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July 22, 2021

BY EMAIL

Dear stakeholders,

Re: IESO's Transmission Planning Guideline – Consideration of Losses in the Transmission Planning Process

The IESO has produced an internal transmission planning guideline for the consideration of losses as a result of stakeholder feedback received as part the IESO's Transmission Losses Stakeholder Engagement.[1] The internal guideline was produced to clearly outline and document how the existing transmission planning process, within the IESO's scope, considers transmission losses and is being shared with stakeholders as part of this engagement.

The guideline and feedback form are posted to the Transmission Losses engagement page. **Please provide feedback by August 13, 2021 to engagement@ieso.ca.** Please use subject: *Feedback: Transmission Losses.*

The guideline provides further detail on the activities outlined in the IESO's stakeholder engagement, namely how losses are considered and impact the option development and evaluation stages of the transmission planning process.

This guideline also includes an appendix which describes the IESO's process for detailed loss evaluations, along with a past example.

In compiling this internal guideline, which is a reflection of the work carried out today, the IESO has identified potential areas where the existing process can be refined to improve consistency:

- Development of a decision making aid to more consistently inform if losses are a material consideration to be incorporated for a given plan.
- Inclusion of consideration of transmission losses as a specific topic in internal training days within Power System Planning.
- Refining guidance on the use of available marginal costs and capacity values for determination of future loss savings.

Given the activities in the guideline were outlined in previous stakeholder engagement sessions, an engagement meeting will not be held to review the document, however, the IESO is open to meeting with stakeholders on an individual basis to discuss their specific feedback as needed. The IESO looks forward to further discussion with stakeholders on these items and other feedback that may be received upon further review of the guideline. As an outcome of this process, the IESO will revise this internal guideline document to capture any accepted recommendations.

Yours truly,

IESO Engagement

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[1] As part of the IESO's 2018 Expenditures, Revenue Requirement, and Fees submission (EB-2018-0143) the IESO agreed to engage with stakeholders regarding the IESO's transmission losses work to explore cost effective opportunities for line loss reduction with Hydro One.

Transmission Planning Guideline

Consideration of Losses in the Transmission Planning Process

July 22, 2021

DRAFT

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1. Purpose and Scope

This is a guideline developed for IESO planners to provide a reference for the consideration of transmission losses when carrying out activities within the bulk or regional transmission planning processes. Due to the varied nature of the transmission system across the province, engineering judgment should always be exercised when approaching unique challenges that may arise in the planning process. This guideline serves as documentation of current practices to guide and ensure consistency in the individual planner's approach.

The planning process provides an opportunity to influence the energy losses associated with operating the transmission system, by carrying out key decisions on voltage level, high-level routing, and capabilities of both new and refurbished assets required to maintain system reliablity. These decisions can, collectively or individually, have an impact on overall system efficiency and should be prudently evaluated where material to identifying the most cost-effective system investments.

2. Overview of Technical and Economic Considerations in Transmission Planning

The transmission planning process generally consists of five activities: load forecasting, identification of reliablity issues and/or opportunties to reduce rate-payer costs, option development, option evaluation, and recommendations. This section will outline how losses are considered in each of these five activities.

Depending on whether regional or bulk planning is being conducted, our role as the IESO in carrying out the stages of the planning process may differ (e.g., for regional planning the LDCs develop the gross load forecasts whereas for bulk planning often provincial or zonal forecasts developed by the IESO are utilized). As well, the planning processes involve LDCs and transmitters to differing extents in the options development and evaluation stage depending on the nature of the need and impacted parties (e.g., who is triggering the need, who pays, whether there is a need for coordinated planning/IRRP).

Load Forecast:

The load forecast is one of the primary drivers for establishing power system needs. For the purpose of evaluating the reliability of the electric power system, generally a forecast pertains to provincial, zonal or regional coincident peak demand. Coincident peak demand is the demand observed at the transformer stations for the hour of the year when overall demand in the study area is at its highest and represents the time period when local transmission and distribution equipment is expected to be the most stressed, and system resources the most constrained. This differs from a non-coincident peak, which is measured by summing each station's individual peak, regardless of whether the stations' peaks occur at different times – which is valuable when determining if a station is adequately sized.

