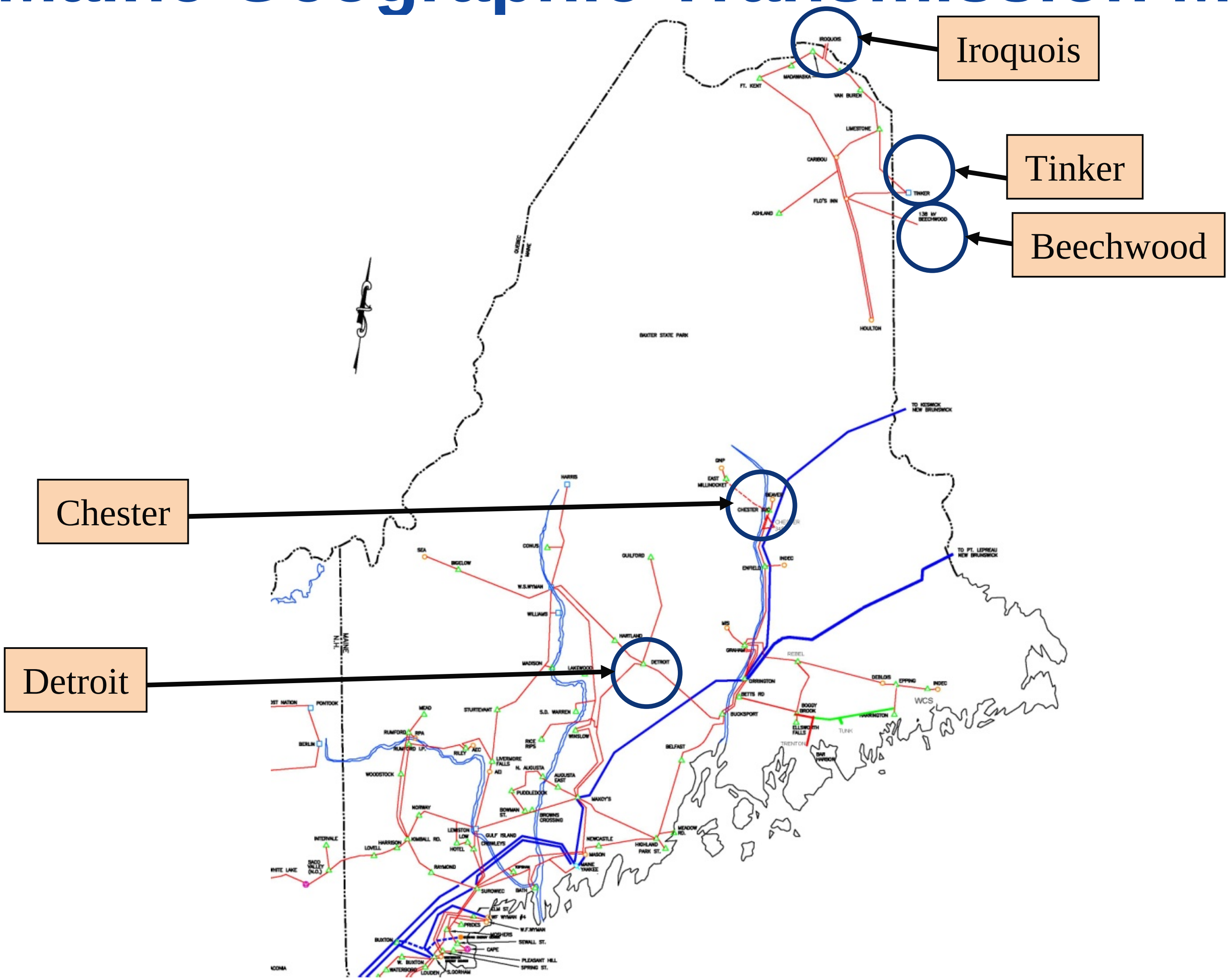
Economic Analysis of the Maine Power Connector (MPC): Draft Study Inputs

Purpose

- Several purposes
  - To review draft study assumptions for MPC study
  - To generate discussion and feedback
  - To introduce metrics and calculations prescribed under the tariff

Maine Geographic Transmission Map



Maine Power Connection (MPC)

- MPC is a proposed transmission project that would interconnect the transmission system of Maine Public Service (MPS) with the rest of New England
- Today MPS is served through New Brunswick only – there is no direct connection to New England
  - Two 69 kV ties to Iroquois Substation
  - Two 69 kV ties to Tinker Substation which steps up to a single 138 kV line
  - One 138 kV tie to Beechwood

Maine Power Connection (MPC)

- Initial study
  - Interconnection of MPS service territory to New England electric system
- Proposed transmission
  - New 345 kV line from MPS to Chester
    - Make use of the reactive capabilities of the Chester SVC
  - New 345 kV line from Chester to Detroit
    - Detroit is along the path of the MPRP which creates a new 345 kV circuit from Orrington to a new substation at Benton
- Existing MPS load and generation included
- Requested to include proposed 800 MW of wind resources in Aroostook County

Market Efficiency Transmission Upgrade Metrics (METU)

- Under Attachment N
  - METU are determined by production cost benefits
  - Over ten year period
- The project qualifies as a METU … if …
  - Present Value (PV) of production cost savings exceeds
  - Present Value (PV) of the carrying cost of the transmission project
  - E.g. the Net Present Value (NPV) is positive
- Following slides describe inputs to the production cost model to be used to make the METU determination

