Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives

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1. Background

1.1 The Regional Planning Process

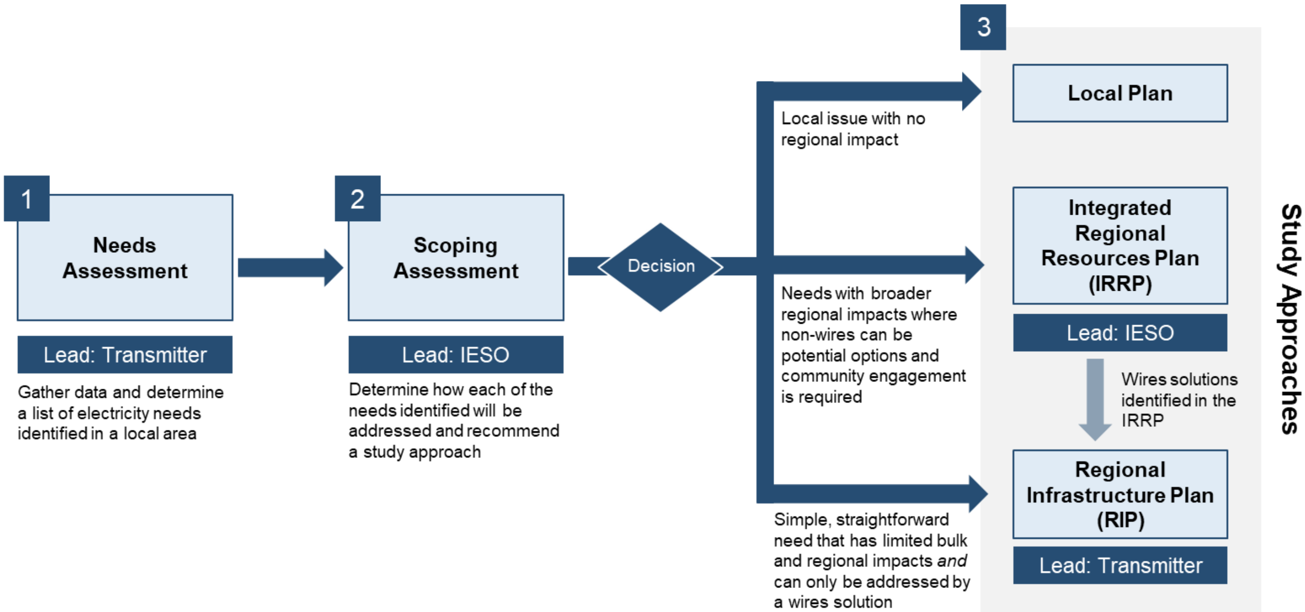
In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure – over the near, medium, and long-term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions. It supports regulatory (e.g., distribution and transmission rate filings) and acquisition processes (e.g., generation or distributed energy resource procurements). Regional planning also serves as a forum for the Independent Electricity System Operator ("IESO"), distributors, transmitters, stakeholders, and communities to share information and coordinate local electricity priorities with provincial electricity needs and policy direction.

The current process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. Regional planning is carried out by the IESO, in collaboration with the transmitters and distributors in each region. It consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if they require regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the needs and the scope of any recommended planning activities;
3. An Integrated Regional Resource Plan ("IRRP"), led by the IESO, which proposes recommendations to meet the needs requiring coordinated planning; and/or
4. A Regional Infrastructure Plan ("RIP"), led by the transmitter, which provides further details on recommended wires solutions.

These stages are summarized in Figure 1.

Figure 1 | Overview of Regional Planning Process Stages



1.2 Purpose of the Guide

IRRPs, which evaluate both wires and non-wires alternatives ("NWAs"), have grown more complex in recent years. With more technology types needing to be assessed, as well as greater stakeholder and community preferences and feedback, the IESO has implemented incremental improvements to the non-wires analysis in IRRPs. These improvements include:

- Formalizing a consistent and predictable approach to studying NWAs during the IRRP;
- Adding a screening mechanism to ensure the NWA analysis is conducted efficiently; and
- Developing the methodologies and tools to characterize needs and develop options with enough detail to assess technical and economic viability.

This guide presents an overview of the current approach for studying NWAs in IRRPs, which include conservation and demand management ("CDM"), distributed generation, demand response, and transmission-connected generation or storage.[1] The guide presents the process diagram and describes each key activity when developing and evaluating NWAs: screening, hourly needs characterization, options development, and the economic analysis. Like other components of IRRP development, these activities are led by the IESO but are conducted with the Technical Working Group[2] and with consideration of stakeholder feedback. This document is not a complete guide for all IRRP development steps, such as how to create a peak demand forecast, conduct technical power flow studies, or carry out stakeholder and community engagement.

The guide is also specific to the IRRP and is not intended for the overall electricity sector. While local distribution companies and other entities may choose to build off this work for their own non-wires-related initiatives, the main purpose of the guide is to improve consistency between regional plans

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[1] Grid-enhancing technologies such as modular power flow control devices are considered wires alternatives.
[2] Consisting of the IESO and the region's lead transmitter and local distribution companies.

and provide greater clarity for stakeholders interested in participating in IRRP development. The guide is not a rulebook or manual on how to assess NWAs; it summarizes general steps within a framework that should remain flexible to accommodate unique needs of each region. Over time, the electricity sector will evolve – new technologies may become available, more stakeholder feedback will be received, new situations and scenarios are encountered, and regulatory processes or procurement mechanisms could change. Therefore, this guide will be updated from time to time as the IRRP study methodology adapts to incorporate these changes and learnings.

The guide is organized as follows:

- A summary of the non-wires analysis process during the IRRP, in Section 2;
- The screening mechanism to focus options development, in Section 3;
- The hourly needs characterization to support options specification, in Section 4;
- A summary of the options development methodology, in Section 5;
- An overview of the financial assessment of options, in Section 6; and
- The conclusion and next steps, in Section 7.

