Preliminary Results for 2010 Economic Study Request

Planning Advisory Committee
February 16, 2011

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Principal Engineer

Overview

- Economic studies are performed under ISO New England's Open Access Transmission Tariff (OATT), Attachment K process (FERC Order 890)
  - ISO performs up to three economic planning studies each year
  - 2010 NESCOE request encompasses the breadth of requests
- Study Assumptions
  - Several "high level" scenarios were defined as the initial phase of the analysis
  - 2009 Governors' Study Assumptions adopted as the basic framework for base case
  - Refinement of assumptions developed as available

Assumptions

- Assumptions and process discussed at previous PAC meetings

May 25 PAC Meeting: Process

http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/may252010/eco_study_requests.pdf

June 16 PAC Meeting: Assumptions

http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/jun162010/economic_studies.pdf

July 15 PAC Meeting: Assumptions

http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/jul152010/eco_study_assumptions.pdf

Framework for Analysis

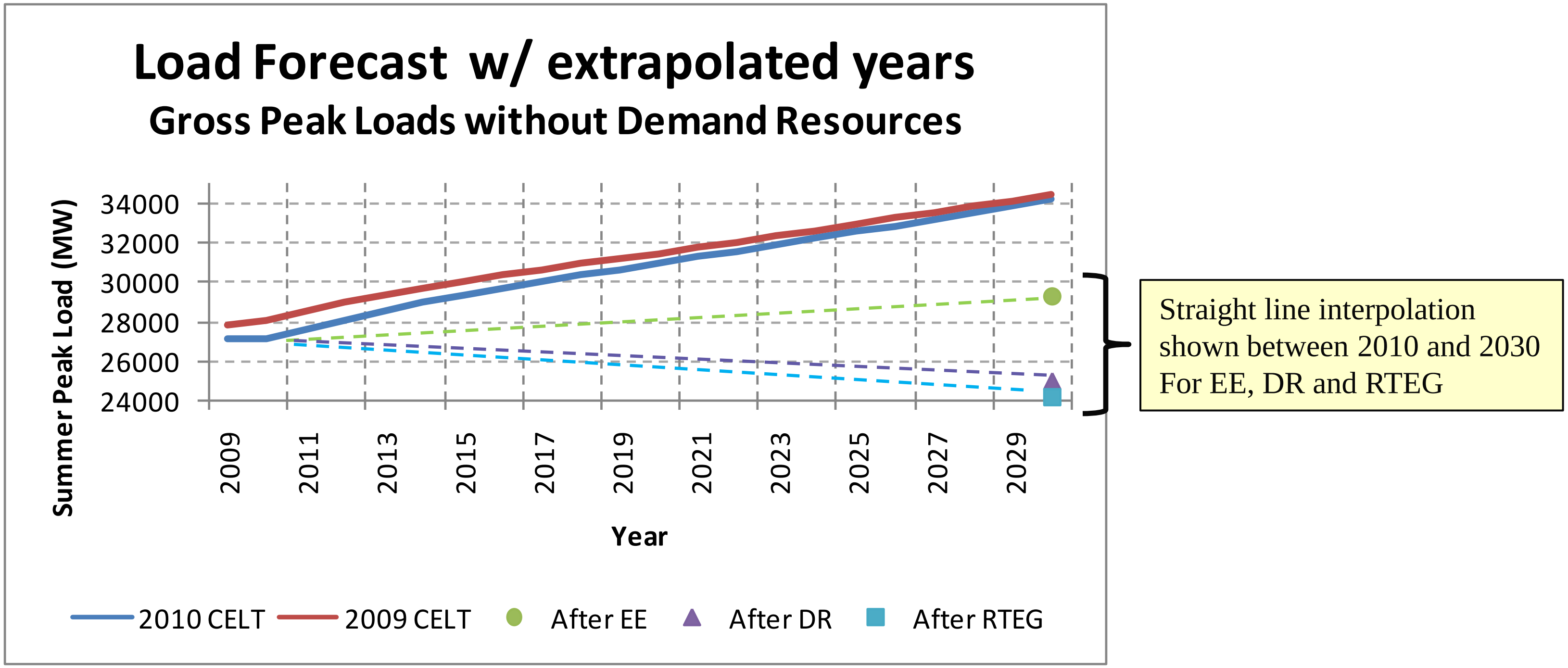
- Build off of the 2009 Governors' Study
  - Evaluate hypothetical New England system in 2030
- Supply resources considered
  - Energy Efficiency and Active Demand Resources
  - Wind generation modeling
    - Based on ISO New England Queue
    - New England Wind Integration Study Profile and Locations (NEWIS)
  - Combined-cycle resources
  - Canadian imports
  - Solar and biomass
- Replace existing carbon-heavy resources

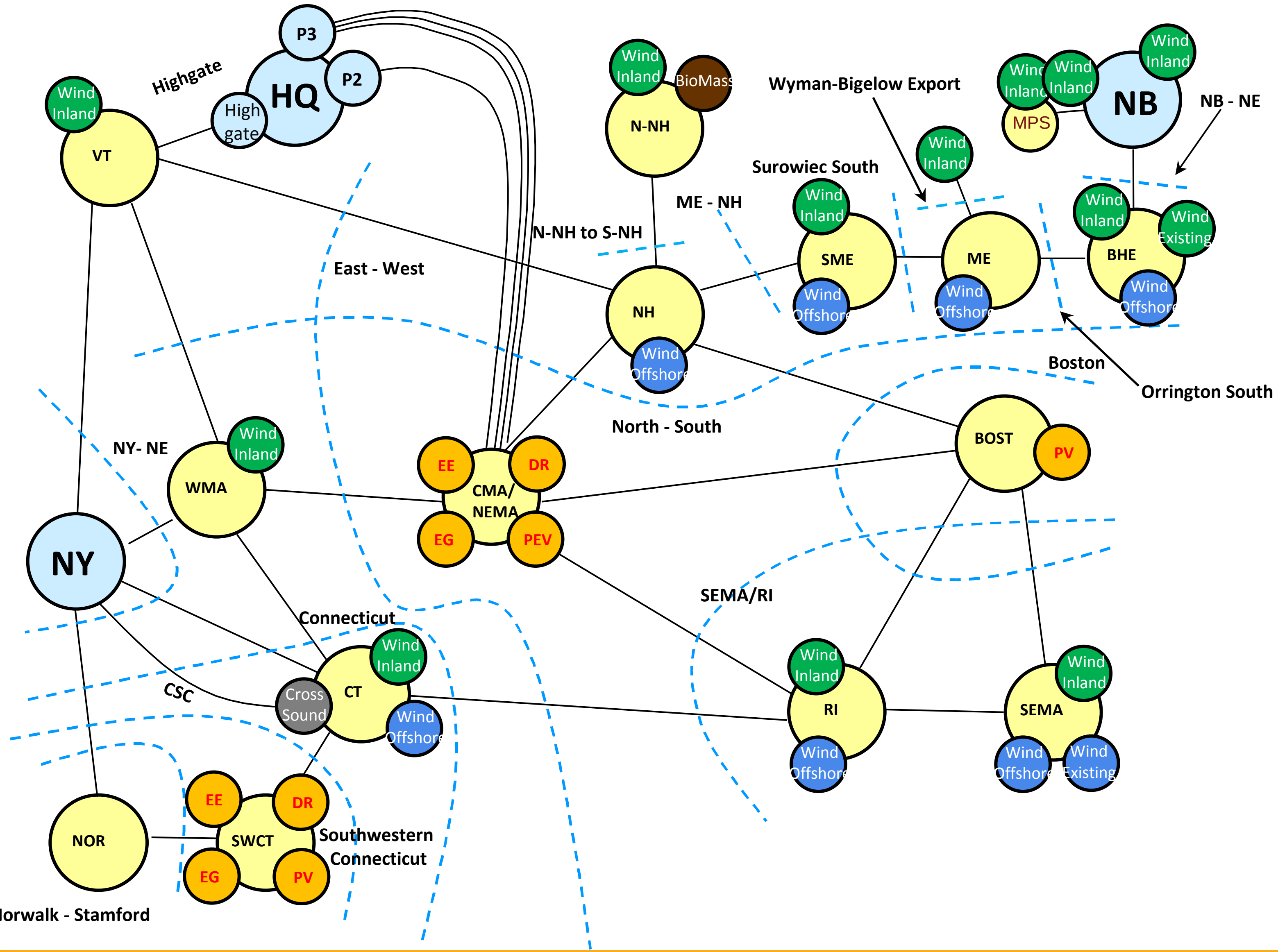
NEWIS and the 2010 Economic Study Requests

- The purpose of ISO New England's New England Wind Integration Study (NEWIS) is:
  - To evaluate the **operational impacts** of a range of hypothetical large-scale wind-integration scenarios
    - The need to forecast wind energy
    - The need for flexible resources to balance the increased variability in "net load" due to increased wind generation
- Economic study requests provide a forum for stakeholder discussions of alternative future system scenarios
  - Results include production cost, load serving entity expenses, congestion, environmental emissions, and other metrics
  - Show potential effects of alternative resource mixes and relieving transmission constraints

Load Forecast

- Summer peak load for (nominal) 2030 assumed 34,300 MW
  - 2009 Governor's Study was 200 MW higher at 34,500 MW
  - With an 11.3% reserve margin, Installed Capacity Requirement (ICR) would be 38,200 MW





Highgate
P3
HQ
P2
High gate
Wind Inland
VT
Wind Inland
BioMass
N-NH
Wyman-Bigelow Export
Wind Inland
Wind Inland
Wind Inland
NB
MPS
NB - NE
Wind Inland
Surowiec South
ME - NH
Wind Inland
N-NH to S-NH
SME
ME
Wind Inland
Wind Existing
BHE
East - West
NH
Wind Offshore
Wind Offshore
Wind Offshore
Wind Offshore
Boston
Orrington South
North - South
NY- NE
Wind Inland
WMA
EE
DR
CMA/ NEMA
EG
PEV
BOST
PV
NY
SEMA/RI
Connecticut
Wind Inland
CSC
Cross Sound
CT
Wind Offshore
Wind Inland
RI
Wind Inland
SEMA
Wind Offshore
Wind Offshore
Wind Existing
EE
DR
NOR
SWCT
EG
PV
Southwestern Connecticut
Norwalk - Stamford

Interfaces

- Interfaces to be evaluated two ways
  - Unconstrained transmission
    - Energy Initiatives Group (EIG) transmission expansion assumed to create unconstrained transmission system for integrating new wind resources, Canadian imports and Joint Coordinated System Plan (JCSP) alternatives
  - Constrained using 2009 Regional System Plan (RSP09) interface limit assumptions
    - RSP09 assumptions include
      - New England East West Solution (NEEWS)
      - Maine Power Reliability Program (MPRP) Note: changes not quantified
      - Remaining constraints likely to impede delivery of energy

      Note: RSP10 assumptions are the same as RSP09

Base Interface Limits

Single-Value Summer Peak Transmission Interface Limits for Use in Subarea Transportation Models									
Interface	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
New Brunswick-New England	1000	1000	1000	1000	1000	1000	1000	1000	1000
Orrington South Export	1200	1200	1200	1200	1200	1200	1200	1200	1200
Surowiec South	1150	1150	1150	1150	1150	1150	1150	1150	1150
Maine-New Hampshire	1600	1575	1550	1525	1500	1475	1450	1450	1450
Wyman Bigelow Export	**350 MW Assumed**	--→							
Northern NH to Southern NH	9999	9999	9999	9999	9999	9999	9999	9999	9999
North-South	2700	2700	2700	2700	2700	2700	2700	2700	2700
Boston Import	4900	4900	4900	4900	4900	4900	4900	4900	4900
SEMA Export	No Limit	No Limit	No Limit	No Limit	No Limit	No Limit	No Limit	No Limit	No Limit
SEMA/RI Export	3000	3000	3000	3000	3300	3300	3300	3300	3300
East-West	2800	2800	2800	2800	3500	3500	3500	3500	3500
Connecticut Import	2500	2500	2500	2500	3600	3600	3600	3600	3600
Southwest Connecticut Import	3200	3200	3200	3200	3200	3200	3200	3200	3200
Norwalk / Stamford	1650	1650	1650	1650	1650	1650	1650	1650	1650
Cross-Sound Cable (CSC) (Out)	330	330	330	330	330	330	330	330	330
Cross-Sound Cable (CSC) (In)	346	346	346	346	346	346	346	346	346
NY-NE Summer	1400	1400	1400	1400	1400	1400	1400	1400	1400
NY-NE Winter	1875	1875	1875	1875	1875	1875	1875	1875	1875
NE-NY Summer	1400	1400	1400	1400	1400	1400	1400	1400	1400
NE-NY Winter	1400	1400	1400	1400	1400	1400	1400	1400	1400
HQ-NE (Highgate)	200	200	200	200	200	200	200	200	200
HQ-NE (Phase II)	1400	1400	1400	1400	1400	1400	1400	1400	1400

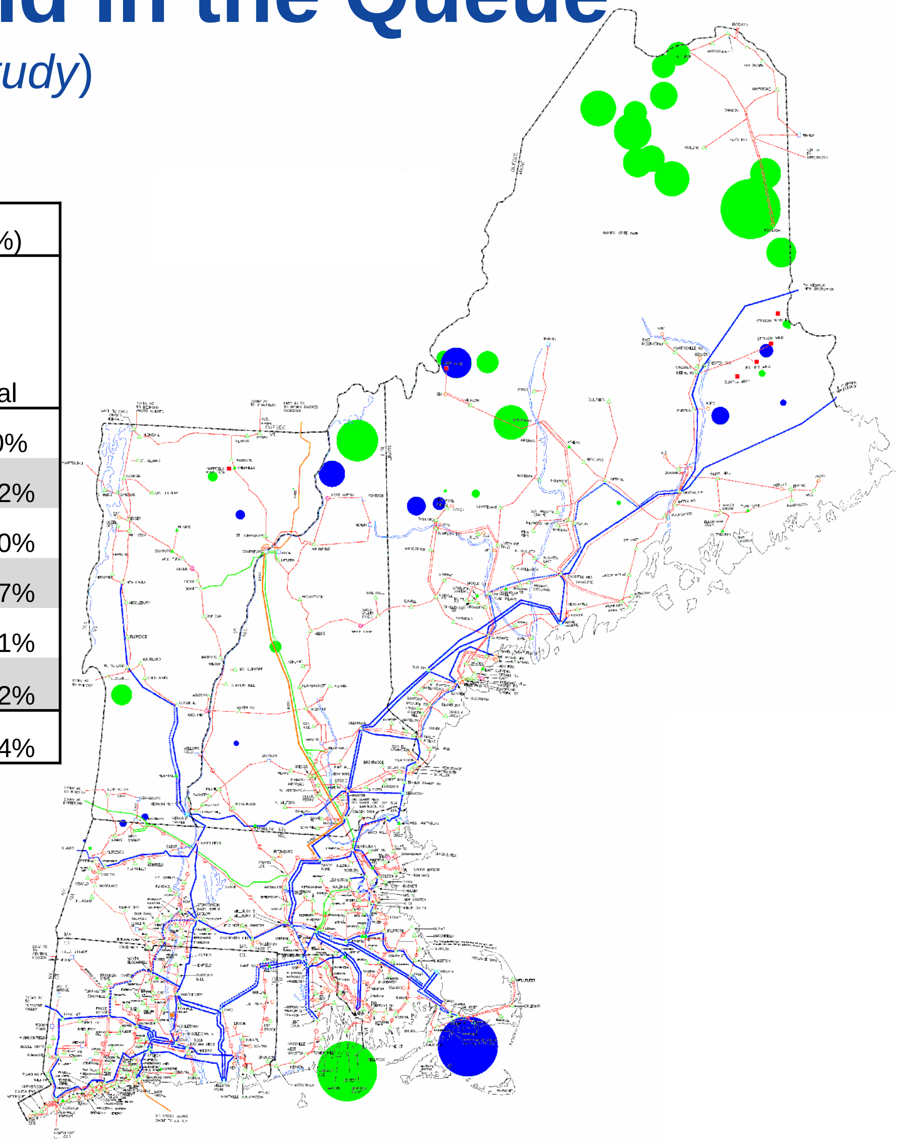
Pre-Specified Profiles for Selected Resource Types

- Wind
  - Meteorologically co-occurring wind / loads based on NEWIS data
    - ME-BHE (On-shore)
    - ME-CMP (On-shore)
    - NH (On-shore)
    - RI (Off-shore)
    - SEMA (Off-shore)
    - VT (On-shore)
    - WEMA (On-shore)
- Canadian hydro imports (65% capacity factor)
- Solar based on co-occurring insolation (Thompson Island)
- Energy Efficiency is a discrete “supply side” resource
  - 38% in west side of East / West interface (based on load share)
  - 62% in east side of East / West interface (based on load share)

Full Build-out of Wind in the Queue

Total: 4.36 GW (*Base case for 2010 study*)

	Onshore			Offshore			Capacity Factor (%)		
State	Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	On shore	Off shore	Total
CT	-	-	-	-	-	-	0%	0%	0%
ME	30	2.888	8,043	-	-	-	32%	0%	32%
MA	2	0.044	135	1	0.460	1,615	35%	40%	40%
NH	5	0.400	1,290	-	-	-	37%	0%	37%
RI	-	-	-	1	0.360	1,295	0%	41%	41%
VT	5	0.209	584	-	-	-	32%	0%	32%
Total	42	3.541	10,053	2	0.820	2,910	32%	41%	34%



Partial Queue

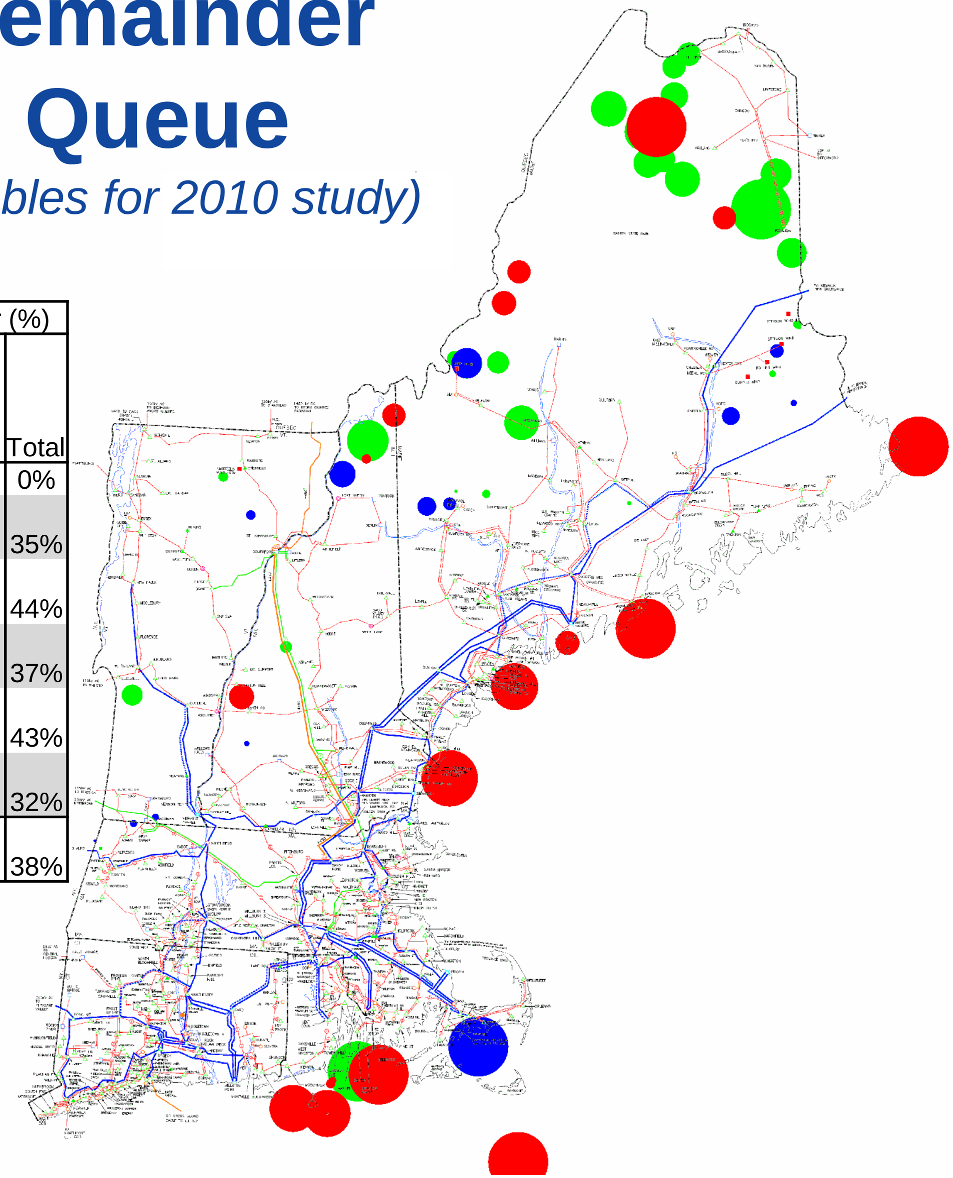
Additional Queue

Additional to 20% Energy

1.5GW Offshore + Remainder Best Onshore + Full Queue

Total: 8.79 GW *(New England renewables for 2010 study)*

State	% Energy by State	Onshore			Offshore			Capacity Factor (%)		
		Site Count	Name Plate (GW)	Energy (GWh)	Site Count	Name Plate (GW)	Energy (GWh)	On shore	Off shore	Total
CT	0%	-	-	-	-	-	-	0%	-	0%
ME	115%	33	3.377	9,619	4	1.500	5,169	33%	39%	35%
MA	9%	2	0.044	135	2	1.498	5,800	35%	44%	44%
NH	19%	8	0.647	2,096	-	-	-	37%	0%	37%
RI	44%	-	-	-	7	1.513	5,657	0%	43%	43%
VT	7%	5	0.209	584	-	-	-	32%	0%	32%
Total	20%	48	4.278	12,435	13	4.511	16,625	33%	42%	38%



Partial Queue

Additional Queue

Additional to 20% Energy

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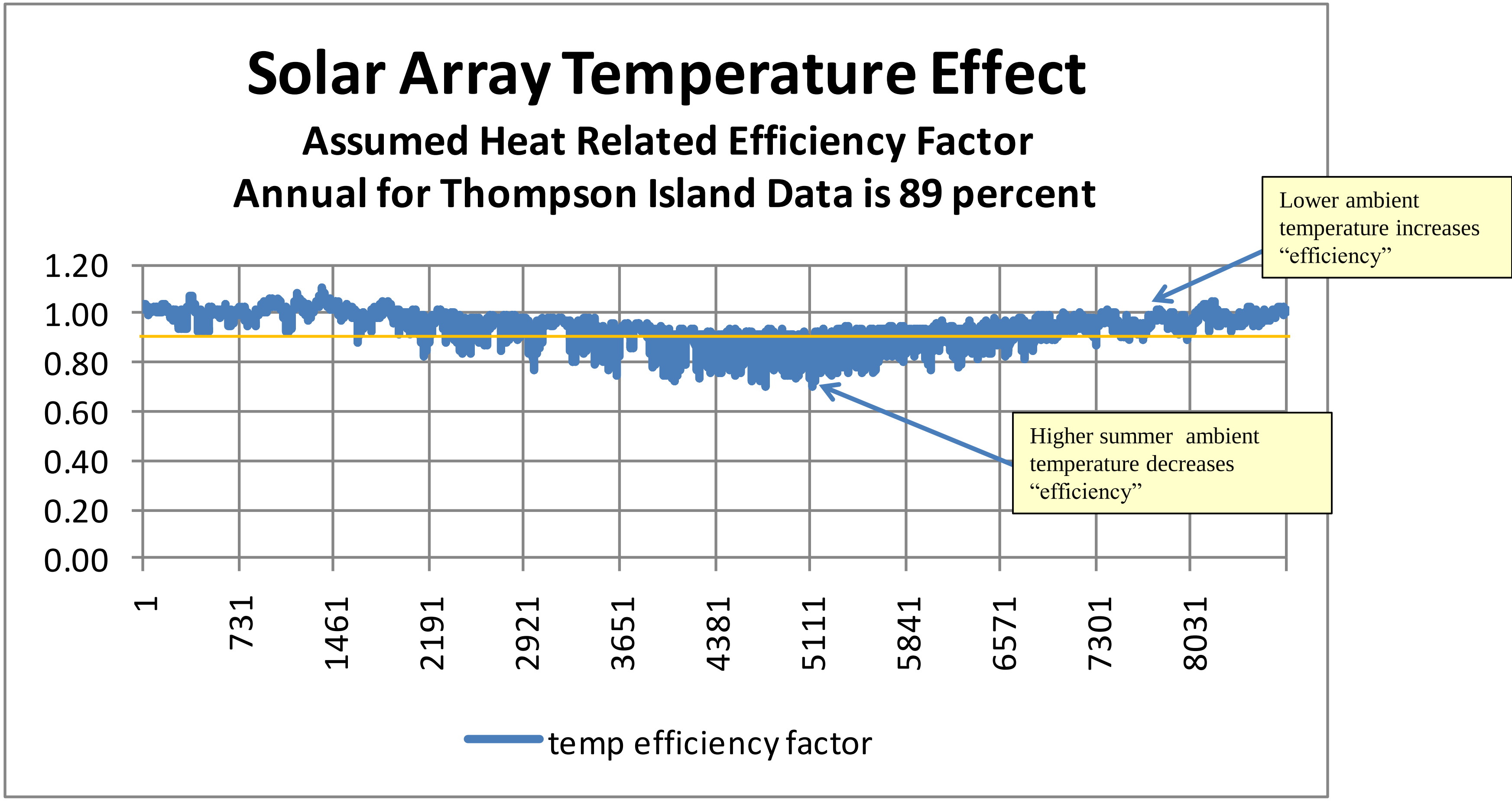
Solar PV Model

- Capturing PV volatility was viewed as important
- Developed a time stamped, chronological solar PV profile
  - Limited data sources for 2006
    - Thompson Island
    - Near Boston
  - Single site is a drawback due to lack of diversity
  - Approach is consistent with wind model generator output, but concentrated at a single location
- Temperature effect was identified as a factor to consider
  - PV output reduced with higher ambient temperature
  - New England demand tends to increase at higher temperatures

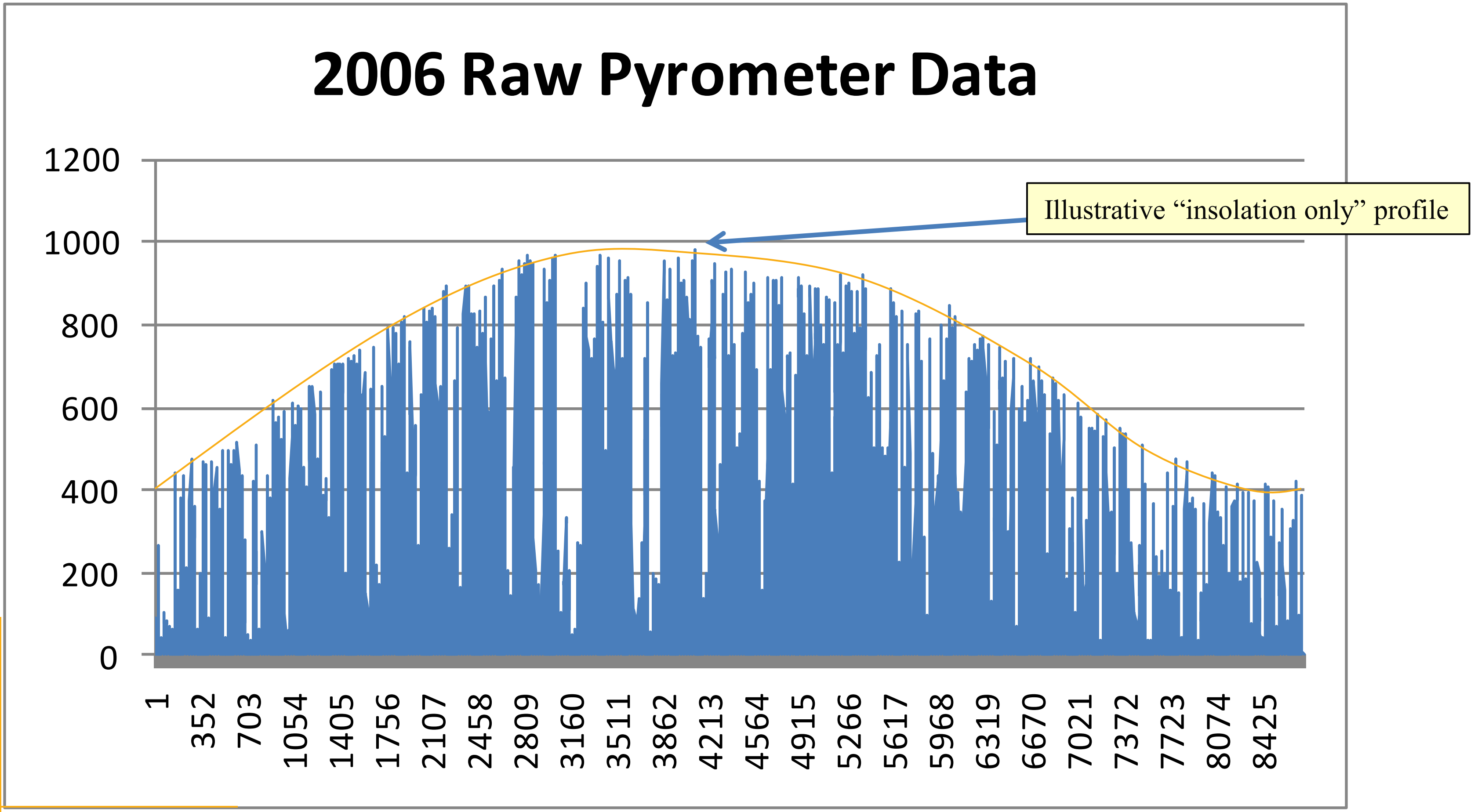
Temperature Adjustments for PV

- Temperature effect referenced to 25 deg C
  - Approximate adjustment for planning purposes
  - This study is not a PV design exercise for a specific facility
- Overall temperature degradation factor is 89 percent
  - Estimated PC plate temp: $T_{plate} = T_{ambient} * (1+ \text{Sunlight Factor})$
    where: $\text{Sunlight Factor} = \text{Sunlight}_{h} / \text{Sunlight}_{\text{max in year}}$
  - For each degree C, the efficiency degrades 0.5 percent
    - Assumed linear over entire temperature range
    - Below 25 degrees C the efficiency is better than nominal
    - Above 25 degrees C the efficiency is lower than nominal
- $F(t) = 89 \text{ percent} * \{ (T_{plate} - 25) * (0.5/100) \}$
- For Thompson Island, $\sum F(t)$ averages to 89 percent