Model Assumptions

New England Demand / ICR Assumptions

- Load forecast based on ISO annual 2008 forecast update
- ICR based on RSP07 indicative values
  - RSP08 indicative values not yet available
  - 2008 update of summer peaks suggest lower RSP08 ICR values
  - Excludes Maine Public Service (MPS) and the Maritimes

Year	RSP07 Summer Peak	RSP07 ICR Requirement	RSP07 HQICC Assumed	ICR Auction Requirement	Summer Peak Loads (2008 Forecast)	Installed Resources (Nameplate MW)
2009	28495	32657	1200	31457	28480	
2010	29035	33705	1400	32305	28955	
2011	29635	34449	1400	33049	29405	33499
2012	30175	35105	1400	33705	29820	33906
2013	30660	35716	1400	34316	30190	34625
2014	31100	36250	1400	34850	30510	34975
2015	31510	36755	1400	35355	30790	35595
2016	31885	37187	1400	35787	31035	36057
2017	32264	37668	1400	36268	31250	36580
2018	32648	38136	1400	36736	31466	37025

Note: Last years (yellow shading) extrapolated at previous year growth rate

Maine Public Service (MPS) Assumptions

- Load in 2011
  - Summer peak 126 MW
  - Winter Peak 141 MW
  - Annual Energy 799 MW
  - Hourly load profile is congruent with the RSP model for BHE loads
- Existing Resources
  - Distillate 12 MW
  - Hydro 78 MW
  - Biomass 87 MW
- Future Resources
  - 800 MW of wind generation

Assumptions – New Resources

- New England resources added based on
  - Buying only enough capacity to meet ICR requirements
  - April 2008 CELT
    - Existing resources
    - FCA cleared
  - Queue resources added
    - Resources with I.3.9 approval added first
      - According to “Proposed Commercial operation date”
      - Added as needed to satisfy ICR requirements
    - Resources without I.3.9 approval added if needed
      - According to “Proposed Commercial operation date”
      - Added as needed to satisfy ICR requirements

New England Resource Additions

- Resources added as needed
  - Values shown reflect nameplate wind rating instead of FCM qualified capacity
- MPS not included in tables

Fuel	2011	2012	2013	2014	2015	2016	2017	2018	Total
Coal	2688								2688
Distillate	985							78	1063
JetFuel	547		18						565
Landfill Gas	47							5	52
Municipal Solid Waste	455								455
Natural Gas	12405	97	608	350	620		407	24	14511
Nuclear	4665	70							4735
Other Biogas	5								5
Residual Fuel	5596								5596
Solar	0								0
Tire Derived Fuels	22								22
Hydro/Pumped Storage	3014	19							3033
Total Demand Response	2279								2279
Biomass	399		93				17		509
Wind	10	221				462	99	338	1130
Purchases	482								482
Exports	-100								-100
Total	33499	407	719	350	620	462	523	445	37025
Cumulative	33499	33906	34625	34975	35595	36057	36580	37025	

