NORTHEAST POWER MARKETS

ENERGY WATCH

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EXECUTIVE SUMMARY

In this issue of *Energy Watch*™, ESAI discusses the outlook for retirements in the northeast markets in light of the current supply and demand balance, expected new capacity additions, and public policy initiatives for greenhouse gas reduction and renewable energy. We begin with a summary of the mechanisms through which the amount and mix of retired capacity will be shaped and then provide additional detail on the planned and economic retirements expected within each market.

In New England, spark spreads are expected to remain flat, as new capacity additions and demand response offset demand growth over time. Power prices are expected to trend with natural gas prices and RGGI allowance costs over time.

In New York, power prices for the downstate zones will be affected by the retirement of Indian Point in 2020 and 2021 and new transmission expansion expected by 2024. Prices in western New York will be affected by transmission upgrades in Zone A. Outside of these impacts, prices in New York are largely expected to follow natural gas price trends. In PJM, projected LMPs and spark spreads reflect expected trends in natural gas prices and additions of new CCGT capacity in western PJM.

ESAI's gas outlook has been lowered such that Henry Hub prices will only reach $3.00/MMBtu after 2028. In this issue, ESAI provides details on recent LNG export project developments and the potential for a 'second wave' of projects.

In This Issue

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Economic Retirements and New Entry

Each of the three northeast RTO markets has a substantial capacity surplus above its reserve margin requirements. As discussed in ESAI's Energy Watch™ and Capacity Watch™ publications over the last few years, these surplus conditions have resulted in lower capacity prices, substantial amounts of unsold capacity in ICAP market auctions and decreasing capacity factors in the energy markets for many resources. The surpluses are also being exacerbated by additional new supply. State-level (and potentially federal) public policies for renewable energy, greenhouse gas (GHG) reduction, fuel diversity, and local power plant jobs are adding more supply or supporting existing supply in each market, further reducing the resource adequacy needs and market potential for other existing generation resources. Moreover, a substantial amount of new gas-fired capacity has recently come online or will enter service over the next three years. Hence, another wave of retirements seems inevitable, but has not yet to fully materialized to the extent expected.

In this issue of *Energy Watch*™, we discuss how the next wave of retirements may play out and how it will be shaped by public policy, market rules, market fundamentals, and the expectations of market participants. We begin with a discussion of the drivers of retirements across the markets. We then provide a more detailed discussion of our retirement outlook for each market as part of the discussion of each regional market outlook and forecast.

CROWDING OUT OF EXISTING RESOURCES

The supply and demand data in each of the three northeast markets paints the same very clear picture: substantial excess capacity is available compared to what is needed for resources adequacy and meeting energy demand. All else equal, the surplus is expected to persist over the next decade, meaning retirements will be necessary to bring supply and demand back into balance. The set of charts below illustrate the surplus and its impact on the capacity and energy market supply/demand balances over time. The first three charts show the installed capacity requirements for each market versus available capacity resources. The blue portion of the vertical bars in each chart shows how much capacity is projected to obtain capacity market obligations and the red line shows the corresponding minimum capacity requirement. The portion of each blue bar above the red line represents excess capacity cleared in the auction (on the downward-sloping demand curves) and the green portion of the bar is capacity that ESAI projects will remain unsold and not get a capacity payment. The capacity represented by the green region will either need to survive without capacity payments or will be retired. The size of the green region is a good indicator of the expected amount of retirements for the region.

In the case of PJM, a large surplus exists currently and is expected to persist over at least the next ten years. However, the mix of capacity that will remain unsold in future Base Residual Auctions (BRAs) within the PJM RPM capacity market is likely to be determined by changes to capacity market rules, discussed in more detail below. For ISO-NE, supply is expected to increase due to contracts for renewable resources and firm capacity from Quebec

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delivered over new transmission. Combined with a declining Installed Capacity Requirement (ICR), this increase in supply will lead to a growing and persistent surplus and substantial retirements will be needed to bring the market back into balance. Similarly, for New York, ESAI projects a combination of renewable additions to meet the New York State targets and additions required to reliability within load pockets to lead to a sustained surplus.

Figure 3: PJM Capacity Surplus

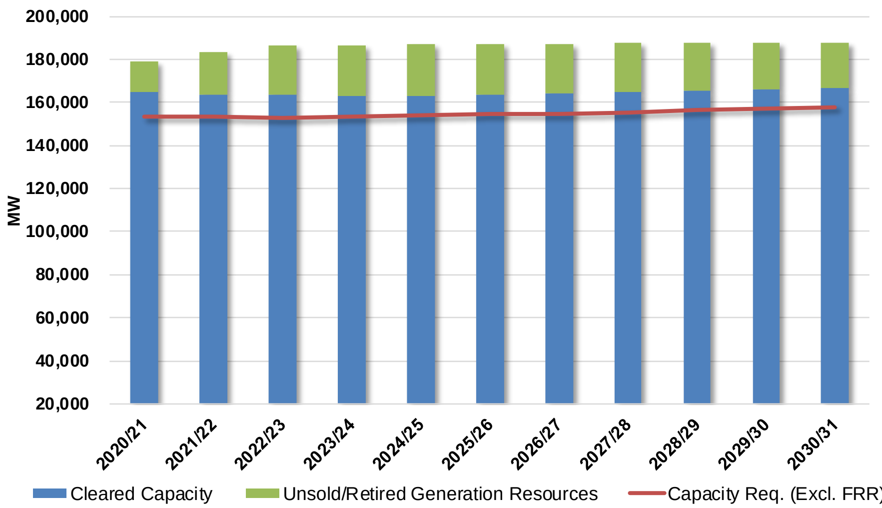


Figure 4: ISO-NE Capacity Surplus

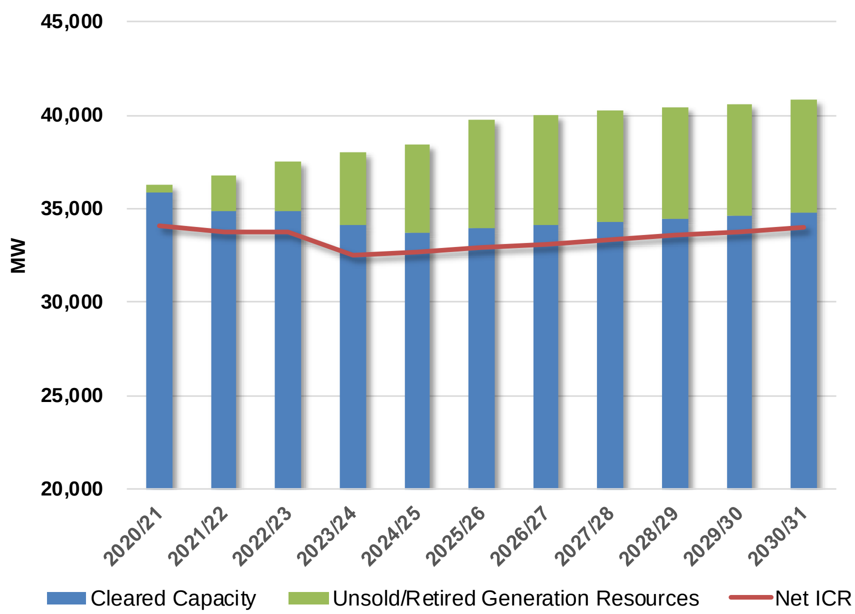
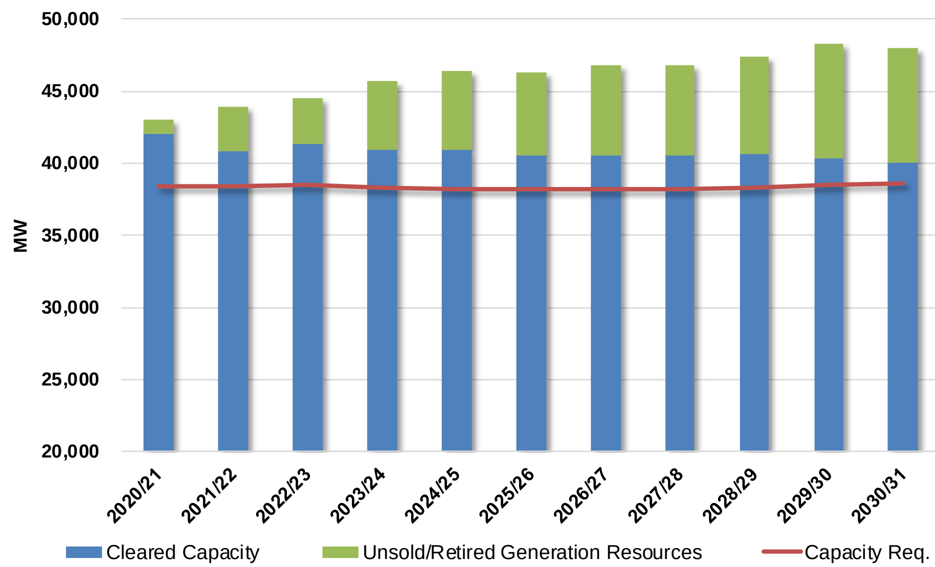


