2017 Economic Study

Planning Advisory Committee

Revised

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BACKGROUND

One Economic Study Request Was Made in 2017

- One request for an Economic Study was submitted to the ISO in 2017
  - Request was from the Conservation Law Foundation (CLF)
  - Request was presented to the PAC on April 19, 2017
  - Associated scope of work was presented to the PAC on May 25, 2017
- The purpose of this presentation is to share preliminary results and metrics associated with the three scenarios proposed by CLF

Scope of Work of the 2017 Economic Study

Assumptions and Scenarios

- The three scenarios model the year 2030 and are based on the 2016 Economic Study Scenario 3
  - Scenario 3 of the 2016 Economic Study is the "Renewables Plus" (also "Renew Plus") scenario: generation fleet meets existing Renewable Portfolio Standards (RPS) and new renewable/clean energy resources are added above the existing RPS requirements
  - For the 2017 Economic Study, incremental changes were made to Scenario 3 of the 2016 Economic Study
- The three Scenarios of the 2017 Economic Study are:
  - 2017 Scenario A —"EE + Offshore": change in mix of new renewable/clean energy resources, with emphasis on energy efficiency and off-shore wind
  - 2017 Scenario B —"Onshore Less EE/PV": change in mix of new renewable/clean energy resources, with emphasis on on-shore wind
  - 2017 Scenario C —"Wind Less Nuc": replacement of some of the base load nuclear generation with renewable/clean energy resources

EE = Energy Efficiency
PV = Photovoltaic and represents solar
Nuc = Nuclear

The 2017 Scenarios Represent Incremental Changes from the Third Scenario Used in the 2016 Study

Year 2030	Gross Demand	Energy Efficiency	Behind The Meter PV (Nameplate)	Utility PV (Nameplate)	Demand Resources	Retirements	On-Shore Wind (Nameplate)	Off-Shore Wind (Nameplate)	Battery Storage	PHEV	Add. Imports from HQ and NB
2016 - Scenario 3 (Reference)	Based on 2016 CELT Forecast 33,343 MW	7,009 MW	6,000 MW	6,000 MW	FCA 10 - Excl. RTEG Add 1,000 MW of Active DR	All oldest Oil/Coal approx. 5,600 MW	4,800 MW	2,483 MW	2,500 MW	4.2 Million	2,000 MW
2017 - Scenario A "EE + Offshore" (Change from 2016 – Scenario 3)		Increased by 2,000 MW	Increased by 2,000 MW	Reduced by 2,000 MW			Reduced by 2,800 MW	Increased by 1,000 MW			Reduced by 1,000 MW
2017 - Scenario B "Onshore Less EE/PV" (Change from 2016 – Scenario 3)		Reduced to 2016 CELT forecast 4,739 MW approx. 2,300 MW reduction	Reduced to reach target of 4,000 MW approx. 2,000 MW reduction	Reduced to FCA #10 amounts approx. 5,800 MW reduction	Remove additional active DR		Increased to reach target of 7,000 MW approx. 2,200 MW increase		Remove battery storage	Remove PHEV	Reduced by 1,000 MW
2017 - Scenario C "Wind Less Nuc" (Change from 2016 – Scenario 3)						Remove an additional 2,122 MW of nuclear generation	Amount determined necessary to replace 2/3 of energy production lost from additional retirements	Amount determined necessary to replace 1/3 of energy production lost from additional retirements			

ASSUMPTIONS

2017 Scenarios Nameplate Assumptions (MW)

Year 2030	Gross Demand 50/50 Summer Peak based on CELT 2016	Energy Efficiency	Behind The Meter PV (Nameplate)	Utility PV (Nameplate)	Demand Resources	Retirements	On-Shore Wind (Nameplate)	Off-Shore Wind (Nameplate)	Battery Storage	PHEV	Add. Imports from HQ and NB
2016 - Scenario 3 **(Reference)**	33,343 MW	7,009 MW	6,000 MW	6,000 MW	1,319 MW, incl. 319 MW from FCA 10 and 1,000 MW of price responsive Active DR	All oldest Oil/Coal 5,577 MW	4,800 MW	2,483 MW	2,500 MW	4.2 Million	2,000 MW
2017 - Scenario A “EE + Offshore”	33,343 MW	9,009 MW	8,000 MW	4,000 MW	1,319 MW	5,577 MW	2,000 MW	3,483 MW	2,500 MW	4.2 Million	1,000 MW
2017 - Scenario B “Onshore Less EE/PV”	33,343 MW	4,739 MW	4,000 MW	154 MW	319 MW of Active DR	5,577 MW	7,000 MW	2,483 MW	0 MW	None	1,000 MW
2017 - Scenario C “Wind Less Nuc”	33,343 MW	7,009 MW	6,000 MW	6,000 MW	1,319 MW	7,699 MW (additional 2,122 MW of nuclear generation removed)	8,906 MW	4,085 MW	2,500 MW	4.2 Million	2,000 MW

2017 Scenarios Capacity Assumptions (MW)

Parameter	Reference Renew Plus	Scenario A EE + Offshore	Scenario B Onshore Less EE/PV	Scenario C Wind Less Nuc
Renewables (biofuels, landfill gas, etc.)	976	976	976	976
Solar[a]	2,462	3,262	62	2,462
Forecasted EE and active demand resources without real-time emergency generation (RTEG)	8,328	10,328	5,058	8,328
Nuclear	3,347	3,347	3,347	1,225
Hydro and pumped storage	3,116	3,116	3,116	3,116
Resource serving Citizen Block load (On boarder, served from Hydro-Québec)	30	30	30	30
Imports[b]	3,006	2,006	2,006	3,006
Wind capacity value	1,900	1,472	2,472	3,448
Gas after retirements (SCC)	16,011	16,011	16,011	16,011
Oil after retirements (SCC)	2,114	2,114	2,114	2,114
Coal after retirements (SCC)	0	0	0	0
Total capacity for existing resources after retirements	41,290	42,662	35,192	40,716
Battery storage (SCC)	2,500	2,500	0	2,500
Renewables to meet RPSs (capacity value)	0	0	0	0
Total capacity for existing resource plus storage and RPS renewables	43,790	45,162	35,192	43,216
Net Installed Capacity Requirement[c]	36,273	36,260	36,570	36,273
NGCC capacity added to replace retirement and to meet NICR	0	0	1,378[d]	0

Notes (a), (b), (c) and (d) associated with this table are on the next slide.

2017 Scenarios Capacity Assumptions, Cont.

Notes:

(a) Solar capacity includes FCA #10 cleared solar capacity (62 MW), plus any additional capacity from non-behind-the-meter (utility) PV resources.

(b) Import capacity includes New York Power Authority imports under a long-term contract plus the average capacity supply obligations associated with energy flows from New Brunswick, Highgate, and Phase II occurring during 2013, 2014, and 2015. Scenarios “Renew plus” and “Wind Less Nuc” assume additional import capacity of 2,000 MW, Scenarios “EE + Offshore” and “Onshore Less EE/PV” assume additional import capacity of 1,000 MW, respectively.

(c) The NICR calculation was based on assuming 114% of the net 50/50 peak load. Summer SCC values were assumed for all units having capacity supply obligations in FCA #10, but capacity values were used for wind and PV resources.

(d) Scenario “Onshore Less EE/PV” requires an additional 1,378 MW of capacity from new NGCC units to meet the NICR.

The 2017 Study Reflects the Same Basic Assumptions That Were Used in the 2016 Study

- Gross demand, solar photovoltaic (PV), and energy-efficiency (EE) forecasts summarized in the ISO's *2016 Capacity, Energy, Load, and Transmission (CELT) Report* are used to establish net load for 2025. The quantities for 2030 assume growth continuing at the same rate for 2025 compared with 2024.
  - Additional PV and EE assumptions as described in slides 5 & 7 of this presentation.
- A representative installed reserve margin of 14% above the gross 50/50 peak load net of behind-the-meter (BTM) PV is assumed to meet the net Installed Capacity Requirement.
- The fleet of supply and demand resources expected as of 2019/2020 using the results of the tenth Forward Capacity Auction (FCA #10) are reflected in the simulations. These cleared resources include renewables (i.e., biofuel, landfill gas, and other fuels), central station PV; coal-, oil-, and gas-fired generators; nuclear; hydroelectric and pumped-storage resources; and external capacity contracts, which will have capacity supply obligations from June 1, 2019, to May 31, 2020. Retired resources known as of FCA #10 are also removed from the simulation data bases.
  - Additional Active Demand Resources (DR), storage, plug-in hybrid electric vehicles (PHEV) and imports assumptions as described in slides 5 & 7 of this presentation.

The 2017 Study Reflects the Same Basic Assumptions That Were Used in the 2016 Study, cont.

- FCM and energy-only generators are simulated at their summer seasonal claimed capabilities and then reduced to reflect forced outages and average daily unavailabilities of generators.
- The as-planned transmission system is used for estimating the system's transfer limits for internal and external interfaces under constrained conditions. The 2030 internal and external transmission-interface transfer capabilities are based on the values established for 2025 for regional planning studies.
- US Energy Information Administration (EIA) fuel-price forecasts with reference projections to 2030, are used for estimating costs to produce electric energy. Monthly multipliers have been applied to the EIA forecasted natural gas price to reflect seasonal adjustment.
- Prices for the Regional Greenhouse Gas Initiative carbon dioxide (CO_2) emission allowances and allowances for other environmental emissions are specified at $24/ton for 2030 and used for estimating the costs to produce electric energy.

The 2017 Study Uses the Same Profiles That Were Used in the 2016 Study

- Load profiles (load shape and daily peak) reflect price-taking resources, including EE, PV, wind, hydro and imports.
- Wind and PV profiles use hourly profiles developed by the National Renewable Energy Lab (NREL) compatible with the hourly system loads used in the GridView simulations.
- Profiles for charging plug-in hybrid electric vehicles (PHEVs) model charging at night.
- Hydro generation profiles and energy delivery transfers (imports) for existing ties are developed using historical diurnal profiles for 2013, 2014, and 2015.
- Additional imports from Hydro-Quebec and New Brunswick are modeled to smooth out the loads after PHEV, PV, wind, local hydro and interchange.
- The storage and discharge of energy by pumped-storage generation and battery systems are designed to further smooth out the net load profile after PHEV, PV, wind, local hydro, interchange and new imports.

The 2017 Study Uses the Threshold Prices That Were Used in the 2016 Study

- Threshold prices for reducing imports, hydro production, wind generators, and PV outputs are assumed to decrease their production during times of oversupply (called “spilling”) and to respect transmission system limitations.

Price-Taking Resource	Threshold Price ($/MWh)
Photovoltaics	1.00
Onshore and offshore wind	4.00
Local New England hydro	4.50
Imports from Québec over Highgate and Phase II ties	5.00
Imports from New Brunswick	10.00
Imports over the new ties modeled	10.50

METRICS AND RESULTS

Summary of Metrics Analyzed in the 2017 NEPOOL Scenario Analysis

- Economic results
  - Total energy production by resource/fuel type
  - Systemwide production costs
  - Average locational marginal prices
  - Load-serving entity energy expenses and congestion
- High order-of-magnitude cost estimates for transmission development
- Relative Annual Resource Costs
  - Using the 2016 Scenario 3 as a reference
- Environmental results
  - Carbon dioxide emissions
  - Renewable resource spillage

