COAL AND SECURITY OF ELECTRIC POWER SUPPLY

National Coal Council

2019 Spring Annual Meeting

ENERGY VENTURES ANALYSIS
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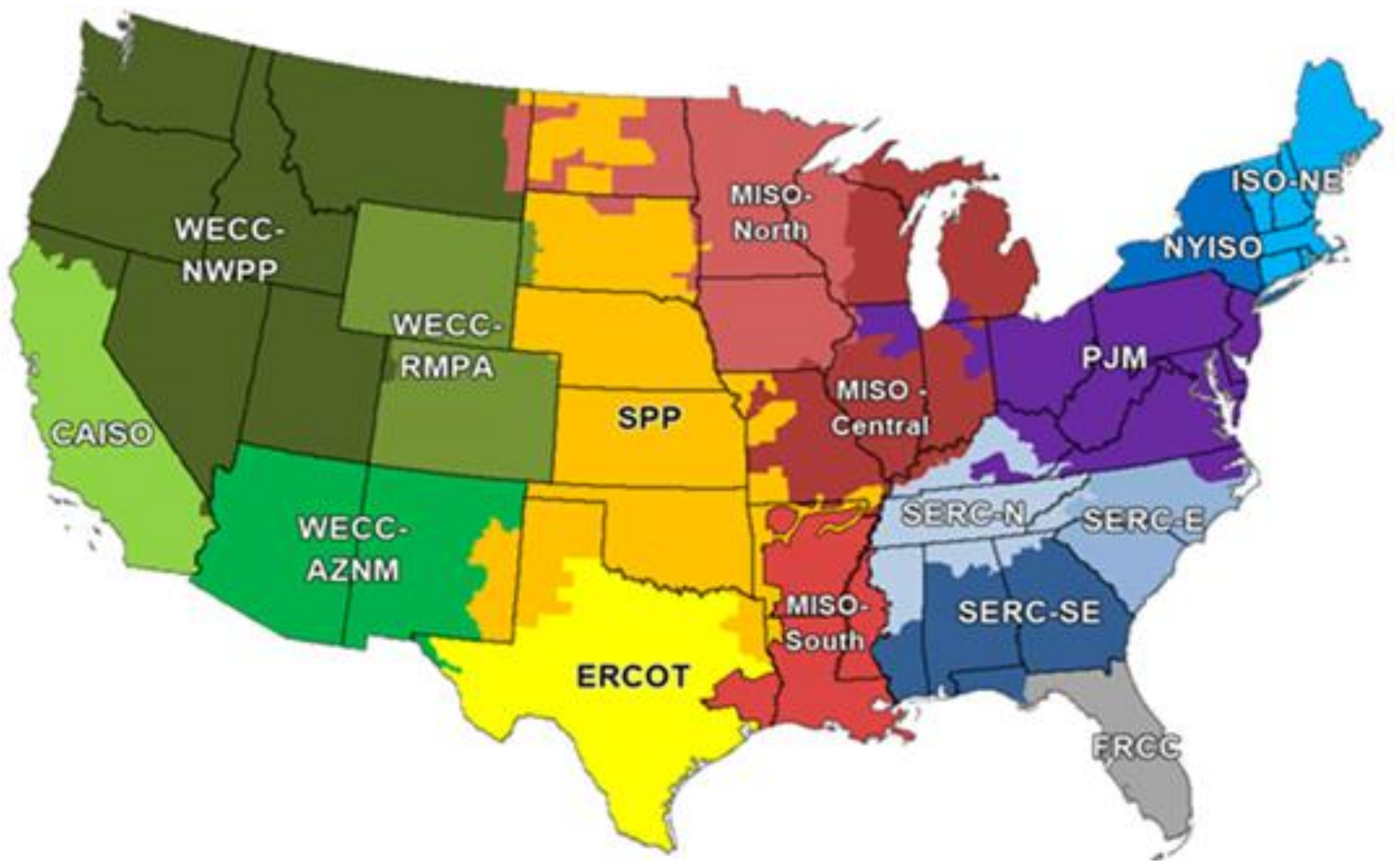
USA POWER MARKETS HAVE A MIX OF ECONOMIC STRUCTURES

