Renewables-Based Distributed Energy Resources in Ontario

A Cost and Implications Assessment

Final Report

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STRATEGIC POLICY ECONOMICS

Executive Summary

Ontario's Long-Term Energy Plan (LTEP) places significant reliance upon Distributed Energy Resources (DER) consisting of renewables and storage to address a gap in the province's electricity supply mix that will emerge over the next fifteen years. This report examines the economics of meeting this supply gap with renewables-based (solar and wind) DER and how the intermittent output of these variable generation sources interacts with storage to undermine those economics.

Background

Today DER is at the center of energy policy discussions around the world. DER can include solar panels, electricity storage, small natural gas-fuelled generators, and controllable loads such as electric vehicles and water heaters. These resources are typically connected to distribution networks and are smaller in scale than traditional transmission grid-connected generation facilities that serve most of Ontario's demand[1]. DER that includes renewables coupled with storage is advocated as the low-cost, low-emission supply alternative to fossil fuels and the basis for adding more intermittent renewables to the supply mix. Three factors have played a critical role in this transition: renewables such as wind and solar are now integral parts of the energy mix in many jurisdictions; the next generation of these technologies have experienced dramatic cost declines; and, Lithium-ion (Li-ion) batteries for energy storage are following a similar cost reduction path.

DER is recognized as a critical component in the evolution of smart grid innovations. Information and communication technology (ICT) innovations in smart control technologies aim to facilitate the integration of renewables and storage technologies and enable two new paradigms: (1) a new class of customers: consumers and producers of electricity ("prosumers"); and (2) community-based microgrids and virtual power plants. DER connected in a microgrid configuration has the potential to provide dispatch flexibility at the local distribution level that natural gas-fired generation currently provides for the transmission grid.

Ontario's LTEP identifies a growing capacity gap in the province's electricity supply. With the retirement of the Pickering Nuclear Generating Station and the subsequent gradual expiration of Ontario's contracted renewables and natural gas-fired generation, 30% of Ontario's generation capacity will have to be renewed or replaced by 2035[2], even under the LTEP's low demand forecast.

The LTEP places significant emphasis and reliance upon renewables-based DER to address this supply gap and recognizes that storage is required to mitigate the effects of the intermittent output from wind and solar generation. The LTEP is focused on increasing the adoption of renewables-based DER to achieve several benefits that are enabled by storage: utilities can defer or avoid "wires" investments through "non-wires" DER solutions; and customers can generate, store and sell their own power, and ensure their own reliable electricity, both during times of peak demand and during power outages. Yet, the degree to which the variable nature of wind and solar generation impacts the ability of storage to provide these benefits is not well understood.

[1] IESO website
[2] MoE, LTEP, 2017

Context

Studies undertaken in Ontario have examined how DER could be used to *mitigate electricity system challenges* resulting from the extensive deployment of renewables over the last decade.[3] In contrast, this report examines the economics of using wind-based DER or solar-based DER solutions to *fill the emerging supply gap* by 2035, explicitly considering the impact of intermittency.

To deliver the expected benefits, DER must supply either the daytime energy demand profile or the baseload demand profile required by Ontario's future electricity system. To this end, three DER configurations are examined:

1. Solar-based DER at the community level or microgrid-scale that integrates solar panels and Li-ion battery storage;
2. Wind-based DER consisting of grid-connected wind farms integrated with adjacent compressed air energy storage systems (CAES); and
3. Baseload-supplied distributed energy storage (DES) is an alternative approach that consists of grid-connected baseload generation such as nuclear or hydro that supplies community level distributed storage. This latter baseload-supplied DES option represents a pathway to a low carbon economy that has received little attention in the climate change and DER discourse.

Findings

The unfortunate truth is that renewables-based DER solutions are not a cost-effective way to meet Ontario's electricity needs in 2035 because the intermittency of renewables output negatively impacts the cost of storage. These intermittency costs outweigh the forecast cost declines of the renewables and storage technologies. When storage assets are coupled with intermittent renewables, storage operations focus on *managing the intermittency of the renewables*. When storage is coupled with a baseload supply, storage operations can be focused on *managing demand fluctuations*, a more direct use of the capabilities of storage. This study has produced the following three major findings:

1. Ontario's Weather-induced intermittency undermines the economics of renewables-based DER
   - Intermittency creates a need for gas backup, which leads to high Levelized Cost of Energy (LCOE) from DER systems - LCOE of solar-based DER is $270/MWh, 10% higher than today.
   - Full renewables-based DER rollout would add $0.7B/year (solar DER) to $3.4B/year (wind DER) to Ontario's total cost of electricity - an increase of 3% to 15% over the LTEP forecast.
   - Small-scale residential renewables-based DER will remain too costly for several decades.

2. Ontario renewables-based DER would have a systemic 35% higher cost structure than the U.S.
   - Ontario's weather would put businesses at a competitive disadvantage on energy costs.

3. Ontario has a better option with nuclear baseload-supplied DES
   - Nuclear-supplied DES LCOE of $160/MWh is ~60% of the solar-based DER LCOE.
   - Nuclear-supplied DES could reduce Ontario's electricity cost by over $2B/year, $5.5B/year less than wind-based DER, and 20% less than U.S. – a competitive advantage for Ontario.
   - Small modular reactors (SMRs) and carbon capture may be the lowest cost solutions.

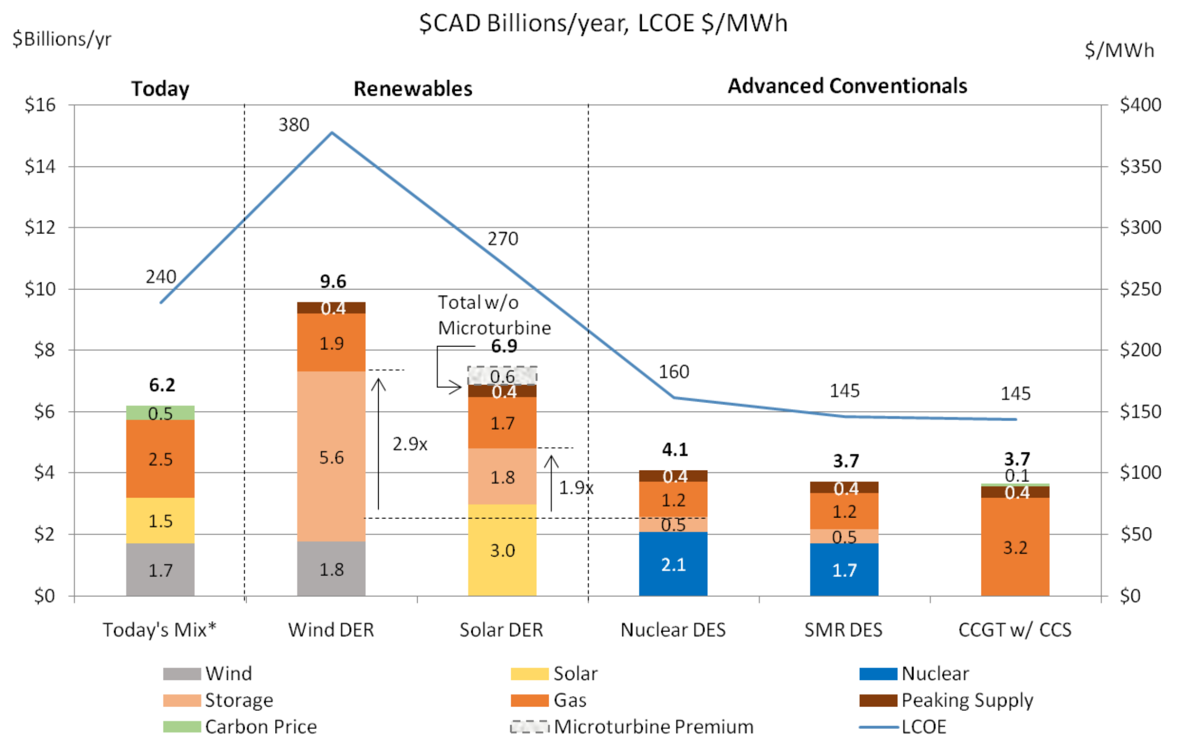
[3] IESO, Energy Storage, 2016; Essex, 2017

Discussion of Findings

Finding #1 – Ontario's Weather-induced intermittency undermines economics of renewables-based DER

Figure ES-1 summarizes the costs of the assessed DER options for meeting Ontario's 2035 supply gap.[4] The costs are compared to those of the existing system[5] as well as other new developing technologies in terms of the Levelized Cost of Energy (LCOE) and the costs expected from each generation type as required to meet Ontario's anticipated LTEP supply gap in 2035. Intermittency creates a need for gas backup, which leads to a high LCOE from renewables-based DER systems.

Figure ES-1 – Total Annual Cost of DER and LCOE Comparison, Ontario, 2030



1. LCOE of solar-based DER is $270/MWh, 20% higher than the $240/MWh cost of today's supplies that it would replace
   a. Today's supply mix would have an LCOE of $240/MWh (if include carbon pricing).
   b. Solar-based DER would have an LCOE of $270/MWh in 2017 dollars[6], or $301/MWh if microturbines are deployed instead of combined cycle gas turbines (CCGT).
   c. The LCOE of the wind-based DER option would be approximately $380/MWh.

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[4] The scenarios all assume the LTEP demand for 2035 within a system built on Ontario's committed hydro and nuclear assets and reflect industry projected 2030 costs.
[5] Existing system costs from OEB RPP, OPO 2015 embedded generation, IESO 2016 Year End data
[6] All currencies in this document are in $2017 CAD except in Section 4.0 or where otherwise specified.

2. A full rollout of renewables-based DER could add $0.7B/year to $3.4B/year to Ontario's cost of electricity.

    a. This is equivalent to a cost increase of 3% to 15% over the 2030 forecast LTEP costs[7].

    b. The DER/DES options have two distinct cost components: the cost of generation and storage; and the cost of the backup natural gas-fired generation and peaking supply.

    c. The future generation and storage cost of a solar-based DER option is projected to be $4.8B/year, 1.9 times the cost of a baseload-supplied DES system comprised of conventional nuclear generation and Li-ion battery storage. The generation and storage costs for the wind-based DER option are projected to be $7.4B/year, 2.9 times the cost of the nuclear baseload-supplied DES solution.

    d. All options include the same need for peaking natural gas-fired generation plants to satisfy the extreme demand peaks that occur on a few days every summer. The cost for 3,000 MW of peaking gas supply in 2030 is forecast to be about $380M/year.[8]

        Natural gas-fired generation would still be required to supply 20% to 30% of the incremental daytime demand mostly as a result of seasonal variations in both demand and generation. The estimated future share of natural gas-fired generation output could range from 3% to 5% of the Ontario supply mix, similar to the 4% in 2017, but less than the 8% realized in 2016[9].

        The cost of the backup natural gas-fired generation required by wind-based DER is $1.9B/year, 12% more than the $1.7B/year required for solar-based DER and 62% more than the $1.2B/year required for the nuclear baseload-supplied DES option. The wind-based DER cost is higher due to a much greater need for backup gas-fired generation capacity.

        Some proposed DER schemes involve the use of microturbines in lieu of the grid-based generation. The incremental cost of a microturbine was examined for the solar-based DER option. Microturbines would increase the cost by 9% due to higher capital costs, low capacity factor and carbon pricing.

3. The impact of renewables intermittency on the LCOE of DER/DES options in Ontario is illustrated in Figure ES-2. Intermittency results in excess unutilized generation, conversion losses in the storage system, low capacity factors of the storage asset, and the need for backup generation.

    a. The LCOE of the solar-based DER has four contributing components:

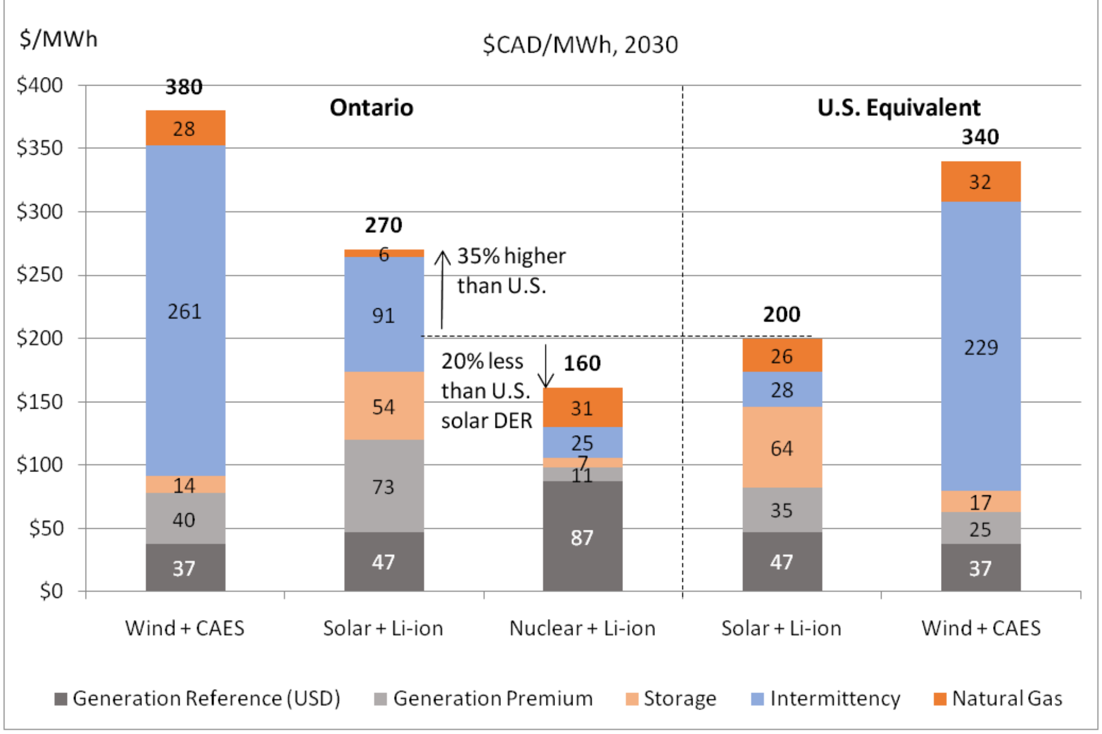
        - The cost of solar panels is based on the forecast LCOE for grid-connected solar of US $47/MWh (for low cost areas of the U.S. with high levels of sunshine[10]). That same technology installed at community-scale in Ontario will cost $120/MWh, a generation premium of $73/MWh.

[7] It is assumed that the OPO Outlook B total cost forecast of $20.2B/year in 2030 is the basis for the LTEP.
[8] EIA 2017 Annual Energy Outlook, Strapolec analysis.
[9] IESO Year End Data, 2016, 2017
[10] Lazard LCOE v11, 2017

- Solar output intermittency combined with demand fluctuations increases the cost of storage and solar output by $91/MWh for the energy that is used.
- DER solutions do not eliminate surplus from intermittent renewable energy production. Up to 30% of solar energy will be curtailed or lost through storage inefficiencies – 19% of wind.
- Natural gas will be required to backup up the solar energy and supply 30% of the demand increasing the total LCOE by $6/MWh to $270/MWh.

b. Wind-based DER solutions are costlier at $380/MWh.

Figure ES-2 – Ontario vs U.S. DER LCOE Contributions



4. Residential renewables-based DER will be uneconomic for decades

To best provide the desired system asset optimization and customer benefits, DER solutions should be located as close to the demand load as possible, preferably on the consumers' premises. Unfortunately, as DER systems are moved closer to loads, the scale of the DER installation decreases: a 1.5 MW solar panel could supply a community of 1,000 homes and businesses; for a single home, a 0.25 kW solar panel could provide all of the daytime energy that would be needed above what could be supplied by Ontario's committed baseload. The components of 5 kW or smaller scale DER solutions are prohibitively expensive without the substantial subsidies that have promoted their use.

a. Cost forecasts show residential solar-based DER solutions will remain uneconomic beyond 2030.

b. For solar-based DER, community-scale solutions may be the most promising DER option. Increasing the size of DER installations to grid-scale solar offers little system benefits or cost advantage.
c. Wind-based DER is only economic when using grid-scale wind, which also offers the potential advantage of being paired with lower cost storage, such as compressed air energy storage (CAES). However, grid-scale wind does not provide the desired DER benefit of reducing the required capacity of the transmission and distribution systems. These must accommodate the backup natural gas-fired generation capacity which is not reduced.

Finding #2 – Ontario renewables-based DER would have a systemic 35% higher cost structure than the U.S.

Figure ES-2 shows that the cost impacts of intermittency in Ontario are greater than in the U.S. This is primarily due to the nature of Ontario's geography and weather conditions, which lower the capacity factors of the renewables. The higher capacity factors in the U.S. result from less variability or intermittency of the renewable generation output.

1. The LCOE of the U.S. solar-based DER would be $200/MWh. The $270/MWh LCOE of the solar-based DER in Ontario (using equivalent DER components) is 35% higher.
2. Similarly, the LCOE of wind-based DER may be 12% more in Ontario compared to the U.S.
3. Pursuing nuclear baseload-supplied DES options in Ontario could create a 20% cost advantage over the U.S. solar-based DER options.

Finding #3 – Of the known and proven technology options, nuclear baseload-supplied DES will be the lowest-cost option in any geography that has high renewables intermittency. Nuclear baseload-supplied DES also has the greatest potential in Ontario to achieve the desired DER benefits of mitigating distribution and transmission costs. Cost forecasts for other technology being developed suggest that:

1. The baseload-supplied DES would have an LCOE of $160/MWh. This option could reduce Ontario's annual electricity cost by over $2B.
2. Small modular reactors (SMRs) may be the lower cost solution for a broad range of jurisdictions and locations compared to conventional nuclear;
3. Natural gas-fired generation (CCGT shown) equipped with carbon capture and sequestration (CCS) may also be a low-cost low-carbon generation option.[11] However, CCGT with CCS would not offer the cost benefits from distribution and transmission system asset optimization and would not be emission-free – three times more emissions than the solar-based DER and four times the emissions of the nuclear baseload-supplied DES.

[11] Assuming an operating capacity factor of 49%.

Implications

1. Renewables-based DER should not be looked to as a cost-effective solution for Ontario's emerging capacity gap identified in the 2017 LTEP.
    - Renewables-based DER can only be justified today based on either direct subsidies or indirect subsidies enabled by market arbitrage.
    - Investment in residential scale renewables-based DER is uneconomic. Incentives such as net-metering, noted in the LTEP, are an indirect subsidy that would increase the total cost of the entire electricity system.
2. Ontario's emerging capacity gap can be best addressed by procurement of up to 5,000 MW of new low-emission baseload electricity supply by 2035. New baseload capacity is required in Ontario to supply two needs:
    a) To fill Ontario's emerging capacity gap for baseload supply requires the procurement of over 2,250 MW of new low-emission baseload supply.
        - These resources will be required as soon as possible after the Pickering Nuclear Generation Station retires in 2024.
        - Based on 2030 cost projections, using renewables-based DER to perform a baseload function will cost three to four times more than new nuclear stations and will not be emissions-free because of the requirement for backup natural gas-fired generation. With the cost projections predicated on significant cost declines to 2030, procurements prior to 2030, such as to replace the retiring Pickering Nuclear Generation Station, will be costlier.

    b) To meet daytime demand, another 2,700 MW of low-emission baseload supply is required by 2035 in order to implement the low-cost baseload-supplied DES.
3. Given the immediate requirement for low-emission baseload generation to fill the emerging capacity gap after 2024, planning for such procurement should begin as soon as possible to best advance a potential Ontario competitive cost advantage with respect to the U.S.

Analysis of the transmission, distribution, and reserve capacity benefits should be conducted. It would likely show improved relative economics of baseload-supplied DES. Such analyses could additionally inform policy and investment decision-makers about the economics of DER/DES solutions, their ability to help address Ontario's emerging capacity gap, and the potential to reduce overall electricity system costs.

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1.0 Introduction

Today, Distributed Energy Resources (DER) are at the center of energy policy discussions around the world. DER can include solar panels, electricity storage, small natural gas-fuelled generators, and controllable loads such as electric vehicles and water heaters. These resources are typically connected to distribution networks and are smaller in scale than traditional transmission (Tx) grid-connected generation facilities that serve most of Ontario demand[12]. DER that includes renewables coupled with storage are advocated as the low-cost, low-emission supply alternative to fossil fuels and the basis for adding more intermittent renewables to the supply mix. Three factors have played a critical role in this transition: renewables such as wind and solar are now integral parts of the energy mix in many jurisdictions; the next generation of these technologies have experienced dramatic cost declines; and, Lithium-ion (Li-ion) batteries for energy storage are following a similar cost reduction path.

DER is recognized as a critical component in the evolution of smart grid innovations. Information and communication technology (ICT) innovations in smart control technologies aim to facilitate the integration of renewables and storage technologies and enable two new paradigms: (1) a new class of customers: consumers and producers of electricity ("prosumers"); and (2) community-based microgrids and virtual power plants. DER connected in a microgrid configuration has the potential to provide dispatch flexibility at the local distribution level that natural gas-fired generation currently provides for the Tx grid.

The LTEP is focused on increasing the adoption of renewables-based DER to achieve several benefits enabled by storage:

"Renewable distributed generation can benefit local distribution companies (LDCs) and their customers: Utilities can defer or avoid certain costly investments in their local distribution networks; and Customers can generate and store their own power, lowering bills and ensuring reliable access to electricity when power from their network is not available."[13]

Several studies undertaken in Ontario have examined how DER could be used to mitigate the electricity system challenges resulting from the extensive deployment of renewables over the last decade.[14] In contrast, this study looks at the emerging capacity gap and examines the economics of how new renewables-based DER solutions could fill the supply gap by 2035, explicitly considering the impact of intermittency.

To deliver the benefits expected, DER must supply either the daytime energy demand profile or the baseload demand profile required by Ontario's future electricity system. Baseload-supplied distributed energy storage (DES) is an alternative approach that consists of grid-connected baseload generation such as nuclear or hydro that supplies community level distributed storage. This latter baseload-supplied DES option represents a pathway to a low carbon economy that has received little attention in the climate change and DER discourse.

[12] IESO website
[13] MoE, LTEP, 2017, pg. 68
[14] IESO, Energy Storage, 2016; Essex, 2017

The implications of DER scenarios are examined across four factors, with specific attention paid to the impacts that renewables intermittency has on storage:

1. The total costs of renewables-based DER solutions in Ontario;
2. Potential for wind and solar renewables-based DER to fill the capacity gap and supply the forecasted demand;
3. How those costs compare to baseload-supplied DES resources; and
4. How costs may differ between Ontario and the U.S.

1.1 Background

Ontario's LTEP identifies a growing capacity gap in the province, as illustrated in Figure 1[15]. By 2035, 30% of Ontario's generation capacity will have to be renewed or replaced[16]. The most significant declines in available capacity occur in 2023/2025 and 2029/2030.

The change in the 2023/2025 timeframe is due to the retirement of the Pickering Nuclear Generating Station (PNGS). This will remove approximately 20% of nuclear baseload supply from Ontario's supply mix creating a future need for a baseload supply replacement. It will also create the need for greater voltage regulation services east of Toronto.[17]

Figure 1 – Ontario's Peak Supply and Demand Outlook

The remaining contributions to the capacity gap, including the large change in 2029/2030, are due to the gradual expiration of the20-year supply contracts for renewables and gas-fired generation. Much of this supply addresses Ontario's daytime demand profile and peak reserve requirements. This includes the

[15] Figure extracted from the 2017 LTEP

[16] One of the criticisms of the 2017 LTEP is that it did not address any demand expectations that may arise from emissions reduction. Should there be appreciable demand growth as has been forecasted by many, then additional capacity will be required beyond what is shown in Figure 1.

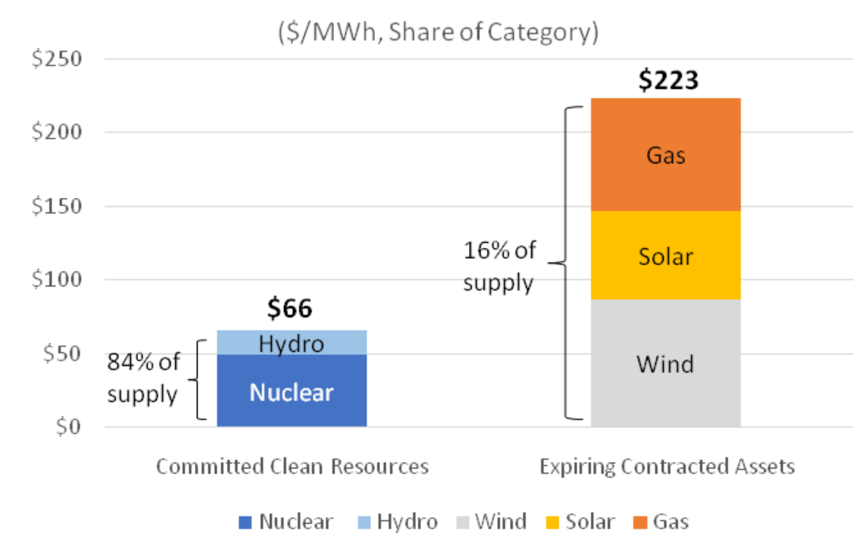
[17] IESO, Energy Storage, 2016, p.29

expiration of the contract for Ontario's only peaking gas plant capable of ramping up quickly enough to meet Ontario's flexible supply requirements.[18]

The existing and committed resources identified in Figure 1 that remain in 2035 are primarily low emission, low cost assets and include: Ontario's hydro fleet, refurbished nuclear, and biomass. Along with the import/export energy exchange capability with Hydro Quebec, these resources provide Ontario with a low-carbon, flexible baseload capability.

Figure 2 contrasts the average cost of the committed baseload resources at $66/MWh against the average cost of the expiring assets at $223/MWh[19]. The expiring assets reflect high cost resources. Ontario has an opportunity to switch out these high cost resources and replace them with lower cost options.

Figure 2 – Blended Cost of Ontario's Energy Supply, 2016



With respect to committed resources, nuclear refurbishment is the single largest asset renewal component of the 2017 LTEP. The Financial Accountability Office of Ontario (FAO) has estimated that the cost of the refurbished nuclear will be $80/MWh when the program is completed[20], a 15% increase over the cost of nuclear today. The cost of refurbished nuclear represents a benchmark for the total generation cost to provide baseload power. It also offers a reference by which DER applications that would supply a baseload equivalent can be measured for their impact on the cost of power assumptions in the LTEP. A cost of $223/MWh is assumed for supplying the rest of Ontario's demand requirements and is a benchmark for comparing the cost-effectiveness of deploying DER solutions to supply the province's daytime demand.

The LTEP identifies three broad initiatives intended to help find lower cost options to replace the expiring contracts:

1. Independent Electricity System Operator (IESO) Market Renewal Initiative

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[18] York Energy Center per IESO Report: Energy Storage, 2016, p.25
[19] OEB RPP, 2017
[20] FAO Nuclear Refurbishment, 2017

2. LDC Grid Modernization
3. Integrated Regional Resource Plans (IRRP)

The latter two initiatives both support and enable renewables-based DER and instruct the Ontario Energy Board (OEB) to develop regulations that price these options to accelerate their adoption.

The LTEP places significant emphasis and reliance upon renewables-based DER to address this supply gap and recognizes that storage is required to mitigate the effects of the intermittent electricity production from wind and solar generation. The LTEP is focussed on increasing the adoption of renewables-based DER to achieve several benefits that are enabled by storage: utilities can defer or avoid "wires" investments through "non-wires" DER solutions; and customers can generate, store and sell their own power, and ensure their own reliable electricity, both during times of peak demand and during power outages. Yet, the degree to which the variable nature of wind and solar generation impacts the ability of storage to provide these benefits is not well understood. The focus of this report is to assess the ability of renewables-based DER to cost-effectively address Ontario's pending capacity gap.

1.2 Structure of this Document

The body of this report consists of six main sections.

Section 2.0 provides a brief overview of the methodology deployed in researching costs and modelling Ontario's future energy system.

Section 3.0 examines the DER promise of expected benefits, introduces the definitions of possible DER locations, summarizes sample technologies that are being deployed, describes the demand conditions that DER should be expected to solve, and defines what DER concepts are examined.

Section 4.0 addresses the perception in the public domain that renewables and storage costs are declining so rapidly that they will be the best economic choice of all generation options. This section presents the research findings that quantify what the expected future costs of renewables and storage technologies are expected to be. The implications for integrating solar and wind technologies with storage in the DER concept are described. The concepts that are currently being used to establish economic viability of renewable-based DER are summarized. The expected costs for conventional technologies are also presented.

Section 5.0 examines the nature of the intermittency of renewables and the associated implications on the use of storage. The nature of demand fluctuations is also described along with the implications on the use of storage for both renewables-based DER as well as baseload-supplied DES.

Section 6.0 interprets the U.S. dollar cost forecast for DER technologies and applies that to the Ontario situation. The unique cost implications of renewables' intermittency in Ontario on the DER options are explored along with the impact of Ontario's expected future demand fluctuations. The ability of the DER/DES options to supply the needed future demand is summarized. The cost implications are compared for the DER options for Ontario's low-emission supply mix.

Finally, Section 7.0 summarizes the findings and offers several observations.

2.0 Methodology

The following steps were taken to establish the basis for the findings in this report:

1. Establishing the Ontario context for DER and the associated options.
2. Identifying the global consensus on future cost expectations for renewables and storage.
3. Analyzing the impact of the intermittency of renewables and demand fluctuations on Ontario's DER options.

Establishing Ontario's DER context

The 2017 LTEP provides the foundational perspective for Ontario's plans to leverage renewable-based DER, including the forecast of Ontario's capacity to be renewed and /or replaced. The IESO defined the impacts of DER and storage challenges for the operation of the Tx system, and the Ontario Ministry of Energy (MoE) subsequently commissioned a study on the potential benefits of storage for the province.

Forecasting Future Costs

Several sources were drawn upon to develop a consensus on the future costs of generation, renewables and storage. The approach taken for this study was generally to accept the most aggressively low-cost forecast for the renewables and storage available. The purpose of embedding a low-cost bias in this study's assumptions was to underscore the significance of the resulting high total system costs after taking into account the impact of intermittency. This represents a conservative approach.

Generation costs were obtained from three U.S based sources published in 2017:

1. U.S. Energy Information Administration (EIA) 2017 Annual Energy Outlook (AEO)
    - The EIA bases its forecasts on actual projects and applies an economy of scale function for lessons learned approach to estimate future costs to 2050.
    - The primary EIA reference was the "Levelized Cost and Levelized Avoided Cost of New Generation Resources" in the 2017 AEO.
    - The research also drew upon reports that the EIA commissioned to support its 2017 AEO estimates for small solar and wind applications.
        - Distributed Generation and Combined Heat & Power System Characteristics and Costs in the Buildings Sector, 2017 (prepared by Leidos).
2. U.S. National Renewable Energy Laboratory (NREL) 2017 Annual Technology Baseline (ATB)
    - The NREL mandate is to keep at the forefront of technology development in this space.
3. Lazard's Levelized Cost of Energy Analysis – Version 11.0
    - Lazard surveys developers of technologies for their expectations on costs, both recent and for the next five years.

Storage cost forecasts were derived and validated based on four sources:

1. The primary source was Lazard's Levelized Cost of Storage (LCOS) 3.0.
    - The earlier version, LCOS 2.0, was also consulted, as it provided estimates for pumped storage and compressed air energy storage (CAES).
    - As Lazard only provides directional long-term forecasts, the forecast used in this study was developed based on a review of industry commentaries, insights, and other proxies.

2. Several secondary NREL research reports were also consulted to understand component costs and the opportunities that may arise when integrating solar with storage.
3. The results of the forecasts used here were then compared to forecasts from the 2018 Green Tech Media (GTM)[21] and the 2017 International Renewables Energy Agency (IRENA) reports to validate that the 2030 values used in this report were also lower than forecasts from these sources.

Analysing Intermittency

To conduct the intermittency analysis, IESO data was obtained for the years 2015 through to 2017. This data included:

1. Generation output by hour, for all Ontario generation including wind and solar.
    - Wind and solar data was obtained for both before and after curtailment.
2. Demand data for 2015 through to 2017.

To assess the implications of demand fluctuations on DER solutions, the 2017 LTEP was consulted to define incremental assumptions to be added to the IESO 2016 Ontario Planning Outlook (OPO) low growth demand Outlook B scenario. From these sources, a detailed hourly forecast was developed for 2035.

Separate simulations were conducted for wind-based DER, solar-based DER, and nuclear baseload-supplied DES options. Assumptions were made on how to size the storage for each case to best illustrate the impacts of intermittency. High level sensitivity assessments were conducted to illustrate the impact of storage capacity. There are many parameters that could be tuned to optimize an actual implementation. However, the results described in this report suggest that fine tuning is not expected to materially change the relative outcomes of the scenarios.

Benchmark data was obtained for U.S. jurisdictions from the EIA and Lazard to assess capacity factor differences between the U.S. and Ontario. These capacity factor differences form the basis for projecting relative impacts from intermittency.

[21] GTM, 2018

3.0 Distributed Energy Resources Capabilities and Applications

DERs are being viewed as a potential game changer with respect to how future electricity systems are planned and developed[22]. According to Ontario's IESO[23], DERs are:

> "…electricity-producing resources or controllable loads that are directly connected to a local distribution system or connected to a host facility within the local distribution system.
>
> DERs can include solar panels, combined heat and power plants, electricity storage, small-natural gas-fuelled generators, electric vehicles and controllable loads, such as heating/cooling systems and electric water heaters. These resources are typically smaller in scale than the traditional generation facilities that serve most of Ontario demand."

DER that includes renewables coupled with storage are advocated as the low-cost, low-emission supply alternative to fossil fuels and the basis for adding more intermittent renewables to the supply mix. Three factors have played a critical role in this transition: renewables such as wind and solar are now integral parts of the energy mix in many jurisdictions; the next generation of these technologies have experienced dramatic cost declines; and, Lithium-ion (Li-ion) batteries for energy storage are following a similar cost reduction path.

Many proponents of renewables-based DER also advocate that DER represents an alternative to nuclear. Conventional power stations, such as coal-fired, gas and nuclear-powered plants, as well as hydroelectric dams and large-scale solar power stations, are centralized and often require electric energy to be transmitted over long distances. By contrast, DER systems are decentralized, modular and flexible technologies, that are located close to the load they serve, typically with capacities of 10 megawatts (MW) or less. These systems can comprise multiple generation and storage components. In contrast, many believe that nuclear must play a significant role in reducing emissions from the production of energy, in particular for 24x7 baseload supply. The hyperbole around DER falls into two categories:

1. The degree to which distributed storage can be coupled with renewables to mitigate intermittency and enable more renewables; and,
2. The degree to which DER can provide broad system benefits beyond just smoothing intermittency.

This section summarizes the DER promise, the types of DER installations that have been identified in the literature, the demand profiles that DER should respond to, and examples of DER technologies that have been considered. This section concludes with a definition of the DER options that are contrasted in the costing and intermittency assessments of this report.

3.1 The DER Promise

The DER promise is that distributed energy production, coupled with appropriate amounts of storage, can provide several benefits to both the electricity system and to consumers, as summarized in Figure 3[24].

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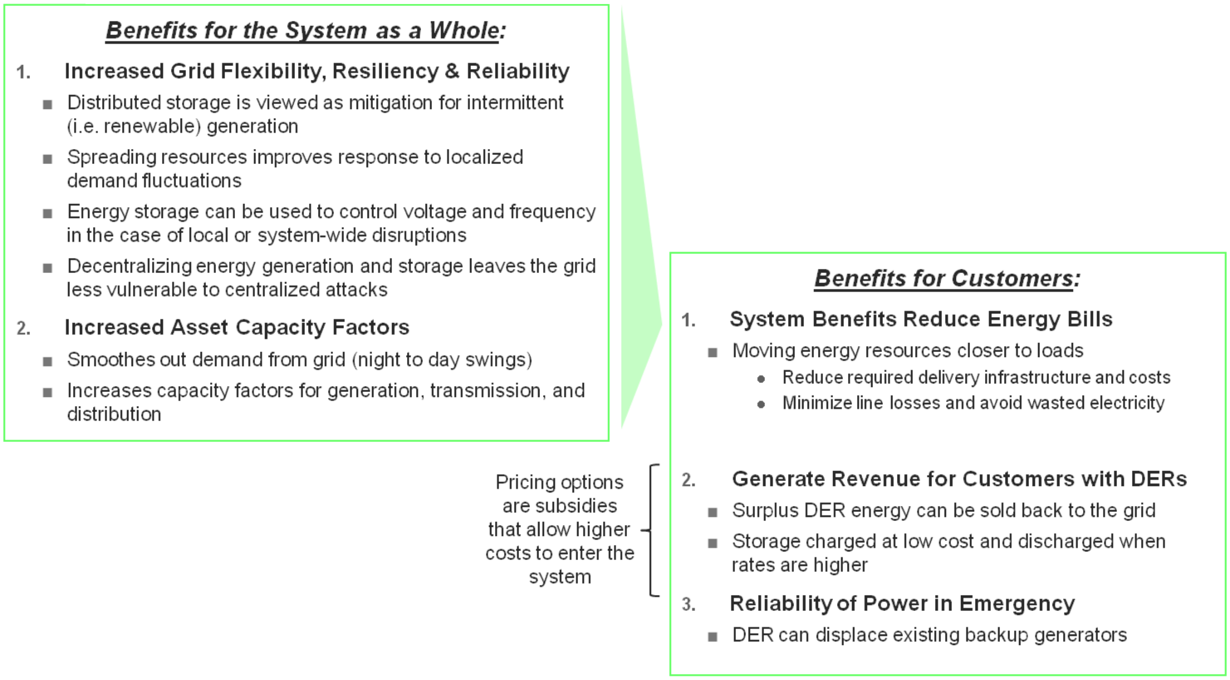
[22] IESO Energy Storage, 2016; MoE, LTEP, 2017
[23] IESO website
[24] Siemens 2011; LTEP 2017; CPI 2017; Massachusetts Energy Storage Initiative, 2016; Lazard LCOS v3.0; Mowat 2017

Figure 3 – DER's Promised Benefits to the Electricity System and Consumers



System benefits are mostly enabled by the capabilities of storage and fall into two main categories:

1. Increased Grid Flexibility, Resiliency and Reliability
   - Among the sought-after benefits for grid reliability, where high renewables are deployed or desired, is the potential for distributed storage to allow for easier integration of intermittent renewable generation.
     - According to the IESO[25], energy storage can be used to enhance the grid's ability to manage the influx of variable renewable generation in the following areas: load following, ramping and dispatch flexibility; regulation; Tx voltage control; operating reserve; and zonal limitations. The IESO also recognizes that storage is not the only available option for addressing these operating challenges.
   - Decentralizing energy generation and storage would also leave the grid less vulnerable to local or system-wide disruptions or centralized cyber attacks and also supports quicker local energizing of the distribution system following a blackout[26]. However, energizing the higher voltage Tx system requires substantial reactive power support be available on-line at both ends of long Tx lines suggesting DER solutions, may have limited benefit.
   - Distributing storage and generation resources throughout the grid, among and closer to user demand centres should allow for better response to localized demand fluctuations.

2. Increased Asset Capacity Factors for Generation, Tx, and Distribution (Dx)
   - DER has the potential to provide a local demand management function that can smooth out the magnitude of electricity demand peaks that are imposed upon the grid. By doing so, DER

[25] IESO Energy Storage, 2016
[26] Essex Energy, 2017

can reduce the capacity requirements for the grid and hence, if the same energy is delivered, increase the capacity factors of generation, Tx and potentially Dx assets in the bulk electricity system.

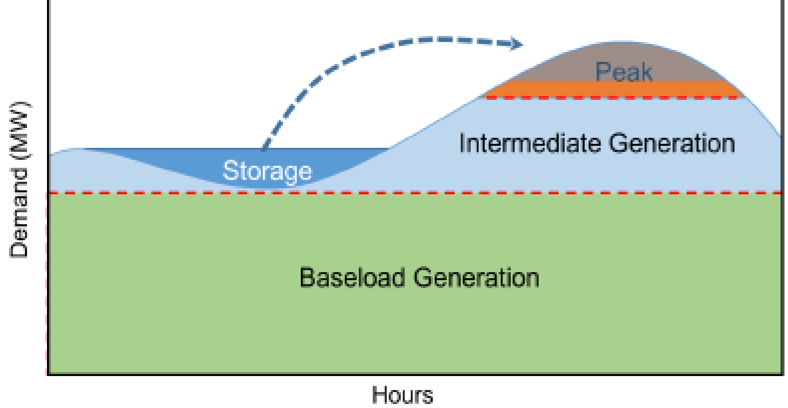
- Increasing the capacity factor of the delivery systems reduces the fixed capacity costs and the effective per MWh electricity rates.
- By potentially reducing the peak reserve margin requirements, DER can reduce the cost of reserve capacity that is very infrequently used.
- The ability to more efficiently size generation, Tx, and Dx assets to best meet energy demand lowers the fixed costs of capacity. Installed capacity represents the lion's share of costs in a low emission electricity system because fuel costs are low or zero. Reducing capacity improves the cost-effectiveness of the entire system.

Consumer benefits fall into three categories of interest:

1. Reducing Energy Bills Through System Benefits
    - System benefits of DER impact consumers through their energy bills. The ability of DER to help optimize system capacities will reduce the effective delivery infrastructure costs that are paid for by the consumer.
    - By locating generation closer to the consumer, electricity losses during delivery to consumers would be reduced.
2. Generate Revenue for Customers with DERs
    - For consumers that have rooftop solar panel based DER systems, experience shows that the electricity output does not generally match the consumer's energy use. The ability to sell the excess energy back to the grid allows the consumer to recover some of the costs of the installation. Net metering is one example of how such revenue opportunities can be enabled. Unfortunately, most pricing incentives that promote the deployment of high cost residential generation systems are subsidies that increase the costs for other ratepayers. This is discussed in Section 4.4.
    - Storage, on its own, creates the opportunity for consumers to charge the storage when retail rates are low, such as at night, and then discharge the energy back to themselves or the system when retail rates are higher. Effectively, consumers can participate in retail pricing arbitrage and benefit from low cost electricity. The pricing arbitrage also offers benefits to the system to the extent that peak demand shaving can be consistently achieved as illustrated in Figure 4[27].
3. Emergency Backup Generation
    - Some consumers feel the need to have an emergency backup electricity supply for when unexpected outages occur on the bulk electricity system. Such backup capability can be provided by the storage capability of DER. Since diesel backup generators are relatively costly and environmentally unfriendly, this DER benefit may be important to those customers wanting emergency backup. However, electrical storage would typically be configured with a shorter backup run-time than diesel generators due to the higher cost.

[27] Massachusetts Energy Storage Initiative, 2016

Figure 4 – DER Potential for Peak Shaving



3.2 Locational Considerations for DER

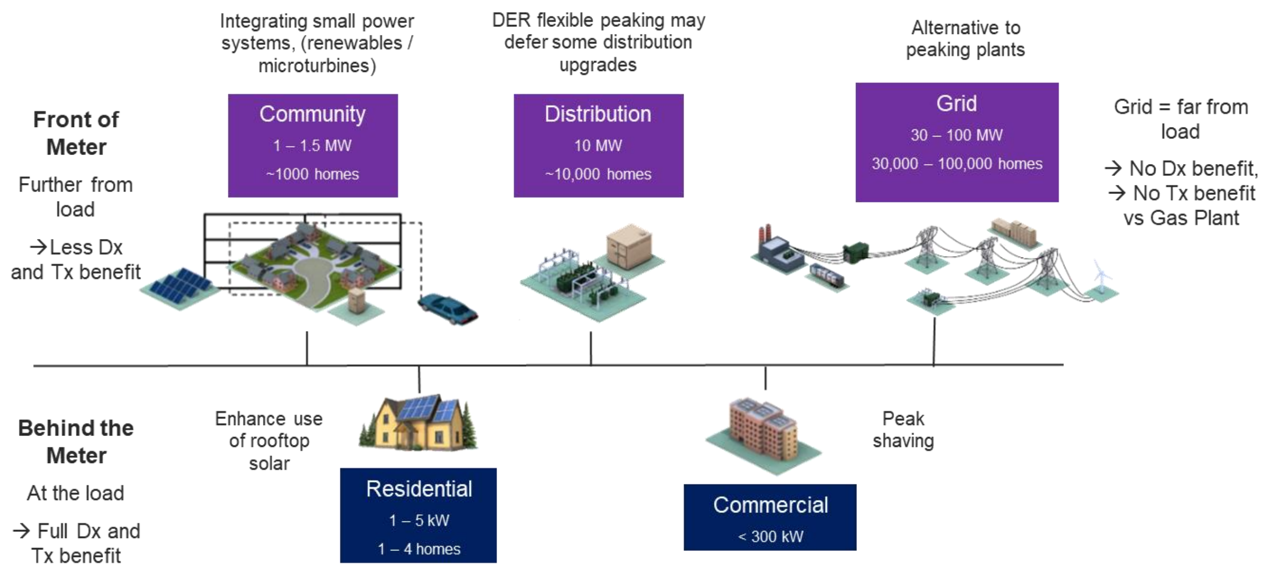
DER can be deployed at many different points within the electricity system. As shown in Figure 5[28], locational options fall into two categories: in front of the meter; and behind the meter. In either case, installations can vary significantly in scale. Residential and commercial DER opportunities are referred to as "behind the meter", as they are installed on consumer premises and are not metered by the utility. These installations are typically very small, with a capacity on the order of 1 to 5 kW for a single home but could be up to 300 kW for commercial applications. In the case of storage, the amount of stored energy typically provides only a few hours of rated capacity.

"In front of the meter" applications involve solutions that would typically be managed by the LDC. These solutions range in size from smaller community installations to large-scale Dx installations. A small community installation would typically serve 1,000 homes with 1 MW to 1.5 MW of generation capacity. A larger Dx scale installation would be optimized around the Dx substations to help smooth peak demands and would serve larger communities of 10,000 homes for example.

The largest scale resources are high voltage grid connected resources typically in excess of 30 MW, which, by definition, are not usually considered to be DER.

