Resource Capacity Accreditation in the Forward Capacity Market

Gas and Oil Modeling for the Seasonal Risk Assessment

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Resource Capacity Accreditation in the Forward Capacity Market

WMPP ID: 157

Proposed Effective Date: FCA 19

- The Resource Capacity Accreditation (RCA) project proposes improvements to ISO-NE's accreditation processes in the Forward Capacity Market (FCM) to further support a reliable, clean-energy transition by implementing methodologies that will more appropriately accredit resource contributions to resource adequacy as the resource mix transforms
- RCA provides an opportunity for continuous improvement of the Resource Adequacy Assessment (RAA) model that is used to calculate capacity requirements (demand side) and resources' reliability contribution (supply side)
- This presentation focuses on gas and oil resource modeling for the seasonal risk assessment

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Outline of today's discussion:

- Recap of previous joint MC/RC discussions (slide 4 – 7)
- Gas resource modeling
  - Overall methodology (slide 8 – 14)
  - Adjustments to historical data (slide 15 – 27)
  - Hourly gas profile development (slide 28 – 32)
  - Additional considerations (slide 33 – 34)
  - Takeaways (slide 35 – 36)
- Oil resource modeling
  - Overall methodology (slide 37 – 42)
  - DFO energy constraint model (slide 43 - 48)
- Next steps (slide 49 – 50)

SUMMARY OF PROPOSED GAS AND OIL MODELING FOR RCA

Proposed gas and oil modeling for seasonal risk assessment

- An aggregate load/temperature-correlated hourly profile will be used to represent the hourly gas fleet generation using the daily gas available to the fleet subject to the gas system limitation during the peak winter months from December to February
- The Distillate Fuel Oil (DFO) capacity (from oil-only and dual-fuel resources) will be modeled in fleet aggregate as a single energy storage resource with a limited amount of energy available during a two-week period for the peak winter months from December to February
- Residual Fuel Oil (RFO) resources will be modeled as individual thermal resources at their winter Qualified Capacity (QC) for the winter months from December to February
- For the other winter months (*October - November* and *March - May*), oil and gas resources (including dual-fuel) will continue to be modeled as individual thermal resources at their seasonal QC (without energy limitations)

Proposed gas and oil modeling for resource accreditation

Introduced November/December 2023 MC/RC Meeting

- RAA case for resource accreditation will use the seasonal risk targets established in the seasonal risk assessment process
- RAA case for resource accreditation will use the following gas and oil models:
  - Gas capacity (from gas-only and dual-fuel) will use the same aggregated hourly profile as for the RAA seasonal risk case
  - Oil capacity (from oil-only and dual-fuel) including RFOs and DFOs will be modeled as individual de-rated resources

Modeling of gas and oil resources for different RAAs during peak winter months (Dec-Feb)

Capacity Resource	Proposed RAA Resource Model	RAA Case
Gas Resources	Profile (a change from current Thermal Model) based upon Winter QC	• Seasonal Risk • Accreditation • Capacity Requirement
DFO Resources DFO-Only and Dual-Fuel using DFO	Storage (a change from current Thermal Model) based upon Winter QC (or back-up fuel capability)	• Seasonal Risk
DFO Resources DFO-Only and Dual-Fuel using DFO	Thermal based upon a derated Winter QC (or back-up fuel capability)	• Accreditation • Capacity Requirement
RFO Resources RFO-Only and Dual-Fuel using RFO	Thermal based upon a derated Winter QC (or back-up fuel capability)	• Seasonal Risk • Accreditation • Capacity Requirement

GAS RESOURCE MODELING

Detailed discussions on methodology and underlying assumptions

OVERALL MODELING METHODOLOGY

Overall gas modeling methodology

- A regression model is used to establish a relationship between the amount of daily gas available to generation and temperature conditions based on historical data
- The amount of daily gas available to generation for each day and each load level simulated in the RAA models will be determined based on the implied HDD associated with the load and the relationship between the amount of daily gas available to generation and temperature conditions as established in the regression model
- The daily available gas will be apportioned to each hour during the day based on historical hourly gas generation patterns and the representative heat rate of the gas fleet
- The load/temperature-correlated hourly profile will be used to represent the hourly gas fleet generation in the RAA models for seasonal risk assessment and resource accreditation