Figure 5: NYISO Capacity Surplus



The next set of charts shows the expected generation mix over time and the corresponding energy market opportunities for existing non-renewable resources. In PJM, with the addition of enough capacity to meet existing state renewable standards along with new gas-fired generation that ESAI projects will clear in the next BRA, the remaining energy demand that will be met by existing non-renewable generating assets will drop significantly by 2030, with approximately half of the current energy output of these resources displaced. Hence, capacity factors for existing resources will decline, with downward pressure on energy gross margins for these assets. With more ambitious targets in New England and New York, the decline in the portion of energy demand that will be served by the existing non-renewable fleet will be even more pronounced. Hence, the energy market is unlikely to provide additional financial support to existing generators, making them even more dependent on the capacity market. With much of the existing fleet crowded out of both the energy and capacity markets, as illustrated by these charts, retirements will follow and will be driven primarily by the capacity market outcomes. However, the path to retirement is often uncertain, and historically there have been several barriers to deactivation of generating resources.

Figure 6: PJM Generation Mix, 2018

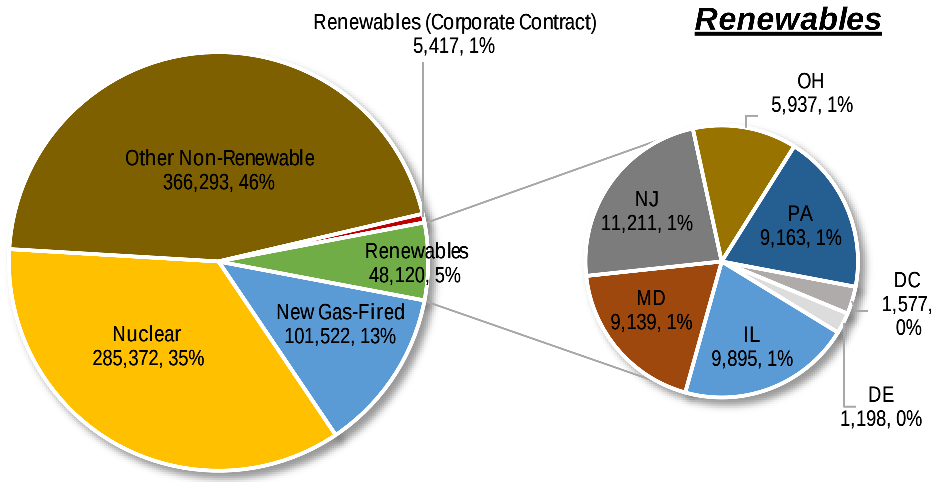
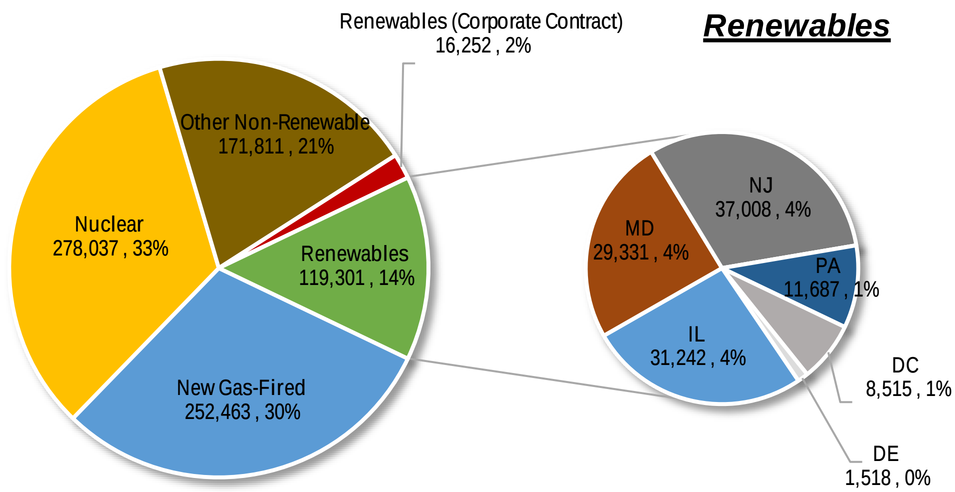


Figure 7: Projected PJM Generation Mix, 2030



bottom of the supply stack. Under Extended RCO, the price will be mitigated to a higher level, reflective of what would have occurred without the subsidies for the RCO supply (See the Q2-2019 and Q3-2019 issues of *Capacity Watch*™ for a more detailed description of these two alternative sets of rules for PJM).

Under both of these rules, the carved-out capacity is, in effect, put at the bottom of the capacity supply stack and is selected ahead of all competitively supplied resources. As a result, more of the competitively supplied resources will fail to clear in the BRAs and are more likely to be retired. Unlike ISO-NE, where at-risk resources must "volunteer" to be displaced by participating in the supplemental CASPR auction for replacement capacity, the at-risk assets in PJM cannot avoid being displaced by the carved-out subsidized resources unless their offers are low enough to allow them to clear in the BRA. However, the displaced resources in PJM are not required to retire, whereas in ISO-NE, resources purchasing replacement capacity in ISO-NE are required to retire. Nonetheless, failing to receive a capacity payment will provide a very strong signal that the capacity should be retired.

The idea of a CASPR-style rule has been floated at NYISO for consideration in its capacity market. Currently, the NYISO relies on existing buyer-side mitigation rules that apply only to Zones G-J. These rules do not apply to subsidized existing resources, but rather only to new supply. The MOPR applied to subsidized new supply is also slightly different from PJM and ISO-NE. Specifically, instead of new resources being subject to offer floors equal to their unsubsidized net cost of new entry (Net CONE), an offer floor equal to 75 percent of the Net CONE for a gas-fired peaking unit is applied. Hence, the subsidized new resources are still able to displace other new resources that otherwise would have been needed by undercutting their price by 25 percent. But the subsidized new entry is not able to undercut existing at-risk resources. The impact of retirements is therefore limited.

Although NYISO is not yet actively pursuing a second-best approach like PJM or ISO-NE, it is addressing the accommodation of public policy through another mechanism—a proposed carbon pricing mechanism. The NYISO approach addresses the market failure of unpriced attributes directly, by attempting to price them into unit offers and the resulting market clearing prices for energy. If implemented, these rules would provide strong incentives for supply of the resources best able to contribute towards public policy goals and disincentives for supply of resources that do not. Hence, the NYISO approach should encourage additional retirements directly through market price signals, rather than the non-price displacement mechanisms proposed for PJM and the voluntary displacement mechanism under CASPR.

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New England

ECONOMIC RETIREMENTS AND NEW ENTRY

Since 2016, over 2,400 MW of fossil capacity has been retired in New England. This capacity is attributed to the retirements of Brayton Point (1,630 MW, coal and 11 MW, oil) and the 670 MW Pilgrim nuclear facility. These retirements were driven by economics and the deactivated capacity has largely been replaced by renewable and natural gas capacity.

Looking ahead, additional retirements are expected due to a growing capacity surplus, aging fleet, and declining demand within the region. ESAI's base case outlook includes significant retirements, with over 5,500 MW deactivated by 2024. Approximately 2,500 MW of this capacity is already slated for retirement, coming mostly from Mystic (Units 7 – 9 and GT 1) and Bridgeport Harbor (Unit 3). The remaining retirements are expected due to market conditions and the outcome of upcoming FCAs. In particular, 1,800 MW of capacity is projected retire after failing to obtain a Capacity Supply Obligation (CSO) in each of the next three FCAs. Additionally, approximately 1,200 MW of capacity is assumed to retire through the CASPR mechanism over these same three FCAs. The 1,200 MW of Sponsored Resources providing the supply in the CASPR SAs is expected to come from the New England Clean Energy Connect (NECEC) HVDC transmission project and renewable additions beyond what can be accommodated by remaining available FCM offer floor exemptions for renewable projects (which are being phased out, as discussed in recent issues of ESAI's *Capacity Watch*™ publication).

ESAI's base case forecast assumes that one 650 MW natural gas combined cycle facility will enter the market in 2022 (Killingly Energy Center) and the 1,200 MW NECEC project will begin service in 2023. Should one or both of these projects fail to move forward, the amount of New England capacity retired may be lower. In addition, significant new renewable capacity additions are expected over the next decade. These additions are driven by each state's Renewable Portfolio Standard (RPS), including offshore wind. Additional increases in the RPS standards or other clean energy goals may result in additional retirements.