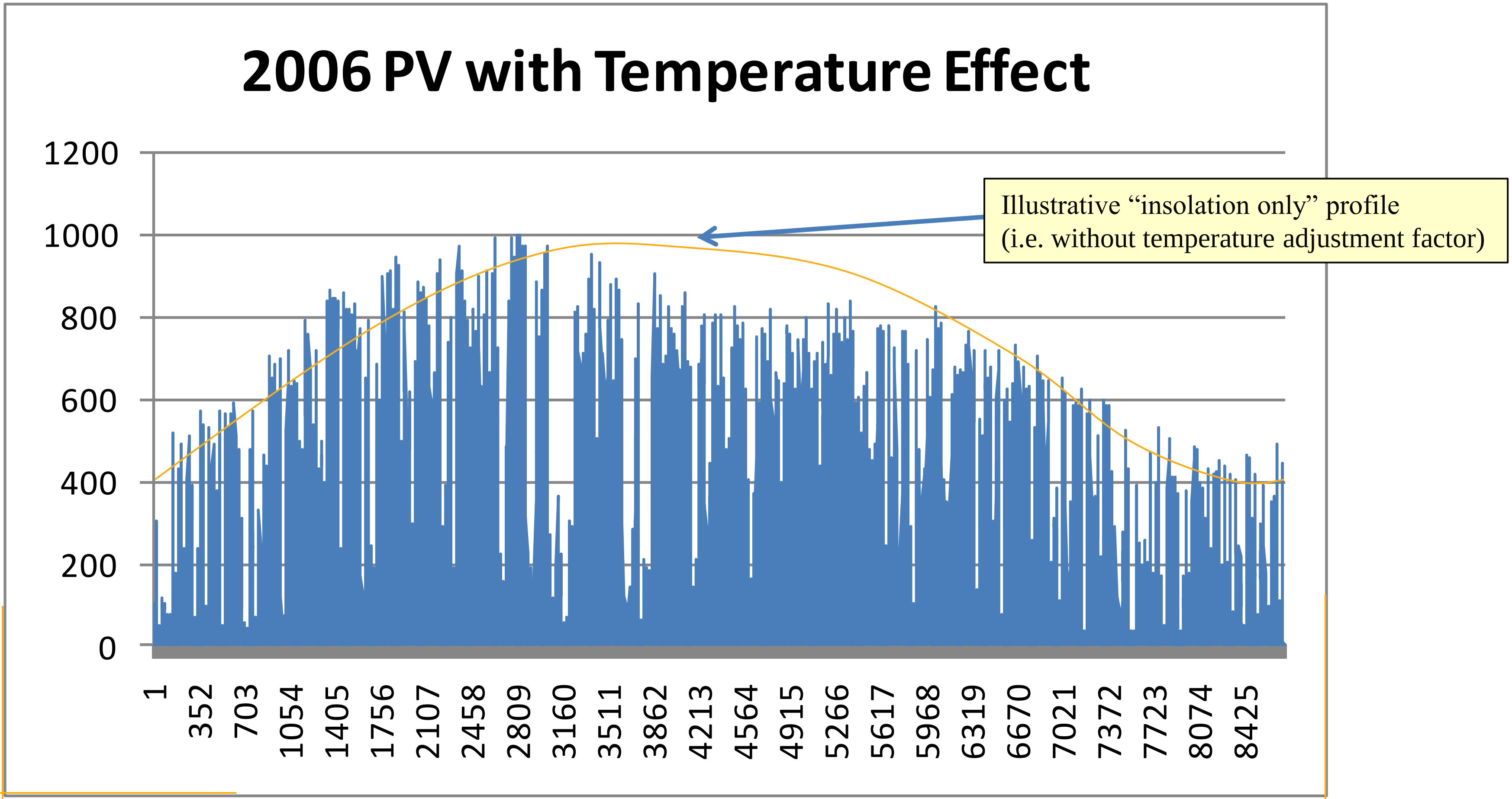
PV Temperature Adjustment Factor



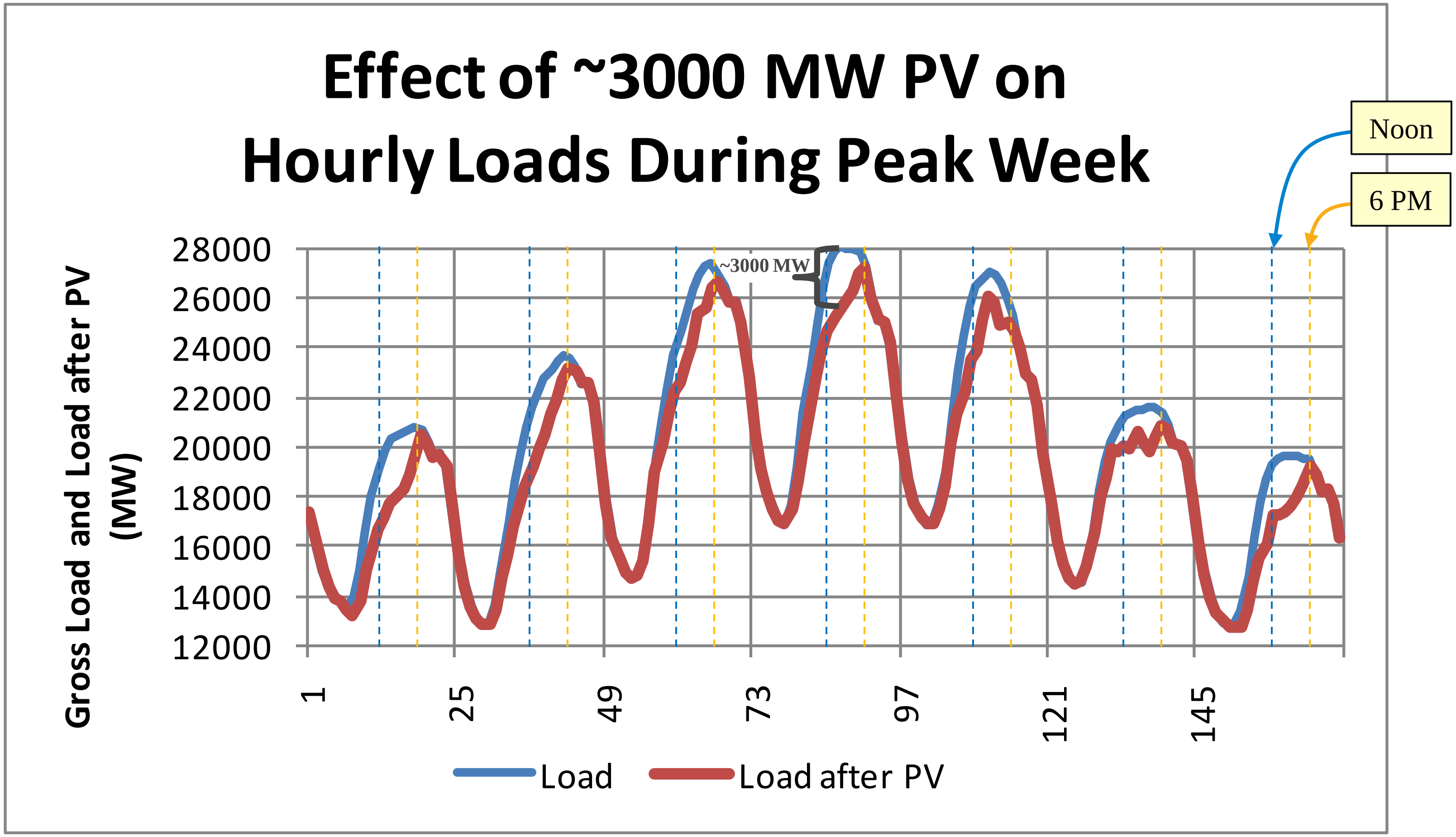
Hourly Chronological PV w/o Temperature Adjustment Factor



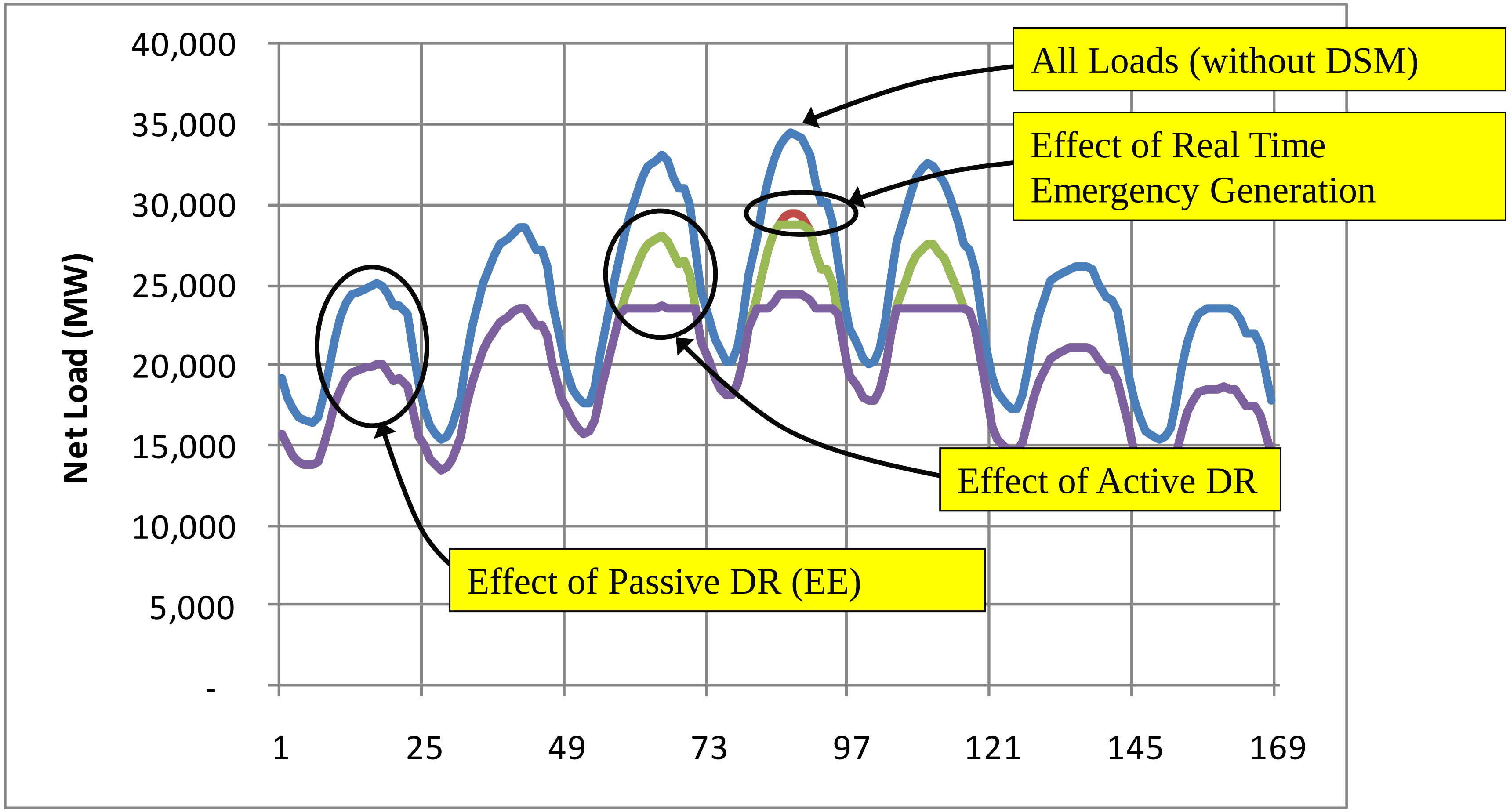
Hourly Chronological PV with Temperature Adjustment Factor



PV Affects Net Loads to be Served



August Peak Week: RTEG and Active DR



Cases and Sensitivities

Revised

Cases Considered (Base case and non-renewables cases)

	Case	Description
1	*Base*	*One Year 2030 Only; All resources in with no retirements* • *All resources in with no retirements* • *Passive Demand Resources (EE) of 5,000 MW (14.7 percent of peak; note 21.4 percent of N.E. energy)* • *Active Demand Resources of 4,300 MW (14.7 percent after EE)* • *Real Time Emergency Generation of 800 MW* • *No Additional purchases from Canada or New York* • *No Additional purchases from assumed EIPC renewable resources* • *Wind expansion from NEWIS "Full Queue Build-Out"* • *CO2 Allowance Price at $10/ton*
2	*Base – Natural Gas*	*Same as "Base" except add 1,500 MW of new efficient natural gas combined cycle (CC) units in place of the NEWIS "Full Queue Build-Out" wind capacity. This replaces the energy from those wind resources*
3	*Base – Plug-in Electric Vehicles*	*Same as "Base" except add 3,000 MW for 1.8 million PEVs*
4	*Base – Higher CO2*	*Same as "Base" except CO2 Allowance Price at $40/ton*
5	*Base – Natural Gas - Higher CO2*	*Same as "Base - Natural Gas" except CO2 Allowance Price at $40/ton*
6	*Retire Coal*	*Same as "Base" except 2518 MW of coal units older than 50 years old will be retired and replaced with an equal amount of repowerered gas combined cycle (CC) with 8500 Btu/kWh heat rate*
7	*Retire Residual Oil*	*Same as "Base" except 6,006 MW of residual oil units older than 50 years old will be retired and replaced with an equal amount of repowerered gas combined cycle (CC) with 8500 Btu/kWh heat rate*
8	*Retire Carbon-Heavy*	*Same as "Base" except 8,523 MW of carbon heavy older than 50 years old will be retired and replaced with an equal amount of repowerered gas combined cycle (CC) with 8500 Btu/kWh heat rate*
6_ACC	*Retire Coal*	*Same as "Base" except 2518 MW of coal units older than 50 years old will be retired and replaced with an equal amount of new efficient advanced gas combined cycle (ACC) with 6500 Btu/kWh heat rate*
7_ACC	*Retire Residual Oil*	*Same as "Base" except 6,006 MW of residual oil units older than 50 years old will be retired and replaced with an equal amount of new efficient advanced gas combined cycle (ACC) with 6500 Btu/kWh heat rate*
8_ACC	*Retire Carbon-Heavy*	*Same as "Base" except 8,523 MW of carbon heavy older than 50 years old will be retired and replaced with an equal amount of new efficient advanced gas combined cycle (ACC) with 6500 Btu/kWh heat rate*

Revised

Cases Considered (Expanded Renewables)

	Case	*Description*
9	*New England Renewables and Imports – wind weighted*	*Same as "Base" except 8,523 MW of carbon heavy units older than 50 years old will be replaced by a percentage (X%) of New England wind (1.5 GW Off-shore, + Remainder Best On-Shore plus Full Queue, totaling 8.79 GW), photovoltaic (1000 MW), biomass (500 MW), plus imported energy from Canada (3000 MW from two new 1,500 MW DC transmission lines) Note: that X% is 158% for an installed amount of 13,885 MW of wind which is documented later.*
10	*New England Renewables and Imports – import weighted*	*Same as "Base" except 8,523 MW of carbon heavy units older than 50 years old will be replaced by a percentage (Y %) of New England wind (1.5 GW Off-shore, + Remainder Best On-Shore plus Full Queue, totaling 8.79 GW), photovoltaic (1500 MW) biomass (500 MW), plus imported energy from Canada (6000 MW from four new 1,500 MW DC transmission lines) Note: that Y% is 26% for an installed amount of 2,285 MW of wind which is documented later.*
11	*New England Renewables and Imports – solar weighted*	*Same as "Base" except 8,523 MW of carbon heavy units older than 50 years old will be replaced by New England wind (1.5 GW Off-shore, + Remainder Best On-Shore plus Full Queue, totaling 8.79 GW), a percentage (Z %) of photovoltaic (3000 MW), biomass (500 MW), plus imported energy from Canada (3000 MW from two new 1,500 MW DC transmission lines) Note: that Z% is 153% for an installed amount of 4,600 MW of PV which is documented later.*

Revised

Retirement Scenarios

- Resource retirement assumptions
  - Approach to coal, residual oil, and all carbon heavy (coal and oil) unit retirements
    - Retirement of units over 50 years old as of 2030
    - Retired resources replaced with Natural Gas Combined Cycle
      - Repowered as a combined cycle with a heat rate of 8500 Btu/kWh
      - Advanced Combined Cycle (ACC) with a heat rate of 6500 Btu/kWh
  - Renewable cases assume all retired resources replaced by:
    - Wind,
    - Solar PV
    - Biomass from New England
    - Imports from Eastern Canada (Hydro)
  - Renewable ‘capacity’ added adjusted to *“equal”* retired capacity (this is a highly approximate estimate)

Carbon Heavy Resources Assumed to be Replaced

ASSET ID	Year	Generator Name	Summer (MW)	Coal-or-Not	Primary Fuel Category	Alternate Fuel Category	Decade Total	Fuel Total
551	1952	SALEM HARBOR 1	82.0	Coal	BIT	FO6		
552	1952	SALEM HARBOR 2	80.0	Coal	BIT	FO6		
556	1952	SCHILLER 4	47.5	Coal	BIT	FO6		
558	1957	SCHILLER 6	47.9	Coal	BIT	FO6		
553	1958	SALEM HARBOR 3	149.8	Coal	BIT	FO6		
577	1959	SOMERSET 6	109.1	Coal	BIT		516.3	
498	1960	MT TOM	143.6	Coal	BIT			
489	1961	MERRIMACK 1	112.5	Coal	BIT			
350	1963	BRAYTON PT 1	228.2	Coal	BIT	NG		
351	1964	BRAYTON PT 2	225.8	Coal	BIT	NG		
340	1968	BRIDGEPORT HARBOR 3	380.0	Coal	BIT	FO6		
490	1968	MERRIMACK 2	320.0	Coal	BIT			
352	1969	BRAYTON PT 3	591.5	Coal	BIT	NG	2001.6	2517.9
493	1954	MONTVILLE 5	81.0	Not-Coal	FO6	NG		
1694	1957	WEST SPRINGFIELD 3	94.3	Not-Coal	NG	FO2		
639	1957	YARMOUTH 1	51.8	Not-Coal	FO6			
480	1958	MIDDLETOWN 2	117.0	Not-Coal	FO6	NG		
640	1958	YARMOUTH 2	51.1	Not-Coal	FO6		395.2	
519	1960	NORWALK HARBOR 1	162.0	Not-Coal	FO6			
	1961	BRIDGEPORT HARBOR 2	130.5	Not-Coal	FO6			
520	1963	NORWALK HARBOR 2	168.0	Not-Coal	FO6			
481	1964	MIDDLETOWN 3	236.0	Not-Coal	FO6	NG		
641	1965	YARMOUTH 3	115.5	Not-Coal	FO6			
365	1968	CANAL 1	550.4	Not-Coal	FO6		1362.4	
494	1971	MONTVILLE 6	407.4	Not-Coal	FO6			
554	1972	SALEM HARBOR 4	436.8	Not-Coal	FO6			
482	1973	MIDDLETOWN 4	400.0	Not-Coal	FO6			
353	1974	BRAYTON PT 4	422.0	Not-Coal	FO6	NG		
508	1974	NEWINGTON 1	400.2	Not-Coal	FO6	NG		
502	1975	MYSTIC 7	577.6	Not-Coal	NG	FO6		
513	1975	NEW HAVEN HARBOR	447.9	Not-Coal	FO6	NG		
366	1976	CANAL 2	553.0	Not-Coal	FO6	NG		
642	1978	YARMOUTH 4	603.5	Not-Coal	FO6		4248.4	6006.0
			8523.9				8523.9	8523.9

ISO new england

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Three Renewable Cases with Focus on Different Technologies

- Renewable Case: Weighted for Wind
  - 3,000 MWs Canadian imports
  - New England resources
    - 1,000 MW solar, 500 MW biomass, remainder from wind (increase)
- Renewable Case: Weighted for Canadian Imports
  - 6,000 MWs Canadian imports
  - New England resources
    - 1,500 MW solar, 500 MW biomass, remainder from wind (decrease)
- Renewable Case: Weighted for Solar
  - 3,000 MW Canadian imports
  - New England resources
    - 4,600 MW solar, 500 MW biomass, 8.79 GW of Wind

Development of Renewable Expansion to Replace Retirements

- Renewable scenarios are designed to consider:
  - Retirement of existing "carbon heavy" resources
  - Replacement with various renewable technologies
    - Wind "weighted" scenario
    - Import (hydro) "weighted" scenario
    - Solar photovoltaic "weighted" scenario
  - Conceptually replace the capacity equivalent amount of retired capacity with renewable capacity
    - Assume capacity values based on:
      - 90% for steam / biomass units
      - 39.4% for solar photovoltaic (based on reliability hour calculation)
      - 27.6% for composite wind (based on reliability hour calculation)
      - 100% for imports from Canada

Development of Renewable Expansion to Replace Retirements (Case 09)

- Retirement of 8523 MW of "carbon heavy" -7671 MW
- Addition of 500 MW of biomass + 450 MW
- Addition of 3000 MW of imports +3000 MW
- Addition of 1000 MW of photovoltaic + 394 MW
- Addition of 13,885 MW of wind +3832 MW
  - Note: For the 'wind weighted' case, more wind than the 8.79 GW was needed to compensate for the retirements. Therefore, 158% of the wind was assumed installed at all locations uniformly.
  - For the 'import weighted' case, 26% of 8.79 GW was needed
  - For the 'solar weighted' case, 4600 MW of PV was needed

Development of Renewable Expansion to Replace Retirements - Summary

		Case 9	Case 10	Case 11
		Wind Weighted	Import Weighted	Solar Weighted
Retirements	Installed Capacity (MW)	-8523	-8523	-8523
	Capacity Value (pu)	0.900	0.900	0.900
	Equivalent Capacity (MW)	-7671	-7671	-7671
Biomass	Installed Capacity (MW)	500	500	500
	Capacity Value (pu)	0.900	0.900	0.900
	Equivalent Capacity (MW)	450	450	450
Solar PV	Installed Capacity (MW)	1000	1500	4600
	Capacity Value (pu)	0.394	0.394	0.394
	Equivalent Capacity (MW)	394	591	1812
Hydro Imports	Installed Capacity (MW)	3000	6000	3000
	Capacity Value (pu)	1.000	1.000	1.000
	Equivalent Capacity (MW)	3000	6000	3000
Wind	NEWIS 8.79 GW Case (M)	8788	8788	8788
	Wind Multiplier	1.580	0.260	1.000
	Installed Capacity (MW)	13885	2285	8788
	Capacity Value (pu)	0.276	0.276	0.276
	Equivalent Capacity (MW)	3832	631	2425
Summary	Carbon Heavy Retirement (MW)	-7671	-7671	-7671
	Addition Biomass (MW)	450	450	450
	Addition: PV (MW)	394	591	1812
	Addition: Hydro Imports (MW)	3000	6000	3000
	Addition: Wind (MW)	3832	631	2425
	Net Capacity Change (MW)	6	1	17

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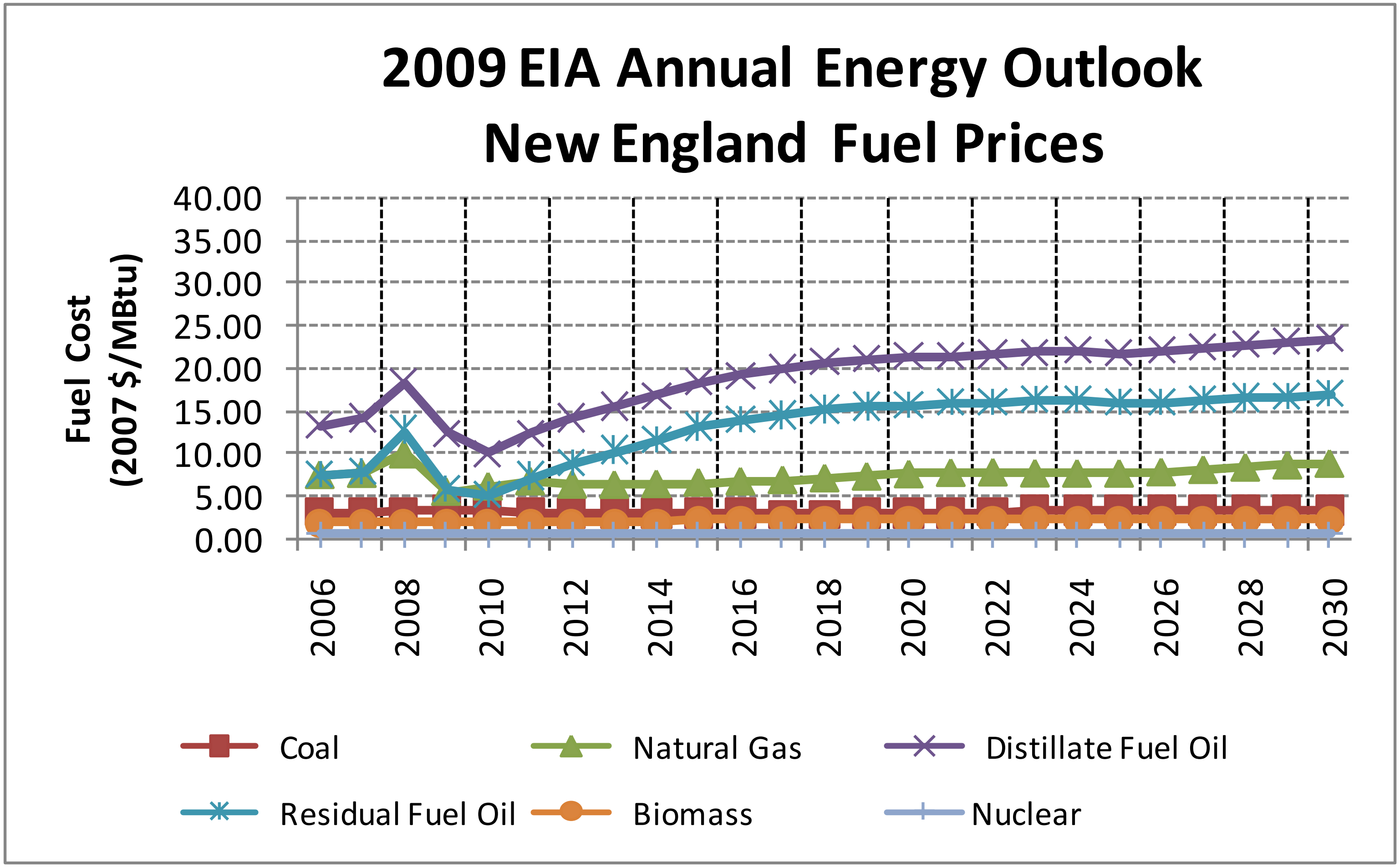
Sensitivity Cases

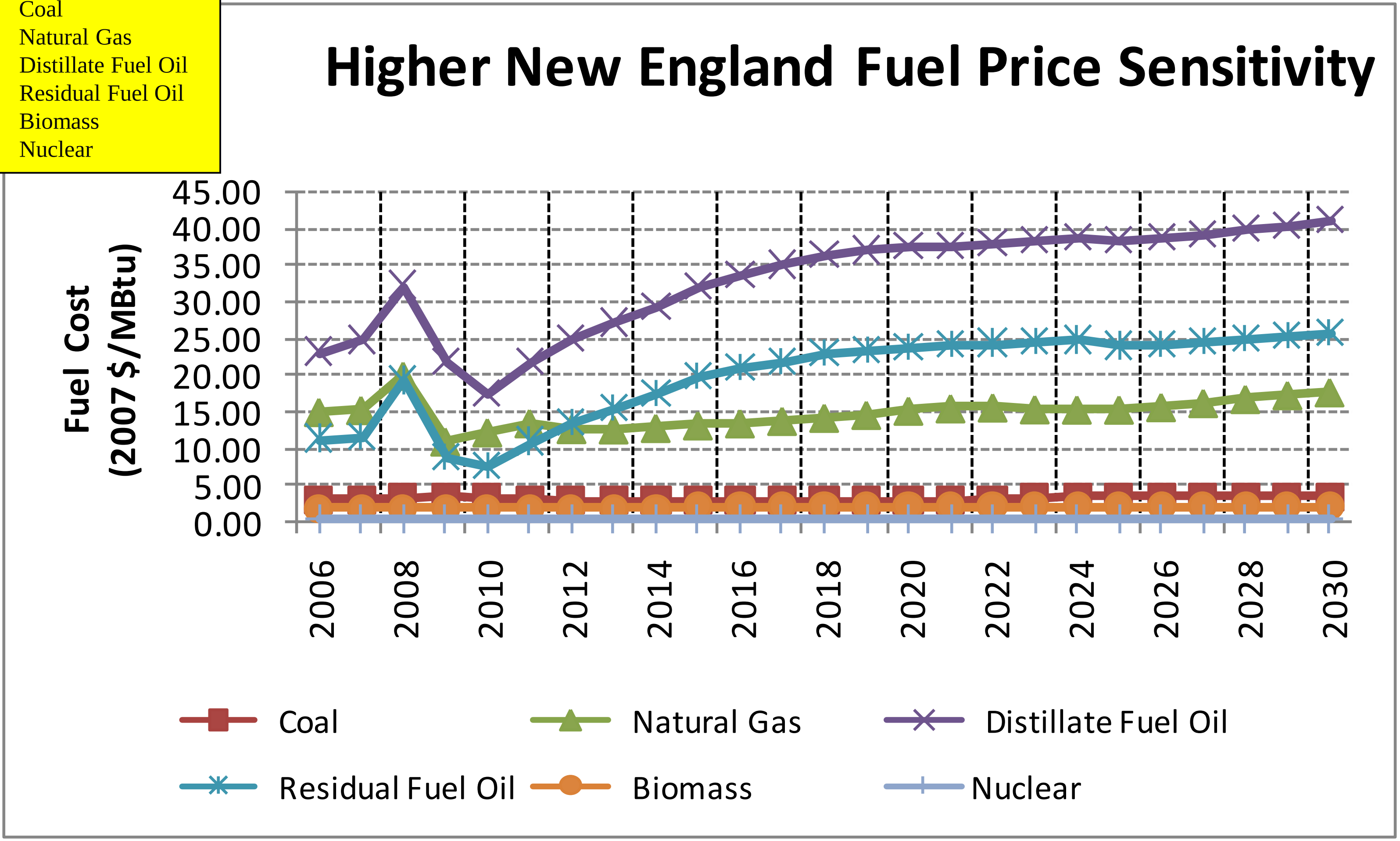
- Base Case with unconstrained transmission
- Constrained transmission sensitivity
- “Higher” fuel prices with unconstrained transmission
  - U.S. DOE *2009 Annual Energy Outlook* fuel price as base price
  - ISO doubled natural gas and increased oil-based fuels

