The Value of Using DERs for Distribution System Services in Ontario

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1. Background

Ontario expects robust electricity growth into the next decade and beyond

Over the next 25 years, Ontario's electricity demand is expected to ramp up significantly due to economic growth, electrification, and evolving technologies.

- Ontario's system-level **net annual energy demand** is projected to rise from **157 TWh (2026) to 250 TWh (2050)**, implying a compound annual growth rate (CAGR) of ~2% over 2026–2050.
- Over the same time frame, the **summer peak** is expected to grow at 1.5% CAGR, from **24 GW to 35 GW (2050)** and the winter peak is expected to grow at 1.8% CAGR from 23 GW to 35 GW.

The IESO is planning to build a significant amount of new generation and supply infrastructure to meet this demand and invest $10.9 billion into its electricity demand side management programs (eDSM) over the next decade to mitigate the pace of load growth.

- These programs include energy efficiency, demand response, behind the meter solar and storage, and targeted beneficial electrification.

These distributed energy resources (DERs) help reduce the bulk system peak and enable integration of renewable resources through flexibility. If these DERs can be optimized to mitigate transmission and distribution constraints, they can provide additional value by helping defer wires investments as non-wires solutions (NWS).

Source: IESO Annual Planning Outlook- 2026 Demand Forecasts & 2027 Demand Scenario, November 2025.

Ontario has significant DER growth potential

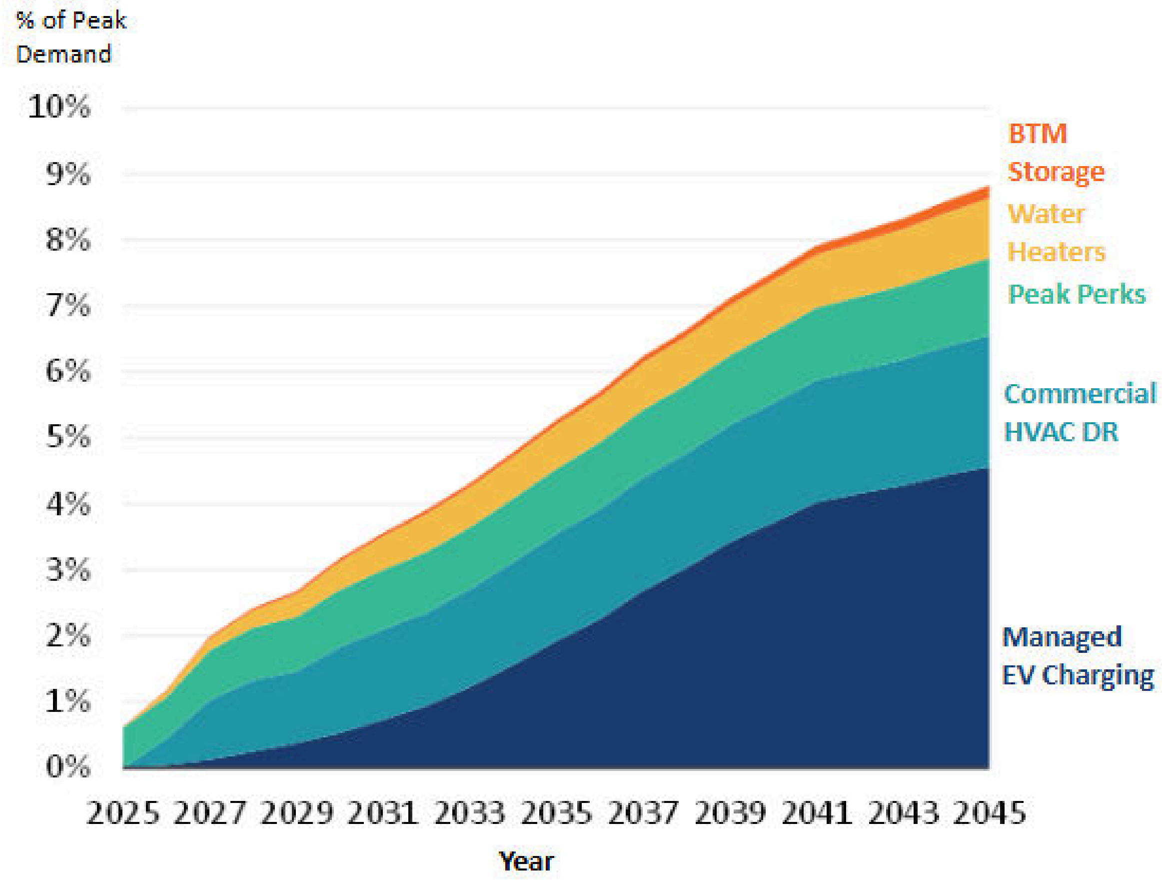
Based on Brattle projections, Ontario DERs could account for approximately 5 percent of peak demand (~1,500 MW) by 2035 and about 9 percent (~3,000 MW) by 2045*

Near-term growth is expected to come primarily from Peak Perks (smart thermostat program) and commercial HVAC DR opportunities, while managed EV charging is projected to expand rapidly in the 2030s.

Battery storage represents a relatively small share of DER potential, largely due to the limited customer base that forms the starting point of projections.

This outlook indicates that DERs can become a material and scalable resource in Ontario, especially when supported with compensation mechanisms that would allow them to stack value for different services they can provide.

TOTAL ACHIEVABLE DER POTENTIAL PROJECTION (2025-2045)



Source: Brattle (2026)

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*These projections exclude the contribution of Industrial Conservation Initiative (ICI) resources as they are already deployed during system peak hours to reduce ICI participants' Global Adjustment charges

Motivation and Framework for This Study

DER adoption has been steadily growing in Ontario, but their main use case has been to provide bulk system services (wholesale energy and capacity).

While there are various DER programs and participation mechanisms in Ontario to provide wholesale services, there are not many programs or mechanisms that utilize and compensate DERs for distribution grid services.

The Ontario Energy Board (OEB) recently took a number of steps to integrate cost-effective NWS into distribution planning processes, but implementation has been slow. This may be partly because the magnitude of the distribution value of DERs is not well understood.

This study is intended to address this gap by quantifying the potential distribution investment deferral value of DERs in Ontario, using data from the Essex Powerlines (EPL) system to illustrate this DER use case.

The study uses assumptions derived from the EPL illustration to estimate the potential value at the province level if/when NWS can be deployed at a wider scale. This value can help keep rising electricity costs in check as Ontario meets increasing demand.

Controlling and dispatching DERs to mitigate distribution grid constraints is likely to require LDC investments in DERMS and/or partnership with third-party aggregators supported by enabling regulatory models.

2. Illustrative Use Case on the Essex Powerlines System

An Illustrative Ontario Use Case

This section is focused on modeling done using data from the Essex Powerlines (EPL) system and illustrates how distribution capacity expansion investments can be cost-effectively deferred by using DERs to provide distribution grid services.

We assessed **11 distribution feeders serving the EPL system** and used Brattle's ***DEFER*** **model to determine the cost-optimal deployment and dispatch of DERs needed to defer feeder upgrades** under a variety of potential future scenarios.

This analysis is not intended to represent a plan specific to the EPL system, but rather an illustrative application of non-wire solutions covering a **range of feeder characteristics and load growth scenarios** that could also be applicable across Ontario LDCs. We use **real-world hourly load profiles** and load forecasts to ensure our scenarios are realistic, and run **several cases for available hosting capacity and load growth rates** to facilitate generalizable insights.

As in distribution planning processes, **we compare the cost of using a DER solution to address an expected overload to that of a traditional wires solution**. Across all cases, we assume that the traditional wires solution would be a new 18-MVA feeder with a cost of CAD $2 million, going into service in the first year that the feeder's peak load exceeds its asset limit.