Drivers for Recent Retirements

Between 2016 and 2019 (YTD), 2,300 MW of capacity was deactivated in New England (see Figure 11 below). Of this amount, 1,630 MW (71 percent) was attributed to the coal-fired Brayton Point plant and 670 MW (29 percent) to the Pilgrim nuclear station. Table 2 below shows the unit-specific deactivations during this period. The Brayton Point plant was retired in advance of the eighth FCA (for 2017/18), the first New England capacity auction conducted without a price floor. With the price floor removed, clearing prices would have dropped very low had all supply remained in the market. In response to this market signal, suppliers opted to exit the market in advance of the auction rather than accept a price that would have failed to cover net going-forward costs. The Pilgrim plant was also not economic at expected capacity price levels for New England, given the decline in power prices

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resulting from dropping natural gas prices. Additionally, the plant faced local opposition and its owner, Entergy, was seeking to exit the New England wholesale market.

Figure 11: New England Fossil Retirements, 2016 – 2019 (YTD)

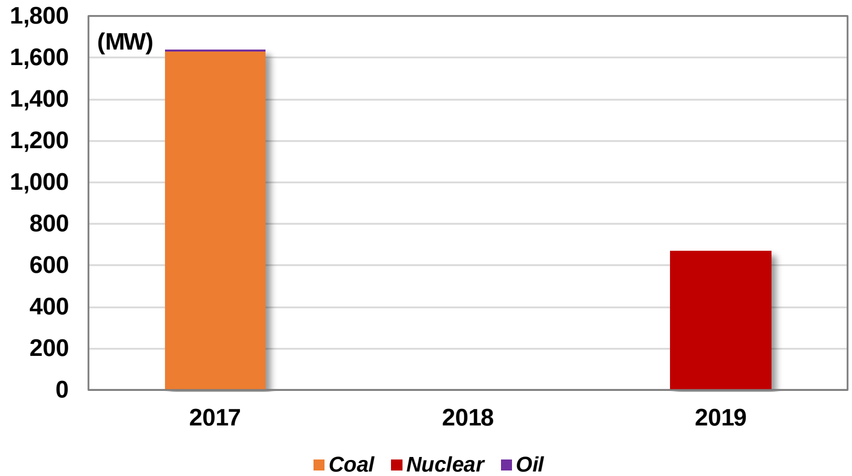


Table 2: New England Unit-Specific Fossil Retirements, 2016 – 2019 (YTD)

Plant Name	Fuel Type	MW (Nameplate)	Retirement Date	Age of Unit at Retirement	State	Zone
Brayton Point (Unit 1)	Coal	241	Jun-17	53	MA	SEMA
Brayton Point (Unit 2)	Coal	241	Jun-17	52	MA	SEMA
Brayton Point (Unit 3)	Coal	673	Jun-17	58	MA	SEMA
Brayton Point (Unit 4)	Coal	476	Jun-17	42	MA	SEMA
Brayton Point Diesels (Units 1-4)	Oil	11	Jun-17	50	MA	SEMA
Pilgrim	Nuclear	670	Jun-19	46	MA	SEMA
Total Retired (2016 - 2019 YTD)		***2,311***				
Total Coal Retired (2016 -2019 YTD)		**1,630**				
Total Oil Retired (2016 -2019 YTD)		**11**				
Total Nuclear Retired (2016 - 2019 YTD)		**670**				

Figure 12 and Figure 13 show how New England's generation mix (GWh) and installed capacity mix has evolved between 2010 and 2018. The share of coal-fired generation in New England has been steadily decreasing from 11 percent in 2010 to less than one percent in 2018. This decline reflects both coal plant deactivations and the underlying market economics that has led to those coal retirements. Over the same period, the share of natural gas in the generation mix has increased from 40 percent to 45 percent in 2018. The share of renewable generation has increased from six percent in 2010 to ten percent in 2018. As the two figures show, total installed capacity has remained relatively constant, while total generation has declined. This trend has resulted in lower capacity factors and energy net revenues for the highest-cost generators, making them more dependent on the capacity market and putting them at increased risk of retirement.

Figure 12: New England's Generation Mix, GWh

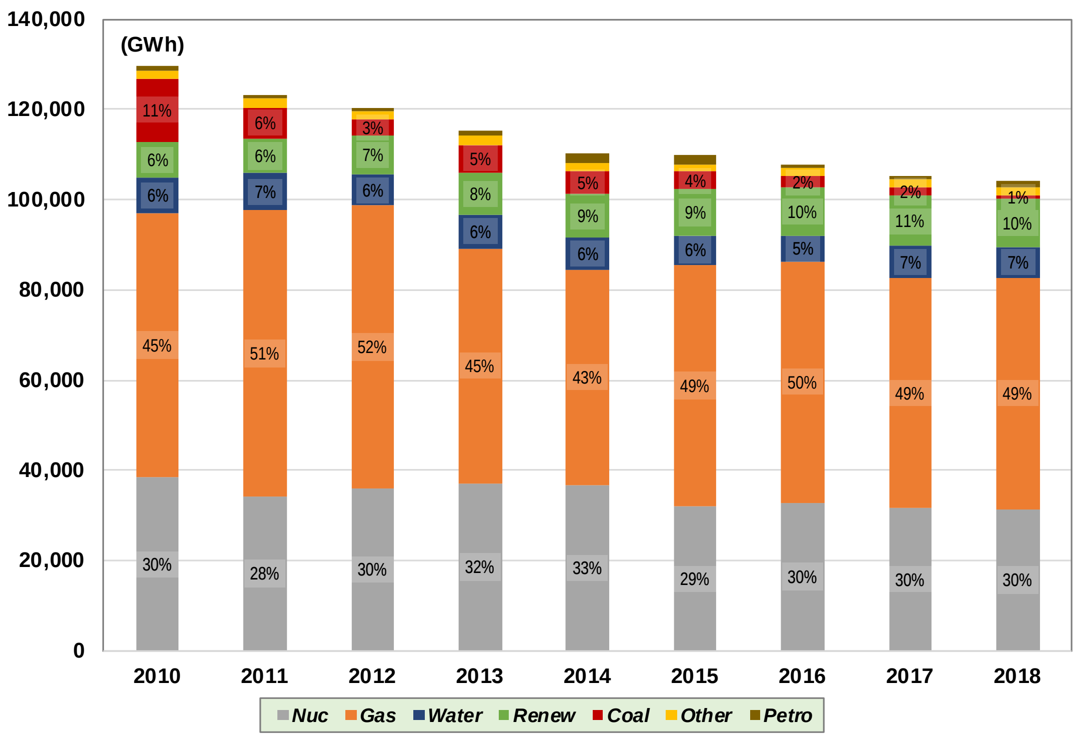
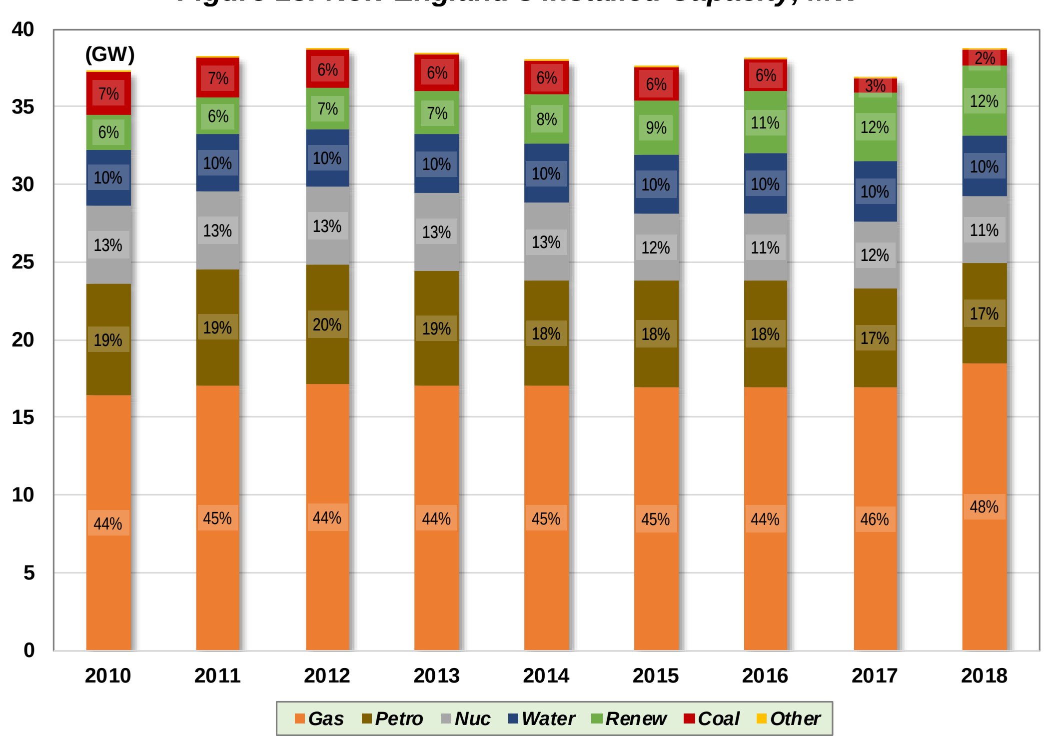