Fuel Price Forecast – 2009 Annual Energy Outlook (AEO) Base



Fuel Price Forecast – High Sensitivity

Multiplier	Fuel
1.00	Coal
2.00	Natural Gas
1.75	Distillate Fuel Oil
1.50	Residual Fuel Oil
1.00	Biomass
1.00	Nuclear



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Evaluation Metrics

Metrics and Sensitivities

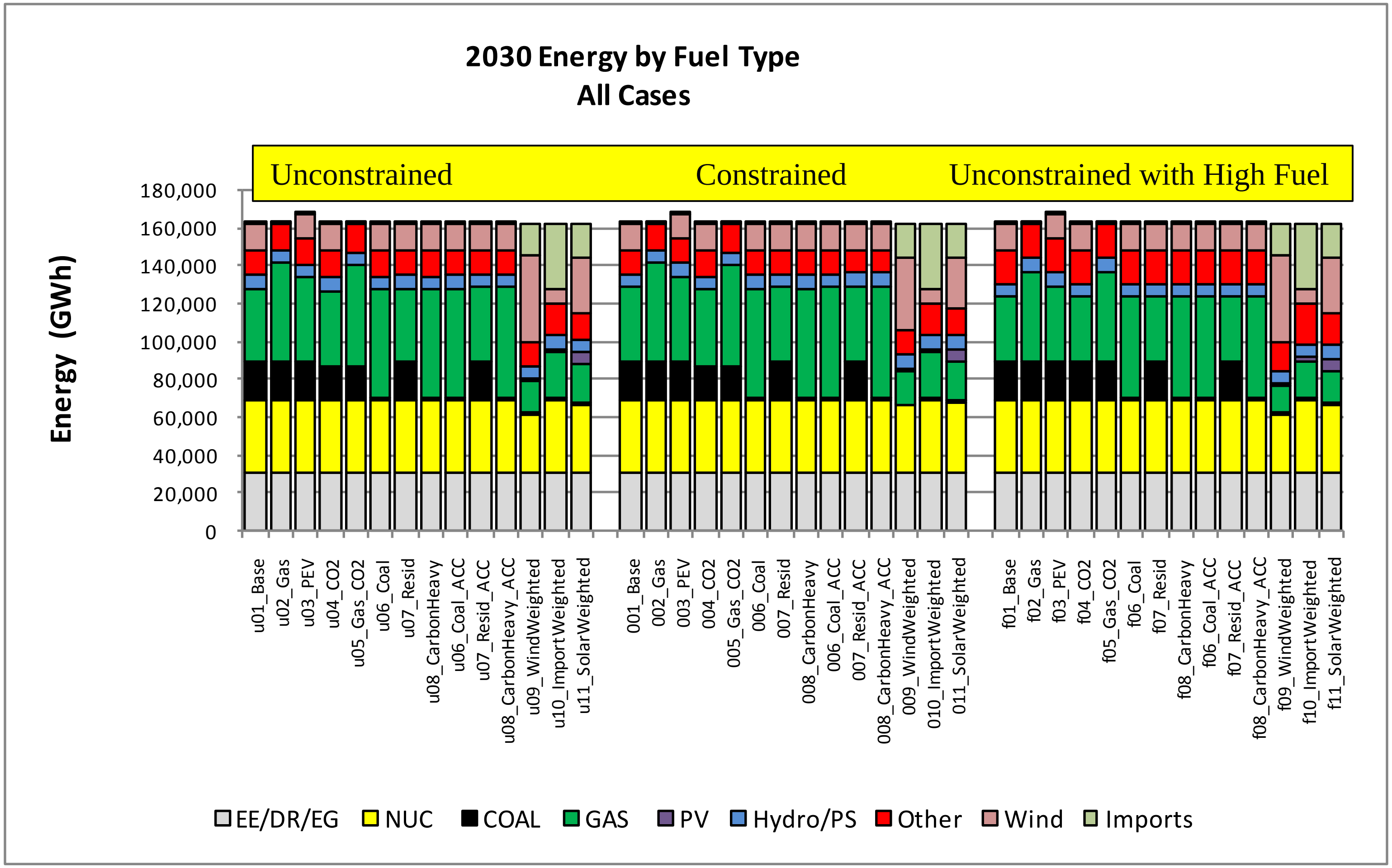
- Metrics
  - Economic (Production Cost, LSE Energy Expense, Congestion)
  - Environmental
  - Fuel consumption/energy by fuel type
  - Congestion (FTR / ARR)
  - Resource revenues from the energy market
- Sensitivities modeled to show impact of
  - Transmission constraints
  - High fuel prices
  - Maritimes energy flows (Labrador Hydro and Maritimes nuclear could be considered part of several new 1,500 MW DC lines)

Fuel Consumption Metric

- Generation (GWh and percent) by fuel type
  - Wind and Demand Resources have no associated MBtus
  - Shows amount of energy assumed to be served by
    - Energy Efficiency
    - Active Demand Resources
    - Wind
    - PV
    - Hydro / Pumped Storage
    - Coal
    - Nuclear
    - Natural Gas
    - Net Imports

Revised

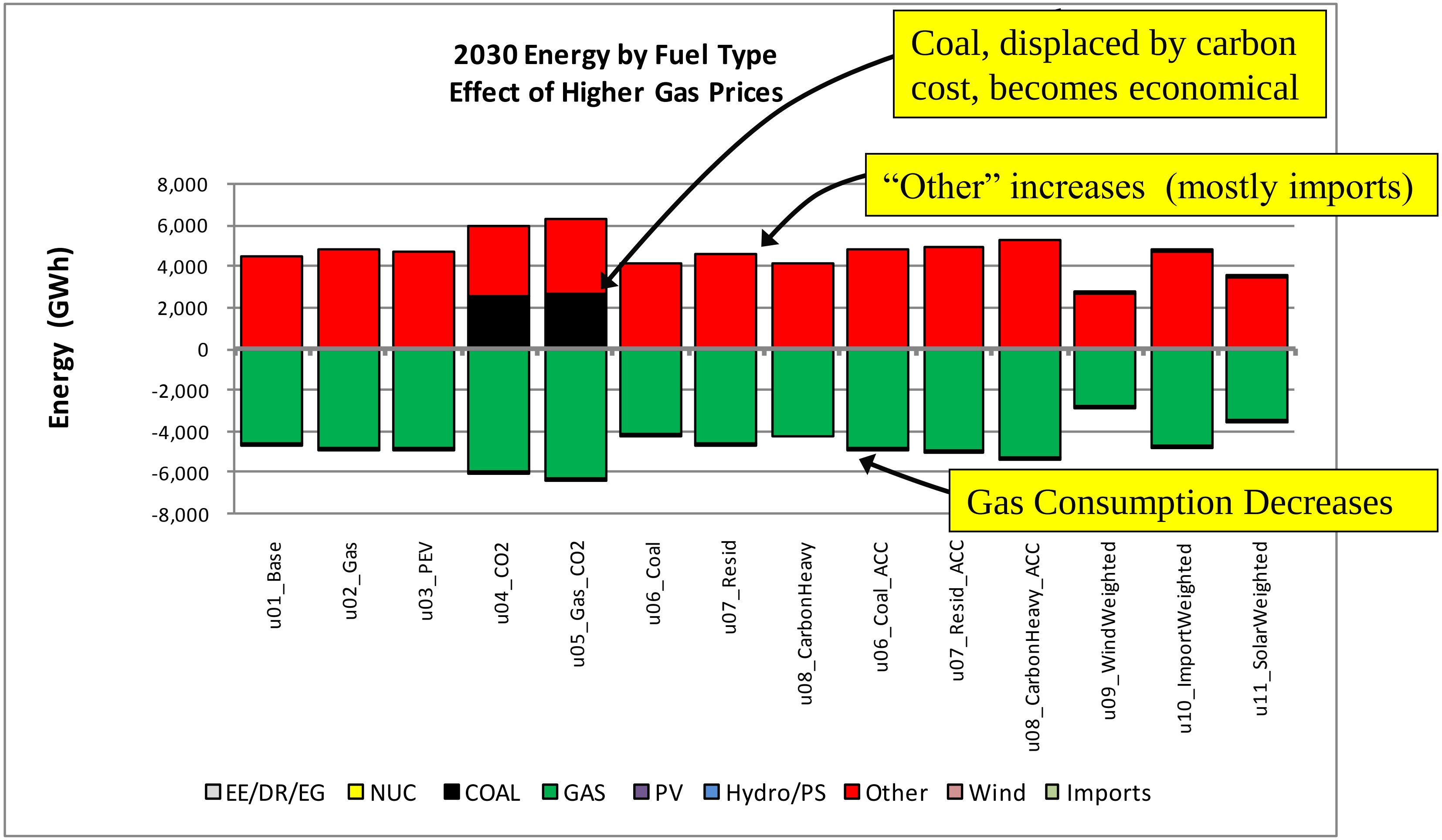
Energy Generation by Fuel Type



Note: Other ("■") is Biomass, Waste, Residual, Distillate fuels and Imports (except HQP3)

Effect of Higher Fuel Prices

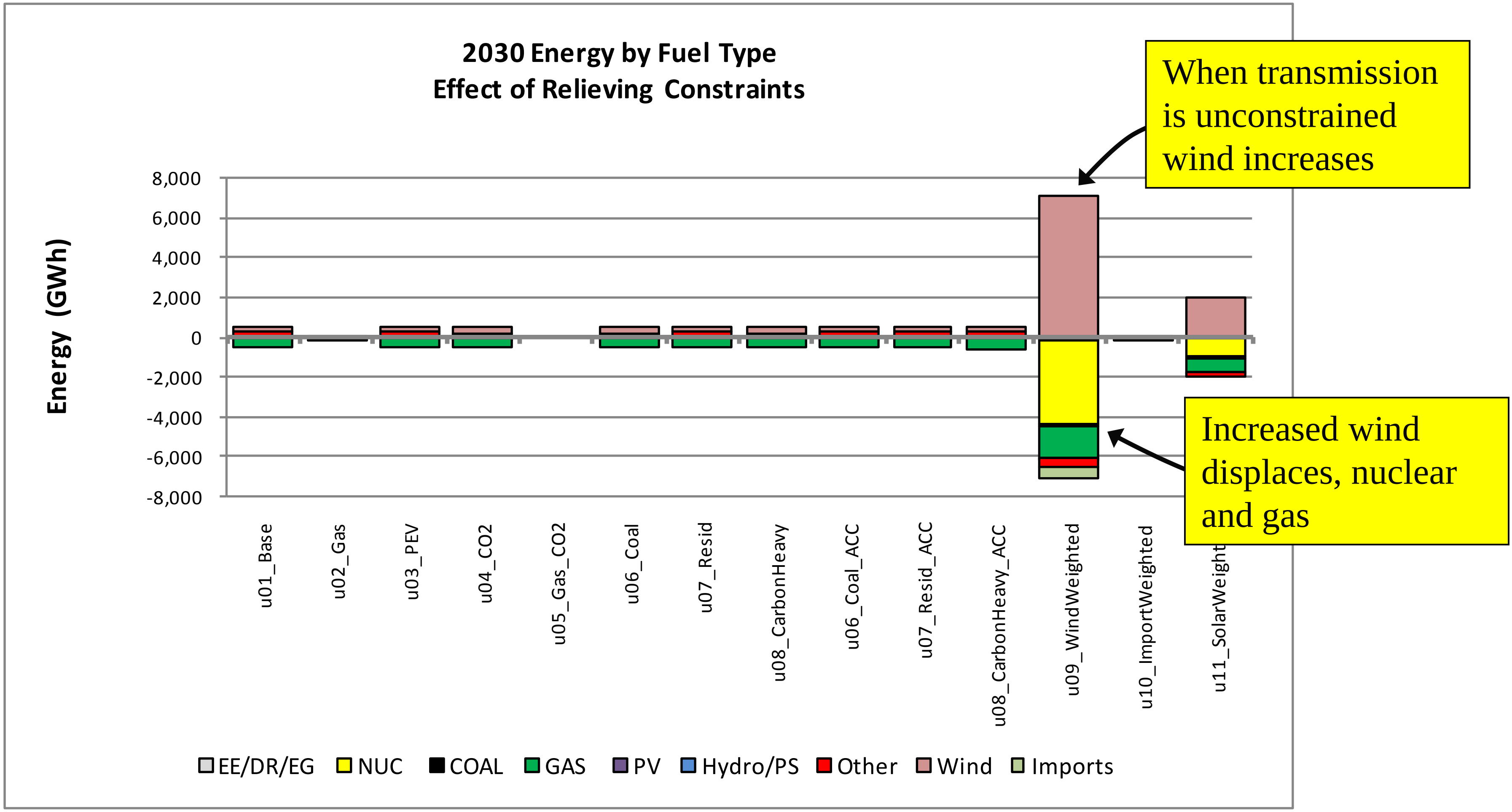
Revised



Note: Other ("■") is Biomass, Waste, Residual, Distillate fuels and Imports (except HQP3)

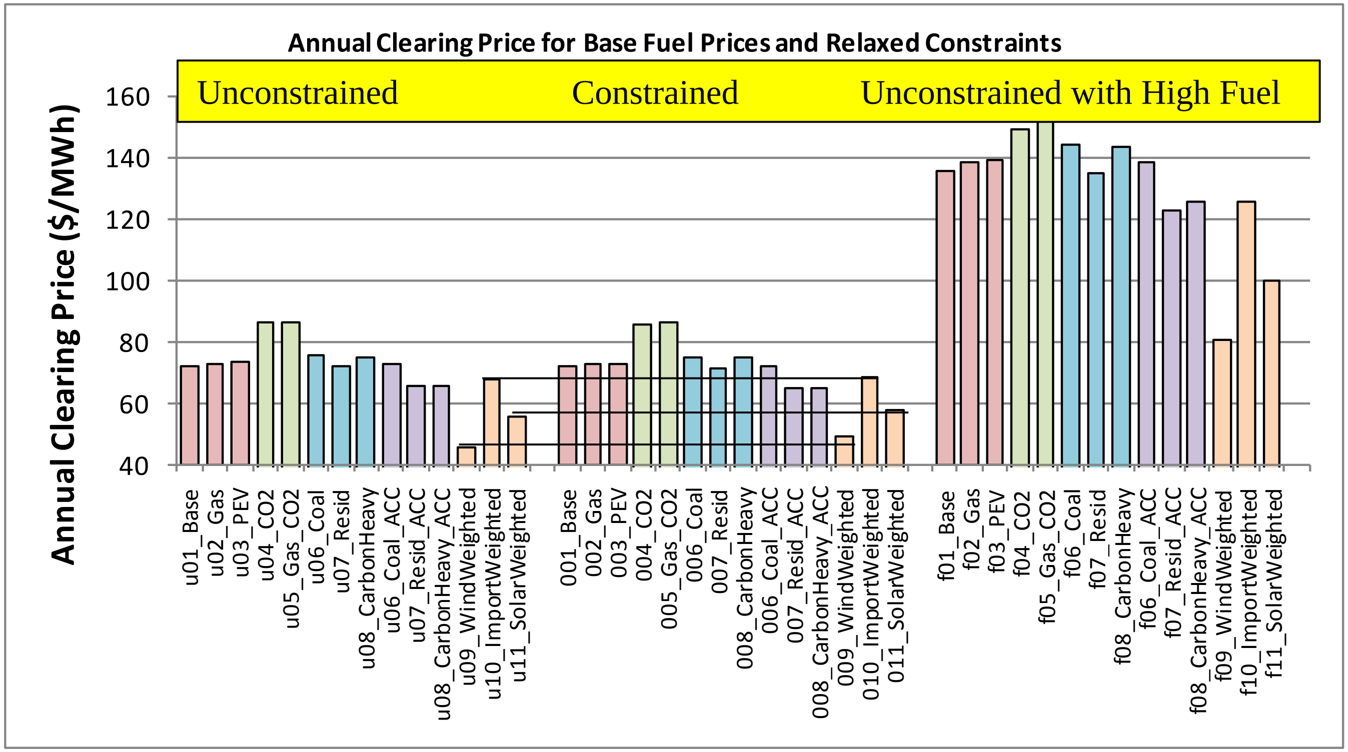
Effect of Relieving Transmission Constraints

Revised



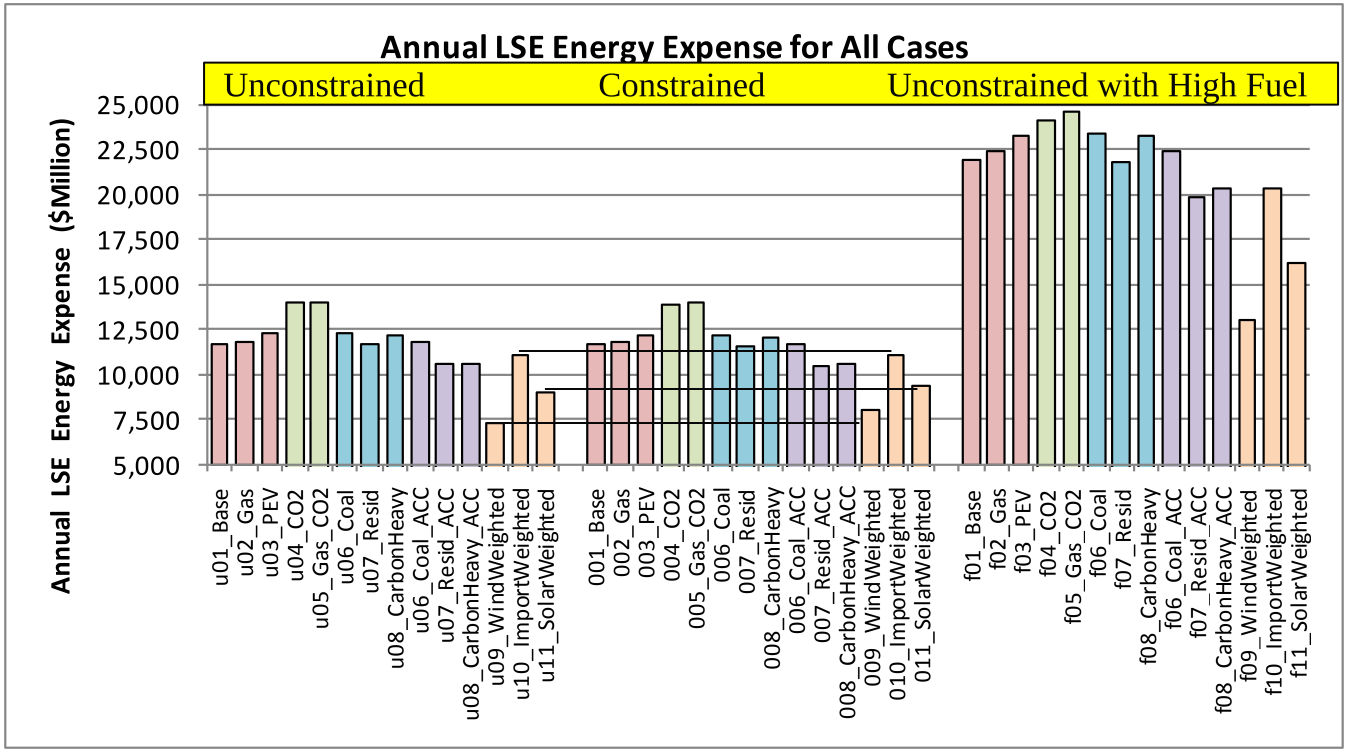
Note: Other ("■") is Biomass, Waste, Residual, Distillate fuels and Imports (except HQP3)