New England Resource Additions

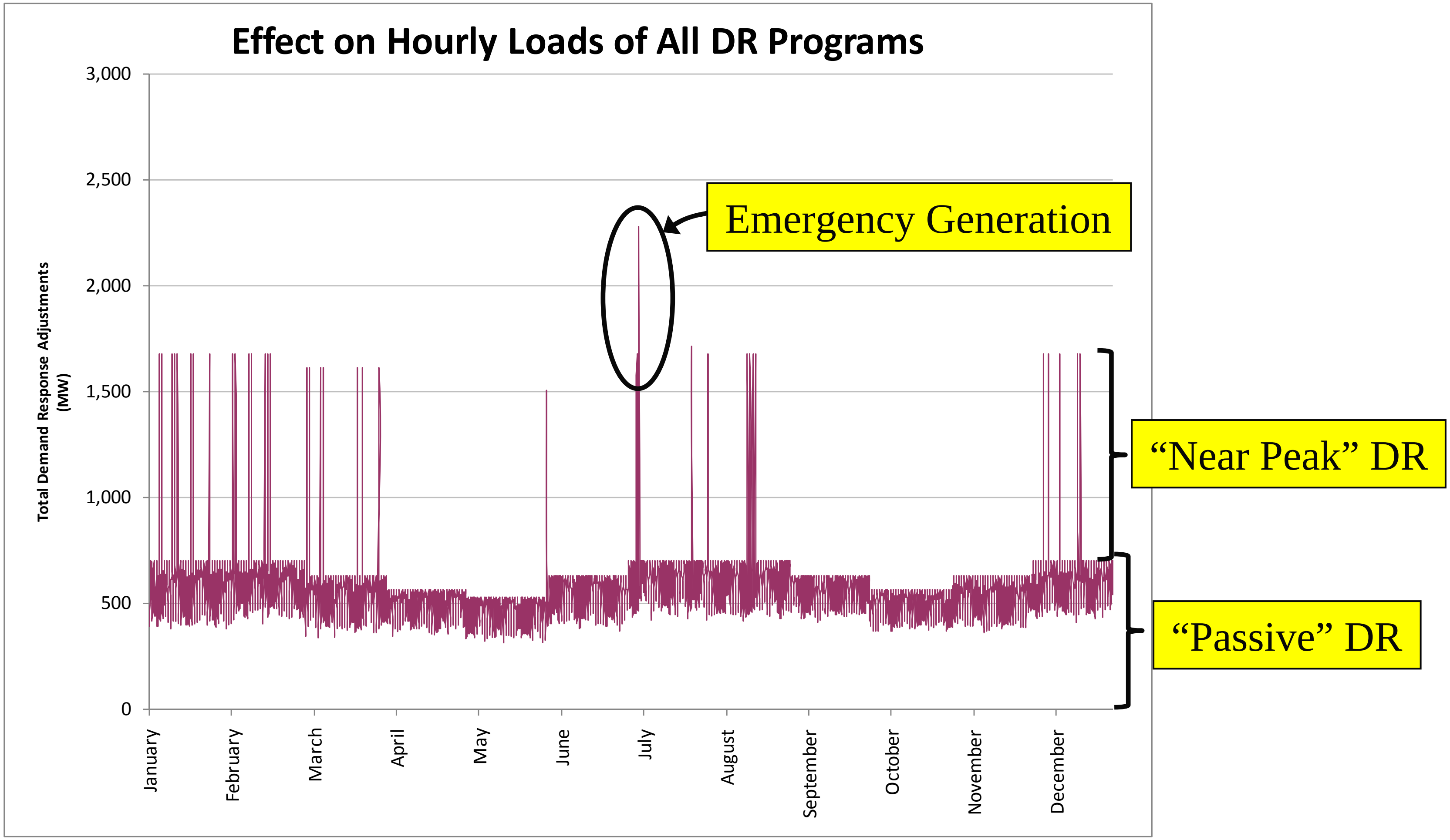
- MPS not included in tables

RSP Area	2011	2012	2013	2014	2015	2016	2017	2018	Total
BHE	873	60	0	0	0	0	0	39	972
BOST	3297	97	18	0	0	0	0	0	3412
CMAN	362	0	99	0	0	0	0	0	461
CT	4454	70	146	0	620	0	82	0	5372
CT 'Near-Peak' DR	979	0	0	0	0	0	0	0	979
CT 'Passive' DR	700	0	0	0	0	0	0	0	700
CT Emergency Gen	600	0	0	0	0	0	0	0	600
ME	877	131	0	0	0	0	90	78	1176
ME 'Near-Peak' DR	0	0	0	0	0	0	0	0	0
ME 'Passive' DR	0	0	0	0	0	0	0	0	0
ME Emergency Gen	0	0	0	0	0	0	0	0	0
NH	4047	8	0	0	0	0	17	146	4218
NOR	500	0	204	0	0	0	0	0	704
RI	5084	0	0	0	0	0	0	0	5084
SEMA	3340	0	0	350	0	462	0	24	4176
SME	1494	0	0	0	0	0	0	0	1494
SWCT	2235	0	197	0	0	0	325	78	2835
VT	1211	11	0	0	0	0	9	80	1311
WMA	3545	30	55	0	0	0	0	0	3630
Export	-100	0	0	0	0	0	0	0	-100
Total	33499	407	719	350	620	462	523	445	37025
Cumulative	33499	33906	34625	34975	35595	36057	36580	37025	

Modeling Demand Resources

- "Passive" Demand Resources (explicit profile)
  - 700 MW in Base Case
    - On-Peak Demand Resources - 554 MW accepted
    - Seasonal Peak Demand Resources - 146 MW accepted
  - Energy Efficiency profile developed for Scenario Analysis used
  - Has a ~78 percent capacity factor
- "Near Peak" Demand Resources (explicit profile)
  - 979 MW in Base Case
    - Real-Time Demand Resources – 874 MW accepted
    - Critical Peak Demand Resources – 105 MW accepted
- Emergency Generation (explicit profile)
  - 600 MW modeled
  - 874 MW accepted, but a maximum of 600 is allowed

Effect of All Demand Resources Programs



Maine Wind Resources

- All assumed located north of Surowiec South Interface
  - 100 MW in the Bangor RSP Area
  - About 300 MW in the center of Maine RSP Area
- Comparison methodology looks at incremental benefits
  - MPS load and capacity resources
  - Assuming other wind resources are added

RSP08 Area	Nameplate (MW)	Assumed In-service Date
VT	40.0	1/1/2010
WMA	30.0	1/1/2012
BHE	60.0	1/1/2012
ME	130.5	1/1/2012
SEMA	462.0	1/1/2015
ME	90.0	1/1/2017
VT	9.0	1/1/2017
VT	75.0	1/1/2018
NH	145.5	1/1/2018
ME	78.0	1/1/2018
BHE	39.0	1/1/2018

Maritimes Resource Additions

- A limited model has been implemented for the Maritimes
  - Approximately equal to existing capacity plus wind resources
  - Wind resources use same profile as wind resources in Maine
  - No energy interchange between Quebec and Maritimes
  - Resources added to maintain 15 percent reserve margin
    - 50 percent distillate fuel fired combustion turbines
    - 50 percent natural gas combined cycle

Fuel	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Coal	1701										**1701**
Distillate	1226		125					125			**1476**
Landfill Gas	62										**62**
Natural Gas	1360	125					125				**1610**
Nuclear	658										**658**
Oriemulsion	300										**300**
Residual Fuel	398										**398**
Hydro/Pumped Storage	1297										**1297**
Wind	229										**229**
Total	**7231**	**125**	**125**	**0**	**0**	**0**	**125**	**125**	**0**	**0**	**7731**
Cumulative	**7231**	**7356**	**7481**	**7481**	**7481**	**7481**	**7606**	**7731**	**7731**	**7731**	