- **Traditional utility markets where generation costs and dispatch are managed by the utility who is the load-serving entity (LSE). Power plant resource decisions are made by the utility – including self-build and power purchase agreements.**
- **Centralized markets where the dispatch is managed by the independent system operator (ISO).**
- **Regulation has always been a mix of state and federal authority. FERC has authority over interstate (including transmission) and many inter-utility transactions. Merchant power markets were created by state authority and have pricing rules subject to FERC review.**
  - Except the independent country of Texas – ERCOT.
- **Merchant markets have separated wholesale power generation from transmission, while retail sales are delivered by traditional utilities – LSE. Retail sales can be regulated or deregulated depending on the state.**

MAP OF USA POWER MARKETS

- Merchant power markets include:
  - PJM Interconnection – the largest merchant market, with 60 GW of coal capacity
  - New York ISO, ISO New England; California ISO – almost no remaining coal capacity
  - ERCOT (Texas), which has limited connections to the rest of the power grid



MERCHANT POWER ENERGY AND CAPACITY MARKETS

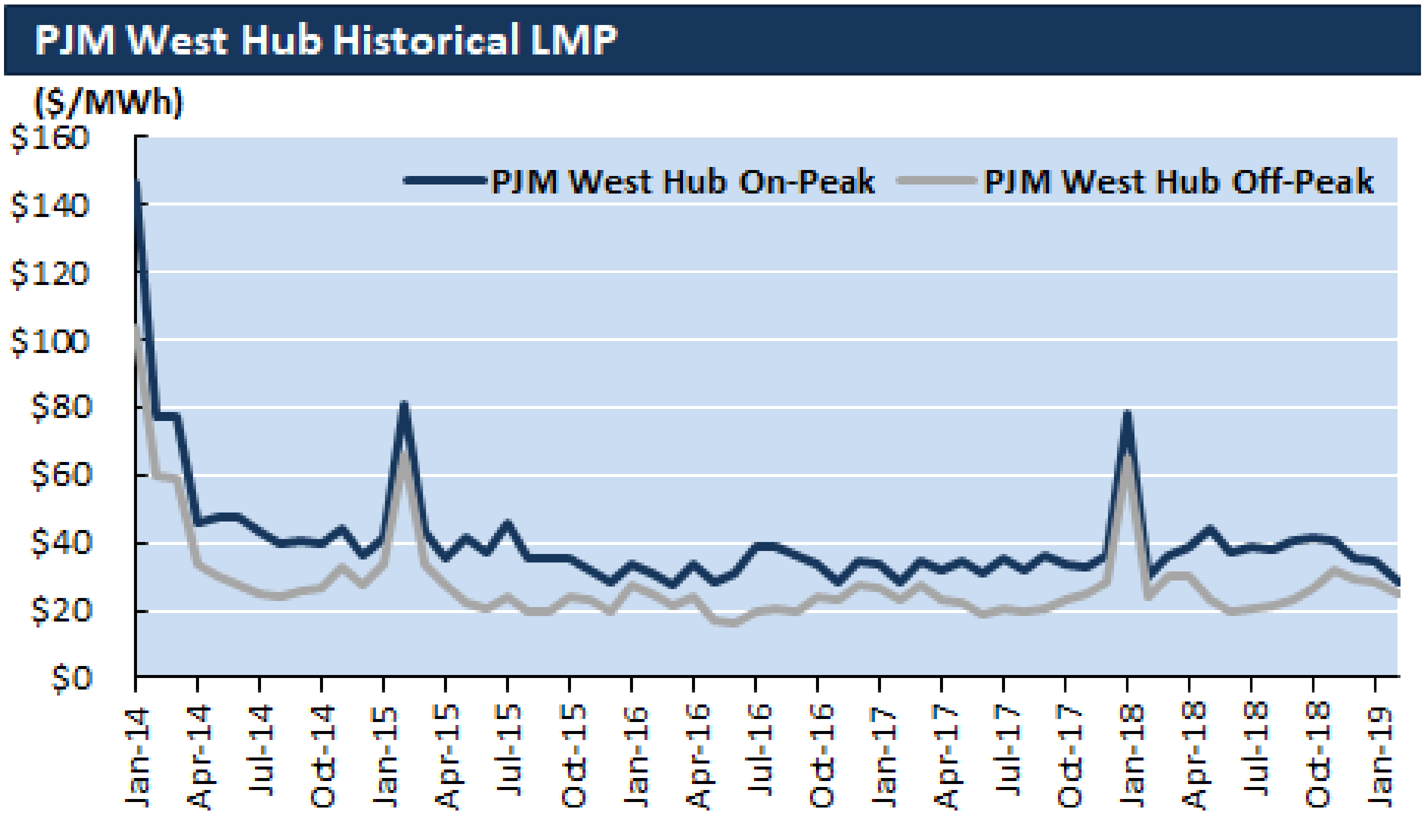
- **Centralized energy markets are one of the primary economic attributes of a merchant power market**
  - Centralized dispatch by the ISO balances power supply and demand in the most efficient manner
  - Dispatch is based upon the variable cost of generation – costs are disclosed to the ISO and subject to audit
  - Energy market prices are set by the marginal cost of generation to meet load – all market participants receive the market clearing price
- **Centralized energy markets do not need to be merchant markets.**
  - PJM began in 1956 – formed to realize the efficiencies of centralized energy dispatch
  - PJM became the first ISO and merchant power market in 1997
  - PJM still has a large umber of utility members with central dispatch but regulated cost-of-service rates
- **Capacity markets are designed to compensate generators (whether merchant or utility) for providing reliable capacity to meet demand**
  - Every ISO has its own capacity market design
  - Not all ISOs have capacity markets – ERCOT is an energy-only market