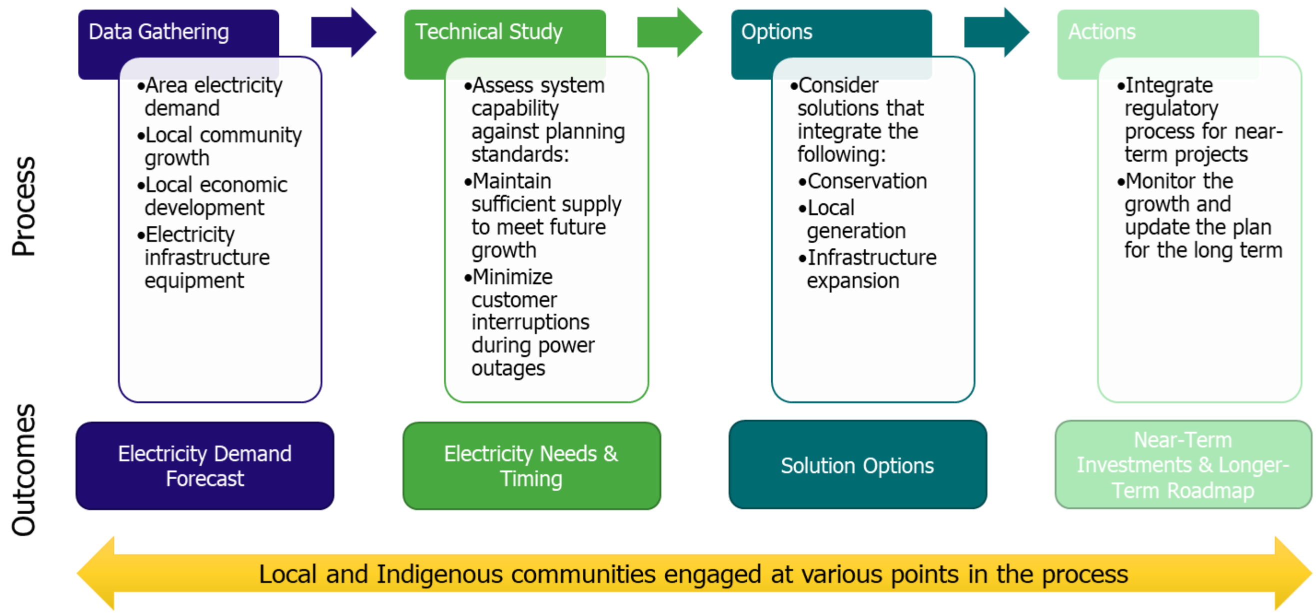
2. Non-Wires Analysis Process in IRRPs

For every IRRP, the Technical Working Group conducts four main activities:

1. Data gathering (to produce a peak demand forecast);
2. Technical study (to identify local electricity system needs);
3. Options development and analysis; and
4. Actions and recommendations.

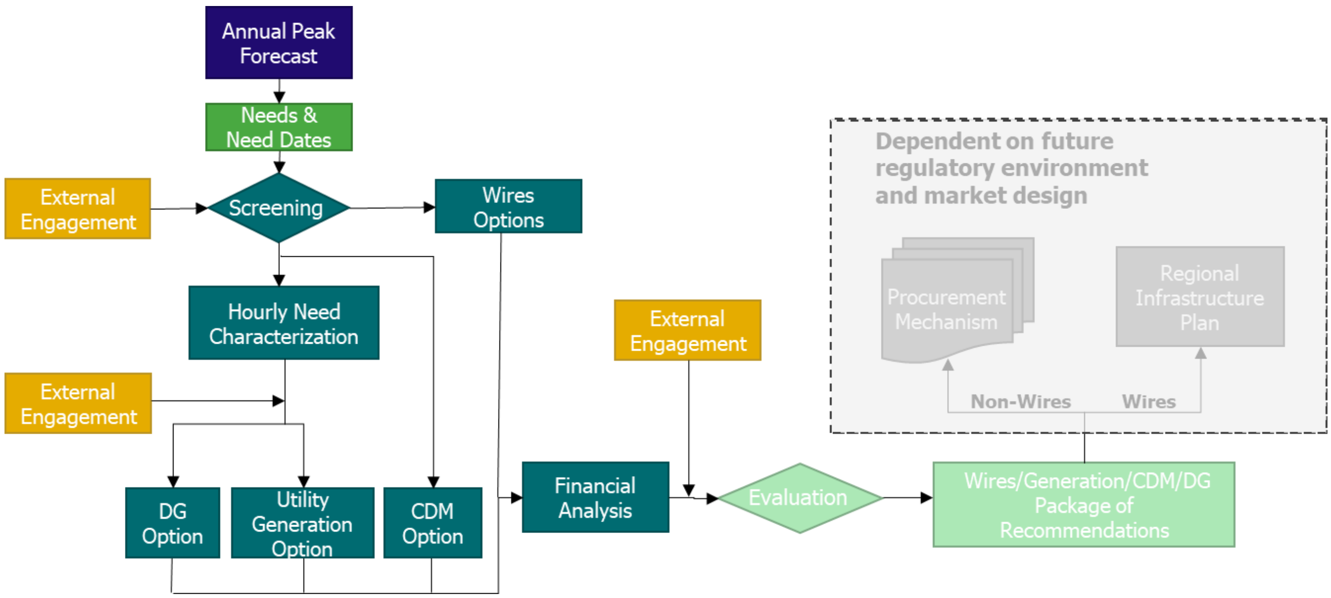
This general development process is shown in Figure 2.

Figure 2 | Overview of an IRRP Development



Within this sequence of activities, there are more detailed steps that are taken for assessing NWAs. Figure 3 illustrates these steps within the IRRP process flow diagram.

Figure 3 | NWA Analysis Process Flow Diagram



After the Technical Working Group identifies needs and their timing, it develops wires options. In parallel, these needs are screened to specify which ones warrant further analysis of NWAs. Hourly needs characterization occurs, during which hourly forecast load profiles are developed and evaluated against the transmission limitations. This work then informs the sizing and specifications of the various NWAs, as applicable. Near the end of the options development step, an economic analysis occurs to compare both wires and NWAs. The Technical Working Group is then able to recommend an integrated package of solutions.

Throughout the IRRP development, the Technical Working Group conducts a variety of external engagement activities. The mechanism for engagement can range from webinars to focused discussions with targeted stakeholders either one-on-one or part of larger discussions such as during regional forums. While the engagement mechanism may vary from IRRP to IRRP according to individual engagement plans, certain data and assumptions are consistently shared publicly. The Technical Working Group provides the hourly needs characterization, need dates, and any other reliability service requirements early in the IRRP development to improve transparency and to request feedback on the NWAs development and evaluation. This enables stakeholders to formally provide input on other options that should be considered – whether they are specific variations of NWAs not previously considered or options that were screened out – as well as information on cost, timelines, and feasibility. This information can then supplement the options development and evaluation at the IESO's discretion – for example, by reintroducing an option that was previously screened out or adding a cost sensitivity assumption.

3. Screening Mechanism

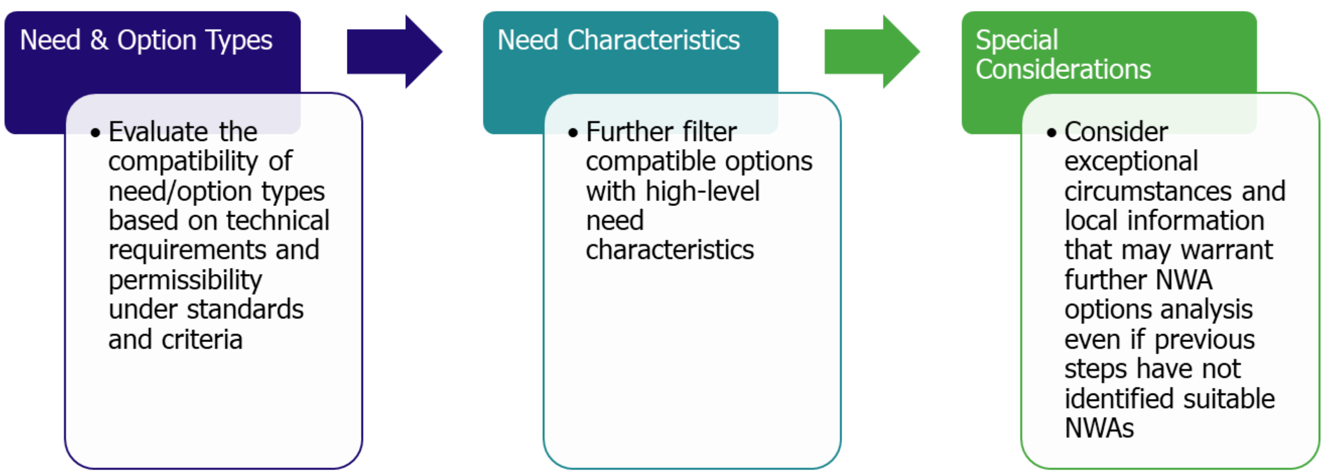
3.1 Overview

A NWA screening step is carried out early in the IRRP development process after local reliability needs have been quantified but before options analysis begins. The screening mechanism provides a framework to identify suitable option types for the unique needs of each IRRP while improving transparency in the Technical Working Group's decision-making process, driving more consistency between different IRRPs, and focusing options analysis efforts on NWAs that are most likely to be feasible and cost-effective. This step is necessary so that time-intensive assessments can focus on the most promising NWAs and still be completed within the 18-month regulatory timeframe for IRRPs, even as more option and technology types become available. Screening should be informed by local intelligence and stakeholder feedback that is typically acquired through the IRRP's comprehensive engagement opportunities.