[28] Definitions adapted from Lazard LCOS v3.0

Figure 5 – DER Opportunities by Location



System benefits from DER vary with location as summarized in Table 1[29].

Table 1 – DER Use Cases by Location

DER Location		Description and Use
Front-of-Meter	Community	Supports community or small power systems that can have some independence from the broader power grid. Could also provide ramping support to enhance system stability and increase reliability of service.
	Distribution	Typically placed at substations or distribution feeders controlled by utilities to defer distribution upgrades. May also provide flexible peaking capacity and mitigate stability problems.
	Grid	Large-scale energy system designed to replace peaking gas turbine facilities and the reliability services they provide. Can be brought online quickly to meet rapidly ramping demand for power at peak and taken offline quickly as power demand diminishes.
Behind the Meter	Residential	Behind-the-meter residential use to provide backup power and extend the usefulness of self-generation (e.g., "solar plus storage"). Smooths the quantity of electricity sold back to the grid from distributed solar PV applications.
	Commercial	Behind-the-meter peak shaving and demand charge reduction services for commercial energy users. Option to provide grid services to the utility.

[29] Paraphrased from Lazard LCOS v3.0

The Ontario MoE commissioned a study[30] to evaluate the economics of using storage based on the value elements of the DER promise. The study focused on the near-term value of DER for Ontario's current extensive deployment of renewables and the associated system challenges identified by the IESO. The possible value of DER that could be obtained from different types of installations at different locations is summarized in Table 2[31].

Table 2 – Direct Benefits of Energy Storage

		Distributed Connected Energy Storage Location			
	Lazard/IRENA Framework	**Grid**	**Distribution**	**Community**	**Residential/ Commercial**
Benefits Category	**Currently Monetizable Benefits**	**At Tx Station**	**Middle of Feeder**	**End of Feeder**	**Behind Meter**
System	Non-Spinning Reserve Availability	✓	✗	✗	✗
	Spinning Reserve Availability	✓	✗	✗	✗
	Reserve Activation	✓	✗	✗	✗
	Power Quality Improvement	✓	✓	✓	✓
	Frequency Regulation	✓	✓	✓	✗
	Voltage Control	✗	✓	✓	✗
	Black Start	✓	✓	✗	✗
Asset Optimization	Distribution System Upgrade Avoidance	✓	✓	✓	✗
	New Generation Capacity Avoidance	✓	✓	✓	✗
	Reduce Dispatching of Peaker Facilities	✓	✓	✓	✓
Consumer Price	Wholesale Market Arbitrage	✓	✓	✓	✗
	Retail Market Arbitrage	✗	✗	✗	✓
	Global Adjustment Charge Reduction (Class A)	✗	✗	✗	✗
Consumer	Redundant Power Supply (Reliability)	✓	✓	✓	✗

Essex's report identified that grid-scale applications located at the Tx/Dx Interface offer the most benefits. This is because grid-based wind intermittency reliability issues occur at this interface. Since 85% of the installed wind in Ontario is connected to the Tx system, mitigating the impacts of variable generation is best managed, as close to the generation source, as possible. From a Dx system perspective, the Tx/Dx interface is the connection to the variable generation. The reverse is true for solar, which has been predominantly installed at individual residences in Ontario. Essex's approach to addressing these challenges with DER is defined here as "intermittency management".

[30] Essex Energy, 2017

[31] Recreated from Essex 2017 report to regroup rows into the broader categories used in this report.

In contrast, the approach taken in this report looks at how to best meet demand through renewables-based DER. From that perspective, the concept of renewables-based DER entails co-locating the storage with the generation, such as with behind the meter applications. Co-location is inherently designed to mitigate the intermittency effects of the generation, but also delivers a broader "demand management" function by ensuring the DER produces an output to meet consumer demand in a specific area. Effective consumer demand management should flatten the load presented back to the Dx and Tx systems, achieving the maximum asset optimization benefit.

To maximize the demand management benefits of DER and optimize system capacity factors, solutions are best located as close as possible to the user demand. For demand management purposes, the following expectations arise:

- Grid based solutions are likely to offer little Tx and Dx benefit as the purpose of grid-based DER would be to mimic the capability of gas-fired generation plants to meet the demand on the grid. Some avoided line loss benefits may be realized if their grid locations are closer to the demand centres than heritage generation sites.
- Dx scale installations would smooth out grid demand but offer little benefit to the Dx networks downstream where peak requirements remain driven by consumer behavior.
- When DER is implemented at the community level or behind the meter, the demand management or levelling function is better positioned to maximally optimize the entire delivery system infrastructure.

3.3 Future Demand for DER Output Capabilities

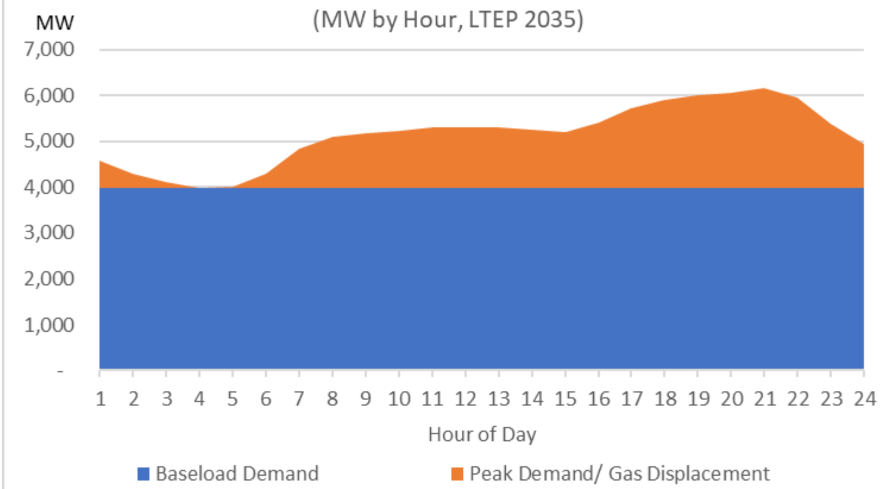
Many of the benefits of DER for smoothing peak demand to optimize delivery infrastructure have been articulated. However, in order to meet the capacity gap challenges that are emerging in Ontario, DER solutions should be expected to supply one of two components of user energy demand:

1. Daytime demand to mitigate the need to renew or replace expired gas plant operations.
2. Baseload demand to replace the 3,000 MW gap when the PNGS retires in 2024.

The two profiles, illustrated in Figure 6, reflect the requirements for a DER system that best supports Ontario's electricity system needs and yields the desired benefits.

Since renewable outputs are determined by the natural energy supply (wind, sun or water) and are only dispatchable to the extent that the wind is blowing, the sun shining and water is available, these resources are to a significant extent uncontrollable. These means storage systems are required to provide the output that meets energy user demands across the entire electricity system.

Figure 6 – Ontario's Capacity Gap – Supply Needed for Baseload and Peak Demand Profiles



To provide a baseload function, storage must smooth intermittent renewables at a lower cost than low emission baseload generations such as nuclear or hydro, or even natural gas with carbon capture and storage.

For renewables-based DER solutions to supply daytime demand, the requisite storage for managing intermittency must be enhanced to also manage demand fluctuations. With a baseload-supplied DER solution, the storage function must only manage the demand fluctuations. Section 5 discusses the nature of intermittent renewables and quantifies the implications of supplying the required demand.

3.4 Candidate DER Technologies

Several storage technology demonstrations have been deployed in the marketplace. These provide examples for the concepts modelled in this report:

- Li-ion batteries coupled with solar to emulate a natural gas peaker system
- Pumped hydro storage coupled with either hydro or wind resources
- CAES coupled with wind resources

A summary of storage technologies that are being piloted in Ontario is provided in Table 3[32].

Table 3 – Ontario Energy Storage Project Summary

Project	Technology	Capacity	Benefits
POWER.HOUSE	Li-ion Battery	228 kWh	Redundant power supply
Penetanguishene Microgrid	Battery	500 kWh	Redundant power supply
Pan Am Games 2015		100 kVA, 125kWh	Load shifting

[32] Reproduced from Essex Energy, 2017

Hydrostor - Toronto	CAES	Varies	Distribution line decongestion
eCAMION – Toronto Hydro	Li-ion battery	25 kW, 16 kWh	Infrastructure support
eCAMION - Toronto	Li-ion battery	500 kW, 250 kWh	Infrastructure support
NRStor - Minto	Flywheel	±2 MW, 500 kWh	Frequency regulation
HONI – Clear Creek	Flywheel	±5 MW, 500 kWh	Voltage control
Opus One - DEMSN	Battery		Voltage support, generation integration
RES Canada - Strathroy	Li-ion battery	4 MW, 2.6 MWh	Frequency regulation
NEDO – Oshawa	Li-ion battery	10 kWh	Load levelling
Convergent Energy – Sault Ste. Marie	Li-ion battery	7 MW	Reliability
Hydrogenics	Power-to-Gas	2 MW	Frequency regulation
Ameresco – Phase II	Solid Battery	(2x) 2 MW, 8 MWh	Peak shaving
Baseload Power – Phase II	Flow Battery	2 MW, 8 MWh	Grid support and arbitrage
NextEra – Phase II	Solid Battery	2 MW, 8 MWh	Grid support and arbitrage
NRStor Inc. – Phase II	CAES	1.75 MW, 7 MWh	Grid support
SunEdison – Phase II	Flow Battery	1 MW, 4 MWh (2x) 2 MW, 8 MWh	Grid support

Examples of underlying DER concepts and applications include:

a) Arizona's Experience with Solar and Storage

One of the major benefits of pairing batteries with solar power is to fix the mismatch between patterns of solar generation and demand. The demand peaks of the morning and evening in Arizona bookend midday peak solar generation. Arizona, at times, has too much solar generation and has little need for additional generation with the same profile.

Tucson Electric signed a power purchase agreement (PPA) with First Solar for a solar plus battery peaker system in February 2018[33]. The peaker system has been contracted to provide up to 50 MW of power between 3pm and 8pm. The cost of this system is expected to be competitive with existing gas peaker plants when completed in 2021. The storage system will be paired with a new 65 MW solar plant and be able to store 135 MWh for almost 3 hours of discharge duration.

b) Ontario Power Generation (OPG) Niagara Falls Pumped Storage

[33] GreenTech, 2018

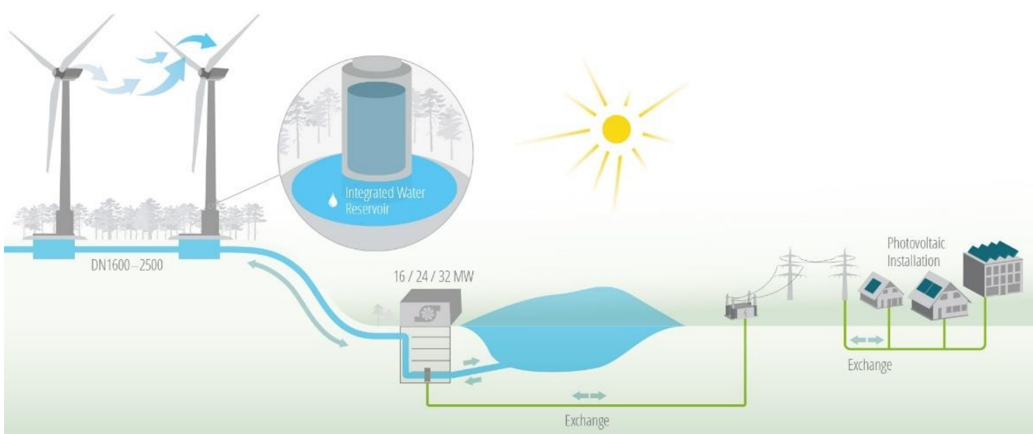
OPG has a pumped hydro station next to the Sir Adam Beck hydro power complex, both of which are adjacent to the Niagara River. Water is pumped into a reservoir at night when demand and electricity prices are low. Filling the reservoir can take up to 8 hours. During high demand, water can be released to flow through turbines at the Sir Adam Beck Complex providing up to 174 MW of capacity.[34] The station has a unique cascade configuration made possible by the unique geography of Niagara Falls and the Niagara Escarpment. The effective power swing is several times greater than the power capacity of the pumped storage facility.

c) Germany Integrated Wind Farm and Pumped Hydro Storage[35]

Large wind turbines in Gaildorf, Germany are connected to a nearby hydro pumped storage facility and store water within the towers themselves as illustrated in Figure 7.

Water from the turbines can be released and channeled into a hydro power station below when needed. Each of four 180-meter-high, 3.4 MW wind turbines can store up to 70 MWh of water pumped up from a nearby lake. Stored water is equivalent to over 20 hours of full capacity wind generation. With wind blades of over 60 Meters, these large grid-scale facilities are almost 80 stories high, larger than most skyscraper office towers in the world's major cities.

Figure 7 – Wind Turbine System Illustrated



d) Toronto Hydro Compressed Air Energy Storage

Toronto Hydro is working with Hydrostor Inc. to analyze the electrical grid benefits of underwater CAES[36]. The world's first system has now been installed in Lake Ontario. The pilot project will focus on the unit's ability to provide reserve power, shift load and smooth out Tx and Dx congestion. The system is designed to store excess electricity generated during low-demand off-peak hours by driving compressed air into

[34] OPG, 2018

[35] Dvorak, 2017

[36] Toronto Hydro, 2018

a flexible wall air accumulator below the lake's surface. When the energy is required, the system is reversed.

e) NRStor-Hydrostor Goderich CAES Demonstration Project[37]

This energy-storage facility with a four-hour discharge capability would provide energy to help the Ontario electricity grid meet peak demand. The expected value for ratepayers is more efficient integrated wind-generated electricity and load levelling. Grid operators need flexible resources to offset errors in wind and solar forecasting.

The 1.75 MW, 7 MWh CAES facility will use proprietary technology to store electricity in the form of compressed air and heat. NRStor's novel solution utilizes an existing bedded salt cavern as a storage cavity. The project is expected to demonstrate the success of fuel-free CAES, creating market opportunities for Canadian companies to globally deploy locally developed technology.

3.5 DER Scenarios

The scenarios chosen for this study are:

1. *Solar-based DER:* Community-scale solar integrated with Li-ion battery storage
    - This is one of the most prevalent architectures discussed in the literature.
    - Stakeholder interviews conducted by the Essex study identified the 1 MW community scale as the most likely form of distributed storage.38
    - This option offers the best opportunity for optimising system capacity benefits and has storage costs comparable to larger scale installations.
2. *Wind-based DER:* Grid-based wind coupled with CAES
    - For the majority of jurisdictions, only grid-scale wind is expected to be a viable economic option (see Section 4.0).39 Small-scale wind has relatively excessive land use implications, even at small scale.40 The planned MoE's net metering siting restrictions will effectively make small scale wind ineligible for Ontario's residential net metering program.41
    - CAES is a lower cost grid-scale storage option than Li-ion batteries. Ontario's topography and resource extraction legacy may present many options for integrating CAES with wind farm output. However, because of the thermodynamics of compressing air, the round-trip energy losses of the process are less efficient than the Li-ion batteries.
3. *Baseload-supplied DES:* Grid-based nuclear baseload coupled with distributed Li-ion battery storage systems
    - Li-ion storage systems have the ability to be ubiquitously distributed at the community level and hence, from a storage perspective, this scenario is analogous to solar.

[37] Sustainable Development Technology Canada, 2018
[38] Essex Energy, 2017
[39] Remote community applications have not been considered
[40] Leidos, 2016
[41] Environmental Registry Regulation Proposal #013-1916, Proposed New Regulation to be made under the Electricity Act, 1998 (28 November 2017).

3.6 Summary

There are many benefits that various DER configurations could provide to the electricity system and consumers. However, not all of the consumer benefits are in the best interests of the overall electricity system. The ability to realize the potential benefits also varies by location.

The system benefits from DER may be best achieved by designing DER solutions that leverage the energy advantages of Ontario's existing electricity systems.

4.0 Understanding the Cost of Renewables + Storage

The declining costs of renewables and energy storage solutions has received a lot of media coverage, with advocates claiming that these technologies are now competitive with fossil fuels. Yet, the MoE-sponsored study found that based on what can be monetized by investors in today's markets, the storage options are not economically viable, with the exception of commercial applications that aim to reduce demand charges[42].

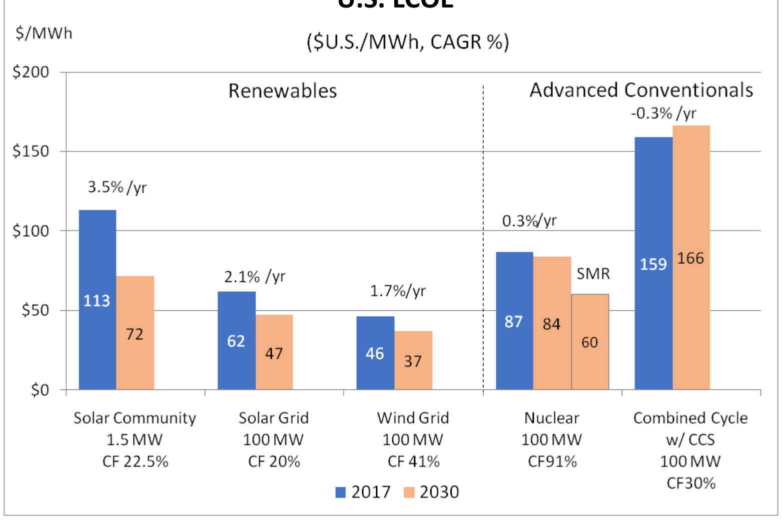
This section explores the costs of renewables, storage and other generation required to enable DER options. Specific attention is given to how the cost of renewables and storage may decline by 2030 and how that compares to the other components of low emission DER system options.

The major findings for the costs of generation, storage, and integrated DER systems are illustrated below in Figures 8, 9, and 10.

a) Costs of renewables are declining modestly

Figure 8[43] summarizes the expected future costs in the U.S., in terms of the Levelized Cost of Electricity (LCOE) of the low emission generation options that could support the long-term objectives of DER: solar, wind, nuclear and Combined Cycle Gas Turbine (CCGT) natural gas-fired generation with carbon capture and sequestration (CCS). Community scale solar systems are expected to have material annual decline rates with total declines of approximately 30% from 2017 to 2030. However, the LCOE for community-scale solar installations will remain above \$70/MWh[44] in regions with average U.S. capacity factors.

Figure 8 – DER vs. Conventional Generation Average U.S. LCOE



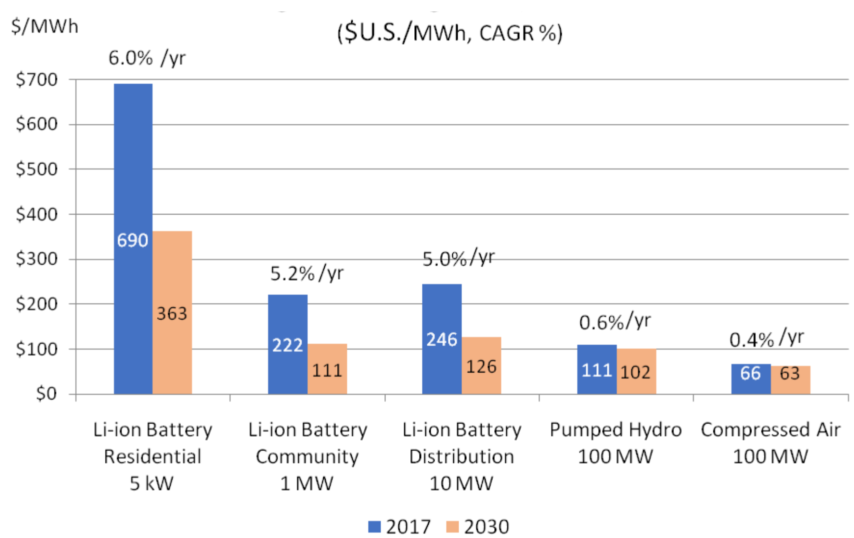
[42] Essex identified monetizable and non-monetizable value areas. Strapolec disagrees with how the non-monetizable benefits have been calculated, the assumption of 100% capacity factor of the storage, and the assumed ongoing existence of surplus energy. Essex use cases only economic due to pricing mechanisms arbitrage. Refer to section 4.4.
[43] CAGR is compounded annual growth rate from 2017 to 2030; Natural gas plant assumes a 30% duty cycle for supplying daytime demand. Renewables costs without storage and subject to from intermittency,
[44] All dollar figures in Section 4.0 are in US \$2017 unless specified otherwise.

At this level, it would appear that the LCOEs of the grid-based solar and wind are indeed lower than nuclear and natural gas with carbon capture. This section establishes that the LCOE of standalone renewables is not the measure that should be used, but rather it is the LCOE of the integrated DER solution that should be the key benchmark. For renewables to be viable in a DER context, they must supply a particular demand load, such as the daytime load that exceeds baseload. To do so, the renewables must be coupled with storage so that the energy provided is coincident with the demanded load. Power engineers refer to this capability as capacity value. Without storage, intermittent renewables have relatively little capacity value.

b) Costs of battery storage expected to decline 50% by 2030

Figure 9[45] summarizes the LCOS of storage systems evaluated in this study: Li-ion batteries of residential to Dx scale; and, pumped hydro and CAES suitable for some grid-scale applications. At $363/MWh, residential storage is expected to remain an excessively high cost option beyond the forecast time horizon of this study. Even community scale storage is expected to remain higher than the more conventional options of pumped hydro and CAES. The CAES technologies are expected to remain the least expensive option by a wide margin looking forward to 2030.

Figure 9 – Storage U.S. Average LCOS, 2017 vs. 2030



The benefits of Li-ion batteries over the other options are their low loss factor and the flexibility to locate them where they are needed. Pumped hydro and CAES are limited to where geological features or other available physical characteristics enable their installation. They may have limited ability to support small-scale DER solutions.

The raw costs of renewables and storage do not reflect the cost of a DER system. The cost of a full system that integrates renewables with storage options to meet a demand requirement is the relevant measure

[45] Storage costs shown do not include cost of energy to be stored and reflect operating duty cycles where storage is fully charged and discharged on a daily basis.

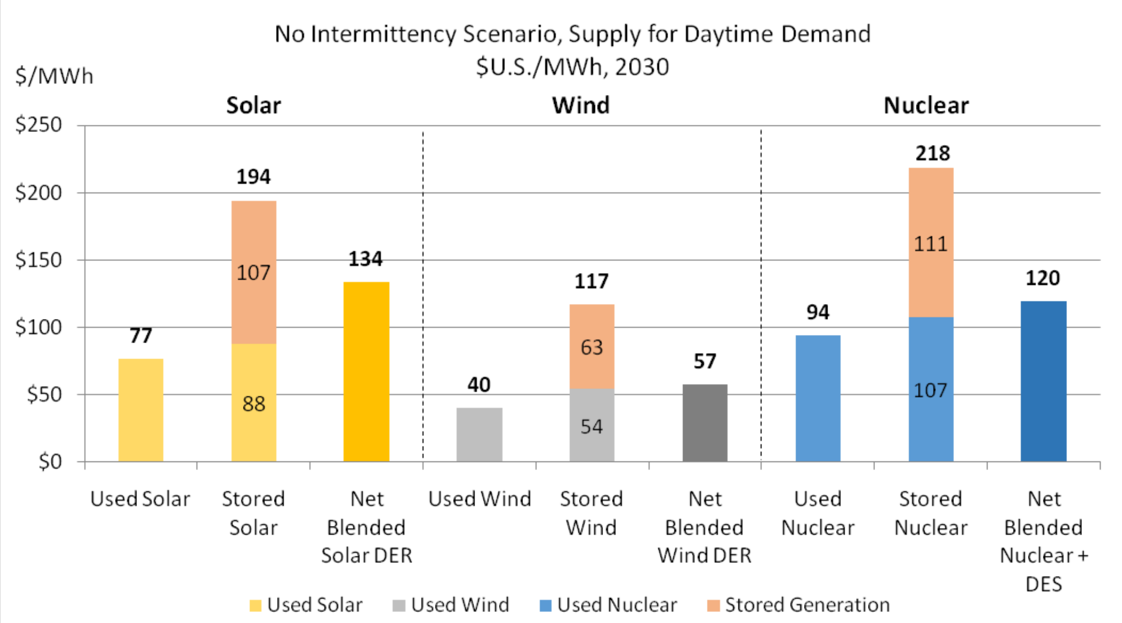
for assessing how competitive these technologies are. The integrated performance of the DER system is determined by several factors:

1. Integrating solar and storage systems could allow for capital cost reductions due to sharing of components.
2. Configuring the components (e.g. the solar panel and battery) to supply the expected demand profile determines the blend of the electricity used.
3. Storage systems are not 100% efficient in the process of charging and discharging the energy to and from the storage. This inefficiency is measured as the round-trip energy loss. Losing energy through the storage device increases the net cost of energy that is output from the storage device.
    - Li-ion batteries are expected to have a 14% round trip energy loss. CAES is expected to have a 35% round trip energy loss.[46]

c) Costs of DER will remain high

Figure 10[47] illustrates how the cost of renewable energy changes when coupled with storage. Three terms capture how the costs are realized. The used generation is at the cost typically expected. Stored energy has a higher cost for the generation that is stored because of the round-trip losses in the system. The cost of the storage then gets added to that of the stored energy to get the full cost of the stored energy. The net blended cost is a function of how much energy is used directly versus stored.

Figure 10 – Integrated DER LCOE Comparison



[46] Lazard, LCOE v11, 2017

[47] Solar case is community-scale, while the wind case is grid-scale with compressed gas storage. Values reflect ideal weather and demand conditions that do not introduce intermittency.

The storage required to help renewables deliver energy in response to user demand will add $107/MWh to the cost of any stored solar for a total LCOE of stored energy of $194/MWh in the U.S. Storage costs when integrated with solar photovoltaic (PV) panels in a tightly coupled manner can realize some capital cost savings which have been reflected. The net blended solar DER cost of $134/MWh reflects a solution where half of the solar energy is directed to storage for use in supplying the expected demand profile. At $134/MWh, it is not clear whether solar-based DER is competitive with alternative generation.

For wind-based DER, the expected blended cost could be as low as $57/MWh. This would be for a grid-scale application and could be competitive with other solutions. The blended cost of a nuclear baseload-supplied DES solution is estimated at $120/MWh, 11% less than solar. Section 5 of this document explores the implications intermittency has on the above LCOEs.

Given these results, why is so much attention being paid today to renewables-based DER? There are two possible answers to this question: (1) DER is considered applicable for optimizing revenue capture in fossil-based energy markets where prices peak with high demand; or, (2) creative subsidies, such as net metering hide the full cost that is being incurred to the whole system.

As discussed earlier, this study examines the costs of available technologies to supply a full demand profile.

This section examines the following relevant subjects:

1. Projected costs for solar and wind generation
2. Projected costs of storage
3. The cost implications for integrated DER solutions under ideal conditions
4. The marketing of DER solutions today
5. The costs of alternative low-emission technologies, such as nuclear and CCGT with CCS.

4.1 Renewable Generation Costs

This section examines the capital cost and LCOE forecasts of solar and wind technologies obtained from multiple sources. For each technology, different scales of implementation are considered, from small-scale residential applications to large grid-scale facilities. Figures 11, 12 and 13 illustrate the expected capital cost and LCOE decline rates.

Figure 11 – Solar U.S. Capital Cost Forecast, 2017 vs. 2030

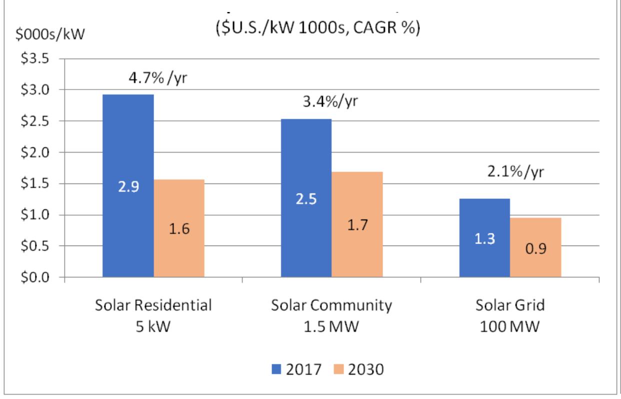


Figure 12 – Wind U.S. Capital Cost Forecast, 2017 vs. 2030

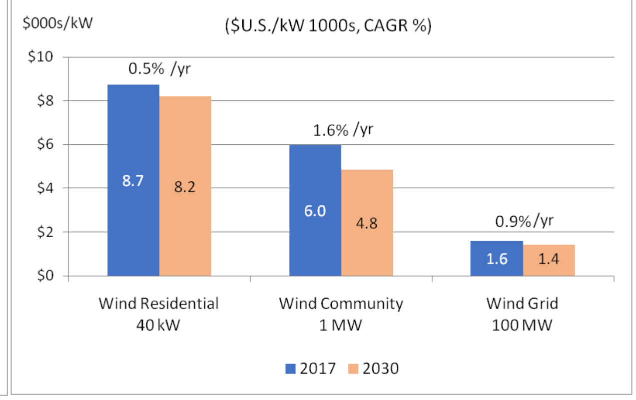
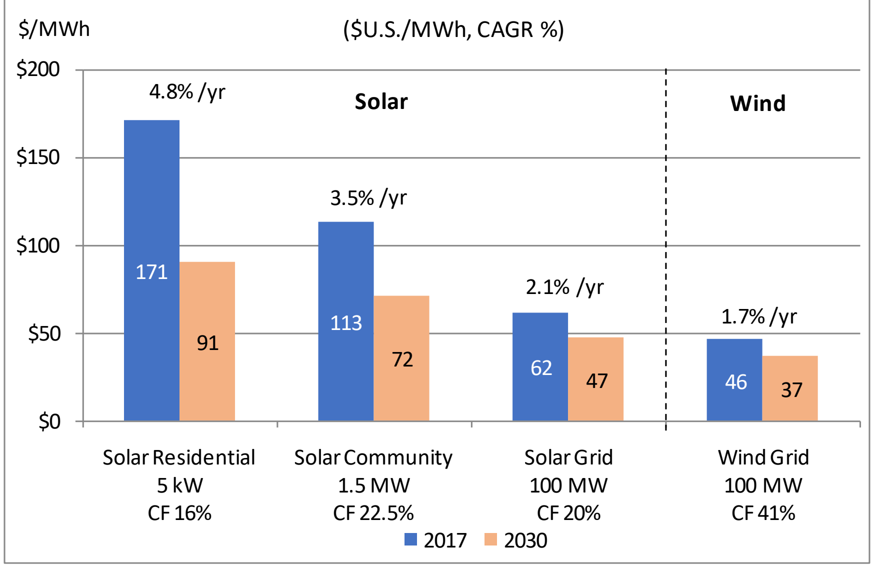


Figure 13 – Solar and Wind Average U.S. LCOE Forecast, 2017 vs. 2030



For solar applications, residential scale systems are expected to drop the fastest, but will remain 25% higher than community solar and almost double that of grid-scale solar by 2030. The capital cost forecasts for small-scale wind suggest it will remain 4-5 times the cost of grid-scale wind. Given land use challenges, small-scale wind in a residential setting is not considered further in this study. Grid-scale wind is expected to have more modest LCOE declines than solar.

4.1.1 Solar Cost Assumptions

Three different scales of solar installations were considered:

1. Residential installations, of 5 kW or less, which are rooftop mounted and feature no tracking mechanisms;
2. Community and commercial scale installations, of up to 1.5 MW, consisting of both fixed-tilt rooftop and pole mounted tracking systems; and,

3. Grid-scale solar installations from 5 MW to 150 MW.

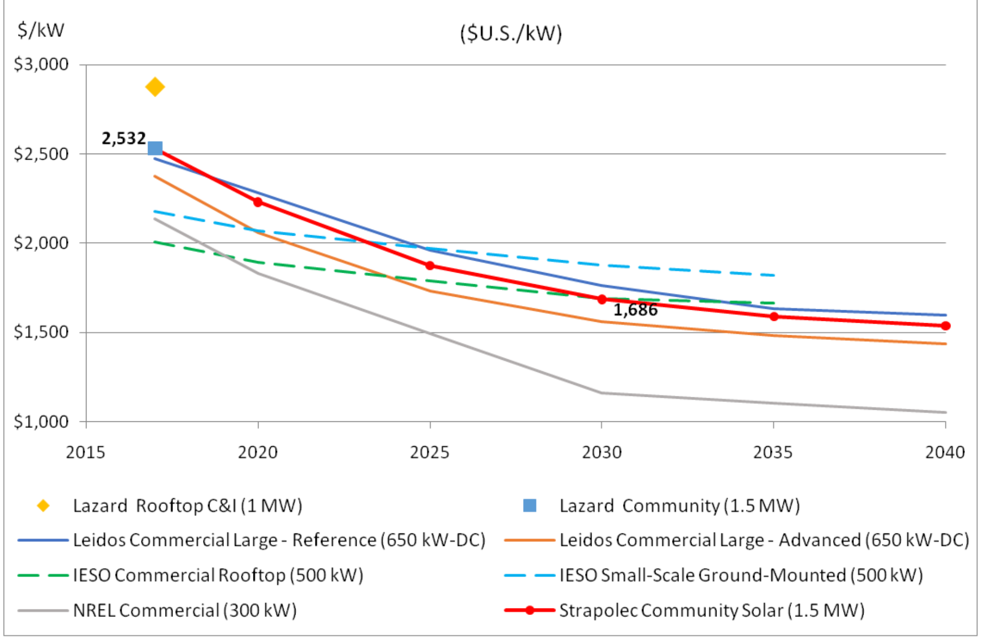
Residential solar systems were not examined, as the capacity size for a single home solar panel is less than 1 kW and very expensive when connected to residential-scale storage.

Community Scale Solar Cost Forecasts

a) Capital costs

Commercial/community solar capital costs, in $/kW, have been projected by Leidos, Lazard, NREL, and IESO[48]. The capacity of commercial installations varied from 300 kW (NREL) to 1 MW (Lazard). Lazard has defined a community solar installation of 1.5 MW, which is the cost design case used in this study. The community installation costing is based on an optimized fixed-tilt installation. Figure 14 shows in red the estimated community-based solar installation capital cost. Most of the sources reflect costs for rooftop commercial installations.

Figure 14 – Solar Community and Commercial Scale Capital Cost Forecast to 2040



The average capital cost used for this analysis is $2,532/kW in 2017 and is expected to drop to $1,686/kW by 2030.

Lazard's 1.5 MW case is used to represent the 2017 solar capital costs for comparison with other types of generation. The rationale is: (1) Lazard's estimate is similar to the Leidos reference estimate; (2) The Leidos system is the largest other system quoted; and (3) the IESO estimates could not be reconciled with the others (after an assumed exchange rate discount of 15%).

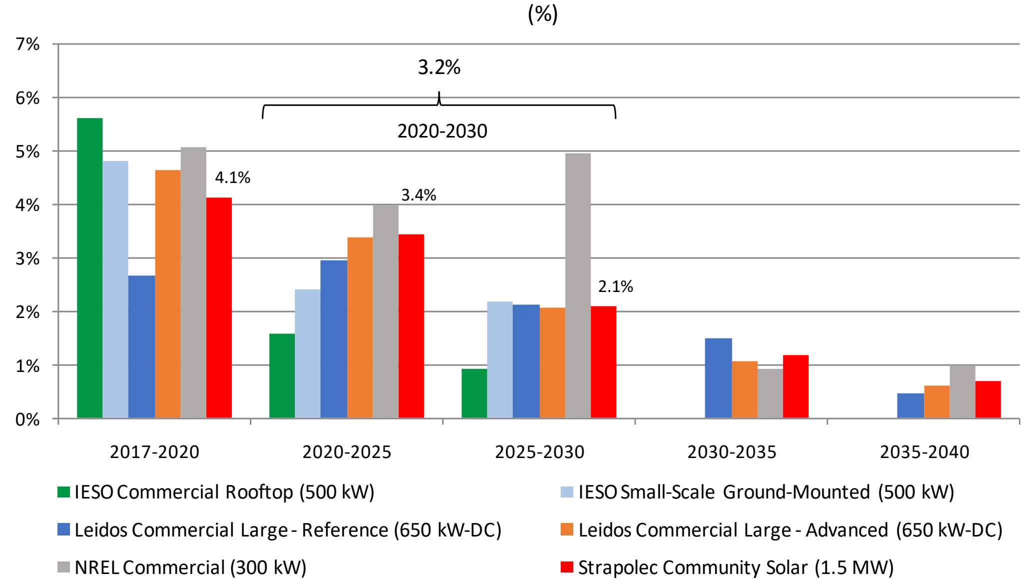
[48] Leidos, 2016; Lazard LCOE v11.0; NREL Annual Technology Baseline, 2017; IESO OPO, 2016

The compound annual growth rates (CAGR) used for each of the projections are summarized in Figure 15. Leidos provides low and high CAGRs for reference and advanced equipment respectively.

The average of the Leidos reference and advanced equipment CAGRs were chosen for the forecast in this report yielding 4.1% for 2017-2020 and 3.2% for 2020-2030. These are near the high end of the rates of decline in the sample set. Applying these CAGRs to the 2017 Lazard data creates a forecast for community-scale solar with a capital forecast that declines from $2,532/kW in 2017 to $1,686/kW in 2030. This is within the range of the IESO's forecast.

Figure 15 – Solar Community and Commercial Scale Capital Cost CAGR Forecast to 2040

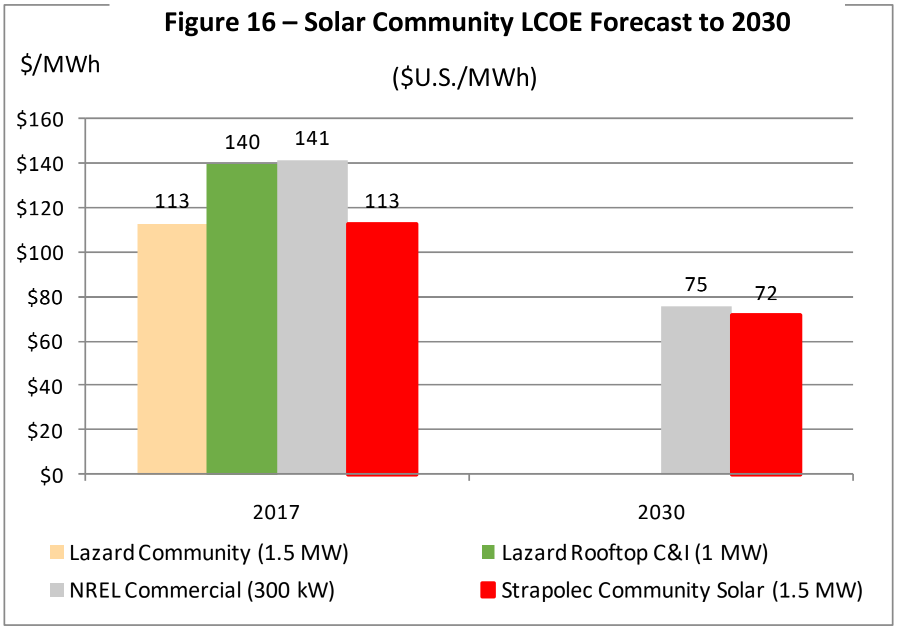
(%)



b) LCOE Forecast

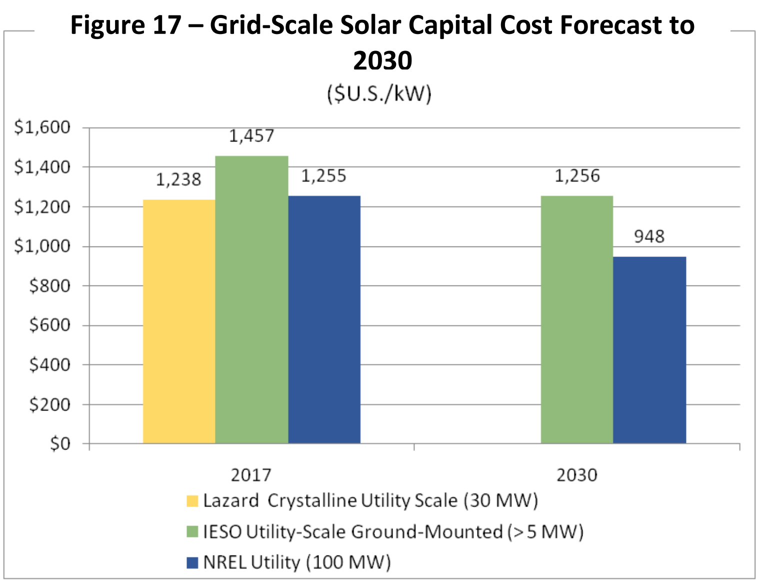
For this analysis, the LCOE is of greater interest and is what will be used directly in the cost comparisons.

Several sources provided estimates of the cost of solar in 2017, but only NREL developed a forecast. The Strapolec forecast uses CAGRs from the above projected capital cost. This resulted in a lower cost than that derived by NREL for 2030. This suggests the cost forecast for the DER option used in this report is conservatively low.



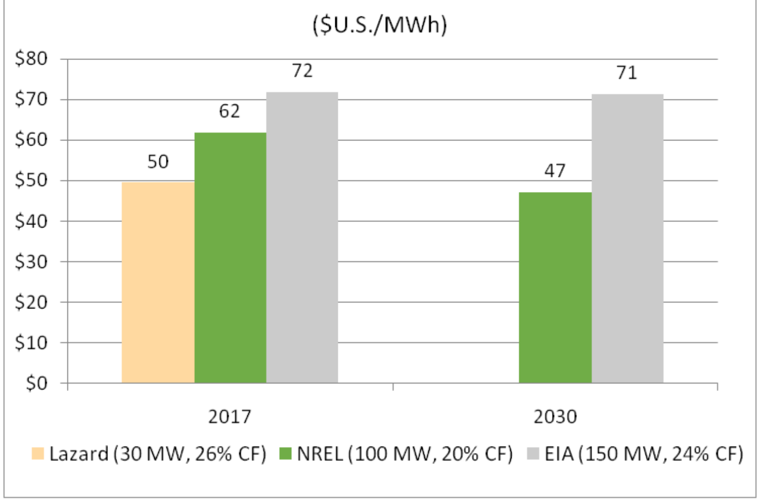
Grid-Scale Solar Cost Forecasts

For grid-scale solar, Lazard, IESO, and NREL provide capital costs, as shown in Figure 17. NREL's forecast was 25% lower than the IESO's forecast, which could reflect issues related to Ontario specific installations (see Section 6.1). The CAGRs for grid-scale solar were smaller at only 1.3%/year after 2020 and lower again after 2030. Nevertheless, grid-scale solar capital costs are expected to decline by 25% from 2017 to 2030.



Of the few LCOE forecasts found for this study, as shown in Figure 18, NREL's forecast decline from $62/MWh in 2017 to $47/MWh in 2030 was chosen to be conservative, as it demonstrates the highest price decline. The capacity factor assumption for the solar installations is 20%.

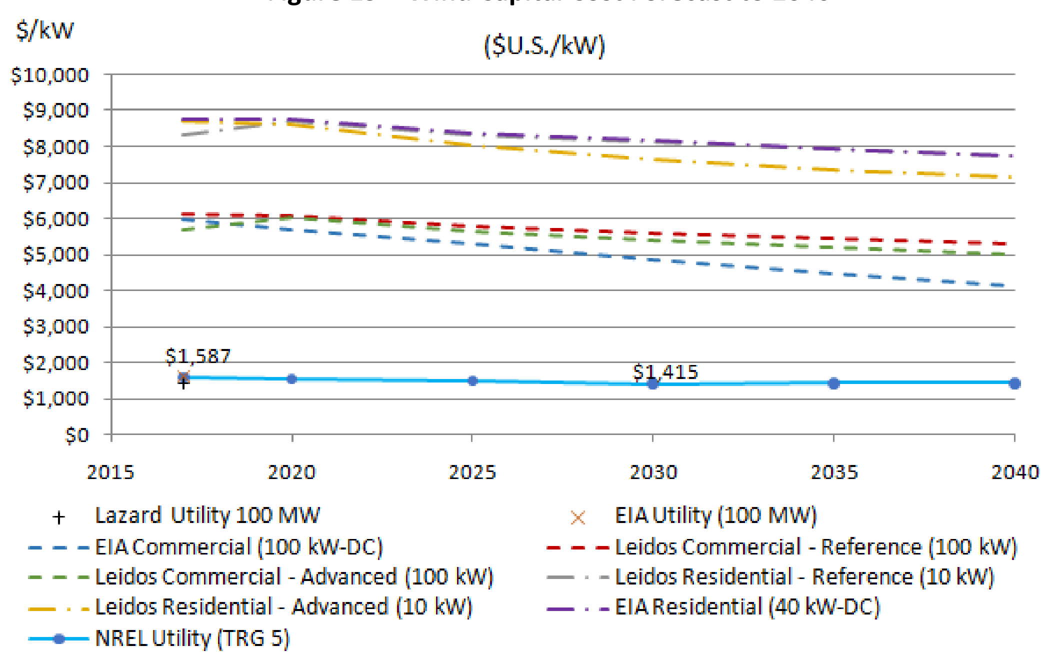
Figure 18 – Grid-Scale Solar LCOE Forecast to 2030



4.1.2 Wind Cost Assumptions

Wind capital costs were projected by the EIA, Leidos, Lazard, and NREL. Figure 19 summarizes the capital cost projections for a range of installations from these sources.

Figure 19 – Wind Capital Cost Forecast to 2040



It is clear from Figure 19 that smaller scale wind installations are expected to remain four to six times as costly as grid-scale applications. CAGRs are in the 1%/year range with the exception of one outlier, EIA's 100 kW commercial application. This estimate is discounted from this analysis. With no prospect of material cost declines, small-scale wind is not considered further in this report.

LCOEs are available from Lazard, EIA and NREL. A long-term LCOE forecast for grid-scale wind was only available from the EIA and NREL. NREL is forecasting 1.6% to 1.8% LCOE declines for grid-scale wind. The EIA is forecasting a 10% cost increase. To be conservative, NREL's aggressive cost declines have been assumed for this analysis. NREL predicts a future LCOE of $37/MWh in 2030, down from $46/MWh in 2017, for a wind farm with a capacity factor of 41% today. Lazard's estimate for a wind farm today is similar to NREL's but assumes a much higher generator capacity factor of 47%. This places the Lazard estimate between the EIA and NREL estimates of common capacity factor assumptions. By choosing the NREL reference point, this report may be understating the future cost of wind by 15%.

