Economic Planning for the Clean Energy Transition (EPCET) Pilot Study

New Modeling Features and Initial Benchmark Scenario Results

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SPECIAL STUDIES AND INTERREGIONAL PLANNING

Overview

- EPCET pilot study overview
- New production cost software features
- Benchmark scenario assumptions
- Preliminary results

EPCET Pilot Study Overview

- As part of the 2021 Economic Study (Future Grid Reliability Study – Phase I), the ISO identified areas for improvement in our current Economic Study framework and software tools to perform the analyses
- To address the areas for improvement in the software tools, the ISO did an extensive evaluation of Energy Exemplar's PLEXOS software program last fall, and has obtained a license for the program

EPCET Pilot Study Overview, cont.

- As discussed in the Transmission Planning for the Clean Energy Transition (TPCET) pilot study, New England is among the leaders in many industry trends
  - Expansive buildout of distributed energy resources (e.g., solar PV)
  - Integration of large scale renewables, most notably offshore wind
  - Increasing imports via HVDC interconnections
  - Integration of significant amounts of energy storage resources
- In addition to these factors having a large effect on the assumptions used in reliability studies, they also have a significant impact in economic planning analyses
- To achieve a better understanding of the effect of these industry trends on our economic planning analyses, the ISO is performing a similar 'pilot' study of Economic Planning for the Clean Energy Transition (EPCET)

EPCET Pilot Study Overview, cont.

- The overall goal of the EPCET study is to prepare our models, tools, and processes such that informative and actionable results can be more readily produced in future Economic Study cycles
- The EPCET study has three main objectives
  - Take a deep dive into all input assumptions in economic planning analyses, propose updates to any assumptions based on our current experience, and test the effect of those modeling changes
  - Gain experience in the features and capabilities of our new economic planning software
  - Perform a dry-run of the Economic Study process improvement currently being discussed with the Transmission Committee

EPCET Pilot Study Overview

- **Benchmark scenario** (Informational Only) (Focus of results) – Model previous calendar year and compare it to historical system performance. This scenario's purpose is to test fidelity of models against historical performance and improve the models for future scenarios
- **Market Efficiency Needs scenario** – Model future year (10-year planning horizon) based on the ISO's existing planning criteria to identify market efficiency issues that could meet the threshold of a market efficiency need and move on to the competitive solution process for market efficiency needs
- **Policy scenario** (Informational Only) – Model future year (10+-year planning horizon) based on satisfying New England region and other energy and climate policies
- **Stakeholder-Requested scenario** (Informational Only) – Model a stakeholder-requested reference scenario not covered by the other scenarios

NEW PRODUCTION COST SOFTWARE FEATURES

PLEXOS

New Production Cost Features Under Evaluation

- After receiving trial sessions for other production cost modeling programs, the ISO switched from ABB's Gridview to Energy Exemplar's PLEXOS for the EPCET
- PLEXOS is a powerful and robust production cost modeling program. The ISO has been able to model several concepts which may be integrated into future studies
- These include:
  - Generator fuel-switching due to fuel constraints
  - Co-located energy storage and generation
  - Full AC power flow with N-1 secure dispatch
  - Distributed generation modeling
  - Robust automation programming interface

New Production Cost Features: Constraint Class

- PLEXOS has the ability to add custom constraints to the unit commitment algorithm
- Many of the new features we are exploring are a result of the constraint class in PLEXOS
- Any desired behavior which can be represented by an inequality equation using data in the model can be enforced via these custom constraints
  - For daily gas constraints (to allow for switching to secondary fuel):
    - $\sum (Generator\ Gas\ Consumption) \leq Temperature\ Dependent\ Daily\ Gas\ Allotment$
    - If the sum of all gas generation requires more gas than the allotment, PLEXOS will optimize some units to switch to their backup fuel
  - For co-located storage and generation (to prevent battery charging from grid):
    - $-1 * Battery\ Load\ + 1 * PV\ Generation \geq 0$
    - The battery can only charge up to the amount of PV generating, preventing it from using grid power to charge
- Too many custom constraints can slow runtime or cause the simulation to not converge
- The ISO invites the PAC to suggest other market or power system features which *may* be able to be modeled in PLEXOS as a constraint

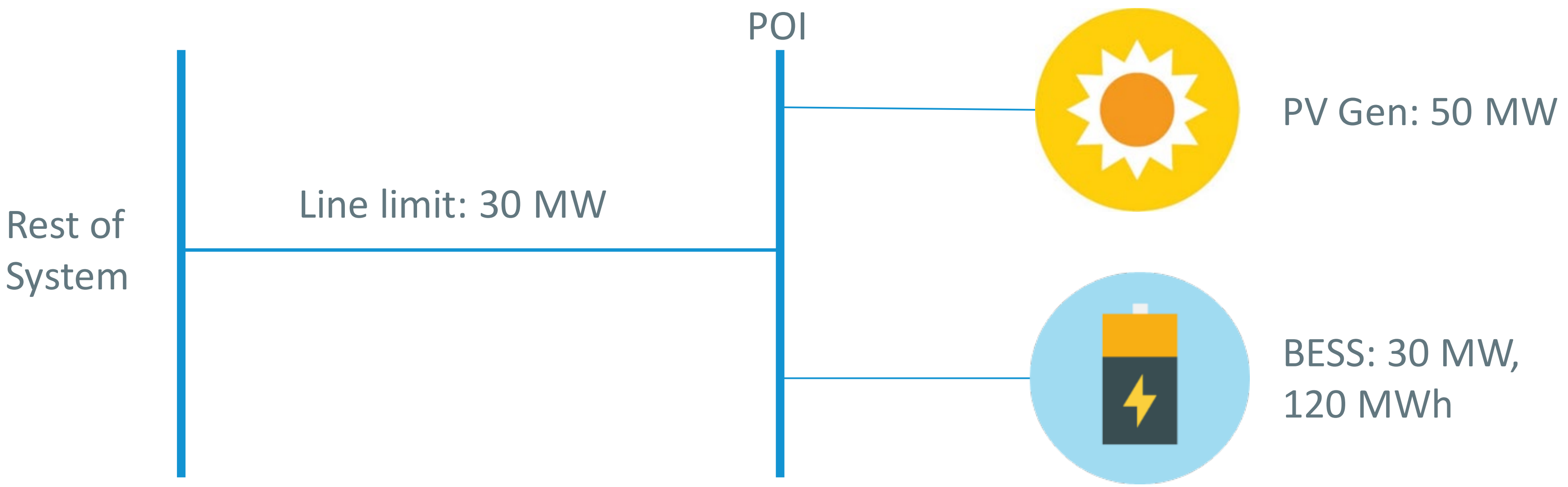
Parent Category	Parent Name	Collection	Child Category	Child Name	Load Coefficient (MW)
BESS	COLOCATED_BESS	Battery.Constraints	-	colocated	-1

Parent Category	Parent Name	Collection	Child Category	Child Name	Generation Coefficient (MW)
-	COLOCATED_PV	Generator.Constraints	-	colocated	1

Parent Object	Constraint	Property	Value	Data File	Units	Band	Date From	Date To	Timeslice	Scenario	Memo
System	colocated	Sense	>=		-	1					
System	colocated	RHS	0		-	1					

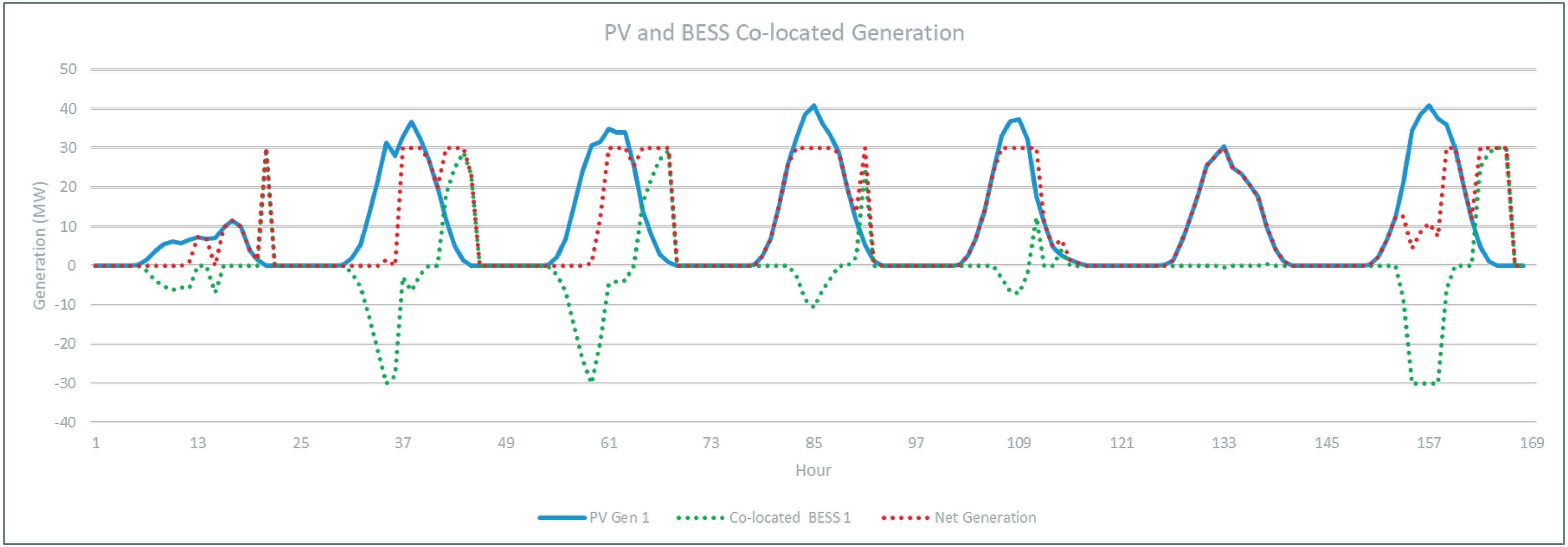
PRELIMINARY RESULTS, DO NOT CITE

New Production Cost Features: Co-located Facilities



- Co-located PV and BESS (battery energy storage system) constraints force the energy storage to only charge while the PV generator is generating and limit the output of the POI to 30 MW to stay at or under the line limit

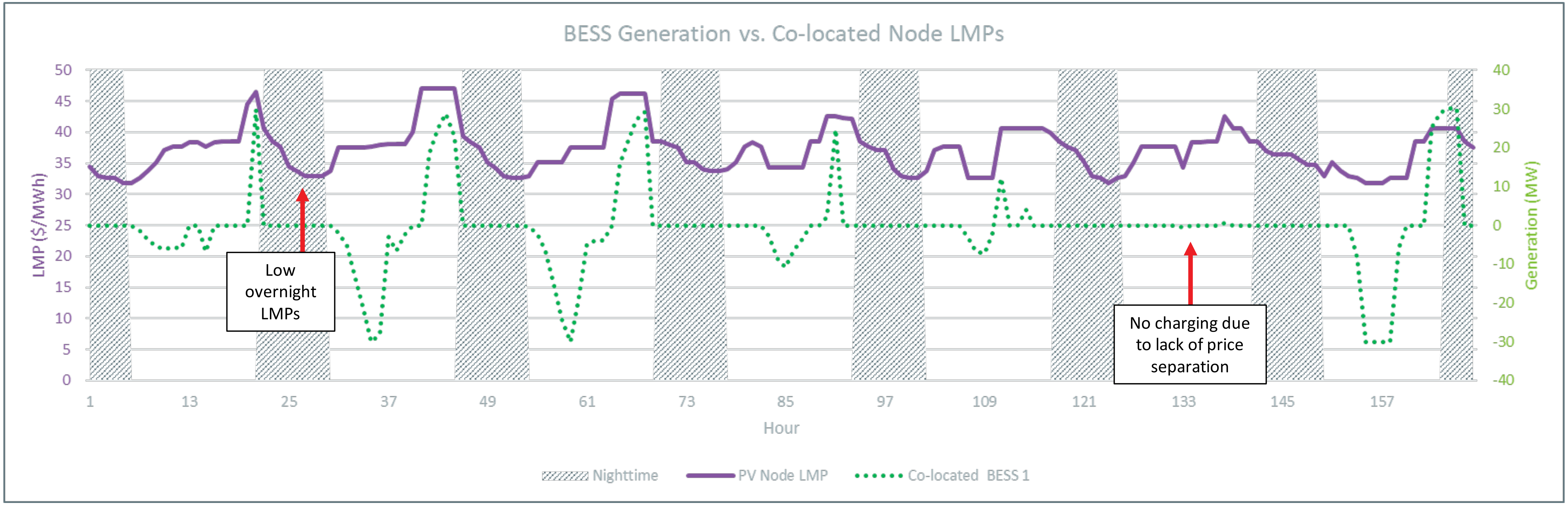
New Production Cost Features: Co-located Facilities, cont.



- The co-located BESS unit economically optimizes charging and discharging and constrains the total output to the line limit
- Due to the constraint, the BESS can only charge while the PV generator is producing

PRELIMINARY RESULTS, DO NOT CITE

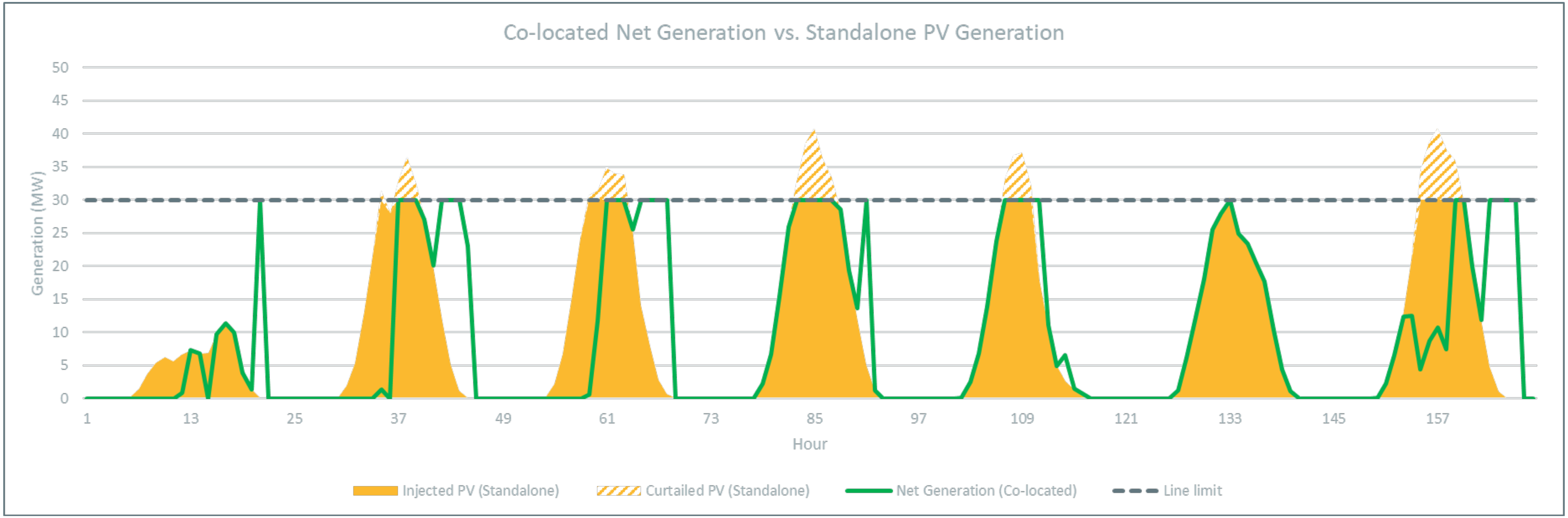
New Production Cost Features: Co-located Energy Storage and Generation, cont.



