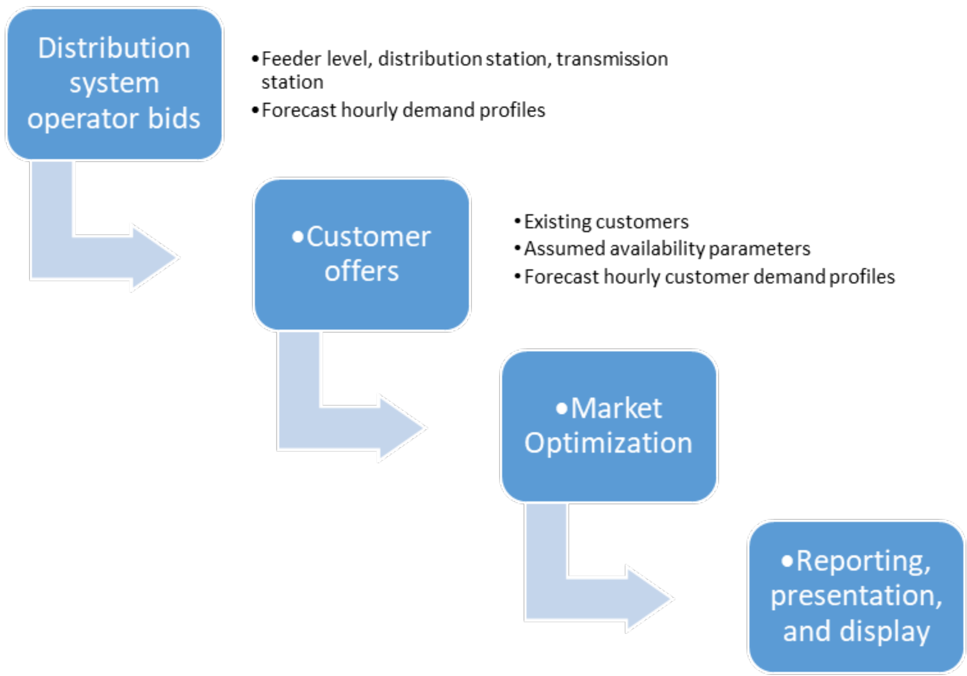

Figure 1 Local energy market construction

Market optimization

The market optimization was based on fully automated bids and offers, and a rolling 24-hour ahead distribution system operator bid. The objective of the optimization was to transact the maximum number of trades to lower peak cost-effectively. Prior transactions were a factor for availability of DERs. For example, battery energy storage systems are limited to 2-hour duration. If a DER was being used for the Industrial Conservation Initiative, then it was assumed to be unavailable for the entire predicted peak day. The market model was based on a double auction clearing mechanism.[53] The double auction model was selected to reflect asymmetrical cost information between buyer and sellers, to create a fair market, and to prevent gaming. Multiple customer offers were optimized to fill each distributor bid.

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[49] 2.2 Fulfillment of the Standard Supply Service Obligation 2.2.1 A distributor shall provide standard supply service for one hundred per cent (100%) of the electricity used by a standard supply service customer. 2.2.2 A distributor shall obtain the electricity required to fulfill its standard supply service obligation through the IESO-administered markets, from an embedded retail generator (as defined in the Retail Settlement Code) located within the distributor's licensed service area in accordance with the Retail Settlement Code or, in the case of an embedded distributor (as defined in the Retail Settlement Code), from the embedded distributor's host distributor (as defined in the Retail Settlement Code).

[50] s.57 Ontario Energy Board Act 1998

Requirement to hold licence

57 Neither the IESO nor the Smart Metering Entity shall exercise their powers or perform their duties under the *Electricity Act, 1998* unless licensed to do so under this Part and no other person shall, unless licensed to do so under this Part,

(a) own or operate a distribution system;

[51] Electricity Distribution Licence

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence: a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; Name of Licensee Electricity Distribution Licence ED-200x-0xxx 3 b) the Distribution System Code; c) the Retail Settlement Code; and d) the Standard Supply Service Code

[52] Ontario Energy Board Act 1998 "distribute", with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less.

[53] Capper, Timothy, et al. 2022. Peer-to-peer, community self-consumption, and transactive energy: a systematic literature review of local energy market models. Renewable and Sustainable Energy Reviews 162 (2022) 112403.

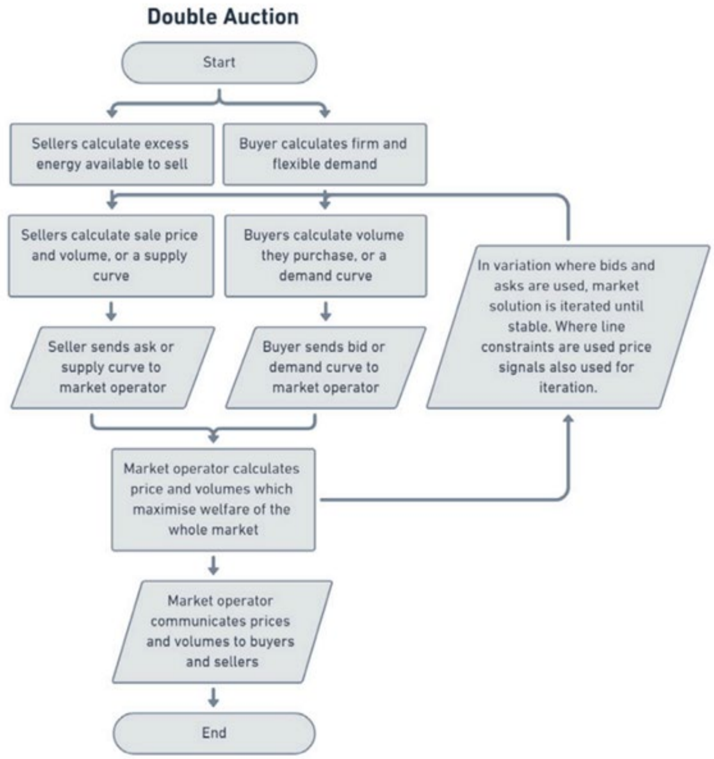


Figure 2 Double auction clearing mechanism (from Capper et al.)

Distributor participation

The term "buy" is used in this report, but in Ontario, the service a distributor can buy is prescribed[54] as electricity for the purpose of conveyance to the customer. A distributor can buy electricity from the IESO, an embedded distributor or an embedded retail generator.

The project presumes a distributor can buy capacity in a local energy market as an alternative to wires in lieu of a procurement process for the 'wires' for which the local energy market capacity is an alternative. It is also presumed that a distributor can participate in a local energy market as a means of providing standard supply service to its customers[55] where actively managing system peak load[56] provides a cost-effective option to defer or avoid system upgrades and expansions[57], or can be demonstrated to result in net benefits to customers.

