NOVEMBER 3, 2022

Northwest Regional Electricity Planning Integrated Regional Resource Plan (IRRP)

Engagement Webinar #4

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Objectives of Today's Webinar

- To provide responses to stakeholder feedback from the Apr 2022 webinar
- To provide an update and seek feedback on:
  - Red Lake area high growth sensitivity findings
  - Draft IRRP recommendations for local reliability and station capacity needs
  - Ring of Fire study
- To outline next steps

Seeking Input

As you listen today, please consider the following items to help guide your feedback after today's webinar:

- What other information or insights should be considered in these recommendations and findings?
- How can the Technical Working Group continue to engage with communities as these recommendations are implemented, or to help prepare for the next planning cycle?

Please submit your written comments by Nov 23rd

using the feedback form by email to engagement@ieso.ca

Recap: IRRP Overview & Activities to Date

IRRP Status

- The IRRP started in Jan 2021 and is scheduled for completion in Jan 2023 (inclusive of a 6-month extension to allow for consideration of additional growth sensitivities and alignment with bulk planning activities)
- Today we will discuss new findings since the April 2022 webinar and the draft IRRP recommendations

Q3 2020	Q4 2020	Q1 2021 ... Q4 2022	Jan 2023
Needs Assessment	Scoping Assessment and Engagement	IRRP Study and Engagement	IRRP Published

Engagement Activities to Date

Event	Purpose
May 2021 Webinar	Provide overview of regional planning process and seek input on electricity demand forecast
Sep 2021 Webinar	Provide overview of and seek input on draft electricity demand forecast, preliminary study results, and updated engagement plan
Nov 2021 Focused Discussion #1	Opportunity for communities to share their customer reliability concerns and learn how their electricity needs are considered in the regional planning process
Nov 2021 Focused Discussion #2	Opportunity for communities to discuss and share their energy plans, climate change goals and/or other local initiatives
Nov 2021 Focused Discussion #3	Deep dive into growth and emerging electricity needs in the North of Dryden area
Apr 2022 Webinar	Provide update on regional electricity system needs and seek feedback on possible solutions; Data tables posted

Summary of Needs Identification & Sensitivity Studies

Needs Identification Results

- The regional Northwest transmission system is generally adequate to support forecast growth
- Three subsystems (Red Lake, Dryden, and Thunder Bay) are forecast to approach but not exceed system capacity in the forecast horizon but no specific actions are required in this IRRP
- Capacity needs identified in the near- to medium-term at Kenora MTS, Margach DS, and Crilly DS

Additional Sensitivities

- The following sensitivities tested the robustness of the regional transmission system to accommodate growth beyond forecast levels:
  - Fort Frances high growth sensitivity
  - Thunder Bay high EV adoption scenario
  - Red Lake/Dryden high growth sensitivity (for discussion today)

Apr 2022 Webinar Stakeholder Feedback

Apr 2022 Stakeholder Feedback

- There were two themes in the feedback from the Apr 2022 IRRP public webinar:
  - Theme 1: Options or local opportunities that should be considered in the options analysis for the Northwest IRRP
  - Theme 2: Comments received about the Northwest Bulk Planning with respect to the Waasigan Transmission Project
- The feedback received and the IESO's responses have been posted on the engagement website

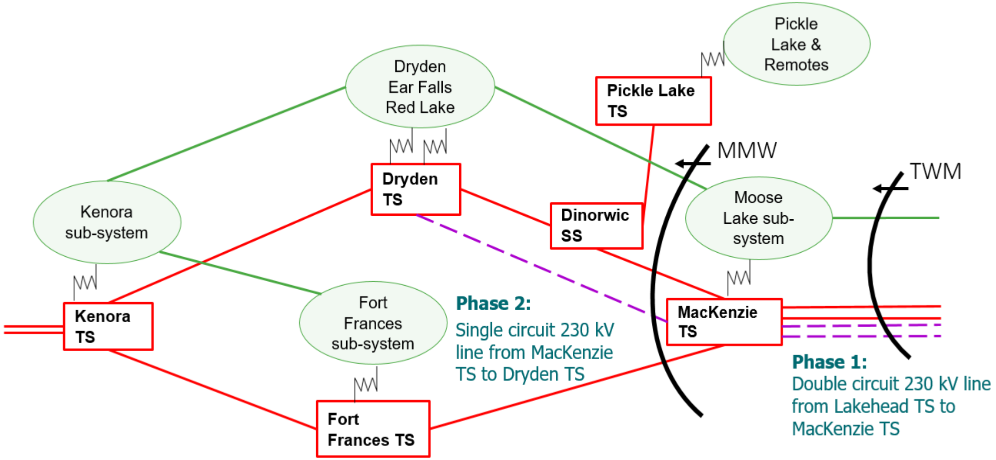
Comments Re: Waasigan Transmission Line Project

- IESO recommended a staged approached for construction where:
  - Hydro One should construct the Project to meet near-term system capacity needs with Phase 1 (new transmission from Thunder Bay to Atikokan) being placed in-service as close to the end of 2025 as possible
  - The IESO will continue to monitor developments in the Region and provide the need date for Phase 2 (new transmission from Atikokan to Dryden)

- Stakeholders and communities expressed concerns that a staged approach to construction would:
  - Limited regional growth and increase uncertainty for industry
  - Increase project costs and implementation risks
  - Complicate engagement with Indigenous communities and their economic participation in the Project

Rationale for Staged Approach (1/2)

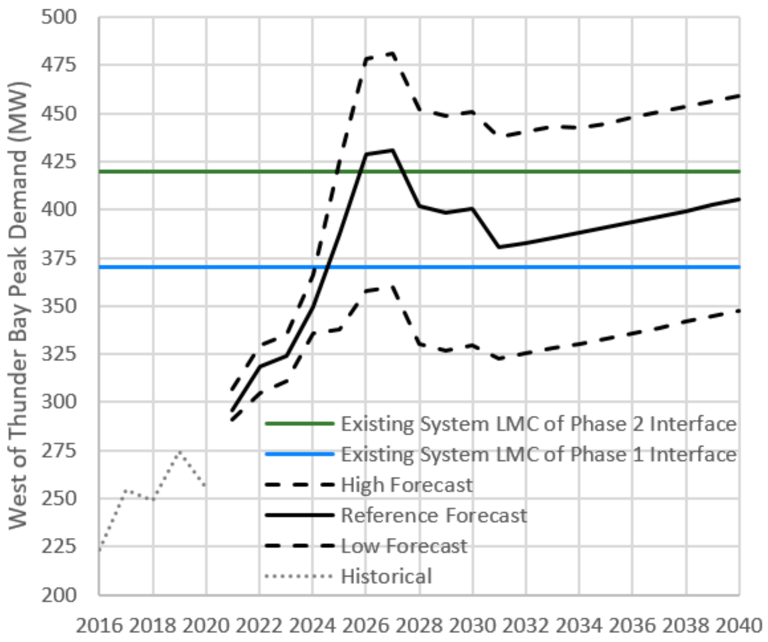
- The IESO's recommendations reflect the characteristics of the supply capacity needs, which are different for Phase 1 and Phase 2
- Phase 1 and 2 reinforce two closely related but distinct interfaces of the existing transmission system



- Based on the application of planning criteria to the existing system configuration, the interface being reinforced by Phase 2 has a higher transfer capability today than that of the interface being reinforced by Phase 1

Rationale for Staged Approach (2/2)