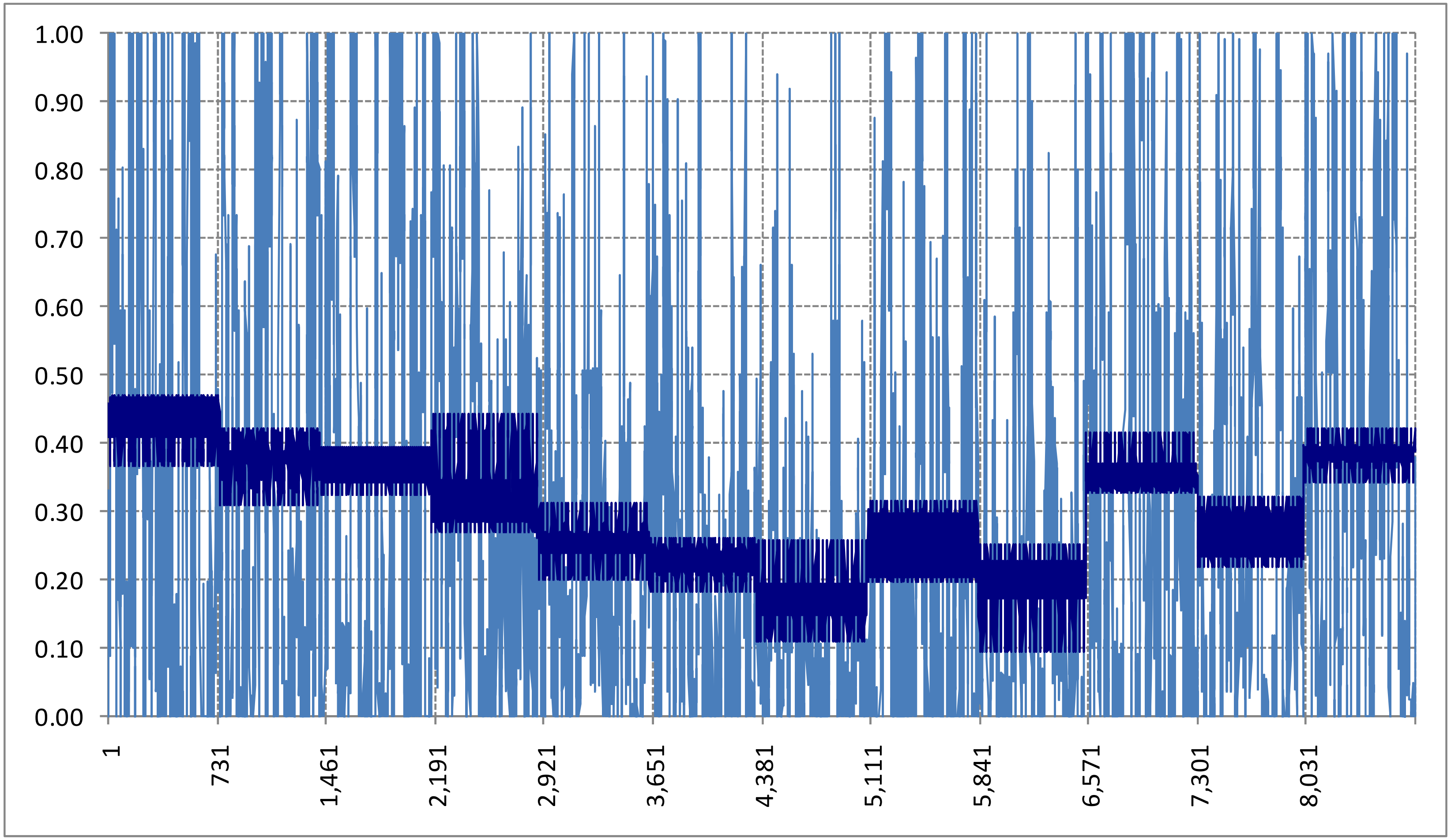
New England Interchange Assumptions

- Assumed purchases modeled as price takers
  - VJO
    - 371 MW summer 418 MW winter
  - NYPA
    - 85 MW
  - Citizens Block Load
    - 26 MW
- Assumed economic purchases from Quebec
    - 300 MW priced as NG based CC at 8400 Btu/kWh heat rate
    - 300 MW priced as NG based Steam at 10340 Btu/kWh heat rate
    - 300 MW priced as DFO based CT at 12600 Btu/kWh heat rate
- Export on Cross Sound Cable
  - 100 MW Firm Export

Development of a 'Volatile' Wind Profile

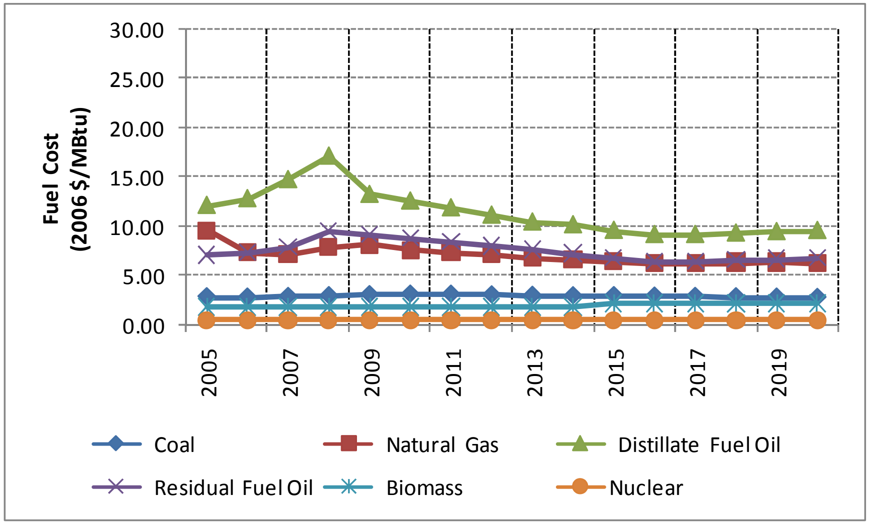
- 'Typical' power output of wind resources is informative
  - Expected annual capacity factor would be 30-ish percent
  - Highest 'typical' output for 800 MW resource is 376 MW (47%)
  - May underestimate transmission congestion
- Wind power output is much more variable than 'typical'
  - Modifying wind model to reflect actual volatility is desirable
  - Measured data would be preferable
  - Adjustment is possible
    - Obtain New England Eight City average hourly wind data
      - Some hours are windy while some are not
    - Define a wind-to-power-output relationship ($P = aV^3 |_{V > 8\ mph}$)
    - Adjust coefficients until capacity factor matches typical output

