THE IMPACT OF EARLY COAL RETIREMENTS ON KEY POWER MARKETS

Prepared for:

National Mining Association
Washington, DC

May 2014

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OUTLINE

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PROBLEM STATEMENT

The winter of 2013-14 posed a large challenge to the power and natural gas markets. The U.S. had its 11th coldest winter in history, record high natural gas demand and average peak power prices that were more than double than what has been observed in the past 5-years. Additionally, the market witnessed record high gas storage withdrawals, and short term gas price spikes reaching as high as $135/MMBtu at some Northeast trading points.

Across the Eastern U.S there was simultaneously strong demand for electricity and natural gas to heat homes and businesses. Every bit of natural gas in storage and every electricity generation asset was needed to meet demand. However, there were gas supply constraints in particular areas and some generation assets were unable to perform as expected because of the frigid temperatures. Because of these situations, coal-fired assets were relied upon heavily to provide dependable electricity across the region.

EPA's Mercury and Air Toxics standards will force 26 gigawatts of coal capacity to exit the power markets between the latter half of 2014 and 2016. The majority of the these coal-fired retirements will occur in the regions where they were relied upon to provide electricity this past winter (New England, East North Central, Middle Atlantic, South Atlantic, East South Central).

If these coal-fired plants were not available during the winter of 2014, there would have been severe reliability issues within key electric power markets, because of the constraints in natural gas supply and power generation outages. Additionally, the seasonal spikes in regional natural gas prices that occur, would have been even greater than what was experienced this past winter, causing average peak electricity prices to surge more than 40 percent more than what was observed.

The purpose of this study is to examine the impact to the power and natural gas markets if the coal-fired assets that will retire in the 2014-2016 period had not been available for the winter of 2014. Additionally, if these coal-fired assets were not available during a hot summer, this study analyzes how the power and natural gas markets would be impacted.

OUTLINE

- Problem Statement
- Introduction
- Impact of Early Coal Retirements in Winter
- Impact of Early Coal Retirements in Summer
- Methodology
- Detailed Gas Analysis
- Detailed Power Analysis
- Appendix

INTRODUCTION

POWER MARKET RESERVE MARGIN SUMMARY PRE and POST COAL RETIREMENTS

Region	Base Capability	Demand	Base Reserve	Retiring Coal Capacity	Post Retire Reserve	Diff.
ISONE	32,631	26,505	23%	1,500	17%	-6%
NYISO	35,000	29,971	17%	75	17%	0%
PJM	180,000	160,000	13%	11,646	5%	-7%
SERC	175,053	135,666	29%	10,614	21%	-8%
FRCC	50,000	43,288	16%	0	16%	0%
MISO	103,945	87,578	19%	4,700	13%	-5%
ERCOT	78,000	67,000	16%	0	16%	0%
SPP	56,326	36,729	53%	1,970	48%	-5%
CAISO	55,000	46,000	20%	101	19%	0%

- EVA identified the power markets having the greatest power reliability risk from the retiring coal units from the change in their reserve margins and fuel delivery constraints.

- Reliability assessment to focus on PJM, MISO and ISO-NE.
  - PJM, because it has the most coal-fired retirements and its reserve margin dropping to only 5%-- well below the 15% target
  - MISO because it has a large amount of coal retirements and reserve margin falls bellow its 15% target
  - ISO-NE because the region is at risk for reliability during periods of constrained gas supply. At critical junctures, only 3,500 MW of ISO-NE’s 18,000 MW gas-fired capacity was available this winter because of gas constraints.

- The coal retirements also have an impact on SERC’s and SPP’s reserve margins, but even after the retirements, these regions have sufficient surplus capacity remaining to remain above reserve margin targets

INTRODUCTION

- In order to systematically and correctly evaluate the issues laid out in the problem statement, EVA designed three sets of scenarios for both the winter and summer reliability assessment (see table below)
- For each scenario, EVA analyzed the PJM, MISO and ISO-NE power markets
- For the ISO-NE winter scenarios, EVA modified its business process from the other two power markets. EVA selectively restricted gas-fired generation assets in ISO-NE that are connected to the Algonquin pipeline, as they were unable to operate during the 2014 winter because of constrained gas supply.

REVIEW OF SCENARIOS PERFORMED	
Winter Assessment	
Base Case - Wint.	Re-Simulation of natural gas and power markets in Winter 2014 (Jan-Feb)
Case #1	Base Case - Wint. *minus* 2014 to 2015 MATS related coal retirements
Case #2	Base Case - Wint. *minus* 2014 to 2016 MATS related coal retirements
Summer Assessment	
Base Case - Sum.	Simulation of natural gas and power markets for extreme summer weather in 2014 (June- Aug)
Case #3	Base Case Sum. minus 2014 to 2015 MATS related coal retirements
Case #4	Base Case Sum. minus 2014 to 2016 MATS related coal retirements

OUTLINE

IMPACT OF COAL RETIREMENTS ON SYSTEM RELIABILITY - WINTER

PJM

- During this past winter, record high electricity demand and generation outages led to several instances in which PJM was low on resources and narrowly avoided load shedding to maintain system reliability
- If the coal plants scheduled to be retired from 2014 to 2016 were not available in PJM during the winter of 2014, there would have been 34 hours where the reserve margin was less than 5% and 4 hours where there would have been a negative reserve margin (insufficient supply) and would have forced power curtailments

NUMBER OF HOURS IN JANUARY 2014 BELOW KEY RESERVE MARGIN LEVELS

		Reserve Margin		
		<10%	<5%	<0%
ISO-NE	Base Case	2	0	0
	2014-15 Retirement	30	16	16
	2014-16 Retirement	30	16	16
PJM	Base Case	16	0	0
	2014-15 Retirement	57	31	3
	2014-16 Retirement	55	34	4
MISO	Base Case	0	0	0
	2014-15 Retirement	1	0	0
	2014-16 Retirement	2	0	0

MISO

- In MISO, despite record high demand due to sustained cold weather, the reserve margin did not become precariously tight
- Under EVA's scenario analysis, no real reliability issues were predicted if the retiring coal plants were not available during the winter of 2014. EVA only estimated 2 hours where there would have been a reserve margin between 5% and 10%

ISO-NE

- In ISO-NE, select gas-fired generators were unable to perform as expected as natural gas pipeline capacity in the Northeast was constrained.
- The reserve margin for ISO-NE would have been negative for 16 hours in January 2014 (without the coal capacity that is expected to retire over the next two years) and would have forced power curtailments.

IMPACT OF COAL RETIREMENTS ON WINTER POWER PRICES (JANUARY-FEBRUARY 2014)

- In addition to threatening system reliability, early coal retirements drove higher wholesale power prices in all three markets, though the impact in PJM in ISO-NE was greater
- The table to right illustrates what the average wholesale power price would have potentially been in January-February 2014, if the coal plants scheduled to retired would not have been available.
- PJM wholesale prices would have been 40% greater without the coal plants, while ISO-NE wholesale prices 50% greater.
- The detailed power analysis section of this report will provide more color on how the power prices would have been effected in the absence of the coal plants

AVG. WHOLESALE POWER PRICE FOR EACH WINTER SCENARIO ($/MWh)

	Base Case	2014-15 Retirements	2014-16 Retirements
ISO-NE	$120	$180	$180
PJM	$102	$143	$145
MISO	$41	$58	$60

IMPACT OF COAL RETIREMENTS ON WINTER POWER PRICES – JANUARY 2014

AVERAGE MONTHLY POWER PRICES – MAJOR U.S. MARKET REGIONS

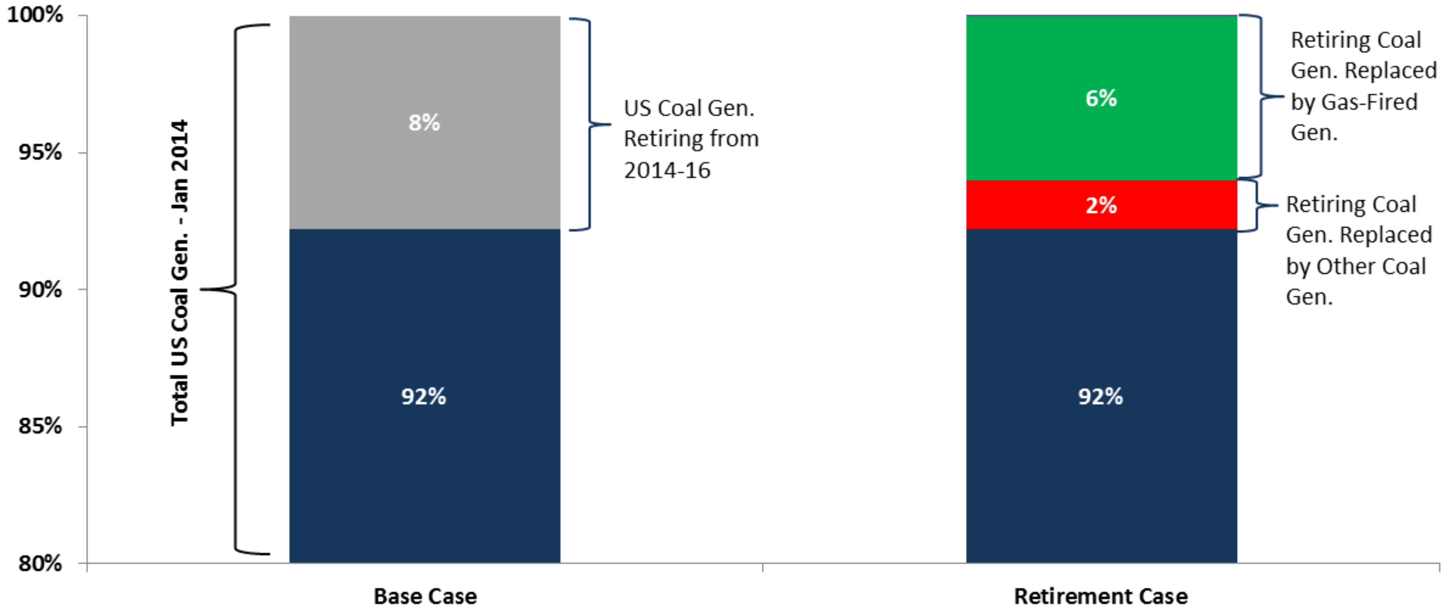
Region	Base Power Prices	Power Prices with Retirements	% Change
ISONE	$130	$190	46.6%
NYISO	$120	$152	27.2%
PJM	$103	$159	55.0%
SERC	$56	$83	47.6%
FRCC	$41	$56	36.8%
MISO	$39	$53	36.8%
ERCOT	$67	$83	23.9%
SPP	$38	$53	37.4%
CAISO	$50	$68	35.3%

- Although the majority of coal retirements affect the Eastern U.S. power markets (PJM, MISO and ISO-NE) the most, the resulting increase in gas demand leads to a rise in the national natural gas prices.
- The table to the left illustrates the effects of the increased price in natural gas on wholesale power prices in other US power markets.
- For example, the California power market, CAISO, would have experienced a 35% power price increase if the coal-fired facilities were retired prior to this past winter.

IMPACT OF COAL RETIREMENTS ON POWER GENERATION

- Of the total Base Case coal generation in January 2014, 92% came from remaining units while 8% came from units slated for retirement.
- With the early retirements, coal's 8% was replaced with three-fourths natural gas and one-fourth incremental coal generation along with a small amount (0.01%) of Demand Side Curtailment.

ESTIMATED REPLACEMENT GENERATION FOR RETIRED COAL GEN. FOR JANUARY 2014



IMPACT OF COAL RETIREMENTS ON GAS INDUSTRY - WINTER

- Even without the projected coal retirements, the gas industry was at a precipice.
  - Record demand, storage withdrawal, prices etc.
  - Pipeline, LDCs and storage operators restrict supplies to non-firm customers.
  - Gas-fired generating capacity lost in several regions due to curtailment of gas supplies.
  - Near record low storage inventories at the end of winter leave industry with a challenge to refill storage to adequate levels.

- With the project coal retirements, the conditions for the gas industry would have been worse
  - Winter Assessment
    - Records for demand, storage withdrawals and prices would have been reset to higher levels.
    - Additional pipeline, LDC and storage operator curtailments likely would have occurred.
    - More power plants likely would have had gas supplies curtailed.
  - In NEPOOL it is unlikely pipeline capacity would have been adequate.
    - As a result NEPOOL would have been faced with selecting from the following alternatives:
      - Increase oil-fired generation (i.e., an additional 1.8 MM barrels).
        - However, NEPOOL outstripped its capability to resupply fuel oil in January in the base case.
      - Increase imported power.
        - Difficult to determine which neighboring regions would have additional power to export.
      - Commence with load shedding.
    - Impact on other regions would not have been as severe as those for NEPOOL.
    - However, curtailment of gas supplies for an additional power plants would be likely.
    - Additional cost to consumers for winter supplies would have been about $35 billion.

OUTLINE

IMPACT OF COAL RETIREMENTS ON SYSTEM RELIABILITY – SUMMER- JULY 2014

- To gauge the impact of these coal retirements during a warmer than normal summer period, EVA created a high demand scenario based upon historical data during peak summer months

PJM

- In PJM, EVA found that the early retirement of this coal capacity could lead to 35 hours of reserve margins below 0% based on installed capacity
  - PJM reports having over 10 GW of demand response capability that can mitigate the risk of blackouts, but in some instances the shortage would be greater than 10 GW.
  - Additionally, demand response resources are only required to perform up to 10 times each year.

MISO

- In MISO, 31 hours were found to have reserve margins below 0% based on installed capacity, while 68 hours had reserve margins below 5%

NUMBER OF HOURS IN JULY 2014 BELOW KEY RESERVE MARGIN LEVELS

		Reserve Margin		
		<10%	<5%	<0%
ISO-NE	Base Case	16	25	25
ISO-NE	2014-15 Retirement	8	17	17
ISO-NE	2014-16 Retirement	11	22	22
PJM	Base Case	27	16	5
PJM	2014-15 Retirement	57	32	34
PJM	2014-16 Retirement	58	34	35
MISO	Base Case	69	34	4
MISO	2014-15 Retirement	60	71	18
MISO	2014-16 Retirement	71	68	31

ISO-NE

- In ISO-NE, capacity shortages exist in all cases due to the high summer demand and the loss of retired coal plants

- With the loss of Salem Harbor and Brayton Point, New England likely would need to rely on either Demand Response, increased imports, or more oil-fired generation to meet peak load

IMPACT OF COAL RETIREMENTS ON POWER PRICES – SUMMER- JUNE-AUGUST

- EVA estimated the effects of extreme summer weather without the coal plants on wholesale power prices during June-August. The results are summarized in the table to the left. A more detailed summary of the effects are presents in the detail power analysis section.

PJM

- Price impacts in PJM are significant during the summer as higher heat rate units and demand response are called upon to meet load
- Wholesale power prices in PJM are estimated to increase 33% in an extreme summer without the coal units

MISO

- In MISO, the price impact is more muted due to fewer retirements and a healthier reserve margin
- EVA estimates that the average wholesale power price for MISO would increase 8% without the coal plants

AVG. WHOLESALE POWER PRICE FOR EACH SUMMER SCENARIO ($/MWh)

	Base Case	2014-15 Retirements	2014-16 Retirements
ISO-NE	$55	$69	$70
PJM	$49	$64	$65
MISO	$39	$42	$42

ISO-NE

- The prices in the Base case are driven up due to the high demand during the hot summer. With summer peaks approaching the available capacity in New England, the power prices are dictated by the high cost marginal resources in the region
- Without the coal plants and the extreme warm weather, ISO-NE power prices increase 27% compared to the base case.
- EVA did not assume any constrained gas-fired capacity in ISO-NE for the summer scenarios

IMPACT OF COAL RETIREMENTS ON POWER PRICES – JULY 2014

AVERAGE MONTHLY WHOLESALE POWER PRICES – MAJOR U.S. MARKET REGIONS

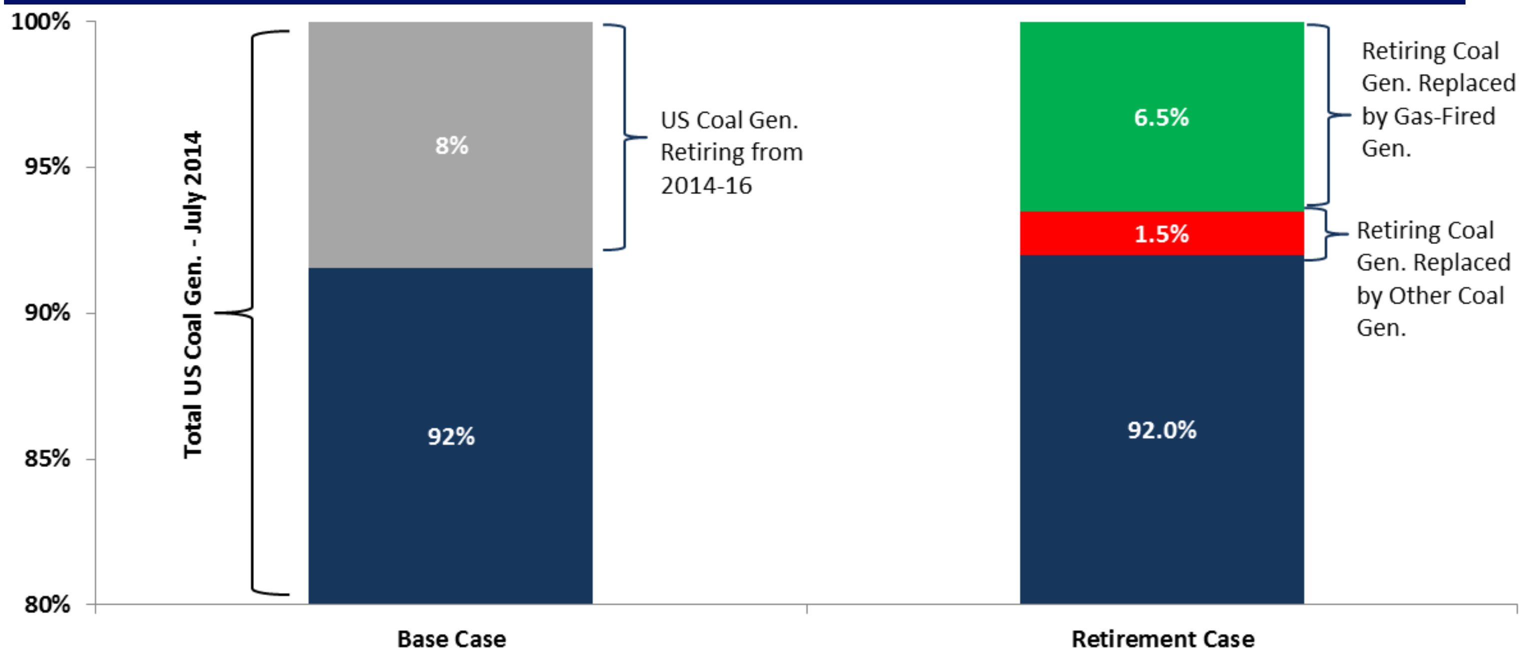
Region	Base Power Prices	Power Prices with Retirements	% Change
ISONE	$74	$106	43.7%
NYISO	$69	$104	49.9%
PJM	$63	$97	54.5%
SERC	$42	$45	8.8%
FRCC	$45	$48	7.0%
MISO	$41	$45	10.4%
ERCOT	$41	$44	6.4%
SPP	$40	$44	10.6%
CAISO	$49	$52	6.3%

- The high withdrawal of natural gas during the winter resulted in storage depletion and lower summer gas storage inventory
- This caused natural gas prices to rise during the summer resulting in higher power prices in EVA's Base Case
- With the coal units not available to provide base load power needs, more gas units are at the margin, which drives up the power prices in PJM, MISO, ISO-NE and SPP
- NYISO is a gas-dominated region that experiences winter basis blowouts which drive much higher prices in the retirement cases

IMPACT OF COAL RETIREMENTS ON POWER GENERATION - SUMMER

- In the summer, the Base Case mix was the same: 92% from remaining units and 8% from retiring units.
- When the early retirements kick in, coal again supplies one-fourth of the replaced generation while gas accounts for roughly 6.5%.
- 10 times the amount of Demand Side Curtailment is required in the summer.

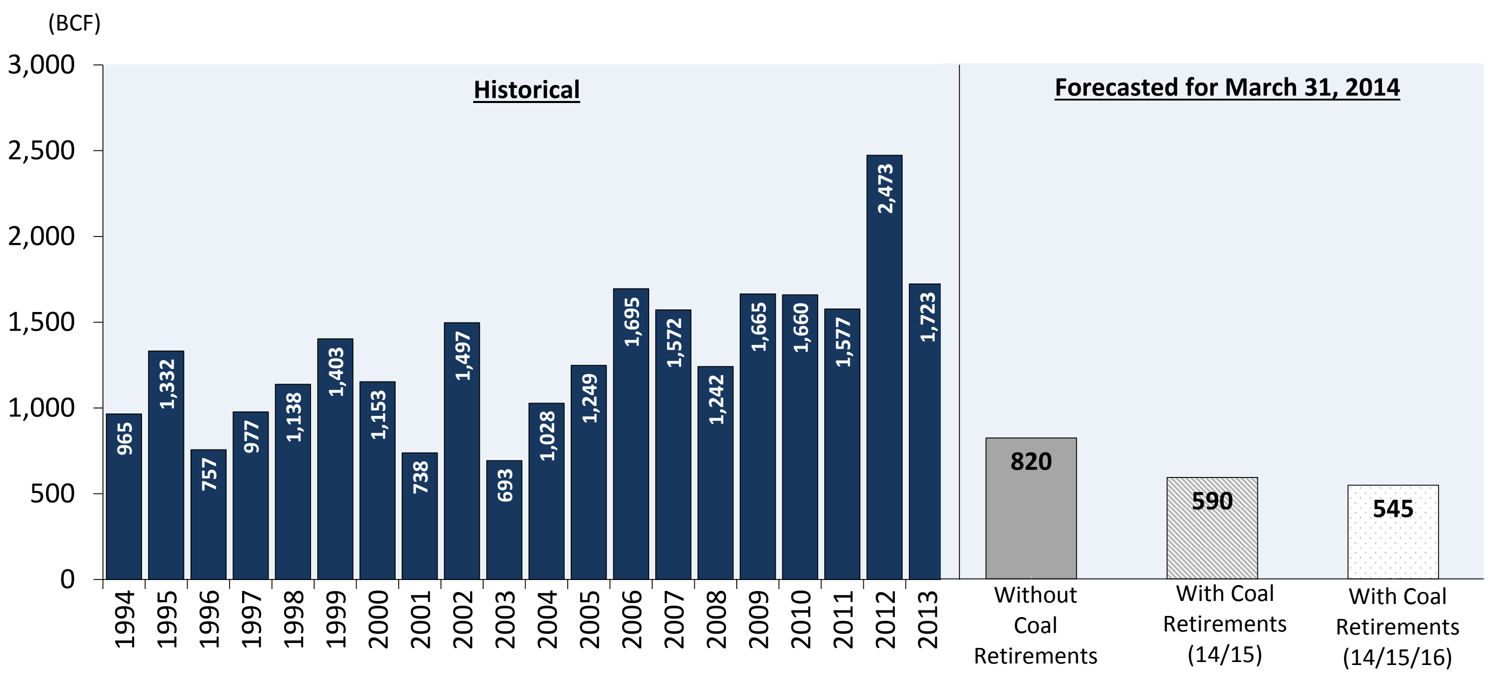
ESTIMATED REPLACEMENT GENERATION FOR RETIRED COAL GENENERATION FOR JULY 2014



IMPACT OF COAL RETIREMENTS ON GAS INDUSTRY - SUMMER

- The winter impact would have resulted in record low storage levels at the beginning of spring (April 1, 2014).

STORAGE LEVELS AT THE END OF WINTER (MARCH 31)

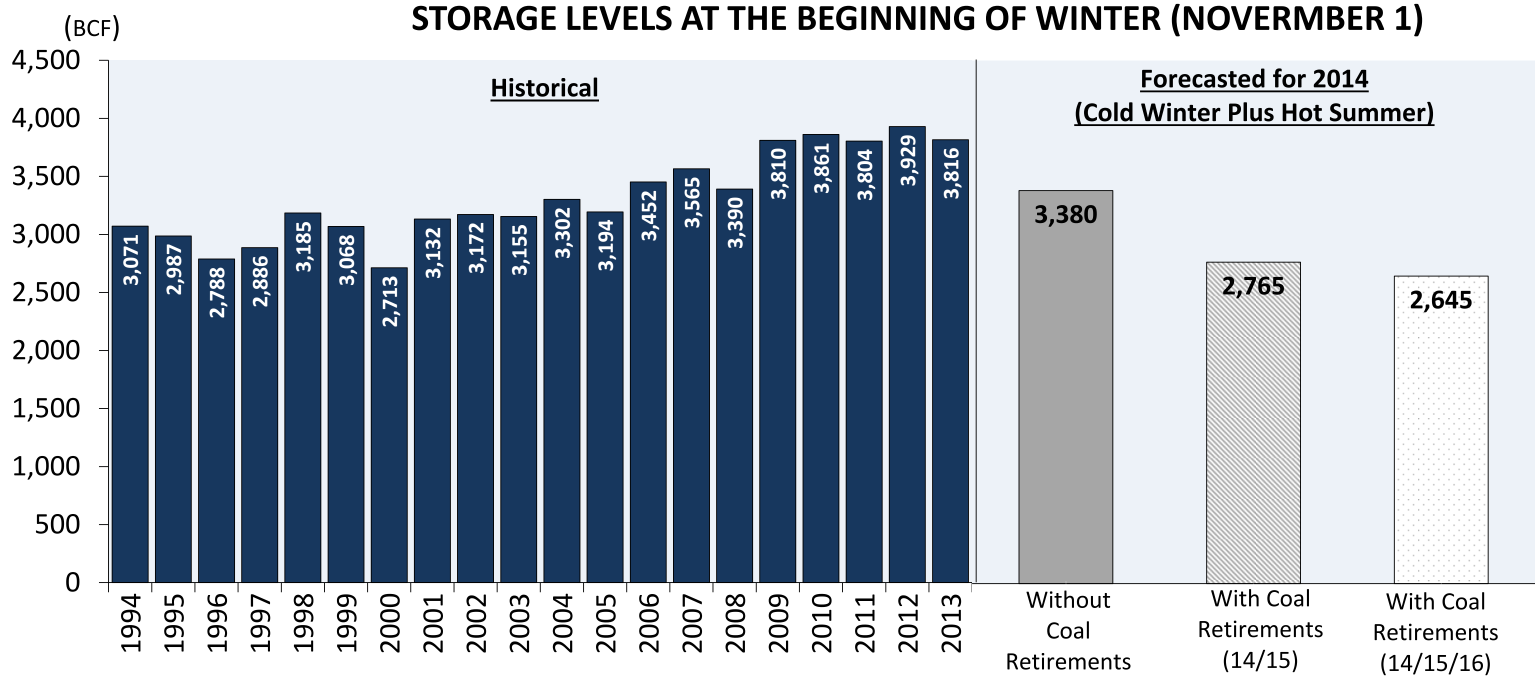


IMPACT OF COAL RETIREMENTS ON GAS INDUSTRY - SUMMER

STORAGE LEVELS AT THE BEGINNING OF WINTER 2014/15

- Storage injections would have been reduced to about 10.4 BCFD because additional summer gas demand.
- Storage refill for next winter likely would have been inadequate unless the winter of 2014/2015 is very mild.
- A supply response likely would occur.
  - However, it would have a minimal impact on 2014 storage injections.
    - Nonetheless, the increased supply would help meet demand during the winter of 2014/2015.
  - Higher gas prices would be required for a supply response.
    - Cost to consumer because of higher gas prices would be in between $11 and $59 billion depending upon timeframe.
  - Total cost to consumers for winter and summer impacts could reach about $90 billion(1).

STORAGE LEVELS AT THE BEGINNING OF WINTER (NOVERMBER 1)



(1) Total cost to all consumers for both gas and power is approximately $100 billion.

OUTLINE

METHODOLOGY

In order to correctly understand the importance of the retiring coal plants to the reliability electric power markets, EVA proceeded with the following methodology.

Natural Gas Market

- National Assessment of the impact of increased demand on:
  - Gas Storage levels, which already at record lows.
  - Natural gas prices for both winter and summer
    - Assessed potential for supply response
    - Assessed potential for demand destruction,
  - Regional assessment of the impact of increased demand on regional pipeline capabilities
    - Pipeline constraints identified

METHODOLOGY

In order to correctly understand the importance of the retiring coal plants to the reliability electric power markets, EVA proceeded with the following methodology.

Power Markets (ISO-NE, PJM, MISO)

- Determined for which power markets that reliability would be affected the most when the coal-fired assets retire.
- For the power markets that will be affected, the list was pared to the markets that had readily available market data from this past winter, so that EVA could calibrate its proprietary models to accurately re-create the situation from the winter of 2014.
- Three scenarios were constructed for the winter assessment
  - *Base Case:* Re-create the performance of the select power markets on an hourly basis for Jan-Feb 2014.
  - *Case 1:* Analyze the performance of the selected power markets without the coal-fired assets retiring in 2014/2015.
  - *Case 2:* Analyze the performance of the selected power markets without the coal-fired assets retiring in 2014-2016.
- Three scenarios were constructed for the summer assessment
  - *Base Case:* Re-create the performance of the select power markets based on extreme historical summer temperatures.
  - *Case 3 :* Analyze the performance of the selected power markets without the coal-fired assets retiring in 2014/2015.
  - *Case 4 :* Analyze the performance of the selected power markets without the coal-fired assets retiring in 2014-2016.
- For each scenario, EVA solved for the following:
  - Estimate the additional gas consumption and the increase in gas prices that would occur without the coal assets.
  - Determine how often the power markets would be at risk for reliability issues without the coal assets.
  - Estimate the impact of power prices with the increased gas prices resulting from the coal plants retiring.

OUTLINE

- Problem Statement
- Methodology
- Impact of Early Coal Retirements in Winter
- Impact of Early Coal Retirements in Summer
- Detailed Gas Analysis
- Detailed Power Analysis
- Conclusions
- Appendix

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

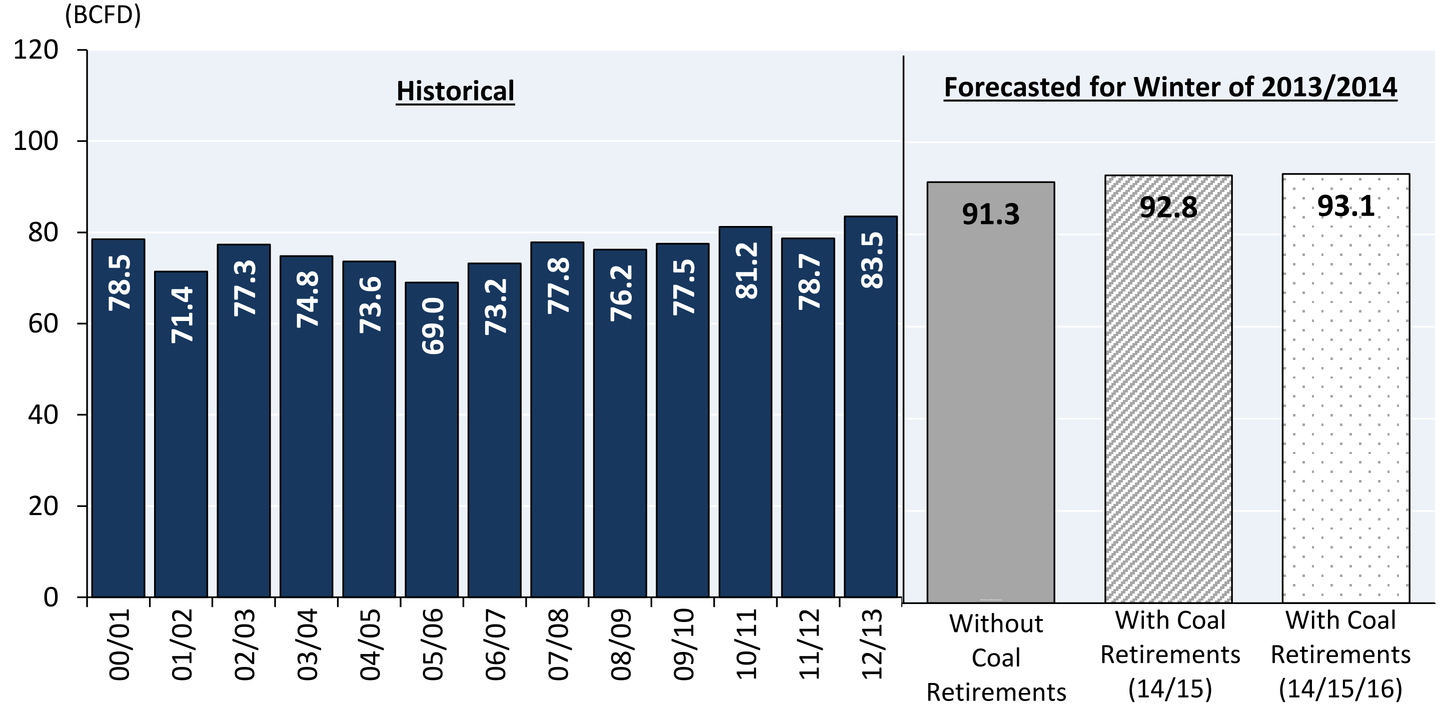
Winter of 2013/14: without projected Retirements

- While the winter weather was cold, it was only the 11th coldest winter on record
  - As a result the outcome could have been worse.
  - Nevertheless, it was an early, long, cold winter.
    - Four distinct cold spells.(1)
- Winter weather resulted in several records
  - Record demand (91.3 BCFD).
    - Due to seasonal and structural demand increases.
  - Record daily demand (125 BCFD).
  - Record storage withdrawals (19.6 BCFD).
  - Record gas prices at key trading hubs ($135/MMBTU).
- Lowest season ending (Mar 31) storage level (820 BCF) since 2003, when demand was 17 percent lower, puts the gas industry at a precipice
- Pipelines, LDC and storage operators issued capacity constraint warnings, OFOs, and withdrawal restrictions
- Well freeze-offs did occur (i.e., at least 1.5. BCFD)

(1) January 6, 7 and 8; January 22, 23 and 24; January 28 and 29; and February 6 and 7.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

WINTER OF 2013/14: WITHOUT PROJECTED RETIREMENTS



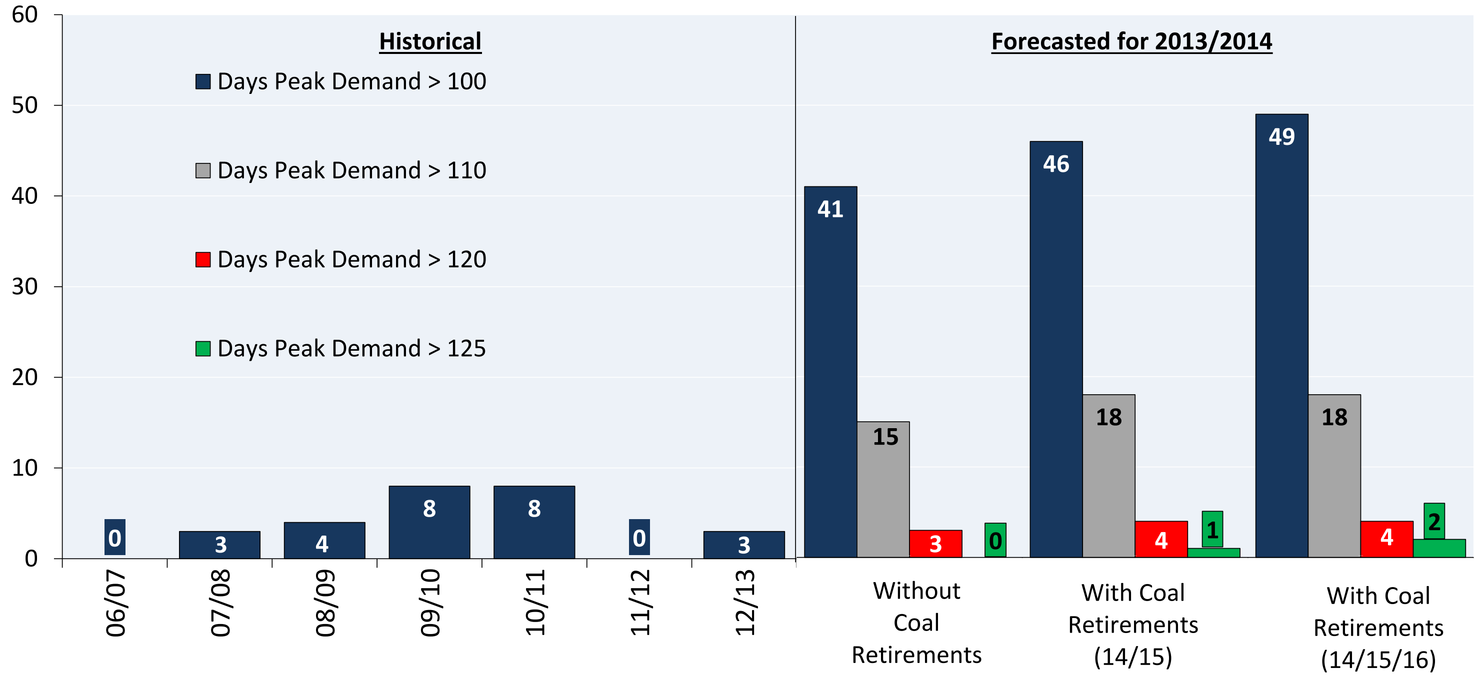
- **Average demand:** Average winter demand increases to 93.1 BCFD

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

WINTER OF 2013/14: WITH PROJECTED RETIREMENTS

- Daily demand: Significant increases in daily demand requirements, which would have further stressed the system
  - Daily demand at 100 BCFD is a significant event for the industry.(1)
  - Daily demand requirements >125 BCFD are a real challenge and can result in significant price spikes, as well as curtailment

COMPARISON OF LOWER-48 PEAK DAY DEMAND REQUIREMENTS DURING WINTER (NOV-MAR)



(1) Average annual daily demand in 2013 was 71.3 BCFD.