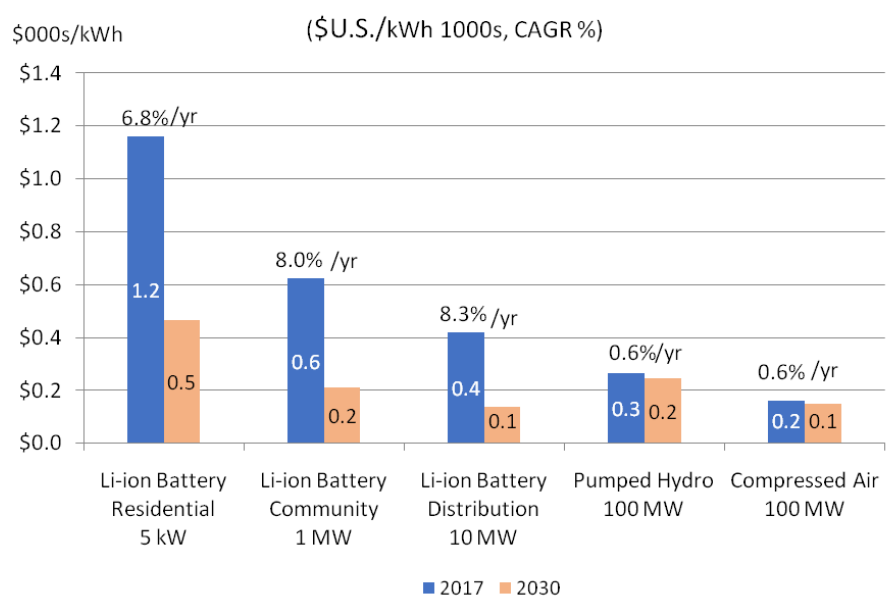
4.2 Storage Costs

This section examines the forecasts for the capital cost and LCOE of storage technologies from multiple sources. For each technology, different deployment scenarios scales are considered from small-scale residential applications to large grid-scale. Three distinct storage technologies are addressed:

- Li-ion batteries
- Pumped hydro storage
- CAES

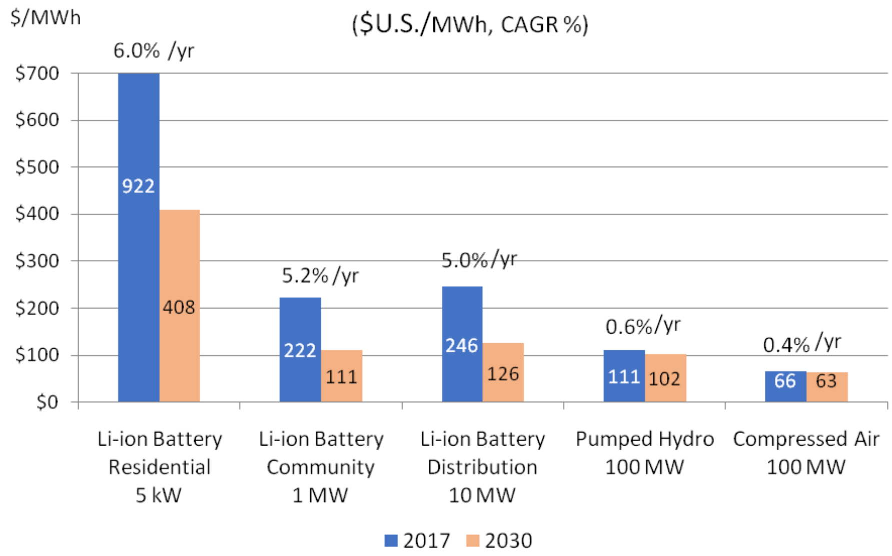
The cost comparisons for both capital and LCOS are provided in Figures 20 and 21.

Figure 20 – Storage U.S. Average Capital Cost, 2017 vs. 2030



Capital costs for storage are measured in two ways: (1) In $/kW, which refers to the current carrying capacity of the input/output electronics required to charge or discharge energy (similar to how a generation plant is measured); and, (2) In $/kWh, which measures the volume of energy that can be stored. In this report, capital costs are compared on a $/kWh basis. Li-ion batteries are more expensive today than pumped hydro or CAES, but with the significant projected capital cost declines may begin to approach the capital cost for pumped hydro.

Figure 21 – Storage U.S. Average LCOS, 2017 vs. 2030



The primary measure used in this study for assessing the cost of storage options is the LCOS[49]. Based on this measure, Li-ion batteries are expected to remain more expensive than pumped hydro or CAES. Small-scale residential storage is expected to remain above $400/MWh suggesting that residential based DER solutions will not be economic for well beyond the time horizon of this analysis.

4.2.1 Lithium-Ion Storage Costs

Lazard[50] is the primary source consulted for Li-ion storage costs and their expected cost declines over the next five years. Three scales of storage have been identified:

- Residential (5 kW)
- Microgrid (1 MW), which is considered as "community" in this study
- Distribution (10 MW)

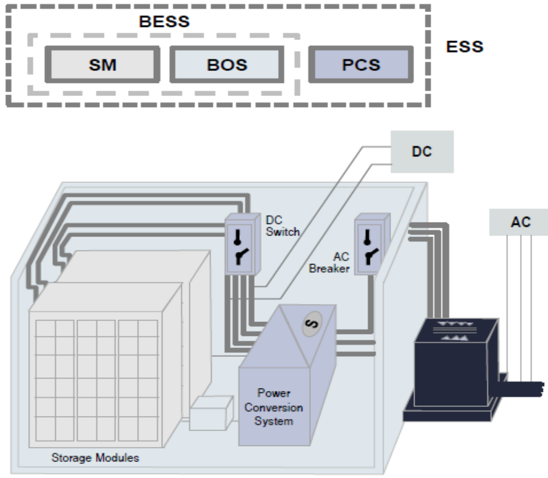
a) Capital Cost Forecasts

The capital cost for an energy storage system (ESS) is comprised of the storage module (SM), balance of system (BOS), power conversion system (PCS) and related engineering, procurement and construction (EPC) costs as illustrated in Figure 22.

[49] The LCOEs shown for all storage devices are assumed to provide 8 hours of storage and to be fully charged and discharged every day for 350 days per year.

[50] Lazard LCOS v3.0

Figure 22 – Lithium-Ion Battery Physical Energy Storage



The contribution of a cost category to LCOS varies by use case and technology.

Lazard summarizes the three capital cost components of a Li-ion Battery system:

- Initial capital cost – Direct Current (DC)
- Initial capital cost – Alternating Current (AC)
- Initial other owner costs

Table 4, based on Lazard's data, summarizes the respective share of each of these cost components.

Table 4 - Lithium-Ion Battery Capital Cost Components
($U.S./kWh, 2017)

	Distribution (10 MW)	**Microgrid** (1 MW)	**Residential** (5 kW)
Li-ion Battery (dc)	347	480	646
Li-ion Battery (ac)	19	39	314
Other owner costs	55	104	200
Total	**421**	**623**	**1160**

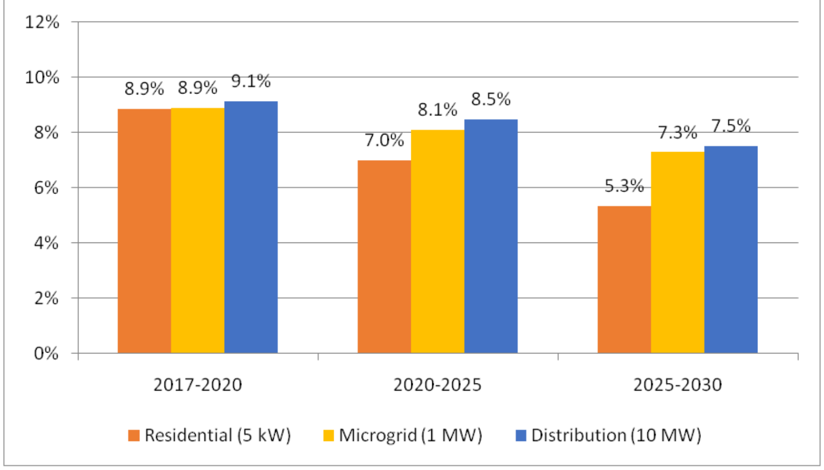
Lazard forecasts that the capital costs of the storage technologies will decline by 10%/year for the next five-years. Lazard also notes that the BOS costs would decline more in line with those of solar. The proxy for solar cost declines was obtained from the Leidos report for large-scale commercial installations.

Applying the 10% per year Lazard cost decline to the DC and AC components for the next 5 years and using solar CAGRs for the rest to 2030, yields CAGRs for the total installed cost of approximately 8% to 9% per year[51] across all technology scales as summarized in Figure 23.

[51] Recent forecast released by GTM suggests storage cost declines will be 8%/year for the next 5 years suggesting that the costs projected here may be aggressively lower than others may expect. IRENA 2017 projects that 2030 costs will be 60% lower than 2016, also not as aggressive as the forecast developed in this report.

Figure 23 – Lithium-Ion Battery Capital Cost CAGR Forecast to 2030

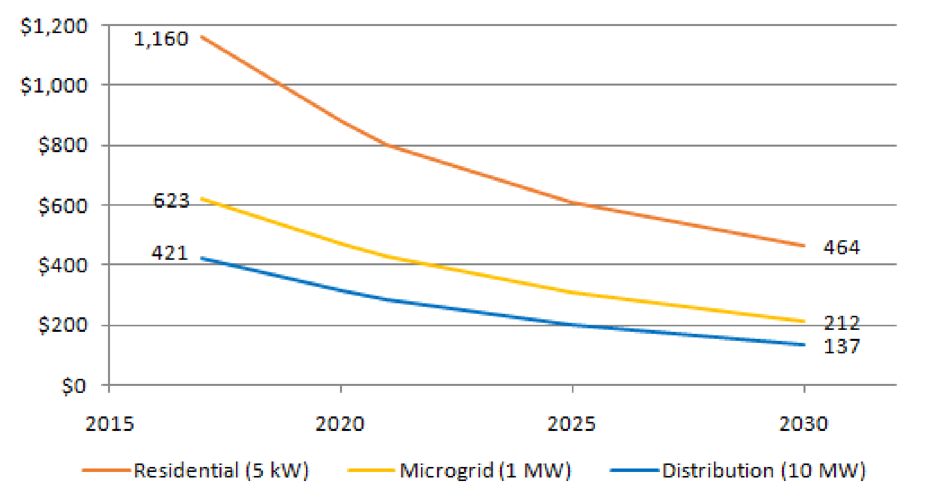
(%)



The resulting capital cost forecast for the three scales of storage is provided in Figure 24.

Figure 24 – Lithium-Ion Battery Capital Cost Forecast to 2030

($U.S./kWh)



b) Levelized Cost of Storage

Lazard identifies several cost components that contribute to the LCOS of Li-ion battery storage. These components are illustrated in Figure 25[52], and include the following four categories:

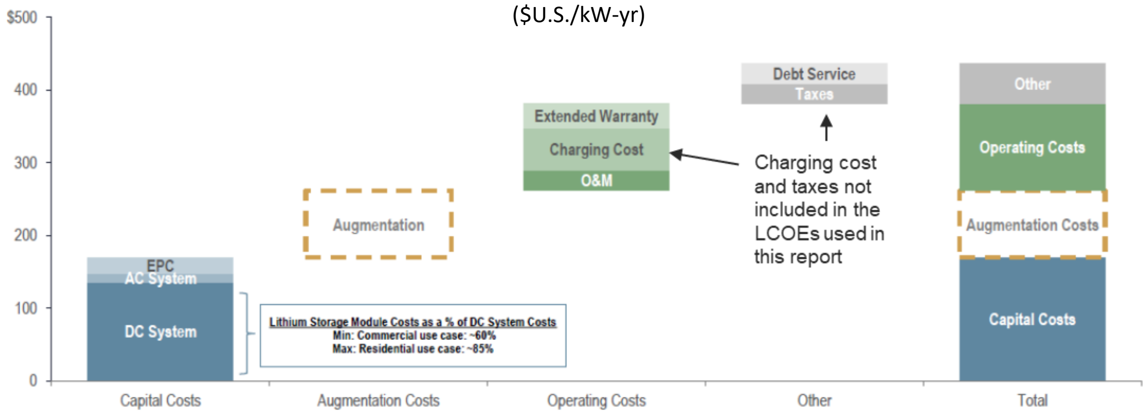
- Capital costs consisting of the AC, DC and EPC components
- Augmentation costs, which account for additional investments that will be required to sustain performance as the battery life degrades

[52] Copied from Lazard LCOS V3.0

- Operation costs, which include operations and maintenance (O&M), warranty, and charging
- Other costs, e.g. debt service (or capital financing costs) and taxes

For the LCOS used in this report, taxes and charging costs are excluded.

Figure 25 – Illustrative System Costs: LCOS by Category
($U.S./kW-yr)



Previous Lazard forecasts did not include augmentation costs which are now known to be material, particularly for small installations. Augmentation costs represent the additional ESS equipment needed to maintain the “Usable Energy” capability: cycling the unit according to the usage profile for the life of the system. Useable Energy may degrade under the following circumstances:

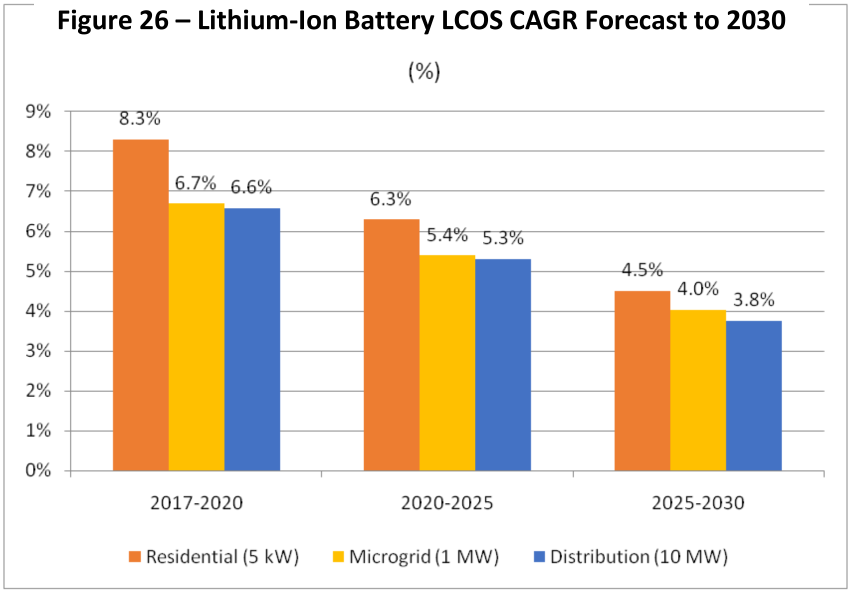
- Unit is not charged/discharged at the planned rate (kWh) per cycle
- Battery chemistry does not have the cycle-life needed to support the desired operating life
- The energy rating (kWh) of the battery chemistry degrades over its life

In assessing the cost of an ESS upgrade, Lazard has taken into account the falling price of ESS system costs.

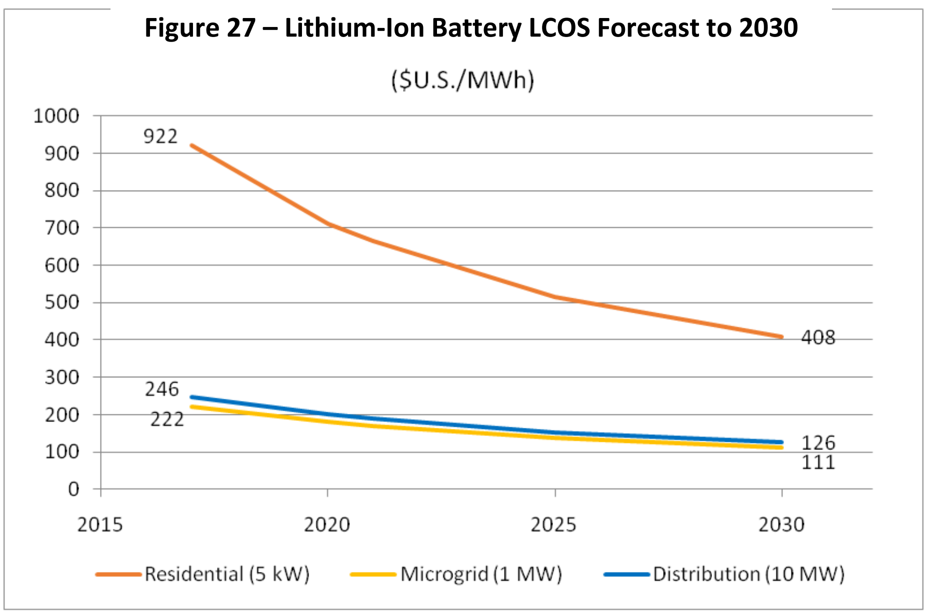
The LCOS forecast was developed as follows:

- For the capital portion of LCOS, the same CAGRs are used as for the capital cost. As augmentation and debt service costs are bot related to capital, it is assumed that they will also see similar declines. This is likely an aggressive assumption for the augmentation costs as they have already been forecast out to the future where ingoing declines will be more modest.
- For the operating cost of the LCOS, CAGRs from the Leidos fixed O&M for large commercial solar PV have been applied.

The resulting LCOS CAGRs range from 6.6-8.3% for the period of 2017-2020 and drop to 3.8-4.5% for 2025-2030 as shown in Figure 26. CAGRs are higher for residential applications due to the predominance of capital costs.



The net LCOS forecast is shown in Figure 27, reflecting a cost of $111/MWh for the community- scale (microgrid) Li-ion battery solution in 2030.

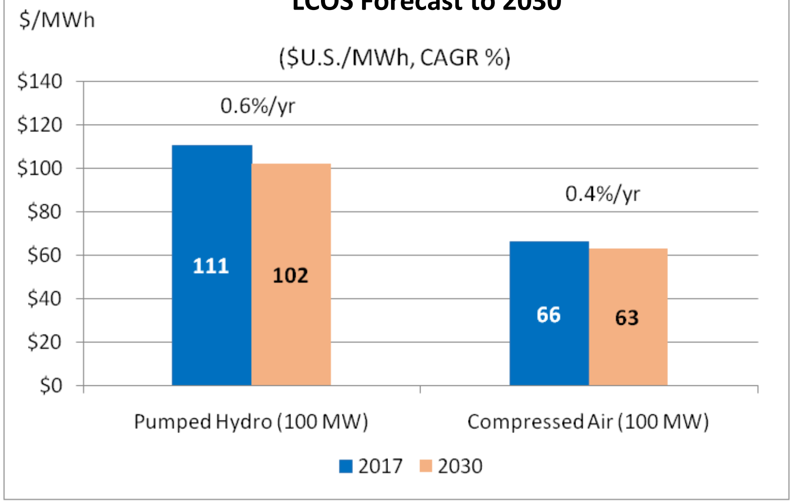


4.2.2 Pumped Hydro and Compressed Air Energy Storage Costs

Pumped hydro and CAES technologies have existed for several decades. The capital costs and LCOS of pumped-hydro and CAES were obtained from Lazard which suggests that capital costs will decline by less than 1%/year. To compute CAGRs for the declining costs of these storage options, the EIA and NREL forecasts for hydro resources were used for pumped hydro and a blend of CAGRs from conventional sources was applied to CAES.

Figure 28 shows modest declines between 2017 and 2030 of 0.6% and 0.4% per year in average forecast costs for pumped hydro and CAES respectively.

Figure 28 – Pumped Hydro and Compressed Air LCOS Forecast to 2030



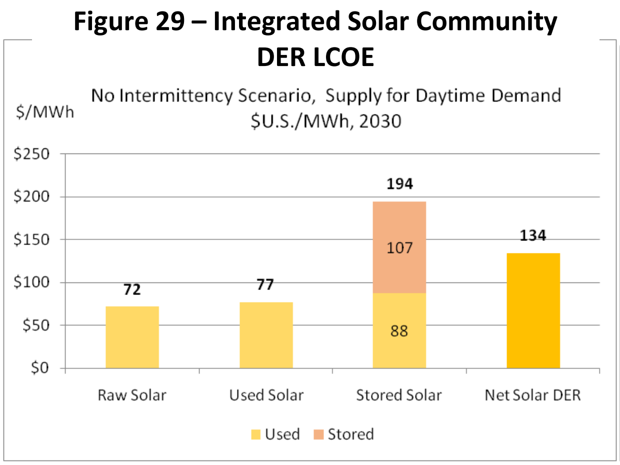
4.3 Integrating Renewables with Storage

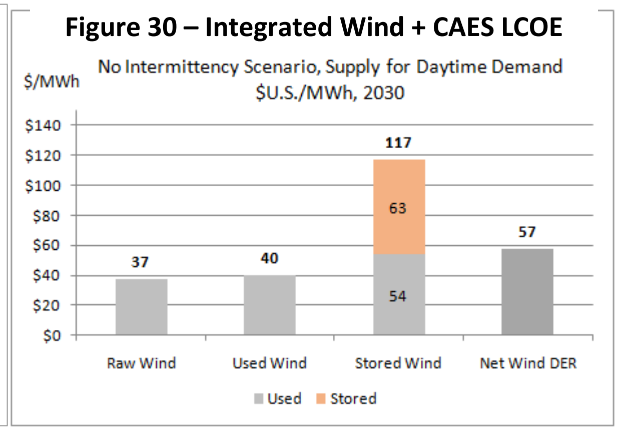
In order for DER solutions to provide the supply required to meet the expected demand profile, the technologies must be integrated. As discussed earlier, two demand profiles must be satisfied: baseload demand; and, daytime demand.

Integrating storage and generation presents both cost and performance implications that are determined by several factors:

1. Configuring the components (e.g. the size of the solar panel and capacity of the battery) to supply the expected demand profile determines the net blend of the directly used electricity or electricity obtained from storage produced by the DER option.
2. Energy losses arising from the round-trip conversions from charging and discharging arise within the storage system.
3. Integrating solar and storage systems through coupling of the electrical components could reduce the combined capital cost.

These parameters yield the LCOE of the system outputs as illustrated in Figures 29 and 30. First, the raw renewable generation cost estimates must be adjusted to account for the connection costs to the grid and to identify the cost of the generation technology employed. The generation that gets stored has a cost increase due to the losses in storage and would also bear the cost of the storage itself. Ultimately, the net cost of energy from the integrated DER system is the weighted average of the directly used and stored energy.

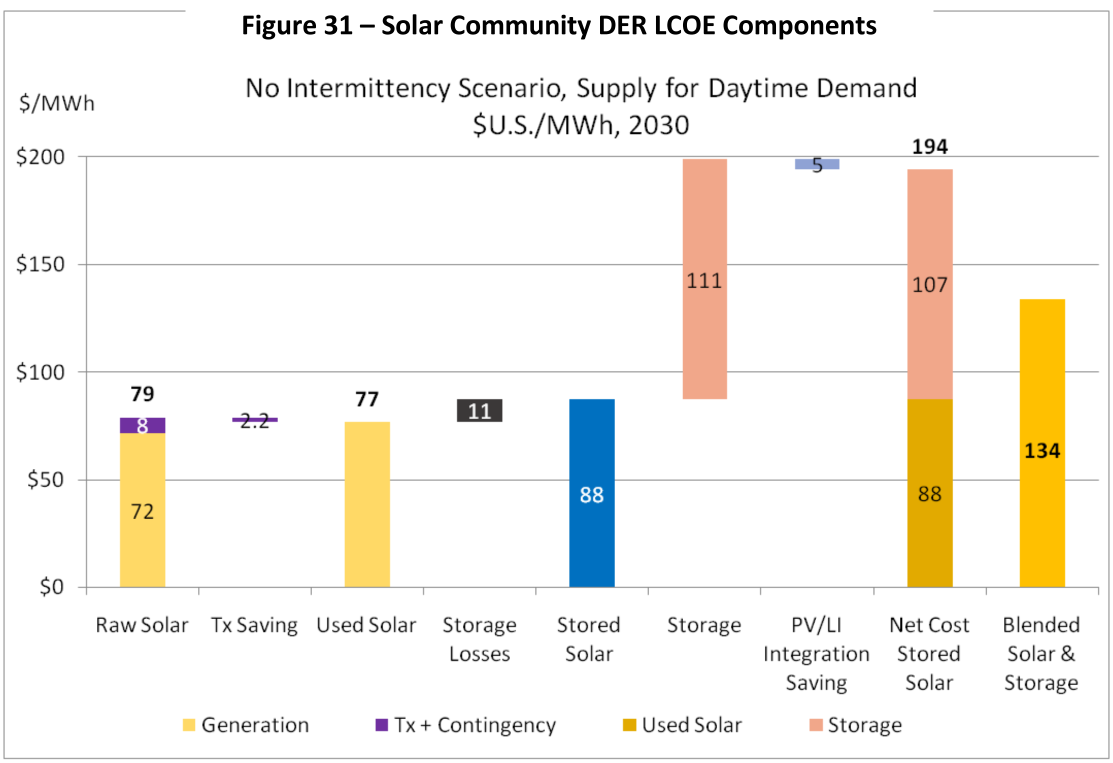




The results illustrated above reflect a usage cycle that sees the storage fully charged and discharged on a daily basis. As such, even without consideration of the intermittency of the renewables, it can be expected that the cost of DER in the future will be double the cost of the renewable inputs.

4.3.1 Solar-based DER Solutions

Figure 31 illustrates the breakdown of cost impacts of solar-based DER required to meet a community-scale daytime demand profile. Four steps include: (1) assessing the cost of the utilized solar output; (2) the costs of the stored solar; (3) the cost/benefits of the storage from the integrated components; (4) and value of the net blended outputs.



a) The Cost of the Utilized Solar Output

When solar generation is installed, there are grid connection charges associated with the installation. The EIA adds two cost factors to their LCOEs when forecasting future costs. The first is a technology uncertainty factor and the second is the cost of Tx. For large scale renewables, their low capacity factor results in unused Tx, especially for the radial connections from the wind and solar farms to the load centres. That all adds additional delivery costs to intermittent renewable supply options. For solar, the EIA factors add ~$8/MWh to the LCOE which have been assumed to be relevant for this study.

Solar grid integration costs are relatively high due to the expected intermittency of the solar output while the system must be able to accommodate 100% of the peak output. For integrated DER solutions, it is assumed that the peaks will be absorbed by storage and hence the grid costs would be reduced. For the purpose of this analysis, 50% of the grid costs have been removed, reducing the forecast cost of community-scale solar by $2.2/MWh. The cost of solar output that is utilized is expected to be $77/MWh.

b) The Cost of Stored Solar

The cost of stored solar is a function of the losses that occur when the solar energy is used to charge the storage and when the storage device discharges the energy back to the system. This round-trip efficiency loss for Li-ion batteries is estimated at 14%. With a utilized solar energy cost of $77/MWh, the cost of the stored solar energy will be 14% higher, or $11/MWh more. This results in a combined cost of $88/MWh, before including the cost of the storage technology itself.

c) Cost/Benefits of Integrated Storage with Solar Panels

NREL conducted a study[53] on the possible benefits of integrating the electronics of the solar panel with that of the storage device. The study found that coupling solar PV and storage can reduce costs by sharing components in two ways:

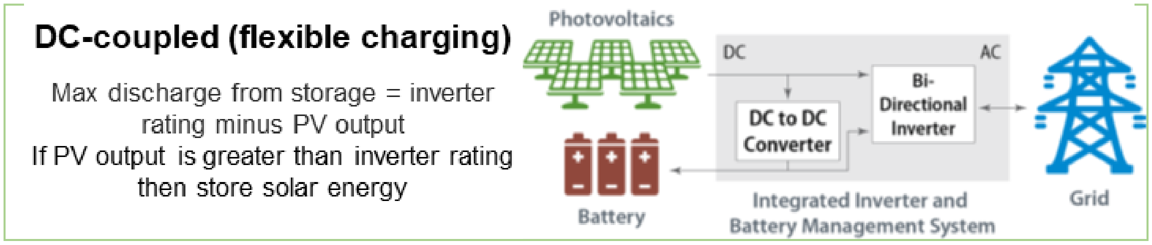
- AC-coupled system shares little hardware, but costs associated with engineering, customer and site acquisition, permitting, and labour can be shared; and,
- For a DC-coupled system, the second inverter can be eliminated to reduce costs

In a tightly integrated arrangement where the storage device is only charged with energy from the solar panel, the cost of the BOS systems can be reduced.

The conceptual arrangement of a DC coupled system that permits some flexible charging is illustrated in Figure 32.

[53] NREL, Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants, 2017

Figure 32 – Conceptual Arrangement of a DC Coupled PV + Storage Battery System



The cost/benefits summarized in Figure 33 were extracted from the NREL report. This data suggests that 40% of the battery BOS capital costs could be avoided.

Figure 33 – Avoided Cost of Battery BOS Associated with PV Coupling
($/kW)

Type of Coupling	Avoided Cost ($/kW)	
	2016	2020
AC-Coupled System	$161 (26%)	118 (30%)
DC-Coupled System	$221 (36%)	158 (40%)
Tight DC-Coupled System	Same as DC-Coupled	

Estimates have been developed for how this integration may impact the different sizes of possible solar installations as summarized in Figures 34 and 35.

Figure 34 – Lithium-Ion Battery Capital Cost Reduction

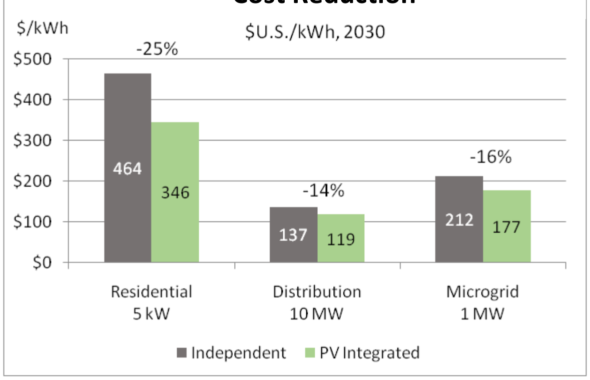
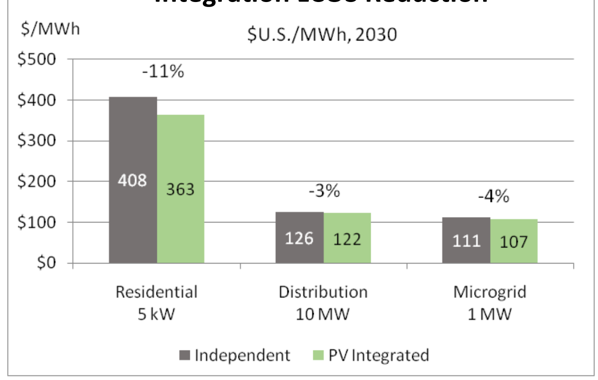


Figure 35 – Lithium-Ion Battery Integration LCOS Reduction



Applying the savings to the LCOS in Figure 35 will reduce the per unit cost of storage for a community solution by $5/MWh from $111/MWh to $107/MWh.

Therefore, the total cost of solar energy from storage in a community DER system is expected to be $194/MWh in 2030.

d) Determining the Net Blended Cost

To determine the net blended cost of energy from a DER system requires a model of system usage. To effectively pair with renewables, an optimum storage function would create an output that matches the demand profile. Two demand profile scenarios are illustrated in Figures 36 and 37: daytime demand; and, baseload demand.

Figure 36 – Solar and Storage Daytime Demand Supply

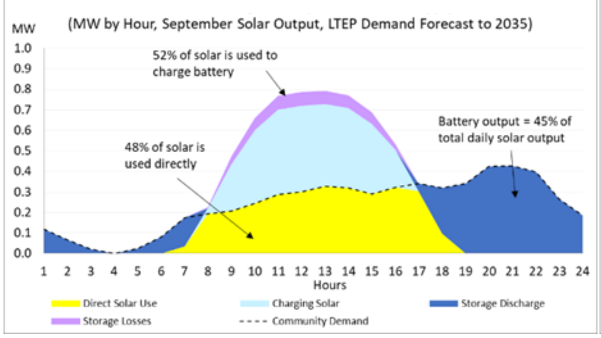
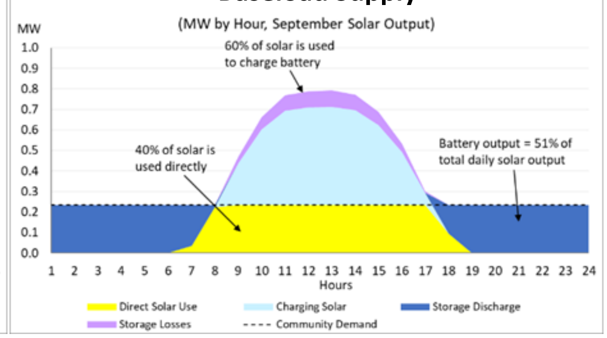


Figure 37 – Solar and Storage for Baseload Supply



In the daytime demand supply scenario, storage and solar combine to emulate a gas plant supply alternative. For an average Ontario day in September, storage would be sized to capture 52% of solar energy, with 45% used to charge the battery after 7% losses. September is a useful month for this analysis as it has 12 hours of sunlight per day. The net cost of blending the 48% of solar that is directly used with the 45% from storage is $134/MWh. This is based on the assumption that the storage system is fully charged and discharged on a daily basis.

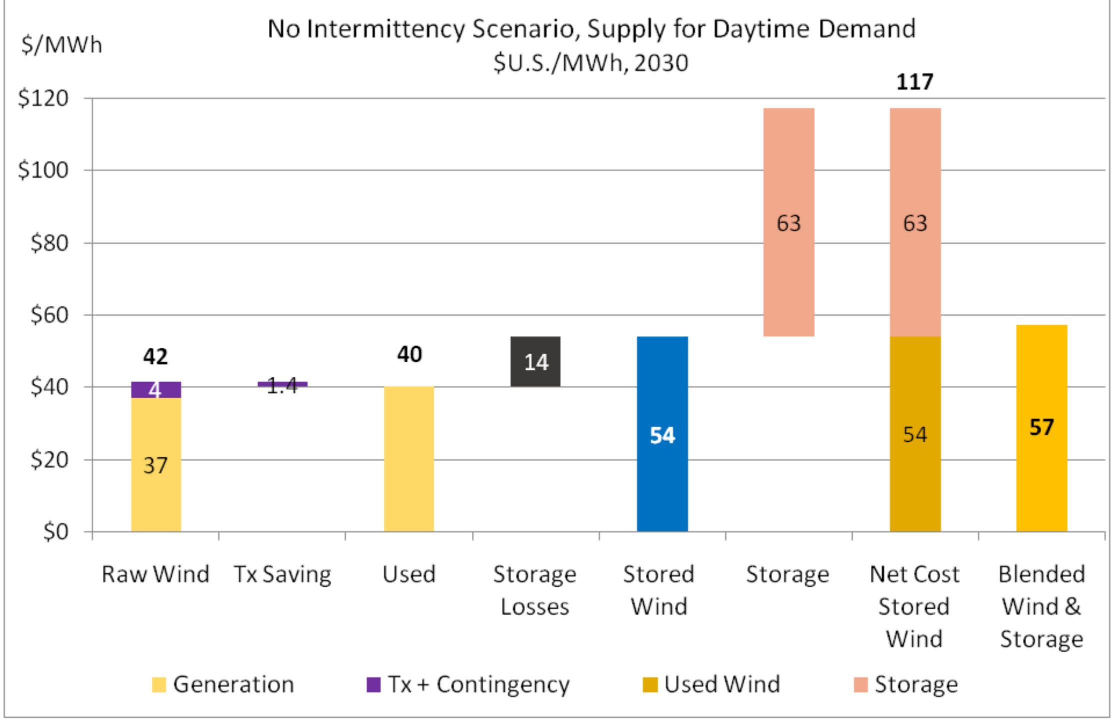
To supply the baseload demand scenario, storage and solar combine to provide a 24x7 supply, emulating a nuclear plant in Ontario. For the same average Ontario day in September (12 hours of daylight), storage would have to be sized to capture over 60% of the solar energy.

To provide a baseload supply solution, 20% more storage would be required. This is because the solar output needs to be spread out at a lower level over a much longer period of time along. This results in an increase in the system LCOE to a cost of over $150/MWh. For this reason, solar baseload DER solutions are not considered further in this analysis.

4.3.2 Wind-based DER Solution

Figure 38 illustrates the breakdown of cost impacts of wind-based DER required to meet a community-scale daytime demand profile. This is based upon: (1) an assessment of the cost of the utilized wind output; (2) determination of the costs of the stored wind; (3) computation of the net blended outputs.

Figure 38 – Wind + CAES LCOE Components



a. The Cost of Utilized Wind Output

As with solar generation, there are grid connection charges associated with wind installations. The low capacity factor for large-scale renewables results in unused Tx especially for the radial connections from the wind and solar farms to the load centres. In the case of wind, the length of the radial lines is typically longer than that for gas or nuclear generation. This adds additional delivery costs to intermittent renewable supply options. For wind, the EIA Tx and contingency factors add $4/MWh to the LCOE.

On a LCOE basis, wind grid integration costs are relatively lower than for solar due to its higher capacity factor. For integrated DER solutions, it is assumed that the peaks will be partially absorbed by storage and hence the grid connection costs will be reduced. For the purpose of this analysis, 50% of the grid costs have been removed, reducing the forecast cost of used wind by $1.4/MWh. The cost of utilized wind output is expected to be $40/MWh.

b. The cost of stored wind

The cost of stored wind is a function of the losses that occur when the wind energy is used to charge the storage facility and then when the storage device discharges the energy. This charge/discharge cycle results in an efficiency loss estimated to be 35% for CAES. For utilized wind output that costs $40/MWh, the stored wind energy cost will be 35% higher, or an additional $14/MWh. This yields a combined cost of $54/MWh before the cost of the storage itself is added. The LCOS of CAES, assuming a full duty cycle, is projected to be $63/MWh. This suggests that the cost of the energy retrieved from storage to be $117/MWh.

c. Determining the Net Blended Cost

Figures 39 and 40 illustrate the design parameters for wind-based DER for the two demand profiles.

Figure 39 – Wind Capacity Sizing for Daytime Community Demand

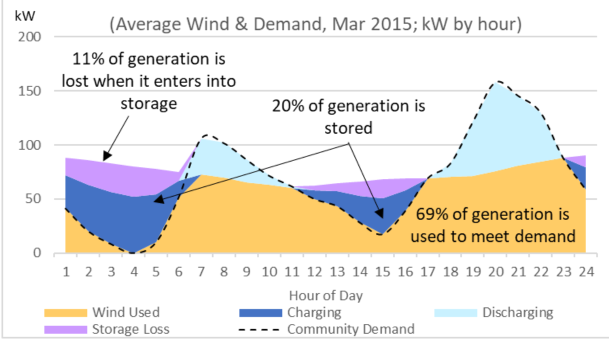
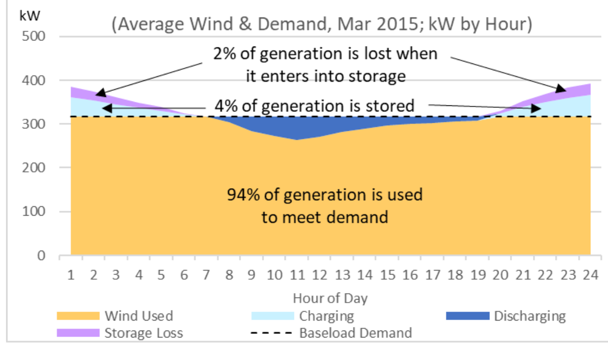


Figure 40 – Wind Capacity Sizing for Baseload Demand



In the daytime demand supply scenario, storage and wind are combined to emulate a gas plant supply alternative. For the average Ontario day in March, storage would be sized to capture 20% of wind energy. March is characterized as a relatively high demand month and also a high wind production month. A net blended cost of $57/MWh is expected based on a 70% utilization of wind output and 20% consumption of stored wind. This assumes that the storage system is fully charged and discharged on a daily basis.

In the baseload demand supply scenario, storage and wind combine to provide a 24x7 supply, emulating a nuclear plant in Ontario. For the same average Ontario day in March, storage would have to be sized to capture only 4% of the wind energy.

To provide a baseload supply solution, much less storage may be required and could result in a lower system LCOE. For this reason, wind-based DER baseload solutions will continue to be considered in this analysis.

4.4 Case Examples of DER Economics

Examples in this section illustrate how DER is being justified today as viable for consumers who install them. Consumer benefits are typically achieved through pricing mechanisms that inherently push costs onto other ratepayers. DER case examples show that the underpinning premise of DER adoption is the economic benefit that can accrue to the owners of DER systems. Those owners take advantage of two benefits: peak pricing (arbitrage) in a fossil-fuelled energy system; or from indirect subsidies (e.g. net metering). Both of these opportunities benefit DER owners but add costs to the system that are borne by other ratepayers.

This study articulates renewables-based DER economics from the following perspectives:

1. Providing advantages to the system
2. Leveraging market pricing to maximize arbitrage
3. Maximizing renewables penetration

4. Combining technologies to provide system solutions

4.4.1 Advantages to the System

Much debate surrounds how to define and capture the value and monetize the benefits of DER for the system. Developers also expect an acceptable rate of return for their DER investments. The state of Massachusetts has demonstrated that most of the DER system benefits cannot be captured by the end user through normal market mechanisms[54]. The Essex report previously discussed in Section 3.0 also identified that consumers can only capture some of the benefits.

NREL's report on DER compensation models[55] stresses the importance of developing well-designed mechanisms to help minimize the negative impacts and maximize the value of DER to all stakeholder groups, including Dx utilities, the DER system owner, and other ratepayers (non-DER-system owners). Like with the Massachusetts report, NREL indicated that it is a relatively straightforward exercise to identify the direct benefits to the DER system developer. NREL also recognized that it is far more difficult to quantify the longer-term benefits to the system in a manner that can be built into a compensation model for the DER developer. If the net effect of DER adoption is determined to be a net cost, then non-adopting customers can be expected to see an increase in their bills. One of the compensation models NREL defined is net metering.

Finding a resolution to the compensation question is fundamental to resolving this debate and fairly allocating the costs/benefits to the system, DER developer/installer and non-DER consumers. In California, the widespread prevalence of rooftop solar panels with net metering has shifted costs from households with residential solar panels to those without. The cost is estimated to be $65 per year for the average household[56]. As noted earlier in this report, distributed solar proponents suggest DER allows utilities to benefit by avoiding or deferring Dx system upgrades, yet these impacts have been found to be relatively small. The New York Public Commission is developing new methodologies to value and compensate DERs that take into account energy price, cost reductions for consumers, and the value of deferred capital[57]. Regulators in California are exploring models, such as locational net benefits, to facilitate the transition to a distributed energy future[58].

4.4.2 Leveraging Market Pricing to Maximize Arbitrage

To date, most DER systems have been implemented either under PPAs (e.g. Tucson Electric and NextEra in Arizona[59]) or are based on leveraging the market pricing. The latter is typically driven by electricity systems in jurisdictions were fossil-fueled generation predominates. The desired outcome of leveraging market pricing is to maximize revenues, leaving it to the grid to fill in the low-cost gaps. In this report, the

[54] Massachusetts DOER, State of Charge, 2016

[55] NREL, Grid-Connected Distributed Generation: Compensation Mechanism Basics, 2017

[56] Davis, 2018

[57] State of New York. Public Service Commission. Order on Net Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters. 2017

[58] California. Public Utilities Commission. California's Distributed Energy Resources Action Plan: Aligning Vision and Action. 2016. Pages 1-14

[59] Maloney, 2017

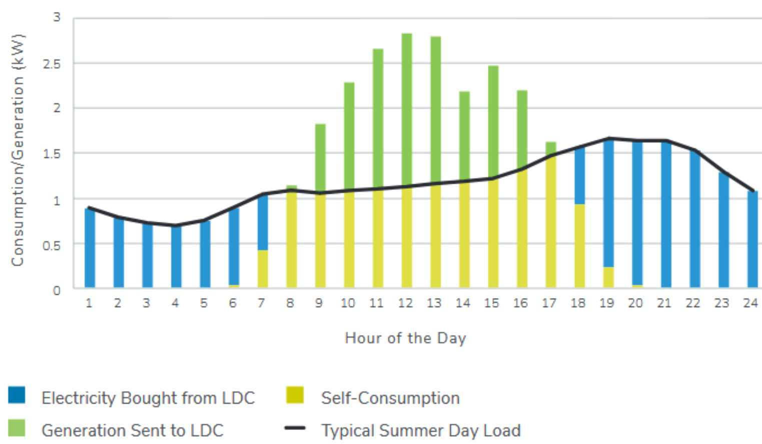
design of DER systems to supply a demand profile does not assume that "grid" supplies will be available to provide that function.

Three models illustrate how value is captured by DER installations through maximizing revenues from market prices versus the delivery of energy to meet a demand profile.

a) Net Metering

Ontario's LTEP describes the virtues of Net Metering and provides an example of how net metering can be used to generate cost savings for DER owners. The LTEP is silent about the cost implications for the total system. The LTEP defines net metering as a billing arrangement that allows consumers to generate their own electricity on site for their consumption and also receive energy credits for any extra electricity that is delivered to the local Dx system. This arrangement is illustrated in Figure 41[60].

Figure 41 – Residential Net-Metering with 4 kW Rooftop Solar PV



Source: Ontario Ministry of Energy

The energy credits are then subtracted from any energy the customer may later draw back from the grid. This approach is more fully illustrated in Figure 42[61].