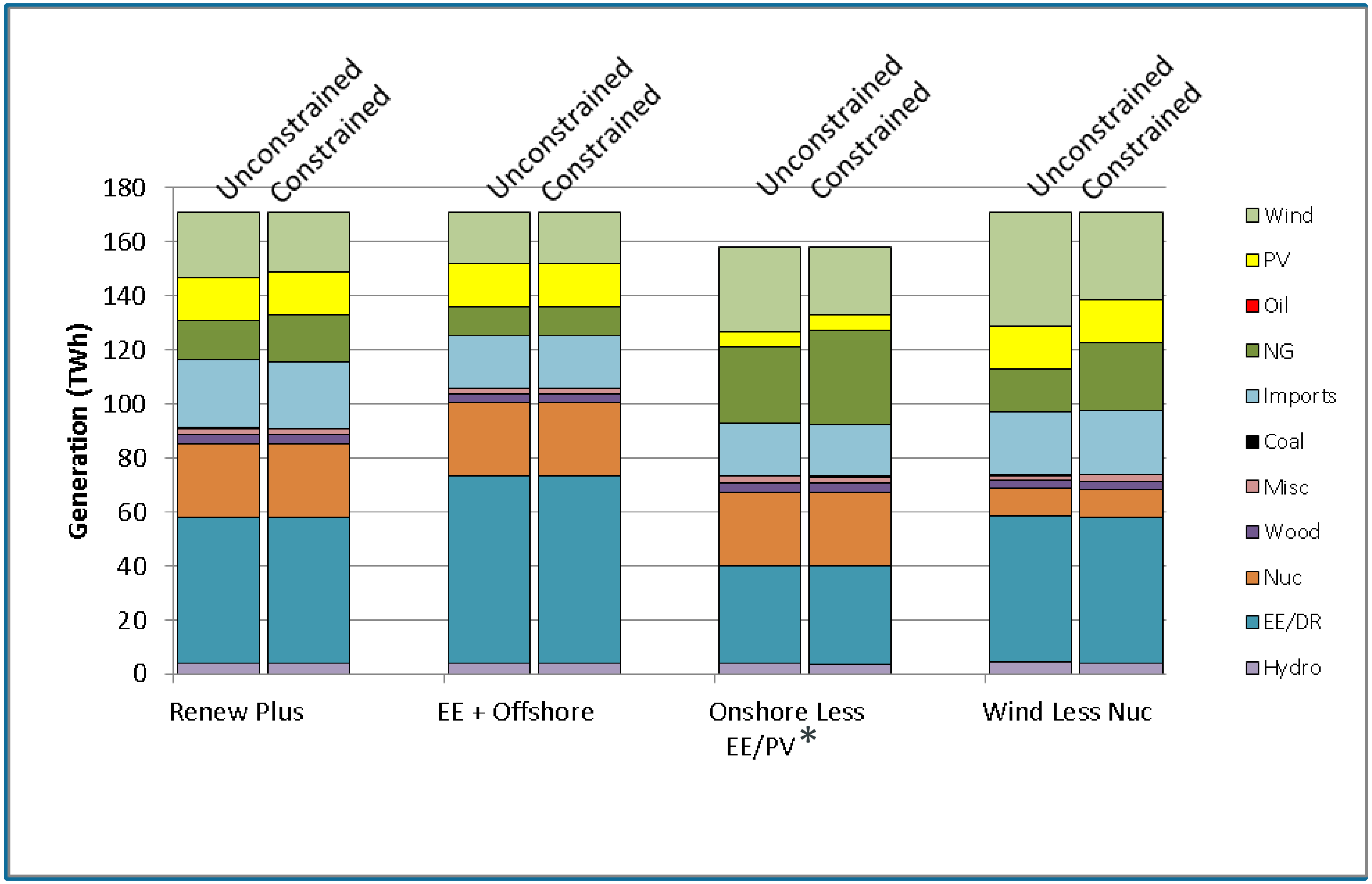
Key Observations

- The assumed resource mixes and locations drive the major scenario results.
  - "EE + Offshore" shows the effects of the large-scale development of renewable EE, PV and offshore wind development in southern New England.
  - Scenario "Onshore Less EE/PV" demonstrates how the large-scale addition of onshore wind resources in northern New England affects the system metrics.
  - Scenario "Wind Less Nuc" demonstrates how the large-scale addition of onshore wind resources in northern New England combined with the loss of baseload nuclear generation affects the system metrics.
- The "EE + Offshore" scenario is the only scenario that meets both the 2.5% and 5% RGGI targets with a Relative Annual Resource Cost (RARC) that is similar to the reference RARC (2016 Scenario 3).
- The "Wind Less Nuc" scenario does not meet the 5% RGGI target, and its RARC is higher than the reference RARC.
- The "Onshore Less EE/PV" scenario does not meet the 5% RGGI target but has a lower RARC than the reference.

ECONOMIC RESULTS

- *Total Energy Production by Resource (Fuel) Type, Including Imports*
- *Systemwide Production Costs for Unconstrained and Constrained Transmission and Congestion Costs*
- *Average Locational Marginal Prices*
- *Load-Serving Entity Energy Expenses and Congestion*

Total Systemwide Production by Fuel Type for Each Scenario, 2030 (TWh)



* "Onshore Less EE/PV' has no PHEV, therefore less total demand and less total generation.

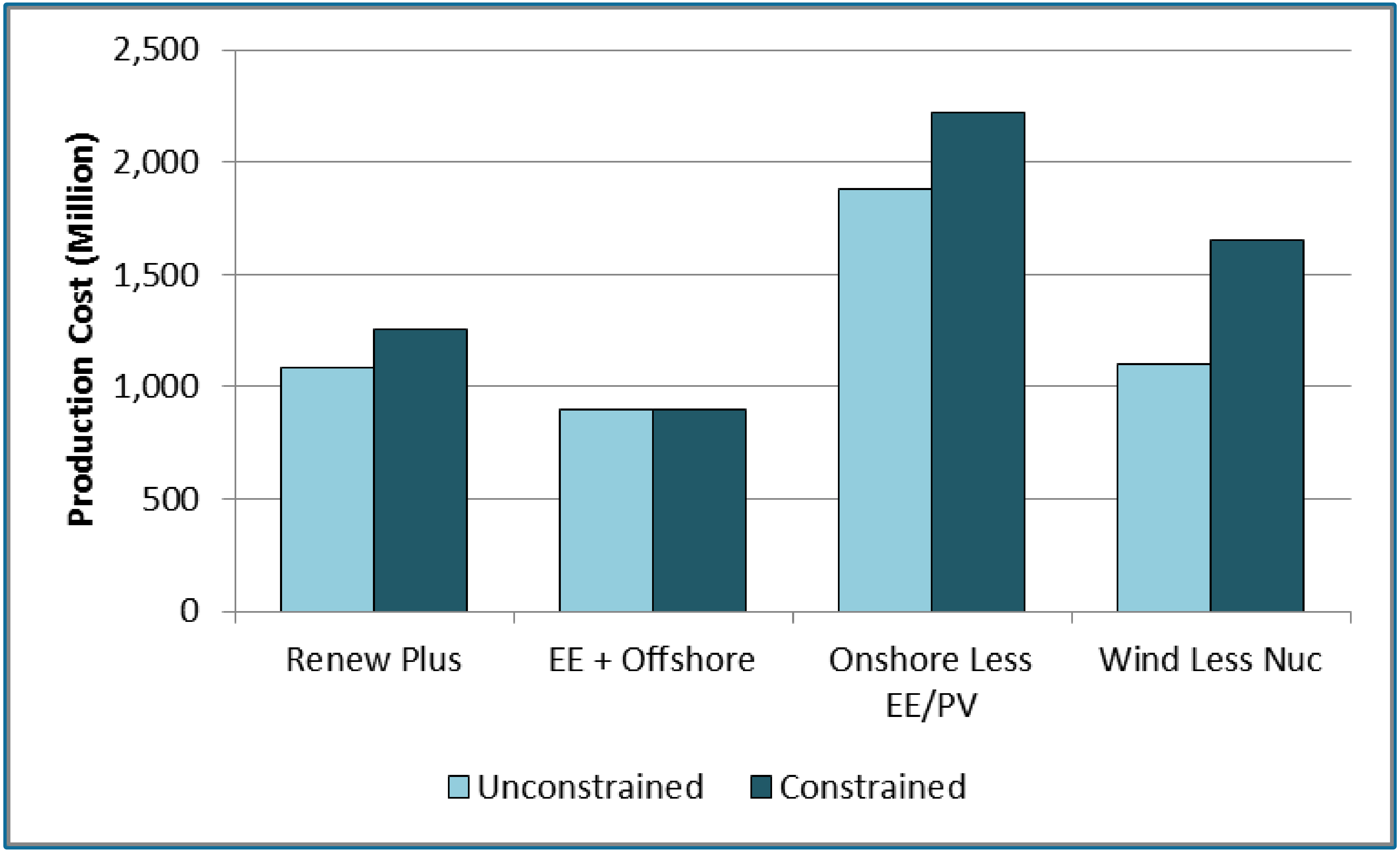
Total Systemwide Production by Fuel Type for Each Scenario, 2030 (TWh), cont.

Fuel Type	Renew Plus		EE + Offshore		Onshore Less EE/PV		Wind Less Nuc	
	Unconstrained	Constrained	Unconstrained	Constrained	Unconstrained	Constrained	Unconstrained	Constrained
Wind	24.36	22.43	19.09	19.09	31.12	25.19	42.26	32.27
PV	16.03	16.03	15.92	15.92	5.56	5.56	16.05	16.04
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NG	14.16	17.04	10.97	11.14	28.71	34.84	15.81	25.07
Imports	25.60	24.83	19.45	19.38	19.43	19.34	23.41	23.78
Coal	0.07	0.05	0.07	0.07	0.10	0.06	0.07	0.03
Misc.	2.05	2.26	1.84	1.82	2.14	2.52	1.80	2.45
Wood	3.70	3.50	3.45	3.37	3.66	3.53	3.27	3.30
Nuc.	27.24	27.24	27.20	27.20	27.26	27.26	10.16	10.17
EE/DR	53.98	54.08	69.16	69.16	36.12	36.12	53.92	54.16
Hydro	3.95	3.68	3.95	3.94	3.86	3.53	4.29	3.76
EV	-12.52	-12.52	-12.52	-12.52	0.00	0.00	-12.52	-12.52
Total	171.15	171.15	171.09	171.09	157.95	157.95	171.03	171.03

Total Systemwide Production by Fuel Type for Each Scenario, 2030 (TWh) - Observations

- The amount of resources assumed for each scenario is adequate to meet the systemwide energy requirements, even when transmission constraints are modeled.
- The differences in production by price-taking resources simulated as $0/MWh are readily apparent.
  - "EE + Offshore" (Offshore +1,000 MW; Onshore -2,800 MW) has the least amount of wind energy.
  - "Onshore Less EE/PV" has more wind energy than the reference case.
  - "Wind Less Nuc" has the most energy production from wind resource, especially when the transmission system is unconstrained.
- Natural-gas-fired generation fluctuates with the differences in production by price-taking resources simulated as $0/MWh and assumed retirements.
  - "EE + Offshore" has the least amount of gas-fired energy.
  - "Onshore Less EE/PV" has the most amount of gas-fired energy.
- Constraining the transmission system generally increases production by gas-fired generation.
  - The largest increase occurs in the "Wind Less Nuc" scenario.

Systemwide Production Costs, 2030 ($ Million)



Systemwide Production Costs, 2030 ($ Million), cont.

Transmission	Renew Plus	EE+Offshore	Onshore Less EE/PV	Wind Less Nuc
Unconstrained	1,086	895	1,877	1,101
Constrained	1,253	901	2,221	1,649

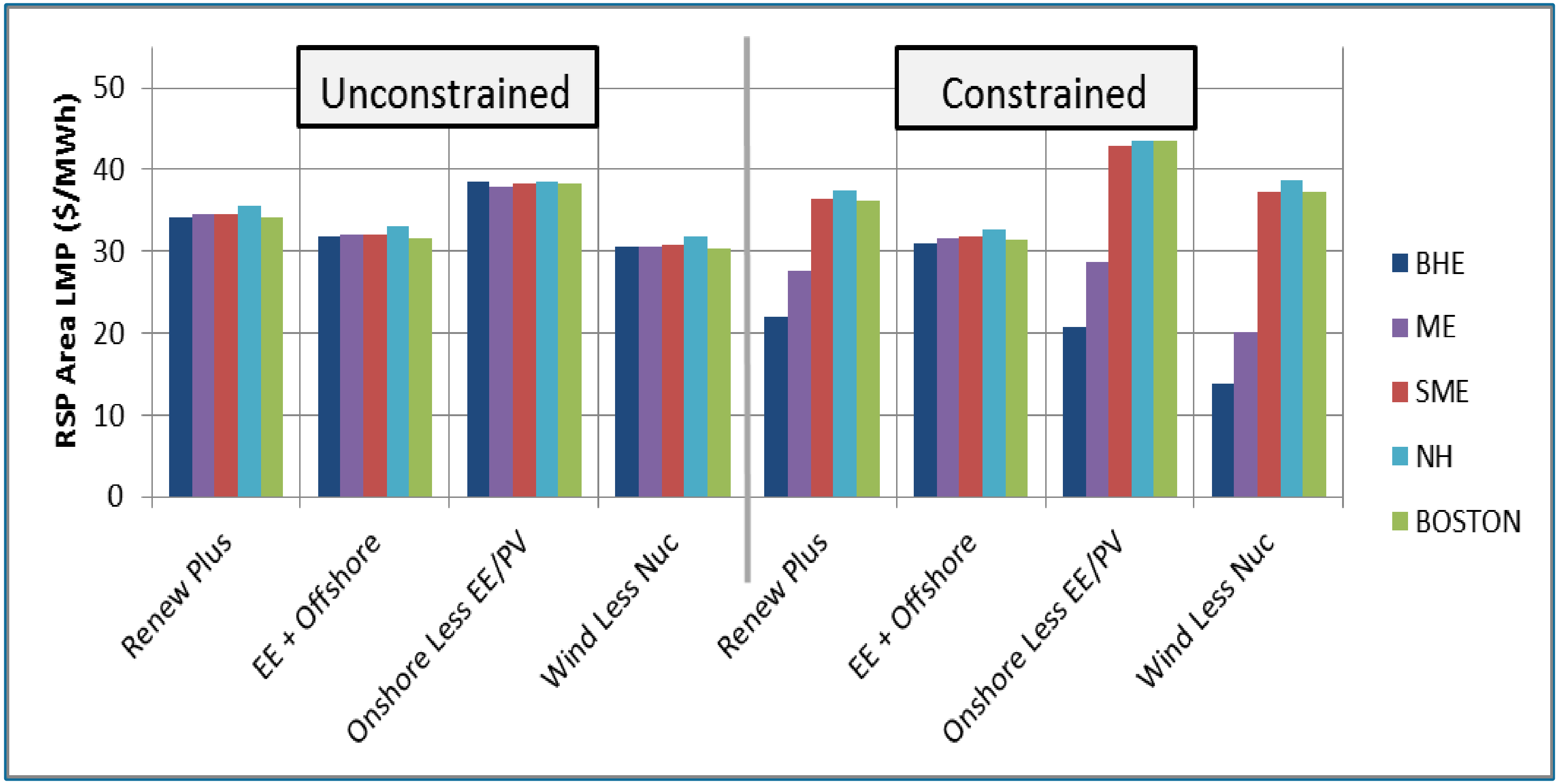
Compared to the Reference case:

Transmission	Renew Plus	EE+Offshore	Onshore Less EE/PV	Wind Less Nuc
Unconstrained	–	(-191)	791	15
Constrained	–	(-352)	968	396

Systemwide Production Costs - Observations

- “EE + Offshore” has the lowest systemwide production costs while “Onshore Less EE/PV” has the highest.
- Production costs are mainly driven by natural gas and to a less extent, other fuels.
  - Increased amount of wind, PV and EE reduces production costs.
  - Increased amount of imports reduces production costs.
  - Transmission constraints reduce the ability to utilize wind and increases reliance on NG.
- A comparison between the constrained and unconstrained scenarios shows the effect of resource development in different locations, which are part of the scenario assumptions:
  - “EE + Offshore” has the smallest difference of systemwide production costs between the constrained and unconstrained cases because EE and offshore wind are developed predominantly near the load centers in southern New England.
  - “Wind Less Nuc” has the largest difference because the scenario assumes the largest wind expansion, totaling 8,906 MW of onshore wind located predominately in northern Maine. When the transmission system constraints limit transfers, this wind energy is spilled.
  - The majority of the spilled energy is replaced by energy from the gas-fired fleet and results in higher production costs in the constrained cases.