- Even though the best recharging opportunities sometimes happen overnight when LMPs are lower, the energy storage is constrained to only charge during the day and requires sufficient price separation to charge and discharge

PRELIMINARY RESULTS, DO NOT CITE

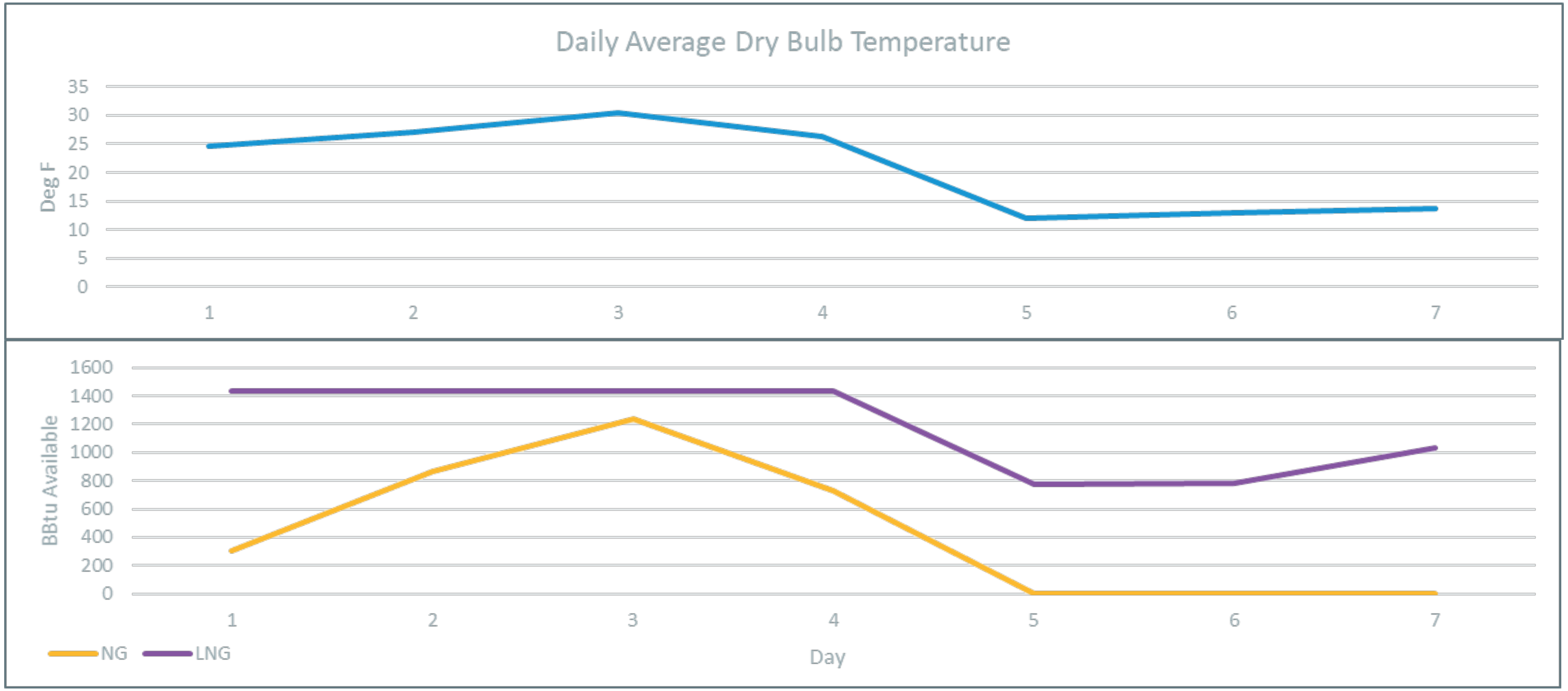
New Production Cost Features: Co-located Facilities, cont.



- Due to the energy storage optimization, the co-located facility is able to host a 50 MW solar farm behind a 30 MW interface without any curtailment and with additional revenue
  - Standalone (1 week): 1,546.6 MWh injected into the grid, 116.4 MWh curtailed
    Capacity factor = 18.4%, revenues = $57,020.5
  - Co-located (1 week): 1,596.4 MWh injected into the grid, 66.7 MWh lost in battery cycling
    Capacity factor = 19.0%, revenues = $62,093.4

PRELIMINARY RESULTS, DO NOT CITE

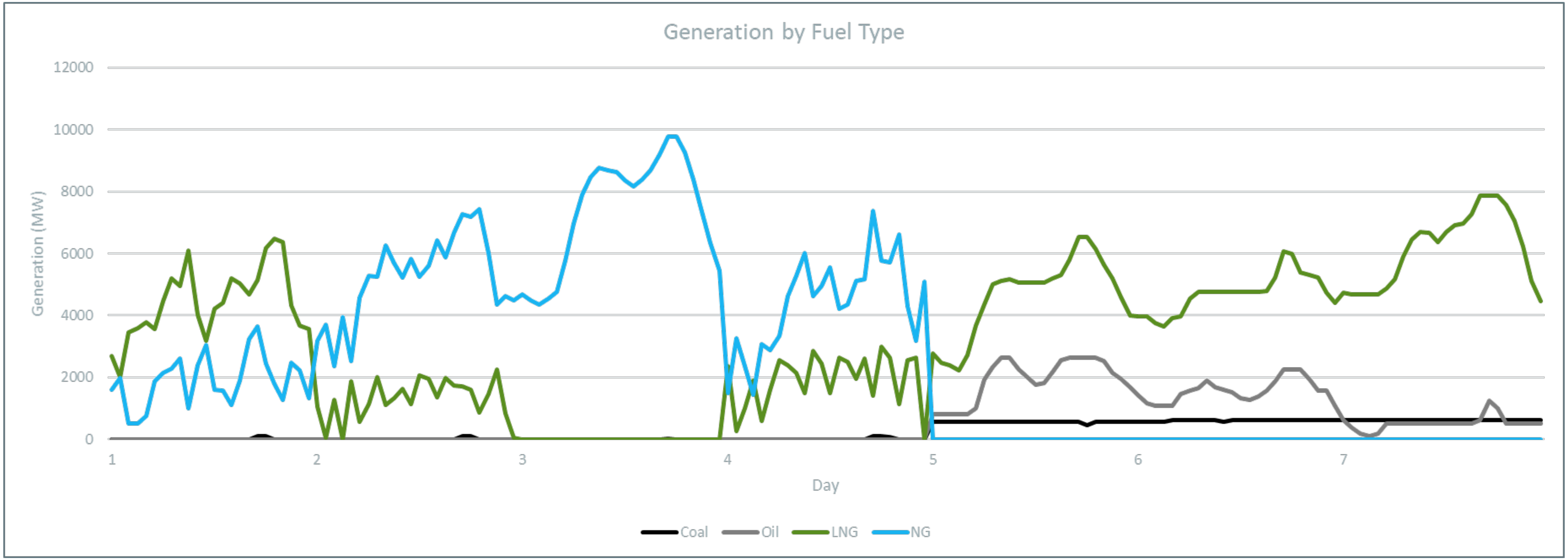
New Production Cost Features: Generator Fuel-Switching



- If an incentive (changing fuel prices) or fuel constraint (limited pipeline capacity) is provided, generators will switch fuel types to minimize production cost
- In this example, low winter temperatures lead to daily NG (and secondary LNG) constraints

PRELIMINARY RESULTS, DO NOT CITE

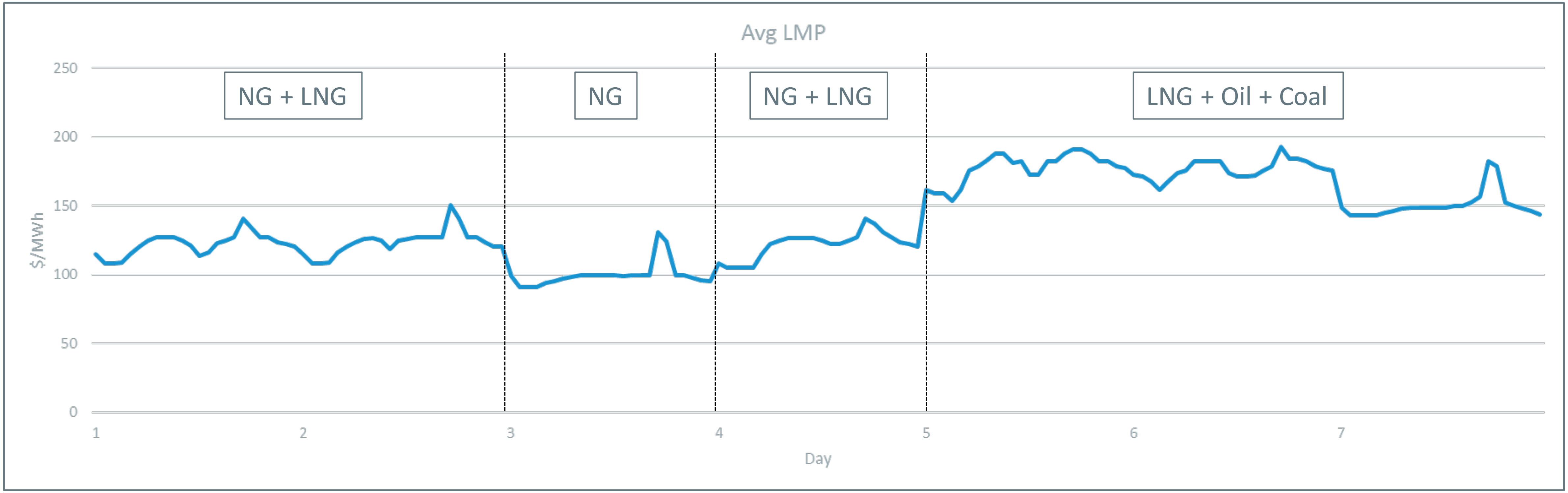
New Production Cost Features: Generator Fuel-Switching, cont.



- Days 1, 2, and 4 require the need for LNG to supplement available NG to meet electric generation demand
- Day 3 has sufficient NG supplies to meet electric generation demand and does not require switching to a unit's secondary fuel
- Days 5-7 have oil and coal production due to significant NG and LNG constraints

PRELIMINARY RESULTS, DO NOT CITE

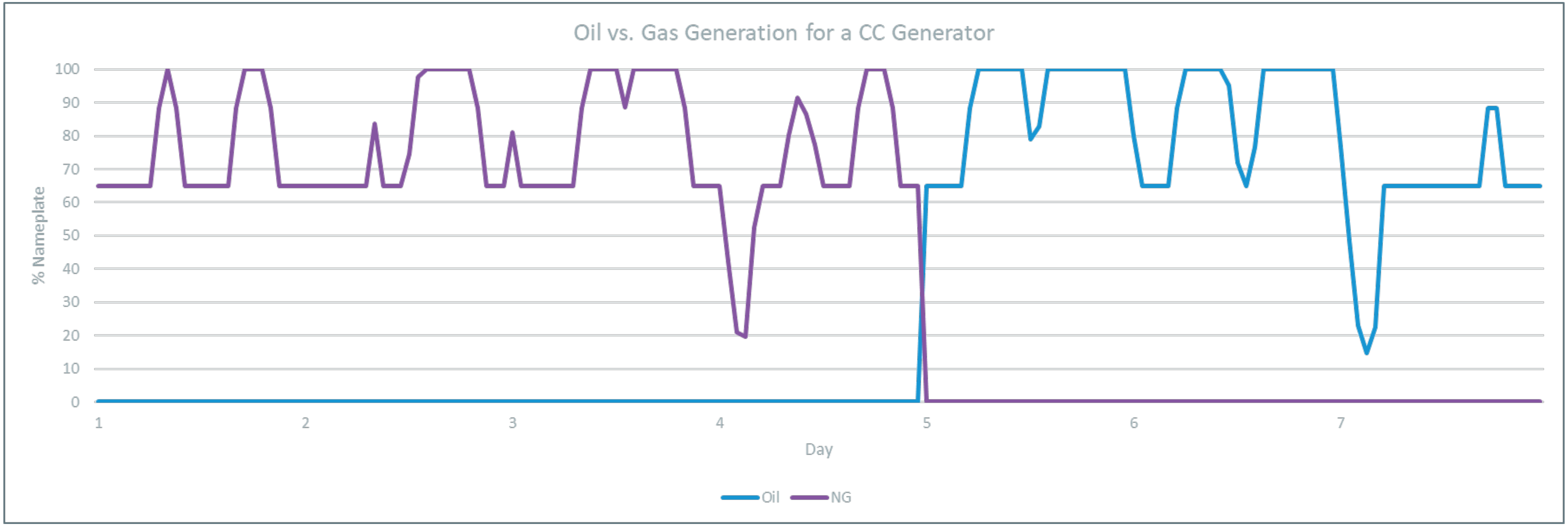
New Production Cost Features: Generation Fuel-Switching, cont.



- Cold winter days with gas scarcity result in LMP spikes as oil and coal generation comes online
- A temperature dependent NG and LNG availability curve allows PLEXOS to mimic historical cold weather driven LMPs

PRELIMINARY RESULTS, DO NOT CITE

New Production Cost Features: Generator Fuel-Switching, cont.



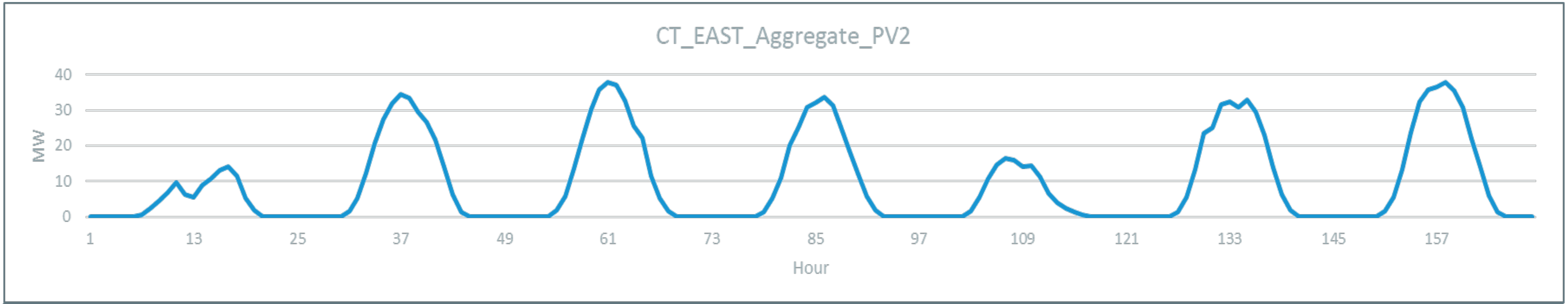
- Individual generators will swap their fuel supplies day to day based on availability and/or fuel price dynamics

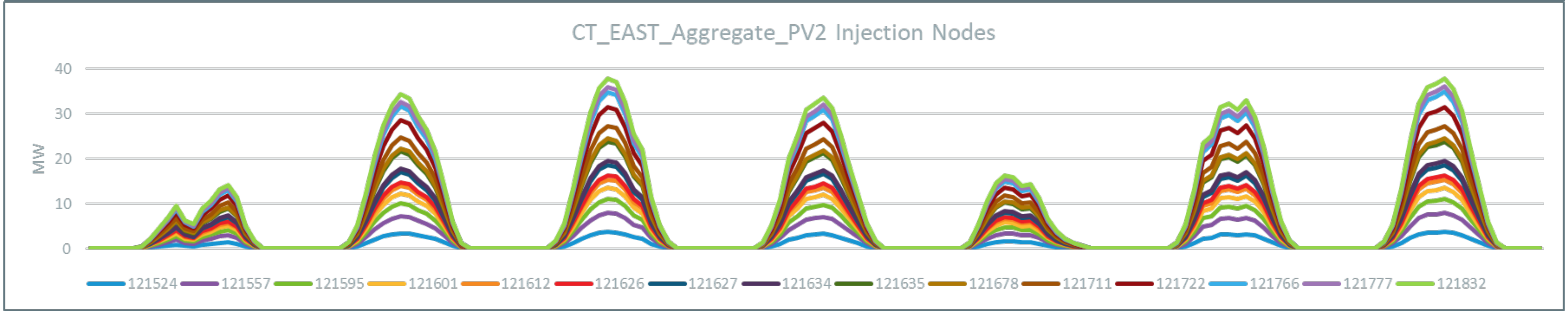
PRELIMINARY RESULTS, DO NOT CITE

New Production Cost Features: Distributed Generation in Nodal Modeling

- While previous economic studies have modeled New England as a 13 bus pipe and bubble model, PLEXOS nodal (bus level) simulations are feasible without excessive runtimes
- Assumed distributed generation has been modeled at the Load Zone or Dispatch Zone level
  - e.g., One aggregate BTM-PV generator for the CT East Dispatch Zone
- PLEXOS allows an aggregate generator to split its profile into multiple nodes, which allows transmission flows to be evaluated at a granular level and under contingencies

New Production Cost Features: Distributed Generation in Nodal Modeling, cont.