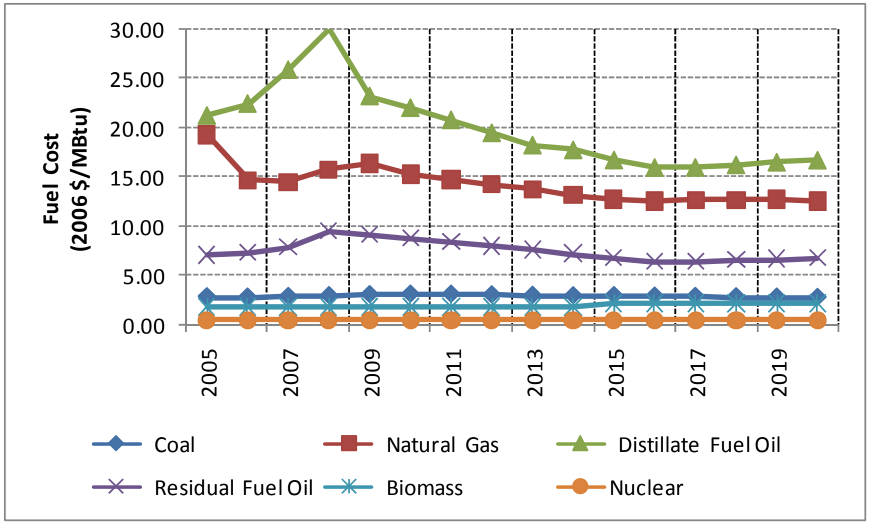
Comparison of Average and Volatile Wind



Comparison of Reference / Higher Fuel

- Price forecast based on 2008 Annual Energy Outlook
  - No differentiation of residual oil by sulfur content
  - Does not provide any information on Nuclear
- Sensitivity consisted of
  - Doubling Natural Gas and
  - Keep distillate more expensive than NG by multiplying by 1.75





Environmental Compliance

- Compliance with emission requirements
  - Reflected in the cost of emission allowances
  - Expressed in cost per ton of a regulated emission
  - NOx allowance requirement only applies to CT and MA
- Compliance technologies
  - Limited retrofits with SO2 scrubbers
  - Reflected unit specific NOx reductions for Massachusetts units

	CO2 Allowances	SO2 Allowances	NOX Allowances
2009	10	190	2480
2010	10	118	2513
2011	10	198	2530
2012	10	254	2635
2013	10	318	2578
2014	10	369	2547
2015	10	277	2818
2016	10	302	2791
2017	10	333	2874
2018	10	348	2932

NOx allowances may change based on RSP /EAG discussions

Development of Dispatch Costs

- Dispatch costs based on
  - Variable costs of production expressed on a $/MWh basis
    - Fuel procurement cost
    - Conversion efficiency (heat rate)
    - Variable O&M (not included)
    - Environmental adders to reflect allowance values
      - NO_x
      - SO_2
      - CO_2
    - Production cost offsets
      - Subtraction from dispatch cost
      - Applied to resources qualifying for Renewable Portfolio Standards (RPS) treatment
      - currently done as an ex-post adjustment

Renewable Portfolio Standards (RPS)

- Renewable Portfolio Standards (RPS) credits are included in dispatch costs
  - Production cost with environmental adders

    Dispatch Cost = Fuel ($/MWh) + Emission (tons/MWh) * Allowance ($/tons)

    Dispatch Cost = $ 70 / MWh + 0.8 tons-CO2/MWh * $10 / ton-CO2

    Dispatch Cost = $ 78 /MWh
  - Production cost with RPS credits for biomass

    Dispatch Cost = Fuel ($/MWh) - RPS Credit ($/MWh)

    Dispatch Cost = $ 70 / MWh - $ 25 / MWh

    Dispatch Cost = $ 45 /MWh
  - Production cost with RPS credits for Wind

    Dispatch Cost = $ 0 / MWh - $ 25 / MWh

    Dispatch Cost = $ -25 /MWh

Renewable Portfolio Standards (RPS)

- Previous production cost assessments
  - RPS credits had not been explicitly included
  - But had been included implicitly
  - Units with RPS attributes had been made “must-run”
- Appropriate future RPS credit values are not known
- Change in future RPS credit value vs. available supply is also not known