Annual New England Energy Clearing Prices



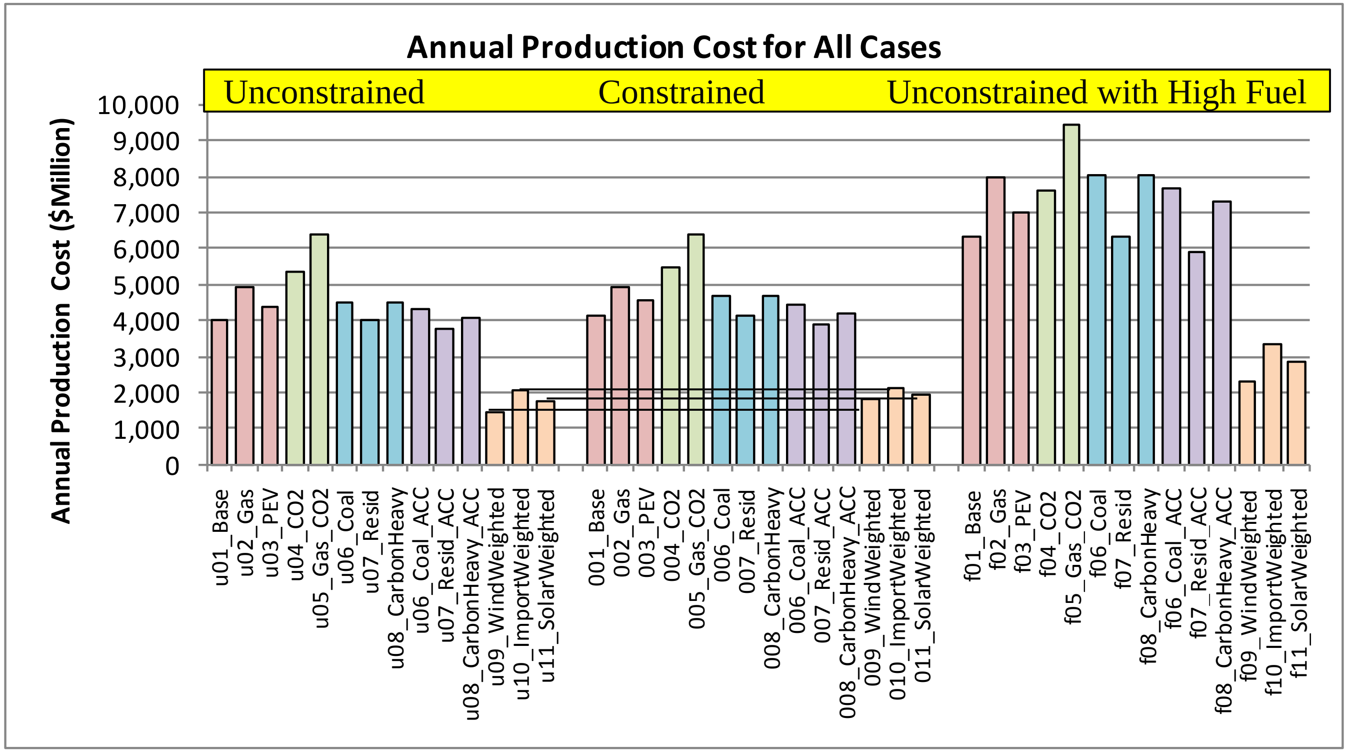
Annual New England LSE Energy Expense

Revised



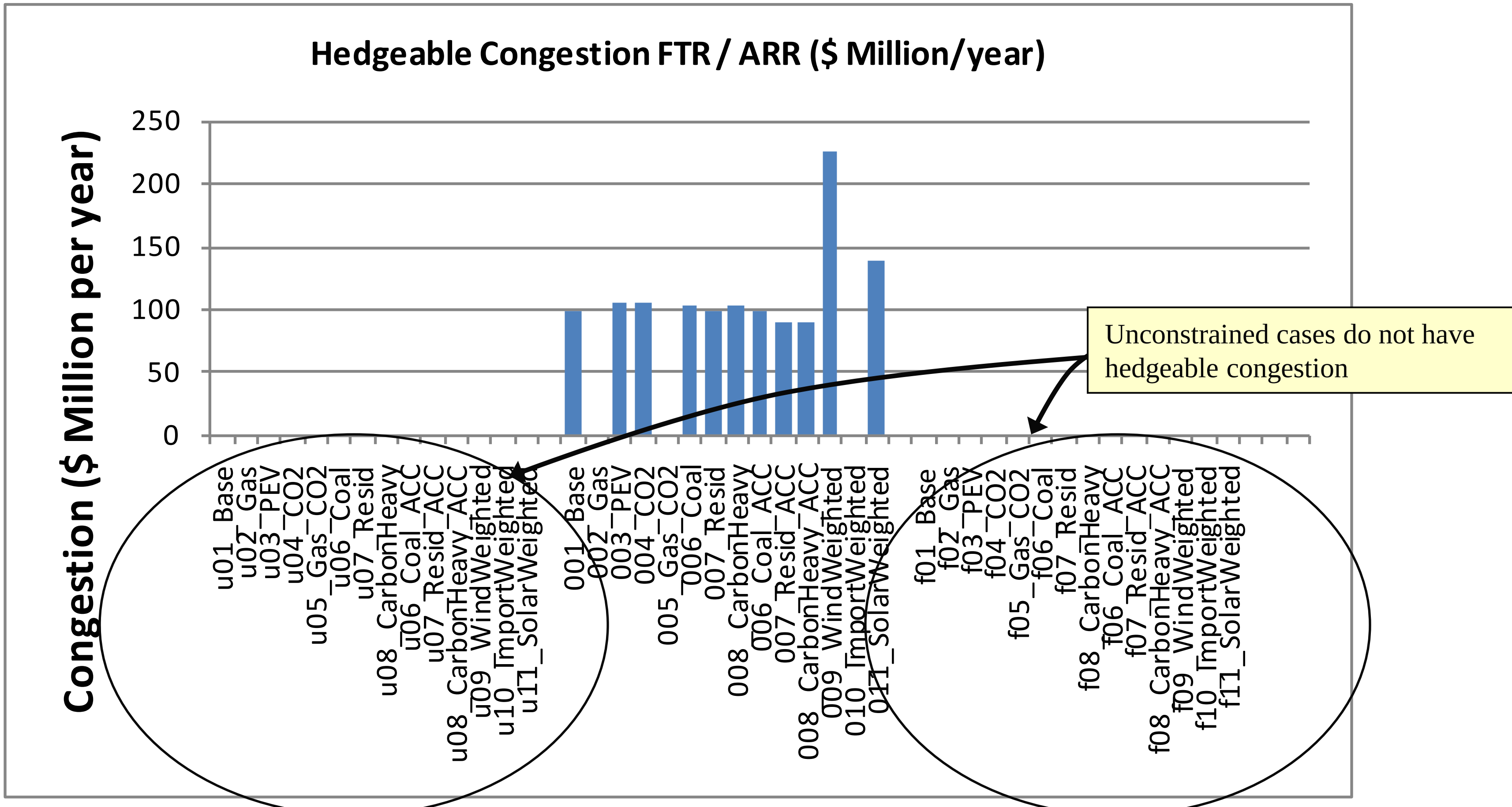
Revised

Annual New England Production Cost



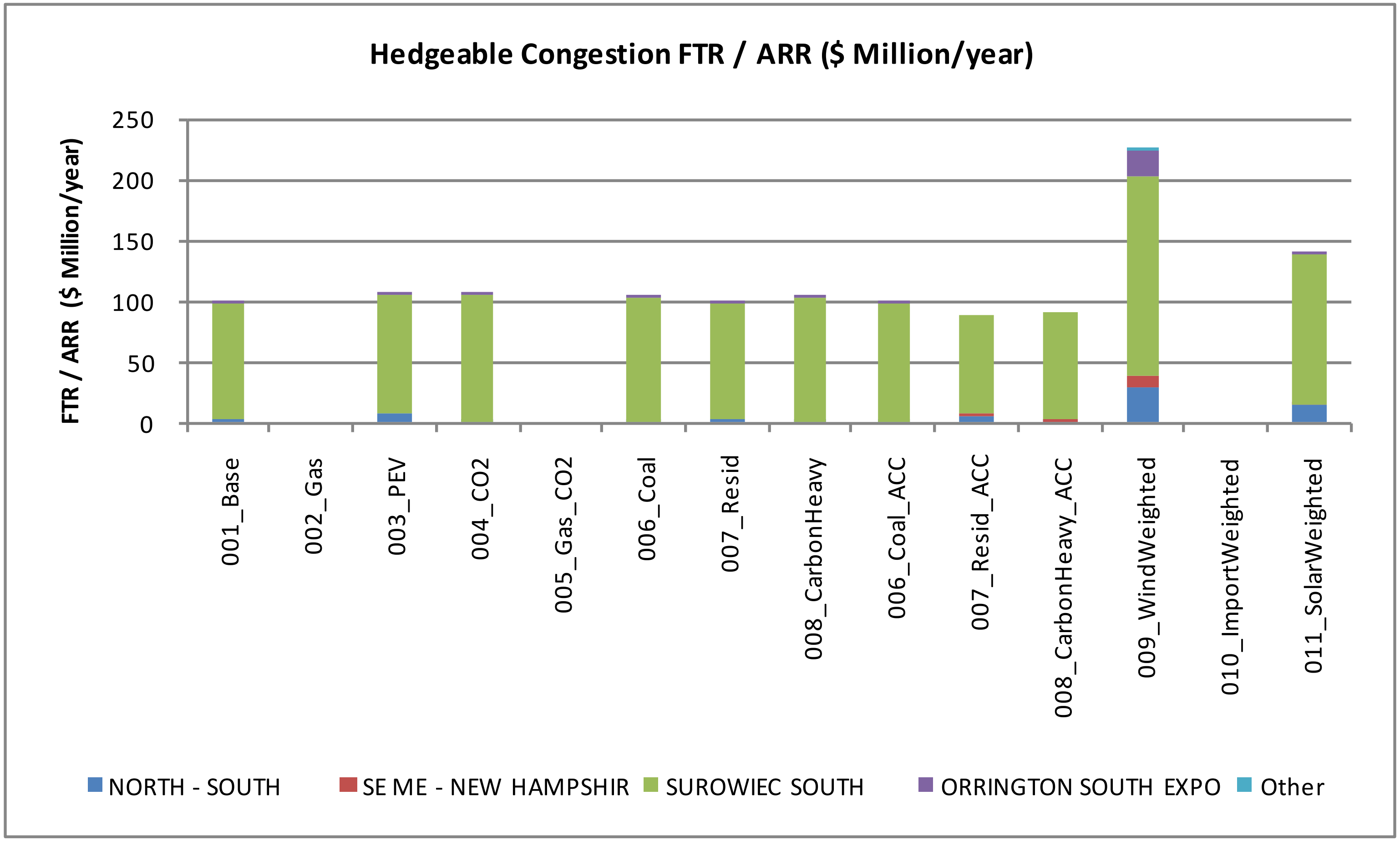
Revised

Hedgeable Congestion for all Cases



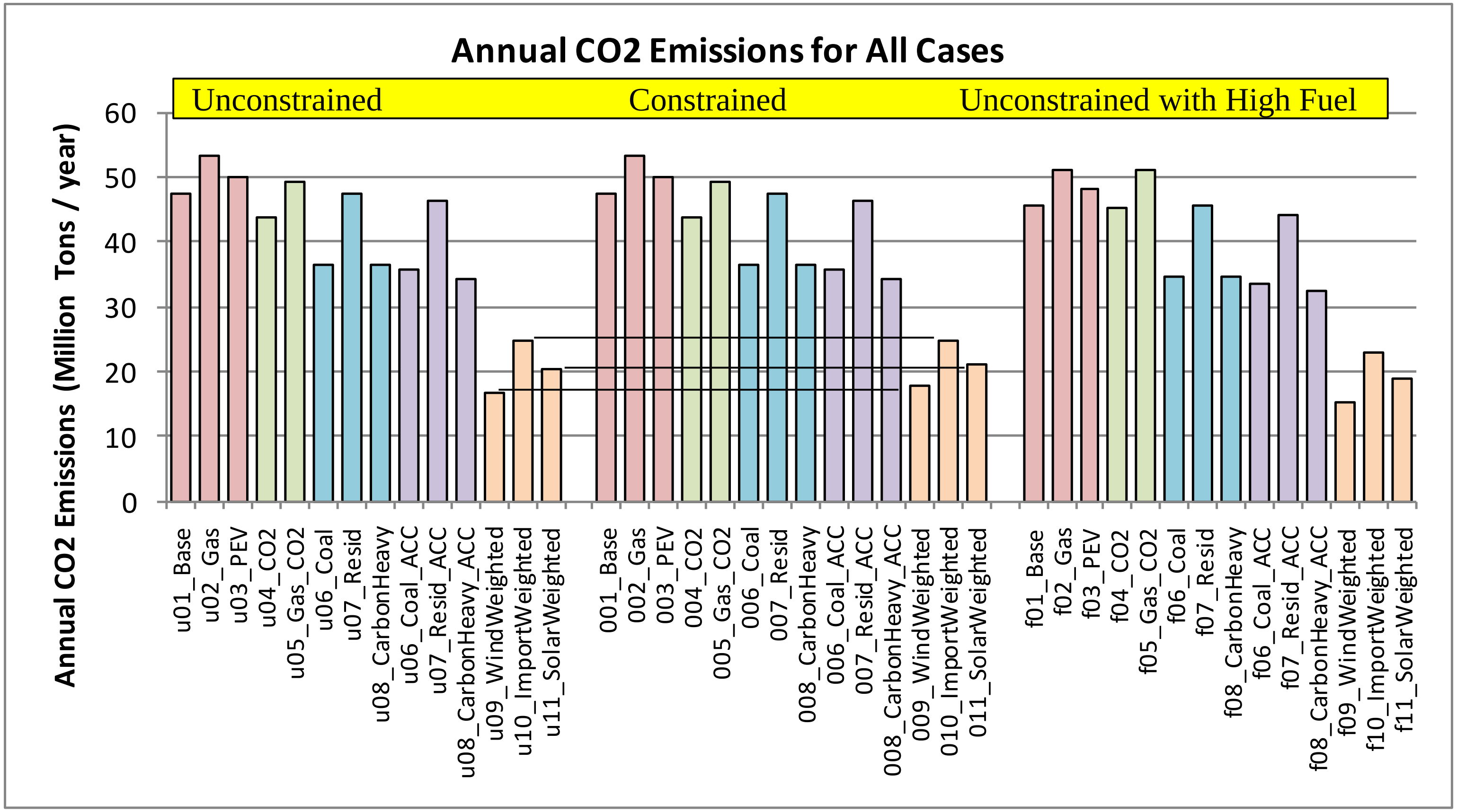
Revised

Hedgeable Congestion by Interface



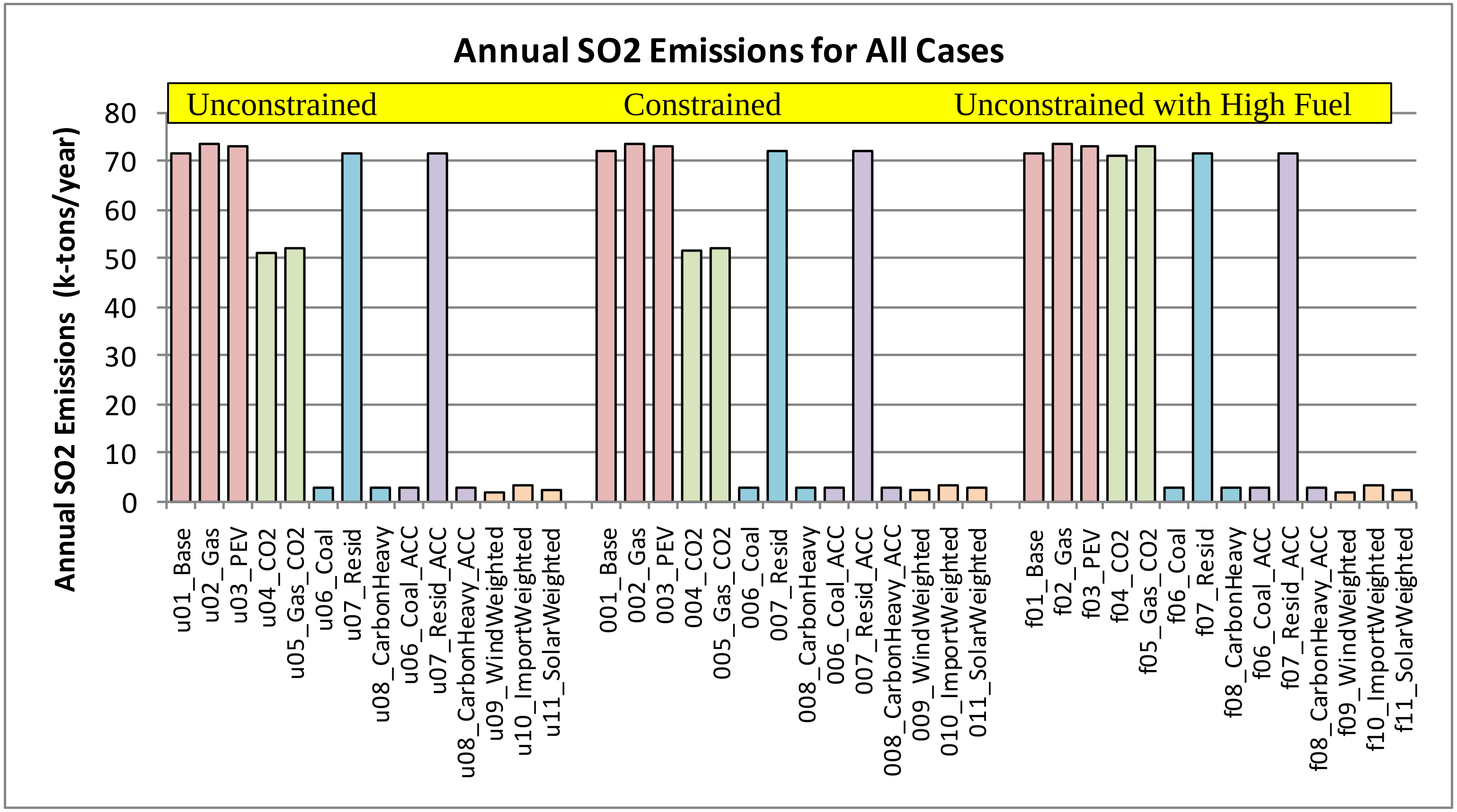
Revised

Annual New England CO2 Emissions



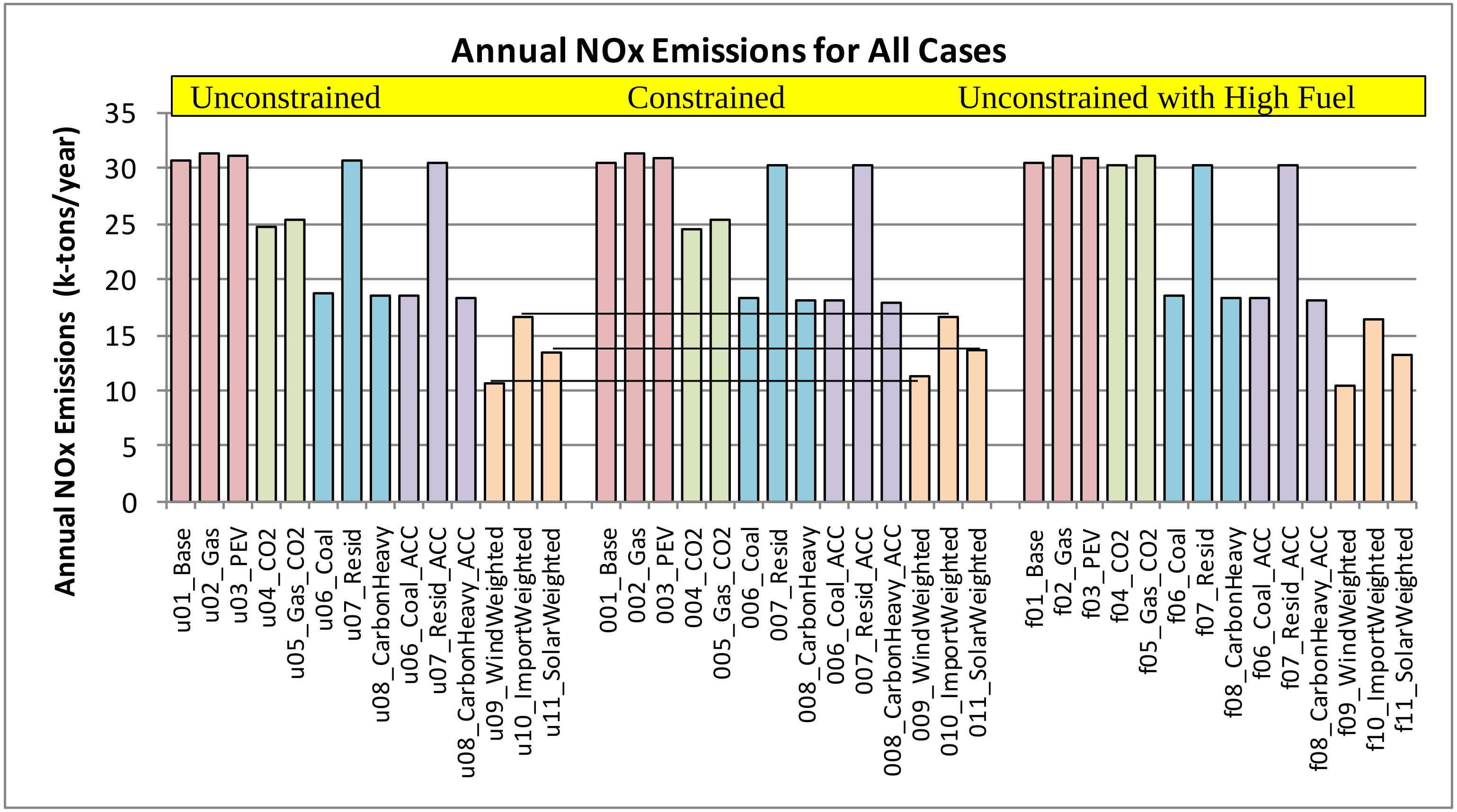
Revised

Annual New England SO2 Emissions



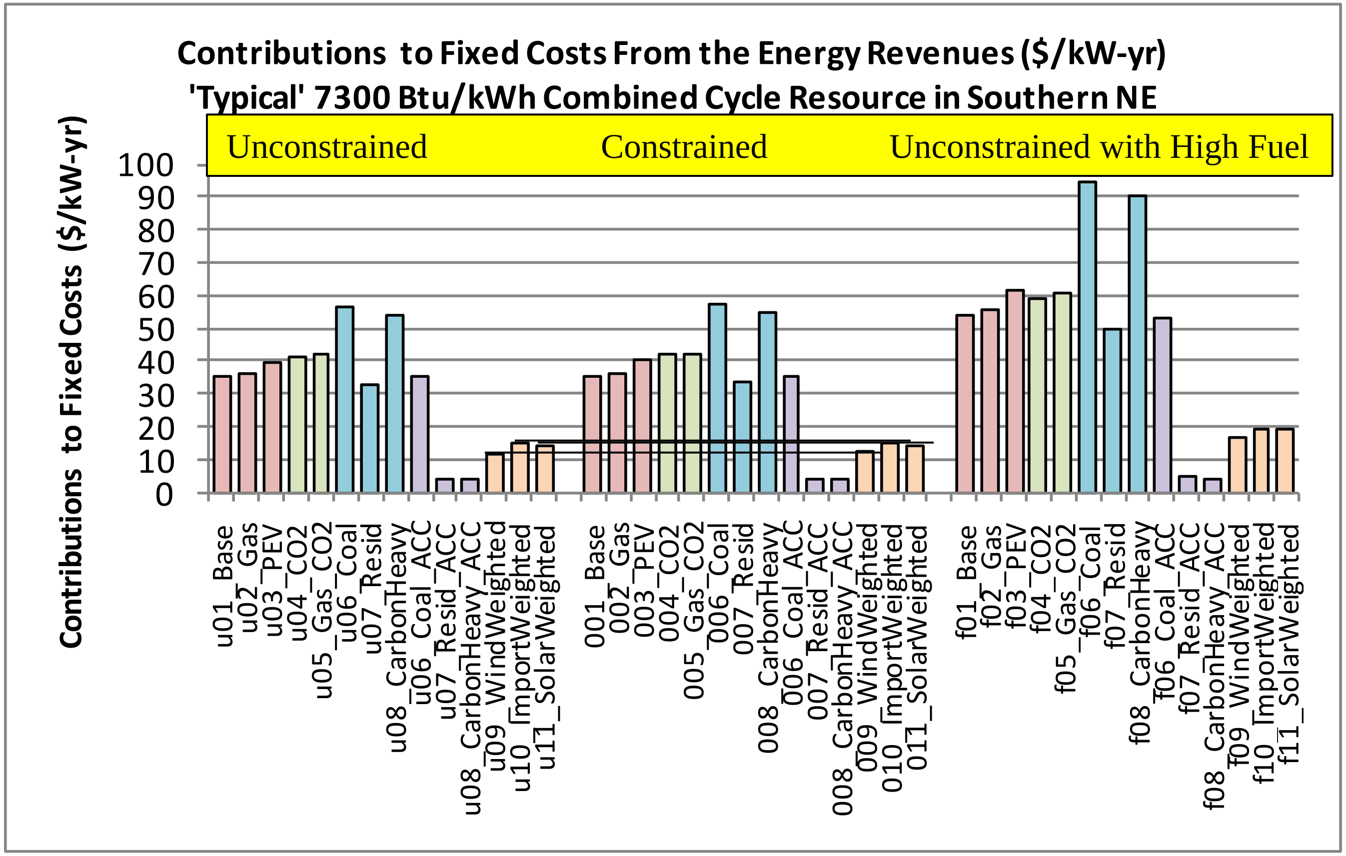
Revised

Annual New England NOx Emissions



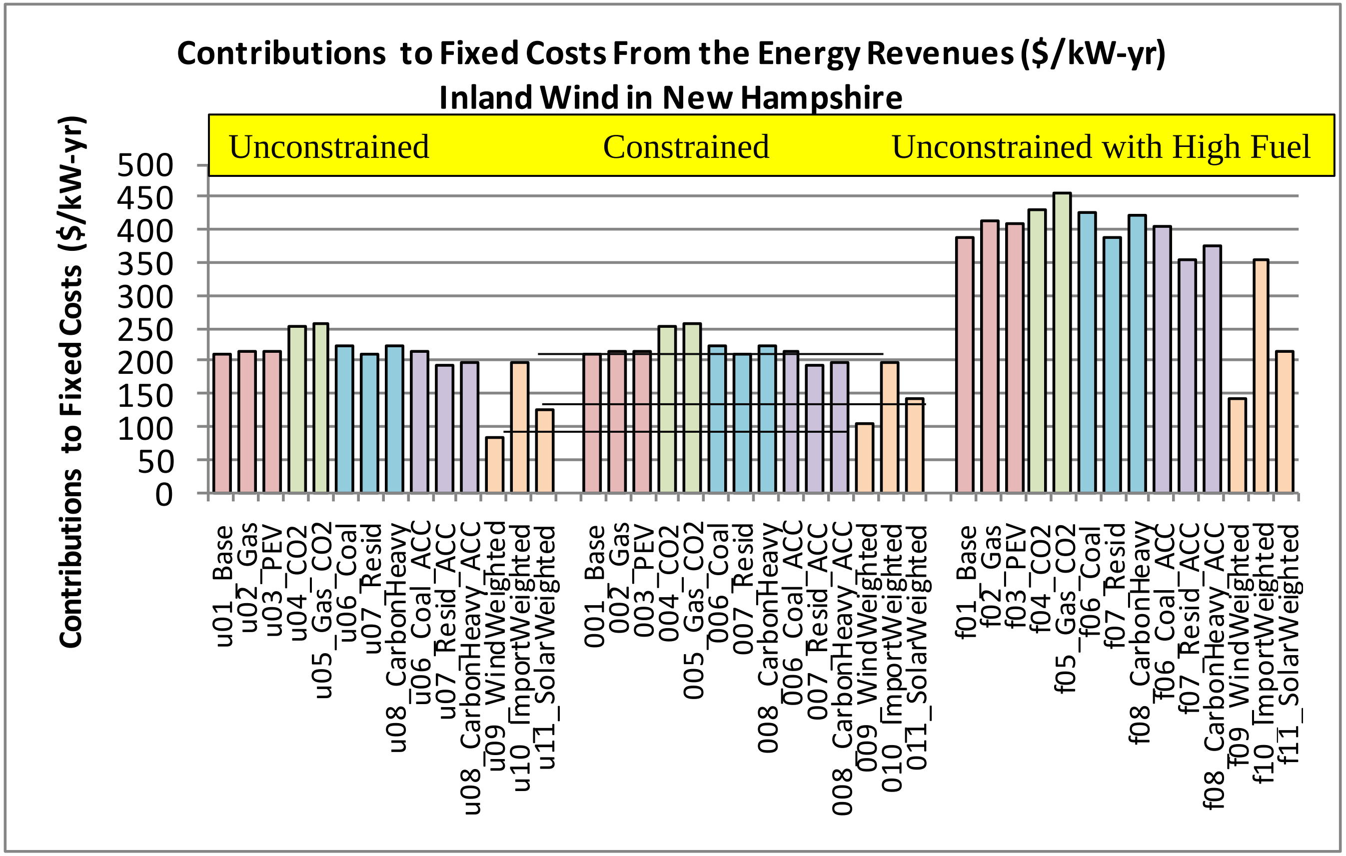
Revised

Contributions to Fixed Costs Combined Cycle in Southern Connecticut



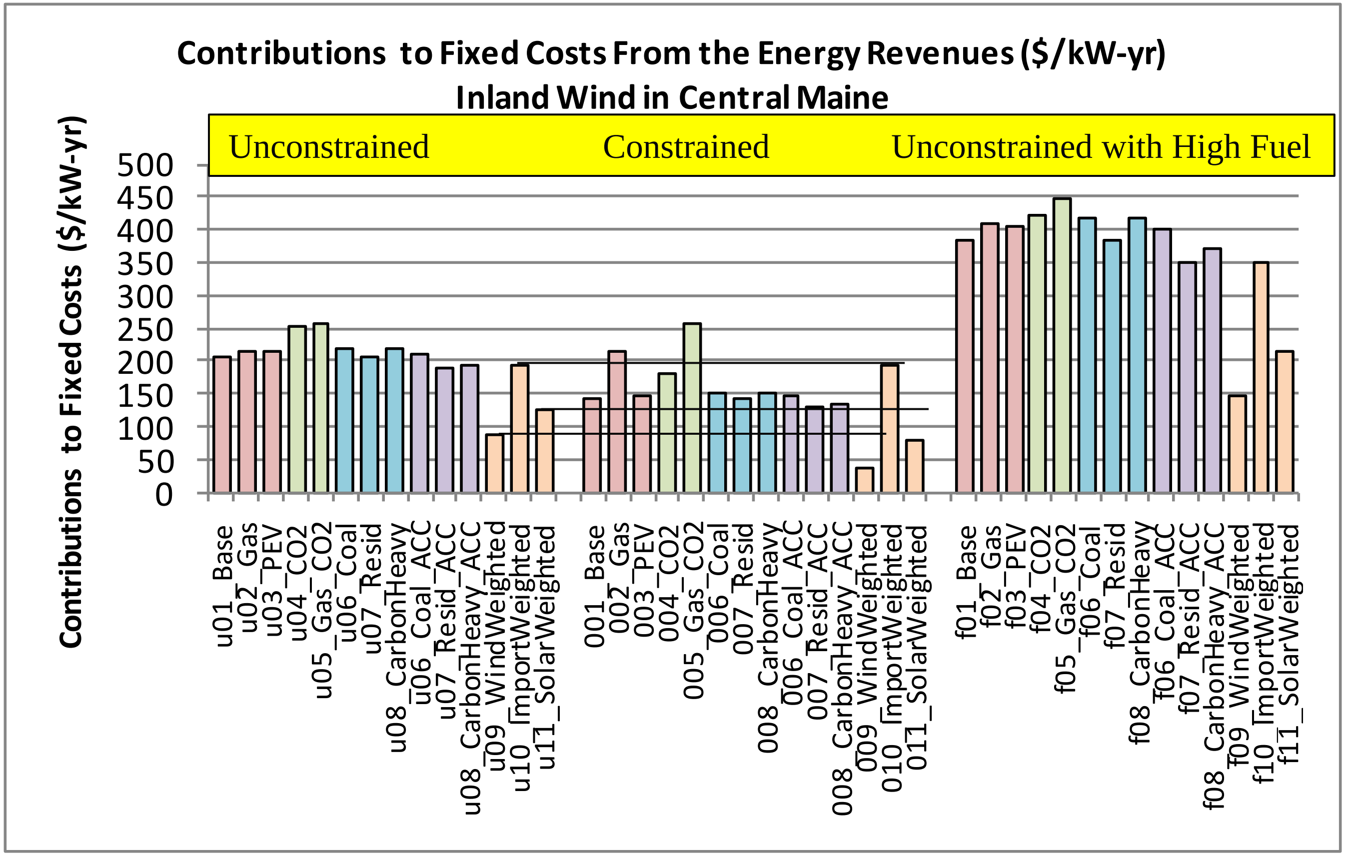
Contributions to Fixed Costs Inland Wind New Hampshire

Revised



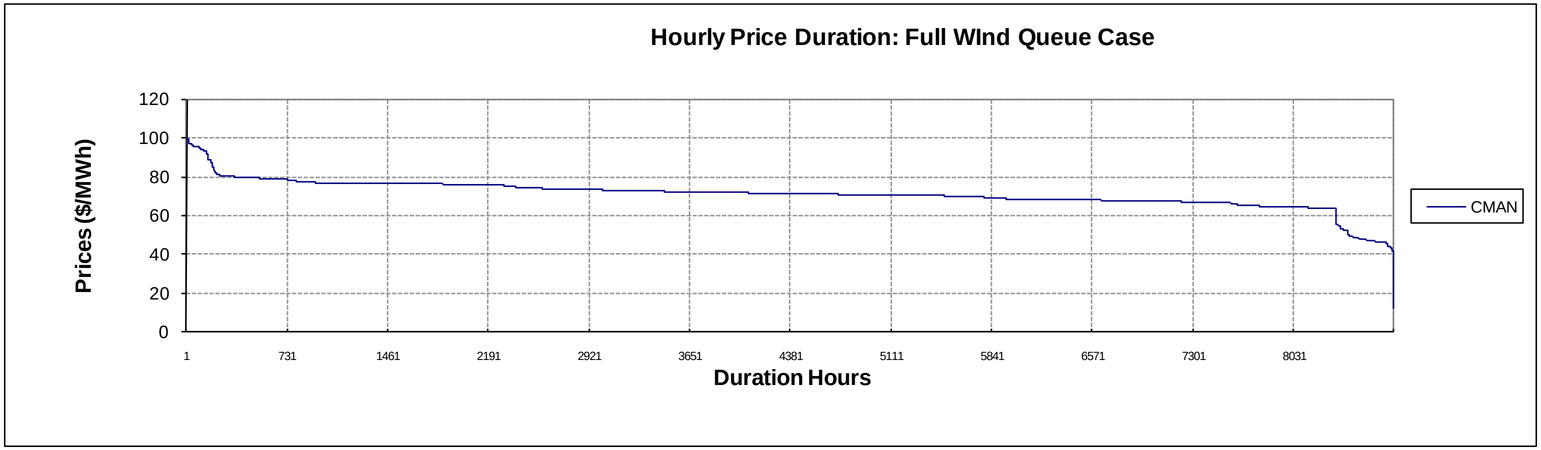
Revised

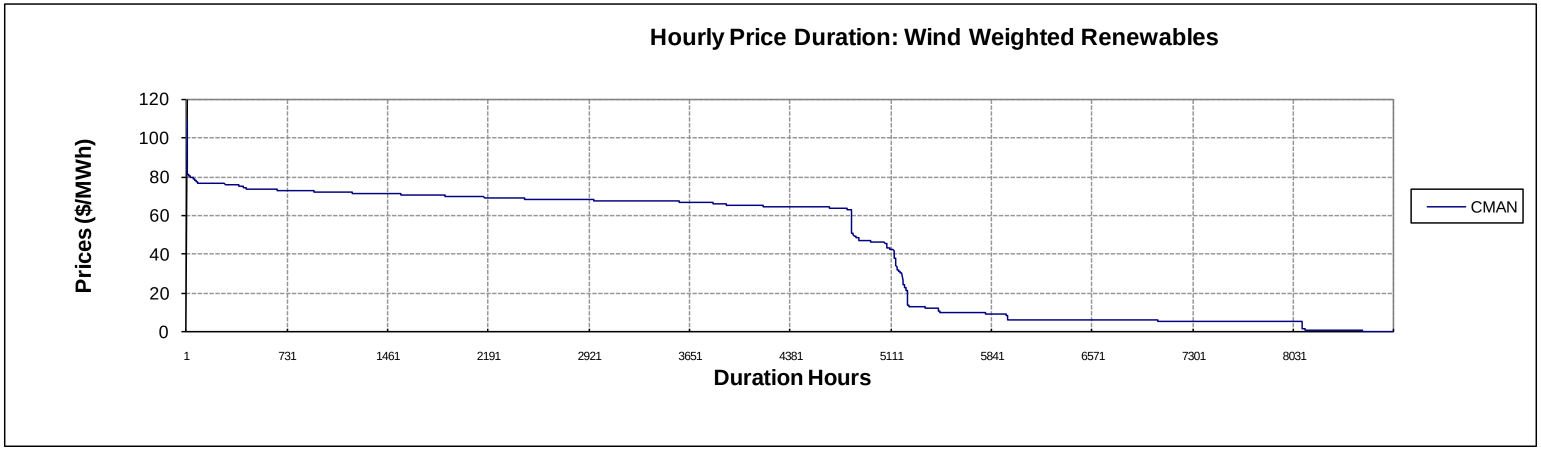
Contributions to Fixed Costs Inland Wind Central Maine