Gas constraints captured in historical data

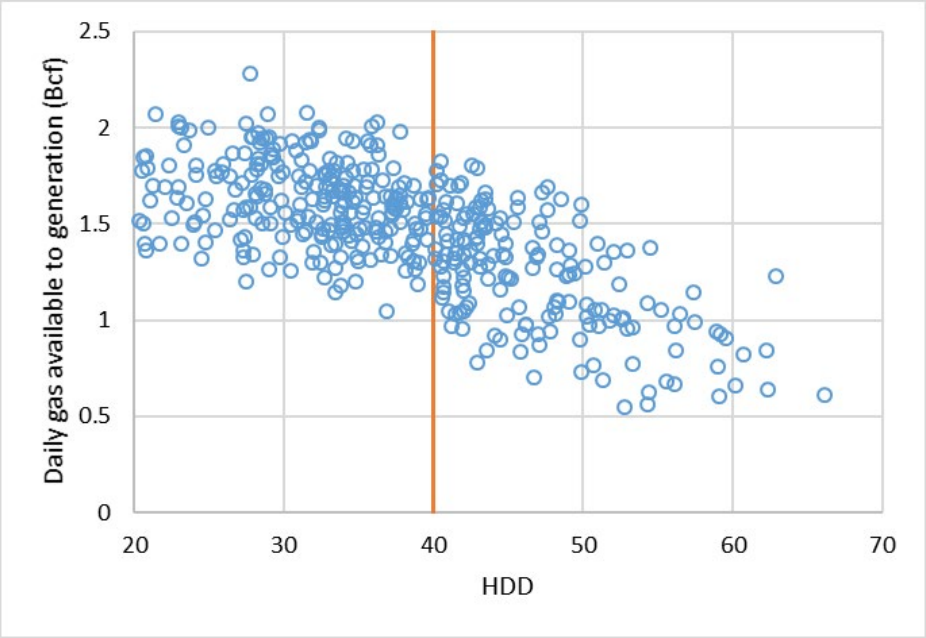
- Gas availability to generation under different temperature conditions is derived from historical data, which has inherently captured:
  - Gas supply and delivery system constraints, including:
    - Supply system constraint: the total amount of daily gas available to New England (from pipeline gas and LNG)
    - Delivery system constraint: interstate pipeline capacity limitation
  - LDC pipeline gas demand and uncertainty, taking into consideration how LDCs used different supply options (pipeline gas, LNG, and satellite LNG storage) to meet their overall gas demand

Historical dataset used

- The historical gas dataset used for the analysis is December to February from 2014/15 to 2022/23 winters
- Post Energy Market Offer Flexibility (EMOF) dataset better recognizes fuel constraints associated with gas and oil resources
  - EMOF became effective in December 2014
- This period contains many cold weather conditions where there were increased risks associated with the unavailability of gas and oil resources

Historical days with tight supply condition

- The regression model uses a subset of the historical dataset, including only the days with tight supply condition identified using two thresholds
  - HDD >= 40
    - Available gas to generation starts drooping at HDD of 40
  - Oil generation has been used (*daily oil generation* >= 100 MWh)
    - When oil resources were dispatched, available pipeline gas was generally fully utilized



Determination of historical available daily gas to generation

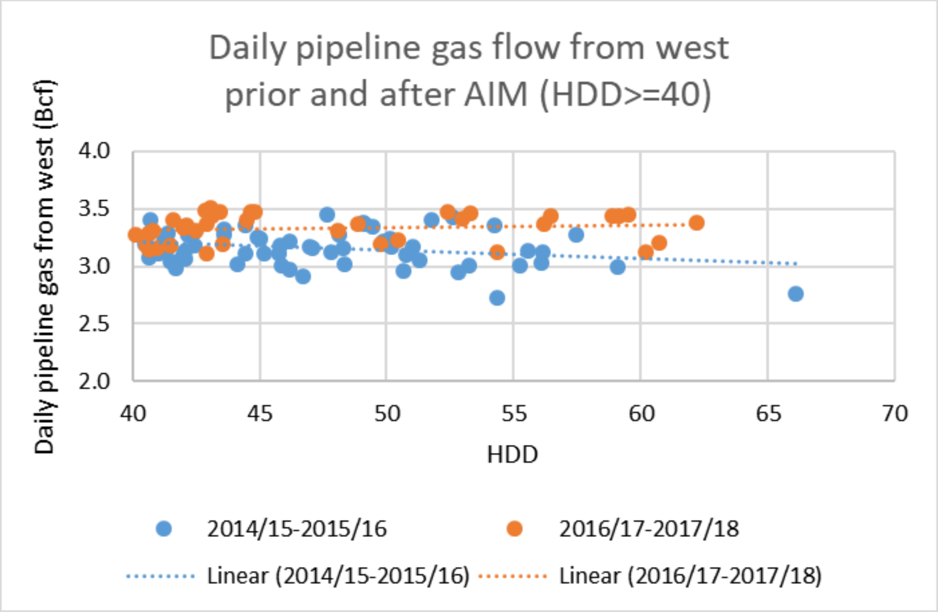
- Historical actual gas burn by generation will be used to represent the amount of gas available to generation for that day, with following adjustments that will be explained in subsequent sections:
  - Historical daily gas available to generation will be adjusted upward by 0.1 Bcf/d for the period prior to Algonquin Incremental Market (AIM) project
  - Historical supply from Excelerate LNG will be excluded
  - Additional available gas from Saint John LNG will be added to the historical daily gas available to generation
    - Impact of historical eastern Canada export from Sable Island and Deep Panuke will be accounted for in this process
  - Adjustment for account for EMT impact
    - Historical generation from Mystic 8&9 will not be included
    - Additional available gas from EMT LNG will not be included
    - Historical EMT LNG injection into interstate pipelines will be assumed to have been utilized to serve the non-power demand, thus no impact on the historical available gas to generation