ENERGY MARKET PRICING STRUCTURE

- **Energy market prices are set both day-ahead and real-time**
  - Most power is sold in the day-ahead market
  - ISO dispatches power based on variable cost until it matches demand
  - The marginal cost of dispatch sets the energy price for all plants
  - Locational market prices vary because of transmission constraints and charges
- **Coal-fired plants have increasing difficulty with variable energy prices**
  - Most coal plants have a minimum turn-down >40% of maximum capacity
    - Plants may run at a loss overnight and weekends to make money during weekdays
    - Cost to startup is high – turning off and on frequently is expensive
  - Fixed O&M costs do not factor into variable-cost energy prices
  - High fixed O&M costs for coal and nuclear plants can create overall losses
- **Gas-fired plants better fit dispatch in the energy market**
  - High turn-down capability and faster ramp rates
  - Lower fixed O&M costs – don’t operate at a loss

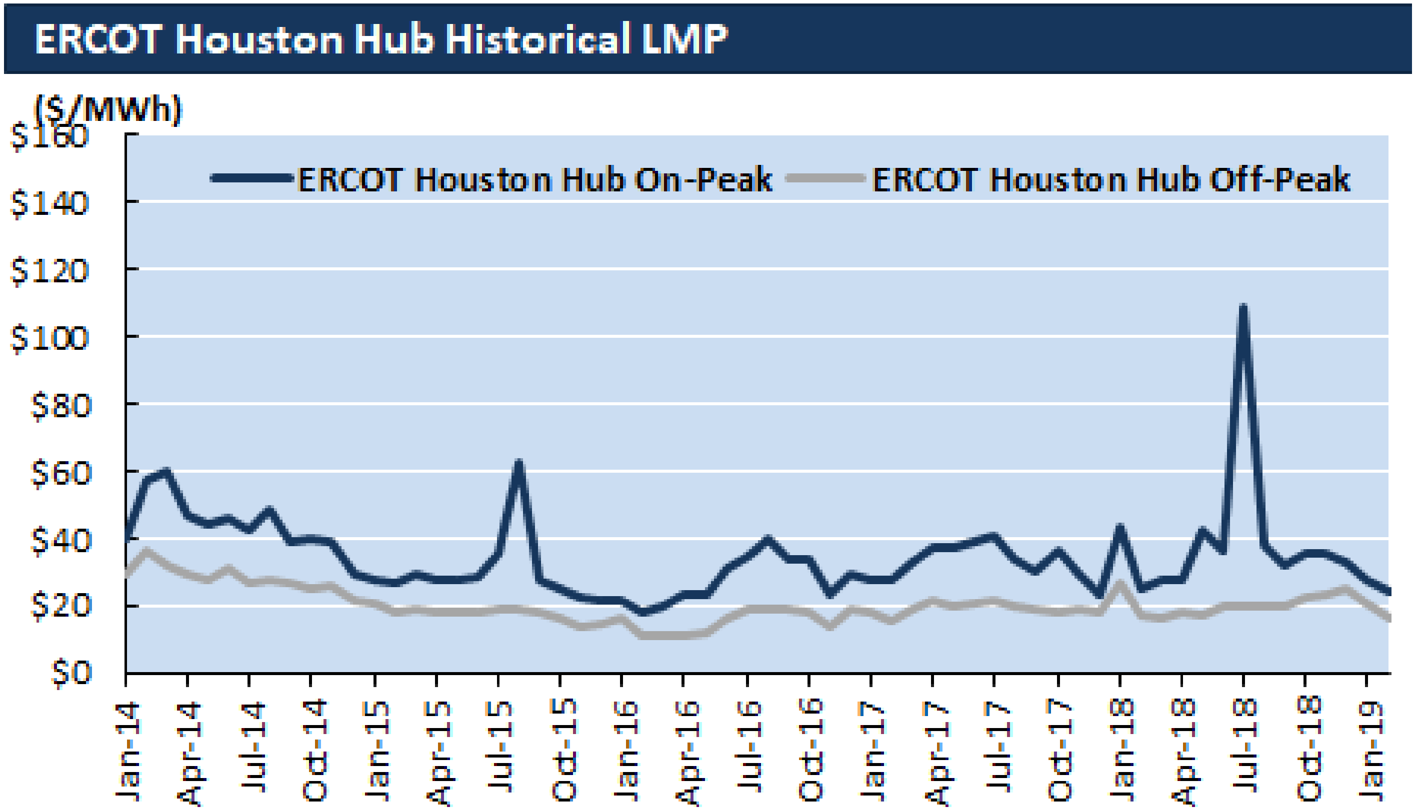
PJM ENERGY MARKET PRICES

- **Monthly average prices have been $30 - $40 per MWh**
  - On-peak average $35 - $45; Off-peak average $20 - $30
  - Occasional winter peaks during cold weather
- **Coal plant typical variable costs are $20 - $30 per MWh – marginal off-peak**



ERCOT ENERGY MARKET PRICES

- **Monthly average prices have been $25 - $30 per MWh**
  - Off-peak average under $20
- **Summer peak prices can exceed $1,000 per MWh for short periods**
- **Hourly prices are below $15/MWh almost 4% of the time**