The Ontario Energy Board Innovation Handbook[58] highlights advice given to regulated distribution system operators undertaking pilot projects in relation to whether activities undertaken as a distribution system operator are permissible under section 71 of the OEB Act:

> "… proposed activities are permissible under section 71(1), as their main purpose is to meet distribution system needs using customer-owned DER assets as NWAs. This is intended to create flexibility within [the] distribution system and mitigate local constraints on the grid, thereby helping avoid the need to build new infrastructure. The

[54] See Footnote 11

[55] Standard Supply Service Code for Electricity Distributors - "standard supply service" means the manner in which a distributor must fulfill its obligation to sell electricity under section 29 of the Electricity Act or to give effect to rates determined by the Board under section 79.16 of the Act as set out in this Code – https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2020-10/Standard-Supply-Service-Code-SSSC-20201013.pdf

[56] See Milestone 1 report Needs Assessment.

[57] OEB Chapter 5 Filing Requirements "the distributor's approach to assessing non-distribution system alternatives to relieving system capacity or operational constraints..."
Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5 Consolidated Distribution System Plan Filing Requirements:
5.4.2 Capital expenditure planning process overview
The information a distributor should provide includes, but need not be restricted to: a) a description of the distributor's capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities; b) if not otherwise specified in (a), the distributor's policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives; …
https://www.oeb.ca/oeb/_Documents/Regulatory/Filing_Reqs_Dx_Applications_ch_5.pdf

[58] The OEB Innovation Handbook is a compendium of existing OEB policies and related materials that have already served to support innovative projects and proposals. It serves as a useful reference guide for sector innovators, provides awareness of the OEB's work to date to support innovation and assists utilities in preparing applications that propose innovative approaches to meeting customer or system needs.

> activities also align with the kinds of activities that the OEB's CDM Guidelines contemplate may be funded through distribution rates."[59]

Distributor bids

The price a distributor can pay for capacity in a local energy market—cumulatively—must be cost-effective compared to the alternatives and meet standard just and reasonable regulatory tests. The distributor bid is composed of cost, quantity, and duration.

i) Marginal cost of capacity at a station

The marginal cost of a kilowatt of deferred peak capacity that a distributor ought to be willing to pay for avoided peak capacity at a location would be derived from engineering and costing studies. Distribution system upgrades vary depending on the design. Based on previous involvement in projects, Powerconsumer has seen a range in costs from $375,000/MW to $700,000/MW depending on the upgrades required. Using a 25-year depreciation at 4%, this equates to $15,000/MW-year to $28,000/MW-year as the price to avoid.

A distributor bid price can be calculated by using the price to avoid and dividing by the duration needed to avoid peak capacity. The duration is variable to the capacity need and specific to localities. In absence of known operational constraints and detailed data on system upgrades needed, the project methodology assumed a distributor bid price of $15/kWh[60], constant for the 15 years of simulation (for the quantity and duration specified below). This price is higher than any seller's maximum offer price of $6/kWh.

For comparison, the IESO capacity auction bid price and York Region Non-Wires Alternative project uses approximately $50,000/MW-year, based on 4 dispatches at 4 hours (16 hours total) = $3.125/kWh.

ii) Quantity and duration

The project assumed capacity limits for the distribution system, e.g., in the form of distribution station limits or thermal limits on feeders. For the project, the limit (threshold) was determined based on a target of 10 deployment/activation days (average 55 to 58 hours across 5 localities) per year for the customer. That is, in absence of a known limit per locality, the methodology assumed that the threshold was reached on average 10 days per year, on average between 5.5 hours and 5.8 hours duration during the 2024-2038 period. Participants in the IESO capacity auction historically could expect 3-4 dispatch days for demand response resources; the project methodology increased this amount to provide more simulation results but remain within the tolerance limit of customers. The activation occurred when a customer offer was below the distribution system operator bid.

Customer participation

Electricity customers are bound to terms and conditions for electricity provision. They are largely passive consumers of electricity services. More active customers are focused on cost minimization for their own facility, internal company governance, and (if an IESO market participant) market rules. Customers can also be bound to contracts with a third-party. The local energy market simulated in this project contemplates many sellers (customers) with one buyer (distributor). The sellers actively manage their demand, i.e., respond to activation notifications, and remain net withdrawers from the system.

iii) Alignment with FERC 2222

Local energy markets can enable resources to participate capacity, energy, and ancillary services markets alongside traditional resources. Local markets can aggregate DERs to satisfy minimum size and performance requirements that they might not meet individually. The table below highlights how the local energy market construction and rules in this project support objectives of FERC 2222.

Table 1 Alignment of local energy market simulation with FERC 2222

FERC 2222	**Local energy market simulated**
DERs are located on the distribution system, a distribution subsystem or behind a customer meter. They range from electric storage and intermittent generation to distributed generation, demand response, energy efficiency, thermal storage and electric vehicles and their charging equipment.	Behind the meter demand response via: - DER: natural gas generator - DER: battery energy storage system - Curtailment without DER
Under the new rule, regional grid operators must revise their tariffs to establish DER aggregators as a type of market participant, which would	The participation model is consistent for all DERs, they can submit an offer consisting of price, capacity, and duration, 24 hours in advance of delivery.

[59] OEB Innovation Handbook - p.9 https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/innovation-handbook
[60] Since the local energy market uses a pay-as-bid transaction method any price higher than the seller's maximum offer results in a trade (the distributor bid price could have been set at e.g., $7/kWh).

allow them to register their resources under one or more participation models that accommodate the physical and operational characteristics of those resources	Market optimization considers the physical and operational characteristics of the demand response and makes assumptions on customer parameters to further consider operational characteristics.
Each tariff must set a minimum size requirement for DERs that does not exceed 100 kW	There is no size limitation for participation. The range in size in this project was 60kW-4,000kW.
The tariffs also must address technical considerations such as: • locational requirements for DER aggregations; • bidding parameters; and • information and data requirements.	Five localities chosen are areas where there were natural aggregations of customers. Offer parameters for customers were assumed but detailed based on technical characteristics of DER and characteristic of customer load. The local energy market platform includes front-end display features for the distributor and for the customer, including a customer portal where parameters can be entered.

iv) Customer Screening

Customer data was obtained for large to medium sized customers in Elexicon Energy and Newmarket Tay Power's service areas. The initial customer count of 175 was screened down to 77 by looking at each customer load profile and type and eliminating customers that would not participate in a local energy market, including schools and commercial customers without a DER or reasonable curtailable load. The number and amount of DERs was held constant for 2024-2038.

Table 2 Customers – locality, type, number, size

Locality	Industrial (number)	Industrial (peak kW)	Commercial (number)	Commercial (peak kW)
Belleville	15	23,700	4	4,100
Whitby	2	4,600	4	2,805
Cherrywood	9	8,340	2	1,330
Newmarket Holland	15	7,900	13	4,268
Newmarket Armitage	3	1,350	10	2,570
Total	44	45,890	33	15,073

Table 3 Customer type – number and available capacity

Customer type	Number	kW available[61]
Demand response	70	60-4,000
Natural gas generator	3	2,400
Battery energy storage system	4	15,100

v) Customer Parameterization

The focus on customer preferences and impact on availability in the project addresses an identified research gap in the literature. Most studies and pilots related to local markets revolve around market transaction mechanics while neglecting bid and offer creation, user preferences, strategic bidding, billing, and settlements. Bids and offers should be able to capture the diverse available resources of the users, the predicted user supply and demand, users' preferences in terms of level of comfort. [62]

Hourly load data for 2019-2022 of the 77 customers was analyzed in detail to determine connection by feeder, distribution station, and transmission station. The data was used to determine if customers have a behind-the-meter DERs and determine if the customer is participating in IESO-administered markets (i.e., capacity auction as demand response) and/or the Industrial Conservation Initiative (ICI) program.