- The demand forecast shows a persistent need for Phase 1 starting in 2025 and a temporary need for Phase 2 in 2026 and 2027 but not thereafter as some existing mining projects reach end of life
- Therefore, it is prudent to proceed with construction for Phase 1 now while closely monitoring growth to determine when Phase 2 will be needed
- This is a balanced approach to accommodate growth in a timely manner while managing ratepayer risks



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Next Steps for Phase 2

- We are aware of many projects with potentially significant electrical demand at early stages of exploration and project development which are currently captured under the high demand forecast scenario
- The IESO recognizes that a firm and persistent need for Phase 2 could materialize quickly given the potential for additional growth in the region
- The IESO continues to support development work for Phase 2
- The IESO is currently in the process of updating the mining demand forecast to:
  - Reflect additional information received over the past year since the last forecast iteration
  - Better capture future growth driven by electrification trends and government policy
- The IESO will provide an update in Q2 2023 on the expected need date for Phase 2

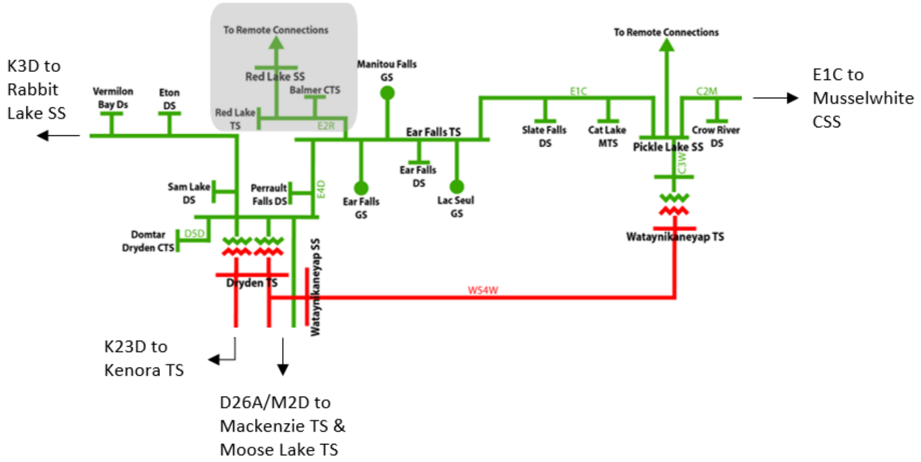
Indigenous Funding Programs

- The IESO is aware of the need for certainty and the impacts that First Nation communities may experience due to the phased approach
- IESO will continue to inform communities in northwest Ontario about regional electricity planning initiatives and invite the communities to participate and provide feedback
- The IESO's Energy Support Programs are available to assist Indigenous communities with building capacity to engage in the electricity sector
  - Details for the 2023 intake period will be updated on the program web pages once available

Red Lake Area High Growth Sensitivity

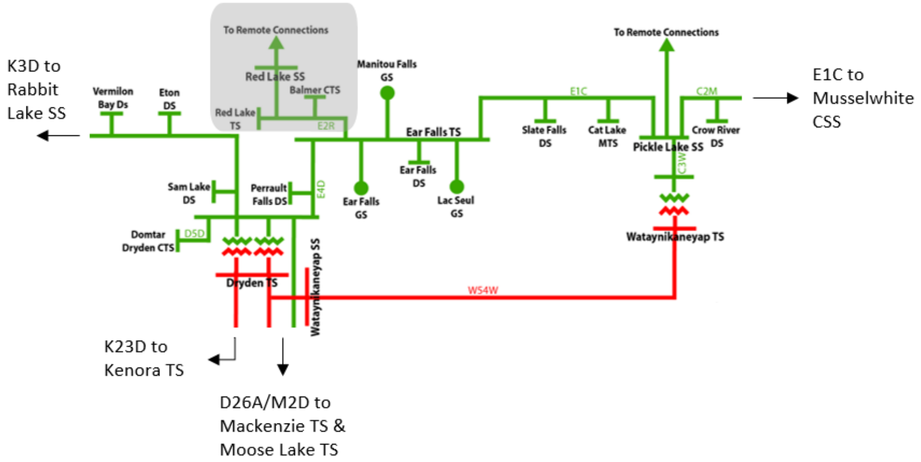
Background

- The Red Lake area has significant mining activity and electrical demand is forecast to grow from ~58 MW today to 70 MW by 2028
- The recently completed 230 kV portion of the Wataynikaneyap ("Watay") Transmission Project will help relieve constraints on the existing 115 kV circuits to Red Lake and no capacity needs are anticipated based on the current demand forecast



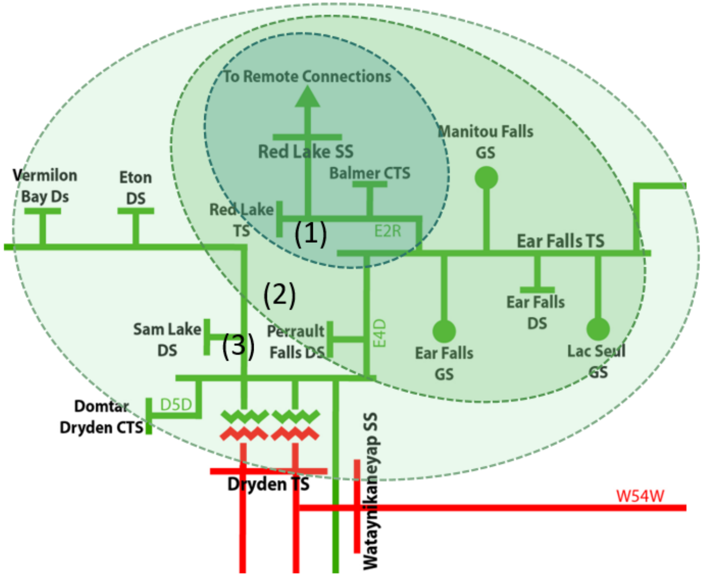
High Growth Sensitivity

- The IRRP performed additional high growth sensitivities beyond forecast demand levels
  - Remaining capacity is relatively tight and new mining developments beyond those already accounted for in the demand forecast may add large incremental blocks of load
- Sensitivity studies can help inform customer decisions and lay the groundwork for future planning activities



Transmission Supply to Red Lake

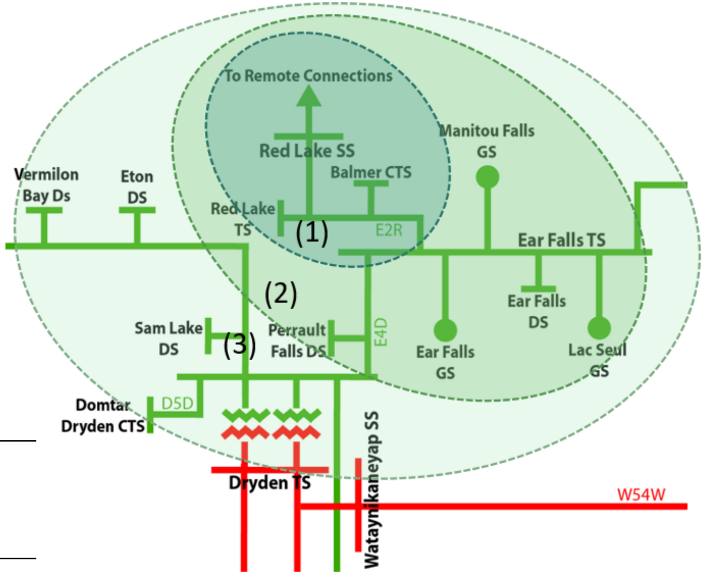
- The Red Lake area is supplied on the 115kV network downstream of Dryden TS
- The load meeting capability (LMC) is a function of three nested local constraints:
  - (1) Supply to Red Lake
  - (2) Supply to Ear Falls
  - (3) Supply to the Dryden subsystem
- Additionally, there are bulk system considerations regarding the 230 kV supply to the West of Thunder Bay and Northwest Region as a whole