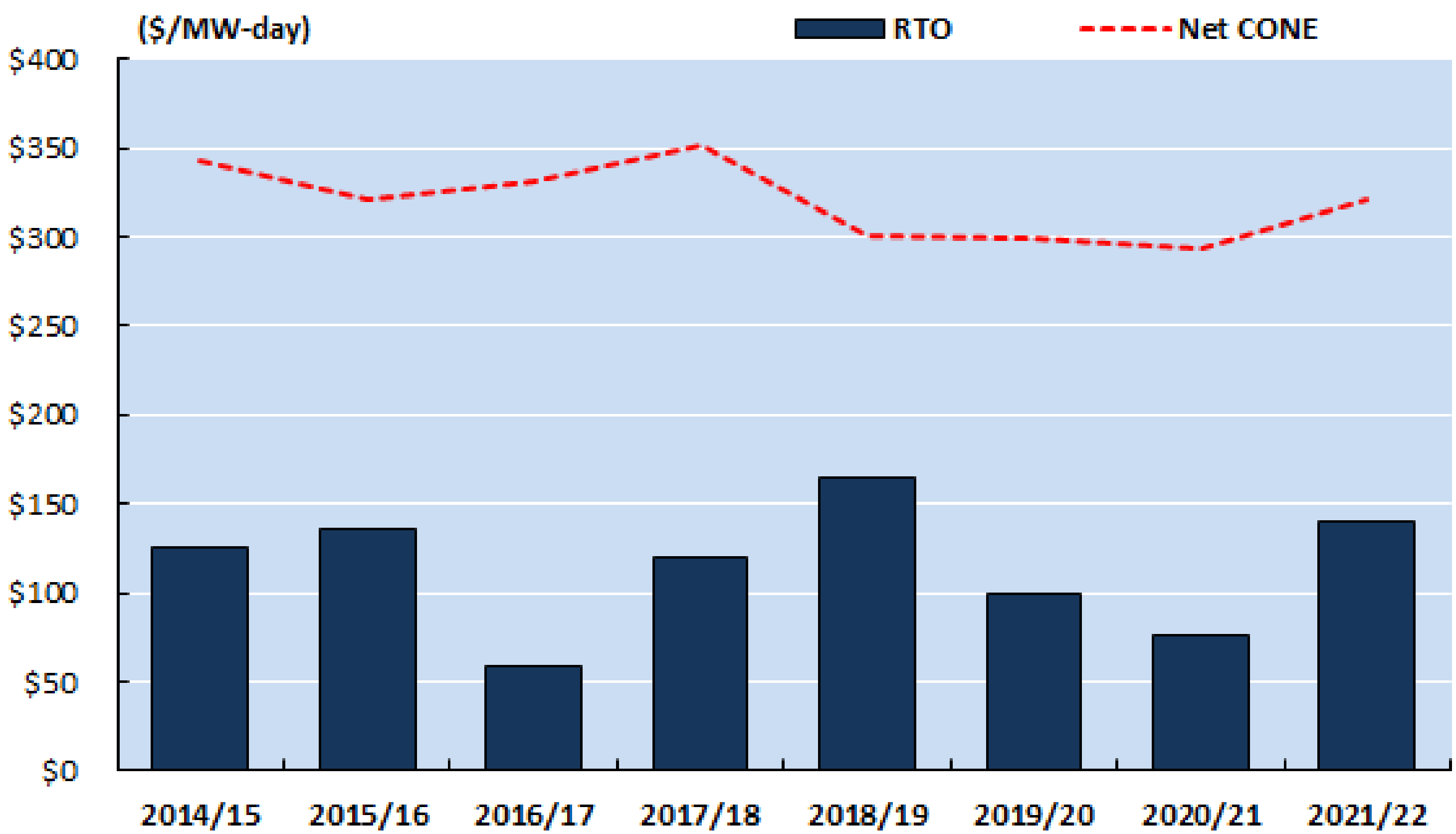
CAPACITY MARKET PRICING STRUCTURES

- **Each ISO has a different capacity market structure**
  - PJM has a 3-year forward capacity market based on prices bid into market – not cost
  - At the other extreme, ERCOT has no capacity market
- **Focus on PJM – largest market for merchant coal**
  - Generators who do not give notice of deactivation are required to bid into BRA auction
  - Bidders can select a price at which they are willing to commit capacity 3 years in advance
  - Capacity price should cover total operating and ongoing capital costs net of margin in energy market
- **Market prices should be capped by the "cost of new entry" - CONE**
  - PJM calculates CONE based on the cost of a new combustion turbine –
    - $321.60 per MW-day = $117 per kW-year for a new plant costing $790 per kW
  - Market prices have stayed well below CONE