In a live local energy market, customers will be able to input their preferences as parameters. In this way, customer parameterization becomes a direct input to the automatic creation of dynamic customer offers (price, quantity, and duration). The figure below shows a screenshot of version 1 of Powerconsumer's customer portal. It is anticipated that changes will be made to make this portal more applicable as it is tested with customers. For the simulation, parameters that could not be inferred from the data (e.g., curtailment unit cost, fatigue factor) were assumed. Detailed modelling of customer load is complex when accounting for customer preferences but is necessary to reveal impacts of competing constraints on customer offers, assets, and customer availability by locality.

[61] For demand response this is the range of kW available (60-4,000kW) of each of the 77 customers providing demand response which varies over the simulation period. Industrial customer capacity is assumed as the forecast demand in an activation hour. Commercial and institutional customers are assumed to participate with HVAC automation only, the potential for which is modelled based on temperature and the forecast demand in an activation hour. For the natural gas generator and BESS customer types, the number in the table is the total amount (sum) of kW available from these resources at any time.

[62] Ibid

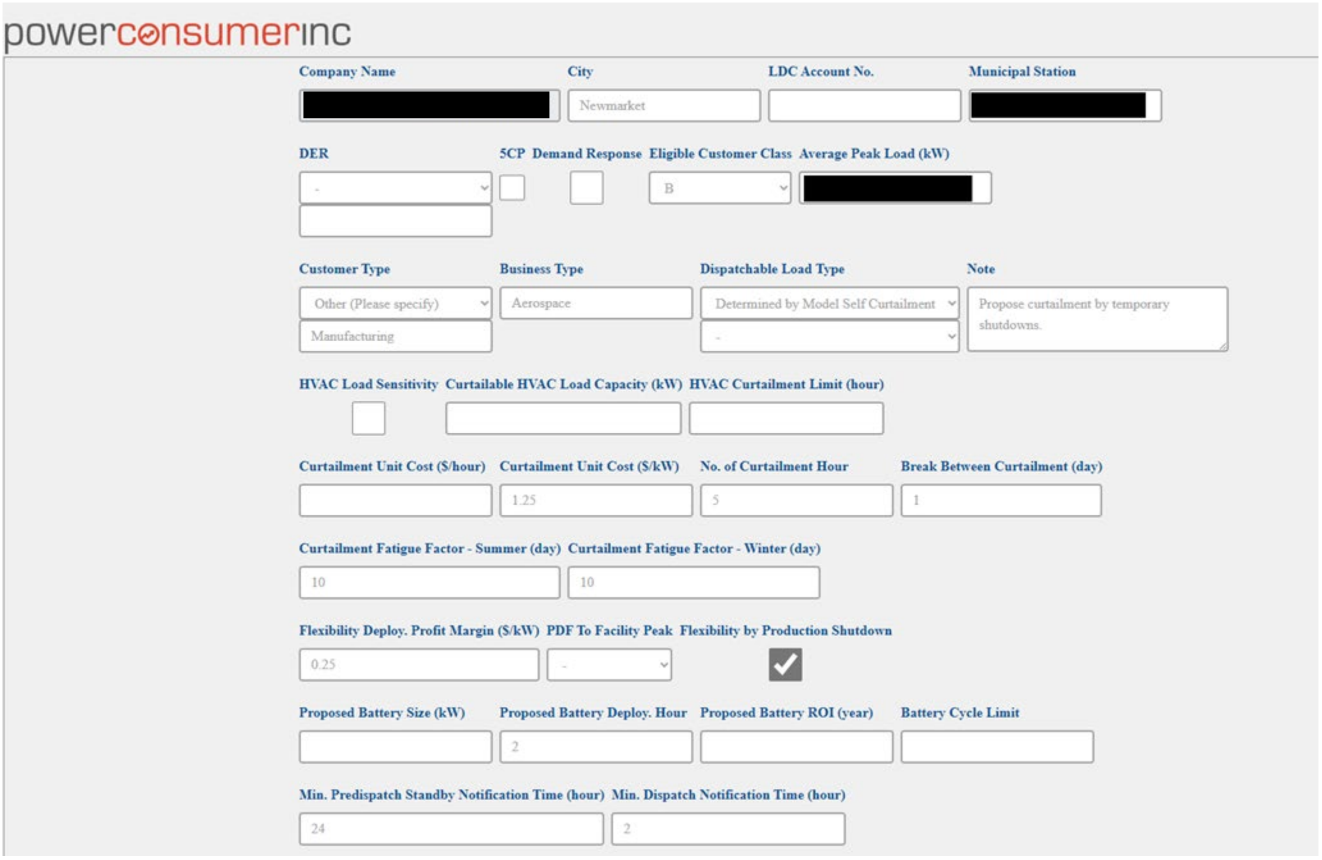


Figure 3 Screenshot of Powerconsumer customer portal detailing customer preferences

Customer offers

Customer parameters were used to construct customer offers which are composed of cost of capacity, quantity, and duration. These offers are providing non-wires alternative solutions to distributor needs.

i) Marginal cost of capacity at a customer site

Different customers face different marginal costs of offering capacity to a local energy market. Customers with a battery energy storage system or natural gas generation asset must operate within specified parameters and support operating priorities. Customers offering demand response have a range of costs to consider including shutdown costs, shift rescheduling, and production loss.

ii) Customer offer components by availability type

There are two types of customers in the simulation: with DERs and without DERs (demand response only). For customers with DER assets, offer components included:

- Asset operating cost ($/kW$_t$)[63]:
- Fuel (natural gas)
- Round trip efficiency of BESS of 85%
- Profit - customer specific

For customers who respond with curtailment, components included:

- Curtailment unit cost - loss of revenue from production ($/kW$_t$)
- Profit – customer specific

[63] kW$_t$ = kilowatts in time, for the simulation t was assumed to equal 1 hour.

iii) Quantity and duration

The quantity that a seller can offer into the market is based on:

- Maximum output of asset (for DERs)
- The remaining power before recharge (for BESSs)
- Actual customer demand at each hour
- Break between curtailments, number of curtailment hours
- Fatigue factors (maximum number of deployments)

The availability of each offer is governed by its start-time and duration. In this simulation, the start-time is every hour except for opt out periods. There are several reasons a customer may want periodically to opt out of a local energy market, including load smoothing (monthly peak 7-7 management), participation in the ICI program, participation in the IESO capacity auction as a demand response resource, asset operating constraints (recharging time, ramp rate, minimum shutdown between operations) and on-site operating priorities. Although the model can consider all factors for opt out periods, only participation in the ICI[64] program and asset operating constraints were used as inputs to the simulation[65].