CAVEATS

Wires solution cost: Costs can vary widely depending on the solution, location, and other project-specific characteristics. This study assumes a wires solution cost of CAD $2 million across all feeders for simplicity; cost-effectiveness of NWS can vary widely based on the wires solution's cost.

Scope of deferral opportunity: While this study considers only distribution feeders for illustrative purposes, DERs can be used to alleviate constraints across the T&D system at multiple levels of the grid, including substations.

Residential DERs only: Given that EPL serves mostly residential customers, we only considered residential BTM DERs. In the broader Ontario context, commercial and industrial (C&I) customers also offer opportunities for demand response at the distribution level, often with the capacity for larger per-customer load reductions. Accounting for C&I DER deployment could create additional cost-effective deferral opportunities.

DER costs: We optimize the NWS using the utility cost perspective. Utility costs for deployment of each DER as part of an NWS are based on the "missing money" needed to cover the cost of a DER after accounting for its bulk system value. We assume customers are willing to cover 40% of the cost of a BTM battery due to the value of onsite backup power.

ILLUSTRATIVE USE CASE

Using Brattle's DEFER Model to Design Non-Wire Solutions

The DEFER model simulates optimal deployment and hourly dispatch of DERs over a 20-year time horizon to defer distribution upgrades, while accounting for asset limits, DER technical limitations, and DER deployment constraints

DEFER is a mixed-integer linear programming (MILP) model that determines the cost-minimizing mix of DERs that defers a grid upgrade for the most economic number of years, based on detailed hourly dispatch logic.

In addition to upfront DER cost, **DEFER** considers the savings that DERs offer to the bulk power system when determining the net cost of DER deployment.

This study considered five residential DER technologies:

- Smart thermostats
- EV managed charging
- Grid-interactive water heaters
- BTM batteries
- BTM solar

Overview of DEFER Model

Inputs

Feeder Load Forecast
Forecasts of hourly load on grid asset

Feeder & Upgrade Parameters
Current asset limits, cost and additional capacity of upgrade

Financial & Scenario Inputs
Discount rate, study time horizon

DER Cost & Operational Params
Net DER cost (utility incentive payment minus lifetime benefits); technology-specific constraints

DER Deployment Limits
Total DER potential in the location and max. annual rate of deployment

Optimization Engine

Objective:
Minimize NPV of Net DER Cost + Grid Upgrade Cost

MILP Optimization

Decision Variables:
- ☐ DER deployment & dispatch
- ☐ Number of deferral years

Constraints:
- ✓ Load limit of asset
- ✓ DER operational constraints (events per year, SOC, load-building, etc.)
- ✓ DER deployment limits

Outputs

Optimal Deferral Length
Determines the year to upgrade that minimizes total net cost; Builds upgrade in first overload year if no cost-effective NWS exists

Cost-Effective DER Deployment
Annual deployment of each DER required for NWS; deploys ahead of need as necessary

Optimized DER Dispatch
Detailed dispatch of each DER technology to ensure load constraints are met in each hour, while respecting operational constraints of each technology

ILLUSTRATIVE USE CASE

Overview of the Essex Powerlines (EPL) System

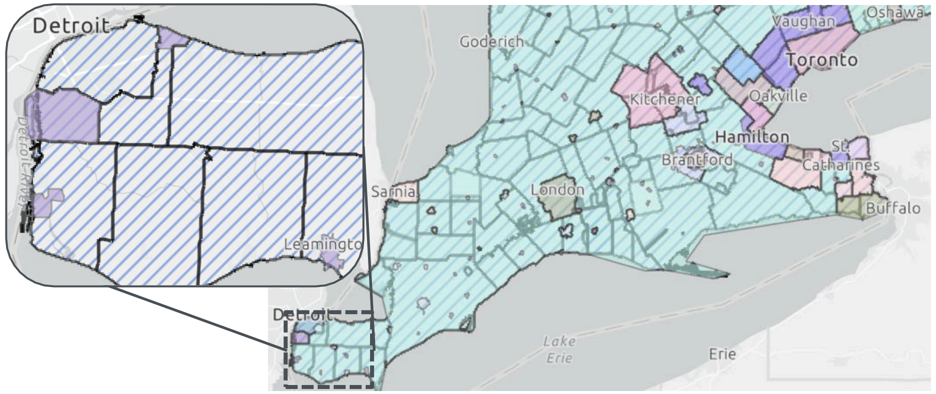
Essex Powerlines (EPL) is an LDC in southern-Ontario serving about 32,000 customers. This study analyzes the potential for DERs to defer upgrades to the 11 feeders serving EPL's system.

EPL's service territory (shown below) covers pockets of the wider West Essex-Windsor and Leamington-Kingsville sub-systems, primarily serving the Municipality of Leamington and the towns of Tecumseh, Amherstburg, and LaSalle.

EPL's system is comprised of 11 distribution feeders supplied by four substations owned by Hydro One Transmission. As an "embedded LDC", EPL does not own these feeders—rather, the feeders are owned by Hydro One Distribution, with EPL reserving a share of feeder capacity to serve its customers.

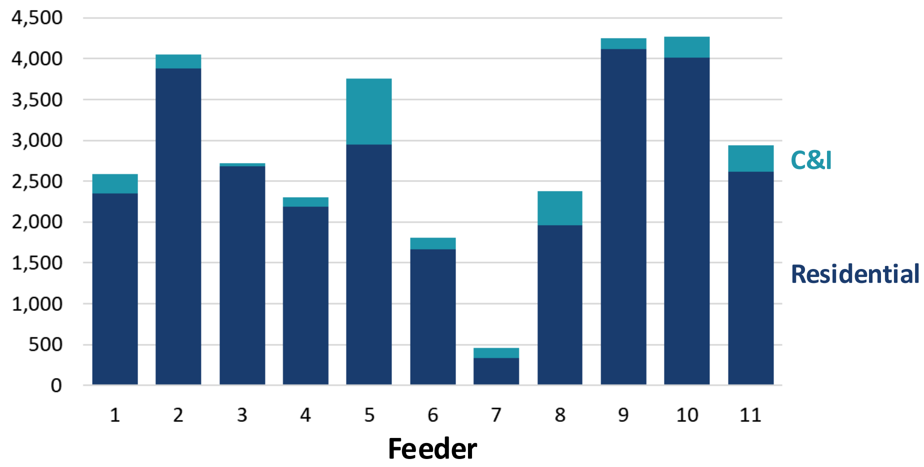
For this study, EPL provided The Brattle Group with hourly load data for its portion of the feeders. As shown in the figure to the right, EPL's customers are predominantly residential. Based on the provided data and estimates of load growth (next slide), we conducted a separate analysis for each feeder, considering only residential DERs.

Essex Power Lines Service Territory



Source: Ontario Electricity and Natural Gas Utilities – Service Area Map (2025).
EPL territory denoted by purple shading in inset map.

Customer Count by Feeder



Note: EPL added a twelfth feeder to their system after the beginning of the study period. This feeder is not considered in the study.