IMPACT OF THE WINTER OF 2013/2014 ON THE NATURAL GAS MARKET

WINTER OF 2013/14: WITH PROJECTED RETIREMENTS

- Curtailments: With daily demand at record levels, there was curtailment of gas supplies this winter
  - Examples:
    - UGI (i.e., a Pennsylvania LDC) had its first curtailment of firm supplies in 10 years.(1)
      - Sapa Extrusions temporarily suspended production and casting activity.
      - Virtually all of UGI's 200 large and commercial IT customers were curtailed.
    - A paper mill in Maine that employs 450 had a production outage.
    - Another paper mill in Maine that employs 850 shut down on Jan 11, 2014 for two weeks.(2)
    - NEPOOL, NYPOOL, PJM, MISO and SW Power Pool cited lack of gas availability as reason for gas-fired units being offline.(3)
  - With projected retirements curtailments would have been greater, however specific cases cannot be determined.

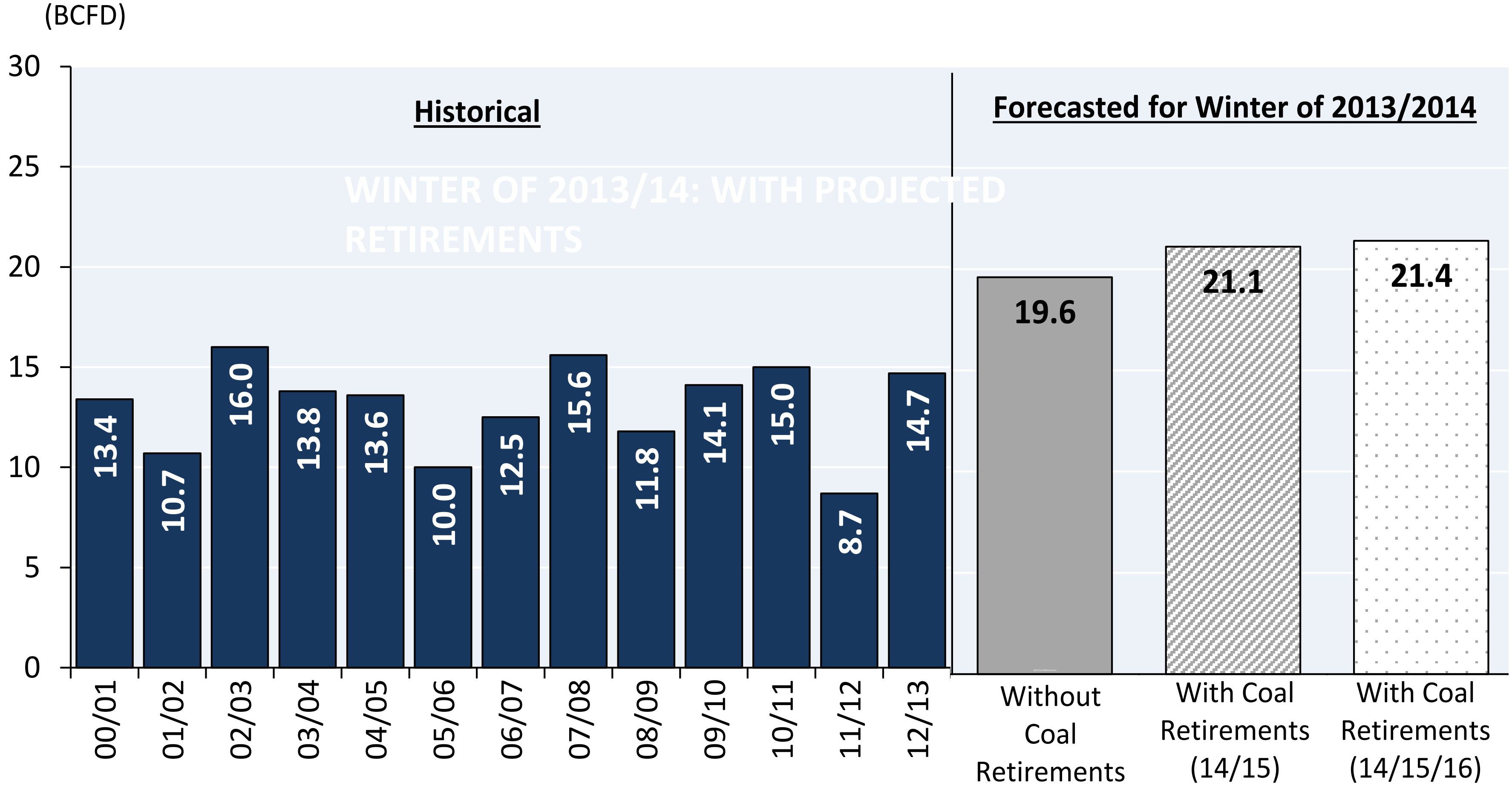
(1) "Although gas services interruptions spike, users take cutoff in stride", *Inside FERC Gas Market Report*, January 31, 2014, pp 1 ff.
(2) "New England Price Volatility as Raising Eyebrows in Senate, DOE", *Natural Gas Week*, February 10, 2014, pp 3-4.
(3) "Power grid operators say cold winter may point to need for more standards", *Inside FERC Gas Market Report*, April 11, 2014, pp 4.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

WINTER OF 2013/14: WITH PROJECTED RETIREMENTS

- Storage withdrawals: Since short-term supply is inelastic, increased demand would cause storage withdrawals to increase to levels that are unprecedented in the industry

STORAGE WITHDRAWALS (NOV-MAR)

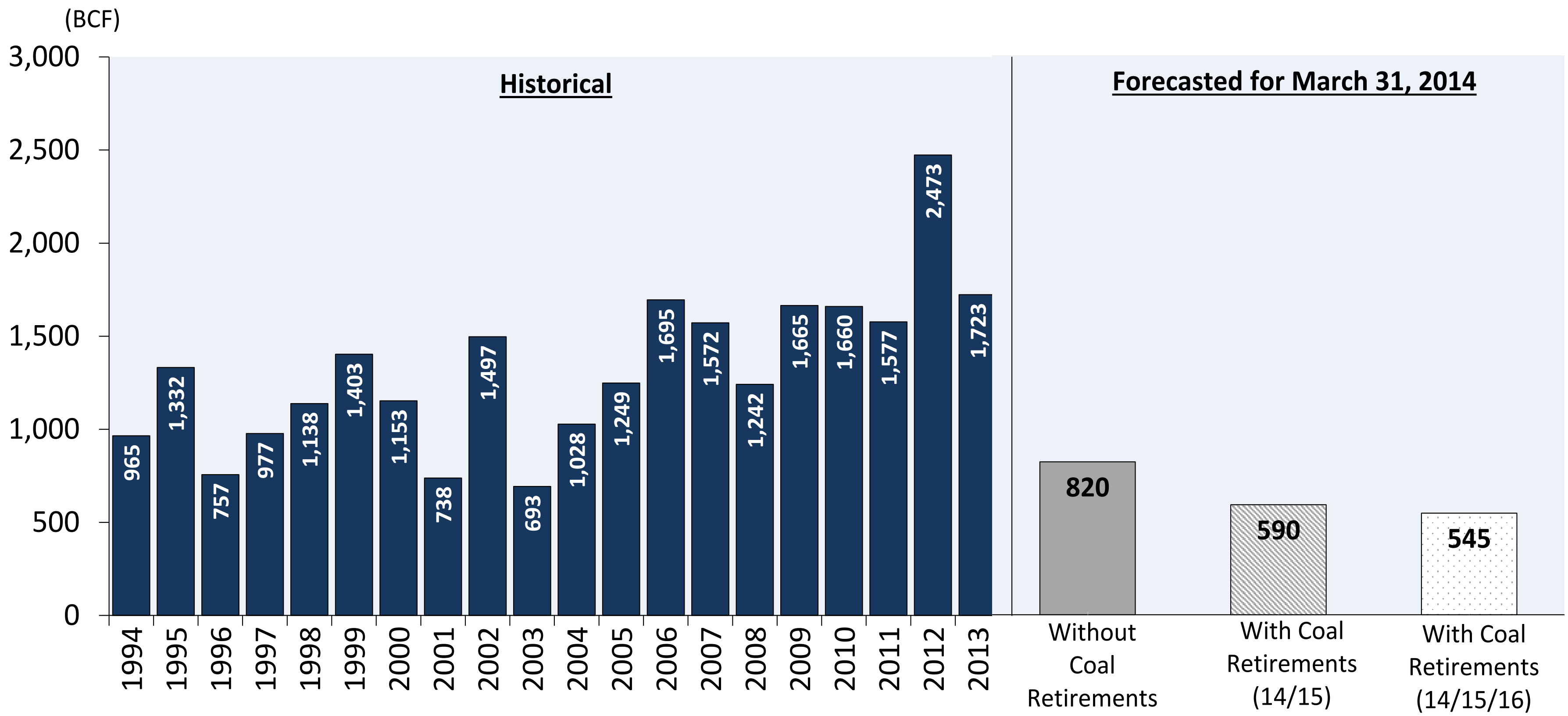


IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

WINTER OF 2013/14: WITH PROJECTED RETIREMENTS

- Season-ending storage: As a result of the above, the March 31 storage level also would have been at an unprecedented level
  - The prior low period for recent times was in 2003, when annual gas demand was 17% lower, which indicates the significant increase in structural demand.

STORAGE LEVELS AT THE END OF WINTER (MAR 31)



IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

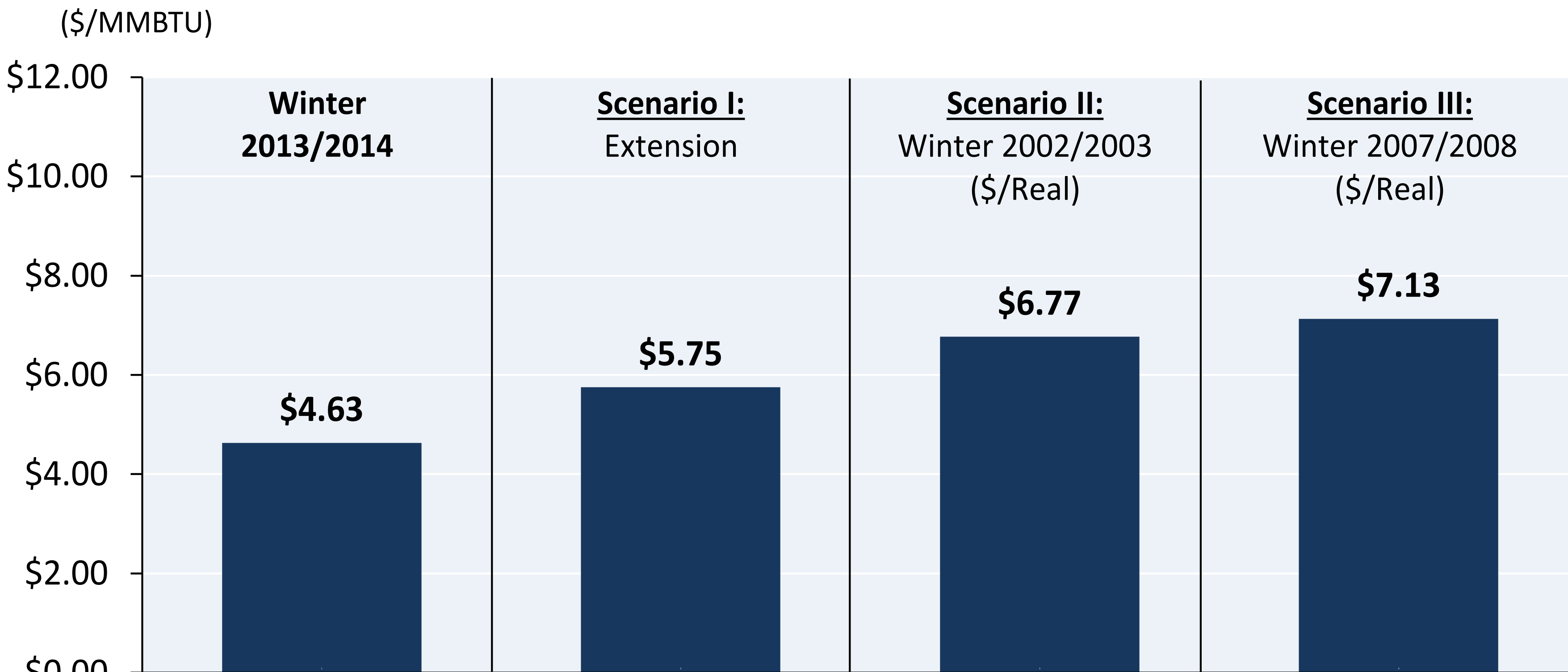
WINTER OF 2013/14: WITH PROJECTED RETIREMENTS

- Gas prices: The combination of (1) higher average winter gas demand; (2) increased stress on the system due to higher daily demand levels; and (3) reduced season-ending storage levels would have caused gas prices to be higher-potentially significantly higher
  - Three potential scenarios examined.
    - Extending the winter 2013/2014 gas prices throughout the remainder of 2014.
    - Use the price trends for 2002/2003 in real terms for the non-winter months for 2014.
    - Use the price trends for 2008 in real terms for the non-winter months of 2014.
  - Analysis is for both Henry Hub and key regional basis differentials.
  - Complete gas price assessment in a separate section.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

WINTER OF 2013/14: WITH PROJECTED RETIREMENTS

SCENARIOS FOR HENRY HUB GAS PRICE ($/MMBTU)



Increased Cost to Consumers for Winter Gas Supplies			
-	$25 Bil.	$31 Bil.	$35 Bil.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

ASSESSMENT OF COLD WINTER AND HOT SUMMER

- Post-Winter of 2013/2014 (No Additional Retirements)
  - Low storage level (820 BCF) at the end of winter
  - Refilling storage to adequate levels prior to next winter is the industry's greatest challenge
    - Even with storage injections at projected record levels (12 BCFD).
  - Gas-directed drilling activity remains at record lows, despite gas prices through May being $1.20/MMBTU, or 32% higher
  - There are wild cards on the horizon, but they will not affect this year's storage injections
    - Potential for November 2014 infrastructure event that will bring stranded gas supplies to market.(1)
  - Current NYMEX strip for summer ($4.43/MMBTU) assumes (1) adequate season-ending storage levels; (2) supply growth; and (3) a mild to normal winter

(1) See 2013 FUELCAST Topical Article VII: "Changes in Northeast Infrastructure", November 2013.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

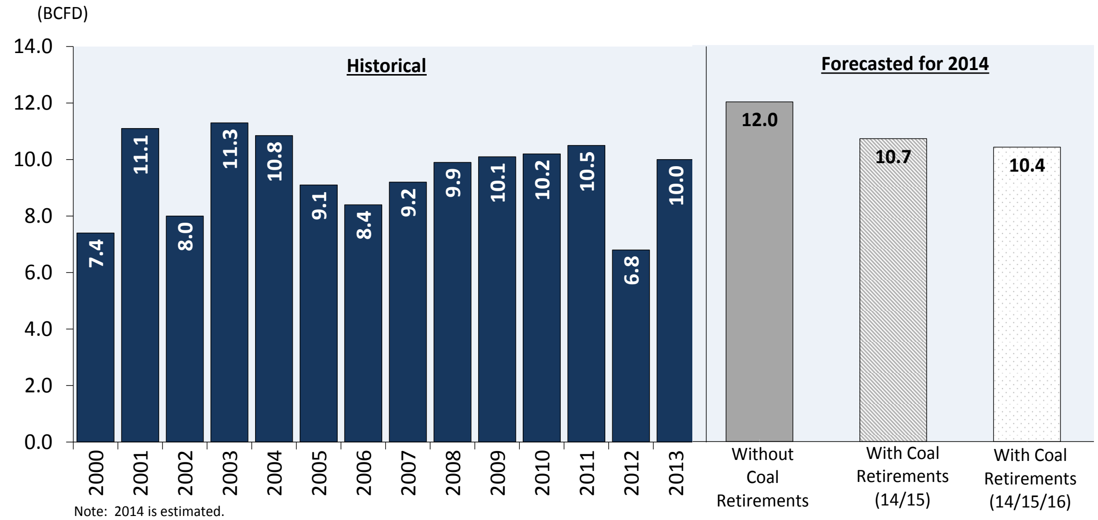
ASSESSMENT OF COLD WINTER AND HOT SUMMER

- Post-Winter of 2013/2014 with Projected Retirements
  - Assumes a hot summer
    - Current forecast is for summer weather to be 6% warmer than normal.
    - The summers of 2010, 2011 and 2012 were 12% to 16% above normal.
  - Gas demand: With gas at the margin increased electricity sales for hot summer results in total summer gas demand increasing from 60.6 to 62.9 BCFD
  - Storage injections: Assuming a negligible short-term supply response, increased gas demand reduces storage injections to only 10.4 BCFD
  - Storage level: Season-ending (Oct 31) storage levels only increase to 2,645 BCF, which is an unprecedented low level entering a winter season and likely not adequate for anything but a mild winter

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

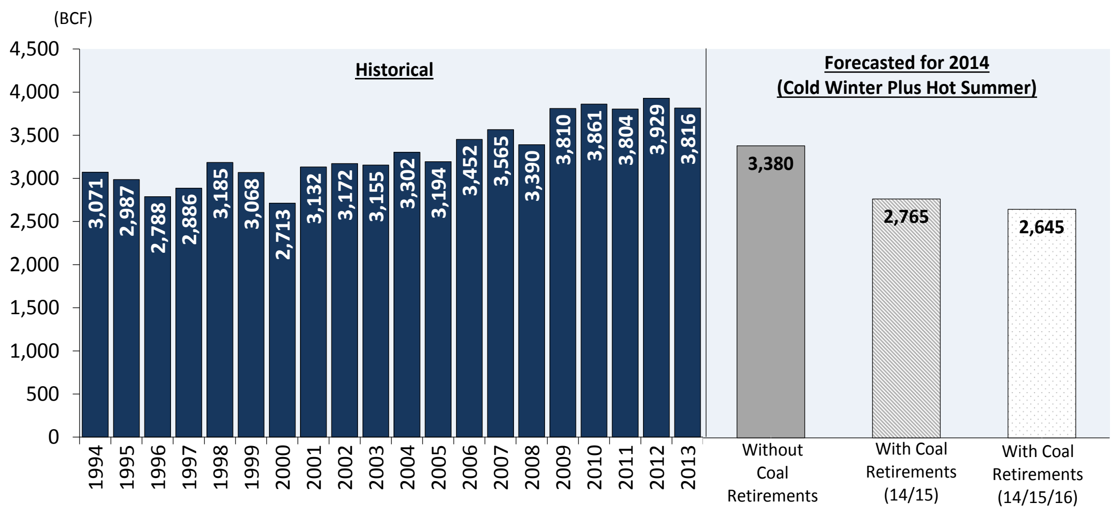
ASSESSMENT OF COLD WINTER AND HOT SUMMER

U.S. STORAGE INJECTIONS (BCFD)



Note: 2014 is estimated.
Source: EIA.

STORAGE LEVELS AT THE BEGINNING OF WINTER (NOVEMBER 1)



IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

ASSESSMENT OF COLD WINTER AND HOT SUMMER

- Supply response: Critical issue is what would be the potential supply response
  - Current gas-directed drilling activity at record lows for recent times.
  - With the exception of the November 2013 infrastructure event, domestic production since July 2013 has only increased 1.0%.
    - Drilling activity in the last 10 months has increased supply 1.0%.
  - E&P industry has made it clear no new dry-gas drilling programs without higher gas prices on a sustained basis and competitive prices.[1]
    - Current NYMEX future prices decline to $4.05 per MMBTU by April 2015.
    - While higher gas prices may meet the minimum ROR threshold, gas prices must be high enough to yield a competitive return to that for oil/liquids projects.[2]
    - Required gas price appears to be $5.00/MMBTU on a sustained basis.[3]

[1] "Higher Gas Prices Fail to Tempt ConocoPhillips From Oiler Focus", *Natural Gas Week*, April 14, 2014, pp 4-5; and "Independents Sticking to Liquids Despite Higher Natural Gas Prices", *Natural Gas Week*, March 3, 2014, pp 3-5.

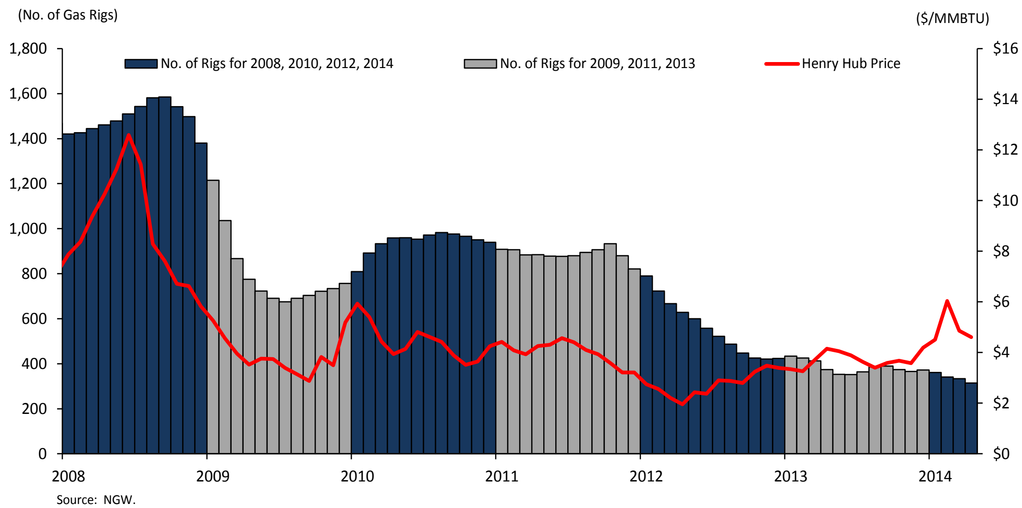
[2] One example of the need for gas prices to be higher in order for gas projects to compete with oil projects is in the Haynesville play. While the core areas for the Haynesville can attain a B/T ROR of 20% with sub- $4.00 per MMBTU gas prices, sustained gas prices just over $5.00 per MMBTU are required to attain a 40% ROR and between $5.50 and $6.00 per MMBTU to attain a 50% ROR. Many oil projects at current oil prices achieve 40 to 50% ROR. For non-core areas of the Haynesville even higher prices are required.

[3] Chesapeake may be an exception.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

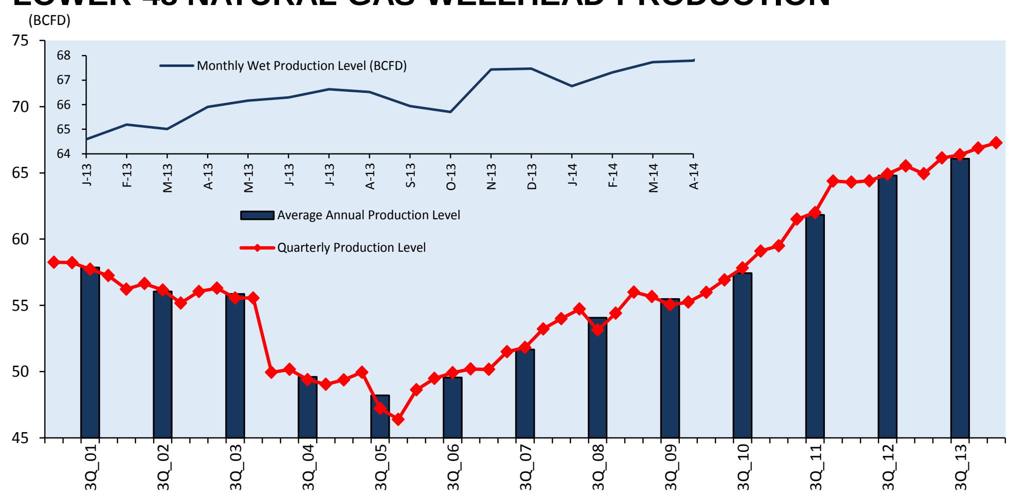
ASSESSMENT OF COLD WINTER AND HOT SUMMER

RIG COUNT FOR GAS WELLS



Source: NGW.

LOWER-48 NATURAL GAS WELLHEAD PRODUCTION



Note: Bars represent average annual production levels, while the dots on the line graphs represent quarterly production levels.
Source: Lippman Consulting, Inc. and EVA.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

ASSESSMENT OF COLD WINTER AND HOT SUMMER

- Combination of higher gas demand and reduced storage levels likely will cause gas prices to increase to the $5.00/MMBTU threshold.
  - However, this would need to be on a sustained basis (i.e., three years for the NYMEX future prices).
  - Historically the gas industry has demonstrated the capability to increase the gas-directed rig count quickly.
  - However, this will be more difficult to do at present because of the high oil-directed rig count.[1]
  - Competition for high-horse power rigs is particularly keen.

INCREASE OVER SIX MONTH PERIOD DURING DRILLING BOOM (2008-2011)

	Increase in Rig Count		Increase in Production (BCFD)	
	Max Increase In 6-Month Period	Avg Increase In 6-Month Period	Max Increase In 6-Month Period	Avg Increase In 6-Month Period
For Six Major Shale Plays(1)	114	34	3.6	2.3
For Haynesville Shale	68	33	1.6	0.95

[1] Currently the oil-directed rig count is 1,528, whereas in January 2008 (i.e., the start of the drilling boom) it was only 321.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

ASSESSMENT OF COLD WINTER AND HOT SUMMER

- While increases in the average gas-directed rig count noted in the above table likely are realistic, the increases production levels are not for several reasons.
  - It is very difficult to estimate the time lags between contracting for a rig and the final hook-up of a well to a pipeline (i.e., 3 to 9 months).
  - As a result, supply response would have a small effect on November 1, 2014 storage levels (25 BCF)[1], but would have a significant impact for 2015 and 2016 production levels.

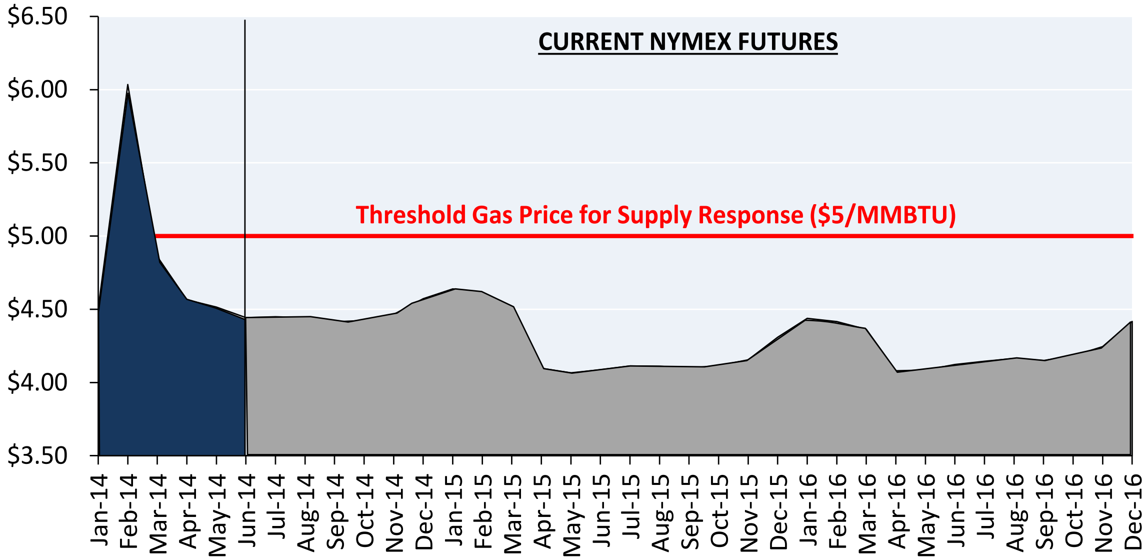
- There is a cost to the consumers for this potential supply response.

[1] Based upon 30 rigs coming online over a 6-month period for the very prolific Haynesville shale play.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

ASSESSMENT OF COLD WINTER AND HOT SUMMER

COMPARISON OF THRESHOLD PRICES TO CURRENT NYMEX ($/MMBTU)



Increased Cost to Consumers for Gas Supplies as a Result of Gas Prices Rising to Threshold Levels From Current NYMEX Future Prices(1)

($/Billions)	2014(2)	2015	2016
Increased Cost to Consumers			
Annual	$11.0	$22.7	$23.8
Cumulative	$11.0	$32.7	$55.4

(1) Based upon case for 2014, 2015 and 2016 projected retirements.