Figure 13: New England's Installed Capacity, MW



NYISO

Since 2016, a total of 1,300 MW of coal, natural gas and oil-fired capacity has been deactivated in New York. These retirements have and will continue to be driven by economics and state environmental regulations. In the near-term, expected major retirements include the Indian Point nuclear units (slated for deactivation in 2020 and 2021) and all remaining coal-fired plants, which will be unable to meet GHG emission standards established for New York State. The local impacts of the Indian Point deactivation will be largely offset by the addition of new gas-fired generation, namely the recently completed CPV Valley project and the Cricket Valley plant, currently under construction. Looking ahead, significant additional capacity is expected to retire, as discussed in more detail below. ESAI's base case includes approximately 4,000 MW of retirements by 2028, with substantially more capacity at-risk. If the New York State target of meeting 70 percent of energy demand with renewable resources by 2030 is achieved, additional retirements are very likely.

RECENT AND UPCOMING RETIREMENTS

Drivers for Recent Retirements

Between 2016 and 2019 (YTD), 1,300 MW of capacity was deactivated in New York (see Figure 1 below). Of this amount, 703 MW (53 percent) was attributed to coal retirements, 444 MW (34 percent) to natural gas peaking facilities, and 168 MW (13 percent) to oil-fried peaking units. Table 1 below shows the unit-specific deactivations during this period.

Figure 19: New York Fossil Retirements, 2016 – 2019 (YTD)

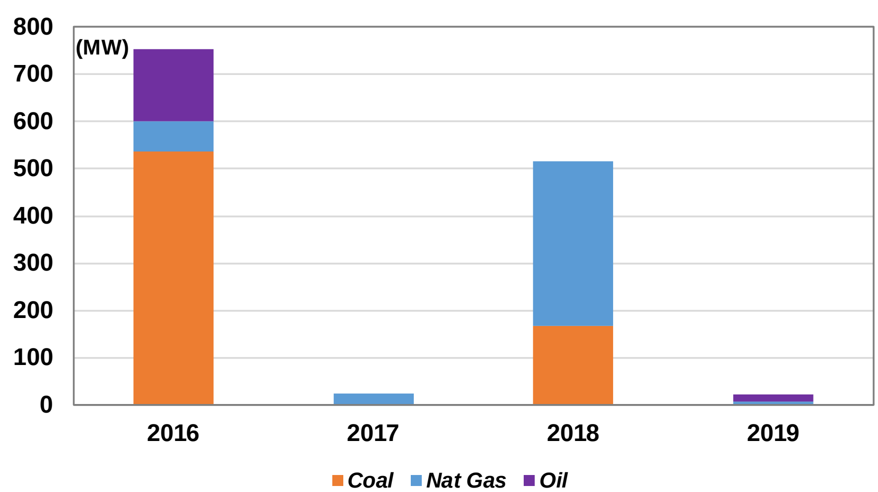


Table 9: New York Unit-Specific Fossil Retirements, 2016 – 2019 (YTD)

Plant Name	Fuel Type	MW (Nameplate)	Retirement Date	Age of Unit at Retirement	Zone
Dunkirk (Unit 2)	Coal	100	Jan-16	69	A
Astoria (Unit 8)	Oil	16	Jan-16	49	J
Astoria (Unit10)	Oil	24	Jan-16	48	J
Astoria (Unit11)	Oil	32	Jan-16	48	J
Astoria (5 and 7), Mothball	Oil	33	Jan-16	49	J
Astoria (Units 12 & 13), Mothball	Oil	48	Jan-16	48	J
C.R. Huntley	Coal	436	Mar-16	62	A
Ravenswood (Units 4-6)	Nat Gas	64	Apr-16	50	J
Ravenswood GT 9	Nat Gas	25	Nov-17	48	J
Standard Binghamton Cogen	Nat Gas	48	Jan-18	25	C
Ravenswood (2-1, 2-2, 2-3, 2-4, 3-1, 3-2 & 3-4	Nat Gas	300	Apr-18	28	J
Cayuga (Unit 2)	Coal	167	Jul-18	61	A
Hudson Avenue (Unit 4)	Oil	16	Apr-19	49	J
Auburn State Street	Nat Gas	7	May-19	9	C
Total Retired (2016 - 2019 YTD)		***1,316***			
Total Coal Retired (2016 -2019 YTD)		**703**			
Total Natural Gas Retired (2016 -2019 YTD)		**444**			
Total Oil Retired (2016 -2019 YTD)		**168**			

Figure 2 and Figure 3 show New York's generation mix (GWh and installed capacity) each year between 2010 and 2018. The share of coal-fired generation in New York has been steadily decreasing from eight percent in 2010 to less than one percent in 2018. Over the same period, natural gas generation has been relatively constant (around 40 percent), as generation from older natural gas units have been replaced with the output of new units. The share of non-hydro renewable generation has increased from three percent in 2010 to five percent in 2018. Note that the output of large hydro facilities in New York count towards the state's renewable targets, so total supply towards the RPS goals is above 25 percent, but still far short of the 70 percent requirement for 2030.

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Figure 20: New York's Generation Mix, GWh

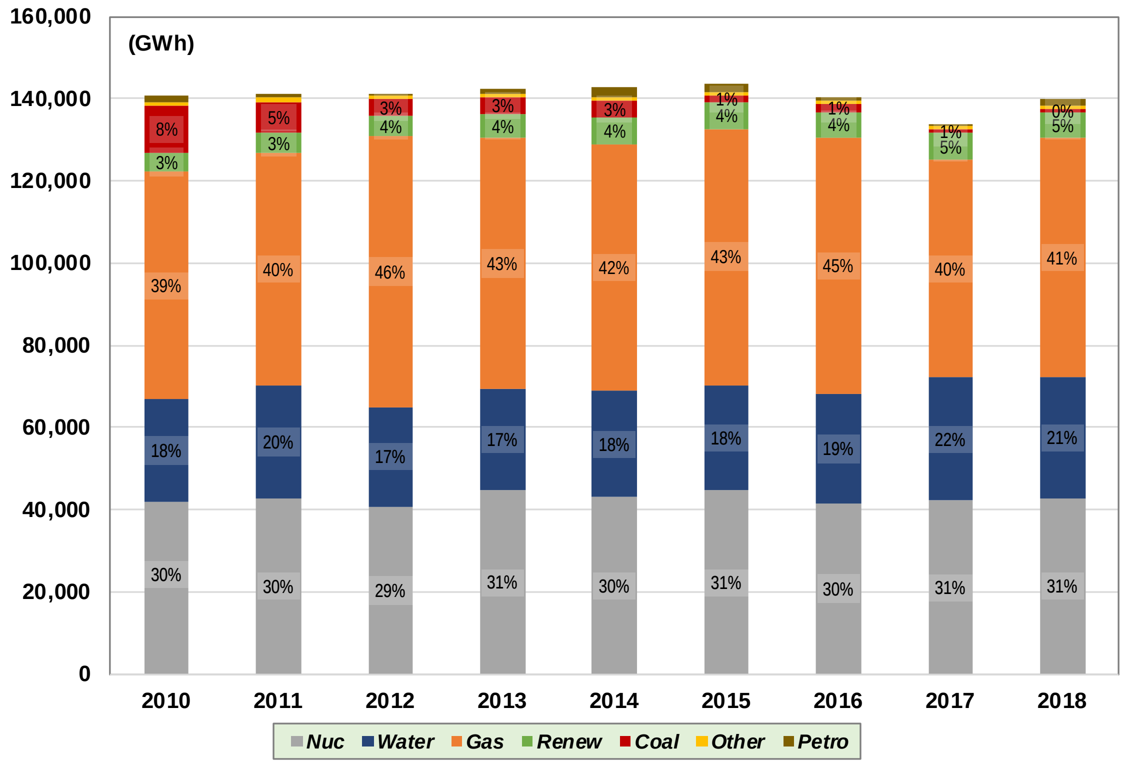
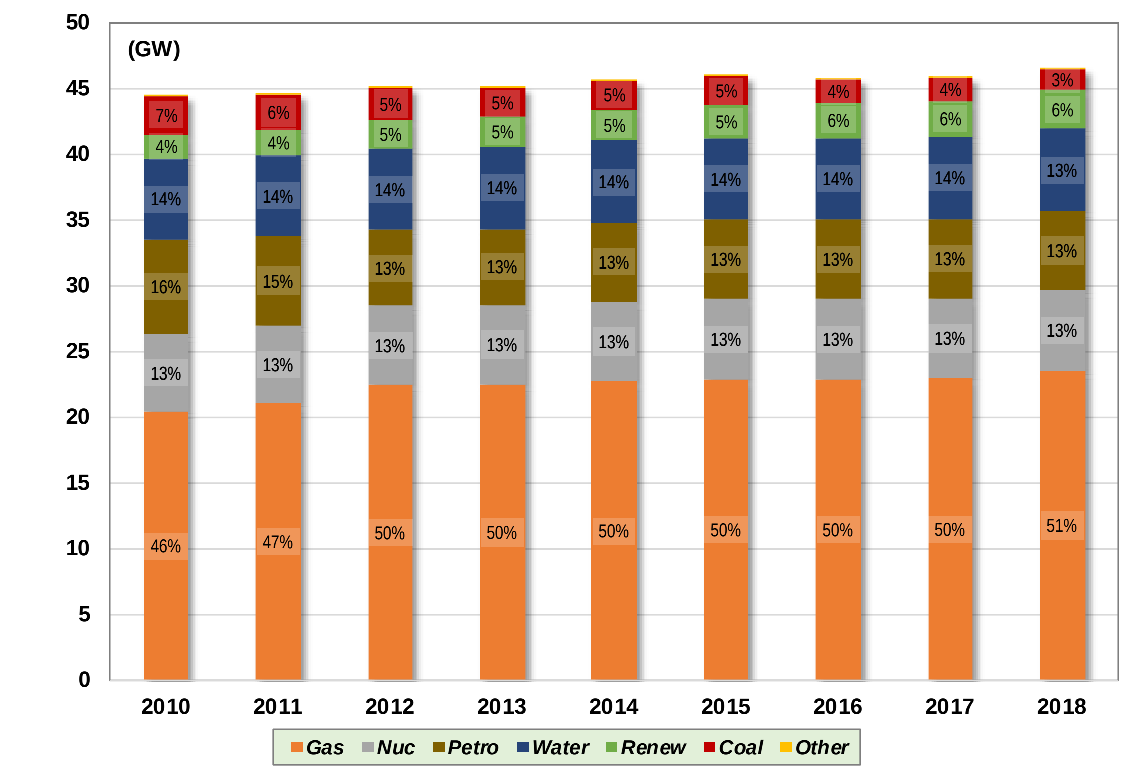