ADJUSTMENT FOR IMPACT OF AIM PROJECT

AIM's impact on total pipeline gas supply

- AIM was placed in service in November 2016, providing an additional 0.342 Bcf/d of pipeline capacity to New England region

- AIM has resulted in an increase to the total gas supply to the region through pipelines from the west



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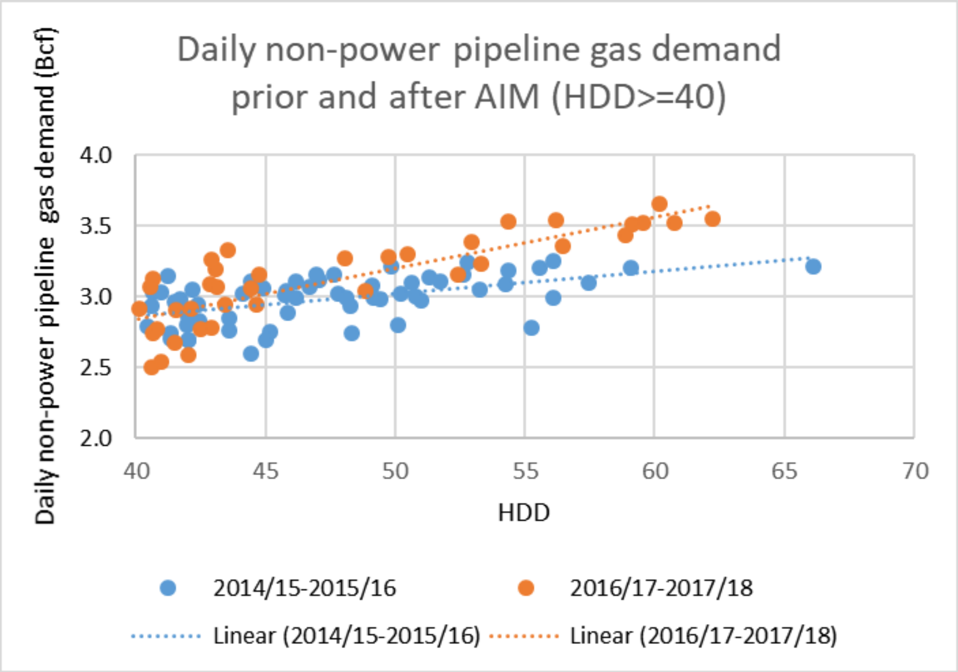
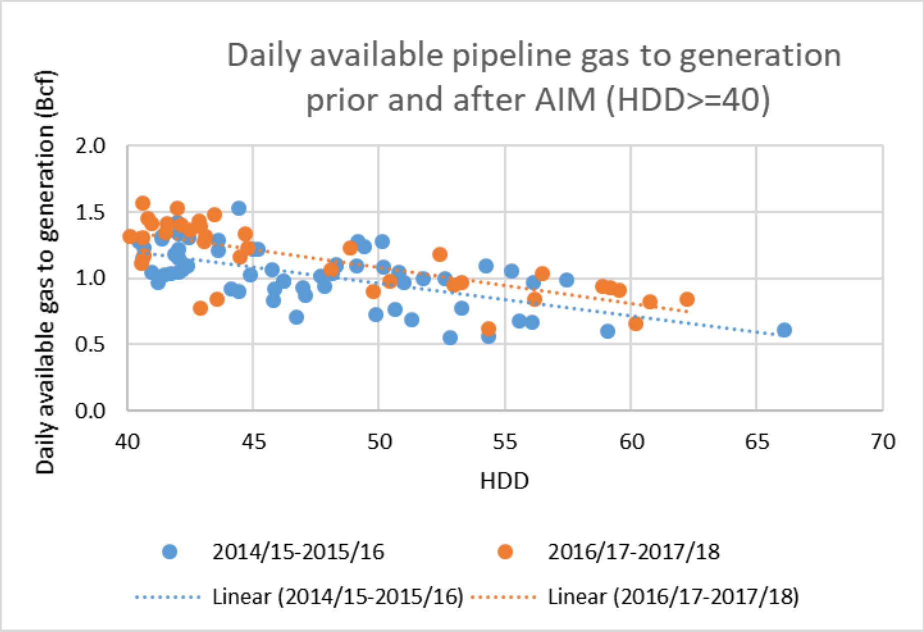
AIM's impact on non-power gas demand

- Majority of the incremental gas from AIM has gone to non-power usage under tight supply conditions