Losses also represent a portion of the overall demand on the system met by supply resources. Provincial or zonal forecasts typically include the associated transmission losses, while a regional planning forecast is typically produced at the transformer station level, since it is developed with the local distribution companies, and would not include transmission losses. Planners should ensure that a forecast is properly incorporated into technical analysis tools (i.e. PSS/E) to ensure the impact of transmission losses is appropriately accounted for/not double counted.

Identification of Reliability Issues and Opportunities

Identification of power system issues/opportunties is supported through technical studies that determine the ability of the local power system to reliably meet forecast electrical demand for the area. The primary method is by simulating expected power flows on transmission assets within the study area with all transmission elements in-service, and by subsequently testing the impact following the loss of transmission elements. This is referred to as a "contingency-based" reliability assessment. Voltage level adequacy is also tested to ensure pre- and post-contingency voltages remain within an acceptable range. In some circumstances, congestion based assessments may also be carried out using an energy simulation.

In general, simulated system performance is measured against the established planning criteria used across North America (NPCC and NERC) and within Ontario (ORTAC). Power system facilities which limit the ability of the power system to deliver reliable service, or are forecast to no longer comply with the planning criteria, are identified through these technical studies.

Both the bulk and regional planning processes also incorporate issues/opportunities related to end-of-life equipment replacement, resource adequacy, and, as appropriate, implementing government policy. Generally, mitigation of transmission losses is not identified as an issue/opportunity on its own, but often represents an additional benefit of potential options to address other identified issues/opportunities.

Once an issue/opportunity has been identified, additional characteristics are documented where possible in order to ensure a solution can be developed to appropriately address it. These include timing, risk, magnitude, drivers, profile and duration, impacted area, and response to planned future system changes.

Option Development:

A broad list of possible solutions to address the issues/opportunities is developed. As part of an integrated planning exercise, these solutions may include:

- New energy efficiency measures, incremental to those developed to achieve provincial targets. This can include demand-side management, energy efficiency options, demand response, and energy storage;
- Generation resources, including utility scale generators and/or small-scale distributed energy resources (DERs) located within the regional planning study area. DERs may include combined heat and power, renewable generation (with or without storage), district energy and/or microgrid options;
- Transmission and distribution options that increase the capacity to deliver energy from the provincial grid into the community.

Each of these three types of options have different cost, technical, and environmental characteristics, all of which need to be considered separately and in combination to address the different types of customer issues and community priorities.

Most energy efficiency programs have traditionally been designed to meet energy targets (measured over an entire year). Electricity system issues, on the other hand, are usually occur on peak demand (single highest observation of hourly demand in a year). As a result, in order to reduce, defer, or otherwise address these issues, energy efficiency programs must have an impact during the hour of peak demand. Programs which are designed to address local issues will therefore go through extra screening to estimate this potential peak benefit, as opposed to raw energy savings. Conservation savings are also associated with loss reductions on both the transmission and distribution system.

Generation resources can refer to either large transmission-connected facilities, or small-scale distribution-connected DER options. Generation options reduce the amount of power which must be transferred via the grid into the local area and therefore can also potentially reduce transmission and/or distribution losses. For both transmission and distribution-connected resources, they must be able to predictably operate during peak demand periods to be of value in addressing issues. In the case of non dispatchable resources, such as solar PV, a capacity factor needs to be assigned to represent the likely peak contribution, or the facility can be combined with a storage project or other initiative to ensure the energy is available when needed. When designing a generation based solution, consideration must also be given to the overall provincial generation mix and system resource needs.