Annual Average LMPs by RSP Subarea, 2030 ($/MWh)



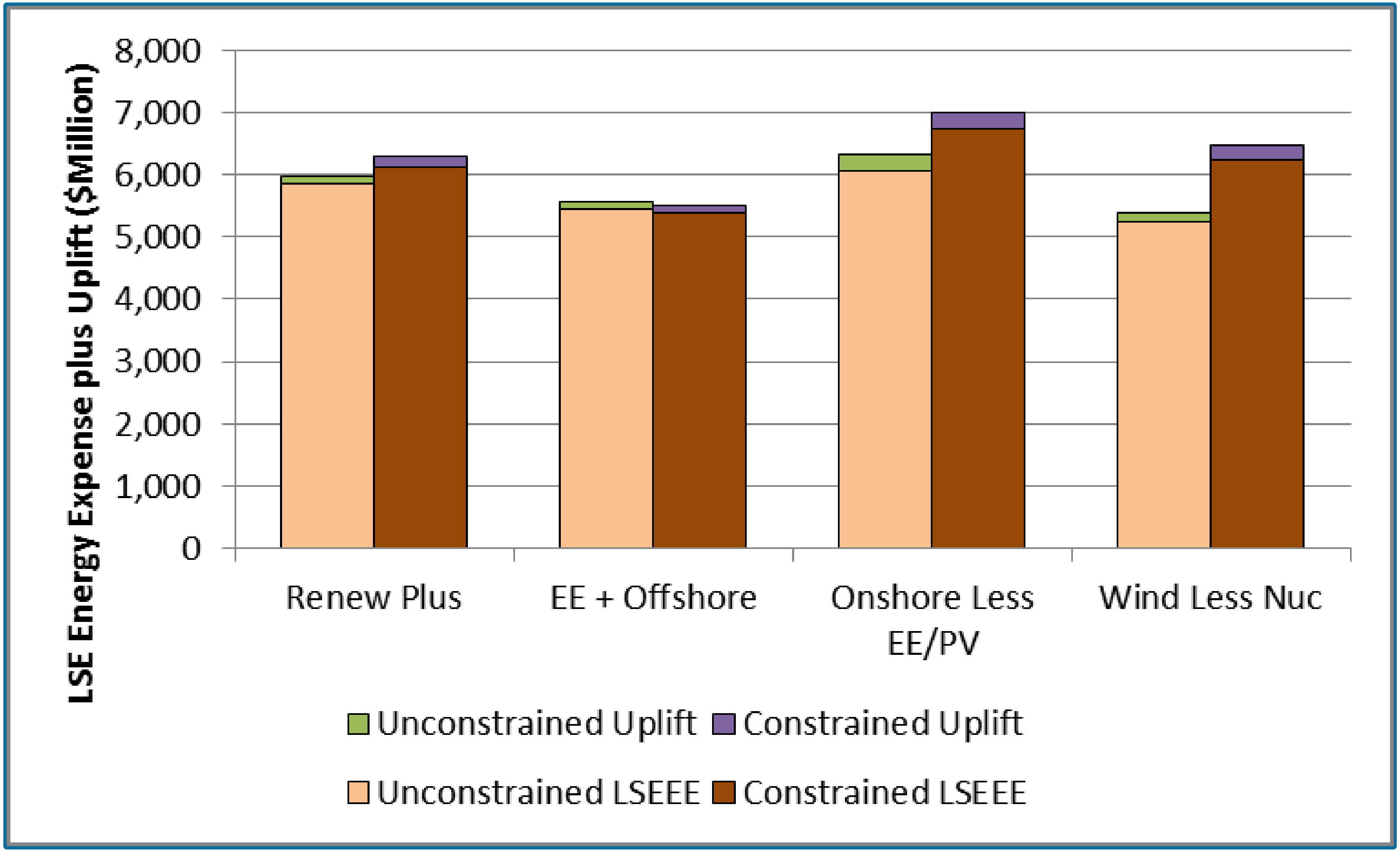
LMPs in Selected Subareas, 2030 ($/MWh)

Transmission	Scenario	BHE	ME	SME	NH	BOSTON
Unconstrained	Renew Plus	34.19	34.54	34.55	35.56	34.07
	EE + Offshore	31.73	32.05	32.07	33.00	31.62
	Onshore Less EE/PV	38.58	37.97	38.21	38.58	38.37
	Wind Less Nuc	30.49	30.66	30.85	31.73	30.36
Constrained	Renew Plus	21.98	27.72	36.33	37.57	36.12
	EE + Offshore	31.08	31.70	31.77	32.62	31.34
	Onshore Less EE/PV	20.69	28.60	42.82	43.60	43.50
	Wind Less Nuc	13.78	20.11	37.20	38.71	37.18

LMPs in Selected Subareas - Observations

- When the transmission system is unconstrained, scenarios that have more energy production from the price-taking resources observe lower LMPs.
  - “Wind Less Nuc” has the lowest LMPs in the range of $30.36 to $31.73 per MWh, followed by “EE + Offshore”, and then “Onshore Less EE/PV”.
  - “Wind Less Nuc” and “EE + Offshore” have lower LMPs than the reference case. “Onshore Less EE/PV” has higher LMPs than the reference case.
- When the transmission system is constrained, the northern Maine subareas experience congestion, which results in lower LMPs compared to those in southern New England.
  - “Wind Less Nuc” has the largest price separation between BHE/ME and the rest of the system, followed by the “Onshore Less EE/PV” scenario.
  - “EE + Offshore” scenario barely has any price separation.

Load-serving Entity Energy Expense and Uplift, 2030 ($ Million)



Load-serving Entity Energy Expense and Uplift, 2030 ($ Million)

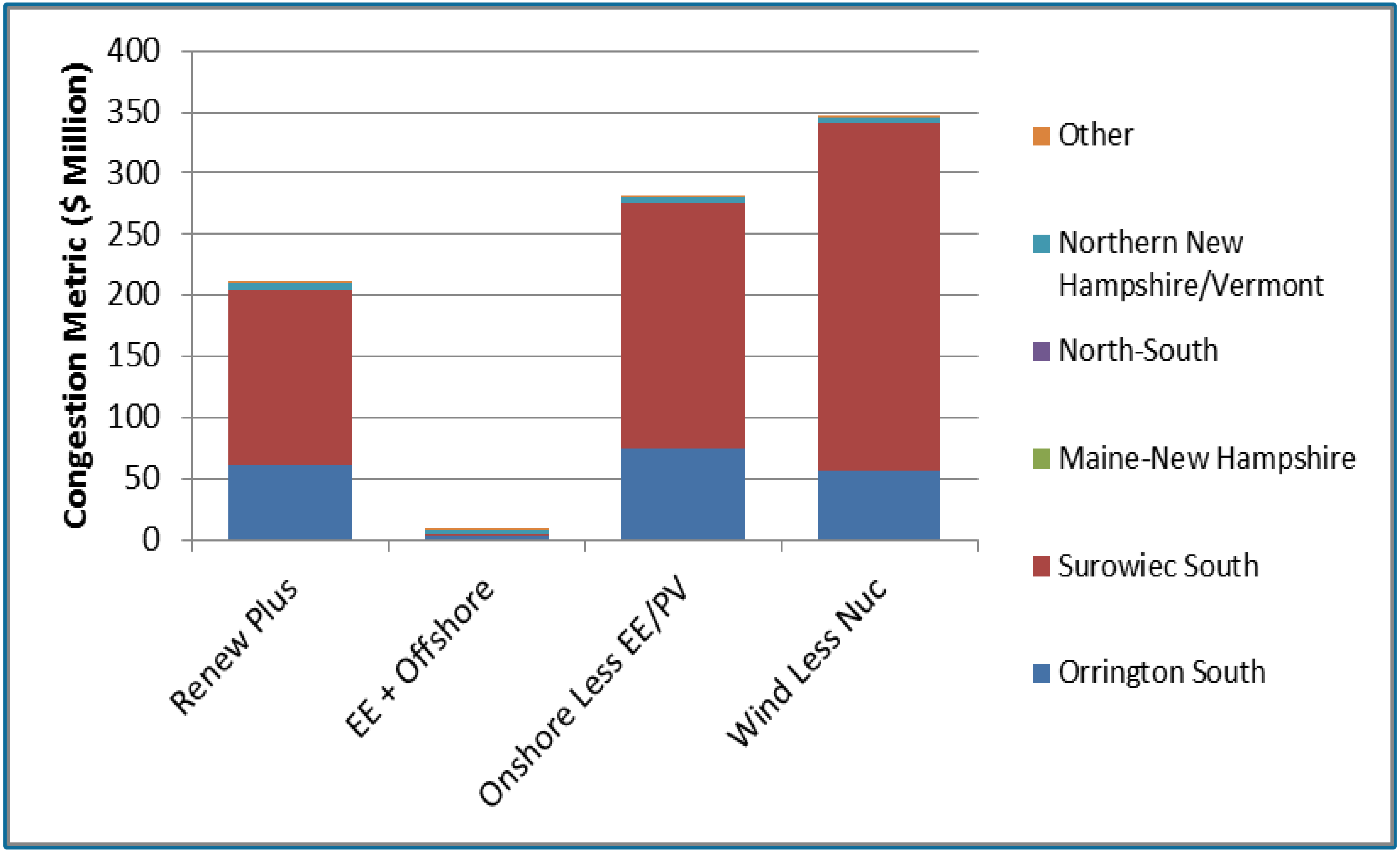
Transmission	Type	Renew Plus	EE + Offshore	Onshore Less EE/PV	Wind Less Nuc
Unconstrained	LSE energy expense	5,866	5,447	6,064	5,231
	Uplift	117	103	249	154
	Total	5,983	5,550	6,313	5,385
Constrained	LSE energy expense	6,130	5,396	6,732	6,232
	Uplift	161	111	263	240
	Total	6,291	5,507	6,995	6,472

Load-serving Entity Energy Expense and Uplift, 2030 ($ Million), cont.

Compared to the reference case:

Transmission	Type	Renew Plus	EE + Offshore	Onshore Less EE/PV	Wind Less Nuc
Unconstrained	LSE energy expense	–	(-419)	198	(-635)
	Uplift	–	(-14)	132	38
	Total	–	(-433)	330	(-598)
Constrained	LSE energy expense	–	(-734)	602	103
	Uplift	–	(-51)	101	79
	Total	–	(-784)	703	181

GridView Congestion Metric by Interface, 2030 ($ Million)



GridView Congestion Metric by Interface, 2030 ($ Million)

Scenario	Renew Plus	EE + Offshore	Onshore Less EE/PV	Wind Less Nuc
Orrington South	60.7	3.7	74.8	57.2
Surowiec South	143.8	0.9	200.5	283.1
Maine-New Hampshire	0.0	0.0	0.0	0.0
North-South	0.3	0.0	0.0	0.0
Northern New Hampshire/Vermont	4.9	3.0	4.3	5.6
Other	1.5	2.5	0.0	0.4
Total	211.2	10.1	279.7	346.4

Load-serving Entity Energy Expense, Uplift and Congestions - Observations

- The LSE energy expense follows the same pattern as the LMPs across all scenarios.
- Uplift is relatively small compared with the LSE energy expense for all scenarios.
  – The amount of congestion is directly related to the amount of assumed onshore resources in Maine in each scenario.
    - “Wind Less Nuc” experiences the highest amount of congestion followed by “Onshore Less EE/PV”.
    - “EE + Offshore” experiences virtually no congestion because the offshore wind expansion is electrically close to the load centers in Southern New England.

TRANSMISSION RESULTS

- *Maine Interface Flow Statistics*
- *High-Order-of-Magnitude Cost Estimates for Transmission Development*
- *Implied Capital Investment*

High-Order-of-Magnitude Cost Estimates for Transmission Development – Onshore Wind

- Similar to what was done in the 2016 Economic Study, high-order-of-magnitude cost estimates for integrator and congestion-relief systems in Maine formed the basis of the transmission-development costs associated with onshore wind for each individual scenario.
- The transmission development cost estimates do not include individual plant-development and interconnection costs, which are assumed as part of the capital costs of generation development.

Integrator System

- The integrator system ties the Point Of Interconnection of each individual plant to the main portion of the bulk power system.
  - The integrator system is conceptually similar to the type of upgrades considered in the *2016 Maine Resource Integration Study.*
- In the "Onshore Less EE/PV" and "Wind Less Nuc" scenarios, the integrator system is bypassed.
  - Relying exclusively on the congestion-relief system is assumed to be the most cost-effective way to integrate the renewable resources in scenarios with extremely large additions of renewable resources.

	Reference Renewables Plus	Scenario A EE + Offshore	Scenario B Onshore Less EE/PV	Scenario C Wind Less Nuc
2030 Maine nameplate wind injection (MW)	3,652 MW	926 MW	5,743 MW	7,579 MW
Integrator system (description)	1 AC parallel or 2 AC parallel 345 kV paths	1 AC parallel 345 kV path	Bypassed—assumed exclusive reliance on congestion relief system	Bypassed—assumed exclusive reliance on congestion relief system
Integrator system cost ($ billion)	$1.5 to $3.0	$1.5 to $3.0	---	---
Integrator system cost + 50% margin ($ billion)	$2.25 to $4.5	$2.25 to $4.5	---	---

Costs described here are preliminary high-level order of magnitude costs and are based on judgement.
Also, they do not account for individual plants' interconnection costs or potential costs from system operational issues.

Congestion Relief System

- The congestion relief system removes 100% of the transmission congestion that otherwise would prevent full energy production from the renewable resources during the summer and the winter peak hours. It also removes most of the congestion at all hours of the year.
- The congestion relief system assumes high-voltage direct-current (HVDC) facilities tying the integrator system to Millbury, MA.