Load Growth Projections for the EPL System

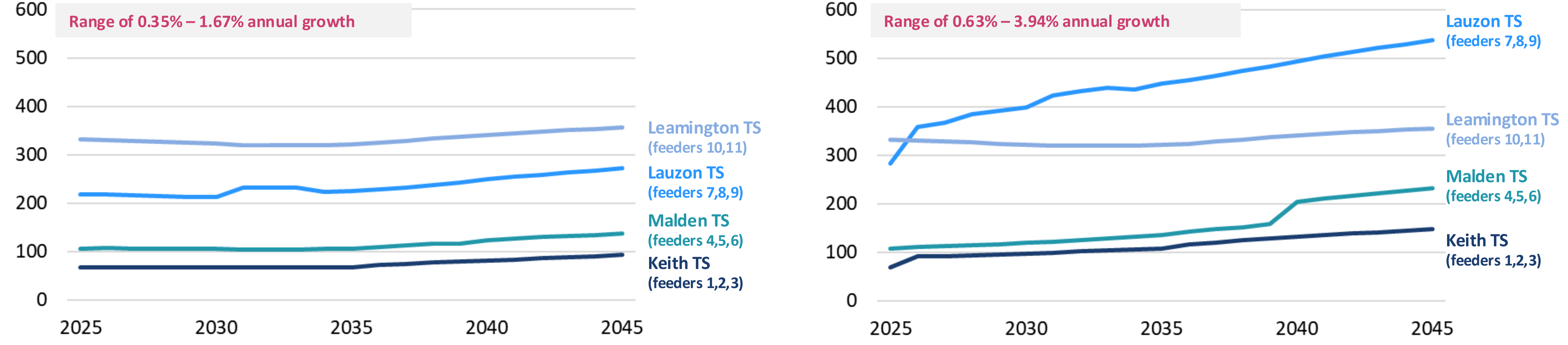
Using substation load growth forecasts from Hydro One's Regional Infrastructure Plan (RIP), we modeled the load on each feeder for 2026–2045 under Reference and High Growth Scenarios.

The RIP provided forecasted non-coincident peaks for summer and winter months for the following two cases:

- **Reference Case Forecast:** based on firm load commitments, organic growth, electrification, community energy plans and industrial greenhouse growth
- **High Case Forecast:** assumes accelerated electrification, higher growth in the agricultural sector and potential additional residential and commercial development

While EPL's feeders were all summer-peaking in 2024, some are projected to become winter peaking in the future. Forecasts of annual peak across both seasons are shown below.

Peak Load Forecasts Applied To The 11 Feeders



Reference Case – *Annual non-coincident peak MW*

High Case – *Annual non-coincident peak MW*

Sources and Notes: Hydro One, Windsor – Essex Regional Infrastructure Plan Report (Oct 25, 2025). 2044 and 2045 Substation peak load forecasted using 2042–2043 growth rates.

ILLUSTRATIVE USE CASE

Feeder Capacity Headroom Scenarios

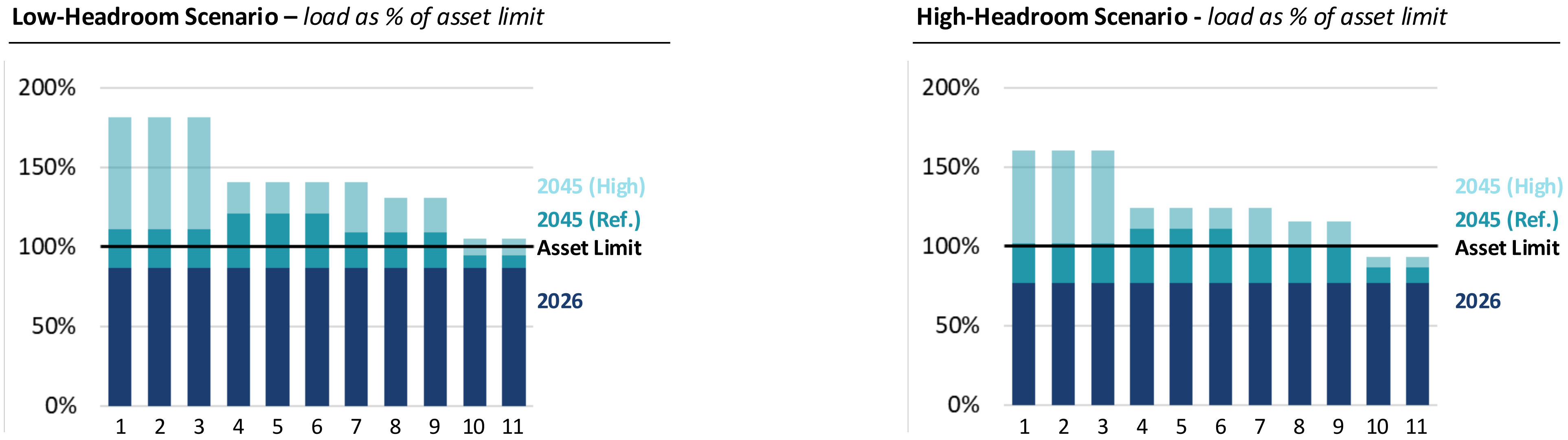
In addition to two load growth scenarios, we considered two capacity headroom scenarios for each feeder as the 2026 starting point.

Since EPL is an embedded LDC, the assigned capacity of each feeder (i.e., the capacity "reserved" for EPL) does not necessarily reflect the asset's physical capacity limit. In lieu of data on these limits and other non-EPL loads, we developed "Low-Headroom" and "High-Headroom" scenarios for each feeder.

- **Low-Headroom Scenario:** We assumed that feeders had spare capacity to support 15% load growth above the 2026 peak.
- **High-Headroom Scenario:** We assumed that feeders had spare capacity to support 25-30% load growth above the 2026 peak under Reference and High Growth scenarios, respectively.

The figure below shows the extent to which asset limits for each feeder are exceeded by 2045, under Low- and High-Headroom scenarios and Reference- and High-Growth scenarios.

Forecasted Peak Load Relative to Asset Limit, by Feeder



Low-Headroom Scenario – *load as % of asset limit*

High-Headroom Scenario - *load as % of asset limit*

Notes: Each bar represents a feeder. 2026 and 2045 peak load are shown as a percentage of each feeder's asset limit.

ILLUSTRATIVE USE CASE

Feeder 9: Characterization of Load Relief Needs

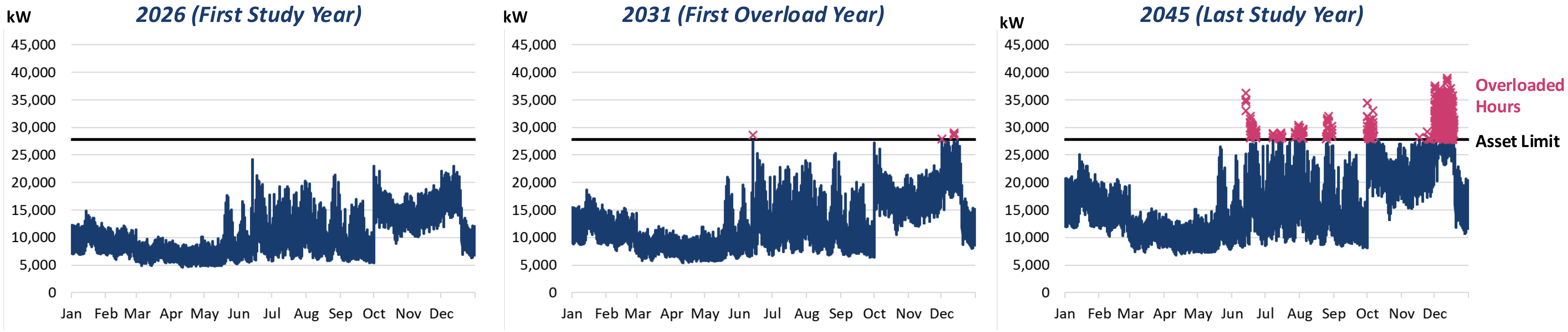
We illustrate how a non-wires solution could be planned and operated to defer the upgrade of Feeder 9 in the "High Load Growth + Low Headroom" scenario

Feeder 9's load shape is characterized by peaks in the summer months and lulls in the shoulder months. It also exhibits a jump in load from October to mid-December—this was due to a load transfer from Feeder 7 to Feeder 9 in the base data and was kept in the input data as a realistic representation of events that can occur throughout a feeder's lifetime.

Rapid annual load growth results in a first overload of 1.2 MW after 6 years in 2031. In cases such as this one with high load growth, NWS portfolios often need to deploy DERs in advance of the first overload year given the magnitude of the overload. They are typically able to defer but not avoid the upgrade given the frequency, magnitude and duration of overload events by 2045.