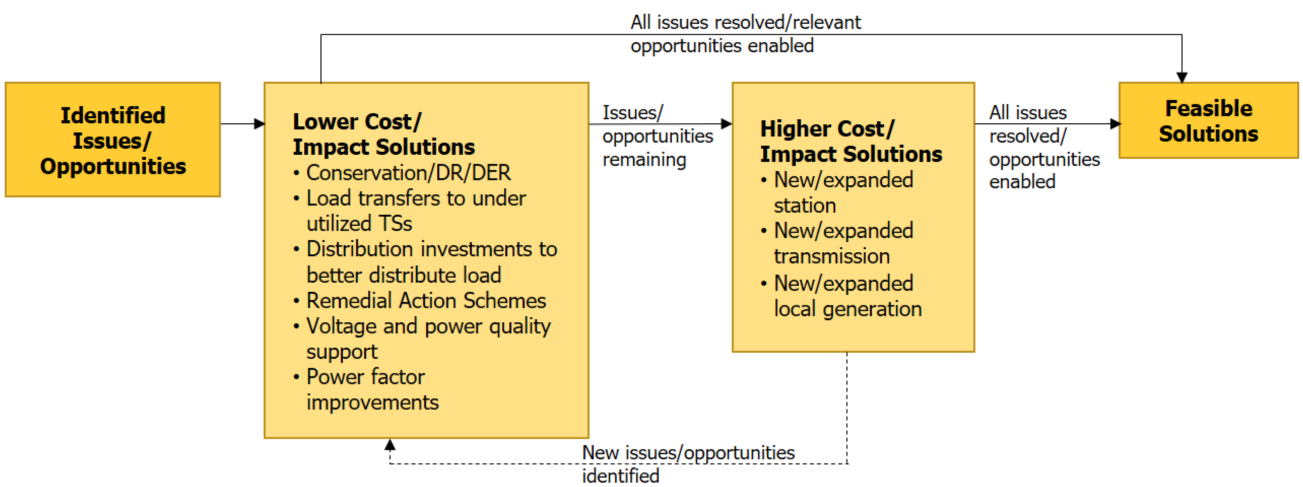
Transmission and/or distribution solutions are composed of new or upgraded system assets, including high voltage lines, stations, and related distribution equipment. These solutions are often characterized by high upfront capital costs, but provide high reliability over the lifetime of the asset. These solutions work well when the overall capacity of an area must be increased to address a rapidly growing customer base (which ensures the full cost of investments can be recouped within a reasonable time period). They are also effective when large electrical demand materializes in areas distant from the existing transmission grid. In some cases, adding new wires infrastructure can also improve the overall economics of operating the electricity system by lowering the cost of congestion, and/or lowering system losses.

Congestion refers to situations where economic generation cannot be dispatched due to transmission capacity limitations resulting in more expensive generation being dispatched elsewhere in the grid. A transmission solution which removes these capacity limitations can potentially reduce congestion, and its related costs, by allowing less costly generation to be dispatched with greater regularity.

Losses are another factor that increases the cost of operating the system. Losses are defined as the difference between the amount of energy inserted into the electricity system and the amount withdrawn by customers. While transmitting electricity along transmission and distribution facilities will always produce some losses (mostly through dissipating heat), the amount can be decreased by creating more redundant paths, and/or reducing the distances travelled at lower voltages.

Options need to be tailored to specific needs. The flow chart below demonstrates the typical order of considering options.

Figure 1 | Generalized Option Development Process



Option Evaluation:

In general, potential options which are known to satisfy key technical requirements and have the lowest cost (economic or societal) tend to be screened for suitability first. When these measures are inadequate, consideration is given to progressively more costly solutions. As potential solutions (specific options or combinations of options) are considered, analysis is required to determine whether all needs are satisfied. Where one solution does not fully meet address all identified issues/opportunities, it could become bundled with other measures to create a portfolio of solution options. The total number of solution options will vary from one study to the next. Where simple, low cost solutions are available, there will generally be no need to pursue higher cost options, and the available list will be shorter.

For areas with higher growth rates (generally defined as >1% /year), incrementally small solutions may not be capable of addressing issues in the longer term. At best, they may be able to defer the issues by a few years. This is especially true in regions where there is significant expansion of new "greenfield" development and where there is minimal to no existing or legacy transmission and distribution infrastructure. In these cases, the cost of implementing the short term solution should be weighed against the value of deferring the more costly alternative, to see if there is value. This type of "staged" solution approach also offers flexibility, since there is more time to respond to changing conditions or assumptions before committing to a long term solution. Lead times for the long-term solution should be a factor in the overall development of the plan. For transmission options with long lead times, development work may be initiated in parallel with short term solutions.

Once a series of feasible solutions have been developed, they are evaluated to produce a range of measures which can be used by the applicable technical working group and stakeholders to assist in identifying a preferred solution. Factors which must be included are cost, technical feasibility, and timelines for implementation. Other factors may include, but are not limited to:

- Environmental impact
- Community preferences
- Additional benefits (performance beyond stated criteria, flexibility, impact on losses, system efficiency/congestion mitigation benefits)
- Other attributes deemed important given the context of the local community (i.e., official plans, zoning bylaws, CEPs, local emissions targets, preference for local resources, etc.)