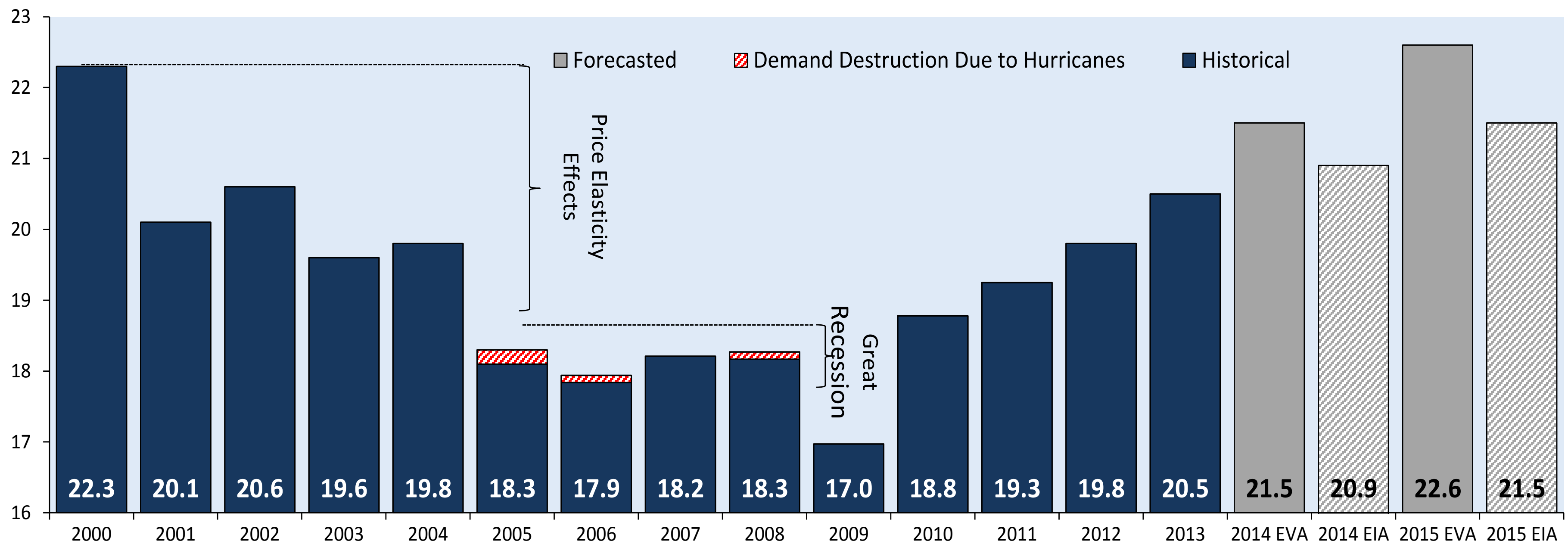
(2) Does not reflect potentially higher gas prices for winter of 2013/2014.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

ASSESSMENT OF COLD WINTER AND HOT SUMMER

- Demand destruction: If market deems supply response inadequate, then prices likely would increase to a level to cause demand destruction
  - Primary candidate for demand destruction is the industrial sector, with the 2000 to 2005 period being the classic example.
    - Gas prices in 2005 reached $13 per MMBTU and averaged $6.76 per MMBTU.
  - However, current conditions are significantly different, particularly oil prices.(1)

INDUSTRIAL SECTOR NATURAL GAS DEMAND (BCFD)



(1) Oil price in the 2000 to 2003 period ranged from $34 to $40.50 per barrel and increased to $67 per barrel in 2005. Current oil prices are in excess of $100 per barrel.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

NATURAL GAS PRICES

- 2014 Gas Prices Without Projected Retirements
  - 2013 average Henry Hub gas prices: $3.70 per MMBTU
  - 2014 average NYMEX prices: $4.64 per MMBTU
    - + $0.94 per MMBTU, or 25%, above 2013 prices.
  - Winter basis differentials at record levels

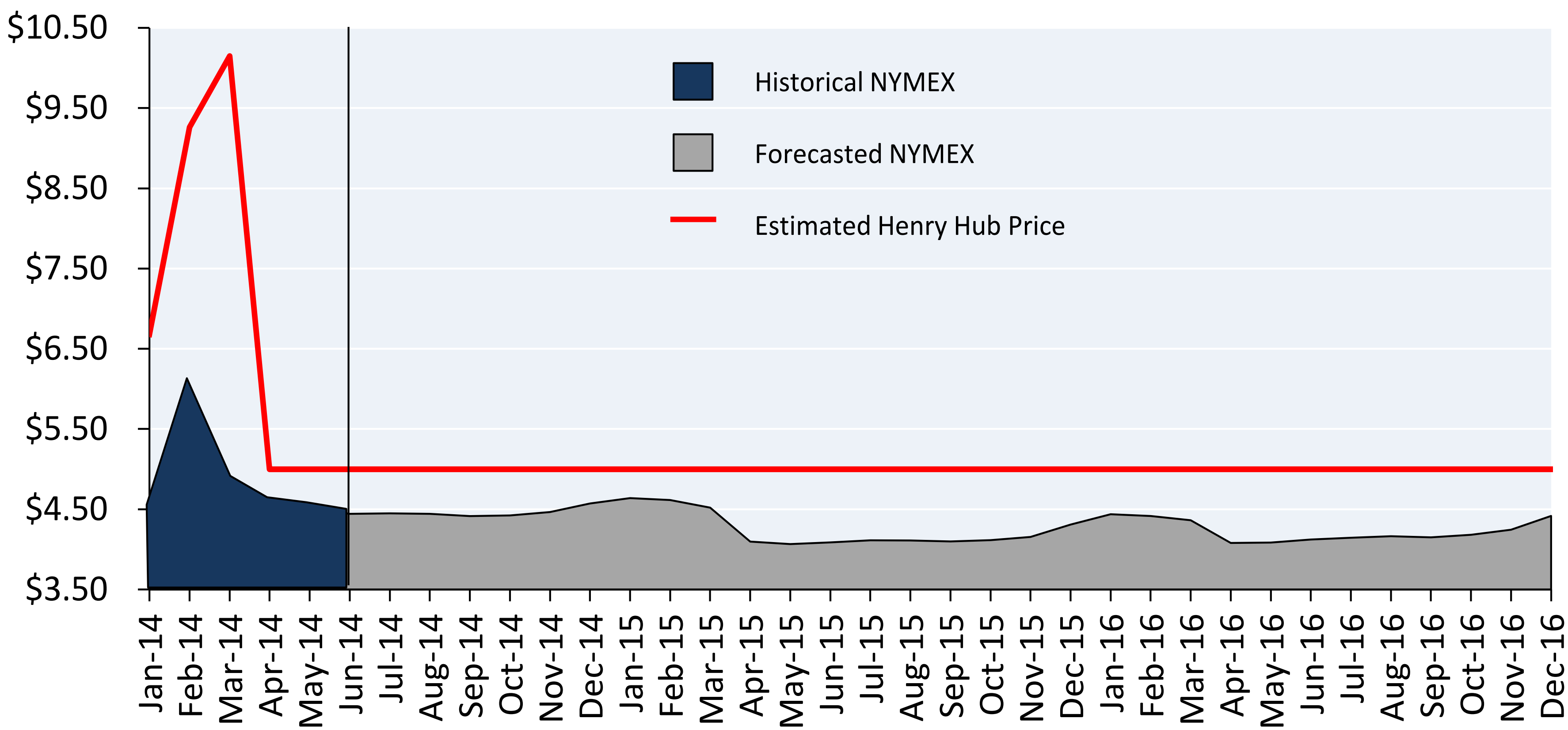
- 2014 Gas Prices With Projected Retirements
  - Focus is on a cold winter plus hot summer with projected retirements for 2014
    - Two distinct price impacts:
      - Increase in Henry Hub gas prices.
      - Increase in winter basis differentials.
  - Unlikely gas prices for the first two months of the winter would have been affected (i.e., Nov. and Dec. 2013)
    - Thus, focus is on 2014 impact.
  - Average annual 2014 Henry Hub gas prices estimated to increase to be $5.92 per MMBTU
    - + $1.28 per MMBTU, or 28%, above current NYMEX.
    - + $2.22 per MMBTU, or 60%, above 2013 gas prices.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

NATURAL GAS PRICES

- Net additional cost in 2014 to consumers approximately $35 billion
  - Understates true cost to consumers because increased prices would have to be on a sustained basis.

COMPARISON OF CURRENT NYMEX TO ESTIMATED HENRY HUB PRICES WITH PROJECTED COAL RETIRMENTS



Note: Assumes cold winter and hot summer with projected retirements for 2014, 2015 and 2016.

IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

NATURAL GAS PRICES

- Second major price impact would be increased basis differentials in the Northeast - approximately $3 to $4 billion
  - Algonquin Citygates.
  - Transco Z6-NY.
  - Transco Z6-Non-NY.
  - TETCO M3.
- Total increase cost to consumers for all sectors about $90 billion

Increased Cost To Consumers

	I. Supply			II. Basis	III. Total
Period	Volume (BCF)	Increased Price ($/MMBTU)	Increased Cost to Consumers(1) ($ Billions)	Increased Cost to Consumers(1) ($ Billions)	Increased Cost to Consumers(1) ($ Billions)
Nov-Dec 2013	5,257	$0.00	$0	$0	$0
Jan-Mar 2014	8,852	$3.44	$31	$4	$35
Apr-Oct 2014	13,594	$0.57	$8	$0	$8
Nov-Dec 2014	5,145	$0.51	$3	$0	$3
Subtotal 2014	27,591	$1.48	$42	$4	$46
2015	27,336	$0.80	$23	$0	$23
2016	28,360	$0.77	$22	$0	$22
Grand Total			**$87**	**$4**	**$91**

(1) For all sectors.

OUTLINE

- Problem Statement
- Methodology
- Impact of Early Coal Retirements in Winter
- Impact of Early Coal Retirements in Summer
- Detailed Gas Analysis
- Detailed Power Analysis
- Conclusions
- Appendix

DETAILED POWER ANALYSIS OUTLINE

- PJM Winter Analysis
- MISO Winter Analysis
- ISO-NE Winter Analysis
- PJM Summer Analysis
- MISO Summer Analysis
- ISO-NE Summer Analysis

PJM WINTER ANALYSIS: IMPACT OF THE WINTER OF 2013/14 ON THE NATURAL GAS MARKET

NATIONAL OVERVIEW

- Winter of 2013/2014 Without Projected Retirements
  - Gas-generation was curtailed in the following regions because of lack of access to gas supplies(1)
    - Likely each case represents a curtailment of interruptible pipeline capacity, as regional pipelines lack the capacity to fully meet both firm (e.g., residential) and interruptible loads.

Region	Total Capacity Offline	Percent With Fuel Issues	Estimated Gas-Fired Capacity Offline
PJM	41,336 MW	24%	9,920 MW
MISO	32,813 MW	20%	6,666 MW
NYPOOL	Lower	Higher	Unknown
Southwest Power Pool	Lower	Higher	Unknown
NEPOOL	14000 MW	100%	14,000 MW(*)

(*) Use Oil-Fired Generation (12.5 GWh).

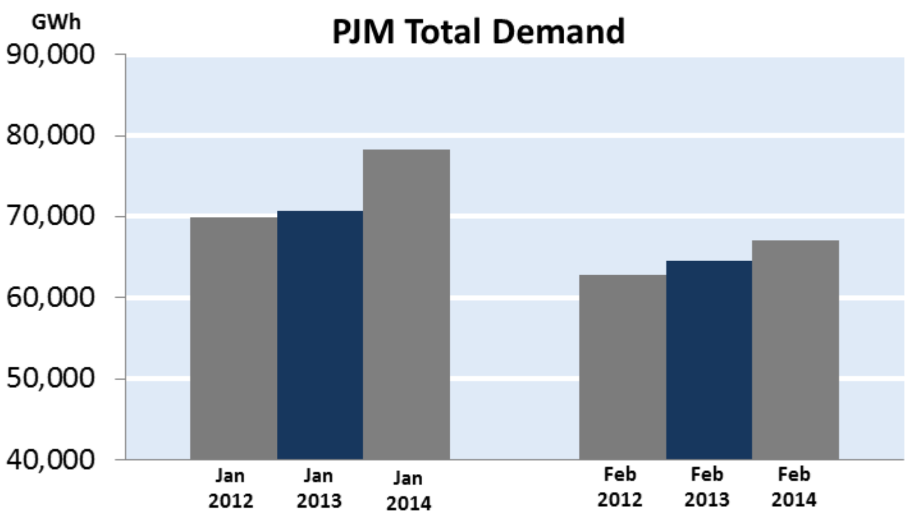
    - In addition, ERCOT had every available unit online on Jan 6 and 7.(2)
      - Gas demand at record levels and one BCFD above prior record level.
      - Regional well freeze-offs (i.e., 1.1 BCFD estimated) occurred.
      - Pipelines and storage operators issued OFOs and limit supplies to IT customers (i.e., power plants).
    - CAISO affected during February 6 weather event.
      - Curtailment of gas supplies to power units occurred.

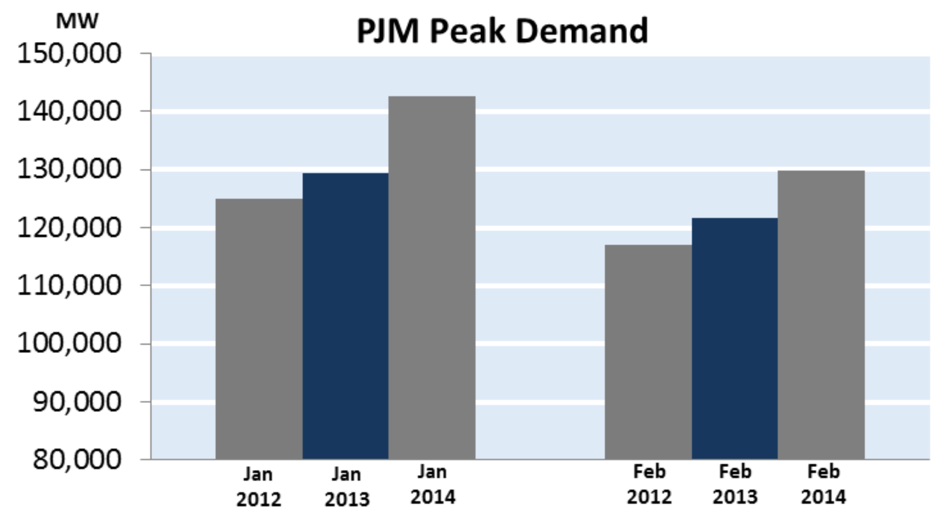
(1) "Power grid operators say cold winter may point to need for new standards", *Inside FERC's Gas Market Report*, April 11, 2014, p. 4; "Northeast Said Too Exposed to Gas Volatility", *Natural Gas Week*, February 10, 2014; and "Oil often trumped gas in Northeast during record-setting winter cold" *Inside FERC's Gas Market Report*, April 22, 2014, p. 3-4.
(2) "Shivering Texas Barely Avoids Rolling Blackouts", *Natural Gas Week*, January 13, 2014, p. 9.

PJM WINTER ANALYSIS: EFFECTS OF POLAR VORTEX ON ELECTRICITY DEMAND

PJM WINTER DEMAND OVER THE PAST THREE YEARS

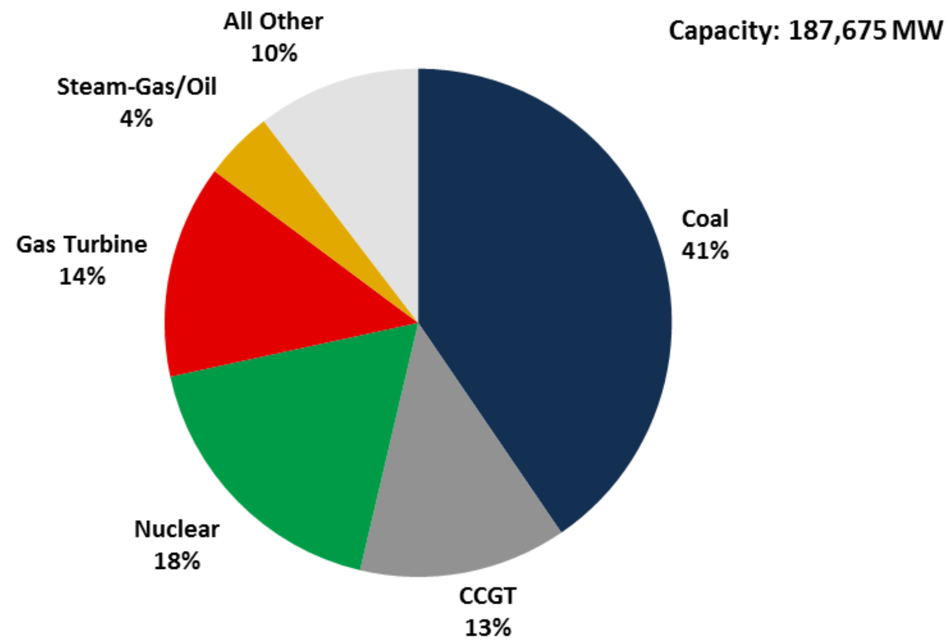
- The polar vortex brought frigid temperatures to most of the Eastern part of the country in January and early February, pushing electricity demand to record levels and forcing generating units out of commission.
- While total January demand grew by 11% YoY, peak demand grew 14% YoY. February total and peak demand growth were 4% and 7%, respectively.
- To simulate the extreme weather conditions in PJM, EVA have used actual hourly load data in its modeling effort.





PJM WINTER ANALYSIS: EXISTING SUPPLY DURING POLAR VORTEX

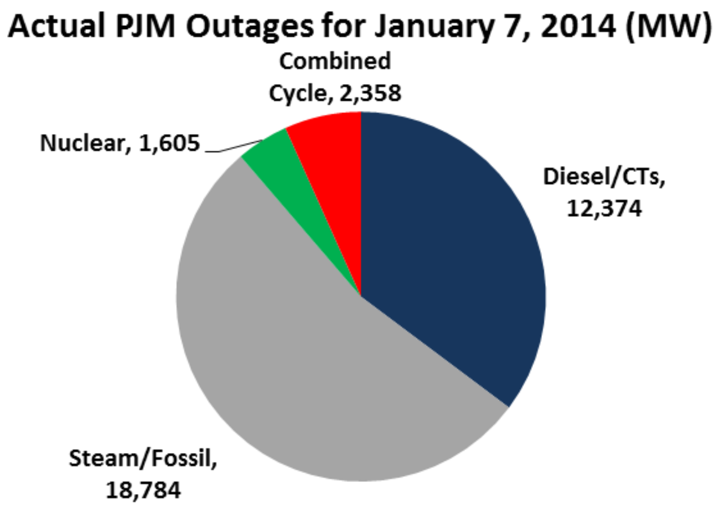
PJM INSTALLED CAPACITY



- Because of its proximity to Appalachian coal, PJM is a coal-dominated region – 41% of all existing capacity is coal-fired. This played a very important role during the polar vortex considering the high price of gas as well as its mercurial deliverability.
- CCGTs currently account for 13% of total capacity though this share is expected to grow as coal retirements mount.
- Until these CCGTs begin commercial operations, however, coal units in PJM are the backbone for system reliability.

PJM WINTER ANALYSIS: OUTAGES DROVE VERY TIGHT RESERVE MARGINS ON SOME DAYS

PJM GENERATION OUTAGES FOR JANUARY 2014



pjm Generation Forced Outages for January 6-8, 2014

FORCED OUTAGES (preliminary)	RTO	Diesel/CTs	Steam/Fossil	Nuclear	Combined Cycle	Hydro	Wind	Other	Confirmed Gas Curtailments*
Monday 1/6/2014 8 p.m. Eastern	30,239	8,120	16,116	2,047	1,665	59	1,200	1,032	*2,160*
Tuesday 1/7/2014									
8 a.m.	35,069	11,238	16,910	1,605	2,299	63	1,313	1,641	*7,489*
7 p.m.	38,033	12,374	18,784	1,605	2,358	61	1,554	1,297	*6,368*

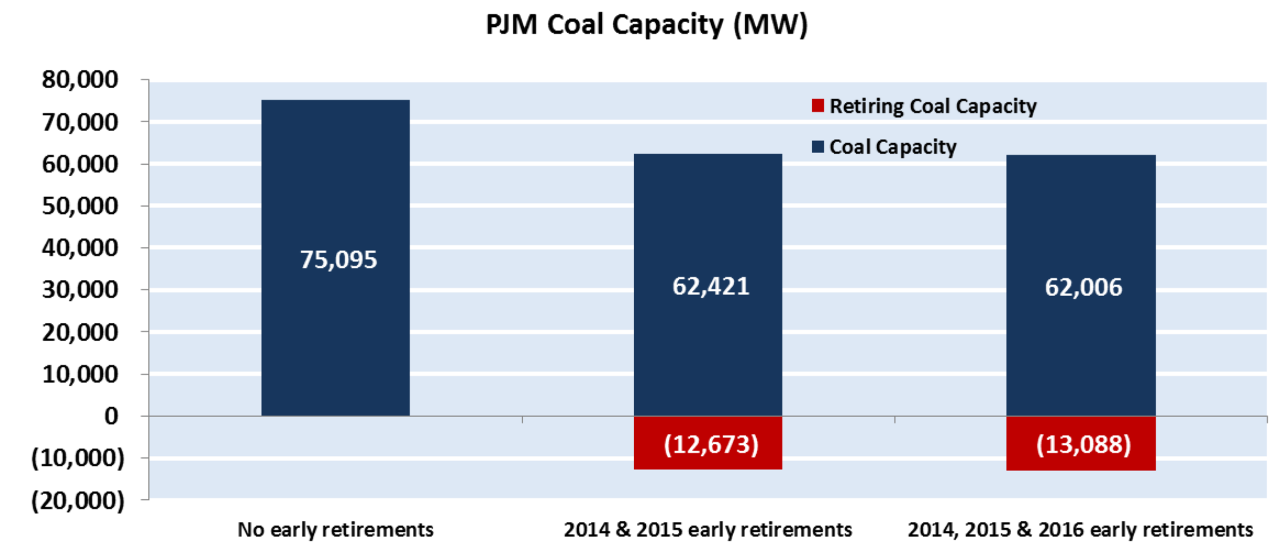
*** PJM revised their Confirmed Gas Curtailment numbers from 6,368 MW to close to 9,000 MW.**

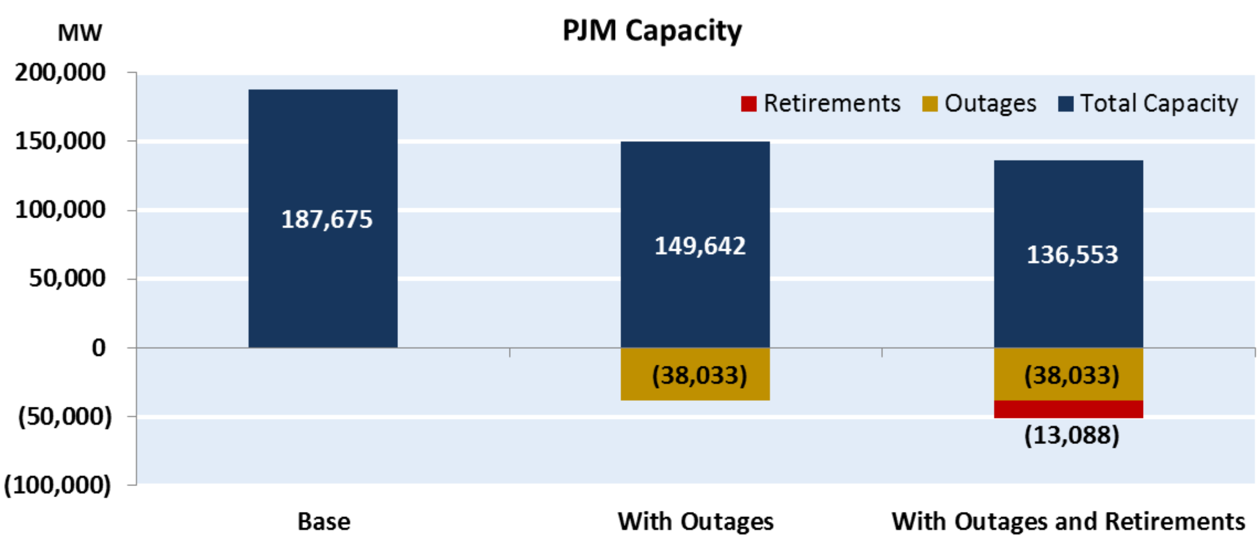
- Despite having sufficient installed capacity to meet the all-time high winter peak of 141,000 MW, PJM faced significant unscheduled outages (nearly 40 GW) and the cold weather resulted in a shortage of gas that left many units unable to run and threatened the grid's reliability.
  - Coal stations dealt with frozen stockpiles, gas pipelines became too constrained to deliver gas, and physical plant parts broke down due to cold temperatures

- For its winter analysis (Case 1 and 2), EVA assumed the above outages for the month of January 2014 as reported by PJM.

PJM WINTER ANALYSIS: TESTING SYSTEM RELIABILITY WITH OUTAGES AND EARLY RETIREMENTS

PJM CAPACITY

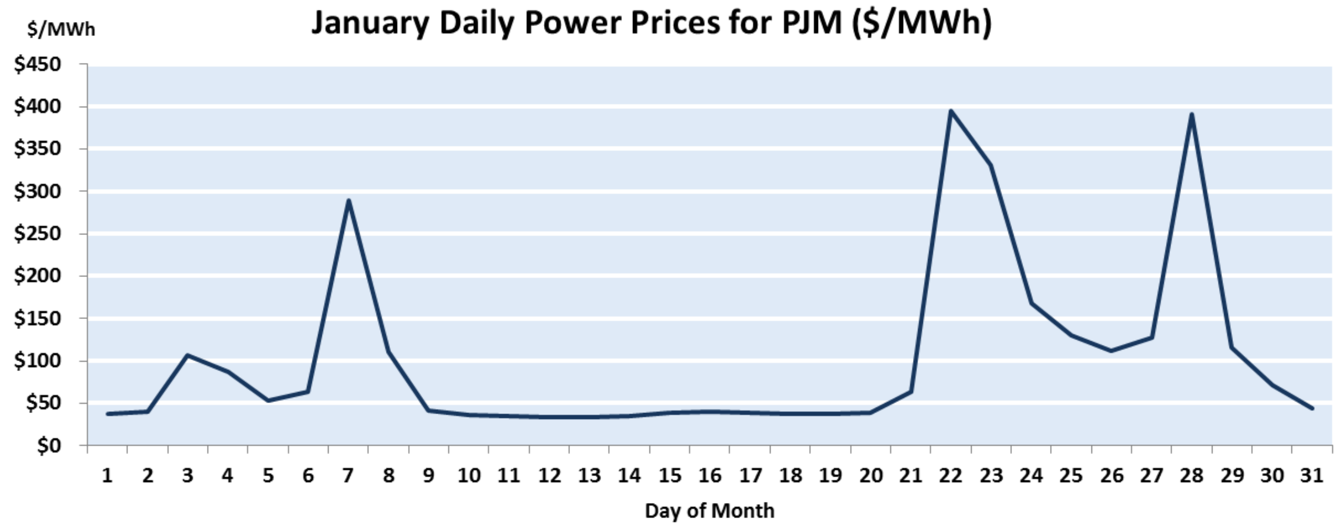




- Of the 75,000 MW of coal capacity in PJM, close to 12,500 MW is scheduled to retire by the end of 2015 and an additional 400 MW by the end of 2016 as a result of environmental regulations and other market drivers.
  - EVA sought to determine the impact of:
  - Extreme weather resulting in high power demand
  - Significant generation outages
  - The loss of coal capacity
- On PJM reliability and prices by simulating an environment where these units were pulled from the market prior to the winter of 2014.

PJM WINTER ANALYSIS: HIGH GAS PRICES AND ELECTRICITY DEMAND DROVE SPIKEY POWER PRICES

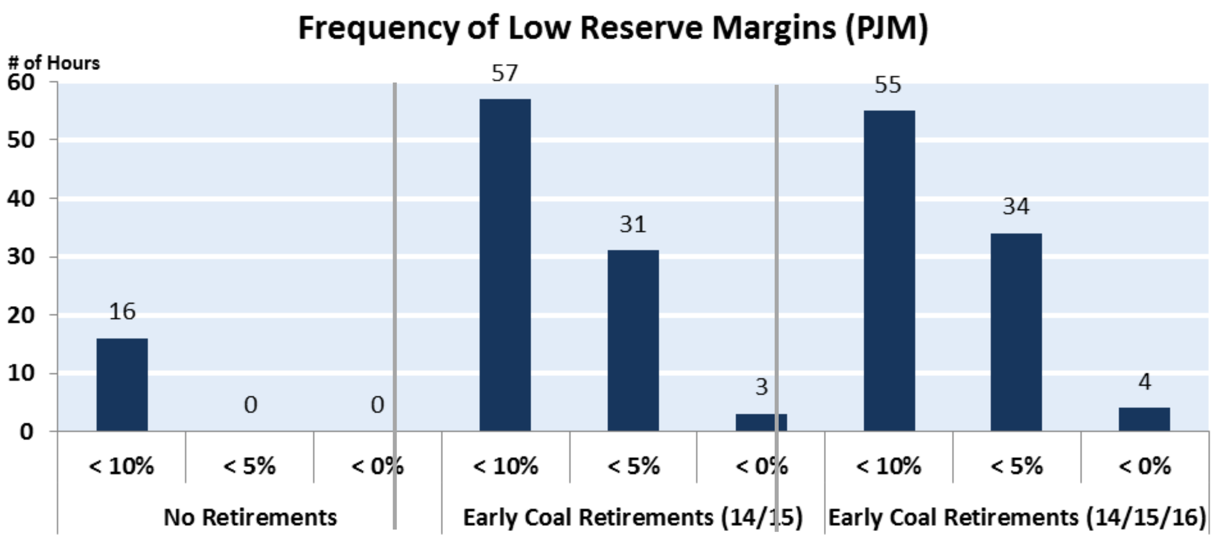
PJM BASE CASE POWER PRICES



- After incorporating the electricity demand and outage information into its modeling, EVA developed the Base Case power prices to the left.
- Though they are close to actual prices, it is impossible to perfectly capture bidding behavior and other market phenomena that drive prices on an hourly basis
- The peaks are consistent with the coldest (and thus highest demand) days of the month.

PJM WINTER ANALYSIS: IMPACT OF COAL RETIREMENTS ON SYSTEM RELIABILITY

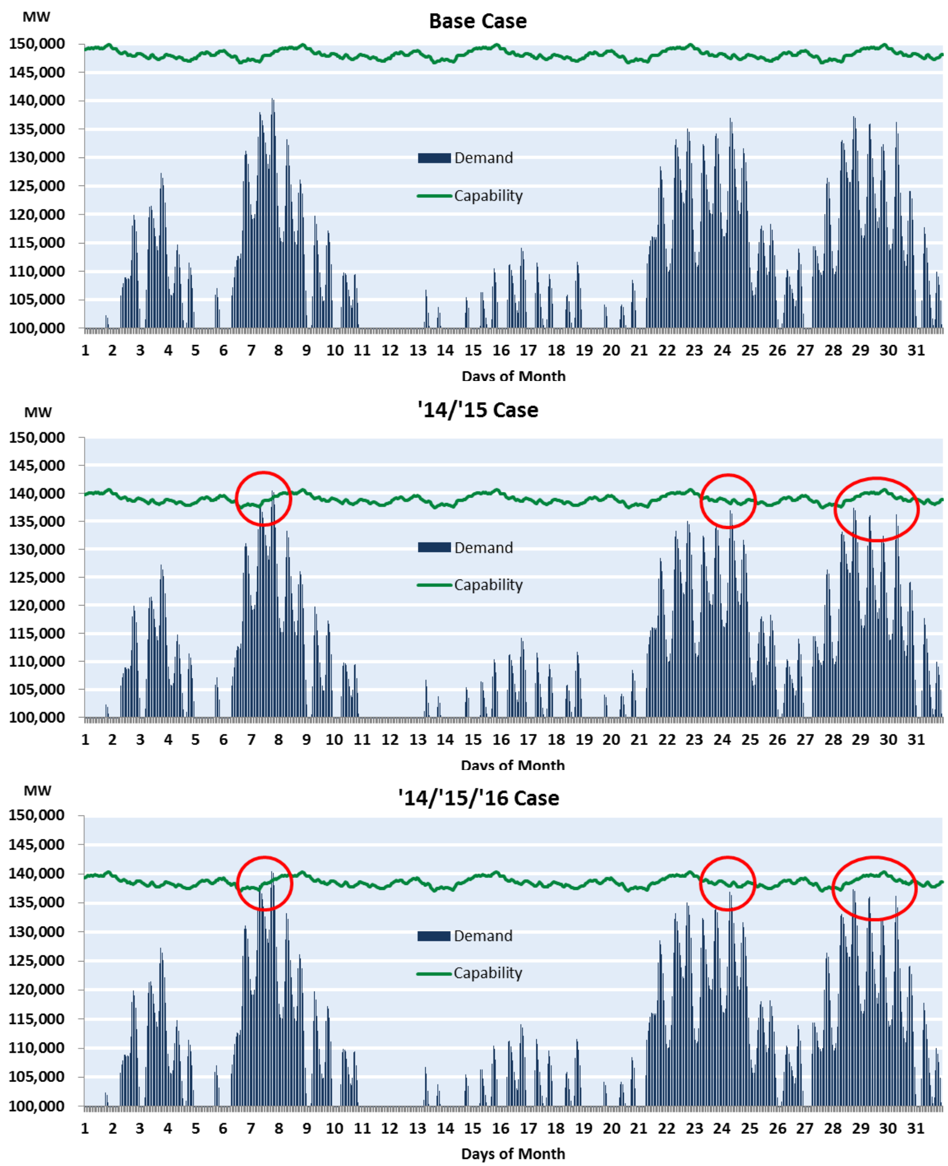
POTENTIAL WINTER BLACKOUTS DUE TO EARLY COAL RETIREMENTS



- The results of the three cases in terms of reliability are shown to the left.
- EVA's modeling indicates that during this past winter, record high electricity demand and generation outages led to several instances in which PJM was low on resources and narrowly avoided load shedding to maintain system reliability.
- Under EVA's two scenarios in which MATS-driven coal retirements exited the market prior to this winter, PJM faced an especially high risk of capacity shortages (31 hours and 34 hours with a reserve margin under 5% in the '14/'15 Case and '14/'15/'16 Case, respectively)

PJM WINTER ANALYSIS: TIMING OF POTENTIAL CAPACITY SHORTAGES

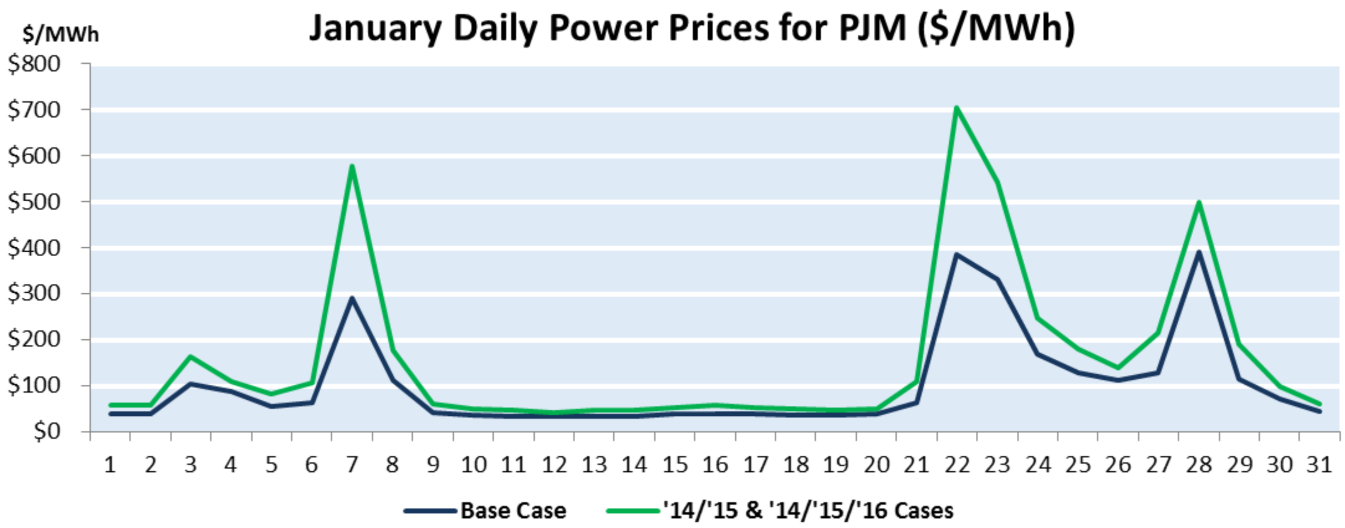
PJM RELIABILITY ANALYSIS FOR JANUARY

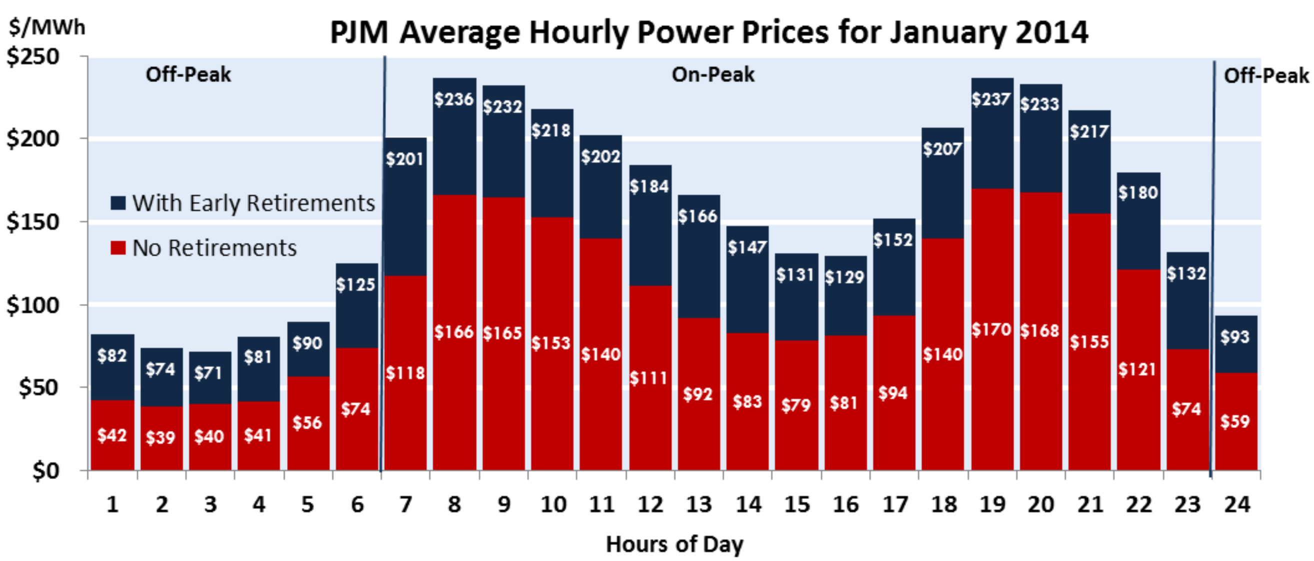


- Over the month of January, there were three major coal weather events that pushed PJM's system to its limits.
  - They occurred in the January 7-8, 22-25, and 28-30 timeframes
- Though the system maintained its integrity during those times in the Base Case, results of the other two cases indicated that multiple shortages would have occurred.
- In the '14/'15 Case, three hours during the January 7-8 cold spell had reserve margins below 0%
- In the '14/'15/'16 Case, four hours during that timeframe had reserve margins below 0%.
  - The later cold spells came perilously close to having negative reserve margins in this case

PJM WINTER ANALYSIS: POWER PRICES DRIVEN EVEN HIGHER DURING COLD SPELLS

PJM POWER PRICES





- As a result of the early retirements, January wholesale prices increased significantly from the Base Case.
- The price impact was almost identical between the '14/'15 Case and '14/'15/'16 Case, where power price spikes in January would have averaged 55% higher, but the majority of the impact would have been seen during those three major cold spells.
- As the retiring units are pulled from the market, generation that historically came from coal is now shifted to gas and higher heat rate peaking units, placing upward pressure on prices.
- The effect is more pronounced during the peak hours when demand is highest, though off-peak prices still increased significantly in the analysis.