Summary of Load Relief Needs

Load Relief Needed	2031 (First Year of Overload)	2045 (End of Study Period)
Max. Magnitude (kW)	1,211 kW	11,196 kW
Max. Duration (hours)	3	20
Frequency (events/yr)	3	55
Season	Early Summer	All except spring
Time of Day	4–7 pm	9 am to midnight


2026 (First Study Year)

2031 (First Overload Year)

2045 (Last Study Year)

ILLUSTRATIVE USE CASE

Feeder 9: Optimizing a Cost-Effective Non-Wire Solution

The DEFER model determines the optimal portfolio of DERs that could defer the feeder upgrade. Based on the modeling, the most cost-effective approach is to defer the upgrade for 5 years using a combination of smart thermostats, EV managed charging, BTM battery storage, and grid-interactive water heaters, and then build the wires solution in 2036.

Cost Optimal Upgrade Plan for Feeder 9

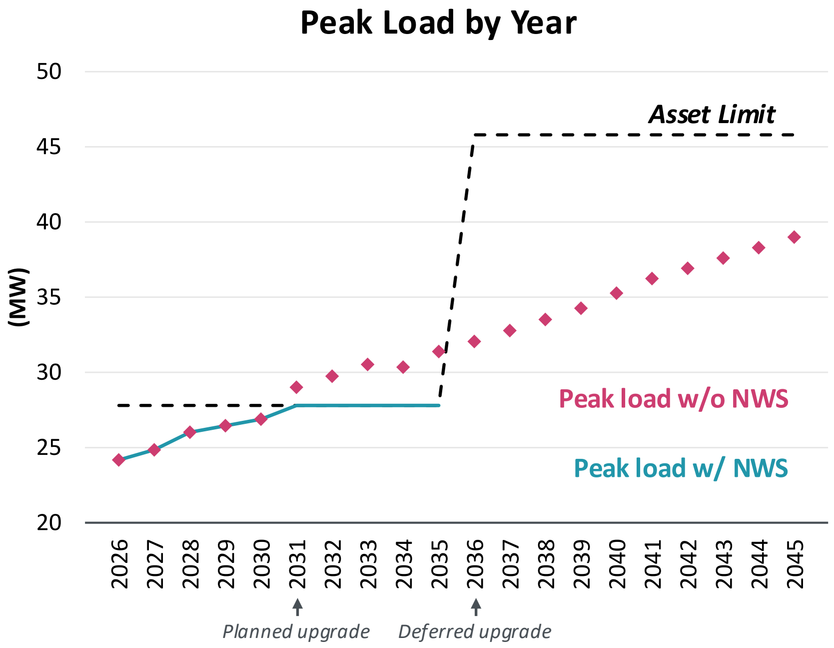
2026:
Begin deploying DERs to ensure sufficient capacity by first year of overload

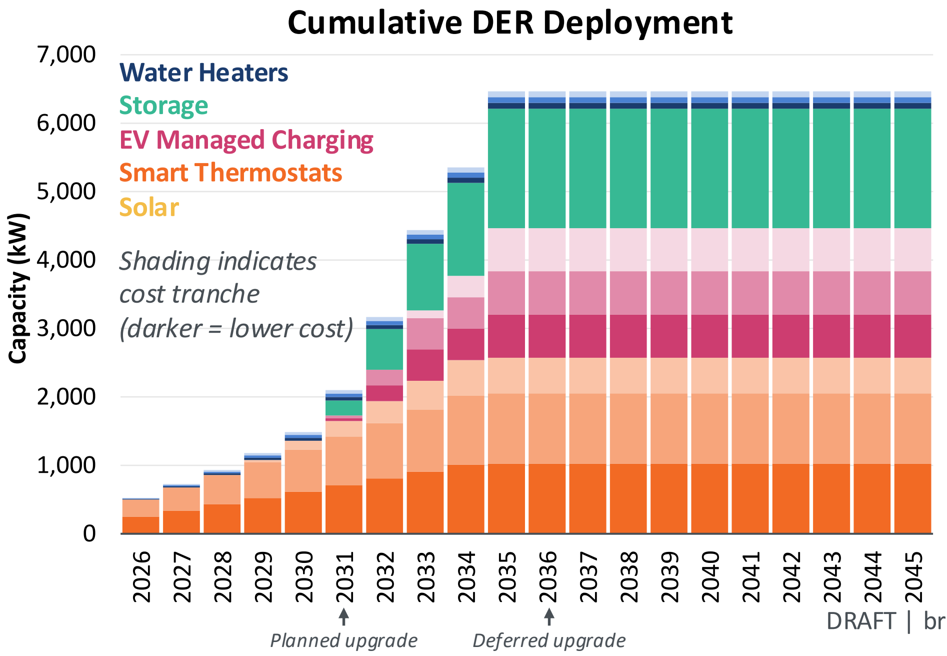
2031:
First year of overload if no DERs – DER operation keeps feeder below load limit

2031–2035:
Deploy additional DERs to meet growing load relief needs

2036:
Load relief needs exceed cost-effective DER potential – build wires solution

2045


Peak Load by Year


Cumulative DER Deployment

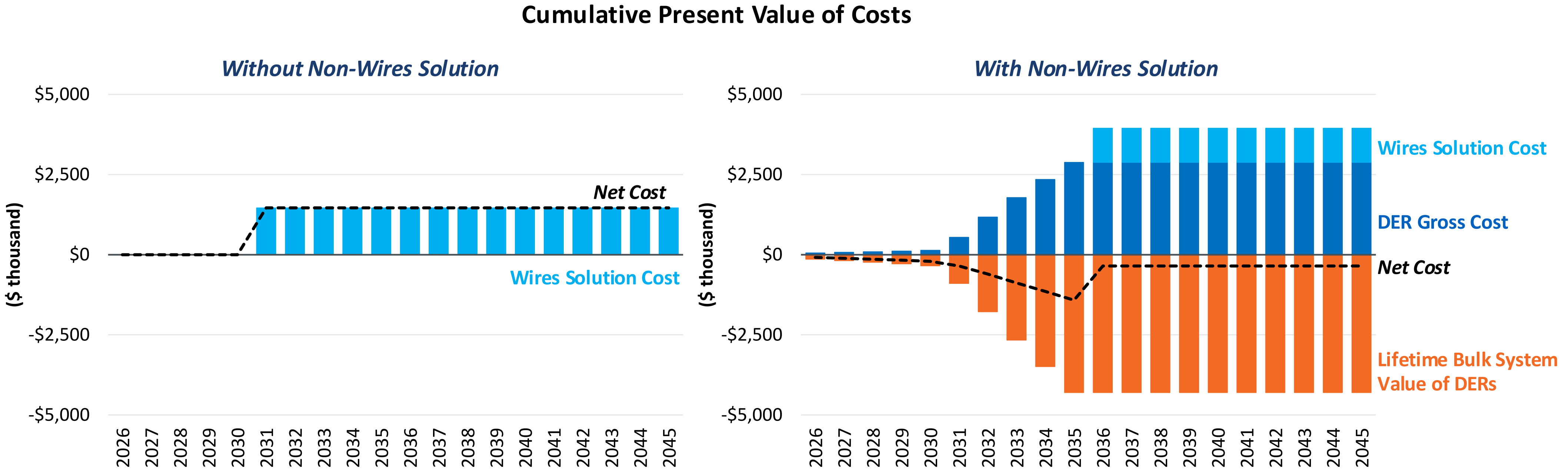
Notes: DER capacity is expressed in kW of installed capacity (i.e., the maximum load-reduction capacity of the DER portfolio).