Load Meeting Capabilities

- The LMC and limiting phenomenon varies by season for each nested subsystem
- The most limiting LMCs are shown below; further details in Appendix

Subsystem	**LMC**	**2032 Peak Demand Forecast**	**2040 Peak Demand Forecast**
1. Red Lake	74 MW (summer thermal limitation)	61 MW summer peak	67 MW summer peak
2. Ear Falls	92 MW (summer thermal limitation)	62 MW summer peak	68 MW summer peak
3. Dryden	159 MW (winter voltage decline)	127 MW winter peak	140 MW winter peak



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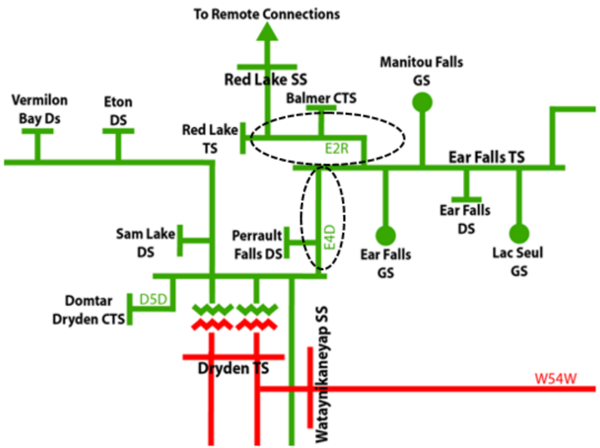
115 kV Reinforcement Options

- LMCs for Red Lake and Ear Falls subsystems can be increased up to ~130 MW with 115 kV reinforcements
- The existing 115 kV E4D/E2R circuits are ~75 years old and refurbishment with higher rated conductors can address thermal limitations
- High-level refurbishment costs for E4D/E2R are $35M and $23M respectively
- Note that refurbishment involves more than replacing conductors; structure heights would need to be increased and provisions would need to be made for alternative power to Red Lake while refurbishment work is underway



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Sensitivity Study Limitations

- The IRRP will not:
  - Make firm commitment for reinforcements; Assessments show that the area is adequate to meet currently forecast demand
  - Study any connection arrangements or requirements for any specific project
  - Decide matters of cost allocation
- Note that all IRRP studies assume that the Watay project is in-service

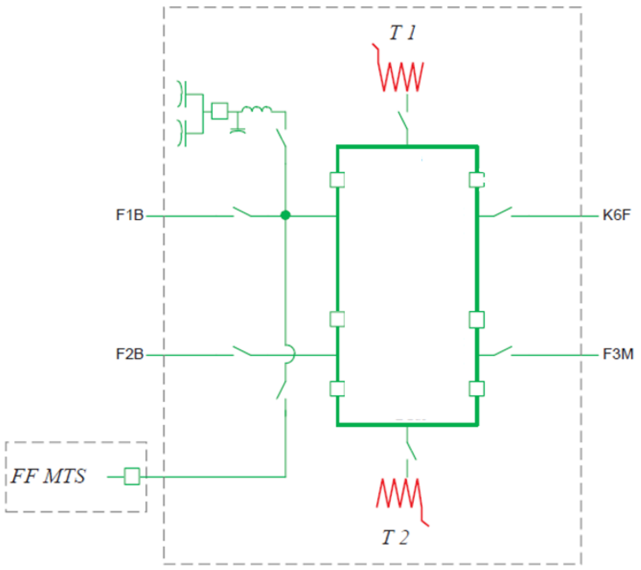
Red Lake Area – Next Steps

- The Red Lake and broader Dryden subsystem is adequate to supply currently forecast demand growth
- No firm recommendations are required at this time but the IESO and regional planning technical working group will continue to engage with potential new customers seeking connection
- The mining forecast will be updated in Q1 2023; growth will be monitored and compared against load meeting capabilities to trigger future planning activities as needed
    - This will also feed into the update on the need for Waasigan Phase 2

Recommendations – Fort Frances Reconfiguration

Fort Frances TS Configuration – Supply to Fort Frances MTS (1/2)

- Fort Frances TS is configured in a manner that would result in Fort Frances MTS supply interruptions during select transmission outages
- Recent customer connection interest at Fort Frances MTS may result in station capacity needs
- Fort Frances Power is developing a roadmap for Fort Frances MTS taking into account replacement of aging assets, load growth, and reliability improvements



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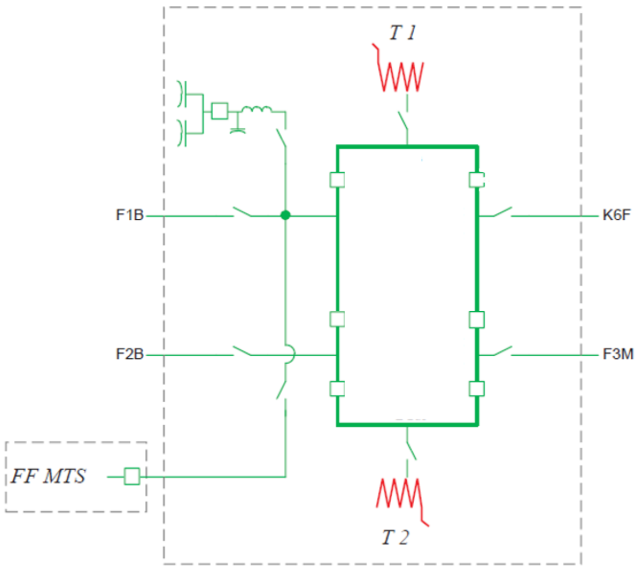
Fort Frances TS Configuration – Supply to Fort Frances MTS (2/2)

- Considering the aging asset sustainment need, potential capacity need, and reconfiguration/customer reliability need simultaneously will ensure the most optimal and cost-effective long-term outcome
- Fort Frances Power and Hydro One Transmission will continue to collaborate on Fort Frances MTS’ connection reconfiguration during the Regional Infrastructure Plan



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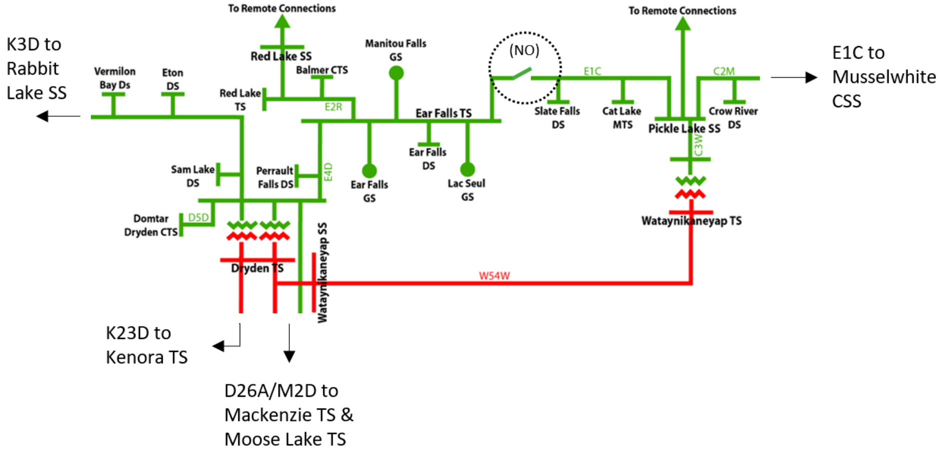
Recommendations – Operation of E1C