AIM's impact on available gas to generation

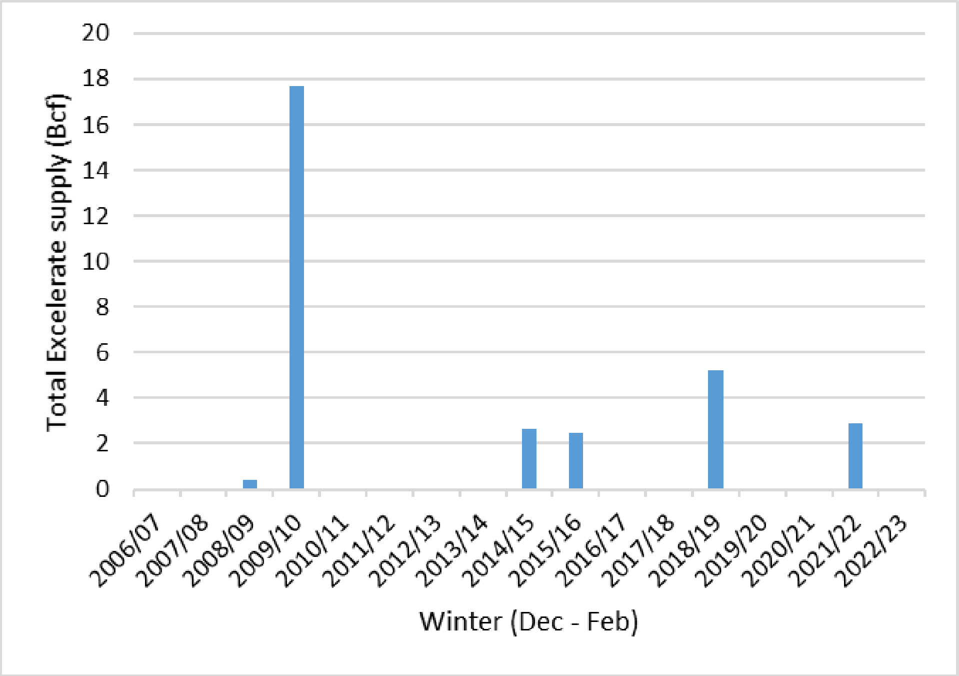
- AIM project resulted in an increase to the available pipeline gas supply to generation
  - by ~0.1 Bcf/d
- Historical daily gas available to generation will be adjusted upward by 0.1 Bcf/d for the winters of 2014/15 to 2015/16



ADJUSTMENT FOR EXCELERATE LNG SUPPLY

Historical Excelerate LNG supply

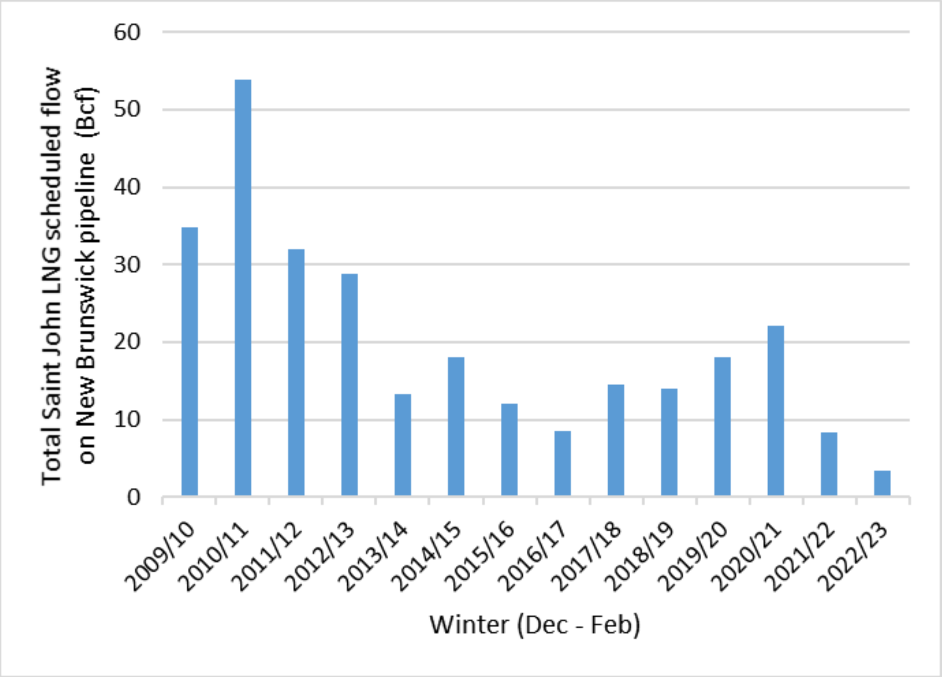
- Excelerate LNG supply to the region has been uncertain in both timing and quantity
- Historical supply from Excelerate will therefore be excluded due to its uncertain availability
  - Forward arrangements from Excelerate will be considered as additional incremental supply in the qualification and accreditation processes