The screening mechanism results in a shortlist of NWAs requiring further investigation. This list informs which local reliability needs require detailed hourly needs characterization, and maps candidate options to each need.

The screening mechanism is intended to be a guide rather than a strict set of criteria. It comprises three general steps that are summarized in Figure 4, and is discussed in more detail in Sections 3.2 to 3.4.

Figure 4 | IRRP NWAs Screening Mechanism



3.2 Screening by Need and Option Type

The first step in the screening mechanism is a general suitability filter that considers the type of need and the suitability of options according to its technical characteristics and permissibility under applicable planning criteria, such as the Ontario Resource and Transmission Assessment Criteria

("ORTAC"), North American Electric Reliability Corporation TPL-001-4, and/or Northeast Power Coordinating Council Directory #1.

There are typically four types of needs identified through an IRRP:

- **Station Capacity Needs** describe limitations to delivering power to the local distribution network through the step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by other equipment such as breakers and disconnect switches.
- **Supply Capacity Needs** describe limitations to the transmission system's ability to provide supply to a local area during peak demand. The load meeting capability is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by planning standards. Load meeting capability studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter through an asset condition assessment, which is based on a range of considerations such as equipment deterioration, technical obsolescence due to outdated design, lack of spare parts availability or manufacturer support, and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life.[3] Recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated. The IRRP presents an opportunity to right-size assets depending on the needs and coordinate the replacement recommendation with other issues in the region.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

On the other hand, there are four categories of NWAs differentiated by operating characteristics (e.g. dispatchable vs. non-dispatchable), scalability, and treatment in current planning criteria. These option types are not specified by technology or fuel type at this stage and include:

- Transmission-connected generation or energy storage;

[3] Transmission asset age demographic information is available by request and updated every five years. This is consistent with proposed code amendments to ensure that end-of-life information related to major transmission assets is reported to the IESO – a recommendation made by the Ontario Energy Board's Regional Planning Process Advisory Group.

- CDM;
- Distributed generation; and
- Demand response.

Table 1 is the matrix used for the first step in the screening; each column is explained further in Sections 3.2.1 to 3.2.4.

Table 1 | Screening Step 1: Suitability by Need and Option Type

NWA should be screened in?	Supply Capacity Need	Station Capacity Need	End-of-Life Need	Load Security Need	Load Restoration Need
Transmission-connected generation or storage	Yes	No	Yes	No	Yes
CDM	Yes	Yes	Yes	No	No
Distributed generation	Yes	Yes	Yes	No	Yes
Demand response	Yes	Yes	Yes	No	No

3.2.1 Supply Capacity and End-of-Life Needs

All NWAs are suitable for supply capacity or end-of-life needs. For supply capacity needs, most can be resolved by reducing the net peak load in the affected local area – something that all NWAs could achieve. However, the limiting phenomena will impact how effective the NWAs are compared to wires options. In most cases of asset replacement needs, NWAs will not be able to replace the existing infrastructure entirely since a grid supply and connection need to be maintained. NWAs (in addition to a like-for-like replacement) may be considered more so for scenarios where the alternative is upsizing the existing infrastructure.

3.2.2 Station Capacity Needs

NWAs can resolve station capacity needs similarly to how they could solve supply capacity needs through the reduction of net peak load. However, transmission-connected NWAs cannot address needs at or downstream of the step-down transformer. Therefore, transmission-connected NWAs are generally screened out for station capacity needs but CDM, distributed generation, and demand response may be suitable options.

3.2.3 Load Security Needs

Load security criteria in ORTAC specify limitations for the total amount of load interrupted by configuration after a contingency event, including requirements for permissible voluntary demand management and planned load curtailment.

Load Interruption by System Configuration

Generally speaking, NWAs are not suitable for mitigating situations where load is interrupted by configuration in excess of the ORTAC-specified limits, since this is a function of how much load is physically connected in protections zones that would be interrupted post-contingency. The intent of load security criteria is to minimize planning the transmission system such that large amounts of load are not supplied with a single failure point. CDM helps reduce load, but does not necessarily decrease the number of impacted customers. Generation options work in theory if they are able to provide an uninterrupted and immediate supply post-contingency; however, there are operational challenges to this application since the islanding of generation and load on the system is not permitted.

Planned Load Curtailment and Voluntary Demand Management

CDM is not considered suitable for permissible planned load curtailment within the load security criteria because it is not a dispatchable resource.

Voluntary load loss (like demand response) is technically permitted beyond the load security limits, but Ontario does not have a demand response procurement mechanism that activates demand response for a very local area (i.e., a single transformer station), for specific contingencies, and at specific load levels.[4] These are the three factors embedded in the ORTAC load security criteria. For these reasons, demand response can be screened out for IRRP load security needs unless there are exceptional circumstances.

Other voluntary demand management solutions such as local generation or storage are currently ruled out too because the adoption of these resources for mitigating load security violations is not widely adopted; this approach would likely need to be customer-driven to be feasible. Moreover, there is currently no existing procurement mechanism to activate local generation instantaneously under high load and post-contingency conditions. This may change with lessons learned from initiatives such as the Interruptible Rate Pilot.

3.2.4 Load Restoration Needs

Generation and storage options (either transmission-connected, distribution-connected, or behind-the-meter) can help meet load restoration requirements, to the extent that they can be operated as part of an island to restore load lost by configuration. For this reason, these options are screened in for restoration needs. However, it is not yet a standard practice – significant work between the transmitter, distributor, and customer would be needed to further investigate these options. In most regions, it may be easier to provide redundant supply or improve transfer capability between stations than to restore load solely through backup generation.

CDM and demand response are screened out because these options inherently do not restore interrupted load.

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[4] Ontario's Capacity Auction acquires resources designed to meet provincial adequacy rather than specific local or regional needs.

3.3 Screening by Need Traits

Step 1 above should result in a shortlist of need type/option type combinations to be further evaluated. The second step of the screening mechanism further reduces this shortlist by considering the need's high-level characteristics[5] such as magnitude and coincidence with system peak. Step 2 is summarized in Table 2 below.