Transactions

For the purposes of this simulation: bid and offer orders were automated hourly based on real-time customer and distribution system data (data was forecasted hourly); orders were made on a rolling basis, 24 hours of advance of delivery; and orders were cancelled if a placed order violated a constraint(s) because of another cleared trade. A cancellation signal was received from the market optimizer and recorded in a database.

The market mechanism for the local energy market was pay-as-bid; all sellers were paid the price they offered. The pay-as-bid mechanism was selected to maximize the number of sellers and trades.

The transactions shown in the figures below are virtual aggregations of customers offers to fill a specific trade (i.e., to meet a need characterized by a distributor bid). This instance shows the business-as-usual scenario on August 11, 2038, 17:00-18:00, six customer offers totalling 4,066 kW in the Elexicon Ajax/Pickering locality - total trade cost equalling $3,828.

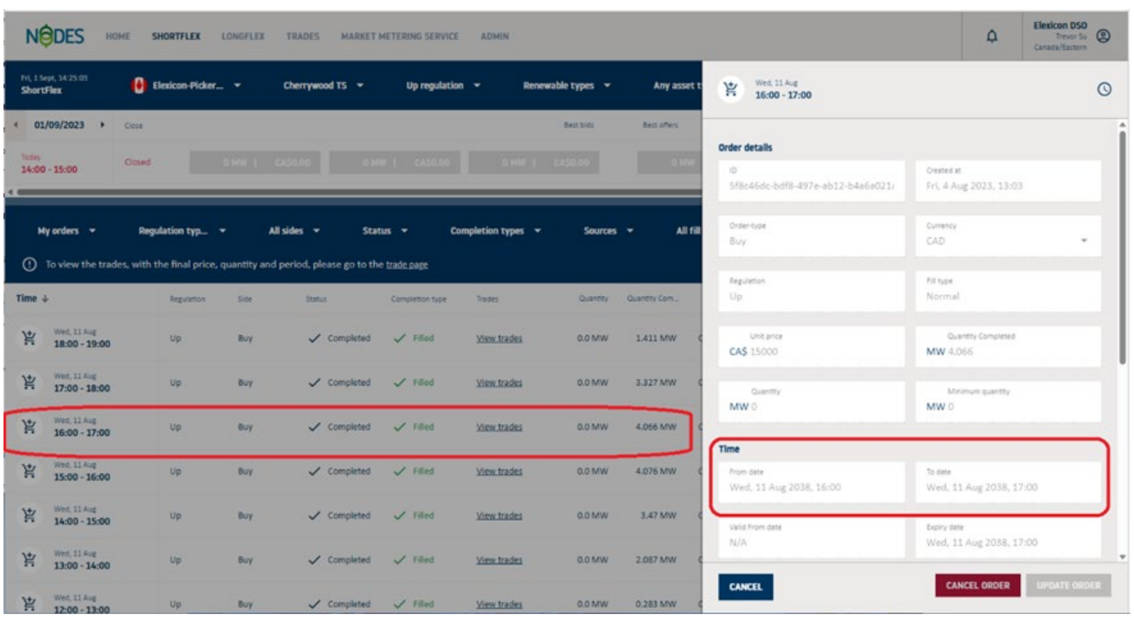
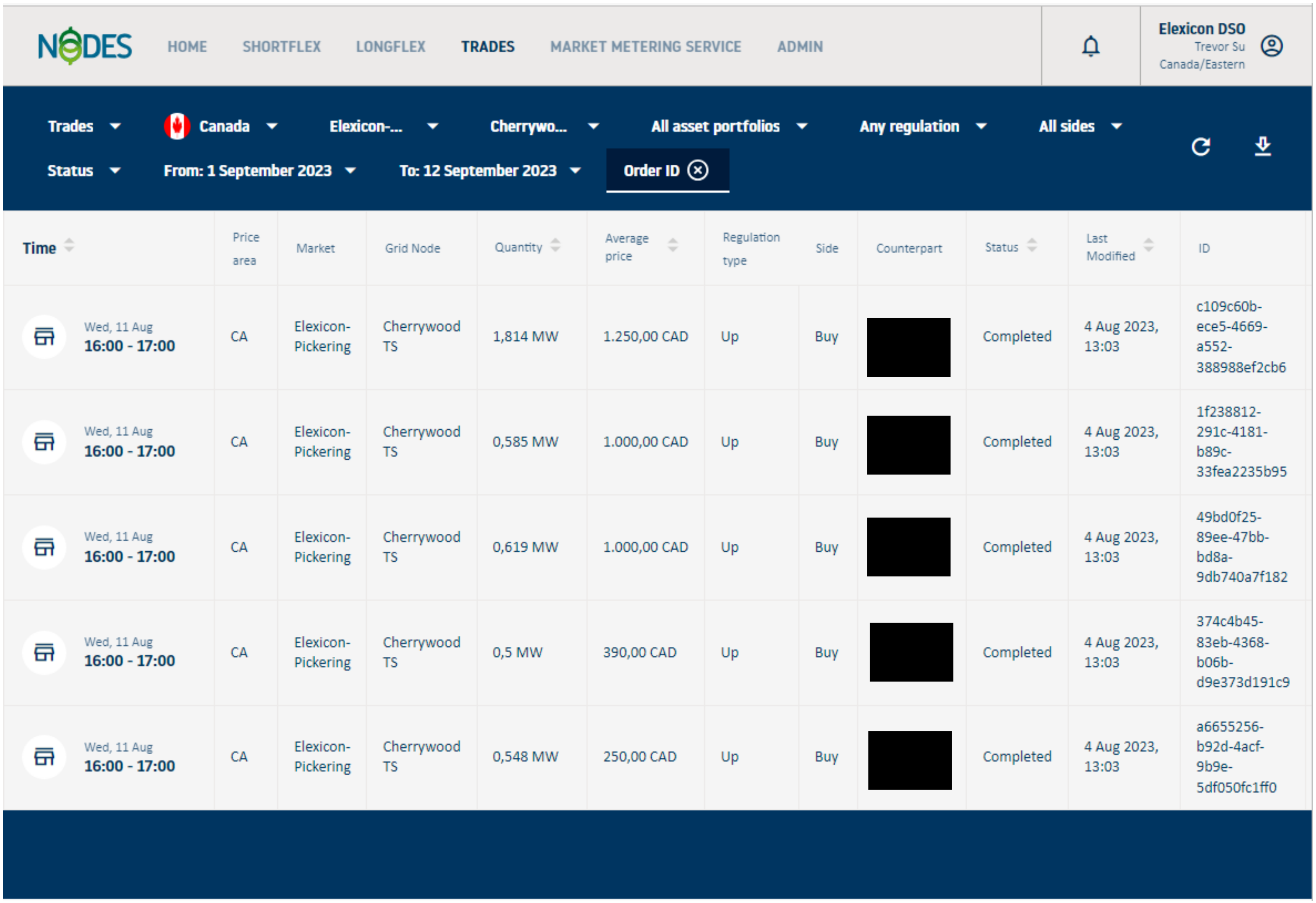


Figure 4 NODES interface showing completed trades

[64] The 2022 peak calls were used to determine the peak day distribution in the summer months: one day in May, four days in June, six days in July and six days in August. The corresponding number of hottest days in each month using Pearson Airport's weather normal as proxy was then selected.
[65] IESO demand response days are random in nature and could not be predicted; 7-7 monthly management and on-site priorities are customer specific) and could not be predicted.