	Reference Renewables Plus	Scenario A EE + Offshore	Scenario B Onshore Less EE/PV	Scenario C Wind Less Nuc
2030 Maine nameplate wind injection (MW)	3,652	926	5,743	7,579
Needed congestion-relief capacity (MW)	1,839	None	3,524	4,870

Congestion-Relief System Components and Costs

Costs described here are preliminary high-level order of magnitude costs and are based on judgement. Also, they do not account for individual plants' interconnection costs or potential costs from system operational issues.

Congestion-Relief System		Reference Renewables Plus		Scenario B Onshore Less EE/PV		Scenario C Wind Less Nuc	
		1,839 MW (2 HVDC Ties)		3,524 MW (3 HVDC Ties)		4,870 MW (4 HVDC Ties)	
Equipment	**$ per unit**	**Quantities**	**Total $ (billions)**	**Quantities**	**Total $ (billions)**	**Quantities**	**Total $ (billions)**
DC portion							
HVDC overhead lines	$3.5 million/ mi	2 × 200 = 400 mi.	$1.40	(2 × 400) + (1 × 300) = 1,100 mi.	$3.85	(2 × 400) + (2 × 300) = 1,400 mi.	$4.90
Converters	$300 million/ converter	4	$1.20	6	$1.80	8	$2.40
Misc. DC additional equipment	$200 million/tie	2	$0.40	3	$0.60	4	$0.80
Total DC portion			$3.00		$6.25		$8.10
AC portion							
Sending end—reactive devices	$0.25 million/MVAR	(included in integrator system)	--	Approx. 1/3 × 3,600 = 1,200 MVAR	$0.30	Approx. 1/3 × 4,800 = 1,600 MVAR	$0.40
Sending end—AC terminations	$10 million/ terminal expansion (assumed two terminal expansions per tie)	2 x 2 = 4	$0.04	--	--	--	--
Sending end—New AC substations	$40 million/AC substation	(included in integrator system)	--	3 (to connect POI to converter station at each tie)	$0.12	4 (to connect POI to converter station at each tie)	$0.16
Receiving end—reactive devices	$0.25 million/MVAR	Approx. 1/3 × 1,800 = 600 MVAR	$0.15	Approx. 1/3 × 3,600 = 1,200 MVAR	$0.30	Approx. 1/3 × 4,800 = 1,600 MVAR	$0.40
Receiving end—AC terminations	$10 million/ terminal expansion (assumed two terminal expansions per tie)	2 x 2 = 4	$0.04	3 x 2 = 6	$0.06	4 x 2 = 8	$0.08
Receiving end—additional upgrades on AC network	Assumed generic cost for each scenario	--	$0.50	--	$1.00	--	$1.00
Total AC portion			$0.73		$1.78		$2.04
AC and DC portions: $B							
Total—Congestion-Relief System			**$3.73**		**$8.03**		**$10.14**
Total cost + 50% margin			**$5.60**		**$12.05**		**$15.21**

Summary of High-Order-of-Magnitude Costs

	Reference Renewables Plus	Scenario A EE + Offshore	Scenario B Onshore Less EE/PV	Scenario C Wind Less Nuc
2030 Maine nameplate wind injection (MW)	3,652	926	5,743	7,579
Needed congestion-relief capacity (MW)	1,839	---	3,524	4,870
Integrator system (description)	2 AC parallel 345 kV paths	1 AC parallel 345 kV path	---	---
Integrator system cost ($ billion)	$1.50 to $3.00	$1.50 to $3.00	---	---
Integrator system cost + 50% margin ($ billion)	$2.25 to $4.50	$2.25 to $4.50	---	---
Congestion-relief system (description)	Connecting Larrabee 345 kV to the Hub	---	Connecting POIs directly to the Hub	Connecting POIs directly to the Hub
Congestion-relief system cost ($ billion)	$3.73	---	$8.03	$10.14
Congestion-relief system cost + 50% margin ($ billion)	$5.60	---	$12.05	$15.21
Total cost + 50% margin ($ billions)	**$7.85 to $10.10**	**$2.25 to $4.50**	**$12.05**	**$15.21**

Costs described here are preliminary high-level order of magnitude costs and are based on judgement.
Also, they do not account for individual plants' interconnection costs or potential costs from system operational issues.

High-Order-of-Magnitude Cost Estimates for Transmission Development – Offshore Wind

- The low-order-of-magnitude transmission costs for the offshore wind development assumed carefully planned points of interconnection split among Connecticut, Rhode Island, and southeastern Massachusetts that would eliminate the need for any integrator or congestion-relief systems.

	Reference Renewables Plus	Scenario A EE + Offshore	Scenario B Onshore Less EE/PV	Scenario C Wind Less Nuc
2030 nameplate SEMA/RI offshore wind injection (MW)	2,483 MW	3,483 MW	2,483 MW	4,085 MW

Suggested POI for Off-shore Resources	Location	Amount of Assumed Retired Generation at the POI (MW)	Example of Possible Nameplate Interconnections (MW)
Millstone/Montville 345 kV	Connecticut	1,127	1,400
Kent County 345 kV	SEMA/RI	---	800
Brayton Point 345 kV	SEMA/RI	1,525	1,600
Pilgrim/Canal 345 kV	SEMA/RI	1,769	1,600
	Total	**4,421**	**5,400**

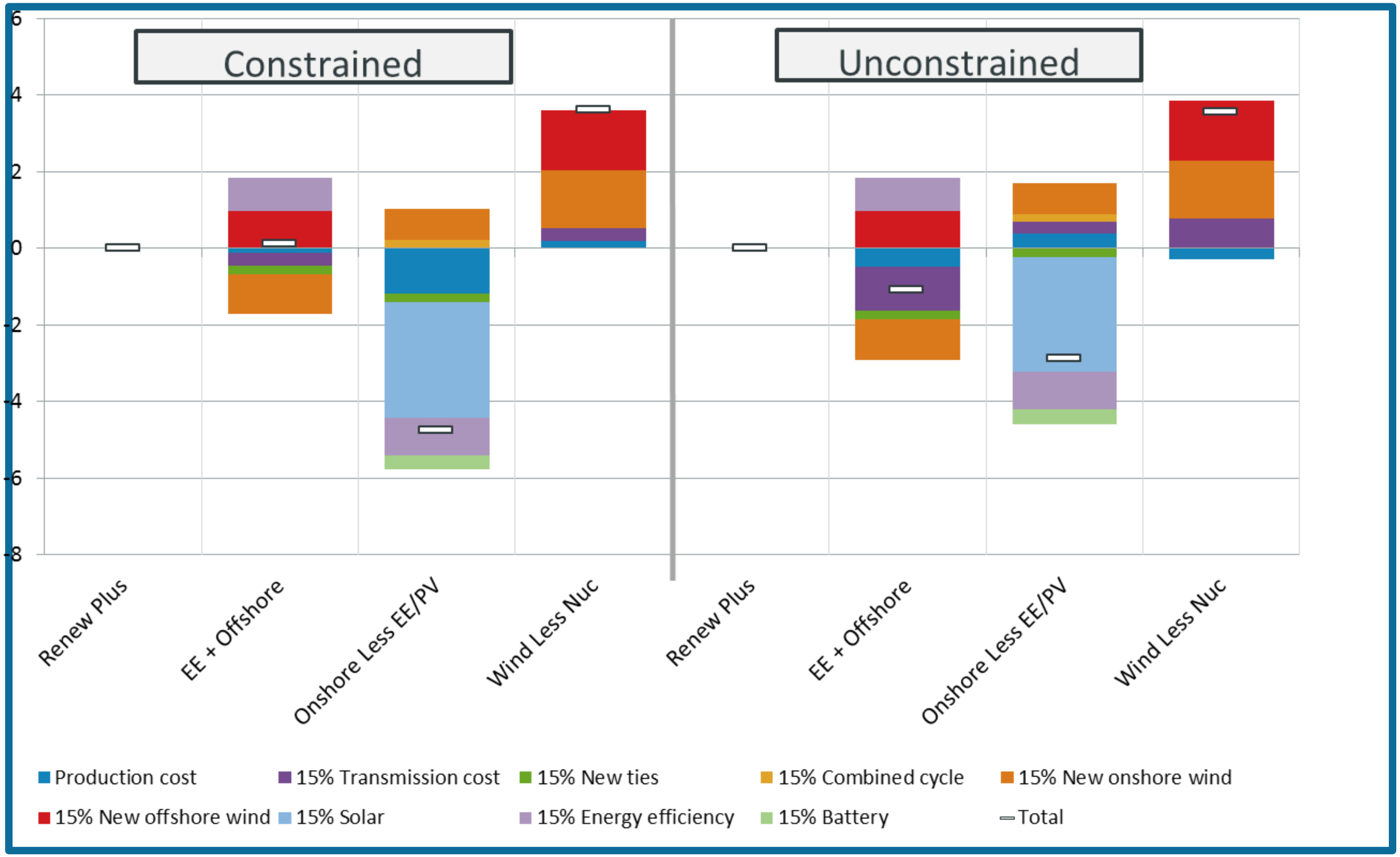
RELATIVE ANNUAL RESOURCE COSTS

- *Relative Annual Resource Costs ($ Billions and ¢/kWh)*

Relative Annual Resource Costs

- The relative annual resource cost (RARC) metric is a means of comparing the total costs of all three 2017 scenarios with the reference case.
- The RARC accounts for the annual systemwide production costs and the annualized carrying costs for new resources and high-order-of-magnitude transmission-development costs.
  - Systemwide production costs can be thought of as operating costs.
  - Annualized carrying costs for new resources and high-order-of-magnitude transmission-development costs capture the annual costs of capital additions.
- RARC is thus a measure of the relative total costs for all scenarios, expressed in billions of dollars and as cents per kilowatt-hour (kWh).

2030 Relative Annual Resource Costs, Compared with Reference ($ Billions)



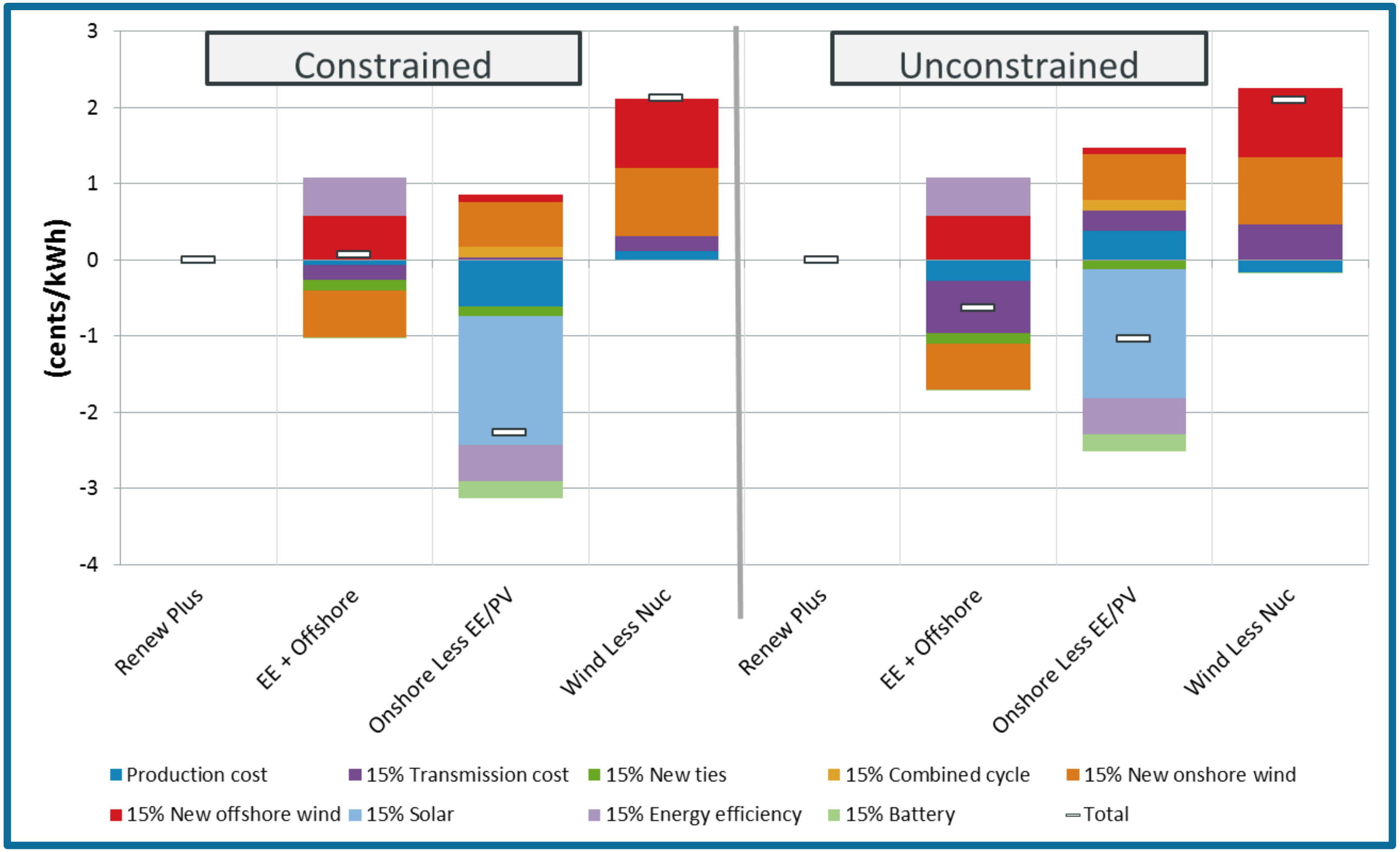
Note: Energy Efficiency and Solar include costs due to individual customer investments that do not reflect benefits received. Production cost reflects the price of carbon emissions at $24/ton.