PJM GAS MARKET ASSESSMENT

- Additional Curtailments of Gas Units Could Have Occurred in a Few Other Regions
  - Pipeline situation is very different than in New England
    - In general, there are not any major pipeline constraints in these regions.
  - Site specific situations could result in some further curtailments of gas supplies, particularly in the 3 to 6 days where peak demand for the nation would have been >120 BCFD

Region	Pipeline Constraints	Approximate Incremental Gas Burn	Observations
SERC	No	0.5 BCFD	Site specific situations could exist.
RFC	No	0.4 BCFD	Site specific situations; higher basis differentials.
SPP	No	0.2 BCFD	Site specific situations could exist.
WECC	Some	0.2 BCFD	In general West was not affected like the East.

DETAILED POWER ANALYSIS OUTLINE

- PJM Winter Analysis
- MISO Winter Analysis
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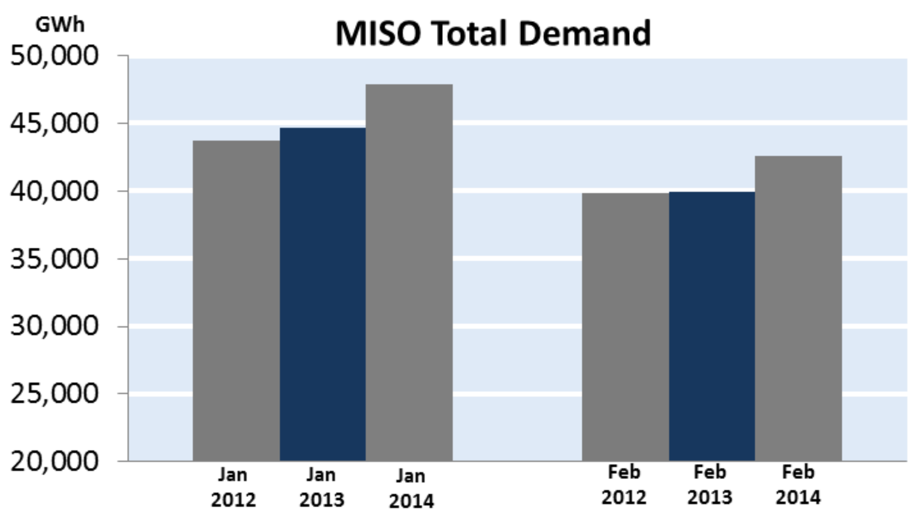
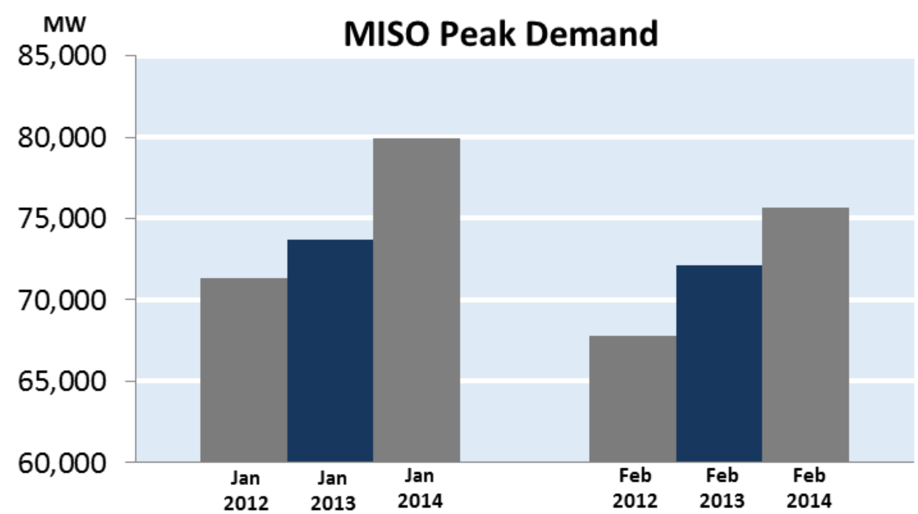
- ISO-NE Summer Analysis

MISO WINTER ANALYSIS: EFFECTS OF POLAR VORTEX ON ELECTRICITY DEMAND

MISO WINTER DEMAND OUTLOOK

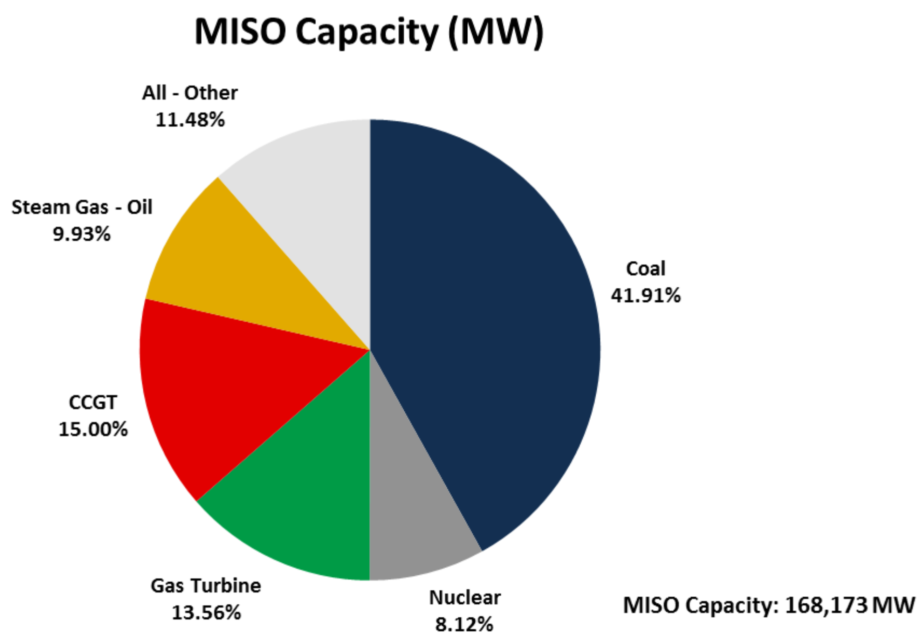
- Extreme weather conditions from the polar vortex in MISO drove peak and total power demand for January up 7% and 5% YoY, respectively.
- The YoY increase seen in February was slightly more tempered.
- To simulate the extreme weather condition in MISO, EVA used actual hourly load data in its modeling effort.





MISO WINTER ANALYSIS: EXISTING SUPPLY DURING POLAR VORTEX

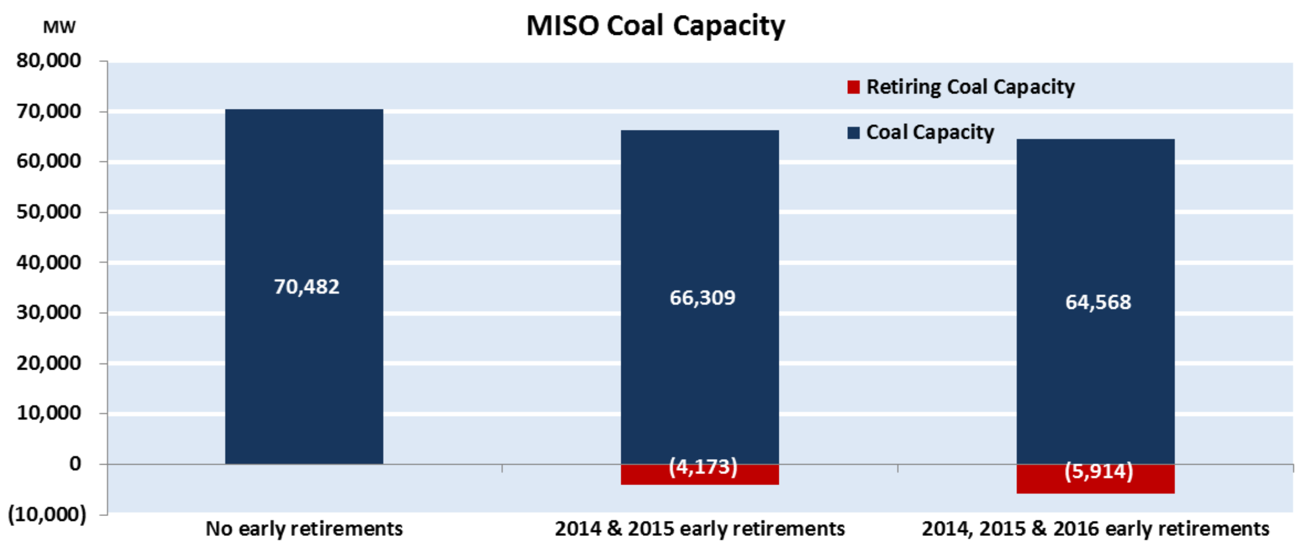
MISO INSTALLED CAPACITY



- MISO also relies heavily on coal to provide system reliability and for producing power – nearly 42% of all MISO capacity is coal-fired.
- CCGTs currently comprise 15% of total capacity though this share is expected to grow as coal retirements mount.
- MISO's reserve margin remained healthy during the polar vortex, meaning reliability did not face a significant threat.

MISO WINTER ANALYSIS: TESTING SYSTEM RELIABILITY WITH EARLY RETIREMENTS

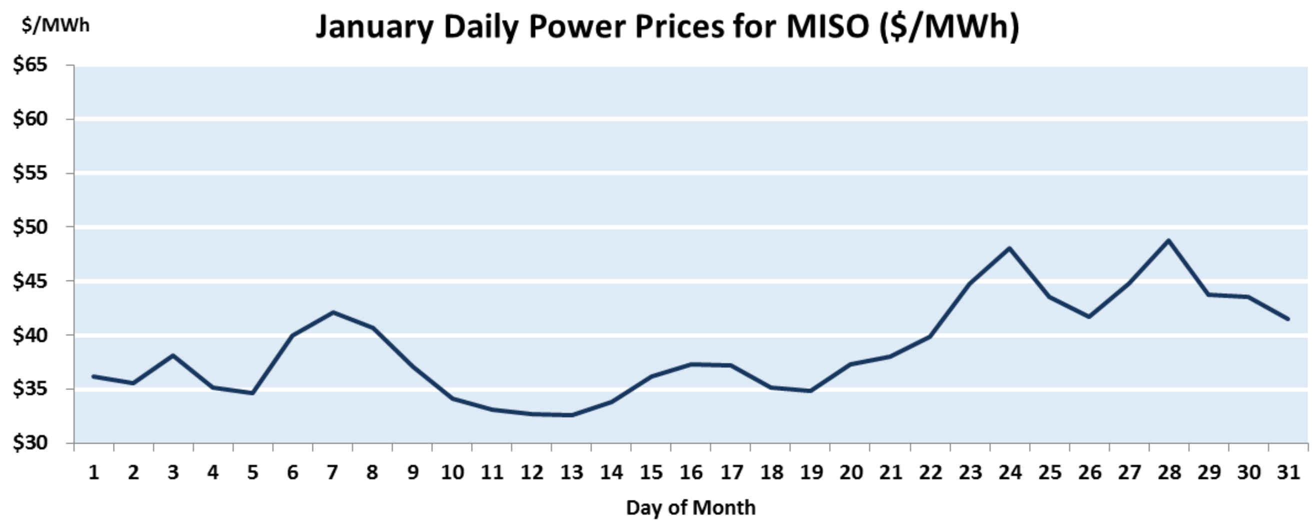
MISO CAPACITY OUTLOOK



- Of the 70,000 MW of coal capacity in MISO, close to 4,000 MW is scheduled to retire by the end of 2015 with an additional 1,800 MW by the end of 2016.
- EVA sought to determine the impact of:
  - Extreme weather resulting in high power demand
  - The loss of coal capacity
- On MISO reliability and prices by simulating an environment where these units were pulled from the market prior to the winter of 2014.
- Fortunately, MISO did not experience the same magnitude of generation outages that PJM did during that time.

MISO WINTER ANALYSIS: PRICE IMPACT WAS TEMPERED DUE TO FEWER OUTAGES

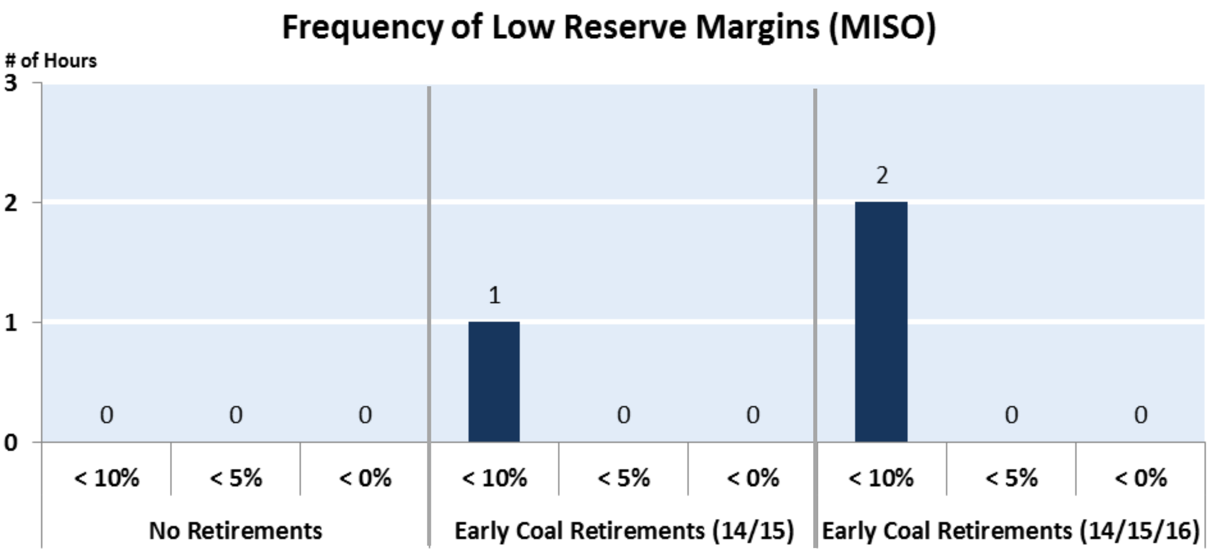
MISO POWER PRICES



- After incorporating the electricity demand and outage information into its modeling, EVA developed the Base Case power prices to the left.
- Though they are close to actual prices, it is impossible to perfectly capture bidding behavior and other market phenomena that drive prices on an hourly basis
- Because coal contributes strongly to the generation mix in MISO, gas-driven power price spikes were not as prevalent.

MISO WINTER ANALYSIS: IMPACT OF COAL RETIREMENTS ON SYSTEM RELIABILITY

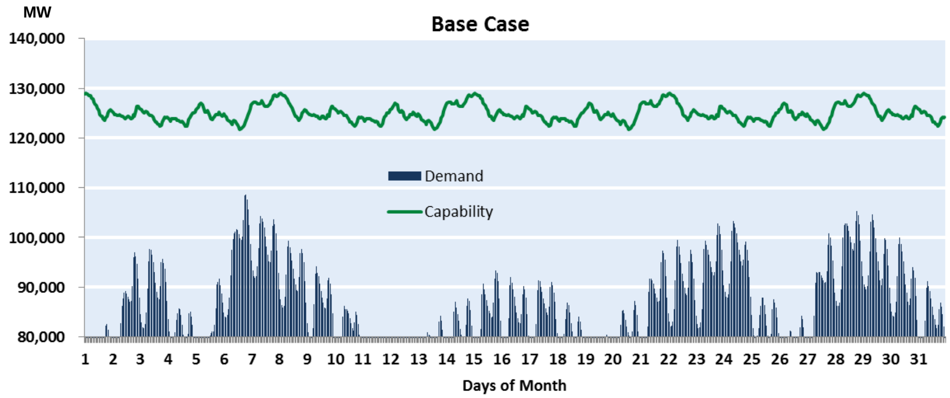
POTENTIAL WINTER BLACKOUTS DUE TO EARLY COAL RETIREMENTS

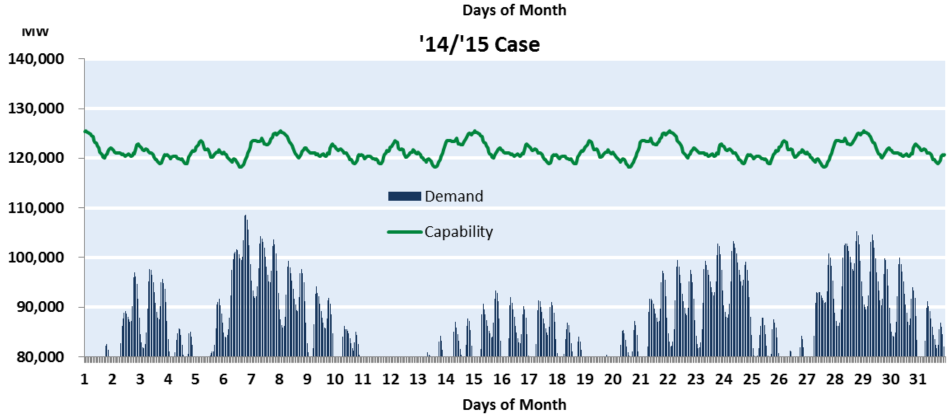


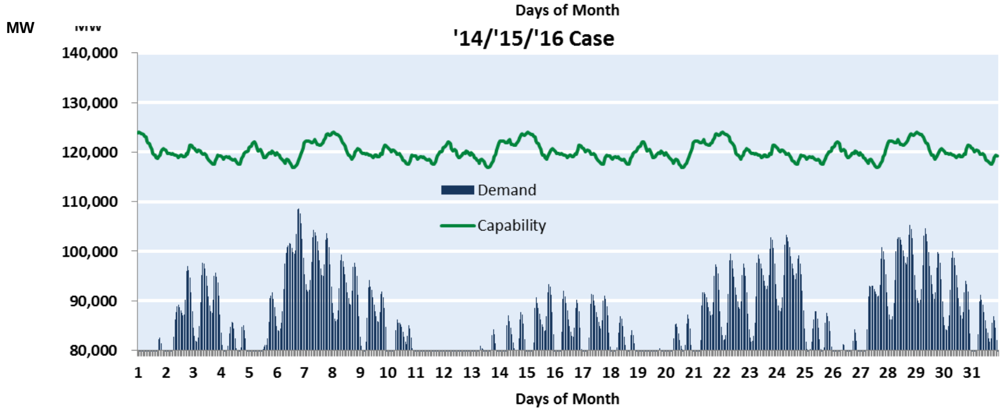
- The results of the three cases in terms of reliability are shown to the left.
- EVA's modeling indicates that despite very high demand due to the sustained cold weather, the reserve margin in MISO did not become precariously tight.
- Under EVA's two scenarios in which MATS-driven coal retirements exited the market prior to this winter (Case 1 and 2), MISO faced only a very small risk of capacity shortages (2 hours with a reserve margin under 10% in the '14/'15/'16 Case).

MISO WINTER ANALYSIS: TIMING OF POTENTIAL CAPACITY SHORTAGES

MISO RELIABILITY ANALYSIS FOR JANUARY



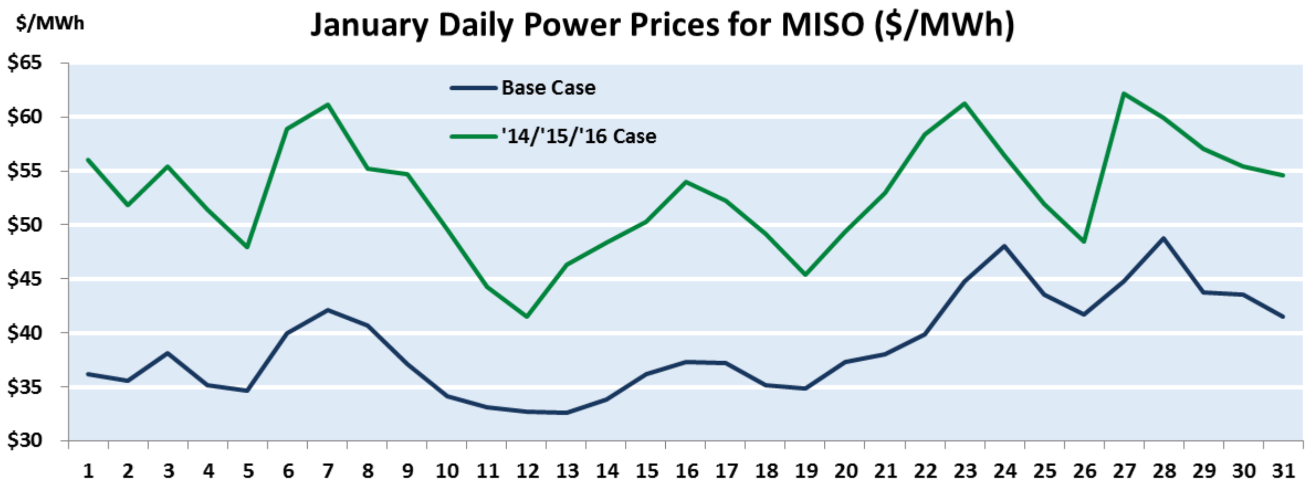


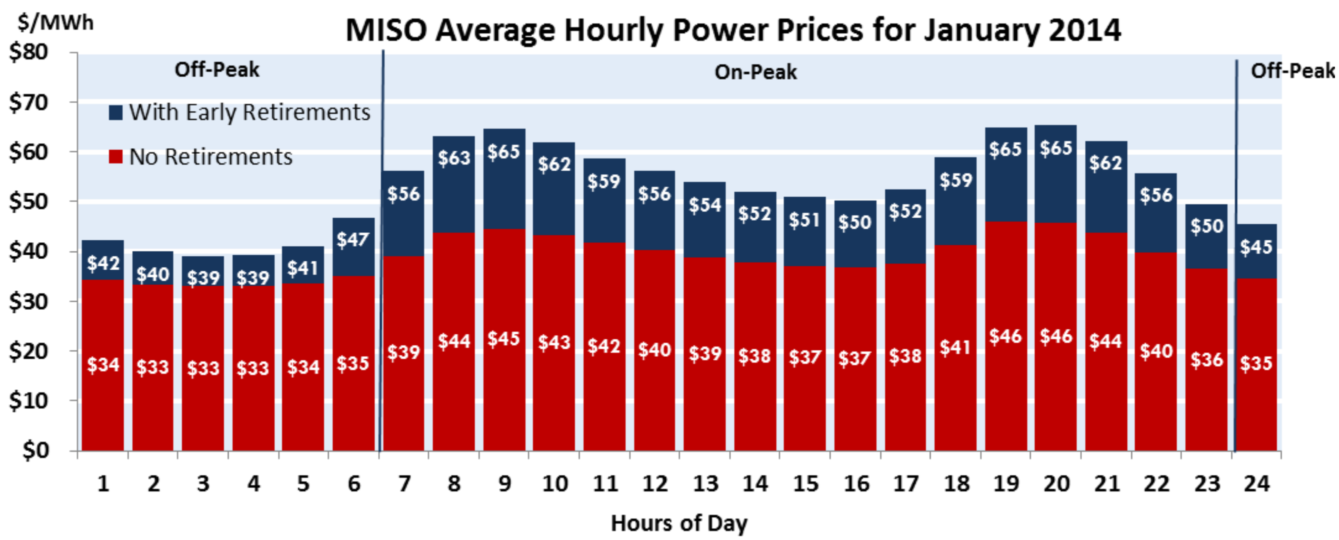


- As shown in the above slide, MISO's supply-demand balance did not become especially tight during the polar vortex because they did not face the same outages that PJM did.
- Even in EVA's retirement cases, MISO had at least a 10,000 MW buffer because the magnitude of coal capacity leaving the market is much lower than that of PJM.

MISO WINTER ANALYSIS

POWER PRICES – MISO





- Despite being a coal-heavy region like PJM, MISO is not expected to be as adversely affected in terms of wholesale power prices by coal retirements as its neighbor to the East.
- In the ’14/’15 Case, January prices climbed an average of 33% as a result of increased gas generation and fuel prices, while July prices climbed just 9%.
- The impact was only slightly greater in the ’14/’15/’16 Case.

MISO WINTER ANALYSIS

MISO GAS MARKET ASSESSMENT

- Impact Minimal for Several Regions

Region	Pipeline Constraints	Approximate Incremental Gas Burn	Observations
NYPOOL			
NYC	Yes		Very constrained pipeline system, but not affected by coal burn; higher basis differentials.
Upstate	No	0.07 BCFD	
MRO	No	0.08 BCFD	Site specific situations could exist.
FRCC	Yes	0.06 BCFD	Site specific situations could exist.
ERCOT	No	0.03 BCFD	Site specific situations could exist.

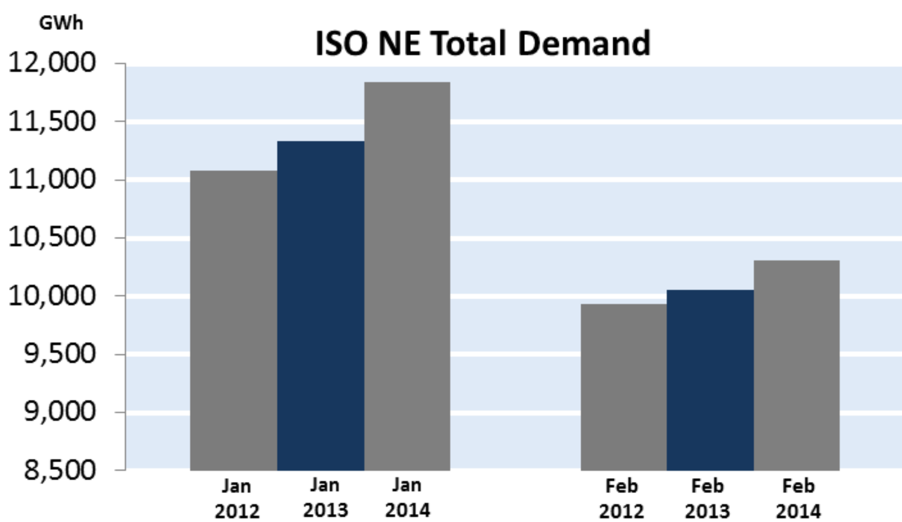
DETAILED POWER ANALYSIS OUTLINE

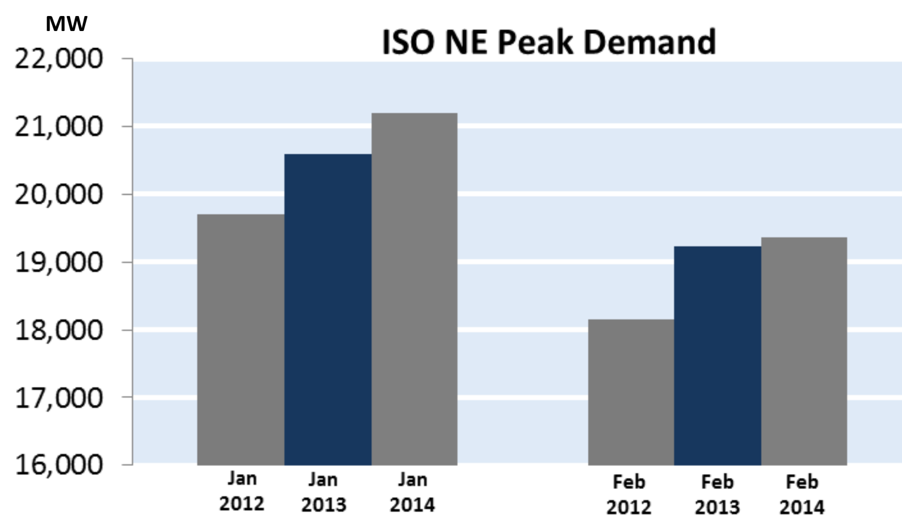
- PJM Winter Analysis
- MISO Winter Analysis
- ISO-NE Winter Analysis
- PJM Summer Analysis
- MISO Summer Analysis
- ISO-NE Summer Analysis

ISO-NE WINTER ANALYSIS: EFFECTS OF POLAR VORTEX ON ELECTRICITY DEMAND

ISO-NE WINTER DEMAND

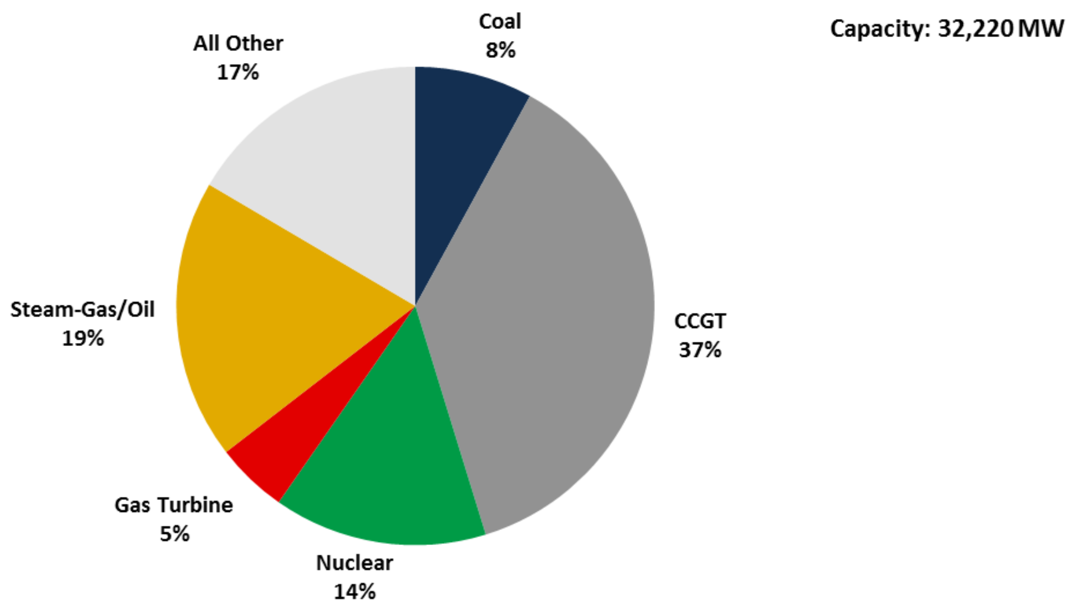
- ISO-NE total January demand grew 7% YoY where as the peak demand for January grew 8% YoY. February total demand growth was at 7% whereas peak demand growth was at 5% YoY.
- To simulate the extreme weather condition in ISO-NE, EVA used actual hourly load data in its modeling effort.





ISO-NE WINTER ANALYSIS: EXISTING SUPPLY DURING POLAR VORTEX

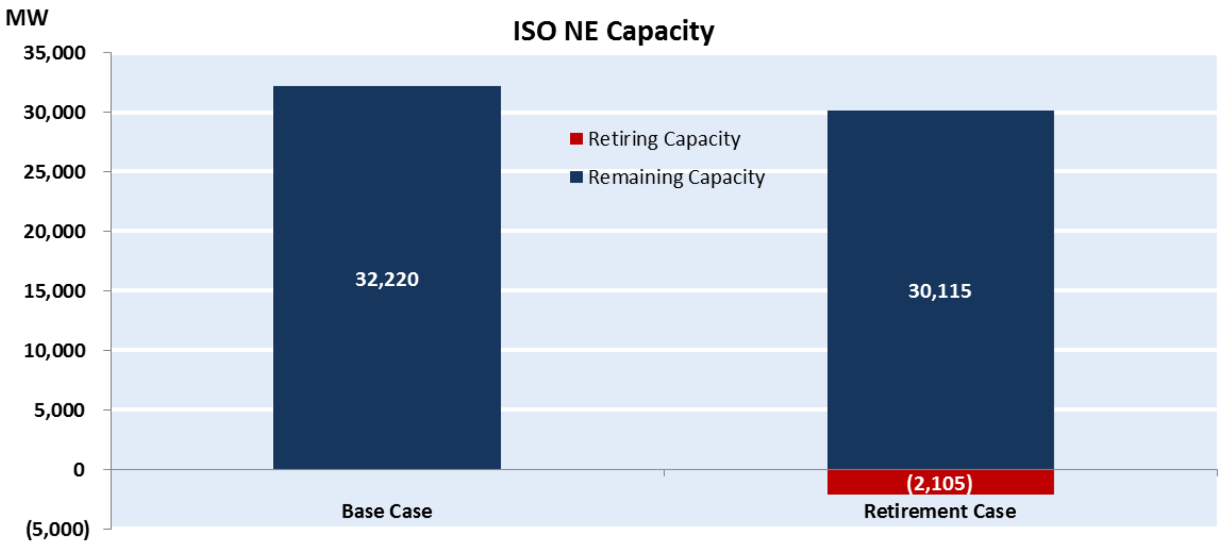
ISO-NE CAPACITY



- Only 8% of ISO-NE's capacity is coal-fired – by far the smallest of the three markets EVA analyzed.
- At first glance, it does not appear that the existing coal capacity is important to reliability, but EVA realized that because of the especially unpredictable nature of gas availability in the region, having a diverse supply is vital to maintaining the system in the winter.
- MATS regulations have a very limited effect on the supply in ISO-NE.