Time	Price area	Market	Grid Node	Quantity	Average price	Regulation type	Side	Counterpart	Status	Last Modified	ID
Wed, 11 Aug 16:00 - 17:00	CA	Elexicon-Pickering	Cherrywood TS	1,814 MW	1.250,00 CAD	Up	Buy	[redacted]	Completed	4 Aug 2023, 13:03	c109c60b-ece5-4669-a552-388988ef2cb6
Wed, 11 Aug 16:00 - 17:00	CA	Elexicon-Pickering	Cherrywood TS	0,585 MW	1.000,00 CAD	Up	Buy	[redacted]	Completed	4 Aug 2023, 13:03	1f238812-291c-4181-b89c-33fea2235b95
Wed, 11 Aug 16:00 - 17:00	CA	Elexicon-Pickering	Cherrywood TS	0,619 MW	1.000,00 CAD	Up	Buy	[redacted]	Completed	4 Aug 2023, 13:03	49bd0f25-89ee-47bb-bd8a-9db740a7f182
Wed, 11 Aug 16:00 - 17:00	CA	Elexicon-Pickering	Cherrywood TS	0,5 MW	390,00 CAD	Up	Buy	[redacted]	Completed	4 Aug 2023, 13:03	374c4b45-83eb-4368-b06b-d9e373d191c9
Wed, 11 Aug 16:00 - 17:00	CA	Elexicon-Pickering	Cherrywood TS	0,548 MW	250,00 CAD	Up	Buy	[redacted]	Completed	4 Aug 2023, 13:03	a6655256-b92d-4acf-9b9e-5df050fc1ff0

Figure 5 NODES interface showing simulated aggregated customer offers that met distributor bids

6. Modelling demand

Hourly demand for 2024-2038 were forecasted for the distributor (NT Power and Elexicon Energy) and for 77 customers. Transactions were then simulated in local energy markets at five localities within the distributor service areas.

Localities

Feeder data represents aggregate customer demand and can be aggregated by station. The station load represents the sum of demand in a geographical area by the sum of feeders supplying customer loads. This approach to the data (see table below) allows for multiple interpretations of the data as aggregations of customer behaviours and patterns within energy geographies.[66] The selection of the final localities (use cases) was based on the number, size and type of potentially participating customers, and the relevance of demand response and DERs to the load profile of a station.

Table 4 Data structure by locality

Locality	Transmission station (sum of distribution feeders)
Belleville	Belleville TS 44 kV
Whitby	Whitby TS DESN2

[66] Hui, Allison and Gordon Walker. 2018. Concept and methodologies for a new relational geography of energy demand: social practice, doing-places and settings. Energy Research and Social Science 36 (2018) 21-29.

Ajax/Pickering	Cherrywood TS
Newmarket north	Holland TS
Newmarket south	Armitage TS

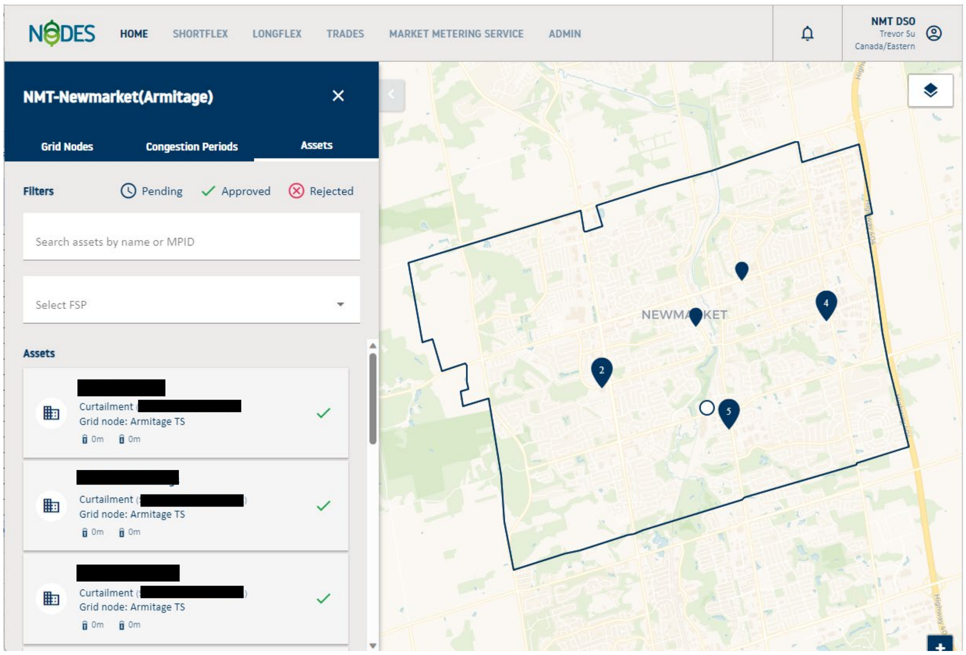


Figure 6 Screenshot of NODES interface showing Newmarket locality and customer clusters

Station demand

For each locality, baseline data from 2019-2021 was used to test how appropriate and useful the approach was to predict future demand at a given locality. Different localities behave differently with the same modelling approach. Some localities are amenable to predictive modelling while others require more analysis of operating conditions.

i) Reference case

The reference case is based on hourly feeder data from 2019 to 2022. The projection for 2024-2038 was based on weather normal data, and calendar days (day of week has an impact demand).

Scenarios were developed to simulate local market transactions in terms of hourly load profiles at 5 localities, 2024-2038 for climate change, and electric vehicles.

ii) Climate change

The reference case forecast uses historical weather for 2019-2022. There is no implicit or explicit modelling of weather normalized against a historical period or trend. Since 2019 to 2023 were typical years overall—from a weather perspective—the forecast assumes implicitly a continuation of this weather on average through the forecast period. To analyze the general impact of climate change on the energy and economic outcomes of the modelling the methodology tested a scenario which increased temperature linearly by a total 1.9 degrees Celsius in 2040.[67]

iii) Electric vehicles

[67] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/trends-variations/spring2023/Climate-Trends-Spring-2023-EN.pdf

Finding value in local energy markets

Government mandates and commitments by automakers indicate only battery and hybrid vehicles will be manufactured after 2030 in most product categories; some manufacturers have commitments to zero emission vehicles in all categories by 2040.[68] In 2022, "… more than half of those surveyed, 52%, who intend to buy a car say they intend to choose either a fully electric, plug-in hybrid or hybrid vehicle."[69]

Population information is available by census division from 2001 to 2021.[70] Projections by census division are available for 2021-2046.[71] The total number of vehicles is expected to continue to grow at a similar rate as population[72].