PJM CAPACITY MARKET AUCTION RESULTS

- **Capacity prices for the 2021/22 delivery year rebounded to $140 per MW-day**
  - Typical coal plant fixed O&M cost $120 - $180 per MW-day
  - New environmental capital costs can make coal uneconomic

HISTORICAL PJM CAPACITY PRICES BY DELIVERY YEAR



PJM CAPACITY MARKET AUCTION RESULTS – 2021/22

- **Transmission constrained zones had prices almost 50% higher**
  - Chicago, Baltimore, New Jersey, Cleveland

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OUT-OF-MARKET SUBSIDIES DISTORT MERCHANT MARKETS

- **The power market is full of out-of-market subsidies which distort results**
  - Massive subsidies for renewable power sources
  - State renewable portfolio standards
  - Zero-emission credits for nuclear plants
  - Regulated rates for utility plants included in merchant markets
- **Subsidies affect the cost of dispatch; development of new plants; retirement**
  - Non-fossil plants (wind, solar, nuclear, hydro) dispatch into the energy market at prices at zero cost – creates hours with very low prices
  - Renewable subsidies contribute to over-development, creating excess capacity
    - Wind receives $23/MWh for projects which commenced construction prior to Jan. 1, 2018
      - Reduced by 60% for plants which began in 2019 and ends after 2019
    - Solar receives investment tax credit of 30% of construction cost; phases down to 10% after 2021
  - Nuclear ZEC subsidies enacted to avoid retirement
  - Regulated plants can bid into capacity market at zero and receive return on rate base
- **Subsidies incent excess capacity and depress both capacity and energy prices**

MERCHANT POWER STATES ARE SUPPORTING NUCLEAR PLANTS

Status	State	At-Risk Plant	Owner	Capacity (MW)	Subsidy Type	Estimated Annual Subsidy ($MM)	Tenor (years)	60-yr License Expiry
ENACTED	IL	**Quad Cities**	Exelon	1,819	ZEC	$150	10	2032
		Clinton	Exelon	1,065	ZEC	$85	10	*TBD***
	NY	**Fitzpatrick**	Exelon	852	ZEC	$115	12	2034
		Nine Mile Point	Exelon	1,773	ZEC	$275	12	2029/46
		R.E. Ginna	Exelon	582	ZEC	$85	12	2029
	NJ	**Hope Creek**	PSEG	1,173	ZEC	$86	*n/a*	2046
		Salem	PSEG	2,326	ZEC	$170	*n/a*	2036/40
		Oyster Creek*	Exelon	610	ZEC	$45	*n/a*	*n/a*
	CT	**Millstone**	Dominion	2,103	ZEC	*not public*	10	2035/45
PROPOSED	PA	**Three Mile Island**	Exelon	805	AEPS inclusion	*too early*	*n/a*	2034
		Beaver Valley	FirstEnergy	1,872	AEPS inclusion	*too early*	*n/a*	2036/47
	OH	**Perry**	FirstEnergy	1,268	Direct payment	$90	*n/a*	*TBD***
		Davis Besse	FirstEnergy	908	Direct payment	$90	*n/a*	2037

*Oyster Creek retired in Sep 2018

**Has not applied for 20yr extension

TOTAL (MW)	**11,693**	*(enacted states only, minus Oyster Creek)*
COST ($/kW-yr)	**$99**	*(enacted states without CT)*