ISO-NE WINTER ANALYSIS: TESTING SYSTEM RELIABILITY WITH EARLY RETIREMENTS

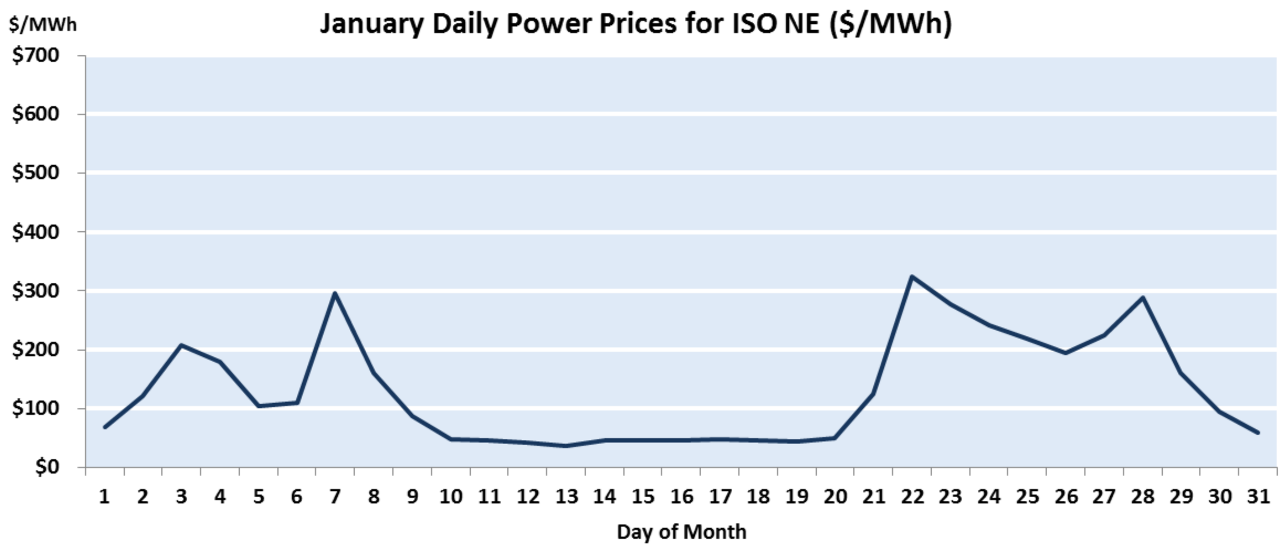
ISO-NE CAPACITY



- Of the 2,600 MW of coal capacity in ISO-NE, EVA assumed that 2,100 MW had left the market prior to the winter of 2014 in Cases 1 and 2.
- Because gas is scarce in New England in the winter, EVA sought to determine the reliability and price impact on the region under the three Cases.

ISO-NE WINTER ANALYSIS

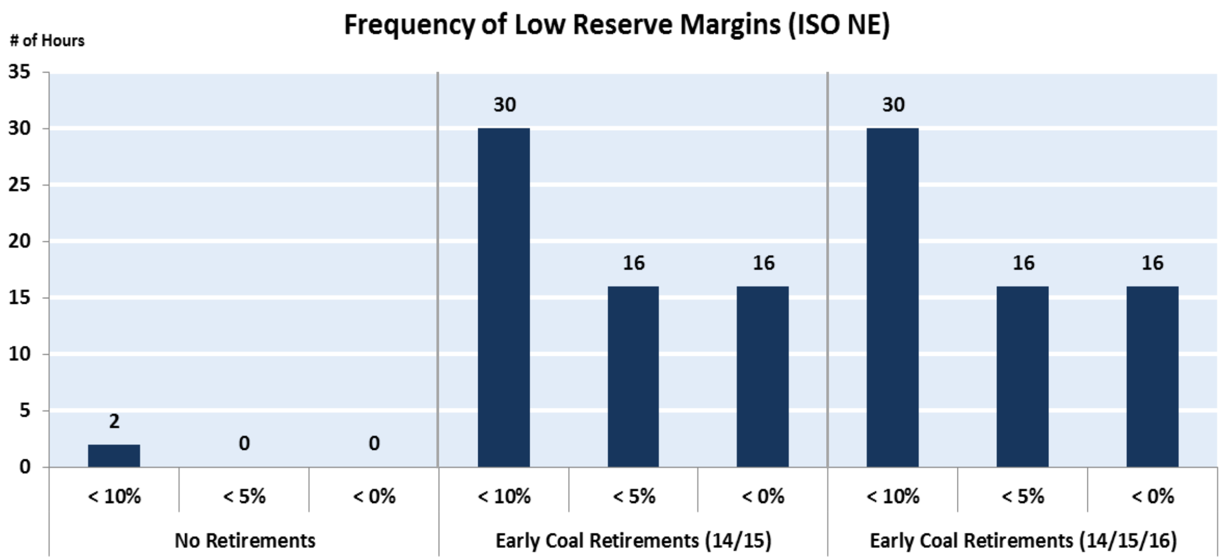
ISO-NE POWER PRICES



- ISO-NE faces a unique situation when it comes to gas availability. Being located at the end of the gas pipelines, ISO-NE has to deal with unavailability of gas due to constraints in the system.
- During the winter of 2014, Oil units in ISO-NE produced 25 times more power than they did last winter as gas prices went through the roof due to the constraints. This resulted in high power prices sustained over a long period of time.
- If the coal units in ISO-NE were to retire last year, the power prices would have seen an even bigger jump during high demand periods crossing the $400/MWh mark.
- Power prices would go through the roof in summer due to the unavailability of the coal units and high temperatures.

ISO-NE WINTER ANALYSIS: IMPACT OF COAL RETIREMENTS ON SYSTEM RELIABILITY

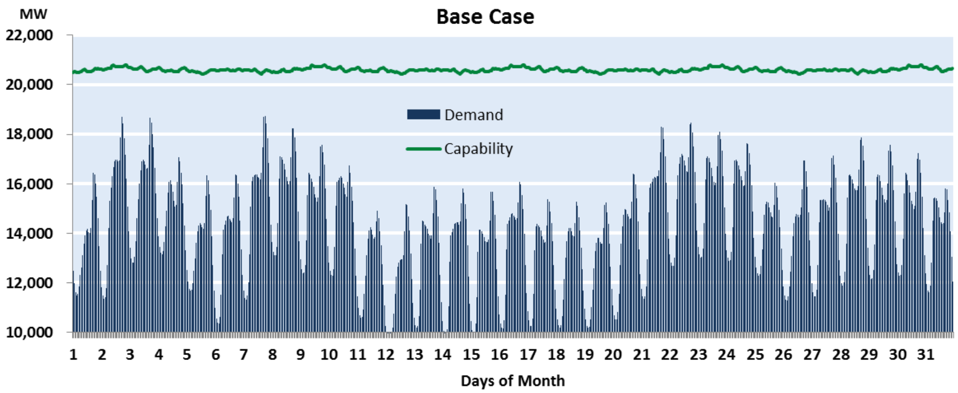
POTENTIAL WINTER BLACKOUTS DUE TO EARLY COAL RETIREMENTS

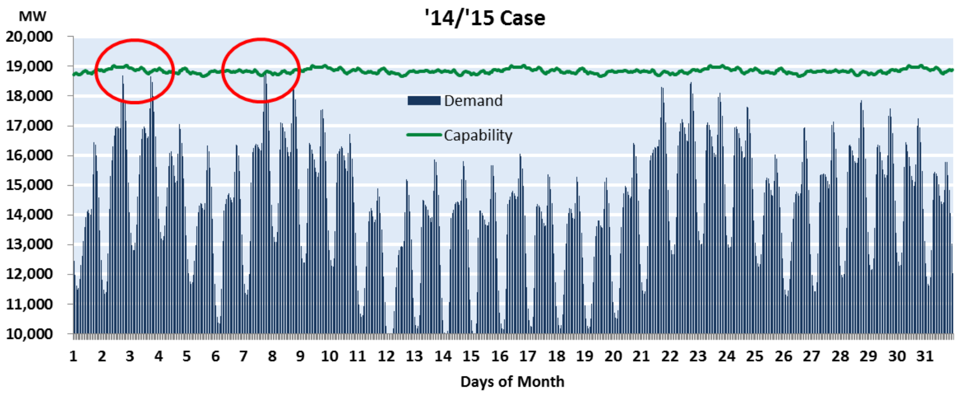


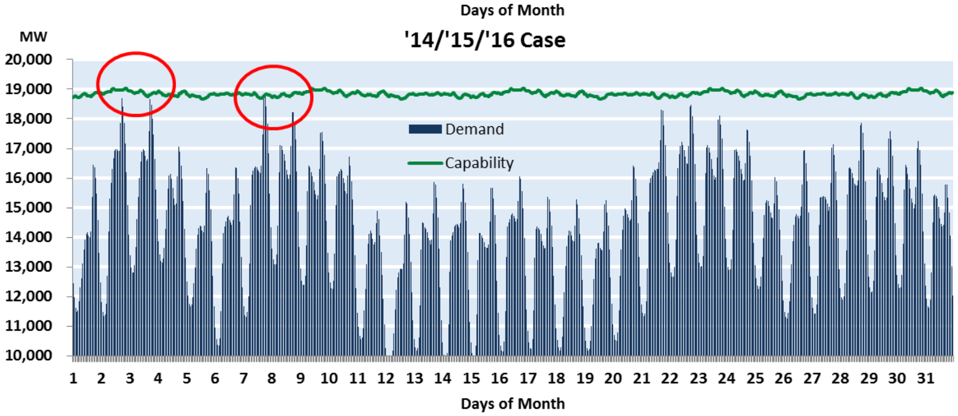
- During this past winter, record high electricity demand and forced generation outages led to several instances in which PJM was low on resources and narrowly avoided load shedding to maintain the system reliability
- In MISO, despite record high demand due to sustained cold weather, the reserve margin did not become precariously tight
- Under EVA's two scenarios in which MATS-driven coal retirements exited the market early, PJM faced an especially high risk of capacity shortages (31 hours and 34 hours with a reserve margin under 5% in the '14/'15 Case and '14/'15/'16 Case, respectively)
- MISO, with fewer retirements, faced only a very small risk of capacity shortages (2 hours with a reserve margin under 10% in the '14/'15/'16 Case)

ISO-NE WINTER ANALYSIS: TIMING OF POTENTIAL CAPACITY SHORTAGES

ISO-NE RELIABILITY ANALYSIS FOR JANUARY



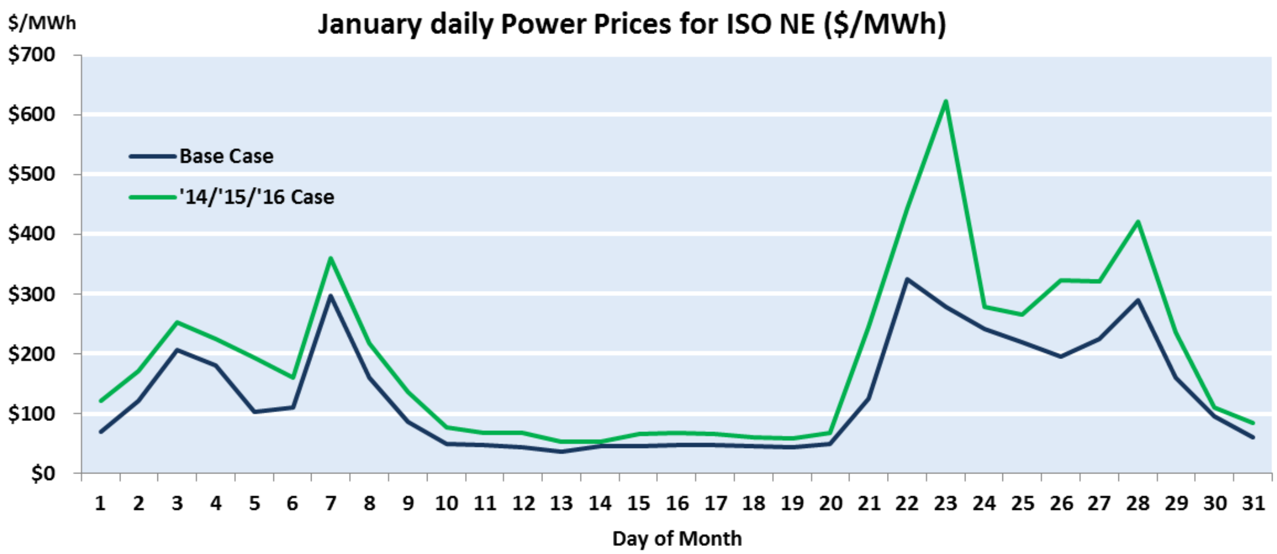


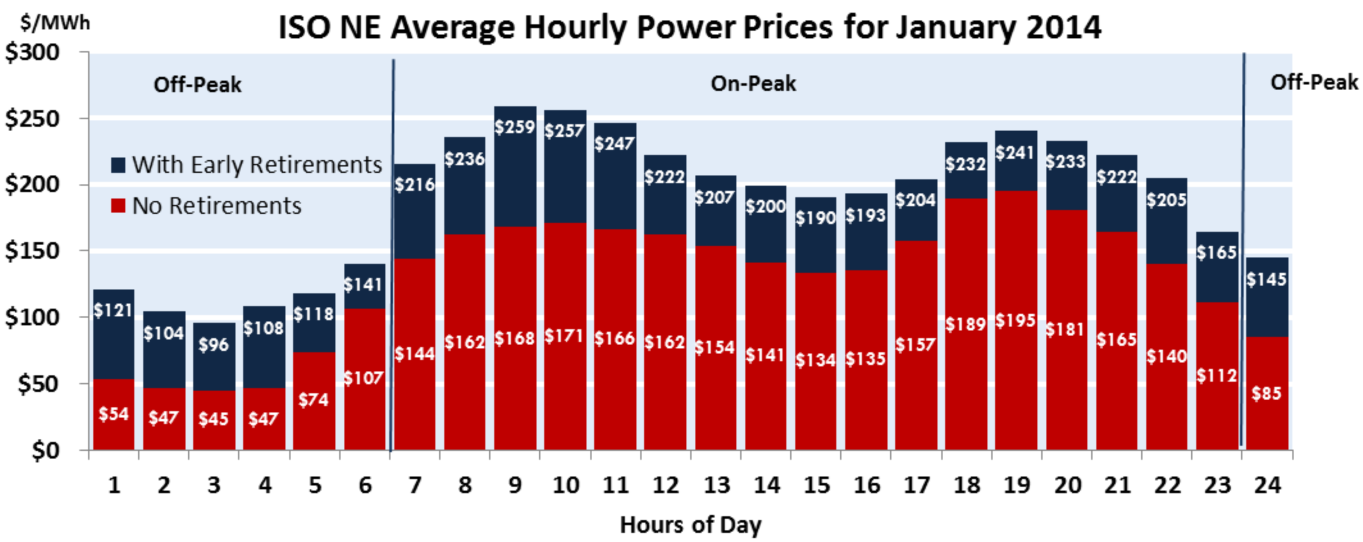


- Over the month of January, there were three major coal weather events that pushed ISO-NE's system to its limits.
  - They occurred in the January 7-8, 22-25, and 28-30 timeframes
- Though the system maintained its integrity during those times in the Base Case, results of the other two cases indicated that multiple shortages would have occurred.
- In the '14/'15 case as well as the '14/'15/'16 case, 16 hours during that timeframe had reserve margins below 5% and 0% potentially causing reliability issues.

ISO-NE WINTER ANALYSIS

ISO-NE POWER PRICES





- ISO-NE faces a unique situation when it comes to gas availability. Being located at the end of the gas pipelines, ISO-NE has to deal with unavailability of gas due to constraints in the system.
- During the winter of 2014, Oil units in ISO-NE produced 25 times more power than they did last winter as gas prices went through the roof due to the constraints. This resulted in high power prices sustained over a long period of time.
- If the coal units in ISO-NE were to retire last year, the power prices would have seen an even bigger jump during high demand periods crossing the $400/MWh mark.
- Power prices would go through the roof in summer due to the unavailability of the coal units and high temperatures.

ISO-NE WINTER ANALYSIS

ISO-NE GAS MARKET ASSESSMENT

- New England (NEPOOL)
  - New England has gas pipeline capacity constraints and can not meet all of the region's gas load requirements
    - Historical synopsis for the three major regional pipelines.

Pipeline	Percent of Northeast Gas-Fired Generation Served	Percent of Gas/Electric Load FT	Curtailments
Algonquin	40%	10%	● Can not meet entire IT load for several months in each year. ● Winter 2011/2012 restricts gas supplies at Cromwell, CT for >100 days (i.e., 2/3 of winter). ● Winter 2013/2014 restricts IT at Stony Point, NY and Cromwell, CT; no receipt increases at Mendin, MA on Dec 13, 2014.(1)
Tennessee	13 Plants	24%	● Winter restrictions at Station 245 during winter of 2009/2010 (41.7% of winter); 2010/2011 (96.0%); and 2011/2012 (99.3%). ● Summer restriction for 2009 (0); 2010 (22.4%) and 2011 (78.5%).
Iroquois	-	20-25%	

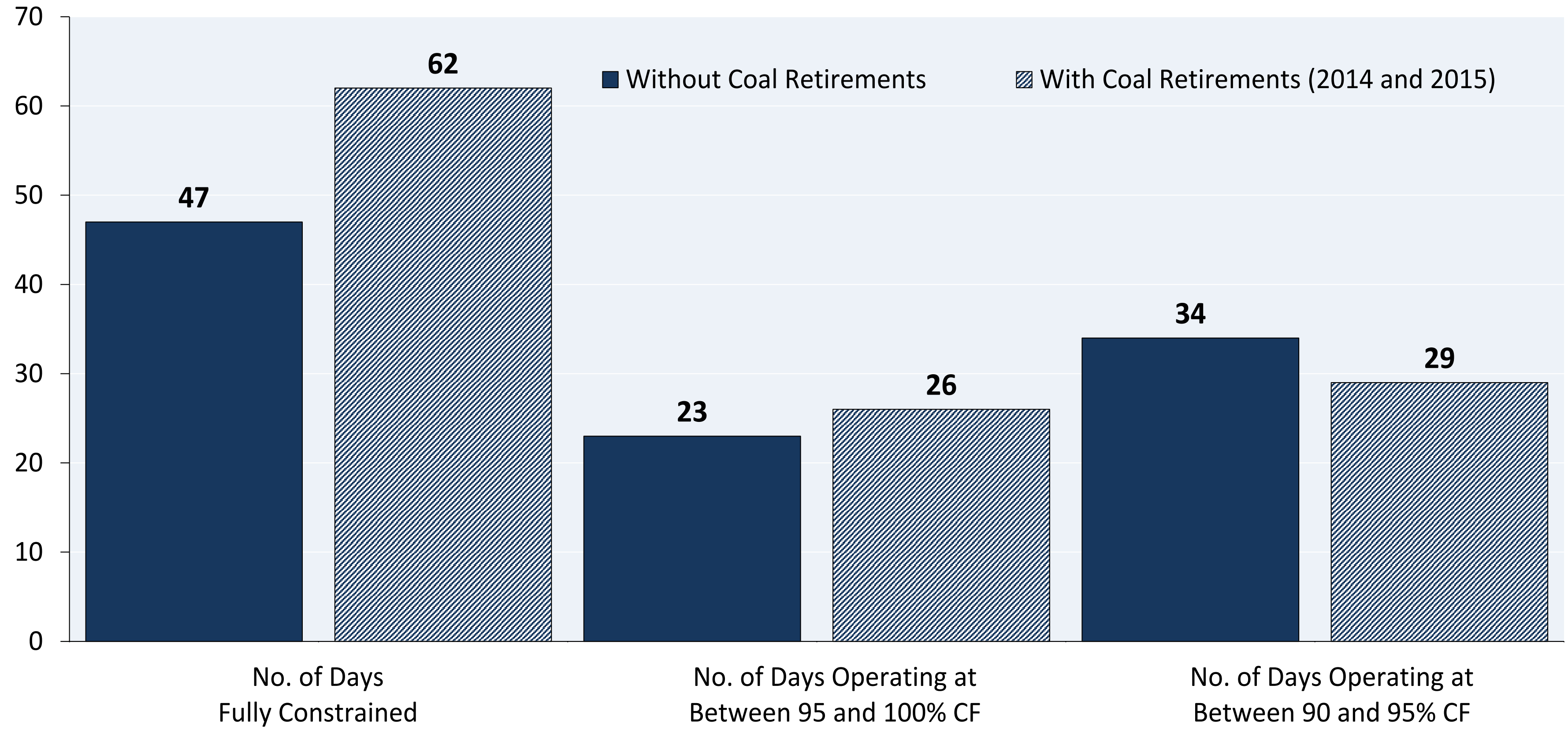
(1) "Power lines replaced gas pipelines during recent Northeast coal snap", *Inside FERC's Gas Market Report*, January 3, 2014, pp 15-16.

ISO-NE WINTER ANALYSIS

ISO-NE GAS MARKET ASSESSMENT

- Case example for Algonquin:
  - Pipeline constraints would increase from about 70 days during the winter to about 88 days.

ALGONQUIN CAPACITY FACTORS FOR WINTER 2013/2014



ISO-NE GAS MARKET ASSESSMENT

- During winter of 2013/2014 used oil-fired generation to meet load requirements (fuel switching).
  - 4% of Dec through Feb load, or 1.13 TWh, was oil-fired.
    - In prior winter only 0.6%, or 167 GWh (i.e., 85% less).
    - A special program for winter 2013/2014 with 90% of 3 MM barrels in tanks consumed.(1)
    - 55-60% of gas units are dual-fuel with 40-45% gas-only.
    - 418 MW of oil-fired generation set to retire by 2017.
- Winter of 2013/2014 with projected retirements
  - Regional gas burn would have increased about 0.1 BCFD.
    - While on the surface this does not seem to be a large amount, already constrained pipelines could not accommodate the increased burn.
    - Key alternatives were:
      - Increased oil-fired generation (i.e., would require additional 1.8 MMB;
        - However, NEPOOL outstripped its capability to resupply fuel oil in January in the base case.(2)
      - Additional imported power, although difficult to determine which neighboring region would be capable of exporting power; and,
      - Load shedding.

(1) "Oil often trumped gas in Northeast during record-setting winter cold", *Inside FERC's Gas Market Report*, April 11, 2014, pp 3-4.
(2) "ISO-NE CEO says New England gas supply issue will get worse before it gets better", *SNL Financial*, March 17, 2014.

DETAILED POWER ANALYSIS OUTLINE

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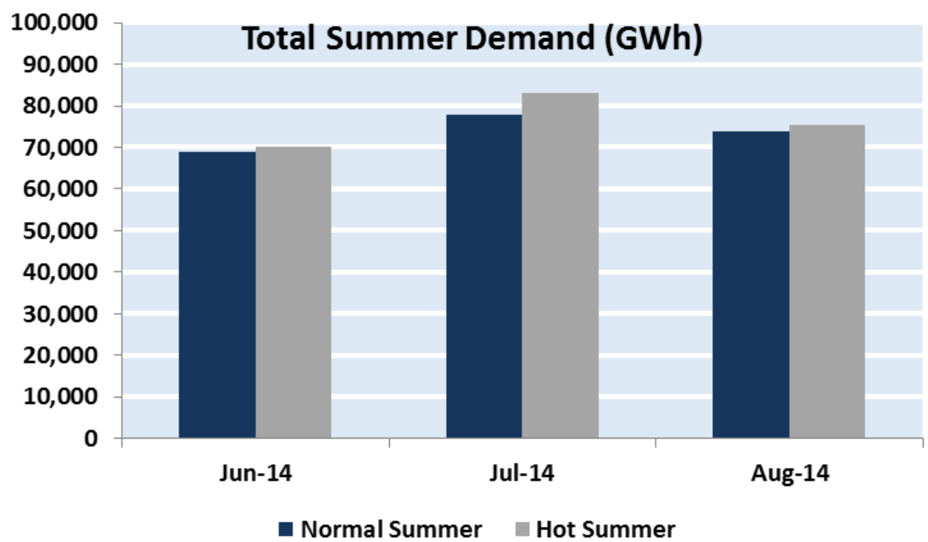
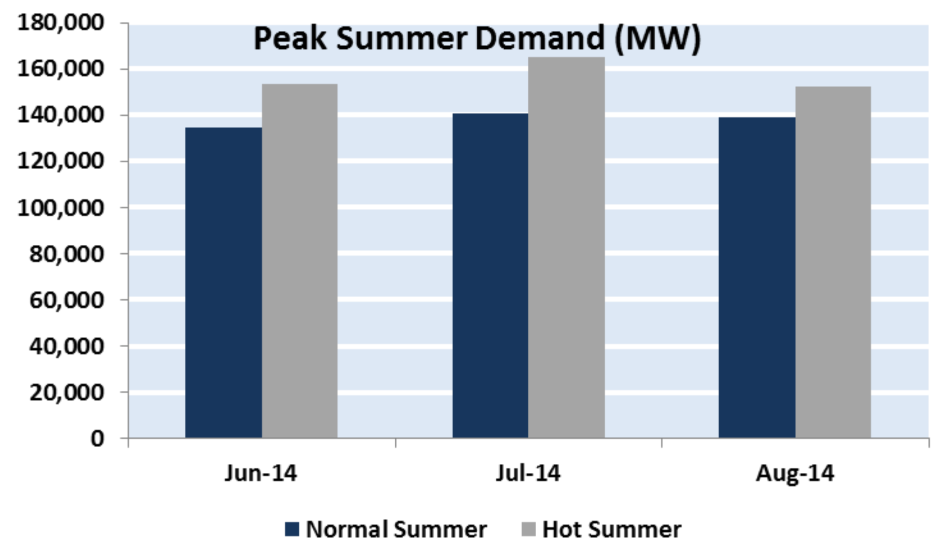
PJM SUMMER ANALYSIS: EFFECTS OF HEAT WAVE ON ELECTRICITY DEMAND

PJM SUMMER DEMAND OUTLOOK

- To simulate a hot summer, EVA used load data from 2011, which had very high peak and total demand due to sustained warm weather.

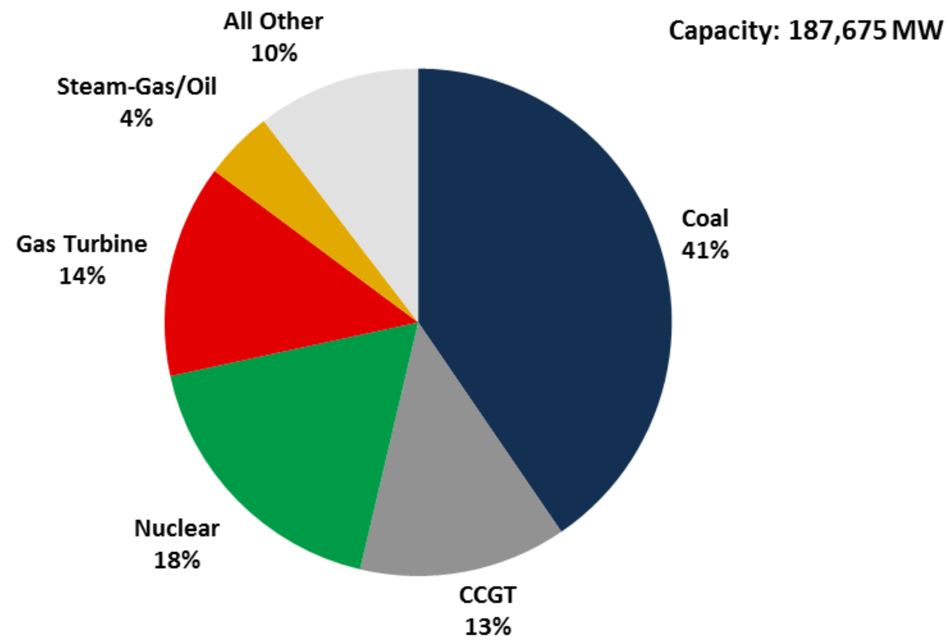
- Compared to our forecast of a normal summer demand, our hot summer demand was 4% higher on average, whereas the peak demand was higher by 17%, resulting in greater stress on the system.





PJM SUMMER ANALYSIS: EXISTING CAPACITY DURING SUMMER HEAT WAVE

PJM INSTALLED CAPACITY



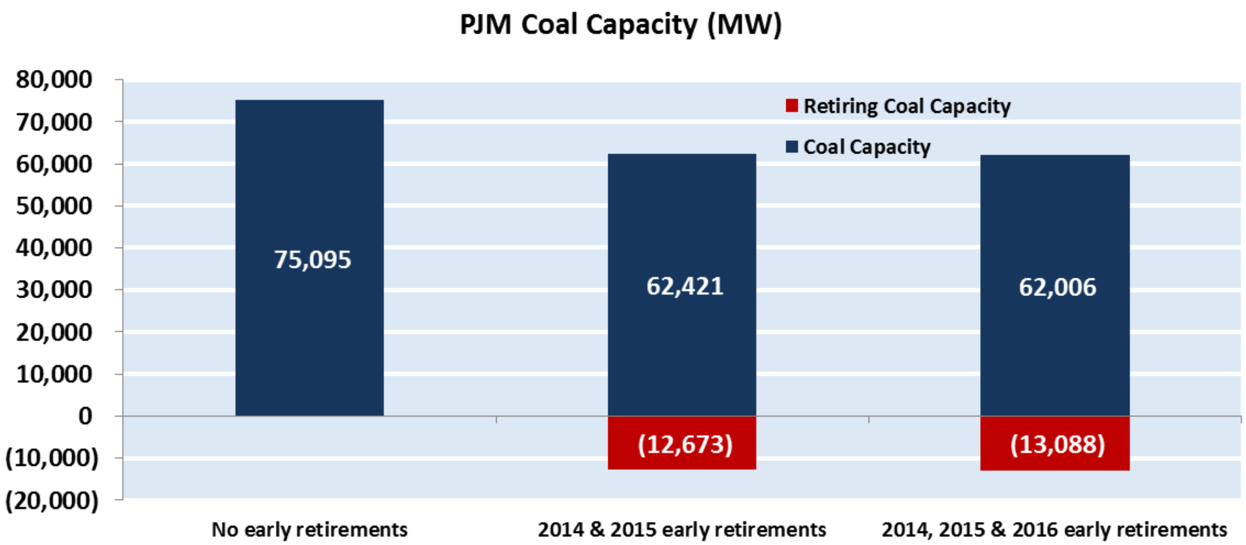
- Because of its proximity to Appalachian coal, PJM is a coal-dominated region – 41% of all existing capacity is coal-fired. This capacity has played a very important role in meeting summer peak demand, typically running at availability during July and August.

- CCGTs currently account for 13% of total capacity though this share is expected to grow as coal retirements mount.

- Until these CCGTs begin commercial operations, however, coal units in PJM are the backbone for system reliability.

PJM SUMMER ANALYSIS: TESTING SYSTEM RELIABILITY WITH EARLY RETIREMENTS

PJM CAPACITY OUTLOOK



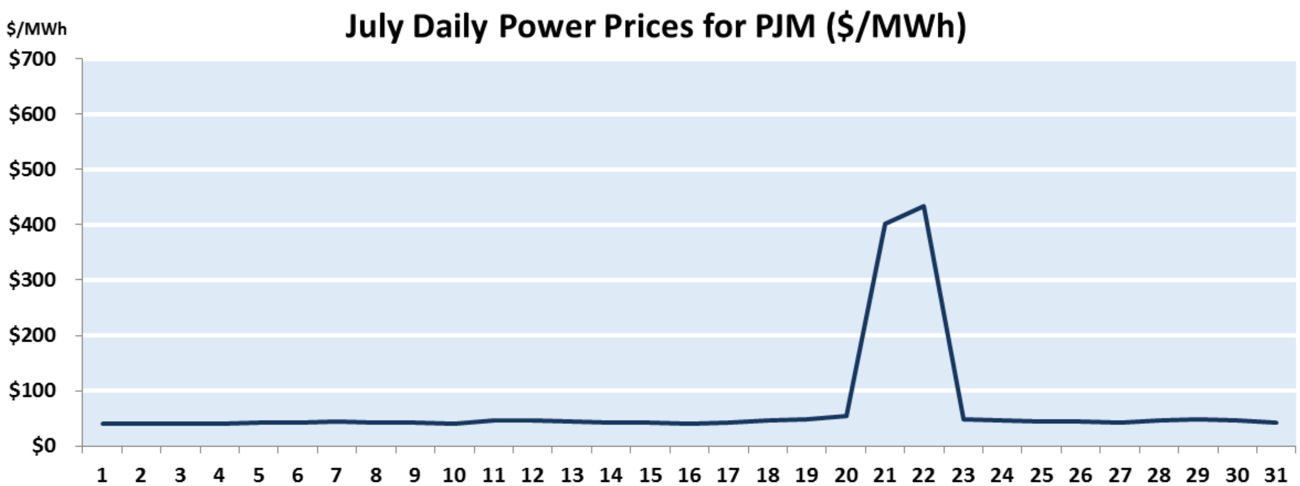
- Of the 75,000 MW of coal capacity in PJM, close to 12,500 MW is scheduled to retire by the end of 2015 and an additional 400 MW by the end of 2016 as a result of environmental regulations and other market drivers.

- EVA sought to determine the impact of:
    - Extreme summer weather resulting in high power demand
    - The loss of coal capacity

On PJM reliability and prices by simulating an environment where these units were pulled from the market prior to the winter of 2014.