Production Cost Metric

- Production cost metric
  - Summation of dispatch costs times energy produced
  - For all units used to serve customer demands
- Effect of baseload units on production cost metric
  - Same MWhs and dispatch cost in both cases to be compared
  - Negligible effect
- Effect of marginal units on production cost metric
  - Different MWhs with same dispatch cost between cases
  - Effect can be significant
- Effect of additional units on production cost metric
  - New resource's MWhs displace other higher dispatch cost MWhs
  - If dispatch cost plus RPS credit value is negative, this is counted as a reduction in production cost

Market Efficiency Upgrade Metrics

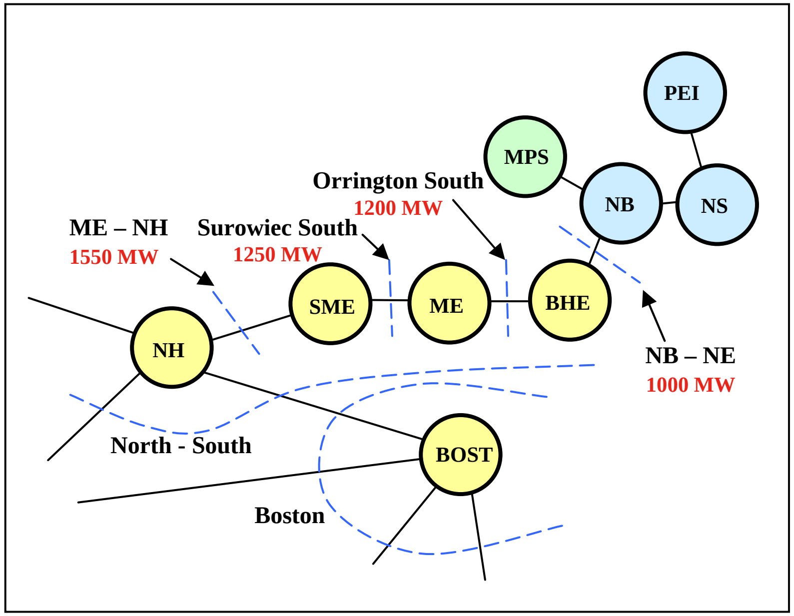
- Addition of any resource will result in:
  - Decreases in production cost
  - Decreases in LSE expense
  - Decreases may be very small or quite large
  - Decreases result from more flexibility to dispatch other resources
  - Operations may become more difficult for intermittent resources
- Displacement of resources
  - FCM framework says
    - "Won't" overbuy capacity
    - FCM purchase of additional wind capacity should reduce purchase of other resources
  - Effect of displacing other resources
    - Production cost may increase or decrease
    - LSE expense may increase or decrease

Evaluation of MPC Benefits

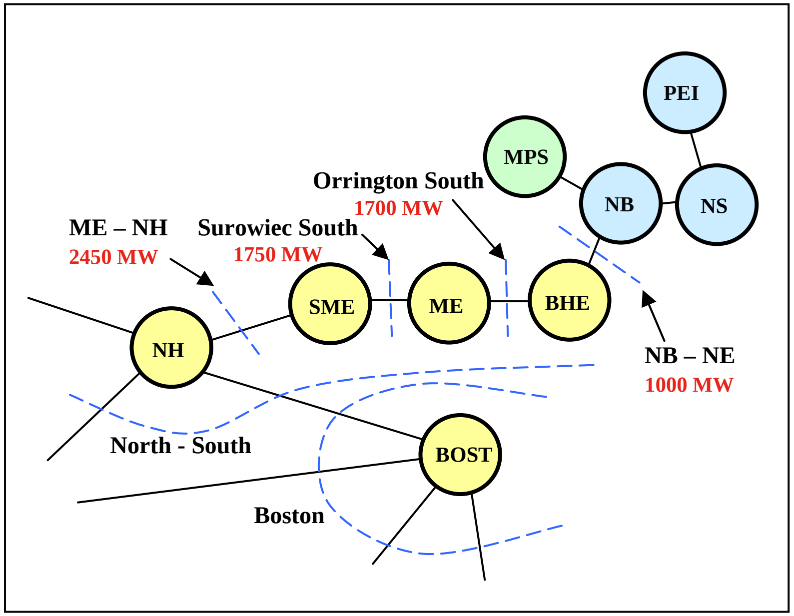
- Benefits measured against reference case without MPC
- MPC includes
  - All MPS load and resources
  - Including 800 MW of wind in Aroostook County
- Economic comparisons
  - Three comparisons envisioned
    - With and without MPC (including New Brunswick)
    - With and without MPC; higher fuel prices (including New Brunswick)
    - With and without MPC (excluding New Brunswick)
  - Other sensitivity cases
    - Permit / allowance prices
    - Other resource assumptions

Base Transmission Modeled with MPRP

- MPRP Assumed to be in-service 01/2013
  - 500 MW increase on Orrington South and Surowiec South
  - 900 MW increase on Maine – New Hampshire