Figure 21: New York's Installed Capacity, MW



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Future Retirements

Table 2 below shows ESAI's expectations for future unit retirements in New York (base case assumptions), including both slated deactivations and projected economic retirements. Table 3 identifies the pool of at-risk natural gas and oil-fired units from which economic retirements are expected to come. Approximately 9,000 MW of capacity is included in ESAI's base case retirement assumptions. Excluding 2,000 MW of nuclear capacity that is assumed to retire upon license expirations, ESAI projects that 8,000 MW will be retired by 2028. Of these projected retirements, 2,200 MW have pending deactivation requests filed with NYISO. Another 3,300 MW of retirements are expected due to environmental regulations, including the Somerset plant which will not meet state GHG emission standards that will be in effect by 2021 and approximately 2,500 MW of GT units in Downstate New York that will be subject to expected revised NOx regulations for peaking units, proposed to take effect between 2023 and 2025. The remaining 1,500 MW is from economic retirements among the significant fleet of aging steam units in New York, which are highly dependent on capacity prices and nearing the end of their expected physical lifespans.

Table 10: Future New York Fossil Retirements

Unit	Nameplate (MW)[1]	Summer ICAP (MW)	Unit Type	Month	Year	Status	Location
Cayuga (Unit 1)	155	152	Coal	Nov	2019	Slated	ROS
Indian Point (Unit 2)	1,299	1,000	Nuclear	Apr	2020	Slated	LHV
Indian Point (Unit 3)	1,012	1,041	Nuclear	Apr	2021	Slated	LHV
Somerset	655	686	Coal		2021	At-Risk	ROS
Nine Mile Point (Unit 1)	642	625	Nuclear	Aug	2029	At-Risk	ROS
Ginna	614	582	Nuclear	Sep	2029	Planned	ROS
FitzPatrick	883	851	Nuclear	Oct	2034	Planned	ROS
Zone J GT Retirements ('20)	70	59	Nat Gas / Oil	May	2020	At-Risk	NYC
Zone J GT Retirements ('20)	51	41	Nat Gas / Oil	Nov	2020	At-Risk	NYC
Zone J GT Retirements (May '21)	162	127	Nat Gas / Oil	May	2021	At-Risk	NYC
Zone J GT Retirements (Nov '21)	159	125	Nat Gas / Oil	Nov	2021	At-Risk	NYC
Zone J GT Retirements ('22)	162	123	Nat Gas / Oil	May	2022	At-Risk	NYC
Zone J GT Retirements ('23)	357	273	Nat Gas / Oil	May	2023	At-Risk	NYC
Zone K GT Retirements ('23)	1,500	1,200	Nat Gas / Oil	May	2023	At-Risk	LI
Zone G GT Retirements ('23)	120	95	Nat Gas / Oil	Nov	2023	At-Risk	LHV
Zone J GT Retirements (May '24)	189	146	Nat Gas / Oil	May	2024	At-Risk	NYC
Zone J GT Retirements (Nov '24)	170	127	Nat Gas / Oil	Nov	2024	At-Risk	NYC
Zone G ST Retirements ('24)	550	500	Nat Gas / Oil	Nov	2024	At-Risk	LHV
Zone J GT Retirements ('25)	333	255	Nat Gas / Oil	May	2025	At-Risk	NYC
Zone C Retirements ('26)	550	500	Nat Gas / Oil	Nov	2026	At-Risk	ROS
Zone G ST Retirements ('28)	550	500	Nat Gas / Oil	Nov	2028	At-Risk	LHV
Total	***11,004***	**9,009**					

[1]Winter capacity shown for unnamed retirement assumptions.

Note: For additional historical data, please reference ESAI PEP file.

New York's state-level environmental regulations are a significant driver for future retirements. Specifically, the New York State Department of Environmental Conservation (DEC) finalized CO_2 emissions standards this past May for the state's existing electric generating units (EGUs). All non-coal EGUs are expected to be compliant with these standards, but the state's only two remaining coal-fired EGUs (Cayuga Unit 1 and Somerset) are not. As such, these two units are required to stop operating by the end of 2020 when compliance with these standards is required. In August, the owners of Cayuga (Unit 1)

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PJM

Since 2016, 11,300 MW of capacity has been deactivated in PJM. Eighty-six percent of these retirements were from coal-fired units as owners struggled to recover their fixed costs. Large surpluses in the PJM capacity market and subsidies for nuclear generation in Illinois and New Jersey are two additional factors contributing to these retirements. Despite continued retirements of coal-fired units, significant quantities of gas-fired resources have entered the PJM market and despite the surplus, this trend continues. The addition of these new gas-fired units is likely to increase the extent of at-risk existing units in PJM, but delays in retirement of at-risk existing capacity may place additional economic pressure on the new entrants.

Looking ahead, significant additional capacity is expected to retire. Between now and 2028, ESAI' base case assumptions include over 12,000 MW of retirements. There is significant additional capacity that is at-risk for retirement looking forward (discussed below). To replace this capacity, ESAI anticipates nearly 12,000 MW of natural gas additions through 2023 and nearly 16,000 MW of renewable additions through 2030 that are required to meet the renewable standards established by several of the PJM states.

RECENT AND UPCOMING RETIREMENTS

Drivers for Recent Retirements

Between 2016 and 2019 (YTD), nearly 11,300 MW of capacity was deactivated across the PJM footprint (see Figure 37 below). Of this amount, 8,500 MW (76 percent) was attributed to coal retirements, 1,960 MW (17 percent) to natural gas facilities, 550 MW (5 percent) to nuclear, and 170 MW (2 percent) to oil units. Table 27 below shows the unit-specific deactivations during this period. Note that in 2015, 10,000 MW of capacity was retired in PJM, mostly coal, in compliance with the Mercury and Air Toxics rule (MATS).