ADJUSTMENT FOR ADDITIONAL AVAILABLE GAS FROM SAINT JOHN LNG

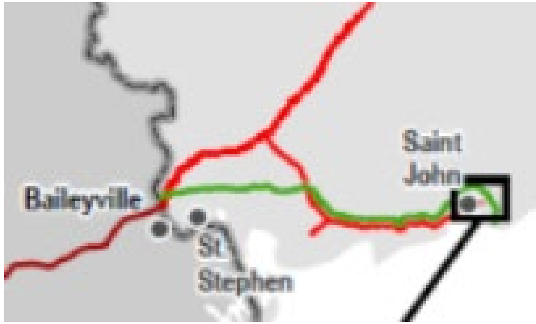
Historical Saint John LNG supply

- Saint John LNG project began operations in 2009, and has been supplying natural gas to the domestic Canadian and American markets
- Additional available gas from Saint John LNG will be added to the daily gas available to generation
  - Forward arrangements from Saint John is inherently part of the total existing gas supply assumed in the RAA model for risk assessment and resource accreditation
  - Such arrangements will limit the total amount of non-firm supply available to other gas-fired generators
- The amount of additional available gas from Saint John is limited to the lesser of the effective remaining LNG inventory and the effective remaining capacity headroom for delivery on M&N pipeline



Effective M&N headroom

- Effective remaining capacity headroom on M&N pipeline is based on:
  - M&N North to South pipeline capacity
    - Assumed at 0.8 Bcf/d, as has been used in many ISO analyses, e.g. PEAT
  - The actual M&N North to South flow for the day
    - Estimated using the Baileyville North to South flow and the Saint John LNG injection amount for the day



- Daily effective M&N remaining headroom =

$$\textit{M\&N North to South capacity} - \underbrace{(\textit{Baileyville North to South flow} + \textit{Canaport LNG injection})}_{\textit{M\&N North to South flow}}$$

Effective Saint John LNG remaining inventory

- Effective Saint John LNG remaining inventory accounts for the impacts of:
  - Historical eastern Canada export (from Sable Island and Deep Panuke that decommissioned in late 2018)
    - The amount is estimated using positive *Baileyville North to South flow*
  - Historical US export to eastern Canada
    - The amount is estimated using positive M&N South to North flow

- Daily effective Saint John remaining inventory =

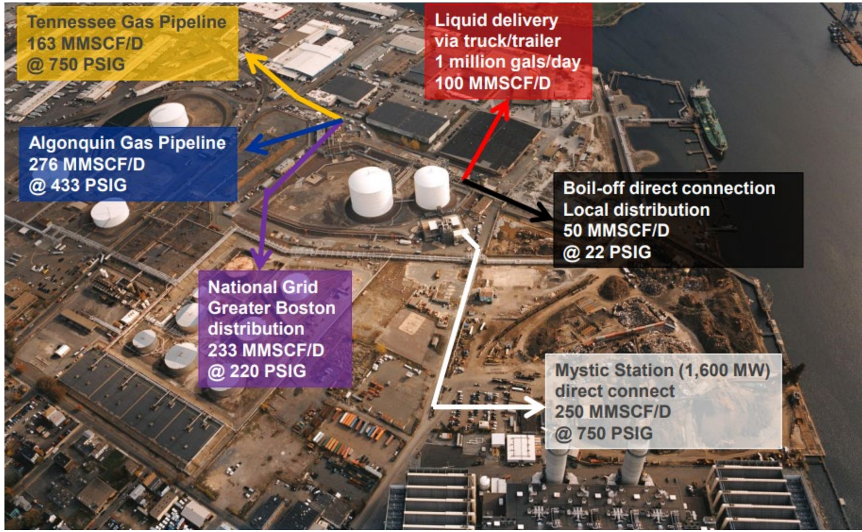
  Estimated total remaining inventory – eastern Canada export (positive *Baileyville North to South flow*) – *US export (positive M&N South to North flow)*

CONSIDERATION OF EMT IMPACT

EMT impact consideration

- Historical generation from Mystic 8&9 will not be included due to their expected retirement

- Additional available gas from EMT LNG will not be included due to:
  - Its uncertain availability in the future
  - The amount of gas available to generation was highly dependent on the inventory management to serve both non-power and power demands
    - There was no complete information available on its daily sendout to other non-power users through NGrid distribution system, boil-off sendout and truck-transported LNG to satellite storages throughout the region



EMT impact consideration, cont.