Table 2 | Screening Step 2: Narrow Down Options with High-Level Need Traits

Option	Size of the need	Coincidence of the need with system peak
Transmission-connected generation or storage	Not applicable – always screened in	Always screened in – generation can likely provide system value during provincial peaks even if local need is not coincident
CDM	Screened in if need is less than 2% of the load forecast in each year	Screened in only if coincident with system peaks
Distributed generation	Screened in if need is less than the available distributed generation connection space	Always screened in – generation can likely provide system value during provincial peaks even if local need is not coincident
Demand response	Screened in if need is proportional to the historically-offered amount of demand response in the capacity auction	Screened in only if coincident with system peaks

Size

The viability of the NWA largely depends on the magnitude of the need. For instance, while transmission-connected resource options can be sized for any local need (as described further in Section 5.4), CDM options are more likely to be feasible if the need is roughly less than 2% of the total demand forecast for each year. CDM demand reduction beyond this may be possible, but there are practical constraints on how quickly electricity demand savings from CDM programs can materialize year-over-year. In contrast, the feasibility of distributed generation options is limited by the available connection space at each transformer station.[6] Measures can be taken to alleviate connection constraints (such as short circuit limitations) but the size of the distributed generation needed, relative to the available connection space gives an early indication if the option is feasible

[5] Distinct from the detailed hourly needs characterization described in Section 4.
[6] For existing station distributed generation connection availability, consider Hydro One's capacity evaluation tool for generation applicants.

and warrants more analysis. Similarly, historically-offered demand response bids in zonal auctions can indicate how much demand response may be feasible for a local area.

Coincidence with System Peak

The local need's coincidence with system peak is another consideration in Step 2 of the screening mechanism. This aspect is examined because most existing capacity procurement mechanisms are currently designed to meet system (provincial) capacity needs.[7] In order to rely on these mechanisms to implement an IRRP-recommended NWA, as well as leverage any system capacity value that has been estimated for the option, the need being addressed should therefore coincide to some degree with provincial needs.

CDM and demand response options are screened in for further analysis for needs that are coincident to (occur at the same time as) the provincial peak needs. There are two main reasons for this decision:

- Targeted CDM providing demand relief to needs coincident with system peak delivers both regional and provincial benefits. This is important, as the under the IESO's current targeted CDM mechanisms, targeted CDM must be cost-effective based on provincial benefits alone.
- There are no regional or sub-regional procurement mechanisms for demand response; locally targeted demand response would have to be implemented through the provincial capacity auction, which acquires resources designed to meet system peaks on a zonal basis.

Conversely, generation (transmission-connected or distributed) options could be dispatchable and able to meet local needs even if implemented through provincial resource procurement mechanisms. Therefore, coincidence to system peaks is not a consideration for generation options at this point in the screening.

Other Considerations: Timing

Depending on the NWA's implementation time relative to the need timing or transmission alternative lead time, other options may be screened out from further analysis. All NWAs require at least two years to implement, though exact lead times will vary depending on if the specific NWA is atypical, requires additional testing/proof of concept, or necessitates a new procurement mechanism. For instance, demand response, which may not involve building new infrastructure, could be implemented faster than transmission-connected generation. Longer timelines are especially suited for CDM savings, which build gradually over time. NWAs may still be possible for more urgent needs but each IRRP's Technical Working Group will have to consider the feasibility of interim solutions in the context of the regional needs and the available wires alternatives.

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[7] This may evolve as more local procurement mechanisms are explored, including the York Region Non-Wires Alternatives Demonstration Pilot and the PowerShare project in Windsor-Essex.

3.4 Special Considerations

The last step of the screening mechanism does not include a set of criteria – rather, it is to recognize the flexibility in IRRPs for exceptional circumstances and the uniqueness of each region. In some cases, special considerations could warrant further NWAs analysis regardless of the screening steps and outcomes described above. The Technical Working Group, using stakeholder and community feedback, should consider factors such as:

- Government policy or stakeholder support (i.e., willing local partners who can access additional funding streams, or municipalities or other entities who are interested in pursuing NWAs for their own purposes);
- Local preferences around solutions that the community will host (i.e., anticipated issues or concerns around a specific option that may present a barrier upon plan implementation);
- Unique load characteristics (i.e., a specific customer or load type that might have characteristics that make NWAs more feasible);
- Opportunities to explore a novel technology or operating model;
- Demand forecast uncertainty (i.e., NWAs can offer more flexibility and be more modular than large transmission infrastructure investments in cases where there is high uncertainty in the demand forecast);
- Opportunities for integrated solutions (i.e., different combinations and sequencing of both wires and NWAs); and
- Availability of inexpensive and simple wires options that maximize the use of existing infrastructure (i.e., sufficient load transfers or permissible control actions/remedial action schemes).

4. Hourly Needs Characterization

4.1 Overview

Peak load forecasts are sufficient to size wires options, but are not granular enough to size and evaluate NWAs for local needs. While every IRRP continues to produce a station-level, annual peak forecast[8], additional work is undertaken to create an hourly forecast for screened-in needs. These forecast profiles enable the Technical Working Group to identify additional need characteristics – information such as the frequency of hours when load might exceed the transmission limit, the MW magnitude of these events, and the maximum duration (in hours) of a single event. These characteristics (often simplified as the need frequency, magnitude, and duration) all have an impact on the technical feasibility of NWAs, as well as their economic viability. These details are less important for developing wires options because new transmission reinforcements generally increase capacity and are available in all hours once they are in service (with the exception of during outages).

Consequently, hourly needs characterization was introduced to the IRRP development process to help determine and size NWAs after screening. It can also support regional planning participants – for instance, non-wires proponents who might need hourly data to propose options for local needs. However, hourly needs characterization is not intended to enable a true probabilistic assessment nor be capable of perfectly predicting when demand will exceed the load meeting capability. This activity during the IRRP is meant to give a general sense of when, for how long, and how often needs are at risk of occurring, how large needs may be, and help inform options development choices such as the technology type and size. The accuracy of hourly load forecasting for a local area heavily depends on the granularity and quality of data available – information such as current and future customer segmentation, or the hourly output of distributed energy resources can be incorporated on a case-by-case basis to improve the need profiles. Other data, such as future end-use changes (i.e., electrification or new large industrial customers) or instances of bi-directional power flow can also improve the forecast.

The two key activities (hourly forecasting and needs characterization) that make up hourly needs characterization are described further in the sections below.

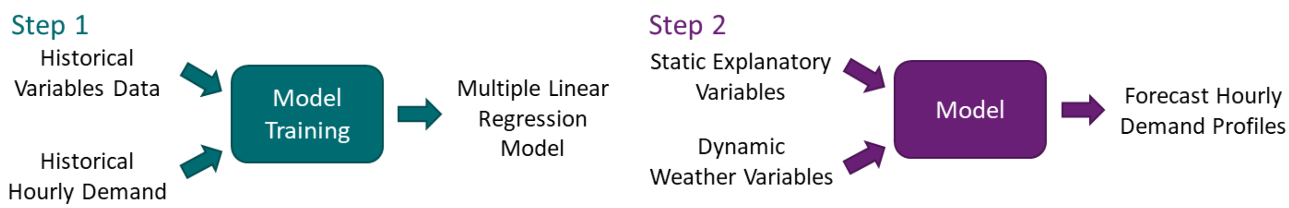
[8] In October 2022, the Ontario Energy Board published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

4.2 Hourly Forecasting

In IRRPs, hourly load forecasts consist of a series of year-long hourly profiles ("8760 profile", based on the number of hours in a non-leap year) that are ultimately scaled to the annual peak demand forecast. These can be created for a single transformer station, an aggregate of multiple stations in a constrained transmission sub-system, or even an aggregate of entire zones or regions within a transmission interface. When combined with the transmission limits, the forecasts can later be used to determine need profiles (also referred to as energy-not-served profiles) that serve as inputs for options development (described further in Section 5).