2030 Relative Annual Resource Costs, Compared with Reference ($ Billions), cont.

Dollars ($ Million)	Constrained				Unconstrained			
	Renew Plus	EE + Offshore	Onshore Less EE/PV	Wind Less Nuc	Renew Plus	EE + Offshore	Onshore Less EE/PV	Wind Less Nuc
Production Cost	Reference	-116	-1,187	200	Reference	-480	374	-292
15% Transmission cost	Reference	-338	0	338	Reference	-1,163	308	782
15% Ties	Reference	-225	-225	0	Reference	-225	-225	0
15% Combined Cycle	Reference	0	219	0	Reference	0	219	0
15% New Onshore Wind	Reference	-1,047	803	1,508	Reference	-1,047	803	1,508
15% New Offshore Wind	Reference	974	0	1,560	Reference	974	0	1,560
15% Solar	Reference	0	-3,013	0	Reference	0	-3,013	0
15% Energy Efficiency	Reference	863	-980	0	Reference	863	-980	0
15% Battery	Reference	0	-375	0	Reference	0	-375	0
Total	Reference	112	-4,758	3,606	Reference	-1,077	-2,889	3,558

Note: Energy Efficiency and Solar include costs due to individual customer investments that do not reflect benefits received. Production cost reflects the price of carbon emissions at $24/ton.

2030 Relative Annual Resource Costs, Compared with Reference (C/kWh)



Note: Energy Efficiency and Solar include costs due to individual customer investments that do not reflect benefits received. Production cost reflects the price of carbon emissions at $24/ton.

2030 Relative Annual Resource Costs, Compared with Reference (C/kWh), cont.

Cent per kWh	Constrained				Unconstrained			
	Renew Plus	EE + Offshore	Onshore Less EE/PV	Wind Less Nuc	Renew Plus	EE + Offshore	Onshore Less EE/PV	Wind Less Nuc
Production Cost	Reference	-0.068	-0.613	0.117	Reference	-0.282	0.386	-0.172
15% Transmission cost	Reference	-0.198	0.031	0.198	Reference	-0.683	0.265	0.459
15% Ties	Reference	-0.132	-0.122	0.000	Reference	-0.132	-0.122	0.000
15% Combined Cycle	Reference	0.000	0.139	0.000	Reference	0.000	0.139	0.000
15% New Onshore Wind	Reference	-0.615	0.593	0.886	Reference	-0.615	0.593	0.886
15% New Offshore Wind	Reference	0.572	0.091	0.917	Reference	0.572	0.091	0.917
15% Solar	Reference	0.000	-1.695	0.000	Reference	0.000	-1.695	0.000
15% Energy Efficiency	Reference	0.507	-0.480	0.000	Reference	0.507	-0.480	0.000
15% Battery	Reference	0.000	-0.220	0.000	Reference	0.000	-0.220	0.000
Total	Reference	0.066	-2.277	2.118	Reference	-0.633	-1.045	2.090

Note: Energy Efficiency and Solar include costs due to individual customer investments that do not reflect benefits received. Production cost reflects the price of carbon emissions at $24/ton.

Relative Annual Resource Costs - Observations

- “Onshore Less EE/PV” requires the lowest investment in new resources and transmission development and has the lowest total RARC.
- Although the production costs for the “EE + Offshore” scenario are the lowest, its total RARC is higher than the “Onshore Less EE/PV” scenario. This is because the “EE + Offshore” has a higher quantity of renewable resources that require higher capital investment in resources and transmission development than “Onshore Less EE/PV”.
- “Wind Less Nuc” has the highest RARC as a result of its higher annual carrying charges for new wind resources and transmission development.

ENVIRONMENTAL RESULTS

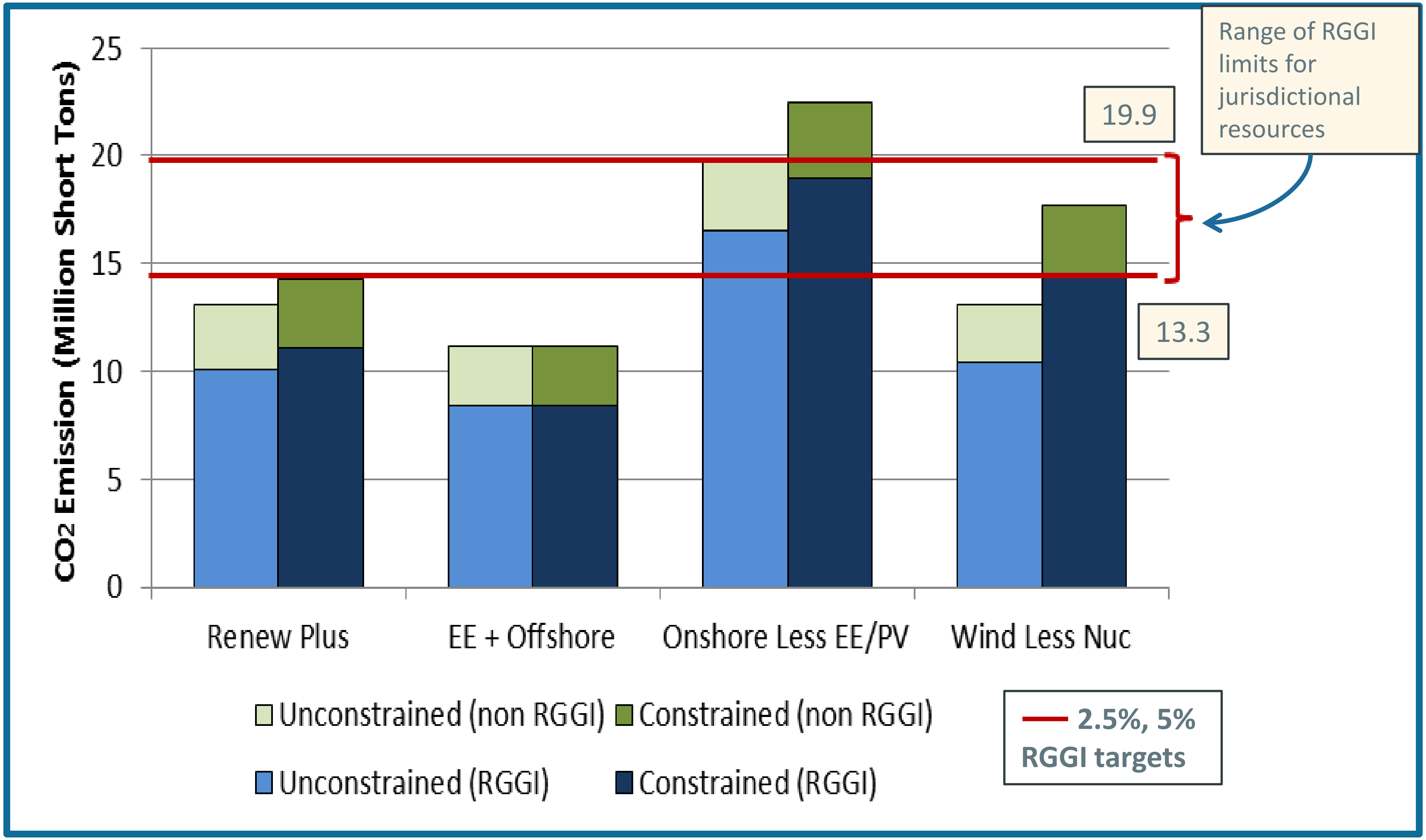
- *Carbon Dioxide Emissions and RGGI Goals*
- *Spilled Renewable Resource Energy*

2030 RGGI Targets

RGGI Targets*	Assumed Annual Reduction	CO_2 Emission (Million Short Tons)
New England	5.0%	13.3
	2.5%	19.9
All 9 RGGI States	5.0%	39.1
	2.5%	58.6

*The proposed 2030 RGGI caps used were under consideration by RGGI States in 2017. The RGGI States agreed to final annual caps for 2021 through 2030 in a model rule text announced on December 19, 2017. The final 2030 caps differ slightly from the proposed caps used in this analysis.

2030 CO_2 Emissions (millions of short tons)



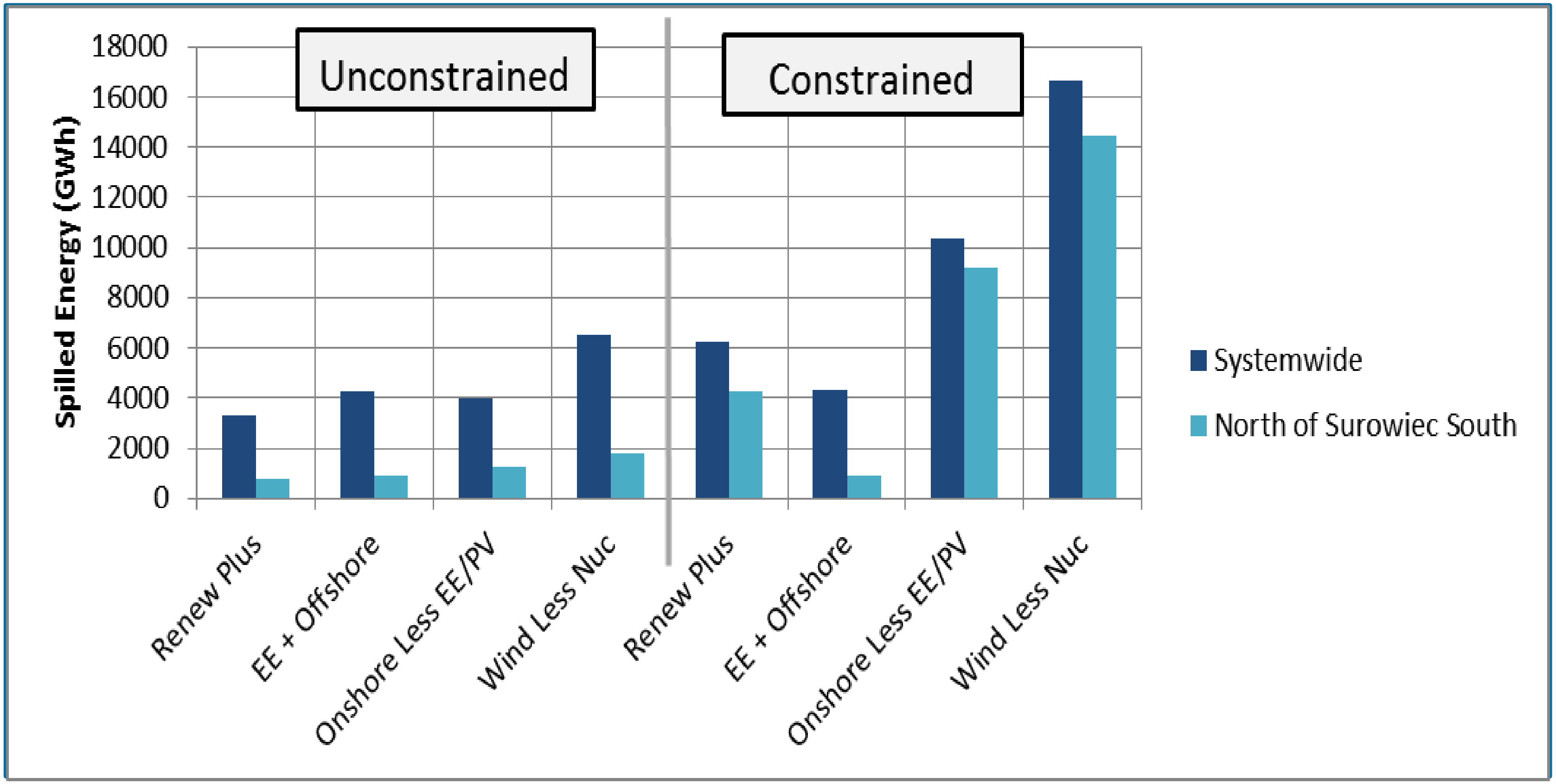
CO2 Emissions Compared with RGGI Targets

Transmission	Scenario	All Sources New England (M Short Tons)	New England RGGI Sources (M Short Tons)	New England RGGI Sources Percentage of New England 2.5% Reduction (%)	New England RGGI Sources Percentage of New England 5.0% Reduction (%)	New England RGGI Sources Percentage of 9 RGGI States 2.5% Reduction (%)	New England RGGI Sources Percentage of 9 RGGI States 5.0% Reduction (%)
Unconstrained	Renew Plus	13.1	10.1	51%	76%	17%	26%
	EE + Offshore	11.2	8.4	42%	63%	14%	21%
	Onshore Less EE/PV	19.7	16.5	83%	124%	28%	42%
	Wind Less Nuc	13.1	10.4	52%	78%	18%	27%
Constrained	Renew Plus	14.3	11.1	56%	83%	19%	28%
	EE + Offshore	11.1	8.4	42%	63%	14%	21%
	Onshore Less EE/PV	22.4	18.9	95%	142%	32%	48%
	Wind Less Nuc	17.7	14.3	72%	108%	24%	37%

CO2 Emission Compared with RGGI Targets - Observations

- "EE + Offshore" produces the least amount of carbon emissions. It satisfies both the New England 2.5% and 5.0% reduction targets by 2030, with or without the transmission system constraints modeled.
- "Wind Less Nuc" produces more carbon emissions compared to the reference case.
  - When the transmission system is unconstrained, carbon emission of the "Wind Less Nuc" scenario satisfies both the New England 2.5% and 5% reduction targets.
  - When the transmission system is constrained, carbon emission of the "Wind Less Nuc" scenario satisfies the New England 2.5% reduction target, but exceeds the New England 5.0% reduction target.
- "Onshore Less EE/PV" produces the most carbon emissions due to the addition of 1,378 MW of NGCC units and the reduction in price-taking resources. Carbon emission of this scenario satisfies the New England 2.5% reduction target, but exceeds the New England 5.0% reduction target, under both transmission system constrained and unconstrained conditions.