ILLUSTRATIVE USE CASE

Feeder 9: Costs and Benefits of the NWS

The 5-year deferral of the wires solution creates value in two ways: by reducing the present value of the grid upgrade, and by enabling the deployment of DERs that can be operated to avoid other power system costs

The figure below shows the annual breakdown of cumulative costs that would be incurred to upgrade Feeder 9 with the planned wires upgrade (left) and with the non-wires solution (right). While gross project costs are higher on aggregate under the NWS due to the costs of deploying DERs, the cost of the wires solution is lower due to the time value of money. Crucially, the increase in gross project costs is more than offset by the cost savings that the deployed DERs can generate for other parts of the power system, including avoided energy, generation capacity, and ancillary service costs.*



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*Our modeling does not account for customer acquisition costs and operational program administration costs, nor costs of foundational enabling infrastructure such as DERMS. We also do not account for non-energy benefits (or costs) to customers or society as a whole, such as reliability, resilience, comfort, health, or greenhouse gas abatement impacts.

Feeder 9: DER Operation for Distribution Load Relief

We model the hourly DER operation needed to keep load below the feeder’s limit. On peak days, load-shifting is required from multiple DERs to ensure that high-magnitude, long-duration overloads are mitigated

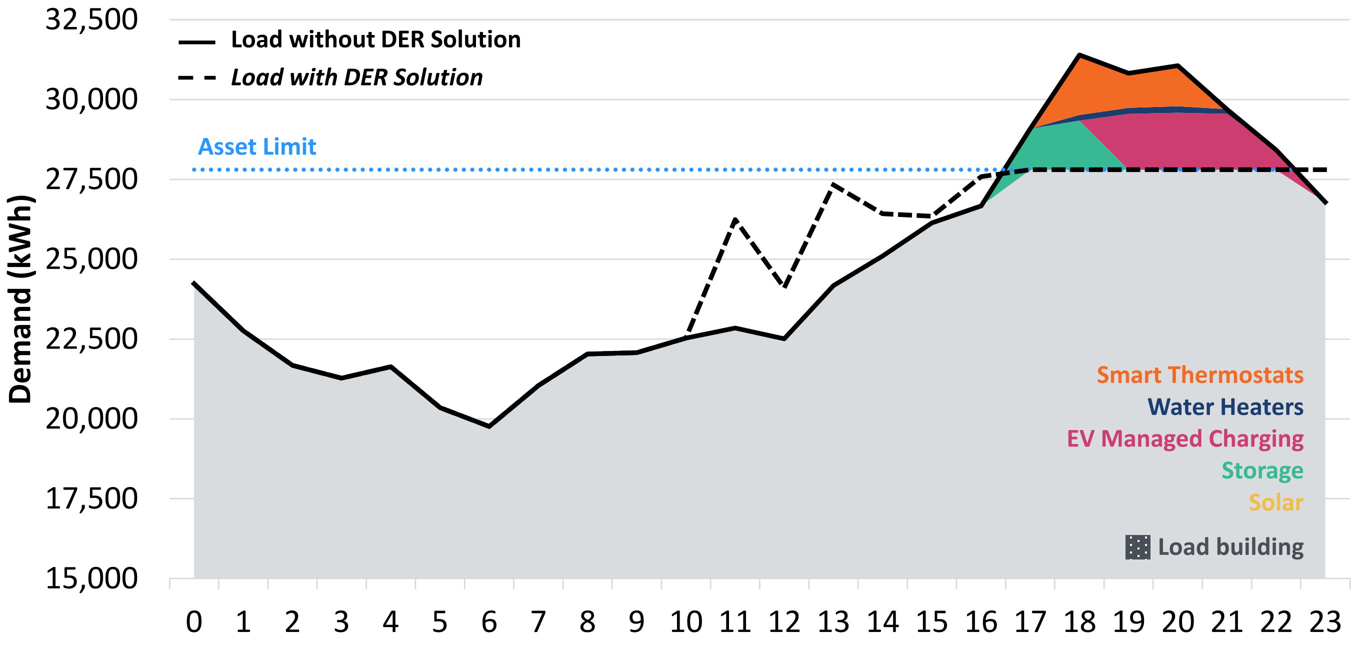
The **DEFER** model optimizes DER load-shifting, accounting for technology-specific limitations on number of demand-response events per year, duration of load reduction possible during an event, and the hours that load can be shifted into (“load-building”).

After several years of deferral, overload magnitude and duration increase significantly. For example, the feeder is forecast to face a 3.6 MW, 6-hour overload without DERs on the day shown here. Significant pre-event load-building is required for DERs to address this overload.

Addressing these kinds of overloads using DERs requires sophisticated operational visibility and control capabilities. Forecasting and real-time monitoring of feeder load must be accurate and responsive to changes in grid conditions.

Additionally, the utility must have sufficient visibility into the availability of customers’ DERs and reliable control of their dispatch to ensure that it can achieve the load reductions necessary to mitigate large overloads.

Hourly Dispatch on Peak Day, 2035 (final year of deferral)



ILLUSTRATIVE USE CASE

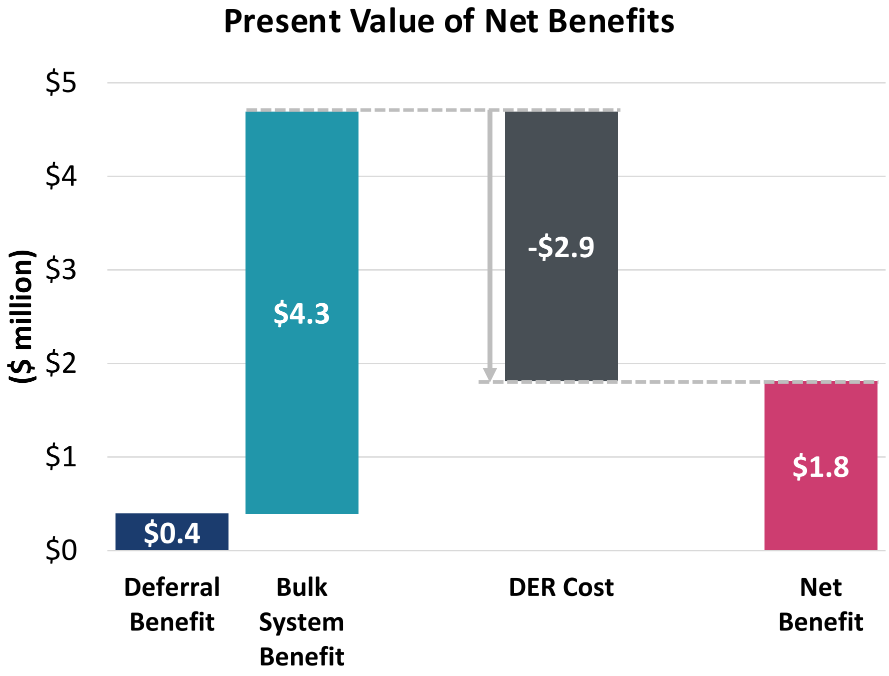
Feeder 9: Benefit Cost Analysis of Non-Wire Solution

The benefit-cost analysis (BCA) below illustrates the value of the non-wires solution and estimates the costs and benefits from the utility cost perspective. Net benefits over the 20-year study horizon exceed $1.8 million, with a benefit-cost ratio of 1.63.

"Deferral benefit" refers to the savings associated with the deferral of the wires investment. "Bulk system benefit" refers to the present value of system costs that DERs will avoid across their lifetimes, including energy costs, generation capacity costs, and ancillary service costs. These avoided costs do not include avoided transmission and distribution costs (distribution value is accounted for through the deferral savings). "DER cost" refers to the share of upfront DER costs that the utility covers (e.g., via incentives or other mechanisms).

In this case, the bulk system costs avoided by the deployed DERs over their lifetime are greater than the gross costs to the utility of deploying DERs, resulting in positive net benefits *before* accounting for deferral savings (~$1.4 million). In contrast, the deferral benefit alone ($0.4 million) is less than the costs to the utility of deploying DERs ($2.9 million).