Recommendations:

The preferred solution is identified by the IESO or the regional planning technical working group (depending on the planning process being applied) with input from the engagement process. The factors and measures prepared when developing options are the main criteria used to identify a preferred solution.

Depending on the need and options available, selecting a preferred solution can either be a straight forward task, or require a significant amount of engagement and the application of multi-criteria analysis. Cost, technical feasibility, and timelines for implementation are primary criteria, and the least cost alternative which meets the required needs in the area must be identified.

In addition to the capital and operating costs of a program or wires infrastructure, the cost of the preferred alternative includes any changes in congestion costs, or the cost of losses, where they are expected to be material. Congestion costs are more likely to have an impact where an alternative includes new generation or transmission infrastructure within, or linking to, an area which may experience congestion. Losses are more likely to be material when comparing wires solutions at different voltage levels, such as a transmission solution versus a distribution solution.

Selection of the preferred solution cannot be accomplished without conducting local engagement. Depending on varying goals and priorities, a different solution than the least cost may be preferred by the community or other stakeholders.

Ultimately, it is possible that different groups will prefer a different solution. The final selection of recommended solutions rests with the IESO for an integrated regional resource plan or a bulk system plan, but within the regional planning process dissenting opinions within the technical working group should be recorded and the parties invited to submit their different views and rationale as appendices.

Note that once a preferred solution is identified, it does not guarantee that the solution will be implemented. All normal approval processes will still apply, including Environmental Assessments (EA), Ontario Energy Board approvals (Leave to Construct, Capital Submission within Rate Applications, etc.), Connection Impact Assessment (CIAs), and System Impact Assessments (SIA), as required.

3. Consideration of Losses in Option Development

Engineering expertise is used to determine technically feasible and efficient options. Further to what is outlined in section 2, additional detail on the consideration of losses in identifying types of options and how options are developed is provided in this section.

Throughout the options development process, best practices inherently result in considering options that will lower losses. Generally close attention should be paid to voltage level, and intial siting/routing considerations (e.g., line start and end points, existing station locations/known available land, upgrades to existing lines/rights-of-way), which can have the largest impact. Generally, the following considerations in options development can lead to ensuring options brought forth to the evaluation stage will include solutions which offer the best loss reduction opportunities:

- **Preference for higher voltage levels and less transformational steps:** Where economically available, supply at 230 kV vs 115 kV for new or refurbished stations should be explored as this would offer transmission loss reduction benefits in addition to providing a more robust supply point and decreasing (or negating the need for futher) upstream transformation requirements.
- **Preference for parallel lines and use of existing rights-of-way:** From a siting and land-use perspective, there is a strong preference for using existing infrastructure rights-of-way where available when planning system expansions. There are also frequently opportunities to reinforce existing transmission lines, through upsizing conductors, creation of supercircuits, or creation of multi-circuit lines. While these options have advantages from a land-use and/or cost-effectiveness perspective, they also create parallel paths which decrease the impedence of the existing system and generally offer loss savings even when balanced against an increase in utilization of the system that may have drove the need for expansion in the first place.
- **Preference for shorter routing distances:** Where possible (e.g., aligns with use of existing rights-of-way, no natural or man-made obstacles), the most direct line routing is preferred where it would result in overall savings on project capital cost. A shorter routing distance also results in lower losses vs an alternative routing, but would not be a significant factor in deciding between routes between the same supply points.[1]
- **Inclusion of local generation options in evaluation of options:** Local generation solutions may result in lower losses during hours the generator is operating, versus a transmission solution that relies on supply from resources a large distance from the studied load.

[1] At this stage in the planning process routing is only considered at a high-level (i.e., start and end point, identification of existing rights-of-way); routing will be finalized by the transmitter in the environmental assessment process.

- **Inclusion of conservation and other demand side options in evaluation of options**: Since conservation (energy efficiency) respresents a decrease in load, this results in a decrease in losses (on both the distribution and transmission system). Consideration of demand side options, such as distributed generation, becomes a bit more complex since dependant on their siting and use, they may result in an overall increase in distribution losses, which may counteract any savings in transmission losses achieved by decreasing net load at the transformer station level.

Where the loss savings associated with any one option may be signifcant relevant to overall project costs this benefit would be quantified in the options evaluation stage.