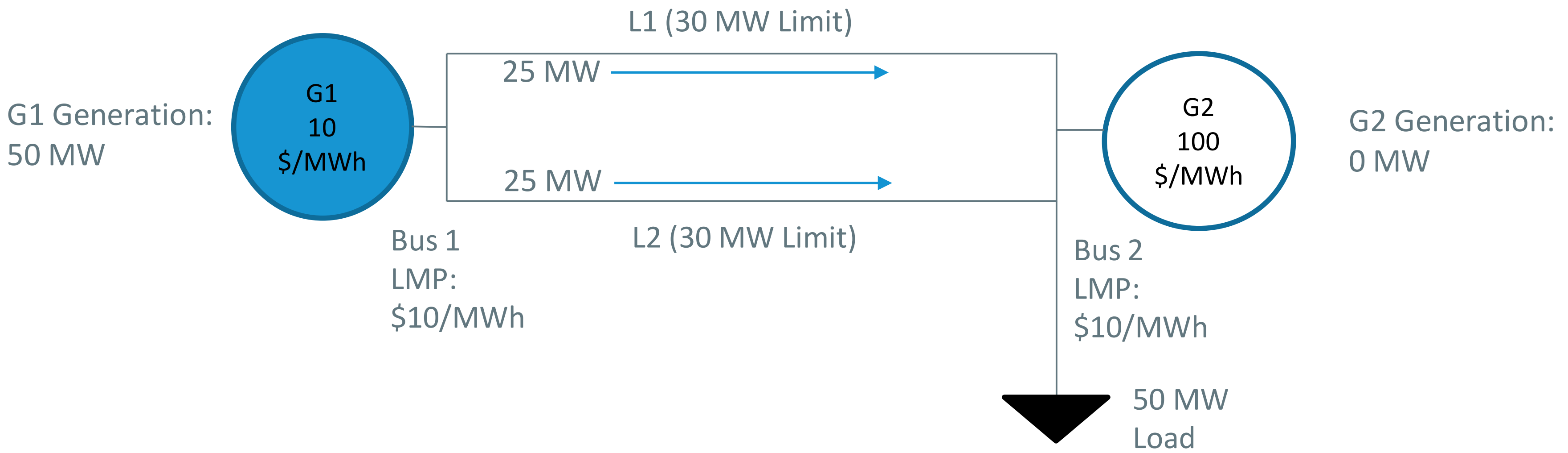




- With distributed generation modeling, one aggregate generator profile can inject power into as many nodes as desired based off of a generation participation factor

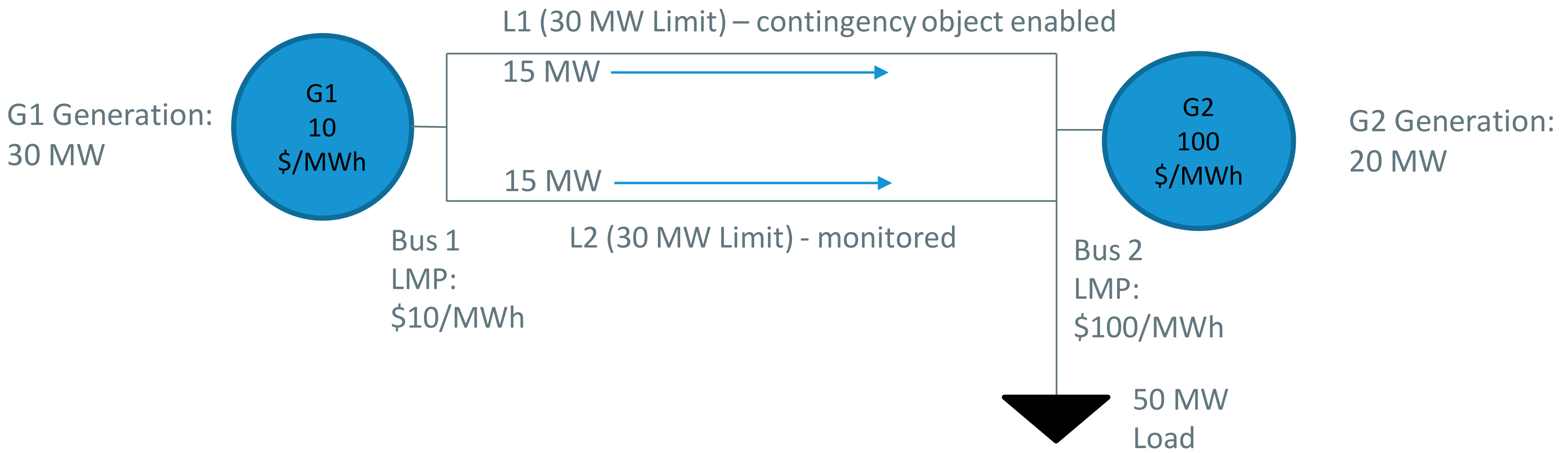
PRELIMINARY RESULTS, DO NOT CITE

New Production Cost Features: Contingency Modeling



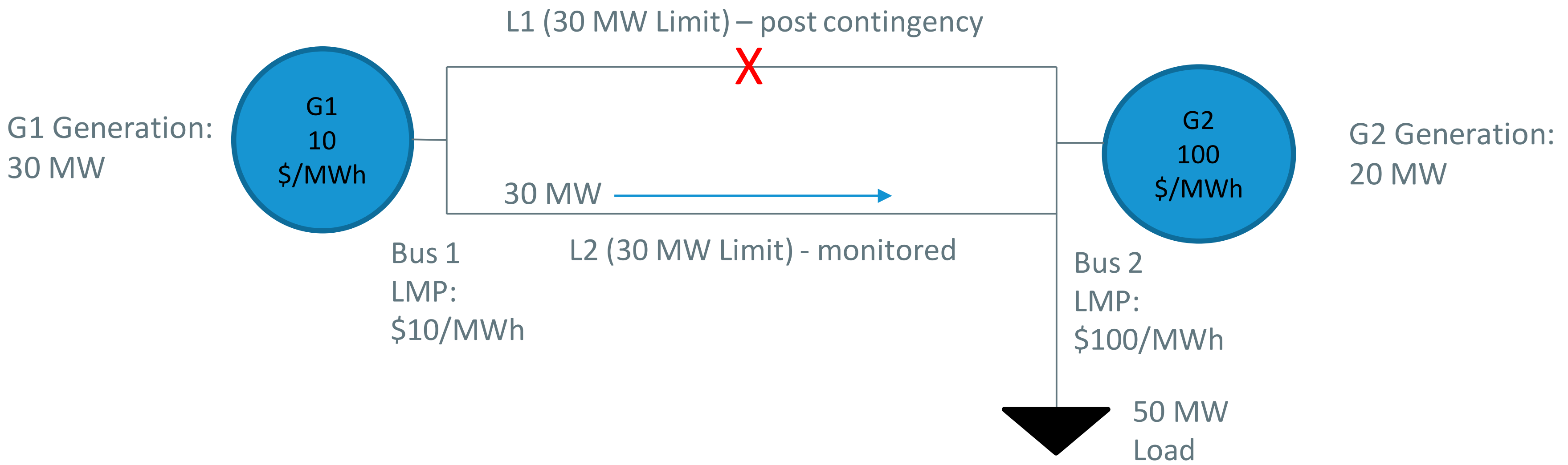
- In operation of the above system without contingency modeling, G1 would supply all of the load through L1 and L2
- LMPs on both buses would be $10/MWh

New Production Cost Features: Contingency Modeling, cont.



- With a contingency object enabled on L1, the system is dispatched such that if a contingency were to happen, the thermal limits of other lines and transformers would be respected (a security-constrained dispatch)
- If L1 were to go out, the limit of L2 would not be violated. To serve the rest of the load at Bus 2, the more expensive G2 is now providing 20 MW, and the LMP on Bus 2 is now $100/MWh
- The contingency on L1 is considered binding, and has a shadow price of $90/MWh

New Production Cost Features: Contingency Modeling, cont.



- Post contingency flows are calculated even though the contingencies do not happen in the actual simulation. In the post contingency flow, L1 is tripped, but L2 can handle the dispatch without violating thermal limits
- Contingency modeling modifies the optimal dispatch to ensure protection of transmission assets. Contingency modeling also reports binding contingencies and their associated shadow prices to allow for calculation of the congestion cost of the contingency
- In a larger system, contingency modeling ***significantly*** (~10x) increases runtime and computational power requirements. The ISO is investigating how to optimize contingency modeling

BENCHMARK SCENARIO ASSUMPTIONS

Economic Planning for the Clean Energy Transition

Benchmark Scenario Assumptions

- The ISO has built a case with assumptions similar to assumptions used in previous economic studies
- After understanding how the historical set of assumptions function in PLEXOS, the ISO will illustrate the effect of changing one assumption at a time in the model
- By changing one assumption at a time, the effects of individual assumptions will be more discernable
- By modeling 2021, the goals for the benchmark scenario are:
  - to test the fidelity of the model as compared to observed outcomes
  - to understand how updated assumptions affect the model results before moving on to future scenarios

Benchmark Scenario Assumptions: Network Model

Topic	Assumption
Network	• The base power flow network model is from the 2021 ISO-NE [Transmission Planning Base Case Library](#) (TPBCL)(CEII needed) • Power flow model used: 2023_PK_SS_Case.sav
Distributed Generation	• Distributed generation (EE, ADR, Class 2 PV, and Class 3 PV) distributions are from the TPBCL • The total capacity of distributed generators is scaled to match the 2021 installed values from the 2021 CELT
RSP Model	• The nodal network has been collapsed into a pipe and bubble (RSP zone) model with 13 internal buses and 5 external buses • Interface limits are from FCA 12 (2021/2022 commitment period), but the initial model will be unconstrained

Benchmark Scenario Assumptions: Generator Model

Topic	Assumption
Generators	• Generator interconnection points, max capacities, and min capacities are sourced from the base case database (BCDB) • Other market sensitive generator information (heat rate, min/max up/downtime, ramp rate, etc.) is from internal ISO sources
Fuels	• Generator fuel types are sourced from the CELT • Region-wide fuel prices are from the EIA website • Natural gas is given a seasonal multiplier of + 10% in the winter and -10% in the summer
Emissions	• Most generator emission rates are from internal ISO sources and generator reports • If internal sources have no information, emission rates are calculated based off of heat rates and average emission rates per fuel type • CO_2 is priced according to the 2021 RGGI clearing price ($7.60 / ton), and Massachusetts generators have MAGWSA CO_2 emission prices ($7.00 / ton)

PRELIMINARY RESULTS, DO NOT CITE

Benchmark Scenario Assumptions: Demand Model

Topic	Assumption
Load	• 2021 DNV gross load data profile is used. The DNV gross load is reconstituted for BTM-PV but not EE, so EE is not included in the model to avoid double counting • Substation load distributions are based off of the TPBCL
BTM-PV (Behind the Meter Photovoltaic)	• Substation distributions are based off of the TPBCL, but are scaled to match the 2021 CELT values for 2021 • DNV profiles are used to determine production
ADR (Active Demand Response)	• Substation distributions are based off of the TPBCL, but are scaled to match the 2021 CELT • One tier of ADR is assigned a price of $500/MWh

Reference Scenario Assumptions: Profiled Resources

Topic	Assumption
Hydro	• The ISO has a historically averaged hydro profile which is integrated into the PLEXOS model. This model determines monthly max/min capacity and energy availability
Wind & Solar	• Wind and Solar production profiles are from the 2021 DNV data
Tie Lines	• A three-year diurnal flow profile has been used to determine interchange with HQ, NB, and NY – this has been created from the years 2019, 2020, and 2021

Benchmark Scenario Assumptions: Additional Assumptions

Topic	Assumption
Energy Storage	• Energy storage operates with a VOM (variable outage and maintenance) cost of $3/MWh • BESS units are assumed to have a charging efficiency of 85% and a discharging efficiency of 100% • Pumped storage: 1,594 MW rating / 11,120 MWh capacity • BESS: 22.2 MW rating / 44.4 MWh capacity (2 hour)
Threshold Prices	• All curtailable resources have a threshold price of -$10/MWh • Though curtailment should be minimal, the ISO wishes to test how the PLEXOS curtailment logic functions before enforcing a multi-tier threshold curtailment order

Benchmark Scenario Assumptions: Generator Capacity by Type

Type	Capacity (MW)	Type	Capacity (MW)
PV I (utility scale)	277	IC (internal combustion)	136
PV II (settlement only)	1,742	GT (gas turbine)	4,020
PV III (behind the meter)	2,726	ST (nuclear) (steam turbine)	3,380
Wind	1,393	ST (non-nuclear) (steam turbine)	6,799
Hydro (pondage and run of river)	1,759	CC (combined cycle)	15,611
ADR (active demand resources)	548	PS (pumped storage)	1,594
SOG (settlement only generators)	336	PB (pressurized fluidized-bed combustion)	68

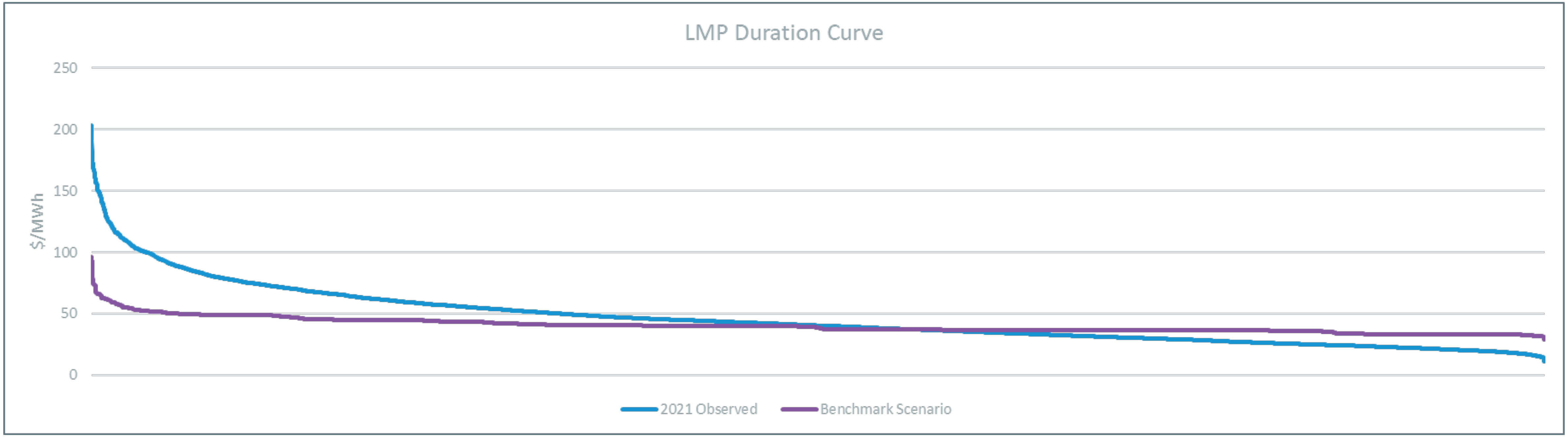
PRELIMINARY RESULTS, DO NOT CITE

PRELIMINARY BENCHMARK RESULTS

Benchmark Scenario Preliminary Results Overview

- Historical metrics from 2021 SMD results were used to compare data from different scenario runs. These include:
  - Average and annual LMPs
  - Production by fuel type
  - Interface flows
- To compare the effects that incremental assumption changes have on the simulation, one variable was changed at a time, then the output differences from each variable was examined

Preliminary Results: Historical vs. Benchmark Scenario



- LMPs were generally lower in PLEXOS due to the real system dispatching off of a bid offer basis, while PLEXOS optimizes dispatches to minimize cost (Pearson coefficient = +0.5386)
- Historical high and low LMPs were more drastic than PLEXOS, which resembled a more average figure
- The 2021 observed average was $45.92/MWh, while the benchmark average was $41.05/MWh

Preliminary Results: Historical vs. Reference Scenario, cont.