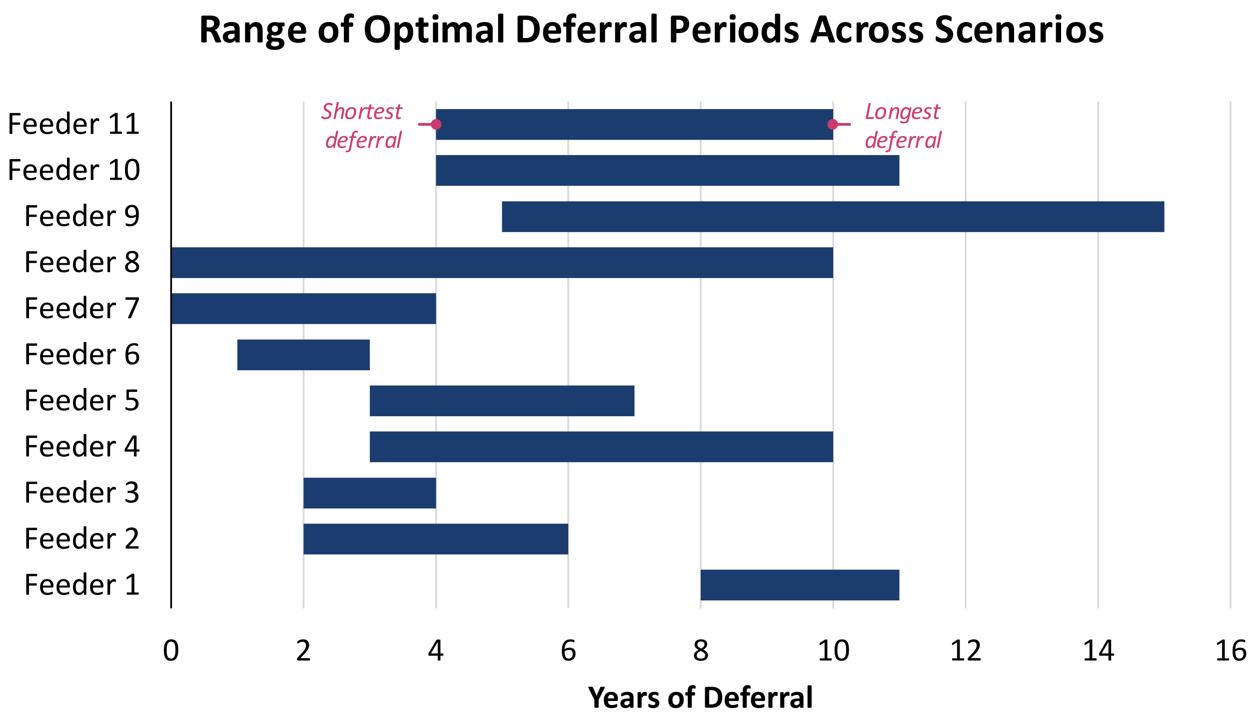
This result was fairly consistent across scenarios and feeders, indicating that *the cost-effectiveness of NWS is significantly affected by the ability for DERs to stack value streams and generate bulk-system value during non-overload hours, and by the inclusion of bulk-system benefits in cost-effectiveness screenings.* The importance of the latter point is evident when considering the OEB's 2024 BCA Framework, which comprises two tests: the mandatory Distribution Service Test (DST) and optional Energy System Test (EST). NWS projects that do not pass the DST may still be considered if they pass the EST. The EST aligns with the cost-effectiveness approach taken here, including avoided bulk system costs as part of the benefits of an NWS. By contrast, the DST considers only deferral benefits in its BCA. Therefore, this NWS would pass the EST but would not pass the DST.



ILLUSTRATIVE USE CASE

Summary of Deferrals Across EPL Feeders

We conducted similar modeling for all 11 EPL feeders in all scenarios and found that DERs could cost-effectively defer upgrades in almost all cases, though the optimal length of deferral varies significantly.



% of feeder-scenarios with feasible and cost-effective NWS

95%

Deferral is possible and cost-effective in the majority of locations and scenarios. Some locations have needs that cannot be cost-effectively resolved by DERs—this only occurs in the high load growth, high-headroom scenario.

Average cost-optimal deferral period

5.7 years

Deferral periods vary based on load growth rate and DER availability, among other factors. The traditional wires solution is likely to be needed eventually even with the NWS in place.

ILLUSTRATIVE USE CASE

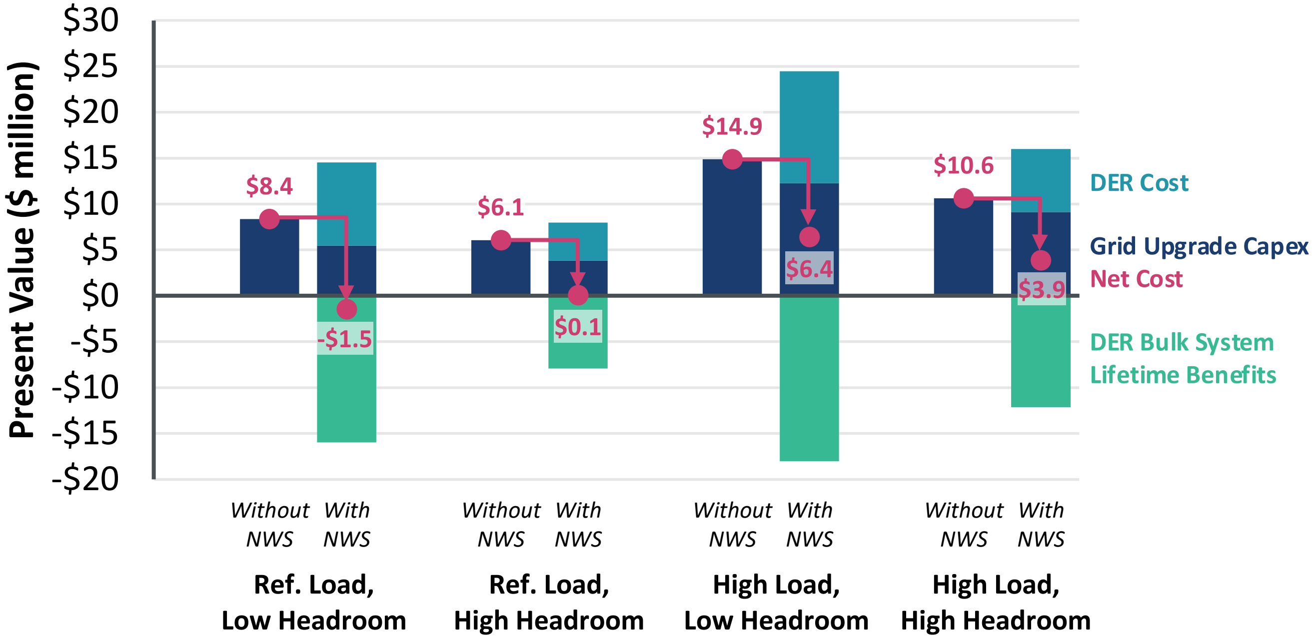
Costs and Benefits Across EPL Feeders

Total net benefits of NWS in the 11 feeders across the scenarios ranged from $6.0 to $9.8 million. Bulk system benefits are the largest source of DER value, with meaningful additional value from distribution deferral.

In almost all scenarios, every dollar spent on DERs generates at least two dollars in benefits. Under reference load growth assumptions, optimal deferral lengths are significantly longer than under high load growth, as DER deployment is able to keep up with load growth.