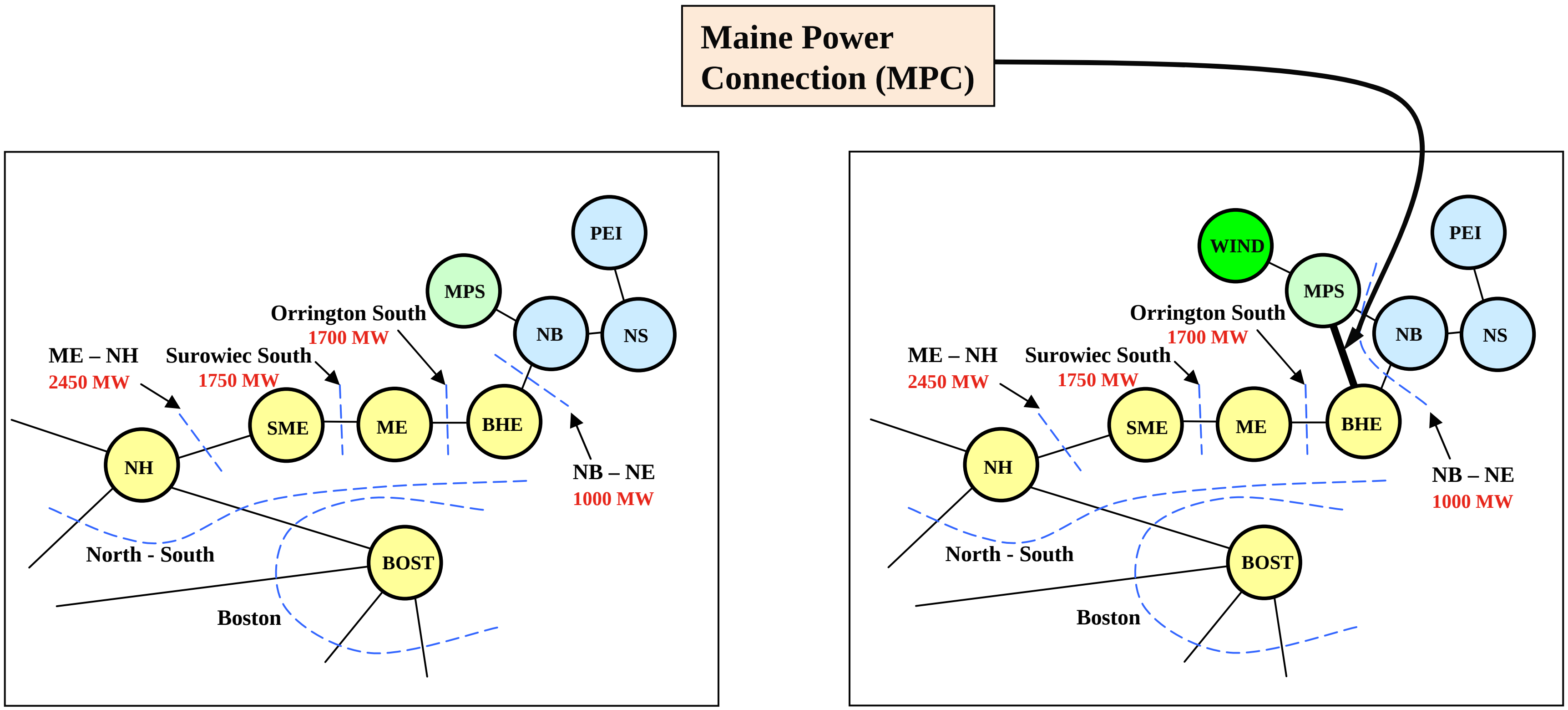


Existing Transmission Before MPRP



Transmission After MPRP

Base Transmission Modeled – w/ Maritimes

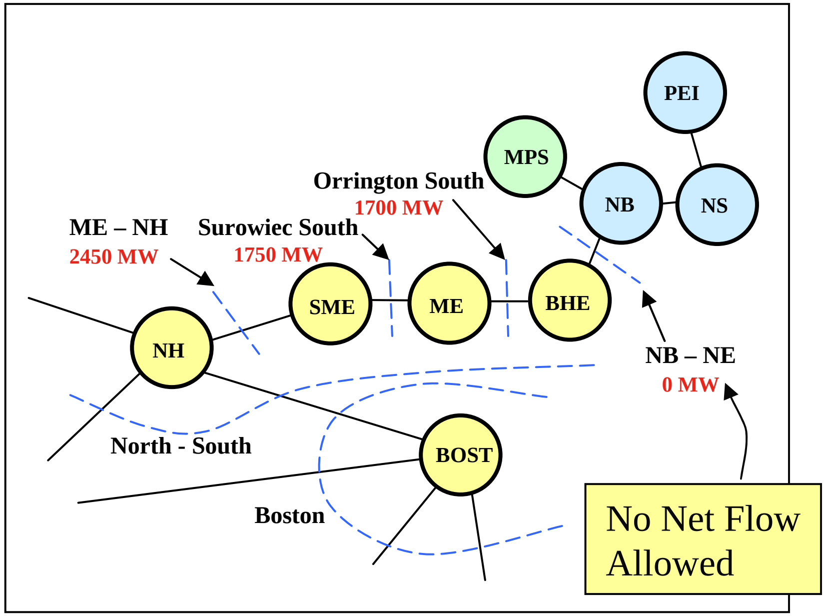


Base Transmission

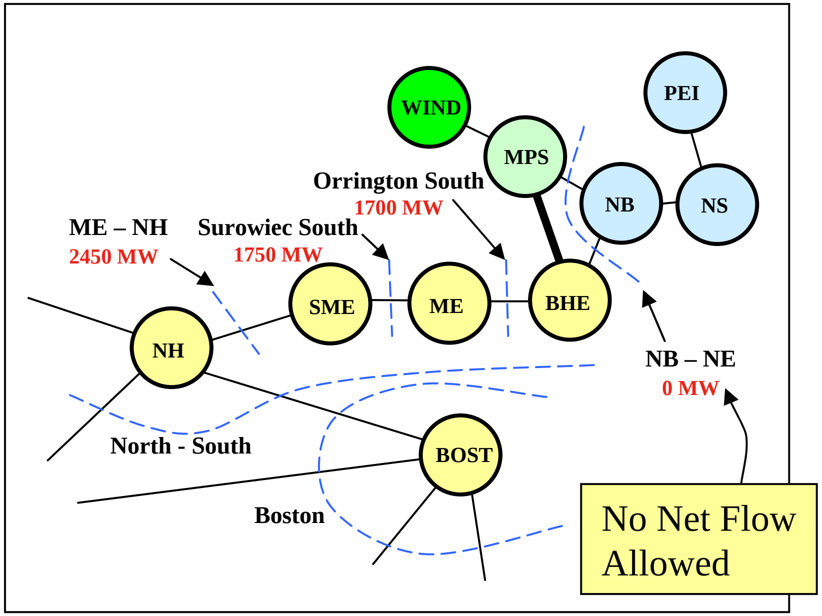
Base Transmission with MPC

Base Transmission Model - w/o Maritimes

- Inclusion of Maritimes affects the analysis
  - Maritimes is a significant landscape issue in Northern Maine
  - Effect of MPS resources seen in both New England and Maritimes



Base Transmission
No Interaction with Maritimes



Base Transmission with MPC
No Interaction with Maritimes

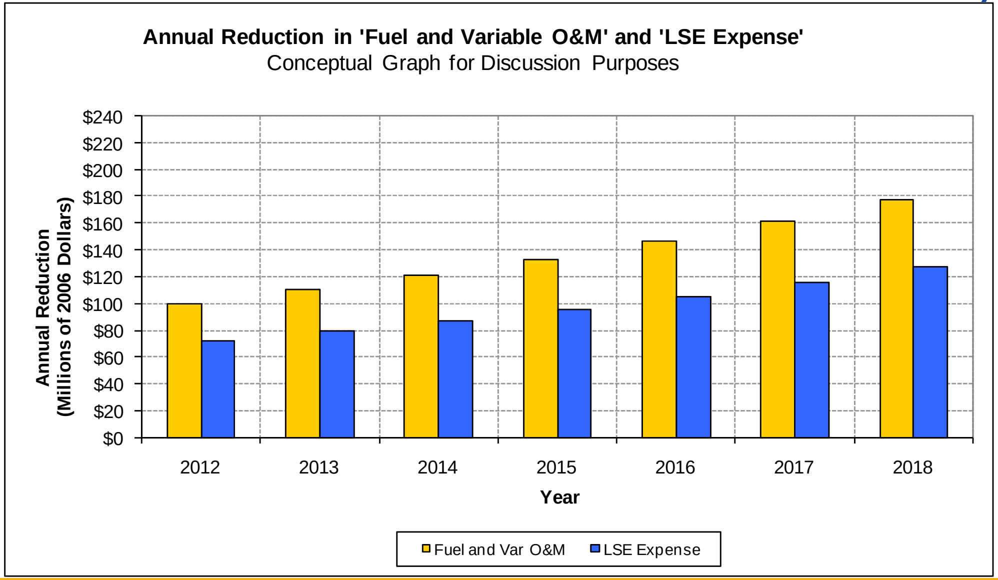
Undiscounted /Present Value Comparison

- Analysis has been performed in constant 2006 dollars
- To develop a Present Value comparison of savings
  - Use a discount rate and develop present worth discount factors
    - Assume “real” discount rate of 4 percent
      - Discount rate applied to 2006 dollars
      - Discount rate would be higher if working in nominal dollars
    - Apply to all 7 years of study (2012 – 2018)
- Metrics for each case would compare
  - Undiscounted benefits
  - Present value benefits
- Comparable to required MPC transmission investment
  - Cost estimates for MPC not yet available