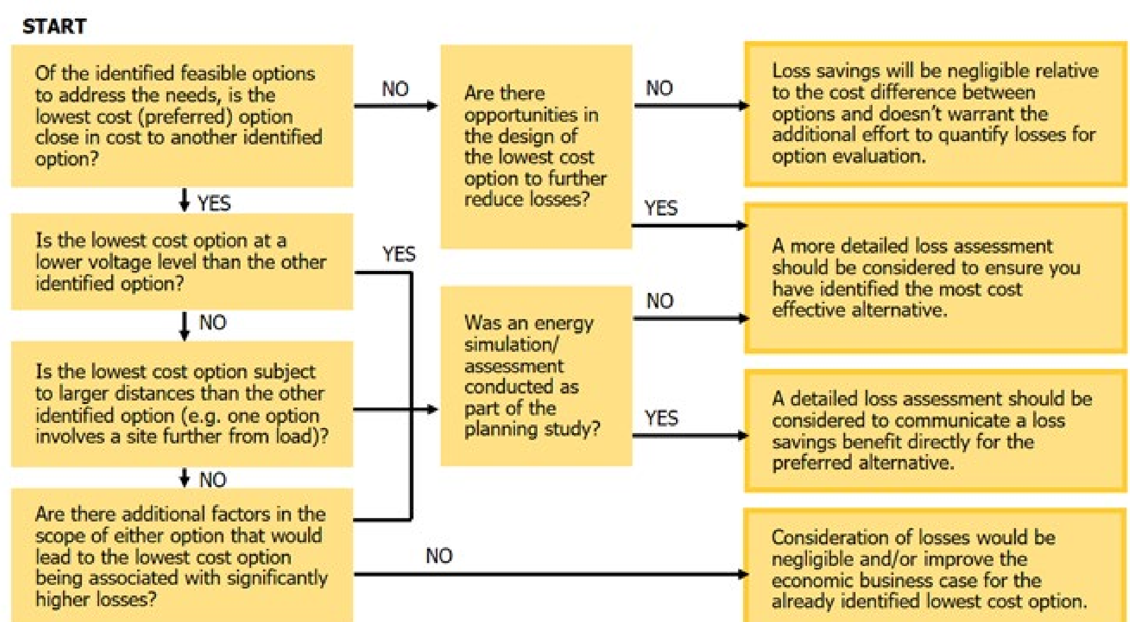
4. Consideration of Losses in Option Evaluation

Typically, the benefits of reducing losses is captured when evaluating the costs of the different options. For example, as part of evaluating the cost of each option the energy production costs are determined, which would include the costs of supplying losses. However, a detailed loss assessment may be warranted under certain circumstances:

- Within the scope of the chosen option, certain design decisions could lead to lower losses (e.g., using a large conductor).
- Distribution losses are not typically assessed when evaulating options. In some cases, distribution losses could materially change depending on the option selected and, so, if the costs of the options are close, there may be value in quantifying the distribution losses.
- Typically, the cost comparison includes relative energy production costs, which would include the impact of losses. However, if one was not carried out, then a detemination should be made if the losses under each option should be explicity quantified.
- Even when energy simulation analysis is available, there may be a desire or benefit to breakout the loss savings component to communicate this seperately (e.g., to quantify a loss savings benefit as part of a Leave to Construct proceeding).

An illustrative guide for determining when it may be warranted to undertake further detailed loss assessments, beyong what is captured in any previously performed energy production cost simulations, is provided in Figure 2. Determination of whether a detailed loss study is required should be done after feasible options for addressing the reliability need have been identified, planning level cost estimates for capital costs have been determined, and any required energy production cost modelling has been completed.

Figure 2 | Determining if a detailed loss study should be considered



When it has been determined that it is benefical to undertake a detailed loss assessment to aid in the selection of the most cost effective option, the approach should vary based on the solution types being compared. Appendix A outlines a detailed approach for a typical bulk system reinforcement, beyond the general use of an energy simulation to examine system production costs for each alternative being compared (e.g., a new transmission line versus a new local generator). While an energy simulation will capture both system efficiency benefits from congestion mitigation and loss reduction, more detailed loss assessment can be used to highlight additional benefits of the recommended alternative versus the status quo for the purpose of a Leave to Construct.

For more local assessments, accounting for the impact of losses in options evaluation may involve more detailed determination of the transmission losses associated with TS siting and voltage level (where beneficial/material to option evaluation as outlined in Figure 2). Generally the process outlined in Appendix A can be followed when it is required to determine the cost of transmission losses associated with each option in order to identify the preferred alternative or if there is a need to highlight the value of the loss benefit.