While distribution capex savings appear modest here compared to bulk system value, this result is highly dependent on the cost of the upgrade being deferred. We assumed a uniform $2 million cost for an 18-MVA feeder upgrade. In practice, different locations and circumstances can have very different upgrade costs, and in the more expensive locations, the value of deferring an upgrade can be comparable to the bulk system value of DERs. In addition, the same DERs can be used to defer upgrades at multiple levels of the distribution grid (e.g., a feeder and a substation). Our illustration only accounts for the deferral of the feeder upgrade.

Net Present Value Cost, without and with Non-Wires Solutions



	Ref. Load, Low Headroom	Ref. Load, High Headroom	High Load, Low Headroom	High Load, High Headroom
Avg. deferral length	7.3 years	7.8 years	3.5 years	3.9 years
Net benefit of NWS	$9.8 million	$6.0 million	$8.4 million	$6.8 million
Benefit-cost ratio	2.09	2.45	1.69	1.99
DER installed capacity*	62 MW	52 MW	32 MW	34 MW

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*The installed capacity of a given DER refers to the maximum load-reduction capacity of a portfolio/VPP of that resource. For example, the installed capacity of a portfolio of 1,000 EV managed chargers is the MW of load reduction that is expected from that portfolio based on the charging profiles of the 1,000 enrolled customers.

ILLUSTRATIVE USE CASE

The DER Value Stack

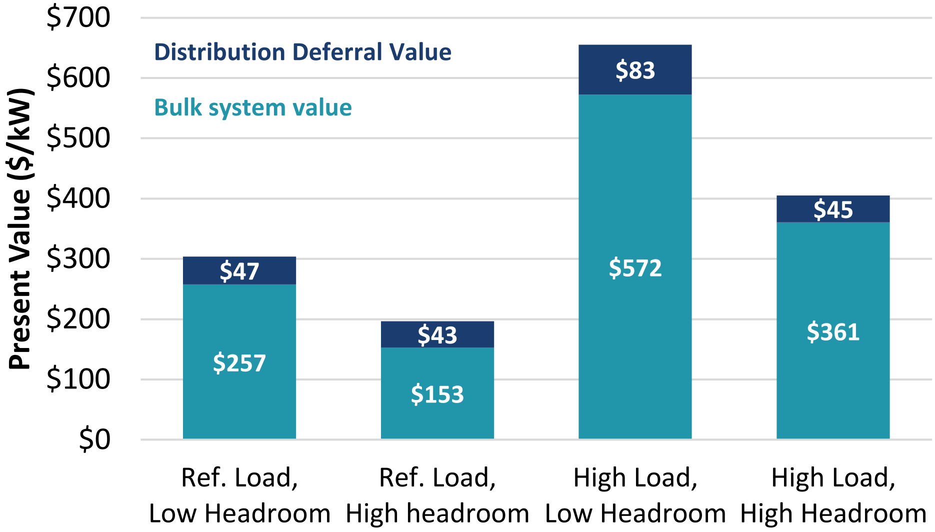
Utilizing DERs for distribution grid services unlocks an important part of the overall DER value stack. This can improve DER economics and accelerate adoption.

The figure to the right compares the bulk system value and distribution value of DERs across the four scenarios in this study. These estimates represent the value today of deploying a kilowatt of DERs* and using them to generate bulk system and distribution value over the next 20 years. Across all cases, distribution deferral value represents 11–22% of the total value stack.

The differences between scenarios stem from several factors. As shown on the previous slide, deferral length and DER deployment vary significantly across scenarios, which in turn impact distribution and bulk system value. Additionally, since value is expressed in present terms, near-term deferral opportunities such as those in the high load growth cases are more valuable today than deferral opportunities far in the future, such as the reference load growth cases.

This effect captures the fact that the distribution value of DERs is highly dependent on the grid conditions at which the DER is sited—DERs located on feeders that are soon to be overloaded have much higher distribution deferral value than those located on feeders with plenty of headroom.

Lifetime Value of DERs Across Scenarios



Deferral starts later (~2042)
↓
Value more heavily discounted

Deferral starts earlier (~2035)
↓
Value less heavily discounted

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*The value stacks shown here are for a kilowatt of an "average" DER—in reality, the bulk system and distribution value will vary by specific DER technology type.

Notes: Value expressed in present value dollars per kW of DER deployment, where DER deployment is measured as the installed capacity of the DER portfolio.

3. Conclusion

Ontario-Wide LDC Capex Savings

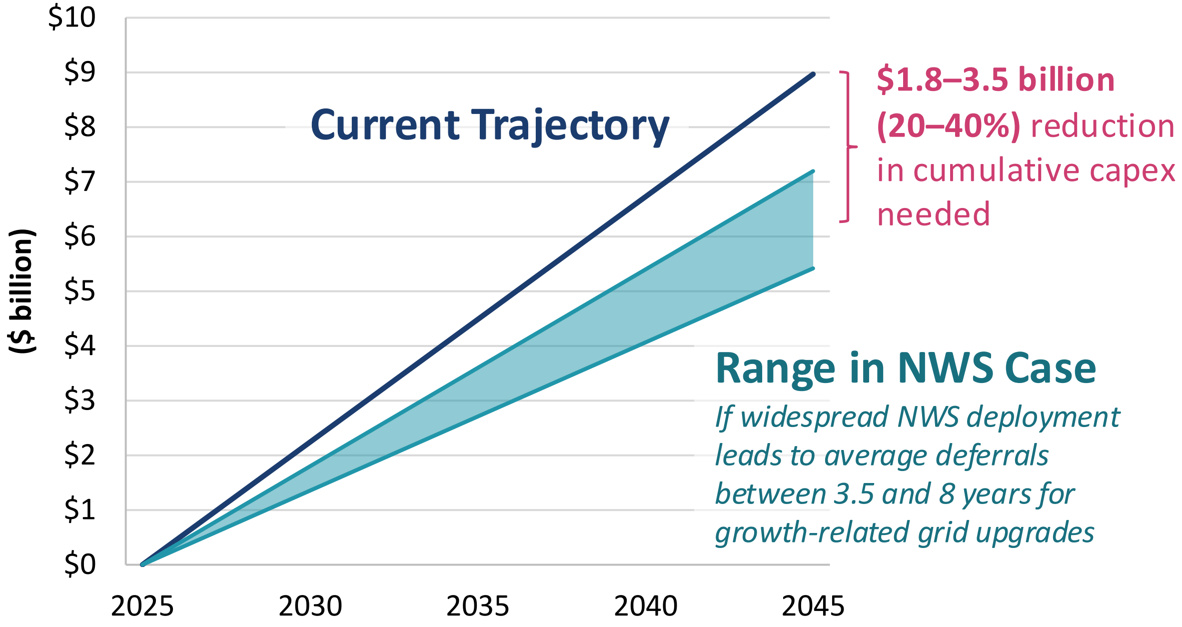
Orchestrating DERs in the manner illustrated for Essex Powerlines could allow LDCs across Ontario to achieve similar deferrals of distribution growth investments. This would reduce the present value of required growth-related capex over 20 years by 20–40%, or $1.8 to $3.5 billion.

The 44 feeder-scenarios analyzed in this study suggest that deferral of distribution upgrades is possible and cost-effective in almost all scenarios. We found that the average deferral length across the 11 feeders ranged from 3.5 years (High Load Growth, Low Headroom Scenario) to 7.8 years (Reference Load Growth, High Headroom Scenario).

To estimate potential Ontario-wide deferral savings, we analyzed two cases based on the optimal deferral lengths identified for the EPL feeders: one where all growth-related distribution upgrades are deferred by 3.5 years on average, and one where they are deferred by 8 years on average.