Effect of MPC
(including New Brunswick)

Sample Cost Metrics Due to Project With New Brunswick – Conceptual for Discussion Only

- Shows hypothetical reduction in production costs from project
- Conceptual Illustration
  - Posits 2012 (base year) reduction
    - $100 Million Production Cost
    - $ 70 Million LSE Expense
  - Annual values shown to increase by 10 %



	Undiscounted 2006 Dollars: Fuel and Var O&M	Undiscounted 2006 Dollars: LSE Expense	Discount Factor	Present Value at 10 Percent 2006 Dollars: Fuel and Var O&M	Present Value at 10 Percent 2006 Dollars: LSE Expense
2012	$100	$70	0.7903	$79	$55
2013	$110	$77	0.7599	$84	$59
2014	$121	$85	0.7307	$88	$62
2015	$133	$93	0.7026	$94	$65
2016	$146	$102	0.6756	$99	$69
2017	$161	$113	0.6496	$105	$73
2018	$177	$124	0.6246	$111	$77
	$949	$664		$659	$461

Renewable Energy Credits	Undiscounted 2006 Dollars: Fuel and Var O&M	Undiscounted 2006 Dollars: LSE Expense	Discount Factor	Present Value at 10 Percent 2006 Dollars: Fuel and Var O&M	Present Value at 10 Percent 2006 Dollars: LSE Expense
$40	$140	$70	0.7903	$111	$55
$44	$110	$77	0.7599	$84	$59
$48	$121	$85	0.7307	$88	$62
$53	$133	$93	0.7026	$94	$65
$59	$146	$102	0.6756	$99	$69
$64	$161	$113	0.6496	$105	$73
$71	$177	$124	0.6246	$111	$77
	$989	$664		$690	$461