E1C Normally-Open Configuration

- The Watay 230 kV circuit W54W was recently put in-service in Aug 2022
- In order to improve transfer limits, the previously existing 115 kV circuit E1C should be operated normally open
  - Operating E1C normally open is consistent with the recommended configuration in the 2015 North of Dryden IRRP
- The Regional Infrastructure Plan will determine the specific open point



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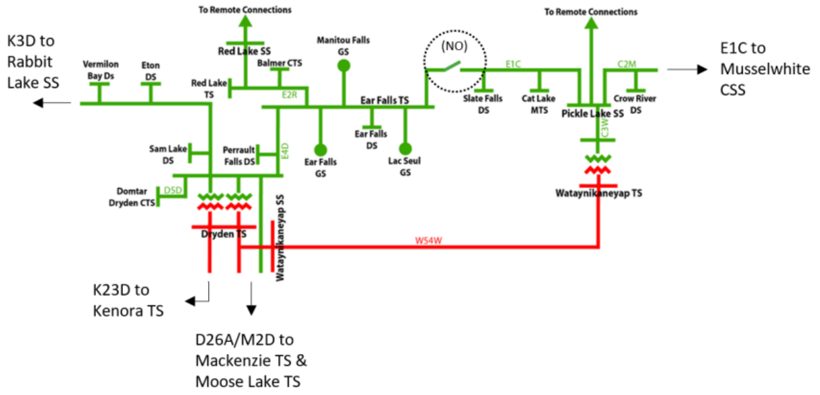
E1C Normally-Open High Voltage Issue

- With E1C normally open, high voltage violations (>127 kV) occur under light load conditions
- High voltage is minimized by opening E1C near the Ear Falls TS end compared to the Pickle Lake SS end
- An additional reactor of approximately 10 MVar at or near Watay TS is required to mitigate high voltage issues following the loss of the existing 20 MVar reactor
- The Regional Infrastructure Plan will refine the reactor sizing depending on asset conditions and the location of the E1C open point



Recommendations – Station Capacity Needs

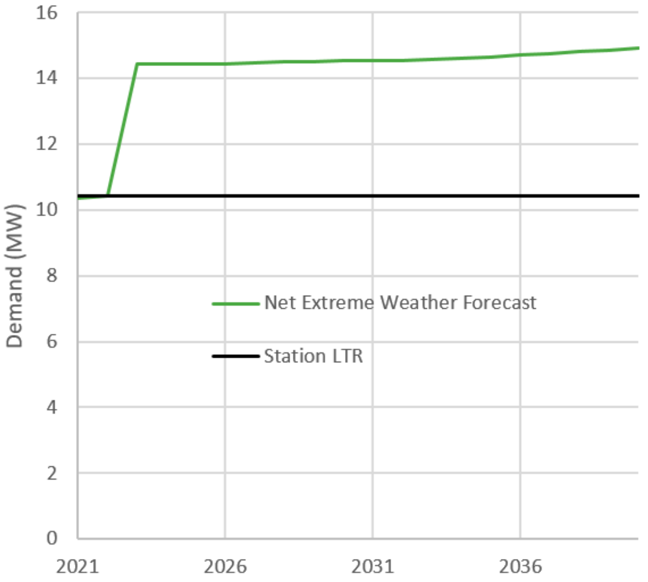
Recap: Station Capacity Needs

- There are several stations reaching their step-down capacity within the forecast horizon:

Station	Need Date	Notes
Sapawe DS and Sam Lake DS	Today	Needs Assessment recommended local planning between the transmitter and distributor, no further actions required for this IRRP
White Dog DS Marathon DS	2032 2038	Long-term need date, no further actions required for this IRRP but growth will be monitored
Margach DS	2023	For discussion today
Crilly DS	2027	For discussion today
Kenora MTS	2029	For discussion today

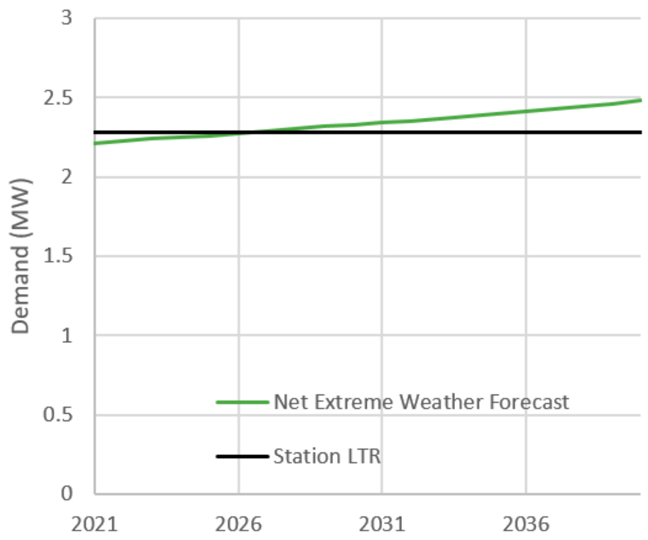
Margach DS

- 10.4 MW station nearing capacity today
- Capacity need is driven by an industrial customer seeking to be resupplied at this station
- Non-wires options are unsuitable for large near-term step increases in demand above station capacity
- Hydro One Distribution will install fan monitoring which will increase station capacity to ~16 MW
- If additional capacity needs arise, a second transformer at the station (currently acting as a spare) can be brought in service



Crilly DS (1/2)

- 2.2 MW station; no specific growth drivers but is projected to reach capacity in 2027
- Currently supplied from Sturgeon Falls CGS bus which results in annual outages when the generator is undergoing maintenance
  - A diesel generator is currently used for backup power when Sturgeon Falls CGS has an outage
- Station equipment is nearing end-of-life and space constraints limit in situ options



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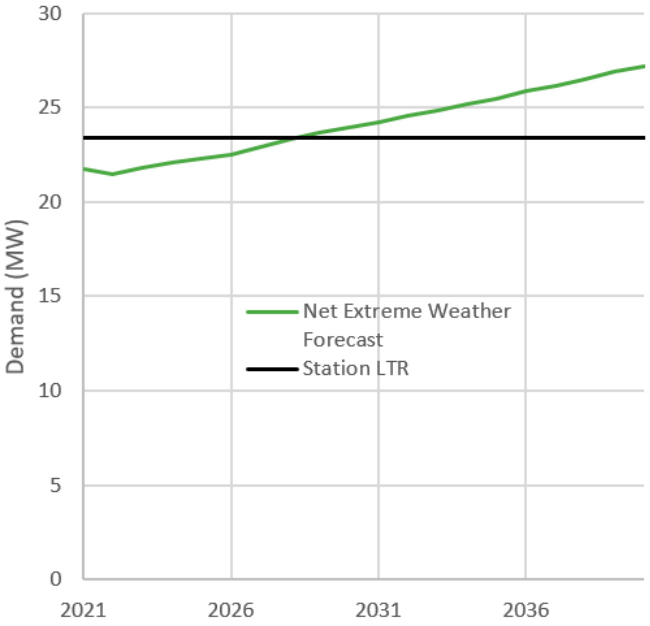
Crilly DS (2/2)

- Crilly DS is not a good candidate for non-wires options because:
  - Targeted conservation and demand management (CDM) measures may not reliably reduce peak demand due to the small pool of customers (~500)
  - The distributed energy resource (DER) option would be defined by the need for backup power rather than managing the peak demand hours above station capacity