Generation (GWh) / % of total	Coal	Gas	Hydro	Nuc	Oil	LFG	MSW	PV (Non BTM)	Wind	Wood	Net Tie Flow	Total
2021 Observed	558 (0.5%)	52,255 (44.1%)	7,345 (6.2%)	27,073 (22.9%)	228 (0.2%)	438 (0.4%)	2,984 (2.5%)	2,669 (2.3%)	3,611 (3.1%)	2,416 (2.0%)	18,826 (15.9%)	118.4 TWh
Reference Scenario	0 (0.0%)	53,328 (44.8%)	7,250 (6.1%)	29,604 (24.9%)	0 (0.0%)	285 (0.2%)	2,842 (2.4%)	2,541 (2.1%)	4,177 (3.5%)	2,540 (2.1%)	16,270 (13.7%)	118.8 TWh
Observed - Reference	558 (+0.5%)	-1,073 (-0.7%)	96 (+0.1%)	-2,531 (-2.0%)	228 (+0.2%)	153 (+0.2%)	142 (+0.1%)	128 (+0.2%)	-556 (-0.4%)	-124 (-0.1%)	2,554 (+2.2%)	-0.4 TWh

- Nuclear generation was different due to historical outages not being included in the model
- The net tie flow energy difference was due to differences between the historical and diurnal flow models. The energy difference was mostly compensated for by gas generation
- Total energy is different due to small differences in BTM-PV modeling

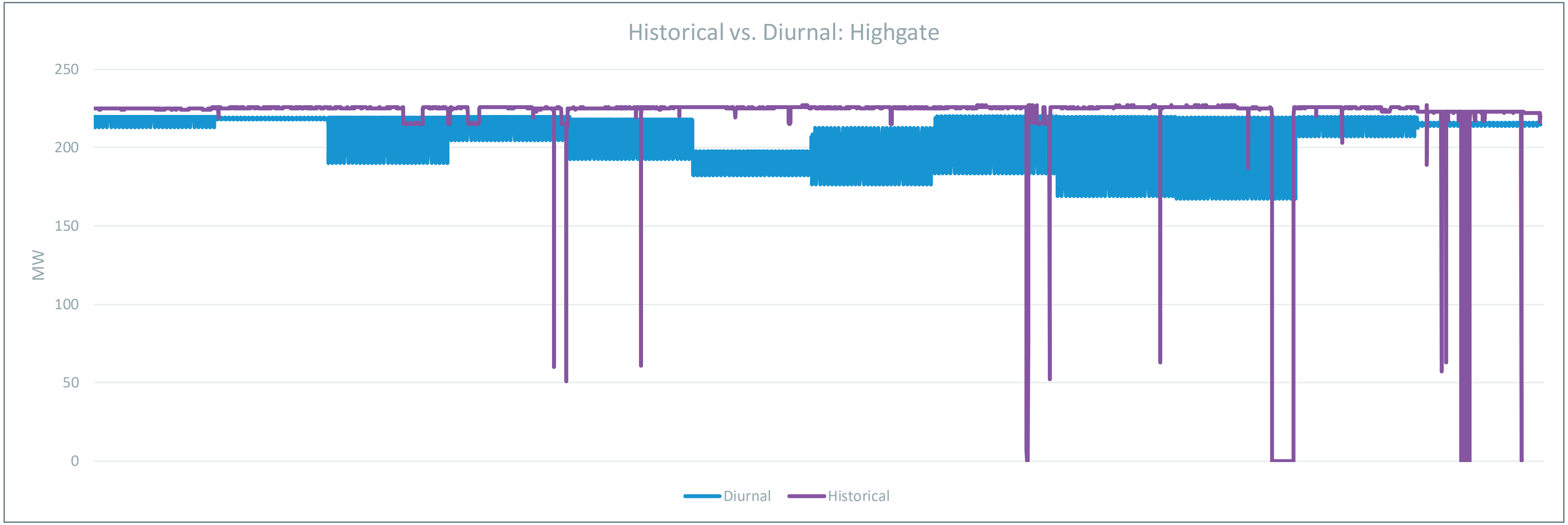
Table of Incremental Assumption Changes

Scenario Name	Change
Historical Tie Profiles	• Replace diurnal import/export profiles with historical metered flows
PI Data Profiles	• Replace DNV wind, solar, and load profiles with historical metered PI data • PI Load data is post EE and BTM-PV - both generator types are turned off • PI Wind data is post-DNE (do not exceed) signal
Fuel Constraints	• Enforce daily NG and LNG constraints based off of daily average temperature
Daily NG Prices	• Replace monthly NG price with daily pipeline spot prices
Interface Constrained	• Enforce interface limits
Daily Pipeline Prices	• Daily NG prices for multiple pipelines

- These assumption changes are additive and are being stacked on top of one another with each iteration

PRELIMINARY RESULTS, DO NOT CITE

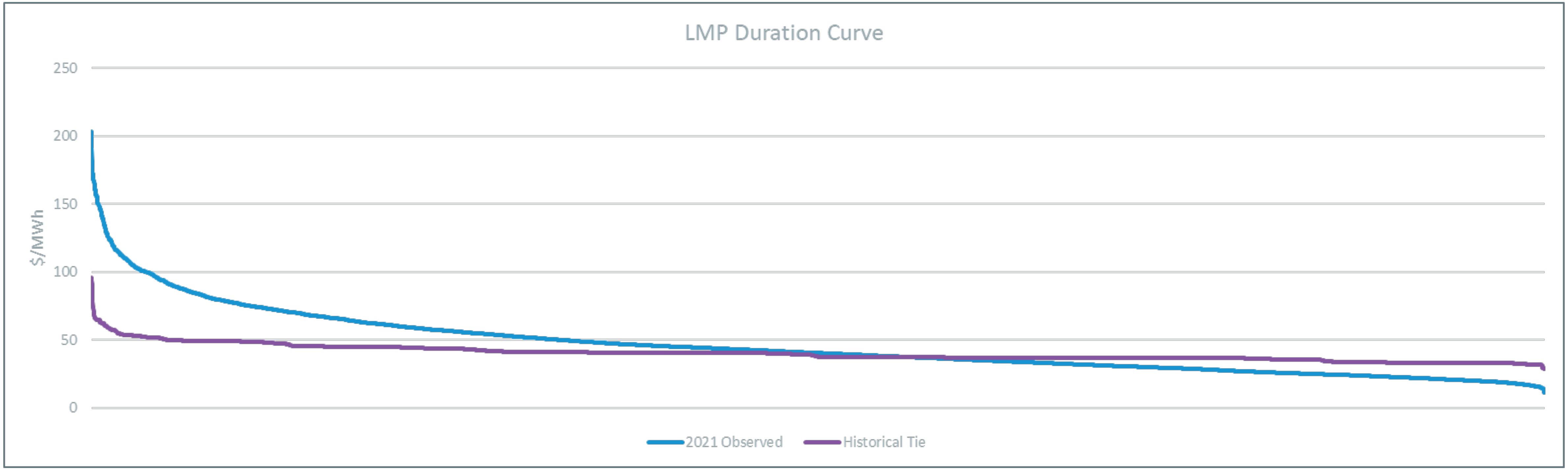
Preliminary Results: Historical Tie Profiles



- Instead of using an average diurnal profile from the past three years, historical tie profiles reflected the actual observed MW flow for all external interfaces (example of Highgate import shown in the graph above)

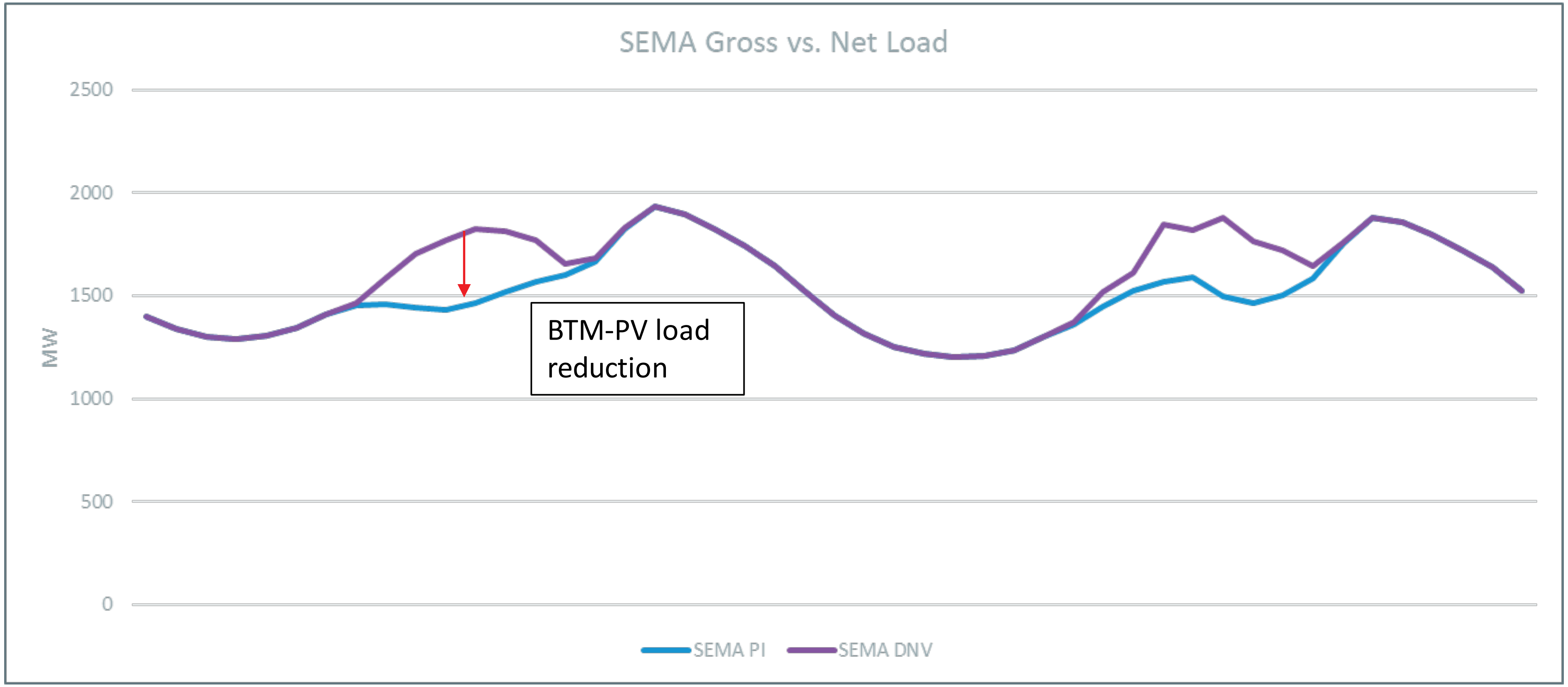
PRELIMINARY RESULTS, DO NOT CITE

Preliminary Results: Historical Tie Profiles



- Historical profiles imported slightly more energy, displacing more expensive generation and slightly reducing average annual LMPs
  - LMPs were $40.78/MWh for Historical Tie, $45.92/MWh for 2021 Observed
  - Pearson coefficient = +0.5427 (improvement of 0.0041 from last iteration)

Preliminary Results: PI Load/Wind/Solar Profiles



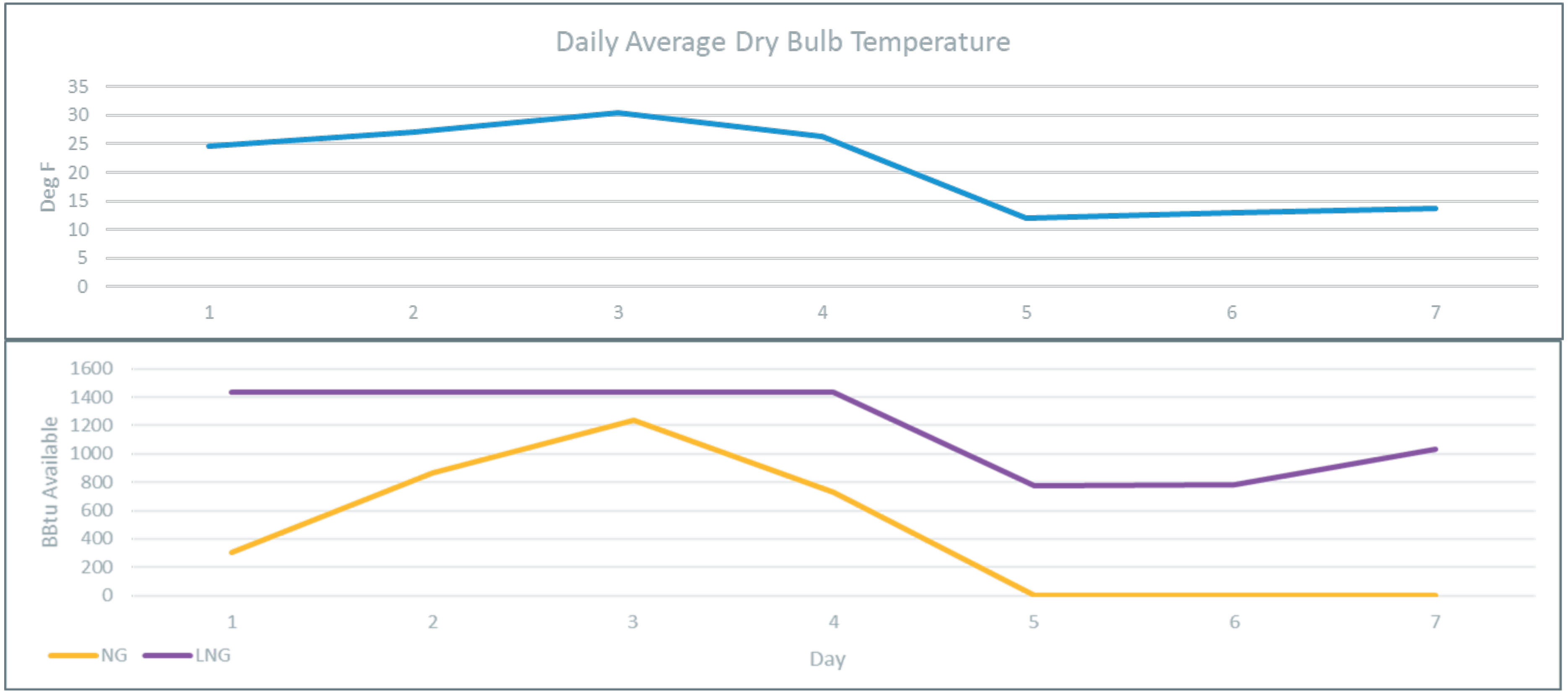
- The PI net load profiles are actual metered loads, while DNV gross load profiles are reconstituted for BTM-PV generation
- Using the PI profiles, BTM-PV is disabled as a generator type, as it is already accounted for in the load