The two-step approach to hourly forecasting in IRRPs is summarized in Figure 5.

Figure 5 | Summary of the Hourly Forecasting Methodology for IRRPs



First, a density-based clustering algorithm is used to filter the historical hourly load data for outliers (including fluctuations that can be caused by between-station load transfers, outages, or infrastructure changes). Subsequently, the historical load data is combined with select predictor variables and their historical values to perform a multi-variable linear regression. These predictor variables include:

- Weather (temperature, cloud cover, humidity, and wind chill);
- Global horizontal irradiance;
- Population;
- Employment;
- COVID-19 impacts; and
- Calendar (day of the week, holiday).

Model diagnostics (training mean absolute error, testing mean absolute error) are then used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. Once the model is developed, it is applied with projections of the predictor variables. Projections of the non-weather variables are consistent with those used in the IESO's Reliability Outlook and come from a variety of sources. Demographic variables are forecast from the Ministry of Finance, whereas economic variables are provided by entities such as the Conference Board or Centre for Spatial Economics.

Weather variables, however, are varied to forecast a range of possible future hourly profiles. Since weather and its interplay with variables like calendar and time of day have a significant impact on electricity demand, the model is applied to different weather and calendar permutations. For example, a hot summer temperature forecast for a weekend will result in a different demand profile than if that same temperature was paired with a future weekday. The impact of an extreme heat event could appear muted if it occurs on a statutory holiday instead of a weekday.

In IRRPs, the model uses 31 years of historical weather data to develop a range of possible load outcomes. Weather variables are permutated with calendar variables by shifting them up to seven days ahead and behind to ultimately generate a total of 465 (31 years of historical weather data ×15 weather sequence shifts) possible hourly profiles for each forecast year. This is illustrated conceptually in Figure 6; each column contains the same chronological series of temperatures that is shifted.

Figure 6 | Weather-Calendar Permutations in Hourly Forecast Development

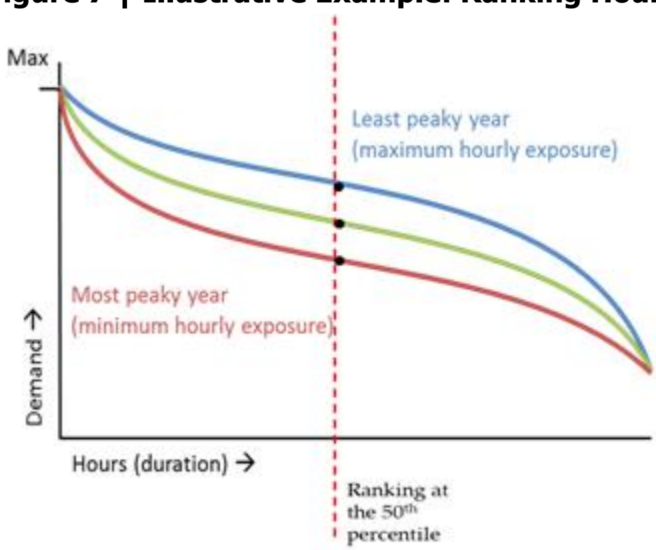
Shifted behind 7 days ←   → Shifted ahead 7 days

2017_B7	2017_B6	2017_B5	2017_B4	2017_B3	2017_B2	2017_B1	2017_A0	2017_A1	2017_A2	2017_A3	2017_A4	2017_A5	2017_A6	2017_A7
5.62	1.2	0.95	-6.66	-0.4	-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43
1.2	0.95	-6.66	-0.4	-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27
0.95	-6.66	-0.4	-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27	2.02
-6.66	-0.4	-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27	2.02	-10.25
-0.4	-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27	2.02	-10.25	-8.22
-0.77	-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27	2.02	-10.25	-8.22	-11.36
-1.23	-3.22	-2.94	-3.75	-14.86	-11.48	-4.16	-2.34	-1.43	5.27	2.02	-10.25	-8.22	-11.36	-7.5

* For illustrative purposes only

Subsequently, the 465 potential forecast profiles are ranked in ascending order based on their annual energy values. Load duration curves which illustrate this ranking can be seen in Figure 7.

Figure 7 | Illustrative Example: Ranking Hourly Load Profiles by Energy



The IRRP Technical Working Group decides which profiles are ultimately scaled to the peak demand forecasts, or if multiple profiles are studied as additional sensitivity scenarios. The choice in profile influences the technical requirements and costs of the NWAs, as described further in Section 5.

Relevant profiles (typically at the station or aggregated stations level) are shared publicly as part of the IRRP engagement to support stakeholder feedback; stakeholders may influence the profile selection or sensitivity analyses, as well as provide additional data (i.e., future customer segmentation information) to use as inputs in the model.

4.3 Needs Characterization

Hourly forecasts are a direct input for further NWAs analysis when combined with the local relevant transmission limits. The shape of the forecast load that exceeds transmission limits is referred to as the need profile, or energy-not-served. Need profiles help identify key characteristics – the magnitude, frequency, and duration of possible need events, and how they could be dispersed over the days, months, and years in the 20-year planning horizon.

Select hourly forecasts and need profiles are published during the IRRP engagement process. This data-sharing is intended to inform planning participants and enable more feedback. Additionally, this data can be translated through figures (as shown below) in IRRP engagement materials.

Figure 8 | Sample Outputs of Needs Characterization: Heat Maps

MW Range	Month 1	2	3	4	5	6	7	8	9	10	11	12
40+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
36	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
31	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%
27	0%	0%	0%	0%	0%	0%	2%	2%	0%	0%	0%	0%
22	0%	0%	0%	0%	1%	1%	4%	4%	0%	0%	0%	0%
18	0%	0%	0%	0%	1%	2%	7%	6%	1%	0%	0%	0%
13	1%	0%	0%	0%	3%	4%	9%	8%	2%	0%	0%	1%
9	2%	1%	0%	0%	5%	6%	11%	10%	4%	3%	1%	2%
4	5%	4%	2%	1%	7%	8%	12%	12%	7%	5%	2%	5%
0	9%	6%	4%	3%	10%	11%	13%	13%	10%	9%	5%	8%

MW Range	Hour 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
40+	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
36	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
31	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%
27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	2%	2%	1%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	1%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	1%	1%	2%	2%	2%	2%	3%	4%	2%	1%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	3%	5%	4%	2%	2%	2%	2%	2%	2%	3%	5%	7%	3%	2%	1%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	6%	7%	6%	5%	3%	3%	3%	3%	3%	5%	7%	8%	6%	3%	2%	1%	0%	0%
0	0%	0%	0%	0%	0%	2%	8%	8%	8%	7%	5%	5%	5%	5%	5%	7%	8%	9%	8%	6%	2%	2%	1%	0%

Heat maps are created in IRRPs to help illustrate need profiles. In the example of an overloaded transformer station in Figure 8, each cell in the heat map indicates the expected frequency of a capacity need according to the month or hour. For instance, the need is estimated to infrequently exceed 9 MW in shoulder season months such as March and April. For the same station and from an hourly perspective, a sustained need is estimated across day hours (roughly 6 AM – 11 PM).