- Hydro One Distribution will consider the following options in local planning:
  - Refurbish Crilly DS at its current location (and continue to rely on backup power during outages)
  - Rebuild Crilly DS at a different location as a 115:25 kV HVDS
  - Rebuild Crilly DS at a different location as a 230:25 kV HVDS
  - Replace Crilly DS with 115:25 kV padmount transformer

Kenora MTS

- Kenora MTS is expected to reach capacity around 2029
- The "wires" options range from installing an additional transformer at the existing station ($5M) to a new station across town ($30M) that would also incrementally improve reliability and provide distribution system benefits
- Hourly demand profiles were created and posted alongside the April 2022 webinar presentation
- The following slides summarize the non-wires options analysis based on the hourly demand profiles shared during the April 2022 webinar



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Identifying Non-wires Alternatives

Energy storage device

Energy storage device in combination with local generation* (when a battery alone does not have sufficient energy to serve the need)

Dispatchable local generation (e.g. gas turbine)

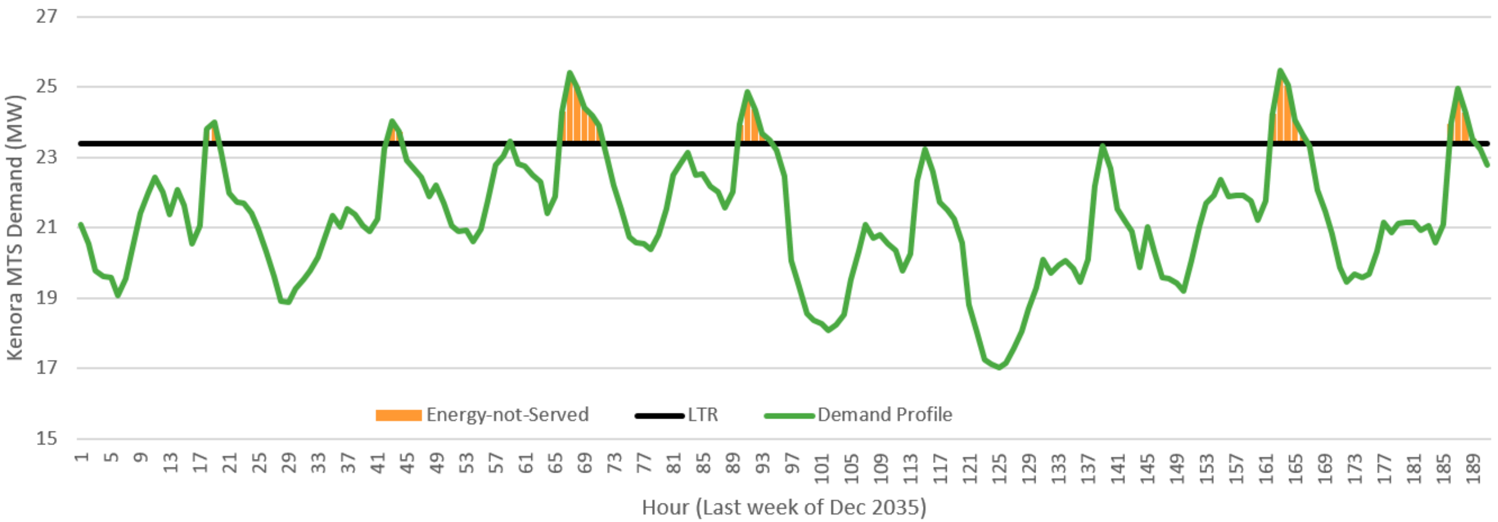
Demand response (DR) or energy efficiency (EE) measures

Integrated solution of any of the above options

*Note that standalone wind/solar local generation are not considered options due to their intermittent nature and poor match with the hourly demand profile

Sizing Non-wires Alternatives

- Non-wires alternatives are selected and sized according to the energy-not-served profile
- Figure below shows a sample week in Dec 2035



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Non-wires Alternatives for Kenora MTS

4 MW gas turbine facility (dispatched to meet the energy-not-served profile)

Storage: **6 hour 4 MW (24 MWh) battery**. Note that local generation is not required to complement the battery due to the relatively low energy requirement (i.e. battery can be recharged from existing grid power).

Combination of **energy efficiency** measures (such as those administered through the IESO Local Initiative Program) and **demand response** (cost based on Northwest zone 2018-2021 capacity auctions)

Comparing Options: LUEC and DCF

- The Levelized Unit Energy Cost (LUEC) is the average price an electricity generator/storage facility must receive for each unit of energy it generates over its lifetime to break even.
- Model used to calculate LUEC of alternative generation/storage options considers factors such as overnight capital costs, fixed O&M costs, variable O&M costs, fuel management fees, etc.)

- A discounted cash flow (DCF) model is made for each option, which at a minimum includes the following considerations:
  - Cost of the option (i.e. LUEC) amortized across its lifetime
  - Bulk system energy and capacity benefits
    - Note that the wires option also accounts for the cost of system resources delivered

Kenora MTS Option Costs and Next Steps

- Generally speaking, the cost of non-wires alternatives fall between the cost for station expansion and a new station
- Non-wires alternatives can be cost effective depending on the distribution system benefits that the non-wires alternative can realize
- Synergy North will continue to refine options post-IRRP and ultimately decide whether or not to pursue non-wires alternatives
- Kenora MTS has been flagged as a potential focus area for the IESO's Local Initiative Program under the 2021-2024 Conservation and Demand Management (CDM) Framework

Option	NPV ($2021 Real)
Station Expansion	$4 M
New Station	$25 M
Gas Generation	$22 M*
Storage	$10 M*
EE and DR	$1-9 M**

*Assumes full (UCAP) credit for system capacity value. Actual cost could be higher depending on the deliverability of the NWA resource.
**Cost ranges from $1-9 M depending on whether the Kenora EE measures are part of provincially cost-effective CDM (i.e implemented through the IESO's Local Initiative Program) or if they are incremental to provincially cost-effective CDM.

Ring of Fire Study

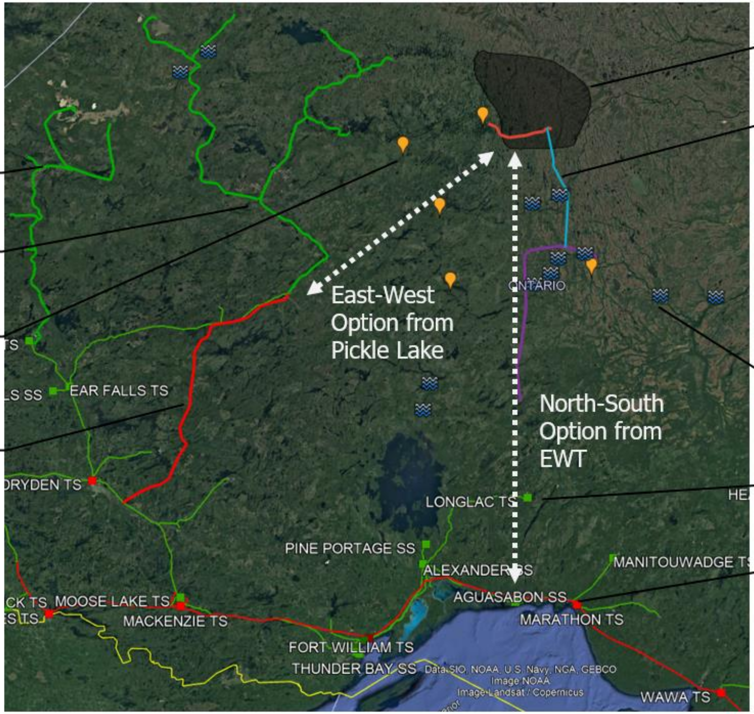
Ring of Fire Map & Notable Features

115 kV Red Lake Subsystem Remotes

115 kV Pickle Lake Subsystem Remotes

Matawa Cluster Remotes (5 communities)