Total Amount of "Spilled" Renewable Resource Energy, 2030 (GWh) (Added)



Total Amount of "Spilled" Renewable Resource Energy, 2030 (GWh, %)

Transmission	Scenario	Renewable Energy Profile (GWh)	Total Spilled (GWh)	% of Total Renewable Spilled[a] (%)	Total Spilled Due to Transmission Constraints[b] (GWh)	Total Spilled North of Surowiec-South (GWh)	Total Renewable North of Surowiec-South (GWh)	% of Total Renewable Spilled North of Surowiec-South[c] (%)
Unconstrained	Renew Plus	73,237	3,296	4.50%	Unconstrained reference	766	18,692	23.26%
	EE + Offshore	62,686	4,285	6.83%	Unconstrained reference	916	10,162	21.37%
	Onshore Less EE/PV	63,983	4,011	6.27%	Unconstrained reference	1,251	25,060	31.19%
	Wind Less Nuc	92,517	6,516	7.04%	Unconstrained reference	1,778	31,099	27.29%
Constrained	Renew Plus	73,237	6,270	8.56%	2,974	4,261	18,692	67.96%
	EE + Offshore	62,686	4,358	6.95%	73	942	10,162	21.62%
	Onshore Less EE/PV	63,983	10,358	16.19%	6,346	9,209	25,060	88.91%
	Wind Less Nuc	92,517	16,664	18.01%	10,148	14,466	31,099	86.81%

Notes (a), (b) and (c) associated with this table are on the next slide.

Total Amount of "Spilled" Renewable Resource Energy, cont.

Notes:

(a) % of Total Renewable Spilled = Total Spilled (GWh) / Renewable Energy Profile (GWh)

(b) "Total Spilled Due to Transmission Constraints" is equal to the difference of the total spilled between the constrained and unconstrained cases

(c) % of Total Renewable Spilled North of Surowiec-South = Total Spilled North of Surowiec-South (GWh) / Total Spilled (GWh)

Total Amount of “Spilled” Renewable Resource Energy - Observations

- Among all constrained scenarios, “Wind Less Nuc” experiences the highest amount of spillage.
- In most constrained scenarios, the vast majority of the spillage occurs north of the Surowiec-South interface.
  - The “EE + Offshore” scenario is the exception with the majority of the renewable energy being spilled south of Surowiec-South; this is the scenario with the highest amount of EE and least amount of onshore generation.
- For all unconstrained scenarios, the proportion of spilled renewable energy falls within a similar range.
  - In these scenarios, spillage is driven by renewable plus nuclear supply exceeding load consumption.

APPENDIX

- *Detailed Assumptions*
- *Additional Transmission Data*

Peak Demand, Annual Energy Use, and Demand Modifiers

- All detailed assumptions can be found at https://www.iso-ne.com/static-assets/documents/2017/11/final_2016_phase1_nepool_scenario_analysis_economic_study.docx
  - Peak Demand, Annual Energy Use, and Demand Modifiers
    - Peak Demand and Annual Energy Use
    - Passive Demand and Behind-the Meter PV Resources
    - Plug-In Hybrid Electric Vehicles
  - Capacity Assumptions
    - Capacity Value Assumptions
    - Wind Generation
    - Resource Retirements
    - Active Demand Resources
    - New England Hydroelectric Generation
    - Pumped Storage and Battery Storage
    - Transmission Interface Limits and Interchanges with Neighboring Systems
  - Fuel Prices
  - Threshold Prices
  - Environmental Emissions Allowance Assumptions
  - Annual Carrying Charges
    - Annual Carrying Charges for New Resources
    - Transmission Development Costs
    - High-Order-of-Magnitude Cost Estimates for Integrating Renewable Resources

ADDITIONAL LOCATIONAL DETAILS REGARDING ONSHORE WIND INJECTIONS

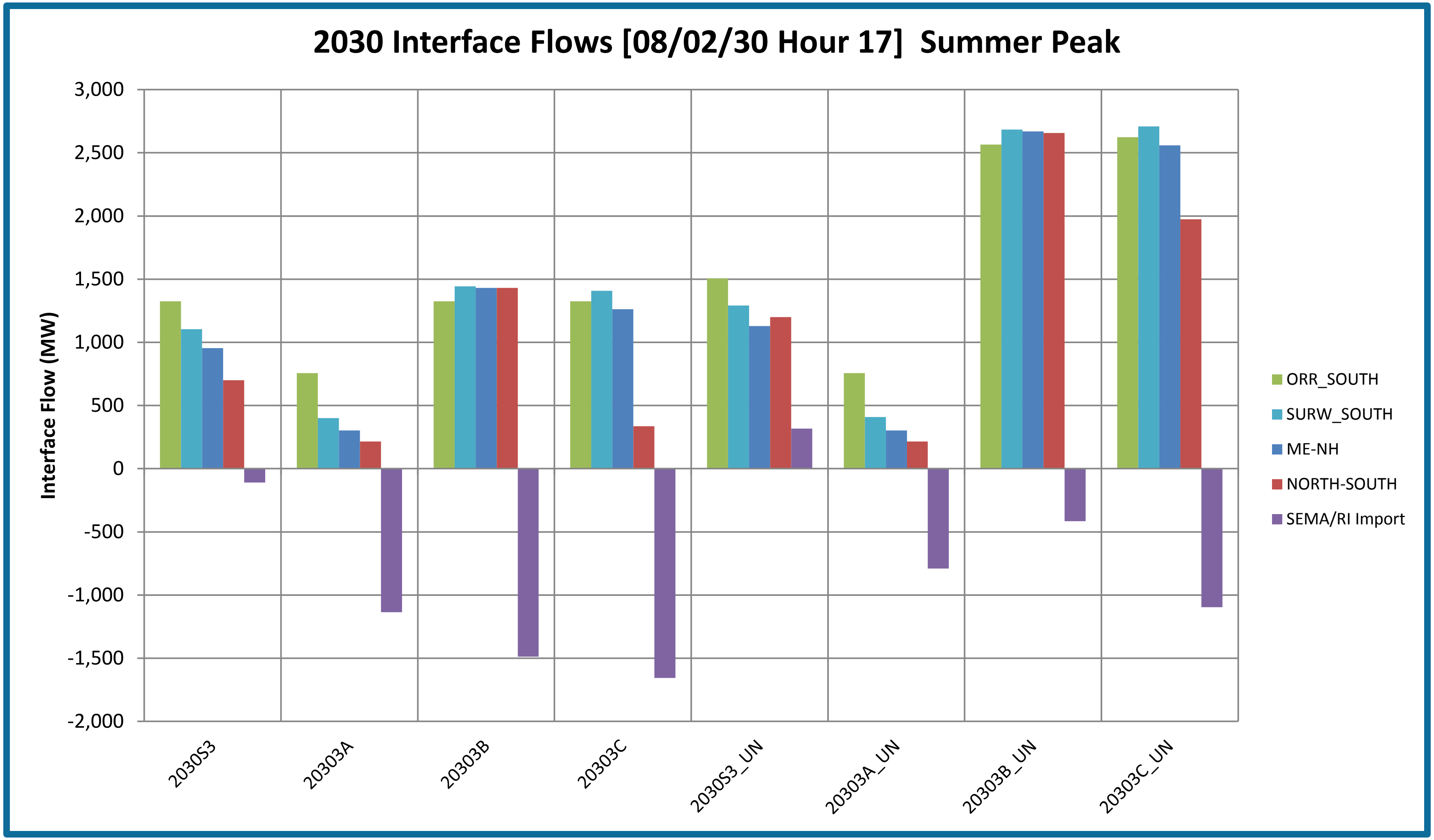
Scenario Specifics

Onshore Wind (MW) – by Subarea

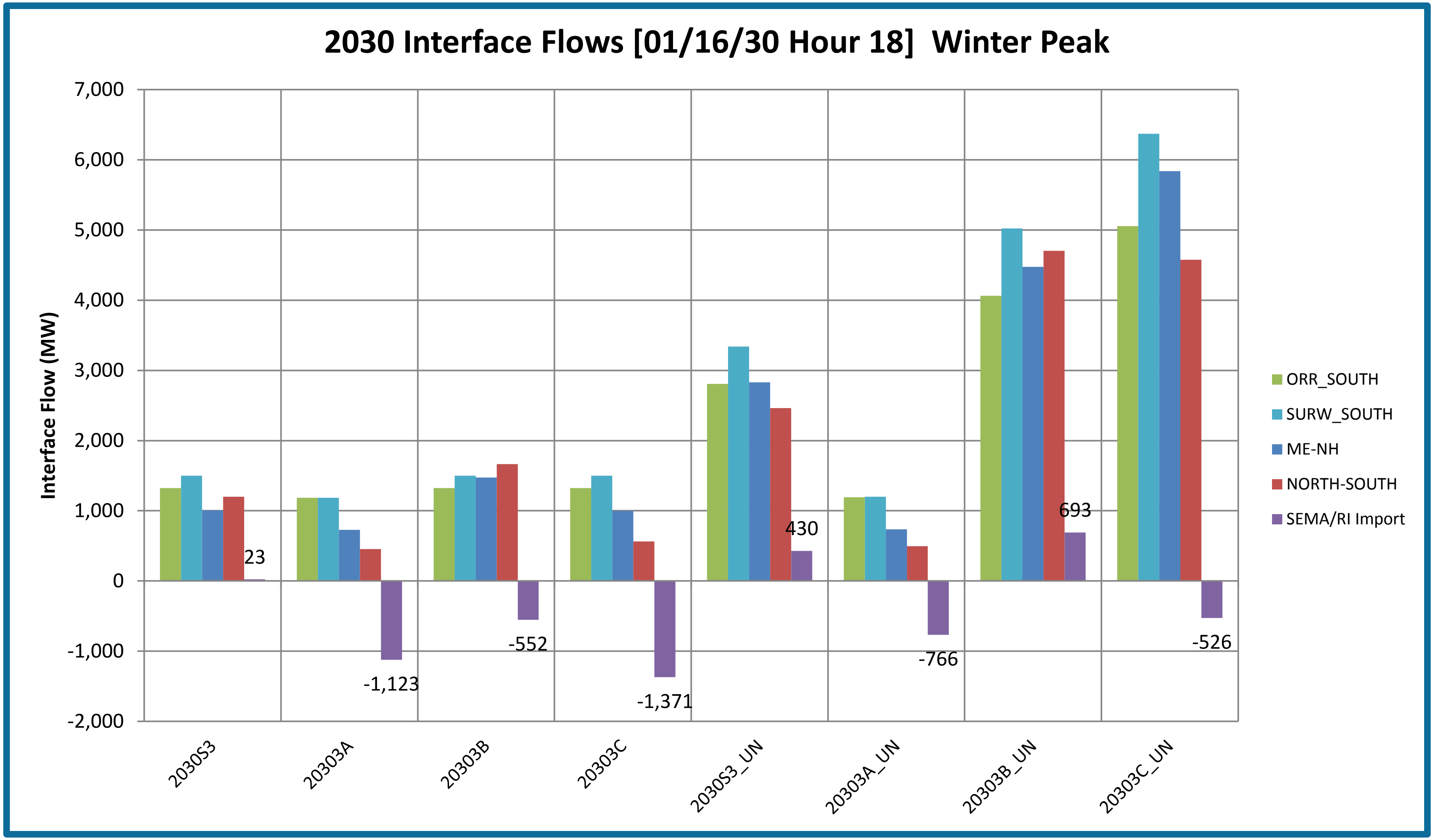
Subarea	Onshore	Renew Plus	EE + Offshore	Onshore Less EE/PV	Wind Less Nuc
BHE	Existing	329	329	329	329
	Added	2,661	675	4,185	5,523
ME	Existing	262	262	262	262
	Added	991	251	1,558	2,056
Rest of NE	Existing	448	448	448	448
	Added	110	35	218	288
Total	Existing	1,039	1,039	1,039	1,039
Total	Added	3,761	961	5,961	7,867
Grand Total	Existing & Added	**4,800**	**2,000**	**7,000**	**8,906**