5. Options Development

5.1 Overview

After screening and hourly needs characterization, NWAs are identified and evaluated. Options are sized to meet specifications of the need such as type, timing, capacity requirement, and energy requirement. Each IRRP identifies NWAs that are most appropriate for the need(s) and considers the following approaches:

- Maximizing the use of existing infrastructure and resources in the region;
- Selecting resources with the attributes that most closely meet the need; and
- Developing integrated solutions that can include combinations of different NWAs or both wires and NWAs.

Options must meet minimum reliability requirements, and are evaluated with consideration for qualitative factors like operational flexibility, dispatchability, resilience, risk tolerance, and social acceptance. However, once a portfolio of feasible options is identified to meet the relevant reliability standards and technical requirements, cost-effectiveness is the main criterion to select the preferred option. Barring unique circumstances, options that satisfy key technical requirements and have the lowest cost are selected.

In cases where one solution does not fully address all identified issues/opportunities, the IRRP could assess whether a portfolio of options might work. This can also include a "staged" solution approach; development work for options with long lead times (such as transmission) may be initiated in parallel with options with shorter lead times that do not meet the full need over the IRRP's 20-year planning horizon. For instance, in areas with high growth rates, incrementally small solutions may not be capable of addressing issues in the longer term even though they could defer the issues by a few years. This is especially relevant to regions where there is minimal to no existing transmission and distribution infrastructure, and significant expansion of new "greenfield" development would be needed. In these cases, the cost of implementing a smaller solution in the nearer term is valued against the deferral of a costlier larger alternative. This staggered solution approach can offer flexibility, since there is more time to respond to changing conditions or assumptions before committing to a long-term solution.

Sections 5.2 to 5.4 describe the methodology used for developing each NWA type: CDM, demand response, and generation and energy storage.

5.2 Conservation and Demand Management

CDM is a low cost resource that offers benefits to individuals, businesses, and the electricity system as a whole. It includes measures that upgrade or replace existing equipment with energy efficient alternatives such as lighting retrofits and controls, chiller replacements, and HVAC redesign. While forecast savings from IESO-delivered province-wide and federal CDM programs are already captured in IRRP demand forecasts, to understand the scale of opportunity and associated costs for targeting incremental CDM for local needs, data and assumptions are leveraged from provincial CDM potential forecasts.

In 2019, the IESO and the Ontario Energy Board completed the first integrated electricity and natural gas achievable potential study in Ontario ("2019 APS") and in 2022 the IESO updated this analysis with refreshed inputs informed by the 2021 Annual Planning Outlook. The main objective of the APS modeling is to identify and quantify energy savings potential, and associated costs from demand side resources over the long-term forecast periods. This achievable potential modeling informs:

- Future CDM policy and/or frameworks;
- Program design and implementation; and
- Assessments of CDM non-wires potential in regional planning.

The 2019 APS and 2022 APS refresh determined that there is significant cost-effective CDM potential available in the near and longer terms. In particular, the maximum achievable potential scenario in the APS estimates the available potential from all CDM measures that are cost effective from the provincial system perspective – i.e., they produce benefits from avoided energy and system capacity costs that are greater than the incremental costs of the measures.

Modeling undertaken for the APS produced considerable data that can be used to understand CDM opportunities at a more local level. Specifically, the APS results are broken out by:

- IESO transmission zone;
- Customer sector (e.g., residential, commercial, industrial);
- Customer segment (e.g., single family dwellings, multi-unit residential buildings, large commercial office, restaurant, school, warehouse, etc);
- End use (e.g., lighting, space heating, space cooling, plug load, etc); and
- Measure – (e.g., high bay LED lighting, air source heat pumps, building recommissioning).

At this time, the annual demand savings potential forecast at the zone and sector level in the maximum achievable potential scenario of the APS is what is used to calculate demand savings opportunities at the station level for an IRRP's local needs. To determine the amount of incremental CDM savings potential, the maximum achievable savings potential forecast is scaled down to the local area impacted by the needs. From there, the committed savings that are expected to come from existing provincial and federal CDM programs are netted out.[9] The result is the remaining cost-effective uncommitted achievable summer peak demand savings potential and its estimated annual

[9] Centrally delivered CDM measures under the 2021-2024 Conservation and Demand Management framework and Save on Energy brand are already included in the IRRP load forecasts.

budgets. This analysis requires the IRRP station-level peak forecasts, sector segmentation data (residential, commercial, vs. industrial), and the forecast committed CDM savings from programs currently in-market delivered by the IESO and the federal government.

In some cases, uncommitted CDM savings potential is also deducted from the hourly demand profiles to create modified need profiles that assume incremental, cost-effective CDM is implemented before other options. If CDM cannot meet the entire need in every hour, these modified need profiles are then used to size solutions for other NWAs to create integrated NWAs packages – this is described further in the next sections.

5.3 Demand Response

In 2021, the IESO commissioned Dunsky Energy and Power Advisory to develop a Distributed Energy Resource APS that highlights the types and amount of distributed energy resources likely to emerge in Ontario over a 10-year timeframe that is both achievable and economic. At this time, demand response potential for IRRPs are considered using this study, combined with historical auction offer information and estimated contribution to local needs.

Past auction offer information is used to assess the cost-effectiveness of demand response, but the IESO is aware that there are some challenges with this approach: offers made historically are based on the capacity product at the time, and the available supply of demand response and target capacity levels may change. As markets mature, information about the feasibility of demand response for local needs will improve and help inform the overall options analysis.

5.4 Generation and Energy Storage

Once built, traditional wires options and non-energy-limited resources generally increase the load meeting capability across all hours in the remainder of the IRRP forecast horizon. Therefore, these options are sized based on the capacity requirements alone. However, the technology type and sizing of generation and energy storage options must be determined by the characteristics of the need and the energy-not-served profile. Capacity (MW) and energy (MWh) requirements also evolve as demand grows over the IRRP planning horizon, and influence the feasibility and economics of generation and storage options. For these reasons (as mentioned previously in Section 5.1), the IRRP can consider integrated options that are deployed in stages.