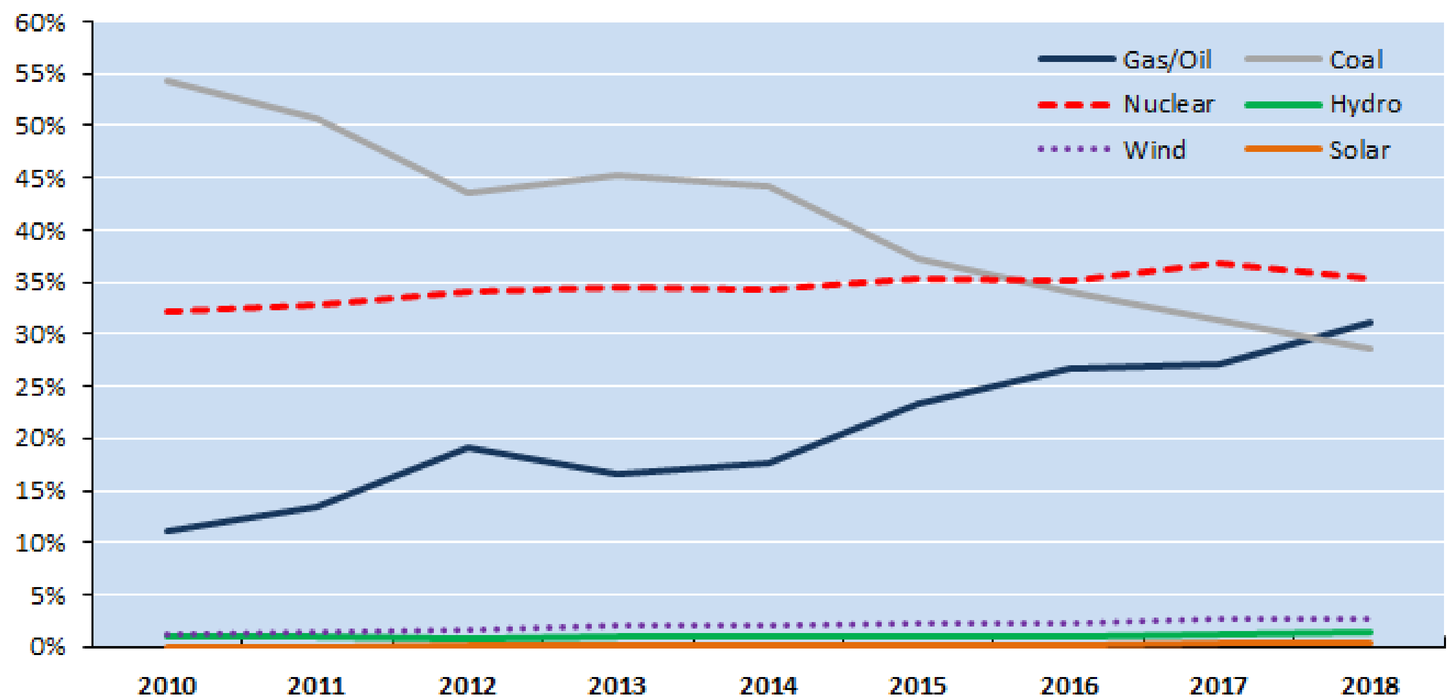
STATE PROGRAM DETAILS

IL	Established a Zero Emission Credit (ZEC) program as part of the 2016 Illinois Future Energy Jobs Act.
NY	Established a Zero Emission Credit (ZEC) program as part of its 2016 Clean Energy Standard.
NJ	Established a Zero Emission Credit (ZEC) program for at-risk plants that "contribute to New Jersey's air quality." ZEC contracts are given in three year increments, and the state will assess the program after 10 years.
CT	Directed CT utilities to enter into contracts for roughly half of Millstone's annual output.
PA	Would add a 3rd tier to PA's existing Alternative Energy Portfolio Standard (AEPS) for nuclear. Bill would benefit all nuclear plants in PA, though only Three Mile Island and Beaver Valley currently are at-risk.
OH	Would create an "Ohio Clean Air Program" and assess a monthly fee to Res/Com/Ind ratepayers.