[60] MoE LTEP, 2017

[61] NREL Grid-Connected Distributed Generation, 2017

Figure 42 – Net Energy Metering

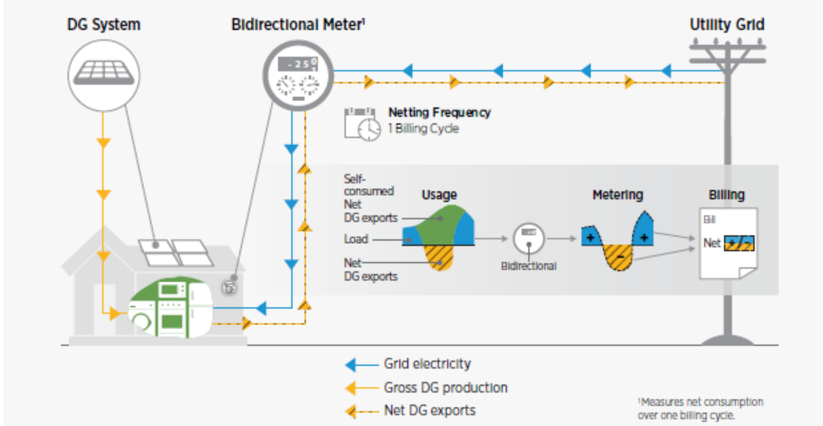


Figure 2. NEM schematic

In this manner, a PV owner in Ontario is avoiding paying the global adjustment. Other benefits that depend on jurisdiction include volume dependent Dx, Tx and regulatory charges for the credited energy receive back from the grid. This bill avoidance is an indirect subsidy that other ratepayers will be providing if there are no benefits to the grid from the net-metered DER.

There are several challenges with the net metering approach for solar installations.

- The excess solar will be put on the grid when electricity prices are lower and will be drawn back when electricity prices are higher. That is because, as illustrated in Figure 41, the solar peak is not coincident with system peak. Ontario is already suffering from many instances of surplus solar energy[62] which drives down further the price commanded mid-day.
- The expected benefits to the system of avoiding or deferring Dx system investments are unlikely to be realized as peak demand is not affected by solar output since it is not coincident. If the DER system is unable to offset peak demand, then system benefits will not accrue.
- The payers of the indirect subsidy are the ratepayers who do not have solar-based DER.

The introduction of rooftop solar is a net extra cost burden on the electricity system and will continue to drive up energy costs through both subsidies and system issues created from its intermittency as described by the IESO.[63] The OEB has recognized that net metering will not be offsetting Dx system costs and has directed that delivery and regulatory costs will be converted to a fixed charge for LDCs in Ontario. This will be implemented over a four-year period. Other ratepayers would still have to absorb the unrecovered global adjustment costs.

The LTEP is also supporting the additional notion of virtual net metering to allow Ontarians who may not be able to install their own renewable energy system to participate in renewable energy projects located away from their homes or businesses, and still receive a credit offsetting their electricity bill. Unless storage solutions can economically ensure peak shaving, there can be no system benefits. Unfortunately, the use of storage in a net-metering context is in conflict with the benefits of net metering to solar panel

[62] IESO data shows that 20% of the solar generation output from the recently installed grid solar farms was curtailed in 2017

[63] IESO, Energy Storage, 2016

owners because it would limit the price arbitrage benefits. Net metering to support the addition of high cost generation in Ontario is a bad approach.

b) NREL Models for Solar PV Plus Storage Systems

NREL undertook a study to assess the benefits of integrating solar PV with storage[64]. They considered several different architectures and tested those architectures against revenue models related to the energy markets in California. All of their revenue models involved attempting to capture the highest value of energy offsets from the PV plus storage system. The purpose of illustrating these cases in this report is to emphasize that the design considerations are not related to demand profiles being served, but to maximizing the revenue potential in a market dominated by fossil fuel prices.

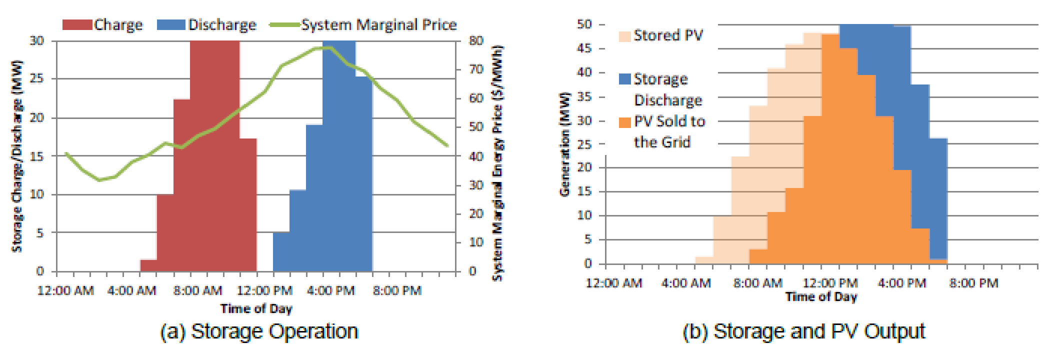
Case 1 – Tightly Coupled PV + Storage System

A tightly coupled system is one where the PV and storage systems use a common set of electronics and the batteries are only charged with energy from the solar PV panels. Figure 43 illustrates the charging and discharging strategy for a tightly coupled PV + storage system in California.

The chart on the right shows how the solar output is used to charge the batteries in the morning and then discharge them in the afternoon. The chart on the left shows how the storage is being charged during periods of low system marginal prices and discharged during times of high system marginal price, hence maximizing the revenue potential for the system owner.

Figure 43 – Optimal Dispatch of a DC Tightly Coupled PV plus Storage System

(June 16, 2014 Price Data from SCE LAP)

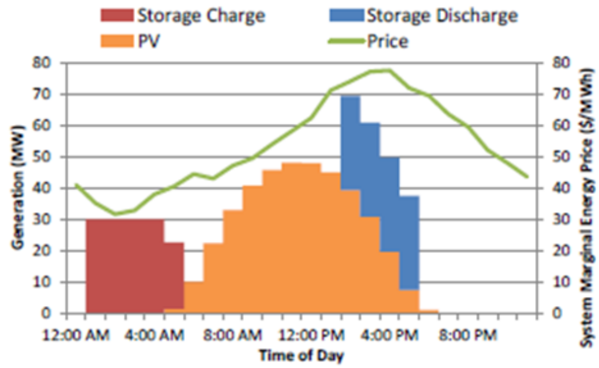


Case 2 – Independent Storage and PV systems

Independent systems do not have integrated shared circuitry. These systems can be individually optimized against market signals. Figure 44 shows how the storage is charged during low cost overnight periods and then discharged during high price periods. The solar is just used when it is available.

[64] NREL, Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants, 2017

Figure 44 – Storage Charging During Low Cost Overnight Periods



(a) Independent

In this case, the storage is not being used to support the solar output in any way, it is being used to independently maximize the revenues of the storage based on market prices.

c) Valuing Energy as a Function of When it is in Demand

Early studies examined the value of renewables output in the context of the market value of energy at the time the renewables outputs were available[65]. The argument presented is that the industry standard LCOE measure for comparing energy sources should not be blindly applied to energy sources such as renewables because their output does not necessarily align with demand. This is a particularly relevant perspective when considering that wind output occurs at any time of the day. Solar output occurs during the middle of the day and so would normally not be impacted by very low market prices; however, surplus solar conditions are emerging in Ontario requiring the curtailment of solar resources. To identify the "value" of this energy source, the market value of energy at the time the renewables are generated could be a criterion for defining the LCOE for comparison purposes.

Renewables' intermittency leads to situations where that energy is simply surplus. The wasted surplus costs are not reflected in this LCOE treatment as the system in which the renewables are inserted impacts on that value. As low-emission generation is pursued, the market price, which is based on the variable cost of generation, is becoming less relevant and not useful as a trading mechanism. This is creating much discourse in the U.S. on how markets require restructuring to address the implications on the future of electricity supply in that country.

4.4.3 Models to Support a Vision for Maximizing Renewables Penetration

The integration of the many components of an energy system have been looked at to estimate how that system may respond to renewables' intermittency and still deliver the energy demanded by the jurisdiction. These approaches look at the system as a whole and consider optimization benefits that could reduce overall costs.

[65] Joskow, 2011

a) Maximizing Renewables in an Energy System

Models of how renewables can form the basis for an entire energy system have been undertaken[66] with the purpose of assessing the total system cost and not considering pricing implications. The underlying premise for the analysis is the perspective that renewables *"should be the solution"* and that other resources (storage and natural gas) would be drawn upon to accommodate the shifting of supply to meet demand when the intermittency results in misalignment. The design of such a system for Germany entailed coupling wind and solar resources sized to deliver the full energy demanded over a year with a mix that minimized the seasonal storage needed. Battery storage was based on the average daily energy shifting required to match the renewables to demand. Modelling of generation and demand profiles indicated that 14% of the renewable energy had to be curtailed, 6% of the renewables were shifted by storage (with the associated losses), and natural gas fired generation was relied upon to supply 14% of the demand. Most of the natural gas use was required to address the seasonality implications. Of note is that natural gas fired generation only represented 4% of the supply mix in Ontario in 2017, a year in which 24% of the renewables supply was curtailed.[67]

Notwithstanding the wasted renewable energy and need for natural gas, the findings suggested that this mostly renewables system could supply Germany's energy needs at less than the cost of a system that relied solely on natural gas, even with a $50/tonne carbon price. However, the German study used: (1) overly optimistic costing assumptions; and (2) simplified generation and demand profiles which did not adequately reflect the impact of intermittency, the most significant factor affecting cost.

b) Advanced data analytics for system optimization

The science of advanced data analytics, and indeed artificial intelligence, is impacting the electricity sector. The concept of microgrids being optimized through balancing demand and supply for the community is yet another innovation in the toolbox for utilities. Smart controllers coupled with smart storage offer the potential to optimize energy resources across a community and marry renewables intermittency to demand fluctuations. It has been postulated that data analytics could also enable effective sharing of energy resources across the grid.

In terms of meeting the demand of a community when the local microgrid has insufficient self-generated energy, relying on sources outside the community does not meet the requirements for DER set out for this analysis. Furthermore, neighboring communities in Ontario have weather patterns that are very similar and hence unlikely to create much of a difference between them in surplus, stored, and need for backup energy.

4.4.4 System Solutions Must Combine Technologies

For systems to optimally match energy supply to demand, multiple technologies need to be engaged. New ICT-based smart control technologies are facilitating the integration of renewables and storage technologies enabling two new paradigms: (1) a new class of customers: consumers and producers of electricity ("prosumers"); and (2) community-based microgrids and virtual power plants. DER connected

[66] CPI, 2017

[67] IESO Year End Review 2017

in a microgrid configuration has the potential to provide at the local Dx system level the dispatch flexibility that natural gas-fired generation currently provides for the Tx grid.

Storage may be the enabler for adapting the energy supply to the demand, as it can intermediate between the supply and energy demanded by users. The advanced controllers and data analytics discussed earlier can also help optimize:

1. Demand fluctuations by encouraging users to adjust their usage profile (e.g. automation that enables EV charging or water heating at night, or curtailment of daytime air-conditioning when other energy usage such as for refrigerators and freezers is high; or managing options for hybrid electrical/gas appliances) to minimize impacts on system peaks.
2. Using storage to follow peaks in demand regardless of how supply is used to charge the batteries (as long as there is enough supply).

The impact of advanced controllers and data analytics may lead to flattening or smoothing of the daily demand load minimizing the impact of demand fluctuations on energy supply. Flattening the daily demand profile may also attenuate the drivers that cause higher prices in the market.

4.4.5 Summary Observations

Methods for establishing the business cases for DER that are predicated upon market pricing practices generally favor installers of DER at the expense of increasing total system costs. These case examples assume the fossil system will fill in any gaps required to meet demand, an approach which ignores the need to account for the cost of backup generation to complement renewable solutions.

Considering the LCOE of the individual components is insufficient for gaining a fair comparison. Just because grid-scale solar is becoming less expensive does not directly imply that an integrated grid-scale solar system will be cheaper. Examining the full system costs of introducing DER allows for a proper assessment of the impacts to the overall system. However, assumptions and modeling practices should be carefully selected to properly illustrate the implications.

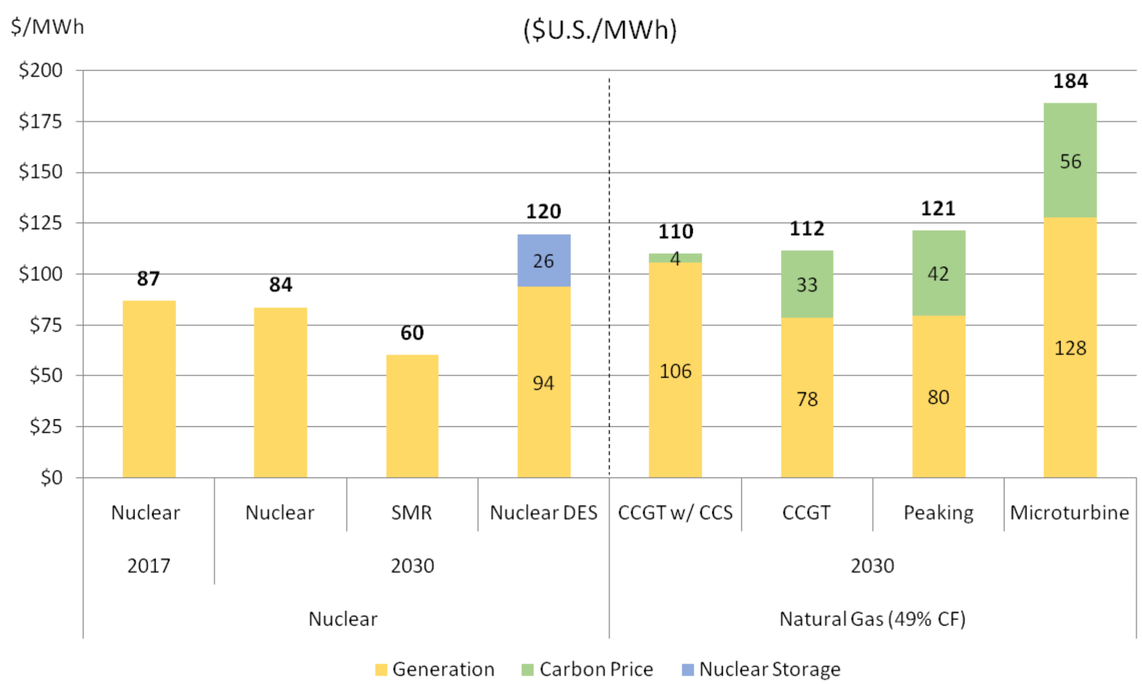
The advent of advanced data analytics, controllers and artificial intelligence (AI) have the potential to alter the demand profiles placed on DER systems by flattening the demand and reducing peaks. Such innovations will tend to favor energy supplies that have reliably flatter or more baseload type characteristics.

4.5 Comparison with Conventional Generation

Understanding the cost of renewable-based DER systems is most informative when those costs can be compared to alternatives. This section summarizes the costs of conventional solutions to the baseload and daytime demand challenges as well as a nuclear baseload-supplied DES. Consideration is given primarily to low emission options which include nuclear and natural gas fired generation equipped with carbon capture.

Figure 45 summarizes the forecast costs for these conventional solutions. Nuclear technologies would provide a baseload supply but can also serve daytime demand if coupled with distributed storage. For supplying daytime demand, CCGT equipped with CCS may be competitive with other forms of gas-fired generation if carbon pricing is included (carbon price of CAD $100/tonne illustrated).

Figure 45 – LCOE of Nuclear and Natural Gas-Fired Generation



This section addresses three topics:

1. The forecast costs of conventional nuclear and CCGT with CCS
2. The cost implications of a nuclear baseload-supplied DES option
3. The costs of alternative gas-fired generation options.

4.5.1 Cost Forecast for Conventional Generation

For conventional generation, the EIA and NREL forecast LCOEs were considered as shown in Figure 46 for nuclear and Figure 47 for CCGT equipped with CCS.

Figure 46 – Nuclear LCOE Forecast to 2030

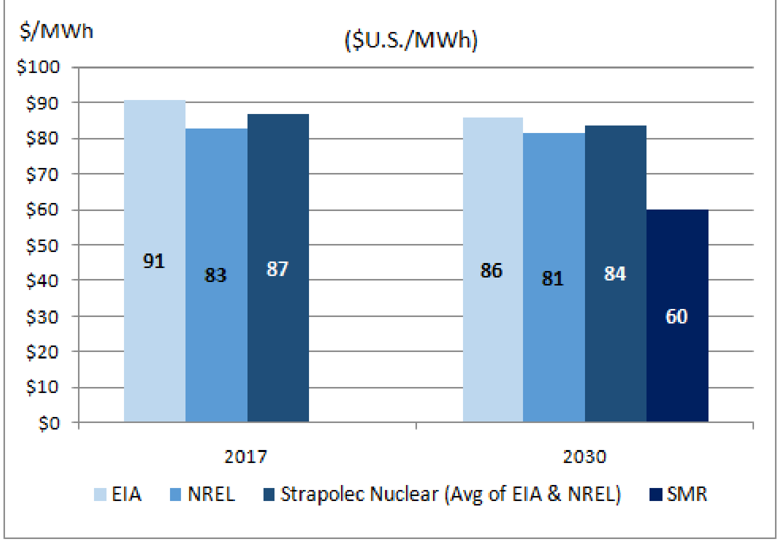
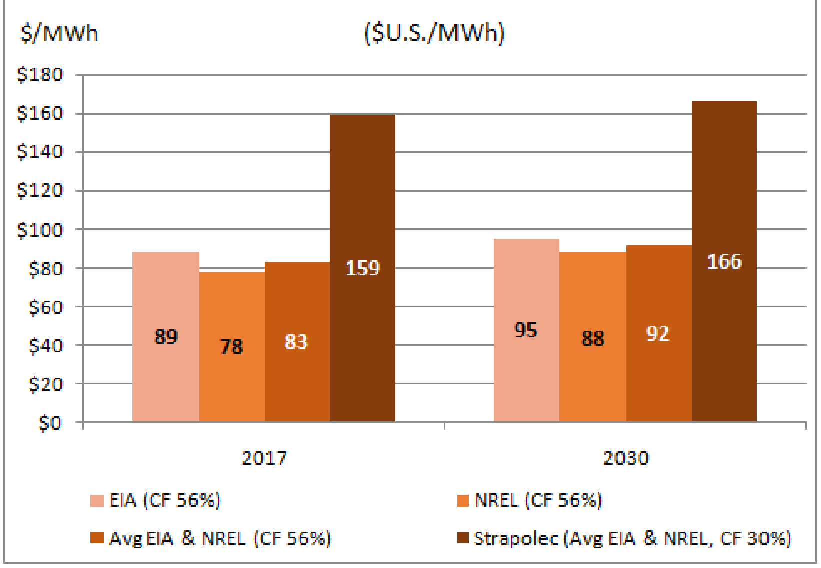


Figure 47 – Combined Cycle Gas Turbine with CCS LCOE Forecast to 2030



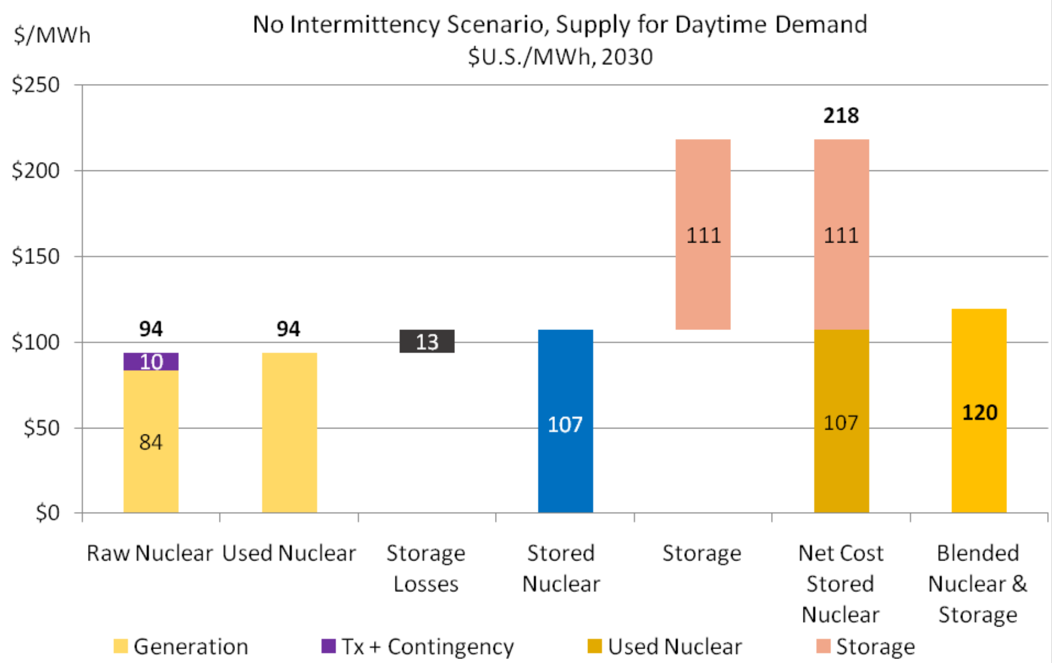
Both capital costs and LCOEs for these technologies are expected to have modest declines of much less than 1% per year. While the EIA and NREL have current estimates for CCS, these estimates grow in the future before starting their modest declines. For that reason, only the 2030 values are shown. The small modular reactor (SMR) estimate is based on the Energy Information Reform Project (EIRP)[68].

[68] EIRP, 2017

4.5.2 Nuclear Baseload-Supplied DES Option

The full cost impact breakdown for nuclear coupled with storage to meet the community-scale daytime demand profile is illustrated in Figure 48. These include: an assessment of the cost of the nuclear energy utilized; the costs of the nuclear output that is stored; and a computation of the net blended outputs.

Figure 48 – Nuclear Baseload-Supplied DES LCOE Components



a) The Cost of Utilized Nuclear Electricity

As the nuclear baseload-supplied DES option provides baseload supply to the grid, the cost of the utilized nuclear electricity includes the full EIA markup for Tx and contingency.

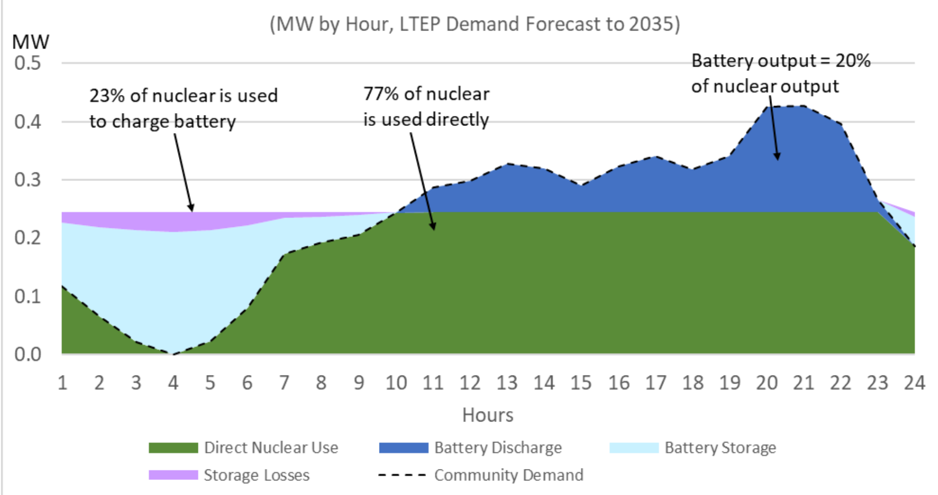
b) The Cost of Stored Nuclear Electricity

The storage for nuclear baseload-supplied DES is assumed to be Li-ion batteries. The full cycle round-trip efficiency loss is 14%. For the utilized nuclear electricity at a cost of $94/MWh, the cost of the stored nuclear electricity will be 14% higher, or $13/MWh more, yielding a total of $107/MWh before the cost of the storage component is added. The LCOS of the batteries is $111/MWh, which is higher than for solar-based DER which benefitted from technology integration economies. The net cost of the stored nuclear electricity would be $218/MWh.

c) Determining the Net Blended Cost

The design parameters for a nuclear baseload-supplied DES solution required to supply the daytime demand profile are shown in Figure 49. The illustration reflects a community DES with 1.2 MWh of storage.

Figure 49 – Nuclear and DES for Daytime Supply



To supply the daytime demand scenario, storage and nuclear are combined to emulate a gas plant supply. For the average Ontario day in September, storage would be sized to capture 23% of the nuclear energy. September was chosen as a sample month to facilitate a comparison with the solar option. The net cost of blending the 77% of nuclear output that is directly utilized plus 20% output from storage totals \$120/MWh. This assumes that the storage system is fully charged and discharged on a daily basis.

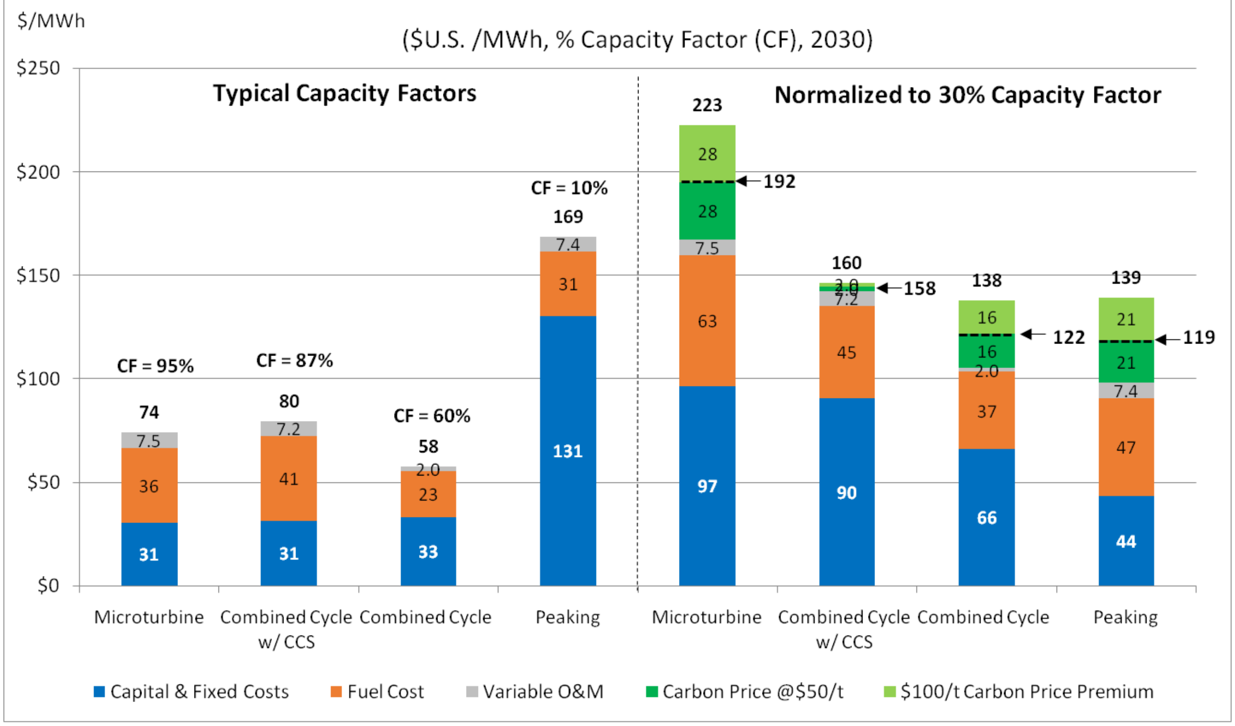
4.5.3 Natural Gas-Fired Generation Options

While CCGT with CCS has been chosen as the low-emission grid-based supply option for contrasting cost performance of DER solutions, other natural gas-fired options may also be desirable depending on the climate policies in place. It may be desirable for cost reasons to accept a high emitting generation option that has a low operating factor and simply pay the carbon price.

In the DER discourse, one of the options considered is microturbines that can be located within community or distribution-scale DER installations.

Figure 50 summarizes the LCOE for several forms of natural gas-fired generation. The left side of the figure shows the LCOE of the gas-fired generation options at the nominal capacity factors assumed for the prices quoted. These are typically the prices referred to when these natural gas-fired generation options are compared. To choose among them for the purpose of this study, the comparison is best based on common capacity factors.

Figure 50 – Natural Gas-Fired Generation LCOE Comparison



The right side of the figure compares the LCOE of each generation type for an installation with a 30% capacity factor. Carbon pricing has been included for two levels: CAD $50/tonne; and CAD $100/tonne. Canada is expected to have a $50/tonne carbon pricing mechanism in place by 2022. Carbon pricing will need to be well in excess of CAD $100/tonne by 2030 if emission reduction objectives continue to be pursued[69]. With carbon pricing considered, the large-scale gas options have similar total cost implications, but clearly have different emissions profiles. CCGT with CCS could cost 15% more than regular CCGT but would produce 90% less emissions.

The capital portions of the LCOEs are an indicator of the sensitivity to the capacity factor. The capacity factor indicates how much the gas plant is used. The small capital component for peaking generators makes them the least expensive option at low capacity factors. The high capital content of the CCGT with CCS option suggests that their competitiveness will improve as capacity factors increase.

The microturbines stand out as the most expensive backup supply option even without carbon pricing given their high capital requirements and high variable fuel consumption. Microturbine solutions for DER applications are likely cost prohibitive from a total system cost perspective.

4.6 Summary of Cost Implications

The research of DER component costs suggests that costs will continue to decline, although not at a rate of acceleration that will make renewables and storage ubiquitously cheap. By 2030, grid-scale wind is expected to decline by 20%, community-scale solar could decline by over 35%, and storage by about 50%.

[69] Strapolec, Emissions and the LTEP Phase 2, 2016

When these technologies are integrated into a DER solution, the total costs will be much higher, even under ideal conditions. Today, costs are far too high for DER solutions to be considered on a large scale for managing system peak demand. By 2030, it appears that grid-based wind solutions may be economic when compared to nuclear or natural gas solutions. The economics of community based solar DER, however, may be questionable even though some capital cost synergies could be realized.

The current high cost of DER calls into question how DER solutions are being adopted in the market place. Most solutions are predicated on market arbitrage opportunities and rarely consider total system costs. There is much literature addressing the challenges of properly valuing and monetizing the costs of DER.

5.0 Reality of Intermittency

Renewables intermittency is a function of how sunny it is and how much the wind blows.

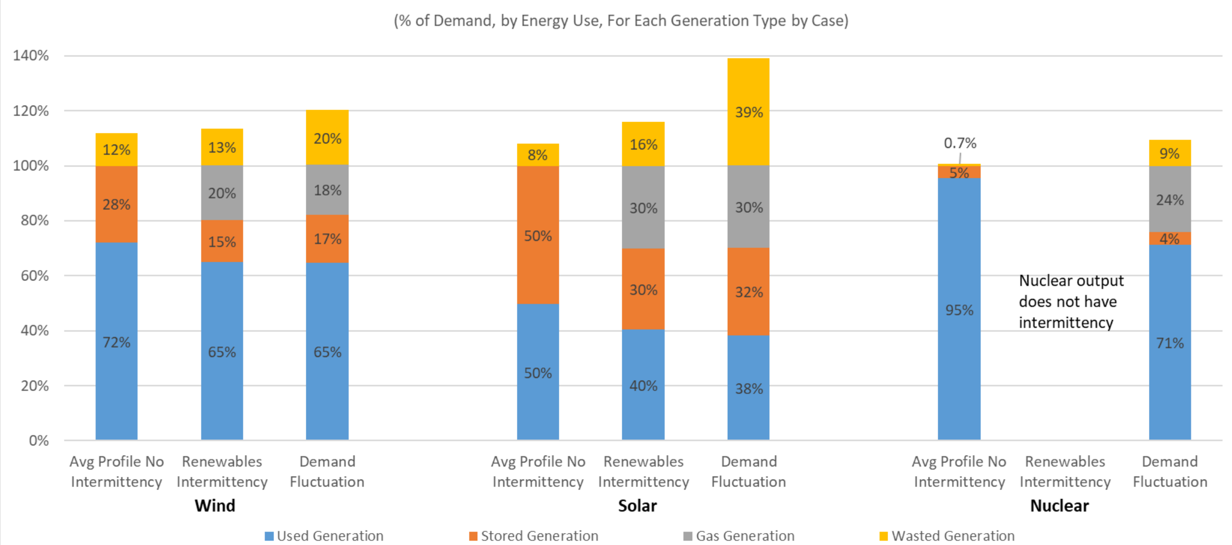
This intermittency undermines the efficiency of a DER solution, increasing the cost of both useable renewable energy and storage. In a solar-based DER system, the solar panel and storage capacity must be physically sized to a set of assumptions, which would typically reflect an average output expectation. The production variability associated with renewables impacts the efficiency and costs of the generation and storage components. These impacts are manifested in several ways:

1. When renewables output exceeds storage capacity, this creates surplus output and the need for curtailment.
2. When renewables output falls below the expected capacity factor, two consequences can occur:
    a. Gas backup is required to meet the demand.
    b. Insufficient energy is available to fully charge the storage device, causing the storage capacity factor to drop.

Demand fluctuations can also impact the efficiency of the DER system. Similar to renewables' intermittency, low or high demand can impact the need to curtail the output from generation, the need for backup supply, and the use of storage capacity.

Figure 51 illustrates the effects of these two factors on a DER system. The characteristics of a system based on the average output that assumes no intermittency, as described in Section 4.4, is contrasted against the impacts of the intermittent nature of renewables and the reality that demand also fluctuates. Wasted generation refers to both losses in the storage system as well as any surplus generation that would get curtailed. As such, even the perfect no-intermittency case has wasted energy in the form of storage losses.

Figure 51 – Intermittency and Demand Fluctuation Impact on DER Component Use



Section 5.1 discusses the various factors that result in intermittency and demand fluctuations and presents the demand requirements that DER systems in Ontario would have to meet.

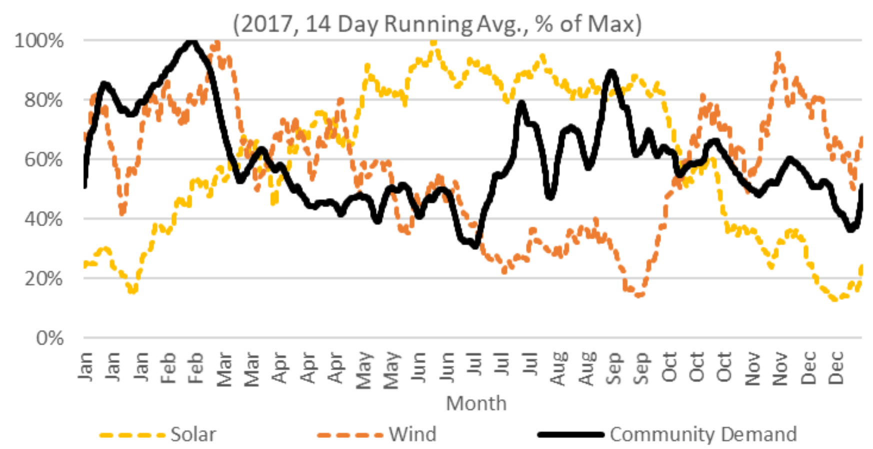
Section 5.2 discusses the causes of solar intermittency while Section 5.3 looks at wind intermittency.

Section 5.4 characterizes the impacts of demand fluctuations on solar-based and wind-based DER, as well as on nuclear baseload-supplied DES, and compares the results.

5.1 Intermittency Defined and Characterized with Demand

It is well understood that the generation profiles of solar and wind output do not match the electricity demand profile, as illustrated by Figure 52.

Figure 52 – Relationship Between Wind, Solar, & Community Demand



Solar peaks in the spring when demand is at its lowest. Wind generation is highest in the winter, matching demand, but then is too high in the spring and fall, and too low in the summer when demand peaks again. Storage is considered to be a solution for addressing this mismatch between output and demand and to facilitate the integration of renewables. The storage system would charge during hours of excess renewable generation and discharge during periods of low or no generation. This concept was illustrated for wind earlier in Figure 39, without consideration of the impacts of intermittency.

In addition to the misalignment with demand, wind and solar generation present a significant intermittency challenge – significant output being generated one day and none on another. Demand variability on a daily and seasonal basis represents another challenge.

To properly compare the effects of both supply intermittency and demand fluctuations on DER options, these intermittency and demand fluctuations need to be characterized and a common set of requirements defined that each DER option would be expected to meet.

This section describes the types of intermittency and the nature of demand fluctuations and establishes the requirements for future DER systems in supplying the expected demand for Ontario.

5.1.1 Renewables Intermittency and Relationship to Storage

Intermittent outputs from wind, solar and hydro generation impact the value of these renewable assets and also the potential value of the storage used to smooth their outputs. Storage capacity utilization is "cost optimized" when the storage is charged and discharged more frequently. Most storage costing assumptions assume a daily charge/discharge cycle for most days of the year. Table 5 summarizes the relationship between storage and renewables intermittency by type.

Table 5 – Types of Renewables Intermittency and Variable Generation

Type of Intermittency	Impact on Storage
Hour to hour	Can be smoothed by storage, it is the easiest job storage can do and aligns nicely with using storage as a "peaker" plant replacement.
Day to day	If the energy and demand differ from day-to-day, then storage system inefficiencies can arise on any given day when the storage system may not be fully charged or discharged.
Month to Month (seasonal)	When generation or demand varies significantly between seasons, to use storage for smoothing these fluctuations would result in few charge/discharge cycles. For seasonal storage applications, many analyses assume that the storage is only discharged once a year, decreasing the capacity factor from the typically assumed 350 charge cycles in a year. This could represent a per MWh energy cost increase factor of 350 It is generally understood that addressing seasonal intermittency with storage is prohibitively expensive and is best addressed by peaking gas plants.[70]
Year to Year Variations	Wind, solar and hydro generation outputs are also affected by annual variations in weather patterns. This means DER systems need to be designed for an annual reference and recognize that capacity factors can be affected on a year to year basis.

5.1.2 Demand Requirements for DER Solutions

A future - reference demand profile for Ontario has been developed to facilitate the modeling of the economics of DER solutions and enable an objective comparison of the DER options.

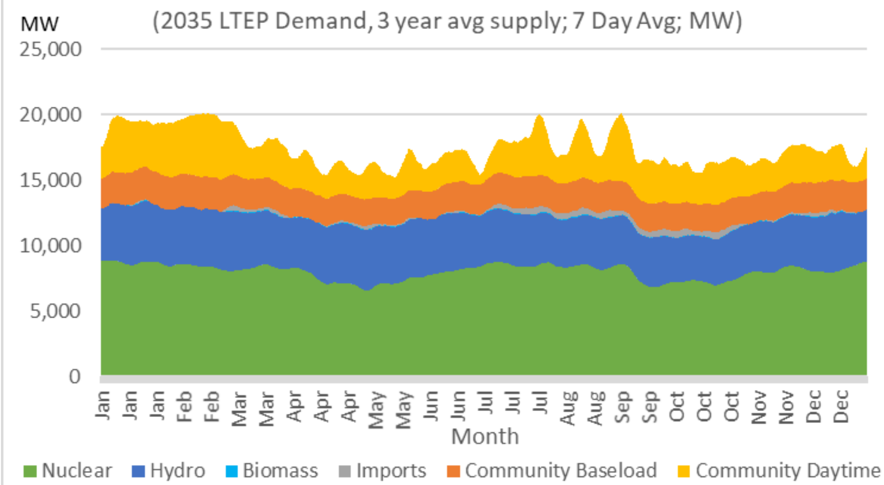
For this analysis, an 8,760-hour annual demand that reflects the 2017 LTEP forecast for 2035 is used. This demand profile incorporates many assumptions including the degree to which daily demand profiles may change with the introduction of 2.4 million electric vehicles.

It is assumed that the requirements for the DER systems would reflect a demand profile that could not be met by the existing and committed resources defined by the 2017 LTEP (as previously discussed in Section 1.0).

[70] CPI, 2017

Figure 53 illustrates the contributions that existing and committed nuclear, hydro, biomass, and import supplies provide, and the gap of community baseload and daytime demand that could be filled by DER solutions. The profile for the committed resource supplies in Figure 53 illustrates that the existing system capabilities provide some seasonal flexibility and demand management capabilities.

Figure 53 – Supply Mix Contributions to Ontario Demand

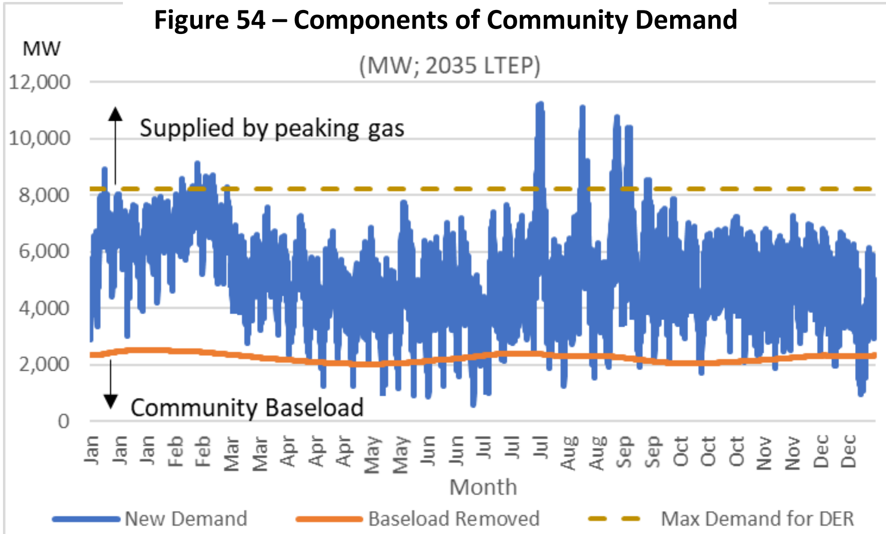


a) Community Demand

Community Demand is defined as the demand that exceeds the capabilities of Ontario's committed resources and that is currently being met by variable generation sources such as wind/solar and natural gas. The capacity of these latter generation resources is covered by contracts that will be gradually expiring and that will need to be renewed or replaced by 2035[71]. This demand profile could potentially be met with DER system options.

"Community" is defined as a mix of residential and commercial customers at a common location, e.g. 1000 homes and/or the equivalent in commercial businesses. The associated demand has baseload, daytime, and peak components. Figure 54 illustrates the community demand profile used for simulation purposes. The design requirements for the baseload component are fairly straightforward, e.g. constant demand every day for the entire year. The daytime demand is more challenging as it contains all the intermittency characteristics previously discussed. The peak component is to be assumed addressed by peaking gas-fired generation.

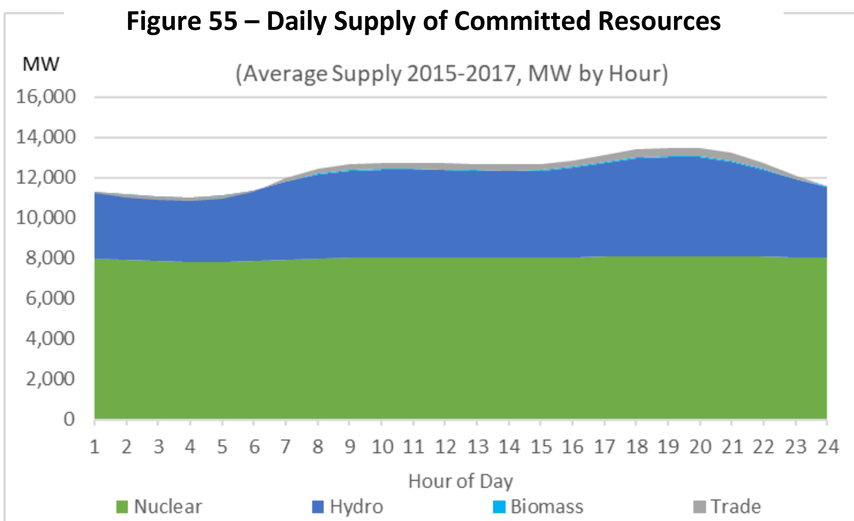
[71] IESO forecast in 2017 LTEP



A demand of 2,250 MW is assumed to be met by a future baseload supply. There are several hours in the year when that baseload supply may be in surplus (as indicated by the weekends when the blue demand line spikes below the baseload supply reference). This level is used so as to not over-burden the daytime demand profile with a baseload requirement. The profile of the baseload community demand was derived from the average output of Ontario's nuclear fleet between 2011 and 2015. This was deemed reasonable as the baseload supply is more cost effectively provided by a reliable grid source such as hydro or nuclear generation.

b) Committed Supply

The committed supply is made up of nuclear[72], hydro, biomass, and import/exports from Quebec[73]. This supply mix provides some daily supply flexibility as illustrated in Figure 55.



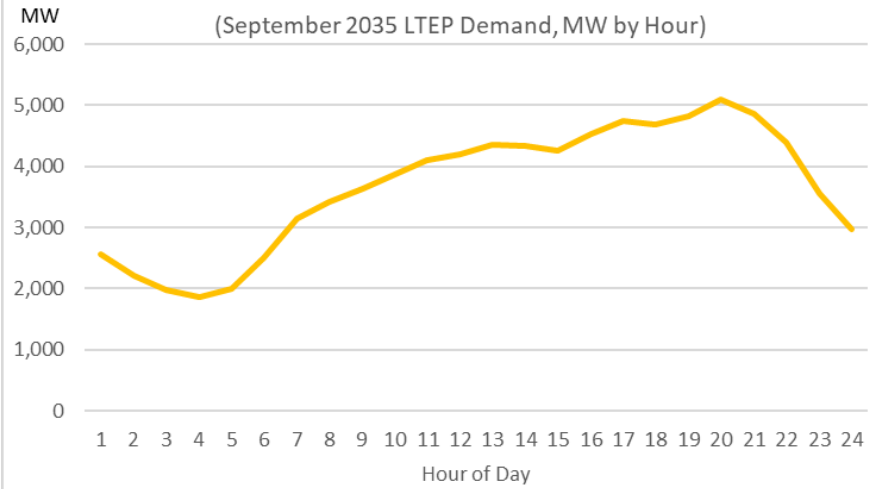
[72] Excluding the Pickering Nuclear Station which retires in 2024

[73] Only 60% of the impacts of energy trading with Quebec impacts the profile as it is assumed the remainder is comprised of power flows through Ontario to neighboring jurisdictions

The profile above reflects a 3-year average of Ontario supply between 2015 to 2017. for the simulation, the output for each hour was computed from a running 28-day average to mitigate the effect on the results that could otherwise be caused by the baseload curtailments that occurred in 2015, 2016 and 2017. This produces a unique 24-hour output profile for each day of the year.