Preliminary Results: PI Load/Wind/Solar Profiles

Generation (GWh) / % of total	Coal	Gas	Hydro	Nuc	Oil	LFG	MSW	PV (Non BTM)	Wind	Wood	Net Tie Flow	Total
2021 Observed	558 (0.5%)	52,255 (44.1%)	7,345 (6.2%)	27,073 (22.9%)	228 (0.2%)	438 (0.4%)	2,984 (2.5%)	2,669 (2.3%)	3,611 (3.1%)	2,416 (2.0%)	18,826 (15.9%)	118.4 TWh
PI Profiles	0 (0.0%)	49,383 (41.6%)	8,924 (7.5%)	29,604 (25.0%)	0 (0.0%)	281 (0.2%)	2,839 (2.4%)	2,643 (2.2%)	3,592 (3.0%)	2,532 (2.1%)	18,826 (15.9%)	118.6 TWh
Observed - PI	558 (+0.5%)	2,872 (+2.5%)	-1,641 (-1.3%)	-2,531 (-2.1%)	228 (+0.2%)	157 (+0.2%)	145 (+0.1%)	26 (+0.1%)	18 (+0.1%)	-117 (-0.1%)	0 (+0.0%)	-0.2 TWh

- Simulated and observed wind and solar generation were roughly equal, and tie generation matched exactly
- Hydro generation was different due to the historical averaged hydro model not matching the 2021 hydro generation and a difference in pumped storage operation (two vs. one cycles/day)
- The differences in nuclear and hydro generation were compensated for with gas generation
- The unit commitment algorithm did not dispatch coal or oil generation

Preliminary Results: Fuel Constraints



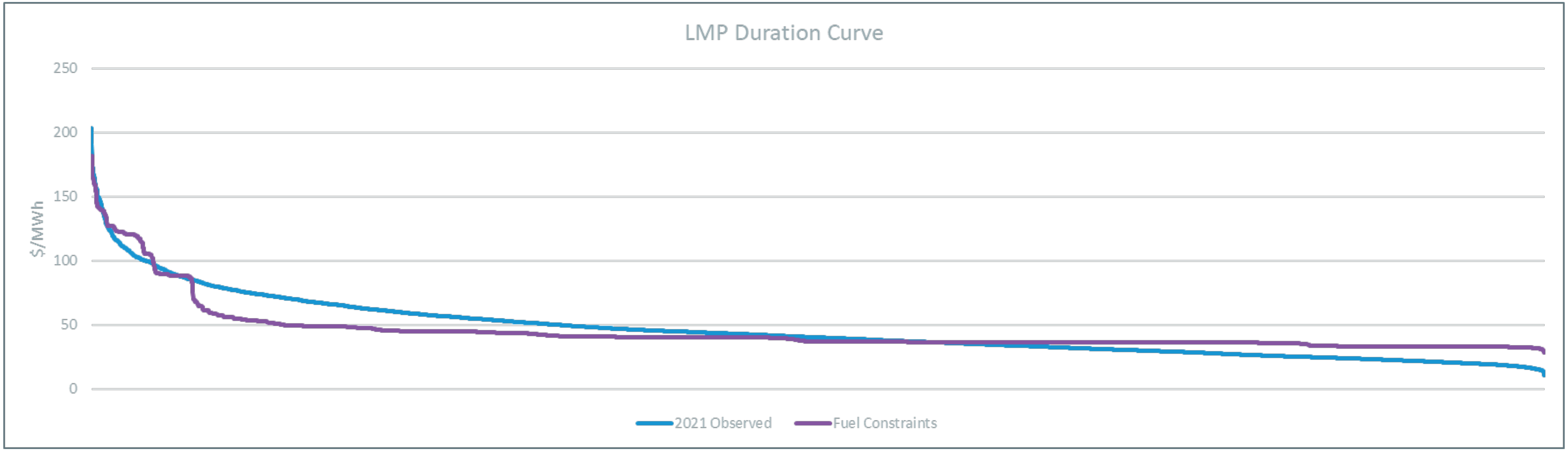
- PLEXOS gas constraints limited the amount of NG and LNG available based off of daily average temperatures
- LNG was available to every NG generator as an alternate fuel

Preliminary Results: Fuel Constraints, cont.

Generation (GWh) / % of total	Coal	Gas	Hydro	Nuc	Oil	LFG	MSW	PV (Non BTM)	Wind	Wood	Net Tie Flow	Total
2021 Observed	558 (0.5%)	52,255 (44.1%)	7,345 (6.2%)	27,073 (22.9%)	228 (0.2%)	438 (0.4%)	2,984 (2.5%)	2,669 (2.3%)	3,611 (3.1%)	2,416 (2.0%)	18,826 (15.9%)	118.4 TWh
Fuel Constraints	88.2 (0.1%)	48,966 (41.3%)	8,876 (7.5%)	29,604 (25.0%)	77 (0.1%)	298 (0.3%)	2,904 (2.5%)	2,643 (2.3%)	3,593 (3.1%)	2,687 (2.3%)	18,826 (15.9%)	118.5 TWh
Observed - Constraints	470 (+0.4%)	3,289 (+2.8%)	-1,530 (-1.3%)	-2,531 (-2.1%)	150 (+0.1%)	140 (+0.1%)	80 (+0.0%)	26 (+0.0%)	18 (+0.0%)	-271 (-0.3%)	0 (+0.0%)	-0.1 TWh

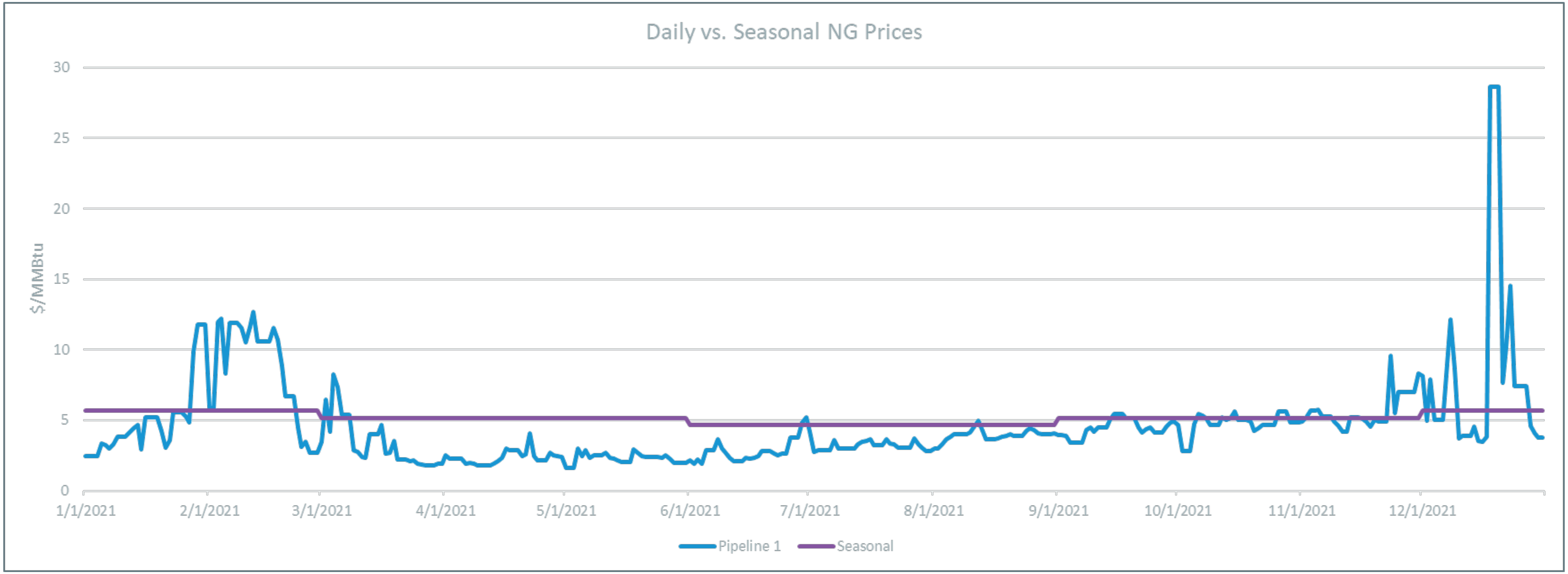
- The benchmark model now experienced some coal and oil generation, as well as a decent amount of LNG generation
  - LNG generation (1,866 GWh) was included in Gas
- LFG, MSW, and Wood generation were also slightly higher

Preliminary Results: Fuel Constraints, cont.



- Winter LMPs were higher when LNG, oil, and coal generation come online
  - Simulated average LMPs were slightly higher than the historical observed ($46.10/MWh vs $45.90/MWh)
- Outside of higher winter LMPs, the remainder of the PLEXOS year resembled an averaged version of the historical LMPs
  - Pearson coefficient = +0.4681 (reduction of 0.0745 compared to last iteration)

Preliminary Results: Daily Natural Gas Prices



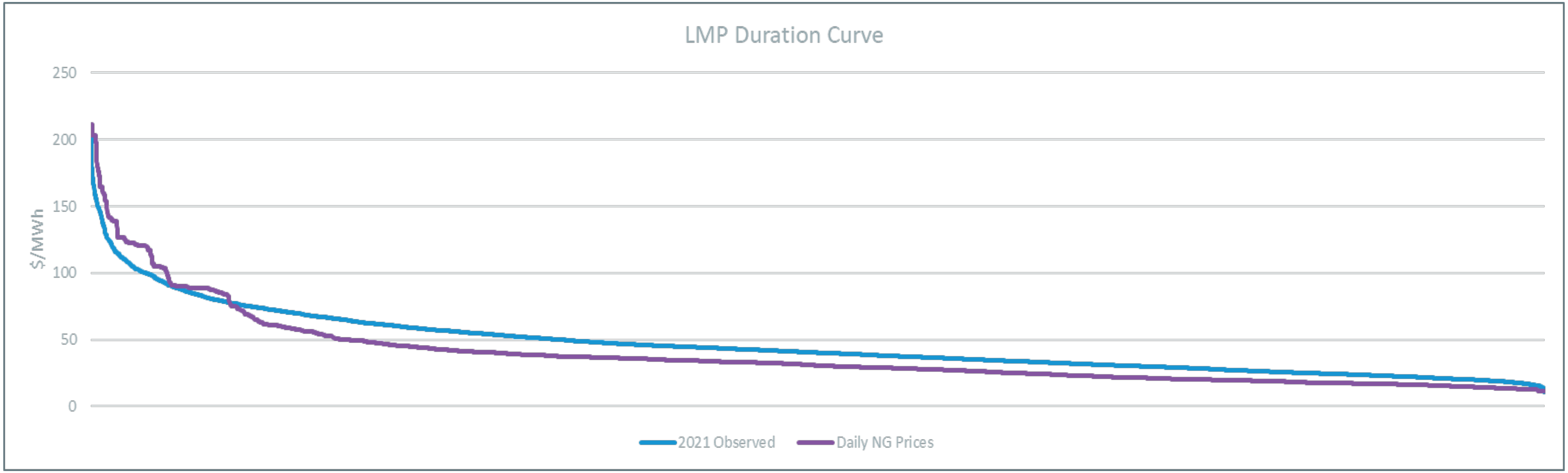
- Rather than seasonal gas prices, daily spot gas prices for a major pipeline were implemented in conjunction with fuel constraints

Preliminary Results: Daily Natural Gas Prices, cont.

Generation (GWh) / % of total	Coal	Gas	Hydro	Nuc	Oil	LFG	MSW	PV (Non BTM)	Wind	Wood	Net Tie Flow	Total
2021 Observed	558 (0.5%)	52,255 (44.1%)	7,345 (6.2%)	27,073 (22.9%)	228 (0.2%)	438 (0.4%)	2,984 (2.5%)	2,669 (2.3%)	3,611 (3.1%)	2,416 (2.0%)	18,826 (15.9%)	118.4 TWh
Daily NG Prices	157 (0.1%)	48,632 (41.0%)	9,091 (7.6%)	29,604 (25.0%)	267 (0.2%)	288 (0.2%)	2,935 (2.5%)	2,643 (2.2%)	3,593 (3.1%)	2,774 (2.3%)	18,826 (15.9%)	118.7 TWh
Observed – Daily NG	402 (+0.4%)	3,623 (+3.1%)	-1,745 (-1.4%)	-2,531 (-2.1%)	-39 (+0.0%)	150 (+0.2%)	49 (+0.0%)	26 (+0.0%)	18 (+0.0%)	-358 (-0.3%)	0 (+0.0%)	-0.3 TWh

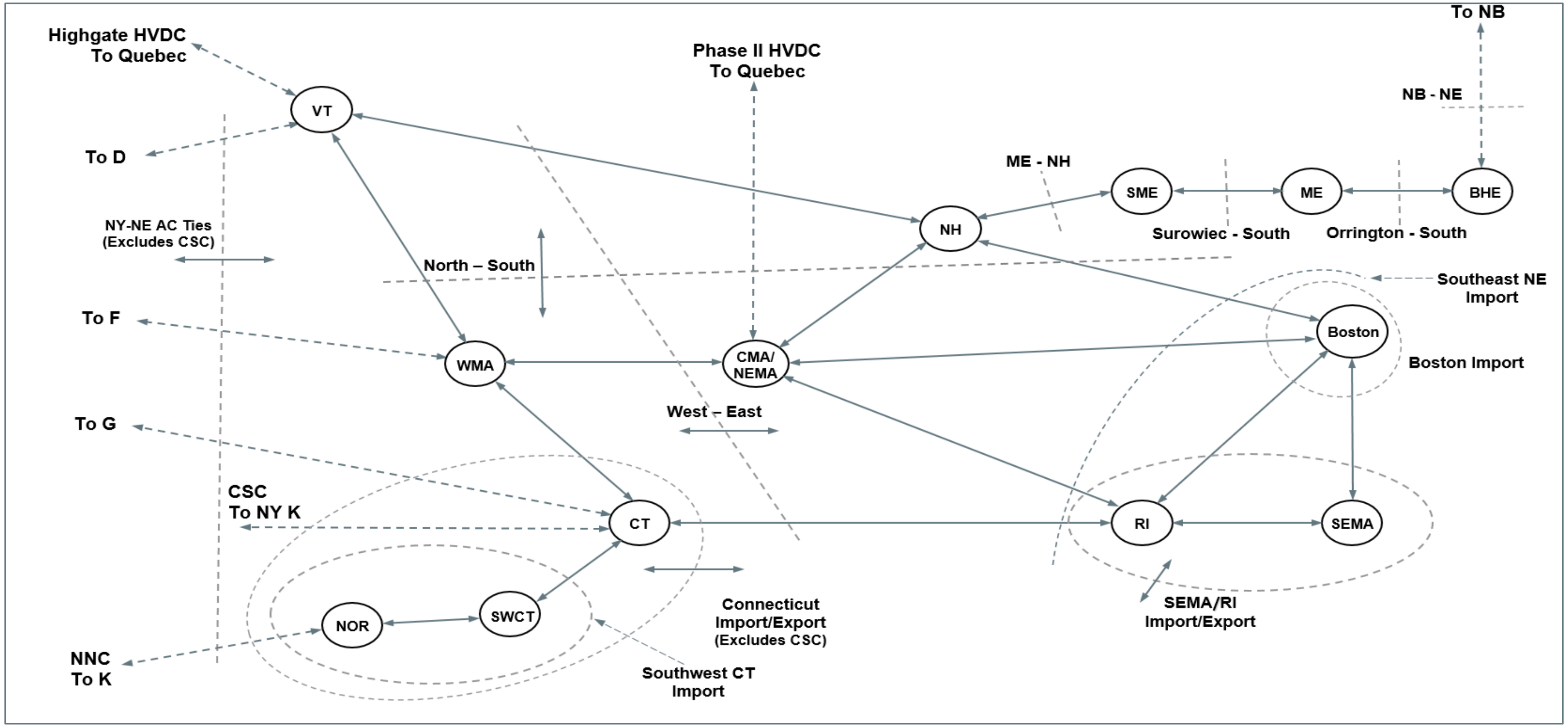
- Daily gas prices caused more coal and oil generation to be dispatched, as the combination of gas constraints and high gas prices created additional economic viability for these units to run

Preliminary Results: Daily Natural Gas Prices, cont.