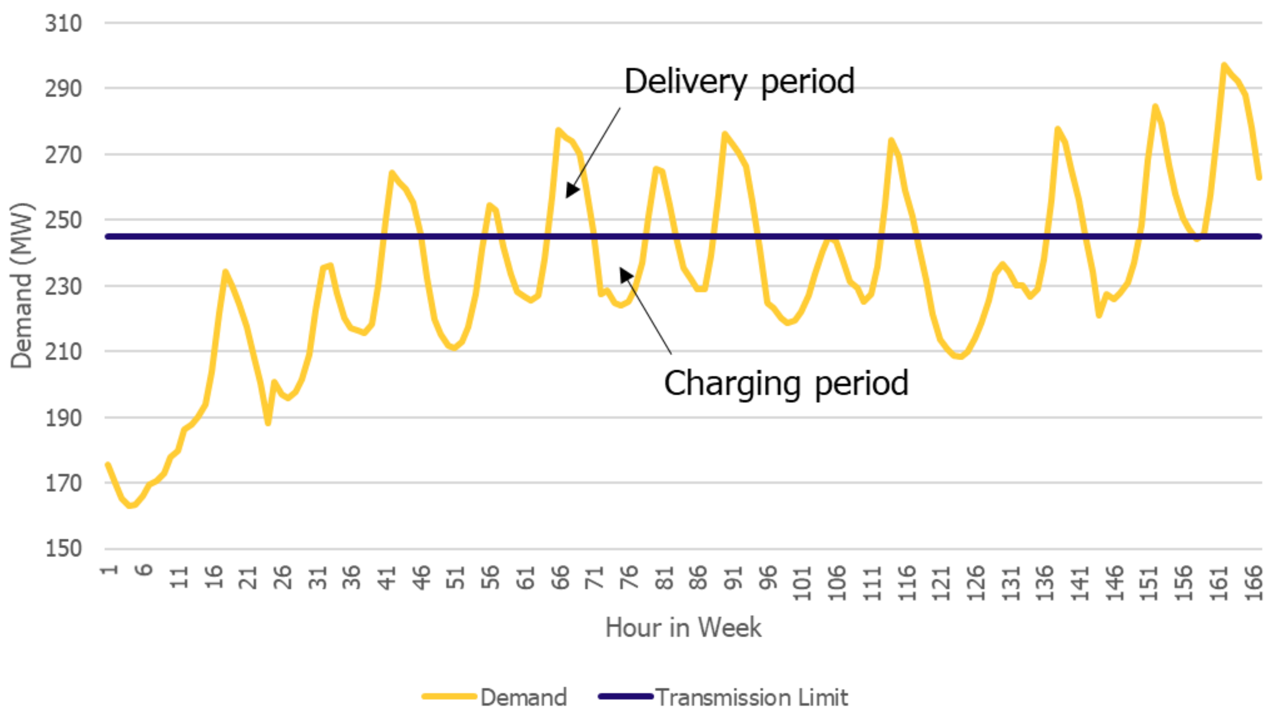
5.4.1 Generation

The IESO undertakes a number of steps using tools, data, and professional judgement to identify generation options. Potential new generation options can include non-emitting resources (such as solar, wind, hydroelectric, nuclear) and emitting resources (such as natural gas combustion turbines). Identifying new generation options involves a comprehensive assessment of the available technologies, geography, and fuel availability profile (especially for solar, wind, and hydroelectric) while also considering the unique characteristics and requirements of the need. For example, a simple cycle gas turbine or battery energy storage systems ("BESS") may be required as a peaking resource for a temporary peak capacity need, while a baseload resource may be required for a sustained capacity need.

5.4.2 Energy Storage

Currently, BESS are assumed for the energy storage option in IRRPs due to their cost-effectiveness and commercial availability compared to other forms of storage. BESS options are sized according to the energy-not-served profiles, albeit with additional considerations than when sizing the generation options. This is described with the help of Figure 9.

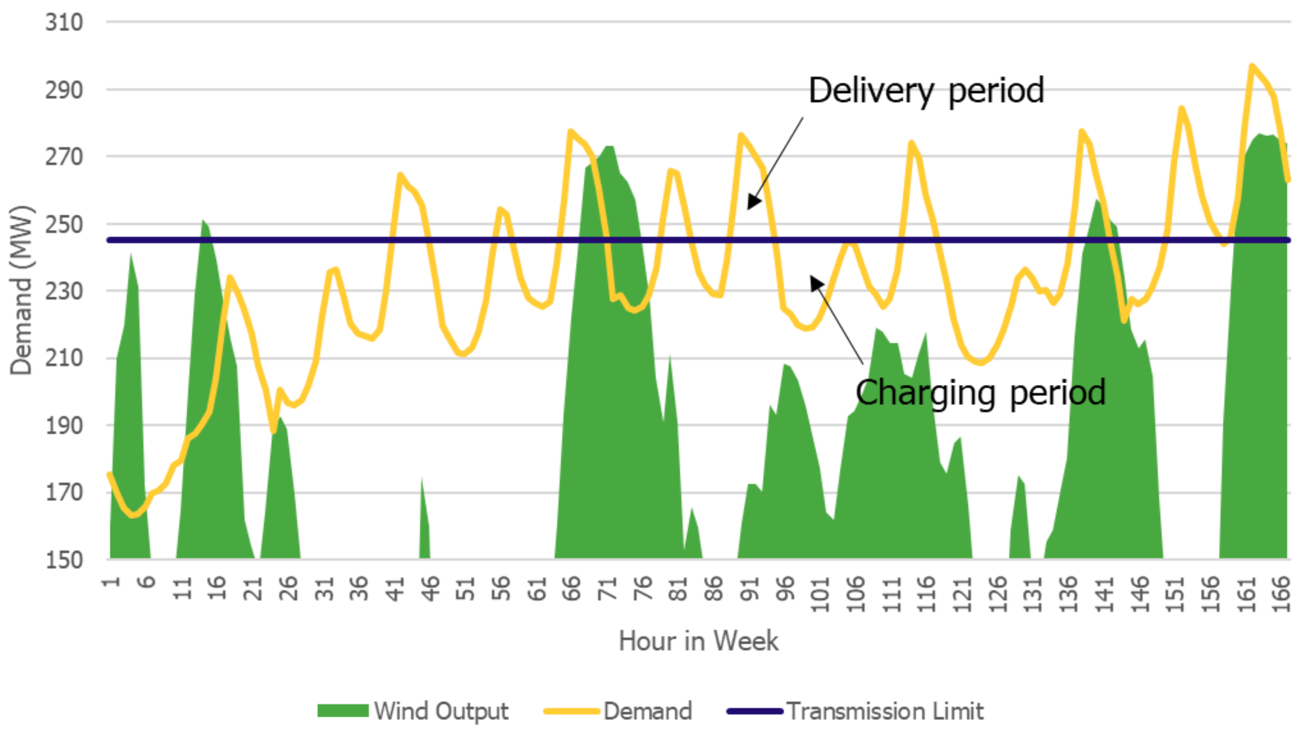
Figure 9 | Sample Load Profile Exceeding Transmission Limit



For the example in Figure 9, the BESS option would be sized to "peak shave" the hourly forecast load such that it does not exceeds the transmission limit. The area below the transmission limit but above the demand line represents the amount of energy that the BESS could theoretically charge, while the area above the transmission limit but below the demand line is the amount (and timing) of energy that needs to be delivered to meet the local need. The BESS option's reservoir must be sized to be able to store enough energy (MWh) and inject it the next day, with enough power capacity (MW) to meet the need at its peak.

The IRRP applies a similar approach for storage options paired with intermittent generation such as wind or solar. In the example shown in Figure 10, there is not enough transmission capacity to allow the BESS to charge from the grid even during low demand, off-peak hours. Additional energy – such as from a wind resource – could be required and paired with the BESS. In this scenario, some of the wind energy output happens to be produced when it is needed, but the facility must be sized such that it can store excess wind output when it is not coincident with the need hours and deliver it when required. The model used in IRRPs finds the least-cost combination of variable generation and storage that can satisfy the local needs.

Figure 10 | Sample Load Profile Exceeding Transmission Limit, With Wind Generation



Local energy storage solutions developed in this manner are very sensitive to the shape of both the energy-not-served profile and the variable generation forecast. When and how much energy is available, as well as when it is required for the need, greatly impacts the size and economics of the BESS option. The current methodology described above is still considered a deterministic approach; each IRRP considers forecast uncertainty and stakeholder feedback before finalizing a recommendation. Moving forward, work is being done to improve the methodology, including characterizing the forecast uncertainties and performing a Monte Carlo simulation to generate a distribution of optimal sizing outcomes. This will allow planners to set reliability criteria for these types of "transmission infrastructure" resources. For example, a reliability criterion might be that for a resource option to be viable, it must be able to support 95% of expected future forecast profiles.