The generation output profile of the committed resources was then subtracted from the total Ontario demand to create a daily community daytime demand profile unique to each day of the forecast 2035 year. This demand profile is used to assess the capabilities of the different DER options. Figure 56 illustrates the average September profile for daily community demand.

Figure 56 – Average Daily September Community Demand



Since the nature of each supply type (wind, solar, nuclear) is different, the initial sizing of the storage capacity was based on different time frames. The design references set a storage capacity so as to minimize curtailment and inefficiencies during that reference period. The month of September was used for solar as demand during this month reflects a 12-hour day in Ontario and it is reasonably sunny. For wind, March demand was selected as a typical demand month when the wind blows strongest. This minimizes surplus output and curtailment. Nuclear capacity is based on the month of May, to reflect a low demand period and to also minimize surplus energy.

Solar-based DER applications can be sized to support communities of 500 homes and up to several thousand homes. To compare solar-based DER to baseload-supplied DES, a common aggregated demand pool was selected to represent the demand for 800,000 homes plus the equivalent commercial demand. This reflects a total annual community daytime demand of 2.5 TWh and a 900 MW peak. To supply this demand, the three scenarios include: 1,700 MW of solar, 920 MW of wind, and 275 MW of nuclear.

5.2 Solar-Based DER Intermittency Implications

To explore the impacts of intermittency on solar-based DER solutions, the effects of intermittency have been segregated from those caused by demand fluctuations. To do so, the simulation assumes that all days of the year have the same daily demand profile. Using the average September daily demand yields an annual demand of 3.2 TWh. The performance measures impacted by intermittency include:

- Wasted Generation – arises when the solar output exceeds the demand and storage capacity.
- Unused storage – arises when there is insufficient generation to charge the storage or there is insufficient demand to discharge the storage. This measure impacts on storage capacity factor.
- Need for natural gas-fired backup generation – arises when there is insufficient solar generation and/or stored energy to meet demand.

The resulting solar-based DER system characteristics are summarized in Table 6. The results of the three-year simulation of intermittency using actual Ontario solar output are summarized in Table 7. This shows that 47% of the solar generation will be used directly, 34% will be retrieved from storage, and natural gas backup will be required to supply 30% of demand.

Table 6 - Solar Constant Demand, System Characteristics

DER Component	Characteristic	Value
Community Daytime Demand	Total (GWh)	3,248
	Peak (MW)	514
Solar	Capacity (MW)	1,669
	Capacity Factor (%)	19.1%
Storage	Capacity (MWh)	4,478
	Capacity (Hours)	8.7
Backup Generation	Gas Peak (MW)	508

Table 7 - Solar Constant Demand, System Performance

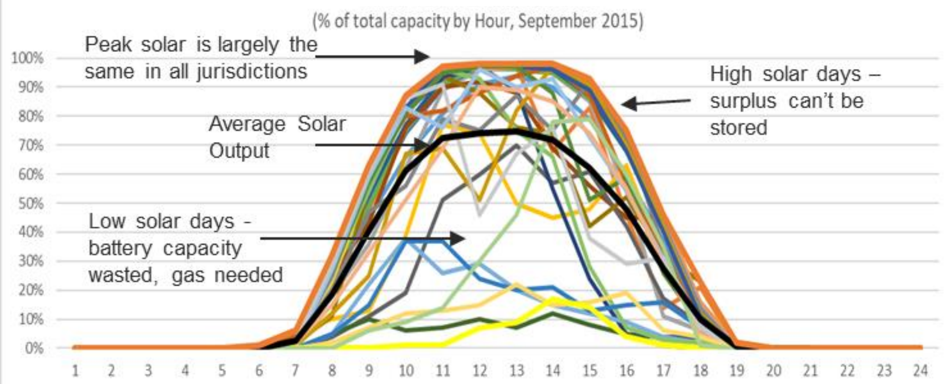
DER Component	Performance Metric	GWh	% of Generation
Generation	Used Directly	1,314	47%
	Excess	364	13%
	Into Storage	1,119	40%
	Total Output	2,798	100%
Storage	Stored Generation	962	34%
	Losses	157	6%
	Capacity Factor (%)	61.3%	
		GWh	% of Used Generation
Backup Generation	Backup Generation	971	43%
	DER Managed Peak (MW)	508	
	Unmanaged Peak (MW)	514	
	Managed Peak Reduction %	-1%	
	Capacity Factor (%)	21.8%	
		GWh	% of Demand
System Totals	Used Generation	1,314	40%
	Stored Generation	962	30%
	Backup Generation	971	30%
	Wasted Generation	521	16%

The following subsections first examine the effects of hourly and daily intermittency, and then assess the seasonal and annual implications.

5.2.1 Solar-Based DER Daily Daytime Operation and Daily Intermittency

Solar can have significant variations in output from hour to hour and day-to-day. Figure 57 shows the solar output for each day in September 2015[74] and how they vary with respect to the average. The solar-based DER solution would have the battery capacity sized according to average solar output. The relationship between the average output and the peak output is an indicator of the capacity factor. The peak output of a solar array is similar in most months of the year. The average profile for any given month is affected by how often the peaks are achieved and over how many hours the sun is above the horizon.

Figure 57 – Daily Solar Output Profile



As Figure 57 shows, solar output can frequently vary above and below the average and can drop to near zero for an entire day. It also illustrates that solar requires storage in order to reliably meet demand, even in relatively sunny months like September. Hour to hour variations of solar output would have minimal impact on the performance of the DER storage system if the cumulative daily output achieves the average assumed in designing the system capacity.

When the output is greater than average, surplus solar cannot be stored, as the battery will be fully charged to its designed capacity before the sun sets. This surplus solar is modelled as "wasted" solar.

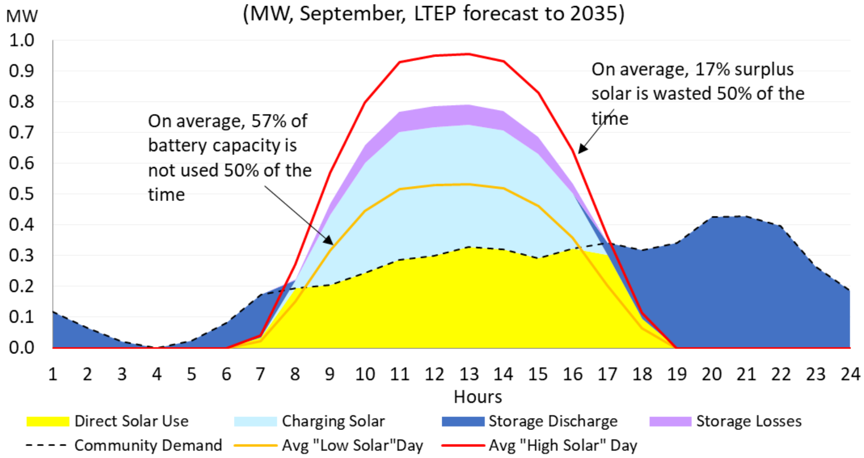
When solar output is below average, the battery will not fully charge to its designed capacity and hence will not be able to discharge sufficient energy after the sun goes down. This leads to unused battery capacity as well as a need for backup supply to make up for the unavailable solar and/or stored energy.

Figure 58 provides a simplified illustration of how solar intermittency parameters relate to daytime demand in the month of September. The average solar output is the sum of the used and charging solar as well as the losses that occur in storage. Since the first draw on the solar output is used to meet demand, the impacts of intermittency are amplified for the use of storage. Surplus solar refers to solar output that exceeds demand and which would be used to charge the battery. The DER storage system would be designed to accommodate the average of this surplus solar. Solar energy losses arise from storage conversion inefficiencies.

[74] Based on September 2015 actuals from IESO data, not curtailed.

Figure 58 – Solar and Storage for Daytime Demand Supply

(MW, September, LTEP forecast to 2035)



The amount of solar output that exceeds the battery capacity is illustrated by the redline in Figure 58. Excess solar output above the designed storage capacity represents on average 17% of the total solar output. Since high solar output days occur 50% of the time, 8.5% of total solar output is wasted. Similarly, the average amount of solar output when there is a shortfall is illustrated by the yellow line in Figure 58. Low solar output days will occur 50% of the time eliminating 57% of the expected battery charging for those days, or 28% of total battery capacity. This 8.5% loss increases the cost of solar by 8.5%. At a 72% battery capacity the cost of storage increases by almost 40% and requires backup generation to supply that battery storage shortfall.

Figure 59 illustrates how the intermittent solar output for September 2017 integrates with storage and backup generation over 30 days of a constant average daytime demand profile for September 2035. This simulation allows for unused stored energy from the previous day to be carried over to the next day.

Figure 59 – Solar and Storage System for September 2017

(MW by Hour, 2017 September Solar Output, 2035 LTEP Demand)

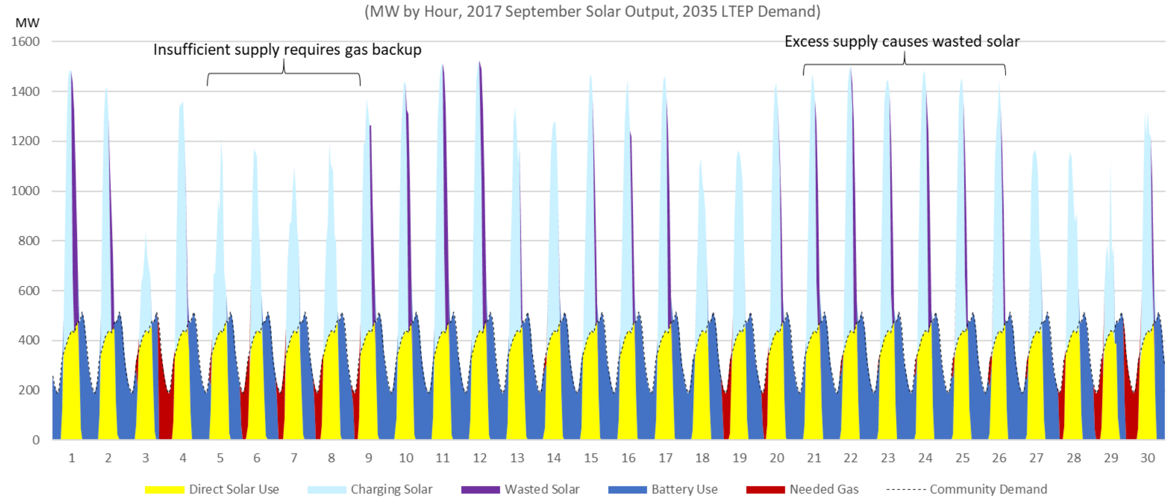


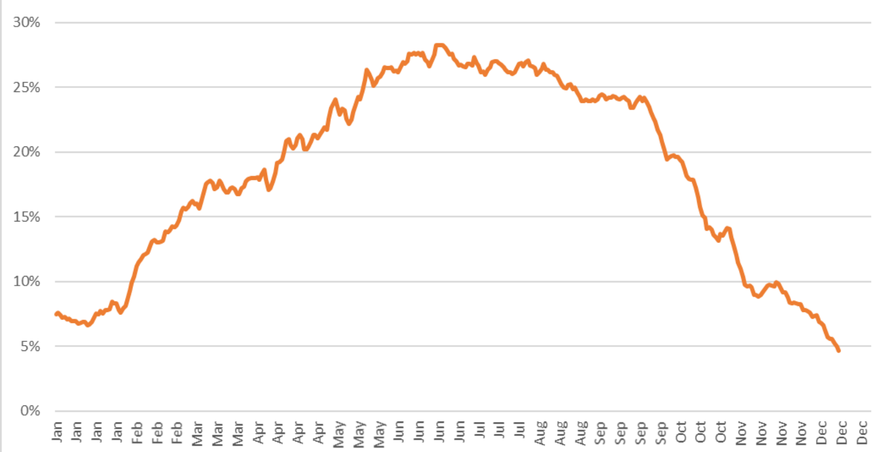
Figure 59 demonstrates how the simulation captures the impacts of intermittency. The colors indicate when storage is being charged and discharged and when backup generation is required to address any shortfalls in output.

5.2.2 Seasonal and Annual Variations

Figure 60 illustrates how the solar output capacity factor in Ontario varies throughout the year. The capacity factor has significant seasonal variations, dropping as low as 5% in December from 28% in June.

Figure 60 – Solar Capacity Factor Rolling 28-Day Average

(% of Maximum Capacity, by Day, 2017)



Lower solar capacity factors in winter result in lower battery capacity usage, because there is not enough sun to fully charge the battery. and will require more gas backup to cover the shortfall.

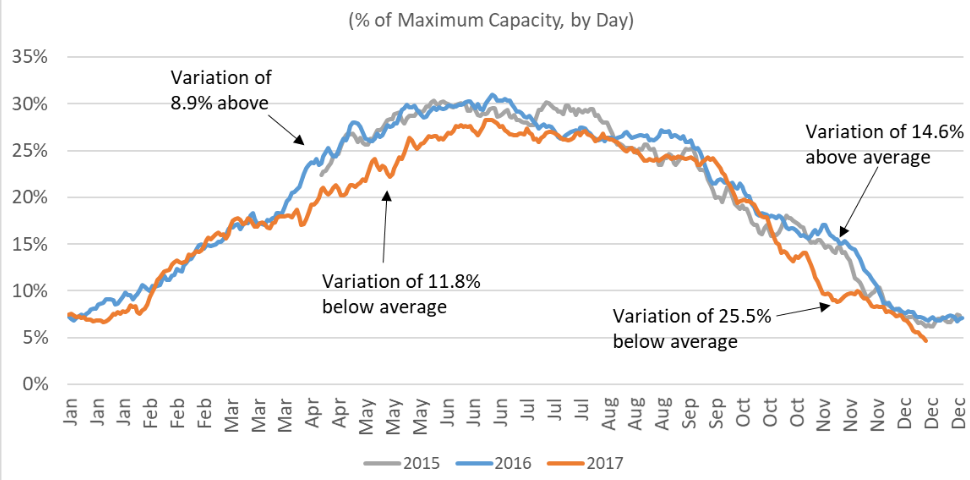
The seasonal variation in capacity factors complicates the appropriate sizing of the storage. Over-building solar capacity will allow better use of the battery in winter and require less gas but will result in unused solar surplus in the summer months. Over-building the battery capacity will allow more flexibility in the use of solar in the summer months but will decrease the realized battery capacity factor. Both of these options lead to increased costs.

Figure 61 illustrates how solar capacity factors can vary from year to year. In 2017 there was significantly less sun in the spring and fall compared to 2015 and 2016. Yearly variations can be up to 25% of the seasonal average.

Periods with lower solar output make the batteries less efficient and require more backup generation. Periods of higher solar output could lead to greater solar waste but an improved battery capacity factor.

There is less choice with the required backup capacity. It must be sized to meet the maximum need anticipated in order to ensure a reliable supply under foreseeable circumstances.

Figure 61 – Solar Output Comparison by Year



5.2.3 Impact of Intermittency on System Parameters Under Constant Demand

The peak backup demand and the associated capacity factor of the backup generation facility are important components of the total system cost. The manner in which the storage capabilities of a DER system are operated can be optimized to help minimize the peak gas used and the peak discharge current of the storage output.

Figure 62 illustrates the needed backup generation for a day in 2035 September when stored energy is withdrawn and before the backup generation is required. This scenario represents the worst case peak demand for backup generation.

Figure 63 illustrates a different scenario when the storage is leveraged by averaging the daily gas requirement as a percentage of the demand in concert with utilized storage and generation over the day. This approach minimizes the peak demand both for the storage output and for backup generation.

It may not be practical to achieve the full benefits of the "Percent of Demand" approach illustrated in Figure 63. To do so may require some predictive capability in the controllers and the amount of gas that can be shifted may be limited by available battery capacity on any given day. For the purpose of the comparative cost analysis, the average of the required peak backup generation from the two approaches is used. With this approach, Table 7 shows that the peak backup generation can be reduced from 514 MW to 508 MW. This would not be a material impact on the peak backup generation demand. However, later in the analysis, when demand fluctuations are taken into account, this method does materially reduce the system peak demand for backup generation.

Figure 62 – Solar and Storage System with Unadjusted Gas Peak

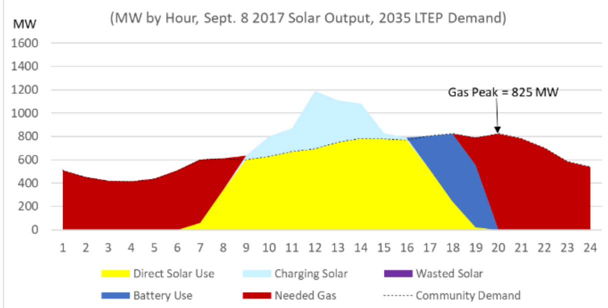
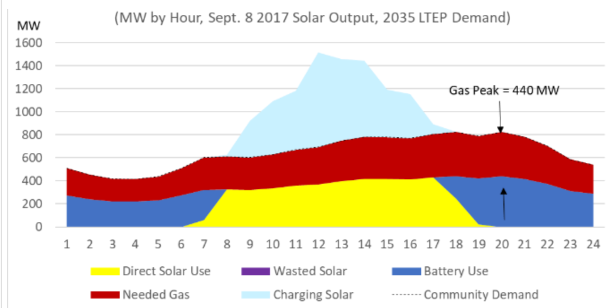


Figure 63 – Solar and Storage System with Gas Averaged as Percent of Demand



5.3 Wind-Based DER Implications

This section examines the impacts that wind intermittency has on the performance of a DER solution assuming a constant demand profile.

To explore the impacts of intermittency on wind-based DER solutions, the effects of intermittency have been segregated from those caused by demand fluctuations. To do so, all twelve months of the year are assumed to have the same demand profile as the month of March. Wind generation could potentially provide either daytime or baseload demand.

Tables 8 and 9 summarize the wind-based DER system characteristics for a daytime and baseload supply function respectively. The annualized daytime demand is 2.8 TWh and the annualized baseload demand is 3.2 TWh with both options assuming a 920 MW aggregated wind farm capacity.

Table 8 - Wind Constant Monthly Daytime Demand

DER Component	Characteristics	Value
Demand	Total (GWh)	2,795
	Peak (MW)	598
Generation	Capacity (MW)	920
	Capacity Factor (%)	32.3%
Storage	Capacity (MWh)	34,887
	Capacity (Hours)	87
Backup Generation	Gas Peak (MW)	533

Table 9 - Wind Baseload Demand

DER Component	Characteristics	Value
Demand	Total (GWh)	3,175
	Peak (MW)	362
Generation	Capacity (MW)	920
	Capacity Factor (%)	32.3%
Storage	Capacity (MWh)	29,189
	Capacity (Hours)	81
Backup Generation	Gas Peak (MW)	350

The performance results under these two scenarios based on full three-year simulation of actual Ontario wind output and intermittency are provided in Tables 10 and 11.

Table 10 - Wind Constant Monthly Demand, System Performance			
DER Component	Performance Metric	GWh	% of Generation
Generation	Used Directly	1,813	69%
	Excess	144	6%
	Into Storage	659	25%
	Total Output	2,617	100%
Storage	Stored Generation	429	16%
	Losses	230	9%
	Capacity Factor (%)	3.5%	
		GWh	% of Used Generation
Backup Generation	Backup Generation	555	25%
	DER Managed Peak (MW)	533	
	Unmanaged Peak (MW)	556	
	Managed Peak Reduction %	-4%	
	Capacity Factor (%)	11.9%	
		GWh	% of Demand
System Totals	Used Generation	1,813	65%
	Stored Generation	429	15%
	Backup Generation	555	20%
	Wasted Generation	374	13%

Table 11 - Wind Baseload Demand, System Performance			
DER Component	Performance Metric	GWh	% of Generation
Generation	Used Directly	2,019	77%
	Excess	49	2%
	Into Storage	549	21%
	Total Output	2,617	100%
Storage	Stored Generation	357	14%
	Losses	192	7%
	Capacity Factor (%)	3.5%	
		GWh	% of Used Generation
Backup Generation	Backup Generation	797	34%
	DER Managed Peak (MW)	350	
	Unmanaged Peak (MW)	362	
	Managed Peak Reduction %	-3%	
	Capacity Factor (%)	26.0%	
		GWh	% of Demand
System Totals	Used Generation	2,019	64%
	Stored Generation	357	11%
	Backup Generation	797	25%
	Wasted Generation	241	8%

The impacts of intermittency on supplying the daytime demand are that 69% of wind energy will be used directly, 16% will be utilized from storage, and 20% of the demand will have to be supplied by backup generation. To provide a baseload generation function, 77% of wind would be used directly, 14% from storage, and 25% of baseload demand would come from backup generation.

This section discusses the nature of wind intermittency and the criteria required to size the storage facility. A constant monthly demand is used to illustrate how a wind-based DER solution would respond to demand. Additionally, the system design parameters required to accommodate seasonal and annual variations in wind generation output are described and the final simulation results are presented.

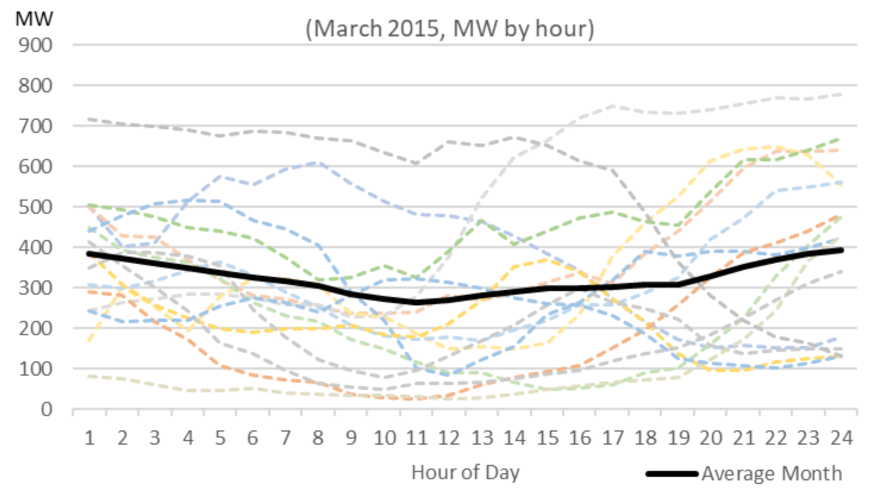
5.3.1 Wind Daily intermittency

As with solar, wind output on any given day can vary dramatically. This section illustrates the nature of intermittency by examining the daily wind output profile, the frequency of wind output magnitude and the pattern of output over several months, and the degree to which battery size can smooth wind output.

a) Daily Wind Profile

Figure 64 illustrates the output of 920 MW of aggregated wind capacity for several days in March 2015. Unlike solar, wind patterns do not have a uniquely shaped daily profile. Wind output does not peak or fall at similar times every day. It can have high or low peaks at any hour of the day.

Figure 64 – Variations in Daily Wind Output



The average daily output appears to be uniform, with 25% higher output at night than mid-day. However, the day-to-day output variation can be as high as 800 MW one day, and as low as 20 MW the next. Variations within the same day can dramatically drop from 700 MW to 100 MW over the course of a few hours.

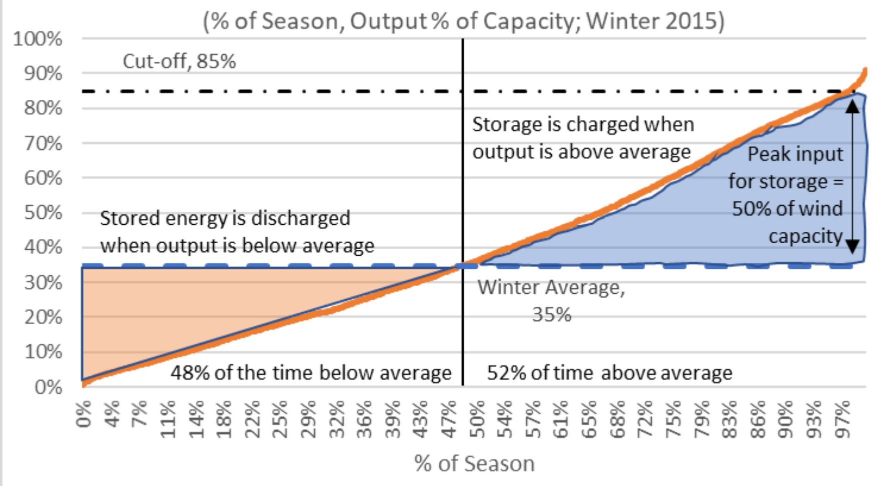
b) Frequency of Wind Output Magnitude

Figure 65 illustrates how often wind output magnitude is achieved as a percentage of time in the winter season.

Assuming a constant baseload demand equal to the average wind output must be supplied, then the objective of storage would be to shift output from times of high generation to times of low generation. When wind output is above the average, the energy will be directed to storage. When wind output is below average, the baseload supply will be achieved by discharging from storage. For the CAES storage considered for wind, its efficiency losses are 35%.

For CAES system based on wind data for the winter of 2015, the average useable wind output capacity factor would 35%. Wind output was below this average 48% of the time, and above it 52% of the time.

Figure 65 – Winter Wind Output as a % of Capacity



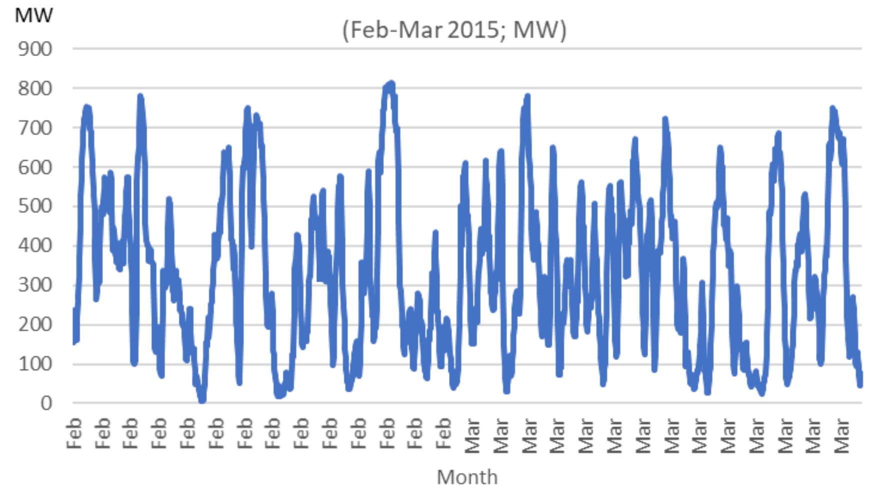
For a scenario where a constant baseload supply is provided from the DER system, the chart highlights two implications:

1. Sizing storage input/output (I/O) circuitry
   - Storage I/O would have to be sized in order to accommodate the peak wind output and/ or peak storage output. Peak storage input is defined by the peak wind output amount that is above the average. Peak storage output would be the desired average output of the system when there is no wind, in this case that would be 35% of the installed wind capacity. The "cut-off" line represents the wind output level above which wind generation injection into storage is curtailed to reduce the maximum of the storage inflow. This curtailment will only occur ~2% of the time, representing 0.2% of the energy. Without such curtailment, the storage system would require 30% more current carrying capacity.
2. Capacity factor for the storage will be at best 73%, increasing costs by 37%
   - Capacity factor is defined by the number of hours assumed in the costing or 8 hours a day, or 33% of the time, at the full discharge rate.
   - The wind patterns depicted in Figure 64 above show that storage output will on average be half of the rated output capacity for 48% of the time, which yields a storage capacity factor of 24%. Such a capacity factor represents only 73% of the 33% discharge rate assumed in the cost estimate. By using the storage for less hours will increase the cost of storage to 1/73% or 137%.

c) Monthly Pattern

Figure 66 illustrates the variability of the wind output during February and March 2015. There is no discernable pattern, as it varies significantly and erratically on a day-to-day basis and can be very low for several consecutive days. In Ontario, because of its geographic location, large weather fronts can create long periods of poor sun and/or wind conditions. These gaps are critical to power system engineers who must design for infrequent longer duration events in order to meet the loss of load expectation (LOLE) for periods of critical public demand. From a customer's perspective, reliable system operation requires infrequent longer duration events that in turn place constraints on the supply mix and/or minimum storage requirements.

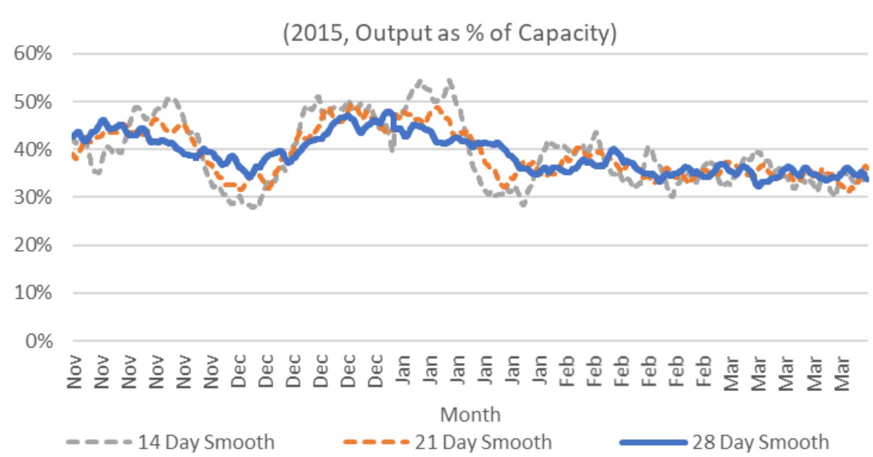
Figure 66 – Hourly Wind Generation



d) Battery Sizing and Wind Smoothing

Several concepts were tested in order to determine a criterion for sizing storage that can best optimize wind output. Figure 67 illustrates a running average of wind output for 14 days, 21 days and 28 days for Ontario's five the highest wind output months, from November to March.

Figure 67 – Storage Size for Smoothing Wind Intermittency



28 days of storage would best smooth the wind intermittent output. The more the wind output is smoothed minimizes wasted wind energy. However, even with 28-day storage, the very significant variations that occur from November to January cannot be fully mitigated. To do so would require three months of storage.

5.3.2 Sizing Storage Capacity to Accommodate Wind Output

The primary role of storage is to capture wind energy that exceeds demand at any point in time and then to discharge that stored energy when the wind output falls below demand. Figure 68 illustrates, for the March 2015 reference, this interaction between wind output and an ideal storage system (i.e. no wasted wind output) when supplying the daytime demand profile. While the surplus wind energy is productively captured, storage discharge occurs intermittently, sometimes several days apart.

Figure 68 – Integrating Wind and Storage

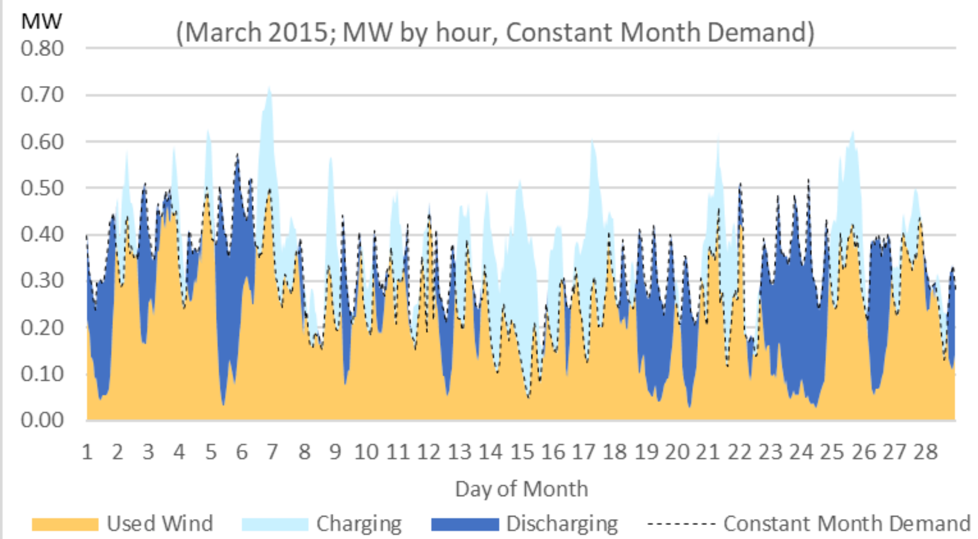
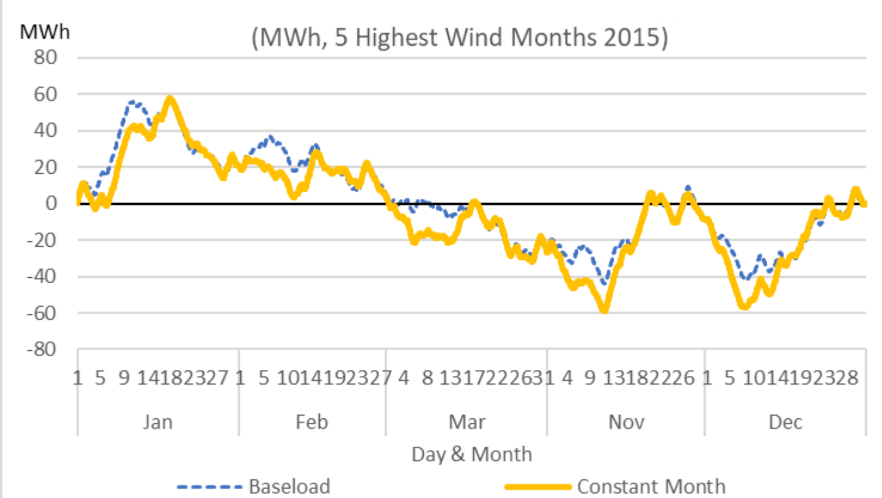


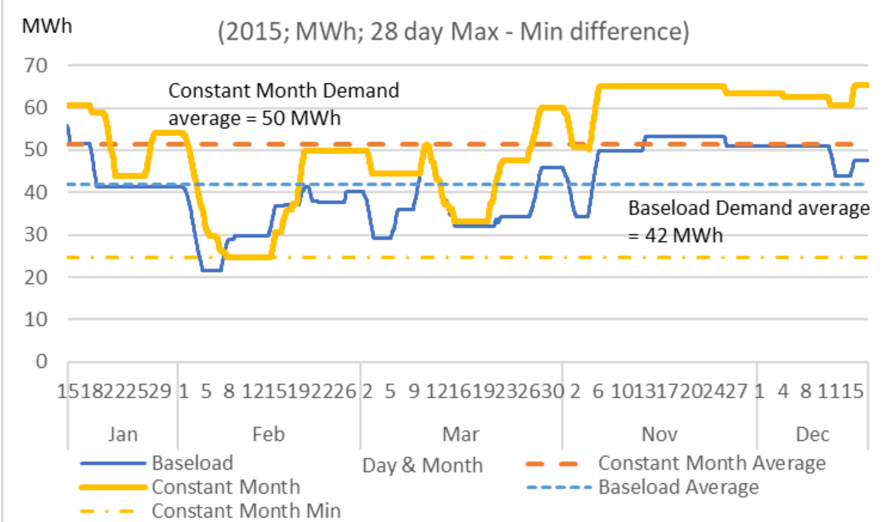
Figure 69 illustrates the cumulative balance of stored energy when the above method is applied to a sequence of the five highest wind energy months. For this analysis, the wind farm was sized to provide the same amount of energy as would be demanded over that five-month period. It is for this reason that the storage starts and ends at zero.

Figure 69 – Cumulative Stored Wind Energy



Sizing the battery requires an estimate of how much surplus energy is available for charging and how much demand will be placed on its output for discharge. The net effect of these two dynamics is how much the cumulative stored energy could change over a targeted timeframe. This change in cumulative energy is referred to as the "swing". Figure 67 suggested that the optimal targeted timeframe is 28 days. From the cumulative stored energy data, the maximum amount of energy swing in any 28-day period can be computed. The swing, or change, between the minimum and maximum storage value shows how much cumulative energy could be put into or withdrawn from storage during that 28-day period. This swing defines the capacity of storage that would be required to smooth a 28-day wind output. Figure 70 illustrates the running 28-day swing of storage for two scenarios: (1) supplying the daytime demand; and (2) supplying a constant baseload output.

Figure 70 – Maximum 28-Day Stored Energy Swing



For the daytime function, the average swing is approximately 50 MWh for a 1 MW wind farm. A smaller storage capacity would be required for a baseload function versus a daytime supply function. The baseload option would require approximately 42 MWh of storage for a 1 MW wind farm. However, by sizing the storage for the average swing, the storage will not be able fully accommodate the surplus energy. Surplus energy that cannot be stored would be wasted. Conversely, for periods when the swing is less than then average, the storage would be underutilized. Sizing the storage capacity based on the average achieves an approximately 50-50 balance between times of wasted energy and times of underutilized storage capacity.

Alternatively, storage could be sized to the minimum swing, thereby maximizing the utilization of the storage capacity but also maximizing wasted wind. Since unused storage capacity is more expensive than wind energy, the system has been sized for simulation purposes halfway between the average storage and the minimum storage.

5.3.3 Results of Storage Sizing for Design Period

Table 12 summarizes the key parameters of a wind-based DER system designed to optimize the use of wind energy for the five highest wind output winter months. Actual wind output data was used for all five months. To bring out the effects of intermittency, the March reference demand was replicated each month. Table 13 summarizes DER performance measures in terms of generation, storage, and backup generation.

Table 12 - Constant Monthly Demand for Winter

DER Component	Performance Metrics	Average
Demand	Total (GWh)	1,159
	Peak (MW)	598
Generation	Capacity (MW)	920
	Capacity Factor (%)	41.8%
Storage	Capacity (MWh)	34,887
	Capacity (Hours)	87
Backup Generation	Gas Peak (MW)	374

Table 13 - Wind Constant Monthly Demand for Winter, System Performance

DER Component	Performance Metric	GWh	% of Generation
Generation	Used Directly	884	63%
	Excess	131	9%
	Into Storage	379	27%
	Total Output	1,395	100%
Storage	Stored Generation	247	18%
	Losses	132	9%
	Capacity Factor (%)	5.3%	
		GWh	% of Used Generation
Backup Generation	Backup Generation	29	2.6%
	DER Managed Peak (MW)	374	
	Capacity Factor (%)	2.1%	
		GWh	% of Demand
System Totals	Used Generation	884	76%
	Stored Generation	247	21%
	Backup Generation	29	3%
	Wasted Generation	263	23%

Sixty three percent (63%) of direct wind generation output and 18% of the wind energy from storage is used to meet demand for a total utilization of the wind output of 81%. The remainder is either lost or wasted.

Excess generation refers to the wind output that is above demand and cannot be stored because the storage is at its maximum capacity at the time. The amount of this wasted excess generation for this period is 9%.

This simulation assumes that wind is stored using CAES, which has a round trip efficiency of 65%, or a loss factor of 35%. Lost wind energy due to storage inefficiencies is thus 9% of total wind output.

Backup generation in this scenario is assumed to be natural gas-fired generation. The total gas output required is very small representing 3% of demand.

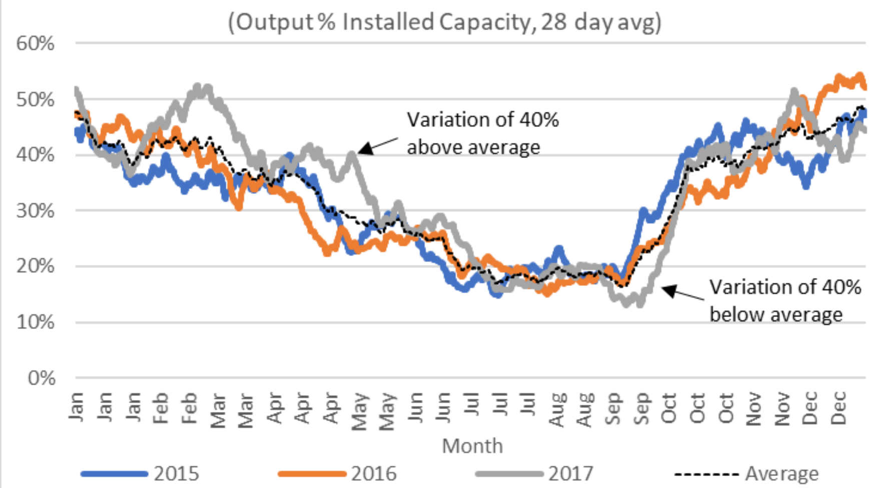
For the winter 2015 scenario a gas plant with a peak capacity of 374 MW is required to meet the shortfall requirements of the 920 MW wind farm. This gas plant will also need to supply a total of 29 GWh of output over the entire season.

These results suggest this approach is an effective way to optimizing the use of the wind energy. However, the storage capacity factor is approximately 5%, which will multiply the unit cost of storage by a factor of almost 20, pushing the cost of energy delivered from storage to over $1,000/MWh.

5.3.4 Seasonal and Annual Fluctuations

Wind energy does not sustain a high output all year long, and these output levels vary from year to year. Figure 71 shows the wind output in Ontario for the three years 2015 to 2017. Generally, wind generation follows a seasonal profile, with the peak coming in winter and a trough in the summer. However, the output could vary by as much as 40% from the seasonal average in any given period.

Figure 71 – Wind Output Comparison by Year



Periods of lower wind output makes storage less efficient and requires more backup generation. Periods of higher wind output should result in improved battery capacity factors but will have higher amounts of excess generation.

The backup capacity needs to be sized for maximum need as the plant size cannot be changed, and this reduces the capacity factor of the backup system and further increases costs.

5.3.5 Impact of Intermittency on System Parameters under Constant Demand

Tables 14 and 15 summarize the results of a three-year simulation of intermittency using actual Ontario wind output with an indication of the sensitivity of the results to year-over-year intermittency variations.

Table 14 - Wind Constant Monthly Demand, 3 Year Comparison				
		Average	% Sensitivity	
DER Component	Performance Metrics	2015-2017	High	Low
		% of Gen.		
Generator	Generator CF	32.3%	3.9%	-2.1%
	Used Generation	69%	0.6%	-0.4%
	Excess Generation	5%	33.6%	-55.0%
	Into Storage	25%	10.4%	-6.2%
Storage	Stored Generation	16%	10.3%	-6.2%
	Storage Losses	9%	10.5%	-6.2%
	Storage CF	3.5%	4.2%	-8.1%
		% of Used Gen.		
Backup Generation	Needed Gas	25%	15.0%	-16.2%
	Total Gas Needed (GWh)	555	12.2%	-13.9%
	Peak Gas Capacity (MW)	533	-	-
	Backup Generation CF	11.9%	12.2%	-13.9%
		% of Dem.		
System Totals	Used Generation	65%	3.2%	-1.8%
	Stored Generation	15%	8.2%	-7.4%
	Needed Gas	20%	12.1%	-13.9%
	Wasted Generation	13%	9.0%	-16.5%

Table 15 - Wind Baseload Demand, 3 Year Comparison				
		Average	% Sensitivity	
DER Component	Performance Metrics	2015-2017	High	Low
		% of Gen.		
Generator	Generator CF	32.3%	3.9%	-2.1%
	Used Generation	77%	0.9%	-1.8%
	Excess Generation	2%	68.1%	-73.7%
	Into Storage	21%	3.2%	-3.8%
Storage	Stored Generation	14%	3.2%	-3.8%
	Storage Losses	7%	3.3%	-3.9%
	Storage CF	3.5%	11.4%	-10.1%
		% of Used Gen.		
Backup Generation	Needed Gas	34%	7.1%	-11.2%
	Total Gas Needed (GWh)	797	6.1%	-9.4%
	Peak Gas Capacity (MW)	350	-	-
	Backup Generation CF	26.0%	6.1%	-9.4%
		% of Dem.		
System Totals	Used Generation	64%	1.6%	-1.1%
	Stored Generation	11%	4.0%	-5.2%
	Needed Gas	25%	5.9%	-9.3%
	Wasted Generation	8%	17.7%	-14.1%

To meet the daytime demand, 69% of wind energy will be used directly, 16% will come from storage, and 20% of demand will be supplied by backup generation. For the baseload function, 77% of wind would be used directly; 14% from storage; and 25% of demand will be supplied from backup generation.

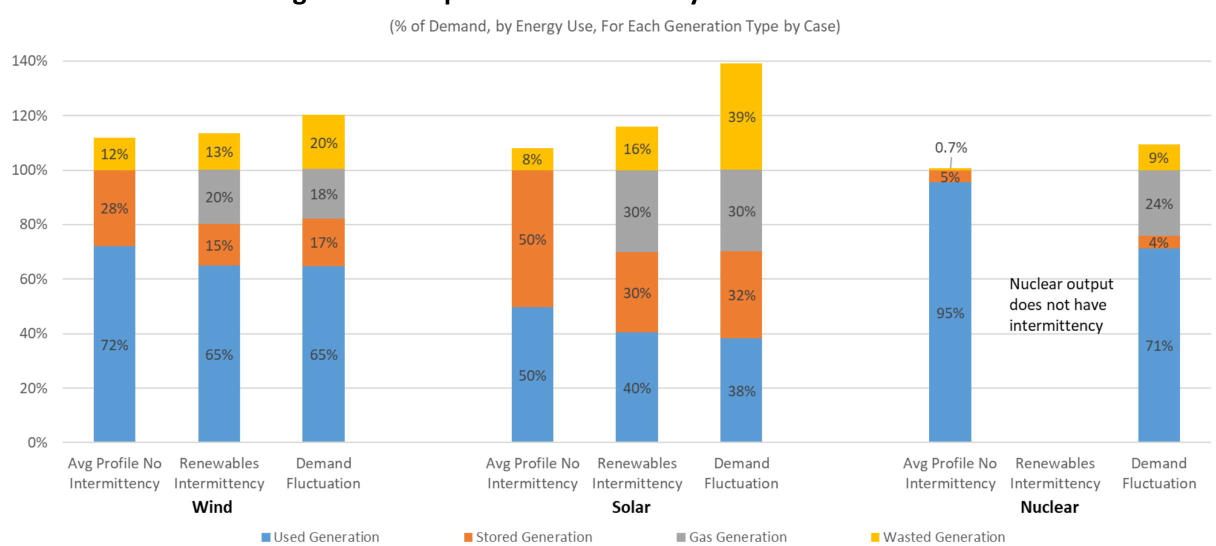
DER system performance varies year-over-year. For the daytime demand scenario, the annual differences can change wasted excess energy by +33%/-55% variation, the capacity factor for storage by +8%/-7%, and the amount of required backup generation by +15%/-16%. The required peak backup generation is consistent across the three years.