INTERFACE FLOWS ON REPRESENTATIVE SUMMER AND WINTER DAYS

MW Flows on Interfaces for Summer Peak Hour – All scenarios



MW Flows on Interfaces for Winter Peak Hour – All scenarios



I. PERCENT OF HOURS INTERFACE FLOWS EXCEED 100% OF RATINGS
II. SEASONAL FLOW DURATION CURVES

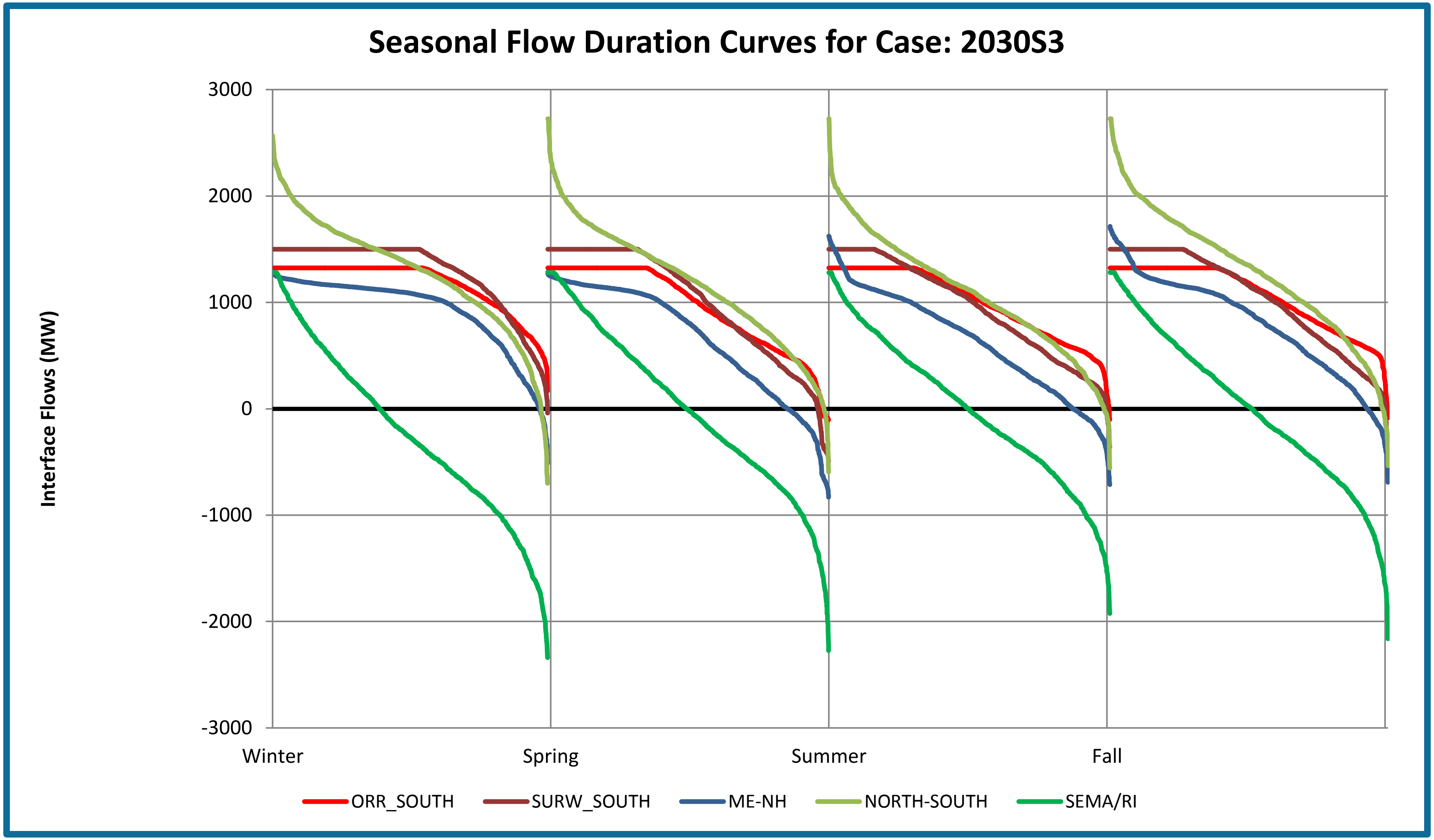
Percent of Hours Interface Flow Reaches or Exceeds 100% of Rating – All scenarios, 2030

Scenarios	Orrington-South	Surowiec-South	Maine-New Hampshire	North-South	SEMA/RI Import	SEMA/RI Export
Renew Plus Constrained	39.5%	31.9%	0.2%	0.0%	1.4%	0.0%
EE + Offshore Constrained	1.6%	0.2%	0.0%	0.0%	0.3%	0.0%
Onshore Less EE/PV Constrained	48.3%	48.4%	0.0%	0.0%	0.1%	0.0%
Wind Less Nuc Constrained	44.2%	57.3%	0.0%	0.0%	0.7%	0.2%
Renew Plus Unconstrained	48.3%	45.1%	14.2%	25.0%	17.8%	0.0%
EE + Offshore Unconstrained	2.1%	1.1%	0.0%	0.0%	5.4%	0.0%
Onshore Less EE/PV Unconstrained	64.3%	63.5%	37.7%	48.9%	5.4%	0.0%
Wind Less Nuc Unconstrained	71.5%	71.7%	36.7%	56.5%	7.5%	0.0%

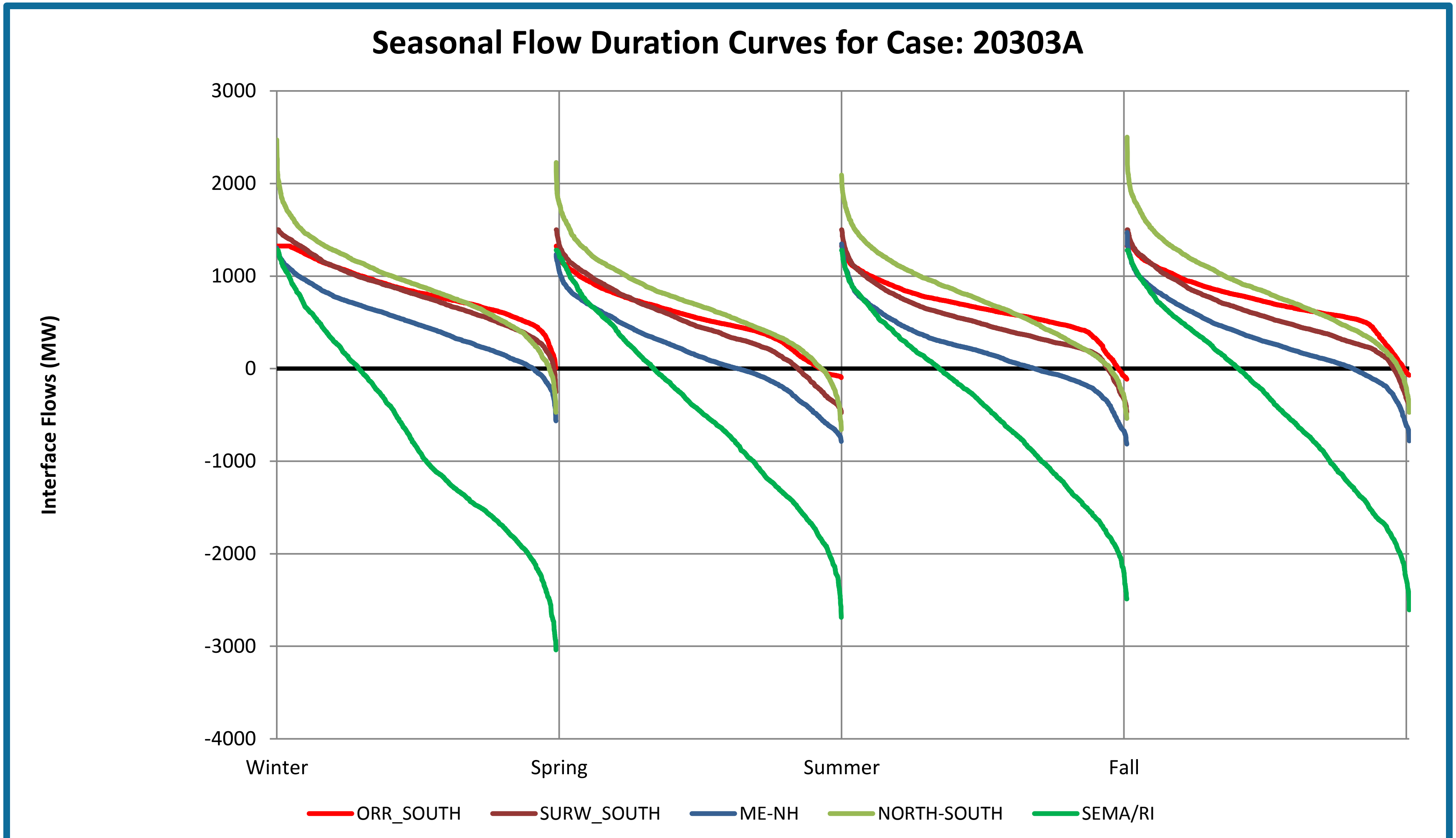
Maine Interface Flow Statistics, 2030

Scenarios	Transfer Limit (MW)	Maximum MW Flow (Unconstrained Case)	% of Time Interface Exceeds Its Capability	Transfer Limit (MW)	Maximum MW Flow (Unconstrained Case)	% of Time Interface Exceeds Its Capability	Transfer Limit (MW)	Maximum MW Flow (Unconstrained Case)	% of Time Interface Exceeds Its Capability
	Orrington-South Interface			Surowiec-South Interface			Maine-New Hampshire Interface		
Renew Plus	1,325	3,366	48.3%	1,500	4,114	45.1%	1,900	4,695	14.2%
EE + Offshore	1,325	1,596	2.1%	1,500	1,804	1.1%	1,900	2,559	0.0%
Onshore Less EE/PV	1,325	4,735	64.3%	1,500	5,917	63.5%	1,900	5,799	37.7%
Wind Less Nuc	1,325	5,890	71.5%	1,500	7,404	71.7%	1,900	6,566	36.7%

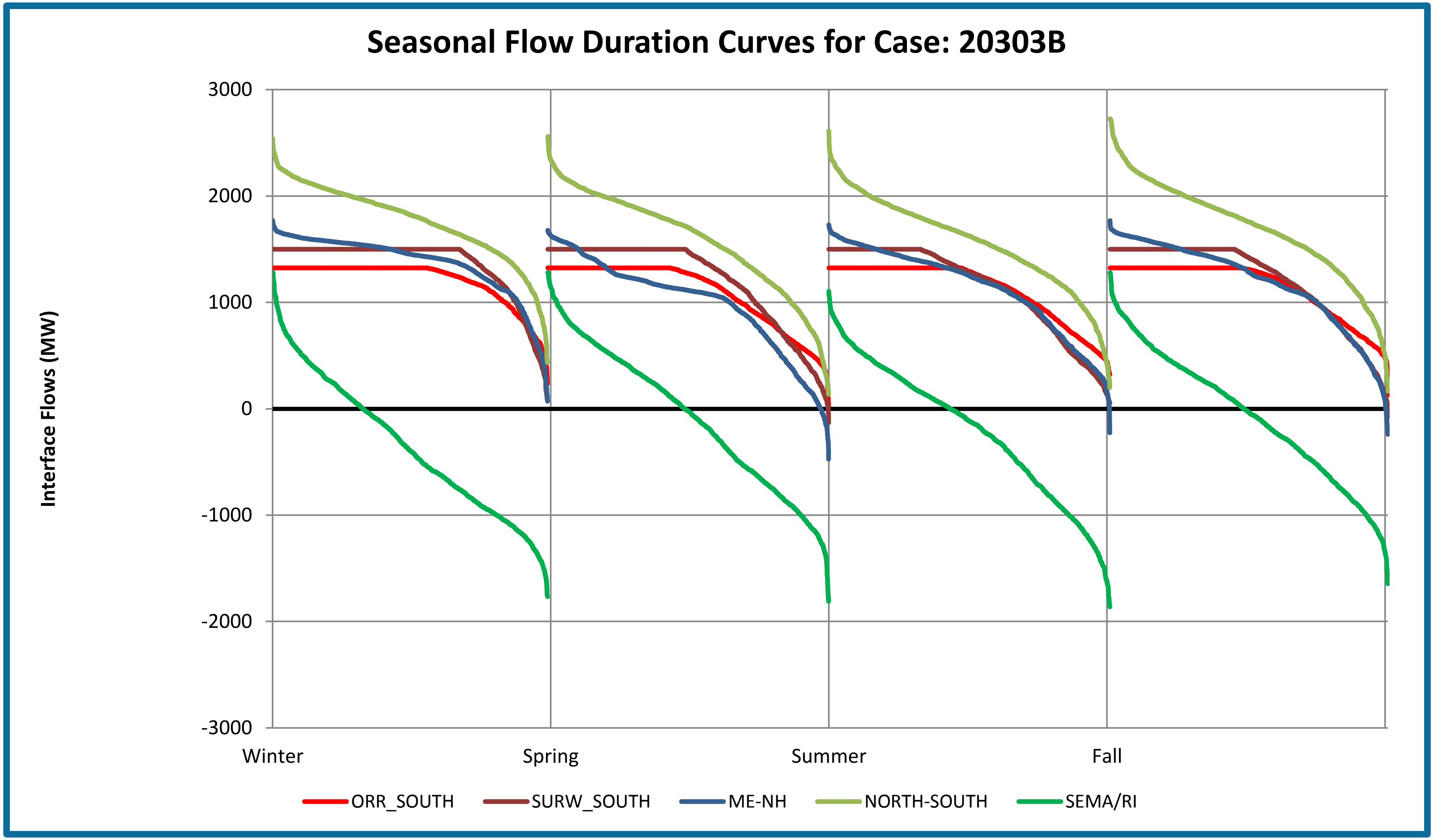
Seasonal Flow Duration Curves – Constrained Reference: "Renew Plus"



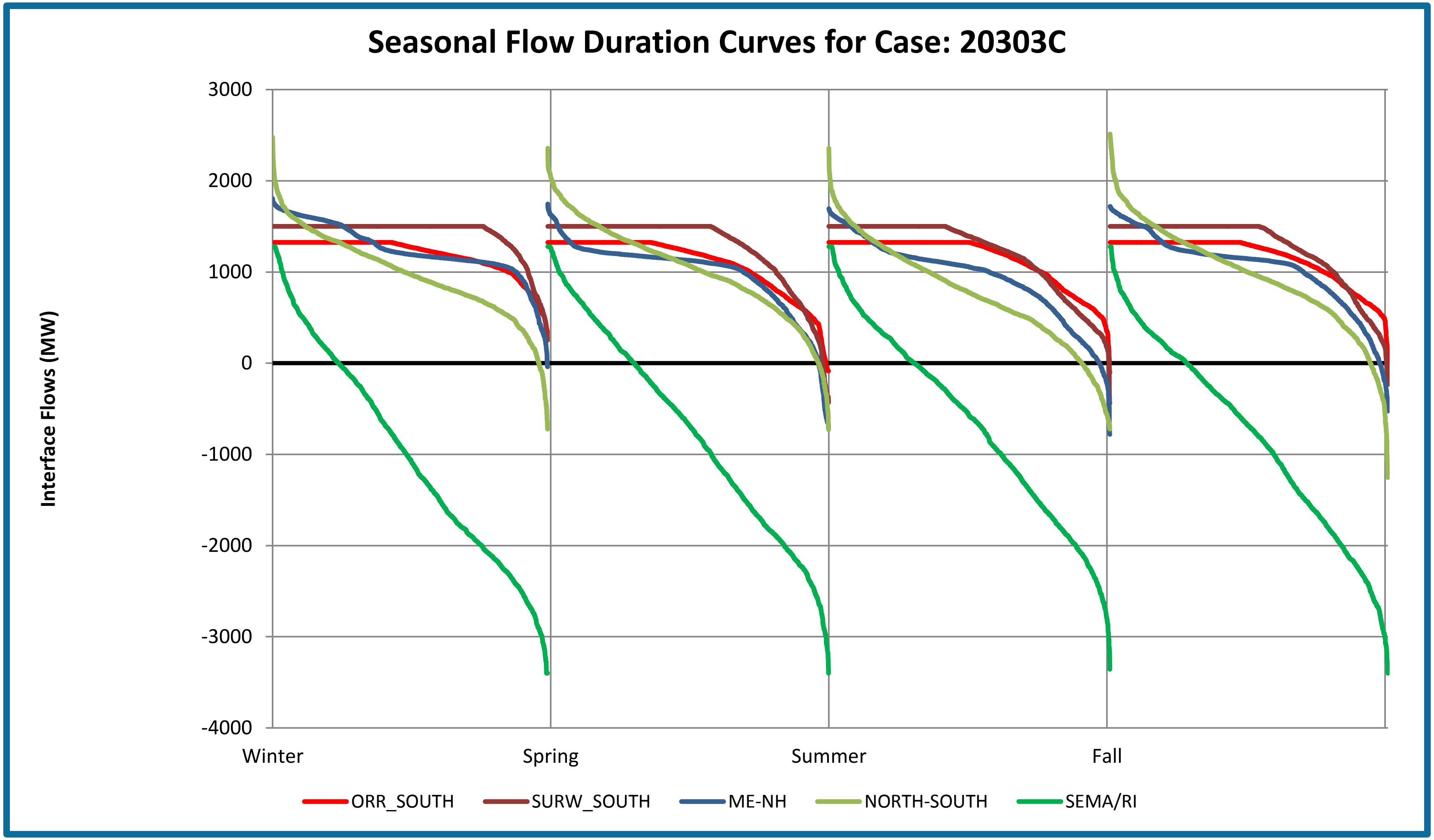
Seasonal Flow Duration Curves – Constrained Scenario A: "EE + Offshore"