Appendix 1 – General Process for Undertaking Detailed Loss Assessment and Example

This appendix outlines a process for undertaking a detailed loss assessment and provides an example case of where this was applied.

When performing a bulk planning assessment, energy simulations are generally performed to obtain the production cost difference for the studied options. By comparing the production costs for each option of interest, the impact of any transmission loss reductions on the cost comparison between evaluated options is captured. However, energy simulations are not performed for all assessments meaning that detailed loss assessments may need to be undertaken.

Detailed loss assessments can be undertaken when competing options are being considered and loss savings can act as a tie-breaker (section 4, Figure 2). They can also be undertaken to quantify loss saving benefits of a given transmission project or upgrade which could be factored in the project's financial planning and cost estimates. Even when energy simulation analysis is available, there may be a desire or benefit to breakout the loss savings component to communicate this seperately (e.g., to quantify a loss savings benefit as part of a Leave to Construct proceeding).

The goal of the detailed loss assessment is to determine the total economic loss savings benefit, this consists of both an economic energy benefit/saving and an economic peak benefit/saving. This assessment can be carried out to compare two different options being evaluated to address system issues, or between the preferred alternative and status quo system, depending on the relative loss savings you are intending to communicate.

To find the hourly energy savings, hourly flows across the transmission line/interface of interest needs to be determined. If an energy simulation was conducted, the hourly flows from the simulation tool should be used. In instances where an energy simulation was not conducted, historical flows can be leveraged, used in conjunction with the most applicable planning forecast for the area (e.g., if analysis is being done as part of a regional plan, use the regional plan's forecast growth rate; if it's a radial line supplying one station use the station's forecast growth rate).

Once the hourly flows are obtained, the next input to be determined is the relationship between flow across the transmission line/interface of interest and resulting losses for each option and/or status quo system, which will be dictated by the impendence of the path in each scenario.

For simple path reinforcements that result in a reduction of conductor impedance/resistance (i.e., doubling up the circuits on a given path), the relative loss savings can be obtained by calculating the difference between the losses resulting from the path impedence/resistance (R) of each option. The hourly flows (I), in amperes, are substituted into the equation to produce an hourly energy savings profile.

$$\Delta P_{loss} = I_{existing}^2 R_{existing} - I_{post\text{-}upgrade}^2 R_{post\text{-}upgrade} \quad (1)$$

For a more complex interface change that involves more than just reinforcing existing circuits along its path (i.e. the addition of new lines), and/or includes transmission equipment such as transformers or reactive devices, a powerflow simulation is performed in order to create loss curves that plot loss as a function of transfer rate for each system status (i.e. existing and post-upgrade).

To create the loss curve, transfer across the interface is increased incrementally in both directions and the aggregate power flow across the two ends of the transmission circuits that make up the interface is recorded for each increment. This transfer increase can be done using traditional methods that utilize the generation dispatch and demand levels, or it can be simplified by using fictitious generators and loads at both ends of the interface. The simplified method is further illustrated in the example below. The difference between the power flow across the two ends is the power loss at the specific transfer level associated with the current increment. The power loss in MW is then plotted as a function of the transfer level at that increment.

The hourly flows across the interface are then mapped against the loss curves created in order to produce hourly loss profiles. The difference between the loss profiles for each system will be the hourly energy savings profile. The sum of the hourly energy savings for the each year will give the annual energy savings.

$$\text{Annual Energy Savings} = \sum \text{hourly Energy Savings} \quad (2)$$

To then calculate the economic energy benefit/saving, the hourly system production marginal costs are multiplied by the hourly energy savings. If an energy simulation was conducted, the marginal costs from the energy simulation should be used. If these are not available, the marginal cost forecast from the APO can be leveraged.

$$\text{Economic Energy Benefit} = \sum \text{hourly production marginal costs x hourly Energy Savings} \quad (3)$$

In addition to the economic energy benefit/saving, there is a potential for additional savings as a result of peak demand reduction. The peak saving is a direct result of power loss savings during peak hours, which theoretically could reduce the system's future generation capacity requirement and/or demand response requirement. This saving can be quatified by a range where the avoided system demand during the peak hour is multiplied by the value of capacity. The capacity value range to utilize could be the short-run value and the long-run value. In the short run, the value of capacity is based on the amount paid for effective capacity in the most recent capacity auction to reflect the current value of capacity. The long-run value of capacity is based on the approximate cost of new entry to reflect the highest exected capacity value.[2] This will result in the economic peak benefit/saving. This exercise can be done for both the winter and summer peaks, as applicable.