Vehicle population data is available for Ontario 2016 and prior years by region and vehicle age.[73] Statistics Canada provides data since 2017 for light and medium-duty vehicle registrations.[74] There were 8,872,498 vehicles registered in Ontario in 2021. New car and truck sales were 634,915 in 2022. In 2016, 96.24 percent of active passenger vehicles were newer than 20 years old. 1.952 million new vehicles have been sold in Ontario since 2020 of which approximately 96 percent are gasoline, 2.4 percent are diesel, and 0.67 percent are battery and hybrid vehicles. Information on electric vehicles registered in Ontario in 2023 is available by forward sortation area.[75]

The ratio of battery electric vehicles was applied in a city to the regional total, to estimate the number of vehicles in each city as a fraction of the total number of passenger vehicles in each region. A logistic growth function was assumed to emulate a smooth vector for battery electric vehicles to transition from a small current percentage to a virtual replacement of internal combustion engines by 2040:

$$f(x) = L/(1 + e^{-kx})$$

Where L is the maximum and k is the midway slope of the function, i.e., 0.96 and 0.4 in the model.

The annual numbers were translated into hourly values based on a 2021 study from Institute of Transportation Studies, University of California Davis[76]. The California study used feeder circuit level data in California from Pacific Gas & Electric to measure the capacity of local feeders and modelled the adoption of electric vehicles to simulate the future loading on circuits throughout Northern California. From this information, the (Finding Value GIF) project derived an hourly index for passenger electric vehicle charging and then applied the index to the values in the table above to determine hourly load increase from 2024-2038 at the 5 localities.

Customer demand

The reference case is based on hourly customer data from 2019 to 2022. The hourly demand projections for 2024-2038 was based on weather normal data, and calendar effects.

7. Electricity outcomes

The outcome of the modelling is a series of worksheets with time series forecasts of hourly station demand, summarizing the trades by station, calculating customer bills by month, over time, and comparing business-as-usual to a climate change plus electric vehicle scenario. Thresholds were established to target 10 activation days per year during which to transact to reduce peaks during activation days. The quantities used in the modelling are shown in Table 11.

Table 5 Locality thresholds, activation assumptions and target capacity business as usual

Locality	**Threshold (kW)**	**Activation days per year**	**Activation hours per year**	**Peak capacity (kW)**	**Capacity to be reduced (kW)**

[68] According to S&P Global (https://www.spglobal.com/mobility/en/index.html) Ford: 100% plug-in passenger cars in Europe by 2026 and all BEVs by 2030, Cadillac: 100% EV lineup by 2030, Bentley: 100% carbon neutral EV by 2030,Jeep: 100% plug-in available by 2025, aim for 50% BEV sales in the US and 100% BEV sales in EU by 2030, Chrysler: 100% BEV lineup by 2028, Toyota: 30 EV models and 3.5 million BEV sales by 2030, BMW: 50% share of BEVs in total deliveries by 2030,Stellantis: 70% low emission vehicle (LEV) sales in Europe, 40% in US by 2030,Volvo: 100% BEV by 2030,Subaru: 100% EV by 2030,GM: 100% BEV by 2035,Lexus: 100% EV by 2035,Kia: 100% EV lineup in Europe by 2030 and globally by 2035,Land Rover: 60% BEV by 2030 and 100% by 2035,Mercedes-Benz: no ICEs in major markets by 2035 and globally by 2040; carbon neutrality by 2039,Honda: 40% BEVs and fuel cell vehicles in major markets by 2030, 80% by 2035, and 100% globally by 2040,JLR: net-zero across supply chain by 2039, GM: carbon neutrality by 2040, Volvo: carbon neutrality by 2040

[69] Ernst & Young Mobility Consumer Index. 2022. https://www.ey.com/en_gl/automotive-transportation/mobility-consumer-index-wave-3

[70] Statistics Canada. 2021. Census of population. https://www150.statcan.gc.ca/n1/en/type/data?MM=1#tables

[71] https://data.ontario.ca/dataset/population-projections

[72] https://www.ey.com/en_gl/automotive-transportation/mobility-consumer-index-wave-3

[73] https://data.ontario.ca/dataset/vehicle-population-data

[74] https://www150.statcan.gc.ca/n1/pub/71-607-x/71-607-x2022023-eng.htm

[75] https://data.ontario.ca/dataset/electric-vehicles-in-ontario-by-forward-sortation-area

[76] Alan Jenn and Jake Highleyman, *Distribution grid impacts of electric vehicles: A California case study,* iScience, January 2022.

Belleville	47,500	10	51	50,206	2,706
Whitby	73,000	10	48	82,198	9,198
Ajax/Pickering	131,000	10	58	140,864	9,864
Newmarket Holland	55,400	10	44	58,527	3,127
Newmarket Armitage	66,700	10	58	76,138	9,438
Total	373,600	n/a	n/a	407,934	34,334

Business as usual

The modeled outcomes are dependent on the modeling methodology, described in this report, and the validity of the input assumptions. An objective of the project was to develop a software modelling platform that could solve for transactions in local energy markets. This objective has been achieved but is based on the assumptions made in the process, all of which would need to be properly validated before drawing conclusions as to the absolute values.

The business-as-usual scenario uses hourly data from 2019 to 2022 to establish a reference case profile at a station, based on the sum of relevant feeder loads. There is no trend in the model. The variability arises from calendar effects like day of week, hour of day, holidays, and weekends, which change by date from year to year.

Table 6 Business as usual trading outcomes by locality

Trading Outcomes	Belleville	Whitby	Cherrywood	Holland	Armitage
Before peak kW	50,206	82,198	140,864	58,527	76,138
After peak kW	47,502	81,698	140,037	55,401	76,138
Reduction on peak	2,704	500	827	3,126	-
Before average kW	48,179	75,970	134,229	56,417	69,548
After average kW	47,500	74,536	132,327	55,401	68,865
Average reduction	679	1,434	1,902	1,902	683
Total kWh reduced	535,570	1,048,163	1,681,249	673,170	602,714
Average unfilled kW	-	1,535	1,327	-	2,165
Max unfilled kW	-	8,698	9,036	-	9,438
Average bid kW	679	2,969	3,229	1,017	2,848
Max bid kW	2,706	9,198	9,863	3,126	9,438
Total unfilled kWh	-	1,122,387	1,172,933	-	1,911,691
Battery energy storage systems	$ 98,210	$ -	$ -	$ -	$ -
Gas Generators	$ 26,700	$ 124,378	$ 150,244	$ 212,023	$ -
Curtailment	$ 63,738	$ 793,817	$ 1,397,071	$ 59,936	$ 718,533
Total	$ 188,648	$ 918,194	$ 1,547,315	$ 271,959	$ 718,533
$/kw_max	$ 69.76	$ 1,836.39	$ 1,871.68	$ 87.00	-
$/kW_avg	$ 277.92	$ 640.36	$ 813.58	$ 143.00	$ 1,052.68
$/kWh	$ 0.35	$ 0.88	$ 0.92	$ 0.40	$ 10.43
Number of customers	19	6	11	28	13

Trading delivered maximum peak reductions at each station except Armitage, but even at Armitage average demand was down during the top 10 activation days and hours. Unfilled kW represents unmet distributor bids, either because there are no sellers at the bid price, or potential sellers are constrained from being activated. Belleville and Holland represent larger participating customer pools which enables all bids to be filled.