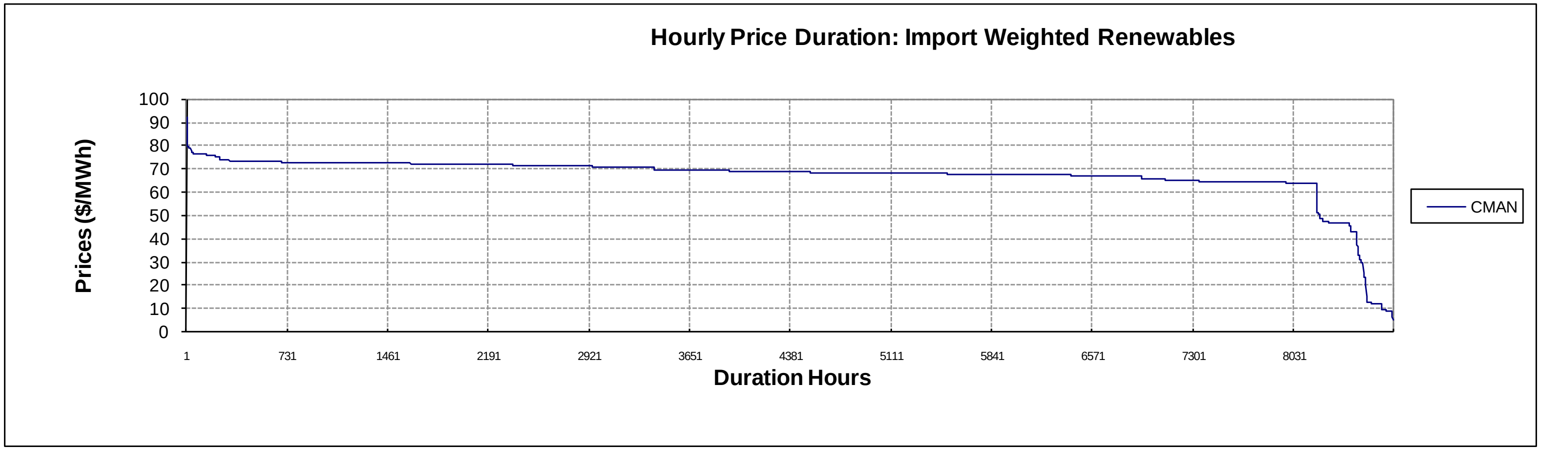
Price Duration Curves for Selected Cases

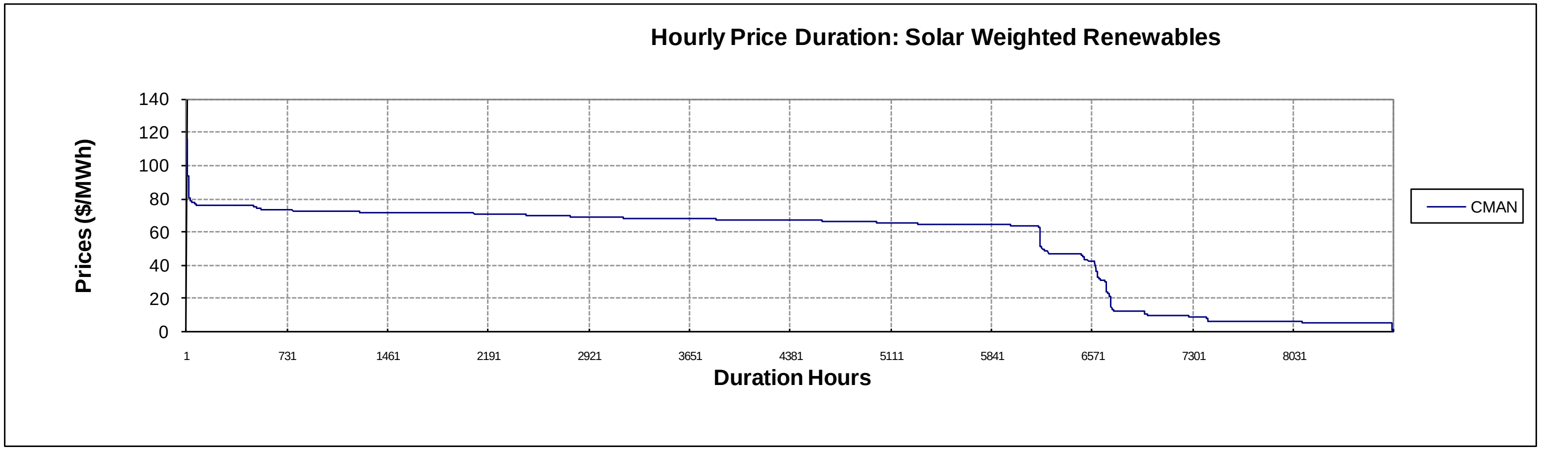
Base Case vs Wind Weighted Renewable (Central Massachusetts)





Import and Solar Weighted Renewable (Central Massachusetts)





Revised DRAFT

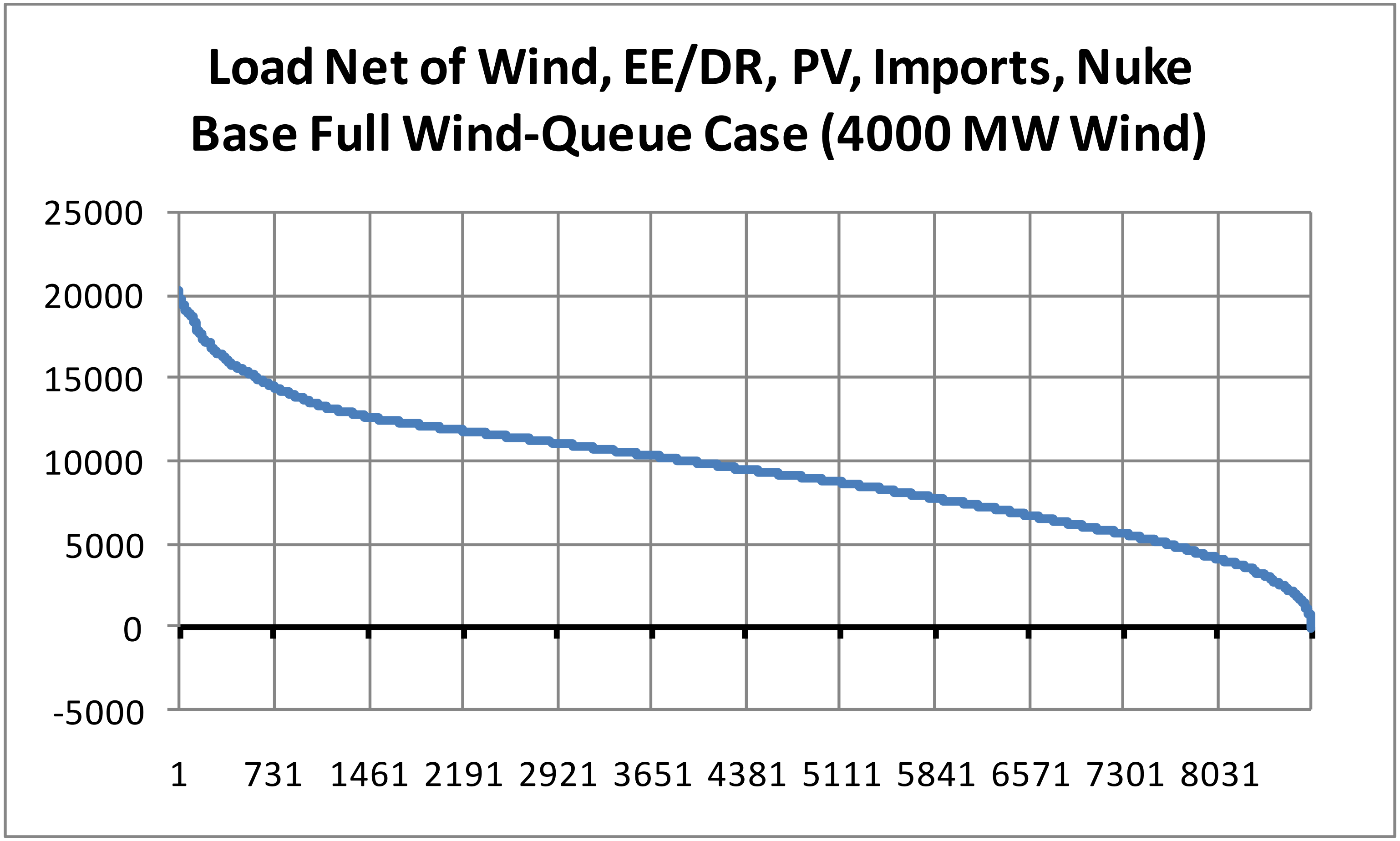
Understanding the Shape of the Price Duration Curves

- The shape of hourly clearing price duration curves for all of New England can be explained for some cases:
  - Many load modifiers are used
    - "Load Modifiers" are not dispatched
    - They are "price takers" at zero dollars per MWh
      - Wind
      - Photovoltaic
      - Hydro Imports
      - Energy efficiency / Demand Response
  - Can displace nuclear units

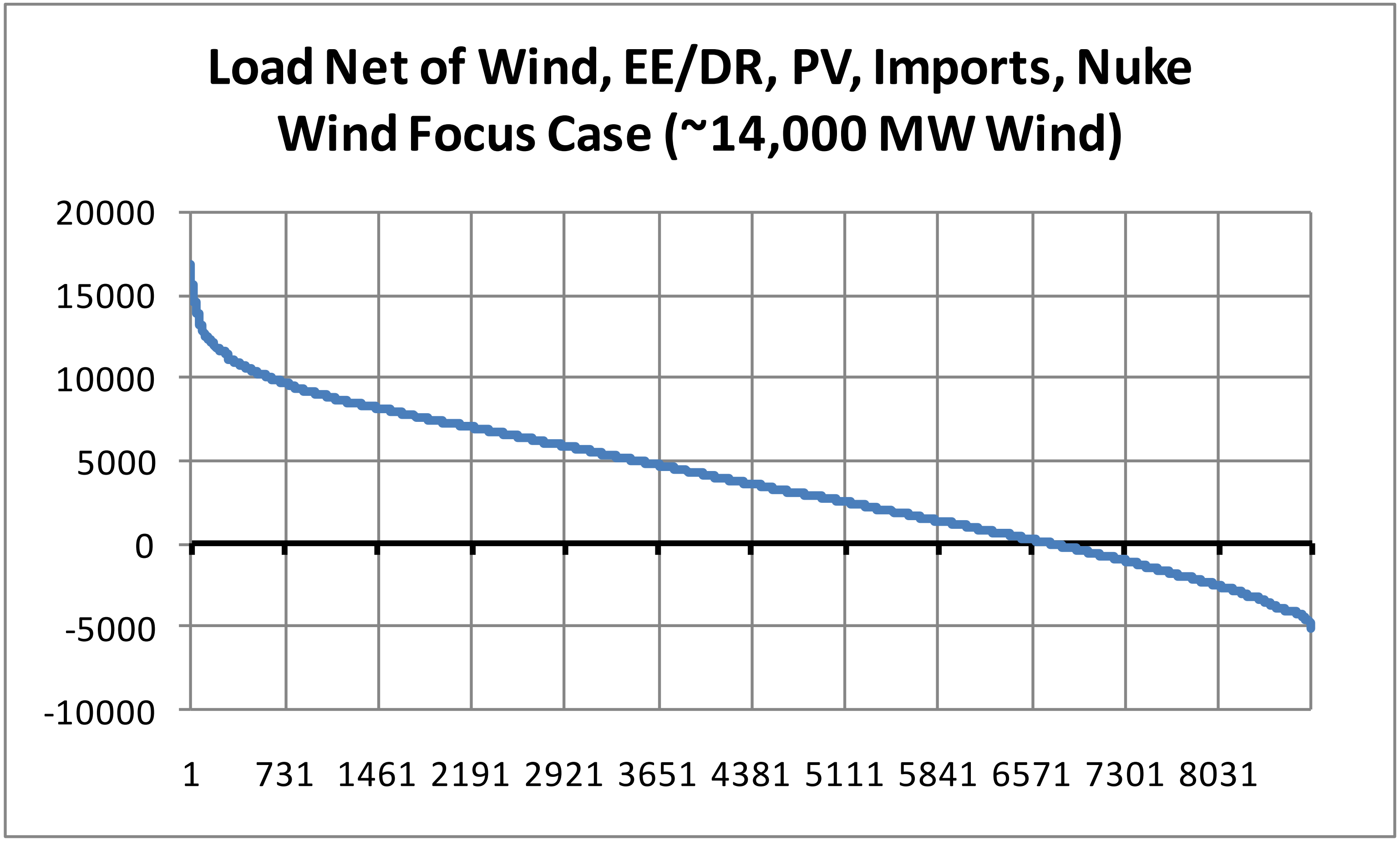
Understanding the Shape of the Price Duration Curves

- Distributions of Net New England Loads to be served from Legacy Generating Technologies
  - New England loads minus
    - EE/DR
    - Wind
    - PV
    - Nuclear (assumed to be 4000 MW for this graph)
  - Can show low, or negative residual
- Other load modifiers are also used
  - Function of gross loads … not prices after wind, EE/DR, PV
    - Conventional hydro
    - Pumped storage

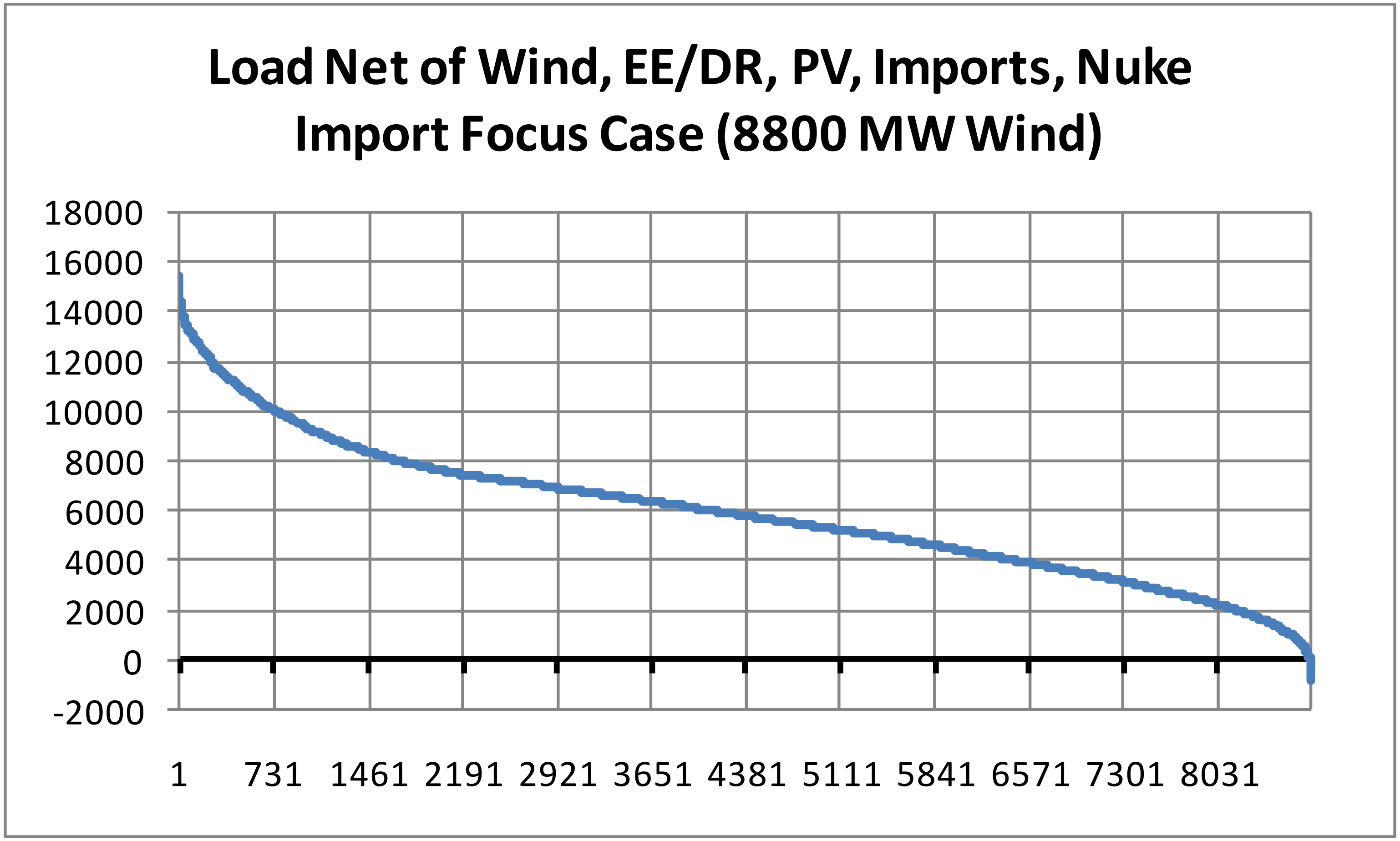
Net Load for 'Legacy' Generating Units Base Case



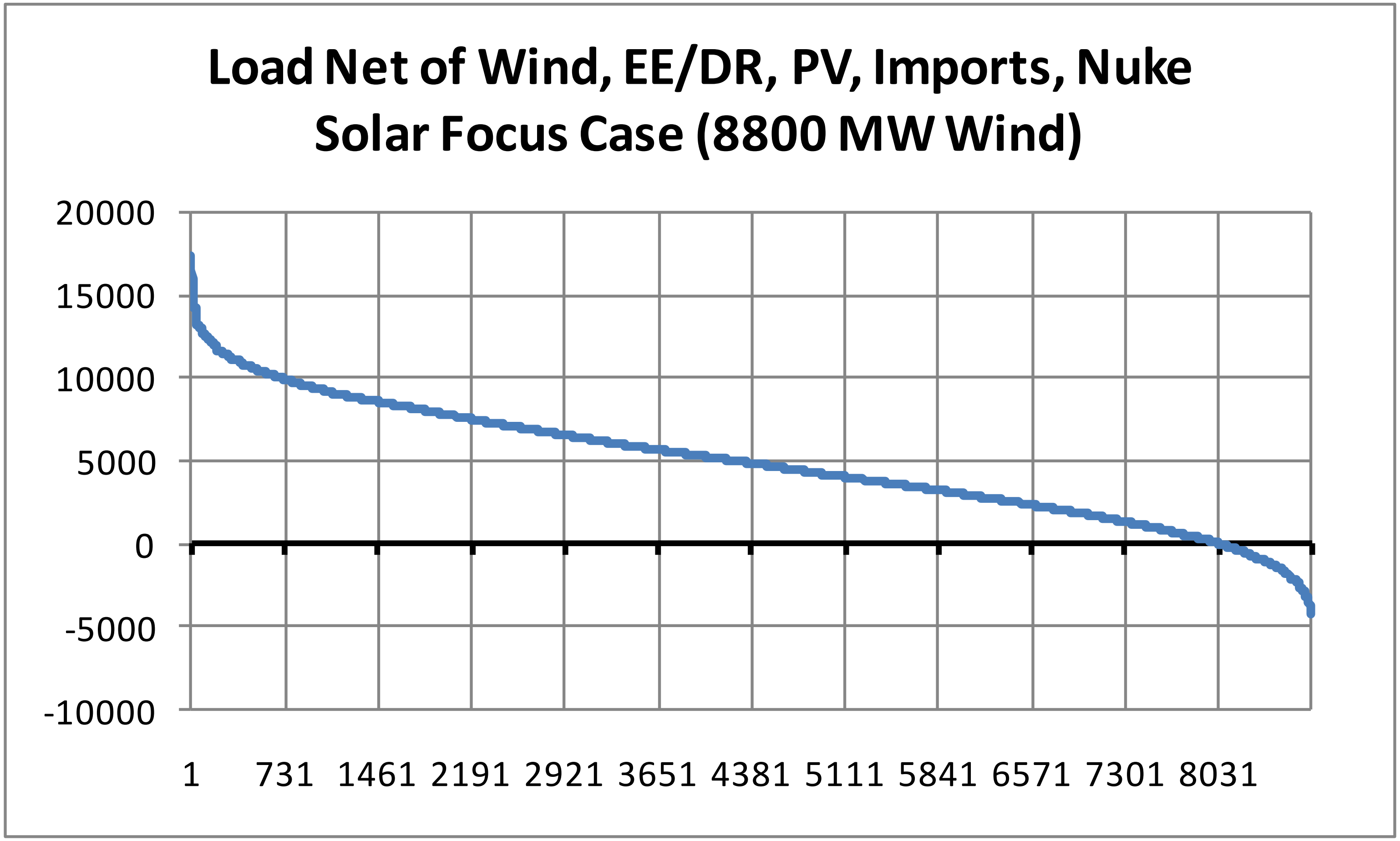
Net Load for 'Legacy' Generating Units Renewables - Wind Focused Case



Net Load for 'Legacy' Generating Units Renewables - Import Focused Case



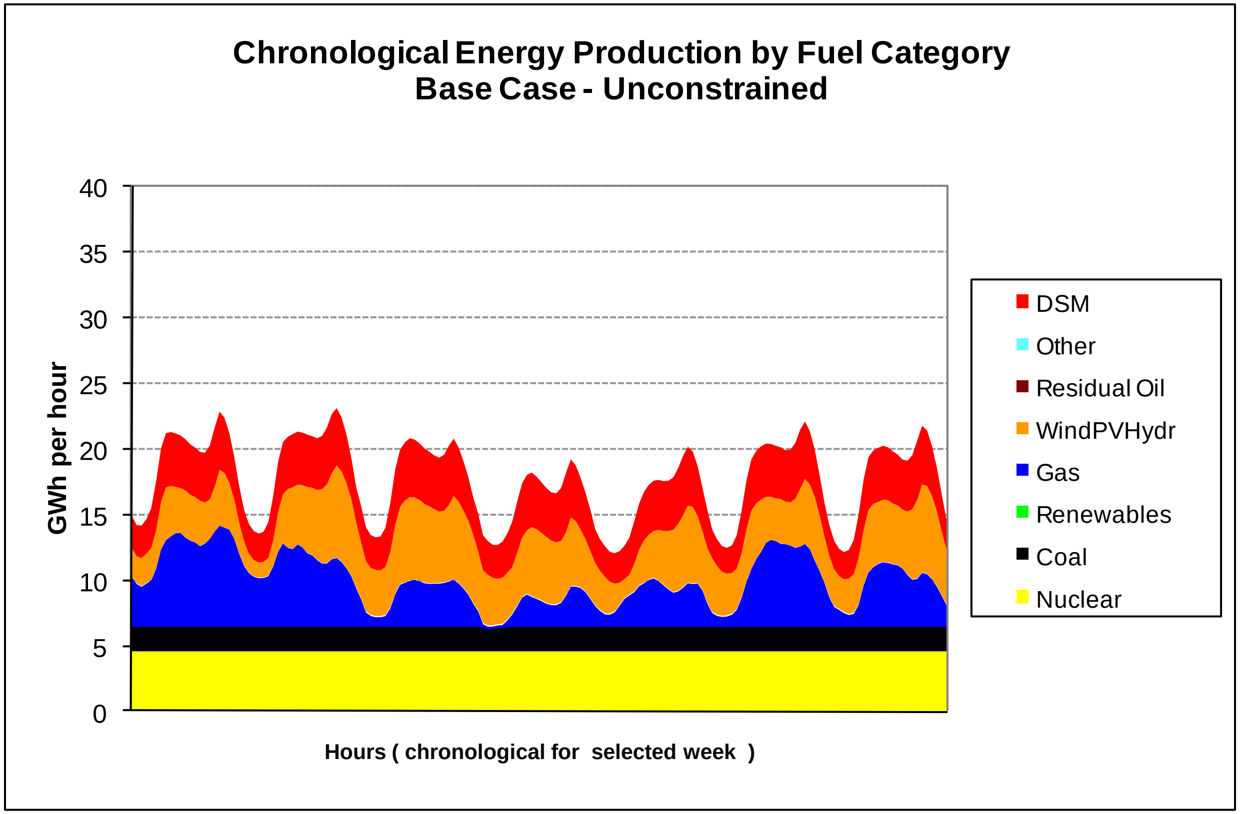
Net Load for 'Legacy' Generating Units Renewables – Solar PV Focused Case



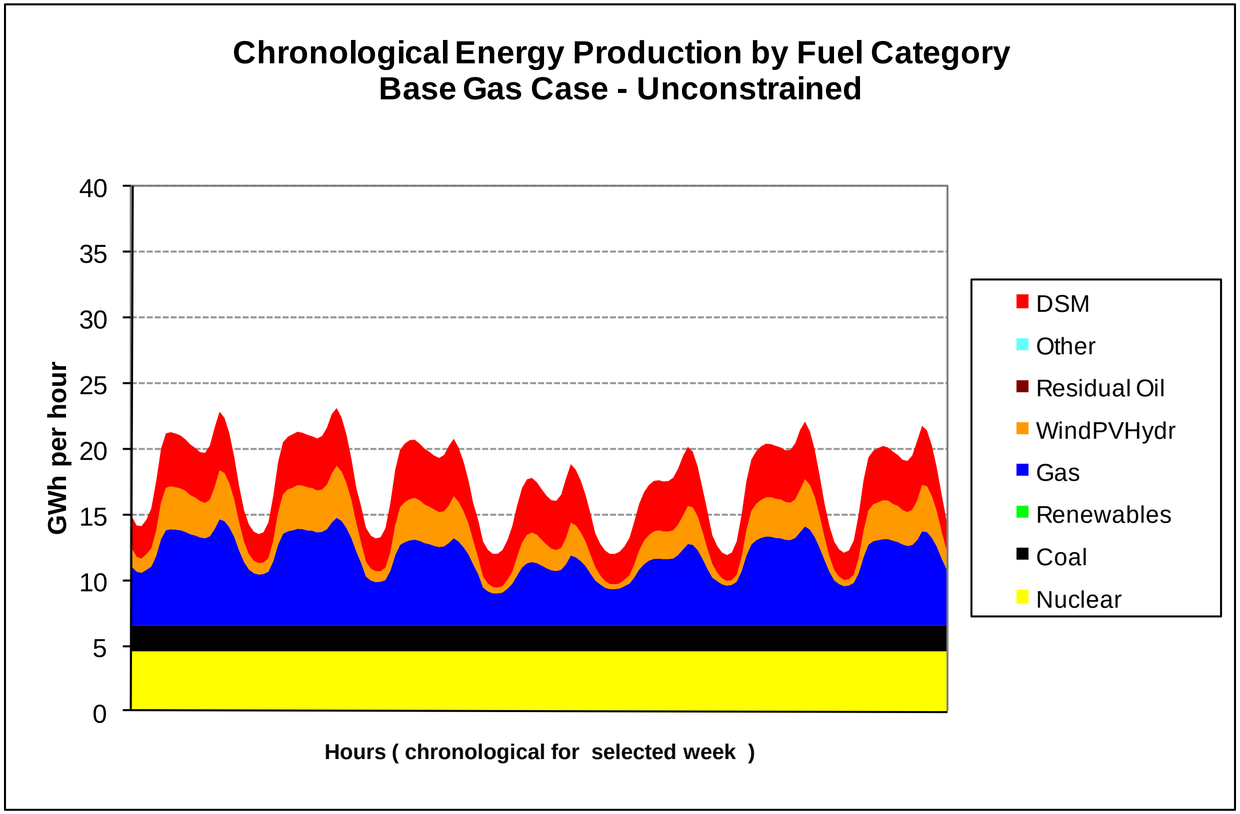
Questions?