The total economic loss savings benefit is the addition of the economic energy benefit/saving and the economic peak benefit/saving.

$$\text{Total Economic Loss Savings Benefit} = \text{Economic Energy Benefit} + \text{Economic Peak Benefit} \quad (4)$$

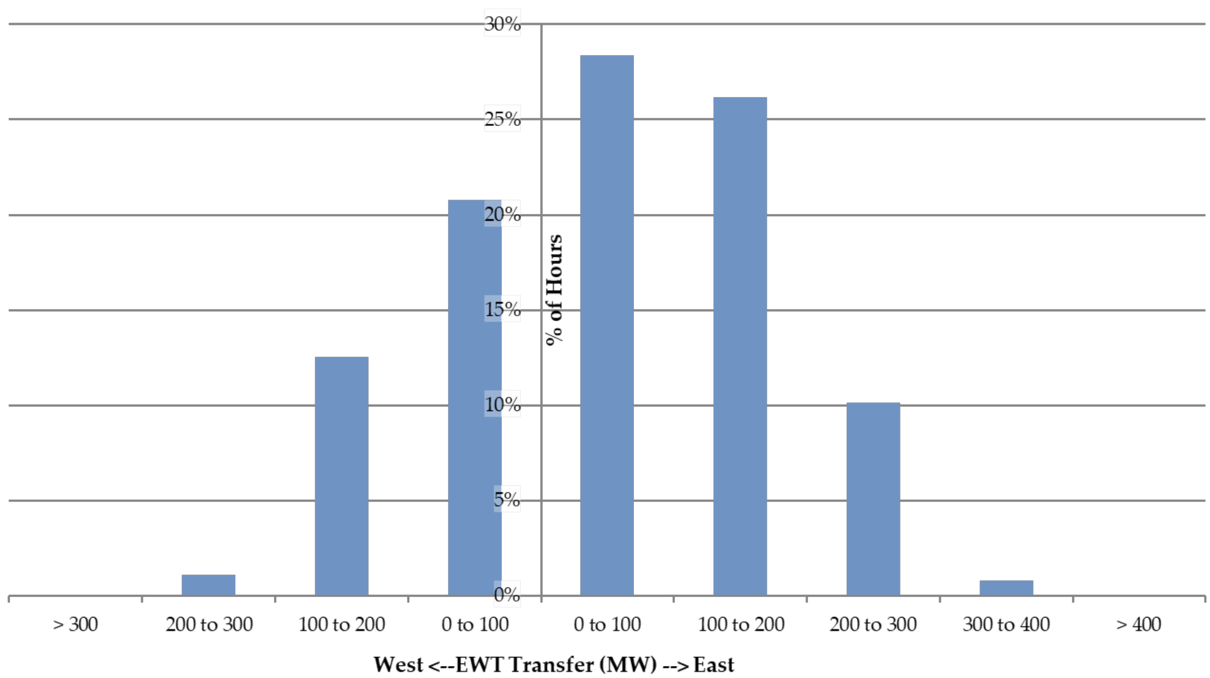
[2] Prior to the establishment of the Capacity Auction, the avoided system demand during the peak hour was multiplied by the demand response auction price to quantify an Economic Peak Benefit/Saving.

Example: East-West Tie (EWT) Expansion – Transmission Loss Reduction

A detailed transmission loss assessment was performed to quantify the loss saving benefits of the East-West Tie (EWT) expansion relative to the status quo, for the purpose of quantifying the loss savings benefit the project provides. The EWT Expansion involves adding a new double-circuit 230 kV line between Lakehead TS and Wawa TS, significantly reducing the impedance along the interface. Transmission losses across the EWT are significantly higher than the Ontario system average (2% system average vs. nearly 5% average along the EWT) and the EWT Expansion is expected to reduce losses along the interface. Therefore, this reduction in losses will result in provincial energy savings and provincial peak savings which will have an economic benefit for Ontario ratepayers.

Energy simulations were performed using UPLAN. It produced hourly flows across the EWT and hourly marginal system production costs for a pre-determined year. Figure A1-1 depicts a histogram of the UPLAN simulation showing the percentage of time the flows across the EWT were at each transfer level.