Figure 38: PJM Fossil Retirements, 2016 – 2019 (YTD)

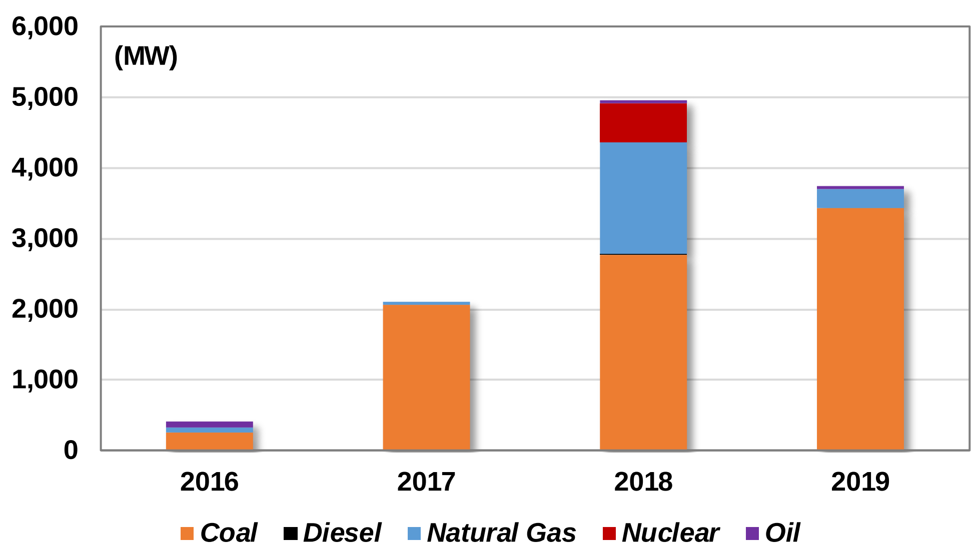

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Table 25: New York Unit-Specific Fossil Retirements, 2016 – 2019 (YTD)

Plant Name	Fuel Type	MW (Nameplate)	Retirement Date	Age of Unit at Retirement	State	Zone
Perryman (Unit 2)	Oil	51	Feb-16	43	MD	BGE
Dale (Unit 3)	Coal	81	Apr-16	58	KY	EKPC
Dale (Unit 4)	Coal	81	Apr-16	55	KY	EKPC
Avon Lake (Unit 7)	Coal	95	Apr-16	55	KY	ATSI
B.L. England Diesels (IC1, IC2, IC3, IC4)	Oil	8	May-16	54	NJ	AECO
Riverside (Unit 4)	Natural Gas	76	Jun-16	64	MD	BGE
Harrisburg 4 CT	Oil	14	Nov-16	49	PA	PPL
Roanoke Valley I	Coal	165	Mar-17	23	NC	23
Roanoke Valley II	Coal	44	Mar-17	22	NC	22
McKee (Units 1 and 2)	Natural Gas	34	May-17	55	DE	DPL
Hudson (Unit 2)	Coal	620	Jun-17	48	NJ	PSEG
Mercer (Units 1 and 2)	Coal	632	Jun-17	56	NJ	PSEG
J.M. Stuart (Unit 1)	Coal	610	Sep-17	46	OH	DAY
B.L. England (Unit 3)	Coal	176	Feb-18	43	NJ	AECO
Brunner Island Diesels	Diesel	8	Feb-18	50	PA	PPL
Bellemeade (Units 1-3)	Natural Gas	330	Apr-18	22	VA	DOM
Bremo (Unit 3)	Natural Gas	69	Apr-18	67	VA	DOM
Bremo (Unit 4)	Natural Gas	185	Apr-18	59	VA	DOM
Buggs Island, Mecklenburg (Units 1 & 2)	Coal	140	Apr-18	25	VA	DOM
Bayonne Cogen	Natural Gas	192	Jun-18	29	NJ	PSEG
J.M. Stuart (Unit 2)	Coal	610	Jun-18	47	OH	DAY
J.M. Stuart (Unit 3)	Coal	214	Jun-18	46	OH	DAY
J.M. Stuart (Unit 4)	Coal	214	Jun-18	44	OH	DAY
J.M. Stuart (Diesels 1-4)	Oil	11	Jun-18	48	OH	DAY
Killen Station (Unit 2)	Coal	661	Jun-18	36	OH	DAY
Killen CT	Oil	29	Jun-18	36	OH	DAY
Crane (Unit 1)	Coal	190	Jun-18	56	MD	BGE
Crane (Unit 2)	Coal	209	Jun-18	55	MD	BGE
Crane GT1	Oil	16	Jun-18	50	MD	BGE
Sewaren (Units 1 & 2)	Natural Gas	218	Jun-18	69	NJ	PSEG
Sewaren (Unit 3)	Natural Gas	108	Jun-18	68	NJ	PSEG
Sewaren (Unit 4)	Natural Gas	127	Jun-18	66	NJ	PSEG
Spruance NUG (Unit 2)	Coal	57	Jul-18	31	VA	DOM
Oyster Creek	Nuclear	550	Sep-18	48	NJ	JCPL
Northeastern Power Cogeneration Facility	Waste Coal	59	Oct-18	29	PA	PPL
Chesterfield (Unit 3)	Coal	113	Dec-18	66	VA	DOM
Chesterfield (Unit 4)	Coal	188	Dec-18	58	VA	DOM
Possum Point (Unit 3)	Natural Gas	114	Dec-18	63	VA	DOM
Possum Point (Unit 4)	Natural Gas	239	Dec-18	56	VA	DOM
Yorktown (Unit 1)	Coal	188	Mar-19	61	VA	DOM
Yorktown (Unit 2)	Coal	188	Mar-19	60	VA	DOM
Bruce Mansfield (Unit 1)	Coal	914	Feb-19	42	PA	PPL
Bruce Mansfield (Unit 2)	Coal	914	Feb-19	41	PA	PPL
Montour (Unit 11)	Coal	17	Feb-19	45	PA	PPL
Riverside (Unit GT7)	Oil	25	Mar-19	48	MD	BGE
B.L. England (Unit 2)	Coal	163	May-19	54	NJ	AECO
Chesapeake (GT2)	Oil	16	May-19	50	VA	DOM
Hopewell James River Cogen (Units 1 & 2)	Natural Gas	115	Jun-19	31	VA	DOM
Conesville (Unit 5)	Coal	444	Jun-19	42	OH	AEP
Conesville (Unit 6)	Coal	444	Jun-19	41	OH	AEP
MH50 Marcus Hook Cogen	Natural Gas	51	Jun-19	31	PA	PECO
Elmer Smith (Unit 1); Pseudo-tied MISO to PJ	Coal	163	Jun-19	55	KY	3O (Big Rive
Gould Street Unit 3	Natural Gas	104	Jun-19	66	MD	BGE
Total Retired (2016 - 2019 YTD)		***11,279***				
Total Coal Retired (2016 -2019 YTD)		**8,533**				
Total Natural Gas Retired (2016 -2019 YTD)		**170**				
Total Oil Retired (2016 -2019 YTD)		**1,960**				
Total Nuclear Retired (2016 - 2019 YTD)		**550**				
Total Other Retired (2016 - 2019 YTD)		**67**				

Figure 38 and Figure 39 show PJM's generation mix (GWh and installed capacity) each year between 2010 and 2018. The share of coal-fired generation in PJM has decreased sharply from 54 percent in 2010 to 28 percent in 2018. Over the same period, natural gas generation increased significantly from 11 percent in 2010 to 31 percent in 2018. The share of renewable generation has increased from two percent in 2010 to four percent in 2018, but still remains a relatively small portion of the PJM generation mix.