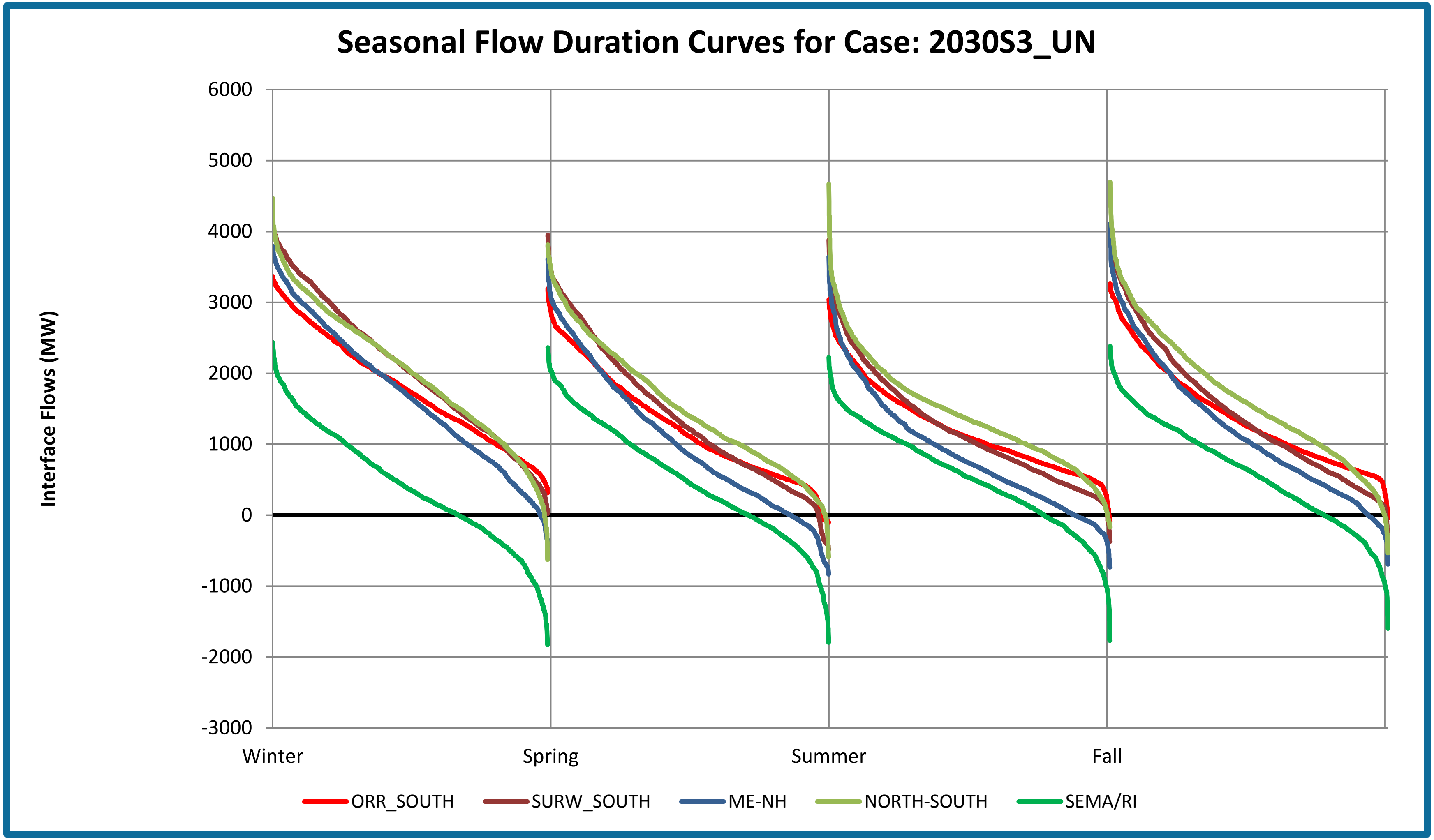
Seasonal Flow Duration Curves – Constrained Scenario B: “Onshore Less EE/PV”



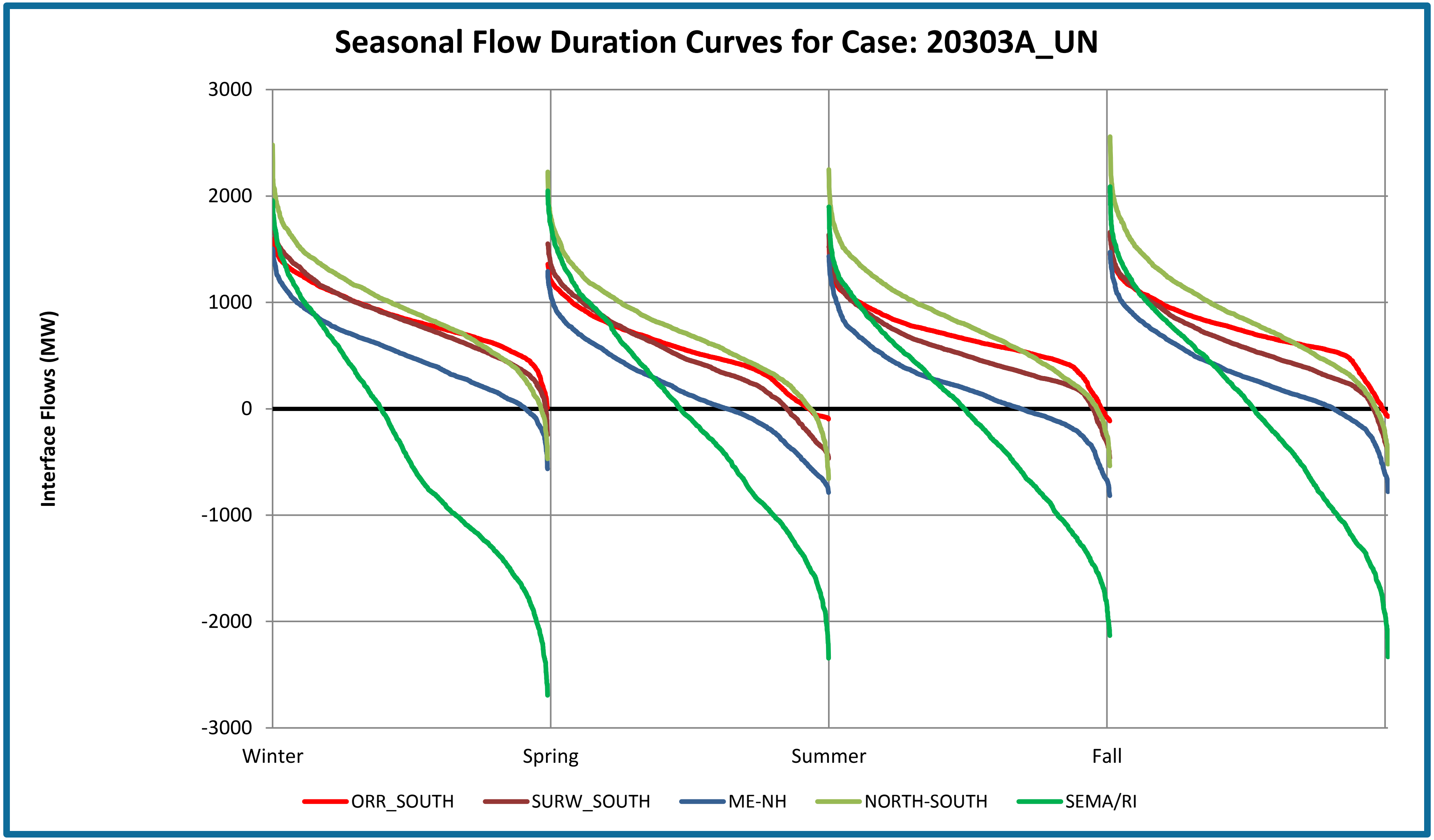
Seasonal Flow Duration Curves – Constrained Scenario C: "Wind Less Nuc"



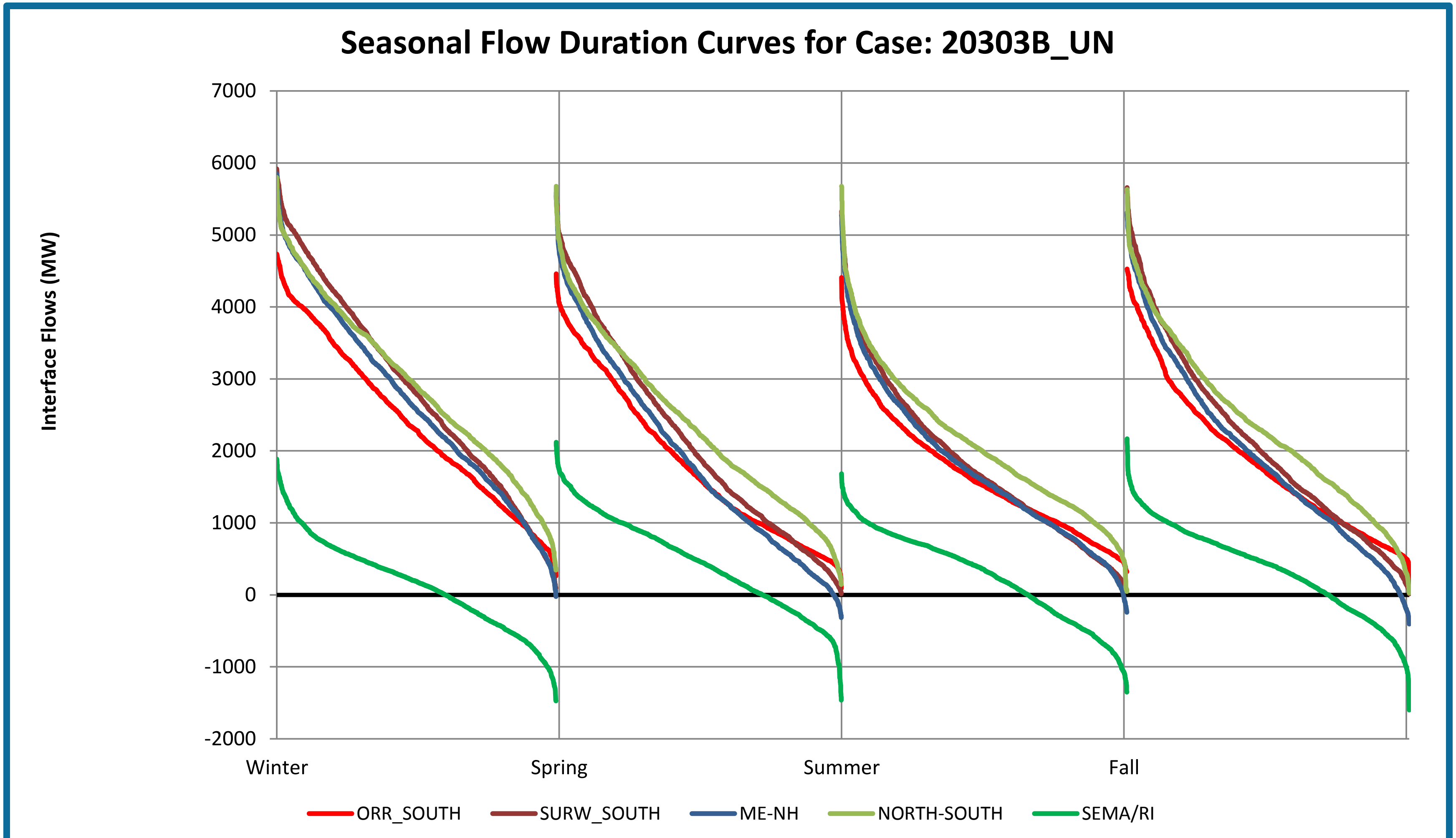
Seasonal Flow Duration Curves – Unconstrained Reference: “Renew Plus”



Seasonal Flow Duration Curves – Unconstrained Scenario A: “EE + Offshore”



Seasonal Flow Duration Curves – Unconstrained Scenario B: "Onshore Less EE/PV"



Seasonal Flow Duration Curves – Unconstrained Scenario C: “Wind Less Nuc”