- On average, simulated LMPs were lower than observed historical
  - $40.39/MWh vs. $45.92/MWh
- The overall shape of LMPs more closely resembled observed historical LMPs
  - Pearson coefficient = +0.7116 (improvement of 0.2435 compared to last iteration)

Preliminary Results: Interface Constrained



- Instead of unlimited flow across interfaces, a RSP constrained simulation enforced interface limits across the system
- Interface limits were from FCA 12, which correspond with the 2021/2022 capacity commitment period

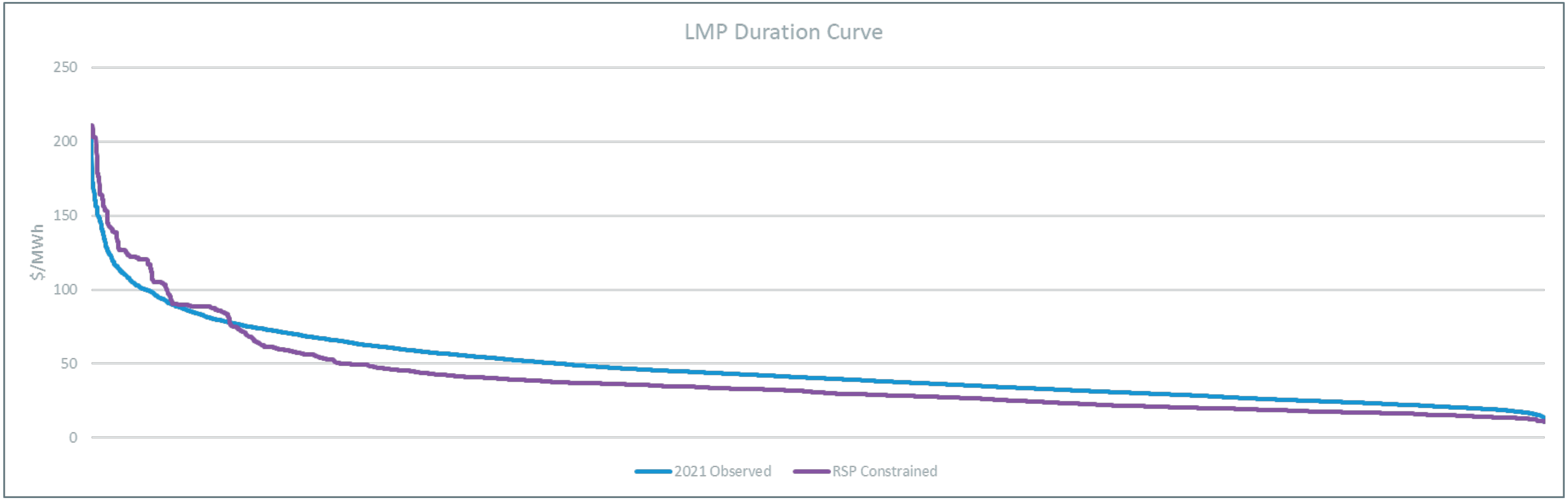
PRELIMINARY RESULTS, DO NOT CITE

Preliminary Results: Interface Constrained, cont.

Generation (GWh) / % of total	Coal	Gas	Hydro	Nuc	Oil	LFG	MSW	PV (Non BTM)	Wind	Wood	Net Tie Flow	Total
2021 Observed	558 (0.5%)	52,255 (44.1%)	7,345 (6.2%)	27,073 (22.9%)	228 (0.2%)	438 (0.4%)	2,984 (2.5%)	2,669 (2.3%)	3,611 (3.1%)	2,416 (2.0%)	18,826 (15.9%)	118.4 TWh
Interface Constrained	155 (0.1%)	48,631 (41.0%)	8,906 (7.5%)	29,604 (25.0%)	271 (0.2%)	288 (0.2%)	2,935 (2.5%)	2,643 (2.2%)	3,593 (3.1%)	2,773 (2.3%)	18,826 (15.9%)	118.6 TWh
Observed - Constrained	403 (+0.4%)	3,624 (+3.1%)	-1,559 (-1.3%)	-2,531 (-2.1%)	-43 (-0.0%)	150 (+0.2%)	49 (+0.0%)	26 (+0.0%)	18 (+0.0%)	-357 (-0.3%)	0 (+0.0%)	-0.2 TWh

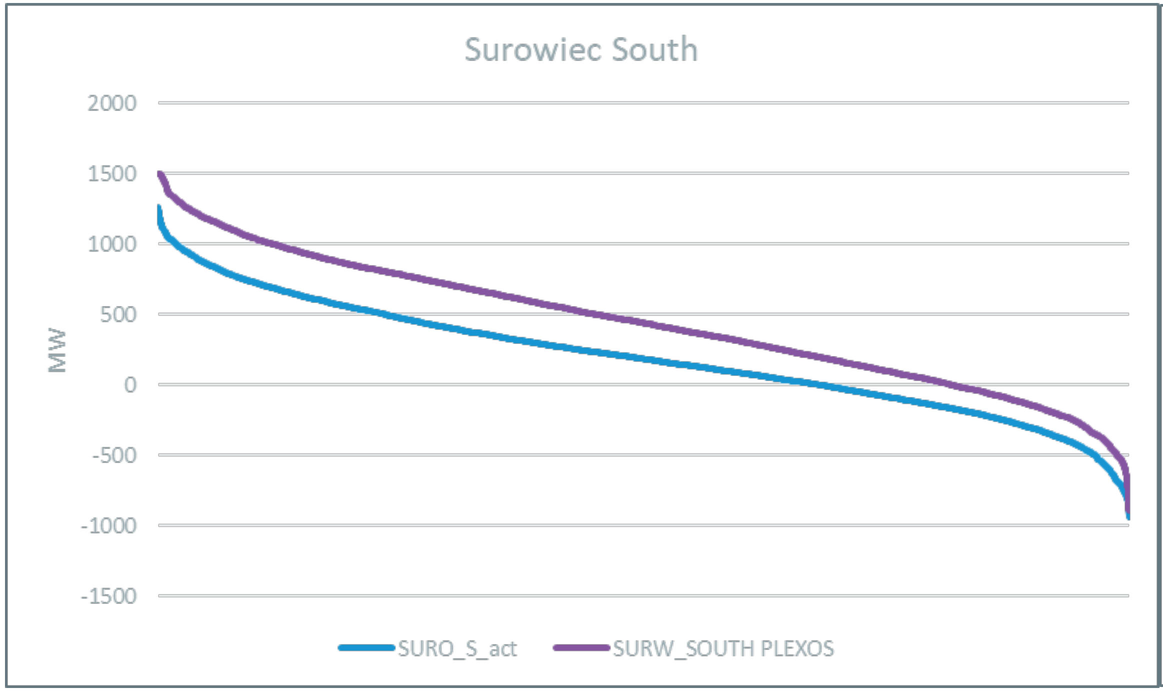
- Interface constraints did not cause any significant changes outside of slightly raising LMPs from the daily NG prices
- Oil produced more energy than observed in 2021, but coal still produced less

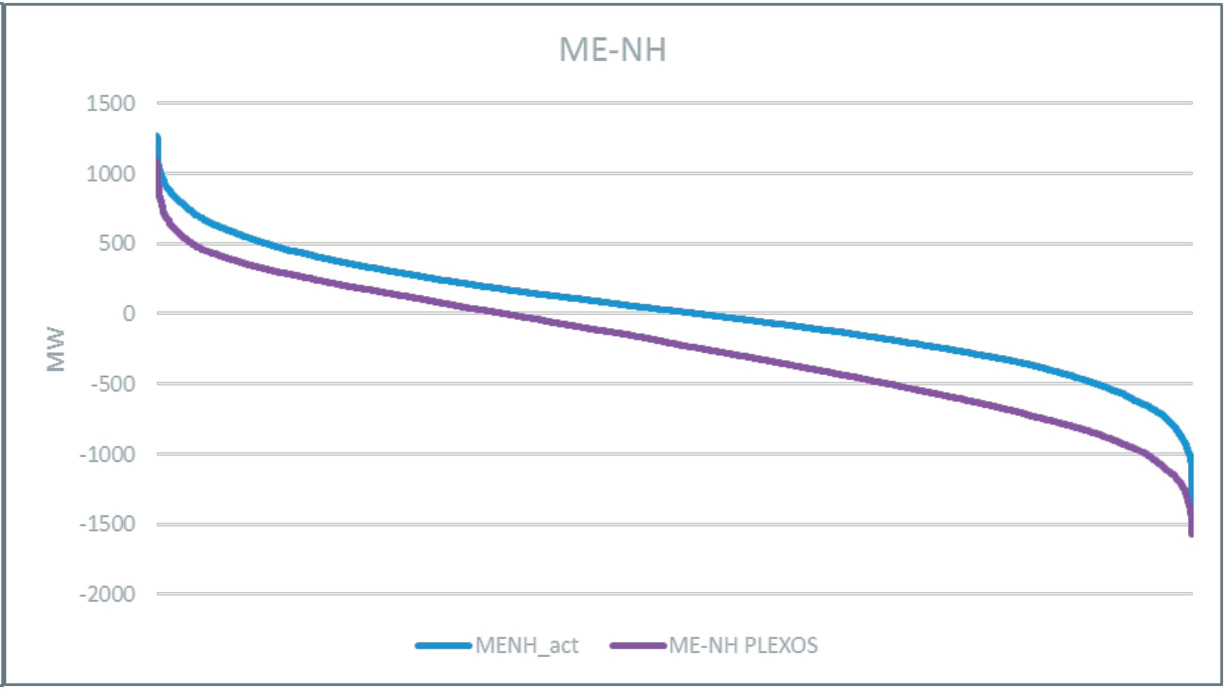
Preliminary Results: Interface Constrained, cont.



- LMPs were slightly increased as congestion caused a slight change in dispatch. However, they were still lower on average than historical
  - $40.50/MWh vs. $45.92/MWh
  - Pearson coefficient = +0.7014 (decrease of 0.0102 from last iteration)

Preliminary Results: Constrained Case Interface Flows

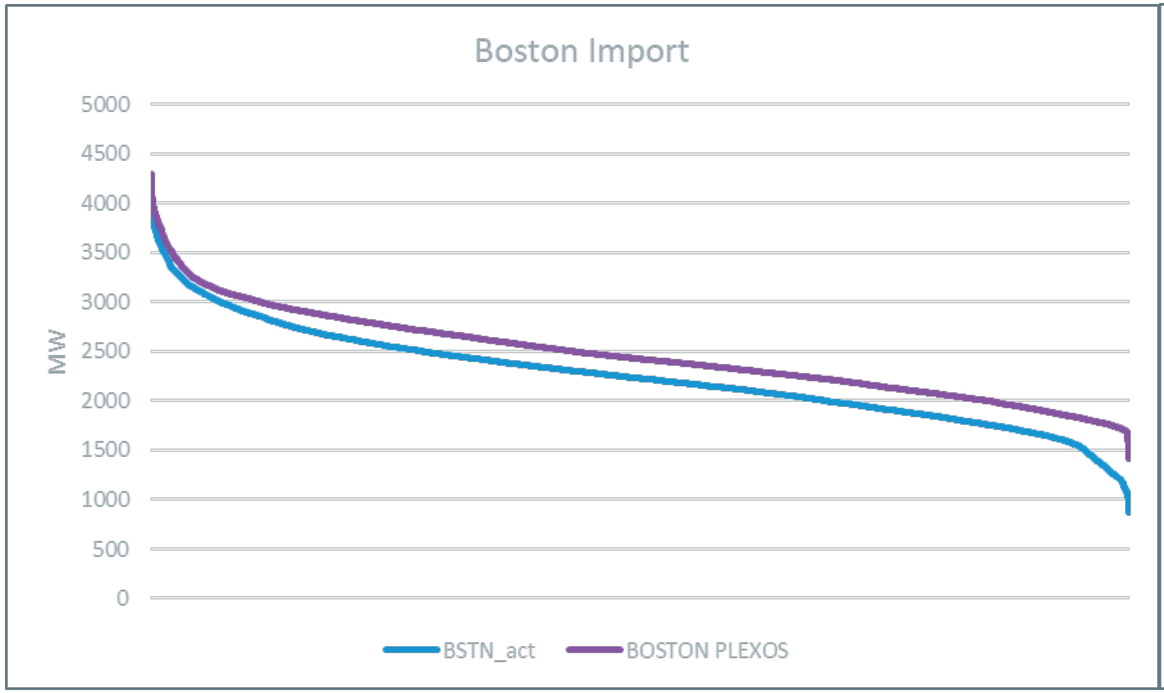


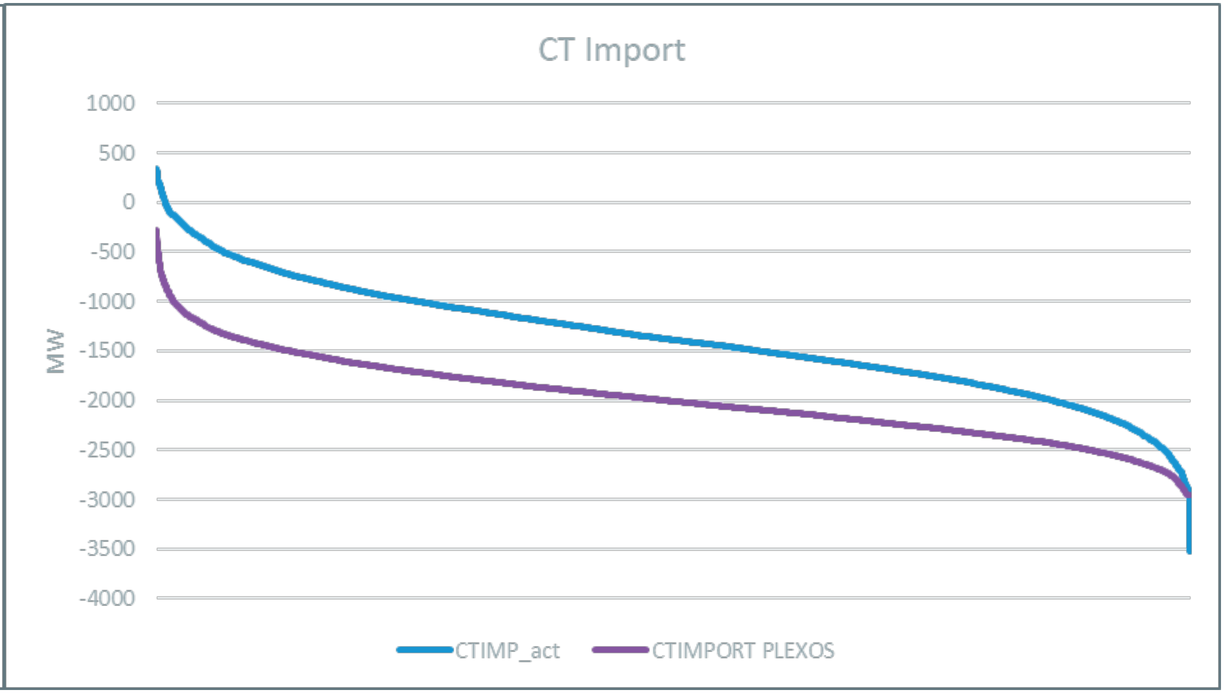


- Differences in historical and simulated flows are due to differences in generator dispatch
- Surowiec South averaged 443 MW, with a simulated net flow of 3.9 TWh
  - Historical values: 197 MW, 1.7 TWh net flow
- ME-NH averaged -234 MW, with a simulated net flow of -2.05 TWh
  - Historical values: 18 MW, 0.1 TWh net flow

PRELIMINARY RESULTS, DO NOT CITE

Preliminary Results: Constrained Case Interface Flows, cont.