PJM SUMMER ANALYSIS: HIGH SUMMER DEMAND MEANT HIGH POWER PRICES ON SOME DAYS

PJM BASE CASE POWER PRICES

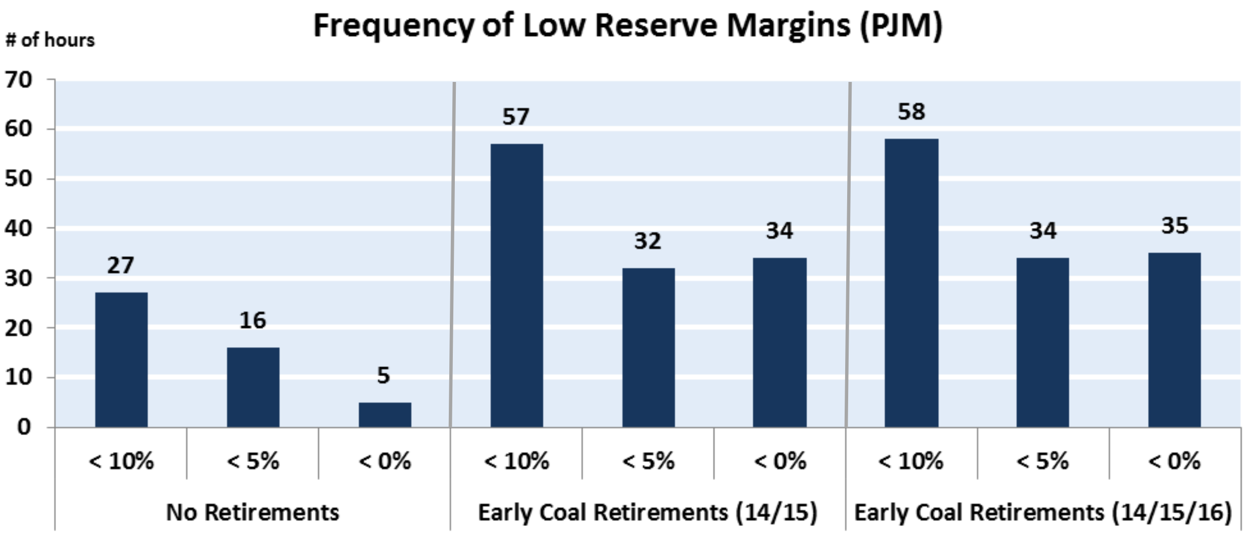


- EVA incorporated all of the market data into its modeling and developed the Base Case power prices to the left

- One specific heat wave led to elevated prices around July 20-22, but they remained fairly tempered for the remainder of the month in the Base Case.

PJM SUMMER ANALYSIS: HOT WEATHER DROVE HIGH SUMMER DEMAND AND TIGHT RESERVE MARGINS

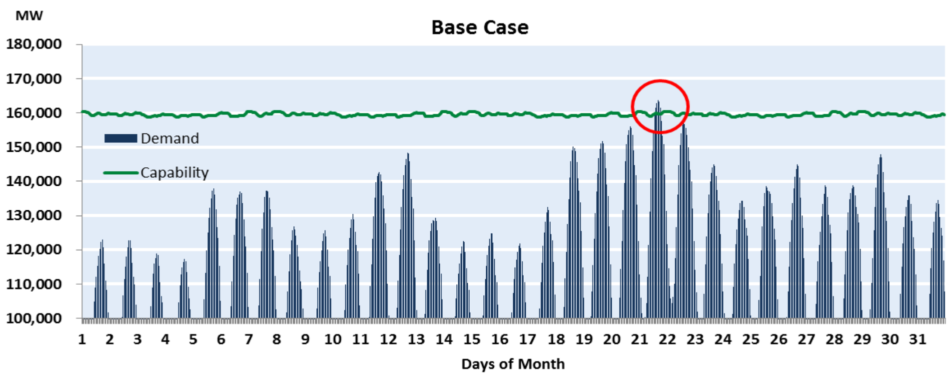
POTENTIAL SUMMER CAPACITY SHORTAGES DUE TO EARLY COAL RETIREMENTS – PJM

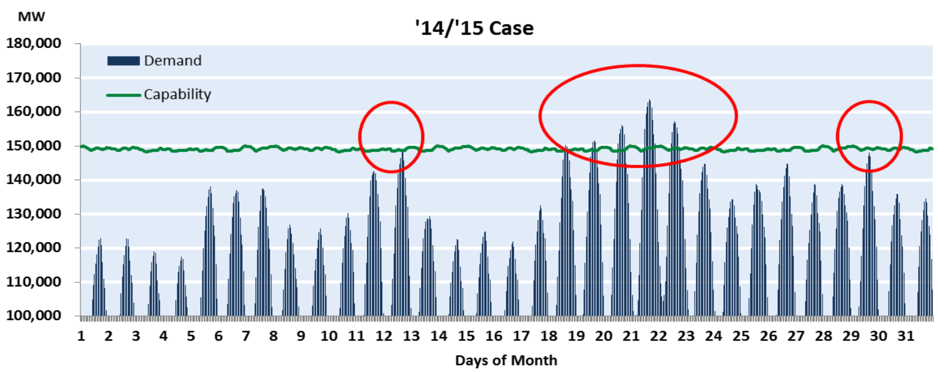


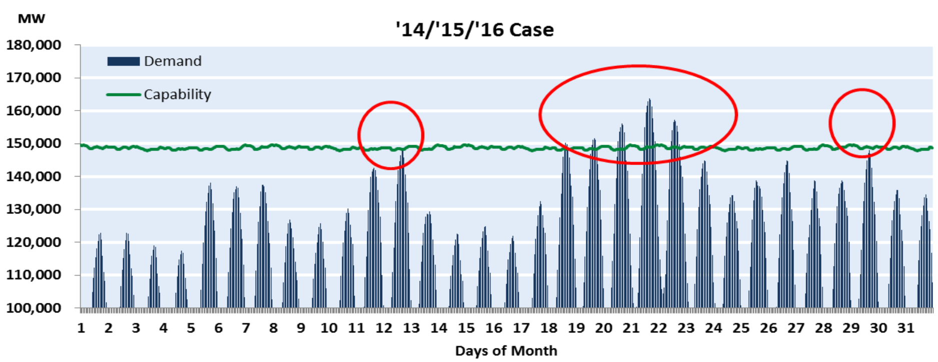
- The results of the PJM analysis suggest that in the Base Case, there would be 5 hours with a negative reserve margin.
  - It is likely that increased imports as well as demand response would be called upon to meet load.
- In Cases 1 and 2, there would be 34 and 35 hours, respectively, of negative reserve margins during the summer.
  - Demand response and increased imports may not be sufficient to make up for this in some hours, resulting in a capacity shortage and potential reliability issues.
- The magnitude of the shortage is detailed in the following slide.

PJM SUMMER ANALYSIS: TIMING OF POTENTIAL CAPACITY SHORTAGES

PJM RELIABILITY ANALYSIS FOR JULY







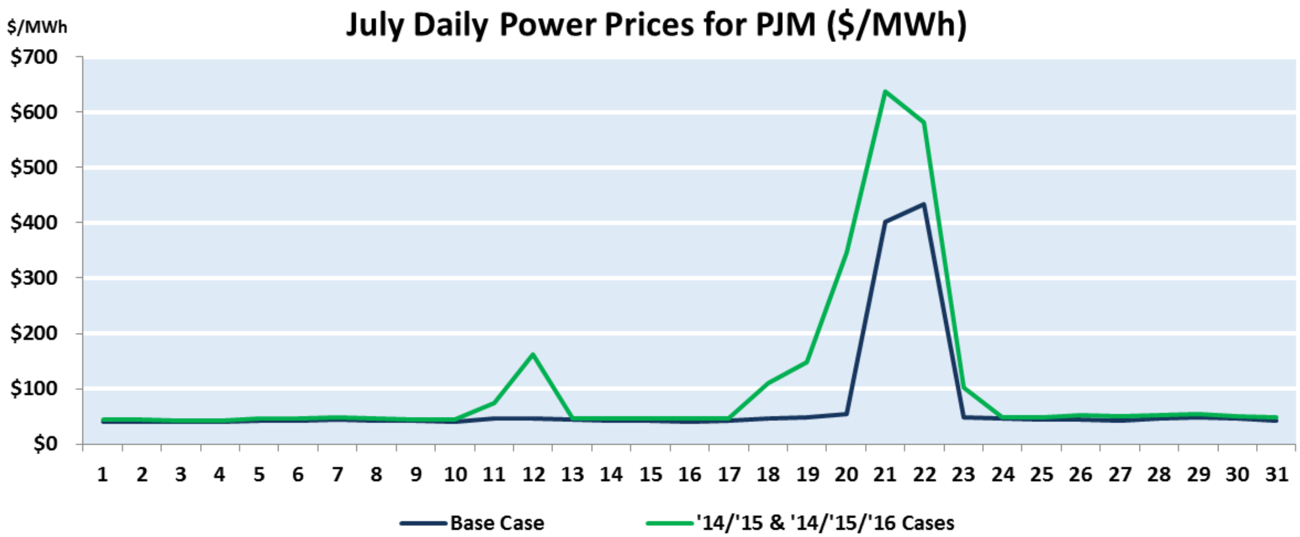
- In the Base Case, the hot summer weather only leads to a capacity shortage on one day in July, but there are several instances where the system gets tight and demand response capacity may be needed.

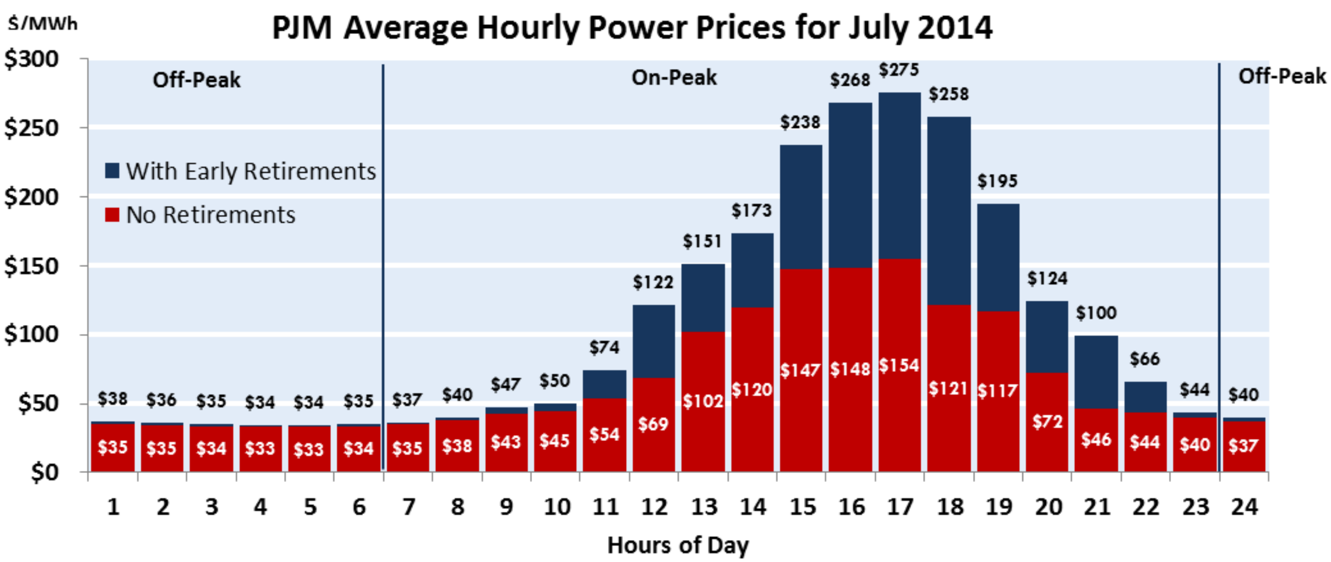
- In Case 1, there are roughly 6 days where demand exceeds capacity, with the bulk of them occurring between July 19 and 22.
  - In one instance, demand exceeds capacity by greater than 10 GW, implying that demand response would likely not be sufficient enough to compensate for the capacity shortage.

- In Case 2, there are roughly 7 days in which demand exceeds capacity and potentially three more where reserves become very tight.

PJM SUMMER ANALYSIS

PJM POWER PRICES





- Tight reserve margins and increased gas generation drove higher power prices in both Case 1 and 2.
    - The price impact was nearly identical between the two cases, so EVA is just showing one line for both of them.
- On an around-the-clock basis, prices increased by an average of 54% in July of 2014 in the retirement cases as higher heat rate units were called upon to meet load in the absence of the retired coal capacity.
- Additional gas demand places upward pressure on gas prices and in turn power prices.
- Peak prices are affected most significantly, where the increase neared 100% in some hours.

DETAILED POWER ANALYSIS OUTLINE

- PJM Winter Analysis
- MISO Winter Analysis
- ISO-NE Winter Analysis
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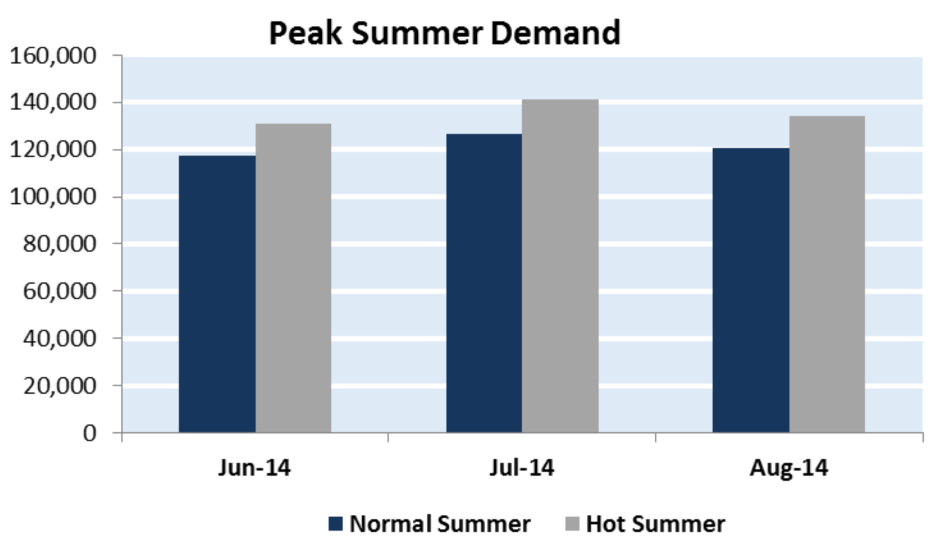
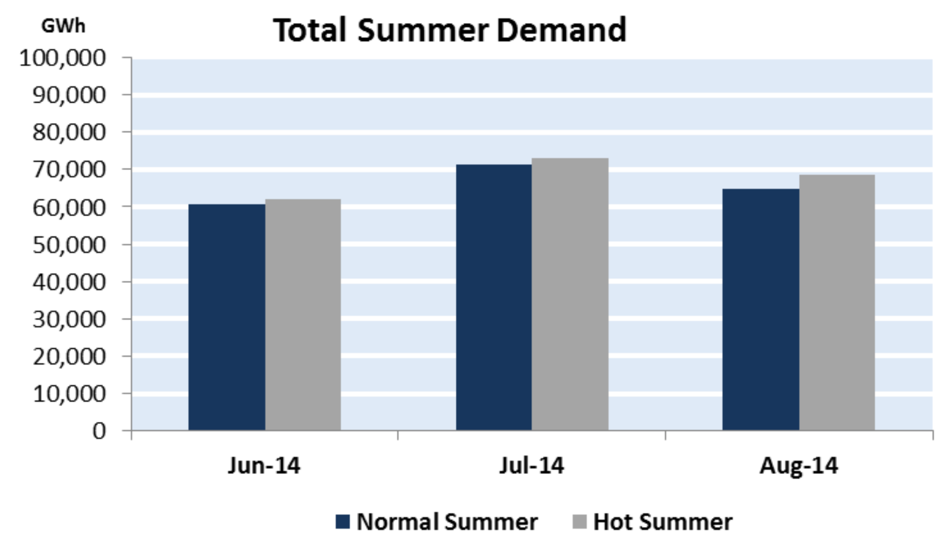
- MISO Summer Analysis
- ISO-NE Summer Analysis

MISO SUMMER ANALYSIS: EFFECTS OF HEAT WAVE ON ELECTRICITY DEMAND

MISO SUMMER DEMAND

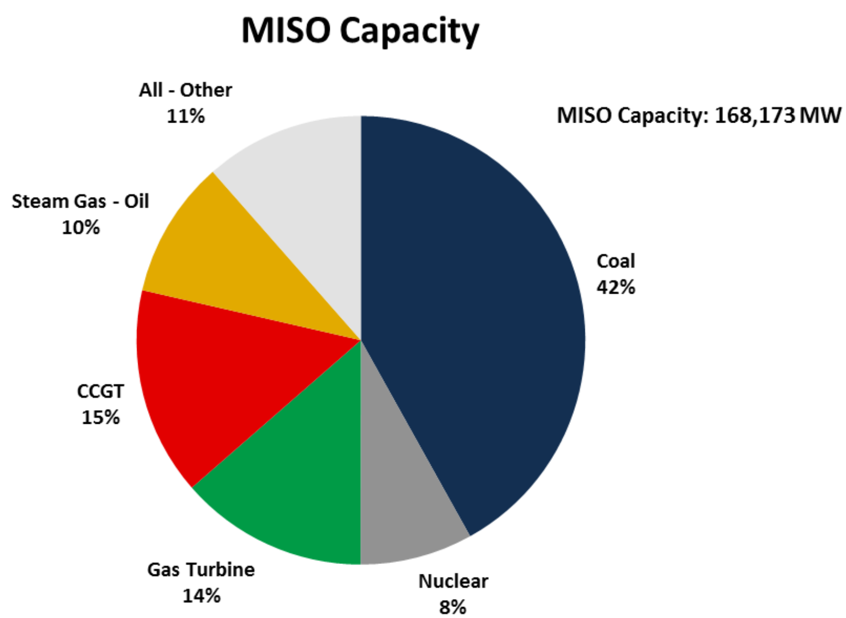
- Like the PJM analysis, EVA used 2011 load data to proxy the effects of a hot summer on electricity demand while also adjusting for the absorption of Entergy into the MISO footprint.
- Compared to EVA's forecast of normal summer demand, the hot summer demand was 3.5% higher on average where as the peak demand was higher by 11%.





MISO SUMMER ANALYSIS: EXISTING SUPPLY DURING SUMMER HEAT WAVE

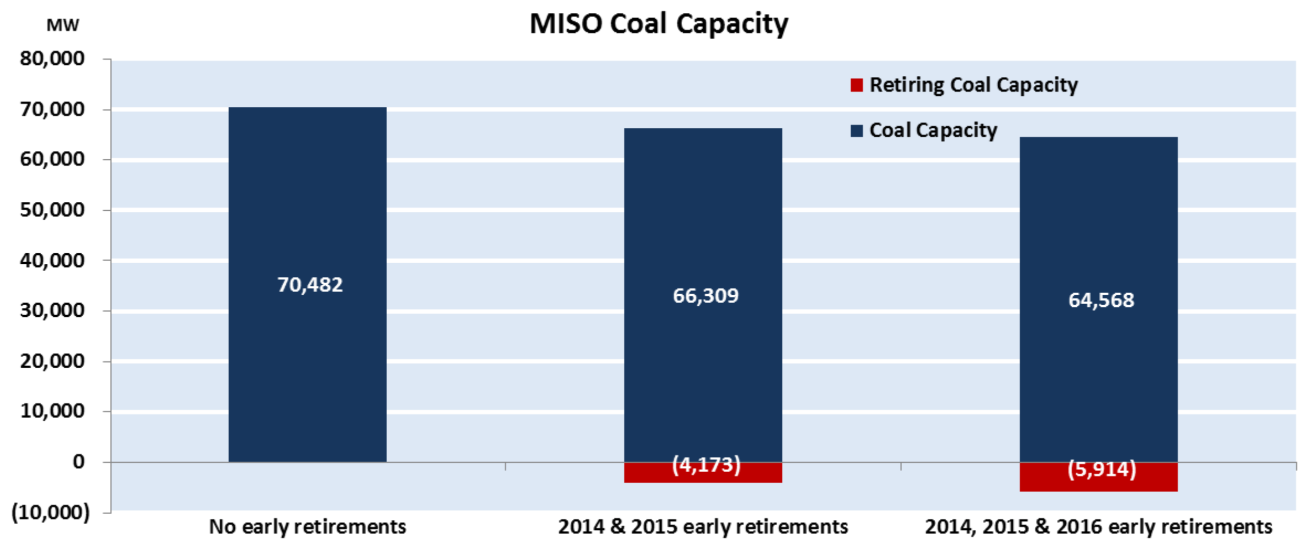
MISO CAPACITY



- MISO also relies heavily on coal to provide system reliability and for producing power – nearly 42% of all MISO capacity is coal-fired.
- CCGTs currently comprise 15% of total capacity though this share is expected to grow steadily as coal retirements mount.
- Like in PJM, coal units are very important for reliability especially in the summer, when MISO's peak demand occurs.

MISO SUMMER ANALYSIS: TESTING SYSTEM RELIABILITY WITH EARLY RETIREMENTS

MISO CAPACITY OUTLOOK



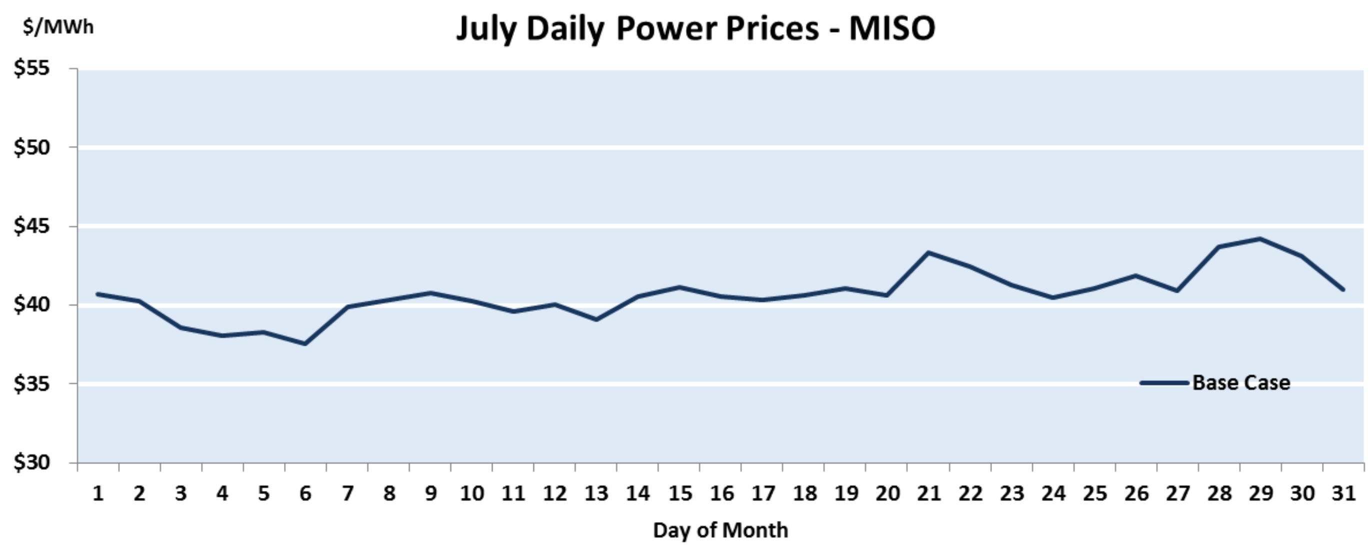
- Of the 70,000 MW of coal capacity in MISO, close to 4,000 MW is schedule o retire by the end of 2015 with an additional 1,800 MW by the end of 2016.

- EVA sought to determine the impact of:
  - Extreme summer weather resulting in high power demand
  - The loss of coal capacity

- On MISO reliability and prices by simulating an environment where these units were pulled from the market prior to the winter of 2014.

MISO SUMMER ANALYSIS

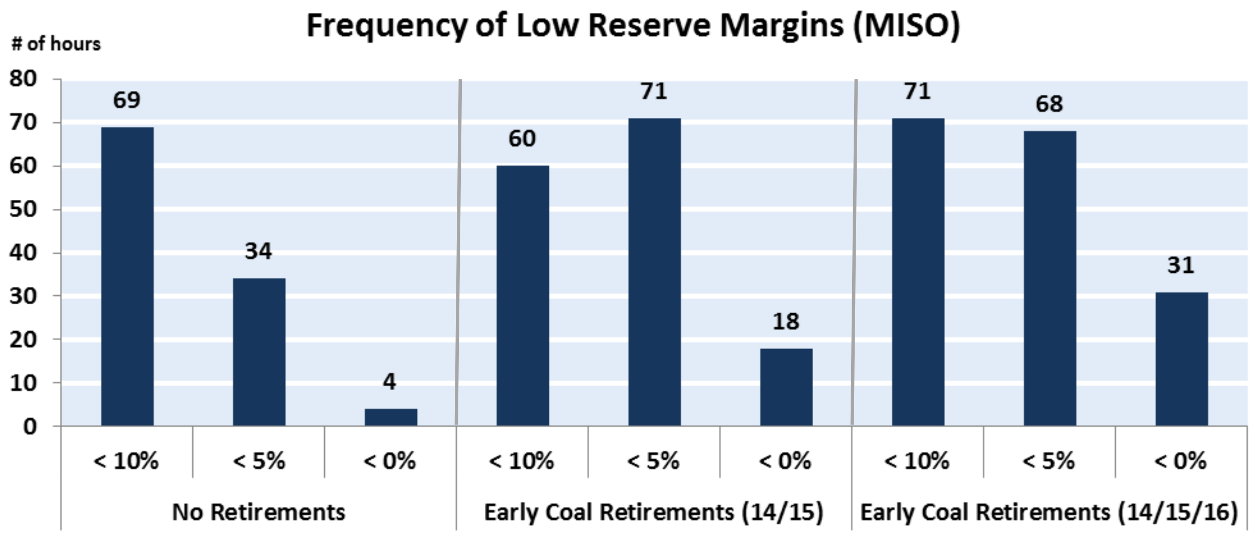
MISO POWER PRICES



- EVA incorporated all of the market data into its modeling and developed the Base Case power prices to the left
- The power prices remained relatively consistent throughout the month of July in the Base Case.

MISO SUMMER ANALYSIS

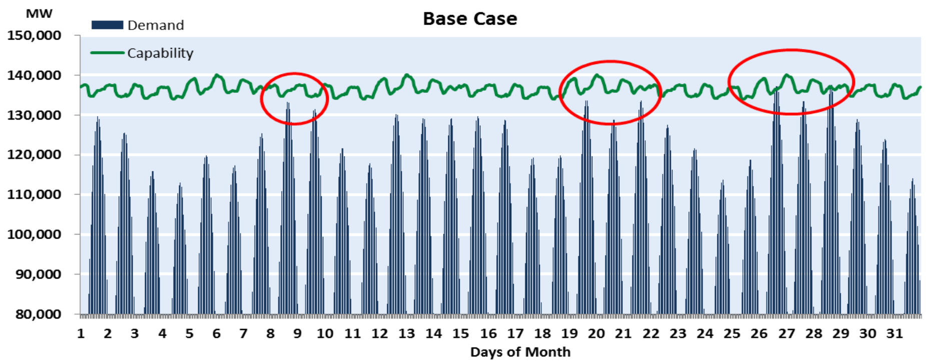
POTENTIAL SUMMER CAPACITY SHORTAGES DUE TO EARLY COAL RETIREMENTS – MISO

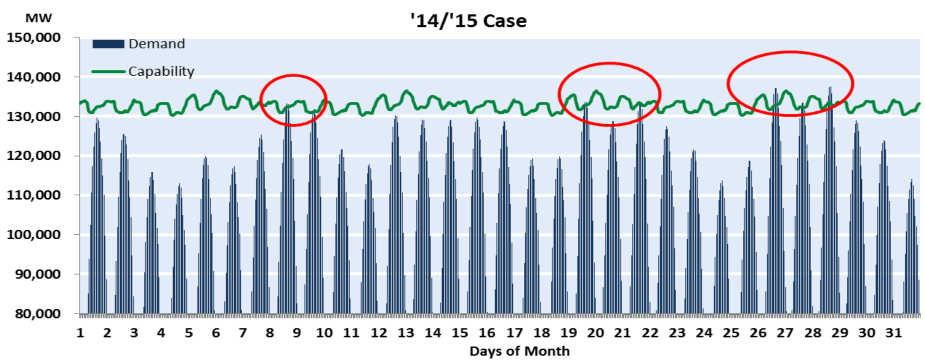


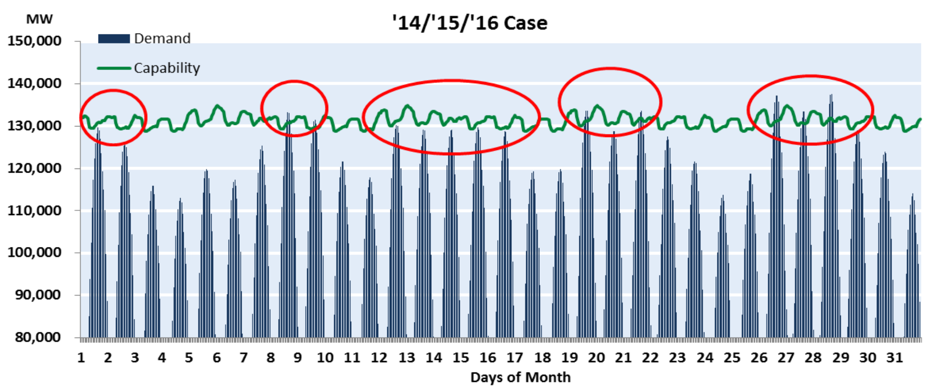
- To gauge the impact of these coal retirements during a warmer than normal summer period, EVA created a high demand scenario based upon historical data during peak summer months
- In MISO, 31 hours were found to have reserve margins below 0% based on installed capacity, while 68 hours had reserve margins below 5%
- For the '14/'15 Case, 18 hours were found to be below 0% and 71 hours below 5% reserve margin resulting in potential reliability issues.

MISO SUMMER ANALYSIS: TIMING OF POTENTIAL CAPACITY SHORTAGES

MISO RELIABILITY ANALYSIS FOR JULY



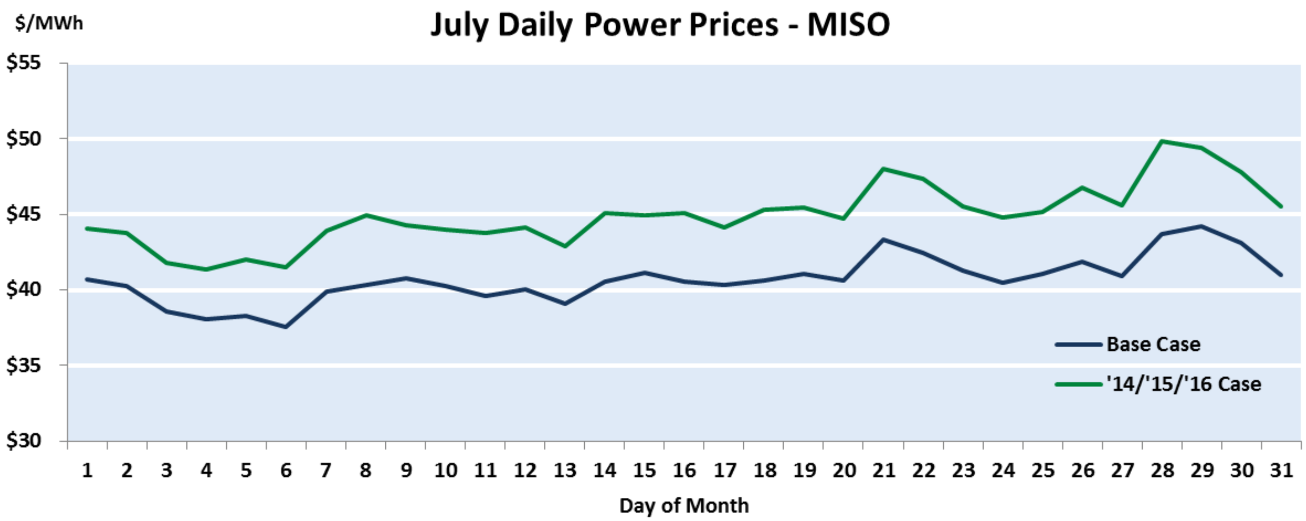


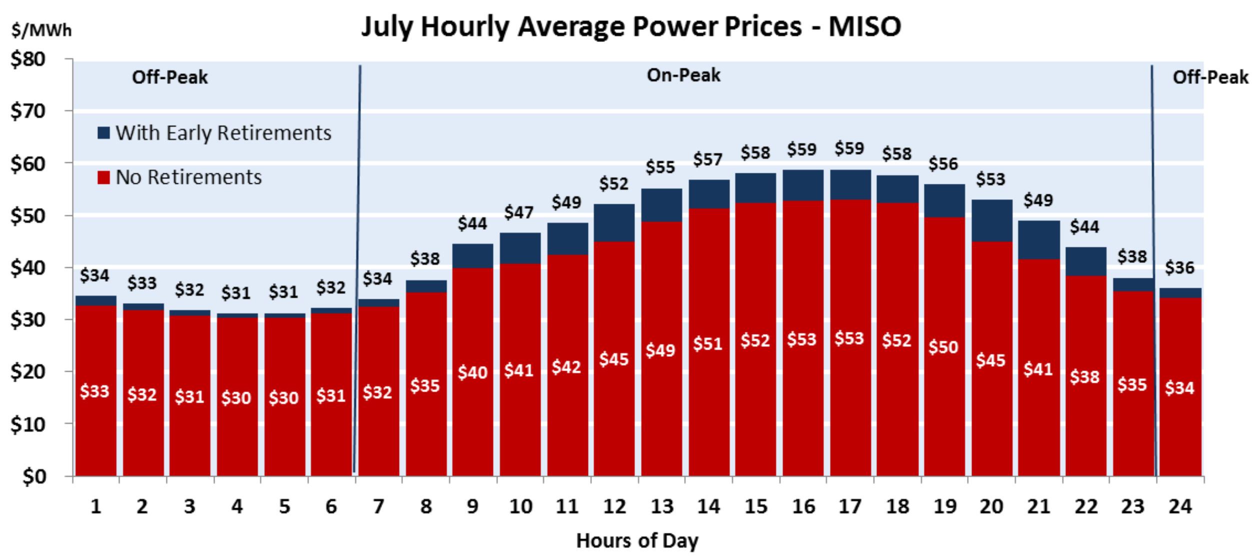


- In the Base Case, the hot summer weather only leads to a capacity shortage on two days in July, but there are several instances where the system gets tight and demand response capacity may be needed.
- In Case 1, there are roughly 7 days where demand exceeds capacity, with the bulk of them occurring between July 19-22 and 26-29 time period.
- In Case 2, there are roughly 7 days in which demand exceeds capacity and potentially 8 more days where reserves become very tight.