230 kV Watay Circuit to Pickle Lake (W54W)



Approximate Ring of Fire Area

Proposed All-season Roads (x3)

Potential Hydro Generation

115 kV Circuit to Longlac TS (A4L)

230 kV East-West Tie Circuits

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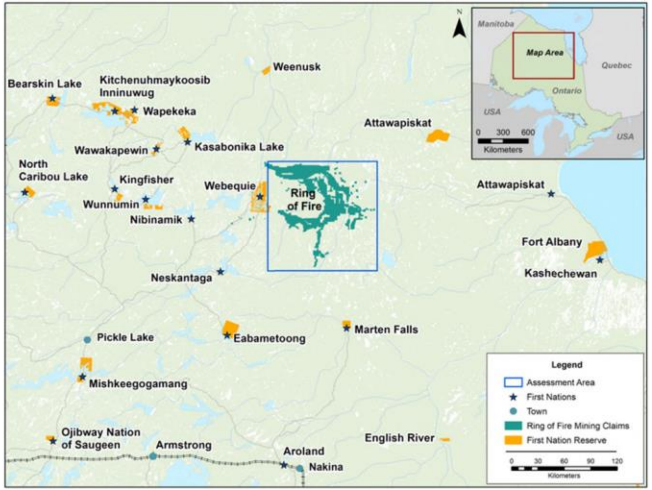
Ring of Fire Background

- The Ring of Fire is a remote area covering 5000 km^2 located 500 km north of Thunder Bay with rich deposits of critical minerals but currently without all-season road access nor grid power supply
- Two transmission options were considered in the 2015 IRRPs: North-South oriented line from Nipigon and East-West oriented line from Pickle Lake
- The decision to pursue transmission supply to the Ring of Fire ultimately lie with the mining companies and remote communities as the direct beneficiaries or with governments to advance broader policy objectives



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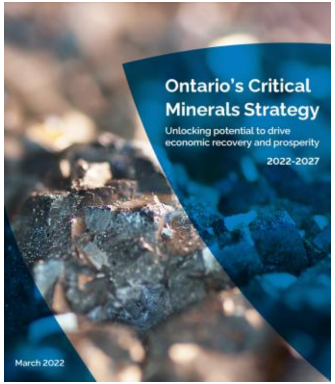
Ring of Fire Demand Forecast

- The IESO's 2022 mining demand forecast includes ~**30 MW** at the Ring of Fire associated with two proposed mining projects
- However, there is a high degree of uncertainty in terms of both magnitude and timing
- If transportation and transmission were developed, mining demand could be much higher than currently forecast
- As of January 2022, there are about **26,000 active mining claims** held by **15 companies** in the Ring of Fire
- The IESO will update the mining forecast in Q1 2023 to better capture Ring of Fire growth scenarios

Policy Drivers

- Enabling development in the Ring of Fire is an important provincial policy objective
- The province expressed support for three indigenous-led all-season roads to the Ring of Fire ("Corridor to Prosperity")
  - Environmental Assessments are underway and the province has committed $1B in funding on the basis of matching federal contributions
- Ontario's March 2022 Critical Mineral Strategy identifies the Ring of Fire as a "priority project" and Ontario's low emission electricity grid is featured as an advantage over other jurisdictions



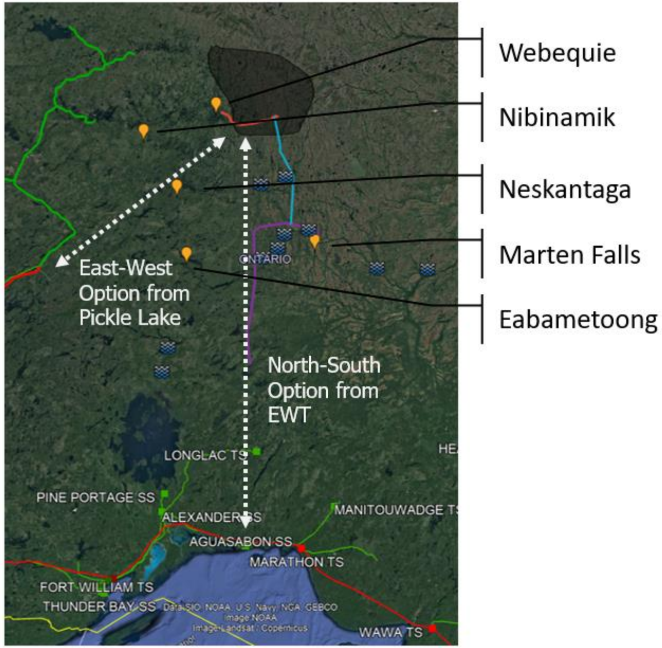
Opportunities for Alignment

- There are four key opportunities that should be considered in both the decision to pursue transmission supply to the Ring of Fire and its routing (North-South from Nipigon or East-West from Pickle Lake)

Supplying Matawa Remote Communities	Enabling Hydro Generation	Improving Supply to Longlac	Co-locating with Transportation Corridor

Matawa Remote Communities

- There are five remote diesel-supplied Matawa First Nations communities (labeled on left) that could be grid connected from a transmission line to the Ring of Fire
- They were previously identified as economic to connect in the 2014 Remote Connection Plan but chose not to participate in the Watay project
- Grid connection can be facilitated by either North-South or East-West transmission option



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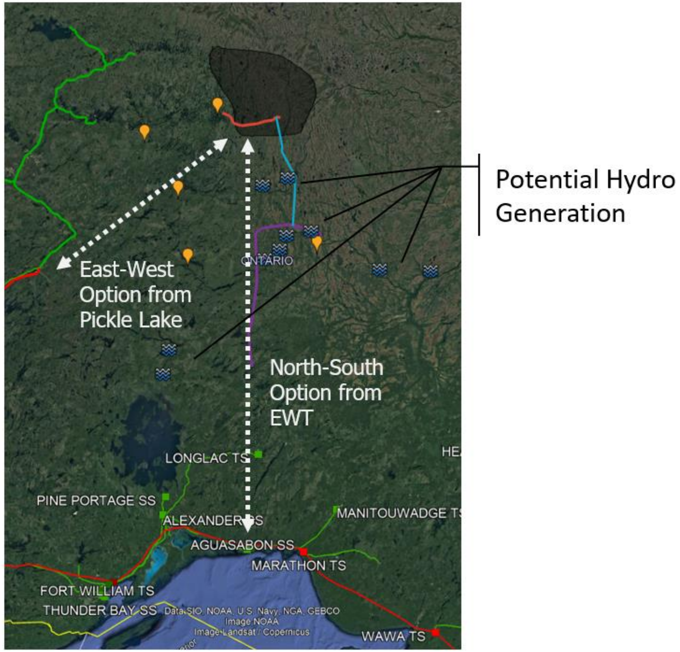
Enabling Hydro Generation

- There is significant hydroelectric generation potential on the Albany and Attawapiskat river systems in the vicinity of the North-South transmission supply option
- The North-South transmission supply option could help facilitate the connection of these facilities
- Note that the East-West transmission option is poorly situated to connect these potential hydro facilities