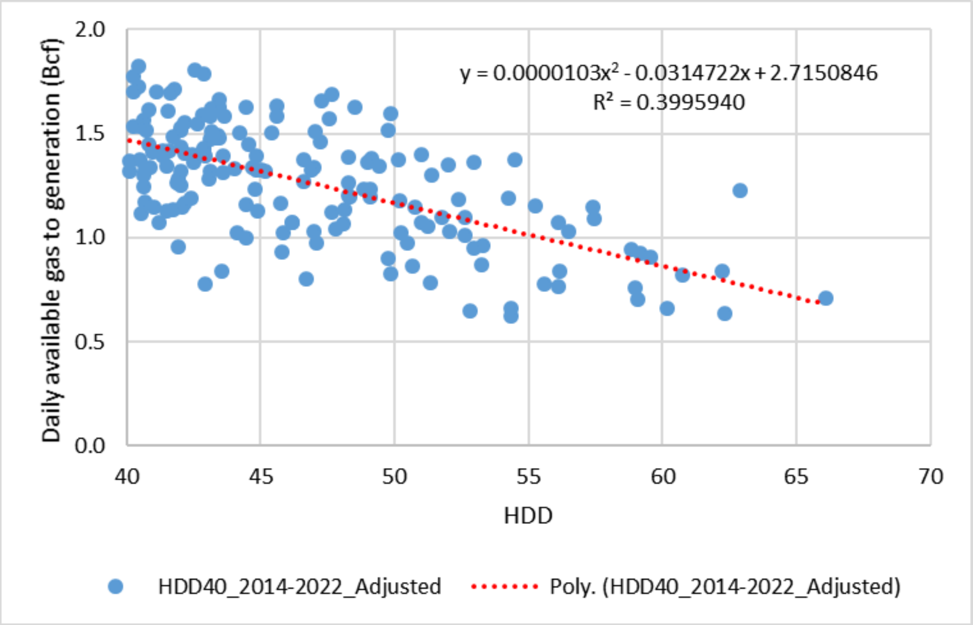
- Historical EMT LNG injection into interstate pipelines will assume to have been utilized to serve the non-power demand, thus no impact on the historical available gas to generation
  - Injection into the end of the AGT and TGP systems in Everett has been used to provide critical support on these constrained portions of the pipelines systems, balancing and shaping services to ensure adequate pressures are maintained to the LDC take stations and to provide for uninterrupted deliveries to the LDC customers
- To the extent that EMT remains in service, forward arrangements from EMT LNG will be considered as additional incremental supply in the qualification and accreditation processes

DAILY GAS REGRESSION MODEL

To establish the relationship between the amount of available gas to generation and different temperature conditions

Daily gas regression model

- A regression model is used to establish the relationship between the amount of available gas to generation and the temperature conditions using the historical data
  - Historical available daily gas to generation is based on the actual gas burn for generation, with the adjustments explained in slides 14-27



HOURLY AVAILABLE GAS TO GENERATION

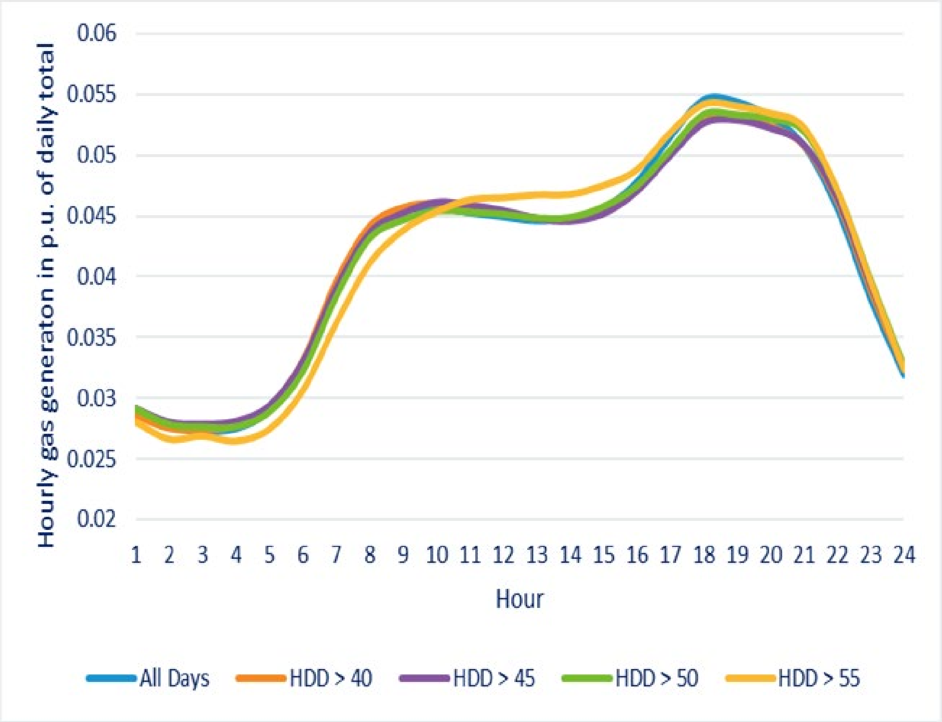
To create the load/temperature-correlated hourly profile for RAA models to represent the hourly available gas fleet generation

Daily gas available for RAA models

- The amount of daily gas available to generation is determined for each day and each load level simulated in the RAA models based on:
  - The implied HDD for each load level of each day, calculated based on the daily peak load uncertainty distribution due to weather variations
    - Higher load has higher implied HDD
  - The relationship between the amount of available gas to generation and the HDD as established in the regression model

Aggregate hourly gas generation profiles

- The daily available gas to generation for each load level of each day will be converted to MWh using a fleet wide representative heat rate of 8,000 Btu/kWh, and apportioned to each hour during the day based on historical hourly gas generation patterns



ADDITIONAL MODELING CONSIDERATIONS

Forward looking considerations

- The proposed gas modeling is based on the historical gas availability, which was adjusted for account for the impacts of future availability/uncertainty associated with historical gas supplies from Excelerate, eastern Canada export to US, US export to Canada, and EMT
- The proposed gas modeling considers the additional gas from Saint John LNG that would have been available historically to generation, without explicitly considering its supply uncertainty in the future
- As electrification increases, the ISO will look into incorporating the impacts from future gas demand changes