IMPACT OF MERCHANT MARKET PRICING ON GENERATION

- **Market prices are driving out capacity with high fixed costs – coal and nuclear**
  - Renewable capacity is being forced into the market through mandates and subsidies
  - Excess capacity persists due to slow growth – keeping capacity prices down
  - Gas-fired capacity is able to follow load and energy prices – preferred solution
- **PJM is rapidly shifting from coal to gas; nuclear retirements are next**

PJM GENERATION BY FUEL TYPE



LOSS OF COAL PLANTS WILL AFFECT RELIABILITY

- **Natural gas supply may not be adequate during cold weather events**
- **The "Bomb Cyclone" was a cold weather event which hit the Northeast from December 28, 2017 to January 7, 2018**
- **PJM issued a report which found that on the peak day, *half* of natural gas capacity was not available to operate on natural gas**
  - 23,939 MW was on line and operating on natural gas
  - 8,096 MW of gas plants had forced outages
  - 5,913 MW of gas plants were unavailable to generate because of gas supply outages
  - 9,500 MW of gas units switched to oil backup fuel
- **In contrast, 87% of coal capacity was on-line and operating**
- **Coal provided almost all of the increased generation in January 2018**

	Eastern Total GWh		Change
Fuel Source	**Dec-17**	**Jan-18**	**Dec - Jan**
Coal	58,364	70,130	11,766
Natural Gas	59,889	63,192	3,303
Oil	1,077	4,426	3,349
Pet Coke	236	378	142
Fossil Total	**119,566**	**138,126**	**18,560**
Nuclear	57,768	58,739	971
Hydro	6,304	6,283	(21)
Wind	3,586	4,397	811
Solar	838	922	84
Geothermal	0	0	0
Biomass	2,087	2,107	20
Pumped Storage	(548)	(441)	107
Other	510	509	(1)
Non-Fossil	**70,545**	**72,516**	**1,971**
Total	**190,111**	**210,642**	**20,531**

THE MARKETS ARE NOT KEEPING RETAIL RATES DOWN

- **Out of the Lower-48 states, the 8 states with retail prices over 16 cents/kWh are all in the Northeast and California power markets**
- **The merchant states in PJM have prices at or above the national average**
- **The average retail rate has been growing faster than inflation despite low fossil fuel prices**
- **Why?**
  - Replacing depreciated capital with new capital increases power supply costs
  - New transmission costs to bring power to market is charged to the retail ratepayer

Residential Power Price (cents/kWh)

State	2018	CAGR 2001-18
Massachusetts	21.57	3.28%
Connecticut	21.20	3.99%
Rhode Island	20.55	3.15%
New Hampshire	19.64	2.70%
California	18.90	2.66%
New York	18.53	1.65%
Vermont	17.98	2.08%
Maine	16.12	1.21%
Michigan	15.56	3.80%
New Jersey	15.47	2.47%
Wisconsin	14.44	3.61%
Pennsylvania	13.93	2.16%
Minnesota	13.38	3.38%
Maryland	13.33	3.30%
Kansas	13.13	3.22%
United States	**12.89**	**2.42%**

CHANGES ARE NEEDED FOR MERCHANT MARKET STRUCTURES

- **Merchant coal (and unsubsidized nuclear) are at high risk of closing**
- **Grid reliability will depend on gas plants to follow load and support renewables**
- **Capacity prices need to reflect reliability of supply**
  - PJM has made progress but more is needed
  - On-site fuel storage should be valued in setting capacity prices
    - Gas plants can meet an on-site standard with oil or LNG backup
  - Subsidized capacity, including utility regulated, should not be setting capacity market prices
- **Energy price formation needs to account for out-of-market subsidies**
  - Renewable energy subsidies allow energy prices to be set below actual cost
  - Off-peak energy prices should reflect value of preserving on-peak generation