Appendix 1: Weekly Energy Profiles for Selected Cases and Selected Weeks (Week 11 and Peak Week)

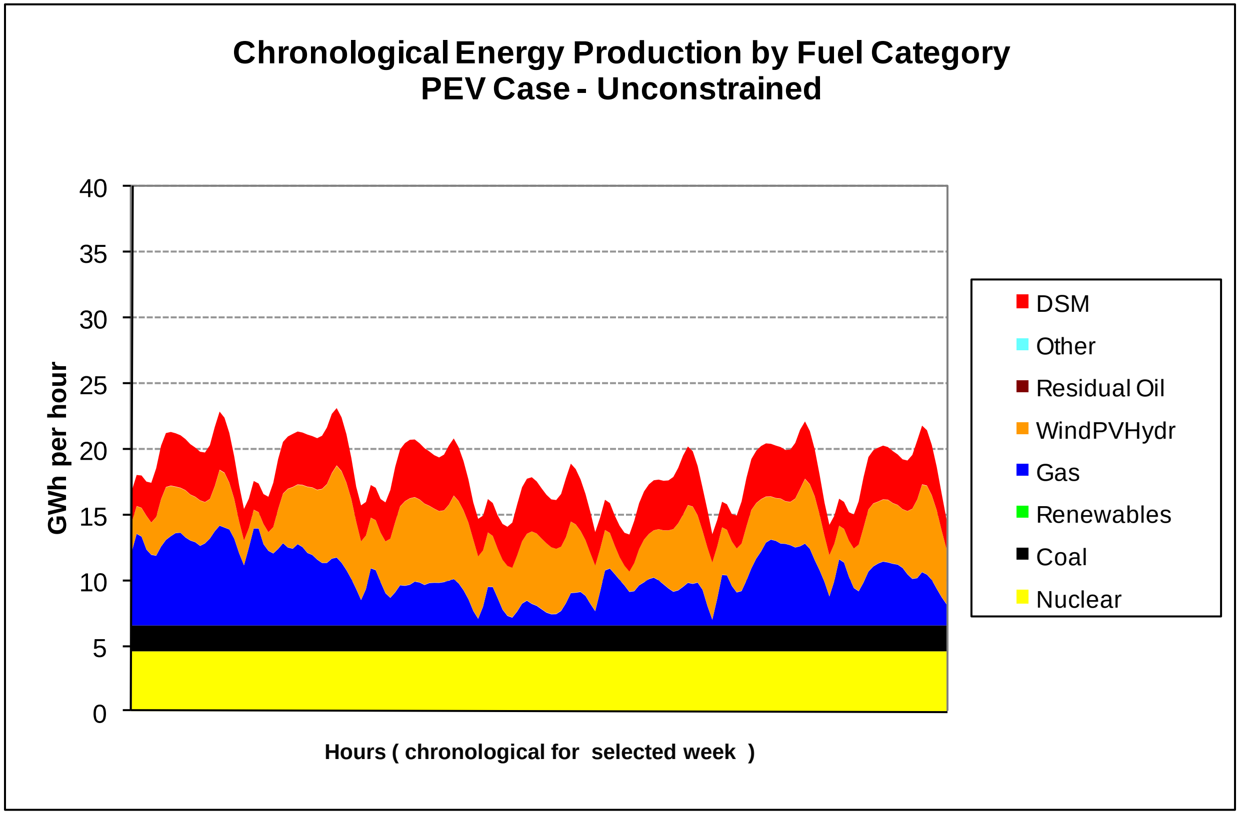
Week 11: Case 1



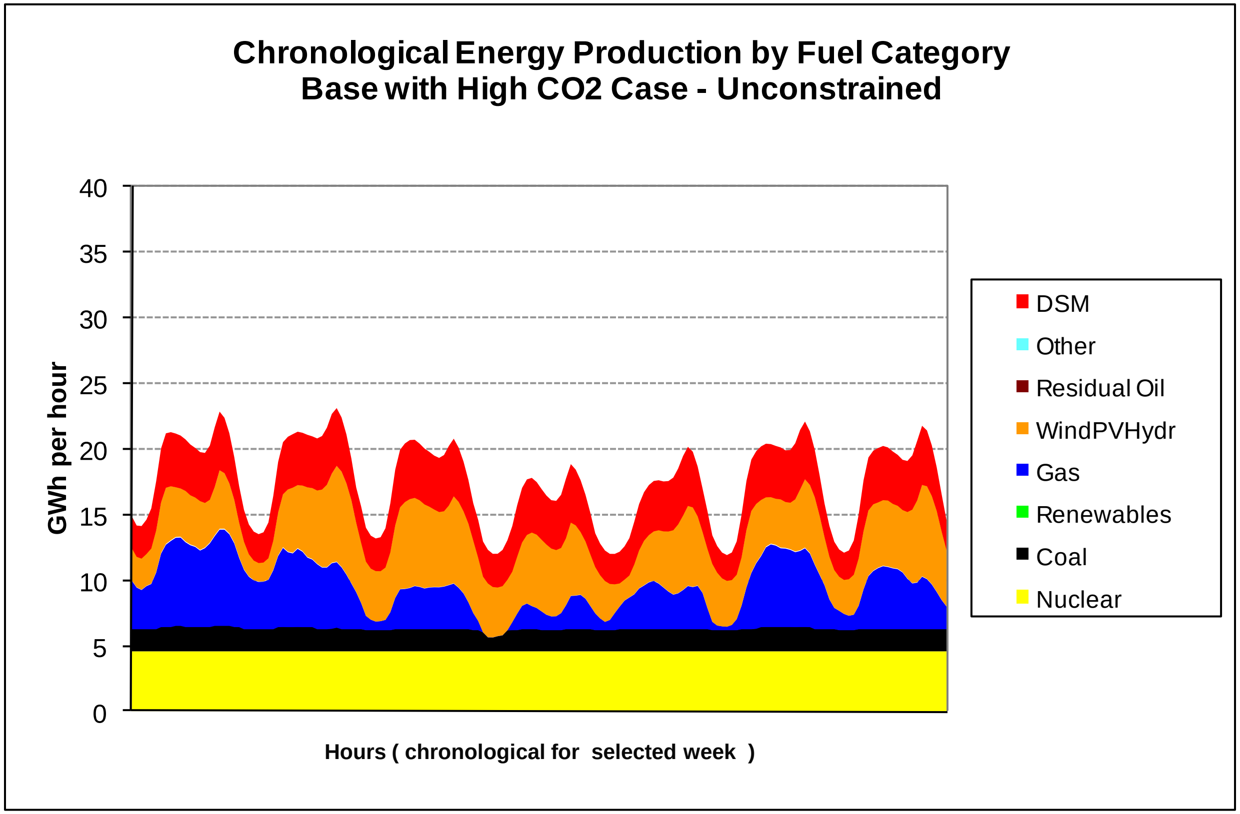
Week 11: Case 2



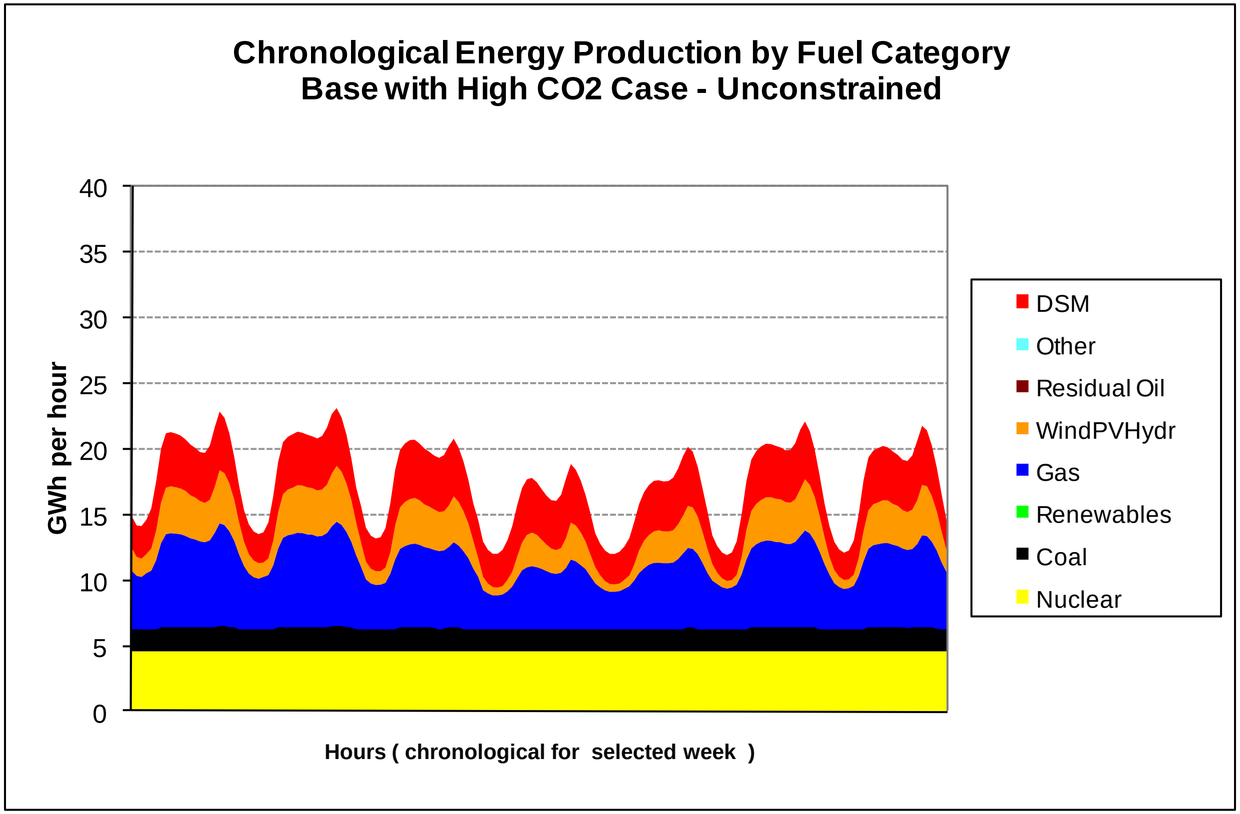
Week 11: Case 3



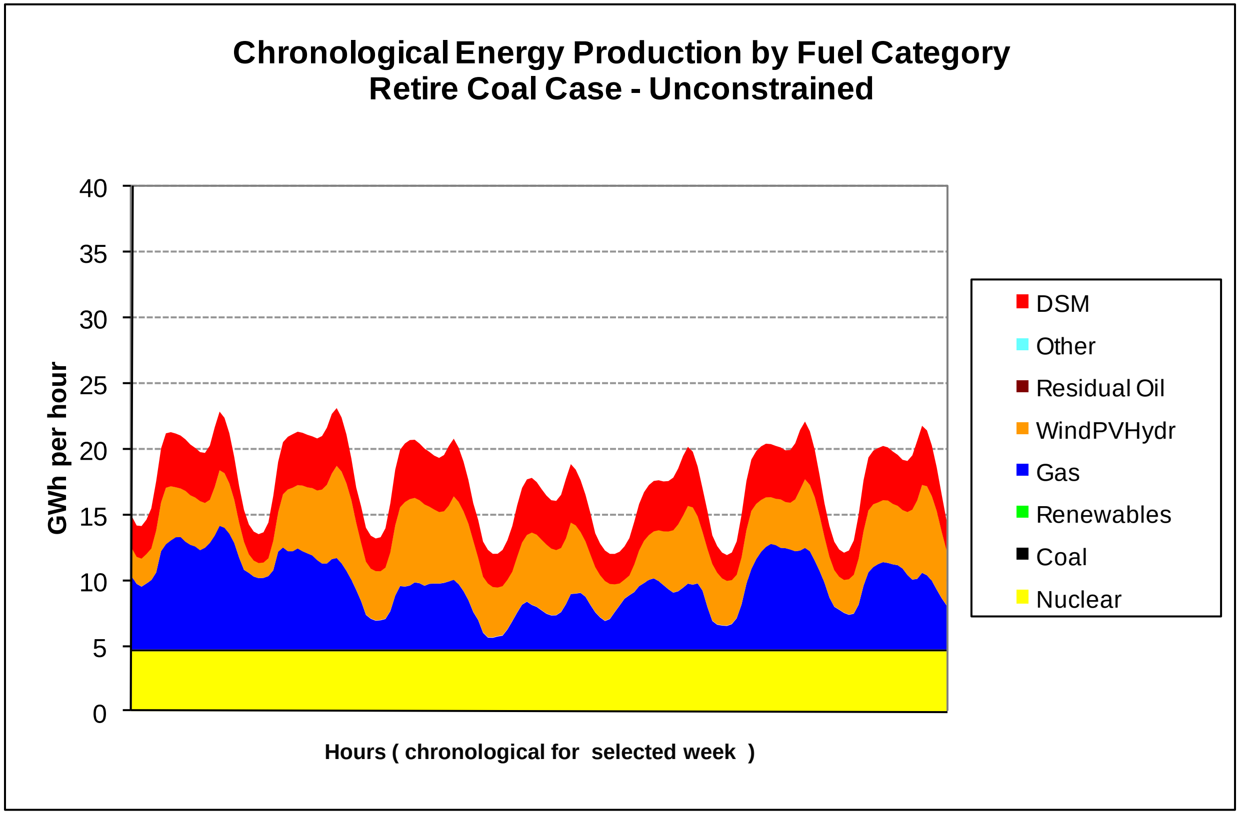
Week 11: Case 4



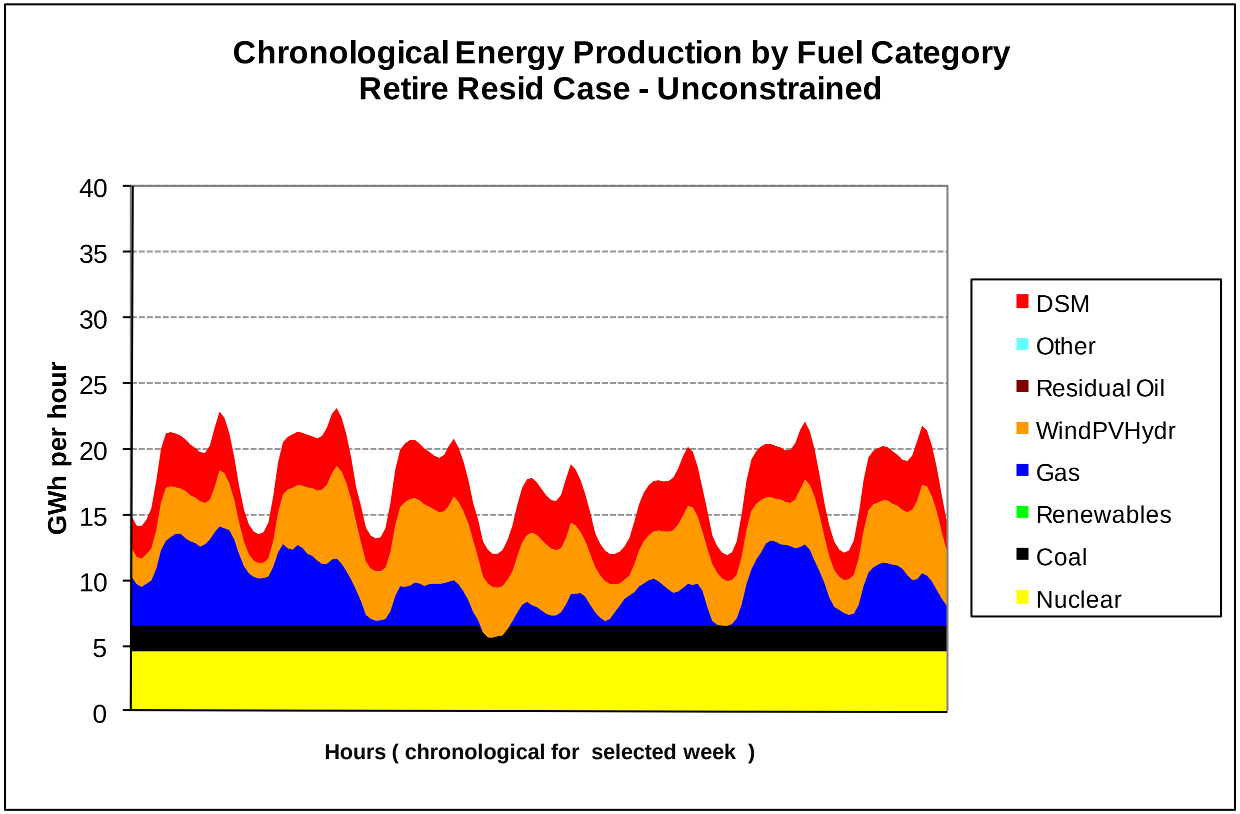
Week 11: Case 5



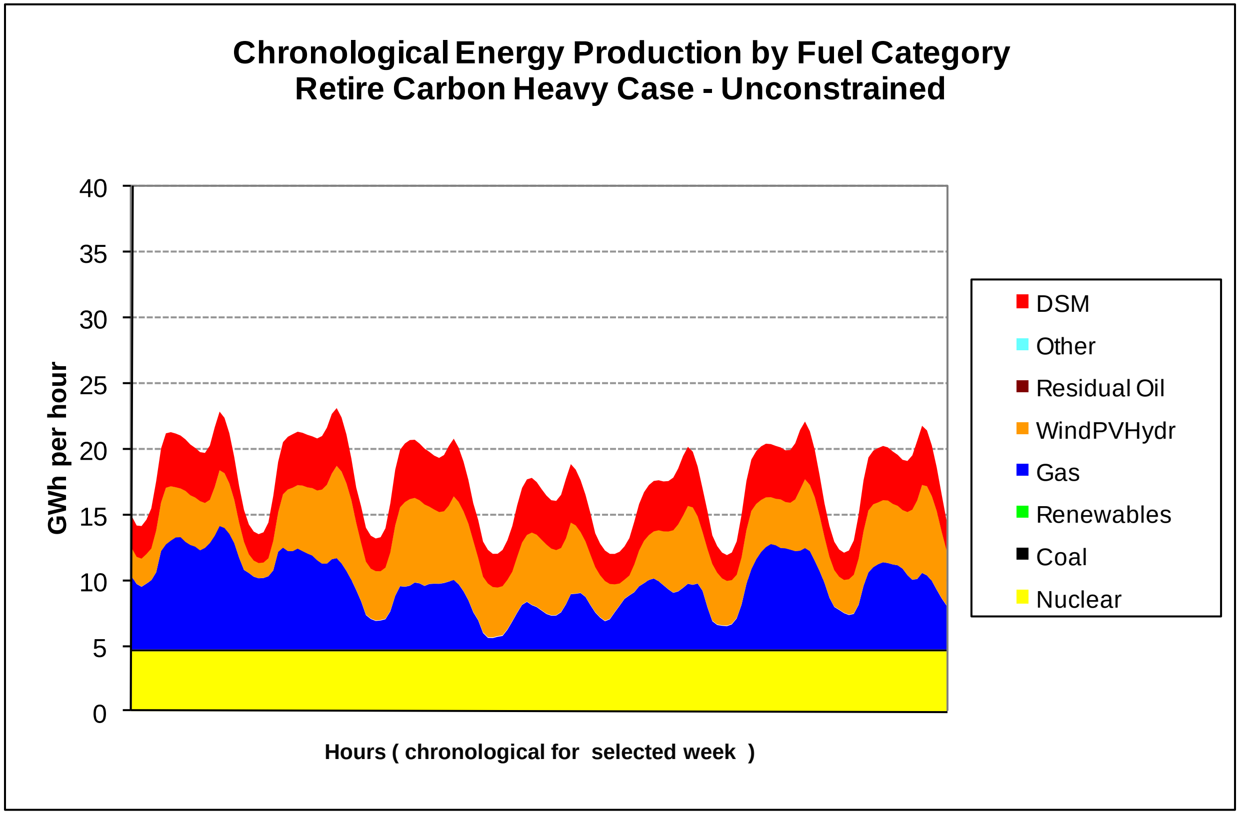
Week 11: Case 6



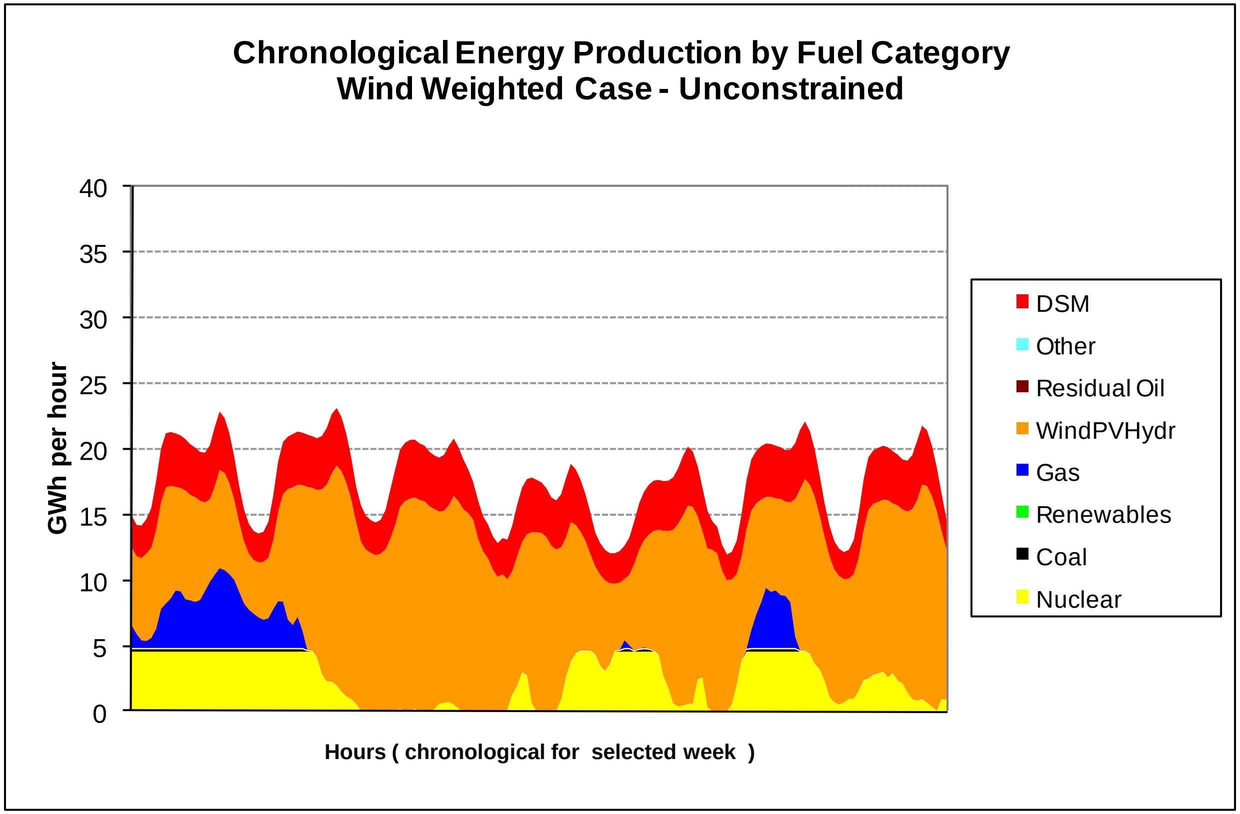
Week 11: Case 7



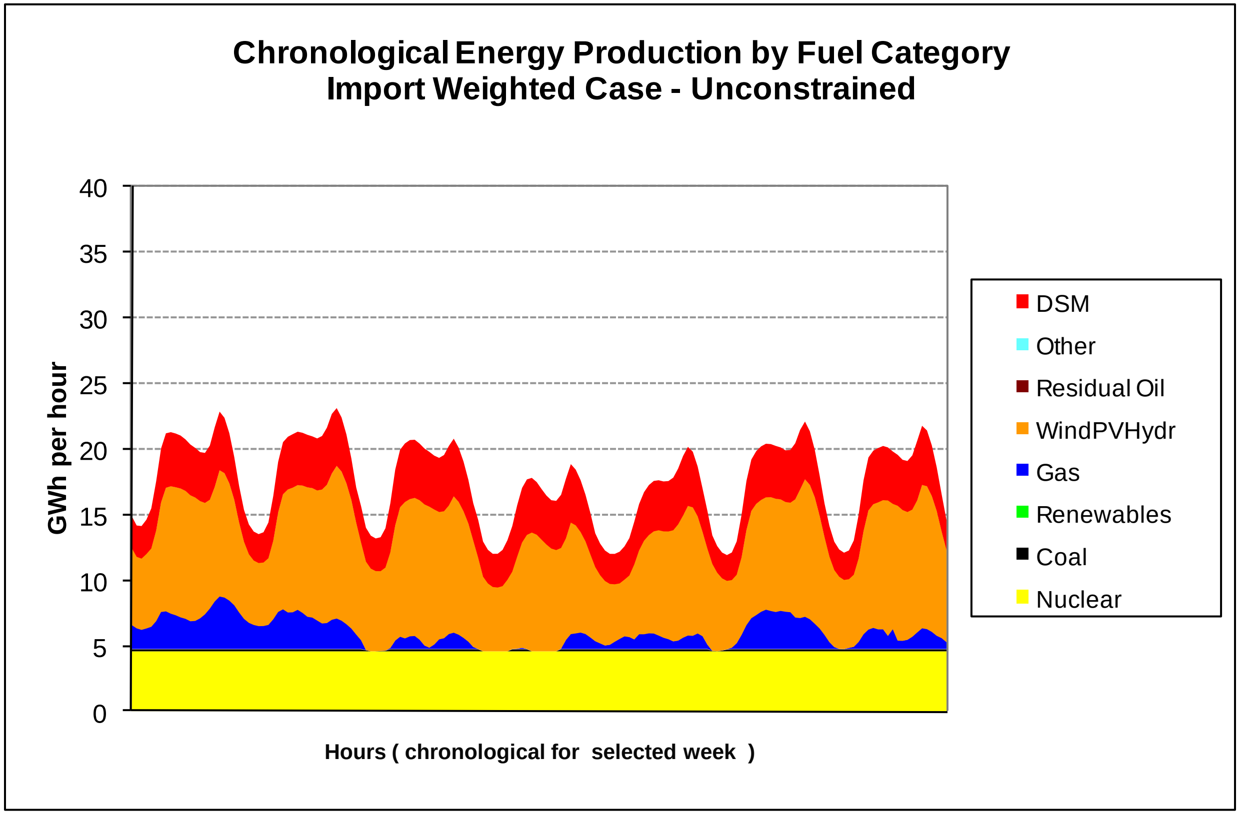
Week 11: Case 8



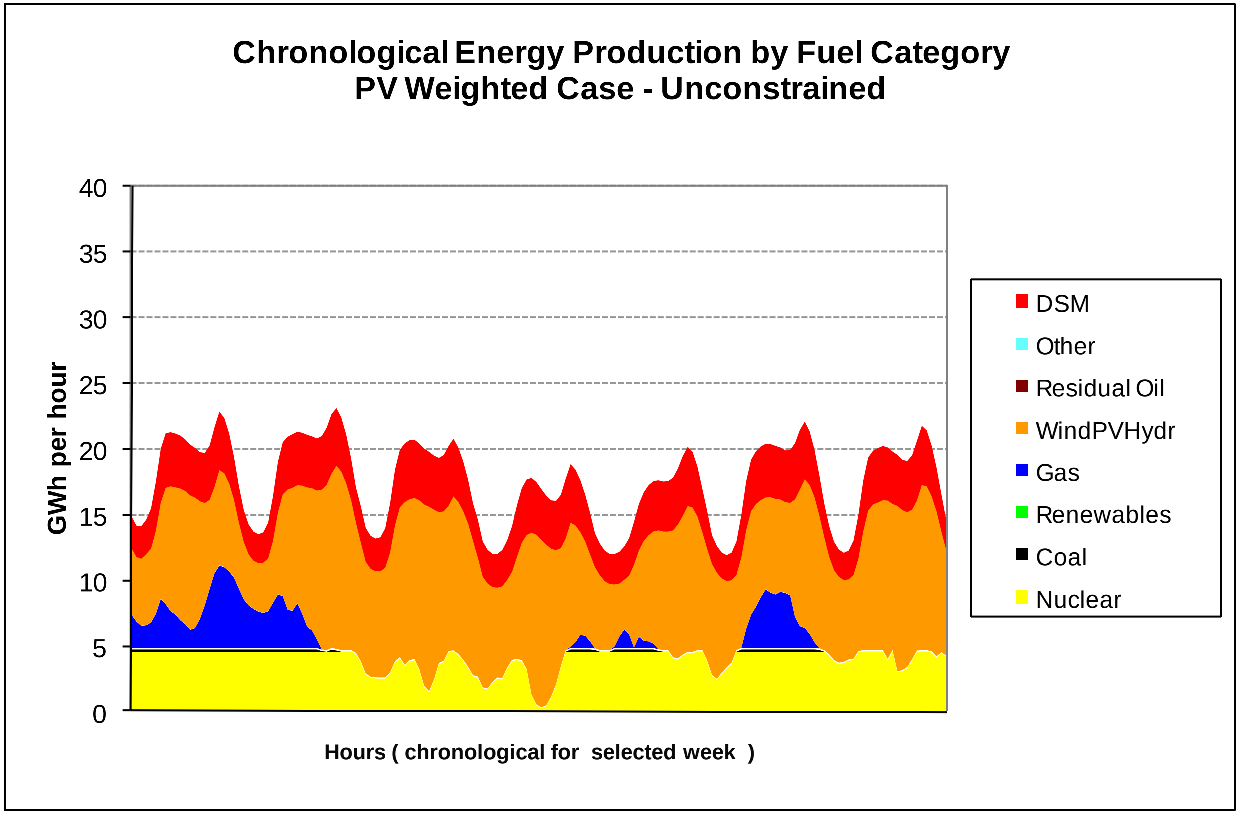
Week 11: Case 9



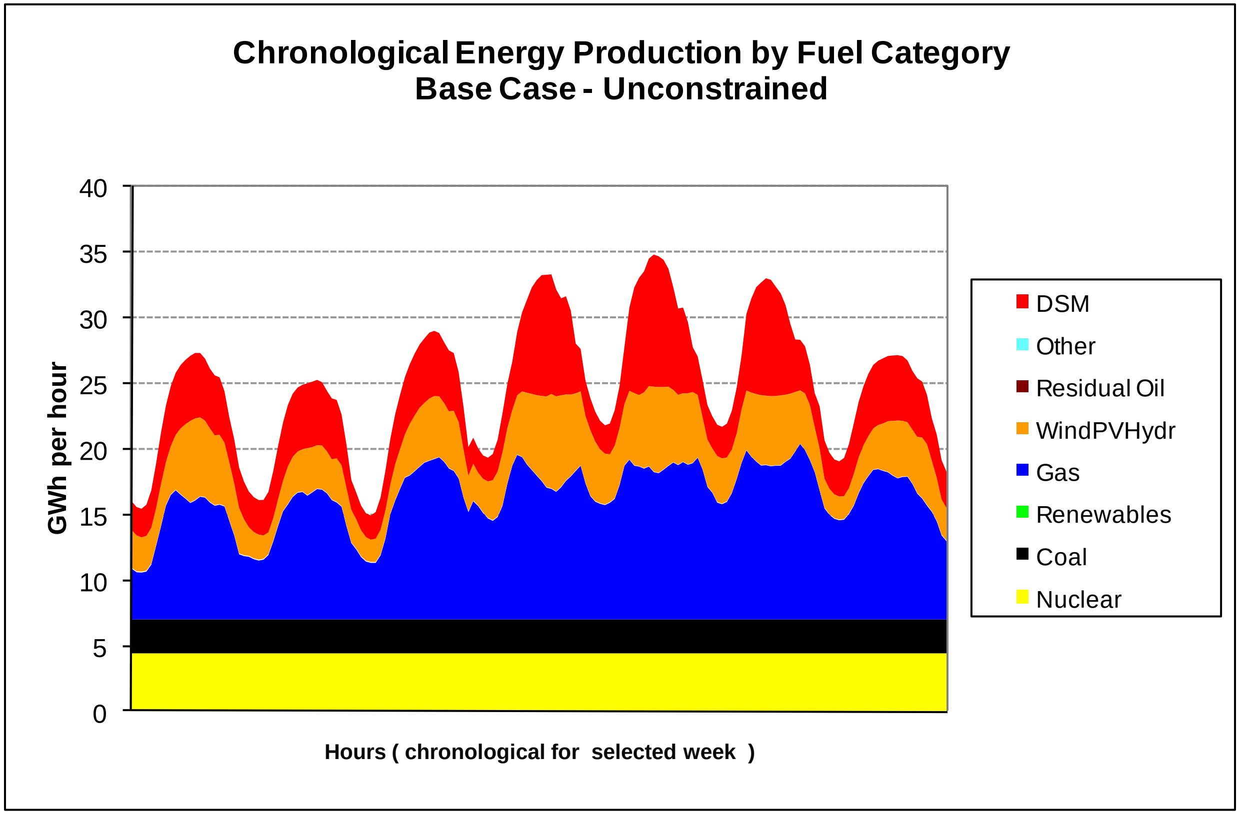
Week 11: Case 10



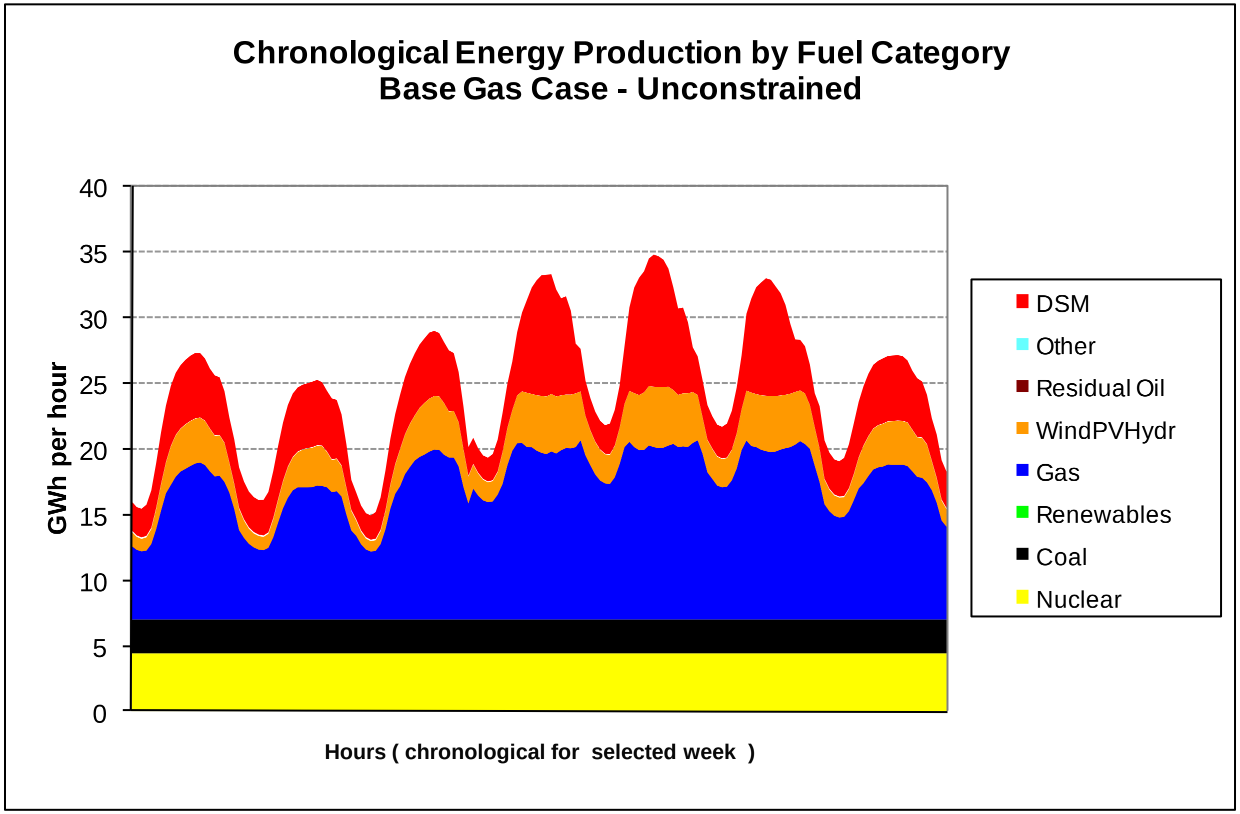
Week 11: Case 11



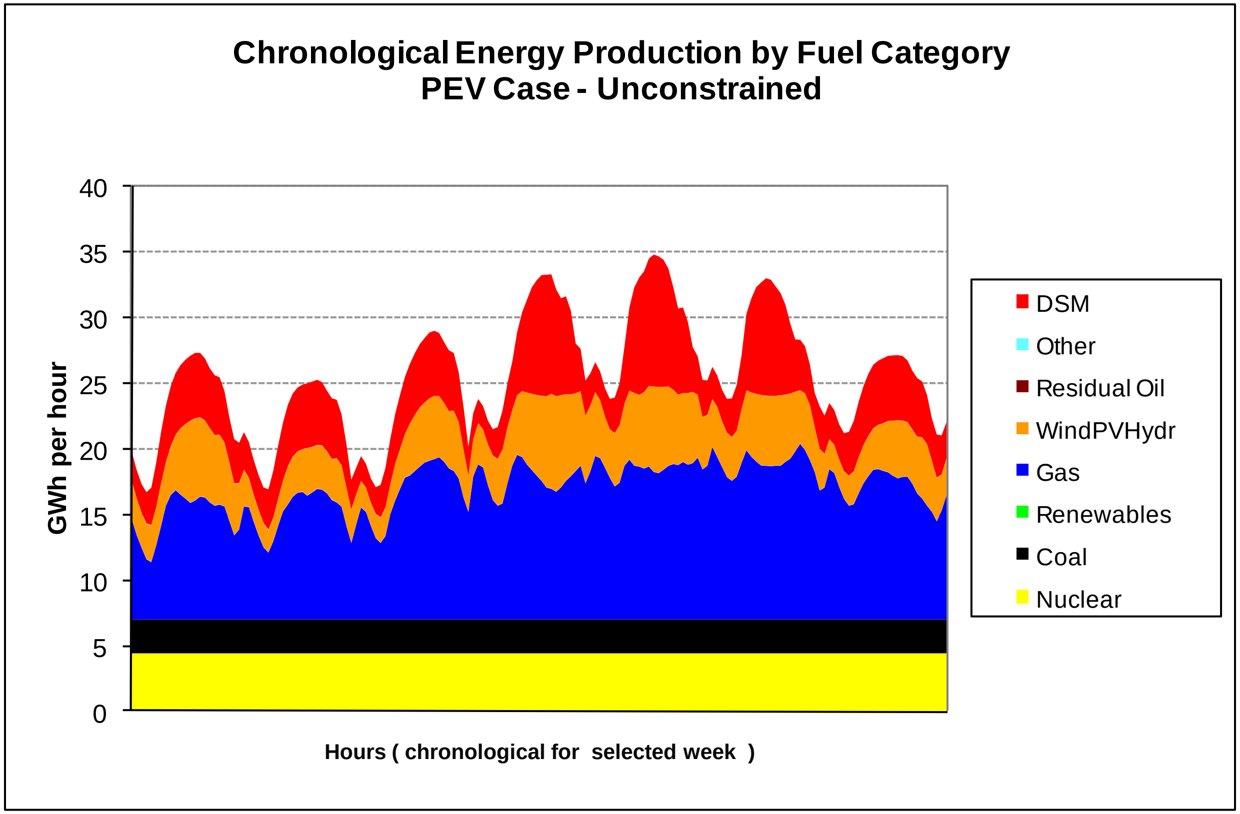
Peak Week: Case 1



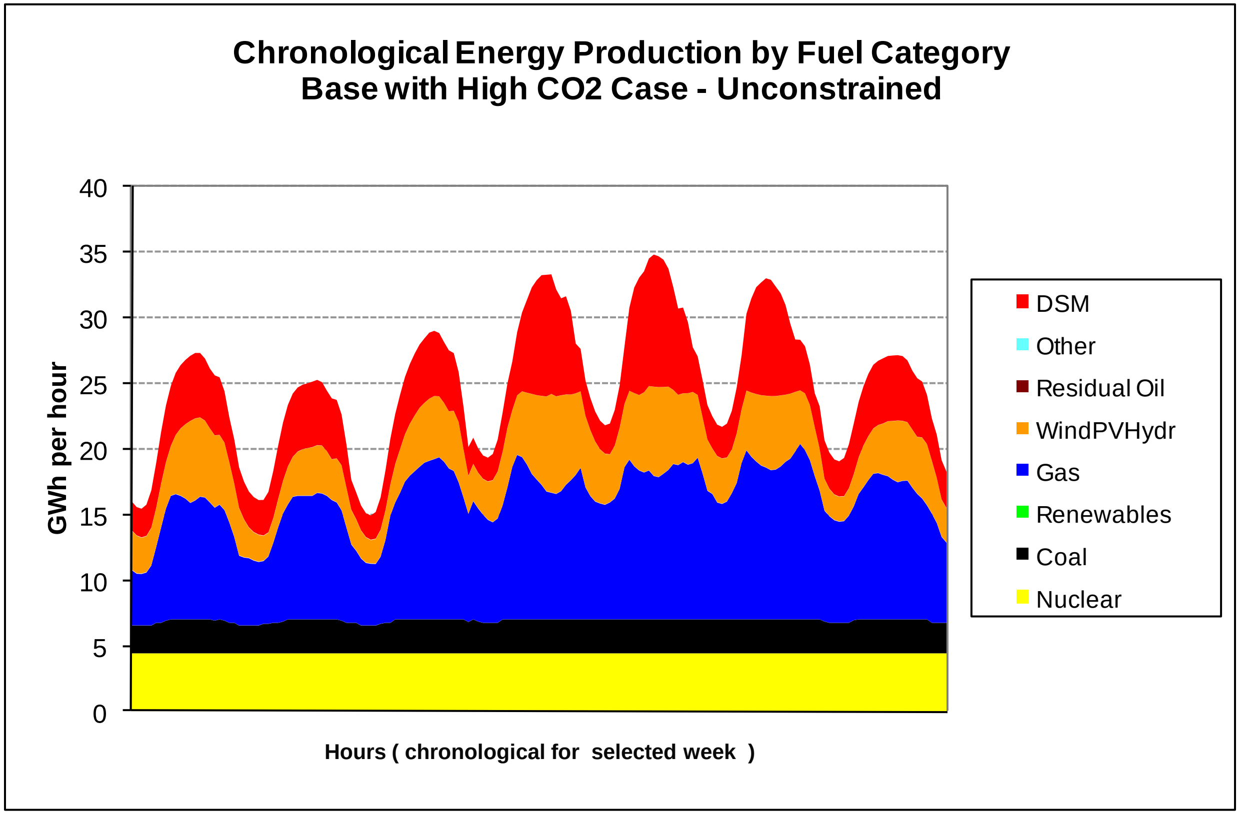