TAKEAWAYS FOR GAS MODELING

Takeaways

- The load/temperature-correlated hourly profile will be used to represent the hourly gas fleet generation in the RAA models for seasonal risk assessment and resource accreditation
- A regression model is used to establish the relationship between the amount of daily available gas to generation and temperature conditions based on historical available gas to generation
- The amount of daily gas available to generation for each day and each load level simulated in the RAA is determined based on the implied HDD associated with the load and the relationship between the amount of daily gas available to generation and temperature conditions as established in the regression model

OIL RESOURCE MODELING

Detail on oil resource modeling and underlying assumptions

OVERALL OIL MODELING

Oil resource risks observed during winter

- Past operational experience shows that most of the risk of oil resources being unavailable arose during prolonged cold snaps
  - RFO fleet experienced more frequent and longer duration outages when they were required to run more frequently and for longer durations, evidenced by their relatively high forced outage rates (xEFORd) that are not related to fuel supply
    - They typically have adequate on-site storage capability and inventories

Oil resource risks observed during winter, cont.

- Most of the DFO fleet have smaller storage tanks relative to the RFO fleet, and their inventories are likely to diminish very quickly if those resources are operated continuously
    - Some would need frequent in-season replenishments to support extended operation well beyond what they traditionally would require
    - Some faced replenishment challenges in the event of extreme weather
    - Uncoordinated inventory management among different DFOs would not fully align fleet's capability to meet the system needs
        - DFO resources have their own inventory management strategy in terms of when and how to maintain their inventory level and in-season replenishment

- DFO resource risks are better captured on a fleet level
    - While it is possible to model individual DFO's energy constraint to reflect its contribution to system reliability, it is very challenging in the GE MARS model to capture the correlation of these individual energy constraints and the resulting impacts on system reliability
    - Individual unit's energy constraint can be used for accreditation to reflect each resource's ability to meet system reliability
        - Different tank size
        - Different capability to replenish (through pipe, truck, etc.)

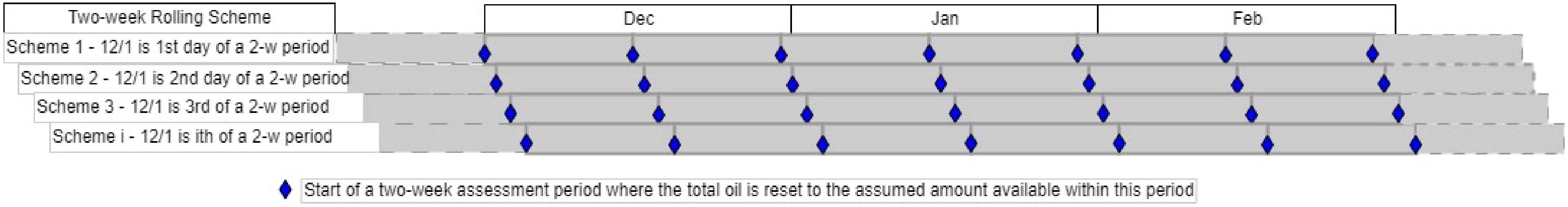
Oil resources modeled in RAA

- In the RAA for seasonal risk assessment:
  - RFO units will be modeled individually as thermal units using their respective xEFORd
  - DFO fleet fuel constraint will be captured by modeling the DFO resources as an aggregate energy storage resource with a limited amount of energy available during a two-week period
    - A two-week period is chosen to represent the duration of a prolonged cold snap
      - Cold snaps observed historically could last longer than one week, but no more than two weeks
      - From modeling perspective, the duration of cold snaps is better to be defined in week (instead of day) because most of the operational data related to oil supply is on weekly basis

- In the RAA for accreditation:
  - Oil capacity (from oil-only and dual-fuel), including RFOs and DFOs, will be modeled as individual de-rated resources

DFO energy limitation modeled on rolling 2-week periods

- DFO constraint is assessed on a rolling two-week basis
  - Peak winter months from December to February is divided into a series of two-week assessment periods
  - There are many possible rolling schemes. One of them will be randomly selected for each replication



- The total amount of available energy of the aggregate storage resource used to represent the DFO fleet is reset to the assumed amount at the start of each two-week assessment period, and subsequently dispatched to serve demand when needed throughout the 2-week period