MISO SUMMER ANALYSIS

MISO POWER PRICES





- Being a coal-heavy region like PJM, MISO is expected to be as adversely affected by coal retirements as its neighbor to the East in terms of reliability.
- However, the power prices are not affected much largely due to the availability of gas resources to provide for the lost base load generation.
- In the ’14/’15 Case, July prices climbed an average of 9% overall and 10% at peak hours.
- The impact was only slightly greater in the ’14/’15/’16 Case.

DETAILED POWER ANALYSIS OUTLINE

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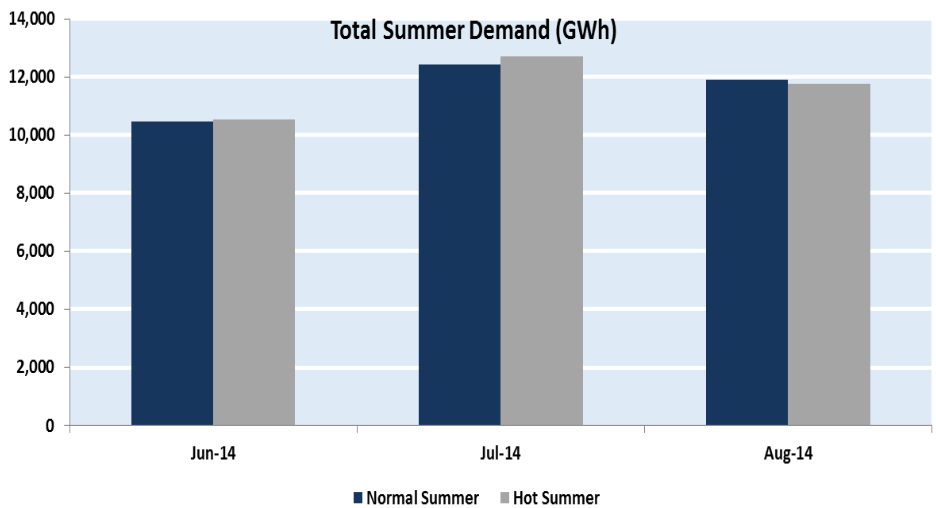
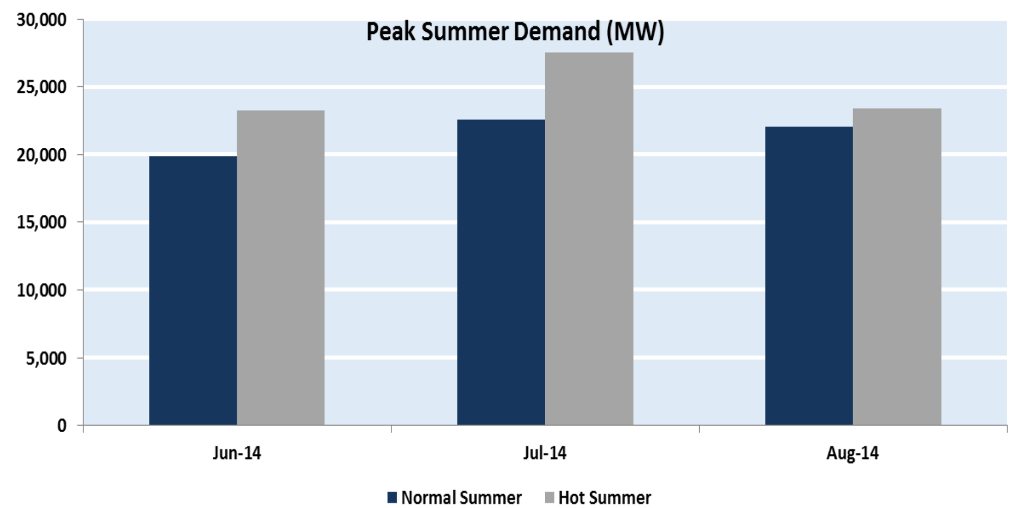
ISO-NE SUMMER ANALYSIS: EFFECTS OF HEAT WAVE ON ELECTRICITY DEMAND

ISO-NE SUMMER DEMAND

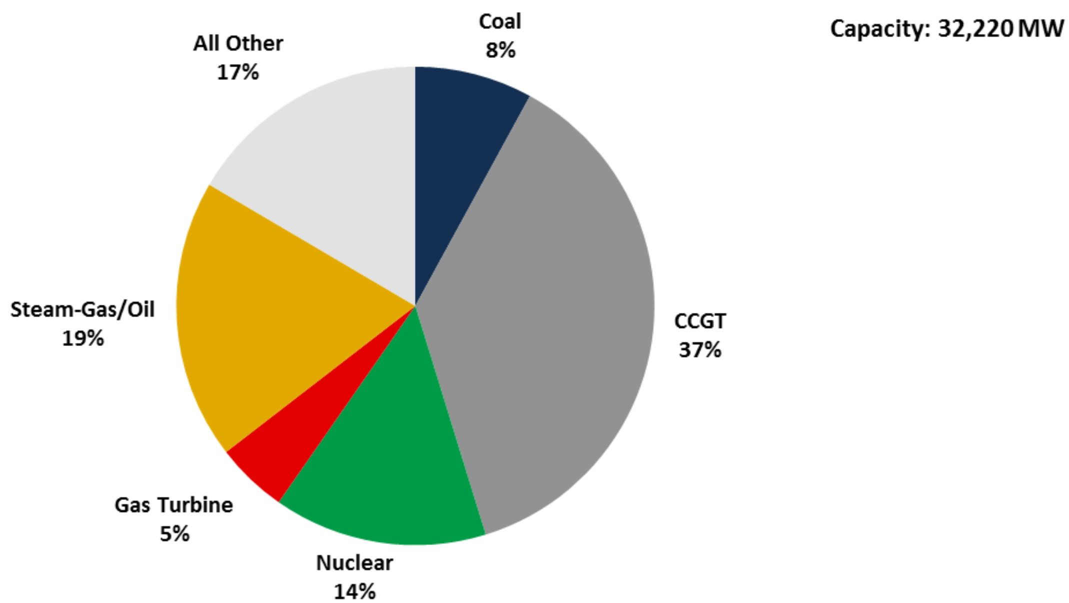
- Only 8% of ISO-NE's capacity is coal-fired – by far the smallest of the three markets EVA analyzed.
- At first glance, it does not appear that the existing coal capacity is important to reliability, but EVA realized that because of the especially unpredictable nature of gas availability in the region, having a diverse supply is vital to maintaining the system in the winter.
- MATS regulations have a very limited effect on the supply in ISO-NE.





ISO-NE SUMMER ANALYSIS: EXISTING SUPPLY DURING SUMMER HEAT WAVE

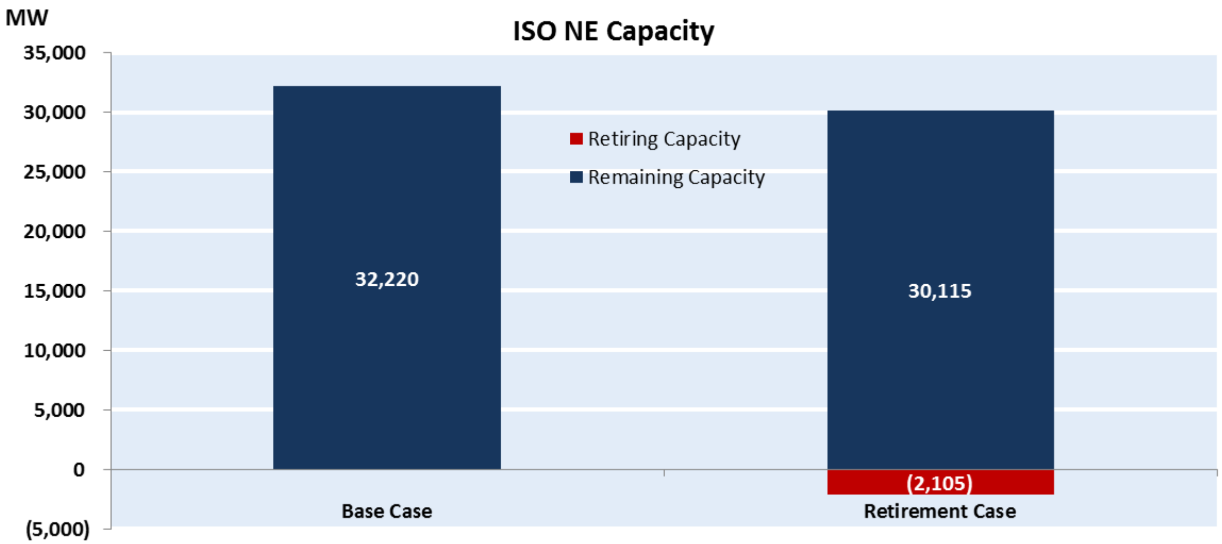
ISO-NE CAPACITY



- Only 8% of ISO-NE's capacity is coal-fired – by far the smallest of the three markets EVA analyzed.
- At first glance, it does not appear that the existing coal capacity is important to reliability, but EVA realized that because of the especially unpredictable nature of gas availability in the region, having a diverse supply is vital to maintaining the system in the winter.
- MATS regulations have a very limited effect on the supply in ISO-NE.

ISO-NE SUMMER ANALYSIS: TESTING SYSTEM RELIABILITY WITH EARLY RETIREMENTS

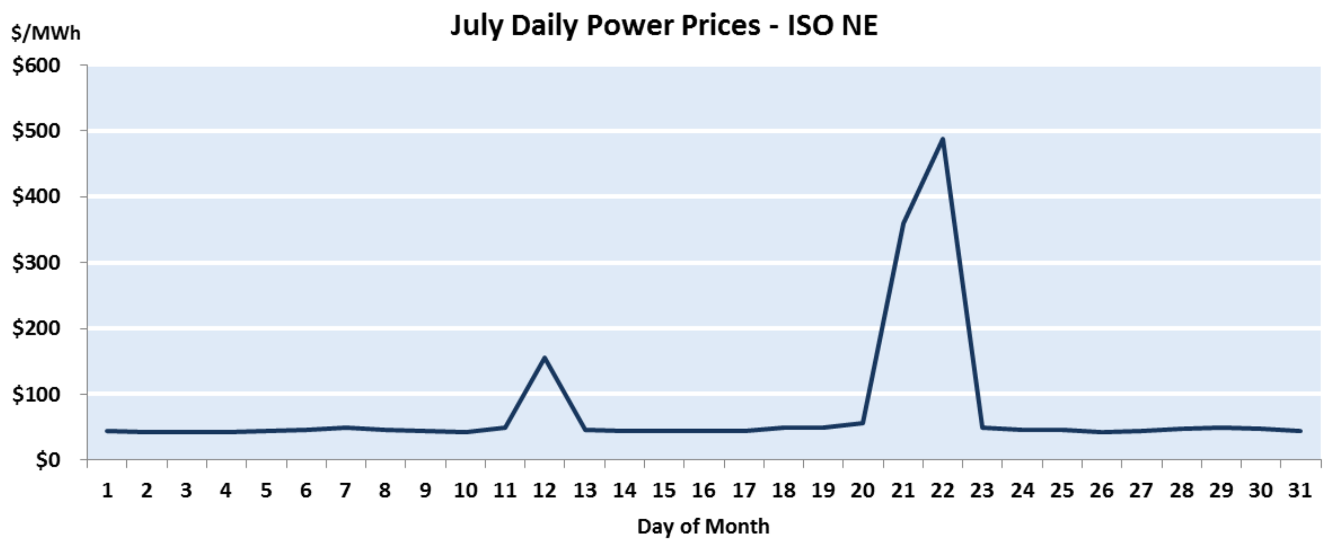
ISO-NE CAPACITY



- Of the 2,600 MW of coal capacity in ISO-NE, EVA assumed that 2,100 MW had left the market prior to the winter of 2014 in Cases 1 and 2.
- Because gas is scarce in New England in the winter, EVA sought to determine the reliability and price impact on the region under the three Cases.

ISO-NE SUMMER ANALYSIS

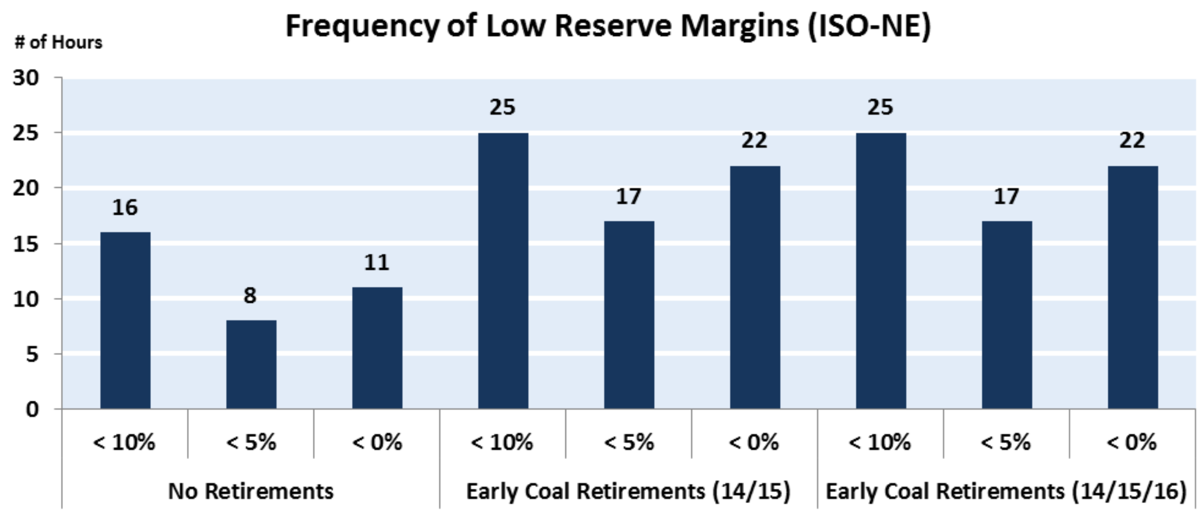
ISO-NE POWER PRICES



- EVA incorporated all of the market data into its modeling and developed the Base Case power prices to the left
- One specific heat wave led to elevated prices around July 20-22, but they remained fairly tempered for the remainder of the month in the Base Case.
- The prices also spiked around 12th of July due to high demand.

ISO-NE SUMMER ANALYSIS

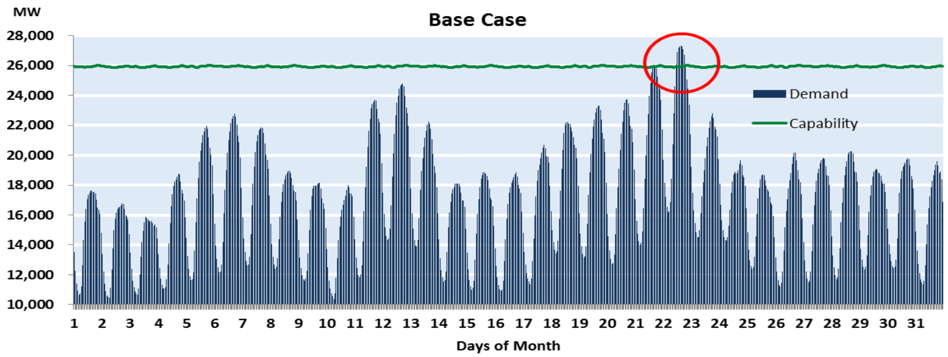
POTENTIAL SUMMER BLACKOUTS DUE TO EARLY COAL RETIREMENTS

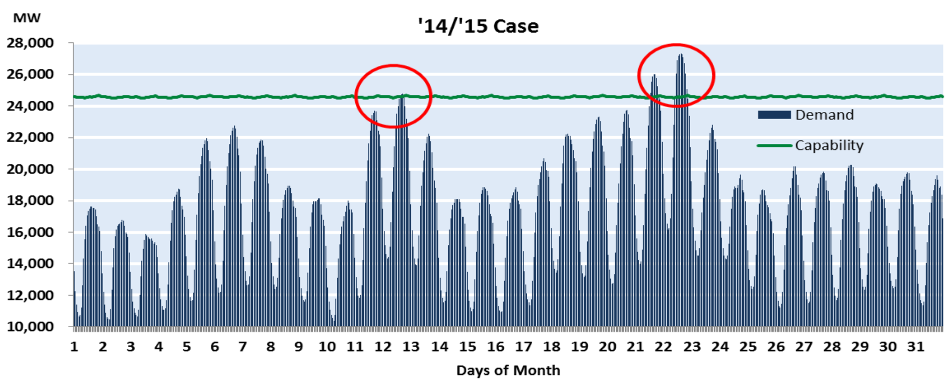


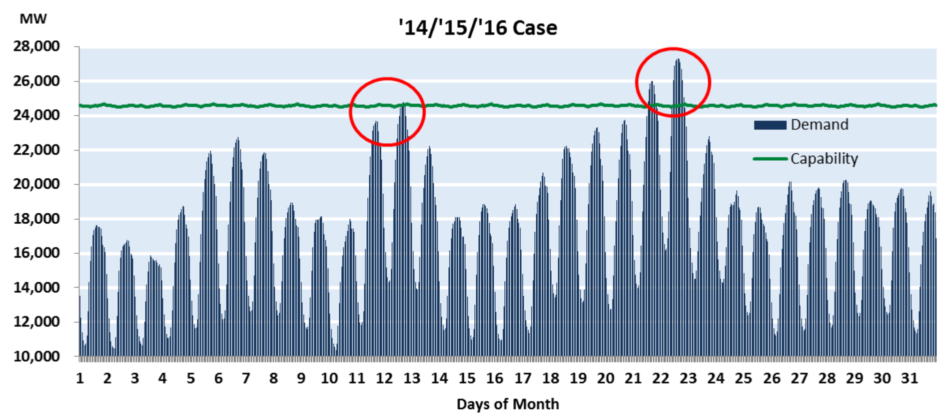
- To gauge the impact of these coal retirements during a warmer than normal summer period, EVA created a high demand scenario based upon historical data during peak summer months
- In ISO-NE, for the '14/'15 as well as the '14/'15/'16 Case, 22 hours were found to have reserve margins below 0% based on installed capacity, while 17 hours had reserve margins below 5%

ISO-NE SUMMER ANALYSIS: TIMING OF POTENTIAL CAPACITY SHORTAGES

ISO-NE RELIABILITY ANALYSIS FOR JULY



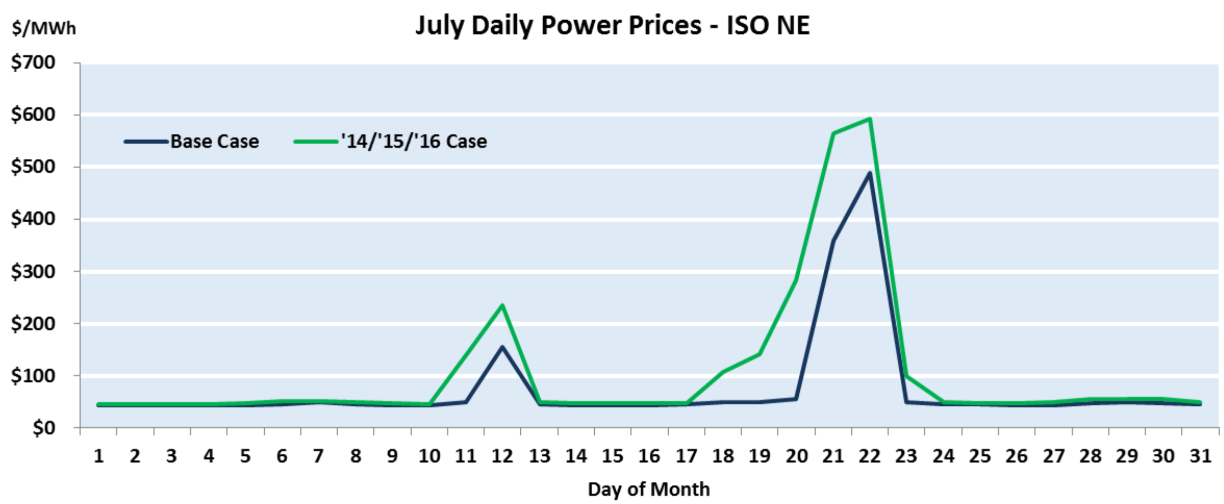


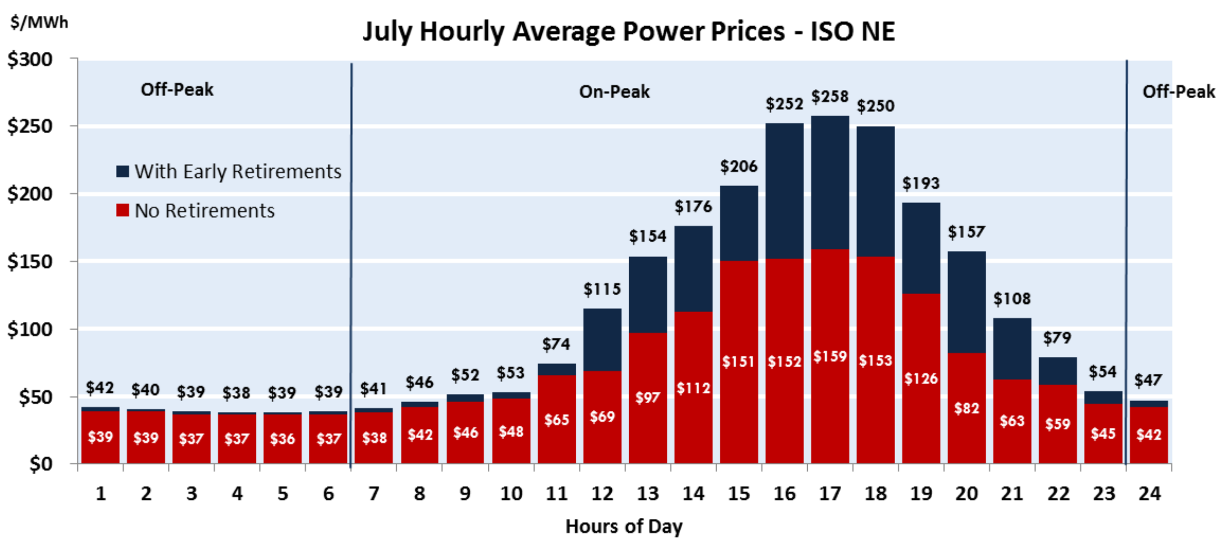


- In the Base Case, the hot summer weather only leads to a capacity shortage on two day in July, but there are several instances where the system gets tight and demand response capacity may be needed.
- In Case 1, there are roughly three days where demand exceeds capacity, with the bulk of them occurring between July 19 and 22.
- In Case 2 as well, there are roughly 7 days in which demand exceeds capacity and potentially two more where reserves become very tight.

ISO-NE SUMMER ANALYSIS

ISO-NE POWER PRICES





- The prices in the Base case are driven up due to the high demand during the hot summer. With summer peaks approaching the available capacity in New England, the power prices are dictated by the high cost marginal resources in the region.
- In the '14/'15/'16 Case, prices averaged 44% higher than in the Base Case, as gas demand and prices are further increased.
- EVA did not assume any constrained gas-fired capacity in ISO-NE for the summer scenarios.
- During this period, ISO-NE daily average prices went as high as $600/MWh.

OUTLINE

- Problem Statement
- Methodology
- Impact of Early Coal Retirements in Winter
- Impact of Early Coal Retirements in Summer
- Detailed Gas Analysis
- Detailed Power Analysis
- Conclusions
- Appendix

CONCLUSIONS

POWER MARKET CONCLUSIONS

- Potential capacity shortages in PJM and ISO-NE during winter due to the early coal retirements.
- Potential capacity shortages in PJM, MISO and ISO-NE during a hot summer due to high demand and early coal retirements.
- High wholesale power prices during both winter and summer months resulting in a potential addition of $35 billion to the energy costs of consumers in 2014.

CONCLUSIONS

NATURAL GAS MARKET CONCLUSIONS

- Without projected retirements gas industry already at a precipice.
  - Pipelines, LDCs and storage operators restrict supplies to non-firm customers.
  - Gas-fired generating capacity lost in several regions due to curtailment of gas supplies.
  - Near record low storage inventories at the end of winter leave industry with a challenge to refill storage to adequate levels.

- With projected retirements
  - Winter
    - Records for demand, storage withdrawals and prices would have been reset to higher levels.
    - Additional pipeline, LDC, and storage operator curtailments likely would have occurred.
      - More power plants likely would have had gas supplies curtailed.
    - Inadequate pipeline capacity in NEPOOL.
      - Alternatives for either increased oil-fired generation or imported power would have been unlikely.
      - Remaining alternative is to curtail electricity demand.
  - Summer
    - Storage levels at the start of next winter (Nov 1, 2014) at unprecedented low levels and likely inadequate, except in the case of a mild winter.
    - Higher gas prices on a sustained basis.

- Total cost to consumers for all sectors for 2014 is approximately $70 billion, and for the period 2014-2016 is $100 billion.

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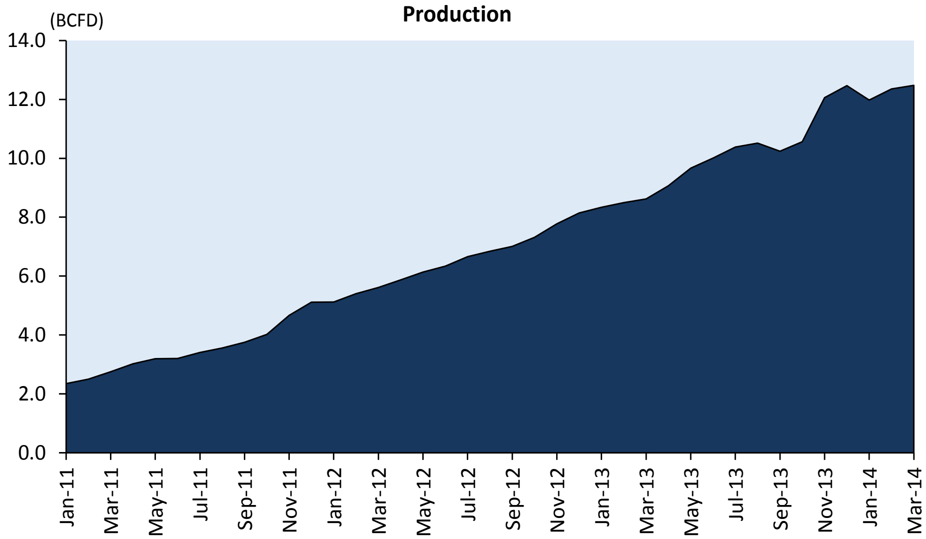
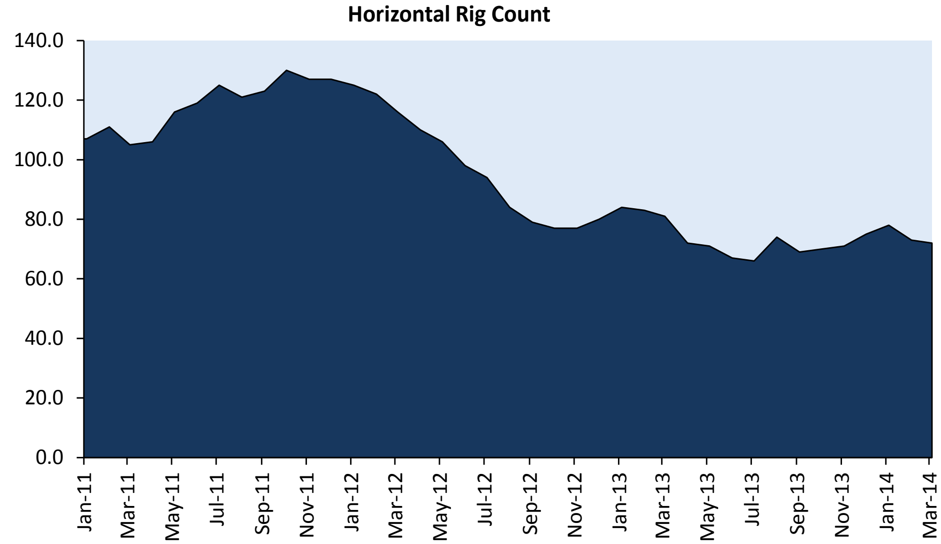
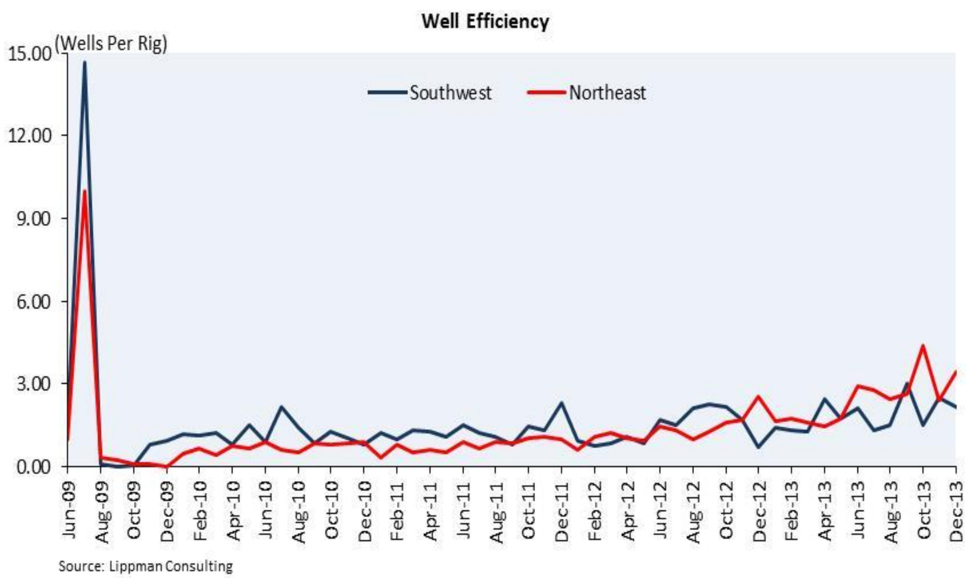
MARCELLUS SHALE PROFILE

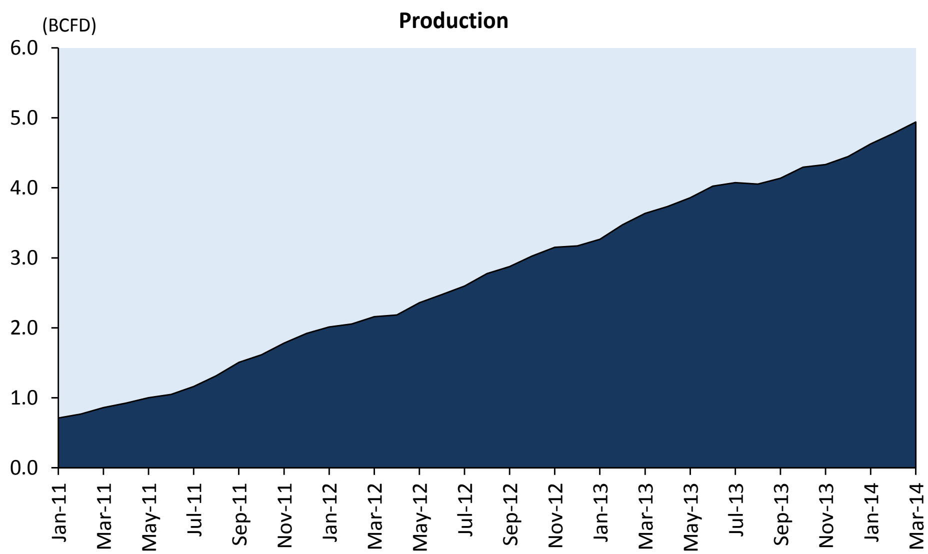


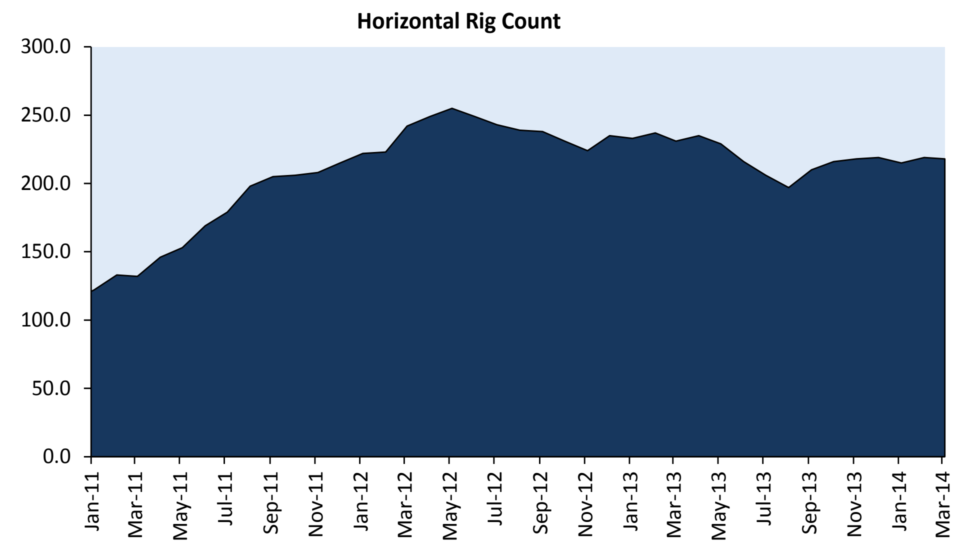


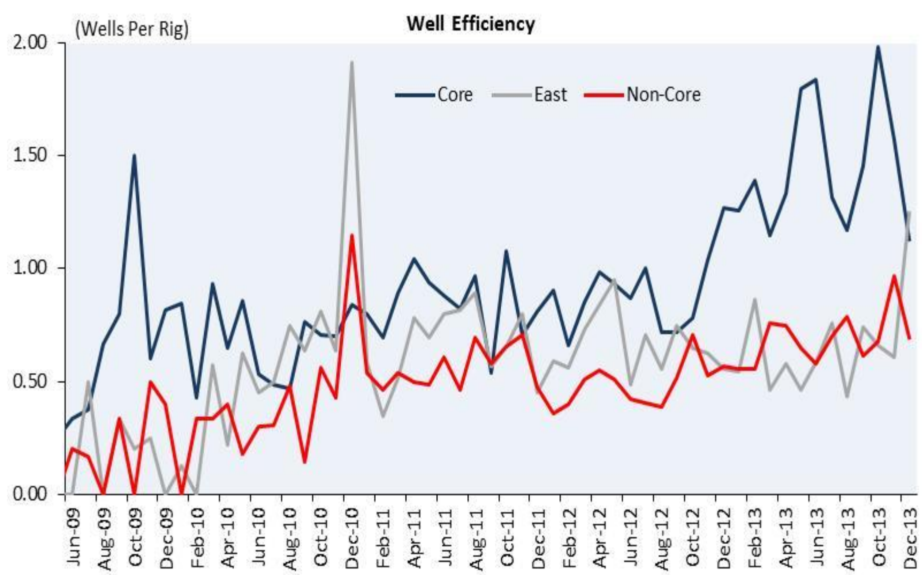


While the growth rate in Marcellus production levels has started to decline, it is still on a growth trajectory, albeit a modest one. For example, when the November 2013 event is excluded Marcellus production over the last nine months has increased only 10%. This decline in the growth rate primarily is due to the decline in drilling activity, as the rig count has declined about 45 percent from prior peak levels. Interestingly, most of the increase in Marcellus production in 2013 is from the dry gas segment of the Marcellus play in northeastern Pennsylvania (+2.1 BCFD), rather than the much discussed wet gas segment in southwestern Pennsylvania and northern West Virginia (1.4 BCFD).