Figure 39: PJM's Generation Mix, GWh

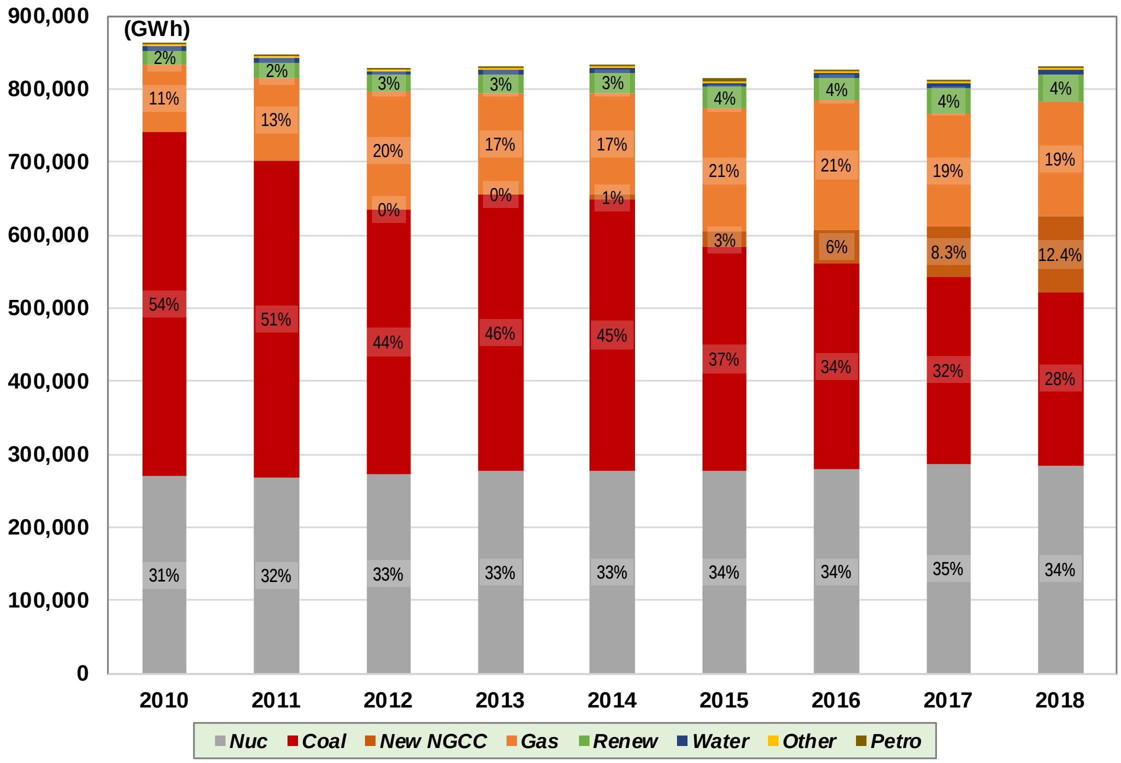
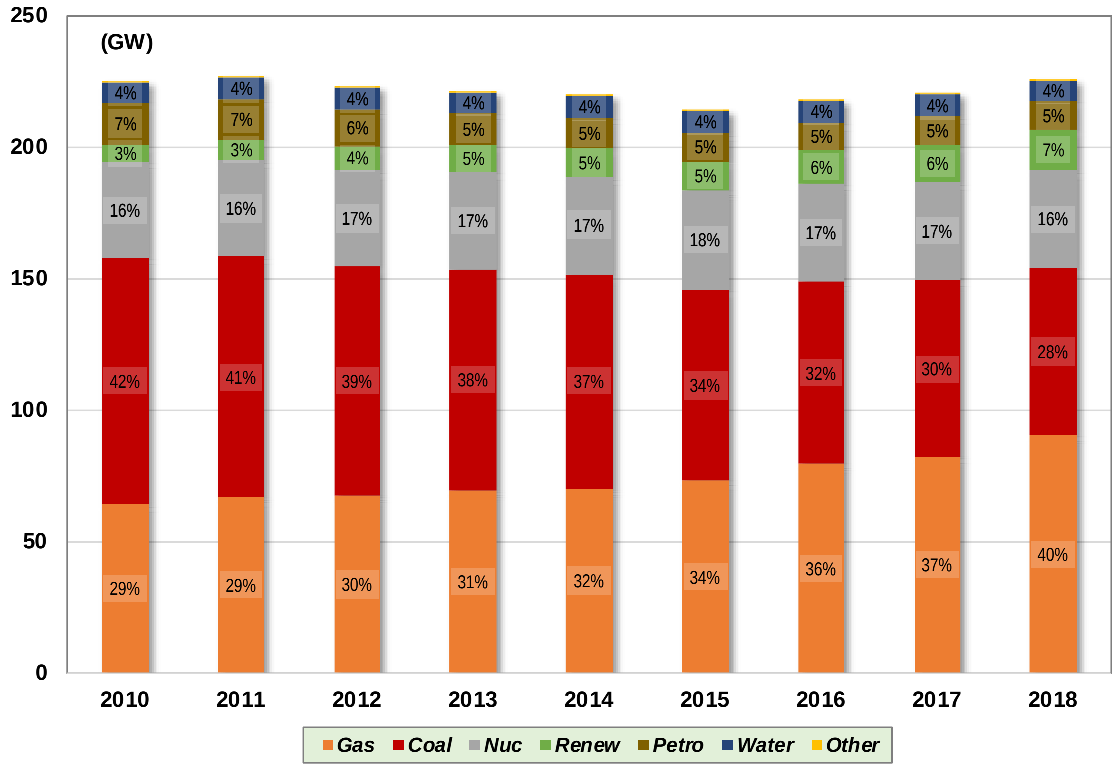


Figure 40: PJM's Installed Capacity, MW



Future Retirements

Table 28 below shows ESAI's expectations for future unit retirements in PJM (base case assumptions), and the tables that follow identify slated, at-risk and announced retirements. Over 12,000 MW of capacity is included in ESAI's base case retirement assumptions, and there is significant additional capacity that is at-risk, but not currently in ESAI's base case. Specifically, ESAI's base case assumes that all existing nuclear units in PJM will continue to operate, except for the recently retired Three Mile Island plant. Continued operation of many of the nuclear units will require subsidies, as a substantial portion of the nuclear fleet has failed to clear in recent BRAs. If the new capacity market rules for PJM implemented following a FERC decision in the on-going MOPR docket do not allow a carve-out provision for subsidized resources, or do so in a way that increases the cost of providing the financial support needed to maintain the nuclear fleet, retirement of more nuclear plants is likely.

Additionally, as discussed below, ESAI's base case includes significant new gas-fired capacity clearing in the next BRA for 2022/23, but very little additional new non-renewable capacity in future auctions. Given ESAI's forecasts for energy and capacity prices, the all-in costs of additional new entry would not be supported. However, if such new entry were to occur, additional economic retirements would likely occur as a result. This scenario of more new entry displacing more existing at-risk capacity could occur if the cost of building new units is lower than ESAI has forecasted, the cost of maintaining existing resources is higher than ESAI has assumed, or relative gas and coal prices are more favorable to new gas-fired plants than under ESAI's base case assumptions.

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PJM ENERGY MARKET OUTLOOK

Overview

ESAI's forecast of power prices for the PJM regional hubs is shown in Figure 41 and Figure 42. The corresponding spark spreads are shown in Figure 43 and Figure 44. The forecast is shown for four hubs spanning PJM: Eastern Hub, Western Hub (PJMWH), AEP-Dayton Hub (AD Hub), and the Northern Illinois Hub (NI Hub). The spark spreads for each location are based on a proxy heat rate of 7,500 Btu/kWh and assumed gas pricing as follows:

- Eastern Hub: Transco Zone 6 Non-NY
- Western Hub: TETCO M3
- AD Hub: Dominion South Point
- NI Hub: Chicago Citygate

The ESAI base case forecast is driven largely by natural gas and coal prices. Implied market heat rates across PJM are relatively constant over the forecast horizon. LMPs follow the slight escalation reflected in the gas price forecast. Across the PJM hubs, ESAI forecasts a small premium at the AEP-Dayton hub over Western Hub. Forward market energy prices, on the other hand, show Western Hub slightly above the AEP-Dayton hub on an annual average basis, but AEP-Dayton above Western Hub in the non-winter months. The winter premium for Western Hub in the forward market is due to winter gas price premiums for TETCO M3 and Transco Zone 6 Non-NY that are reflected in forward gas prices. ESAI's fundamental gas price forecast includes much lower winter basis for these gas hubs than is reflected in the forward market. As a result, winter LMP premiums for Western Hub over the AEP-Dayton hub are much lower in the ESAI forecast, resulting in annual average LMPs for Western Hub slightly below AEP-Dayton.

As discussed below, the 2019 PJM Load Forecast Report used as the basis for ESAI's forecast includes low, but positive long-term growth in demand. This increase in demand supports moderate increases in spark spreads over time across the PJM hubs, with the exception of the AEP-Dayton hub. The spark spreads for the AEP Dayton hub decline with expected new entry of gas-fired generation through 2023, then escalate slightly for the duration of the forecast.

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A ‘second wave’ of LNG plants is now under active development, seeking to take advantage of natural gas cost structures that are lower than were available four to five years ago for the first wave plants. However, while supply side economics are more favorable, the global appetite for commitments to incremental supply is subsiding for now and thus obtaining offtake commitments is becoming more competitive. This is a result of the large number of contracts concluded with first wave U.S. LNG facilities as well as other new facilities in Russia, Australia, Argentina and Indonesia. However, global LNG demand growth is all but certain as coal and nuclear generation are being phased out in many countries and energy growth in the emerging markets outpaces that of U.S. and Europe. Although the global market is somewhat oversupplied at present, meeting global demand growth will require new liquefaction capacity by 2024.