5.4 Demand Fluctuation Implications

Demand fluctuations present challenges for all DER options as they impact the efficiency of these options much like the intermittency of renewables. The impacts of intermittency and demand fluctuations on the DER option are illustrated in Figure 72.

The characteristics of a system based on the average output that assumes no intermittency, as described in Section 4.4, is contrasted against the impacts of the intermittent nature of renewables and the reality that demand also fluctuates. The primary system measures brought out in the comparison is the wasted generation and the need for backup generation. Wasted generation refers to both losses in the storage system as well as any surplus generation that would get curtailed. As such, even the perfect no-intermittency case has wasted energy in the form of storage losses.

Figure 72 – Impact of Intermittency and Demand on DER



The "No Intermittency" scenario refers to an ideal case where average output and demand are used as inputs and are assumed to be constant for an entire year. The "Renewables Intermittency" scenario considers the impact on DER performance characteristics of daily variations in solar and wind output with demand patterns held constant throughout the year. Intermittency wastes energy, reduces storage utilization, and requires backup generation. Unlike intermittent renewables, nuclear baseload-supplied DES is not a variable generation resource and hence has no impact due to intermittency.

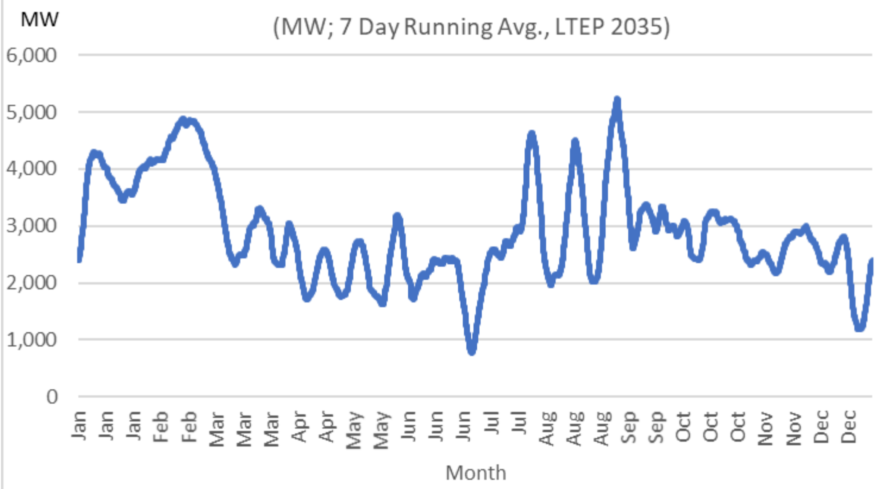
Fluctuations in demand further increase waste and backup generation but can increase the use of storage. This section looks at the sources of demand fluctuation and how this results in performance degradations of the DER system options.

5.4.1 Understanding Demand Fluctuation

Demand has its own fluctuations: month-to-month (seasonal); daily; and weekly. Each are described below.

Figure 73 illustrates the annual profile for Community Daytime demand used for this analysis. While the prevailing view is that demand peaks in the summer, the average daily demand is noticeably higher in the winter, averaging approximately 4,000 MW per hour.

Figure 73 – Annual Community Daytime Demand Profile



For the rest of the year, the average daily demand increases from ~2,200 MW in the spring to ~3,000 MW in the summer and then falls back to ~2,500 MW in the late fall. This means that any generation built for the winter would likely be underutilized during the rest of the year. However, this higher winter demand fits well with the design assumptions for the wind-based DER option. Winter was used as the reference demand case because it is the time when both demand and wind are at their highest. Other periods of the year were used to size both the solar-based DER (September) and nuclear baseload-supplied DES options (May).

Higher than average daily winter demand is influenced by the swing between the low and high demand that occurs in a day. The average daily profiles for winter and summer are illustrated in Figures 74 and 75.

Figure 74 – Average Daily Winter Community Daytime Demand Profile

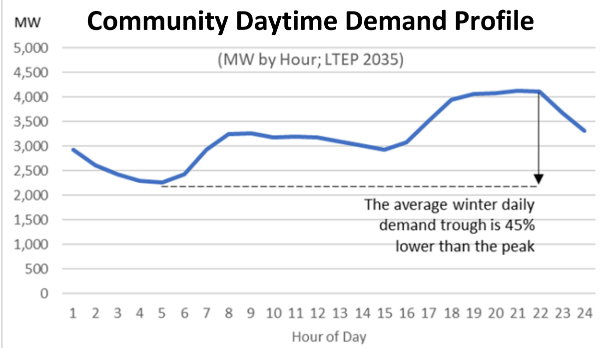
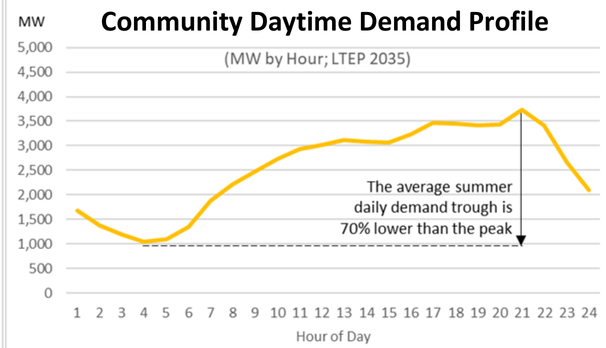


Figure 75 – Average Daily Summer Community Daytime Demand Profile



The difference or demand swing from the night time lows to the daytime highs are more pronounced in summer than in winter. The summer nighttime low in demand is over 70% lower than the daytime peak, compared to only a 45% difference in winter. This means that storage has to work harder in the summer. This circumstance should favor solar-based DER systems as the solar generation also comes on during the day with storage providing less of the daytime demand as compared to the wind-based DER or nuclear baseload-supplied options.

Demand on a day-to-day basis varies significantly at all times in the year. Figures 76, 77, and 78 illustrate the range of hourly demand that can occur over the day in the design reference months of March (wind), May (nuclear), and September (solar). This range translates into demand uncertainty day to day.

Figure 76 – Daily March Demand Profile

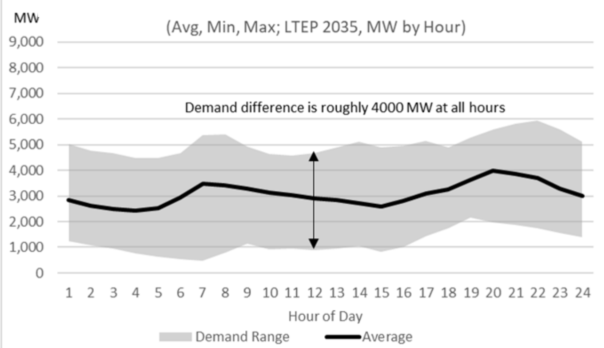


Figure 77 – Daily May Demand Profile

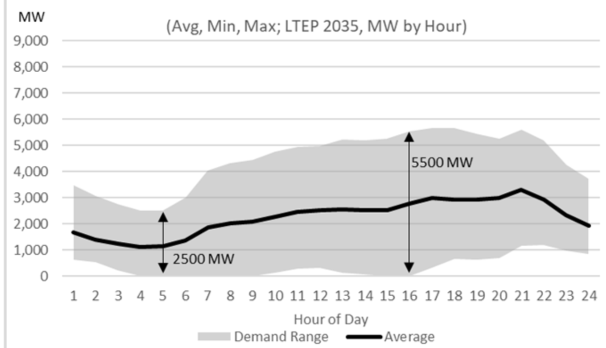
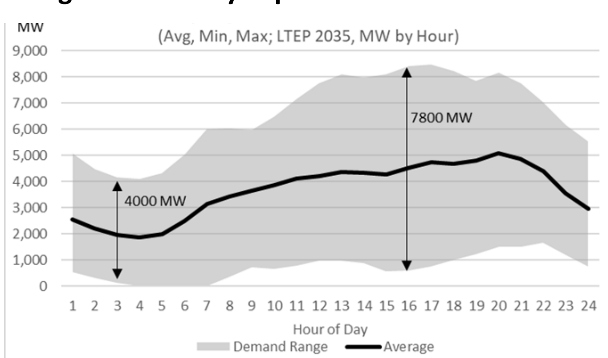


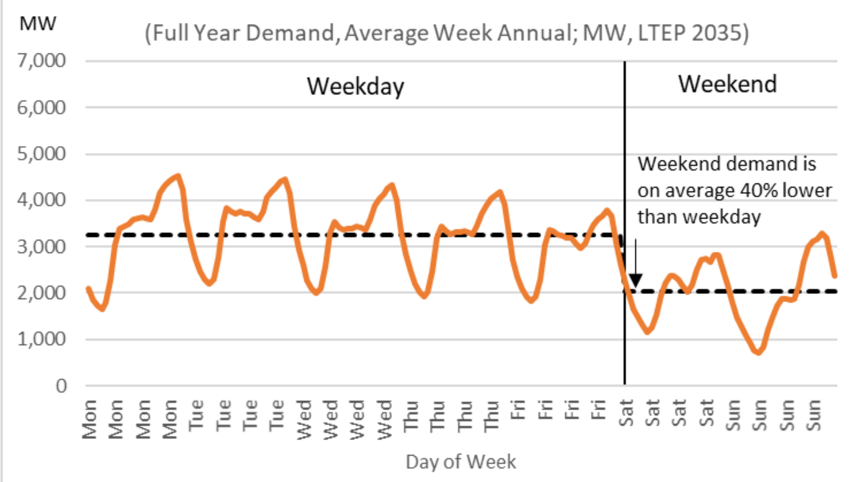
Figure 78 – Daily September Demand Profile



March has the least amount of demand variability with demand uncertainty of 4,000 MW at an almost constant level of throughout the day. May nighttime demand variations have the smallest uncertainty of approximately 2,500 MW, but with daytime demand swings of 5,500 MW. September has the widest possible daily demand variations of 4,000 MW nighttime and 7,800 MW daytime. These variations show that even in the designed months, demand fluctuations will impact wasted energy, unused storage capacity, and the need for backup generation similar to intermittent renewables.

Weekend demand is another factor that contributes to the wide variations in average daytime demand. Over the year, weekend demand is on average 40% less than weekday demand as illustrated in Figure 79. All DER options will in general have lower usage factors on weekends. It is also evident that energy use is higher earlier in the work week.

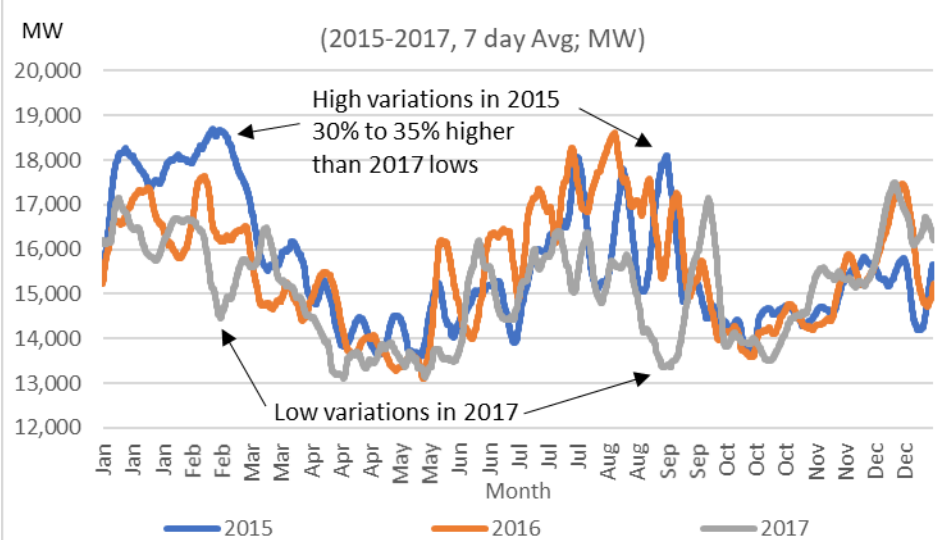
Figure 79 – Community Daytime Weekly Demand Profile



5.4.2 Annual Demand Variations

The annual variations in demand are another important factor for the designing of DER solutions that will be expected to operated for many decades. Figure 80 shows how the annual demand profile varied significantly during the period from 2015 to 2017.

Figure 80 – Yearly Ontario Demand Profile Comparison



The year-to-year differences in demand are due to uncontrollable factors such as the weather. Potential variations can be highlighted by comparing the demand for the months of February and September between 2015 and 2017. Demand in February 2015 was 30% higher than in 2017, while September 2015 demand was 35% higher than in 2017. Such significant variations will impact DER system performance i.e., wasted energy, storage capacity and backup generation requirement. The impact of annual demand variations has not been incorporated into the analyses of this report.

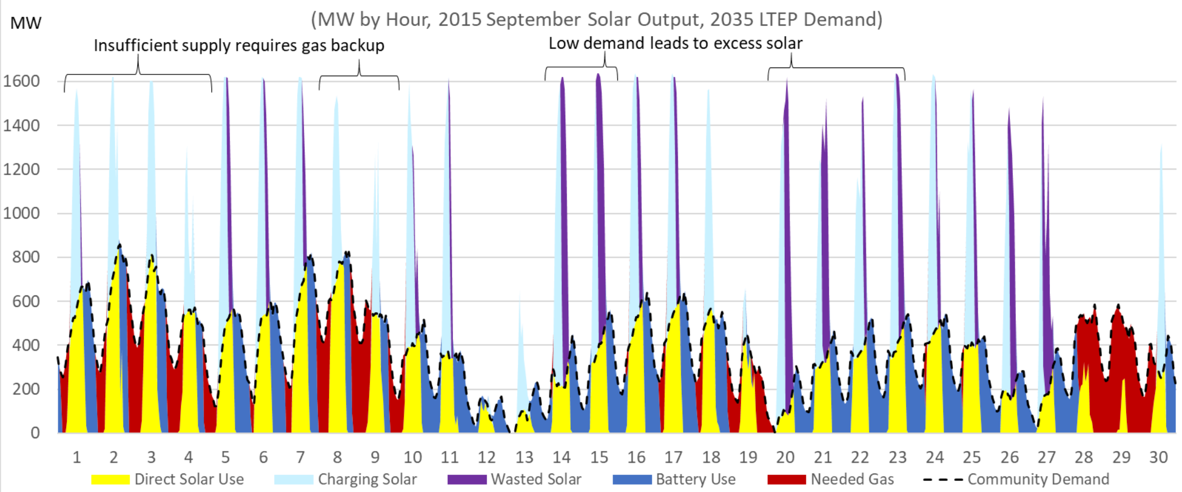
5.4.3 Implications of Demand Fluctuations on DER options

The fluctuations in demand present different challenges for each DER option.

5.4.3.1 Implications of Demand on Solar-Based DER

As discussed earlier, the solar-based DER model was sized to optimally supply the demand from an average September day. Figure 81 shows how fluctuations in demand would interact with solar intermittency and impact the performance of a DER system during the month of September.

Figure 81 – Solar and Storage System for September 2017



Overlaying demand and supply intermittency demonstrates that there is insufficient solar energy output during periods of high demand or low solar activity. Conversely, during periods of low demand, solar energy gets wasted and the storage never fully discharges.

Table 16 summarizes the results of full year simulations of the solar-based DER options and how performance varied between constant and real demand fluctuation scenarios.

Table 16 - Comparison of Solar Constant Demand and Full Year Demand Cases				
DER Component	Performance Metric	Constand Demand	Full Year Demand	% Change
Generation	Used Directly	47%	35%	-25%
	Excess	13%	31%	138%
	Into Storage	40%	34%	-15%
	Total Output	100%	100%	0%
Storage	Stored Generation	34%	29%	-15%
	Losses	6%	5%	-15%
	Capacity Factor	61.3%	52.1%	-15%
Backup Generation	Backup Generation	43%	43%	0%
	DER Managed Peak (MW)	508	722	42%
	Unmanaged Peak (MW)	514	865	68%
	Managed Peak Reduction %	-1%	-17%	-
	Capacity Factor (%)	21.8%	12.2%	-44%
System Totals	Used Generation	40%	38%	-6%
	Stored Generation	30%	32%	8%
	Backup Generation	30%	30%	1%
	Wasted Generation	16%	39%	144%

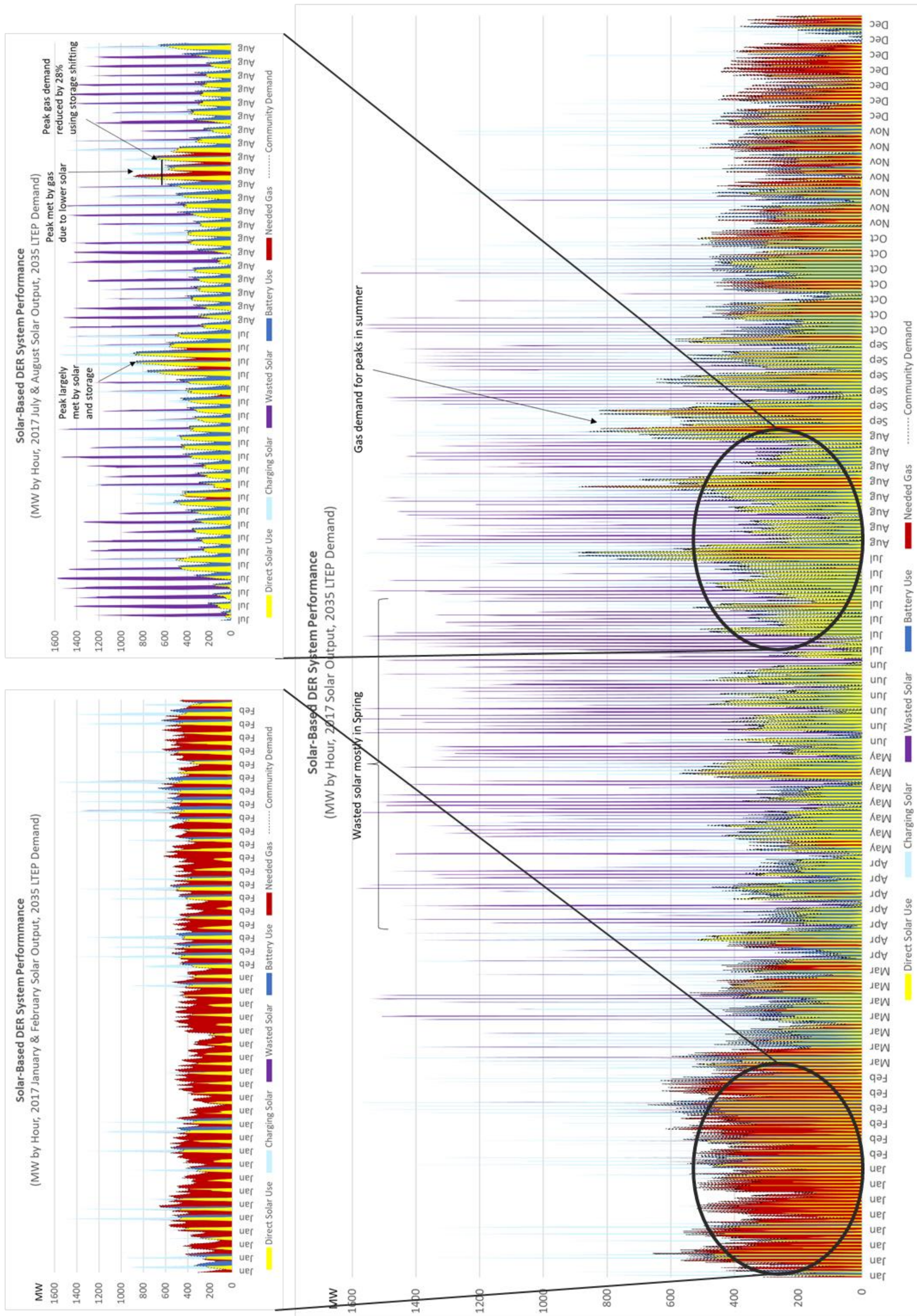
The impact of demand fluctuations on a solar-based DER system is best understood by visualizing the interplay between demand and solar output over a full year. This visualization is provided in Figure 82 which highlights several factors:

1. Backup generation is primarily needed in the winter months but also late fall, coinciding with low solar capacity factors.
2. Solar output can be strong in any season, even January. However, more high output days increasingly occur in the spring and summer.
3. Summer peak demand does not correspond with peak solar production.
4. The majority of wasted solar occurs in the low demand spring season.

The performance of the DER system is impacted by the size of the solar panels and the capacity of the storage. While some design approaches size the system to produce the energy required to meet demand, this analysis sized the system based on the month of September, which has 12-hour days of average sunshine and demand.

While future work could be conducted to optimize the design parameters beyond the reference case assumptions used here. Figure 82 suggests that optimization may only have a marginal impact on the net results. Increasing the size of the solar panel may provide some additional energy during periods of low solar output to increase the storage capacity factor and to offset backup gas generation. However, this would increase wasted energy to a far greater degree in spring and summer due to the ratio of the capacity factors between the seasons. Increasing the storage size is unlikely to materially reduce the need for backup generation as there is no solar energy available when backup generation is required (e.g. in winter). The marginal benefit would likely be offset by the cost of the larger and costlier battery capacities.

Figure 82 – Solar-based DER System Behavior

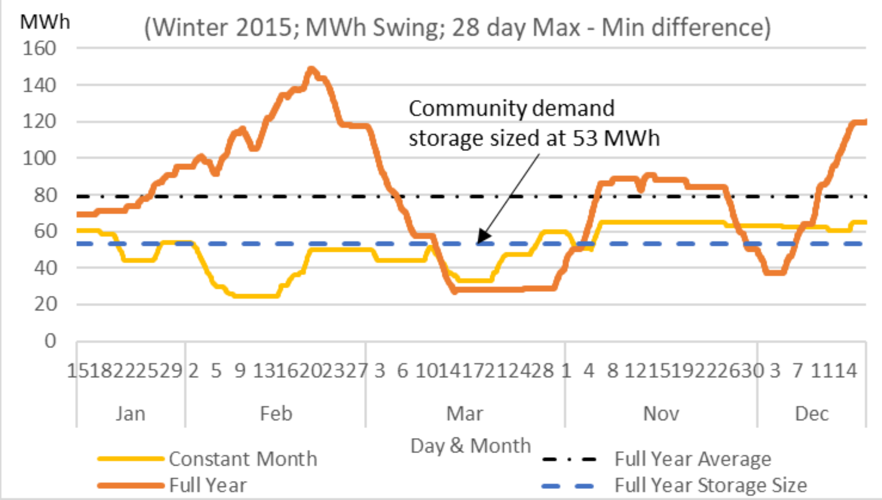


5.4.3.2 Implications of Demand on Wind-Based DER

As previously discussed, the wind-based DER model was sized to optimally supply the average March demand.

Demand fluctuations significantly impact storage sizing. Figure 83 illustrates the sizing criteria for storage under real demand conditions and contrasts that with the same criteria discussed earlier based on the constant demand scenario. The average swing in the cumulative energy in storage is about 80 MWh. Averaging this with the minimum swing gives a storage size required to accommodate actual demand – 53 MWh for 1 MW wind farm. This is larger than the 42 MWh previously identified as required by the constant demand scenario. The cumulative stored energy swing shown in Figure 83 arises from excessive surplus generation in February. A larger storage capacity is required to shift that energy to March.

Figure 83 – Required Demand Storage Outflow



An assessment was conducted to determine the sensitivity of DER performance to storage size. Table 17 shows how 28-day, 21-day, and 10-14 days of storage impact the performance parameters for the 920 MW wind DER system.

Table 17 - Wind Storage Size Sensitivity Analysis					
DER Component	Demand Scenario	**Full Year**			**Constant Month**
	Scenario Name	Demand Case	Inter Case	Recommended Case	Reference Case
Storage Size	Storage (Days)	28	21	10-14	28
	Storage Size (GWh)	48	35	24	35
		% of Generation			
Generation	Used Generation	64%	64%	64%	69%
	Excess Generation	8%	9%	10%	5%
	Into Storage	29%	27%	26%	25%
Storage	Stored Generation	19%	18%	17%	16%
	Storage Losses	10%	10%	9%	9%
	Storage CF	2.8%	3.7%	5.2%	3.5%
		% of Used Generation			
Backup Generation	Needed Gas (GWh)	426	445	463	555
	Needed Gas	20%	21%	22%	25%
	DER Managed Peak (MW)	862			533
	Unmanaged Peak (MW)	866			556
	Managed Peak Reduction %	-0.5%			-4.0%
	Backup Generation CF	5.6%	5.9%	6.1%	11.9%
		% of Demand			
System Totals	Used Generation	65%	65%	65%	65%
	Stored Generation	19%	18%	17%	15%
	Needed Gas	17%	17%	18%	20%
	Wasted Generation	18%	19%	20%	13%

The results in Table 17 suggest that a smaller storage size could meet the assumed demand. Halving the storage capacity would only increase excess generation by 25% (from 8% to 10% of energy wasted) and need for gas-fired generation by 10% (from 20% to 22% of used generation). While the amount of energy stored declines to 9%, the storage capacity factor increases by 85% (from 2.8% to 5.2%). The lower storage capacity and improved capacity factors could reduce the expected cost of storage by about a factor of 4. For the full year simulation, a 10-14 days storage capacity was assumed. Referring back to Figure 67, this is the period required to satisfy the demand in late March. These results demonstrate the impracticality of designing Ontario's future electricity system based upon 100% solar and/or wind with storage as the LOLE requirements will result in uneconomic amounts of storage.

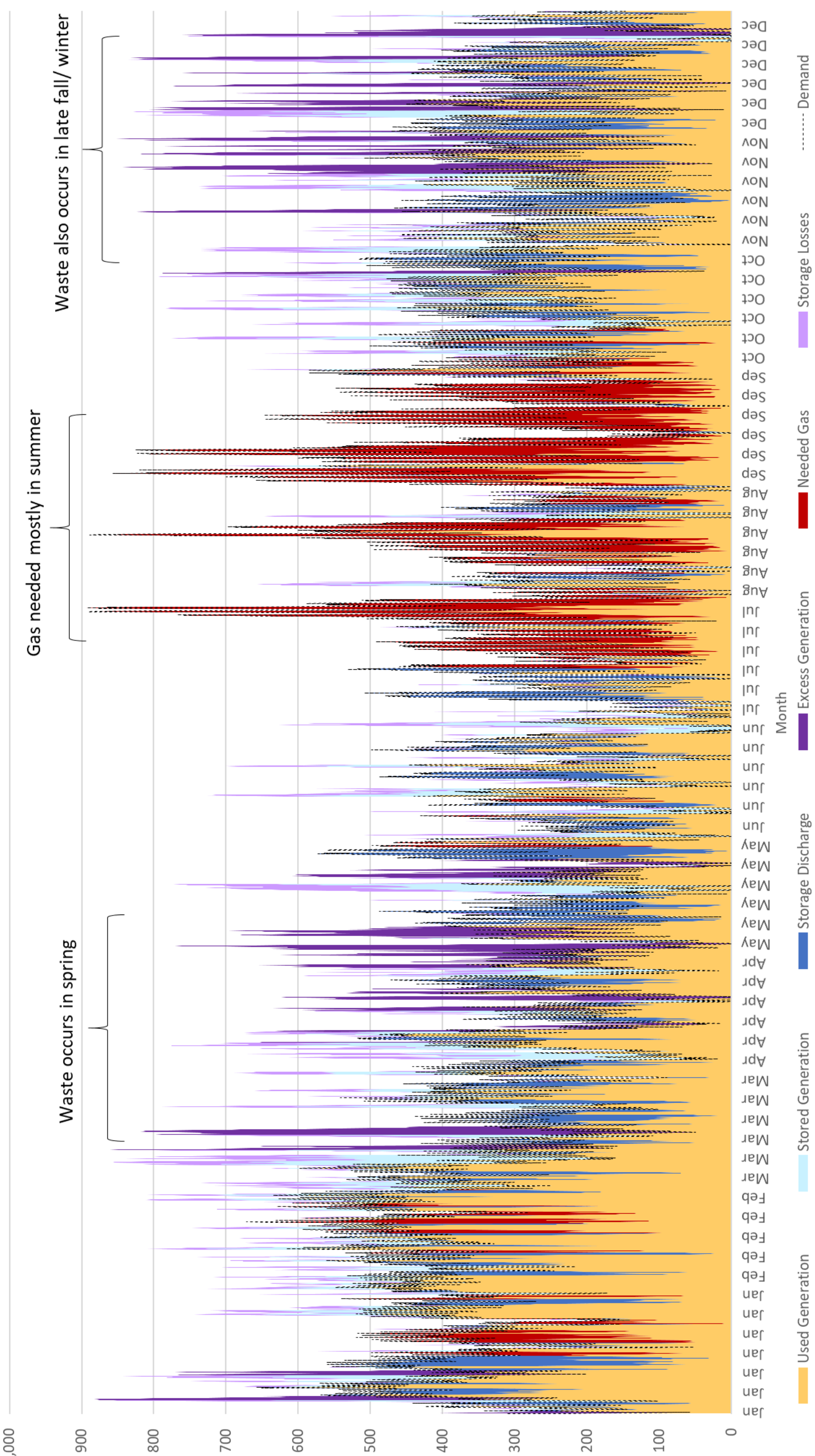
Figure 84 visually depicts the results of the full year wind simulation and illustrates several factors:

1. Wind output is well matched and balanced to demand in the winter months
2. Most of the excess generation in the model occurs in the spring and late fall when demand is low.
3. The need for gas generation is primarily during the high demand periods of late summer when wind output is lowest.

The pathways to further system performance optimization are not apparent from the results observed.

Figure 84 – Wind-based DER System Behavior

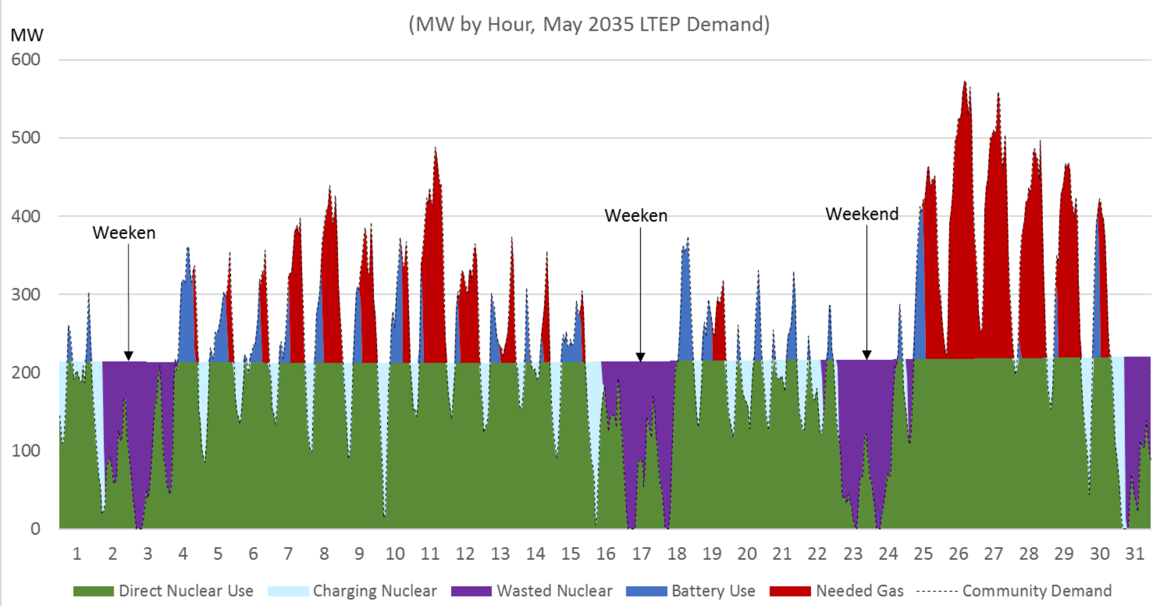
(MW by Hour; 2017 Wind Output, 2035 LTEP Demand)



5.4.3.3 Implications of Demand on Nuclear Baseload-Supplied DES

The nuclear baseload-supplied DES model was sized to optimally supply the average May demand. Figure 85 shows how the fluctuations in demand interact with the nuclear baseload supply for the month of May.

Figure 85 – Nuclear and Storage System for May



The overlay of demand and supply intermittency shows that when periods of high daytime demand occur, there was insufficient surplus nuclear energy at night to sufficiently charge the batteries resulting in the need for backup generation from other sources. Conversely, during periods of low demand, which for May was invariably weekends, nuclear energy is curtailed as the small battery size became fully charged.

Table 18 summarizes the performance of the nuclear baseload-supplied DES option for the constant demand and the full year real demand fluctuation scenarios. Under the constant demand scenario, nuclear baseload characteristics are a good fit with the optimal operation of a DES system. The benefits include: no wasted nuclear output; a 100% battery storage capacity factor; and, no gas generation backup requirement. Clearly, this is not the case for a real demand scenario where ten percent of nuclear output is wasted, battery capacity factors decline to 28.6% and backup gas generation is needed to supply 24% of demand.

Table 18 - Comparison of Nuclear Constant Demand and Full Year Demand Cases				
DER Component	Performance Metric	Constand Demand	Full Year Demand	% Change
Generation	Used Directly	95%	84%	-12%
	Excess	0%	10%	-
	Into Storage	5%	6%	15%
	Total Output	100%	100%	0%
Storage	Stored Generation	5%	5%	15%
	Losses	1%	1%	15%
	Capacity Factor	100%	28.6%	-71%
Backup Generation	Backup Generation	0%	32%	-
	DER Managed Peak (MW)	0	573	-
	Unmanaged Peak (MW)	0	621	-
	Managed Peak Reduction %	-	-8%	-
	Capacity Factor (%)	-	12.3%	-
System Totals	Used Generation	95%	71%	-25%
	Stored Generation	5%	4%	-3%
	Backup Generation	0%	24%	-
	Wasted Generation	1%	9%	1163%

Figure 86 visualizes the results of the full year nuclear simulation and illustrates several factors:

1. Most backup generation is required in the winter months, coinciding with high average demand[75], but is also present during the peak summer days.
2. Backup generation is also required in early fall when nuclear energy is at its lowest.
3. Most nuclear output is wasted in the low demand spring season but with dips occurring around the July long weekend and at Christmas. Increased storage capacity could help manage these circumstances, however, only for 6 months of the year.

A sensitivity assessment was conducted to identify how the system performance parameters would vary with storage size. The results are summarized in Table 19.

Table 19 - Sensitivity Analysis Results for Nuclear-Based DER Storage Size						
% Difference from Reference	**-67%**	**-33%**	**0%***	**+33%**	**+300%**	**+1233%**
Storage Size (MWh)	378	756	1,134	1,512	4,537	15,125
Storage Size (Hours)	1.0	1.9	2.9	3.9	11.7	38.9
Wasted Nuclear (%)	13.5%	11.9%	11.0%	10.2%	6.4%	2.3%
Battery Capacity (%)	51.0%	36.2%	28.6%	23.7%	11.9%	4.9%
Backup Generation (GWh)	665	637	620	607	543	473
Backup Generation Peak (MW)	573	573	573	573	573	573

*Reference Design Case

[75] Note that the 91.5% nuclear capacity factor was optimized for peaks in winter and summer to reflect lower output levels in the spring and fall. Between 2011 and 2015, the performance of Ontario's nuclear fleet on average was able to achieve such patterns.

The nominal design storage size is 1,134 MWh or 2.9 hours of storage. Varying the amount of storage capacity by +/- 33% results in the following effects:

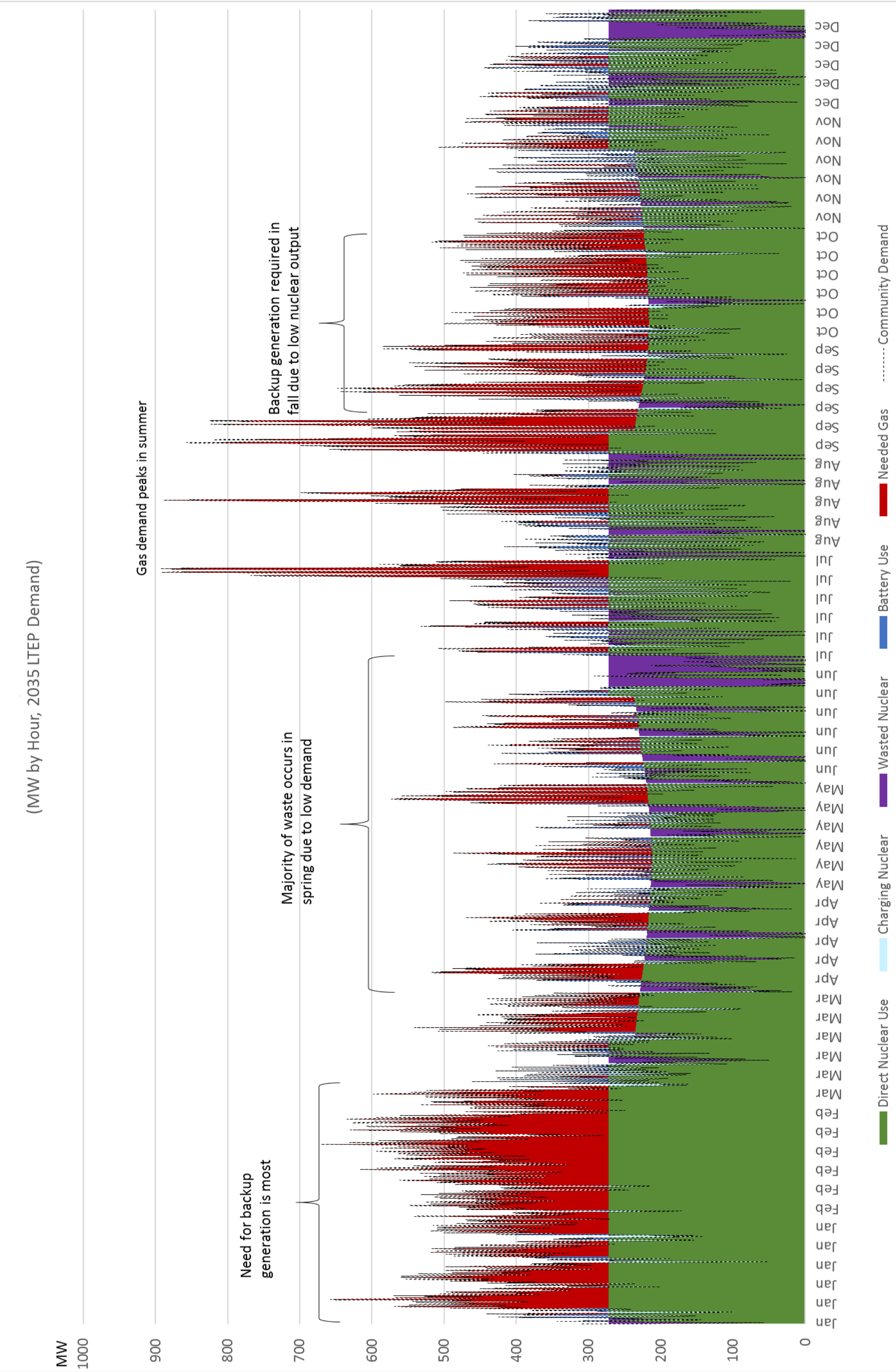
- The capacity factor of the storage changes to 36.2% with smaller storage (a 27% improvement) or to 23.7% (a degradation of 17%) with larger storage.
- Underutilized nuclear production increases to 11.9% with smaller storage (a +9% degradation) or to 10.2% (a 7% improvement) with larger storage. This is not a material change.
- The need for backup generations changes by +2.7%/- 2.1%, also not a material change. The need for peak gas-fired backup is unaffected.

Most likely the potential cost changes for the backup generation requirements and underutilized nuclear production are more modest than those for altering the storage size. Reducing the storage size by 66% to achieve the 50% capacity factor is not likely to be as optimal as the impacts on underutilized nuclear and the requirement for backup generation become larger. For the purposes of this assessment, 2.9 hours of storage was assumed to be adequate.

Further work may be warranted to choose an optimal balance, including the benefits of increasing the nuclear capacity, and must consider the costs as a criterion. Costs are addressed in the next section.

Figure 86 – Nuclear Baseload-Supplied DES Behavior

(MW by Hour, 2035 LTEP Demand)



5.5 Summary Implications: Comparative Performance of DER Options

The results of the supply and demand analysis for the DER options are summarized and compared in this section from two perspectives:

1. DER System Design Characteristics
2. DER Option Performance Indicators

The performance measures observed for the nuclear solution suggest it will be the most cost effective.

5.5.1 DER System Design Characteristics

Table 20 summarizes the system design characteristics for the solar-based, wind-based and nuclear baseload-supplied DER/DES options that have been developed to supply the projected 2035 LTEP demand for an aggregation of communities.

Table 20 - Full Year Demand System Characteristics for DER Options

DER Component	Characteristic	Wind	Solar	Nuclear
Community Daytime Demand	Total (GWh)	2,562	2,562	2,562
	Peak (MW)	893	893	893
Generation	Capacity (MW)	920	1,669	272
	Capacity Factor (%)	32.3%	19.1%	91.5%
Storage	Capacity (MWh)	24,350	4,478	1,134
	Capacity (Hours)	62	11.5	2.9
Backup Generation	Gas Peak (MW)	862	722	573

As the nuclear and wind generation options are grid-based and necessarily larger scale, an aggregated community daytime demand was modelled to reflect the combination of 800,000 homes and a commercial equivalent demand. This demand is over and above that which is supplied by Ontario's committed resources for 2035. Total annual demand would approximate 2,500 GWhs, with an annual peak demand of ~890 MW.

This demand could be met with 1670 MW of solar capacity coupled to 4500 MWhs or 11.5 hours of storage. Since wind has a higher capacity factor than solar, it requires a lower installed capacity of 920 MW. Nuclear with its 91.5% capacity factor can meet the demand with 270 MW of capacity. The wind-based DER system includes 62 hours of storage and nuclear only requires 3 hours of storage.

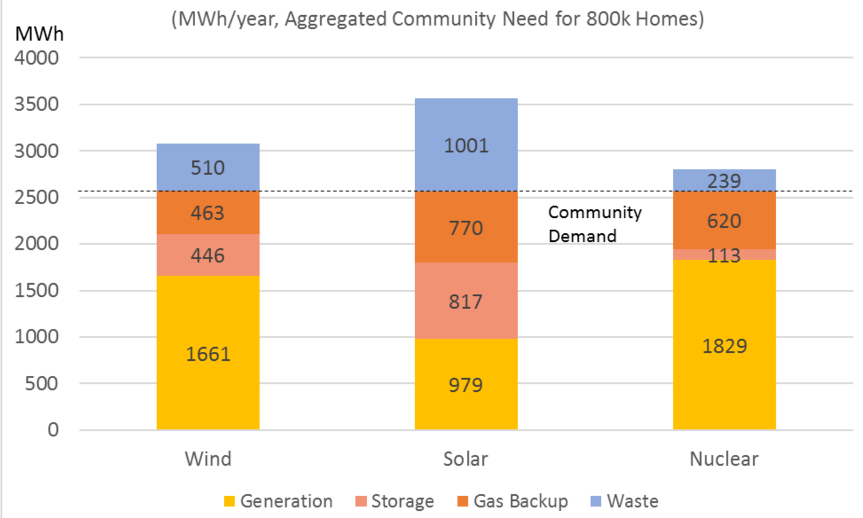
The wind solution has the highest backup generation capacity requirement at 860 MW, almost 60% more than the 575 MW required by the nuclear baseload-supplied DES option.

5.5.2 DER Option Performance Indicators

Three years of supply intermittency have been modeled for the wind and solar options. The same 2015 demand projection was used for all three years.

Figure 87 illustrates for each DER option how each energy source contributes to meeting the community demand. The solar option requires the most gas backup generation and produces the greatest amount of wasted energy. Nuclear requires the least amount of storage and wastes the least energy. Wind is in between the nuclear and solar options with respect to the use of storage and the amount of wasted energy yet has the lowest need for backup generation. As Table 20 indicates, the wind-based DER has the highest need for storage and backup capacity suggesting the costs of these will be greater for wind.

Figure 87 – DER Generation Required for Community Daytime Demand



The performance characteristics of the DER/DES options are summarized in Table 21 and suggest that the nuclear baseload-supplied DES option may have the most efficient use of resources.