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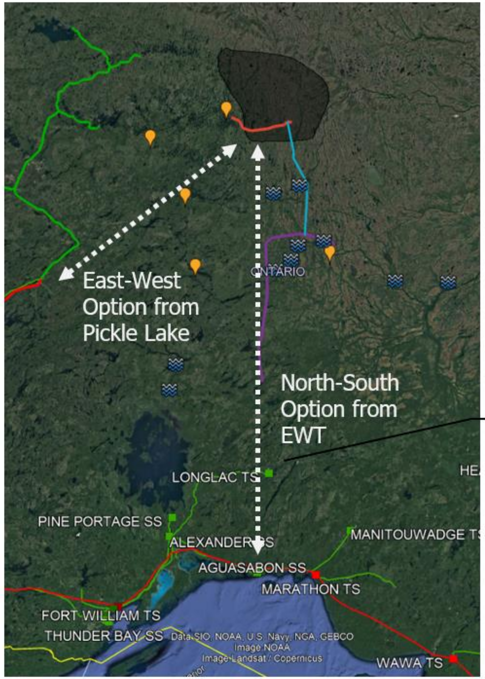
Improving Supply to Longlac

- The existing radial 115 kV A4L circuit to Longlac TS is near capacity and customers have expressed concern about poor reliability due to long and frequent outages
  - A4L refurbishment is underway and distance-to-fault relays have been installed to improve restoration times
- The North-South transmission option passes directly by Longlac and could help increase capacity and provide a secondary supply path to further improve reliability



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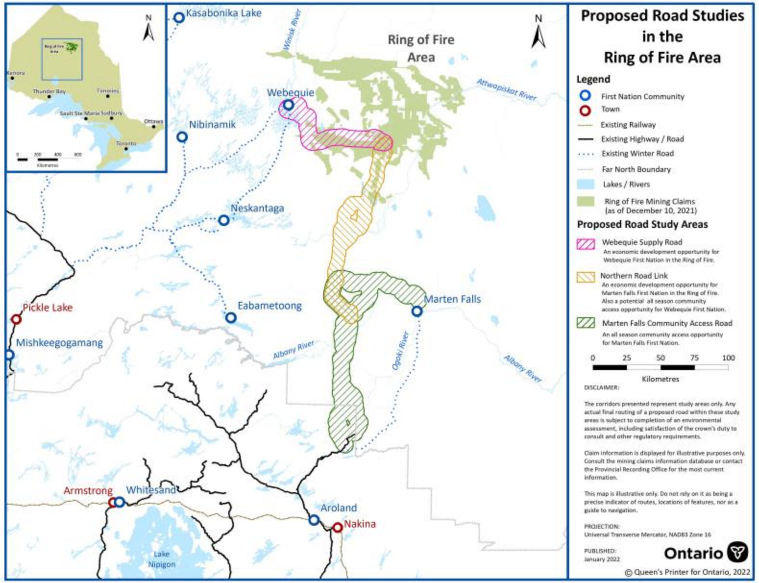
Co-locating with Transportation Corridor

- There are three proposed roads currently undergoing Environmental Assessments which will provide a continuous all-season road to the Ring of Fire
- The North-South transmission option is aligned with the proposed roads consistent with provincial policy supporting the co-location of linear infrastructure
  - Co-location may help reduce costs and environmental impact



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Supply to the Ring of Fire Study

- The IESO is conducting a Ring of Fire study in parallel with the ongoing Northwest Integrated Regional Resource Plan
- Preliminary findings will be summarized in the IRRP report but the Ring of Fire study will continue post-IRRP
- The IESO will continue to coordinate with government and other stakeholders on the scope of work which may evolve with future policy direction

- The near-term scope of work for the remainder for 2022 includes estimating:
  - High-level cost for transmission supply options,
  - Avoided diesel system costs from connecting remote Matawa First Nations, and
  - Greenhouse gas reductions from both remote communities and mines as a result of connecting them to the grid versus supplying them with local generation

Preliminary Ring of Fire Transmission Supply Costs

- Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs
- This high-level (-50/+100%) cost estimate ($2022 real, overnight capital) does not include step-down stations at the mines/loads nor reactive compensation devices which will depend on the magnitude of demand

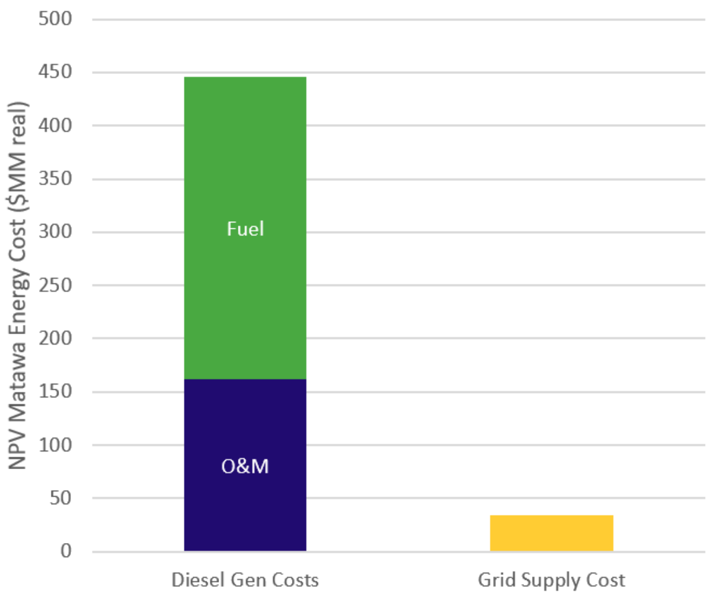
- North-South option is estimated to cost between $860M to $1.06B including:
  - 230 kV SS on the East-West Tie (EWT)
  - 120 km single 230 kV line from EWT to Longlac
  - 230/115 kV TS at Longlac
  - 410 km single 230 kV line from Longlac to McFaulds Lake
- East-West option is estimated to cost between $600M to $780M including:
  - Station modifications at Watay TS
  - 370 km single 230 kV line from Pickle Lake to McFaulds Lake

Preliminary Avoided Diesel System Costs (1/2)

- The Matawa remote communities were previously identified as economic for grid connection in the 2014 Remote Connections Plan but elected not to participate in the Watay project
- The Matawa remote communities are currently supplied by remote on-site diesel generation which are costly to operate
  - Up to 70% of the fuel must be flown in when winter roads are not available contributing to high costs and increased emissions

Preliminary Avoided Diesel System Costs (2/2)

- The net present value ($ real in the year transmission supply is made available) of avoided diesel systems costs over the first 20 years of transmission connection:
  - $160M avoided O&M
  - $285M avoided fuel costs
- The net present value of grid power over the same period totals $35M



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GHG Reductions

Mining

- In the absence of grid power supply, mining loads would likely rely on natural gas generation
- GHG reduction depends on the amount of mining demand:
  - For 30 MW: 68 000 tCO_2e per year or the equivalent of removing 26k cars
  - For 70 MW: 160 000 tCO_2e per year or the equivalent of removing 61k cars

Matawa Communities

- GHG reduction depends on forecast demand levels and growth rate when transmission supply is made available
- On average over the first 20 years of grid connection, GHG reductions totals approximately 27 000 tCO_2e per year or the equivalent of removing 10k cars

Ring of Fire Study Next Steps

- Preliminary findings will be summarized in the IRRP report but the Supply to the Ring of Fire Study will continue after the IRRP
- The mining demand forecast will be updated by Q1 2023 to better understand Ring of Fire demand potential
- The study scope will evolve in coordination with the Ministry of Energy and in consideration of input received from today's webinar