EAGLE FORD SHALE PROFILE

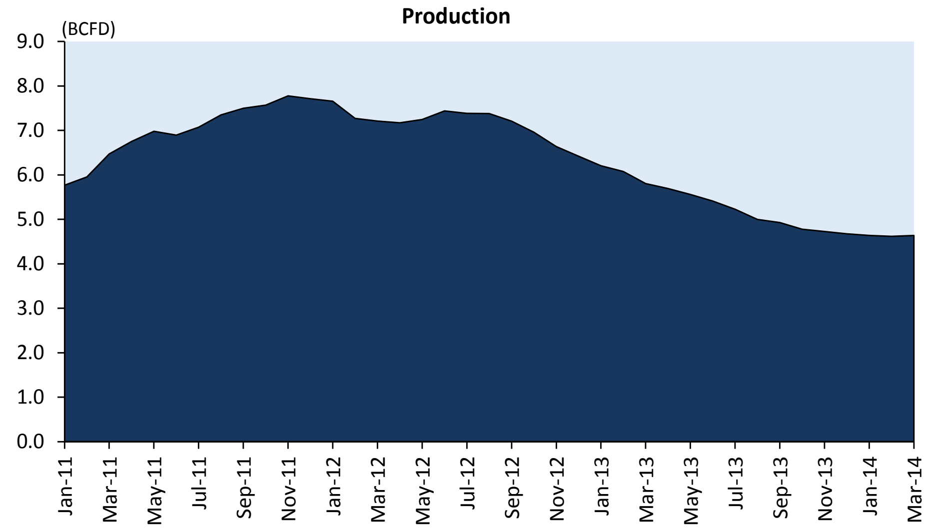


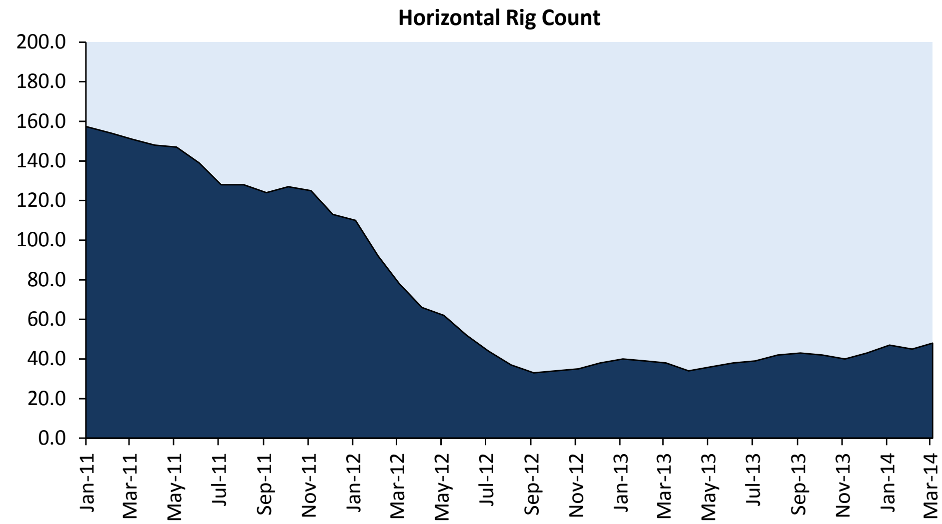


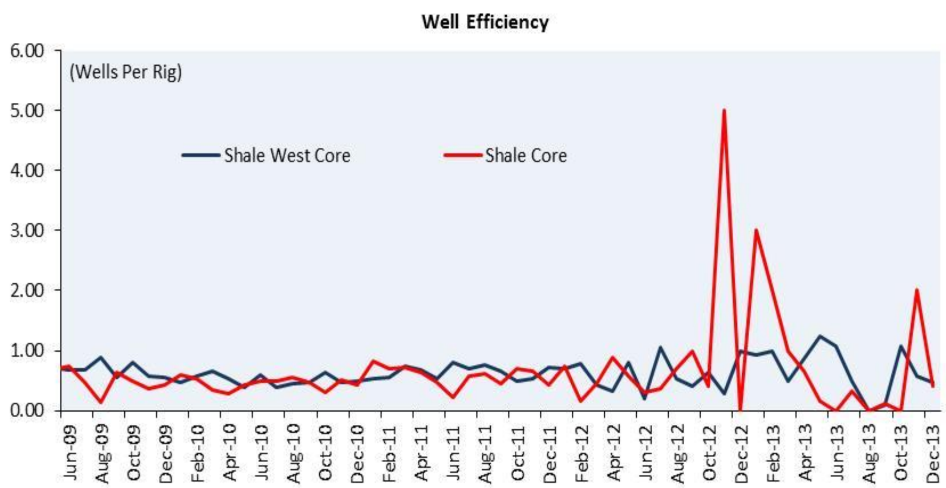


Eagle Ford gas production continues to increase, as does oil production from the Eagle Ford play (i.e., in 2013 Eagle Ford oil production nearly doubled to 1.1 MMBD). As indicated, while drilling activity is slightly below prior peak levels, overall drilling activity in the play remains strong, with approximately 218 horizontal rigs currently active in the play. For 2013 about 75 percent of the 1.5 BCFD increase in Eagle Ford production was produced form the core area of the play, which is oil prone. Complementing this increase in associated gas was a 0.4 BCFD increase from the non-core area, which for the most part has a significant NGL component. Well economics for the latter, because of the liquids credit, can be viable at $1.00 per MMBTU gas prices.

HAYNESVILLE SHALE PROFILE

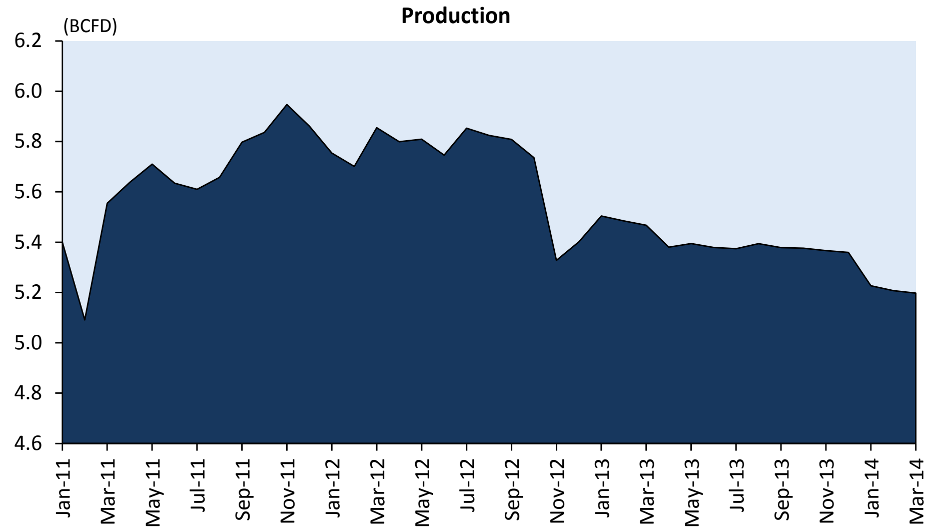


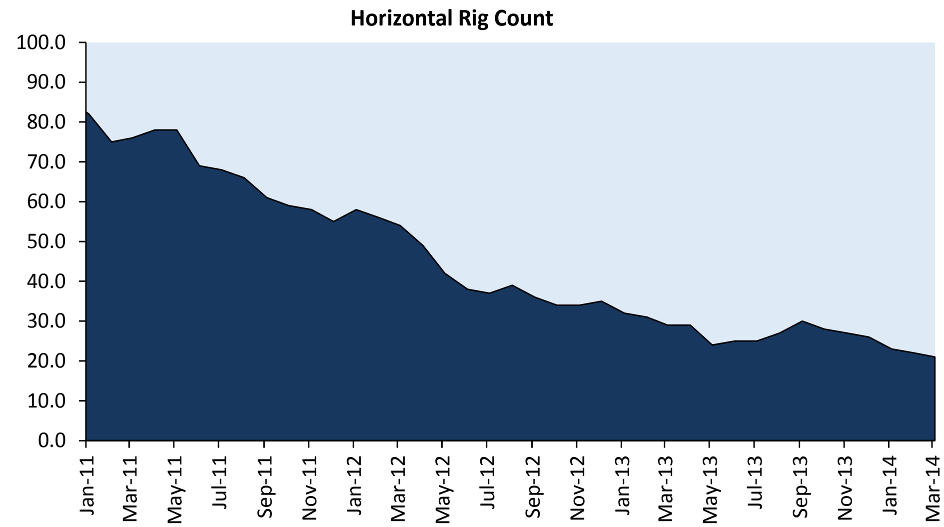


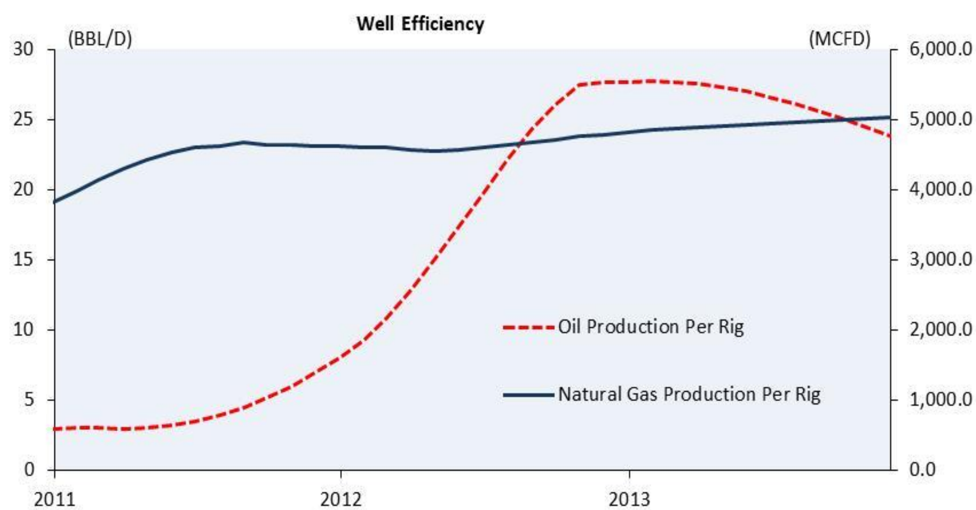


The Haynesville shale play, which is a dry gas play, on average declined about 1.5 BCFD in 2013, with year end production levels being 3.1 BCFD below prior peak levels. This decline is the net result of the decline in drilling activity, as the current horizontal rig count for the play (i.e., 48 rigs) is about 140 rigs below prior peak levels. While parts of the play appear economic at sub -$4.00 per MMBTU gas prices, sustained gas prices at just above $5.00 per MMBTU are required to attain a 40% ROR in core areas, which would be required to compete with oil projects.

BARNETT SHALE PROFILE

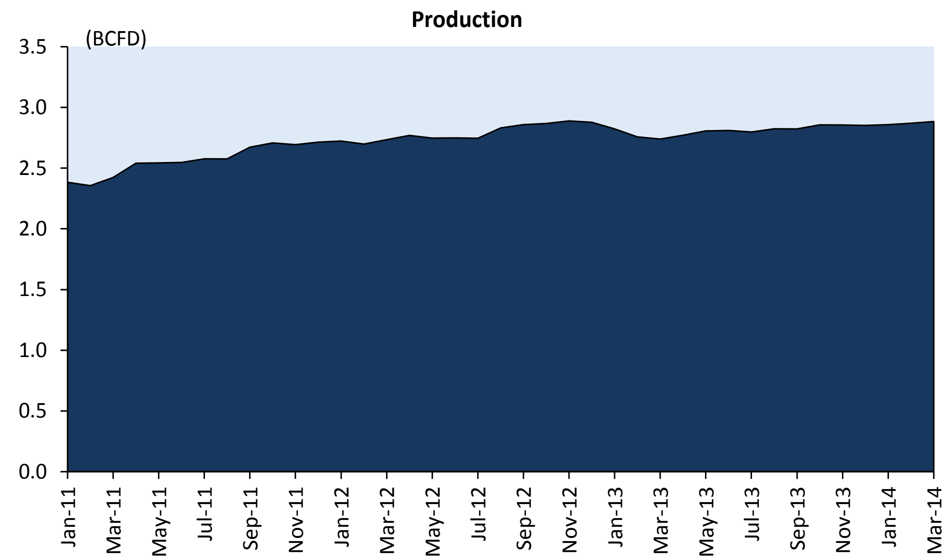


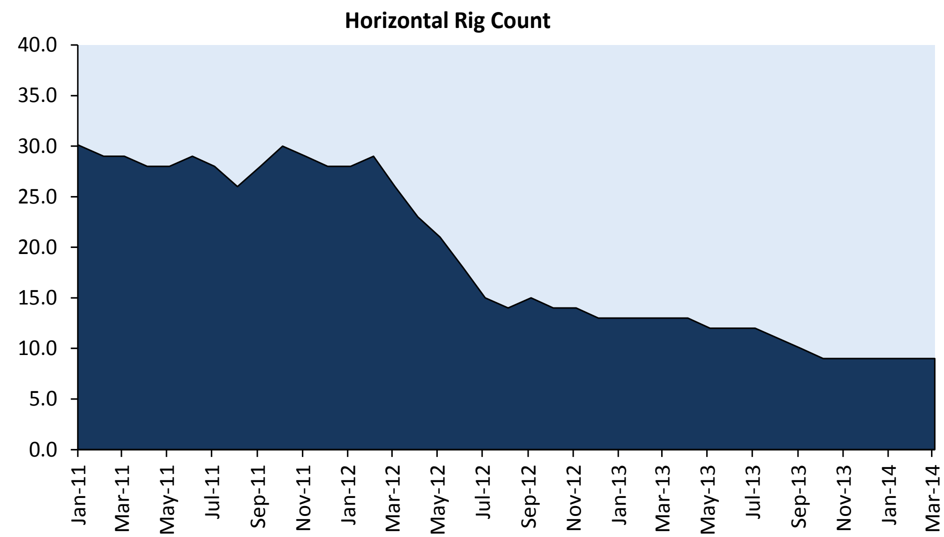


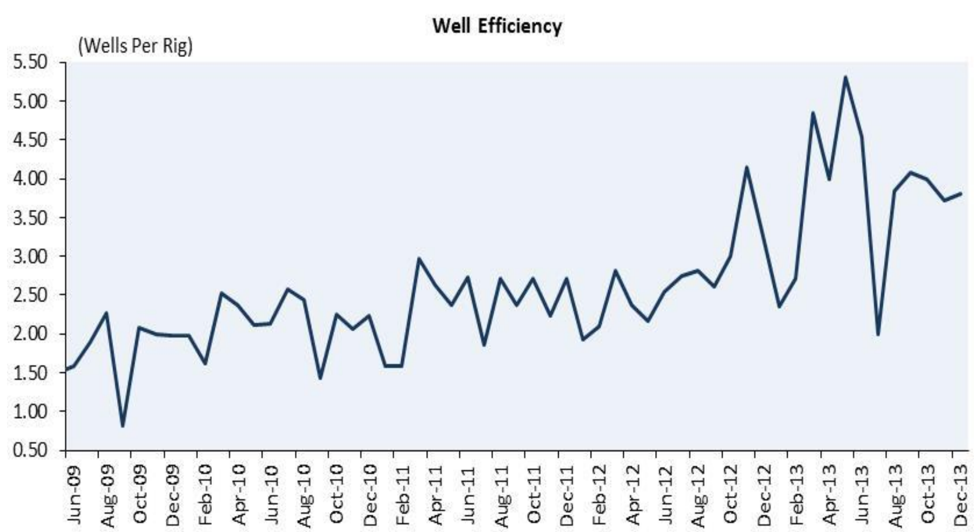


Production from the Barnett shale play, which is the most mature of the seven major shale plays, declined 0.4 BCFD in 2013, with almost all of this decline occurring in the mature core area of the play. Drilling activity for the play has been in steady decline for the last six months, despite the attractiveness of the Barnett Combo play, which has a significant liquids component. Expect drilling activity to continue to decline until gas prices on a sustained level reach $5.00 per MMBTU.

FAYETTEVILLE SHALE PROFILE

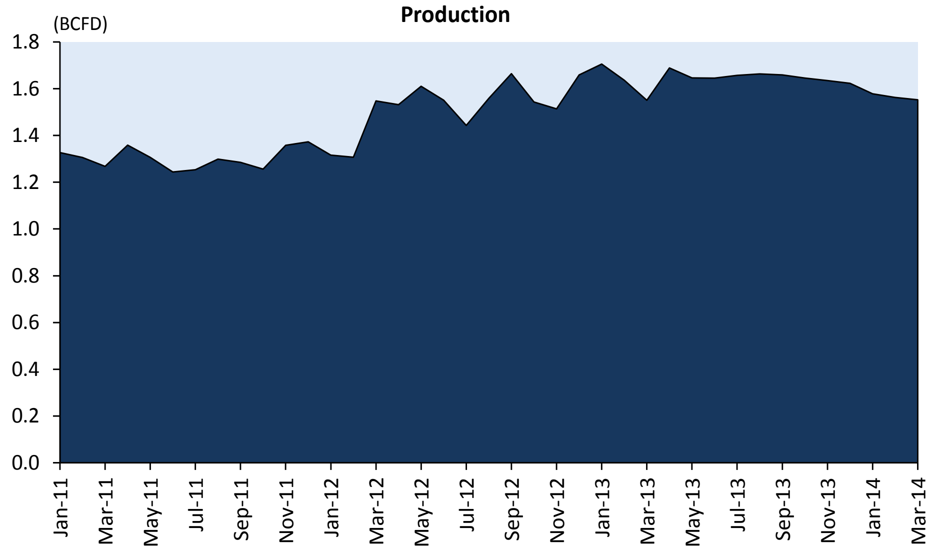


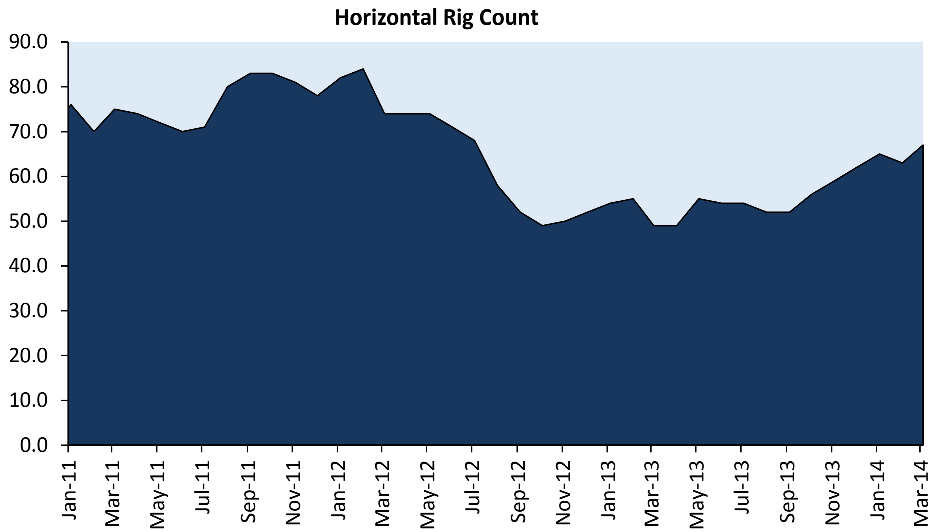




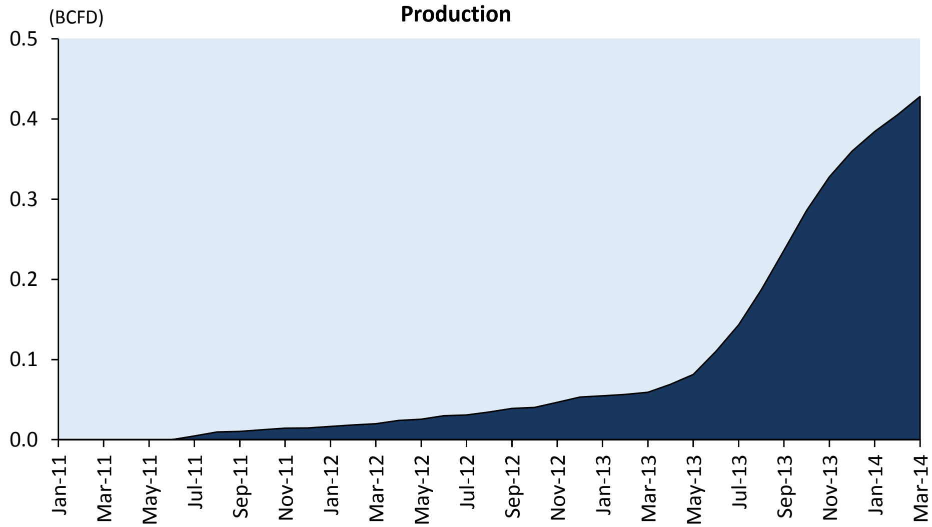
Fayetteville production basically has been flat for the last year, despite the success of the industry leader, Southwestern Energy, in improving well economics. Drilling activity has been in a steady decline for twp years and currently is at only nine rigs.

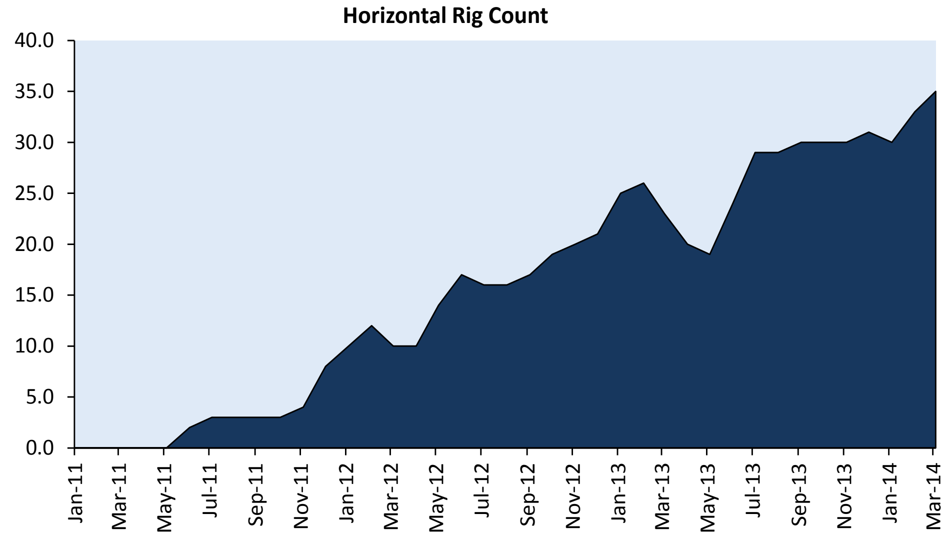
WOODFORD SHALE PROFILE





UTICA SHALE PROFILE



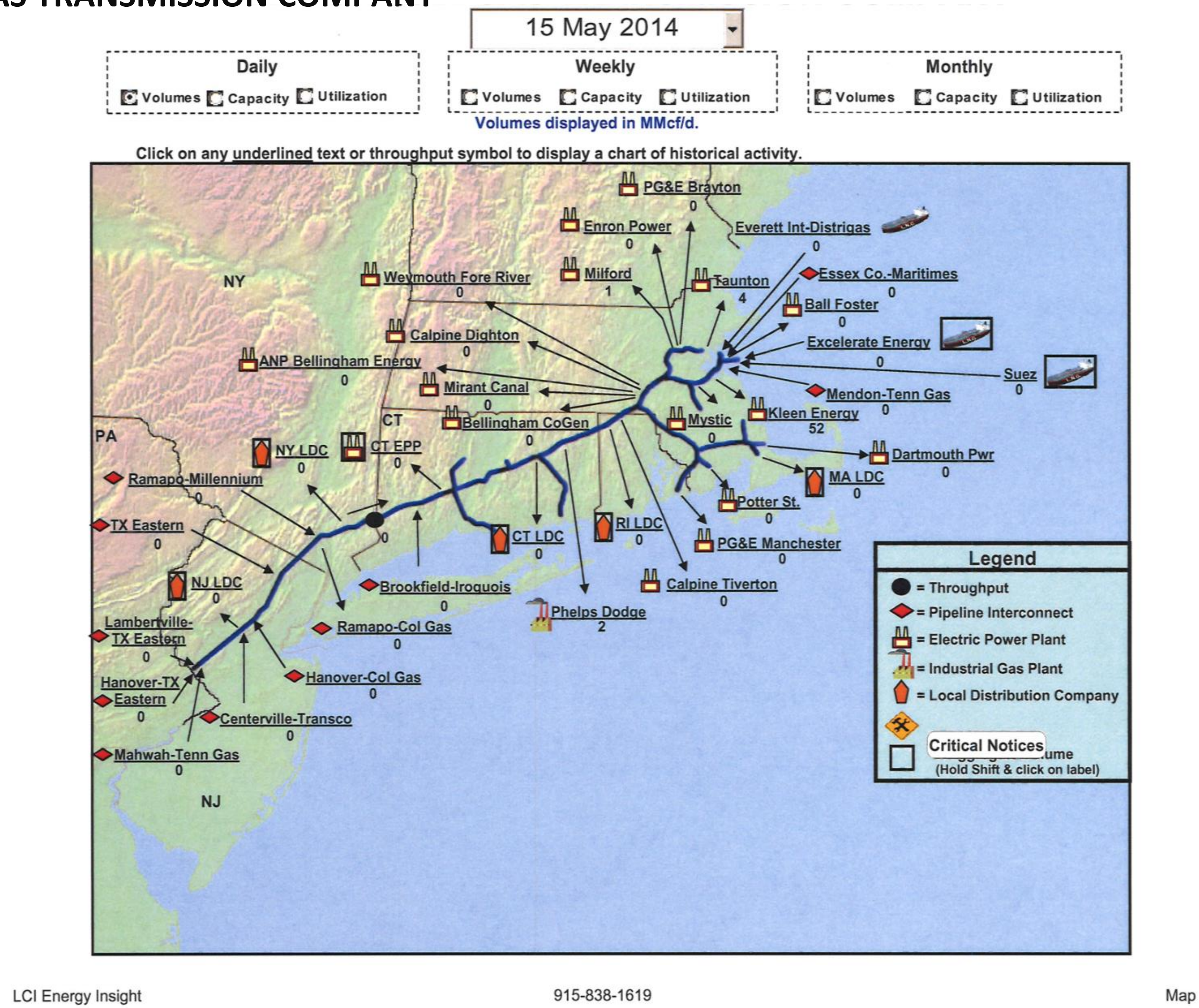


IPP OWNED GAS UNITS IN ISO-NE

GAS-FIRED UNITS IN ISO-NE THAT LIKELY WOULD HAVE GAS SUPPLIES CURTAILED

Zone	ID	Name	Capacity (MV	Primary_Fuel	Owner
isoNE-Boston	1595-CCGT	Kendall Square Station	217.4	EVA GAS:Algonquin	IPP CHP
isoNE-ConnSouthwest	55149-CCGT	Lake Road Generating Plant	795.0	EVA GAS:Algonquin	IPP Non-CHP
isoNE-Boston	1588-CCGT	Mystic Generating Station	1550.5	EVA GAS:Algonquin	IPP Non-CHP
isoNE-Boston	54586-CCGT	L'Energia Energy Center	74.0	EVA GAS:Algonquin	IPP Non-CHP
isoNE-ConnCentral	56798-CCGT	Kleen Energy Systems Project	622.5	EVA GAS:Algonquin	IPP Non-CHP
isoNE-Boston	1588-7-GSTM	Mystic Generating Station	581.7	EVA GAS:Algonquin	IPP Non-CHP
isoNE-Boston	55999-GEN1-PEAK	NECCO Co-Generation	2.9	EVA GAS:Algonquin	IPP CHP
isoNE-Boston	55999-GEN2-PEAK	NECCO Co-Generation	2.9	EVA GAS:Algonquin	IPP CHP
isoNE-MassWest	1642-GT-1-GTRB	NAEA Energy Massachusetts LLC	42.8	EVA GAS:Algonquin	IPP Non-CHP
isoNE-MassWest	1642-GT-2-GTRB	NAEA Energy Massachusetts LLC	42.7	EVA GAS:Algonquin	IPP Non-CHP
isoNE-ConnCentral	57068-12-GTRB	Middletown Peaking	48.8	EVA GAS:Algonquin	IPP Non-CHP
isoNE-ConnCentral	57068-13-GTRB	Middletown Peaking	48.8	EVA GAS:Algonquin	IPP Non-CHP
isoNE-ConnCentral	57068-14-GTRB	Middletown Peaking	48.8	EVA GAS:Algonquin	IPP Non-CHP
isoNE-ConnCentral	57068-15-GTRB	Middletown Peaking	48.8	EVA GAS:Algonquin	IPP Non-CHP
isoNE-MassSoutheast	52026-CCGT	Dartmouth Power Associates	65.0	EVA GAS:Algonquin	IPP Non-CHP
isoNE-MassSoutheast	55026-CCGT	Dighton Power Plant	169.8	EVA GAS:Algonquin	IPP Non-CHP
isoNE-MassSoutheast	55048-CCGT	Tiverton Power Plant	267.3	EVA GAS:Algonquin	IPP Non-CHP
isoNE-MassSoutheast	55317-CCGT	Fore River Generating Station	762.5	EVA GAS:Algonquin	IPP Non-CHP
isoNE-MassSoutheast	52026-GEN3-GTRB	Dartmouth Power Associates	22.0	EVA GAS:Algonquin	IPP Non-CHP

ALGONQUIN GAS TRANSMISSION COMPANY



TENNESSEE GAS PIPELINE

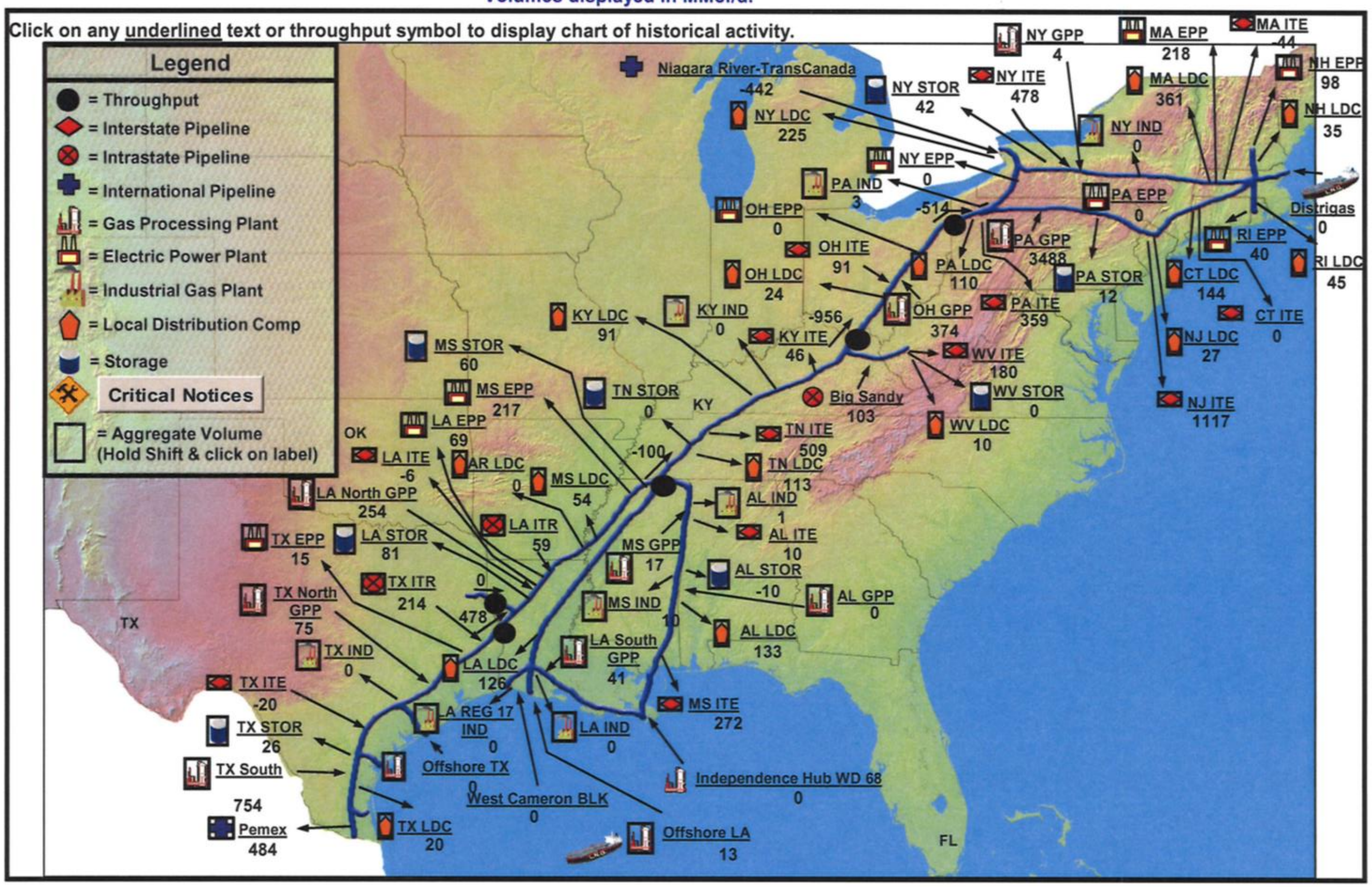
08 May 2014

Daily: Volumes | Capacity | Utilization

Weekly: Volumes | Capacity | Utilization

Monthly: Volumes | Capacity | Utilization

Volumes displayed in MMcf/d.



LCI Energy Insight 915-838-1619 Map

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