Trading resulted in different revenues (net bill impacts) to customers and different costs to distributors. The difference in load shape during peak at each locality drives the determination of activation price, timing, and duration. A flatter peak, for example, requires more hours of curtailment than a sharp peak. Variability in customer demand similarly can affect offer price and duration among customers. The dollar estimates of cost are indicative and highly sensitive to input assumptions related to price and quantity offered.

Impact of climate change and electric vehicles

Assumptions about climate change and electric vehicles both introduce trend to the station demand modelling. These trends are assumed to have no effect on participating customer demand.

The long-run effect of climate change is assumed to follow a general linear trend over the forecast period, corresponding to long-term modelling undertaken by the Government of Canada[77]. As a result, the impact of adding this trend variable is slight, leading to modest variations, i.e., milder weather conditions in fall, winter and spring, and warmer conditions in summer.

The effect of electric vehicles is assumed to be significant and as a result is evident at every station. Higher station demand increases the frequency and duration of peak events. Activation constraints mean that resources remain available only for 10 activations per year and are subject to the same limits for duration. The model reflects the higher station demand with higher bid quantities during the activation days, clearing more customer offers, and resulting in more trades.

Belleville is distinct from the other four localities in showing negative sums of kW traded. These amounts are not traded *per se* but reflect recharging quantities of the four battery energy storage systems in the Belleville locality.

In Pickering/Ajax the growth of station demand as an impact of climate change and EVs results in a change in trading patterns as more hours are selected for activation but peak volumes available are lower.

Higher station demand at Holland leads to higher frequency and duration and higher peak trading volumes.

8. Customer bills

Projections of the cost of delivered power to customers are based on the IESO Annual Planning Outlook to 2040, incorporating known and planned changes to capacity, fuel prices, carbon taxes and inclusive of the impact of the Hourly Ontario Energy Price and the monthly Global Adjustment, transmission costs and distribution costs are assumed to be static, or, in other words, to rise at a rate consistent with inflation and therefore able to be expressed in nominal 2024 dollars. Because modelling outcomes are presented in terms of customer bills, inclusive of tariffs for a customer, changes in trends and tariffs for a customer or customer class would be modelled as separate scenarios.

Monthly bills are calculated for each customer through the forecast period without trading and with trading in the business-as-usual scenario and the climate change plus electric vehicles scenario.

Bill impacts and carbon emissions

Targeting station peaks with curtailment results in lower bills and lower carbon emissions associated with customer electricity demand. Activating gas-fired generators results in higher local emissions which are partially offset by lower system emissions.

Net bill impacts are positive. Customers that experience zero effect are those that are not activated for their offer price. Positive bill impacts are significantly increased in the 2038 scenario with climate change and electric vehicles.

9. Other system benefits

The data modelling is based on aggregated historical hourly 44kV feeder data for 2019 to 2022 for transmission/distribution station service areas within which the markets are simulated. The discussion of distribution system benefits is constrained by that data and all the inferences subsequently are drawn from the analyses that were used in constructing the simulations.

Reliability

There were no interruptions evident in the baseline data set for NT Power and Elexicon Energy. The distribution sides of the stations operate at 44 kV. Elexicon reports[78] for the LDC as a whole, the Average Number of Hours that Power to a Customer is Interrupted as 1.71 hours and the Average Number of Times that Power to a Customer is Interrupted as 1.19 times in 2022. Comparable system-side statistics for NT Power[79] are 1.56 hours and 0.68 times in 2022. This could mean that all of the incidents reported as part of the indices

[77] https://www.canada.ca/en/environment-climate-change/services/climate-change/canadian-centre-climate-services/basics/scenario-models.html
[78] https://elexiconenergy.com/files/2023/09/Elexicon-Energy-2022-Scorecard.pdf
[79] https://www.oeb.ca/documents/scorecard/2022/Scorecard%20-%20Newmarket-Tay%20Power%20Distribution%20Ltd..pdf

occurred at low voltage, at the customer end of the system, rather than the transmission end, to explain why none appeared in the data used.

Distribution outage events are stochastic, triggered by factors exogenous to the model (like wildlife encounters, storms, and human activity), and because they are intrinsic to the overhead nature of the infrastructure, are highly locally specific, typically subsumed at the scale of aggregation modelled in the simulation. One conclusion of the project is that the presence or absence of a local market—as it has been simulated—has no effect on interruption frequency or duration. Maintaining the grid in real time is necessary for a local market to operate; when the grid is down the market cannot function. The local energy market is complementary to the bulk energy market; it is not a substitute provider of reliability.

Where there are energy storage systems or generators, those assets primarily are purposed for emergency standby and backup, secondarily for load management during system critical peaks, and are available for activation in a local energy market only when not otherwise committed. During an emergency event in which grid supply is lost, individual generators and batteries will operate in an islanded state, not connected to the grid, and will provide reliability and resilience services exclusively to the host customer site. Interconnecting more generators and batteries behind customer meters can improve reliability and resilience for those customers that make the investments but generally will not affect reliability and resilience for other customers connected to the same system when the grid is down.

Resource adequacy is a measure of bulk system reliability.[80] Local energy markets can enhance resource adequacy, which we estimate in the simulation as the offer capacity in each hour of the customers in each market. This storage, generation, and demand response capacity is presumed to be existing but latent, unused, until it is activated in a local energy market. Aggregated distribution station peak reductions will contribute to lower transmission station and energy system peaks generally.

Resilience

Resilience is a term whose meaning continues to evolve, but for our purposes can be defined as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions."[81]

Resilience benefits "are fundamentally localized, and community- and customer-level metrics are necessary to identify cost effective resilience investments by utilities and customers".[82] The data set used for the simulation shows continuity of supply for 2019 to 2022 at these locations on the distribution system which could mean that there were no sufficiently disruptive events or incidents which the system could not withstand.

10. Project learnings

The project resulted in an integrated software platform environment comprising components developed and provided by Powerconsumer and NODES to simulate transactions between Elexicon Energy and NT Power and their customers. An important project outcome was to collect learnings from the simulation to inform the feasibility of local energy markets as a tool for distributors to procure non-wires alternatives. The project allows detailed customer parameterization that can be converted to customer offers. Distributors can view participating customers and customers' offers, submit bids, and track transactions. The integrated platform can simulate local energy markets and transact in a live environment. Results and learnings from the project support ongoing sector development, specifically: distributor needs determination and planning integration, distributor functionality determination and readiness, distribution system value, and tools for customer engagement in the energy transition.