Table 21 - Full Year Demand Performance Metrics for DER Options							
DER Component	Performance Metric	Wind		Solar		Nuclear	
		GWh	% of Generation	GWh	% of Generation	GWh	% of Generation
Generation	Used Directly	1,661	63%	979	35%	1,829	84%
	Excess	271	10%	868	31%	221	10%
	Into Storage	684	26%	950	34%	132	6%
	Total Output	2,617	100%	2,798	100%	2,182	100%
Storage	Stored Generation	446	17%	817	29%	113	5%
	Losses	239	9%	133	5%	18	0.8%
	Capacity Factor (%)	5.2%		52.1%		28.6%	
		GWh	% of Used Generation	GWh	% of Used Generation	GWh	% of Used Generation
Backup Generation	Backup Generation	463	28%	770	43%	620	32%
	DER Managed Peak (MW)	862		722		573	
	Unmanaged Peak (MW)	866		865		621	
	Managed Peak Reduction %	-0.45%		-17%		-8%	
	Capacity Factor (%)	6.1%		12.2%		12.3%	
		GWh	% of Demand	GWh	% of Demand	GWh	% of Demand
System Totals	Used Generation	1,661	65%	979	38%	1,829	71%
	Stored Generation	446	17%	817	32%	113	4%
	Backup Generation	463	18%	770	30%	620	24%
	Wasted Generation	510	20%	1001	39%	239	9%

The DER options vary on many of the following key parameters:

- Utilized and stored generation
  - After storage losses, nuclear baseload-supplied DES has the highest energy utilization rate at 89%, either directly or discharged from storage. This is an important a balancing factor for the DES system LCOE as nuclear generation has high capital costs.
  - Wind has the next highest use of generation at 80%. Solar is the least efficient option with only 64% of solar output used either directly or via storage.
  - When considering excess energy and losses in storage, only 11% of nuclear generation is unused, starkly different than the 19% of wind and 35% of solar.
  - Wind, the lowest cost generation option, has the greatest storage losses. The wind option has the least efficient storage due to the use of CAES. Even though CAES is one third the cost of the Li-ion battery storage, it has a 35% loss factor on the energy storage cycle. Curtailing wind generation to save storage costs could provide a balancing factor to the DER system LCOE and economics.
- Storage Capacity Factor
  - Solar, with a storage capacity factor of over 50%, makes the best use of its storage capacity. Since Li-ion batteries are the most expensive component of the solar-based DER solution, high capacity factors are important.
  - Nuclear has a lower storage capacity factor than solar, but also requires much less storage capacity.
  - Despite 26% of wind energy being cycled through storage, wind-based DER storage capacity factors are extremely low due to the large numbers of hours of storage required to capture the wind energy.
- Backup Generation Requirement

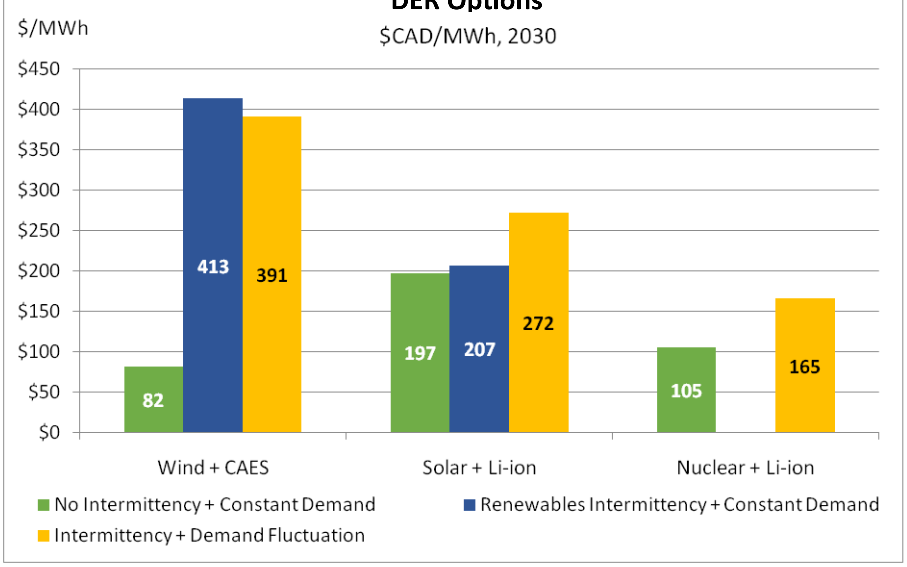
- Wind requires the least amount of backup generation but has the highest peak generation requirement to cover periods with no wind or stored energy. As a result, the capacity factor of the backup generation is only 6%. This is half the capacity factor of the solar-based DER or nuclear baseload-supplied DES options, which are similar at 12%.
- The solar option requires 25% more total backup generation than the nuclear option.
- Wind requires backup generation to provide 18% of the community demand and the nuclear and solar options 24% and 30%, respectively.

6.0 Ontario's Geographical Challenge

This section looks at the cost of implementing the DER/DES options in Ontario from a total LCOE perspective. The five major findings are:

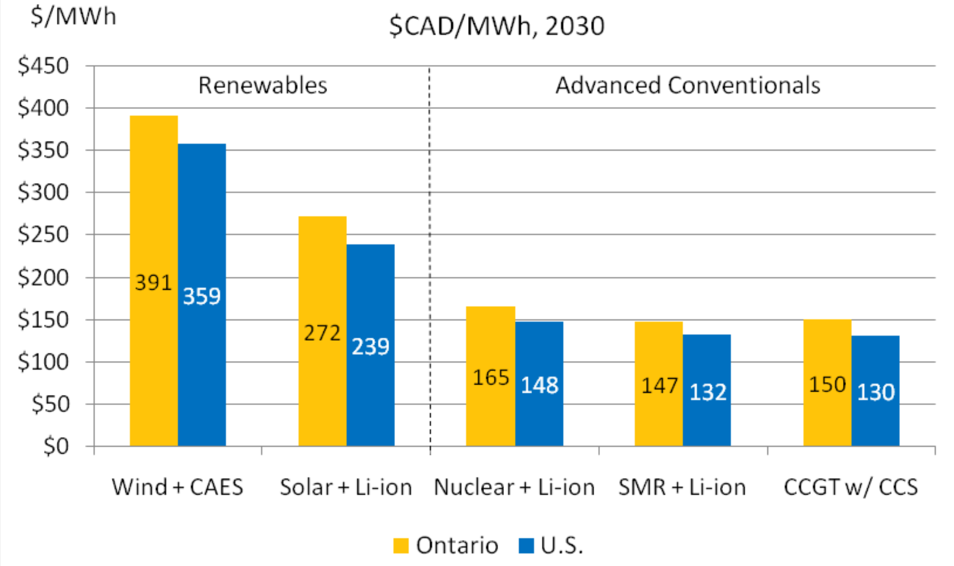
1. Intermittency of renewables and demand fluctuations can each increase the cost of DER/DES solutions as shown in Figure 88:
    a. Renewables intermittency increases the expected costs of DER systems when compared to the ideal model where average renewable outputs are assumed against a constant demand. The impact of wind intermittency is substantial at a factor of 5 cost increase. Solar has a 5% cost increase. No intermittency is assumed for nuclear.
    b. When demand fluctuations are included in the simulations, solar-based DER costs increase a further 30%. Surprisingly, the cost of wind-based DER drops when demand fluctuations are reflected. The nuclear baseload-supplied DES costs increase by almost 60%.
2. Conventional nuclear baseload-supplied DES will be almost 40% less expensive than solar-based DER options and less than half the cost of wind based DER options.
3. Figure 89 shows that Ontario DER systems will cost approximately 10-15% more than the same systems installed in most locations in the U.S.
4. Renewable-based DER options could be twice the cost of SMR-based[76] or carbon capture options.
    a. The forecast cost of a CCGT solution fitted with CCS technology is similar to an SMR-based DES solution.
5. Wind solutions are considerably more expensive, over twice the cost of the nuclear baseload-supplied DES option.

Figure 88 – Intermittency Implications on LCOE of Ontario DER Options



[76] Assumes SMR generation LCOE of approximately CAD $75/MWh based on EIRP. LCOE DER comparisons based on substituting SMR LCOE for conventional nuclear with all other assumptions remaining the same.

Figure 89 – Ontario vs. U.S. LCOE Comparison Supplying Daytime Demand



The cost implications are based on several factors. The following sub-sections examine:

- The costs to purchase and install DER systems in Ontario;
- Total system implementation costs;
- The impacts of renewables intermittency and demand fluctuations on Ontario LCOEs;
- U.S. geography driven competitive disadvantages for Ontario DER systems.

6.1 DER Component LCOEs for Ontario

Ontario's DER cost estimates are derived from the costs of the individual system components as discussed previously based on available U.S. average costs. Different capital cost and capacity characteristics exist in the U.S. Several cost adjustments have been made to highlight the differences between the two jurisdictions. These include:

1. Exchange rate, applied to 60% of the cost of solar and wind
2. Cost premium for building in Ontario based on EIA estimates
3. Average Ontario capacity factor differences for community-based solutions

The net impact of these cost adjustment factors on solar-based DER and wind-based DER LCOEs are illustrated in Figures 90 and 91.

The estimates are compiled from the 2030 cost forecasts described earlier, a community scale solar LCOE of US $77/MWh including Tx/Dx connection cost becomes a LCOE of CAD $120/MWh for an Ontario community scale solar installation. Similarly, the 2030 forecast cost of US $42/MWh for grid-scale wind installations rises to CAD $78/MWh in Ontario.

Figure 90 – Solar (Community-Scale) Ontario LCOE Components

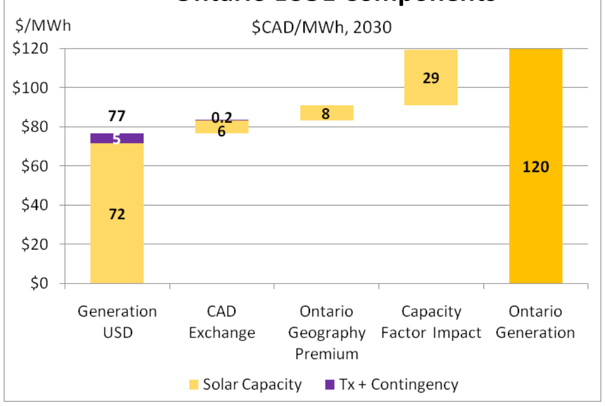
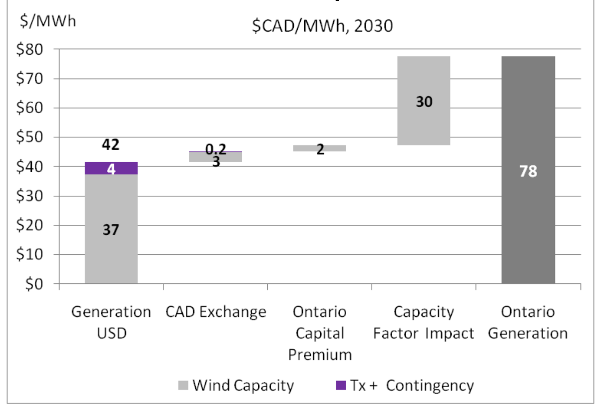


Figure 91 – Wind (Grid-Scale) Ontario LCOE Components



6.1.1 Exchange Rate Assumptions

Exchange rate assumptions have been made to facilitate cost comparisons with Ontario installations in Canadian dollars. There are two components to the exchange rate impacts:

1. The exchange rate itself
2. Imported content of the energy solutions being installed

An exchange rate of 15%, or more specifically 1.15 CAD for 1 USD, is assumed for this analysis. This exchange rate is based on the average exchange rate between the U.S. and Canadian dollars for the 30 years ending in 2015[77] and is conservatively low.

- The FAO predicts an average long-term exchange rate of 16.3% out to 2050 but predicts it will remain above 21% between 2020 and 2030, the period of interest to this study.[78]
- A low exchange rate assumption depresses what the costs could be in Canadian dollars. This means the cost represented here is likely to be lower than can be expected, particularly for renewables and storage.

The exchange rate is applied only to the imported content of the energy options. The rationale is that while exchange rates have fluctuated significantly since the 2008 recession, inflation in the two countries has been similar suggesting that cost factors have not changed since the currencies were at par several years ago. [79] As a result, the ability to construct DER solutions in Ontario is assumed to be similar to the economically equivalent regions of the U.S., except when the component content is purchased from abroad. When component content is imported, the exchange rate is applied.

Table 22 summarizes the imported content assumptions that have been applied to the various technologies. The assumption for renewables reflects the earlier unfavourable World Trade Organization (WTO) ruling on Ontario's 50% domestic content Feed-in-Tariff (FIT) requirement. This is a conservative

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[77] Strapolec, Pickering study referring to OANDA. CAD/USD Historical Exchange Rates. Rates retrieved from Oanda 2018

[78] FAO, 2017

[79] Inflation.eu, 2018

assumption, which could understate the solar and wind costs. Batteries are assumed to have imported content similar to that of wind and solar. The imported content costs for nuclear, CAES, pumped hydro, and Tx are assumed to be low given the extensive supply chain in Canada for these established technologies. Natural-gas fired generation has a high imported value due to the cost of the imported fuel, in particular from U.S. sources.

Table 22 - Imported Content (%)		
Generation	Solar	60%
	Wind	60%
	Nuclear	25%
	SMR	50%
	Tx & Contingency	25%
Storage	Li-ion Storage	60%
	Pumped Storage	25%
	CAES	25%
Backup Gas	CCGT w/ CCS*	90%

* 90% is due to considering imported fuel

6.1.2 Installation Cost Premium for Ontario

Many reports of low cost of renewables are from regions that can be characterized as low cost economic zones. For example, the forecast costs in the Leidos report reflects costs in the gulf coast region, where capital costs are cheaper and output is more reliable. Leidos explicitly states that adjustment factors should be applied for other jurisdictions.

The EIA has investigated the differing costs of renewable installations across the U.S.[80]. These differences, reflecting the relative cost multipliers for solar and wind installations in the U.S. defined electrical regions are summarized in Table 23. The EIA also provided the generic costs factors multipliers that the Leidos study used to produced future estimates for the EIA[81]. The Leidos parameters are assumed to be generic to all electrical capital projects.

[80] EIA, 2017

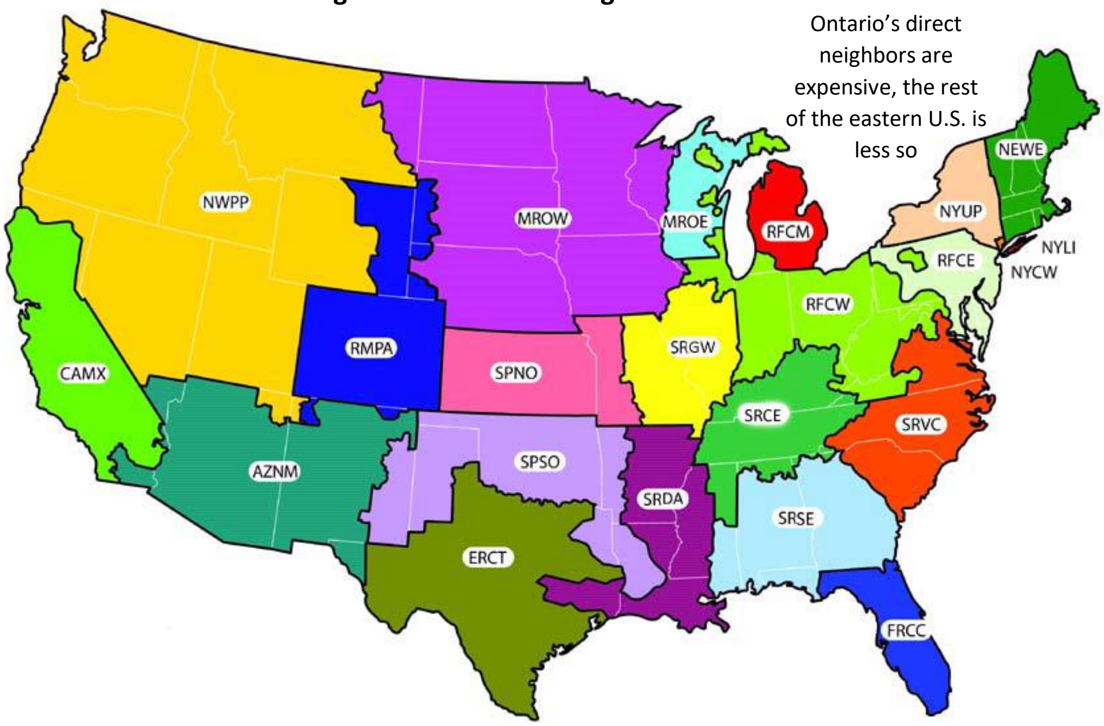
[81] Leidos, 2016

Table 23 - Regional Cost Multiplication Factors				
Region Number	**Region Name**	**Leidos**	**EIA Solar**	**EIA Wind**
1	ERCT	0.94	1.08	0.78
2	FRCC	1	0.87	N/A
3	MROE	1.21	1.03	1.06
4	MROW	1	0.93	0.88
5	NEWE	1.05	1.20	1.19
6	NYCW	1.38	1.60	N/A
7	NYLI	1.32	1.02	1.08
8	NYUP	1.05	0.97	1.08
9	RFCE	1.06	1.13	1.08
10	MICHIGAN	1	1.48	1.06
11	RFCW	0.95	0.98	1.06
12	SRDA	0.97	0.93	1.15
13	SRGW	1.05	0.81	1.06
14	SOUTHERN	0.98	0.82	1.15
15	TVA	0.95	0.69	1.15
16	SRVC	0.92	0.86	1.15
17	SPNO	1	0.72	0.73
18	SPSO	0.8	0.93	0.73
19	DSW	1.03	1.10	0.95
20	NP15	1.12	1.16	0.96
21	NWPP	1.05	0.73	0.95
22	ROCKIES	1	0.95	0.73
Average		1.04	1.00	1.00
Average of ON similar regions		1.07	1.16	1.10
Gulf coast avg (SRDA & ERCT)		0.96	1.01	0.97
Ontario to U.S. Avg ratio		103%	116%	110%

The location of the regions in Table 23 are illustrated in Figure 92.[82]

[82] Map sourced from EIA Assumptions to the AEO, 2017

Figure 92 – Electrical Regions in the U.S.



It is assumed that Ontario's cost reference would be similar to that of the northeastern U.S. regions, e.g. MORE (Wisconsin), NEWE (New England), NYUP (Upstate New York), RFCE (Pennsylvania), and RFCM (Michigan). The cost of solar and wind installations in Ontario's neighbouring jurisdictions is relatively expensive. The rest of the eastern U.S. is less so. RFCW is not included in the Ontario average as they are known to have significantly lower economic costs than Ontario. Based on the EIA's average cost factors for these regions, Ontario's costs are assumed to be 16% higher for solar than the U.S. average and 10% higher for wind. These factors are applied only to capital and fixed costs.

The regional multipliers for use with storage, nuclear, and natural gas fixed costs have been assumed to be 1.03 based on the Leidos average.

The LCOE differences for nuclear and gas generation are summarized in Table 24 are minor and only reflect the 3% capital premium applied.

Table 24 - Ontario vs. U.S. LCOE of Generation
($CAD/MWh)

	Nuclear	SMR	CCGT w/ CCS*
U.S.	97	75	133
Ontario	98	76	135

Costs include Tx and contingency.
*49% capacity factor and including a cabon price at $100/t for emission not captured by CCS.

6.1.3 Ontario Geography Capacity Factor Implications for Renewables

Geography is important as it impacts weather patterns and subsequently the output from renewables. Factors including how much the sun shines and how frequently the wind blows. These two factors are geographically dependent and have a significant impact on the cost of renewable installations.

Figure 93 illustrates the number of hours of sunshine that are prevalent in various regions across North America.[83] Ontario has far fewer hours of sunshine than the U.S., about 2,100 sunny hours per year[84], the lower end of the range for north eastern U.S. Ontario has less than half the sunshine that Arizona sees, as indicated by the small red region in Figure 93. As a result of fewer sunny hours in a year, the average annual capacity factor of solar generation is commensurately reduced.

Figure 93 – Annual Hours of Sunshine

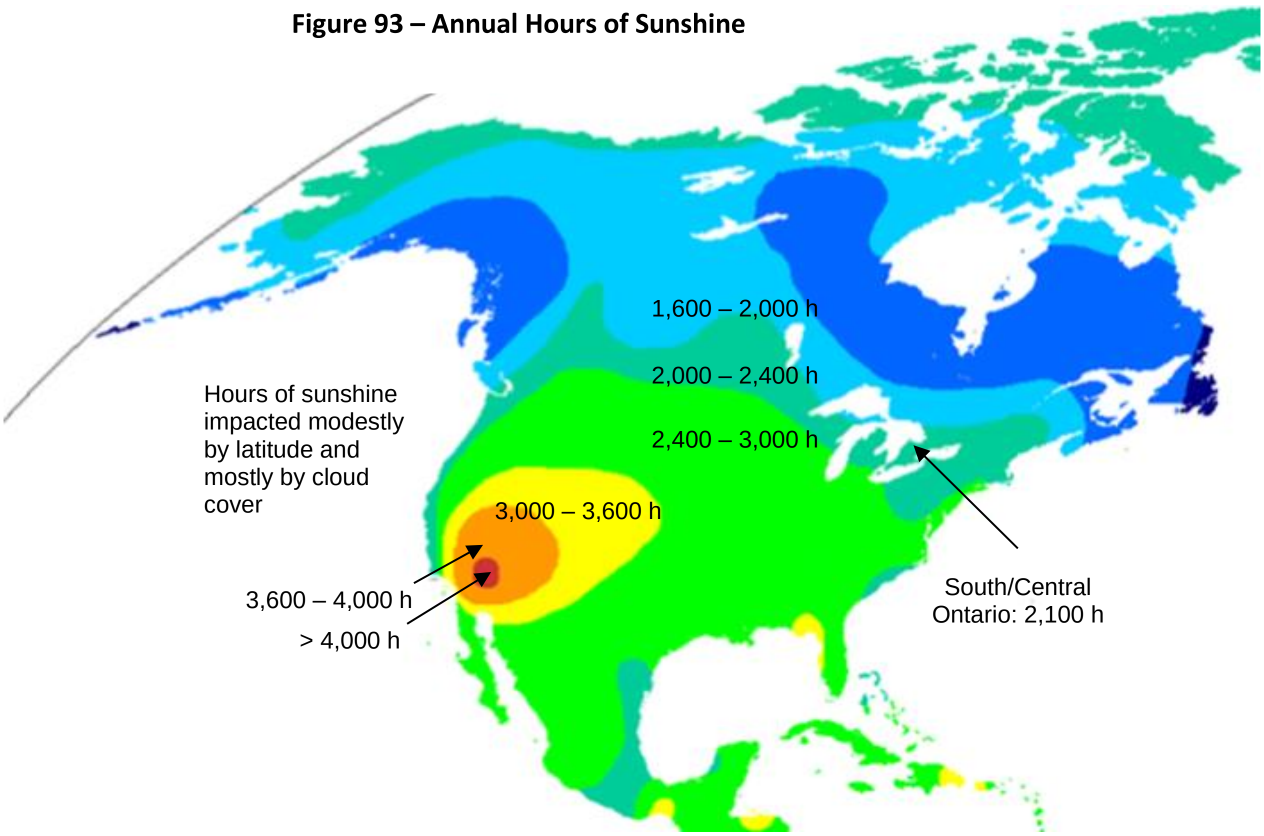
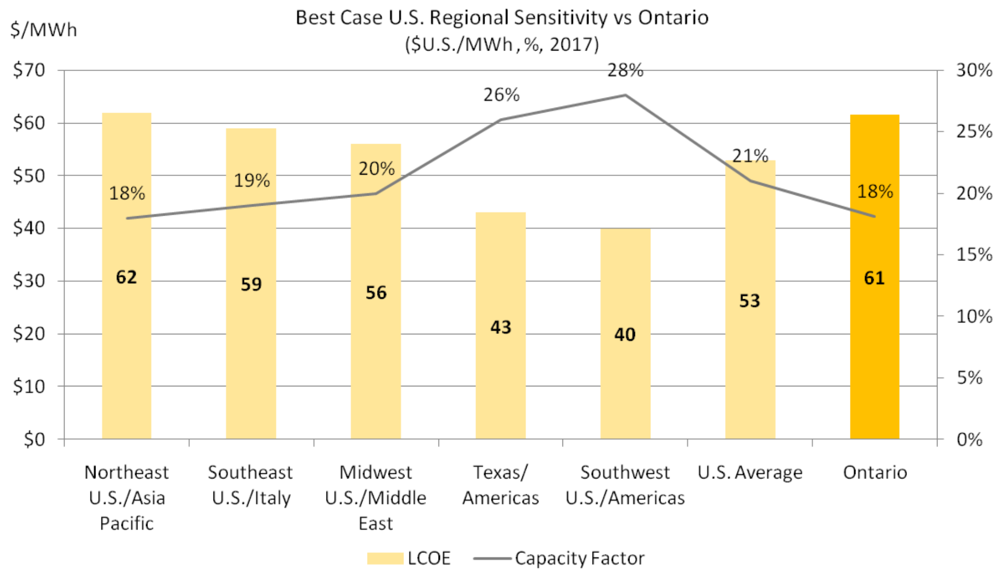


Figure 94 summarizes the capacity factors of solar energy and the associated LCOE for various regions of the U.S. in 2017[85]. Ontario's capacity factor for its grid-scale installations was 18% in 2017 prior to curtailment action being taken by the IESO[86]. Capacity factors directly impact the cost of solar generation. According to Lazard's cost assumptions, the assumed capacity factor for the southwest U.S. was 28%

[83] Landsberg, 1978
[84] Osborne, 2018; Strapolec analysis
[85] Lazard LCOE v11.0
[86] IESO actuals

leading to solar LCOEs of $40/MWh. Ontario's solar power will be over 50% more costly than in those sunny U.S. states for the same installed equipment.

Figure 94 – Solar (Grid-Scale) LCOE and Capacity Factor

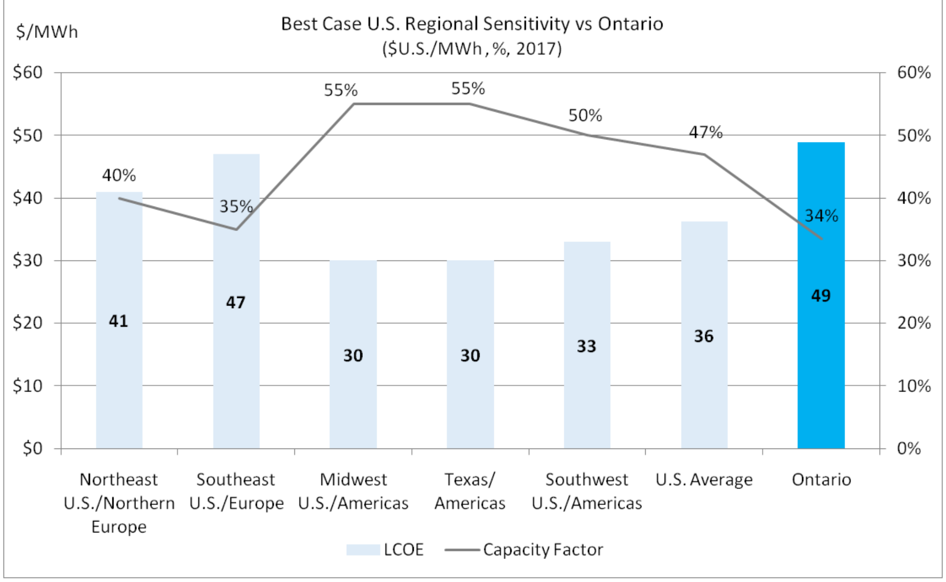


The Lazard capacity factor assumptions represent the conditions under which the costs have been forecast. The LCOE for community installations assumed a capacity factor of 22.5% as discussed earlier. Ontario's capacity factor for community installations is assumed to be 17% based on the ratios of Lazard's assumptions for its grid and community scale costing scenarios[87] and IESO data for Ontario's embedded solar generation.[88] This suggests that Ontario solar could cost approximately 40% more than the average U.S. equivalent installation.

Wind resources will be similarly affected. Figure 95 summarizes the wind capacity factors for various regions of the U.S.[89] In 2017, the capacity factor of Ontario's wind installations was 34%[90]. This is significantly lower than the Lazard LCOE capacity factor assumption of 47% for the average U.S. grid-based wind. This means Ontario LCOEs could be 65% higher than the U.S. averages forecasted by Lazard.

[87] Note that the IESO assumed that future solar would have a 15% capacity factor in its 2016 OPO
[88] IESO OPO 2016
[89] Lazard LCOE v11.0, U.S. average not same as LCOE chart as it is for best case scenario
[90] IESO data prior to curtailment

Figure 95 – Wind (Grid-Scale) LCOE and Capacity Factor



6.2 Total System Costs

If the DER options were relied upon to fully provide for the province wide LTEP 2035 community daytime demand, then the resulting architecture and capacity requirements would be as summarized in Table 25. The architecture defines how much capacity of each generation and storage type is required to implement the DER options. For the DER options, 16,500 MW of solar, 9,100 MW of wind, or 2,700 MW of nuclear would be required.[91]

The backup gas capacity required varies from 5,700 MW for the nuclear baseload-supplied DES option to 8,500 MW in the wind-based DER option, not including reserve capacity margins. Common to all the DER/DES options is a need for 3,000 MW of backup natural gas-fired generation to satisfy summer peak demand. Setting aside this 3,000 MW reduces the required backup generation to 2,700 MW for the nuclear baseload-supplied DES option, less than half the backup required by the wind-based DER option of 5,500 MW.

[91] Note that an additional 2,250 MW of baseload supply would be required to satisfy the community baseload demand.

Table 25 - Full Year Demand Scaled-Up System Characteristics for DER Options				
DER Component	Characteristic	Wind	Solar	Nuclear
Community Daytime Demand	Total (GWh)	25,384	25,384	25,384
	Peak (MW)	8,852	8,852	8,852
Generation	Capacity (MW)	9,116	16,535	2,698
	Capacity Factor (%)	32.3%	19.1%	91.5%
Storage	Capacity (MWh)	241,275	44,375	11,240
	Capacity (Hours)	62	11.5	2.9
Backup Generation	Gas Peak (MW)	8,537	7,151	5,679
	Summer Peak (MW)	3,000	3,000	3,000
	Less Summer Peak (MW)	5,537	4,151	2,679
	Total Required (GWh)	4,592	7,629	6,139

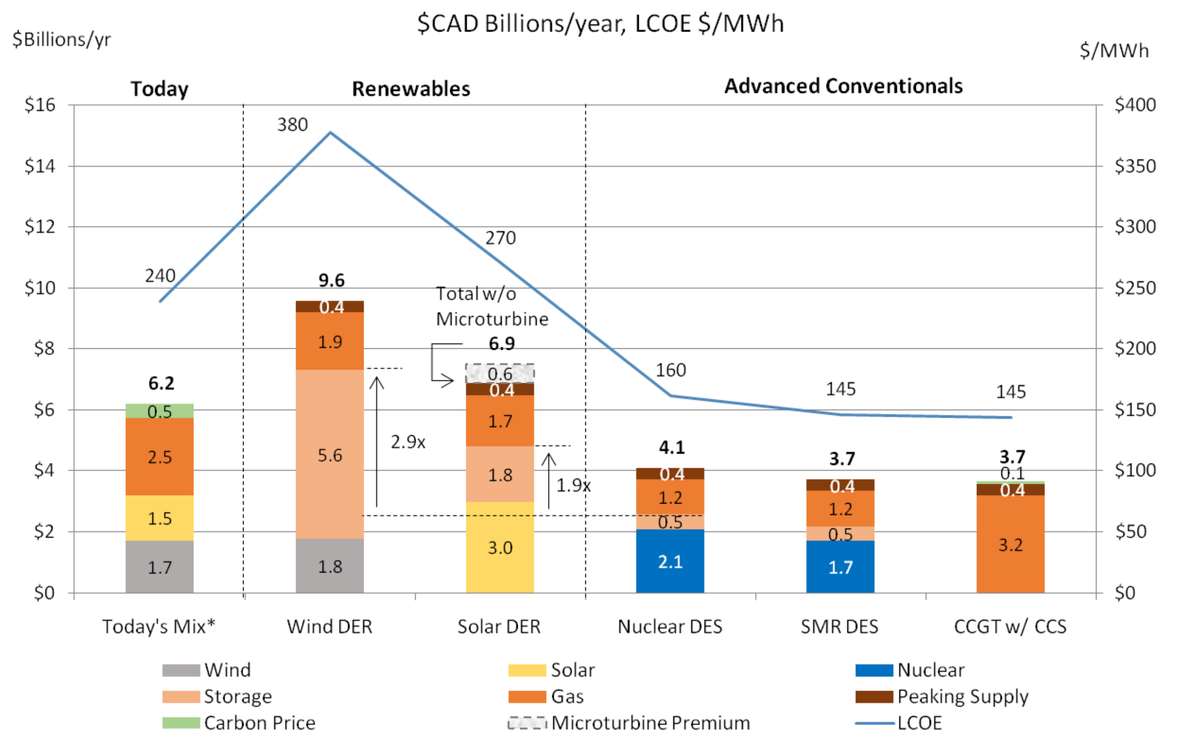
All of these DER/DES options provide reductions in emissions from natural gas-fired generation. The amount of natural gas-fired generation required would represent only 3 to 5% of the total supply mix. This is equal to or less than the record 4% of the supply mix that natural gas-fired generation represented in 2017[92]. The share of output from each generation type in the total supply mix is summarized in Table 26.

Table 26 - Supply Make Up of Total Ontario Demand				
Supply Source		Wind	Solar	Nuclear
Commited Resources		71%	71%	71%
Community Baseload		13%	13%	13%
Supply Required	DER + Storage	14%	12%	13%
	Gas	3%	5%	4%

Using the total system architecture requirements, Figure 96 shows the annualized cost of the DER options which consists of three components: Generation cost, storage cost, and backup natural gas-fired generation cost. The total cost is the sum of the annual cost of each component. The LCOE that reflects this total cost is determined by dividing the total cost by the demand being served, which for all three cases is 25,384 GWh as shown in Table 25.

[92] IESO Year End Review 2017

Figure 96 – Total Annual Cost of DER and LCOE Comparison, Ontario, 2030



Costs for all DER/DES options are dominated by the fixed costs that reflect the annualized cost of capital to construct and commission the solution as well as the fixed annual operating costs. Only nuclear and gas-fired generation options have variable costs which include operations, maintenance and fuel. Nuclear variable costs are a small portion of the total.

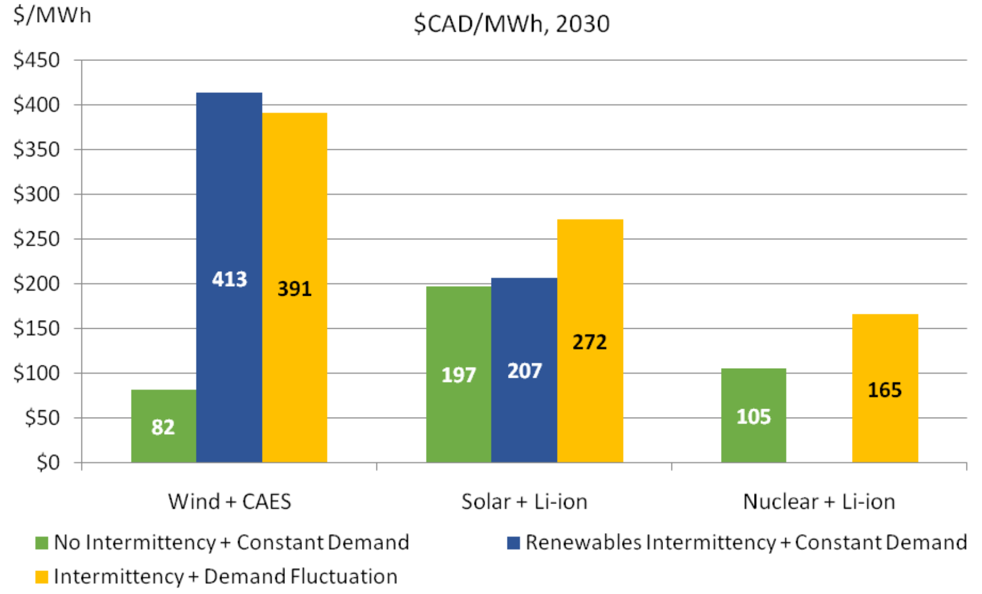
The cost of the nuclear generation and associated storage components is less than half the cost of the solar and storage components of the solar-based DER solution. When excluding the common gas-fired peaking capacity, the costs of the backup generation for the wind-based DER option is $1.9B/year or 60% more than the $1.2B/year cost required to backup the nuclear baseload-supplied DES solution.

6.3 Intermittency and Demand Fluctuation Impacts on LCOE

As discussed in Section 5, renewables intermittency and demand fluctuations create production inefficiencies for all generation types. Figure 97 summarizes the impact these factors have on the LCOE of solar-based DER, wind-based DER, and nuclear baseload-supplied DES solutions[93].

[93] Portraying the intermittency and demand fluctuations impacts on LCOEs involves an analytical method different from that used to the total costs in Section 6.2. Wind-based DER LCOEs for the two methods differ by 3%, solar-based DER LCOEs differ by 1%.

Figure 97 – Intermittency Implications on LCOE of Ontario DER Options



Demand fluctuations decrease the wind-based DER option costs but significantly increase the solar-based DER and nuclear baseload-supplied DES option costs.

The inefficiencies caused by intermittency and demand fluctuation include:

- More underutilized generation
- Unused storage capacity
- Need for backup generation

The degree to which these factors impact on the LCOE varies by option.

6.3.1 LCOE for Solar-Based DER

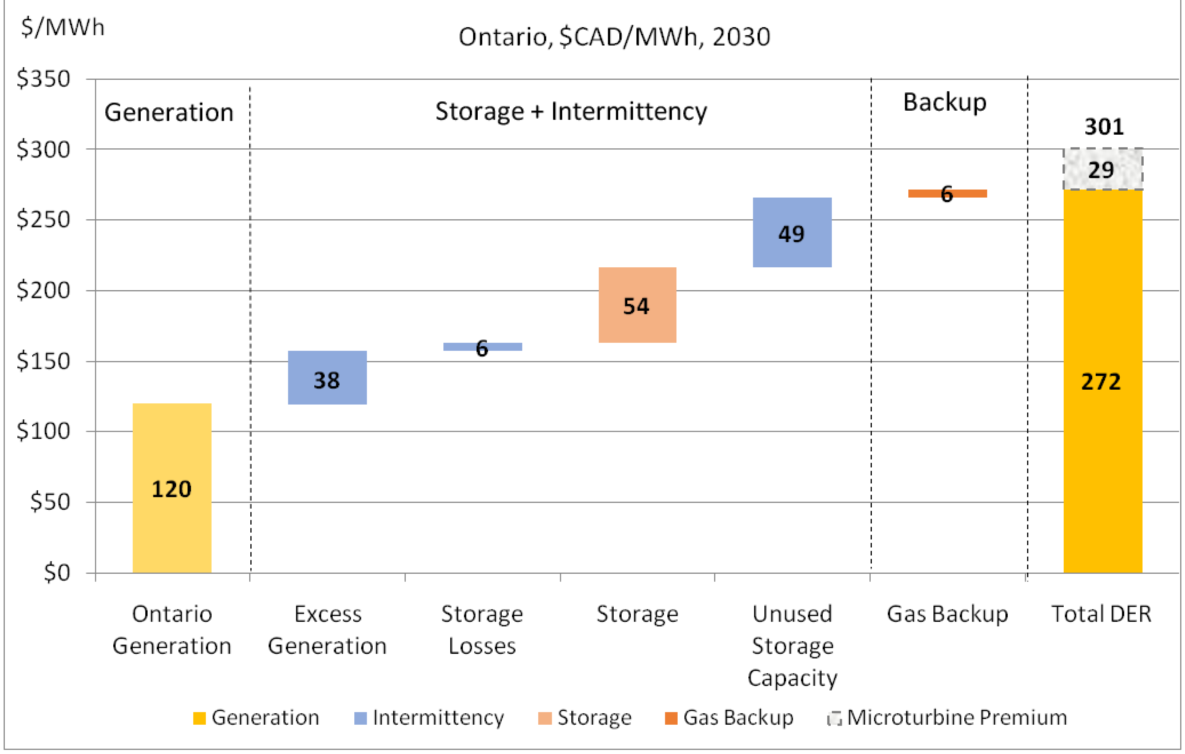
Table 27 summarizes the performance characteristics of the solar-based DER option for the aggregated community demand scenario. These performance characteristics impact the three cost components of solar-based DER:

1. Cost of solar energy used to supply demand
2. Cost of storage
3. Costs of backup supply

Table 27 - Factors Impacting Solar-Based DER Costs			
DER Component	Performance Metric	GWh	% of Generation
Generation	Used Directly	979	35%
	Excess	868	31%
	Into Storage	950	34%
	Total Output	2,798	100%
	Capacity Factor (%)	19.1%	
Storage	Stored Generation	817	29%
	Losses	133	5%
	Capacity Factor (%)	52.1%	
		GWh	% of Used Generation
Backup Generation	Backup Generation	770	43%
	DER Managed Peak (MW)	722	
	Summer Peak (MW)	303	
	Less Summer Peak (MW)	419	
	Capacity Factor (%)	21.0%	

The factors in Table 27 contribute to the LCOE as illustrated in Figure 98. Intermittency increases the cost of solar generation, reduces the used storage capacity, and requires backup generation.

Figure 98 – Community Solar-Based DER Component LCOE Contributions



a) Solar cost impacts

Two factors used in this analysis impact the cost of solar energy: underutilized excess generation; and, losses resulting from the inefficiencies of the storage device.

Excess generation impacts on the LCOE by increasing the cost of the utilized solar output. If 31% of the solar is wasted excess, then only 69% is used. This adds a premium of $38 to the LCOE as shown in Figure 98.

Similarly, when storage losses occur, the effective amount of solar energy that can be used is reduced. This cost specifically applies to stored solar energy, however, the net impact can be applied to the total cost. With 5% of the total utilized solar output is lost through storage, the LCOE for solar would increase by $6 as shown in Figure 98.

b) Cost of storage

The storage contributes to the LCOE results through two factors: the amount of utilized energy drawn from storage; and the unused storage capacity.

The total LCOE is a function of the weighted average cost of solar utilized directly and from storage. If 60% of the solar is utilized directly and 30% of the solar energy via storage, the new LCOE would be (60% * cost of solar after surplus + 30% * cost of stored solar plus the nominal cost of storage). This storage adds $54 to the direct cost of solar after wastage and losses.

The impact of unused storage capacity is calculated in the same way except that the cost of storage is increased. The cost forecast assumes that the storage is sized to produce the rated output for 8 hours per day 350 days per year[94]. This is defined as the 100% capacity factor for storage. If only four hours of storage output is available or utilized, the capacity factor will be 50%. At this capacity factor, the effective per MWh cost of the energy drawn from storage will be double. This is because storage is a fixed cost and if only half as much energy is extracted from the unit, the LCOE will have to double to recover that fixed cost from half as much energy. For the solar-based DER storage capacity factor of 52%, the new weighted average total cost of the solar-based DER system is estimated at $272/MWh, or $67/MWh more than if the storage capacity factor was 100%.

c) Cost of Backup Generation

The estimated cost of backup generation is based on several factors: capacity factor, heat rate, and actual MWh output.

It is assumed that 300 MW of capacity is obtained from a natural gas peaker plant for all cases. This peak reserve capacity mostly sits idle and only operates a few days per year, when demand is especially high. The peaking gas plant adds a fixed total cost for all of the scenarios assessed in this study.

As an example, for the solar-based DER option, the peak demand for natural-gas-fired backup generation capacity is 722 MW. Of that, 30 MW is to be provided by the peaker plant at an LCOE of CAD $50/MWh, which is predominantly composed of fixed costs since the peaker plant sits idle for the majority of the time. This leaves a need for 419 MW of CCGT with CCS capacity to produce 769 GWh of output implying

[94] Lazard LCOS v3.0

a capacity factor of 21%. The fixed portion of the CCGT w/ CCS gas plant costs US $131 per MWh. The heat rate is 8,304 mmbtu/MWh or 10% greater than the assumed heat rate for a CCGT with CCS at an 87% capacity factor. The variable cost for the CCGT with CCS becomes US $53/MWh, which includes fuel and O&M plus $4/MWh of carbon pricing for the emissions that escape the CCS process (based on a carbon price of CAD $100/t).

The total cost of backup generation becomes US $187/MWh or CAD $237/MWh including the exchange rate, Ontario's capital premium, and the cost of Tx and contingency.

To compute the total LCOE for the DER system and backup generation, the weighted average costs of the directly used solar, stored solar, and backup is computed. The backup generation increases the LCOE of the system by $6/MWh to $272/MWh as shown in Figure 98.

If a microturbine option is pursued in lieu of the centralized CCGT with CCS the costs are different. For a microturbine with a capacity factor of 21%, the heat rate is 11,718 mmbtu/MWh with an associated variable cost of US $72/MWh including fuel, plus US $59/MWh of carbon pricing at CAD $100/t of emissions. Tx and contingency costs are added by scaling from EIA factors for the CCGT with CCS case, and represent 6% of microturbine costs (the lowest Tx and contingency assumption compared to other generation types in this analysis). The cost of 303 MW of peaker plant capacity is added as with the CCGT with CCS scenario. The use of microturbines increases the net blended LCOE by $29/MWh to $301/MWh.

6.3.2 LCOE for Wind-Based DER

The factors impacting the costs of wind-based DER fall into the same three categories as discussed previously for the solar-based DER case:

1. Cost of wind energy used to supply demand
2. Cost of storage
3. Costs of backup supply

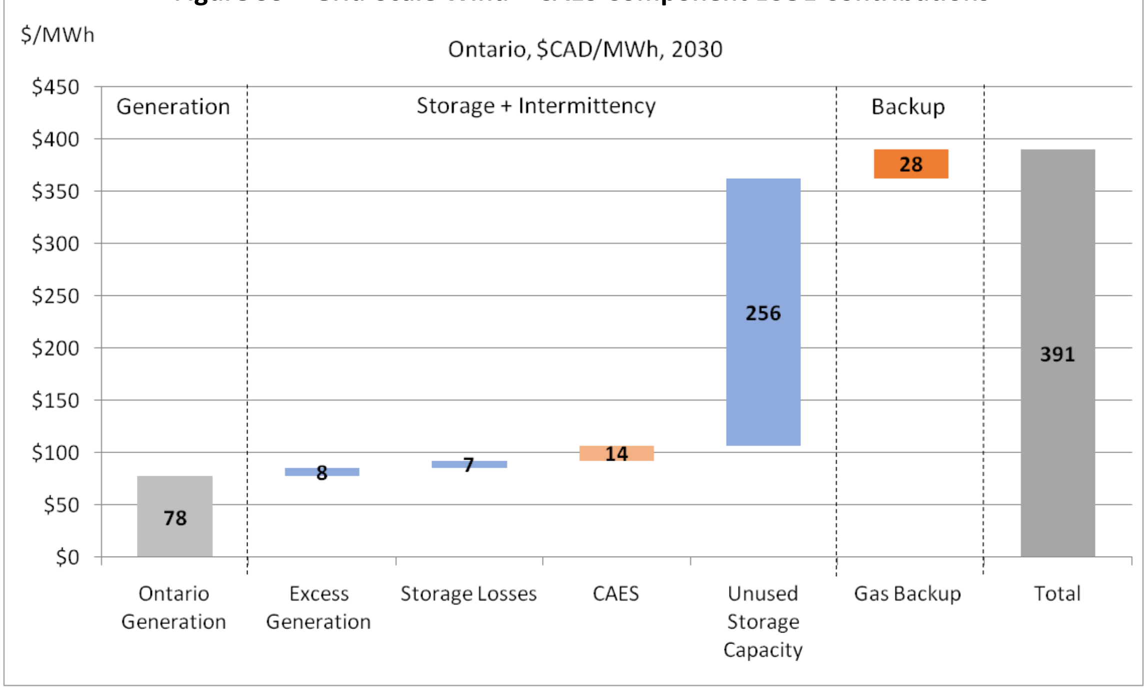
Table 28 summarizes the performance characteristics of the wind-based DER option that impact the three cost components.