6. Economic Analysis

6.1 Overview

After NWAs are sized to address the IRRP need, they are evaluated for their cost-effectiveness on an equivalent reliability basis. In other words, costs are compared based on each need (size and timing) and the level of reliability or performance expected of the option. In some cases, other qualitative attributes (such as the option's quick start ability, fast ramp rates, flexibility in operation, dispatch ability, etc) are considered as well. Ultimately, the option (wires or non-wires) with the lowest net present value ("NPV") of annual net consumer costs is usually selected as the preferred recommendation in IRRPs.

A discounted cash flow model is created to find the NPV of expected future cash flows of the option's cost and system benefits. Future cash flows are discounted at a rate that reflects the time-value of money and the inherent risk associated with future uncertainty. The IRRP evaluations assume a real Social Discount Rate of 4%, which reflects an estimate of the time value of infrastructure investments on a broad societal level. The discounted cash flow model is made for each option, which (at a minimum) considers:

- The cost of the option (levelized unit energy and/or capacity cost) amortized across its lifetime; and
- The bulk system energy and capacity benefits.

For the wires options, capital cost estimates are provided by the IRRP Technical Working Group. During the financial analysis, the IESO also accounts for the cost of system resources delivered with the wires options.

Levelized unit energy costs represent the average price ($/MWh) that an electricity generator or storage facility must receive for each unit of energy it generates over its lifetime to break even. It includes factors such as overnight capital costs, fixed operation, maintenance, and administration ("OM&A") costs, variable OM&A costs, fuel management fees, etc. Table 3 summarizes some of these factors.

Table 3 | Variables Considered in the IRRP Economic Analysis

Year	Description
Project life	The time horizon over which cash flows will be considered and the project costs will be amortized.
Overnight capital cost	The cost of constructing a project as if it could be performed the same day (this does not include the interest incurred from borrowed funds during the construction period).
Fixed OM&A	The operational, maintenance and administration costs which do not depend on production.

Year	Description
Variable OM&A	The operational, maintenance and administration costs which depend on production.

Options can also be compared according to levelized capacity costs (either $/MW-year, $/MW-month, or $/MW-day). The value of capacity is driven by the type of need and the suite of alternative resources available with appropriate characteristics. This suite of resources can also be impacted by technology readiness and applicable policy. Based on historical capacity costs and forecast supply conditions, the estimated Net Cost of New Entry ("Net CONE") of the anticipated lowest cost marginal resource in Ontario that would be developed when new generation is required is determined. Without further policy direction from the government, a range of system capacity values is considered. If considering emitting resources, the system value of capacity is assumed to be the Net CONE of a gas combustion turbine plant. Alternatively, the Net CONE of a BESS is a good indicator of capacity costs that may be seen in the mid-to long-term given future policy decisions and customer choice of non-emitting resources.

In general, the capacity value and discount rate assumptions have the greatest impact on the IRRP financial analysis and may evolve going forward. This is due to evolving policy, and the last decade's low inflation rates/cost of capital associated with these asset types. As capacity markets mature, information about locational capacity and energy values will also improve and help inform the IRRP options analysis. In the interim, key inputs like locational capacity and energy values can be varied in IRRPs to better understand if or how preferred solutions could change under a reasonable range of assumptions. Stakeholder feedback during IRRP engagement activities can help inform and influence these assumptions and sensitivity tests.

6.2 Typical Assumptions

The following is a list of the typical assumptions currently made in the IRRP economic analysis:

- The NPV of the cash flows is expressed in CAD of the IRRP study year.
- The USD/CAD exchange rate is assumed to be the current rate for the study period.
- Natural gas price forecast is the current Sproule Price Outlook (Dawn).
- The NPV analysis is conducted using a 4% real Social Discount Rate.
- The long-run assumption for inflation is 2%.
- The size of the resource option is determined by a deterministic capacity assessment.
- System capacity value is $144 k/MW-yr based on an estimate for the Cost of the Marginal New Resource, a new simple cycle gas turbine in Ontario.
- Carbon pricing assumptions are based on the proposed federal carbon price increase of a carbon price that escalates to $170/tCO2e by 2030. Thereafter, the $170/tCO2e assumption is held constant in real dollars for the forecast period. The benchmark (tCO2e/GWh) for new gas facilities is assumed to be eliminated by 2030.

- The assessment is performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.

7. Conclusion and Next Steps

Evolving the Guide

This guide describes the current approach to assessing NWAs in IRRPs – the key activities and their objectives, and how they all fit into the overall existing IRRP development process. The guide presents the process flow diagram, screening mechanism, hourly needs characterization, development of options, and economic evaluation methodology to select preferred solutions.

As the sector evolves, the IESO will update the approach to non-wires analyses and revise this guide as necessary - the next update is anticipated for Q4 2024. Factors that influence the current methodology and IRRP development process include (but are not limited to): policy direction, stakeholder feedback, regulatory consultations (such as the Ontario Energy Board's Framework for Energy Innovation initiative), changes in planning criteria, or new technologies. Besides directly participating in regional planning, stakeholders can refer to the IESO's Distributed Energy Resource Roadmap to keep apprised of the latest developments.

Implementation of NWAs

This guide is the culmination of work undertaken by the IESO to better consider NWAs in IRRPs; it is part of a broader set of projects defined in the Distributed Energy Resource Roadmap:

- Non-wires regional planning process improvements: to refine the approach to identifying opportunities for cost-effective distributed energy resources and CDM to defer traditional transmission solutions.
- Non-wires options development: to develop NWAs in sufficient detail to assess economic viability and operationalize IRRP recommendations.
- Procurement mechanisms for NWAs: to consider how procure and implement cost effective non-wires solutions.

Implementation of NWAs occurs downstream of the IRRP. During the planning stage, the focus is on creating a forecast, identifying needs, developing and recommending options, and engaging stakeholders. When new investments like transmission reinforcements are recommended during regional planning, they must go through development processes such as an Environmental Assessment, detailed siting and routing evaluations, detailed facility design, or Ontario Energy Board regulatory approvals such as a Leave to Construct or rate filing. Between planning and real-time operation, investment decisions are subject to further studies, connection processes, verification, permitting, and construction.

While the transmission implementation process is better understood, implementation of NWAs depends on the outcomes of other ongoing initiatives pertaining to distributed energy resource ownership, market design, procurement mechanisms, and the transmission-distribution system interface. Existing procurement mechanisms (such as the Local Initiative Program or the Ontario Energy Board's Conservation and Demand Management Guides) are leveraged where possible for regions where the Technical Working Group recommends a non-wires solution. In 2023 and beyond, the IESO will evolve the IRRP options development approach according to any changes to regulation and implementation mechanisms for non-wires solutions. For instance, financial assumptions used during the IRRP can be refined based on price discovery/market sounding activities and reflect market mechanisms and the ability to stack benefits. New tools may be required to model system and production costs. Cost-effective NWAs that meet local needs will continue to be identified and signaled through IRRPs even if there are any downstream implementation challenges.

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