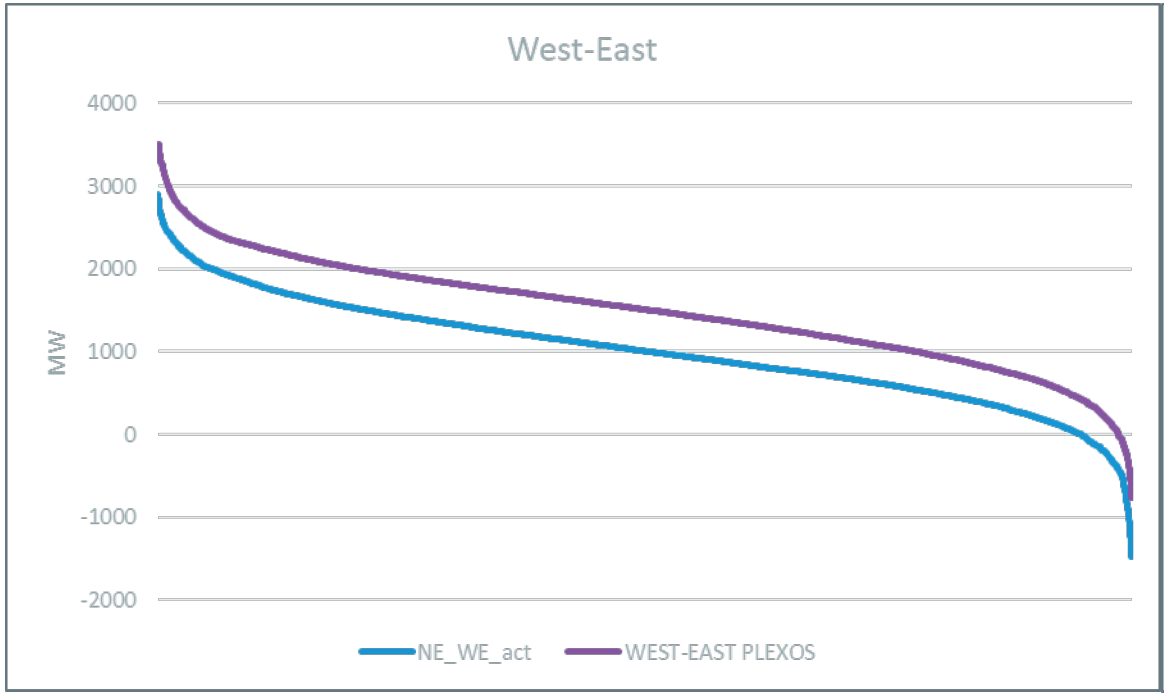


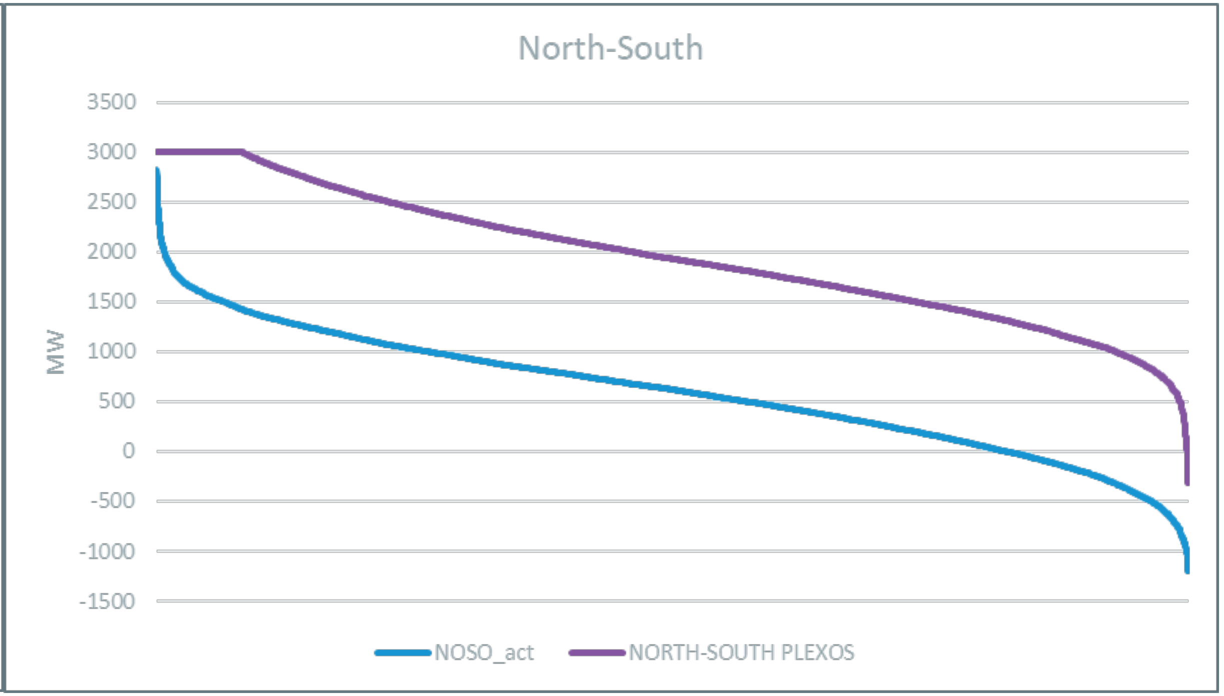


- Boston Import averaged 2,466 MW, with a simulated net flow of 21.6 TWh
  – Historical values: 2,253 MW, 19.7 TWh net flow
- CT Import averaged -1,980 MW, with a simulated net flow of -17.3 TWh
  – Historical values: -1,376 MW, -12.0 TWh net flow

PRELIMINARY RESULTS, DO NOT CITE

Preliminary Results: Constrained Case Interface Flows, cont.

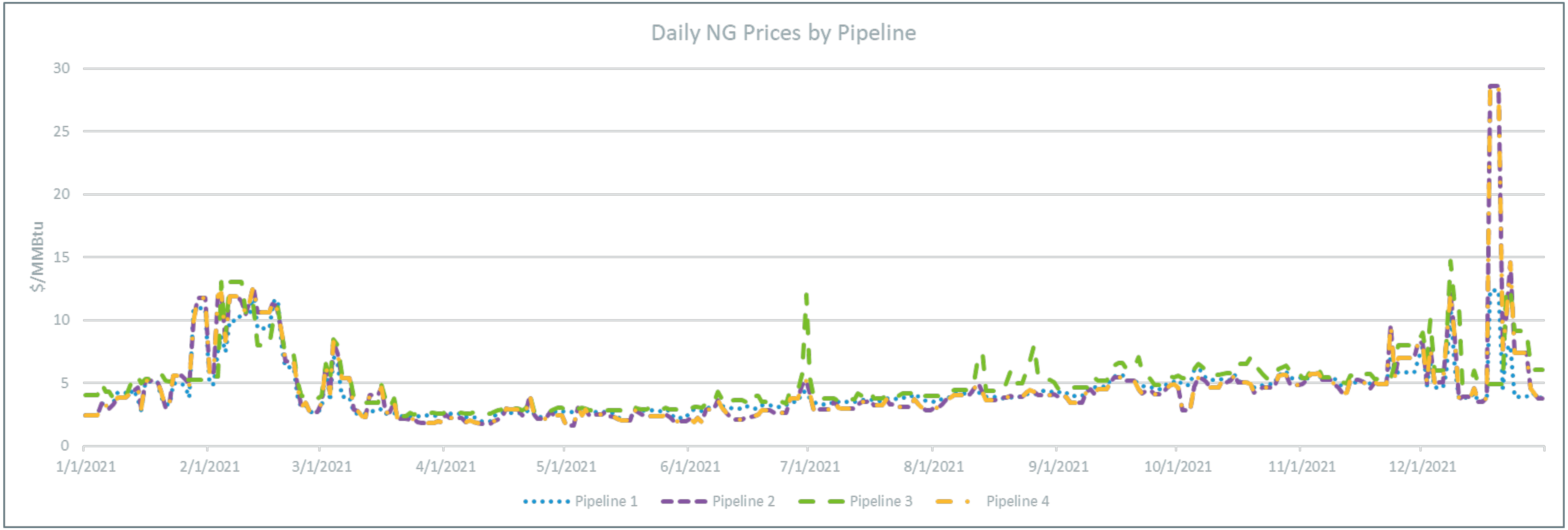




- West-East averaged 1,484 MW, with a simulated net flow of 13.0 TWh
  - Historical values: 1,007 MW, 8.8 TWh net flow
- North-South averaged 1,948 MW, with a simulated net flow of 17.0 TWh
  - Historical values: 597 MW, 5.2 TWh net flow
  - North-South was constrained in the model for 8.3% of the year

PRELIMINARY RESULTS, DO NOT CITE

Preliminary Results: Daily Pipeline Prices



- Instead of using a uniform daily gas price, daily gas prices were used for four major gas pipelines and their associated generators

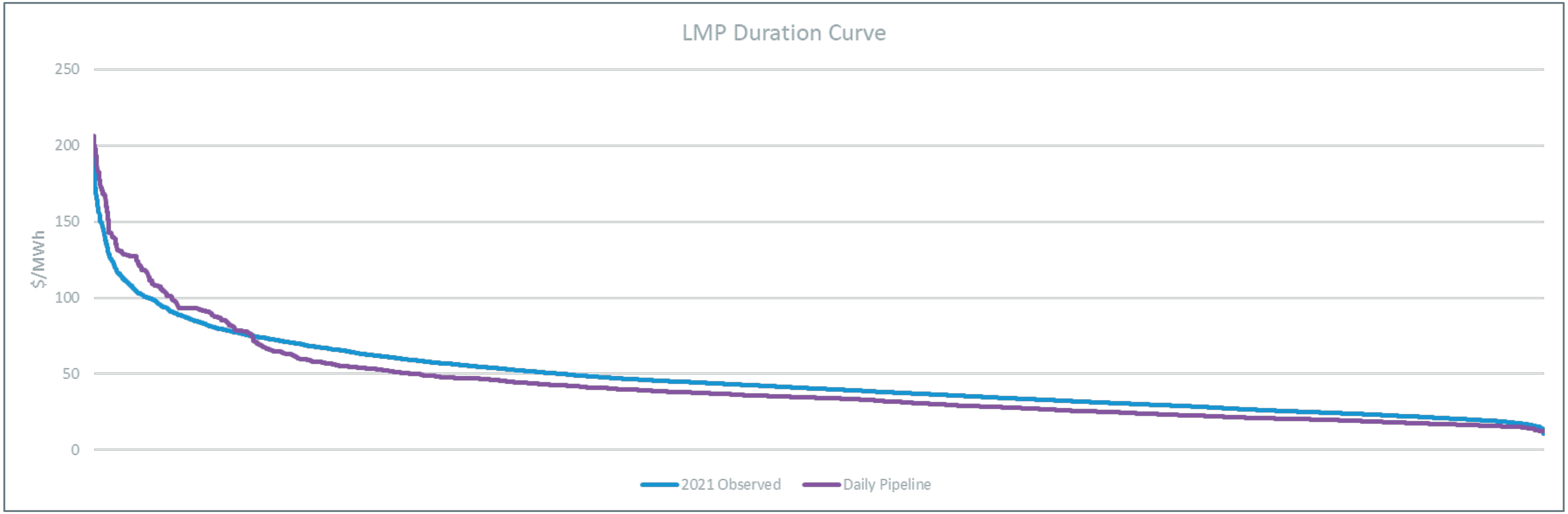
Preliminary Results: Daily Pipeline Prices, cont.

Generation (GWh) / % of total	Coal	Gas	Hydro	Nuc	Oil	LFG	MSW	PV (Non BTM)	Wind	Wood	Net Tie Flow	Total
2021 Observed	558 (0.5%)	52,255 (44.1%)	7,345 (6.2%)	27,073 (22.9%)	228 (0.2%)	438 (0.4%)	2,984 (2.5%)	2,669 (2.3%)	3,611 (3.1%)	2,416 (2.0%)	18,826 (15.9%)	118.4 TWh
Daily Pipeline	145 (0.1%)	49,215 (41.3%)	9,547 (8.0%)	29,604 (25.0%)	113 (0.1%)	336 (0.3%)	3,010 (2.5%)	2,643 (2.3%)	3,593 (3.1%)	2,743 (2.3%)	18,826 (15.8%)	119.2 TWh
Observed – Daily Pipeline	413 (+0.4%)	3,040 (+2.8%)	-2,202 (-1.8%)	-2,531 (-2.1%)	115 (+0.1%)	102 (+0.1%)	-26 (-0.0%)	26 (+0.0%)	18 (+0.0%)	-327 (-0.3%)	0 (+0.0%)	-0.8 TWh

- Having a variety of pipeline supplies and prices increased gas production at the expense of oil and coal
- Liquefied natural gas generation was the highest of any simulated case at 2,200 GWh
- Increased LMP variation caused more storage cycling, resulting in more hydro generation