Peak Week: Case 2



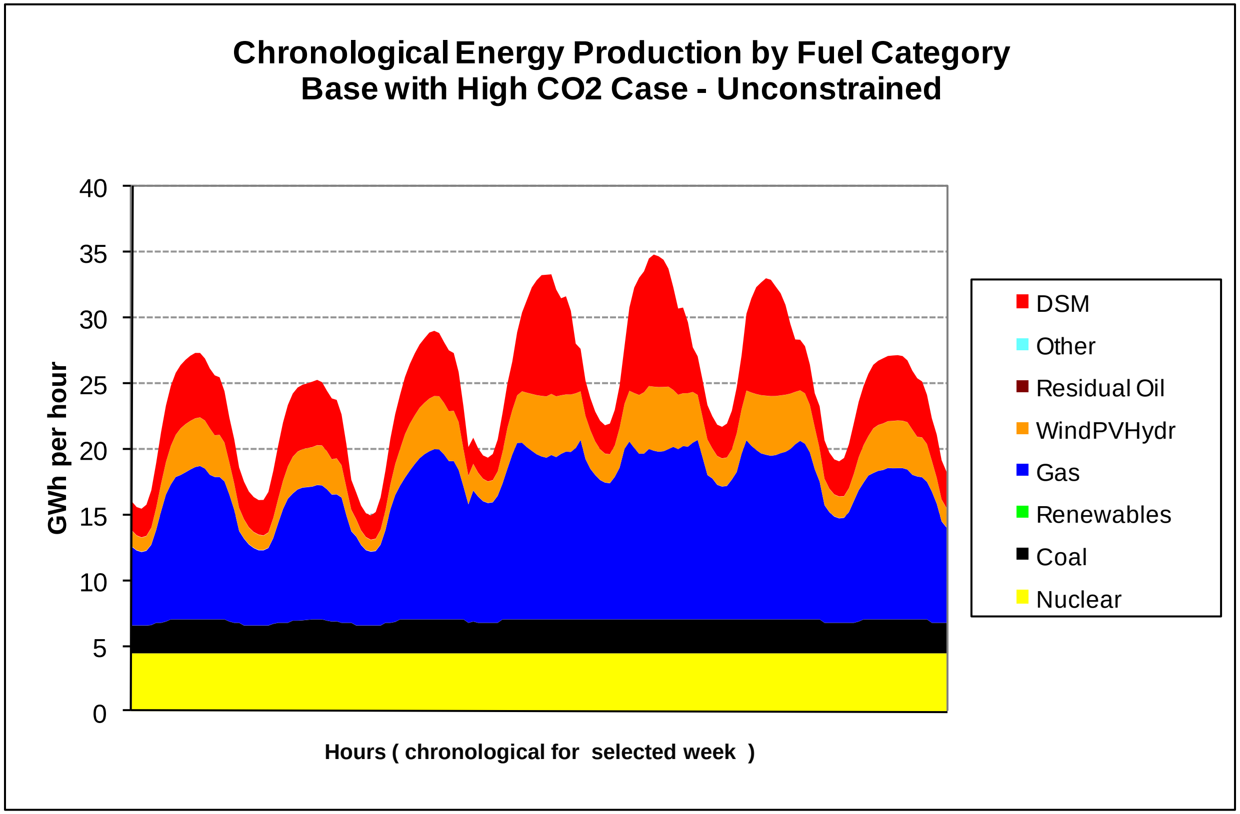
Peak Week: Case 3



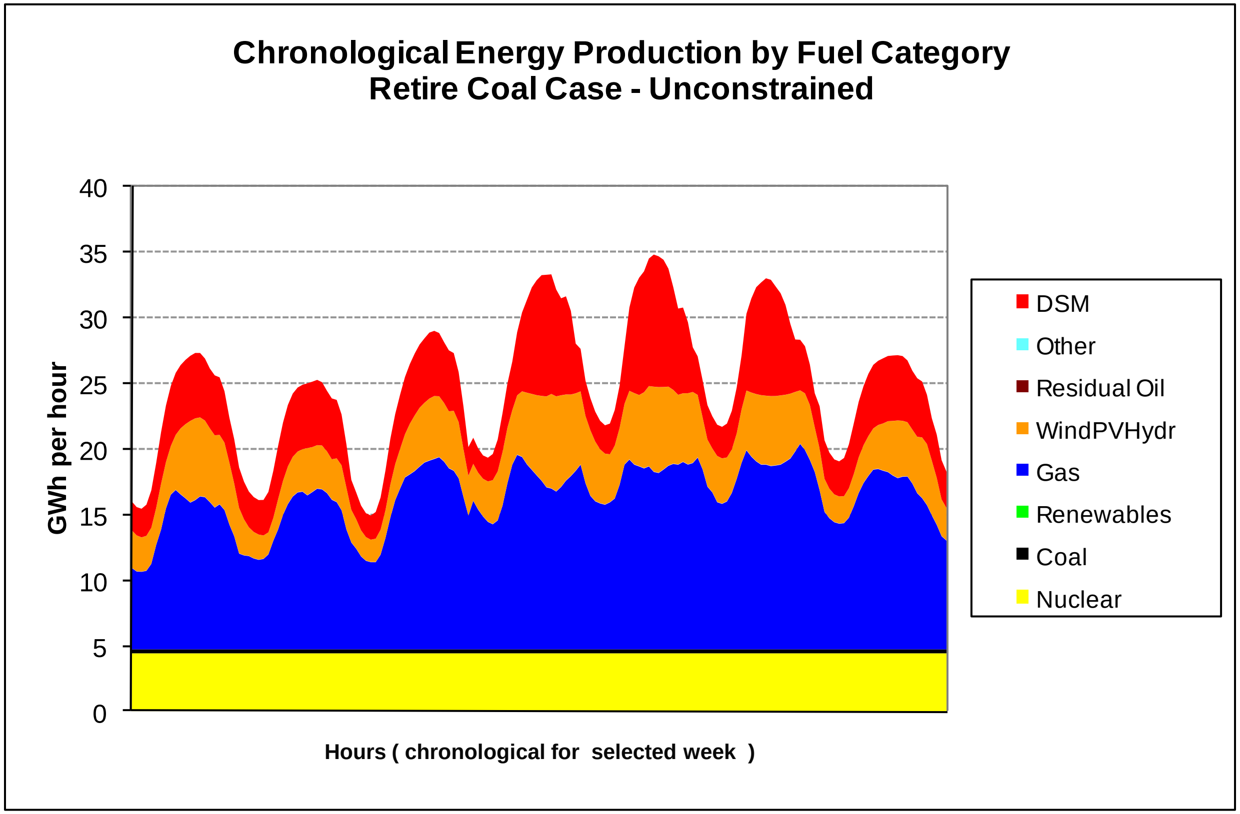
Peak Week: Case 4



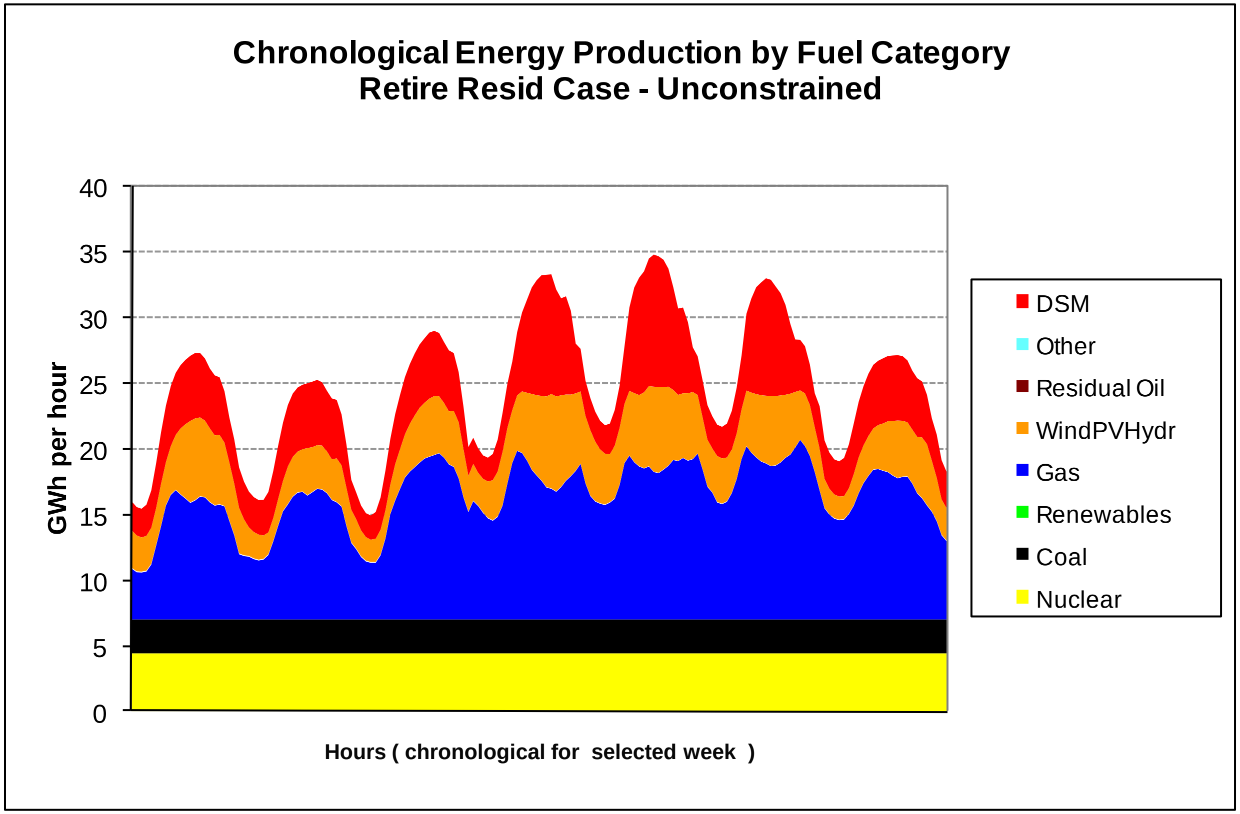
Peak Week: Case 5



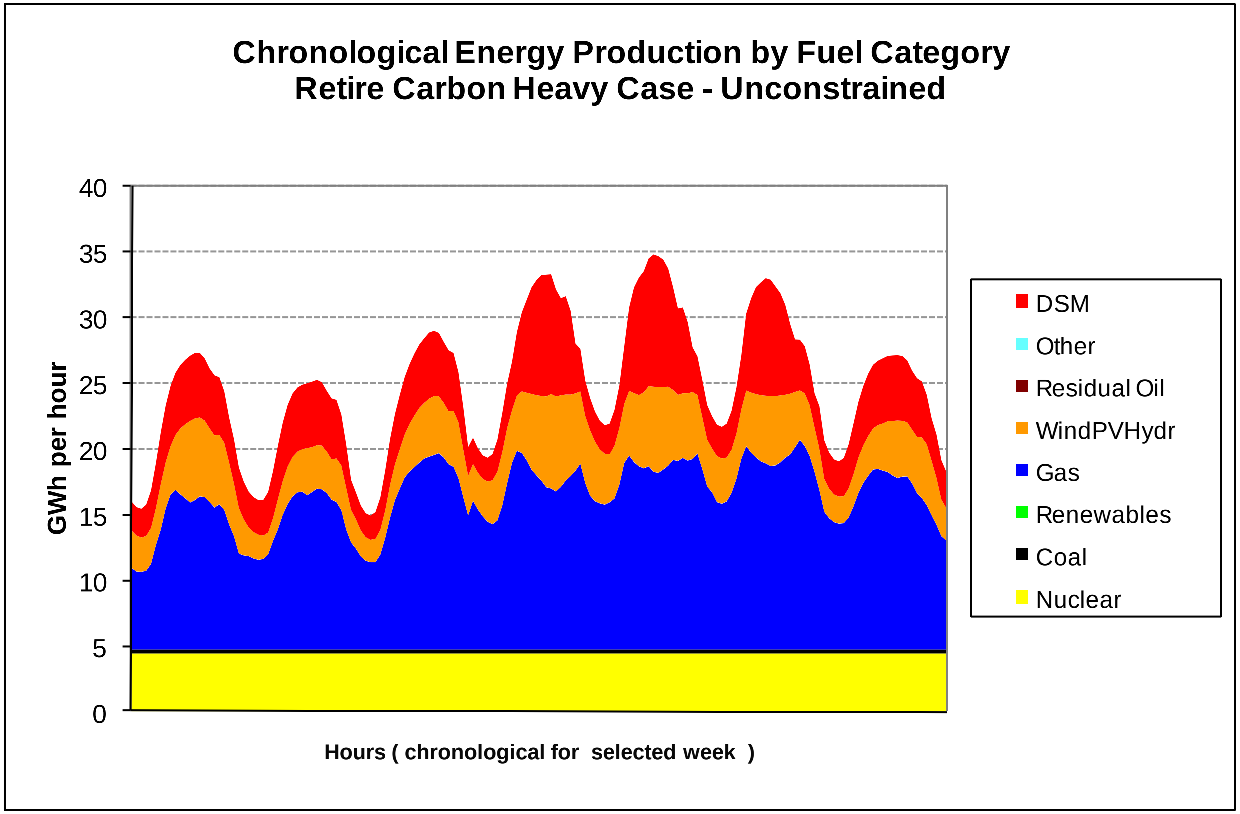
Peak Week: Case 6



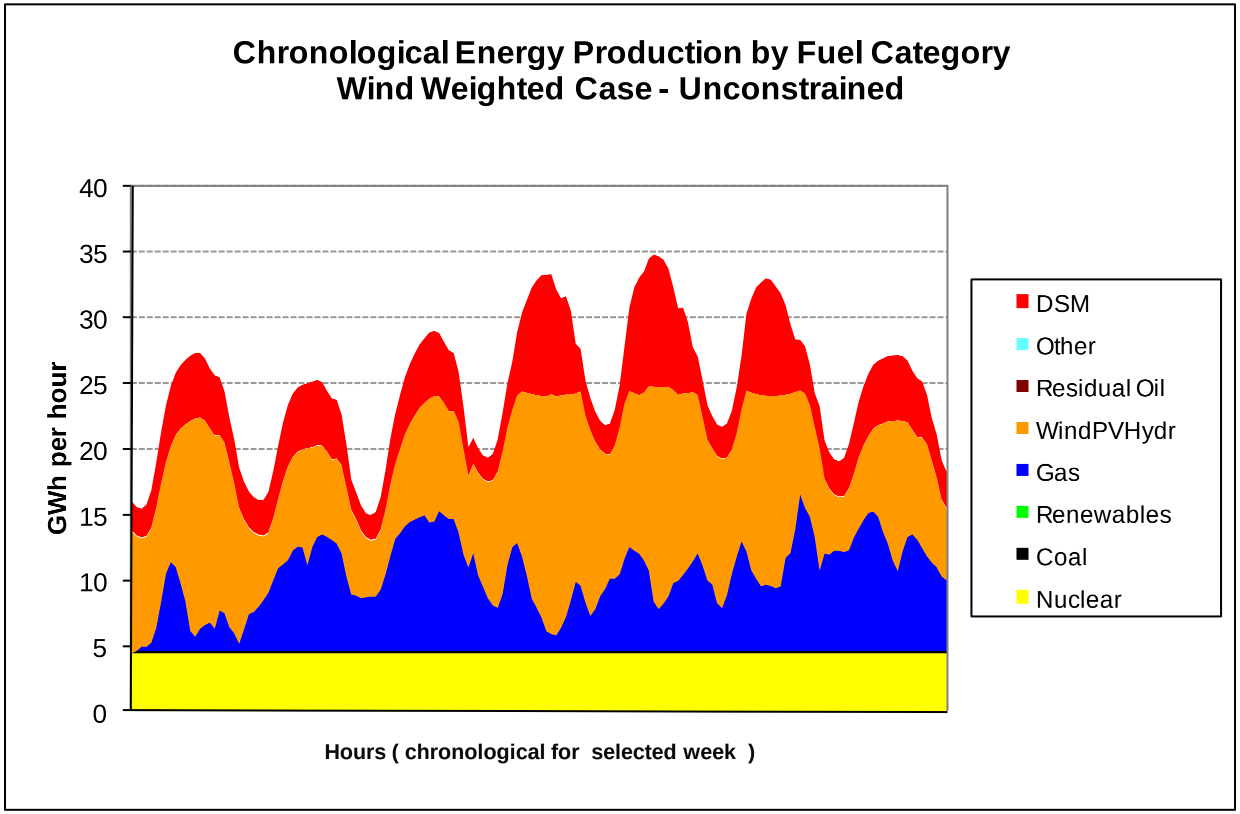
Peak Week: Case 7



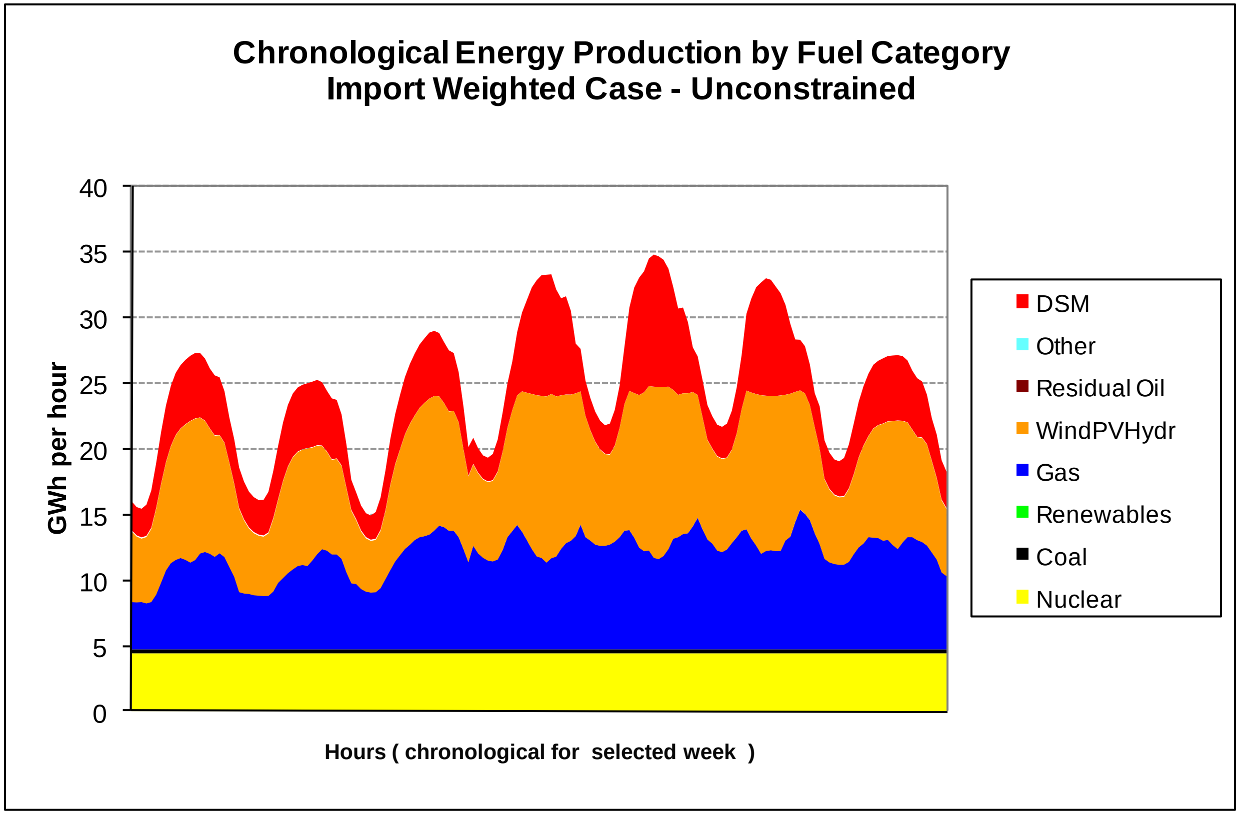
Peak Week: Case 8



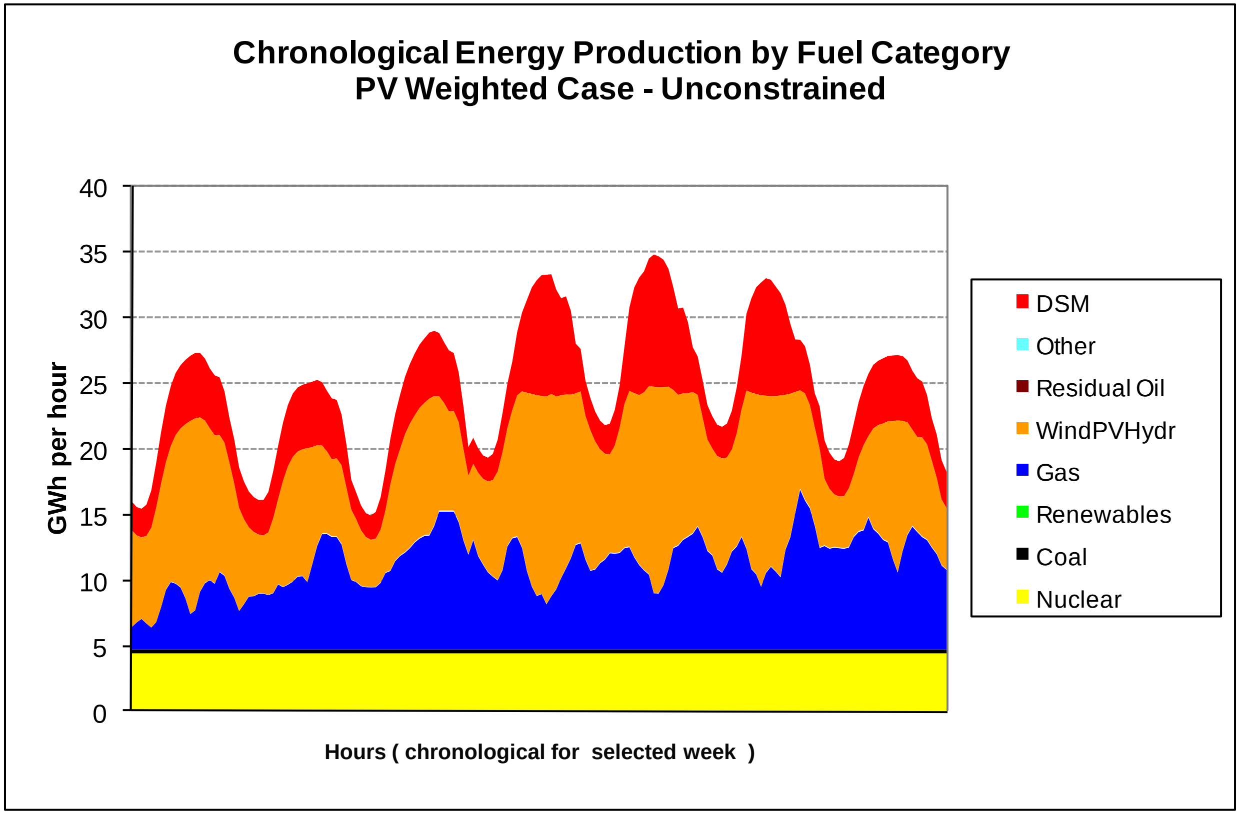
Peak Week: Case 9



Peak Week: Case 10



Peak Week: Case 11



Appendix 2: Assumptions Discussed Previously

Areas Modeled

RSP Areas	Area Name
BHE	Bangor Hydro
BOST	Boston
CMAN	Central Massachusetts
CT	Connecticut
ME	Central Maine
NH	New Hampshire
N-NH	Northern New Hampshire
NOR	Norwalk
RI	Rhode Island
SEMA	Southeastern Masachusetts
SME	Southern Maine
SWCT	Southwestern Connecticut
VT	Vermont
WMA	Western Massachusetts