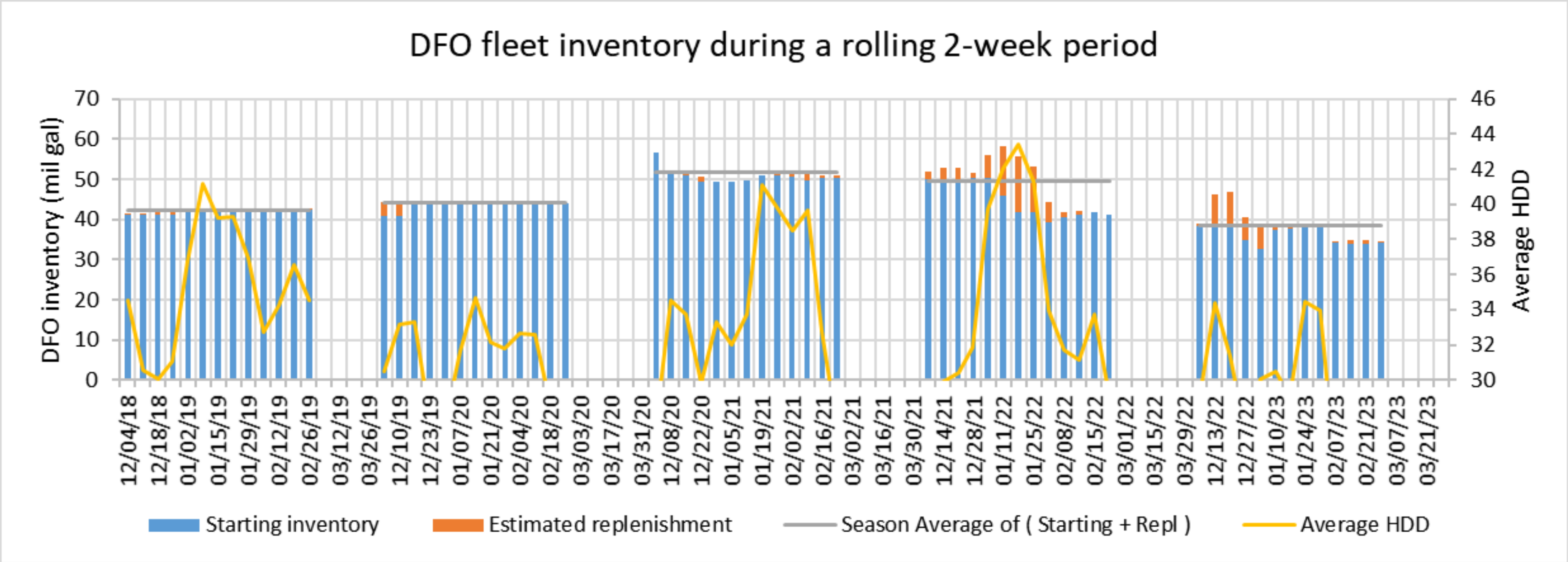
DFO FLEET ENERGY CONSTRAINT DURING 2-WEEK PERIOD

DFO fleet energy constraint during a 2-week period

- The total amount of energy available from DFO fleet during a two-week period is formulated based on the historical OP-21 weekly generator fuel survey data from the past five winters
  - Granular weekly generator fuel survey data became available after 2018/19
  - Recent five winters are more representative of the current DFO fleet
    - No major retirements and additions
- This historical data has inherently reflected how DFO fleet had historically maintained its fuel inventory and managed replenishments
  - What was the starting level at the beginning of the week
  - How much the DFO fleet had replenished during the next 2 weeks
    - The sum of these two quantities forms the expected amount of energy the DFO fleet would have been able to provide during a 2-week period

Historical DFO inventory 2018/19 – 2022/23

- Historical DFO total inventory (starting + estimated replenishment) during a rolling 2-week period varied by season
  - There are some variations within the 2021/22 winter due to in-season replenishments
  - Using seasonal average inventory levels for seasonal risk assessment seemed reasonable



DFO inventory levels for risk assessment

- Seasonal risk assessment will be conducted to identify the winter/summer LOLE split when system annual LOLE at 0.1 days/year, assuming the total DFO inventory during a 2-week period at each of last five season's average levels
- The DFO inventory will be derated by 10% to account for reduction due to outages, and converted to MWh using a fleet wide representative Fuel to Energy Conversion Rate of 64 gal/MWh

Seasonal risks calculation

- The final seasonal risks will be calculated as the average of the seasonal risks for all scenarios with different the DFO inventory levels assumed
- Illustration example

Assumed 2-week DFO inventory level (mil gal)	2-week DFO inventory derated by 10% for outage (mil gal)	2-week DFO energy (MWh)	Winter/Summer LOLE split (%)	Final Winter/Summer LOLE split (%)
42 (2018/19)	38	590,625	30/70	24/76
44 (2019/20)	40	618,750	25/75	
52 (2020/21)	47	731,250	10/90	
50 (2021/22)	45	703,125	15/85	
39 (2022/23)	35	548,438	40/60	

Takeaways

- RFO units will be modeled individually as thermal units using their respective xEFORd
- For the seasonal risk assessment, DFO fleet will be modeled as an aggregate energy storage resource with a limited amount of energy available during a 2-week period
- Seasonal risk assessment considers different DFO inventory levels observed in the past winters

NEXT STEPS

Next steps

- The ISO plans to apply the proposed gas and oil modeling to conduct seasonal risk assessment and resource MRI calculation for the impact analysis
- The ISO will consider stakeholder feedback and evaluate further enhancements

Questions