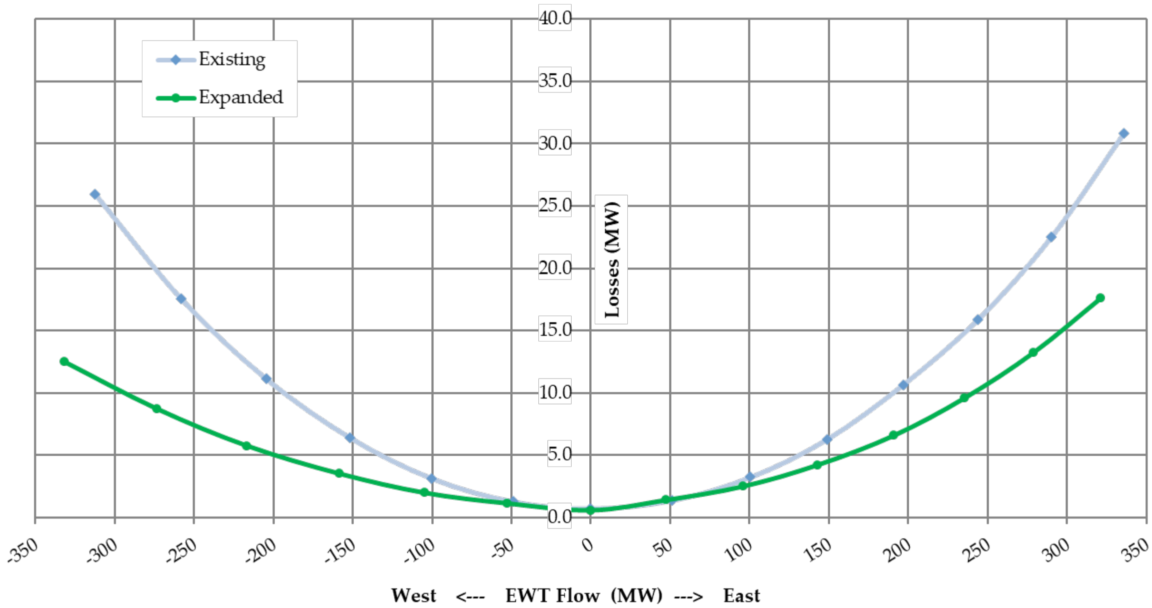
Figure A1-1 | Histogram of UPLAN simulation of hourly EWT transfer results



Afterwards, a loss curve was created by iteratively adjusting the EWT transfer at 50 MW increments. The transfer levels were adjusted using fake generators and loads (outputting active power only) that were placed at Lakehead TS and Wawa TS. For simplicity, loads and generators connected along the monitored corridors were disconnected.

After each iteration the flows and losses for monitored elements are exported to create a loss curve where losses were plotted as a function of the transfer rate as shown in Figure A1-3 below. This exercise was performed on both the existing system and the expanded system.

Figure A1-2 | Losses as a function of total EWT transfer (existing vs. expanded)



Hourly loss profiles for the existing and expanded EWT are calculated by multiplying the hourly EWT transfers, provided by UPLAN, by the corresponding loss curve. Then the difference between the existing and expanded EWT hourly losses is found which resulted in the hourly loss reduction or the hourly energy savings. The annual energy savings is found by summing up the hourly energy savings for the year as shown by equation (2) above. The economic energy benefit is calculated by summing the products of hourly energy savings and hourly marginal costs produced by UPLAN for each hour of the year as shown in equation (3) above.

The summer and winter peak hours of the provincial peak demand of the UPLAN simulation was noted and the loss savings for the particular hours were recorded. The loss savings during the peak hours are capacity benefits as they effectively reduce the amount of capacity required to serve the load during peak hours. In this instance, the demand response auction price was multiplied by the loss savings during peak hours in order to estimate the economic peak benefit (should now apply a range as outlined in the methodology).[3] Afterward equation (4) was used to quantify the total economic loss savings benefit. This total economic loss savings benefit would then be used to communicate the loss savings/benefit associated with the project verus the existing system.

[3] The demand response auction price was used in this instance since it was the best proxy for local capacity value when the analysis was conducted in 2017/2018 (i.e IESO used the DRA clearing price in the relevant zones).

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