We analyzed distribution investment plans and public OEB data to estimate that if Ontario-wide annual distribution capacity growth spending continued at the current rate, the capex over 20 years would be $9 billion. As shown in the table to the right, deferring these annual investments by 3.5 to 8 years on average would save $1.8 billion to $3.5 billion. This corresponds to a **20–40% reduction in present value of growth-related capex** in that period. As growth-related capex is roughly 27% of total capex, this implies that **NWS could reduce total distribution capex needs by 5–11% across Ontario.**

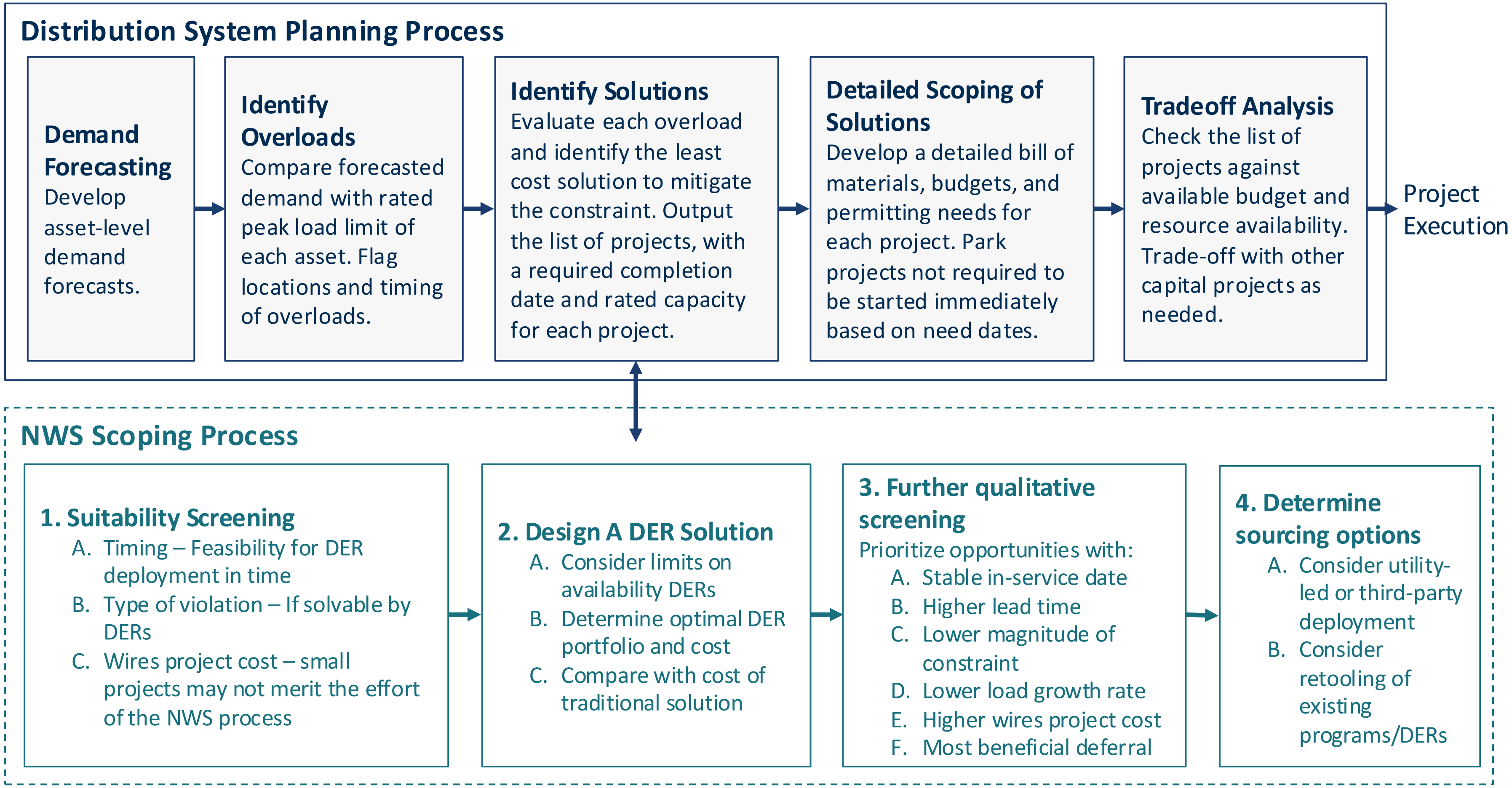
Cumulative Present Value of Ontario-Wide Growth-Related Distribution Capex Needed for 2026–2045



Notes: Savings calculated using public data from OEB, Hydro One, Toronto Hydro, and Alectra.

A Distribution Planning Process that Integrates DER Planning

Utilizing DERs for distribution grid services in the manner illustrated in this report requires modifications to distribution system planning processes. We outline where an NWS scoping process could fit within the broader distribution system planning process and enumerate the high-level steps of a potential process.



Distribution System Planning Process

Demand Forecasting
Develop asset-level demand forecasts.

Identify Overloads
Compare forecasted demand with rated peak load limit of each asset. Flag locations and timing of overloads.

Identify Solutions
Evaluate each overload and identify the least cost solution to mitigate the constraint. Output the list of projects, with a required completion date and rated capacity for each project.

Detailed Scoping of Solutions
Develop a detailed bill of materials, budgets, and permitting needs for each project. Park projects not required to be started immediately based on need dates.

Tradeoff Analysis
Check the list of projects against available budget and resource availability. Trade-off with other capital projects as needed.

Project Execution

NWS Scoping Process

1. Suitability Screening
A. Timing – Feasibility for DER deployment in time
B. Type of violation – If solvable by DERs
C. Wires project cost – small projects may not merit the effort of the NWS process

2. Design A DER Solution
A. Consider limits on availability DERs
B. Determine optimal DER portfolio and cost
C. Compare with cost of traditional solution

3. Further qualitative screening
Prioritize opportunities with:
A. Stable in-service date
B. Higher lead time
C. Lower magnitude of constraint
D. Lower load growth rate
E. Higher wires project cost
F. Most beneficial deferral

4. Determine sourcing options
A. Consider utility-led or third-party deployment
B. Consider retooling of existing programs/DERs

Data Needs To Enable NWS Scoping Process

- **DER registry** to track installed DERs, location, and capabilities
- **DER potential** by location and technology type to enable planning and NWS feasibility assessment
- **Locational forecasts** of organic DER adoption
- **Locational forecasts of load** growth and load shape to enable development of a tailored NWS
- **A platform** for DER owners and aggregators to offer available DER capacity for distribution services
- **Hosting capacity maps** to direct DER deployment to locations where there could be near-term value

Takeaways and Next Steps For Regulators and LDCs

- **Sizable deferral opportunities**. Using the EPL system to illustrate the distribution value of DERs, we estimated that optimized non-wires solutions could cost-effectively defer upgrades across EPL's 11 feeders by an average of 5.7 years
- **Huge province-wide upside**. Scaling NWS across Ontario could reduce total growth-related distribution capex by 20–40%, yielding ~$1.8B–$3.5B in net savings over 20 years
- **Strong benefit-cost ratio.** In nearly all scenarios, $1 spent on NWS delivers ≥ $2 in benefits. In locations with high distribution upgrade costs, NWS even more beneficial
- **Prioritize the right upgrades.** Deferability depends on various overload characteristics (magnitude, frequency, duration, and growth rate). Locations with favorable characteristics for deferral through DERs should be prioritized to achieve higher deferral value at limited DER deployment cost
- **Value stacking is critical to ensure cost-effectiveness**. Avoided bulk system costs form an important part of the overall value stack of NWS—compensation mechanisms and programs that enable value stacking are key
- **New regulatory models** are needed to enable LDCs to utilize DERs for distribution services and share savings with customers
- **New LDC investments** in distributed energy resource management solutions (DERMs) and/or aggregator participation are needed to fully utilize DERs as illustrated in this study
- **Roles and responsibilities for coordination of DERs** for bulk grid and distribution system needs should be clarified to maximize the value of NWS and ensure a seamless customer experience

Clarity in the face of complexity

Brattle