Next Steps

Summary of Draft Recommendations

Need/Subsystem	Recommendation
Kenora MTS station capacity need	Non-wires alternatives (NWAs) can be cost effective depending on distribution system benefits; Kenora MTS will be a potential focus area for the IESO’s Local Initiative Program and Synergy North will lead further non-wires analysis in local planning
Margach DS station capacity need	NWAs not suitable; Hydro One Dx will refine options for refurbishment or new station in local planning
Crilly DS station capacity need	NWAs not suitable; Hydro One Dx will install fan monitoring if growth materializes and monitor for additional growth that might necessitate a second transformer
Customer Reliability at Fort Frances MTS	Reconfiguration of Fort Frances TS to reduce supply interruptions to Fort Frances MTS during transmission system outages; Regional Infrastructure Plan will refine configuration
E1C operation and high voltage	With the new W54W circuit in-service, E1C will be operated "normally open" and additional reactors will be installed at/near Watay TS to manage high voltages; Regional Infrastructure Plan will refine location of open point and reactor sizing
Red Lake Area high growth sensitivity	No immediate actions required - mining forecast will be updated in Q1 2023; growth will be monitored and compared against load meeting capabilities to trigger future planning activities as needed

Feedback on…

- What other information or insights should be considered in these recommendations and findings?
- How can the Technical Working Group continue to engage with communities as these recommendations are implemented, or to help prepare for the next planning cycle?

Please submit your written comments by Nov 23rd

using the feedback form by email to engagement@ieso.ca

Keeping in Touch

- **Subscribe** to receive updates for Northwest regional planning on the IESO website – www.ieso.ca/subscribe; select 'Northwest'
- **Follow** the Northwest regional planning activities on the dedicated engagement webpage
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Thank You

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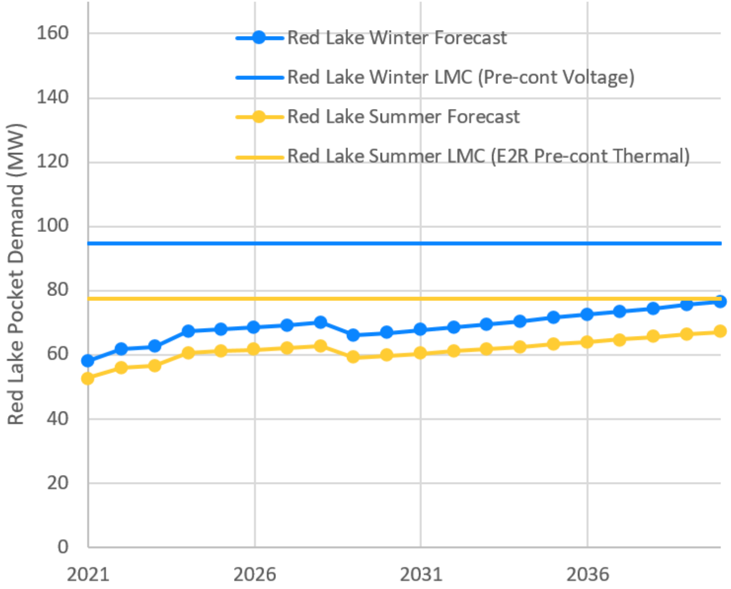
Appendix – Red Lake Area LMCs

Red Lake Load Meeting Capability (LMC)

- Limited by summer LMC: **74 MW** due to E2R pre-cont thermal overload
- Winter LMC: **93 MW** due to pre-cont thermal overload followed closely by voltage decline
  - Note that voltage decline can be mitigated by installing appropriately sized voltage devices at new loads' connection points; All LMC figures in the following slides assume that new load is accompanied by voltage devices to maintain adequate voltage performance



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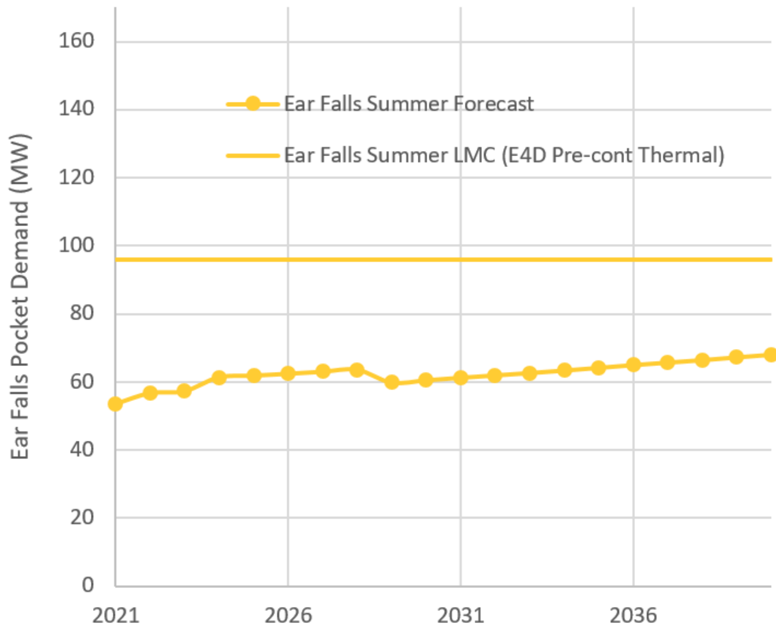
Ear Falls Pocket Load Meeting Capability (LMC)

- Limited by summer LMC – **92 MW** due to pre-contingency E4D thermal overload
  - Assumes 35 degree summer ratings on E4D and ~18 MW of dependable hydro (summer 98th percentile)



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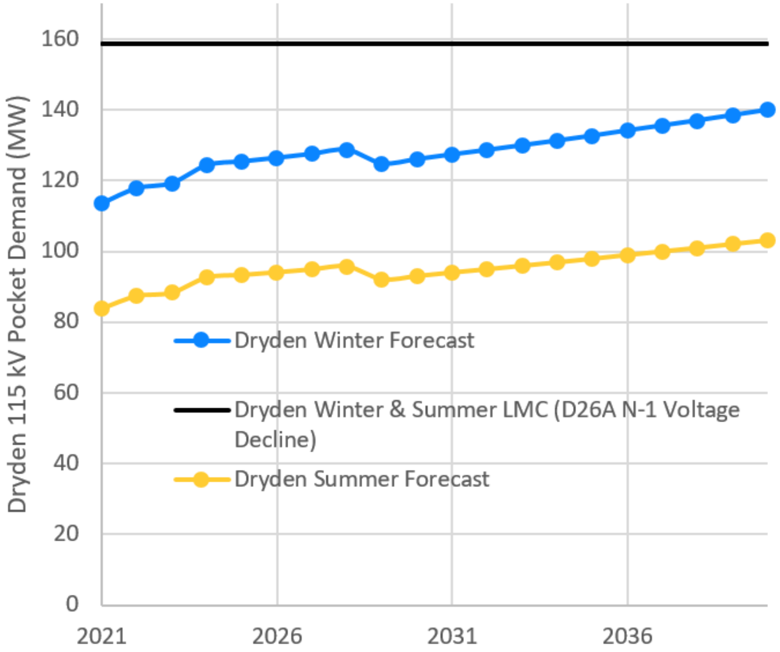
Dryden Subsystem Load Meeting Capability (LMC)

- The supply to the Dryden 115 kV subsystem is limited to **159 MW** due to voltage decline following the loss of D26A
  - Assumes ~18 MW of dependable Hydro
- Other limitations:
  - 133 MW winter/summer LMC due to voltage decline for D26A + K23D N-1-1 contingency (but can be addressed by a load rejection scheme)
  - 191 MW summer LMC due to thermal overloading following the loss of one of the Dryden auto-transformers



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