Internal Areas	Area Name
DRCT	WESTERN DEMAND RESPONSE
EECT	WESTERN ENERGY EFFICIENCY
EGCT	WESTERN EMERGENCY GENERATION
DRMA	EASTERN DEMAND RESPONSE
EEMA	EASTERN ENERGY EFFICIENCY
EGMA	EASTERN EMERGENCY GENERATION

External Areas	Area Name
JCSP	JCSP INTERCONNECTION
HQHG	HQHG
HQP2	HQ PHASE II ECONOMIC MWH
HQP3	HQ PHASE III HYDRO OR ECONOMIC
XSND	CROSS SOUND CABLE
NY	NEW YORK
MARI	MARITIMES
MPS	MPS

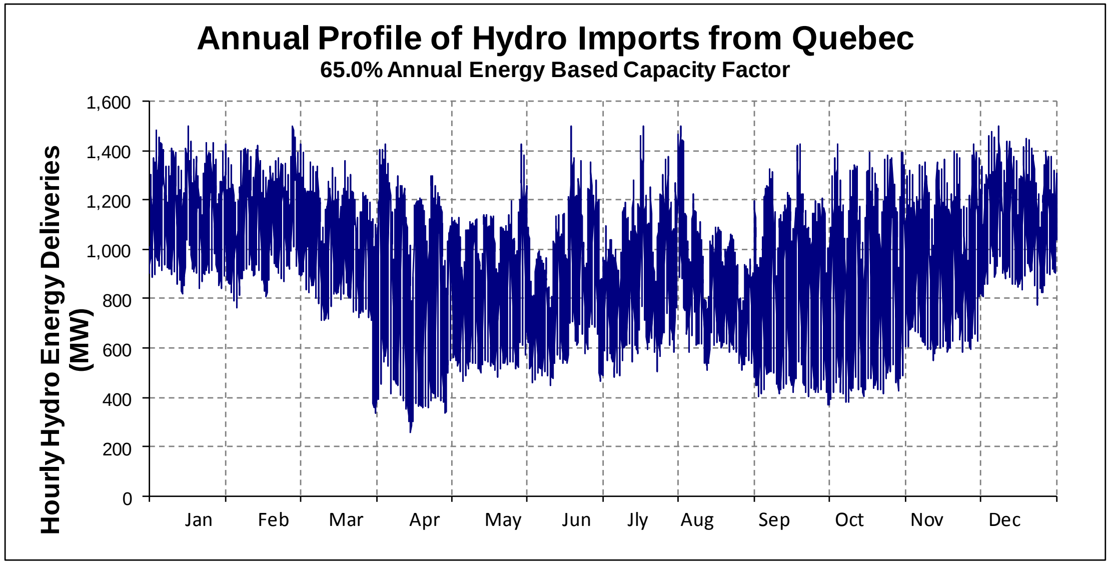
Additional Wind and DR Areas Modeled For Reporting

Modeling External Areas

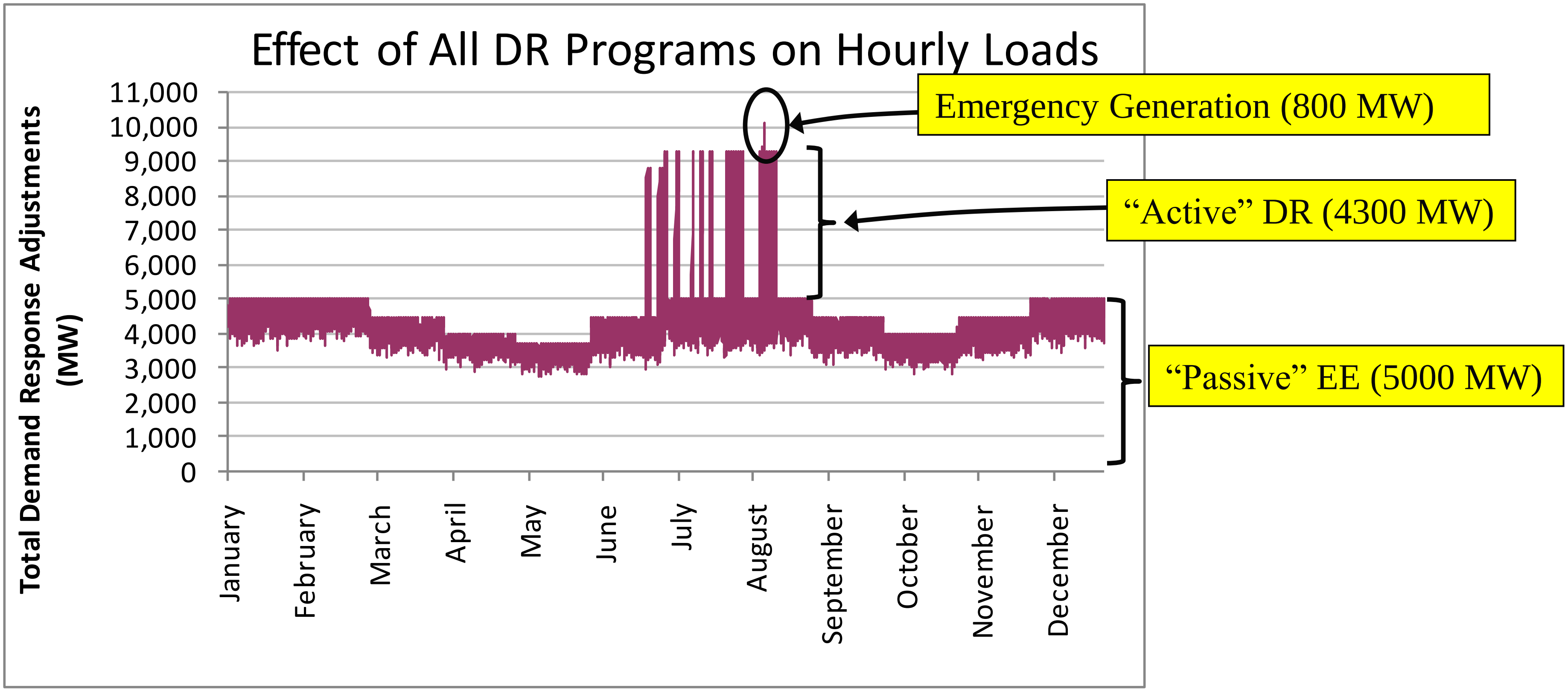
- Base Models for External Areas
  - No loads or resources modeled for New York, Maritimes, or Quebec
  - Existing Phase II modeled with economic opportunity blocks
    - Block 1: 300 MW at Natural Gas based on 8,400 Btu/kWh Combined Cycle (CC)
    - Block 2: 300 MW at Natural Gas based on 10,349 Btu/kWh Steam
    - Block 3: 300 MW at Distillate Fuel Oil based 12,593 Btu/kWh Combustion Turbine (CT)
  - Maritimes bubble has no loads or resources
    - Sensitivity case will investigate the effect of Maritimes
  - Maine Public Service (MPS) modeled using a BHE load shape
    - Connected via the Maritimes bubble
    - Limited number of resource
  - 100 MW Cross Sound Cable export assumed
  - NYPA purchases assumed to continue
  - Vermont Joint Owners (VJO) purchases assumed to continue

Canadian Hydro Imports

- Assumed 65.0% capacity factor
  - Consistent with 2007 Scenario Analysis
  - Peak-shaving bias for energy deliveries
  - 8.5 TWh of energy is comparable to Firm Energy Contract (7 TWh)
  - Several lines (~1,500 MW each) added to supplement other resources required for the retirement of carbon heavy resources



Energy Efficiency (EE) / Demand Resources (DR) / Real-Time Emergency Generation (RTEG) Load Modifiers (Base Case)

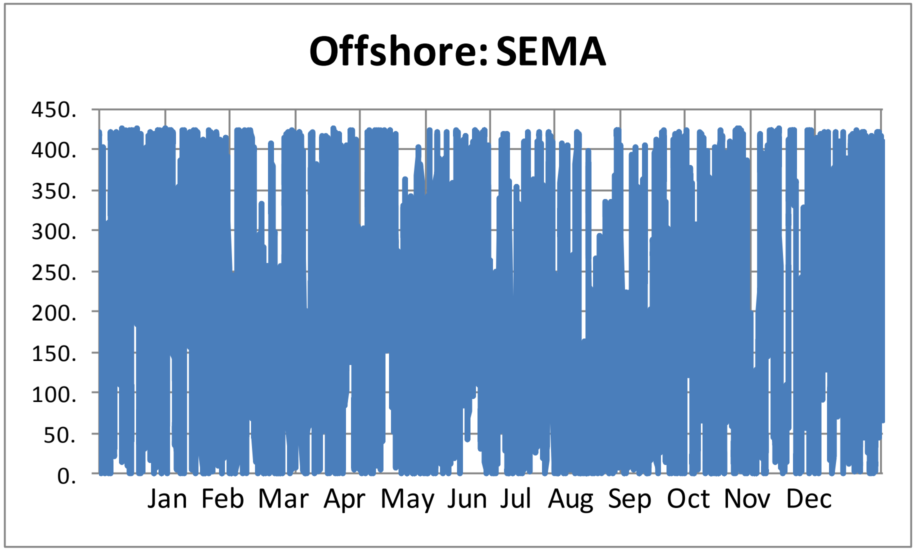


Wind Models

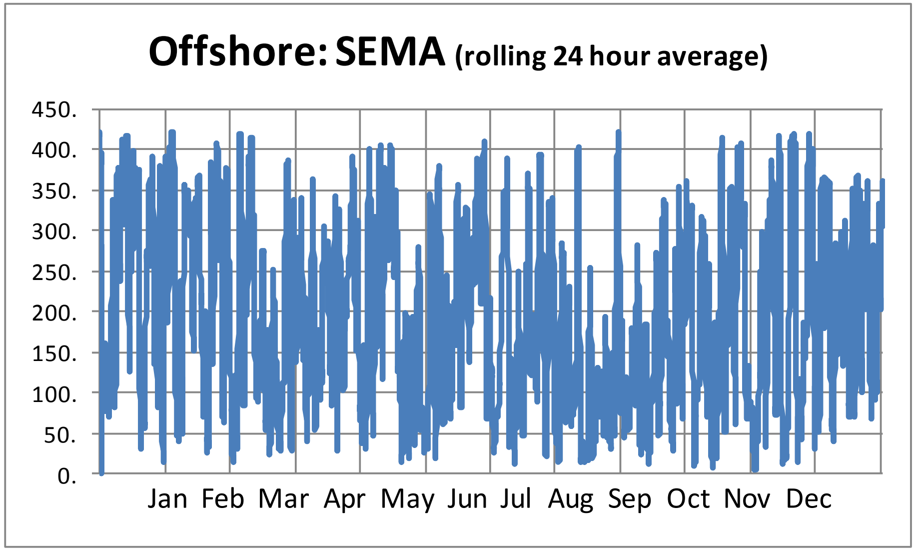
- Based on NEWIS
  - New England sites
  - Neighboring area sites
- Multiple wind models have been developed
  - Hourly granularity
  - Site specific (aggregated to an RSP bubble)
  - Correlated to meteorology present in the loads
  - Intention
    - Not intended to be estimates for specific project
    - Intended to be regional estimates

Wind Profiles Based on NEWIS Profiles

Hourly Profile (to be used in the simulations)



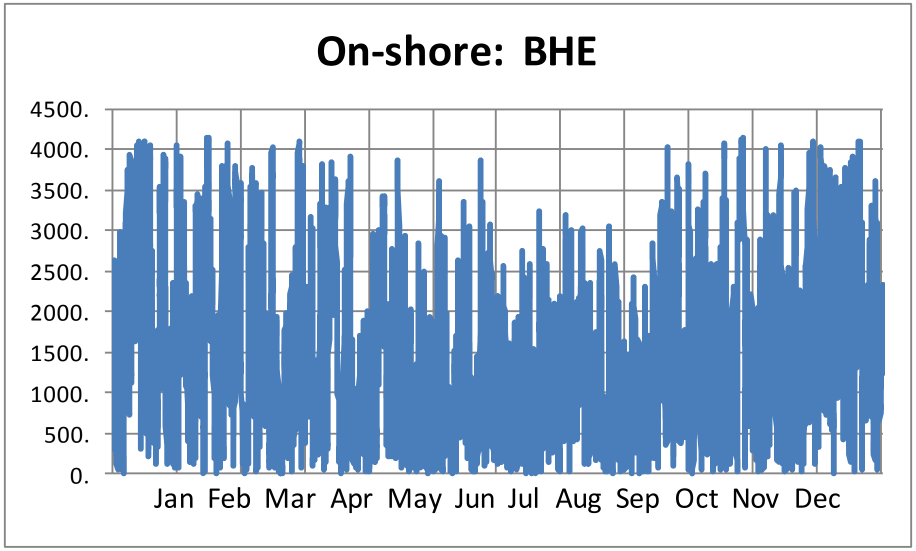
Smoothed Hourly Profile (conceptual visualization)



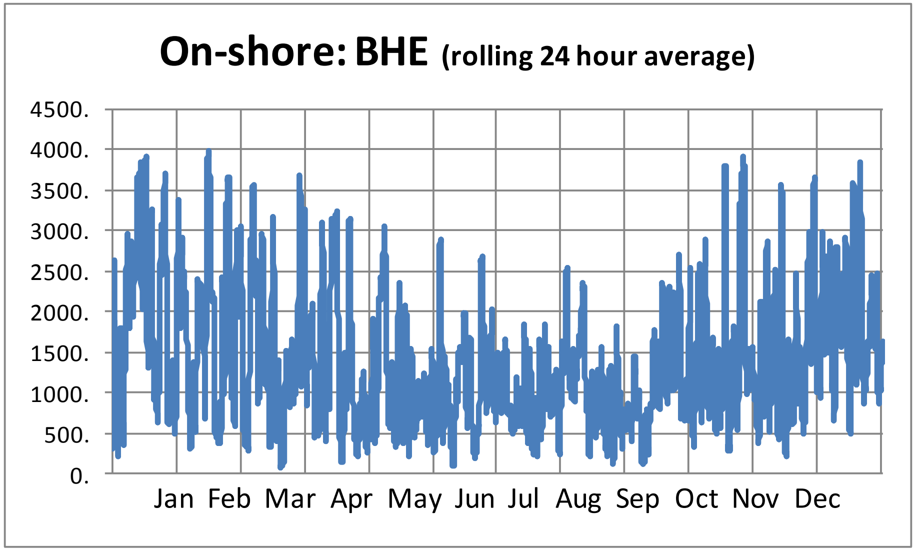
Offshore wind energy production: 42 percent capacity factor

Wind Profiles Based on NEWIS Profiles

Hourly Profile (to be used in the simulations)

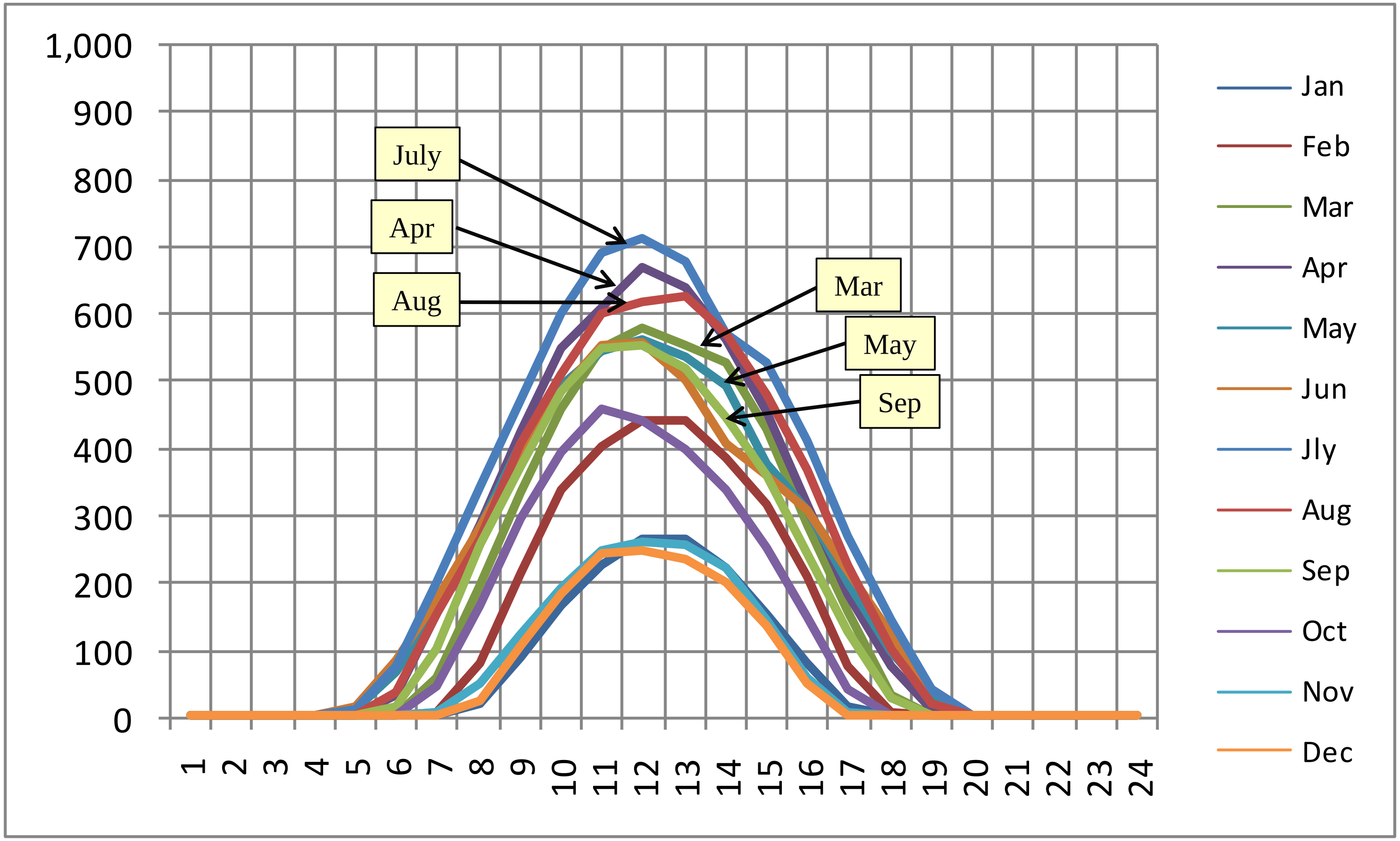


Smoothed Hourly Profile (conceptual visualization)

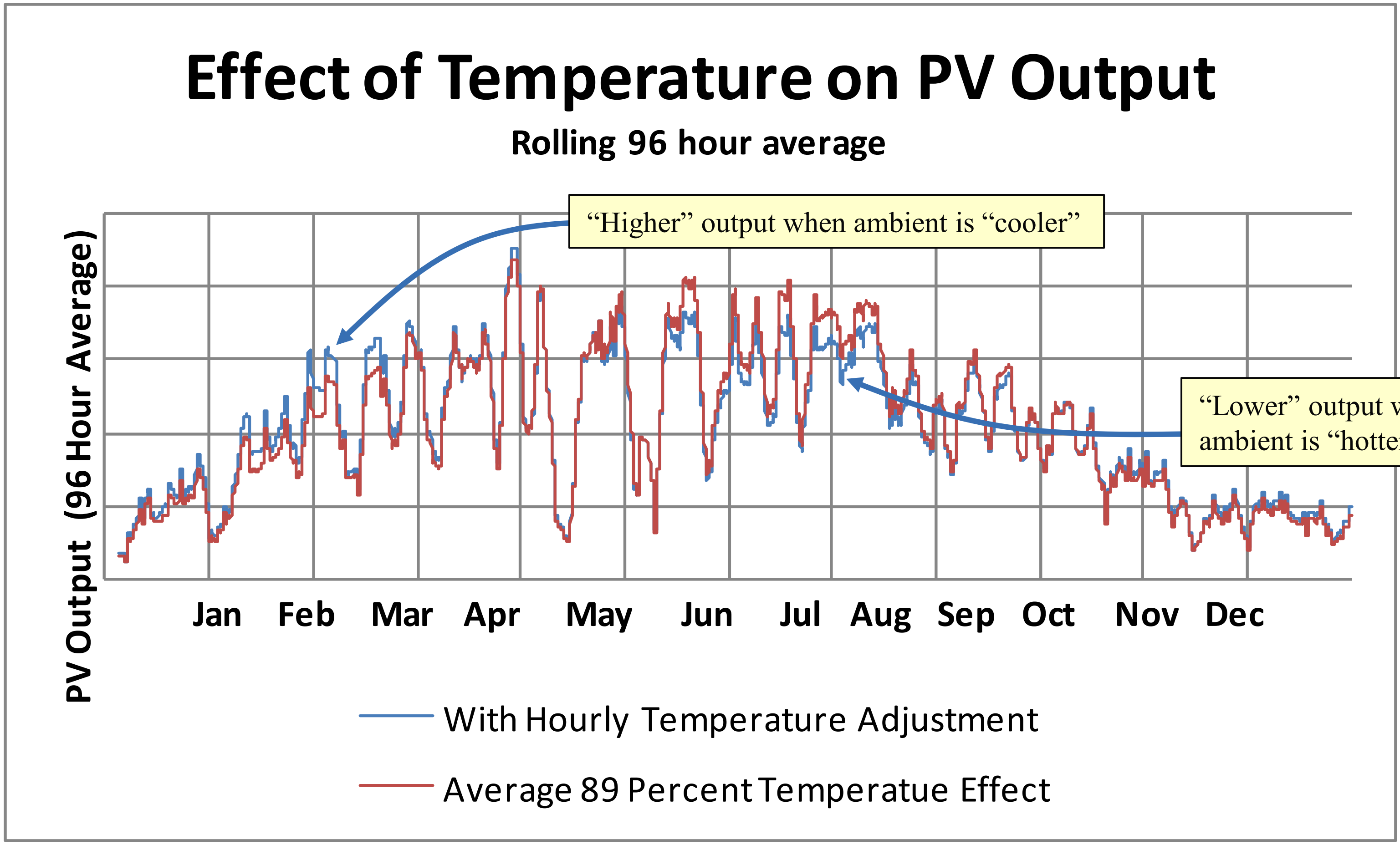


Onshore wind energy production: 34 percent capacity factor

Thompson Island Diurnal Monthly Insolation Profiles 2006

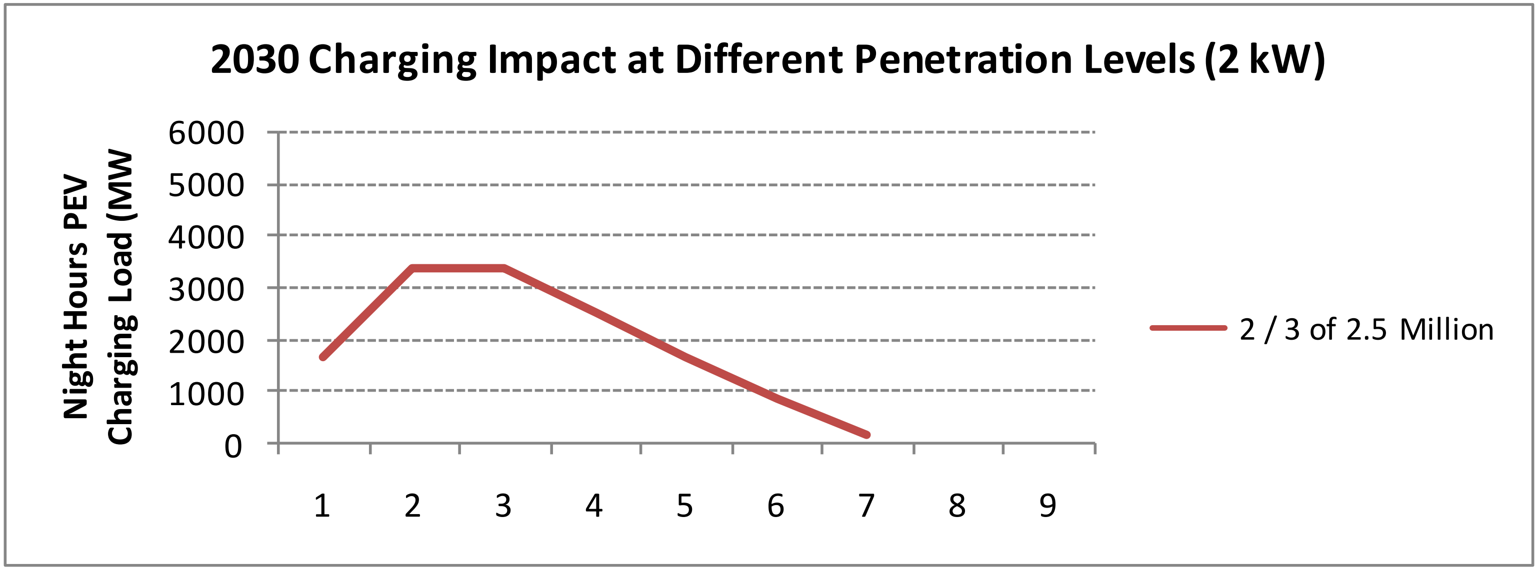


Higher Temperatures Derate PV Resources



Plug-in Electric Vehicles

- Sensitivity case assumes 1.8 Million Plug-in Electric Vehicles (PEVs) by 2030
  - Maximum charging of 3000 MW after midnight
  - Charging load diminishes to zero MW by 8 AM
  - No discharging energy from vehicles to grid assumed



Questions?