Second wave facilities that can capture long term contracts for their exports are highly likely to move forward. U.S. producers are ready and willing to produce the gas at favorable prices, therefore the supply side of the LNG export equation is relatively straightforward; except for the fact that pipeline transportation to these facilities is getting tight. So while securing supply from producers is readily attainable, securing transportation to a specific facility can present challenges. On the demand side, buyers in the global marketplace understand that U.S. natural gas is cheap and that there are significantly less buyers for incremental long-term supplies at this time. As a result, margins are getting squeezed as sellers from potential new LNG export facilities chase a limited pool of buyers. Nonetheless, contracts that support the construction of facilities that cost $4-5 billion, or more, are highly lucrative even if returns are slightly lower than optimal, particularly if there is no risk between the purchase contracts for feed gas and the sales contracts for LNG exports.

The total capacity of U.S. second wave plants under active development is over 30 Bcf/d and most are targeting completion in 2024 or 2025, although several have earlier target dates. Using an estimated probability of completion of 20 percent (typical for power generation queues), the second wave could generate another 6 Bcf/d of demand by 2026. However, a reasonable range of expectation would be for an increase of 6-10 Bcf/d from new second wave U.S.-based facilities based on current commitments that already total close to 8 Bcf/d.

Despite a much smaller gas production base, Canadian developers are actively pursuing LNG export projects. While the windows of opportunity are much smaller in Canada, total development is roughly equal to the U.S. second wave with over 30 Bcf/d of projects in active development. Total development would be expected to be in the 2-4 Bcf/d range, leaving an expectation that only about 10 percent of proposed projects would move forward.

LNG EXPORTS ACCELERATE IN 2019, MORE FIRST WAVE TO COME IN 2020/21

In January 2016, Cheniere commenced commercial operations with Train 1 at the Sabine Pass facility. Train 2 came on line in July, Train 3 in January 2017 and Train 4 in October 2017. Each train has a capacity of 0.7 Bcf/d resulting in LNG export capacity of 2.8 Bcf/d with the completion of Train 4. As shown below in Figure 58 and Table 46, Cove Point was the next LNG export facility to come online with its first deliveries in March 2018.

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Figure 60: U.S. LNG Export Capacity Growth & Actual Exports

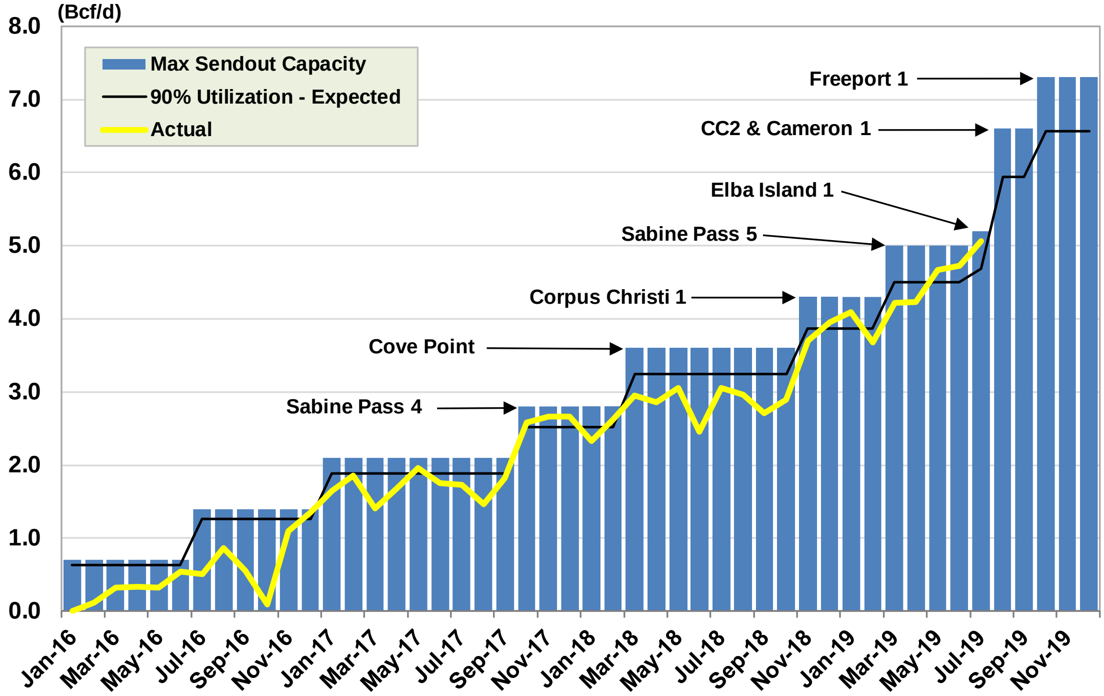

Table 41: U.S. LNG Export Facilities – First Wave

"FIRST WAVE BUILDOUT" Project Name	*Location*	*Total Capacity (Bcf/d)*	*Completion Date*	*Status*
Cheniere - Sabine Pass LNG	Sabine, LA	***3.50***		
Train 1		0.70	Jan-16	Completed
Train 2		0.70	Jul-16	Completed
Train 3		0.70	Jan-17	Completed
Train 4		0.70	Aug-17	Completed
Train 5		0.70	Mar-19	Completed
Dominion - Cove Point LNG	Cove Point, MD	***0.75***		
Train 1		0.75	Mar-18	Completed
Sempra - Cameron LNG	Hackberry, LA	***2.10***		
Train 1		0.70	Aug-19	Completed
Train 2		0.70	Mar-20	U/C
Train 3		0.70	Jul-20	U/C
Southern LNG	Elba Island, GA	***0.375***		
Phase 1 (50%)		0.19	Jul-19	Completed
Phase 2 (50%)		0.19	Apr-20	U/C
Freeport LNG	Freeport, TX	***2.10***		
Train 1		0.70	Oct-19	Completed
Train 2		0.70	Feb-20	U/C
Train 3		0.70	Jun-20	U/C
Cheniere – Corpus Christi LNG	Corpus Christi, TX	***1.40***		
Train 1		0.70	Nov-18	Completed
Train 2		0.70	Aug-19	Completed
Train 3		0.70	Sep-21	FEED
Total LNG Completed or Under Construction		***10.23***		

By the end of 2019, eleven trains will have been completed at six locations for a total capacity of 7.3 Bcf/d. Actual exports have growing in proportion to new capacity as shown in Figure 58. In 2016 and 2017, average utilization at Sabine Pass was only 65 percent, which was partly due to ongoing startup issues. In 2018, utilization at operating facilities increased to 83 percent and in 2019, utilization has been much higher at almost 91 percent. ESAI's expectation is for utilization to average near 90 percent over the long term.

Table 46 provides details of completed facilities and projects under construction. Note that the third train at Cheniere's Corpus Christi facility is in Front End Engineering and Design (FEED) and has not started construction.

Feed Gas Demand Considerations

In terms of projecting natural gas demand as feed for LNG export facilities, a good rule of thumb is to use the total expected capacity as representative to gas demand. This assumes an average utilization of 90 percent. Although utilization is 10 percent below maximum, the liquification process uses about 10 percent of the feedgas to support high energy consuming operations such as the compression required to liquify the gas. Therefore, the additional 10 percent of feedgas required above actual exports exactly offsets the lower utilization. The result is that export capacity is a good proxy for total demand expectations, assuming utilization at 90 percent.

SECOND WAVE OF LNG PROJECTS GAINING MOMENTUM

Given the success of first wave projects and the demonstrated availability of feed gas supply at attractive prices, second wave projects are gaining momentum (see Table 47). As noted earlier, there will be significant competition to secure the customer offtake agreements that will be needed to obtain financial commitments. As a general rule, most project developers will look to secure commitments for at least 75 percent of their capacity before moving forward to Financial Investment Decisions (FID).

Early stage development includes clearing the permitting hurdles, many of which are included in the status column in Table 47. The first step in the permitting process is a FERC pre-filing of all the relevant documentation needed for the environmental assessment. Upon receipt of a positive Environmental Impact Statement (FEIS), the process moves towards FERC approval of the project. If the project is offshore (floating terminal) then it must also receive Coast Guard (MARAD) approvals. Table 47 below provides the status of each project whether in pre-filing, achieved FEIS, or achieved FERC approval. Having achieved FERC approval, projects will need financial commitments from their sponsors with a final investment decision or FID.

As indicated in Table 47, four second wave projects have reached FID to date. The first is for Train 6 at Sabine Pass with an expected completion date of late 2023. Other projects that have reached FID include Exxon/Mobil's Golden Pass, Eagle LNG, and Venture Global's Calcasieu Pass. The Driftwood project, sponsored by Tellurian, has received commitments

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