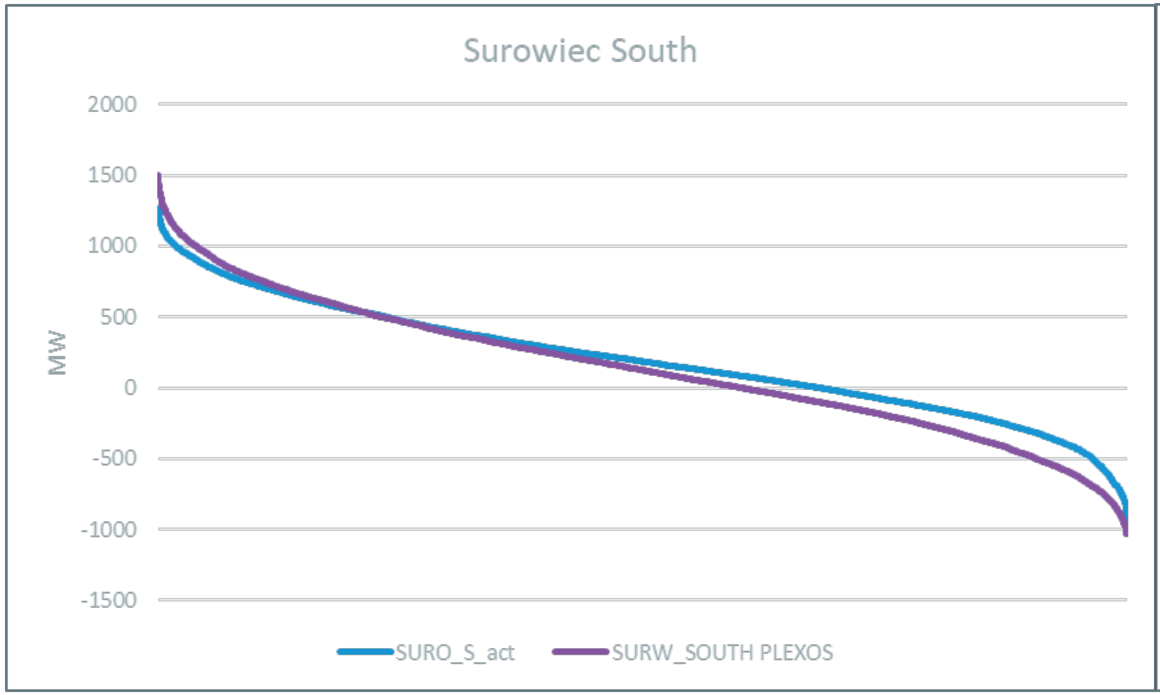
PRELIMINARY RESULTS, DO NOT CITE

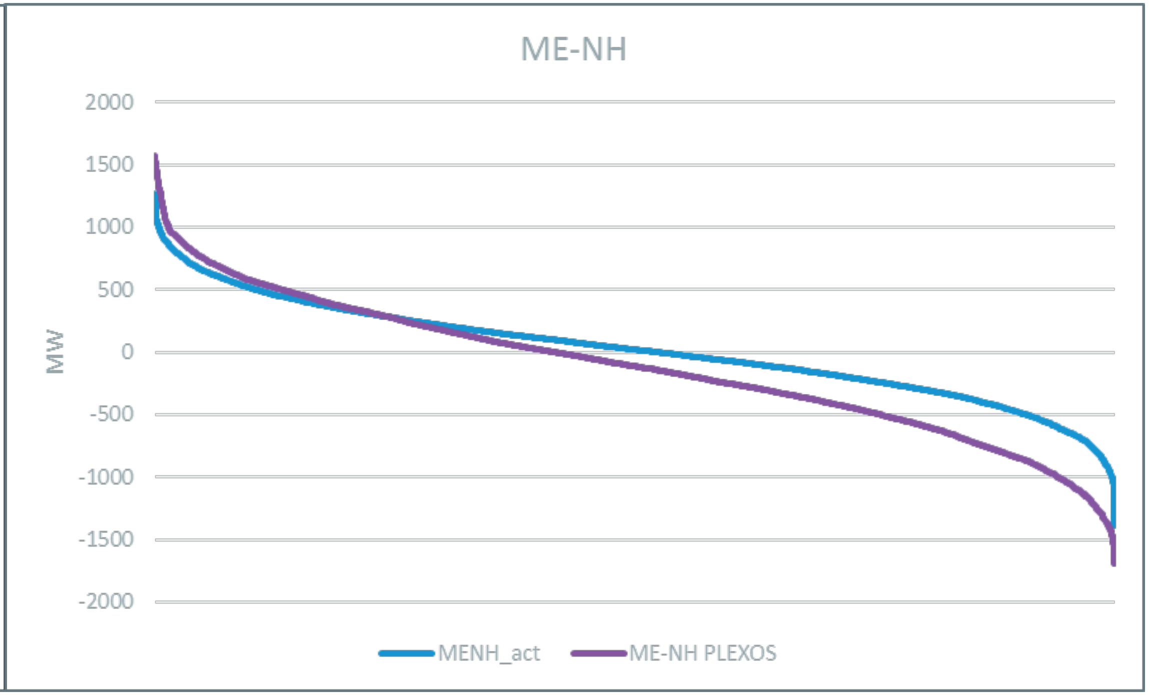
Preliminary Results: Daily Pipeline Prices, cont.



- More diverse and detailed gas prices led to the best reflection of observed 2021 LMPs, though wintertime LMPs were still higher and other LMPs were slightly lower than observed
  - $43.81/MWh vs. $45.92/MWh
  - Pearson coefficient = +0.7329 (highest of simulated LMPs)

Preliminary Results: Daily Pipeline Prices Interface Flows

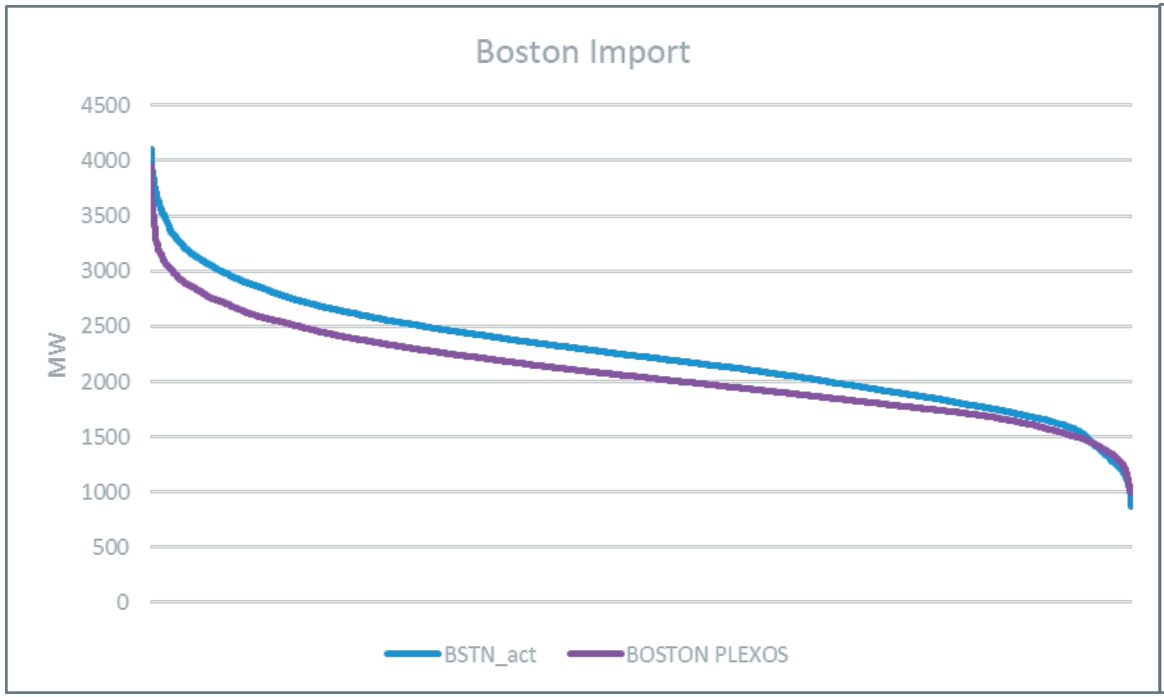


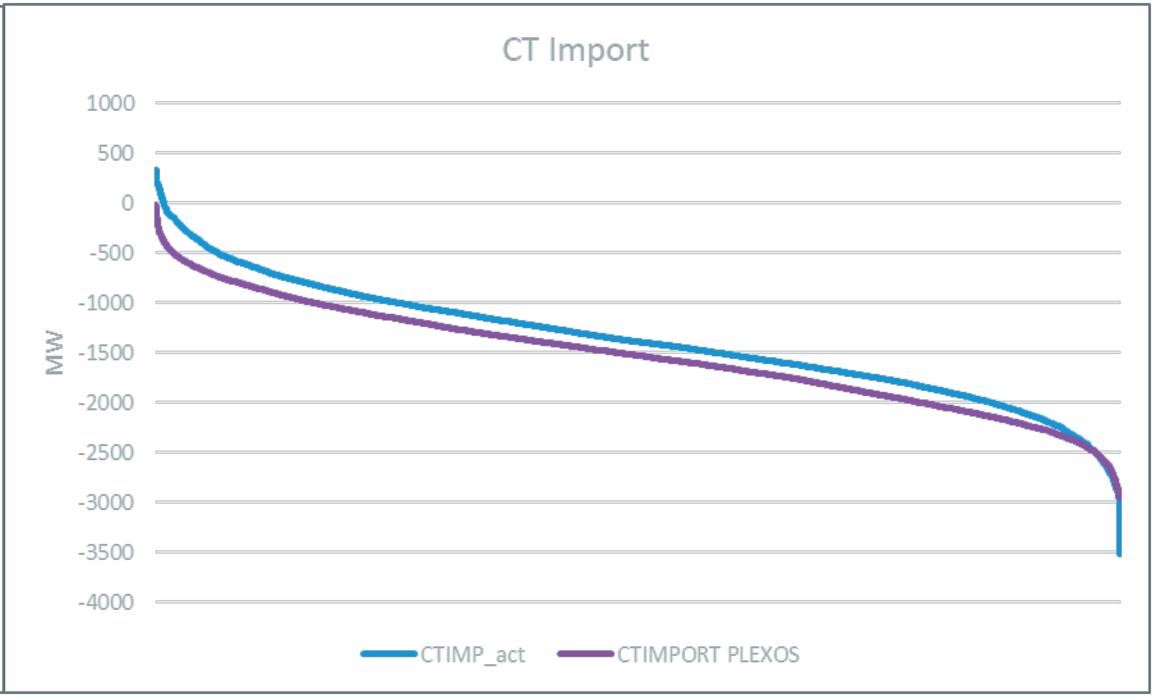


- A generator dispatch closer to the observed historical dispatch led to simulated interface flows which better reflected historical flows
- Surowiec South averaged 139 MW, with a simulated net flow of 1.2 TWh
  - Historical values: 197 MW, 1.7 TWh net flow
- ME-NH averaged -120 MW, with a simulated net flow of -1.0 TWh
  - Historical values: 18 MW, 0.1 TWh net flow

PRELIMINARY RESULTS, DO NOT CITE

Preliminary Results: Daily Pipeline Prices Interface Flows, cont.

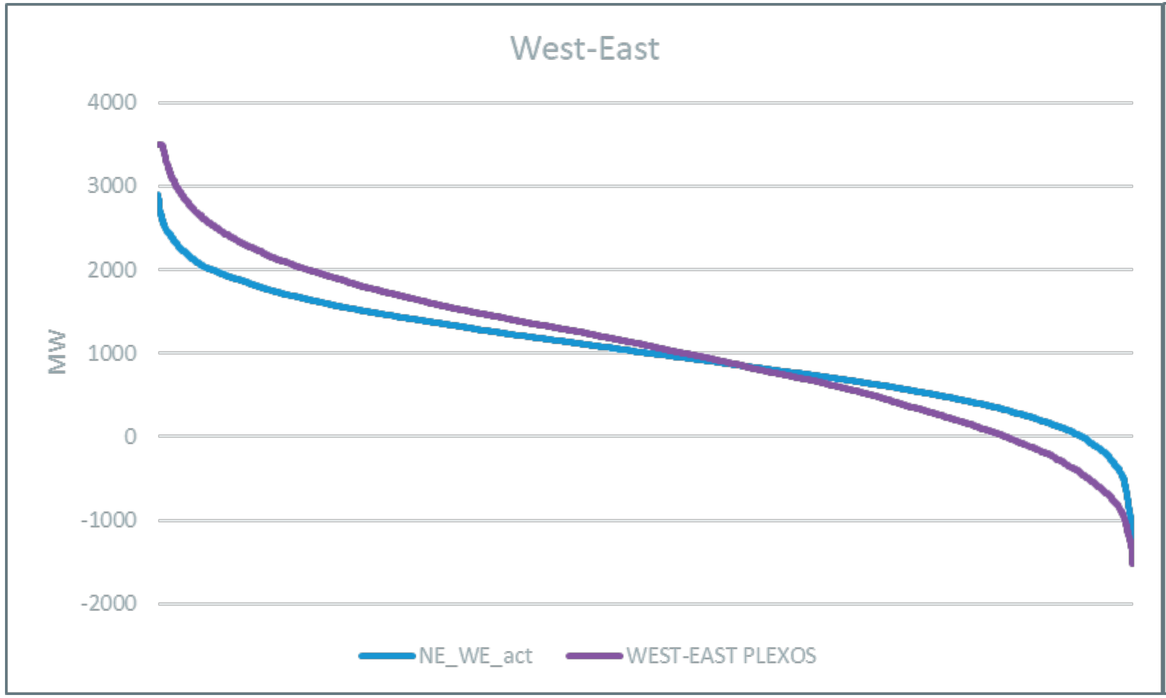


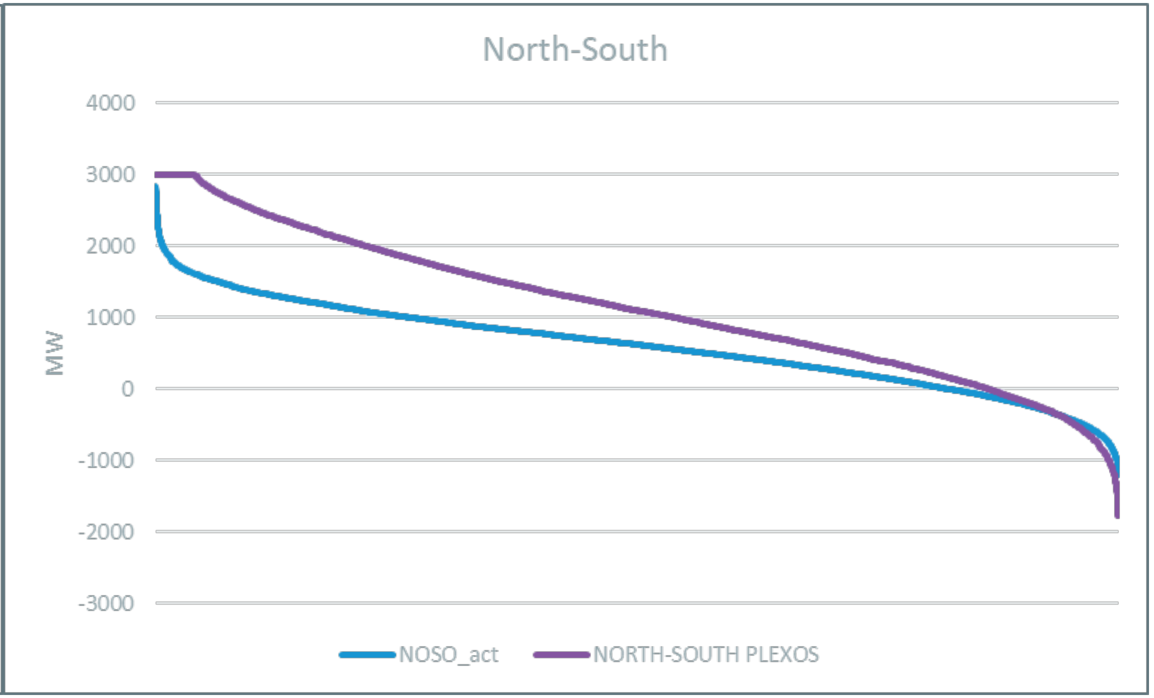


- Boston Import averaged 2,079 MW, with a simulated net flow of 18.2 TWh
  - Historical values: 2,253 MW, 19.7 TWh net flow
- CT Import averaged -1,531 MW, with a simulated net flow of -13.4 TWh
  - Historical values: -1,376 MW, -12.0 TWh net flow

PRELIMINARY RESULTS, DO NOT CITE

Preliminary Results: Daily Pipeline Prices Interface Flows, cont.





- West-East averaged 1,070 MW, with a simulated net flow of 9.4 TWh
  - Historical values: 1,007 MW, 8.8 TWh net flow
- North-South averaged 1,135 MW, with a simulated net flow of 9.9 TWh
  - Historical values: 597 MW, 5.2 TWh net flow
  - North-South was still constrained in the model, but only for 3.9% of the year

PRELIMINARY RESULTS, DO NOT CITE

Conclusions

- Gas constraints and gas price dynamics provided the most accurate price signals and interface flows
- After adding multiple historical profiles (tie flows, PV/wind production, gas prices), the differences in unit commitment and dispatch decreased
  - Note: Adding 2021 hydro models, large generator outage profiles, and nodal transmission constraints (planned for future work), it is expected the difference will further decrease
- There are many variables in the real market the ISO has not modeled which can significantly affect commitment and dispatch
  - Generator self-scheduling, out of market revenues, transmission constraints, generator gas contracts, etc.
- With assumptions that the ISO would typically use in an Economic Study and some additional fuel constraint modeling, the ISO is encouraged by the benchmark scenario results and satisfied with the PLEXOS unit commitment and dispatch logic

Questions