Distributor business models for DER integration

The project undertook a comprehensive review of planning documents for the relevant service areas to identify a common element of need. The common need was determined to be ensuring the distribution system has the capacity to deliver peak energy in the system. Transmission and distribution investments are driven by peak demand on elements of the system. This led to the project focus on simulating transactions that lowered peak demand.

A barrier for Ontario distributors to integrate DERs (through market participation) is a detailed understanding of the costs of the non-wires alternative (i.e., the non-wires solution) presented by DERs and a way to compare costs to the traditional solution, i.e., distribution station upgrades.

[80] https://www.npcc.org/program-areas/rapa/resource-adequacy
[81] Juan Pablo Carvallo, N. M. Frick, L. Schwartz. A review of examples and opportunities to quantify the grid reliability and resilience impacts of energy efficiency. Energy Policy 169 (2022) 113185.
[82] https://energystorage.pnnl.gov/pdf/PNNL-29738.pdf

Finding value in local energy markets

Distributors convey electricity by building infrastructure. The buying/bid logic for a distributor must have a capacity component so that it can be compared to the traditional solution capacity costs. The number of times and event duration for which the DERs must be activated is a key piece of information that drives the cost of the non-wires DER alternative. This information is critical to allow for comparing of costs and will form the business case for distributor to use DER to solve system needs. More granular information from advanced distribution management systems will allow for more accurate and closer to real-time costing and price signals for customers.

Bidding parameters to meet distribution system requirements

The project developed a detailed distributor bid logic for the purpose of setting price and targeting the quantity and duration of bid events to maximize trades and bill savings to customers within an activation limit of 10 days per year.

Customer business model for DER participation.

The project considered customer participation with behind-the-meter gas-fired generators, battery energy storage systems, and demand response from HVAC curtailment or production scheduling where there were no DERs. The project included commercial and industrial customer participation of 60 kW – 4,000 kW, and included participation models, registration criteria, and offer parameters to meet customer needs.

The project developed a registration portal with parameters for customers to self-identify constraints that would affect their ability to deliver capacity to the energy system on peak. These inputs inform the customer offer. For the simulation these values were assumed. In practice, in a pay-as-bid model, the customer offers form the cost of the non-wires alternative solution. Validation of these assumptions is the next step to better understand costs. The local energy market transacted on rolling 24-hour bids, that were locked in 2 hours prior to delivery. There is no corresponding capacity auction. In theory a dynamic customer driven commitment window should enable more customers – this needs to be validated with customers in a test or live setting.

Distributor-IESO interoperability

Customer offers factored in opt-out periods when a customer would be participating in IESO programs, as in a Dual Participation model.

The project modeled an energy market entirely located within distribution system service areas and on distribution system assets. The local energy market simulated in this project is envisioned to be an independent marketplace software solution that could be licensed by a distributor, workable in both distributor-IESO participation models currently being contemplated by the IESO (Total DSO and Dual Participation).

Powerconsumer has a cloud-based infrastructure that allows secure and robust machine-to-machine data interchange with partners and customers via APIs. This environment allows for real-time bi-directional analytics and data communication at will.

Given the data interchange capabilities, any real time local energy market transaction data such as capacity volume/size, time, and duration can be made available to the IESO 24-hours in advance based on the current 24-hour look ahead optimization scheme. The timing might vary depending on the evolution of future market operating constructs. Price can be omitted as private information. Sharing information with the IESO will need to be agreed upon between a local market operator, distributor, and the IESO.

Distributor functionality and technology requirements

There are two basic components to the distributor's participation in the local energy market: (1) to be the buyer of capacity/non-wires alternative; and (2) to be the settlement and billing entity for customers.

The buying role is informed by planning and engineering; once a need can be identified and costed, a local energy market simulation can act as a pre-feasibility to understand if customer sited DERs can provide a cost-effective non-wires alternative solution. A local energy market can be implemented by a distributor, in partnership with technology providers. The settlement and billing functions are a combination of software, hardware, and business systems and were out of scope for this project.

Distribution System Benefits

The premise of the simulation is that transactions take place only where distribution benefits arise, in other words where the customer offer price is lower than the distributor bid price. The simulation calculated the range of net bill impacts to customers for each of the use cases and estimated the cost of capacity for the distributors. The presumption is that the cost of transactions is lower than the bid or buying price of the distributor, otherwise the transaction would not take place.

Addressing barriers of expanded DER participation in local energy markets

The principal barrier for expanded customer participation in local energy markets is cost of entry for customers, both in terms of direct costs to customers involved in supporting business decision-making in a local energy market, and costs to the distributor to recruit and engage customers. The project developed a platform to simplify this with the customer portal with parameters for customers to self report constraints. The intent is to reduce transaction costs that are related to asymmetries of information or absence of economic information altogether.

The expectation is not for customers “to pay” but that they bear costs related to transacting with a distributor. These opportunity costs relate to the time and effort of information gathering and validation to inform internal business processes for decision-making. Similarly, distributors are expected to bear costs related to transacting with customers. The actual costs to customers and to distributors is an important empirical question. A key hypothesis of platform models in general, and local energy markets in particular, is that they can reduce transaction costs to customers and distributors by enabling standardized transactions in an open market environment.

For distributors the challenge of increasing customer participation can be approached from a planning and engineering integration perspective and from a meter to cash settlement and billing perspective. Both functions need to operate to facilitate an active buying role for the distributor, a way of appropriately compensating participating customers, and a way of reconciling market outcomes against expectations.

Perfect markets are assumed to have several attributes including perfect information and free entry and exit. In perfect markets, trade is frictionless, i.e., there are no transaction costs.

Information needed by customers and distributors both is missing and where it exists it is asymmetrical—different information is held in different places—between/inside the distributor, expressed in different ways, and often not translatable to operational business terms that are useful to typical customers operating industrial plants or managing buildings and facilities. The potential of a local energy market is to aggregate this diffuse knowledge in a local marketplace that provides useful and translatable information about benefits and costs of participating. The market itself creates new knowledge.

There are costs of entry to a distributor associated with marketing and outreach to customers to attract and retain interest, to register customers, and to encourage active participation. These costs include direct marketing costs, key account management activities, potentially including site visits and meetings with each customer that participates. These costs scale by customer, not by kilowatt; recruiting kilowatts from small customers is relatively more expensive on a per-customer basis. The platform is intended to simplify and automate this process for distributors and customers with online recruitment and parameterization, and tools for automated customer relationship management. The customer registration portal is intended to simplify the process for customers with a single window interface that walks through the parameters in basic terms and allows customers to make informed decisions based on an expert system.

Customer analytics reduce the cost and risk of customer recruitment to distributors by targeting the most likely and most cost-effective potential customers and developing a customized strategy to support each customer’s journey to becoming an active market participant.