Table 28 - Factors Impacting Wind-Based DER Costs

DER Component	Performance Metric	GWh	% of Generation
Generation	Used Directly	1,661	63%
	Excess	271	10%
	Into Storage	684	26%
	Total Output	2,617	100%
	Capacity Factor (%)	32.3%	
Storage	Stored Generation	446	17%
	Losses	239	9%
	Capacity Factor (%)	3.5%	
		GWh	% of Used Generation
Backup Generation	Backup Generation	463	28%
	DER Managed Peak (MW)	862	
	Summer Peak (MW)	303	
	Less Summer Peak (MW)	559	
	Capacity Factor (%)	9.5%	

The LCOE of the fully backed up wind-based DER option is summarized in Figure 99. The major contributors are the costs of storage and the cost of backup generation. The storage and backup contributions to the LCOE are considerably higher than for the solar-based DER case because the capacity factors of these assets are very low, 3.5% and 9.5% respectively. The backup generation capacity factors are lower than the solar solution because the wind option does not reduce the maximum peak demand but only requires backup generation to output half the energy.

Figure 99 – Grid-Scale Wind + CAES Component LCOE Contributions



The results suggest that the wind-based DER option cold perhaps be optimized further by significantly reducing the storage capacity. A smaller storage however, would lead to greater wind output underutilized and more gas-fire backup generation required.

6.3.3 LCOE for Nuclear Baseload-Supplied DES

The factors impacting the costs of the nuclear baseload-supplied DES fall into the same three categories as those discussed previously for both the solar and wind-based DER cases:

1. Cost of nuclear energy used to supply demand
2. Cost of storage
3. Costs of backup supply

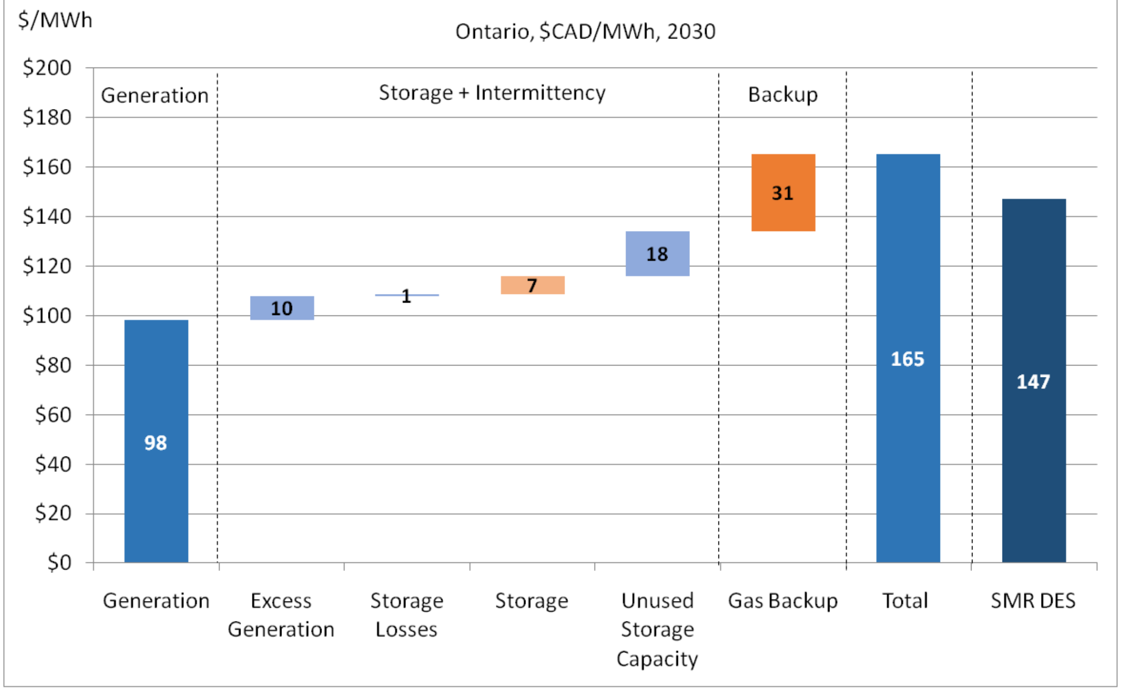
Table 29 summarizes the performance characteristics of the nuclear baseload-supplied DES option that impact the three cost components.

Table 29 - Factors Impacting Nuclear-Based DER Costs

DER Component	Performance Metric	GWh	% of Generation
Generation	Used Directly	1,829	84%
	Excess	221	10%
	Into Storage	132	6%
	Total Output	2,182	100%
	Capacity Factor (%)	91.5%	
Storage	Stored Generation	113	5%
	Losses	18	1%
	Capacity Factor (%)	28.6%	
		GWh	% of Used Generation
Backup Generation	Backup Generation	620	32%
	DER Managed Peak (MW)	573	
	Summer Peak (MW)	303	
	Less Summer Peak (MW)	270	
	Capacity Factor (%)	26.2%	

The LCOE of the fully backed up nuclear baseload-supplied DER option is summarized in Figure 100. The cost of the nuclear plant and the required natural gas-fired backup generation are the major contributors to the LCOE. The backup costs appear considerably higher than for the solar case, however, that is only because the overall nuclear baseload-supplied DES option costs are low. The LCOE of the backup generation is $264/MWh. The backup generation costs for nuclear are lower than for solar due to the lower backup capacity, the lower backup generation required, and the associated higher capacity factor.

Figure 100 – Nuclear Baseload-Supplied DES Component LCOE Contributions



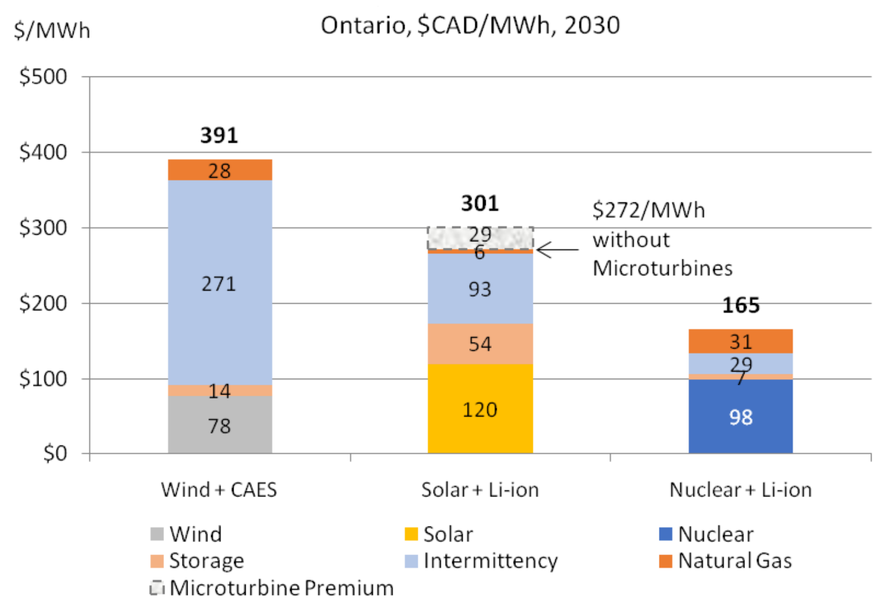
In the above comparison of the LCOEs of the DER options, the SMR LCOE is substituted for conventional nuclear generation with all other assumptions remaining the same. The cost for an SMR was assumed to be approximated CAD $75/MWh.[95]

6.3.4 LCOE Impact summary

Simulations of the DER/DES options using on Ontario's demand environment and three years of wind and solar output characteristics produced results that can be used to estimate the LCOEs of these options. Figure 101 summarises the results that indicate that the wind-based DER option could cost $391/MWh, solar-based DER $272/MWh, and nuclear baseload-supplied DES could be approximately $165/MWh. Many DER concepts also advocate for gas-fired microturbines to provide local backup generation. However, the microturbines could add another $29/MWh to the solar-based DER solution.

[95] EIRP, 2017; cost of Tx and contingency added per EIA 2017

Figure 101 – LCOE Comparison of DER Solutions

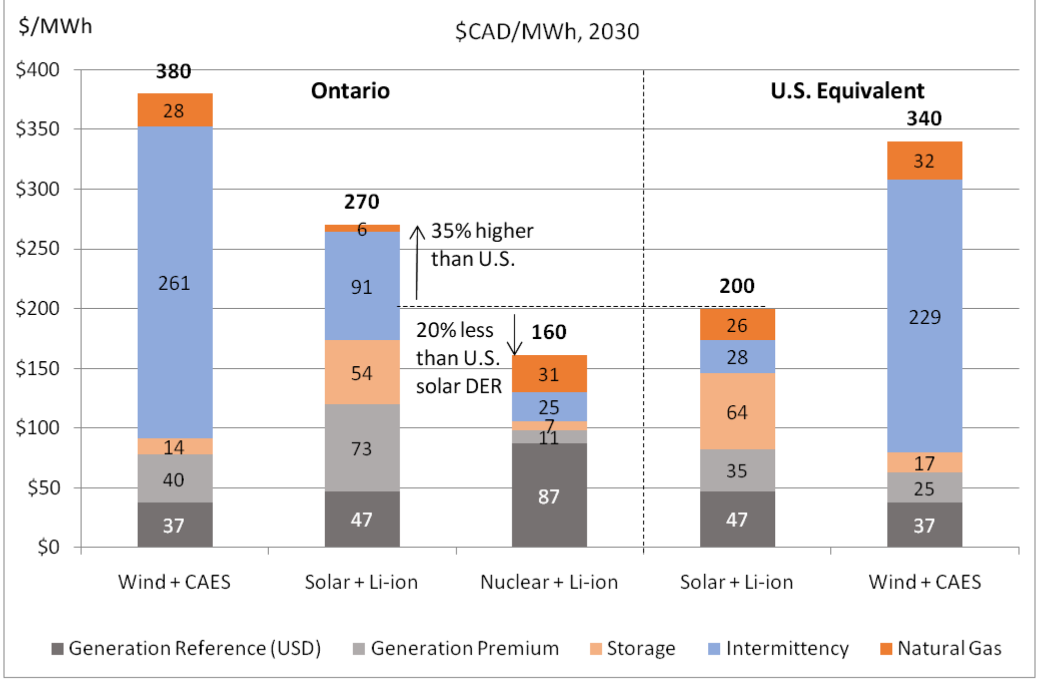


6.4 U.S. Geography Induced Competitive Disadvantages for DER

As discussed in Section 6.1.3, weather induced impacts on the output of solar and wind generation are on average less in the U.S. As a result, the U.S. benefits from higher capacity factors than in Ontario. This section examines how the system architecture of the DER options for the U.S. would be impacted by the higher capacity factors and associated lower intermittency.

Figure 102 illustrates how the components of the LCOE are impacted by differences between the jurisdictions. While solar-based DER in Ontario could be 35% higher than in the U.S., a nuclear baseload-supplied DES option in Ontario will be 20% less expensive than U.S. installations of solar-based DER. This suggests that Ontario may have a competitive advantage opportunity on electricity costs if that option was pursued. This section discusses how differences in U.S. capacity factors have been used to derive the U.S. equivalent LCOE for the solar-based DER and wind-based DER options. The three cost drivers as discussed in Section 6.2 are: generation capacity, installed storage capacity, and installed gas-fired backup generation capacity and its use.

Figure 102 – Ontario vs U.S. DER LCOE Contributions

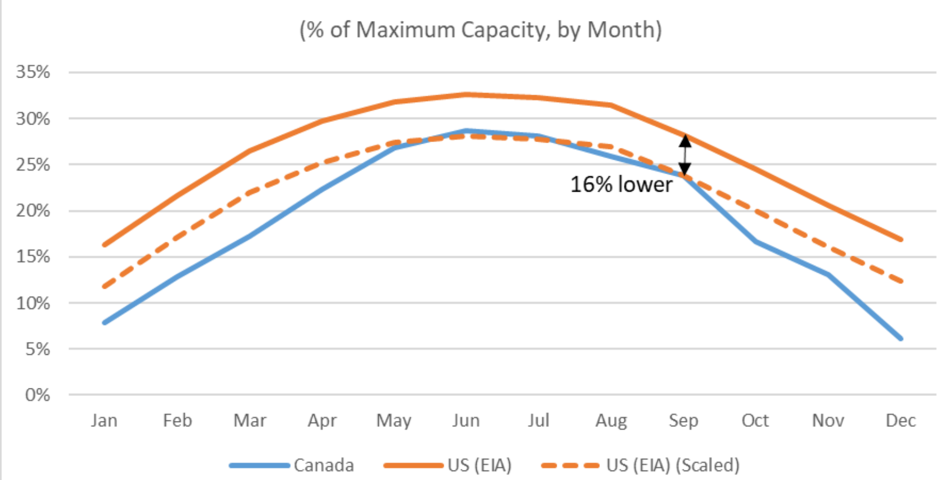


Note: in USD, solar-based DER would cost approximately $190/MWh, and wind-based DER would be about $300/MWh.

6.4.1 Solar Capacity Factor Impacts

The average solar capacity factor in the U.S. is 26% versus 19% in Ontario[96]. Figure 103 illustrates the capacity factor differences by month for Ontario and the U.S.[97]

Figure 103 – Solar Capacity Factor Comparison



[96] IESO actuals for 2015 to 2017 averages by solar farm, before curtailment.
[97] EIA Electric Power Monthly with Data for October 2017, Table 6.7.B

The differences between the average capacity factor in Ontario and the U.S. are caused by two factors: on average there are more hours of sunshine in the U.S. in a year; and, solar output degrades more rapidly in Ontario in the winter than in the U.S. The smaller month-month deviations in the U.S. solar capacity profile should improve the effectiveness of storage by reducing the seasonal variability effects.

For the purpose of modelling, a scaled U.S. profile was created to intersect and align with Ontario's September capacity factor, the reference month used to align the solar output with size the storage and meet demand.

The Ontario simulations of solar-based performance indicators were analysed to identify relationships between the capacity factor, underutilized storage capacity, and backup generation. The constant demand scenario method described earlier was used to isolate the effects of demand fluctuations from intermittency. The derived correlations define, for a given solar capacity factor, what the expected used storage capacity factor will be as well as how much natural gas-fired backup generation will be required. Implications of solar capacity factors were assessed under two scenarios: U.S. solar capacity factors; and, the adjusted U.S. solar capacity factor. The results are summarized in Table 30 identifying the results used to estimate the cost impacts.

Table 30 - U.S. Solar Capacity Adjustments

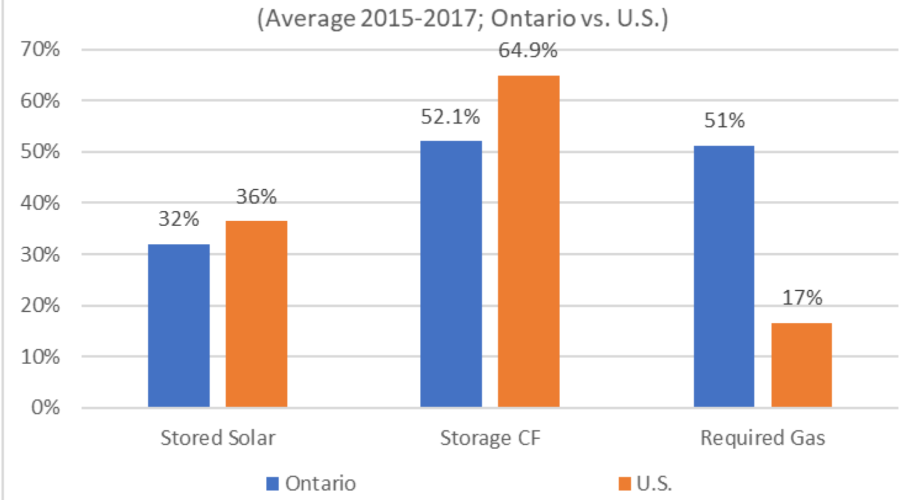
	Ontario	U.S.	U.S. Adj	Assumed	% Change
Installed Capacity	1669	1669	1405	1405	-16%
Stored Solar	32%	39%	34%	36%	14%
Storage CF	52.1%	69.3%	60.6%	64.9%	25%
Required Gas	51%	11%	22%	17%	-68%

Since the U.S capacity factors are higher than in Ontario, less solar capacity must be installed to achieve the same energy output, otherwise an "oversized" system would result. By reducing the installed solar capacity matches the desired output to the required demand. To match the Ontario September design capacity factor as shown in Figure 103, 12% less solar capacity is required. By aligning similar solar output, the required storage capacity is unchanged.

There are limitations to this method as some of the intermittency benefits of the higher solar capacity factors are lost. These lost intermittency benefits could increase the battery capacity factor and reduce the need for backup generation. This is illustrated by Table 30 which contrasts the results of the U.S. and adjusted capacity factors. To account for this limitation, and given the uncertainties inherent in this approach, the average outcomes of the two cases was used for cost purposes.

Figure 104 illustrates the relative differences for the cost drivers of solar-based DER installations in the U.S. and Ontario.

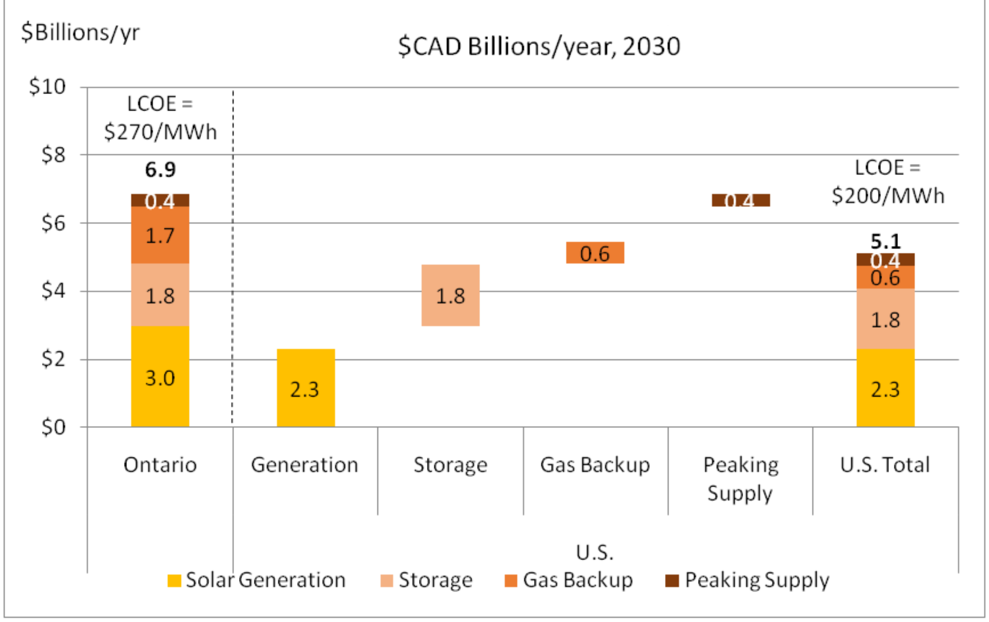
Figure 104 – Solar Capacity Factor Implications on U.S. Cost Drivers



For a constant demand scenario, a U.S. capacity factor that is on average 36% higher than Ontario leads to 16% less installed solar, 14% more solar being stored, a 25% higher battery capacity factor, and requires 68% less backup gas generation.

Figure 105 illustrates the cost implications. U.S. LCOEs can be expected to be 25% or $70/MWh less than in Ontario.

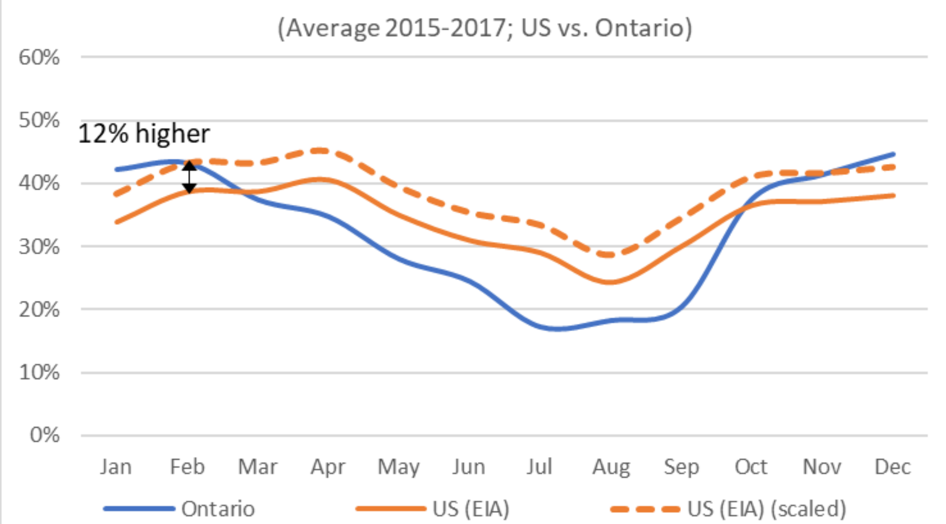
Figure 105 – Ontario vs. U.S. Solar-Based DER Cost Implications



6.4.2 Wind Capacity Factor Implications

Figure 106 illustrates the capacity factor differences by month for Ontario and the U.S.[98] As with the solar-based DER analysis, a scaled proxy to the U.S. capacity factors was created to align expected generation output for the reference months. For wind, those months are the five highest generation fall/winter months.

Figure 106 – Average Monthly Wind Capacity Factor



The U.S. experiences stronger winds throughout the spring and summer. The seasonal decline from winter to summer is more moderate in the U.S., declining from a peak of 40% to a low of 25% - an overall drop of 40%. In Ontario, the decline for the same period is from 45% to 18%, a 60% overall drop.

Correlations were established between the wind capacity factor and DER storage use and backup gas generation need. The results are summarized in Table 31 for both the U.S. nominal capacity factor and the adjusted capacity factor profile. As with solar, the average of the two cases has been adopted or costing purposes.

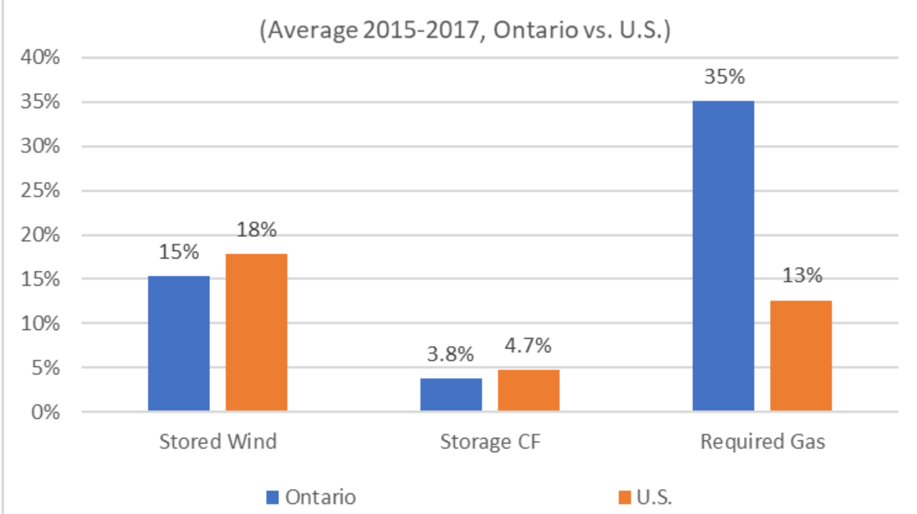
Table 31 - U.S. Wind Capacity Adjustments

	Ontario	U.S.	U.S. Adj.	Assumed	% Change
Installed Capacity	920	920	1030	1030	12%
Stored Wind	15%	17%	18%	17.8%	17%
Storage CF	3.8%	4.5%	4.9%	4.7%	24%
Required Gas	35%	17%	8%	12.6%	-64%

Figure 107 illustrates the relative differences in expected cost drivers for the U.S. and Ontario wind-based DER options, highlighting the impact that a more consistent wind regime can have on the performance of a DER system.

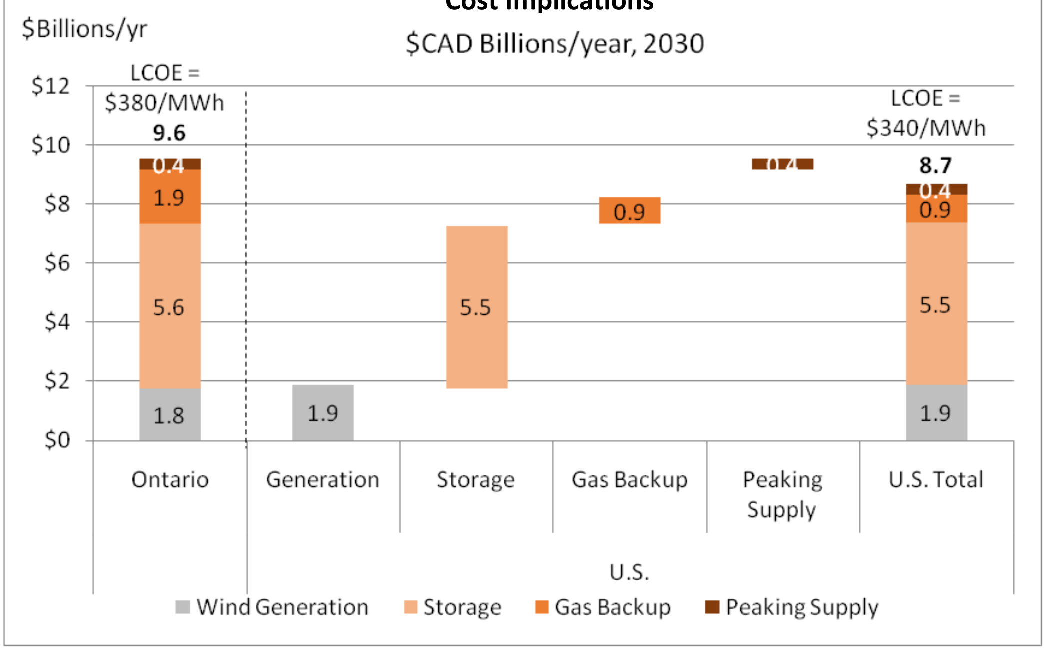
98 EIA Electric Power Monthly with Data for October 2017, Table 6.7.B; IESO actuals

Figure 107 – Wind Capacity Factor Implications on U.S. Cost Drivers



The results of expected U.S. installed cost drivers are applied to the LCOE components as illustrated in Figure 108 which shows that U.S. costs could be 10%, or $40/MWh, less than in Ontario.

Figure 108 – Ontario vs. U.S. Grid-Scale Wind-Based DER Cost Implications



6.5 Summary of Ontario's Geographic Cost Disadvantage

Converting the costs of renewables and storage into Canadian currencies enables a comparison to existing electricity costs in Ontario. The exchange rate, amount of domestic content, higher costs to build in

Canada, and the expected capacity factors significantly increase the comparative cost of these technologies.

The intermittency of renewables makes them uneconomic beyond 2030. When demand fluctuations are reflected, the renewables-based DER options become 65% to 135% more expensive than the nuclear baseload-supplied DES option.

Unfortunately, introducing more renewables in Ontario will propagate a systemic and structural energy cost disadvantage for Ontario vis-a-vis the U.S.

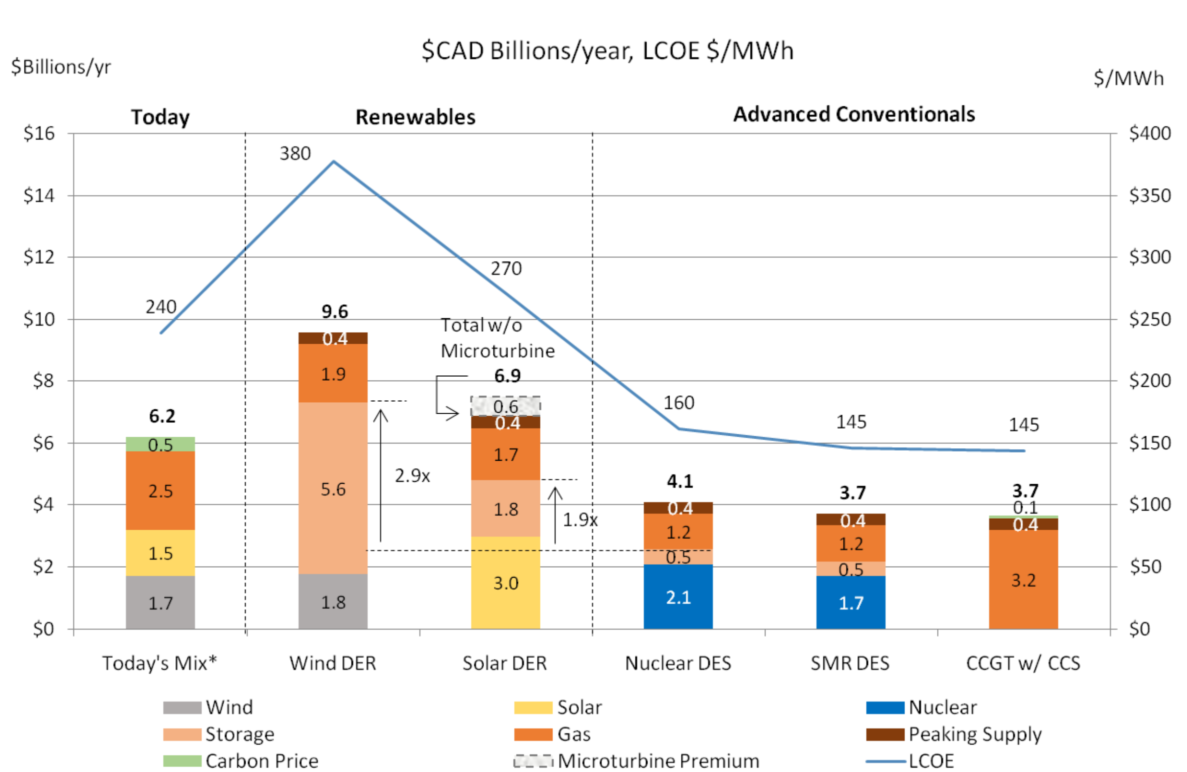
7.0 Summary Findings and Observations

The results of this study have produced the following three major findings:

Finding #1 – Ontario's Weather-induced intermittency undermines economics of renewables-based DER

Figure 109 summarizes the costs of the assessed DER options for meeting Ontario's 2035 supply gap.[99] The costs are compared to those of the existing system[100] as well as other new developing technologies in terms of the LCOE and the costs expected from each generation type as required to meet Ontario's anticipated LTEP supply gap in 2035. Intermittency creates a need for gas backup, which leads to a high LCOE from renewables-based DER systems.

Figure 109 – Total Annual Cost of DER for Ontario, 2030



1. LCOE of solar-based DER is $270/MWh, 20% higher than the $240/MWh cost of today's supplies that it would replace
    a. Today's supply mix would have an LCOE of $240/MWh (if include carbon pricing).
    b. Solar-based DER would have an LCOE of $270/MWh in 2017 dollars[101], or $301/MWh if microturbines are deployed instead of combined cycle gas turbines (CCGT).

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[99] The scenarios all assume the LTEP demand for 2035 within a system built on Ontario's committed hydro and nuclear assets and reflect industry projected 2030 costs.
[100] Existing system costs from OEB RPP, OPO 2015 embedded generation, IESO 2016 Year End data
[101] All currencies in this document are in $2017 CAD except in Section 4.0 or where otherwise specified.

   c. The LCOE of the wind-based DER option would be approximately $380/MWh.

2. A full rollout of renewables-based DER could add $0.7B/year to $3.4B/year to Ontario's cost of electricity.

   a. This is equivalent to a cost increase of 3% to 15% over the 2030 forecast LTEP costs[102].

   b. The DER/DES options have two distinct cost components: the cost of generation and storage; and the cost of the backup natural gas-fired generation and peaking supply.

   c. The future generation and storage cost of a solar-based DER option is projected to be $4.8B/year, 1.9 times the cost of a baseload-supplied DES system comprised of conventional nuclear generation and Li-ion battery storage. The generation and storage costs for the wind-based DER option are projected to be $7.4B/year, 2.9 times the cost of the nuclear baseload-supplied DES solution.

   d. All options include the same need for peaking natural gas-fired generation plants to satisfy the extreme demand peaks that occur on a few days every summer. The cost for 3,000 MW of peaking gas supply in 2030 is forecast to be about $380M/year.[103]

      Natural gas-fired generation would still be required to supply 20% to 30% of the incremental daytime demand mostly as a result of seasonal variations in both demand and generation. The estimated future share of natural gas-fired generation output could range from 3% to 5% of the Ontario supply mix, similar to the 4% in 2017, but less than the 8% realized in 2016[104].

      The cost of the backup natural gas-fired generation required by wind-based DER is $1.9B/year, 12% more than the $1.7B/year required for solar-based DER and 62% more than the $1.2B/year required for the nuclear baseload-supplied DES option. The wind-based DER cost is higher due to a much greater need for backup gas-fired generation capacity.

      Some proposed DER schemes involve the use of microturbines in lieu of the grid-based generation. The incremental cost of a microturbine was examined for the solar-based DER option. Microturbines would increase the cost by 9% due to higher capital costs, low capacity factor and carbon pricing.

3. The impact of renewables intermittency on the LCOE of DER/DES options in Ontario is illustrated in Figure ES-2. Intermittency results in excess unutilized generation, conversion losses in the storage system, low capacity factors of the storage asset, and the need for backup generation.

   a. The LCOE of the solar-based DER has four contributing components:

      - The cost of solar panels is based on the forecast LCOE for grid-connected solar of US $47/MWh (for low cost areas of the U.S. with high levels of sunshine[105]). That same

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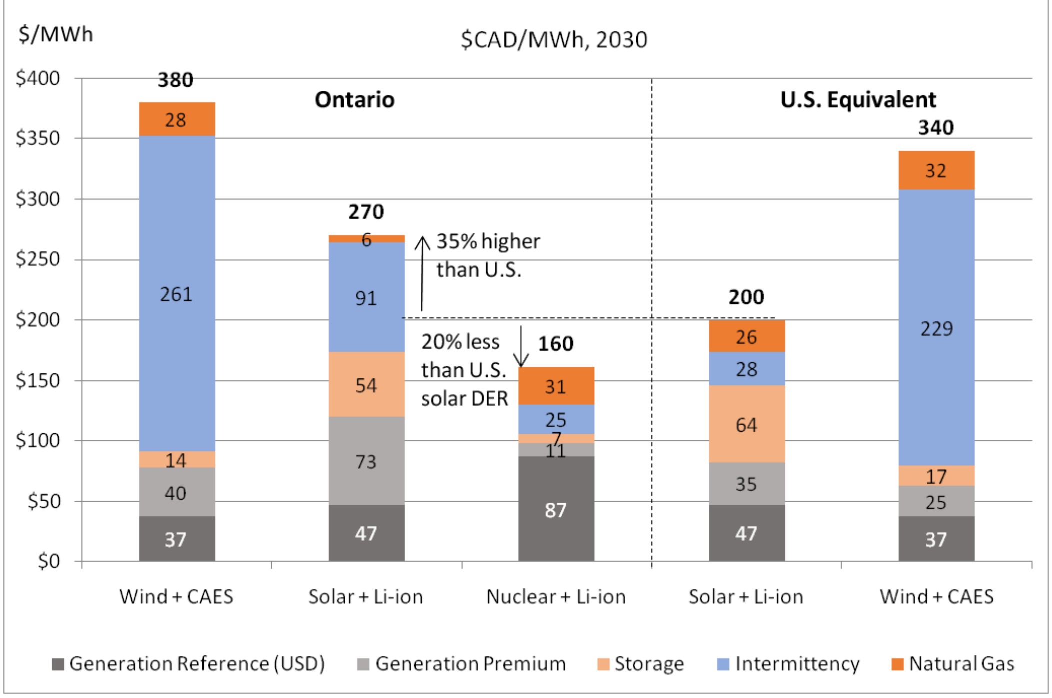
[102] It is assumed that the OPO Outlook B total cost forecast of $20.2B/year in 2030 is the basis for the LTEP.
[103] EIA 2017 Annual Energy Outlook, Strapolec analysis.
[104] IESO Year End Data, 2016, 2017
[105] Lazard LCOE v11, 2017

technology installed at community-scale in Ontario will cost \$120/MWh, a generation premium of \$73/MWh.

- Solar output intermittency combined with demand fluctuations increases the cost of storage and solar output by \$91/MWh for the energy that is used.
- DER solutions do not eliminate surplus from intermittent renewable energy production. Up to 30% of solar energy will be curtailed or lost through storage inefficiencies – 19% of wind.
- Natural gas will be required to backup up the solar energy and supply 30% of the demand increasing the total LCOE by \$6/MWh to \$270/MWh.

b. Wind-based DER solutions are costlier at \$380/MWh.

Figure 110 – Ontario vs U.S. DER LCOE Contributions



4. Residential renewables-based DER will be uneconomic for decades

To best provide the desired system asset optimization and customer benefits, DER solutions should be located as close to the demand load as possible, preferably on the consumers' premises. Unfortunately, as DER systems are moved closer to loads, the scale of the DER installation decreases: a 1.5 MW solar panel could supply a community of 1,000 homes and businesses; for a single home, a 0.25 kW solar panel could provide all of the daytime energy that would be needed above what could be supplied by Ontario's committed baseload. The components of 5 kW or smaller scale DER solutions are prohibitively expensive without the substantial subsidies that have promoted their use.

a. Cost forecasts show residential solar-based DER solutions will remain uneconomic beyond 2030.

b. For solar-based DER, community-scale solutions may be the most promising DER option. Increasing the size of DER installations to grid-scale solar offers little system benefits or cost advantage.
c. Wind-based DER is only economic when using grid-scale wind, which also offers the potential advantage of being paired with lower cost storage, such as compressed air energy storage (CAES). However, grid-scale wind does not provide the desired DER benefit of reducing the required capacity of the transmission and distribution systems. These must accommodate the backup natural gas-fired generation capacity which is not reduced.

Finding #2 – Ontario renewables-based DER would have a systemic 35% higher cost structure than the U.S.

Figure ES-2 shows that the cost impacts of intermittency in Ontario are greater than in the U.S. This is primarily due to the nature of Ontario's geography and weather conditions, which lower the capacity factors of the renewables. The higher capacity factors in the U.S. result from less variability or intermittency of the renewable generation output.

1. The LCOE of the U.S. solar-based DER would be $200/MWh. The $270/MWh LCOE of the solar-based DER in Ontario (using equivalent DER components) is 35% higher.
2. Similarly, the LCOE of wind-based DER may be 12% more in Ontario compared to the U.S.
3. Pursuing nuclear baseload-supplied DES options in Ontario could create a 20% cost advantage over the U.S. solar-based DER options.

Finding #3 – Of the known and proven technology options, nuclear baseload-supplied DES will be the lowest-cost option in any geography that has high renewables intermittency. Nuclear baseload-supplied DES also has the greatest potential in Ontario to achieve the desired DER benefits of mitigating distribution and transmission costs. Cost forecasts for other technology being developed suggest that:

1. The baseload-supplied DES would have an LCOE of $160/MWh. This option could reduce Ontario's annual electricity cost by over $2B.
2. Small modular reactors (SMRs) may be the lower cost solution for a broad range of jurisdictions and locations compared to conventional nuclear;
3. Natural gas-fired generation (CCGT shown) equipped with carbon capture and sequestration (CCS) may also be a low-cost low-carbon generation option.[106] However, CCGT with CCS would not offer the cost benefits from distribution and transmission system asset optimization and would not be emission-free – three times more emissions than the solar-based DER and four times the emissions of the nuclear baseload-supplied DES.

Implications

1. Renewables-based DER should not be looked to as a cost-effective solution for Ontario's emerging capacity gap identified in the 2017 LTEP.
    - Renewables-based DER can only be justified today based on either direct subsidies or indirect subsidies enabled by market arbitrage.

[106] Assuming an operating capacity factor of 49%.

- Investment in residential scale renewables-based DER is uneconomic. Incentives such as net-metering, noted in the LTEP, are an indirect subsidy that would increase the total cost of the entire electricity system.

2. Ontario's emerging capacity gap can be best addressed by procurement of up to 5,000 MW of new low-emission baseload electricity supply by 2035. New baseload capacity is required in Ontario to supply two needs:
   a) To fill Ontario's emerging capacity gap for baseload supply requires the procurement of over 2,250 MW of new low-emission baseload supply.
      - These resources will be required as soon as possible after the Pickering Nuclear Generation Station retires in 2024.
      - Based on 2030 cost projections, using renewables-based DER to perform a baseload function will cost three to four times more than new nuclear stations and will not be emissions-free because of the requirement for backup natural gas-fired generation. With the cost projections predicated on significant cost declines to 2030, procurements prior to 2030, such as to replace the retiring Pickering Nuclear Generation Station, will be costlier.
   b) To meet daytime demand, another 2,700 MW of low-emission baseload supply is required by 2035 in order to implement the low-cost baseload-supplied DES.
3. Given the immediate requirement for low-emission baseload generation to fill the emerging capacity gap after 2024, planning for such procurement should begin as soon as possible to best advance a potential Ontario competitive cost advantage with respect to the U.S.

Analysis of the transmission, distribution, and reserve capacity benefits should be conducted. It would likely show improved relative economics of baseload-supplied DES. Such analyses could additionally inform policy and investment decision-makers about the economics of DER/DES solutions, their ability to help address Ontario's emerging capacity gap, and the potential to reduce overall electricity system costs.

Acknowledgements

This study was conceived of and proposed by Strategic Policy Economics to fill a perceived void in the understanding of renewables-based distributed energy resources that figure prominently in the Ontario 2017 LTEP as a solution to the forecasted supply gap.

Overview of Strategic Policy Economics

Founded by Marc Brouillette in 2012, Strategic Policy Economics helps clients address multi-stakeholder issues stemming from technology-based innovations in policy-driven regulated environments. The consultancy assesses strategic opportunities related to emerging innovations or marketplace conditions and identifies approaches that will achieve positive benefits to affected stakeholders. Strategic Policy Economics specializes in framing strategic market, science, technology and innovation challenges for resolution, facilitating client teams in determining their alternatives, developing business cases and business models, and negotiating multi-stakeholder public/private agreements. Marc has worked directly with federal and provincial ministries, crown corporations and regulators, as well as with the private sector, municipalities, and non-profit organizations.

The Strategic Policy Economics team deployed to develop this report included Marc Brouillette, Scott Lawson, Andisheh Beiki, Marty Tzolov and Jesse Berlin.

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The Strategic Policy Economics team hopes this report provides a constructive contribution to the LTEP implementation process.

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Appendix B – List of Abbreviations

AC – Alternating Current
AEO – Annual Energy Outlook
AI – Artificial Intelligence
ATB – Annual Technical Baseline
BOS – Balance of System
CAD – Canadian Dollar
CAES – Compressed Air Energy Storage
CAGR – Compound Annual Growth Rate
CCGT – Combined Cycle Gas Turbine
CCS – Carbon Capture and Sequestration
CPI – Climate Policy Initiative
DC – Direct Current
DER – Distributed Energy Resource
DES – Distributed Energy Storage
Dx – Distribution
EIA – U.S. Energy Information Administration
EIRP – Energy Innovation Reform Project
EPC – Engineering, Procurement, and Construction
ESS – Energy Storage System
FAO – Financial Accountability Office of Ontario
FIT – Feed-in-Tariff
GTM – Greentech Media
GW – Gigawatt
GWh – Gigawatt Hour (one billion watts being produced for 1 hour)
HOEP – Hourly Ontario Energy Price
IESO – Independent Electricity System Operator
ICT – Information and Communication Technology
I/O – In/Out
IRENA – International Renewable Energy Agency
IRRP - Integrated Regional Resource Plans
kW - Kilowatt
kWh – Kilowatt Hour (one thousand watts being produced for 1 hour)
LCOE – Levelized Cost of Electricity
LCOS – Levelized Cost of Storage
LDC – Local Distribution Company
Li-ion – Lithium-Ion
LOLE – Loss of Load Expectation
LTEP – Long-Term Energy Plan
MoE – Ontario's Ministry of Energy
mmBTU – Million British Thermal Units
MW – Megawatt

MWh – Megawatt Hour (one million watts being produced for 1 hour, enough to power ten thousand 100W light bulbs for one hour)
NREL – National Renewable Energy Laboratory
O&M – Operating and Maintenance
OEB – Ontario Energy Board
OPG – Ontario Power Generation Inc.
OPO – Ontario Planning Outlook
PCS – Power Conversion System
PNGS – Pickering Nuclear Generating Station
PPA – Power Purchase Agreement
PV – Photovoltaic
SM – Storage Module
SMR – Small Modular Reactor
Strapolec – Strategy Policy Economics
t – Tonne (1,000 kg)
TWh – Terawatt hour (one trillion watts being produced for 1 hour)
Tx – Transmission
U.S. – United States of America
USD – United States Dollar
WTO – World Trade Organization

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